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

April 1, 2021

Public Utility Commission, Oregon
201 High St. SE, Suite 100
Salem, OR 97301

RE: Avista Utilities 2021 Natural Gas Integrated Resource Plan (IRP)

Filing Center:

Avista Corporation d/b/a/ Avista Utilities, hereby submits for filing with the Commission its final 2021 Natural Gas Integrated Resource Plan (IRP). Supporting documents can be found on our website at https://myavista.com/about-us/integrated-resource-planning.

If you have any questions regarding this filing, please contact Tom Pardee at 509-495-2159.

Sincerely,

/s/ Shawn Bonfield

Shawn Bonfield
Sr. Manager of Regulatory Strategy & Policy
509-434-6502
shawn.bonfield@avistacorp.com

2021 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

Primary Natural Gas IRP Team

Name	Title	Contribution
Tom Pardee	Natural Gas Planning Manager	IRP Core Team
Michael Brutocao	Natural Gas Analyst	IRP Core Team
Terrence Browne	Sr Gas Planning Engr	Gas Engineering
Grant Forsyth	Chief Economist	Load Forecast
Ryan Finesilver	Mgr. of Energy Efficiency, Planning & Analysis	Energy Efficiency

Natural Gas IRP Contributors

Name	Title	Contribution
Jody Morehouse	Director of Gas Supply	Gas Supply
John Lyons	Sr. Policy Analyst	Power Supply
Shawn Bonfield	Sr. Manager of Regulatory Policy	Regulatory
James Gall	IRP Manager	Power Supply
Justin Dorr	Natural Gas Resource Manager	Gas Supply
Michael Whitby	Mgr Renewable Natural Gas Prog	Gas Supply
Annie Gannon	Communications Manager	Communications

TABLE OF CONTENTS

Executive Summary

Avista's 2021 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio to meet customer demand requirements over the next 20 years. Price volatility, or uncertainty, in the Pacific Northwest region, due to fully subscribed transportation has increased in recent years. As weather events throughout the United States have continued to rise, the risk to energy providers, utilities and consumers to these unknown events are also on the rise. Some recent examples include freezing temperatures in Texas and wildfire risk in California. Both events created the loss of a supply source and potentially dangerous circumstances for its customers. This IRP's primary focus is to meet our customers' needs under peak weather conditions, while evaluating our customer needs under normal or average conditions. The formal exercise of bringing together customer demand forecasts with comprehensive analyses of resource options, including supply-side resources and demand-side measures, is valuable to Avista, its customers, regulatory agencies, and other stakeholders for long-range planning.

Benefits of Natural Gas

For Customers: Natural gas is affordable, resilient, and reliable.

For Society: Natural gas is an abundant energy resource produced in North America, which helps lessen our dependency on foreign oil.

For Innovation: Natural gas can play a supporting role in expanding the use of renewable energy sources.

For Environment: Natural gas is the cleanest burning fossil fuel, so it helps reduce smog and greenhouse gas emissions.

For Economy: Natural gas provides nearly a fourth of North America's energy today.

IRP Process and Stakeholder Involvement

The IRP is a coordinated effort by several Avista departments with input from our Technical Advisory Committee (TAC), which includes Commission Staff, peer utilities, customers, and other stakeholders. The TAC is a vital component of our IRP process that provides a forum for discussing multiple perspectives, identifies issues and risks, and improves analytical planning methods. TAC topics include natural gas demand forecasts, price forecasts, demand-side management (DSM), supply-side resources, modeling tools, distribution planning, and policy issues. The IRP process produces a resource portfolio designed to serve our customers' natural gas needs while balancing cost and risk.

Planning Environment

A long-term resource plan addresses the uncertainties inherent in any planning exercise. Natural gas is an abundant North American resource with expectations for ample supplies for many decades because of continuing technological advancements in extraction. The use of natural gas in liquefied natural gas (LNG) exports, power generation and exports to Mexico will continue to add demand for natural gas. In addition to fossil fuel natural gas, renewable natural gas and hydrogen are considered vital toward any carbon reduction goal, but currently not as readily available. All future scenarios carry risk based on unknown prices and expected resources. To account for risk associated with these uncertainties, we model various sensitivities and scenarios to account for the risks in supply and demand.

Demand Forecasts

Avista defines eleven distinct demand areas in this IRP structured around the pipeline transportation and storage resources that serve them. Demand areas include Avista's service territories (Washington; Idaho; Medford/Roseburg, Oregon; Klamath Falls, Oregon and La Grande, Oregon) and then disaggregated by the pipelines serving them. The Washington, Medford and Idaho service territories include areas served only by Northwest Pipeline (NWP), only by Gas Transmission Northwest (GTN), and by both pipelines.

Weather, customer growth and use-per-customer are the most significant demand influencing factors. Other demand influencing factors include population, employment, age and income demographics, construction levels, conservation technology, new uses, and use-per-customer trends.

Customers may adjust consumption in response to price, so Avista analyzed factors that could influence natural gas prices and demand through price elasticity. These factors include:

- **Supply:** shale gas, industrial use, and exports to Mexico and of LNG.
- **Infrastructure:** regional pipeline projects, national pipeline projects, and storage.
- **Regulatory:** subsidies, market transparency/speculation, and carbon regulation.

- **Other:** drilling innovations, thermal generation and energy correlations (i.e. oil/gas, coal/gas, and liquids/gas).

Avista developed a historical-based reference case and conducted sensitivity analysis on key demand drivers by varying assumptions to understand how demand changes. Using this information, and incorporating input from the TAC, Avista created alternate demand scenarios for detailed analysis. Table 1 summarizes these demand scenarios, which represent a broad range of potential scenarios for planning purposes. The Average Case represents Avista's demand forecast for normal planning purposes. The Expected Case is the most likely scenario for peak day planning purposes.

Table 1: Demand Scenarios

2021 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Carbon Reduction

The IRP process defines the methodology for the development of two primary types of demand forecasts – annual average daily and peak day. The annual average daily demand forecast is useful for preparing revenue budgets, developing natural gas procurement plans, and preparing purchased gas adjustment filings. Forecasts of peak day demand are critical for determining the adequacy of existing resources or the timing for new resource acquisitions to meet our customers' natural gas needs in extreme weather conditions. Table 2 shows the Average and Expected Case demand forecasts:

Table 2: Annual Average and Peak Day Demand Cases (Dth/day)

Year	Annual Average Daily Demand	Peak Day Demand	Non-coincidental Peak Day Demand
2021	95,126	363,586	349,210
2040	102,054	407,216	388,615

Annual Average Daily Demand

Expected average day, system-wide core demand increases from an average of 95,126 dekatherms per day (Dth/day) in 2021 to 102,054 Dth/day in 2040. These numbers are net of projected conservation savings from DSM programs. Appendix 3.1 shows gross demand, conservation savings and net demand.

Peak Day Demand

The peak day demand for the Washington, Idaho and La Grande service territories is modeled on and around February 28th of each year. For the southwestern Oregon service territories (Medford, Roseburg, Klamath Falls), the model assumes this event on and around December 20th of each year. Expected coincidental peak day, or the sum of demand from each territories modeled peak, the system-wide core demand increases from a peak of 363,586 Dth/day in 2021 to 407,216 Dth/day in 2040. Forecasted non-coincidental peak day demand, or the sum of demand from the highest single day including all forecasted territories, peaks at 349,210 Dth/day in 2021 and increases to 388,615 Dth/day in 2040. This is also net of projected conservation savings from DSM programs.

Figure 1 shows forecasted average daily demand for the five demand scenarios modeled over the IRP planning horizon.

Figure 1: Average Daily Demand (Net of DSM Savings)

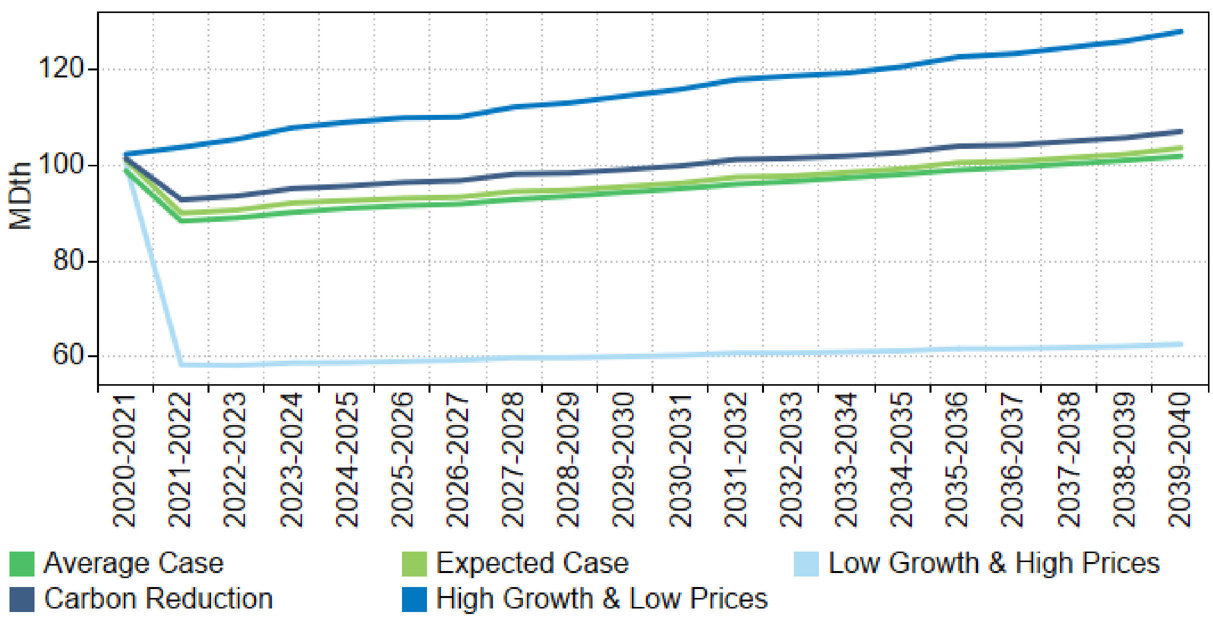
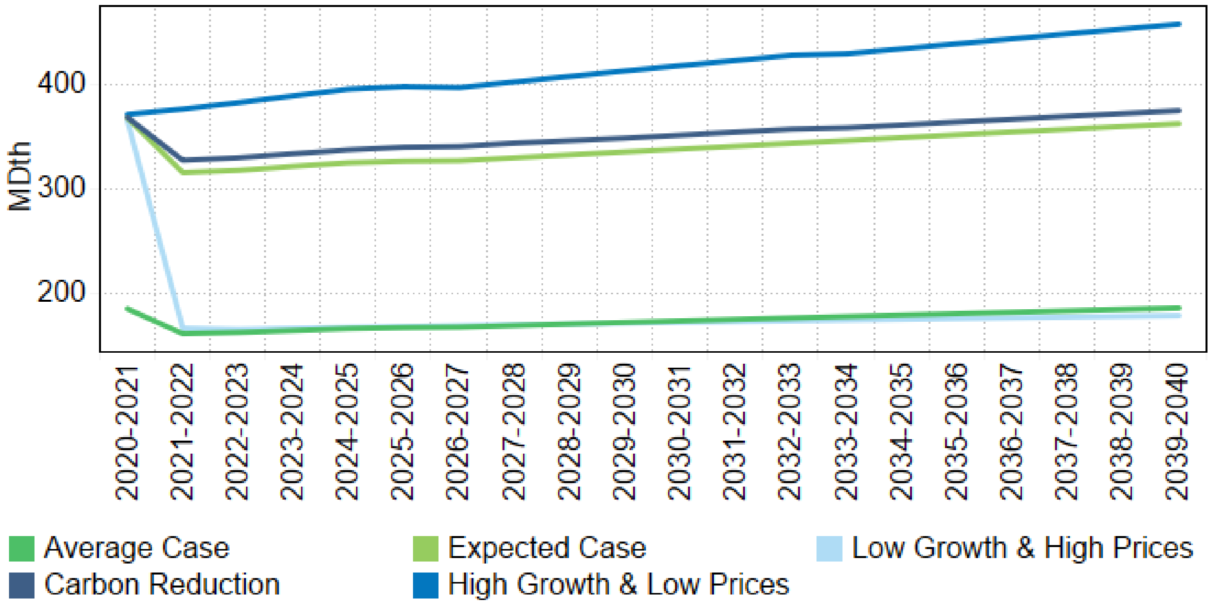


Figure 2 shows forecasted system-wide peak day demand for the five demand scenarios modeled over the IRP planning horizon.

Figure 2: Peak Day Demand Scenarios (Net of DSM Savings)



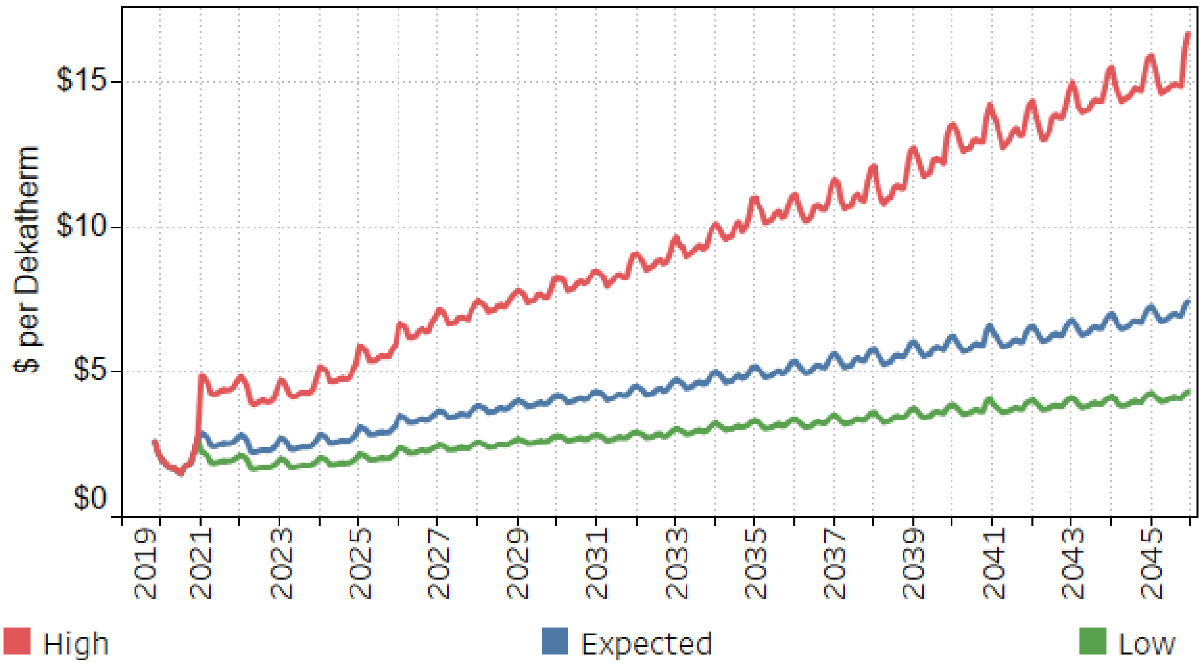
Natural Gas Price Forecasts

Natural gas prices are a fundamental component of integrated resource planning as the commodity price is a significant element to the total cost of a resource option. Price forecasts affect the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas also influences the consumption of natural gas by customers. A price elasticity adjustment to use-per-customer reflects customer responses to changing natural gas prices.

Avista expects carbon legislation at the state level through a cap and reduce (Oregon) or social cost of carbon tax mechanism (Washington). Current IRP price forecasts include a considerably higher carbon adder in Oregon and Washington, but no carbon cost in Idaho. Avista analyzed three carbon sensitivities and their impact on demand forecasts to address the uncertainty about carbon legislation. These sensitivities were applied to all jurisdictions.

Avista combined forward prices with three fundamental price forecasts including a futures pricing strip in the near term to develop an expected price strip at the Henry Hub. A set of high and low price strips were developed based on the 95th and 25th percentile results of 1,000 simulated prices. These three price curves represent a reasonable range of pricing possibilities for this IRP analysis. The array of prices provides necessary variation for addressing uncertainty of future prices. Figure 3 depicts the price forecasts used in this IRP.

Figure 3: Low/Medium/High Henry Hub Forecasts (Nominal $/Dth)



Historical statistical analysis shows a long run consumption response to price changes. In order to model consumption response to these price curves, Avista utilized an expected elasticity response factor of -0.081 for every 10% of price movement, as found in our Medford/Roseburg service territory, and applied it under various scenarios and sensitivities. As this price response continues to have a near muted response, Avista will look for additional studies and methodologies to account for elasticity in future resource plans where applicable.

Existing and Potential Resources

Avista has a diversified portfolio of natural gas supply resources, including access to and contracts for the purchase of natural gas from several supply basins; owned and contracted storage providing supply source flexibility; and firm capacity rights on six pipelines. For potential resource additions, Avista considers incremental pipeline transportation, renewable natural gas, storage options, hydrogen, distribution enhancements, and various forms of LNG storage or service. Avista models aggregated conservation potential that reduces demand if the conservation programs are cost-effective over the planning horizon. The identification and incorporation of conservation savings into the SENDOUT® model utilizes projected natural gas prices and the estimated cost of alternative supply resources. The operational business planning process starts with IRP identified savings and ultimately determines the near-term program offerings. Avista actively promotes cost-effective DSM measures to our customers as one component of a comprehensive strategy to arrive at a mix of best cost/risk adjusted resources.

Resource Needs

In both the High Growth and Low-price and the Carbon Reduction scenarios a resource deficiency was observed. The High Growth and Low-Price scenario observed an energy shortage, or it requires additional assets of any kind to supply more energy. The Carbon Reduction scenario does not have an energy shortage, but rather a need for carbon neutral or carbon reducing resources in order to reduce the carbon intensity of its supply stream. Avista is not resource deficient within the Expected Case for the 20-year planning horizon. As further information on goals and legislation come into focus, Avista will integrate these guideposts into our Expected Case.

Figures 4 through 7 illustrate Avista's peak day demand by service territory for both the current and prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show the timing and extent of resource deficiencies, if any, for the Expected Case. Based on this information, Avista has time to carefully monitor, plan and analyze potential resource additions as described in the Ongoing Activities section of Chapter 9 – Action Plan. Any underutilized resources will be optimized to mitigate the costs incurred by customers until the resource is required to meet demand. This management of long and short term resources provides the flexibility to meet firm customer demand in a reliable and cost-effective manner as described in Supply Side Resources – Chapter 4.

Figure 4: Expected Case – WA & ID Existing Resources vs. Peak Day Demand (Net of DSM)

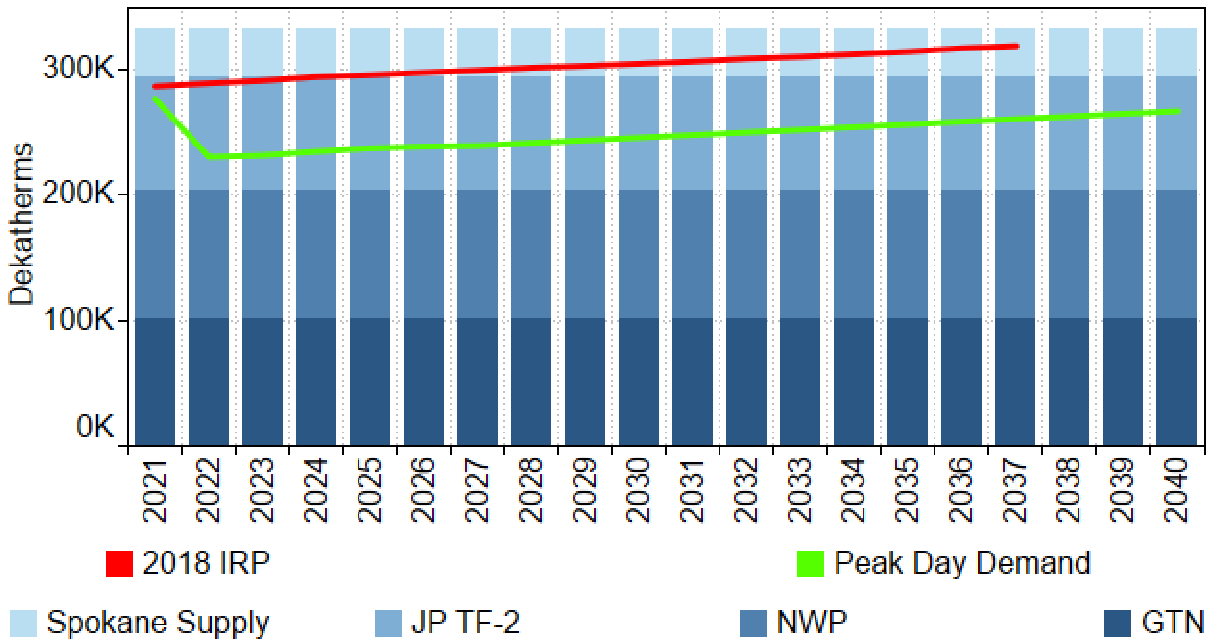


Figure 5: Expected Case – Medford/Roseburg Existing Resources vs. Peak Day Demand (Net of DSM)

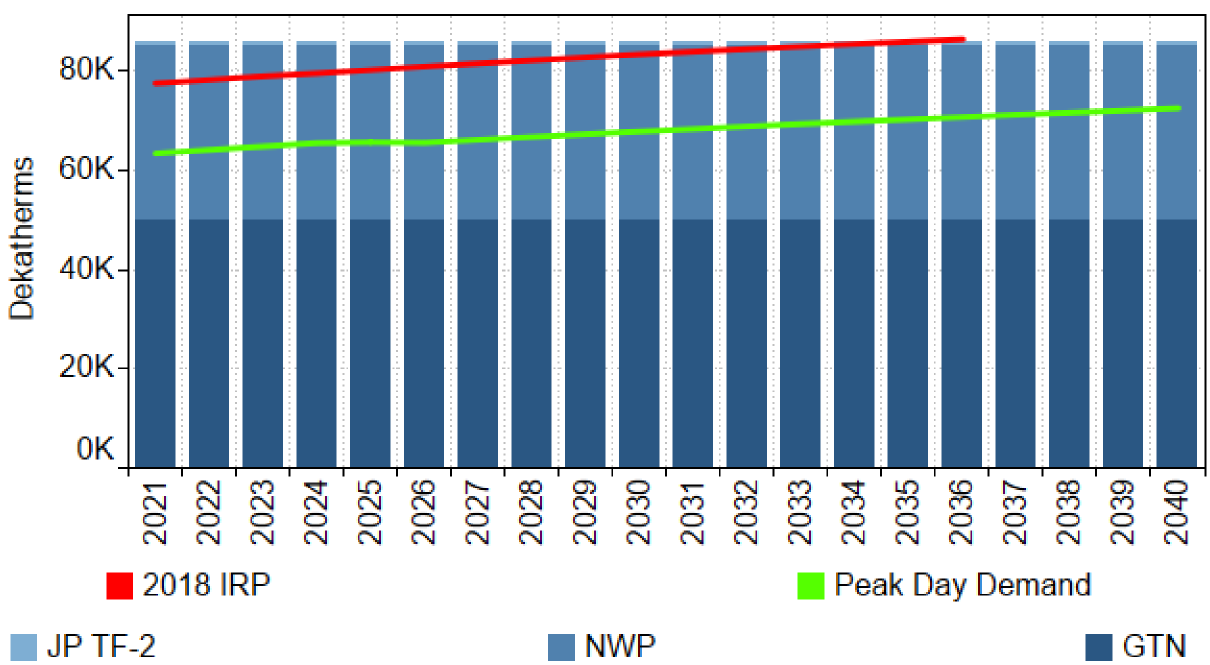


Figure 6: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand (Net of DSM)

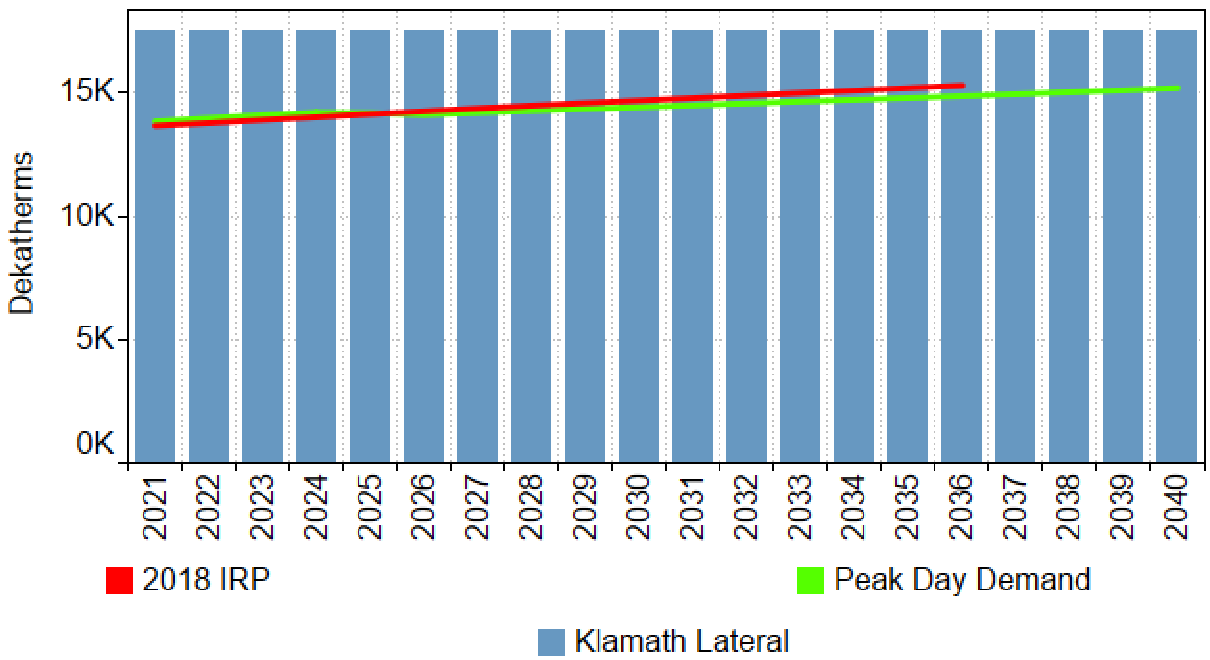


Figure 7: Expected Case – La Grande Existing Resources vs. Peak Day Demand (Net of DSM)

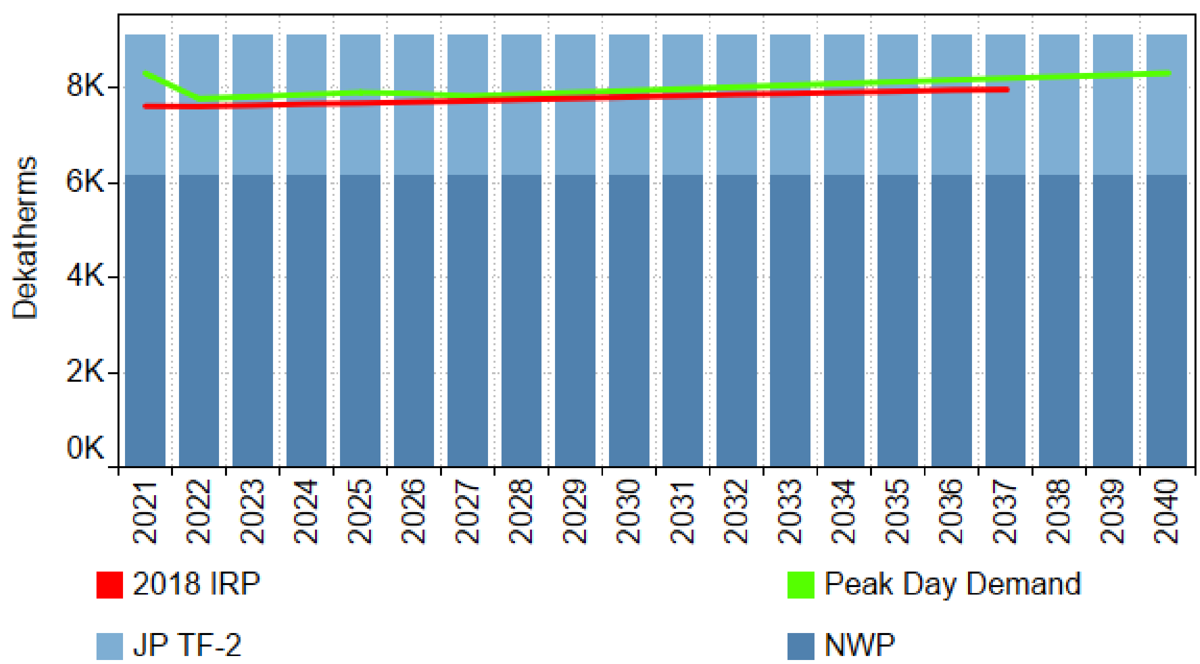
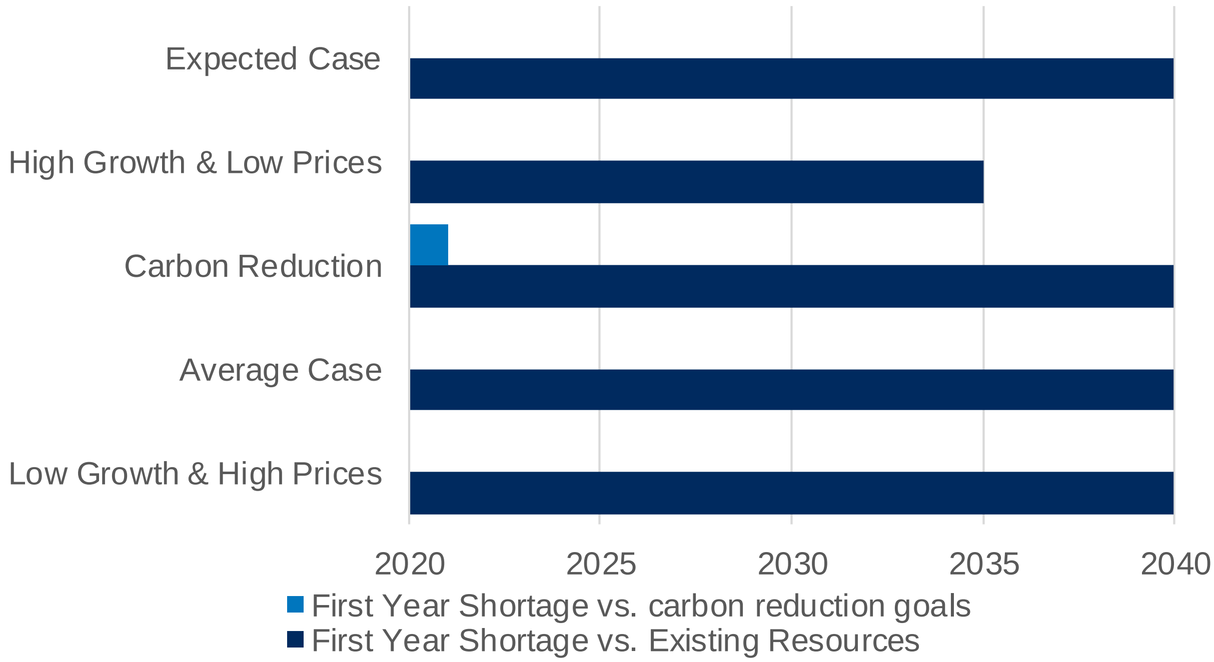
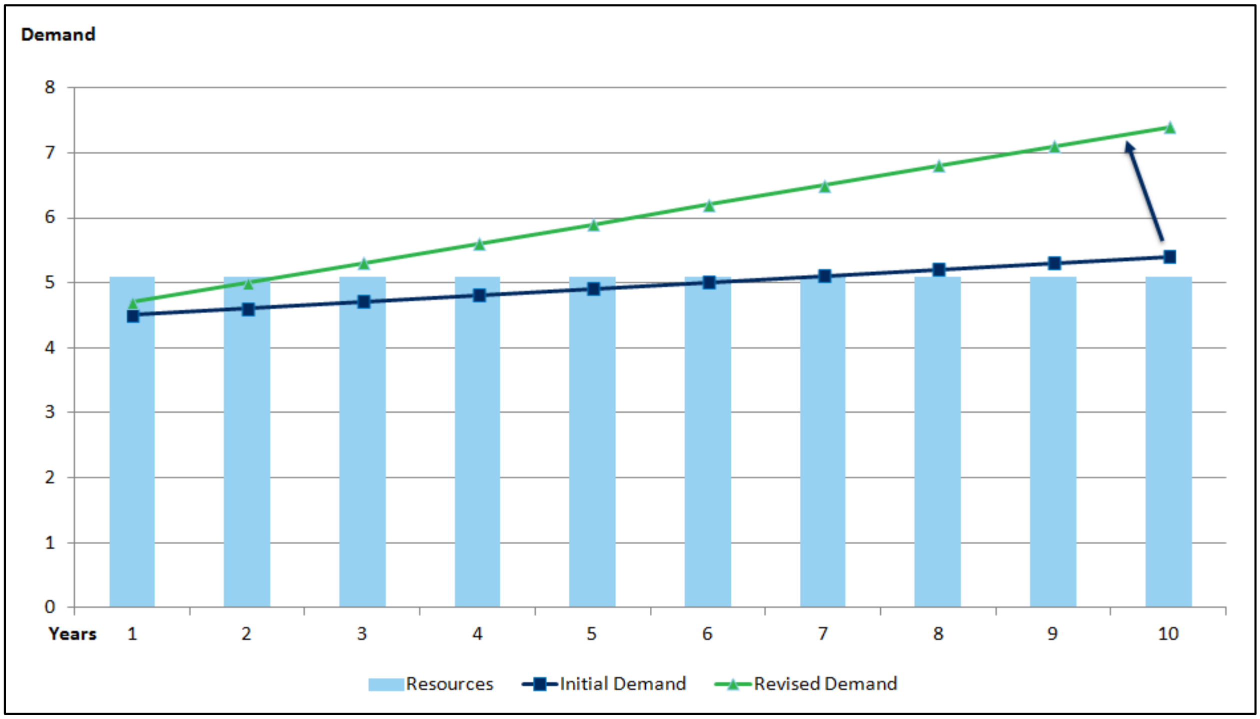


Figure 8: Scenario Comparisons of First Year Peak Demand Not Met with Existing Resources



A critical risk remains in the slope of forecasted demand growth, which although increasing continues to be almost flat in Avista's current projections. This outlook implies that existing resources will be sufficient within the planning horizon to meet demand. However, if demand growth accelerates, the steeper demand curve could quickly accelerate resource shortages by several years. Figure 9 conceptually illustrates this risk. In this hypothetical example, a resource shortage does not occur until year eight in the initial demand case. However, the shortage accelerates by five years under the revised demand case to year three. This "flat demand risk" requires close monitoring of accelerating demand, as well as careful evaluation of lead times to acquire the preferred incremental resource.

Figure 9: Hypothetical Flat Demand Risk Example



Issues and Challenges

Even with the planning, analysis, and conclusions reached in this IRP, there is still uncertainty requiring diligent monitoring of the following issues.

Demand Issues

Although the future customer growth trajectory in Avista's service territory has slightly decreased compared to the 2018 IRP, the need in considering a range of demand scenarios provides insight into how quickly resource needs can change if demand varies from the Expected Case.

With a robust supply forecast and continued low costs, there is increasing interest in using natural gas. Avista does not anticipate traditional residential and commercial customers will provide increased growth in demand. Power generation from natural gas is increasingly being used to back up solar and wind technology as well as replacing retired coal plants. In terms of North American demand, exports of LNG could consume 20 Bcf per day by 2030 and more than 30 Bcf per day by 2040. Although smaller in size, Mexico exports could increase from 5 Bcf per day in 2020 to over 8 Bcf per day in 2040. Most of these emerging markets will not be core customers of the LDC, but could affect regional natural gas infrastructure and natural gas pricing if an LNG export facility is built in the area.

Price Issues

Shale oil and gas drilling technology is adding an abundant amount of supply at low cost. This is primarily due to increasingly efficient drilling technology and the rapid advancement in understanding of drilling shale wells. In areas such as the eastern United States, shale production is so prolific the entire flow of gas on the pipeline infrastructure has changed and is now flowing out of the highest demand areas in the US. This supply also flows into Canada and across the U.S. which benefits Northwest consumers as the prices for Canadian gas have deep discounts as compared to the Henry Hub.

Action Plan

Avista's 2021-2022 Action Plan outlines activities for study, development and preparation for the 2023 IRP. The purpose of the Action Plan is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. The Action Plan identifies needed supply and demand side resources 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 ongoing planning processes (Chapter 9 – Action Plan).

Key ongoing components of the Action Plan include:

1. Further model carbon reduction
2. Investigate new resource plan modeling software and integrate Avista's system into software to run in parallel with Sendout
3. Model all requirements as directed in Executive Order 20-04
4. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.
5. Explore the feasibility of using projected future weather conditions in its design day methodology, rather than relying exclusively on historic data.
6. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high-pressure distribution line or city gate station 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.
    - Construction of gas infrastructure associated with growth
    - 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

Ongoing Activities
Meet regularly with Commission Staff to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.

Conclusion

A slightly lower customer growth level combined with an updated peak weather planning standard combine to create a lower overall peak day demand. Prices have a lower levelized price as compared to the 2018 IRP creating a slightly reduced amount of DSM. When combined, the need for additional supply side resources is pushed well into the future. By managing these assets through releases and optimization, Avista can help offset these costs while managing peak day demand need. A changing dynamic related to carbon emissions will continue to evolve future planning environments and any need for supply side resources. Regardless of policy, prices or demand, Avista will continue to properly plan to continue delivering safe, reliable, and economic natural gas service to our customers.

1: Introduction

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 NWP) to develop the Jackson Prairie natural gas underground storage facility in 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 361,000 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

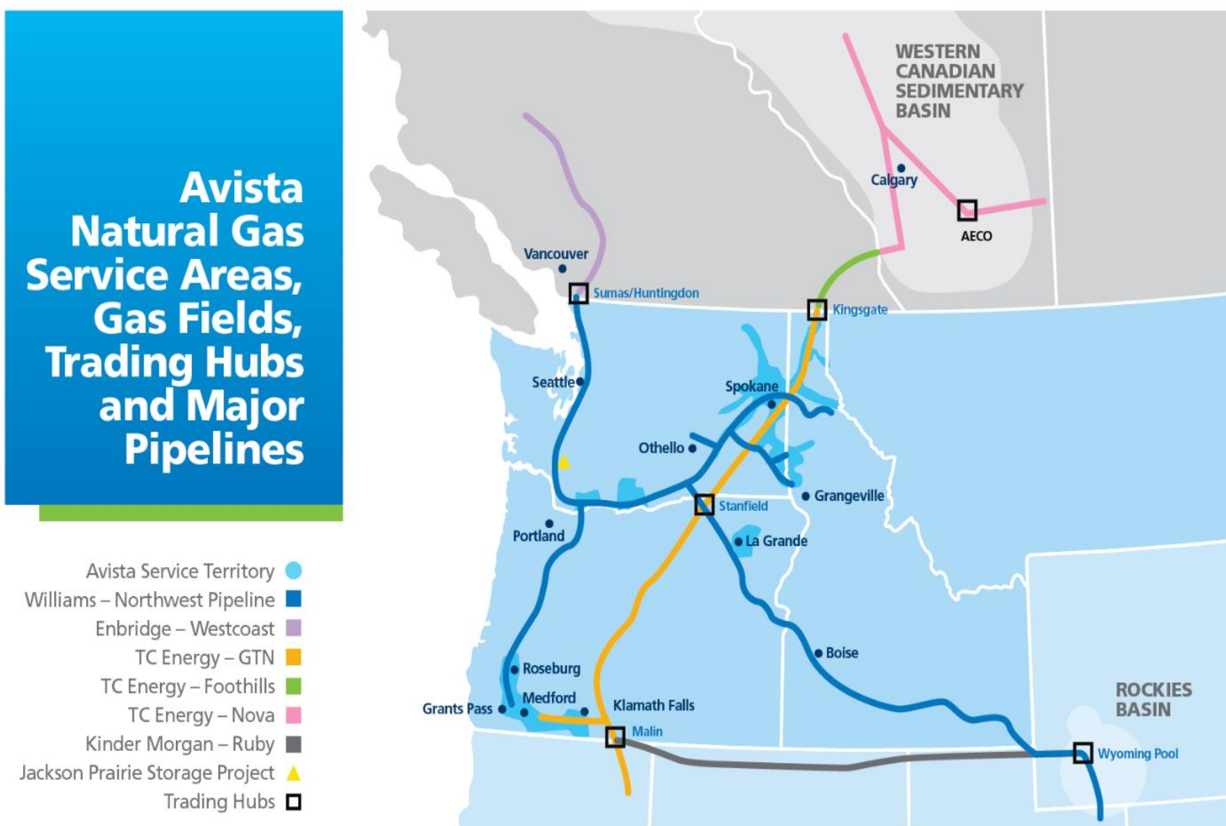
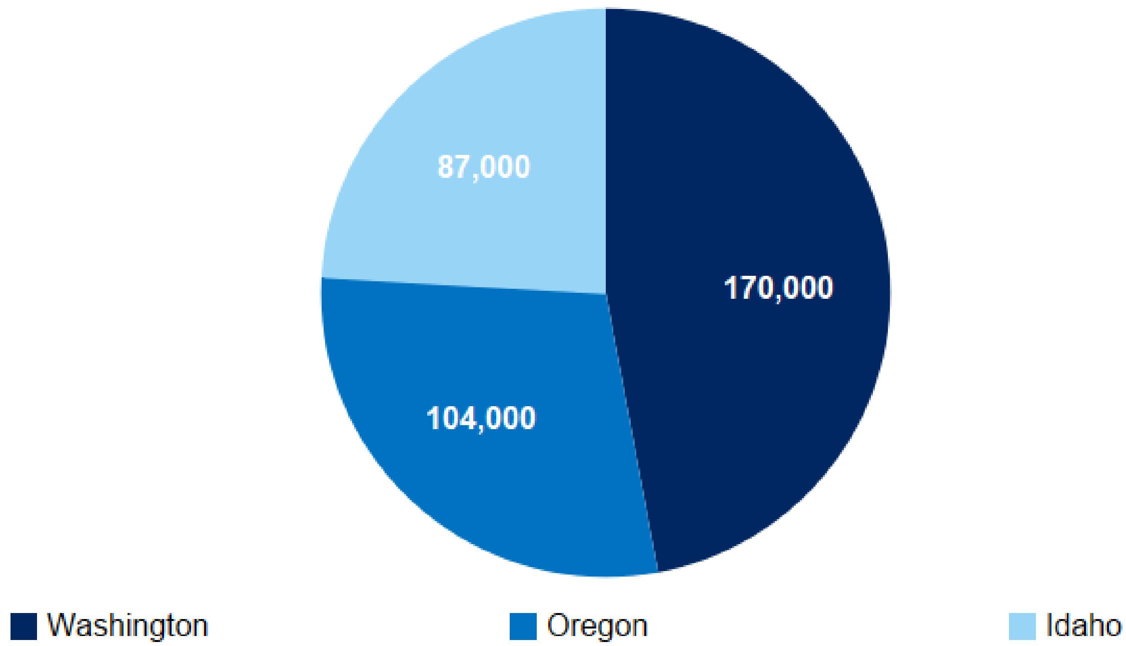


Figure 1.2: Avista's Natural Gas Customer Counts



Avista's natural gas operations covers 30,000 square miles in eastern Washington, northern Idaho and portions of southern and eastern Oregon, with a population of 1.6 million. The company 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 which is home to over 1,000,000 people. 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 523,000 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 points along interstate pipelines for distribution to over 257,000 customers.
- The South Division serves four counties in southern Oregon and one county in eastern Oregon. The combined population of these areas is over 514,000 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 by Avista in this division with a regional population of approximately 308,000. The South Division consists of about 15 miles of natural gas transmission main and 3,700 miles of distribution pipelines. Avista receives natural gas at more than 20 points along interstate pipelines and distributes it to more than 104,000 customers.

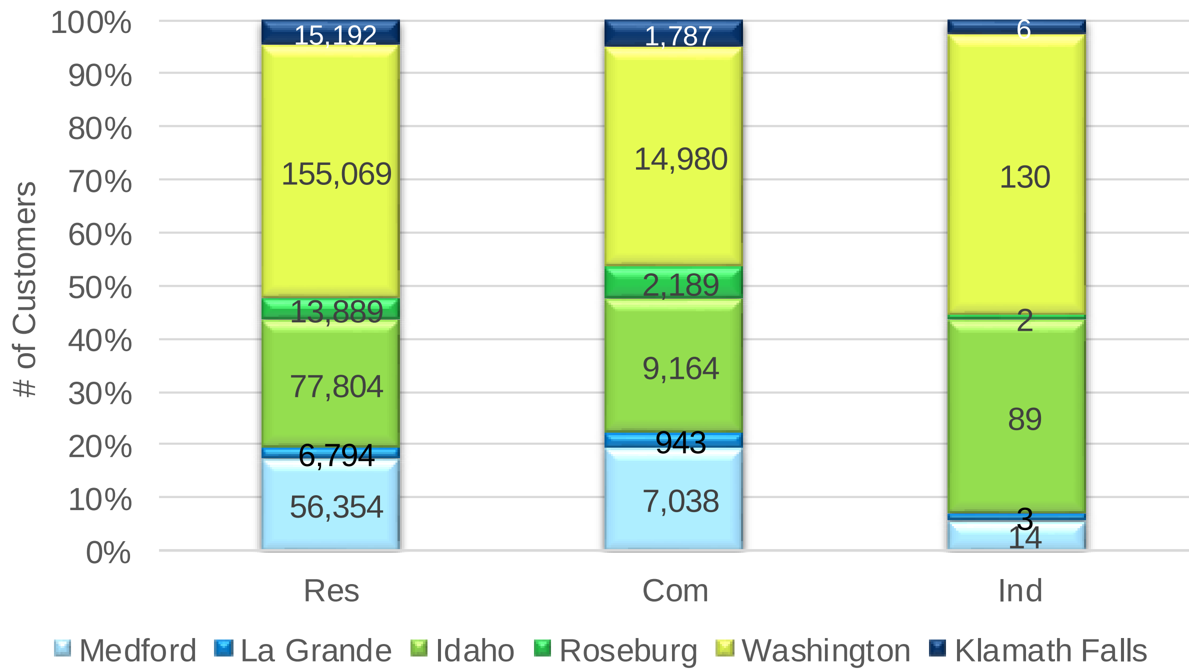
Customers

Avista provides natural gas services to both core and transportation-only customer classes. Core or retail customers purchase natural gas directly from Avista with delivery to their home or business 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 their business charging a distribution rate only. Avista can interrupt the delivery service when following the priority of service tariff. The long-term resource planning exercise excludes transportation-only customers because they purchase their own natural gas and utilize their own interstate pipeline transportation contracts. However, distribution planning includes these customers.

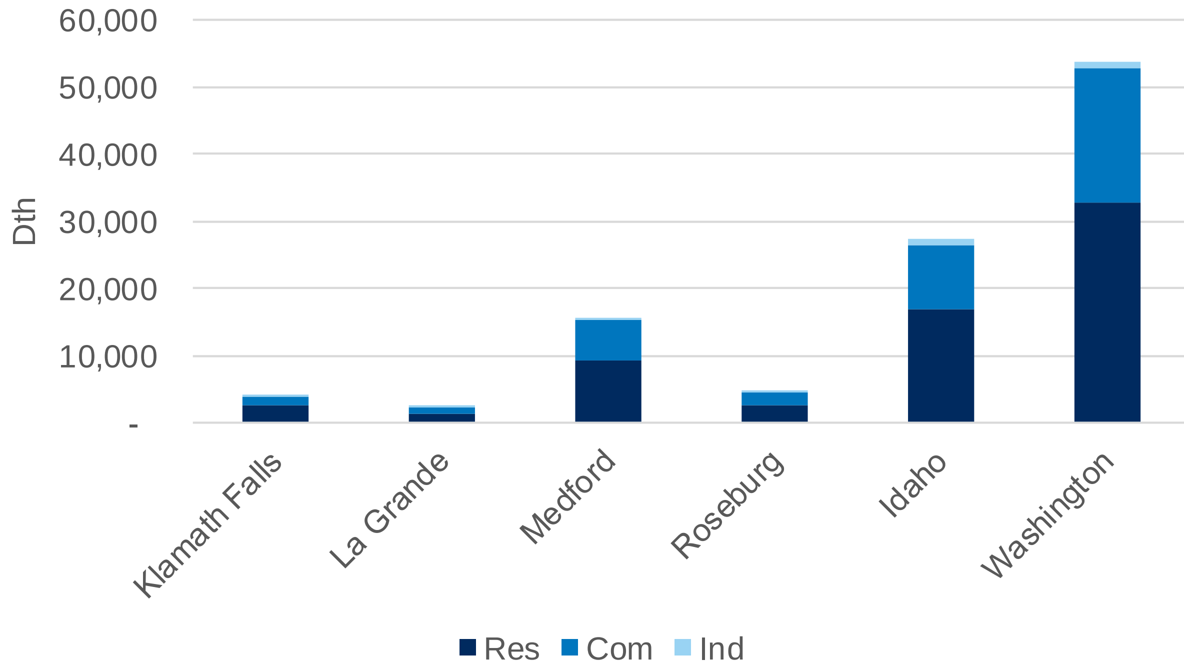
Avista's core or retail customers include residential, commercial and industrial categories. Most of Avista's customers are residential, followed by commercial and relatively few industrial accounts (Figure 1.3).

Figure 1.3: Firm Customer Mix



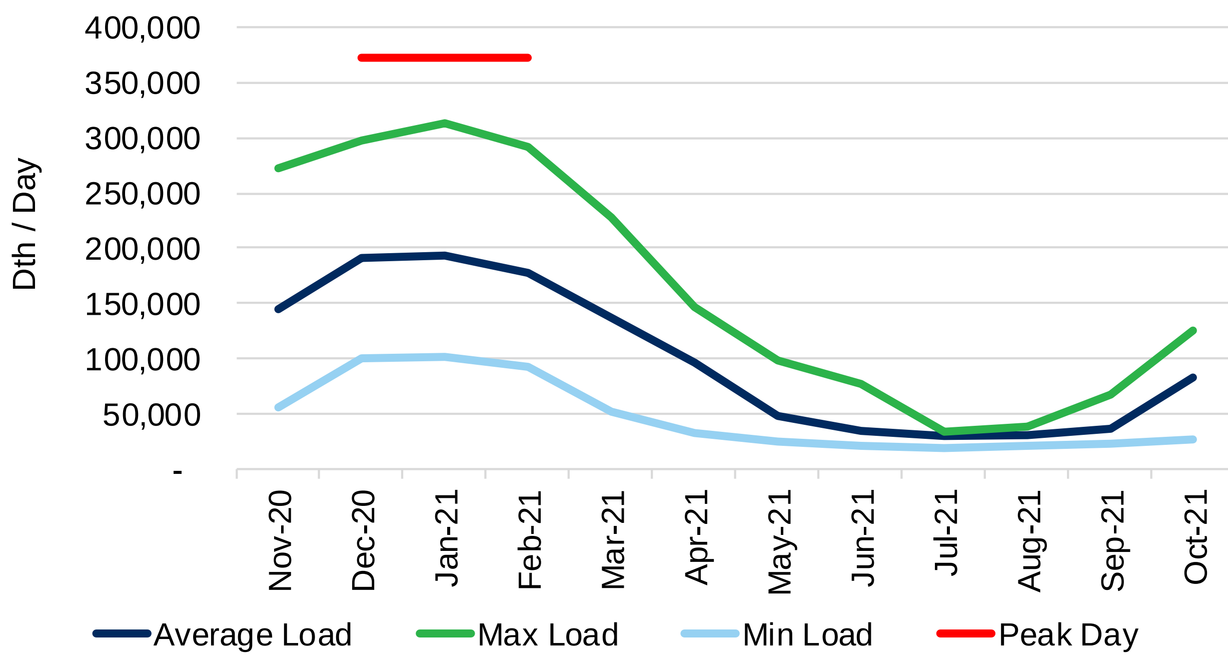
The customer mix is found mostly in the residential and commercial accounts on an annual volume basis (Figure 1.4). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in Avista's service territories are transportation-only customers.

Figure 1.4: 2019 Daily 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 that produce 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 that 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 average daily and peak-day demand delivery requirements over a 20-year planning horizon.

Purpose of the IRP

Avista's 2021 Natural Gas IRP:

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

Avista's IRP Process

The natural gas IRP process considers:

- Customer growth and usage;
- Weather planning standard;

- Conservation opportunities;
- Existing and potential supply-side resource options;
- Current and potential legislation/regulation;
- Risk; and
- Least cost mix of supply and conservation.

Public Participation

Avista's TAC members play a key role and have a significant impact in developing the IRP. TAC members included 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 four TAC meetings to facilitate stakeholder involvement in the 2021 IRP. The first meeting convened on June 17, 2020 and the last meeting occurred on November 18, 2020. All meetings were held virtually, via web meetings, due to the restrictions and guidelines around the COVID-19 pandemic. 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. TAC members received a draft of this IRP on January 4, 2021 for their review. Avista appreciates the time and effort TAC members contributed to the IRP process; they provided valuable input through their participation in the TAC process. 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	Idaho Conservation League
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	Alliance of Western Energy Consumers	

Preparation of the IRP is a coordinated endeavor by several departments within Avista with involvement and guidance from management. We are grateful for their efforts and contributions.

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 regulation. 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 cause Avista to determine that alternative resources are more cost effective than resources reviewed and selected in this IRP. Avista will continue to review and refine our understanding of resource options and will act to secure these risk-adjusted, least-cost options when appropriate.

Planning Model

Consistent with prior IRPs, Avista used the SENDOUT® planning model to perform comprehensive natural gas supply planning and analysis for this IRP. SENDOUT® is a linear programming-based model that is widely used to solve natural gas supply, storage and transportation optimization problems. This model uses present value revenue requirement (PVRR) methodology to perform least-cost optimization based on daily, monthly, seasonal and annual assumptions related to the following:

- 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 by utilizing a SENDOUT® module to incorporate weather and price uncertainty. Some examples of the types of stochastic analysis provided include:

- 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. 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-Carbon Reduction. 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 that the planning approach needs to:

- Recognize historical trends may be fundamentally altered;
- Critically review all modeling assumptions;
- Stress test assumptions via sensitivity analysis;
- Pursue a spectrum of scenarios;
- Develop a flexible analytical framework to accommodate changes; and
- Maintain a long-term perspective.

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 2018 IRP (Table 1.2).

Table 1.2: Summary of Changes from the 2018 IRP

Chapter	Issue	2021 Natural Gas IRP	2018 Natural Gas IRP
Demand	Expected Customer Growth	Expected Case – system wide – growth is slightly lower at 1.0%.	Expected Case – system wide – growth at 1.2%.
	Weather Planning Standard	99% probability of a temperature occurring based on the coldest temperature each year for the past 30 years	Coldest on record
DSM	CPA potential	A lower price curve and slightly less conservation potential Cumulative Savings over 20 years: ID: 21.4 Million Therms OR: 14.8Million Therms WA: 37.7 Million Therms	Cumulative Savings over 20 years: ID: 21.1 Million Therms OR: 17.2 Million Therms WA: 41.4 Million Therms
Environmental Issues	Carbon Dioxide Emission (Carbon)	ID: No federal or State initiatives ($0) OR: Cap and Reduce ($15.83 – $97.90) WA – Social Cost of Carbon @ 2.5% discount rate ($79.86 - $158.06) *Prices are in nominal dollars per MTCO2e	ID: No federal or State initiatives ($0) OR: HB 4001 & SB 1507 ($17.86 – $51.58) WA – SSB 6203 ($10 - $30) *Prices are in nominal dollars per MTCO2e
Prices	Price Curve	A lower price curve at $3.73 levelized cost in real 2019 US $	A levelized price at the Henry Hub of $3.99 in 2017 real US $

Supply Side Resources	Supply Side Scenarios	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 is looking to reduce emissions and Dairy RNG provides the greatest amount of carbon intensity/carbon capture of RNG sources.	The only case that identifies a resource deficiency is the High Growth/Low Price scenario. Avista solved this case by using existing resources plus added contracted capacity on GTN. Landfill RNG is also selected as a resource in Idaho. Also selected is the upsized compressor on the Medford lateral.

2: Demand Forecasts

Overview

The integrated resource planning process begins with the development of forecasted demand. 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 outcomes.

Demand Areas

Avista defined eleven demand areas, structured around the pipeline transportation resources ability to serve them, within the SENDOUT® 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

Demand Forecast Methodology

Avista uses the IRP process to develop two types of demand forecasts – annual and peak day. Annual average demand forecasts are useful for preparing revenue budgets, developing natural gas procurement plans, and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for acquiring new resources to meet customers' natural gas needs in extreme weather conditions.

In general, if existing resources are sufficient to meet peak day demand, they will be sufficient to meet annual average day demand. Developing annual average demand first and evaluating it against existing resources is an important step in understanding the performance of the portfolio under normal circumstances. It also facilitates synchronization of modeling processes and assumptions for planning purposes.

Peak weather analysis aids in assessing resource adequacy and any differences in resource utilization. For example, storage may be dispatched differently under peak weather scenarios.

Demand Modeling Equation

Developing daily demand forecasts is essential because natural gas demand can vary widely from day-to-day, especially in winter months when heating demand is at its highest. In its most basic form, natural gas demand is a function of customer base usage (non-weather sensitive usage) plus customer weather sensitive usage. Basic demand takes the formula in Table 2.2:

Table 2.2: Basic Demand Formula

# of customers x daily base usage / customer **+** # of customers x daily weather sensitive usage / customer

SENDOUT® requires inputs as expressed in the Table 2.3 format to compute daily demand in dekatherms.

Table 2.3: SENDOUT® Demand Formula

# of customers x daily Dth base usage / customer **+** # of customers x daily Dth weather sensitive usage / customer x # of daily degree days

Customer Forecasts

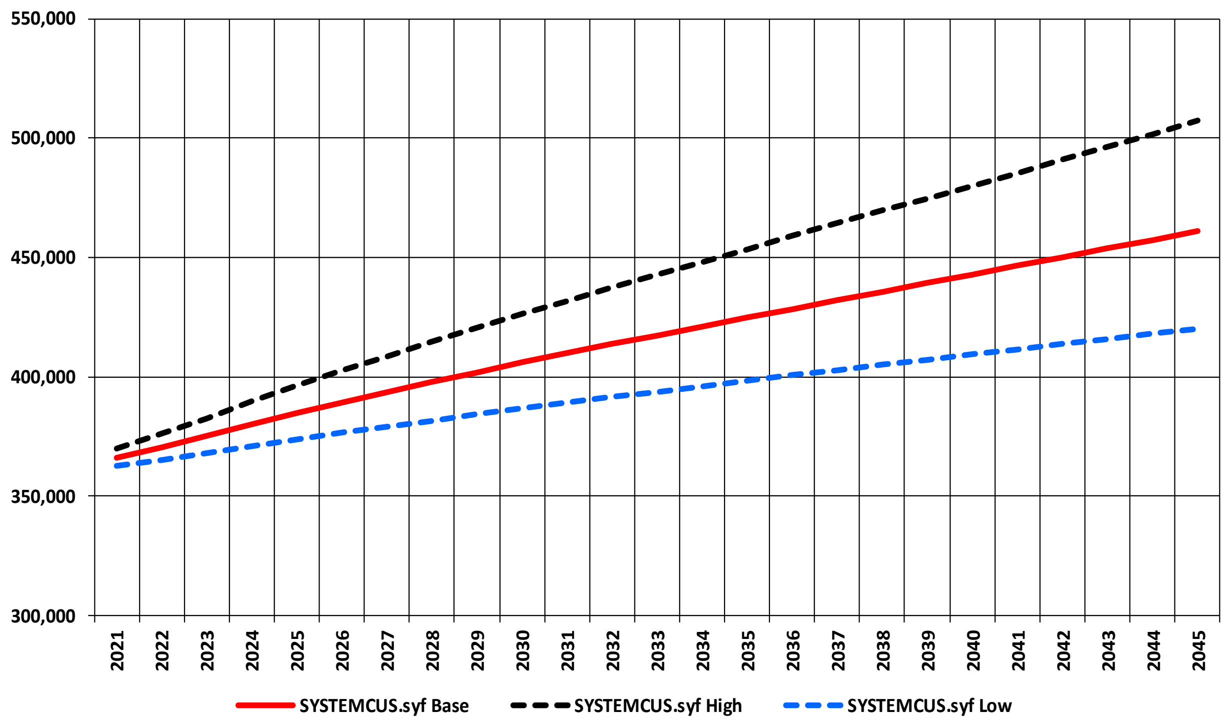
Avista's customer base includes firm residential, commercial and industrial categories. For each of the customer categories, Avista develops customer forecasts incorporating national economic forecasts and then drilling down into regional economies. U.S. GDP growth, national and regional employment growth, and regional population growth expectations are key drivers in regional economic forecasts and are useful in estimating the number of natural gas customers. A detailed description of the customer forecast is found in Appendix 2.1 – Economic Outlook and Customer Count Forecast. 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.

Several Avista departments' use these forecasts including Finance, Accounting, Rates, and Gas Supply. The natural gas distribution engineering group utilizes the forecast data for system optimization and planning purposes (see discussion in Chapter 8 – Distribution Planning).

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.

Figure 2.1 shows the three customer growth forecasts. The expected case customer counts are lower than the last IRP. This has impacted 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 – Customer Forecasts by Region. In comparison to Avista's 2018 IRP, the base forecast for customer growth decreases by nearly 1,400 new customers.

Figure 2.1: Customer Growth Scenarios

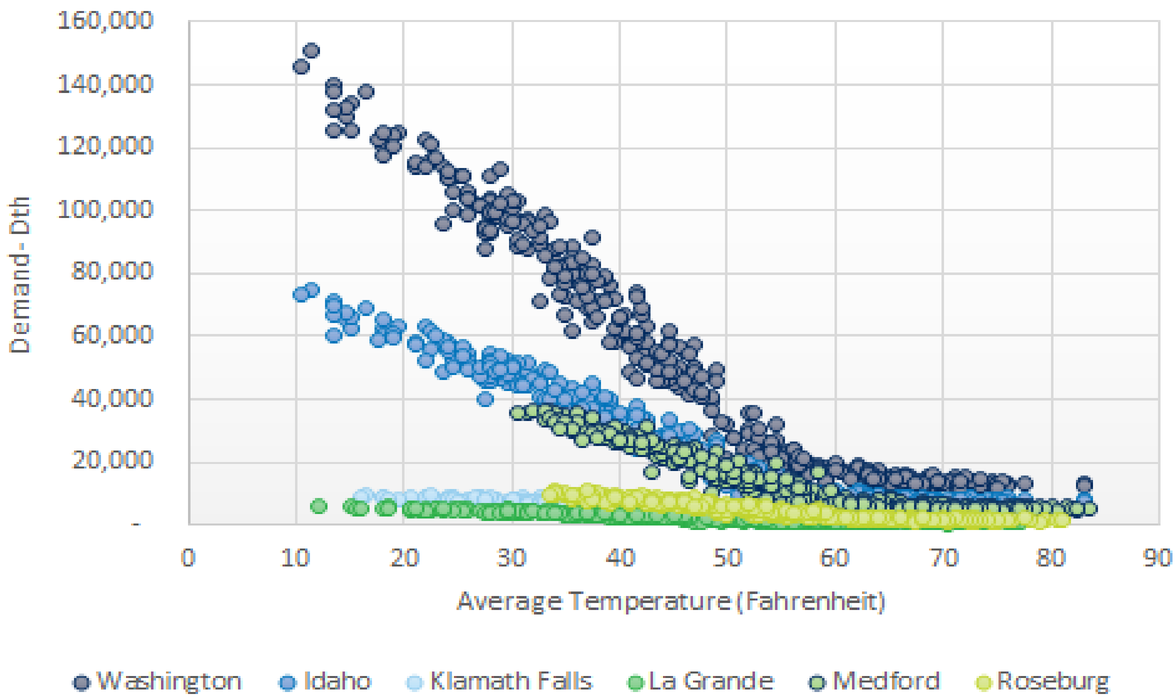


Variable	Low Growth	Base Growth	High Growth
Customers	0.6%	1.0%	1.3%
Population	0.4%	0.8%	1.1%

Use-per-Customer Forecast

The goal for a use-per-customer forecast is to develop base and weather sensitive demand coefficients that can be combined and 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 example scatter plot in Figure 2.2.

Figure 2.2: Example Demand vs. Temperature – 2019



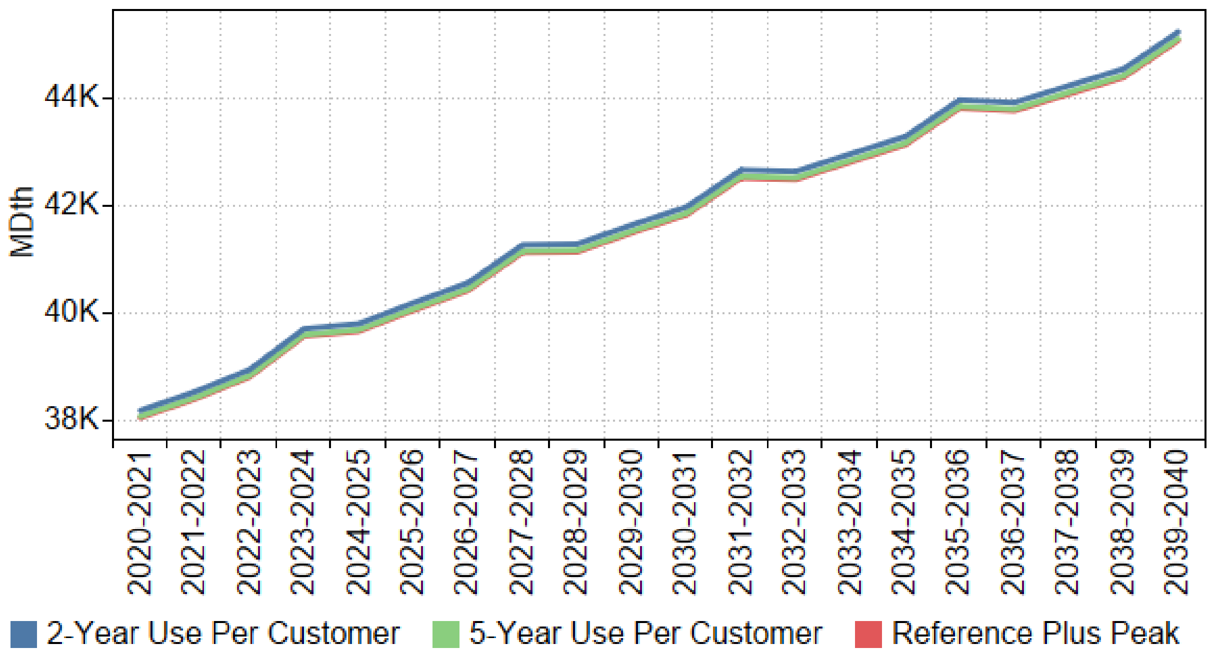
The first step in developing demand coefficients was gathering daily historical gas flow data for Avista city gates. The use of city gate data over revenue data is due to the tight correlation between weather and demand. The revenue system does not capture data daily and, therefore, makes a statistical analysis with tight correlations on a daily basis virtually impossible. Avista reconciles city gate flow data to revenue data to ensure that total demand is properly captured.

The historical city gate data was gathered, sorted by service territory/temperature zone, and then by month. As in the last IRP, Avista used three years of historical data to derive the use-per-customer coefficients, but also considered varying the number of years of historical data as sensitivities. When comparing five years of historical use-per-customer to three years of data, the five-year data had slightly higher use-per-customer, which may overstate use as efficiency and use-per-customer-per-HDD have been relatively stable in recent history. The two-year use-per-customer was much more pronounced for demand, likely based on a shorter timeframe for weather to impact the overall use-per-customer.

The three-year coefficient most closely aligns with economic expectations and use within Avista's territories in the short-term forecast. Figure 2.3 illustrates the annual demand differences between the three and five-year use-per-customer with normal and peak weather conditions.

You can see the three year and 5-year coefficients are very close, with the two-year coefficient clearly higher.

Figure 2.3: Annual Demand – Demand Sensitivities 2-Year, 3-Year and 5-Year Use-per-Customer



The base usage calculation used three years of July and August data to derive coefficients. Average usage in these months divided by the average number of customers provides the base usage coefficient input into SENDOUT®. This calculation is done for each area and customer class based on customer billing data demand ratios.

To derive weather sensitive demand coefficients for each monthly data subset, Avista removed base demand 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 input into SENDOUT®. Again, this calculation is done by area and by customer class using allocations based on customer billing data demand ratios.

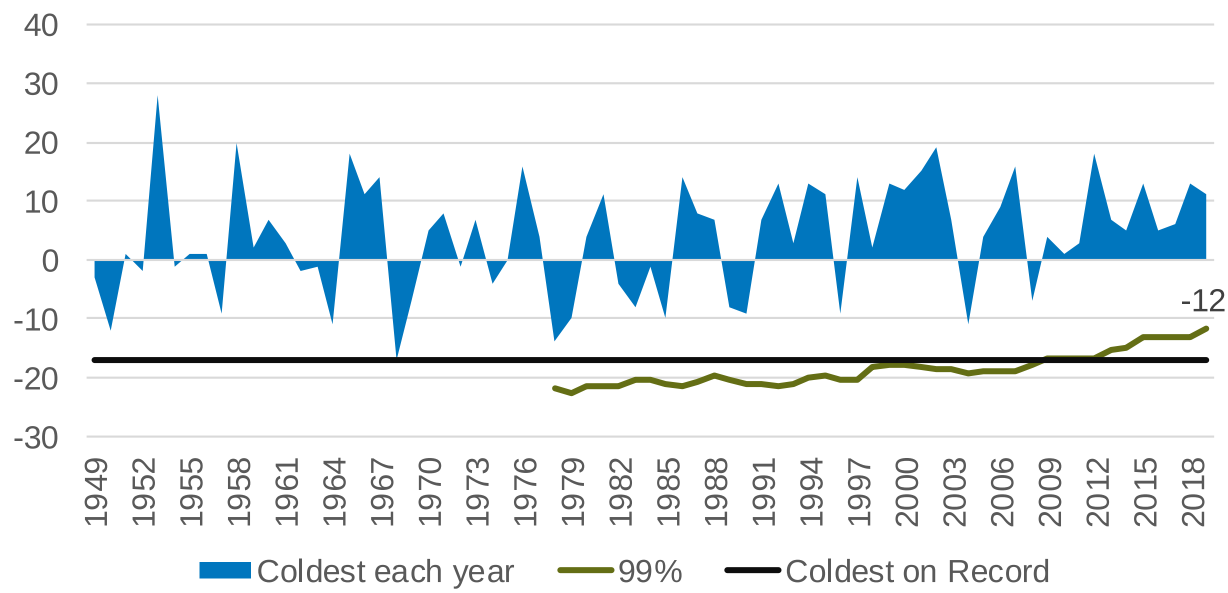
Weather Forecast

The last input in the demand modeling equation is weather. The most current 20 years of daily weather data (minimums and maximums) from the National Oceanic Atmospheric Administration (NOAA) is used to compute an average for each day; this 20-year daily average is used as a basis for the normal weather forecast. 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 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 goes back 70 years and contains minimum, maximum and average weather data. The program utilizes the historic weather data patterns to simulate realistic weather data algorithms when running stochastic simulations.

The weather planning standard is an important piece of system planning for resources in an IRP. In prior IRP's a coldest on record approach was considered the planning standard. With the complexities of changing weather and maintaining a reliable and affordable system, finding a statistical methodology to weigh weather risk and cost risk led to the development of a new weather planning standard methodology. The expected weather planning standard will utilize a coldest average temperature each year for the past thirty years, by planning area, and combine these temperatures with a 99% probability of a weather occurrence. As shown in Figure 2.4. the coldest on record temperature in Washington and Idaho has remained static, ignoring any weather trends. With the updated methodology the 99% will adjust with changing trends in climate. This will ensure capital is not being invested where an event is statistically unlikely to occur. In the planning areas of La Grande and Klamath Falls, OR this peak weather standard has become colder due to the large amount of peak or near peak events in the recent 30-year weather history. This new standard will enhance Avista's ability to plan for peak weather events and paired with stochastic analysis will introduce more rigor and risk analysis into the planning process and climate uncertainty.

Figure 2.4: Spokane Weather Station – Weather Planning Standard Comparison



Utilizing a five-day cold weather event with the new weather planning standard will occur 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 28 each year. As discussed in TAC 1, moving the peak day from February 15th to February 28th will allow for availability of resources to serve customers in these 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, Klamath Falls), the model assumes this event on and around December 20 each year. The following section provides a comparison of prior IRP planning standard vs. The updated methodology (Table 2.4).

Table 2.4: Weather Planning Standard

Area	Coldest on Record (Prior IRP's)	99% Probability Avg. Temp
La Grande	-10	-11
Klamath Falls	-7	-9
Medford	4	11
Roseburg	10	14
Spokane	-17	-12

Warming trends are beginning to emerge in Roseburg and Medford, though the volatility surrounding the peak is still present as seen in Figures 2.6 and 2.9. This indicates that although temperatures, specifically in the Roseburg and Medford areas, are deviating from the base years of 1950-1981 the peaking potential remains the same. The following figures show this same analysis for all weather areas for the months of December, January and February.

Figure 2.5: Spokane

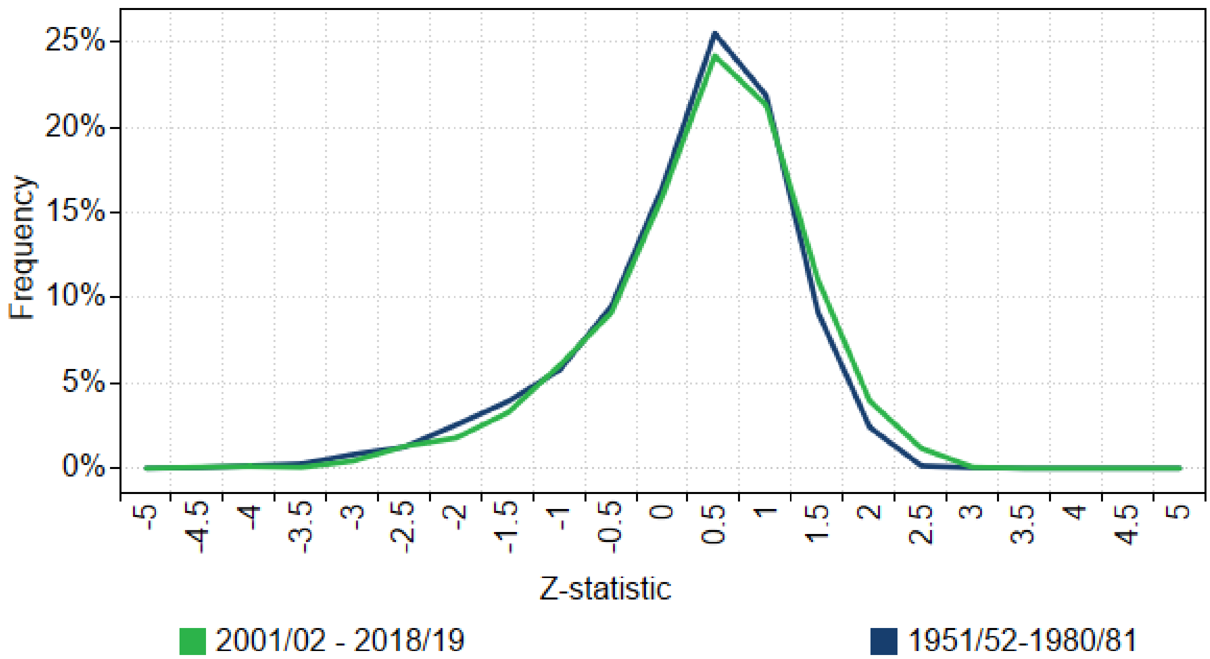


Figure 2.6: Medford

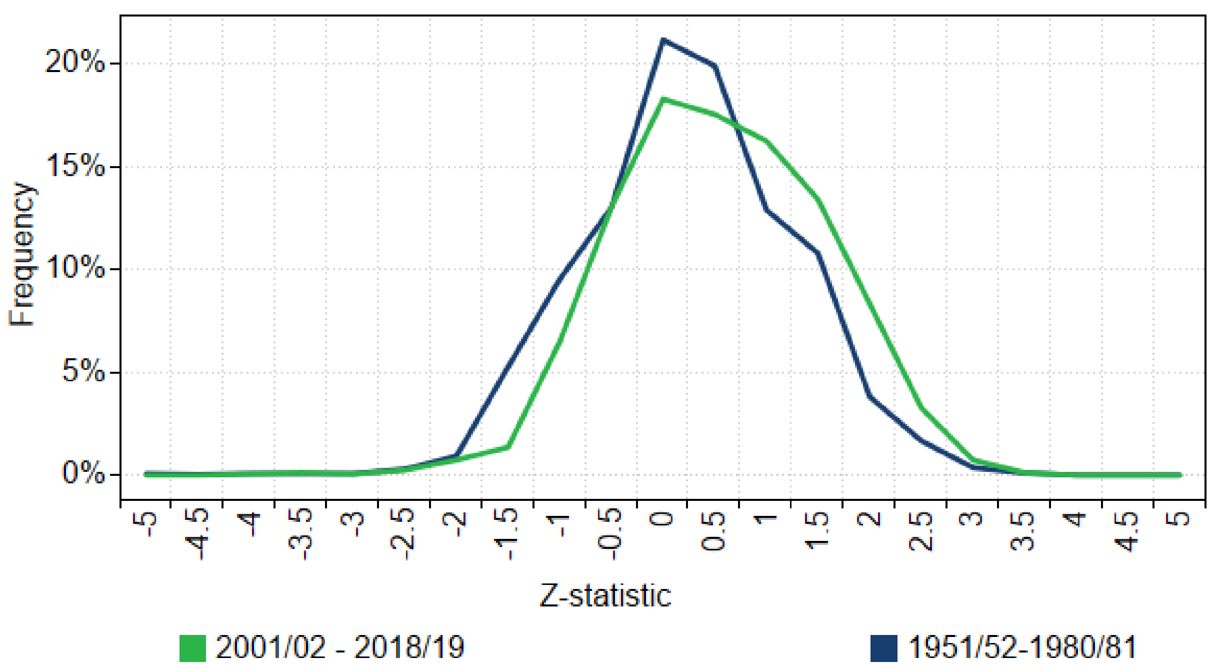


Figure 2.7: La Grande

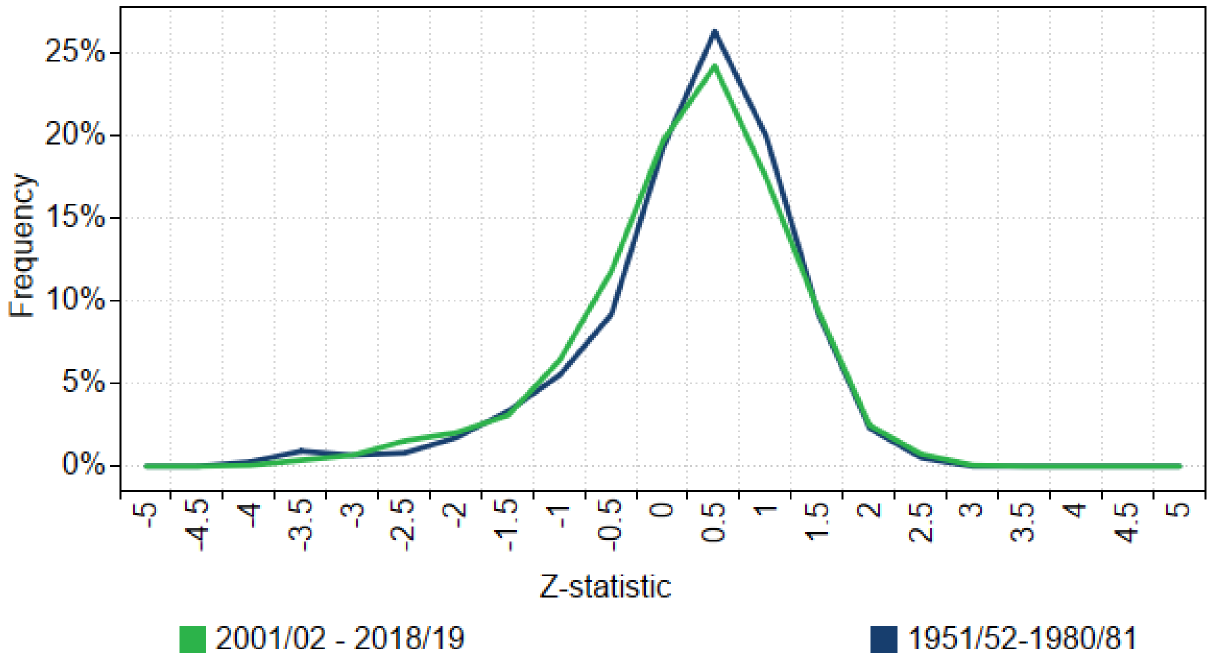


Figure 2.8: Klamath Falls

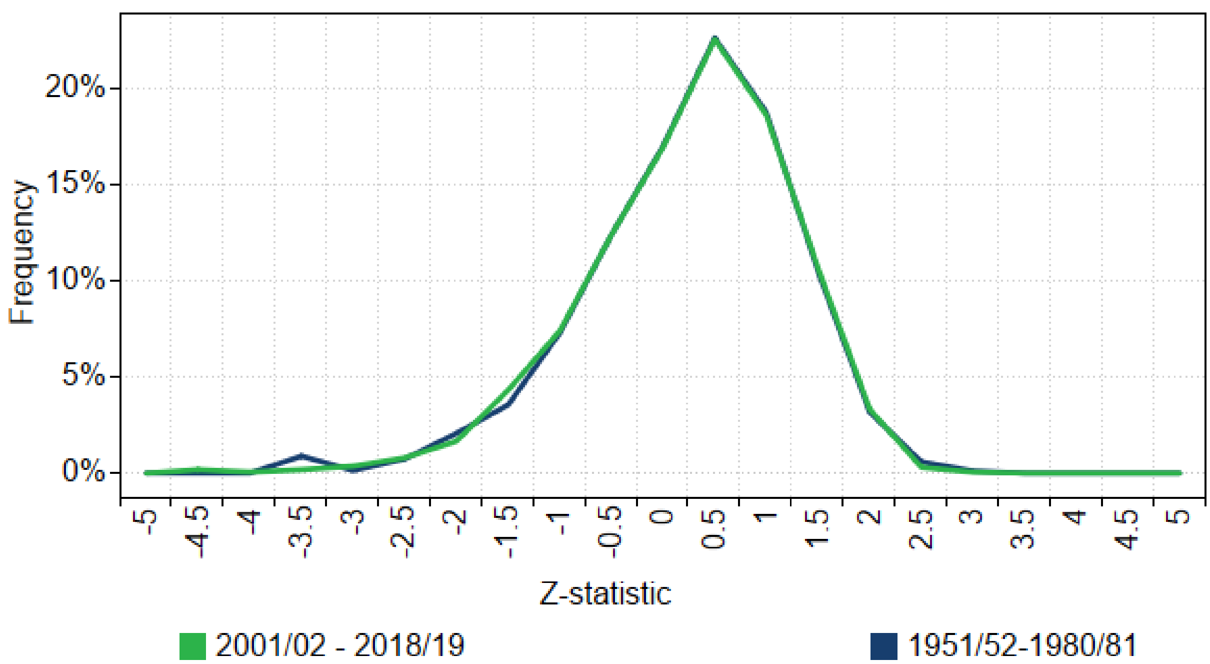
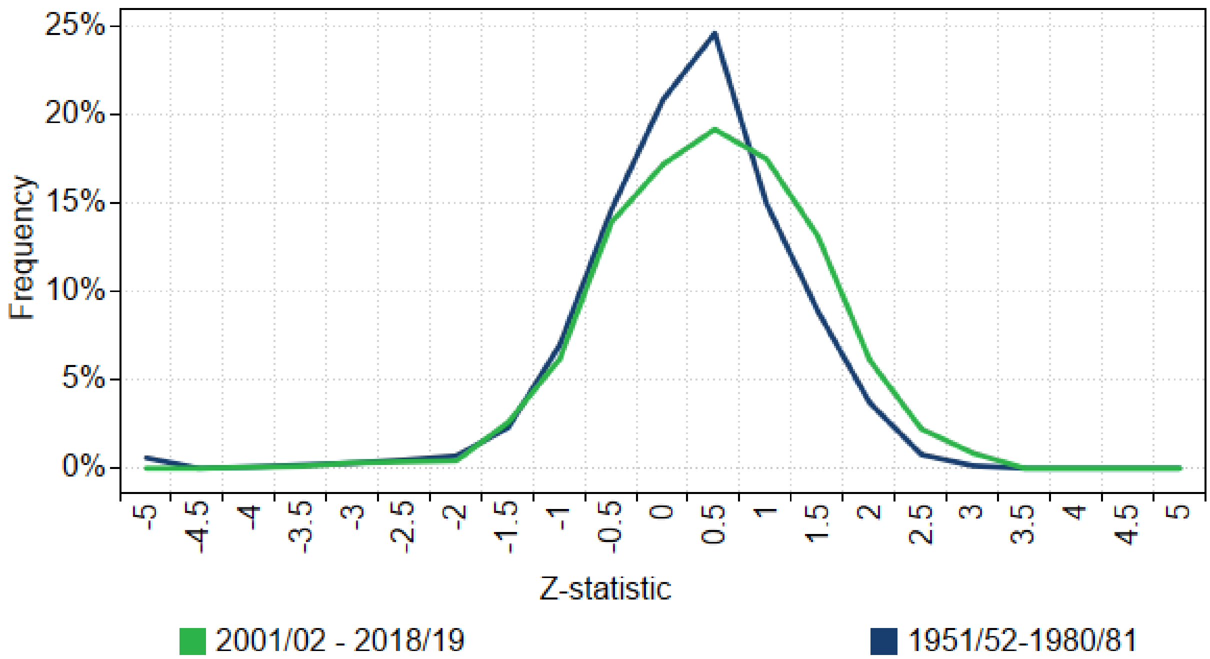


Figure 2.9: Roseburg



Developing a Reference Case

To adjust for uncertainty, Avista developed a dynamic demand forecasting methodology that is flexible to changing assumptions. To understand how various alternative assumptions influence forecasted demand Avista needed a reference point for comparative analysis. For this, Avista defined the reference case demand forecast shown in Figure 2.10. This case is only a starting point to compare other cases.

Figure 2.10: Reference Case Assumptions

1. **Customer Compound Annual Growth Rates**

Area	Residential	Commercial	Industrial
Idaho	1.4%	0.4%	-1.0%
Oregon	0.7%	0.6%	0.0%
Washington	1.0%	0.4%	-0.08%
System	**1.0%**	**0.5%**	**-0.8%**

2. **Use-Per-Customer Coefficients**

   Mostly Flat Across All Classes

   3-year Average Use per Customer per HDD by Area/Class

3. **Weather**

   20-year Normal – NOAA (2000-2019)

4. **Elasticity**

   None

5. Conservation
None

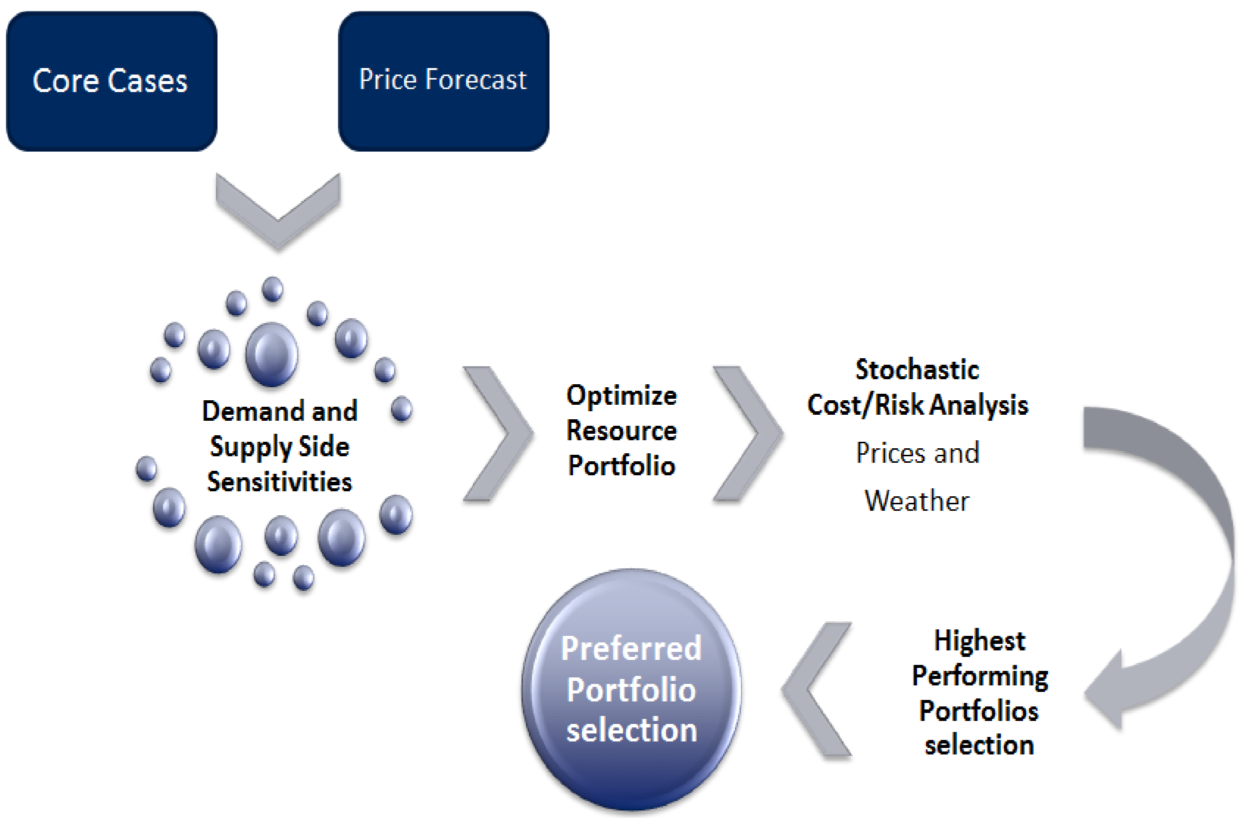
Dynamic Demand Methodology

The dynamic demand planning strategy examines a range of potential outcomes. The approach consists of:

- Identifying key demand drivers behind natural gas consumption;
- Performing sensitivity analysis on each demand driver;
- Combining demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand; and
- Matching demand scenarios with supply scenarios to identify unserved demand.

Figure 2.11 represents Avista's methodology of starting with sensitivities, progressing to portfolios, and ultimately selecting a preferred portfolio.

Figure 2.11: Sensitivities and Preferred Portfolio Selection



Sensitivity Analysis

In analyzing demand drivers, Avista grouped them into three categories based on:

- Demand Influencing Factors directly influencing the volume of natural gas consumed by core customers.
- Price Influencing Factors indirectly influencing the volume of natural gas consumed by core customers through a price elasticity response.
- Emissions Influencing Factors directly influencing the volume of gas and the price elasticity response.

After identifying demand, price, and emissions influencing factors, Avista developed sensitivities to focus on the analysis of a specific natural gas demand driver and its impact on forecasted demand relative to the Reference Case when modifying the underlying input assumptions.

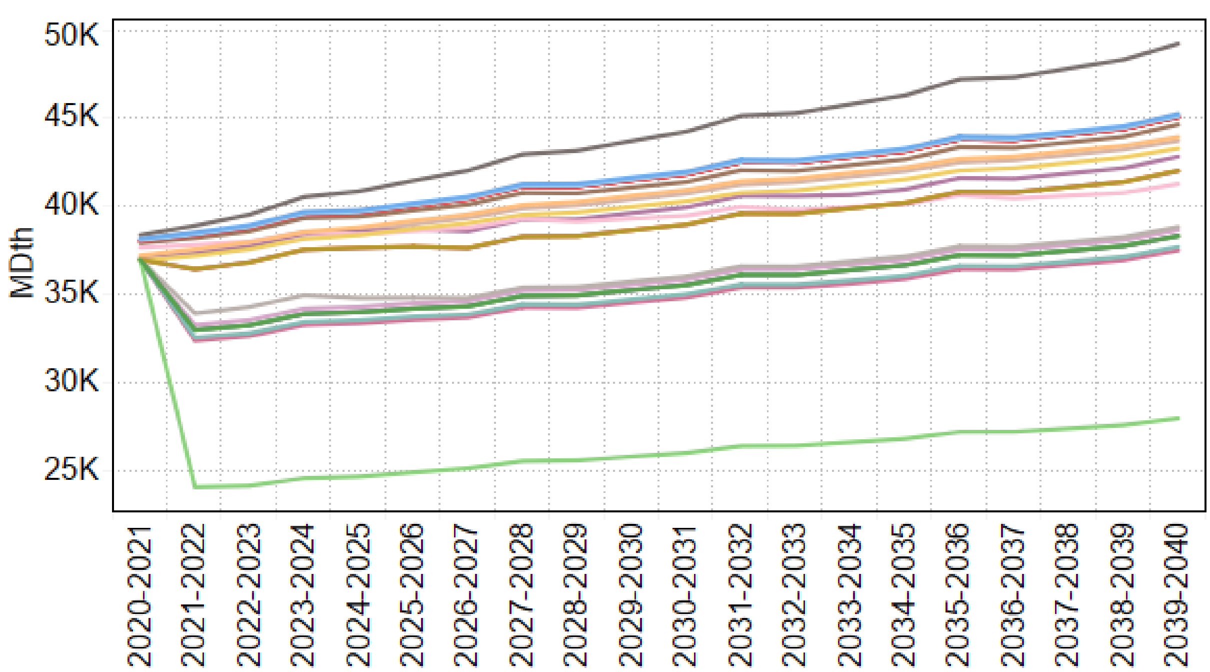
Sensitivity assumptions reflect incremental adjustments not captured in the underlying Reference Case forecast. Avista analyzed 33 demand sensitivities to determine the results relative to the Reference Case. Table 2.5 lists these sensitivities. Detailed information about these sensitivities is in Appendix 2.5 – Demand Forecast Sensitivities and Scenarios Descriptions.

Table 2.5: Demand Sensitivities

Influence Type	Chart Color	Sensitivity	Customer Growth Rate	Use per Customer	Weather	Demand Side Management	Prices	Elasticity	First Year System Unserved	Location Unserved
DEMAND INFLUENCING - DIRECT		Reference	Reference	3 Year Historical	20 Year Average	None	Expected	None	-	
		Reference Plus Peak			Planning Standard				2035	Washington
		Low Cust	Low Growth						-	
		High Cust	High Growth						2029	Washington
		Alternate Weather Standard	Reference		Coldest in 20yrs				2035	Washington
		DSM			20 Year Average	Expected			-	
		Peak plus DSM			Planning Standard				2036	Washington
		80% below 1990 emissions				None			2035	Washington
		2 Year use per customer Alternate		2 Year Historical					2035	Washington
		5 Year use per customer Alternate		5 Year Historical					2035	Washington
		JP Outage Only (0% capacity)		3 Year Historical					2021	Washington
		AECO Outage Only (0% capacity)							2020	WA, ID
		Sumas Outage Only (0% capacity)							2020	Medford
		Rockies Outage Only (0% capacity)							2020	La Grande
		JP Outage Only (50% capacity)							2021	Washington
		AECO Outage Only (50% capacity)							2026	Washington
		Sumas Outage Only (50% capacity)							2025	Washington
		Rockies Outage Only (50% capacity)							2025	La Grande
		NWP Outage (0% capacity)							2020	WA, ID, La Grande
		GTN Outage (0% capacity)							2020	WA, ID, Klamath Falls
		NWP Outage (50% capacity)							2020	WA, La Grande
		GTN Outage (50% capacity)							2026	Washington
PRICE INFLUENCING - INDIRECT		Expected Prices						Expected	-	
		Low Prices					Low		-	
		High Prices					High		-	
		Carbon Cost - High (SCC 95% at 3%)					Expected		-	
		Carbon Cost - Expected (SCC 2.5% (WA) & Cap&Red (OR))							-	
		Carbon Cost - Low $0							-	
EMISSIONS INFLUENCING		High Upstream Emissions 2.47% leakage (EDF study)							-	
		Expected Upstream Emissions (0.79% leakage)							-	
		No Upstream Emissions							-	
		Expected Global Warming Potential (20 Years)							-	
		Expected Global Warming Potential (100 Years)							-	

Figure 2.12 shows the annual demand from each of the sensitivities modeled for this IRP with the associated legend colors in Table 2.5.

Figure 2.12: 2021 IRP Demand Sensitivities



Scenario Analysis

After testing the sensitivities, Avista grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 2.6 identifies the scenarios developed for this IRP. The Average Case represents the case used for normal planning purposes, such as corporate budgeting, procurement planning, and PGA/General Rate Cases. The Expected Case reflects the demand forecast Avista believes is most likely given peak weather conditions. The High Growth/Low Price and Low Growth/High Price cases represent a range of possibilities for customer growth and future prices. The Carbon Reduction emissions scenario is intended to show a progressive loss of demand in the areas of Oregon and Washington (Idaho is unaffected) from policies targeting methane and carbon dioxide emissions to an estimated emissions level. Each of these scenarios provides a “what if” analysis given the volatile nature of key assumptions, including weather and price. Appendix 2.6 lists the specific assumptions within the scenarios while Appendix 2.7 contains a detailed description of each scenario.

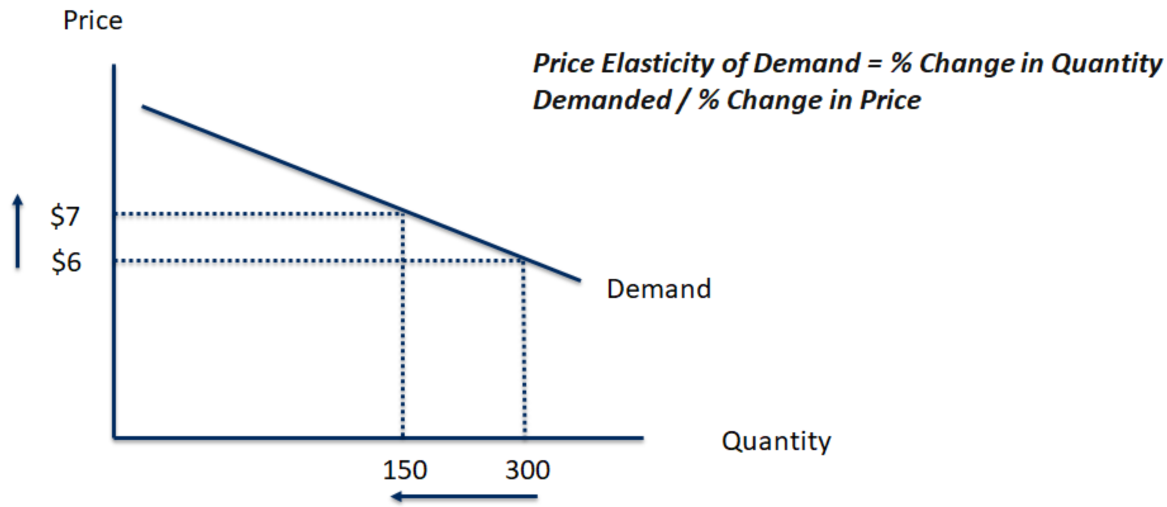
Table 2.6: Demand Scenarios

2021 IRP Demand Scenarios
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Carbon Reduction

Price Elasticity

The economic theory of price elasticity states that the quantity demanded for a good or service will change with its price. Price elasticity is a numerical factor that identifies the relationship of a customer’s consumption change in response to a price change. Typically, the factor is a negative number as customers normally reduce their consumption in response to higher prices or will increase their consumption in response to lower prices. For example, a price elasticity factor of negative 0.15 for a good or service means a 10 percent price increase will prompt a 1.5 percent consumption decrease and a 10 percent price decrease will prompt a 1.5 percent consumption increase. An example of price elasticity is depicted in Figure 2.13:

Figure 2.13: Price Elasticity Example



Complex regulatory pricing mechanisms shield customers from price volatility, thereby dampening price signals and affecting price elastic responses. For example, comfort level billing averages a customer's bills into equal payments throughout the year. This popular program helps customers manage household budgets but does not send a timely price signal. Additionally, natural gas cost adjustments, such as the Purchased Gas Adjustment (PGA), annually adjusts the commodity cost which shields customers from daily gas price volatility. These mechanisms do not completely remove price signals, but they can significantly dampen the potential demand impact.

When considering a variety of studies on energy price elasticity, a range of potential outcomes was identified, including the existence of positive price elastic adjustments to demand. One study looking at the regional differences in price elasticity of demand for energy found that the statistical significance of price becomes more uncertain as the geographic area of measurement shrinks.[1] This is particularly important given Avista's geographically diverse and relatively small service territories.

Avista acknowledges changing price levels can and do influence natural gas usage. This IRP includes a price elasticity of demand factor of -0.081 for every 10% change in price as measured in the Roseburg and Medford service territories. We assume the same elasticity for all service areas in this study. When putting this elasticity into our model, it allows the use-per-customer to vary as the natural gas price forecast changes.

Recent usage data indicates that even with declines in the retail rate for natural gas, long run use-per-customer continues to decline. This likely includes a confluence of factors

[1] Bernstein, M.A. and J. Griffin (2005). Regional Differences in Price-Elasticity of Demand for Energy, Rand Corporation.

including increased investments in energy DSM measures, building code improvements, behavioral changes, and heightened focus of consumers' household budgets.

Results

During 2021, the Average Case demand forecast indicates Avista will serve an average of 366,157 core natural gas customers with 34,720,917 Dth of natural gas. By 2040, Avista projects 442,863 core natural gas customers with an annual demand of over 37,351,708 Dth. In Washington/Idaho, the projected number of customers increases at an average annual rate of 1.11 percent, with demand growing at a compounded average annual rate of 0.33 percent. In Oregon, the projected number of customers increases at an average annual rate of 0.75 percent, with demand growing 0.54 percent per year.

The Expected Case demand forecast indicates Avista will serve an average of 366,157 core natural gas customers with 35,440,513 Dth of natural gas in 2021. By 2040, Avista projects 442,863 core natural gas customers with an annual demand of 37,987,712 Dth.

Figure 2.14 shows system forecasted demand for the demand scenarios on an average daily basis for each year.[2]

Figure 2.14: Average Daily Demand – 2021 IRP Scenarios

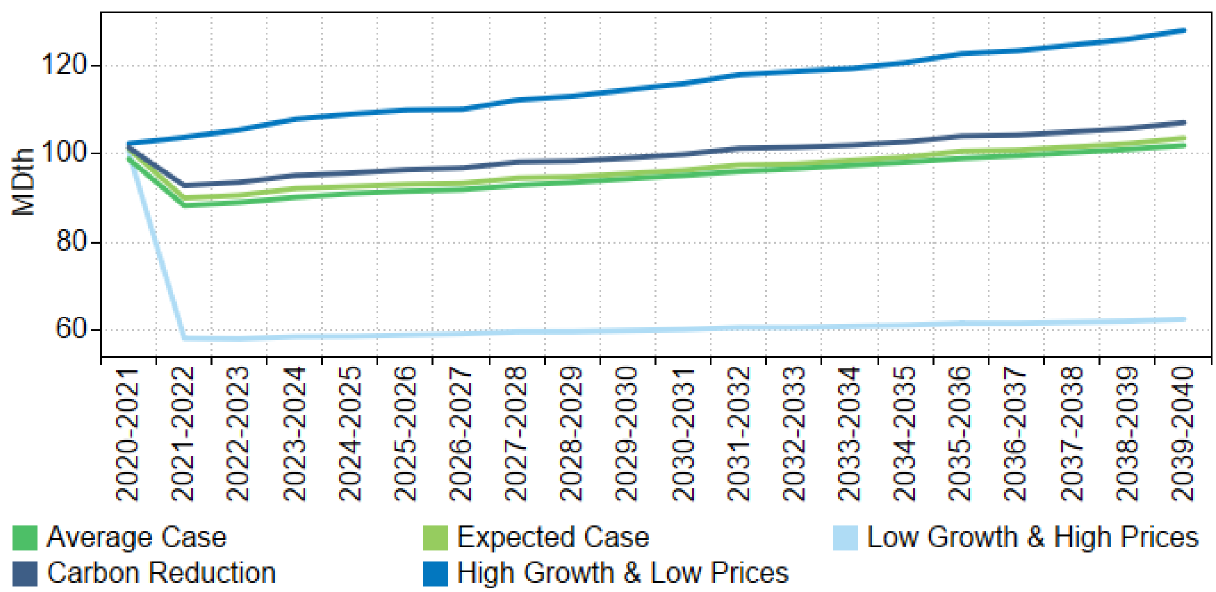
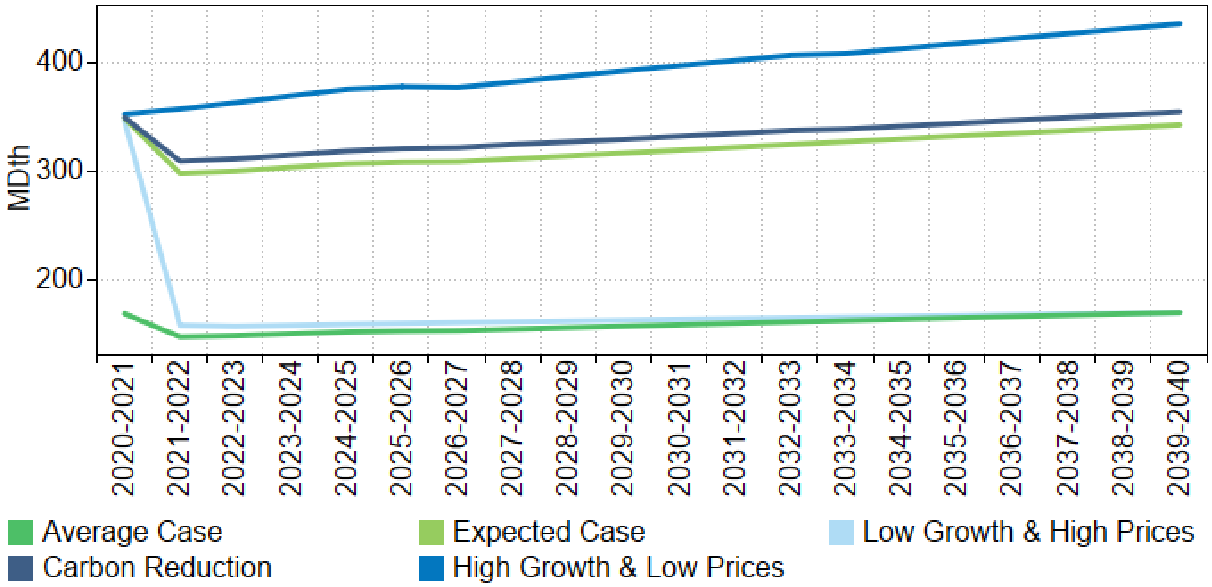


Figure 2.15 shows system forecasted demand for the Expected, High and Low Demand cases on a peak day basis for each year relative to the Average Case average daily winter

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

demand. Detailed data for all demand scenarios is in Appendix 2.8 – Demand Before and After DSM.

Figure 2.15: February 28th – Peak Day – 2021 IRP Demand Scenarios



The IRP balances forecasted demand with existing and new supply alternatives. Since new supply sources include conservation resources, which act as a demand reduction, the demand forecasts prepared and described in this section include existing DSM standards and normal market acceptance levels. The methodology for modeling DSM initiatives is in Chapter 3 – Demand-Side Resources.

Alternative Forecasting Methodologies

There are many forecasting methods available and used throughout different industries. Avista uses methods that 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. 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 which, if any, alternative methodologies to include 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 that these can and will change over time. Therefore, monitoring key assumptions driving the demand forecast is an ongoing effort that will be shared with the TAC as they develop.

Flat Demand Risk

Forecasting customer usage is a complex process because of the number of underlying assumptions and the relative uncertainty of future patterns of usage with a goal of increasing forecast accuracy. There are many factors that can be incorporated into these models, assessing which ones are significant and improving the accuracy are key. Avista continues to evaluate economic and non-economic drivers to determine which factors improve forecasting accuracy. The forecasting process will continue to review research on climate change and the best way to incorporate the results of that research into the forecasting process.

For the last few planning cycles, the TAC has discussed the changing slope of forecasted demand. Growth has slowed due to a declining use-per-customer. Use-per-customer seems to have stabilized, though it is still on a downward trajectory in some areas.

This reduced demand pushes the need for resources beyond the planning horizon, which means no new investment in resources is necessary from an energy standpoint. However, as discussed in Chapter 5 – Carbon Reduction, policy may change the resource demand for fossil fuels based on carbon reduction goals where new carbon reducing resources will be required to help meet these targets. Monitoring both growth and policy changes is key to managing assets needed to serve customers energy demand in all types of weather.

Emerging Natural Gas Demand

The shale gas revolution has fundamentally changed the long-term availability and price of natural gas. An ever-growing demand for natural gas-fired generation to integrate variable wind and solar resources along with an increasing demand from coal retirements and fuel switching has developed over the last decade. This demand is expected to increase due to the availability of natural gas combined with its lower carbon emissions. Other areas of emerging demand include everything from methanol plants to food processors, and interest in industrial processes using natural gas as a feedstock is growing.

Conclusion

Avista’s 20-year outlook for customer growth has decreased by nearly 1,400 customers, as compared to Avista’s 2018 IRP. With the inclusion of energy efficiency, known as DSM, measures going into new construction and purchased through Avista’s programs, homes are becoming better equipped to keep the heat in. This in turn leads to a decreasing amount of natural gas usage. Until a point is reached where maximum efficiency is found, these trends will likely continue to decline in nature.

3: Demand Side Resources

Overview

Avista is committed to offering natural gas Energy Efficiency portfolios 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 energy efficiency programs to its customers in 1995. Program delivery includes both prescriptive and site-specific offerings. Prescriptive programs, or standard offerings, provide cash incentives for standardized products such as the installation of qualifying high-efficiency heating equipment. Delivering programs through a prescriptive approach works in situations where uniform products or offerings are applicable for large groups of homogeneous customers and primarily occur in programs for residential and small commercial customers. Site specific is the most comprehensive offering of the nonresidential segment. Avista's Account Executives work with nonresidential customers to aid in identifying energy efficiency opportunities. Customers receive technical assistance in determining potential energy and cost savings as well as identifying and estimating incentives for participation. Other delivery methods build off these approaches and may include upstream buy downs of low-cost measures, free-to-customer direct install programs, and coordination with regional entities for market transformation efforts.

Recently, programs with the highest impacts on natural gas energy savings include the residential prescriptive HVAC measures, residential water heat measures, and nonresidential prescriptive and site-specific HVAC.

Improved drilling and extraction techniques of natural gas has led to declines in natural gas prices in recent years which has made offering cost-effective DSM programs challenging using the Total Resource Cost Test (TRC) to test cost-effectiveness. Since January 1, 2016, Washington and Idaho programs utilize the Utility Cost Test (UCT). Effective January 1, 2017, all Oregon DSM programs, with the exception of low-income conservation, are delivered and administered by the Energy Trust of Oregon (ETO)[1].

Avista issued an RFP and chose Applied Energy Group (AEG) to perform an external independent evaluation of Avista's conservation potential in Idaho and Washington while ETO continues to evaluate and manage DSM in Oregon. Included with these evaluations was the technical, economic and achievable conservation potential for each state over a 20-year planning horizon (2021-2040).

[1] As part of the settlement for the Avista 2015 Oregon General Rate case

The preliminary cost-effective conservation potential is determined by applying the stream of annual natural gas avoided costs to the Avista-specific supply curve for conservation resources. This quantity of conservation acquisition is then decremented from the load which the utility must serve and the SENDOUT® model is rerun against the modified (reduced) load requirements. The resulting avoided costs are compared to those obtained from the previous iteration of SENDOUT® avoided costs. This process continues until the differential between the avoided cost streams of the most recent and the immediately previous iteration becomes immaterial. The resulting avoided costs were provided to AEG and ETO to use in selecting cost-effective potential within Avista's service territories.

Applied Energy Group (AEG): Idaho and Washington - CPA

Avista Early in 2020, Avista Utilities (Avista) contracted with Applied Energy Group (AEG) to conduct this Conservation Potential Assessment (CPA) in support of their conservation and resource planning activities. This 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 energy conservation efforts in the time period of 2021 to 2040. To produce a reliable and transparent estimate of energy efficiency (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 gas by sector, segment, end use and technology.
- Developed a baseline projection of how customers are likely to use gas in absence of future EE programs. This defines the metric against which future program savings are measured. This projection used up-to-date technology data, modeling assumptions, and energy baselines that reflect both current and anticipated federal, state, and local energy efficiency legislation that will impact energy EE potential.
- Estimated the technical, achievable technical, and achievable economic potential at the measure level for energy efficiency within Avista's service territory over the 2021 to 2040 planning horizon.
- Delivered a fully configured end-use conservation planning model, LoadMAP, for Avista to use in future potential and resource planning initiatives
- In summary, the potential study provided a solid foundation for the development of Avista's energy savings targets.

Table ES-1 summarizes the results for Avista's Washington territory at a high level. AEG analyzed potential for the residential, commercial, and industrial market sectors. First-year utility cost test (UCT) achievable economic potential in Washington is 75,820 dekatherms. This increases to a cumulative total of 173,838 dekatherms in the second year and 1,386,479 dekatherms by the tenth year (2030).

Table ES-1: Washington Conservation Potential by Case, Selected Years (dekatherms)

Scenario	2021	2022	2023	2030	2040
Baseline Forecast (Dth)	19,118,293	19,289,575	19,805,020	20,612,516	21,619,876
Cumulative Savings (Dth)					
UCT Achievable Economic	75,820	173,838	457,423	1,386,479	3,560,512
Achievable Technical	41,871	416,584	1,221,810	3,183,398	6,309,826
Technical	187,983	897,098	2,314,334	5,084,999	8,908,493
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.3%	6.7%	16.5%
Achievable Technical Potential	0.2%	2.2%	6.2%	15.4%	29.2%
Technical Potential	1.0%	4.7%	11.7%	24.7%	41.2%

Table ES-2 summarizes the results for Avista's Idaho territory at a high level. First-year utility cost test (UCT) achievable economic potential in Idaho is 35,816 dekatherms. This increases to a cumulative total of 87,995 dekatherms in the second year and 737,710 dekatherms by the tenth year (2030).

Table ES-2: Idaho Conservation Potential by Case, Selected Years (dekatherms)

Scenario	2021	2022	2023	2030	2040
Baseline Forecast (Dth)	10,019,377	10,144,894	10,520,169	11,004,568	12,006,819
Cumulative Savings (Dth)					
UCT Achievable Economic	35,816	87,995	229,283	737,710	2,025,410
Achievable Technical	26,220	226,613	657,997	1,722,830	3,544,048
Technical	102,031	490,826	1,273,202	2,777,509	5,013,697
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.2%	6.7%	16.9%
Achievable Technical Potential	0.3%	2.2%	6.3%	15.7%	29.5%
Technical Potential	1.0%	4.8%	12.1%	25.2%	41.8%

As part of this study, we also estimated total resource cost (TRC) potential, with the focus of fully balancing non-energy impacts. This includes the use of full measure costs as well as quantified and monetizable non-energy impacts and non-gas fuel impacts (e.g. electric cooling or wood secondary heating) consistent with methodology within the 2021 Northwest Conservation and Electric Power Plan (2021 Plan). We explore this potential in more detail throughout the report.

The entire CPA report including the methodology can be found in Appendix 3.1.

Energy Trust of Oregon - CPA

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.[2]

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 783 aMW of electricity and 71 million annual therms. This equates to more than 32.7 million 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 2009 to 2018, as shown in OPUC utility statistic books.[3]

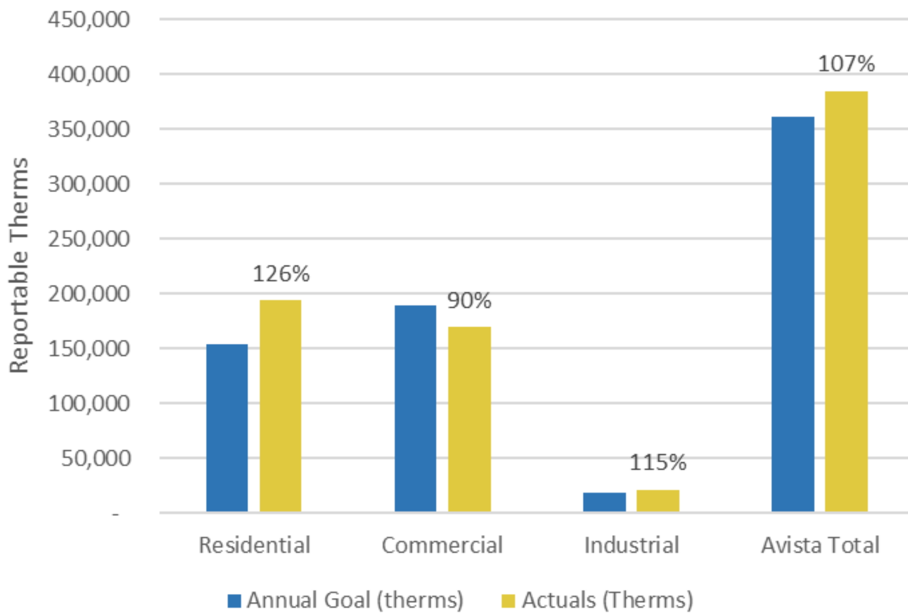
Energy Trust serves residential, commercial, and firm industrial customers in Avista's natural gas service territory in the areas of Medford, Klamath Falls, and La Grande, Oregon. In 2019, Energy Trust's programs achieved savings of 384,000 therms—equivalent to 107% of the established savings goal of 360,000 therms, as shown in Figure 3.1.

---

[2] 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 $182 million in 2020.

[3] OPUC 2018 Stat book – 10 Year Summary Tables: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2018-Oregon-Utility-Statistics-Book.pdf

Figure 3.1: 2019 Achieved Savings vs. Goals for Avista Service Territory



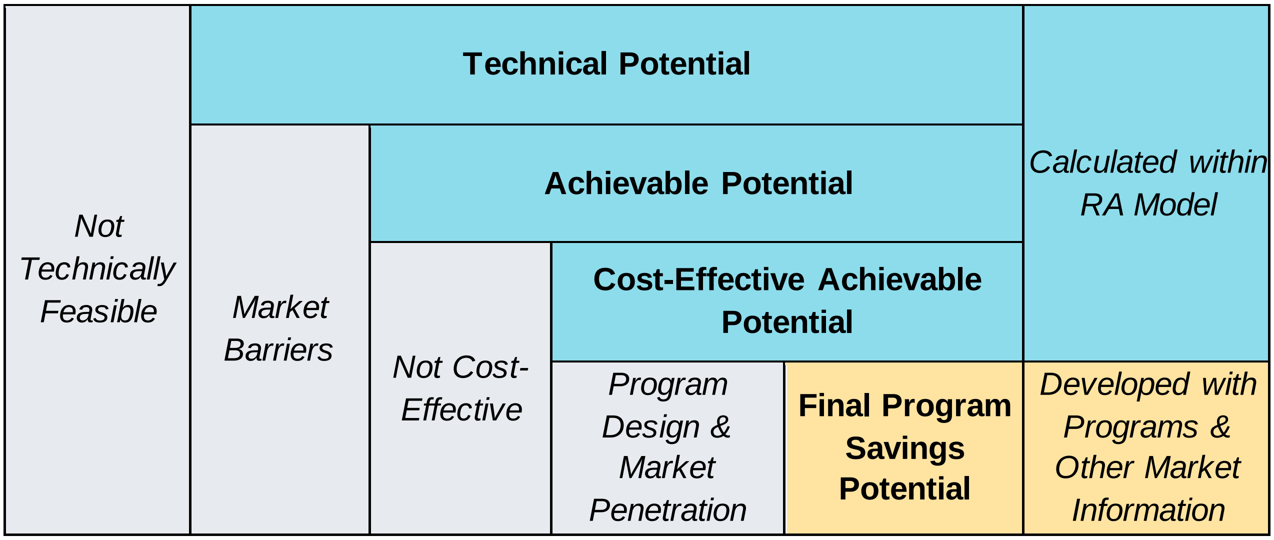
In addition to administering energy efficiency programs on behalf of the utilities, Energy Trust also provides each utility with a 20-year forecast of cost-effective energy efficiency savings potential expected to be achieved by Energy Trust. The results are used by Avista and other utilities in Integrated Resource Plans (IRP) to inform the energy efficiency resource potential in their territory that can be used 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 3.2 and discussed in greater detail in the sections below.

Figure 3.2: Types of Potential Calculated in 20-Year Forecast Determination



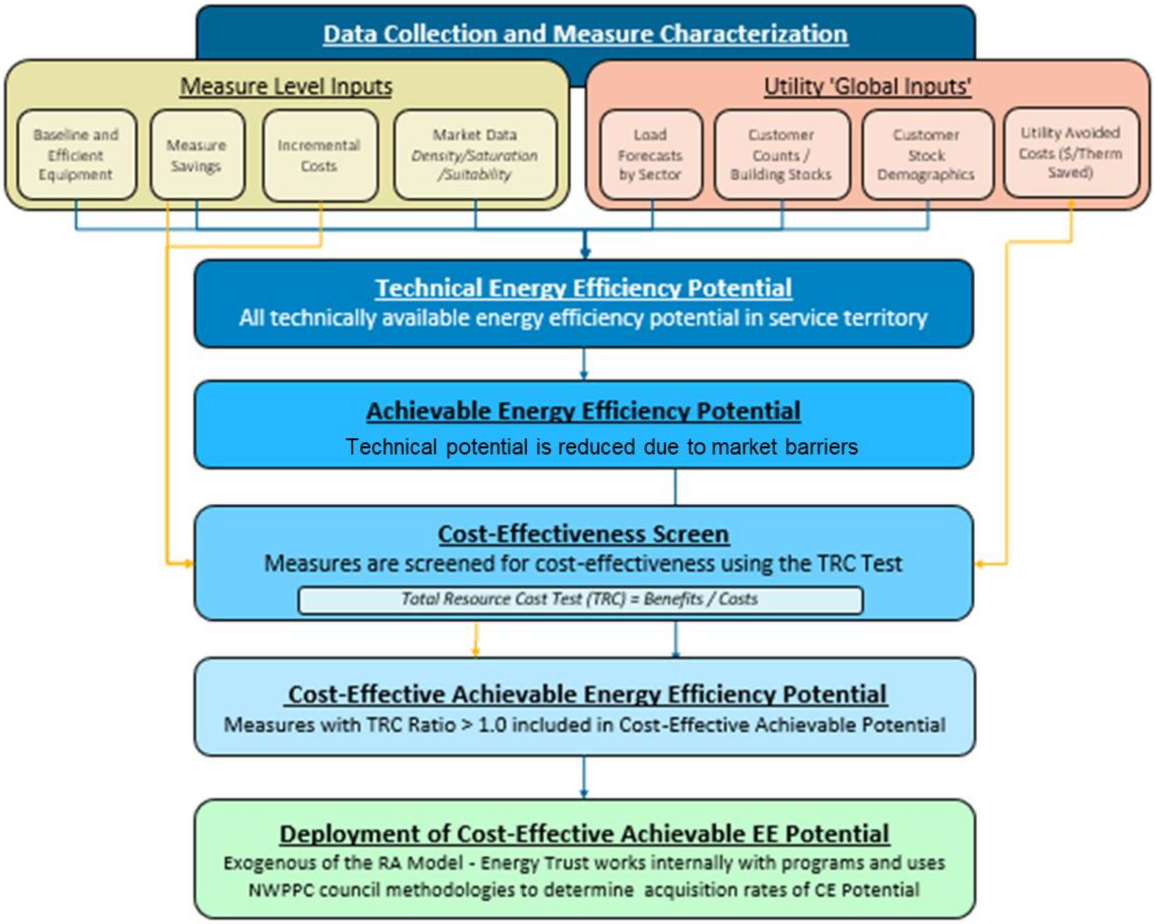
The RA Model utilizes the modeling platform Analytica®[4], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, 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 Figure 3.3. 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.

[4] http://www.lumina.com/why-analytica/what-is-analytica1/

Figure 3.3: 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.[5] 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').

[5] 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.

- ***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. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[6], 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., a 95% AFUE furnace replacing an 80% AFUE baseline furnace). 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. For example, a duct sealing measure would need to reflect the share of homes that actually have ducted heating systems. 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:

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

1. ***Customer and Load Forecasts****:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a ‘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 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. For Avista's 2020 IRP, Energy Trust updated its methodology to reflect the maximum achievability estimated by the Northwest Power and Conservation Council for the 2021 Power Plan. While in past power plans a universal assumption of 85% was used, these factors now typically range from 85% to 95%.[7]

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.
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

[7] For details on this, see https://www.nwcouncil.org/sites/default/files/2019_0813_p5.pdf.

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

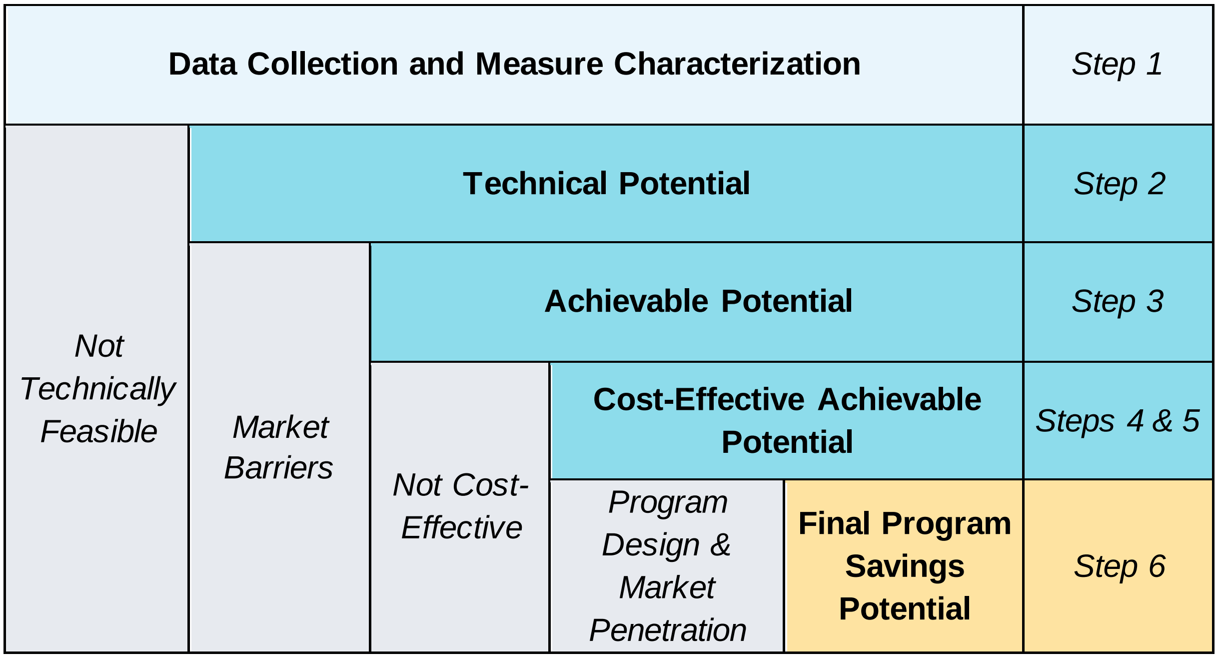
The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures unless an exception has been granted by the OPUC.

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 3.4 below reiterates the types of potential shown in Figure 3.2, and how the steps described above and in the flow chart fit together.

Figure 3.4: The Progression to Program Savings Projections



Forecast Results

The results of Energy Trust’s forecast are shown below.

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

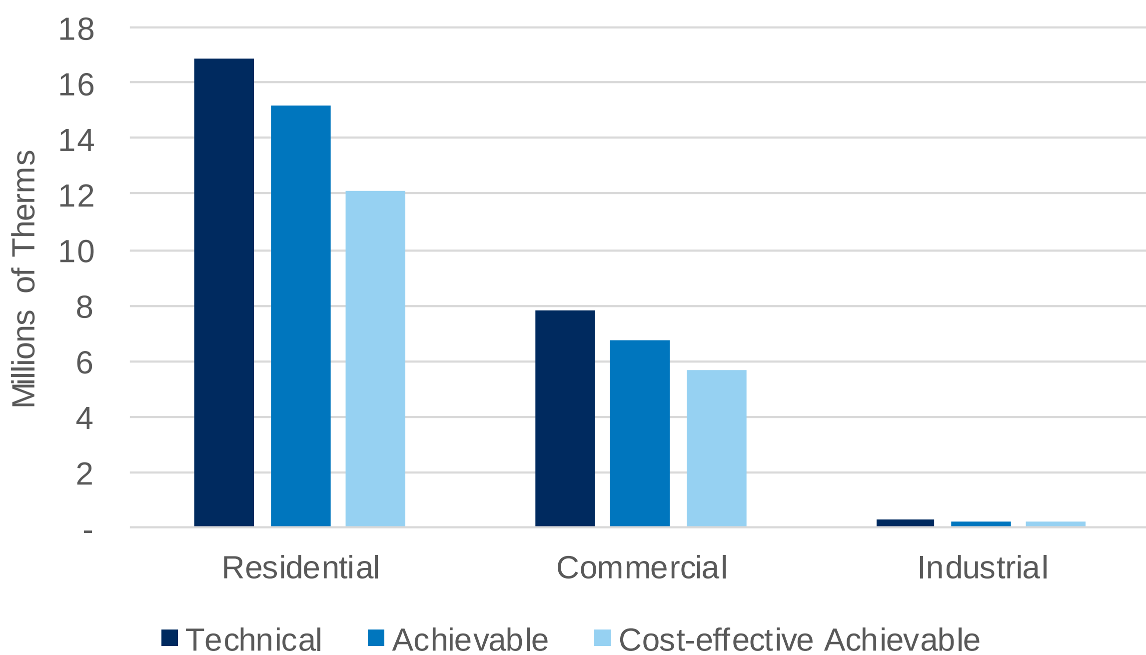
Table 3.3 summarizes the technical, achievable, and cost-effective potential for Avista’s system in Oregon. These savings represent the total 20-year cumulative savings potential identified in the RA Model by the three types identified in Figure 3.4 above. Modeled savings represent the full spectrum 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 3.3: Summary of Cumulative Modeled Savings Potential - 2021–2040

Sector	Technical Potential (Million Therms)	Achievable Potential (Million Therms)	Cost-Effective Achievable Potential (Million Therms)
Residential	16.9	15.2	12.1
Commercial	7.8	6.8	5.7
Industrial	0.3	0.2	0.2
Total	**24.9**	**22.2**	**18.0**

Figure 3.5 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 72% and 73% of technical potential, respectively.

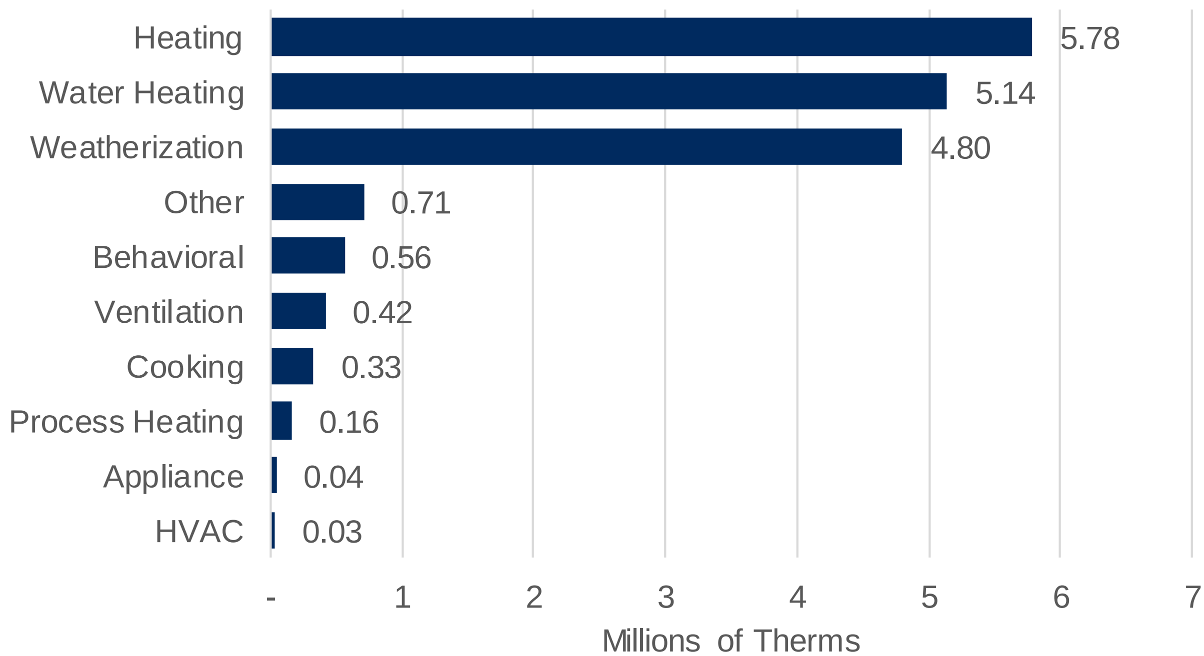
Figure 3.5: Savings Potential by Sector and Type – Cumulative 2021–2040 (Millions of Therms)



Cost-Effective Achievable Savings by End-Use

Figure 3.6 below provides a breakdown of Avista's 20-year cost-effective savings potential by end use.

Figure 3.6: 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, as well as showerheads and aerators. Heating, weatherization, 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 3.4.

Table 3.4: Emerging Technologies Included in the Model

Residential	Commercial	Industrial
• Path 5 Emerging Super-Efficient Whole Home • Window Replacement (U<.20) • Absorption Gas Heat Pump Water Heaters • Advanced Insulation	• DOAS/HRV • Gas-fired Heat Pump Hot Water • Gas-fired Heat Pump, Heating • Advanced Windows	• Gas-fired Heat Pump Water Heater • Wall Insulation-Vacuum Insulated Panel, R0-R35

Energy Trust recognizes that emerging technologies are inherently uncertain and utilizes 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 3.5. 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.

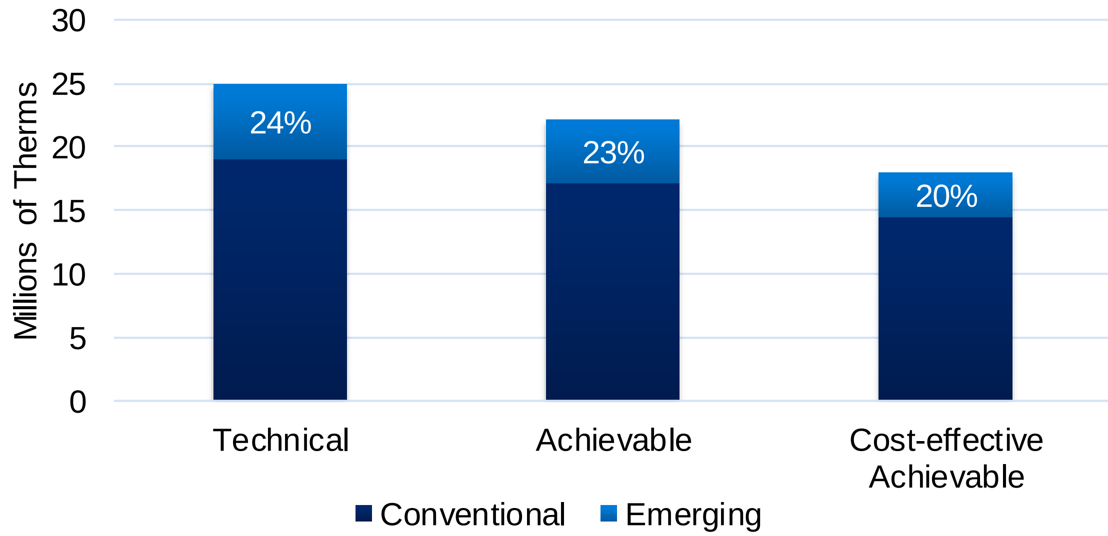
Table 3.5: Emerging Technology Risk Factor Score Card

	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 3.7 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 25%, 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 3.7: Cumulative Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

Table 3.6 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 3.6: Cumulative Cost-Effective Potential (2021-2040) due to Cost-Effectiveness Override (Millions of therms)

Sector	With Cost Effectiveness Override	Without Cost Effectiveness Override	Difference
Residential	12.1	10.9	(1.2)
Commercial	5.7	5.7	-
Industrial	0.2	0.2	-
Total	**18.0**	**16.8**	**(1.2)**

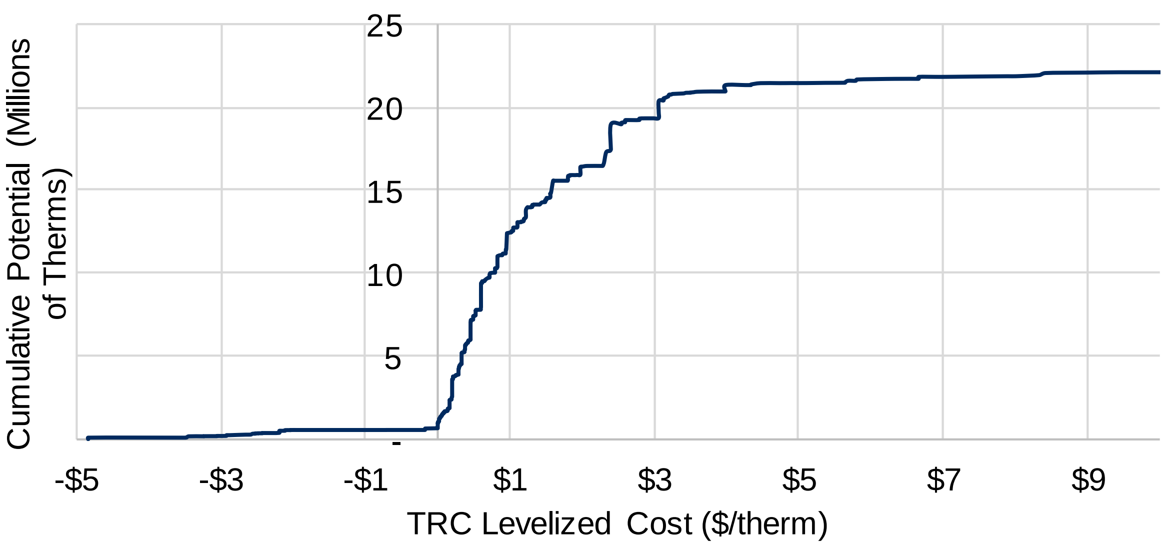
In this IRP, approximately 7% of the cost-effective potential identified by the model is due to the use of the cost-effective override. The measures that had this option applied to them included residential attic, floor, and wall insulation, clothes dryers, certain new homes packages, and clothes washers in the commercial sector.

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 the 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 3.8 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 identified in this assessment is approximately 18 million therms, which translates to approximately $2.40/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. 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 3.8: Natural Gas 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 3.7, which compares the technical, achievable, and cost –effective achievable potential for comparison.

Table 3.7: 20-Year Cumulative Savings Potential by Type (Millions of Therms)

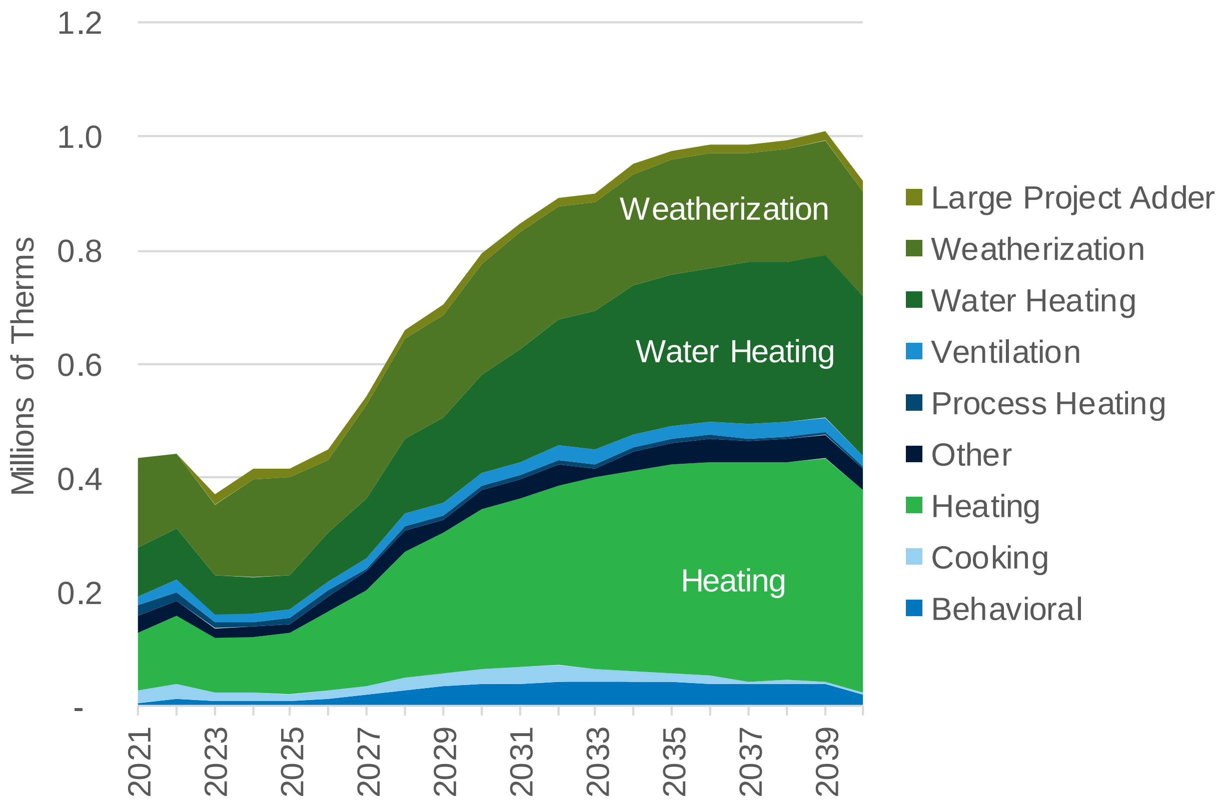
	Technical Potential	Achievable Potential	Achievable Cost-Effective Potential	Energy Trust Deployed Savings Projection
Residential	16.9	15.2	12.1	8.2
Commercial	7.8	6.8	5.7	6.1
Industrial	0.3	0.2	0.2	0.5
Total	**24.9**	**22.2**	**18.0**	**14.8**

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.

However, in the commercial and industrial sectors, the final Energy Trust savings projection is higher than the model-identified cost-effective potential. In the commercial sector, new construction savings are difficult to adequately represent in the model and program forecasts exceed the available potential quantified in the RA model. The industrial sector projection is higher because it includes an adder for large projects that are not forecast by the RA model but are nonetheless expected to be acquired over time.

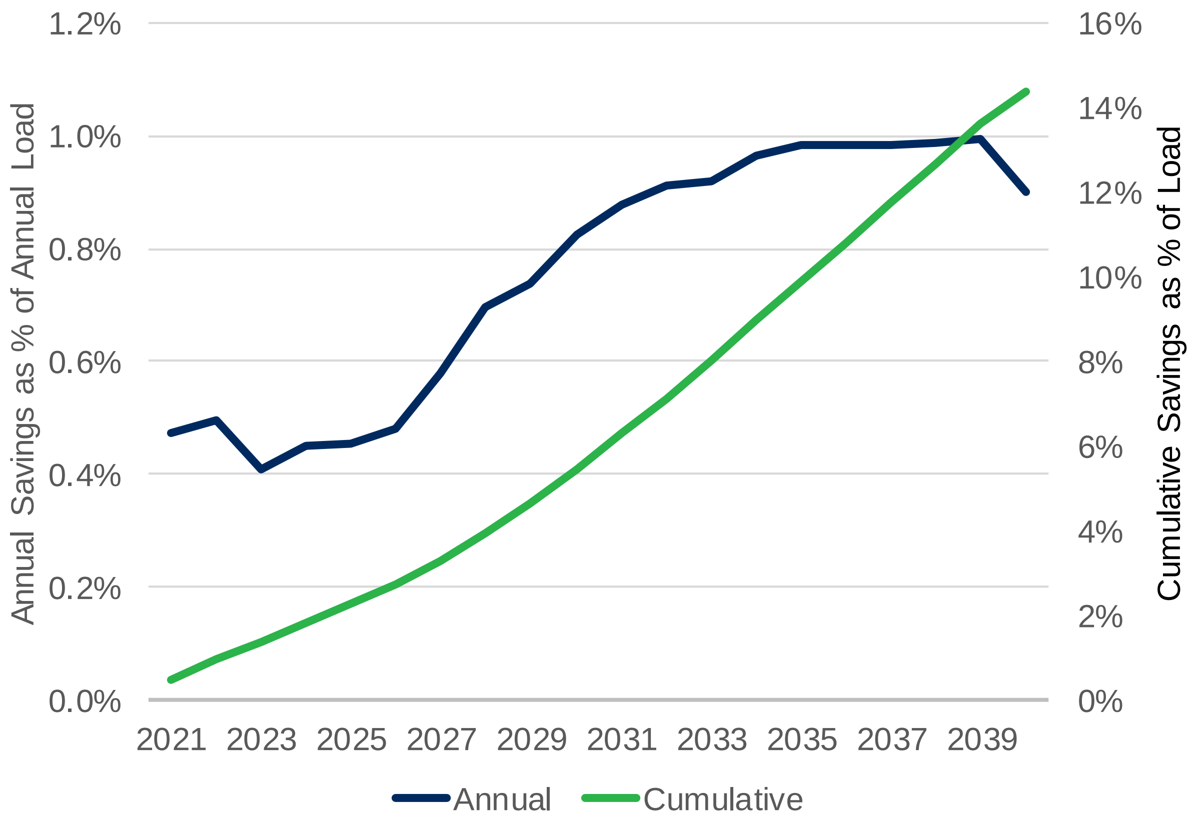
Figure 3.9 below shows the annual savings projection by end use. The savings acquisitions in the initial years are fairly flat due to expected market conditions. After this point, expected program savings ramp up over the forecast period, to achieve as much cost-effective potential as possible.

Figure 3.9: Annual Deployed Final Savings Potential by End Use



Finally, Figure 3.10 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 14.4% by 2040, as shown on the right axis and the gold line.

Figure 3.10: Annual and Cumulated Forecasted Savings as a Percentage of Avista Load Forecast



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 their impact on capacity investments. This new focus has led some utilities to embark on targeted load management efforts for avoiding or delaying distribution system reinforcements. Therefore, Avista and Energy Trust have collaborated to develop estimates of peak day contributions from the energy efficiency measures that Energy Trust forecasts to install.

Peak day coincident factors are the percentage of annual savings that occur on a peak day and are shown in Table 3.8 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 measure 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 in 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 aligns with a typical winter system peak of natural gas utilities. These peak day factors will be reviewed and updated by Avista to be specific to Avista's Oregon service territory in the next IRP.

Table 3.8: Peak Day Coincident Factors by Load Profile

Load Profile	Peak Day Factor	Source
Residential Space Heating	2.10%	NW Natural
Commercial Space Heating	1.80%	NW Natural
Water Heating	0.40%	NWPCC
Clothes Washer	0.20%	NWPCC
Process Load	0.30%	NWPCC

Figure 3.11 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 207,427 therms, or 1.4% of the total deployed savings potential in Avista's Oregon service territory over the 20-year forecast, as shown below.

Figure 3.11: Annual Deployed Peak Day DSM Savings Contribution by Sector

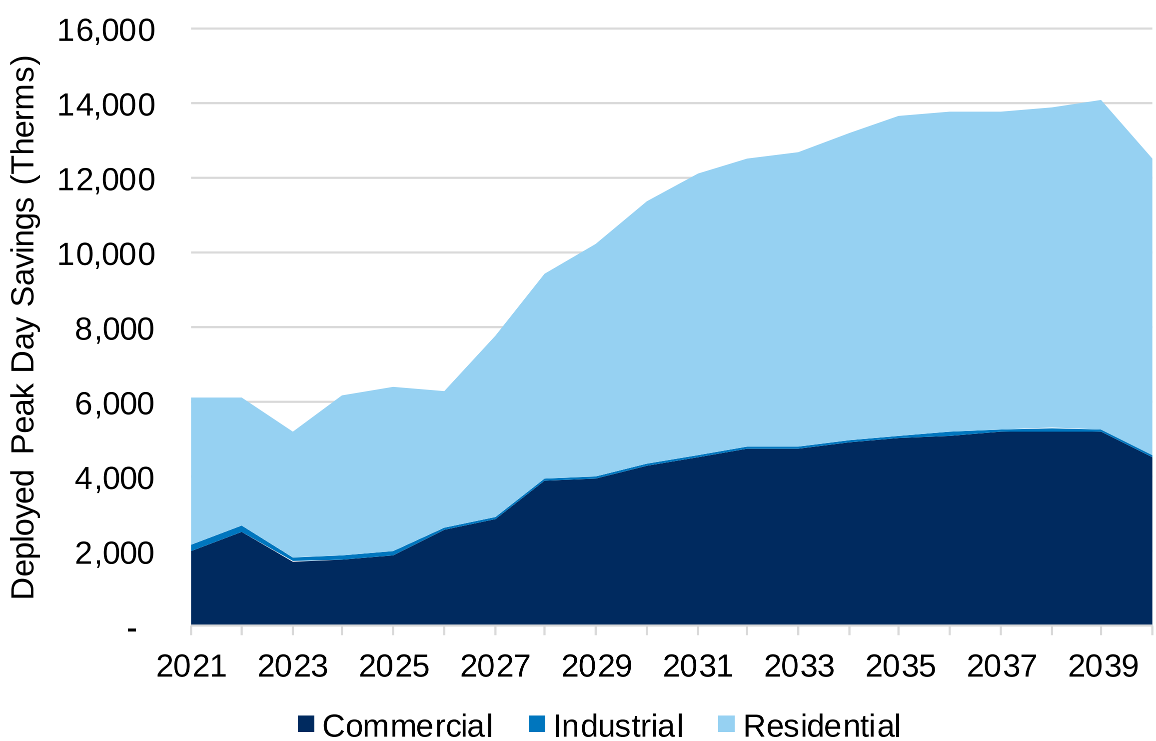


Table 3.9: Cumulative Deployed Peak Day DSM Savings Contribution by Sector (Therms)

Sector	Cumulative Peak Day Savings (Therms)	% of Overall Sector Savings
Commercial	76,529	1.3%
Residential	129,245	1.6%
Industrial	1,653	0.3%
Total	**207,427**	**1.4%**

Conclusion

Avista has a long-term commitment to responsibly pursuing all available and cost-effective efficiency options as an important means to reduce its customer's energy cost. Cost-effective demand-side management options are a key element in the Company's strategy to meet those commitments. Falling avoided costs and lower growth in customer demand have led to a reduced role for conservation in the overall natural gas portfolio compared with IRPs done prior to 2012, however, a regulatory shift to utilizing the UCT in Washington and Idaho DSM programs will continue to provide a vital role in offsetting future natural gas load growth. The company transitioned its Oregon DSM regular income, commercial, and industrial customer programs to the Energy Trust of Oregon (ETO), with the ETO being the sole administrator effective January 1, 2017. Avista is continuing to adaptively manage its DSM programs in response to the ever-shifting economic climate.

Market transformation is not itself called out within the CPA since the CPA focuses upon conservation potential without regard to how that potential is achieved. The prospect for a regional market transformation entity will potentially bring a valuable tool to bear in working towards the achievement of the cost-effective conservation opportunities identified within the natural gas CPA.

4: Supply-Side Resources

Overview

Avista analyzed a range of future demand scenarios and possible cost-effective conservation measures to reduce demand. This chapter discusses supply options to meet net energy demand. Avista's objective is to provide reliable 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 consider 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 components 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 (H2) are also considered.

Commodity Resources

Supply Basins

The Northwest continues to enjoy a low-cost commodity environment with abundant supply availability, especially when compared 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 that had historically been delivered from the Western Canadian Sedimentary Basis (WCSB). Current forecasts show a long-term regional price advantage for Western Canada and Rockies gas basins as the need for this gas diminishes. High Canadian production paired with limited options for flowing gas into demand areas has created a, generally, discounted commodity in the Northwest when compared to the Henry Hub. Although stalled due to an oil price collapse in 2020, associated gas from oil wells is still providing a large amount of the natural gas supply. 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. There are a few LNG export facilities in the Western half of North America. The first is Jordan Cove and although approved by FERC, it is not expected to be built in the long-term outlook from Wood Mackenzie. The second is Canadian project known 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, like Jordan Cove, is roughly 1 Bcf per day, but contains an option for up to 3.5 Bcf per day in total. 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.

Another relatively new demand area is Mexico. 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 Bcf per day.

Recent estimates from both the EIA and Natural Resources Canada reflect a large potential supply of natural gas in North America of over 4,000 trillion cubic feet (Tcf) or enough supply to last many decades at current demand levels. This estimate is based on known geological areas combined with the ability to economically recover natural gas as infrastructure expands and technology improves.

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 which take 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

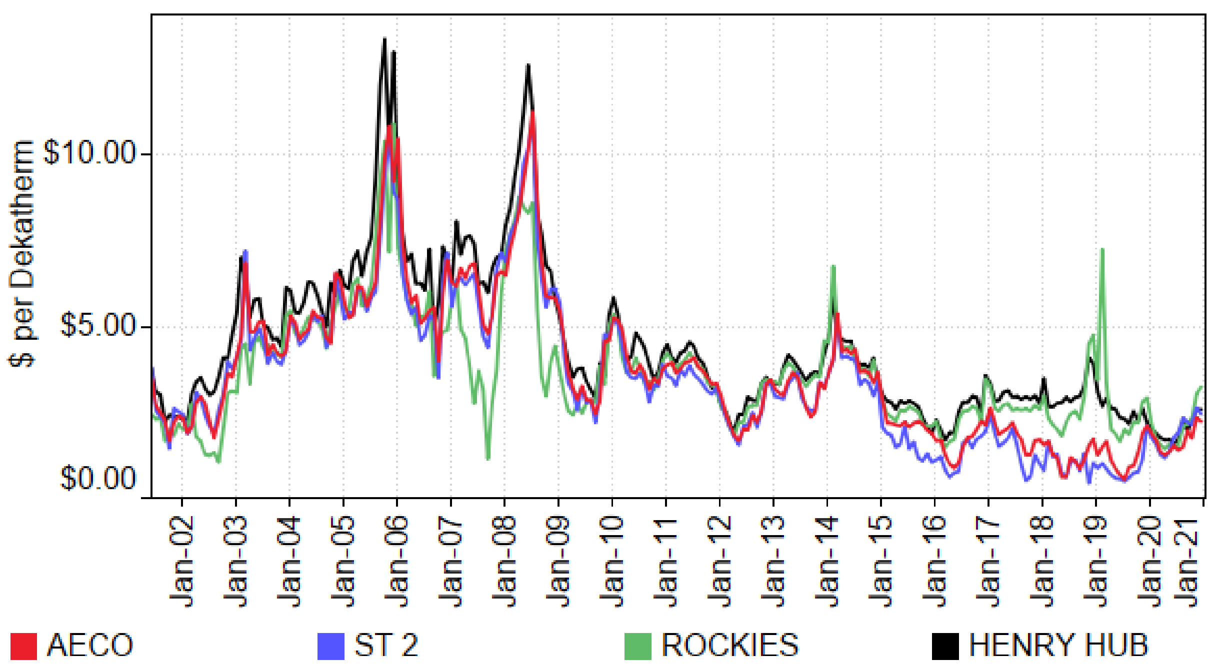
Enbridge's Westcoast Pipeline and predominantly markets Canadian natural gas from Northern British Columbia.

- **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.

Given the ability to transport natural gas across North America, natural gas pricing is often compared to the Henry Hub price. 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 via 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:

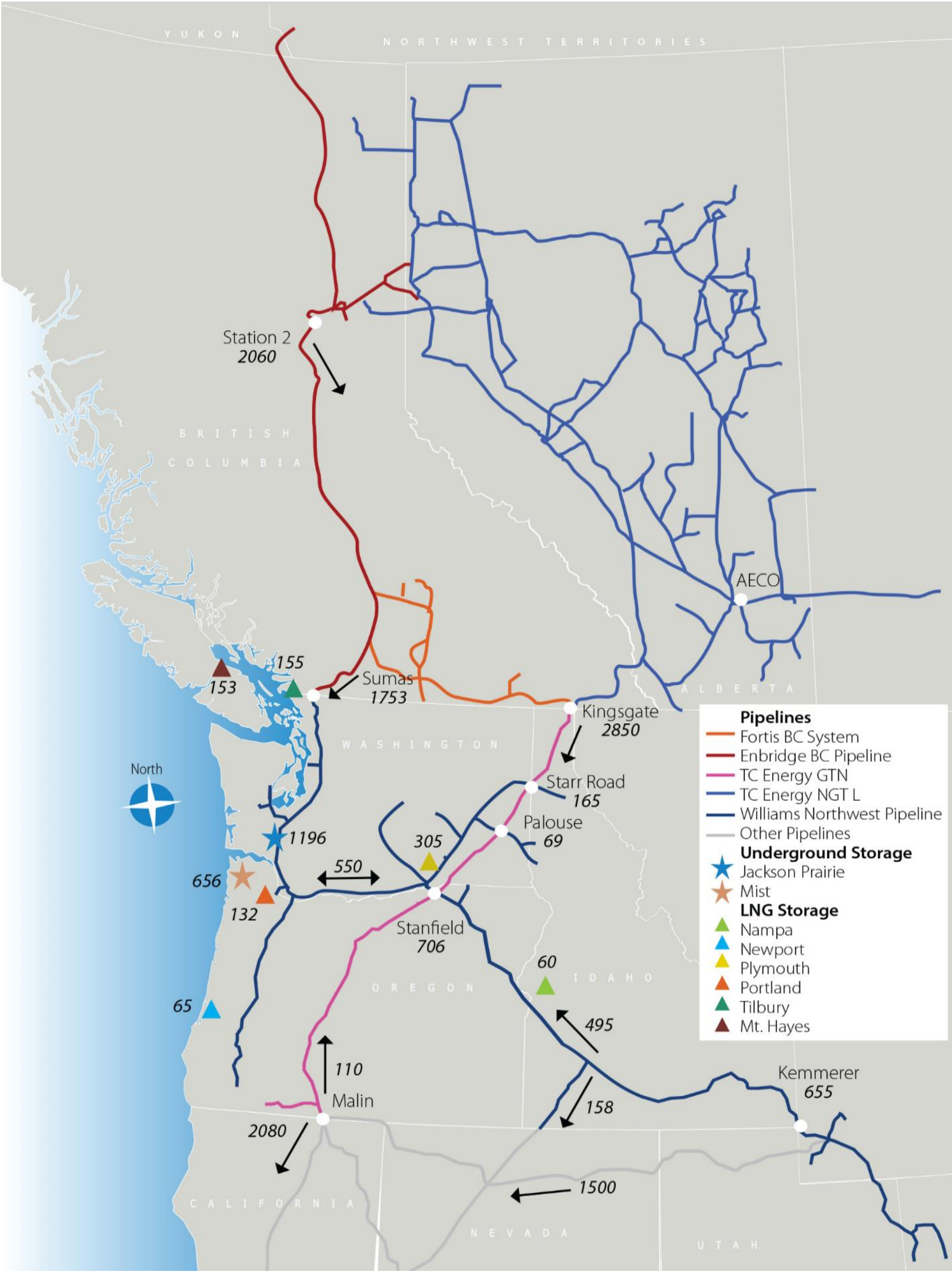
- **Firm vs. Non-Firm:** Most term contracts specify that supplies are firm except for force majeure conditions. In the case of non-firm supplies, the standard provision is that they may be cut for reasons other than force majeure conditions.
- **Fixed vs. Floating Pricing:** The agreed-upon price for the delivered gas may be fixed or based on a daily or monthly index.
- **Physical vs. 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, the SENDOUT® model 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.

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 a sufficient amount of diversified firm pipeline capacity from various receipt and delivery points (including storage facilities), so that 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 4.2)

Figure 4.2: 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 of the above pipelines (with the exception of Ruby Pipeline) for firm transportation to serve core customers. Table 4.1 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 4.1: Firm Transportation Resources Contracted (Dth/Day)

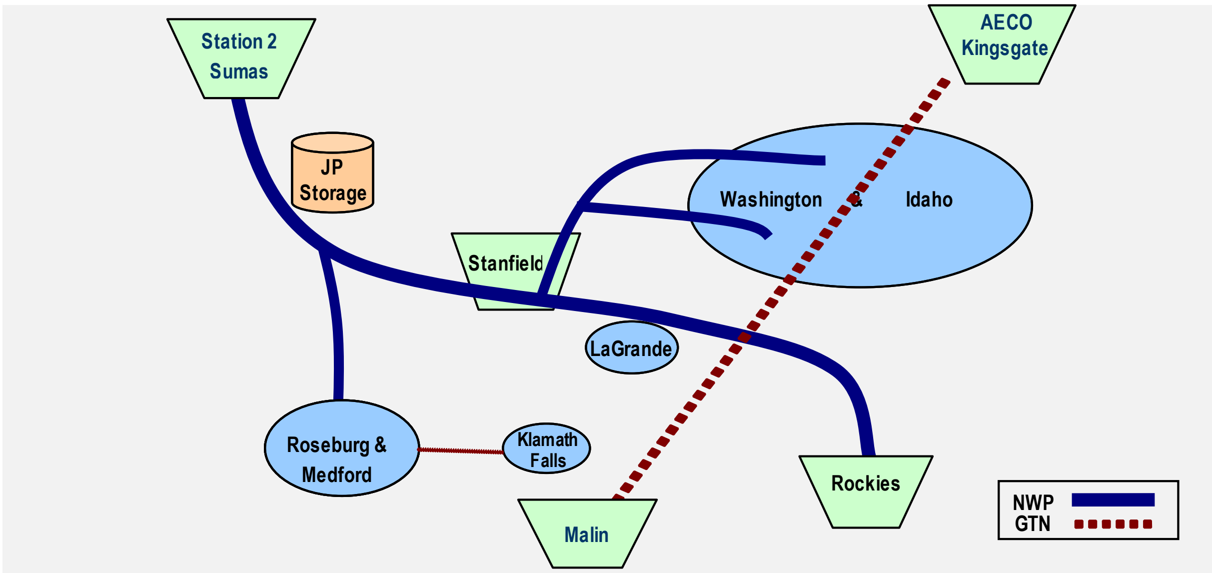
	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson Prairie	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 our one third ownership rights. This number only indicates how much we can withdraw from the facility, as transport on NWP is needed to move it from the facility itself. Figure 4.3 illustrates the direct-connect pipeline network relative to Avista's supply sources and service territories.[1]

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.

Figure 4.3: 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 that deliver supply to service territories among regional LDCs are similar but are rarely generic.

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 which Avista would likely bear most of the incremental costs.

The GTN system, also fully contracted, runs from the Kingsgate trading point on the Idaho-Canadian border down 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. Northwest Pipeline (NWP) provides direct access to Rockies and British Columbia supply 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 – Integrated Resource Portfolio 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 the 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 that allow available resources 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 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 that enables improved management of a highly seasonal and varied demand profile. Storage benefits include:

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

While there are several storage facilities available in the region, Avista's existing storage resources consist solely of ownership and leasehold rights at the Jackson Prairie Storage facility.

Avista optimizes storage as part of its asset management program. This helps to ensure a controlled cost mechanism is in place to manage the large supply found within the storage facility. An example of this storage optimization is selling today at a cash price and buying a forward month contract or selling between different forward months. Since forward months have risks or premiums built into the price the result is Avista locking in a given spread. Storage optimization takes place all 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

Avista is one-third owner, with NWP 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 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 SENDOUT® 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

In some instances, there is available capacity on existing pipelines. As previously discussed, both GTN and NWP are fully subscribed, but GTN currently maintains the ability to flow additional supply from Kingsgate to Spokane as noted in Chapter 7. Avista has modeled access to the GTN capacity as an option to meet future demand needs in addition to some capacity in the La Grande area where some quantities are available on NWP.

GTN Backhauls

The GTN interconnection with the Ruby Pipeline has enabled 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.

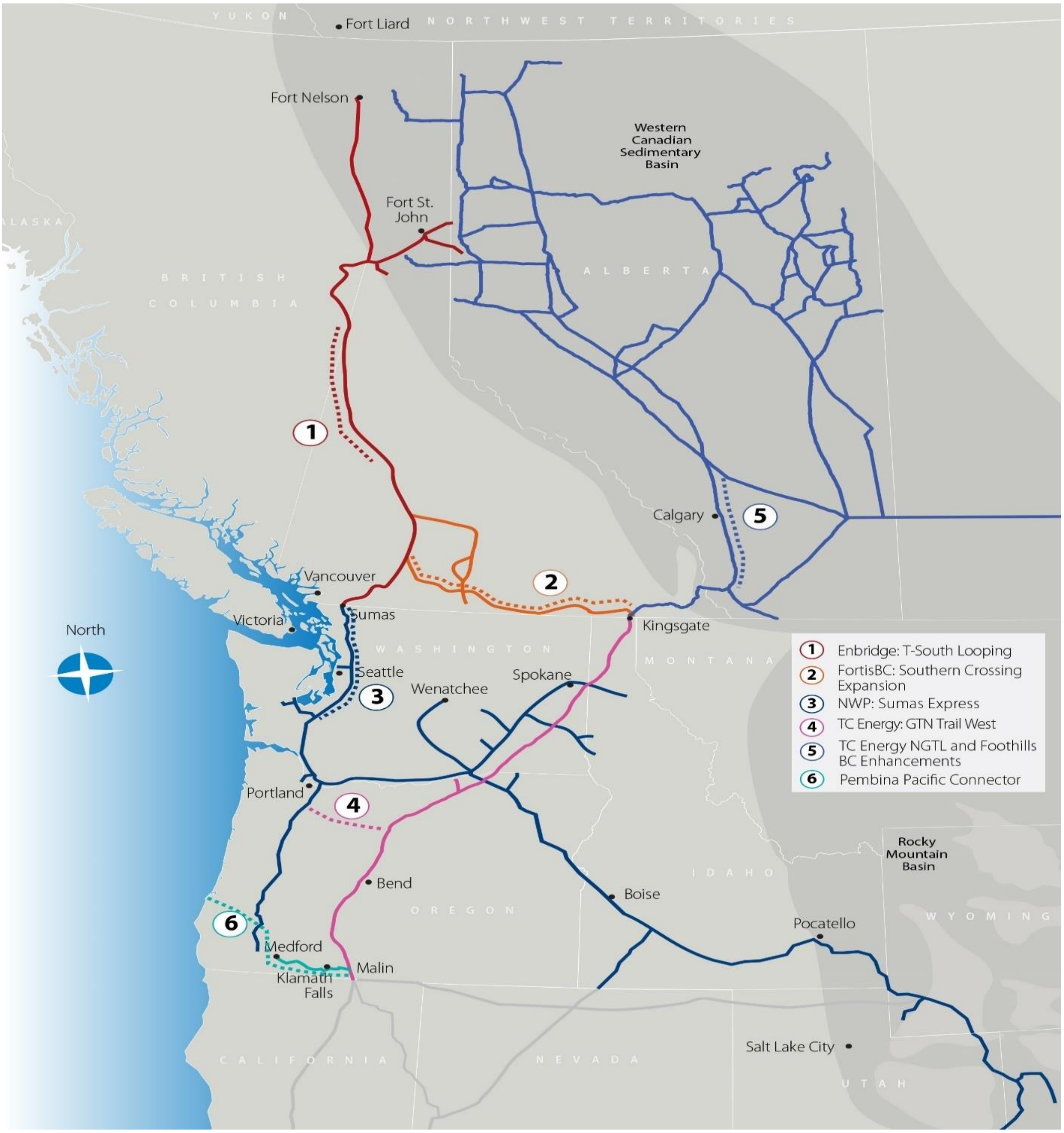
New Pipeline Transportation

Additional firm pipeline transportation resources are viable and attractive resource options. However, determining the appropriate level, supply source and associated pipeline path, costs and timing, and if existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline transportation provides several advantages; it provides the ability to receive firm supplies at the production basin, it provides for base-load demand, and it can be a low-cost option given optimization and capacity release opportunities. Pipeline transportation has several drawbacks, including typically long-dated contract requirements, limited need in the summer months (many pipelines require annual contracts), and limited availability and/or inconvenient sizing/timing relative to resource need. No new pipelines were considered in the current IRP as resource options due to the exceedingly difficult legal path in getting approval for their construction. If one of these pipeline projects were to come forward as a viable option Avista would consider the costs and risks in a future IRP.

Pipeline expansions are typically more expensive than existing pipeline capacity and often require long-term contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option given that some of the other options require matching pipeline transportation. Matching pipeline transportation is creating equivalent volumes on different pipelines from the basin to the delivery point in order to fully utilize subscribed capacity. Expansions may also provide increased reliability or access to supply that cannot be obtained through existing pipelines. This is the case with the Pacific Connector pipeline being proposed as the connecting feedstock for the Jordan Cove LNG facility in Oregon. The pipeline’s current path connects into Northwest Pipelines Grants Pass Lateral where capacity is limited. The Pacific Connector pipeline would add an additional 50,000 Dth/day of capacity along that lateral flowing south from the Roseburg interconnect.

Several specific projects have been proposed for the region. The following summaries describe these projects while Figure 4.4 illustrates their location.

Figure 4.4: Proposed Pipeline Locations



1. **Enbridge T-South System Looping**

   FortisBC and Enbridge are system enhancement on the T-South pipeline. Removing constraints will allow expansion of Enbridge's T-South enhanced service offering, which provides shippers the options of delivering to Sumas or the Kingsgate market. Expanding the bi-directional Southern Crossing system would increase capacity at Sumas during peak demand periods. Initial capacity from the Enbridge system to Kingsgate would increase capacity by 190MMcf/d. This would add incremental gas into the Huntingdon/Sumas market through looping and compressor station upgrades along the system.

2. **FortisBC Southern Crossing Expansion:**

The Southern Crossing pipeline system is a bidirectional pipeline connecting Westcoast T South system at Kingsvale, BC and TransCanada's Alberta/BC border. This expansion would include over 90 miles of pipeline looping allowing access to an additional 300-400 MMcf/d of bi-directional capacity, tying together station 2 and AECO markets.

3. **NWP - Sumas Express**

NWP continues to explore options to expand service from Sumas, Wash., to markets along the Interstate-5 corridor. This project could help relieve the congestion along this highly populated geographical region in both Washington and Oregon. Various methods could be used to add this additional capacity including looping, additional compression and increasing the pipe size and can be scaled based off demand.

4. **TC Energy GTN Trail West**

The pipeline taking natural gas off of GTN and onto NWP hub near Molalla is referred to as Trail West. TransCanada GTN, Northwest Natural and Northwest Pipeline are the project sponsors of this 106-mile, 30-inch diameter pipeline. The initial design capacity of this pipeline is 500 MMcf/d and expandable up to 1,000 MMcf/d. This could be an important project if built as it would bring more gas into the I-5 corridor where unused pipeline capacity is quickly disappearing based on the demand for natural gas and population increase.

5. **TC Energy NGTL and Foothills BC Enhancements**

In order to meet existing aggregate demand in southern AB and incremental long-term delivery commitments at the A/BC border, NGTL is ongoing and expected to have an in-service date of 2022. This project will increase the delivery point capacity at the A/BC border by 288,000 GJ per day and will operationally true-up capacity differences between NGTL and Foothills and provide additional export capacity into the US.

6. **Pacific Connector**

Pembina is currently attempting to acquire approval for a 232-mile, 36-inch diameter pipeline designed to transport up to 1.2 billion cubic feet of natural gas per day from interconnects near Malin, Oregon, to the Jordan Cove LNG terminal in Coos Bay, Oregon. The pipeline would deliver the feedstock to the LNG terminal providing natural gas to international markets, but also to the Pacific Northwest. The pipeline will connect with Williams' Northwest Pipeline on the Grants Pass lateral. This ties in directly within Avista's service territory and will bring in an additional 50,000 Dth/day of capacity into that area. This new option could provide Avista's customers in the area new capacity for growth and supply diversity.

Avista supports proposals that bring supply diversity and reliability to the region. Supply diversity provides a varied supply base in the procurement of natural gas. Since there are few options in the Northwest, supply diversity provides options and security when constraints or high demand are present. Avista engages in discussions and analysis of the potential impact of each regional proposal from a demand serving and reliability/supply diversity perspective. In most cases, for Avista to consider them a viable incremental resource to meet demand needs, it would require combining them with additional capacity on existing pipeline resources.

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 that could fully utilize these additional resource options. When an opportunity presents itself, Avista assesses the financial and reliability impact to customers. Due to the fast paced 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 market environment.

LNG Exports

Liquefied natural gas is a process of chilling natural gas to -260 degrees Fahrenheit to create a condensed version, 1/600 the volume, of natural gas. This process acts as a virtual pipeline taking domestic production to nearly any location in the world. For years the U.S. was expected to be an importer of LNG. This is a stark contrast to reality as in 2017 the export of LNG from the U.S. has quadrupled led by two projects, Sabine Pass in Louisiana and Cove Point in Maryland. In recent history, this market dynamic has changed from fixed price gas contracts to more spot purchases of LNG. The three largest countries for U.S. LNG exports are South Korea, Japan and Spain. Waiting in the wings to provide more LNG supply are four additional export facilities located mostly in the gulf coast region of the U.S. and will bring the additional demand to nearly 9 Bcf per day. This massive buildout of LNG exports has led to the U.S. becoming the third largest exporter of LNG in the world.

LNG and CNG

LNG is another resource option in Avista’s service territories and is suited for meeting peak day or cold weather events. Satellite LNG uses natural gas that is trucked to the facilities in liquid form from an offsite liquefaction facility. Alternatively, small-scale liquefaction and storage may also be an effective resource option if natural gas supply during non-peak times is sufficient to build adequate inventory for peak events. Permitting issues notwithstanding, facilities could be located in optimal locations within the distribution system.

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.

Estimates for LNG and CNG resources vary because of sizing and location issues. This IRP uses estimates from other facilities constructed in the area and from conversations with experts in the industry. Avista will monitor and refine the costs of developing LNG and CNG resources while considering lead time requirements and environmental issues.

Plymouth LNG

NWP owns and operates an LNG storage facility at Plymouth, Wash., which provides natural gas liquefaction, storage and vaporization service under its LS-1, LS-2F and LS-3F tariffs. An example ratio of injection and withdrawal rates show that it can take more than 200 days to fill to capacity, but only three to five days to empty. As such, the resource is best suited for needle-peak demands. Incremental transportation capacity to Avista’s service territories would have to be obtained in order for it to be an effective peaking resource. With available capacity, Plymouth LNG was considered in our supply side resource modeling but was not selected.

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.

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 has been found to have a multiplier effect on global warming of 34[2] times that of carbon dioxide. Each type of RNG has a different carbon intensity as compared to natural gas as shown in table 4.2.

[2] https://www.ipcc.ch/

Table 4.2: Carbon Intensity[3]

Source	Current Carbon Intensity (g CO2e/MJ)	Estimated % of Carbon reduction as compared to natural gas	lbs. per Dth
Natural Gas	78.37		128.27
Landfill	46.42	41%	75.98
Dairy	-276.24	-452%	(580.40)
WWT	19.34	75%	31.65
Solid Waste	-22.93	-129%	(165.80)

RNG is a renewable fuel, so it may qualify for renewable energy subsidies. Once contained, 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 greater the need for pipeline quality gas.

Biogas projects are unique, so reliable cost estimates are difficult to obtain. Project sponsorship has many complex issues, and the more likely participation in such a project is as a long-term contracted purchaser. Avista considered biogas as a resource in this planning cycle and depending on the location of the facility it may be cost effective. This is especially the case when found within Avista's internal distribution system where transportation and fuel costs can be avoided. For more information about RNG and its potential uses in energy policy within Avista territories please see Chapter 5 - Carbon Reduction.

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 the volatility and cost of that supply. Avista manages the procurement plan by layering in hedges over a period of time based on average system load 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 we have secured firm load at a reasonable price while addressing risk inherent

[3] California Air Resources Board

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 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 2021 IRP focuses on two areas of risk: the financial risk of the cost of natural gas to supply customers will be unreasonably high or volatile, and the physical risk that there may not be enough natural gas 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 through which 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 two-fold:

1. Serve Load – Assure adequate and reliable energy supplies for Avista Utilities natural gas customers.

2. Manage Resources – Exercise prudent stewardship of Avista Utilities energy supply facilities and related Company resources.

Through the use of fixed-priced hedges, daily balancing transactions and storage injections and withdrawals the Company can meet its obligation to serve load. In addition, through our Dynamic Window Hedges and Risk Responsive Hedges, we are also able to provide a level of price certainty in volatile commodity markets and reduce cost risk exposure. Related to managing our resources, we have secured firm natural gas transportation capacity in order to ensure we are able to reliably deliver the commodity to our customers. Finally, we have secured a level of storage (through ownership at Jackson Prairie) providing Avista with an additional level of firm supply and associated transportation contracts.

It is part of Avista's culture to be good stewards of our customer's resources. While there is no "targeted performance level", success is measured by the ability to capture benefit from our existing resources to the best of our ability, which results in either lower overall expenses for our customers or a higher level of price certainty. As such, we are continuously monitoring the procurement plan, evolving market conditions, new supply opportunities, and regulatory conditions.

Accordingly, effective in 2015 the Company implemented a new Storage Optimization Model which meets the definition of "Strategic Initiative" as described above. Prior to the implementation of the model, Storage had been utilized in the standard way – to purchase natural gas in the spring and summer when prices are historically low, inject into Storage, and withdraw in the winter when prices are historically high. Through the use of this model, we are able to still provide reliability of supply for our customers, but also capture benefits of price spreads between time periods. The model is governed by a storage management program that sets boundaries on injections and withdrawals as well as tracks real time market data to guide the purchase and sale of natural gas storage transactions with favorable spreads. Through this model, the Company can purchase natural gas in one period and sell into a higher priced market, effectively locking in a benefit for our customers.

The program enforces storage constraints and requirements such as the storage fill schedule, peak day load requirements, transportation capacity limits, and deliverability constraints.

The Company also has mechanisms in place which allow us to optimize the value of our existing pipeline and storage assets in order to reduce costs for customers until such resources are required to meet demand. Should there be transportation capacity that is not required to serve load, we may be able to optimize this capacity by purchasing natural gas, transporting it, and selling it into a higher priced market. Commodity purchases and sales are carefully tracked and allocated, or directly assigned, jurisdictionally based on the unique characteristics of each individual pipeline capacity.[4] Avista may also be able to release a portion of this unutilized firm transportation capacity to third parties, further reducing customer's firm transportation expense.

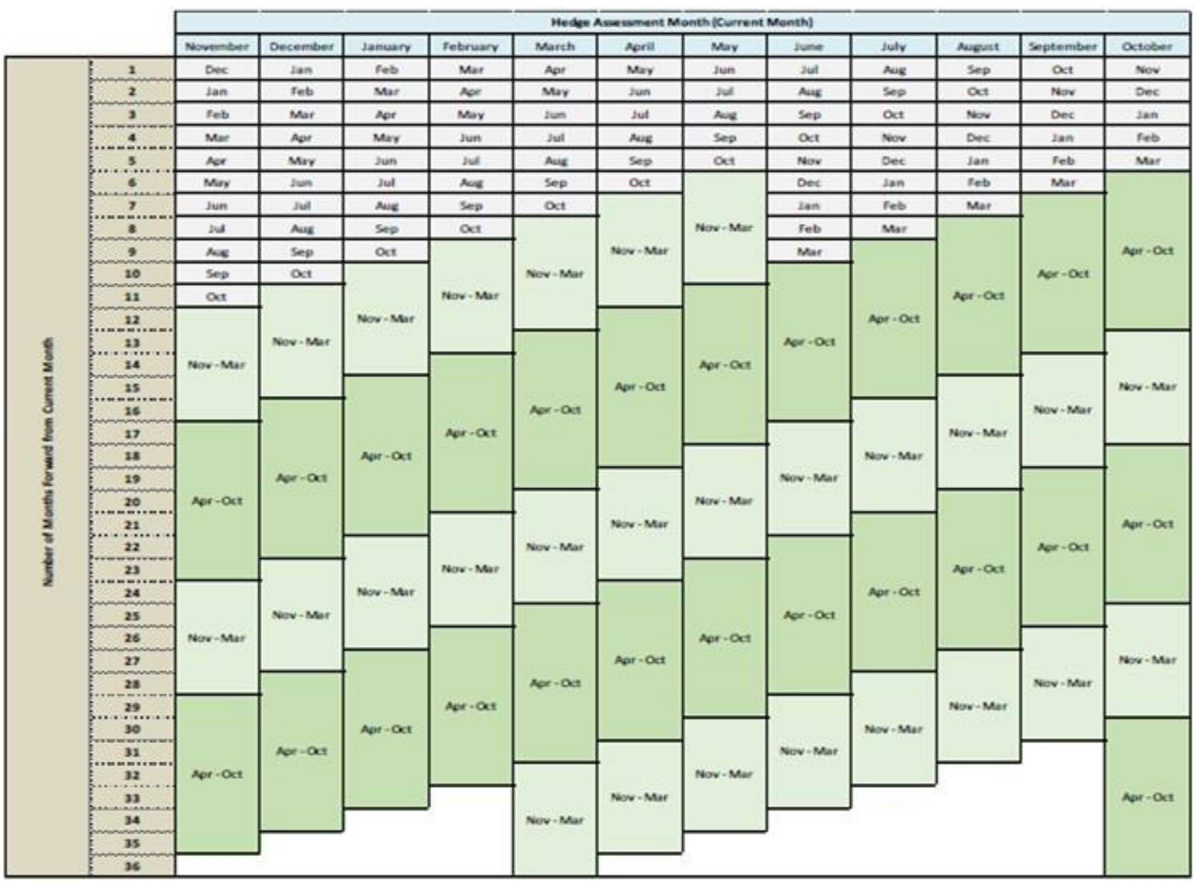
[4] Allocation between Washington and Idaho for Commodity purchases and sales is based on actual calendar load for each respective month.

Dynamic Window Hedges (DWH)

The DWH portion of the plan secures a pre-determined, minimum hedge portion for LDC load with fixed priced purchases. These transactions are diversified in terms of time, location and delivery period. The target delivery periods, development, procures, and execution are described below. Dynamic Window Hedging reduces the cost risk and increases the loss risk.[5]

The target delivery periods for the DWH portion of the Plan is for a period of 30 to 36 months depending on market availability of the hedging period (Figure 4.5).

Figure 4.5: Dynamic Window Hedging Plan



DWH Development

A DWH is defined by its set-price (SP), an upper control limit (UCL), a lower control limit (LCL) and an expiration date. The SP is the closing price of the day prior to the window

[5] Loss risk is the potential to pay more than the daily gas price with a forward hedge. Cost risk is the potential for daily prices to rise above the hedge price.

opening. The UCL and LCL are developed using quantitative mathematics to define boundaries in relation to the SP. Expiration dates are determined based on the remaining volumes to be hedged and remaining time to expiration. Each DWH's SP is based upon the closing price, of the selected supply basin for the delivery period. The supply basin for each hedge window will be selected from available term markets, based on whichever market has the highest volatility.

Hedge windows remain "open" as long as the previous day's forward delivery period price remains between the UCL and the LCL, and the window has not reached its time expiration. The selected basin closing price will be the determining benchmark of the forward delivery period price. Hedge window status is examined each business day. If the hedge window's current rate moved outside the UCL or LCL, a hedge transaction is triggered, subject to execution provisions described later in this report. If a SP does not move outside the UCL or LCL prior to time expiration, then the window's hedge transaction is executed on the expiration date.

Figure 4.6 shows a hedge which was executed for the Summer of 2022 (April – October) time period and the associated limits.

Figure 4.6: Dynamic Window Hedge (April 2022 – October 2022)

Risk Responsive Hedging Tool (RRHT)

In 2018, Gas Supply incorporated a Risk Responsive Hedging Tool in addition to the Dynamic Window Hedges discussed above. The RRHT helps to manage the Value at Risk (VaR) of Avista's LDC natural gas portfolio's open position on a daily basis. The forward gas prices are the basis for the VaR analysis. The analysis utilizes a confidence level and historic volatility to calculate a portfolio VaR, and combines it with the current mark-to-market portfolio price to develop a price risk metric that is compared to a predetermined threshold value (Operative Boundary). If the price metric exceeds the Operative Boundary, then one or more hedges will be executed to bring the price metric back within the Operative Boundary. In any case, hedge volumes should not exceed the Maximum Hedge Ratio. Upon trigger, Gas Supply will begin to transact to bring the price metric back within the Operative Boundary.

The Dynamic Window Hedging will continue to systematically hedge to a certain minimum hedge level through the use of time limits and UCL/LCL. RRHT will monitor the market financially and call for additional hedging if pre-determined risk tolerance limits are triggered.

The RRHT includes all utility purchase and sales transactions, estimated customer load, and storage injections and withdrawals to derive open positions (by basin) that are marked to forward market prices. These monthly financial positions, along with market volatility, are then used to calculate the Value at Risk (VaR) by basin, which in turn is used to evaluate recommended hedging actions.

Supply Issues

The abundance and accessibility of shale gas has fundamentally altered North American natural gas supply and the outlook for future natural gas prices. Even though the supply is available and the technology exists to access it, there are issues that can affect the cost and availability of natural gas.

Hydraulic Fracturing

Hydraulic fracturing (commonly referred to as fracking) was invented by Hubbert and Willis of Standard Oil and Gas Corporation back in the late 1940's. The process involves a technique to fracture shale rock with a pressurized liquid. In the past 15 years, the techniques and materials used have become increasingly perfected opening up large deposits of shale gas formations at a low prices. The Energy Information Administration (EIA) tracks production per well in the seven key oil and natural gas production formations in the United States as shown in Figure 4.7. Figure 4.8 shows the continued increase in efficiency of production compared to just a year ago as shown by the EIA's Drilling Productivity Report 4.9[6].

Figure 4.7: Seven Major Drilling Regions in the United States

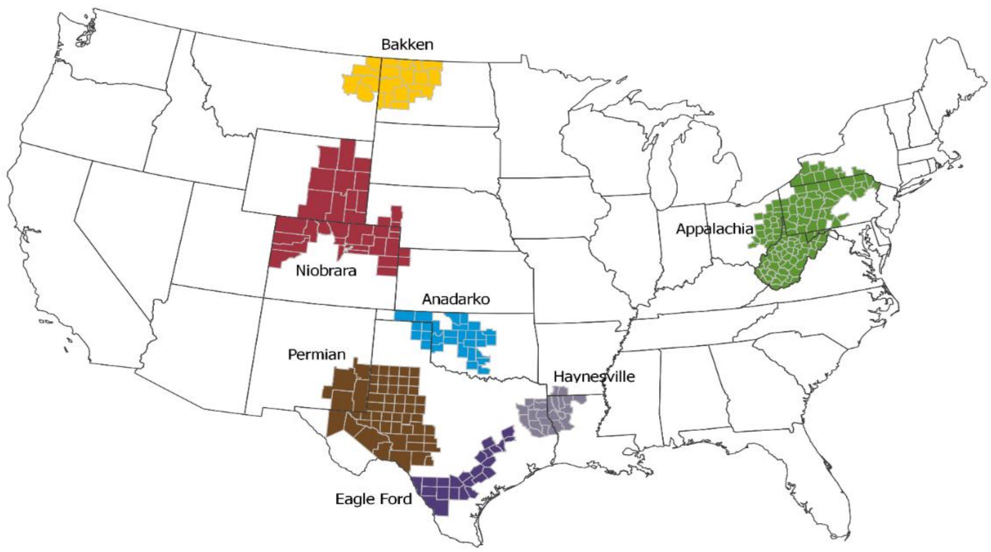
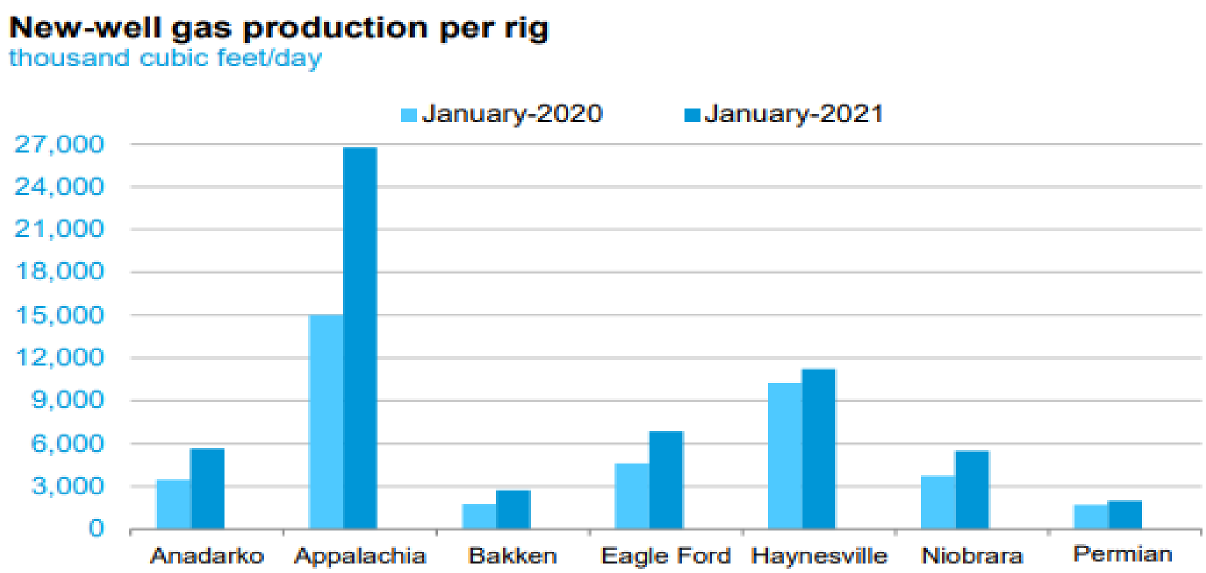


Figure 4.8: December 2020 Drilling Productivity Report, EIA[7]



With the increasingly prevalent use of hydraulic fracturing came concerns of chemicals used in the process. The publicity caused by movies, documentaries and articles in

[6] Drilling Productivity Report, https://www.eia.gov/petroleum/drilling/pdf/summary.pdf

[7] www.eia.gov

national newspapers about “fracking” has plagued the natural gas and oil industry. There is concern that hydraulic fracturing is contaminating aquifers, increasing air pollution and causing earthquakes. The actual cause of earthquakes is wastewater injection used in operations at the well site. Based on research at the U.S. Geological Survey, only a small number of these earthquakes are from fracking itself.[8] Additionally, wastewater injections are used for all well types, not just those where fracking is involved.

The wide-spread publicity generated interest in the production process and caused some states to issue bans or moratoriums on drilling until further research was conducted. To help combat these fears, Frac Focus[9] was created and is a chemical disclosure registry allowing users to view chemicals used by over 125,000 wells throughout North America. This information, voluntarily submitted by Exploration and production companies, provides a detailed list of materials used to frack each individual well.

Pipeline Availability

The Pacific Northwest has efficiently utilized its relatively sparse network of pipeline infrastructure to meet the region’s needs. As the amount of renewable energy increases, future demand for natural gas-fired generation will increase. Pipeline capacity is the link between natural gas and power.

There are currently a few industrial plants being considered in the Pacific Northwest. The project with the highest likelihood is the project located in Washington’s Port of Kalama. This process uses large amounts of natural gas as a feedstock for creating methanol, which is used to make other chemicals and as a fuel. At over 300,000 Dth per day this plant would consume large amounts of natural gas.

Ongoing Activity

Without resource deficiencies or a need to acquire incremental supply-side resources to meet peak day demands over the next 20 years, Avista will focus on normal activities in the near term, including:

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, supply dynamics and marketplace, and pipeline and storage infrastructure availability.

[8] https://profile.usgs.gov/myscience/upload_folder/ci2015Jun1012005755600Induced_EQs_Review.pdf

[9] https://fracfocus.org/

- Monitor availability of resource options and assess new resource lead-time requirements relative to resource need to preserve flexibility.
- Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.
- Monitor renewable supply resource options, availability and pricing trends.

Conclusion

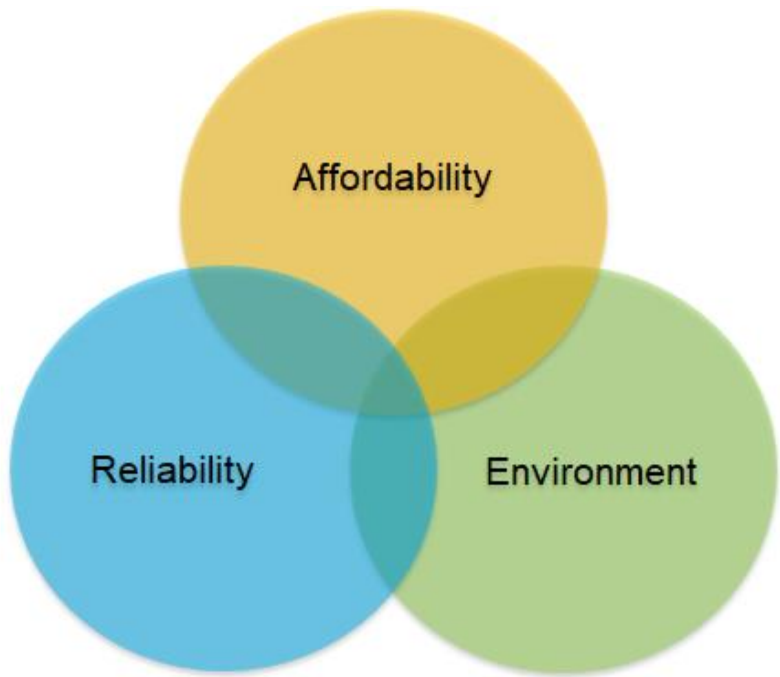
North American fossil natural gas supply continues to show its robustness in spite of challenges it faces. Regional supply constraints are beginning to increase in their likelihood causing prices to act in a more volatile fashion. This volatility in pricing paired with supply side resource availability has made Avista's procurement plan an increasingly important piece to manage customer rates, diversity of supply and peak day demand. Without new supply side resources, the region will face some difficult decisions in the coming decades. This in combination with the optimization of our storage, transportation and basin resources have helped Avista to provide natural gas reliably to our customers at a fair and reasonable price.

5: Carbon Reduction

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 and Carbon Reduction:

Focus on solutions that balance carbon reduction, affordability, and reliability.



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 a generation portfolio that is already more than half renewable, 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 System Emissions

Upstream emissions include any emission found upstream of the point of combustion and includes production, processing, transmission and equipment. To fully account for emissions in the natural gas stream the upstream emissions are now included in the totals as measured in pounds of carbon dioxide equivalent. This becomes important when placing a tax or cost of emissions on the price per Mmbtu. The emissions are measured at the standard 100-year Global Warming Potential (GWP) meaning a 34 multiplier of the heat that would be absorbed by the same mass of carbon dioxide. The levels of upstream gas are determined by production region, specifically in Canada and the Rockies in the United States and multiplied by the associated emissions estimate. Over the past five years, nearly 90 percent of Avista's natural gas was sourced from Canadian production leaving roughly 10 percent of estimated upstream emissions to the Rockies region. When combined with a 0.77 percent of Canadian production attributed to upstream emissions, as calculated in a study for the Tacoma LNG project, the majority of Avista's fossil fuel natural gas is less intensive as compared to the fossil natural gas emissions from the Rockies region of 1.0 percent as calculated in the EIA sinks and emissions estimates. This estimate[1] from the EIA is updated on a yearly basis and will show gains and losses as they occur as compared to a point in time study.

The final upstream emissions from CH4 in carbon equivalent add nearly 10.66 pounds per MMBtu as shown in Table 5.1:

Table 5.1: Avista Specific LDC Natural Gas Emissions

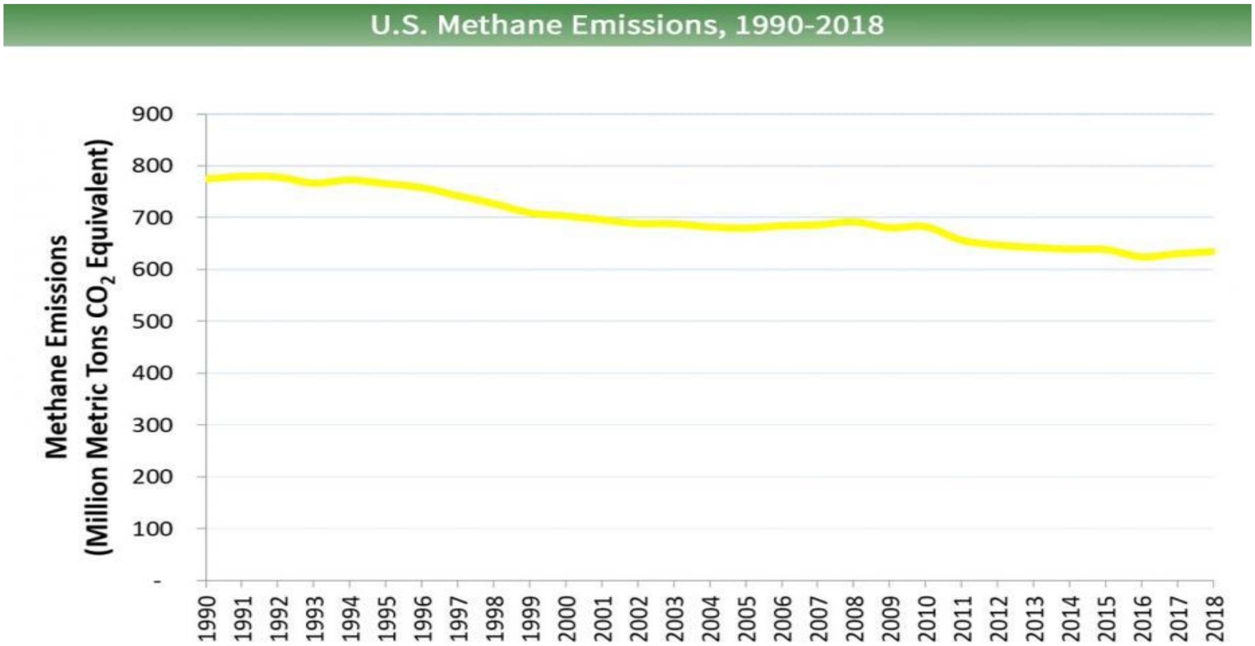
	Avista Specific Natural Gas	
Combustion	**Lbs. GHG/MMBtu**	**Lbs. CO2e/MMBtu**
CO2	116.88	116.88
CH4	0.0022	0.0748
N2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH4	0.313406851	10.66
Total		128.27

At a national level, overall methane emissions in the U.S. have been on the decline for many decades. As illustrated in Figure 5.1, the EPA has estimated methane emissions as decreasing by nearly 20 percent as compared to 1990. As coal fired plants have

[1] Inventory of U.S. Greenhouse Gas Emissions and Sinks | Greenhouse Gas (GHG) Emissions | US EPA

retired, production of electricity natural gas generation has dramatically increased to cover this demand. Interestingly, during this reference period, production from natural gas has more than doubled while total electric production increased 35 percent during this same timeframe.

Figure 5.1: United States Methane Emissions



Carbon dioxide equivalent (CO2e) is the most common unit to measure climate warming. In order to understand how different greenhouse gasses such as methane (CH4) and nitrous oxide (N20) affect the earths warming a conversion must occur. As illustrated in Table 5.2 below, the Intergovernmental Panel on Climate Change released their 5th assessment study to help define these impacts to global warming in units of CO2e.

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

5th Assessment of the Intergovernmental Panel on Climate Change		
Greenhouse Gas	**GWP – 100 Year**	**GWP – 20 Year**
CO_2	1	1
CH_4	34	86
N_2O	298	268

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 that overall levels of leakage were around 0.1 percent to 0.2 percent of methane delivered nationwide. The study goes on to state that the Eastern regions of the United States contribute much more methane to the total, as compared to the Western regions, which were found to account for only 5 percent of these emissions overall. The study theorizes that 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 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."[2]

State and Regional Level Policy Considerations

The lack of a comprehensive federal greenhouse gas policy encouraged states, such as California, to develop their own climate change laws and regulations. Climate change legislation takes many forms, including economy-wide regulation under a cap and trade system, a cap and reduce system, and a carbon tax. Comprehensive climate change policy can include multiple components, such as renewable portfolio standards, DSM standards, and emission performance standards. Individual state actions produce a patchwork of competing rules and regulations for utilities to follow and may be particularly problematic for multi-jurisdictional utilities such as Avista.

Idaho

Idaho Policy Considerations

Idaho does not regulate greenhouse gases. There is no indication Idaho is moving toward regulation of greenhouse gas emissions beyond federal regulations.

Oregon

Oregon Policy Considerations

The State of Oregon has a history of greenhouse gas emissions and renewable portfolio standards legislation. In March of 2020, Governor Brown signed into law Executive Order (EO) 20-04 requiring the reduction of greenhouse gas emissions to at least 45 percent below 1990 levels by 2035 and 80 percent below 1990 levels by 2050. This EO requires the reductions statewide by all carbon emitting sources and managed by the respective emissions sources governing agencies. State agencies are directed to exercise any and all authority to achieve GHG emissions reduction goals expeditiously. Many specifics of

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

this EO will be taking shape in the upcoming year including systems, carbon costs, programs such as to a cap and reduce program to buy or sell offsets and many other complexities of an endeavor of this magnitude.

Oregon SB 334

In Oregon, Senate Bill 334[3] was passed in 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 renewable natural gas 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 SB 844

Senate bill 844 passed in 2013 with rulemaking following under AR 580, placed 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 SB 98 & AR 632 Rule Making

Oregon Senate Bill 98 passed during the 2019 regular session and mandates the Oregon Public Utility Commission (PUC) "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 Oregon PUC initiated the AR 632 rulemaking process in late 2019 with a series of public workshops. This collaborative process with various stakeholder involvement and input concluded in the spring of 2020. Final rules were made effective on July 17, 2020. The rule allows investment recovery. In order to participate in Oregon's 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 AR 632 the RNG attributes will be tracked by the

[3] https://olis.leg.state.or.us/liz/2017R1/Downloads/MeasureDocument/SB334

M-RETS system as renewable thermal certificates (RTC) in which (1) RTC = (1) Dekatherm of RNG.

Washington

Washington State Policy Considerations[4]

In December 2020 a State Energy Strategy was released as a roadmap that commits Washington to reducing greenhouse gas emissions:

- 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

Washington HB 2580

Washington State House Bill 2580[5] was signed by Governor Jay Inslee on March 22, 2018 and will become effective on July 1, 2018 bringing into law a bill to help encourage production of renewable natural gas (RNG). This bill requires the Washington State University Extension Energy Program and the Department of Commerce (DOC) along with the consulting of the Washington State Utilities and Transportation Commission, 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 passed during the 2019 Regular Session, coined the "Building Energy Efficiency" bill, mandates 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 to customers. This program is subject to review and approval by the UTC. With regard to natural gas distribution companies, this bill was designed for the purpose of establishing *"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 that:

[4] 2021 State Energy Strategy - Washington State Department of Commerce
[5] http://apps2.leg.wa.gov/billsummary?Year=2017&BillNumber=2580&Year=2017&BillNumber=2580

a) Renewable natural gas provides benefits to natural gas utility customers and to the public;

b) The development of RNG resources should be encouraged to support a smooth transition to a low carbon energy economy in Washington;

c) It is the policy of the state to provide clear and reliable guidelines for gas companies that opt to supply RNG resources to serve their customers and that ensure robust ratepayer protections."

Section 13 of the bill allows LDC's to propose an RNG program under which the company would supply RNG for a portion of the natural gas sold or delivered to its retail customers.

Section 14 of the bill states that LDC's must offer by tariff a voluntary RNG service available to all customers to replace any portions of the natural gas that would otherwise be provided by the gas company.

HB 1257 provided limited direction and the necessary details to advance RNG programs and projects. As such, there has been an effort on behalf of the impacted utilities to provide the commission with feedback and clarity with respect to gas quality and cost treatment. More specifically, the Northwest Gas Association (NWGA) has collaborated with Washington LDC's to develop a common Gas Quality Standard Framework, and proposed language defining the treatment of RNG program costs.

On December 16, 2020, the Washington UTC issued a Policy Statement to provide guidance with respect to the following elements of HB 1257 as follows; General Program Design, RNG Program cost cap, Voluntary Program cost treatment, gas quality standards, and pipeline safety, environmental attributes and carbon intensity, renewable thermal credit (RTC) tracking, banking and verification.

RNG at Avista

Avista has been preparing for RNG. A new RNG Program, RNG Manager, and a cross-functional working team has been assembled and includes representatives from Gas Engineering, Gas Supply, Legal, Governmental Affairs, Regulatory Affairs, Products & Services, Business Development & Strategy, Corporate Communications, and Environmental. This team meets on a routine basis for program and project updates and coordination purposes. Additionally, internal efforts to prepare for and advance RNG include but are not limited to; draft charter document, draft business cases for use in Capital Budget Planning process, internal communications, gas quality, interconnection requirements, and business development efforts in pursuit of potential RNG projects.

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 HB 1257 & Oregon SB 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 rule making and policy:
- Participation in HB 1257 Policy development
- Participation in SB 98 Policy Rulemaking via 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

Pipeline Safety & Interconnection Requirements

Avista's Gas Engineering Department has researched and learned about gas quality, testing, and interconnection requirements from those at the forefront of the RNG industry. Additionally, through a collaborative effort coordinated by the Northwest West Gas Association (NWGA), all four Washington LDC's have developed a common Gas Quality Framework which is now that basis for Avista's Gas Quality Specification. The development of Interconnection requirements and draft contractual language has also been developed and has taken form as an Interconnection Agreement template. Other procedural documents such as an Interconnection Study Agreement and RNG Interconnection Request Form have been developed.

RNG workshops and rulemaking

In addition to participating in RNG industry workshops and conferences to learn how others are implementing RNG projects and programs, Avista has actively participated in Oregon SB 98 informal and formal rulemaking, and Washington HB 1257 workshops including collaborative efforts with the NWGA to develop a common Gas Quality Framework, and proposed cost cap language.

Utility RNG Projects

RNG projects require feedstocks that are not always readily available and feedstock owners who are willing to partner with an LDC. 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 we have learned during our business development efforts;

- New 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
- Economies of scale – Low volume biogas opportunities face economic challenges
- 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 3-4 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 tracking process just to name a few
- Customers have paid for a vast pipeline infrastructure that can be utilized for a cleaner future by transitioning the fuel and keeping the pipe

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 AAC or GRC. Avista can also buy RNG from other RNG producers and pass the costs through the GPA.

Build

Both Oregon SB 98 and Washington HB 1257 are both focused on decarbonization for the greater good of society and both pieces of legislation clearly support the development of new RNG infrastructure and RNG resources by allowing utility companies (LDC's) to build and deliver RNG on a utility cost-of-service model for utility customer building heat usage. Both allow the recovery of investments through an AAC or GRC. Avista believes the "build" option best meets the intent of the legislation as it affords a higher level of cost control through the elimination of for-profit intermediary burdens, delivering RNG to customers at the true cost. Further, local projects contribute to improved local air quality, and support the local economy during construction and during annual operations.

Naturally, feedstock biogas royalties are expected to be a key factor in project economics, as will operating costs including power, conditioning equipment type, interconnection pipeline distance and cost. Since utility companies are institutional credit worthy partners that can offer long term off-take contracts for biogas, it is expected that these types of arrangements will be desirable with feedstock owners, and that long-term arrangements will temper biogas royalty pricing. Ultimately the utility customer benefits from this scenario.

Buy

The new legislation in Oregon and Washington is an intentional shift away from the transportation market and opens the door for a new renewable thermal credit (RTC) market which is not intended to compete with the existing heavily subsidized transportation markets, federal and state alike. In the short term, and since the transportation and utility markets are in conflict with respect to RNG values, the procurement of RNG for utility use is an inherent challenge for utility use.

At Avista, we expect our voluntary RNG program demands to be limited volumes, and short-term in nature in the initial years. Since a short-term, low-volume off-take purchase scenario is not likely to be attractive to producers that typically seek 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 will allow Avista to ramp-up and learn more about our new first ever voluntary RNG program and minimize risk until at a point in time in which Avista can supply RNG from new RNG infrastructure investment projects.

Voluntary RNG Programs

Avista's Products and Services Department will be developing Avista's first ever voluntary RNG product. To date the following market studies and observations have been completed:

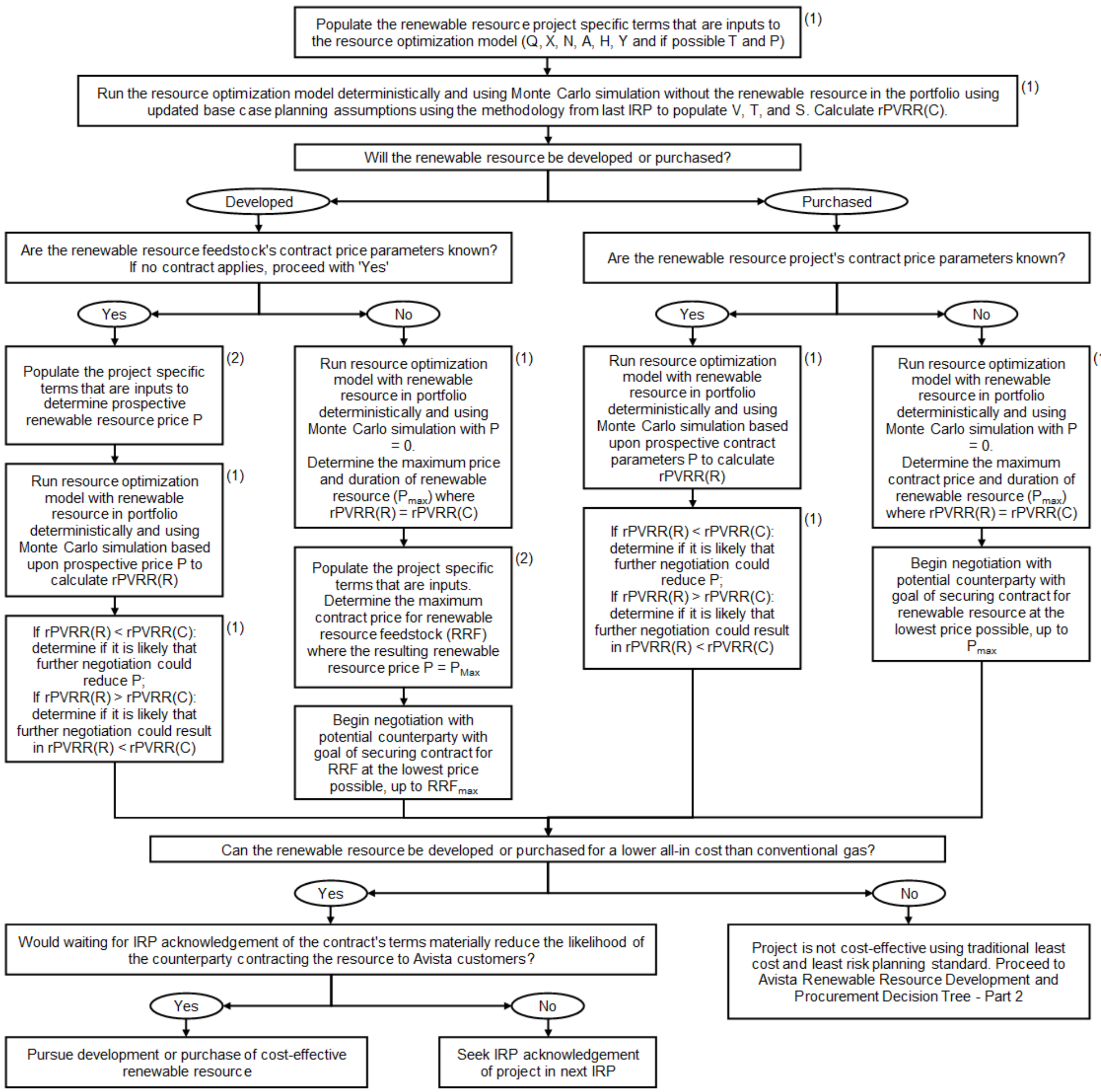
- RNG Commercial Market Study completed in 2019
- RNG Residential Market Survey concluded in September 2020
- Customers lack understanding of RNG since it is a new concept
- Customers like the environmental aspects of RNG
- Customers like to choose their level of participation to manage costs predictably

The voluntary customer RNG program design will advance based on the studies above. Estimated voluntary customer program demands are yet to be defined, however volumes are expected to be very small initially. Eventually, Avista is looking forward to adding RNG to Avista's renewables portfolio.

Cost Effective Evaluation Methodology

At Avista, developing a methodology has been a work in process. To date, the methodology shown is derived from OPUC UM2030, also referenced in the OPUC SB 98 AR 632 Rulemaking. The evaluation method shown herein is subject to input, refinement and reconsideration (Figure 5.2).

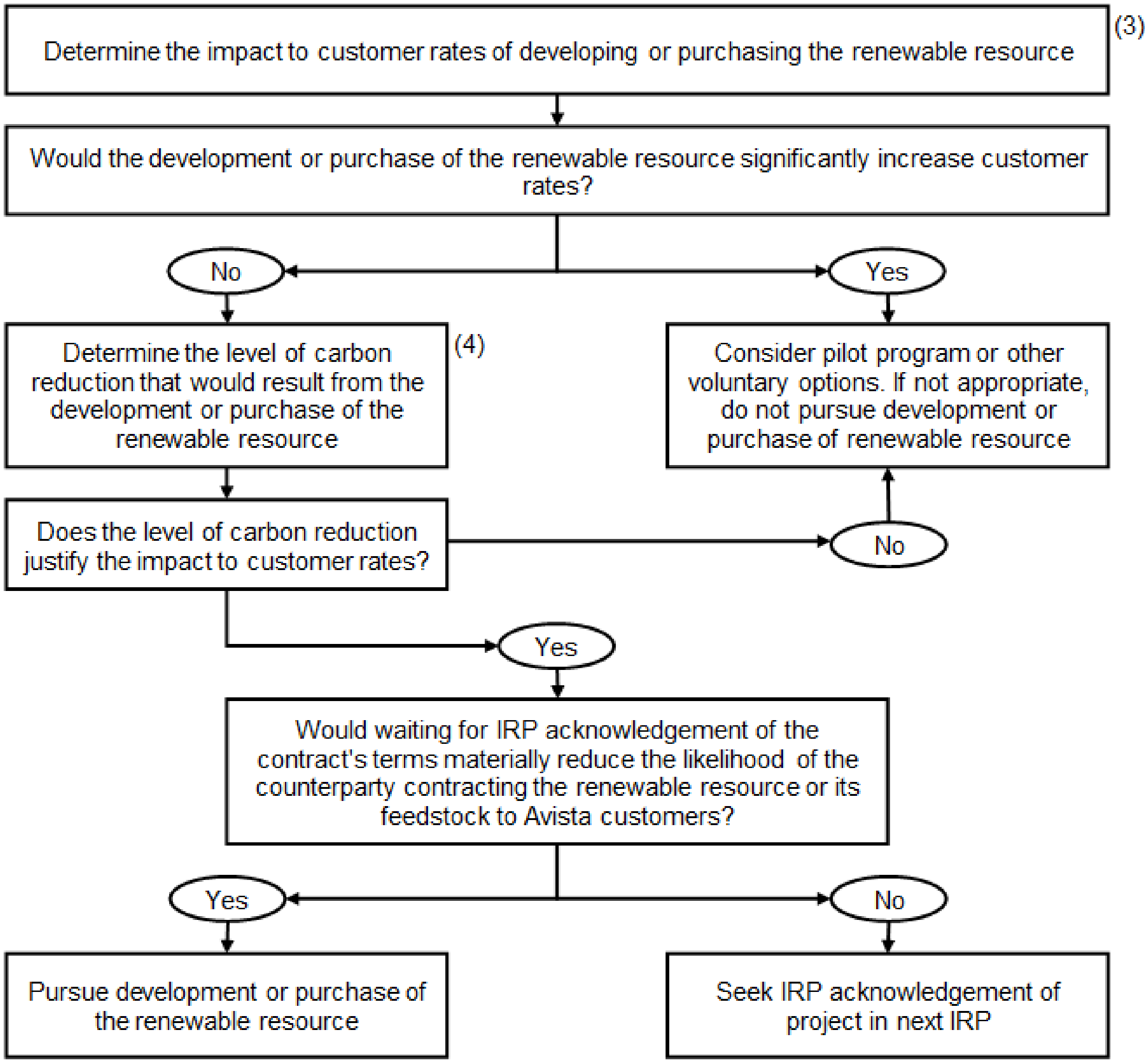
Figure 5.2: Avista Renewable Resource Development and Procurement Decision Tree – Part 1[6]



(1) Avista Renewable Resource Least Cost/Least Risk Evaluation Criteria and Calculations
(2) Avista Renewable Resource Project Revenue Requirement Model

[6] 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 5.3: Avista Renewable Resource Development and Procurement Decision Tree – Part 2



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

In-depth descriptions of the calculations and components used in the Avista Renewable Resource Development and Procurement Decision Tree are in Appendix 5.

Environmental Attribute Tracking

Oregon SB 98 specifies M-RETS as the third-party entity designated to manage environmental attribute tracking and banking. M-RETS will utilize a proprietary transparent electronic certificate tracking system in which (1) renewable thermal certificate (RTC) is equal to (1) dekatherm (Dth) of RNG per the OPUC.

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 draw for renewable resources due to the low carbon fuel standard (LCFS) in addition to the federal RIN market. These incentives can bring 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 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 just a few of the major obstacles potential producers run into when looking for financing of their projects.

A potential solution to some of these unknowns in the market are through utility RNG projects. These feedstock owners would now be able to partner with LDC's to cultivate new RNG projects. The obstacle of 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. This concept would test the project owner's willingness to partner with the utility's cost of service model, which is a foreign concept when seeking the highest value for their biogas.

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 pipeline, feedstock type, gas conditioning equipment and requirements and operating costs. In general terms, new RNG projects can take 2-3 years to develop depending on size and scope.

Hydrogen

Hydrogen 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. While hydrogen can be made from any energy source including nuclear (pink H2) and electric renewables (green H2), most is currently made by reforming natural gas, also known as grey H2. The high cost of this energy has been the primary barrier to an accelerated use and adoption. With expanding renewable electricity production, the ability to create green H2 with excess renewable electricity is moving from concept to market throughout the world. 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, it can be combined with a carbon dioxide source first to produce methane, referred to as methanation, and then injected in a natural gas pipe without limits on the percent in the gas stream. This process of using power to separate water into hydrogen and oxygen is known as power to gas. This process can provide seasonal energy storage needs while providing a useful product based on when renewable electricity is being produced.

Conclusion

Avista views RNG and low carbon fuels as an important component of its corporate environmental strategy and decarbonization goals. By utilizing waste streams to create green fuel, RNG and H2 both support Avista's environmental strategy and will provide Avista's customers with a new environmentally friendly, low carbon fuel choice, delivered seamlessly via Avista's existing natural gas system.

6: Integrated Resource Portfolio

Overview

This chapter combines the previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. This chapter provides an analysis of potential resource options to meet resource deficiencies as exhibited in the High Growth, Low Prices scenario and the Carbon Reduction scenario.

The foundation for integrated resource planning is the criteria used for developing demand forecasts. The weather planning standard has been updated in the current IRP cycle. The new planning standard has Avista moving away from coldest on record and into a 99 percent probability of a daily temperature occurring. Avista plans to serve expected peak day in each demand region with firm resources. Firm resources include natural gas 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.

It is assumed that 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, so IRP analysis of demand-serving capabilities 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 natural gas supply needed. In order to deliver the forecasted demand, the supply forecast needs to increase between 1.0 percent and 3.0 percent on both an annual and peak-day basis to account for additional supplies purchased primarily for pipeline compressor station fuel. The range of 1.0 percent to 3.0 percent, 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.

SENDOUT® Planning Model

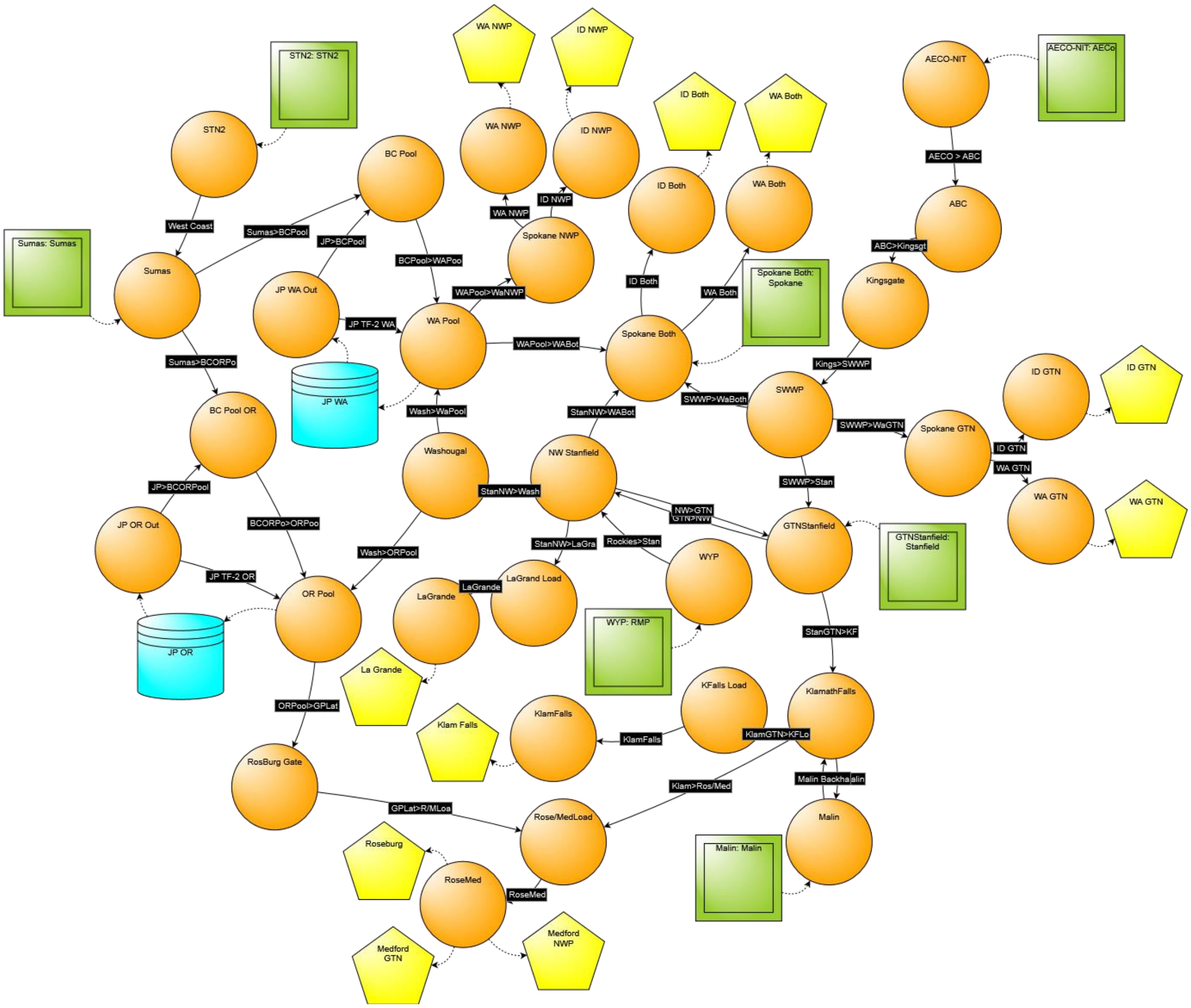
SENDOUT® is a linear programming model used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique to solve minimization/maximization problems. SENDOUT® analyzes the complete problem at one time within the study horizon, while accounting for physical limitations 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 and industrial).
- Weather data, including minimum, maximum and average temperatures.
- Existing and potential transportation data which 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.
- Conservation potential.

Figure 6.1 is a SENDOUT® network diagram of Avista's demand centers and resources. This diagram illustrates current transportation and storage assets, flow paths and constraint points.

Figure 6.1 SENDOUT® Model Diagram



The SENDOUT® 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 gas price increases upon total natural gas costs;
- Storage optimization studies;
- Resource mix analysis for conservation;
- Weather pattern testing and analysis;

- Transportation cost analysis;
- Avoided cost calculations; and
- Short-term planning comparisons.

SENDOUT® also includes Monte Carlo capabilities, which facilitates price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. More information and analytical results are located in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis. The SENDOUT® model is used by LDC's across the U.S., however it is becoming increasingly outdated for the current regulatory environment when it comes to carbon reduction. Because of this enhanced need for modeling software, Avista is planning on replacing SENDOUT® as stated in Chapter 9 – Action Plan.

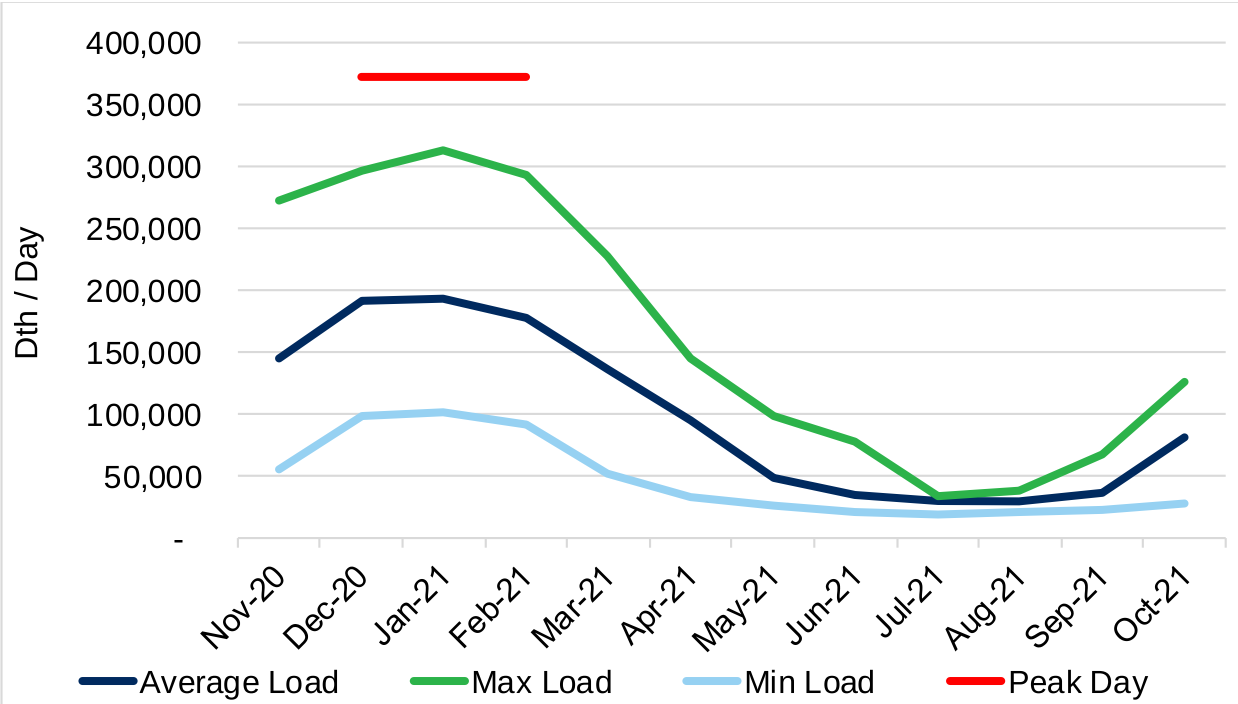
Resource Integration

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 - Demand Forecasts describes Avista's demand forecasting approach.

Avista forecasts demand in the SENDOUT® model in eleven service areas given the existence of distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The SENDOUT® 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 6.2 captures this variability showing monthly system-wide average demand, minimum demand day observed by month, maximum demand day observed in each month, and winter projected peak day demand for the first year of the Expected Case forecast as determined in SENDOUT®.

Figure 6.2: Total System Average Daily Load (Average, Minimum and Maximum)



Natural Gas Price Forecasts

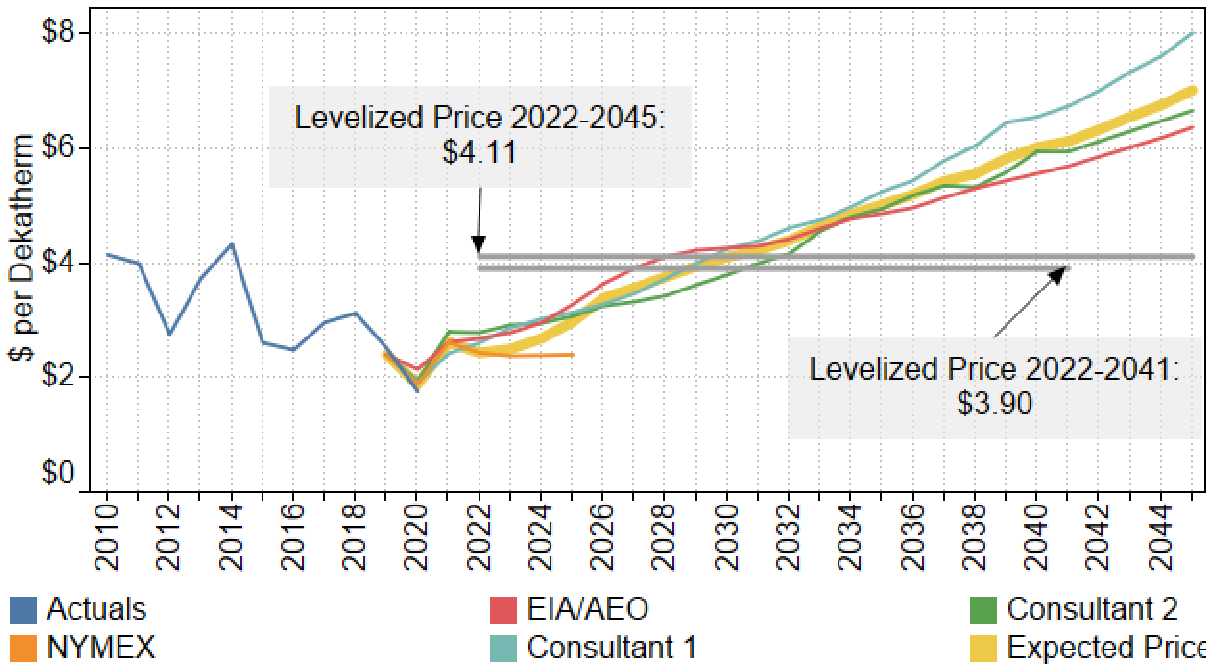
Natural gas prices play an integral role in the development of the IRP. It is the most significant variable in determining the cost-effectiveness of DSM measures and of procuring new resources. The price of natural gas also influences consumption through price elasticity, which affects demand in Avista's natural gas service territories.

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. 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. Estimates of these supply resource additions 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 6.3 depicts the annual average prices of these forecasts in nominal dollars and includes the expected price resulting from a blending technique.

Figure 6.3: Henry Hub Forecasted Price (Nominal $/Dth)



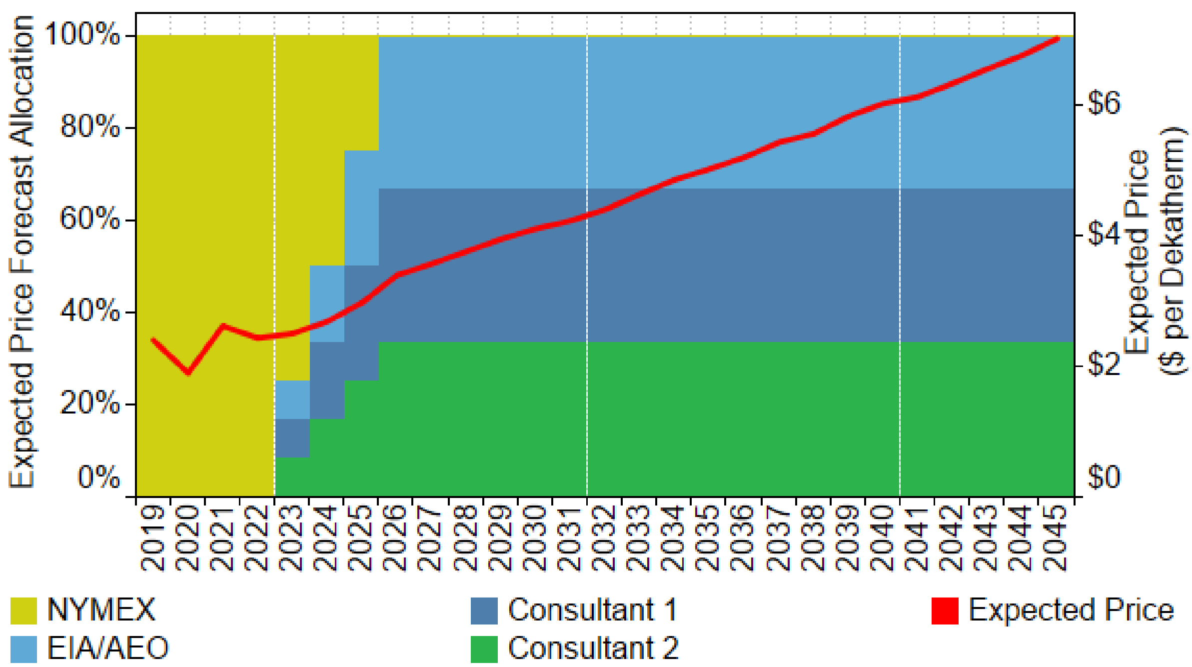
Expected prices at Henry Hub were derived through a blend of forecasts from four sources, including the New York Mercantile Exchange (NYMEX) forward strip on June 30, 2020, the Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO), and two reputable market consultants. Combining an ensemble of forecasts improves the accuracy of our model based on the premise that 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 2023 through 2025, 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 2026, 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 6.1 and the resulting annual average expected price at Henry Hub is depicted in Figure 6.4 below.

Table 6.1: Price Blend Methodology

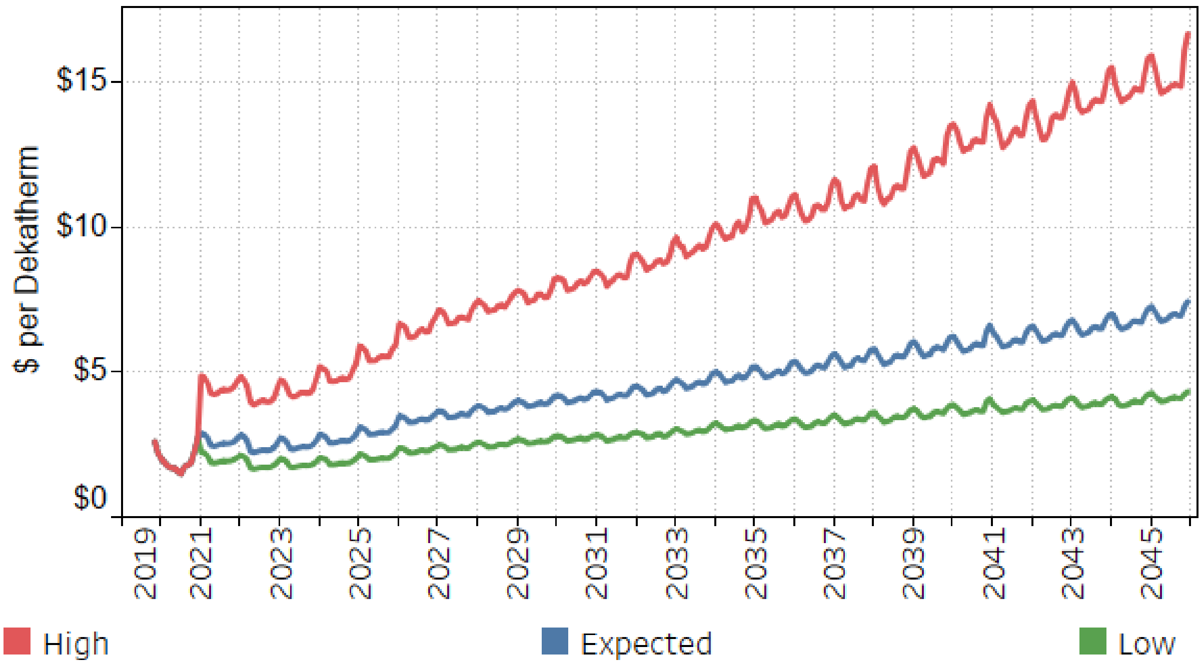
Years	Price Blend Methodology
2021 & 2022	forward price only
2023	forward price / 25% average consultant forecasts
2024	50% forward price / 50% average consultant forecasts
2025	25% forward price / 75% average consultant forecasts
2026 - 2040	100% average consultant forecasts

Figure 6.4: Expected Price with Allocated Price Forecast



To accommodate for the likelihood that 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 1,000 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 6.5 below.

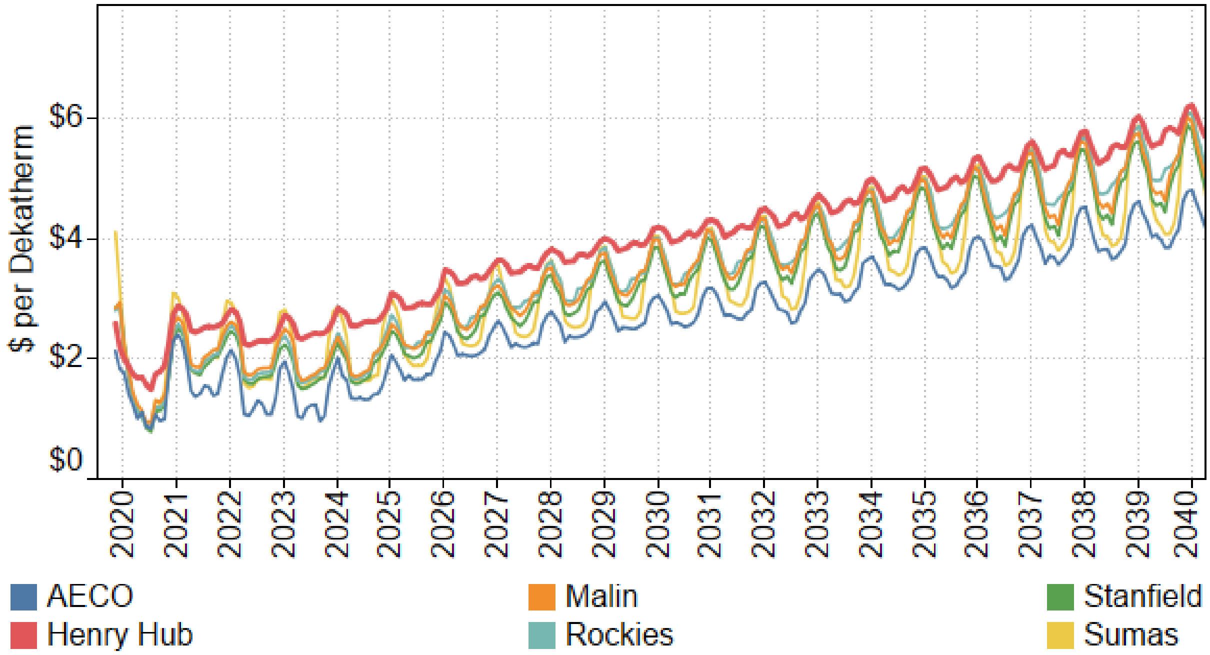
Figure 6.5: Henry Hub Forecasts for IRP Low/ Expected/ High Forecasted Price – Nominal $/Dth



Henry Hub is located 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, or spot, market 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, or negative basis differential, to Henry Hub because of their proximity to the largest natural gas basins in North America (Western Canada and the Rockies). Figure 6.6 below shows the resulting regional prices as compared to the Henry Hub.

Figure 6.6: Regional Price as a compared to the Henry Hub Price



Carbon Policy Resource Utilization Summary

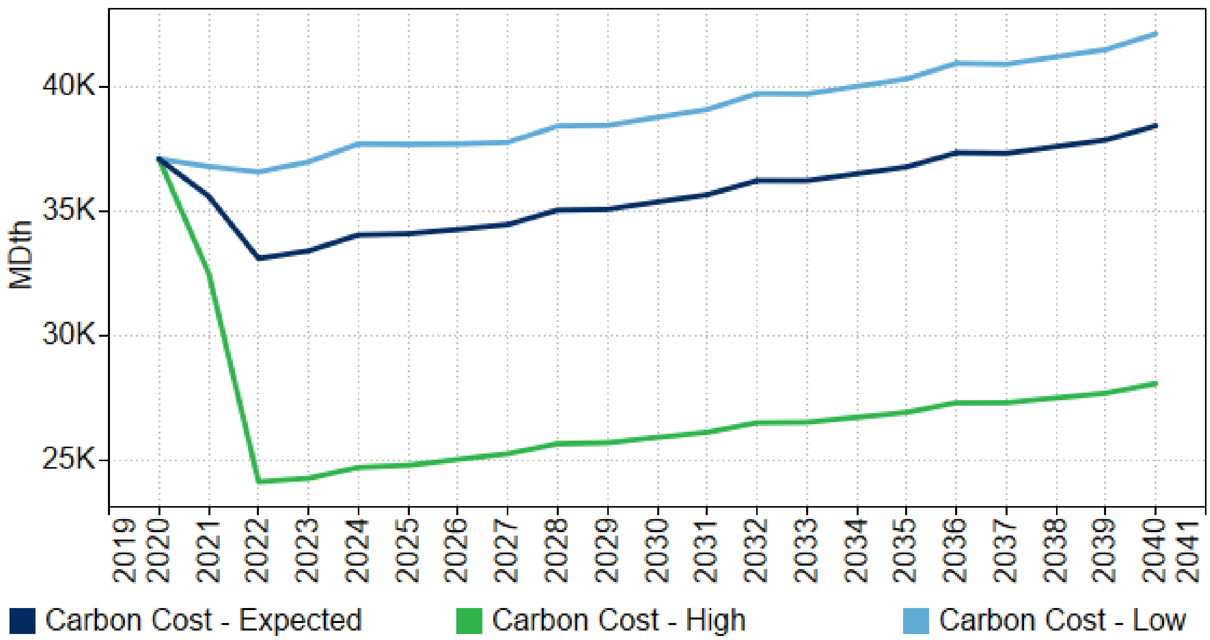
Avista uses an estimated carbon price as an incremental adder to address any potential policy. Carbon adders increase the price of a dekatherm of natural gas and impact resource selections and demand through expected elasticity (Chapter 2 – Demand Forecasts, Price Elasticity). Oregon was assumed to have a cap and reduce market as estimated by Wood Mackenzie, through a cap and trade estimate, and presented to the TAC on September 30, 2020. In this price estimate, the initial level starts low per MTCO2e at around $15.83, rising to $97.90 by 2040. The cap and reduce market discussed in Oregon's EO 20-04[1] is still under development at the time of this filing making modeling of a market price difficult. Washington State was modeled at $79.86 per MTCO2e starting in 2021 and rising to $158.06 per MTCO2e by 2040. These carbon tax figures are based on the requirement to utilize SCC at 2.5% discount estimates from the EPA as required by RCW 80.28.395. The State of Idaho does not have a carbon adder as there is no current or proposed state or federal legislation associated with carbon in that jurisdiction.

Avista also completed sensitivities to account for risk including a lower and higher than expected price of carbon and are applied to all three jurisdictions. The low carbon price is assumed at $0, or no cost, of carbon to help measure the risk of a continued stalemate

[1] https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf

with carbon pricing. The high carbon price is the EPA's high impact scenario of the average of 95 percent of results at a 3 percent discount rate. This rate produces a much higher cost of carbon beginning in 2021 at $151.01 and increasing to $219.33 per MTCO$_2$e by 2040. The effect of these modeled carbon prices, combined with our expected elasticity as described in Chapter 2 Demand Forecasts, change demand as shown in Figure 6.7.

Figure 6.7: 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 – Supply-Side Resources) is represented by the firm resource duration curves depicted in Figures 6.8 and 6.9.

Figure 6.8: Existing Firm Transportation Resources – Washington & Idaho

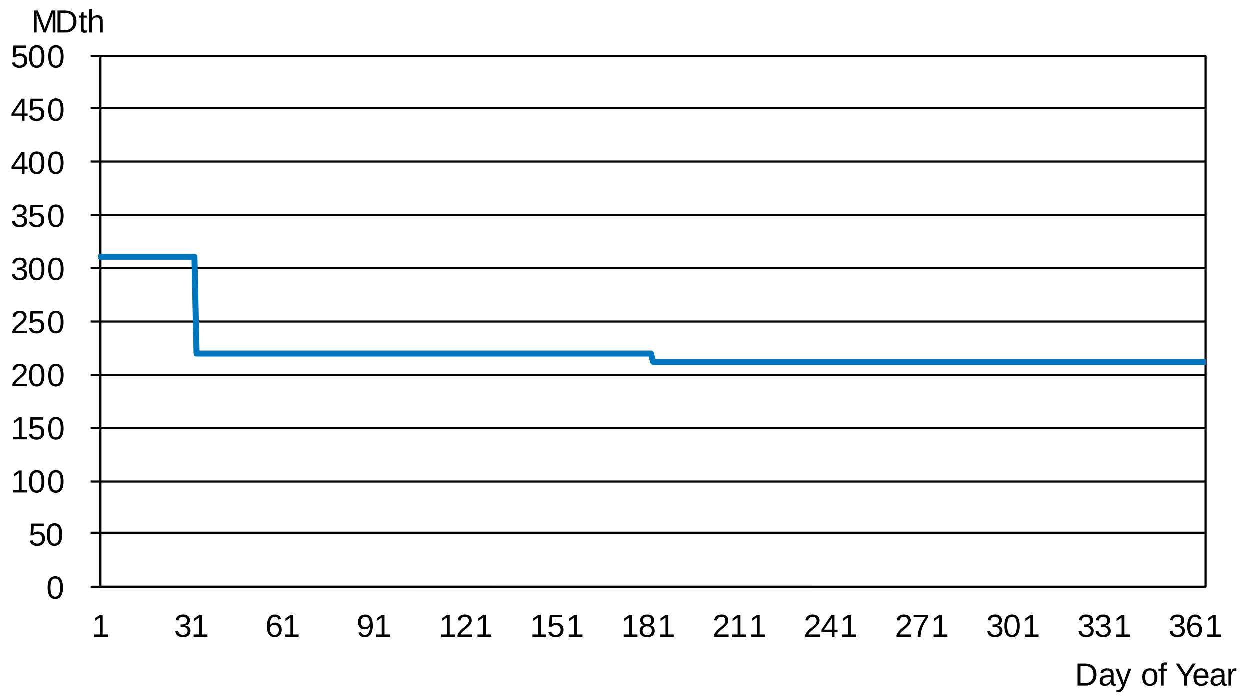
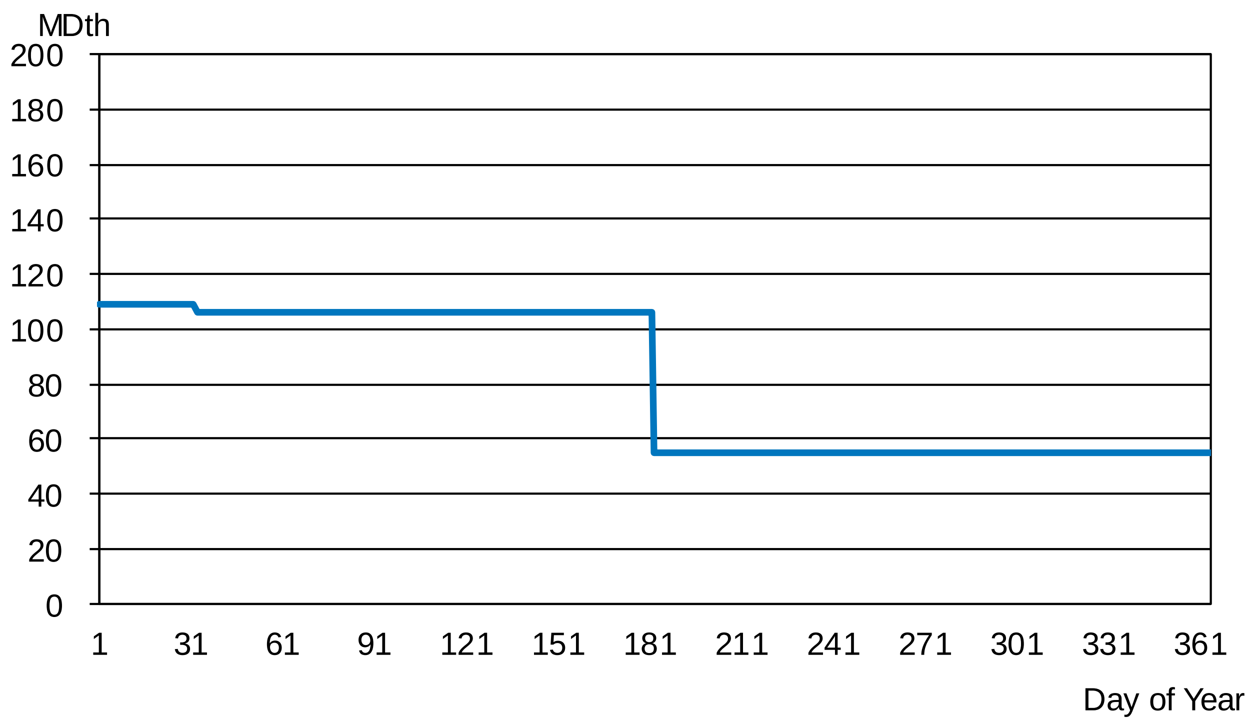


Figure 6.9: Existing Firm Transportation Resources – Oregon



Current rates for capacity are in Appendix 6.1 – Monthly Price Data by Basin. 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 – Weighted Average Cost of Capital).

Demand-Side Management

Chapter 3 – Demand-Side Resources describes the methodology used to identify conservation potential and the interactive process that utilizes avoided cost thresholds for determining the cost effectiveness of conservation measures on an equivalent basis with supply-side resources.

Demand Results

After incorporating the above data into the SENDOUT® model, Avista generated an assessment of demand compared to existing resources for several scenarios. Chapter 2 – Demand Forecasts discusses the demand results from these cases, with additional details in Appendices 2.1 through 2.9.

Figures 6.10 through 6.13 provide graphic summaries of Average Case demand as compared to existing resources on a peak day. This demand is net of conservation savings and shows the adequacy of Avista's resources under normal weather conditions. For this case, current resources meet demand needs over the planning horizon.

Figure 6.10: Average Case – Washington/Idaho Existing Resources vs. Average Demand – February 28th

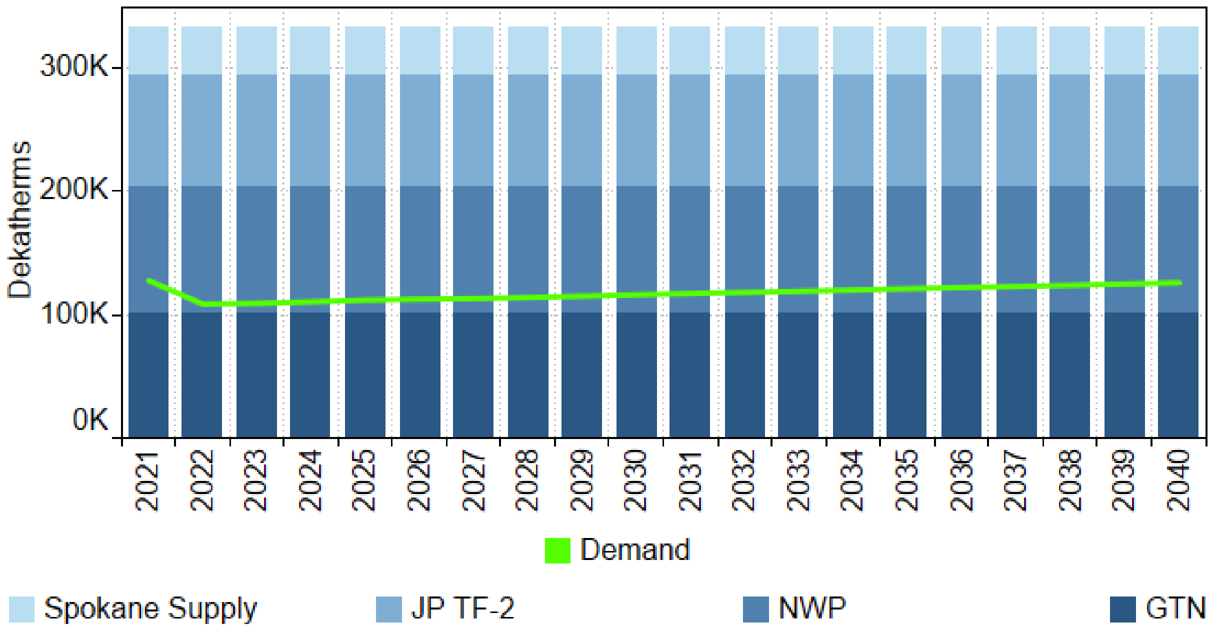


Figure 6.11: Average Case – Medford / Roseburg Existing Resources vs. Average Demand – December 20th

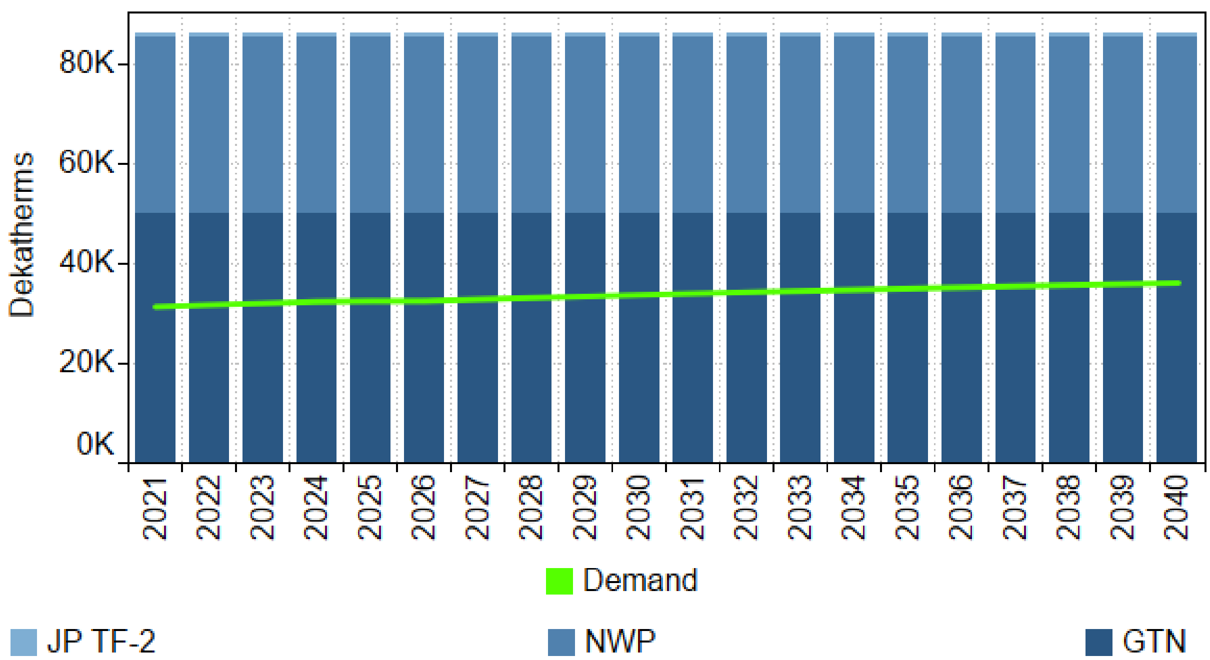


Figure 6.12: Average Case – Klamath Falls Existing Resources vs. Average Demand – December 20th

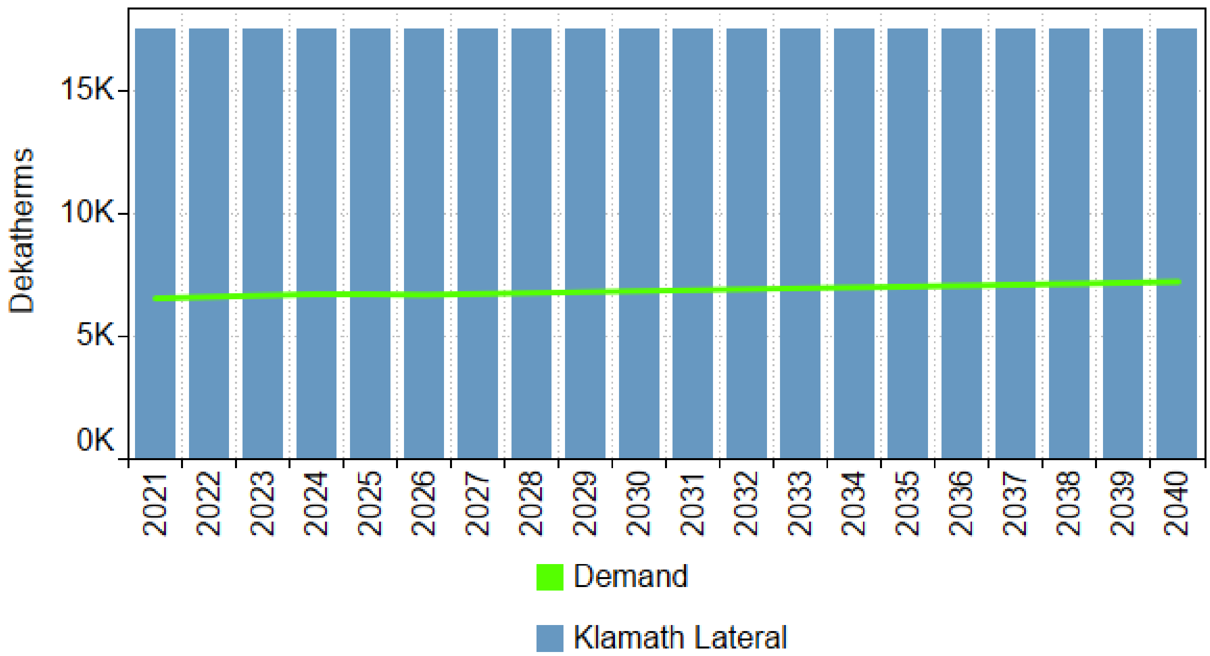
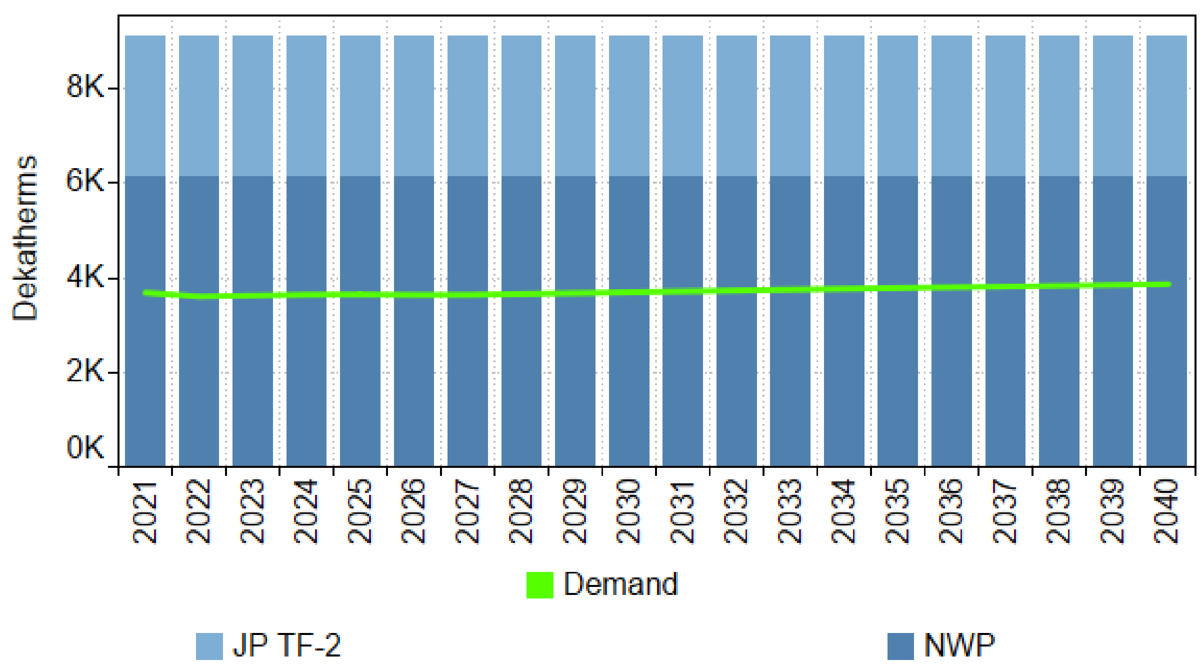


Figure 6.13: Average Case – La Grande Existing Resources vs. Average Demand February 28th



Figures 6.14 through 6.17 summarize Expected Case peak day demand compared to existing resources, as well as demand comparisons to the 2018 IRP. This demand is net of conservation savings. Based on this information Avista has time to carefully monitor, plan and analyze potential resource additions as described in the Ongoing Activities section of Chapter 9 – Action Plan. 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 Supply Side Resources – Chapter 4.

Figure 6.14: Expected Case – Washington & Idaho Existing Resources vs. Peak Day Demand – February 28th

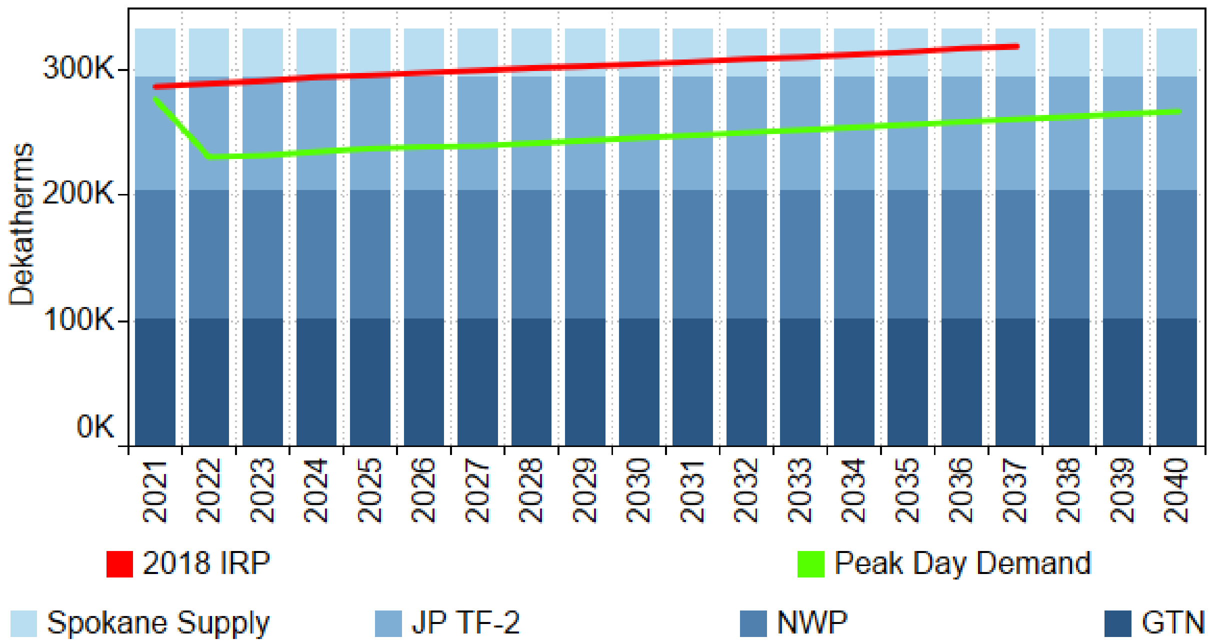


Figure 6.15: Expected Case – Medford / Roseburg Existing Resources vs. Peak Day Demand – December 20th

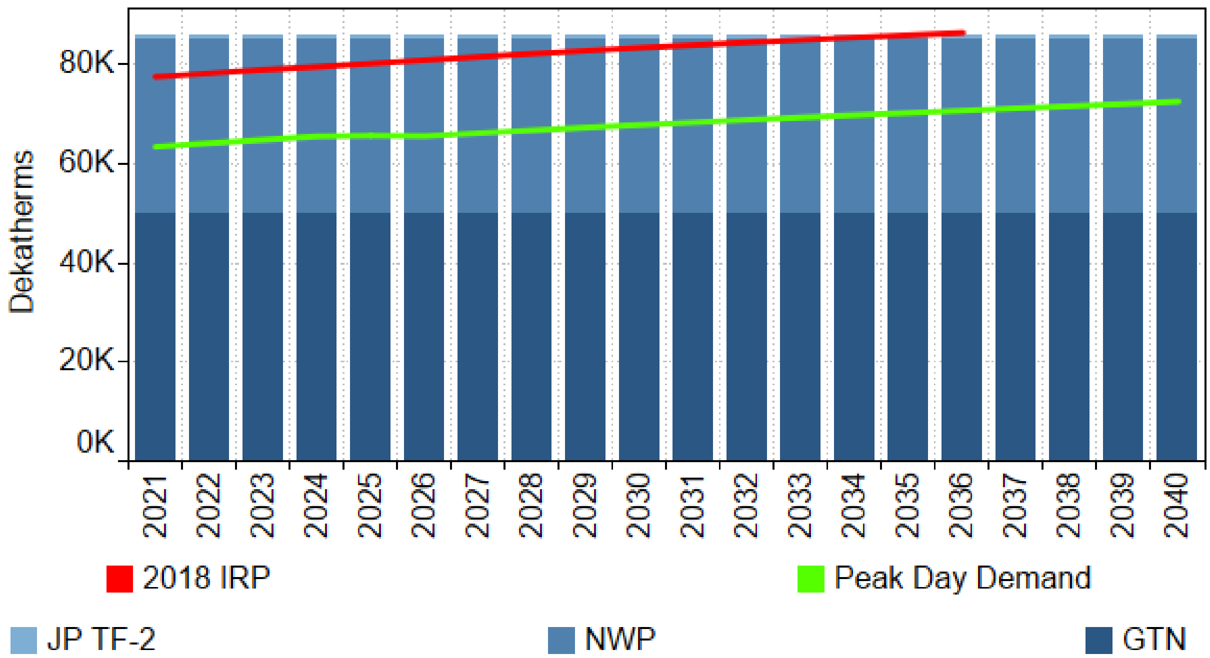


Figure 6.16: Expected Case – Klamath Falls Existing Resources vs. Peak Day Demand – December 20th

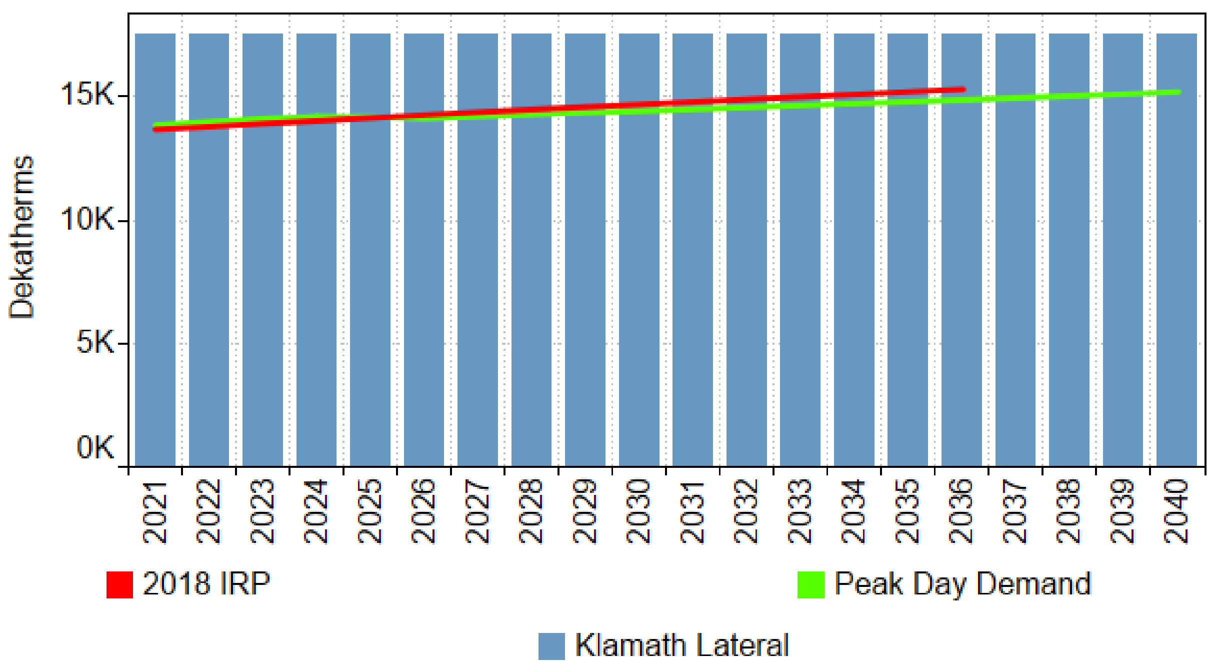
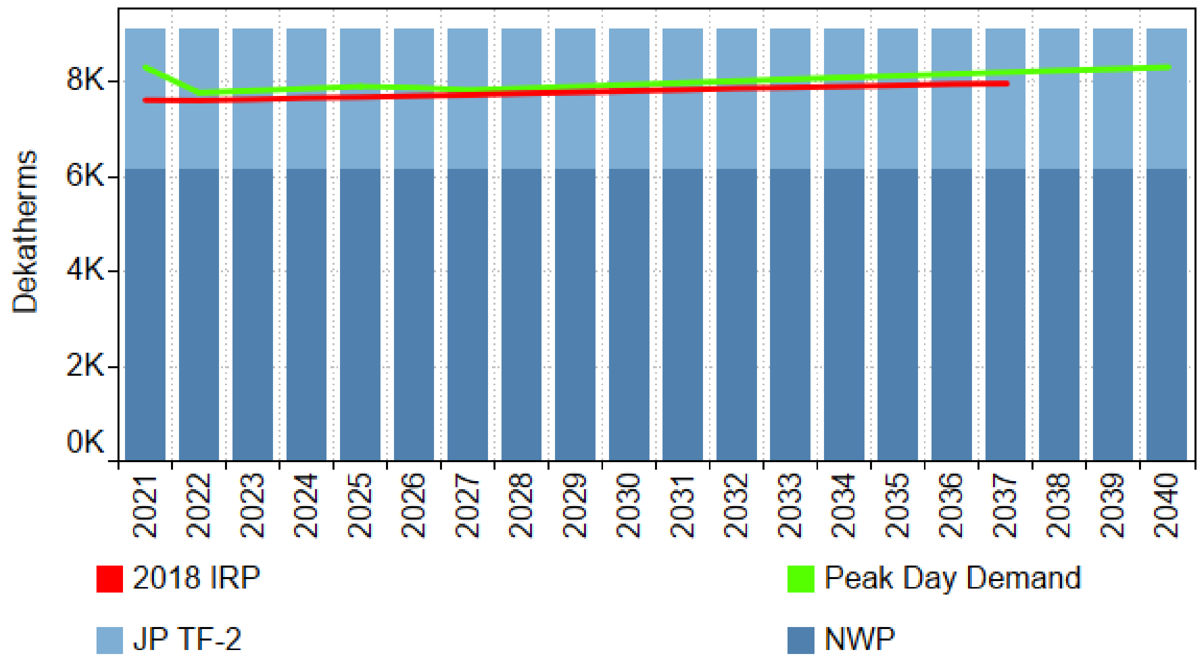


Figure 6.17: Expected Case – La Grande Existing Resources vs. Peak Day Demand – February 28th



If demand grows faster than expected, the need for new resources will be earlier. Flat demand risk requires close monitoring for signs of increasing demand and reevaluation of lead times to acquire preferred incremental resources. The monitoring of flat demand risk includes a reconciliation of forecasted demand to actual demand on a monthly basis. This reconciliation helps identify customer growth trends and use-per-customer trends. If they meaningfully differ compared to forecasted trends, Avista will assess the impacts on planning from procurement and resource sufficiency standing.

Table 6.2 quantifies the forecasted total demand net of conservation savings and unserved demand from the above charts.

Table 6.2: Peak Day Demand – Served and Unserved (MDth/day)

Case	Gas Year	LaGrande				Idaho				Washington			
		Served	Unserved	Total	% of Peak Day Served	Served	Unserved	Total	% of Peak Day Served	Served	Unserved	Total	% of Peak Day Served
Expected Case	2020-2021	8.31	-	8.31	100%	96.37	-	96.37	100%	179.82	-	179.82	100%
Expected Case	2021-2022	7.78	-	7.78	100%	94.17	-	94.17	100%	135.76	-	135.76	100%
Expected Case	2022-2023	7.82	-	7.82	100%	95.36	-	95.36	100%	135.83	-	135.83	100%
Expected Case	2023-2024	7.87	-	7.87	100%	96.79	-	96.79	100%	137.38	-	137.38	100%
Expected Case	2024-2025	7.91	-	7.91	100%	98.06	-	98.06	100%	138.75	-	138.75	100%
Expected Case	2025-2026	7.89	-	7.89	100%	98.04	-	98.04	100%	140.11	-	140.11	100%
Expected Case	2026-2027	7.84	-	7.84	100%	97.40	-	97.40	100%	141.39	-	141.39	100%
Expected Case	2027-2028	7.87	-	7.87	100%	98.30	-	98.30	100%	142.67	-	142.67	100%
Expected Case	2028-2029	7.91	-	7.91	100%	99.16	-	99.16	100%	143.93	-	143.93	100%
Expected Case	2029-2030	7.95	-	7.95	100%	100.03	-	100.03	100%	145.21	-	145.21	100%
Expected Case	2030-2031	7.99	-	7.99	100%	100.94	-	100.94	100%	146.38	-	146.38	100%
Expected Case	2031-2032	8.02	-	8.02	100%	101.90	-	101.90	100%	147.55	-	147.55	100%
Expected Case	2032-2033	8.06	-	8.06	100%	102.82	-	102.82	100%	148.67	-	148.67	100%
Expected Case	2033-2034	8.10	-	8.10	100%	103.80	-	103.80	100%	149.83	-	149.83	100%
Expected Case	2034-2035	8.14	-	8.14	100%	104.81	-	104.81	100%	150.95	-	150.95	100%
Expected Case	2035-2036	8.17	-	8.17	100%	105.85	-	105.85	100%	152.10	-	152.10	100%
Expected Case	2036-2037	8.21	-	8.21	100%	106.86	-	106.86	100%	153.18	-	153.18	100%
Expected Case	2037-2038	8.24	-	8.24	100%	107.88	-	107.88	100%	154.24	-	154.24	100%
Expected Case	2038-2039	8.28	-	8.28	100%	108.93	-	108.93	100%	155.29	-	155.29	100%
Expected Case	2039-2040	8.32	-	8.32	100%	109.99	-	109.99	100%	156.35	-	156.35	100%

Case	Gas Year	Klamath Falls				Medford/Roseburg			
		Served	Unserved	Total	% of Peak Day Served	Served	Unserved	Total	% of Peak Day Served
Expected Case	2020-2021	14.87	-	14.87	100%	67.94	-	67.94	100%
Expected Case	2021-2022	13.85	-	13.85	100%	63.46	-	63.46	100%
Expected Case	2022-2023	13.98	-	13.98	100%	64.18	-	64.18	100%
Expected Case	2023-2024	14.10	-	14.10	100%	64.86	-	64.86	100%
Expected Case	2024-2025	14.21	-	14.21	100%	65.54	-	65.54	100%
Expected Case	2025-2026	14.19	-	14.19	100%	65.70	-	65.70	100%
Expected Case	2026-2027	14.12	-	14.12	100%	65.61	-	65.61	100%
Expected Case	2027-2028	14.20	-	14.20	100%	66.20	-	66.20	100%
Expected Case	2028-2029	14.27	-	14.27	100%	66.76	-	66.76	100%
Expected Case	2029-2030	14.35	-	14.35	100%	67.34	-	67.34	100%
Expected Case	2030-2031	14.42	-	14.42	100%	67.87	-	67.87	100%
Expected Case	2031-2032	14.50	-	14.50	100%	68.39	-	68.39	100%
Expected Case	2032-2033	14.57	-	14.57	100%	68.90	-	68.90	100%
Expected Case	2033-2034	14.65	-	14.65	100%	69.41	-	69.41	100%
Expected Case	2034-2035	14.72	-	14.72	100%	69.87	-	69.87	100%
Expected Case	2035-2036	14.80	-	14.80	100%	70.33	-	70.33	100%
Expected Case	2036-2037	14.87	-	14.87	100%	70.79	-	70.79	100%
Expected Case	2037-2038	14.95	-	14.95	100%	71.25	-	71.25	100%
Expected Case	2038-2039	15.03	-	15.03	100%	71.69	-	71.69	100%
Expected Case	2039-2040	15.11	-	15.11	100%	72.12	-	72.12	100%

New Resource Options

When existing resources are insufficient to meet expected demand, there are many important considerations in determining the appropriateness of potential resources. Interruptible customers' transportation may be cut, as needed, when resources are not sufficient to meet firm customer demand.

Resource Cost

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.

Lead Time Requirements

New resource options can take one 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 DSM 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 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 natural gas 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 that 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.

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 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).

Demand-Side Resources

Integration by Price

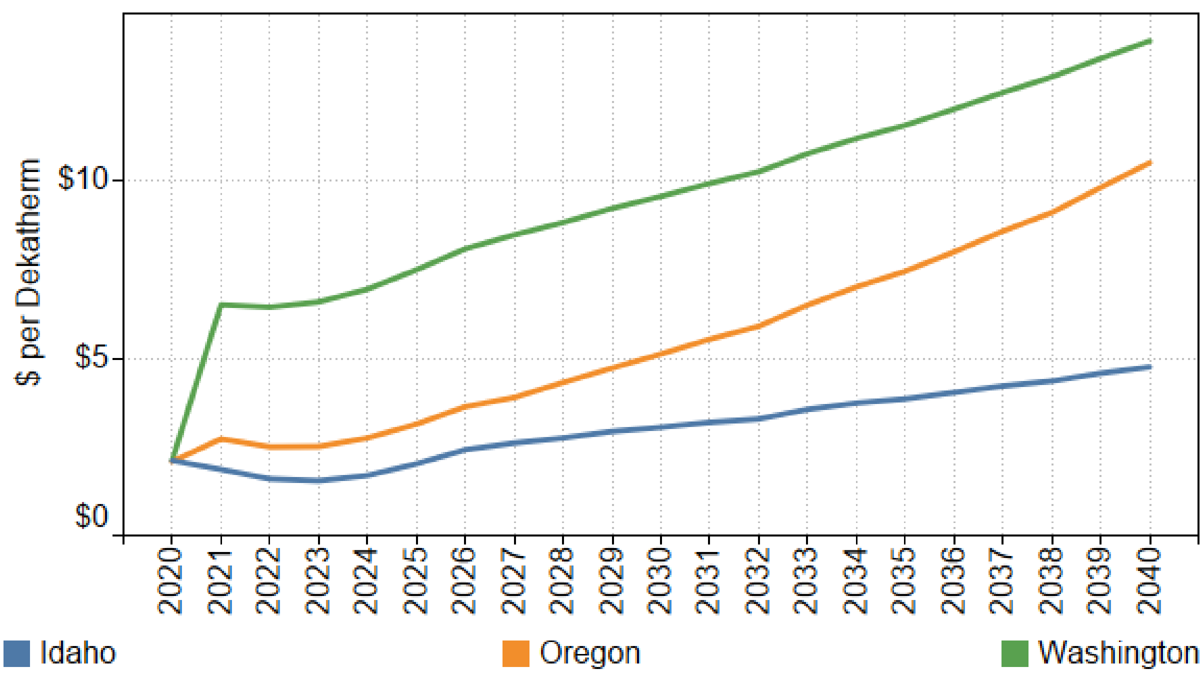
As described in Chapter 3 – Demand-Side Resources, the model runs without future DSM programs. This preliminary model run provides an avoided cost curve for both Applied Energy Group (AEG) and Energy Trust of Oregon (ETO) to evaluate the cost effectiveness of DSM programs against the initial avoided 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 SENDOUT® model. After incorporation, the avoided costs are re-evaluated. This process continues until the change in avoided cost curve is immaterial.

Avoided Cost

The SENDOUT® model determined 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 a conservation measure's total resource cost (Oregon), or utility cost (for Idaho and Washington), 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.

SENDOUT® 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 6.18. The detailed data is in Appendix 6.4 – Avoided Cost Details. Other than the carbon tax adder, avoided costs include additional environmental externality adders for adverse environmental impacts. Appendix 3.2 – Environmental Externalities discusses this concept more fully and includes specific requirements required in modeling for the Oregon service territory.

Figure 6.18: Avoided Cost (by jurisdiction)



Conservation Potential

Using the avoided cost thresholds, AEG selected all potential cost-effective DSM programs for the Idaho and Washington service areas, while ETO performed the CPA study for Oregon. Table 6.3 shows potential DSM savings in each region from the selected conservation potential for the Expected Case.

Table 6.3: Annual and Average Daily Demand Served by Conservation

Case	Gas Year	Klamath Falls		LaGrande		Medford/Roseburg		Oregon	
		Annual DSM (MDth)	Daily DSM (MDth/Day)	Annual DSM (MDth)	Daily DSM (MDth/Day)	Annual DSM (MDth)	Daily DSM (MDth/Day)	Annual DSM (MDth)	Daily DSM (MDth/Day)
Expected Case	2020-2021	4.51	0.01	3.45	0.01	22.73	0.06	30.69	0.08
Expected Case	2021-2022	6.50	0.02	4.92	0.01	33.07	0.09	44.49	0.12
Expected Case	2022-2023	5.81	0.02	4.79	0.01	28.93	0.08	39.52	0.11
Expected Case	2023-2024	5.99	0.02	4.86	0.01	29.40	0.08	40.25	0.11
Expected Case	2024-2025	6.26	0.02	4.99	0.01	30.59	0.08	41.84	0.11
Expected Case	2025-2026	6.55	0.02	5.18	0.01	32.68	0.09	44.41	0.12
Expected Case	2026-2027	7.66	0.02	5.74	0.02	38.45	0.11	51.85	0.14
Expected Case	2027-2028	9.29	0.03	6.67	0.02	46.90	0.13	62.86	0.17
Expected Case	2028-2029	10.34	0.03	7.25	0.02	52.02	0.14	69.61	0.19
Expected Case	2029-2030	11.49	0.03	7.89	0.02	57.66	0.16	77.04	0.21
Expected Case	2030-2031	12.51	0.03	8.46	0.02	62.70	0.17	83.68	0.23
Expected Case	2031-2032	13.24	0.04	8.88	0.02	66.38	0.18	88.50	0.24
Expected Case	2032-2033	13.57	0.04	9.04	0.02	67.77	0.19	90.38	0.25
Expected Case	2033-2034	14.12	0.04	9.35	0.03	70.45	0.19	93.92	0.26
Expected Case	2034-2035	14.63	0.04	9.61	0.03	72.78	0.20	97.02	0.27
Expected Case	2035-2036	14.89	0.04	9.74	0.03	74.05	0.20	98.67	0.27
Expected Case	2036-2037	14.96	0.04	9.75	0.03	74.34	0.20	99.05	0.27
Expected Case	2037-2038	15.03	0.04	9.77	0.03	74.67	0.20	99.47	0.27
Expected Case	2038-2039	15.23	0.04	9.87	0.03	75.62	0.21	100.71	0.28
Expected Case	2039-2040	14.43	0.04	9.37	0.03	71.48	0.20	95.28	0.26

Case	Gas Year	Washington		Idaho		Total System	
		Annual DSM (MDth)	Daily DSM (MDth/Day)	Annual DSM (MDth)	Daily DSM (MDth/Day)	Annual DSM (MDth)	Daily DSM (MDth/Day)
Expected Case	2020-2021	52.69	0.14	24.83	0.07	108.21	0.30
Expected Case	2021-2022	91.95	0.25	47.52	0.13	183.96	0.50
Expected Case	2022-2023	114.86	0.31	60.30	0.17	214.68	0.59
Expected Case	2023-2024	118.33	0.32	61.90	0.17	220.48	0.60
Expected Case	2024-2025	128.52	0.35	67.15	0.18	237.50	0.65
Expected Case	2025-2026	146.36	0.40	76.80	0.21	267.57	0.73
Expected Case	2026-2027	168.03	0.46	91.28	0.25	311.17	0.85
Expected Case	2027-2028	190.26	0.52	104.33	0.29	357.44	0.98
Expected Case	2028-2029	207.19	0.57	113.78	0.31	390.58	1.07
Expected Case	2029-2030	219.84	0.60	121.78	0.33	418.66	1.15
Expected Case	2030-2031	229.45	0.63	127.88	0.35	441.01	1.21
Expected Case	2031-2032	238.49	0.65	132.89	0.36	459.88	1.26
Expected Case	2032-2033	243.14	0.67	138.05	0.38	471.56	1.29
Expected Case	2033-2034	239.15	0.66	137.80	0.38	470.87	1.29
Expected Case	2034-2035	233.38	0.64	135.32	0.37	465.72	1.28
Expected Case	2035-2036	227.09	0.62	133.12	0.36	458.89	1.25
Expected Case	2036-2037	220.49	0.60	131.07	0.36	450.60	1.23
Expected Case	2037-2038	218.81	0.60	132.68	0.36	450.96	1.24
Expected Case	2038-2039	214.36	0.59	132.59	0.36	447.66	1.23
Expected Case	2039-2040	211.27	0.58	132.79	0.36	439.33	1.20

Conservation Acquisition Goals

The avoided cost established in SENDOUT®, the conservation potential selected, and the amount of therm savings is the basis for determining conservation acquisition goals and subsequent DSM program implementation planning. Chapter 3 – Demand-Side Resources has additional details on this process.

Supply-Side Resources

SENDOUT® considers all options entered into the model, determines when and what resources are needed, and which options are cost effective. Selected resources represent the best cost/risk solution, within given constraints, to serve anticipated customer requirements. Since the Expected Case has no resource additions in the planning horizon, Avista will continue to review and refine knowledge of resource options and will act to secure best cost/risk options when necessary or advantageous.

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 resources to meet highly variable demand under multiple scenarios, including peak weather events.

Avista acquired most of its upstream pipeline capacity during the deregulation or unbundling of the natural gas industry. Pipelines were required to allocate capacity and costs to their existing customers as they transitioned to transportation only service providers. The FERC allowed a rate structure for pipelines to recover costs through a Straight Fixed Variable rate design. This 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 in excess of 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 is discussed in detail in Chapter 4 – Supply side resources. The resource strategies addressed are:

- 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/Deferral 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

As determined through the IRP modeling of demand and existing resources, new resources under the Expected Case are not required over the next 20 years. 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.

Conclusion

Choosing reliable information and methods to utilize in these analyses help Avista determine an expected standard. To do this, Avista utilizes industry experts to help determine prices and a market environment, decades of historic weather by major service area, daily weather adjusted usage metrics combined with a statistical based customer forecast all help to provide a reasonable range of expectations for this planning period. There are no expected resource deficiencies during this 20-year forecast in either the Average Case or Expected Case in this IRP. Avista will rely on its Expected Case for peak operational planning activities and in its optimization programs to sufficiently plan for cold day events.

Avista recognizes that there are other potential outcomes. The process described in this chapter applies to the alternate demand and supply resource scenarios covered in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

7: Alternate Scenarios, Portfolios and Stochastic Analysis

Overview

Avista applied the IRP analysis in Chapter 6 – Integrated Resource Portfolio 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.

Avista also performed stochastic modeling for estimating probability distributions of potential outcomes by allowing for random variation in natural gas prices and weather based on fluctuations in historical data. This statistical analysis, in conjunction with the deterministic analysis, enabled statistical quantification of risk from reliability and cost perspectives related to resource portfolios under varying price and weather conditions.

Alternate Demand Scenarios

As discussed in the Demand Forecasting section, Avista identified alternate scenarios for detailed analysis to capture a range of possible outcomes over the planning horizon. Table 7.1 summarizes these scenarios and Chapter 2 – Demand Forecasts and Appendices 2.6 and 2.7 describes them in detail. The scenarios consider different demand influencing factors and price elasticity effects for various price influencing factors.

Table 7.1: 2021 IRP Scenarios

<table>
<tr><th>Proposed Scenarios
INPUT ASSUMPTIONS</th><th>Expected Case</th><th>Average Case</th><th>Low Growth & High Prices</th><th>Carbon Reduction</th><th>High Growth & Low Prices</th></tr>
<tr><td>Customer Growth Rate</td><td colspan="2">Reference Case Cust Growth Rates</td><td>Low Growth Rate</td><td>Reference Case Cust Growth Rates</td><td>High Growth Rate</td></tr>
<tr><td>Use per Customer</td><td colspan="5">3 yr + Price Elasticity</td></tr>
<tr><td>Demand Side Management</td><td colspan="2">Expected Case CPA</td><td>High Prices DSM</td><td colspan="2">Low Prices DSM</td></tr>
<tr><td>Weather Planning Standard</td><td>99% probability of coldest in 30 years</td><td>20 year average</td><td colspan="3">99% probability of coldest in 30 years</td></tr>
<tr><td>GWP</td><td colspan="5">100-Year GWP</td></tr>
<tr><td>Prices
Price curve</td><td colspan="2">Expected</td><td>High</td><td colspan="2">Low</td></tr>
<tr><td>Carbon Legislation
($/Metric Ton)</td><td colspan="2">SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID</td><td>Carbon Cost - High (SCC 95% at 3%)</td><td>SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID</td><td>$0</td></tr>
</table>

Demand profiles over the planning horizon for each of the scenarios shown in Figures 7.1 and 7.2 reflect the two winter peaks modeled for the different service territories.

Figure 7.1: Peak Day (Feb 28) – 2021 IRP Demand Scenarios

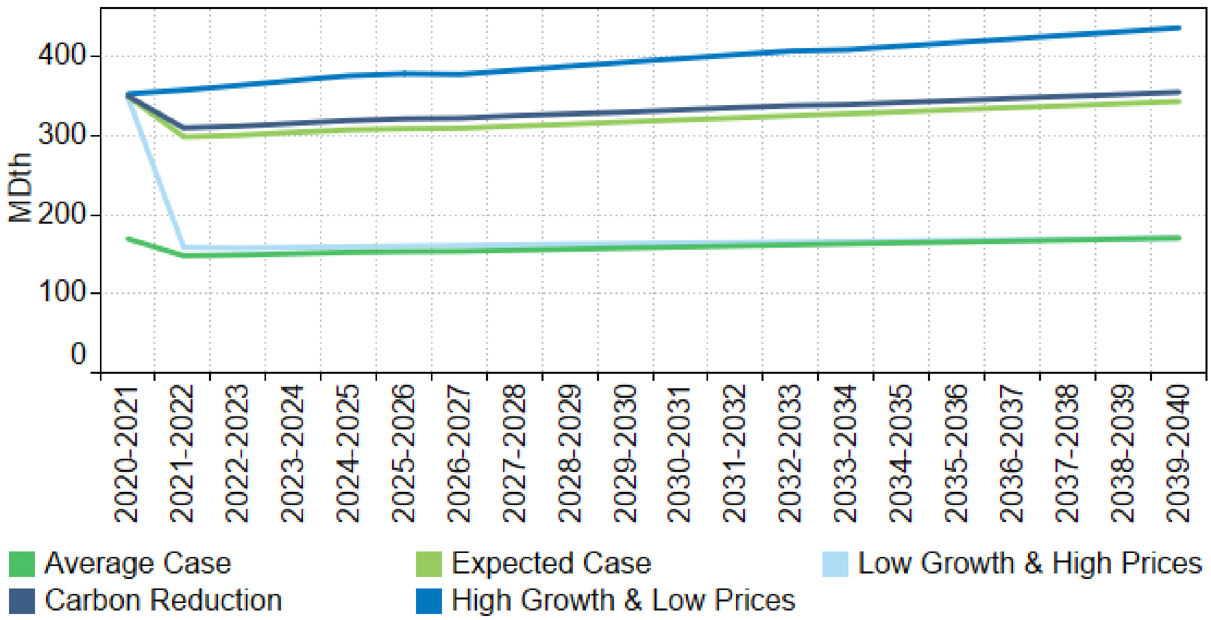
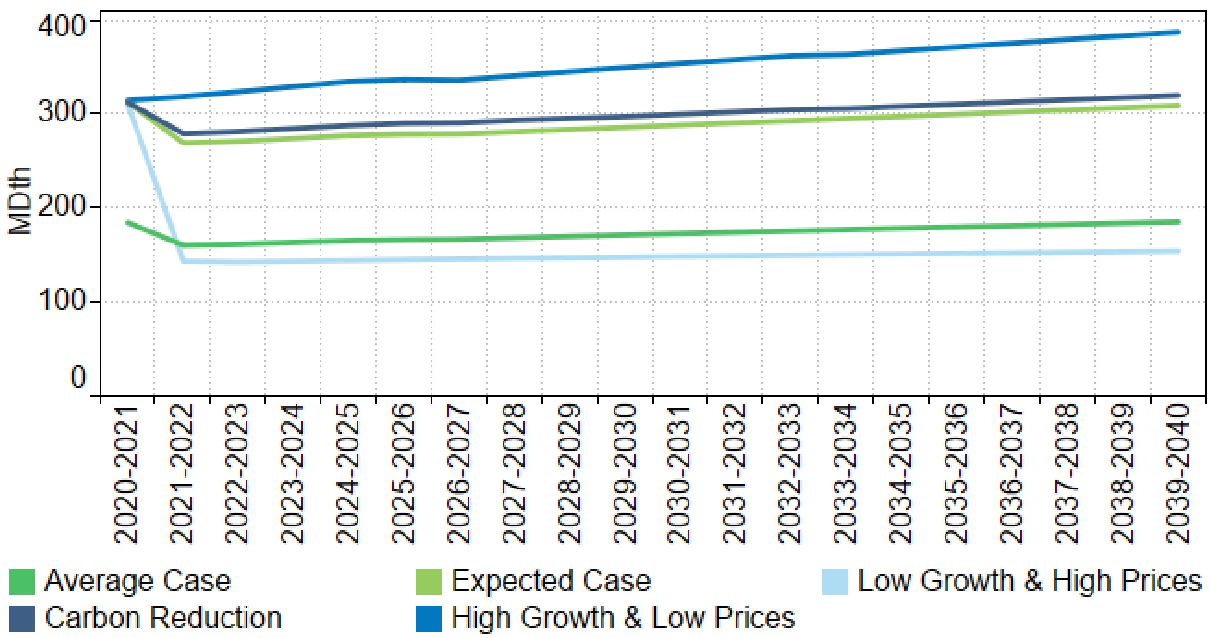
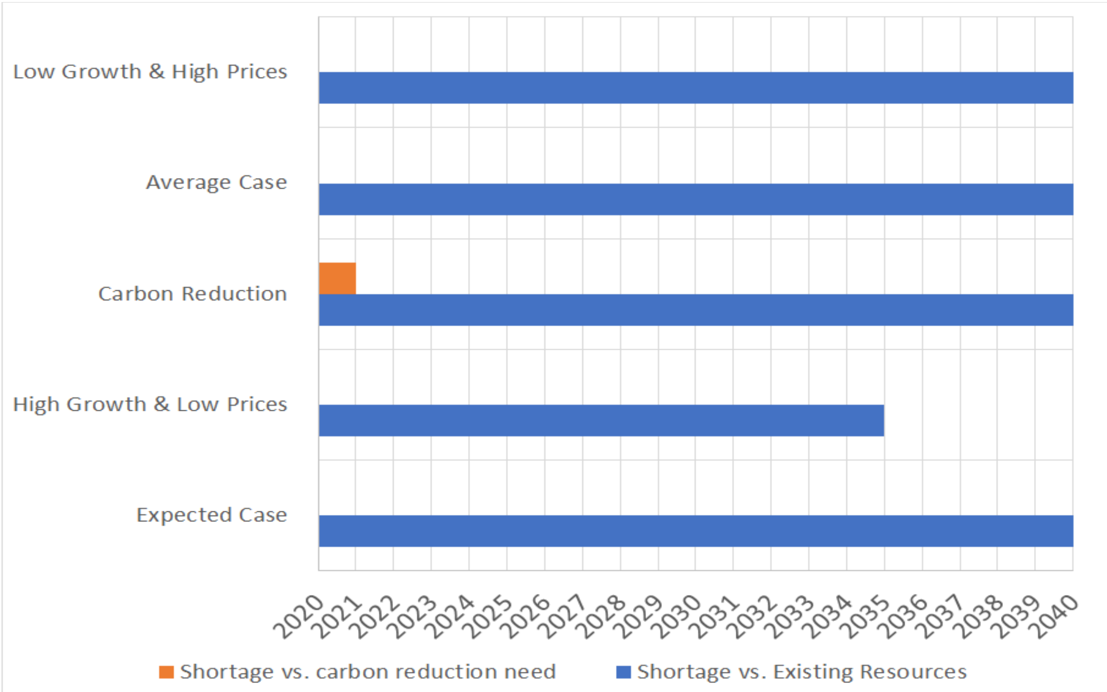


Figure 7.2: Peak Day (Dec 20) – 2021 IRP Demand Scenarios



As in the Expected Case, Avista used SENDOUT® to model the same resource integration and optimization process described in this section for each of the five demand scenarios (see Appendix 2.7 for a complete listing of portfolios considered). This deterministic analysis identified the first-year unserved dates for each scenario by service territory shown in Figure 7.3.

Figure 7.3: First Year Peak Demand Not Met with Existing Resources



Steeper demand highlights the flat demand risk discussed earlier. This could be a regional issue with utilities look toward carbon reduction with limited resources available. The likelihood of this scenario occurring is remote due to a yearly recurrence of the weather planning standard paired with a much steeper growth of customer population; however, any potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times as described in the Ongoing Activities section of Chapter 9 – Action Plan. The remaining scenarios do not identify resource deficiencies in the planning horizon.

Alternate Supply Resources

Avista identified supply-side resources that could meet resource deficiencies or provide a least cost solution. There are other options Avista considered in its modeling approach to solve for High Growth & Low-Price unserved conditions and to determine whether the Expected Case with existing resources is least cost/least risk. A list of the modeled available renewable supply resources is displayed in Table 7.2 and fossil resources are included in Table 7.3.

Table 7.2: Levelized Cost of Renewable Resources

Resource	Dth per year	20-year Levelized Cost Per Dth (Year 1)	$ per kWh (retail)
Distributed Renewable Hydrogen Production	60,509	$47.25	$0.161
Distributed LFG to RNG Production	231,790	$15.90	$0.054
Centralized LFG to RNG Production	662,256	$14.11	$0.048
Dairy Manure to RNG Production	231,790	$14.30	$0.049
Wastewater Sludge to RNG Production	187,245	$23.34	$0.080
Food Waste to RNG Production	108,799	$33.14	$0.113

Table 7.3: Other Supply Resources

Additional Resource	Size	Cost/Rates	Availability	Notes
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate	2021	Currently available unsubscribed capacity from Kingsgate to Spokane
Medford Lateral Expansion	50,000 Dth / Day	$35M capital + GTN Rate	2022	Additional compression to facilitate more gas to flow from mainline GTN to Medford
Plymouth LNG	241,700 Dth w/70,500 Dth deliverability	NWP Rate	2021	Provides for peaking services and alleviates the need for costly pipeline expansions Pair with excess pipeline MDDO's to create firm transport

As discussed in Chapter 5 – Carbon Reduction, Hydrogen is beginning to emerge as a true potential as a clean fuel to help offset emissions in the natural gas system. Excess electricity from renewable resources can create green. Not only will this act as a type of storage desperately needed by the electric grid, it will capture excess green energy for future use. Some estimates have green hydrogen as a major fuel in the supply mix by 2050. However, the market-based price and other terms are difficult to reliably determine until a formal agreement is negotiated. Exchange agreements also have market-based terms and are hard to reliably model when the resource need is later in the planning horizon. Current tariff prices were used to model additional GTN capacity and Plymouth LNG, while an estimate was provided from GTN for the upsized Medford lateral compressor combined with tariff rates in order to flow the gas. For those costs specifically related to all four RNG projects and hydrogen Avista contracted with a consultant to provide cost estimates for these types of facilities. Some of the major costs include: Capital, O&M, Avista's revenue requirement, federal income tax, and depreciation. Avista also included any subsidies known at the time of modeling. These projects include a cost of carbon adder for any amount of carbon intensity still associated with each project type. Specifically, dairy and solid waste have a negative carbon intensity, as discussed in Chapter 5. The net effect of using this is the removal of carbon from the atmosphere. Finally, Renewable Identification Number (RIN) values were not included in the valuation of RNG as it is assumed that these RIN's would be needed to provide proof of Avista's utilization of RNG or in complying with new environmental legislation[1].

Many of the potential resources are not yet commercially available or well tested, technically making them speculative. Avista will continue to monitor all resources and assess their appropriateness for inclusion in future IRPs as described in Chapter 9 – Action Plan.

Deterministic – Portfolio Evaluation

There is no resource deficiency identified in the planning period and the existing resource portfolio is adequate to meet forecasted demand. The alternate demand scenarios and supply scenarios are placed in the model as predicted future conditions that the supply portfolio will have to satisfy via least cost and least risk strategies. This creates bounds for analyzing the Expected Case by creating high and low boundaries for customer count, weather and pricing. Each portfolio runs through SENDOUT® where the supply resources (Chapter 4 – Supply Side Resources) and conservation resources (Chapter 3 – Demand Side Management) are compared and selected on a least cost basis. Once new

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

resources are determined, a net present value of the revenue requirement (PVRR) is calculated. Results from each scenario can be found in Table 7.4.

Table 7.4: PVRR by Portfolio

Scenario	System Cost (PVRR) Billions of $
Expected Case	$6.88
High Growth & Low Prices	$2.68
Carbon Reduction*	$5.70
Average Case	$5.69
Low Growth & High Prices	$9.80

*Carbon Reduction Scenario does not have sufficient factors to stochastically represent alternative futures due to the unknown nature of the cost and availability of RNG and H2.

Stochastic Analysis[2]

The scenario (deterministic) analysis described earlier in this chapter represents specific what if situations based on predetermined 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. 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 Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of portfolio performance under unknown weather and price profiles.

This IRP employs stochastic analysis in two ways. The first tested the weather-planning standard and the second assessed risk related to costs of our Expected Case (existing portfolio) under varying price environments. The Monte Carlo simulation in SENDOUT® can vary index price and weather simultaneously. This simulates the effects each have on the other.

---

[2] SENDOUT® 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.

Weather

In order to evaluate weather and its effect on the portfolio, Avista developed 1,000 simulations (draws) through SENDOUT®'s stochastic capabilities. Unlike deterministic scenarios or sensitivities, the 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 7.5) 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 7.5: 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 into the 2021 IRP, and Avista assessed the frequency of the weather planning standard peak day occurs in each area from the simulation data. The stochastic analysis shows that in over 1,000, 20-year simulations, peak day (or more) occurs with enough frequency to utilize the new planning standard for the current IRP. This topic remains a subject of continued analysis. For example, the Medford weather pattern over the 1,000 20-year draws (i.e, 20,000 years) HDDs at or above peak weather (49 HDDs) occur 1,926 times or once every 10 years.

See Figures 7.4 through 7.8 for the number of peak day occurrences by weather area. help explain why this can occur we look 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 7.4: Frequency of Peak Day Occurrences – Spokane

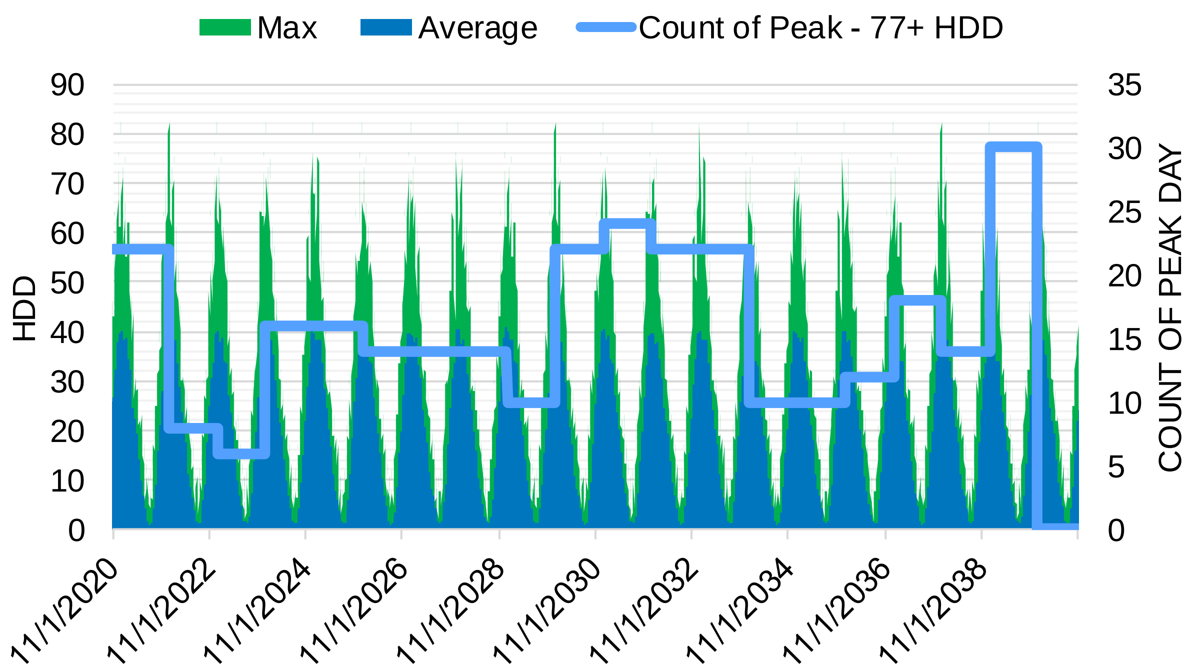


Figure 7.5: Frequency of Peak Day Occurrences – Medford

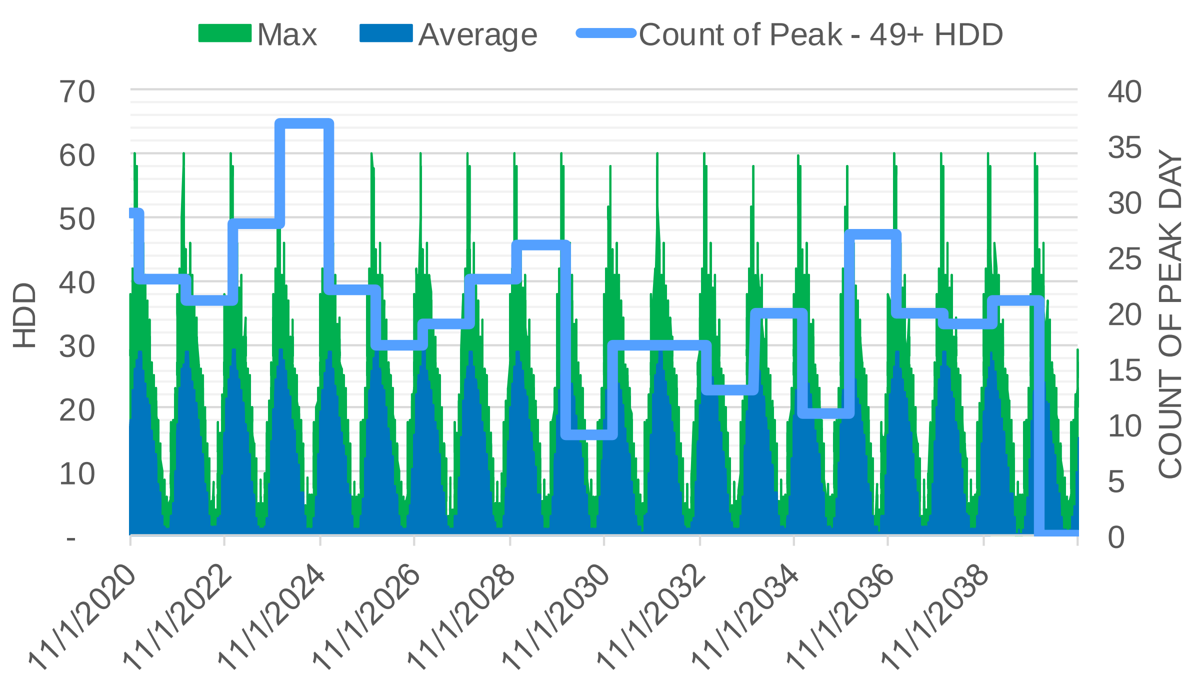


Figure 7.6: Frequency of Peak Day Occurrences – Roseburg

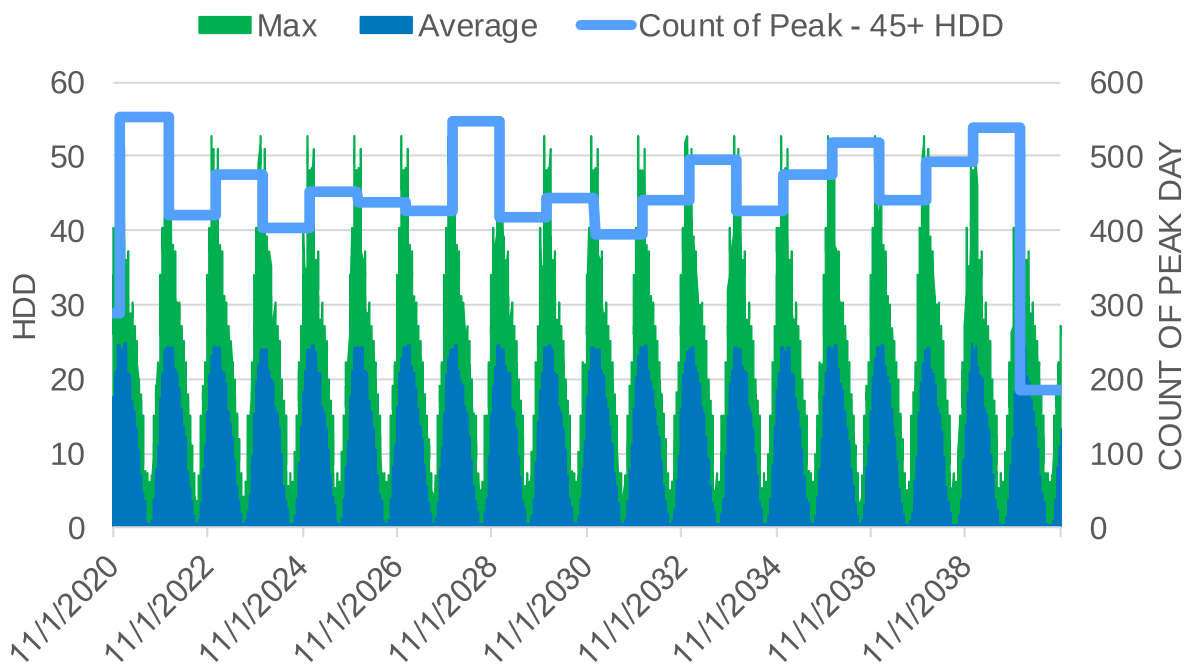


Figure 7.7: Frequency of near Peak Day Occurrences – Klamath Falls

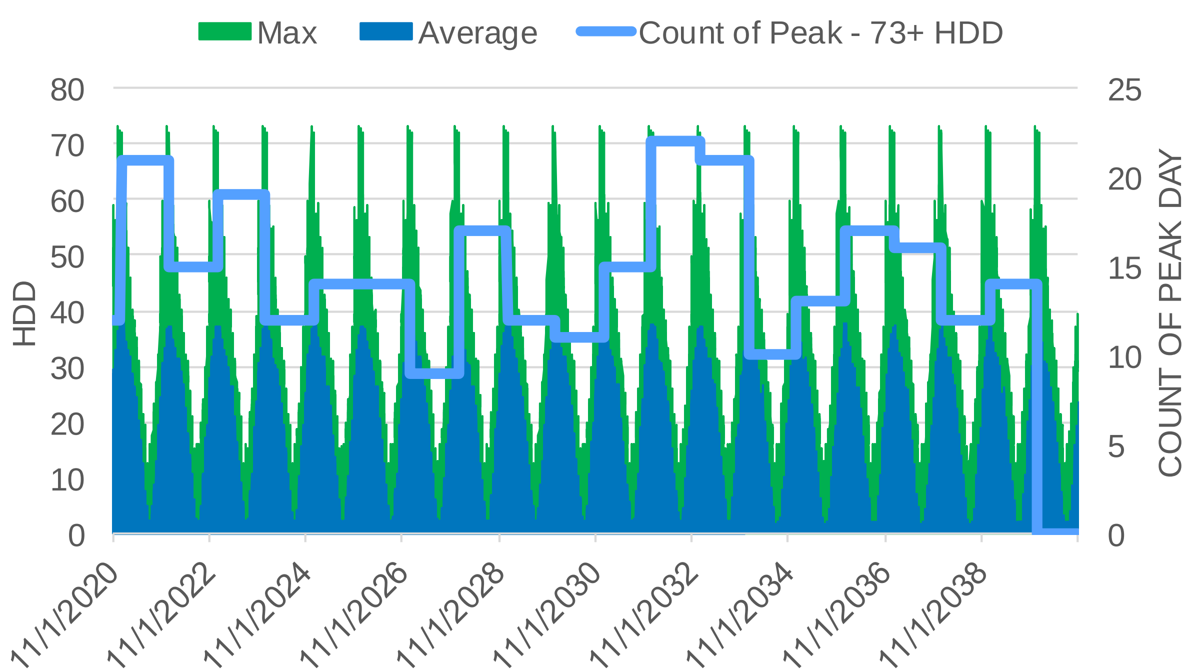
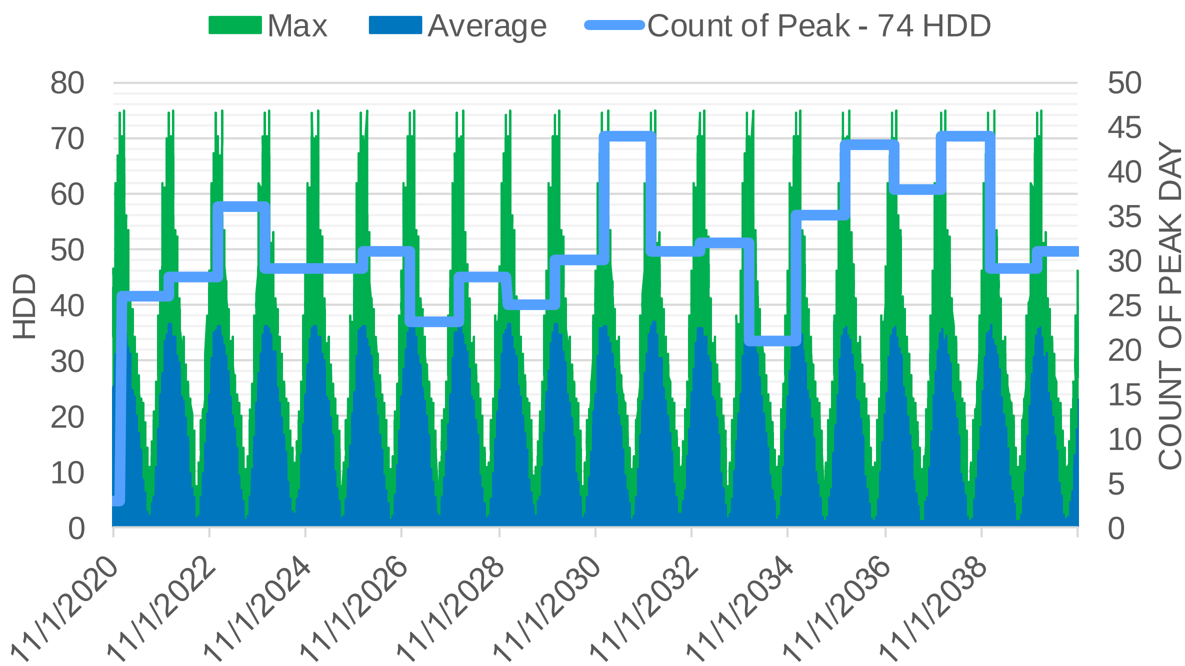


Figure 7.8: Frequency of near Peak Day Occurrences – La Grande

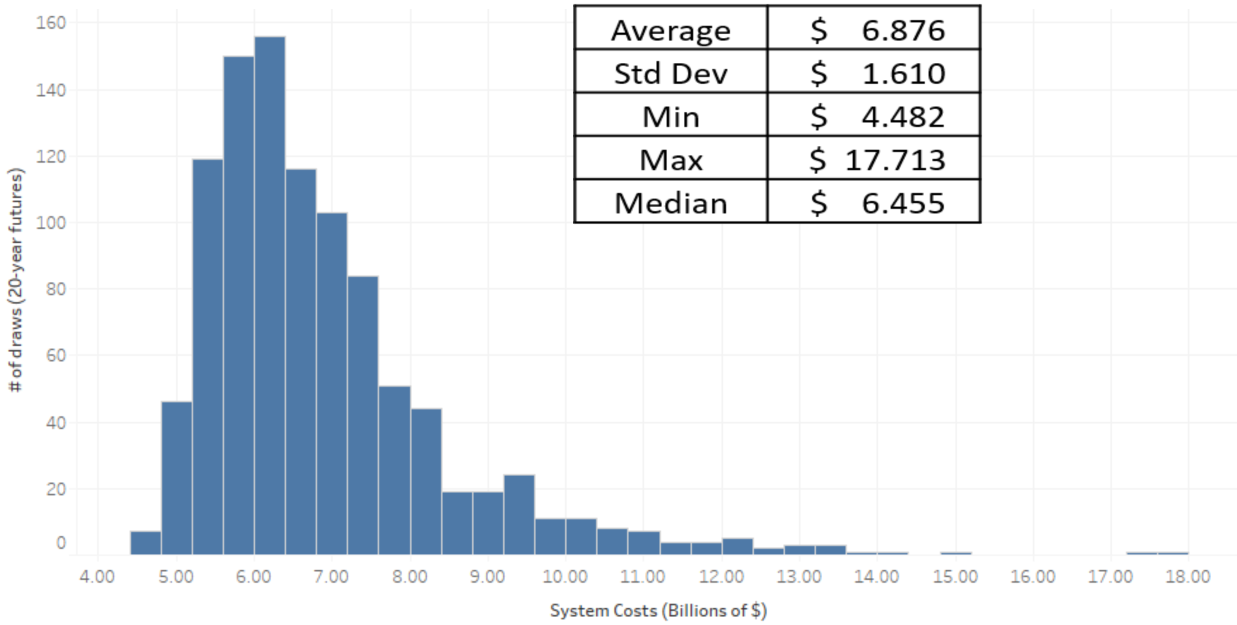


Price

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 1,000 draws, varying prices, to investigate whether the Expected Case total portfolio costs from the deterministic analysis is within the range of occurrences in the stochastic analysis. Figure 6.9 shows a histogram of the total portfolio cost of all 1,000 draws, plus the Expected Case results. This histogram depicts the frequency and the total cost of the portfolio among all of the draws, the mean of the draws, the standard deviation of the total costs, and the total costs from the Expected Case.

Figure 7.9: 2018 IRP Total 20-Year Cost (Billions of $)



Measuring risk in both weather and price is done through a statistical approach of shocking each of these measures to reflect the uncertain nature of a future outcome. Risk can be measured in 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.

Solving Unserved Demand

High Growth & Low Price

The components, methods and topics covered in this and previous chapters will now help to solve unserved demand in The High Growth & Low Price scenario. This scenario includes customer growth rates higher than the Expected Case, incremental demand driven by emerging markets and no adjustment for price elasticity. Even with aggressive assumptions, deterministic analysis shows resource shortages do not occur until late in the planning horizon.

- 2036 in Washington/Idaho
- 2040 in La Grande

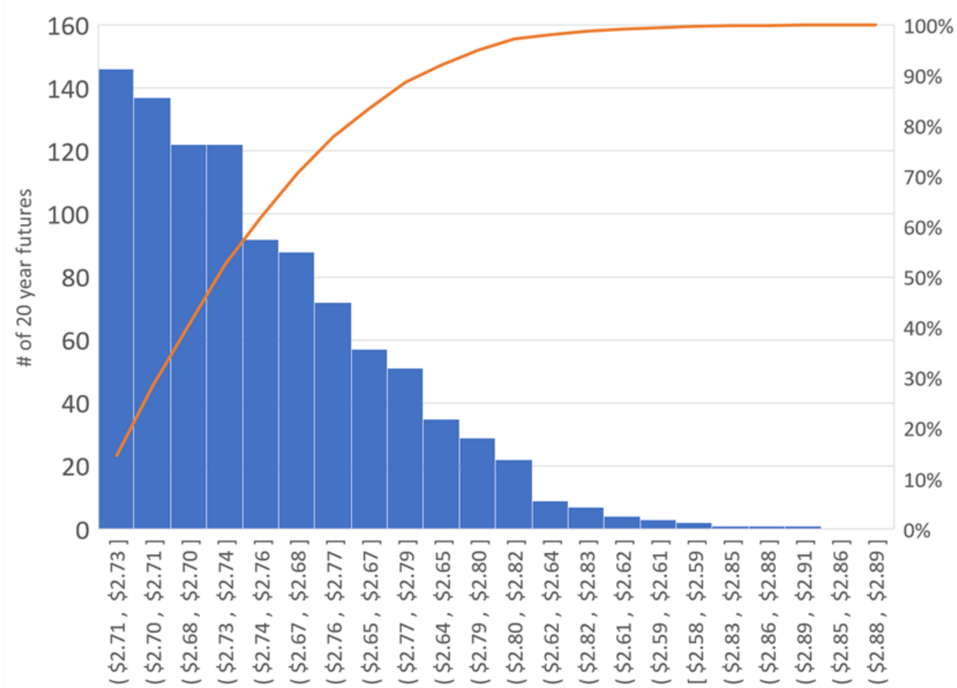
We begin to solve for unserved demand by adding additional resources as supply side options. The resources Avista modeled for the current IRP include 5 types of renewable natural gas, hydrogen, and an upsized compressor on the Medford lateral, additional GTN capacity and Plymouth LNG as seen in Table 7.2. All costs are entered by location with the associated daily, pipeline quality, volume available to inform the model. A deterministic resource mix is performed allowing the model to solve the demand based on the optimal least cost solution for the system. Avista performed this selection process both deterministically and stochastically with the statistical measures shown for each resource option as illustrated in Table 7.6.

Table 7.6: System Cost, Standard Deviation and Outcome of Adding Resource to System

Solve – No Unserved	Average	Stdev	Median	Max	Min
RNG Resources Only	$2.683	$0.043	$2.681	$2.861	$2.542
Plymouth, RNG in La Grande	$2.721	$0.043	$2.719	$2.901	$2.580
GTN – RNG in La Grande	$2.734	$0.042	$2.675	$2.855	$2.540
Medford Lateral Expansion, RNG in La Grande	$2.734	$0.044	$2.731	$2.915	$2.600
*$ in Billions **1,000 draws each scenario					

Once an optimal resource is found deterministically a stochastic analysis takes place to measure risk. Figure 7.10 shows the frequency of occurrence from the solve (RNG Resources Only) by cost in addition to a running sum of overall percentage of the total number of future 20 year draws.

The Optimal Solution Figure 7.10: High Growth and Low Price Cost vs. Risk (1,000 Draws – Billions of $)

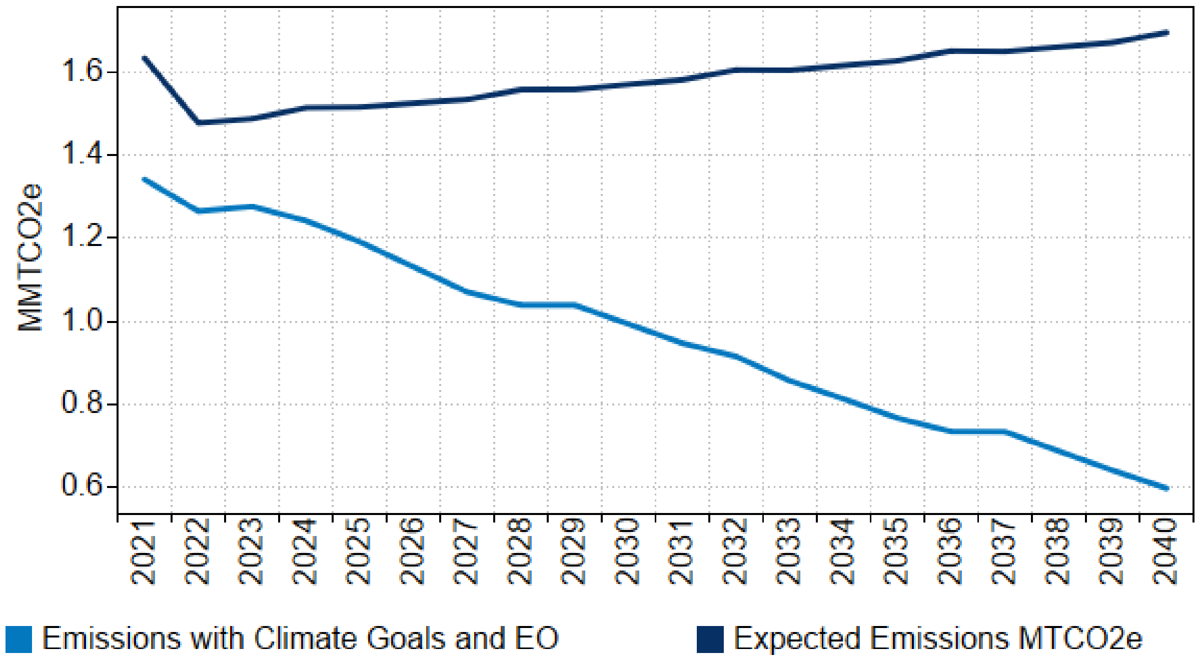


Carbon Reduction Scenario

As carbon policy continues to shift and evolve, mapping out potential supply options to meet these climate goals is increasingly important. Understanding the dynamic between serving the energy demand while reducing carbon emissions is a relatively new paradigm in the natural gas industry. Reducing carbon can take the form of alternate fuel choices either partially reducing, increased energy efficiency (DSM) or fully offsetting the carbon intensity of fossil natural gas. Some RNG sources, as mentioned in Chapter 5 – Carbon Reduction, will turn each unit of energy into a methodology to capture carbon rather than just fully offset the emissions of fossil fuel natural gas. These sources such as dairy or WWTP RNG will leave a deficit of energy for the number of emissions offsets provided. Pairing the right amount of energy with the necessary amount of emissions reduction is where this IRP will begin to discover solutions and provide answers.

Future IRP's will have the ability to solve for emissions and costs to meet a dual goal least cost and risk set of supply side resources. Emissions reduction goals can be measured to include various goals as a percentage based on a specific year or timeframe. In this scenario, we take the Expected case assumptions as inputs and combine them with an estimated 1990 emissions goal for Oregon and Washington. The emissions reduction for Oregon and Washington can be seen in Figure 7.11.

Figure 7.11: Expected Emissions vs. Emissions with Climate Goals (Net of DSM)



It is assumed the goal and reductions need to be met on a yearly basis based on the average emissions reduction needed to meet these major milestones. Carbon emissions offsets are not modeled in the current IRP as their costs are unknown as are the allowable quantity by timeframe for their use. The selling of carbon credits, like RINs, will need consideration in future resource plans. As the cost of carbon increases, the levelized cost of resources decreases especially those with the ability to capture carbon as opposed to just offsetting emissions. This places dairy RNG into the preferred supply side resource if the ability to obtain the quantity of projects and the respective output is available as displayed in Figure 7.12 along with each modeled scenario's carbon emissions (Figure 7.13).

Figure 7.12: Carbon Reduction Solve

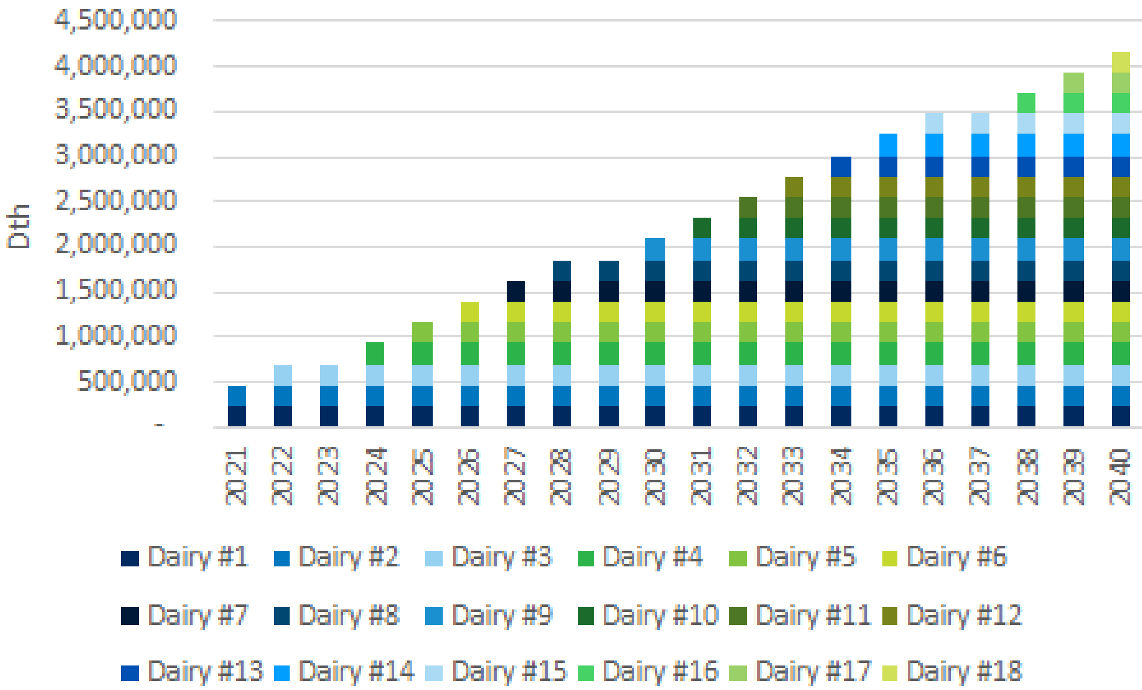
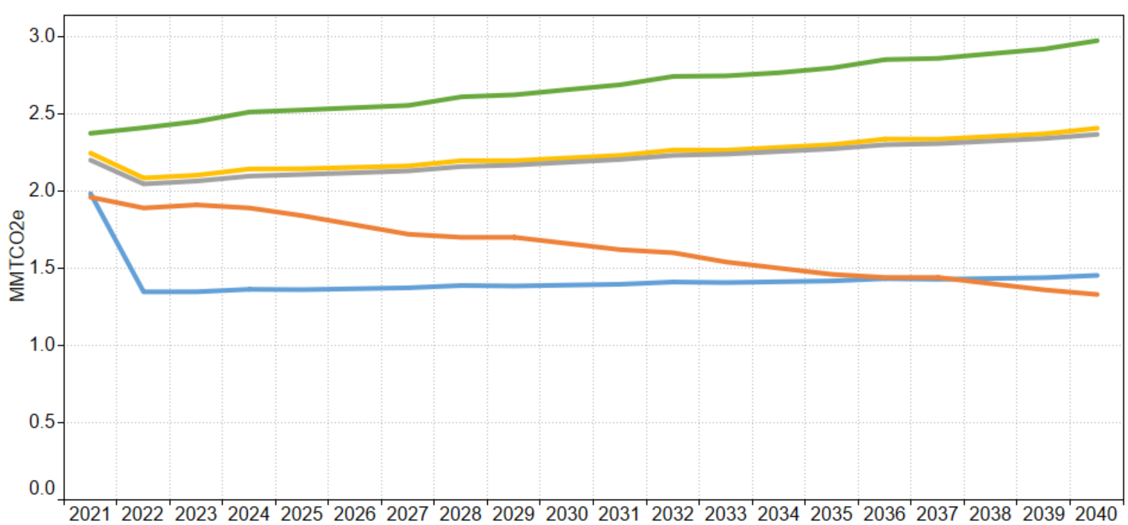


Figure 7.13: Depicts System Emissions for each Scenario



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Carbon Reduction	1.96	1.89	1.91	1.89	1.84	1.78	1.72	1.70	1.70	1.66	1.62	1.60	1.54	1.50	1.46	1.44	1.44	1.40	1.36	1.33
Average Case	2.20	2.05	2.06	2.10	2.11	2.12	2.13	2.16	2.17	2.19	2.20	2.23	2.24	2.26	2.27	2.30	2.31	2.32	2.34	2.37
Expected Case	2.25	2.08	2.10	2.14	2.14	2.15	2.16	2.20	2.20	2.21	2.23	2.27	2.26	2.28	2.30	2.34	2.34	2.35	2.37	2.41
Low Growth	1.98	1.35	1.35	1.36	1.36	1.37	1.37	1.39	1.38	1.39	1.40	1.41	1.41	1.41	1.42	1.43	1.43	1.43	1.44	1.45
High Growth	2.37	2.41	2.45	2.51	2.52	2.54	2.55	2.61	2.62	2.66	2.69	2.74	2.75	2.77	2.80	2.85	2.86	2.89	2.92	2.97

Electrification Scenarios

Avista uses three scenarios to identify impacts to the power system if space and water heating is electrified in the Washington service area[3], specifically for the residential and commercial customers. The first scenario of electrification uses current electric technology and efficiency. The second, continues to use the natural gas system for peak heating needs with non-peak electrified. Finally, the third scenario uses an assumption of high efficiency electric equipment. Each scenario uses the conversion from natural gas to electric assumes a 50 percent reduction in natural gas load by 2030 and an 80 percent reduction by 2045. Avista estimates 75 percent of the added electric load will be on Avista's system and the remaining load on other utilities.

Figure 7.14 below illustrates additional Avista load on the Avista electric system in Washington:

Figure 7.14: Additional Avista Load on Avista Electric System - Washington

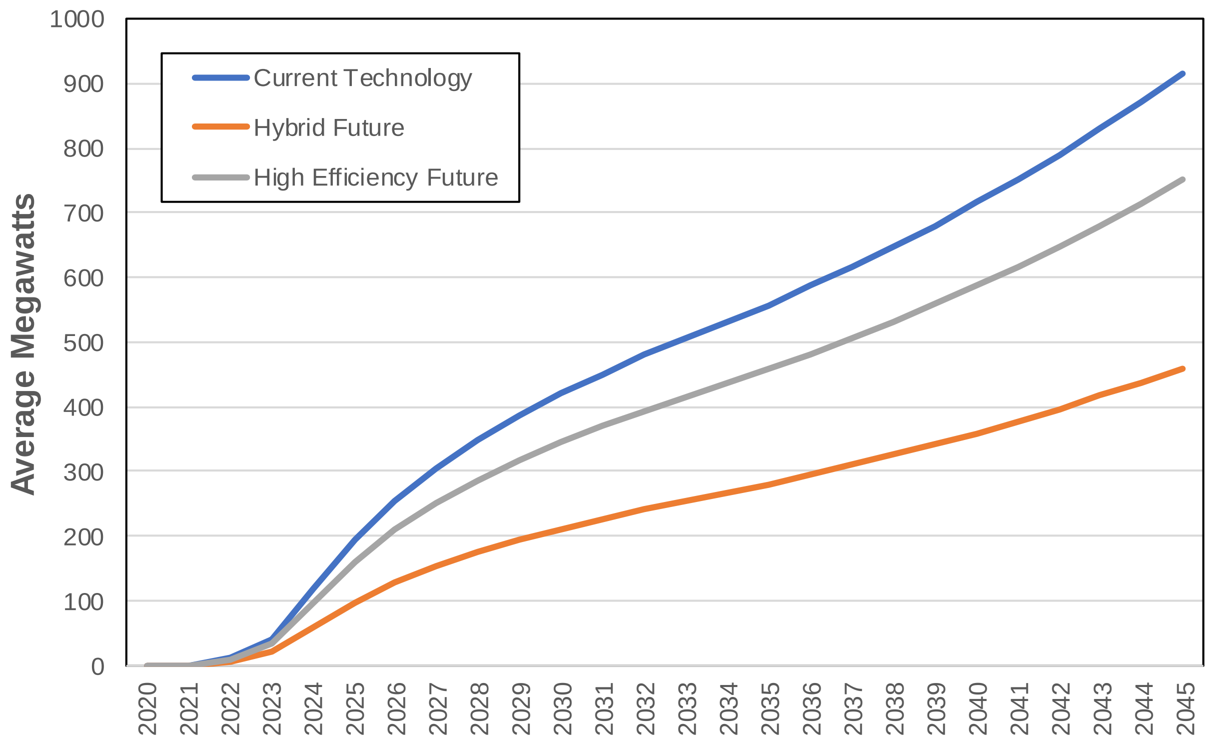
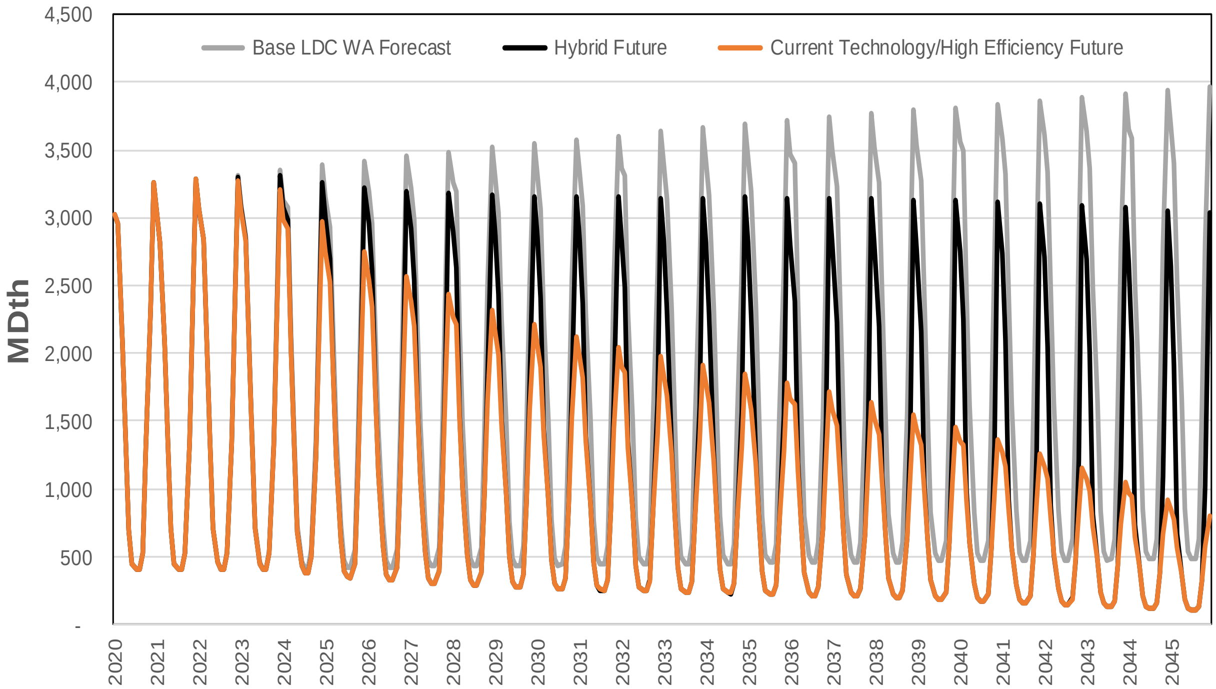


Figure 7.15 displays the natural gas supplied for each electrification scenario:

[3] The load conversion analysis also includes natural gas process conversion such as cooking, cloths drying, etc.

Figure 7.15: Natural Gas Supply by Electrification Scenario



While these scenarios have advanced our understanding of an electrification future, further studies are needed to fully understand the full impacts and costs of electrification. Some of these areas include:

- cost to homeowners to convert equipment;
- transmission or distribution grid impacts and costs;
- Avista has not re-studied the northwest electric market to account for pricing and resource availability impacts.

Given the large scope and impacts of this future scenario it may be best suited for a non-IRP analysis on a regional level. For additional detail on these scenarios, please refer to the Avista 2021 Electric IRP (Chapter 12-Portfolio Scenario Analysis).

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 Case planning conclusions. This included dynamic demand analytical methods and sensitivity analysis on demand drivers that impacted demand forecast assumptions. From this, Avista created multiple demand sensitivities and five demand scenario alternatives, which incorporated different customer growth, use-per-customer, weather, and price elasticity 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 SENDOUT® supplemented this analysis. Avista also used simulations from SENDOUT® 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.

Conclusion

In planning, a reasonable set of criteria is necessary to help measure the inherent risk of the unknown in future events. With the inclusion of the Carbon Reduction scenario, Avista will continue to consider resources to solve the energy demand in combination with new policy, specifically those requiring carbon reductions. As policy continues to require green sources from the electric grid, the existing natural gas infrastructure should be used in the battle against climate change. Resources such as RNG and H2 can play an important part in these electric generation green resources, utilizing the excess energy while providing mitigation to outages and weather-related events that are far more common in the electric industry[4]. Energy security during the coldest of times is a pillar of resource planning and Avista will continue to consider all the environment, affordability and reliability of resources to meet our customer's needs.

[4] www.energy.gov

8: Distribution Planning

Overview

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 such that 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. 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 GL Noble Denton'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 percent 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. Enhancements can 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 that has, or may become, a 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

[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.

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

Pipeline upsizing involves replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area 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 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 that 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 relatively slow and steady pace, so that purchasing and installing these less expensive compressors over time allows a pipeline 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 conservation through the DSM measures discussed in Chapter 3 – Demand-Side Resources, but does not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraints. Over the longer-term, targeted conservation 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.

Avista's design HDD for distribution system modeling is determined using a 99% statistical probability method for each given service area. 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 experienced rarely. Given the potential impacts of an extreme weather event on customers' personal safety and property damage to customer appliances and Avista's infrastructure, it is a prudent regionally accepted planning standard.

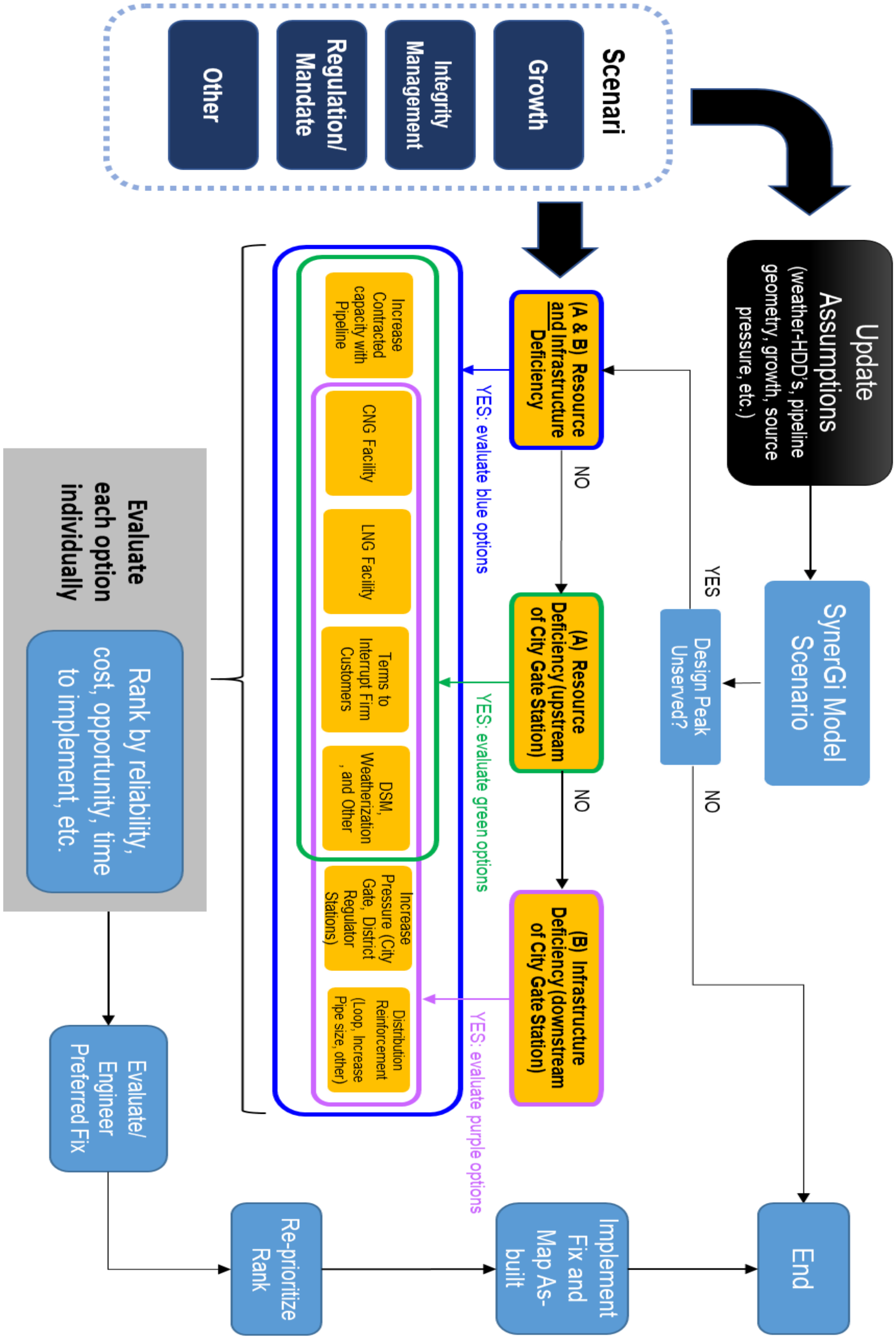
These areas of concern are then risk ranked against each other to ensure the highest risk areas are corrected first. Within a given area, projects/reinforcements are selected using the following criteria:

- 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, etc.
- 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



An example of the distribution scenario decision making process is from the Medford high pressure loop reinforcement where the analysis resulted in multiple paths or pipeline routes. The initial path was based on quantitative factors, specifically the shortest length and least cost route. However, as field investigations and coordination with local city and county governments began, alternative routes had to be determined to minimize future conflicts, environmental considerations, and field and community disruptions. The final path was based on several qualitative factors that including:

- Available right-of-way along city streets;
- Availability of private easements from property owners;
- Restrictions due to City of Medford future planned growth with limited planning information; and
- Potential to avoid conflict with other utilities including a large electric substation along the initial route.

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); and
- Budget approval (will require approval for capital funding).

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 aforementioned ongoing reassessment of information.

The following discussion provides information about key near-term projects.

Airway Heights High Pressure Reinforcement, WA: The Airway Heights high pressure line has provided natural gas to one of the fasted growing regions in all of Avista's service territories. Recent rapid growth has included both residential and industrial customers, quickly depleting the available capacity of the high pressure line. This reinforcement will provide additional capacity and ensure reliable pressure at the end of the high pressure line, which supplies a major regulator station feeding the Downtown Spokane neighborhoods.

Cheney High Pressure Reinforcement, WA: This project will reinforce the Cheney distribution system, whose customer demands have exceeded the capacity of the high pressure line constructed in 1957. During cold weather conditions, Avista periodically asks some large firm customers to reduce their natural gas usage in order to serve core customer demand. Project began in 2020 and will continue in 2021.

Pullman High Pressure Reinforcement, WA: The Pullman high pressure reinforcement would connect both 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 2024 and we continue to monitor existing customer demand. Construction timelines may change due to customer growth expectations.

Warden High Pressure Reinforcement, WA: The Warden high pressure reinforcement is necessary to serve either new or increased industrial customer demand. At this time, prospective industrial customers, whose projected demands necessitated reinforcements, have either cancelled expansion plans or are considering alternative locations. In anticipation of similar industrial loads in the future, Avista will continue to list this project, but defer major construction until supply constraints subside.

Table 8.1 High Pressure - Distribution Planning Capital Projects

Location	2021	2022	2023	2024	2025+
Airway Heights High Pressure Reinforcement, WA	$3,000,000	$3,000,000	---	---	---
Cheney High Pressure Reinforcement, WA	$3,100,000	---	---	---	---
Pullman High Pressure Reinforcement, WA	---	---	---	$2,400,000	---
Warden High Pressure Reinforcement, WA	$100,000	$2,950,000	$2,950,000	---	---

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. Actual solutions may differ 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 these city gate stations at this time.

Table 8.2 City Gate Station Upgrades

Location	Gate Station	Project to Remediate	Cost	Year
Colton, WA	Colton #316	TBD	-	TBD
Medford, OR	Medford #2431	TBD		TBD
Pullman, WA	Pullman #350	TBD	-	TBD
Roseburg, OR	Melrose #2608	TBD	-	TBD
Sprague, WA	Sprague #117	TBD	-	TBD
Sutherlin, OR	Sutherlin #2626	TBD	-	TBD

Conclusion

Avista’s goal is to maintain its natural gas distribution systems reliably and cost effectively to deliver natural gas to every customer. This goal relies on modeling to increase the capacity and reliability of the distribution system by identifying specific areas that may require changes. The ability to meet the goal of reliable and cost-effective natural gas delivery is enhanced through localized distribution planning, which enables coordinated targeting of distribution projects responsive to customer growth patterns.

9: Action Plan

The purpose of an action plan is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. The Action Plan identifies needed supply and demand side resources 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.

2017-2018 Action Plan Review

Avista's 2020 IRP will contain an individual measure level for dynamic DSM program structure in its analytics. In prior IRP's, it was a deterministic method based on based on Expected Case assumptions. In the 2020 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.

Result – Result- Avista discussed with Energy Trust of Oregon. It was decided that we will continue to use Energy Trust's current modeling protocols to run scenarios analyses for the Conversation Potential Assessment (CPA). This decision enables the greatest alignment between what Energy Trust expects they will be able to achieve under different policy scenarios. These scenarios may include modeling using differential assumptions such as: a) different avoided costs and b) accelerated and decelerated program uptake scenarios. This also allows Energy Trust to include measures in the CPA that are offered through Energy Trust programs under cost-effectiveness exceptions granted by the OPUC under UM-551 guidelines. These CPA practices coincide well with the capabilities of the software that Avista is using for other IRP modeling purposes. Consequently, Avista has chosen not to further investigate dynamic DSM program structure modeling in its analytics. Based on Avista's efforts with ETO, it was decided to forgo the ability to analyze DSM in Washington and Idaho due to any disparities that may occur from the separation of analysis types.

Work with Staff to get clarification on types of natural gas distribution system analyses for possible inclusion in the 2020 IRP.

Result - Any large natural gas distribution system analysis will be included in all future IRP's against system resources where necessary.

Work with Staff to clarify types of distribution system costs for possible inclusion in our avoided cost calculation.

Result – Distribution system costs are included in the avoided cost calculation and will be included in all future IRP documents.

Revisit coldest on record planning standard and discuss with TAC for prudency.

Result – Avista has changed its weather planning standard based on a probability of occurrence based on each weather planning location. The current methodology uses the most recent 30 years of weather and the coldest day of each year combined with a 99% probability of a weather event occurring.

Provide additional information on resource optimization benefits and analyze risk exposure.

Result – Chapter 4 – Supply Side Resources has been expanded to not only add in resource optimization benefits and risk exposure, but also includes additional details of Avista's natural gas hedging program

DSM—Integration of ETO and AEG/CPA data. Discuss the integration of ETO and AEG/CPA data as well as past program(s) experience, knowledge of current and developing markets, and future codes and standards.

Result – The integration of Avista's CPA providers is discussed in Chapter 3 – Demand Side Management.

Carbon Costs – consult Washington State Commission's *Acknowledgement Letter Attachment* in its 2017 Electric IRP (Docket UE-161036), where emissions price modeling is discussed, including the cost of risk of future greenhouse gas regulation, in addition to known regulations.

Result – The social cost of carbon is used in the Expected Scenario for the State of Washington.

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

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

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.
        - Construction of gas infrastructure associated with growth
        - 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

An updated table 8.1 for those distribution projects in Oregon:

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

Result – Large High-pressure distribution and City Gas projects did not occur since the 2018 IRP. Quarterly updates will continue to occur with Oregon Staff to ensure any change in projects is known along with reasons for any major changes in expected capital expenditures.

Avista will work with members of the OPUC to determine an alternative stochastic approach to Monte Carlo analysis prior to Avista's 2020 IRP and share any recommendations with the TAC members.

Result – Avista and the OPUC agreed on a 1,000 draw minimum in all scenarios and were performed to this standard in all stochastic simulations in the current IRP.

2021-2022 Action Plan

New Activities for the 2023 IRP

1. Further model carbon reduction in Oregon and Washington
2. Investigate new resource plan modeling software and integrate Avista's system into software to run in parallel with Sendout
3. Model all requirements as directed in Executive Order 20-04
4. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.
5. Explore the feasibility of using projected future weather conditions in its design day methodology.
6. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections. However, should conditions warrant that capital work is needed on a high-pressure distribution line or city gate station 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.
    - Construction of gas infrastructure associated with growth
    - 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

Ongoing Activities

- Continue to monitor supply resource trends including the availability and price of natural gas to the region, LNG exports, methanol plants, supply and market dynamics and pipeline and storage infrastructure availability.
- Monitor availability of resource options and assess new resource lead-time requirements relative to resource need to preserve flexibility.
- Meet regularly with Commission Staff to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.
- Appropriate management of existing resources including optimizing underutilized resources to help reduce costs to customers.

2021 Natural Gas Integrated Resource Plan Appendices

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.

TABLE OF CONTENTS: APPENDICES

APPENDIX 0.1: TAC MEMBER LIST

Organization	Representatives	
Applied Energy Group	Kenneth Walter	
Avista	Terrence Browne Amanda Ghering Ryan Finesilver Grant Forsyth James Gall Justin Dorr John Lyons Lisa McGarity	Jody Morehouse Tom Pardee Michael Brutocao Jason Thackston Jaime Majure Michael Whitby Shawn Bonfield Jeff Webb
Biomethane, LLC	Kathlyn Kinney	
Cascade Natural Gas Company	Ashton Davis Mark Sellers-Vaughn	Brian Robertson
Citizens Utility Board of Oregon	Sudeshna Pal	Will Gehrke
Energy Trust of Oregon	Peter Schaffer Ted Light	Spencer Moersfelder
Fortis	Ken Ross	
Idaho Conservation League	Dainee Gibson-Webb	
Idaho Public Utility Commission	Donn English Terri Carlock Joseph Terry	Kevin Keyt Mike Louis Rick Keller
Intermountain Gas	Raycee Thompson Dave Swenson	Lori Blattner
Northwest Energy Coalition	Amy Wheeless	
Northwest Gas Association	Dan Kirschner	
Northwest Natural Gas	Tammy Linver	

Northwest Power and Conservation Council	Steve Simmons	
Oregon Public Utility Commission	Anna Kim	Kim Herb
Washington State Department of Commerce	Peter Moulton Chuck Murray	Greg Nothstein
Washington State Office of the Attorney General	Shay Bauman Chuck Murray	Corey J Dahl
Washington Utilities and Transportation Commission	Jennifer Snyder Andrew Rector	Deborah Reynolds Steve Johnson

APPENDIX 0.2: COMMENTS AND RESPONSES TO 2021 DRAFT INTEGRATED RESOURCE PLAN

The following table summarizes the significant comments on our DRAFT as submitted by TAC members and Avista's responses. This IRP produced reduced forecasted demand scenarios and no near term resource needs even in our most robust demand scenario. We appreciate the time and effort invested by all our TAC members throughout the IRP process. Many good suggestions have been made and we have incorporated those that enhance the document.

Document Reference	Comment / Question	Avista Response
Chapter 5	For upstream methane emissions, Avista uses a global warming potential (GWP) factor that was calculated based on the International Panel on Climate Change's Assessment Report 5 (IPCC AR5), which Staff prefers over older analyses. Avista uses the upstream methane leakage factor of 0.77 percent for Canadian natural gas, and uses 1.0 percent for the U.S. Rockies natural gas factor. Given that this U.S. Rockies natural gas emissions factor is significantly lower than any of the factors analyzed by the NWPCC in its analysis of upstream natural gas emissions, Staff recommends the Final IRP explain why the factor is appropriate.	Added supplimental language to Chapter 5
Chapter 7	Consider effects of policy trends towards electrification on both the electric and natural gas systems.	Included supplemental language

Chapter 2	Explain the new design day methodology, providing a more detailed narrative.	Updated within Chapter 2
Chapter 2	Further explain why the new design day standard is now the most appropriate one.	Updated within Chapter 2
Chapter 9	Explore the feasibility of using projected future weather conditions in its design day methodology, rather than relying exclusively on historic data.	added to Action Plan
Appendix 7.2	Include details of RNG cost assumptions in the appendices.	Included in Appendix 7.2
Appendix 7.2	Use any up-to-date cost data that is available to model potential RNG resources.	Avista will use the most recent data available where details are verified, reasonable and sufficient enough for cost determination in all resources
Avista 2021 Electric IRP	Avista's Draft 2021 IRP, p11, provides some explanation for factors that could drive future natural gas demand. While Avista does not anticipate any increase in demand from the traditional residential and commercial customer classes, the Company expects growing demand from electric utilities in terms of natural gas back up for solar and wind technologies. CUB is aware that electric utilities serving the Pacific Northwest like, Portland General Electric and PacifiCorp do not have plans to build new gas plants in the long-term. Idaho Power targets for 100% clean energy by 2045. BC Hydro's Clean Power 2040 mandate includes reduction of GHG emissions through clean electricity. CUB would therefore like to see some discussion in the IRP that could substantiate the claim that electric utilities in the Pacific Northwest region are increasingly becoming reliant on gas plants as backups for their renewable generation resources.	Please refer to the Avista 2021 Electric IRP for peaking needs from natural gas plants as summarized in it's Preferred Resource Strategy (PRS). The Wood Mackenzie material shown during TAC 2 on August 6, 2020 will provide a high level summary of expected need in the Pacific Northwest, which dispite the massive expected buildout of renewable resources, less than half of the natural gas leaves the forecast. On a national level the forecast for the next 20 years remains mostly unchanged in spite of the new electric clean resources. In this case, growing demand does not infer new natural gas plants, just continued demand to meet electric capacity requirements.
Chapter 2, 5 & 7	CUB realizes that Carbon price sensitivities are designed around Oregon and Washington's carbon policy futures as Idaho does not contemplate having a carbon policy in near future. Hence Avista assumes a carbon cost of $0 for Idaho and other carbon price ranges for Oregon and Washington. CUB suggests that for a long-term planning purpose, Avista should look at a price range for Idaho with a lower limit of $0 and set a positive dollar amount as upper limit, like it has for Oregon and Washington. CUB would like to cite Idaho Power's 2019 IRP in which the utility considers four carbon cost scenarios, namely,	Chapter 2 contains the sensitivities to a high, expected and low price as compared to the reference case for all jurisdictions. The expected carbon price considers any known policy or direction by state or federal entities that may help indicate a carbon price. In the event there is no policy, like Idaho, formulating a potential price indicator is problematic leading Avista to measure the bounds for risk vs. a specific policy as done through the

		scenarios of high growth and low prices and low growth and high prices. Electric utilities can use shadow pricing or inferred pricing to determine when plants are still cost effective. Natural gas, mostly, uses the single fossil commodity to determine demand. Avista will continue to look for ways to value carbon and include where appropriate.
Chapter 2, 5, 7	Zero Cost – no state or federal tax or fee on carbon emissions),	A low price of carbon of $0 is assumed for all 3 jurisdictions in the High Growth and Low Prices case to measure no carbon policy.
Chapter 2, 5, 7	Planning Carbon – Based on Wood Mckenzie's forecasts, starting with $2/ton in 2028 and goes up to $22/ton by the end of the planning period,	A Wood Mackenzie carbon assumption was put in place to measure Oregon's cap and reduce future
Chapter 2, 5, 7	Generational Carbon – Based on EPA's estimated of social cost of carbon, starting at $55.73/ton starting in 2020 and increasing to $101.16/ton by the end of the planning period, and,	This is assumed for WA in the Expected Case
Chapter 2, 5, 7	High Carbon – Based on California Energy Commission's Integrated Energy Policy Report only for federal programs. Carbon costs under this scenario are assumed to start at $28.65/ton in 2022 increasing to $107.87 by the end of the IRP planning horizon. CUB believes using a carbon price range for Idaho will address local, state and federal environment policy related uncertainties for the system as a whole for the planning period.	high carbon costs are included for all jurisdictions to measure the upper limits of carbon prices in the Low Growth and High Prices
Chapter 7	Avista's Electric IRP includes a natural gas to electricity switching scenario. CUB is wondering why this scenario analysis was not also a part of the natural gas IRP. Recently there have been proposals to phase out gas space and water heating in Washington state. Around forty communities in California have imposed a ban on natural gas heating in new buildings. Avista's service territory in Southern Oregon is well suited in terms of climate for electrification of heating load. CUB suggests that Avista explore a No Growth scenario for its long-term demand forecast.	A write up is included in Chapter 7. Avista will explore a no growth scenario in the 2023 Avista Natural Gas IRP

Chapter 7	Staff is particularly interested in understanding how different RNG resources were compared for selection in the alternate scenario.	Resources were compared against all resource modeled options which can be viewed in Chapter 7. The options account for all estimated costs to build and maintain the facility and account for the cost of carbon based on the carbon intensity savings by source
Chapter 8	With regard to demand response (Guideline 7), the Company mentions a single project on page 165. Staff would like to see more information about demand response as a demand-side option in the final IRP, both as a system resource and its potential to offset distribution upgrades.	The high pressure projects mentioned on page 165 were identified after comprehensive load study analyses. Each analysis uses 18-24 months of historical customer billing history, so any DSM or energy efficiency measures adopted by customers are reflected in the loads of the analysis. The projects listed reflect current shortfalls on the distribution system. These shortfalls or deficiencies are also too large to be eliminated or even mitigated by DSM or energy efficiency measures. Since most of these projects will be completed over more than one year, Avista will use subsequent load studies to determine if there is a change in the necessity of a project, and then revise or defer accordingly.
Chapter 5	Regarding Environmental Costs (Guideline 8), Staff appreciates the Company's analysis of a portfolio under the Carbon Reduction scenario, and the Company's consideration of creative solutions to compete as a buyer with California's Low Carbon Fuel Standard market. Staff has questions about the assumptions leading to a portfolio of all dairy RNG and will like to see more discussion about how realistic that portfolio is, considering both total accumulation and the timing of additions over 20 years.	Unlike WWTP and landfills, for example, the ability to move livestock and create the product of methane capture seems reasonable. The quantity of these products supply needed is high. The overall potential of this is unknown and so based on the plan to go after the next cheapest resource the product potentials will be better known once carbon pricing, targets and deadlines are clear. This is mostly illustrative in nature and future potential must be estimated by state to have a realistic guideline in place for obtaining these goals.

Chapter 5	In addition to the carbon reduction alternate portfolio, Staff will also consider whether the preferred portfolio and action plan are consistent with Oregon policies. Staff acknowledges that the Company is awaiting additional guidance on how to implement EO 20-04 and understands the Company is prepared to comply by guidance provided, however Staff looks forward to understanding the extent to which the preferred portfolio is consistent with current Oregon policy, including EO 20-04. Further, Staff is preparing to engage with stakeholders on the implementation feasibility and impact of the IRP related activities identified in OPUC EO 20-04 work plan section 1.1. Staff suggests that the company be familiar with this section and be prepared to discuss metrics the Company could provide to track and forecast GHG emissions and strategies to reduce emissions to be compliant with EO 20-04.	The company is engaged in dialogue and meetings surrounding the effort around EO 20-04 and will implement the necessary strategies to reduce emissions.
Chapter 5, 6, 7	With regards to Guideline 10 (Multi-State Utilities), Staff also has questions about how policies across states interact, particularly for RNG. Staff would like to understand the assumptions the Company is using regarding the interaction of RNG policies in Washington and Oregon, and any system-wide strategies being considered.	Resources are solved on a system basis for least cost supply. In the case where Oregon and Washington may both be requiring in state emissions reduction supply sources, Avista modeled these resources directly into the demand zones. This will also help to correctly allocate costs by jurisdiction
Chapter 2, 5, 6, 7	1. Staff made a number of recommendations for potential improvements to the demand forecast. Staff has identified this topic as a key area of focus, particularly in terms of forecasted customer counts and usage per customer. Many of the recommendations relate to improving the modeling of potential carbon policy. For example, although the Company describes on page 11 that "Avista does not anticipate traditional residential and commercial customers will provide increased growth in demand," even in its low growth scenario, the Company is forecasting	A scenario with reduced demand could be the carbon reduction scenario in the 2021 natural gas IRP. In future IRP's we will consider a declining customer growth scenario. The Low Growth & High Prices scenarios is the best indicator for where Avista currently sees a reduced customer set paired with DSM to offset demand. The Carbon Reduction was included for our Washington service territory with the results and demand loss summarized in Chapter 7. If a similar load loss to electrification were to occur in Oregon, the impact to Avista would strictly be a loss of natural gas demand. The impacts to local electric utilities would need to be quantified by the utilities in each

		of these service areas. The costs to run natural gas service for those remaining customers would be held by fewer and fewer customers meaning their rates would continue to go up.
Chapter 2 – Appendix 2.6	2. Staff also recommended that the Company explore a large-scale supply interruption scenario, and the role of storage in such a situation. This scenario does not appear to be addressed in the draft IRP.	A large scale supply interruption and its impacts to Avista's natural gas system can be seen in Chapter 2. In the cases of a 100% loss of supply or even 50% loss of supply at AECO, JP, SUMAS, or Rockies trading points puts an unserved in the first or second year of planning. Based on these sensitivities it became evident as to the extreme predictions and outcomes of these supply basin outages, so Avista chose not to run a specified scenario.
Chapter 8	Staff is interested in better understanding the lack of anticipated distribution system upgrades. Staff would like to learn more about the certainty of this prediction and what sorts of upgrades the Company is excluding (i.e., is the Company completely foregoing all distribution investments for the next two years, or does the exclusion of distribution projects in the Company's IRP reflect a lack of larger investments?) the Company should include information the Company relied upon to come to this conclusion in its IRP filing.	Please see Chapter 8 Table 8.2. Also, 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 these city gate stations at this time.
Chapter 5, 6, 7	Staff is interested in the interaction between resources, policies, and plans between the Company's Washington and Oregon territories.	Carbon Reduction scenario for specifics on the interaction between policies, resources and plans between our WA and OR territories

APPENDIX 1.1: AVISTA CORPORATION 2021 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

The 2021 IRP process will be similar to that used to produce the previously published plan. Avista will use SENDOUT® (a PC based linear programming model widely used to solve natural gas supply and transportation optimization questions) to develop the risk adjusted least-cost resource mix for the 20 year planning period.

This plan will continue to include demand analysis, demand side management and avoided cost determination, existing and potential supply-side resource analysis, resource integration and alternative sensitivities and scenario analysis.

Additionally, Avista intends to incorporate action plan items identified in the 2021 Natural Gas IRP including more detailed demand analysis regarding use per customer, demand side management results and possible price elastic responses to evolving economic conditions, an updated assessment of conservation potential in our service territories, consideration of alternate forecasting methodologies, and the changing landscape of natural gas supply (i.e. shale gas, Canadian exports, and US LNG exports) and its implications to the planning process. Further details about Avista's process for determining the risk adjusted least-cost resource mix is shown in Exhibit 1.

TIMELINE

The following is Avista's 2021 Natural Gas IRP timeline:

TAC 1: Wednesday, June 17, 2020: TAC meeting expectations, 2020 IRP process and schedule, energy efficiency update, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits. fugitive Emissions, Weather Analysis, Weather Planning Standard

TAC 2 (Dual Meeting with Power side): Thursday, August 6, 2020: Market Analysis, Price Forecasts, Cost Of Carbon, demand forecasts and CPA results from AEG, Environmental Policies

TAC 3: Wednesday, September 30, 2020: Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, SENDOUT overview, sensitivities and portfolio selection modeling.

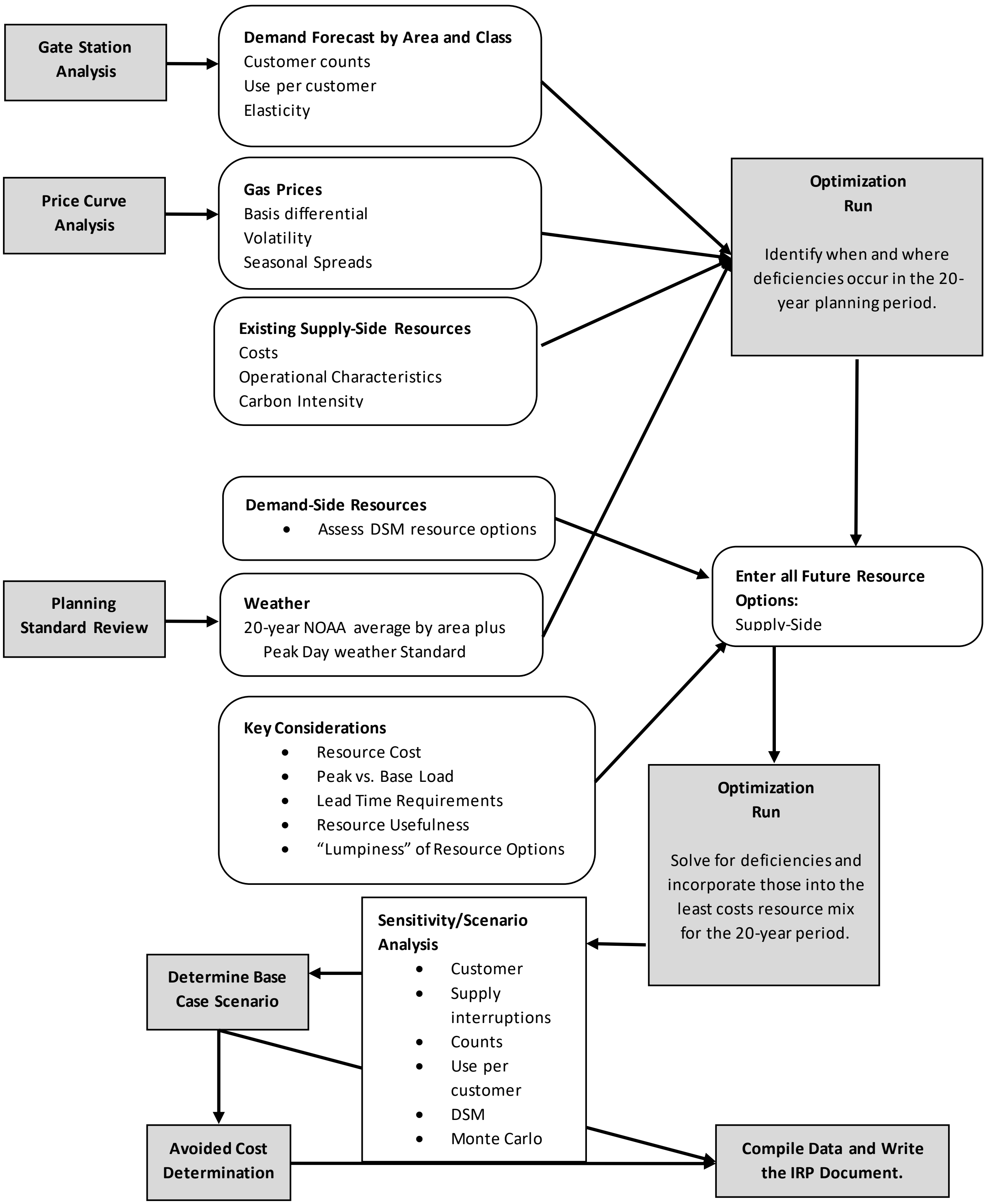
TAC 4: Wednesday, November 18, 2020: Review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

TAC 5: February 2021: TAC final review meeting (if necessary)

Avista's TENTATIVE 2023 Natural Gas IRP timeline:

Major Milestone	Date	Topics
TAC 1	Nov-2022	Use per customer, Policy, 2021 Action Item Review, price elasticity
TAC 2	Mar-2022	Customer Forecast, price forecast
TAC 3	Apr-2022	sensitivities, distribution, model overview
TAC 4	Jun-2022	Renewable Resources, Supply Side Resources, Demand Side Resources (CPA)
TAC 5	Jul-2022	Results / Stochastics, Action Items
Write IRP Draft	Sep-2022	
Draft Feedback Due	Oct-2022	
File	Dec-2022	

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 August 31, 2019, 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 August 31, 2018
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 Supply Side 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 Supply Side Resources and Chapter 6 Integrated Resource Portfolio
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 Supply Side 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 Supply Side 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 Supply Side 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.
WAC 480-90-238(2)(b)	LRC analysis considers public policies regarding resource preference	See Chapter 2 demand scenarios

	adopted by Washington state or federal government.	
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 Supply Side 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 Supply Side Resources
WAC 480-90-238(3)(d)	Plan includes an assessment of opportunities for using company-owned or contracted storage.	See Chapter 4 on Supply Side 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 Supply Side 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 Supply Side 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 supply-side 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:	Filing extension approved for 2021 IRP to be filed on or before April 1, 2021. The last IRP was filed on August 31, 2018.
	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 - Supply-Side 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 supply-side resources are compared on par with each other in the SENDOUT® 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 - Integrated Resource Portfolio** 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 four Technical Advisory Committee meetings beginning in June and ending in November. 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 - Supply-Side 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 - Integrated Resource Portfolio** 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 SENDOUT® 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, and storage options including liquefied natural gas. Chapter 3 and Appendix 3.1 documents Avista's demand-side management resources considered. Chapter 4 and Appendix 6.3 documents supply-side 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 SENDOUT® modeling software. All portfolio resources both demand and supply-side were evaluated within SENDOUT® 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.	Avista applied its after-tax WACC of 4.36% 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 and uncertainty are key considerations in long term planning. In order to address risk and uncertainties a wide range of sensitivity, scenario and portfolio analysis is completed. A description of risk associated with each scenario is included in Appendix 2.6. Avista performed 33 sensitivities on demand and price. From there five demand scenarios were developed (Table 1.1) for SENDOUT® modeling purposes. Monthly demand coefficients were developed for base, heating demand while peak demand was contemplated through modeling a weather planning standard using 99% probability (see heating degree day data in Appendix 2.4).

		Avista evaluated several price forecasts and performed stochastic simulations to derive a high and a low price based on the Expected price. Avista stochastic modeling techniques for price and weather variables to analyze weather sensitivity and to quantify the risk to customers under varying price environments. While there continues to be some uncertainty around GHG emission, Avista considered GHG emissions regulatory compliance costs in Appendix 3.2. As currently modeled, we include a carbon adder if the commodity is selected in the base
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Avista evaluated additional risks and uncertainties. Risks associated with the planning environment are detailed in Chapter 0 Introduction. Avista also analyzed demand risk which is detailed in Chapter 2. Chapter 3 discusses the uncertainty around how much DSM is achievable. Supply-side resource risks are discussed in Chapter 4. Chapter 6 and 7 discusses the variables modeled for scenario and stochastic risk analysis.
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 5 and 6 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 20-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 SENDOUT® 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 1,000 scenarios around varying gas price inputs via Monte Carlo iterations developing a distribution of Total 20 year cost estimates utilizing SENDOUT®'s PVRR methodology. Chapter 7 further describes this analysis. The variability of costs is plotted against the Expected Case while the scenarios beyond the 95^{th} 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 6 describes 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 2018 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, 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 4, 2021 and requested comments by February 3, 2021
Guideline 3: Plan Filing, Review and Updates		
3a	Utility must file an IRP within two years of its previous IRP acknowledgement order.	Acknowledgement of the 2018 IRP was on March 11, 2020. The 2021 IRP will be filed on April 1, 2021 or within two years of previous acknowledgement order
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	The annual update was submitted on January 26, 2020. The filing was a filing requesting an extension from August 31, 2020 to April 1, 2021. Approval was given through Order 20-071 on March 11, 2020.
3g	Unless the utility requests acknowledgement of changes in 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.	The updates described in 3f above explained changes since acknowledgment of the 2018 IRP and an update 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.	Avista developed six demand growth forecasts for scenario analysis. Stochastic variability of demand was also captured in the risk analysis. Chapter 2 describes the demand forecast data and Chapter 7 provides the scenario and risk analysis results. Appendix 5 details major assumptions.
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.	Figures 6.10 – 6.17 summarize graphically projected annual peak day demand and the existing and selected resources by year to meet demand for the expected case. Appendix 6.1 and 6.2 summarizes the peak day demand for the other demand scenarios.
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 supply-side 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. Appendix 2.6 highlights key risks associated with each portfolio.
4g	Identification of key assumptions about the future (e.g. fuel prices and environmental compliance costs) and alternative scenarios considered.	Appendix 7 and Chapter 7 describe the key assumptions and alternative scenarios used in this IRP.
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 this IRP (see Table 7.1 for scenarios considered).
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 SENDOUT® varying price under 1,000 different scenarios. Additionally, we test the portfolio of options with the use of SENDOUT® under deterministic scenarios where demand and price vary. For resources selected, we assess other risk factors such as varying lead times required and potential for cost overruns outside of the amounts included in the modeling assumptions.
4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Avista's four distinct geographic Oregon service territories limit many resource option synergies which inherently reduces available portfolio options. Feasibility uncertainty, lead time variability and uncertain cost escalation around certain resource options also reduce reasonably viable options. Chapter 4 describes resource options reviewed including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g.

		LNG). Appendix 6.3 summarizes the potential resource options identifying investment and variable costs, asset availability and lead time requirements while results of resources selected are identified in Table 6.5 as well as graphically presented in Figure 6.18 and 6.19 for the Expected Case and Appendix 7.1 for the High Growth case.
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 portfolios considered. Chapter 6 and Appendix 2.6 show the company's portfolio risk analysis, as well as the process and determination of the preferred portfolio.
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
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 locations, acquiring alternative fuel supplies, and improving reliability.	Not applicable to Avista's gas utility operations.
Guideline 6: Conservation		
6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	AEG performed a conservation potential assessment study for our 2021 IRP. A discussion of the study is included in Chapter 3. The 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.	As discussed in Chapter 5, all upstream emissions from the point of use are included in this IRP. 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	The 2021 IRP conforms to the multi-state planning approach.

	integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	
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 supply-side 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.	Not applicable to Avista's gas utility operations.
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	Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems) do produce CO2 emissions via compressors used to pressurize and move gas throughout the system. The Environmental Externalities discussion in Appendix 3.2 describes our process for addressing these costs.

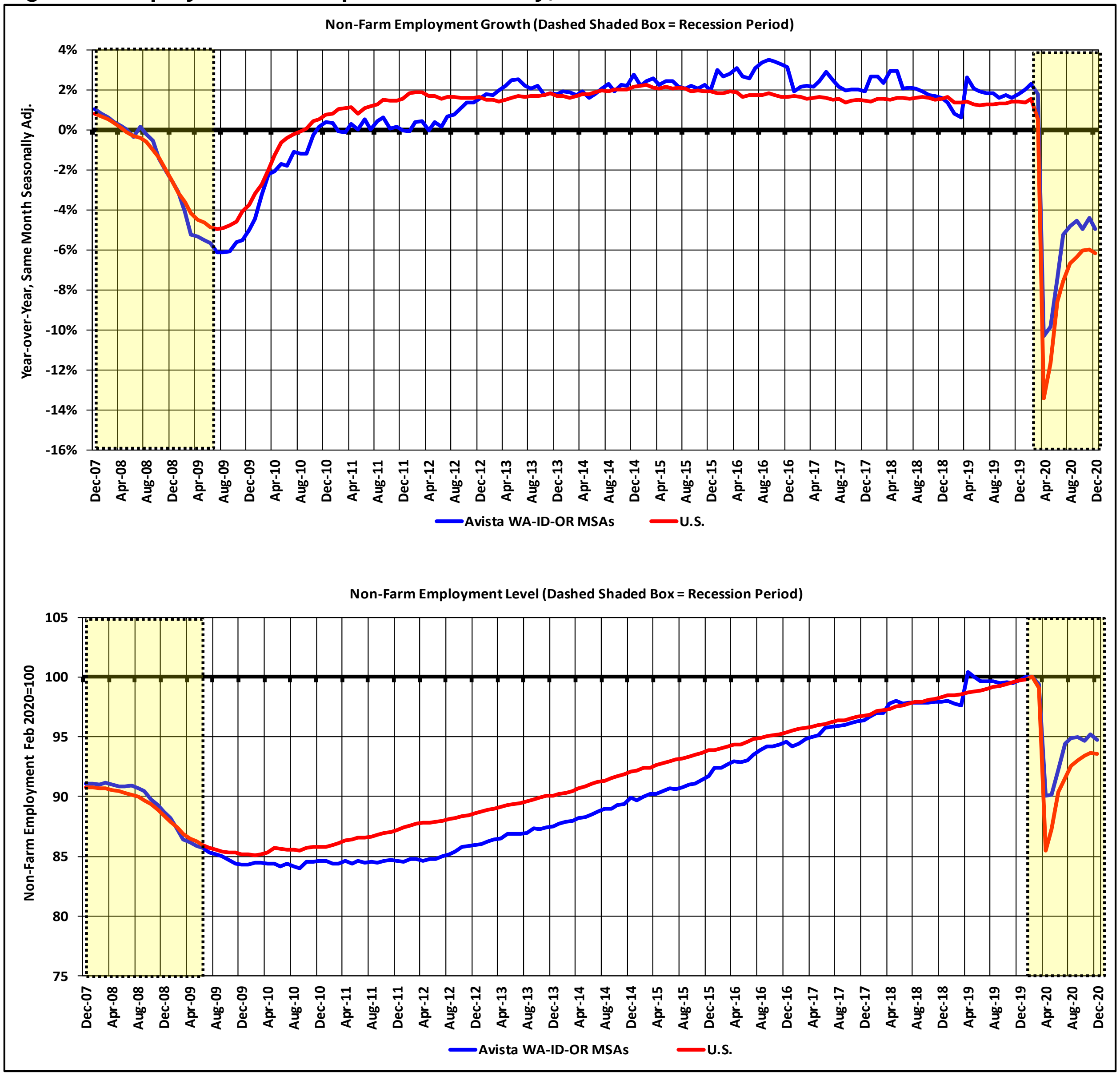
	mechanisms such as allowance or credit trading or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	
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.

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, December 2007- December 2020



Data source: Employment from the BLS; population from the U.S. Census.

In the wake of the Great Recession, our service area recovered more slowly than the U.S. Although the U.S. recession officially ended in June 2009 (dated by the National Bureau of Economic Research), our service area did not start a significant employment recovery until the second half of 2012 (Figure 1, top and bottom graph). However, by the end of 2015, year-over-year employment growth exceeded U.S. growth and employment levels returned to pre-recession levels. Due to strong employment growth in the 2016-2019 period, the total percentage gain in employment was roughly the same as the U.S. by the middle of 2018. As a result, service area population growth, which is significantly influenced by in-migration through employment opportunities, continued to improve after 2014 (Figure 2). This is important because population growth is the largest contributor to overall customer growth.

However, as Figure 1 shows Avista's service areas did not escape the employment impacts of COIVD-19 induced recession at the start of 2020. The expectation in IRP customer forecast is that COVID-19 recession will slow population growth in 2021, with a return to pre-pandemic growth starting in 2022. Historically, service area population growth has slowed in one or more years following an employment shock.

Figure 2: Avista MSA Annual Population Growth, 2005-2019

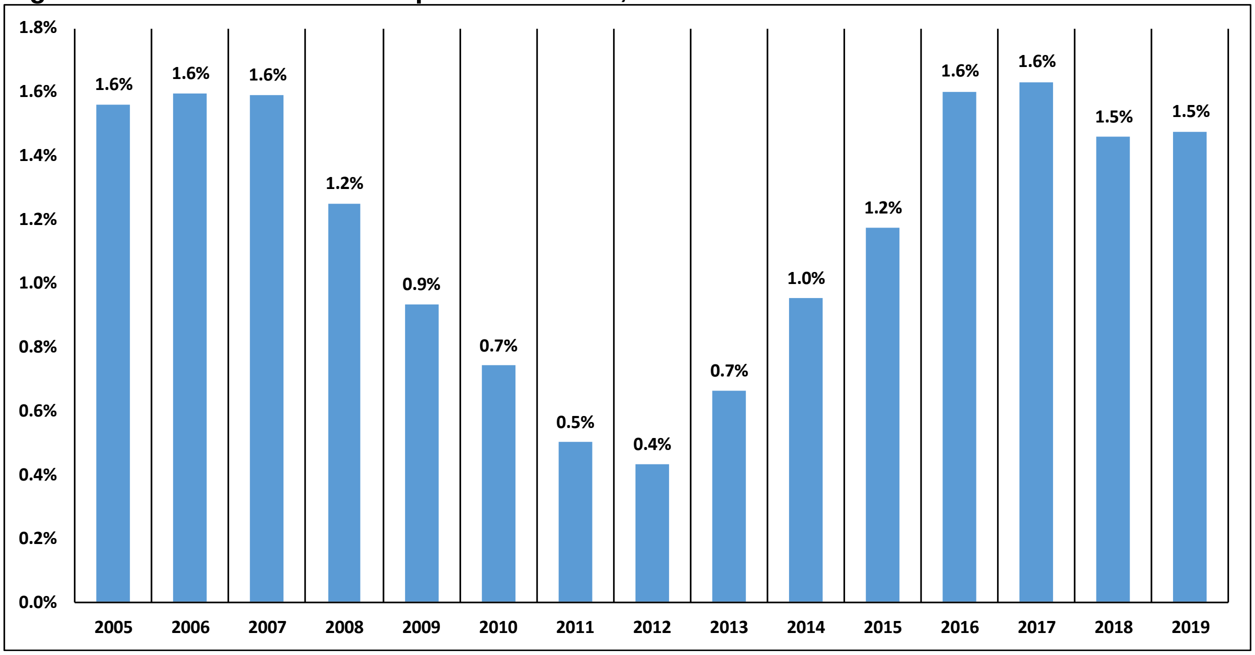
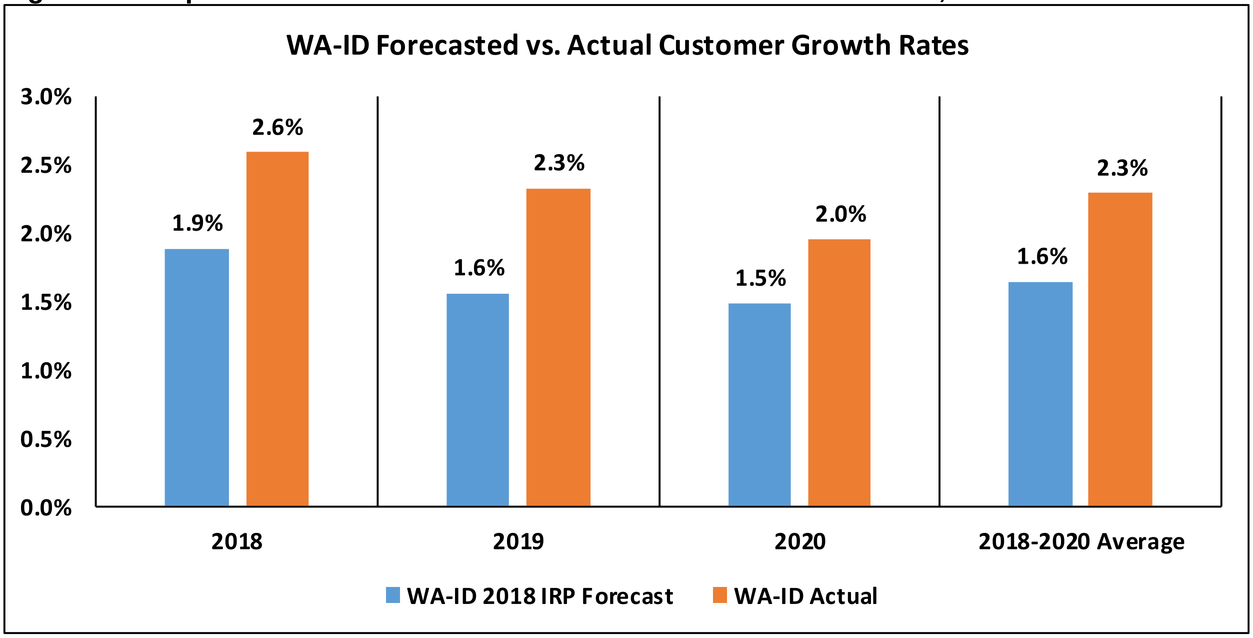
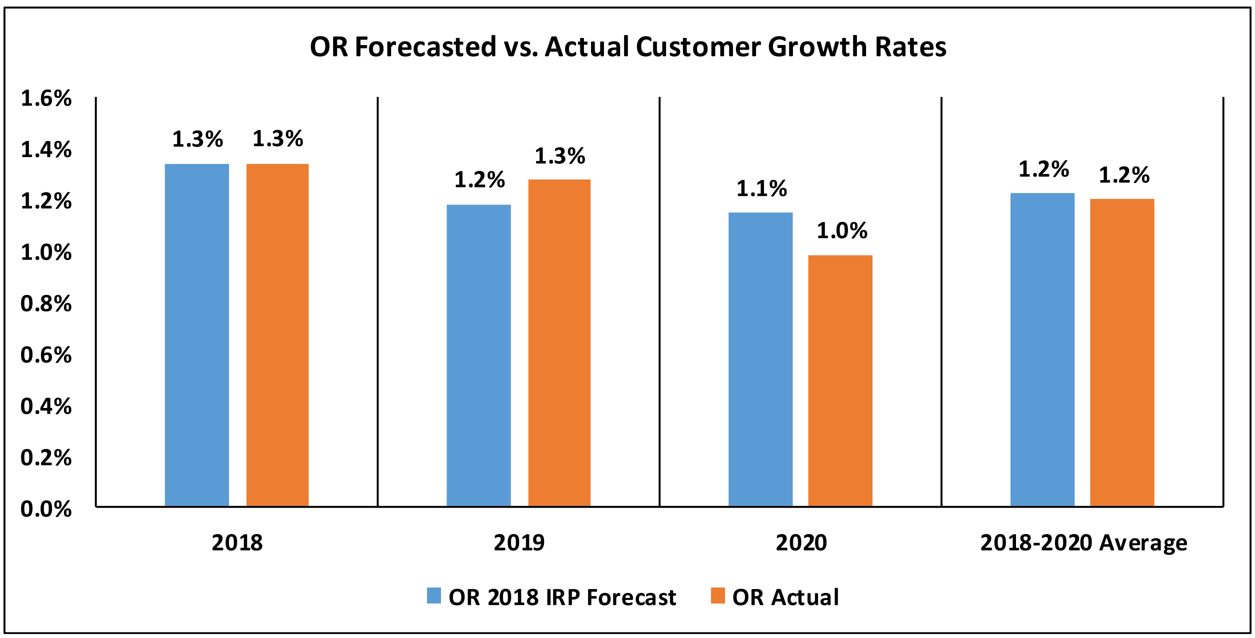


Figure 3 shows that compared to the 2018 IRP, actual average customer growth in WA-ID over the 2018-2018 period is considerably higher than forecasted. This reflects (1) stronger than expected population growth, especially in ID, and (2) Avista's LEAP gas conversion program in WA (which expired in February 2019). In contrast, OR's actual growth rate is equal to forecast over the same period. Figure 4 shows since the 2018 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 2018 IRP, this IRP shows a system-wide downward revision of approximately 1,400 customers by 2040. This reflects the net impact of a 1,400-customer increase in WA-ID and 2,800 decrease in OR. The OR change reflects lower forecasted population growth in the Roseburg and Klamath service regions. Figure 5 and Table 1 show the change in the customer forecast by for the system and by class between the 2016 and 2018 IRPs.

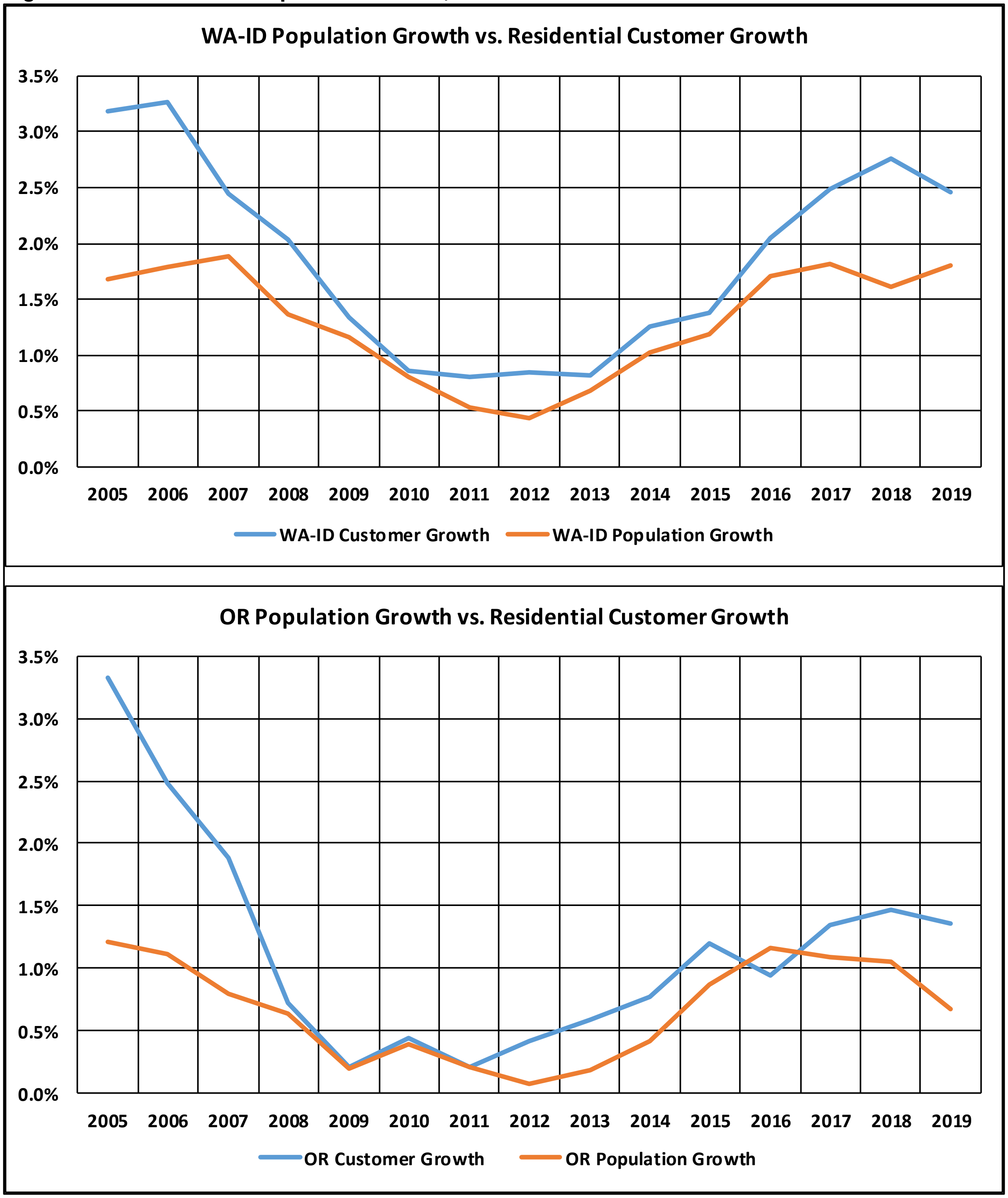
Figure 3: Comparison of 2018-IRP Customer Growth Forecasts to Actuals, 2018-2020





Data source: Company data.

Figure 4: Customer and Population Growth, 2005-2019

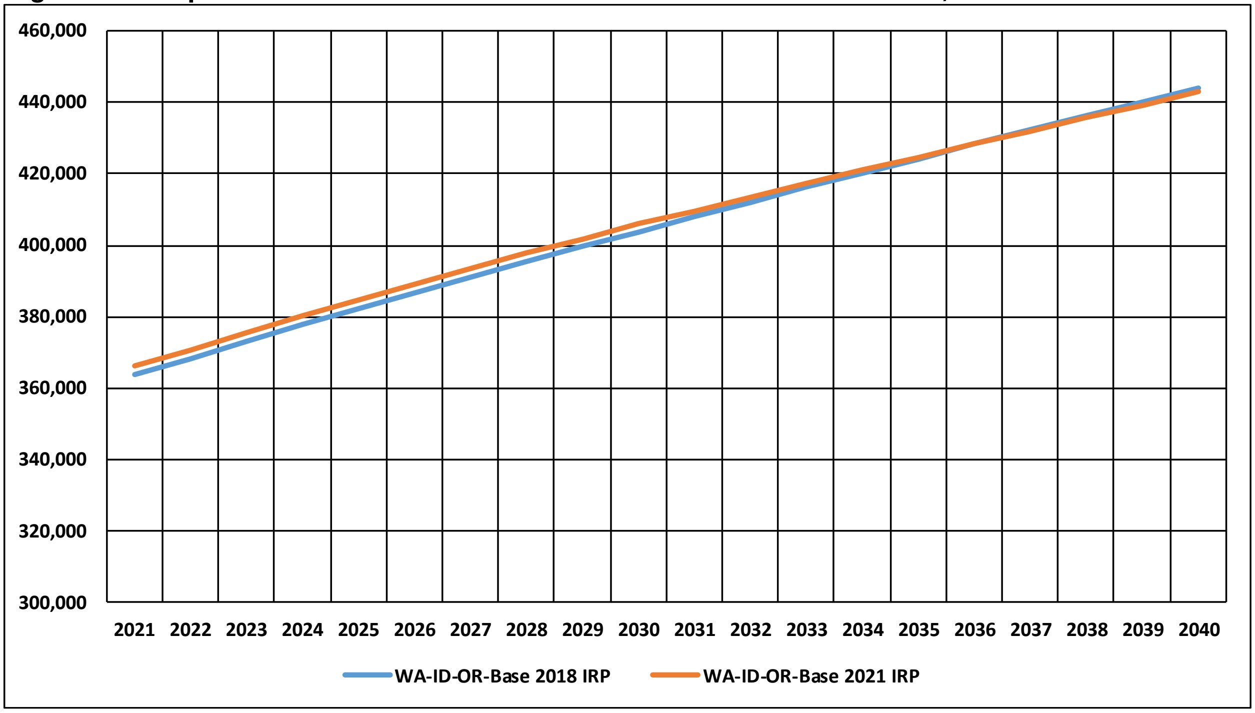


Data source: Company data.

Table 1: Change in Forecast between the 2018 IRP and 2021 IRP in 2040

Area	Residential	Commercial	Industrial	Total Change
WA-ID	+2,493	- 1,077	-22	+1,394
OR	-2,440	-351	-2	-2,793
System	53	-1,428	-24	-1,400

Figure 5: Comparison IRP Forecasted Customer Growth in WA-ID and OR, 2021-2040

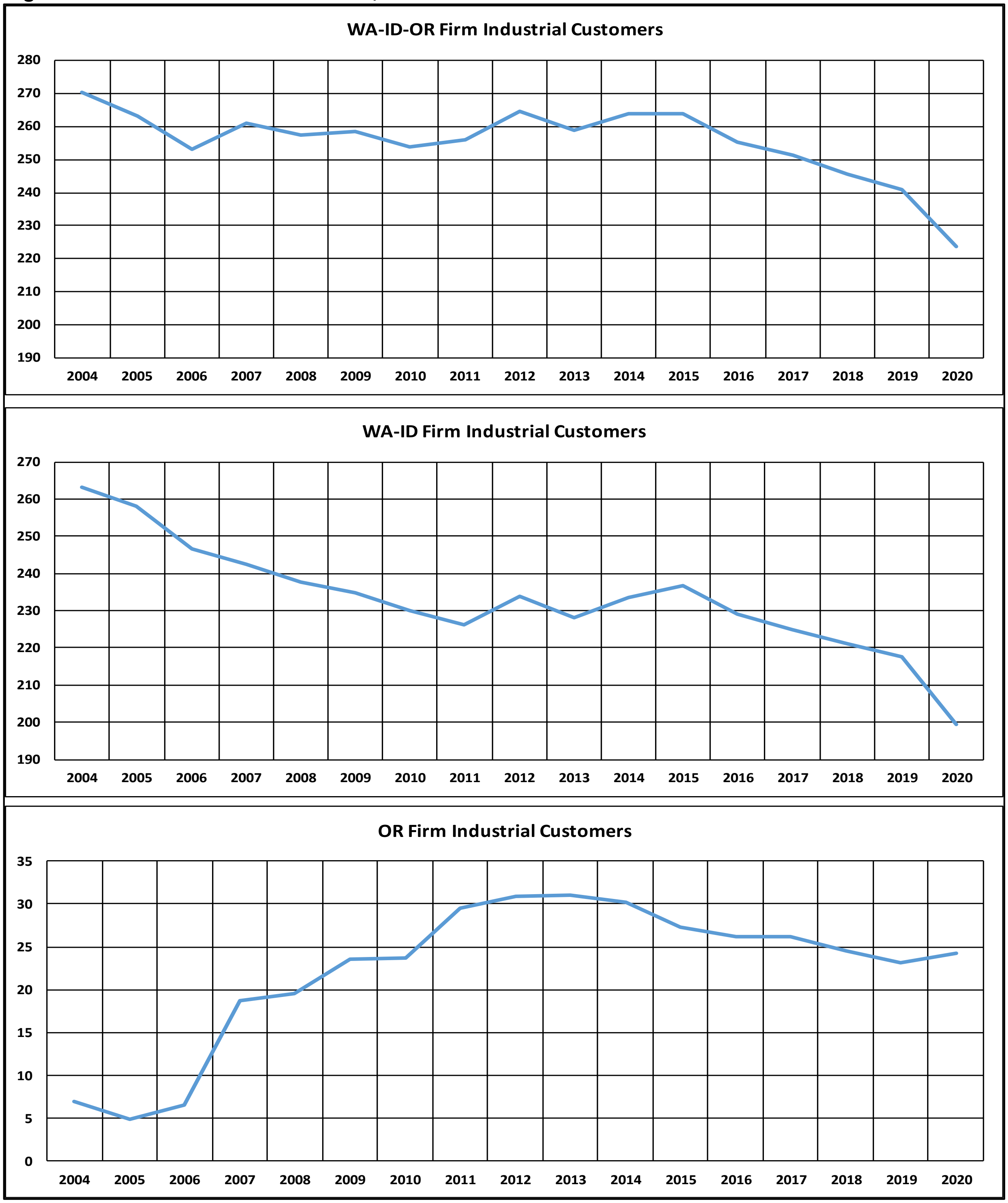


Data source: Company data.

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 2018 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 2020 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 2018 IRP, the current IRP forecast shows a declining base.

Figure 7: Industrial Customer Count, 2004-2020



Data source: Company data.

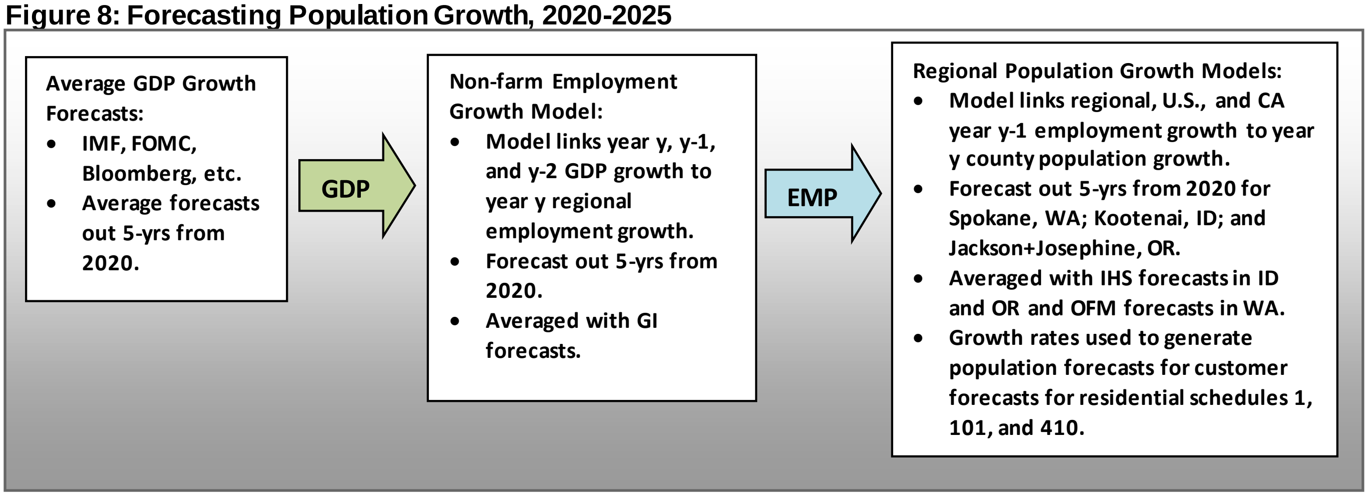
II. IRP Forecast Process and Methodology

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 Sendout® 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 (2021-2025). 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, 2020-2025



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

[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. In the case of Spokane, OFM forecasts are used because the IHS's forecasts exhibit a level and time-path that is inconsistent with recent population behavior. 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:

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

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.

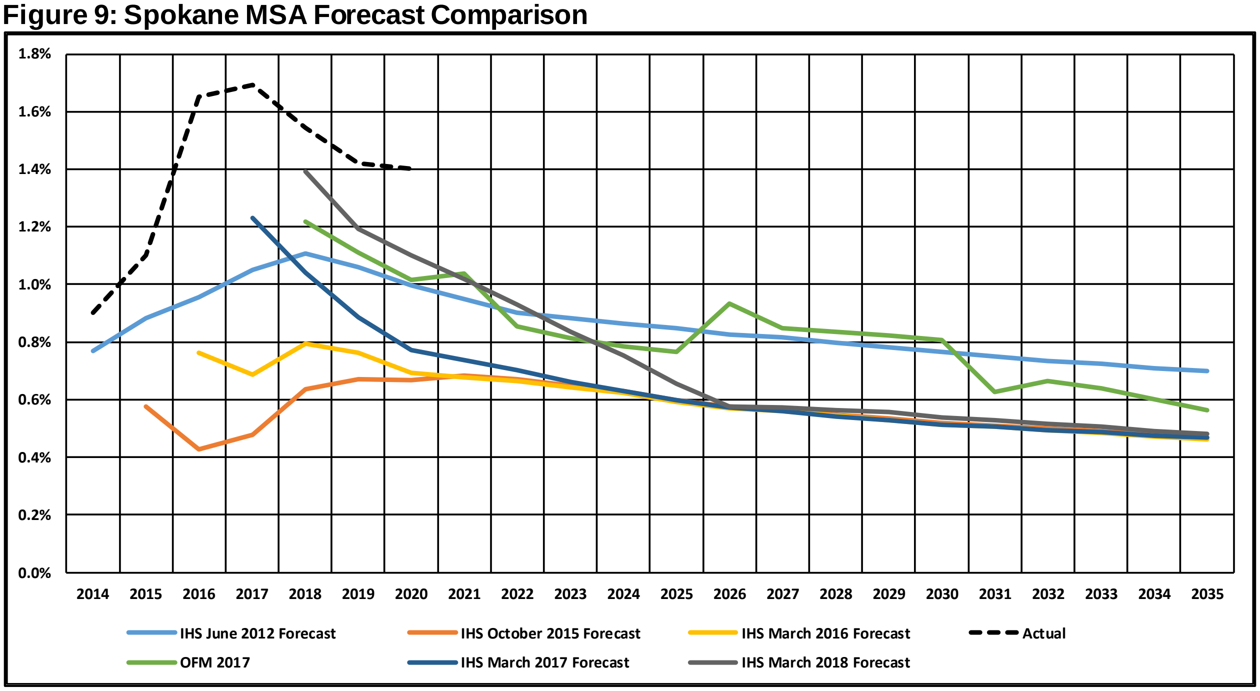
$w_{OL} D_{Oct\ 2015=1} = w_{OL}$ outlier (OL) coefficient to be estimated and D is a dummy that equals 1 for October 2015. There are three additional outlier dummies that follow August 2010. In some cases, the dummy variable may be a structural change (SC) dummy that takes the form, for example, $w_{SC}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

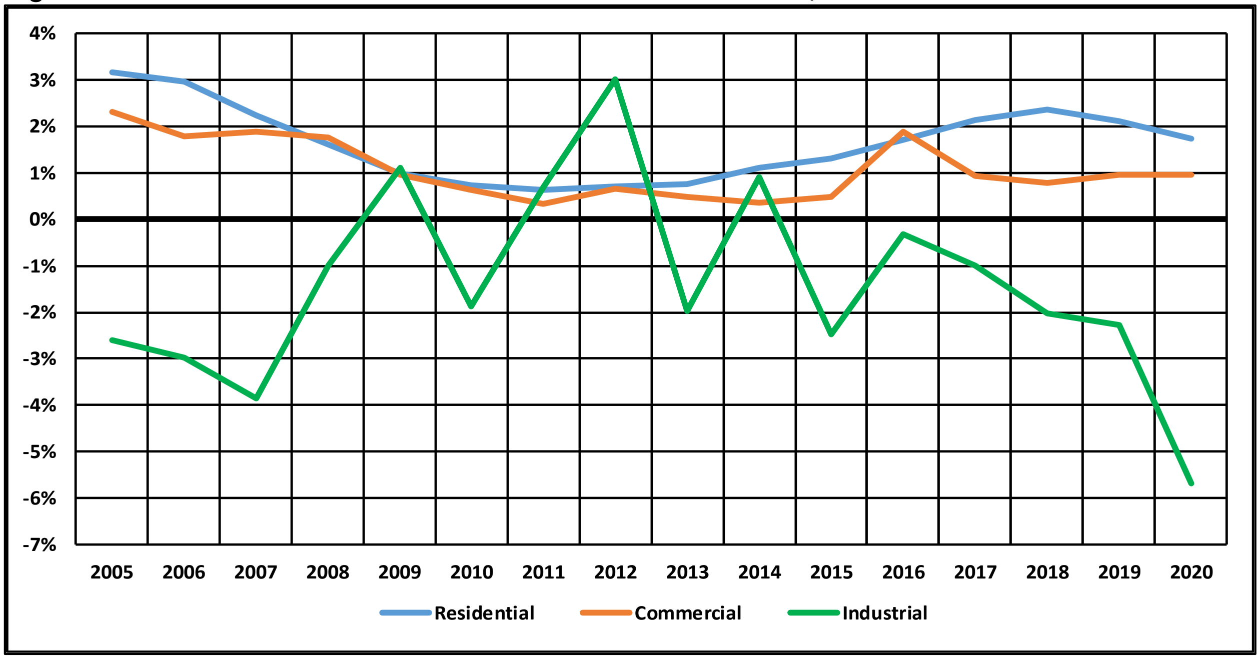
The above describes the medium-term population forecast to 2025. For IRPs, the medium-term customer forecasts must be extended an additional 15+ years. This is done using the IHS population forecast for Kootenai, Jackson+Josephine, Douglas, Klamath, and Union counties. That is, IHS is the sole source for forecasted population growth beyond the medium-term forecast horizon by [10] through [12]. In the case of Spokane County, the forecast from Washington's Office of Financial Management (OFM) is instead of IHS's. The choice to use OFM's forecasts reflects the unusually sharp changes that have occurred in the IHS forecasts for the Spokane MSA over a short period of time. Figure 9 shows how much these forecasts have changed in level and shape since June 2012. From the October 2015 to March 2018 forecasts, there were significant changes for the 2015-2025 period. There is no clear rational for why IHS's forecasts changed so significantly between 2012 and 2018. For firm schedules without explicit regression drivers like population, the forecast model run to cover the entire forecast period of the IRP.

Figure 9: Spokane MSA Forecast Comparison



Data source: IHS, Washington State of Office of Financial Management, and U.S. Census.

Figure 10: Annual Customer Growth for the Three Rate Classes, 2005-2020



Data source: Company data.

Figure 10 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 1.1%, 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 different 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 -1.4%, 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 2% 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, 2021-2045

Area	Low Growth	Base Growth	High Growth
WA-ID:			
WA-ID Customers	0.7%	1.1%	1.5%
WA Population	0.4%	0.7%	1.0%
ID Population	0.8%	1.4%	2.0%
OR:			
OR Customers	0.5%	0.7%	0.9%
OR Population	0.3%	0.5%	0.7%
System:			
System Customers	0.6%	1.0%	1.3%
System Population	0.4%	0.8%	1.1%

III. IRP Customer Forecast Equations

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

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

[1] Model notes:
1. WA schedule 2 customers are schedule 1 customers that have been moved to a new low-income schedule. 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 2020 forecast the average Δ = 6.6.

[2] $C_{t,y,WA102.r} = C_{t-1} + \Delta,\ where\ \Delta = \frac{\sum(C_{t,y} - C_{t-1,y})}{N} for\ N\ months\ between\ October\ 2015 - May\ 2020$

[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 2020 forecast the average Δ = 3.4.

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

[3] Model notes:
1. Error structure white noise, but not quite normally distributed.
2. SC dummies control for a step-up in customers starting in October 2011 and October 2013.

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

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

[4] Model notes:
1. SC dummy 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.

[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.

3. WA commercial customer forecast models:

[6] $C_{t,y,WA101.c} = \alpha_0 + \alpha_1 POP_{t,y,SPK} + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_{RAMP} T_{Jan\ 2010} + \omega_{OL} D_{Nov\ 2005=1} + \omega_{OL} D_{Feb\ 2007=1} + \omega_{OL} D_{Sep\ 2013=1} + +\omega_{OL} D_{Oct\ 2013=1} + \omega_{OL} D_{Dec\ 2015=1} + \omega_{OL} D_{Feb\ 2016=1} + \omega_{OL} D_{Jun\ 2017=1} + \omega_{OL} D_{Oct\ 2019=1} + \psi COVIDD D_{Apr-Jul\ 2020=1} + ARIMA\epsilon_{t,y}\ (2,1,0)(0,0,0)_{12}$

[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.

3. COVIDD dummy controls for the impact of the shut-down shock.

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

[7] Model notes:

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

4. ID commercial customer forecast models:

[8] $C_{t,y,ID101.c} = \beta_0 + \beta_1 POP_{t,y,Koot} + \omega_{SC} D_{Nov\ 2005\uparrow=1} + \omega_{SC} D_{Sep\ 2006\uparrow=1} + \omega_{SC} D_{Nov\ 2007\uparrow=1} + \omega_{OL} D_{Mar\ 2005=1} + \omega_{OL} D_{Jun\ 2005=1} + \omega_{OL} D_{Oct\ 2005=1} + \omega_{OL} D_{Dec\ 2005=1} + \omega_{OL} D_{Mar\ 2007=1} + \omega_{OL} D_{Dec\ 2015=1} + \omega_{OL} D_{Sep\ 2018=1} + \omega_{OL} D_{Oct\ 2018=1} + ARIMA\epsilon_{t,y}\ (9,1,0)(3,1,0)_{12}$

[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 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.

[9] $C_{t,y,ID111.c} = \beta_0 + \gamma_{RAMP} T_{Jan\ 2012} + \omega_{SC} D_{Nov\ 2008\uparrow=1} + \omega_{SC} D_{Nov\ 2011\uparrow=1} + \omega_{SC} D_{Jan\ 2012\uparrow=1} + \omega_{OL} D_{Sep\ 2009=1} + \omega_{OL} D_{Feb\ 2011=1} + \omega_{OL} D_{Feb\ 2015=1} + \omega_{OL} D_{Dec\ 2015=1} + ARIMA\epsilon_{t,y}\ (1,1,0)(0,0,0)_{12}$

[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] $C_{t,y,WA101.i} = \alpha_0 + \omega_{SC} D_{Apr\ 2008\uparrow=1} + \omega_{SC} D_{Oct\ 2013\uparrow=1} + \omega_{OL} D_{Oct\ 2006=1} + \omega_{OL} D_{Jan\ 2007=1} + \omega_{OL} D_{Feb\ 2007=1} + + \omega_{OL} D_{Dec\ 2013=1} + \omega_{OL} D_{Jan\ 2015=1} + \omega_{OL} D_{Mar\ 2017=1} + ARIMA\epsilon_{t,y}\ (7,1,0)(0,0,0)_{12}$

[10] Model notes:

1. SC dummies control for a step-down in customers starting in April 2008 and October 2013.

[11] $C_{t,y,WA111.i} = ARIMA(2,1,0)(0,0,0)_{12}$

[11] Model notes:
1. Error structure is white noise, but not quite normally distributed.
2. 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 25. 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.

6. ID industrial customer forecast models:

[12] $C_{t,y,ID101.i} = \beta_0 + \omega_{SC}D_{Dec\ 2010\uparrow=1} + \omega_{SC}D_{Nov\ 2011\uparrow=1} + \omega_{SC}D_{Dec\ 2011\uparrow=1} + \omega_{SC}D_{Jun\ 2014\uparrow=1} + \omega_{SC}D_{Jan\ 2018\uparrow=1} + \omega_{OL}D_{Dec\ 2008=1} + \omega_{OL}D_{Jul\ 2014=1} + \omega_{OL}D_{Jan\ 2015=1} + \omega_{OL}D_{Jan\ 2016=1} + \omega_{OL}D_{Feb\ 2017=1} + ARIMA\epsilon_{t,y}(13,1,0)(0,0,0)_{12}$

[12] Model notes:
1. SC dummies control for step-downs in customers starting in December 2010, November 2011, December 2011, and January 2018; June 2014 controls for a step-up in customers.
2. The large number of OL dummies controls for a range of factors including changes in billing cycles, billing errors, and software changes.

[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] $C_{t,y,MED410.r} = \alpha_0 + \alpha_1 POP_{t,y,JACK+JOS} + \boldsymbol{\omega_{SD}D_{t,y}} + \gamma_{RAMP}T_{Jan\ 2008} + \omega_{SC}D_{Jan\ 2008\uparrow=1} + \omega_{SC}D_{Nov\ 2004\uparrow=1} + \omega_{OL}D_{Dec\ 2005\ =1} + ARIMA\epsilon_{t,y}(7,1,0)(0,0,0)_{12}$

[15] Model notes:
1. SC dummy and ramping time trend control for a change in the time-path of customer growth staring in January 2008.
2. POP is Jackson plus Josephine counties.

Commercial Sector, Customers:

[16] $C_{t,y,MED420.c} = \alpha_0 + \alpha_1 C_{t,y,MED410.r} + \boldsymbol{\omega_{SD}D_{t,y}} + \omega_{OL}D_{Nov\ 2009=1} + \omega_{OL}D_{Jan\ 2016=1} + \psi COVIDD_{Apr-Jul\ 2020=1} + ARIMA\epsilon_{t,y}(7,1,0)(0,0,0)_{12}$

[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. COVIDD dummy controls for the impact of the shut-down shock.

[17] $C_{y,MED424.c} = C_{y-1} + (\hat{\alpha}_0 + \hat{\alpha}_1 \Delta EMP_{y-1,4County})$

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

[19] 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. In IRP years, the forecast is repeated out monthly until December 2045.

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

[20] 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. Customer count is most frequently reported as 2; however, starting in March 2018, the customer count fell to one.

<u>8. Roseburg, OR forecasting models</u>:

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

Residential Sector, Customers:

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

[21] 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:

[22] $C_{t,y,ROS420.c} = \varphi_0 + \varphi_1 POP_{t,y,DOUGLAS} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Dec\ 2004\uparrow=1} + \omega_{OL} D_{Nov\ 2004=1} + \omega_{OL} D_{Jan\ 2005=1} + \omega_{OL} D_{Jan\ 2008=1} + \omega_{OL} D_{May\ 2016=1} + \omega_{OL} D_{Mar\ 2019=1} + \omega_{OL} D_{Sept\ 2019=1} + \omega_{OL} D_{Oct\ 2019=1} + \psi COVIDD_{Apr-Jul\ 2020=1} + ARIMA\epsilon_{t,y}\ (9,1,0)(0,0,0)_{12}$

[22] 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 it is significant at the 10% level
2. The lack of correlation noted in Point 1 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.
3. SC dummy controls for a significant step-up in customers starting in December 2004.
4. COVIDD dummy controls for the impact of the shut-down shock.

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

[23] 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 three-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:

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

[24] 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.

<u>9. Klamath Falls, OR forecasting models</u>:

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

Residential Sector, Customers:

[25] $C_{t,y,KLM410.r} = \beta_0 + \beta_1 POP_{t,y,KLAMATH} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Apr\ 2015=1} + ARIMA\epsilon_{t,y}\ (7,1,0)(0,0,0)_{12}$

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

Commercial Sector, Customers:

[26] $C_{t,y,KLM420.c} = \beta_0 + \beta_1 C_{t,y,KLM410.r} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Oct\ 2006=1} + ARIMA\epsilon_{t,y}\ (11{,}1{,}0)(1{,}0{,}0)_{12}$

[26] 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.

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

[27] 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 three-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:

Industrial Sector, Customers:

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

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

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

[29] 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:

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

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

Commercial Sector, Customers:

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

[31] 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:

[7.32] $C_{t,y,LaG440.i} = \frac{1}{N}\sum_{j=1}^{N} C_{t,y-j}\ for\ y-j = 2012 \uparrow\ up\ to\ the\ end\ of\ the\ nearest\ calendar\ year.$

[7.32] Model notes:
1. Even in the presence of some seasonality, customer count can be highly erratic. Regression models produced poor diagnostics. As a result, a historical monthly average is used as the forecast.
2. Restricted to 2012 ↑ because of a significant change in behavior starting in 2012.

[7.31] $C_{t,y,LaG444.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL}D_{Aug\ 2007=1} + \omega_{OL}D_{Nov\ 2009=1} + \omega_{OL}D_{Nov\ 2010=1} + \omega_{OL}D_{Aug\ 2012=1} + \omega_{OL}D_{Nov\ 2012=1} + \omega_{OL}D_{Dec\ 2012=1} + \omega_{OL}D_{Jan\ 2013=1} + \omega_{OL}D_{Feb\ 2013=1} + \omega_{OL}D_{Jan\ 2014=1} + \omega_{OL}D_{Oct\ 2015=1} + ARIMA\epsilon_{t,y}\ (10,0,0)(2,0,0)_{12}$

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION WASHINGTON

	Washington - Expected Growth			Washington - High Growth			Washington - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-19	154,755	14,895	127	154,755	14,895	127	154,755	14,895	127
Dec-19	155,069	14,979	130	155,069	14,979	130	155,069	14,979	130
Jan-20	155,673	15,064	128	155,673	15,064	128	155,673	15,064	128
Feb-20	155,515	14,935	127	155,515	14,935	127	155,515	14,935	127
Mar-20	155,696	15,017	128	155,696	15,017	128	155,696	15,017	128
Apr-20	155,821	15,032	129	155,821	15,032	129	155,821	15,032	129
May-20	155,314	14,858	126	155,314	14,858	126	155,314	14,858	126
Jun-20	155,434	14,877	127	156,228	14,953	126	154,678	14,805	126
Jul-20	155,600	14,854	127	156,416	14,932	127	154,825	14,780	126
Aug-20	155,568	14,959	126	156,404	15,039	127	154,774	14,883	125
Sep-20	155,782	14,958	126	156,639	15,040	127	154,967	14,880	125
Oct-20	156,075	14,955	127	156,954	15,039	127	155,240	14,875	125
Nov-20	156,556	14,974	127	157,458	15,060	128	155,698	14,892	125
Dec-20	156,921	15,048	126	157,846	15,137	128	156,043	14,964	124
Jan-21	157,115	15,059	127	158,061	15,150	128	156,216	14,973	124
Feb-21	157,078	15,071	126	158,045	15,164	128	156,160	14,983	124
Mar-21	157,076	15,073	126	158,063	15,168	129	156,138	14,983	124
Apr-21	156,831	15,043	126	157,837	15,140	129	155,876	14,951	123
May-21	156,731	15,023	126	157,757	15,121	129	155,757	14,930	123
Jun-21	156,566	15,023	126	157,612	15,123	129	155,574	14,928	123
Jul-21	156,686	15,004	126	157,782	15,109	130	155,645	14,904	123
Aug-21	156,845	15,007	126	157,993	15,117	130	155,756	14,903	122
Sep-21	157,068	15,008	126	158,268	15,123	130	155,930	14,899	122
Oct-21	157,472	15,006	126	158,726	15,125	130	156,283	14,893	122
Nov-21	158,031	15,027	126	159,341	15,152	131	156,790	14,909	122
Dec-21	158,443	15,103	126	159,807	15,233	131	157,151	14,980	121
Jan-22	158,743	15,116	126	160,160	15,251	131	157,400	14,988	121
Feb-22	158,743	15,129	126	160,211	15,269	131	157,352	14,996	121
Mar-22	158,741	15,132	125	160,261	15,277	132	157,302	14,995	121
Apr-22	158,689	15,104	125	160,260	15,253	132	157,202	14,963	120
May-22	158,658	15,087	125	160,280	15,241	132	157,124	14,941	120
Jun-22	158,497	15,089	125	160,168	15,248	132	156,917	14,939	120
Jul-22	158,668	15,070	125	160,397	15,234	133	157,034	14,915	120
Aug-22	158,824	15,074	125	160,610	15,244	133	157,136	14,914	119
Sep-22	159,064	15,074	125	160,908	15,249	133	157,321	14,909	119
Oct-22	159,486	15,073	125	161,392	15,253	133	157,686	14,903	119
Nov-22	160,056	15,093	125	162,025	15,279	134	158,197	14,918	119
Dec-22	160,496	15,170	125	162,527	15,362	134	158,580	14,989	118
Jan-23	160,788	15,183	125	162,879	15,380	134	158,815	14,997	118
Feb-23	160,780	15,197	125	162,927	15,400	134	158,754	15,006	118

	Washington - Expected Growth			Washington - High Growth			Washington - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-23	160,822	15,200	124	163,027	15,408	135	158,743	15,004	118
Apr-23	160,793	15,172	124	163,054	15,385	135	158,662	14,971	117
May-23	160,753	15,155	124	163,071	15,373	135	158,570	14,949	117
Jun-23	160,611	15,159	124	162,983	15,383	135	158,377	14,948	117
Jul-23	160,800	15,139	124	163,238	15,369	136	158,504	14,923	117
Aug-23	160,969	15,144	124	163,474	15,380	136	158,612	14,922	116
Sep-23	161,228	15,144	124	163,800	15,386	136	158,808	14,917	116
Oct-23	161,669	15,143	124	164,313	15,391	136	159,183	14,910	116
Nov-23	162,263	15,165	124	164,980	15,419	137	159,708	14,926	116
Dec-23	162,713	15,241	124	165,502	15,502	137	160,091	14,995	115
Jan-24	163,012	15,255	124	165,871	15,523	137	160,326	15,004	115
Feb-24	163,031	15,269	124	165,955	15,543	137	160,285	15,012	115
Mar-24	163,096	15,273	124	166,086	15,553	138	160,290	15,010	115
Apr-24	163,078	15,245	123	166,132	15,531	138	160,212	14,977	114
May-24	163,057	15,229	123	166,175	15,520	138	160,131	14,956	114
Jun-24	162,932	15,232	123	166,113	15,529	138	159,950	14,953	114
Jul-24	163,104	15,212	123	166,345	15,514	139	160,065	14,929	114
Aug-24	163,258	15,217	123	166,560	15,525	139	160,164	14,929	113
Sep-24	163,504	15,217	123	166,868	15,530	139	160,353	14,924	113
Oct-24	163,935	15,216	123	167,365	15,534	139	160,722	14,918	113
Nov-24	164,510	15,237	123	168,011	15,561	140	161,233	14,933	113
Dec-24	164,941	15,313	123	168,509	15,644	140	161,602	15,003	112
Jan-25	165,228	15,327	123	168,861	15,664	140	161,830	15,012	112
Feb-25	165,234	15,341	123	168,925	15,684	140	161,783	15,021	112
Mar-25	165,284	15,344	123	169,033	15,692	141	161,778	15,019	112
Apr-25	165,251	15,315	122	169,059	15,668	141	161,693	14,985	111
May-25	165,215	15,299	122	169,080	15,657	141	161,604	14,965	111
Jun-25	165,074	15,302	122	168,994	15,665	141	161,414	14,963	111
Jul-25	165,248	15,282	122	169,231	15,650	142	161,530	14,938	111
Aug-25	165,406	15,286	122	169,451	15,660	142	161,630	14,937	110
Sep-25	165,656	15,287	122	169,767	15,666	142	161,821	14,933	110
Oct-25	166,088	15,286	122	170,268	15,671	142	162,189	14,927	110
Nov-25	166,665	15,307	122	170,920	15,698	143	162,699	14,943	110
Dec-25	167,099	15,383	122	171,424	15,781	143	163,068	15,012	109
Jan-26	167,390	15,396	122	171,783	15,800	143	163,298	15,020	109
Feb-26	167,398	15,410	122	171,851	15,820	143	163,251	15,028	109
Mar-26	167,450	15,414	122	171,964	15,830	144	163,247	15,027	109
Apr-26	167,420	15,385	122	171,993	15,805	144	163,164	14,994	108
May-26	167,386	15,369	121	172,018	15,794	144	163,076	14,973	108
Jun-26	167,247	15,372	121	171,935	15,803	144	162,887	14,971	108

	Washington - Expected Growth			Washington - High Growth			Washington - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jul-26	167,411	15,352	121	172,158	15,787	145	162,997	14,947	108
Aug-26	167,560	15,355	121	172,365	15,795	145	163,093	14,946	107
Sep-26	167,799	15,356	121	172,666	15,801	145	163,277	14,942	107
Oct-26	168,220	15,355	121	173,154	15,805	145	163,636	14,937	107
Nov-26	168,786	15,375	121	173,792	15,831	146	164,138	14,952	107
Dec-26	169,210	15,451	121	174,283	15,914	146	164,500	15,021	106
Jan-27	169,491	15,464	121	174,628	15,933	146	164,723	15,029	106
Feb-27	169,487	15,478	121	174,679	15,952	146	164,670	15,038	106
Mar-27	169,529	15,482	121	174,778	15,961	147	164,661	15,037	106
Apr-27	169,488	15,453	121	174,791	15,936	147	164,572	15,005	105
May-27	169,443	15,436	121	174,800	15,924	147	164,478	14,984	105
Jun-27	169,295	15,438	120	174,702	15,931	147	164,284	14,981	105
Jul-27	169,457	15,419	120	174,924	15,916	148	164,393	14,958	105
Aug-27	169,605	15,422	120	175,131	15,925	148	164,487	14,957	104
Sep-27	169,843	15,423	120	175,432	15,931	148	164,669	14,953	104
Oct-27	170,264	15,422	120	175,922	15,934	148	165,028	14,948	104
Nov-27	170,830	15,442	120	176,561	15,960	149	165,527	14,963	104
Dec-27	171,253	15,518	120	177,054	16,044	149	165,888	15,032	103
Jan-28	171,533	15,531	120	177,398	16,062	149	166,109	15,040	103
Feb-28	171,529	15,545	120	177,450	16,082	149	166,056	15,049	103
Mar-28	171,570	15,548	120	177,548	16,090	150	166,046	15,047	103
Apr-28	171,529	15,520	120	177,560	16,066	150	165,957	15,016	102
May-28	171,483	15,503	120	177,569	16,053	150	165,863	14,995	102
Jun-28	171,334	15,505	119	177,469	16,060	150	165,669	14,992	102
Jul-28	171,495	15,485	119	177,691	16,044	151	165,777	14,969	102
Aug-28	171,642	15,489	119	177,898	16,054	151	165,870	14,968	101
Sep-28	171,880	15,490	119	178,198	16,059	151	166,051	14,965	101
Oct-28	172,299	15,488	119	178,688	16,062	151	166,408	14,958	101
Nov-28	172,864	15,508	119	179,329	16,088	152	166,904	14,973	101
Dec-28	173,286	15,585	119	179,822	16,173	152	167,263	15,043	100
Jan-29	173,565	15,597	119	180,167	16,190	152	167,483	15,050	100
Feb-29	173,561	15,611	119	180,217	16,210	152	167,429	15,060	100
Mar-29	173,600	15,614	119	180,314	16,218	153	167,419	15,058	100
Apr-29	173,558	15,586	119	180,325	16,194	153	167,329	15,027	99
May-29	173,511	15,569	119	180,332	16,181	153	167,235	15,006	99
Jun-29	173,361	15,572	119	180,231	16,189	153	167,041	15,004	99
Jul-29	173,522	15,551	118	180,452	16,172	154	167,148	14,980	99
Aug-29	173,667	15,555	118	180,658	16,181	154	167,240	14,979	98
Sep-29	173,904	15,556	118	180,959	16,187	154	167,419	14,976	98
Oct-29	174,321	15,554	118	181,448	16,190	154	167,773	14,970	98

	Washington - Expected Growth			Washington - High Growth			Washington - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-29	174,885	15,575	118	182,089	16,217	155	168,267	14,986	98
Dec-29	175,306	15,651	118	182,582	16,301	155	168,624	15,054	97
Jan-30	175,583	15,664	118	182,926	16,319	155	168,842	15,063	97
Feb-30	175,578	15,677	118	182,976	16,338	155	168,788	15,071	97
Mar-30	175,616	15,680	118	183,071	16,346	156	168,777	15,069	97
Apr-30	175,572	15,652	118	183,080	16,321	156	168,686	15,038	96
May-30	175,524	15,635	118	183,085	16,308	156	168,592	15,017	96
Jun-30	175,372	15,637	118	182,981	16,315	156	168,397	15,015	96
Jul-30	175,509	15,616	118	183,167	16,297	157	168,490	14,992	96
Aug-30	175,629	15,620	117	183,335	16,305	157	168,569	14,992	95
Sep-30	175,841	15,619	117	183,599	16,308	157	168,734	14,988	95
Oct-30	176,233	15,617	117	184,052	16,310	157	169,073	14,982	95
Nov-30	176,772	15,637	117	184,658	16,335	158	169,552	14,998	95
Dec-30	177,169	15,712	117	185,115	16,417	158	169,894	15,067	94
Jan-31	177,420	15,725	117	185,421	16,434	158	170,097	15,076	94
Feb-31	177,390	15,738	117	185,433	16,452	158	170,030	15,085	94
Mar-31	177,403	15,741	117	185,491	16,459	159	170,005	15,085	94
Apr-31	177,335	15,711	117	185,462	16,431	159	169,902	15,052	93
May-31	177,262	15,694	117	185,429	16,417	159	169,794	15,033	93
Jun-31	177,085	15,695	117	185,288	16,422	159	169,587	15,030	93
Jul-31	177,227	15,674	117	185,482	16,404	160	169,682	15,007	93
Aug-31	177,353	15,678	116	185,660	16,412	160	169,763	15,007	92
Sep-31	177,571	15,678	116	185,934	16,416	160	169,931	15,003	92
Oct-31	177,970	15,676	116	186,398	16,418	160	170,272	14,998	92
Nov-31	178,515	15,696	116	187,016	16,443	161	170,754	15,014	92
Dec-31	178,917	15,771	116	187,483	16,526	161	171,097	15,082	91
Jan-32	179,175	15,784	116	187,800	16,544	161	171,304	15,091	91
Feb-32	179,151	15,797	116	187,821	16,562	161	171,240	15,099	91
Mar-32	179,171	15,800	116	187,889	16,569	162	171,218	15,099	91
Apr-32	179,108	15,770	116	187,870	16,541	162	171,118	15,066	90
May-32	179,041	15,754	116	187,846	16,529	162	171,013	15,048	90
Jun-32	178,870	15,755	116	187,713	16,534	162	170,810	15,045	90
Jul-32	179,009	15,735	116	187,904	16,517	163	170,903	15,023	90
Aug-32	179,133	15,738	116	188,078	16,524	163	170,982	15,022	89
Sep-32	179,348	15,737	115	188,350	16,527	163	171,149	15,018	89
Oct-32	179,744	15,736	115	188,810	16,530	163	171,487	15,013	89
Nov-32	180,286	15,755	115	189,425	16,554	164	171,966	15,028	89
Dec-32	180,685	15,830	115	189,890	16,636	164	172,307	15,096	88
Jan-33	180,941	15,843	115	190,204	16,654	164	172,511	15,105	88
Feb-33	180,913	15,856	115	190,220	16,672	164	172,445	15,114	88

	Washington - Expected Growth			Washington - High Growth			Washington - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-33	180,930	15,859	115	190,283	16,679	165	172,422	15,113	88
Apr-33	180,864	15,830	115	190,260	16,652	165	172,320	15,082	87
May-33	180,795	15,812	115	190,232	16,637	165	172,215	15,062	87
Jun-33	180,622	15,814	115	190,095	16,643	165	172,010	15,060	87
Jul-33	180,755	15,794	115	190,279	16,626	166	172,101	15,038	87
Aug-33	180,874	15,797	115	190,446	16,633	166	172,177	15,037	86
Sep-33	181,083	15,797	115	190,710	16,637	166	172,339	15,034	86
Oct-33	181,475	15,794	114	191,165	16,637	166	172,675	15,028	86
Nov-33	182,012	15,814	114	191,773	16,662	167	173,148	15,044	86
Dec-33	182,405	15,889	114	192,231	16,745	167	173,485	15,112	85
Jan-34	182,656	15,901	114	192,538	16,761	167	173,687	15,120	85
Feb-34	182,623	15,914	114	192,548	16,779	167	173,618	15,129	85
Mar-34	182,635	15,917	114	192,603	16,786	168	173,592	15,129	85
Apr-34	182,565	15,888	114	192,572	16,759	168	173,488	15,098	84
May-34	182,489	15,870	114	192,536	16,744	168	173,379	15,078	84
Jun-34	182,311	15,871	114	192,391	16,749	168	173,173	15,075	84
Jul-34	182,440	15,851	114	192,568	16,731	169	173,261	15,053	84
Aug-34	182,554	15,854	114	192,729	16,738	169	173,334	15,053	83
Sep-34	182,758	15,853	114	192,985	16,740	169	173,493	15,049	83
Oct-34	183,145	15,851	113	193,434	16,742	169	173,825	15,044	83
Nov-34	183,678	15,870	113	194,038	16,765	170	174,295	15,059	83
Dec-34	184,067	15,946	113	194,491	16,849	170	174,630	15,128	82
Jan-35	184,313	15,958	113	194,791	16,865	170	174,827	15,137	82
Feb-35	184,275	15,970	113	194,793	16,881	170	174,756	15,145	82
Mar-35	184,282	15,973	113	194,841	16,888	171	174,727	15,145	82
Apr-35	184,207	15,944	113	194,802	16,861	171	174,621	15,114	81
May-35	184,127	15,926	113	194,760	16,846	171	174,510	15,094	81
Jun-35	183,944	15,928	113	194,607	16,851	171	174,301	15,093	81
Jul-35	184,075	15,907	113	194,788	16,833	172	174,390	15,070	81
Aug-35	184,191	15,910	113	194,952	16,840	172	174,464	15,070	80
Sep-35	184,398	15,909	113	195,213	16,842	172	174,624	15,066	80
Oct-35	184,786	15,907	113	195,666	16,844	172	174,956	15,061	80
Nov-35	185,321	15,927	112	196,274	16,868	173	175,426	15,077	80
Dec-35	185,711	16,002	112	196,730	16,951	173	175,759	15,144	79
Jan-36	185,960	16,015	112	197,036	16,969	173	175,959	15,154	79
Feb-36	185,925	16,027	112	197,041	16,985	173	175,889	15,162	79
Mar-36	185,933	16,029	112	197,092	16,991	174	175,861	15,161	79
Apr-36	185,860	16,000	112	197,057	16,964	174	175,755	15,130	78
May-36	185,782	15,983	112	197,017	16,950	174	175,646	15,111	78
Jun-36	185,601	15,984	112	196,867	16,954	174	175,439	15,109	78
Jul-36	185,728	15,963	112	197,042	16,935	175	175,524	15,086	78

	Washington - Expected Growth			Washington - High Growth			Washington - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Aug-36	185,840	15,966	112	197,201	16,942	175	175,596	15,086	77
Sep-36	186,044	15,965	112	197,458	16,944	175	175,754	15,082	77
Oct-36	186,428	15,963	112	197,907	16,946	175	176,083	15,077	77
Nov-36	186,959	15,983	111	198,510	16,971	176	176,549	15,093	77
Dec-36	187,347	16,058	111	198,963	17,054	176	176,881	15,161	76
Jan-37	187,591	16,070	111	199,263	17,070	176	177,077	15,169	76
Feb-37	187,552	16,083	111	199,262	17,087	176	177,005	15,179	76
Mar-37	187,557	16,086	111	199,309	17,094	177	176,976	15,178	76
Apr-37	187,480	16,056	111	199,267	17,065	177	176,868	15,147	75
May-37	187,399	16,038	111	199,222	17,050	177	176,757	15,127	75
Jun-37	187,213	16,039	111	199,065	17,054	177	176,548	15,125	75
Jul-37	187,338	16,018	111	199,237	17,035	178	176,632	15,103	75
Aug-37	187,446	16,021	111	199,391	17,042	178	176,702	15,103	74
Sep-37	187,647	16,020	111	199,643	17,044	178	176,858	15,099	74
Oct-37	188,028	16,019	111	200,087	17,046	178	177,184	15,095	74
Nov-37	188,555	16,038	111	200,688	17,070	179	177,648	15,110	74
Dec-37	188,939	16,113	110	201,135	17,153	179	177,976	15,178	73
Jan-38	189,180	16,125	110	201,432	17,169	179	178,170	15,187	73
Feb-38	189,138	16,138	110	201,426	17,186	179	178,097	15,196	73
Mar-38	189,140	16,140	110	201,467	17,192	180	178,066	15,195	73
Apr-38	189,059	16,110	110	201,420	17,163	180	177,957	15,164	72
May-38	188,974	16,093	110	201,369	17,149	180	177,843	15,145	72
Jun-38	188,785	16,094	110	201,207	17,153	180	177,633	15,143	72
Jul-38	188,907	16,073	110	201,374	17,134	181	177,715	15,121	72
Aug-38	189,014	16,075	110	201,526	17,139	181	177,784	15,120	71
Sep-38	189,210	16,075	110	201,773	17,142	181	177,937	15,117	71
Oct-38	189,589	16,073	110	202,215	17,143	181	178,261	15,113	71
Nov-38	190,113	16,092	110	202,813	17,167	182	178,722	15,128	71
Dec-38	190,495	16,166	110	203,258	17,249	182	179,049	15,195	70
Jan-39	190,733	16,179	109	203,550	17,266	182	179,241	15,204	70
Feb-39	190,689	16,191	109	203,541	17,282	182	179,167	15,213	70
Mar-39	190,688	16,194	109	203,578	17,289	183	179,134	15,213	70
Apr-39	190,604	16,164	109	203,527	17,260	183	179,023	15,182	69
May-39	190,517	16,146	109	203,472	17,244	183	178,909	15,162	69
Jun-39	190,325	16,147	109	203,306	17,248	183	178,697	15,160	69
Jul-39	190,446	16,127	109	203,472	17,230	184	178,779	15,139	69
Aug-39	190,551	16,129	109	203,621	17,235	184	178,846	15,138	68
Sep-39	190,746	16,129	109	203,867	17,238	184	178,999	15,136	68
Oct-39	191,124	16,126	109	204,308	17,238	184	179,322	15,130	68
Nov-39	191,646	16,145	109	204,904	17,262	185	179,780	15,145	68
Dec-39	192,027	16,220	109	205,348	17,345	185	180,106	15,213	67

	Washington - Expected Growth			Washington - High Growth			Washington - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jan-40	192,264	16,232	108	205,639	17,361	185	180,296	15,222	67
Feb-40	192,217	16,244	108	205,627	17,377	185	180,221	15,230	67
Mar-40	192,215	16,247	108	205,662	17,384	186	180,188	15,230	67
Apr-40	192,130	16,217	108	205,609	17,355	186	180,077	15,200	66
May-40	192,041	16,199	108	205,551	17,339	186	179,962	15,180	66
Jun-40	191,849	16,200	108	205,383	17,343	186	179,750	15,178	66
Jul-40	191,981	16,180	108	205,569	17,325	187	179,838	15,157	66
Aug-40	192,099	16,183	108	205,738	17,332	187	179,911	15,156	65
Sep-40	192,307	16,182	108	206,006	17,335	187	180,070	15,152	65
Oct-40	192,698	16,180	108	206,468	17,336	187	180,399	15,147	65

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
IDAHO

	Idaho - Expected Growth			Idaho - High Growth			Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-19	77,428	9,129	87	77,428	9,129	87	77,428	9,129	87
Dec-19	77,804	9,164	89	77,804	9,164	89	77,804	9,164	89
Jan-20	78,014	9,229	89	78,014	9,229	89	78,014	9,229	89
Feb-20	78,071	9,153	89	78,071	9,153	89	78,071	9,153	89
Mar-20	78,174	9,211	89	78,174	9,211	89	78,174	9,211	89
Apr-20	78,258	9,199	89	78,258	9,199	89	78,258	9,199	89
May-20	78,205	9,063	87	78,205	9,063	87	78,205	9,063	87
Jun-20	78,176	9,078	89	78,887	9,160	87	77,472	8,996	87
Jul-20	78,330	9,074	89	79,071	9,160	87	77,597	8,989	87
Aug-20	78,346	9,192	89	79,116	9,282	88	77,584	9,103	87
Sep-20	78,485	9,174	89	79,285	9,268	88	77,693	9,081	86
Oct-20	78,647	9,200	89	79,477	9,297	88	77,824	9,104	86
Nov-20	78,845	9,184	88	79,707	9,284	88	77,992	9,085	86
Dec-20	79,147	9,215	89	80,041	9,319	88	78,262	9,112	86
Jan-21	79,275	9,233	88	80,200	9,341	88	78,360	9,126	86
Feb-21	79,226	9,203	88	80,180	9,314	89	78,283	9,093	86
Mar-21	79,185	9,189	88	80,168	9,303	89	78,214	9,076	85
Apr-21	79,153	9,201	88	80,165	9,319	89	78,154	9,085	85
May-21	79,088	9,192	88	80,128	9,313	89	78,061	9,073	85
Jun-21	79,035	9,196	88	80,104	9,320	89	77,980	9,073	85
Jul-21	79,155	9,191	88	80,271	9,321	89	78,053	9,063	85
Aug-21	79,243	9,190	88	80,407	9,325	90	78,095	9,057	84
Sep-21	79,426	9,170	88	80,639	9,310	90	78,230	9,032	84
Oct-21	79,622	9,198	88	80,885	9,344	90	78,378	9,054	84
Nov-21	79,864	9,201	87	81,177	9,352	90	78,571	9,052	84
Dec-21	80,172	9,212	88	81,537	9,369	90	78,829	9,058	84
Jan-22	80,330	9,254	87	81,745	9,417	90	78,939	9,094	84
Feb-22	80,331	9,216	88	81,793	9,384	91	78,894	9,051	83
Mar-22	80,340	9,207	87	81,849	9,380	91	78,858	9,037	83
Apr-22	80,325	9,244	87	81,881	9,423	91	78,798	9,068	83
May-22	80,302	9,239	87	81,905	9,423	91	78,730	9,058	83
Jun-22	80,294	9,226	87	81,944	9,416	91	78,677	9,040	83
Jul-22	80,429	9,239	87	82,137	9,435	91	78,756	9,047	83
Aug-22	80,543	9,226	87	82,309	9,428	92	78,815	9,028	82
Sep-22	80,733	9,202	87	82,558	9,410	92	78,947	8,999	82
Oct-22	80,947	9,265	87	82,833	9,481	92	79,103	9,054	82
Nov-22	81,213	9,245	87	83,161	9,467	92	79,310	9,028	82
Dec-22	81,542	9,269	87	83,554	9,498	92	79,578	9,046	82
Jan-23	81,715	9,325	86	83,788	9,562	92	79,693	9,094	82
Feb-23	81,733	9,271	87	83,863	9,513	93	79,657	9,036	81

	Idaho - Expected Growth			Idaho - High Growth			Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-23	81,765	9,278	86	83,952	9,526	93	79,634	9,036	81
Apr-23	81,768	9,316	86	84,012	9,572	93	79,584	9,067	81
May-23	81,767	9,317	86	84,067	9,579	93	79,529	9,062	81
Jun-23	81,774	9,295	86	84,131	9,563	93	79,482	9,035	81
Jul-23	81,908	9,318	86	84,324	9,593	93	79,560	9,051	81
Aug-23	82,024	9,310	86	84,499	9,591	94	79,621	9,037	80
Sep-23	82,213	9,289	86	84,750	9,576	94	79,752	9,011	80
Oct-23	82,426	9,355	86	85,025	9,650	94	79,906	9,069	80
Nov-23	82,690	9,332	86	85,353	9,633	94	80,109	9,041	80
Dec-23	83,020	9,362	86	85,750	9,670	94	80,376	9,064	80
Jan-24	83,192	9,403	86	85,984	9,719	94	80,489	9,098	80
Feb-24	83,210	9,359	86	86,060	9,680	95	80,454	9,049	79
Mar-24	83,241	9,369	86	86,148	9,696	95	80,431	9,053	79
Apr-24	83,242	9,387	86	86,206	9,721	95	80,379	9,064	79
May-24	83,242	9,384	85	86,263	9,725	95	80,326	9,055	79
Jun-24	83,248	9,385	85	86,326	9,732	95	80,279	9,050	79
Jul-24	83,378	9,390	85	86,514	9,743	95	80,355	9,050	79
Aug-24	83,490	9,388	85	86,685	9,747	96	80,412	9,042	78
Sep-24	83,676	9,370	85	86,932	9,735	96	80,541	9,019	78
Oct-24	83,885	9,411	85	87,203	9,783	96	80,692	9,053	78
Nov-24	84,145	9,402	85	87,528	9,780	96	80,892	9,039	78
Dec-24	84,470	9,427	85	87,921	9,812	96	81,154	9,057	78
Jan-25	84,638	9,464	85	88,151	9,857	96	81,264	9,087	78
Feb-25	84,653	9,427	85	88,222	9,824	97	81,228	9,046	77
Mar-25	84,680	9,425	85	88,305	9,828	97	81,203	9,038	77
Apr-25	84,677	9,452	85	88,357	9,863	97	81,150	9,058	77
May-25	84,673	9,449	85	88,408	9,866	97	81,095	9,050	77
Jun-25	84,675	9,445	85	88,465	9,868	97	81,047	9,040	77
Jul-25	84,782	9,449	85	88,620	9,877	97	81,109	9,040	77
Aug-25	84,871	9,439	84	88,756	9,871	98	81,155	9,026	76
Sep-25	85,034	9,416	84	88,970	9,852	98	81,271	8,999	76
Oct-25	85,219	9,461	84	89,207	9,904	98	81,408	9,038	76
Nov-25	85,456	9,448	84	89,499	9,895	98	81,595	9,021	76
Dec-25	85,758	9,466	84	89,859	9,919	98	81,843	9,034	76
Jan-26	85,903	9,510	84	90,055	9,970	98	81,942	9,072	76
Feb-26	85,894	9,463	84	90,089	9,925	99	81,893	9,022	75
Mar-26	85,897	9,459	84	90,136	9,926	99	81,856	9,014	75
Apr-26	85,871	9,490	84	90,153	9,963	99	81,792	9,039	75
May-26	85,843	9,485	84	90,168	9,963	99	81,725	9,030	75
Jun-26	85,822	9,470	84	90,189	9,952	99	81,665	9,011	75

	Idaho - Expected Growth			Idaho - High Growth			Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jul-26	85,927	9,481	84	90,343	9,968	99	81,726	9,018	75
Aug-26	86,014	9,469	84	90,477	9,960	100	81,770	9,002	74
Sep-26	86,176	9,444	84	90,690	9,939	100	81,886	8,974	74
Oct-26	86,360	9,499	84	90,927	10,001	100	82,022	9,022	74
Nov-26	86,595	9,478	83	91,217	9,984	100	82,206	8,998	74
Dec-26	86,896	9,500	83	91,578	10,012	100	82,453	9,014	74
Jan-27	87,039	9,543	83	91,772	10,062	100	82,549	9,051	74
Feb-27	87,029	9,493	83	91,805	10,014	101	82,501	8,999	73
Mar-27	87,031	9,495	83	91,851	10,021	101	82,464	8,997	73
Apr-27	87,003	9,520	83	91,865	10,052	101	82,398	9,016	73
May-27	86,974	9,515	83	91,877	10,051	101	82,332	9,007	73
Jun-27	86,951	9,502	83	91,897	10,043	101	82,271	8,991	73
Jul-27	87,057	9,512	83	92,052	10,058	101	82,332	8,996	73
Aug-27	87,144	9,503	83	92,187	10,053	102	82,376	8,983	72
Sep-27	87,306	9,480	83	92,402	10,033	102	82,491	8,957	72
Oct-27	87,490	9,530	83	92,640	10,091	102	82,626	9,000	72
Nov-27	87,726	9,510	83	92,933	10,075	102	82,810	8,977	72
Dec-27	88,028	9,534	83	93,297	10,105	102	83,056	8,996	72
Jan-28	88,171	9,572	83	93,492	10,150	102	83,152	9,027	72
Feb-28	88,161	9,526	82	93,525	10,106	103	83,103	8,980	71
Mar-28	88,163	9,527	82	93,571	10,111	103	83,066	8,976	71
Apr-28	88,136	9,549	82	93,587	10,140	103	83,002	8,993	71
May-28	88,106	9,543	82	93,599	10,138	103	82,935	8,983	71
Jun-28	88,084	9,534	82	93,619	10,133	103	82,875	8,970	71
Jul-28	88,190	9,539	82	93,775	10,143	103	82,936	8,971	71
Aug-28	88,279	9,531	82	93,914	10,139	104	82,982	8,959	70
Sep-28	88,441	9,508	82	94,130	10,120	104	83,095	8,933	70
Oct-28	88,626	9,553	82	94,371	10,172	104	83,230	8,971	70
Nov-28	88,862	9,538	82	94,666	10,161	104	83,413	8,953	70
Dec-28	89,164	9,559	82	95,032	10,188	104	83,658	8,969	70
Jan-29	89,308	9,597	82	95,230	10,233	104	83,754	9,000	70
Feb-29	89,298	9,552	82	95,263	10,190	105	83,706	8,954	69
Mar-29	89,301	9,550	82	95,311	10,193	105	83,669	8,948	69
Apr-29	89,274	9,576	82	95,326	10,225	105	83,605	8,968	69
May-29	89,245	9,570	81	95,340	10,224	105	83,539	8,958	69
Jun-29	89,223	9,559	81	95,360	10,217	105	83,480	8,944	69
Jul-29	89,329	9,566	81	95,517	10,229	105	83,541	8,946	69
Aug-29	89,417	9,555	81	95,655	10,222	106	83,585	8,932	68
Sep-29	89,579	9,531	81	95,872	10,201	106	83,698	8,905	68
Oct-29	89,763	9,580	81	96,113	10,258	106	83,832	8,947	68

	Idaho - Expected Growth			Idaho - High Growth			Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-29	89,999	9,562	81	96,410	10,243	106	84,014	8,926	68
Dec-29	90,301	9,583	81	96,778	10,270	106	84,257	8,942	68
Jan-30	90,444	9,624	81	96,975	10,319	106	84,352	8,976	68
Feb-30	90,434	9,576	81	97,009	10,272	107	84,304	8,927	67
Mar-30	90,437	9,575	81	97,056	10,276	107	84,268	8,922	67
Apr-30	90,409	9,601	81	97,071	10,308	107	84,204	8,942	67
May-30	90,380	9,596	81	97,084	10,308	107	84,138	8,933	67
Jun-30	90,358	9,583	81	97,105	10,299	107	84,079	8,917	67
Jul-30	90,466	9,592	81	97,266	10,313	107	84,141	8,921	67
Aug-30	90,557	9,582	80	97,409	10,307	108	84,186	8,908	66
Sep-30	90,721	9,557	80	97,631	10,285	108	84,300	8,881	66
Oct-30	90,908	9,608	80	97,877	10,345	108	84,434	8,924	66
Nov-30	91,147	9,589	80	98,180	10,329	108	84,617	8,902	66
Dec-30	91,451	9,611	80	98,553	10,357	108	84,860	8,918	66
Jan-31	91,597	9,651	80	98,757	10,405	108	84,956	8,951	66
Feb-31	91,590	9,604	80	98,795	10,360	109	84,910	8,904	65
Mar-31	91,594	9,604	80	98,845	10,364	109	84,874	8,899	65
Apr-31	91,570	9,628	80	98,865	10,395	109	84,812	8,918	65
May-31	91,543	9,623	80	98,882	10,395	109	84,748	8,909	65
Jun-31	91,524	9,612	80	98,907	10,387	109	84,691	8,894	65
Jul-31	91,634	9,619	80	99,072	10,400	109	84,753	8,897	65
Aug-31	91,726	9,610	80	99,218	10,395	110	84,799	8,884	64
Sep-31	91,892	9,587	80	99,444	10,375	110	84,913	8,859	64
Oct-31	92,081	9,636	80	99,695	10,433	110	85,048	8,900	64
Nov-31	92,321	9,617	79	100,002	10,417	110	85,230	8,878	64
Dec-31	92,627	9,639	79	100,380	10,446	110	85,472	8,894	64
Jan-32	92,775	9,678	79	100,587	10,493	110	85,569	8,926	64
Feb-32	92,769	9,633	79	100,628	10,449	111	85,523	8,881	63
Mar-32	92,776	9,632	79	100,682	10,453	111	85,490	8,876	63
Apr-32	92,753	9,657	79	100,704	10,485	111	85,429	8,894	63
May-32	92,728	9,650	79	100,724	10,482	111	85,366	8,884	63
Jun-32	92,710	9,640	79	100,752	10,476	111	85,309	8,871	63
Jul-32	92,822	9,647	79	100,920	10,489	111	85,373	8,873	63
Aug-32	92,915	9,638	79	101,069	10,484	112	85,418	8,860	62
Sep-32	93,083	9,614	79	101,299	10,463	112	85,533	8,834	62
Oct-32	93,273	9,662	79	101,553	10,520	112	85,667	8,874	62
Nov-32	93,515	9,645	79	101,864	10,506	112	85,849	8,854	62
Dec-32	93,822	9,666	79	102,246	10,534	112	86,091	8,870	62
Jan-33	93,971	9,706	79	102,457	10,583	112	86,187	8,902	62
Feb-33	93,967	9,660	79	102,500	10,537	113	86,143	8,856	61

	Idaho - Expected Growth			Idaho - High Growth			Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-33	93,975	9,659	78	102,557	10,541	113	86,111	8,851	61
Apr-33	93,954	9,685	78	102,582	10,574	113	86,051	8,870	61
May-33	93,930	9,679	78	102,604	10,573	113	85,989	8,861	61
Jun-33	93,914	9,668	78	102,634	10,566	113	85,934	8,847	61
Jul-33	94,027	9,675	78	102,806	10,578	113	85,997	8,849	61
Aug-33	94,122	9,665	78	102,958	10,572	114	86,043	8,835	60
Sep-33	94,292	9,642	78	103,193	10,552	114	86,158	8,810	60
Oct-33	94,483	9,691	78	103,450	10,611	114	86,292	8,851	60
Nov-33	94,727	9,673	78	103,766	10,596	114	86,475	8,830	60
Dec-33	95,036	9,695	78	104,154	10,625	114	86,716	8,846	60
Jan-34	95,187	9,736	78	104,368	10,675	114	86,813	8,880	60
Feb-34	95,185	9,688	78	104,415	10,627	115	86,770	8,832	59
Mar-34	95,194	9,688	78	104,474	10,632	115	86,738	8,827	59
Apr-34	95,175	9,713	78	104,502	10,665	115	86,680	8,846	59
May-34	95,153	9,708	78	104,527	10,664	115	86,619	8,837	59
Jun-34	95,139	9,697	77	104,561	10,657	115	86,565	8,823	59
Jul-34	95,253	9,705	77	104,735	10,671	115	86,628	8,826	59
Aug-34	95,350	9,695	77	104,891	10,665	116	86,676	8,813	58
Sep-34	95,520	9,671	77	105,128	10,644	116	86,790	8,787	58
Oct-34	95,713	9,721	77	105,390	10,704	116	86,924	8,828	58
Nov-34	95,958	9,703	77	105,709	10,689	116	87,106	8,808	58
Dec-34	96,268	9,725	77	106,100	10,718	116	87,346	8,824	58
Jan-35	96,421	9,765	77	106,319	10,767	116	87,444	8,856	58
Feb-35	96,420	9,719	77	106,368	10,722	117	87,402	8,810	57
Mar-35	96,431	9,718	77	106,430	10,726	117	87,371	8,805	57
Apr-35	96,412	9,743	77	106,459	10,758	117	87,313	8,823	57
May-35	96,392	9,737	77	106,487	10,757	117	87,253	8,814	57
Jun-35	96,379	9,727	77	106,522	10,751	117	87,201	8,801	57
Jul-35	96,495	9,734	77	106,701	10,764	117	87,265	8,803	57
Aug-35	96,593	9,725	77	106,860	10,759	118	87,312	8,791	56
Sep-35	96,765	9,702	76	107,100	10,738	118	87,426	8,766	56
Oct-35	96,960	9,750	76	107,367	10,797	118	87,561	8,805	56
Nov-35	97,207	9,733	76	107,691	10,783	118	87,743	8,785	56
Dec-35	97,519	9,755	76	108,088	10,812	118	87,983	8,801	56
Jan-36	97,673	9,795	76	108,309	10,862	118	88,080	8,833	56
Feb-36	97,673	9,749	76	108,361	10,816	119	88,039	8,787	55
Mar-36	97,686	9,748	76	108,426	10,820	119	88,009	8,782	55
Apr-36	97,670	9,773	76	108,459	10,853	119	87,953	8,801	55
May-36	97,651	9,767	76	108,490	10,851	119	87,895	8,791	55
Jun-36	97,639	9,756	76	108,527	10,844	119	87,842	8,777	55
Jul-36	97,756	9,764	76	108,709	10,858	119	87,906	8,780	55

	Idaho - Expected Growth			Idaho - High Growth			Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Aug-36	97,856	9,755	76	108,871	10,853	120	87,955	8,768	54
Sep-36	98,029	9,732	76	109,115	10,833	120	88,069	8,743	54
Oct-36	98,225	9,781	76	109,384	10,892	120	88,203	8,783	54
Nov-36	98,473	9,762	76	109,712	10,876	120	88,384	8,762	54
Dec-36	98,786	9,784	75	110,113	10,906	120	88,624	8,778	54
Jan-37	98,941	9,824	75	110,337	10,956	120	88,721	8,809	54
Feb-37	98,943	9,778	75	110,392	10,909	121	88,681	8,764	53
Mar-37	98,957	9,778	75	110,459	10,915	121	88,652	8,760	53
Apr-37	98,942	9,803	75	110,495	10,948	121	88,597	8,778	53
May-37	98,924	9,798	75	110,526	10,947	121	88,539	8,769	53
Jun-37	98,914	9,786	75	110,567	10,939	121	88,488	8,755	53
Jul-37	99,032	9,794	75	110,751	10,953	121	88,552	8,758	53
Aug-37	99,132	9,785	75	110,915	10,948	122	88,600	8,745	52
Sep-37	99,306	9,761	75	111,161	10,926	122	88,714	8,720	52
Oct-37	99,503	9,811	75	111,434	10,987	122	88,849	8,761	52
Nov-37	99,751	9,793	75	111,764	10,972	122	89,029	8,740	52
Dec-37	100,065	9,815	75	112,168	11,002	122	89,267	8,756	52
Jan-38	100,221	9,854	75	112,395	11,051	122	89,365	8,787	52
Feb-38	100,223	9,808	75	112,450	11,005	123	89,325	8,741	51
Mar-38	100,238	9,807	74	112,520	11,009	123	89,296	8,737	51
Apr-38	100,223	9,833	74	112,555	11,043	123	89,241	8,756	51
May-38	100,206	9,828	74	112,589	11,043	123	89,184	8,747	51
Jun-38	100,197	9,817	74	112,632	11,035	123	89,135	8,733	51
Jul-38	100,316	9,825	74	112,818	11,049	123	89,199	8,736	51
Aug-38	100,417	9,814	74	112,984	11,042	124	89,247	8,722	50
Sep-38	100,593	9,791	74	113,235	11,022	124	89,361	8,698	50
Oct-38	100,791	9,840	74	113,511	11,082	124	89,495	8,737	50
Nov-38	101,041	9,823	74	113,846	11,068	124	89,675	8,718	50
Dec-38	101,356	9,845	74	114,254	11,098	124	89,913	8,734	50
Jan-39	101,513	9,885	74	114,485	11,148	124	90,010	8,765	50
Feb-39	101,517	9,838	74	114,543	11,100	125	89,972	8,719	49
Mar-39	101,533	9,837	74	114,615	11,104	125	89,944	8,714	49
Apr-39	101,519	9,862	74	114,652	11,138	125	89,889	8,732	49
May-39	101,504	9,857	74	114,689	11,137	125	89,834	8,724	49
Jun-39	101,496	9,846	73	114,734	11,130	125	89,785	8,710	49
Jul-39	101,614	9,854	73	114,920	11,144	125	89,848	8,713	49
Aug-39	101,716	9,845	73	115,088	11,139	126	89,897	8,701	48
Sep-39	101,891	9,820	73	115,339	11,116	126	90,010	8,675	48
Oct-39	102,088	9,869	73	115,615	11,177	126	90,143	8,714	48
Nov-39	102,338	9,851	73	115,952	11,161	126	90,322	8,694	48
Dec-39	102,652	9,873	73	116,361	11,192	126	90,558	8,710	48

	Idaho - Expected Growth			Idaho - High Growth			Idaho - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jan-40	102,809	9,913	73	116,592	11,242	126	90,654	8,741	48
Feb-40	102,813	9,867	73	116,650	11,195	127	90,616	8,697	47
Mar-40	102,828	9,866	73	116,721	11,199	127	90,588	8,692	47
Apr-40	102,814	9,890	73	116,759	11,231	127	90,534	8,709	47
May-40	102,798	9,885	73	116,794	11,231	127	90,478	8,700	47
Jun-40	102,790	9,874	73	116,839	11,224	127	90,430	8,687	47
Jul-40	102,910	9,882	73	117,029	11,238	127	90,494	8,690	47
Aug-40	103,012	9,872	73	117,199	11,232	128	90,542	8,677	46
Sep-40	103,188	9,849	72	117,453	11,211	128	90,655	8,653	46
Oct-40	103,387	9,898	72	117,733	11,272	128	90,788	8,692	46

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION MEDFORD

	Medford - Expected Growth			Medford - High Growth			Medford - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-19	56,068	6,975	14	56,068	6,975	14	56,068	6,975	14
Dec-19	56,354	7,038	14	56,354	7,038	14	56,354	7,038	14
Jan-20	56,493	7,088	14	56,493	7,088	14	56,493	7,088	14
Feb-20	56,432	7,074	14	56,432	7,074	14	56,432	7,074	14
Mar-20	56,507	7,073	14	56,507	7,073	14	56,507	7,073	14
Apr-20	56,516	7,053	14	56,516	7,053	14	56,516	7,053	14
May-20	56,377	6,941	14	56,377	6,941	14	56,377	6,941	14
Jun-20	56,298	6,909	14	56,396	6,921	14	56,188	6,895	14
Jul-20	56,152	6,896	14	56,259	6,909	14	56,032	6,881	14
Aug-20	56,070	7,012	14	56,186	7,026	14	55,940	6,995	14
Sep-20	56,037	6,994	14	56,162	7,009	14	55,897	6,976	14
Oct-20	56,266	7,007	14	56,401	7,023	14	56,115	6,988	14
Nov-20	56,600	7,042	14	56,745	7,060	14	56,438	7,021	14
Dec-20	56,918	7,090	14	57,073	7,109	14	56,744	7,068	14
Jan-21	57,105	7,107	14	57,270	7,128	14	56,920	7,084	14
Feb-21	57,090	7,120	14	57,264	7,142	14	56,895	7,096	14
Mar-21	57,106	7,122	14	57,290	7,145	14	56,900	7,097	14
Apr-21	57,063	7,103	14	57,256	7,127	14	56,847	7,076	14
May-21	56,973	7,095	14	57,175	7,121	15	56,747	7,067	14
Jun-21	56,842	7,082	14	57,053	7,109	15	56,606	7,053	13
Jul-21	56,718	7,062	14	56,941	7,090	15	56,468	7,031	13
Aug-21	56,661	7,055	14	56,897	7,085	15	56,396	7,022	13
Sep-21	56,654	7,046	14	56,903	7,077	15	56,375	7,012	13
Oct-21	56,928	7,063	14	57,191	7,096	15	56,633	7,027	13
Nov-21	57,289	7,100	14	57,567	7,135	15	56,978	7,062	13
Dec-21	57,631	7,145	14	57,924	7,182	15	57,303	7,105	13
Jan-22	57,847	7,185	14	58,155	7,223	15	57,503	7,142	13
Feb-22	57,847	7,194	14	58,168	7,234	15	57,488	7,149	13
Mar-22	57,880	7,196	14	58,214	7,238	15	57,506	7,150	13
Apr-22	57,854	7,181	14	58,202	7,224	15	57,465	7,133	13
May-22	57,780	7,174	14	58,140	7,219	15	57,377	7,124	13
Jun-22	57,671	7,163	14	58,044	7,209	15	57,254	7,111	13
Jul-22	57,527	7,140	14	57,909	7,187	15	57,101	7,087	13
Aug-22	57,452	7,134	14	57,843	7,183	15	57,015	7,080	13
Sep-22	57,429	7,122	14	57,829	7,172	15	56,982	7,067	13
Oct-22	57,685	7,138	14	58,097	7,189	15	57,225	7,081	13
Nov-22	58,029	7,174	14	58,453	7,226	15	57,556	7,115	13
Dec-22	58,351	7,218	14	58,787	7,272	15	57,864	7,158	13
Jan-23	58,547	7,256	14	58,995	7,312	15	58,047	7,194	13
Feb-23	58,527	7,264	14	58,984	7,321	15	58,017	7,201	13

	Medford - Expected Growth			Medford - High Growth			Medford - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-23	58,540	7,265	14	59,007	7,323	15	58,019	7,201	13
Apr-23	58,493	7,247	14	58,970	7,306	15	57,961	7,181	13
May-23	58,400	7,239	14	58,886	7,300	16	57,858	7,172	13
Jun-23	58,270	7,227	14	58,765	7,289	16	57,719	7,159	12
Jul-23	58,132	7,204	14	58,636	7,267	16	57,570	7,135	12
Aug-23	58,061	7,198	14	58,575	7,262	16	57,488	7,127	12
Sep-23	58,043	7,187	14	58,567	7,252	16	57,459	7,115	12
Oct-23	58,304	7,203	14	58,841	7,270	16	57,706	7,129	12
Nov-23	58,651	7,239	14	59,202	7,307	16	58,038	7,164	12
Dec-23	58,978	7,283	14	59,542	7,353	16	58,349	7,206	12
Jan-24	59,178	7,321	14	59,755	7,393	16	58,536	7,242	12
Feb-24	59,162	7,329	14	59,749	7,402	16	58,508	7,248	12
Mar-24	59,179	7,331	14	59,777	7,406	16	58,513	7,249	12
Apr-24	59,137	7,313	14	59,746	7,389	16	58,460	7,230	12
May-24	59,047	7,306	14	59,665	7,383	16	58,359	7,221	12
Jun-24	58,922	7,293	14	59,550	7,371	16	58,224	7,207	12
Jul-24	58,791	7,271	14	59,429	7,350	16	58,081	7,184	12
Aug-24	58,729	7,266	14	59,378	7,347	16	58,007	7,177	12
Sep-24	58,718	7,255	14	59,379	7,337	16	57,983	7,165	12
Oct-24	58,987	7,272	14	59,663	7,356	16	58,235	7,180	12
Nov-24	59,342	7,309	14	60,034	7,395	16	58,573	7,215	12
Dec-24	59,677	7,353	14	60,385	7,441	16	58,890	7,256	12
Jan-25	59,885	7,391	14	60,608	7,480	16	59,082	7,292	12
Feb-25	59,877	7,400	14	60,612	7,491	16	59,061	7,299	12
Mar-25	59,902	7,402	14	60,649	7,494	16	59,072	7,299	12
Apr-25	59,867	7,385	14	60,626	7,479	16	59,024	7,281	12
May-25	59,786	7,378	14	60,556	7,473	17	58,931	7,272	12
Jun-25	59,669	7,366	14	60,450	7,462	17	58,803	7,259	11
Jul-25	59,531	7,344	14	60,321	7,441	17	58,655	7,236	11
Aug-25	59,462	7,338	14	60,262	7,437	17	58,575	7,229	11
Sep-25	59,444	7,327	14	60,254	7,427	17	58,546	7,216	11
Oct-25	59,706	7,343	14	60,531	7,444	17	58,792	7,231	11
Nov-25	60,055	7,380	14	60,895	7,483	17	59,124	7,266	11
Dec-25	60,383	7,424	14	61,239	7,529	17	59,435	7,307	11
Jan-26	60,584	7,460	14	61,454	7,567	17	59,620	7,341	11
Feb-26	60,569	7,468	14	61,449	7,576	17	59,594	7,348	11
Mar-26	60,587	7,470	14	61,479	7,580	17	59,599	7,348	11
Apr-26	60,546	7,453	14	61,448	7,564	17	59,547	7,330	11
May-26	60,458	7,445	14	61,370	7,557	17	59,449	7,321	11
Jun-26	60,334	7,433	14	61,255	7,546	17	59,315	7,307	11

	Medford - Expected Growth			Medford - High Growth			Medford - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jul-26	60,195	7,410	14	61,124	7,524	17	59,167	7,283	11
Aug-26	60,125	7,404	14	61,064	7,519	17	59,086	7,276	11
Sep-26	60,106	7,393	14	61,055	7,510	17	59,056	7,264	11
Oct-26	60,368	7,409	14	61,332	7,527	17	59,302	7,278	11
Nov-26	60,715	7,446	14	61,695	7,566	17	59,631	7,313	11
Dec-26	61,042	7,490	14	62,038	7,612	17	59,940	7,355	11
Jan-27	61,242	7,525	14	62,252	7,649	17	60,125	7,388	11
Feb-27	61,226	7,533	14	62,247	7,659	17	60,098	7,394	11
Mar-27	61,243	7,535	14	62,275	7,662	17	60,102	7,395	11
Apr-27	61,201	7,518	14	62,243	7,646	17	60,050	7,377	11
May-27	61,112	7,510	14	62,163	7,639	18	59,950	7,367	11
Jun-27	60,987	7,498	14	62,047	7,629	18	59,816	7,354	10
Jul-27	60,847	7,475	14	61,915	7,606	18	59,668	7,330	10
Aug-27	60,775	7,469	14	61,852	7,602	18	59,586	7,323	10
Sep-27	60,755	7,458	14	61,842	7,592	18	59,555	7,311	10
Oct-27	61,014	7,474	14	62,116	7,609	18	59,797	7,325	10
Nov-27	61,360	7,510	14	62,479	7,647	18	60,125	7,359	10
Dec-27	61,686	7,554	14	62,821	7,693	18	60,433	7,401	10
Jan-28	61,884	7,589	14	63,034	7,730	18	60,616	7,434	10
Feb-28	61,866	7,597	14	63,026	7,740	18	60,587	7,440	10
Mar-28	61,882	7,599	14	63,053	7,743	18	60,591	7,441	10
Apr-28	61,838	7,581	14	63,018	7,726	18	60,536	7,422	10
May-28	61,747	7,573	14	62,936	7,719	18	60,436	7,413	10
Jun-28	61,620	7,561	14	62,817	7,708	18	60,300	7,399	10
Jul-28	61,478	7,538	14	62,683	7,686	18	60,150	7,376	10
Aug-28	61,404	7,532	14	62,617	7,681	18	60,067	7,368	10
Sep-28	61,382	7,520	14	62,605	7,670	18	60,035	7,355	10
Oct-28	61,639	7,536	14	62,877	7,688	18	60,275	7,370	10
Nov-28	61,983	7,572	14	63,238	7,726	18	60,601	7,403	10
Dec-28	62,306	7,616	14	63,578	7,772	18	60,906	7,445	10
Jan-29	62,503	7,651	14	63,789	7,809	18	61,087	7,478	10
Feb-29	62,483	7,659	14	63,779	7,818	18	61,057	7,484	10
Mar-29	62,496	7,661	14	63,802	7,821	18	61,058	7,485	10
Apr-29	62,450	7,643	14	63,766	7,804	18	61,002	7,466	10
May-29	62,357	7,635	14	63,681	7,797	19	60,901	7,457	10
Jun-29	62,228	7,622	14	63,559	7,785	19	60,764	7,443	9
Jul-29	62,084	7,599	14	63,422	7,763	19	60,613	7,419	9
Aug-29	62,009	7,593	14	63,355	7,758	19	60,529	7,412	9
Sep-29	61,985	7,582	14	63,340	7,748	19	60,495	7,400	9
Oct-29	62,241	7,597	14	63,612	7,765	19	60,734	7,413	9

	Medford - Expected Growth			Medford - High Growth			Medford - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-29	62,583	7,633	14	63,971	7,803	19	61,057	7,447	9
Dec-29	62,904	7,677	14	64,309	7,849	19	61,360	7,489	9
Jan-30	63,099	7,712	14	64,518	7,886	19	61,539	7,522	9
Feb-30	63,078	7,720	14	64,507	7,895	19	61,508	7,528	9
Mar-30	63,089	7,721	14	64,528	7,897	19	61,508	7,528	9
Apr-30	63,041	7,703	14	64,489	7,880	19	61,451	7,509	9
May-30	62,947	7,695	14	64,403	7,873	19	61,349	7,500	9
Jun-30	62,816	7,682	14	64,279	7,861	19	61,210	7,486	9
Jul-30	62,670	7,659	14	64,139	7,839	19	61,058	7,462	9
Aug-30	62,592	7,653	14	64,068	7,834	19	60,972	7,455	9
Sep-30	62,565	7,641	14	64,050	7,822	19	60,936	7,442	9
Oct-30	62,818	7,656	14	64,318	7,839	19	61,172	7,456	9
Nov-30	63,158	7,692	14	64,676	7,877	19	61,493	7,489	9
Dec-30	63,477	7,736	14	65,012	7,923	19	61,794	7,531	9
Jan-31	63,669	7,771	14	65,218	7,960	19	61,970	7,564	9
Feb-31	63,645	7,778	14	65,203	7,968	19	61,937	7,569	9
Mar-31	63,654	7,779	14	65,222	7,971	19	61,935	7,569	9
Apr-31	63,604	7,761	14	65,180	7,953	19	61,877	7,550	9
May-31	63,507	7,753	14	65,090	7,946	20	61,772	7,541	9
Jun-31	63,374	7,740	14	64,963	7,934	20	61,633	7,527	8
Jul-31	63,225	7,717	14	64,819	7,912	20	61,478	7,504	8
Aug-31	63,145	7,710	14	64,746	7,906	20	61,391	7,496	8
Sep-31	63,116	7,698	14	64,725	7,894	20	61,353	7,483	8
Oct-31	63,367	7,713	14	64,992	7,911	20	61,588	7,497	8
Nov-31	63,704	7,749	14	65,347	7,949	20	61,905	7,530	8
Dec-31	64,021	7,793	14	65,681	7,995	20	62,204	7,572	8
Jan-32	64,211	7,827	14	65,885	8,031	20	62,379	7,604	8
Feb-32	64,185	7,835	14	65,867	8,041	20	62,344	7,611	8
Mar-32	64,191	7,835	14	65,883	8,042	20	62,340	7,609	8
Apr-32	64,139	7,817	14	65,838	8,024	20	62,280	7,591	8
May-32	64,040	7,809	14	65,746	8,017	20	62,174	7,582	8
Jun-32	63,904	7,796	14	65,615	8,005	20	62,032	7,568	8
Jul-32	63,753	7,772	14	65,469	7,982	20	61,876	7,544	8
Aug-32	63,671	7,766	14	65,393	7,976	20	61,788	7,537	8
Sep-32	63,641	7,754	14	65,371	7,965	20	61,749	7,524	8
Oct-32	63,890	7,769	14	65,636	7,982	20	61,982	7,537	8
Nov-32	64,225	7,804	14	65,988	8,019	20	62,297	7,570	8
Dec-32	64,540	7,848	14	66,321	8,065	20	62,594	7,612	8
Jan-33	64,728	7,883	14	66,523	8,101	20	62,767	7,644	8
Feb-33	64,700	7,890	14	66,503	8,110	20	62,730	7,650	8

	Medford - Expected Growth			Medford - High Growth			Medford - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-33	64,705	7,891	14	66,517	8,112	20	62,726	7,649	8
Apr-33	64,650	7,873	14	66,469	8,094	20	62,663	7,631	8
May-33	64,549	7,864	14	66,374	8,086	21	62,556	7,621	8
Jun-33	64,412	7,851	14	66,242	8,074	21	62,414	7,607	7
Jul-33	64,260	7,827	14	66,094	8,050	21	62,258	7,583	7
Aug-33	64,176	7,821	14	66,016	8,045	21	62,168	7,576	7
Sep-33	64,143	7,809	14	65,990	8,034	21	62,127	7,563	7
Oct-33	64,391	7,824	14	66,254	8,050	21	62,358	7,577	7
Nov-33	64,724	7,859	14	66,605	8,087	21	62,672	7,610	7
Dec-33	65,038	7,902	14	66,936	8,132	21	62,967	7,650	7
Jan-34	65,224	7,936	14	67,136	8,169	21	63,138	7,682	7
Feb-34	65,194	7,944	14	67,114	8,178	21	63,100	7,689	7
Mar-34	65,197	7,944	14	67,125	8,179	21	63,094	7,688	7
Apr-34	65,141	7,926	14	67,076	8,161	21	63,031	7,669	7
May-34	65,038	7,917	14	66,979	8,153	21	62,922	7,659	7
Jun-34	64,899	7,904	14	66,844	8,141	21	62,779	7,646	7
Jul-34	64,744	7,880	14	66,692	8,117	21	62,620	7,622	7
Aug-34	64,659	7,873	14	66,613	8,111	21	62,529	7,614	7
Sep-34	64,625	7,861	14	66,586	8,100	21	62,488	7,601	7
Oct-34	64,870	7,876	14	66,846	8,116	21	62,717	7,615	7
Nov-34	65,202	7,911	14	67,196	8,153	21	63,029	7,647	7
Dec-34	65,514	7,954	14	67,526	8,198	21	63,322	7,688	7
Jan-35	65,698	7,988	14	67,724	8,235	21	63,491	7,720	7
Feb-35	65,667	7,995	14	67,700	8,243	21	63,453	7,726	7
Mar-35	65,668	7,996	14	67,709	8,245	21	63,445	7,726	7
Apr-35	65,610	7,977	14	67,658	8,226	21	63,380	7,706	7
May-35	65,505	7,969	14	67,558	8,219	22	63,270	7,697	7
Jun-35	65,364	7,955	14	67,420	8,206	22	63,126	7,683	6
Jul-35	65,209	7,931	14	67,268	8,182	22	62,968	7,659	6
Aug-35	65,123	7,924	14	67,188	8,176	22	62,876	7,651	6
Sep-35	65,088	7,912	14	67,159	8,164	22	62,834	7,638	6
Oct-35	65,333	7,927	14	67,420	8,181	22	63,062	7,652	6
Nov-35	65,664	7,962	14	67,770	8,218	22	63,373	7,685	6
Dec-35	65,974	8,005	14	68,098	8,263	22	63,664	7,725	6
Jan-36	66,158	8,040	14	68,296	8,299	22	63,833	7,757	6
Feb-36	66,126	8,047	14	68,271	8,308	22	63,794	7,763	6
Mar-36	66,126	8,048	14	68,279	8,310	22	63,785	7,763	6
Apr-36	66,067	8,029	14	68,226	8,291	22	63,720	7,743	6
May-36	65,962	8,020	14	68,125	8,283	22	63,610	7,734	6
Jun-36	65,820	8,006	14	67,987	8,269	22	63,465	7,719	6
Jul-36	65,664	7,983	14	67,833	8,246	22	63,306	7,696	6

	Medford - Expected Growth			Medford - High Growth			Medford - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Aug-36	65,577	7,976	14	67,751	8,240	22	63,214	7,688	6
Sep-36	65,542	7,963	14	67,723	8,228	22	63,172	7,675	6
Oct-36	65,785	7,978	14	67,982	8,244	22	63,398	7,688	6
Nov-36	66,116	8,013	14	68,332	8,281	22	63,709	7,721	6
Dec-36	66,425	8,056	14	68,659	8,327	22	63,999	7,761	6
Jan-37	66,608	8,090	14	68,856	8,363	22	64,167	7,793	6
Feb-37	66,575	8,097	14	68,830	8,371	22	64,127	7,799	6
Mar-37	66,575	8,098	14	68,837	8,373	22	64,118	7,799	6
Apr-37	66,515	8,079	14	68,783	8,354	22	64,052	7,780	6
May-37	66,408	8,070	14	68,681	8,346	23	63,941	7,770	6
Jun-37	66,266	8,056	14	68,542	8,333	23	63,796	7,756	5
Jul-37	66,109	8,032	14	68,387	8,309	23	63,637	7,732	5
Aug-37	66,020	8,025	14	68,302	8,302	23	63,544	7,724	5
Sep-37	65,983	8,013	14	68,271	8,291	23	63,500	7,711	5
Oct-37	66,226	8,027	14	68,530	8,306	23	63,726	7,724	5
Nov-37	66,555	8,063	14	68,878	8,344	23	64,035	7,758	5
Dec-37	66,863	8,105	14	69,205	8,389	23	64,323	7,797	5
Jan-38	67,044	8,139	14	69,400	8,425	23	64,489	7,829	5
Feb-38	67,010	8,146	14	69,372	8,433	23	64,448	7,835	5
Mar-38	67,008	8,146	14	69,378	8,434	23	64,438	7,834	5
Apr-38	66,947	8,128	14	69,322	8,417	23	64,372	7,816	5
May-38	66,839	8,119	14	69,218	8,408	23	64,260	7,806	5
Jun-38	66,695	8,105	14	69,077	8,395	23	64,114	7,792	5
Jul-38	66,537	8,081	14	68,920	8,371	23	63,954	7,768	5
Aug-38	66,447	8,074	14	68,834	8,364	23	63,860	7,760	5
Sep-38	66,409	8,061	14	68,802	8,352	23	63,816	7,747	5
Oct-38	66,650	8,076	14	69,059	8,368	23	64,040	7,760	5
Nov-38	66,978	8,111	14	69,407	8,405	23	64,347	7,793	5
Dec-38	67,285	8,153	14	69,732	8,450	23	64,634	7,832	5
Jan-39	67,465	8,188	14	69,926	8,486	23	64,800	7,864	5
Feb-39	67,429	8,195	14	69,896	8,495	23	64,757	7,870	5
Mar-39	67,426	8,195	14	69,901	8,495	23	64,747	7,869	5
Apr-39	67,364	8,176	14	69,844	8,477	23	64,679	7,850	5
May-39	67,255	8,167	14	69,738	8,468	24	64,567	7,840	5
Jun-39	67,110	8,153	14	69,595	8,455	24	64,420	7,826	4
Jul-39	66,950	8,129	14	69,437	8,431	24	64,259	7,802	4
Aug-39	66,860	8,122	14	69,350	8,424	24	64,165	7,794	4
Sep-39	66,820	8,109	14	69,316	8,412	24	64,119	7,781	4
Oct-39	67,060	8,124	14	69,572	8,428	24	64,342	7,794	4
Nov-39	67,387	8,159	14	69,919	8,465	24	64,648	7,827	4
Dec-39	67,693	8,201	14	70,243	8,510	24	64,934	7,867	4

	Medford - Expected Growth			Medford - High Growth			Medford - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jan-40	67,872	8,235	14	70,436	8,546	24	65,099	7,899	4
Feb-40	67,835	8,242	14	70,405	8,554	24	65,056	7,904	4
Mar-40	67,831	8,242	14	70,408	8,555	24	65,044	7,903	4
Apr-40	67,768	8,223	14	70,350	8,536	24	64,976	7,884	4
May-40	67,658	8,214	14	70,243	8,528	24	64,863	7,875	4
Jun-40	67,512	8,200	14	70,099	8,514	24	64,716	7,860	4
Jul-40	67,351	8,176	14	69,939	8,490	24	64,554	7,837	4
Aug-40	67,259	8,168	14	69,850	8,483	24	64,459	7,828	4
Sep-40	67,219	8,156	14	69,815	8,471	24	64,413	7,816	4
Oct-40	67,458	8,170	14	70,071	8,486	24	64,635	7,828	4

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION ROSEBURG

	Roseburg - Expected Growth			Roseburg - High Growth			Roseburg - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-19	13,797	2,165	2	13,797	2,165	2	13,797	2,165	2
Dec-19	13,889	2,189	2	13,889	2,189	2	13,889	2,189	2
Jan-20	13,970	2,191	2	13,970	2,191	2	13,970	2,191	2
Feb-20	13,876	2,184	2	13,876	2,184	2	13,876	2,184	2
Mar-20	13,983	2,193	2	13,983	2,193	2	13,983	2,193	2
Apr-20	13,952	2,193	2	13,952	2,193	2	13,952	2,193	2
May-20	13,902	2,169	2	13,902	2,169	2	13,902	2,169	2
Jun-20	13,879	2,169	2	14,010	2,189	2	13,797	2,156	2
Jul-20	13,813	2,157	2	13,953	2,178	2	13,726	2,143	2
Aug-20	13,746	2,164	2	13,894	2,187	2	13,653	2,149	2
Sep-20	13,761	2,162	2	13,919	2,186	2	13,663	2,146	2
Oct-20	13,841	2,163	2	14,009	2,189	2	13,736	2,146	2
Nov-20	13,902	2,176	2	14,080	2,203	2	13,791	2,158	2
Dec-20	14,022	2,191	2	14,211	2,220	2	13,904	2,172	2
Jan-21	14,044	2,190	2	14,243	2,221	2	13,920	2,171	2
Feb-21	14,038	2,196	2	14,246	2,229	2	13,909	2,176	2
Mar-21	14,078	2,194	2	14,296	2,228	2	13,942	2,173	2
Apr-21	14,022	2,189	2	14,249	2,225	2	13,881	2,167	2
May-21	14,002	2,186	2	14,238	2,223	3	13,856	2,163	2
Jun-21	13,946	2,183	2	14,190	2,221	3	13,794	2,160	1
Jul-21	13,880	2,174	2	14,132	2,214	3	13,724	2,150	1
Aug-21	13,833	2,166	2	14,092	2,207	3	13,672	2,141	1
Sep-21	13,824	2,165	2	14,091	2,207	3	13,658	2,139	1
Oct-21	13,900	2,166	2	14,177	2,209	3	13,728	2,139	1
Nov-21	13,993	2,176	2	14,281	2,221	3	13,815	2,149	1
Dec-21	14,096	2,195	2	14,395	2,242	3	13,911	2,166	1
Jan-22	14,130	2,198	2	14,438	2,246	3	13,940	2,169	1
Feb-22	14,134	2,202	2	14,451	2,252	3	13,938	2,172	1
Mar-22	14,142	2,201	2	14,468	2,252	3	13,941	2,170	1
Apr-22	14,107	2,195	2	14,441	2,247	3	13,901	2,163	1
May-22	14,083	2,193	2	14,425	2,247	3	13,872	2,161	1
Jun-22	14,011	2,189	2	14,359	2,244	3	13,796	2,156	1
Jul-22	13,959	2,180	2	14,313	2,236	3	13,741	2,146	1
Aug-22	13,901	2,173	2	14,261	2,230	3	13,679	2,139	1
Sep-22	13,888	2,171	2	14,255	2,229	3	13,662	2,136	1
Oct-22	13,977	2,173	2	14,353	2,232	3	13,745	2,137	1
Nov-22	14,065	2,183	2	14,451	2,243	3	13,828	2,147	1
Dec-22	14,168	2,201	2	14,564	2,263	3	13,925	2,164	1
Jan-23	14,209	2,205	2	14,613	2,267	3	13,961	2,166	1
Feb-23	14,205	2,209	2	14,616	2,273	3	13,952	2,170	1

	Roseburg - Expected Growth			Roseburg - High Growth			Roseburg - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-23	14,214	2,209	2	14,633	2,274	3	13,957	2,169	1
Apr-23	14,184	2,202	2	14,609	2,268	3	13,923	2,161	1
May-23	14,150	2,200	2	14,581	2,267	3	13,885	2,159	0
Jun-23	14,081	2,197	2	14,517	2,265	4	13,813	2,155	0
Jul-23	14,030	2,187	2	14,471	2,256	4	13,759	2,145	0
Aug-23	13,966	2,180	2	14,412	2,249	4	13,692	2,137	0
Sep-23	13,959	2,178	2	14,412	2,248	4	13,681	2,135	0
Oct-23	14,047	2,180	2	14,509	2,252	4	13,764	2,136	0
Nov-23	14,133	2,190	2	14,605	2,263	4	13,844	2,145	0
Dec-23	14,240	2,208	2	14,722	2,283	4	13,945	2,162	0
Jan-24	14,279	2,211	2	14,770	2,287	4	13,979	2,164	0
Feb-24	14,274	2,215	2	14,771	2,292	4	13,970	2,168	0
Mar-24	14,286	2,214	2	14,791	2,292	4	13,977	2,166	0
Apr-24	14,253	2,208	2	14,763	2,287	4	13,941	2,159	0
May-24	14,219	2,206	2	14,735	2,286	4	13,904	2,157	0
Jun-24	14,152	2,202	2	14,673	2,283	4	13,834	2,152	0
Jul-24	14,098	2,193	2	14,623	2,274	4	13,777	2,143	0
Aug-24	14,035	2,186	2	14,564	2,268	4	13,712	2,135	0
Sep-24	14,029	2,184	2	14,565	2,267	4	13,702	2,133	0
Oct-24	14,115	2,186	2	14,660	2,270	4	13,782	2,134	0
Nov-24	14,202	2,196	2	14,757	2,282	4	13,863	2,143	0
Dec-24	14,310	2,214	2	14,876	2,301	4	13,965	2,160	0
Jan-25	14,348	2,217	2	14,923	2,305	4	13,998	2,162	0
Feb-25	14,344	2,221	2	14,925	2,310	4	13,990	2,166	0
Mar-25	14,356	2,220	2	14,944	2,310	4	13,998	2,164	0
Apr-25	14,321	2,213	2	14,915	2,304	4	13,960	2,157	0
May-25	14,288	2,211	2	14,887	2,303	5	13,924	2,154	0
Jun-25	14,220	2,208	2	14,823	2,301	5	13,853	2,151	0
Jul-25	14,166	2,199	2	14,773	2,293	5	13,797	2,141	0
Aug-25	14,103	2,191	2	14,713	2,285	5	13,732	2,133	0
Sep-25	14,097	2,190	2	14,713	2,285	5	13,722	2,131	0
Oct-25	14,183	2,191	2	14,809	2,287	5	13,802	2,132	0
Nov-25	14,270	2,201	2	14,907	2,299	5	13,883	2,141	0
Dec-25	14,378	2,220	2	15,026	2,320	5	13,985	2,159	0
Jan-26	14,416	2,222	2	15,072	2,323	5	14,018	2,161	0
Feb-26	14,412	2,225	2	15,074	2,327	5	14,010	2,163	0
Mar-26	14,423	2,225	2	15,092	2,328	5	14,017	2,162	0
Apr-26	14,389	2,218	2	15,063	2,322	5	13,980	2,155	0
May-26	14,356	2,216	2	15,035	2,321	5	13,945	2,153	0
Jun-26	14,287	2,213	2	14,969	2,319	5	13,874	2,149	0

	Roseburg - Expected Growth			Roseburg - High Growth			Roseburg - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jul-26	14,233	2,203	2	14,919	2,309	5	13,818	2,139	0
Aug-26	14,171	2,196	2	14,860	2,303	5	13,754	2,131	0
Sep-26	14,164	2,194	2	14,859	2,302	5	13,744	2,129	0
Oct-26	14,250	2,196	2	14,955	2,305	5	13,823	2,130	0
Nov-26	14,338	2,206	2	15,053	2,316	5	13,905	2,139	0
Dec-26	14,445	2,224	2	15,172	2,336	5	14,005	2,156	0
Jan-27	14,483	2,226	2	15,218	2,339	5	14,039	2,158	0
Feb-27	14,479	2,230	2	15,220	2,344	5	14,031	2,161	0
Mar-27	14,490	2,229	2	15,238	2,344	5	14,038	2,160	0
Apr-27	14,456	2,223	2	15,209	2,339	5	14,001	2,153	0
May-27	14,423	2,221	2	15,180	2,338	6	13,966	2,151	0
Jun-27	14,354	2,217	2	15,114	2,335	6	13,895	2,146	0
Jul-27	14,300	2,208	2	15,063	2,326	6	13,840	2,137	0
Aug-27	14,237	2,200	2	15,003	2,319	6	13,775	2,129	0
Sep-27	14,230	2,199	2	15,001	2,319	6	13,765	2,127	0
Oct-27	14,317	2,200	2	15,099	2,321	6	13,846	2,128	0
Nov-27	14,404	2,210	2	15,197	2,332	6	13,926	2,137	0
Dec-27	14,512	2,229	2	15,317	2,353	6	14,027	2,155	0
Jan-28	14,550	2,231	2	15,363	2,356	6	14,060	2,156	0
Feb-28	14,546	2,234	2	15,365	2,360	6	14,053	2,159	0
Mar-28	14,557	2,234	2	15,383	2,361	6	14,060	2,158	0
Apr-28	14,523	2,227	2	15,353	2,355	6	14,024	2,151	0
May-28	14,489	2,225	2	15,324	2,354	6	13,987	2,148	0
Jun-28	14,421	2,222	2	15,258	2,351	6	13,918	2,145	0
Jul-28	14,367	2,212	2	15,206	2,342	6	13,863	2,135	0
Aug-28	14,304	2,205	2	15,145	2,335	6	13,799	2,128	0
Sep-28	14,297	2,203	2	15,144	2,334	6	13,789	2,125	0
Oct-28	14,383	2,205	2	15,240	2,337	6	13,868	2,127	0
Nov-28	14,470	2,215	2	15,338	2,348	6	13,949	2,136	0
Dec-28	14,577	2,233	2	15,458	2,368	6	14,049	2,153	0
Jan-29	14,615	2,236	2	15,504	2,372	6	14,082	2,154	0
Feb-29	14,611	2,239	2	15,505	2,376	6	14,075	2,156	0
Mar-29	14,623	2,239	2	15,524	2,377	6	14,083	2,156	0
Apr-29	14,588	2,232	2	15,493	2,370	6	14,046	2,149	0
May-29	14,555	2,230	2	15,463	2,369	7	14,011	2,146	0
Jun-29	14,486	2,227	2	15,396	2,366	7	13,941	2,143	0
Jul-29	14,432	2,217	2	15,343	2,357	7	13,886	2,133	0
Aug-29	14,369	2,210	2	15,282	2,350	7	13,823	2,126	0
Sep-29	14,361	2,208	2	15,278	2,349	7	13,812	2,123	0
Oct-29	14,448	2,210	2	15,376	2,352	7	13,893	2,125	0

	Roseburg - Expected Growth			Roseburg - High Growth			Roseburg - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-29	14,535	2,220	2	15,473	2,363	7	13,974	2,134	0
Dec-29	14,642	2,238	2	15,592	2,383	7	14,074	2,151	0
Jan-30	14,680	2,240	2	15,638	2,386	7	14,107	2,152	0
Feb-30	14,675	2,243	2	15,638	2,390	7	14,100	2,155	0
Mar-30	14,686	2,243	2	15,655	2,391	7	14,107	2,154	0
Apr-30	14,652	2,236	2	15,624	2,384	7	14,072	2,147	0
May-30	14,618	2,234	2	15,593	2,383	7	14,036	2,145	0
Jun-30	14,549	2,231	2	15,524	2,380	7	13,967	2,141	0
Jul-30	14,494	2,221	2	15,469	2,370	7	13,912	2,132	0
Aug-30	14,431	2,214	2	15,405	2,363	7	13,850	2,125	0
Sep-30	14,423	2,212	2	15,399	2,361	7	13,840	2,122	0
Oct-30	14,509	2,213	2	15,494	2,363	7	13,921	2,123	0
Nov-30	14,596	2,223	2	15,591	2,374	7	14,003	2,132	0
Dec-30	14,702	2,241	2	15,707	2,394	7	14,103	2,149	0
Jan-31	14,739	2,243	2	15,750	2,397	7	14,136	2,151	0
Feb-31	14,735	2,247	2	15,749	2,402	7	14,131	2,155	0
Mar-31	14,745	2,246	2	15,763	2,401	7	14,138	2,153	0
Apr-31	14,710	2,239	2	15,729	2,394	7	14,103	2,146	0
May-31	14,676	2,237	2	15,696	2,392	8	14,068	2,144	0
Jun-31	14,607	2,234	2	15,625	2,390	8	14,000	2,141	0
Jul-31	14,552	2,224	2	15,569	2,379	8	13,946	2,131	0
Aug-31	14,488	2,217	2	15,503	2,372	8	13,883	2,124	0
Sep-31	14,480	2,215	2	15,497	2,370	8	13,874	2,122	0
Oct-31	14,566	2,216	2	15,592	2,372	8	13,955	2,123	0
Nov-31	14,652	2,226	2	15,687	2,383	8	14,036	2,132	0
Dec-31	14,759	2,244	2	15,804	2,403	8	14,137	2,149	0
Jan-32	14,796	2,246	2	15,846	2,405	8	14,171	2,151	0
Feb-32	14,791	2,250	2	15,843	2,410	8	14,165	2,155	0
Mar-32	14,801	2,249	2	15,857	2,410	8	14,173	2,154	0
Apr-32	14,766	2,242	2	15,822	2,402	8	14,138	2,147	0
May-32	14,732	2,240	2	15,788	2,401	8	14,104	2,145	0
Jun-32	14,662	2,236	2	15,716	2,397	8	14,035	2,141	0
Jul-32	14,607	2,227	2	15,659	2,387	8	13,982	2,132	0
Aug-32	14,543	2,219	2	15,592	2,379	8	13,919	2,124	0
Sep-32	14,535	2,218	2	15,586	2,378	8	13,910	2,123	0
Oct-32	14,621	2,219	2	15,680	2,380	8	13,991	2,124	0
Nov-32	14,707	2,229	2	15,775	2,391	8	14,072	2,133	0
Dec-32	14,813	2,247	2	15,891	2,411	8	14,173	2,150	0
Jan-33	14,851	2,249	2	15,934	2,413	8	14,208	2,152	0
Feb-33	14,846	2,252	2	15,930	2,417	8	14,202	2,155	0

	Roseburg - Expected Growth			Roseburg - High Growth			Roseburg - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-33	14,856	2,251	2	15,943	2,416	8	14,210	2,154	0
Apr-33	14,821	2,245	2	15,908	2,410	8	14,175	2,148	0
May-33	14,786	2,242	2	15,873	2,407	9	14,141	2,145	0
Jun-33	14,716	2,239	2	15,800	2,404	9	14,072	2,141	0
Jul-33	14,661	2,229	2	15,742	2,394	9	14,019	2,132	0
Aug-33	14,597	2,222	2	15,675	2,387	9	13,957	2,125	0
Sep-33	14,589	2,220	2	15,669	2,385	9	13,948	2,123	0
Oct-33	14,675	2,221	2	15,763	2,386	9	14,029	2,124	0
Nov-33	14,761	2,231	2	15,857	2,397	9	14,110	2,133	0
Dec-33	14,867	2,249	2	15,972	2,417	9	14,211	2,150	0
Jan-34	14,904	2,252	2	16,014	2,419	9	14,245	2,152	0
Feb-34	14,899	2,255	2	16,010	2,423	9	14,239	2,155	0
Mar-34	14,909	2,255	2	16,023	2,423	9	14,248	2,155	0
Apr-34	14,874	2,248	2	15,987	2,416	9	14,214	2,148	0
May-34	14,839	2,246	2	15,951	2,414	9	14,179	2,146	0
Jun-34	14,769	2,242	2	15,878	2,410	9	14,111	2,142	0
Jul-34	14,714	2,233	2	15,820	2,401	9	14,058	2,133	0
Aug-34	14,650	2,225	2	15,753	2,392	9	13,996	2,125	0
Sep-34	14,642	2,223	2	15,746	2,390	9	13,987	2,123	0
Oct-34	14,727	2,225	2	15,838	2,393	9	14,068	2,125	0
Nov-34	14,813	2,234	2	15,932	2,402	9	14,149	2,134	0
Dec-34	14,919	2,252	2	16,048	2,422	9	14,250	2,151	0
Jan-35	14,956	2,254	2	16,089	2,425	9	14,284	2,153	0
Feb-35	14,951	2,258	2	16,085	2,429	9	14,279	2,156	0
Mar-35	14,961	2,257	2	16,097	2,428	9	14,287	2,155	0
Apr-35	14,926	2,250	2	16,061	2,421	9	14,253	2,149	0
May-35	14,891	2,248	2	16,025	2,419	10	14,219	2,146	0
Jun-35	14,821	2,244	2	15,951	2,415	10	14,151	2,143	0
Jul-35	14,766	2,235	2	15,893	2,406	10	14,098	2,134	0
Aug-35	14,702	2,227	2	15,826	2,397	10	14,036	2,126	0
Sep-35	14,694	2,225	2	15,818	2,395	10	14,028	2,124	0
Oct-35	14,779	2,227	2	15,911	2,398	10	14,108	2,126	0
Nov-35	14,865	2,236	2	16,005	2,407	10	14,189	2,134	0
Dec-35	14,971	2,254	2	16,121	2,427	10	14,290	2,151	0
Jan-36	15,008	2,256	2	16,162	2,430	10	14,324	2,153	0
Feb-36	15,003	2,260	2	16,158	2,434	10	14,319	2,157	0
Mar-36	15,013	2,259	2	16,170	2,433	10	14,328	2,156	0
Apr-36	14,978	2,252	2	16,134	2,426	10	14,293	2,149	0
May-36	14,943	2,250	2	16,097	2,424	10	14,259	2,147	0
Jun-36	14,873	2,246	2	16,023	2,420	10	14,192	2,143	0
Jul-36	14,818	2,237	2	15,965	2,410	10	14,138	2,135	0

	Roseburg - Expected Growth			Roseburg - High Growth			Roseburg - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Aug-36	14,754	2,229	2	15,898	2,402	10	14,077	2,127	0
Sep-36	14,745	2,227	2	15,889	2,400	10	14,067	2,125	0
Oct-36	14,831	2,229	2	15,983	2,402	10	14,149	2,127	0
Nov-36	14,917	2,238	2	16,078	2,412	10	14,230	2,135	0
Dec-36	15,023	2,257	2	16,193	2,433	10	14,330	2,153	0
Jan-37	15,060	2,259	2	16,234	2,435	10	14,365	2,154	0
Feb-37	15,055	2,263	2	16,230	2,439	10	14,359	2,158	0
Mar-37	15,065	2,262	2	16,242	2,438	10	14,368	2,157	0
Apr-37	15,029	2,255	2	16,205	2,431	10	14,333	2,150	0
May-37	14,994	2,253	2	16,169	2,429	11	14,299	2,148	0
Jun-37	14,924	2,249	2	16,094	2,425	11	14,231	2,144	0
Jul-37	14,869	2,240	2	16,037	2,415	11	14,178	2,135	0
Aug-37	14,806	2,232	2	15,971	2,407	11	14,117	2,128	0
Sep-37	14,797	2,230	2	15,963	2,405	11	14,107	2,126	0
Oct-37	14,883	2,232	2	16,058	2,408	11	14,188	2,127	0
Nov-37	14,969	2,242	2	16,153	2,419	11	14,269	2,137	0
Dec-37	15,075	2,260	2	16,269	2,438	11	14,369	2,154	0
Jan-38	15,112	2,262	2	16,311	2,441	11	14,403	2,156	0
Feb-38	15,107	2,265	2	16,307	2,445	11	14,397	2,158	0
Mar-38	15,117	2,264	2	16,320	2,444	11	14,406	2,157	0
Apr-38	15,082	2,257	2	16,284	2,437	11	14,371	2,150	0
May-38	15,048	2,255	2	16,250	2,435	11	14,338	2,148	0
Jun-38	14,978	2,252	2	16,176	2,432	11	14,270	2,145	0
Jul-38	14,923	2,242	2	16,119	2,421	11	14,216	2,136	0
Aug-38	14,859	2,235	2	16,052	2,414	11	14,154	2,129	0
Sep-38	14,851	2,233	2	16,045	2,412	11	14,145	2,127	0
Oct-38	14,937	2,234	2	16,141	2,414	11	14,226	2,127	0
Nov-38	15,023	2,244	2	16,236	2,425	11	14,307	2,137	0
Dec-38	15,129	2,262	2	16,353	2,445	11	14,406	2,154	0
Jan-39	15,166	2,264	2	16,395	2,448	11	14,440	2,156	0
Feb-39	15,161	2,267	2	16,392	2,451	11	14,434	2,158	0
Mar-39	15,171	2,267	2	16,405	2,451	11	14,442	2,158	0
Apr-39	15,136	2,260	2	16,369	2,444	11	14,408	2,151	0
May-39	15,102	2,258	2	16,335	2,442	12	14,374	2,149	0
Jun-39	15,032	2,254	2	16,261	2,438	12	14,306	2,145	0
Jul-39	14,977	2,245	2	16,204	2,429	12	14,253	2,137	0
Aug-39	14,913	2,237	2	16,136	2,421	12	14,191	2,129	0
Sep-39	14,905	2,235	2	16,130	2,419	12	14,182	2,127	0
Oct-39	14,991	2,237	2	16,225	2,421	12	14,263	2,128	0
Nov-39	15,077	2,246	2	16,320	2,431	12	14,344	2,137	0
Dec-39	15,183	2,265	2	16,436	2,452	12	14,444	2,155	0

	Roseburg - Expected Growth			Roseburg - High Growth			Roseburg - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jan-40	15,220	2,266	2	16,478	2,454	12	14,478	2,156	0
Feb-40	15,215	2,270	2	16,475	2,458	12	14,472	2,160	0
Mar-40	15,225	2,269	2	16,488	2,458	12	14,480	2,158	0
Apr-40	15,190	2,262	2	16,452	2,450	12	14,446	2,152	0
May-40	15,155	2,260	2	16,416	2,448	12	14,412	2,150	0
Jun-40	15,085	2,256	2	16,342	2,444	12	14,344	2,146	0
Jul-40	15,030	2,247	2	16,284	2,435	12	14,291	2,137	0
Aug-40	14,966	2,239	2	16,216	2,426	12	14,229	2,129	0
Sep-40	14,958	2,238	2	16,209	2,426	12	14,221	2,128	0
Oct-40	15,043	2,239	2	16,302	2,427	12	14,301	2,129	0

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION KLAMATH FALLS

	Klamath Falls - Expected Growth			Klamath Falls - High Growth			Klamath Falls - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-19	15,093	1,780	6	15,093	1,780	6	15,093	1,780	6
Dec-19	15,192	1,787	6	15,192	1,787	6	15,192	1,787	6
Jan-20	15,173	1,783	6	15,173	1,783	6	15,173	1,783	6
Feb-20	15,203	1,793	6	15,203	1,793	6	15,203	1,793	6
Mar-20	15,200	1,795	6	15,200	1,795	6	15,200	1,795	6
Apr-20	15,199	1,791	6	15,199	1,791	6	15,199	1,791	6
May-20	15,227	1,787	6	15,227	1,787	6	15,227	1,787	6
Jun-20	15,157	1,780	6	15,383	1,807	6	14,880	1,748	6
Jul-20	15,093	1,778	6	15,333	1,807	6	14,799	1,744	6
Aug-20	15,024	1,774	6	15,277	1,804	6	14,713	1,738	6
Sep-20	15,012	1,769	6	15,280	1,801	6	14,684	1,731	6
Oct-20	15,143	1,775	6	15,428	1,809	6	14,794	1,735	6
Nov-20	15,262	1,785	6	15,564	1,821	6	14,892	1,742	6
Dec-20	15,368	1,793	6	15,688	1,831	6	14,978	1,748	6
Jan-21	15,429	1,806	6	15,765	1,845	6	15,019	1,758	6
Feb-21	15,444	1,809	6	15,796	1,850	6	15,015	1,758	6
Mar-21	15,449	1,805	6	15,816	1,847	6	15,002	1,752	6
Apr-21	15,430	1,800	6	15,812	1,844	6	14,965	1,745	6
May-21	15,402	1,796	6	15,799	1,842	7	14,920	1,739	6
Jun-21	15,323	1,793	6	15,733	1,840	7	14,826	1,734	5
Jul-21	15,237	1,786	6	15,657	1,835	7	14,728	1,726	5
Aug-21	15,167	1,780	6	15,598	1,830	7	14,645	1,718	5
Sep-21	15,161	1,777	6	15,604	1,828	7	14,625	1,714	5
Oct-21	15,305	1,784	6	15,765	1,837	7	14,749	1,719	5
Nov-21	15,441	1,794	6	15,917	1,849	7	14,865	1,727	5
Dec-21	15,552	1,806	6	16,045	1,863	7	14,957	1,736	5
Jan-22	15,617	1,818	6	16,125	1,877	7	15,005	1,747	5
Feb-22	15,628	1,821	6	16,149	1,882	7	15,001	1,748	5
Mar-22	15,625	1,819	6	16,159	1,881	7	14,983	1,744	5
Apr-22	15,597	1,814	6	16,142	1,878	7	14,941	1,738	5
May-22	15,561	1,810	6	16,118	1,875	7	14,892	1,732	5
Jun-22	15,478	1,805	6	16,045	1,871	7	14,798	1,726	5
Jul-22	15,390	1,797	6	15,963	1,864	7	14,703	1,717	5
Aug-22	15,321	1,792	6	15,900	1,860	7	14,627	1,711	5
Sep-22	15,318	1,790	6	15,906	1,859	7	14,613	1,708	5
Oct-22	15,463	1,797	6	16,066	1,867	7	14,741	1,713	5
Nov-22	15,600	1,808	6	16,218	1,880	7	14,861	1,723	5
Dec-22	15,710	1,819	6	16,341	1,892	7	14,955	1,732	5
Jan-23	15,772	1,832	6	16,415	1,907	7	15,003	1,743	5
Feb-23	15,780	1,835	6	16,433	1,911	7	15,000	1,745	5

	Klamath Falls - Expected Growth			Klamath Falls - High Growth			Klamath Falls - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-23	15,773	1,833	6	16,435	1,910	7	14,983	1,741	5
Apr-23	15,742	1,828	6	16,412	1,906	7	14,943	1,735	5
May-23	15,703	1,823	6	16,381	1,902	8	14,895	1,729	4
Jun-23	15,619	1,818	6	16,302	1,898	8	14,805	1,724	4
Jul-23	15,531	1,811	6	16,218	1,891	8	14,713	1,716	4
Aug-23	15,462	1,806	6	16,153	1,887	8	14,639	1,710	4
Sep-23	15,459	1,803	6	16,158	1,885	8	14,628	1,706	4
Oct-23	15,604	1,811	6	16,317	1,894	8	14,757	1,713	4
Nov-23	15,740	1,821	6	16,467	1,905	8	14,877	1,721	4
Dec-23	15,849	1,832	6	16,588	1,918	8	14,971	1,731	4
Jan-24	15,910	1,846	6	16,660	1,933	8	15,020	1,742	4
Feb-24	15,917	1,849	6	16,675	1,937	8	15,018	1,744	4
Mar-24	15,908	1,846	6	16,673	1,935	8	15,001	1,740	4
Apr-24	15,876	1,841	6	16,647	1,930	8	14,962	1,735	4
May-24	15,837	1,837	6	16,614	1,927	8	14,916	1,730	4
Jun-24	15,752	1,831	6	16,533	1,922	8	14,828	1,723	4
Jul-24	15,664	1,824	6	16,446	1,915	8	14,738	1,716	4
Aug-24	15,594	1,819	6	16,379	1,910	8	14,665	1,710	4
Sep-24	15,590	1,817	6	16,381	1,909	8	14,655	1,708	4
Oct-24	15,734	1,824	6	16,538	1,917	8	14,783	1,714	4
Nov-24	15,870	1,834	6	16,688	1,928	8	14,904	1,722	4
Dec-24	15,978	1,846	6	16,807	1,942	8	14,999	1,733	4
Jan-25	16,038	1,858	6	16,877	1,955	8	15,048	1,743	4
Feb-25	16,044	1,861	6	16,889	1,959	8	15,047	1,745	4
Mar-25	16,035	1,858	6	16,886	1,957	8	15,031	1,742	4
Apr-25	16,002	1,853	6	16,858	1,952	8	14,993	1,736	4
May-25	15,962	1,849	6	16,822	1,949	9	14,949	1,732	3
Jun-25	15,877	1,843	6	16,738	1,943	9	14,862	1,725	3
Jul-25	15,788	1,836	6	16,649	1,936	9	14,774	1,718	3
Aug-25	15,717	1,831	6	16,579	1,931	9	14,702	1,713	3
Sep-25	15,713	1,829	6	16,580	1,930	9	14,693	1,710	3
Oct-25	15,857	1,836	6	16,736	1,938	9	14,823	1,716	3
Nov-25	15,992	1,847	6	16,884	1,950	9	14,943	1,726	3
Dec-25	16,099	1,858	6	17,001	1,962	9	15,038	1,736	3
Jan-26	16,158	1,870	6	17,069	1,975	9	15,088	1,746	3
Feb-26	16,164	1,873	6	17,080	1,979	9	15,088	1,748	3
Mar-26	16,154	1,870	6	17,074	1,976	9	15,073	1,745	3
Apr-26	16,120	1,865	6	17,043	1,972	9	15,036	1,740	3
May-26	16,080	1,861	6	17,005	1,968	9	14,994	1,735	3
Jun-26	15,993	1,855	6	16,918	1,962	9	14,907	1,729	3

	Klamath Falls - Expected Growth			Klamath Falls - High Growth			Klamath Falls - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jul-26	15,904	1,848	6	16,828	1,955	9	14,820	1,722	3
Aug-26	15,833	1,843	6	16,756	1,950	9	14,750	1,717	3
Sep-26	15,828	1,841	6	16,754	1,949	9	14,742	1,715	3
Oct-26	15,971	1,848	6	16,909	1,956	9	14,871	1,721	3
Nov-26	16,106	1,858	6	17,056	1,967	9	14,993	1,730	3
Dec-26	16,213	1,870	6	17,173	1,981	9	15,089	1,740	3
Jan-27	16,271	1,882	6	17,238	1,993	9	15,139	1,751	3
Feb-27	16,276	1,885	6	17,247	1,997	9	15,139	1,753	3
Mar-27	16,265	1,882	6	17,239	1,994	9	15,125	1,750	3
Apr-27	16,232	1,877	6	17,207	1,989	9	15,090	1,745	3
May-27	16,190	1,873	6	17,166	1,985	9	15,047	1,740	2
Jun-27	16,104	1,867	6	17,079	1,980	10	14,963	1,734	2
Jul-27	16,014	1,860	6	16,986	1,972	10	14,877	1,728	2
Aug-27	15,942	1,855	6	16,912	1,967	10	14,807	1,723	2
Sep-27	15,937	1,852	6	16,909	1,964	10	14,800	1,719	2
Oct-27	16,079	1,860	6	17,062	1,973	10	14,929	1,727	2
Nov-27	16,213	1,870	6	17,207	1,984	10	15,051	1,736	2
Dec-27	16,320	1,881	6	17,323	1,996	10	15,147	1,745	2
Jan-28	16,378	1,893	6	17,387	2,010	10	15,198	1,757	2
Feb-28	16,382	1,896	6	17,394	2,013	10	15,199	1,759	2
Mar-28	16,371	1,893	6	17,385	2,010	10	15,186	1,756	2
Apr-28	16,337	1,888	6	17,351	2,005	10	15,152	1,751	2
May-28	16,295	1,884	6	17,309	2,001	10	15,110	1,747	2
Jun-28	16,208	1,878	6	17,219	1,995	10	15,027	1,741	2
Jul-28	16,118	1,871	6	17,125	1,988	10	14,942	1,735	2
Aug-28	16,045	1,866	6	17,049	1,983	10	14,872	1,730	2
Sep-28	16,040	1,863	6	17,046	1,980	10	14,866	1,727	2
Oct-28	16,182	1,870	6	17,198	1,987	10	14,996	1,733	2
Nov-28	16,315	1,881	6	17,341	1,999	10	15,117	1,743	2
Dec-28	16,421	1,892	6	17,455	2,011	10	15,214	1,753	2
Jan-29	16,479	1,904	6	17,519	2,024	10	15,266	1,763	2
Feb-29	16,483	1,907	6	17,525	2,027	10	15,268	1,766	2
Mar-29	16,472	1,905	6	17,515	2,025	10	15,256	1,764	2
Apr-29	16,437	1,900	6	17,479	2,020	10	15,221	1,759	2
May-29	16,395	1,895	6	17,436	2,015	11	15,181	1,754	1
Jun-29	16,307	1,889	6	17,344	2,009	11	15,098	1,748	1
Jul-29	16,216	1,882	6	17,247	2,001	11	15,013	1,742	1
Aug-29	16,143	1,877	6	17,170	1,996	11	14,945	1,737	1
Sep-29	16,137	1,875	6	17,163	1,994	11	14,940	1,735	1
Oct-29	16,279	1,882	6	17,315	2,001	11	15,071	1,742	1

	Klamath Falls - Expected Growth			Klamath Falls - High Growth			Klamath Falls - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-29	16,411	1,892	6	17,455	2,012	11	15,193	1,751	1
Dec-29	16,517	1,904	6	17,568	2,025	11	15,291	1,762	1
Jan-30	16,574	1,915	6	17,629	2,037	11	15,344	1,773	1
Feb-30	16,577	1,918	6	17,632	2,040	11	15,347	1,776	1
Mar-30	16,565	1,915	6	17,619	2,037	11	15,335	1,773	1
Apr-30	16,529	1,910	6	17,581	2,031	11	15,302	1,768	1
May-30	16,486	1,905	6	17,536	2,026	11	15,262	1,763	1
Jun-30	16,398	1,900	6	17,442	2,021	11	15,180	1,759	1
Jul-30	16,307	1,893	6	17,347	2,014	11	15,096	1,752	1
Aug-30	16,234	1,888	6	17,271	2,008	11	15,028	1,748	1
Sep-30	16,227	1,885	6	17,265	2,005	11	15,021	1,745	1
Oct-30	16,369	1,892	6	17,418	2,013	11	15,152	1,751	1
Nov-30	16,501	1,903	6	17,560	2,025	11	15,274	1,761	1
Dec-30	16,606	1,914	6	17,673	2,037	11	15,371	1,772	1
Jan-31	16,663	1,925	6	17,735	2,049	11	15,424	1,782	1
Feb-31	16,666	1,928	6	17,740	2,053	11	15,426	1,785	1
Mar-31	16,654	1,925	6	17,729	2,050	11	15,415	1,782	1
Apr-31	16,618	1,920	6	17,692	2,045	11	15,381	1,777	1
May-31	16,575	1,916	6	17,648	2,040	12	15,341	1,774	0
Jun-31	16,486	1,910	6	17,555	2,034	12	15,258	1,768	0
Jul-31	16,395	1,903	6	17,459	2,027	12	15,174	1,762	0
Aug-31	16,322	1,898	6	17,382	2,022	12	15,106	1,757	0
Sep-31	16,316	1,895	6	17,377	2,019	12	15,100	1,754	0
Oct-31	16,457	1,902	6	17,528	2,026	12	15,231	1,761	0
Nov-31	16,590	1,913	6	17,671	2,038	12	15,354	1,771	0
Dec-31	16,695	1,924	6	17,783	2,050	12	15,451	1,781	0
Jan-32	16,752	1,936	6	17,845	2,062	12	15,503	1,792	0
Feb-32	16,755	1,940	6	17,849	2,067	12	15,506	1,795	0
Mar-32	16,742	1,937	6	17,836	2,064	12	15,494	1,792	0
Apr-32	16,707	1,932	6	17,800	2,058	12	15,461	1,788	0
May-32	16,664	1,927	6	17,755	2,053	12	15,421	1,783	0
Jun-32	16,575	1,921	6	17,661	2,047	12	15,338	1,778	0
Jul-32	16,484	1,914	6	17,566	2,040	12	15,254	1,771	0
Aug-32	16,411	1,909	6	17,489	2,034	12	15,186	1,766	0
Sep-32	16,405	1,907	6	17,484	2,032	12	15,180	1,765	0
Oct-32	16,546	1,914	6	17,636	2,040	12	15,311	1,771	0
Nov-32	16,679	1,924	6	17,779	2,051	12	15,433	1,780	0
Dec-32	16,784	1,936	6	17,892	2,064	12	15,530	1,791	0
Jan-33	16,840	1,948	6	17,954	2,076	12	15,582	1,802	0
Feb-33	16,843	1,951	6	17,958	2,080	12	15,584	1,805	0

	Klamath Falls - Expected Growth			Klamath Falls - High Growth			Klamath Falls - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-33	16,831	1,948	6	17,947	2,077	12	15,573	1,802	0
Apr-33	16,796	1,943	6	17,911	2,072	12	15,540	1,797	0
May-33	16,752	1,938	6	17,865	2,066	13	15,499	1,793	0
Jun-33	16,664	1,933	6	17,773	2,061	13	15,418	1,788	0
Jul-33	16,573	1,926	6	17,678	2,054	13	15,333	1,782	0
Aug-33	16,500	1,921	6	17,602	2,049	13	15,265	1,777	0
Sep-33	16,493	1,918	6	17,596	2,046	13	15,258	1,774	0
Oct-33	16,634	1,925	6	17,748	2,054	13	15,389	1,780	0
Nov-33	16,767	1,936	6	17,892	2,065	13	15,511	1,791	0
Dec-33	16,872	1,947	6	18,006	2,077	13	15,608	1,801	0
Jan-34	16,928	1,958	6	18,067	2,090	13	15,660	1,811	0
Feb-34	16,931	1,961	6	18,073	2,093	13	15,662	1,814	0
Mar-34	16,919	1,958	6	18,062	2,090	13	15,651	1,811	0
Apr-34	16,883	1,953	6	18,025	2,085	13	15,617	1,807	0
May-34	16,840	1,949	6	17,981	2,081	13	15,577	1,803	0
Jun-34	16,752	1,943	6	17,889	2,075	13	15,495	1,797	0
Jul-34	16,660	1,936	6	17,794	2,068	13	15,409	1,791	0
Aug-34	16,587	1,931	6	17,720	2,063	13	15,341	1,786	0
Sep-34	16,580	1,928	6	17,716	2,060	13	15,334	1,783	0
Oct-34	16,721	1,935	6	17,870	2,068	13	15,464	1,790	0
Nov-34	16,853	1,946	6	18,015	2,080	13	15,585	1,800	0
Dec-34	16,958	1,957	6	18,131	2,093	13	15,681	1,810	0
Jan-35	17,015	1,969	6	18,196	2,105	13	15,733	1,821	0
Feb-35	17,017	1,972	6	18,202	2,109	13	15,735	1,823	0
Mar-35	17,005	1,970	6	18,192	2,107	13	15,723	1,821	0
Apr-35	16,969	1,964	6	18,158	2,101	13	15,689	1,816	0
May-35	16,926	1,960	6	18,115	2,098	13	15,648	1,812	0
Jun-35	16,837	1,954	6	18,024	2,092	14	15,565	1,806	0
Jul-35	16,745	1,947	6	17,929	2,084	14	15,480	1,800	0
Aug-35	16,672	1,942	6	17,854	2,079	14	15,412	1,795	0
Sep-35	16,665	1,939	6	17,849	2,077	14	15,405	1,792	0
Oct-35	16,807	1,947	6	18,005	2,086	14	15,535	1,800	0
Nov-35	16,939	1,957	6	18,150	2,097	14	15,657	1,809	0
Dec-35	17,044	1,968	6	18,265	2,109	14	15,753	1,819	0
Jan-36	17,100	1,979	6	18,329	2,122	14	15,804	1,829	0
Feb-36	17,103	1,983	6	18,335	2,126	14	15,806	1,833	0
Mar-36	17,090	1,980	6	18,325	2,124	14	15,794	1,830	0
Apr-36	17,055	1,975	6	18,291	2,119	14	15,761	1,826	0
May-36	17,011	1,970	6	18,247	2,114	14	15,719	1,821	0
Jun-36	16,923	1,965	6	18,156	2,109	14	15,638	1,816	0
Jul-36	16,831	1,958	6	18,060	2,101	14	15,552	1,810	0

	Klamath Falls - Expected Growth			Klamath Falls - High Growth			Klamath Falls - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Aug-36	16,758	1,952	6	17,984	2,095	14	15,484	1,804	0
Sep-36	16,751	1,950	6	17,980	2,093	14	15,477	1,802	0
Oct-36	16,892	1,957	6	18,134	2,101	14	15,607	1,809	0
Nov-36	17,025	1,967	6	18,279	2,112	14	15,729	1,818	0
Dec-36	17,130	1,979	6	18,395	2,126	14	15,826	1,829	0
Jan-37	17,186	1,991	6	18,458	2,138	14	15,877	1,839	0
Feb-37	17,189	1,994	6	18,464	2,142	14	15,879	1,842	0
Mar-37	17,177	1,991	6	18,454	2,139	14	15,868	1,839	0
Apr-37	17,141	1,986	6	18,418	2,134	14	15,834	1,835	0
May-37	17,098	1,982	6	18,375	2,130	14	15,793	1,831	0
Jun-37	17,009	1,976	6	18,282	2,124	15	15,711	1,825	0
Jul-37	16,918	1,969	6	18,185	2,117	15	15,627	1,819	0
Aug-37	16,845	1,964	6	18,107	2,111	15	15,559	1,814	0
Sep-37	16,838	1,961	6	18,101	2,108	15	15,552	1,811	0
Oct-37	16,980	1,968	6	18,254	2,116	15	15,683	1,818	0
Nov-37	17,112	1,979	6	18,397	2,128	15	15,805	1,828	0
Dec-37	17,218	1,990	6	18,512	2,140	15	15,903	1,838	0
Jan-38	17,274	2,002	6	18,573	2,152	15	15,954	1,849	0
Feb-38	17,278	2,005	6	18,578	2,156	15	15,958	1,852	0
Mar-38	17,265	2,002	6	18,565	2,152	15	15,946	1,849	0
Apr-38	17,230	1,997	6	18,528	2,147	15	15,913	1,844	0
May-38	17,187	1,993	6	18,483	2,143	15	15,873	1,840	0
Jun-38	17,098	1,987	6	18,388	2,137	15	15,791	1,835	0
Jul-38	17,008	1,980	6	18,288	2,129	15	15,709	1,828	0
Aug-38	16,935	1,975	6	18,207	2,123	15	15,642	1,824	0
Sep-38	16,929	1,972	6	18,198	2,119	15	15,637	1,821	0
Oct-38	17,071	1,980	6	18,347	2,128	15	15,768	1,829	0
Nov-38	17,204	1,990	6	18,487	2,138	15	15,892	1,838	0
Dec-38	17,310	2,001	6	18,598	2,150	15	15,990	1,848	0
Jan-39	17,367	2,012	6	18,657	2,162	15	16,043	1,859	0
Feb-39	17,370	2,016	6	18,657	2,166	15	16,047	1,863	0
Mar-39	17,359	2,013	6	18,642	2,162	15	16,037	1,860	0
Apr-39	17,324	2,008	6	18,602	2,157	15	16,005	1,855	0
May-39	17,281	2,003	6	18,553	2,151	15	15,966	1,851	0
Jun-39	17,193	1,998	6	18,456	2,145	16	15,885	1,846	0
Jul-39	17,102	1,991	6	18,357	2,138	16	15,801	1,840	0
Aug-39	17,029	1,986	6	18,278	2,132	16	15,734	1,835	0
Sep-39	17,023	1,983	6	18,271	2,129	16	15,729	1,833	0
Oct-39	17,165	1,990	6	18,422	2,136	16	15,860	1,839	0
Nov-39	17,298	2,001	6	18,564	2,148	16	15,983	1,849	0
Dec-39	17,403	2,012	6	18,676	2,160	16	16,080	1,859	0

	Klamath Falls - Expected Growth			Klamath Falls - High Growth			Klamath Falls - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jan-40	17,460	2,024	6	18,736	2,172	16	16,133	1,870	0
Feb-40	17,463	2,027	6	18,738	2,175	16	16,136	1,873	0
Mar-40	17,451	2,024	6	18,725	2,172	16	16,125	1,870	0
Apr-40	17,416	2,019	6	18,686	2,166	16	16,093	1,866	0
May-40	17,373	2,015	6	18,639	2,162	16	16,053	1,862	0
Jun-40	17,285	2,009	6	18,544	2,155	16	15,972	1,856	0
Jul-40	17,194	2,002	6	18,447	2,148	16	15,888	1,850	0
Aug-40	17,121	1,997	6	18,370	2,143	16	15,820	1,845	0
Sep-40	17,114	1,994	6	18,363	2,140	16	15,814	1,842	0
Oct-40	17,256	2,001	6	18,517	2,147	16	15,945	1,849	0

APPENDIX 2.2: CUSTOMER FORECASTS BY REGION
LA GRANDE

	La Grande - Expected Growth			La Grande - High Growth			La Grande - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-19	6,772	937	2	6,772	937	2	6,772	937	2
Dec-19	6,794	943	2	6,794	943	2	6,794	943	2
Jan-20	6,801	933	1	6,801	933	1	6,801	933	1
Feb-20	6,795	934	1	6,795	934	1	6,795	934	1
Mar-20	6,801	933	1	6,801	933	1	6,801	933	1
Apr-20	6,781	937	1	6,781	937	1	6,781	937	1
May-20	6,773	936	2	6,773	936	2	6,773	936	2
Jun-20	6,761	931	2	6,821	939	3	6,681	920	2
Jul-20	6,722	926	2	6,786	935	3	6,637	914	2
Aug-20	6,718	930	3	6,786	939	5	6,627	917	4
Sep-20	6,707	929	6	6,780	939	6	6,611	915	5
Oct-20	6,751	928	4	6,829	939	3	6,648	914	2
Nov-20	6,810	928	3	6,893	939	3	6,701	913	2
Dec-20	6,837	935	2	6,925	947	3	6,721	919	2
Jan-21	6,854	943	1	6,946	956	2	6,732	926	1
Feb-21	6,847	941	1	6,944	955	2	6,719	924	1
Mar-21	6,839	941	1	6,940	955	2	6,706	922	1
Apr-21	6,823	939	1	6,929	954	2	6,684	920	1
May-21	6,814	940	1	6,924	955	3	6,669	920	2
Jun-21	6,792	938	2	6,906	953	3	6,642	917	1
Jul-21	6,752	933	2	6,870	949	3	6,598	911	1
Aug-21	6,742	932	3	6,864	948	5	6,582	910	3
Sep-21	6,734	931	6	6,860	948	6	6,569	908	4
Oct-21	6,781	934	5	6,912	952	3	6,610	911	1
Nov-21	6,847	934	3	6,983	953	3	6,669	910	1
Dec-21	6,882	940	2	7,023	960	3	6,697	915	1
Jan-22	6,902	942	1	7,048	962	2	6,711	916	0
Feb-22	6,897	948	1	7,047	968	2	6,701	921	0
Mar-22	6,886	946	1	7,040	967	2	6,685	919	0
Apr-22	6,869	945	1	7,027	966	2	6,663	916	0
May-22	6,857	942	2	7,019	965	3	6,646	913	1
Jun-22	6,830	941	2	6,996	964	4	6,614	911	1
Jul-22	6,787	938	2	6,955	961	4	6,568	908	1
Aug-22	6,773	937	3	6,945	961	6	6,550	907	3
Sep-22	6,765	934	6	6,940	959	7	6,537	903	4
Oct-22	6,815	937	5	6,995	962	4	6,581	905	1
Nov-22	6,884	939	3	7,070	964	4	6,643	906	1
Dec-22	6,923	946	2	7,114	972	4	6,676	912	1
Jan-23	6,947	947	1	7,142	974	3	6,694	913	0
Feb-23	6,943	950	1	7,142	977	3	6,685	914	0

	La Grande - Expected Growth			La Grande - High Growth			La Grande - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-23	6,932	951	1	7,134	979	3	6,670	915	0
Apr-23	6,914	949	1	7,119	978	3	6,648	913	0
May-23	6,899	948	1	7,108	976	4	6,629	910	1
Jun-23	6,869	945	2	7,081	974	4	6,595	907	0
Jul-23	6,824	942	2	7,038	971	4	6,547	904	0
Aug-23	6,807	942	3	7,024	972	6	6,527	903	2
Sep-23	6,800	940	6	7,020	970	7	6,515	900	3
Oct-23	6,851	942	5	7,077	973	4	6,560	902	0
Nov-23	6,921	943	3	7,153	974	4	6,622	902	0
Dec-23	6,963	950	2	7,200	983	4	6,658	909	0
Jan-24	6,988	952	1	7,229	985	3	6,677	910	0
Feb-24	6,986	955	1	7,231	988	3	6,671	912	0
Mar-24	6,974	954	1	7,222	988	3	6,655	911	0
Apr-24	6,956	954	1	7,207	988	3	6,633	910	0
May-24	6,940	952	1	7,194	987	4	6,613	907	0
Jun-24	6,908	950	2	7,165	985	5	6,578	904	0
Jul-24	6,862	946	2	7,121	981	5	6,530	900	0
Aug-24	6,844	946	3	7,106	982	7	6,508	900	2
Sep-24	6,837	944	6	7,102	981	8	6,497	897	3
Oct-24	6,888	946	5	7,158	984	5	6,541	899	0
Nov-24	6,959	947	3	7,236	985	5	6,605	899	0
Dec-24	7,002	954	2	7,284	993	5	6,641	905	0
Jan-25	7,028	957	1	7,315	996	4	6,661	907	0
Feb-25	7,026	959	1	7,316	999	4	6,655	909	0
Mar-25	7,015	959	1	7,309	999	4	6,640	908	0
Apr-25	6,996	958	1	7,292	998	4	6,617	906	0
May-25	6,980	956	1	7,279	998	5	6,598	904	0
Jun-25	6,947	954	2	7,249	995	5	6,562	901	0
Jul-25	6,900	950	2	7,203	992	5	6,514	897	0
Aug-25	6,882	950	3	7,188	993	7	6,493	897	1
Sep-25	6,874	948	6	7,183	991	8	6,481	894	2
Oct-25	6,926	951	5	7,241	994	5	6,526	896	0
Nov-25	6,997	952	3	7,318	995	5	6,588	896	0
Dec-25	7,041	959	2	7,368	1,003	5	6,625	902	0
Jan-26	7,067	961	1	7,399	1,006	4	6,646	903	0
Feb-26	7,066	963	1	7,401	1,009	4	6,640	905	0
Mar-26	7,055	964	1	7,393	1,010	4	6,626	905	0
Apr-26	7,036	962	1	7,377	1,009	4	6,604	903	0
May-26	7,020	961	1	7,364	1,008	5	6,584	901	0
Jun-26	6,987	958	2	7,333	1,006	6	6,549	898	0

	La Grande - Expected Growth			La Grande - High Growth			La Grande - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jul-26	6,939	955	2	7,286	1,003	6	6,500	894	0
Aug-26	6,921	955	3	7,270	1,003	8	6,479	894	1
Sep-26	6,913	953	6	7,265	1,001	9	6,467	891	2
Oct-26	6,964	955	5	7,322	1,004	6	6,511	893	0
Nov-26	7,036	956	3	7,402	1,006	6	6,574	893	0
Dec-26	7,079	963	2	7,450	1,014	6	6,610	899	0
Jan-27	7,106	965	1	7,482	1,016	5	6,631	901	0
Feb-27	7,105	968	1	7,485	1,020	5	6,626	903	0
Mar-27	7,094	968	1	7,477	1,020	5	6,612	902	0
Apr-27	7,075	967	1	7,460	1,019	5	6,590	900	0
May-27	7,059	965	1	7,447	1,018	6	6,571	898	0
Jun-27	7,025	963	2	7,414	1,016	6	6,535	895	0
Jul-27	6,978	959	2	7,368	1,013	6	6,487	892	0
Aug-27	6,959	959	3	7,352	1,013	8	6,466	891	0
Sep-27	6,951	957	6	7,347	1,011	9	6,454	889	1
Oct-27	7,002	959	5	7,404	1,014	6	6,497	890	0
Nov-27	7,074	960	3	7,483	1,016	6	6,560	891	0
Dec-27	7,118	967	2	7,533	1,024	6	6,597	897	0
Jan-28	7,144	970	1	7,565	1,027	5	6,617	898	0
Feb-28	7,144	972	1	7,568	1,030	5	6,613	900	0
Mar-28	7,132	972	1	7,559	1,030	5	6,598	899	0
Apr-28	7,114	971	1	7,543	1,030	5	6,577	898	0
May-28	7,097	969	1	7,529	1,028	6	6,557	896	0
Jun-28	7,064	967	2	7,497	1,026	7	6,523	893	0
Jul-28	7,016	963	2	7,450	1,023	7	6,474	889	0
Aug-28	6,998	964	3	7,434	1,024	9	6,454	889	0
Sep-28	6,989	961	6	7,428	1,022	10	6,441	886	1
Oct-28	7,041	964	5	7,486	1,025	7	6,485	888	0
Nov-28	7,112	965	3	7,565	1,026	7	6,547	888	0
Dec-28	7,156	972	2	7,616	1,034	7	6,583	894	0
Jan-29	7,183	974	1	7,648	1,037	6	6,604	895	0
Feb-29	7,182	977	1	7,650	1,040	6	6,599	897	0
Mar-29	7,171	977	1	7,642	1,041	6	6,585	897	0
Apr-29	7,153	975	1	7,626	1,040	6	6,565	895	0
May-29	7,136	974	1	7,612	1,039	7	6,545	893	0
Jun-29	7,103	971	2	7,580	1,037	7	6,511	890	0
Jul-29	7,055	968	2	7,532	1,033	7	6,463	887	0
Aug-29	7,036	968	3	7,515	1,034	9	6,441	886	0
Sep-29	7,028	966	6	7,511	1,032	10	6,430	883	0
Oct-29	7,079	968	6	7,569	1,035	7	6,472	885	0

	La Grande - Expected Growth			La Grande - High Growth			La Grande - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Nov-29	7,151	969	3	7,649	1,037	7	6,534	885	0
Dec-29	7,195	976	2	7,700	1,045	7	6,570	891	0
Jan-30	7,222	978	1	7,733	1,047	6	6,590	893	0
Feb-30	7,221	981	1	7,735	1,051	6	6,585	895	0
Mar-30	7,210	981	1	7,727	1,051	6	6,571	894	0
Apr-30	7,191	980	1	7,710	1,051	6	6,549	892	0
May-30	7,175	978	1	7,697	1,049	7	6,531	890	0
Jun-30	7,142	976	2	7,665	1,047	8	6,496	887	0
Jul-30	7,094	972	2	7,617	1,044	8	6,449	884	0
Aug-30	7,075	972	3	7,600	1,045	10	6,427	883	0
Sep-30	7,067	970	6	7,595	1,043	11	6,416	881	0
Oct-30	7,118	972	6	7,654	1,046	8	6,459	882	0
Nov-30	7,190	973	3	7,734	1,047	8	6,520	883	0
Dec-30	7,233	980	2	7,784	1,055	8	6,555	889	0
Jan-31	7,260	983	1	7,817	1,058	7	6,575	890	0
Feb-31	7,260	985	1	7,821	1,061	7	6,571	892	0
Mar-31	7,249	985	1	7,812	1,062	7	6,557	891	0
Apr-31	7,230	984	1	7,795	1,061	7	6,536	890	0
May-31	7,214	983	1	7,782	1,060	8	6,518	888	0
Jun-31	7,180	980	2	7,749	1,058	8	6,483	885	0
Jul-31	7,132	977	2	7,700	1,054	8	6,436	881	0
Aug-31	7,113	977	3	7,683	1,055	10	6,415	881	0
Sep-31	7,105	974	6	7,677	1,053	11	6,404	878	0
Oct-31	7,156	977	6	7,736	1,056	8	6,447	880	0
Nov-31	7,228	978	3	7,817	1,057	8	6,508	880	0
Dec-31	7,272	985	2	7,868	1,065	8	6,544	886	0
Jan-32	7,299	987	1	7,900	1,068	7	6,565	888	0
Feb-32	7,298	990	1	7,902	1,072	7	6,560	890	0
Mar-32	7,287	990	1	7,894	1,072	7	6,546	889	0
Apr-32	7,268	989	1	7,876	1,071	7	6,526	888	0
May-32	7,252	987	1	7,862	1,070	8	6,508	886	0
Jun-32	7,218	984	2	7,829	1,068	9	6,474	883	0
Jul-32	7,170	981	2	7,780	1,064	9	6,427	879	0
Aug-32	7,151	981	3	7,762	1,065	11	6,407	879	0
Sep-32	7,143	979	6	7,756	1,063	12	6,396	876	0
Oct-32	7,194	981	6	7,815	1,066	9	6,439	878	0
Nov-32	7,266	982	3	7,896	1,067	9	6,500	879	0
Dec-32	7,309	989	2	7,946	1,075	9	6,535	884	0
Jan-33	7,336	991	1	7,978	1,078	8	6,556	886	0
Feb-33	7,335	994	1	7,980	1,081	8	6,551	888	0

	La Grande - Expected Growth			La Grande - High Growth			La Grande - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Mar-33	7,324	994	1	7,971	1,082	8	6,538	887	0
Apr-33	7,306	993	1	7,955	1,081	8	6,519	886	0
May-33	7,289	991	1	7,939	1,080	9	6,500	884	0
Jun-33	7,255	989	2	7,905	1,077	9	6,466	881	0
Jul-33	7,207	985	2	7,856	1,074	9	6,421	878	0
Aug-33	7,188	985	3	7,838	1,075	11	6,401	878	0
Sep-33	7,180	983	6	7,831	1,072	12	6,391	875	0
Oct-33	7,231	986	6	7,890	1,075	9	6,434	877	0
Nov-33	7,303	986	3	7,971	1,077	9	6,495	877	0
Dec-33	7,346	994	2	8,020	1,085	9	6,530	883	0
Jan-34	7,373	996	1	8,052	1,087	8	6,551	885	0
Feb-34	7,372	998	1	8,054	1,091	8	6,548	887	0
Mar-34	7,361	998	1	8,045	1,091	8	6,535	886	0
Apr-34	7,342	997	1	8,026	1,090	8	6,515	885	0
May-34	7,325	996	1	8,011	1,089	9	6,497	883	0
Jun-34	7,292	993	2	7,977	1,086	10	6,465	880	0
Jul-34	7,243	990	2	7,926	1,083	10	6,419	877	0
Aug-34	7,224	990	3	7,908	1,083	12	6,400	877	0
Sep-34	7,216	987	6	7,901	1,081	13	6,390	874	0
Oct-34	7,267	990	6	7,960	1,084	10	6,432	876	0
Nov-34	7,339	991	3	8,041	1,086	10	6,493	877	0
Dec-34	7,382	998	2	8,091	1,094	10	6,528	883	0
Jan-35	7,409	1,000	1	8,123	1,096	9	6,550	884	0
Feb-35	7,408	1,003	1	8,124	1,100	9	6,546	886	0
Mar-35	7,397	1,003	1	8,115	1,100	9	6,533	886	0
Apr-35	7,378	1,002	1	8,097	1,099	9	6,514	884	0
May-35	7,361	1,000	1	8,080	1,098	10	6,496	883	0
Jun-35	7,327	997	2	8,046	1,095	10	6,463	880	0
Jul-35	7,279	994	2	7,995	1,092	10	6,419	877	0
Aug-35	7,260	994	3	7,976	1,092	12	6,400	876	0
Sep-35	7,251	992	6	7,968	1,090	13	6,390	874	0
Oct-35	7,302	994	6	8,026	1,093	10	6,433	876	0
Nov-35	7,374	995	3	8,107	1,094	10	6,494	876	0
Dec-35	7,417	1,002	2	8,157	1,102	10	6,530	882	0
Jan-36	7,444	1,004	1	8,188	1,104	9	6,551	884	0
Feb-36	7,443	1,007	1	8,189	1,108	9	6,548	886	0
Mar-36	7,431	1,007	1	8,178	1,108	9	6,536	886	0
Apr-36	7,413	1,006	1	8,160	1,107	9	6,518	884	0
May-36	7,396	1,004	1	8,144	1,106	10	6,500	882	0
Jun-36	7,362	1,002	2	8,108	1,103	11	6,468	880	0
Jul-36	7,314	998	2	8,057	1,100	11	6,425	877	0

	La Grande - Expected Growth			La Grande - High Growth			La Grande - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Aug-36	7,294	999	3	8,036	1,100	13	6,405	877	0
Sep-36	7,286	996	6	8,029	1,098	14	6,397	875	0
Oct-36	7,336	999	6	8,086	1,101	11	6,439	876	0
Nov-36	7,408	1,000	3	8,167	1,102	11	6,501	877	0
Dec-36	7,451	1,007	2	8,216	1,110	11	6,537	883	0
Jan-37	7,478	1,009	1	8,247	1,113	10	6,559	885	0
Feb-37	7,477	1,011	1	8,247	1,115	10	6,556	886	0
Mar-37	7,465	1,011	1	8,236	1,115	10	6,544	886	0
Apr-37	7,446	1,010	1	8,216	1,114	10	6,526	885	0
May-37	7,429	1,009	1	8,199	1,114	11	6,509	884	0
Jun-37	7,395	1,006	2	8,163	1,110	11	6,478	881	0
Jul-37	7,347	1,003	2	8,111	1,107	11	6,434	878	0
Aug-37	7,328	1,003	3	8,092	1,108	13	6,416	878	0
Sep-37	7,319	1,001	6	8,083	1,105	14	6,407	876	0
Oct-37	7,370	1,003	6	8,141	1,108	11	6,450	878	0
Nov-37	7,441	1,004	3	8,221	1,109	11	6,511	878	0
Dec-37	7,484	1,011	2	8,270	1,117	11	6,547	884	0
Jan-38	7,511	1,013	1	8,301	1,120	10	6,569	886	0
Feb-38	7,510	1,016	1	8,301	1,123	10	6,567	888	0
Mar-38	7,498	1,016	1	8,289	1,123	10	6,555	888	0
Apr-38	7,479	1,015	1	8,270	1,122	10	6,536	887	0
May-38	7,462	1,013	1	8,252	1,120	11	6,520	885	0
Jun-38	7,428	1,011	2	8,216	1,118	12	6,489	883	0
Jul-38	7,380	1,007	2	8,164	1,114	12	6,446	880	0
Aug-38	7,361	1,007	3	8,144	1,114	14	6,428	879	0
Sep-38	7,352	1,005	6	8,135	1,112	15	6,419	877	0
Oct-38	7,402	1,007	6	8,192	1,114	12	6,461	879	0
Nov-38	7,474	1,008	3	8,273	1,116	12	6,523	880	0
Dec-38	7,517	1,015	2	8,321	1,124	12	6,559	886	0
Jan-39	7,543	1,017	1	8,351	1,126	11	6,581	887	0
Feb-39	7,542	1,020	1	8,351	1,129	11	6,579	890	0
Mar-39	7,531	1,020	1	8,340	1,130	11	6,568	890	0
Apr-39	7,512	1,019	1	8,320	1,129	11	6,550	889	0
May-39	7,495	1,017	1	8,303	1,127	12	6,534	887	0
Jun-39	7,461	1,015	2	8,266	1,125	12	6,504	885	0
Jul-39	7,412	1,011	2	8,213	1,120	12	6,460	881	0
Aug-39	7,393	1,012	3	8,193	1,121	14	6,442	882	0
Sep-39	7,384	1,009	6	8,184	1,118	15	6,433	879	0
Oct-39	7,435	1,012	6	8,241	1,122	12	6,477	882	0
Nov-39	7,506	1,013	3	8,321	1,123	12	6,537	882	0
Dec-39	7,549	1,020	2	8,370	1,131	12	6,574	888	0

	La Grande - Expected Growth			La Grande - High Growth			La Grande - Low Growth		
	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers	Residential Customers	Commercial Customers	Industrial Customers
Jan-40	7,575	1,022	1	8,400	1,133	11	6,595	890	0
Feb-40	7,574	1,024	1	8,400	1,136	11	6,593	891	0
Mar-40	7,563	1,024	1	8,388	1,136	11	6,583	891	0
Apr-40	7,544	1,023	1	8,368	1,135	11	6,565	890	0
May-40	7,527	1,022	1	8,350	1,134	12	6,549	889	0
Jun-40	7,493	1,019	2	8,314	1,131	13	6,519	886	0
Jul-40	7,444	1,016	2	8,260	1,127	13	6,475	884	0
Aug-40	7,425	1,016	3	8,240	1,128	15	6,458	884	0
Sep-40	7,416	1,014	6	8,231	1,125	16	6,449	882	0
Oct-40	7,467	1,016	6	8,288	1,128	13	6,492	883	0

APPENDIX 2.3: DEMAND COEFFICIENTS

	January	February	March	April	May	June	July	August	September	October	November	December
HEAT COEFFICIENTS												
WA | Residential	0.010019	0.009649	0.008975	0.007554	0.004732	0.002420	0.001202	0.000985	0.003780	0.007364	0.009143	0.009637
WA | Commercial	0.054204	0.055659	0.048708	0.039937	0.022778	0.016037	0.008276	0.010106	0.029505	0.038390	0.050902	0.053432
WA | Industrial	0.134000	0.170731	0.134465	0.107716	0.078664	0.135746	0.099441	0.090432	0.416632	0.183366	0.183506	0.130699
ID | Residential	0.009982	0.009734	0.009393	0.008056	0.005415	0.002854	0.001831	0.000407	0.003866	0.007696	0.009350	0.009867
ID | Commercial	0.041681	0.040871	0.037664	0.028885	0.016144	0.014984	0.007763	0.012945	0.021341	0.027719	0.035806	0.039590
ID | Industrial	0.134941	0.222589	0.109472	0.087363	0.062252	0.129064	0.098101	0.118899	0.366413	0.245318	0.246271	0.162023
Roseburg | Residential	0.011149	0.012593	0.009735	0.009125	0.004685	0.003684	0.002130	0.007033	0.004377	0.008847	0.010957	0.011989
Roseburg | Commercial	0.047161	0.055445	0.042659	0.040917	0.020398	0.021348	0.014584	0.057240	0.025390	0.033820	0.042781	0.049083
Roseburg | Industrial	0.053693	0.057258	0.030779	0.111947	0.168205	0.287326	0.235004	0.387348	0.178307	0.143281	0.110984	0.073515
Medford | Residential	0.010917	0.010712	0.009939	0.008005	0.005892	0.003467	0.000000	0.000000	0.003414	0.007311	0.009582	0.010439
Medford | Commercial	0.041922	0.042473	0.036943	0.029781	0.020873	0.016028	0.000000	0.000000	0.025067	0.033347	0.039269	0.041024
Medford | Industrial	0.021203	0.050709	0.031701	0.039025	0.038903	0.065874	0.000000	0.000000	0.261701	0.171043	0.102115	0.045663
La Grande | Residential	0.009192	0.008803	0.007669	0.006581	0.005085	0.001944	0.000105	0.004633	0.000405	0.004864	0.007728	0.008849
La Grande | Commercial	0.042772	0.041172	0.035023	0.027635	0.007455	0.003707	0.000243	0.028535	0.004161	0.019996	0.030626	0.038067
La Grande | Industrial	0.000000	0.000000	0.000000	0.000000	1.623316	1.716208	7.876864	1.227047	2.524977	1.812518	0.100882	0.000000
Klamath Falls | Residential	0.008363	0.008150	0.007709	0.006461	0.004610	0.002944	0.001342	0.000180	0.002579	0.005540	0.007408	0.008571
Klamath Falls | Commercial	0.031363	0.031426	0.028144	0.022725	0.013172	0.009605	0.004353	0.003762	0.018697	0.021748	0.027153	0.031994
Klamath Falls | Industrial	0.076215	0.109912	0.068231	0.083678	0.034930	0.060598	0.030497	0.151866	0.354761	0.223751	0.249885	0.149191
BASE COEFFICIENTS												
WA | Residential	0.046575	0.046575	0.046575	0.046575	0.046575	0.046575	0.046575	0.046575	0.046575	0.046575	0.046575	0.046575
WA | Commercial	0.381192	0.381192	0.381192	0.381192	0.381192	0.381192	0.381192	0.381192	0.381192	0.381192	0.381192	0.381192
WA | Industrial	3.230733	3.230733	3.230733	3.230733	3.230733	3.230733	3.230733	3.230733	3.230733	3.230733	3.230733	3.230733
ID | Residential	0.046699	0.046699	0.046699	0.046699	0.046699	0.046699	0.046699	0.046699	0.046699	0.046699	0.046699	0.046699
ID | Commercial	0.378458	0.378458	0.378458	0.378458	0.378458	0.378458	0.378458	0.378458	0.378458	0.378458	0.378458	0.378458
ID | Industrial	5.618589	5.618589	5.618589	5.618589	5.618589	5.618589	5.618589	5.618589	5.618589	5.618589	5.618589	5.618589
Roseburg | Residential	0.040149	0.040149	0.040149	0.040149	0.040149	0.040149	0.040149	0.040149	0.040149	0.040149	0.040149	0.040149
Roseburg | Commercial	0.317350	0.317350	0.317350	0.317350	0.317350	0.317350	0.317350	0.317350	0.317350	0.317350	0.317350	0.317350
Roseburg | Industrial	2.811309	2.811309	2.811309	2.811309	2.811309	2.811309	2.811309	2.811309	2.811309	2.811309	2.811309	2.811309
Medford | Residential	0.047701	0.047701	0.047701	0.047701	0.047701	0.047701	0.047701	0.047701	0.047701	0.047701	0.047701	0.047701
Medford | Commercial	0.366506	0.366506	0.366506	0.366506	0.366506	0.366506	0.366506	0.366506	0.366506	0.366506	0.366506	0.366506
Medford | Industrial	4.048021	4.048021	4.048021	4.048021	4.048021	4.048021	4.048021	4.048021	4.048021	4.048021	4.048021	4.048021
La Grande | Residential	0.068987	0.068987	0.068987	0.068987	0.068987	0.068987	0.068987	0.068987	0.068987	0.068987	0.068987	0.068987
La Grande | Commercial	0.386380	0.386380	0.386380	0.386380	0.386380	0.386380	0.386380	0.386380	0.386380	0.386380	0.386380	0.386380
La Grande | Industrial	52.512335	52.512335	52.512335	52.512335	52.512335	52.512335	52.512335	52.512335	52.512335	52.512335	52.512335	52.512335
Klamath Falls | Residential	0.034536	0.034536	0.034536	0.034536	0.034536	0.034536	0.034536	0.034536	0.034536	0.034536	0.034536	0.034536
Klamath Falls | Commercial	0.229013	0.229013	0.229013	0.229013	0.229013	0.229013	0.229013	0.229013	0.229013	0.229013	0.229013	0.229013
Klamath Falls | Industrial	4.059241	4.059241	4.059241	4.059241	4.059241	4.059241	4.059241	4.059241	4.059241	4.059241	4.059241	4.059241

APPENDIX 2.3: WA BASE COEFFICIENT CALCULATION

WA Average Actual Demand by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	6,625	7,149	6,574	7,128	7,213	6,938
Average of Com Demand	5,244	5,908	5,380	5,546	5,897	5,595
Average of Ind Demand	394	410	427	425	412	413

WA Average Customers by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	139,093	141,755	145,535	149,924	153,598	145,981
Average of Com Demand	14,173	14,456	14,551	14,721	14,863	14,553
Average of Ind Demand	135	130	133	130	129	131

Base Coefficients

(Actual Average Demand/Customer Count)

Res Base Usage	0.04752577
Com Base Usage	0.38447113
Ind Base Usage	3.15590337

APPENDIX 2.3: ID BASE COEFFICIENT CALCULATION

ID Average Actual Demand by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	2,979	3,361	3,140	3,583	3,739	3,361
Average of Com Demand	3,511	3,322	3,464	3,246	3,482	3,405
Average of Ind Demand	436	509	495	524	529	499

ID Average Customers by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	69,436	71,062	72,686	74,722	76,651	72,911
Average of Com Demand	8,613	8,751	8,881	8,958	9,092	8,859
Average of Ind Demand	100	97	93	92	91	94

Base Coefficients

(Actual Average Demand/Customer Count)

Res Base Usage	0.04609207
Com Base Usage	0.38436467
Ind Base Usage	5.28295751

APPENDIX 2.3: MEDFORD BASE COEFFICIENT CALCULATION

Medford Average Actual Demand by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	2,316	2,582	2,596	2,603	2,647	2,549
Average of Com Demand	2,303	2,487	2,487	2,481	2,633	2,478
Average of Ind Demand	60	60	68	49	58	59

Medford Average Customers by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	52,605	53,084	53,920	54,837	55,737	54,036
Average of Com Demand	6,596	6,796	6,850	6,906	6,987	6,827
Average of Ind Demand	15	15	15	14	14	15

Base Coefficients

(Actual Average Demand/Customer Count)

Res Base Usage	0.04716918
Com Base Usage	0.36305328
Ind Base Usage	4.03557818

APPENDIX 2.3: ROSEBURG BASE COEFFICIENT CALCULATION

Roseburg Average Actual Demand by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	430	466	486	474	667	505
Average of Com Demand	557	557	628	597	817	631
Average of Ind Demand	4	4	5	3	5	4

Roseburg Average Customers by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	13,227	13,242	13,337	13,518	13,685	13,402
Average of Com Demand	2,130	2,156	2,141	2,146	2,150	2,144
Average of Ind Demand	2	2	2	1	2	2

Base Coefficients

(Actual Average Demand/Customer Count)

Res Base Usage	0.03765259
Com Base Usage	0.29442810
Ind Base Usage	2.45310434

APPENDIX 2.3: KLAMATH FALLS BASE COEFFICIENT CALCULATION

Klamath Falls Average Actual Demand by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	531	397	458	495	562	488
Average of Com Demand	484	308	361	401	448	400
Average of Ind Demand	30	19	26	28	27	26

Klamath Falls Average Customers by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	14,106	14,206	14,397	14,619	14,823	14,430
Average of Com Demand	1,667	1,722	1,762	1,753	1,770	1,734
Average of Ind Demand	7	7	7	7	6	7

Base Coefficients

(Actual Average Demand/Customer Count)

Res Base Usage	0.03384355
Com Base Usage	0.23084798
Ind Base Usage	3.84363453

APPENDIX 2.3: LA GRANDE BASE COEFFICIENT CALCULATION

La Grande Average Actual Demand by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	554	497	439	478	457	485
Average of Com Demand	441	377	338	367	359	376
Average of Ind Demand	122	192	202	86	159	152

La Grande Average Customers by Class (July & August)

Year	2015	2016	2017	2018	2019	Total Average
Average of Res Demand	6,547	6,529	6,565	6,660	6,695	6,599
Average of Com Demand	897	919	914	916	923	914
Average of Ind Demand	4	3	3	3	4	3

Base Coefficients

(Actual Average Demand/Customer Count)

Res Base Usage	0.07350633
Com Base Usage	0.41177227
Ind Base Usage	50.71916892

APPENDIX 2.4: HEATING DEGREE DAY DATA MONTHLY TABLES

Temperature Pattern	WA/ID												
Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual Total
2020-2021	887	1,152	1,107	946	791	561	297	139	20	24	182	550	6,656
2021-2022	892	1,149	1,115	943	793	559	306	140	22	24	178	547	6,667
2022-2023	887	1,140	1,110	947	789	561	298	140	21	23	179	545	6,640
2023-2024	879	1,141	1,119	945	791	556	306	140	21	24	184	544	6,651
2024-2025	886	1,148	1,115	944	792	560	304	137	21	24	180	548	6,658
2025-2026	884	1,145	1,118	945	791	555	299	141	21	24	181	544	6,649
2026-2027	891	1,141	1,114	942	793	550	301	139	21	23	181	549	6,645
2027-2028	881	1,141	1,113	947	795	558	301	140	21	24	181	550	6,652
2028-2029	889	1,147	1,112	948	789	555	301	141	21	24	180	549	6,656
2029-2030	893	1,148	1,112	944	797	555	299	140	22	24	181	548	6,664
2030-2031	887	1,151	1,119	948	794	557	301	138	21	24	178	547	6,662
2031-2032	883	1,143	1,108	945	794	558	299	141	21	24	178	546	6,640
2032-2033	890	1,147	1,110	951	793	560	302	143	22	24	182	550	6,674
2033-2034	891	1,139	1,111	945	794	553	305	140	21	24	181	549	6,654
2034-2035	894	1,146	1,111	947	791	558	298	140	20	24	178	547	6,653
2035-2036	885	1,141	1,110	940	790	556	300	141	20	24	180	546	6,632
2036-2037	884	1,147	1,117	948	795	563	300	142	21	24	177	548	6,665
2037-2038	887	1,141	1,111	945	794	559	300	141	20	24	177	549	6,648
2038-2039	883	1,146	1,112	949	791	554	306	140	22	24	180	544	6,650
2039-2040	889	1,146	1,110	944	793	559	299	141	22	23	180	547	6,654

Temperature Pattern	Klamath Falls												
Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual Total
2020-2021	875	1,084	1,053	870	809	660	431	204	43	58	236	567	6,889
2021-2022	868	1,081	1,047	867	817	656	430	210	42	59	240	565	6,882
2022-2023	872	1,079	1,055	875	811	658	431	206	42	57	237	564	6,887
2023-2024	872	1,078	1,050	870	813	653	431	209	42	57	237	564	6,877
2024-2025	871	1,082	1,055	869	815	661	428	205	43	58	234	563	6,883
2025-2026	872	1,075	1,044	865	814	658	430	207	41	58	235	568	6,868
2026-2027	871	1,080	1,057	868	815	656	426	206	41	58	233	570	6,882
2027-2028	871	1,081	1,050	871	813	653	429	207	44	58	232	567	6,876
2028-2029	874	1,077	1,062	869	813	650	425	209	42	57	234	569	6,881
2029-2030	871	1,080	1,052	868	814	659	425	206	44	58	234	571	6,882
2030-2031	868	1,084	1,051	864	818	654	427	205	43	58	235	564	6,872
2031-2032	869	1,081	1,054	869	812	653	424	203	42	57	236	565	6,867
2032-2033	875	1,082	1,053	868	811	656	433	205	43	57	235	569	6,886
2033-2034	871	1,082	1,055	867	812	657	428	205	43	57	233	568	6,879
2034-2035	878	1,081	1,053	867	818	654	428	205	43	56	235	567	6,886
2035-2036	870	1,080	1,050	870	814	655	428	209	42	58	233	569	6,877
2036-2037	869	1,078	1,056	869	813	656	427	203	43	58	237	566	6,876
2037-2038	874	1,077	1,059	874	814	655	427	207	40	58	235	567	6,887
2038-2039	867	1,082	1,053	870	815	654	429	208	42	56	234	568	6,879
2039-2040	871	1,082	1,052	867	814	654	435	209	42	57	238	566	6,886

Temperature Pattern	Medford												
Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual Total
2020-2021	605	805	775	604	526	379	177	51	2	3	55	291	4,273
2021-2022	608	808	776	604	533	378	179	53	2	3	54	294	4,294
2022-2023	613	803	776	605	530	372	178	52	2	3	55	290	4,280
2023-2024	602	805	771	607	530	378	180	52	2	3	55	291	4,275
2024-2025	608	804	778	607	523	376	186	54	2	3	54	291	4,287
2025-2026	611	802	776	606	528	377	181	52	2	3	58	293	4,288
2026-2027	607	802	778	609	530	374	179	53	2	3	56	293	4,286
2027-2028	603	799	774	603	529	376	183	52	2	3	56	293	4,272
2028-2029	607	806	776	608	523	375	181	53	2	3	55	295	4,284
2029-2030	609	804	777	606	524	374	182	52	2	3	55	293	4,281
2030-2031	610	799	774	606	533	375	181	52	2	3	58	294	4,287
2031-2032	605	806	775	605	529	373	182	53	2	3	55	295	4,282
2032-2033	605	804	776	607	529	378	182	53	2	3	56	293	4,285
2033-2034	604	803	773	608	525	374	182	54	2	3	55	294	4,277
2034-2035	610	801	776	606	532	374	183	51	2	3	57	291	4,286
2035-2036	609	804	773	604	527	375	180	52	2	3	56	292	4,277
2036-2037	605	800	777	604	530	373	180	51	2	3	56	290	4,271
2037-2038	603	804	776	602	528	370	181	53	2	3	57	293	4,272
2038-2039	605	810	776	601	527	374	179	52	2	3	57	295	4,280
2039-2040	606	807	776	603	532	375	180	52	2	3	56	288	4,281

Temperature Pattern	Roseburg												
Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual Total
2020-2021	539	702	684	559	499	376	204	77	4	5	61	285	3,994
2021-2022	540	706	685	562	506	377	200	79	4	4	62	283	4,009
2022-2023	545	700	686	560	503	379	200	77	4	5	61	281	4,000
2023-2024	537	701	678	564	502	376	204	78	4	5	62	284	3,996
2024-2025	542	703	684	562	496	375	201	78	4	5	62	289	4,001
2025-2026	542	700	685	561	500	377	203	77	4	5	62	284	4,001
2026-2027	540	700	685	564	504	375	203	79	5	5	61	280	3,999
2027-2028	536	698	682	558	502	375	201	76	4	4	63	280	3,979
2028-2029	540	702	684	564	496	374	203	78	4	5	63	285	3,997
2029-2030	542	702	686	561	498	377	205	76	4	5	61	283	4,000
2030-2031	543	700	684	562	505	379	204	78	4	5	61	284	4,010
2031-2032	540	704	682	560	501	379	204	78	4	4	62	286	4,004
2032-2033	541	702	685	562	501	374	200	75	4	5	62	285	3,996
2033-2034	537	701	681	563	497	376	200	77	4	5	63	282	3,986
2034-2035	542	699	682	561	506	380	199	79	5	5	63	284	4,003
2035-2036	543	703	682	559	499	372	204	78	4	5	60	287	3,996
2036-2037	537	699	687	560	504	379	199	77	5	5	61	286	3,998
2037-2038	538	702	683	558	500	376	204	77	4	5	61	285	3,992
2038-2039	537	708	685	556	499	374	201	78	4	5	62	282	3,990
2039-2040	539	706	685	559	505	376	206	78	4	5	62	282	4,007

Temperature Pattern	La Grande												
Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual Total
2020-2021	793	1,041	1,029	829	724	556	336	150	23	37	198	524	6,240
2021-2022	791	1,038	1,027	828	727	554	335	150	23	36	198	523	6,229
2022-2023	794	1,041	1,015	825	727	551	338	149	22	37	199	523	6,221
2023-2024	791	1,038	1,025	828	726	552	337	151	23	38	199	528	6,235
2024-2025	797	1,040	1,022	829	728	553	336	149	23	37	201	521	6,236
2025-2026	791	1,045	1,016	829	727	552	336	147	23	38	199	522	6,224
2026-2027	795	1,041	1,020	827	726	559	337	150	23	37	200	519	6,235
2027-2028	790	1,045	1,025	826	728	553	337	151	23	37	197	525	6,237
2028-2029	795	1,038	1,025	825	728	556	334	148	22	36	199	518	6,227
2029-2030	798	1,040	1,026	830	730	553	334	151	23	37	198	530	6,250
2030-2031	793	1,046	1,020	827	729	553	332	152	22	37	199	521	6,231
2031-2032	790	1,038	1,029	827	724	551	341	150	24	36	201	516	6,228
2032-2033	799	1,039	1,017	826	723	555	338	149	24	38	199	526	6,235
2033-2034	790	1,044	1,018	826	723	554	337	148	24	37	197	527	6,223
2034-2035	794	1,040	1,028	828	724	555	334	150	23	36	198	521	6,231
2035-2036	793	1,042	1,031	827	725	554	334	150	24	37	199	524	6,239
2036-2037	789	1,043	1,018	831	724	553	338	149	23	37	198	524	6,226
2037-2038	797	1,040	1,024	829	723	557	335	149	22	36	200	521	6,233
2038-2039	797	1,041	1,025	827	729	555	339	152	24	37	195	523	6,244
2039-2040	790	1,042	1,025	830	720	554	336	151	25	37	200	521	6,232

APPENDIX 2.4: AVERAGE HEATING DEGREE DAILY MONTH BY AREA

Temperature Pattern		WA/ID										
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	39	35	31	22	15	2	0	0	0	10	25	35
2	39	34	31	23	13	5	0	0	0	12	24	34
3	39	34	30	22	13	4	0	0	1	14	25	35
4	36	33	29	22	12	4	0	0	1	14	25	35
5	37	33	27	22	13	4	0	0	2	14	26	36
6	36	33	27	20	14	5	0	0	3	13	26	37
7	35	34	27	19	12	4	0	0	2	13	26	38
8	34	34	28	19	11	6	0	0	3	15	26	38
9	33	34	28	20	12	7	0	0	4	16	27	38
10	35	34	27	19	12	7	0	0	3	17	28	36
11	37	34	25	19	9	7	0	0	2	18	29	36
12	36	31	24	18	9	5	0	0	1	18	28	35
13	36	32	24	19	10	4	0	0	2	16	28	35
14	36	33	24	21	7	6	0	0	2	15	29	36
15	39	32	24	22	7	5	0	0	2	17	28	37
16	38	31	24	19	6	4	0	0	5	15	27	37
17	36	32	26	19	8	4	0	0	6	15	28	37
18	34	33	25	18	8	4	0	0	6	16	29	36
19	35	33	25	17	7	4	0	0	7	16	29	37
20	35	33	24	15	10	3	0	0	9	16	30	36
21	35	32	24	14	8	1	0	0	10	18	31	35
22	35	32	24	16	8	0	0	0	8	17	32	37
23	34	34	24	17	7	1	0	0	7	20	32	37
24	34	35	24	16	7	1	0	0	6	20	33	36
25	33	35	24	16	7	0	0	0	5	21	33	37
26	34	35	24	15	7	0	0	0	6	22	32	37
27	35	32	23	14	6	0	0	0	6	23	34	37
28	35	32	23	16	6	0	0	0	7	23	35	36
29	34	28	22	17	6	0	0	0	8	24	36	38
30	34		20	15	5	0	0	0	9	25	35	39
31	34		22		4		0	0		24		40
Total	1,102	957	784	551	279	97	0	0	133	537	876	1,133

Temperature Pattern			Medford									
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	27	24	20	15	8	0	0	0	0	4	15	25
2	26	22	20	14	6	0	0	0	0	6	16	24
3	28	21	20	15	6	0	0	0	0	6	16	25
4	26	22	19	13	6	0	0	0	0	6	17	25
5	25	22	19	14	8	0	0	0	0	7	17	26
6	26	22	19	12	7	0	0	0	0	5	16	25
7	24	21	19	13	6	0	0	0	0	5	17	27
8	23	22	19	13	6	1	0	0	0	6	18	25
9	24	21	18	13	7	1	0	0	0	8	20	24
10	25	22	17	12	6	2	0	0	0	9	18	26
11	24	21	16	12	6	1	0	0	0	10	19	27
12	24	21	16	13	5	0	0	0	0	10	18	26
13	26	21	16	14	3	0	0	0	0	7	18	24
14	27	21	17	16	2	0	0	0	0	7	18	25
15	26	20	16	17	3	0	0	0	0	8	19	27
16	26	20	17	14	4	0	0	0	0	7	20	27
17	26	19	17	13	4	0	0	0	0	8	21	27
18	25	21	16	13	4	0	0	0	0	8	22	26
19	24	22	15	12	4	0	0	0	0	8	20	24
20	26	21	15	11	5	0	0	0	0	10	21	24
21	25	20	15	11	5	0	0	0	0	11	22	24
22	24	22	16	9	4	0	0	0	1	10	22	25
23	24	23	17	10	3	0	0	0	1	11	23	25
24	23	20	15	10	2	0	0	0	0	12	23	26
25	23	21	18	9	3	0	0	0	0	13	22	26
26	23	22	17	8	2	0	0	0	0	13	23	27
27	25	21	16	9	3	0	0	0	0	14	24	26
28	24	21	15	10	2	0	0	0	0	13	23	26
29	23	21	14	10	1	0	0	0	1	14	25	26
30	24		14	9	0	0	0	0	2	13	25	26
31	25		14		0		0	0		14		27
Total	771	617	522	364	131	5	0	0	5	283	598	793

Temperature Pattern		La Grande										
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	38	32	28	21	16	4	0	0	1	11	24	30
2	36	31	26	22	14	5	0	0	2	13	22	32
3	36	30	28	21	14	5	0	0	2	13	23	32
4	34	28	27	20	13	4	0	0	2	15	22	33
5	35	29	24	21	13	5	0	0	2	16	23	34
6	34	29	25	18	15	6	0	0	3	14	22	33
7	31	30	25	18	13	5	0	0	3	12	23	35
8	29	29	26	18	12	6	0	0	4	14	22	34
9	29	30	24	19	14	7	0	0	5	15	24	34
10	32	30	24	18	14	9	0	0	4	17	24	31
11	32	29	24	18	11	8	0	0	5	18	26	32
12	33	28	22	18	11	6	0	0	3	18	25	32
13	32	29	21	18	10	5	0	0	3	15	26	30
14	33	28	22	21	8	6	0	0	4	15	26	32
15	36	28	22	21	8	4	0	0	3	15	26	32
16	34	28	22	20	9	5	0	0	6	14	26	35
17	33	28	24	18	9	4	0	0	6	14	26	36
18	32	29	23	19	8	6	0	0	7	15	27	35
19	30	30	23	17	9	5	0	0	7	14	25	33
20	31	29	22	15	11	3	0	0	9	15	26	32
21	32	29	23	16	11	3	0	0	10	18	28	31
22	33	28	22	16	10	2	0	0	10	17	28	32
23	32	30	23	16	9	2	0	0	9	18	29	34
24	31	30	22	18	8	2	0	1	8	20	30	34
25	30	30	22	16	9	1	0	0	9	19	30	35
26	32	30	24	16	8	0	0	0	8	21	29	35
27	33	29	23	14	7	0	0	0	7	21	30	34
28	33	28	21	17	8	0	0	0	8	20	32	32
29	32	26	20	18	7	0	0	0	8	22	32	33
30	30		20	17	6	0	0	0	9	22	32	37
31	31		20		6		0	1		22		38
Total	1,009	844	722	545	321	118	0	2	167	513	788	1,032

Temperature Pattern			Klamath Falls									
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	37	32	30	24	18	7	0	0	3	14	25	32
2	36	31	30	25	16	8	0	0	3	15	26	33
3	36	29	30	24	15	7	0	0	3	16	26	34
4	36	31	29	23	15	7	0	0	4	17	26	34
5	36	31	28	24	16	8	0	0	6	16	26	34
6	35	30	27	22	17	8	0	0	5	14	25	33
7	32	30	28	22	15	9	0	0	5	14	26	36
8	31	31	27	22	15	9	1	0	5	15	27	34
9	33	30	27	23	17	10	0	0	6	17	29	33
10	33	31	27	22	16	11	0	0	6	18	28	34
11	34	30	25	22	15	10	0	0	4	20	28	35
12	34	29	25	22	14	8	0	0	3	19	26	34
13	35	28	25	23	13	8	0	0	5	16	27	33
14	35	29	25	26	11	7	0	0	6	15	26	35
15	35	29	24	26	11	6	0	0	8	16	27	37
16	34	30	25	24	13	7	0	0	11	16	27	36
17	34	30	26	22	13	7	0	0	10	17	28	38
18	33	32	25	23	13	7	0	0	9	17	28	35
19	33	33	24	21	13	6	0	0	10	18	27	33
20	33	31	24	20	14	6	0	0	10	19	27	32
21	34	30	23	20	13	4	0	0	10	20	29	33
22	34	31	25	19	13	4	0	1	11	18	30	35
23	33	32	26	19	12	3	0	2	11	20	31	34
24	33	30	25	19	11	4	0	1	9	20	33	35
25	32	30	26	19	12	3	0	1	10	21	32	35
26	32	32	26	19	11	2	0	2	9	21	33	37
27	33	31	25	18	11	0	0	1	8	23	34	35
28	33	31	24	20	12	0	0	1	8	22	35	34
29	32	33	24	20	10	0	0	0	10	23	35	35
30	32		23	19	9	0	0	3	12	23	34	37
31	34		23		7		0	4		24		38
Total	1,047	887	801	652	411	176	1	16	220	564	861	1,073

Temperature Pattern		Roseburg										
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	24	20	19	15	8	2	0	0	0	5	14	21
2	24	19	18	15	7	1	0	0	0	7	13	21
3	24	20	19	15	8	1	0	0	0	7	14	21
4	23	19	18	13	7	1	0	0	0	7	15	22
5	22	19	18	14	9	2	0	0	0	6	14	22
6	22	19	18	12	8	1	0	0	0	5	14	23
7	20	20	18	12	7	1	0	0	0	5	17	25
8	20	20	17	13	7	2	0	0	0	6	17	23
9	21	20	15	13	8	3	0	0	0	8	17	22
10	21	20	16	13	7	5	0	0	0	9	17	23
11	22	19	15	12	7	2	0	0	0	10	17	22
12	22	19	15	13	6	1	0	0	0	10	15	21
13	23	20	15	13	5	1	0	0	0	7	15	22
14	24	20	15	16	4	2	0	0	0	7	16	24
15	24	18	15	16	5	1	0	0	0	8	16	24
16	22	20	16	14	5	1	0	0	0	7	17	23
17	22	18	17	12	4	0	0	0	1	8	17	24
18	21	20	15	11	5	1	0	0	1	8	19	24
19	21	21	15	11	5	0	0	0	1	7	16	22
20	22	21	15	11	6	0	0	0	1	9	20	20
21	21	19	16	11	6	0	0	0	2	9	20	21
22	22	20	16	10	5	0	0	0	2	8	20	22
23	20	21	16	11	4	0	0	0	2	11	21	20
24	21	20	15	10	4	0	0	0	0	12	20	22
25	21	20	16	9	5	0	0	0	1	12	21	23
26	22	21	16	10	3	0	0	0	0	12	21	24
27	22	20	15	10	4	0	0	0	0	14	22	22
28	21	20	15	10	5	0	0	0	1	12	22	22
29	20	20	14	11	3	0	0	0	3	13	22	23
30	20		14	10	2	0	0	0	3	13	22	24
31	21		14		1		0	0		13		24
Total	675	573	496	366	170	28	0	0	18	275	531	696

APPENDIX 2.5: DEMAND SENSITIVITIES
SUMMARY OF ASSUMPTIONS – DEMAND SCENARIOS

<table>
<tr><th>Influence Type</th><th>Sensitivity</th><th>Customer Growth Rate</th><th>Use per Customer</th><th>Weather</th><th>Demand Side Management</th><th>Prices</th><th>Elasticity</th><th>First Year System Unserved</th><th>Location Unserved</th></tr>
<tr><td rowspan="22">DEMAND INFLUENCING - DIRECT</td><td>Reference</td><td rowspan="2">Reference</td><td rowspan="8">3 Year Historical</td><td>20 Year Average</td><td rowspan="5">None</td><td rowspan="23">Expected</td><td rowspan="22">None</td><td>-</td><td></td></tr>
<tr><td>Reference Plus Peak</td><td rowspan="3">Planning Standard</td><td>2035</td><td>Washington</td></tr>
<tr><td>Low Cust</td><td>Low Growth</td><td>-</td><td></td></tr>
<tr><td>High Cust</td><td>High Growth</td><td>2029</td><td>Washington</td></tr>
<tr><td>Alternate Weather Standard</td><td rowspan="29">Reference</td><td>Coldest in 20yrs</td><td>2035</td><td>Washington</td></tr>
<tr><td>DSM</td><td>20 Year Average</td><td rowspan="2">Expected</td><td>-</td><td></td></tr>
<tr><td>Peak plus DSM</td><td rowspan="27">Planning Standard</td><td>2036</td><td>Washington</td></tr>
<tr><td>80% below 1990 emissions</td><td rowspan="26">None</td><td>2035</td><td>Washington</td></tr>
<tr><td>2 Year use per customer Alternate</td><td>2 Year Historical</td><td>2035</td><td>Washington</td></tr>
<tr><td>5 Year use per customer Alternate</td><td>5 Year Historical</td><td>2035</td><td>Washington</td></tr>
<tr><td>JP Outage Only (0% capacity)</td><td rowspan="23">3 Year Historical</td><td>2021</td><td>Washington</td></tr>
<tr><td>AECO Outage Only (0% capacity)</td><td>2020</td><td>WA, ID</td></tr>
<tr><td>Sumas Outage Only (0% capacity)</td><td>2020</td><td>Medford</td></tr>
<tr><td>Rockies Outage Only (0% capacity)</td><td>2020</td><td>La Grande</td></tr>
<tr><td>JP Outage Only (50% capacity)</td><td>2021</td><td>Washington</td></tr>
<tr><td>AECO Outage Only (50% capacity)</td><td>2026</td><td>Washington</td></tr>
<tr><td>Sumas Outage Only (50% capacity)</td><td>2025</td><td>Washington</td></tr>
<tr><td>Rockies Outage Only (50% capacity)</td><td>2025</td><td>La Grande</td></tr>
<tr><td>NWP Outage (0% capacity)</td><td>2020</td><td>WA, ID, La Grande</td></tr>
<tr><td>GTN Outage (0% capacity)</td><td>2020</td><td>WA, ID, Klamath Falls</td></tr>
<tr><td>NWP Outage (50% capacity)</td><td>2020</td><td>WA, La Grande</td></tr>
<tr><td>GTN Outage (50% capacity)</td><td>2026</td><td>Washington</td></tr>
<tr><td rowspan="6">PRICE INFLUENCING - INDIRECT</td><td>Expected Prices</td><td rowspan="11">Expected</td><td>-</td><td></td></tr>
<tr><td>Low Prices</td><td>Low</td><td>-</td><td></td></tr>
<tr><td>High Prices</td><td>High</td><td>-</td><td></td></tr>
<tr><td>Carbon Cost - High (SCC 95% at 3%)</td><td rowspan="8">Expected</td><td>-</td><td></td></tr>
<tr><td>Carbon Cost - Expected (SCC 2.5% (WA) & Cap&Red (OR))</td><td>-</td><td></td></tr>
<tr><td>Carbon Cost - Low $0</td><td>-</td><td></td></tr>
<tr><td rowspan="5">EMISSIONS INFLUENCING</td><td>High Upstream Emissions 2.47% leakage (EDF study)</td><td>-</td><td></td></tr>
<tr><td>Expected Upstream Emissions (0.79% leakage)</td><td>-</td><td></td></tr>
<tr><td>No Upstream Emissions</td><td>-</td><td></td></tr>
<tr><td>Expected Global Warming Potential (20 Years)</td><td>-</td><td></td></tr>
<tr><td>Expected Global Warming Potential (100 Years)</td><td>-</td><td></td></tr>
</table>

APPENDIX 2.5: DEMAND SCENARIOS PROPOSED SCENARIOS

Proposed Scenarios INPUT ASSUMPTIONS	Expected Case	Average Case	Low Growth & High Prices	Electrification - Carbon Reduction	High Growth & Low Prices
Customer Growth Rate	Reference Case Cust Growth Rates		Low Growth Rate	Reference Case Cust Growth Rates	High Growth Rate
Use per Customer	3 yr + Price Elasticity				
Demand Side Management	Expected Case CPA		High Prices DSM	Low Prices DSM	
Weather Planning Standard	99% probability of coldest in 30 years	20 year average	99% probability of coldest in 30 years		
GWP	100-Year GWP				
Prices Price curve	Expected		High	Low	
Carbon Legislation ($/Metric Ton)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID		Carbon Cost - High (SCC 95% at 3%)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID	$0
RESULTS					
First Gas Year Unserved					
Washington	N/A	N/A	N/A	N/A	2036
Idaho	N/A	N/A	N/A	N/A	2036
Medford	N/A	N/A	N/A	N/A	N/A
Roseburg	N/A	N/A	N/A	N/A	N/A
Klamath	N/A	N/A	N/A	N/A	N/A
La Grande	N/A	N/A	N/A	N/A	2040
Scenario Summary					
	Most aggressive peak planning case utilizing Average Case assumptions as a starting point and layering in peak day 99% probability. The likelihood of occurrence is low.	Case most representative of our average (budget, PGA, rate case) planning criteria.	Stagnant growth assumptions in order to evaluate if a shortage does occur. Not likely to occur.	Reduction of the use of natural gas to 80% below 1990 targets in OR and WA by 2050. The case assumes the overall reduction is an average goal before applying figures like elasticity and DSM.	Aggressive growth assumptions in order to evaluate when our earliest resource shortage could occur. Not likely to occur.

Risk Assessment

Higher or lower customer growth rates, which are heavily based on economic recovery. Higher or lower growth rates will lead to accelerated or delayed unserved demand. Looking at various growth assumptions off the Expected Case allows us to capture the risk in terms of the change in demand linked to customer growth.

Higher or lower use per customer will also lead to accelerated or delayed unserved demand. Use per customer can differ in many ways. Direct use per customer influencers, such as demand side management, NGV/CNG usage, and derivation of the use per customer starting point (i.e. one year, three year, etc.). Again, varying these assumptions under our forecasting methodology allows us to quantify the change each assumption has to our forecast.

Weather volatility and predictability are a key risk. As the most correlated direct demand influencer, varying weather assumptions is key to understanding the weather related risks.

Indirect influencers including elasticity and price are also important assumptions. The two go hand in hand, as price changes it will influence how much customers consume. If forecasted prices remain relatively stable over the planning horizon, our current elasticity assumption will not provide much decreased usage. However, price adders or an overall steepening of the price curve will trigger a greater decline in usage due to the price elastic response. The magnitude of the elasticity adjustment is also important. We are using a long run elasticity factor as calculated by the AGA. We continue to evaluate this assumption and are looking to update the study as part of our Action Plan.

APPENDIX 2.6: DEMAND FORECAST SENSITIVITIES AND SCENARIOS DESCRIPTIONS

DEFINITIONS

DYNAMIC DEMAND METHODOLOGY – Avista's demand forecasting approach wherein we 1) identify key demand drivers behind natural gas consumption, 2) perform sensitivity analysis on each demand driver, and 3) combine demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand.

DEMAND INFLUENCING FACTORS – Factors that directly influence the volume of natural gas consumed by our core customers.

PRICE INFLUENCING FACTORS – Factors that, through price elasticity response, indirectly influence the volume of natural gas consumed by our core customers.

REFERENCE CASE – A baseline point of reference that captures the basic inputs for determining a demand forecast in SENDOUT® which includes number of customers, use per customer, average daily weather temperatures and expected natural gas prices.

SENSITIVITIES – Focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to the Reference Case when underlying input assumptions are modified.

SCENARIOS – Combination of natural gas demand drivers that make up a demand forecast.

Avista evaluates each sensitivities impact.

SENSITIVITIES

The following Sensitivities were performed on identified demand drivers against the reference case for consideration in Scenario development. Note that Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying reference case forecast.

Following are the Demand Influencing (Direct) Sensitivities we evaluated:

REFERENCE CASE – This benchmark case uses expected customer growth rates, the most recent three years of actual use per customer per heating degree day data, average daily temperature (HDDs) in the most recent 20 years in each region, no DSM, expected prices, and no elasticity of demand.

REFERENCE CASE PLUS PEAK – Same assumptions as in the Reference Case with an adjustment made to normal weather to incorporate peak weather conditions. The peak weather data being the coldest day on record for each weather area.

LOW & HIGH CUSTOMER GROWTH – Same assumptions as in Reference Case Plus Peak with an adjustment made to customer growth rates as discussed in detail in Appendix 2.1: Economic Outlook and Customer Count Forecast.

ALTERNATE WEATHER STANDARD (COLDEST DAY 20 YRS) – Same assumptions as in the Reference Case with an adjustment made to normal weather to incorporate peak day weather conditions. The peak day weather data reflecting the coldest average daily temperature (HDDs) experienced in the most recent 20 years in each region.

DSM – Same assumptions as in Reference Case with the inclusion of Washington and Idaho DSM potential identified by the Conservation Potential Assessment provided by Applied Energy Group and Oregon DSM potential provided by Energy Trust of Oregon. See Appendix 3.1 for full assessment reports.

PEAK PLUS DSM – Same assumptions as in Reference Case Plus Peak with the inclusion of Washington and Idaho DSM potential identified by the Conservation Potential Assessment provided by Applied Energy Group and Oregon DSM potential provided by Energy Trust of Oregon. See Appendix 3.1 for full assessment reports.

80% BELOW 1990 EMISSIONS REFERENCE CASE – Reference Case Plus Peak assumptions including reduction in Oregon and Washington consumption to 80% below 1990 emission levels by 2050. The case shows the overall risk of a scenario with the overall goal of reducing natural gas emissions but does not consider what methods will be used to get to these levels or their costs.

ALTERNATE HISTORICAL 2-YEAR USE PER CUSTOMER – Reference Case Plus Peak use per customer was based upon three years of actual use per customer per heating degree day data. Same assumptions as in Reference Case Plus Peak with an adjustment made to use two years of historical use per customer per heating degree day data.

ALTERNATE HISTORICAL 5-YEAR USE PER CUSTOMER – Reference Case Plus Peak use per customer was based upon three years of actual use per customer per heating degree day data. Same assumptions as in Reference Case Plus Peak with an adjustment made to use five years of historical use per customer per heating degree day data.

JP OUTAGE AT 50% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from Jackson Prairie storage field reduced to 50% of expected capacity.

AECO OUTAGE AT 50% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from AECO reduced to 50% of expected capacity.

SUMAS OUTAGE AT 50% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from Sumas reduced to 50% of expected capacity.

ROCKIES OUTAGE AT 50% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from Rockies reduced to 50% of expected capacity.

GTN OUTAGE AT 50% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation on GTN reduced to 50% of expected capacity.

NWP OUTAGE AT 50% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation on NWP reduced to 50% of expected capacity.

JP OUTAGE AT 0% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from Jackson Prairie storage field reduced to 0% of expected capacity.

AECO OUTAGE AT 0% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from AECO reduced to 0% of expected capacity.

SUMAS OUTAGE AT 0% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from Sumas reduced to 0% of expected capacity.

ROCKIES OUTAGE AT 0% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation from Rockies reduced to 0% of expected capacity.

GTN OUTAGE AT 0% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation on GTN reduced to 0% of expected capacity.

NWP OUTAGE AT 0% CAPACITY – Same assumptions as in Reference Case Plus Peak with available transportation on NWP reduced to 0% of expected capacity.

Following are the Price Influencing (Indirect) Sensitivities we evaluated:

EXPECTED ELASTICITY – For our Expected Elasticity Sensitivity, we incorporate reduced consumption in response to higher natural gas prices by applying a price elasticity to demand. See Price Elasticity in Chapter 2: Demand Forecasts for further detail.

LOW & HIGH PRICES – To capture a wide range of alternative price forecasts, we performed a stochastic analysis based on the probability distribution of the expected price to develop 1,000 unique price forecasts around the expected price. Our high and low price forecasts represent the 95th and 25th highest percentile in each month of the 1,000 resultant price forecasts, respectively.

CARBON COST LOW CASE – Same assumptions as in Reference Case Plus Peak with consideration for price elasticity including the cost of carbon. The price of carbon in Idaho, Oregon, and Washington is set to $0 in all years.

CARBON COST EXPECTED CASE – The price of carbon in Oregon was based on a Wood Mackenzie study for Cap and Trade. It begins with a 2021 price of $15.83 MTCO2e and rising to $142.59 by 2045. The assumption is the cap and trade price will be similar to a cap and reduce price. Rules for EO 20-04 are still being developed and will be included in the 2023 IRP. Washington State was modeled using the required SCC @ 2.5%. This price is begins at $79.86 and increases yearly with a 2045 price of $185.75 (2019$). These values were provided by the WUTC Staff and are per their assumptions on inflation.

CARBON COST HIGH CASE – Assumes the EPA estimates on the social cost of carbon. Specifically, the high case includes 95% of results at a 3% discount rate average. These costs begin at $112.20 in 2017 and increase to $174 by 2037 for a metric ton of CO2. This will measure the risk of carbon pricing in all three jurisdictions.

Following are the Emissions Influencing Sensitivities we evaluated:

HIGH UPSTREAM EMISSIONS – Same assumptions as in Carbon Cost Expected Case with an adjustment to upstream emissions. Expected upstream emissions are based on 0.79% methane leakage. Per a study performed by the Environmental Defense Fund, high upstream emissions are based on 2.47% methane leakage. Higher upstream emissions increase the associated cost of carbon per dekatherm.

EXPECTED UPSTREAM EMISSIONS – Same assumption as in Carbon Cost Expected Case.

NO UPSTREAM EMISSIONS – Same assumptions as in Carbon Cost Expected Case with an adjustment to upstream emissions. Expected upstream emissions are based on 0.79% methane leakage. No upstream emissions are based on 0% methane leakage. Lower upstream emissions decrease the associated cost of carbon per dekatherm.

20-YEAR GWP – Same assumptions as in Carbon Cost Expected Case with an adjustment to the time period over which the energy absorbed by a gas is measured relative to CO2 and converted into its Global Warming Potential. The time period of 100 years used for the expected GWP is reduced to 20 years. The shorter lifetime of methane relative to CO2 results in a more significant GWP when the measurement's time period is reduced.

100-YEAR GWP – Same assumptions as in Carbon Cost Expected Case.

SCENARIOS

After identifying the above demand drivers and analyzing the various Sensitivities, we have developed the following demand forecast Scenarios:

AVERAGE CASE – This Scenario we believe represents the most likely average demand forecast modeled. We assume service territory customer growth rates consistent with the reference case, rolling 20 year normal weather in each service territory, our expected natural gas price forecast (blend of two consultants and the U.S. Energy Information Administration's Annual Energy Outlook, along with the NYMEX forward strip), expected price elasticity, the CO2 cost adders from our Carbon Cost Expected Case Sensitivity, 100 year GWP, and DSM. The Scenario does not include incremental cost adders for declining Canadian imports or drilling restrictions beyond what is incorporated in the selected price forecast.

EXPECTED CASE – This Scenario represents the peak demand forecast. We assume service territory customer growth rates consistent with the reference case, a weather standard of coldest day on record in each service territory, our expected natural gas price forecast (blend of two consultants and the U.S. Energy Information Administration's Annual Energy Outlook, along with the NYMEX forward strip), expected price elasticity, 100 year GWP, DSM, and the CO2 cost adders from our Carbon Cost Expected Case Sensitivity.

HIGH GROWTH, LOW PRICE – This Scenario models a rapid return to robust growth in part spurred on by low energy prices. We assume higher customer growth rates than the reference case, coldest day on record weather standard, our low natural gas price forecast, expected price elasticity, 100 year GWP, DSM, and no CO2 adders.

LOW GROWTH, HIGH PRICE – This Scenario models an extended period of slow economic growth in part resulting from high energy prices. We assume lower customer growth rates than the reference case, coldest day on record weather standard, our high natural gas price forecast, expected price elasticity, 100 year GWP, DSM, and CO2 adders from our Carbon Cost High Case Sensitivity.

80% BELOW 1990 EMISSIONS – This Scenario models the impact of potential consumption curtailment due to carbon legislation coupled with low energy prices. We assume a straight line reduction in Washington and Oregon consumption from reference case growth in order to meet 80% below 1990 emission levels by 2050, along with our low natural gas price forecast rather than our expected natural gas price forecast. All other assumptions remain the same as our Expected Case Scenario.

APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE EXPECTED

Scenario	Gas Year	Annual Demand Klamath Falls (MDth)	Daily Demand Klamath Falls (MDth/day)	Peak Day Klamath Falls (MDth/day)	Annual Demand La Grande (Mdth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Expected Case	2019-2020	1,431.68	3.91	14.74	866.76	2.37	8.27	6,861.29	18.75	67.27
Expected Case	2020-2021	1,434.26	3.93	14.87	859.79	2.36	8.31	6,864.56	18.81	67.94
Expected Case	2021-2022	1,357.90	3.72	13.85	823.30	2.26	7.78	6,570.96	18.00	63.46
Expected Case	2022-2023	1,370.80	3.76	13.98	828.16	2.27	7.82	6,646.71	18.21	64.18
Expected Case	2023-2024	1,389.93	3.80	14.10	840.49	2.30	7.87	6,758.07	18.46	64.86
Expected Case	2024-2025	1,391.93	3.81	14.21	836.93	2.29	7.91	6,787.07	18.59	65.54
Expected Case	2025-2026	1,392.10	3.81	14.19	836.57	2.29	7.89	6,817.61	18.68	65.70
Expected Case	2026-2027	1,387.48	3.80	14.12	834.13	2.29	7.84	6,826.75	18.70	65.61
Expected Case	2027-2028	1,402.92	3.83	14.20	844.96	2.31	7.87	6,929.47	18.93	66.20
Expected Case	2028-2029	1,402.04	3.84	14.27	840.67	2.30	7.91	6,943.47	19.02	66.76
Expected Case	2029-2030	1,408.92	3.86	14.35	844.06	2.31	7.95	6,999.94	19.18	67.34
Expected Case	2030-2031	1,415.56	3.88	14.42	847.48	2.32	7.99	7,054.23	19.33	67.87
Expected Case	2031-2032	1,431.04	3.91	14.50	858.92	2.35	8.02	7,153.87	19.55	68.39
Expected Case	2032-2033	1,430.01	3.92	14.57	854.79	2.34	8.06	7,160.77	19.62	68.90
Expected Case	2033-2034	1,437.10	3.94	14.65	858.35	2.35	8.10	7,210.88	19.76	69.41
Expected Case	2034-2035	1,444.15	3.96	14.72	861.93	2.36	8.14	7,259.44	19.89	69.87
Expected Case	2035-2036	1,460.08	3.99	14.80	873.50	2.39	8.17	7,355.73	20.10	70.33
Expected Case	2036-2037	1,459.01	4.00	14.87	869.17	2.38	8.21	7,356.66	20.16	70.79
Expected Case	2037-2038	1,466.64	4.02	14.95	872.78	2.39	8.24	7,404.20	20.29	71.25
Expected Case	2038-2039	1,474.45	4.04	15.03	876.20	2.40	8.28	7,449.86	20.41	71.69
Expected Case	2039-2040	1,492.07	4.08	15.11	888.47	2.43	8.32	7,548.45	20.62	72.12

Scenario	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Oregon (MDth/day)	Annual Demand Washington (Mdth)	Daily Demand Washington (MDth/day)	Peak Day Washington (MDth/day)	Annual Demand Idaho (MDth)	Daily Demand Idaho (MDth/day)	Peak Day Idaho (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Total System (MDth/day)
Expected Case	2019-2020	9,159.72	25.03	88.64	18,098.76	49.45	178.46	9,725.02	26.57	95.47	36,983.49	101.05	346.27
Expected Case	2020-2021	9,158.60	25.09	89.44	18,027.95	49.39	179.82	9,713.93	26.61	96.37	36,900.49	101.10	349.16
Expected Case	2021-2022	8,752.16	23.98	83.49	14,544.96	39.85	135.76	9,546.09	26.15	94.17	32,843.20	89.98	298.44
Expected Case	2022-2023	8,845.68	24.23	84.37	14,571.45	39.92	135.83	9,659.25	26.46	95.36	33,076.38	90.62	300.40
Expected Case	2023-2024	8,988.50	24.56	85.21	14,844.90	40.56	137.38	9,879.87	26.99	96.79	33,713.27	92.11	303.99
Expected Case	2024-2025	9,015.93	24.70	86.02	14,864.79	40.73	138.75	9,915.34	27.17	98.06	33,796.06	92.59	307.30
Expected Case	2025-2026	9,046.28	24.78	86.15	14,995.92	41.08	140.11	9,927.99	27.20	98.04	33,970.19	93.07	308.69
Expected Case	2026-2027	9,048.36	24.79	85.95	15,118.27	41.42	141.39	9,888.21	27.09	97.40	34,054.84	93.30	309.14
Expected Case	2027-2028	9,177.34	25.07	86.65	15,363.78	41.98	142.67	10,052.75	27.47	98.30	34,593.87	94.52	311.88
Expected Case	2028-2029	9,186.17	25.17	87.31	15,360.33	42.08	143.93	10,045.48	27.52	99.16	34,591.98	94.77	314.53
Expected Case	2029-2030	9,252.92	25.35	88.00	15,486.27	42.43	145.21	10,126.53	27.74	100.03	34,865.71	95.52	317.22
Expected Case	2030-2031	9,317.27	25.53	88.63	15,601.79	42.74	146.38	10,211.81	27.98	100.94	35,130.88	96.25	319.81
Expected Case	2031-2032	9,443.83	25.80	89.25	15,845.89	43.29	147.55	10,390.15	28.39	101.90	35,679.86	97.49	322.44
Expected Case	2032-2033	9,445.57	25.88	89.87	15,831.83	43.37	148.67	10,389.15	28.46	102.82	35,666.55	97.72	324.97
Expected Case	2033-2034	9,506.33	26.04	90.48	15,954.13	43.71	149.83	10,485.67	28.73	103.80	35,946.13	98.48	327.57
Expected Case	2034-2035	9,565.52	26.21	91.04	16,074.41	44.04	150.95	10,586.03	29.00	104.81	36,225.96	99.25	330.15
Expected Case	2035-2036	9,689.30	26.47	91.60	16,330.15	44.62	152.10	10,781.21	29.46	105.85	36,800.66	100.55	332.82
Expected Case	2036-2037	9,684.84	26.53	92.17	16,314.36	44.70	153.18	10,789.75	29.56	106.86	36,788.95	100.79	335.33
Expected Case	2037-2038	9,743.62	26.69	92.73	16,425.97	45.00	154.24	10,889.37	29.83	107.88	37,058.96	101.53	337.86
Expected Case	2038-2039	9,800.51	26.85	93.28	16,537.95	45.31	155.29	10,991.52	30.11	108.93	37,329.99	102.27	340.38
Expected Case	2039-2040	9,928.99	27.13	93.82	16,786.41	45.86	156.35	11,190.36	30.57	109.99	37,905.75	103.57	342.98

APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE AVERAGE

Scenario	Gas Year	Annual Demand Klamath Falls (MDth)	Daily Demand Klamath Falls (MDth/day)	Peak Day Klamath Falls (MDth/day)	Annual Demand La Grande (Mdth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Average Case	2019-2020	1,392.92	3.81	6.92	841.05	2.30	3.60	6,656.84	18.19	32.83
Average Case	2020-2021	1,396.72	3.83	6.98	838.66	2.30	3.61	6,672.13	18.28	33.16
Average Case	2021-2022	1,323.03	3.62	6.52	803.75	2.20	3.43	6,392.14	17.51	31.15
Average Case	2022-2023	1,335.61	3.66	6.58	808.50	2.22	3.45	6,465.95	17.71	31.51
Average Case	2023-2024	1,352.91	3.70	6.64	816.33	2.23	3.47	6,562.17	17.93	31.87
Average Case	2024-2025	1,356.17	3.72	6.69	817.06	2.24	3.49	6,602.62	18.09	32.19
Average Case	2025-2026	1,356.42	3.72	6.68	816.78	2.24	3.48	6,632.93	18.17	32.31
Average Case	2026-2027	1,351.99	3.70	6.66	814.48	2.23	3.46	6,642.58	18.20	32.30
Average Case	2027-2028	1,365.66	3.73	6.69	820.81	2.24	3.48	6,729.96	18.39	32.58
Average Case	2028-2029	1,366.11	3.74	6.72	820.82	2.25	3.49	6,755.89	18.51	32.83
Average Case	2029-2030	1,372.78	3.76	6.76	824.11	2.26	3.51	6,810.75	18.66	33.11
Average Case	2030-2031	1,379.23	3.78	6.78	827.43	2.27	3.52	6,863.48	18.80	33.35
Average Case	2031-2032	1,392.92	3.81	6.82	834.28	2.28	3.54	6,947.58	18.98	33.60
Average Case	2032-2033	1,393.28	3.82	6.85	834.54	2.29	3.56	6,967.11	19.09	33.85
Average Case	2033-2034	1,400.18	3.84	6.89	838.01	2.30	3.57	7,015.85	19.22	34.11
Average Case	2034-2035	1,407.04	3.85	6.92	841.49	2.31	3.59	7,063.09	19.35	34.32
Average Case	2035-2036	1,421.15	3.88	6.95	848.39	2.32	3.60	7,143.65	19.52	34.55
Average Case	2036-2037	1,421.50	3.89	6.99	848.55	2.32	3.62	7,157.74	19.61	34.78
Average Case	2037-2038	1,428.94	3.91	7.02	852.07	2.33	3.63	7,204.05	19.74	35.00
Average Case	2038-2039	1,436.55	3.94	7.06	855.40	2.34	3.65	7,248.50	19.86	35.22
Average Case	2039-2040	1,452.31	3.97	7.10	862.93	2.36	3.67	7,331.13	20.03	35.43

Scenario	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Oregon (MDth/day)	Annual Demand Washington (Mdth)	Daily Demand Washington (MDth/day)	Peak Day Washington (MDth/day)	Annual Demand Idaho (MDth)	Daily Demand Idaho (MDth/day)	Peak Day Idaho (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Total System (MDth/day)
Average Case	2019-2020	8,890.81	24.29	43.73	17,565.86	47.99	81.97	9,441.78	25.80	44.12	35,898.45	98.08	182.25
Average Case	2020-2021	8,907.50	24.40	44.11	17,574.40	48.15	82.40	9,472.26	25.95	44.44	35,954.16	98.50	184.09
Average Case	2021-2022	8,518.92	23.34	41.39	14,211.37	38.94	64.09	9,310.46	25.51	43.52	32,040.76	87.78	159.26
Average Case	2022-2023	8,610.07	23.59	41.83	14,237.69	39.01	64.13	9,420.49	25.81	44.03	32,268.25	88.41	160.25
Average Case	2023-2024	8,731.41	23.86	42.27	14,444.62	39.47	64.88	9,592.37	26.21	44.70	32,768.39	89.53	162.00
Average Case	2024-2025	8,775.86	24.04	42.66	14,523.67	39.79	65.48	9,669.63	26.49	45.26	32,969.15	90.33	163.87
Average Case	2025-2026	8,806.13	24.13	42.76	14,651.22	40.14	66.07	9,682.33	26.53	45.26	33,139.68	90.79	164.66
Average Case	2026-2027	8,809.05	24.13	42.71	14,770.09	40.47	66.61	9,644.23	26.42	44.99	33,223.37	91.02	164.98
Average Case	2027-2028	8,916.43	24.36	43.03	14,946.78	40.84	67.17	9,760.50	26.67	45.37	33,623.71	91.87	166.27
Average Case	2028-2029	8,942.82	24.50	43.32	15,005.40	41.11	67.71	9,796.76	26.84	45.74	33,744.98	92.45	167.56
Average Case	2029-2030	9,007.63	24.68	43.66	15,127.99	41.45	68.28	9,875.47	27.06	46.12	34,011.09	93.18	168.95
Average Case	2030-2031	9,070.13	24.85	43.95	15,240.47	41.75	68.81	9,958.36	27.28	46.52	34,268.97	93.89	170.27
Average Case	2031-2032	9,174.79	25.07	44.24	15,413.88	42.11	69.35	10,086.63	27.56	46.95	34,675.30	94.74	171.61
Average Case	2032-2033	9,194.94	25.19	44.54	15,464.66	42.37	69.85	10,130.79	27.76	47.34	34,790.38	95.32	172.95
Average Case	2033-2034	9,254.04	25.35	44.85	15,584.11	42.70	70.40	10,224.79	28.01	47.79	35,062.93	96.06	174.33
Average Case	2034-2035	9,311.61	25.51	45.11	15,701.63	43.02	70.93	10,322.58	28.28	48.26	35,335.82	96.81	175.72
Average Case	2035-2036	9,413.20	25.72	45.39	15,884.78	43.40	71.50	10,465.67	28.59	48.74	35,763.64	97.71	177.11
Average Case	2036-2037	9,427.80	25.83	45.67	15,936.12	43.66	72.00	10,521.09	28.82	49.19	35,885.00	98.32	178.51
Average Case	2037-2038	9,485.05	25.99	45.95	16,045.09	43.96	72.50	10,618.04	29.09	49.65	36,148.19	99.04	179.91
Average Case	2038-2039	9,540.45	26.14	46.22	16,154.49	44.26	73.00	10,717.52	29.36	50.12	36,412.46	99.76	181.25
Average Case	2039-2040	9,646.36	26.36	46.49	16,328.60	44.61	73.51	10,862.23	29.68	50.61	36,837.19	100.65	182.60

APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE HIGH GROWTH

Scenario	Gas Year	Annual Demand Klamath Falls (MDth)	Daily Demand Klamath Falls (MDth/day)	Peak Day Klamath Falls (MDth/day)	Annual Demand La Grande (Mdth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
High Growth & Low Prices	2019-2020	1,435.98	3.92	14.74	866.71	2.37	8.27	6,864.78	18.76	67.27
High Growth & Low Prices	2020-2021	1,468.73	4.02	15.18	880.04	2.41	8.45	6,892.78	18.88	68.19
High Growth & Low Prices	2021-2022	1,497.41	4.10	15.47	899.99	2.47	8.60	6,979.54	19.12	68.87
High Growth & Low Prices	2022-2023	1,524.38	4.18	15.75	921.13	2.52	8.73	7,074.55	19.38	69.79
High Growth & Low Prices	2023-2024	1,555.98	4.25	15.99	950.19	2.60	8.86	7,206.76	19.69	70.66
High Growth & Low Prices	2024-2025	1,566.72	4.29	16.20	961.70	2.63	8.99	7,249.92	19.86	71.53
High Growth & Low Prices	2025-2026	1,573.56	4.31	16.24	976.66	2.68	9.04	7,293.70	19.98	71.81
High Growth & Low Prices	2026-2027	1,567.81	4.30	16.14	986.58	2.70	9.01	7,291.01	19.98	71.50
High Growth & Low Prices	2027-2028	1,590.17	4.34	16.28	1,014.74	2.77	9.13	7,415.76	20.26	72.27
High Growth & Low Prices	2028-2029	1,592.54	4.36	16.40	1,025.22	2.81	9.25	7,442.01	20.39	73.01
High Growth & Low Prices	2029-2030	1,602.26	4.39	16.51	1,044.67	2.86	9.37	7,512.46	20.58	73.75
High Growth & Low Prices	2030-2031	1,612.33	4.42	16.61	1,064.23	2.92	9.49	7,579.37	20.77	74.41
High Growth & Low Prices	2031-2032	1,632.86	4.46	16.71	1,093.23	2.99	9.61	7,696.03	21.03	75.06
High Growth & Low Prices	2032-2033	1,633.75	4.48	16.82	1,102.80	3.02	9.72	7,706.60	21.11	75.69
High Growth & Low Prices	2033-2034	1,634.17	4.48	16.80	1,116.17	3.06	9.76	7,722.22	21.16	75.68
High Growth & Low Prices	2034-2035	1,646.50	4.51	16.92	1,134.32	3.11	9.87	7,778.25	21.31	76.24
High Growth & Low Prices	2035-2036	1,669.51	4.56	17.05	1,161.76	3.17	9.97	7,886.81	21.55	76.78
High Growth & Low Prices	2036-2037	1,672.63	4.58	17.18	1,169.26	3.20	10.06	7,892.36	21.62	77.33
High Growth & Low Prices	2037-2038	1,683.95	4.61	17.30	1,186.06	3.25	10.15	7,948.80	21.78	77.88
High Growth & Low Prices	2038-2039	1,692.27	4.64	17.39	1,202.31	3.29	10.23	8,003.40	21.93	78.41
High Growth & Low Prices	2039-2040	1,711.39	4.68	17.47	1,228.84	3.36	10.31	8,112.10	22.16	78.93

Scenario	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Oregon (MDth/day)	Annual Demand Washington (Mdth)	Daily Demand Washington (MDth/day)	Peak Day Washington (MDth/day)	Annual Demand Idaho (MDth)	Daily Demand Idaho (MDth/day)	Peak Day Idaho (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Total System (MDth/day)
High Growth & Low Prices	2019-2020	9,167.47	25.05	88.64	18,115.23	49.50	178.46	9,740.07	26.61	95.47	37,022.77	101.16	346.27
High Growth & Low Prices	2020-2021	9,241.55	25.32	90.12	18,179.86	49.81	181.18	9,845.41	26.97	97.59	37,266.82	102.10	352.38
High Growth & Low Prices	2021-2022	9,376.95	25.69	91.17	18,380.79	50.36	183.28	9,996.12	27.39	99.12	37,753.86	103.44	357.17
High Growth & Low Prices	2022-2023	9,520.07	26.08	92.49	18,640.01	51.07	185.92	10,206.52	27.96	101.21	38,366.60	105.11	362.96
High Growth & Low Prices	2023-2024	9,712.93	26.54	93.71	19,101.00	52.19	188.92	10,535.48	28.79	103.63	39,349.41	107.51	369.31
High Growth & Low Prices	2024-2025	9,778.34	26.79	94.88	19,220.11	52.66	191.80	10,666.50	29.22	105.87	39,664.95	108.67	375.41
High Growth & Low Prices	2025-2026	9,843.93	26.97	95.26	19,361.87	53.05	192.93	10,776.22	29.52	106.79	39,982.02	109.54	377.75
High Growth & Low Prices	2026-2027	9,845.40	26.97	94.85	19,378.99	53.09	192.49	10,806.95	29.61	106.73	40,031.34	109.67	376.89
High Growth & Low Prices	2027-2028	10,020.67	27.38	95.85	19,810.55	54.13	195.13	11,067.89	30.24	108.40	40,899.11	111.75	382.03
High Growth & Low Prices	2028-2029	10,059.77	27.56	96.81	19,896.43	54.51	197.74	11,136.13	30.51	110.05	41,092.33	112.58	387.08
High Growth & Low Prices	2029-2030	10,159.38	27.83	97.76	20,154.03	55.22	200.36	11,301.98	30.96	111.72	41,615.40	114.01	392.11
High Growth & Low Prices	2030-2031	10,255.93	28.10	98.61	20,386.60	55.85	202.70	11,473.41	31.43	113.43	42,115.95	115.39	396.90
High Growth & Low Prices	2031-2032	10,422.12	28.48	99.46	20,793.50	56.81	204.99	11,750.62	32.11	115.19	42,966.24	117.39	401.67
High Growth & Low Prices	2032-2033	10,443.15	28.61	100.30	20,836.72	57.09	207.26	11,826.00	32.40	116.97	43,105.87	118.10	406.35
High Growth & Low Prices	2033-2034	10,472.56	28.69	100.30	20,926.69	57.33	207.83	11,935.63	32.70	117.86	43,334.88	118.73	407.84
High Growth & Low Prices	2034-2035	10,559.07	28.93	101.07	21,139.42	57.92	209.96	12,121.64	33.21	119.71	43,820.12	120.06	412.45
High Growth & Low Prices	2035-2036	10,718.08	29.28	101.82	21,542.65	58.86	212.11	12,420.52	33.94	121.61	44,681.26	122.08	417.14
High Growth & Low Prices	2036-2037	10,734.24	29.41	102.58	21,566.96	59.09	214.21	12,505.27	34.26	123.51	44,806.48	122.76	421.74
High Growth & Low Prices	2037-2038	10,818.82	29.64	103.33	21,773.10	59.65	216.27	12,700.84	34.80	125.45	45,292.77	124.09	426.33
High Growth & Low Prices	2038-2039	10,897.97	29.86	104.02	21,975.85	60.21	218.28	12,899.21	35.34	127.42	45,773.03	125.41	430.87
High Growth & Low Prices	2039-2040	11,052.33	30.20	104.69	22,370.77	61.12	220.27	13,211.47	36.10	129.40	46,634.57	127.42	435.42

APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CASE LOW GROWTH

Scenario	Gas Year	Annual Demand Klamath Falls (MDth)	Daily Demand Klamath Falls (MDth/day)	Peak Day Klamath Falls (MDth/day)	Annual Demand La Grande (Mdth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Low Growth & High Prices	2019-2020	1,426.57	3.90	14.74	853.39	2.33	8.27	6,855.58	18.73	67.27
Low Growth & High Prices	2020-2021	1,392.75	3.82	14.49	821.59	2.25	8.13	6,817.71	18.68	67.54
Low Growth & High Prices	2021-2022	759.51	2.08	6.37	510.49	1.40	3.75	4,197.95	11.50	31.28
Low Growth & High Prices	2022-2023	752.97	2.06	6.28	499.18	1.37	3.70	4,202.93	11.51	31.14
Low Growth & High Prices	2023-2024	756.45	2.07	6.29	496.96	1.36	3.69	4,250.88	11.61	31.37
Low Growth & High Prices	2024-2025	752.93	2.06	6.29	490.31	1.34	3.68	4,257.22	11.66	31.56
Low Growth & High Prices	2025-2026	753.43	2.06	6.30	487.01	1.33	3.66	4,281.51	11.73	31.79
Low Growth & High Prices	2026-2027	753.42	2.06	6.31	483.21	1.32	3.65	4,299.56	11.78	31.96
Low Growth & High Prices	2027-2028	757.53	2.07	6.32	483.70	1.32	3.64	4,338.30	11.85	32.09
Low Growth & High Prices	2028-2029	754.90	2.07	6.33	477.47	1.31	3.63	4,333.70	11.87	32.22
Low Growth & High Prices	2029-2030	756.55	2.07	6.36	475.46	1.30	3.61	4,350.20	11.92	32.38
Low Growth & High Prices	2030-2031	758.66	2.08	6.38	473.71	1.30	3.60	4,367.91	11.97	32.51
Low Growth & High Prices	2031-2032	764.89	2.09	6.40	475.76	1.30	3.59	4,408.45	12.04	32.66
Low Growth & High Prices	2032-2033	763.88	2.09	6.43	471.01	1.29	3.59	4,401.85	12.06	32.79
Low Growth & High Prices	2033-2034	766.99	2.10	6.46	470.19	1.29	3.58	4,418.42	12.11	32.94
Low Growth & High Prices	2034-2035	770.02	2.11	6.49	469.62	1.29	3.58	4,434.79	12.15	33.06
Low Growth & High Prices	2035-2036	777.58	2.12	6.51	473.17	1.29	3.58	4,477.21	12.23	33.19
Low Growth & High Prices	2036-2037	777.37	2.13	6.54	470.25	1.29	3.58	4,472.54	12.25	33.33
Low Growth & High Prices	2037-2038	781.38	2.14	6.58	471.01	1.29	3.59	4,490.79	12.30	33.48
Low Growth & High Prices	2038-2039	785.69	2.15	6.61	471.79	1.29	3.59	4,507.25	12.35	33.61
Low Growth & High Prices	2039-2040	795.14	2.17	6.65	476.95	1.30	3.61	4,553.17	12.44	33.73

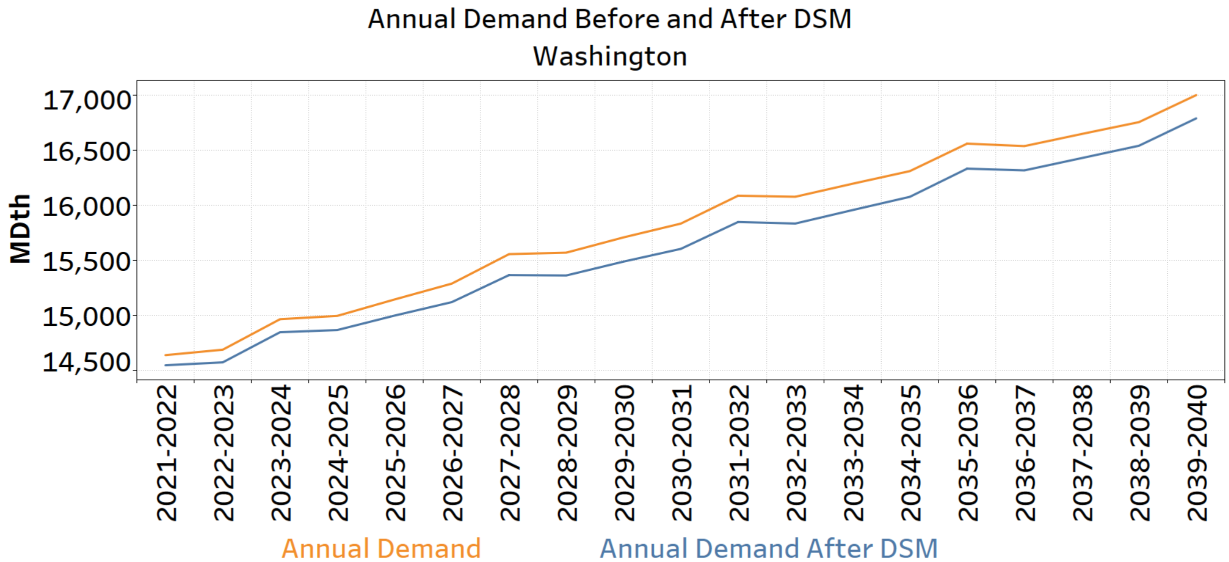
Scenario	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Oregon (MDth/day)	Annual Demand Washington (Mdth)	Daily Demand Washington (MDth/day)	Peak Day Washington (MDth/day)	Annual Demand Idaho (MDth)	Daily Demand Idaho (MDth/day)	Peak Day Idaho (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Total System (MDth/day)
Low Growth & High Prices	2019-2020	9,135.54	24.96	88.64	18,081.89	49.40	178.46	9,706.05	26.52	95.47	36,923.49	100.88	346.27
Low Growth & High Prices	2020-2021	9,032.06	24.75	88.54	17,804.05	48.78	177.97	9,540.59	26.14	94.85	36,376.70	99.66	344.94
Low Growth & High Prices	2021-2022	5,467.95	14.98	40.75	9,952.51	27.27	79.56	5,412.27	14.83	42.55	20,832.74	57.08	156.34
Low Growth & High Prices	2022-2023	5,455.08	14.95	40.46	9,886.58	27.09	78.90	5,360.76	14.69	42.11	20,702.42	56.72	155.06
Low Growth & High Prices	2023-2024	5,504.30	15.04	40.67	10,007.73	27.34	79.53	5,430.01	14.84	42.52	20,942.04	57.22	156.22
Low Growth & High Prices	2024-2025	5,500.46	15.07	40.85	9,964.46	27.30	79.79	5,400.42	14.80	42.60	20,865.34	57.17	156.74
Low Growth & High Prices	2025-2026	5,521.94	15.13	41.08	9,985.35	27.36	80.15	5,396.73	14.79	42.70	20,904.02	57.27	157.32
Low Growth & High Prices	2026-2027	5,536.20	15.17	41.25	10,016.59	27.44	80.54	5,396.31	14.78	42.79	20,949.10	57.39	157.91
Low Growth & High Prices	2027-2028	5,579.53	15.24	41.38	10,123.31	27.66	80.99	5,438.12	14.86	42.93	21,140.95	57.76	158.61
Low Growth & High Prices	2028-2029	5,566.06	15.25	41.50	10,085.56	27.63	81.32	5,403.28	14.80	43.01	21,054.90	57.68	159.15
Low Growth & High Prices	2029-2030	5,582.20	15.29	41.68	10,123.96	27.74	81.74	5,406.05	14.81	43.09	21,112.21	57.84	159.75
Low Growth & High Prices	2030-2031	5,600.28	15.34	41.81	10,168.48	27.86	82.16	5,415.13	14.84	43.23	21,183.89	58.04	160.45
Low Growth & High Prices	2031-2032	5,649.10	15.43	41.98	10,294.69	28.13	82.67	5,466.47	14.94	43.41	21,410.26	58.50	161.26
Low Growth & High Prices	2032-2033	5,636.75	15.44	42.13	10,278.86	28.16	83.08	5,440.74	14.91	43.52	21,356.34	58.51	161.91
Low Growth & High Prices	2033-2034	5,655.60	15.49	42.30	10,343.82	28.34	83.56	5,462.39	14.97	43.70	21,461.82	58.80	162.68
Low Growth & High Prices	2034-2035	5,674.43	15.55	42.45	10,407.67	28.51	84.02	5,488.90	15.04	43.91	21,571.00	59.10	163.48
Low Growth & High Prices	2035-2036	5,727.97	15.65	42.60	10,549.24	28.82	84.55	5,556.26	15.18	44.15	21,833.47	59.65	164.40
Low Growth & High Prices	2036-2037	5,720.16	15.67	42.78	10,543.59	28.89	85.00	5,542.57	15.19	44.32	21,806.32	59.74	165.15
Low Growth & High Prices	2037-2038	5,743.18	15.73	42.97	10,604.05	29.05	85.43	5,564.75	15.25	44.50	21,911.99	60.03	165.90
Low Growth & High Prices	2038-2039	5,764.73	15.79	43.13	10,660.78	29.21	85.85	5,586.95	15.31	44.68	22,012.46	60.31	166.64
Low Growth & High Prices	2039-2040	5,825.26	15.92	43.30	10,791.38	29.48	86.29	5,647.85	15.43	44.88	22,264.50	60.83	167.48

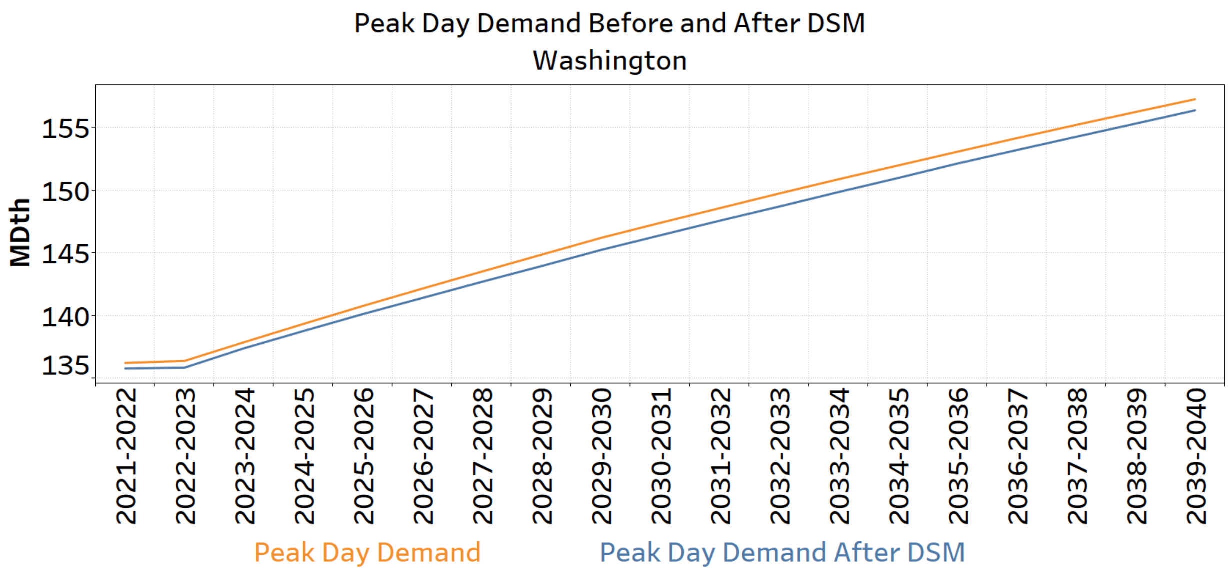
APPENDIX 2.7: ANNUAL DEMAND, AVERAGE DAY DEMAND AND PEAK DAY DEMAND (NET OF DSM) – CARBON REDUCTION

Scenario	Gas Year	Annual Demand Klamath Falls (MDth)	Daily Demand Klamath Falls (MDth/day)	Peak Day Klamath Falls (MDth/day)	Annual Demand La Grande (Mdth)	Daily Demand La Grande (MDth/day)	Peak Day La Grande (MDth/day)	Annual Demand Medford/Roseburg (MDth)	Daily Demand Medford/Roseburg (MDth/day)	Peak Day Medford/Roseburg (MDth/day)
Electrification & Carbon Reduction	2019-2020	1,431.68	3.91	14.74	866.76	2.37	8.27	6,861.29	18.75	67.27
Electrification & Carbon Reduction	2020-2021	1,434.26	3.93	14.87	859.81	2.36	8.31	6,864.75	18.81	67.94
Electrification & Carbon Reduction	2021-2022	1,391.90	3.81	14.28	839.39	2.30	8.01	6,711.03	18.39	65.38
Electrification & Carbon Reduction	2022-2023	1,405.20	3.85	14.42	844.46	2.31	8.05	6,789.13	18.60	66.12
Electrification & Carbon Reduction	2023-2024	1,424.78	3.89	14.54	857.10	2.34	8.10	6,903.05	18.86	66.82
Electrification & Carbon Reduction	2024-2025	1,426.81	3.91	14.65	853.42	2.34	8.15	6,932.56	18.99	67.52
Electrification & Carbon Reduction	2025-2026	1,436.98	3.94	14.76	857.74	2.35	8.19	7,005.50	19.19	68.25
Electrification & Carbon Reduction	2026-2027	1,433.78	3.93	14.71	855.97	2.35	8.15	7,021.55	19.24	68.25
Electrification & Carbon Reduction	2027-2028	1,450.21	3.96	14.79	867.45	2.37	8.19	7,129.94	19.48	68.87
Electrification & Carbon Reduction	2028-2029	1,440.23	3.95	14.76	858.76	2.35	8.16	7,106.20	19.47	68.94
Electrification & Carbon Reduction	2029-2030	1,437.77	3.94	14.72	857.77	2.35	8.14	7,123.63	19.52	69.00
Electrification & Carbon Reduction	2030-2031	1,444.61	3.96	14.79	861.27	2.36	8.18	7,179.02	19.67	69.53
Electrification & Carbon Reduction	2031-2032	1,460.77	3.99	14.86	873.14	2.39	8.22	7,282.30	19.90	70.07
Electrification & Carbon Reduction	2032-2033	1,459.29	4.00	14.95	868.64	2.38	8.25	7,286.90	19.96	70.61
Electrification & Carbon Reduction	2033-2034	1,456.43	3.99	14.89	867.56	2.38	8.22	7,294.77	19.99	70.52
Electrification & Carbon Reduction	2034-2035	1,463.39	4.01	14.97	871.06	2.39	8.26	7,342.80	20.12	71.00
Electrification & Carbon Reduction	2035-2036	1,479.49	4.04	15.04	882.76	2.41	8.30	7,440.12	20.33	71.46
Electrification & Carbon Reduction	2036-2037	1,478.51	4.05	15.12	878.43	2.41	8.34	7,441.58	20.39	71.93
Electrification & Carbon Reduction	2037-2038	1,486.30	4.07	15.20	882.12	2.42	8.37	7,490.04	20.52	72.40
Electrification & Carbon Reduction	2038-2039	1,494.24	4.09	15.28	885.57	2.43	8.41	7,536.29	20.65	72.85
Electrification & Carbon Reduction	2039-2040	1,511.59	4.13	15.36	897.67	2.45	8.44	7,633.16	20.86	73.29

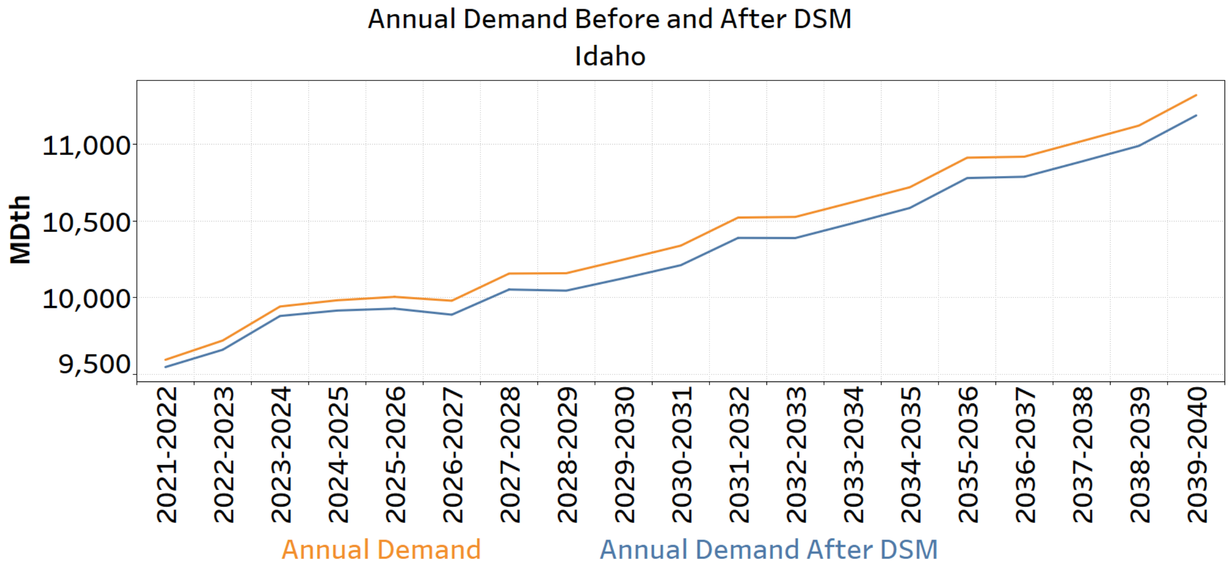
Scenario	Gas Year	Annual Demand Oregon (MDth)	Daily Demand Oregon (MDth/day)	Peak Day Oregon (MDth/day)	Annual Demand Washington (Mdth)	Daily Demand Washington (MDth/day)	Peak Day Washington (MDth/day)	Annual Demand Idaho (MDth)	Daily Demand Idaho (MDth/day)	Peak Day Idaho (MDth/day)	Annual Demand Total System (MDth)	Daily Demand Total System (MDth/day)	Peak Day Total System (MDth/day)
Electrification & Carbon Reduction	2019-2020	9,159.72	25.03	88.64	18,098.76	49.45	178.46	9,725.02	26.57	95.47	36,983.49	101.05	346.27
Electrification & Carbon Reduction	2020-2021	9,158.82	25.09	89.44	18,062.12	49.49	180.05	9,725.34	26.64	96.44	36,946.27	101.22	349.46
Electrification & Carbon Reduction	2021-2022	8,942.33	24.50	86.02	15,016.07	41.14	141.26	9,806.47	26.87	97.31	33,764.87	92.51	309.10
Electrification & Carbon Reduction	2022-2023	9,038.78	24.76	86.92	15,065.78	41.28	141.49	9,929.11	27.20	98.56	34,033.67	93.24	311.30
Electrification & Carbon Reduction	2023-2024	9,184.93	25.10	87.80	15,354.91	41.95	143.09	10,161.96	27.76	100.06	34,701.80	94.81	315.03
Electrification & Carbon Reduction	2024-2025	9,212.79	25.24	88.63	15,383.96	42.15	144.58	10,204.57	27.96	101.41	34,801.32	95.35	318.56
Electrification & Carbon Reduction	2025-2026	9,300.22	25.48	89.50	15,531.68	42.55	146.05	10,237.36	28.05	101.59	35,069.26	96.08	320.87
Electrification & Carbon Reduction	2026-2027	9,311.30	25.51	89.42	15,676.32	42.95	147.47	10,200.85	27.95	100.90	35,188.47	96.41	321.49
Electrification & Carbon Reduction	2027-2028	9,447.59	25.81	90.16	15,950.91	43.58	148.88	10,381.86	28.37	101.86	35,780.37	97.76	324.45
Electrification & Carbon Reduction	2028-2029	9,405.20	25.77	90.17	15,960.18	43.73	150.26	10,380.87	28.44	102.79	35,746.24	97.93	326.77
Electrification & Carbon Reduction	2029-2030	9,419.18	25.81	90.17	16,101.50	44.11	151.65	10,471.06	28.69	103.73	35,991.74	98.61	329.05
Electrification & Carbon Reduction	2030-2031	9,484.90	25.99	90.80	16,230.47	44.47	152.90	10,564.90	28.94	104.69	36,280.27	99.40	331.80
Electrification & Carbon Reduction	2031-2032	9,616.22	26.27	91.45	16,492.34	45.06	154.12	10,753.95	29.38	105.69	36,862.51	100.72	334.55
Electrification & Carbon Reduction	2032-2033	9,614.83	26.34	92.09	16,478.59	45.15	155.32	10,756.09	29.47	106.67	36,849.51	100.96	337.20
Electrification & Carbon Reduction	2033-2034	9,618.76	26.35	91.94	16,600.50	45.48	156.51	10,788.76	29.56	106.84	37,008.02	101.39	338.43
Electrification & Carbon Reduction	2034-2035	9,677.25	26.51	92.52	16,719.56	45.81	157.65	10,889.73	29.83	107.87	37,286.54	102.15	341.07
Electrification & Carbon Reduction	2035-2036	9,802.37	26.78	93.08	16,982.35	46.40	158.82	11,090.44	30.30	108.93	37,875.16	103.48	343.76
Electrification & Carbon Reduction	2036-2037	9,798.52	26.85	93.66	16,960.20	46.47	159.94	11,097.59	30.40	109.97	37,856.31	103.72	346.38
Electrification & Carbon Reduction	2037-2038	9,858.45	27.01	94.24	17,075.82	46.78	161.04	11,202.89	30.69	111.04	38,137.16	104.49	349.00
Electrification & Carbon Reduction	2038-2039	9,916.10	27.17	94.79	17,190.01	47.10	162.13	11,309.35	30.98	112.11	38,415.46	105.25	351.60
Electrification & Carbon Reduction	2039-2040	10,042.43	27.44	95.34	17,447.22	47.67	163.20	11,514.51	31.46	113.19	39,004.15	106.57	354.22

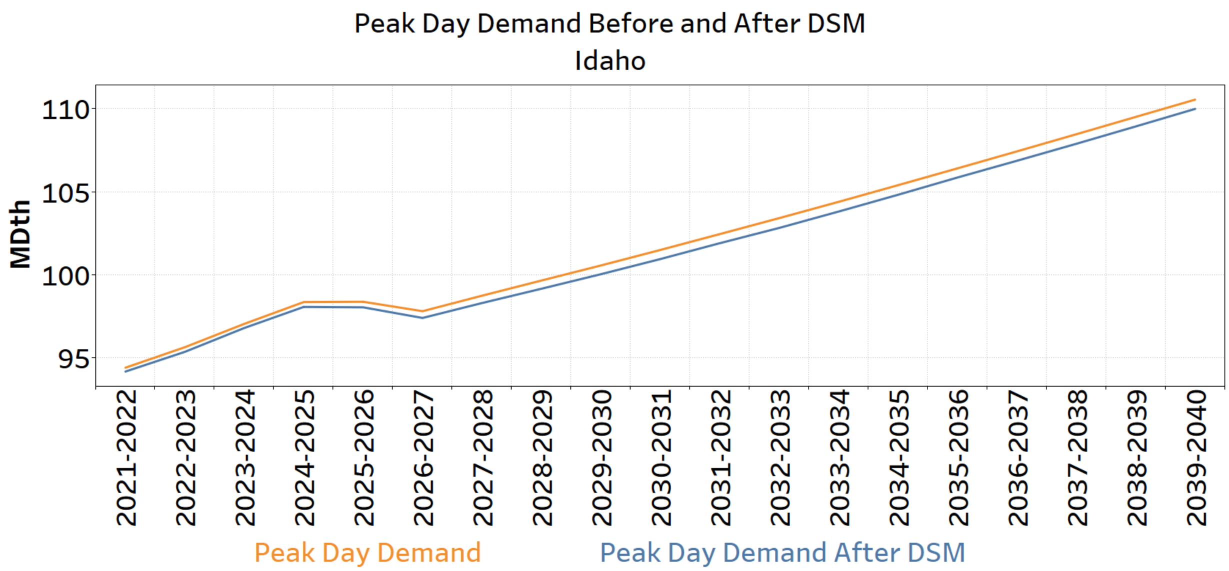
APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM WASHINGTON



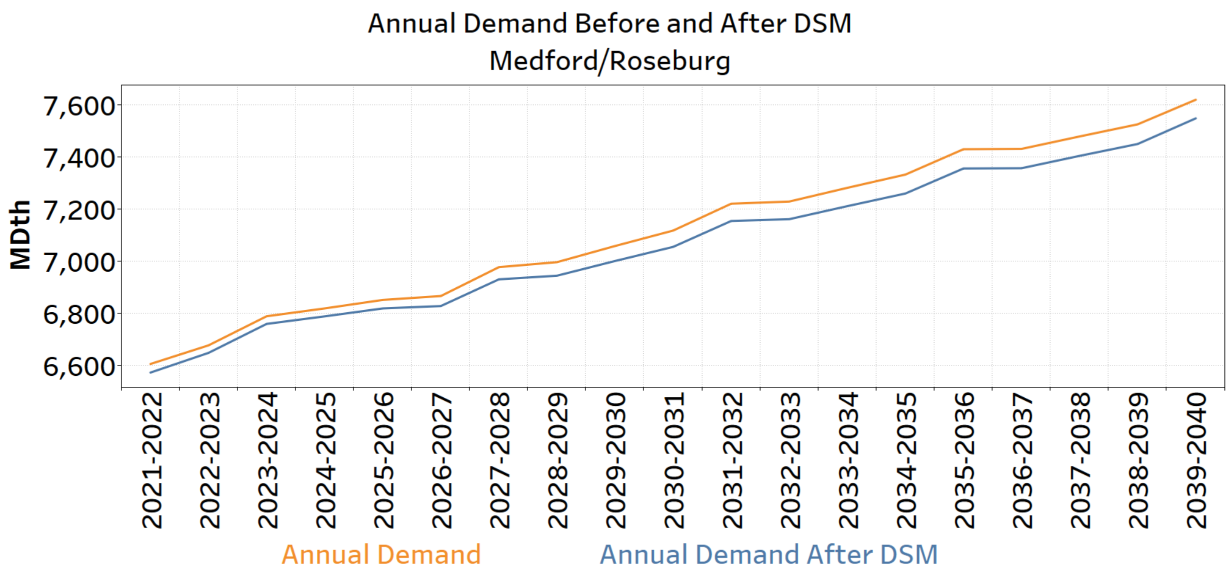


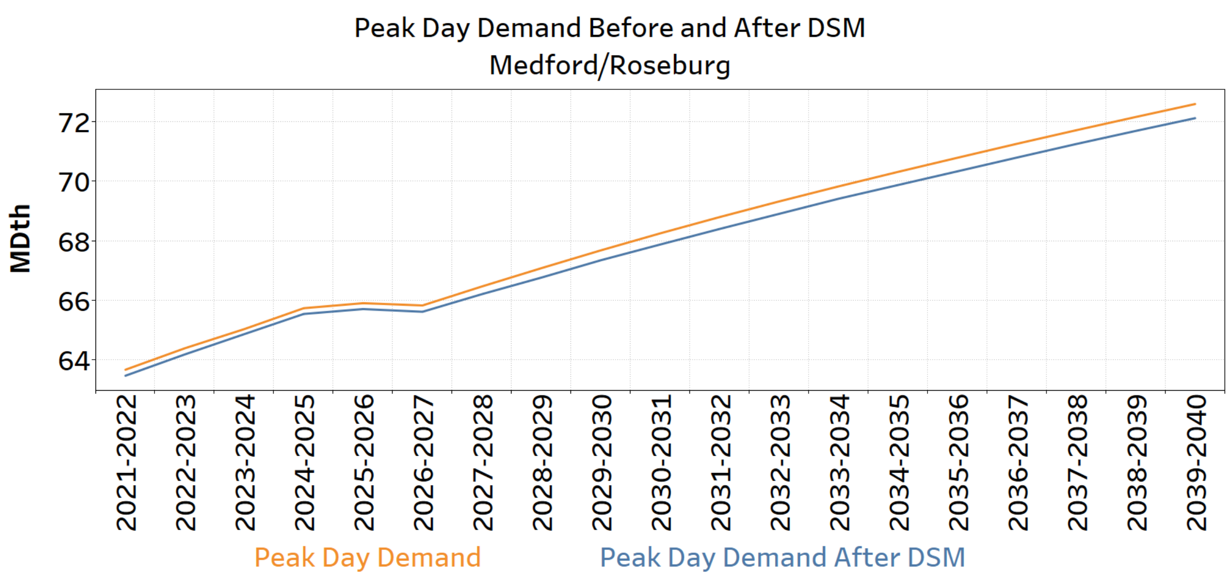
APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM IDAHO



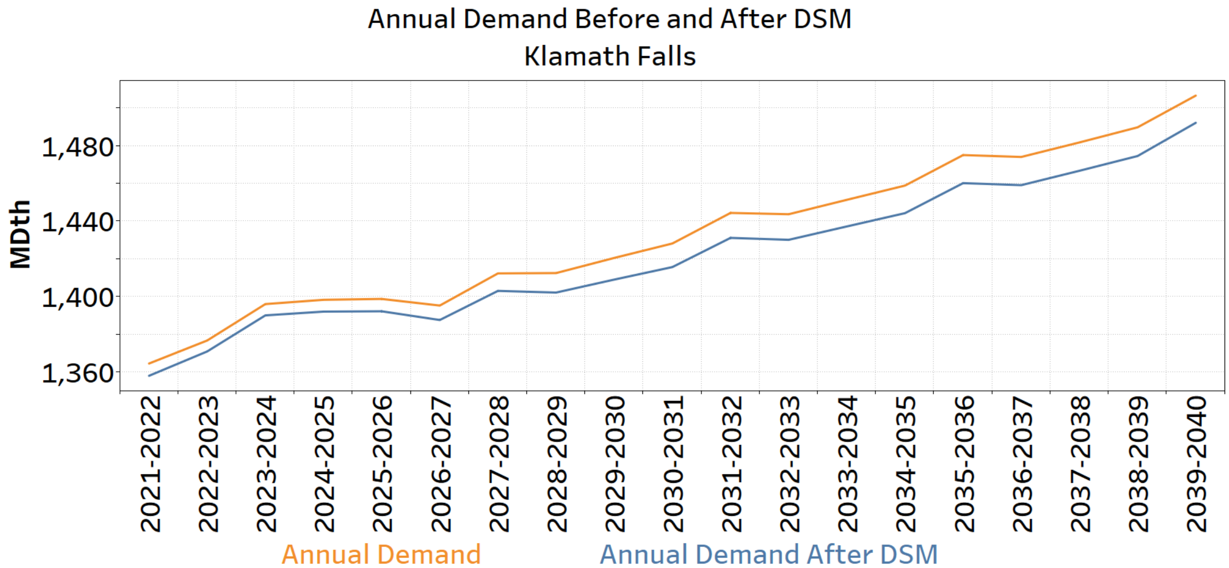


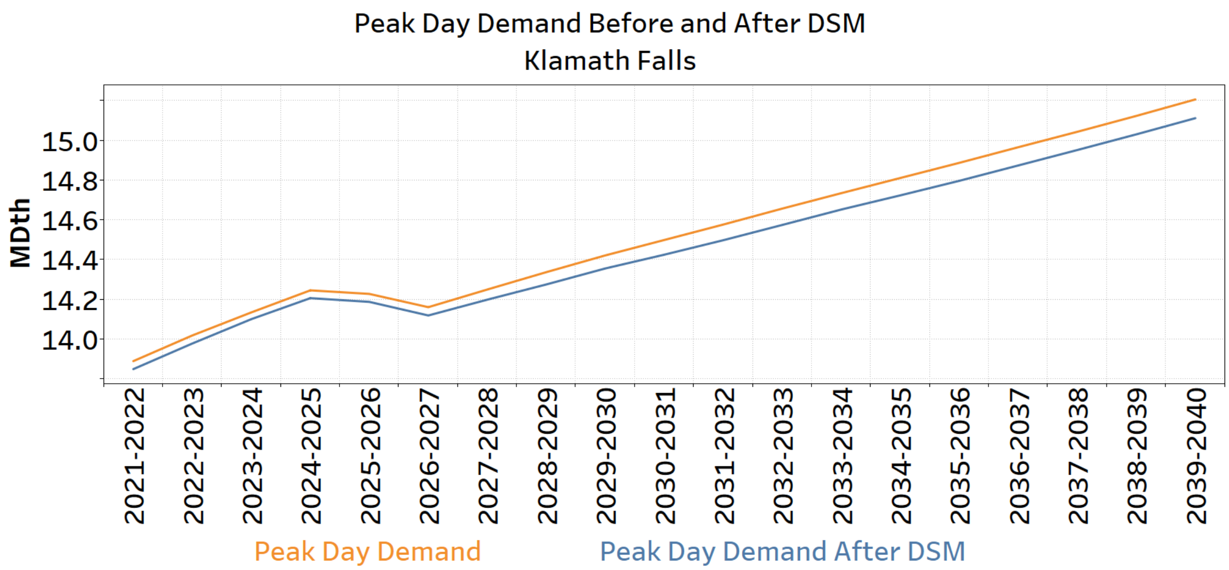
APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM MEDFORD/ROSEBURG





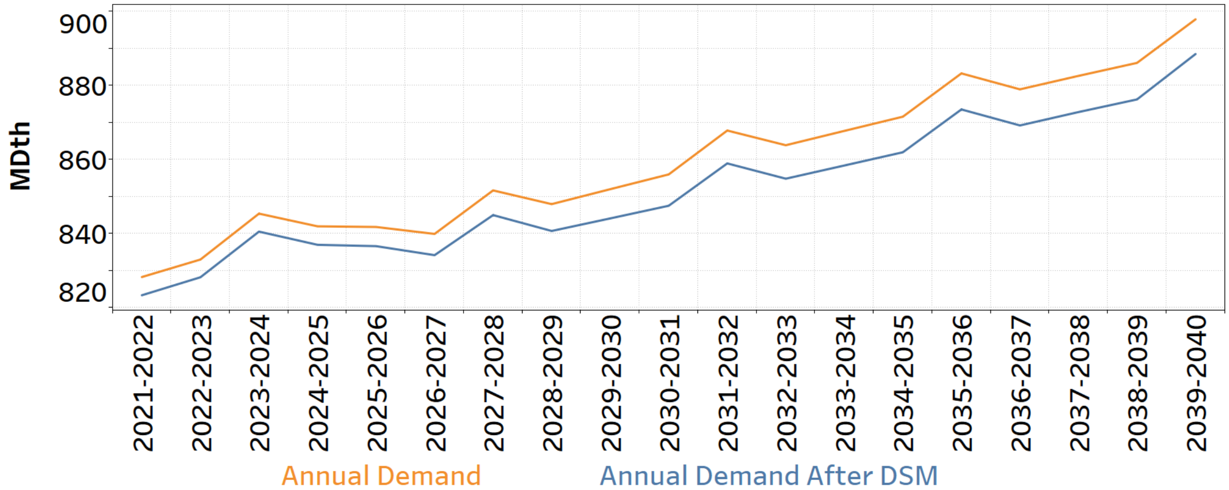
APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM KLAMATH FALLS



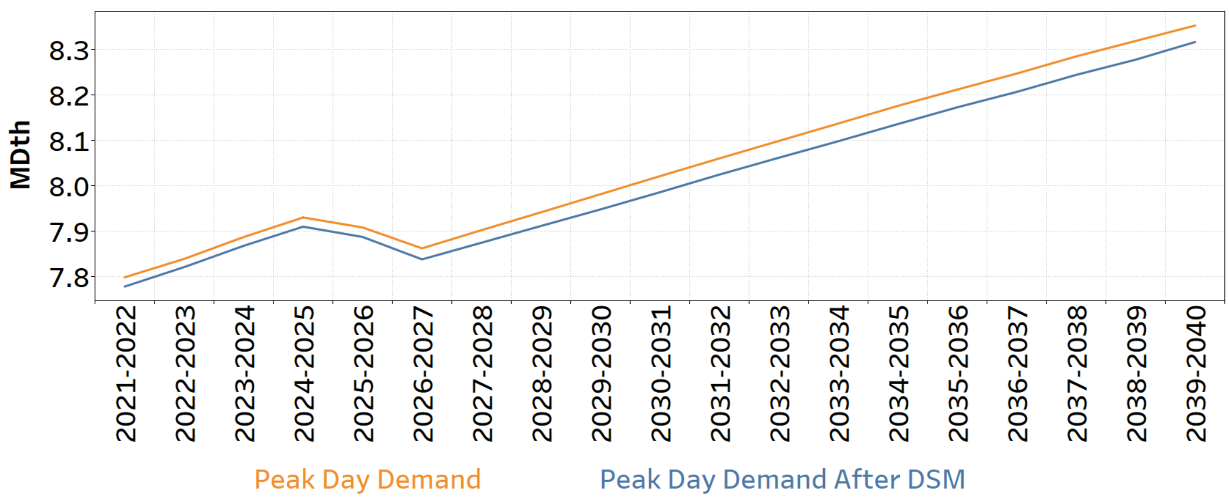


APPENDIX 2.8: PEAK DAY DEMAND BEFORE AND AFTER DSM LA GRANDE

Annual Demand Before and After DSM
La Grande



Peak Day Demand Before and After DSM
La Grande



APPENDIX 2.9: DETAILED DEMAND DATA EXPECTED MIX

Area	2019-2020: Residential	2019-2020: Commercial	2019-2020: Industrial	2019-2020: Total	2020-2021: Residential	2020-2021: Commercial	2020-2021: Industrial	2020-2021: Total	2021-2022: Residential	2021-2022: Commercial	2021-2022: Industrial	2021-2022: Total
Klamath Falls	939.27	478.09	14.32	**1,431.68**	943.98	476.28	13.99	**1,434.26**	892.49	451.95	13.47	**1,357.90**
La Grande	491.98	322.74	52.03	**866.76**	488.93	319.17	51.69	**859.79**	465.69	304.66	52.95	**823.30**
Medford GTN	2,287.91	1,438.38	16.65	**3,742.95**	2,297.13	1,440.33	16.69	**3,754.15**	2,198.37	1,390.57	16.95	**3,605.88**
Medford NWP	1,027.55	645.93	7.46	**1,680.94**	1,028.86	645.08	7.30	**1,681.24**	982.20	621.26	7.18	**1,610.64**
Roseburg	792.62	642.08	2.70	**1,437.40**	790.18	636.35	2.64	**1,429.17**	746.36	605.50	2.57	**1,354.43**
Oregon Subtotal	**5,539.33**	**3,527.22**	**93.16**	9,159.72	**5,549.09**	**3,517.21**	**92.31**	9,158.60	**5,285.11**	**3,373.94**	**93.11**	8,752.16
Washington Both	6,902.44	3,388.40	168.03	**10,458.87**	6,888.03	3,366.34	163.93	**10,418.30**	5,484.77	2,782.22	141.37	**8,408.36**
Washington GTN	935.28	551.25	22.29	**1,508.83**	933.21	547.39	21.77	**1,502.37**	744.08	444.59	18.89	**1,207.56**
Washington NWP	4,046.26	1,986.30	98.50	**6,131.06**	4,037.81	1,973.37	96.10	**6,107.28**	3,215.21	1,630.96	82.87	**4,929.04**
Washington Subtotal	**11,883.98**	**5,925.95**	**288.83**	18,098.76	**11,859.05**	**5,887.10**	**281.80**	18,027.95	**9,444.06**	**4,857.77**	**243.13**	14,544.96
Idaho Both	3,474.88	2,001.23	164.40	**5,640.51**	3,487.35	1,985.45	161.28	**5,634.08**	3,437.04	1,941.82	157.87	**5,536.73**
Idaho GTN	479.29	276.03	22.68	**778.00**	481.01	273.85	22.25	**777.11**	474.07	267.84	21.78	**763.69**
Idaho NWP	2,037.00	1,173.14	96.37	**3,306.51**	2,044.31	1,163.88	94.55	**3,302.74**	2,014.82	1,138.31	92.55	**3,245.67**
Idaho Subtotal	**5,991.17**	**3,450.40**	**283.45**	9,725.02	**6,012.67**	**3,423.18**	**278.08**	9,713.93	**5,925.93**	**3,347.96**	**272.20**	9,546.09
Case Total	**23,414.48**	**12,903.57**	**665.44**	36,983.49	**23,420.81**	**12,827.49**	**652.18**	36,900.49	**20,655.10**	**11,579.67**	**608.43**	32,843.20

Area	2022-2023: Residential	2022-2023: Commercial	2022-2023: Industrial	2022-2023: Total	2023-2024: Residential	2023-2024: Commercial	2023-2024: Industrial	2023-2024: Total	2024-2025: Residential	2024-2025: Commercial	2024-2025: Industrial	2024-2025: Total
Klamath Falls	901.39	456.04	13.38	**1,370.80**	914.29	462.22	13.42	**1,389.93**	915.81	462.75	13.37	**1,391.93**
La Grande	468.65	306.51	53.01	**828.16**	475.76	311.13	53.60	**840.49**	473.67	309.54	53.72	**836.93**
Medford GTN	2,229.87	1,409.14	17.38	**3,656.39**	2,272.75	1,434.19	18.01	**3,724.96**	2,289.89	1,443.33	18.54	**3,751.76**
Medford NWP	994.03	628.13	7.13	**1,629.29**	1,011.01	637.94	7.15	**1,656.10**	1,016.27	640.51	7.13	**1,663.91**
Roseburg	750.40	608.08	2.55	**1,361.03**	759.87	614.59	2.56	**1,377.02**	757.18	611.68	2.55	**1,371.41**
Oregon Subtotal	**5,344.33**	**3,407.90**	**93.44**	8,845.68	**5,433.67**	**3,460.08**	**94.75**	8,988.50	**5,452.82**	**3,467.81**	**95.31**	9,015.93
Washington Both	5,510.58	2,773.62	139.72	**8,423.92**	5,640.13	2,802.24	139.63	**8,582.00**	5,666.81	2,789.57	137.54	**8,593.93**
Washington GTN	747.60	443.09	18.67	**1,209.36**	765.24	448.19	18.64	**1,232.07**	768.80	445.86	18.38	**1,233.04**
Washington NWP	3,230.34	1,625.91	81.91	**4,938.16**	3,306.28	1,642.69	81.85	**5,030.83**	3,321.92	1,635.27	80.63	**5,037.82**
Washington Subtotal	**9,488.53**	**4,842.61**	**240.31**	14,571.45	**9,711.66**	**4,893.12**	**240.12**	14,844.90	**9,757.54**	**4,870.70**	**236.56**	14,864.79
Idaho Both	3,493.86	1,952.16	156.35	**5,602.37**	3,591.74	1,982.70	155.89	**5,730.33**	3,620.47	1,976.99	153.44	**5,750.90**
Idaho GTN	481.91	269.26	21.57	**772.74**	495.41	273.48	21.50	**790.39**	499.38	272.69	21.16	**793.23**
Idaho NWP	2,048.13	1,144.37	91.65	**3,284.15**	2,105.50	1,162.27	91.38	**3,359.16**	2,122.35	1,158.92	89.94	**3,371.22**
Idaho Subtotal	**6,023.90**	**3,365.79**	**269.57**	9,659.25	**6,192.65**	**3,418.45**	**268.77**	9,879.87	**6,242.20**	**3,408.60**	**264.54**	9,915.34
Case Total	**20,856.76**	**11,616.30**	**603.32**	33,076.38	**21,337.98**	**11,771.64**	**603.65**	33,713.27	**21,452.55**	**11,747.11**	**596.41**	33,796.06

Area	2025-2026: Residential	2025-2026: Commercial	2025-2026: Industrial	2025-2026: Total	2026-2027: Residential	2026-2027: Commercial	2026-2027: Industrial	2026-2027: Total	2027-2028: Residential	2027-2028: Commercial	2027-2028: Industrial	2027-2028: Total
Klamath Falls	916.34	462.43	13.34	**1,392.10**	913.18	460.99	13.30	**1,387.48**	923.86	465.71	13.36	**1,402.92**
La Grande	473.72	309.00	53.85	**836.57**	472.28	307.93	53.92	**834.13**	479.04	311.84	54.07	**844.96**
Medford GTN	2,307.79	1,451.33	19.12	**3,778.24**	2,316.44	1,456.23	19.72	**3,792.38**	2,358.62	1,477.68	20.38	**3,856.68**
Medford NWP	1,021.93	642.63	7.13	**1,671.68**	1,023.60	643.44	7.13	**1,674.17**	1,040.12	651.60	7.16	**1,698.87**
Roseburg	755.95	609.19	2.55	**1,367.68**	752.15	605.50	2.54	**1,360.20**	761.06	610.30	2.56	**1,373.91**
Oregon Subtotal	**5,475.72**	**3,474.57**	**95.99**	9,046.28	**5,477.65**	**3,474.09**	**96.62**	9,048.36	**5,562.70**	**3,517.12**	**97.52**	9,177.34
Washington Both	5,736.00	2,797.39	136.53	**8,669.92**	5,799.59	2,805.62	135.60	**8,740.81**	5,910.71	2,836.33	135.63	**8,882.68**
Washington GTN	778.18	447.21	18.25	**1,243.64**	786.79	448.62	18.12	**1,253.53**	801.90	454.00	18.11	**1,274.01**
Washington NWP	3,362.48	1,639.85	80.04	**5,082.36**	3,399.76	1,644.67	79.49	**5,123.92**	3,464.90	1,662.68	79.51	**5,207.09**
Washington Subtotal	**9,876.66**	**4,884.45**	**234.81**	14,995.92	**9,986.13**	**4,898.92**	**233.22**	15,118.27	**10,177.51**	**4,953.01**	**233.25**	15,363.78
Idaho Both	3,638.82	1,967.99	151.42	**5,758.23**	3,634.21	1,951.73	149.22	**5,735.16**	3,709.11	1,972.67	148.81	**5,830.59**
Idaho GTN	501.91	271.45	20.89	**794.24**	501.27	269.20	20.58	**791.06**	511.60	272.09	20.53	**804.22**
Idaho NWP	2,133.10	1,153.65	88.76	**3,375.52**	2,130.40	1,144.12	87.47	**3,361.99**	2,174.31	1,156.39	87.23	**3,417.93**
Idaho Subtotal	**6,273.82**	**3,393.09**	**261.07**	9,927.99	**6,265.89**	**3,365.05**	**257.27**	9,888.21	**6,395.02**	**3,401.16**	**256.56**	10,052.75
Case Total	**21,626.21**	**11,752.11**	**591.87**	33,970.19	**21,729.67**	**11,738.06**	**587.11**	34,054.84	**22,135.23**	**11,871.30**	**587.34**	34,593.87

Area	2028-2029: Residential	2028-2029: Commercial	2028-2029: Industrial	2028-2029: Total	2029-2030: Residential	2029-2030: Commercial	2029-2030: Industrial	2029-2030: Total	2030-2031: Residential	2030-2031: Commercial	2030-2031: Industrial	2030-2031: Total
Klamath Falls	923.17	465.56	13.31	**1,402.04**	927.62	467.99	13.31	**1,408.92**	931.90	470.35	13.31	**1,415.56**
La Grande	476.57	310.07	54.02	**840.67**	478.74	311.29	54.04	**844.06**	480.93	312.51	54.04	**847.48**
Medford GTN	2,369.30	1,483.53	20.89	**3,873.72**	2,394.25	1,497.27	21.48	**3,912.99**	2,418.32	1,510.55	22.06	**3,950.93**
Medford NWP	1,042.78	652.89	7.13	**1,702.81**	1,051.79	657.70	7.13	**1,716.62**	1,060.46	662.35	7.13	**1,729.94**
Roseburg	757.68	606.71	2.55	**1,366.94**	760.32	607.46	2.55	**1,370.33**	762.80	608.01	2.55	**1,373.36**
Oregon Subtotal	**5,569.50**	**3,518.76**	**97.91**	9,186.17	**5,612.72**	**3,541.70**	**98.50**	9,252.92	**5,654.41**	**3,563.76**	**99.09**	9,317.27
Washington Both	5,921.32	2,826.04	133.71	**8,881.08**	5,983.36	2,837.95	132.75	**8,954.06**	6,039.58	2,849.65	131.78	**9,021.00**
Washington GTN	803.26	451.97	17.87	**1,273.10**	811.66	453.87	17.74	**1,283.28**	819.28	455.73	17.61	**1,292.62**
Washington NWP	3,471.12	1,656.65	78.38	**5,206.15**	3,507.48	1,663.63	77.82	**5,248.93**	3,540.44	1,670.48	77.25	**5,288.17**
Washington Subtotal	**10,195.71**	**4,934.66**	**229.97**	15,360.33	**10,302.50**	**4,955.45**	**228.31**	15,486.27	**10,399.30**	**4,975.86**	**226.64**	15,601.79
Idaho Both	3,718.86	1,961.00	146.52	**5,826.38**	3,762.30	1,965.92	145.16	**5,873.38**	3,807.09	1,971.96	143.80	**5,922.85**
Idaho GTN	512.95	270.48	20.21	**803.64**	518.94	271.16	20.02	**810.12**	525.12	271.99	19.83	**816.94**
Idaho NWP	2,180.02	1,149.55	85.89	**3,415.46**	2,205.48	1,152.44	85.10	**3,443.02**	2,231.74	1,155.98	84.30	**3,472.02**
Idaho Subtotal	**6,411.82**	**3,381.04**	**252.63**	10,045.48	**6,486.72**	**3,389.52**	**250.28**	10,126.53	**6,563.95**	**3,399.93**	**247.93**	10,211.81
Case Total	**22,177.02**	**11,834.46**	**580.50**	34,591.98	**22,401.94**	**11,886.67**	**577.10**	34,865.71	**22,617.67**	**11,939.55**	**573.66**	35,130.88

Area	2031-2032: Residential	2031-2032: Commercial	2031-2032: Industrial	2031-2032: Total	2032-2033: Residential	2032-2033: Commercial	2032-2033: Industrial	2032-2033: Total	2033-2034: Residential	2033-2034: Commercial	2033-2034: Industrial	2033-2034: Total
Klamath Falls	942.15	475.54	13.36	**1,431.04**	941.08	475.62	13.31	**1,430.01**	945.59	478.20	13.31	**1,437.10**
La Grande	487.99	316.81	54.12	**858.92**	485.54	315.19	54.05	**854.79**	487.77	316.53	54.05	**858.35**
Medford GTN	2,457.93	1,532.19	22.72	**4,012.84**	2,464.63	1,537.02	23.22	**4,024.87**	2,486.27	1,549.67	23.81	**4,059.74**
Medford NWP	1,076.00	670.70	7.16	**1,753.86**	1,077.18	671.72	7.13	**1,756.04**	1,084.96	676.20	7.13	**1,768.29**
Roseburg	771.59	613.03	2.55	**1,387.18**	767.89	609.42	2.55	**1,379.86**	770.30	610.00	2.55	**1,382.85**
Oregon Subtotal	**5,735.65**	**3,608.27**	**99.91**	**9,443.83**	**5,736.33**	**3,608.98**	**100.26**	**9,445.57**	**5,774.89**	**3,630.60**	**100.84**	**9,506.33**
Washington Both	6,147.62	2,882.71	131.71	**9,162.04**	6,151.04	2,873.49	129.78	**9,154.30**	6,208.01	2,888.39	128.77	**9,225.17**
Washington GTN	833.99	461.42	17.59	**1,312.99**	834.38	459.49	17.35	**1,311.21**	842.11	461.77	17.21	**1,321.09**
Washington NWP	3,603.78	1,689.87	77.21	**5,370.85**	3,605.78	1,684.46	76.08	**5,366.32**	3,639.18	1,693.19	75.49	**5,407.86**
Washington Subtotal	**10,585.38**	**5,034.00**	**226.51**	**15,845.89**	**10,591.20**	**5,017.43**	**223.20**	**15,831.83**	**10,689.30**	**5,043.36**	**221.47**	**15,954.13**
Idaho Both	3,888.45	1,994.51	143.33	**6,026.29**	3,900.06	1,984.60	141.05	**6,025.71**	3,949.19	1,992.84	139.66	**6,081.69**
Idaho GTN	536.34	275.11	19.77	**831.21**	537.94	273.74	19.45	**831.13**	544.72	274.87	19.26	**838.85**
Idaho NWP	2,279.43	1,169.20	84.02	**3,532.65**	2,286.24	1,163.39	82.68	**3,532.31**	2,315.04	1,168.22	81.87	**3,565.13**
Idaho Subtotal	**6,704.22**	**3,438.82**	**247.11**	**10,390.15**	**6,724.24**	**3,421.73**	**243.18**	**10,389.15**	**6,808.95**	**3,435.93**	**240.79**	**10,485.67**
Case Total	**23,025.25**	**12,081.08**	**573.54**	**35,679.86**	**23,051.76**	**12,048.14**	**566.64**	**35,666.55**	**23,273.13**	**12,109.89**	**563.11**	**35,946.13**

Area	2034-2035: Residential	2034-2035: Commercial	2034-2035: Industrial	2034-2035: Total	2035-2036: Residential	2035-2036: Commercial	2035-2036: Industrial	2035-2036: Total	2036-2037: Residential	2036-2037: Commercial	2036-2037: Industrial	2036-2037: Total
Klamath Falls	949.99	480.85	13.31	**1,444.15**	960.40	486.31	13.36	**1,460.08**	959.41	486.28	13.32	**1,459.01**
La Grande	489.93	317.94	54.05	**861.93**	496.97	322.38	54.15	**873.50**	494.37	320.71	54.09	**869.17**
Medford GTN	2,506.95	1,562.15	24.39	**4,093.50**	2,544.29	1,583.48	25.06	**4,152.83**	2,548.39	1,586.66	25.57	**4,160.63**
Medford NWP	1,092.36	680.64	7.13	**1,780.14**	1,107.04	688.94	7.16	**1,803.14**	1,107.27	689.36	7.14	**1,803.78**
Roseburg	772.64	610.62	2.55	**1,385.80**	781.48	615.71	2.56	**1,399.75**	777.81	611.90	2.55	**1,392.25**
Oregon Subtotal	**5,811.87**	**3,652.21**	**101.43**	**9,565.52**	**5,890.18**	**3,696.83**	**102.29**	**9,689.30**	**5,887.25**	**3,694.91**	**102.67**	**9,684.84**
Washington Both	6,263.98	2,903.15	127.75	**9,294.88**	6,375.61	2,939.43	127.63	**9,442.67**	6,376.36	2,931.82	125.74	**9,433.93**
Washington GTN	849.70	464.03	17.08	**1,330.81**	864.91	470.17	17.04	**1,352.12**	864.95	468.44	16.81	**1,350.19**
Washington NWP	3,671.99	1,701.84	74.89	**5,448.72**	3,737.43	1,723.11	74.82	**5,535.36**	3,737.87	1,718.66	73.71	**5,530.23**
Washington Subtotal	**10,785.67**	**5,069.02**	**219.72**	**16,074.41**	**10,977.95**	**5,132.71**	**219.49**	**16,330.15**	**10,979.17**	**5,118.92**	**216.27**	**16,314.36**
Idaho Both	3,999.99	2,001.65	138.26	**6,139.90**	4,088.65	2,026.74	137.72	**6,253.10**	4,103.87	2,018.69	135.49	**6,258.06**
Idaho GTN	551.72	276.09	19.07	**846.88**	563.95	279.55	19.00	**862.50**	566.05	278.44	18.69	**863.18**
Idaho NWP	2,344.82	1,173.38	81.05	**3,599.25**	2,396.79	1,188.09	80.73	**3,665.61**	2,405.72	1,183.37	79.43	**3,668.52**
Idaho Subtotal	**6,896.53**	**3,451.11**	**238.38**	**10,586.03**	**7,049.39**	**3,494.37**	**237.45**	**10,781.21**	**7,075.64**	**3,480.50**	**233.61**	**10,789.75**
Case Total	**23,494.07**	**12,172.35**	**559.54**	**36,225.96**	**23,917.53**	**12,323.91**	**559.23**	**36,800.66**	**23,942.07**	**12,294.33**	**552.55**	**36,788.95**

Area	2037-2038: Residential	2037-2038: Commercial	2037-2038: Industrial	2037-2038: Total	2038-2039: Residential	2038-2039: Commercial	2038-2039: Industrial	2038-2039: Total	2039-2040: Residential	2039-2040: Commercial	2039-2040: Industrial	2039-2040: Total
Klamath Falls	964.36	488.95	13.32	**1,466.64**	969.44	491.68	13.33	**1,474.45**	981.01	497.67	13.38	**1,492.07**
La Grande	496.55	322.13	54.11	**872.78**	498.64	323.43	54.12	**876.20**	505.91	328.32	54.23	**888.47**
Medford GTN	2,568.53	1,598.59	26.16	**4,193.27**	2,587.66	1,610.19	26.75	**4,224.59**	2,624.87	1,632.19	27.44	**4,284.49**
Medford NWP	1,114.51	693.61	7.14	**1,815.26**	1,121.35	697.73	7.14	**1,826.23**	1,136.05	706.38	7.17	**1,849.61**
Roseburg	780.51	612.61	2.55	**1,395.66**	783.18	613.31	2.55	**1,399.04**	792.74	619.06	2.56	**1,414.35**
Oregon Subtotal	**5,924.47**	**3,715.87**	**103.28**	**9,743.62**	**5,960.28**	**3,736.34**	**103.89**	**9,800.51**	**6,040.58**	**3,783.62**	**104.78**	**9,928.99**
Washington Both	6,428.70	2,945.21	124.70	**9,498.61**	6,482.15	2,957.71	123.64	**9,563.50**	6,591.82	2,991.79	123.45	**9,707.06**
Washington GTN	872.04	470.50	16.67	**1,359.21**	879.30	472.44	16.53	**1,368.26**	894.24	478.27	16.48	**1,389.00**
Washington NWP	3,768.55	1,726.50	73.10	**5,568.15**	3,799.88	1,733.83	72.48	**5,606.19**	3,864.17	1,753.81	72.37	**5,690.35**
Washington Subtotal	**11,069.29**	**5,142.21**	**214.47**	**16,425.97**	**11,161.33**	**5,163.98**	**212.65**	**16,537.95**	**11,350.24**	**5,223.87**	**212.30**	**16,786.41**
Idaho Both	4,154.83	2,026.92	134.08	**6,315.83**	4,207.62	2,034.81	132.66	**6,375.08**	4,299.53	2,058.83	132.05	**6,490.41**
Idaho GTN	573.08	279.57	18.49	**871.15**	580.36	280.66	18.30	**879.32**	593.04	283.98	18.21	**895.23**
Idaho NWP	2,435.59	1,188.19	78.60	**3,702.38**	2,466.53	1,192.82	77.76	**3,737.12**	2,520.41	1,206.90	77.41	**3,804.72**
Idaho Subtotal	**7,163.50**	**3,494.69**	**231.18**	**10,889.37**	**7,254.51**	**3,508.29**	**228.72**	**10,991.52**	**7,412.98**	**3,549.70**	**227.68**	**11,190.36**
Case Total	**24,157.25**	**12,352.77**	**548.93**	**37,058.96**	**24,376.12**	**12,408.61**	**545.26**	**37,329.99**	**24,803.80**	**12,557.19**	**544.76**	**37,905.75**

APPENDIX 2.9: DETAILED DEMAND DATA LOW GROWTH HIGH PRICE

Area	2019-2020: Residential	2019-2020: Commercial	2019-2020: Industrial	2019-2020: Total	2020-2021: Residential	2020-2021: Commercial	2020-2021: Industrial	2020-2021: Total	2021-2022: Residential	2021-2022: Commercial	2021-2022: Industrial	2021-2022: Total
Klamath Falls	936.21	476.09	14.27	**1,426.57**	917.16	462.57	13.02	**1,392.75**	480.08	270.20	9.23	**759.51**
La Grande	490.74	321.84	40.80	**853.39**	479.48	312.96	29.15	**821.59**	291.73	201.20	17.57	**510.49**
Medford GTN	2,286.26	1,436.97	16.53	**3,739.76**	2,281.72	1,430.42	15.58	**3,727.72**	1,337.18	967.11	13.99	**2,318.29**
Medford NWP	1,027.16	645.59	7.43	**1,680.18**	1,025.19	642.72	7.06	**1,674.97**	600.86	434.61	6.31	**1,041.77**
Roseburg	791.78	641.21	2.64	**1,435.64**	782.74	630.26	2.03	**1,415.02**	436.10	400.61	1.17	**837.89**
Oregon Subtotal	**5,532.16**	**3,521.70**	**81.68**	**9,135.54**	**5,486.30**	**3,478.93**	**66.83**	**9,032.06**	**3,145.94**	**2,273.73**	**48.28**	**5,467.95**
Washington Both	6,896.81	3,384.95	167.34	**10,449.10**	6,788.83	3,339.84	159.98	**10,288.65**	3,597.99	2,048.05	111.15	**5,757.20**
Washington GTN	934.52	550.73	22.20	**1,507.45**	919.63	543.24	21.24	**1,484.12**	489.43	315.97	15.01	**820.41**
Washington NWP	4,042.96	1,984.28	98.10	**6,125.34**	3,979.66	1,957.84	93.78	**6,031.28**	2,109.17	1,200.58	65.16	**3,374.91**
Washington Subtotal	**11,874.29**	**5,919.96**	**287.64**	**18,081.89**	**11,688.13**	**5,840.92**	**275.00**	**17,804.05**	**6,196.59**	**3,564.60**	**191.32**	**9,952.51**
Idaho Both	3,469.42	1,997.20	162.89	**5,629.51**	3,420.40	1,956.87	156.27	**5,533.54**	1,813.10	1,206.06	119.96	**3,139.12**
Idaho GTN	478.54	275.48	22.47	**776.48**	471.78	269.91	21.55	**763.25**	250.08	166.35	16.55	**432.98**
Idaho NWP	2,033.80	1,170.77	95.48	**3,300.06**	2,005.06	1,147.13	91.61	**3,243.80**	1,062.85	707.00	70.32	**1,840.17**
Idaho Subtotal	**5,981.76**	**3,443.45**	**280.84**	**9,706.05**	**5,897.24**	**3,373.92**	**269.43**	**9,540.59**	**3,126.03**	**2,079.42**	**206.82**	**5,412.27**
Case Total	**23,388.22**	**12,885.11**	**650.15**	**36,923.49**	**23,071.67**	**12,693.77**	**611.26**	**36,376.70**	**12,468.57**	**7,917.75**	**446.42**	**20,832.74**

Area	2022-2023: Residential	2022-2023: Commercial	2022-2023: Industrial	2022-2023: Total	2023-2024: Residential	2023-2024: Commercial	2023-2024: Industrial	2023-2024: Total	2024-2025: Residential	2024-2025: Commercial	2024-2025: Industrial	2024-2025: Total
Klamath Falls	476.62	268.17	8.18	**752.97**	479.61	269.59	7.24	**756.45**	477.83	268.80	6.30	**752.93**
La Grande	289.44	199.48	10.27	**499.18**	290.78	200.29	5.90	**496.96**	287.78	198.32	4.21	**490.31**
Medford GTN	1,341.74	970.26	13.26	**2,325.25**	1,360.27	981.94	12.69	**2,354.89**	1,365.22	985.30	12.11	**2,362.62**
Medford NWP	602.89	436.01	6.00	**1,044.90**	611.22	441.25	5.75	**1,058.23**	613.45	442.75	5.49	**1,061.70**
Roseburg	433.82	398.37	0.57	**832.77**	437.19	400.53	0.04	**837.76**	434.71	398.23	0.00	**832.94**
Oregon Subtotal	**3,144.51**	**2,272.30**	**38.27**	**5,455.08**	**3,179.08**	**2,293.60**	**31.62**	**5,504.30**	**3,179.00**	**2,293.40**	**28.11**	**5,500.51**
Washington Both	3,580.14	2,031.12	107.92	**5,719.19**	3,644.85	2,038.67	105.71	**5,789.23**	3,641.12	2,021.01	102.27	**5,764.40**
Washington GTN	487.00	313.20	14.57	**814.77**	495.83	314.72	14.26	**824.82**	495.28	311.83	13.81	**820.93**
Washington NWP	2,098.70	1,190.66	63.27	**3,352.63**	2,136.64	1,195.08	61.97	**3,393.68**	2,134.45	1,184.73	59.95	**3,379.13**
Washington Subtotal	**6,165.84**	**3,534.98**	**185.76**	**9,886.58**	**6,277.32**	**3,548.47**	**181.94**	**10,007.73**	**6,270.85**	**3,517.57**	**176.04**	**9,964.46**
Idaho Both	1,797.91	1,194.59	116.74	**3,109.24**	1,835.48	1,199.57	114.36	**3,149.41**	1,833.81	1,187.53	110.91	**3,132.24**
Idaho GTN	247.99	164.77	16.10	**428.86**	253.17	165.46	15.77	**434.40**	252.94	163.80	15.30	**432.03**
Idaho NWP	1,053.95	700.28	68.43	**1,822.66**	1,075.97	703.20	67.04	**1,846.20**	1,074.99	696.14	65.01	**1,836.14**
Idaho Subtotal	**3,099.84**	**2,059.64**	**201.28**	**5,360.76**	**3,164.62**	**2,068.22**	**197.17**	**5,430.01**	**3,161.73**	**2,047.47**	**191.22**	**5,400.42**
Case Total	**12,410.20**	**7,866.91**	**425.31**	**20,702.42**	**12,621.01**	**7,910.30**	**410.72**	**20,942.04**	**12,611.58**	**7,858.44**	**395.36**	**20,865.38**

Area	2025-2026: Residential	2025-2026: Commercial	2025-2026: Industrial	2025-2026: Total	2026-2027: Residential	2026-2027: Commercial	2026-2027: Industrial	2026-2027: Total	2027-2028: Residential	2027-2028: Commercial	2027-2028: Industrial	2027-2028: Total
Klamath Falls	479.15	268.90	5.37	**753.43**	479.89	269.08	4.45	**753.42**	483.32	270.66	3.54	**757.53**
La Grande	287.12	197.38	2.51	**487.01**	286.00	196.38	0.83	**483.21**	287.00	196.74	0.00	**483.74**
Medford GTN	1,377.46	990.57	11.56	**2,379.60**	1,386.71	995.15	11.02	**2,392.88**	1,402.84	1,003.65	10.51	**2,417.00**
Medford NWP	618.95	445.14	5.25	**1,069.34**	623.14	447.22	5.00	**1,075.36**	630.42	451.06	4.78	**1,086.26**
Roseburg	435.31	397.31	0.00	**832.62**	435.19	396.18	0.00	**831.37**	437.91	397.17	0.00	**835.09**
Oregon Subtotal	**3,198.00**	**2,299.30**	**24.69**	**5,521.99**	**3,210.94**	**2,304.01**	**21.30**	**5,536.24**	**3,241.49**	**2,319.30**	**18.82**	**5,579.61**
Washington Both	3,660.15	2,016.85	99.53	**5,776.54**	3,683.66	2,014.14	96.88	**5,794.68**	3,736.37	2,025.20	94.77	**5,856.34**
Washington GTN	497.84	311.28	13.44	**822.56**	501.03	310.93	13.08	**825.03**	508.21	312.95	12.79	**833.94**
Washington NWP	2,145.61	1,182.29	58.34	**3,386.25**	2,159.38	1,180.70	56.79	**3,396.88**	2,190.29	1,187.19	55.55	**3,433.03**
Washington Subtotal	**6,303.61**	**3,510.43**	**171.31**	**9,985.35**	**6,344.07**	**3,505.77**	**166.75**	**10,016.59**	**6,434.87**	**3,525.33**	**163.10**	**10,123.31**
Idaho Both	1,840.34	1,181.72	108.04	**3,130.11**	1,848.11	1,176.51	105.24	**3,129.86**	1,871.87	1,179.33	102.91	**3,154.11**
Idaho GTN	253.84	163.00	14.90	**431.74**	254.91	162.28	14.52	**431.71**	258.19	162.67	14.19	**435.05**
Idaho NWP	1,078.82	692.73	63.33	**1,834.89**	1,083.37	689.68	61.69	**1,834.75**	1,097.30	691.33	60.33	**1,848.96**
Idaho Subtotal	**3,173.00**	**2,037.45**	**186.28**	**5,396.73**	**3,186.39**	**2,028.47**	**181.45**	**5,396.31**	**3,227.35**	**2,033.33**	**177.44**	**5,438.12**
Case Total	**12,674.61**	**7,847.18**	**382.28**	**20,904.07**	**12,741.40**	**7,838.25**	**369.50**	**20,949.14**	**12,903.72**	**7,877.95**	**359.36**	**21,141.04**

Area	2028-2029: Residential	2028-2029: Commercial	2028-2029: Industrial	2028-2029: Total	2029-2030: Residential	2029-2030: Commercial	2029-2030: Industrial	2029-2030: Total	2030-2031: Residential	2030-2031: Commercial	2030-2031: Industrial	2030-2031: Total
Klamath Falls	481.90	270.39	2.60	**754.90**	483.32	271.55	1.68	**756.55**	485.17	272.72	0.76	**758.66**
La Grande	283.73	194.65	0.00	**478.38**	282.53	193.84	0.00	**476.37**	281.57	193.05	0.00	**474.62**
Medford GTN	1,403.34	1,004.63	9.93	**2,417.90**	1,410.87	1,009.55	9.39	**2,429.81**	1,419.02	1,014.24	8.85	**2,442.11**
Medford NWP	630.67	451.51	4.52	**1,086.70**	634.09	453.73	4.27	**1,092.09**	637.77	455.85	4.03	**1,097.65**
Roseburg	434.81	394.33	0.00	**829.14**	434.68	393.65	0.00	**828.33**	435.08	393.11	0.00	**828.19**
Oregon Subtotal	**3,234.45**	**2,315.51**	**17.06**	**5,567.02**	**3,245.49**	**2,322.32**	**15.35**	**5,583.16**	**3,258.62**	**2,328.96**	**13.65**	**5,601.23**
Washington Both	3,731.32	2,011.84	91.55	**5,834.71**	3,755.37	2,012.76	88.87	**5,857.00**	3,781.68	2,014.96	86.19	**5,882.83**
Washington GTN	507.48	310.66	12.36	**830.50**	510.74	310.81	12.00	**833.55**	514.32	311.14	11.64	**837.10**
Washington NWP	2,187.32	1,179.36	53.67	**3,420.35**	2,201.42	1,179.89	52.10	**3,433.41**	2,216.85	1,181.19	50.52	**3,448.55**
Washington Subtotal	**6,426.12**	**3,501.86**	**157.58**	**10,085.56**	**6,467.54**	**3,503.46**	**152.97**	**10,123.96**	**6,512.84**	**3,507.29**	**148.35**	**10,168.48**
Idaho Both	1,867.26	1,167.02	99.62	**3,133.90**	1,875.70	1,163.01	96.80	**3,135.51**	1,886.83	1,159.97	93.98	**3,140.77**
Idaho GTN	257.55	160.97	13.74	**432.26**	258.72	160.42	13.35	**432.48**	260.25	160.00	12.96	**433.21**
Idaho NWP	1,094.60	684.12	58.40	**1,837.11**	1,099.55	681.76	56.75	**1,838.06**	1,106.07	679.98	55.09	**1,841.14**
Idaho Subtotal	**3,219.41**	**2,012.11**	**171.76**	**5,403.28**	**3,233.96**	**2,005.19**	**166.90**	**5,406.05**	**3,253.15**	**1,999.95**	**162.03**	**5,415.13**
Case Total	**12,879.98**	**7,829.48**	**346.39**	**21,055.85**	**12,946.99**	**7,830.96**	**335.21**	**21,113.17**	**13,024.62**	**7,836.20**	**324.02**	**21,184.84**

Area	2031-2032: Residential	2031-2032: Commercial	2031-2032: Industrial	2031-2032: Total	2032-2033: Residential	2032-2033: Commercial	2032-2033: Industrial	2032-2033: Total	2033-2034: Residential	2033-2034: Commercial	2033-2034: Industrial	2033-2034: Total
Klamath Falls	489.64	275.31	0.00	**764.95**	488.55	275.56	0.00	**764.10**	490.24	276.98	0.00	**767.21**
La Grande	282.88	193.79	0.00	**476.67**	279.88	192.04	0.00	**471.92**	279.32	191.77	0.00	**471.10**
Medford GTN	1,434.45	1,023.56	8.34	**2,466.35**	1,432.94	1,024.37	7.77	**2,465.08**	1,439.47	1,029.41	7.23	**2,476.11**
Medford NWP	644.73	460.04	3.80	**1,108.57**	644.08	460.41	3.54	**1,108.03**	647.03	462.68	3.30	**1,113.01**
Roseburg	438.55	395.03	0.00	**833.58**	435.91	392.87	0.00	**828.78**	436.46	392.88	0.00	**829.34**
Oregon Subtotal	**3,290.25**	**2,347.73**	**12.14**	**5,650.12**	**3,281.36**	**2,345.25**	**11.31**	**5,637.92**	**3,292.52**	**2,353.72**	**10.53**	**5,656.77**
Washington Both	3,841.16	2,030.65	83.98	**5,955.78**	3,844.78	2,021.28	80.80	**5,946.86**	3,877.99	2,028.47	78.08	**5,984.54**
Washington GTN	522.44	313.81	11.33	**847.58**	522.92	312.08	10.91	**845.91**	527.45	313.11	10.55	**851.10**
Washington NWP	2,251.71	1,190.38	49.23	**3,491.32**	2,253.84	1,184.89	47.36	**3,486.09**	2,273.30	1,189.10	45.77	**3,508.18**
Washington Subtotal	**6,615.31**	**3,534.84**	**144.54**	**10,294.69**	**6,621.53**	**3,518.25**	**139.07**	**10,278.86**	**6,678.74**	**3,530.68**	**134.40**	**10,343.82**
Idaho Both	1,914.21	1,164.77	91.57	**3,170.55**	1,912.62	1,154.70	88.32	**3,155.63**	1,928.29	1,154.43	85.47	**3,168.19**
Idaho GTN	264.03	160.66	12.63	**437.32**	263.81	159.27	12.18	**435.26**	265.97	159.23	11.79	**436.99**
Idaho NWP	1,122.12	682.80	53.68	**1,858.60**	1,121.19	676.89	51.77	**1,849.85**	1,130.38	676.73	50.10	**1,857.21**
Idaho Subtotal	**3,300.35**	**2,008.23**	**157.88**	**5,466.47**	**3,297.61**	**1,990.86**	**152.27**	**5,440.74**	**3,324.64**	**1,990.39**	**147.37**	**5,462.39**
Case Total	**13,205.91**	**7,890.80**	**314.56**	**21,411.27**	**13,200.50**	**7,854.35**	**302.66**	**21,357.51**	**13,295.90**	**7,874.79**	**292.30**	**21,462.99**

Area	2034-2035: Residential	2034-2035: Commercial	2034-2035: Industrial	2034-2035: Total	2035-2036: Residential	2035-2036: Commercial	2035-2036: Industrial	2035-2036: Total	2036-2037: Residential	2036-2037: Commercial	2036-2037: Industrial	2036-2037: Total
Klamath Falls	491.96	278.29	0.00	**770.25**	496.60	281.20	0.00	**777.80**	496.13	281.46	0.00	**777.59**
La Grande	278.95	191.57	0.00	**470.52**	281.05	193.03	0.00	**474.08**	279.20	191.96	0.00	**471.16**
Medford GTN	1,446.06	1,034.15	6.69	**2,486.89**	1,461.19	1,044.30	6.16	**2,511.66**	1,460.50	1,044.94	5.60	**2,511.04**
Medford NWP	650.01	464.81	3.06	**1,117.88**	656.82	469.37	2.82	**1,129.01**	656.52	469.65	2.57	**1,128.73**
Roseburg	437.19	392.86	0.00	**830.05**	441.18	395.40	0.00	**836.58**	439.32	393.49	0.00	**832.81**
Oregon Subtotal	**3,304.17**	**2,361.68**	**9.74**	**5,675.60**	**3,336.85**	**2,383.30**	**8.99**	**5,729.13**	**3,331.66**	**2,381.49**	**8.17**	**5,721.33**
Washington Both	3,909.95	2,036.27	75.36	**6,021.58**	3,973.26	2,057.14	73.04	**6,103.44**	3,978.63	2,051.85	69.93	**6,100.41**
Washington GTN	531.81	314.22	10.18	**856.20**	540.46	317.61	9.86	**867.92**	541.18	316.44	9.45	**867.07**
Washington NWP	2,292.04	1,193.68	44.18	**3,529.89**	2,329.15	1,205.91	42.81	**3,577.88**	2,332.30	1,202.81	41.00	**3,576.10**
Washington Subtotal	**6,733.80**	**3,544.16**	**129.71**	**10,407.67**	**6,842.88**	**3,580.65**	**125.71**	**10,549.24**	**6,852.11**	**3,571.10**	**120.38**	**10,543.59**
Idaho Both	1,946.01	1,154.93	82.62	**3,183.56**	1,979.52	1,162.98	80.13	**3,222.63**	1,982.21	1,155.55	76.93	**3,214.69**
Idaho GTN	268.42	159.30	11.40	**439.11**	273.04	160.41	11.05	**444.50**	273.41	159.39	10.61	**443.41**
Idaho NWP	1,140.76	677.03	48.43	**1,866.22**	1,160.41	681.75	46.97	**1,889.13**	1,161.99	677.39	45.10	**1,884.48**
Idaho Subtotal	**3,355.19**	**1,991.26**	**142.45**	**5,488.90**	**3,412.97**	**2,005.14**	**138.15**	**5,556.26**	**3,417.61**	**1,992.32**	**132.64**	**5,542.57**
Case Total	**13,393.15**	**7,897.11**	**281.90**	**21,572.16**	**13,592.69**	**7,969.10**	**272.85**	**21,834.63**	**13,601.38**	**7,944.92**	**261.19**	**21,807.49**

Area	2037-2038: Residential	2037-2038: Commercial	2037-2038: Industrial	2037-2038: Total	2038-2039: Residential	2038-2039: Commercial	2038-2039: Industrial	2038-2039: Total	2039-2040: Residential	2039-2040: Commercial	2039-2040: Industrial	2039-2040: Total
Klamath Falls	498.66	282.95	0.00	**781.61**	501.37	284.54	0.00	**785.92**	507.37	287.99	0.00	**795.36**
La Grande	279.65	192.25	0.00	**471.91**	280.15	192.54	0.00	**472.69**	283.16	194.69	0.00	**477.86**
Medford GTN	1,467.93	1,049.75	5.06	**2,522.74**	1,474.68	1,054.22	4.52	**2,533.41**	1,490.92	1,065.07	3.99	**2,559.98**
Medford NWP	659.85	471.81	2.33	**1,133.99**	662.89	473.82	2.08	**1,138.80**	670.18	478.68	1.85	**1,150.71**
Roseburg	440.51	393.60	0.00	**834.10**	441.53	393.55	0.00	**835.09**	446.09	396.43	0.00	**842.52**
Oregon Subtotal	**3,346.60**	**2,390.36**	**7.39**	**5,744.35**	**3,360.62**	**2,398.67**	**6.60**	**5,765.90**	**3,397.72**	**2,422.87**	**5.84**	**5,826.43**
Washington Both	4,009.53	2,058.78	67.18	**6,135.49**	4,038.56	2,065.43	64.40	**6,168.39**	4,097.69	2,084.21	61.97	**6,243.88**
Washington GTN	545.40	317.43	9.07	**871.91**	549.36	318.39	8.70	**876.44**	557.44	321.50	8.36	**887.30**
Washington NWP	2,350.41	1,206.87	39.38	**3,596.66**	2,367.43	1,210.77	37.75	**3,615.95**	2,402.10	1,221.78	36.33	**3,660.20**
Washington Subtotal	**6,905.34**	**3,583.08**	**115.63**	**10,604.05**	**6,955.35**	**3,594.58**	**110.85**	**10,660.78**	**7,057.22**	**3,627.49**	**106.66**	**10,791.38**
Idaho Both	1,998.44	1,155.06	74.06	**3,227.56**	2,014.66	1,154.60	71.17	**3,240.43**	2,046.22	1,160.94	68.60	**3,275.76**
Idaho GTN	275.65	159.32	10.21	**445.18**	277.88	159.26	9.82	**446.96**	282.24	160.13	9.46	**451.83**
Idaho NWP	1,171.50	677.10	43.41	**1,892.02**	1,181.01	676.83	41.72	**1,899.56**	1,199.51	680.55	40.21	**1,920.27**
Idaho Subtotal	**3,445.59**	**1,991.48**	**127.69**	**5,564.75**	**3,473.55**	**1,990.69**	**122.71**	**5,586.95**	**3,527.96**	**2,001.63**	**118.27**	**5,647.85**
Case Total	**13,697.52**	**7,964.92**	**250.71**	**21,913.15**	**13,789.52**	**7,983.95**	**240.16**	**22,013.63**	**13,982.90**	**8,051.99**	**230.77**	**22,265.66**

APPENDIX 2.9: DETAILED DEMAND DATA HIGH GROWTH LOW PRICE

Area	2019-2020: Residential	2019-2020: Commercial	2019-2020: Industrial	2019-2020: Total	2020-2021: Residential	2020-2021: Commercial	2020-2021: Industrial	2020-2021: Total	2021-2022: Residential	2021-2022: Commercial	2021-2022: Industrial	2021-2022: Total
Klamath Falls	941.76	479.72	14.50	**1,435.98**	965.86	487.69	15.18	**1,468.73**	986.00	495.11	16.30	**1,497.41**
La Grande	492.92	323.42	50.38	**866.71**	496.03	323.98	60.03	**880.04**	502.44	327.20	70.36	**899.99**
Medford GTN	2,287.91	1,438.38	16.65	**3,742.95**	2,296.76	1,440.79	16.69	**3,754.24**	2,330.38	1,455.61	17.14	**3,803.14**
Medford NWP	1,027.90	646.23	7.48	**1,681.61**	1,031.95	647.38	7.55	**1,686.88**	1,047.09	654.07	7.78	**1,708.94**
Roseburg	793.97	643.48	2.77	**1,440.21**	802.03	646.35	3.27	**1,451.66**	811.94	651.60	3.93	**1,467.47**
Oregon Subtotal	**5,544.46**	**3,531.23**	**91.78**	**9,167.47**	**5,592.63**	**3,546.19**	**102.73**	**9,241.55**	**5,677.85**	**3,583.60**	**115.51**	**9,376.95**
Washington Both	6,908.36	3,392.02	168.02	**10,468.41**	6,943.88	3,394.39	167.90	**10,506.17**	7,036.36	3,414.41	171.77	**10,622.53**
Washington GTN	936.08	551.80	22.29	**1,510.17**	940.81	551.78	22.30	**1,514.89**	953.31	555.13	22.82	**1,531.26**
Washington NWP	4,049.73	1,988.43	98.50	**6,136.65**	4,070.55	1,989.82	98.43	**6,158.79**	4,124.76	2,001.55	100.69	**6,227.00**
Washington Subtotal	**11,894.17**	**5,932.25**	**288.81**	**18,115.23**	**11,955.23**	**5,935.99**	**288.63**	**18,179.86**	**12,114.43**	**5,971.09**	**295.27**	**18,380.79**
Idaho Both	3,480.39	2,005.30	163.55	**5,649.24**	3,532.48	2,014.28	163.58	**5,710.34**	3,601.19	2,029.33	167.22	**5,797.75**
Idaho GTN	480.05	276.59	22.56	**779.21**	487.24	277.83	22.56	**787.63**	496.72	279.91	23.07	**799.69**
Idaho NWP	2,040.23	1,175.52	95.87	**3,311.62**	2,070.76	1,180.79	95.89	**3,347.44**	2,111.05	1,189.61	98.03	**3,398.68**
Idaho Subtotal	**6,000.67**	**3,457.42**	**281.98**	**9,740.07**	**6,090.48**	**3,472.90**	**282.03**	**9,845.41**	**6,208.96**	**3,498.84**	**288.32**	**9,996.12**
Case Total	**23,439.30**	**12,920.89**	**662.58**	**37,022.77**	**23,638.35**	**12,955.08**	**673.39**	**37,266.82**	**24,001.23**	**13,053.54**	**699.10**	**37,753.86**

Area	2022-2023: Residential	2022-2023: Commercial	2022-2023: Industrial	2022-2023: Total	2023-2024: Residential	2023-2024: Commercial	2023-2024: Industrial	2023-2024: Total	2024-2025: Residential	2024-2025: Commercial	2024-2025: Industrial	2024-2025: Total
Klamath Falls	1,003.28	503.69	17.41	**1,524.38**	1,023.58	513.73	18.67	**1,555.98**	1,030.11	516.81	19.80	**1,566.72**
La Grande	508.88	331.58	80.67	**921.13**	519.85	338.86	91.47	**950.19**	520.57	339.16	101.97	**961.70**
Medford GTN	2,363.14	1,476.01	17.59	**3,856.74**	2,408.25	1,502.89	18.24	**3,929.38**	2,426.01	1,512.57	18.77	**3,957.34**
Medford NWP	1,061.81	663.20	8.00	**1,733.01**	1,082.09	675.26	8.29	**1,765.65**	1,090.08	679.61	8.53	**1,778.22**
Roseburg	821.33	658.89	4.59	**1,484.80**	836.41	670.04	5.28	**1,511.73**	837.89	670.53	5.94	**1,514.36**
Oregon Subtotal	**5,758.43**	**3,633.37**	**128.26**	**9,520.07**	**5,870.19**	**3,700.78**	**141.96**	**9,712.93**	**5,904.66**	**3,718.69**	**155.00**	**9,778.34**
Washington Both	7,156.01	3,440.97	175.67	**10,772.65**	7,359.86	3,498.27	181.00	**11,039.12**	7,425.67	3,499.46	183.47	**11,108.59**
Washington GTN	969.52	559.51	23.33	**1,552.37**	997.23	569.42	24.01	**1,590.67**	1,006.07	569.14	24.37	**1,599.58**
Washington NWP	4,194.90	2,017.12	102.98	**6,315.00**	4,314.40	2,050.71	106.10	**6,471.21**	4,352.98	2,051.40	107.55	**6,511.93**
Washington Subtotal	**12,320.43**	**6,017.61**	**301.98**	**18,640.01**	**12,671.49**	**6,118.40**	**311.11**	**19,101.00**	**12,784.71**	**6,120.00**	**315.39**	**19,220.11**
Idaho Both	3,690.97	2,057.91	170.90	**5,919.78**	3,826.30	2,108.59	175.69	**6,110.58**	3,888.24	2,120.08	178.25	**6,186.57**
Idaho GTN	509.10	283.85	23.57	**816.52**	527.77	290.84	24.23	**842.84**	536.31	292.42	24.59	**853.32**
Idaho NWP	2,163.67	1,206.36	100.18	**3,470.22**	2,243.00	1,236.07	102.99	**3,582.06**	2,279.31	1,242.80	104.49	**3,626.61**
Idaho Subtotal	**6,363.74**	**3,548.12**	**294.65**	**10,206.52**	**6,597.06**	**3,635.50**	**302.91**	**10,535.48**	**6,703.87**	**3,655.31**	**307.33**	**10,666.50**
Case Total	**24,442.61**	**13,199.10**	**724.89**	**38,366.60**	**25,138.74**	**13,454.68**	**755.99**	**39,349.41**	**25,393.24**	**13,494.00**	**777.72**	**39,664.95**

Area	2025-2026: Residential	2025-2026: Commercial	2025-2026: Industrial	2025-2026: Total	2026-2027: Residential	2026-2027: Commercial	2026-2027: Industrial	2026-2027: Total	2027-2028: Residential	2027-2028: Commercial	2027-2028: Industrial	2027-2028: Total
Klamath Falls	1,034.24	518.39	20.93	**1,573.56**	1,029.31	516.51	22.00	**1,567.81**	1,043.63	523.27	23.27	**1,590.17**
La Grande	523.54	340.57	112.55	**976.66**	523.16	340.37	123.05	**986.58**	533.81	346.98	133.96	**1,014.74**
Medford GTN	2,444.32	1,520.97	19.35	**3,984.64**	2,444.39	1,522.08	19.94	**3,986.40**	2,489.37	1,545.80	20.61	**4,055.78**
Medford NWP	1,098.30	683.40	8.79	**1,790.48**	1,098.34	683.90	9.04	**1,791.29**	1,118.58	694.58	9.34	**1,822.50**
Roseburg	840.65	671.32	6.60	**1,518.58**	837.40	668.66	7.25	**1,513.31**	851.66	677.87	7.95	**1,537.48**
Oregon Subtotal	**5,941.06**	**3,734.66**	**168.22**	**9,843.93**	**5,932.60**	**3,731.52**	**181.27**	**9,845.40**	**6,037.04**	**3,788.51**	**195.12**	**10,020.67**
Washington Both	7,498.70	3,505.71	186.53	**11,190.94**	7,518.91	3,493.56	188.85	**11,201.32**	7,707.49	3,549.02	194.25	**11,450.76**
Washington GTN	1,016.00	569.94	24.78	**1,610.72**	1,018.81	567.46	25.10	**1,611.38**	1,044.46	577.03	25.78	**1,647.28**
Washington NWP	4,395.79	2,055.07	109.35	**6,560.21**	4,407.64	2,047.95	110.71	**6,566.29**	4,518.18	2,080.46	113.87	**6,712.51**
Washington Subtotal	**12,910.49**	**6,130.72**	**320.66**	**19,361.87**	**12,945.36**	**6,108.97**	**324.66**	**19,378.99**	**13,270.13**	**6,206.52**	**333.90**	**19,810.55**
Idaho Both	3,941.15	2,127.74	181.32	**6,250.21**	3,961.67	2,122.51	183.85	**6,268.03**	4,072.28	2,158.40	188.69	**6,419.38**
Idaho GTN	543.61	293.48	25.01	**862.10**	546.44	292.76	25.36	**864.56**	561.69	297.71	26.03	**885.43**
Idaho NWP	2,310.33	1,247.30	106.29	**3,663.92**	2,322.36	1,244.23	107.78	**3,674.36**	2,387.20	1,265.27	110.61	**3,763.08**
Idaho Subtotal	**6,795.08**	**3,668.52**	**312.62**	**10,776.22**	**6,830.47**	**3,659.50**	**316.99**	**10,806.95**	**7,021.18**	**3,721.38**	**325.34**	**11,067.89**
Case Total	**25,646.62**	**13,533.90**	**801.50**	**39,982.02**	**25,708.43**	**13,499.99**	**822.92**	**40,031.34**	**26,328.34**	**13,716.40**	**854.36**	**40,899.11**

Area	2028-2029: Residential	2028-2029: Commercial	2028-2029: Industrial	2028-2029: Total	2029-2030: Residential	2029-2030: Commercial	2029-2030: Industrial	2029-2030: Total	2030-2031: Residential	2030-2031: Commercial	2030-2031: Industrial	2030-2031: Total
Klamath Falls	1,044.37	523.81	24.37	**1,592.54**	1,050.06	526.65	25.55	**1,602.26**	1,055.91	529.70	26.73	**1,612.33**
La Grande	534.00	346.91	144.32	**1,025.22**	539.57	350.16	154.94	**1,044.67**	545.18	353.49	165.56	**1,064.23**
Medford GTN	2,500.82	1,551.93	21.13	**4,073.87**	2,527.49	1,565.81	21.71	**4,115.01**	2,553.24	1,579.54	22.30	**4,155.08**
Medford NWP	1,123.74	697.34	9.58	**1,830.66**	1,135.75	703.59	9.84	**1,849.18**	1,147.34	709.77	10.11	**1,867.21**
Roseburg	851.88	677.01	8.59	**1,537.48**	858.54	680.47	9.26	**1,548.27**	864.07	683.08	9.93	**1,557.08**
Oregon Subtotal	**6,054.80**	**3,796.99**	**207.97**	**10,059.77**	**6,111.41**	**3,826.68**	**221.30**	**10,159.38**	**6,165.73**	**3,855.58**	**234.62**	**10,255.93**
Washington Both	7,757.23	3,547.15	196.61	**11,500.99**	7,875.36	3,574.32	200.50	**11,650.18**	7,981.19	3,599.29	204.40	**11,784.88**
Washington GTN	1,051.11	576.24	26.13	**1,653.48**	1,067.12	580.67	26.65	**1,674.43**	1,081.46	584.72	27.17	**1,693.35**
Washington NWP	4,547.34	2,079.36	115.25	**6,741.96**	4,616.59	2,095.29	117.53	**6,829.42**	4,678.63	2,109.93	119.82	**6,908.38**
Washington Subtotal	**13,355.68**	**6,202.75**	**337.99**	**19,896.43**	**13,559.07**	**6,250.28**	**344.68**	**20,154.03**	**13,741.28**	**6,293.94**	**351.39**	**20,386.60**
Idaho Both	4,110.56	2,157.23	191.17	**6,458.96**	4,186.00	2,174.32	194.84	**6,555.15**	4,263.27	2,192.80	198.51	**6,654.58**
Idaho GTN	566.97	297.55	26.37	**890.89**	577.38	299.91	26.87	**904.16**	588.04	302.46	27.38	**917.87**
Idaho NWP	2,409.64	1,264.58	112.06	**3,786.29**	2,453.86	1,274.60	114.21	**3,842.67**	2,499.16	1,285.44	116.37	**3,900.96**
Idaho Subtotal	**7,087.17**	**3,719.37**	**329.60**	**11,136.13**	**7,217.24**	**3,748.82**	**335.92**	**11,301.98**	**7,350.47**	**3,780.69**	**342.26**	**11,473.41**
Case Total	**26,497.65**	**13,719.11**	**875.57**	**41,092.33**	**26,887.72**	**13,825.78**	**901.90**	**41,615.40**	**27,257.47**	**13,930.21**	**928.26**	**42,115.95**

Area	2031-2032: Residential	2031-2032: Commercial	2031-2032: Industrial	2031-2032: Total	2032-2033: Residential	2032-2033: Commercial	2032-2033: Industrial	2032-2033: Total	2033-2034: Residential	2033-2034: Commercial	2033-2034: Industrial	2033-2034: Total
Klamath Falls	1,068.73	536.11	28.01	**1,632.86**	1,068.23	536.42	29.09	**1,633.75**	1,067.23	536.76	30.18	**1,634.17**
La Grande	556.33	360.36	176.54	**1,093.23**	555.99	360.01	186.79	**1,102.80**	557.73	361.19	197.24	**1,116.17**
Medford GTN	2,596.00	1,602.61	22.97	**4,221.58**	2,602.35	1,606.79	23.48	**4,232.62**	2,609.14	1,612.24	24.04	**4,245.42**
Medford NWP	1,166.56	720.14	10.40	**1,897.11**	1,169.43	722.03	10.63	**1,902.09**	1,172.50	724.48	10.89	**1,907.86**
Roseburg	876.27	690.44	10.64	**1,577.35**	873.40	687.23	11.27	**1,571.89**	871.78	685.24	11.92	**1,568.94**
Oregon Subtotal	**6,263.89**	**3,909.68**	**248.56**	**10,422.12**	**6,269.40**	**3,912.48**	**261.27**	**10,443.15**	**6,278.39**	**3,919.91**	**274.27**	**10,472.56**
Washington Both	8,157.64	3,652.44	209.95	**12,020.03**	8,187.94	3,645.43	212.20	**12,045.57**	8,233.92	3,648.83	215.17	**12,097.91**
Washington GTN	1,105.47	593.91	27.87	**1,727.24**	1,109.48	592.27	28.20	**1,729.95**	1,115.75	592.55	28.60	**1,736.90**
Washington NWP	4,782.06	2,141.09	123.07	**7,046.22**	4,799.83	2,136.98	124.39	**7,061.20**	4,826.78	2,138.97	126.13	**7,091.88**
Washington Subtotal	**14,045.17**	**6,387.44**	**360.89**	**20,793.50**	**14,097.25**	**6,374.68**	**364.79**	**20,836.72**	**14,176.45**	**6,380.34**	**369.90**	**20,926.69**
Idaho Both	4,382.01	2,229.89	203.46	**6,815.36**	4,423.83	2,229.40	205.85	**6,859.08**	4,477.28	2,236.53	208.85	**6,922.66**
Idaho GTN	604.42	307.57	28.06	**940.05**	610.18	307.50	28.39	**946.08**	617.56	308.49	28.81	**954.85**
Idaho NWP	2,568.77	1,307.17	119.27	**3,995.21**	2,593.28	1,306.89	120.67	**4,020.84**	2,624.61	1,311.07	122.43	**4,058.11**
Idaho Subtotal	**7,555.19**	**3,844.63**	**350.80**	**11,750.62**	**7,627.29**	**3,843.79**	**354.92**	**11,826.00**	**7,719.45**	**3,856.09**	**360.09**	**11,935.63**
Case Total	**27,864.25**	**14,141.74**	**960.25**	**42,966.24**	**27,993.94**	**14,130.95**	**980.98**	**43,105.87**	**28,174.29**	**14,156.34**	**1,004.26**	**43,334.88**

Area	2034-2035: Residential	2034-2035: Commercial	2034-2035: Industrial	2034-2035: Total	2035-2036: Residential	2035-2036: Commercial	2035-2036: Industrial	2035-2036: Total	2036-2037: Residential	2036-2037: Commercial	2036-2037: Industrial	2036-2037: Total
Klamath Falls	1,074.43	540.70	31.36	**1,646.50**	1,088.73	548.12	32.66	**1,669.51**	1,089.71	549.19	33.73	**1,672.63**
La Grande	562.36	364.09	207.87	**1,134.32**	572.38	370.42	218.96	**1,161.76**	570.72	369.42	229.12	**1,169.26**
Medford GTN	2,630.80	1,624.72	24.63	**4,280.15**	2,670.11	1,647.02	25.31	**4,342.44**	2,674.26	1,650.49	25.82	**4,350.57**
Medford NWP	1,182.24	730.09	11.15	**1,923.49**	1,199.91	740.12	11.46	**1,951.48**	1,201.78	741.67	11.68	**1,955.13**
Roseburg	875.47	686.56	12.58	**1,574.61**	886.49	693.09	13.30	**1,592.89**	883.18	689.55	13.92	**1,586.65**
Oregon Subtotal	**6,325.31**	**3,946.15**	**287.60**	**10,559.07**	**6,417.62**	**3,998.77**	**301.69**	**10,718.08**	**6,419.65**	**4,000.32**	**314.27**	**10,734.24**
Washington Both	8,330.19	3,671.91	219.02	**12,221.12**	8,502.94	3,726.57	224.64	**12,454.16**	8,521.83	3,720.17	226.75	**12,468.76**
Washington GTN	1,128.80	596.28	29.11	**1,754.19**	1,152.31	605.65	29.82	**1,787.78**	1,154.77	604.03	30.14	**1,788.94**
Washington NWP	4,883.22	2,152.50	128.39	**7,164.11**	4,984.48	2,184.54	131.69	**7,300.71**	4,995.56	2,180.79	132.92	**7,309.27**
Washington Subtotal	**14,342.21**	**6,420.68**	**376.53**	**21,139.42**	**14,639.74**	**6,516.77**	**386.15**	**21,542.65**	**14,672.16**	**6,504.99**	**389.82**	**21,566.96**
Idaho Both	4,561.60	2,256.46	212.49	**7,030.55**	4,689.72	2,296.68	217.51	**7,203.90**	4,734.63	2,298.63	219.79	**7,253.06**
Idaho GTN	629.19	311.24	29.31	**969.73**	646.86	316.78	30.00	**993.64**	653.05	317.05	30.32	**1,000.42**
Idaho NWP	2,674.04	1,322.75	124.56	**4,121.36**	2,749.15	1,346.33	127.50	**4,222.98**	2,775.47	1,347.48	128.84	**4,251.79**
Idaho Subtotal	**7,864.82**	**3,890.45**	**366.36**	**12,121.64**	**8,085.72**	**3,959.79**	**375.01**	**12,420.52**	**8,163.16**	**3,963.16**	**378.95**	**12,505.27**
Case Total	**28,532.34**	**14,257.29**	**1,030.49**	**43,820.12**	**29,143.08**	**14,475.34**	**1,062.85**	**44,681.26**	**29,254.97**	**14,468.47**	**1,083.04**	**44,806.48**

Area	2037-2038: Residential	2037-2038: Commercial	2037-2038: Industrial	2037-2038: Total	2038-2039: Residential	2038-2039: Commercial	2038-2039: Industrial	2038-2039: Total	2039-2040: Residential	2039-2040: Commercial	2039-2040: Industrial	2039-2040: Total
Klamath Falls	1,096.28	552.77	34.91	**1,683.95**	1,100.94	555.24	36.08	**1,692.27**	1,113.01	560.97	37.41	**1,711.39**
La Grande	574.43	371.89	239.74	**1,186.06**	577.90	374.05	250.36	**1,202.31**	587.28	379.97	261.59	**1,228.84**
Medford GTN	2,695.30	1,663.18	26.41	**4,384.89**	2,715.48	1,675.20	27.00	**4,417.68**	2,754.68	1,696.58	27.70	**4,478.96**
Medford NWP	1,211.24	747.37	11.95	**1,970.55**	1,220.30	752.77	12.21	**1,985.29**	1,237.91	762.38	12.52	**2,012.81**
Roseburg	887.38	691.39	14.59	**1,593.36**	891.89	693.28	15.26	**1,600.43**	904.15	700.20	15.99	**1,620.34**
Oregon Subtotal	**6,464.63**	**4,026.59**	**327.60**	**10,818.82**	**6,506.52**	**4,050.55**	**340.91**	**10,897.97**	**6,597.02**	**4,100.11**	**355.20**	**11,052.33**
Washington Both	8,613.91	3,743.63	230.61	**12,588.15**	8,704.37	3,766.75	234.47	**12,705.59**	8,874.04	3,819.56	240.21	**12,933.80**
Washington GTN	1,167.24	607.79	30.66	**1,805.69**	1,179.50	611.49	31.17	**1,822.16**	1,202.60	620.60	31.89	**1,855.09**
Washington NWP	5,049.53	2,194.54	135.19	**7,379.26**	5,102.56	2,208.09	137.45	**7,448.10**	5,202.02	2,239.05	140.81	**7,581.88**
Washington Subtotal	**14,830.69**	**6,545.96**	**396.45**	**21,773.10**	**14,986.44**	**6,586.33**	**403.09**	**21,975.85**	**15,278.66**	**6,679.20**	**412.91**	**22,370.77**
Idaho Both	4,823.08	2,319.97	223.44	**7,366.49**	4,913.10	2,341.35	227.09	**7,481.54**	5,048.95	2,381.51	232.19	**7,662.65**
Idaho GTN	665.25	320.00	30.82	**1,016.07**	677.67	322.95	31.32	**1,031.94**	696.41	328.48	32.03	**1,056.92**
Idaho NWP	2,827.32	1,359.98	130.98	**4,318.29**	2,880.09	1,372.52	133.12	**4,385.73**	2,959.73	1,396.06	136.11	**4,491.90**
Idaho Subtotal	**8,315.66**	**3,999.94**	**385.24**	**12,700.84**	**8,470.86**	**4,036.82**	**391.53**	**12,899.21**	**8,705.09**	**4,106.05**	**400.32**	**13,211.47**
Case Total	**29,610.98**	**14,572.49**	**1,109.29**	**45,292.77**	**29,963.82**	**14,673.69**	**1,135.53**	**45,773.03**	**30,580.77**	**14,885.36**	**1,168.43**	**46,634.57**

APPENDIX 2.9: DETAILED DEMAND DATA AVERAGE MIX

Area	2019-2020: Residential	2019-2020: Commercial	2019-2020: Industrial	2019-2020: Total	2020-2021: Residential	2020-2021: Commercial	2020-2021: Industrial	2020-2021: Total	2021-2022: Residential	2021-2022: Commercial	2021-2022: Industrial	2021-2022: Total
Klamath Falls	912.55	466.22	14.15	**1,392.92**	918.04	464.85	13.83	**1,396.72**	868.35	441.37	13.32	**1,323.03**
La Grande	476.16	312.86	52.03	**841.05**	475.85	311.12	51.69	**838.66**	453.59	297.22	52.95	**803.75**
Medford GTN	2,218.28	1,404.07	16.58	**3,638.93**	2,231.18	1,407.96	16.61	**3,655.75**	2,136.82	1,360.48	16.88	**3,514.17**
Medford NWP	996.27	630.52	7.42	**1,634.21**	999.31	630.57	7.27	**1,637.15**	954.69	607.81	7.15	**1,569.65**
Roseburg	760.32	620.71	2.67	**1,383.70**	760.00	616.62	2.61	**1,379.22**	718.45	587.32	2.55	**1,308.32**
Oregon Subtotal	**5,363.58**	**3,434.38**	**92.85**	**8,890.81**	**5,384.37**	**3,431.12**	**92.01**	**8,907.50**	**5,131.89**	**3,294.20**	**92.84**	**8,518.92**
Washington Both	6,685.34	3,302.20	164.40	**10,151.94**	6,702.78	3,293.29	160.97	**10,157.04**	5,348.25	2,728.72	139.22	**8,216.19**
Washington GTN	905.77	535.12	21.90	**1,462.79**	908.06	533.72	21.45	**1,463.23**	725.54	434.58	18.66	**1,178.79**
Washington NWP	3,918.99	1,935.77	96.37	**5,951.14**	3,929.22	1,930.55	94.36	**5,954.13**	3,135.18	1,599.59	81.61	**4,816.39**
Washington Subtotal	**11,510.10**	**5,773.09**	**282.68**	**17,565.86**	**11,540.06**	**5,757.56**	**276.79**	**17,574.40**	**9,208.97**	**4,762.90**	**239.50**	**14,211.37**
Idaho Both	3,365.91	1,948.44	161.88	**5,476.23**	3,393.92	1,940.78	159.21	**5,493.91**	3,345.54	1,898.63	155.89	**5,400.07**
Idaho GTN	464.26	268.75	22.33	**755.34**	468.13	267.69	21.96	**757.78**	461.45	261.88	21.50	**744.84**
Idaho NWP	1,973.12	1,142.19	94.89	**3,210.20**	1,989.54	1,137.70	93.33	**3,220.57**	1,961.18	1,112.99	91.39	**3,165.56**
Idaho Subtotal	**5,803.30**	**3,359.38**	**279.10**	**9,441.78**	**5,851.58**	**3,346.17**	**274.51**	**9,472.26**	**5,768.18**	**3,273.50**	**268.78**	**9,310.46**
Case Total	**22,676.98**	**12,566.85**	**654.62**	**35,898.45**	**22,776.01**	**12,534.84**	**643.31**	**35,954.16**	**20,109.04**	**11,330.60**	**601.11**	**32,040.76**

Area	2022-2023: Residential	2022-2023: Commercial	2022-2023: Industrial	2022-2023: Total	2023-2024: Residential	2023-2024: Commercial	2023-2024: Industrial	2023-2024: Total	2024-2025: Residential	2024-2025: Commercial	2024-2025: Industrial	2024-2025: Total
Klamath Falls	877.01	445.38	13.23	**1,335.61**	888.63	451.01	13.27	**1,352.91**	891.02	451.93	13.22	**1,356.17**
La Grande	456.46	299.04	53.01	**808.50**	460.82	301.91	53.60	**816.33**	461.34	302.00	53.72	**817.06**
Medford GTN	2,167.42	1,378.68	17.30	**3,563.40**	2,205.08	1,401.22	17.93	**3,624.23**	2,225.73	1,412.17	18.46	**3,656.36**
Medford NWP	966.18	614.55	7.10	**1,587.83**	980.89	623.27	7.12	**1,611.28**	987.78	626.67	7.10	**1,621.55**
Roseburg	722.35	589.84	2.53	**1,314.72**	729.39	594.74	2.54	**1,326.66**	728.85	593.34	2.53	**1,324.72**
Oregon Subtotal	**5,189.41**	**3,327.49**	**93.17**	**8,610.07**	**5,264.81**	**3,372.15**	**94.46**	**8,731.41**	**5,294.72**	**3,386.11**	**95.03**	**8,775.86**
Washington Both	5,373.64	2,720.40	137.62	**8,231.66**	5,475.64	2,738.69	137.09	**8,351.42**	5,526.07	2,735.85	135.47	**8,397.40**
Washington GTN	729.00	433.13	18.45	**1,180.58**	742.88	436.29	18.37	**1,197.54**	749.69	435.81	18.16	**1,203.66**
Washington NWP	3,150.07	1,594.72	80.67	**4,825.45**	3,209.86	1,605.44	80.37	**4,895.66**	3,239.42	1,603.78	79.41	**4,922.61**
Washington Subtotal	**9,252.71**	**4,748.25**	**236.74**	**14,237.69**	**9,428.38**	**4,780.41**	**235.83**	**14,444.62**	**9,515.19**	**4,775.44**	**233.04**	**14,523.67**
Idaho Both	3,400.79	1,908.71	154.39	**5,463.89**	3,479.47	1,930.56	153.54	**5,563.57**	3,524.07	1,932.81	151.51	**5,608.39**
Idaho GTN	469.07	263.27	21.30	**753.64**	479.93	266.28	21.18	**767.39**	486.08	266.59	20.90	**773.57**
Idaho NWP	1,993.56	1,118.90	90.51	**3,202.97**	2,039.69	1,131.71	90.00	**3,261.40**	2,065.83	1,133.02	88.82	**3,287.67**
Idaho Subtotal	**5,863.42**	**3,290.88**	**266.19**	**9,420.49**	**5,999.09**	**3,328.55**	**264.72**	**9,592.37**	**6,075.97**	**3,332.42**	**261.23**	**9,669.63**
Case Total	**20,305.55**	**11,366.61**	**596.10**	**32,268.25**	**20,692.27**	**11,481.11**	**595.01**	**32,768.39**	**20,885.88**	**11,493.97**	**589.30**	**32,969.15**

Area	2025-2026: Residential	2025-2026: Commercial	2025-2026: Industrial	2025-2026: Total	2026-2027: Residential	2026-2027: Commercial	2026-2027: Industrial	2026-2027: Total	2027-2028: Residential	2027-2028: Commercial	2027-2028: Industrial	2027-2028: Total
Klamath Falls	891.58	451.64	13.19	1,356.42	888.56	450.27	13.16	1,351.99	898.00	454.45	13.21	1,365.66
La Grande	461.43	301.49	53.85	816.78	460.09	300.47	53.92	814.48	464.09	302.64	54.07	820.81
Medford GTN	2,243.32	1,420.08	19.04	3,682.44	2,251.93	1,425.02	19.64	3,696.59	2,288.74	1,443.93	20.29	3,752.96
Medford NWP	993.37	628.79	7.10	1,629.25	995.08	629.65	7.10	1,631.83	1,009.29	636.71	7.13	1,653.13
Roseburg	727.74	590.97	2.53	1,321.24	724.17	587.47	2.52	1,314.16	730.66	590.69	2.53	1,323.87
Oregon Subtotal	5,317.45	3,392.97	95.71	8,806.13	5,319.82	3,392.89	96.34	8,809.05	5,390.79	3,428.41	97.23	8,916.43
Washington Both	5,593.42	2,743.42	134.47	8,471.32	5,655.22	2,751.42	133.56	8,540.20	5,737.62	2,771.63	133.17	8,642.42
Washington GTN	758.82	437.12	18.02	1,213.96	767.18	438.48	17.90	1,223.57	778.37	441.89	17.84	1,238.11
Washington NWP	3,278.90	1,608.21	78.83	4,965.94	3,315.13	1,612.90	78.29	5,006.32	3,363.43	1,624.75	78.07	5,066.25
Washington Subtotal	9,631.14	4,788.76	231.32	14,651.22	9,737.53	4,802.80	229.76	14,770.09	9,879.42	4,838.27	229.09	14,946.78
Idaho Both	3,542.08	1,924.14	149.54	5,615.75	3,537.81	1,908.45	147.39	5,593.65	3,593.42	1,921.06	146.61	5,661.09
Idaho GTN	488.56	265.40	20.63	774.59	487.97	263.24	20.33	771.54	495.64	264.97	20.22	780.84
Idaho NWP	2,076.39	1,127.94	87.66	3,291.99	2,073.89	1,118.75	86.40	3,279.04	2,106.49	1,126.14	85.94	3,318.57
Idaho Subtotal	6,107.03	3,317.47	257.83	9,682.33	6,099.68	3,290.44	254.11	9,644.23	6,195.56	3,312.17	252.77	9,760.50
Case Total	21,055.62	11,499.20	584.86	33,139.68	21,157.03	11,486.13	580.21	33,223.37	21,465.77	11,578.86	579.09	33,623.71

Area	2028-2029: Residential	2028-2029: Commercial	2028-2029: Industrial	2028-2029: Total	2029-2030: Residential	2029-2030: Commercial	2029-2030: Industrial	2029-2030: Total	2030-2031: Residential	2030-2031: Commercial	2030-2031: Industrial	2030-2031: Total
Klamath Falls	898.23	454.71	13.16	1,366.11	902.54	457.08	13.16	1,372.78	906.69	459.38	13.16	1,379.23
La Grande	464.24	302.55	54.02	820.82	466.34	303.73	54.04	824.11	468.46	304.92	54.04	827.43
Medford GTN	2,303.19	1,451.67	20.81	3,775.67	2,327.39	1,465.10	21.39	3,813.87	2,350.73	1,478.08	21.97	3,850.77
Medford NWP	1,013.68	638.87	7.11	1,659.65	1,022.41	643.56	7.11	1,673.08	1,030.81	648.11	7.10	1,686.02
Roseburg	729.43	588.61	2.52	1,320.57	731.95	589.32	2.52	1,323.80	734.32	589.84	2.52	1,326.69
Oregon Subtotal	5,408.78	3,436.41	97.62	8,942.82	5,450.62	3,458.79	98.22	9,007.63	5,491.01	3,480.32	98.80	9,070.13
Washington Both	5,773.48	2,771.37	131.70	8,676.56	5,833.79	2,783.05	130.76	8,747.60	5,888.45	2,794.53	129.80	8,812.78
Washington GTN	783.19	441.74	17.66	1,242.58	791.36	443.60	17.53	1,252.49	798.76	445.42	17.40	1,261.58
Washington NWP	3,384.45	1,624.60	77.21	5,086.26	3,419.81	1,631.44	76.65	5,127.90	3,451.85	1,638.17	76.09	5,166.11
Washington Subtotal	9,941.12	4,837.71	226.56	15,005.40	10,044.96	4,858.10	224.93	15,127.99	10,139.06	4,878.12	223.29	15,240.47
Idaho Both	3,619.94	1,917.46	144.73	5,682.12	3,662.12	1,922.27	143.38	5,727.77	3,705.64	1,928.18	142.04	5,775.85
Idaho GTN	499.30	264.48	19.96	783.74	505.12	265.14	19.78	790.04	511.12	265.96	19.59	796.67
Idaho NWP	2,122.03	1,124.03	84.84	3,330.90	2,146.76	1,126.85	84.05	3,357.66	2,172.27	1,130.31	83.26	3,385.84
Idaho Subtotal	6,241.27	3,305.96	249.53	9,796.76	6,314.00	3,314.26	247.21	9,875.47	6,389.03	3,324.44	244.89	9,958.36
Case Total	21,591.18	11,580.09	573.72	33,744.98	21,809.58	11,631.14	570.37	34,011.09	22,019.10	11,682.89	566.98	34,268.97

Area	2031-2032: Residential	2031-2032: Commercial	2031-2032: Industrial	2031-2032: Total	2032-2033: Residential	2032-2033: Commercial	2032-2033: Industrial	2032-2033: Total	2033-2034: Residential	2033-2034: Commercial	2033-2034: Industrial	2033-2034: Total
Klamath Falls	915.70	464.01	13.21	1,392.92	915.59	464.53	13.16	1,393.28	919.97	467.05	13.16	1,400.18
La Grande	472.72	307.45	54.12	834.28	472.95	307.54	54.05	834.54	475.11	308.85	54.05	838.01
Medford GTN	2,384.88	1,497.12	22.62	3,904.61	2,395.68	1,503.96	23.13	3,922.77	2,416.68	1,516.34	23.71	3,956.73
Medford NWP	1,044.01	655.34	7.13	1,706.48	1,047.04	657.27	7.10	1,711.42	1,054.58	661.65	7.10	1,723.34
Roseburg	740.67	593.29	2.53	1,336.49	739.19	591.21	2.52	1,332.92	741.50	591.76	2.52	1,335.78
Oregon Subtotal	5,557.98	3,517.21	99.60	9,174.79	5,570.45	3,524.51	99.97	9,194.94	5,607.84	3,545.65	100.55	9,254.04
Washington Both	5,966.81	2,816.96	129.33	8,913.10	5,996.91	2,817.96	127.83	8,942.70	6,052.42	2,832.66	126.84	9,011.92
Washington GTN	809.41	449.11	17.33	1,275.85	813.45	449.10	17.14	1,279.69	820.98	451.35	17.00	1,289.33
Washington NWP	3,497.79	1,651.32	75.82	5,224.92	3,515.43	1,651.91	74.94	5,242.27	3,547.97	1,660.52	74.36	5,282.85
Washington Subtotal	10,274.01	4,917.39	222.48	15,413.88	10,325.79	4,918.97	219.90	15,464.66	10,421.38	4,944.53	218.20	15,584.11
Idaho Both	3,766.71	1,942.33	141.21	5,850.25	3,795.97	1,940.57	139.32	5,875.86	3,843.75	1,948.67	137.95	5,930.38
Idaho GTN	519.55	267.91	19.48	806.93	523.58	267.66	19.22	810.46	530.17	268.78	19.03	817.98
Idaho NWP	2,208.07	1,138.61	82.78	3,429.45	2,225.22	1,137.57	81.67	3,444.47	2,253.24	1,142.33	80.87	3,476.43
Idaho Subtotal	6,494.33	3,348.84	243.47	10,086.63	6,544.78	3,345.80	240.20	10,130.79	6,627.16	3,359.78	237.84	10,224.79
Case Total	22,326.31	11,783.43	565.55	34,675.30	22,441.02	11,789.28	560.08	34,790.38	22,656.38	11,849.96	556.59	35,062.93

Area	2034-2035: Residential	2034-2035: Commercial	2034-2035: Industrial	2034-2035: Total	2035-2036: Residential	2035-2036: Commercial	2035-2036: Industrial	2035-2036: Total	2036-2037: Residential	2036-2037: Commercial	2036-2037: Industrial	2036-2037: Total
Klamath Falls	924.24	469.63	13.16	1,407.04	933.40	474.54	13.21	1,421.15	933.40	474.93	13.17	1,421.50
La Grande	477.21	310.22	54.05	841.49	481.39	312.85	54.15	848.39	481.53	312.92	54.09	848.55
Medford GTN	2,436.75	1,528.55	24.29	3,989.60	2,468.56	1,547.23	24.95	4,040.74	2,477.02	1,552.54	25.47	4,055.02
Medford NWP	1,061.77	666.00	7.10	1,734.87	1,074.08	673.17	7.13	1,754.38	1,076.25	674.53	7.11	1,757.89
Roseburg	743.73	592.37	2.52	1,338.62	750.12	595.88	2.53	1,348.53	748.70	593.60	2.53	1,344.83
Oregon Subtotal	5,643.70	3,566.77	101.14	9,311.61	5,707.56	3,603.67	101.97	9,413.20	5,716.90	3,608.53	102.37	9,427.80
Washington Both	6,106.98	2,847.22	125.84	9,080.03	6,187.96	2,872.71	125.33	9,186.00	6,216.56	2,875.50	123.86	9,215.93
Washington GTN	828.38	453.57	16.87	1,298.82	839.40	457.68	16.79	1,313.88	843.25	457.90	16.61	1,317.76
Washington NWP	3,579.95	1,669.06	73.77	5,322.78	3,627.43	1,684.00	73.47	5,384.90	3,644.19	1,685.64	72.61	5,402.44
Washington Subtotal	10,515.31	4,969.84	216.48	15,701.63	10,654.79	5,014.40	215.59	15,884.78	10,704.00	5,019.04	213.08	15,936.12
Idaho Both	3,893.18	1,957.34	136.57	5,987.10	3,960.48	1,973.92	135.69	6,070.09	3,994.28	1,974.11	133.84	6,102.23
Idaho GTN	536.99	269.98	18.84	825.81	546.27	272.26	18.72	837.25	550.93	272.29	18.46	841.69
Idaho NWP	2,282.21	1,147.41	80.06	3,509.68	2,321.66	1,157.13	79.54	3,558.33	2,341.47	1,157.24	78.46	3,577.17
Idaho Subtotal	6,712.39	3,374.73	235.47	10,322.58	6,828.41	3,403.31	233.95	10,465.67	6,886.68	3,403.65	230.75	10,521.09
Case Total	22,871.40	11,911.35	553.08	35,335.82	23,190.75	12,021.38	551.51	35,763.64	23,307.59	12,031.21	546.20	35,885.00

Area	2037-2038: Residential	2037-2038: Commercial	2037-2038: Industrial	2037-2038: Total	2038-2039: Residential	2038-2039: Commercial	2038-2039: Industrial	2038-2039: Total	2039-2040: Residential	2039-2040: Commercial	2039-2040: Industrial	2039-2040: Total
Klamath Falls	938.22	477.54	13.18	**1,428.94**	943.16	480.21	13.18	**1,436.55**	953.45	485.63	13.23	**1,452.31**
La Grande	483.66	314.30	54.11	**852.07**	485.69	315.58	54.12	**855.40**	490.06	318.63	54.23	**862.93**
Medford GTN	2,496.59	1,564.21	26.05	**4,086.85**	2,515.17	1,575.56	26.64	**4,117.36**	2,546.76	1,594.86	27.32	**4,168.94**
Medford NWP	1,083.29	678.69	7.11	**1,769.08**	1,089.93	682.72	7.11	**1,779.76**	1,102.23	690.22	7.14	**1,799.60**
Roseburg	751.30	594.29	2.53	**1,348.12**	753.87	594.97	2.53	**1,351.37**	760.93	599.13	2.54	**1,362.60**
Oregon Subtotal	**5,753.05**	**3,629.03**	**102.98**	**9,485.05**	**5,787.82**	**3,649.05**	**103.59**	**9,540.45**	**5,853.43**	**3,688.47**	**104.46**	**9,646.36**
Washington Both	6,267.55	2,888.69	122.84	**9,279.07**	6,319.68	2,901.01	121.79	**9,342.47**	6,397.81	2,924.17	121.22	**9,443.20**
Washington GTN	850.16	459.93	16.47	**1,326.56**	857.23	461.83	16.33	**1,335.39**	867.87	465.61	16.25	**1,349.73**
Washington NWP	3,674.08	1,693.37	72.01	**5,439.46**	3,704.64	1,700.59	71.39	**5,476.62**	3,750.44	1,714.17	71.06	**5,535.67**
Washington Subtotal	**10,791.79**	**5,041.99**	**211.31**	**16,045.09**	**10,881.55**	**5,063.43**	**209.51**	**16,154.49**	**11,016.11**	**5,103.95**	**208.53**	**16,328.60**
Idaho Both	4,043.82	1,982.21	132.44	**6,158.47**	4,095.17	1,989.96	131.03	**6,216.16**	4,164.61	2,005.37	130.11	**6,300.09**
Idaho GTN	557.77	273.41	18.27	**849.44**	564.85	274.48	18.07	**857.40**	574.43	276.60	17.95	**868.98**
Idaho NWP	2,370.51	1,161.98	77.64	**3,610.13**	2,400.62	1,166.53	76.81	**3,643.96**	2,441.33	1,175.56	76.27	**3,693.16**
Idaho Subtotal	**6,972.10**	**3,417.60**	**228.35**	**10,618.04**	**7,060.64**	**3,430.97**	**225.92**	**10,717.52**	**7,180.37**	**3,457.54**	**224.32**	**10,862.23**
Case Total	**23,516.93**	**12,088.61**	**542.64**	**36,148.19**	**23,730.00**	**12,143.44**	**539.02**	**36,412.46**	**24,049.91**	**12,249.96**	**537.31**	**36,837.19**

APPENDIX 2.9: DETAILED DEMAND DATA CARBON REDUCTION

Area	2019-2020: Residential	2019-2020: Commercial	2019-2020: Industrial	2019-2020: Total	2020-2021: Residential	2020-2021: Commercial	2020-2021: Industrial	2020-2021: Total	2021-2022: Residential	2021-2022: Commercial	2021-2022: Industrial	2021-2022: Total
Klamath Falls	939.27	478.09	14.32	**1,431.68**	943.84	476.42	13.99	**1,434.26**	915.92	462.35	13.63	**1,391.90**
La Grande	491.98	322.74	52.03	**866.76**	488.86	319.26	51.69	**859.81**	475.55	310.63	53.21	**839.39**
Medford GTN	2,287.91	1,438.38	16.65	**3,742.95**	2,296.76	1,440.79	16.69	**3,754.24**	2,248.81	1,415.87	17.02	**3,681.70**
Medford NWP	1,027.55	645.93	7.46	**1,680.94**	1,028.69	645.28	7.31	**1,681.27**	1,004.74	632.56	7.21	**1,644.51**
Roseburg	792.62	642.08	2.70	**1,437.40**	790.06	636.54	2.64	**1,429.23**	764.53	617.70	2.59	**1,384.83**
Oregon Subtotal	**5,539.33**	**3,527.22**	**93.16**	**9,159.72**	**5,548.22**	**3,518.29**	**92.31**	**9,158.82**	**5,409.55**	**3,439.12**	**93.67**	**8,942.33**
Washington Both	6,902.44	3,388.40	168.03	**10,458.87**	6,900.31	3,372.97	164.84	**10,438.12**	5,673.64	2,861.91	144.87	**8,680.43**
Washington GTN	935.28	551.25	22.29	**1,508.83**	934.91	548.30	21.90	**1,505.11**	769.60	458.17	19.35	**1,247.12**
Washington NWP	4,046.26	1,986.30	98.50	**6,131.06**	4,045.01	1,977.26	96.63	**6,118.90**	3,325.93	1,677.67	84.93	**5,088.53**
Washington Subtotal	**11,883.98**	**5,925.95**	**288.83**	**18,098.76**	**11,880.23**	**5,898.53**	**283.36**	**18,062.12**	**9,769.18**	**4,997.75**	**249.15**	**15,016.07**
Idaho Both	3,474.88	2,001.23	164.40	**5,640.51**	3,489.36	1,989.43	161.91	**5,640.70**	3,535.37	1,991.83	160.55	**5,687.75**
Idaho GTN	479.29	276.03	22.68	**778.00**	481.29	274.40	22.33	**778.03**	487.64	274.74	22.14	**784.52**
Idaho NWP	2,037.00	1,173.14	96.37	**3,306.51**	2,045.49	1,166.22	94.91	**3,306.62**	2,072.46	1,167.63	94.11	**3,334.20**
Idaho Subtotal	**5,991.17**	**3,450.40**	**283.45**	**9,725.02**	**6,016.14**	**3,430.05**	**279.15**	**9,725.34**	**6,095.47**	**3,434.20**	**276.80**	**9,806.47**
Case Total	**23,414.48**	**12,903.57**	**665.44**	**36,983.49**	**23,444.59**	**12,846.86**	**654.82**	**36,946.27**	**21,274.19**	**11,871.06**	**619.62**	**33,764.87**

Area	2022-2023: Residential	2022-2023: Commercial	2022-2023: Industrial	2022-2023: Total	2023-2024: Residential	2023-2024: Commercial	2023-2024: Industrial	2023-2024: Total	2024-2025: Residential	2024-2025: Commercial	2024-2025: Industrial	2024-2025: Total
Klamath Falls	924.81	466.84	13.55	**1,405.20**	937.83	473.35	13.60	**1,424.78**	939.31	473.96	13.55	**1,426.81**
La Grande	478.43	312.72	53.30	**844.46**	485.62	317.57	53.91	**857.10**	483.40	315.99	54.03	**853.42**
Medford GTN	2,280.40	1,435.78	17.46	**3,733.64**	2,323.74	1,461.87	18.11	**3,803.72**	2,340.99	1,471.40	18.64	**3,831.03**
Medford NWP	1,016.56	640.00	7.17	**1,663.72**	1,033.70	650.23	7.19	**1,691.13**	1,038.96	652.95	7.17	**1,699.08**
Roseburg	768.46	620.73	2.57	**1,391.77**	778.01	627.61	2.58	**1,408.21**	775.16	624.73	2.57	**1,402.46**
Oregon Subtotal	**5,468.66**	**3,476.07**	**94.05**	**9,038.78**	**5,558.91**	**3,530.63**	**95.39**	**9,184.93**	**5,577.82**	**3,539.03**	**95.95**	**9,212.79**
Washington Both	5,709.12	2,857.10	143.23	**8,709.45**	5,843.86	2,889.59	143.15	**8,876.59**	5,873.60	2,879.25	141.01	**8,893.85**
Washington GTN	774.44	457.22	19.13	**1,250.80**	792.79	462.90	19.10	**1,274.79**	796.77	460.87	18.83	**1,276.48**
Washington NWP	3,346.73	1,674.85	83.96	**5,105.54**	3,425.71	1,693.89	83.91	**5,203.52**	3,443.14	1,687.83	82.66	**5,213.63**
Washington Subtotal	**9,830.29**	**4,989.17**	**246.32**	**15,065.78**	**10,062.37**	**5,046.38**	**246.16**	**15,354.91**	**10,113.51**	**5,027.95**	**242.50**	**15,383.96**
Idaho Both	3,595.62	2,004.26	159.00	**5,758.88**	3,698.07	2,037.32	158.55	**5,893.94**	3,729.67	2,032.92	156.05	**5,918.65**
Idaho GTN	495.95	276.45	21.93	**794.33**	510.08	281.01	21.87	**812.96**	514.44	280.40	21.52	**816.37**
Idaho NWP	2,107.78	1,174.91	93.21	**3,375.90**	2,167.83	1,194.29	92.94	**3,455.07**	2,186.36	1,191.71	91.48	**3,469.55**
Idaho Subtotal	**6,199.35**	**3,455.63**	**274.14**	**9,929.11**	**6,375.98**	**3,512.62**	**273.36**	**10,161.96**	**6,430.46**	**3,505.04**	**269.06**	**10,204.57**
Case Total	**21,498.30**	**11,920.86**	**614.51**	**34,033.67**	**21,997.26**	**12,089.64**	**614.90**	**34,701.80**	**22,121.79**	**12,072.02**	**607.51**	**34,801.32**

Area	2025-2026: Residential	2025-2026: Commercial	2025-2026: Industrial	2025-2026: Total	2026-2027: Residential	2026-2027: Commercial	2026-2027: Industrial	2026-2027: Total	2027-2028: Residential	2027-2028: Commercial	2027-2028: Industrial	2027-2028: Total
Klamath Falls	946.72	476.71	13.56	**1,436.98**	944.46	475.79	13.53	**1,433.78**	955.59	481.03	13.58	**1,450.21**
La Grande	486.32	317.19	54.23	**857.74**	485.25	316.41	54.31	**855.97**	492.29	320.70	54.46	**867.45**
Medford GTN	2,374.44	1,487.22	19.24	**3,880.90**	2,385.53	1,493.70	19.84	**3,899.07**	2,429.28	1,516.89	20.51	**3,966.67**
Medford NWP	1,051.45	658.51	7.17	**1,717.13**	1,054.13	659.99	7.18	**1,721.30**	1,071.28	668.87	7.20	**1,747.36**
Roseburg	779.15	625.74	2.57	**1,407.47**	775.99	622.61	2.57	**1,401.18**	785.28	628.05	2.58	**1,415.91**
Oregon Subtotal	**5,638.07**	**3,565.37**	**96.78**	**9,300.22**	**5,645.36**	**3,568.51**	**97.43**	**9,311.30**	**5,733.72**	**3,615.53**	**98.34**	**9,447.59**
Washington Both	5,950.19	2,889.37	139.90	**8,979.46**	6,024.25	2,900.23	138.80	**9,063.28**	6,149.75	2,933.54	138.70	**9,221.99**
Washington GTN	807.16	462.56	18.69	**1,288.40**	817.21	464.34	18.54	**1,300.08**	834.29	470.13	18.51	**1,322.93**
Washington NWP	3,488.04	1,693.77	82.01	**5,263.82**	3,531.46	1,700.14	81.36	**5,312.96**	3,605.02	1,719.66	81.31	**5,405.99**
Washington Subtotal	**10,245.39**	**5,045.70**	**240.59**	**15,531.68**	**10,372.92**	**5,064.70**	**238.70**	**15,676.32**	**10,589.06**	**5,123.33**	**238.52**	**15,950.91**
Idaho Both	3,756.37	2,027.24	154.06	**5,937.67**	3,754.28	2,010.56	151.65	**5,916.49**	3,837.36	2,032.96	151.16	**6,021.48**
Idaho GTN	518.12	279.62	21.25	**818.99**	517.83	277.32	20.92	**816.07**	529.29	280.41	20.85	**830.55**
Idaho NWP	2,202.01	1,188.38	90.31	**3,480.70**	2,200.79	1,178.60	88.90	**3,468.29**	2,249.49	1,191.74	88.61	**3,529.83**
Idaho Subtotal	**6,476.49**	**3,495.25**	**265.62**	**10,237.36**	**6,472.90**	**3,466.48**	**261.47**	**10,200.85**	**6,616.14**	**3,505.11**	**260.62**	**10,381.86**
Case Total	**22,359.95**	**12,106.32**	**602.99**	**35,069.26**	**22,491.18**	**12,099.69**	**597.60**	**35,188.47**	**22,938.92**	**12,243.98**	**597.47**	**35,780.37**

Area	2028-2029: Residential	2028-2029: Commercial	2028-2029: Industrial	2028-2029: Total	2029-2030: Residential	2029-2030: Commercial	2029-2030: Industrial	2029-2030: Total	2030-2031: Residential	2030-2031: Commercial	2030-2031: Industrial	2030-2031: Total
Klamath Falls	948.59	478.15	13.49	**1,440.23**	946.68	477.65	13.45	**1,437.77**	951.15	480.01	13.45	**1,444.61**
La Grande	487.10	317.33	54.34	**858.76**	486.62	316.87	54.28	**857.77**	488.90	318.08	54.28	**861.27**
Medford GTN	2,426.15	1,516.07	21.00	**3,963.21**	2,437.11	1,522.47	21.56	**3,981.14**	2,461.87	1,535.80	22.15	**4,019.81**
Medford NWP	1,067.81	667.20	7.17	**1,742.18**	1,070.62	668.77	7.16	**1,746.55**	1,079.56	673.42	7.16	**1,760.14**
Roseburg	776.99	621.25	2.57	**1,400.81**	774.78	618.61	2.56	**1,395.95**	777.39	619.12	2.56	**1,399.07**
Oregon Subtotal	**5,706.63**	**3,600.00**	**98.57**	**9,405.20**	**5,715.80**	**3,604.37**	**99.01**	**9,419.18**	**5,758.88**	**3,626.42**	**99.60**	**9,484.90**
Washington Both	6,168.97	2,922.19	136.62	**9,227.78**	6,240.36	2,933.77	135.55	**9,309.68**	6,304.75	2,945.18	134.49	**9,384.42**
Washington GTN	836.84	467.92	18.25	**1,323.01**	846.52	469.79	18.11	**1,334.42**	855.26	471.62	17.96	**1,344.84**
Washington NWP	3,616.29	1,713.01	80.09	**5,409.39**	3,658.14	1,719.80	79.46	**5,457.40**	3,695.89	1,726.48	78.84	**5,501.21**
Washington Subtotal	**10,622.10**	**5,103.11**	**234.96**	**15,960.18**	**10,745.02**	**5,123.36**	**233.12**	**16,101.50**	**10,855.89**	**5,143.28**	**231.29**	**16,230.47**
Idaho Both	3,851.78	2,020.37	148.76	**6,020.90**	3,900.85	2,025.04	147.32	**6,073.22**	3,950.87	2,030.88	145.89	**6,127.64**
Idaho GTN	531.28	278.67	20.52	**830.47**	538.05	279.32	20.32	**837.68**	544.95	280.12	20.12	**845.19**
Idaho NWP	2,257.94	1,184.36	87.20	**3,529.50**	2,286.71	1,187.09	86.36	**3,560.16**	2,316.03	1,190.52	85.52	**3,592.07**
Idaho Subtotal	**6,640.99**	**3,483.40**	**256.48**	**10,380.87**	**6,725.60**	**3,491.46**	**254.00**	**10,471.06**	**6,811.85**	**3,501.52**	**251.53**	**10,564.90**
Case Total	**22,969.73**	**12,186.51**	**590.01**	**35,746.24**	**23,186.43**	**12,219.18**	**586.13**	**35,991.74**	**23,426.61**	**12,271.23**	**582.42**	**36,280.27**

Area	2031-2032: Residential	2031-2032: Commercial	2031-2032: Industrial	2031-2032: Total	2032-2033: Residential	2032-2033: Commercial	2032-2033: Industrial	2032-2033: Total	2033-2034: Residential	2033-2034: Commercial	2033-2034: Industrial	2033-2034: Total
Klamath Falls	961.88	485.40	13.49	**1,460.77**	960.57	485.27	13.44	**1,459.29**	958.17	484.86	13.40	**1,456.43**
La Grande	496.24	322.53	54.36	**873.14**	493.62	320.73	54.29	**868.64**	492.96	320.38	54.22	**867.56**
Medford GTN	2,502.94	1,558.10	22.80	**4,083.85**	2,509.16	1,562.27	23.31	**4,094.74**	2,515.06	1,567.32	23.87	**4,106.25**
Medford NWP	1,095.71	682.04	7.19	**1,784.94**	1,096.65	682.76	7.16	**1,786.57**	1,097.52	683.91	7.15	**1,788.59**
Roseburg	786.58	624.37	2.57	**1,413.52**	782.62	620.41	2.56	**1,405.59**	779.78	617.60	2.56	**1,399.93**
Oregon Subtotal	**5,843.35**	**3,672.45**	**100.42**	**9,616.22**	**5,842.62**	**3,671.44**	**100.77**	**9,614.83**	**5,843.49**	**3,674.07**	**101.20**	**9,618.76**
Washington Both	6,422.90	2,978.45	134.39	**9,535.75**	6,430.73	2,965.11	132.36	**9,528.20**	6,491.77	2,975.84	131.23	**9,598.85**
Washington GTN	871.35	477.39	17.93	**1,366.67**	872.35	474.86	17.68	**1,364.89**	880.63	476.58	17.53	**1,374.74**
Washington NWP	3,765.15	1,745.99	78.78	**5,589.92**	3,769.74	1,738.17	77.59	**5,585.50**	3,805.52	1,744.46	76.93	**5,626.91**
Washington Subtotal	**11,059.41**	**5,201.83**	**231.11**	**16,492.34**	**11,072.81**	**5,178.14**	**227.63**	**16,478.59**	**11,177.93**	**5,196.88**	**225.69**	**16,600.50**
Idaho Both	4,038.27	2,053.65	145.38	**6,237.29**	4,053.98	2,041.53	143.02	**6,238.53**	4,079.92	2,036.44	141.12	**6,257.48**
Idaho GTN	557.00	283.26	20.05	**860.32**	559.17	281.59	19.73	**860.49**	562.75	280.89	19.46	**863.10**
Idaho NWP	2,367.26	1,203.86	85.22	**3,656.34**	2,376.47	1,196.76	83.84	**3,657.07**	2,391.68	1,193.78	82.72	**3,668.18**
Idaho Subtotal	**6,962.53**	**3,540.78**	**250.65**	**10,753.95**	**6,989.62**	**3,519.88**	**246.59**	**10,756.09**	**7,034.35**	**3,511.11**	**243.31**	**10,788.76**
Case Total	**23,865.28**	**12,415.05**	**582.17**	**36,862.51**	**23,905.05**	**12,369.46**	**575.00**	**36,849.51**	**24,055.77**	**12,382.05**	**570.20**	**37,008.02**

Area	2034-2035: Residential	2034-2035: Commercial	2034-2035: Industrial	2034-2035: Total	2035-2036: Residential	2035-2036: Commercial	2035-2036: Industrial	2035-2036: Total	2036-2037: Residential	2036-2037: Commercial	2036-2037: Industrial	2036-2037: Total
Klamath Falls	962.59	487.39	13.40	**1,463.39**	973.11	492.93	13.46	**1,479.49**	972.12	492.98	13.41	**1,478.51**
La Grande	495.12	321.70	54.23	**871.06**	502.24	326.20	54.32	**882.76**	499.60	324.57	54.26	**878.43**
Medford GTN	2,535.89	1,579.44	24.46	**4,139.79**	2,573.61	1,601.01	25.13	**4,199.74**	2,577.77	1,604.50	25.64	**4,207.91**
Medford NWP	1,104.97	688.18	7.16	**1,800.31**	1,119.80	696.58	7.18	**1,823.56**	1,120.03	697.13	7.16	**1,824.32**
Roseburg	782.11	618.03	2.56	**1,402.70**	791.05	623.20	2.57	**1,416.82**	787.33	619.45	2.56	**1,409.34**
Oregon Subtotal	**5,880.69**	**3,694.74**	**101.81**	**9,677.25**	**5,959.80**	**3,739.92**	**102.65**	**9,802.37**	**5,956.85**	**3,738.63**	**103.03**	**9,798.52**
Washington Both	6,550.72	2,986.98	130.14	**9,667.84**	6,666.99	3,022.72	129.99	**9,819.70**	6,667.76	3,011.56	127.97	**9,807.29**
Washington GTN	888.63	478.35	17.38	**1,384.37**	904.47	484.46	17.34	**1,406.28**	904.51	482.21	17.09	**1,403.81**
Washington NWP	3,840.08	1,750.99	76.29	**5,667.35**	3,908.24	1,771.94	76.20	**5,756.37**	3,908.69	1,765.40	75.02	**5,749.10**
Washington Subtotal	**11,279.43**	**5,216.32**	**223.81**	**16,719.56**	**11,479.70**	**5,279.12**	**223.53**	**16,982.35**	**11,480.96**	**5,259.16**	**220.08**	**16,960.20**
Idaho Both	4,133.40	2,042.97	139.67	**6,316.05**	4,225.59	2,067.76	139.10	**6,432.45**	4,241.97	2,057.85	136.79	**6,436.60**
Idaho GTN	570.12	281.79	19.26	**871.18**	582.84	285.21	19.19	**887.24**	585.10	283.84	18.87	**887.81**
Idaho NWP	2,423.03	1,197.61	81.87	**3,702.51**	2,477.07	1,212.14	81.54	**3,770.75**	2,486.67	1,206.33	80.19	**3,773.18**
Idaho Subtotal	**7,126.56**	**3,522.37**	**240.80**	**10,889.73**	**7,285.50**	**3,565.10**	**239.83**	**11,090.44**	**7,313.73**	**3,548.02**	**235.84**	**11,097.59**
Case Total	**24,286.68**	**12,433.44**	**566.42**	**37,286.54**	**24,725.00**	**12,584.14**	**566.02**	**37,875.16**	**24,751.55**	**12,545.81**	**558.95**	**37,856.31**

Area	2037-2038: Residential	2037-2038: Commercial	2037-2038: Industrial	2037-2038: Total	2038-2039: Residential	2038-2039: Commercial	2038-2039: Industrial	2038-2039: Total	2039-2040: Residential	2039-2040: Commercial	2039-2040: Industrial	2039-2040: Total
Klamath Falls	977.11	495.78	13.41	**1,486.30**	982.29	498.54	13.41	**1,494.24**	994.01	504.11	13.47	**1,511.59**
La Grande	501.79	326.06	54.27	**882.12**	503.92	327.38	54.27	**885.57**	511.28	332.01	54.39	**897.67**
Medford GTN	2,598.04	1,616.85	26.23	**4,241.12**	2,617.48	1,628.54	26.81	**4,272.83**	2,655.15	1,649.19	27.50	**4,331.85**
Medford NWP	1,127.32	701.55	7.16	**1,836.03**	1,134.27	705.70	7.16	**1,847.14**	1,149.15	713.76	7.19	**1,870.10**
Roseburg	790.04	620.29	2.56	**1,412.89**	792.77	621.00	2.56	**1,416.33**	802.45	626.19	2.57	**1,431.21**
Oregon Subtotal	**5,994.29**	**3,760.53**	**103.63**	**9,858.45**	**6,030.73**	**3,781.16**	**104.21**	**9,916.10**	**6,112.04**	**3,825.26**	**105.12**	**10,042.43**
Washington Both	6,723.73	3,023.68	126.88	**9,874.28**	6,778.88	3,035.79	125.79	**9,940.46**	6,893.10	3,070.36	125.61	**10,089.07**
Washington GTN	912.10	484.11	16.95	**1,413.16**	919.58	486.00	16.80	**1,422.39**	935.15	491.95	16.76	**1,443.86**
Washington NWP	3,941.49	1,772.50	74.38	**5,788.37**	3,973.82	1,779.60	73.74	**5,827.17**	4,040.78	1,799.87	73.63	**5,914.28**
Washington Subtotal	**11,577.32**	**5,280.28**	**218.21**	**17,075.82**	**11,672.28**	**5,301.39**	**216.34**	**17,190.01**	**11,869.03**	**5,362.18**	**216.00**	**17,447.22**
Idaho Both	4,296.97	2,065.36	135.35	**6,497.68**	4,352.70	2,072.82	133.90	**6,559.42**	4,448.34	2,096.78	133.30	**6,678.41**
Idaho GTN	592.69	284.88	18.67	**896.23**	600.37	285.91	18.47	**904.75**	613.56	289.21	18.39	**921.16**
Idaho NWP	2,518.91	1,210.73	79.34	**3,808.98**	2,551.58	1,215.10	78.49	**3,845.18**	2,607.65	1,229.15	78.14	**3,914.93**
Idaho Subtotal	**7,408.57**	**3,560.97**	**233.36**	**11,202.89**	**7,504.66**	**3,573.82**	**230.87**	**11,309.35**	**7,669.55**	**3,615.13**	**229.82**	**11,514.51**
Case Total	**24,980.18**	**12,601.78**	**555.20**	**38,137.16**	**25,207.67**	**12,656.37**	**551.42**	**38,415.46**	**25,650.63**	**12,802.58**	**550.95**	**39,004.15**

AEG
Applied Energy Group

2020 AVISTA UTILITIES NATURAL GAS CONSERVATION POTENTIAL ASSESSMENT

Volume 1, Final Report

December 1, 2020

Report prepared for:
AVISTA UTILITIES

Energy Solutions. Delivered.

This work was performed by:

Applied Energy Group, Inc.
500 Ygnacio Valley Road, Suite 250
Walnut Creek, CA 94596

Project Director: I. Rohmund
Project Manager: K. Walter

AEG would also like to acknowledge the valuable contributions of

Avista Utilities
1411 E Mission MSC-15
Spokane, WA 99220

Project Team: Ryan Finesilver
James Gall
Leona Haley
Tom Pardee

EXECUTIVE SUMMARY

Early in 2020, Avista Utilities (Avista) contracted with Applied Energy Group (AEG) to conduct this Conservation Potential Assessment (CPA) in support of their conservation and resource planning activities. This 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 energy conservation efforts in the time period of 2021 to 2040. To produce a reliable and transparent estimate of energy efficiency (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 gas by sector, segment, end use and technology.
- Developed a baseline projection of how customers are likely to use gas in absence of future EE programs. This defines the metric against which future program savings are measured. This projection used up-to-date technology data, modeling assumptions, and energy baselines that reflect both current and anticipated federal, state, and local energy efficiency legislation that will impact energy EE potential.
- Estimated the technical, achievable technical, and achievable economic potential at the measure level for energy efficiency within Avista's service territory over the 2021 to 2040 planning horizon.
- Delivered a fully configured end-use conservation planning model, LoadMAP, for Avista to use in future potential and resource planning initiatives

In summary, the potential study provided a solid foundation for the development of Avista's energy savings targets.

Table ES-1 summarizes the results for Avista's Washington territory at a high level. AEG analyzed potential for the residential, commercial, and industrial market sectors. First-year utility cost test (UCT) achievable economic potential in Washington is 75,820 dekatherms. This increases to a cumulative total of 173,838 dekatherms in the second year and 1,386,479 dekatherms by the tenth year (2030).

Table ES-1 Washington Conservation Potential by Case, Selected Years (dekatherms)

Scenario	2021	2022	2023	2030	2040
Baseline Forecast (Dth)	19,118,293	19,289,575	19,805,020	20,612,516	21,619,876
Cumulative Savings (Dth)					
UCT Achievable Economic	75,820	173,838	457,423	1,386,479	3,560,512
Achievable Technical	41,871	416,584	1,221,810	3,183,398	6,309,826
Technical	187,983	897,098	2,314,334	5,084,999	8,908,493
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.3%	6.7%	16.5%
Achievable Technical Potential	0.2%	2.2%	6.2%	15.4%	29.2%
Technical Potential	1.0%	4.7%	11.7%	24.7%	41.2%

Table ES-2 summarizes the results for Avista's Idaho territory at a high level. First-year utility cost test (UCT) achievable economic potential in Idaho is 35,816 dekatherms. This increases to a cumulative total of 87,995 dekatherms in the second year and 737,710 dekatherms by the tenth year (2030).

Table ES-2 Idaho Conservation Potential by Case, Selected Years (dekatherms)

Scenario	2021	2022	2023	2030	2040
Baseline Forecast (Dth)	10,019,377	10,144,894	10,520,169	11,004,568	12,006,819
Cumulative Savings (Dth)					
UCT Achievable Economic	35,816	87,995	229,283	737,710	2,025,410
Achievable Technical	26,220	226,613	657,997	1,722,830	3,544,048
Technical	102,031	490,826	1,273,202	2,777,509	5,013,697
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.2%	6.7%	16.9%
Achievable Technical Potential	0.3%	2.2%	6.3%	15.7%	29.5%
Technical Potential	1.0%	4.8%	12.1%	25.2%	41.8%

As part of this study, we also estimated total resource cost (TRC) potential, with the focus of fully balancing non-energy impacts. This includes the use of full measure costs as well as quantified and monetizable non-energy impacts and non-gas fuel impacts (e.g. electric cooling or wood secondary heating) consistent with methodology within the 2021 Northwest Conservation and Electric Power Plan (2021 Plan). We explore this potential in more detail throughout the report.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

This report documents the results of the Avista Utilities 2021-2040 Conservation Potential Assessment (CPA) as well as the steps followed in its completion. Throughout this study, AEG worked with Avista to understand the baseline characteristics of their service territory, including a detailed understanding of energy consumption in the territory, the assumptions and methodologies used in Avista's official load forecast, and recent programmatic accomplishments. Adapting methodologies consistent with the Northwest Power and Conservation Council's (Council's) 2021 Power Plan[1] for natural gas studies, AEG then developed an independent estimate of achievable, cost-effective EE potential within Avista's service territory between 2021 and 2040.

Goals of the Conservation Potential Assessment

The first primary objective of this study was to develop independent and credible estimates of EE potential achievably available within Avista's service territory using accepted regional inputs and methodologies. This included estimating technical, *achievable* technical, then achievable *economic* potential, using the Council's ramp rates as the starting point for all achievability assumptions, leveraging Northwest Energy Efficiency Alliance's (NEEA's) market research initiatives, and utilizing assumptions consistent with 2021 Power Plan supply curves and RTF measure workbooks when appropriate for use in natural gas planning studies.

Additionally, the CPA is intended to support the design of programs to be implemented by Avista during the upcoming years. One output of the LoadMAP model is a comprehensive summary of measures. This summary documents input assumptions and sources on a per-unit value, program applicability and achievability (ramp rates), and potential results (units, incremental potential, and cumulative potential) as well as cost-effectiveness at the UCT and TRC levels. This summary was developed in collaboration with Avista and refined throughout the project.

Finally, this study was developed to provide EE inputs into Avista's Integrated Resource Planning (IRP) process. To this end, AEG developed detailed achievable economic EE inputs by measure for input into Avista's SENDOUT planning model under the utility cost test (UCT). These inputs are highly customizable and provide potential estimates at the state level by measure and end use. We present a map of Avista's service territory in Figure 1-1.

[1] "2021 Power Plan. Northwest Power & Conservation Council, 2020. https://www.nwcouncil.org/2021-northwest-power-plan

Figure 1-1 Avista's Service Territory (courtesy Avista)

Summary of Report Contents

The document is divided into seven additional chapters, summarizing the approach, assumptions, and results of the EE potential analysis. We describe each section below:

Volume 1, Final Report:

- Analysis Approach and Data Development. Detailed description of AEG's approach to conducting Avista's 2021-2040 Natural Gas CPA and documentation of primary and secondary sources used.
- Market Characterization and Market Profiles. Characterization of Avista's service territory in the base year of the study, 2019, including total consumption, number of customers and market units, and energy intensity. This also includes a breakdown of the energy consumption for residential, commercial, and eligible industrial customers by end use and technology.
- Baseline Projection. Projection of baseline energy consumption under a naturally occurring efficiency case, described at the end-use level. The LoadMAP models were first aligned with actual sales and Avista's official, weather-normalized econometric forecast and then varied to include the impacts of future federal standards, ongoing impacts of energy codes, such as the 2015 Washington State Energy Code on new construction, and future technology purchasing decisions.
- Overall Energy Efficiency Potential. Summary of EE potential for Avista's Washington and Idaho service territories for selected years between 2021 and 2040.
- Sector-Level Energy Efficiency Potential. Summary of EE potential for each market sector within Avista's service territory, including residential, commercial, and eligible industrial customers for both

Washington and Idaho. This section includes a more detailed breakdown of potential by measure type, vintage, market segment, end use, and state.

- Comparison with Current Programs Detailed comparison of potential with current Avista programs, including new opportunities for potential.
- Comparison with 2018 CPA Detailed comparison of potential with Avista's 2018 CPA, conducted by AEG.

Volume 2, Appendices:

The appendices for this report are provided in separate spreadsheets accompanying 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 use in 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

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
AEO	Annual Energy Outlook forecast developed by EIA
B/C Ratio	Benefit to Cost Ratio
BEST	AEG's Building Energy Simulation Tool
BPA	Bonneville Power Administration
C&I	Commercial and Industrial
CBSA	NEEA's 2019 Commercial Building Stock Assessment
Council	Northwest Power and Conservation Council (NWPCC)
DHW	Domestic Hot Water
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EUL	Estimated Useful Life
EUI	Energy Usage Intensity
HVAC	Heating Ventilation and Air Conditioning
IFSA	NEEA's 2014 Industrial Facilities Site Assessment
IRP	Integrated Resource Plan
LoadMAP	AEG's Load Management Analysis and Planning™ tool
NEEA	Northwest Energy Efficiency Alliance
O&M	Operations and Maintenance
RBSA	NEEA's 2016 Residential Building Stock Assessment
RTF	Regional Technical Forum
RVT	Resource Value Test
TRC	Total Resource Cost test
UCT	Utility Cost Test
UEC	Unit Energy Consumption
UES	Unit Energy Savings
WSEC	2015 Washington State Energy Code

2

ANALYSIS APPROACH AND DATA DEVELOPMENT

This section describes the analysis approach taken for the study and the data sources used to develop the potential estimates.

Overview of Analysis Approach

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

1. Performed a market characterization to describe sector-level natural gas use for the residential, commercial, and industrial sectors for the base year, 2019. This included extensive use of Avista data and other secondary data sources from NEEA and the Energy Information Administration (EIA).
2. Developed a baseline projection of energy consumption by sector, segment, end use, and technology for 2021 through 2040.
3. Defined and characterized several hundred EE measures to be applied to all sectors, segments, and end uses.
4. Estimated technical, achievable technical, and achievable economic energy savings at the measure level for 2021-2040. Achievable economic potential was assessed using both the UCT and TRC screens.

Comparison with Northwest Power & Conservation Council Methodology

It is important to note the Council's methodology was developed for, and used, in electric CPAs. 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). The Council's ramp rates were also developed with electric utility DSM programs in mind. Electricity is the primary focus of the regionwide potential assessed in the Council's Plans. 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 adapted Council methodologies in some cases, rather than using them directly from the source. This is especially relevant in the development of ramp rates when achievability was determined to not be applicable to a specific natural gas measure or program. We discuss this in Section 7 of this report.

A primary objective of the study was to estimate natural gas potential consistent with the Northwest Power & Conservation Council's (NWPCC) analytical methodologies and procedures for electric utilities. While developing Avista's 2021-2040 CPA, the AEG team relied on an approach vetted and adapted through the successful completion of CPAs under the Council'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, Seventh 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 as well as Council's TRC method, including non-energy impacts (and non-gas energy impacts) which may be quantified and monetized as well as O&M impacts within the TRC
- Conservation credits: applied a 10% conservation credit to avoided energy costs for energy benefits was applied to the TRC calculation

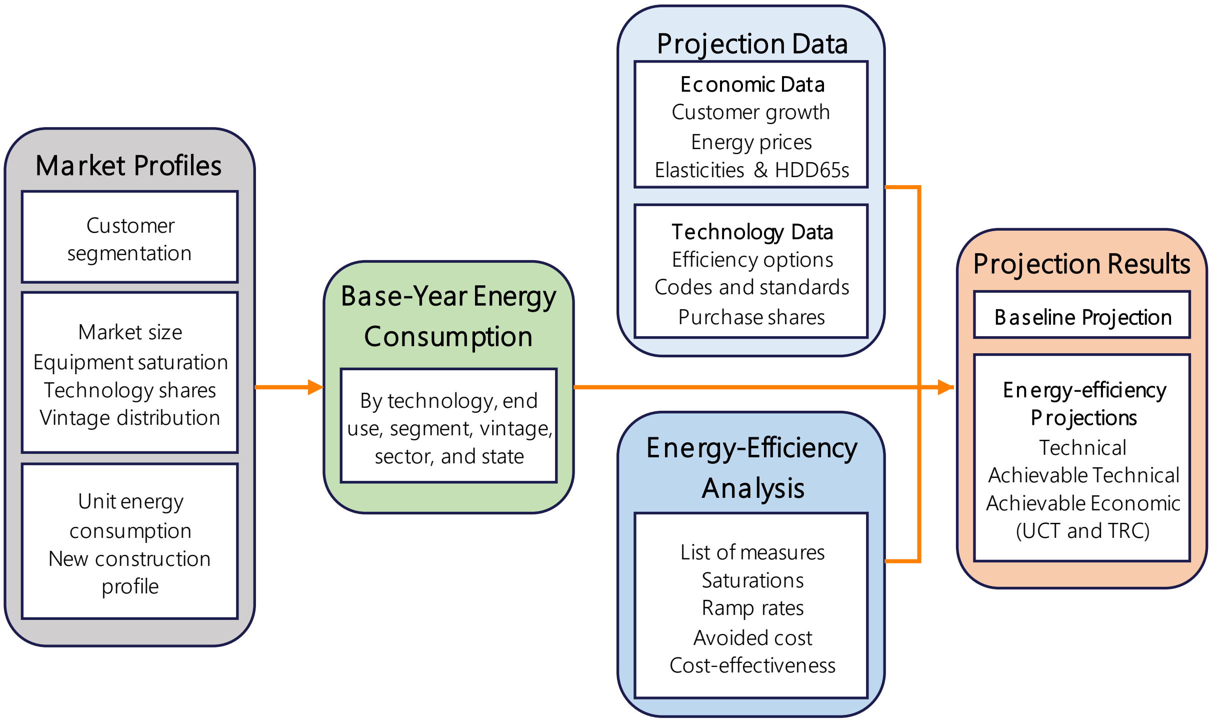
LoadMAP Model

For this analysis, 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 EPRI National Potential Study and numerous utility-specific forecasting and potential studies since. Built in Excel, the LoadMAP framework (see Figure 2-1) 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 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, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible approach 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 the market profiles we describe below, the LoadMAP model provides projections of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the various types of potential. [2]

Figure 2-1 LoadMAP Analysis Framework



Definitions of Potential

Before we delve into the details of the analysis approach, it is important to define what we mean when discussing energy efficiency (EE) potential. In this study, the savings estimates are developed for three types of potential: technical potential, economic potential, and achievable potential. These are developed at the measure level, and results are provided as savings impacts over the 20-year forecasting horizon. The various levels are described below.

- **Technical Potential** is defined as the *theoretical* upper limit of EE potential. It assumes customers adopt all feasible 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 also choose the most efficient equipment option.
  - Technical potential also assumes the adoption of every other available measure, where technically feasible. For example, it includes installation of high-efficiency windows in all new construction opportunities and furnace maintenance in all existing buildings with installed furnaces. These retrofit measures are phased in over a number of years to align with the stock turnover of related equipment units, rather than modeled as immediately available all at once.

[2] 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).

- **Achievable Technical Potential** refines technical potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation measures. The customer adoption rates used in this study were the ramp rates developed for the Northwest Power & Conservation Council's Seventh Plan based on the electric-utility model, tailored for use in natural gas EE programs.
- **UCT Achievable Economic Potential** further refines achievable technical potential by applying an economic cost-effectiveness screen. In this analysis, primary cost-effectiveness is measured by the utility cost test (UCT), which 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. These costs are the incentive, as a percent of incremental cost of the given efficiency measure, relative to the relevant baseline course of action (e.g. 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** is similar to UCT achievable economic potential in that it refines achievable technical potential through cost-effectiveness analysis. The total resource cost (TRC) test assesses cost-effectiveness from a combined utility and participant perspective. As such, this test includes full measure costs but also includes non-energy impacts realized by the customer if quantifiable and monetized. In addition to non-energy impacts, we assessed the impacts of non-gas savings following Council methodology. This includes 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. As a secondary screen, we include TRC results for comparative purposes.

Market Characterization

Now that we have described the modeling tool and provided the definitions of the potential cases, the first step in the actual analysis approach is 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 in service. This 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 in use. For this we rely primarily on information from Avista, augmenting with secondary sources as necessary.

Segmentation for Modeling Purposes

This assessment first defined the market segments (states, building types, end uses, and other dimensions) that are relevant in Avista's service territory. The segmentation scheme for this project is presented in Table 2-1.

Table 2-1 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, Mobile Home, Low Income Commercial: Office, Restaurant, Retail, Grocery, School, College, Health, Lodging, Warehouse, Miscellaneous Industrial
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, 2019. 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. A market profile includes the following elements:

- Market size is a representation of the number of customers in the segment. For the residential sector, the unit we use is number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, it is 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:

- The conditioned space approach accounts for the fraction of each building that is conditioned by the end use. This applies 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 that is served by the end use. Examples are commercial refrigeration and food service, and domestic water heating and appliances.
- The 100% saturation approach applies to end uses that are generally present in every building or home and are simply set to 100% in the base year.

- UEC (Unit Energy Consumption) or EUI (Energy Usage Index) define consumption for a given technology. UEC represents the amount of energy a given piece of equipment is expected to use in one year. EUI is a UEC indexed to a non-building market unit, such as per square foot or per employee)
- These are indices that refer to a measure of average annual energy use per market unit (home, floor space, or employee in the residential, commercial, and industrial sector, respectively) that are served by an end-use technology. UECs and EUIs embody an average level of service and average equipment efficiency for the market segment.
- Annual energy intensity for the residential sector represents the average energy use for the technology across all homes in 2015. It is computed as the product of the saturation and the UEC and is defined as therms/household for natural gas. For the commercial and industrial sectors, intensity, computed as the product of the saturation and the EUI, represents the average use for the technology across all floor space or all employees in the base year.
- Annual usage is the annual energy used by each 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 results and the market profiles are presented in Section 3 and Appendix A.

Baseline Projection

The next step was to develop the baseline projection of annual natural gas use for 2021 through 2040 by customer segment and end use in the absence of new utility energy efficiency programs.

We first aligned with Avista's official forecast. AEG incorporated assumptions and data utilized in the official utility forecast. Avista's heating degree days (base 65°F) were incorporated into the LoadMAP model to align the baseline projection with the official utility forecast. We calibrated to actual sales when available.

The end-use projection includes impacts of future federal standards that were effective as of December 2017, which drive energy consumption down through the study period.

Naturally occurring energy conservation, that is, energy conservation that is realized within the service area independent of utility-sponsored programs, is incorporated into the baseline projection consistent with the US Energy Information Administration's Annual Energy Outlook for the Pacific region. Results of the primary market research were used to calibrate these assumptions to ensure the secondary sources were relevant to Avista customers. For example, some customers will purchase and install energy conservation measures that are available in the market without a utility incentive.

As such, the baseline projection is the foundation for the analysis of savings in future conservation cases and scenarios as well as the metric against which potential savings are measured.

Inputs to the baseline projection include:

- Current economic growth forecasts (i.e., customer growth, changes in weather (Heating Degree Day, base-65°F (HDD65) normalization))
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards

We present the baseline projection results for the system as a whole, and for each sector in Section 4.

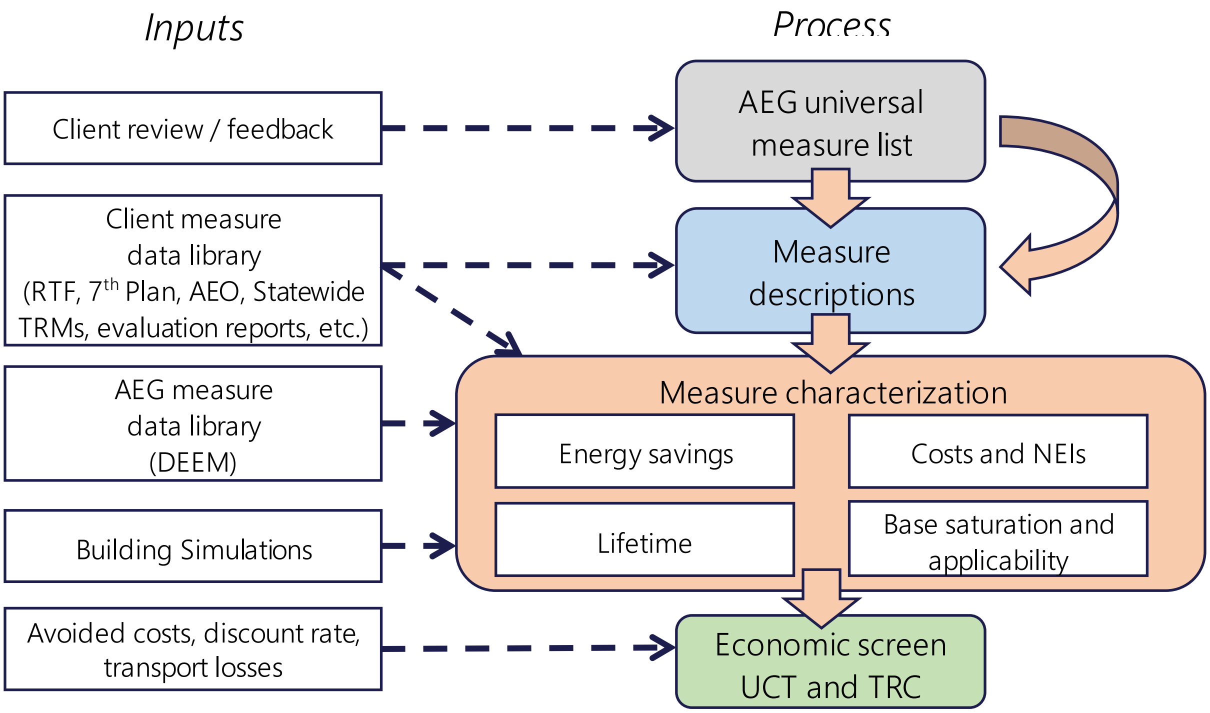
Energy Efficiency Measure Development

This section describes the framework used to assess the savings, costs, and other attributes of energy efficiency measures. These characteristics form the basis for measure-level cost-effectiveness analyses as well as for determining measure-level savings. For all measures, AEG assembled information to reflect equipment performance, incremental costs, and equipment lifetimes. This information combined with Avista's avoided cost data informs the economic screens that determine economically feasible measures. In this section, AEG would like to acknowledge the work of the Avista team in detailed measure assumptions specific to the territory and region within the Avista TRM, which was provided at the outset of this study.

Figure 2-2 outlines the framework for measure characterization analysis. First, the list of measures is identified; each measure is then assigned an applicability for each market sector and segment and characterized with appropriate savings, costs and other attributes; then the cost-effectiveness screening is performed. Avista provided feedback during each step of the process to ensure measure assumptions and results lined up with programmatic experience.

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

Figure 2-2 Approach for ECM Assessment



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

- **Equipment measures** are efficient energy-consuming pieces of equipment that save energy by providing the same service with a lower energy requirement than a standard unit. An example is 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 in general, are referred to as lost opportunity (LO) measures by the Council because once a purchase decision is made, there will not be another opportunity to improve the efficiency of that equipment item until its effective useful life (EUL) is reached once again.
- **Non-equipment measures** save energy by reducing the need for delivered energy, but do not necessarily involve replacement or purchase of major end-use equipment (such as a furnace or water heater). Measure installation is not tied to a piece of equipment reaching end of useful life, so these are generally categorized as "retrofit" measures. An example would be low-flow showerheads that modify a household's hot water consumption. The existing showerheads can be achievably 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 we assembled the list of measures, the AEG team assessed their energy-saving characteristics. For each measure, we also characterized 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.

Representative Measure Data Inputs

To provide an example of measure data, Table 2-2 and Table 2-3 present examples of the detailed data inputs behind both equipment and non-equipment measures, respectively, for the case of residential direct-fuel furnaces in single-family homes in Washington. Table 2-2 displays the various efficiency levels available as equipment measures, as well as the corresponding effective useful life, energy usage, and cost estimates. The columns labeled "On Market" and "Off Market" reflect equipment availability due to codes and standards or the entry of new products to the market.

Table 2-2 Example Equipment Measures for Direct Fuel Furnace – Single-Family Home, Washington

Efficiency Level	Useful Life (years)	Equipment Cost	Energy Usage (therms/yr)	On Market	Off Market
AFUE 80%	20	$1,955	517	2019	2023
AFUE 90%	20	$2,058	465	2019	2023
AFUE 92%	20	$2,099	453	2019	n/a
AFUE 95%	20	$2,778	438	2019	n/a
AFUE 98%	20	$3,035	423	2019	n/a
Convert to NG Heat Pump	20	$6,739	345	2019	n/a

Table 2-3 lists some of the non-equipment measures applicable to a direct-fuel furnace in an existing single-family home. All measures are evaluated for cost effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings, costs, and monetized non-energy impacts are calculated for each year of the study and depend on the base year saturation of the measure, the applicability of the measure, and the savings as a percentage of the relevant energy end uses. We model two flavors of most shell insulations measures. The first is the installation of insulation where there is none (or very little). This applies to a small subset of the population (roughly 7% of the population is eligible for this measure per RBSA 2016) but has large savings impacts. This percentage is low due to the impacts of current Avista programs, strict Washington building codes, and naturally occurring efficiency. The second is an insulation upgrade measure where homes with existing insulation below the threshold but not classified as no insulation, may be upgraded to higher R-values. This applies to a much larger percentage of the market.

Table 2-3 Example Non-Equipment Measures – Existing Single Family Home, Washington[3]

End Use	Measure	Saturation in 2019[4]	Applicability	Lifetime (yrs)	Measure Installed Cost	Energy Savings (%)
Heating	Insulation - Ceiling Installation	0%	7%	45	$1,280	31.3%
Heating	Insulation – Ceiling Upgrade	78%	87%	45	$1,739	1.2%
Heating	Ducting Repair and Sealing	20%	50%	20	$794	6.0%
Heating	Windows - High Efficiency[5]	0%	25%	45	$5,337	25.5%

Table 2-4 summarizes the number of measures evaluated for each segment within each sector.

Table 2-4 Number of Measures Evaluated

Sector	Total Measures	Measure Permutations w/ 2 Vintages	Measure Permutations w/ All Segments & States
Residential	46	92	736
Commercial	51	102	2,040
Industrial	30	60	120
Total Measures Evaluated	**127**	**254**	**2,896**

Calculation of Energy Conservation Potential

The approach we used for this study to calculate the energy conservation potential adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies.[6] This document represents credible and comprehensive industry best practices for specifying energy conservation potential. Three types of potential were developed as part of this effort: technical potential, achievable technical potential, and achievable economic potential (using UCT and TRC). The calculation of technical potential is a straightforward algorithm which, as described above, assumes that customers adopt all feasible measures regardless of their cost.

Stacking of Measures and Interactive Effects

An important factor when estimating potential is to consider interactions between measures when they are applied within the same space. This is important to avoid double counting and could feasibly result in savings at greater than 100% of equipment consumption if not properly accounted for.

This occurs at the population or system level, where multiple DSM actions must be stacked or layered on top of each other in succession, rather than simply summed arithmetically. These interactions are automatically handled within the LoadMAP models where measure impacts are stacked on top of each

[3] The applicability factors consider whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, duct repair and sealing is not applicable to homes with zonal heating systems since there is no ductwork present to repair.

[4] Note that saturation levels reflected increase from their base year saturation as more measures are adopted.

[5] The RTF has increased the efficiency requirements for what is considered a "high efficiency" window for the purpose of future programs. As a result, no respondents to the 2016 RBSA have windows that already meet this threshold. However, the qualified savings in the RTF workbook require a certain level of *inefficiency* in the pre-existing window to be eligible. The 25% applicability reflects the population that is eligible to participate.

[6] 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.

other, modifying the baseline for each subsequent measure. We first compute the total savings of each measure on a standalone basis, then also assign a stacking priority, based on levelized cost, to the measures such that "integrated" or "stacked" savings will be calculated as a percent reduction to the running total of baseline energy remaining in each end use after the previous measures have been applied. This ensures that the available pie of baseline energy shrinks in proportion to the number of DSM measures applied, as it would in reality. The loading order is based on the levelized cost of conserved energy, such that the more economical measures that are more likely to be selected from a resource planning perspective will be the first to be applied to the modeled population.

We also account for exclusivity of certain measure options when defining measure assumptions. For instance, if an AFUE 95% furnace is installed in a single-family home, the model will not allow that same home to install an AFUE 98% furnace, or any other furnace, until the newly installed AFUE 95% option has reached its end of useful life. For non-equipment measures, which do not have a native applicability limit, we define base saturations and applicabilities such that measures do not overlap. For example, we model two flavors of ceiling insulation. The first assumes the installation of insulation where there previously was none. The second upgrades pre-existing insulation if it falls under a certain threshold. We used regional market research data to ensure exclusivity of these two options. NEEA's 2014 RBSA contains information on average R-values of insulation installed. The AEG team used this data to define the percent of homes that could install one measure, but not the other.

Estimating Customer Adoption

Once the technical potential is established, estimates for the market adoption rates for each measure are applied that specify the percentage of customers that will select the highest–efficiency economic option. This phases potential in over a more realistic time frame that considers barriers such as imperfect information, supplier constraints, technology availability, and individual customer preferences. The intent of market adoption rates is to establish a path to full market maturity for each measure or technology group and ensure resource planning does not overstep acquisition capabilities. We adapted the Northwest Power and Conservation Council's 2021 Plan ramp rates to develop these achievability factors for each measure. Applying these ramp rates as factors leads directly to the achievable technical potential.

Screening Measures for Cost-Effectiveness

With achievable technical potential established, the final step is to apply an economic screen and arrive at the subset of measures that are cost-effective and ultimately included in achievable economic potential.

LoadMAP performs an economic screen for each individual measure in each year of the planning horizon. This study uses the UCT test as the primary cost-effectiveness metric, which compares the lifetime hourly energy benefits of each applicable measure with the incentive and administrative costs incurred by the utility. The lifetime benefits are calculated by multiplying the annual energy savings for each measure by Avista's avoided costs and discounting the dollar savings to the present value equivalent. Lifetime costs represent incremental measure cost. The analysis uses each measure's values for savings, costs, and lifetimes that were developed as part of the measure characterization process described above.

The LoadMAP model performs this screening dynamically, considering changing savings and cost data over time. Thus, some measures pass the economic screen for some, but not all, of the years in the forecast.

It is important to note the following about the economic screen:

- The economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the therm savings potential of a measure, consumption with the measure applied must be compared to the consumption of a baseline condition.
- The economic screening was conducted only for measures that are applicable to each building type and vintage; thus, if a measure is deemed to be irrelevant to a building type and vintage, it is excluded from the respective economic screen.

This constitutes the achievable economic potential and includes every program-ready opportunity for conservation savings. Potential results are presented in Sections 4 and 5. Measure-level detail is available as a separate appendix to this report.

Data Development

This section details the data sources used in this study, followed by a discussion of how these sources were applied. In general, data were adapted to local conditions, for example, by using local sources for measure data and local weather for building simulations.

Data Sources

The data sources are organized into the following categories:

- Avista-provided data
- AEG's databases and analysis tools
- Other secondary data and reports

Avista Data

Our highest priority data sources for this study were those that were specific to Avista, including the primary market research conducted specifically for this study. This data is specific to Avista's service territory and is an important consideration when customizing the model for Avista's market. This is best practice when developing CPA baselines when the data is available.

- Avista customer account database. Avista provided billing data for development of customer counts and energy use for each sector. This included a very detailed database of customer building classifications which was instrumental in the development of segmentation.
- Avista's 2013 GenPOP Residential Survey. In 2013, Avista hired The Cadmus Group to conduct a residential saturation survey, which included results from 1,051 customers. The results of this survey helped segment the residential sector and establish fuel and technology shares for the base year. This data was very useful in developing a detailed estimate of energy consumption within Avista's service territory.
- Load forecasts. Avista provided forecasts, by sector and state, of energy consumption, customer counts, weather actuals for 2015 and 2017, as well as weather-normal HDD65s.
- Economic information. Avista provided a discount rate as well as avoided cost forecasts consistent with those utilized in the IRP.
- Avista program data. Avista provided information about past and current programs, including program descriptions, goals, and measure achievements to date.

- **Avista TRM.** Avista provided a documented list of energy conservation measures and assumptions considered within current programs. We utilized this as a primary source of measure information, supplemented by Northwest data, AEG data, and secondary data as described below.

Northwest Regional Data

The study utilized a variety of local data and research, including research performed by the Northwest Energy Efficiency Alliance (NEEA) and analyses conducted by the Council. Most important among these are:

- **Northwest Power and Conservation Council, 2021 Power Plan and Regional Technical Forum workbooks.** To develop its Power Plan, the Council maintains workbooks with detailed information about measu res. This was used as a primary data source when Avista-specific program data was not available, and the data was determined to be applicable to natural gas conservation measures. The most recent data and workbooks available were used at the time of this study.
    - https://www.nwcouncil.org/2021-northwest-power-plan
    - https://rtf.nwcouncil.org/measures
- **Northwest Energy Efficiency Alliance, 2011 Residential Building Stock Assessment Single-Family,** Market Research Report, http://neea.org/docs/reports/residential-building-stock-assessment-single-family-characteristics-and-energy-use.pdf?sfvrsn=8
- **Northwest Energy Efficiency Alliance, 2014 Commercial Building Stock Assessment,** December 16, 2014, http://neea.org/docs/default-source/reports/2014-cbsa-final-report 05-dec-2014.pdf?sfvrsn=12.
- **Northwest Energy Efficiency Alliance, 2014 Industrial Facilities Site Assessment,** December 29, 2014, http://neea.org/resource-center/regional-data-resources/industrial-facilities-site-assessment

Since Avista's GenPOP survey contained detailed appliance saturations, the RBSA was used more for benchmarking and comparative purposes, rather than as a primary source of data. The NEEA surveys were used extensively to develop base saturation and applicability assumptions for many of the non-equipment measures within the study.

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.** For more than 10 years, AEG staff has maintained profiles of end-use consumption for the residential, commercial, and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, and annual energy use by fuel (natural gas and electricity), customer segment and end use for 10 regions in the U.S. The Energy Information Administration 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 the HVAC-related measures.

- AEG's Database of Energy Conservation Measures (DEEM). AEG maintains an extensive database of measure data for our studies. Our database draws 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 more than 60 studies of EE 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 are identified below.

- Annual Energy Outlook. The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2015 and 2017 AEO.
- American Community Survey. The US Census American Community Survey is an ongoing survey that provides data every year on household characteristics. http://www.census.gov/acs/www/
- Local Weather Data. Weather from NOAA's National Climatic Data Center for Spokane in Washington and Coure d'Alene in Idaho were used where applicable.
- EPRI End-Use Models (REEPS and COMMEND). These models provide the energy-use elasticities we apply to prices, household income, home size, heating, and cooling.
- Database for Energy Efficient Resources (DEER). The California Energy Commission and California Public Utilities Commission (CPUC) sponsor this database, which is designed to provide well-documented estimates of energy and peak demand savings values, measure costs, and effective useful life (EUL) for the state of California. We used the DEER database to cross check the measure savings we developed using BEST and DEEM.
- Other relevant resources: These include reports from the Consortium for Energy Efficiency, the EPA, and the American Council for an Energy-Efficient Economy. This also includes technical reference manuals (TRMs) from other states. When using data from outside the region, especially weather-sensitive data, AEG adapted assumptions for use within Avista's territory.

Application of Data to the Analysis

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.

Data Application for Market Profiles

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-5. To develop the market profiles for each segment, we used the following approach:

1. Develop 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. We used the market profiles from the 2016 CPA as a starting point.
2. Develop existing appliance saturations and the energy characteristics of appliances, equipment, and buildings using equipment flags within Avista's billing data, NEEA's 2016 RBSA, 2019 CBSA, and 2014 IFSA, DOE's 2015 RECS, the 2019 edition of the Annual Energy Outlook, AEG's Energy Market Profile (EMP) for the Pacific region, and the American Community Survey.
3. Ensure calibration to Avista control totals for annual natural gas sales in each sector and segment.
4. Compare and cross-check with other recent AEG studies.
5. Work with Avista staff to verify the data aligns with their knowledge and experience.

Table 2-5 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings, commercial floor space, and industrial employment	Avista 2019 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 AEO 2019 – Pacific Region Other recent studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space/employment with equipment/technology	Avista 2013 GenPOP Survey 2016 RBSA, 2019 CBSA and IFSA 2018 American Community Survey 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 2019 – Pacific Region Recent AEG studies
Appliance/equipment age distribution	Age distribution for each technology	2016 RBSA, 2019 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 2019 CA DEER Recent AEG studies

Data Application for Baseline Projection

Table 2-6 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 2-6 Data Applied for the Baseline Projection in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential and C&I 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 2019 regional forecast assumptions[7] Appliance/efficiency standards analysis
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models

In addition, assumptions were incorporated for known future equipment standards as of June 2020, as shown in Table 2-7 and Table 2-8. The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

[7] We developed baseline purchase decisions using the Energy Information Agency's *Annual Energy Outlook* report (2017), which utilizes the National Energy Modeling System (NEMS) 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 2-7 Residential Natural Gas Equipment Federal Standards[8]

End Use	Technology	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace – Direct Fuel	AFUE 80%					AFUE 92%*	
	Boiler – Direct Fuel	AFUE 82%		AFUE 84%				
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						

* This code was originally set to take effect in 2021 but exempts smaller systems. The comment period was also extended into 2017 and the standard will not take effect until at least 5 years after that has concluded. As a result, we modeled this standard coming online officially in 2024.

Table 2-8 Commercial and Industrial Natural Gas Equipment Standards

End Use	Technology	2019	2020	2021	2022	2023	2024	2025
Cooling	Furnace	AFUE 80% / TE 0.80						
	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						

[8] The assumptions tables here extend through 2025, after which all standards are assumed to hold steady.

Energy Conservation Measure Data Application

Table 2-9 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 2-9 Data Inputs 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 2019 CA DEER Other secondary sources
Costs	Equipment Measures: Includes the 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 - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	Avista TRM NWPCC workbooks, RTF AEG DEEM AEO 2019 CA 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 2019 CA 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.	2016 RBSA, 2019 CBSA 2015 WSEC for limitations on new construction AEG DEEM CA DEER Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	AEG appliance standards and building codes analysis

Data Application for Cost-effectiveness Screening

To perform the cost-effectiveness screening, a number of economic assumptions were needed. 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 4.34% 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

To estimate the timing and rate of customer adoption in the potential forecasts, two sets of parameters are needed:

- 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 Council's retrofit ramp rates, labeled "Retro".
- Customer adoption rates, also referred to as take rates or ramp rates, are applied to measures on a year by year basis. These rates represent customer adoption of measures when delivered through a best-practice portfolio of well-operated efficiency programs under a reasonable policy or regulatory framework. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. The primary barrier to adoption reflected in this case is customer preferences. Again, these are based on the ramp rates from the Northwest Power and Conservation Council's 2021 Plan.

The ramp rates referenced above were adapted for use for assessing natural gas measure potential. We describe this process in Section 7. The customer adoption rates used in this study are available in Appendix B.

3

MARKET CHARACTERIZATION AND MARKET PROFILES

In this section, we describe how customers in the Avista service territory use natural gas in the base year of the study, 2019. It begins with a high-level summary of energy use across all sectors and then delves into each sector in more detail.

Overall Energy Use Summary

Total natural gas consumption for all sectors for Avista's Washington territory in 2019 was 19,411,285 dekatherms. As shown in Figure 3-1 and Table 3-1, the residential sector accounts for the largest share of annual energy use at 64%, followed by the commercial sector at 35%. The industrial sector accounts for 2% of usage.

Figure 3-1 Sector-Level Natural Gas Use in Base Year 2019, Washington (annual therms, percent)

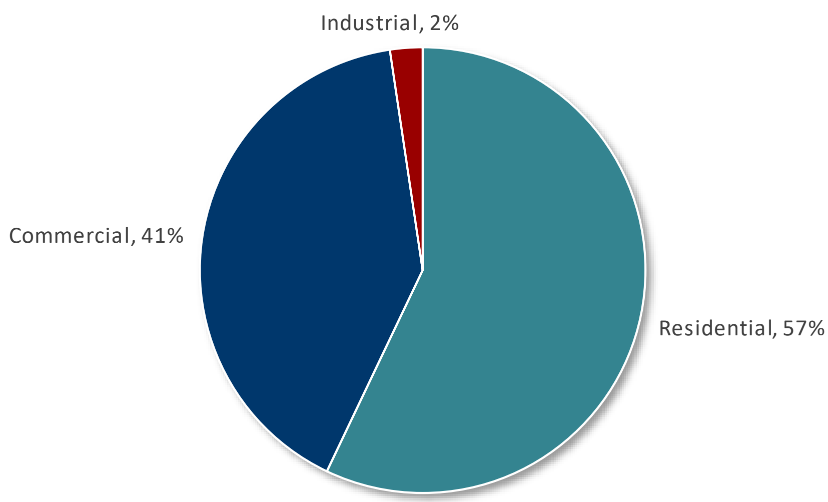


Table 3-1 Avista Sector Control Totals, Washington, 2019

Sector	Natural Gas Use (dekatherms)	% of Use
Residential	12,344,250	64%
Commercial	6,718,365	35%
Industrial	348,670	2%
Total	**19,411,285**	**100%**

Total natural gas consumption for all sectors for Avista's Idaho territory in 2019 was 10,131,866 dekatherms. As shown in Figure 3-2 and Table 3-2, the residential sector accounts for the largest share of annual energy use at 57%, followed by the commercial sector at 41%. The industrial sector accounts for 2% of usage.

Figure 3-2 Sector-Level Natural Gas Use in Base Year 2019, Idaho (annual therms, percent)

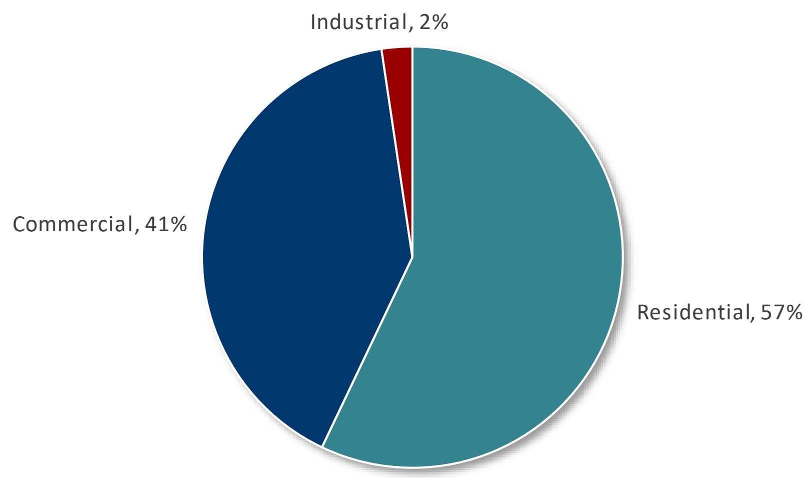


Table 3-2 Avista Sector Control Totals, Idaho, 2019

Sector	Natural Gas Use (dekatherms)	% of Use
Residential	5,782,934	57%
Commercial	4,110,228	41%
Industrial	238,705	2%
Total	**10,131,866**	**100%**

Residential Sector

Washington Characterization

The total number of households and gas sales for the service territory were obtained from Avista's actual sales for 2019. Details, including number of households and 2019 natural gas consumption for the residential sector in Washington can be found in Table 3-3 below. In 2019, there were nearly 156,000 households in Avista's Washington territory that used a total of 12,344,250 dekatherms, resulting in an average use per household of 796 therms per year. This is an important number for the calibration process.

These values represent weather actuals for 2019 and were adjusted within LoadMAP to normal weather using heating degree day, base 65°F, using data provided by Avista.

Table 3-3 Residential Sector Control Totals, Washington, 2019

Segment	Households	Natural Gas Use (dekatherms)	Annual Use/Customer (therms/HH)
Single Family	94,282	8,083,082	857
Multi-Family	8,684	469,031	540
Mobile Home	5,582	402,027	720
Low Income	46,521	3,390,109	729
Total	**155,069**	**12,344,250**	**796**

Figure 3-3 Residential Natural Gas Use by Segment, Washington, 2019

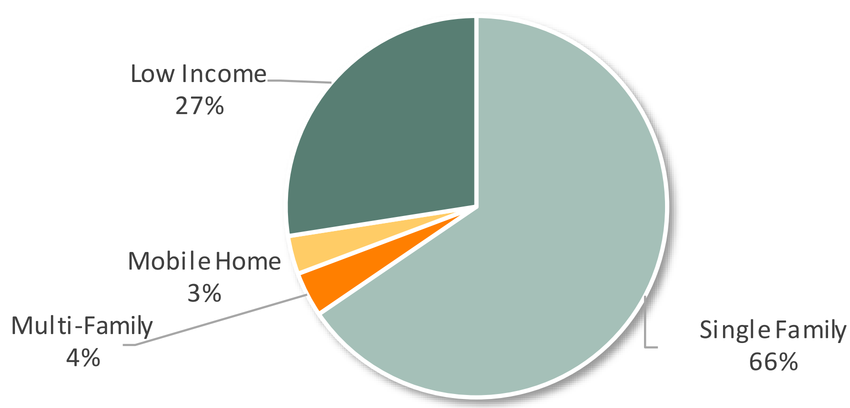
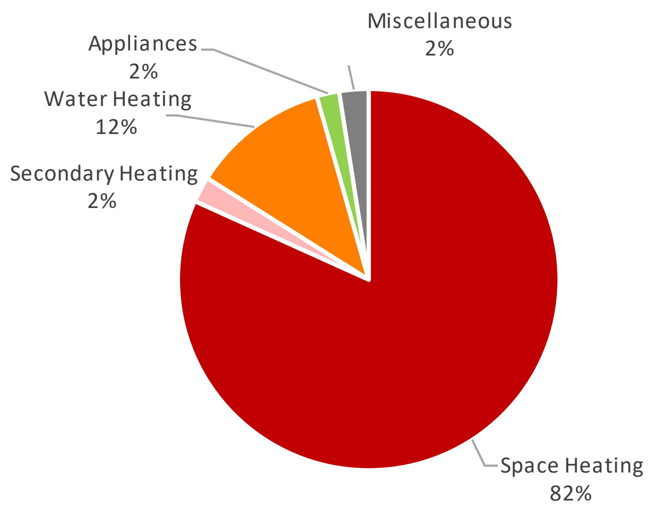


Figure 3-4 shows the distribution of annual natural gas consumption by end use for an average residential household. Space heating comprises most of the load at 82% followed by water heating at 12%. Appliances, Secondary Heating, and Miscellaneous loads make up the remaining portion (6%) of the total load. This is expected for a natural gas profile as there are very few miscellaneous technologies. One example is natural gas barbecues.

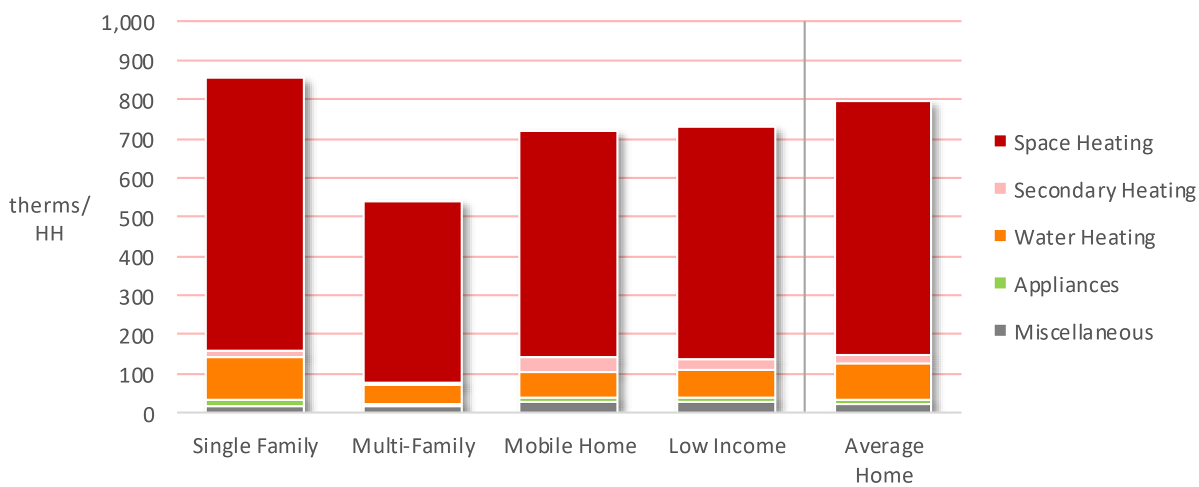
Figure 3-4 Residential Natural Gas Use by End Use, Washington, 2019



Avista's GenPOP survey informed estimates of the saturation of key equipment types, which were used to distribute usage at the technology and end use level. However, because the vintage of the GenPOP survey is 2013, trends from more recent surveys were applied where appropriate, while still maintaining the more unique characteristics of Avista's market.

Figure 3-4 presents average natural gas intensities by end use and housing type. Single family homes consume substantially more energy in space heating. This is due to two factors. The first is that single family homes are larger. The second is that more walls are exposed to the outside environment, compared to multifamily dwellings with many shared walls. This increases heat transfer, resulting in greater heating loads. Water heating consumption is higher in single family homes as well. This is due to a greater number of occupants, which increases the demand for hot water.

Figure 3-5 Residential Energy Intensity by End Use and Segment, Washington, 2019 (Annual Therms/HH)



The market profile for an average home in the residential sector is presented in Table 3-4 below. An important step in the profile development process is model calibration. All consumption within an average home must sum up to the intensity extracted from billing data. This is necessary so estimates of consumption for a piece of equipment do not exceed the actual usage in a home.

Table 3-4 Average Market Profile for the Residential Sector, Washington, 2019

End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (dekatherms)
Space Heating	Furnace - Direct Fuel	84.9%	747.2	634.6	9,840,233
	Boiler - Direct Fuel	2.4%	674.2	16.2	251,417
Secondary Heating	Fireplace	12.7%	137.3	17.4	269,840
Water Heating	Water Heater <= 55 gal.	52.2%	177.8	92.9	1,440,263
Appliances	Clothes Dryer	27.3%	18.0	4.9	76,440
	Stove/Oven	58.9%	17.4	10.3	159,040
Miscellaneous	Pool Heater	0.8%	80.1	0.6	9,491
	Miscellaneous	100.0%	19.2	19.2	297,525
Total				**796.0**	**12,344,250**

Idaho Characterization

Details for the residential sector in Idaho can be found in Table 3-5 below. In 2019, there were 77,804 households in Avista's Washington territory that used a total of 5,782,934 dekatherms, resulting in an average use per household of 743 therms per year.

Table 3-5 Residential Sector Control Totals, Idaho, 2019

Segment	Households	Natural Gas Use (dekatherms)	Annual Use/Customer (therms/HH)
Single Family	47,305	3,780,793	799
Multi-Family	3,812	191,962	504
Mobile Home	3,501	235,056	671
Low Income	23,186	1,575,123	679
Total	**77,804**	**5,782,934**	**743**

Figure 3-6 Residential Natural Gas Use by Segment, Idaho, 2019

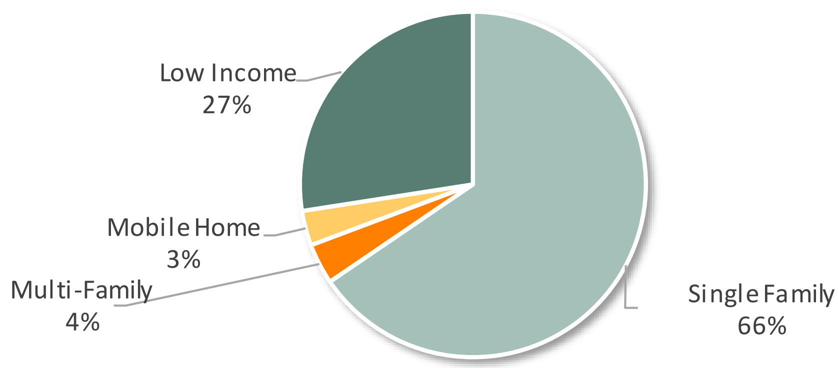
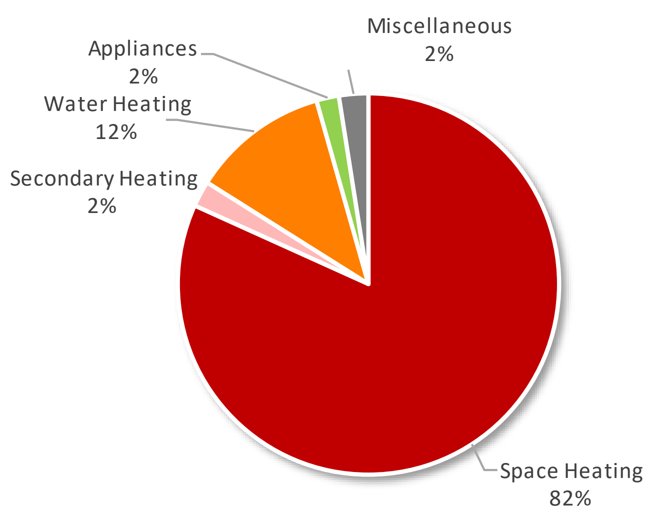


Figure 3-7 shows the distribution of annual natural gas consumption by end use for an average residential household. Space heating comprises a majority of the load at 82% followed by water heating at 12%. Miscellaneous loads make up a very small portion of the total load, as expected.

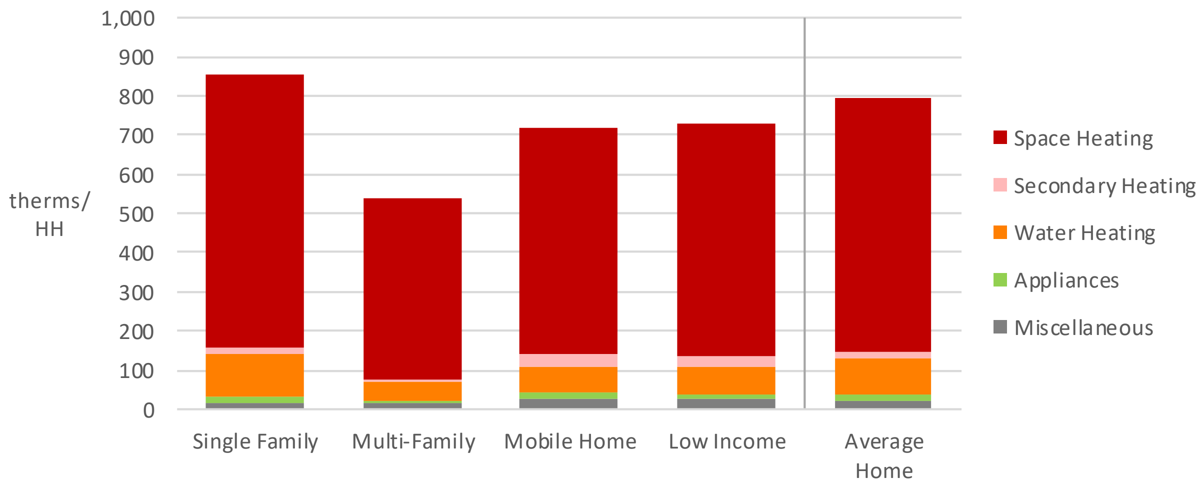
Figure 3-7 Residential Natural Gas Use by End Use, Idaho, 2019



Avista's 2013 GenPOP survey informed estimates of the saturation of key equipment types, which were used to distribute usage at the technology and end use level.

Figure 3-8 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 3-8 Residential Energy Intensity by End Use and Segment, Idaho, 2019 (Annual Therms/HH)



The market profile for an average home in the residential sector is presented in Table 3-6 below. An important step in the profile development process is model calibration. All consumption within an average home must sum up to the intensity extracted from billing data. This is necessary so estimates of consumption for a piece of equipment do not exceed the actual usage in a home.

Table 3-6 Average Market Profile for the Residential Sector, 2019

End Use	Technology	Saturation	UEC (therms)	Intensity (therms/HH)	Usage (dekatherms)
Space Heating	Furnace - Direct Fuel	81.0%	712.8	577.0	4,489,534
	Boiler - Direct Fuel	2.2%	643.6	14.0	108,672
Secondary Heating	Fireplace	16.9%	131.4	22.2	172,526
Water Heating	Water Heater <= 55 gal.	54.6%	177.5	96.9	753,951
Appliances	Clothes Dryer	14.7%	21.6	3.2	24,700
	Stove/Oven	31.7%	20.8	6.6	51,415
Miscellaneous	Pool Heater	0.3%	105.0	0.3	2,345
	Miscellaneous	100.0%	23.1	23.1	179,792
Total				**743.3**	**5,782,934**

Commercial Sector

Washington Characterization

The total number of nonresidential accounts and natural gas sales for the Washington service territory were obtained from Avista's customer account database.

AEG first separated the Commercial accounts from Industrial by analyzing the SIC codes and rate codes assigned in the company's billing system. Prior to using the data, AEG inspected individual accounts to confirm proper assignment. This was done on the top accounts within each segment, but also via spot checks when reviewing the database. 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 2019 nonresidential load to the sectors and segments according to the proportions in the billing data.

Table 3-7 below 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 2019 CBSA and equipment saturations extracted from Avista's database. The CBSA intensities corresponded to spaces with lower natural gas saturations than Avista's database, so AEG increased intensities proportionally based on the additional presence of natural gas-consuming equipment.

Table 3-7 Commercial Sector Control Totals, Washington, 2019

Segment	Description	Intensity (therms/Sq Ft)	2019 Natural Gas Use (dekatherms)
Office	Traditional office-based businesses including finance, insurance, law, government buildings, etc.	0.60	481,953
Restaurant	Sit-down, fast food, coffee shop, food service, etc.	2.68	65,351
Retail	Department stores, services, boutiques, strip malls etc.	0.83	837,065
Grocery	Supermarkets, convenience stores, market, etc.	0.95	154,034
School	Day care, pre-school, elementary, secondary schools	0.29	269,873
College	College, university, trade schools, etc.	0.62	272,030
Health	Health practitioner office, hospital, urgent care centers, etc.	1.04	315,668
Lodging	Hotel, motel, bed and breakfast, etc.	0.68	172,829
Warehouse	Large storage facility, refrigerated/unrefrigerated warehouse	0.68	358,315
Miscellaneous	Catchall for buildings not included in other segments, includes churches, recreational facilities, public assembly, correctional facilities, etc.	1.16	1,183,111
Total		**0.75**	**4,110,228**

Figure 3-9 shows each segments' natural gas consumption as a percentage of the entire commercial sector energy consumption. The three segments with the highest natural gas usage in 2019 are miscellaneous, retail, and office, in descending order. As expected, the highest intensity segment is restaurant. This is based on the high presence of food preparation equipment.

Figure 3-9 Commercial Natural Gas Use by Segment, Washington, 2019

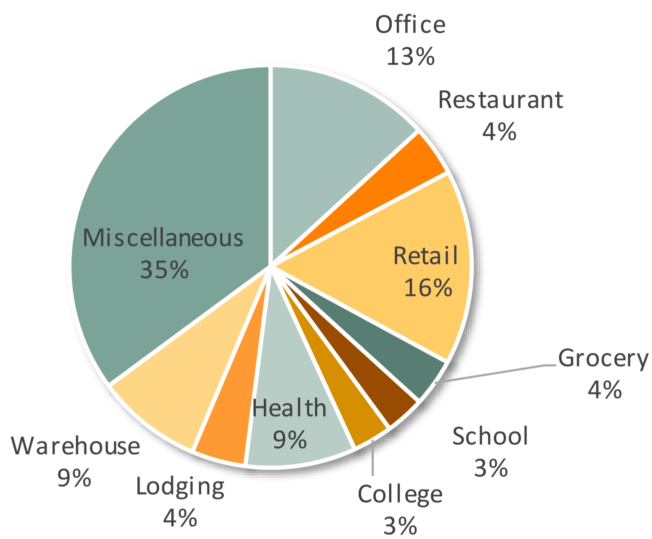


Figure 3-10 shows the distribution of natural gas consumption by end use for the entire commercial sector. Space heating is the largest end use, followed closely by water heating. The miscellaneous end use is quite small, as expected.

Figure 3-10 Commercial Sector Natural Gas Use by End Use, Washington, 2019

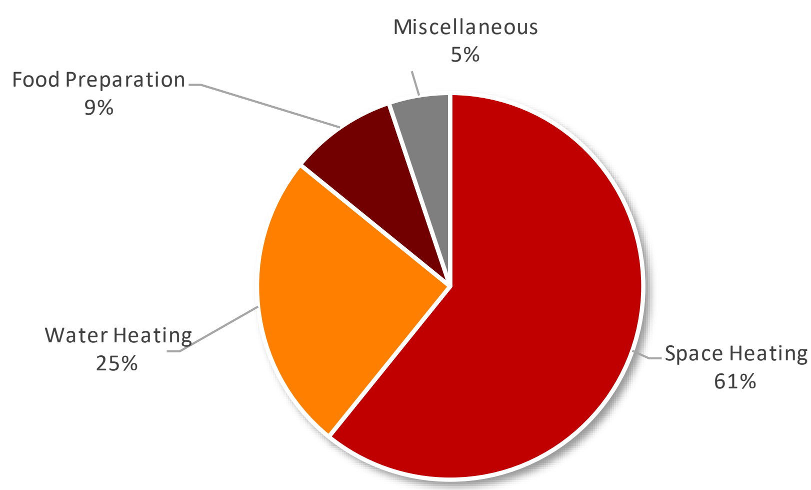
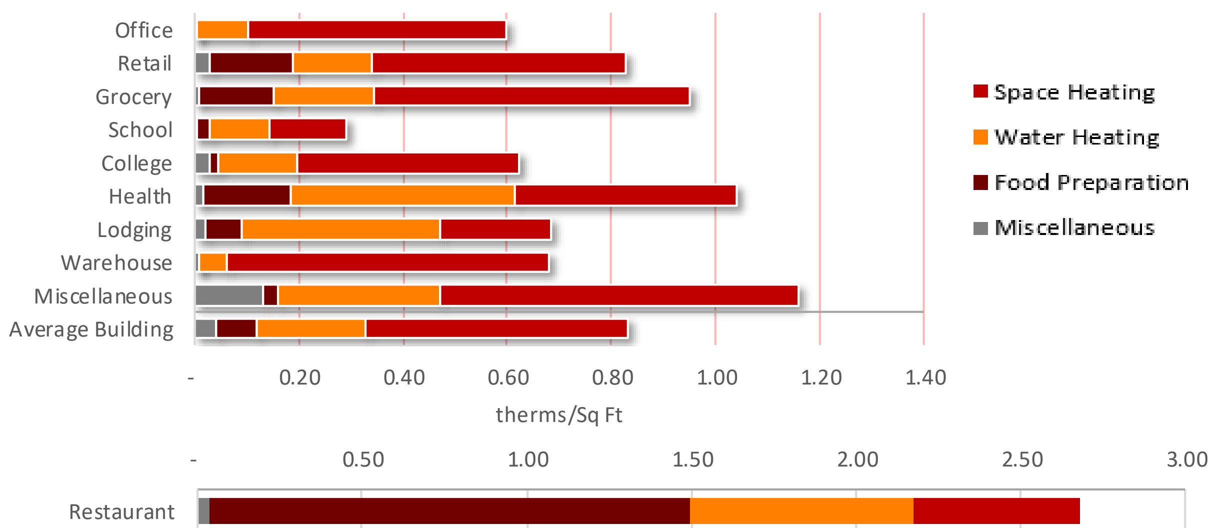


Figure 3-11 presents average natural gas intensities by end use and segment.

Figure 3-11 Commercial Energy Usage Intensity by End Use and Segment, Washington, 2019 (Annual Therms/Sq. Ft)



The total market profile for an average building in the commercial sector is presented in Table 3-8 below. 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 to fill in saturations for any equipment types not included in the database.

Table 3-8 Average Market Profile for the Commercial Sector, Washington, 2019

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/ Sq Ft)	Usage (dekatherms)
Space Heating	Furnace	53.6%	0.44	0.23	1,898,166
	Boiler	32.6%	0.79	0.26	2,086,967
	Unit Heater	4.7%	0.27	0.01	100,644
Water Heating	Water Heater	69.7%	0.30	0.21	1,681,122
Food Preparation	Oven	11.3%	0.06	0.01	53,746
	Conveyor Oven	5.6%	0.10	0.01	45,982
	Double Rack Oven	5.6%	0.15	0.01	69,855
	Fryer	7.3%	0.34	0.03	202,977
	Broiler	12.2%	0.07	0.01	70,869
	Griddle	16.4%	0.05	0.01	70,017
	Range	17.9%	0.06	0.01	82,852
	Steamer	2.1%	0.06	0.00	9,251
	Commercial Food Prep Other	0.2%	0.01	0.00	149
Miscellaneous	Pool Heater	0.9%	0.01	0.00	1,034
	Miscellaneous	100.0%	0.04	0.04	344,734
Total				**0.83**	**6,718,365**

Idaho Characterization

The total number of nonresidential accounts and natural gas sales for the Idaho service territory were obtained from Avista's customer account database.

Table 3-9 below 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 2019 CBSA and equipment saturations extracted from Avista's database. The CBSA intensities corresponded to spaces with lower natural gas saturations than Avista's database, so AEG increased intensities proportionally based on the additional presence of natural gas-consuming equipment.

Table 3-9 Commercial Sector Control Totals, Idaho, 2019

Segment	Description	Intensity (therms/Sq Ft)	2019 Natural Gas Use (dekatherms)
Office	Traditional office-based businesses including finance, insurance, law, government buildings, etc.	0.60	481,953
Restaurant	Sit-down, fast food, coffee shop, food service, etc.	2.68	65,351
Retail	Department stores, services, boutiques, strip malls etc.	0.83	837,065
Grocery	Supermarkets, convenience stores, market, etc.	0.95	154,034
School	Day care, pre-school, elementary, secondary schools	0.29	269,873
College	College, university, trade schools, etc.	0.62	272,030
Health	Health practitioner office, hospital, urgent care centers, etc.	1.04	315,668
Lodging	Hotel, motel, bed and breakfast, etc.	0.68	172,829
Warehouse	Large storage facility, refrigerated/unrefrigerated warehouse	0.68	358,315
Miscellaneous	Catchall for buildings not included in other segments, includes churches, recreational facilities, public assembly, correctional facilities, etc.	1.16	1,183,111
Total		**0.75**	**4,110,228**

Figure 3-12 shows each segments' natural gas consumption as a percentage of the entire commercial sector energy consumption. The four segments with the highest natural gas usage in 2019 are miscellaneous, retail, office, and warehouse, in descending order. As expected, the highest intensity segment is restaurant. This is based on the high presence of food preparation equipment.

Figure 3-12 Commercial Natural Gas Use by Segment, Idaho, 2019

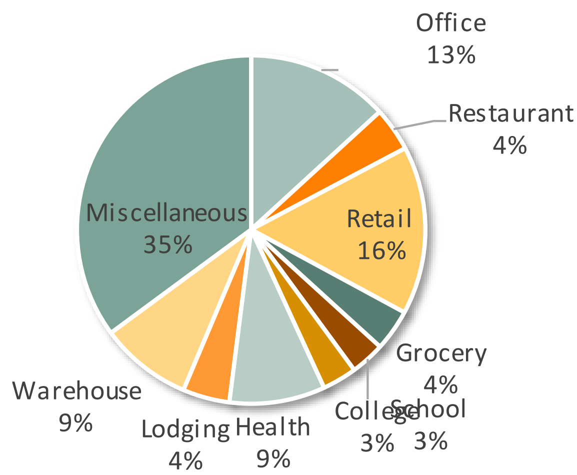


Figure 3-13 shows the distribution of natural gas consumption by end use for the entire commercial sector. Space heating is the largest end use, followed closely by water heating and food preparation. The miscellaneous end use is quite small, as expected.

Figure 3-13 Commercial Sector Natural Gas Use by End Use, Idaho, 2019

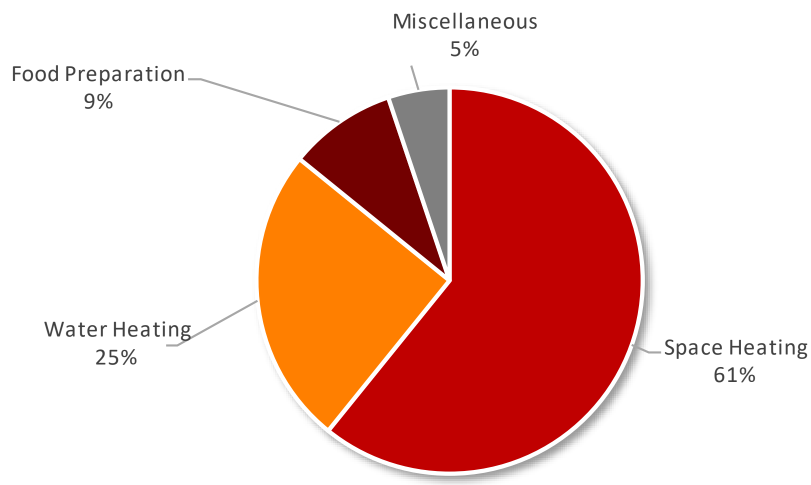
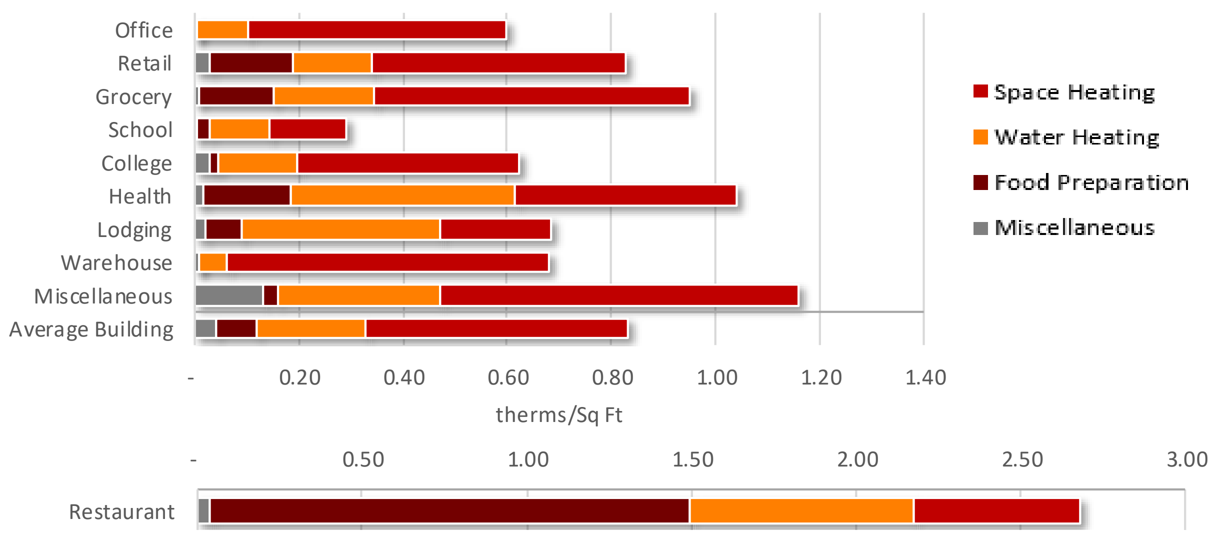


Figure 3-14 presents average natural gas intensities by end use and segment.

Figure 3-14 Commercial Energy Usage Intensity by End Use and Segment, Idaho, 2019 (Annual Therms/Sq. Ft)



The total market profile for an average building in the commercial sector is presented in Table 3-10 below. 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 to fill in saturations for any equipment types not included in the database.

Table 3-10 Average Market Profile for the Commercial Sector, Idaho, 2019

End Use	Technology	Saturation	EUI (therms/ Sq Ft)	Intensity (therms/ Sq Ft)	Usage (dekatherms)
Space Heating	Furnace	50.7%	0.43	0.22	1,183,907
	Boiler	35.7%	0.66	0.24	1,286,757
	Unit Heater	4.9%	0.25	0.01	67,294
Water Heating	Water Heater	69.3%	0.27	0.19	1,025,922
Food Preparation	Oven	9.9%	0.07	0.01	37,863
	Conveyor Oven	4.9%	0.12	0.01	32,393
	Double Rack Oven	4.9%	0.18	0.01	49,212
	Fryer	7.2%	0.32	0.02	125,738
	Broiler	11.3%	0.05	0.01	29,409
	Griddle	15.7%	0.04	0.01	32,103
	Range	17.5%	0.04	0.01	39,839
	Steamer	3.1%	0.04	0.00	5,935
	Commercial Food Prep Other	0.3%	0.01	0.00	141
Miscellaneous	Pool Heater	0.8%	0.01	0.00	563
	Miscellaneous	100.0%	0.04	0.04	193,152
Total				**0.75**	**4,110,228**

Industrial Sector

Washington Characterization

The total sum of natural gas used in 2019 by Avista's Washington industrial customers was 348,670 dekatherms. 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.

Table 3-11 Industrial Sector Control Totals, Washington, 2019

Segment	Intensity (therms/employee)	Natural Gas Usage (dekatherms)
Washington Industrial	**1,716**	**348,670**

Figure 3-15 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. Accordingly, process is the largest overall end use for the industrial sector, accounting for 87% of energy use. Heating is the second largest end use, and miscellaneous, non-process industrial uses round out consumption.

Figure 3-15 Industrial Natural Gas Use by End Use, Washington, 2019

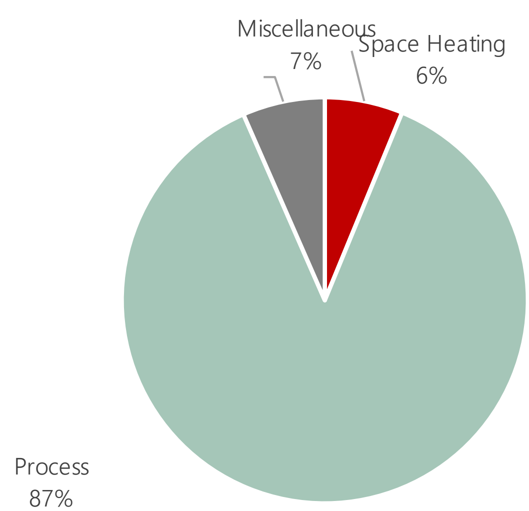


Table 3-12 shows the composite market profile for the industrial sector. Process cooling is very small and represents niche technologies such as gas-driven absorption chillers.

Table 3-12 Average Natural Gas Market Profile for the Industrial Sector, Washington, 2019

End Use	Technology	Saturation	EUI (therms/ sq ft)	Intensity (therms/ Sq ft)	Usage (dekatherms)
Space Heating	Furnace	27.5%	107.88	29.64	6,024
	Boiler	58.8%	107.88	63.42	12,890
	Unit Heater	13.7%	107.88	14.82	3,012
Process	Process Boiler	100.0%	758.47	758.47	154,154
	Process Heating	100.0%	675.00	675.00	137,190
	Process Cooling	100.0%	7.83	7.83	1,592
	Other Process	100.0%	50.93	50.93	10,350
Miscellaneous	Miscellaneous	100.0%	115.41	115.41	23,457
Total				**1,715.53**	**348,670**

Idaho Characterization

The total sum of natural gas used in 2019 by Avista's Idaho industrial customers was 238,705 dekatherms. Energy use intensity is slightly higher than Washington at 2,008 therms/sq ft.

Table 3-13 Industrial Sector Control Totals, Idaho, 2019

Segment	Intensity (therms/employee)	Natural Gas Usage (dekatherms)
Idaho Industrial	**2,008**	**238,705**

Figure 3-16 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. Accordingly, process is the largest overall end use for the industrial sector, accounting for 87% of energy use. Heating is the second largest end use, and miscellaneous, non-process industrial uses round out consumption.

Figure 3-16 Industrial Natural Gas Use by End Use, Idaho, 2019

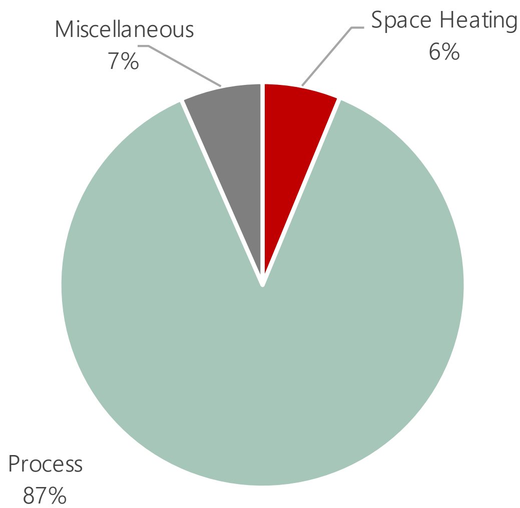


Table 3-14 shows the composite market profile for the industrial sector. Process cooling is very small and represents technologies such as gas-driven absorption chillers.

Table 3-14 Average Natural Gas Market Profile for the Industrial Sector, Idaho, 2019

End Use	Technology	Saturation	EUI (therms/ sq ft)	Intensity (therms/ Sq ft)	Usage (dekatherms)
Space Heating	Furnace	27.5%	126.29	34.70	4,124
	Boiler	58.8%	126.29	74.24	8,824
	Unit Heater	13.7%	126.29	17.35	2,062
Process	Process Boiler	100.0%	887.92	887.92	105,537
	Process Heating	100.0%	790.21	790.21	93,922
	Process Cooling	100.0%	9.17	9.17	1,090
	Other Process	100.0%	59.62	59.62	7,086
Miscellaneous	Miscellaneous	100.0%	135.11	135.11	16,059
Total				**2,008.33**	**238,705**

4

BASELINE PROJECTION

Prior to developing estimates of energy conservation potential, we developed a baseline end-use projection to quantify what the consumption is likely to be in the future in absence of any energy 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. Thus, the potential analysis captures all possible savings from future programs.

The baseline projection incorporates assumptions about:

- 2019 energy consumption based on the market profiles
- Customer population growth
- Appliance/equipment standards and building codes already mandated
- Appliance/equipment purchase decisions
- Avista's customer forecast

Trends in fuel shares and appliance saturations and assumptions about miscellaneous natural gas growth

Although it aligns closely, the baseline projection is not Avista's official load forecast. Rather it was developed as an integral component of our modeling construct to serve as the metric against which energy conservation potentials are measured. This chapter presents the baseline projections we developed for this study. Below, we present the baseline projections for each sector, which include projections of annual use in dekatherms. We also present a summary across all sectors.

Overall Baseline Projection

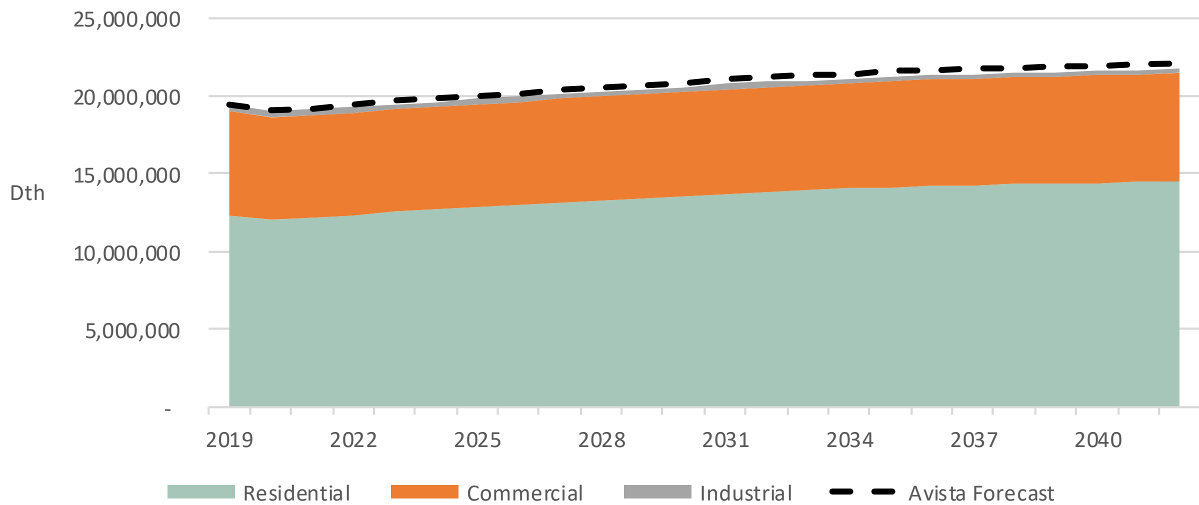
Washington Projection

Table 4-1 and Figure 4-1 provide a summary of the baseline projection for annual use by sector for the Avista's Washington service territory. Overall, the forecast shows modest growth in natural gas consumption, driven by the residential and commercial sectors

Table 4-1 Baseline Projection Summary by Sector, Washington, Selected Years (dekatherms)

Sector	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Residential	12,344,250	12,180,267	12,523,563	13,568,829	14,418,227	16.8%	0.7%
Commercial	6,718,365	6,596,157	6,622,904	6,725,824	6,909,984	2.9%	0.1%
Industrial	348,670	341,870	336,318	317,863	291,665	-16.3%	-0.9%
Total	**19,411,285**	**19,118,293**	**19,482,785**	**20,612,516**	**21,619,876**	**11.4%**	**0.5%**

Figure 4-1 Baseline Projection Summary by Sector, Washington (dekatherms)



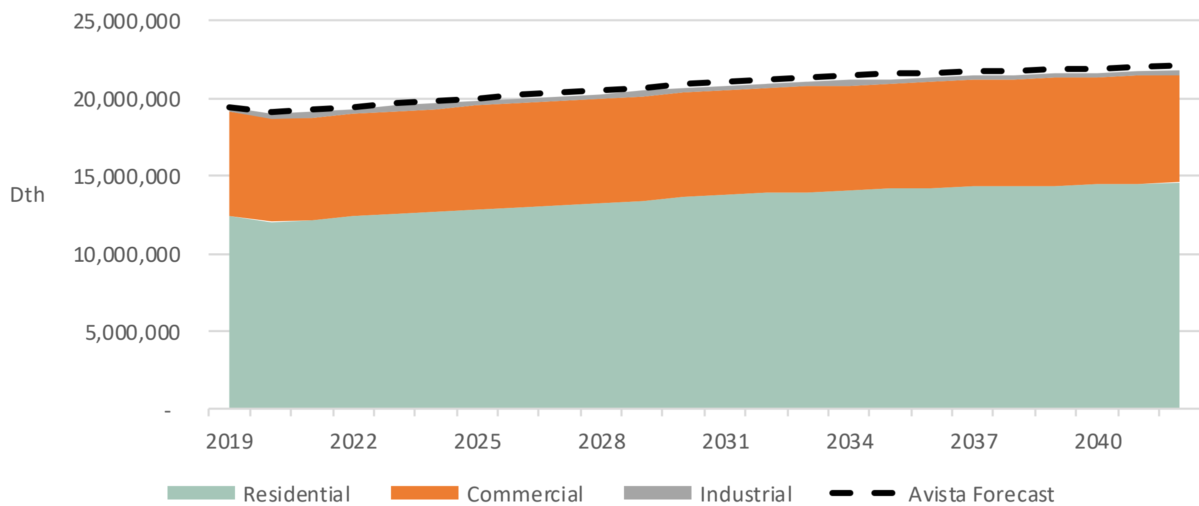
Idaho Projection

Table 4-2 and Figure 4-2 provide a summary of the baseline projection for annual use by sector for Avista's Idaho service territory. Overall, the forecast shows modest growth in natural gas consumption, driven roughly equally by the residential sector.

Table 4-2 Baseline Projection Summary by Sector, Idaho, Selected Years (dekatherms)

Sector	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Residential	5,782,934	5,757,753	5,989,779	6,677,657	7,614,162	31.7%	1.3%
Commercial	4,110,228	4,027,575	4,071,925	4,112,209	4,199,550	2.2%	0.1%
Industrial	238,705	234,049	229,897	214,701	193,107	-19.1%	-1.0%
Total	10,131,866	10,019,377	10,291,600	11,004,568	12,006,819	18.5%	0.8%

Figure 4-2 Baseline Projection Summary by Sector, Idaho (dekatherms)



Residential Sector

Washington Projection

Table 4-3 and

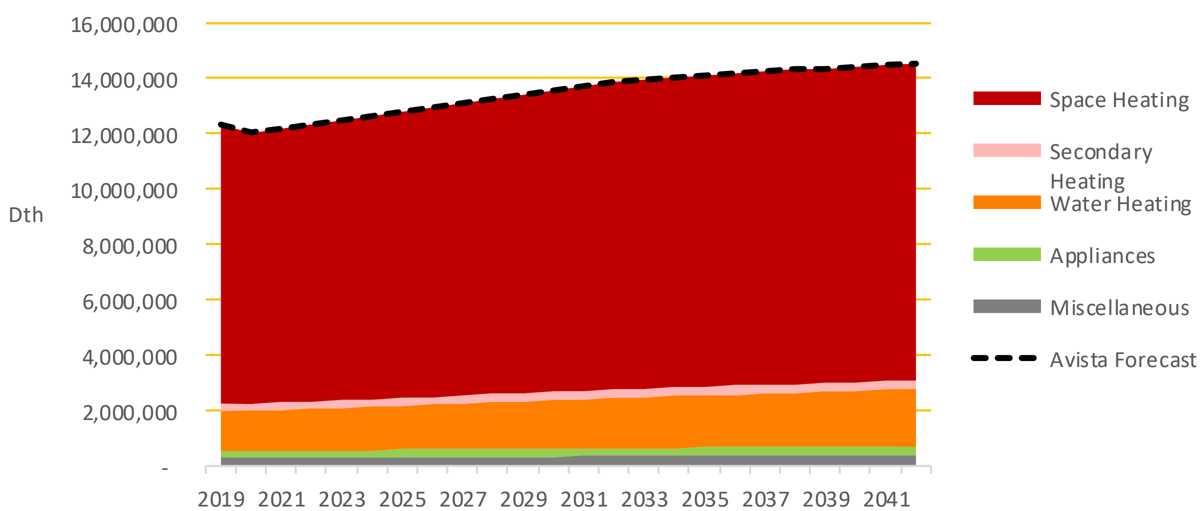
Figure 4-3 present the baseline projection for natural gas at the end-use level for the residential sector, as a whole. Overall, residential use increases from 12,344,250 dekatherms in 2019 to 14,418,227 dekatherms in 2040, an increase of 16.8%. Factors affecting growth include a moderate increase in number of households and customers, and a decrease in equipment consumption due to future standards and naturally occurring efficiency improvements (notably the AFUE upcoming 92% furnace standard).

We model gas-fired fireplaces as secondary heating. These consume energy and may heat a space but are rarely relied on to be a 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 4-3 Residential Baseline Projection by End Use, Washington (dekatherms)

End Use	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Space Heating	10,091,649	9,884,547	10,148,613	10,898,317	11,377,205	12.7%	0.6%
Secondary Heating	269,840	268,460	275,328	300,411	328,634	21.8%	0.9%
Water Heating	1,440,263	1,475,763	1,532,049	1,743,214	2,015,278	39.9%	1.6%
Appliances	235,480	240,292	248,325	278,255	315,399	33.9%	1.4%
Miscellaneous	307,017	311,205	319,248	348,632	381,710	24.3%	1.0%
Total	**12,344,250**	**12,180,267**	**12,523,563**	**13,568,829**	**14,418,227**	**16.8%**	**0.7%**

Figure 4-3 Residential Baseline Projection by End Use, Washington (dekatherms)



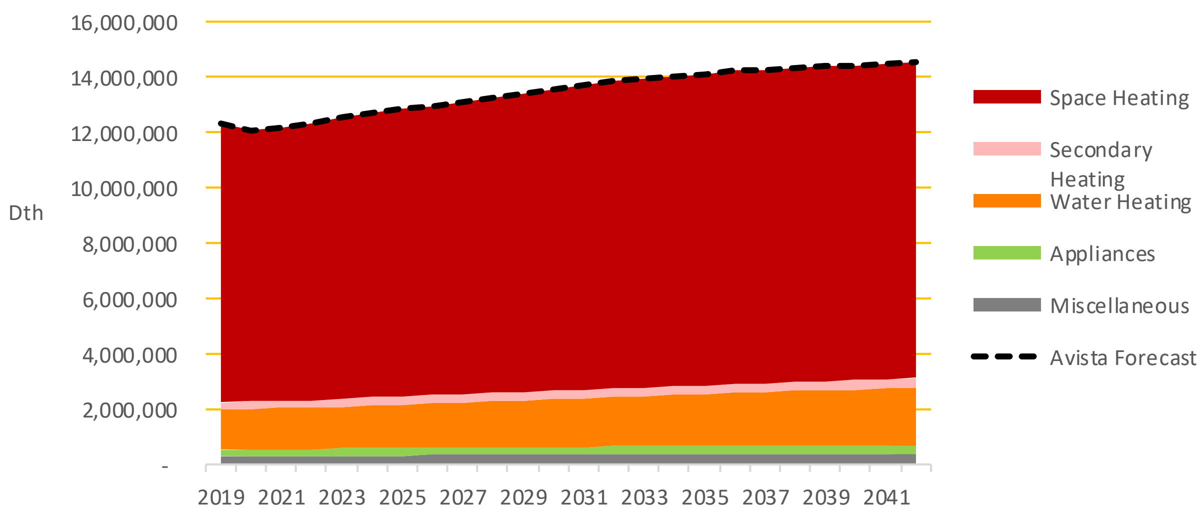
Idaho Projection

Table 4-4 and Figure 4-4 present the baseline projection for natural gas at the end-use level for the residential sector, as a whole. Overall, residential use increases from 5,782,934 dekatherms in 2019 to 7,614,162 dekatherms in 2040, an increase of 31.7%.

Table 4-4 Residential Baseline Projection by End Use, Idaho (dekatherms)

End Use	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Space Heating	4,598,206	4,543,217	4,723,227	5,238,352	5,912,290	28.6%	1.2%
Secondary Heating	172,526	172,767	178,636	197,303	224,372	30.1%	1.3%
Water Heating	753,951	777,712	814,170	936,965	1,126,311	49.4%	1.9%
Appliances	76,115	78,239	81,587	92,714	109,623	44.0%	1.7%
Miscellaneous	182,137	185,819	192,158	212,322	241,565	32.6%	1.3%
Total	**5,782,934**	**5,757,753**	**5,989,779**	**6,677,657**	**7,614,162**	**31.7%**	**1.3%**

Figure 4-4 Residential Baseline Projection by End Use, Idaho (dekatherms)



Commercial Sector

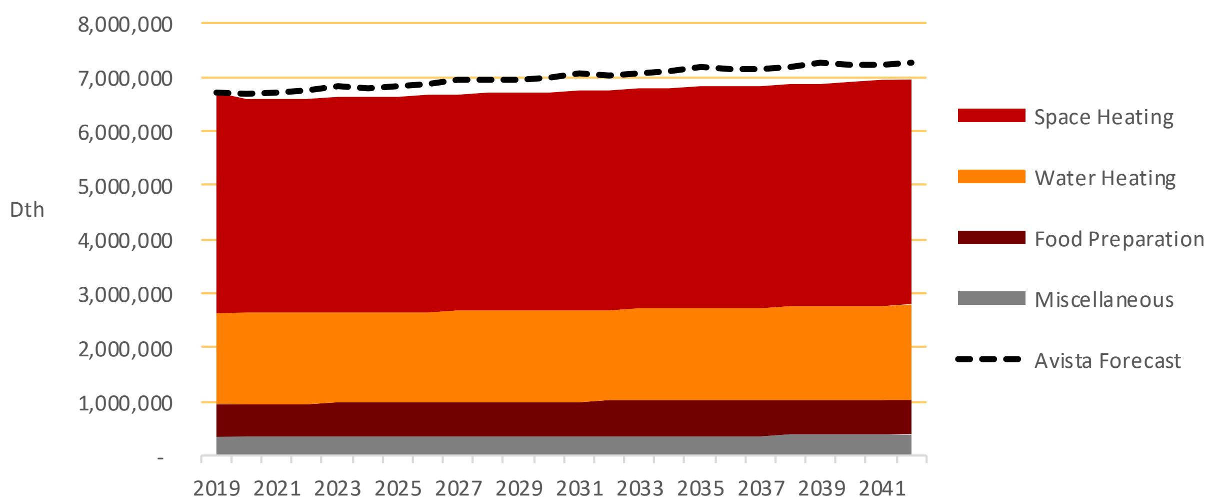
Washington Projection

Annual natural gas use in the commercial sector grows 24.7% during the overall forecast horizon, starting at 6,197,173 dekatherms in 2019, and increasing to 6,909,984 dekatherms in 2040. Table 4-5 and Figure 4-5 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 4-5 Commercial Baseline Projection by End Use, Washington (dekatherms)

End Use	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Space Heating	4,085,777	3,956,080	3,975,113	4,039,997	4,138,972	1.3%	0.1%
Water Heating	1,681,122	1,679,620	1,678,355	1,686,750	1,736,171	3.3%	0.2%
Food Preparation	605,698	611,422	617,138	636,007	658,775	8.8%	0.4%
Miscellaneous	345,768	349,035	352,298	363,069	376,067	8.8%	0.4%
Total	**6,718,365**	**6,596,157**	**6,622,904**	**6,725,824**	**6,909,984**	**2.9%**	**0.1%**

Figure 4-5 Commercial Baseline Projection by End Use, Washington (dekatherms)



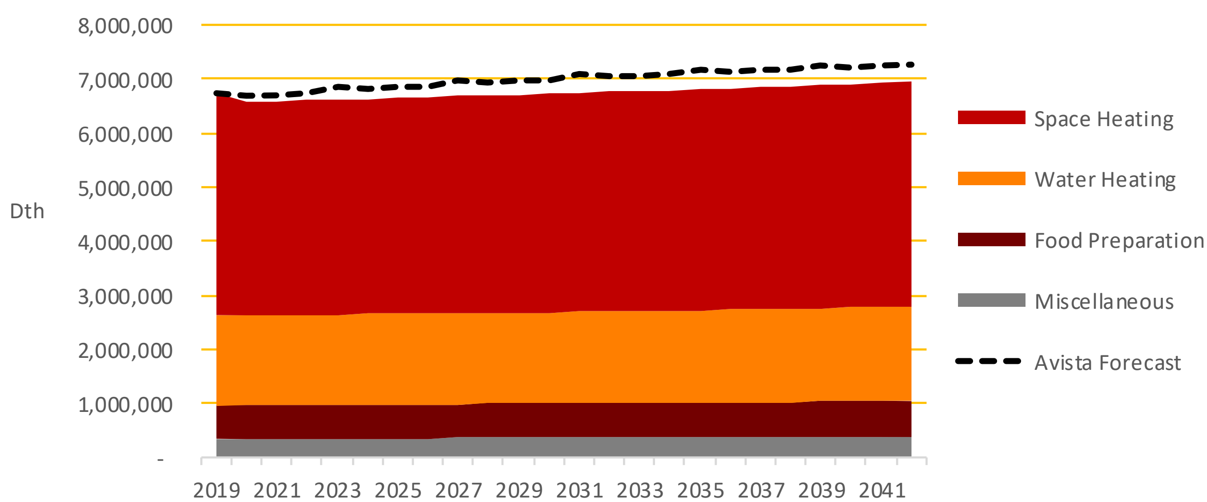
Idaho Projection

Annual natural gas use in the Idaho commercial sector grows 2.2% during the overall forecast horizon, starting at 4,110,228 dekatherms in 2019, and increasing to 4,199,550 dekatherms in 2040. Table 4-6 and Figure 4-6 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 4-6 Commercial Baseline Projection by End Use, Idaho (dekatherms)

End Use	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Space Heating	2,537,957	2,453,619	2,482,525	2,509,340	2,555,560	0.7%	0.0%
Water Heating	1,025,922	1,023,306	1,029,755	1,029,131	1,052,936	2.6%	0.1%
Food Preparation	352,633	355,410	361,216	370,312	381,488	8.2%	0.4%
Miscellaneous	193,715	195,240	198,430	203,426	209,566	8.2%	0.4%
Total	**4,110,228**	**4,027,575**	**4,071,925**	**4,112,209**	**4,199,550**	**2.2%**	**0.1%**

Figure 4-6 Commercial Baseline Projection by End Use, Idaho (dekatherms)



Industrial Sector

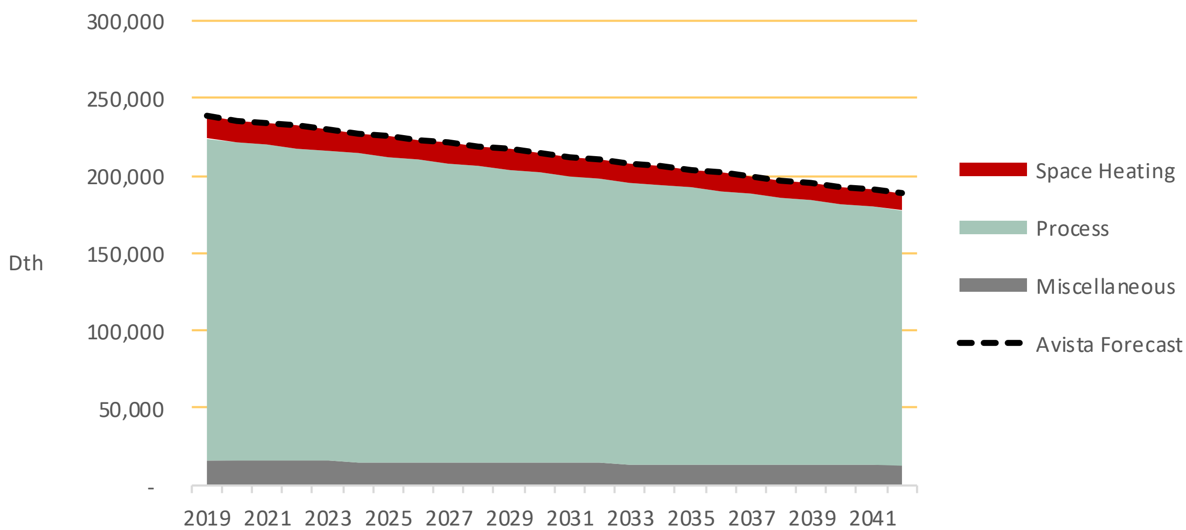
Washington Projection

Industrial sector usage increases throughout the planning horizon. Table 4-7 and Figure 4-7 present the projection at the end-use level. Overall, industrial annual natural gas use decreases from 348,670 dekatherms in 2019 to 291,665 dekatherms in 2040. Growth is consistently around -0.9% per year.

Table 4-7 Industrial Baseline Projection by End Use, Washington (dekatherms)

End Use	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Space Heating	21,926	20,665	20,227	18,789	16,903	-22.9%	-1.2%
Process	303,287	298,146	293,399	277,603	255,037	-15.9%	-0.8%
Miscellaneous	23,457	23,059	22,692	21,470	19,725	-15.9%	-0.8%
Total	**348,670**	**341,870**	**336,318**	**317,863**	**291,665**	**-16.3%**	**-0.9%**

Figure 4-7 Industrial Baseline Projection by End Use, Washington (dekatherms)



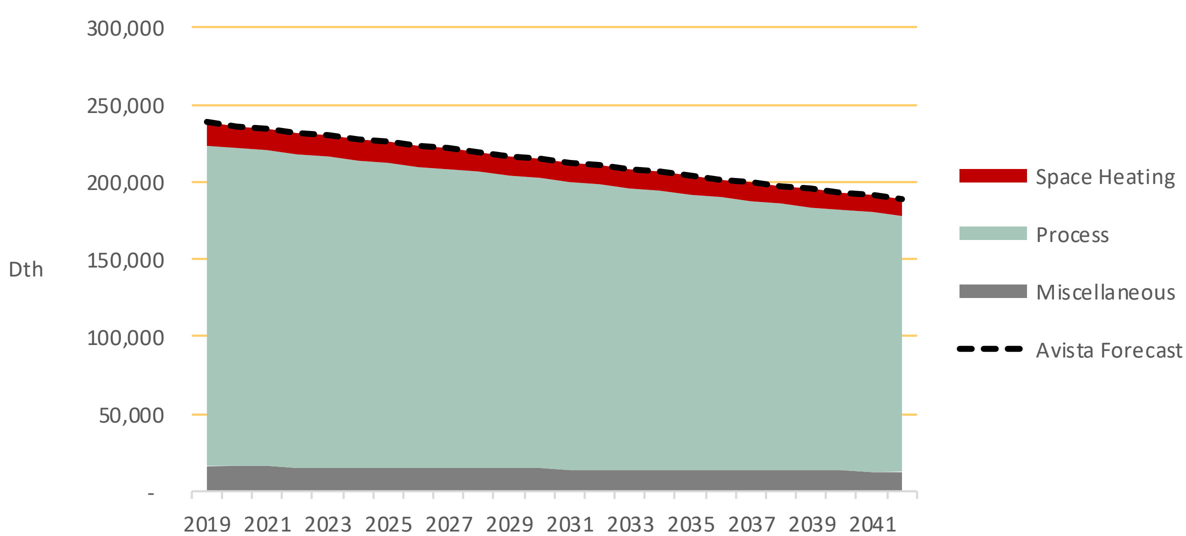
Idaho Projection

Industrial sector usage increases throughout the planning horizon. Table 4-8 and Figure 4-8 present the projection at the end-use level. Overall, industrial annual natural gas use descreases from 238,705 dekatherms in 2019 to 193,107 dekatherms in 2040.

Table 4-8 Industrial Baseline Projection by End Use, Idaho (dekatherms)

End Use	2019	2021	2023	2030	2040	% Change ('19-'40)	Avg. Growth
Heating	15,011	14,147	13,829	12,713	11,232	-25.2%	-1.4%
Process	207,635	204,115	200,556	187,488	168,818	-18.7%	-1.0%
Miscellaneous	16,059	15,787	15,511	14,501	13,057	-18.7%	-1.0%
Total	**238,705**	**234,049**	**229,897**	**214,701**	**193,107**	**-19.1%**	**-1.0%**

Figure 4-8 Industrial Baseline Projection by End Use, Idaho (dekatherms)



5

OVERALL ENERGY EFFICIENCY POTENTIAL

This chapter presents the measure-level energy conservation potential across all sectors for Avista's Washington and Idaho territories. This includes every possible measure that is considered in the measure list, regardless of program implementation concerns. Year-by-year savings for annual energy usage are available in the LoadMAP model and measure assumption summary, which were provided to Avista at the conclusion of the study. Please note that all savings are provided at the customer site. This section includes potential from the residential, commercial, and industrial analyses.

Overall Energy Efficiency Potential

Washington Potential

Table 5-1 and Figure 5-1 summarize the energy conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection. Figure 5-2 displays the energy conservation forecasts. Savings are represented in cumulative terms, which reflect the effects of persistent savings in prior years in addition to new savings. This allows for the reporting of annual savings impacts as they actually impact each year of the forecast.

- Technical Potential reflects the adoption of all conservation measures regardless of cost-effectiveness. In this potential case, efficient equipment makes up all lost opportunity installations and all retrofit measures are installed, regardless of achievability. 2021 first-year savings are 421,965 dekatherms, or 2.2% of the baseline projection. Cumulative savings in 2030 are 5,084,999 dekatherms, or 24.7% of the baseline. By 2040, cumulative savings reach 8,908,493 dekatherms, or 41.2% of the baseline. Technical potential is useful as a theoretical construct, applying an upper bound to the potential that may be realized in any one year. Other levels of potential are based off this level which makes it an important component in the estimation of potential.
- Achievable Technical Potential refines technical potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation measures. For Avista's gas CPA, ramp rates from the 2021 Power Plan were customized for use in natural gas programs and applied. Since the 2021 Plan does not assign ramp rates for the majority of natural gas measures, we assigned these based on similar electric technologies present in the Plan as a starting point. These ramp rates may be found in Appendix B. 2021 first-year net savings are 187,983 dekatherms, or 1.0% of the baseline projection. Cumulative net savings in 2030 are 3,183,398 dekatherms, or 15.4% of the baseline. By 2040 cumulative savings reach 6,309,826 dekatherms, or 29.2% of the baseline.
- UCT Achievable Economic Potential further refines achievable technical potential by applying an economic cost-effectiveness screen. In this analysis, the cost-effectiveness is measured by the utility cost test (UCT), which compares lifetime energy benefits to the total utility costs of delivering the measure through a utility program, excluding monetized non-energy impacts. Avoided costs of energy were provided by Avista. 2021 first-year savings are 75,820 dekatherms, or 0.4% of the baseline projection. Cumulative savings in 2030 are 1,386,479 dekatherms, or 6.7% of the baseline. By 2040 cumulative savings reach 3,560,512 dekatherms, or 16.5% of the baseline.

- **TRC Achievable Economic Potential** further refines achievable technical potential by applying an economic cost-effectiveness screen. In this analysis, the cost-effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy benefits to the total customer and utility costs of delivering the measure through a utility program, including monetized non-energy impacts. AEG also applied benefits for non-gas energy savings, such as electric HVAC savings for weatherization and lighting savings for retrocommissioning. We also applied the Council's calibration credit to space heating savings to reflect the fact that additional fuels may be used as a supplemental heat source within an average home and may be accounted for within the TRC. Avoided costs of energy were provided by Avista. A 10% conservation credit was applied to these costs per the Council methodologies. 2021 first-year savings are 41,871 dekatherms, or 0.2% of the baseline projection. Cumulative net savings in 2030 are 708,778 dekatherms, or 3.4% of the baseline. By 2040 cumulative savings reach 2,319,723 dekatherms, or 10.7% of the baseline. Potential under the TRC test is lower than UCT due to the inclusion of full measure costs rather than the utility portion. For most measures, these far outweigh the quantified and monetized non-energy impacts included in the TRC.

Table 5-1 Summary of Energy Efficiency Potential, Washington (dekatherms)

Scenario	2021	2022	2025	2030	2040
Baseline Projection (Dth)	19,118,293	19,289,575	19,805,020	20,612,516	21,619,876
Cumulative Savings (Dth)					
UCT Achievable Economic Potential	75,820	173,838	457,423	1,386,479	3,560,512
TRC Achievable Economic Potential	41,871	100,872	227,922	708,778	2,319,723
Achievable Technical Potential	187,983	416,584	1,221,810	3,183,398	6,309,826
Technical Potential	429,965	897,098	2,314,334	5,084,999	8,908,493
Cumulative Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.3%	6.7%	16.5%
TRC Achievable Economic Potential	0.2%	0.5%	1.2%	3.4%	10.7%
Achievable Technical Potential	1.0%	2.2%	6.2%	15.4%	29.2%
Technical Potential	2.2%	4.7%	11.7%	24.7%	41.2%

Figure 5-1 Summary of Energy Efficiency Potential as % of Baseline Projection, Washington (dekatherms)

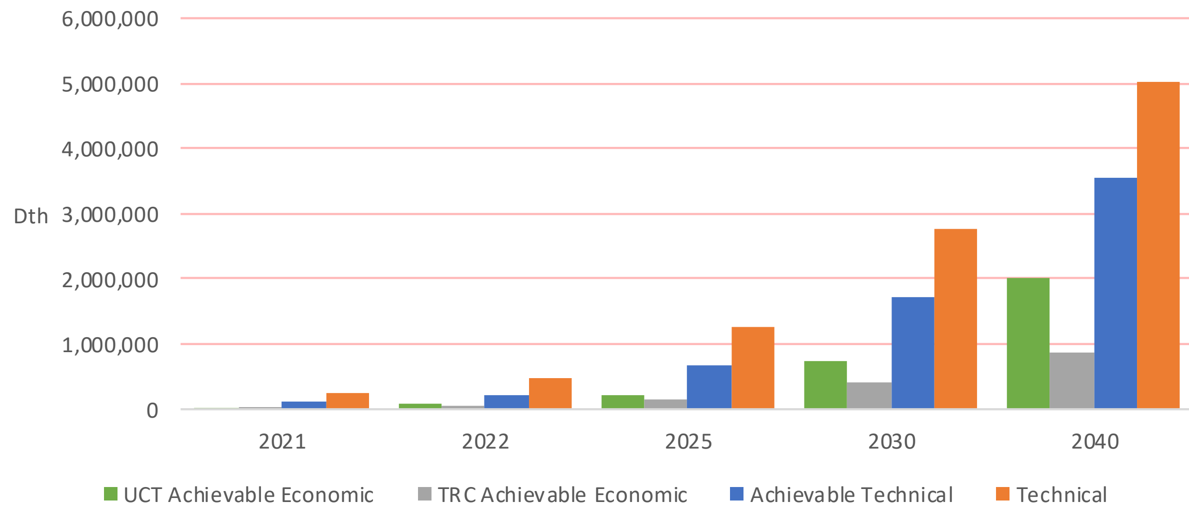


Figure 5-2 Baseline Projection and Energy Efficiency Forecasts, Washington (dekatherms)

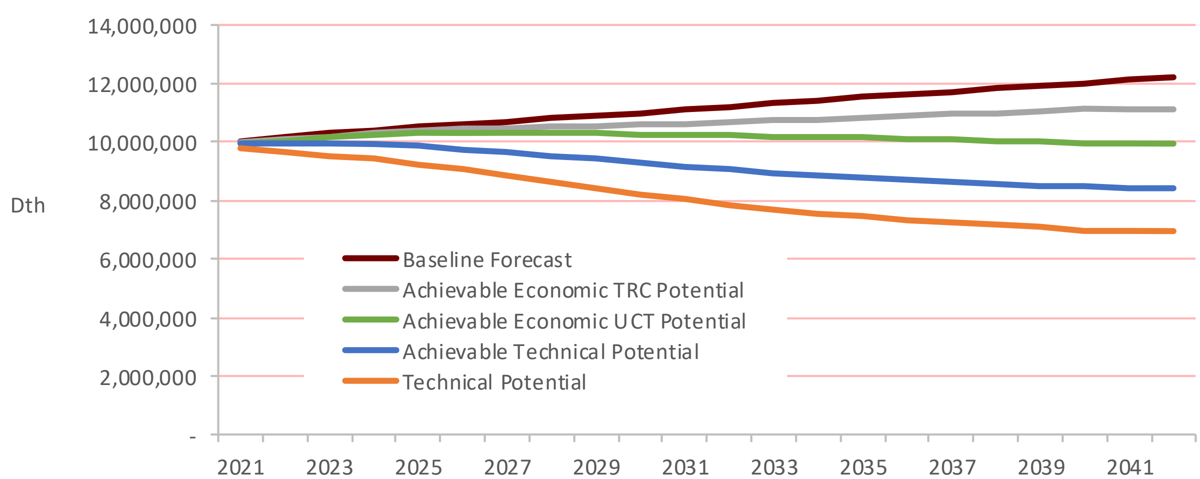


Figure 5-3 shows the cumulative UCT achievable potential by sector for the full timeframe of the analysis as percent of total. Table 5-2 summarizes UCT achievable potential by market sector for selected years.

While the residential and commercial sectors represent the lion's share of the overall potential in the early years, by the late-2020s, the residential sector share grows to a significant majority of savings potential. Since industrial consumption is such a low percentage of the baseline once ineligible customers have been excluded, potential for this sector makes up a lower percentage of the total. While residential and commercial potential ramps up, industrial potential is mainly retrofit in nature, and is much flatter. This is because process equipment is highly custom and most potential comes from controls modifications or process adjustments rather than high-efficiency equipment upgrades. Additionally, we model retrocommissioning to phase in evenly over the next twenty years. This measure has a maintenance component, and not all existing facilities may be old enough to require the tune-up immediately but will be eligible at some point over the course of the study.

There is a notable downtick in residential savings around 2024. This is due to the impacts of the residential forced-air furnace standard, which raises the baseline from AFUE 80% to AFUE 92%, which is a substantial increase when the efficient option is an AFUE 95% unit.

Figure 5-3 Cumulative UCT Achievable Economic Potential by Sector, Washington (% of Total)

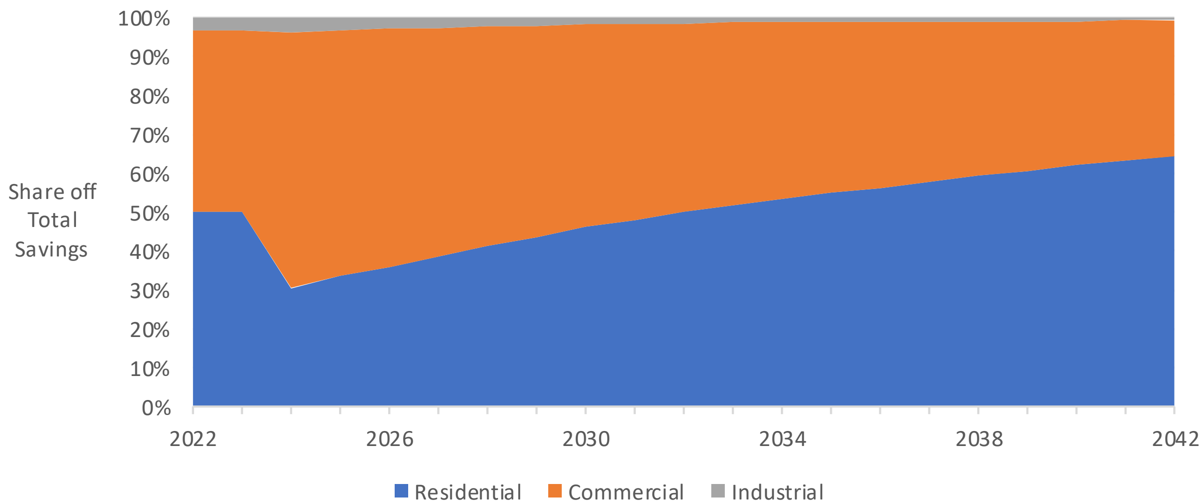


Table 5-2 Cumulative UCT Achievable Economic Potential by Sector, Washington, Selected Years (dekatherms)

Sector	2021	2022	2025	2030	2040
Residential	45,545	102,725	208,449	725,000	2,294,322
Commercial	28,070	66,690	237,773	642,051	1,241,314
Industrial	2,206	4,424	11,200	19,428	24,876
Total	**75,820**	**173,838**	**457,423**	**1,386,479**	**3,560,512**

Idaho Potential

Table 5-3 and Figure 5-4 summarize the energy conservation savings in terms of annual energy use for all measures for four levels of potential relative to the baseline projection. Figure 5-5 displays the energy conservation forecasts. Savings are represented in cumulative terms, which reflect the effects of persistent savings in prior years in addition to new savings. This allows for the reporting of annual savings impacts as they actually impact each year of the forecast.

- Technical Potential first-year savings in 2021 are 232,772 dekatherms, or 2.3% of the baseline projection. Cumulative savings in 2030 are 2,777,509 dekatherms, or 25.2% of the baseline. By 2040, cumulative savings reach 5,013,697 dekatherms, or 41.8% of the baseline.
- Achievable Technical Potential first-year net savings are 102,031 dekatherms, or 1.0% of the baseline projection. Cumulative net savings in 2030 are 1,722,830 dekatherms, or 15.7% of the baseline. By 2040 cumulative savings reach 3,544,048 dekatherms, or 29.5% of the baseline.
- UCT Achievable Economic Potential first-year savings are 35,816 dekatherms, or 0.4% of the baseline projection. Cumulative savings in 2030 are 737,710 dekatherms, or 6.7% of the baseline. By 2040 cumulative savings reach 2,025,410 dekatherms, or 16.9% of the baseline.
- TRC Achievable Economic Potential first-year savings are 26,220 dekatherms, or 0.3% of the baseline projection. Cumulative net savings in 2030 are 417,020 dekatherms, or 3.8% of the baseline. By 2040 cumulative savings reach 868,456 dekatherms, or 7.2% of the baseline. Potential under the TRC test is lower than UCT due to the inclusion of full measure costs rather than the utility portion. For most measures, these far outweigh the quantified and monetized non-energy impacts included in the TRC.

Table 5-3 Summary of Energy Efficiency Potential, Idaho (dekatherms)

Scenario	2021	2022	2025	2030	2040
Baseline Projection (Dth)	10,019,377	10,144,894	10,520,169	11,004,568	12,006,819
Cumulative Savings (Dth)					
UCT Achievable Economic Potential	35,816	87,995	229,283	737,710	2,025,410
TRC Achievable Economic Potential	26,220	62,285	136,883	417,028	868,456
Achievable Technical Potential	102,031	226,613	657,997	1,722,830	3,544,048
Technical Potential	232,772	490,826	1,273,202	2,777,509	5,013,697
Cumulative Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.9%	2.2%	6.7%	16.9%
TRC Achievable Economic Potential	0.3%	0.6%	1.3%	3.8%	7.2%
Achievable Technical Potential	1.0%	2.2%	6.3%	15.7%	29.5%
Technical Potential	2.3%	4.8%	12.1%	25.2%	41.8%

Figure 5-4 Summary of Energy Efficiency Potential as % of Baseline Projection, Idaho (dekatherms)

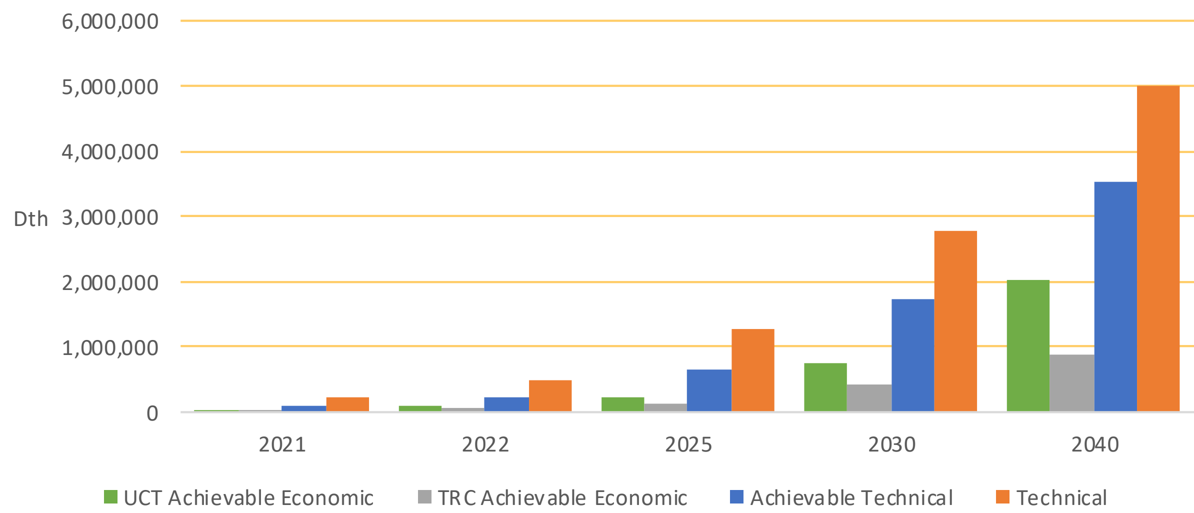


Figure 5-5 Summary of Energy Efficiency Potential as % of Baseline Projection, Idaho (dekatherms)

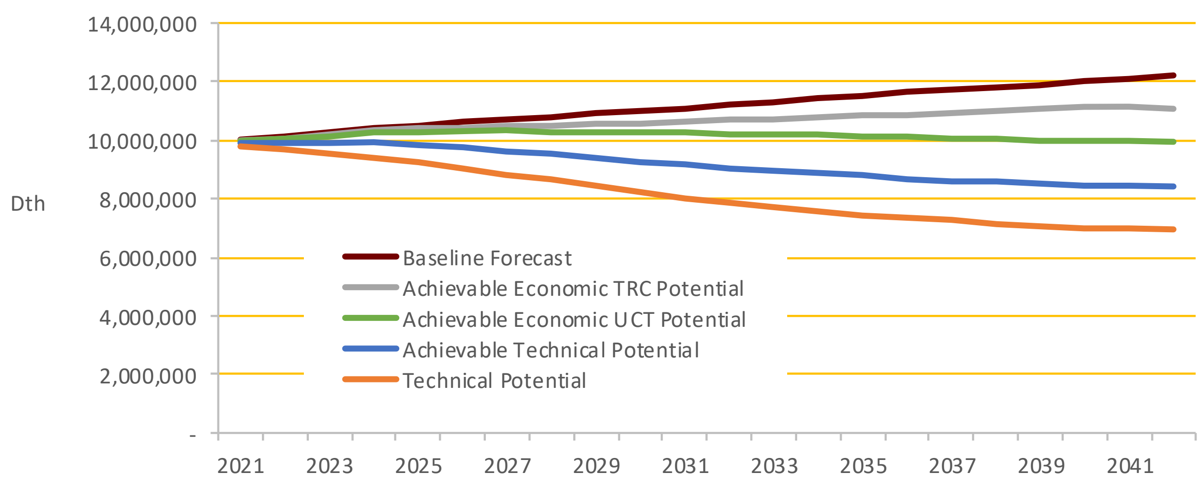


Figure 5-6 shows the cumulative UCT achievable potential by sector for the full timeframe of the analysis as percent of total. Table 5-4 summarizes UCT achievable potential by market sector for selected years.

.

Figure 5-6 Cumulative UCT Achievable Economic Potential by Sector, Idaho (% of Total)

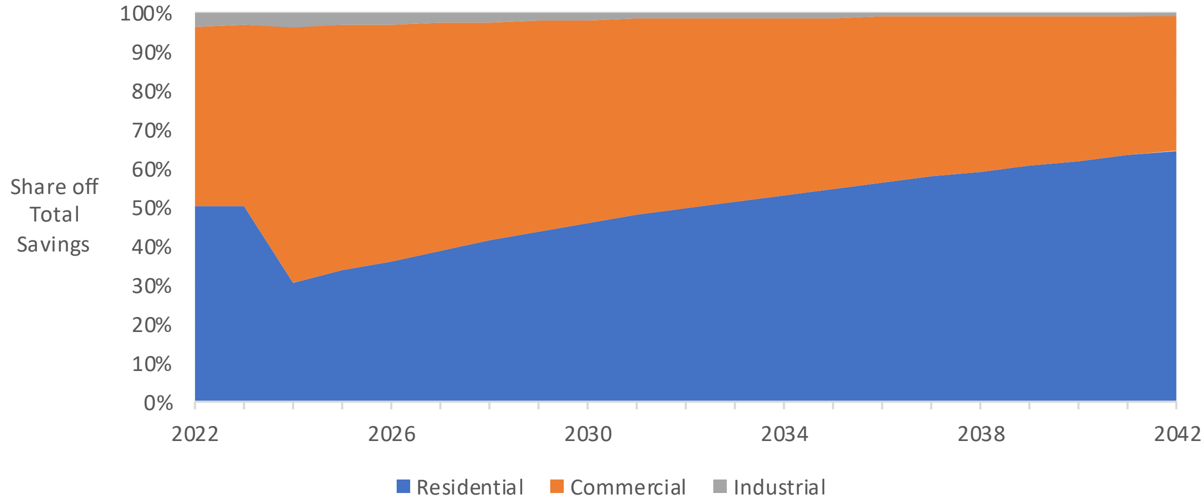


Table 5-4 Cumulative UCT Achievable Economic Potential by Sector, Idaho, Selected Years (dekatherms)

Sector	2021	2022	2025	2030	2040
Residential	17,529	44,289	77,379	339,502	1,256,282
Commercial	16,775	40,676	144,201	384,730	751,926
Industrial	1,512	3,030	7,703	13,477	17,202
Total	**35,816**	**87,995**	**229,283**	**737,710**	**2,025,410**

6

SECTOR-LEVEL ENERGY EFFICIENCY POTENTIAL

The previous section provided a summary of potential for the Avista territory at the state level. In this section, we provide details for each sector.

Residential Sector

Washington Potential

Table 6-1 and Figure 6-1 summarize the energy efficiency potential for the residential sector. In 2021, UCT achievable economic potential is 45,545 dekatherms, or 0.4% of the baseline projection. By 2040, cumulative savings are 2,294,322 dekatherms, or 15.9% of the baseline.

Table 6-1 Residential Energy Conservation Potential Summary, Washington (dekatherms)

Scenario	2021	2022	2025	2030	2040
Baseline Forecast (Dth)	12,180,267	12,342,203	12,822,709	13,568,829	14,418,227
Cumulative Savings (Dth)					
UCT Achievable Economic Potential	45,545	102,725	208,449	725,000	2,294,322
TRC Achievable Economic Potential	22,729	53,315	48,069	211,706	1,312,883
Achievable Technical Potential	137,500	304,182	858,976	2,272,407	4,576,510
Technical Potential	292,972	616,103	1,560,420	3,510,309	6,413,126
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	0.8%	1.6%	5.3%	15.9%
TRC Achievable Economic Potential	0.2%	0.4%	0.4%	1.6%	9.1%
Achievable Technical Potential	1.1%	2.5%	6.7%	16.7%	31.7%
Technical Potential	2.4%	5.0%	12.2%	25.9%	44.5%

Figure 6-1 Residential Energy Conservation by Case, Washington (dekatherms)

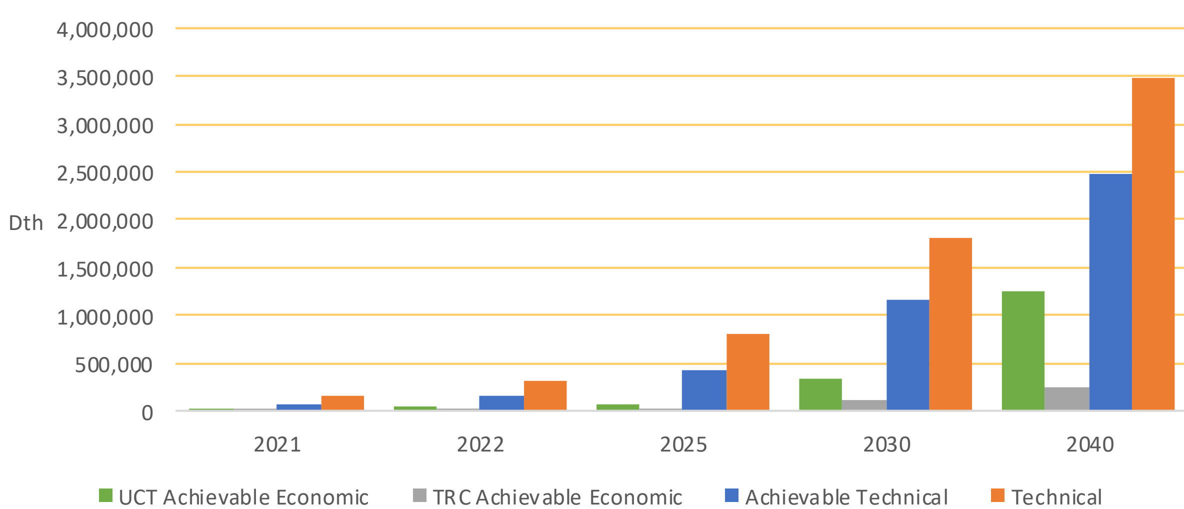


Figure 6-2 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings. Space heating makes up a majority of potential but declines slightly in the early to mid-2020s due to the future furnace standard.

Figure 6-2 Residential UCT Achievable Economic Potential – Cumulative Savings by End Use, Washington (dekatherms, % of total)

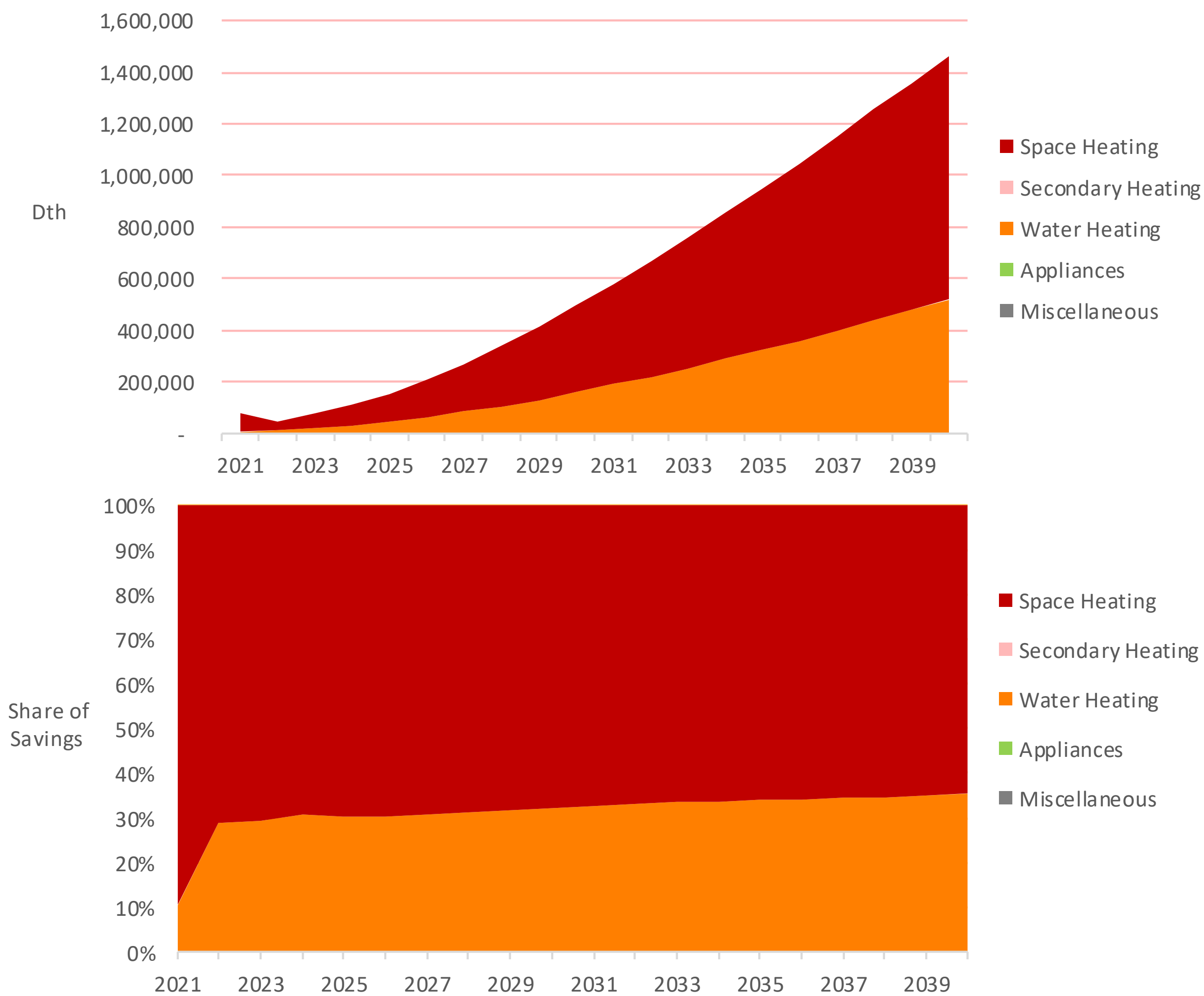


Table 6-2 identifies the top 20 residential measures by cumulative 2021 and 2022 savings. Furnaces, learning thermostats, insulation and water heating are the top measures.

Table 6-2 Residential Top Measures in 2021 and 2022, UCT Achievable Economic Potential, Washington (dekatherms)

Rank	Measure / Technology	2021 Cumulative Potential Savings (dekatherms)	% of Total	2022 Cumulative Potential Savings (dekatherms)	% of Total
1	Furnace - AFUE 92%	21,548	47%	50,231	49%
2	Gas Furnace - Maintenance - Restored to nameplate 80% AFUE	13,118	29%	26,107	25%
3	ENERGY STAR Connected Thermostat - Interactive/learning thermostat (ie, NEST)	4,435	10%	9,925	10%
4	Insulation - Ceiling, Installation - R-38 (Retro only)	3,611	8%	8,000	8%
5	Water Heater - Instantaneous - ENERGY STAR (UEF 0.87)	1,901	4%	5,973	6%
6	Insulation - Wall Cavity, Installation - R-11	333	1%	741	1%
7	Gas Boiler - Steam Trap Maintenance - Cleaned and restored	202	0%	399	0%
8	Building Shell - Whole-Home Aerosol Sealing - 20% reduction in ACH50	163	0%	492	0%
9	Water Heater - Low Flow Showerhead (1.5 GPM) - 1.5 GPM showerhead	75	0%	194	0%
10	Boiler - AFUE 85%	51	0%	130	0%
11	Water Heater - Faucet Aerators - 1.5 GPM faucet	51	0%	131	0%
12	ENERGY STAR Homes - Built Green spec (NC Only)	47	0%	265	0%
13	Water Heater - Pipe Insulation - Insulated 5' of pipe between unit and conditioned space	10	0%	25	0%
14	Insulation - Slab Foundation - R-11 (NC Only)	0	0%	23	0%
15	Building Shell - Liquid-Applied Weather-Resistive Barrier - Spray-on weather barrier applied	0	0%	0	0%
16	Clothes Dryer - NEEA/ENERGY STAR (CE >60%)	0	0%	0	0%
17	Combined Boiler + DHW System (Storage Tank) - Combined tankless boiler unit for space and DHW	0	0%	0	0%
18	Combined Boiler + DHW System (Tankless) - Combined tankless boiler unit for space and DHW	0	0%	0	0%
19	Doors - Storm and Thermal - R-5 door	0	0%	0	0%
20	Ducting - Repair and Sealing - 50% reduction in duct leakage	0	0%	0	0%
Subtotal		**45,545**	**100%**	**102,636**	**100%**
Total Savings in Year		**45,545**	**100%**	**102,725**	**100%**

Idaho Potential

Table 6-3 and Figure 6-3 summarize the energy efficiency potential for the residential sector. In 2021, UCT achievable economic potential is 17,529 dekatherms, or 0.3% of the baseline projection. By 2040, cumulative savings are 1,256,282 dekatherms, or 16.5% of the baseline.

Table 6-3 Residential Energy Conservation Potential Summary, Idaho (dekatherms)

Scenario	2021	2022	2025	2030	2040
Baseline Forecast (Dth)	5,757,753	5,864,931	6,201,524	6,677,657	7,614,162
Cumulative Savings (Dth)					
UCT Achievable Economic Potential	17,529	44,289	77,379	339,502	1,256,282
TRC Achievable Economic Potential	14,700	32,896	26,285	117,618	255,801
Achievable Technical Potential	70,759	156,239	432,644	1,167,372	2,486,556
Technical Potential	148,844	313,749	798,652	1,806,313	3,485,609
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.3%	0.8%	1.2%	5.1%	16.5%
TRC Achievable Economic Potential	0.3%	0.6%	0.4%	1.8%	3.4%
Achievable Technical Potential	1.2%	2.7%	7.0%	17.5%	32.7%
Technical Potential	2.6%	5.3%	12.9%	27.1%	45.8%

Figure 6-3 Residential Energy Conservation by Case, Idaho (dekatherms)

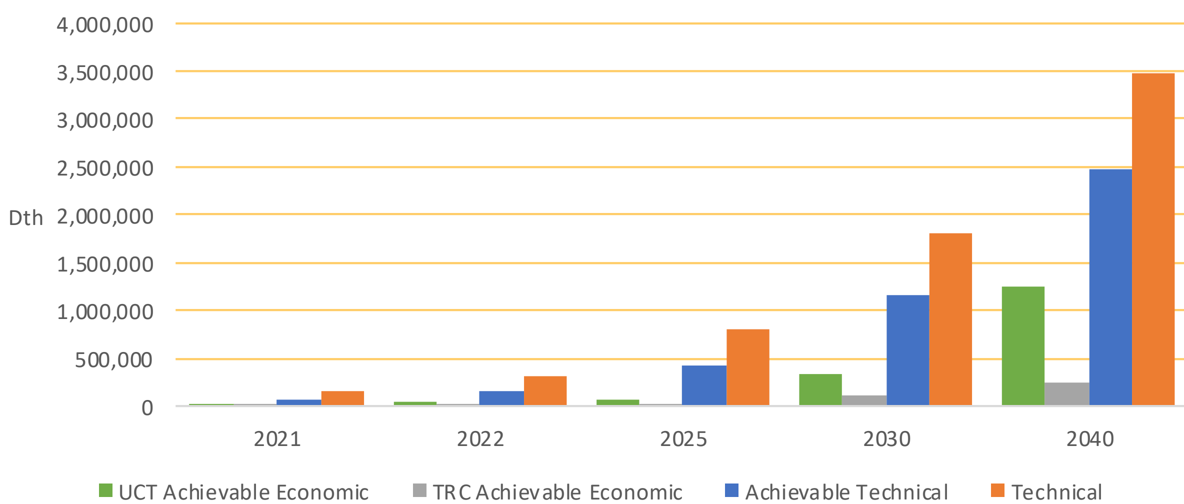


Figure 6-4 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings. Space heating makes up a majority of potential but declines slightly in the early to mid-2020s due to the future furnace standard.

Figure 6-4 Residential UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho (dekatherms, % of total)

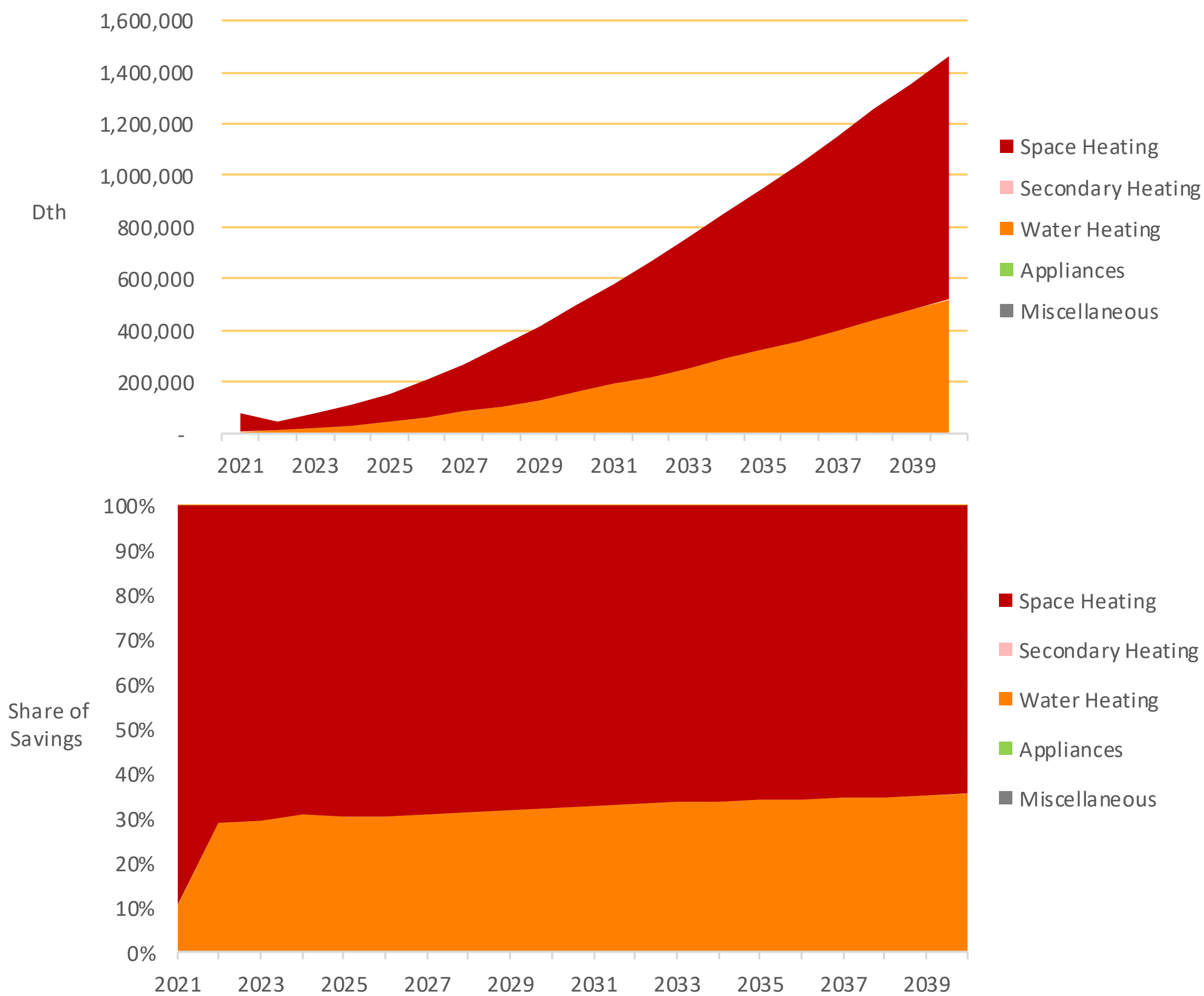


Table 6-4 identifies the top 20 residential measures by cumulative 2018 and 2019 savings. Furnaces, tankless water heaters, windows, and insulation are the top measures.

Table 6-4 Residential Top Measures in 2021 and 2022, UCT Achievable Economic Potential, Idaho (dekatherms)

Rank	Measure / Technology	2021 Cumulative Potential Savings (dekatherms)	% of Total	2022 Cumulative Potential Savings (dekatherms)	% of Total
1	Furnace - AFUE 92%	14,054	80%	31,241	71%
2	Insulation - Ceiling, Installation - R-38 (Retro only)	1,643	9%	3,640	8%
3	Water Heater - Instantaneous - ENERGY STAR (UEF 0.87)	1,053	6%	3,293	7%
4	Gas Furnace - Maintenance - Restored to nameplate 80% AFUE	284	2%	4,805	11%
5	Insulation - Wall Cavity, Installation - R-11	142	1%	316	1%
6	Water Heater - Low Flow Showerhead (1.5 GPM) - 1.5 GPM showerhead	93	1%	243	1%
7	Gas Boiler - Steam Trap Maintenance - Cleaned and restored	91	1%	180	0%
8	Building Shell - Whole-Home Aerosol Sealing - 20% reduction in ACH50	79	0%	237	1%
9	ENERGY STAR Homes - Built Green spec (NC Only)	32	0%	176	0%
10	Water Heater - Faucet Aerators - 1.5 GPM faucet	32	0%	87	0%
11	Water Heater - Low Flow Showerhead (2.0 GPM) - 2.0 GPM showerhead	21	0%	56	0%
12	Water Heater - Pipe Insulation - Insulated 5' of pipe between unit and conditioned space	5	0%	14	0%
Subtotal		**17,529**	**100%**	**44,289**	**100%**
Total Savings in Year		**17,529**	**100%**	**44,289**	**100%**

Commercial Sector

Washington Potential

Table 6-5 and Figure 6-5 summarize the energy conservation potential for the commercial sector. In 2021, UCT achievable economic potential is 28,070 dekatherms, or 0.4% of the baseline projection. By 2040, cumulative savings are 1,241,314 dekatherms, or 18.0% of the baseline.

Table 6-5 Commercial Energy Conservation Potential Summary, Washington

Scenario	2021	2022	2025	2030	2040
Baseline Forecast (dekatherms)	6,596,157	6,608,411	6,651,275	6,725,824	6,909,984
Cumulative Savings (dekatherms)					
UCT Achievable Economic Potential	28,070	66,690	237,773	642,051	1,241,314
TRC Achievable Economic Potential	18,820	46,887	177,954	492,563	999,201
Achievable Technical Potential	47,867	107,183	349,669	887,910	1,704,037
Technical Potential	133,767	274,570	737,799	1,546,608	2,459,821
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	1.0%	3.6%	9.5%	18.0%
TRC Achievable Economic Potential	0.3%	0.7%	2.7%	7.3%	14.5%
Achievable Technical Potential	0.7%	1.6%	5.3%	13.2%	24.7%
Technical Potential	2.0%	4.2%	11.1%	23.0%	35.6%

Figure 6-5 Commercial Energy Conservation by Case, Washington (dekatherms)

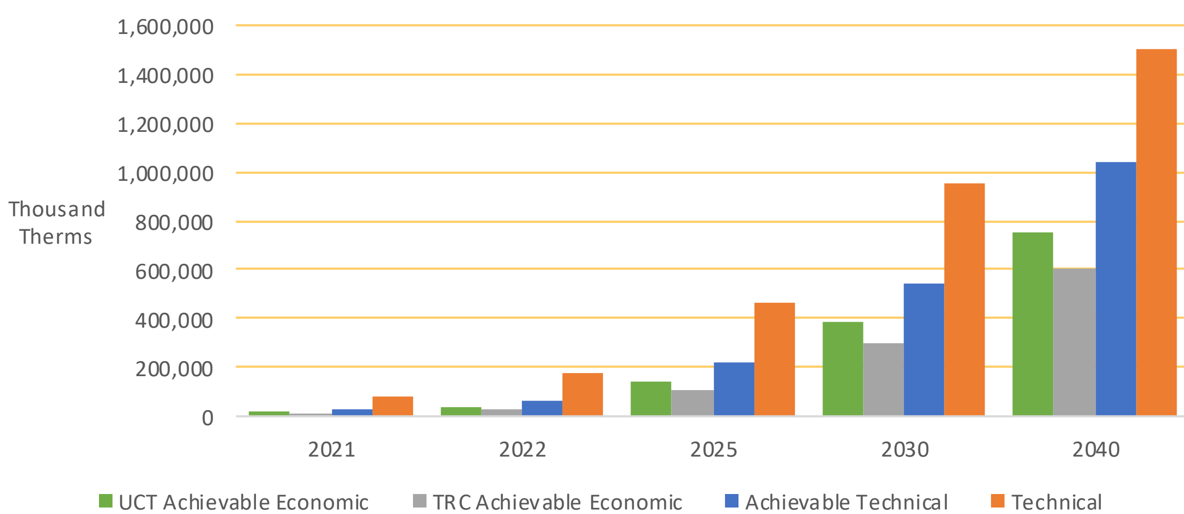
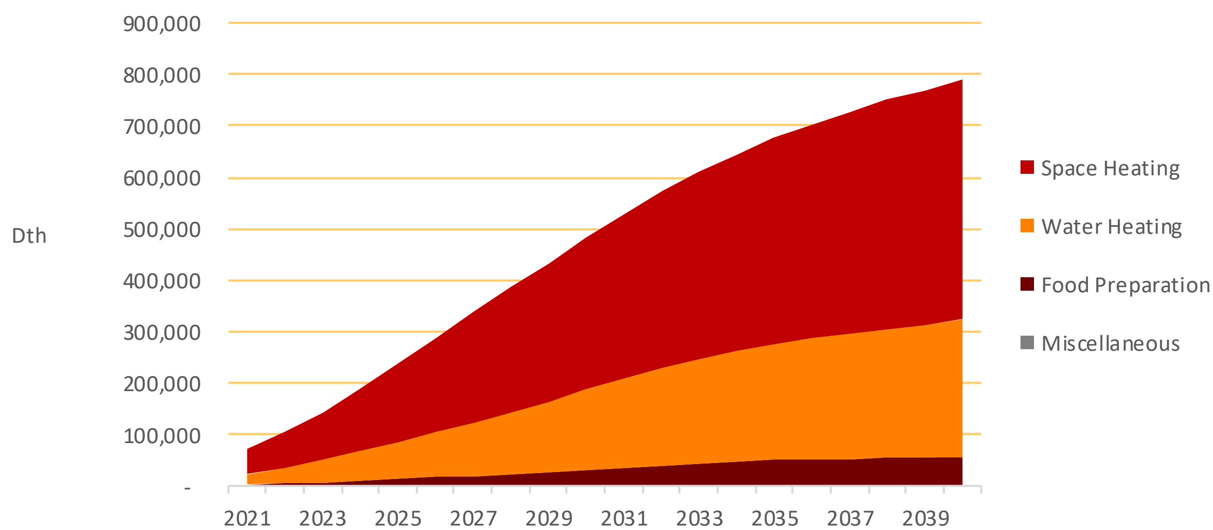


Figure 6-6 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings. Space heating makes up a majority of the potential early, but food preparation equipment upgrades provide substantial savings opportunities in the later years.

Figure 6-6 Commercial UCT Achievable Economic Potential – Cumulative Savings by End Use, Washington (dekatherms, % of total)



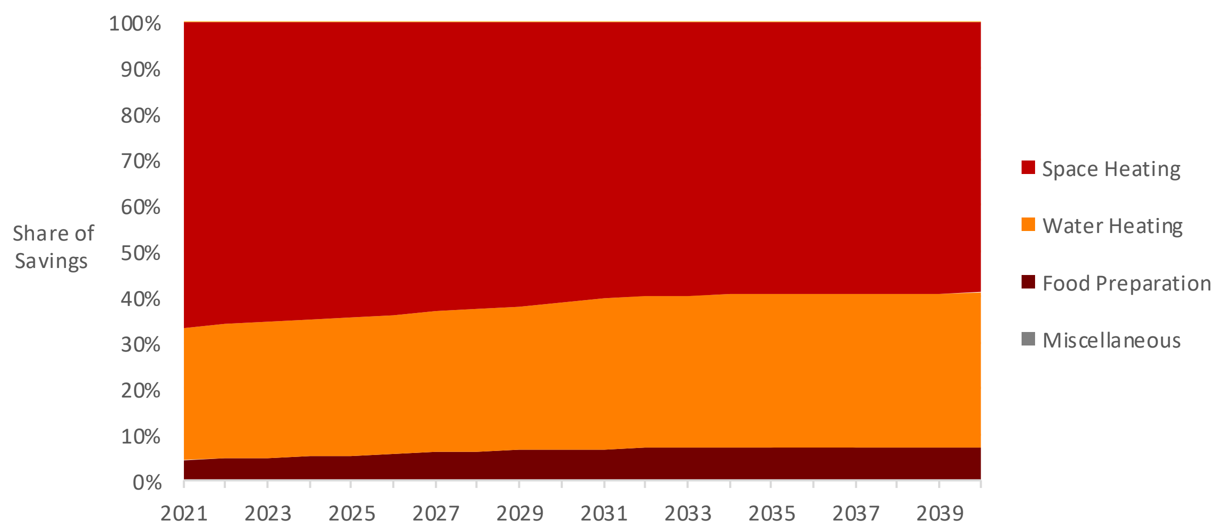


Table 6-6 identifies the top 20 commercial measures by cumulative savings in 2021 and 2022. Heat Pump Water Heaters are the top measure, followed by several HVAC and space heating measures, along with insulation.

Table 6-6 Commercial Top Measures in 2021 and 2022, UCT Achievable Economic Potential, Washington (dekatherms)

Rank	Measure / Technology	2018 Cumulative Potential Savings (dekatherms)	% of Total	2019 Cumulative Potential Savings (dekatherms)	% of Total
1	Water Heater - Gas-Fired Absorption HPWH	5,714	20%	15,883	24%
2	Space Heating - Heat Recovery Ventilator - HRV installed	4,763	17%	9,542	14%
3	Boiler - AFUE 97%	4,136	15%	10,378	16%
4	HVAC - Duct Repair and Sealing - 30% reduced duct leaking	2,323	8%	4,589	7%
5	Insulation - Wall Cavity - R-21	2,059	7%	5,578	8%
6	Insulation - Roof/Ceiling - R-38	1,584	6%	4,318	6%
7	Gas Boiler - Insulate Steam Lines/Condensate Tank - Lines and condenstate tank insulated	1,456	5%	2,871	4%
8	Water Heater - Central Controls - Central water boiler controls installed	1,267	5%	2,508	4%
9	Gas Boiler - Hot Water Reset - Reset control installed	1,127	4%	2,476	4%
10	Gas Boiler - High Turndown - Turndown control installed	766	3%	1,509	2%
11	Fryer - ENERGY STAR	751	3%	1,800	3%
12	Water Heater - Faucet Aerator - 1.5 GPM faucet	362	1%	791	1%
13	Building Automation System - Automation system installed and programmed	360	1%	1,059	2%
14	Kitchen Hood - DCV/MUA - DCV/HUA vent hood	316	1%	629	1%
15	HVAC - Demand Controlled Ventilation - DCV enabled	227	1%	539	1%
16	Furnace - AFUE 96%	129	0%	426	1%
17	Gas Furnace - Maintenance - General cleaning and maintenance	125	0%	211	0%
18	Double Rack Oven - FTSC Qualified (>50% Cooking Efficiency)	96	0%	257	0%
19	Steam Trap Maintenance - Cleaning and maintenance	78	0%	153	0%
20	Oven - ENERGY STAR (>42% Baking Efficiency)	74	0%	196	0%
Subtotal		**27,713**	**99%**	**65,714**	**99%**
Total Savings in Year		**28,070**	**100%**	**66,690**	**100%**

Idaho Potential

Table 6-7 and Figure 6-7 summarize the energy conservation potential for the commercial sector. In 2021, UCT achievable economic potential is 16,775 dekatherms, or 0.4% of the baseline projection. By 2040, cumulative savings are 751,926 dekatherms, or 17.9% of the baseline.

Table 6-7 Commercial Energy Conservation Potential Summary, Idaho

Scenario	2021	2022	2025	2030	2040
Baseline Forecast (dekatherms)	4,027,575	4,047,905	4,093,096	4,112,209	4,199,550
Cumulative Savings (dekatherms)					
UCT Achievable Economic Potential	16,775	40,676	144,201	384,730	751,926
TRC Achievable Economic Potential	11,301	28,926	109,041	295,643	606,619
Achievable Technical Potential	29,482	66,801	216,357	539,726	1,037,584
Technical Potential	81,719	172,678	463,550	952,082	1,503,965
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.4%	1.0%	3.5%	9.4%	17.9%
TRC Achievable Economic Potential	0.3%	0.7%	2.7%	7.2%	14.4%
Achievable Technical Potential	0.7%	1.7%	5.3%	13.1%	24.7%
Technical Potential	2.0%	4.3%	11.3%	23.2%	35.8%

Figure 6-7 Commercial Energy Conservation by Case, Idaho (dekatherms)

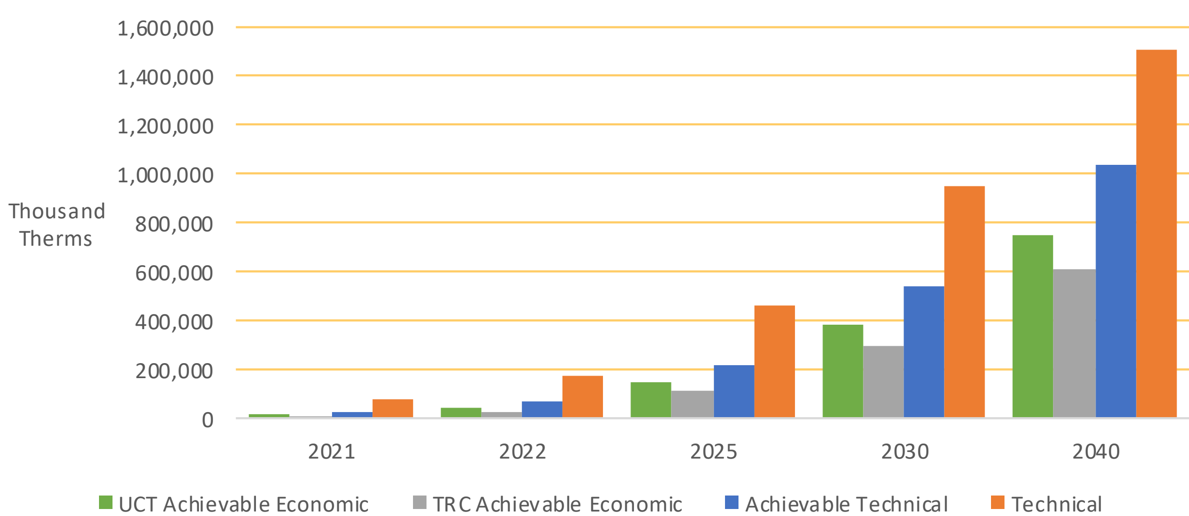


Figure 6-8 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings. Space heating makes up a majority of the potential early, but food preparation equipment upgrades provide substantial savings opportunities in the later years.

Figure 6-8 Commercial UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho (dekatherms, % of total)

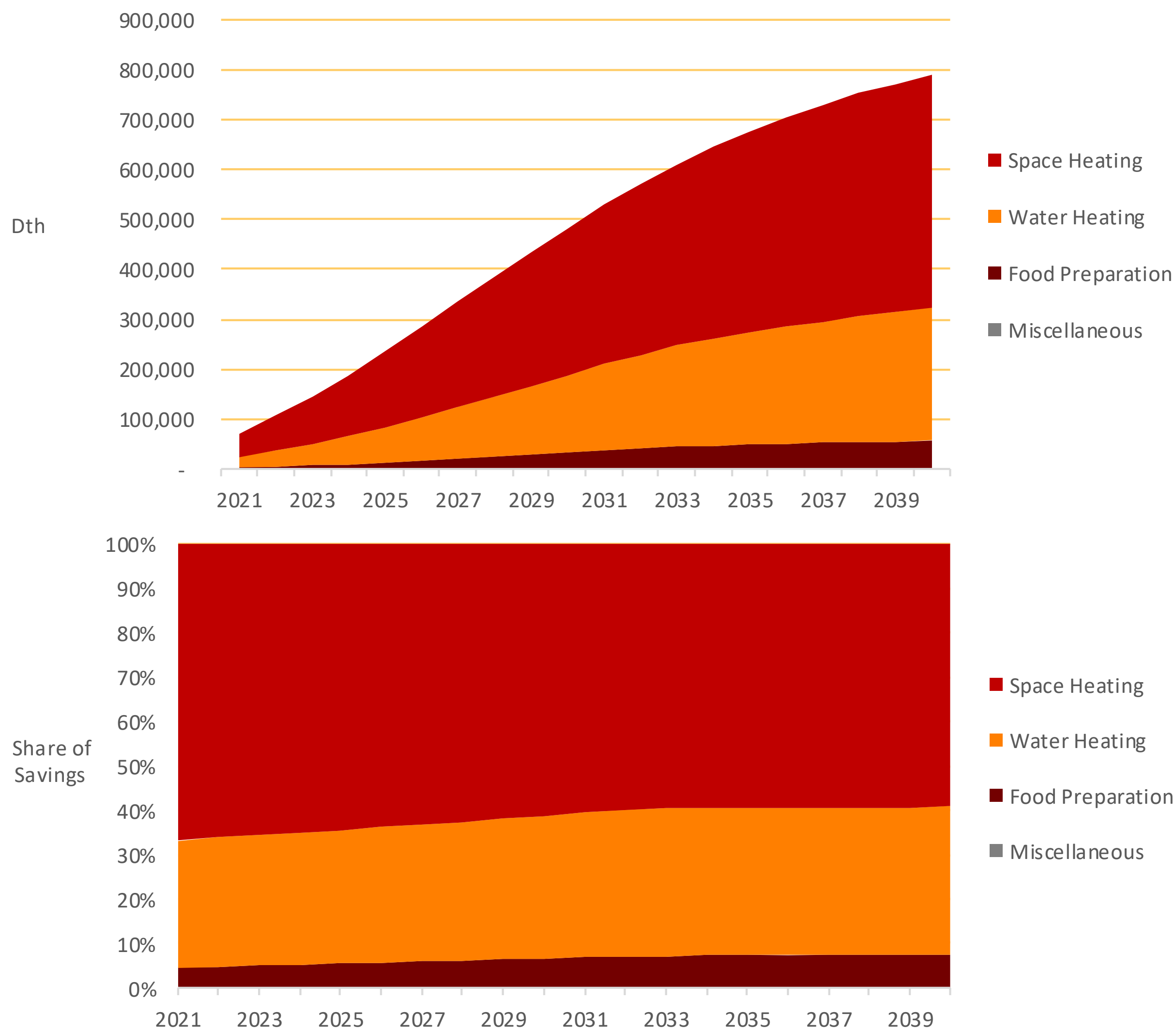


Table 6-8 identifies the top 20 commercial measures by cumulative savings in 2021 and 2022. Water Heaters are the top measure, followed by custom HVAC measures and insulation.

Table 6-8 Commercial Top Measures in 2021 and 2022, UCT Achievable Economic Potential, Idaho (dekatherms)

Rank	Measure / Technology	2021 Cumulative Potential Savings (dekatherms)	% of Total	2022 Cumulative Potential Savings (dekatherms)	% of Total
1	Water Heater - Gas-Fired Absorption HPWH	3,140	19%	9,188	23%
2	Space Heating - Heat Recovery Ventilator - HRV installed	2,806	17%	5,620	14%
3	Boiler - AFUE 97%	2,507	15%	6,733	17%
4	HVAC - Duct Repair and Sealing - 30% reduced duct leaking	1,454	9%	2,872	7%
5	Insulation - Wall Cavity - R-21	1,279	8%	3,464	9%
6	Gas Boiler - Insulate Steam Lines/Condensate Tank - Lines and condenstate tank insulated	1,062	6%	2,094	5%
7	Insulation - Roof/Ceiling - R-38	924	6%	2,506	6%
8	Gas Boiler - Hot Water Reset - Reset control installed	695	4%	1,526	4%
9	Water Heater - Central Controls - Central water boiler controls installed	634	4%	1,258	3%
10	Gas Boiler - High Turndown - Turndown control installed	465	3%	915	2%
11	Fryer - ENERGY STAR	458	3%	1,145	3%
12	Building Automation System - Automation system installed and programmed	230	1%	676	2%
13	Water Heater - Faucet Aerator - 1.5 GPM faucet	218	1%	477	1%
14	Kitchen Hood - DCV/MUA - DCV/HUA vent hood	214	1%	426	1%
15	HVAC - Demand Controlled Ventilation - DCV enabled	142	1%	334	1%
16	Furnace - AFUE 96%	89	1%	304	1%
17	Gas Furnace - Maintenance - General cleaning and maintenance	78	0%	132	0%
18	Double Rack Oven - FTSC Qualified (>50% Cooking Efficiency)	67	0%	186	0%
19	Steam Trap Maintenance - Cleaning and maintenance	55	0%	109	0%
20	Oven - ENERGY STAR (>42% Baking Efficiency)	52	0%	141	0%
Subtotal		**16,567**	**99%**	**40,107**	**99%**
Total Savings in Year		**16,775**	**100%**	**40,676**	**100%**

Industrial Sector

Washington Potential

Table 6-9 and Figure 6-9 summarize the energy conservation potential for the core industrial sector. In 2021, UCT achievable economic potential is 2,206 dekatherms, or 0.6% of the baseline projection. By 2040, cumulative savings reach 24,876 dekatherms, or 8.5% 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. As seen in the figure below, industrial potential is substantially lower due to the smaller sector size and process uses.

Table 6-9 Industrial Energy Conservation Potential Summary, Washington (dekatherms)

Scenario	2021	2022	2025	2030	2040
Baseline Forecast (dekatherms)	341,870	338,961	331,037	317,863	291,665
Cumulative Savings (dekatherms)					
UCT Achievable Economic Potential	2,206	4,424	11,200	19,428	24,876
TRC Achievable Economic Potential	321	669	1,899	4,508	7,639
Achievable Technical Potential	2,616	5,219	13,165	23,081	29,280
Technical Potential	3,226	6,425	16,116	28,082	35,546
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.6%	1.3%	3.4%	6.1%	8.5%
TRC Achievable Economic Potential	0.1%	0.2%	0.6%	1.4%	2.6%
Achievable Technical Potential	0.8%	1.5%	4.0%	7.3%	10.0%
Technical Potential	0.9%	1.9%	4.9%	8.8%	12.2%

Figure 6-9 Industrial Energy Conservation Potential, Washington (dekatherms)

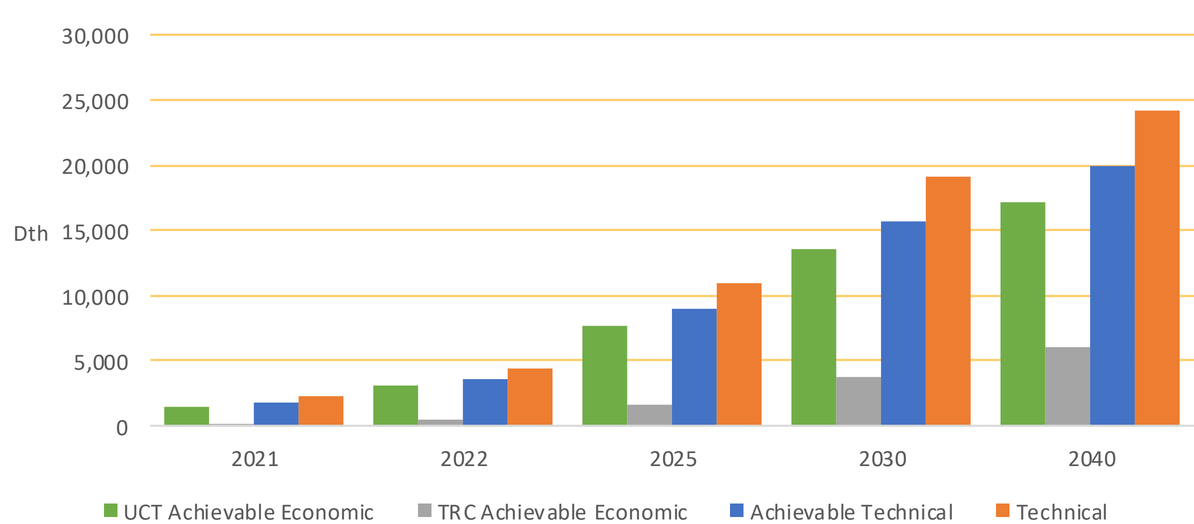
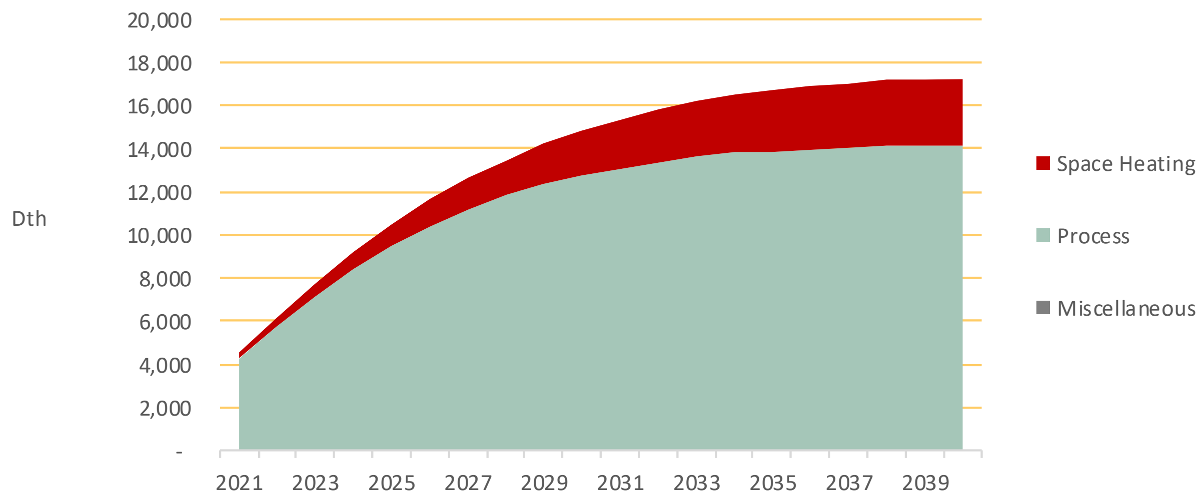


Figure 6-10 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings.

Figure 6-10 Industrial UCT Achievable Economic Potential – Cumulative Savings by End Use, Washington (dekatherms, % of total)



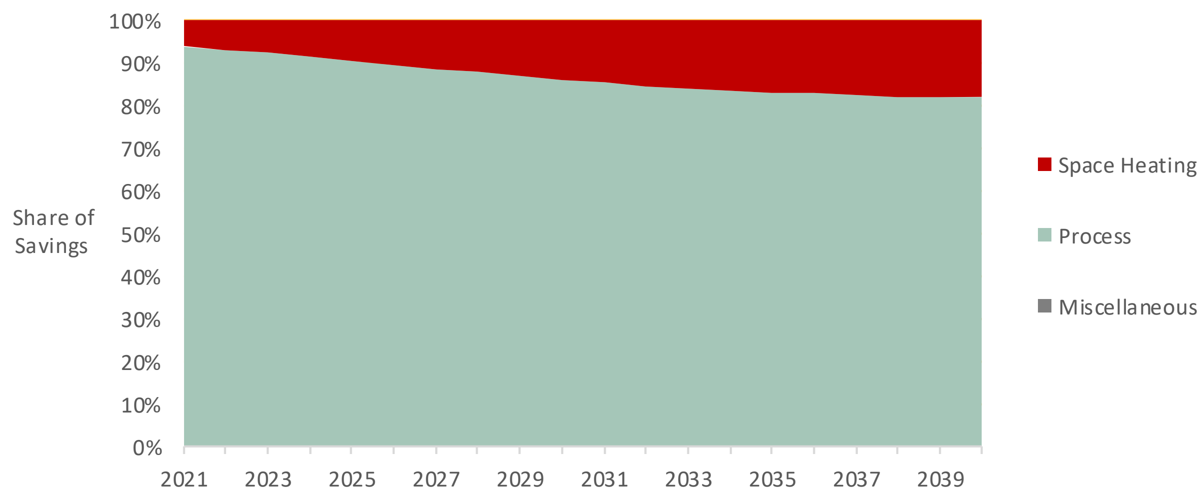


Table 6-10 identifies the top 20 industrial measures by cumulative 2021 and 2022 savings. Process Heat Recovery and Retrocommissioning optimization measures have the largest potential savings. Process Heat Recovery alone accounts for more than 70% of 2021-2022 industrial potential in Washington.

Table 6-10 Industrial Top Measures in 2021 and 2022, UCT Achievable Economic Potential, Washington (dekatherms)

Rank	Measure / Technology	2021 Cumulative Potential Savings (dekatherms)	% of Total	2022 Cumulative Potential Savings (dekatherms)	% of Total
1	Process Heat Recovery - HR system installed	1,691	72%	3,366	71%
2	Retrocommissioning - Optimized HVAC flow and controls	156	7%	306	6%
3	Retrocommissioning - Optimized process design and controls	156	7%	306	6%
4	Gas Boiler - High Turndown - Turndown control installed	112	5%	222	5%
5	Gas Boiler - Hot Water Reset - Reset control installed	111	5%	244	5%
6	Destratification Fans (HVLS) - Fans installed	40	2%	79	2%
7	Gas Boiler - Insulate Steam Lines/Condensate Tank - Lines and condenstate tank insulated	28	1%	55	1%
8	Gas Boiler - Insulate Hot Water Lines - Insulated water lines	19	1%	37	1%
9	ENERGY STAR Connected Thermostat - Wi-Fi/interactive thermostat installed	17	1%	34	1%
10	Space Heating - Heat Recovery Ventilator - HRV installed	15	1%	30	1%
11	Boiler - AFUE 97%	5	0%	14	0%
12	Insulation - Wall Cavity - R-21	4	0%	10	0%
13	Furnace - AFUE 96%	3	0%	10	0%
14	Gas Furnace - Maintenance - General cleaning and maintenance	2	0%	4	0%
15	Thermostat - Programmable - Programmable thermostat installed	2	0%	4	0%
16	Steam Trap Maintenance - Cleaning and maintenance	1	0%	1	0%
17	Unit Heater - Infrared Radiant	0	0%	1	0%
18	Insulation - Roof/Ceiling - R-38	0	0%	0	0%
Subtotal		**2,362**	**100%**	**4,725**	**100%**
Total Savings in Year		**2,362**	**100%**	**4,730**	**100%**

Idaho Potential

Table 6-11 and Figure 6-11 summarize the energy conservation potential for the core industrial sector. In 2021, UCT achievable economic potential is 1,512 dekatherms, or 0.6% of the baseline projection. By 2040, cumulative savings reach 19,908 dekatherms, or 10.3% 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. As seen in the figure below, industrial potential is substantially lower due to the smaller sector size and process uses.

Table 6-11 Industrial Energy Conservation Potential Summary, Idaho (dekatherms)

Scenario	2021	2022	2025	2030	2040
Baseline Forecast (dekatherms)	234,049	232,058	225,549	214,701	193,107
Cumulative Savings (dekatherms)					
UCT Achievable Economic Potential	1,512	3,030	7,703	13,477	17,202
TRC Achievable Economic Potential	220	463	1,557	3,767	6,036
Achievable Technical Potential	1,791	3,573	8,996	15,731	19,908
Technical Potential	2,209	4,398	11,000	19,113	24,123
Energy Savings (% of Baseline)					
UCT Achievable Economic Potential	0.6%	1.3%	3.4%	6.3%	8.9%
TRC Achievable Economic Potential	0.1%	0.2%	0.7%	1.8%	3.1%
Achievable Technical Potential	0.8%	1.5%	4.0%	7.3%	10.3%
Technical Potential	0.9%	1.9%	4.9%	8.9%	12.5%

Figure 6-11 Industrial Energy Conservation Potential, Idaho (dekatherms)

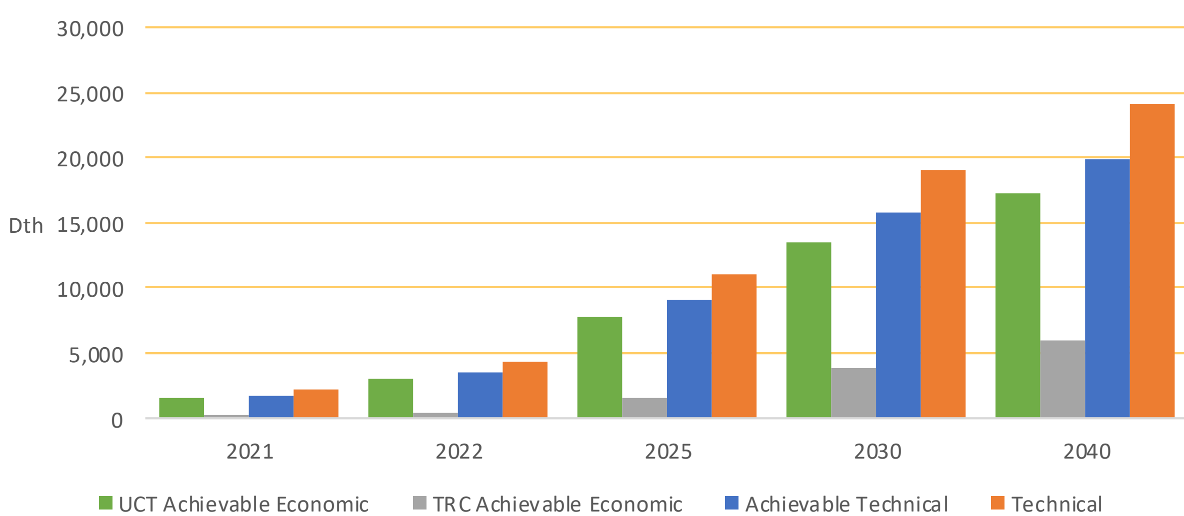
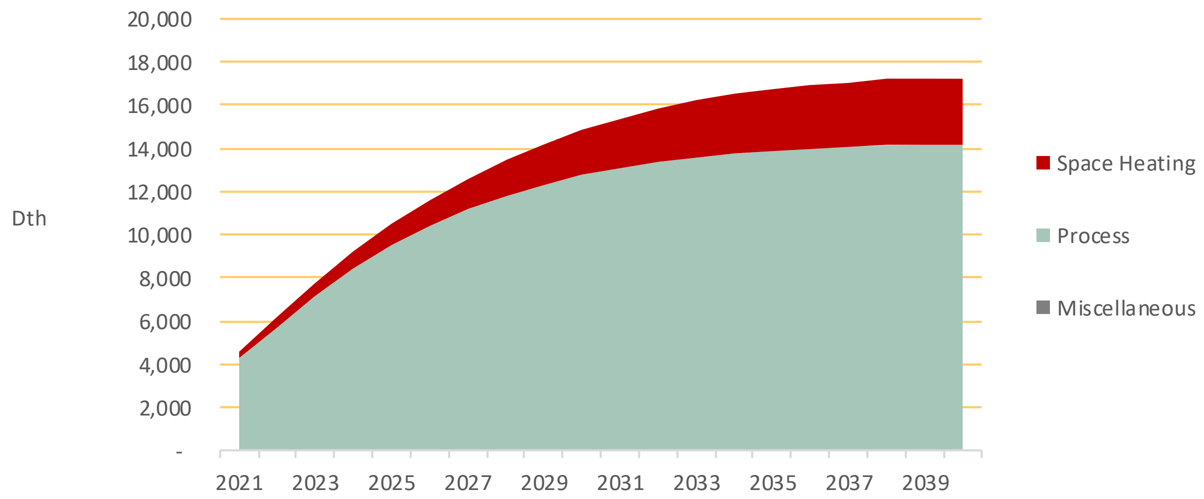


Figure 6-12 presents forecasts of energy savings by end use as a percent of total annual savings and cumulative savings.

Figure 6-12 Industrial UCT Achievable Economic Potential – Cumulative Savings by End Use, Idaho (dekatherms, % of total)



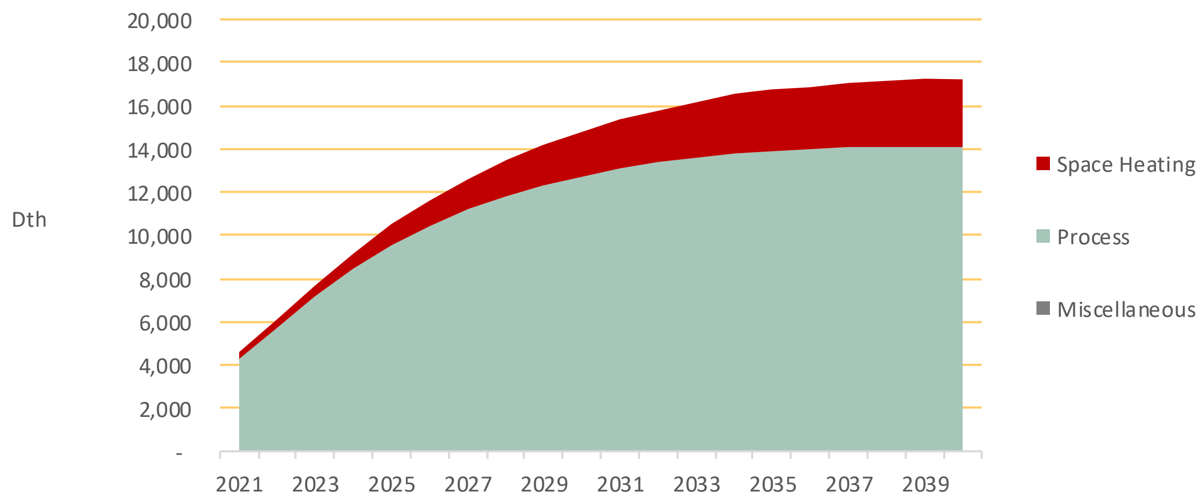


Table 6-12 identifies the top 20 industrial measures by cumulative 2021 and 2022 savings. Much like Washington, Process Heat Recovery is the largest measure by far, accounting for more than 70% of total industrial potential in Idaho.

Table 6-12 Industrial Top Measures in 2018 and 2019, UCT Achievable Economic Potential, Idaho (dekatherms)

Rank	Measure / Technology	2021 Cumulative Potential Savings (dekatherms)	% of Total	2022 Cumulative Potential Savings (dekatherms)	% of Total
1	Process Heat Recovery - HR system installed	1,158	72%	2,304	71%
2	Retrocommissioning - Optimized HVAC flow and controls	107	7%	210	6%
3	Retrocommissioning - Optimized process design and controls	107	7%	210	6%
4	Gas Boiler - High Turndown - Turndown control installed	77	5%	152	5%
5	Gas Boiler - Hot Water Reset - Reset control installed	76	5%	167	5%
6	Destratification Fans (HVLS) - Fans installed	27	2%	54	2%
7	Gas Boiler - Insulate Steam Lines/Condensate Tank - Lines and condenstate tank insulated	19	1%	38	1%
8	Gas Boiler - Insulate Hot Water Lines - Insulated water lines	13	1%	25	1%
9	ENERGY STAR Connected Thermostat - Wi-Fi/interactive thermostat installed	12	1%	23	1%
10	Space Heating - Heat Recovery Ventilator - HRV installed	10	1%	21	1%
11	Boiler - AFUE 97%	3	0%	10	0%
12	Insulation - Wall Cavity - R-21	3	0%	7	0%
13	Furnace - AFUE 96%	2	0%	7	0%
14	Building Automation System - Automation system installed and programmed	2	0%	5	0%
15	Gas Furnace - Maintenance - General cleaning and maintenance	2	0%	3	0%
16	Thermostat - Programmable - Programmable thermostat installed	1	0%	3	0%
17	Steam Trap Maintenance - Cleaning and maintenance	1	0%	1	0%
18	Unit Heater - Infrared Radiant	0	0%	1	0%
Subtotal		**1,619**	**100%**	**3,240**	**100%**
Total Savings in Year		**1,619**	**100%**	**3,240**	**100%**

Incorporating the Total Resource Cost Test

In addition to the UCT, LoadMAP has been configured to evaluate potential using the TRC. This test focuses on impacts for both the utility and customer, which is an alternative frame of reference from the UCT. The TRC includes the full measure cost (incremental for lost opportunities, full cost for retrofits), which is generally substantially higher than the incentive cost included within the UCT. The TRC does include one additional value stream that the UCT does not, non-energy impacts. This test is fully incorporated into LoadMAP and prepared for Avista to use in the event the Company feels a "fully balanced" TRC is identified.

In accordance with Council methodology, these impacts must be quantified and monetized, meaning impacts such as personal comfort, which are difficult to assign a value to, are not included. What this does include are additional savings including water reductions due to low-flow measures or reduced detergent requirements to wash clothes in a high-efficiency clothes washer. AEG has incorporated these impacts as they are available in source documentation, such as RTF UES workbooks.

Some impacts are already included within Avista's avoided costs. These include the 10% conservation credit applied by the Council for infrastructure benefits of efficiency. The future prices of carbon are also included. Per TRC methodology, as these impacts are already captured within the avoided costs provided to AEG, we did not incorporate them a second time outside the costs.

Another set of impacts captured within Council methodology include the Simplified Energy Enthalpy Model (SEEM) "calibration credits". The Council calibrates this energy model using metered end-use energy consumption to reflect actual conditions. While these are technically energy impacts, they are not captured as a benefit to a natural-gas utility as they are instead an impact on the customer. The Council then assumes the difference between the uncalibrated and calibrated models represents the impacts of secondary heating by different fuels present in the home. In the Council's case, these could be small gas heaters or wood stoves present alongside an electric forced-air furnace. For Avista, AEG followed a similar methodology, but instead applied the calibration percent impact to estimated gas-heating savings rather than electric. To monetize these impacts, we incorporated the latest Mid C energy prices, including carbon impacts, from the RTF's website, adjusted for differences in efficiency between electric and natural gas heating equipment (e.g. converted therm savings from an AFUE 80% baseline to kWh savings from an EF 0.97 resistance heater baseline). We applied these impacts to many non-equipment measures with space heating impacts in all sectors as well as to residential space heating equipment, which was the primary use for the Council.

Finally, AEG identified additional non-gas end uses which may be impacted by gas efficiency measures. These include impacts from other end uses, such as cooling savings due to efficient shell measures or lighting savings due to a comprehensive retrocommissioning or strategic energy management program. Like the calibration credit above, these do not have a benefit to a natural-gas utility but do to the customer. It is worth a note of caution when incorporating these impacts. Certain comprehensive building measures, such as retrocommissioning and strategic energy management have very large electric impacts that may be greater than the original estimated gas impacts. LED lighting is a very popular technology within electric utility-programs and can have massive impacts. Commercial HVAC retrocommissioning (RCx) includes both cooling and ventilation electric impacts, which could outweigh the gas space heating impacts. To realize these cost-effective savings, Avista would need to offer a comprehensive RCx program affecting both electric and natural gas end uses.

7

COMPARISON WITH CURRENT PROGRAMS

One of the goals of this study is to inform targets for future programs. As such, AEG conducted an in-depth comparison of the CPA's 2021 UCT Achievable Economic Potential with Avista's 2019 accomplishments at the sector-level. This involved assigning each measure within the CPA to an existing Avista program.

Washington Comparison with 2019 Programs

Residential Sector

Table 7-1 summarizes Avista's 2019 residential accomplishments and the 2021 UCT Achievable Economic potential estimates from LoadMAP. The LoadMAP estimate of 32,164 dekatherms is lower than Avista's 2019 accomplishments at 49,161 dekatherms.

Table 7-1 Comparison of Avista's Washington Residential Programs with 2018 UCT Achievable Economic Potential (dekatherms)

Program Group	2019 Accomplishments (dekatherms)	LoadMAP 2021 UCT (dekatherms)
Furnace	31,172	21,548
Boiler	433	51
Water Heater	3,303	1,901
ENERGY STAR Homes	67	47
Smart Thermostat	3,822	4,435
Ceiling Insulation	3,762	3,611
Wall Insulation	447	333
Floor Insulation	342	0
Doors	93	0
Windows	5,556	0
Air Sealing	134	163
Duct Insulation	10	0
Duct Sealing	21	0
Showerheads	0	75
Miscellaneous	1	0
Program Total	**49,161**	**32,164**

The main reason that potential is lower is that the baseline assumed for forced-air furnaces is adjusted in the following ways.

- The 2015 Washington State Energy Code (WSEC) prescribes very efficient building shell requirements, which substantially reduces the consumption of a new home. Since every new home requires a lost opportunity purchasing decision when constructed, they make up a large portion of the potential. The lower unit energy savings in new homes due to lower heating requirements reduces the unit energy savings (UES) from this measure.
- Another reason is the incorporation of a market baseline, which assumes not everyone purchases the minimum federal standard in the absence of efficiency programs. This results in approximately 20% of customers purchasing an AFUE 90% and 5% purchasing an AFUE 92% in the baseline, which reduces the average unit energy consumption upon which savings for an AFUE 95% are based,

Additional descriptions for other measure differences are provided below:

- Potential for ENERGY STAR Homes has been reduced due to WSEC 2015. The efficient shell requirements lower space heating savings from the prior estimate, which was made before this code went into effect.
- The most recently updated savings and cost characterizations for water heater and windows are reducing their cost effectiveness in some or all segments.

Commercial and Industrial Sectors

Table 7-2 summarizes Avista's 2019 commercial and industrial accomplishments and the 2021 UCT Achievable Economic potential estimates from LoadMAP. The LoadMAP estimate of 22,537 dekatherms is much higher than Avista's 2019 accomplishments at 7,902 dekatherms.

Table 7-2 Comparison of Avista's Washington Nonresidential Accomplishments with 2021 UCT Achievable Economic Potential (dekatherms)

Program Group	2019 Accomplishments (dekatherms)	LoadMAP 2021 UCT (dekatherms)
HVAC	1,786	11,683
Weatherization	0	3,711
Food Preparation	3,547	1,044
Custom	2,569	6,099
Program Total	**7,902**	**22,537**

The following are key drivers in commercial potential:

- The HVAC category includes both efficient equipment (e.g. boilers) as well as custom HVAC measures.
- Fryer and convection oven potential is substantial due to the high gas consumption of restaurants and Avista's current success with this program. This measure was heavily accelerated in LoadMAP.

Idaho Comparison with 2019 Programs

Residential Sector

Table 7-3 summarizes Avista's 2019 residential accomplishments and the 2021 UCT Achievable Economic potential estimates from LoadMAP. The LoadMAP estimate of 17,117 dekatherms is lower than Avista's 2019 accomplishments at 23,667 dekatherms.

Table 7-3 Comparison of Avista's Idaho Residential Programs with 2021 UCT Achievable Economic Potential (dekatherms)

Program Group	2019 Accomplishments (dekatherms)	LoadMAP 2021 UCT (dekatherms)
Furnace	17,308	14,054
Boiler	247	0
Water Heater	1,735	1,053
ENERGY STAR Homes	40	32
Smart Thermostat	1,931	0
Ceiling Insulation	722	1,643
Wall Insulation	55	142
Floor Insulation	21	0
Doors	4	0
Windows	1,579	0
Air Sealing	21	79
Duct Insulation	1	0
Duct Sealing	2	0
Showerheads	-	114
Miscellaneous	-	0
Program Total	**23,667**	**17,117**

Cost effective measures in LoadMAP show similar potential to Avista's programs, however some measures, such as Smart Thermostats and HE Windows, are not showing as cost effective in 2021 forward in LoadMAP. This is offset somewhat by the fact that, in contrast to Washington, Idaho's energy code does not cannibalize a large portion of the HVAC-related savings, resulting in a much steadier range of potential.

Commercial and Industrial Sectors

Table 7-4 summarizes Avista's 2019 commercial and industrial accomplishments and the 2021 UCT Achievable Economic potential estimates from LoadMAP. The LoadMAP estimate of 14,023 dekatherms is substantially higher than Avista's 2017 accomplishments at 3,024 dekatherms.

Table 7-4 Comparison of Avista's Idaho Nonresidential Accomplishments with 2021 UCT Achievable Economic Potential (dekatherms)

Program Group	2019 Accomplishments (dekatherms)	LoadMAP 2021 UCT (dekatherms)
HVAC	1,337	7,068
Weatherization	0	2,241
Food Preparation	1,273	638
Custom	414	4,075
Program Total	**3,024**	**14,023**

Similar to Washington, many custom HVAC measures were included within the HVAC category to reflect actual accomplishments.

8

COMPARISON WITH PREVIOUS STUDY

Residential Comparison with 2018 CPA

Table 8-1 compares first-year residential potential between Avista's 2018 and 2020 Natural Gas CPAs conducted by AEG. For both states, first year savings are marginally lower (for program categories).

Table 8-1 Comparison of Avista's Residential UCT Achievable Economic Potential between the 2016 and 2018 CPAs (dekatherms)

Program Group	Washington		Idaho	
	2018	2020	2018	2020
Furnace	19,091	21,548	11,816	14,054
Boiler	619	51	307	0
Water Heater	4,257	1,901	2,014	1,053
ENERGY STAR Homes	294	47	146	32
Smart Thermostat	1,344	4,435	664	0
Ceiling Insulation	1,072	3,611	534	1,643
Wall Insulation	904	333	452	142
Floor Insulation	1,135	0	774	0
Doors	0	0	0	0
Windows	9,426	0	820	0
Air Sealing	0	163	0	79
Duct Insulation	367	0	181	0
Duct Sealing	0	0	0	0
Showerheads	575	75	286	114
Miscellaneous	893	0	362	0
CPA Total	**39,979**	**32,164**	**18,354**	**17,117**

The slight decrease in potential is due to a few factors:

- Baseline efficiency has been improving
- Some measures are no longer cost effective as a result of updates to characterization of costs and savings

Nonresidential Comparison with 2018 CPA

Table 8-2 compares first-year nonresidential potential between Avista's 2018 and 2020 Natural Gas CPAs conducted by AEG. In Washington, the potential is similar, while it is higher in Idaho.

Table 8-2 Comparison of Avista's Nonresidential UCT Achievable Economic Potential between the 2016 and 2018 CPAs (dekatherms)

Program Group	Washington		Idaho	
	2018	2018	2017	2018
HVAC	11,925	11,683	3,769	7,068
Weatherization	1,694	3,711	941	2,241
Food Preparation	2,761	1,044	1,045	638
Custom	4,082	6,099	2,033	4,075
CPA Total	**21,300**	**22,537**	**7,986**	**14,023**

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 (2020$)

Case	Pollutant	Unit	2025	2030	2035	2040
Expected Carbon Case	NOx – Annual	$/short ton	$ 2.00	$ 2.00	$ 2.00	$ 2.00
		$/lb	$ 0.001	$ 0.001	$ 0.001	$ 0.001
		lbs/therm	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	NOx – Seasonal	$/short ton	$ 290	$ 290	$ 290	$ 290
		$/lb	$ 0.145	$ 0.145	$ 0.145	$ 0.145
		lbs/therm	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/Metric Ton	$ 20.91	$ 36.86	$ 63.37	$ 97.90
		$/lb	$ 0.009	$ 0.017	$ 0.029	$ 0.044
		lbs/therm	12.827	12.827	12.827	12.827
		CO2 Adder $/therm	$ 0.12	$ 0.21	$ 0.37	$ 0.57

Case	Pollutant	Unit	2025	2030	2035	2040
High Carbon Case	NOx – Annual	$/short ton	$ 2.00	$ 2.00	$ 2.00	$ 2.00
		$/lb	$ 0.001	$ 0.001	$ 0.001	$ 0.001
		lbs/therm	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	NOx – Seasonal	$/short ton	$ 290	$ 290	$ 290	$ 290
		$/lb	$ 0.145	$ 0.145	$ 0.145	$ 0.145
		lbs/therm	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/Metric Ton	$ 187.44	$ 229.15	$ 281.11	$ 339.87
		$/lb	$ 0.085	$ 0.104	$ 0.128	$ 0.154
		lbs/therm	12.827	12.827	12.827	12.827
		CO2 Adder $/therm	$ 1.09	$ 1.33	$ 1.64	$ 1.98

			2025	2030	2035	2040
Low Carbon Low NOx	NOx – Annual	$/short ton	$ 2.00	$ 2.00	$ 2.00	$ 2.00
		$/lb	$ 0.001	$ 0.001	$ 0.001	$ 0.001
		lbs/therm	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.00	$ 0.00	$ 0.00	$ 0.00
	NOx – Seasonal	$/short ton	$ 290	$ 290	$ 290	$ 290
		$/lb	$ 0.145	$ 0.145	$ 0.145	$ 0.145
		lbs/therm	0.066	0.066	0.066	0.066
		NOx Adder $/therm	$ 0.01	$ 0.01	$ 0.01	$ 0.01
	CO2	$/Metric Ton	$ -	$ -	$ -	$ -
		$/lb	$ -	$ -	$ -	$ -
		lbs/therm	12.827	12.827	12.827	12.827
		CO2 Adder $/therm	$ -	$ -	$ -	$ -

APPENDIX 4.1: CURRENT TRANSPORTATION/STORAGE RATES AND ASSUMPTIONS

Current Tariff Rates (1)

	Reservation	Commodity	Fuel Rate
TransCanada NGTL System Firm Rates (2)			
FT-D Demand Rate Alberta-B.C. Border	$4.79CAD/GJ/month	N/A	N/A
TransCanada Foothills BC System Firm Rates (3)			
FT A/BC to Kingsgate	$1.777CAD/GJ/month	N/A	2.10%
GTN FTS-1 Rates			
Mileage Based - Representative Example			
Kingsgate to Spokane	$0.067812/Dth/day	$0.001733/Dth/day	0.0046% per Dth/mile
Kingsgate to Malin	$0.250322/Dth/day	$0.009799/Dth/day	0.0046% per Dth/mile
Medford Lateral	$0.222544/Dth/day	$0.002291/Dth/day	N/A
Spectra Energy/Westcoast System Firm Rates (4)			
Postage Stamp Rates			
Station 2 to Huntingdon/Sumas	$613.3CAD/103/m3/month	N/A	N/A
Williams NWP			
Postage Stamp Rates			
TF-1	$0.39033/Dth/day	$0.00832/Dth/day	0.88%
TF-2	$0.39033/Dth/day	$0.00832/Dth/day	0.88%
SGS-2F	$0.01562/Dth/day	$0.00057/Dth/day	0.88%

(1) Rates and Fuel reported are from current tariffed rates in the established currency and energy units of each pipeline
(2) Rate does not reflect current term-differentiation or Abandonment Surcharge
(3) Rate does not include Abandonment Surcharge
(4) Rate changes annually

APPENDIX 5: 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	$/$TonCO_2e$	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 5.2: 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 5.3: 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	$TonsCO_2e/Dth$	Greenhouse gas intensity of resource being considered	Yes	Input	No
G	$TonsCo_2e$	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	$TonsCo_2e$	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 6.1: Monthly Price Data by Basin

Expected Price

			Nominal $											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Prices	AECO	2019-2020	$2.13	$1.84	$1.77	$1.41	$1.23	$1.01	$1.12	$0.88	$0.85	$1.08	$0.97	$1.00
Expected Prices	AECO	2020-2021	$1.77	$2.32	$2.40	$2.29	$1.98	$1.47	$1.37	$1.42	$1.55	$1.54	$1.39	$1.42
Expected Prices	AECO	2021-2022	$1.76	$2.04	$2.15	$2.01	$1.70	$1.08	$1.06	$1.16	$1.31	$1.26	$1.08	$1.08
Expected Prices	AECO	2022-2023	$1.35	$1.85	$1.96	$1.76	$1.50	$1.04	$1.01	$1.18	$1.23	$1.24	$0.97	$1.05
Expected Prices	AECO	2023-2024	$1.56	$1.81	$2.02	$1.72	$1.65	$1.35	$1.34	$1.35	$1.33	$1.33	$1.41	$1.42
Expected Prices	AECO	2024-2025	$1.56	$1.80	$2.07	$1.95	$1.83	$1.65	$1.73	$1.66	$1.66	$1.66	$1.75	$1.75
Expected Prices	AECO	2025-2026	$1.97	$2.13	$2.45	$2.39	$2.25	$2.06	$2.08	$2.06	$2.05	$2.06	$2.10	$2.16
Expected Prices	AECO	2026-2027	$2.39	$2.51	$2.64	$2.53	$2.39	$2.20	$2.26	$2.21	$2.20	$2.22	$2.27	$2.26
Expected Prices	AECO	2027-2028	$2.57	$2.73	$2.79	$2.69	$2.57	$2.28	$2.38	$2.36	$2.36	$2.38	$2.43	$2.52
Expected Prices	AECO	2028-2029	$2.79	$2.84	$2.96	$2.82	$2.67	$2.47	$2.53	$2.52	$2.50	$2.51	$2.56	$2.60
Expected Prices	AECO	2029-2030	$2.90	$3.03	$3.06	$2.94	$2.81	$2.58	$2.61	$2.58	$2.53	$2.56	$2.62	$2.75
Expected Prices	AECO	2030-2031	$3.04	$3.18	$3.19	$3.09	$2.93	$2.72	$2.74	$2.71	$2.67	$2.67	$2.77	$2.82
Expected Prices	AECO	2031-2032	$3.17	$3.27	$3.28	$3.16	$3.00	$2.83	$2.82	$2.77	$2.60	$2.62	$2.81	$2.93
Expected Prices	AECO	2032-2033	$3.32	$3.42	$3.50	$3.44	$3.29	$3.10	$3.08	$3.08	$2.96	$2.98	$3.11	$3.19
Expected Prices	AECO	2033-2034	$3.60	$3.66	$3.71	$3.59	$3.45	$3.25	$3.25	$3.22	$3.16	$3.18	$3.28	$3.39
Expected Prices	AECO	2034-2035	$3.74	$3.85	$3.86	$3.72	$3.52	$3.37	$3.37	$3.32	$3.18	$3.23	$3.36	$3.44
Expected Prices	AECO	2035-2036	$3.84	$4.01	$4.04	$3.97	$3.78	$3.55	$3.55	$3.53	$3.32	$3.35	$3.50	$3.65
Expected Prices	AECO	2036-2037	$4.06	$4.19	$4.24	$4.02	$3.86	$3.59	$3.72	$3.70	$3.57	$3.67	$3.76	$3.90
Expected Prices	AECO	2037-2038	$4.35	$4.51	$4.54	$4.26	$4.00	$3.79	$3.83	$3.83	$3.67	$3.70	$3.80	$3.92
Expected Prices	AECO	2038-2039	$4.37	$4.57	$4.64	$4.42	$4.28	$4.04	$4.08	$3.99	$3.86	$3.86	$4.04	$4.15
Expected Prices	AECO	2039-2040	$4.64	$4.80	$4.82	$4.59	$4.42	$4.20	$4.23	$4.20	$4.09	$4.13	$4.26	$4.37

			Nominal $											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Prices	Malin	2019-2020	$2.85	$2.95	$2.20	$1.80	$1.43	$1.24	$1.14	$0.95	$0.95	$1.31	$1.28	$1.38
Expected Prices	Malin	2020-2021	$1.86	$2.58	$2.69	$2.62	$2.35	$1.92	$1.88	$1.87	$2.04	$2.08	$2.15	$2.16
Expected Prices	Malin	2021-2022	$2.39	$2.55	$2.62	$2.56	$2.38	$1.78	$1.73	$1.75	$1.83	$1.85	$1.85	$1.86
Expected Prices	Malin	2022-2023	$2.16	$2.37	$2.50	$2.44	$2.30	$1.77	$1.64	$1.67	$1.72	$1.75	$1.84	$1.85
Expected Prices	Malin	2023-2024	$2.01	$2.21	$2.36	$2.21	$2.08	$1.74	$1.71	$1.73	$1.78	$1.82	$2.09	$2.14
Expected Prices	Malin	2024-2025	$2.23	$2.37	$2.57	$2.52	$2.41	$2.24	$2.22	$2.17	$2.20	$2.25	$2.45	$2.46
Expected Prices	Malin	2025-2026	$2.63	$2.76	$3.06	$2.98	$2.84	$2.61	$2.53	$2.49	$2.55	$2.66	$2.88	$2.89
Expected Prices	Malin	2026-2027	$3.06	$3.18	$3.23	$3.13	$2.98	$2.86	$2.79	$2.72	$2.79	$2.92	$3.11	$3.11
Expected Prices	Malin	2027-2028	$3.35	$3.50	$3.53	$3.29	$3.20	$2.93	$2.90	$2.93	$2.98	$3.14	$3.32	$3.36
Expected Prices	Malin	2028-2029	$3.58	$3.74	$3.76	$3.49	$3.33	$3.13	$3.08	$3.06	$3.15	$3.29	$3.47	$3.48
Expected Prices	Malin	2029-2030	$3.73	$4.00	$3.99	$3.73	$3.51	$3.28	$3.21	$3.26	$3.25	$3.46	$3.58	$3.65
Expected Prices	Malin	2030-2031	$3.92	$4.15	$4.12	$3.88	$3.66	$3.48	$3.34	$3.34	$3.44	$3.62	$3.82	$3.84
Expected Prices	Malin	2031-2032	$4.14	$4.35	$4.33	$3.99	$3.81	$3.61	$3.49	$3.55	$3.44	$3.64	$3.95	$4.01
Expected Prices	Malin	2032-2033	$4.34	$4.52	$4.56	$4.29	$4.02	$3.93	$3.68	$3.67	$3.71	$3.97	$4.28	$4.31
Expected Prices	Malin	2033-2034	$4.65	$4.79	$4.80	$4.50	$4.20	$4.09	$3.91	$3.98	$3.96	$4.19	$4.47	$4.52
Expected Prices	Malin	2034-2035	$4.83	$5.00	$4.96	$4.66	$4.34	$4.17	$4.03	$4.10	$4.02	$4.29	$4.56	$4.65
Expected Prices	Malin	2035-2036	$4.99	$5.20	$5.15	$4.82	$4.56	$4.35	$4.15	$4.23	$4.06	$4.44	$4.74	$4.81
Expected Prices	Malin	2036-2037	$5.17	$5.42	$5.44	$5.15	$4.80	$4.52	$4.36	$4.40	$4.24	$4.65	$4.91	$5.01
Expected Prices	Malin	2037-2038	$5.40	$5.63	$5.60	$5.28	$4.98	$4.62	$4.52	$4.59	$4.43	$4.85	$5.13	$5.19
Expected Prices	Malin	2038-2039	$5.53	$5.73	$5.76	$5.44	$5.26	$4.85	$4.75	$4.79	$4.64	$5.05	$5.28	$5.40
Expected Prices	Malin	2039-2040	$5.79	$6.04	$5.95	$5.57	$5.30	$5.02	$4.93	$4.85	$4.90	$5.21	$5.49	$5.59

Nominal $														
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Expected Prices	Rockies	2019-2020	$2.81	$2.93	$2.18	$1.76	$1.36	$1.12	$1.02	$0.87	$0.86	$1.22	$1.19	$1.29
Expected Prices	Rockies	2020-2021	$1.79	$2.44	$2.58	$2.50	$2.28	$1.84	$1.80	$1.79	$1.96	$2.01	$2.08	$2.08
Expected Prices	Rockies	2021-2022	$2.31	$2.48	$2.55	$2.49	$2.30	$1.70	$1.65	$1.67	$1.75	$1.78	$1.78	$1.79
Expected Prices	Rockies	2022-2023	$2.08	$2.31	$2.38	$2.28	$2.05	$1.64	$1.60	$1.63	$1.68	$1.70	$1.79	$1.81
Expected Prices	Rockies	2023-2024	$2.01	$2.24	$2.43	$2.29	$2.12	$1.69	$1.67	$1.69	$1.74	$1.78	$2.04	$2.10
Expected Prices	Rockies	2024-2025	$2.29	$2.47	$2.73	$2.65	$2.47	$2.19	$2.20	$2.20	$2.28	$2.29	$2.41	$2.41
Expected Prices	Rockies	2025-2026	$2.66	$2.81	$3.15	$3.11	$2.91	$2.57	$2.53	$2.53	$2.69	$2.71	$2.83	$2.85
Expected Prices	Rockies	2026-2027	$3.09	$3.24	$3.33	$3.26	$3.05	$2.86	$2.87	$2.87	$2.96	$2.99	$3.06	$3.07
Expected Prices	Rockies	2027-2028	$3.35	$3.56	$3.63	$3.44	$3.32	$2.97	$2.97	$2.95	$3.17	$3.18	$3.27	$3.32
Expected Prices	Rockies	2028-2029	$3.55	$3.80	$3.86	$3.62	$3.45	$3.14	$3.13	$3.15	$3.34	$3.34	$3.42	$3.43
Expected Prices	Rockies	2029-2030	$3.70	$4.01	$4.02	$3.82	$3.60	$3.26	$3.25	$3.26	$3.42	$3.47	$3.53	$3.60
Expected Prices	Rockies	2030-2031	$3.87	$4.13	$4.13	$3.98	$3.77	$3.45	$3.42	$3.44	$3.63	$3.64	$3.78	$3.80
Expected Prices	Rockies	2031-2032	$4.10	$4.30	$4.34	$4.14	$3.94	$3.61	$3.56	$3.58	$3.62	$3.68	$3.91	$3.97
Expected Prices	Rockies	2032-2033	$4.32	$4.48	$4.56	$4.42	$4.18	$3.89	$3.81	$3.85	$3.94	$4.01	$4.23	$4.26
Expected Prices	Rockies	2033-2034	$4.63	$4.76	$4.83	$4.66	$4.39	$4.07	$4.02	$4.03	$4.14	$4.23	$4.43	$4.48
Expected Prices	Rockies	2034-2035	$4.83	$4.98	$5.00	$4.84	$4.55	$4.20	$4.17	$4.19	$4.23	$4.37	$4.51	$4.60
Expected Prices	Rockies	2035-2036	$4.99	$5.16	$5.18	$5.01	$4.75	$4.41	$4.34	$4.38	$4.44	$4.53	$4.70	$4.77
Expected Prices	Rockies	2036-2037	$5.18	$5.43	$5.48	$5.32	$5.00	$4.59	$4.58	$4.57	$4.68	$4.75	$4.86	$4.96
Expected Prices	Rockies	2037-2038	$5.42	$5.67	$5.70	$5.46	$5.12	$4.75	$4.75	$4.77	$4.91	$4.97	$5.11	$5.17
Expected Prices	Rockies	2038-2039	$5.55	$5.81	$5.88	$5.63	$5.39	$4.99	$4.97	$4.98	$5.16	$5.20	$5.29	$5.39
Expected Prices	Rockies	2039-2040	$5.80	$6.11	$6.08	$5.76	$5.53	$5.20	$5.18	$5.20	$5.33	$5.39	$5.50	$5.59

Nominal $														
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Expected Prices	Stanfield	2019-2020	$2.85	$2.93	$2.19	$1.74	$1.32	$1.13	$1.05	$0.85	$0.79	$1.14	$1.14	$1.23
Expected Prices	Stanfield	2020-2021	$1.71	$2.36	$2.51	$2.44	$2.24	$1.83	$1.77	$1.74	$1.87	$1.94	$2.03	$2.05
Expected Prices	Stanfield	2021-2022	$2.20	$2.37	$2.46	$2.40	$2.20	$1.66	$1.59	$1.59	$1.67	$1.70	$1.71	$1.72
Expected Prices	Stanfield	2022-2023	$1.93	$2.16	$2.24	$2.15	$1.97	$1.56	$1.50	$1.52	$1.56	$1.61	$1.69	$1.70
Expected Prices	Stanfield	2023-2024	$1.88	$2.10	$2.27	$2.11	$1.99	$1.63	$1.59	$1.60	$1.66	$1.70	$1.93	$1.99
Expected Prices	Stanfield	2024-2025	$2.11	$2.25	$2.47	$2.41	$2.28	$2.09	$2.06	$2.01	$2.04	$2.10	$2.30	$2.30
Expected Prices	Stanfield	2025-2026	$2.49	$2.64	$2.94	$2.88	$2.72	$2.46	$2.36	$2.34	$2.39	$2.50	$2.72	$2.74
Expected Prices	Stanfield	2026-2027	$2.92	$3.05	$3.11	$3.02	$2.85	$2.69	$2.62	$2.55	$2.63	$2.76	$2.95	$2.95
Expected Prices	Stanfield	2027-2028	$3.20	$3.37	$3.41	$3.19	$3.08	$2.76	$2.73	$2.76	$2.81	$2.98	$3.16	$3.20
Expected Prices	Stanfield	2028-2029	$3.43	$3.61	$3.64	$3.37	$3.20	$2.96	$2.90	$2.89	$2.98	$3.14	$3.31	$3.32
Expected Prices	Stanfield	2029-2030	$3.57	$3.86	$3.87	$3.61	$3.38	$3.11	$3.03	$3.09	$3.08	$3.31	$3.43	$3.50
Expected Prices	Stanfield	2030-2031	$3.77	$4.02	$3.99	$3.76	$3.52	$3.30	$3.17	$3.16	$3.27	$3.47	$3.67	$3.69
Expected Prices	Stanfield	2031-2032	$3.99	$4.22	$4.20	$3.86	$3.67	$3.43	$3.32	$3.38	$3.26	$3.49	$3.80	$3.86
Expected Prices	Stanfield	2032-2033	$4.19	$4.39	$4.43	$4.17	$3.89	$3.76	$3.50	$3.48	$3.54	$3.81	$4.12	$4.15
Expected Prices	Stanfield	2033-2034	$4.50	$4.66	$4.68	$4.38	$4.07	$3.91	$3.73	$3.81	$3.79	$4.03	$4.31	$4.37
Expected Prices	Stanfield	2034-2035	$4.68	$4.86	$4.83	$4.54	$4.20	$4.00	$3.84	$3.93	$3.85	$4.13	$4.40	$4.49
Expected Prices	Stanfield	2035-2036	$4.83	$5.06	$5.02	$4.69	$4.43	$4.18	$3.97	$4.05	$3.89	$4.27	$4.58	$4.65
Expected Prices	Stanfield	2036-2037	$5.02	$5.28	$5.31	$5.02	$4.67	$4.35	$4.17	$4.22	$4.06	$4.48	$4.74	$4.84
Expected Prices	Stanfield	2037-2038	$5.24	$5.49	$5.47	$5.15	$4.84	$4.44	$4.33	$4.40	$4.25	$4.68	$4.96	$5.02
Expected Prices	Stanfield	2038-2039	$5.37	$5.59	$5.63	$5.31	$5.11	$4.67	$4.56	$4.60	$4.45	$4.87	$5.11	$5.22
Expected Prices	Stanfield	2039-2040	$5.63	$5.90	$5.81	$5.43	$5.16	$4.84	$4.73	$4.65	$4.72	$5.03	$5.32	$5.42

			Nominal $											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Expected Prices	Sumas	2019-2020	$4.11	$3.20	$2.28	$1.70	$1.36	$1.14	$1.03	$0.88	$0.89	$1.31	$1.25	$1.45
Expected Prices	Sumas	2020-2021	$2.22	$3.10	$3.03	$2.81	$2.44	$1.82	$1.77	$1.76	$1.95	$2.02	$2.03	$2.02
Expected Prices	Sumas	2021-2022	$2.57	$2.96	$2.94	$2.79	$2.41	$1.59	$1.52	$1.55	$1.66	$1.68	$1.67	$1.66
Expected Prices	Sumas	2022-2023	$2.31	$2.77	$2.83	$2.67	$2.30	$1.58	$1.51	$1.56	$1.65	$1.68	$1.69	$1.69
Expected Prices	Sumas	2023-2024	$2.35	$2.80	$2.87	$2.66	$2.37	$1.73	$1.64	$1.66	$1.63	$1.64	$1.72	$1.73
Expected Prices	Sumas	2024-2025	$2.51	$2.81	$2.99	$2.86	$2.63	$2.07	$1.97	$1.89	$1.89	$1.89	$2.00	$2.34
Expected Prices	Sumas	2025-2026	$2.76	$3.14	$3.35	$3.22	$2.89	$2.55	$2.26	$2.23	$2.22	$2.24	$2.33	$2.74
Expected Prices	Sumas	2026-2027	$3.08	$3.55	$3.56	$3.25	$3.03	$2.78	$2.44	$2.38	$2.37	$2.39	$2.49	$2.88
Expected Prices	Sumas	2027-2028	$3.35	$3.58	$3.65	$3.43	$3.29	$2.64	$2.56	$2.53	$2.53	$2.56	$2.68	$3.29
Expected Prices	Sumas	2028-2029	$3.55	$3.84	$3.88	$3.62	$3.42	$3.06	$2.71	$2.70	$2.68	$2.68	$2.79	$3.38
Expected Prices	Sumas	2029-2030	$3.70	$4.05	$4.05	$3.81	$3.57	$3.20	$2.79	$2.76	$2.76	$2.79	$2.88	$3.36
Expected Prices	Sumas	2030-2031	$3.88	$4.16	$4.18	$3.97	$3.73	$3.38	$2.97	$2.94	$2.90	$2.90	$3.05	$3.45
Expected Prices	Sumas	2031-2032	$4.11	$4.36	$4.38	$4.12	$3.91	$3.51	$3.05	$3.01	$2.83	$2.86	$3.10	$3.58
Expected Prices	Sumas	2032-2033	$4.33	$4.53	$4.61	$4.41	$4.17	$3.75	$3.32	$3.32	$3.19	$3.22	$3.39	$3.82
Expected Prices	Sumas	2033-2034	$4.64	$4.82	$4.87	$4.66	$4.38	$3.90	$3.49	$3.46	$3.40	$3.42	$3.57	$4.06
Expected Prices	Sumas	2034-2035	$4.84	$5.03	$5.05	$4.84	$4.52	$4.02	$3.62	$3.56	$3.43	$3.47	$3.64	$4.12
Expected Prices	Sumas	2035-2036	$4.99	$5.20	$5.23	$5.01	$4.74	$4.09	$3.79	$3.77	$3.56	$3.59	$3.77	$4.22
Expected Prices	Sumas	2036-2037	$5.19	$5.47	$5.52	$5.32	$4.99	$4.16	$3.97	$3.95	$3.81	$3.91	$4.03	$4.46
Expected Prices	Sumas	2037-2038	$5.43	$5.69	$5.73	$5.46	$5.12	$4.34	$4.06	$4.05	$3.89	$3.91	$4.02	$4.47
Expected Prices	Sumas	2038-2039	$5.56	$5.83	$5.89	$5.63	$5.39	$4.58	$4.32	$4.22	$4.08	$4.09	$4.27	$4.71
Expected Prices	Sumas	2039-2040	$5.81	$6.11	$6.09	$5.76	$5.47	$4.75	$4.47	$4.43	$4.32	$4.35	$4.49	$4.91

Appendix 6.1: Monthly Price Data by Basin
High Growth Low Price

			Nominal $											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Low Prices	AECO	2019-2020	$2.13	$1.84	$1.77	$1.41	$1.23	$1.01	$1.12	$0.88	$0.85	$1.08	$0.97	$1.00
Low Prices	AECO	2020-2021	$1.77	$2.32	$1.76	$1.65	$1.35	$0.89	$0.79	$0.83	$0.94	$0.94	$0.79	$0.81
Low Prices	AECO	2021-2022	$1.14	$1.37	$1.45	$1.31	$1.04	$0.51	$0.49	$0.58	$0.72	$0.67	$0.50	$0.49
Low Prices	AECO	2022-2023	$0.75	$1.19	$1.25	$1.05	$0.82	$0.41	$0.39	$0.55	$0.59	$0.59	$0.32	$0.40
Low Prices	AECO	2023-2024	$0.88	$1.08	$1.22	$0.94	$0.89	$0.61	$0.59	$0.60	$0.56	$0.56	$0.65	$0.66
Low Prices	AECO	2024-2025	$0.77	$0.97	$1.14	$1.04	$0.92	$0.77	$0.86	$0.78	$0.77	$0.76	$0.86	$0.86
Low Prices	AECO	2025-2026	$1.04	$1.18	$1.35	$1.30	$1.18	$1.01	$1.03	$1.01	$0.97	$0.99	$1.04	$1.09
Low Prices	AECO	2026-2027	$1.29	$1.36	$1.48	$1.38	$1.24	$1.09	$1.15	$1.10	$1.06	$1.07	$1.13	$1.12
Low Prices	AECO	2027-2028	$1.38	$1.49	$1.54	$1.44	$1.32	$1.09	$1.18	$1.16	$1.13	$1.15	$1.21	$1.27
Low Prices	AECO	2028-2029	$1.51	$1.53	$1.63	$1.50	$1.37	$1.20	$1.25	$1.23	$1.19	$1.18	$1.25	$1.30
Low Prices	AECO	2029-2030	$1.57	$1.63	$1.66	$1.55	$1.43	$1.26	$1.29	$1.26	$1.17	$1.18	$1.24	$1.34
Low Prices	AECO	2030-2031	$1.61	$1.69	$1.69	$1.60	$1.46	$1.32	$1.32	$1.28	$1.21	$1.20	$1.31	$1.37
Low Prices	AECO	2031-2032	$1.67	$1.69	$1.70	$1.60	$1.48	$1.36	$1.34	$1.28	$1.06	$1.06	$1.26	$1.36
Low Prices	AECO	2032-2033	$1.68	$1.75	$1.80	$1.77	$1.65	$1.52	$1.49	$1.49	$1.32	$1.33	$1.47	$1.55
Low Prices	AECO	2033-2034	$1.90	$1.89	$1.93	$1.84	$1.74	$1.61	$1.60	$1.58	$1.43	$1.45	$1.59	$1.70
Low Prices	AECO	2034-2035	$1.97	$2.00	$2.01	$1.89	$1.70	$1.60	$1.60	$1.53	$1.36	$1.40	$1.55	$1.62
Low Prices	AECO	2035-2036	$1.95	$2.04	$2.05	$2.03	$1.88	$1.68	$1.68	$1.63	$1.37	$1.41	$1.57	$1.73
Low Prices	AECO	2036-2037	$2.07	$2.10	$2.12	$1.95	$1.83	$1.64	$1.77	$1.73	$1.51	$1.58	$1.71	$1.85
Low Prices	AECO	2037-2038	$2.23	$2.33	$2.35	$2.12	$1.97	$1.80	$1.83	$1.83	$1.59	$1.58	$1.70	$1.82
Low Prices	AECO	2038-2039	$2.18	$2.29	$2.34	$2.17	$2.10	$1.92	$1.95	$1.85	$1.65	$1.64	$1.82	$1.97
Low Prices	AECO	2039-2040	$2.38	$2.45	$2.45	$2.32	$2.21	$2.03	$2.04	$2.01	$1.83	$1.84	$1.98	$2.10
			Nominal $											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Low Prices	Malin	2019-2020	$2.85	$2.95	$2.20	$1.80	$1.43	$1.24	$1.14	$0.95	$0.95	$1.31	$1.28	$1.38
Low Prices	Malin	2020-2021	$1.86	$2.58	$2.05	$1.98	$1.72	$1.33	$1.29	$1.28	$1.43	$1.48	$1.55	$1.55
Low Prices	Malin	2021-2022	$1.78	$1.89	$1.93	$1.87	$1.72	$1.21	$1.16	$1.17	$1.25	$1.26	$1.27	$1.27
Low Prices	Malin	2022-2023	$1.56	$1.71	$1.79	$1.74	$1.62	$1.14	$1.02	$1.04	$1.08	$1.10	$1.19	$1.20
Low Prices	Malin	2023-2024	$1.32	$1.48	$1.56	$1.42	$1.32	$1.00	$0.97	$0.98	$1.02	$1.06	$1.33	$1.37
Low Prices	Malin	2024-2025	$1.44	$1.54	$1.64	$1.60	$1.50	$1.36	$1.35	$1.29	$1.31	$1.35	$1.57	$1.57
Low Prices	Malin	2025-2026	$1.70	$1.82	$1.96	$1.89	$1.77	$1.56	$1.48	$1.44	$1.47	$1.58	$1.82	$1.83
Low Prices	Malin	2026-2027	$1.95	$2.03	$2.06	$1.98	$1.83	$1.75	$1.68	$1.61	$1.65	$1.78	$1.97	$1.98
Low Prices	Malin	2027-2028	$2.16	$2.27	$2.28	$2.04	$1.96	$1.73	$1.69	$1.72	$1.74	$1.90	$2.09	$2.12
Low Prices	Malin	2028-2029	$2.30	$2.43	$2.43	$2.17	$2.03	$1.86	$1.80	$1.77	$1.83	$1.97	$2.16	$2.17
Low Prices	Malin	2029-2030	$2.39	$2.60	$2.60	$2.33	$2.13	$1.96	$1.88	$1.93	$1.89	$2.08	$2.20	$2.25
Low Prices	Malin	2030-2031	$2.48	$2.66	$2.62	$2.39	$2.19	$2.08	$1.92	$1.91	$1.98	$2.15	$2.37	$2.39
Low Prices	Malin	2031-2032	$2.65	$2.77	$2.75	$2.43	$2.29	$2.14	$2.02	$2.05	$1.90	$2.09	$2.40	$2.44
Low Prices	Malin	2032-2033	$2.71	$2.85	$2.86	$2.62	$2.38	$2.35	$2.09	$2.08	$2.07	$2.31	$2.64	$2.66
Low Prices	Malin	2033-2034	$2.95	$3.02	$3.02	$2.74	$2.49	$2.46	$2.27	$2.33	$2.24	$2.46	$2.78	$2.82
Low Prices	Malin	2034-2035	$3.06	$3.15	$3.11	$2.83	$2.52	$2.40	$2.25	$2.32	$2.20	$2.47	$2.75	$2.83
Low Prices	Malin	2035-2036	$3.10	$3.23	$3.16	$2.87	$2.66	$2.49	$2.29	$2.34	$2.12	$2.49	$2.82	$2.89
Low Prices	Malin	2036-2037	$3.18	$3.33	$3.33	$3.07	$2.78	$2.57	$2.41	$2.43	$2.18	$2.56	$2.85	$2.96
Low Prices	Malin	2037-2038	$3.28	$3.45	$3.41	$3.14	$2.95	$2.62	$2.52	$2.58	$2.35	$2.74	$3.03	$3.09
Low Prices	Malin	2038-2039	$3.35	$3.45	$3.47	$3.19	$3.08	$2.73	$2.63	$2.64	$2.43	$2.83	$3.06	$3.21
Low Prices	Malin	2039-2040	$3.53	$3.70	$3.58	$3.29	$3.09	$2.86	$2.75	$2.66	$2.64	$2.93	$3.22	$3.32

			Nominal $											
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Low Prices	Rockies	2019-2020	$2.81	$2.93	$2.18	$1.76	$1.36	$1.12	$1.02	$0.87	$0.86	$1.22	$1.19	$1.29
Low Prices	Rockies	2020-2021	$1.79	$2.44	$1.93	$1.87	$1.65	$1.25	$1.22	$1.20	$1.36	$1.40	$1.48	$1.47
Low Prices	Rockies	2021-2022	$1.70	$1.81	$1.85	$1.79	$1.64	$1.13	$1.08	$1.10	$1.17	$1.18	$1.19	$1.19
Low Prices	Rockies	2022-2023	$1.48	$1.65	$1.67	$1.57	$1.37	$1.01	$0.97	$1.00	$1.03	$1.05	$1.14	$1.16
Low Prices	Rockies	2023-2024	$1.33	$1.51	$1.63	$1.51	$1.36	$0.95	$0.93	$0.93	$0.98	$1.01	$1.28	$1.33
Low Prices	Rockies	2024-2025	$1.50	$1.64	$1.80	$1.73	$1.56	$1.32	$1.32	$1.32	$1.39	$1.39	$1.52	$1.52
Low Prices	Rockies	2025-2026	$1.73	$1.87	$2.05	$2.01	$1.83	$1.52	$1.48	$1.48	$1.61	$1.64	$1.77	$1.78
Low Prices	Rockies	2026-2027	$1.99	$2.10	$2.17	$2.10	$1.90	$1.75	$1.75	$1.75	$1.82	$1.84	$1.92	$1.93
Low Prices	Rockies	2027-2028	$2.15	$2.33	$2.38	$2.19	$2.07	$1.78	$1.77	$1.75	$1.94	$1.94	$2.05	$2.07
Low Prices	Rockies	2028-2029	$2.27	$2.49	$2.53	$2.30	$2.15	$1.87	$1.85	$1.85	$2.02	$2.02	$2.12	$2.13
Low Prices	Rockies	2029-2030	$2.37	$2.62	$2.63	$2.42	$2.22	$1.94	$1.92	$1.93	$2.06	$2.09	$2.15	$2.20
Low Prices	Rockies	2030-2031	$2.44	$2.63	$2.64	$2.49	$2.30	$2.05	$1.99	$2.00	$2.16	$2.17	$2.32	$2.35
Low Prices	Rockies	2031-2032	$2.60	$2.73	$2.76	$2.57	$2.42	$2.14	$2.08	$2.08	$2.09	$2.12	$2.35	$2.39
Low Prices	Rockies	2032-2033	$2.68	$2.81	$2.87	$2.75	$2.54	$2.31	$2.22	$2.26	$2.30	$2.36	$2.59	$2.61
Low Prices	Rockies	2033-2034	$2.93	$2.99	$3.05	$2.91	$2.68	$2.43	$2.37	$2.38	$2.42	$2.49	$2.73	$2.78
Low Prices	Rockies	2034-2035	$3.06	$3.13	$3.15	$3.02	$2.73	$2.44	$2.39	$2.40	$2.41	$2.55	$2.71	$2.78
Low Prices	Rockies	2035-2036	$3.10	$3.19	$3.20	$3.06	$2.85	$2.55	$2.48	$2.49	$2.49	$2.59	$2.77	$2.84
Low Prices	Rockies	2036-2037	$3.18	$3.34	$3.37	$3.24	$2.98	$2.64	$2.63	$2.60	$2.62	$2.66	$2.81	$2.91
Low Prices	Rockies	2037-2038	$3.30	$3.49	$3.51	$3.33	$3.08	$2.76	$2.75	$2.77	$2.82	$2.86	$3.01	$3.07
Low Prices	Rockies	2038-2039	$3.36	$3.53	$3.59	$3.37	$3.22	$2.87	$2.85	$2.84	$2.95	$2.98	$3.07	$3.20
Low Prices	Rockies	2039-2040	$3.54	$3.77	$3.72	$3.48	$3.32	$3.03	$2.99	$3.01	$3.07	$3.11	$3.23	$3.32

			Nominal $											
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Low Prices	Stanfield	2019-2020	$2.85	$2.93	$2.19	$1.74	$1.32	$1.13	$1.05	$0.85	$0.79	$1.14	$1.14	$1.23
Low Prices	Stanfield	2020-2021	$1.71	$2.36	$1.87	$1.81	$1.61	$1.24	$1.19	$1.14	$1.27	$1.33	$1.43	$1.44
Low Prices	Stanfield	2021-2022	$1.59	$1.71	$1.76	$1.71	$1.54	$1.09	$1.02	$1.01	$1.09	$1.11	$1.12	$1.13
Low Prices	Stanfield	2022-2023	$1.34	$1.50	$1.53	$1.45	$1.29	$0.93	$0.88	$0.89	$0.92	$0.95	$1.04	$1.05
Low Prices	Stanfield	2023-2024	$1.20	$1.37	$1.46	$1.33	$1.23	$0.89	$0.85	$0.85	$0.90	$0.93	$1.17	$1.22
Low Prices	Stanfield	2024-2025	$1.32	$1.42	$1.54	$1.50	$1.37	$1.21	$1.19	$1.14	$1.15	$1.20	$1.41	$1.41
Low Prices	Stanfield	2025-2026	$1.56	$1.69	$1.84	$1.78	$1.64	$1.40	$1.31	$1.28	$1.31	$1.43	$1.66	$1.67
Low Prices	Stanfield	2026-2027	$1.82	$1.91	$1.95	$1.87	$1.70	$1.58	$1.50	$1.43	$1.48	$1.62	$1.81	$1.82
Low Prices	Stanfield	2027-2028	$2.01	$2.13	$2.16	$1.94	$1.83	$1.56	$1.52	$1.56	$1.57	$1.74	$1.93	$1.96
Low Prices	Stanfield	2028-2029	$2.15	$2.30	$2.31	$2.05	$1.90	$1.69	$1.62	$1.59	$1.66	$1.81	$2.00	$2.01
Low Prices	Stanfield	2029-2030	$2.24	$2.46	$2.47	$2.21	$2.00	$1.79	$1.71	$1.77	$1.72	$1.93	$2.05	$2.09
Low Prices	Stanfield	2030-2031	$2.34	$2.53	$2.50	$2.27	$2.05	$1.90	$1.74	$1.73	$1.81	$2.00	$2.21	$2.24
Low Prices	Stanfield	2031-2032	$2.50	$2.64	$2.62	$2.30	$2.15	$1.96	$1.84	$1.88	$1.73	$1.93	$2.24	$2.28
Low Prices	Stanfield	2032-2033	$2.56	$2.72	$2.73	$2.50	$2.25	$2.18	$1.91	$1.89	$1.90	$2.16	$2.48	$2.50
Low Prices	Stanfield	2033-2034	$2.80	$2.89	$2.90	$2.62	$2.35	$2.28	$2.08	$2.16	$2.06	$2.30	$2.62	$2.67
Low Prices	Stanfield	2034-2035	$2.90	$3.01	$2.98	$2.71	$2.39	$2.23	$2.07	$2.14	$2.03	$2.31	$2.59	$2.67
Low Prices	Stanfield	2035-2036	$2.94	$3.09	$3.04	$2.75	$2.53	$2.32	$2.10	$2.16	$1.94	$2.33	$2.65	$2.73
Low Prices	Stanfield	2036-2037	$3.02	$3.20	$3.20	$2.95	$2.64	$2.39	$2.22	$2.25	$2.00	$2.39	$2.69	$2.79
Low Prices	Stanfield	2037-2038	$3.12	$3.31	$3.28	$3.01	$2.80	$2.44	$2.32	$2.40	$2.16	$2.56	$2.86	$2.92
Low Prices	Stanfield	2038-2039	$3.19	$3.31	$3.33	$3.06	$2.93	$2.54	$2.43	$2.46	$2.24	$2.65	$2.89	$3.04
Low Prices	Stanfield	2039-2040	$3.36	$3.55	$3.45	$3.16	$2.95	$2.67	$2.54	$2.46	$2.46	$2.75	$3.05	$3.15

			Nominal $											
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Low Prices	Sumas	2019-2020	$4.11	$3.20	$2.28	$1.70	$1.36	$1.14	$1.03	$0.88	$0.89	$1.31	$1.25	$1.45
Low Prices	Sumas	2020-2021	$2.22	$3.10	$2.39	$2.18	$1.81	$1.23	$1.19	$1.16	$1.35	$1.42	$1.43	$1.41
Low Prices	Sumas	2021-2022	$1.96	$2.30	$2.24	$2.10	$1.76	$1.01	$0.95	$0.97	$1.07	$1.09	$1.09	$1.07
Low Prices	Sumas	2022-2023	$1.71	$2.11	$2.11	$1.97	$1.62	$0.95	$0.89	$0.92	$1.00	$1.02	$1.04	$1.04
Low Prices	Sumas	2023-2024	$1.67	$2.07	$2.06	$1.88	$1.60	$0.99	$0.90	$0.91	$0.87	$0.87	$0.96	$0.97
Low Prices	Sumas	2024-2025	$1.72	$1.99	$2.06	$1.95	$1.72	$1.20	$1.09	$1.01	$1.00	$0.99	$1.11	$1.45
Low Prices	Sumas	2025-2026	$1.83	$2.20	$2.25	$2.13	$1.81	$1.50	$1.21	$1.18	$1.14	$1.16	$1.27	$1.68
Low Prices	Sumas	2026-2027	$1.98	$2.41	$2.40	$2.09	$1.88	$1.67	$1.32	$1.27	$1.23	$1.25	$1.35	$1.75
Low Prices	Sumas	2027-2028	$2.15	$2.35	$2.40	$2.18	$2.05	$1.45	$1.36	$1.33	$1.30	$1.32	$1.46	$2.04
Low Prices	Sumas	2028-2029	$2.27	$2.53	$2.55	$2.30	$2.12	$1.79	$1.43	$1.40	$1.36	$1.35	$1.49	$2.08
Low Prices	Sumas	2029-2030	$2.37	$2.66	$2.65	$2.41	$2.20	$1.88	$1.47	$1.43	$1.40	$1.41	$1.50	$1.95
Low Prices	Sumas	2030-2031	$2.44	$2.67	$2.68	$2.48	$2.26	$1.97	$1.55	$1.51	$1.44	$1.43	$1.59	$2.00
Low Prices	Sumas	2031-2032	$2.61	$2.78	$2.80	$2.56	$2.39	$2.03	$1.57	$1.51	$1.30	$1.30	$1.54	$2.00
Low Prices	Sumas	2032-2033	$2.69	$2.86	$2.92	$2.74	$2.53	$2.17	$1.73	$1.73	$1.55	$1.57	$1.75	$2.18
Low Prices	Sumas	2033-2034	$2.94	$3.05	$3.09	$2.90	$2.66	$2.26	$1.84	$1.81	$1.67	$1.69	$1.88	$2.36
Low Prices	Sumas	2034-2035	$3.06	$3.18	$3.20	$3.02	$2.71	$2.25	$1.84	$1.78	$1.60	$1.65	$1.84	$2.30
Low Prices	Sumas	2035-2036	$3.10	$3.23	$3.25	$3.06	$2.84	$2.23	$1.92	$1.88	$1.61	$1.65	$1.84	$2.30
Low Prices	Sumas	2036-2037	$3.19	$3.38	$3.41	$3.24	$2.96	$2.20	$2.01	$1.98	$1.75	$1.82	$1.98	$2.41
Low Prices	Sumas	2037-2038	$3.30	$3.51	$3.53	$3.33	$3.08	$2.34	$2.06	$2.04	$1.80	$1.80	$1.92	$2.38
Low Prices	Sumas	2038-2039	$3.37	$3.54	$3.60	$3.37	$3.22	$2.46	$2.19	$2.07	$1.87	$1.86	$2.05	$2.53
Low Prices	Sumas	2039-2040	$3.55	$3.77	$3.72	$3.48	$3.26	$2.58	$2.28	$2.24	$2.06	$2.07	$2.21	$2.64

APPENDIX 6.1: MONTHLY PRICE DATA BY BASIN
LOW GROWTH HIGH PRICE

			Nominal $											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Prices	AECO	2019-2020	$ 2.13	$ 1.84	$ 1.77	$ 1.41	$ 1.23	$ 1.01	$ 1.12	$ 0.88	$ 0.85	$ 1.08	$ 0.97	$ 1.00
High Prices	AECO	2020-2021	$ 1.77	$ 2.32	$ 4.38	$ 4.25	$ 3.86	$ 3.27	$ 3.15	$ 3.21	$ 3.39	$ 3.39	$ 3.23	$ 3.27
High Prices	AECO	2021-2022	$ 3.65	$ 4.01	$ 4.16	$ 3.94	$ 3.56	$ 2.78	$ 2.70	$ 2.83	$ 3.01	$ 2.96	$ 2.76	$ 2.75
High Prices	AECO	2022-2023	$ 3.06	$ 3.71	$ 3.95	$ 3.74	$ 3.37	$ 2.88	$ 2.82	$ 2.98	$ 3.10	$ 3.11	$ 2.82	$ 2.90
High Prices	AECO	2023-2024	$ 3.48	$ 3.96	$ 4.36	$ 4.02	$ 3.96	$ 3.48	$ 3.46	$ 3.46	$ 3.47	$ 3.48	$ 3.54	$ 3.58
High Prices	AECO	2024-2025	$ 3.91	$ 4.25	$ 4.87	$ 4.73	$ 4.53	$ 4.18	$ 4.26	$ 4.19	$ 4.26	$ 4.27	$ 4.37	$ 4.36
High Prices	AECO	2025-2026	$ 4.73	$ 4.91	$ 5.63	$ 5.55	$ 5.37	$ 4.98	$ 5.01	$ 5.01	$ 5.10	$ 5.16	$ 5.15	$ 5.20
High Prices	AECO	2026-2027	$ 5.64	$ 5.83	$ 6.11	$ 6.00	$ 5.77	$ 5.42	$ 5.50	$ 5.45	$ 5.54	$ 5.54	$ 5.60	$ 5.55
High Prices	AECO	2027-2028	$ 6.06	$ 6.27	$ 6.42	$ 6.26	$ 6.11	$ 5.75	$ 5.87	$ 5.85	$ 5.90	$ 5.94	$ 5.96	$ 6.15
High Prices	AECO	2028-2029	$ 6.52	$ 6.60	$ 6.77	$ 6.60	$ 6.42	$ 6.05	$ 6.15	$ 6.14	$ 6.25	$ 6.25	$ 6.22	$ 6.27
High Prices	AECO	2029-2030	$ 6.71	$ 7.05	$ 7.10	$ 6.99	$ 6.85	$ 6.44	$ 6.48	$ 6.47	$ 6.52	$ 6.57	$ 6.61	$ 6.77
High Prices	AECO	2030-2031	$ 7.13	$ 7.32	$ 7.34	$ 7.17	$ 6.99	$ 6.65	$ 6.75	$ 6.77	$ 6.79	$ 6.81	$ 6.83	$ 6.89
High Prices	AECO	2031-2032	$ 7.58	$ 7.82	$ 7.83	$ 7.64	$ 7.41	$ 7.14	$ 7.18	$ 7.15	$ 7.01	$ 7.04	$ 7.21	$ 7.33
High Prices	AECO	2032-2033	$ 7.81	$ 8.24	$ 8.40	$ 8.12	$ 8.01	$ 7.63	$ 7.68	$ 7.70	$ 7.60	$ 7.69	$ 7.76	$ 7.89
High Prices	AECO	2033-2034	$ 8.50	$ 8.68	$ 8.79	$ 8.63	$ 8.37	$ 8.18	$ 8.23	$ 8.21	$ 8.37	$ 8.48	$ 8.33	$ 8.55
High Prices	AECO	2034-2035	$ 9.10	$ 9.65	$ 9.67	$ 9.34	$ 9.09	$ 8.69	$ 8.71	$ 8.68	$ 8.65	$ 8.72	$ 8.74	$ 8.83
High Prices	AECO	2035-2036	$ 9.41	$ 9.70	$ 9.79	$ 9.48	$ 9.13	$ 8.79	$ 8.79	$ 8.86	$ 8.84	$ 8.86	$ 8.93	$ 9.09
High Prices	AECO	2036-2037	$ 9.57	$10.03	$10.24	$10.01	$ 9.45	$ 9.05	$ 9.23	$ 9.19	$ 9.19	$ 9.31	$ 9.29	$ 9.40
High Prices	AECO	2037-2038	$10.31	$10.75	$10.82	$10.04	$ 9.55	$ 9.31	$ 9.49	$ 9.50	$ 9.49	$ 9.53	$ 9.58	$ 9.71
High Prices	AECO	2038-2039	$10.59	$11.19	$11.31	$10.94	$10.68	$10.24	$10.28	$10.24	$10.34	$10.34	$10.51	$10.57
High Prices	AECO	2039-2040	$11.75	$12.07	$12.11	$11.86	$11.47	$11.09	$11.15	$11.12	$11.13	$11.13	$11.27	$11.38

			Nominal $											
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Prices	Malin	2019-2020	$ 2.85	$ 2.95	$ 2.20	$ 1.80	$ 1.43	$ 1.24	$ 1.14	$ 0.95	$ 0.95	$ 1.31	$ 1.28	$ 1.38
High Prices	Malin	2020-2021	$ 1.86	$ 2.58	$ 4.68	$ 4.57	$ 4.24	$ 3.71	$ 3.66	$ 3.65	$ 3.88	$ 3.93	$ 3.99	$ 4.01
High Prices	Malin	2021-2022	$ 4.28	$ 4.52	$ 4.63	$ 4.50	$ 4.24	$ 3.48	$ 3.37	$ 3.42	$ 3.53	$ 3.56	$ 3.53	$ 3.53
High Prices	Malin	2022-2023	$ 3.87	$ 4.23	$ 4.49	$ 4.43	$ 4.17	$ 3.61	$ 3.45	$ 3.48	$ 3.59	$ 3.61	$ 3.68	$ 3.70
High Prices	Malin	2023-2024	$ 3.92	$ 4.36	$ 4.70	$ 4.51	$ 4.39	$ 3.87	$ 3.83	$ 3.84	$ 3.93	$ 3.98	$ 4.22	$ 4.30
High Prices	Malin	2024-2025	$ 4.58	$ 4.82	$ 5.37	$ 5.29	$ 5.11	$ 4.77	$ 4.75	$ 4.70	$ 4.80	$ 4.86	$ 5.07	$ 5.07
High Prices	Malin	2025-2026	$ 5.39	$ 5.54	$ 6.24	$ 6.14	$ 5.96	$ 5.53	$ 5.45	$ 5.44	$ 5.60	$ 5.75	$ 5.92	$ 5.94
High Prices	Malin	2026-2027	$ 6.31	$ 6.50	$ 6.70	$ 6.59	$ 6.36	$ 6.08	$ 6.03	$ 5.96	$ 6.13	$ 6.25	$ 6.43	$ 6.41
High Prices	Malin	2027-2028	$ 6.83	$ 7.04	$ 7.16	$ 6.87	$ 6.74	$ 6.39	$ 6.39	$ 6.42	$ 6.51	$ 6.69	$ 6.84	$ 7.00
High Prices	Malin	2028-2029	$ 7.31	$ 7.50	$ 7.57	$ 7.27	$ 7.08	$ 6.71	$ 6.70	$ 6.68	$ 6.89	$ 7.04	$ 7.13	$ 7.15
High Prices	Malin	2029-2030	$ 7.53	$ 8.02	$ 8.03	$ 7.77	$ 7.55	$ 7.14	$ 7.08	$ 7.14	$ 7.24	$ 7.47	$ 7.57	$ 7.67
High Prices	Malin	2030-2031	$ 8.00	$ 8.29	$ 8.27	$ 7.96	$ 7.72	$ 7.41	$ 7.35	$ 7.40	$ 7.56	$ 7.76	$ 7.88	$ 7.91
High Prices	Malin	2031-2032	$ 8.56	$ 8.90	$ 8.88	$ 8.47	$ 8.22	$ 7.91	$ 7.86	$ 7.92	$ 7.85	$ 8.06	$ 8.34	$ 8.41
High Prices	Malin	2032-2033	$ 8.83	$ 9.34	$ 9.46	$ 8.97	$ 8.75	$ 8.46	$ 8.28	$ 8.29	$ 8.36	$ 8.67	$ 8.93	$ 9.00
High Prices	Malin	2033-2034	$ 9.55	$ 9.81	$ 9.89	$ 9.54	$ 9.12	$ 9.02	$ 8.89	$ 8.96	$ 9.18	$ 9.48	$ 9.52	$ 9.68
High Prices	Malin	2034-2035	$10.18	$10.80	$10.78	$10.27	$ 9.91	$ 9.48	$ 9.37	$ 9.46	$ 9.49	$ 9.79	$ 9.94	$10.04
High Prices	Malin	2035-2036	$10.55	$10.89	$10.89	$10.33	$ 9.91	$ 9.59	$ 9.40	$ 9.56	$ 9.59	$ 9.95	$10.18	$10.25
High Prices	Malin	2036-2037	$10.68	$11.26	$11.44	$11.14	$10.39	$ 9.98	$ 9.86	$ 9.90	$ 9.86	$10.29	$10.43	$10.51
High Prices	Malin	2037-2038	$11.35	$11.87	$11.88	$11.06	$10.53	$10.14	$10.18	$10.25	$10.25	$10.69	$10.92	$10.98
High Prices	Malin	2038-2039	$11.75	$12.35	$12.44	$11.96	$11.66	$11.05	$10.96	$11.04	$11.13	$11.53	$11.75	$11.81
High Prices	Malin	2039-2040	$12.90	$13.32	$13.24	$12.83	$12.35	$11.92	$11.86	$11.77	$11.94	$12.22	$12.50	$12.60

			Nominal $											
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
High Prices	Rockies	2019-2020	$ 2.81	$ 2.93	$ 2.18	$ 1.76	$ 1.36	$ 1.12	$ 1.02	$ 0.87	$ 0.86	$ 1.22	$ 1.19	$ 1.29
High Prices	Rockies	2020-2021	$ 1.79	$ 2.44	$ 4.56	$ 4.46	$ 4.16	$ 3.63	$ 3.58	$ 3.58	$ 3.81	$ 3.85	$ 3.91	$ 3.93
High Prices	Rockies	2021-2022	$ 4.21	$ 4.45	$ 4.56	$ 4.42	$ 4.16	$ 3.40	$ 3.29	$ 3.34	$ 3.45	$ 3.48	$ 3.45	$ 3.45
High Prices	Rockies	2022-2023	$ 3.79	$ 4.17	$ 4.37	$ 4.26	$ 3.92	$ 3.48	$ 3.40	$ 3.43	$ 3.55	$ 3.57	$ 3.64	$ 3.65
High Prices	Rockies	2023-2024	$ 3.92	$ 4.39	$ 4.77	$ 4.59	$ 4.43	$ 3.82	$ 3.79	$ 3.80	$ 3.89	$ 3.93	$ 4.18	$ 4.25
High Prices	Rockies	2024-2025	$ 4.64	$ 4.92	$ 5.53	$ 5.42	$ 5.18	$ 4.72	$ 4.73	$ 4.73	$ 4.88	$ 4.89	$ 5.02	$ 5.03
High Prices	Rockies	2025-2026	$ 5.42	$ 5.59	$ 6.33	$ 6.27	$ 6.02	$ 5.49	$ 5.45	$ 5.48	$ 5.74	$ 5.81	$ 5.88	$ 5.89
High Prices	Rockies	2026-2027	$ 6.34	$ 6.56	$ 6.81	$ 6.72	$ 6.43	$ 6.09	$ 6.10	$ 6.10	$ 6.30	$ 6.31	$ 6.39	$ 6.36
High Prices	Rockies	2027-2028	$ 6.83	$ 7.11	$ 7.26	$ 7.02	$ 6.85	$ 6.43	$ 6.46	$ 6.45	$ 6.71	$ 6.74	$ 6.80	$ 6.95
High Prices	Rockies	2028-2029	$ 7.28	$ 7.56	$ 7.67	$ 7.40	$ 7.20	$ 6.72	$ 6.75	$ 6.76	$ 7.08	$ 7.09	$ 7.09	$ 7.10
High Prices	Rockies	2029-2030	$ 7.51	$ 8.04	$ 8.06	$ 7.86	$ 7.64	$ 7.12	$ 7.12	$ 7.15	$ 7.41	$ 7.48	$ 7.53	$ 7.63
High Prices	Rockies	2030-2031	$ 7.96	$ 8.26	$ 8.28	$ 8.06	$ 7.83	$ 7.38	$ 7.43	$ 7.49	$ 7.75	$ 7.77	$ 7.83	$ 7.86
High Prices	Rockies	2031-2032	$ 8.51	$ 8.85	$ 8.89	$ 8.62	$ 8.35	$ 7.91	$ 7.92	$ 7.95	$ 8.04	$ 8.10	$ 8.30	$ 8.37
High Prices	Rockies	2032-2033	$ 8.81	$ 9.29	$ 9.47	$ 9.10	$ 8.91	$ 8.42	$ 8.42	$ 8.47	$ 8.59	$ 8.71	$ 8.89	$ 8.96
High Prices	Rockies	2033-2034	$ 9.53	$ 9.78	$ 9.92	$ 9.70	$ 9.31	$ 9.00	$ 9.00	$ 9.01	$ 9.35	$ 9.52	$ 9.48	$ 9.63
High Prices	Rockies	2034-2035	$10.18	$10.78	$10.82	$10.46	$10.12	$ 9.52	$ 9.51	$ 9.55	$ 9.70	$ 9.86	$ 9.90	$10.00
High Prices	Rockies	2035-2036	$10.55	$10.84	$10.93	$10.52	$10.10	$ 9.65	$ 9.59	$ 9.71	$ 9.96	$10.05	$10.13	$10.21
High Prices	Rockies	2036-2037	$10.68	$11.27	$11.48	$11.31	$10.59	$10.05	$10.09	$10.06	$10.30	$10.39	$10.39	$10.47
High Prices	Rockies	2037-2038	$11.37	$11.91	$11.98	$11.24	$10.67	$10.27	$10.41	$10.44	$10.72	$10.81	$10.90	$10.96
High Prices	Rockies	2038-2039	$11.77	$12.43	$12.56	$12.15	$11.80	$11.19	$11.18	$11.23	$11.65	$11.68	$11.76	$11.80
High Prices	Rockies	2039-2040	$12.91	$13.39	$13.38	$13.02	$12.58	$12.09	$12.10	$12.12	$12.37	$12.40	$12.51	$12.60

			Nominal $											
Scenario	**Index**	**Gas Year**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
High Prices	Stanfield	2019-2020	$ 2.85	$ 2.93	$ 2.19	$ 1.74	$ 1.32	$ 1.13	$ 1.05	$ 0.85	$ 0.79	$ 1.14	$ 1.14	$ 1.23
High Prices	Stanfield	2020-2021	$ 1.71	$ 2.36	$ 4.49	$ 4.40	$ 4.13	$ 3.63	$ 3.55	$ 3.52	$ 3.72	$ 3.79	$ 3.87	$ 3.89
High Prices	Stanfield	2021-2022	$ 4.09	$ 4.34	$ 4.47	$ 4.34	$ 4.06	$ 3.36	$ 3.23	$ 3.26	$ 3.37	$ 3.41	$ 3.38	$ 3.39
High Prices	Stanfield	2022-2023	$ 3.64	$ 4.02	$ 4.23	$ 4.14	$ 3.84	$ 3.40	$ 3.31	$ 3.32	$ 3.44	$ 3.47	$ 3.53	$ 3.55
High Prices	Stanfield	2023-2024	$ 3.80	$ 4.24	$ 4.60	$ 4.41	$ 4.30	$ 3.75	$ 3.71	$ 3.71	$ 3.81	$ 3.85	$ 4.06	$ 4.14
High Prices	Stanfield	2024-2025	$ 4.46	$ 4.70	$ 5.27	$ 5.19	$ 4.99	$ 4.62	$ 4.60	$ 4.54	$ 4.64	$ 4.71	$ 4.91	$ 4.91
High Prices	Stanfield	2025-2026	$ 5.25	$ 5.42	$ 6.12	$ 6.04	$ 5.83	$ 5.38	$ 5.29	$ 5.28	$ 5.43	$ 5.60	$ 5.76	$ 5.78
High Prices	Stanfield	2026-2027	$ 6.17	$ 6.37	$ 6.58	$ 6.49	$ 6.23	$ 5.92	$ 5.86	$ 5.79	$ 5.97	$ 6.09	$ 6.28	$ 6.25
High Prices	Stanfield	2027-2028	$ 6.68	$ 6.91	$ 7.04	$ 6.76	$ 6.61	$ 6.22	$ 6.22	$ 6.26	$ 6.35	$ 6.54	$ 6.68	$ 6.84
High Prices	Stanfield	2028-2029	$ 7.15	$ 7.36	$ 7.45	$ 7.15	$ 6.95	$ 6.54	$ 6.52	$ 6.50	$ 6.73	$ 6.88	$ 6.97	$ 6.99
High Prices	Stanfield	2029-2030	$ 7.38	$ 7.88	$ 7.91	$ 7.65	$ 7.42	$ 6.97	$ 6.90	$ 6.98	$ 7.07	$ 7.32	$ 7.42	$ 7.52
High Prices	Stanfield	2030-2031	$ 7.86	$ 8.16	$ 8.14	$ 7.84	$ 7.58	$ 7.23	$ 7.17	$ 7.22	$ 7.39	$ 7.60	$ 7.73	$ 7.75
High Prices	Stanfield	2031-2032	$ 8.41	$ 8.77	$ 8.75	$ 8.35	$ 8.08	$ 7.74	$ 7.68	$ 7.75	$ 7.68	$ 7.91	$ 8.19	$ 8.26
High Prices	Stanfield	2032-2033	$ 8.68	$ 9.20	$ 9.34	$ 8.85	$ 8.61	$ 8.29	$ 8.10	$ 8.10	$ 8.18	$ 8.52	$ 8.77	$ 8.84
High Prices	Stanfield	2033-2034	$ 9.40	$ 9.67	$ 9.76	$ 9.41	$ 8.99	$ 8.85	$ 8.71	$ 8.79	$ 9.00	$ 9.33	$ 9.36	$ 9.52
High Prices	Stanfield	2034-2035	$10.03	$10.66	$10.65	$10.15	$ 9.78	$ 9.31	$ 9.18	$ 9.29	$ 9.32	$ 9.63	$ 9.78	$ 9.88
High Prices	Stanfield	2035-2036	$10.40	$10.74	$10.77	$10.21	$ 9.77	$ 9.42	$ 9.22	$ 9.38	$ 9.41	$ 9.79	$10.02	$10.09
High Prices	Stanfield	2036-2037	$10.53	$11.12	$11.31	$11.01	$10.26	$ 9.80	$ 9.68	$ 9.71	$ 9.68	$10.12	$10.27	$10.35
High Prices	Stanfield	2037-2038	$11.20	$11.73	$11.75	$10.93	$10.39	$ 9.95	$ 9.98	$10.07	$10.06	$10.51	$10.75	$10.81
High Prices	Stanfield	2038-2039	$11.60	$12.21	$12.31	$11.83	$11.51	$10.87	$10.77	$10.85	$10.93	$11.35	$11.58	$11.64
High Prices	Stanfield	2039-2040	$12.74	$13.17	$13.11	$12.70	$12.21	$11.73	$11.65	$11.57	$11.76	$12.04	$12.33	$12.43

Nominal $														
Scenario	Index	Gas Year	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
High Prices	Sumas	2019-2020	$ 4.11	$ 3.20	$ 2.28	$ 1.70	$ 1.36	$ 1.14	$ 1.03	$ 0.88	$ 0.89	$ 1.31	$ 1.25	$ 1.45
High Prices	Sumas	2020-2021	$ 2.22	$ 3.10	$ 5.01	$ 4.77	$ 4.32	$ 3.61	$ 3.55	$ 3.54	$ 3.80	$ 3.87	$ 3.87	$ 3.86
High Prices	Sumas	2021-2022	$ 4.46	$ 4.93	$ 4.95	$ 4.73	$ 4.28	$ 3.29	$ 3.17	$ 3.21	$ 3.36	$ 3.39	$ 3.35	$ 3.33
High Prices	Sumas	2022-2023	$ 4.02	$ 4.63	$ 4.82	$ 4.66	$ 4.17	$ 3.42	$ 3.32	$ 3.36	$ 3.52	$ 3.54	$ 3.54	$ 3.53
High Prices	Sumas	2023-2024	$ 4.27	$ 4.95	$ 5.21	$ 4.96	$ 4.67	$ 3.86	$ 3.76	$ 3.77	$ 3.78	$ 3.79	$ 3.85	$ 3.89
High Prices	Sumas	2024-2025	$ 4.86	$ 5.27	$ 5.79	$ 5.64	$ 5.34	$ 4.61	$ 4.50	$ 4.42	$ 4.49	$ 4.50	$ 4.62	$ 4.95
High Prices	Sumas	2025-2026	$ 5.52	$ 5.92	$ 6.53	$ 6.38	$ 6.00	$ 5.47	$ 5.19	$ 5.18	$ 5.26	$ 5.33	$ 5.37	$ 5.79
High Prices	Sumas	2026-2027	$ 6.33	$ 6.87	$ 7.03	$ 6.71	$ 6.41	$ 6.00	$ 5.68	$ 5.62	$ 5.71	$ 5.72	$ 5.82	$ 6.18
High Prices	Sumas	2027-2028	$ 6.83	$ 7.13	$ 7.28	$ 7.00	$ 6.83	$ 6.11	$ 6.05	$ 6.02	$ 6.07	$ 6.12	$ 6.21	$ 6.92
High Prices	Sumas	2028-2029	$ 7.28	$ 7.59	$ 7.69	$ 7.40	$ 7.17	$ 6.64	$ 6.33	$ 6.32	$ 6.43	$ 6.42	$ 6.46	$ 7.05
High Prices	Sumas	2029-2030	$ 7.51	$ 8.08	$ 8.09	$ 7.85	$ 7.62	$ 7.06	$ 6.66	$ 6.65	$ 6.75	$ 6.80	$ 6.87	$ 7.38
High Prices	Sumas	2030-2031	$ 7.96	$ 8.30	$ 8.32	$ 8.05	$ 7.79	$ 7.31	$ 6.98	$ 7.00	$ 7.02	$ 7.04	$ 7.11	$ 7.52
High Prices	Sumas	2031-2032	$ 8.52	$ 8.91	$ 8.93	$ 8.61	$ 8.32	$ 7.81	$ 7.41	$ 7.38	$ 7.25	$ 7.28	$ 7.49	$ 7.98
High Prices	Sumas	2032-2033	$ 8.81	$ 9.34	$ 9.52	$ 9.09	$ 8.89	$ 8.28	$ 7.92	$ 7.94	$ 7.84	$ 7.93	$ 8.05	$ 8.52
High Prices	Sumas	2033-2034	$ 9.54	$ 9.83	$ 9.96	$ 9.69	$ 9.30	$ 8.83	$ 8.47	$ 8.45	$ 8.61	$ 8.72	$ 8.62	$ 9.21
High Prices	Sumas	2034-2035	$10.19	$10.83	$10.86	$10.46	$10.10	$ 9.34	$ 8.95	$ 8.92	$ 8.90	$ 8.97	$ 9.02	$ 9.52
High Prices	Sumas	2035-2036	$10.56	$10.89	$10.98	$10.52	$10.09	$ 9.33	$ 9.04	$ 9.10	$ 9.08	$ 9.11	$ 9.21	$ 9.66
High Prices	Sumas	2036-2037	$10.69	$11.31	$11.52	$11.31	$10.58	$ 9.61	$ 9.47	$ 9.44	$ 9.43	$ 9.56	$ 9.56	$ 9.97
High Prices	Sumas	2037-2038	$11.38	$11.93	$12.01	$11.24	$10.67	$ 9.85	$ 9.72	$ 9.72	$ 9.70	$ 9.75	$ 9.81	$10.26
High Prices	Sumas	2038-2039	$11.78	$12.44	$12.57	$12.15	$11.80	$10.78	$10.53	$10.47	$10.57	$10.57	$10.74	$11.12
High Prices	Sumas	2039-2040	$12.92	$13.39	$13.38	$13.02	$12.52	$11.64	$11.39	$11.35	$11.36	$11.36	$11.49	$11.93

APPENDIX 6.2: WEIGHTED AVERAGE COST OF CAPITAL

Avista Corporation Capital Structure and Overall Rate of Return				
WASHINGTON				
From 2019 Rate Case Settlement				
Cost of Capital	Percent of Total Capital	Cost	Component	After Tax
L/T Debt	51.50%	5.15%	2.65%	2.10%
Common Equity	48.50%	9.40%	4.56%	4.56%
TOTAL	100.00%		7.21%	6.65%
IDAHO				
From 2019 Rate Case Settlement				
Cost of Capital	Percent of Total Capital	Cost	Component	After Tax
L/T Debt	50.00%	5.20%	2.60%	2.05%
Common Equity	50.00%	9.50%	4.75%	4.75%
TOTAL	100.00%		7.35%	6.80%
OREGON				
From 2020 Rate Case Settlement				
Cost of Capital	Percent of Total Capital	Cost	Component	After Tax
L/T Debt	50.00%	5.07%	2.54%	2.00%
Common Equity	50.00%	9.40%	4.70%	4.70%
TOTAL	100.00%		7.24%	6.70%
Gas Net Rate Base AMA Thru December 2020				
WA	$ 435,241	48%		
ID	$ 179,466	20%		
OR	$ 292,204	32%		
	$ 906,911			
System Weighted Average Cost of Capital (Nominal)*				6.70%
GDP price deflator				2.00%
Real After Tax WACC				4.36%

APPENDIX 6.3: POTENTIAL SUPPLY SIDE RESOURCE OPTIONS

Fossil Fuel Resources Modeled

Additional Resource	Size	Cost/Rates	Availability	Notes
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate	2021	Currently available unsubscribed capacity from Kingsgate to Spokane
Medford Lateral Exp	50,000 Dth / Day	$35M capital + GTN Rate	2022	Additional compression to facilitate more gas to flow from mainline GTN to Medford
Plymouth LNG	241,700 Dth w/70,500 Dth deliverability	NWP Rate	2021	Provides for peaking services and alleviates the need for costly pipeline expansions Pair with excess pipeline MDDO's to create firm transport

Renewable Resources Modeled

Resource	Dth per day	Dth per year	Levelized Cost Per Dth (Year 1)
Distributed Renewable Hydrogen Production - WA	166	60,509	$53.48
Distributed Renewable Hydrogen Production - OR	166	60,509	$50.00
Distributed LFG to RNG Production - WA	635	231,790	$13.53
Centralized LFG to RNG Production - WA	1,814	662,256	$11.73
Dairy Manure to RNG Production - WA	635	231,790	$40.70
Wastewater Sludge to RNG Production - WA	513	187,245	$18.95
Food Waste to RNG Production - WA	298	108,799	$40.68
Distributed LFG to RNG Production - OR	635	231,790	$13.53
Centralized LFG to RNG Production - OR	1,814	662,256	$11.73
Dairy Manure to RNG Production - OR	635	231,790	$40.23
Wastewater Sludge to RNG Production - OR	513	187,245	$18.75
Food Waste to RNG Production - OR	298	108,799	$40.21

APPENDIX 6.4: EXPECTED CASE AVOIDED COST

Annual Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Expected Case	2019-2020	$1.34	$1.30	$1.43	$1.33	$1.44	$1.34	$1.34	$1.34	$1.34	$1.30	$1.43	$1.36	$1.36	$1.36
Expected Case	2020-2021	$1.80	$1.78	$2.06	$1.81	$2.06	$1.84	$1.84	$1.84	$1.80	$1.78	$2.06	$1.88	$1.88	$1.88
Expected Case	2021-2022	$1.51	$1.50	$1.89	$1.54	$1.90	$1.58	$1.58	$1.58	$1.51	$1.50	$1.89	$1.63	$1.63	$1.64
Expected Case	2022-2023	$1.38	$1.37	$1.80	$1.41	$1.81	$1.46	$1.46	$1.46	$1.38	$1.37	$1.80	$1.52	$1.52	$1.52
Expected Case	2023-2024	$1.57	$1.56	$1.85	$1.60	$1.86	$1.63	$1.63	$1.63	$1.57	$1.56	$1.85	$1.66	$1.66	$1.67
Expected Case	2024-2025	$1.81	$1.79	$2.09	$1.84	$2.10	$1.88	$1.88	$1.88	$1.81	$1.79	$2.09	$1.89	$1.89	$1.92
Expected Case	2025-2026	$2.21	$2.19	$2.46	$2.25	$2.48	$2.29	$2.29	$2.29	$2.21	$2.19	$2.46	$2.29	$2.29	$2.32
Expected Case	2026-2027	$2.40	$2.39	$2.64	$2.45	$2.66	$2.49	$2.49	$2.49	$2.40	$2.39	$2.64	$2.47	$2.47	$2.52
Expected Case	2027-2028	$2.56	$2.56	$2.79	$2.62	$2.82	$2.65	$2.65	$2.65	$2.56	$2.56	$2.79	$2.64	$2.64	$2.67
Expected Case	2028-2029	$2.71	$2.70	$2.97	$2.77	$2.99	$2.81	$2.81	$2.81	$2.71	$2.70	$2.97	$2.79	$2.79	$2.84
Expected Case	2029-2030	$2.81	$2.80	$3.06	$2.87	$3.08	$2.92	$2.92	$2.92	$2.81	$2.80	$3.06	$2.89	$2.89	$2.94
Expected Case	2030-2031	$2.94	$2.94	$3.21	$3.01	$3.24	$3.06	$3.06	$3.06	$2.94	$2.94	$3.21	$3.03	$3.03	$3.08
Expected Case	2031-2032	$3.00	$3.00	$3.29	$3.07	$3.32	$3.12	$3.12	$3.12	$3.00	$3.00	$3.29	$3.10	$3.10	$3.15
Expected Case	2032-2033	$3.28	$3.27	$3.54	$3.35	$3.58	$3.40	$3.40	$3.40	$3.28	$3.27	$3.54	$3.36	$3.36	$3.43
Expected Case	2033-2034	$3.47	$3.46	$3.74	$3.55	$3.77	$3.65	$3.65	$3.65	$3.47	$3.46	$3.74	$3.56	$3.56	$3.65
Expected Case	2034-2035	$3.57	$3.57	$3.85	$3.70	$3.93	$3.80	$3.80	$3.80	$3.57	$3.57	$3.85	$3.66	$3.66	$3.81
Expected Case	2035-2036	$3.76	$3.75	$4.02	$3.89	$4.11	$3.97	$3.97	$3.97	$3.76	$3.75	$4.02	$3.85	$3.85	$3.98
Expected Case	2036-2037	$3.96	$3.93	$4.24	$4.08	$4.33	$4.16	$4.16	$4.16	$3.96	$3.93	$4.24	$4.04	$4.04	$4.18
Expected Case	2037-2038	$4.13	$4.10	$4.39	$4.25	$4.49	$4.33	$4.33	$4.33	$4.13	$4.10	$4.39	$4.20	$4.20	$4.34
Expected Case	2038-2039	$4.34	$4.28	$4.64	$4.43	$4.72	$4.51	$4.51	$4.51	$4.34	$4.28	$4.64	$4.42	$4.42	$4.54
Expected Case	2039-2040	$4.58	$4.48	$4.87	$4.66	$4.95	$4.73	$4.73	$4.73	$4.58	$4.48	$4.87	$4.64	$4.64	$4.76

[1] Avoided costs are before Environmental Externalities adder

Winter Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Expected Case	2019-2020	$1.99	$2.02	$1.99	$2.20	$2.23	$2.20	$2.20	$2.20	$1.99	$2.02	$1.99	$2.00	$2.00	$2.20
Expected Case	2020-2021	$2.13	$2.09	$2.14	$2.10	$2.15	$2.10	$2.10	$2.10	$2.13	$2.09	$2.14	$2.12	$2.12	$2.11
Expected Case	2021-2022	$1.96	$1.94	$2.16	$2.01	$2.18	$2.01	$2.01	$2.01	$1.96	$1.94	$2.16	$2.02	$2.02	$2.04
Expected Case	2022-2023	$1.65	$1.64	$1.97	$1.71	$2.00	$1.71	$1.71	$1.71	$1.65	$1.64	$1.97	$1.75	$1.75	$1.76
Expected Case	2023-2024	$1.76	$1.73	$2.03	$1.81	$2.05	$1.81	$1.81	$1.81	$1.76	$1.73	$2.03	$1.84	$1.84	$1.86
Expected Case	2024-2025	$1.80	$1.72	$2.07	$1.83	$2.12	$1.83	$1.83	$1.83	$1.80	$1.72	$2.07	$1.86	$1.86	$1.88
Expected Case	2025-2026	$2.19	$2.09	$2.47	$2.22	$2.51	$2.22	$2.22	$2.22	$2.19	$2.09	$2.47	$2.25	$2.25	$2.28
Expected Case	2026-2027	$2.53	$2.50	$2.65	$2.61	$2.71	$2.61	$2.61	$2.61	$2.53	$2.50	$2.65	$2.56	$2.56	$2.63
Expected Case	2027-2028	$2.72	$2.71	$2.81	$2.81	$2.89	$2.81	$2.81	$2.81	$2.72	$2.71	$2.81	$2.74	$2.74	$2.83
Expected Case	2028-2029	$2.91	$2.88	$2.97	$3.00	$3.06	$3.00	$3.00	$3.00	$2.91	$2.88	$2.97	$2.92	$2.92	$3.01
Expected Case	2029-2030	$3.03	$3.03	$3.08	$3.15	$3.19	$3.15	$3.15	$3.15	$3.03	$3.03	$3.08	$3.05	$3.05	$3.16
Expected Case	2030-2031	$3.18	$3.18	$3.23	$3.30	$3.33	$3.30	$3.30	$3.30	$3.18	$3.18	$3.23	$3.20	$3.20	$3.30
Expected Case	2031-2032	$3.29	$3.28	$3.32	$3.41	$3.43	$3.41	$3.41	$3.41	$3.29	$3.28	$3.32	$3.30	$3.30	$3.42
Expected Case	2032-2033	$3.46	$3.44	$3.52	$3.59	$3.64	$3.59	$3.59	$3.59	$3.46	$3.44	$3.52	$3.47	$3.47	$3.60
Expected Case	2033-2034	$3.71	$3.70	$3.74	$3.86	$3.87	$3.86	$3.86	$3.86	$3.71	$3.70	$3.74	$3.72	$3.72	$3.86
Expected Case	2034-2035	$3.88	$3.87	$3.90	$4.30	$4.31	$4.30	$4.30	$4.30	$3.88	$3.87	$3.90	$3.89	$3.89	$4.31
Expected Case	2035-2036	$4.04	$4.01	$4.13	$4.47	$4.54	$4.47	$4.47	$4.47	$4.04	$4.01	$4.13	$4.06	$4.06	$4.49
Expected Case	2036-2037	$4.26	$4.21	$4.34	$4.72	$4.77	$4.72	$4.72	$4.72	$4.26	$4.21	$4.34	$4.27	$4.27	$4.73
Expected Case	2037-2038	$4.56	$4.52	$4.63	$5.02	$5.07	$5.02	$5.02	$5.02	$4.56	$4.52	$4.63	$4.57	$4.57	$5.03
Expected Case	2038-2039	$4.71	$4.56	$4.87	$5.09	$5.26	$5.09	$5.09	$5.09	$4.71	$4.56	$4.87	$4.71	$4.71	$5.13
Expected Case	2039-2040	$5.03	$4.82	$5.17	$5.41	$5.59	$5.41	$5.41	$5.41	$5.03	$4.82	$5.17	$5.00	$5.00	$5.45

[1] Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: LOW GROWTH & HIGH PRICES CASE AVOIDED COST

Annual Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Low Growth & High Prices	2019-2020	$1.34	$1.30	$1.43	$1.33	$1.44	$1.34	$1.34	$1.34	$1.34	$1.30	$1.43	$1.36	$1.36	$1.36
Low Growth & High Prices	2020-2021	$3.38	$3.35	$3.62	$3.42	$3.63	$3.45	$3.45	$3.45	$3.38	$3.35	$3.62	$3.45	$3.45	$3.48
Low Growth & High Prices	2021-2022	$3.24	$3.32	$3.54	$3.39	$3.64	$3.37	$3.37	$3.37	$3.24	$3.32	$3.54	$3.37	$3.37	$3.43
Low Growth & High Prices	2022-2023	$3.19	$3.27	$3.51	$3.33	$3.60	$3.31	$3.31	$3.31	$3.19	$3.27	$3.51	$3.32	$3.32	$3.37
Low Growth & High Prices	2023-2024	$3.72	$3.76	$3.92	$3.83	$3.99	$3.83	$3.83	$3.83	$3.72	$3.76	$3.92	$3.80	$3.80	$3.86
Low Growth & High Prices	2024-2025	$4.39	$4.44	$4.60	$4.52	$4.66	$4.51	$4.51	$4.51	$4.39	$4.44	$4.60	$4.47	$4.47	$4.54
Low Growth & High Prices	2025-2026	$5.21	$5.25	$5.44	$5.35	$5.50	$5.34	$5.34	$5.34	$5.21	$5.25	$5.44	$5.30	$5.30	$5.37
Low Growth & High Prices	2026-2027	$5.74	$5.78	$5.93	$5.88	$5.99	$5.87	$5.87	$5.87	$5.74	$5.78	$5.93	$5.82	$5.82	$5.90
Low Growth & High Prices	2027-2028	$6.14	$6.17	$6.30	$6.28	$6.36	$6.27	$6.27	$6.27	$6.14	$6.17	$6.30	$6.20	$6.20	$6.29
Low Growth & High Prices	2028-2029	$6.47	$6.48	$6.65	$6.60	$6.70	$6.59	$6.59	$6.59	$6.47	$6.48	$6.65	$6.53	$6.53	$6.61
Low Growth & High Prices	2029-2030	$6.83	$6.85	$7.03	$6.97	$7.09	$6.97	$6.97	$6.97	$6.83	$6.85	$7.03	$6.90	$6.90	$6.99
Low Growth & High Prices	2030-2031	$7.08	$7.09	$7.29	$7.22	$7.35	$7.21	$7.21	$7.21	$7.08	$7.09	$7.29	$7.15	$7.15	$7.24
Low Growth & High Prices	2031-2032	$7.49	$7.51	$7.73	$7.65	$7.80	$7.63	$7.63	$7.63	$7.49	$7.51	$7.73	$7.58	$7.58	$7.67
Low Growth & High Prices	2032-2033	$8.00	$8.04	$8.24	$8.18	$8.32	$8.17	$8.17	$8.17	$8.00	$8.04	$8.24	$8.09	$8.09	$8.20
Low Growth & High Prices	2033-2034	$8.61	$8.61	$8.86	$8.77	$8.90	$8.75	$8.75	$8.75	$8.61	$8.61	$8.86	$8.69	$8.69	$8.79
Low Growth & High Prices	2034-2035	$9.09	$9.17	$9.31	$9.33	$9.44	$9.32	$9.32	$9.32	$9.09	$9.17	$9.31	$9.19	$9.19	$9.35
Low Growth & High Prices	2035-2036	$9.29	$9.32	$9.52	$9.49	$9.61	$9.47	$9.47	$9.47	$9.29	$9.32	$9.52	$9.38	$9.38	$9.50
Low Growth & High Prices	2036-2037	$9.59	$9.68	$9.79	$9.86	$9.94	$9.83	$9.83	$9.83	$9.59	$9.68	$9.79	$9.69	$9.69	$9.86
Low Growth & High Prices	2037-2038	$9.92	$10.04	$10.14	$10.22	$10.32	$10.19	$10.19	$10.19	$9.92	$10.04	$10.14	$10.03	$10.03	$10.22
Low Growth & High Prices	2038-2039	$10.74	$10.82	$10.97	$11.01	$11.11	$10.99	$10.99	$10.99	$10.74	$10.82	$10.97	$10.85	$10.85	$11.02
Low Growth & High Prices	2039-2040	$11.66	$11.69	$11.89	$11.90	$11.98	$11.87	$11.87	$11.87	$11.66	$11.69	$11.89	$11.75	$11.75	$11.90

[1] Avoided costs are before Environmental Externalities adder

Winter Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Low Growth & High Prices	2019-2020	$1.99	$2.02	$1.99	$2.20	$2.23	$2.20	$2.20	$2.20	$1.99	$2.02	$1.99	$2.00	$2.00	$2.20
Low Growth & High Prices	2020-2021	$2.31	$2.09	$2.32	$2.13	$2.32	$2.18	$2.18	$2.18	$2.31	$2.09	$2.32	$2.24	$2.24	$2.20
Low Growth & High Prices	2021-2022	$3.75	$3.91	$3.75	$3.98	$3.98	$3.98	$3.98	$3.98	$3.75	$3.91	$3.75	$3.81	$3.81	$3.98
Low Growth & High Prices	2022-2023	$3.34	$3.46	$3.53	$3.52	$3.68	$3.52	$3.52	$3.52	$3.34	$3.46	$3.53	$3.44	$3.44	$3.56
Low Growth & High Prices	2023-2024	$3.80	$3.80	$4.01	$3.87	$4.05	$3.87	$3.87	$3.87	$3.80	$3.80	$4.01	$3.87	$3.87	$3.91
Low Growth & High Prices	2024-2025	$4.17	$4.17	$4.57	$4.25	$4.57	$4.25	$4.25	$4.25	$4.17	$4.17	$4.57	$4.30	$4.30	$4.31
Low Growth & High Prices	2025-2026	$4.92	$4.92	$5.41	$5.01	$5.41	$5.01	$5.01	$5.01	$4.92	$4.92	$5.41	$5.08	$5.08	$5.09
Low Growth & High Prices	2026-2027	$5.85	$5.85	$5.92	$5.96	$5.98	$5.96	$5.96	$5.96	$5.85	$5.85	$5.92	$5.88	$5.88	$5.96
Low Growth & High Prices	2027-2028	$6.26	$6.29	$6.29	$6.40	$6.40	$6.40	$6.40	$6.40	$6.26	$6.29	$6.29	$6.28	$6.28	$6.40
Low Growth & High Prices	2028-2029	$6.69	$6.69	$6.69	$6.81	$6.81	$6.81	$6.81	$6.81	$6.69	$6.69	$6.69	$6.69	$6.69	$6.81
Low Growth & High Prices	2029-2030	$6.97	$7.02	$7.05	$7.15	$7.16	$7.15	$7.15	$7.15	$6.97	$7.02	$7.05	$7.01	$7.01	$7.15
Low Growth & High Prices	2030-2031	$7.33	$7.37	$7.33	$7.51	$7.51	$7.51	$7.51	$7.51	$7.33	$7.37	$7.33	$7.34	$7.34	$7.51
Low Growth & High Prices	2031-2032	$7.79	$7.85	$7.79	$8.00	$8.00	$8.00	$8.00	$8.00	$7.79	$7.85	$7.79	$7.81	$7.81	$8.00
Low Growth & High Prices	2032-2033	$8.13	$8.19	$8.23	$8.33	$8.36	$8.33	$8.33	$8.33	$8.13	$8.19	$8.23	$8.18	$8.18	$8.34
Low Growth & High Prices	2033-2034	$8.76	$8.76	$8.82	$8.92	$8.92	$8.92	$8.92	$8.92	$8.76	$8.76	$8.82	$8.78	$8.78	$8.92
Low Growth & High Prices	2034-2035	$9.36	$9.56	$9.37	$9.74	$9.73	$9.74	$9.74	$9.74	$9.36	$9.56	$9.37	$9.43	$9.43	$9.74
Low Growth & High Prices	2035-2036	$9.67	$9.75	$9.67	$9.92	$9.92	$9.92	$9.92	$9.92	$9.67	$9.75	$9.67	$9.69	$9.69	$9.92
Low Growth & High Prices	2036-2037	$9.84	$10.00	$9.85	$10.18	$10.18	$10.18	$10.18	$10.18	$9.84	$10.00	$9.85	$9.90	$9.90	$10.18
Low Growth & High Prices	2037-2038	$10.36	$10.74	$10.36	$10.94	$10.94	$10.94	$10.94	$10.94	$10.36	$10.74	$10.36	$10.49	$10.49	$10.94
Low Growth & High Prices	2038-2039	$10.94	$11.11	$11.00	$11.31	$11.31	$11.31	$11.31	$11.31	$10.94	$11.11	$11.00	$11.02	$11.02	$11.31
Low Growth & High Prices	2039-2040	$12.08	$12.15	$12.08	$12.37	$12.37	$12.37	$12.37	$12.37	$12.08	$12.15	$12.08	$12.10	$12.10	$12.37

[1] Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: HIGH GROWTH & LOW PRICES CASE AVOIDED COST

Annual Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
High Growth & Low Prices	2019-2020	$1.34	$1.30	$1.43	$1.33	$1.44	$1.34	$1.34	$1.34	$1.34	$1.30	$1.43	$1.36	$1.36	$1.36
High Growth & Low Prices	2020-2021	$1.27	$1.26	$1.54	$1.28	$1.57	$1.31	$1.31	$1.31	$1.27	$1.26	$1.54	$1.36	$1.36	$1.36
High Growth & Low Prices	2021-2022	$0.95	$0.87	$1.32	$0.92	$1.33	$0.96	$0.96	$0.96	$0.95	$0.87	$1.32	$1.05	$1.05	$1.02
High Growth & Low Prices	2022-2023	$0.78	$0.71	$1.18	$0.76	$1.20	$0.80	$0.80	$0.80	$0.78	$0.71	$1.18	$0.89	$0.89	$0.88
High Growth & Low Prices	2023-2024	$0.88	$0.79	$1.13	$0.84	$1.15	$0.87	$0.87	$0.87	$0.88	$0.79	$1.13	$0.93	$0.93	$0.92
High Growth & Low Prices	2024-2025	$1.03	$0.89	$1.33	$0.96	$1.35	$1.04	$1.04	$1.04	$1.03	$0.89	$1.33	$1.08	$1.08	$1.09
High Growth & Low Prices	2025-2026	$1.26	$1.12	$1.55	$1.20	$1.57	$1.29	$1.29	$1.29	$1.26	$1.12	$1.55	$1.31	$1.31	$1.33
High Growth & Low Prices	2026-2027	$1.36	$1.23	$1.64	$1.31	$1.68	$1.41	$1.41	$1.41	$1.36	$1.23	$1.64	$1.41	$1.41	$1.44
High Growth & Low Prices	2027-2028	$1.45	$1.31	$1.74	$1.38	$1.79	$1.47	$1.47	$1.47	$1.45	$1.31	$1.74	$1.50	$1.50	$1.52
High Growth & Low Prices	2028-2029	$1.51	$1.37	$1.80	$1.46	$1.88	$1.57	$1.57	$1.57	$1.51	$1.37	$1.80	$1.56	$1.56	$1.61
High Growth & Low Prices	2029-2030	$1.56	$1.41	$1.96	$1.50	$2.04	$1.60	$1.60	$1.60	$1.56	$1.41	$1.96	$1.64	$1.64	$1.67
High Growth & Low Prices	2030-2031	$1.60	$1.45	$1.99	$1.59	$2.09	$1.70	$1.70	$1.70	$1.60	$1.45	$1.99	$1.68	$1.68	$1.75
High Growth & Low Prices	2031-2032	$1.60	$1.44	$2.14	$1.60	$2.23	$1.70	$1.70	$1.70	$1.60	$1.44	$2.14	$1.73	$1.73	$1.79
High Growth & Low Prices	2032-2033	$1.76	$1.60	$2.31	$1.77	$2.40	$1.87	$1.87	$1.87	$1.76	$1.60	$2.31	$1.89	$1.89	$1.96
High Growth & Low Prices	2033-2034	$1.89	$1.73	$2.46	$1.90	$2.54	$2.01	$2.01	$2.01	$1.89	$1.73	$2.46	$2.03	$2.03	$2.09
High Growth & Low Prices	2034-2035	$1.90	$1.73	$2.50	$1.91	$2.58	$2.02	$2.02	$2.02	$1.90	$1.73	$2.50	$2.04	$2.04	$2.11
High Growth & Low Prices	2035-2036	$2.06	$1.79	$2.65	$1.98	$2.70	$2.07	$2.07	$2.07	$2.06	$1.79	$2.65	$2.17	$2.17	$2.18
High Growth & Low Prices	2036-2037	$2.14	$1.86	$2.71	$2.07	$2.76	$2.16	$2.16	$2.16	$2.14	$1.86	$2.71	$2.24	$2.24	$2.26
High Growth & Low Prices	2037-2038	$2.25	$1.97	$2.84	$2.17	$2.88	$2.26	$2.26	$2.26	$2.25	$1.97	$2.84	$2.35	$2.35	$2.37
High Growth & Low Prices	2038-2039	$2.32	$2.03	$2.94	$2.25	$2.98	$2.34	$2.34	$2.34	$2.32	$2.03	$2.94	$2.43	$2.43	$2.45
High Growth & Low Prices	2039-2040	$2.47	$2.19	$3.08	$2.41	$3.12	$2.50	$2.50	$2.50	$2.47	$2.19	$3.08	$2.58	$2.58	$2.61

[1] Avoided costs are before Environmental Externalities adder

Winter Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
High Growth & Low Prices	2019-2020	$1.99	$2.02	$1.99	$2.20	$2.23	$2.20	$2.20	$2.20	$1.99	$2.02	$1.99	$2.00	$2.00	$2.20
High Growth & Low Prices	2020-2021	$1.91	$2.09	$1.91	$2.08	$2.12	$2.08	$2.08	$2.08	$1.91	$2.09	$1.91	$1.97	$1.97	$2.09
High Growth & Low Prices	2021-2022	$1.48	$1.28	$1.64	$1.42	$1.66	$1.42	$1.42	$1.42	$1.48	$1.28	$1.64	$1.47	$1.47	$1.47
High Growth & Low Prices	2022-2023	$1.20	$0.99	$1.41	$1.20	$1.51	$1.20	$1.20	$1.20	$1.20	$0.99	$1.41	$1.20	$1.20	$1.27
High Growth & Low Prices	2023-2024	$1.23	$1.00	$1.37	$1.20	$1.42	$1.20	$1.20	$1.20	$1.23	$1.00	$1.37	$1.20	$1.20	$1.25
High Growth & Low Prices	2024-2025	$1.24	$0.89	$1.51	$1.18	$1.56	$1.18	$1.18	$1.18	$1.24	$0.89	$1.51	$1.21	$1.21	$1.26
High Growth & Low Prices	2025-2026	$1.48	$1.13	$1.76	$1.46	$1.81	$1.46	$1.46	$1.46	$1.48	$1.13	$1.76	$1.46	$1.46	$1.53
High Growth & Low Prices	2026-2027	$1.69	$1.35	$1.85	$1.69	$1.96	$1.69	$1.69	$1.69	$1.69	$1.35	$1.85	$1.63	$1.63	$1.75
High Growth & Low Prices	2027-2028	$1.87	$1.47	$1.98	$1.76	$2.11	$1.76	$1.76	$1.76	$1.87	$1.47	$1.98	$1.77	$1.77	$1.83
High Growth & Low Prices	2028-2029	$1.95	$1.55	$2.02	$1.92	$2.26	$1.92	$1.92	$1.92	$1.95	$1.55	$2.02	$1.84	$1.84	$1.99
High Growth & Low Prices	2029-2030	$2.03	$1.63	$2.14	$2.02	$2.38	$2.02	$2.02	$2.02	$2.03	$1.63	$2.14	$1.94	$1.94	$2.10
High Growth & Low Prices	2030-2031	$2.08	$1.68	$2.17	$2.05	$2.41	$2.05	$2.05	$2.05	$2.08	$1.68	$2.17	$1.98	$1.98	$2.12
High Growth & Low Prices	2031-2032	$2.15	$1.72	$2.32	$2.17	$2.54	$2.17	$2.17	$2.17	$2.15	$1.72	$2.32	$2.06	$2.06	$2.24
High Growth & Low Prices	2032-2033	$2.19	$1.75	$2.46	$2.22	$2.65	$2.22	$2.22	$2.22	$2.19	$1.75	$2.46	$2.13	$2.13	$2.31
High Growth & Low Prices	2033-2034	$2.40	$1.93	$2.67	$2.43	$2.85	$2.43	$2.43	$2.43	$2.40	$1.93	$2.67	$2.33	$2.33	$2.52
High Growth & Low Prices	2034-2035	$2.49	$2.02	$2.80	$2.54	$2.98	$2.54	$2.54	$2.54	$2.49	$2.02	$2.80	$2.44	$2.44	$2.63
High Growth & Low Prices	2035-2036	$2.51	$2.04	$2.98	$2.57	$3.10	$2.57	$2.57	$2.57	$2.51	$2.04	$2.98	$2.51	$2.51	$2.68
High Growth & Low Prices	2036-2037	$2.63	$2.13	$3.17	$2.72	$3.27	$2.72	$2.72	$2.72	$2.63	$2.13	$3.17	$2.64	$2.64	$2.83
High Growth & Low Prices	2037-2038	$2.82	$2.33	$3.30	$2.91	$3.41	$2.91	$2.91	$2.91	$2.82	$2.33	$3.30	$2.82	$2.82	$3.01
High Growth & Low Prices	2038-2039	$2.80	$2.28	$3.37	$2.93	$3.46	$2.93	$2.93	$2.93	$2.80	$2.28	$3.37	$2.82	$2.82	$3.04
High Growth & Low Prices	2039-2040	$2.98	$2.47	$3.55	$3.12	$3.68	$3.12	$3.12	$3.12	$2.98	$2.47	$3.55	$3.00	$3.00	$3.23

[1] Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: AVERAGE CASE AVOIDED COST

Annual Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Average Case	2019-2020	$1.30	$1.30	$1.38	$1.32	$1.40	$1.32	$1.32	$1.32	$1.30	$1.30	$1.38	$1.32	$1.32	$1.34
Average Case	2020-2021	$1.79	$1.78	$2.06	$1.81	$2.06	$1.84	$1.84	$1.84	$1.79	$1.78	$2.06	$1.88	$1.88	$1.88
Average Case	2021-2022	$1.50	$1.50	$1.87	$1.54	$1.88	$1.58	$1.58	$1.58	$1.50	$1.50	$1.87	$1.62	$1.62	$1.63
Average Case	2022-2023	$1.37	$1.37	$1.80	$1.40	$1.80	$1.45	$1.45	$1.45	$1.37	$1.37	$1.80	$1.52	$1.52	$1.51
Average Case	2023-2024	$1.56	$1.56	$1.85	$1.59	$1.86	$1.62	$1.62	$1.62	$1.56	$1.56	$1.85	$1.66	$1.66	$1.66
Average Case	2024-2025	$1.80	$1.79	$2.09	$1.84	$2.10	$1.87	$1.87	$1.87	$1.80	$1.79	$2.09	$1.89	$1.89	$1.91
Average Case	2025-2026	$2.20	$2.19	$2.47	$2.24	$2.48	$2.28	$2.28	$2.28	$2.20	$2.19	$2.47	$2.29	$2.29	$2.31
Average Case	2026-2027	$2.39	$2.39	$2.65	$2.44	$2.65	$2.48	$2.48	$2.48	$2.39	$2.39	$2.65	$2.47	$2.47	$2.51
Average Case	2027-2028	$2.56	$2.56	$2.80	$2.61	$2.81	$2.64	$2.64	$2.64	$2.56	$2.56	$2.80	$2.64	$2.64	$2.67
Average Case	2028-2029	$2.71	$2.70	$2.97	$2.76	$2.98	$2.80	$2.80	$2.80	$2.71	$2.70	$2.97	$2.79	$2.79	$2.83
Average Case	2029-2030	$2.80	$2.80	$3.06	$2.86	$3.08	$2.91	$2.91	$2.91	$2.80	$2.80	$3.06	$2.89	$2.89	$2.93
Average Case	2030-2031	$2.94	$2.94	$3.21	$3.00	$3.23	$3.04	$3.04	$3.04	$2.94	$2.94	$3.21	$3.03	$3.03	$3.07
Average Case	2031-2032	$3.00	$3.00	$3.30	$3.06	$3.31	$3.11	$3.11	$3.11	$3.00	$3.00	$3.30	$3.10	$3.10	$3.14
Average Case	2032-2033	$3.27	$3.27	$3.55	$3.34	$3.57	$3.39	$3.39	$3.39	$3.27	$3.27	$3.55	$3.36	$3.36	$3.41
Average Case	2033-2034	$3.47	$3.46	$3.74	$3.53	$3.76	$3.63	$3.63	$3.63	$3.47	$3.46	$3.74	$3.56	$3.56	$3.64
Average Case	2034-2035	$3.57	$3.57	$3.86	$3.64	$3.88	$3.74	$3.74	$3.74	$3.57	$3.57	$3.86	$3.67	$3.67	$3.74
Average Case	2035-2036	$3.75	$3.75	$4.01	$3.82	$4.04	$3.90	$3.90	$3.90	$3.75	$3.75	$4.01	$3.84	$3.84	$3.91
Average Case	2036-2037	$3.94	$3.93	$4.22	$4.01	$4.24	$4.09	$4.09	$4.09	$3.94	$3.93	$4.22	$4.03	$4.03	$4.11
Average Case	2037-2038	$4.11	$4.10	$4.39	$4.18	$4.41	$4.25	$4.25	$4.25	$4.11	$4.10	$4.39	$4.20	$4.20	$4.27
Average Case	2038-2039	$4.29	$4.28	$4.57	$4.36	$4.60	$4.44	$4.44	$4.44	$4.29	$4.28	$4.57	$4.38	$4.38	$4.46
Average Case	2039-2040	$4.50	$4.48	$4.75	$4.57	$4.78	$4.64	$4.64	$4.64	$4.50	$4.48	$4.75	$4.58	$4.58	$4.66

[1] Avoided costs are before Environmental Externalities adder

Winter Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Average Case	2019-2020	$1.87	$2.02	$1.87	$2.12	$2.13	$2.12	$2.12	$2.12	$1.87	$2.02	$1.87	$1.92	$1.92	$2.12
Average Case	2020-2021	$2.13	$2.09	$2.13	$2.09	$2.14	$2.09	$2.09	$2.09	$2.13	$2.09	$2.13	$2.12	$2.12	$2.10
Average Case	2021-2022	$1.94	$1.94	$2.09	$1.98	$2.11	$1.98	$1.98	$1.98	$1.94	$1.94	$2.09	$1.99	$1.99	$2.00
Average Case	2022-2023	$1.64	$1.64	$1.95	$1.68	$1.95	$1.68	$1.68	$1.68	$1.64	$1.64	$1.95	$1.74	$1.74	$1.73
Average Case	2023-2024	$1.74	$1.73	$2.03	$1.78	$2.03	$1.78	$1.78	$1.78	$1.74	$1.73	$2.03	$1.83	$1.83	$1.83
Average Case	2024-2025	$1.78	$1.72	$2.07	$1.79	$2.08	$1.79	$1.79	$1.79	$1.78	$1.72	$2.07	$1.86	$1.86	$1.85
Average Case	2025-2026	$2.17	$2.09	$2.46	$2.18	$2.47	$2.18	$2.18	$2.18	$2.17	$2.09	$2.46	$2.24	$2.24	$2.24
Average Case	2026-2027	$2.52	$2.50	$2.65	$2.57	$2.66	$2.57	$2.57	$2.57	$2.52	$2.50	$2.65	$2.56	$2.56	$2.59
Average Case	2027-2028	$2.71	$2.71	$2.80	$2.77	$2.83	$2.77	$2.77	$2.77	$2.71	$2.71	$2.80	$2.74	$2.74	$2.78
Average Case	2028-2029	$2.90	$2.88	$2.97	$2.95	$2.98	$2.95	$2.95	$2.95	$2.90	$2.88	$2.97	$2.92	$2.92	$2.96
Average Case	2029-2030	$3.03	$3.03	$3.08	$3.09	$3.12	$3.09	$3.09	$3.09	$3.03	$3.03	$3.08	$3.04	$3.04	$3.10
Average Case	2030-2031	$3.18	$3.18	$3.23	$3.24	$3.26	$3.24	$3.24	$3.24	$3.18	$3.18	$3.23	$3.20	$3.20	$3.24
Average Case	2031-2032	$3.29	$3.28	$3.31	$3.35	$3.35	$3.35	$3.35	$3.35	$3.29	$3.28	$3.31	$3.29	$3.29	$3.35
Average Case	2032-2033	$3.46	$3.44	$3.51	$3.53	$3.56	$3.53	$3.53	$3.53	$3.46	$3.44	$3.51	$3.47	$3.47	$3.54
Average Case	2033-2034	$3.71	$3.70	$3.73	$3.79	$3.79	$3.79	$3.79	$3.79	$3.71	$3.70	$3.73	$3.71	$3.71	$3.79
Average Case	2034-2035	$3.88	$3.87	$3.90	$3.95	$3.95	$3.95	$3.95	$3.95	$3.88	$3.87	$3.90	$3.88	$3.88	$3.95
Average Case	2035-2036	$4.02	$4.01	$4.08	$4.09	$4.13	$4.09	$4.09	$4.09	$4.02	$4.01	$4.08	$4.03	$4.03	$4.10
Average Case	2036-2037	$4.22	$4.21	$4.27	$4.31	$4.33	$4.31	$4.31	$4.31	$4.22	$4.21	$4.27	$4.23	$4.23	$4.31
Average Case	2037-2038	$4.54	$4.52	$4.59	$4.62	$4.64	$4.62	$4.62	$4.62	$4.54	$4.52	$4.59	$4.55	$4.55	$4.62
Average Case	2038-2039	$4.60	$4.56	$4.68	$4.68	$4.75	$4.68	$4.68	$4.68	$4.60	$4.56	$4.68	$4.61	$4.61	$4.69
Average Case	2039-2040	$4.84	$4.82	$4.87	$4.92	$4.94	$4.92	$4.92	$4.92	$4.84	$4.82	$4.87	$4.84	$4.84	$4.92

[1] Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: CARBON REDUCTION AVOIDED COST

Annual Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Carbon Reduction	2019-2020	$1.34	$1.30	$1.43	$1.33	$1.44	$1.34	$1.34	$1.34	$1.34	$1.30	$1.43	$1.36	$1.36	$1.36
Carbon Reduction	2020-2021	$1.27	$1.26	$1.54	$1.28	$1.57	$1.31	$1.31	$1.31	$1.27	$1.26	$1.54	$1.36	$1.36	$1.36
Carbon Reduction	2021-2022	$0.88	$0.87	$1.25	$0.91	$1.26	$0.95	$0.95	$0.95	$0.88	$0.87	$1.25	$1.00	$1.00	$1.00
Carbon Reduction	2022-2023	$0.71	$0.71	$1.12	$0.74	$1.13	$0.78	$0.78	$0.78	$0.71	$0.71	$1.12	$0.85	$0.85	$0.84
Carbon Reduction	2023-2024	$0.80	$0.79	$1.07	$0.82	$1.08	$0.85	$0.85	$0.85	$0.80	$0.79	$1.07	$0.89	$0.89	$0.89
Carbon Reduction	2024-2025	$0.91	$0.89	$1.18	$0.93	$1.20	$0.97	$0.97	$0.97	$0.91	$0.89	$1.18	$0.99	$0.99	$1.00
Carbon Reduction	2025-2026	$1.14	$1.12	$1.37	$1.17	$1.39	$1.21	$1.21	$1.21	$1.14	$1.12	$1.37	$1.21	$1.21	$1.23
Carbon Reduction	2026-2027	$1.24	$1.23	$1.48	$1.27	$1.50	$1.32	$1.32	$1.32	$1.24	$1.23	$1.48	$1.32	$1.32	$1.35
Carbon Reduction	2027-2028	$1.32	$1.31	$1.56	$1.35	$1.58	$1.38	$1.38	$1.38	$1.32	$1.31	$1.56	$1.40	$1.40	$1.41
Carbon Reduction	2028-2029	$1.39	$1.37	$1.64	$1.42	$1.66	$1.47	$1.47	$1.47	$1.39	$1.37	$1.64	$1.47	$1.47	$1.50
Carbon Reduction	2029-2030	$1.42	$1.41	$1.65	$1.46	$1.68	$1.51	$1.51	$1.51	$1.42	$1.41	$1.65	$1.49	$1.49	$1.53
Carbon Reduction	2030-2031	$1.46	$1.45	$1.73	$1.50	$1.75	$1.55	$1.55	$1.55	$1.46	$1.45	$1.73	$1.55	$1.55	$1.58
Carbon Reduction	2031-2032	$1.47	$1.43	$1.77	$1.52	$1.82	$1.63	$1.63	$1.63	$1.47	$1.43	$1.77	$1.56	$1.56	$1.65
Carbon Reduction	2032-2033	$1.64	$1.60	$1.92	$1.70	$1.98	$1.80	$1.80	$1.80	$1.64	$1.60	$1.92	$1.72	$1.72	$1.81
Carbon Reduction	2033-2034	$1.79	$1.72	$2.10	$1.82	$2.15	$1.93	$1.93	$1.93	$1.79	$1.72	$2.10	$1.87	$1.87	$1.95
Carbon Reduction	2034-2035	$1.80	$1.72	$2.12	$1.83	$2.18	$1.94	$1.94	$1.94	$1.80	$1.72	$2.12	$1.88	$1.88	$1.96
Carbon Reduction	2035-2036	$1.91	$1.79	$2.25	$1.90	$2.29	$1.99	$1.99	$1.99	$1.91	$1.79	$2.25	$1.98	$1.98	$2.03
Carbon Reduction	2036-2037	$1.98	$1.86	$2.32	$1.98	$2.38	$2.07	$2.07	$2.07	$1.98	$1.86	$2.32	$2.05	$2.05	$2.11
Carbon Reduction	2037-2038	$2.09	$1.97	$2.45	$2.08	$2.50	$2.17	$2.17	$2.17	$2.09	$1.97	$2.45	$2.17	$2.17	$2.22
Carbon Reduction	2038-2039	$2.15	$2.03	$2.50	$2.15	$2.56	$2.24	$2.24	$2.24	$2.15	$2.03	$2.50	$2.23	$2.23	$2.29
Carbon Reduction	2039-2040	$2.31	$2.18	$2.63	$2.31	$2.69	$2.40	$2.40	$2.40	$2.31	$2.18	$2.63	$2.37	$2.37	$2.44

[1] Avoided costs are before Environmental Externalities adder

Winter Avoided Costs[1]
Nominal $

Scenario	Gas Year	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	ID Annual	WA Annual	OR Annual
Carbon Reduction	2019-2020	$1.99	$2.02	$1.99	$2.20	$2.23	$2.20	$2.20	$2.20	$1.99	$2.02	$1.99	$2.00	$2.00	$2.20
Carbon Reduction	2020-2021	$1.91	$2.09	$1.91	$2.08	$2.12	$2.08	$2.08	$2.08	$1.91	$2.09	$1.91	$1.97	$1.97	$2.09
Carbon Reduction	2021-2022	$1.30	$1.28	$1.45	$1.35	$1.49	$1.35	$1.35	$1.35	$1.30	$1.28	$1.45	$1.35	$1.35	$1.38
Carbon Reduction	2022-2023	$1.01	$0.99	$1.25	$1.05	$1.29	$1.05	$1.05	$1.05	$1.01	$0.99	$1.25	$1.08	$1.08	$1.10
Carbon Reduction	2023-2024	$1.05	$1.00	$1.22	$1.08	$1.25	$1.08	$1.08	$1.08	$1.05	$1.00	$1.22	$1.09	$1.09	$1.11
Carbon Reduction	2024-2025	$0.96	$0.89	$1.16	$1.00	$1.21	$1.00	$1.00	$1.00	$0.96	$0.89	$1.16	$1.01	$1.01	$1.04
Carbon Reduction	2025-2026	$1.23	$1.13	$1.36	$1.25	$1.41	$1.25	$1.25	$1.25	$1.23	$1.13	$1.36	$1.24	$1.24	$1.29
Carbon Reduction	2026-2027	$1.41	$1.35	$1.48	$1.46	$1.55	$1.46	$1.46	$1.46	$1.41	$1.35	$1.48	$1.41	$1.41	$1.48
Carbon Reduction	2027-2028	$1.50	$1.47	$1.57	$1.56	$1.64	$1.56	$1.56	$1.56	$1.50	$1.47	$1.57	$1.51	$1.51	$1.58
Carbon Reduction	2028-2029	$1.60	$1.55	$1.63	$1.68	$1.72	$1.68	$1.68	$1.68	$1.60	$1.55	$1.63	$1.59	$1.59	$1.68
Carbon Reduction	2029-2030	$1.64	$1.63	$1.67	$1.74	$1.77	$1.74	$1.74	$1.74	$1.64	$1.63	$1.67	$1.65	$1.65	$1.75
Carbon Reduction	2030-2031	$1.69	$1.68	$1.73	$1.78	$1.82	$1.78	$1.78	$1.78	$1.69	$1.68	$1.73	$1.70	$1.70	$1.79
Carbon Reduction	2031-2032	$1.78	$1.72	$1.83	$2.08	$2.13	$2.08	$2.08	$2.08	$1.78	$1.72	$1.83	$1.77	$1.77	$2.09
Carbon Reduction	2032-2033	$1.87	$1.75	$1.96	$2.14	$2.24	$2.14	$2.14	$2.14	$1.87	$1.75	$1.96	$1.86	$1.86	$2.16
Carbon Reduction	2033-2034	$2.09	$1.93	$2.19	$2.35	$2.46	$2.35	$2.35	$2.35	$2.09	$1.93	$2.19	$2.07	$2.07	$2.38
Carbon Reduction	2034-2035	$2.19	$2.02	$2.30	$2.47	$2.59	$2.47	$2.47	$2.47	$2.19	$2.02	$2.30	$2.17	$2.17	$2.50
Carbon Reduction	2035-2036	$2.33	$2.04	$2.52	$2.51	$2.74	$2.51	$2.51	$2.51	$2.33	$2.04	$2.52	$2.30	$2.30	$2.56
Carbon Reduction	2036-2037	$2.42	$2.13	$2.58	$2.66	$2.87	$2.66	$2.66	$2.66	$2.42	$2.13	$2.58	$2.38	$2.38	$2.70
Carbon Reduction	2037-2038	$2.62	$2.33	$2.81	$2.81	$3.05	$2.81	$2.81	$2.81	$2.62	$2.33	$2.81	$2.59	$2.59	$2.86
Carbon Reduction	2038-2039	$2.58	$2.28	$2.77	$2.80	$3.05	$2.80	$2.80	$2.80	$2.58	$2.28	$2.77	$2.54	$2.54	$2.85
Carbon Reduction	2039-2040	$2.76	$2.47	$2.92	$3.02	$3.24	$3.02	$3.02	$3.02	$2.76	$2.47	$2.92	$2.72	$2.72	$3.07

[1] Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: LOW GROWTH & HIGH PRICES MONTHLY DETAIL

Monthly Avoided Costs[1]
Nominal $

Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Low Growth & High Prices	2019-2020	Nov	$2.00	$2.18	$2.00	$2.22	$2.22	$2.22	$2.22	$2.22	$2.00	$2.18	$2.00	$2.06	$2.06	$2.22
Low Growth & High Prices	2019-2020	Dec	$1.99	$1.87	$1.99	$2.17	$2.25	$2.17	$2.17	$2.17	$1.99	$1.87	$1.99	$1.95	$1.95	$2.19
Low Growth & High Prices	2019-2020	Jan	$2.00	$1.80	$2.00	$1.84	$2.02	$1.84	$1.84	$1.84	$2.00	$1.80	$2.00	$1.93	$1.93	$1.88
Low Growth & High Prices	2019-2020	Feb	$1.95	$1.43	$1.97	$1.50	$1.97	$1.50	$1.50	$1.50	$1.95	$1.43	$1.97	$1.79	$1.79	$1.60
Low Growth & High Prices	2019-2020	Mar	$1.25	$1.25	$1.38	$1.28	$1.38	$1.28	$1.28	$1.28	$1.25	$1.25	$1.38	$1.30	$1.30	$1.30
Low Growth & High Prices	2019-2020	Apr	$1.03	$1.03	$1.15	$1.05	$1.14	$1.15	$1.15	$1.15	$1.03	$1.03	$1.15	$1.07	$1.07	$1.13
Low Growth & High Prices	2019-2020	May	$1.05	$1.14	$1.05	$1.07	$1.05	$1.05	$1.05	$1.05	$1.05	$1.14	$1.05	$1.08	$1.08	$1.06
Low Growth & High Prices	2019-2020	Jun	$0.90	$0.90	$1.06	$0.86	$0.90	$0.86	$0.86	$0.86	$0.90	$0.90	$1.06	$0.95	$0.95	$0.87
Low Growth & High Prices	2019-2020	Jul	$0.86	$0.86	$1.06	$0.80	$0.90	$0.80	$0.80	$0.80	$0.86	$0.86	$1.06	$0.93	$0.93	$0.82
Low Growth & High Prices	2019-2020	Aug	$1.10	$1.10	$1.11	$1.13	$1.11	$1.11	$1.11	$1.11	$1.10	$1.10	$1.11	$1.11	$1.11	$1.12
Low Growth & High Prices	2019-2020	Sep	$0.99	$0.99	$1.06	$1.01	$1.06	$1.01	$1.01	$1.01	$0.99	$0.99	$1.06	$1.01	$1.01	$1.02
Low Growth & High Prices	2019-2020	Oct	$1.02	$1.02	$1.31	$1.04	$1.31	$1.04	$1.04	$1.04	$1.02	$1.02	$1.31	$1.12	$1.12	$1.10
Low Growth & High Prices	2020-2021	Nov	$1.81	$1.81	$1.82	$1.74	$1.82	$1.74	$1.74	$1.74	$1.81	$1.81	$1.82	$1.81	$1.81	$1.75
Low Growth & High Prices	2020-2021	Dec	$2.80	$2.36	$2.81	$2.52	$2.80	$2.60	$2.60	$2.60	$2.80	$2.36	$2.81	$2.66	$2.66	$2.62
Low Growth & High Prices	2020-2021	Jan	$4.33	$4.47	$4.33	$4.55	$4.55	$4.55	$4.55	$4.55	$4.33	$4.47	$4.33	$4.38	$4.38	$4.55
Low Growth & High Prices	2020-2021	Feb	$4.36	$4.33	$4.36	$4.43	$4.43	$4.43	$4.43	$4.43	$4.36	$4.33	$4.36	$4.35	$4.35	$4.43
Low Growth & High Prices	2020-2021	Mar	$3.94	$3.94	$4.01	$4.02	$4.06	$4.02	$4.02	$4.02	$3.94	$3.94	$4.01	$3.96	$3.96	$4.03
Low Growth & High Prices	2020-2021	Apr	$3.34	$3.34	$3.69	$3.40	$3.69	$3.67	$3.67	$3.67	$3.34	$3.34	$3.69	$3.46	$3.46	$3.62
Low Growth & High Prices	2020-2021	May	$3.22	$3.22	$3.69	$3.28	$3.64	$3.28	$3.28	$3.28	$3.22	$3.22	$3.69	$3.38	$3.38	$3.35
Low Growth & High Prices	2020-2021	Jun	$3.27	$3.27	$3.69	$3.34	$3.63	$3.34	$3.34	$3.34	$3.27	$3.27	$3.69	$3.41	$3.41	$3.40
Low Growth & High Prices	2020-2021	Jul	$3.46	$3.46	$3.69	$3.53	$3.69	$3.53	$3.53	$3.53	$3.46	$3.46	$3.69	$3.54	$3.54	$3.56
Low Growth & High Prices	2020-2021	Aug	$3.46	$3.46	$3.69	$3.52	$3.69	$3.52	$3.52	$3.52	$3.46	$3.46	$3.69	$3.54	$3.54	$3.56
Low Growth & High Prices	2020-2021	Sep	$3.29	$3.29	$3.69	$3.36	$3.69	$3.36	$3.36	$3.36	$3.29	$3.29	$3.69	$3.43	$3.43	$3.43
Low Growth & High Prices	2020-2021	Oct	$3.33	$3.33	$3.92	$3.40	$3.92	$3.40	$3.40	$3.40	$3.33	$3.33	$3.92	$3.53	$3.53	$3.50
Low Growth & High Prices	2021-2022	Nov	$3.72	$3.72	$3.72	$3.79	$3.79	$3.79	$3.79	$3.79	$3.72	$3.72	$3.72	$3.72	$3.72	$3.79
Low Growth & High Prices	2021-2022	Dec	$3.78	$4.09	$3.78	$4.16	$4.16	$4.16	$4.16	$4.16	$3.78	$4.09	$3.78	$3.88	$3.88	$4.16
Low Growth & High Prices	2021-2022	Jan	$3.78	$4.24	$3.78	$4.33	$4.33	$4.33	$4.33	$4.33	$3.78	$4.24	$3.78	$3.94	$3.94	$4.33
Low Growth & High Prices	2021-2022	Feb	$3.81	$4.02	$3.81	$4.10	$4.05	$3.84	$3.84	$3.84	$3.81	$4.02	$3.81	$3.88	$3.88	$3.93
Low Growth & High Prices	2021-2022	Mar	$3.64	$3.64	$3.73	$3.71	$3.77	$3.71	$3.71	$3.71	$3.64	$3.64	$3.73	$3.67	$3.67	$3.72
Low Growth & High Prices	2021-2022	Apr	$2.84	$2.84	$3.38	$2.90	$3.38	$2.90	$2.90	$2.90	$2.84	$2.84	$3.38	$3.02	$3.02	$2.99
Low Growth & High Prices	2021-2022	May	$2.75	$2.75	$3.38	$2.81	$3.35	$2.81	$2.81	$2.81	$2.75	$2.75	$3.38	$2.96	$2.96	$2.92
Low Growth & High Prices	2021-2022	Jun	$2.88	$2.88	$3.38	$2.94	$3.38	$2.94	$2.94	$2.94	$2.88	$2.88	$3.38	$3.05	$3.05	$3.03
Low Growth & High Prices	2021-2022	Jul	$3.07	$3.07	$3.38	$3.13	$3.38	$3.13	$3.13	$3.13	$3.07	$3.07	$3.38	$3.18	$3.18	$3.18
Low Growth & High Prices	2021-2022	Aug	$3.02	$3.02	$3.38	$3.08	$3.38	$3.08	$3.08	$3.08	$3.02	$3.02	$3.38	$3.14	$3.14	$3.14
Low Growth & High Prices	2021-2022	Sep	$2.81	$2.81	$3.38	$2.87	$3.38	$2.87	$2.87	$2.87	$2.81	$2.81	$3.38	$3.00	$3.00	$2.97
Low Growth & High Prices	2021-2022	Oct	$2.81	$2.81	$3.38	$2.86	$3.38	$2.86	$2.86	$2.86	$2.81	$2.81	$3.38	$3.00	$3.00	$2.97
Low Growth & High Prices	2022-2023	Nov	$3.12	$3.12	$3.51	$3.18	$3.51	$3.18	$3.18	$3.18	$3.12	$3.12	$3.51	$3.25	$3.25	$3.24
Low Growth & High Prices	2022-2023	Dec	$3.56	$3.79	$3.56	$3.86	$3.86	$3.86	$3.86	$3.86	$3.56	$3.79	$3.56	$3.64	$3.64	$3.86
Low Growth & High Prices	2022-2023	Jan	$3.56	$4.03	$3.56	$4.11	$4.11	$4.11	$4.11	$4.11	$3.56	$4.03	$3.56	$3.72	$3.72	$4.11
Low Growth & High Prices	2022-2023	Feb	$3.57	$3.82	$3.57	$3.89	$3.85	$3.64	$3.64	$3.64	$3.57	$3.82	$3.57	$3.65	$3.65	$3.73
Low Growth & High Prices	2022-2023	Mar	$3.43	$3.43	$3.49	$3.50	$3.50	$3.50	$3.50	$3.50	$3.43	$3.43	$3.49	$3.45	$3.45	$3.50
Low Growth & High Prices	2022-2023	Apr	$2.94	$2.94	$3.48	$2.99	$3.48	$2.99	$2.99	$2.99	$2.94	$2.94	$3.48	$3.12	$3.12	$3.09
Low Growth & High Prices	2022-2023	May	$2.88	$2.88	$3.49	$2.93	$3.46	$2.93	$2.93	$2.93	$2.88	$2.88	$3.49	$3.08	$3.08	$3.04
Low Growth & High Prices	2022-2023	Jun	$3.05	$3.05	$3.49	$3.11	$3.49	$3.11	$3.11	$3.11	$3.05	$3.05	$3.49	$3.19	$3.19	$3.18
Low Growth & High Prices	2022-2023	Jul	$3.17	$3.17	$3.49	$3.23	$3.49	$3.23	$3.23	$3.23	$3.17	$3.17	$3.49	$3.27	$3.27	$3.28
Low Growth & High Prices	2022-2023	Aug	$3.17	$3.17	$3.49	$3.23	$3.49	$3.23	$3.23	$3.23	$3.17	$3.17	$3.49	$3.28	$3.28	$3.28
Low Growth & High Prices	2022-2023	Sep	$2.87	$2.87	$3.49	$2.93	$3.49	$2.93	$2.93	$2.93	$2.87	$2.87	$3.49	$3.08	$3.08	$3.04
Low Growth & High Prices	2022-2023	Oct	$2.96	$2.96	$3.49	$3.01	$3.49	$3.01	$3.01	$3.01	$2.96	$2.96	$3.49	$3.13	$3.13	$3.11
Low Growth & High Prices	2023-2024	Nov	$3.55	$3.55	$3.98	$3.62	$3.98	$3.62	$3.62	$3.62	$3.55	$3.55	$3.98	$3.69	$3.69	$3.69
Low Growth & High Prices	2023-2024	Dec	$4.04	$4.04	$4.04	$4.12	$4.12	$4.12	$4.12	$4.12	$4.04	$4.04	$4.04	$4.04	$4.04	$4.12
Low Growth & High Prices	2023-2024	Jan	$4.04	$4.45	$4.04	$4.53	$4.53	$4.53	$4.53	$4.53	$4.04	$4.45	$4.04	$4.18	$4.18	$4.53
Low Growth & High Prices	2023-2024	Feb	$4.04	$4.10	$4.04	$4.18	$4.13	$4.13	$4.13	$4.13	$4.04	$4.10	$4.04	$4.06	$4.06	$4.14
Low Growth & High Prices	2023-2024	Mar	$4.01	$4.04	$4.01	$4.12	$4.11	$4.11	$4.11	$4.11	$4.01	$4.04	$4.01	$4.02	$4.02	$4.12
Low Growth & High Prices	2023-2024	Apr	$3.55	$3.55	$3.85	$3.62	$3.85	$3.62	$3.62	$3.62	$3.55	$3.55	$3.85	$3.65	$3.65	$3.66
Low Growth & High Prices	2023-2024	May	$3.53	$3.53	$3.85	$3.59	$3.85	$3.59	$3.59	$3.59	$3.53	$3.53	$3.85	$3.63	$3.63	$3.64
Low Growth & High Prices	2023-2024	Jun	$3.54	$3.54	$3.85	$3.60	$3.85	$3.60	$3.60	$3.60	$3.54	$3.54	$3.85	$3.64	$3.64	$3.65
Low Growth & High Prices	2023-2024	Jul	$3.54	$3.54	$3.85	$3.61	$3.85	$3.61	$3.61	$3.61	$3.54	$3.54	$3.85	$3.64	$3.64	$3.66
Low Growth & High Prices	2023-2024	Aug	$3.55	$3.55	$3.85	$3.62	$3.85	$3.62	$3.62	$3.62	$3.55	$3.55	$3.85	$3.65	$3.65	$3.67
Low Growth & High Prices	2023-2024	Sep	$3.62	$3.62	$3.85	$3.69	$3.85	$3.69	$3.69	$3.69	$3.62	$3.62	$3.85	$3.69	$3.69	$3.72
Low Growth & High Prices	2023-2024	Oct	$3.65	$3.65	$3.85	$3.72	$3.85	$3.72	$3.72	$3.72	$3.65	$3.65	$3.85	$3.72	$3.72	$3.75
Low Growth & High Prices	2024-2025	Nov	$3.99	$3.99	$4.57	$4.07	$4.57	$4.07	$4.07	$4.07	$3.99	$3.99	$4.57	$4.19	$4.19	$4.17
Low Growth & High Prices	2024-2025	Dec	$4.34	$4.34	$4.57	$4.42	$4.57	$4.42	$4.42	$4.42	$4.34	$4.34	$4.57	$4.41	$4.41	$4.45
Low Growth & High Prices	2024-2025	Jan	$4.64	$4.96	$4.64	$5.06	$5.06	$5.06	$5.06	$5.06	$4.64	$4.96	$4.64	$4.75	$4.75	$5.06
Low Growth & High Prices	2024-2025	Feb	$4.64	$4.82	$4.64	$4.91	$4.86	$4.78	$4.78	$4.78	$4.64	$4.82	$4.64	$4.70	$4.70	$4.82
Low Growth & High Prices	2024-2025	Mar	$4.57	$4.62	$4.57	$4.71	$4.71	$4.71	$4.71	$4.71	$4.57	$4.62	$4.57	$4.59	$4.59	$4.71
Low Growth & High Prices	2024-2025	Apr	$4.26	$4.26	$4.57	$4.34	$4.57	$4.34	$4.34	$4.34	$4.26	$4.26	$4.57	$4.37	$4.37	$4.39
Low Growth & High Prices	2024-2025	May	$4.35	$4.35	$4.57	$4.43	$4.57	$4.43	$4.43	$4.43	$4.35	$4.35	$4.57	$4.42	$4.42	$4.46
Low Growth & High Prices	2024-2025	Jun	$4.27	$4.27	$4.57	$4.35	$4.57	$4.35	$4.35	$4.35	$4.27	$4.27	$4.57	$4.37	$4.37	$4.40
Low Growth & High Prices	2024-2025	Jul	$4.35	$4.35	$4.57	$4.43	$4.57	$4.43	$4.43	$4.43	$4.35	$4.35	$4.57	$4.42	$4.42	$4.46
Low Growth & High Prices	2024-2025	Aug	$4.36	$4.36	$4.57	$4.44	$4.57	$4.44	$4.44	$4.44	$4.36	$4.36	$4.57	$4.43	$4.43	$4.47
Low Growth & High Prices	2024-2025	Sep	$4.45	$4.45	$4.57	$4.54	$4.57	$4.54	$4.54	$4.54	$4.45	$4.45	$4.57	$4.49	$4.49	$4.54
Low Growth & High Prices	2024-2025	Oct	$4.45	$4.45	$4.75	$4.54	$4.75	$4.54	$4.54	$4.54	$4.45	$4.45	$4.75	$4.55	$4.55	$4.58
Low Growth & High Prices	2025-2026	Nov	$4.83	$4.83	$5.41	$4.92	$5.41	$4.92	$4.92	$4.92	$4.83	$4.83	$5.41	$5.02	$5.02	$5.02
Low Growth & High Prices	2025-2026	Dec	$5.01	$5.01	$5.41	$5.10	$5.41	$5.10	$5.10	$5.10	$5.01	$5.01	$5.41	$5.14	$5.14	$5.16
Low Growth & High Prices	2025-2026	Jan	$5.49	$5.75	$5.49	$5.85	$5.85	$5.85	$5.85	$5.85	$5.49	$5.75	$5.49	$5.58	$5.58	$5.85
Low Growth & High Prices	2025-2026	Feb	$5.49	$5.66	$5.49	$5.77	$5.71	$5.64	$5.64	$5.64	$5.49	$5.66	$5.49	$5.55	$5.55	$5.68
Low Growth & High Prices	2025-2026	Mar	$5.41	$5.47	$5.41	$5.58	$5.57	$5.57	$5.57	$5.57	$5.41	$5.47	$5.41	$5.43	$5.43	$5.57
Low Growth & High Prices	2025-2026	Apr	$5.08	$5.08	$5.41	$5.18	$5.41	$5.18	$5.18	$5.18	$5.08	$5.08	$5.41	$5.19	$5.19	$5.23
Low Growth & High Prices	2025-2026	May	$5.11	$5.11	$5.41	$5.20	$5.41	$5.20	$5.20	$5.20	$5.11	$5.11	$5.41	$5.21	$5.21	$5.24
Low Growth & High Prices	2025-2026	Jun	$5.11	$5.11	$5.41	$5.21	$5.41	$5.21	$5.21	$5.21	$5.11	$5.11	$5.41	$5.21	$5.21	$5.25
Low Growth & High Prices	2025-2026	Jul	$5.20	$5.20	$5.41	$5.30	$5.41	$5.30	$5.30	$5.30	$5.20	$5.20	$5.41	$5.27	$5.27	$5.32
Low Growth & High Prices	2025-2026	Aug	$5.26	$5.26	$5.41	$5.36	$5.41	$5.36	$5.36	$5.36	$5.26	$5.26	$5.41	$5.31	$5.31	$5.37
Low Growth & High Prices	2025-2026	Sep	$5.25	$5.25	$5.41	$5.35	$5.41	$5.35	$5.35	$5.35	$5.25	$5.25	$5.41	$5.31	$5.31	$5.36
Low Growth & High Prices	2025-2026	Oct	$5.31	$5.31	$5.63	$5.41	$5.63	$5.41	$5.41	$5.41	$5.31	$5.31	$5.63	$5.41	$5.41	$5.45
Low Growth & High Prices	2026-2027	Nov	$5.75	$5.75	$5.90	$5.86	$5.90	$5.86	$5.86	$5.86	$5.75	$5.75	$5.90	$5.80	$5.80	$5.87
Low Growth & High Prices	2026-2027	Dec	$5.95	$5.95	$5.95	$6.05	$6.05	$6.05	$6.05	$6.05	$5.95	$5.95	$5.95	$5.95	$5.95	$6.05
Low Growth & High Prices	2026-2027	Jan	$5.99	$6.23	$5.99	$6.35	$6.35	$6.35	$6.35	$6.35	$5.99	$6.23	$5.99	$6.07	$6.07	$6.35
Low Growth & High Prices	2026-2027	Feb	$5.99	$6.12	$5.99	$6.23	$6.16	$6.07	$6.07	$6.07	$5.99	$6.12	$5.99	$6.03	$6.03	$6.12
Low Growth & High Prices	2026-2027	Mar	$5.88	$5.88	$5.90	$5.99	$5.99	$5.99	$5.99	$5.99	$5.88	$5.88	$5.90	$5.89	$5.89	$5.99
Low Growth & High Prices	2026-2027	Apr	$5.53	$5.53	$5.90	$5.64	$5.90	$5.64	$5.64	$5.64	$5.53	$5.53	$5.90	$5.66	$5.66	$5.69
Low Growth & High Prices	2026-2027	May	$5.61	$5.61	$5.90	$5.71	$5.90	$5.71	$5.71	$5.71	$5.61	$5.61	$5.90	$5.71	$5.71	$5.75
Low Growth & High Prices	2026-2027	Jun	$5.56	$5.56	$5.91	$5.67	$5.91	$5.67	$5.67	$5.67	$5.56	$5.56	$5.91	$5.68	$5.68	$5.71
Low Growth & High Prices	2026-2027	Jul	$5.65	$5.65	$5.91	$5.75	$5.91	$5.75	$5.75	$5.75	$5.65	$5.65	$5.91	$5.73	$5.73	$5.78
Low Growth & High Prices	2026-2027	Aug	$5.66	$5.66	$5.91	$5.76	$5.91	$5.76	$5.76	$5.76	$5.66	$5.66	$5.91	$5.74	$5.74	$5.79
Low Growth & High Prices	2026-2027	Sep	$5.71	$5.71	$5.91	$5.81	$5.91	$5.81	$5.81	$5.81	$5.71	$5.71	$5.91	$5.77	$5.77	$5.83
Low Growth & High Prices	2026-2027	Oct	$5.67	$5.67	$6.04	$5.77	$6.04	$5.77	$5.77	$5.77	$5.67	$5.67	$6.04	$5.79	$5.79	$5.82
Low Growth & High Prices	2027-2028	Nov	$6.18	$6.18	$6.24	$6.29	$6.29	$6.29	$6.29	$6.29	$6.18	$6.18	$6.24	$6.20	$6.20	$6.29

[1]Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Low Growth & High Prices	2027-2028	Dec	$6.33	$6.40	$6.33	$6.51	$6.51	$6.51	$6.51	$6.51	$6.33	$6.40	$6.33	$6.36	$6.36	$6.51
Low Growth & High Prices	2027-2028	Jan	$6.33	$6.55	$6.33	$6.67	$6.67	$6.67	$6.67	$6.67	$6.33	$6.55	$6.33	$6.41	$6.41	$6.67
Low Growth & High Prices	2027-2028	Feb	$6.34	$6.39	$6.34	$6.50	$6.44	$6.41	$6.41	$6.41	$6.34	$6.39	$6.34	$6.36	$6.36	$6.44
Low Growth & High Prices	2027-2028	Mar	$6.23	$6.23	$6.24	$6.34	$6.34	$6.34	$6.34	$6.34	$6.23	$6.23	$6.24	$6.23	$6.23	$6.34
Low Growth & High Prices	2027-2028	Apr	$5.86	$5.86	$6.21	$5.97	$6.21	$5.97	$5.97	$5.97	$5.86	$5.86	$6.21	$5.98	$5.98	$6.02
Low Growth & High Prices	2027-2028	May	$5.99	$5.99	$6.21	$6.10	$6.21	$6.10	$6.10	$6.10	$5.99	$5.99	$6.21	$6.06	$6.06	$6.12
Low Growth & High Prices	2027-2028	Jun	$5.97	$5.97	$6.21	$6.08	$6.21	$6.08	$6.08	$6.08	$5.97	$5.97	$6.21	$6.05	$6.05	$6.11
Low Growth & High Prices	2027-2028	Jul	$6.02	$6.02	$6.21	$6.13	$6.21	$6.13	$6.13	$6.13	$6.02	$6.02	$6.21	$6.08	$6.08	$6.15
Low Growth & High Prices	2027-2028	Aug	$6.06	$6.06	$6.21	$6.17	$6.21	$6.17	$6.17	$6.17	$6.06	$6.06	$6.21	$6.11	$6.11	$6.18
Low Growth & High Prices	2027-2028	Sep	$6.08	$6.08	$6.21	$6.19	$6.21	$6.19	$6.19	$6.19	$6.08	$6.08	$6.21	$6.12	$6.12	$6.19
Low Growth & High Prices	2027-2028	Oct	$6.28	$6.28	$6.82	$6.39	$6.82	$6.39	$6.39	$6.39	$6.28	$6.28	$6.82	$6.46	$6.46	$6.48
Low Growth & High Prices	2028-2029	Nov	$6.65	$6.65	$6.65	$6.77	$6.77	$6.77	$6.77	$6.77	$6.65	$6.65	$6.65	$6.65	$6.65	$6.77
Low Growth & High Prices	2028-2029	Dec	$6.73	$6.73	$6.73	$6.85	$6.85	$6.85	$6.85	$6.85	$6.73	$6.73	$6.73	$6.73	$6.73	$6.85
Low Growth & High Prices	2028-2029	Jan	$6.75	$6.90	$6.75	$7.03	$7.03	$7.03	$7.03	$7.03	$6.75	$6.90	$6.75	$6.80	$6.80	$7.03
Low Growth & High Prices	2028-2029	Feb	$6.73	$6.73	$6.73	$6.86	$6.78	$6.73	$6.73	$6.73	$6.73	$6.73	$6.73	$6.73	$6.73	$6.77
Low Growth & High Prices	2028-2029	Mar	$6.55	$6.55	$6.69	$6.67	$6.70	$6.67	$6.67	$6.67	$6.55	$6.55	$6.69	$6.60	$6.60	$6.68
Low Growth & High Prices	2028-2029	Apr	$6.17	$6.17	$6.55	$6.28	$6.55	$6.28	$6.28	$6.28	$6.17	$6.17	$6.55	$6.30	$6.30	$6.34
Low Growth & High Prices	2028-2029	May	$6.27	$6.27	$6.55	$6.39	$6.55	$6.39	$6.39	$6.39	$6.27	$6.27	$6.55	$6.36	$6.36	$6.42
Low Growth & High Prices	2028-2029	Jun	$6.26	$6.26	$6.55	$6.38	$6.55	$6.38	$6.38	$6.38	$6.26	$6.26	$6.55	$6.36	$6.36	$6.41
Low Growth & High Prices	2028-2029	Jul	$6.38	$6.38	$6.55	$6.49	$6.55	$6.49	$6.49	$6.49	$6.38	$6.38	$6.55	$6.44	$6.44	$6.51
Low Growth & High Prices	2028-2029	Aug	$6.37	$6.37	$6.56	$6.49	$6.56	$6.49	$6.49	$6.49	$6.37	$6.37	$6.56	$6.43	$6.43	$6.50
Low Growth & High Prices	2028-2029	Sep	$6.35	$6.35	$6.56	$6.46	$6.56	$6.46	$6.46	$6.46	$6.35	$6.35	$6.56	$6.42	$6.42	$6.48
Low Growth & High Prices	2028-2029	Oct	$6.40	$6.40	$6.95	$6.51	$6.95	$6.51	$6.51	$6.51	$6.40	$6.40	$6.95	$6.58	$6.58	$6.60
Low Growth & High Prices	2029-2030	Nov	$6.84	$6.84	$7.00	$6.97	$6.99	$6.97	$6.97	$6.97	$6.84	$6.84	$7.00	$6.89	$6.89	$6.97
Low Growth & High Prices	2029-2030	Dec	$7.10	$7.19	$7.10	$7.32	$7.32	$7.32	$7.32	$7.32	$7.10	$7.19	$7.10	$7.13	$7.13	$7.32
Low Growth & High Prices	2029-2030	Jan	$7.10	$7.24	$7.10	$7.37	$7.37	$7.37	$7.37	$7.37	$7.10	$7.24	$7.10	$7.15	$7.15	$7.37
Low Growth & High Prices	2029-2030	Feb	$7.10	$7.13	$7.10	$7.26	$7.18	$7.16	$7.16	$7.16	$7.10	$7.13	$7.10	$7.11	$7.11	$7.18
Low Growth & High Prices	2029-2030	Mar	$6.99	$6.99	$7.00	$7.12	$7.12	$7.12	$7.12	$7.12	$6.99	$6.99	$7.00	$7.00	$7.00	$7.12
Low Growth & High Prices	2029-2030	Apr	$6.57	$6.57	$6.97	$6.69	$6.97	$6.69	$6.69	$6.69	$6.57	$6.57	$6.97	$6.70	$6.70	$6.75
Low Growth & High Prices	2029-2030	May	$6.61	$6.61	$6.97	$6.73	$6.97	$6.73	$6.73	$6.73	$6.61	$6.61	$6.97	$6.73	$6.73	$6.78
Low Growth & High Prices	2029-2030	Jun	$6.60	$6.60	$6.97	$6.72	$6.97	$6.72	$6.72	$6.72	$6.60	$6.60	$6.97	$6.72	$6.72	$6.77
Low Growth & High Prices	2029-2030	Jul	$6.66	$6.66	$6.97	$6.78	$6.97	$6.78	$6.78	$6.78	$6.66	$6.66	$6.97	$6.76	$6.76	$6.82
Low Growth & High Prices	2029-2030	Aug	$6.70	$6.70	$6.97	$6.82	$6.97	$6.82	$6.82	$6.82	$6.70	$6.70	$6.97	$6.79	$6.79	$6.85
Low Growth & High Prices	2029-2030	Sep	$6.74	$6.74	$6.97	$6.86	$6.97	$6.86	$6.86	$6.86	$6.74	$6.74	$6.97	$6.82	$6.82	$6.89
Low Growth & High Prices	2029-2030	Oct	$6.90	$6.90	$7.30	$7.03	$7.30	$7.03	$7.03	$7.03	$6.90	$6.90	$7.30	$7.04	$7.04	$7.08
Low Growth & High Prices	2030-2031	Nov	$7.27	$7.27	$7.27	$7.40	$7.40	$7.40	$7.40	$7.40	$7.27	$7.27	$7.27	$7.27	$7.27	$7.40
Low Growth & High Prices	2030-2031	Dec	$7.38	$7.47	$7.38	$7.60	$7.60	$7.60	$7.60	$7.60	$7.38	$7.47	$7.38	$7.41	$7.41	$7.60
Low Growth & High Prices	2030-2031	Jan	$7.38	$7.49	$7.38	$7.62	$7.62	$7.62	$7.62	$7.62	$7.38	$7.49	$7.38	$7.41	$7.41	$7.62
Low Growth & High Prices	2030-2031	Feb	$7.32	$7.32	$7.32	$7.45	$7.37	$7.33	$7.33	$7.33	$7.32	$7.32	$7.32	$7.32	$7.32	$7.36
Low Growth & High Prices	2030-2031	Mar	$7.13	$7.13	$7.29	$7.26	$7.29	$7.26	$7.26	$7.26	$7.13	$7.13	$7.29	$7.19	$7.19	$7.27
Low Growth & High Prices	2030-2031	Apr	$6.78	$6.78	$7.41	$6.91	$7.41	$6.91	$6.91	$6.91	$6.78	$6.78	$7.41	$6.99	$6.99	$7.01
Low Growth & High Prices	2030-2031	May	$6.89	$6.89	$7.21	$7.01	$7.21	$7.01	$7.01	$7.01	$6.89	$6.89	$7.21	$6.99	$6.99	$7.05
Low Growth & High Prices	2030-2031	Jun	$6.91	$6.91	$7.21	$7.03	$7.21	$7.03	$7.03	$7.03	$6.91	$6.91	$7.21	$7.01	$7.01	$7.07
Low Growth & High Prices	2030-2031	Jul	$6.93	$6.93	$7.21	$7.05	$7.21	$7.05	$7.05	$7.05	$6.93	$6.93	$7.21	$7.02	$7.02	$7.08
Low Growth & High Prices	2030-2031	Aug	$6.94	$6.94	$7.21	$7.07	$7.21	$7.07	$7.07	$7.07	$6.94	$6.94	$7.21	$7.03	$7.03	$7.10
Low Growth & High Prices	2030-2031	Sep	$6.96	$6.96	$7.21	$7.09	$7.21	$7.09	$7.09	$7.09	$6.96	$6.96	$7.21	$7.05	$7.05	$7.11
Low Growth & High Prices	2030-2031	Oct	$7.03	$7.03	$7.44	$7.15	$7.44	$7.15	$7.15	$7.15	$7.03	$7.03	$7.44	$7.16	$7.16	$7.21
Low Growth & High Prices	2031-2032	Nov	$7.73	$7.73	$7.73	$7.87	$7.87	$7.87	$7.87	$7.87	$7.73	$7.73	$7.73	$7.73	$7.73	$7.87
Low Growth & High Prices	2031-2032	Dec	$7.85	$7.97	$7.85	$8.12	$8.12	$8.12	$8.12	$8.12	$7.85	$7.97	$7.85	$7.89	$7.89	$8.12
Low Growth & High Prices	2031-2032	Jan	$7.85	$7.99	$7.85	$8.13	$8.13	$8.13	$8.13	$8.13	$7.85	$7.99	$7.85	$7.89	$7.89	$8.13
Low Growth & High Prices	2031-2032	Feb	$7.79	$7.79	$7.79	$7.93	$7.85	$7.80	$7.80	$7.80	$7.79	$7.79	$7.79	$7.79	$7.79	$7.84
Low Growth & High Prices	2031-2032	Mar	$7.56	$7.56	$7.77	$7.70	$7.77	$7.70	$7.70	$7.70	$7.56	$7.56	$7.77	$7.63	$7.63	$7.71
Low Growth & High Prices	2031-2032	Apr	$7.28	$7.28	$7.92	$7.41	$7.92	$7.41	$7.41	$7.41	$7.28	$7.28	$7.92	$7.49	$7.49	$7.51
Low Growth & High Prices	2031-2032	May	$7.32	$7.32	$7.59	$7.46	$7.59	$7.46	$7.46	$7.46	$7.32	$7.32	$7.59	$7.41	$7.41	$7.48
Low Growth & High Prices	2031-2032	Jun	$7.29	$7.29	$7.60	$7.43	$7.60	$7.43	$7.43	$7.43	$7.29	$7.29	$7.60	$7.39	$7.39	$7.46
Low Growth & High Prices	2031-2032	Jul	$7.16	$7.16	$7.60	$7.29	$7.60	$7.29	$7.29	$7.29	$7.16	$7.16	$7.60	$7.30	$7.30	$7.35
Low Growth & High Prices	2031-2032	Aug	$7.18	$7.18	$7.60	$7.31	$7.60	$7.31	$7.31	$7.31	$7.18	$7.18	$7.60	$7.32	$7.32	$7.37
Low Growth & High Prices	2031-2032	Sep	$7.35	$7.35	$7.60	$7.48	$7.60	$7.48	$7.48	$7.48	$7.35	$7.35	$7.60	$7.43	$7.43	$7.51
Low Growth & High Prices	2031-2032	Oct	$7.48	$7.48	$7.92	$7.62	$7.92	$7.62	$7.62	$7.62	$7.48	$7.48	$7.92	$7.63	$7.63	$7.68
Low Growth & High Prices	2032-2033	Nov	$7.96	$7.96	$8.17	$8.11	$8.17	$8.11	$8.11	$8.11	$7.96	$7.96	$8.17	$8.03	$8.03	$8.12
Low Growth & High Prices	2032-2033	Dec	$8.29	$8.40	$8.29	$8.55	$8.55	$8.55	$8.55	$8.55	$8.29	$8.40	$8.29	$8.33	$8.33	$8.55
Low Growth & High Prices	2032-2033	Jan	$8.29	$8.57	$8.29	$8.73	$8.72	$8.73	$8.73	$8.73	$8.29	$8.57	$8.29	$8.38	$8.38	$8.73
Low Growth & High Prices	2032-2033	Feb	$8.28	$8.28	$8.28	$8.43	$8.34	$8.34	$8.34	$8.34	$8.28	$8.28	$8.28	$8.28	$8.28	$8.36
Low Growth & High Prices	2032-2033	Mar	$8.17	$8.17	$8.18	$8.32	$8.32	$8.32	$8.32	$8.32	$8.17	$8.17	$8.18	$8.18	$8.18	$8.32
Low Growth & High Prices	2032-2033	Apr	$7.78	$7.78	$8.40	$7.92	$8.40	$7.92	$7.92	$7.92	$7.78	$7.78	$8.40	$7.99	$7.99	$8.02
Low Growth & High Prices	2032-2033	May	$7.84	$7.84	$8.16	$7.98	$8.16	$7.98	$7.98	$7.98	$7.84	$7.84	$8.16	$7.94	$7.94	$8.01
Low Growth & High Prices	2032-2033	Jun	$7.86	$7.86	$8.16	$8.00	$8.16	$8.00	$8.00	$8.00	$7.86	$7.86	$8.16	$7.96	$7.96	$8.03
Low Growth & High Prices	2032-2033	Jul	$7.76	$7.76	$8.16	$7.90	$8.16	$7.90	$7.90	$7.90	$7.76	$7.76	$8.16	$7.89	$7.89	$7.95
Low Growth & High Prices	2032-2033	Aug	$7.84	$7.84	$8.16	$7.99	$8.16	$7.99	$7.99	$7.99	$7.84	$7.84	$8.16	$7.95	$7.95	$8.02
Low Growth & High Prices	2032-2033	Sep	$7.92	$7.92	$8.16	$8.06	$8.16	$8.06	$8.06	$8.06	$7.92	$7.92	$8.16	$8.00	$8.00	$8.08
Low Growth & High Prices	2032-2033	Oct	$8.05	$8.05	$8.49	$8.19	$8.49	$8.19	$8.19	$8.19	$8.05	$8.05	$8.49	$8.20	$8.20	$8.25
Low Growth & High Prices	2033-2034	Nov	$8.67	$8.67	$8.80	$8.82	$8.82	$8.82	$8.82	$8.82	$8.67	$8.67	$8.80	$8.71	$8.71	$8.82
Low Growth & High Prices	2033-2034	Dec	$8.85	$8.85	$8.85	$9.01	$9.01	$9.01	$9.01	$9.01	$8.85	$8.85	$8.85	$8.85	$8.85	$9.01
Low Growth & High Prices	2033-2034	Jan	$8.93	$8.97	$8.93	$9.13	$9.13	$9.13	$9.13	$9.13	$8.93	$8.97	$8.93	$8.94	$8.94	$9.13
Low Growth & High Prices	2033-2034	Feb	$8.80	$8.80	$8.80	$8.96	$8.87	$8.79	$8.79	$8.79	$8.80	$8.80	$8.80	$8.80	$8.80	$8.84
Low Growth & High Prices	2033-2034	Mar	$8.54	$8.54	$8.80	$8.69	$8.80	$8.69	$8.69	$8.69	$8.54	$8.54	$8.80	$8.62	$8.62	$8.71
Low Growth & High Prices	2033-2034	Apr	$8.34	$8.34	$8.96	$8.49	$8.96	$8.49	$8.49	$8.49	$8.34	$8.34	$8.96	$8.55	$8.55	$8.59
Low Growth & High Prices	2033-2034	May	$8.39	$8.39	$8.80	$8.55	$8.80	$8.55	$8.55	$8.55	$8.39	$8.39	$8.80	$8.53	$8.53	$8.60
Low Growth & High Prices	2033-2034	Jun	$8.37	$8.37	$8.80	$8.52	$8.80	$8.52	$8.52	$8.52	$8.37	$8.37	$8.80	$8.52	$8.52	$8.58
Low Growth & High Prices	2033-2034	Jul	$8.54	$8.54	$8.80	$8.69	$8.80	$8.69	$8.69	$8.69	$8.54	$8.54	$8.80	$8.62	$8.62	$8.71
Low Growth & High Prices	2033-2034	Aug	$8.65	$8.65	$8.80	$8.80	$8.80	$8.80	$8.80	$8.80	$8.65	$8.65	$8.80	$8.70	$8.70	$8.80
Low Growth & High Prices	2033-2034	Sep	$8.50	$8.50	$8.80	$8.65	$8.80	$8.65	$8.65	$8.65	$8.50	$8.50	$8.80	$8.60	$8.60	$8.68
Low Growth & High Prices	2033-2034	Oct	$8.72	$8.72	$9.22	$8.88	$9.22	$8.88	$8.88	$8.88	$8.72	$8.72	$9.22	$8.89	$8.89	$8.94
Low Growth & High Prices	2034-2035	Nov	$9.28	$9.28	$9.30	$9.45	$9.45	$9.45	$9.45	$9.45	$9.28	$9.28	$9.30	$9.29	$9.29	$9.45
Low Growth & High Prices	2034-2035	Dec	$9.43	$9.84	$9.43	$10.01	$10.01	$10.01	$10.01	$10.01	$9.43	$9.84	$9.43	$9.57	$9.57	$10.01
Low Growth & High Prices	2034-2035	Jan	$9.43	$9.87	$9.43	$10.04	$10.04	$10.04	$10.04	$10.04	$9.43	$9.87	$9.43	$9.58	$9.58	$10.04
Low Growth & High Prices	2034-2035	Feb	$9.44	$9.52	$9.44	$9.69	$9.59	$9.53	$9.53	$9.53	$9.44	$9.52	$9.44	$9.47	$9.47	$9.57
Low Growth & High Prices	2034-2035	Mar	$9.27	$9.27	$9.32	$9.44	$9.46	$9.44	$9.44	$9.44	$9.27	$9.27	$9.32	$9.29	$9.29	$9.45
Low Growth & High Prices	2034-2035	Apr	$8.86	$8.86	$9.47	$9.02	$9.47	$9.02	$9.02	$9.02	$8.86	$8.86	$9.47	$9.06	$9.06	$9.11
Low Growth & High Prices	2034-2035	May	$8.89	$8.89	$9.15	$9.05	$9.15	$9.05	$9.05	$9.05	$8.89	$8.89	$9.15	$8.97	$8.97	$9.07
Low Growth & High Prices	2034-2035	Jun	$8.85	$8.85	$9.15	$9.01	$9.15	$9.01	$9.01	$9.01	$8.85	$8.85	$9.15	$8.95	$8.95	$9.04
Low Growth & High Prices	2034-2035	Jul	$8.83	$8.83	$9.15	$8.99	$9.15	$8.99	$8.99	$8.99	$8.83	$8.83	$9.15	$8.94	$8.94	$9.02
Low Growth & High Prices	2034-2035	Aug	$8.90	$8.90	$9.15	$9.06	$9.15	$9.06	$9.06	$9.06	$8.90	$8.90	$9.15	$8.98	$8.98	$9.08
Low Growth & High Prices	2034-2035	Sep	$8.92	$8.92	$9.15	$9.08	$9.15	$9.08	$9.08	$9.08	$8.92	$8.92	$9.15	$9.00	$9.00	$9.09
Low Growth & High Prices	2034-2035	Oct	$9.01	$9.01	$9.53	$9.17	$9.53	$9.17	$9.17	$9.17	$9.01	$9.01	$9.53	$9.19	$9.19	$9.24
Low Growth & High Prices	2035-2036	Nov	$9.59	$9.59	$9.59	$9.77	$9.77	$9.77	$9.77	$9.77	$9.59	$9.59	$9.59	$9.59	$9.59	$9.77
Low Growth & High Prices	2035-2036	Dec	$9.73	$9.89	$9.73	$10.07	$10.07	$10.07	$10.07	$10.07	$9.73	$9.89	$9.73	$9.79	$9.79	$10.07

[1] Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1]
Nominal $

Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Low Growth & High Prices	2035-2036	Jan	$9.73	$9.98	$9.73	$10.16	$10.16	$10.16	$10.16	$10.16	$9.73	$9.98	$9.73	$9.82	$9.82	$10.16
Low Growth & High Prices	2035-2036	Feb	$9.67	$9.67	$9.67	$9.85	$9.75	$9.64	$9.64	$9.64	$9.67	$9.67	$9.67	$9.67	$9.67	$9.70
Low Growth & High Prices	2035-2036	Mar	$9.31	$9.31	$9.67	$9.48	$9.67	$9.48	$9.48	$9.48	$9.31	$9.31	$9.67	$9.43	$9.43	$9.52
Low Growth & High Prices	2035-2036	Apr	$8.96	$8.96	$9.47	$9.12	$9.47	$9.12	$9.12	$9.12	$8.96	$8.96	$9.47	$9.13	$9.13	$9.19
Low Growth & High Prices	2035-2036	May	$8.97	$8.97	$9.34	$9.13	$9.34	$9.13	$9.13	$9.13	$8.97	$8.97	$9.34	$9.09	$9.09	$9.17
Low Growth & High Prices	2035-2036	Jun	$9.04	$9.04	$9.34	$9.20	$9.34	$9.20	$9.20	$9.20	$9.04	$9.04	$9.34	$9.14	$9.14	$9.23
Low Growth & High Prices	2035-2036	Jul	$9.02	$9.02	$9.34	$9.18	$9.34	$9.18	$9.18	$9.18	$9.02	$9.02	$9.34	$9.13	$9.13	$9.21
Low Growth & High Prices	2035-2036	Aug	$9.04	$9.04	$9.34	$9.20	$9.34	$9.20	$9.20	$9.20	$9.04	$9.04	$9.34	$9.14	$9.14	$9.23
Low Growth & High Prices	2035-2036	Sep	$9.11	$9.11	$9.34	$9.27	$9.34	$9.27	$9.27	$9.27	$9.11	$9.11	$9.34	$9.19	$9.19	$9.29
Low Growth & High Prices	2035-2036	Oct	$9.27	$9.27	$9.69	$9.44	$9.69	$9.44	$9.44	$9.44	$9.27	$9.27	$9.69	$9.41	$9.41	$9.49
Low Growth & High Prices	2036-2037	Nov	$9.76	$9.76	$9.78	$9.93	$9.93	$9.93	$9.93	$9.93	$9.76	$9.76	$9.78	$9.76	$9.76	$9.93
Low Growth & High Prices	2036-2037	Dec	$9.92	$10.23	$9.92	$10.41	$10.41	$10.41	$10.41	$10.41	$9.92	$10.23	$9.92	$10.02	$10.02	$10.41
Low Growth & High Prices	2036-2037	Jan	$9.92	$10.44	$9.92	$10.63	$10.63	$10.63	$10.63	$10.63	$9.92	$10.44	$9.92	$10.09	$10.09	$10.63
Low Growth & High Prices	2036-2037	Feb	$9.95	$10.22	$9.95	$10.40	$10.29	$10.02	$10.02	$10.02	$9.95	$10.22	$9.95	$10.04	$10.04	$10.15
Low Growth & High Prices	2036-2037	Mar	$9.64	$9.64	$9.69	$9.81	$9.81	$9.81	$9.81	$9.81	$9.64	$9.64	$9.69	$9.65	$9.65	$9.81
Low Growth & High Prices	2036-2037	Apr	$9.23	$9.23	$9.75	$9.39	$9.75	$9.39	$9.39	$9.39	$9.23	$9.23	$9.75	$9.40	$9.40	$9.46
Low Growth & High Prices	2036-2037	May	$9.41	$9.41	$9.69	$9.58	$9.69	$9.58	$9.58	$9.58	$9.41	$9.41	$9.69	$9.51	$9.51	$9.60
Low Growth & High Prices	2036-2037	Jun	$9.38	$9.38	$9.70	$9.55	$9.70	$9.55	$9.55	$9.55	$9.38	$9.38	$9.70	$9.48	$9.48	$9.58
Low Growth & High Prices	2036-2037	Jul	$9.38	$9.38	$9.70	$9.54	$9.70	$9.54	$9.54	$9.54	$9.38	$9.38	$9.70	$9.48	$9.48	$9.57
Low Growth & High Prices	2036-2037	Aug	$9.50	$9.50	$9.70	$9.67	$9.70	$9.67	$9.67	$9.67	$9.50	$9.50	$9.70	$9.57	$9.57	$9.68
Low Growth & High Prices	2036-2037	Sep	$9.48	$9.48	$9.70	$9.64	$9.70	$9.64	$9.64	$9.64	$9.48	$9.48	$9.70	$9.55	$9.55	$9.66
Low Growth & High Prices	2036-2037	Oct	$9.59	$9.59	$10.01	$9.76	$10.01	$9.76	$9.76	$9.76	$9.59	$9.59	$10.01	$9.73	$9.73	$9.81
Low Growth & High Prices	2037-2038	Nov	$10.34	$10.51	$10.34	$10.70	$10.70	$10.70	$10.70	$10.70	$10.34	$10.51	$10.34	$10.40	$10.40	$10.70
Low Growth & High Prices	2037-2038	Dec	$10.38	$10.97	$10.38	$11.16	$11.16	$11.16	$11.16	$11.16	$10.38	$10.97	$10.38	$10.58	$10.58	$11.16
Low Growth & High Prices	2037-2038	Jan	$10.39	$11.03	$10.39	$11.23	$11.23	$11.23	$11.23	$11.23	$10.39	$11.03	$10.39	$10.60	$10.60	$11.23
Low Growth & High Prices	2037-2038	Feb	$10.24	$10.24	$10.24	$10.42	$10.31	$10.13	$10.13	$10.13	$10.24	$10.24	$10.24	$10.24	$10.24	$10.22
Low Growth & High Prices	2037-2038	Mar	$9.74	$9.74	$10.33	$9.91	$10.33	$9.91	$9.91	$9.91	$9.74	$9.74	$10.33	$9.94	$9.94	$10.00
Low Growth & High Prices	2037-2038	Apr	$9.50	$9.50	$10.00	$9.67	$10.00	$9.67	$9.67	$9.67	$9.50	$9.50	$10.00	$9.66	$9.66	$9.73
Low Growth & High Prices	2037-2038	May	$9.68	$9.68	$9.95	$9.85	$9.95	$9.85	$9.85	$9.85	$9.68	$9.68	$9.95	$9.77	$9.77	$9.87
Low Growth & High Prices	2037-2038	Jun	$9.69	$9.69	$9.95	$9.86	$9.95	$9.86	$9.86	$9.86	$9.69	$9.69	$9.95	$9.77	$9.77	$9.87
Low Growth & High Prices	2037-2038	Jul	$9.68	$9.68	$9.95	$9.85	$9.95	$9.85	$9.85	$9.85	$9.68	$9.68	$9.95	$9.77	$9.77	$9.87
Low Growth & High Prices	2037-2038	Aug	$9.72	$9.72	$9.95	$9.90	$9.95	$9.89	$9.89	$9.89	$9.72	$9.72	$9.95	$9.80	$9.80	$9.90
Low Growth & High Prices	2037-2038	Sep	$9.78	$9.78	$9.95	$9.95	$9.95	$9.95	$9.95	$9.95	$9.78	$9.78	$9.95	$9.83	$9.83	$9.95
Low Growth & High Prices	2037-2038	Oct	$9.90	$9.90	$10.31	$10.08	$10.31	$10.08	$10.08	$10.08	$9.90	$9.90	$10.31	$10.04	$10.04	$10.13
Low Growth & High Prices	2038-2039	Nov	$10.80	$10.80	$10.92	$10.99	$10.99	$10.99	$10.99	$10.99	$10.80	$10.80	$10.92	$10.84	$10.84	$10.99
Low Growth & High Prices	2038-2039	Dec	$11.08	$11.41	$11.08	$11.62	$11.62	$11.62	$11.62	$11.62	$11.08	$11.41	$11.08	$11.19	$11.19	$11.62
Low Growth & High Prices	2038-2039	Jan	$11.08	$11.54	$11.08	$11.75	$11.75	$11.75	$11.75	$11.75	$11.08	$11.54	$11.08	$11.24	$11.24	$11.75
Low Growth & High Prices	2038-2039	Feb	$11.09	$11.16	$11.09	$11.35	$11.24	$11.19	$11.19	$11.19	$11.09	$11.16	$11.09	$11.11	$11.11	$11.23
Low Growth & High Prices	2038-2039	Mar	$10.90	$10.90	$10.91	$11.09	$11.09	$11.09	$11.09	$11.09	$10.90	$10.90	$10.91	$10.90	$10.90	$11.09
Low Growth & High Prices	2038-2039	Apr	$10.45	$10.45	$10.93	$10.63	$10.93	$10.63	$10.63	$10.63	$10.45	$10.45	$10.93	$10.61	$10.61	$10.69
Low Growth & High Prices	2038-2039	May	$10.49	$10.49	$10.89	$10.68	$10.89	$10.68	$10.68	$10.68	$10.49	$10.49	$10.89	$10.62	$10.62	$10.72
Low Growth & High Prices	2038-2039	Jun	$10.45	$10.45	$10.89	$10.63	$10.89	$10.63	$10.63	$10.63	$10.45	$10.45	$10.89	$10.60	$10.60	$10.69
Low Growth & High Prices	2038-2039	Jul	$10.55	$10.55	$10.89	$10.74	$10.89	$10.72	$10.72	$10.72	$10.55	$10.55	$10.89	$10.66	$10.66	$10.76
Low Growth & High Prices	2038-2039	Aug	$10.55	$10.55	$10.89	$10.74	$10.89	$10.72	$10.72	$10.72	$10.55	$10.55	$10.89	$10.66	$10.66	$10.76
Low Growth & High Prices	2038-2039	Sep	$10.72	$10.72	$10.89	$10.91	$10.89	$10.89	$10.89	$10.89	$10.72	$10.72	$10.89	$10.78	$10.78	$10.90
Low Growth & High Prices	2038-2039	Oct	$10.78	$10.78	$11.22	$10.97	$11.22	$10.97	$10.97	$10.97	$10.78	$10.78	$11.22	$10.92	$10.92	$11.02
Low Growth & High Prices	2039-2040	Nov	$11.99	$11.99	$11.99	$12.20	$12.20	$12.20	$12.20	$12.20	$11.99	$11.99	$11.99	$11.99	$11.99	$12.20
Low Growth & High Prices	2039-2040	Dec	$12.16	$12.31	$12.16	$12.53	$12.53	$12.53	$12.53	$12.53	$12.16	$12.31	$12.16	$12.21	$12.21	$12.53
Low Growth & High Prices	2039-2040	Jan	$12.16	$12.36	$12.16	$12.57	$12.57	$12.57	$12.57	$12.57	$12.16	$12.36	$12.16	$12.23	$12.23	$12.57
Low Growth & High Prices	2039-2040	Feb	$12.10	$12.10	$12.10	$12.31	$12.19	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.10	$12.16
Low Growth & High Prices	2039-2040	Mar	$11.70	$11.70	$12.09	$11.90	$12.09	$11.90	$11.90	$11.90	$11.70	$11.70	$12.09	$11.83	$11.83	$11.94
Low Growth & High Prices	2039-2040	Apr	$11.31	$11.31	$11.80	$11.51	$11.80	$11.51	$11.51	$11.51	$11.31	$11.31	$11.80	$11.47	$11.47	$11.57
Low Growth & High Prices	2039-2040	May	$11.38	$11.38	$11.66	$11.58	$11.66	$11.56	$11.56	$11.56	$11.38	$11.38	$11.66	$11.47	$11.47	$11.58
Low Growth & High Prices	2039-2040	Jun	$11.35	$11.35	$11.66	$11.55	$11.66	$11.52	$11.52	$11.52	$11.35	$11.35	$11.66	$11.45	$11.45	$11.55
Low Growth & High Prices	2039-2040	Jul	$11.36	$11.36	$11.66	$11.56	$11.66	$11.52	$11.52	$11.52	$11.36	$11.36	$11.66	$11.46	$11.46	$11.56
Low Growth & High Prices	2039-2040	Aug	$11.36	$11.36	$11.66	$11.56	$11.66	$11.52	$11.52	$11.52	$11.36	$11.36	$11.66	$11.46	$11.46	$11.56
Low Growth & High Prices	2039-2040	Sep	$11.49	$11.49	$11.66	$11.70	$11.66	$11.66	$11.66	$11.66	$11.49	$11.49	$11.66	$11.55	$11.55	$11.67
Low Growth & High Prices	2039-2040	Oct	$11.61	$11.61	$12.06	$11.81	$12.06	$11.81	$11.81	$11.81	$11.61	$11.61	$12.06	$11.76	$11.76	$11.86

[1]Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: EXPECTED CASE MONTHLY DETAIL

Monthly Avoided Costs[1]
Nominal $

Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Expected Case	2019-2020	Nov	$2.00	$2.18	$2.00	$2.22	$2.22	$2.22	$2.22	$2.22	$2.00	$2.18	$2.00	$2.06	$2.06	$2.22
Expected Case	2019-2020	Dec	$1.99	$1.87	$1.99	$2.17	$2.25	$2.17	$2.17	$2.17	$1.99	$1.87	$1.99	$1.95	$1.95	$2.19
Expected Case	2019-2020	Jan	$2.00	$1.80	$2.00	$1.84	$2.02	$1.84	$1.84	$1.84	$2.00	$1.80	$2.00	$1.93	$1.93	$1.88
Expected Case	2019-2020	Feb	$1.95	$1.43	$1.97	$1.50	$1.97	$1.50	$1.50	$1.50	$1.95	$1.43	$1.97	$1.79	$1.79	$1.60
Expected Case	2019-2020	Mar	$1.25	$1.25	$1.38	$1.28	$1.38	$1.28	$1.28	$1.28	$1.25	$1.25	$1.38	$1.30	$1.30	$1.30
Expected Case	2019-2020	Apr	$1.03	$1.03	$1.15	$1.05	$1.14	$1.15	$1.15	$1.15	$1.03	$1.03	$1.15	$1.07	$1.07	$1.13
Expected Case	2019-2020	May	$1.05	$1.14	$1.05	$1.07	$1.05	$1.05	$1.05	$1.05	$1.05	$1.14	$1.05	$1.08	$1.08	$1.06
Expected Case	2019-2020	Jun	$0.90	$0.90	$1.06	$0.86	$0.90	$0.86	$0.86	$0.86	$0.90	$0.90	$1.06	$0.95	$0.95	$0.87
Expected Case	2019-2020	Jul	$0.86	$0.86	$1.06	$0.80	$0.90	$0.80	$0.80	$0.80	$0.86	$0.86	$1.06	$0.93	$0.93	$0.82
Expected Case	2019-2020	Aug	$1.10	$1.10	$1.11	$1.13	$1.11	$1.11	$1.11	$1.11	$1.10	$1.10	$1.11	$1.11	$1.11	$1.12
Expected Case	2019-2020	Sep	$0.99	$0.99	$1.06	$1.01	$1.06	$1.01	$1.01	$1.01	$0.99	$0.99	$1.06	$1.01	$1.01	$1.02
Expected Case	2019-2020	Oct	$1.02	$1.02	$1.31	$1.04	$1.31	$1.04	$1.04	$1.04	$1.02	$1.02	$1.31	$1.12	$1.12	$1.10
Expected Case	2020-2021	Nov	$1.81	$1.81	$1.82	$1.74	$1.82	$1.74	$1.74	$1.74	$1.81	$1.81	$1.82	$1.81	$1.81	$1.75
Expected Case	2020-2021	Dec	$2.44	$2.36	$2.44	$2.46	$2.46	$2.46	$2.46	$2.46	$2.44	$2.36	$2.44	$2.42	$2.42	$2.46
Expected Case	2020-2021	Jan	$2.45	$2.45	$2.45	$2.50	$2.52	$2.50	$2.50	$2.50	$2.45	$2.45	$2.45	$2.45	$2.45	$2.51
Expected Case	2020-2021	Feb	$2.47	$2.33	$2.47	$2.41	$2.47	$2.41	$2.41	$2.41	$2.47	$2.33	$2.47	$2.42	$2.42	$2.42
Expected Case	2020-2021	Mar	$2.02	$2.02	$2.31	$2.06	$2.31	$2.06	$2.06	$2.06	$2.02	$2.02	$2.31	$2.12	$2.12	$2.11
Expected Case	2020-2021	Apr	$1.51	$1.51	$1.87	$1.54	$1.87	$1.85	$1.85	$1.85	$1.51	$1.51	$1.87	$1.63	$1.63	$1.79
Expected Case	2020-2021	May	$1.40	$1.40	$1.87	$1.43	$1.83	$1.43	$1.43	$1.43	$1.40	$1.40	$1.87	$1.56	$1.56	$1.51
Expected Case	2020-2021	Jun	$1.45	$1.45	$1.87	$1.48	$1.82	$1.48	$1.48	$1.48	$1.45	$1.45	$1.87	$1.59	$1.59	$1.55
Expected Case	2020-2021	Jul	$1.58	$1.58	$1.87	$1.62	$1.87	$1.62	$1.62	$1.62	$1.58	$1.58	$1.87	$1.68	$1.68	$1.67
Expected Case	2020-2021	Aug	$1.57	$1.57	$1.87	$1.61	$1.87	$1.61	$1.61	$1.61	$1.57	$1.57	$1.87	$1.67	$1.67	$1.66
Expected Case	2020-2021	Sep	$1.42	$1.42	$1.87	$1.45	$1.87	$1.45	$1.45	$1.45	$1.42	$1.42	$1.87	$1.57	$1.57	$1.54
Expected Case	2020-2021	Oct	$1.45	$1.45	$2.05	$1.48	$2.05	$1.48	$1.48	$1.48	$1.45	$1.45	$2.05	$1.65	$1.65	$1.60
Expected Case	2021-2022	Nov	$1.79	$1.79	$2.15	$1.83	$2.15	$1.83	$1.83	$1.83	$1.79	$1.79	$2.15	$1.91	$1.91	$1.90
Expected Case	2021-2022	Dec	$2.11	$2.08	$2.16	$2.18	$2.21	$2.18	$2.18	$2.18	$2.11	$2.08	$2.16	$2.12	$2.12	$2.18
Expected Case	2021-2022	Jan	$2.19	$2.19	$2.19	$2.24	$2.24	$2.24	$2.24	$2.24	$2.19	$2.19	$2.19	$2.19	$2.19	$2.24
Expected Case	2021-2022	Feb	$2.10	$2.05	$2.20	$2.13	$2.20	$2.13	$2.13	$2.13	$2.10	$2.05	$2.20	$2.11	$2.11	$2.15
Expected Case	2021-2022	Mar	$1.74	$1.74	$2.15	$1.77	$2.15	$1.77	$1.77	$1.77	$1.74	$1.74	$2.15	$1.87	$1.87	$1.85
Expected Case	2021-2022	Apr	$1.11	$1.11	$1.69	$1.13	$1.69	$1.62	$1.62	$1.62	$1.11	$1.11	$1.69	$1.30	$1.30	$1.53
Expected Case	2021-2022	May	$1.08	$1.08	$1.69	$1.11	$1.68	$1.11	$1.11	$1.11	$1.08	$1.08	$1.69	$1.28	$1.28	$1.22
Expected Case	2021-2022	Jun	$1.18	$1.18	$1.69	$1.21	$1.69	$1.21	$1.21	$1.21	$1.18	$1.18	$1.69	$1.35	$1.35	$1.31
Expected Case	2021-2022	Jul	$1.34	$1.34	$1.69	$1.37	$1.69	$1.37	$1.37	$1.37	$1.34	$1.34	$1.69	$1.45	$1.45	$1.43
Expected Case	2021-2022	Aug	$1.29	$1.29	$1.69	$1.32	$1.69	$1.32	$1.32	$1.32	$1.29	$1.29	$1.69	$1.42	$1.42	$1.39
Expected Case	2021-2022	Sep	$1.11	$1.11	$1.69	$1.13	$1.69	$1.13	$1.13	$1.13	$1.11	$1.11	$1.69	$1.30	$1.30	$1.24
Expected Case	2021-2022	Oct	$1.11	$1.11	$1.69	$1.13	$1.69	$1.13	$1.13	$1.13	$1.11	$1.11	$1.69	$1.30	$1.30	$1.24
Expected Case	2022-2023	Nov	$1.38	$1.38	$1.96	$1.41	$1.96	$1.41	$1.41	$1.41	$1.38	$1.38	$1.96	$1.57	$1.57	$1.52
Expected Case	2022-2023	Dec	$1.92	$1.89	$1.97	$1.99	$2.03	$1.99	$1.99	$1.99	$1.92	$1.89	$1.97	$1.93	$1.93	$2.00
Expected Case	2022-2023	Jan	$2.00	$2.00	$2.00	$2.04	$2.04	$2.04	$2.04	$2.04	$2.00	$2.00	$2.00	$2.00	$2.00	$2.04
Expected Case	2022-2023	Feb	$1.85	$1.79	$2.00	$1.88	$2.00	$1.88	$1.88	$1.88	$1.85	$1.79	$2.00	$1.88	$1.88	$1.91
Expected Case	2022-2023	Mar	$1.53	$1.53	$1.94	$1.56	$1.94	$1.56	$1.56	$1.56	$1.53	$1.53	$1.94	$1.66	$1.66	$1.64
Expected Case	2022-2023	Apr	$1.07	$1.07	$1.67	$1.09	$1.67	$1.61	$1.61	$1.61	$1.07	$1.07	$1.67	$1.27	$1.27	$1.52
Expected Case	2022-2023	May	$1.03	$1.03	$1.67	$1.06	$1.63	$1.06	$1.06	$1.06	$1.03	$1.03	$1.67	$1.25	$1.25	$1.17
Expected Case	2022-2023	Jun	$1.21	$1.21	$1.67	$1.23	$1.66	$1.23	$1.23	$1.23	$1.21	$1.21	$1.67	$1.36	$1.36	$1.32
Expected Case	2022-2023	Jul	$1.26	$1.26	$1.67	$1.29	$1.67	$1.29	$1.29	$1.29	$1.26	$1.26	$1.67	$1.40	$1.40	$1.37
Expected Case	2022-2023	Aug	$1.27	$1.27	$1.67	$1.30	$1.67	$1.30	$1.30	$1.30	$1.27	$1.27	$1.67	$1.40	$1.40	$1.37
Expected Case	2022-2023	Sep	$0.99	$0.99	$1.68	$1.01	$1.68	$1.01	$1.01	$1.01	$0.99	$0.99	$1.68	$1.22	$1.22	$1.14
Expected Case	2022-2023	Oct	$1.07	$1.07	$1.72	$1.10	$1.72	$1.10	$1.10	$1.10	$1.07	$1.07	$1.72	$1.29	$1.29	$1.22
Expected Case	2023-2024	Nov	$1.60	$1.60	$2.03	$1.63	$2.03	$1.63	$1.63	$1.63	$1.60	$1.60	$2.03	$1.74	$1.74	$1.71
Expected Case	2023-2024	Dec	$1.92	$1.85	$2.03	$1.98	$2.08	$1.98	$1.98	$1.98	$1.92	$1.85	$2.03	$1.93	$1.93	$2.00
Expected Case	2023-2024	Jan	$2.06	$2.06	$2.06	$2.11	$2.12	$2.11	$2.11	$2.11	$2.06	$2.06	$2.06	$2.06	$2.06	$2.11
Expected Case	2023-2024	Feb	$1.83	$1.76	$2.06	$1.81	$2.07	$1.81	$1.81	$1.81	$1.83	$1.76	$2.06	$1.88	$1.88	$1.86
Expected Case	2023-2024	Mar	$1.69	$1.69	$2.00	$1.72	$2.00	$1.72	$1.72	$1.72	$1.69	$1.69	$2.00	$1.79	$1.79	$1.78
Expected Case	2023-2024	Apr	$1.38	$1.38	$1.73	$1.41	$1.73	$1.73	$1.73	$1.73	$1.38	$1.38	$1.73	$1.49	$1.49	$1.66
Expected Case	2023-2024	May	$1.36	$1.36	$1.70	$1.40	$1.70	$1.40	$1.40	$1.40	$1.36	$1.36	$1.70	$1.48	$1.48	$1.46
Expected Case	2023-2024	Jun	$1.38	$1.38	$1.70	$1.41	$1.70	$1.41	$1.41	$1.41	$1.38	$1.38	$1.70	$1.49	$1.49	$1.47
Expected Case	2023-2024	Jul	$1.35	$1.35	$1.70	$1.38	$1.70	$1.38	$1.38	$1.38	$1.35	$1.35	$1.70	$1.47	$1.47	$1.45
Expected Case	2023-2024	Aug	$1.36	$1.36	$1.70	$1.39	$1.70	$1.39	$1.39	$1.39	$1.36	$1.36	$1.70	$1.47	$1.47	$1.45
Expected Case	2023-2024	Sep	$1.44	$1.44	$1.70	$1.47	$1.70	$1.47	$1.47	$1.47	$1.44	$1.44	$1.70	$1.53	$1.53	$1.52
Expected Case	2023-2024	Oct	$1.45	$1.45	$1.76	$1.48	$1.76	$1.48	$1.48	$1.48	$1.45	$1.45	$1.76	$1.56	$1.56	$1.54
Expected Case	2024-2025	Nov	$1.60	$1.60	$2.07	$1.63	$2.07	$1.63	$1.63	$1.63	$1.60	$1.60	$2.07	$1.76	$1.76	$1.72
Expected Case	2024-2025	Dec	$1.99	$1.84	$2.08	$2.01	$2.16	$2.01	$2.01	$2.01	$1.99	$1.84	$2.08	$1.97	$1.97	$2.04
Expected Case	2024-2025	Jan	$2.11	$2.11	$2.11	$2.15	$2.17	$2.15	$2.15	$2.15	$2.11	$2.11	$2.11	$2.11	$2.11	$2.16
Expected Case	2024-2025	Feb	$2.02	$1.99	$2.09	$2.07	$2.14	$2.07	$2.07	$2.07	$2.02	$1.99	$2.09	$2.04	$2.04	$2.08
Expected Case	2024-2025	Mar	$1.86	$1.86	$2.03	$1.90	$2.03	$1.90	$1.90	$1.90	$1.86	$1.86	$2.03	$1.92	$1.92	$1.93
Expected Case	2024-2025	Apr	$1.68	$1.68	$2.11	$1.72	$2.11	$2.11	$2.11	$2.11	$1.68	$1.68	$2.11	$1.82	$1.82	$2.03
Expected Case	2024-2025	May	$1.77	$1.77	$2.03	$1.80	$2.03	$1.80	$1.80	$1.80	$1.77	$1.77	$2.03	$1.85	$1.85	$1.85
Expected Case	2024-2025	Jun	$1.69	$1.69	$2.03	$1.73	$2.03	$1.73	$1.73	$1.73	$1.69	$1.69	$2.03	$1.80	$1.80	$1.79
Expected Case	2024-2025	Jul	$1.70	$1.70	$2.03	$1.74	$2.03	$1.74	$1.74	$1.74	$1.70	$1.70	$2.03	$1.81	$1.81	$1.80
Expected Case	2024-2025	Aug	$1.70	$1.70	$2.03	$1.73	$2.03	$1.73	$1.73	$1.73	$1.70	$1.70	$2.03	$1.81	$1.81	$1.79
Expected Case	2024-2025	Sep	$1.79	$1.79	$2.03	$1.82	$2.03	$1.82	$1.82	$1.82	$1.79	$1.79	$2.03	$1.87	$1.87	$1.87
Expected Case	2024-2025	Oct	$1.79	$1.79	$2.38	$1.82	$2.38	$1.82	$1.82	$1.82	$1.79	$1.79	$2.38	$1.98	$1.98	$1.93
Expected Case	2025-2026	Nov	$2.01	$2.01	$2.46	$2.05	$2.46	$2.05	$2.05	$2.05	$2.01	$2.01	$2.46	$2.16	$2.16	$2.14
Expected Case	2025-2026	Dec	$2.36	$2.17	$2.47	$2.38	$2.55	$2.38	$2.38	$2.38	$2.36	$2.17	$2.47	$2.33	$2.33	$2.41
Expected Case	2025-2026	Jan	$2.50	$2.50	$2.50	$2.56	$2.58	$2.56	$2.56	$2.56	$2.50	$2.50	$2.50	$2.50	$2.50	$2.56
Expected Case	2025-2026	Feb	$2.48	$2.44	$2.50	$2.53	$2.56	$2.53	$2.53	$2.53	$2.48	$2.44	$2.50	$2.47	$2.47	$2.54
Expected Case	2025-2026	Mar	$2.30	$2.30	$2.39	$2.35	$2.39	$2.35	$2.35	$2.35	$2.30	$2.30	$2.39	$2.33	$2.33	$2.35
Expected Case	2025-2026	Apr	$2.10	$2.10	$2.59	$2.15	$2.59	$2.59	$2.59	$2.59	$2.10	$2.10	$2.59	$2.27	$2.27	$2.50
Expected Case	2025-2026	May	$2.13	$2.13	$2.36	$2.17	$2.36	$2.17	$2.17	$2.17	$2.13	$2.13	$2.36	$2.21	$2.21	$2.21
Expected Case	2025-2026	Jun	$2.11	$2.11	$2.36	$2.15	$2.36	$2.15	$2.15	$2.15	$2.11	$2.11	$2.36	$2.19	$2.19	$2.19
Expected Case	2025-2026	Jul	$2.09	$2.09	$2.36	$2.14	$2.36	$2.14	$2.14	$2.14	$2.09	$2.09	$2.36	$2.18	$2.18	$2.18
Expected Case	2025-2026	Aug	$2.11	$2.11	$2.37	$2.15	$2.37	$2.15	$2.15	$2.15	$2.11	$2.11	$2.37	$2.19	$2.19	$2.19
Expected Case	2025-2026	Sep	$2.15	$2.15	$2.37	$2.19	$2.37	$2.19	$2.19	$2.19	$2.15	$2.15	$2.37	$2.22	$2.22	$2.23
Expected Case	2025-2026	Oct	$2.20	$2.20	$2.79	$2.25	$2.79	$2.25	$2.25	$2.25	$2.20	$2.20	$2.79	$2.40	$2.40	$2.36
Expected Case	2026-2027	Nov	$2.44	$2.44	$2.65	$2.49	$2.65	$2.49	$2.49	$2.49	$2.44	$2.44	$2.65	$2.51	$2.51	$2.52
Expected Case	2026-2027	Dec	$2.62	$2.56	$2.66	$2.72	$2.77	$2.72	$2.72	$2.72	$2.62	$2.56	$2.66	$2.61	$2.61	$2.73
Expected Case	2026-2027	Jan	$2.69	$2.69	$2.69	$2.75	$2.75	$2.75	$2.75	$2.75	$2.69	$2.69	$2.69	$2.69	$2.69	$2.75
Expected Case	2026-2027	Feb	$2.63	$2.59	$2.69	$2.68	$2.72	$2.68	$2.68	$2.68	$2.63	$2.59	$2.69	$2.64	$2.64	$2.69
Expected Case	2026-2027	Mar	$2.43	$2.43	$2.57	$2.48	$2.57	$2.48	$2.48	$2.48	$2.43	$2.43	$2.57	$2.48	$2.48	$2.50
Expected Case	2026-2027	Apr	$2.24	$2.24	$2.82	$2.29	$2.82	$2.82	$2.82	$2.82	$2.24	$2.24	$2.82	$2.44	$2.44	$2.72
Expected Case	2026-2027	May	$2.31	$2.31	$2.53	$2.36	$2.53	$2.36	$2.36	$2.36	$2.31	$2.31	$2.53	$2.38	$2.38	$2.39
Expected Case	2026-2027	Jun	$2.26	$2.26	$2.53	$2.31	$2.53	$2.31	$2.31	$2.31	$2.26	$2.26	$2.53	$2.35	$2.35	$2.35
Expected Case	2026-2027	Jul	$2.24	$2.24	$2.54	$2.29	$2.54	$2.29	$2.29	$2.29	$2.24	$2.24	$2.54	$2.34	$2.34	$2.34
Expected Case	2026-2027	Aug	$2.26	$2.26	$2.54	$2.31	$2.54	$2.31	$2.31	$2.31	$2.26	$2.26	$2.54	$2.35	$2.35	$2.35
Expected Case	2026-2027	Sep	$2.32	$2.32	$2.54	$2.36	$2.54	$2.36	$2.36	$2.36	$2.32	$2.32	$2.54	$2.39	$2.39	$2.40
Expected Case	2026-2027	Oct	$2.30	$2.30	$2.93	$2.35	$2.93	$2.35	$2.35	$2.35	$2.30	$2.30	$2.93	$2.51	$2.51	$2.47
Expected Case	2027-2028	Nov	$2.63	$2.63	$2.80	$2.68	$2.80	$2.68	$2.68	$2.68	$2.63	$2.63	$2.80	$2.69	$2.69	$2.70

[1]Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Expected Case	2027-2028	Dec	$2.81	$2.78	$2.81	$2.94	$2.98	$2.94	$2.94	$2.94	$2.81	$2.78	$2.81	$2.80	$2.80	$2.95
Expected Case	2027-2028	Jan	$2.85	$2.85	$2.85	$2.91	$2.93	$2.91	$2.91	$2.91	$2.85	$2.85	$2.85	$2.85	$2.85	$2.91
Expected Case	2027-2028	Feb	$2.79	$2.74	$2.84	$2.83	$2.90	$2.83	$2.83	$2.83	$2.79	$2.74	$2.84	$2.79	$2.79	$2.84
Expected Case	2027-2028	Mar	$2.62	$2.62	$2.71	$2.68	$2.71	$2.68	$2.68	$2.68	$2.62	$2.62	$2.71	$2.65	$2.65	$2.68
Expected Case	2027-2028	Apr	$2.33	$2.33	$2.69	$2.38	$2.69	$2.69	$2.69	$2.69	$2.33	$2.33	$2.69	$2.45	$2.45	$2.63
Expected Case	2027-2028	May	$2.43	$2.43	$2.69	$2.48	$2.69	$2.48	$2.48	$2.48	$2.43	$2.43	$2.69	$2.52	$2.52	$2.52
Expected Case	2027-2028	Jun	$2.41	$2.41	$2.69	$2.46	$2.69	$2.46	$2.46	$2.46	$2.41	$2.41	$2.69	$2.50	$2.50	$2.50
Expected Case	2027-2028	Jul	$2.41	$2.41	$2.69	$2.46	$2.69	$2.46	$2.46	$2.46	$2.41	$2.41	$2.69	$2.51	$2.51	$2.51
Expected Case	2027-2028	Aug	$2.43	$2.43	$2.69	$2.48	$2.69	$2.48	$2.48	$2.48	$2.43	$2.43	$2.69	$2.52	$2.52	$2.52
Expected Case	2027-2028	Sep	$2.48	$2.48	$2.69	$2.53	$2.69	$2.53	$2.53	$2.53	$2.48	$2.48	$2.69	$2.55	$2.55	$2.57
Expected Case	2027-2028	Oct	$2.57	$2.57	$3.34	$2.62	$3.34	$2.62	$2.62	$2.62	$2.57	$2.57	$3.34	$2.83	$2.83	$2.77
Expected Case	2028-2029	Nov	$2.85	$2.85	$2.97	$2.91	$2.97	$2.91	$2.91	$2.91	$2.85	$2.85	$2.97	$2.89	$2.89	$2.92
Expected Case	2028-2029	Dec	$2.96	$2.90	$2.98	$3.10	$3.14	$3.10	$3.10	$3.10	$2.96	$2.90	$2.98	$2.95	$2.95	$3.11
Expected Case	2028-2029	Jan	$3.02	$3.02	$3.02	$3.08	$3.10	$3.08	$3.08	$3.08	$3.02	$3.02	$3.02	$3.02	$3.02	$3.08
Expected Case	2028-2029	Feb	$2.93	$2.88	$3.01	$2.98	$3.05	$2.98	$2.98	$2.98	$2.93	$2.88	$3.01	$2.94	$2.94	$2.99
Expected Case	2028-2029	Mar	$2.73	$2.73	$2.90	$2.78	$2.90	$2.78	$2.78	$2.78	$2.73	$2.73	$2.90	$2.78	$2.78	$2.80
Expected Case	2028-2029	Apr	$2.52	$2.52	$3.11	$2.57	$3.11	$3.11	$3.11	$3.11	$2.52	$2.52	$3.11	$2.72	$2.72	$3.00
Expected Case	2028-2029	May	$2.58	$2.58	$2.84	$2.63	$2.84	$2.63	$2.63	$2.63	$2.58	$2.58	$2.84	$2.67	$2.67	$2.67
Expected Case	2028-2029	Jun	$2.57	$2.57	$2.84	$2.63	$2.84	$2.63	$2.63	$2.63	$2.57	$2.57	$2.84	$2.66	$2.66	$2.67
Expected Case	2028-2029	Jul	$2.56	$2.56	$2.84	$2.61	$2.84	$2.61	$2.61	$2.61	$2.56	$2.56	$2.84	$2.65	$2.65	$2.65
Expected Case	2028-2029	Aug	$2.56	$2.56	$2.84	$2.61	$2.84	$2.61	$2.61	$2.61	$2.56	$2.56	$2.84	$2.65	$2.65	$2.65
Expected Case	2028-2029	Sep	$2.61	$2.61	$2.84	$2.66	$2.84	$2.66	$2.66	$2.66	$2.61	$2.61	$2.84	$2.69	$2.69	$2.70
Expected Case	2028-2029	Oct	$2.66	$2.66	$3.44	$2.71	$3.44	$2.71	$2.71	$2.71	$2.66	$2.66	$3.44	$2.92	$2.92	$2.86
Expected Case	2029-2030	Nov	$2.96	$2.96	$3.07	$3.02	$3.07	$3.02	$3.02	$3.02	$2.96	$2.96	$3.07	$3.00	$3.00	$3.03
Expected Case	2029-2030	Dec	$3.09	$3.09	$3.09	$3.27	$3.31	$3.27	$3.27	$3.27	$3.09	$3.09	$3.09	$3.09	$3.09	$3.28
Expected Case	2029-2030	Jan	$3.12	$3.12	$3.12	$3.18	$3.21	$3.18	$3.18	$3.18	$3.12	$3.12	$3.12	$3.12	$3.12	$3.19
Expected Case	2029-2030	Feb	$3.05	$3.00	$3.12	$3.10	$3.16	$3.10	$3.10	$3.10	$3.05	$3.00	$3.12	$3.06	$3.06	$3.11
Expected Case	2029-2030	Mar	$2.87	$2.87	$3.00	$2.93	$3.00	$2.93	$2.93	$2.93	$2.87	$2.87	$3.00	$2.91	$2.91	$2.94
Expected Case	2029-2030	Apr	$2.63	$2.63	$3.25	$2.69	$3.25	$3.25	$3.25	$3.25	$2.63	$2.63	$3.25	$2.84	$2.84	$3.14
Expected Case	2029-2030	May	$2.67	$2.67	$2.92	$2.72	$2.92	$2.72	$2.72	$2.72	$2.67	$2.67	$2.92	$2.75	$2.75	$2.76
Expected Case	2029-2030	Jun	$2.64	$2.64	$2.92	$2.69	$2.92	$2.69	$2.69	$2.69	$2.64	$2.64	$2.92	$2.73	$2.73	$2.74
Expected Case	2029-2030	Jul	$2.59	$2.59	$2.92	$2.64	$2.92	$2.64	$2.64	$2.64	$2.59	$2.59	$2.92	$2.70	$2.70	$2.69
Expected Case	2029-2030	Aug	$2.61	$2.61	$2.92	$2.66	$2.92	$2.66	$2.66	$2.66	$2.61	$2.61	$2.92	$2.72	$2.72	$2.72
Expected Case	2029-2030	Sep	$2.67	$2.67	$2.92	$2.72	$2.92	$2.72	$2.72	$2.72	$2.67	$2.67	$2.92	$2.75	$2.75	$2.76
Expected Case	2029-2030	Oct	$2.80	$2.80	$3.41	$2.86	$3.41	$2.86	$2.86	$2.86	$2.80	$2.80	$3.41	$3.00	$3.00	$2.97
Expected Case	2030-2031	Nov	$3.11	$3.10	$3.20	$3.16	$3.20	$3.16	$3.16	$3.16	$3.11	$3.10	$3.20	$3.14	$3.14	$3.17
Expected Case	2030-2031	Dec	$3.25	$3.25	$3.25	$3.43	$3.46	$3.43	$3.43	$3.43	$3.25	$3.25	$3.25	$3.25	$3.25	$3.43
Expected Case	2030-2031	Jan	$3.26	$3.26	$3.26	$3.32	$3.35	$3.32	$3.32	$3.32	$3.26	$3.26	$3.26	$3.26	$3.26	$3.32
Expected Case	2030-2031	Feb	$3.21	$3.16	$3.25	$3.27	$3.31	$3.27	$3.27	$3.27	$3.21	$3.16	$3.25	$3.21	$3.21	$3.27
Expected Case	2030-2031	Mar	$2.99	$2.99	$3.11	$3.05	$3.11	$3.05	$3.05	$3.05	$2.99	$2.99	$3.11	$3.03	$3.03	$3.06
Expected Case	2030-2031	Apr	$2.78	$2.78	$3.43	$2.83	$3.43	$3.43	$3.43	$3.43	$2.78	$2.78	$3.43	$3.00	$3.00	$3.31
Expected Case	2030-2031	May	$2.80	$2.80	$3.10	$2.85	$3.10	$2.85	$2.85	$2.85	$2.80	$2.80	$3.10	$2.90	$2.90	$2.90
Expected Case	2030-2031	Jun	$2.77	$2.77	$3.10	$2.82	$3.10	$2.82	$2.82	$2.82	$2.77	$2.77	$3.10	$2.88	$2.88	$2.88
Expected Case	2030-2031	Jul	$2.73	$2.73	$3.10	$2.78	$3.10	$2.78	$2.78	$2.78	$2.73	$2.73	$3.10	$2.85	$2.85	$2.84
Expected Case	2030-2031	Aug	$2.72	$2.72	$3.10	$2.78	$3.10	$2.78	$2.78	$2.78	$2.72	$2.72	$3.10	$2.85	$2.85	$2.84
Expected Case	2030-2031	Sep	$2.83	$2.83	$3.10	$2.88	$3.10	$2.88	$2.88	$2.88	$2.83	$2.83	$3.10	$2.92	$2.92	$2.92
Expected Case	2030-2031	Oct	$2.88	$2.88	$3.51	$2.94	$3.51	$2.94	$2.94	$2.94	$2.88	$2.88	$3.51	$3.09	$3.09	$3.05
Expected Case	2031-2032	Nov	$3.24	$3.23	$3.30	$3.29	$3.30	$3.29	$3.29	$3.29	$3.24	$3.23	$3.30	$3.25	$3.25	$3.29
Expected Case	2031-2032	Dec	$3.34	$3.33	$3.34	$3.53	$3.56	$3.53	$3.53	$3.53	$3.34	$3.33	$3.34	$3.33	$3.33	$3.54
Expected Case	2031-2032	Jan	$3.35	$3.35	$3.35	$3.42	$3.45	$3.42	$3.42	$3.42	$3.35	$3.35	$3.35	$3.35	$3.35	$3.42
Expected Case	2031-2032	Feb	$3.29	$3.22	$3.35	$3.32	$3.42	$3.32	$3.32	$3.32	$3.29	$3.22	$3.35	$3.29	$3.29	$3.34
Expected Case	2031-2032	Mar	$3.06	$3.06	$3.20	$3.12	$3.20	$3.12	$3.12	$3.12	$3.06	$3.06	$3.20	$3.11	$3.11	$3.14
Expected Case	2031-2032	Apr	$2.89	$2.89	$3.56	$2.95	$3.56	$3.56	$3.56	$3.56	$2.89	$2.89	$3.56	$3.12	$3.12	$3.44
Expected Case	2031-2032	May	$2.87	$2.87	$3.14	$2.93	$3.14	$2.93	$2.93	$2.93	$2.87	$2.87	$3.14	$2.96	$2.96	$2.97
Expected Case	2031-2032	Jun	$2.83	$2.83	$3.15	$2.89	$3.14	$2.89	$2.89	$2.89	$2.83	$2.83	$3.15	$2.93	$2.93	$2.94
Expected Case	2031-2032	Jul	$2.65	$2.65	$3.15	$2.70	$3.15	$2.70	$2.70	$2.70	$2.65	$2.65	$3.15	$2.81	$2.81	$2.79
Expected Case	2031-2032	Aug	$2.68	$2.68	$3.15	$2.73	$3.15	$2.73	$2.73	$2.73	$2.68	$2.68	$3.15	$2.83	$2.83	$2.81
Expected Case	2031-2032	Sep	$2.87	$2.87	$3.15	$2.93	$3.15	$2.93	$2.93	$2.93	$2.87	$2.87	$3.15	$2.96	$2.96	$2.97
Expected Case	2031-2032	Oct	$2.99	$2.99	$3.63	$3.05	$3.63	$3.05	$3.05	$3.05	$2.99	$2.99	$3.63	$3.21	$3.21	$3.17
Expected Case	2032-2033	Nov	$3.40	$3.38	$3.51	$3.45	$3.51	$3.45	$3.45	$3.45	$3.40	$3.38	$3.51	$3.43	$3.43	$3.46
Expected Case	2032-2033	Dec	$3.52	$3.49	$3.52	$3.73	$3.76	$3.73	$3.73	$3.73	$3.52	$3.49	$3.52	$3.51	$3.51	$3.74
Expected Case	2032-2033	Jan	$3.57	$3.57	$3.57	$3.64	$3.67	$3.64	$3.64	$3.64	$3.57	$3.57	$3.57	$3.57	$3.57	$3.64
Expected Case	2032-2033	Feb	$3.54	$3.51	$3.55	$3.62	$3.67	$3.62	$3.62	$3.62	$3.54	$3.51	$3.55	$3.53	$3.53	$3.63
Expected Case	2032-2033	Mar	$3.35	$3.35	$3.44	$3.42	$3.44	$3.42	$3.42	$3.42	$3.35	$3.35	$3.44	$3.38	$3.38	$3.42
Expected Case	2032-2033	Apr	$3.16	$3.16	$3.81	$3.22	$3.81	$3.81	$3.81	$3.81	$3.16	$3.16	$3.81	$3.38	$3.38	$3.69
Expected Case	2032-2033	May	$3.14	$3.14	$3.44	$3.21	$3.44	$3.21	$3.21	$3.21	$3.14	$3.14	$3.44	$3.24	$3.24	$3.25
Expected Case	2032-2033	Jun	$3.15	$3.15	$3.45	$3.21	$3.45	$3.21	$3.21	$3.21	$3.15	$3.15	$3.45	$3.25	$3.25	$3.26
Expected Case	2032-2033	Jul	$3.02	$3.02	$3.45	$3.08	$3.45	$3.08	$3.08	$3.08	$3.02	$3.02	$3.45	$3.16	$3.16	$3.15
Expected Case	2032-2033	Aug	$3.04	$3.04	$3.45	$3.10	$3.45	$3.10	$3.10	$3.10	$3.04	$3.04	$3.45	$3.18	$3.18	$3.17
Expected Case	2032-2033	Sep	$3.17	$3.17	$3.45	$3.23	$3.45	$3.23	$3.23	$3.23	$3.17	$3.17	$3.45	$3.26	$3.26	$3.28
Expected Case	2032-2033	Oct	$3.26	$3.26	$3.88	$3.32	$3.88	$3.32	$3.32	$3.32	$3.26	$3.26	$3.88	$3.47	$3.47	$3.43
Expected Case	2033-2034	Nov	$3.68	$3.67	$3.73	$3.74	$3.74	$3.74	$3.74	$3.74	$3.68	$3.67	$3.73	$3.69	$3.69	$3.74
Expected Case	2033-2034	Dec	$3.75	$3.73	$3.75	$3.97	$4.00	$3.97	$3.97	$3.97	$3.75	$3.73	$3.75	$3.74	$3.74	$3.97
Expected Case	2033-2034	Jan	$3.79	$3.78	$3.79	$3.86	$3.89	$3.86	$3.86	$3.86	$3.79	$3.78	$3.79	$3.78	$3.78	$3.86
Expected Case	2033-2034	Feb	$3.75	$3.67	$3.78	$3.78	$3.85	$3.78	$3.78	$3.78	$3.75	$3.67	$3.78	$3.73	$3.73	$3.79
Expected Case	2033-2034	Mar	$3.52	$3.52	$3.63	$3.59	$3.63	$3.59	$3.59	$3.59	$3.52	$3.52	$3.63	$3.56	$3.56	$3.60
Expected Case	2033-2034	Apr	$3.31	$3.31	$3.96	$3.38	$3.96	$3.96	$3.96	$3.96	$3.31	$3.31	$3.96	$3.53	$3.53	$3.84
Expected Case	2033-2034	May	$3.32	$3.32	$3.62	$3.38	$3.62	$3.38	$3.38	$3.38	$3.32	$3.32	$3.62	$3.42	$3.42	$3.43
Expected Case	2033-2034	Jun	$3.29	$3.29	$3.62	$3.35	$3.62	$3.35	$3.35	$3.35	$3.29	$3.29	$3.62	$3.40	$3.40	$3.41
Expected Case	2033-2034	Jul	$3.22	$3.22	$3.62	$3.28	$3.62	$3.28	$3.28	$3.28	$3.22	$3.22	$3.62	$3.35	$3.35	$3.35
Expected Case	2033-2034	Aug	$3.25	$3.25	$3.62	$3.31	$3.62	$3.31	$3.31	$3.31	$3.25	$3.25	$3.62	$3.37	$3.37	$3.37
Expected Case	2033-2034	Sep	$3.35	$3.35	$3.62	$3.41	$3.62	$3.41	$3.41	$3.41	$3.35	$3.35	$3.62	$3.44	$3.44	$3.45
Expected Case	2033-2034	Oct	$3.46	$3.46	$4.12	$3.53	$4.12	$4.12	$4.12	$4.12	$3.46	$3.46	$4.12	$3.68	$3.68	$4.00
Expected Case	2034-2035	Nov	$3.83	$3.82	$3.88	$3.89	$3.89	$3.89	$3.89	$3.89	$3.83	$3.82	$3.88	$3.84	$3.84	$3.89
Expected Case	2034-2035	Dec	$3.93	$3.93	$3.93	$4.70	$4.71	$4.70	$4.70	$4.70	$3.93	$3.93	$3.93	$3.93	$3.93	$4.70
Expected Case	2034-2035	Jan	$3.94	$3.94	$3.94	$4.01	$4.05	$4.01	$4.01	$4.01	$3.94	$3.94	$3.94	$3.94	$3.94	$4.02
Expected Case	2034-2035	Feb	$3.89	$3.80	$3.93	$3.93	$3.99	$3.93	$3.93	$3.93	$3.89	$3.80	$3.93	$3.87	$3.87	$3.94
Expected Case	2034-2035	Mar	$3.59	$3.59	$3.79	$3.66	$3.79	$3.66	$3.66	$3.66	$3.59	$3.59	$3.79	$3.66	$3.66	$3.68
Expected Case	2034-2035	Apr	$3.44	$3.44	$4.08	$3.50	$4.08	$4.08	$4.08	$4.08	$3.44	$3.44	$4.08	$3.65	$3.65	$3.97
Expected Case	2034-2035	May	$3.44	$3.44	$3.70	$3.51	$3.70	$3.51	$3.51	$3.51	$3.44	$3.44	$3.70	$3.53	$3.53	$3.55
Expected Case	2034-2035	Jun	$3.39	$3.39	$3.70	$3.45	$3.70	$3.45	$3.45	$3.45	$3.39	$3.39	$3.70	$3.49	$3.49	$3.50
Expected Case	2034-2035	Jul	$3.25	$3.25	$3.70	$3.31	$3.70	$3.31	$3.31	$3.31	$3.25	$3.25	$3.70	$3.40	$3.40	$3.39
Expected Case	2034-2035	Aug	$3.30	$3.30	$3.70	$3.36	$3.70	$3.36	$3.36	$3.36	$3.30	$3.30	$3.70	$3.43	$3.43	$3.43
Expected Case	2034-2035	Sep	$3.43	$3.43	$3.70	$3.49	$3.70	$3.49	$3.49	$3.49	$3.43	$3.43	$3.70	$3.52	$3.52	$3.53
Expected Case	2034-2035	Oct	$3.51	$3.51	$4.19	$3.58	$4.19	$4.19	$4.19	$4.19	$3.51	$3.51	$4.19	$3.74	$3.74	$4.06
Expected Case	2035-2036	Nov	$3.94	$3.92	$4.12	$3.99	$4.12	$3.99	$3.99	$3.99	$3.94	$3.92	$4.12	$3.99	$3.99	$4.02
Expected Case	2035-2036	Dec	$4.14	$4.09	$4.14	$4.94	$4.94	$4.94	$4.94	$4.94	$4.14	$4.09	$4.14	$4.13	$4.13	$4.94

[1]Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Expected Case	2035-2036	Jan	$4.14	$4.12	$4.14	$4.20	$4.23	$4.20	$4.20	$4.20	$4.14	$4.12	$4.14	$4.13	$4.13	$4.21
Expected Case	2035-2036	Feb	$4.16	$4.05	$4.18	$4.17	$4.26	$4.17	$4.17	$4.17	$4.16	$4.05	$4.18	$4.13	$4.13	$4.19
Expected Case	2035-2036	Mar	$3.86	$3.86	$4.03	$3.93	$4.03	$3.93	$3.93	$3.93	$3.86	$3.86	$4.03	$3.92	$3.92	$3.95
Expected Case	2035-2036	Apr	$3.62	$3.62	$4.16	$3.69	$4.16	$4.16	$4.16	$4.16	$3.62	$3.62	$4.16	$3.80	$3.80	$4.06
Expected Case	2035-2036	May	$3.62	$3.62	$3.85	$3.69	$3.85	$3.69	$3.69	$3.69	$3.62	$3.62	$3.85	$3.69	$3.69	$3.72
Expected Case	2035-2036	Jun	$3.60	$3.60	$3.85	$3.67	$3.85	$3.67	$3.67	$3.67	$3.60	$3.60	$3.85	$3.68	$3.68	$3.70
Expected Case	2035-2036	Jul	$3.39	$3.39	$3.85	$3.45	$3.85	$3.45	$3.45	$3.45	$3.39	$3.39	$3.85	$3.54	$3.54	$3.53
Expected Case	2035-2036	Aug	$3.42	$3.42	$3.85	$3.48	$3.85	$3.48	$3.48	$3.48	$3.42	$3.42	$3.85	$3.56	$3.56	$3.56
Expected Case	2035-2036	Sep	$3.57	$3.57	$3.85	$3.64	$3.85	$3.64	$3.64	$3.64	$3.57	$3.57	$3.85	$3.66	$3.66	$3.68
Expected Case	2035-2036	Oct	$3.73	$3.73	$4.29	$3.80	$4.29	$4.29	$4.29	$4.29	$3.73	$3.73	$4.29	$3.91	$3.91	$4.19
Expected Case	2036-2037	Nov	$4.16	$4.14	$4.32	$4.22	$4.32	$4.22	$4.22	$4.22	$4.16	$4.14	$4.32	$4.21	$4.21	$4.24
Expected Case	2036-2037	Dec	$4.35	$4.27	$4.35	$5.19	$5.21	$5.19	$5.19	$5.19	$4.35	$4.27	$4.35	$4.32	$4.32	$5.20
Expected Case	2036-2037	Jan	$4.34	$4.32	$4.34	$4.41	$4.44	$4.41	$4.41	$4.41	$4.34	$4.32	$4.34	$4.33	$4.33	$4.41
Expected Case	2036-2037	Feb	$4.32	$4.11	$4.37	$4.23	$4.44	$4.23	$4.23	$4.23	$4.32	$4.11	$4.37	$4.27	$4.27	$4.28
Expected Case	2036-2037	Mar	$3.93	$3.93	$4.27	$4.01	$4.27	$4.01	$4.01	$4.01	$3.93	$3.93	$4.27	$4.05	$4.05	$4.06
Expected Case	2036-2037	Apr	$3.66	$3.66	$4.22	$3.73	$4.22	$4.22	$4.22	$4.22	$3.66	$3.66	$4.22	$3.85	$3.85	$4.12
Expected Case	2036-2037	May	$3.80	$3.80	$4.09	$3.87	$4.09	$3.87	$3.87	$3.87	$3.80	$3.80	$4.09	$3.89	$3.89	$3.91
Expected Case	2036-2037	Jun	$3.77	$3.77	$4.09	$3.85	$4.09	$3.85	$3.85	$3.85	$3.77	$3.77	$4.09	$3.88	$3.88	$3.89
Expected Case	2036-2037	Jul	$3.65	$3.65	$4.09	$3.72	$4.09	$3.72	$3.72	$3.72	$3.65	$3.65	$4.09	$3.79	$3.79	$3.79
Expected Case	2036-2037	Aug	$3.74	$3.74	$4.09	$3.81	$4.09	$3.81	$3.81	$3.81	$3.74	$3.74	$4.09	$3.86	$3.86	$3.87
Expected Case	2036-2037	Sep	$3.84	$3.84	$4.09	$3.91	$4.09	$3.91	$3.91	$3.91	$3.84	$3.84	$4.09	$3.92	$3.92	$3.95
Expected Case	2036-2037	Oct	$3.97	$3.97	$4.53	$4.05	$4.53	$4.53	$4.53	$4.53	$3.97	$3.97	$4.53	$4.16	$4.16	$4.43
Expected Case	2037-2038	Nov	$4.47	$4.44	$4.60	$4.52	$4.60	$4.52	$4.52	$4.52	$4.47	$4.44	$4.60	$4.51	$4.51	$4.54
Expected Case	2037-2038	Dec	$4.65	$4.61	$4.65	$5.49	$5.51	$5.49	$5.49	$5.49	$4.65	$4.61	$4.65	$4.63	$4.63	$5.50
Expected Case	2037-2038	Jan	$4.64	$4.63	$4.64	$4.72	$4.86	$4.72	$4.72	$4.72	$4.64	$4.63	$4.64	$4.64	$4.64	$4.75
Expected Case	2037-2038	Feb	$4.61	$4.34	$4.67	$4.50	$4.71	$4.50	$4.50	$4.50	$4.61	$4.34	$4.67	$4.54	$4.54	$4.54
Expected Case	2037-2038	Mar	$4.08	$4.08	$4.55	$4.16	$4.55	$4.16	$4.16	$4.16	$4.08	$4.08	$4.55	$4.24	$4.24	$4.24
Expected Case	2037-2038	Apr	$3.87	$3.87	$4.40	$3.95	$4.40	$4.40	$4.40	$4.40	$3.87	$3.87	$4.40	$4.05	$4.05	$4.31
Expected Case	2037-2038	May	$3.91	$3.91	$4.13	$3.98	$4.13	$3.98	$3.98	$3.98	$3.91	$3.91	$4.13	$3.98	$3.98	$4.01
Expected Case	2037-2038	Jun	$3.91	$3.91	$4.13	$3.99	$4.13	$3.99	$3.99	$3.99	$3.91	$3.91	$4.13	$3.98	$3.98	$4.01
Expected Case	2037-2038	Jul	$3.74	$3.74	$4.13	$3.82	$4.13	$3.82	$3.82	$3.82	$3.74	$3.74	$4.13	$3.87	$3.87	$3.88
Expected Case	2037-2038	Aug	$3.77	$3.77	$4.13	$3.84	$4.13	$3.84	$3.84	$3.84	$3.77	$3.77	$4.13	$3.89	$3.89	$3.90
Expected Case	2037-2038	Sep	$3.87	$3.87	$4.13	$3.95	$4.13	$3.95	$3.95	$3.95	$3.87	$3.87	$4.13	$3.96	$3.96	$3.98
Expected Case	2037-2038	Oct	$4.00	$4.00	$4.54	$4.08	$4.54	$4.54	$4.54	$4.54	$4.00	$4.00	$4.54	$4.18	$4.18	$4.45
Expected Case	2038-2039	Nov	$4.53	$4.46	$4.84	$4.54	$4.84	$4.54	$4.54	$4.54	$4.53	$4.46	$4.84	$4.61	$4.61	$4.60
Expected Case	2038-2039	Dec	$4.89	$4.67	$4.89	$5.63	$5.66	$5.63	$5.63	$5.63	$4.89	$4.67	$4.89	$4.81	$4.81	$5.64
Expected Case	2038-2039	Jan	$4.87	$4.73	$4.87	$4.82	$5.01	$4.82	$4.82	$4.82	$4.87	$4.73	$4.87	$4.83	$4.83	$4.86
Expected Case	2038-2039	Feb	$4.82	$4.51	$4.90	$4.64	$4.94	$4.64	$4.64	$4.64	$4.82	$4.51	$4.90	$4.75	$4.75	$4.70
Expected Case	2038-2039	Mar	$4.37	$4.37	$4.81	$4.45	$4.81	$4.45	$4.45	$4.45	$4.37	$4.37	$4.81	$4.52	$4.52	$4.52
Expected Case	2038-2039	Apr	$4.13	$4.13	$4.65	$4.20	$4.65	$4.65	$4.65	$4.65	$4.13	$4.13	$4.65	$4.30	$4.30	$4.56
Expected Case	2038-2039	May	$4.16	$4.16	$4.39	$4.24	$4.39	$4.24	$4.24	$4.24	$4.16	$4.16	$4.39	$4.23	$4.23	$4.27
Expected Case	2038-2039	Jun	$4.07	$4.07	$4.39	$4.15	$4.39	$4.15	$4.15	$4.15	$4.07	$4.07	$4.39	$4.18	$4.18	$4.20
Expected Case	2038-2039	Jul	$3.94	$3.94	$4.39	$4.01	$4.39	$4.01	$4.01	$4.01	$3.94	$3.94	$4.39	$4.09	$4.09	$4.09
Expected Case	2038-2039	Aug	$3.94	$3.94	$4.39	$4.02	$4.39	$4.02	$4.02	$4.02	$3.94	$3.94	$4.39	$4.09	$4.09	$4.09
Expected Case	2038-2039	Sep	$4.13	$4.13	$4.39	$4.20	$4.39	$4.20	$4.20	$4.20	$4.13	$4.13	$4.39	$4.21	$4.21	$4.24
Expected Case	2038-2039	Oct	$4.24	$4.24	$4.78	$4.32	$4.78	$4.78	$4.78	$4.78	$4.24	$4.24	$4.78	$4.42	$4.42	$4.69
Expected Case	2039-2040	Nov	$4.86	$4.74	$5.14	$4.83	$5.14	$4.83	$4.83	$4.83	$4.86	$4.74	$5.14	$4.91	$4.91	$4.89
Expected Case	2039-2040	Dec	$5.19	$4.89	$5.19	$5.99	$6.02	$5.99	$5.99	$5.99	$5.19	$4.89	$5.19	$5.09	$5.09	$5.99
Expected Case	2039-2040	Jan	$5.18	$4.91	$5.18	$5.01	$5.30	$5.01	$5.01	$5.01	$5.18	$4.91	$5.18	$5.09	$5.09	$5.06
Expected Case	2039-2040	Feb	$5.14	$4.68	$5.21	$4.82	$5.24	$4.82	$4.82	$4.82	$5.14	$4.68	$5.21	$5.01	$5.01	$4.90
Expected Case	2039-2040	Mar	$4.51	$4.51	$5.12	$4.59	$5.12	$4.59	$4.59	$4.59	$4.51	$4.51	$5.12	$4.71	$4.71	$4.70
Expected Case	2039-2040	Apr	$4.28	$4.28	$4.82	$4.36	$4.82	$4.82	$4.82	$4.82	$4.28	$4.28	$4.82	$4.46	$4.46	$4.73
Expected Case	2039-2040	May	$4.31	$4.31	$4.55	$4.40	$4.55	$4.40	$4.40	$4.40	$4.31	$4.31	$4.55	$4.39	$4.39	$4.43
Expected Case	2039-2040	Jun	$4.29	$4.29	$4.55	$4.37	$4.55	$4.37	$4.37	$4.37	$4.29	$4.29	$4.55	$4.38	$4.38	$4.41
Expected Case	2039-2040	Jul	$4.17	$4.17	$4.55	$4.25	$4.55	$4.25	$4.25	$4.25	$4.17	$4.17	$4.55	$4.30	$4.30	$4.31
Expected Case	2039-2040	Aug	$4.21	$4.21	$4.55	$4.29	$4.55	$4.29	$4.29	$4.29	$4.21	$4.21	$4.55	$4.32	$4.32	$4.34
Expected Case	2039-2040	Sep	$4.34	$4.34	$4.55	$4.43	$4.55	$4.43	$4.43	$4.43	$4.34	$4.34	$4.55	$4.41	$4.41	$4.45
Expected Case	2039-2040	Oct	$4.46	$4.46	$4.99	$4.54	$4.99	$4.99	$4.99	$4.99	$4.46	$4.46	$4.99	$4.63	$4.63	$4.90

[1]Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: HIGH GROWTH & LOW PRICES MONTHLY DETAIL

Monthly Avoided Costs[1]
Nominal $

Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
High Growth & Low Prices	2019-2020	Nov	$2.00	$2.18	$2.00	$2.22	$2.22	$2.22	$2.22	$2.22	$2.00	$2.18	$2.00	$2.06	$2.06	$2.22
High Growth & Low Prices	2019-2020	Dec	$1.99	$1.87	$1.99	$2.17	$2.25	$2.17	$2.17	$2.17	$1.99	$1.87	$1.99	$1.95	$1.95	$2.19
High Growth & Low Prices	2019-2020	Jan	$2.00	$1.80	$2.00	$1.84	$2.02	$1.84	$1.84	$1.84	$2.00	$1.80	$2.00	$1.93	$1.93	$1.88
High Growth & Low Prices	2019-2020	Feb	$1.95	$1.43	$1.97	$1.50	$1.97	$1.50	$1.50	$1.50	$1.95	$1.43	$1.97	$1.79	$1.79	$1.60
High Growth & Low Prices	2019-2020	Mar	$1.25	$1.25	$1.38	$1.28	$1.38	$1.28	$1.28	$1.28	$1.25	$1.25	$1.38	$1.30	$1.30	$1.30
High Growth & Low Prices	2019-2020	Apr	$1.03	$1.03	$1.15	$1.05	$1.14	$1.15	$1.15	$1.15	$1.03	$1.03	$1.15	$1.07	$1.07	$1.13
High Growth & Low Prices	2019-2020	May	$1.05	$1.14	$1.05	$1.07	$1.05	$1.05	$1.05	$1.05	$1.05	$1.14	$1.05	$1.08	$1.08	$1.06
High Growth & Low Prices	2019-2020	Jun	$0.90	$0.90	$1.06	$0.86	$0.90	$0.86	$0.86	$0.86	$0.90	$0.90	$1.06	$0.95	$0.95	$0.87
High Growth & Low Prices	2019-2020	Jul	$0.86	$0.86	$1.06	$0.80	$0.90	$0.80	$0.80	$0.80	$0.86	$0.86	$1.06	$0.93	$0.93	$0.82
High Growth & Low Prices	2019-2020	Aug	$1.10	$1.10	$1.13	$1.13	$1.13	$1.13	$1.13	$1.13	$1.10	$1.10	$1.13	$1.11	$1.11	$1.13
High Growth & Low Prices	2019-2020	Sep	$0.99	$0.99	$1.06	$1.01	$1.06	$1.01	$1.01	$1.01	$0.99	$0.99	$1.06	$1.01	$1.01	$1.02
High Growth & Low Prices	2019-2020	Oct	$1.02	$1.02	$1.31	$1.04	$1.31	$1.04	$1.04	$1.04	$1.02	$1.02	$1.31	$1.12	$1.12	$1.10
High Growth & Low Prices	2020-2021	Nov	$1.81	$1.81	$1.82	$1.74	$1.82	$1.74	$1.74	$1.74	$1.81	$1.81	$1.82	$1.81	$1.81	$1.75
High Growth & Low Prices	2020-2021	Dec	$2.01	$2.36	$2.01	$2.41	$2.41	$2.41	$2.41	$2.41	$2.01	$2.36	$2.01	$2.13	$2.13	$2.41
High Growth & Low Prices	2020-2021	Jan	$1.93	$1.80	$1.93	$1.83	$1.93	$1.83	$1.83	$1.83	$1.93	$1.80	$1.93	$1.88	$1.88	$1.85
High Growth & Low Prices	2020-2021	Feb	$2.02	$1.69	$2.02	$1.75	$2.02	$1.75	$1.75	$1.75	$2.02	$1.69	$2.02	$1.91	$1.91	$1.81
High Growth & Low Prices	2020-2021	Mar	$1.38	$1.38	$1.67	$1.41	$1.67	$1.41	$1.41	$1.41	$1.38	$1.38	$1.67	$1.47	$1.47	$1.46
High Growth & Low Prices	2020-2021	Apr	$0.91	$0.91	$1.27	$0.93	$1.27	$1.25	$1.25	$1.25	$0.91	$0.91	$1.27	$1.03	$1.03	$1.19
High Growth & Low Prices	2020-2021	May	$0.81	$0.81	$1.28	$0.83	$1.24	$0.83	$0.83	$0.83	$0.81	$0.81	$1.28	$0.96	$0.96	$0.91
High Growth & Low Prices	2020-2021	Jun	$0.85	$0.85	$1.28	$0.87	$1.22	$0.87	$0.87	$0.87	$0.85	$0.85	$1.28	$0.99	$0.99	$0.94
High Growth & Low Prices	2020-2021	Jul	$0.96	$0.96	$1.28	$0.99	$1.28	$0.99	$0.99	$0.99	$0.96	$0.96	$1.28	$1.07	$1.07	$1.05
High Growth & Low Prices	2020-2021	Aug	$0.96	$0.96	$1.28	$0.98	$1.28	$0.98	$0.98	$0.98	$0.96	$0.96	$1.28	$1.06	$1.06	$1.04
High Growth & Low Prices	2020-2021	Sep	$0.81	$0.81	$1.28	$0.83	$1.28	$0.83	$0.83	$0.83	$0.81	$0.81	$1.28	$0.96	$0.96	$0.92
High Growth & Low Prices	2020-2021	Oct	$0.83	$0.83	$1.44	$0.85	$1.44	$0.85	$0.85	$0.85	$0.83	$0.83	$1.44	$1.03	$1.03	$0.97
High Growth & Low Prices	2021-2022	Nov	$1.30	$1.17	$1.62	$1.19	$1.62	$1.19	$1.19	$1.19	$1.30	$1.17	$1.62	$1.36	$1.36	$1.28
High Growth & Low Prices	2021-2022	Dec	$1.65	$1.40	$1.65	$1.64	$1.69	$1.64	$1.64	$1.64	$1.65	$1.40	$1.65	$1.57	$1.57	$1.65
High Growth & Low Prices	2021-2022	Jan	$1.65	$1.48	$1.65	$1.51	$1.69	$1.51	$1.51	$1.51	$1.65	$1.48	$1.65	$1.59	$1.59	$1.55
High Growth & Low Prices	2021-2022	Feb	$1.67	$1.34	$1.67	$1.42	$1.67	$1.42	$1.42	$1.42	$1.67	$1.34	$1.67	$1.56	$1.56	$1.47
High Growth & Low Prices	2021-2022	Mar	$1.06	$1.06	$1.59	$1.09	$1.59	$1.09	$1.09	$1.09	$1.06	$1.06	$1.59	$1.24	$1.24	$1.19
High Growth & Low Prices	2021-2022	Apr	$0.52	$0.52	$1.10	$0.54	$1.10	$1.04	$1.04	$1.04	$0.52	$0.52	$1.10	$0.72	$0.72	$0.95
High Growth & Low Prices	2021-2022	May	$0.50	$0.50	$1.10	$0.51	$1.10	$0.51	$0.51	$0.51	$0.50	$0.50	$1.10	$0.70	$0.70	$0.63
High Growth & Low Prices	2021-2022	Jun	$0.60	$0.60	$1.10	$0.62	$1.10	$0.62	$0.62	$0.62	$0.60	$0.60	$1.10	$0.77	$0.77	$0.71
High Growth & Low Prices	2021-2022	Jul	$0.74	$0.74	$1.10	$0.76	$1.10	$0.76	$0.76	$0.76	$0.74	$0.74	$1.10	$0.86	$0.86	$0.83
High Growth & Low Prices	2021-2022	Aug	$0.68	$0.68	$1.11	$0.70	$1.11	$0.70	$0.70	$0.70	$0.68	$0.68	$1.11	$0.82	$0.82	$0.78
High Growth & Low Prices	2021-2022	Sep	$0.51	$0.51	$1.11	$0.52	$1.11	$0.52	$0.52	$0.52	$0.51	$0.51	$1.11	$0.71	$0.71	$0.64
High Growth & Low Prices	2021-2022	Oct	$0.50	$0.50	$1.11	$0.52	$1.11	$0.52	$0.52	$0.52	$0.50	$0.50	$1.11	$0.70	$0.70	$0.63
High Growth & Low Prices	2022-2023	Nov	$0.96	$0.77	$1.40	$0.79	$1.40	$0.79	$0.79	$0.79	$0.96	$0.77	$1.40	$1.04	$1.04	$0.91
High Growth & Low Prices	2022-2023	Dec	$1.43	$1.21	$1.43	$1.61	$1.63	$1.61	$1.61	$1.61	$1.43	$1.21	$1.43	$1.35	$1.35	$1.61
High Growth & Low Prices	2022-2023	Jan	$1.43	$1.27	$1.43	$1.30	$1.50	$1.30	$1.30	$1.30	$1.43	$1.27	$1.43	$1.37	$1.37	$1.34
High Growth & Low Prices	2022-2023	Feb	$1.46	$1.07	$1.46	$1.15	$1.46	$1.15	$1.15	$1.15	$1.46	$1.07	$1.46	$1.33	$1.33	$1.21
High Growth & Low Prices	2022-2023	Mar	$0.84	$0.84	$1.32	$0.86	$1.32	$0.86	$0.86	$0.86	$0.84	$0.84	$1.32	$1.00	$1.00	$0.95
High Growth & Low Prices	2022-2023	Apr	$0.42	$0.42	$1.02	$0.43	$1.02	$0.97	$0.97	$0.97	$0.42	$0.42	$1.02	$0.62	$0.62	$0.87
High Growth & Low Prices	2022-2023	May	$0.40	$0.40	$1.02	$0.41	$0.99	$0.41	$0.41	$0.41	$0.40	$0.40	$1.02	$0.61	$0.61	$0.53
High Growth & Low Prices	2022-2023	Jun	$0.56	$0.56	$1.02	$0.58	$1.02	$0.58	$0.58	$0.58	$0.56	$0.56	$1.02	$0.72	$0.72	$0.67
High Growth & Low Prices	2022-2023	Jul	$0.60	$0.60	$1.02	$0.62	$1.02	$0.62	$0.62	$0.62	$0.60	$0.60	$1.02	$0.74	$0.74	$0.70
High Growth & Low Prices	2022-2023	Aug	$0.60	$0.60	$1.02	$0.62	$1.02	$0.62	$0.62	$0.62	$0.60	$0.60	$1.02	$0.74	$0.74	$0.70
High Growth & Low Prices	2022-2023	Sep	$0.33	$0.33	$1.02	$0.34	$1.02	$0.34	$0.34	$0.34	$0.33	$0.33	$1.02	$0.56	$0.56	$0.48
High Growth & Low Prices	2022-2023	Oct	$0.41	$0.41	$1.06	$0.43	$1.06	$0.43	$0.43	$0.43	$0.41	$0.41	$1.06	$0.63	$0.63	$0.55
High Growth & Low Prices	2023-2024	Nov	$1.08	$0.90	$1.35	$0.92	$1.35	$0.92	$0.92	$0.92	$1.08	$0.90	$1.35	$1.11	$1.11	$1.01
High Growth & Low Prices	2023-2024	Dec	$1.38	$1.10	$1.38	$1.47	$1.50	$1.47	$1.47	$1.47	$1.38	$1.10	$1.38	$1.29	$1.29	$1.48
High Growth & Low Prices	2023-2024	Jan	$1.38	$1.24	$1.38	$1.27	$1.51	$1.27	$1.27	$1.27	$1.38	$1.24	$1.38	$1.33	$1.33	$1.32
High Growth & Low Prices	2023-2024	Feb	$1.41	$0.97	$1.41	$0.99	$1.41	$0.99	$0.99	$0.99	$1.41	$0.97	$1.41	$1.26	$1.26	$1.08
High Growth & Low Prices	2023-2024	Mar	$0.93	$0.91	$1.31	$0.93	$1.31	$0.93	$0.93	$0.93	$0.93	$0.91	$1.31	$1.05	$1.05	$1.01
High Growth & Low Prices	2023-2024	Apr	$0.62	$0.62	$0.97	$0.64	$0.97	$0.97	$0.97	$0.97	$0.62	$0.62	$0.97	$0.74	$0.74	$0.91
High Growth & Low Prices	2023-2024	May	$0.61	$0.61	$0.95	$0.63	$0.95	$0.63	$0.63	$0.63	$0.61	$0.61	$0.95	$0.72	$0.72	$0.69
High Growth & Low Prices	2023-2024	Jun	$0.62	$0.62	$0.95	$0.63	$0.95	$0.63	$0.63	$0.63	$0.62	$0.62	$0.95	$0.73	$0.73	$0.70
High Growth & Low Prices	2023-2024	Jul	$0.58	$0.58	$0.95	$0.60	$0.95	$0.60	$0.60	$0.60	$0.58	$0.58	$0.95	$0.70	$0.70	$0.67
High Growth & Low Prices	2023-2024	Aug	$0.58	$0.58	$0.95	$0.59	$0.95	$0.59	$0.59	$0.59	$0.58	$0.58	$0.95	$0.70	$0.70	$0.67
High Growth & Low Prices	2023-2024	Sep	$0.66	$0.66	$0.95	$0.68	$0.95	$0.68	$0.68	$0.68	$0.66	$0.66	$0.95	$0.76	$0.76	$0.74
High Growth & Low Prices	2023-2024	Oct	$0.67	$0.67	$0.99	$0.69	$0.99	$0.69	$0.69	$0.69	$0.67	$0.67	$0.99	$0.78	$0.78	$0.75
High Growth & Low Prices	2024-2025	Nov	$0.98	$0.79	$1.50	$0.81	$1.50	$0.81	$0.81	$0.81	$0.98	$0.79	$1.50	$1.09	$1.09	$0.95
High Growth & Low Prices	2024-2025	Dec	$1.48	$0.99	$1.51	$1.54	$1.61	$1.54	$1.54	$1.54	$1.48	$0.99	$1.51	$1.33	$1.33	$1.55
High Growth & Low Prices	2024-2025	Jan	$1.53	$1.16	$1.53	$1.19	$1.75	$1.19	$1.19	$1.19	$1.53	$1.16	$1.53	$1.41	$1.41	$1.30
High Growth & Low Prices	2024-2025	Feb	$1.57	$1.07	$1.57	$1.10	$1.57	$1.10	$1.10	$1.10	$1.57	$1.07	$1.57	$1.40	$1.40	$1.20
High Growth & Low Prices	2024-2025	Mar	$0.98	$0.94	$1.46	$0.96	$1.46	$0.96	$0.96	$0.96	$0.98	$0.94	$1.46	$1.12	$1.12	$1.06
High Growth & Low Prices	2024-2025	Apr	$0.79	$0.79	$1.22	$0.81	$1.22	$1.22	$1.22	$1.22	$0.79	$0.79	$1.22	$0.94	$0.94	$1.14
High Growth & Low Prices	2024-2025	May	$0.88	$0.88	$1.13	$0.90	$1.13	$0.90	$0.90	$0.90	$0.88	$0.88	$1.13	$0.96	$0.96	$0.95
High Growth & Low Prices	2024-2025	Jun	$0.80	$0.80	$1.13	$0.82	$1.13	$0.82	$0.82	$0.82	$0.80	$0.80	$1.13	$0.91	$0.91	$0.88
High Growth & Low Prices	2024-2025	Jul	$0.78	$0.78	$1.13	$0.81	$1.13	$0.81	$0.81	$0.81	$0.78	$0.78	$1.13	$0.90	$0.90	$0.87
High Growth & Low Prices	2024-2025	Aug	$0.78	$0.78	$1.14	$0.80	$1.14	$0.80	$0.80	$0.80	$0.78	$0.78	$1.14	$0.90	$0.90	$0.87
High Growth & Low Prices	2024-2025	Sep	$0.88	$0.88	$1.14	$0.90	$1.14	$0.90	$0.90	$0.90	$0.88	$0.88	$1.14	$0.97	$0.97	$0.95
High Growth & Low Prices	2024-2025	Oct	$0.88	$0.88	$1.48	$0.90	$1.48	$1.48	$1.48	$1.48	$0.88	$0.88	$1.48	$1.08	$1.08	$1.36
High Growth & Low Prices	2025-2026	Nov	$1.25	$1.06	$1.76	$1.09	$1.76	$1.09	$1.09	$1.09	$1.25	$1.06	$1.76	$1.36	$1.36	$1.22
High Growth & Low Prices	2025-2026	Dec	$1.70	$1.20	$1.77	$1.82	$1.86	$1.82	$1.82	$1.82	$1.70	$1.20	$1.77	$1.56	$1.56	$1.83
High Growth & Low Prices	2025-2026	Jan	$1.79	$1.38	$1.79	$1.41	$2.00	$1.41	$1.41	$1.41	$1.79	$1.38	$1.79	$1.66	$1.66	$1.53
High Growth & Low Prices	2025-2026	Feb	$1.83	$1.34	$1.83	$1.39	$1.83	$1.39	$1.39	$1.39	$1.83	$1.34	$1.83	$1.67	$1.67	$1.48
High Growth & Low Prices	2025-2026	Mar	$1.25	$1.20	$1.74	$1.23	$1.74	$1.23	$1.23	$1.23	$1.25	$1.20	$1.74	$1.40	$1.40	$1.33
High Growth & Low Prices	2025-2026	Apr	$1.03	$1.03	$1.53	$1.06	$1.53	$1.53	$1.53	$1.53	$1.03	$1.03	$1.53	$1.20	$1.20	$1.43
High Growth & Low Prices	2025-2026	May	$1.05	$1.05	$1.29	$1.08	$1.29	$1.08	$1.08	$1.08	$1.05	$1.05	$1.29	$1.13	$1.13	$1.12
High Growth & Low Prices	2025-2026	Jun	$1.03	$1.03	$1.29	$1.06	$1.29	$1.06	$1.06	$1.06	$1.03	$1.03	$1.29	$1.12	$1.12	$1.10
High Growth & Low Prices	2025-2026	Jul	$0.99	$0.99	$1.29	$1.02	$1.29	$1.02	$1.02	$1.02	$0.99	$0.99	$1.29	$1.09	$1.09	$1.07
High Growth & Low Prices	2025-2026	Aug	$1.01	$1.01	$1.29	$1.03	$1.29	$1.03	$1.03	$1.03	$1.01	$1.01	$1.29	$1.10	$1.10	$1.09
High Growth & Low Prices	2025-2026	Sep	$1.07	$1.07	$1.29	$1.09	$1.29	$1.09	$1.09	$1.09	$1.07	$1.07	$1.29	$1.14	$1.14	$1.13
High Growth & Low Prices	2025-2026	Oct	$1.11	$1.11	$1.71	$1.14	$1.71	$1.71	$1.71	$1.71	$1.11	$1.11	$1.71	$1.31	$1.31	$1.59
High Growth & Low Prices	2026-2027	Nov	$1.50	$1.31	$1.83	$1.34	$1.83	$1.34	$1.34	$1.34	$1.50	$1.31	$1.83	$1.55	$1.55	$1.44
High Growth & Low Prices	2026-2027	Dec	$1.86	$1.39	$1.86	$2.03	$2.09	$2.03	$2.03	$2.03	$1.86	$1.39	$1.86	$1.71	$1.71	$2.05
High Growth & Low Prices	2026-2027	Jan	$1.87	$1.51	$1.87	$1.54	$2.11	$1.54	$1.54	$1.54	$1.87	$1.51	$1.87	$1.75	$1.75	$1.65
High Growth & Low Prices	2026-2027	Feb	$1.90	$1.42	$1.90	$1.48	$1.90	$1.48	$1.48	$1.48	$1.90	$1.42	$1.90	$1.74	$1.74	$1.56
High Growth & Low Prices	2026-2027	Mar	$1.31	$1.26	$1.82	$1.29	$1.82	$1.29	$1.29	$1.29	$1.31	$1.26	$1.82	$1.47	$1.47	$1.40
High Growth & Low Prices	2026-2027	Apr	$1.11	$1.11	$1.70	$1.14	$1.70	$1.70	$1.70	$1.70	$1.11	$1.11	$1.70	$1.31	$1.31	$1.59
High Growth & Low Prices	2026-2027	May	$1.17	$1.17	$1.37	$1.20	$1.37	$1.20	$1.20	$1.20	$1.17	$1.17	$1.37	$1.24	$1.24	$1.23
High Growth & Low Prices	2026-2027	Jun	$1.12	$1.12	$1.38	$1.15	$1.38	$1.15	$1.15	$1.15	$1.12	$1.12	$1.38	$1.21	$1.21	$1.19
High Growth & Low Prices	2026-2027	Jul	$1.08	$1.08	$1.38	$1.10	$1.38	$1.10	$1.10	$1.10	$1.08	$1.08	$1.38	$1.18	$1.18	$1.16
High Growth & Low Prices	2026-2027	Aug	$1.10	$1.10	$1.38	$1.12	$1.38	$1.12	$1.12	$1.12	$1.10	$1.10	$1.38	$1.19	$1.19	$1.17
High Growth & Low Prices	2026-2027	Sep	$1.15	$1.15	$1.38	$1.18	$1.38	$1.18	$1.18	$1.18	$1.15	$1.15	$1.38	$1.23	$1.23	$1.22
High Growth & Low Prices	2026-2027	Oct	$1.14	$1.14	$1.78	$1.17	$1.78	$1.78	$1.78	$1.78	$1.14	$1.14	$1.78	$1.36	$1.36	$1.66
High Growth & Low Prices	2027-2028	Nov	$1.74	$1.41	$1.96	$1.44	$1.96	$1.44	$1.44	$1.44	$1.74	$1.41	$1.96	$1.70	$1.70	$1.55

[1]Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
High Growth & Low Prices	2027-2028	Dec	$1.99	$1.52	$1.99	$2.07	$2.26	$2.07	$2.07	$2.07	$1.99	$1.52	$1.99	$1.84	$1.84	$2.11
High Growth & Low Prices	2027-2028	Jan	$1.99	$1.57	$1.99	$1.61	$2.35	$1.61	$1.61	$1.61	$1.99	$1.57	$1.99	$1.85	$1.85	$1.76
High Growth & Low Prices	2027-2028	Feb	$1.98	$1.48	$2.00	$1.53	$2.01	$1.53	$1.53	$1.53	$1.98	$1.48	$2.00	$1.82	$1.82	$1.62
High Growth & Low Prices	2027-2028	Mar	$1.41	$1.35	$1.94	$1.38	$1.94	$1.38	$1.38	$1.38	$1.41	$1.35	$1.94	$1.57	$1.57	$1.49
High Growth & Low Prices	2027-2028	Apr	$1.11	$1.11	$1.48	$1.14	$1.48	$1.48	$1.48	$1.48	$1.11	$1.11	$1.48	$1.23	$1.23	$1.41
High Growth & Low Prices	2027-2028	May	$1.20	$1.20	$1.48	$1.23	$1.48	$1.23	$1.23	$1.23	$1.20	$1.20	$1.48	$1.29	$1.29	$1.28
High Growth & Low Prices	2027-2028	Jun	$1.18	$1.18	$1.48	$1.21	$1.48	$1.21	$1.21	$1.21	$1.18	$1.18	$1.48	$1.28	$1.28	$1.26
High Growth & Low Prices	2027-2028	Jul	$1.15	$1.15	$1.48	$1.18	$1.48	$1.18	$1.18	$1.18	$1.15	$1.15	$1.48	$1.26	$1.26	$1.24
High Growth & Low Prices	2027-2028	Aug	$1.17	$1.17	$1.48	$1.20	$1.48	$1.20	$1.20	$1.20	$1.17	$1.17	$1.48	$1.27	$1.27	$1.26
High Growth & Low Prices	2027-2028	Sep	$1.24	$1.24	$1.48	$1.26	$1.48	$1.26	$1.26	$1.26	$1.24	$1.24	$1.48	$1.32	$1.32	$1.31
High Growth & Low Prices	2027-2028	Oct	$1.30	$1.30	$2.08	$1.33	$2.08	$2.08	$2.08	$2.08	$1.30	$1.30	$2.08	$1.56	$1.56	$1.93
High Growth & Low Prices	2028-2029	Nov	$1.87	$1.54	$2.00	$1.58	$2.00	$1.58	$1.58	$1.58	$1.87	$1.54	$2.00	$1.80	$1.80	$1.66
High Growth & Low Prices	2028-2029	Dec	$2.03	$1.56	$2.03	$2.25	$2.50	$2.25	$2.25	$2.25	$2.03	$1.56	$2.03	$1.87	$1.87	$2.30
High Growth & Low Prices	2028-2029	Jan	$2.03	$1.66	$2.03	$1.70	$2.49	$1.70	$1.70	$1.70	$2.03	$1.66	$2.03	$1.91	$1.91	$1.86
High Growth & Low Prices	2028-2029	Feb	$2.04	$1.57	$2.04	$1.61	$2.05	$1.61	$1.61	$1.61	$2.04	$1.57	$2.04	$1.88	$1.88	$1.69
High Growth & Low Prices	2028-2029	Mar	$1.46	$1.40	$2.00	$1.43	$2.00	$1.43	$1.43	$1.43	$1.46	$1.40	$2.00	$1.62	$1.62	$1.54
High Growth & Low Prices	2028-2029	Apr	$1.23	$1.23	$1.82	$1.26	$1.82	$1.82	$1.82	$1.82	$1.23	$1.23	$1.82	$1.42	$1.42	$1.71
High Growth & Low Prices	2028-2029	May	$1.27	$1.27	$1.51	$1.30	$1.51	$1.30	$1.30	$1.30	$1.27	$1.27	$1.51	$1.35	$1.35	$1.34
High Growth & Low Prices	2028-2029	Jun	$1.25	$1.25	$1.51	$1.28	$1.51	$1.28	$1.28	$1.28	$1.25	$1.25	$1.51	$1.34	$1.34	$1.33
High Growth & Low Prices	2028-2029	Jul	$1.21	$1.21	$1.51	$1.24	$1.51	$1.24	$1.24	$1.24	$1.21	$1.21	$1.51	$1.31	$1.31	$1.30
High Growth & Low Prices	2028-2029	Aug	$1.20	$1.20	$1.52	$1.23	$1.52	$1.23	$1.23	$1.23	$1.20	$1.20	$1.52	$1.31	$1.31	$1.29
High Growth & Low Prices	2028-2029	Sep	$1.28	$1.28	$1.52	$1.31	$1.52	$1.31	$1.31	$1.31	$1.28	$1.28	$1.52	$1.36	$1.36	$1.35
High Growth & Low Prices	2028-2029	Oct	$1.33	$1.33	$2.11	$1.36	$2.11	$2.11	$2.11	$2.11	$1.33	$1.33	$2.11	$1.59	$1.59	$1.96
High Growth & Low Prices	2029-2030	Nov	$1.93	$1.60	$2.12	$1.64	$2.12	$1.64	$1.64	$1.64	$1.93	$1.60	$2.12	$1.89	$1.89	$1.74
High Growth & Low Prices	2029-2030	Dec	$2.14	$1.67	$2.15	$2.40	$2.63	$2.40	$2.40	$2.40	$2.14	$1.67	$2.15	$1.98	$1.98	$2.44
High Growth & Low Prices	2029-2030	Jan	$2.16	$1.70	$2.16	$1.73	$2.64	$1.73	$1.73	$1.73	$2.16	$1.70	$2.16	$2.01	$2.01	$1.92
High Growth & Low Prices	2029-2030	Feb	$2.09	$1.61	$2.16	$1.65	$2.19	$1.65	$1.65	$1.65	$2.09	$1.61	$2.16	$1.96	$1.96	$1.76
High Growth & Low Prices	2029-2030	Mar	$1.52	$1.46	$2.10	$1.50	$2.10	$1.50	$1.50	$1.50	$1.52	$1.46	$2.10	$1.70	$1.70	$1.62
High Growth & Low Prices	2029-2030	Apr	$1.29	$1.29	$1.91	$1.32	$1.91	$1.91	$1.91	$1.91	$1.29	$1.29	$1.91	$1.50	$1.50	$1.79
High Growth & Low Prices	2029-2030	May	$1.32	$1.32	$1.78	$1.35	$1.78	$1.35	$1.35	$1.35	$1.32	$1.32	$1.78	$1.47	$1.47	$1.43
High Growth & Low Prices	2029-2030	Jun	$1.28	$1.28	$1.78	$1.31	$1.78	$1.31	$1.31	$1.31	$1.28	$1.28	$1.78	$1.45	$1.45	$1.41
High Growth & Low Prices	2029-2030	Jul	$1.20	$1.20	$1.78	$1.22	$1.78	$1.22	$1.22	$1.22	$1.20	$1.20	$1.78	$1.39	$1.39	$1.34
High Growth & Low Prices	2029-2030	Aug	$1.21	$1.21	$1.78	$1.23	$1.78	$1.23	$1.23	$1.23	$1.21	$1.21	$1.78	$1.40	$1.40	$1.34
High Growth & Low Prices	2029-2030	Sep	$1.26	$1.26	$1.78	$1.29	$1.78	$1.29	$1.29	$1.29	$1.26	$1.26	$1.78	$1.44	$1.44	$1.39
High Growth & Low Prices	2029-2030	Oct	$1.37	$1.37	$1.99	$1.40	$1.99	$1.99	$1.99	$1.99	$1.37	$1.37	$1.99	$1.58	$1.58	$1.87
High Growth & Low Prices	2030-2031	Nov	$1.97	$1.64	$2.15	$1.68	$2.15	$1.68	$1.68	$1.68	$1.97	$1.64	$2.15	$1.92	$1.92	$1.77
High Growth & Low Prices	2030-2031	Dec	$2.19	$1.72	$2.19	$2.41	$2.65	$2.41	$2.41	$2.41	$2.19	$1.72	$2.19	$2.03	$2.03	$2.46
High Growth & Low Prices	2030-2031	Jan	$2.19	$1.73	$2.19	$2.36	$2.68	$2.36	$2.36	$2.36	$2.19	$1.73	$2.19	$2.04	$2.04	$2.43
High Growth & Low Prices	2030-2031	Feb	$2.15	$1.67	$2.20	$1.71	$2.33	$1.71	$1.71	$1.71	$2.15	$1.67	$2.20	$2.01	$2.01	$1.84
High Growth & Low Prices	2030-2031	Mar	$1.58	$1.49	$2.12	$1.53	$2.12	$1.53	$1.53	$1.53	$1.58	$1.49	$2.12	$1.73	$1.73	$1.64
High Growth & Low Prices	2030-2031	Apr	$1.35	$1.35	$2.01	$1.38	$2.01	$2.01	$2.01	$2.01	$1.35	$1.35	$2.01	$1.57	$1.57	$1.88
High Growth & Low Prices	2030-2031	May	$1.35	$1.35	$1.81	$1.38	$1.81	$1.38	$1.38	$1.38	$1.35	$1.35	$1.81	$1.50	$1.50	$1.46
High Growth & Low Prices	2030-2031	Jun	$1.31	$1.31	$1.81	$1.34	$1.81	$1.34	$1.34	$1.34	$1.31	$1.31	$1.81	$1.47	$1.47	$1.43
High Growth & Low Prices	2030-2031	Jul	$1.24	$1.24	$1.81	$1.26	$1.81	$1.26	$1.26	$1.26	$1.24	$1.24	$1.81	$1.43	$1.43	$1.37
High Growth & Low Prices	2030-2031	Aug	$1.23	$1.23	$1.81	$1.26	$1.81	$1.26	$1.26	$1.26	$1.23	$1.23	$1.81	$1.42	$1.42	$1.37
High Growth & Low Prices	2030-2031	Sep	$1.34	$1.34	$1.81	$1.37	$1.81	$1.37	$1.37	$1.37	$1.34	$1.34	$1.81	$1.50	$1.50	$1.46
High Growth & Low Prices	2030-2031	Oct	$1.40	$1.40	$2.04	$1.43	$2.04	$2.04	$2.04	$2.04	$1.40	$1.40	$2.04	$1.61	$1.61	$1.92
High Growth & Low Prices	2031-2032	Nov	$2.08	$1.70	$2.30	$1.80	$2.30	$1.80	$1.80	$1.80	$2.08	$1.70	$2.30	$2.03	$2.03	$1.90
High Growth & Low Prices	2031-2032	Dec	$2.22	$1.73	$2.34	$2.53	$2.77	$2.53	$2.53	$2.53	$2.22	$1.73	$2.34	$2.09	$2.09	$2.58
High Growth & Low Prices	2031-2032	Jan	$2.20	$1.74	$2.33	$2.48	$2.80	$2.48	$2.48	$2.48	$2.20	$1.74	$2.33	$2.09	$2.09	$2.55
High Growth & Low Prices	2031-2032	Feb	$2.17	$1.67	$2.35	$1.71	$2.46	$1.71	$1.71	$1.71	$2.17	$1.67	$2.35	$2.06	$2.06	$1.86
High Growth & Low Prices	2031-2032	Mar	$1.60	$1.51	$2.25	$1.54	$2.25	$1.54	$1.54	$1.54	$1.60	$1.51	$2.25	$1.79	$1.79	$1.69
High Growth & Low Prices	2031-2032	Apr	$1.39	$1.39	$2.07	$1.42	$2.07	$2.07	$2.07	$2.07	$1.39	$1.39	$2.07	$1.62	$1.62	$1.94
High Growth & Low Prices	2031-2032	May	$1.37	$1.37	$2.01	$1.40	$2.01	$1.40	$1.40	$1.40	$1.37	$1.37	$2.01	$1.58	$1.58	$1.52
High Growth & Low Prices	2031-2032	Jun	$1.30	$1.30	$2.01	$1.33	$2.01	$1.33	$1.33	$1.33	$1.30	$1.30	$2.01	$1.54	$1.54	$1.47
High Growth & Low Prices	2031-2032	Jul	$1.09	$1.09	$2.01	$1.11	$2.01	$1.11	$1.11	$1.11	$1.09	$1.09	$2.01	$1.39	$1.39	$1.29
High Growth & Low Prices	2031-2032	Aug	$1.09	$1.09	$2.01	$1.11	$2.01	$1.11	$1.11	$1.11	$1.09	$1.09	$2.01	$1.40	$1.40	$1.29
High Growth & Low Prices	2031-2032	Sep	$1.28	$1.28	$2.01	$1.31	$2.01	$1.31	$1.31	$1.31	$1.28	$1.28	$2.01	$1.53	$1.53	$1.45
High Growth & Low Prices	2031-2032	Oct	$1.39	$1.39	$2.04	$1.42	$2.04	$2.04	$2.04	$2.04	$1.39	$1.39	$2.04	$1.60	$1.60	$1.91
High Growth & Low Prices	2032-2033	Nov	$2.09	$1.72	$2.44	$1.82	$2.44	$1.82	$1.82	$1.82	$2.09	$1.72	$2.44	$2.08	$2.08	$1.95
High Growth & Low Prices	2032-2033	Dec	$2.29	$1.79	$2.48	$2.61	$2.85	$2.61	$2.61	$2.61	$2.29	$1.79	$2.48	$2.18	$2.18	$2.66
High Growth & Low Prices	2032-2033	Jan	$2.30	$1.84	$2.47	$2.56	$2.91	$2.56	$2.56	$2.56	$2.30	$1.84	$2.47	$2.20	$2.20	$2.63
High Growth & Low Prices	2032-2033	Feb	$2.33	$1.85	$2.49	$1.90	$2.71	$1.90	$1.90	$1.90	$2.33	$1.85	$2.49	$2.22	$2.22	$2.06
High Growth & Low Prices	2032-2033	Mar	$1.83	$1.68	$2.39	$1.72	$2.39	$1.72	$1.72	$1.72	$1.83	$1.68	$2.39	$1.97	$1.97	$1.85
High Growth & Low Prices	2032-2033	Apr	$1.56	$1.56	$2.21	$1.59	$2.21	$2.21	$2.21	$2.21	$1.56	$1.56	$2.21	$1.77	$1.77	$2.08
High Growth & Low Prices	2032-2033	May	$1.52	$1.52	$2.21	$1.56	$2.21	$1.56	$1.56	$1.56	$1.52	$1.52	$2.21	$1.75	$1.75	$1.69
High Growth & Low Prices	2032-2033	Jun	$1.52	$1.52	$2.21	$1.55	$2.21	$1.55	$1.55	$1.55	$1.52	$1.52	$2.21	$1.75	$1.75	$1.69
High Growth & Low Prices	2032-2033	Jul	$1.34	$1.34	$2.21	$1.37	$2.21	$1.37	$1.37	$1.37	$1.34	$1.34	$2.21	$1.63	$1.63	$1.54
High Growth & Low Prices	2032-2033	Aug	$1.36	$1.36	$2.21	$1.39	$2.21	$1.39	$1.39	$1.39	$1.36	$1.36	$2.21	$1.64	$1.64	$1.55
High Growth & Low Prices	2032-2033	Sep	$1.50	$1.50	$2.21	$1.53	$2.21	$1.53	$1.53	$1.53	$1.50	$1.50	$2.21	$1.74	$1.74	$1.67
High Growth & Low Prices	2032-2033	Oct	$1.58	$1.58	$2.21	$1.61	$2.21	$2.21	$2.21	$2.21	$1.58	$1.58	$2.21	$1.79	$1.79	$2.09
High Growth & Low Prices	2033-2034	Nov	$2.35	$1.94	$2.65	$2.04	$2.65	$2.04	$2.04	$2.04	$2.35	$1.94	$2.65	$2.31	$2.31	$2.16
High Growth & Low Prices	2033-2034	Dec	$2.44	$1.93	$2.69	$2.81	$3.04	$2.81	$2.81	$2.81	$2.44	$1.93	$2.69	$2.36	$2.36	$2.85
High Growth & Low Prices	2033-2034	Jan	$2.43	$1.97	$2.68	$2.77	$3.10	$2.77	$2.77	$2.77	$2.43	$1.97	$2.68	$2.36	$2.36	$2.83
High Growth & Low Prices	2033-2034	Feb	$2.42	$1.93	$2.70	$1.98	$2.89	$1.98	$1.98	$1.98	$2.42	$1.93	$2.70	$2.35	$2.35	$2.16
High Growth & Low Prices	2033-2034	Mar	$1.92	$1.77	$2.59	$1.81	$2.59	$1.81	$1.81	$1.81	$1.92	$1.77	$2.59	$2.09	$2.09	$1.97
High Growth & Low Prices	2033-2034	Apr	$1.65	$1.65	$2.30	$1.68	$2.30	$2.30	$2.30	$2.30	$1.65	$1.65	$2.30	$1.86	$1.86	$2.18
High Growth & Low Prices	2033-2034	May	$1.64	$1.64	$2.30	$1.67	$2.30	$1.67	$1.67	$1.67	$1.64	$1.64	$2.30	$1.86	$1.86	$1.80
High Growth & Low Prices	2033-2034	Jun	$1.61	$1.61	$2.30	$1.64	$2.30	$1.64	$1.64	$1.64	$1.61	$1.61	$2.30	$1.84	$1.84	$1.78
High Growth & Low Prices	2033-2034	Jul	$1.46	$1.46	$2.30	$1.49	$2.30	$1.49	$1.49	$1.49	$1.46	$1.46	$2.30	$1.74	$1.74	$1.66
High Growth & Low Prices	2033-2034	Aug	$1.48	$1.48	$2.30	$1.51	$2.30	$1.51	$1.51	$1.51	$1.48	$1.48	$2.30	$1.75	$1.75	$1.67
High Growth & Low Prices	2033-2034	Sep	$1.62	$1.62	$2.30	$1.66	$2.30	$1.66	$1.66	$1.66	$1.62	$1.62	$2.30	$1.85	$1.85	$1.79
High Growth & Low Prices	2033-2034	Oct	$1.73	$1.73	$2.40	$1.77	$2.40	$2.40	$2.40	$2.40	$1.73	$1.73	$2.40	$1.95	$1.95	$2.27
High Growth & Low Prices	2034-2035	Nov	$2.42	$2.01	$2.78	$2.13	$2.78	$2.13	$2.13	$2.13	$2.42	$2.01	$2.78	$2.41	$2.41	$2.26
High Growth & Low Prices	2034-2035	Dec	$2.55	$2.04	$2.82	$2.94	$3.18	$2.94	$2.94	$2.94	$2.55	$2.04	$2.82	$2.47	$2.47	$2.99
High Growth & Low Prices	2034-2035	Jan	$2.51	$2.05	$2.82	$2.90	$3.20	$2.90	$2.90	$2.90	$2.51	$2.05	$2.82	$2.46	$2.46	$2.96
High Growth & Low Prices	2034-2035	Feb	$2.54	$1.99	$2.89	$2.04	$3.14	$2.04	$2.04	$2.04	$2.54	$1.99	$2.89	$2.47	$2.47	$2.26
High Growth & Low Prices	2034-2035	Mar	$1.89	$1.74	$2.60	$1.78	$2.60	$1.78	$1.78	$1.78	$1.89	$1.74	$2.60	$2.08	$2.08	$1.94
High Growth & Low Prices	2034-2035	Apr	$1.63	$1.63	$2.29	$1.67	$2.29	$2.29	$2.29	$2.29	$1.63	$1.63	$2.29	$1.85	$1.85	$2.17
High Growth & Low Prices	2034-2035	May	$1.63	$1.63	$2.29	$1.67	$2.29	$1.67	$1.67	$1.67	$1.63	$1.63	$2.29	$1.85	$1.85	$1.79
High Growth & Low Prices	2034-2035	Jun	$1.57	$1.57	$2.29	$1.60	$2.29	$1.60	$1.60	$1.60	$1.57	$1.57	$2.29	$1.81	$1.81	$1.74
High Growth & Low Prices	2034-2035	Jul	$1.39	$1.39	$2.29	$1.42	$2.29	$1.42	$1.42	$1.42	$1.39	$1.39	$2.29	$1.69	$1.69	$1.60
High Growth & Low Prices	2034-2035	Aug	$1.43	$1.43	$2.29	$1.47	$2.29	$1.47	$1.47	$1.47	$1.43	$1.43	$2.29	$1.72	$1.72	$1.63
High Growth & Low Prices	2034-2035	Sep	$1.59	$1.59	$2.29	$1.62	$2.29	$1.62	$1.62	$1.62	$1.59	$1.59	$2.29	$1.82	$1.82	$1.75
High Growth & Low Prices	2034-2035	Oct	$1.65	$1.65	$2.34	$1.69	$2.34	$2.34	$2.34	$2.34	$1.65	$1.65	$2.34	$1.88	$1.88	$2.21
High Growth & Low Prices	2035-2036	Nov	$2.40	$1.99	$2.96	$2.13	$2.96	$2.13	$2.13	$2.13	$2.40	$1.99	$2.96	$2.45	$2.45	$2.29
High Growth & Low Prices	2035-2036	Dec	$2.62	$2.08	$3.01	$3.00	$3.24	$3.00	$3.00	$3.00	$2.62	$2.08	$3.01	$2.57	$2.57	$3.05

[1]Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
High Growth & Low Prices	2035-2036	Jan	$2.55	$2.10	$3.00	$2.96	$3.25	$2.96	$2.96	$2.96	$2.55	$2.10	$3.00	$2.55	$2.55	$3.02
High Growth & Low Prices	2035-2036	Feb	$3.88	$2.12	$4.27	$2.16	$4.39	$2.16	$2.16	$2.16	$3.88	$2.12	$4.27	$3.42	$3.42	$2.61
High Growth & Low Prices	2035-2036	Mar	$2.09	$1.92	$2.73	$1.96	$2.73	$1.96	$1.96	$1.96	$2.09	$1.92	$2.73	$2.24	$2.24	$2.12
High Growth & Low Prices	2035-2036	Apr	$1.72	$1.72	$2.27	$1.75	$2.27	$2.27	$2.27	$2.27	$1.72	$1.72	$2.27	$1.90	$1.90	$2.16
High Growth & Low Prices	2035-2036	May	$1.72	$1.72	$2.27	$1.75	$2.27	$1.75	$1.75	$1.75	$1.72	$1.72	$2.27	$1.90	$1.90	$1.86
High Growth & Low Prices	2035-2036	Jun	$1.67	$1.67	$2.27	$1.71	$2.27	$1.71	$1.71	$1.71	$1.67	$1.67	$2.27	$1.87	$1.87	$1.82
High Growth & Low Prices	2035-2036	Jul	$1.40	$1.40	$2.27	$1.43	$2.27	$1.43	$1.43	$1.43	$1.40	$1.40	$2.27	$1.69	$1.69	$1.60
High Growth & Low Prices	2035-2036	Aug	$1.44	$1.44	$2.27	$1.47	$2.27	$1.47	$1.47	$1.47	$1.44	$1.44	$2.27	$1.71	$1.71	$1.63
High Growth & Low Prices	2035-2036	Sep	$1.60	$1.60	$2.27	$1.64	$2.27	$1.64	$1.64	$1.64	$1.60	$1.60	$2.27	$1.82	$1.82	$1.76
High Growth & Low Prices	2035-2036	Oct	$1.77	$1.77	$2.34	$1.80	$2.34	$2.34	$2.34	$2.34	$1.77	$1.77	$2.34	$1.96	$1.96	$2.23
High Growth & Low Prices	2036-2037	Nov	$2.57	$2.11	$3.14	$2.25	$3.14	$2.25	$2.25	$2.25	$2.57	$2.11	$3.14	$2.61	$2.61	$2.43
High Growth & Low Prices	2036-2037	Dec	$2.70	$2.15	$3.19	$3.17	$3.39	$3.17	$3.17	$3.17	$2.70	$2.15	$3.19	$2.68	$2.68	$3.22
High Growth & Low Prices	2036-2037	Jan	$2.62	$2.17	$3.19	$3.14	$3.42	$3.14	$3.14	$3.14	$2.62	$2.17	$3.19	$2.66	$2.66	$3.20
High Growth & Low Prices	2036-2037	Feb	$3.85	$2.06	$4.49	$2.11	$4.61	$2.11	$2.11	$2.11	$3.85	$2.06	$4.49	$3.47	$3.47	$2.61
High Growth & Low Prices	2036-2037	Mar	$2.03	$1.87	$2.78	$1.91	$2.78	$1.91	$1.91	$1.91	$2.03	$1.87	$2.78	$2.23	$2.23	$2.08
High Growth & Low Prices	2036-2037	Apr	$1.67	$1.67	$2.24	$1.71	$2.24	$2.24	$2.24	$2.24	$1.67	$1.67	$2.24	$1.86	$1.86	$2.13
High Growth & Low Prices	2036-2037	May	$1.80	$1.80	$2.24	$1.84	$2.24	$1.84	$1.84	$1.84	$1.80	$1.80	$2.24	$1.95	$1.95	$1.92
High Growth & Low Prices	2036-2037	Jun	$1.77	$1.77	$2.24	$1.80	$2.24	$1.80	$1.80	$1.80	$1.77	$1.77	$2.24	$1.93	$1.93	$1.89
High Growth & Low Prices	2036-2037	Jul	$1.54	$1.54	$2.24	$1.58	$2.24	$1.58	$1.58	$1.58	$1.54	$1.54	$2.24	$1.78	$1.78	$1.71
High Growth & Low Prices	2036-2037	Aug	$1.61	$1.61	$2.24	$1.64	$2.24	$1.64	$1.64	$1.64	$1.61	$1.61	$2.24	$1.82	$1.82	$1.76
High Growth & Low Prices	2036-2037	Sep	$1.74	$1.74	$2.25	$1.78	$2.25	$1.78	$1.78	$1.78	$1.74	$1.74	$2.25	$1.91	$1.91	$1.87
High Growth & Low Prices	2036-2037	Oct	$1.89	$1.89	$2.45	$1.93	$2.45	$2.45	$2.45	$2.45	$1.89	$1.89	$2.45	$2.07	$2.07	$2.35
High Growth & Low Prices	2037-2038	Nov	$2.73	$2.28	$3.28	$2.51	$3.28	$2.51	$2.51	$2.51	$2.73	$2.28	$3.28	$2.76	$2.76	$2.67
High Growth & Low Prices	2037-2038	Dec	$2.91	$2.38	$3.32	$3.30	$3.54	$3.30	$3.30	$3.30	$2.91	$2.38	$3.32	$2.87	$2.87	$3.35
High Growth & Low Prices	2037-2038	Jan	$2.85	$2.40	$3.32	$3.27	$3.57	$3.27	$3.27	$3.27	$2.85	$2.40	$3.32	$2.86	$2.86	$3.33
High Growth & Low Prices	2037-2038	Feb	$4.01	$2.23	$4.63	$2.28	$4.69	$2.28	$2.28	$2.28	$4.01	$2.23	$4.63	$3.62	$3.62	$2.76
High Growth & Low Prices	2037-2038	Mar	$2.21	$2.01	$2.90	$2.05	$2.90	$2.05	$2.05	$2.05	$2.21	$2.01	$2.90	$2.38	$2.38	$2.22
High Growth & Low Prices	2037-2038	Apr	$1.84	$1.84	$2.38	$1.88	$2.38	$2.38	$2.38	$2.38	$1.84	$1.84	$2.38	$2.02	$2.02	$2.28
High Growth & Low Prices	2037-2038	May	$1.87	$1.87	$2.38	$1.90	$2.38	$1.90	$1.90	$1.90	$1.87	$1.87	$2.38	$2.04	$2.04	$2.00
High Growth & Low Prices	2037-2038	Jun	$1.86	$1.86	$2.38	$1.90	$2.38	$1.90	$1.90	$1.90	$1.86	$1.86	$2.38	$2.04	$2.04	$2.00
High Growth & Low Prices	2037-2038	Jul	$1.62	$1.62	$2.38	$1.65	$2.38	$1.65	$1.65	$1.65	$1.62	$1.62	$2.38	$1.87	$1.87	$1.80
High Growth & Low Prices	2037-2038	Aug	$1.62	$1.62	$2.38	$1.65	$2.38	$1.65	$1.65	$1.65	$1.62	$1.62	$2.38	$1.87	$1.87	$1.80
High Growth & Low Prices	2037-2038	Sep	$1.73	$1.73	$2.39	$1.77	$2.39	$1.77	$1.77	$1.77	$1.73	$1.73	$2.39	$1.95	$1.95	$1.89
High Growth & Low Prices	2037-2038	Oct	$1.86	$1.86	$2.42	$1.90	$2.42	$2.42	$2.42	$2.42	$1.86	$1.86	$2.42	$2.05	$2.05	$2.31
High Growth & Low Prices	2038-2039	Nov	$2.68	$2.23	$3.34	$2.49	$3.34	$2.49	$2.49	$2.49	$2.68	$2.23	$3.34	$2.75	$2.75	$2.66
High Growth & Low Prices	2038-2039	Dec	$2.91	$2.34	$3.39	$3.36	$3.58	$3.36	$3.36	$3.36	$2.91	$2.34	$3.39	$2.88	$2.88	$3.40
High Growth & Low Prices	2038-2039	Jan	$2.91	$2.39	$3.39	$3.34	$3.64	$3.34	$3.34	$3.34	$2.91	$2.39	$3.39	$2.90	$2.90	$3.40
High Growth & Low Prices	2038-2039	Feb	$4.06	$2.27	$4.69	$2.32	$4.74	$2.32	$2.32	$2.32	$4.06	$2.27	$4.69	$3.67	$3.67	$2.81
High Growth & Low Prices	2038-2039	Mar	$2.35	$2.15	$3.04	$2.19	$3.04	$2.19	$2.19	$2.19	$2.35	$2.15	$3.04	$2.51	$2.51	$2.36
High Growth & Low Prices	2038-2039	Apr	$1.96	$1.96	$2.50	$2.00	$2.50	$2.50	$2.50	$2.50	$1.96	$1.96	$2.50	$2.14	$2.14	$2.40
High Growth & Low Prices	2038-2039	May	$1.99	$1.99	$2.50	$2.03	$2.50	$2.03	$2.03	$2.03	$1.99	$1.99	$2.50	$2.16	$2.16	$2.12
High Growth & Low Prices	2038-2039	Jun	$1.89	$1.89	$2.50	$1.93	$2.50	$1.93	$1.93	$1.93	$1.89	$1.89	$2.50	$2.09	$2.09	$2.04
High Growth & Low Prices	2038-2039	Jul	$1.68	$1.68	$2.50	$1.72	$2.50	$1.72	$1.72	$1.72	$1.68	$1.68	$2.50	$1.96	$1.96	$1.88
High Growth & Low Prices	2038-2039	Aug	$1.67	$1.67	$2.50	$1.71	$2.50	$1.71	$1.71	$1.71	$1.67	$1.67	$2.50	$1.95	$1.95	$1.87
High Growth & Low Prices	2038-2039	Sep	$1.86	$1.86	$2.50	$1.90	$2.50	$1.90	$1.90	$1.90	$1.86	$1.86	$2.50	$2.08	$2.08	$2.02
High Growth & Low Prices	2038-2039	Oct	$2.01	$2.01	$2.57	$2.05	$2.57	$2.57	$2.57	$2.57	$2.01	$2.01	$2.57	$2.20	$2.20	$2.47
High Growth & Low Prices	2039-2040	Nov	$2.88	$2.43	$3.52	$2.69	$3.53	$2.69	$2.69	$2.69	$2.88	$2.43	$3.52	$2.95	$2.95	$2.85
High Growth & Low Prices	2039-2040	Dec	$3.08	$2.50	$3.58	$3.54	$3.82	$3.55	$3.55	$3.55	$3.08	$2.50	$3.58	$3.05	$3.05	$3.60
High Growth & Low Prices	2039-2040	Jan	$3.03	$2.50	$3.57	$3.51	$3.77	$3.51	$3.51	$3.51	$3.03	$2.50	$3.57	$3.03	$3.03	$3.57
High Growth & Low Prices	2039-2040	Feb	$4.18	$2.42	$4.80	$2.48	$4.80	$2.48	$2.48	$2.48	$4.18	$2.42	$4.80	$3.80	$3.80	$2.94
High Growth & Low Prices	2039-2040	Mar	$2.46	$2.25	$3.20	$2.30	$3.20	$2.30	$2.30	$2.30	$2.46	$2.25	$3.20	$2.64	$2.64	$2.48
High Growth & Low Prices	2039-2040	Apr	$2.07	$2.07	$2.62	$2.11	$2.62	$2.62	$2.62	$2.62	$2.07	$2.07	$2.62	$2.25	$2.25	$2.52
High Growth & Low Prices	2039-2040	May	$2.09	$2.09	$2.62	$2.13	$2.62	$2.13	$2.13	$2.13	$2.09	$2.09	$2.62	$2.26	$2.26	$2.23
High Growth & Low Prices	2039-2040	Jun	$2.06	$2.06	$2.62	$2.10	$2.62	$2.10	$2.10	$2.10	$2.06	$2.06	$2.62	$2.24	$2.24	$2.20
High Growth & Low Prices	2039-2040	Jul	$1.87	$1.87	$2.62	$1.91	$2.62	$1.91	$1.91	$1.91	$1.87	$1.87	$2.62	$2.12	$2.12	$2.05
High Growth & Low Prices	2039-2040	Aug	$1.88	$1.88	$2.62	$1.92	$2.62	$1.92	$1.92	$1.92	$1.88	$1.88	$2.62	$2.13	$2.13	$2.06
High Growth & Low Prices	2039-2040	Sep	$2.03	$2.03	$2.62	$2.07	$2.62	$2.07	$2.07	$2.07	$2.03	$2.03	$2.62	$2.23	$2.23	$2.18
High Growth & Low Prices	2039-2040	Oct	$2.14	$2.14	$2.69	$2.18	$2.69	$2.69	$2.69	$2.69	$2.14	$2.14	$2.69	$2.32	$2.32	$2.59

[1]Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: AVERAGE CASE MONTHLY DETAIL

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Average Case	2019-2020	Nov	$1.87	$2.18	$1.87	$2.22	$2.22	$2.22	$2.22	$2.22	$1.87	$2.18	$1.87	$1.97	$1.97	$2.22
Average Case	2019-2020	Dec	$1.87	$1.87	$1.87	$2.02	$2.05	$2.02	$2.02	$2.02	$1.87	$1.87	$1.87	$1.87	$1.87	$2.03
Average Case	2019-2020	Jan	$1.91	$1.80	$1.91	$1.84	$1.96	$1.84	$1.84	$1.84	$1.91	$1.80	$1.91	$1.88	$1.88	$1.87
Average Case	2019-2020	Feb	$1.70	$1.43	$1.73	$1.47	$1.73	$1.47	$1.47	$1.47	$1.70	$1.43	$1.73	$1.62	$1.62	$1.52
Average Case	2019-2020	Mar	$1.25	$1.25	$1.38	$1.28	$1.38	$1.28	$1.28	$1.28	$1.25	$1.25	$1.38	$1.30	$1.30	$1.30
Average Case	2019-2020	Apr	$1.03	$1.03	$1.15	$1.05	$1.14	$1.15	$1.15	$1.15	$1.03	$1.03	$1.15	$1.07	$1.07	$1.13
Average Case	2019-2020	May	$1.05	$1.14	$1.05	$1.07	$1.05	$1.05	$1.05	$1.05	$1.05	$1.14	$1.05	$1.08	$1.08	$1.06
Average Case	2019-2020	Jun	$0.90	$0.90	$1.06	$0.86	$0.90	$0.86	$0.86	$0.86	$0.90	$0.90	$1.06	$0.95	$0.95	$0.87
Average Case	2019-2020	Jul	$0.86	$0.86	$1.06	$0.80	$0.90	$0.80	$0.80	$0.80	$0.86	$0.86	$1.06	$0.93	$0.93	$0.82
Average Case	2019-2020	Aug	$1.10	$1.10	$1.11	$1.13	$1.11	$1.11	$1.11	$1.11	$1.10	$1.10	$1.11	$1.11	$1.11	$1.12
Average Case	2019-2020	Sep	$0.99	$0.99	$1.06	$1.01	$1.06	$1.01	$1.01	$1.01	$0.99	$0.99	$1.06	$1.01	$1.01	$1.02
Average Case	2019-2020	Oct	$1.02	$1.02	$1.31	$1.04	$1.31	$1.04	$1.04	$1.04	$1.02	$1.02	$1.31	$1.12	$1.12	$1.10
Average Case	2020-2021	Nov	$1.81	$1.81	$1.82	$1.74	$1.82	$1.74	$1.74	$1.74	$1.81	$1.81	$1.82	$1.81	$1.81	$1.75
Average Case	2020-2021	Dec	$2.43	$2.36	$2.43	$2.44	$2.45	$2.44	$2.44	$2.44	$2.43	$2.36	$2.43	$2.41	$2.41	$2.44
Average Case	2020-2021	Jan	$2.44	$2.45	$2.44	$2.50	$2.52	$2.50	$2.50	$2.50	$2.44	$2.45	$2.44	$2.44	$2.44	$2.51
Average Case	2020-2021	Feb	$2.43	$2.33	$2.43	$2.38	$2.43	$2.38	$2.38	$2.38	$2.43	$2.33	$2.43	$2.40	$2.40	$2.39
Average Case	2020-2021	Mar	$2.02	$2.02	$2.32	$2.06	$2.32	$2.06	$2.06	$2.06	$2.02	$2.02	$2.32	$2.12	$2.12	$2.11
Average Case	2020-2021	Apr	$1.51	$1.51	$1.87	$1.54	$1.87	$1.85	$1.85	$1.85	$1.51	$1.51	$1.87	$1.63	$1.63	$1.79
Average Case	2020-2021	May	$1.40	$1.40	$1.87	$1.43	$1.83	$1.43	$1.43	$1.43	$1.40	$1.40	$1.87	$1.56	$1.56	$1.51
Average Case	2020-2021	Jun	$1.45	$1.45	$1.87	$1.48	$1.82	$1.48	$1.48	$1.48	$1.45	$1.45	$1.87	$1.59	$1.59	$1.55
Average Case	2020-2021	Jul	$1.58	$1.58	$1.87	$1.62	$1.87	$1.62	$1.62	$1.62	$1.58	$1.58	$1.87	$1.68	$1.68	$1.67
Average Case	2020-2021	Aug	$1.57	$1.57	$1.87	$1.61	$1.87	$1.61	$1.61	$1.61	$1.57	$1.57	$1.87	$1.67	$1.67	$1.66
Average Case	2020-2021	Sep	$1.42	$1.42	$1.87	$1.45	$1.87	$1.45	$1.45	$1.45	$1.42	$1.42	$1.87	$1.57	$1.57	$1.54
Average Case	2020-2021	Oct	$1.45	$1.45	$2.05	$1.48	$2.05	$1.48	$1.48	$1.48	$1.45	$1.45	$2.05	$1.65	$1.65	$1.60
Average Case	2021-2022	Nov	$1.79	$1.79	$2.09	$1.83	$2.09	$1.83	$1.83	$1.83	$1.79	$1.79	$2.09	$1.89	$1.89	$1.88
Average Case	2021-2022	Dec	$2.08	$2.08	$2.09	$2.12	$2.12	$2.12	$2.12	$2.12	$2.08	$2.08	$2.09	$2.08	$2.08	$2.12
Average Case	2021-2022	Jan	$2.13	$2.19	$2.13	$2.24	$2.24	$2.24	$2.24	$2.24	$2.13	$2.19	$2.13	$2.15	$2.15	$2.24
Average Case	2021-2022	Feb	$2.05	$2.05	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.05	$2.05	$2.09	$2.06	$2.06	$2.09
Average Case	2021-2022	Mar	$1.74	$1.74	$2.18	$1.77	$2.18	$1.77	$1.77	$1.77	$1.74	$1.74	$2.18	$1.88	$1.88	$1.85
Average Case	2021-2022	Apr	$1.11	$1.11	$1.69	$1.13	$1.69	$1.62	$1.62	$1.62	$1.11	$1.11	$1.69	$1.30	$1.30	$1.53
Average Case	2021-2022	May	$1.08	$1.08	$1.69	$1.11	$1.68	$1.11	$1.11	$1.11	$1.08	$1.08	$1.69	$1.28	$1.28	$1.22
Average Case	2021-2022	Jun	$1.18	$1.18	$1.69	$1.21	$1.69	$1.21	$1.21	$1.21	$1.18	$1.18	$1.69	$1.35	$1.35	$1.31
Average Case	2021-2022	Jul	$1.34	$1.34	$1.69	$1.37	$1.69	$1.37	$1.37	$1.37	$1.34	$1.34	$1.69	$1.45	$1.45	$1.43
Average Case	2021-2022	Aug	$1.29	$1.29	$1.69	$1.32	$1.69	$1.32	$1.32	$1.32	$1.29	$1.29	$1.69	$1.42	$1.42	$1.39
Average Case	2021-2022	Sep	$1.11	$1.11	$1.69	$1.13	$1.69	$1.13	$1.13	$1.13	$1.11	$1.11	$1.69	$1.30	$1.30	$1.24
Average Case	2021-2022	Oct	$1.11	$1.11	$1.69	$1.13	$1.69	$1.13	$1.13	$1.13	$1.11	$1.11	$1.69	$1.30	$1.30	$1.24
Average Case	2022-2023	Nov	$1.38	$1.38	$1.95	$1.41	$1.95	$1.41	$1.41	$1.41	$1.38	$1.38	$1.95	$1.57	$1.57	$1.52
Average Case	2022-2023	Dec	$1.90	$1.89	$1.95	$1.93	$1.95	$1.93	$1.93	$1.93	$1.90	$1.89	$1.95	$1.91	$1.91	$1.94
Average Case	2022-2023	Jan	$1.99	$2.00	$1.99	$2.04	$2.04	$2.04	$2.04	$2.04	$1.99	$2.00	$1.99	$1.99	$1.99	$2.04
Average Case	2022-2023	Feb	$1.79	$1.79	$1.95	$1.83	$1.95	$1.83	$1.83	$1.83	$1.79	$1.79	$1.95	$1.85	$1.85	$1.85
Average Case	2022-2023	Mar	$1.53	$1.53	$2.01	$1.56	$2.01	$1.56	$1.56	$1.56	$1.53	$1.53	$2.01	$1.69	$1.69	$1.65
Average Case	2022-2023	Apr	$1.07	$1.07	$1.67	$1.09	$1.67	$1.61	$1.61	$1.61	$1.07	$1.07	$1.67	$1.27	$1.27	$1.52
Average Case	2022-2023	May	$1.03	$1.03	$1.67	$1.06	$1.63	$1.06	$1.06	$1.06	$1.03	$1.03	$1.67	$1.25	$1.25	$1.17
Average Case	2022-2023	Jun	$1.21	$1.21	$1.67	$1.23	$1.66	$1.23	$1.23	$1.23	$1.21	$1.21	$1.67	$1.36	$1.36	$1.32
Average Case	2022-2023	Jul	$1.26	$1.26	$1.67	$1.29	$1.67	$1.29	$1.29	$1.29	$1.26	$1.26	$1.67	$1.40	$1.40	$1.37
Average Case	2022-2023	Aug	$1.27	$1.27	$1.67	$1.30	$1.67	$1.30	$1.30	$1.30	$1.27	$1.27	$1.67	$1.40	$1.40	$1.37
Average Case	2022-2023	Sep	$0.99	$0.99	$1.68	$1.01	$1.68	$1.01	$1.01	$1.01	$0.99	$0.99	$1.68	$1.22	$1.22	$1.14
Average Case	2022-2023	Oct	$1.07	$1.07	$1.72	$1.10	$1.72	$1.10	$1.10	$1.10	$1.07	$1.07	$1.72	$1.29	$1.29	$1.22
Average Case	2023-2024	Nov	$1.60	$1.60	$2.03	$1.63	$2.03	$1.63	$1.63	$1.63	$1.60	$1.60	$2.03	$1.74	$1.74	$1.71
Average Case	2023-2024	Dec	$1.89	$1.85	$2.03	$1.93	$2.04	$1.93	$1.93	$1.93	$1.89	$1.85	$2.03	$1.92	$1.92	$1.95
Average Case	2023-2024	Jan	$2.06	$2.06	$2.06	$2.11	$2.12	$2.11	$2.11	$2.11	$2.06	$2.06	$2.06	$2.06	$2.06	$2.11
Average Case	2023-2024	Feb	$1.76	$1.76	$2.03	$1.79	$2.03	$1.79	$1.79	$1.79	$1.76	$1.76	$2.03	$1.85	$1.85	$1.84
Average Case	2023-2024	Mar	$1.69	$1.69	$2.09	$1.72	$2.09	$1.72	$1.72	$1.72	$1.69	$1.69	$2.09	$1.82	$1.82	$1.80
Average Case	2023-2024	Apr	$1.38	$1.38	$1.73	$1.41	$1.73	$1.73	$1.73	$1.73	$1.38	$1.38	$1.73	$1.49	$1.49	$1.66
Average Case	2023-2024	May	$1.36	$1.36	$1.70	$1.40	$1.70	$1.40	$1.40	$1.40	$1.36	$1.36	$1.70	$1.48	$1.48	$1.46
Average Case	2023-2024	Jun	$1.38	$1.38	$1.70	$1.41	$1.70	$1.41	$1.41	$1.41	$1.38	$1.38	$1.70	$1.49	$1.49	$1.47
Average Case	2023-2024	Jul	$1.35	$1.35	$1.70	$1.38	$1.70	$1.38	$1.38	$1.38	$1.35	$1.35	$1.70	$1.47	$1.47	$1.45
Average Case	2023-2024	Aug	$1.36	$1.36	$1.70	$1.39	$1.70	$1.39	$1.39	$1.39	$1.36	$1.36	$1.70	$1.47	$1.47	$1.45
Average Case	2023-2024	Sep	$1.44	$1.44	$1.70	$1.47	$1.70	$1.47	$1.47	$1.47	$1.44	$1.44	$1.70	$1.53	$1.53	$1.52
Average Case	2023-2024	Oct	$1.45	$1.45	$1.76	$1.48	$1.76	$1.48	$1.48	$1.48	$1.45	$1.45	$1.76	$1.56	$1.56	$1.54
Average Case	2024-2025	Nov	$1.60	$1.60	$2.07	$1.63	$2.07	$1.63	$1.63	$1.63	$1.60	$1.60	$2.07	$1.76	$1.76	$1.72
Average Case	2024-2025	Dec	$1.96	$1.84	$2.07	$1.94	$2.09	$1.94	$1.94	$1.94	$1.96	$1.84	$2.07	$1.96	$1.96	$1.97
Average Case	2024-2025	Jan	$2.11	$2.11	$2.11	$2.15	$2.17	$2.15	$2.15	$2.15	$2.11	$2.11	$2.11	$2.11	$2.11	$2.16
Average Case	2024-2025	Feb	$1.99	$1.99	$2.07	$2.03	$2.07	$2.03	$2.03	$2.03	$1.99	$1.99	$2.07	$2.02	$2.02	$2.04
Average Case	2024-2025	Mar	$1.86	$1.86	$2.09	$1.90	$2.09	$1.90	$1.90	$1.90	$1.86	$1.86	$2.09	$1.94	$1.94	$1.94
Average Case	2024-2025	Apr	$1.68	$1.68	$2.11	$1.72	$2.11	$2.11	$2.11	$2.11	$1.68	$1.68	$2.11	$1.82	$1.82	$2.03
Average Case	2024-2025	May	$1.77	$1.77	$2.03	$1.80	$2.03	$1.80	$1.80	$1.80	$1.77	$1.77	$2.03	$1.85	$1.85	$1.85
Average Case	2024-2025	Jun	$1.69	$1.69	$2.03	$1.73	$2.03	$1.73	$1.73	$1.73	$1.69	$1.69	$2.03	$1.80	$1.80	$1.79
Average Case	2024-2025	Jul	$1.70	$1.70	$2.03	$1.74	$2.03	$1.74	$1.74	$1.74	$1.70	$1.70	$2.03	$1.81	$1.81	$1.80
Average Case	2024-2025	Aug	$1.70	$1.70	$2.03	$1.73	$2.03	$1.73	$1.73	$1.73	$1.70	$1.70	$2.03	$1.81	$1.81	$1.79
Average Case	2024-2025	Sep	$1.79	$1.79	$2.03	$1.82	$2.03	$1.82	$1.82	$1.82	$1.79	$1.79	$2.03	$1.87	$1.87	$1.87
Average Case	2024-2025	Oct	$1.79	$1.79	$2.38	$1.82	$2.38	$1.82	$1.82	$1.82	$1.79	$1.79	$2.38	$1.98	$1.98	$1.93
Average Case	2025-2026	Nov	$2.01	$2.01	$2.46	$2.05	$2.46	$2.05	$2.05	$2.05	$2.01	$2.01	$2.46	$2.16	$2.16	$2.14
Average Case	2025-2026	Dec	$2.32	$2.17	$2.46	$2.30	$2.48	$2.30	$2.30	$2.30	$2.32	$2.17	$2.46	$2.32	$2.32	$2.34
Average Case	2025-2026	Jan	$2.50	$2.50	$2.50	$2.56	$2.58	$2.56	$2.56	$2.56	$2.50	$2.50	$2.50	$2.50	$2.50	$2.56
Average Case	2025-2026	Feb	$2.44	$2.44	$2.46	$2.49	$2.49	$2.49	$2.49	$2.49	$2.44	$2.44	$2.46	$2.45	$2.45	$2.49
Average Case	2025-2026	Mar	$2.30	$2.30	$2.49	$2.35	$2.49	$2.35	$2.35	$2.35	$2.30	$2.30	$2.49	$2.36	$2.36	$2.38
Average Case	2025-2026	Apr	$2.10	$2.10	$2.59	$2.15	$2.59	$2.59	$2.59	$2.59	$2.10	$2.10	$2.59	$2.27	$2.27	$2.50
Average Case	2025-2026	May	$2.13	$2.13	$2.36	$2.17	$2.36	$2.17	$2.17	$2.17	$2.13	$2.13	$2.36	$2.21	$2.21	$2.21
Average Case	2025-2026	Jun	$2.11	$2.11	$2.36	$2.15	$2.36	$2.15	$2.15	$2.15	$2.11	$2.11	$2.36	$2.19	$2.19	$2.19
Average Case	2025-2026	Jul	$2.09	$2.09	$2.36	$2.14	$2.36	$2.14	$2.14	$2.14	$2.09	$2.09	$2.36	$2.18	$2.18	$2.18
Average Case	2025-2026	Aug	$2.11	$2.11	$2.37	$2.15	$2.37	$2.15	$2.15	$2.15	$2.11	$2.11	$2.37	$2.19	$2.19	$2.19
Average Case	2025-2026	Sep	$2.15	$2.15	$2.37	$2.19	$2.37	$2.19	$2.19	$2.19	$2.15	$2.15	$2.37	$2.22	$2.22	$2.23
Average Case	2025-2026	Oct	$2.20	$2.20	$2.79	$2.25	$2.79	$2.25	$2.25	$2.25	$2.20	$2.20	$2.79	$2.40	$2.40	$2.36
Average Case	2026-2027	Nov	$2.44	$2.44	$2.65	$2.49	$2.65	$2.49	$2.49	$2.49	$2.44	$2.44	$2.65	$2.51	$2.51	$2.52
Average Case	2026-2027	Dec	$2.61	$2.56	$2.65	$2.64	$2.67	$2.64	$2.64	$2.64	$2.61	$2.56	$2.65	$2.61	$2.61	$2.65
Average Case	2026-2027	Jan	$2.69	$2.69	$2.69	$2.75	$2.75	$2.75	$2.75	$2.75	$2.69	$2.69	$2.69	$2.69	$2.69	$2.75
Average Case	2026-2027	Feb	$2.59	$2.59	$2.65	$2.64	$2.65	$2.64	$2.64	$2.64	$2.59	$2.59	$2.65	$2.61	$2.61	$2.64
Average Case	2026-2027	Mar	$2.43	$2.43	$2.68	$2.48	$2.68	$2.48	$2.48	$2.48	$2.43	$2.43	$2.68	$2.52	$2.52	$2.52
Average Case	2026-2027	Apr	$2.24	$2.24	$2.82	$2.29	$2.82	$2.82	$2.82	$2.82	$2.24	$2.24	$2.82	$2.44	$2.44	$2.72
Average Case	2026-2027	May	$2.31	$2.31	$2.53	$2.36	$2.53	$2.36	$2.36	$2.36	$2.31	$2.31	$2.53	$2.38	$2.38	$2.39
Average Case	2026-2027	Jun	$2.26	$2.26	$2.53	$2.31	$2.53	$2.31	$2.31	$2.31	$2.26	$2.26	$2.53	$2.35	$2.35	$2.35
Average Case	2026-2027	Jul	$2.24	$2.24	$2.54	$2.29	$2.54	$2.29	$2.29	$2.29	$2.24	$2.24	$2.54	$2.34	$2.34	$2.34
Average Case	2026-2027	Aug	$2.26	$2.26	$2.54	$2.31	$2.54	$2.31	$2.31	$2.31	$2.26	$2.26	$2.54	$2.35	$2.35	$2.35
Average Case	2026-2027	Sep	$2.32	$2.32	$2.54	$2.36	$2.54	$2.36	$2.36	$2.36	$2.32	$2.32	$2.54	$2.39	$2.39	$2.40
Average Case	2026-2027	Oct	$2.30	$2.30	$2.93	$2.35	$2.93	$2.35	$2.35	$2.35	$2.30	$2.30	$2.93	$2.51	$2.51	$2.47
Average Case	2027-2028	Nov	$2.63	$2.63	$2.80	$2.68	$2.80	$2.68	$2.68	$2.68	$2.63	$2.63	$2.80	$2.69	$2.69	$2.70

[1]Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Average Case	2027-2028	Dec	$2.80	$2.78	$2.80	$2.85	$2.85	$2.85	$2.85	$2.85	$2.80	$2.78	$2.80	$2.79	$2.79	$2.85
Average Case	2027-2028	Jan	$2.85	$2.85	$2.85	$2.91	$2.93	$2.91	$2.91	$2.91	$2.85	$2.85	$2.85	$2.85	$2.85	$2.91
Average Case	2027-2028	Feb	$2.74	$2.74	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80	$2.74	$2.74	$2.80	$2.76	$2.76	$2.80
Average Case	2027-2028	Mar	$2.62	$2.62	$2.84	$2.68	$2.84	$2.68	$2.68	$2.68	$2.62	$2.62	$2.84	$2.70	$2.70	$2.71
Average Case	2027-2028	Apr	$2.33	$2.33	$2.69	$2.38	$2.69	$2.69	$2.69	$2.69	$2.33	$2.33	$2.69	$2.45	$2.45	$2.63
Average Case	2027-2028	May	$2.43	$2.43	$2.69	$2.48	$2.69	$2.48	$2.48	$2.48	$2.43	$2.43	$2.69	$2.52	$2.52	$2.52
Average Case	2027-2028	Jun	$2.41	$2.41	$2.69	$2.46	$2.69	$2.46	$2.46	$2.46	$2.41	$2.41	$2.69	$2.50	$2.50	$2.50
Average Case	2027-2028	Jul	$2.41	$2.41	$2.69	$2.46	$2.69	$2.46	$2.46	$2.46	$2.41	$2.41	$2.69	$2.51	$2.51	$2.51
Average Case	2027-2028	Aug	$2.43	$2.43	$2.69	$2.48	$2.69	$2.48	$2.48	$2.48	$2.43	$2.43	$2.69	$2.52	$2.52	$2.52
Average Case	2027-2028	Sep	$2.48	$2.48	$2.69	$2.53	$2.69	$2.53	$2.53	$2.53	$2.48	$2.48	$2.69	$2.55	$2.55	$2.57
Average Case	2027-2028	Oct	$2.57	$2.57	$3.34	$2.62	$3.34	$2.62	$2.62	$2.62	$2.57	$2.57	$3.34	$2.83	$2.83	$2.77
Average Case	2028-2029	Nov	$2.85	$2.85	$2.97	$2.91	$2.97	$2.91	$2.91	$2.91	$2.85	$2.85	$2.97	$2.89	$2.89	$2.92
Average Case	2028-2029	Dec	$2.95	$2.90	$2.97	$2.99	$3.00	$2.99	$2.99	$2.99	$2.95	$2.90	$2.97	$2.94	$2.94	$3.00
Average Case	2028-2029	Jan	$3.02	$3.02	$3.02	$3.08	$3.10	$3.08	$3.08	$3.08	$3.02	$3.02	$3.02	$3.02	$3.02	$3.08
Average Case	2028-2029	Feb	$2.88	$2.88	$2.97	$2.93	$2.97	$2.93	$2.93	$2.93	$2.88	$2.88	$2.97	$2.91	$2.91	$2.94
Average Case	2028-2029	Mar	$2.73	$2.73	$3.01	$2.78	$3.01	$2.78	$2.78	$2.78	$2.73	$2.73	$3.01	$2.82	$2.82	$2.83
Average Case	2028-2029	Apr	$2.52	$2.52	$3.11	$2.57	$3.11	$3.11	$3.11	$3.11	$2.52	$2.52	$3.11	$2.72	$2.72	$3.00
Average Case	2028-2029	May	$2.58	$2.58	$2.84	$2.63	$2.84	$2.63	$2.63	$2.63	$2.58	$2.58	$2.84	$2.67	$2.67	$2.67
Average Case	2028-2029	Jun	$2.57	$2.57	$2.84	$2.63	$2.84	$2.63	$2.63	$2.63	$2.57	$2.57	$2.84	$2.66	$2.66	$2.67
Average Case	2028-2029	Jul	$2.56	$2.56	$2.84	$2.61	$2.84	$2.61	$2.61	$2.61	$2.56	$2.56	$2.84	$2.65	$2.65	$2.65
Average Case	2028-2029	Aug	$2.56	$2.56	$2.84	$2.61	$2.84	$2.61	$2.61	$2.61	$2.56	$2.56	$2.84	$2.65	$2.65	$2.65
Average Case	2028-2029	Sep	$2.61	$2.61	$2.84	$2.66	$2.84	$2.66	$2.66	$2.66	$2.61	$2.61	$2.84	$2.69	$2.69	$2.70
Average Case	2028-2029	Oct	$2.66	$2.66	$3.44	$2.71	$3.44	$2.71	$2.71	$2.71	$2.66	$2.66	$3.44	$2.92	$2.92	$2.86
Average Case	2029-2030	Nov	$2.96	$2.96	$3.07	$3.02	$3.07	$3.02	$3.02	$3.02	$2.96	$2.96	$3.07	$3.00	$3.00	$3.03
Average Case	2029-2030	Dec	$3.09	$3.09	$3.09	$3.16	$3.16	$3.16	$3.16	$3.16	$3.09	$3.09	$3.09	$3.09	$3.09	$3.16
Average Case	2029-2030	Jan	$3.12	$3.12	$3.12	$3.18	$3.21	$3.18	$3.18	$3.18	$3.12	$3.12	$3.12	$3.12	$3.12	$3.19
Average Case	2029-2030	Feb	$3.00	$3.00	$3.07	$3.06	$3.07	$3.06	$3.06	$3.06	$3.00	$3.00	$3.07	$3.03	$3.03	$3.06
Average Case	2029-2030	Mar	$2.87	$2.87	$3.12	$2.93	$3.12	$2.93	$2.93	$2.93	$2.87	$2.87	$3.12	$2.95	$2.95	$2.96
Average Case	2029-2030	Apr	$2.63	$2.63	$3.25	$2.69	$3.25	$3.25	$3.25	$3.25	$2.63	$2.63	$3.25	$2.84	$2.84	$3.14
Average Case	2029-2030	May	$2.67	$2.67	$2.92	$2.72	$2.92	$2.72	$2.72	$2.72	$2.67	$2.67	$2.92	$2.75	$2.75	$2.76
Average Case	2029-2030	Jun	$2.64	$2.64	$2.92	$2.69	$2.92	$2.69	$2.69	$2.69	$2.64	$2.64	$2.92	$2.73	$2.73	$2.74
Average Case	2029-2030	Jul	$2.59	$2.59	$2.92	$2.64	$2.92	$2.64	$2.64	$2.64	$2.59	$2.59	$2.92	$2.70	$2.70	$2.69
Average Case	2029-2030	Aug	$2.61	$2.61	$2.92	$2.66	$2.92	$2.66	$2.66	$2.66	$2.61	$2.61	$2.92	$2.72	$2.72	$2.72
Average Case	2029-2030	Sep	$2.67	$2.67	$2.92	$2.72	$2.92	$2.72	$2.72	$2.72	$2.67	$2.67	$2.92	$2.75	$2.75	$2.76
Average Case	2029-2030	Oct	$2.80	$2.80	$3.41	$2.86	$3.41	$2.86	$2.86	$2.86	$2.80	$2.80	$3.41	$3.00	$3.00	$2.97
Average Case	2030-2031	Nov	$3.11	$3.10	$3.20	$3.16	$3.20	$3.16	$3.16	$3.16	$3.11	$3.10	$3.20	$3.14	$3.14	$3.17
Average Case	2030-2031	Dec	$3.25	$3.25	$3.25	$3.32	$3.32	$3.32	$3.32	$3.32	$3.25	$3.25	$3.25	$3.25	$3.25	$3.32
Average Case	2030-2031	Jan	$3.26	$3.26	$3.26	$3.32	$3.35	$3.32	$3.32	$3.32	$3.26	$3.26	$3.26	$3.26	$3.26	$3.32
Average Case	2030-2031	Feb	$3.16	$3.16	$3.20	$3.22	$3.22	$3.22	$3.22	$3.22	$3.16	$3.16	$3.20	$3.17	$3.17	$3.22
Average Case	2030-2031	Mar	$2.99	$2.99	$3.24	$3.05	$3.24	$3.05	$3.05	$3.05	$2.99	$2.99	$3.24	$3.07	$3.07	$3.09
Average Case	2030-2031	Apr	$2.78	$2.78	$3.43	$2.83	$3.43	$3.43	$3.43	$3.43	$2.78	$2.78	$3.43	$3.00	$3.00	$3.31
Average Case	2030-2031	May	$2.80	$2.80	$3.10	$2.85	$3.10	$2.85	$2.85	$2.85	$2.80	$2.80	$3.10	$2.90	$2.90	$2.90
Average Case	2030-2031	Jun	$2.77	$2.77	$3.10	$2.82	$3.10	$2.82	$2.82	$2.82	$2.77	$2.77	$3.10	$2.88	$2.88	$2.88
Average Case	2030-2031	Jul	$2.73	$2.73	$3.10	$2.78	$3.10	$2.78	$2.78	$2.78	$2.73	$2.73	$3.10	$2.85	$2.85	$2.84
Average Case	2030-2031	Aug	$2.72	$2.72	$3.10	$2.78	$3.10	$2.78	$2.78	$2.78	$2.72	$2.72	$3.10	$2.85	$2.85	$2.84
Average Case	2030-2031	Sep	$2.83	$2.83	$3.10	$2.88	$3.10	$2.88	$2.88	$2.88	$2.83	$2.83	$3.10	$2.92	$2.92	$2.92
Average Case	2030-2031	Oct	$2.88	$2.88	$3.51	$2.94	$3.51	$2.94	$2.94	$2.94	$2.88	$2.88	$3.51	$3.09	$3.09	$3.05
Average Case	2031-2032	Nov	$3.24	$3.23	$3.30	$3.29	$3.30	$3.29	$3.29	$3.29	$3.24	$3.23	$3.30	$3.25	$3.25	$3.29
Average Case	2031-2032	Dec	$3.33	$3.33	$3.33	$3.41	$3.41	$3.41	$3.41	$3.41	$3.33	$3.33	$3.33	$3.33	$3.33	$3.41
Average Case	2031-2032	Jan	$3.35	$3.35	$3.35	$3.42	$3.45	$3.42	$3.42	$3.42	$3.35	$3.35	$3.35	$3.35	$3.35	$3.42
Average Case	2031-2032	Feb	$3.23	$3.22	$3.30	$3.28	$3.30	$3.28	$3.28	$3.28	$3.23	$3.22	$3.30	$3.25	$3.25	$3.29
Average Case	2031-2032	Mar	$3.06	$3.06	$3.35	$3.12	$3.35	$3.12	$3.12	$3.12	$3.06	$3.06	$3.35	$3.16	$3.16	$3.17
Average Case	2031-2032	Apr	$2.89	$2.89	$3.56	$2.95	$3.56	$3.56	$3.56	$3.56	$2.89	$2.89	$3.56	$3.12	$3.12	$3.44
Average Case	2031-2032	May	$2.87	$2.87	$3.14	$2.93	$3.14	$2.93	$2.93	$2.93	$2.87	$2.87	$3.14	$2.96	$2.96	$2.97
Average Case	2031-2032	Jun	$2.83	$2.83	$3.15	$2.89	$3.14	$2.89	$2.89	$2.89	$2.83	$2.83	$3.15	$2.93	$2.93	$2.94
Average Case	2031-2032	Jul	$2.65	$2.65	$3.15	$2.70	$3.15	$2.70	$2.70	$2.70	$2.65	$2.65	$3.15	$2.81	$2.81	$2.79
Average Case	2031-2032	Aug	$2.68	$2.68	$3.15	$2.73	$3.15	$2.73	$2.73	$2.73	$2.68	$2.68	$3.15	$2.83	$2.83	$2.81
Average Case	2031-2032	Sep	$2.87	$2.87	$3.15	$2.93	$3.15	$2.93	$2.93	$2.93	$2.87	$2.87	$3.15	$2.96	$2.96	$2.97
Average Case	2031-2032	Oct	$2.99	$2.99	$3.63	$3.05	$3.63	$3.05	$3.05	$3.05	$2.99	$2.99	$3.63	$3.21	$3.21	$3.17
Average Case	2032-2033	Nov	$3.40	$3.38	$3.51	$3.45	$3.51	$3.45	$3.45	$3.45	$3.40	$3.38	$3.51	$3.43	$3.43	$3.46
Average Case	2032-2033	Dec	$3.51	$3.49	$3.51	$3.61	$3.61	$3.61	$3.61	$3.61	$3.51	$3.49	$3.51	$3.51	$3.51	$3.61
Average Case	2032-2033	Jan	$3.57	$3.57	$3.57	$3.64	$3.67	$3.64	$3.64	$3.64	$3.57	$3.57	$3.57	$3.57	$3.57	$3.64
Average Case	2032-2033	Feb	$3.51	$3.51	$3.51	$3.57	$3.57	$3.57	$3.57	$3.57	$3.51	$3.51	$3.51	$3.51	$3.51	$3.57
Average Case	2032-2033	Mar	$3.35	$3.35	$3.54	$3.42	$3.54	$3.42	$3.42	$3.42	$3.35	$3.35	$3.54	$3.42	$3.42	$3.44
Average Case	2032-2033	Apr	$3.16	$3.16	$3.81	$3.22	$3.81	$3.81	$3.81	$3.81	$3.16	$3.16	$3.81	$3.38	$3.38	$3.69
Average Case	2032-2033	May	$3.14	$3.14	$3.44	$3.21	$3.44	$3.21	$3.21	$3.21	$3.14	$3.14	$3.44	$3.24	$3.24	$3.25
Average Case	2032-2033	Jun	$3.15	$3.15	$3.45	$3.21	$3.45	$3.21	$3.21	$3.21	$3.15	$3.15	$3.45	$3.25	$3.25	$3.26
Average Case	2032-2033	Jul	$3.02	$3.02	$3.45	$3.08	$3.45	$3.08	$3.08	$3.08	$3.02	$3.02	$3.45	$3.16	$3.16	$3.15
Average Case	2032-2033	Aug	$3.04	$3.04	$3.45	$3.10	$3.45	$3.10	$3.10	$3.10	$3.04	$3.04	$3.45	$3.18	$3.18	$3.17
Average Case	2032-2033	Sep	$3.17	$3.17	$3.45	$3.23	$3.45	$3.23	$3.23	$3.23	$3.17	$3.17	$3.45	$3.26	$3.26	$3.28
Average Case	2032-2033	Oct	$3.26	$3.26	$3.88	$3.32	$3.88	$3.32	$3.32	$3.32	$3.26	$3.26	$3.88	$3.47	$3.47	$3.43
Average Case	2033-2034	Nov	$3.68	$3.67	$3.72	$3.74	$3.74	$3.74	$3.74	$3.74	$3.68	$3.67	$3.72	$3.69	$3.69	$3.74
Average Case	2033-2034	Dec	$3.74	$3.73	$3.74	$3.84	$3.84	$3.84	$3.84	$3.84	$3.74	$3.73	$3.74	$3.73	$3.73	$3.84
Average Case	2033-2034	Jan	$3.78	$3.78	$3.78	$3.86	$3.89	$3.86	$3.86	$3.86	$3.78	$3.78	$3.78	$3.78	$3.78	$3.86
Average Case	2033-2034	Feb	$3.69	$3.67	$3.73	$3.74	$3.74	$3.74	$3.74	$3.74	$3.69	$3.67	$3.73	$3.70	$3.70	$3.74
Average Case	2033-2034	Mar	$3.52	$3.52	$3.76	$3.59	$3.76	$3.59	$3.59	$3.59	$3.52	$3.52	$3.76	$3.60	$3.60	$3.62
Average Case	2033-2034	Apr	$3.31	$3.31	$3.96	$3.38	$3.96	$3.96	$3.96	$3.96	$3.31	$3.31	$3.96	$3.53	$3.53	$3.84
Average Case	2033-2034	May	$3.32	$3.32	$3.62	$3.38	$3.62	$3.38	$3.38	$3.38	$3.32	$3.32	$3.62	$3.42	$3.42	$3.43
Average Case	2033-2034	Jun	$3.29	$3.29	$3.62	$3.35	$3.62	$3.35	$3.35	$3.35	$3.29	$3.29	$3.62	$3.40	$3.40	$3.41
Average Case	2033-2034	Jul	$3.22	$3.22	$3.62	$3.28	$3.62	$3.28	$3.28	$3.28	$3.22	$3.22	$3.62	$3.35	$3.35	$3.35
Average Case	2033-2034	Aug	$3.25	$3.25	$3.62	$3.31	$3.62	$3.31	$3.31	$3.31	$3.25	$3.25	$3.62	$3.37	$3.37	$3.37
Average Case	2033-2034	Sep	$3.35	$3.35	$3.62	$3.41	$3.62	$3.41	$3.41	$3.41	$3.35	$3.35	$3.62	$3.44	$3.44	$3.45
Average Case	2033-2034	Oct	$3.46	$3.46	$4.12	$3.53	$4.12	$4.12	$4.12	$4.12	$3.46	$3.46	$4.12	$3.68	$3.68	$4.00
Average Case	2034-2035	Nov	$3.83	$3.82	$3.88	$3.89	$3.89	$3.89	$3.89	$3.89	$3.83	$3.82	$3.88	$3.84	$3.84	$3.89
Average Case	2034-2035	Dec	$3.93	$3.93	$3.93	$4.01	$4.01	$4.01	$4.01	$4.01	$3.93	$3.93	$3.93	$3.93	$3.93	$4.01
Average Case	2034-2035	Jan	$3.94	$3.94	$3.94	$4.01	$4.05	$4.01	$4.01	$4.01	$3.94	$3.94	$3.94	$3.94	$3.94	$4.02
Average Case	2034-2035	Feb	$3.83	$3.80	$3.88	$3.87	$3.88	$3.87	$3.87	$3.87	$3.83	$3.80	$3.88	$3.84	$3.84	$3.87
Average Case	2034-2035	Mar	$3.59	$3.59	$3.94	$3.66	$3.94	$3.66	$3.66	$3.66	$3.59	$3.59	$3.94	$3.70	$3.70	$3.71
Average Case	2034-2035	Apr	$3.44	$3.44	$4.08	$3.50	$4.08	$4.08	$4.08	$4.08	$3.44	$3.44	$4.08	$3.65	$3.65	$3.97
Average Case	2034-2035	May	$3.44	$3.44	$3.70	$3.51	$3.70	$3.51	$3.51	$3.51	$3.44	$3.44	$3.70	$3.53	$3.53	$3.55
Average Case	2034-2035	Jun	$3.39	$3.39	$3.70	$3.45	$3.70	$3.45	$3.45	$3.45	$3.39	$3.39	$3.70	$3.49	$3.49	$3.50
Average Case	2034-2035	Jul	$3.25	$3.25	$3.70	$3.31	$3.70	$3.31	$3.31	$3.31	$3.25	$3.25	$3.70	$3.40	$3.40	$3.39
Average Case	2034-2035	Aug	$3.30	$3.30	$3.70	$3.36	$3.70	$3.36	$3.36	$3.36	$3.30	$3.30	$3.70	$3.43	$3.43	$3.43
Average Case	2034-2035	Sep	$3.43	$3.43	$3.70	$3.49	$3.70	$3.49	$3.49	$3.49	$3.43	$3.43	$3.70	$3.52	$3.52	$3.53
Average Case	2034-2035	Oct	$3.51	$3.51	$4.19	$3.58	$4.19	$4.19	$4.19	$4.19	$3.51	$3.51	$4.19	$3.74	$3.74	$4.06
Average Case	2035-2036	Nov	$3.93	$3.92	$4.06	$3.99	$4.06	$3.99	$3.99	$3.99	$3.93	$3.92	$4.06	$3.97	$3.97	$4.01
Average Case	2035-2036	Dec	$4.10	$4.09	$4.10	$4.19	$4.19	$4.19	$4.19	$4.19	$4.10	$4.09	$4.10	$4.10	$4.10	$4.19

[1] Avoided costs are before Environmental Externalities adder

Monthly Avoided Costs[1]
Nominal $

Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Average Case	2035-2036	Jan	$4.12	$4.12	$4.12	$4.20	$4.23	$4.20	$4.20	$4.20	$4.12	$4.12	$4.12	$4.12	$4.12	$4.21
Average Case	2035-2036	Feb	$4.06	$4.05	$4.06	$4.13	$4.13	$4.13	$4.13	$4.13	$4.06	$4.05	$4.06	$4.05	$4.05	$4.13
Average Case	2035-2036	Mar	$3.86	$3.86	$4.13	$3.93	$4.13	$3.93	$3.93	$3.93	$3.86	$3.86	$4.13	$3.95	$3.95	$3.97
Average Case	2035-2036	Apr	$3.62	$3.62	$4.16	$3.69	$4.16	$4.16	$4.16	$4.16	$3.62	$3.62	$4.16	$3.80	$3.80	$4.06
Average Case	2035-2036	May	$3.62	$3.62	$3.85	$3.69	$3.85	$3.69	$3.69	$3.69	$3.62	$3.62	$3.85	$3.69	$3.69	$3.72
Average Case	2035-2036	Jun	$3.60	$3.60	$3.85	$3.67	$3.85	$3.67	$3.67	$3.67	$3.60	$3.60	$3.85	$3.68	$3.68	$3.70
Average Case	2035-2036	Jul	$3.39	$3.39	$3.85	$3.45	$3.85	$3.45	$3.45	$3.45	$3.39	$3.39	$3.85	$3.54	$3.54	$3.53
Average Case	2035-2036	Aug	$3.42	$3.42	$3.85	$3.48	$3.85	$3.48	$3.48	$3.48	$3.42	$3.42	$3.85	$3.56	$3.56	$3.56
Average Case	2035-2036	Sep	$3.57	$3.57	$3.85	$3.64	$3.85	$3.64	$3.64	$3.64	$3.57	$3.57	$3.85	$3.66	$3.66	$3.68
Average Case	2035-2036	Oct	$3.73	$3.73	$4.29	$3.80	$4.29	$4.29	$4.29	$4.29	$3.73	$3.73	$4.29	$3.91	$3.91	$4.19
Average Case	2036-2037	Nov	$4.15	$4.14	$4.26	$4.22	$4.26	$4.22	$4.22	$4.22	$4.15	$4.14	$4.26	$4.19	$4.19	$4.23
Average Case	2036-2037	Dec	$4.28	$4.27	$4.28	$4.39	$4.39	$4.39	$4.39	$4.39	$4.28	$4.27	$4.28	$4.28	$4.28	$4.39
Average Case	2036-2037	Jan	$4.32	$4.32	$4.32	$4.41	$4.44	$4.41	$4.41	$4.41	$4.32	$4.32	$4.32	$4.32	$4.32	$4.41
Average Case	2036-2037	Feb	$4.21	$4.11	$4.26	$4.18	$4.26	$4.18	$4.18	$4.18	$4.21	$4.11	$4.26	$4.19	$4.19	$4.20
Average Case	2036-2037	Mar	$3.93	$3.93	$4.32	$4.01	$4.32	$4.01	$4.01	$4.01	$3.93	$3.93	$4.32	$4.06	$4.06	$4.07
Average Case	2036-2037	Apr	$3.66	$3.66	$4.22	$3.73	$4.22	$4.22	$4.22	$4.22	$3.66	$3.66	$4.22	$3.85	$3.85	$4.12
Average Case	2036-2037	May	$3.80	$3.80	$4.09	$3.87	$4.09	$3.87	$3.87	$3.87	$3.80	$3.80	$4.09	$3.89	$3.89	$3.91
Average Case	2036-2037	Jun	$3.77	$3.77	$4.09	$3.85	$4.09	$3.85	$3.85	$3.85	$3.77	$3.77	$4.09	$3.88	$3.88	$3.89
Average Case	2036-2037	Jul	$3.65	$3.65	$4.09	$3.72	$4.09	$3.72	$3.72	$3.72	$3.65	$3.65	$4.09	$3.79	$3.79	$3.79
Average Case	2036-2037	Aug	$3.74	$3.74	$4.09	$3.81	$4.09	$3.81	$3.81	$3.81	$3.74	$3.74	$4.09	$3.86	$3.86	$3.87
Average Case	2036-2037	Sep	$3.84	$3.84	$4.09	$3.91	$4.09	$3.91	$3.91	$3.91	$3.84	$3.84	$4.09	$3.92	$3.92	$3.95
Average Case	2036-2037	Oct	$3.97	$3.97	$4.53	$4.05	$4.53	$4.53	$4.53	$4.53	$3.97	$3.97	$4.53	$4.16	$4.16	$4.43
Average Case	2037-2038	Nov	$4.46	$4.44	$4.56	$4.52	$4.56	$4.52	$4.52	$4.52	$4.46	$4.44	$4.56	$4.49	$4.49	$4.53
Average Case	2037-2038	Dec	$4.62	$4.61	$4.62	$4.71	$4.71	$4.71	$4.71	$4.71	$4.62	$4.61	$4.62	$4.61	$4.61	$4.71
Average Case	2037-2038	Jan	$4.63	$4.63	$4.63	$4.72	$4.86	$4.72	$4.72	$4.72	$4.63	$4.63	$4.63	$4.63	$4.63	$4.75
Average Case	2037-2038	Feb	$4.49	$4.34	$4.56	$4.42	$4.56	$4.42	$4.42	$4.42	$4.49	$4.34	$4.56	$4.47	$4.47	$4.45
Average Case	2037-2038	Mar	$4.08	$4.08	$4.68	$4.16	$4.68	$4.16	$4.16	$4.16	$4.08	$4.08	$4.68	$4.28	$4.28	$4.26
Average Case	2037-2038	Apr	$3.87	$3.87	$4.40	$3.95	$4.40	$4.40	$4.40	$4.40	$3.87	$3.87	$4.40	$4.05	$4.05	$4.31
Average Case	2037-2038	May	$3.91	$3.91	$4.13	$3.98	$4.13	$3.98	$3.98	$3.98	$3.91	$3.91	$4.13	$3.98	$3.98	$4.01
Average Case	2037-2038	Jun	$3.91	$3.91	$4.13	$3.99	$4.13	$3.99	$3.99	$3.99	$3.91	$3.91	$4.13	$3.98	$3.98	$4.01
Average Case	2037-2038	Jul	$3.74	$3.74	$4.13	$3.82	$4.13	$3.82	$3.82	$3.82	$3.74	$3.74	$4.13	$3.87	$3.87	$3.88
Average Case	2037-2038	Aug	$3.77	$3.77	$4.13	$3.84	$4.13	$3.84	$3.84	$3.84	$3.77	$3.77	$4.13	$3.89	$3.89	$3.90
Average Case	2037-2038	Sep	$3.87	$3.87	$4.13	$3.95	$4.13	$3.95	$3.95	$3.95	$3.87	$3.87	$4.13	$3.96	$3.96	$3.98
Average Case	2037-2038	Oct	$4.00	$4.00	$4.54	$4.08	$4.54	$4.54	$4.54	$4.54	$4.00	$4.00	$4.54	$4.18	$4.18	$4.45
Average Case	2038-2039	Nov	$4.50	$4.46	$4.66	$4.54	$4.66	$4.54	$4.54	$4.54	$4.50	$4.46	$4.66	$4.54	$4.54	$4.56
Average Case	2038-2039	Dec	$4.70	$4.67	$4.70	$4.81	$4.84	$4.81	$4.81	$4.81	$4.70	$4.67	$4.70	$4.69	$4.69	$4.82
Average Case	2038-2039	Jan	$4.73	$4.73	$4.73	$4.82	$4.97	$4.82	$4.82	$4.82	$4.73	$4.73	$4.73	$4.73	$4.73	$4.85
Average Case	2038-2039	Feb	$4.61	$4.51	$4.66	$4.60	$4.66	$4.60	$4.60	$4.60	$4.61	$4.51	$4.66	$4.59	$4.59	$4.61
Average Case	2038-2039	Mar	$4.37	$4.37	$4.74	$4.45	$4.74	$4.45	$4.45	$4.45	$4.37	$4.37	$4.74	$4.49	$4.49	$4.51
Average Case	2038-2039	Apr	$4.13	$4.13	$4.65	$4.20	$4.65	$4.65	$4.65	$4.65	$4.13	$4.13	$4.65	$4.30	$4.30	$4.56
Average Case	2038-2039	May	$4.16	$4.16	$4.39	$4.24	$4.39	$4.24	$4.24	$4.24	$4.16	$4.16	$4.39	$4.23	$4.23	$4.27
Average Case	2038-2039	Jun	$4.07	$4.07	$4.39	$4.15	$4.39	$4.15	$4.15	$4.15	$4.07	$4.07	$4.39	$4.18	$4.18	$4.20
Average Case	2038-2039	Jul	$3.94	$3.94	$4.39	$4.01	$4.39	$4.01	$4.01	$4.01	$3.94	$3.94	$4.39	$4.09	$4.09	$4.09
Average Case	2038-2039	Aug	$3.94	$3.94	$4.39	$4.02	$4.39	$4.02	$4.02	$4.02	$3.94	$3.94	$4.39	$4.09	$4.09	$4.09
Average Case	2038-2039	Sep	$4.13	$4.13	$4.39	$4.20	$4.39	$4.20	$4.20	$4.20	$4.13	$4.13	$4.39	$4.21	$4.21	$4.24
Average Case	2038-2039	Oct	$4.24	$4.24	$4.78	$4.32	$4.78	$4.78	$4.78	$4.78	$4.24	$4.24	$4.78	$4.42	$4.42	$4.69
Average Case	2039-2040	Nov	$4.77	$4.74	$4.84	$4.83	$4.84	$4.83	$4.83	$4.83	$4.77	$4.74	$4.84	$4.78	$4.78	$4.83
Average Case	2039-2040	Dec	$4.90	$4.89	$4.90	$5.00	$5.04	$5.00	$5.00	$5.00	$4.90	$4.89	$4.90	$4.90	$4.90	$5.01
Average Case	2039-2040	Jan	$4.91	$4.91	$4.91	$5.01	$5.16	$5.01	$5.01	$5.01	$4.91	$4.91	$4.91	$4.91	$4.91	$5.04
Average Case	2039-2040	Feb	$4.82	$4.68	$4.84	$4.77	$4.84	$4.77	$4.77	$4.77	$4.82	$4.68	$4.84	$4.78	$4.78	$4.79
Average Case	2039-2040	Mar	$4.51	$4.51	$4.93	$4.59	$4.93	$4.59	$4.59	$4.59	$4.51	$4.51	$4.93	$4.65	$4.65	$4.66
Average Case	2039-2040	Apr	$4.28	$4.28	$4.82	$4.36	$4.82	$4.82	$4.82	$4.82	$4.28	$4.28	$4.82	$4.46	$4.46	$4.73
Average Case	2039-2040	May	$4.31	$4.31	$4.55	$4.40	$4.55	$4.40	$4.40	$4.40	$4.31	$4.31	$4.55	$4.39	$4.39	$4.43
Average Case	2039-2040	Jun	$4.29	$4.29	$4.55	$4.37	$4.55	$4.37	$4.37	$4.37	$4.29	$4.29	$4.55	$4.38	$4.38	$4.41
Average Case	2039-2040	Jul	$4.17	$4.17	$4.55	$4.25	$4.55	$4.25	$4.25	$4.25	$4.17	$4.17	$4.55	$4.30	$4.30	$4.31
Average Case	2039-2040	Aug	$4.21	$4.21	$4.55	$4.29	$4.55	$4.29	$4.29	$4.29	$4.21	$4.21	$4.55	$4.32	$4.32	$4.34
Average Case	2039-2040	Sep	$4.34	$4.34	$4.55	$4.43	$4.55	$4.43	$4.43	$4.43	$4.34	$4.34	$4.55	$4.41	$4.41	$4.45
Average Case	2039-2040	Oct	$4.46	$4.46	$4.99	$4.54	$4.99	$4.99	$4.99	$4.99	$4.46	$4.46	$4.99	$4.63	$4.63	$4.90

[1]Avoided costs are before Environmental Externalities adder

APPENDIX 6.4: CARBON REDUCTION MONTHLY DETAIL

Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Carbon Reduction	2019-2020	Nov	$2.00	$2.18	$2.00	$2.22	$2.22	$2.22	$2.22	$2.22	$2.00	$2.18	$2.00	$2.06	$2.06	$2.22
Carbon Reduction	2019-2020	Dec	$1.99	$1.87	$1.99	$2.17	$2.25	$2.17	$2.17	$2.17	$1.99	$1.87	$1.99	$1.95	$1.95	$2.19
Carbon Reduction	2019-2020	Jan	$2.00	$1.80	$2.00	$1.84	$2.02	$1.84	$1.84	$1.84	$2.00	$1.80	$2.00	$1.93	$1.93	$1.88
Carbon Reduction	2019-2020	Feb	$1.95	$1.43	$1.97	$1.50	$1.97	$1.50	$1.50	$1.50	$1.95	$1.43	$1.97	$1.79	$1.79	$1.60
Carbon Reduction	2019-2020	Mar	$1.25	$1.25	$1.38	$1.28	$1.38	$1.28	$1.28	$1.28	$1.25	$1.25	$1.38	$1.30	$1.30	$1.30
Carbon Reduction	2019-2020	Apr	$1.03	$1.03	$1.15	$1.05	$1.14	$1.15	$1.15	$1.15	$1.03	$1.03	$1.15	$1.07	$1.07	$1.13
Carbon Reduction	2019-2020	May	$1.05	$1.14	$1.05	$1.07	$1.05	$1.05	$1.05	$1.05	$1.05	$1.14	$1.05	$1.08	$1.08	$1.06
Carbon Reduction	2019-2020	Jun	$0.90	$0.90	$1.06	$0.86	$0.90	$0.86	$0.86	$0.86	$0.90	$0.90	$1.06	$0.95	$0.95	$0.87
Carbon Reduction	2019-2020	Jul	$0.86	$0.86	$1.06	$0.80	$0.90	$0.80	$0.80	$0.80	$0.86	$0.86	$1.06	$0.93	$0.93	$0.82
Carbon Reduction	2019-2020	Aug	$1.10	$1.10	$1.11	$1.13	$1.11	$1.11	$1.11	$1.11	$1.10	$1.10	$1.11	$1.11	$1.11	$1.12
Carbon Reduction	2019-2020	Sep	$0.99	$0.99	$1.06	$1.01	$1.06	$1.01	$1.01	$1.01	$0.99	$0.99	$1.06	$1.01	$1.01	$1.02
Carbon Reduction	2019-2020	Oct	$1.02	$1.02	$1.31	$1.04	$1.31	$1.04	$1.04	$1.04	$1.02	$1.02	$1.31	$1.12	$1.12	$1.10
Carbon Reduction	2020-2021	Nov	$1.81	$1.81	$1.82	$1.74	$1.82	$1.74	$1.74	$1.74	$1.81	$1.81	$1.82	$1.81	$1.81	$1.75
Carbon Reduction	2020-2021	Dec	$2.01	$2.36	$2.01	$2.41	$2.41	$2.41	$2.41	$2.41	$2.01	$2.36	$2.01	$2.13	$2.13	$2.41
Carbon Reduction	2020-2021	Jan	$1.93	$1.80	$1.93	$1.83	$1.93	$1.83	$1.83	$1.83	$1.93	$1.80	$1.93	$1.88	$1.88	$1.85
Carbon Reduction	2020-2021	Feb	$2.02	$1.69	$2.02	$1.75	$2.02	$1.75	$1.75	$1.75	$2.02	$1.69	$2.02	$1.91	$1.91	$1.81
Carbon Reduction	2020-2021	Mar	$1.38	$1.38	$1.67	$1.41	$1.67	$1.41	$1.41	$1.41	$1.38	$1.38	$1.67	$1.48	$1.48	$1.46
Carbon Reduction	2020-2021	Apr	$0.91	$0.91	$1.27	$0.93	$1.27	$1.25	$1.25	$1.25	$0.91	$0.91	$1.27	$1.03	$1.03	$1.19
Carbon Reduction	2020-2021	May	$0.81	$0.81	$1.28	$0.83	$1.24	$0.83	$0.83	$0.83	$0.81	$0.81	$1.28	$0.96	$0.96	$0.91
Carbon Reduction	2020-2021	Jun	$0.85	$0.85	$1.28	$0.87	$1.22	$0.87	$0.87	$0.87	$0.85	$0.85	$1.28	$0.99	$0.99	$0.94
Carbon Reduction	2020-2021	Jul	$0.96	$0.96	$1.28	$0.99	$1.28	$0.99	$0.99	$0.99	$0.96	$0.96	$1.28	$1.07	$1.07	$1.05
Carbon Reduction	2020-2021	Aug	$0.96	$0.96	$1.28	$0.98	$1.28	$0.98	$0.98	$0.98	$0.96	$0.96	$1.28	$1.06	$1.06	$1.04
Carbon Reduction	2020-2021	Sep	$0.81	$0.81	$1.28	$0.83	$1.28	$0.83	$0.83	$0.83	$0.81	$0.81	$1.28	$0.96	$0.96	$0.92
Carbon Reduction	2020-2021	Oct	$0.83	$0.83	$1.44	$0.85	$1.44	$0.85	$0.85	$0.85	$0.83	$0.83	$1.44	$1.03	$1.03	$0.97
Carbon Reduction	2021-2022	Nov	$1.17	$1.17	$1.45	$1.19	$1.45	$1.19	$1.19	$1.19	$1.17	$1.17	$1.45	$1.26	$1.26	$1.25
Carbon Reduction	2021-2022	Dec	$1.44	$1.40	$1.46	$1.50	$1.53	$1.50	$1.50	$1.50	$1.44	$1.40	$1.46	$1.43	$1.43	$1.51
Carbon Reduction	2021-2022	Jan	$1.48	$1.48	$1.48	$1.51	$1.53	$1.51	$1.51	$1.51	$1.48	$1.48	$1.48	$1.48	$1.48	$1.52
Carbon Reduction	2021-2022	Feb	$1.39	$1.34	$1.49	$1.42	$1.49	$1.42	$1.42	$1.42	$1.39	$1.34	$1.49	$1.41	$1.41	$1.43
Carbon Reduction	2021-2022	Mar	$1.06	$1.06	$1.43	$1.09	$1.43	$1.09	$1.09	$1.09	$1.06	$1.06	$1.43	$1.19	$1.19	$1.16
Carbon Reduction	2021-2022	Apr	$0.52	$0.52	$1.10	$0.54	$1.10	$1.04	$1.04	$1.04	$0.52	$0.52	$1.10	$0.72	$0.72	$0.95
Carbon Reduction	2021-2022	May	$0.50	$0.50	$1.10	$0.51	$1.10	$0.51	$0.51	$0.51	$0.50	$0.50	$1.10	$0.70	$0.70	$0.63
Carbon Reduction	2021-2022	Jun	$0.60	$0.60	$1.10	$0.62	$1.10	$0.62	$0.62	$0.62	$0.60	$0.60	$1.10	$0.77	$0.77	$0.71
Carbon Reduction	2021-2022	Jul	$0.74	$0.74	$1.10	$0.76	$1.10	$0.76	$0.76	$0.76	$0.74	$0.74	$1.10	$0.86	$0.86	$0.83
Carbon Reduction	2021-2022	Aug	$0.68	$0.68	$1.11	$0.70	$1.11	$0.70	$0.70	$0.70	$0.68	$0.68	$1.11	$0.82	$0.82	$0.78
Carbon Reduction	2021-2022	Sep	$0.51	$0.51	$1.11	$0.52	$1.11	$0.52	$0.52	$0.52	$0.51	$0.51	$1.11	$0.71	$0.71	$0.64
Carbon Reduction	2021-2022	Oct	$0.50	$0.50	$1.11	$0.52	$1.11	$0.52	$0.52	$0.52	$0.50	$0.50	$1.11	$0.70	$0.70	$0.63
Carbon Reduction	2022-2023	Nov	$0.77	$0.77	$1.25	$0.79	$1.25	$0.79	$0.79	$0.79	$0.77	$0.77	$1.25	$0.93	$0.93	$0.88
Carbon Reduction	2022-2023	Dec	$1.24	$1.21	$1.25	$1.31	$1.33	$1.31	$1.31	$1.31	$1.24	$1.21	$1.25	$1.23	$1.23	$1.32
Carbon Reduction	2022-2023	Jan	$1.27	$1.27	$1.27	$1.30	$1.32	$1.30	$1.30	$1.30	$1.27	$1.27	$1.27	$1.27	$1.27	$1.31
Carbon Reduction	2022-2023	Feb	$1.13	$1.07	$1.28	$1.14	$1.29	$1.14	$1.14	$1.14	$1.13	$1.07	$1.28	$1.16	$1.16	$1.17
Carbon Reduction	2022-2023	Mar	$0.84	$0.84	$1.20	$0.86	$1.20	$0.86	$0.86	$0.86	$0.84	$0.84	$1.20	$0.96	$0.96	$0.93
Carbon Reduction	2022-2023	Apr	$0.42	$0.42	$1.02	$0.43	$1.02	$0.97	$0.97	$0.97	$0.42	$0.42	$1.02	$0.62	$0.62	$0.87
Carbon Reduction	2022-2023	May	$0.40	$0.40	$1.02	$0.41	$0.99	$0.41	$0.41	$0.41	$0.40	$0.40	$1.02	$0.61	$0.61	$0.53
Carbon Reduction	2022-2023	Jun	$0.56	$0.56	$1.02	$0.58	$1.02	$0.58	$0.58	$0.58	$0.56	$0.56	$1.02	$0.72	$0.72	$0.67
Carbon Reduction	2022-2023	Jul	$0.60	$0.60	$1.02	$0.62	$1.02	$0.62	$0.62	$0.62	$0.60	$0.60	$1.02	$0.74	$0.74	$0.70
Carbon Reduction	2022-2023	Aug	$0.60	$0.60	$1.02	$0.62	$1.02	$0.62	$0.62	$0.62	$0.60	$0.60	$1.02	$0.74	$0.74	$0.70
Carbon Reduction	2022-2023	Sep	$0.33	$0.33	$1.02	$0.34	$1.02	$0.34	$0.34	$0.34	$0.33	$0.33	$1.02	$0.56	$0.56	$0.48
Carbon Reduction	2022-2023	Oct	$0.41	$0.41	$1.06	$0.43	$1.06	$0.43	$0.43	$0.43	$0.41	$0.41	$1.06	$0.63	$0.63	$0.55
Carbon Reduction	2023-2024	Nov	$0.90	$0.90	$1.22	$0.92	$1.22	$0.92	$0.92	$0.92	$0.90	$0.90	$1.22	$1.01	$1.01	$0.98
Carbon Reduction	2023-2024	Dec	$1.20	$1.10	$1.22	$1.23	$1.28	$1.23	$1.23	$1.23	$1.20	$1.10	$1.22	$1.18	$1.18	$1.24
Carbon Reduction	2023-2024	Jan	$1.24	$1.24	$1.24	$1.27	$1.29	$1.27	$1.27	$1.27	$1.24	$1.24	$1.24	$1.24	$1.24	$1.28
Carbon Reduction	2023-2024	Feb	$1.03	$0.96	$1.26	$0.99	$1.26	$0.99	$0.99	$0.99	$1.03	$0.96	$1.26	$1.08	$1.08	$1.05
Carbon Reduction	2023-2024	Mar	$0.91	$0.91	$1.17	$0.93	$1.17	$0.93	$0.93	$0.93	$0.91	$0.91	$1.17	$1.00	$1.00	$0.98
Carbon Reduction	2023-2024	Apr	$0.62	$0.62	$0.97	$0.64	$0.97	$0.97	$0.97	$0.97	$0.62	$0.62	$0.97	$0.74	$0.74	$0.91
Carbon Reduction	2023-2024	May	$0.61	$0.61	$0.95	$0.63	$0.95	$0.63	$0.63	$0.63	$0.61	$0.61	$0.95	$0.72	$0.72	$0.69
Carbon Reduction	2023-2024	Jun	$0.62	$0.62	$0.95	$0.63	$0.95	$0.63	$0.63	$0.63	$0.62	$0.62	$0.95	$0.73	$0.73	$0.70
Carbon Reduction	2023-2024	Jul	$0.58	$0.58	$0.95	$0.60	$0.95	$0.60	$0.60	$0.60	$0.58	$0.58	$0.95	$0.70	$0.70	$0.67
Carbon Reduction	2023-2024	Aug	$0.58	$0.58	$0.95	$0.59	$0.95	$0.59	$0.59	$0.59	$0.58	$0.58	$0.95	$0.70	$0.70	$0.67
Carbon Reduction	2023-2024	Sep	$0.66	$0.66	$0.95	$0.68	$0.95	$0.68	$0.68	$0.68	$0.66	$0.66	$0.95	$0.76	$0.76	$0.74
Carbon Reduction	2023-2024	Oct	$0.67	$0.67	$0.99	$0.69	$0.99	$0.69	$0.69	$0.69	$0.67	$0.67	$0.99	$0.78	$0.78	$0.75
Carbon Reduction	2024-2025	Nov	$0.79	$0.79	$1.16	$0.81	$1.16	$0.81	$0.81	$0.81	$0.79	$0.79	$1.16	$0.91	$0.91	$0.88
Carbon Reduction	2024-2025	Dec	$1.13	$0.99	$1.16	$1.18	$1.25	$1.18	$1.18	$1.18	$1.13	$0.99	$1.16	$1.10	$1.10	$1.19
Carbon Reduction	2024-2025	Jan	$1.16	$1.16	$1.16	$1.19	$1.21	$1.19	$1.19	$1.19	$1.16	$1.16	$1.16	$1.16	$1.16	$1.19
Carbon Reduction	2024-2025	Feb	$1.10	$1.06	$1.18	$1.10	$1.22	$1.10	$1.10	$1.10	$1.10	$1.06	$1.18	$1.11	$1.11	$1.12
Carbon Reduction	2024-2025	Mar	$0.94	$0.94	$1.13	$0.96	$1.13	$0.96	$0.96	$0.96	$0.94	$0.94	$1.13	$1.00	$1.00	$0.99
Carbon Reduction	2024-2025	Apr	$0.79	$0.79	$1.22	$0.81	$1.22	$1.22	$1.22	$1.22	$0.79	$0.79	$1.22	$0.94	$0.94	$1.14
Carbon Reduction	2024-2025	May	$0.88	$0.88	$1.13	$0.90	$1.13	$0.90	$0.90	$0.90	$0.88	$0.88	$1.13	$0.96	$0.96	$0.95
Carbon Reduction	2024-2025	Jun	$0.80	$0.80	$1.13	$0.82	$1.13	$0.82	$0.82	$0.82	$0.80	$0.80	$1.13	$0.91	$0.91	$0.88
Carbon Reduction	2024-2025	Jul	$0.78	$0.78	$1.13	$0.81	$1.13	$0.81	$0.81	$0.81	$0.78	$0.78	$1.13	$0.90	$0.90	$0.87
Carbon Reduction	2024-2025	Aug	$0.78	$0.78	$1.14	$0.80	$1.14	$0.80	$0.80	$0.80	$0.78	$0.78	$1.14	$0.90	$0.90	$0.87
Carbon Reduction	2024-2025	Sep	$0.88	$0.88	$1.14	$0.90	$1.14	$0.90	$0.90	$0.90	$0.88	$0.88	$1.14	$0.97	$0.97	$0.95
Carbon Reduction	2024-2025	Oct	$0.88	$0.88	$1.48	$0.90	$1.48	$0.90	$0.90	$0.90	$0.88	$0.88	$1.48	$1.08	$1.08	$1.02
Carbon Reduction	2025-2026	Nov	$1.09	$1.06	$1.35	$1.09	$1.35	$1.09	$1.09	$1.09	$1.09	$1.06	$1.35	$1.17	$1.17	$1.14
Carbon Reduction	2025-2026	Dec	$1.36	$1.20	$1.36	$1.41	$1.47	$1.41	$1.41	$1.41	$1.36	$1.20	$1.36	$1.31	$1.31	$1.43
Carbon Reduction	2025-2026	Jan	$1.38	$1.38	$1.38	$1.41	$1.44	$1.41	$1.41	$1.41	$1.38	$1.38	$1.38	$1.38	$1.38	$1.42
Carbon Reduction	2025-2026	Feb	$1.36	$1.33	$1.39	$1.39	$1.43	$1.39	$1.39	$1.39	$1.36	$1.33	$1.39	$1.36	$1.36	$1.40
Carbon Reduction	2025-2026	Mar	$1.20	$1.20	$1.29	$1.23	$1.29	$1.23	$1.23	$1.23	$1.20	$1.20	$1.29	$1.23	$1.23	$1.24
Carbon Reduction	2025-2026	Apr	$1.03	$1.03	$1.53	$1.06	$1.53	$1.53	$1.53	$1.53	$1.03	$1.03	$1.53	$1.20	$1.20	$1.43
Carbon Reduction	2025-2026	May	$1.05	$1.05	$1.29	$1.08	$1.29	$1.08	$1.08	$1.08	$1.05	$1.05	$1.29	$1.13	$1.13	$1.12
Carbon Reduction	2025-2026	Jun	$1.03	$1.03	$1.29	$1.06	$1.29	$1.06	$1.06	$1.06	$1.03	$1.03	$1.29	$1.12	$1.12	$1.10
Carbon Reduction	2025-2026	Jul	$0.99	$0.99	$1.29	$1.02	$1.29	$1.02	$1.02	$1.02	$0.99	$0.99	$1.29	$1.09	$1.09	$1.07
Carbon Reduction	2025-2026	Aug	$1.01	$1.01	$1.29	$1.03	$1.29	$1.03	$1.03	$1.03	$1.01	$1.01	$1.29	$1.10	$1.10	$1.09
Carbon Reduction	2025-2026	Sep	$1.07	$1.07	$1.29	$1.09	$1.29	$1.09	$1.09	$1.09	$1.07	$1.07	$1.29	$1.14	$1.14	$1.13
Carbon Reduction	2025-2026	Oct	$1.11	$1.11	$1.71	$1.14	$1.71	$1.14	$1.14	$1.14	$1.11	$1.11	$1.71	$1.31	$1.31	$1.25
Carbon Reduction	2026-2027	Nov	$1.33	$1.31	$1.48	$1.34	$1.48	$1.34	$1.34	$1.34	$1.33	$1.31	$1.48	$1.37	$1.37	$1.37
Carbon Reduction	2026-2027	Dec	$1.48	$1.39	$1.48	$1.57	$1.61	$1.57	$1.57	$1.57	$1.48	$1.39	$1.48	$1.45	$1.45	$1.58
Carbon Reduction	2026-2027	Jan	$1.51	$1.51	$1.51	$1.54	$1.56	$1.54	$1.54	$1.54	$1.51	$1.51	$1.51	$1.51	$1.51	$1.54
Carbon Reduction	2026-2027	Feb	$1.46	$1.41	$1.52	$1.48	$1.55	$1.48	$1.48	$1.48	$1.46	$1.41	$1.52	$1.46	$1.46	$1.49
Carbon Reduction	2026-2027	Mar	$1.26	$1.26	$1.39	$1.29	$1.39	$1.29	$1.29	$1.29	$1.26	$1.26	$1.39	$1.31	$1.31	$1.31
Carbon Reduction	2026-2027	Apr	$1.11	$1.11	$1.70	$1.14	$1.70	$1.70	$1.70	$1.70	$1.11	$1.11	$1.70	$1.31	$1.31	$1.59
Carbon Reduction	2026-2027	May	$1.17	$1.17	$1.37	$1.20	$1.37	$1.20	$1.20	$1.20	$1.17	$1.17	$1.37	$1.24	$1.24	$1.23
Carbon Reduction	2026-2027	Jun	$1.12	$1.12	$1.38	$1.15	$1.38	$1.15	$1.15	$1.15	$1.12	$1.12	$1.38	$1.21	$1.21	$1.19
Carbon Reduction	2026-2027	Jul	$1.08	$1.08	$1.38	$1.10	$1.38	$1.10	$1.10	$1.10	$1.08	$1.08	$1.38	$1.18	$1.18	$1.16
Carbon Reduction	2026-2027	Aug	$1.10	$1.10	$1.38	$1.12	$1.38	$1.12	$1.12	$1.12	$1.10	$1.10	$1.38	$1.19	$1.19	$1.17
Carbon Reduction	2026-2027	Sep	$1.15	$1.15	$1.38	$1.18	$1.38	$1.18	$1.18	$1.18	$1.15	$1.15	$1.38	$1.23	$1.23	$1.22
Carbon Reduction	2026-2027	Oct	$1.14	$1.14	$1.78	$1.17	$1.78	$1.17	$1.17	$1.17	$1.14	$1.14	$1.78	$1.36	$1.36	$1.29
Carbon Reduction	2027-2028	Nov	$1.43	$1.41	$1.57	$1.44	$1.57	$1.44	$1.44	$1.44	$1.43	$1.41	$1.57	$1.47	$1.47	$1.47

[1] Avoided costs are before Environmental Externalities adder

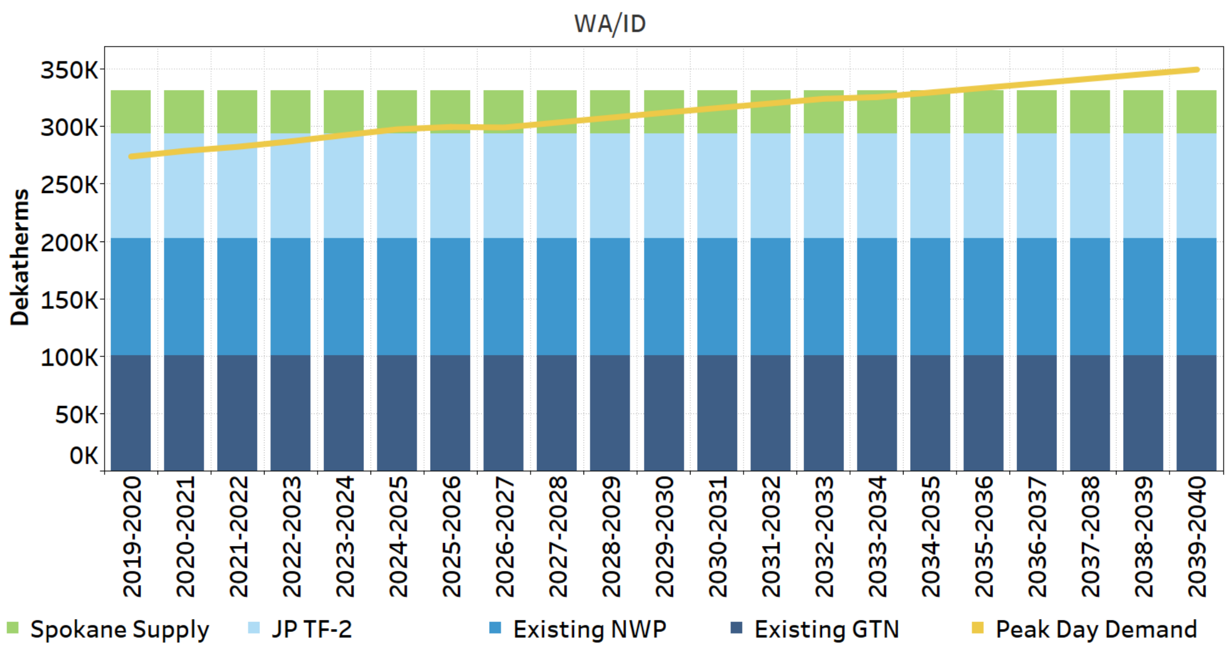
Monthly Avoided Costs[1] Nominal $																
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Carbon Reduction	2027-2028	Dec	$1.57	$1.52	$1.57	$1.68	$1.72	$1.68	$1.68	$1.68	$1.57	$1.52	$1.57	$1.56	$1.56	$1.69
Carbon Reduction	2027-2028	Jan	$1.58	$1.57	$1.58	$1.61	$1.63	$1.61	$1.61	$1.61	$1.58	$1.57	$1.58	$1.57	$1.57	$1.61
Carbon Reduction	2027-2028	Feb	$1.53	$1.47	$1.60	$1.53	$1.66	$1.53	$1.53	$1.53	$1.53	$1.47	$1.60	$1.53	$1.53	$1.55
Carbon Reduction	2027-2028	Mar	$1.35	$1.35	$1.48	$1.38	$1.48	$1.38	$1.38	$1.38	$1.35	$1.35	$1.48	$1.39	$1.39	$1.40
Carbon Reduction	2027-2028	Apr	$1.11	$1.11	$1.48	$1.14	$1.48	$1.48	$1.48	$1.48	$1.11	$1.11	$1.48	$1.23	$1.23	$1.41
Carbon Reduction	2027-2028	May	$1.20	$1.20	$1.48	$1.23	$1.48	$1.23	$1.23	$1.23	$1.20	$1.20	$1.48	$1.29	$1.29	$1.28
Carbon Reduction	2027-2028	Jun	$1.18	$1.18	$1.48	$1.21	$1.48	$1.21	$1.21	$1.21	$1.18	$1.18	$1.48	$1.28	$1.28	$1.26
Carbon Reduction	2027-2028	Jul	$1.15	$1.15	$1.48	$1.18	$1.48	$1.18	$1.18	$1.18	$1.15	$1.15	$1.48	$1.26	$1.26	$1.24
Carbon Reduction	2027-2028	Aug	$1.17	$1.17	$1.48	$1.20	$1.48	$1.20	$1.20	$1.20	$1.17	$1.17	$1.48	$1.27	$1.27	$1.25
Carbon Reduction	2027-2028	Sep	$1.24	$1.24	$1.48	$1.26	$1.48	$1.26	$1.26	$1.26	$1.24	$1.24	$1.48	$1.32	$1.32	$1.31
Carbon Reduction	2027-2028	Oct	$1.30	$1.30	$2.08	$1.33	$2.08	$1.33	$1.33	$1.33	$1.30	$1.30	$2.08	$1.56	$1.56	$1.48
Carbon Reduction	2028-2029	Nov	$1.55	$1.54	$1.63	$1.58	$1.63	$1.58	$1.58	$1.58	$1.55	$1.54	$1.63	$1.58	$1.58	$1.59
Carbon Reduction	2028-2029	Dec	$1.64	$1.56	$1.64	$1.77	$1.81	$1.77	$1.77	$1.77	$1.64	$1.56	$1.64	$1.61	$1.61	$1.78
Carbon Reduction	2028-2029	Jan	$1.66	$1.66	$1.66	$1.70	$1.73	$1.70	$1.70	$1.70	$1.66	$1.66	$1.66	$1.66	$1.66	$1.70
Carbon Reduction	2028-2029	Feb	$1.62	$1.53	$1.67	$1.60	$1.71	$1.60	$1.60	$1.60	$1.62	$1.53	$1.67	$1.61	$1.61	$1.62
Carbon Reduction	2028-2029	Mar	$1.40	$1.40	$1.55	$1.43	$1.55	$1.43	$1.43	$1.43	$1.40	$1.40	$1.55	$1.45	$1.45	$1.45
Carbon Reduction	2028-2029	Apr	$1.23	$1.23	$1.82	$1.26	$1.82	$1.82	$1.82	$1.82	$1.23	$1.23	$1.82	$1.42	$1.42	$1.71
Carbon Reduction	2028-2029	May	$1.27	$1.27	$1.51	$1.30	$1.51	$1.30	$1.30	$1.30	$1.27	$1.27	$1.51	$1.35	$1.35	$1.34
Carbon Reduction	2028-2029	Jun	$1.25	$1.25	$1.51	$1.28	$1.51	$1.28	$1.28	$1.28	$1.25	$1.25	$1.51	$1.34	$1.34	$1.33
Carbon Reduction	2028-2029	Jul	$1.21	$1.21	$1.51	$1.24	$1.51	$1.24	$1.24	$1.24	$1.21	$1.21	$1.51	$1.31	$1.31	$1.30
Carbon Reduction	2028-2029	Aug	$1.20	$1.20	$1.52	$1.23	$1.52	$1.23	$1.23	$1.23	$1.20	$1.20	$1.52	$1.31	$1.31	$1.29
Carbon Reduction	2028-2029	Sep	$1.28	$1.28	$1.52	$1.31	$1.52	$1.31	$1.31	$1.31	$1.28	$1.28	$1.52	$1.36	$1.36	$1.35
Carbon Reduction	2028-2029	Oct	$1.33	$1.33	$2.11	$1.36	$2.11	$1.36	$1.36	$1.36	$1.33	$1.33	$2.11	$1.59	$1.59	$1.51
Carbon Reduction	2029-2030	Nov	$1.61	$1.60	$1.67	$1.64	$1.67	$1.64	$1.64	$1.64	$1.61	$1.60	$1.67	$1.63	$1.63	$1.64
Carbon Reduction	2029-2030	Dec	$1.67	$1.67	$1.67	$1.84	$1.88	$1.84	$1.84	$1.84	$1.67	$1.67	$1.67	$1.67	$1.67	$1.85
Carbon Reduction	2029-2030	Jan	$1.70	$1.70	$1.70	$1.73	$1.77	$1.73	$1.73	$1.73	$1.70	$1.70	$1.70	$1.70	$1.70	$1.74
Carbon Reduction	2029-2030	Feb	$1.67	$1.58	$1.71	$1.65	$1.75	$1.65	$1.65	$1.65	$1.67	$1.58	$1.71	$1.65	$1.65	$1.67
Carbon Reduction	2029-2030	Mar	$1.46	$1.46	$1.59	$1.50	$1.59	$1.50	$1.50	$1.50	$1.46	$1.46	$1.59	$1.50	$1.50	$1.51
Carbon Reduction	2029-2030	Apr	$1.29	$1.29	$1.91	$1.32	$1.91	$1.91	$1.91	$1.91	$1.29	$1.29	$1.91	$1.50	$1.50	$1.79
Carbon Reduction	2029-2030	May	$1.32	$1.32	$1.52	$1.35	$1.52	$1.35	$1.35	$1.35	$1.32	$1.32	$1.52	$1.39	$1.39	$1.38
Carbon Reduction	2029-2030	Jun	$1.28	$1.28	$1.52	$1.31	$1.52	$1.31	$1.31	$1.31	$1.28	$1.28	$1.52	$1.36	$1.36	$1.36
Carbon Reduction	2029-2030	Jul	$1.20	$1.20	$1.53	$1.22	$1.53	$1.22	$1.22	$1.22	$1.20	$1.20	$1.53	$1.31	$1.31	$1.28
Carbon Reduction	2029-2030	Aug	$1.21	$1.21	$1.53	$1.23	$1.53	$1.23	$1.23	$1.23	$1.21	$1.21	$1.53	$1.31	$1.31	$1.29
Carbon Reduction	2029-2030	Sep	$1.26	$1.26	$1.53	$1.29	$1.53	$1.29	$1.29	$1.29	$1.26	$1.26	$1.53	$1.35	$1.35	$1.34
Carbon Reduction	2029-2030	Oct	$1.37	$1.37	$1.99	$1.40	$1.99	$1.40	$1.40	$1.40	$1.37	$1.37	$1.99	$1.58	$1.58	$1.52
Carbon Reduction	2030-2031	Nov	$1.65	$1.64	$1.72	$1.68	$1.72	$1.68	$1.68	$1.68	$1.65	$1.64	$1.72	$1.67	$1.67	$1.69
Carbon Reduction	2030-2031	Dec	$1.73	$1.72	$1.73	$1.88	$1.91	$1.88	$1.88	$1.88	$1.73	$1.72	$1.73	$1.73	$1.73	$1.88
Carbon Reduction	2030-2031	Jan	$1.73	$1.73	$1.73	$1.76	$1.79	$1.76	$1.76	$1.76	$1.73	$1.73	$1.73	$1.73	$1.73	$1.77
Carbon Reduction	2030-2031	Feb	$1.75	$1.64	$1.77	$1.71	$1.81	$1.71	$1.71	$1.71	$1.75	$1.64	$1.77	$1.72	$1.72	$1.73
Carbon Reduction	2030-2031	Mar	$1.49	$1.49	$1.63	$1.53	$1.63	$1.53	$1.53	$1.53	$1.49	$1.49	$1.63	$1.54	$1.54	$1.55
Carbon Reduction	2030-2031	Apr	$1.35	$1.35	$2.01	$1.38	$2.01	$2.01	$2.01	$2.01	$1.35	$1.35	$2.01	$1.57	$1.57	$1.88
Carbon Reduction	2030-2031	May	$1.35	$1.35	$1.62	$1.38	$1.62	$1.38	$1.38	$1.38	$1.35	$1.35	$1.62	$1.44	$1.44	$1.42
Carbon Reduction	2030-2031	Jun	$1.31	$1.31	$1.62	$1.34	$1.62	$1.34	$1.34	$1.34	$1.31	$1.31	$1.62	$1.41	$1.41	$1.39
Carbon Reduction	2030-2031	Jul	$1.24	$1.24	$1.62	$1.26	$1.62	$1.26	$1.26	$1.26	$1.24	$1.24	$1.62	$1.36	$1.36	$1.34
Carbon Reduction	2030-2031	Aug	$1.23	$1.23	$1.62	$1.26	$1.62	$1.26	$1.26	$1.26	$1.23	$1.23	$1.62	$1.36	$1.36	$1.33
Carbon Reduction	2030-2031	Sep	$1.34	$1.34	$1.62	$1.37	$1.62	$1.37	$1.37	$1.37	$1.34	$1.34	$1.62	$1.44	$1.44	$1.42
Carbon Reduction	2030-2031	Oct	$1.40	$1.40	$2.04	$1.43	$2.04	$1.43	$1.43	$1.43	$1.40	$1.40	$2.04	$1.61	$1.61	$1.55
Carbon Reduction	2031-2032	Nov	$1.72	$1.70	$1.82	$1.74	$1.82	$1.74	$1.74	$1.74	$1.72	$1.70	$1.82	$1.75	$1.75	$1.76
Carbon Reduction	2031-2032	Dec	$1.83	$1.73	$1.83	$2.41	$2.42	$2.41	$2.41	$2.41	$1.83	$1.73	$1.83	$1.80	$1.80	$2.41
Carbon Reduction	2031-2032	Jan	$1.83	$1.74	$1.83	$1.78	$1.86	$1.78	$1.78	$1.78	$1.83	$1.74	$1.83	$1.80	$1.80	$1.79
Carbon Reduction	2031-2032	Feb	$1.82	$1.63	$1.87	$1.70	$1.93	$1.70	$1.70	$1.70	$1.82	$1.63	$1.87	$1.77	$1.77	$1.74
Carbon Reduction	2031-2032	Mar	$1.51	$1.51	$1.74	$1.54	$1.74	$1.54	$1.54	$1.54	$1.51	$1.51	$1.74	$1.59	$1.59	$1.58
Carbon Reduction	2031-2032	Apr	$1.39	$1.39	$2.07	$1.42	$2.07	$2.07	$2.07	$2.07	$1.39	$1.39	$2.07	$1.62	$1.62	$1.94
Carbon Reduction	2031-2032	May	$1.37	$1.37	$1.60	$1.40	$1.60	$1.40	$1.40	$1.40	$1.37	$1.37	$1.60	$1.44	$1.44	$1.44
Carbon Reduction	2031-2032	Jun	$1.30	$1.30	$1.60	$1.33	$1.60	$1.33	$1.33	$1.33	$1.30	$1.30	$1.60	$1.40	$1.40	$1.39
Carbon Reduction	2031-2032	Jul	$1.09	$1.09	$1.60	$1.11	$1.60	$1.11	$1.11	$1.11	$1.09	$1.09	$1.60	$1.26	$1.26	$1.21
Carbon Reduction	2031-2032	Aug	$1.09	$1.09	$1.60	$1.11	$1.60	$1.11	$1.11	$1.11	$1.09	$1.09	$1.60	$1.26	$1.26	$1.21
Carbon Reduction	2031-2032	Sep	$1.28	$1.28	$1.60	$1.31	$1.60	$1.31	$1.31	$1.31	$1.28	$1.28	$1.60	$1.39	$1.39	$1.37
Carbon Reduction	2031-2032	Oct	$1.39	$1.39	$2.04	$1.42	$2.04	$2.04	$2.04	$2.04	$1.39	$1.39	$2.04	$1.60	$1.60	$1.91
Carbon Reduction	2032-2033	Nov	$1.76	$1.72	$1.94	$1.75	$1.94	$1.75	$1.75	$1.75	$1.76	$1.72	$1.94	$1.81	$1.81	$1.79
Carbon Reduction	2032-2033	Dec	$1.97	$1.79	$1.97	$2.52	$2.53	$2.52	$2.52	$2.52	$1.97	$1.79	$1.97	$1.91	$1.91	$2.52
Carbon Reduction	2032-2033	Jan	$1.95	$1.84	$1.95	$1.88	$2.07	$1.88	$1.88	$1.88	$1.95	$1.84	$1.95	$1.92	$1.92	$1.92
Carbon Reduction	2032-2033	Feb	$1.95	$1.80	$1.99	$1.87	$2.04	$1.87	$1.87	$1.87	$1.95	$1.80	$1.99	$1.92	$1.92	$1.90
Carbon Reduction	2032-2033	Mar	$1.68	$1.68	$1.87	$1.72	$1.87	$1.72	$1.72	$1.72	$1.68	$1.68	$1.87	$1.75	$1.75	$1.75
Carbon Reduction	2032-2033	Apr	$1.56	$1.56	$2.21	$1.59	$2.21	$2.21	$2.21	$2.21	$1.56	$1.56	$2.21	$1.77	$1.77	$2.08
Carbon Reduction	2032-2033	May	$1.52	$1.52	$1.78	$1.56	$1.78	$1.56	$1.56	$1.56	$1.52	$1.52	$1.78	$1.61	$1.61	$1.60
Carbon Reduction	2032-2033	Jun	$1.52	$1.52	$1.78	$1.55	$1.78	$1.55	$1.55	$1.55	$1.52	$1.52	$1.78	$1.61	$1.61	$1.60
Carbon Reduction	2032-2033	Jul	$1.34	$1.34	$1.78	$1.37	$1.78	$1.37	$1.37	$1.37	$1.34	$1.34	$1.78	$1.49	$1.49	$1.46
Carbon Reduction	2032-2033	Aug	$1.36	$1.36	$1.78	$1.39	$1.78	$1.39	$1.39	$1.39	$1.36	$1.36	$1.78	$1.50	$1.50	$1.47
Carbon Reduction	2032-2033	Sep	$1.50	$1.50	$1.78	$1.53	$1.78	$1.53	$1.53	$1.53	$1.50	$1.50	$1.78	$1.59	$1.59	$1.58
Carbon Reduction	2032-2033	Oct	$1.58	$1.58	$2.21	$1.61	$2.21	$2.21	$2.21	$2.21	$1.58	$1.58	$2.21	$1.79	$1.79	$2.09
Carbon Reduction	2033-2034	Nov	$1.98	$1.94	$2.18	$1.98	$2.18	$1.98	$1.98	$1.98	$1.98	$1.94	$2.18	$2.03	$2.03	$2.02
Carbon Reduction	2033-2034	Dec	$2.20	$1.93	$2.20	$2.72	$2.74	$2.72	$2.72	$2.72	$2.20	$1.93	$2.20	$2.11	$2.11	$2.72
Carbon Reduction	2033-2034	Jan	$2.19	$1.97	$2.19	$2.01	$2.31	$2.01	$2.01	$2.01	$2.19	$1.97	$2.19	$2.12	$2.12	$2.07
Carbon Reduction	2033-2034	Feb	$2.15	$1.88	$2.23	$1.94	$2.26	$1.94	$1.94	$1.94	$2.15	$1.88	$2.23	$2.09	$2.09	$2.00
Carbon Reduction	2033-2034	Mar	$1.77	$1.77	$2.11	$1.81	$2.11	$1.81	$1.81	$1.81	$1.77	$1.77	$2.11	$1.89	$1.89	$1.87
Carbon Reduction	2033-2034	Apr	$1.65	$1.65	$2.30	$1.68	$2.30	$2.30	$2.30	$2.30	$1.65	$1.65	$2.30	$1.86	$1.86	$2.18
Carbon Reduction	2033-2034	May	$1.64	$1.64	$1.91	$1.67	$1.91	$1.67	$1.67	$1.67	$1.64	$1.64	$1.91	$1.73	$1.73	$1.72
Carbon Reduction	2033-2034	Jun	$1.61	$1.61	$1.91	$1.64	$1.91	$1.64	$1.64	$1.64	$1.61	$1.61	$1.91	$1.71	$1.71	$1.70
Carbon Reduction	2033-2034	Jul	$1.46	$1.46	$1.91	$1.49	$1.91	$1.49	$1.49	$1.49	$1.46	$1.46	$1.91	$1.61	$1.61	$1.58
Carbon Reduction	2033-2034	Aug	$1.48	$1.48	$1.91	$1.51	$1.91	$1.51	$1.51	$1.51	$1.48	$1.48	$1.91	$1.62	$1.62	$1.59
Carbon Reduction	2033-2034	Sep	$1.62	$1.62	$1.91	$1.66	$1.91	$1.66	$1.66	$1.66	$1.62	$1.62	$1.91	$1.72	$1.72	$1.71
Carbon Reduction	2033-2034	Oct	$1.73	$1.73	$2.40	$1.77	$2.40	$2.40	$2.40	$2.40	$1.73	$1.73	$2.40	$1.95	$1.95	$2.27
Carbon Reduction	2034-2035	Nov	$2.07	$2.01	$2.29	$2.05	$2.29	$2.05	$2.05	$2.05	$2.07	$2.01	$2.29	$2.12	$2.12	$2.10
Carbon Reduction	2034-2035	Dec	$2.31	$2.04	$2.31	$2.88	$2.89	$2.88	$2.88	$2.88	$2.31	$2.04	$2.31	$2.22	$2.22	$2.88
Carbon Reduction	2034-2035	Jan	$2.31	$2.05	$2.31	$2.09	$2.42	$2.09	$2.09	$2.09	$2.31	$2.05	$2.31	$2.22	$2.22	$2.16
Carbon Reduction	2034-2035	Feb	$2.32	$1.93	$2.35	$2.02	$2.37	$2.02	$2.02	$2.02	$2.32	$1.93	$2.35	$2.20	$2.20	$2.09
Carbon Reduction	2034-2035	Mar	$1.74	$1.74	$2.23	$1.78	$2.23	$1.78	$1.78	$1.78	$1.74	$1.74	$2.23	$1.90	$1.90	$1.87
Carbon Reduction	2034-2035	Apr	$1.63	$1.63	$2.29	$1.67	$2.29	$2.29	$2.29	$2.29	$1.63	$1.63	$2.29	$1.85	$1.85	$2.17
Carbon Reduction	2034-2035	May	$1.63	$1.63	$1.87	$1.67	$1.87	$1.67	$1.67	$1.67	$1.63	$1.63	$1.87	$1.71	$1.71	$1.71
Carbon Reduction	2034-2035	Jun	$1.57	$1.57	$1.88	$1.60	$1.88	$1.60	$1.60	$1.60	$1.57	$1.57	$1.88	$1.67	$1.67	$1.65
Carbon Reduction	2034-2035	Jul	$1.39	$1.39	$1.88	$1.42	$1.88	$1.42	$1.42	$1.42	$1.39	$1.39	$1.88	$1.55	$1.55	$1.51
Carbon Reduction	2034-2035	Aug	$1.43	$1.43	$1.88	$1.47	$1.88	$1.47	$1.47	$1.47	$1.43	$1.43	$1.88	$1.58	$1.58	$1.55
Carbon Reduction	2034-2035	Sep	$1.59	$1.59	$1.88	$1.62	$1.88	$1.62	$1.62	$1.62	$1.59	$1.59	$1.88	$1.68	$1.68	$1.67
Carbon Reduction	2034-2035	Oct	$1.65	$1.65	$2.34	$1.69	$2.34	$2.34	$2.34	$2.34	$1.65	$1.65	$2.34	$1.88	$1.88	$2.21
Carbon Reduction	2035-2036	Nov	$2.13	$1.99	$2.50	$2.03	$2.50	$2.03	$2.03	$2.03	$2.13	$1.99	$2.50	$2.21	$2.21	$2.13
Carbon Reduction	2035-2036	Dec	$2.53	$2.08	$2.53	$2.97	$2.98	$2.97	$2.97	$2.97	$2.53	$2.08	$2.53	$2.38	$2.38	$2.97

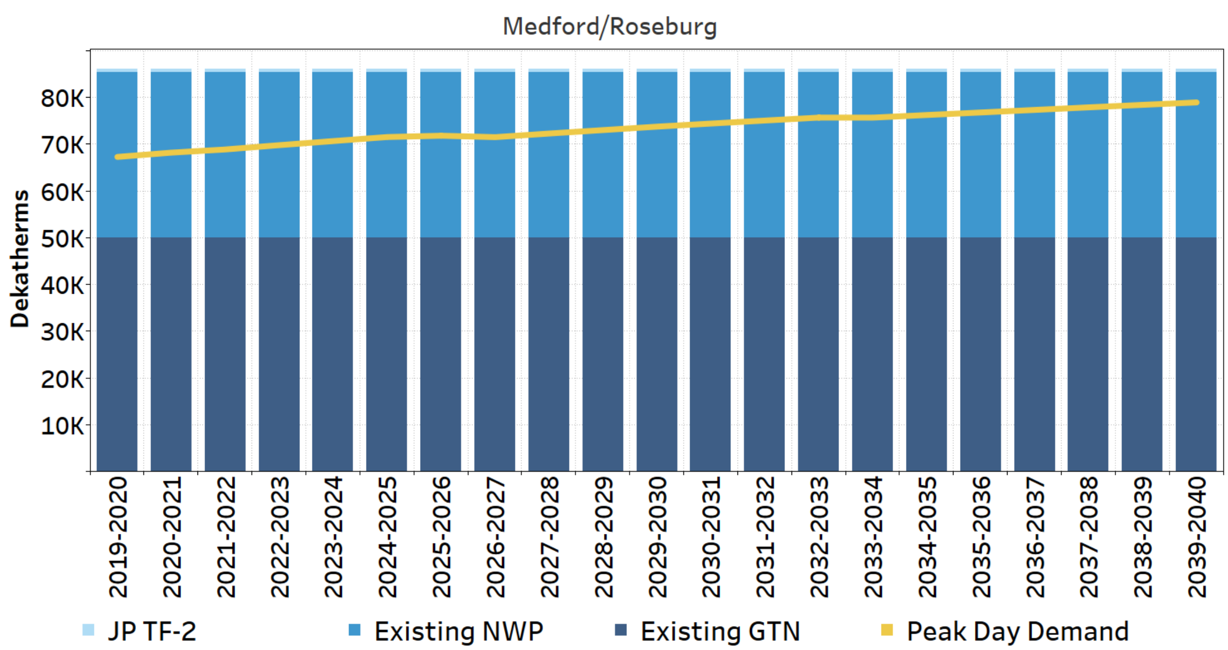
[1]Avoided costs are before Environmental Externalities adder

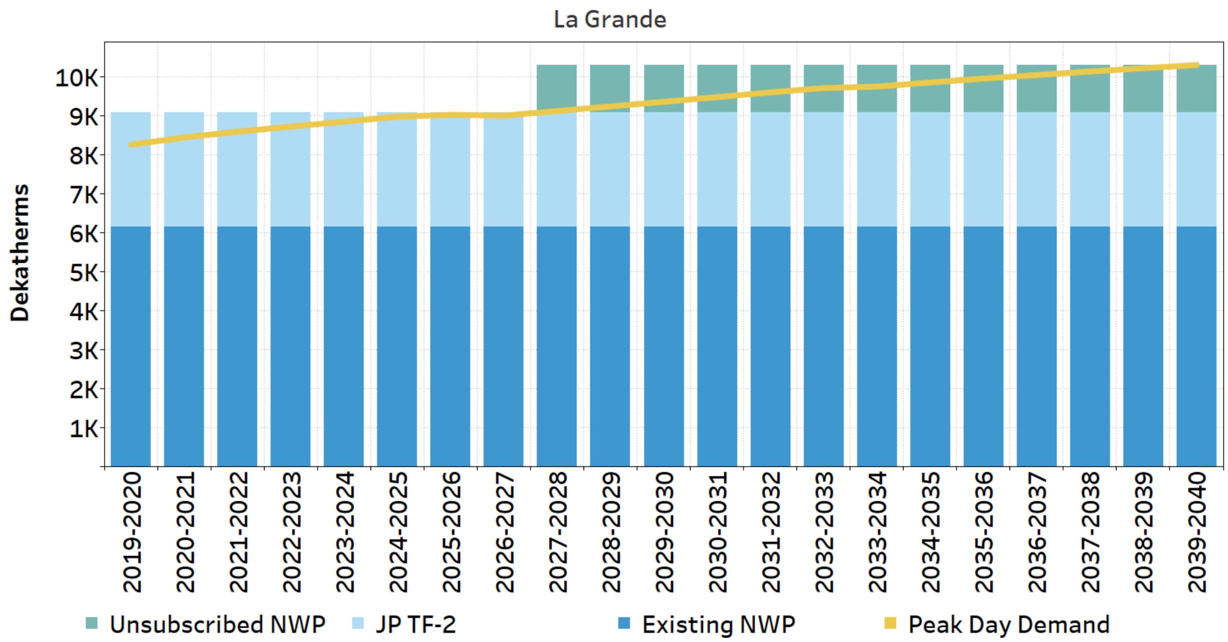
Monthly Avoided Costs[1] Nominal $																	
Scenario	Gas Year	Month	ID Both	ID GTN	ID NWP	Klamath Falls	La Grande	Medford GTN	Medford NWP	Roseburg	WA Both	WA GTN	WA NWP	Idaho	Washington	Oregon
Carbon Reduction	2035-2036	Jan	$2.52	$2.10	$2.52	$2.14	$2.61	$2.14	$2.14	$2.14	$2.52	$2.10	$2.52	$2.38	$2.38	$2.23
Carbon Reduction	2035-2036	Feb	$2.53	$2.07	$2.56	$2.15	$2.59	$2.15	$2.15	$2.15	$2.53	$2.07	$2.56	$2.39	$2.39	$2.24
Carbon Reduction	2035-2036	Mar	$1.92	$1.92	$2.46	$1.96	$2.46	$1.96	$1.96	$1.96	$1.92	$1.92	$2.46	$2.10	$2.10	$2.06
Carbon Reduction	2035-2036	Apr	$1.72	$1.72	$2.27	$1.75	$2.27	$2.27	$2.27	$2.27	$1.72	$1.72	$2.27	$1.90	$1.90	$2.16
Carbon Reduction	2035-2036	May	$1.72	$1.72	$1.96	$1.75	$1.96	$1.75	$1.75	$1.75	$1.72	$1.72	$1.96	$1.80	$1.80	$1.79
Carbon Reduction	2035-2036	Jun	$1.67	$1.67	$1.96	$1.71	$1.96	$1.71	$1.71	$1.71	$1.67	$1.67	$1.96	$1.77	$1.77	$1.76
Carbon Reduction	2035-2036	Jul	$1.40	$1.40	$1.96	$1.43	$1.96	$1.43	$1.43	$1.43	$1.40	$1.40	$1.96	$1.59	$1.59	$1.54
Carbon Reduction	2035-2036	Aug	$1.44	$1.44	$1.96	$1.47	$1.96	$1.47	$1.47	$1.47	$1.44	$1.44	$1.96	$1.61	$1.61	$1.57
Carbon Reduction	2035-2036	Sep	$1.60	$1.60	$1.96	$1.64	$1.96	$1.64	$1.64	$1.64	$1.60	$1.60	$1.96	$1.72	$1.72	$1.70
Carbon Reduction	2035-2036	Oct	$1.77	$1.77	$2.34	$1.80	$2.34	$2.34	$2.34	$2.34	$1.77	$1.77	$2.34	$1.96	$1.96	$2.23
Carbon Reduction	2036-2037	Nov	$2.24	$2.11	$2.56	$2.15	$2.56	$2.15	$2.15	$2.15	$2.24	$2.11	$2.56	$2.30	$2.30	$2.23
Carbon Reduction	2036-2037	Dec	$2.59	$2.15	$2.59	$3.15	$3.16	$3.15	$3.15	$3.15	$2.59	$2.15	$2.59	$2.44	$2.44	$3.15
Carbon Reduction	2036-2037	Jan	$2.59	$2.17	$2.59	$2.21	$2.69	$2.21	$2.21	$2.21	$2.59	$2.17	$2.59	$2.45	$2.45	$2.31
Carbon Reduction	2036-2037	Feb	$2.48	$1.99	$2.61	$2.04	$2.64	$2.04	$2.04	$2.04	$2.48	$1.99	$2.61	$2.36	$2.36	$2.16
Carbon Reduction	2036-2037	Mar	$1.87	$1.87	$2.54	$1.91	$2.54	$1.91	$1.91	$1.91	$1.87	$1.87	$2.54	$2.09	$2.09	$2.04
Carbon Reduction	2036-2037	Apr	$1.67	$1.67	$2.24	$1.71	$2.24	$2.24	$2.24	$2.24	$1.67	$1.67	$2.24	$1.86	$1.86	$2.13
Carbon Reduction	2036-2037	May	$1.80	$1.80	$2.05	$1.84	$2.05	$1.84	$1.84	$1.84	$1.80	$1.80	$2.05	$1.89	$1.89	$1.88
Carbon Reduction	2036-2037	Jun	$1.77	$1.77	$2.05	$1.80	$2.05	$1.80	$1.80	$1.80	$1.77	$1.77	$2.05	$1.86	$1.86	$1.85
Carbon Reduction	2036-2037	Jul	$1.54	$1.54	$2.05	$1.58	$2.05	$1.58	$1.58	$1.58	$1.54	$1.54	$2.05	$1.71	$1.71	$1.67
Carbon Reduction	2036-2037	Aug	$1.61	$1.61	$2.05	$1.64	$2.05	$1.64	$1.64	$1.64	$1.61	$1.61	$2.05	$1.76	$1.76	$1.73
Carbon Reduction	2036-2037	Sep	$1.74	$1.74	$2.05	$1.78	$2.05	$1.78	$1.78	$1.78	$1.74	$1.74	$2.05	$1.85	$1.85	$1.84
Carbon Reduction	2036-2037	Oct	$1.89	$1.89	$2.45	$1.93	$2.45	$2.45	$2.45	$2.45	$1.89	$1.89	$2.45	$2.07	$2.07	$2.35
Carbon Reduction	2037-2038	Nov	$2.41	$2.28	$2.79	$2.32	$2.79	$2.32	$2.32	$2.32	$2.41	$2.28	$2.79	$2.49	$2.49	$2.41
Carbon Reduction	2037-2038	Dec	$2.82	$2.38	$2.82	$3.28	$3.30	$3.28	$3.28	$3.28	$2.82	$2.38	$2.82	$2.68	$2.68	$3.29
Carbon Reduction	2037-2038	Jan	$2.82	$2.40	$2.82	$2.45	$2.91	$2.45	$2.45	$2.45	$2.82	$2.40	$2.82	$2.68	$2.68	$2.54
Carbon Reduction	2037-2038	Feb	$2.68	$2.17	$2.83	$2.25	$2.85	$2.25	$2.25	$2.25	$2.68	$2.17	$2.83	$2.56	$2.56	$2.37
Carbon Reduction	2037-2038	Mar	$2.01	$2.01	$2.83	$2.05	$2.83	$2.05	$2.05	$2.05	$2.01	$2.01	$2.83	$2.28	$2.28	$2.21
Carbon Reduction	2037-2038	Apr	$1.84	$1.84	$2.38	$1.88	$2.38	$2.38	$2.38	$2.38	$1.84	$1.84	$2.38	$2.02	$2.02	$2.28
Carbon Reduction	2037-2038	May	$1.87	$1.87	$2.10	$1.90	$2.10	$1.90	$1.90	$1.90	$1.87	$1.87	$2.10	$1.94	$1.94	$1.94
Carbon Reduction	2037-2038	Jun	$1.86	$1.86	$2.10	$1.90	$2.10	$1.90	$1.90	$1.90	$1.86	$1.86	$2.10	$1.94	$1.94	$1.94
Carbon Reduction	2037-2038	Jul	$1.62	$1.62	$2.10	$1.65	$2.10	$1.65	$1.65	$1.65	$1.62	$1.62	$2.10	$1.78	$1.78	$1.74
Carbon Reduction	2037-2038	Aug	$1.62	$1.62	$2.10	$1.65	$2.10	$1.65	$1.65	$1.65	$1.62	$1.62	$2.10	$1.78	$1.78	$1.74
Carbon Reduction	2037-2038	Sep	$1.73	$1.73	$2.10	$1.77	$2.10	$1.77	$1.77	$1.77	$1.73	$1.73	$2.10	$1.85	$1.85	$1.83
Carbon Reduction	2037-2038	Oct	$1.86	$1.86	$2.42	$1.90	$2.42	$2.42	$2.42	$2.42	$1.86	$1.86	$2.42	$2.05	$2.05	$2.31
Carbon Reduction	2038-2039	Nov	$2.36	$2.23	$2.74	$2.27	$2.74	$2.27	$2.27	$2.27	$2.36	$2.23	$2.74	$2.45	$2.45	$2.37
Carbon Reduction	2038-2039	Dec	$2.79	$2.34	$2.79	$3.31	$3.34	$3.31	$3.31	$3.31	$2.79	$2.34	$2.79	$2.64	$2.64	$3.31
Carbon Reduction	2038-2039	Jan	$2.78	$2.39	$2.78	$2.44	$2.89	$2.44	$2.44	$2.44	$2.78	$2.39	$2.78	$2.65	$2.65	$2.53
Carbon Reduction	2038-2039	Feb	$2.73	$2.21	$2.80	$2.29	$2.82	$2.29	$2.29	$2.29	$2.73	$2.21	$2.80	$2.58	$2.58	$2.40
Carbon Reduction	2038-2039	Mar	$2.15	$2.15	$2.74	$2.19	$2.74	$2.19	$2.19	$2.19	$2.15	$2.15	$2.74	$2.34	$2.34	$2.30
Carbon Reduction	2038-2039	Apr	$1.96	$1.96	$2.50	$2.00	$2.50	$2.50	$2.50	$2.50	$1.96	$1.96	$2.50	$2.14	$2.14	$2.40
Carbon Reduction	2038-2039	May	$1.99	$1.99	$2.23	$2.03	$2.23	$2.03	$2.03	$2.03	$1.99	$1.99	$2.23	$2.07	$2.07	$2.07
Carbon Reduction	2038-2039	Jun	$1.89	$1.89	$2.23	$1.93	$2.23	$1.93	$1.93	$1.93	$1.89	$1.89	$2.23	$2.00	$2.00	$1.99
Carbon Reduction	2038-2039	Jul	$1.68	$1.68	$2.23	$1.72	$2.23	$1.72	$1.72	$1.72	$1.68	$1.68	$2.23	$1.87	$1.87	$1.82
Carbon Reduction	2038-2039	Aug	$1.67	$1.67	$2.23	$1.71	$2.23	$1.71	$1.71	$1.71	$1.67	$1.67	$2.23	$1.86	$1.86	$1.81
Carbon Reduction	2038-2039	Sep	$1.86	$1.86	$2.23	$1.90	$2.23	$1.90	$1.90	$1.90	$1.86	$1.86	$2.23	$1.99	$1.99	$1.97
Carbon Reduction	2038-2039	Oct	$2.01	$2.01	$2.57	$2.05	$2.57	$2.57	$2.57	$2.57	$2.01	$2.01	$2.57	$2.20	$2.20	$2.47
Carbon Reduction	2039-2040	Nov	$2.57	$2.43	$2.90	$2.48	$2.90	$2.48	$2.48	$2.48	$2.57	$2.43	$2.90	$2.63	$2.63	$2.56
Carbon Reduction	2039-2040	Dec	$2.95	$2.50	$2.95	$3.54	$3.57	$3.54	$3.54	$3.54	$2.95	$2.50	$2.95	$2.80	$2.80	$3.55
Carbon Reduction	2039-2040	Jan	$2.95	$2.50	$2.95	$2.55	$3.08	$2.55	$2.55	$2.55	$2.95	$2.50	$2.95	$2.80	$2.80	$2.66
Carbon Reduction	2039-2040	Feb	$2.90	$2.37	$2.97	$2.44	$2.99	$2.44	$2.44	$2.44	$2.90	$2.37	$2.97	$2.74	$2.74	$2.55
Carbon Reduction	2039-2040	Mar	$2.25	$2.25	$2.85	$2.30	$2.85	$2.30	$2.30	$2.30	$2.25	$2.25	$2.85	$2.45	$2.45	$2.41
Carbon Reduction	2039-2040	Apr	$2.07	$2.07	$2.62	$2.11	$2.62	$2.62	$2.62	$2.62	$2.07	$2.07	$2.62	$2.25	$2.25	$2.52
Carbon Reduction	2039-2040	May	$2.09	$2.09	$2.32	$2.13	$2.32	$2.13	$2.13	$2.13	$2.09	$2.09	$2.32	$2.16	$2.16	$2.17
Carbon Reduction	2039-2040	Jun	$2.06	$2.06	$2.32	$2.10	$2.32	$2.10	$2.10	$2.10	$2.06	$2.06	$2.32	$2.14	$2.14	$2.14
Carbon Reduction	2039-2040	Jul	$1.87	$1.87	$2.32	$1.91	$2.32	$1.91	$1.91	$1.91	$1.87	$1.87	$2.32	$2.02	$2.02	$1.99
Carbon Reduction	2039-2040	Aug	$1.88	$1.88	$2.32	$1.92	$2.32	$1.92	$1.92	$1.92	$1.88	$1.88	$2.32	$2.03	$2.03	$2.00
Carbon Reduction	2039-2040	Sep	$2.03	$2.03	$2.32	$2.07	$2.32	$2.07	$2.07	$2.07	$2.03	$2.03	$2.32	$2.13	$2.13	$2.12
Carbon Reduction	2039-2040	Oct	$2.14	$2.14	$2.69	$2.18	$2.69	$2.69	$2.69	$2.69	$2.14	$2.14	$2.69	$2.32	$2.32	$2.59

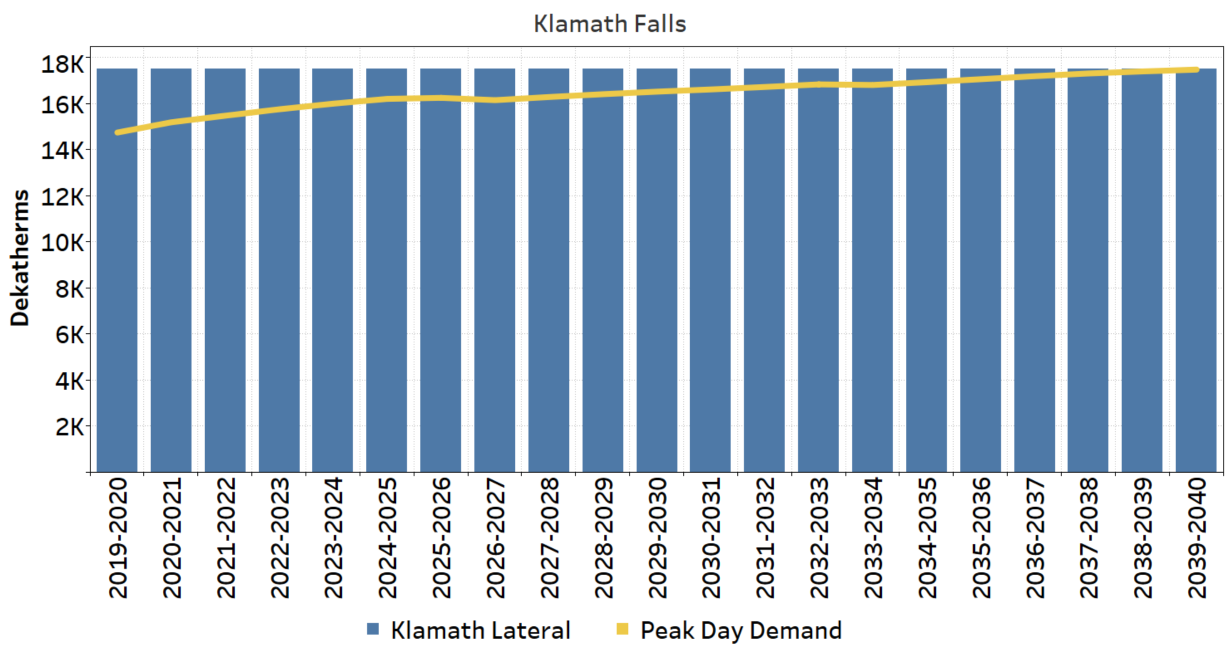
[1]Avoided costs are before Environmental Externalities adder

APPENDIX 7.1: HIGH GROWTH CASES
SELECTED RESOURCES VS. PEAK DAY DEMAND
EXISTING PLUS EXPECTED AVAILABLE






La Grande
Dekatherms
10K
9K
8K
7K
6K
5K
4K
3K
2K
1K
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
2029-2030
2030-2031
2031-2032
2032-2033
2033-2034
2034-2035
2035-2036
2036-2037
2037-2038
2038-2039
2039-2040
Unsubscribed NWP
JP TF-2
Existing NWP
Peak Day Demand


Klamath Falls
Dekatherms
18K
16K
14K
12K
10K
8K
6K
4K
2K
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
2029-2030
2030-2031
2031-2032
2032-2033
2033-2034
2034-2035
2035-2036
2036-2037
2037-2038
2038-2039
2039-2040
Klamath Lateral
Peak Day Demand

APPENDIX 7.2: PEAK DAY DEMAND TABLE
HIGH GROWTH & LOW PRICES

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medord/Roseburg Served	Medord/Roseburg Unserved	Medord/Roseburg Total	Medord/Roseburg % of Peak Day Served
High Growth & Low Prices	2019-2020	8.27	0.00	8.27	100%	14.74	0.00	14.74	100%	67.27	0.00	67.27	100%
High Growth & Low Prices	2020-2021	8.45	0.00	8.45	100%	15.18	0.00	15.18	100%	68.19	0.00	68.19	100%
High Growth & Low Prices	2021-2022	8.60	0.00	8.60	100%	15.47	0.00	15.47	100%	68.87	0.00	68.87	100%
High Growth & Low Prices	2022-2023	8.73	0.00	8.73	100%	15.75	0.00	15.75	100%	69.79	0.00	69.79	100%
High Growth & Low Prices	2023-2024	8.86	0.00	8.86	100%	15.99	0.00	15.99	100%	70.66	0.00	70.66	100%
High Growth & Low Prices	2024-2025	8.99	0.00	8.99	100%	16.20	0.00	16.20	100%	71.53	0.00	71.53	100%
High Growth & Low Prices	2025-2026	9.04	0.00	9.04	100%	16.24	0.00	16.24	100%	71.81	0.00	71.81	100%
High Growth & Low Prices	2026-2027	9.01	0.00	9.01	100%	16.14	0.00	16.14	100%	71.50	0.00	71.50	100%
High Growth & Low Prices	2027-2028	9.13	0.00	9.13	100%	16.28	0.00	16.28	100%	72.27	0.00	72.27	100%
High Growth & Low Prices	2028-2029	9.25	0.00	9.25	100%	16.40	0.00	16.40	100%	73.01	0.00	73.01	100%
High Growth & Low Prices	2029-2030	9.37	0.00	9.37	100%	16.51	0.00	16.51	100%	73.75	0.00	73.75	100%
High Growth & Low Prices	2030-2031	9.49	0.00	9.49	100%	16.61	0.00	16.61	100%	74.41	0.00	74.41	100%
High Growth & Low Prices	2031-2032	9.61	0.00	9.61	100%	16.71	0.00	16.71	100%	75.06	0.00	75.06	100%
High Growth & Low Prices	2032-2033	9.72	0.00	9.72	100%	16.82	0.00	16.82	100%	75.69	0.00	75.69	100%
High Growth & Low Prices	2033-2034	9.76	0.00	9.76	100%	16.80	0.00	16.80	100%	75.68	0.00	75.68	100%
High Growth & Low Prices	2034-2035	9.87	0.00	9.87	100%	16.92	0.00	16.92	100%	76.24	0.00	76.24	100%
High Growth & Low Prices	2035-2036	9.97	0.00	9.97	100%	17.05	0.00	17.05	100%	76.78	0.00	76.78	100%
High Growth & Low Prices	2036-2037	10.06	0.00	10.06	100%	17.18	0.00	17.18	100%	77.33	0.00	77.33	100%
High Growth & Low Prices	2037-2038	10.15	0.00	10.15	100%	17.30	0.00	17.30	100%	77.88	0.00	77.88	100%
High Growth & Low Prices	2038-2039	10.23	0.00	10.23	100%	17.39	0.00	17.39	100%	78.41	0.00	78.41	100%
High Growth & Low Prices	2039-2040	10.25	0.07	10.31	99%	17.47	0.00	17.47	100%	78.93	0.00	78.93	100%

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	WA Served	WA Unserved	WA Total	WA % of Peak Day Served	ID Served	ID Unserved	ID Total	ID % of Peak Day Served
High Growth & Low Prices	2019-2020	178.46	0.00	178.46	100%	95.47	0.00	95.47	100%
High Growth & Low Prices	2020-2021	181.18	0.00	181.18	100%	97.59	0.00	97.59	100%
High Growth & Low Prices	2021-2022	183.28	0.00	183.28	100%	99.12	0.00	99.12	100%
High Growth & Low Prices	2022-2023	185.92	0.00	185.92	100%	101.21	0.00	101.21	100%
High Growth & Low Prices	2023-2024	188.92	0.00	188.92	100%	103.63	0.00	103.63	100%
High Growth & Low Prices	2024-2025	191.80	0.00	191.80	100%	105.87	0.00	105.87	100%
High Growth & Low Prices	2025-2026	192.93	0.00	192.93	100%	106.79	0.00	106.79	100%
High Growth & Low Prices	2026-2027	192.49	0.00	192.49	100%	106.73	0.00	106.73	100%
High Growth & Low Prices	2027-2028	195.13	0.00	195.13	100%	108.40	0.00	108.40	100%
High Growth & Low Prices	2028-2029	197.74	0.00	197.74	100%	110.05	0.00	110.05	100%
High Growth & Low Prices	2029-2030	200.36	0.00	200.36	100%	111.72	0.00	111.72	100%
High Growth & Low Prices	2030-2031	202.70	0.00	202.70	100%	113.43	0.00	113.43	100%
High Growth & Low Prices	2031-2032	204.99	0.00	204.99	100%	115.19	0.00	115.19	100%
High Growth & Low Prices	2032-2033	207.26	0.00	207.26	100%	116.97	0.00	116.97	100%
High Growth & Low Prices	2033-2034	207.83	0.00	207.83	100%	117.86	0.00	117.86	100%
High Growth & Low Prices	2034-2035	209.96	0.00	209.96	100%	119.71	0.00	119.71	100%
High Growth & Low Prices	2035-2036	212.06	0.05	212.11	100%	121.56	0.05	121.61	100%
High Growth & Low Prices	2036-2037	212.28	1.93	214.21	99%	121.58	1.93	123.51	98%
High Growth & Low Prices	2037-2038	212.45	3.81	216.27	98%	121.64	3.81	125.45	97%
High Growth & Low Prices	2038-2039	212.60	5.69	218.28	97%	121.74	5.69	127.42	96%
High Growth & Low Prices	2039-2040	212.76	7.52	220.27	97%	121.89	7.52	129.40	94%

APPENDIX 7.2: PEAK DAY DEMAND TABLE
LOW GROWTH & HIGH PRICES

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medord/Roseburg Served	Medord/Roseburg Unserved	Medord/Roseburg Total	Medord/Roseburg % of Peak Day Served
Low Growth & High Prices	2019-2020	8.27	0.00	8.27	100%	14.74	0.00	14.74	100%	67.27	0.00	67.27	100%
Low Growth & High Prices	2020-2021	8.13	0.00	8.13	100%	14.49	0.00	14.49	100%	67.54	0.00	67.54	100%
Low Growth & High Prices	2021-2022	3.75	0.00	3.75	100%	6.37	0.00	6.37	100%	31.28	0.00	31.28	100%
Low Growth & High Prices	2022-2023	3.70	0.00	3.70	100%	6.28	0.00	6.28	100%	31.14	0.00	31.14	100%
Low Growth & High Prices	2023-2024	3.69	0.00	3.69	100%	6.29	0.00	6.29	100%	31.37	0.00	31.37	100%
Low Growth & High Prices	2024-2025	3.68	0.00	3.68	100%	6.29	0.00	6.29	100%	31.56	0.00	31.56	100%
Low Growth & High Prices	2025-2026	3.66	0.00	3.66	100%	6.30	0.00	6.30	100%	31.79	0.00	31.79	100%
Low Growth & High Prices	2026-2027	3.65	0.00	3.65	100%	6.31	0.00	6.31	100%	31.96	0.00	31.96	100%
Low Growth & High Prices	2027-2028	3.64	0.00	3.64	100%	6.32	0.00	6.32	100%	32.09	0.00	32.09	100%
Low Growth & High Prices	2028-2029	3.63	0.00	3.63	100%	6.33	0.00	6.33	100%	32.22	0.00	32.22	100%
Low Growth & High Prices	2029-2030	3.61	0.00	3.61	100%	6.36	0.00	6.36	100%	32.38	0.00	32.38	100%
Low Growth & High Prices	2030-2031	3.60	0.00	3.60	100%	6.38	0.00	6.38	100%	32.51	0.00	32.51	100%
Low Growth & High Prices	2031-2032	3.59	0.00	3.59	100%	6.40	0.00	6.40	100%	32.66	0.00	32.66	100%
Low Growth & High Prices	2032-2033	3.59	0.00	3.59	100%	6.43	0.00	6.43	100%	32.79	0.00	32.79	100%
Low Growth & High Prices	2033-2034	3.58	0.00	3.58	100%	6.46	0.00	6.46	100%	32.94	0.00	32.94	100%
Low Growth & High Prices	2034-2035	3.58	0.00	3.58	100%	6.49	0.00	6.49	100%	33.06	0.00	33.06	100%
Low Growth & High Prices	2035-2036	3.58	0.00	3.58	100%	6.51	0.00	6.51	100%	33.19	0.00	33.19	100%
Low Growth & High Prices	2036-2037	3.58	0.00	3.58	100%	6.54	0.00	6.54	100%	33.33	0.00	33.33	100%
Low Growth & High Prices	2037-2038	3.59	0.00	3.59	100%	6.58	0.00	6.58	100%	33.48	0.00	33.48	100%
Low Growth & High Prices	2038-2039	3.59	0.00	3.59	100%	6.61	0.00	6.61	100%	33.61	0.00	33.61	100%
Low Growth & High Prices	2039-2040	3.61	0.00	3.61	100%	6.65	0.00	6.65	100%	33.73	0.00	33.73	100%

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	WA Served	WA Unserved	WA Total	WA % of Peak Day Served	ID Served	ID Unserved	ID Total	ID % of Peak Day Served
Low Growth & High Prices	2019-2020	178.46	0.00	178.46	100%	95.47	0.00	95.47	100%
Low Growth & High Prices	2020-2021	177.97	0.00	177.97	100%	94.85	0.00	94.85	100%
Low Growth & High Prices	2021-2022	79.56	0.00	79.56	100%	42.55	0.00	42.55	100%
Low Growth & High Prices	2022-2023	78.90	0.00	78.90	100%	42.11	0.00	42.11	100%
Low Growth & High Prices	2023-2024	79.53	0.00	79.53	100%	42.52	0.00	42.52	100%
Low Growth & High Prices	2024-2025	79.79	0.00	79.79	100%	42.60	0.00	42.60	100%
Low Growth & High Prices	2025-2026	80.15	0.00	80.15	100%	42.70	0.00	42.70	100%
Low Growth & High Prices	2026-2027	80.54	0.00	80.54	100%	42.79	0.00	42.79	100%
Low Growth & High Prices	2027-2028	80.99	0.00	80.99	100%	42.93	0.00	42.93	100%
Low Growth & High Prices	2028-2029	81.32	0.00	81.32	100%	43.01	0.00	43.01	100%
Low Growth & High Prices	2029-2030	81.74	0.00	81.74	100%	43.09	0.00	43.09	100%
Low Growth & High Prices	2030-2031	82.16	0.00	82.16	100%	43.23	0.00	43.23	100%
Low Growth & High Prices	2031-2032	82.67	0.00	82.67	100%	43.41	0.00	43.41	100%
Low Growth & High Prices	2032-2033	83.08	0.00	83.08	100%	43.52	0.00	43.52	100%
Low Growth & High Prices	2033-2034	83.56	0.00	83.56	100%	43.70	0.00	43.70	100%
Low Growth & High Prices	2034-2035	84.02	0.00	84.02	100%	43.91	0.00	43.91	100%
Low Growth & High Prices	2035-2036	84.55	0.00	84.55	100%	44.15	0.00	44.15	100%
Low Growth & High Prices	2036-2037	85.00	0.00	85.00	100%	44.32	0.00	44.32	100%
Low Growth & High Prices	2037-2038	85.43	0.00	85.43	100%	44.50	0.00	44.50	100%
Low Growth & High Prices	2038-2039	85.85	0.00	85.85	100%	44.68	0.00	44.68	100%
Low Growth & High Prices	2039-2040	86.29	0.00	86.29	100%	44.88	0.00	44.88	100%

APPENDIX 7.2: PEAK DAY DEMAND TABLE
CARBON REDUCTION

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medord/Roseburg Served	Medord/Roseburg Unserved	Medord/Roseburg Total	Medord/Roseburg % of Peak Day Served
Carbon Reduction	2019-2020	8.27	0.00	8.27	100%	14.74	0.00	14.74	100%	67.27	0.00	67.27	100%
Carbon Reduction	2020-2021	8.31	0.00	8.31	100%	14.87	0.00	14.87	100%	67.94	0.00	67.94	100%
Carbon Reduction	2021-2022	8.01	0.00	8.01	100%	14.28	0.00	14.28	100%	65.38	0.00	65.38	100%
Carbon Reduction	2022-2023	8.05	0.00	8.05	100%	14.42	0.00	14.42	100%	66.12	0.00	66.12	100%
Carbon Reduction	2023-2024	8.10	0.00	8.10	100%	14.54	0.00	14.54	100%	66.82	0.00	66.82	100%
Carbon Reduction	2024-2025	8.15	0.00	8.15	100%	14.65	0.00	14.65	100%	67.52	0.00	67.52	100%
Carbon Reduction	2025-2026	8.19	0.00	8.19	100%	14.76	0.00	14.76	100%	68.25	0.00	68.25	100%
Carbon Reduction	2026-2027	8.15	0.00	8.15	100%	14.71	0.00	14.71	100%	68.25	0.00	68.25	100%
Carbon Reduction	2027-2028	8.19	0.00	8.19	100%	14.79	0.00	14.79	100%	68.87	0.00	68.87	100%
Carbon Reduction	2028-2029	8.16	0.00	8.16	100%	14.76	0.00	14.76	100%	68.94	0.00	68.94	100%
Carbon Reduction	2029-2030	8.14	0.00	8.14	100%	14.72	0.00	14.72	100%	69.00	0.00	69.00	100%
Carbon Reduction	2030-2031	8.18	0.00	8.18	100%	14.79	0.00	14.79	100%	69.53	0.00	69.53	100%
Carbon Reduction	2031-2032	8.22	0.00	8.22	100%	14.86	0.00	14.86	100%	70.07	0.00	70.07	100%
Carbon Reduction	2032-2033	8.25	0.00	8.25	100%	14.95	0.00	14.95	100%	70.61	0.00	70.61	100%
Carbon Reduction	2033-2034	8.22	0.00	8.22	100%	14.89	0.00	14.89	100%	70.52	0.00	70.52	100%
Carbon Reduction	2034-2035	8.26	0.00	8.26	100%	14.97	0.00	14.97	100%	71.00	0.00	71.00	100%
Carbon Reduction	2035-2036	8.30	0.00	8.30	100%	15.04	0.00	15.04	100%	71.46	0.00	71.46	100%
Carbon Reduction	2036-2037	8.34	0.00	8.34	100%	15.12	0.00	15.12	100%	71.93	0.00	71.93	100%
Carbon Reduction	2037-2038	8.37	0.00	8.37	100%	15.20	0.00	15.20	100%	72.40	0.00	72.40	100%
Carbon Reduction	2038-2039	8.41	0.00	8.41	100%	15.28	0.00	15.28	100%	72.85	0.00	72.85	100%
Carbon Reduction	2039-2040	8.44	0.00	8.44	100%	15.36	0.00	15.36	100%	73.29	0.00	73.29	100%

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	WA Served	WA Unserved	WA Total	WA % of Peak Day Served	ID Served	ID Unserved	ID Total	ID % of Peak Day Served
Carbon Reduction	2019-2020	178.46	0.00	178.46	100%	95.47	0.00	95.47	100%
Carbon Reduction	2020-2021	180.05	0.00	180.05	100%	96.44	0.00	96.44	100%
Carbon Reduction	2021-2022	141.26	0.00	141.26	100%	97.31	0.00	97.31	100%
Carbon Reduction	2022-2023	141.49	0.00	141.49	100%	98.56	0.00	98.56	100%
Carbon Reduction	2023-2024	143.09	0.00	143.09	100%	100.06	0.00	100.06	100%
Carbon Reduction	2024-2025	144.58	0.00	144.58	100%	101.41	0.00	101.41	100%
Carbon Reduction	2025-2026	146.05	0.00	146.05	100%	101.59	0.00	101.59	100%
Carbon Reduction	2026-2027	147.47	0.00	147.47	100%	100.90	0.00	100.90	100%
Carbon Reduction	2027-2028	148.88	0.00	148.88	100%	101.86	0.00	101.86	100%
Carbon Reduction	2028-2029	150.26	0.00	150.26	100%	102.79	0.00	102.79	100%
Carbon Reduction	2029-2030	151.65	0.00	151.65	100%	103.73	0.00	103.73	100%
Carbon Reduction	2030-2031	152.90	0.00	152.90	100%	104.69	0.00	104.69	100%
Carbon Reduction	2031-2032	154.12	0.00	154.12	100%	105.69	0.00	105.69	100%
Carbon Reduction	2032-2033	155.32	0.00	155.32	100%	106.67	0.00	106.67	100%
Carbon Reduction	2033-2034	156.51	0.00	156.51	100%	106.84	0.00	106.84	100%
Carbon Reduction	2034-2035	157.65	0.00	157.65	100%	107.87	0.00	107.87	100%
Carbon Reduction	2035-2036	158.82	0.00	158.82	100%	108.93	0.00	108.93	100%
Carbon Reduction	2036-2037	159.94	0.00	159.94	100%	109.97	0.00	109.97	100%
Carbon Reduction	2037-2038	161.04	0.00	161.04	100%	111.04	0.00	111.04	100%
Carbon Reduction	2038-2039	162.13	0.00	162.13	100%	112.11	0.00	112.11	100%
Carbon Reduction	2039-2040	163.20	0.00	163.20	100%	113.19	0.00	113.19	100%

APPENDIX 7.2: PEAK DAY DEMAND TABLE
AVERAGE CASE

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medord/Roseburg Served	Medord/Roseburg Unserved	Medord/Roseburg Total	Medord/Roseburg % of Peak Day Served
Average Case	2019-2020	3.60	0.00	3.60	100%	6.92	0.00	6.92	100%	32.83	0.00	32.83	100%
Average Case	2020-2021	3.61	0.00	3.61	100%	6.98	0.00	6.98	100%	33.16	0.00	33.16	100%
Average Case	2021-2022	3.43	0.00	3.43	100%	6.52	0.00	6.52	100%	31.15	0.00	31.15	100%
Average Case	2022-2023	3.45	0.00	3.45	100%	6.58	0.00	6.58	100%	31.51	0.00	31.51	100%
Average Case	2023-2024	3.47	0.00	3.47	100%	6.64	0.00	6.64	100%	31.87	0.00	31.87	100%
Average Case	2024-2025	3.49	0.00	3.49	100%	6.69	0.00	6.69	100%	32.19	0.00	32.19	100%
Average Case	2025-2026	3.48	0.00	3.48	100%	6.68	0.00	6.68	100%	32.31	0.00	32.31	100%
Average Case	2026-2027	3.46	0.00	3.46	100%	6.66	0.00	6.66	100%	32.30	0.00	32.30	100%
Average Case	2027-2028	3.48	0.00	3.48	100%	6.69	0.00	6.69	100%	32.58	0.00	32.58	100%
Average Case	2028-2029	3.49	0.00	3.49	100%	6.72	0.00	6.72	100%	32.83	0.00	32.83	100%
Average Case	2029-2030	3.51	0.00	3.51	100%	6.76	0.00	6.76	100%	33.11	0.00	33.11	100%
Average Case	2030-2031	3.52	0.00	3.52	100%	6.78	0.00	6.78	100%	33.35	0.00	33.35	100%
Average Case	2031-2032	3.54	0.00	3.54	100%	6.82	0.00	6.82	100%	33.60	0.00	33.60	100%
Average Case	2032-2033	3.56	0.00	3.56	100%	6.85	0.00	6.85	100%	33.85	0.00	33.85	100%
Average Case	2033-2034	3.57	0.00	3.57	100%	6.89	0.00	6.89	100%	34.11	0.00	34.11	100%
Average Case	2034-2035	3.59	0.00	3.59	100%	6.92	0.00	6.92	100%	34.32	0.00	34.32	100%
Average Case	2035-2036	3.60	0.00	3.60	100%	6.95	0.00	6.95	100%	34.55	0.00	34.55	100%
Average Case	2036-2037	3.62	0.00	3.62	100%	6.99	0.00	6.99	100%	34.78	0.00	34.78	100%
Average Case	2037-2038	3.63	0.00	3.63	100%	7.02	0.00	7.02	100%	35.00	0.00	35.00	100%
Average Case	2038-2039	3.65	0.00	3.65	100%	7.06	0.00	7.06	100%	35.22	0.00	35.22	100%
Average Case	2039-2040	3.67	0.00	3.67	100%	7.10	0.00	7.10	100%	35.43	0.00	35.43	100%

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	WA Served	WA Unserved	WA Total	WA % of Peak Day Served	ID Served	ID Unserved	ID Total	ID % of Peak Day Served
Average Case	2019-2020	81.97	0.00	81.97	100%	44.12	0.00	44.12	100%
Average Case	2020-2021	82.40	0.00	82.40	100%	44.44	0.00	44.44	100%
Average Case	2021-2022	64.09	0.00	64.09	100%	43.52	0.00	43.52	100%
Average Case	2022-2023	64.13	0.00	64.13	100%	44.03	0.00	44.03	100%
Average Case	2023-2024	64.88	0.00	64.88	100%	44.70	0.00	44.70	100%
Average Case	2024-2025	65.48	0.00	65.48	100%	45.26	0.00	45.26	100%
Average Case	2025-2026	66.07	0.00	66.07	100%	45.26	0.00	45.26	100%
Average Case	2026-2027	66.61	0.00	66.61	100%	44.99	0.00	44.99	100%
Average Case	2027-2028	67.17	0.00	67.17	100%	45.37	0.00	45.37	100%
Average Case	2028-2029	67.71	0.00	67.71	100%	45.74	0.00	45.74	100%
Average Case	2029-2030	68.28	0.00	68.28	100%	46.12	0.00	46.12	100%
Average Case	2030-2031	68.81	0.00	68.81	100%	46.52	0.00	46.52	100%
Average Case	2031-2032	69.35	0.00	69.35	100%	46.95	0.00	46.95	100%
Average Case	2032-2033	69.85	0.00	69.85	100%	47.34	0.00	47.34	100%
Average Case	2033-2034	70.40	0.00	70.40	100%	47.79	0.00	47.79	100%
Average Case	2034-2035	70.93	0.00	70.93	100%	48.26	0.00	48.26	100%
Average Case	2035-2036	71.50	0.00	71.50	100%	48.74	0.00	48.74	100%
Average Case	2036-2037	72.00	0.00	72.00	100%	49.19	0.00	49.19	100%
Average Case	2037-2038	72.50	0.00	72.50	100%	49.65	0.00	49.65	100%
Average Case	2038-2039	73.00	0.00	73.00	100%	50.12	0.00	50.12	100%
Average Case	2039-2040	73.51	0.00	73.51	100%	50.61	0.00	50.61	100%

APPENDIX 7.2: PEAK DAY DEMAND TABLE
EXPECTED CASE

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medord/Roseburg Served	Medord/Roseburg Unserved	Medord/Roseburg Total	Medord/Roseburg % of Peak Day Served
Expected Case	2019-2020	8.27	0.00	8.27	100%	14.74	0.00	14.74	100%	67.27	0.00	67.27	100%
Expected Case	2020-2021	8.31	0.00	8.31	100%	14.87	0.00	14.87	100%	67.94	0.00	67.94	100%
Expected Case	2021-2022	7.78	0.00	7.78	100%	13.85	0.00	13.85	100%	63.46	0.00	63.46	100%
Expected Case	2022-2023	7.82	0.00	7.82	100%	13.98	0.00	13.98	100%	64.18	0.00	64.18	100%
Expected Case	2023-2024	7.87	0.00	7.87	100%	14.10	0.00	14.10	100%	64.86	0.00	64.86	100%
Expected Case	2024-2025	7.91	0.00	7.91	100%	14.21	0.00	14.21	100%	65.54	0.00	65.54	100%
Expected Case	2025-2026	7.89	0.00	7.89	100%	14.19	0.00	14.19	100%	65.70	0.00	65.70	100%
Expected Case	2026-2027	7.84	0.00	7.84	100%	14.12	0.00	14.12	100%	65.61	0.00	65.61	100%
Expected Case	2027-2028	7.87	0.00	7.87	100%	14.20	0.00	14.20	100%	66.20	0.00	66.20	100%
Expected Case	2028-2029	7.91	0.00	7.91	100%	14.27	0.00	14.27	100%	66.76	0.00	66.76	100%
Expected Case	2029-2030	7.95	0.00	7.95	100%	14.35	0.00	14.35	100%	67.34	0.00	67.34	100%
Expected Case	2030-2031	7.99	0.00	7.99	100%	14.42	0.00	14.42	100%	67.87	0.00	67.87	100%
Expected Case	2031-2032	8.02	0.00	8.02	100%	14.50	0.00	14.50	100%	68.39	0.00	68.39	100%
Expected Case	2032-2033	8.06	0.00	8.06	100%	14.57	0.00	14.57	100%	68.90	0.00	68.90	100%
Expected Case	2033-2034	8.10	0.00	8.10	100%	14.65	0.00	14.65	100%	69.41	0.00	69.41	100%
Expected Case	2034-2035	8.14	0.00	8.14	100%	14.72	0.00	14.72	100%	69.87	0.00	69.87	100%
Expected Case	2035-2036	8.17	0.00	8.17	100%	14.80	0.00	14.80	100%	70.33	0.00	70.33	100%
Expected Case	2036-2037	8.21	0.00	8.21	100%	14.87	0.00	14.87	100%	70.79	0.00	70.79	100%
Expected Case	2037-2038	8.24	0.00	8.24	100%	14.95	0.00	14.95	100%	71.25	0.00	71.25	100%
Expected Case	2038-2039	8.28	0.00	8.28	100%	15.03	0.00	15.03	100%	71.69	0.00	71.69	100%
Expected Case	2039-2040	8.32	0.00	8.32	100%	15.11	0.00	15.11	100%	72.12	0.00	72.12	100%

Peak Day Demand - Served and Unserved (MDth/day)
Before Resource Additions & Net of DSM Savings

Scenario	Gas Year	WA Served	WA Unserved	WA Total	WA % of Peak Day Served	ID Served	ID Unserved	ID Total	ID % of Peak Day Served
Expected Case	2019-2020	178.46	0.00	178.46	100%	95.47	0.00	95.47	100%
Expected Case	2020-2021	179.82	0.00	179.82	100%	96.37	0.00	96.37	100%
Expected Case	2021-2022	135.76	0.00	135.76	100%	94.17	0.00	94.17	100%
Expected Case	2022-2023	135.83	0.00	135.83	100%	95.36	0.00	95.36	100%
Expected Case	2023-2024	137.38	0.00	137.38	100%	96.79	0.00	96.79	100%
Expected Case	2024-2025	138.75	0.00	138.75	100%	98.06	0.00	98.06	100%
Expected Case	2025-2026	140.11	0.00	140.11	100%	98.04	0.00	98.04	100%
Expected Case	2026-2027	141.39	0.00	141.39	100%	97.40	0.00	97.40	100%
Expected Case	2027-2028	142.67	0.00	142.67	100%	98.30	0.00	98.30	100%
Expected Case	2028-2029	143.93	0.00	143.93	100%	99.16	0.00	99.16	100%
Expected Case	2029-2030	145.21	0.00	145.21	100%	100.03	0.00	100.03	100%
Expected Case	2030-2031	146.38	0.00	146.38	100%	100.94	0.00	100.94	100%
Expected Case	2031-2032	147.55	0.00	147.55	100%	101.90	0.00	101.90	100%
Expected Case	2032-2033	148.67	0.00	148.67	100%	102.82	0.00	102.82	100%
Expected Case	2033-2034	149.83	0.00	149.83	100%	103.80	0.00	103.80	100%
Expected Case	2034-2035	150.95	0.00	150.95	100%	104.81	0.00	104.81	100%
Expected Case	2035-2036	152.10	0.00	152.10	100%	105.85	0.00	105.85	100%
Expected Case	2036-2037	153.18	0.00	153.18	100%	106.86	0.00	106.86	100%
Expected Case	2037-2038	154.24	0.00	154.24	100%	107.88	0.00	107.88	100%
Expected Case	2038-2039	155.29	0.00	155.29	100%	108.93	0.00	108.93	100%
Expected Case	2039-2040	156.35	0.00	156.35	100%	109.99	0.00	109.99	100%

APPENDIX 7.2: ALTERNATE SUPPLY RESOURCES

Fossil Fuel Resources Modeled

Additional Resource	Size	Cost/Rates	Availability	Notes
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate	2021	Currently available unsubscribed capacity from Kingsgate to Spokane
Medford Lateral Exp	50,000 Dth / Day	$35M capital + GTN Rate	2022	Additional compression to facilitate more gas to flow from mainline GTN to Medford
Plymouth LNG	241,700 Dth w/70,500 Dth deliverability	NWP Rate	2021	Provides for peaking services and alleviates the need for costly pipeline expansions Pair with excess pipeline MDDO's to create firm transport

Renewable Resources Modeled

Resource	Dth per day	Dth per year	Levelized Cost Per Dth (Year 1)
Distributed Renewable Hydrogen Production - WA	166	60,509	$53.48
Distributed Renewable Hydrogen Production - OR	166	60,509	$50.00
Distributed LFG to RNG Production - WA	635	231,790	$13.53
Centralized LFG to RNG Production - WA	1,814	662,256	$11.73
Dairy Manure to RNG Production - WA	635	231,790	$40.70
Wastewater Sludge to RNG Production - WA	513	187,245	$18.95
Food Waste to RNG Production - WA	298	108,799	$40.68
Distributed LFG to RNG Production - OR	635	231,790	$13.53
Centralized LFG to RNG Production - OR	1,814	662,256	$11.73
Dairy Manure to RNG Production - OR	635	231,790	$40.23
Wastewater Sludge to RNG Production - OR	513	187,245	$18.75
Food Waste to RNG Production - OR	298	108,799	$40.21

Resources Not Modeled

Future Supply Resources	Size	Cost/Rates	Availability	Notes
Co. Owned LNG	600,000 Dth w/ 150,000 of deliverability	$75 Million plus $2 Million annual O&M	2024	On site, in service territory liquefaction and vaporization facility
Various pipelines – Pacific Connector, Cross-Cascades, etc.	Varies	Precedent Agreement Rates	2022	Requires additional mainline capacity on NWPL or GTN to get to service territory
Large Scale LNG	Varies	Commodity less Fuel	2024	Speculative, needs pipeline transport
In Ground Storage	Varies	Varies	Varies	Requires additional mainline transport to get to service territory
Satellite LNG	Varies	$13M capital cost plus 665k O&M	2022	provides for peaking services and alleviates the need for costly pipeline expansions. $3,000 per m3 with O&M assumed at 5.4%.

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 ongoing 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.

2020 Avista Natural Gas IRP

Technical Advisory Committee Meeting
June 17, 2020

2020 Natural Gas IRP schedule

•**TAC 1: Wednesday, June 17, 2020**: TAC meeting expectations, 2020 IRP process and schedule, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits, Demand, Weather Analysis and a Weather Planning Standard, and an energy efficiency update.

•**TAC 2: Thursday, August 6, 2020:** Market Analysis, Price Forecasts, Cost Of Carbon, demand forecasts and CPA results from AEG, Environmental Policies, fugitive emissions

•**TAC 3: Wednesday, September 30, 2020:** Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, overview of the major interstate pipelines and projects, and sensitivities and portfolio selection modeling.

•**TAC 4: Wednesday, November 18, 2020:** Review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

•**TAC 5: February 2021:** TAC final review meeting (if necessary)

Agenda

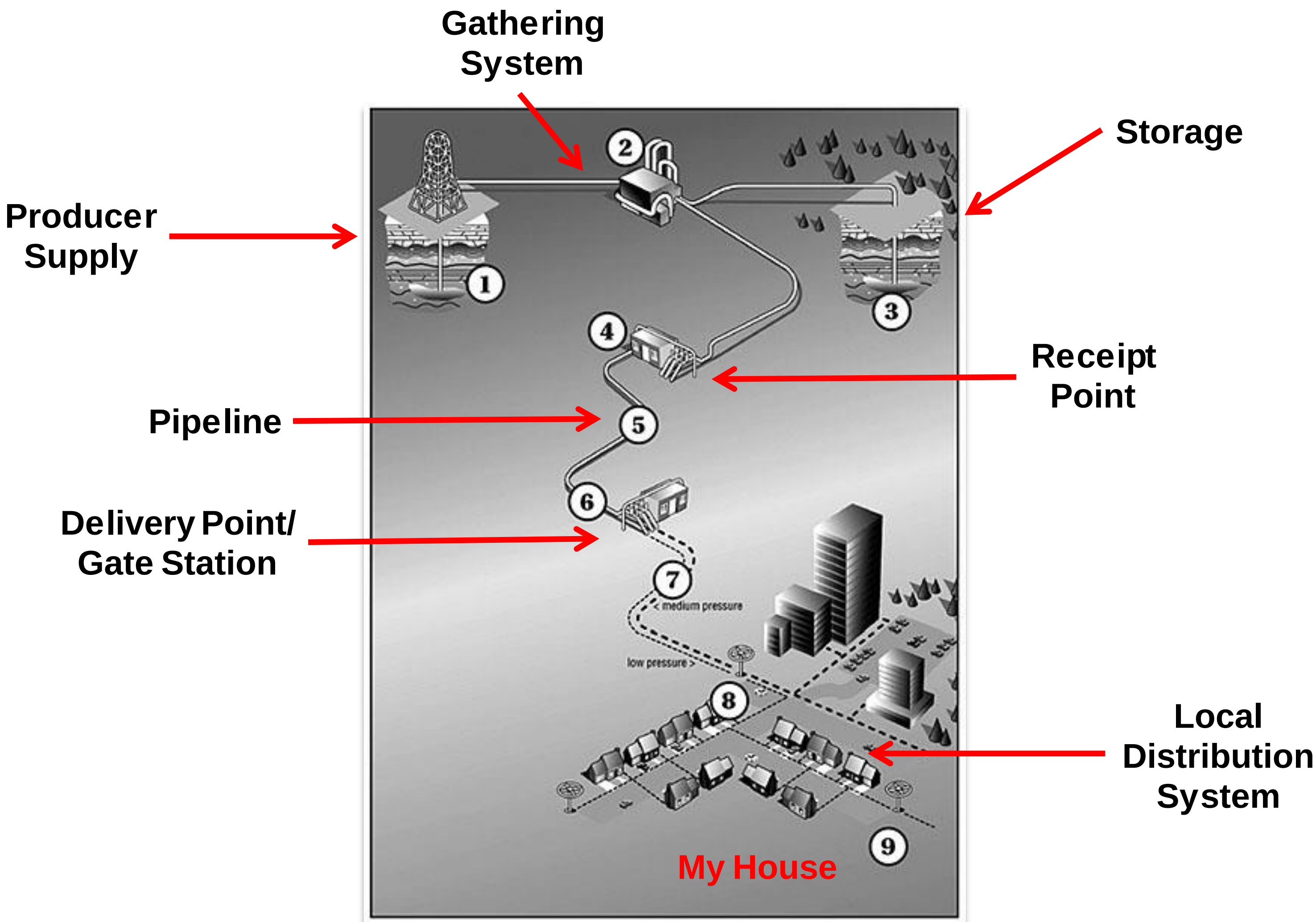
- TAC meeting expectations
- 2020 IRP process and schedule
- Actions from 2018 IRP
- Winter of 2018-2019 review
- Demand
- Demand Forecast Methodology
- Weather Analysis
- Weather Planning Standard
- Procurement Plan
- Resource Optimization benefits
- Energy efficiency update

Avista's IRP Process

- Comprehensive analysis bringing demand forecasting and existing and potential supply-side and demand-side resources together into a 20-year, risk adjusted least-cost plan
- Considers:
  - Customer growth and usage
  - Weather planning standard
  - Demand-side management opportunities
  - Existing and potential supply-side resource options
  - Risk
  - Public participation through Technical Advisory Committee meetings (TAC)
  - Distribution upgrades
- 2018 IRP filed in all three jurisdictions on

August 31, 2018 and acknowledged

The Natural Gas System



2018 Avista Natural Gas IRP – Action Plan

1. Avista's 2020 IRP will contain an individual measure level for dynamic DSM program structure in its analytics. In prior IRP's, it was a deterministic method based on based on Expected Case assumptions. In the 2020 IRP, each portfolio will have the ability to select conservation to meet unserved customer demand. Avista will explore methods to enable a dynamic analytical process for the evaluation of conservation potential within individual portfolios.
2. Work with Staff to get clarification on types of natural gas distribution system analyses for possible inclusion in the 2020 IRP.
3. Work with Staff to clarify types of distribution system costs for possible inclusion in our avoided cost calculation.
4. Revisit coldest on record planning standard and discuss with TAC for prudency.
5. Provide additional information on resource optimization benefits and analyze risk exposure.
6. DSM—Integration of ETO and AEG/CPA data. Discuss the integration of ETO and AEG/CPA data as well as past program(s) experience, knowledge of current and developing markets, and future codes and standards.
7. Carbon Costs – consult Washington State Commission's Acknowledgement Letter Attachment in its 2017 Electric IRP (Docket UE-161036), where emissions price modeling is discussed, including the cost of risk of future greenhouse gas regulation, in addition to known regulations.
8. Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board.

2018 Avista Natural Gas IRP Action Plan cont.

- 9. 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 requires 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.
- – Construction of gas infrastructure associated with growth
- – 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

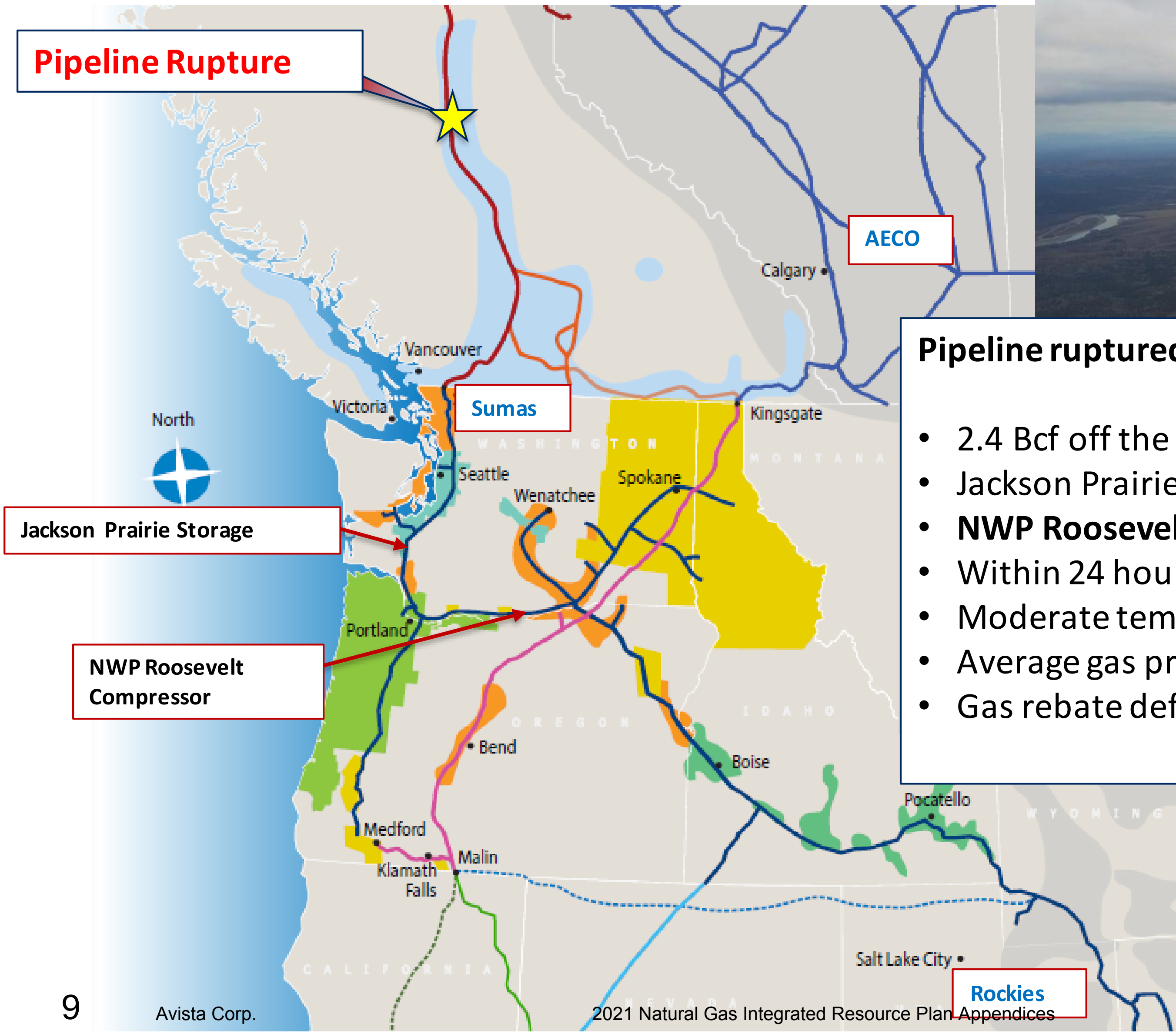
- An updated table 8.4 for those distribution projects in Oregon:
- Location
- Klamath Falls, OR
- Sutherlin, OR

- 10. Avista will work with members of the OPUC to determine an alternative stochastic approach to Monte Carlo analysis prior to Avista's 2020 IRP and share any recommendations with the TAC members.

That Could Never Happen!

Gas Supply Winter 2018-2019

Enbridge Pipeline Rupture

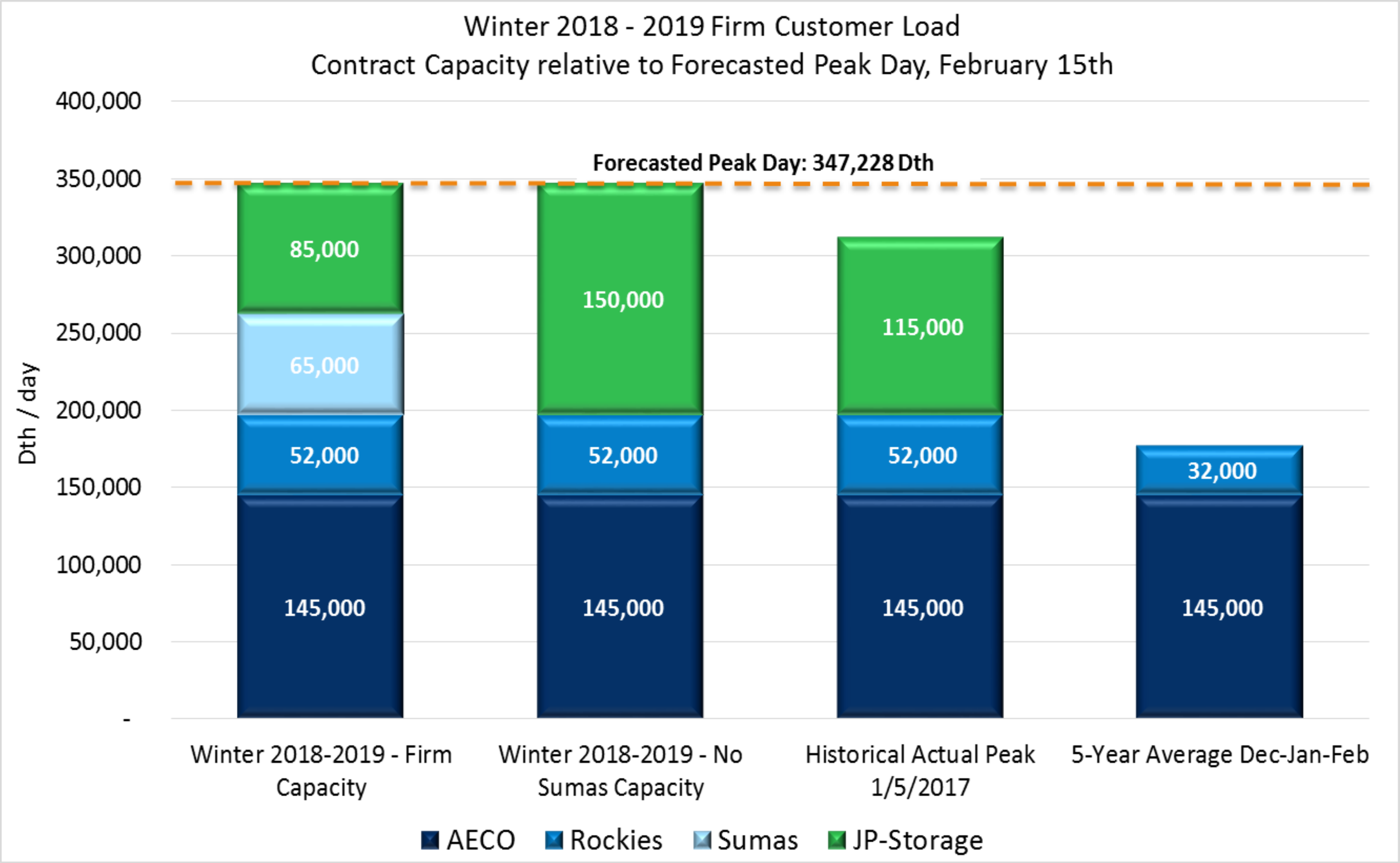


Pipeline ruptured October 9th

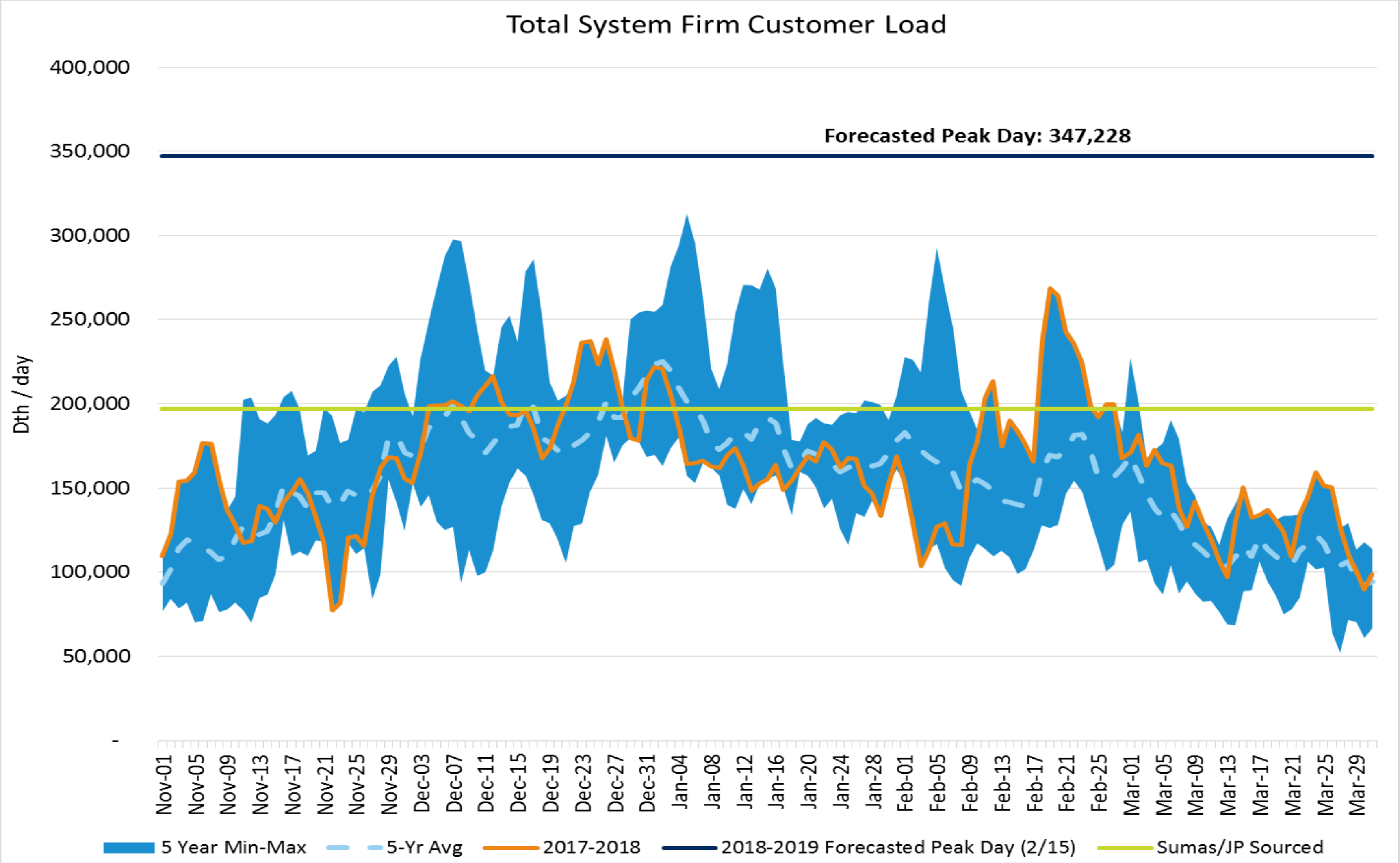
- 2.4 Bcf off the system
- Jackson Prairie Storage - down
- **NWP Roosevelt** compressor maintenance
- Within 24 hours, 50% of demand came off
- Moderate temperatures across Pacific NW
- Average gas prices < $3/Dth
- Gas rebate deferral balances growing

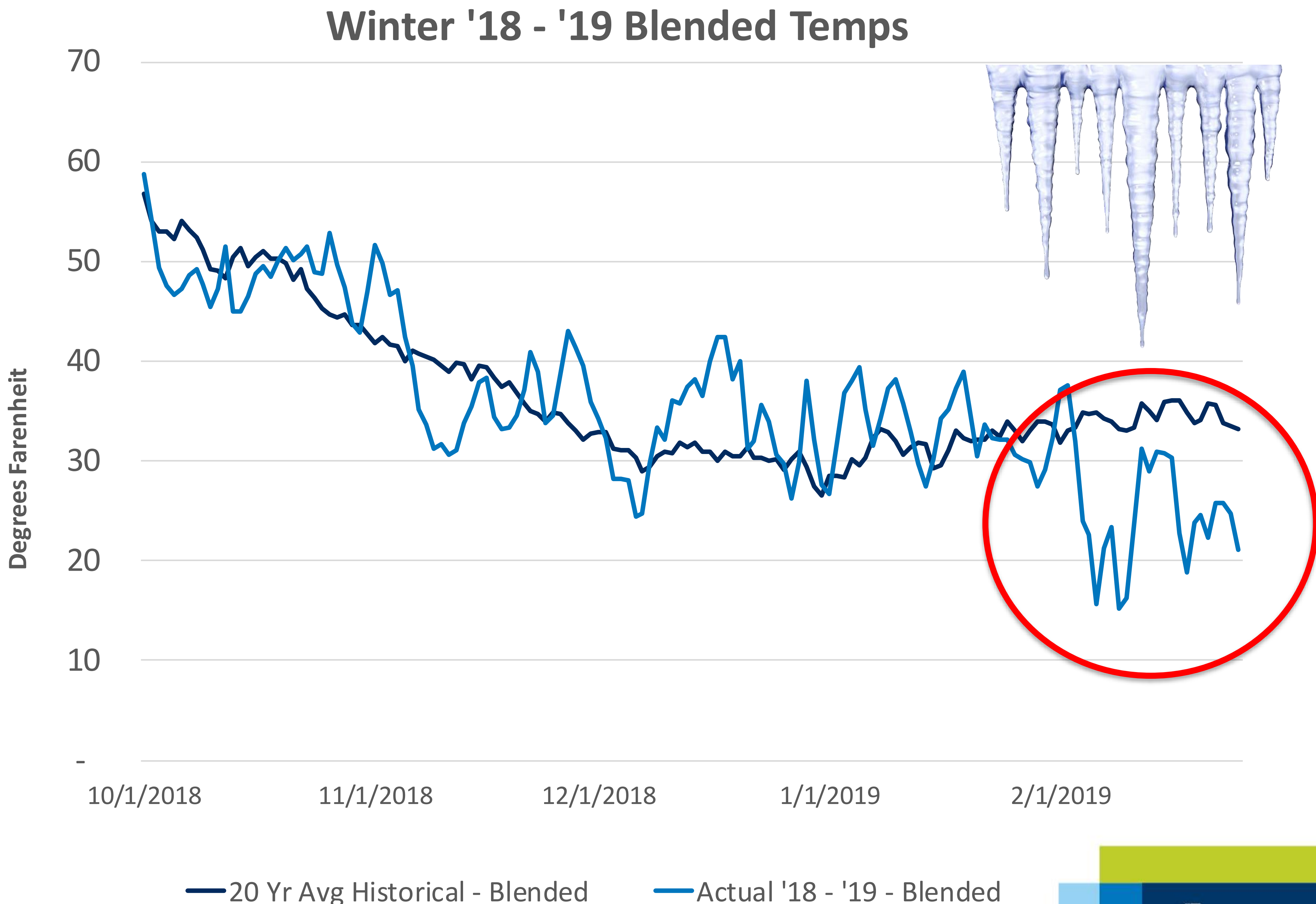
Source: NWGA 2017 Annual Outlook

Winter 2018-2019 Outlook



Historical Winter Firm Customer Load




Winter '18 - '19 Blended Temps
70
60
50
40
30
20
10
-
Degrees Farenheit
10/1/2018
11/1/2018
12/1/2018
1/1/2019
2/1/2019
20 Yr Avg Historical - Blended
Actual '18 - '19 - Blended

*Avg. weather

Operation Flow Order (OFO)

- **Northwest Pipeline (NWP) Operational Flow Order**

An OFO is declared to provide the needed displacement on NWP's system to meet firm commitments. When scheduled quantities exceed physical capacity, NWP is in a potential OFO situation. In other words,

****Avista must flow gas from west to east.****

US Storage

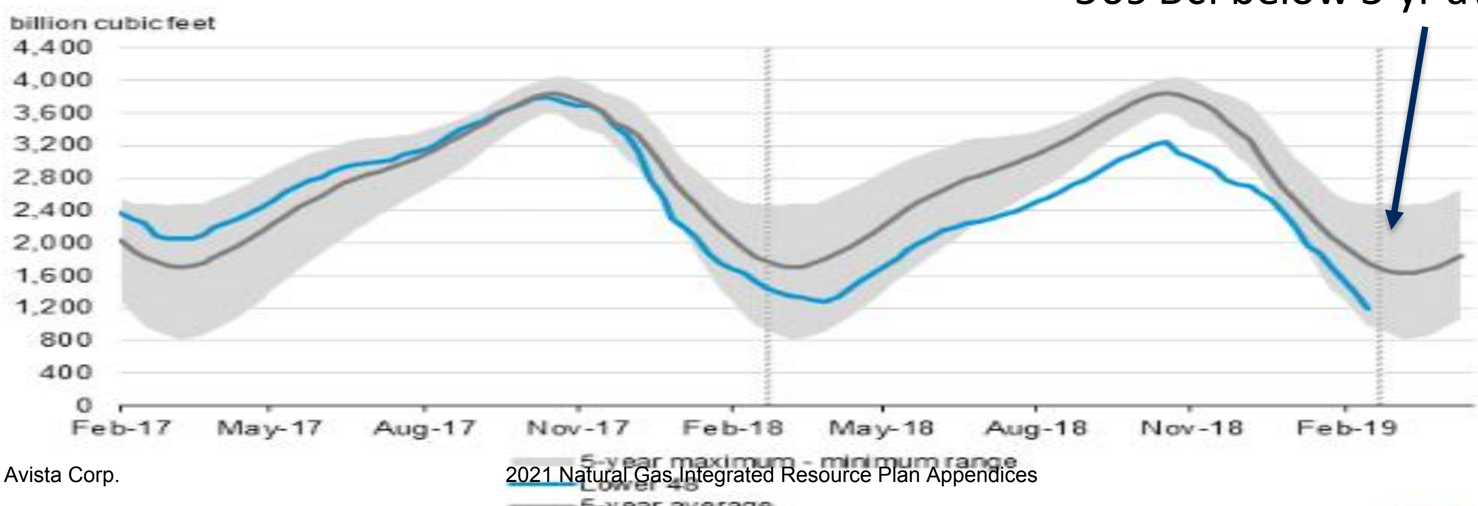
Working gas in underground storage, Lower 48 states

Summary text | CSV | JSN

	Stocks billion cubic feet (Bcf)				Historical Comparisons: Year ago (03/08/18)		Historical Comparisons: 5-year average (2014-18)	
Region	03/08/19	03/01/19	net change	implied flow	Bcf	% change	Bcf	% change
East	262	311	-49	-49	320	-18.1	338	-22.5
Midwest	287	338	-51	-51	354	-18.9	398	-27.9
Mountain	66	73	-7	-7	94	-29.8	116	-43.1
Pacific	102	112	-10	-10	170	-40.0	199	-48.7
South Central	469	557	-88	-88	607	-22.7	705	-33.5
Salt	129	180	-51	-51	186	-30.6	195	-33.8
Nonsalt	340	377	-37	-37	420	-19.0	510	-33.3
Total	1,186	1,390	-204	-204	1,545	-23.2	1,755	-32.4

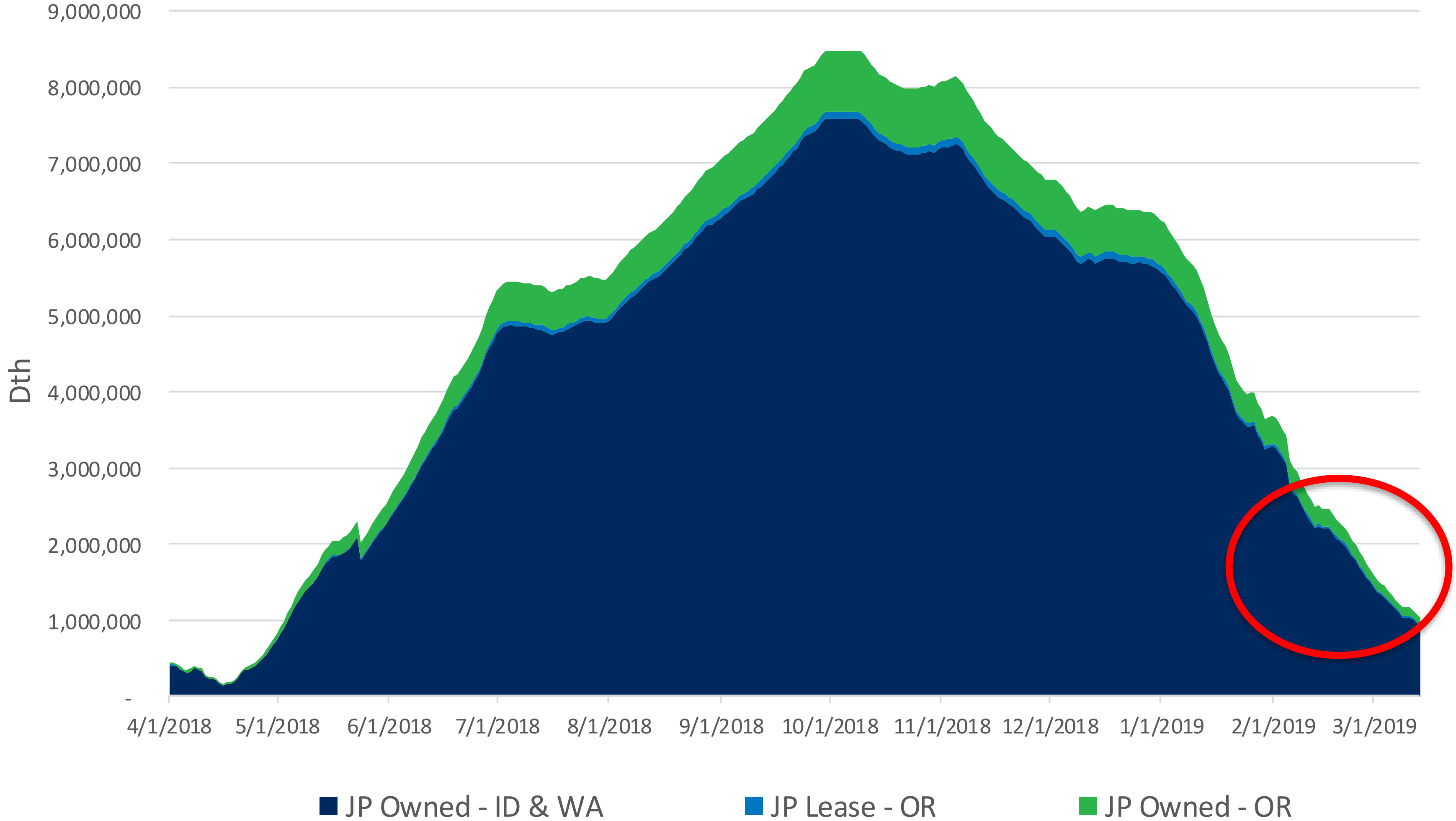
Totals may not equal sum of components because of independent rounding.

569 Bcf below 5 yr avg

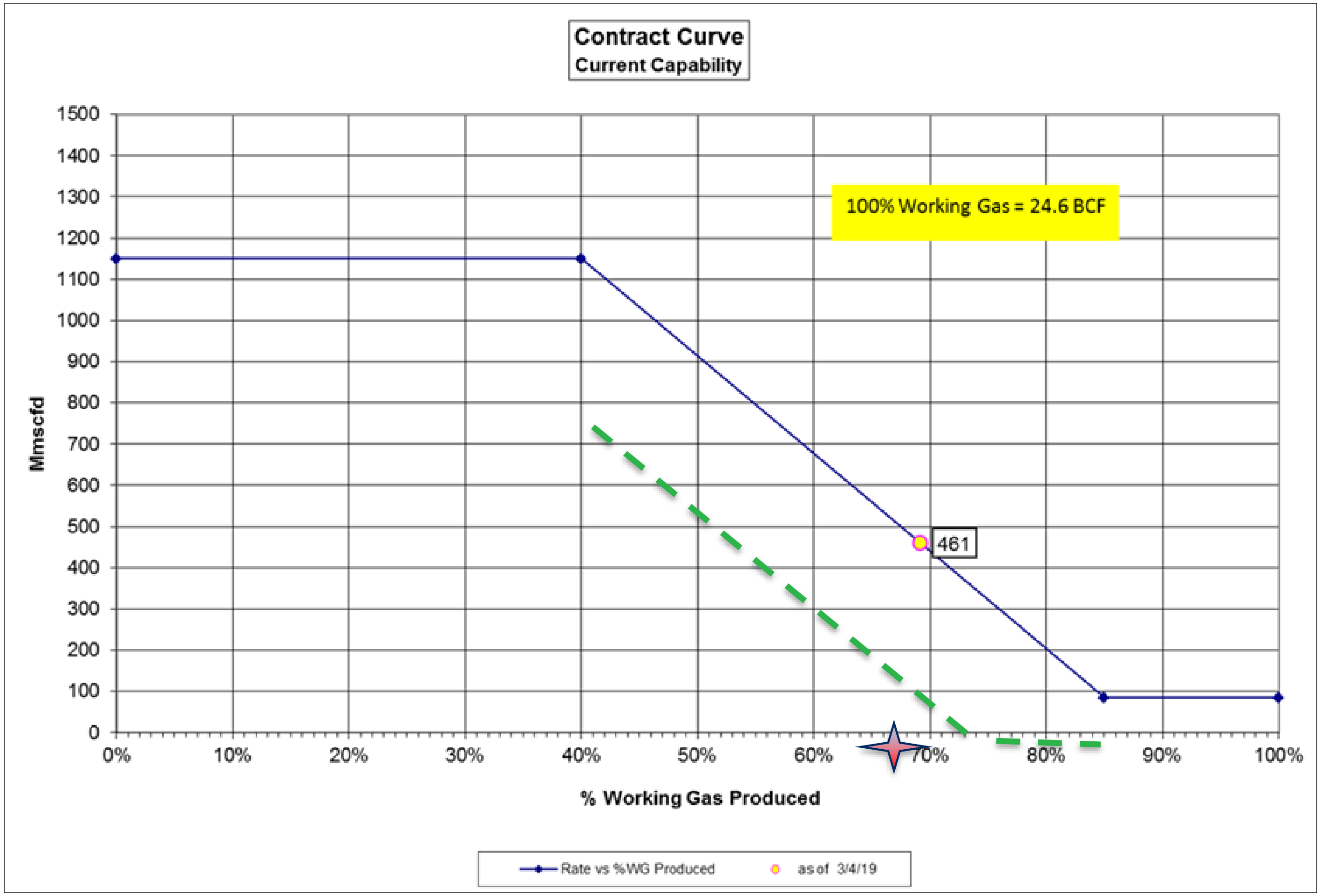


JP Storage Levels

Avista – 1.0 bcf
Puget – 2.2 bcf
Nwp – 3.5 bcf



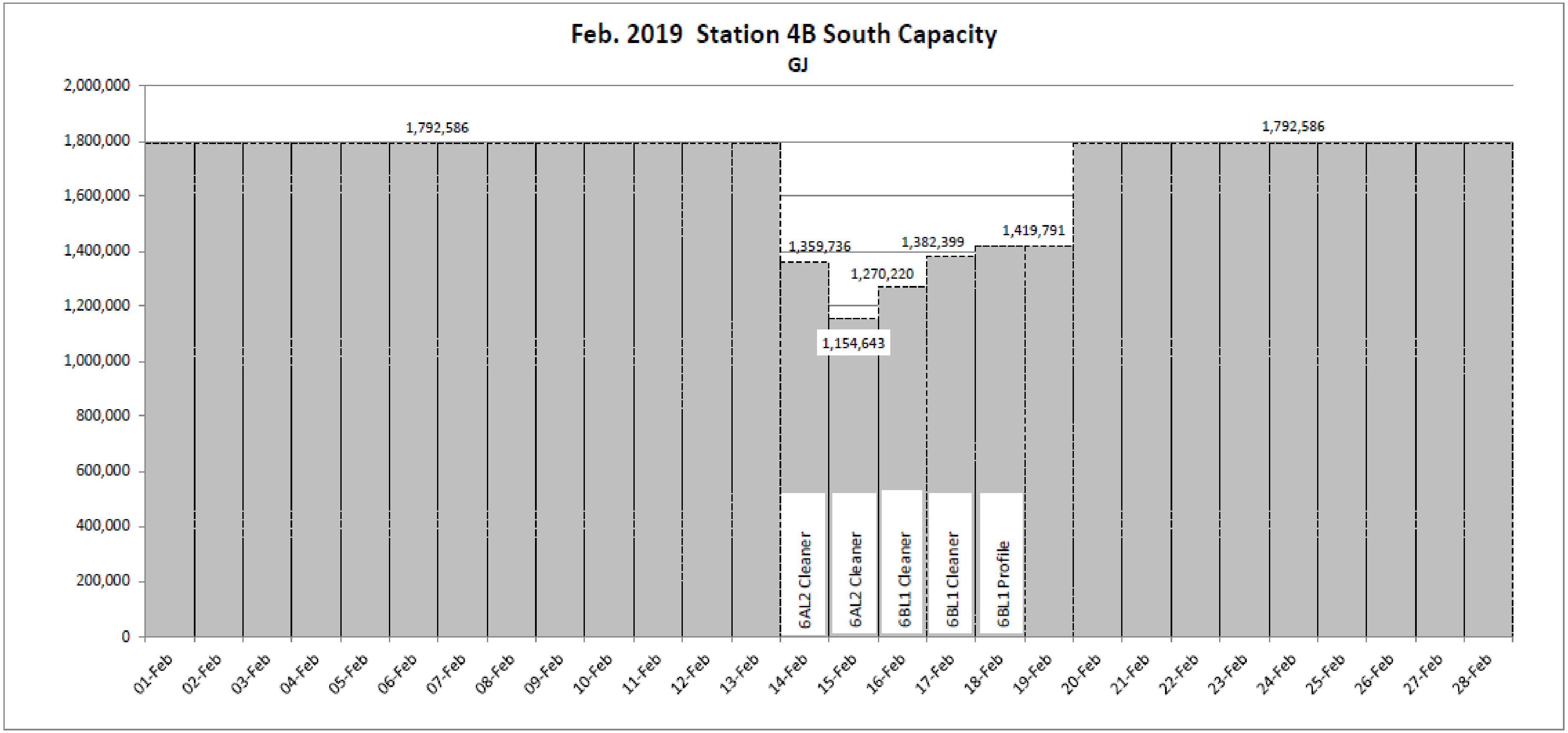
Jackson Prairie Compressor C-9



Compressor
Failed
2/10/19

Reduction of withdrawal capability by approx. 200-300 MMscfd
Avista withdrawal ability < 90 MMscfd (JP demand 50 – 90 MMscfd)

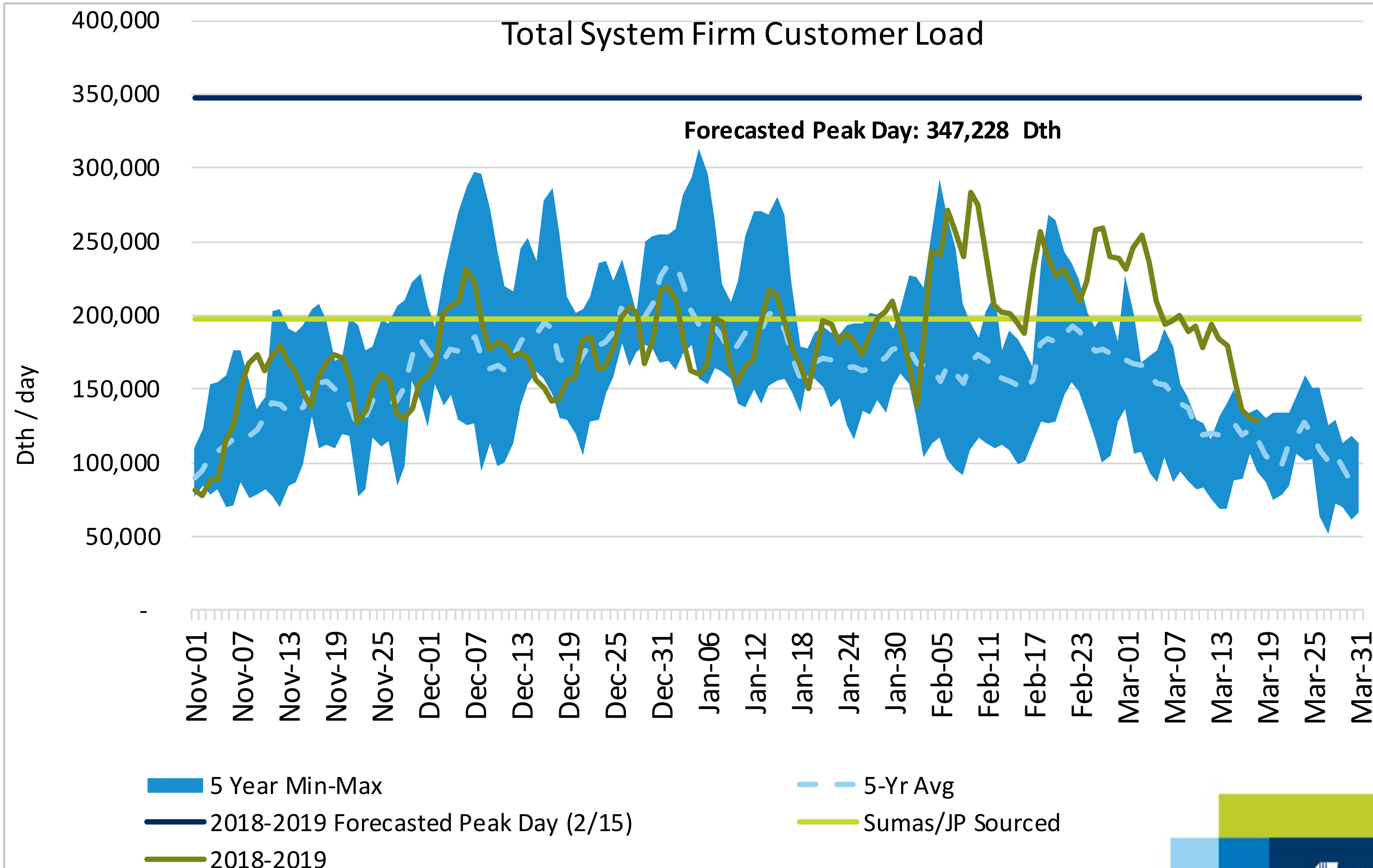
Enbridge Capacity Cuts



Pipeline Entitlements

- Entitlements are used to balance demand
  - Entitlement tolerances are tiered
    - 13%, 8%, 5%, 3% depending on severity of issue
  - Overrun entitlement
    - Total demand must not exceed nominations by the prescribed level
    - Example: Avista nominates 150,000 Dth on pipeline, demand must be AT MOST 169,500 Dth
  - Entitlement penalties
    - Greater of $10.00/ dth or 4x the highest midpoint price in region

Historical and Current Winter Loads



Planning Outcomes changes

- In order to reduce the risk around not being able to serve load on a peak day with late winter weather Avista is moving it's peak day from 2/15 to 2/28 for the WA/ID and La Grande

Avista's Demand Overview

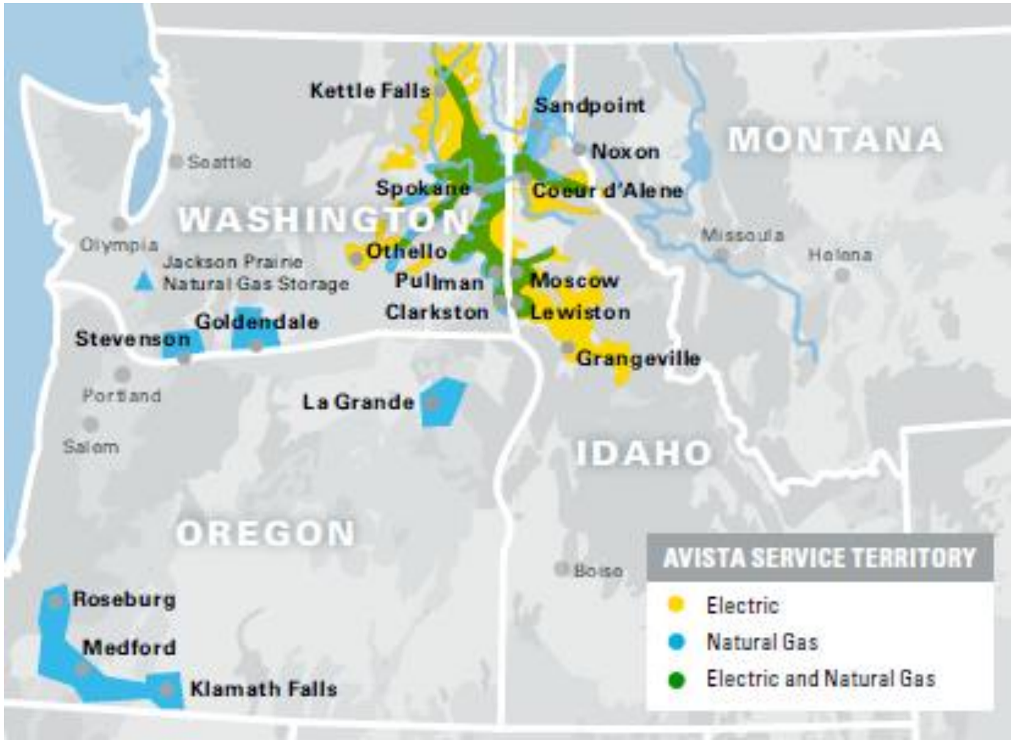
Tom Pardee
Manager of Natural Gas Planning

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 1.5 million
    - 385,000 electric customers
    - 360,000 natural gas customers

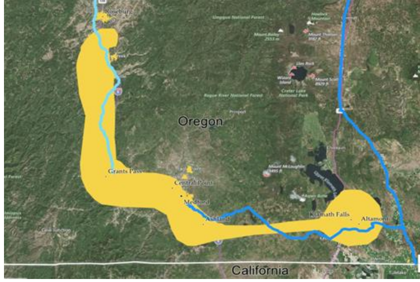
- Has one of the smallest carbon footprints among America's 100 largest investor-owned utilities

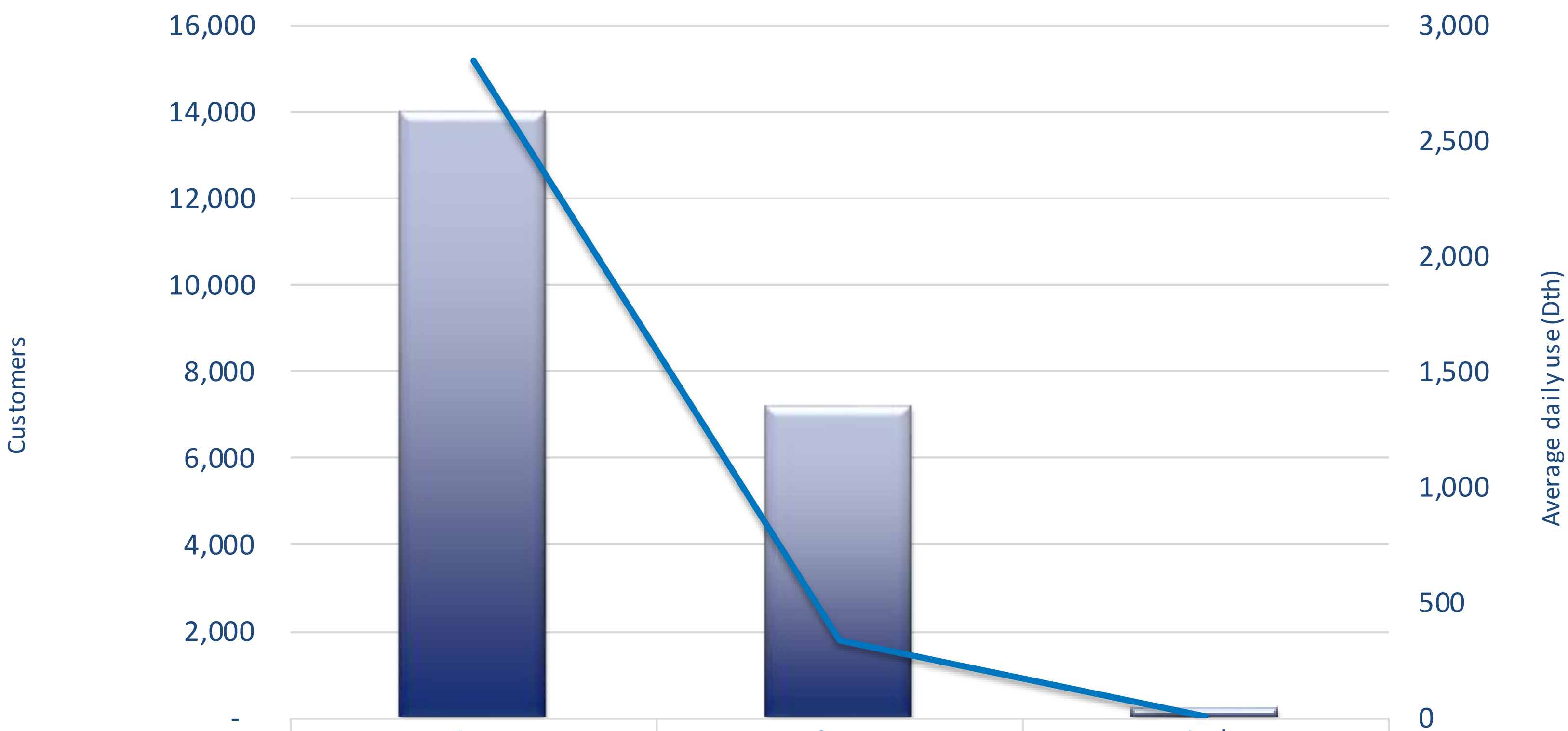
- Committed to environmental stewardship and efficient use of resources



State	Total Customers	% of Total
Washington	170,000	47%
Oregon	103,000	29%
Idaho	87,000	24%
Total	360,000	100%

Klamath Falls

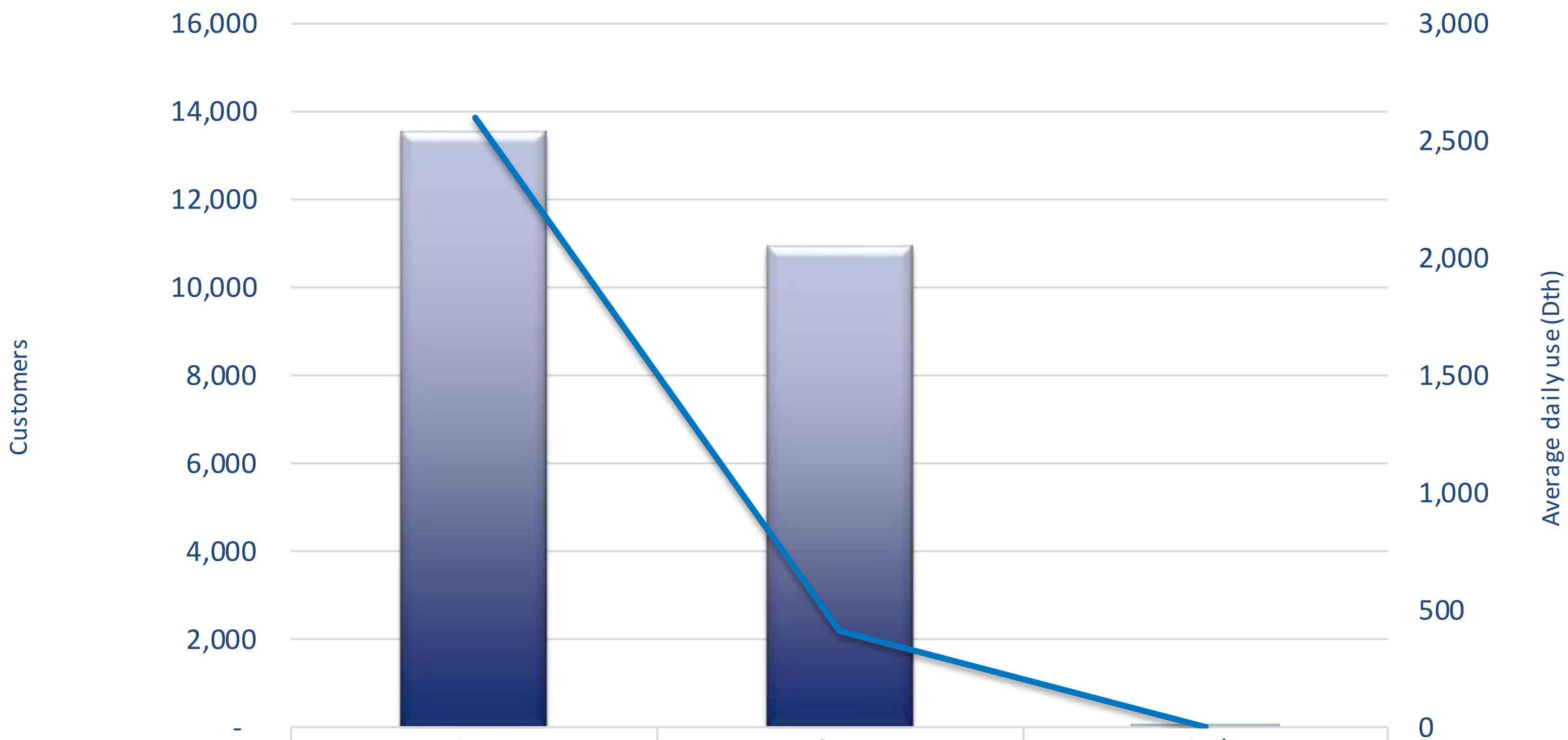




	Res	Com	Ind
Average demand	2,628	1,352	44
Customers	15,192	1,787	6

Average 2019 Temp Fahrenheit 47

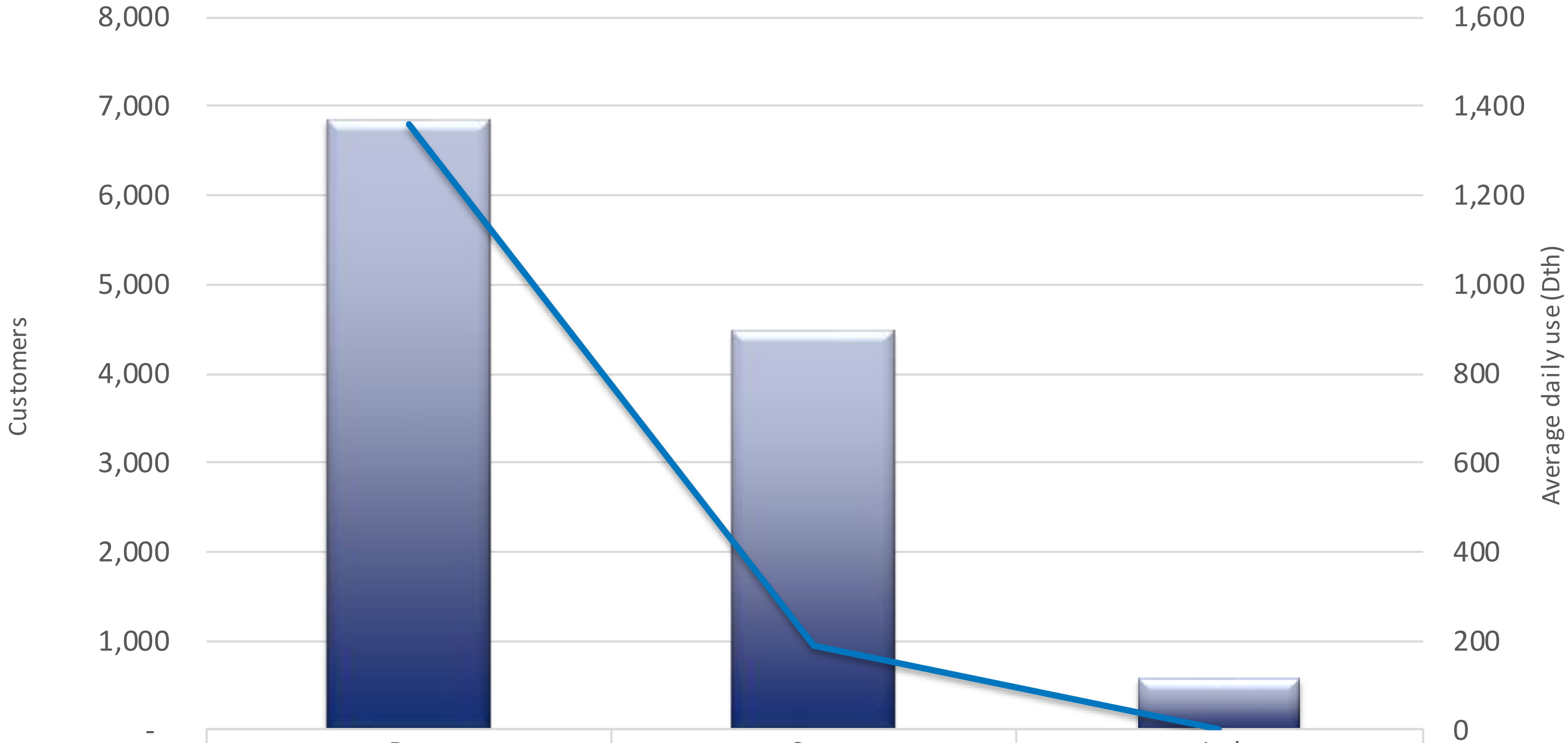
Roseburg



	Res	Com	Ind
Average demand	2,537	2,051	7
Customers	13,889	2,189	2

Average 2019 Temp Fahrenheit 55

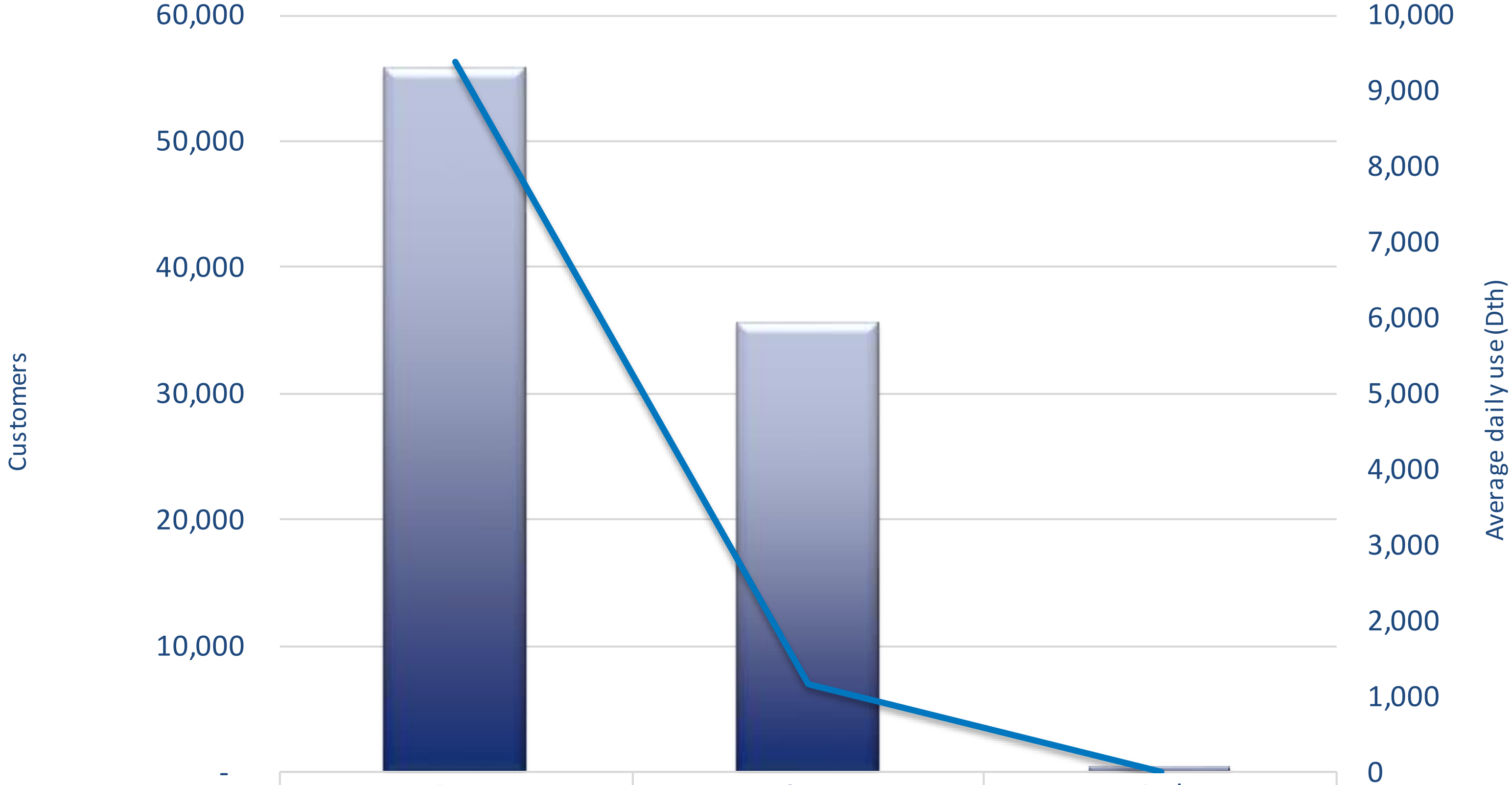
La Grande



	Res	Com	Ind
Demand	1,371	896	116
Customers	6,794	943	3

Average 2019 Temp Fahrenheit 47

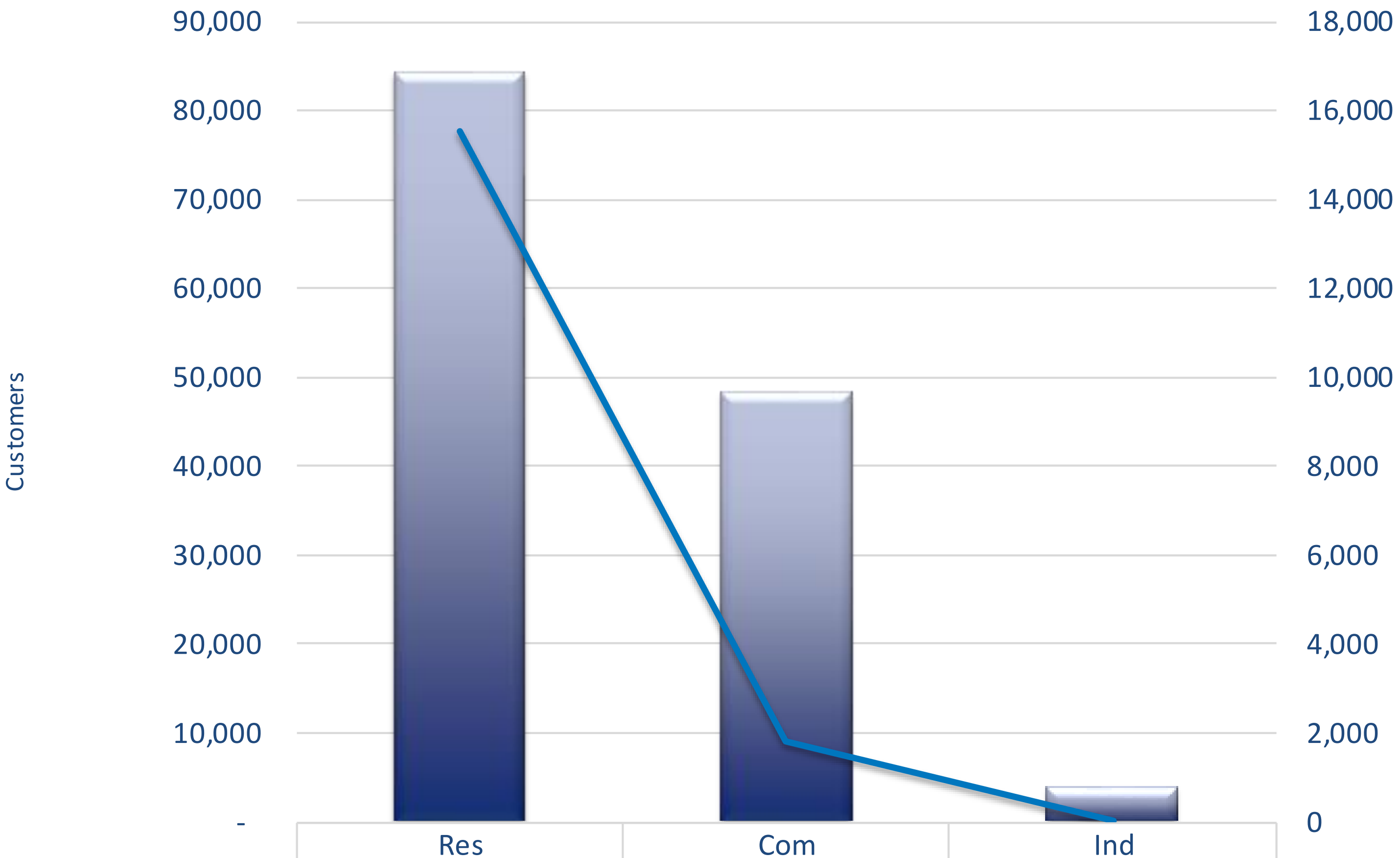
Medford



	Res	Com	Ind
Average demand	9,312	5,939	62
Customers	56,354	7,038	14

Average 2019 Temp Fahrenheit 55

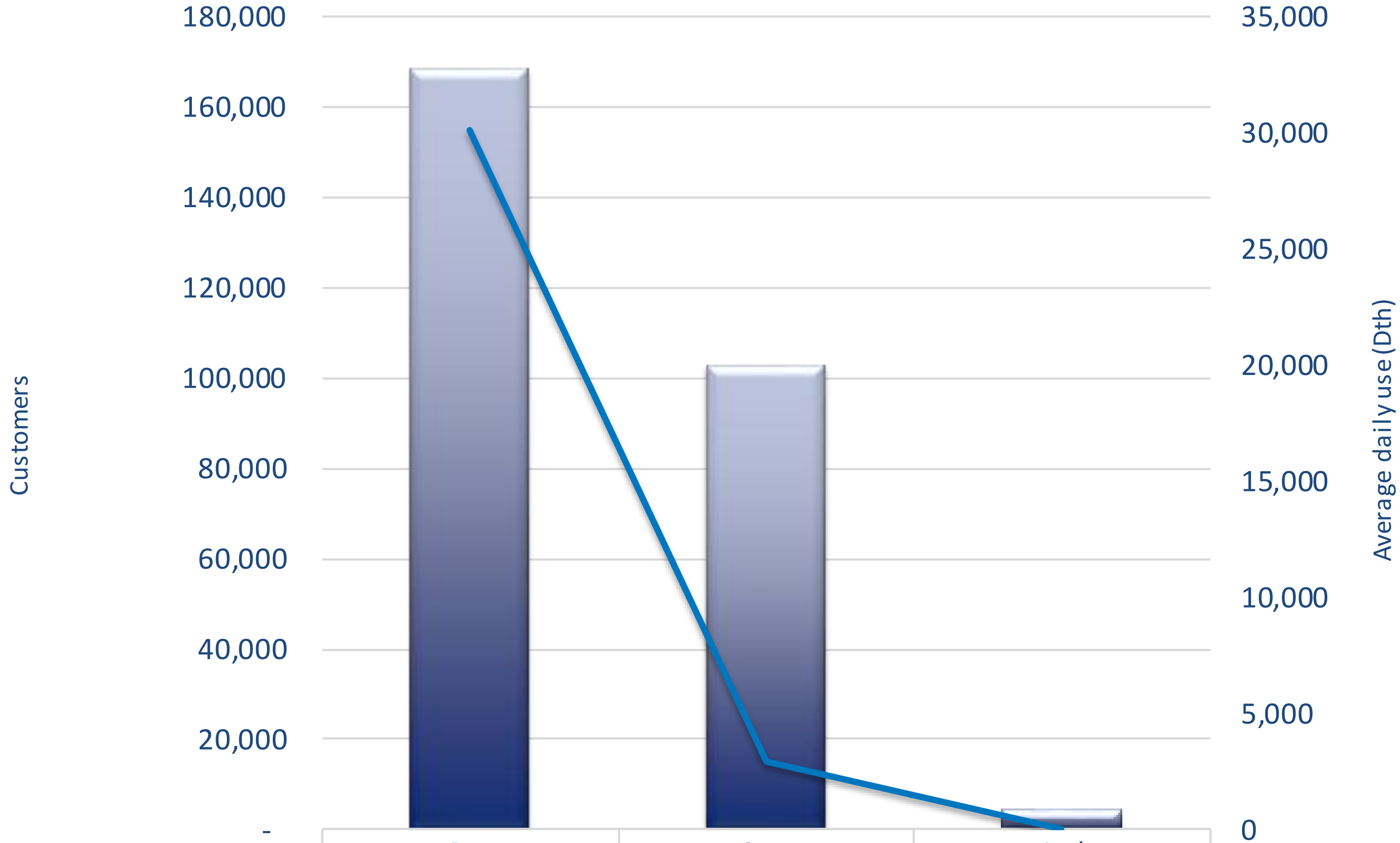
Idaho



	Res	Com	Ind
Average demand	16,872	9,668	800
Customers	77,804	9,164	89

Average 2019 Temp Fahrenheit 47

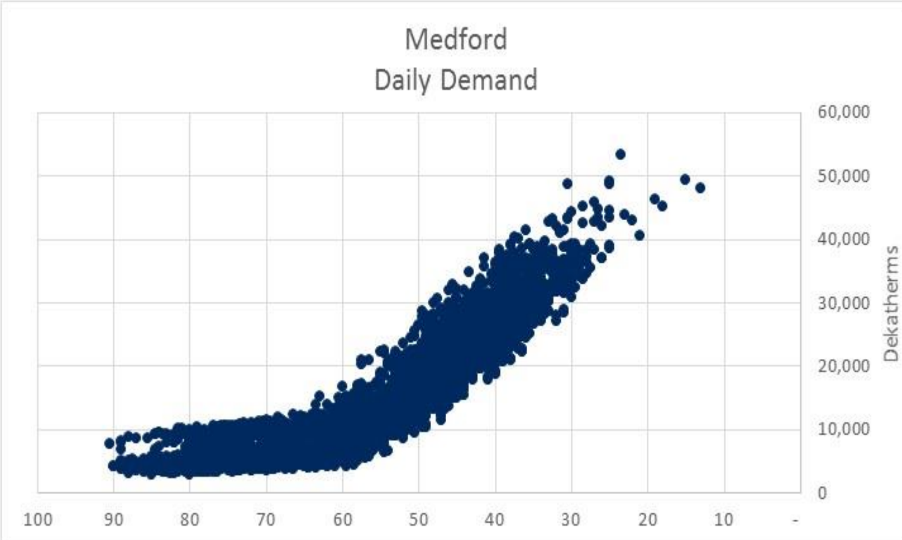
Washington

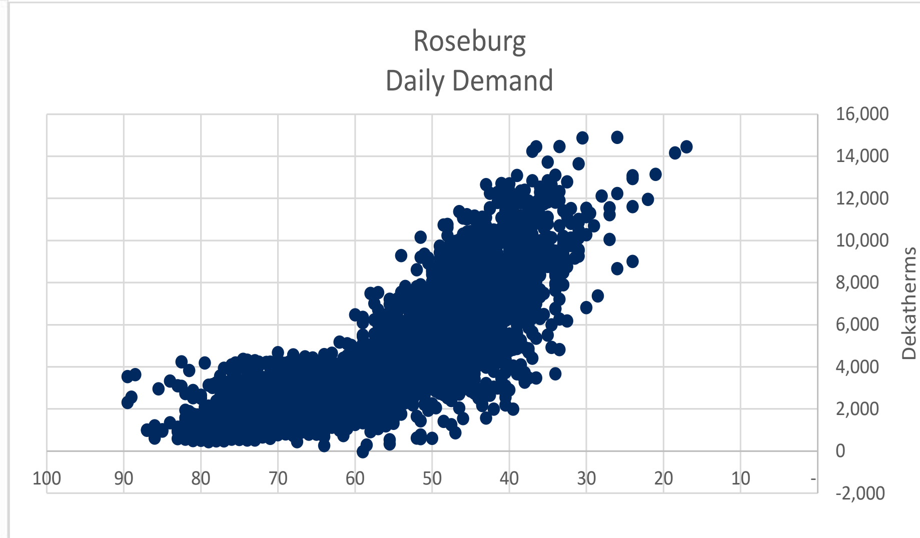


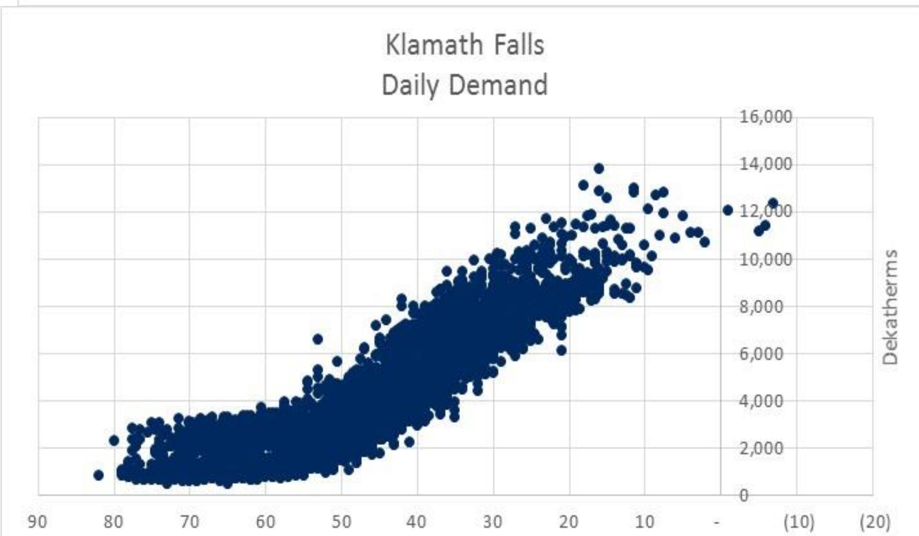
	Res	Com	Ind
Average demand	32,792	19,999	810
Customers	155,069	14,980	130

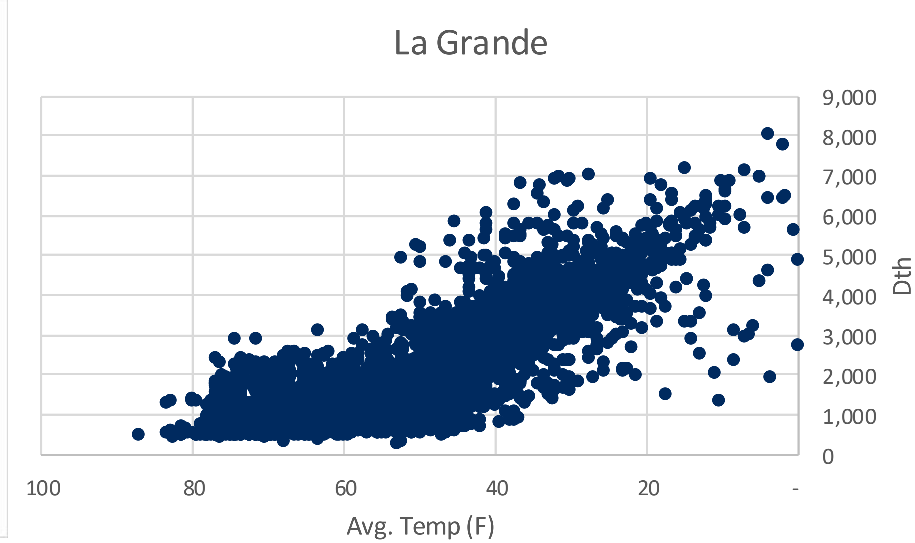
Average 2019 Temp Fahrenheit 47

OR Daily Demand Profiles

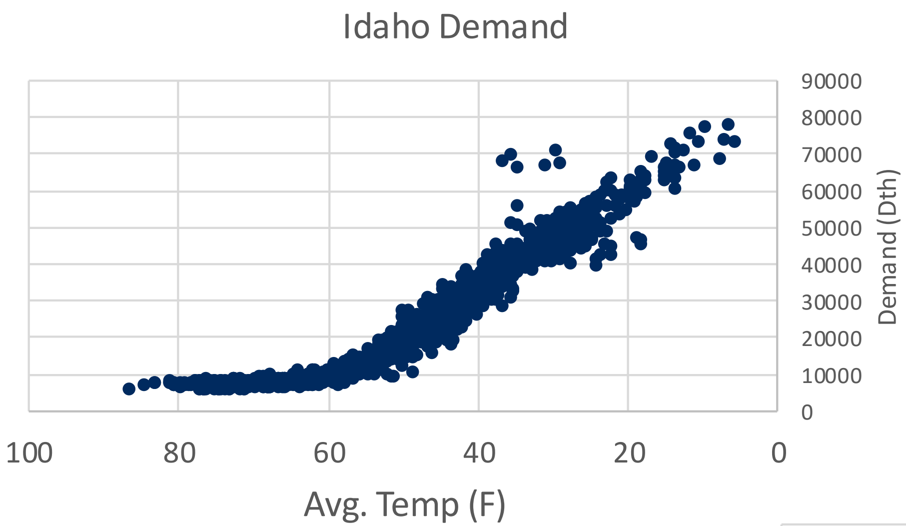


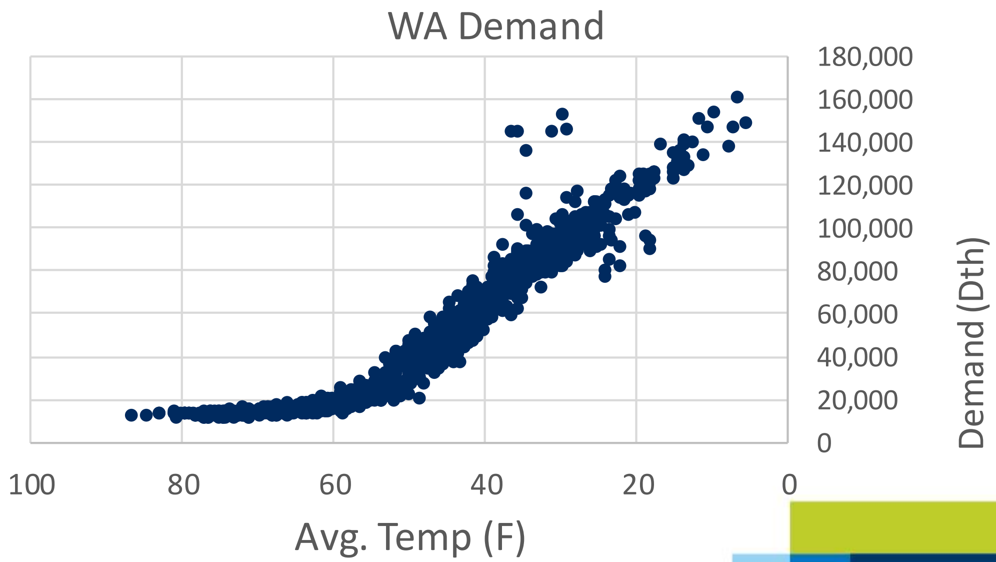






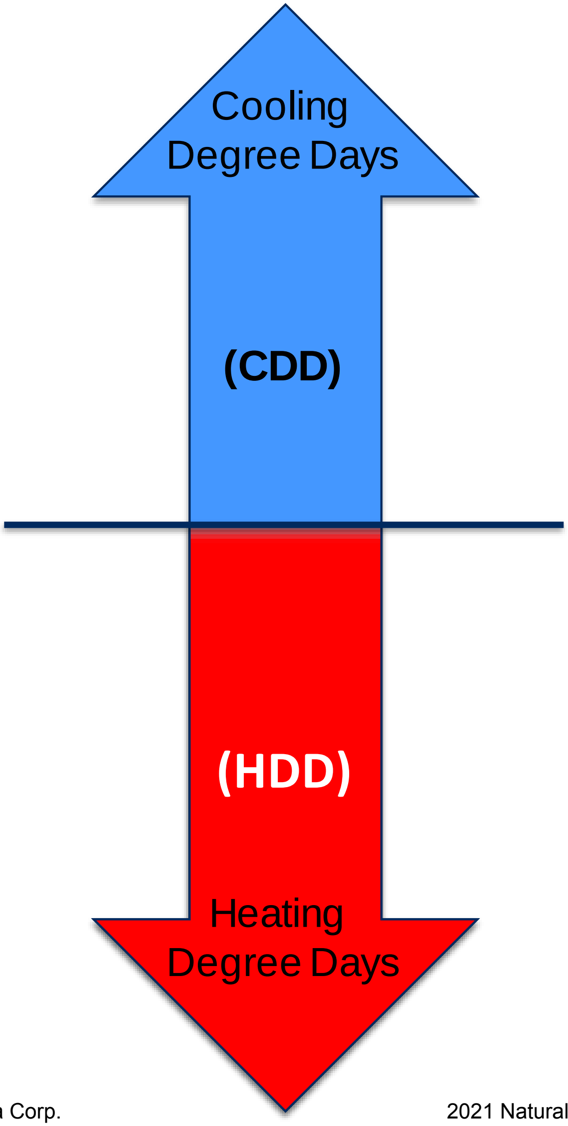
WA-ID Daily Demand Profiles





Demand Forecast Methodology

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

Weather

- NOAA 20 year actual average daily HDD's (2000-2019)
- Peak weather includes two winter storms (5 day duration), one in December and one in February
- Planning Standard
- Sensitivity around planning standard including
  - Normal/Average
  - Monte Carlo simulation

Base Coefficients

Planning Area - Residential Class	2 year	3 year	5 year
Roseburg (Oregon)	0.041949146	0.040148823	0.03765259
Medford (Oregon)	0.04748832	0.047701223	0.04716918
La Grande (Oregon)	0.069994892	0.068986632	0.073506326
Klamath Falls (Oregon)	0.035881027	0.034536108	0.033843554
Idaho	0.048375922	0.046698825	0.046092068
Washington	0.047248771	0.046575066	0.047525773

*Base Coefficients

*Historic Data - July and August Average

Heat Coefficients

Planning Area - Residential Class	2 Year	3 Year	5 Year
Roseburg (Oregon)	0.008829	0.008046	0.00699
Medford (Oregon)	0.00639	0.0065	0.006068
La Grande (Oregon)	0.006223	0.007297	0.00665
Klamath Falls (Oregon)	0.005284	0.005268	0.004902
Idaho	0.006445	0.006344	0.005896
Washington	0.006307	0.006313	0.005957

*Avg. of monthly heat coefficient

*Historic Data – adjusted by price elasticity and DSM

Demand Modeling Equation – a closer look

SENDOUT® requires inputs expressed in the below format to compute daily demand in dekatherms. The **base** and **weather sensitive** usage (degree-day usage) factors are developed outside the model and capture a variety of demand usage assumptions.

Table 3.2 Basic Demand Formula

# of customers **x** Daily **base usage** / customer
Plus
# of customers **x** Daily **weather sensitive** usage / customer

Developing a Reference Case

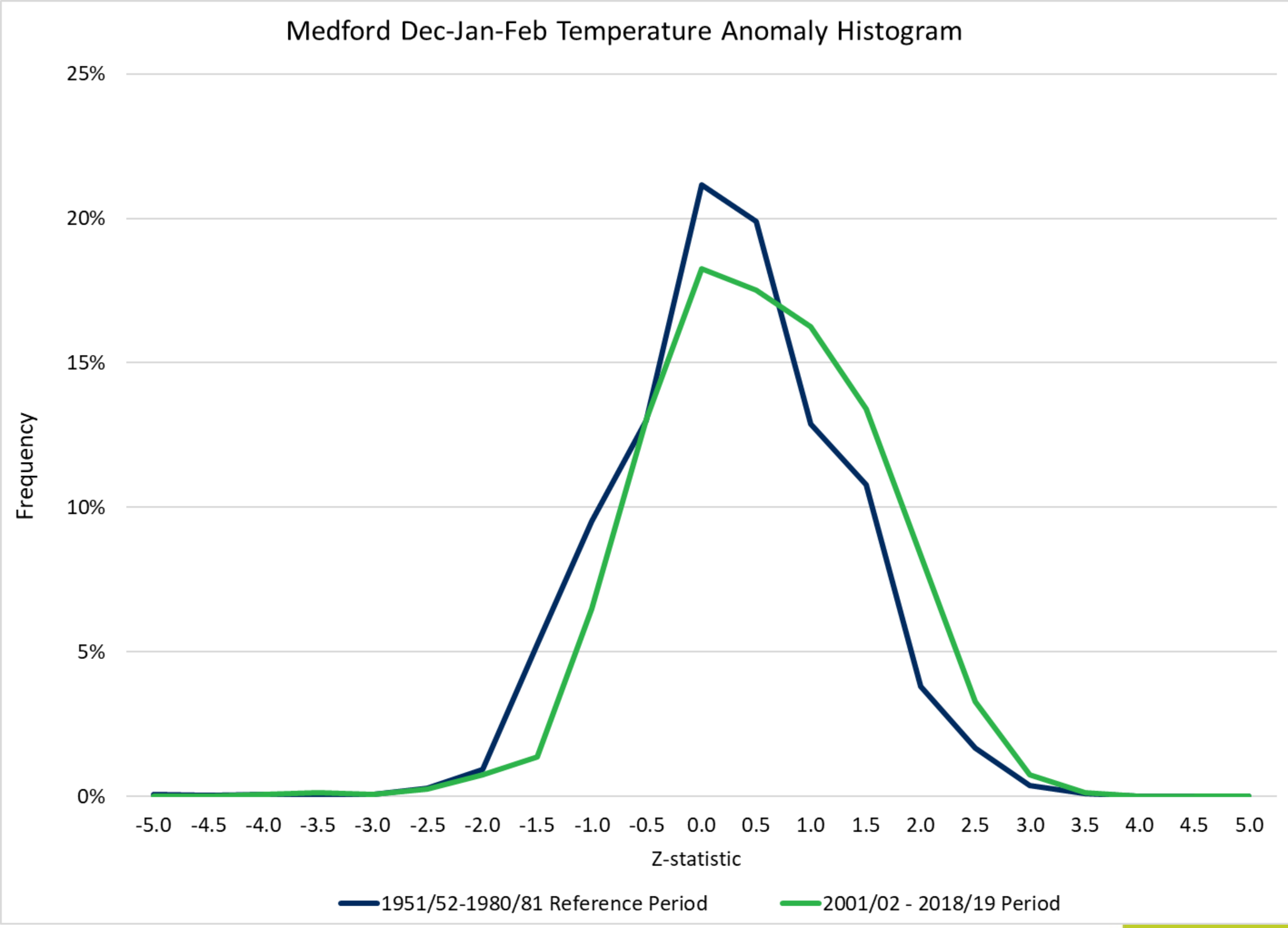
Customer count forecast + Use per customer coefficients + Weather = Reference Case Demand

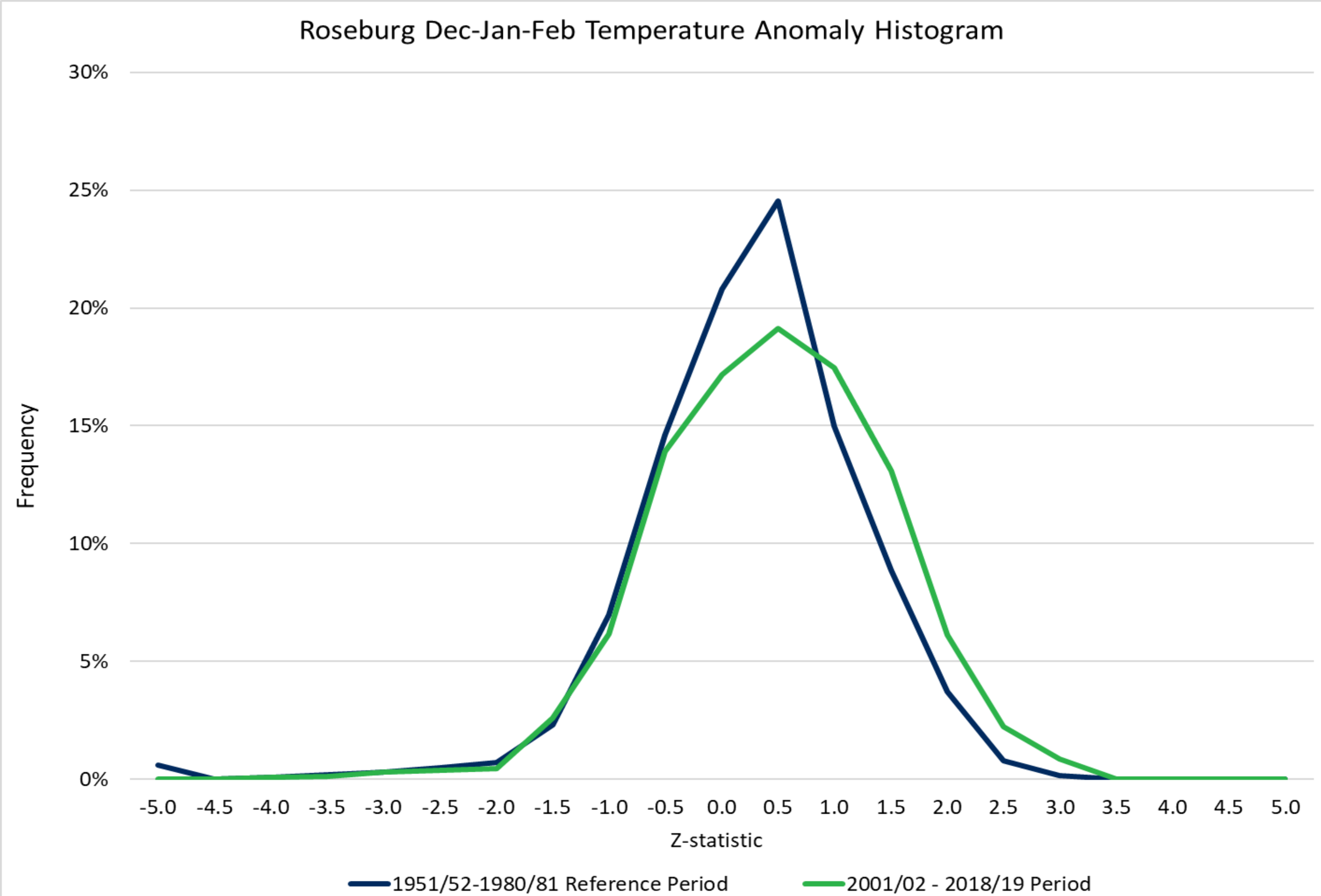
1. Expected customer count forecast by each of the 6 areas
2. Use per customer coefficients –5 year, 3 year or last 2 year average use per HDD per customer
3. Current weather planning standard

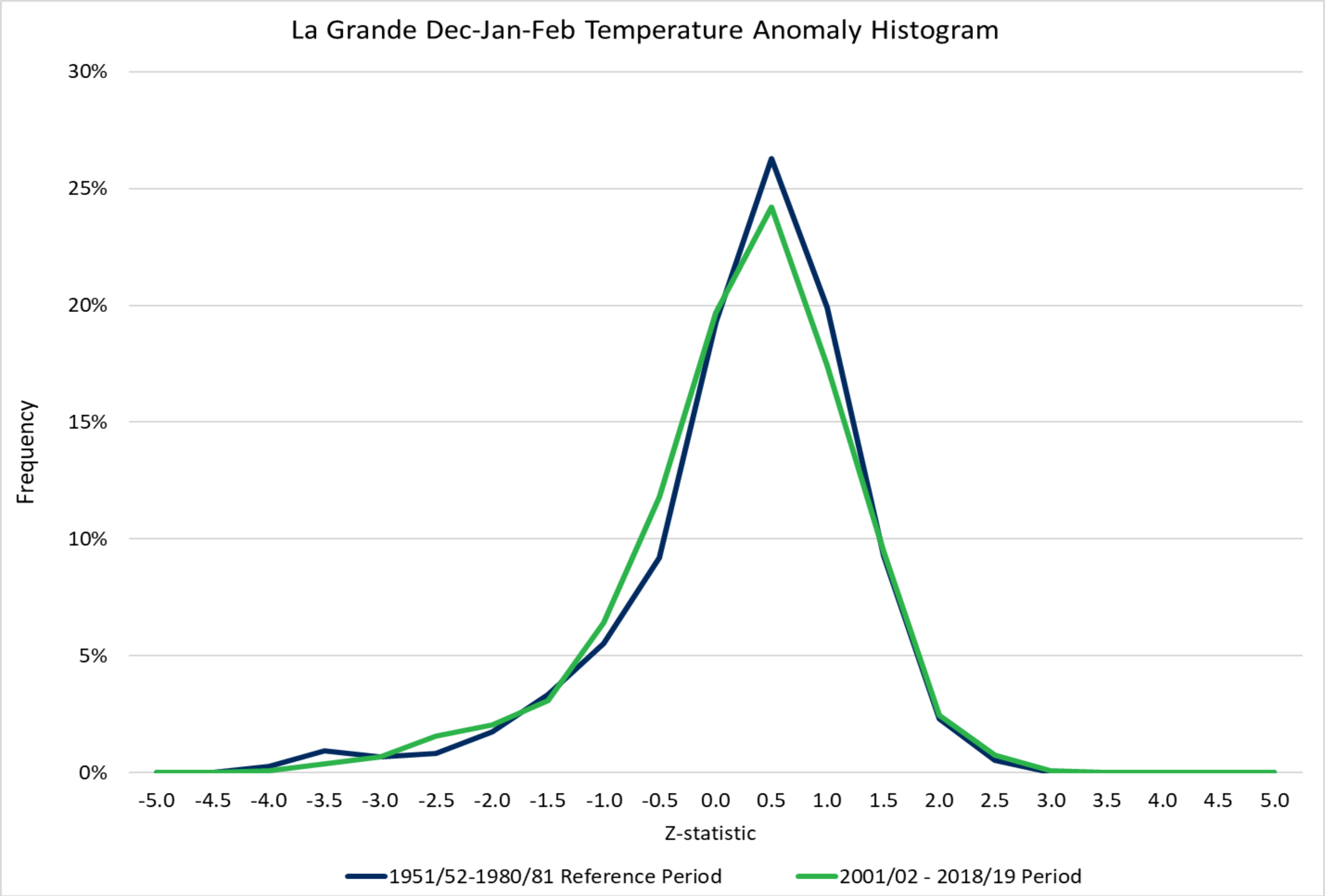
Weather Analysis

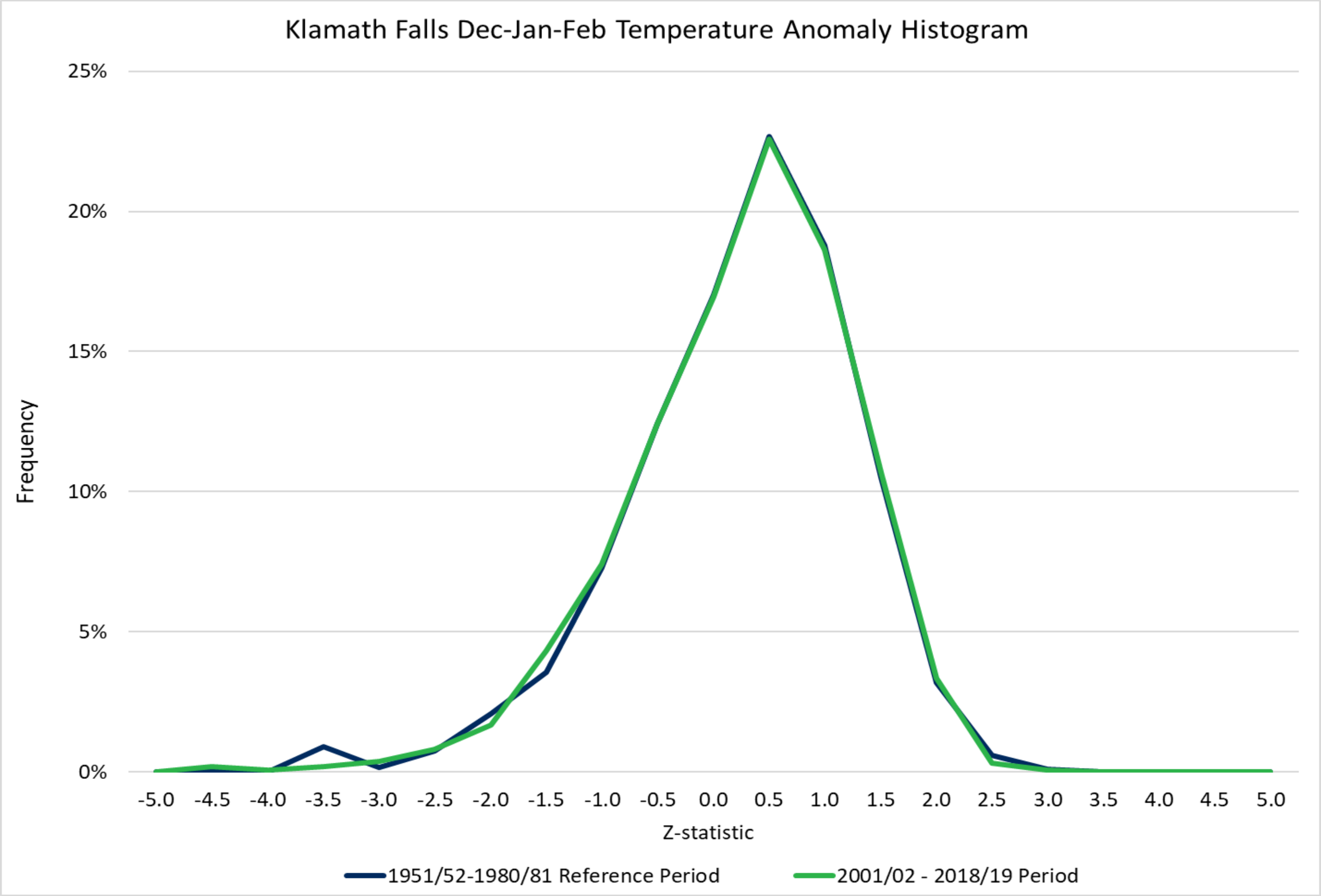
Z-Stat

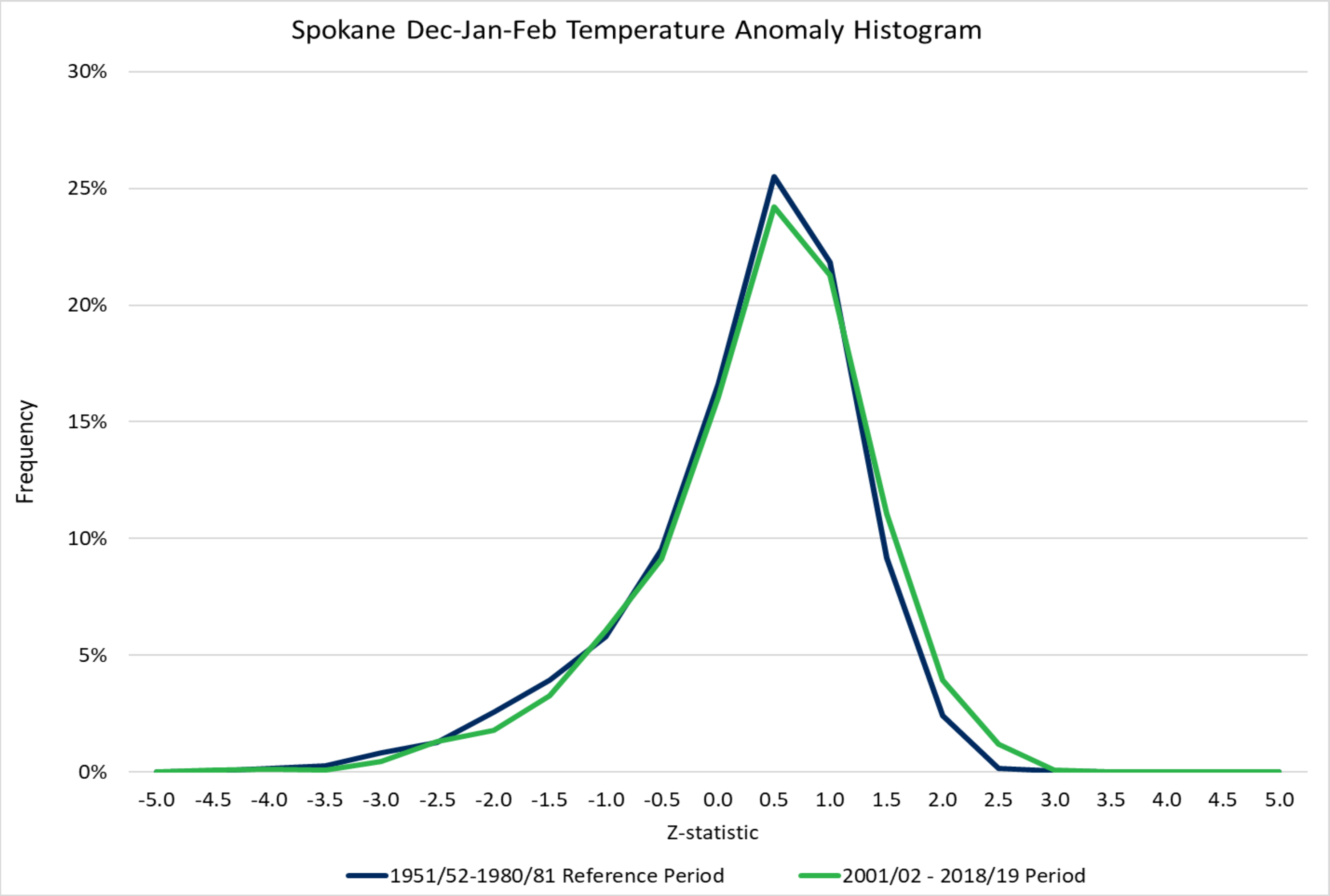
- Compare one period to another
- Shows how far from the average the data point falls


Medford Dec-Jan-Feb Temperature Anomaly Histogram
25%
20%
15%
10%
5%
0%
Frequency
-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 - 2018/19 Period


Roseburg Dec-Jan-Feb Temperature Anomaly Histogram
30%
25%
20%
15%
10%
5%
0%
Frequency
-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 - 2018/19 Period


La Grande Dec-Jan-Feb Temperature Anomaly Histogram
30%
25%
20%
15%
10%
5%
0%
Frequency
-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 - 2018/19 Period


Klamath Falls Dec-Jan-Feb Temperature Anomaly Histogram
25%
20%
15%
10%
5%
0%
Frequency
-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 - 2018/19 Period


Spokane Dec-Jan-Feb Temperature Anomaly Histogram
30%
25%
20%
15%
10%
5%
0%
Frequency
-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 - 2018/19 Period

Summary

- Avista's warmer climate locations, Roseburg and Medford, continue to see a shift in temperatures vs. the reference period

- The colder weather climate locations, Klamath Falls, La Grande, Spokane (ID, WA), have maintained the general shape and remain consistent vs. the reference period

Weather Planning Standard

Weather Standard

- Has the potential to significantly change timing of resource needs
- Significant qualitative considerations
  - No infrastructure response time if standard exceeded
  - Significant safety and property damage risks
- Current Peak HDD Planning Standards
  - WA/ID 82
  - Medford 61
  - Roseburg 55
  - Klamath 72
  - La Grande 75

Wind Chill Chart

Temperature (°F)

Wind (mph) \ Calm	40	35	30	25	20	15	10	5	0	-5	-10	-15	-20	-25	-30	-35	-40	-45
5	36	31	25	19	13	7	1	-5	-11	-16	-22	-28	-34	-40	-46	-52	-57	-63
10	34	27	21	15	9	3	-4	-10	-16	-22	-28	-35	-41	-47	-53	-59	-66	-72
15	32	25	19	13	6	0	-7	-13	-19	-26	-32	-39	-45	-51	-58	-64	-71	-77
20	30	24	17	11	4	-2	-9	-15	-22	-29	-35	-42	-48	-55	-61	-68	-74	-81
25	29	23	16	9	3	-4	-11	-17	-24	-31	-37	-44	-51	-58	-64	-71	-78	-84
30	28	22	15	8	1	-5	-12	-19	-26	-33	-39	-46	-53	-60	-67	-73	-80	-87
35	28	21	14	7	0	-7	-14	-21	-27	-34	-41	-48	-55	-62	-69	-76	-82	-89
40	27	20	13	6	-1	-8	-15	-22	-29	-36	-43	-50	-57	-64	-71	-78	-84	-91
45	26	19	12	5	-2	-9	-16	-23	-30	-37	-44	-51	-58	-65	-72	-79	-86	-93
50	26	19	12	4	-3	-10	-17	-24	-31	-38	-45	-52	-60	-67	-74	-81	-88	-95
55	25	18	11	4	-3	-11	-18	-25	-32	-39	-46	-54	-61	-68	-75	-82	-89	-97
60	25	17	10	3	-4	-11	-19	-26	-33	-40	-48	-55	-62	-69	-76	-84	-91	-98

Frostbite Times: 30 minutes; 10 minutes; 5 minutes

$$\text{Wind Chill (°F)} = 35.74 + 0.6215T - 35.75(V^{0.16}) + 0.4275T(V^{0.16})$$

Where, T= Air Temperature (°F) V= Wind Speed (mph)

Effective 11/01/01

Wind chill effects

- Wind on homes causes two effects. One is wind chill on the exterior of the building and the other is infiltration increases due to the pressure difference caused by wind blowing past the home.
- The greatest effect of wind on heating is low humidity in the home which makes the customers feel like the temperature is 64 degrees when they have the thermostat set at 72 if their humidity is lower than 10% Relative Humidity.

Weather Peak Planning Day alternative

- Coldest Average Day, each year, for the past 30 years combined with a 99% probability

Area	Coldest on Record	99% Probability Avg. Temp	99% Probability Avg. Temp & Wind Chill*
La Grande	-10	-11	-23
Klamath Falls	-7	-9	-16
Medford	4	11	9
Roseburg	10	14	16
Spokane	-17	-12	-26

*this was done with the recent 20 years of data combined with windspeed for example purposes

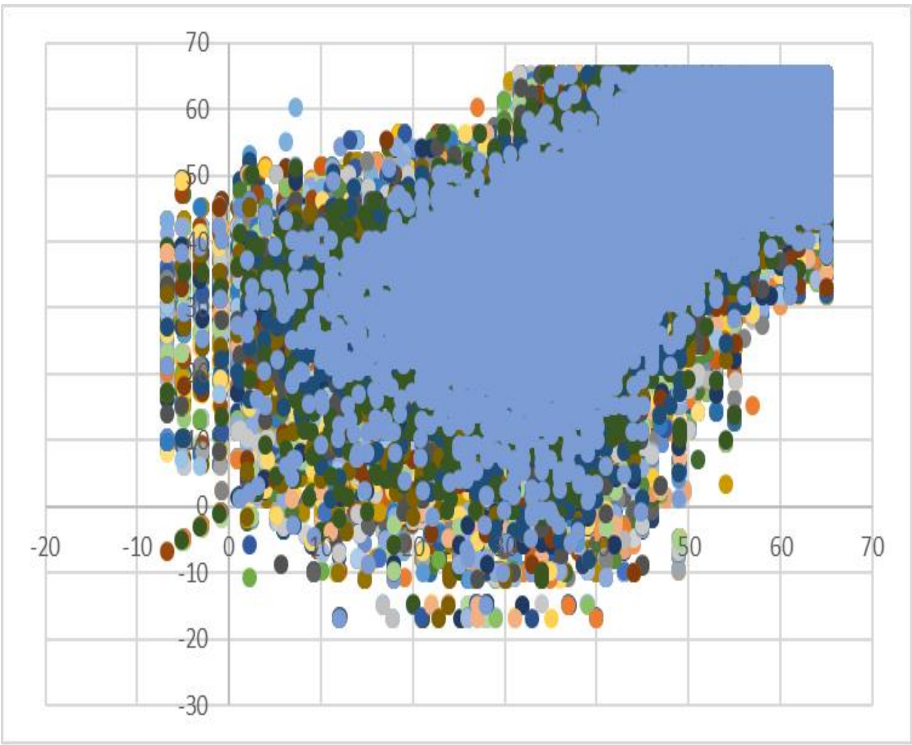
Risks

- Using wind chill effects combined with a 99% probability produces some drastic changes in peak day planning and may require a large amount of capital to meet those design criteria

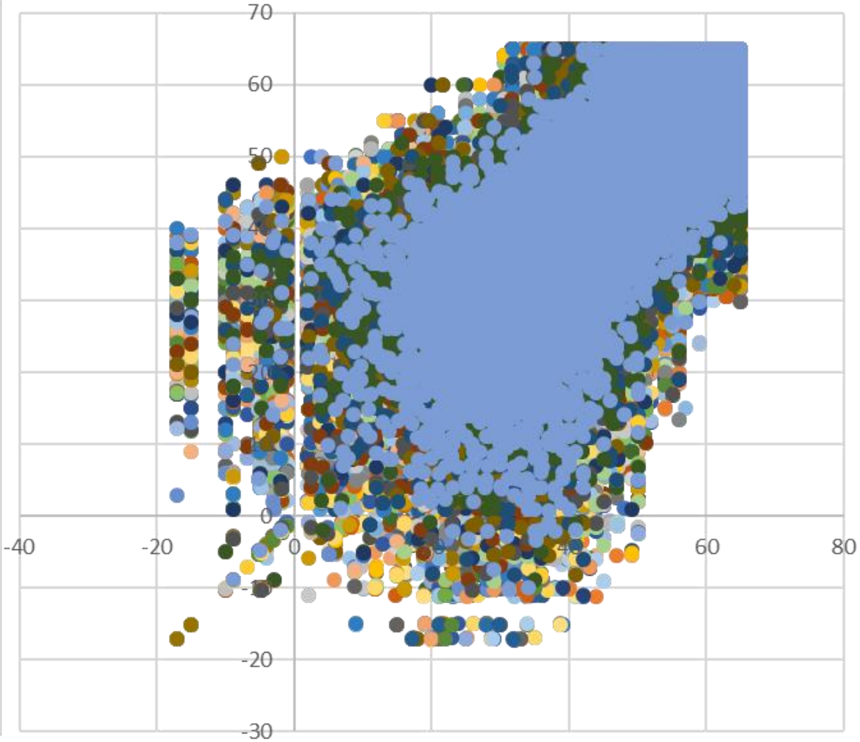
- Utilizing a 99% probability means there is a 1 in 100 event where Avista may not be able to meet the demand

Risk around moving WA and ID peak day temps (1,000 simulated futures run)

Draws 1 - 200



Draws 201 - 400

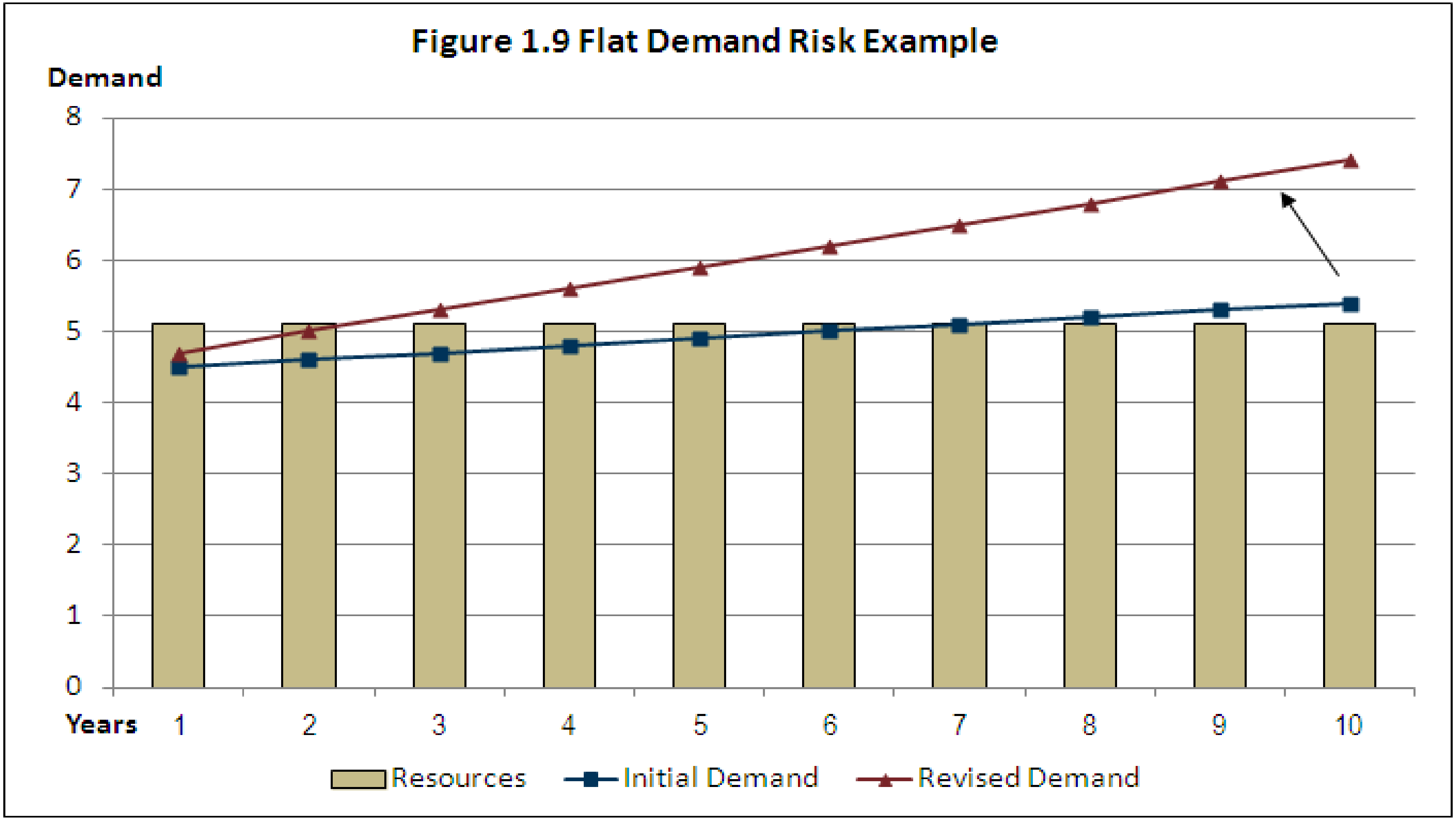


33

38

Coldest on Record Peak Days
(82 HDD's, or -17 Avg. Temp Fahrenheit)

"Flat Demand" Risk



Avista Weather Recommendation

- Utilize coldest day for each of the past 30 years with a 99% probability supply can be fulfilled

Area	99% Probability Avg. Temp
La Grande	-11
Klamath Falls	-9
Medford	11
Roseburg	14
Spokane	-12

Procurement Plan

Hedging Objectives and Goals

Mission

To provide a diversified portfolio of reliable supply and a level of price certainty in volatile markets.

- Avista cannot predict future market prices, however we use experience, market intelligence, and fundamental market analysis to structure and guide our procurement strategies.
- Avista's goal is to develop a plan that utilizes customer resources (storage and transportation), layers in pricing over time for stability (time averaging), allows discretion to take advantage of pricing opportunities should they arise, and appropriately manages risk.

Oversight and Control

Risk Policy

Risk Management Committee (RMC)

- Comprised of Executive Officers & Sr. Management
- Responsible for the Risk Management Policy
- Provides oversight and guidance on natural gas procurement plan

Natural Gas Supply

- Monitors and manages the Procurement Plan on a daily basis
- Leads in the annual Procurement Plan review and modification

Commission Update

- Semi-Annual Update
- New Procurement Plan is communicated semi-annually in the fall and spring
- Intra-year changes communicated to staff on an ad-hoc basis

Strategic Oversight Group (SOG)

- Cross functional group consisting of:
  - Credit, Electric/Gas Supply, Rates, Resource Accounting, Risk
- Co-develops the Procurement Plan
- Meets regularly

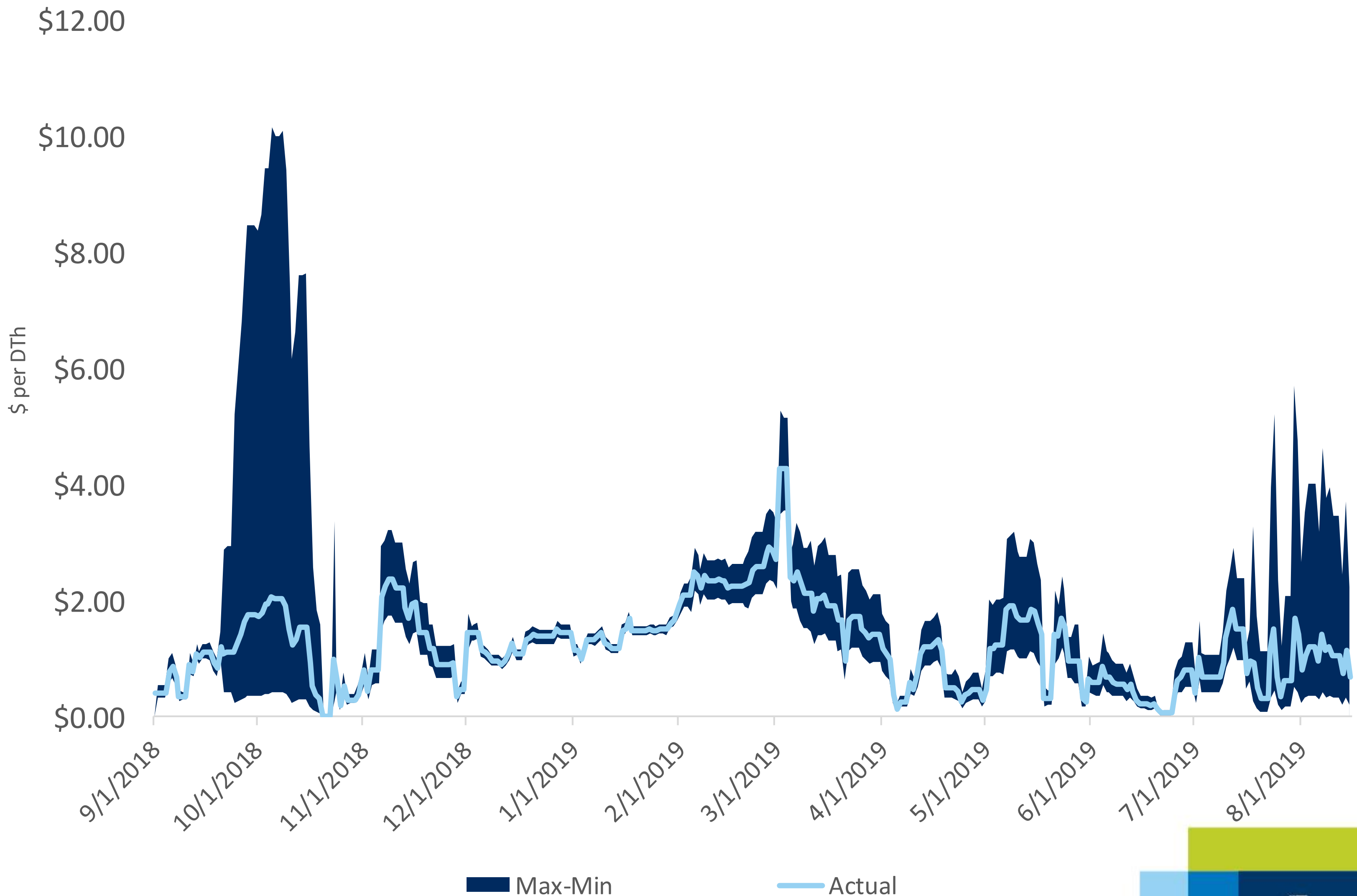
Comprehensive Annual Review of Previous Plan

Review conducted with SOG includes:

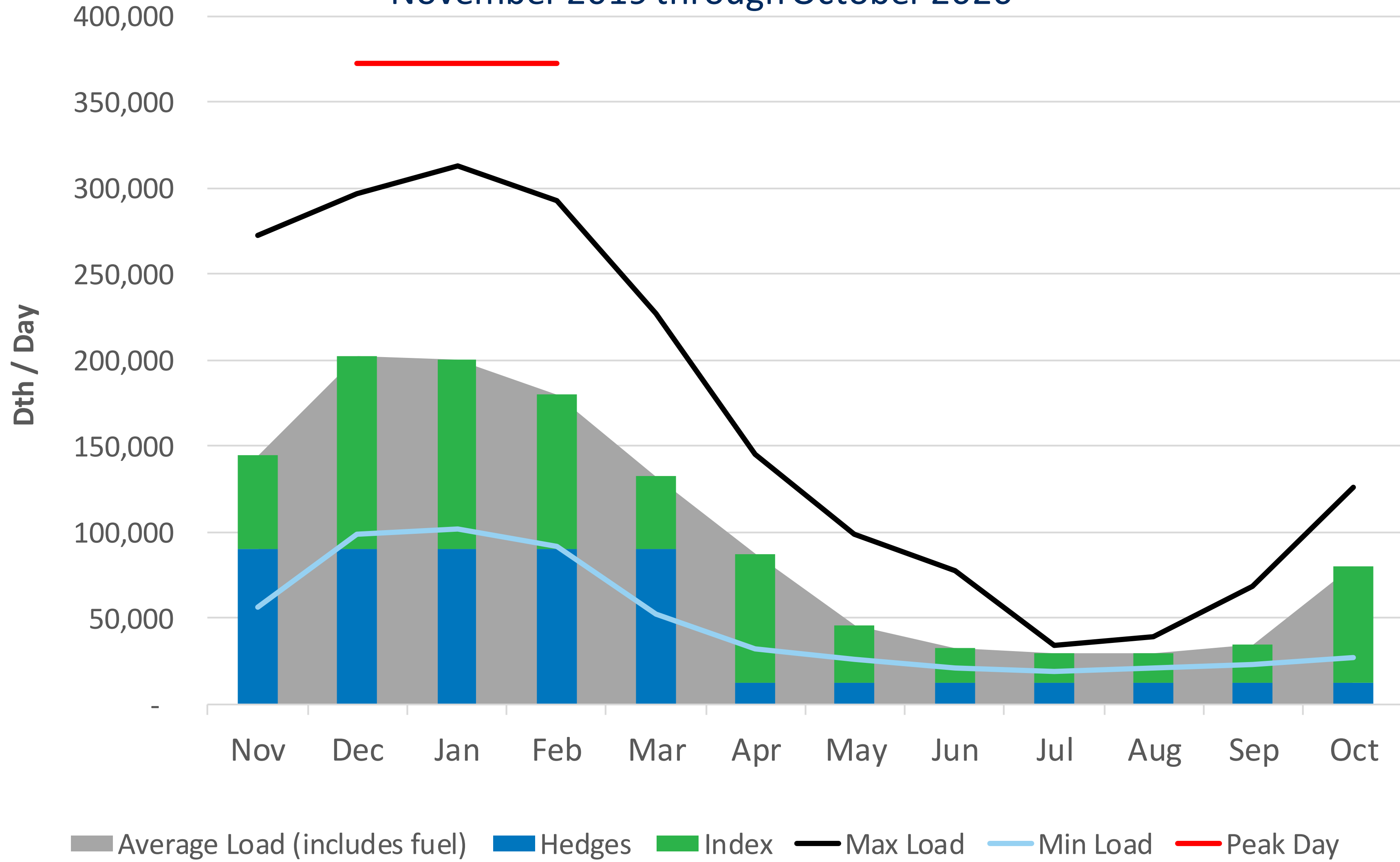
- Mission statement and approach
- Current and future market dynamics
- Hedge percentage
- Operative Boundary
- Resources available (i.e. storage and transportation)
- Hedge windows and quantity (how many, how long)
- Storage utilization
- Analysis (volatility, past performance, scenarios, risk)

A Thorough Evaluation of Risks

AECO Daily Volatility



Natural Gas Procurement Plan vs. System Demand
November 2019 through October 2020



*As of 10/9/2019

Plan Overview

Dynamic Window Hedge (DWH) Plan

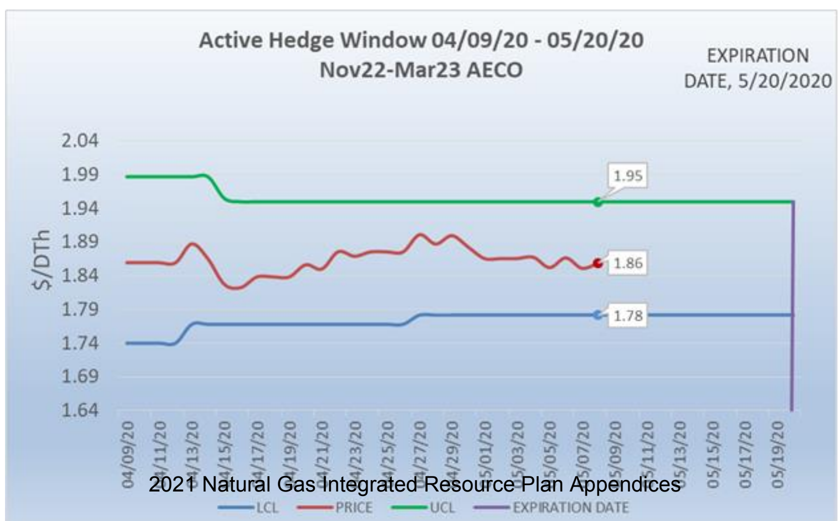
- Manages hedges based on average volumetric load
- Firm local distribution customers only
- **Delivery Periods:** Hedges up to 3 years out into the future from the prompt month in monthly and/or seasonal timeframes
- **Supply Basins:** Windows will use VAR as a way to determine the best basin for a hedge. (AECO, Rockies, Sumas).

Risk Responsive Hedging Tool (RRHT)

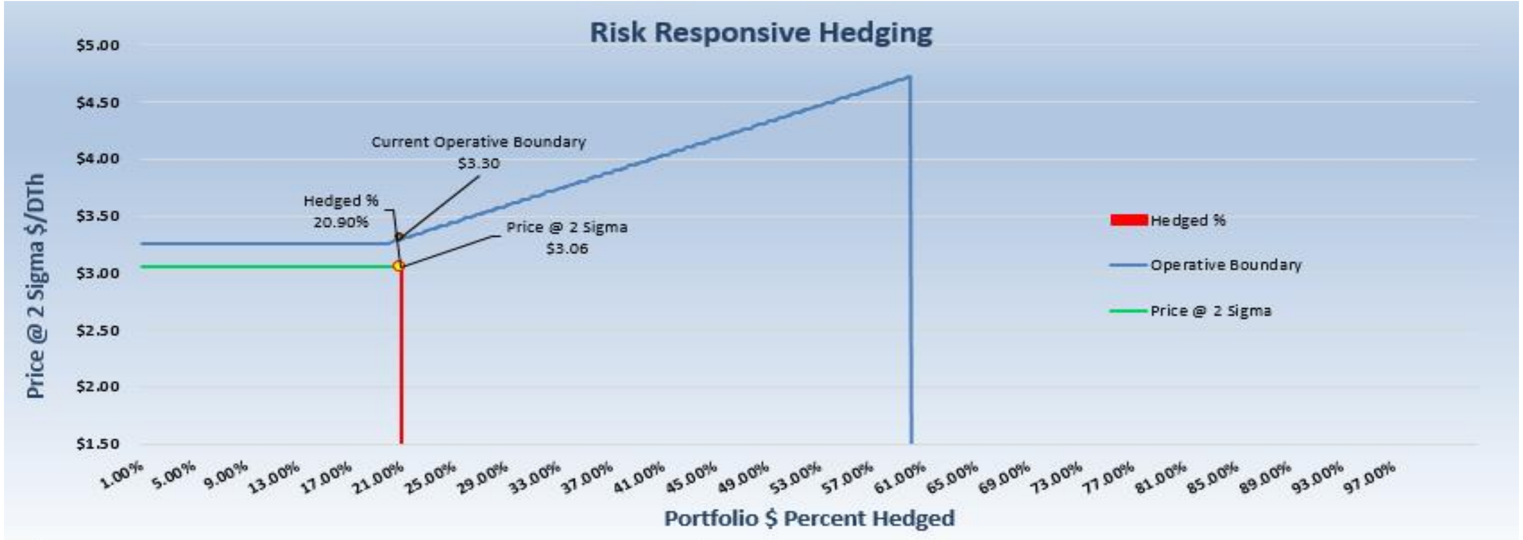
- Manages all hedges in the portfolio based on a financial position
  - Transport optimization hedges
  - Storage optimization hedges
  - LDC hedges from the DWH program
- Incorporates the financial value at risk (VaR) as a daily position based on current firm supply side assets combined with price volatility at each futures market basin

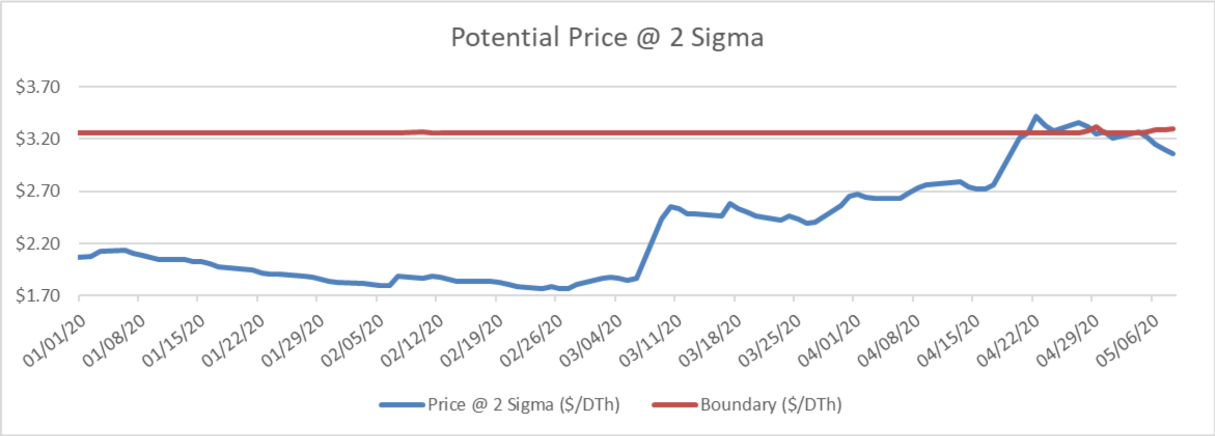
Dynamic Window Hedging

May 8, 2020													
	Physical Positions			Dynamic Window Hedging									
	Load Estimate (DTh/Day)	Completed Hedges (DTh/Day)	Net Position (DTh/Day)	Window Hedging Threshold	Load Hedged (%)	Hedges Left	Set Date	Expire Date	Low Price Trigger ($/DTh)	Today's Price ($/DTh)	High Price Trigger ($/DTh)	Hedge Required (DTh/Day)	Preferred Basin
June-20	-33,221	12,500	-20,721	40%	38%	0							
July-20	-29,585	12,500	-17,085	40%	42%	0							
August-20	-29,623	12,500	-17,123	40%	42%	0							
September-20	-37,700	15,000	-22,700	40%	40%	0							
October-20	-84,793	27,500	-57,293	40%	32%	3	05/01/20	06/11/20	1.52	1.67	2.08		AECO
Nov20-Mar21	-169,784	85,000	-84,784	33%	50%	0							
Apr21-Oct21	-52,143	12,500	-39,643	23%	24%	0							
Nov21-Mar22	-175,136	37,500	-137,636	33%	21%	8	04/22/20	06/27/20	1.86	2.01	2.22		AECO
Apr22-Oct22	-52,700	5,000	-47,700	23%	9%	3	04/23/20	12/05/20	1.34	1.59	1.93		AECO
Nov22-Mar23	-177,261	2,500	-174,761	33%	1%	22	04/09/20	05/20/20	1.78	1.86	1.95		AECO



Risk Responsive Hedging Tool





Optimization

Avista Gas Supply Asset Optimization

- Storage Optimization.
  - Utilize Avista owned portion of Jackson Prairie storage facility
  - Maintain a peak day capability in order to serve needed demand from the facility during a peak event.
  - Optimize excess capacity through arbitrage between daily prices and forward months as well as between different forward months.
- Transport Optimization.
  - Avista owns transport capacity sufficient to serve peak day load. Unused capacity is optimized by purchasing/selling gas at different hubs to capture locational price spreads.

Storage Optimization Examples

- Day ahead market arbitrage with forward month

  Purchase: daily sumas 75,000 dth for $1.45/dth.

  Sale: 75,000 dth October 2020 Sumas for $2.48/dth.

  Realized arbitrage value: $1.03*75,000 = $77,250

- Arbitrage between different forward months

  Purchase: Q3 2020 sumas 225,000 dth for $1.81

  Sale: Q1 2021 sumas 225,000 dth for $3.47

  Realized arbitrage value : $1.66*225,000 = $373,500

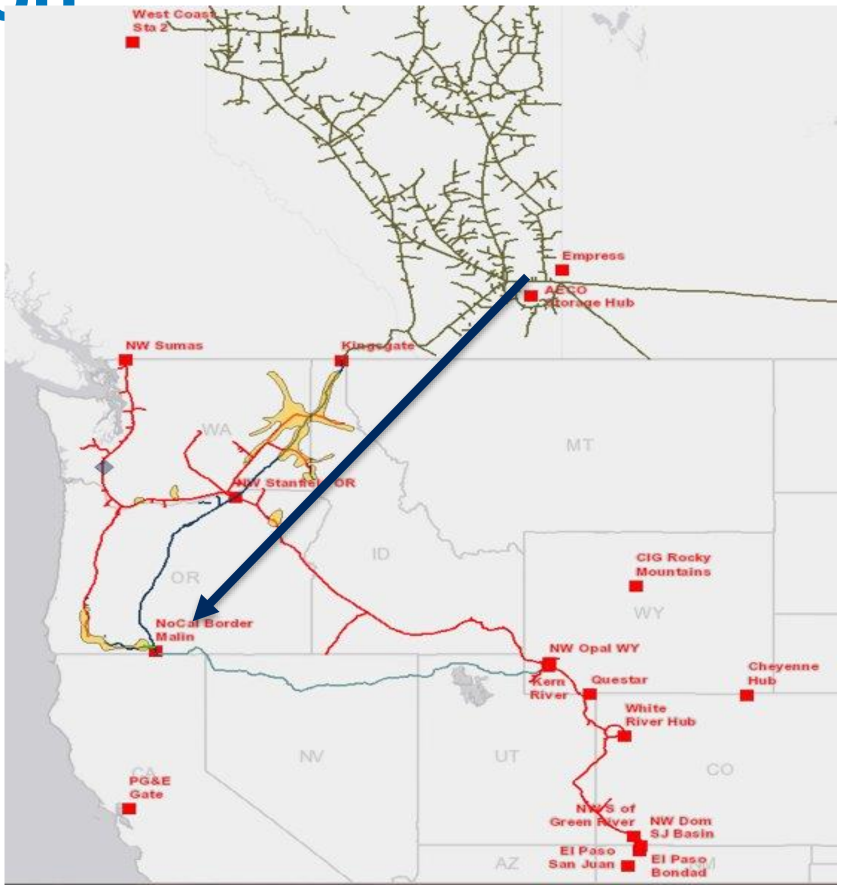
Transport Optimization

- Transport Capacity in excess of Avista core load can be optimized to reduce customer costs.
- Optimization can be done in either the daily or forward markets

Example:

Purchase: 30,000 dth AECO for $2.00/dth

Sale: 30,000 dth Malin for $2.30/dth
Realized cost reduction to customers: $0.30*30,000 = $9,000



Risks

- Operational Flow Orders:
  - NW Pipeline may require the use of JP storage gas to satisfy OFO's.
  - May require additional purchases from market to replace storage inventory.
- Unplanned maintenance:
  - Unexpected reductions to pipeline capacity or reduced access to storage may limit optimization activity
- Damage or failure of infrastructure

2020 Natural Gas IRP Energy Efficiency

Ryan Finesilver – Energy Efficiency Planning and Analytics Manager

First Technical Advisory Committee Meeting

Team Roles

Planning & Analytics Team

Applied Energy Group (AEG)

Gas Supply

ACP

CPA

IRP

Oregon DSM Programs

Alphabet Soup

- CPA: Conservation Potential Assessment
- IRP: Integrated Resource Plan
- AEG: Applied Energy Group
- IPUC: Idaho Public Utility Commission
- TRC: Total Resource Cost Test
- UCT: Utility Cost Test
- UTC: Utilities and Transportation Commission

The CPA within the IRP is done by AEG and as per the UTC, is according to the TRC but the IPUC requires the UCT.

Who Energy Efficiency Serves

Three Jurisdictions

- Washington
- Idaho
- Oregon (ETO except for Low-Income)

Multiple Customer Segments

- Residential
- Industrial/Commercial
- Low-Income Residential

The Company's Infrastructure

- Aids in reducing overall capacity
- Defers capital investments

Energy Efficiency Funding – Natural Gas

SCHEDULE 191

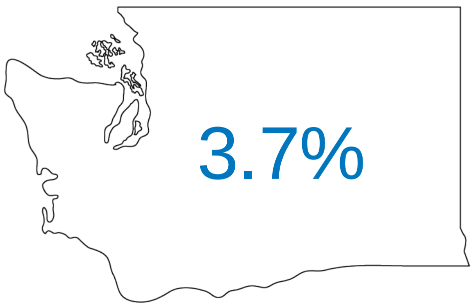
DEMAND SIDE MANAGEMENT RATE ADJUSTMENT - WASHINGTON

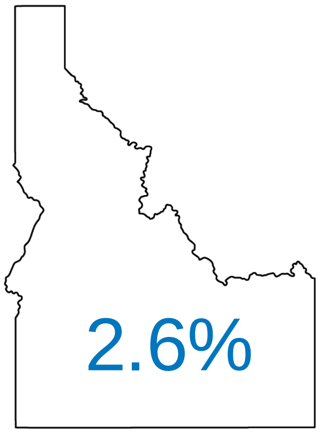
APPLICABLE:
To Customers in the State of Washington where the Company has natural gas service available. This Demand Side Management Rate Adjustment or Rate Adjustment shall be applicable to all retail customers taking service under Schedules 101, 111, 112, 121, 122, 131, and 132. This Rate Adjustment is designed to recover costs incurred by the Company associated with providing Demand Side Management services and programs to customers.

MONTHLY RATE:
The energy charges of the individual rate schedules are to be increased by the following amounts:

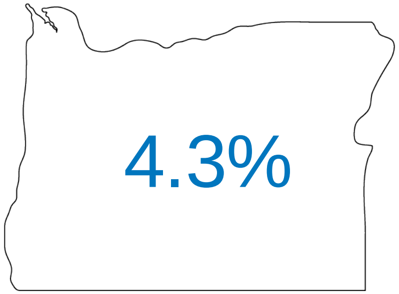
Schedule 101	$0.03472 per Therm
Schedule 111 & 112	$0.02475 per Therm

Tariff percentage of customer bill by state:

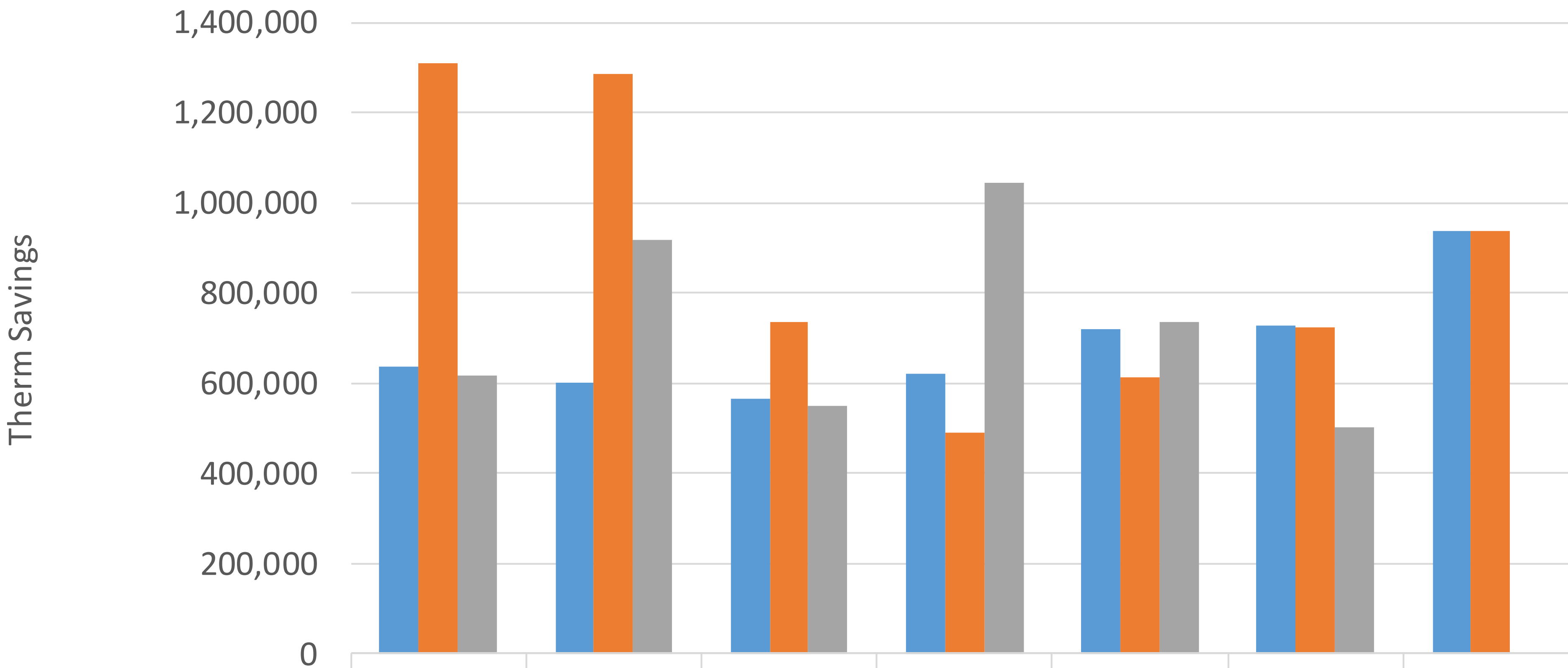




$8.4 Million
Annual
Funding
(2019)

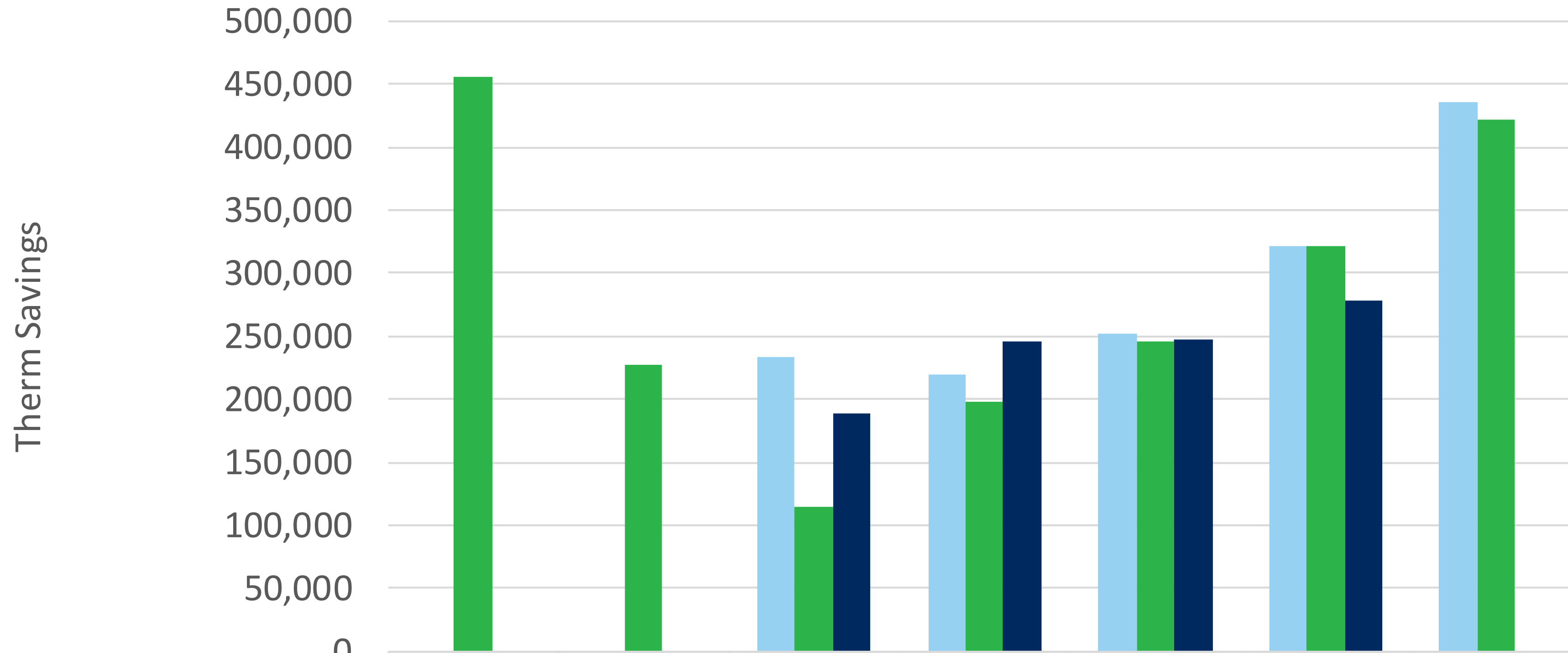


WA Gas Targets to Actual Savings



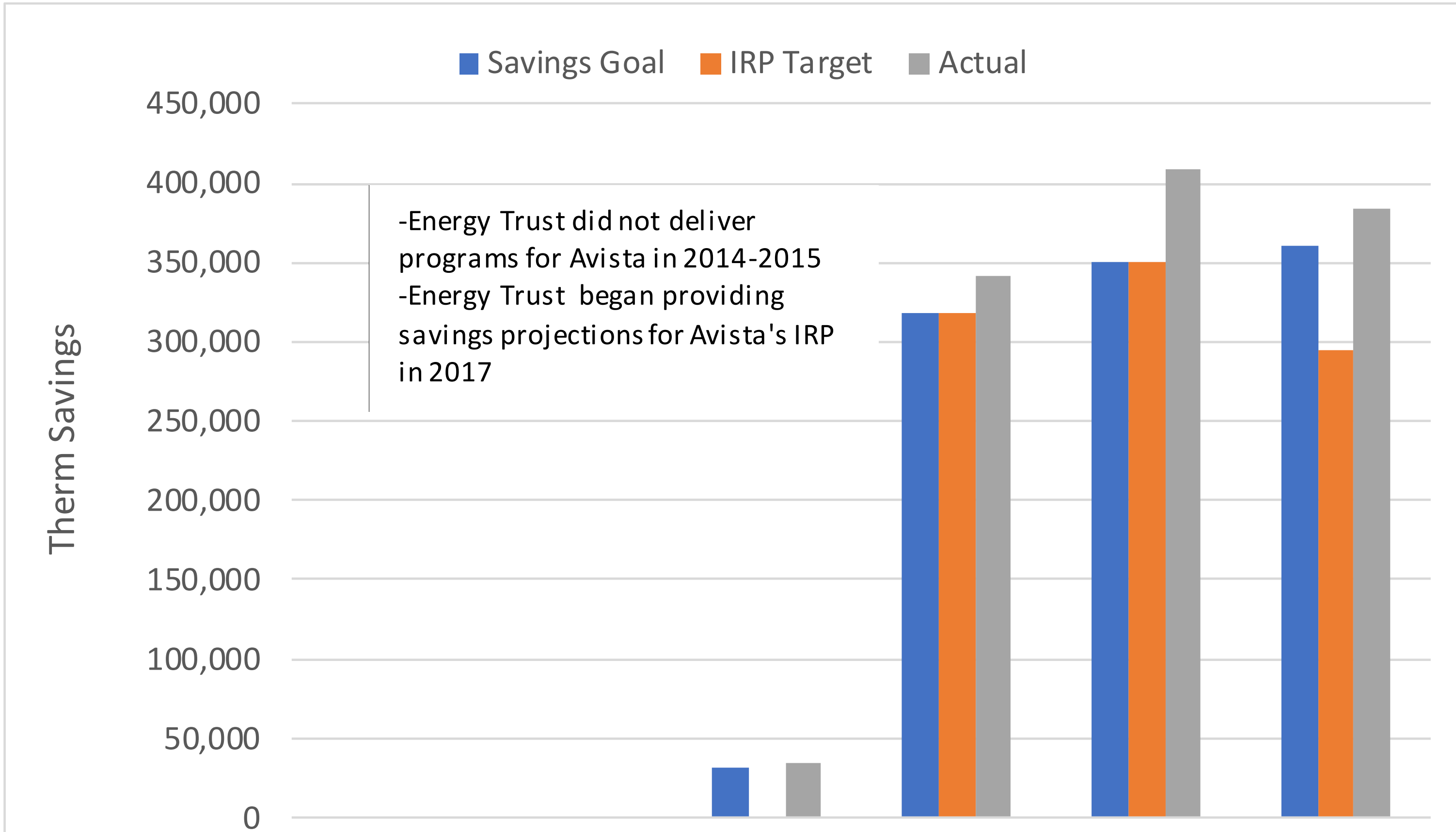
	2014	2015	2016	2017	2018	2019	2020
Business Plan Target	637,042	602,010	567,653	620,310	719,451	726,128	937,402
IRP Target	1,310,000	1,287,000	737,000	489,110	612,830	725,180	936,350
Actual	615,418	919,892	548,756	1,046,356	736,985	504,113	

ID Gas Targets to Actual Savings



	2014	2015	2016	2017	2018	2019	2020
Business Plan Target	0	0	232,737	219,272	252,712	321,120	436,405
IRP Target	456,000	228,000	114,000	197,640	246,440	320,830	421,270
Actual	0	0	189,295	245,747	247,756	278,922	

OR Energy Trust Gas Targets to Actual Savings



	2014	2015	2016	2017	2018	2019
Savings Goal			31,574	318,332	349,520	360,682
IRP Target				318,332	349,520	294,720
Actual			34,708	340,738	409,128	384,599

Energy Efficiency Business Planning

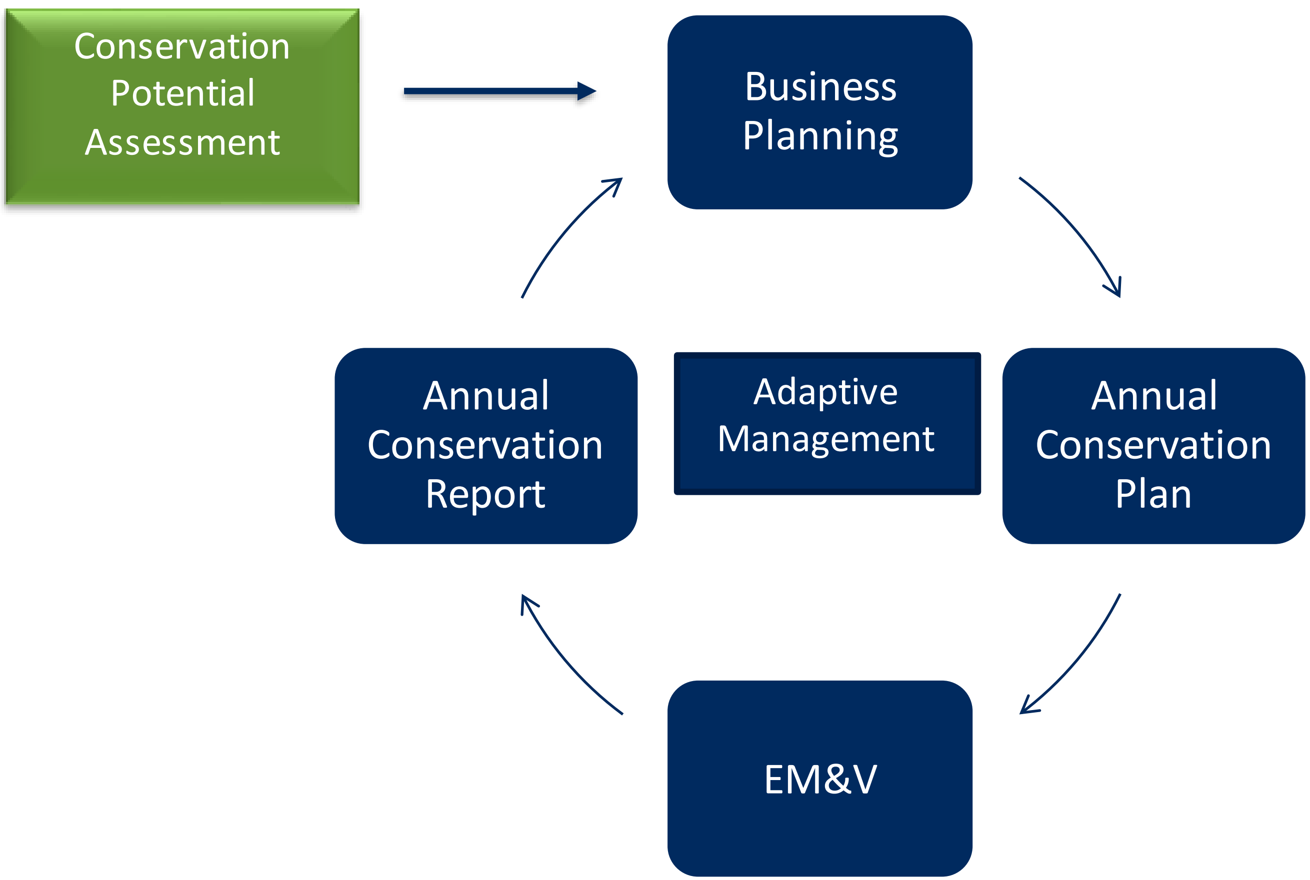
Conservation Potential Assessment (CPA)

- Primary Objectives
  - Meet legislative and regulatory requirements
  - Support integrated resource planning
  - Identify opportunities for savings; key measures in target segments
- Key Deliverables
  - 20-year conservation potential
  - Individual measures
  - IRP target

Conservation Potential Assessment

Technical Potential	• Theoretical upper limit of conservation • All efficiency measures are phased in regardless of cost
Achievable Technical Potential	• Realistically achievable, accounting for adoption rates and how quickly programs can be implemented • Does not consider cost-effectiveness of measures
Achievable Potential	• Includes economic screening of measures (cost effectiveness) • Sets our conservation target

Business Planning Process



Business Planning Process

Business Planning Process

CPA
- Sets overall Savings Goal
- Identifies Measures

Avista Programs
- Consult with our existing programs
- Add new measures to existing programs

Update and Evaluate
- Update existing savings values
- Test for Cost-Effectiveness (TRC/UCT)

Feedback and Modify
- DSM Program Managers
- Engineers
- Industry Trends
- Other Parties

Energy Efficiency Advisory Group

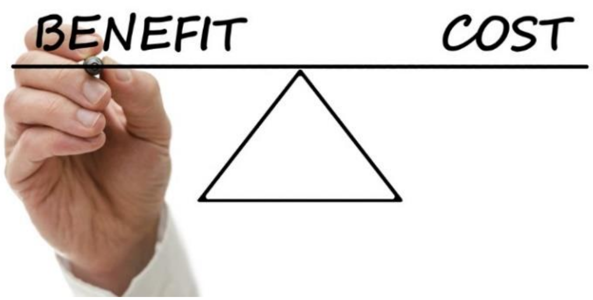
Incentive Setting

Cost-Effective Test

Utility Cost Test (UCT) Total Resource Cost (TRC)	Must have a B/E ratio of 1.0 or Higher

Decide Incentive Level

$3 per Therm	70% of CIC	CE Impact	Portfolio Alignment



Significant Costs and Benefits

COSTS

- **Administration**
  (e.g., program design, development, operations, maintenance, overhead, customer service, marketing & outreach, sales, IT infrastructure, customer education, program evaluation, measurement & verification)
- **Measure (Capital) Costs**
  (equipment costs incurred by the utility and participants)
- **Incentives**
- **Revenue Loss**
  (bill reductions)
- **Participant Costs**
  (Other than capital costs – value of service lost & transaction costs)

BENEFITS

- **Avoided Costs**
  (complex)
- **Tax Credits**
  (currently available for DG only)
- **Market/Reliability Benefits**
- **Non-energy benefits**
- **Incentives**
- **Bill reductions**

From Cost-effectiveness training (3/6/15) Powerpoint
http://www.cpuc.ca.gov/General.aspx?id=5267

Energy Trust's Resource Assessment Model

- What is a resource assessment model?
  - Energy Trust's version of a Conservation Potential Assessment
  - Model that provides an estimate of energy efficiency resource potential achievable over a 20-year period
  - 'Bottom-up' approach to estimate potential starting at the measure level and scaling to a service territory
- Energy Trust uses a Model that calculates Technical, Achievable and Cost-Effective Achievable Energy Efficiency Potential
  - Final program/IRP targets are established via a deployment forecast in a separate tool
- We provide a 20-year energy efficiency forecast for utility IRPs about every two years.

Energy Trust’s Resource Assessment Model is “Living Model”

- Energy Trust makes continuous improvements to the model
- Measures in the model are updated on an ongoing basis to reflect changing market conditions and savings estimates
- Emerging technologies are added to the model as data availability and product viability allows
- Cost-effective potential may be realized through programs, market transformation and/or codes and standards
- Under discussion: use of a “large project adder” to account for large, unexpected projects

Energy Trust Resource Assessment 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)
- Units per site
- Baseline/efficient equipment saturations
- Suitability

Utility 'Global' Inputs

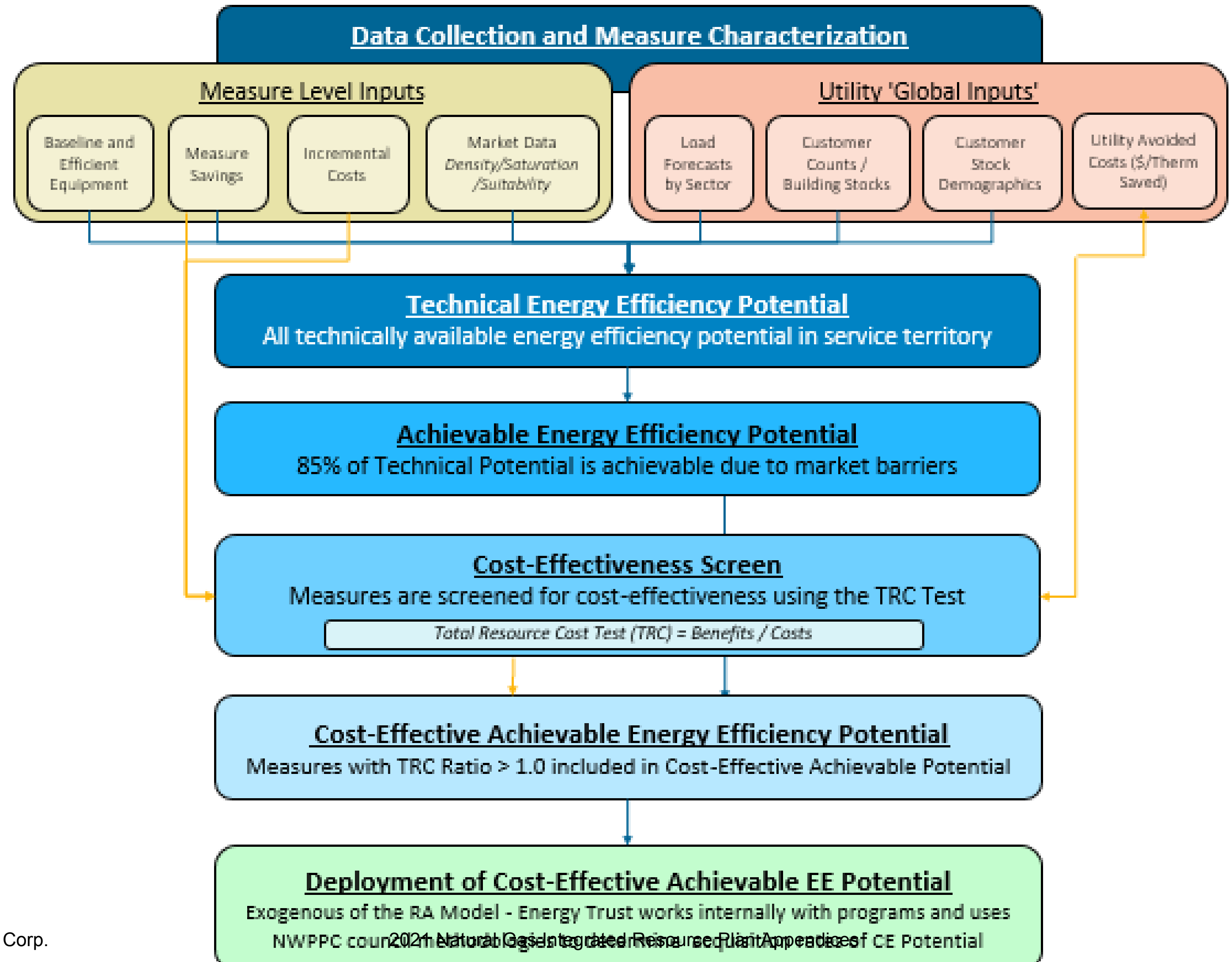
Customer and Load Forecasts
- Used to scale measure level savings to a service territory
  - Residential Stocks: # of homes
  - Commercial Stocks: 1000s of Sq.Ft.
  - Industrial Stocks: Customer load

Avoided Costs

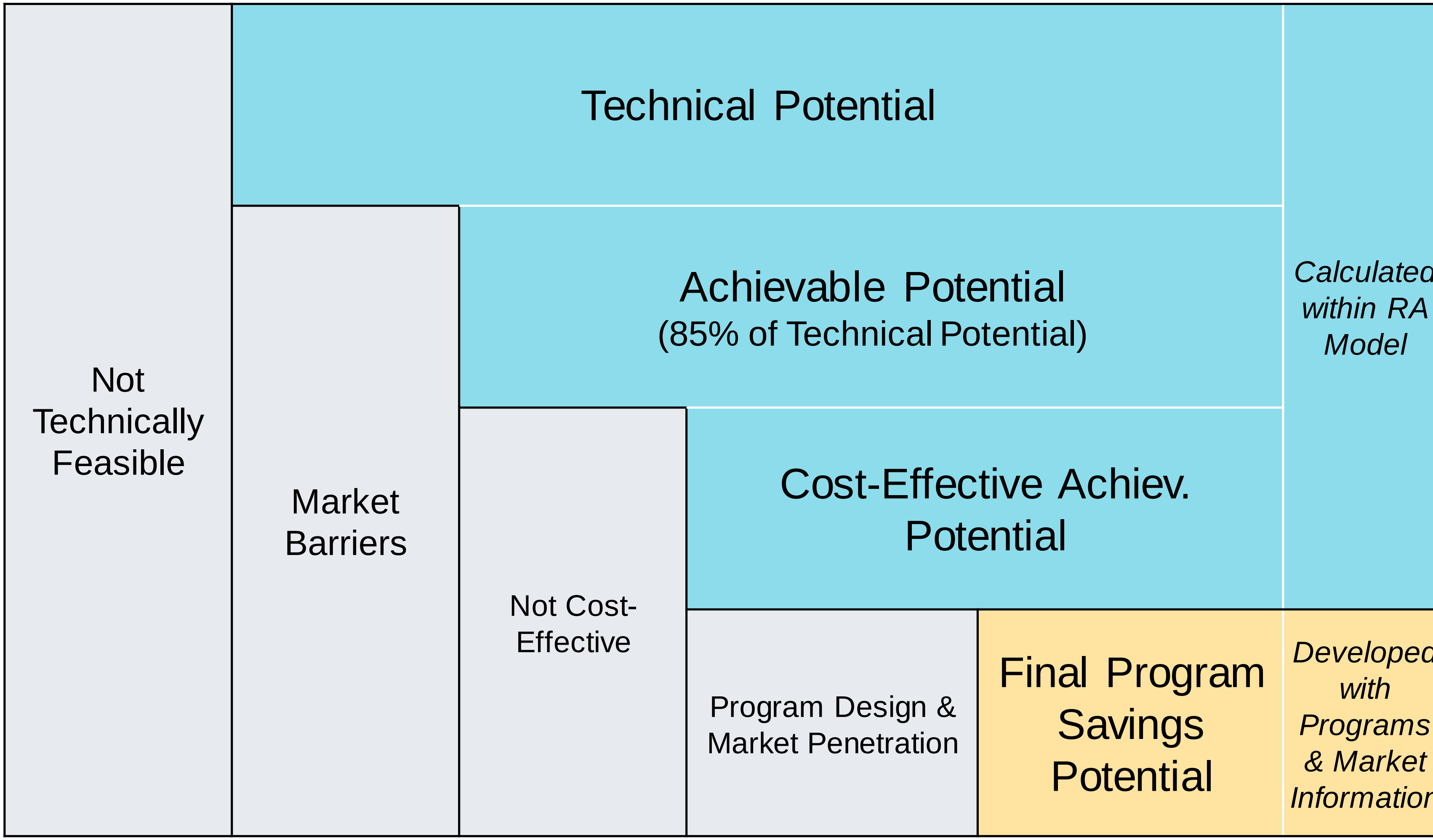
Customer Stock Demographics:
- Heating fuel splits
- Water heat fuel splits

** RET = Retrofit; ROB = Replace on Burnout; NEW = New Construction*

Energy Trust 20-Year IRP EE Forecast Flow Chart



Energy Trust Forecasted Potential Types



Energy Trust Cost-Effectiveness Screen For RA Modeling

- Energy Trust utilizes the Total Resource Cost (TRC) test to screen measures in the model for cost effectiveness

$$TRC = \frac{\textit{Measure Benefits}}{\textit{Total Measure Cost}}$$

- If TRC is > 1.0, it is cost-effective and the resources is included in cost-effective achievable potential
- Measure Benefits:
  - Avoided Costs
    - Annual measure savings x NPV avoided costs per therm or kWh
  - 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)

- Some gas measures are forced into the model if they have exceptions from the OPUC under the criteria established via UM 551

Energy Trust Deployment

- 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 Avista's system in a given year.
- Energy Trust ramp rates are based on NWPCC methods and ramp rates, but calibrated to be specific to Energy Trust.

Energy Trust Final Savings Projection Methodology

Energy Trust calibrates the first five years of energy efficiency acquisition ramp rates to program performance and budget goals.

Years 1-2

- Program forecasts – they know what is happening short term best

Years 3-5

- Planning and Programs work together to create forecast

Years 6-20

- Planning forecasts long-term acquisition rate to generally align NWPCC

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%

Energy Trust Ramp Rate Examples

Avista's OR IRP Savings Targets Influence Annual Energy Trust Savings Goals and Budgets

- The savings forecasts that Avista incorporates into their IRPs is a reference point for setting annual Energy Trust savings goals and budgets
- Likewise, the Energy Trust savings goals from the last budget cycle inform the early years of the next IRP forecast
- This results in a cycle of iterative updates to savings projections based on the most recent market intelligence
- In addition, Energy Trust's measure development process uses the Utility Cost Test to screen measures for cost-effectiveness
  - This test sets an upper bound on the incentive that can be offered and this factors into the budget process

Questions?

2020 Natural Gas IRP schedule

•**TAC 1: Wednesday, June 17, 2020**: TAC meeting expectations, 2020 IRP process and schedule, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits, Demand, Weather Analysis and a Weather Planning Standard, and an energy efficiency update.

•**TAC 2: Thursday, August 6, 2020:** Market Analysis, Price Forecasts, Cost Of Carbon, demand forecasts and CPA results from AEG, Environmental Policies, fugitive emissions

•**TAC 3: Wednesday, September 30, 2020:** Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, overview of the major interstate pipelines and projects, and sensitivities and portfolio selection modeling.

•**TAC 4: Wednesday, November 18, 2020:** Review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

•**TAC 5: February 2021:** TAC final review meeting (if necessary)

2021 Electric Integrated Resource Plan

Technical Advisory Committee Meeting No. 2 Agenda

Thursday, August 6, 2020
Virtual Meeting- 9:00 AM PST

Topic	Time	Staff
Introductions & IRP Process Updates	9:00	Lyons
Natural Gas & RNG Market Overview	9:30	Pardee
Break	10:45	
Natural Gas Price Forecast	11:00	Brutocao
Lunch	11:30	
Upstream Natural Gas Emissions	12:30	Pardee
Break	1:30	
Regional Energy Policy Update	1:45	Lyons
Natural Gas and Electric Coordinated Study	2:15	Gall/Pardee
Highly Impacted & Vulnerable Populations Baseline Analysis	3:00	Gall
Adjourn	3:45	

2021 Electric and Natural Gas IRPs TAC Introductions and IRP Process Updates

John Lyons, Ph.D.

Second Technical Advisory Committee Meeting

August 6, 2020

Updated Meeting Guidelines

- Gas and electric IRP teams working remotely, but still available by email and phone for questions and comments
- Some processes are taking longer remotely
- Virtual IRP meetings until back in the office and able to hold large group meetings
- TAC presentations, notes, work plans and past IRPs are posted on joint IRP page for gas and electric: https://www.myavista.com/about-us/integrated-resource-planning

Virtual TAC Meeting Reminders

- Please mute mics unless speaking or asking a question
- Use the Skype chat box to write questions or comments or let us know you would like to say something
- Respect the pause
- Please try not to speak over the presenter or a speaker who is voicing a question or thought
- Remember to state your name before speaking for the note taker
- This is a public advisory meeting – presentations and comments will be recorded and documented

Integrated Resource Planning

- Required by Idaho, Oregon and Washington* every other year
- Guides resource strategy over the next twenty + years
- Current and projected load & resource position
- Resource strategies under different future policies
  - Resource choices
  - Conservation measures and programs
  - Transmission and distribution integration for electric
  - Gas distribution planning
  - Gas and electric market price forecasts
- Scenarios for uncertain future events and issues
- Key dates for modeling and IRP development are available in the Work Plans

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
  - Ask questions
  - Help with soliciting new members
- Open forum while balancing need to get through all of the topics
- Welcome requests for studies or different assumptions.
  - Time or resources may limit the number or type of studies
  - Earlier study requests allow us to be more accommodating
  - **August 1, 2020** was the electric study request deadline
- Planning teams are available by email or phone for questions or comments between the TAC meetings

2020 Electric IRP Meetings – IPUC

- AVU-E-19-01 https://puc.idaho.gov/case/Details/3633
- Telephonic public hearing on August 5, 2020
- August 19, 2020 comment deadline, September 2, 2020 response
- Overview of topics discussed at July 9, 2020 virtual public workshop:
  - Moving away from coal
  - Cost impacts for Idaho customers from Washington laws
  - IRP procedural questions about acknowledgment of the IRP
  - Climate change questions and timing of actions
  - Colstrip: decommissioning, other owners, cost sharing with Washington
  - Consideration of social costs/externalities and public health
  - Support for clean energy and Commission authority to require it
  - Resource timing
  - Risks considered in the IRP: economic, qualitative and climate
  - Idaho versus Montana wind locations
  - Maintaining Idaho RECs
  - Climate change law applicability and lawsuits

2021 Natural Gas IRP TAC Schedule

- TAC 1: Wednesday, June 17, 2020
- **TAC 2: Thursday, August 6, 2020 (Joint with Electric TAC)**
- TAC 3: Wednesday, September 30, 2020
- TAC 4: Wednesday, November 18, 2020
- TAC 5: February 2021 – TAC final review meeting if necessary
- Natural Gas TAC agendas, presentations and meeting minutes available at: https://myavista.com/about-us/integrated-resource-planning

2021 Electric IRP TAC Schedule

- TAC 1: Thursday, June 18, 2020
- **TAC 2: Thursday, August 6, 2020 (Joint with Natural Gas TAC)**
- Economic and Load Forecast, August 2020
- TAC 3: Tuesday, September 29, 2020
- TAC 4: Tuesday, November 17, 2020
- TAC 5: Thursday, January 21, 2021
- Public Outreach Meeting: February 2021
- TAC agendas, presentations and meeting minutes available at: https://myavista.com/about-us/integrated-resource-planning

Process Updates

Economic and load forecast delay

- Special meeting 1:00 – 3:30 pm PST on Tuesday, August 18 or Wednesday, August 19, 2020 to cover the forecasts

AEG Conservation Potential Assessment and Demand Response Studies – delayed from TAC 2

- AEG has developed baseline assumptions, market profiles and energy/gas use per customer
- Market data has been collected and compiled
- Measure Assumption development is complete
- Compiled 2021 Power Plan Assumptions
- Measure List is in-process and is expected to be available mid-September
- CPA discussion with TAC – September TAC meeting.

Today's TAC Agenda

9:00 – Introductions & IRP Process Updates, Lyons

9:30 – Natural Gas & RNG Market Overview, Pardee

10:45 – Break

11:00 – Natural Gas Price Forecast, Brutocao

11:30 – Lunch

12:30 – Upstream Natural Gas Emissions, Pardee

1:30 – Break

1:45 – Regional Energy Policy Update, Lyons

2:15 – Natural Gas and Electric Coordinated Study, Gall/Pardee

3:00 – Highly Impacted & Vulnerable Populations Baseline Analysis, Gall

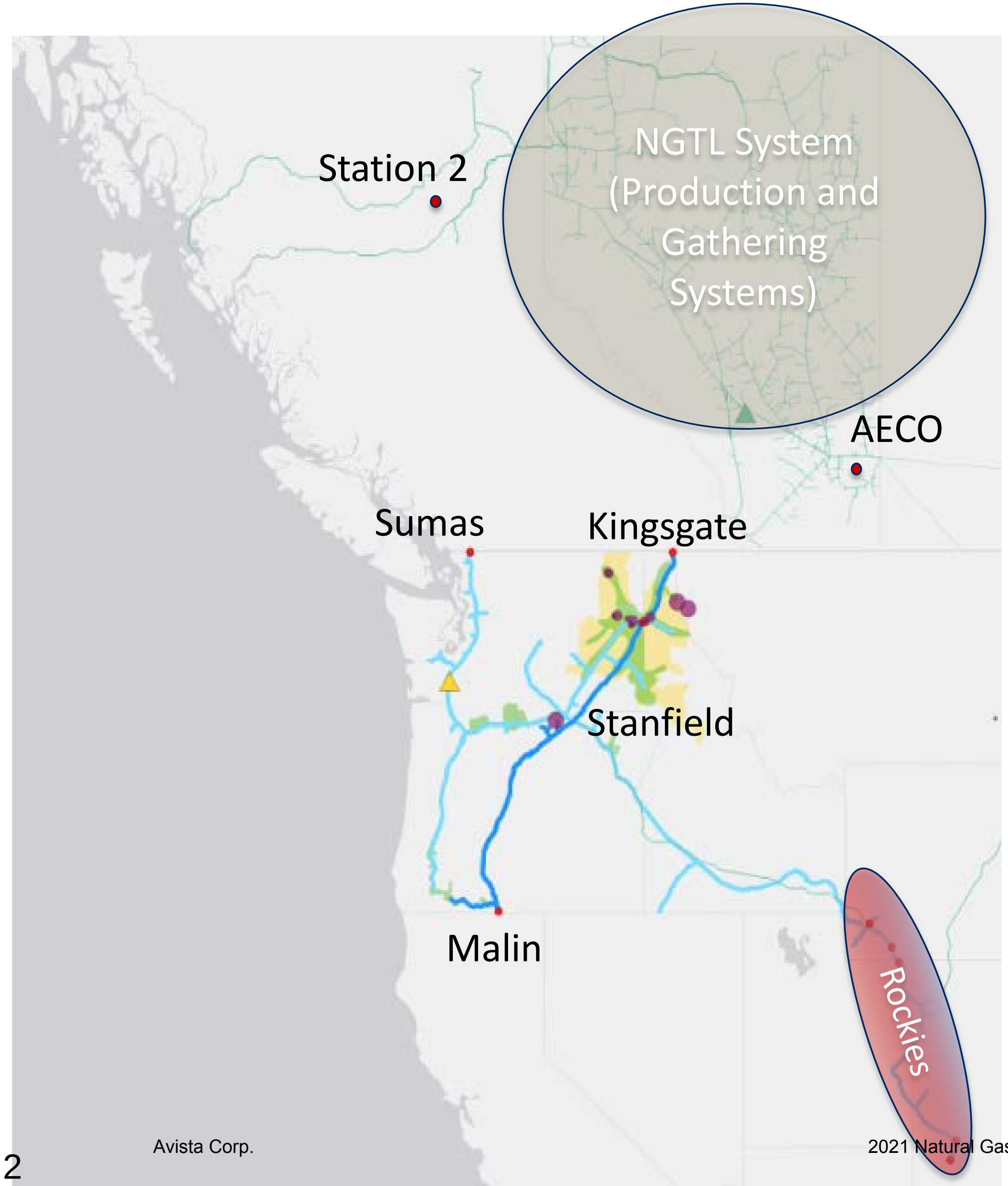
3:45 – Adjourn

Natural Gas Market Overview

Tom Pardee, Natural Gas Planning Manager
Second Technical Advisory Committee Meeting
August 6, 2020

Units

	Common Gas Units		
	1 Bcf	1 Dth	1 Therm
kWh	302,062,888	293.001	29.300
MWh	302,063	0.293	0.029



Avista Electric Territory

Avista Natural Gas Territory

Electric Power Plants

Gas Transmission Network

Northwest Pipeline

Receipt Point

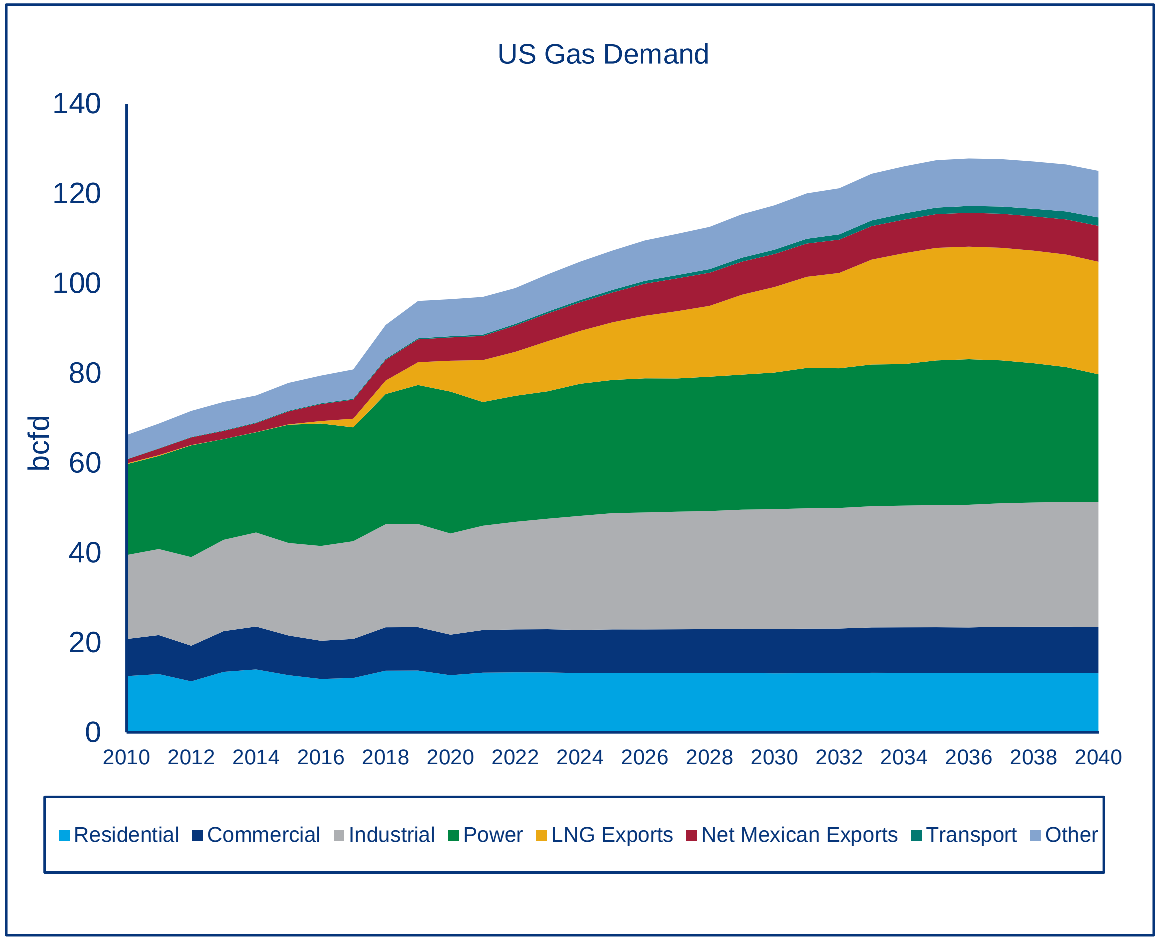
Jackson Prairie Storage (LDC Owned)

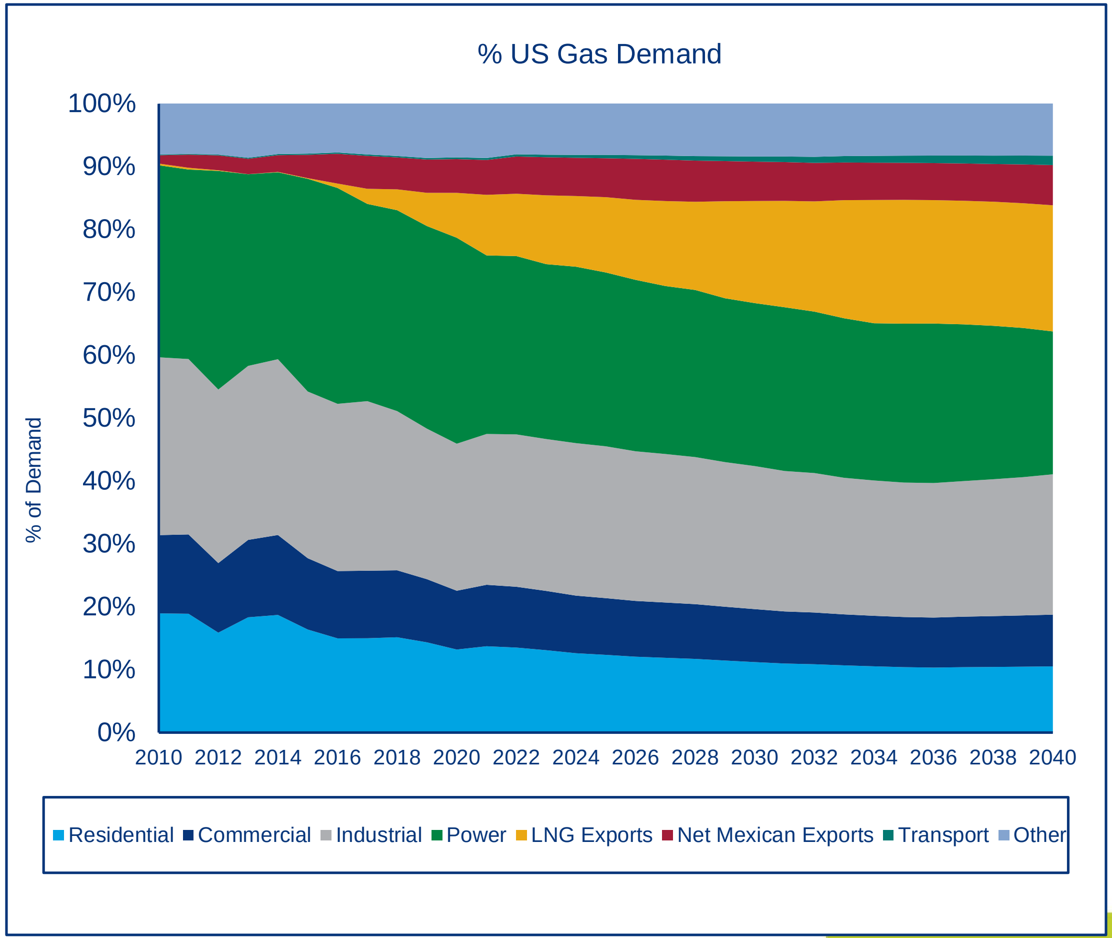
Avista's Supply

- Natural Gas LDC Side
  - – 10% contracted from US supply basins
  - – 90% contracted from Canadian supply basins

- Electric Side
  - – 100% contracted from Canadian supply basins

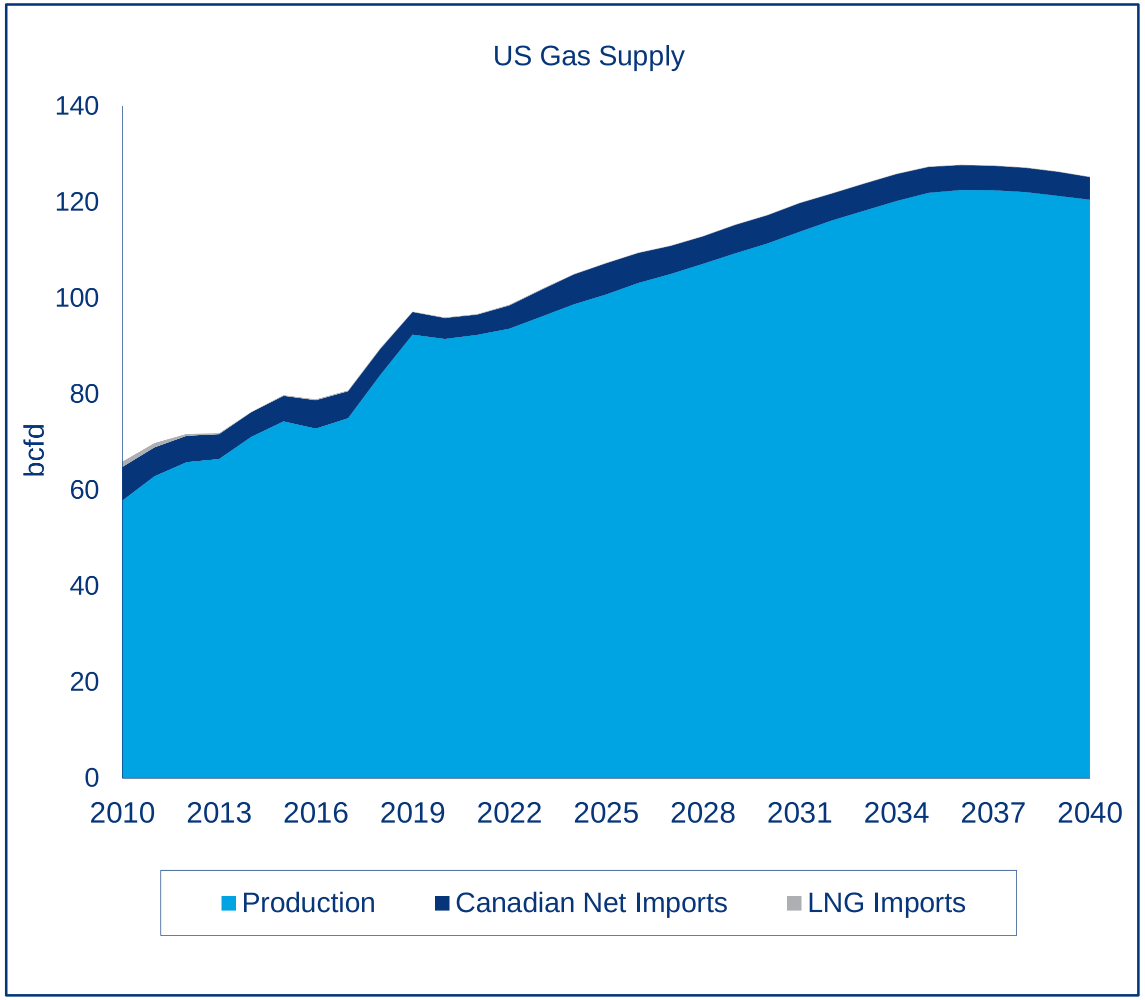
US Demand

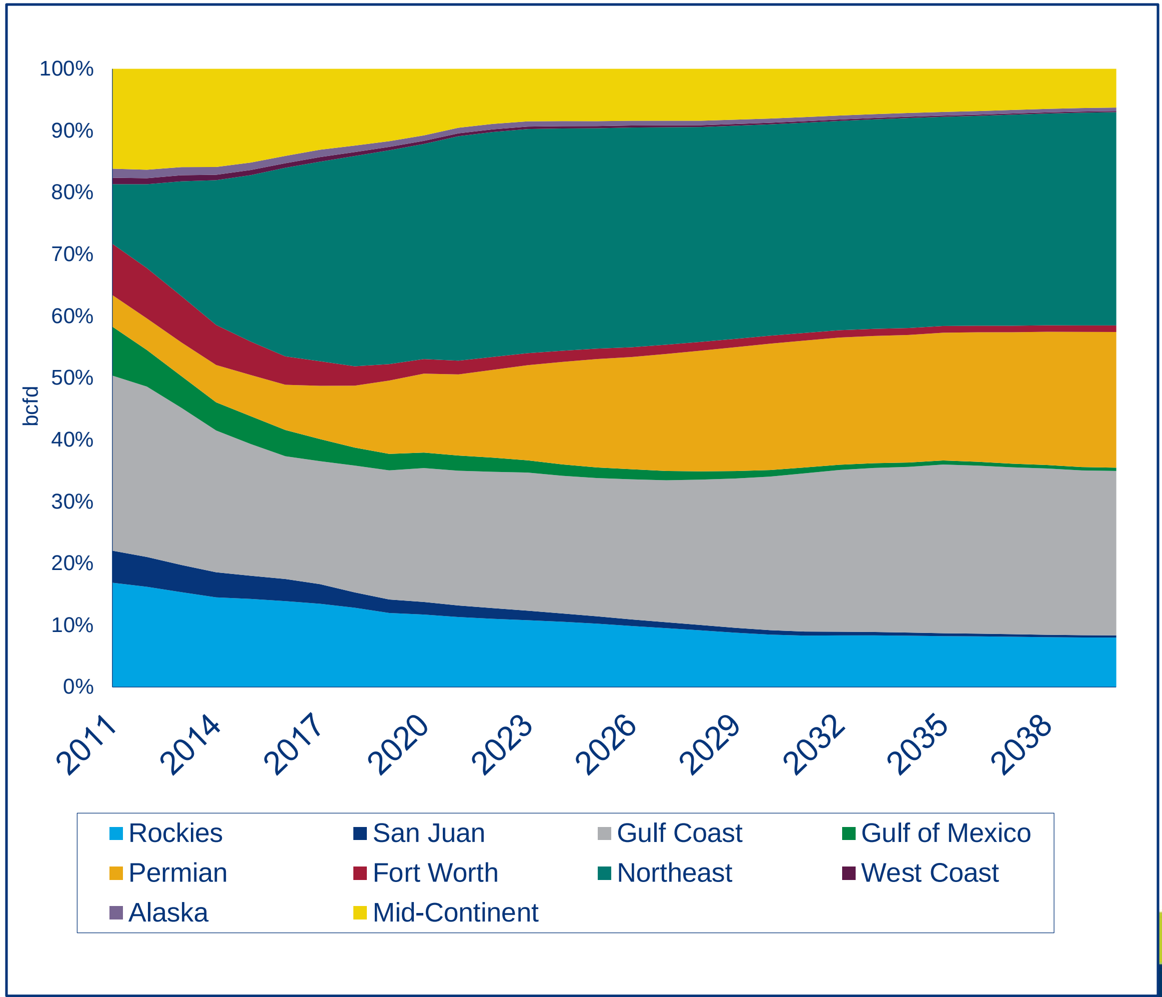




Source: Wood Mackenzie

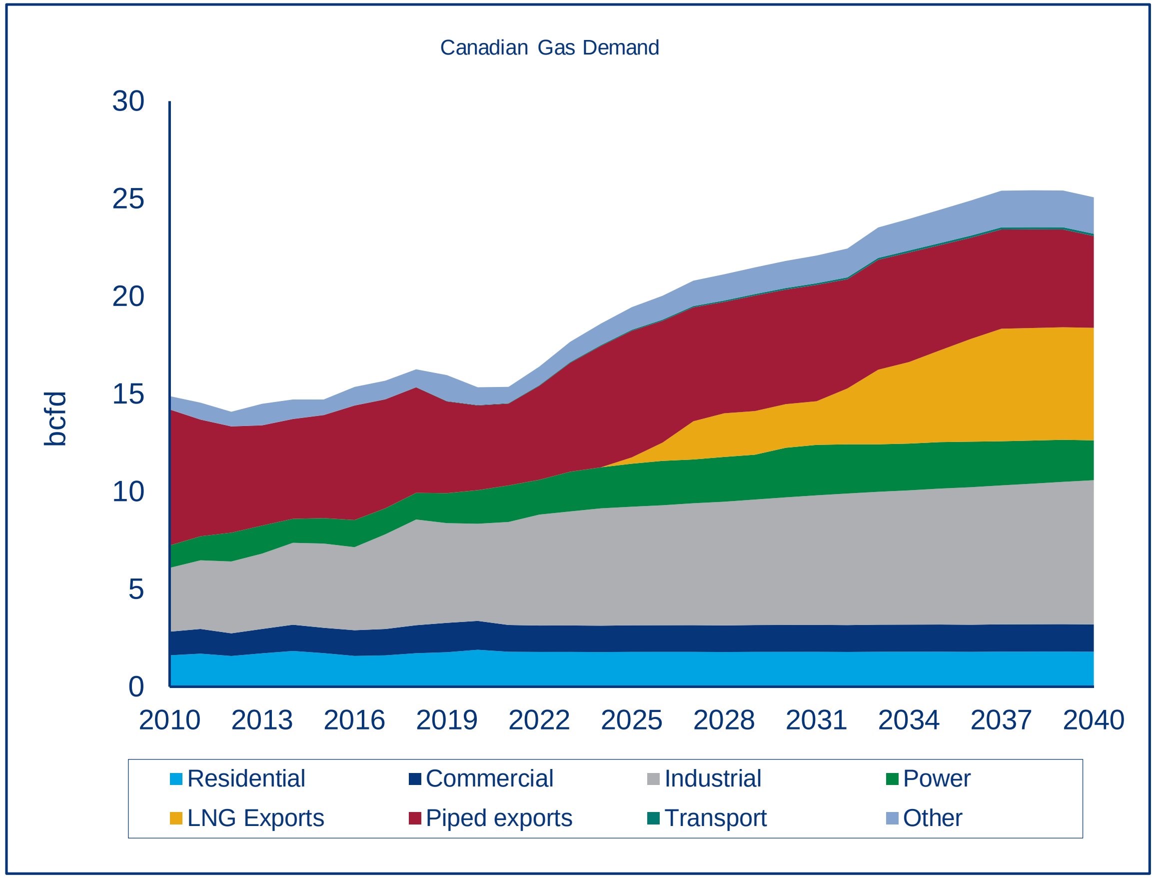
US Supply

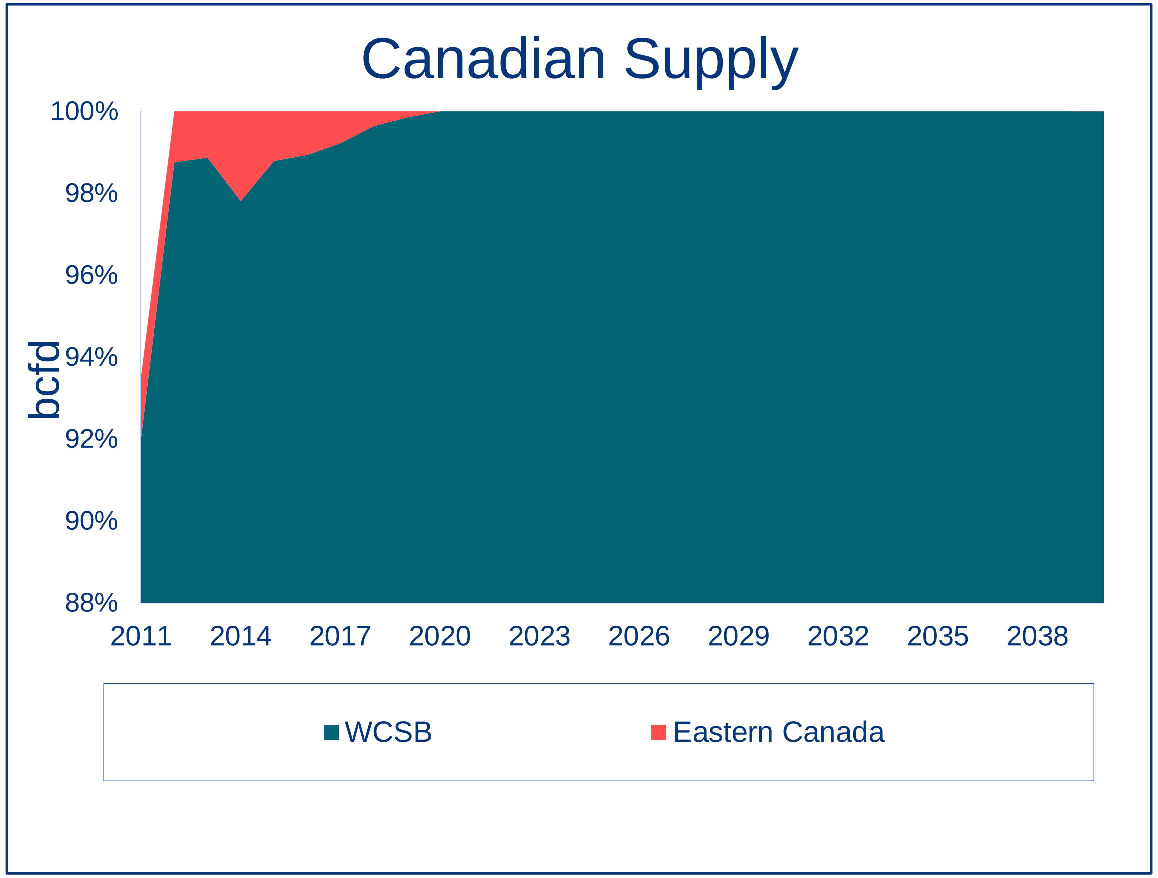




Source: Wood Mackenzie

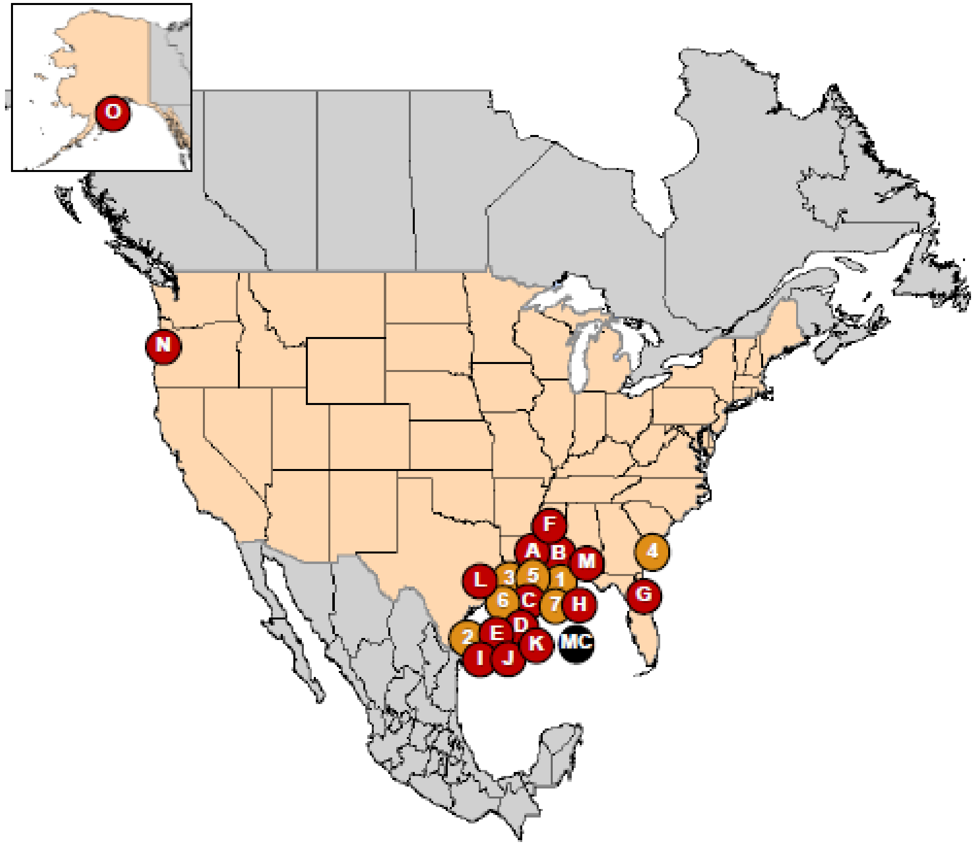
Canadian Supply and Demand





Source: Wood Mackenzie

North American LNG Export Terminals
Approved, Not Yet Built



U.S. Jurisdiction & Status

- FERC - Approved, Under Construction
- FERC - Approved, Not Under Construction
- MARAD / U.S. Coast Guard

<u>Export Terminals</u>

UNITED STATES

APPROVED - UNDER CONSTRUCTION - FERC

1. **Hackberry, LA:** .71 Bcfd (Sempra–Cameron LNG Train 3) (CP13-25)
2. **Corpus Christi, TX:** 0.72 Bcfd (Cheniere–Corpus Christi LNG Train 2) (CP12-507)
3. **Sabine Pass, LA:** 0.7 Bcfd <u>Train 6</u> (Sabine Pass Liquefaction) (CP13-552)
4. **Elba Island, GA:** 140 MMcfd (Southern LNG Company Units 7-10) (CP14-103)
5. **Cameron Parish, LA:** 1.41 Bcfd (Venture Global Calcasieu Pass) (CP15-550)
6. **Sabine Pass, TX:** 2.1 Bcfd (ExxonMobil – Golden Pass) (CP14-517)
7. **Calcasieu Parish, LA:** 4.0 Bcfd (Driftwood LNG) (CP17-117)

APPROVED – NOT UNDER CONSTRUCTION - FERC

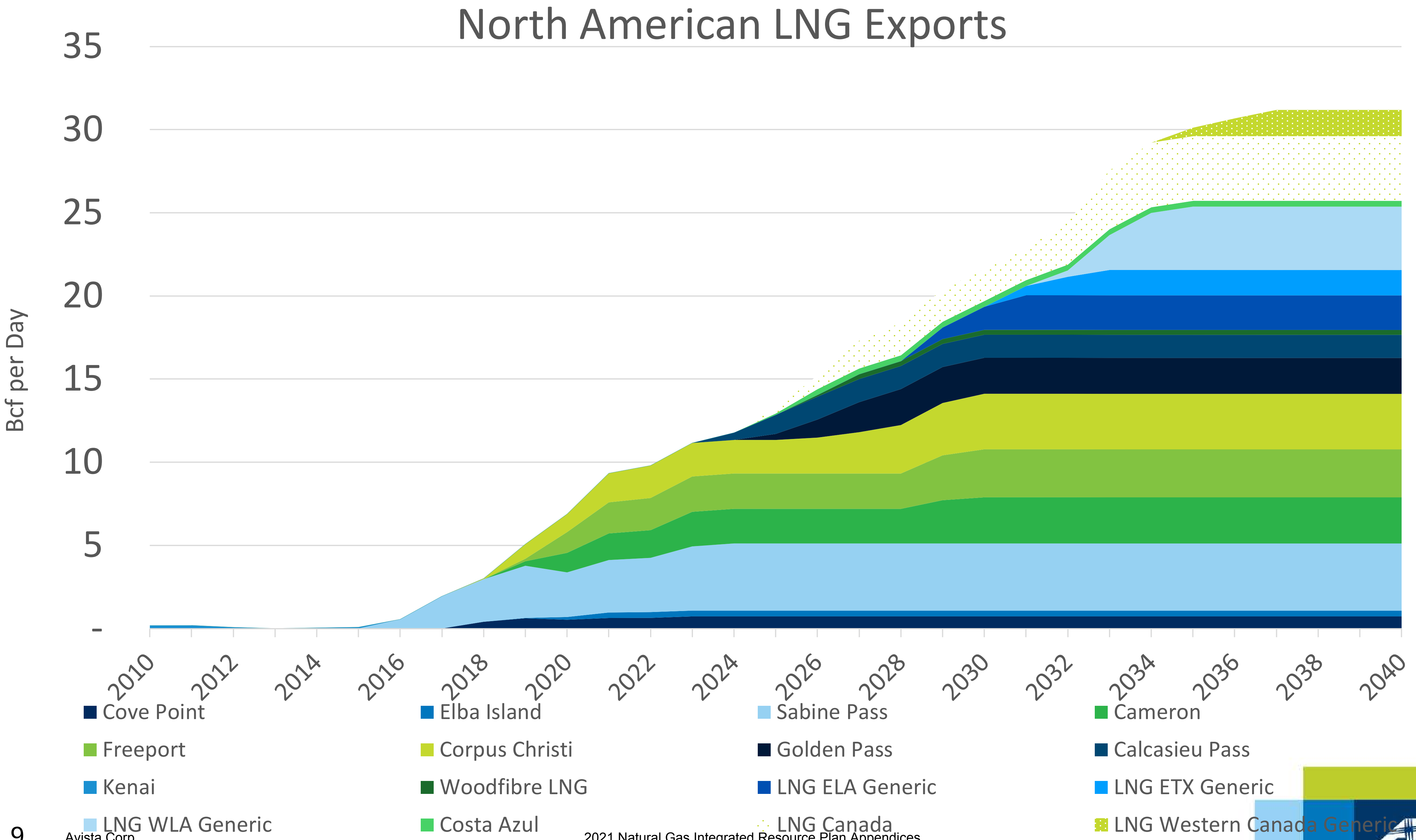
A. **Lake Charles, LA:** 2.2 Bcfd (Lake Charles LNG) (CP14-120)
B. **Lake Charles, LA:** 1.08 Bcfd (Magnolia LNG) (CP14-347)
C. **Hackberry, LA:** 1.41 Bcfd (Sempra - Cameron LNG Trains 4 & 5) (CP15-560)
D. **Port Arthur, TX:** 1.86 Bcfd (Port Arthur LNG Trains 1 & 2) (CP17-20)
E. **Freeport, TX:** 0.72 Bcfd (Freeport LNG Dev Train 4) (CP17-470)
F. **Pascagoula, MS:** 1.5 Bcfd (Gulf LNG Liquefaction) (CP15-521)
G. **Jacksonville, FL:** 0.132 Bcf/d (Eagle LNG Partners) (CP17-41)
H. **Plaquemines Parish, LA:** 3.40 Bcfd (Venture Global LNG) (CP17-66)
I. **Brownsville, TX:** 0.55 Bcfd (Texas LNG Brownsville) (CP16-116)
J. **Brownsville, TX:** 3.6 Bcfd (Rio Grande LNG – NextDecade) (CP16-454)
K. **Brownsville, TX:** 0.9 Bcfd (Annova LNG Brownsville) (CP16-480)
L. **Corpus Christi, TX:** 1.86 Bcfd (Cheniere Corpus Christi LNG) (CP18-512)
M. **Sabine Pass, LA:** NA Bcfd (Sabine Pass Liquefaction) (CP19-11)
N. **Coos Bay, OR:** 1.08 Bcfd (Jordan Cove) (CP17-494)
O. **Nikiski, AK:** 2.63 Bcfd (Alaska Gasline) (CP17-178)

APPROVED – NOT UNDER CONSTRUCTION – MARAD/Coast Guard
MC. Gulf of Mexico: 1.8 Bcfd (Delfin LNG)

CANADA
For Canadian LNG Import and Proposed Export Facilities:

https://www.nrcan.gc.ca/energy/natural-gas/5683

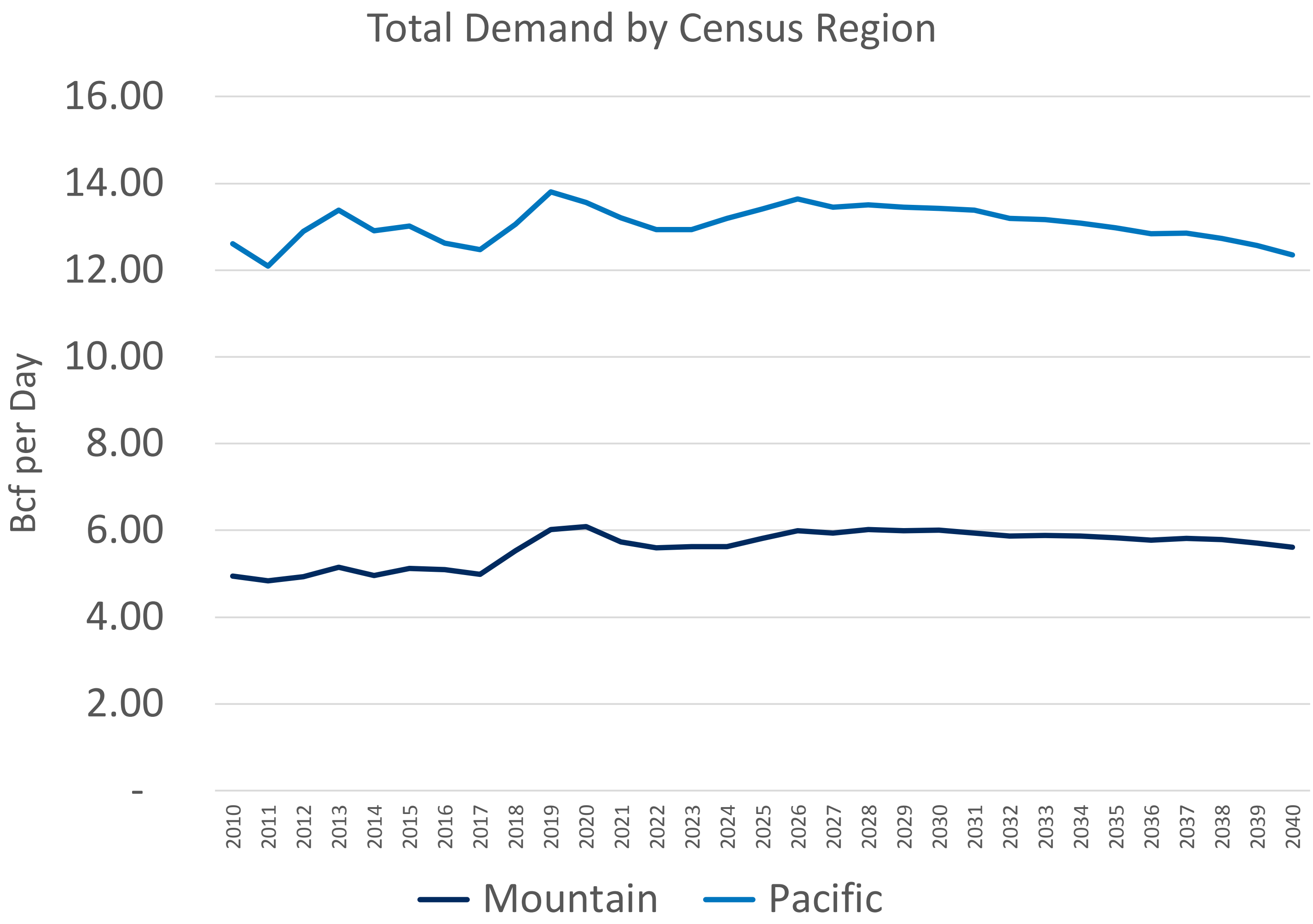
As of May 29, 2020



*WM does not assume Jordan Cove will enter service within forecasted period

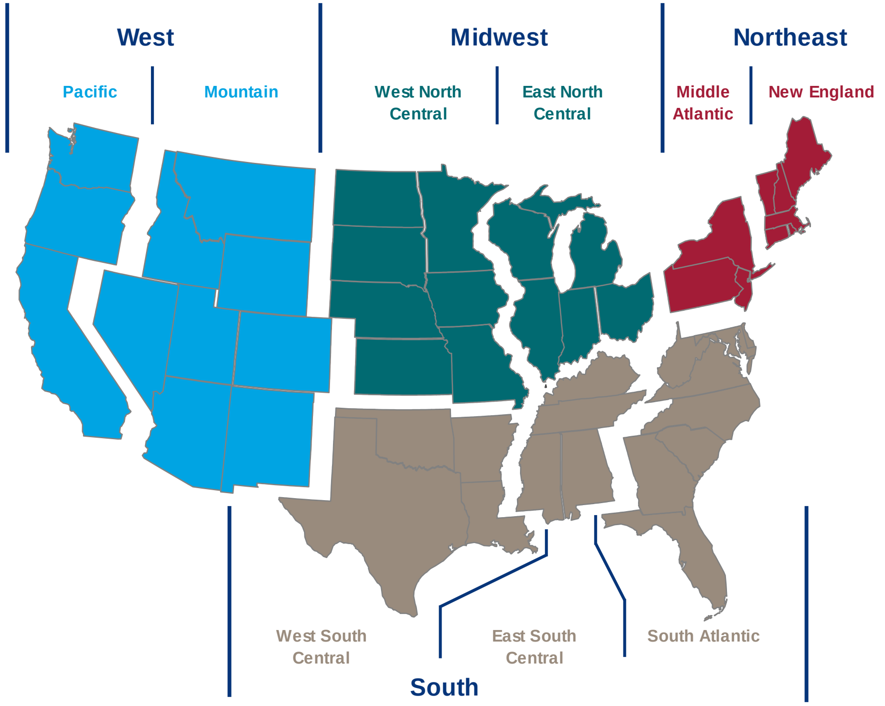
Source: Wood Mackenzie

West



Wood Mackenzie
North America Natural Gas Long-Term View
2020 H1

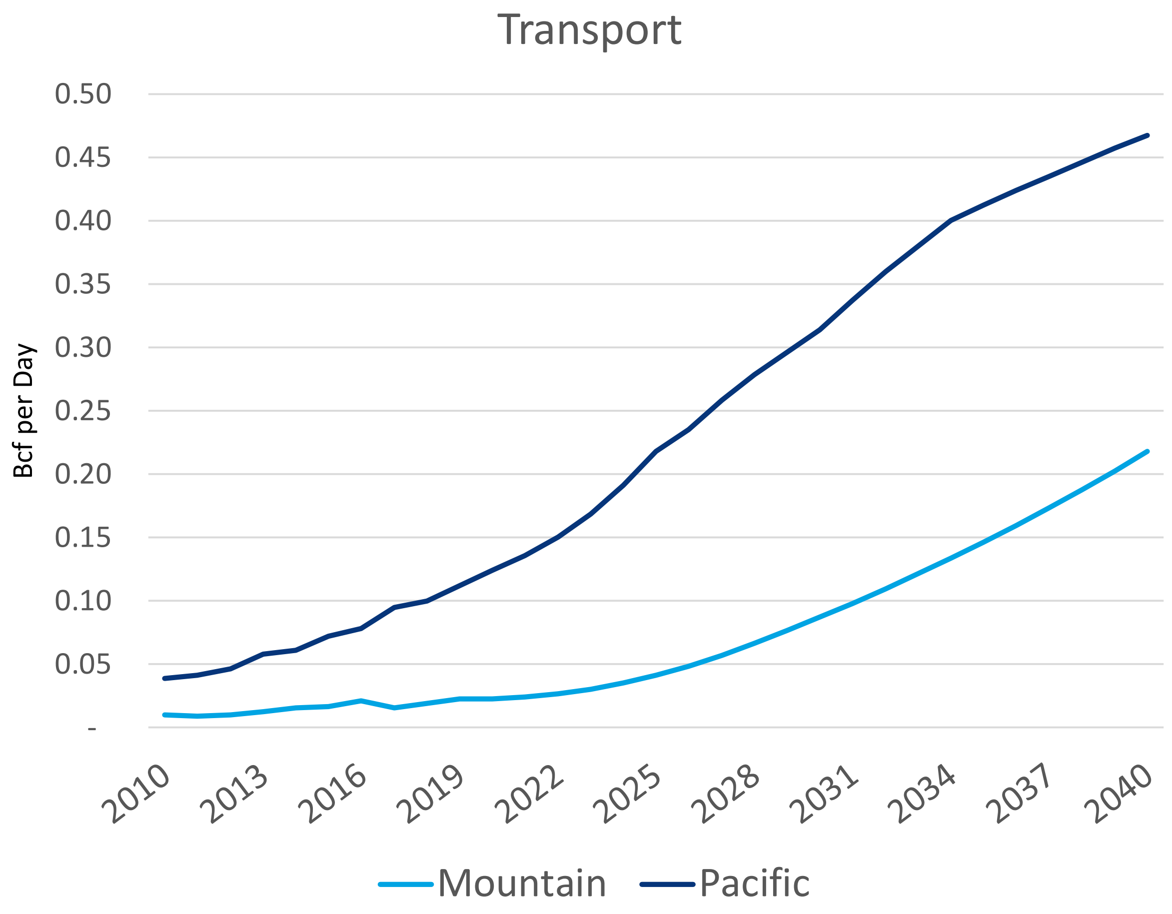
Census Region Map

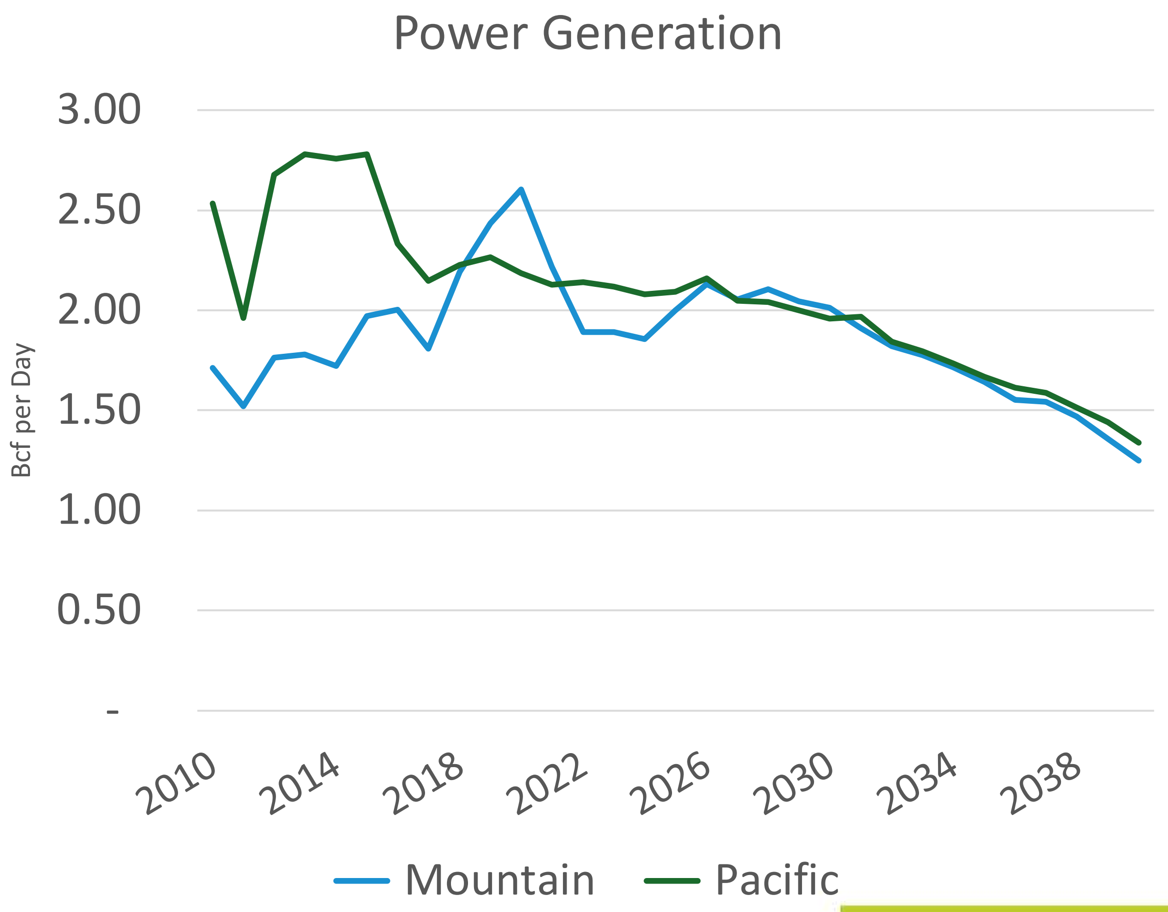


Note: Pacific does not include Alaska or Hawaii

Source: Wood Mackenzie

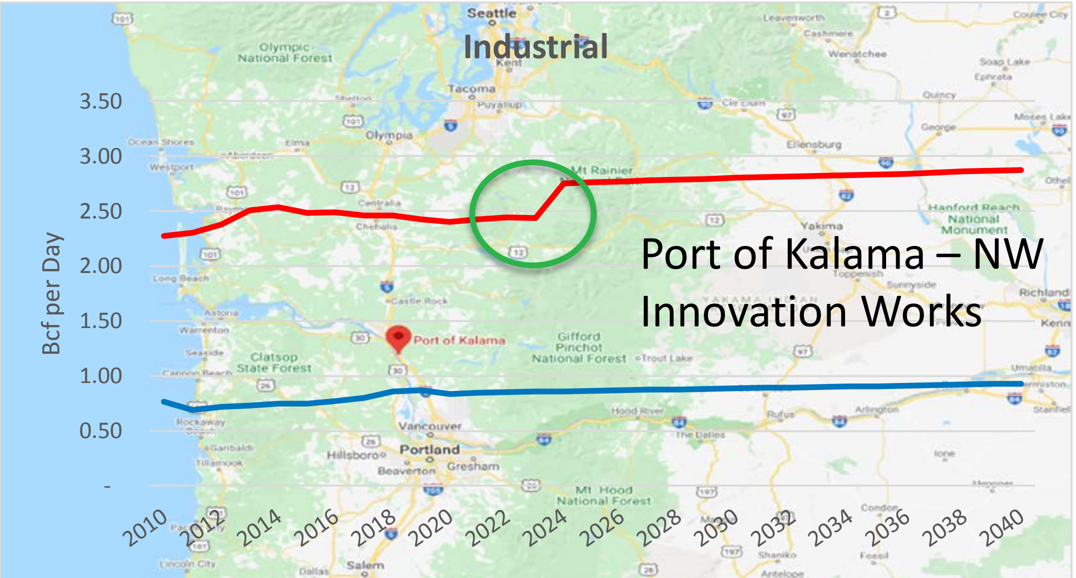
Power Generation and Transport demand



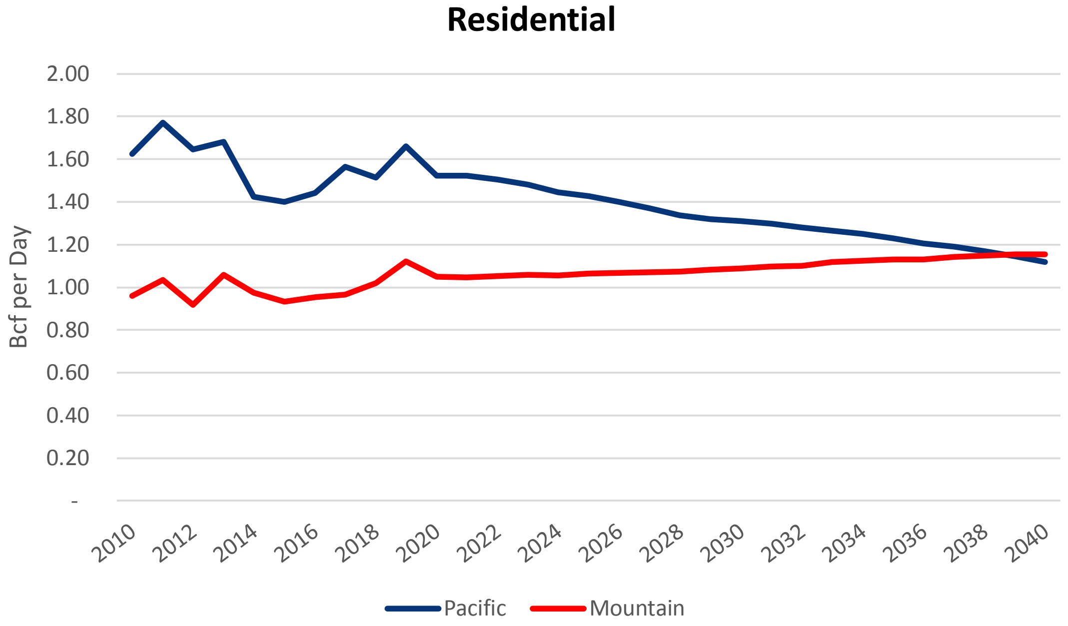


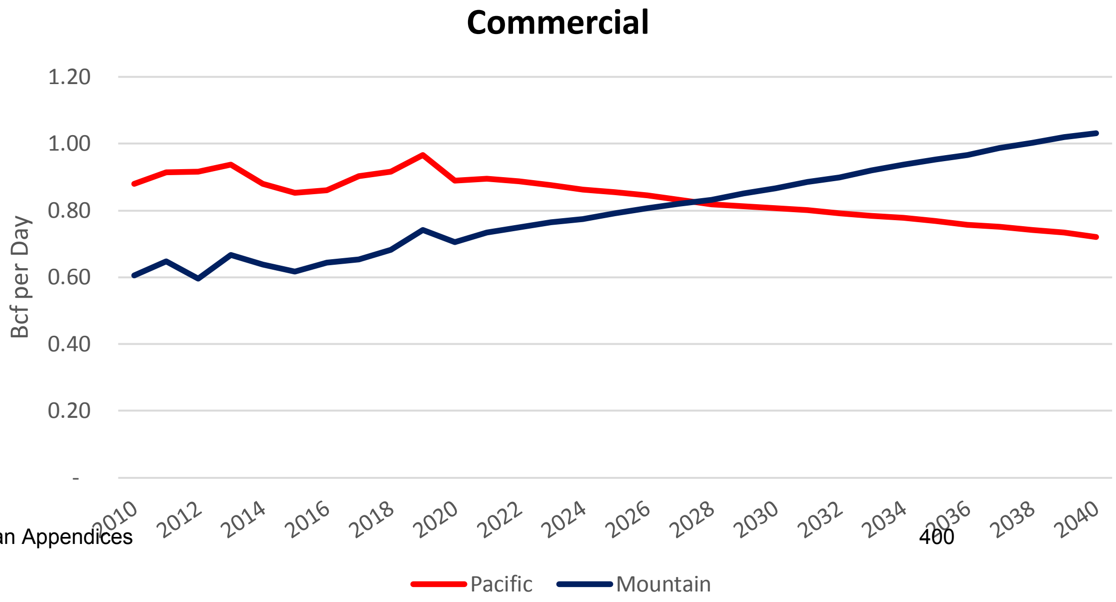
Source: Wood Mackenzie

West demand of Res-Com-Ind



Source: Wood Mackenzie





Source: Wood Mackenzie

Wood Mackenzie Disclaimer

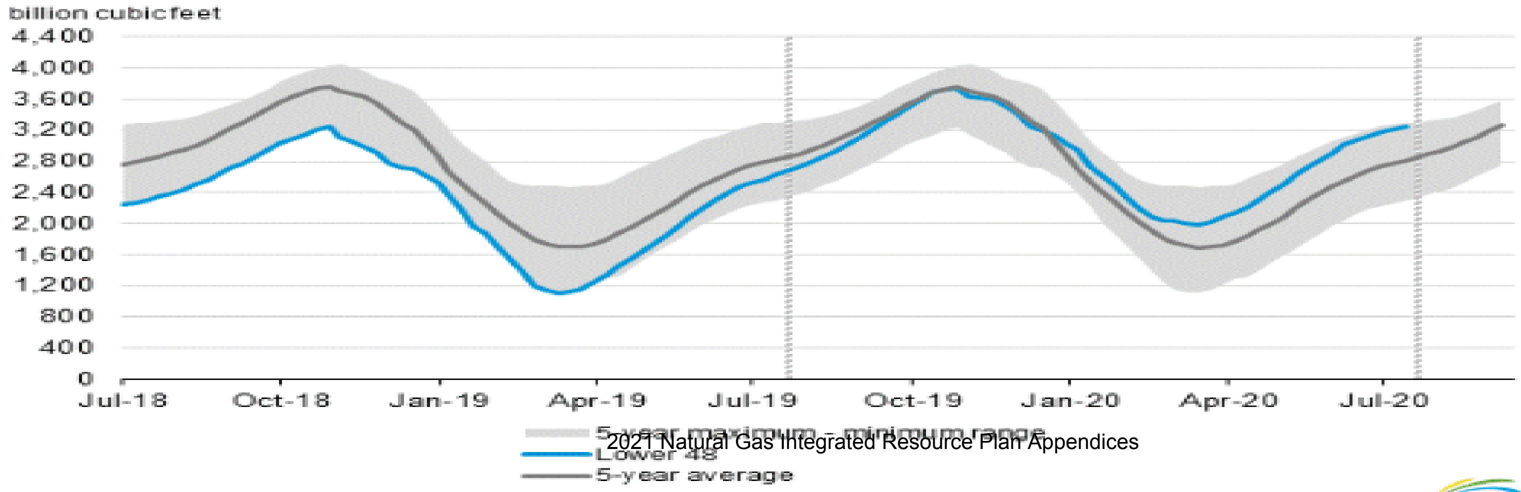
- The foregoing [chart/graph/table/information] was obtained from the [North America Gas Service]™, a product of Wood Mackenzie."
- Any information disclosed pursuant to this agreement shall further include the following disclaimer: "The data and information provided by Wood Mackenzie should not be interpreted 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

Us Natural Gas Storage

	Stocks billion cubic feet (Bcf)				Historical Comparisons: Year ago (07/24/19)		Historical Comparisons: 5-year average (2015-19)	
Region	07/24/20	07/17/20	net change	implied flow	Bcf	% change	Bcf	% change
East	706	693	13	13	591	19.5	626	12.8
Midwest	815	799	16	16	669	21.8	687	18.6
Mountain	196	190	6	6	155	26.5	176	11.4
Pacific	313	311	2	2	270	15.9	295	6.1
South Central	1,211	1,221	-10	-10	930	30.2	1,028	17.8
Salt	339	349	-10	-10	227	49.3	274	23.7
Nonsalt	872	872	0	0	703	24.0	754	15.6
Total	**3,241**	**3,215**	**26**	**26**	**2,615**	**23.9**	**2,812**	**15.3**

Totals may not equal sum of components because of independent rounding.

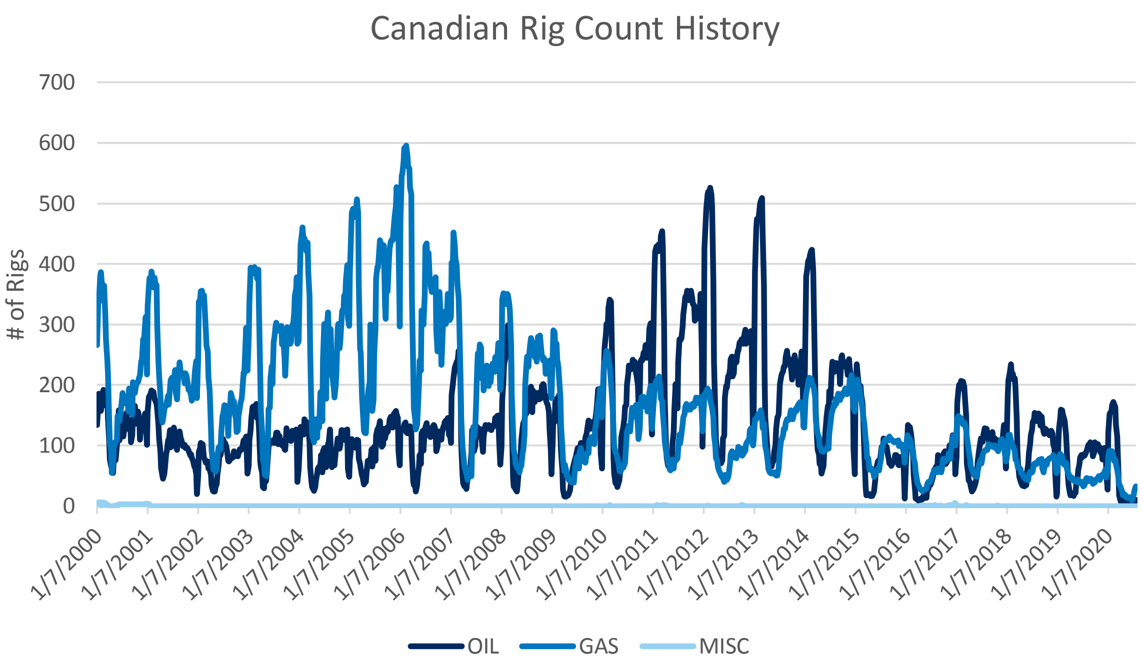
Working gas in underground storage compared with the 5-year maximum and minimum

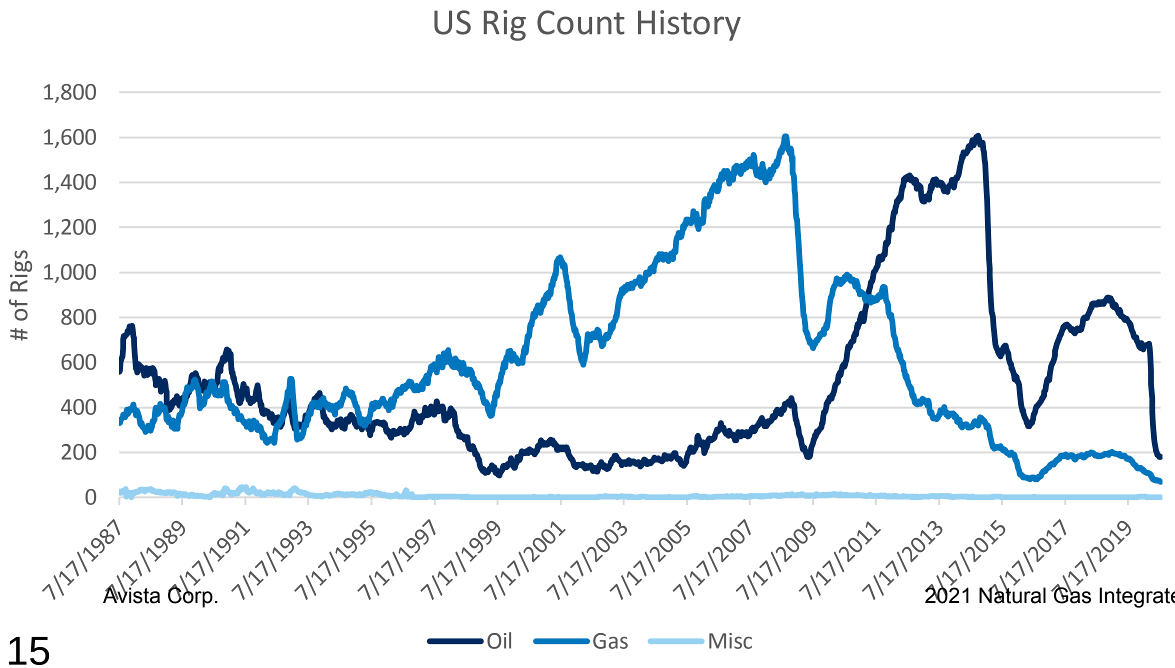


Source: U.S. Energy Information Administration

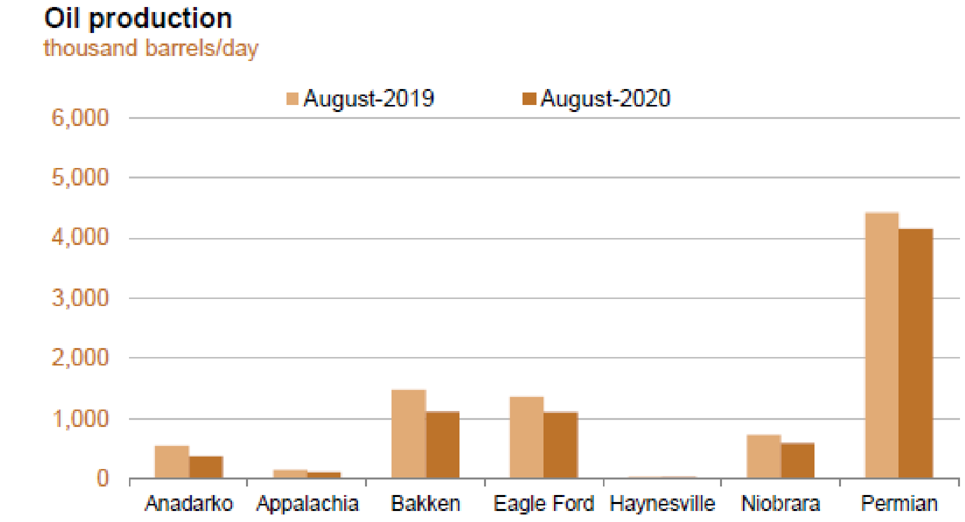
Rig Counts

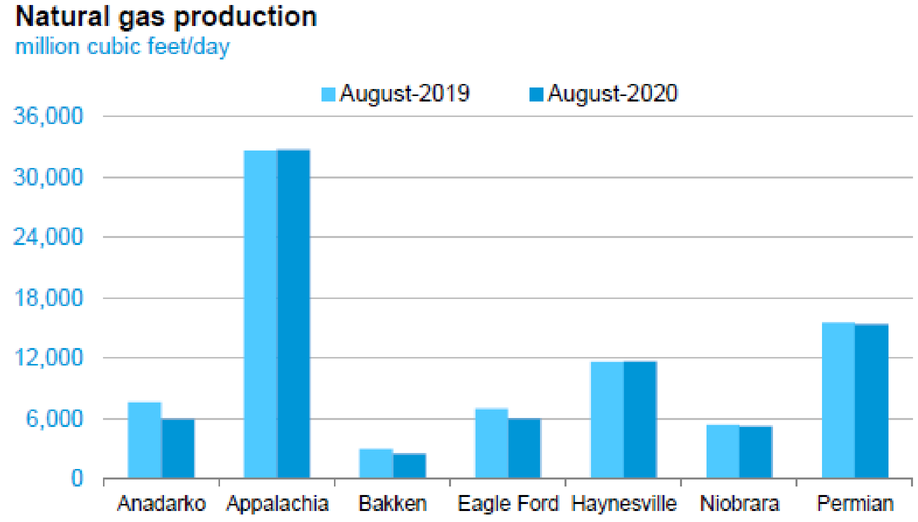
Area	Last Count	Count	Change from Prior Count	Date of Prior Count	Change from Last Year	Date of Last Year's Count
U.S.	24 July 2020	251	-2	17 July 2020	-695	26 July 2019
Canada	24 July 2020	42	+10	17 July 2020	-85	26 July 2019
International	June 2020	781	-24	May 2020	-357	June 2019

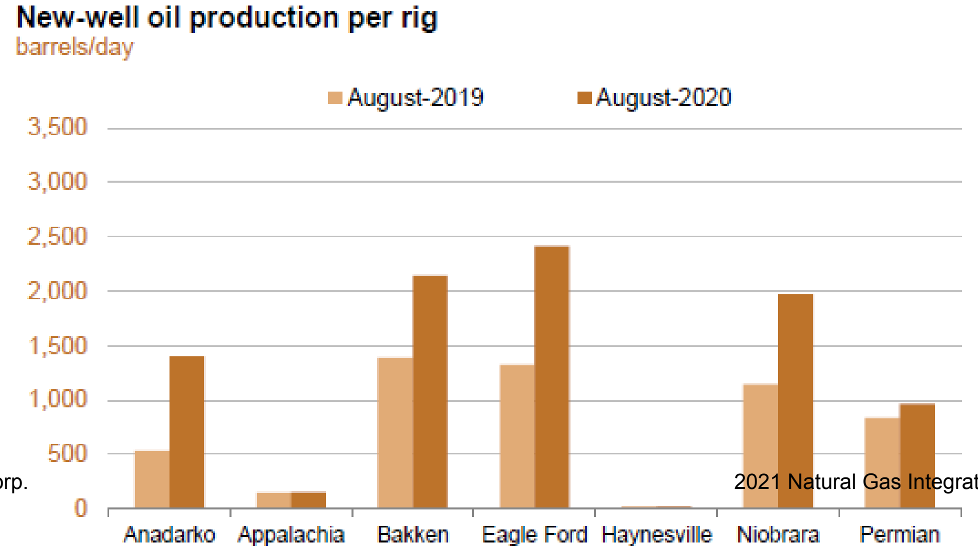


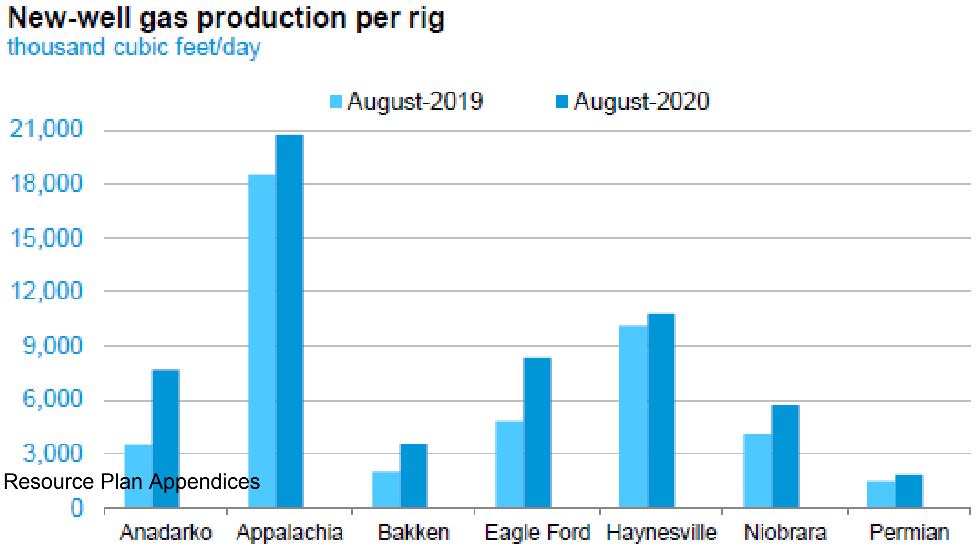


Production and Drilling efficiency

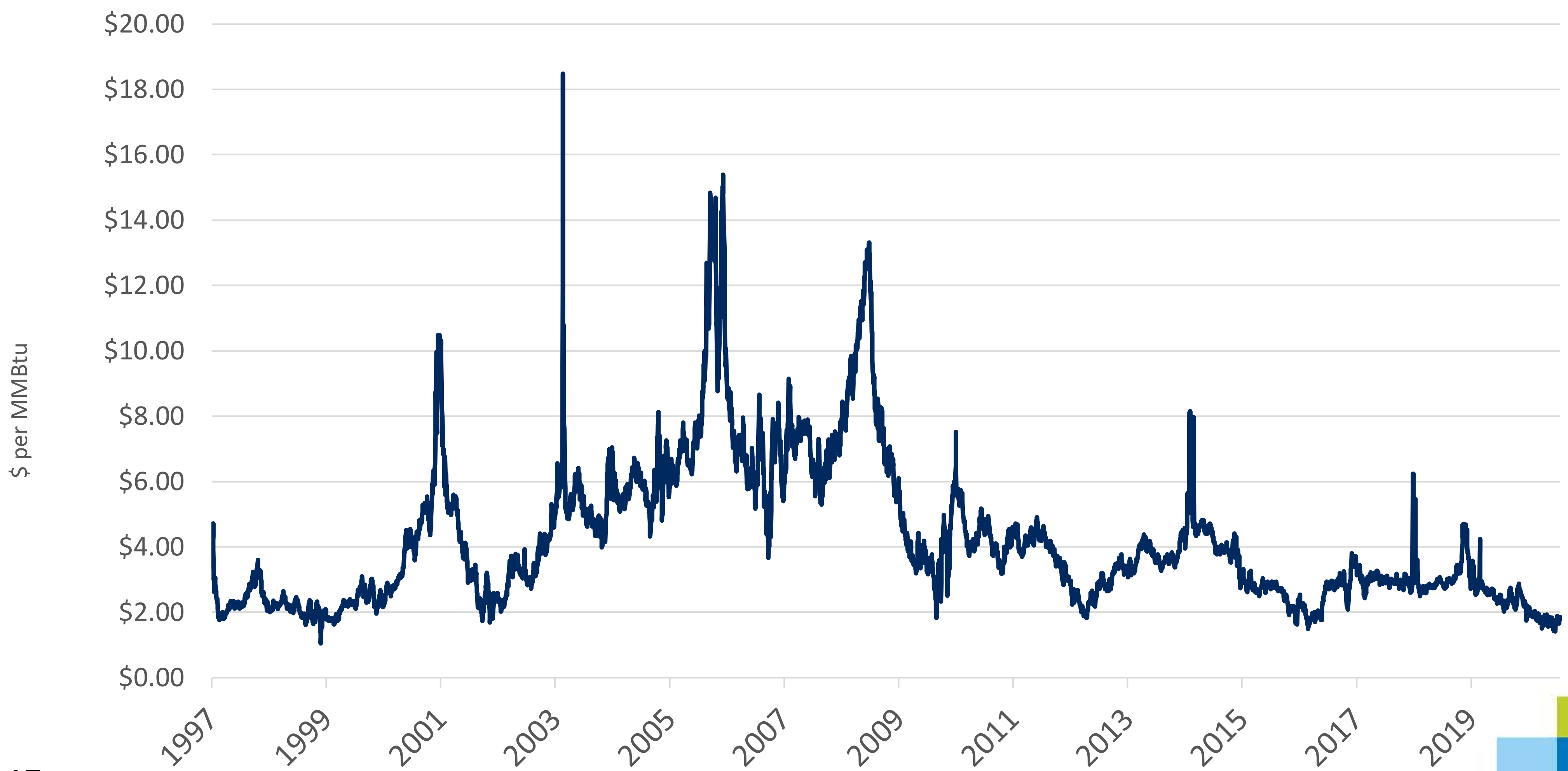








Historic Cash prices (Jan. 1997 – July 2020)



Upstream Emissions

Tom Pardee

Upstream Emissions

- Use based greenhouse gas emissions at the point of combustion and include upstream methane emissions
- Link for Natural Gas Advisory Committee information on upstream methane: https://www.nwcouncil.org/energy/energy-advisory-committees/natural-gas-advisory-committee

Global Warming Potential

5th Assessment of the Intergovernmental Panel on Climate Change		
Greenhouse Gas	**GWP – 100 Year**	**GWP – 20 Year**
CO_2	1	1
CH_4	34	86
N_2O	298	268

Global warming potential (GWP) factors for conversion to CO_2 equivalents (CO_2e)

https://www.c2es.org/content/ipcc-fifth-assessment-report/

Upstream Emissions Sources and Estimates

- Rockies emissions – The EPA estimates all leakage through a bottoms up analysis. It will estimate leaks based on equipment operated as designed and combines these values to determine an overall rate of 1%. The emissions and sinks study is published yearly and will capture emissions as they change.

- Canadian emissions (British Columbia and Alberta) – A value of 0.77% was developed from data pertaining to the recent environmental impact studies for the PSE Tacoma LNG plant, Kalama Manufacturing and Export Facility and the 2019 Puget Sound Energy IRP.

WSU Natural Gas Methane Study

- Sponsored by EDF and utilities to estimate the leakage of distribution systems
- National project and estimated a loss of **0.1 – 0.2** percent of the methane delivered nationwide
- Western region contributes much less as compared to the East
- “Out of **230 measurements, three large leaks accounted for 50%** of the total measured emissions from pipeline leaks. In these types of emission studies, a few leaks accounting for a large fraction of total emissions are not unusual.”

LDC Upstream Emissions

	Avista Specific Natural Gas	
Combustion	Lbs. GHG/MMBtu	Lbs. CO2e/Mmbtu
CO2	116.88	116.88
CH4	0.0022	0.0748
N2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH4	0.313406851	10.66
Total		128.27

Upstream Emissions	Avista's Purchases	Emissions Location
0.77	89.72%	Canada
1.00	10.28%	Rockies
0.79		

*Avista gas purchases
An average of the total volume purchased over the past 5 years by emissions location

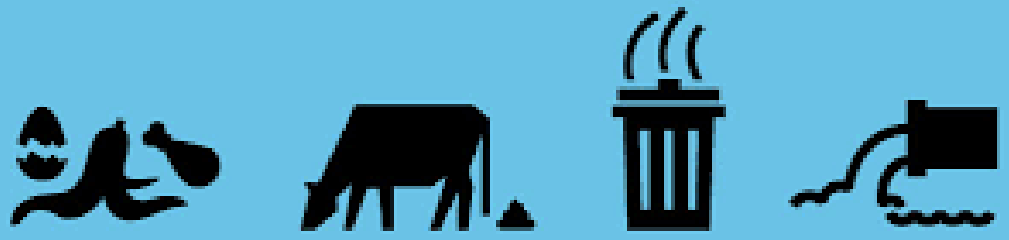
Electric Upstream Emissions

	Avista Specific Natural Gas	
Combustion	Lbs. GHG/MMBtu	Lbs. CO2e/Mmbtu
CO2	116.88	116.88
CH4	0.0022	0.0748
N2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH4	0.304065693	10.34
Total		127.95
Upstream Emissions	Avista's Purchases	Emissions Location
0.77	100.00%	Canada
1.00	0.00%	Rockies
0.77		

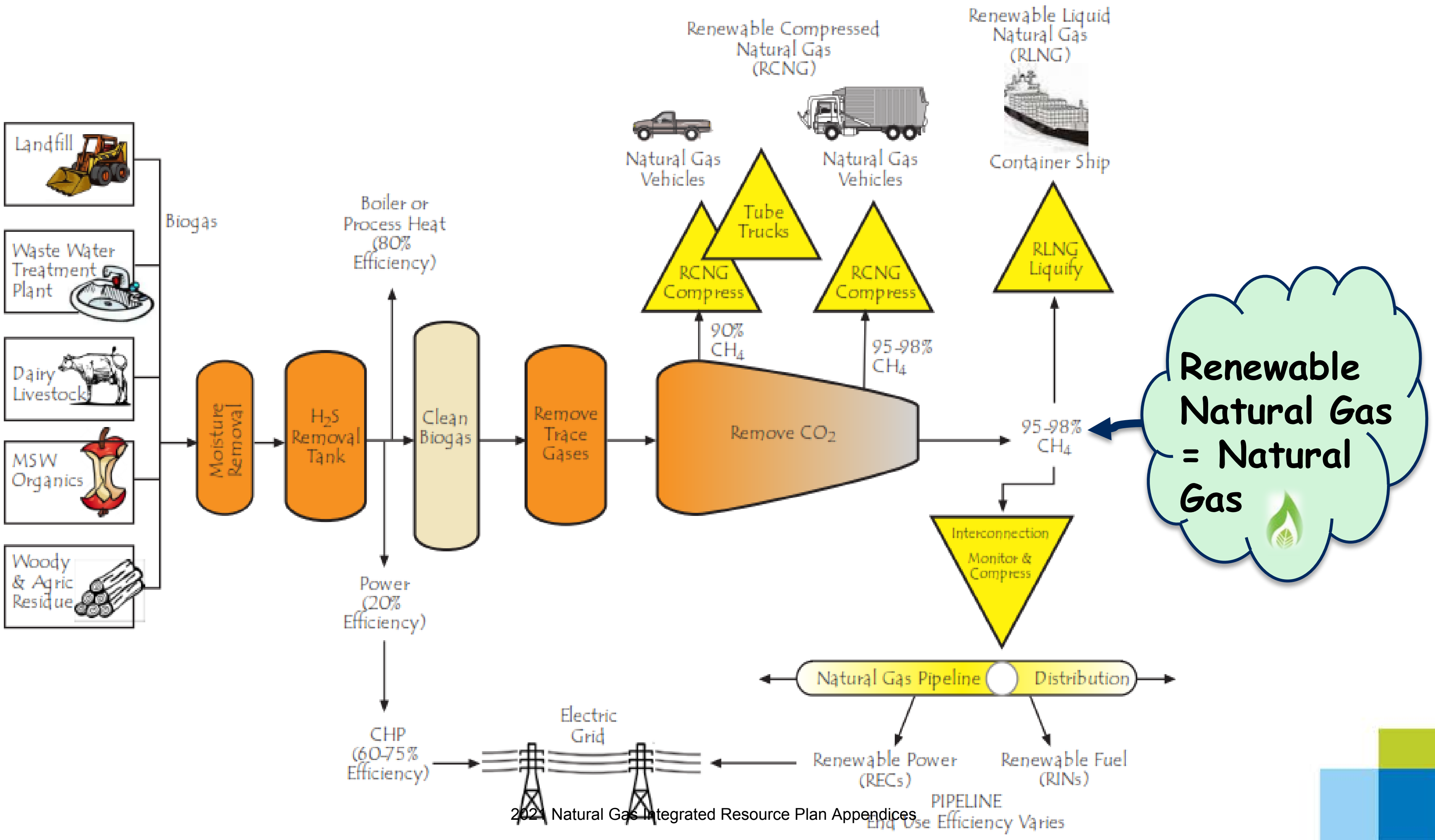
*Avista Purchases

All firm transportation to supply gas is located in Canada

Renewable Natural Gas (RNG)



What is Renewable Natural Gas (RNG)?



Why does RNG matter?

Climate Change Solution

- Natural gas plays critical role for meeting aggressive green house gas (GHG) reductions goals, RNG even more so!

- Utilizes existing infrastructure

- Advantages of RNG
  - “De-carbonizes” gas stream
  - Gives customers another renewable choice

Carbon Intensity

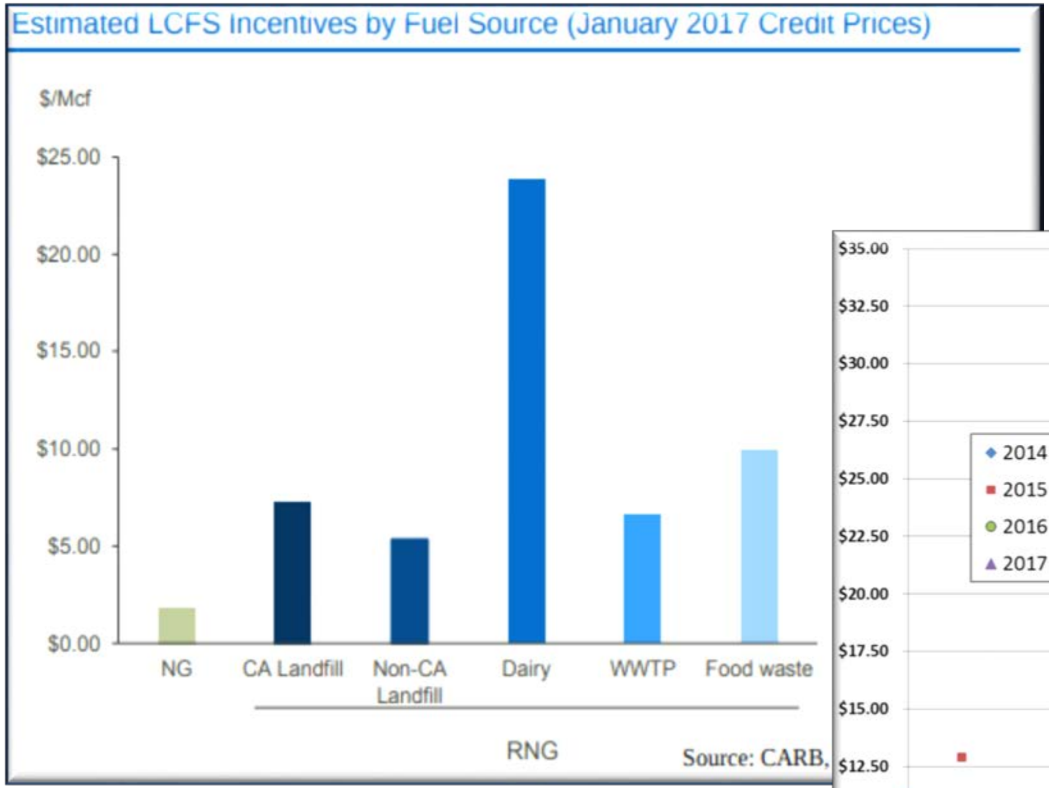
Fuel Pathway	Carbon Intensity $\frac{gCO_{2e}}{MJ}$
Diesel*	102.01
Gasoline*	99.78
Fossil CNG†	78.37
Landfill CNG†	46.42
WWTP CNG*	19.34
MSW CNG*	-22.93
Dairy CNG‡	-276.24

*California Code of Regulation Title 17, §95488, Table 6. Carbon intensity for WWTP is the average of two WWTP pathways.

†California Code of Regulation Title 17, §95488, Table 7.

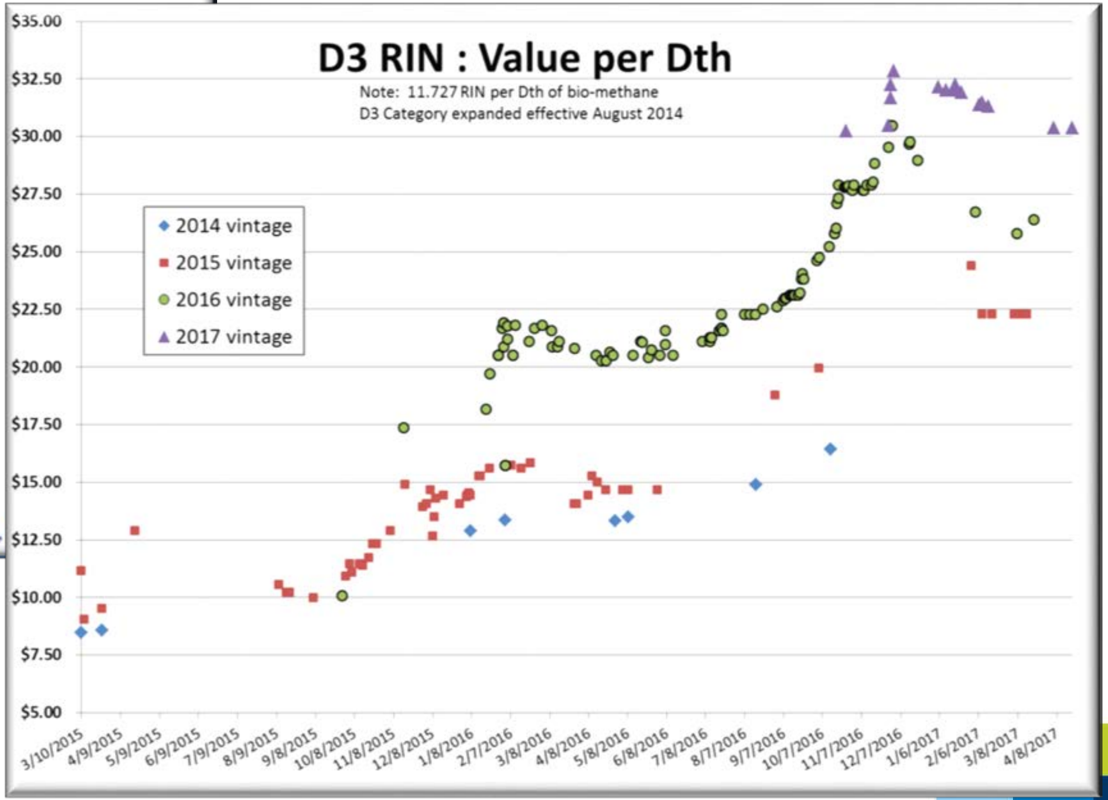
†Method 2B Application CalBio LLC, Dallas Texas, Dairy Digester Biogas to CNG.

RFS and LCFS Effect on RNG Value



Source: CARB

RIN = renewable identification number



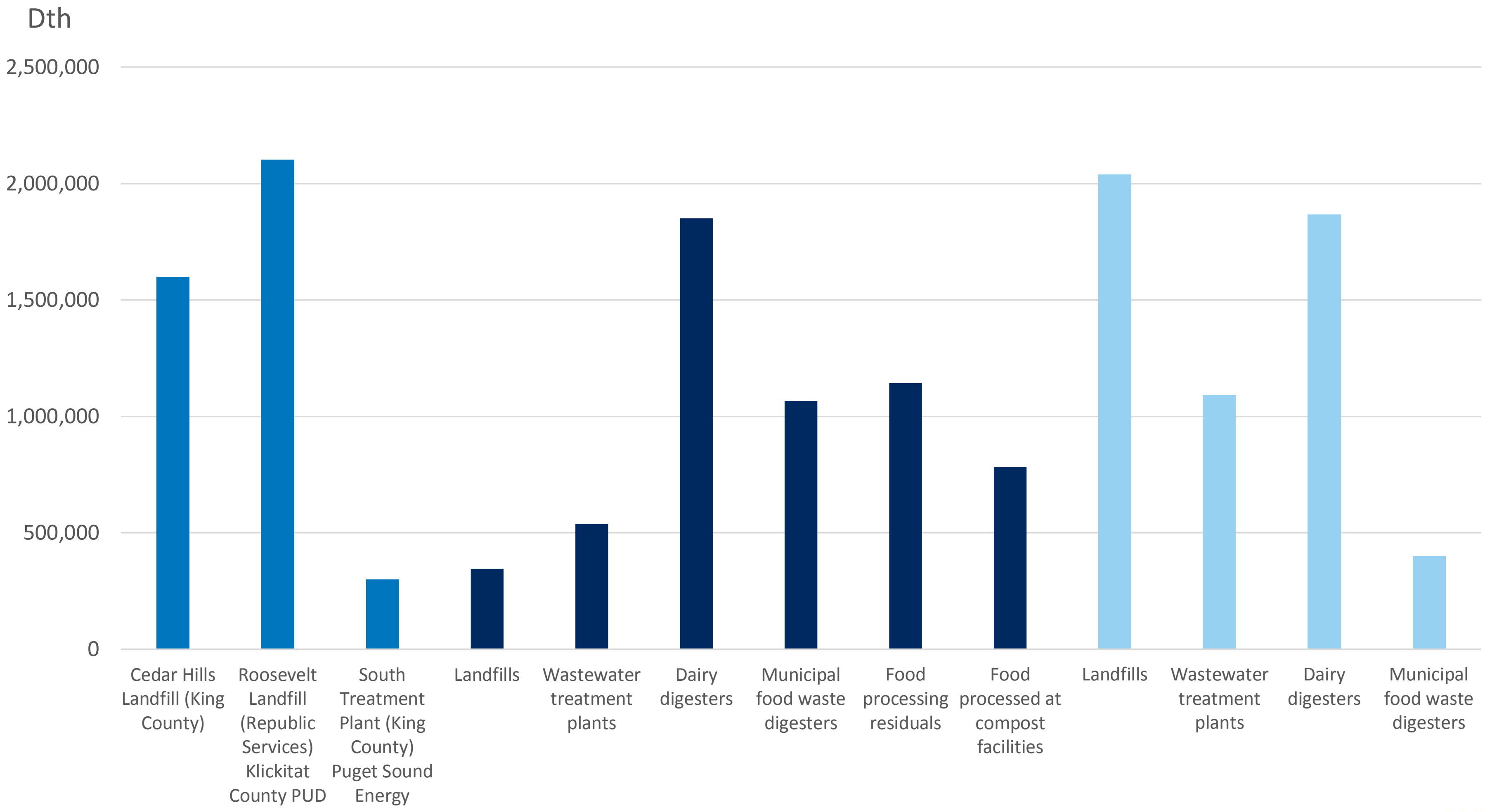
Source: EPA

What are the challenges & barriers?

- California RNG market ($30+/Dth v. $2/Dth)
  - Vehicle emission incentives shut-out other potential end users
  - Producers see the pot of gold in California
- Financing for producers
  - RIN market is volatile
  - No forward pricing for RNG RINs in carbon market
  - Vehicle market may be approaching saturation in CA
  - Producer/LDC partnerships may make sense

WA RNG Report (HB 2580)

Existing Projects
Near Term Projects
Medium Term Projects



WSU Energy Program, Harnessing Renewable Natural Gas for Low-Carbon Fuel: A Roadmap for Washington State

*Released December 1, 2018

ID RNG NREL Estimates

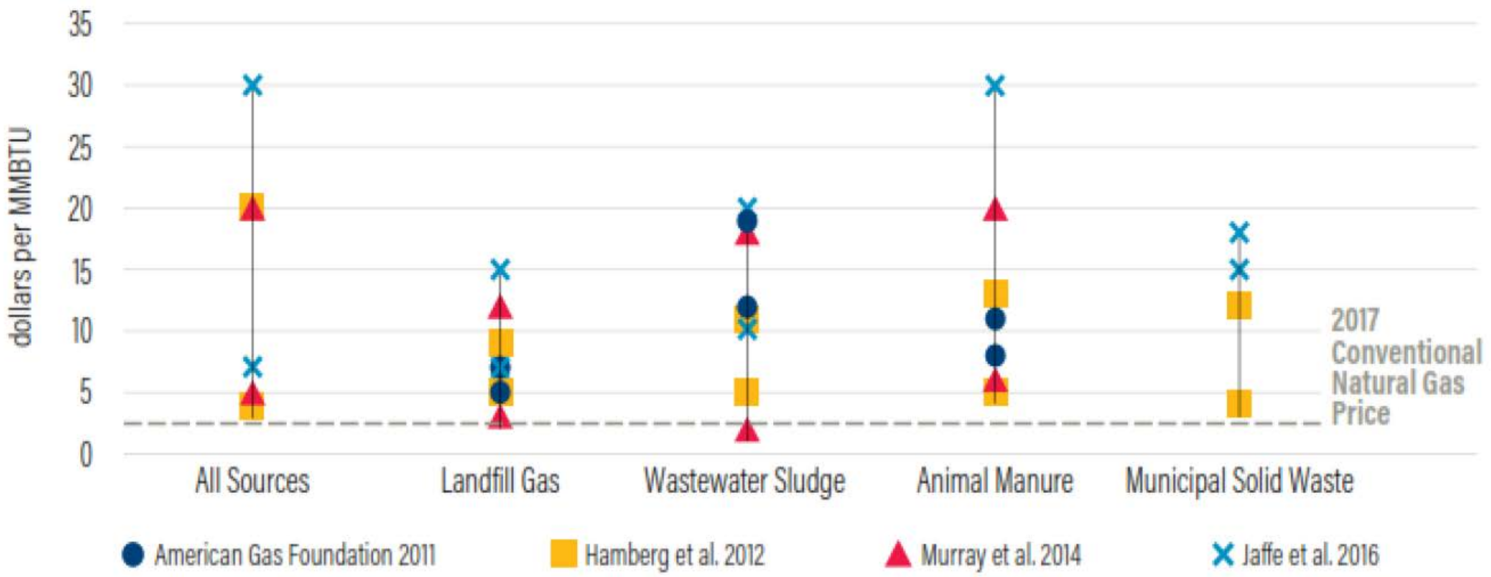
Total Potential Annual Production = 32 Bcf

Source - Anaerobic	MMBtu per Year
Landfills	3,712,221
Wastewater Treatment	6,196,531
Agriculture Manure	20,220,571
Source-Separated Organics (Solid Waste)	2,311,354
Total	**32,440,676**

National Renewable Energy Laboratory, NREL Biofuels Atlas

RNG $ per Dth/MMBtu

Avista Owned and Operated	ID - WA 2035 Premium Estimate ($ / Dth)
RNG - Landfills	$7 - $10
RNG - Waste Water Treatment Plants (WWTP)	$12 - $22
RNG - Agriculture Manure	$28 - $53
RNG - Food Waste	$29 - $53



Source: Promoting RNG in WA State

Natural Gas IRP

A detailed level of RNG understanding and evaluation process will be included in the Natural Gas IRP TAC #3 meeting on September 30, 2020

Natural Gas Price Forecast

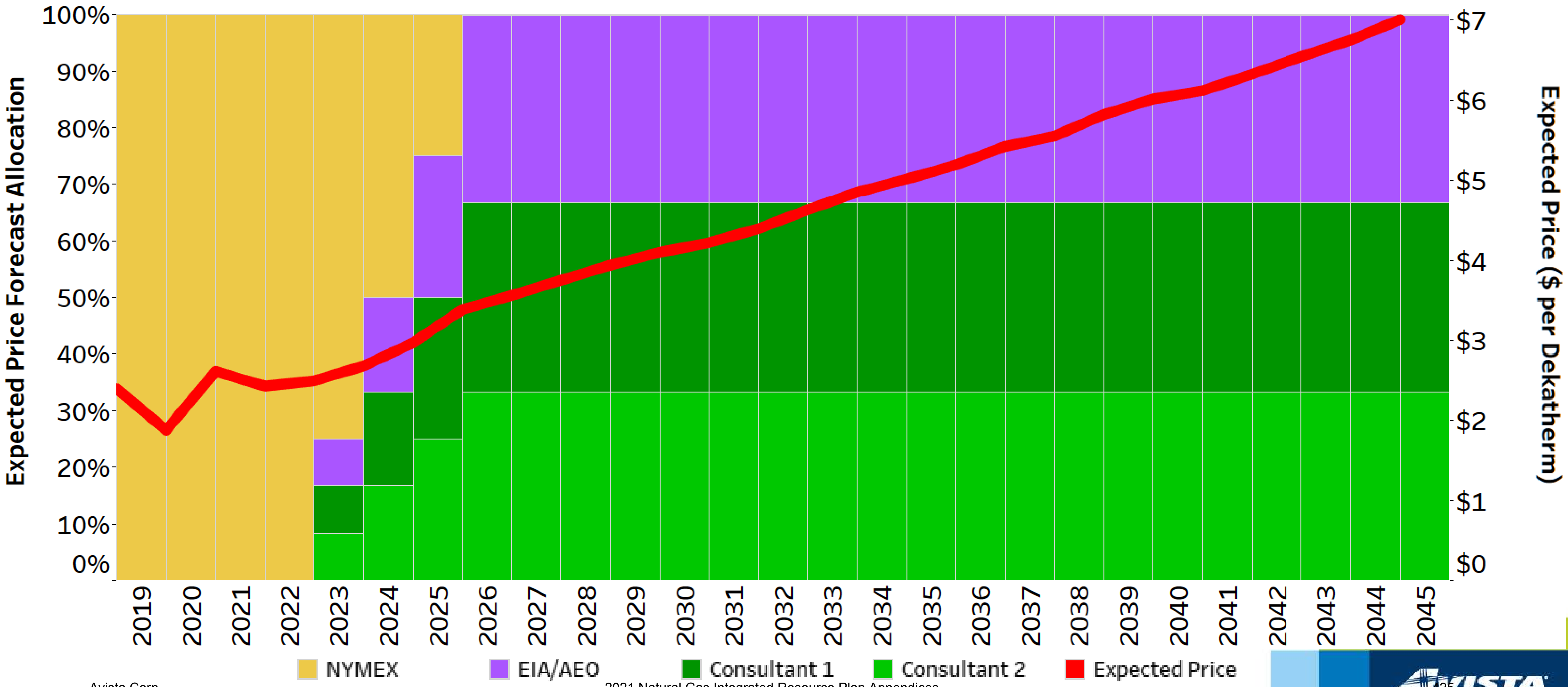
Michael Brutocao, Natural Gas Analyst
Second Technical Advisory Committee Meeting
August 6, 2020

Henry Hub Expected Price Methodology

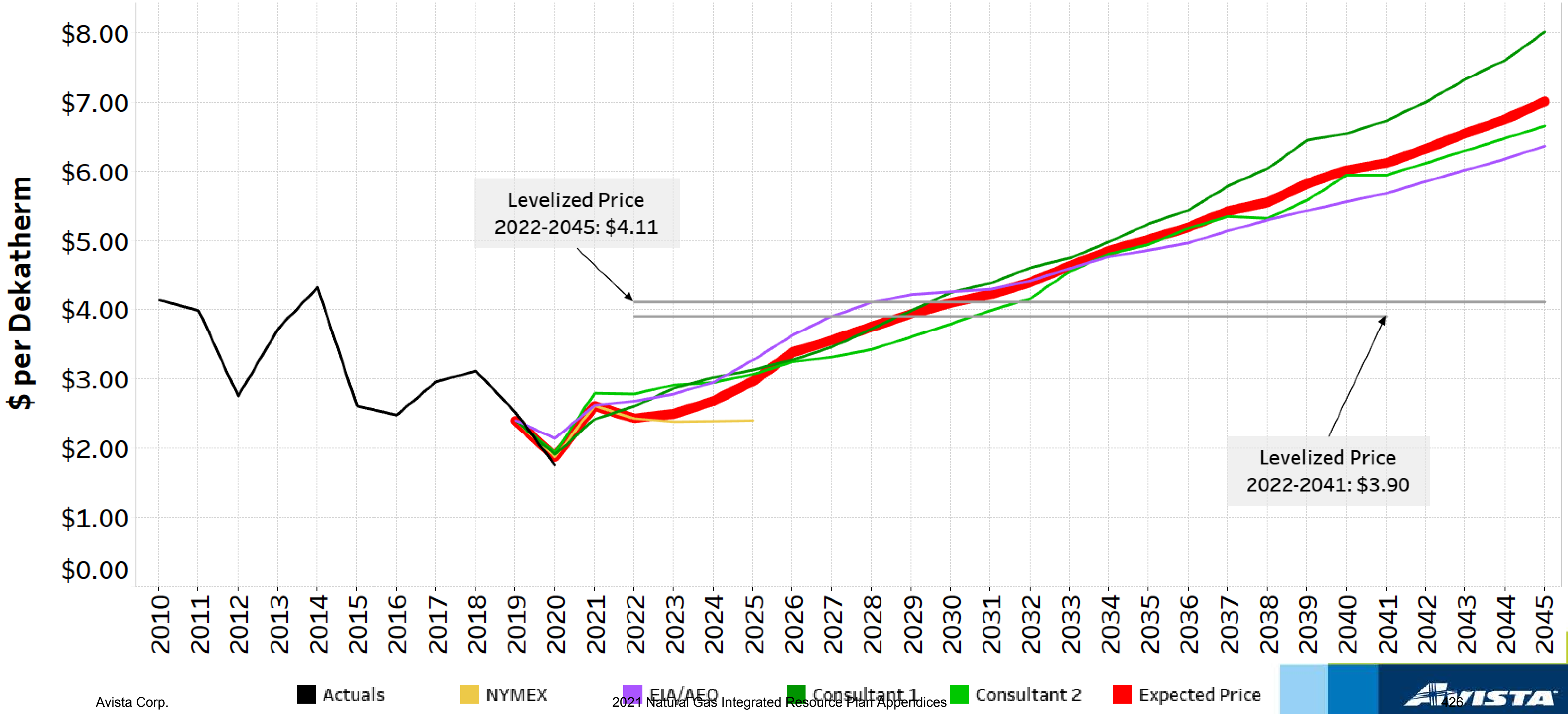
- Expected Henry Hub prices derived from a blend of forward market prices on the NYMEX (as of 6/30/2020) and forecasted prices from the 2020 Annual Energy Outlook (EIA) and two consultants

	2020 – 2022	2023	2024	2025	2026 – 2045
NYMEX	100%	75%	50%	25%	-
EIA/AEO	-	8.33%	16.66%	25%	33.33%
Consultant 1	-	8.33%	16.66%	25%	33.33%
Consultant 2	-	8.33%	16.66%	25%	33.33%

Henry Hub Expected Price and Forecast Blending



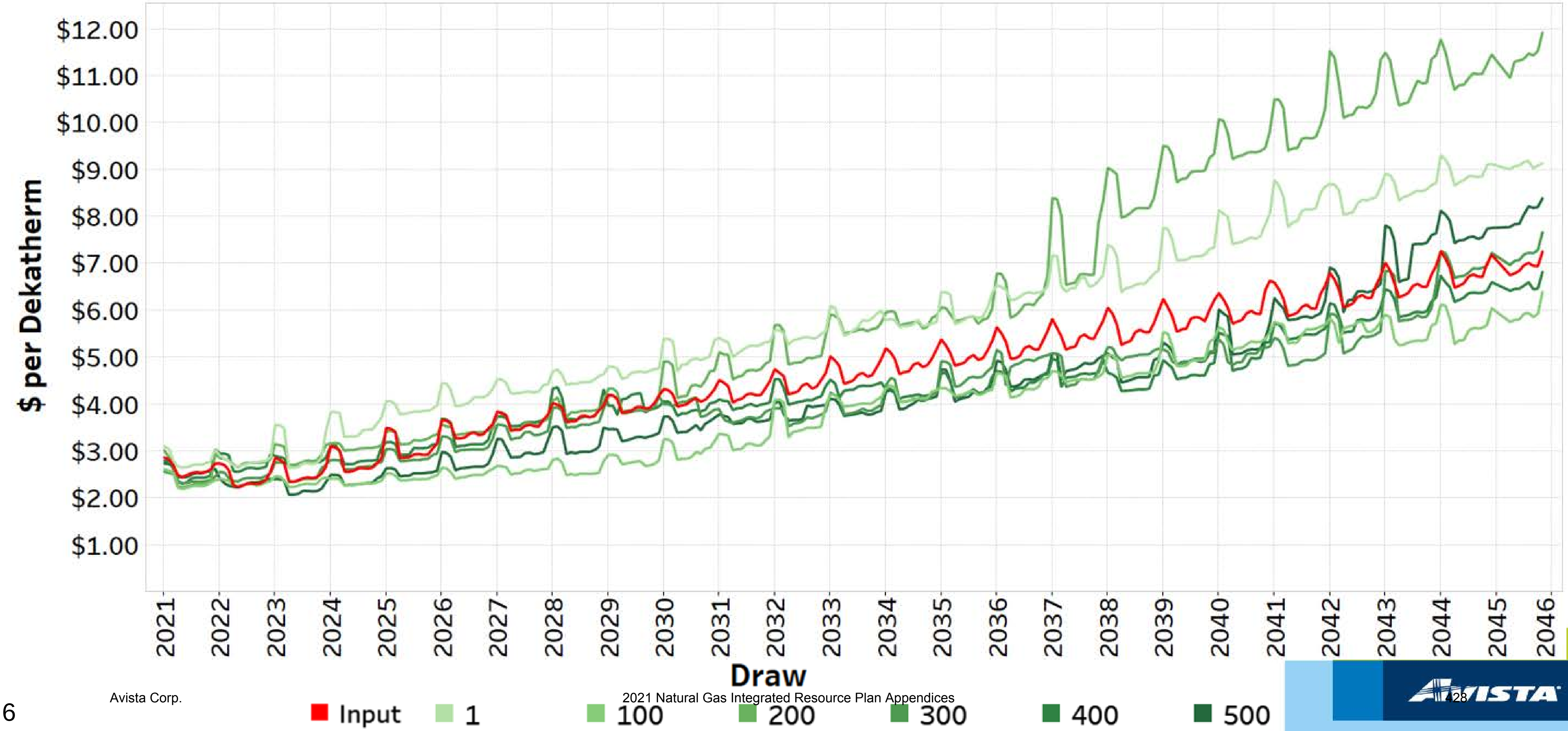
Henry Hub Expected Price and Average Annual Forecasts



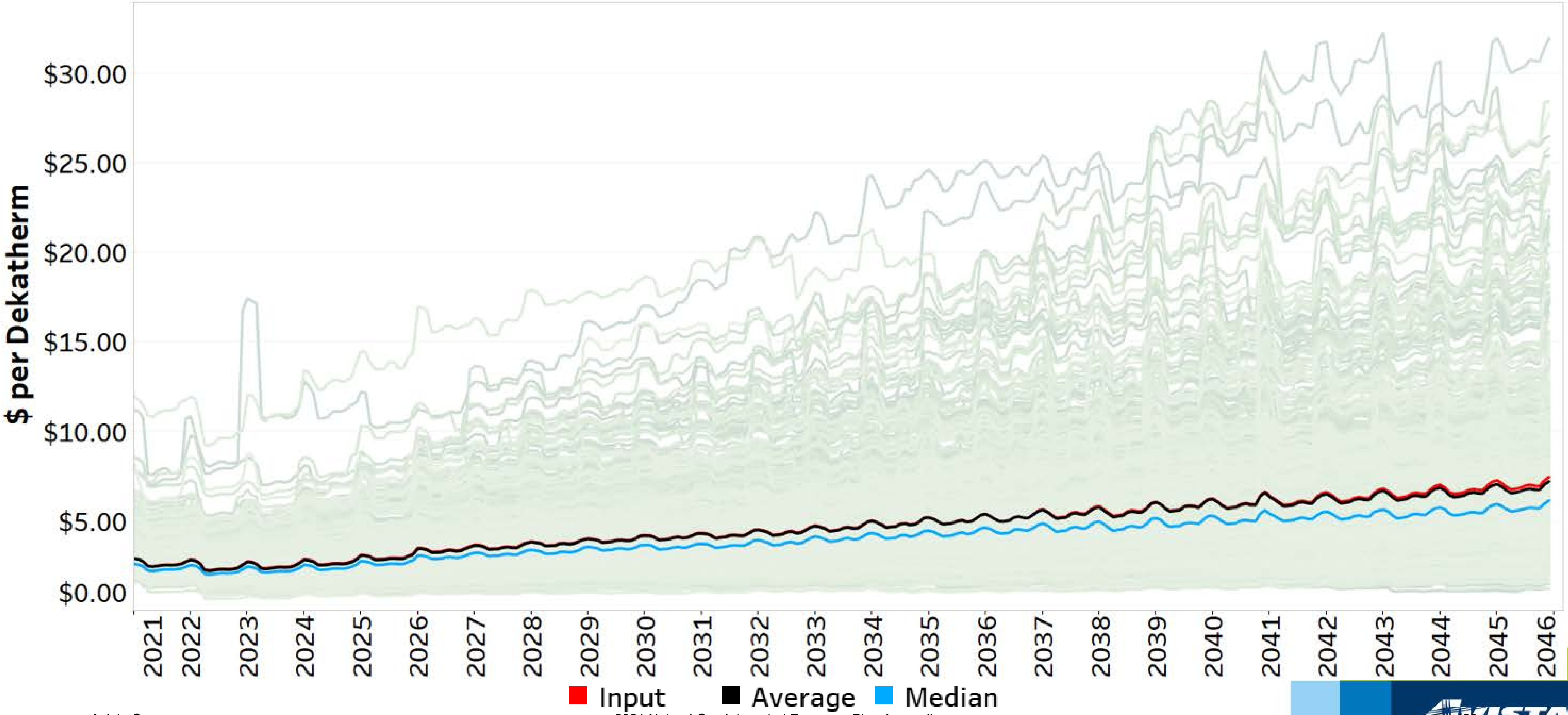
Stochastic Price Forecasting Methodology

- Evaluate a set of potential future outcomes based on the probability of occurrence
  - Expected Price used as the input
  - At each period, random price adjustments follow a lognormal distribution based on the Expected Price
    - It is common practice to use lognormal distributions in forecasting prices as they have no upward bound and should not fall below zero
- A single “draw” contains a set of unique price movements
- 500 (electric) and 1000 (gas) draws were evaluated

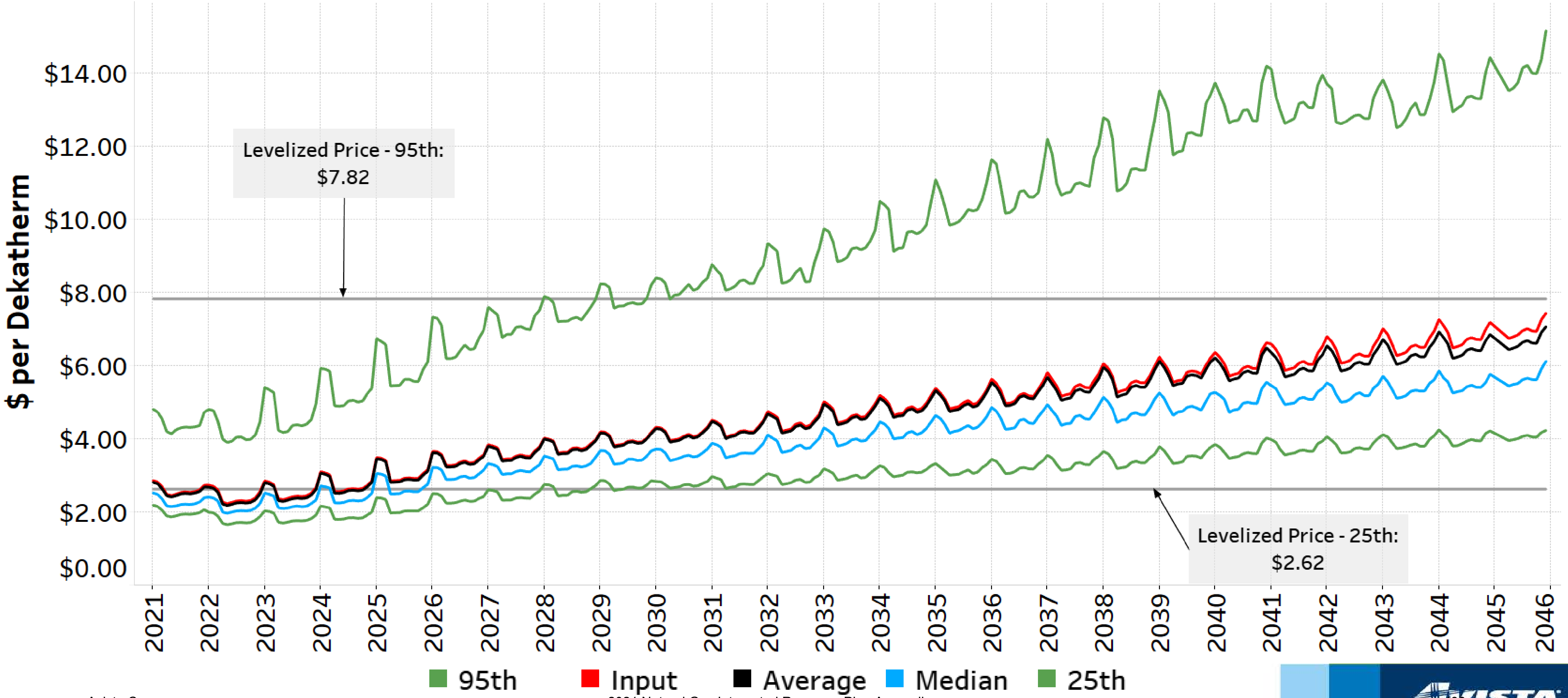
Sample Stochastic Price Draws



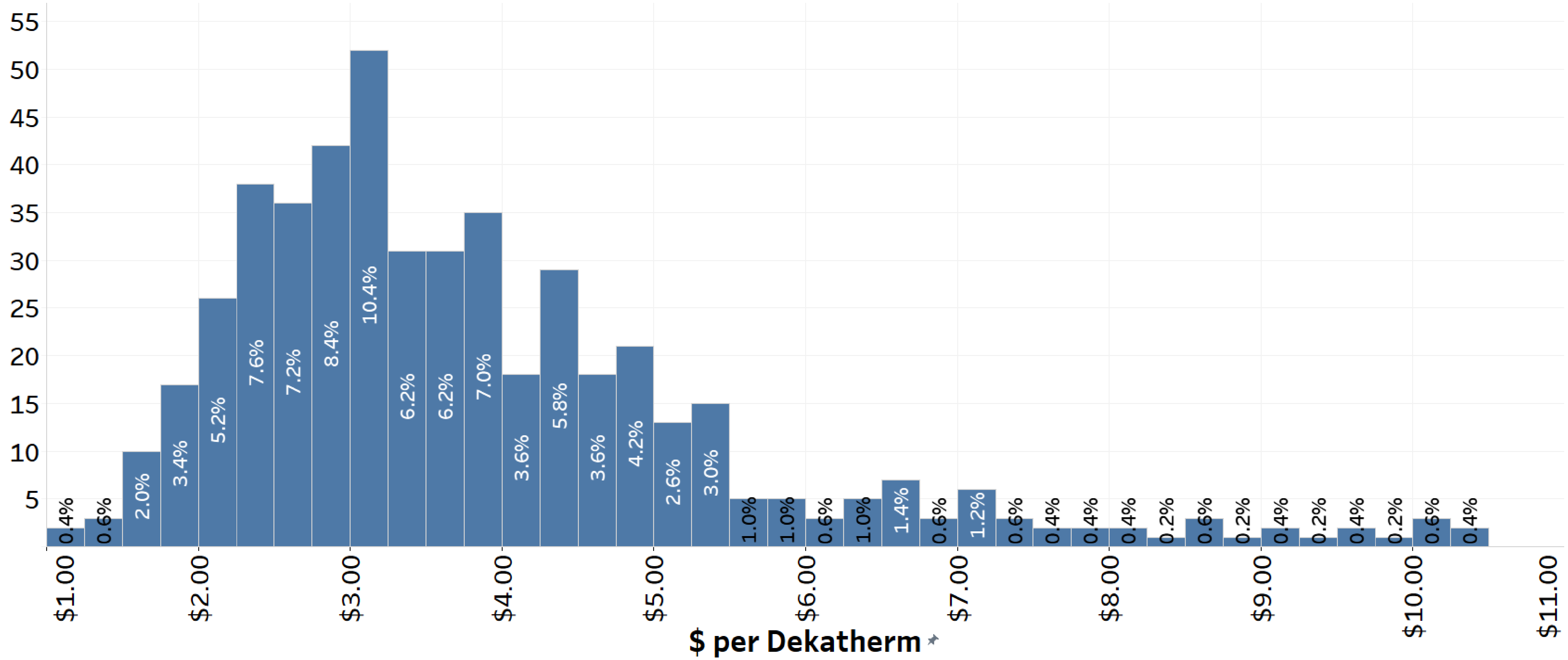
Stochastic Price Draws



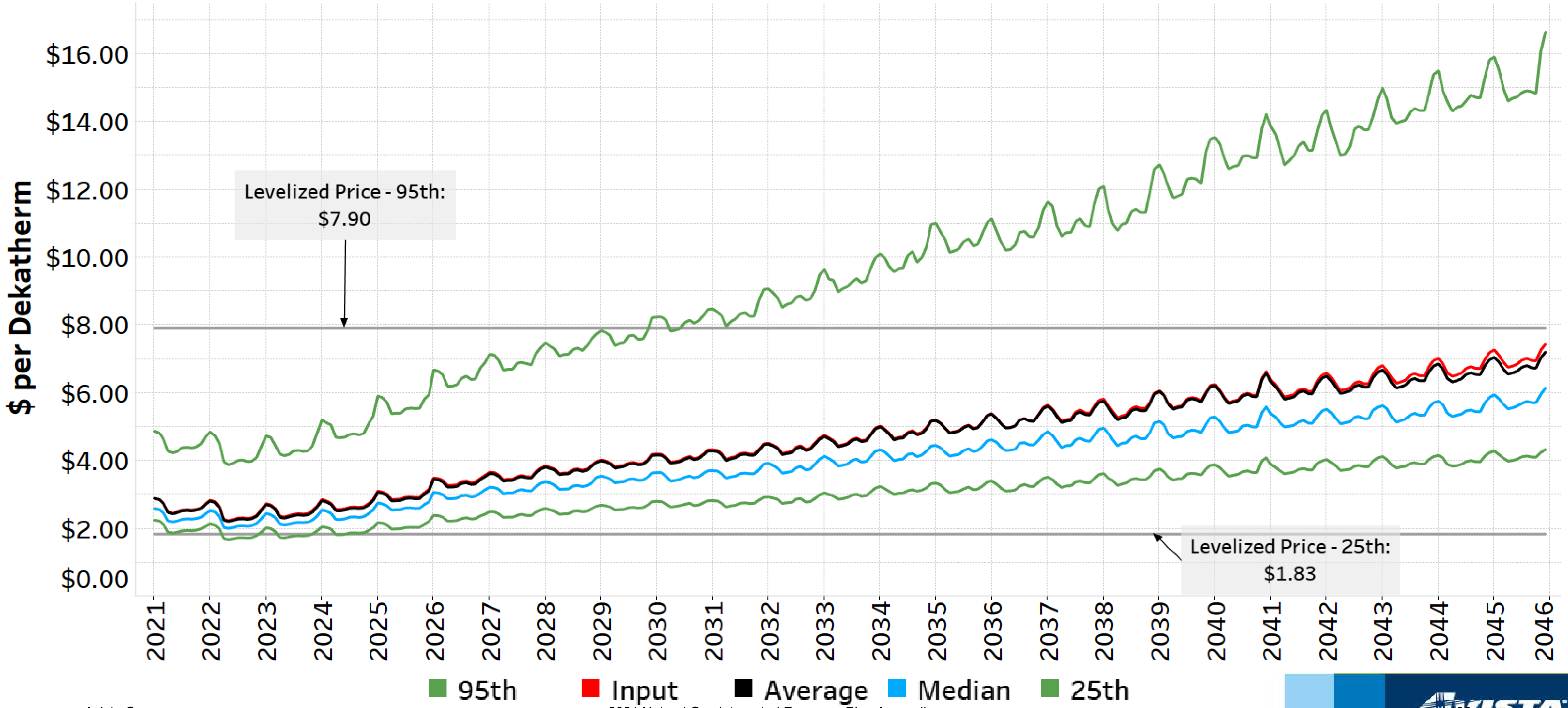
Stochastic Prices (Results from 500 Draws)



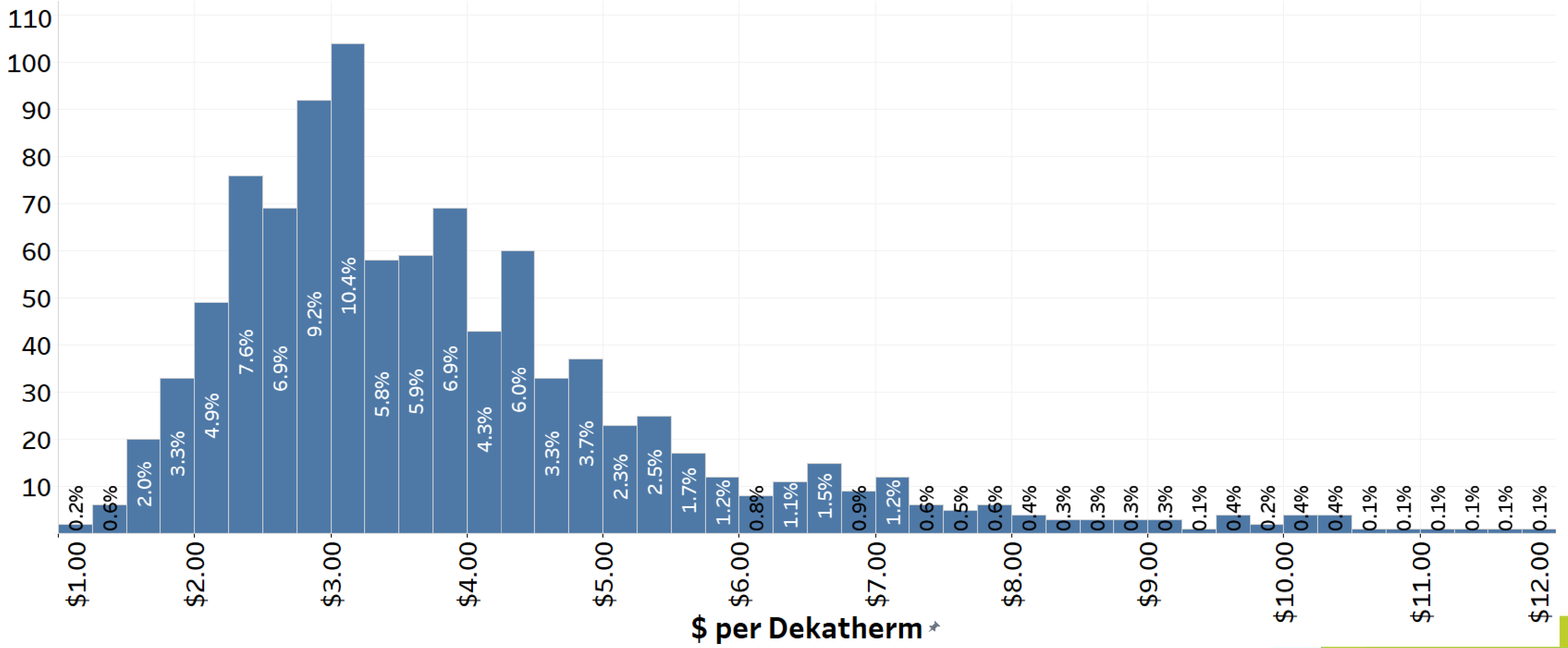
Levelized Stochastic Prices (Results from 500 Draws)



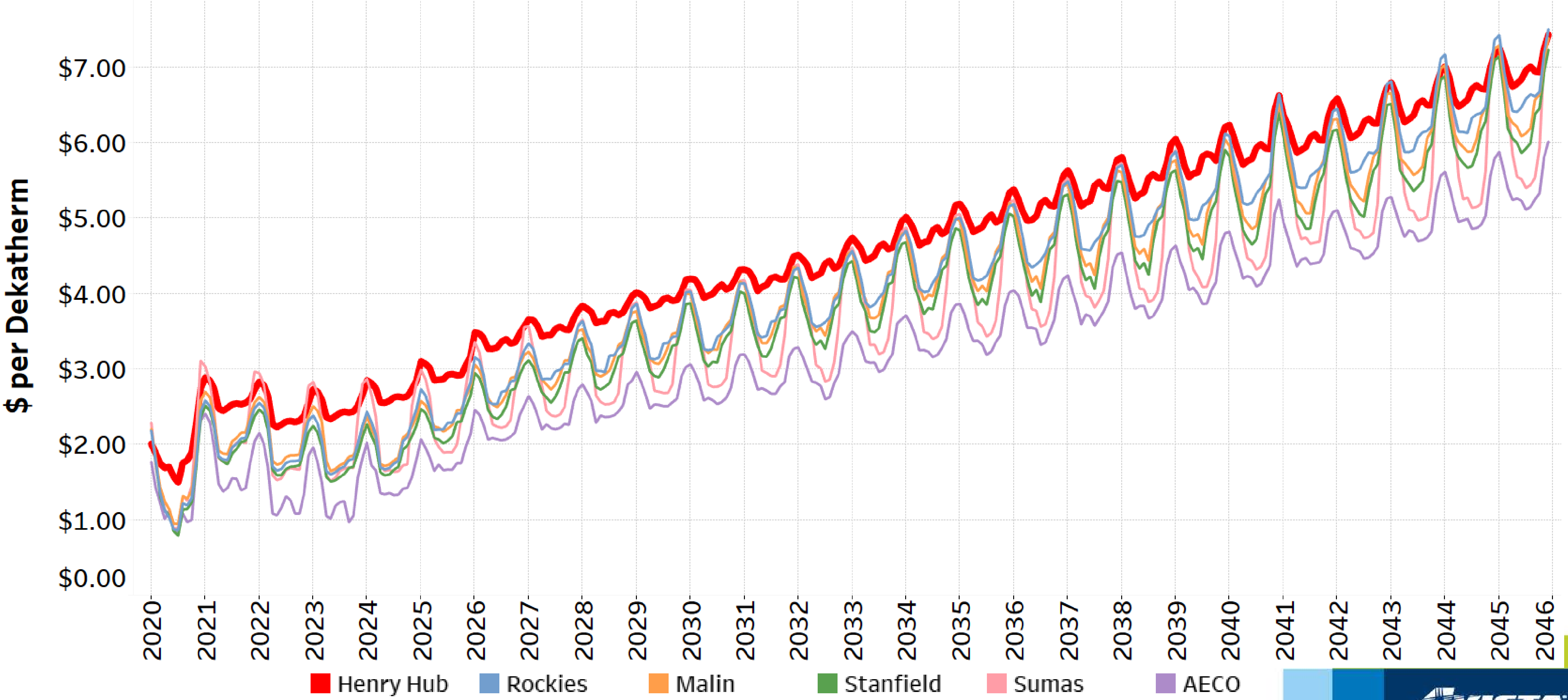
Stochastic Prices (Results from 1000 Draws)



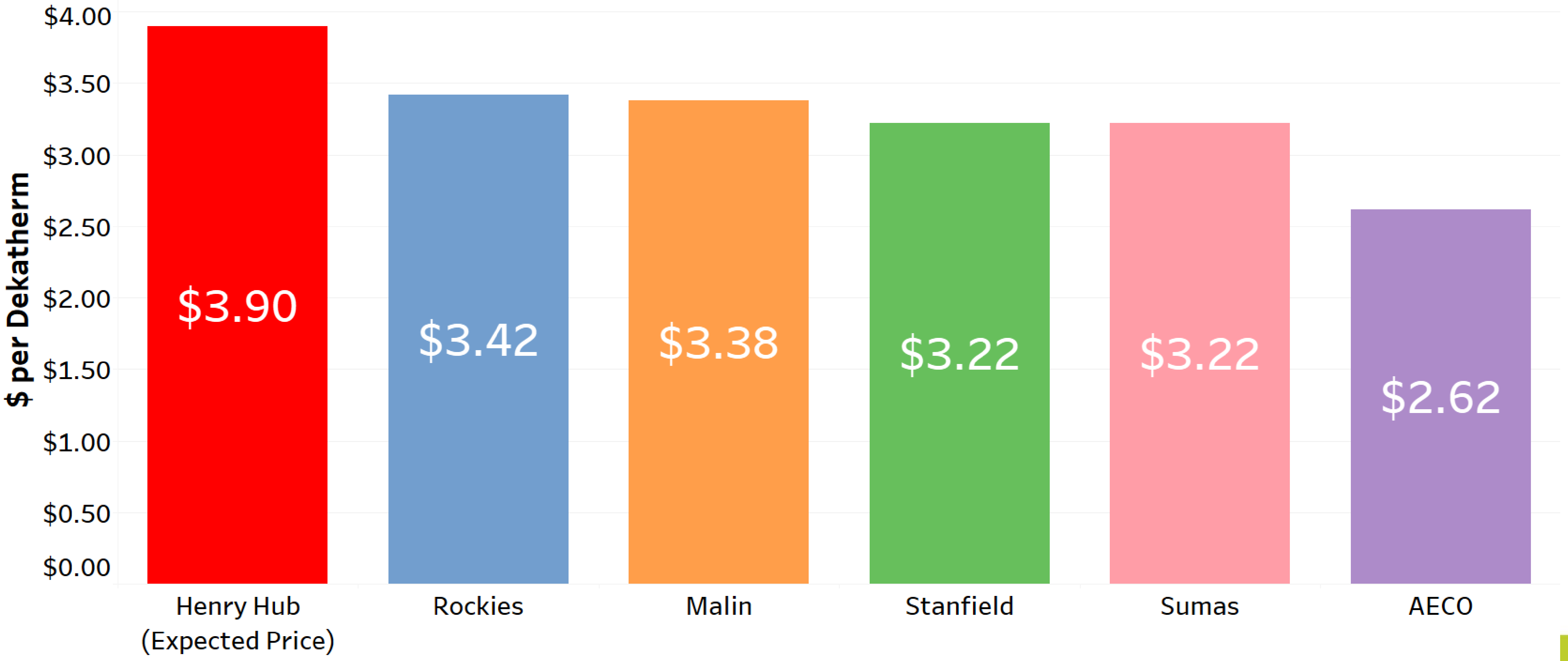
Levelized Stochastic Prices (Results from 1000 Draws)



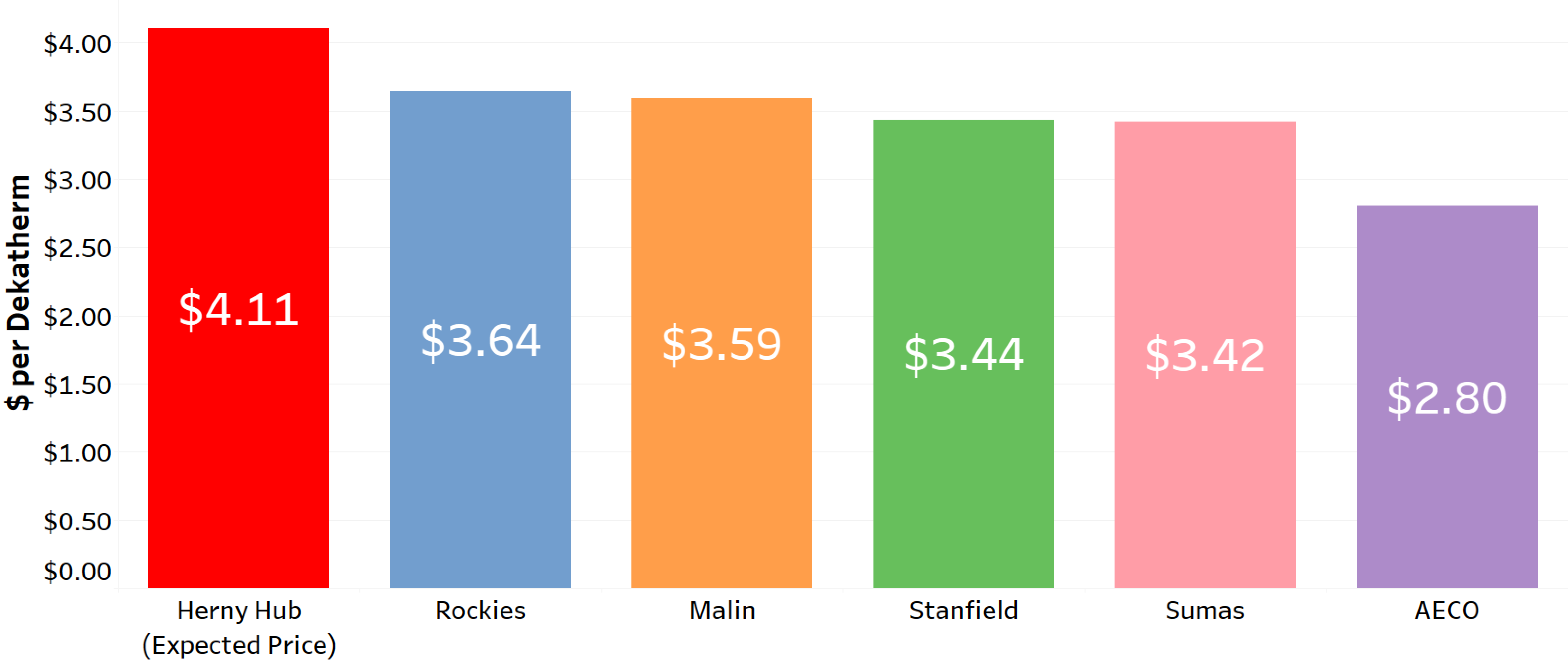
Prices by Gas Hub (Henry Hub Expected Price + Basis)



Levelized Prices 2022-2041



Levelized Prices 2022-2045



2021 Electric IRP
Regional Energy Policy Update

John Lyons, Ph.D.
Second Technical Advisory Committee Meeting
August 6, 2020

Production and Investment Tax Credits

- Production tax credit $15/MWh adjusted for inflation ($25/MWh for 2019) for 10 years for wind construction started by 12/31/20
- Investment tax credit for new solar construction drops from 30% in 2019
  - 26% in 2020
  - 22% in 2021
  - 10% from 2022 onward
- Will be watching for any possible extensions with all of the COVID-19 proposals

State and Provincial Policies

State/Province	No Coal	RPS	Clean Energy/Carbon Goal
Alberta	Yes	Yes	Yes
Arizona	No	Yes	No
British Columbia	Yes	Yes	Yes
California	Yes	Yes	Yes
Colorado	No	Yes	Yes
Idaho	No	No	No
Montana	No	Yes	No
Nevada	No	Yes	Goal
New Mexico	No	Yes	No
Oregon	Yes	Yes	Yes
Utah	No	Goal	No
Washington	Yes	Yes	Yes
Wyoming	No	No	No

Washington

- Clean Energy Transformation Act (CETA) SB 5116:
  - No coal serving Washington customers by end of 2025
  - Greenhouse gas neutral by 2030, up to 20% alternative compliance
  - 2% cost cap over four-year compliance period
  - 100% non-emitting by January 1, 2045
  - Social cost of carbon for new resources
  - Additional reporting and planning requirements
  - Highly impacted and vulnerable community identification and resource planning implications
  - Ongoing rulemaking in various stages for planning and reporting

Washington

- HB 1257: Clean Buildings for Washington Act
  - Develop energy performance standards for commercial buildings over 50,000 square feet (2020 – 2028) "… to maximize reductions of greenhouse gas emissions from the building sector"
  - By 2022, natural gas utilities must identify and acquire all available cost-effective conservation including a social cost of carbon at the 2.5% discount rate.(Section 11 and 15)
  - Natural gas utilities may propose renewable natural gas (RNG) programs for their customers and offer a voluntary RNG tariff
  - Building code updates to improve efficiency and develop electric vehicle charging infrastructure

Oregon

Executive Order 20-04

- New GHG reduction goal
  - 45% below 1990 levels by 2035
  - 80% below 1990 levels by 2050
- Directs 16 Oregon agencies to “exercise any and all authority and discretion” to reach GHG reduction goals and “prioritize and expedite” action on GHG reductions “to the full extent allowed by law.”
- Agencies are working on rulemaking and implementation

SB 98

- Development of utility renewable natural gas programs

2021 Electric and Natural Gas IRPs
Natural Gas & Electric Coordinated Scenario

James Gall/Tom Pardee

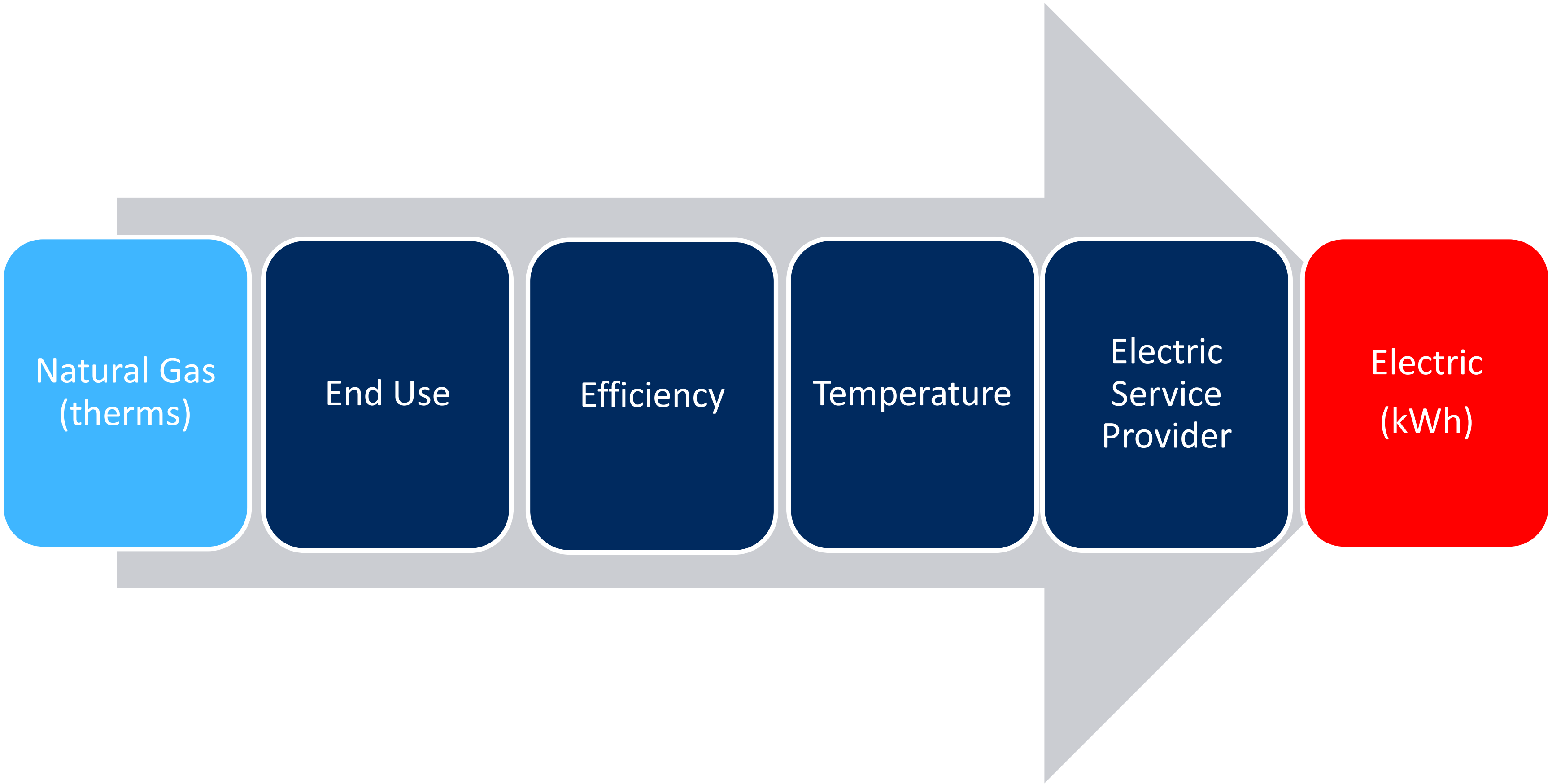
Second Technical Advisory Committee Meeting

August 6, 2020

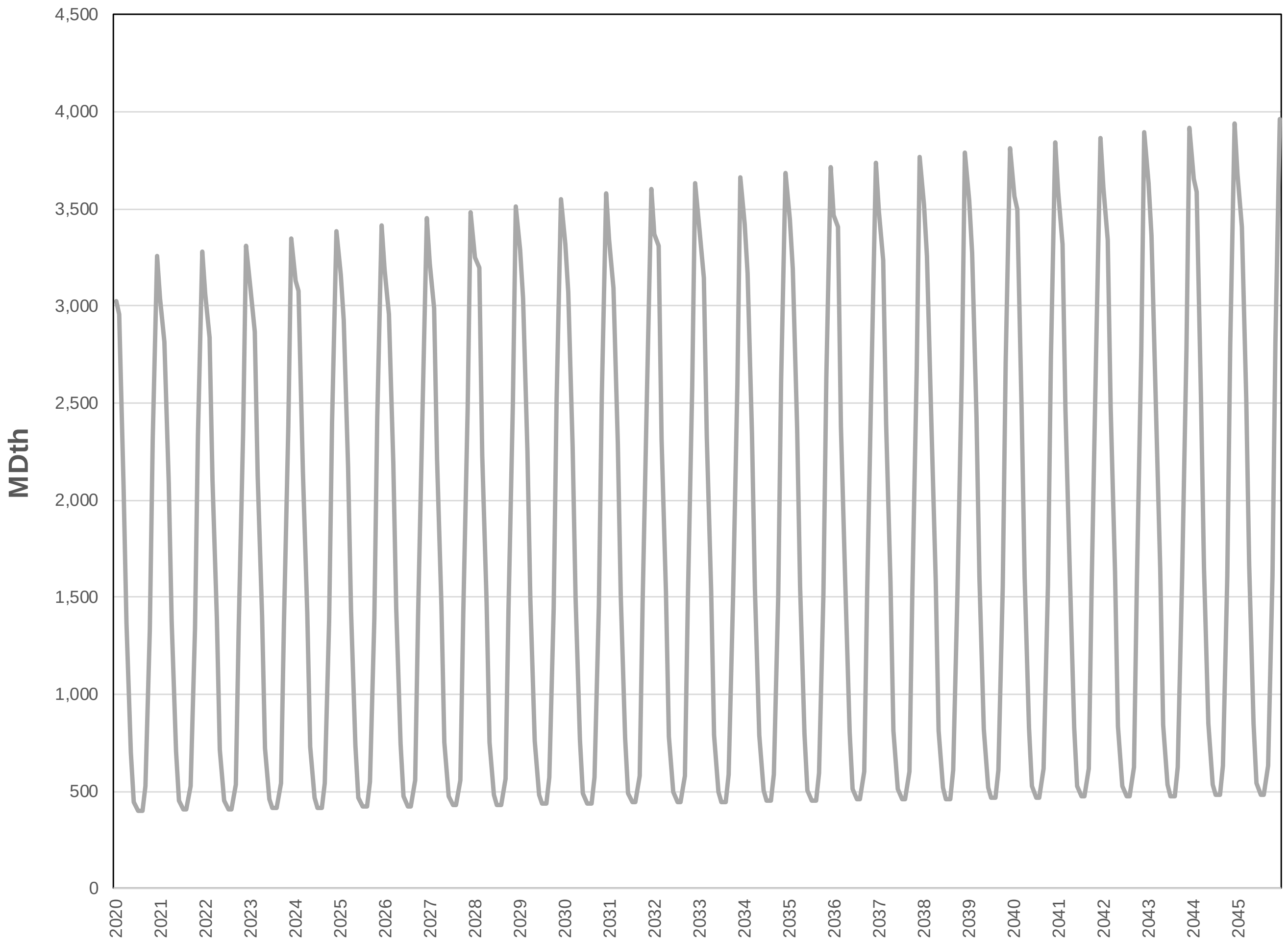
Scenario Goal

- Understand impact to electric resource planning if customers switch from natural gas to electric service
- Scenario Proposal:
  - By 2030: 50% of Washington Residential & Commercial customers
  - By 2045: 80% of Washington Residential & Commercial customers
- Potential Scenarios:
  - Hybrid natural gas/electric heat pumps
  - Highly efficient technology allows for cold temperature space heating

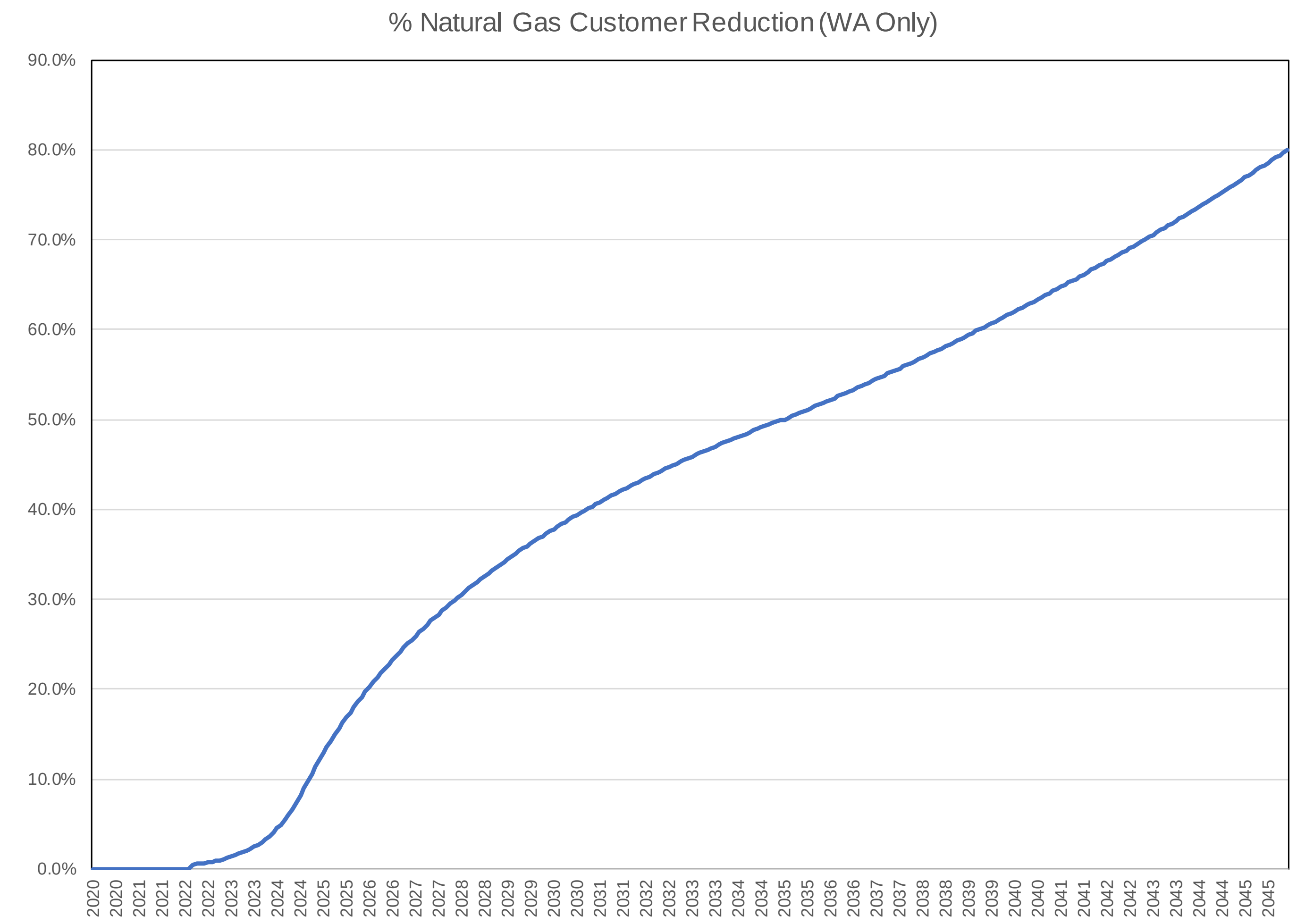
Converting Natural Gas Load to Electric Load



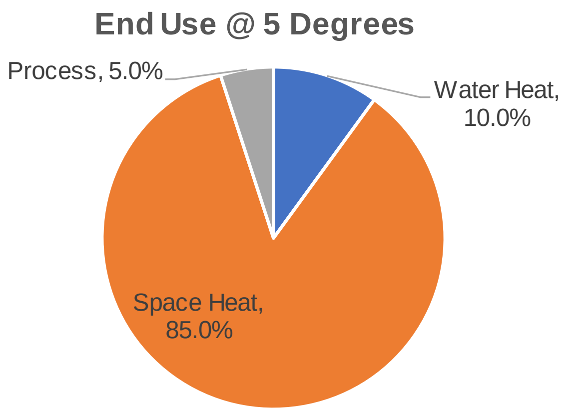
WA Res/Com Natural Gas Load Forecast

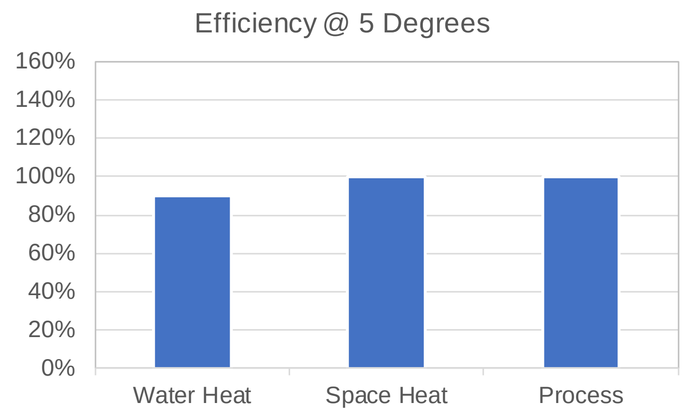


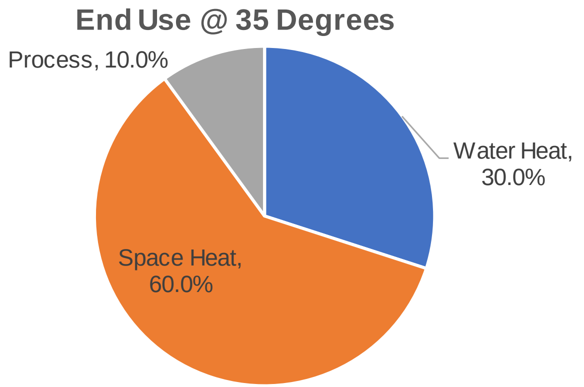
Customer Penetration Forecast

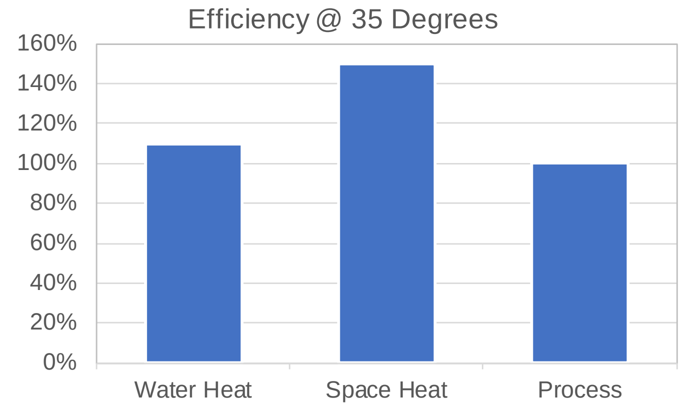


End Use Efficiency



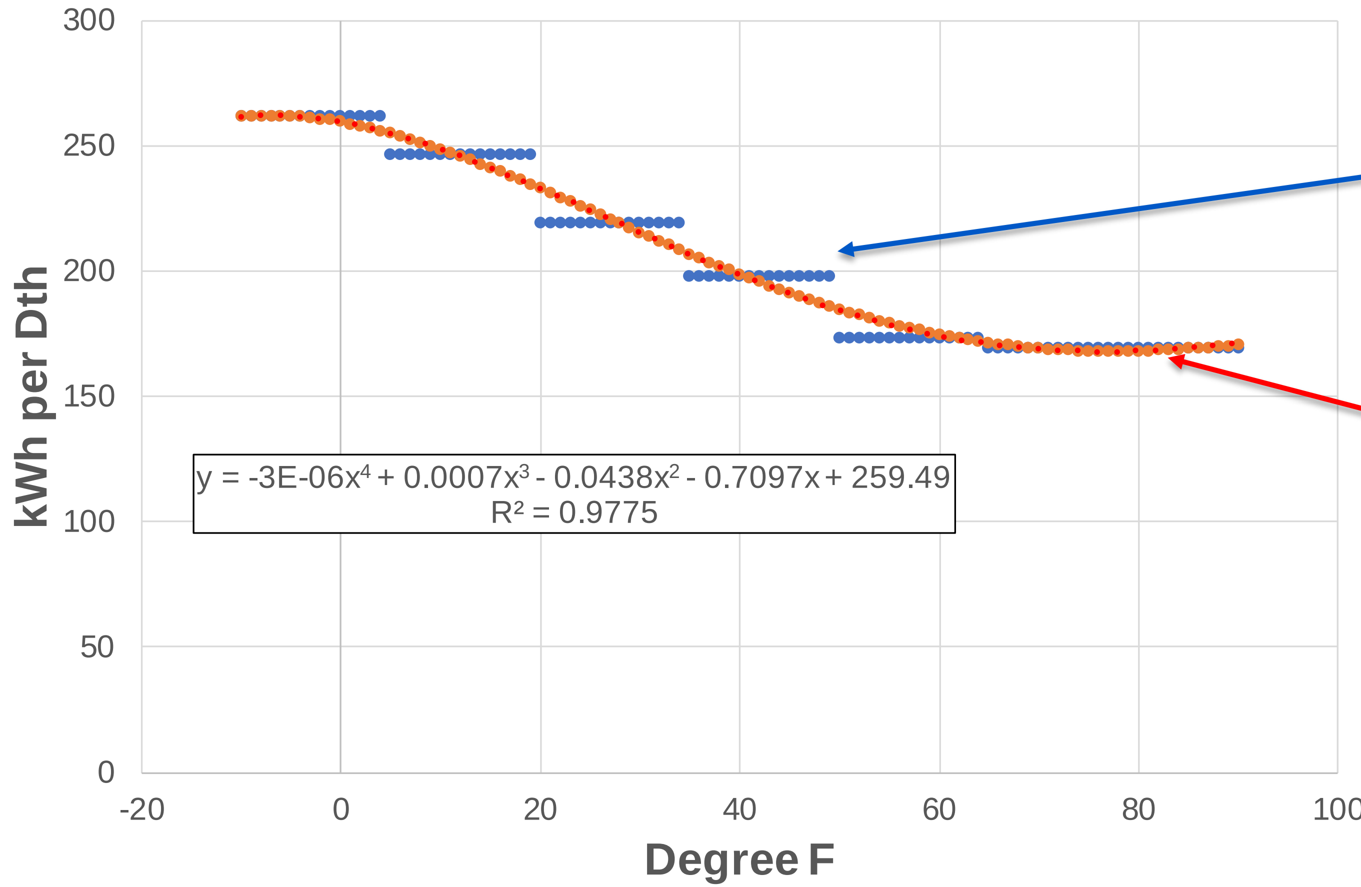






Note: All efficiency conversion use a 10% efficiency benefit to electric

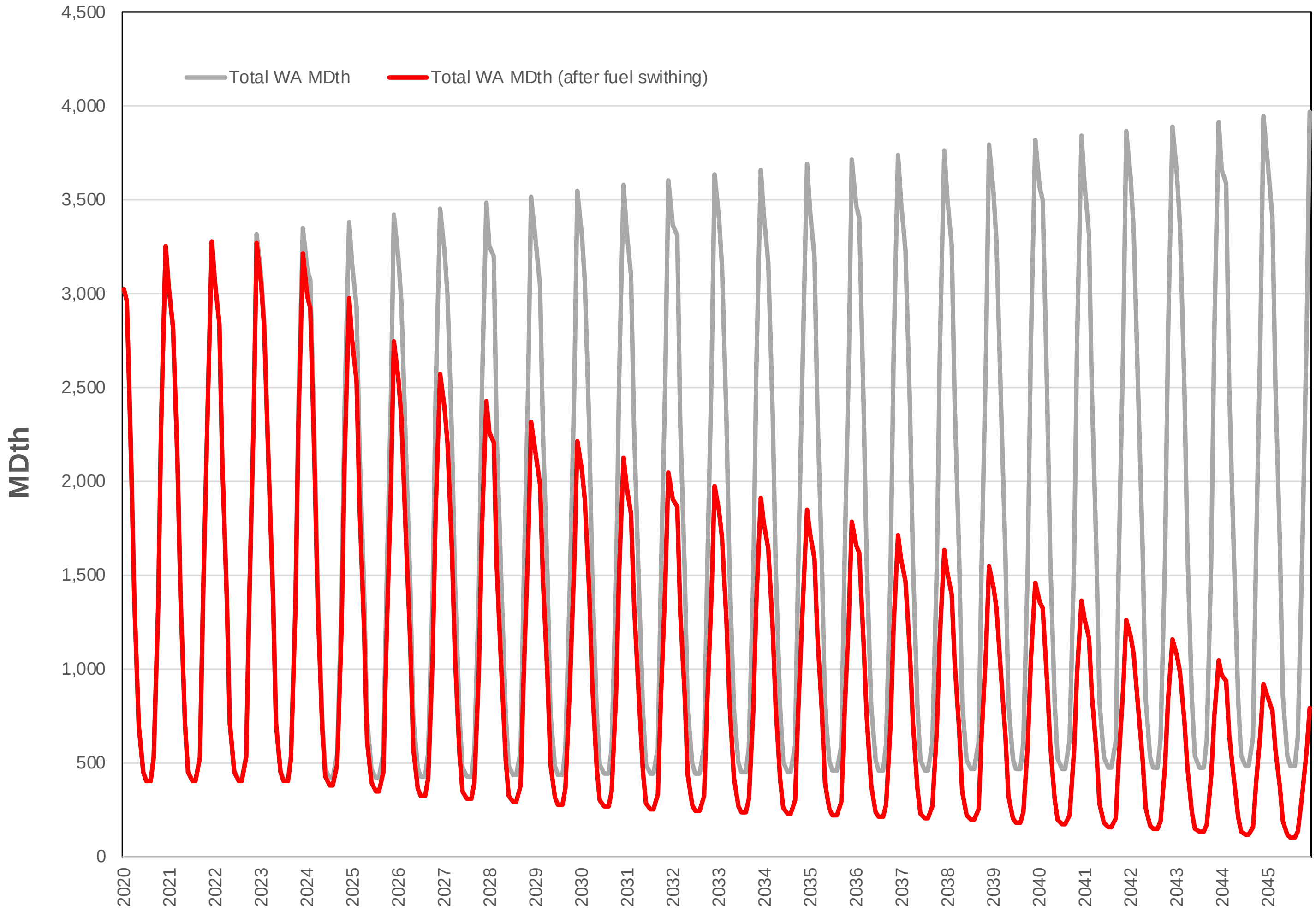
Energy Conversion Factor



Use temperature point estimates for conversion efficiency

Curve fit to smooth out steps

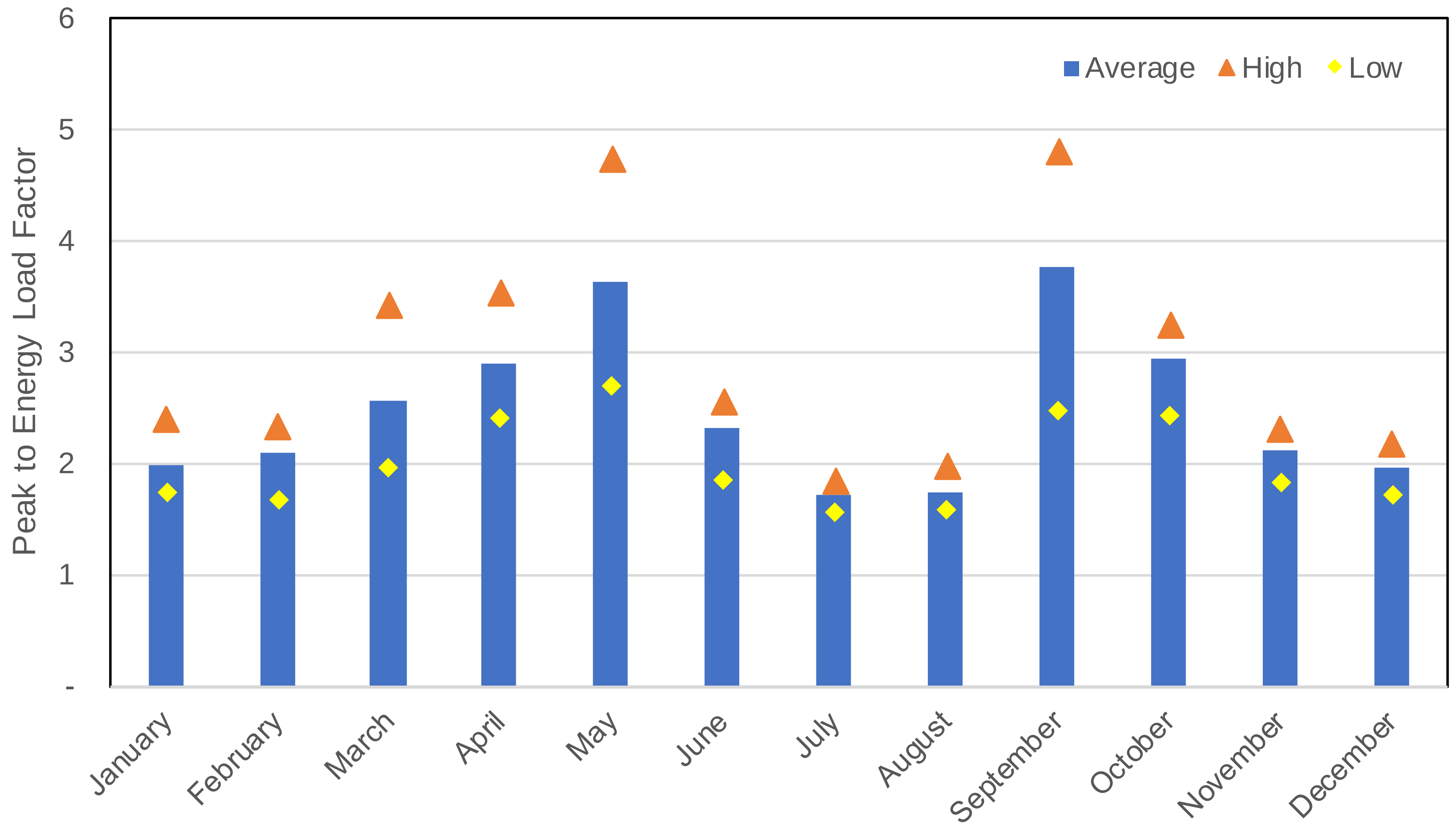
WA Res/Com Natural Gas Load Forecast



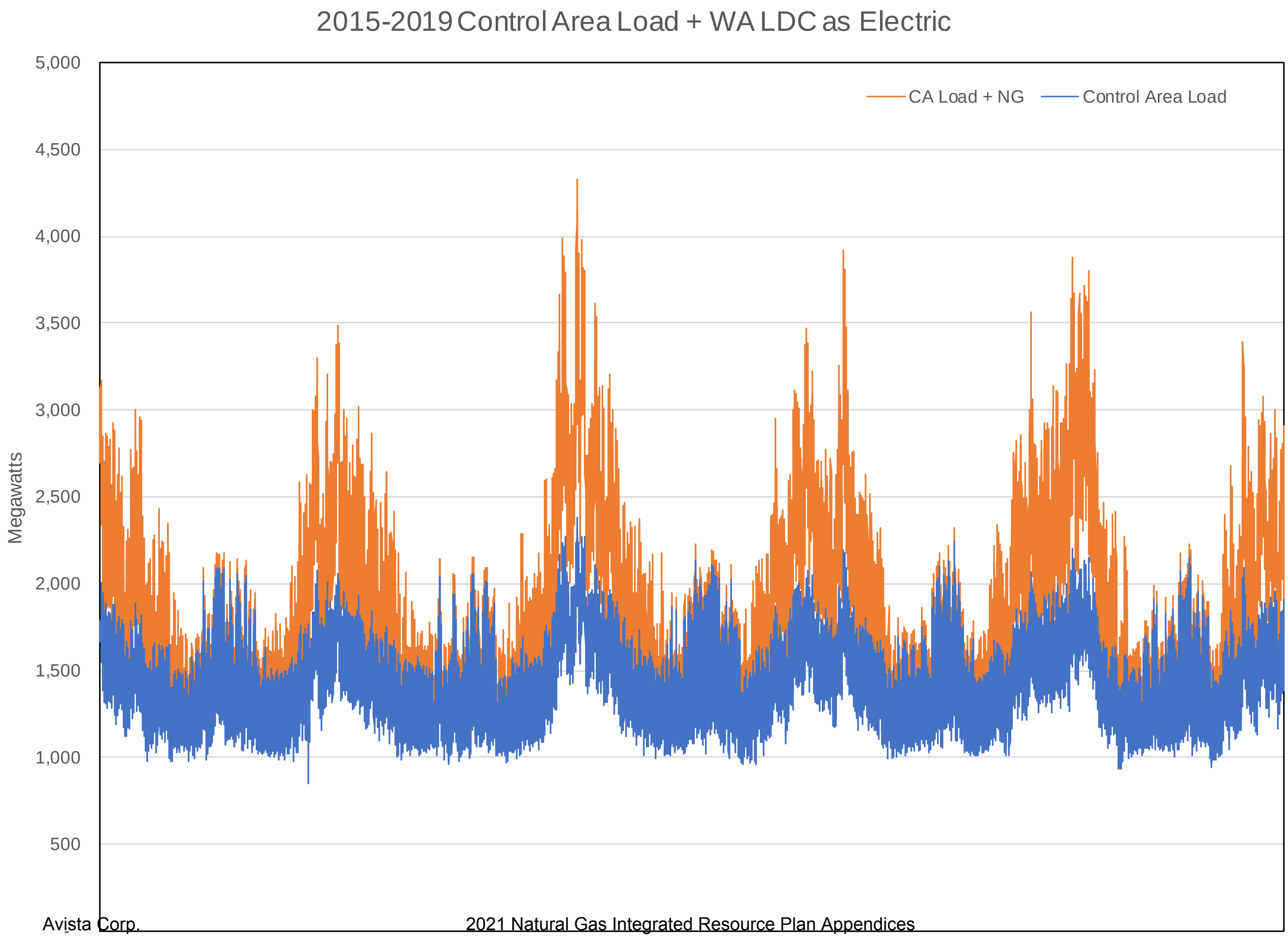
Electric Peak Estimation Methodology

- Natural gas is typically daily nominations, while electric is instantaneous.
  - Hourly flow metering is available for some areas
- Sampled large gate-station hourly instantaneous natural gas flow data
- Use sample data to estimate hourly natural gas load from 2015-2019
- Estimate Peak-to-Energy load factor for each historical month
- Use average monthly load factor for the peak adjustment

Estimated Load Factors (2015-19)

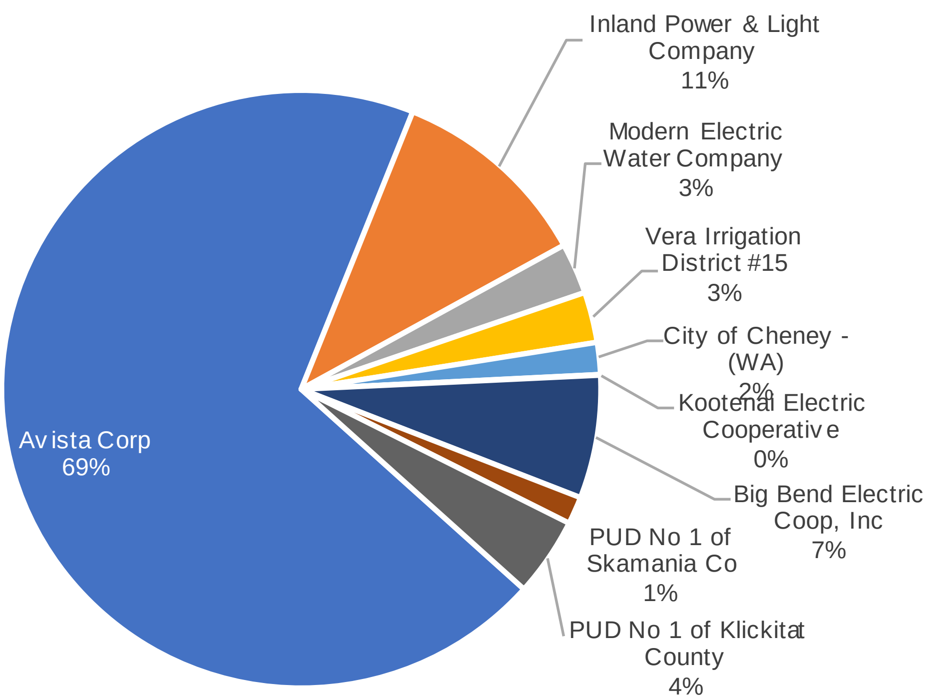


Hourly Electric Load History

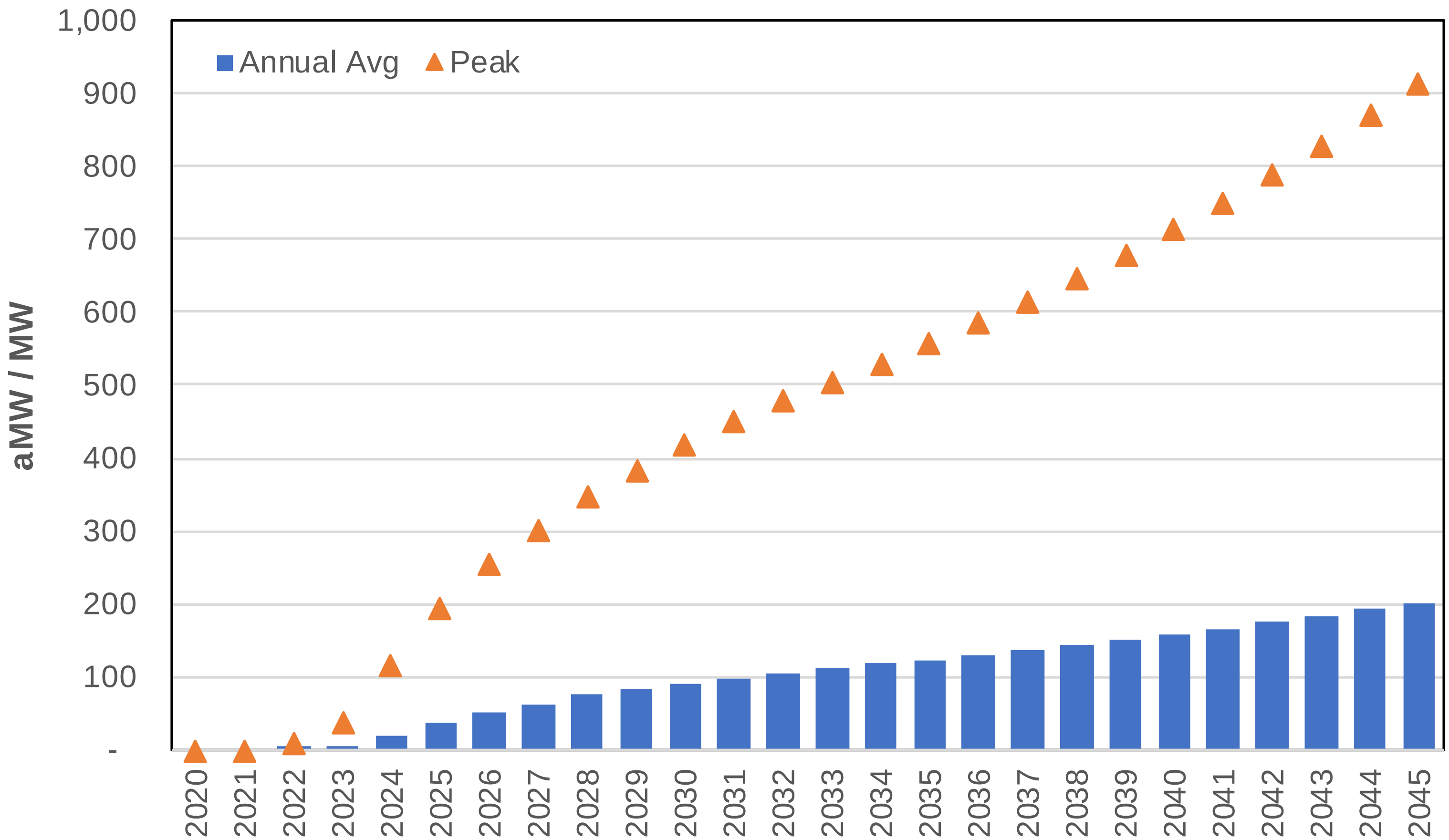


Eastern Washington Electric Service Providers

EIA reported retail sales for 2018
Scenario assumes Avista will receive 75 percent of electric conversions

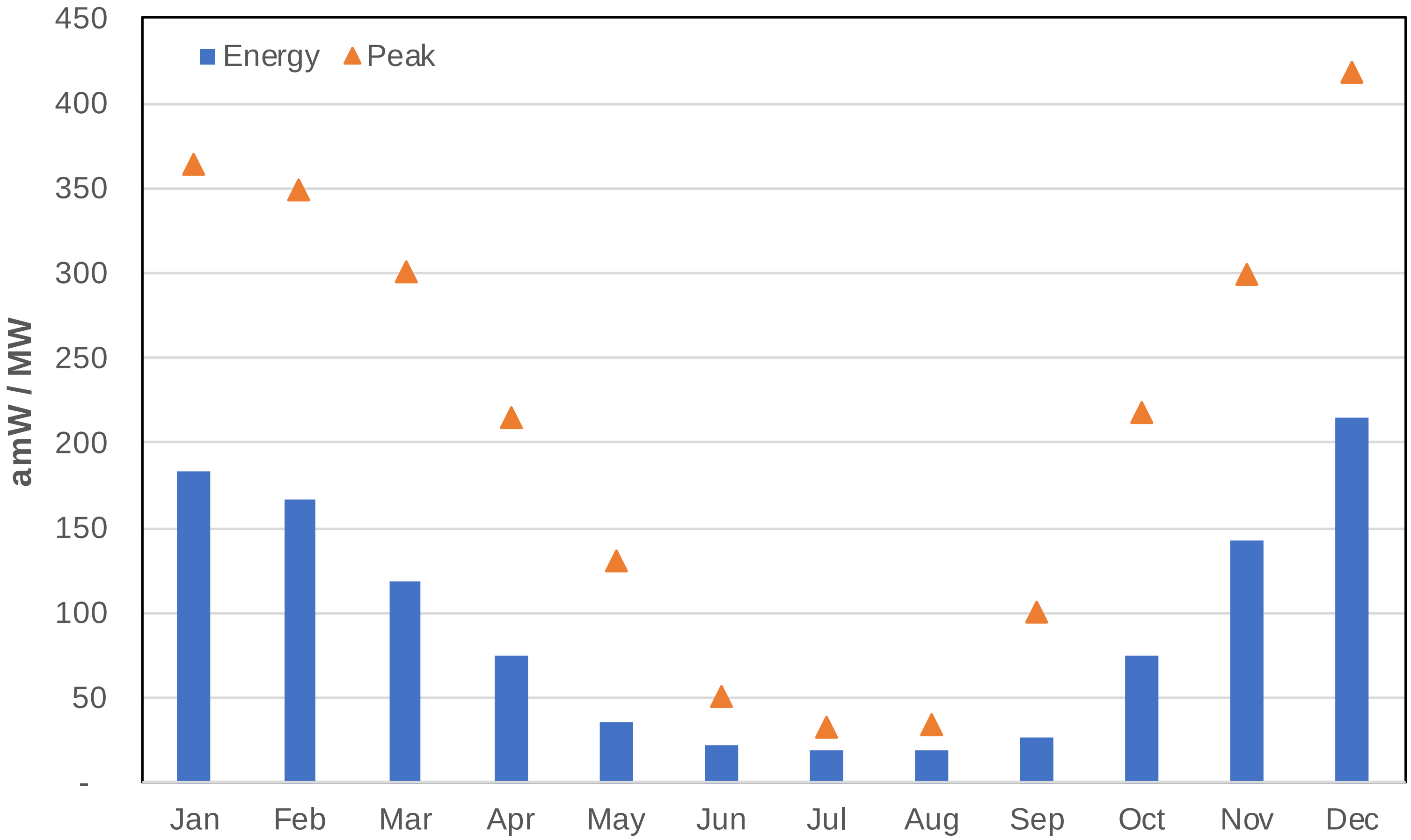


Annual Conversion Load Forecast

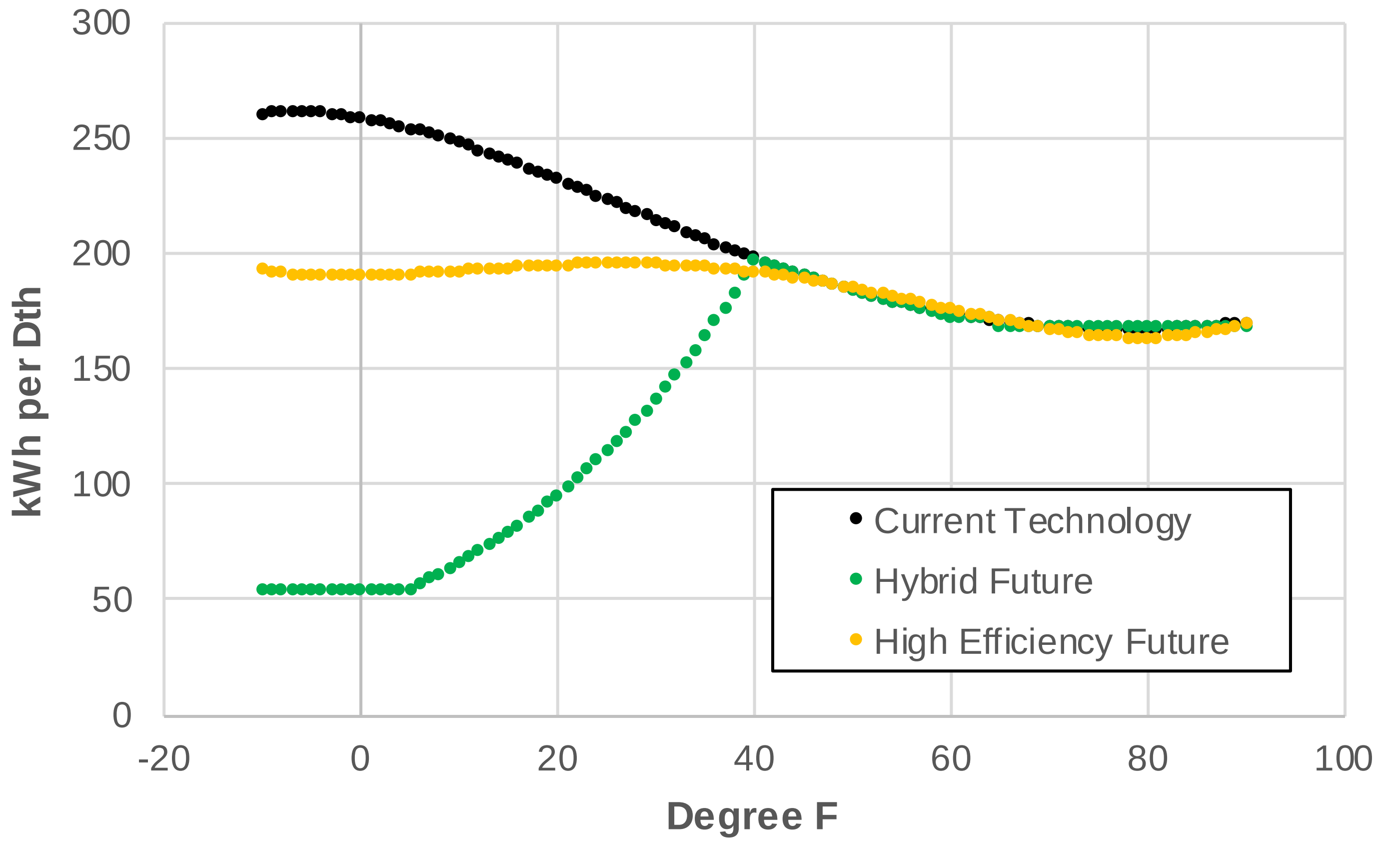


2020 IRP Forecast for 2030 absent fuel conversion:
Peak: 1,762 MW
Energy: 1,209 aMW

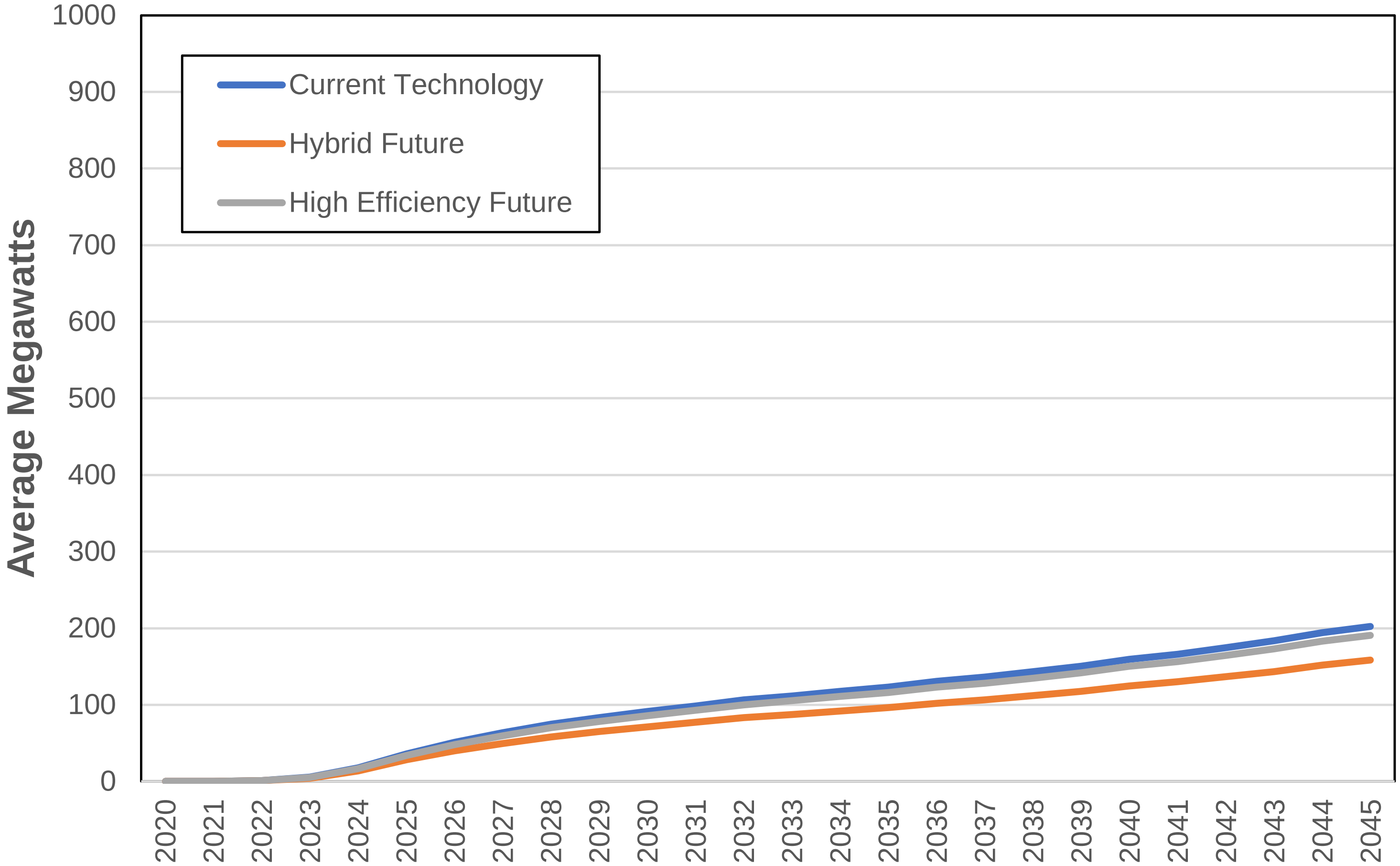
2030 Monthly Load Forecast



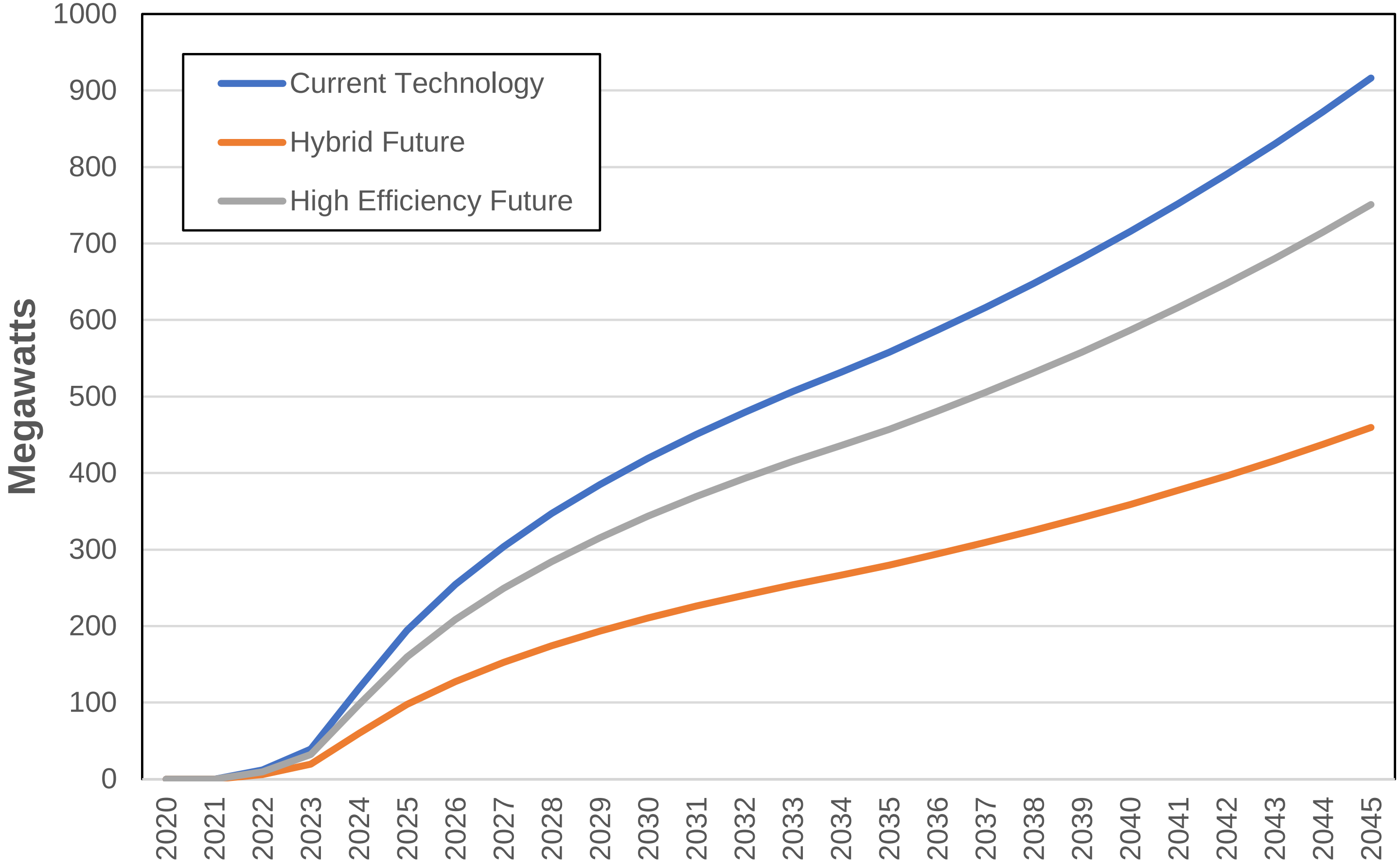
Scenario Analysis- Conversion Rates



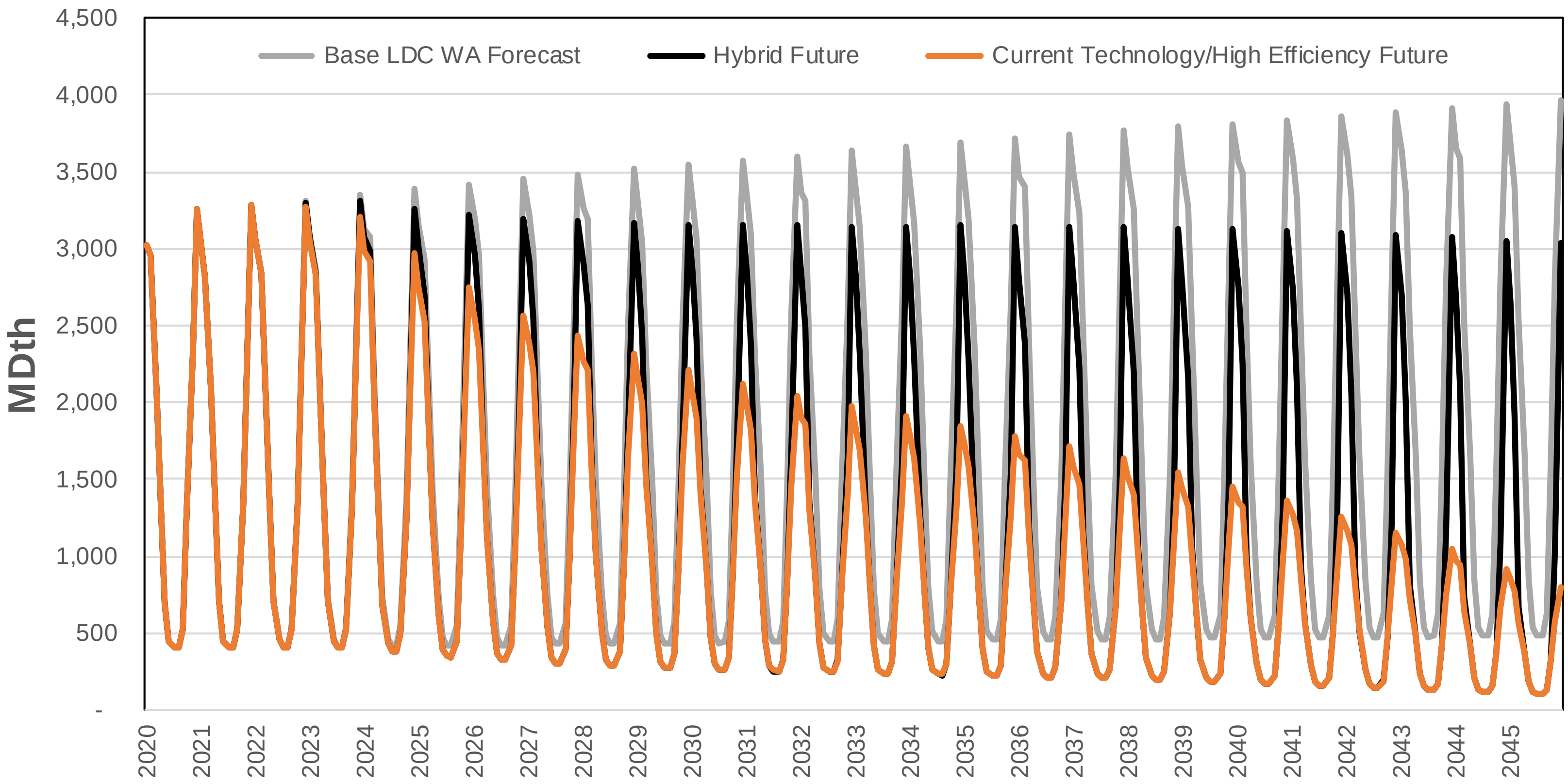
Scenario Analysis- Electric Energy



Scenario Analysis: Electric December Peak Load



Scenario Analysis: Natural Gas Demand



Next Steps

- Input into PRiSM model to determine resource selection and cost
  - Estimate cost meeting CETA requirements
  - Estimate cost using least cost methodology
  - Estimate emissions savings
  - Estimate $/tonne
- Conduct electric resource adequacy study if time permits

2021 Electric IRP
Washington Vulnerable Populations & Highly Impacted Communities

James Gall, IRP Manager

Second Technical Advisory Committee Meeting

August 6, 2020

Identifying Communities or “Customers”

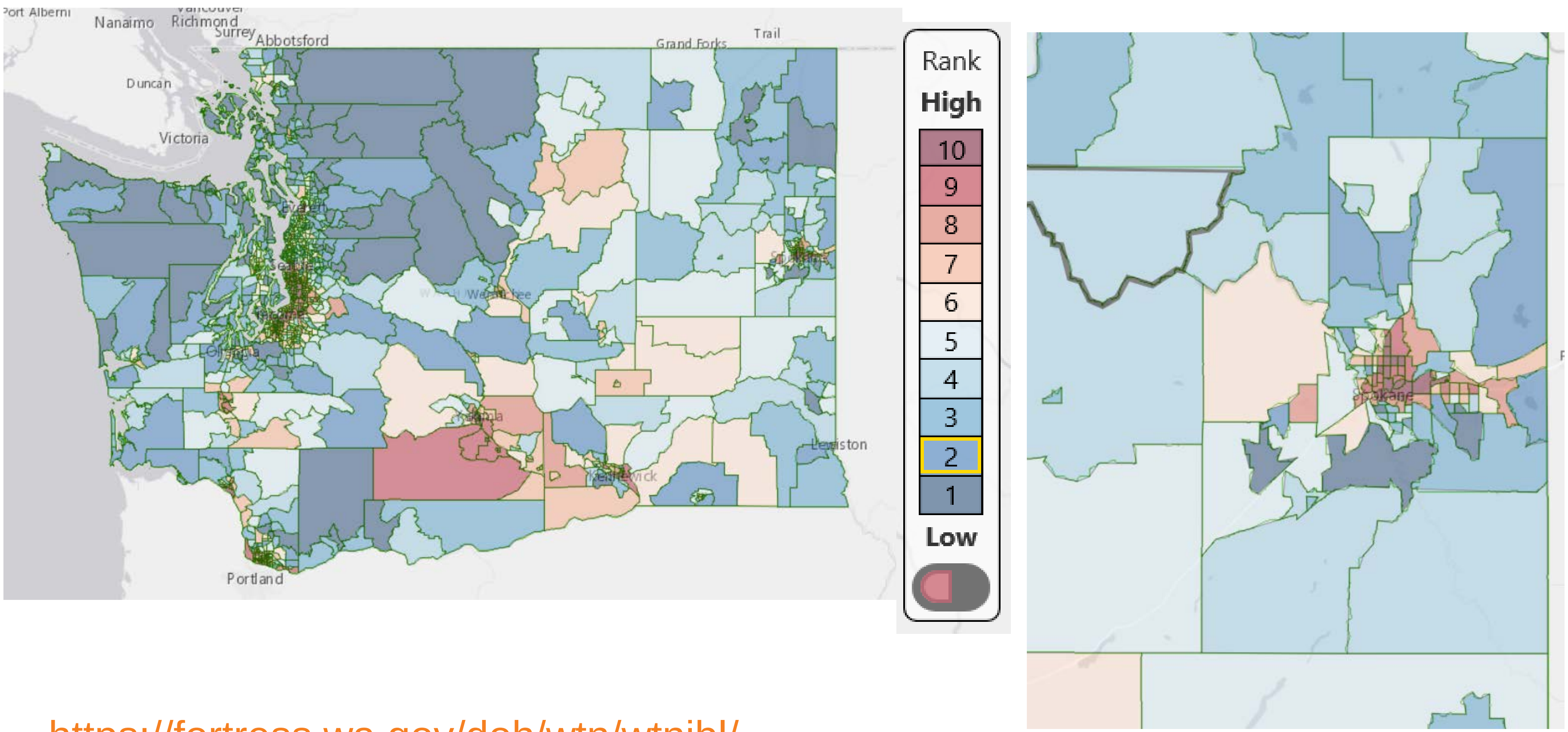
Highly Impacted Communities

– Cumulative Impact Analysis
– Tribal lands
  - Spokane
  - Colville
– Locations should be available by end of 2020
  - State held workshops in August & September 2019

Vulnerable Populations

– Use Washington State Health Disparities map
  - What is disproportionate on a scale of 1 to 10?
  - Avista proposes areas with a score 8 or higher in either Socioeconomic factors or Sensitive population metrics
– Should we include other metrics to identify these communities?

Environmental Health Disparities Map

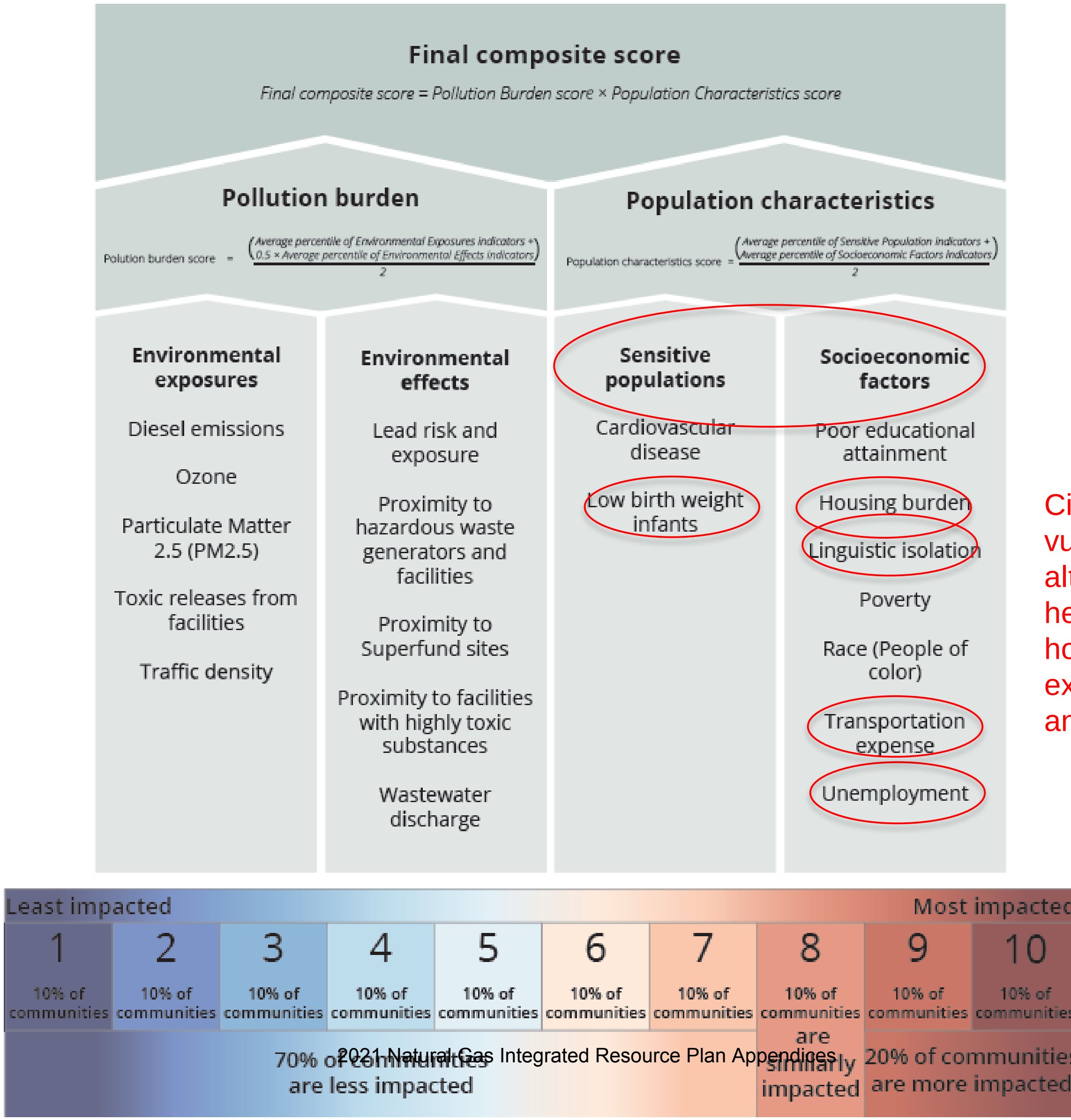


https://fortress.wa.gov/doh/wtn/wtnibl/

Department of Health data is divided up by Federal Information Processing Standards (FIPS) Code

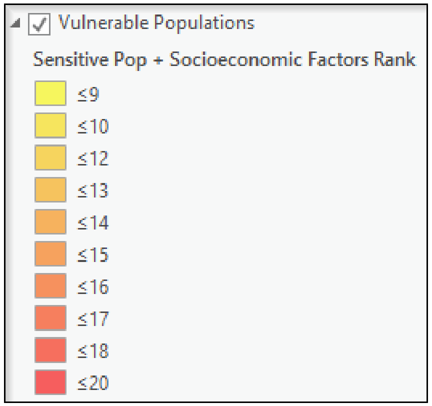
Environmental Health Scoring

From WA Department of Health

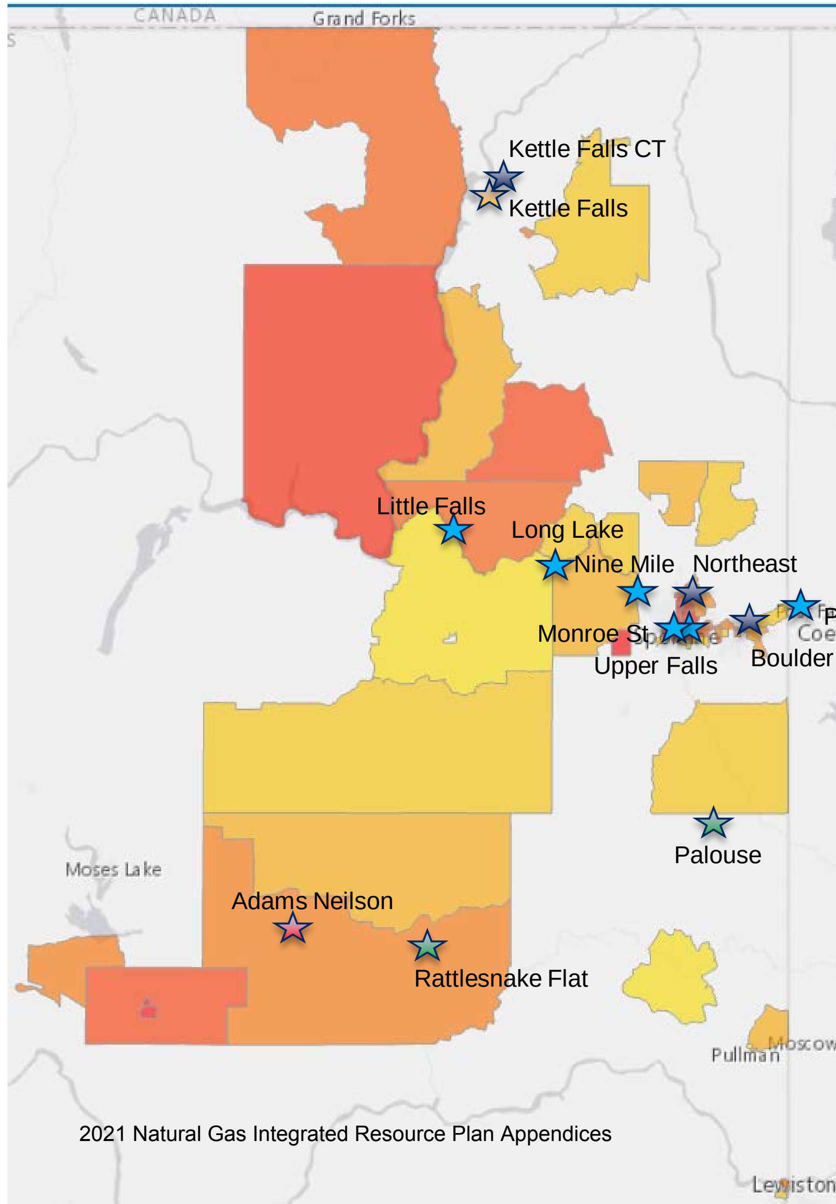


Circle areas match definition of vulnerable population, although access to food & health care, higher rates of hospitalization are not expressively included but are an indication of poverty

Selected Vulnerable Populations



Data is shown by combined score



<u>"Large" Resource Legend</u>

- Natural Gas
- Biomass
- Hydro
- Wind
- Solar

Spokane Area "Avista" Vulnerable Populations

Resource Legend

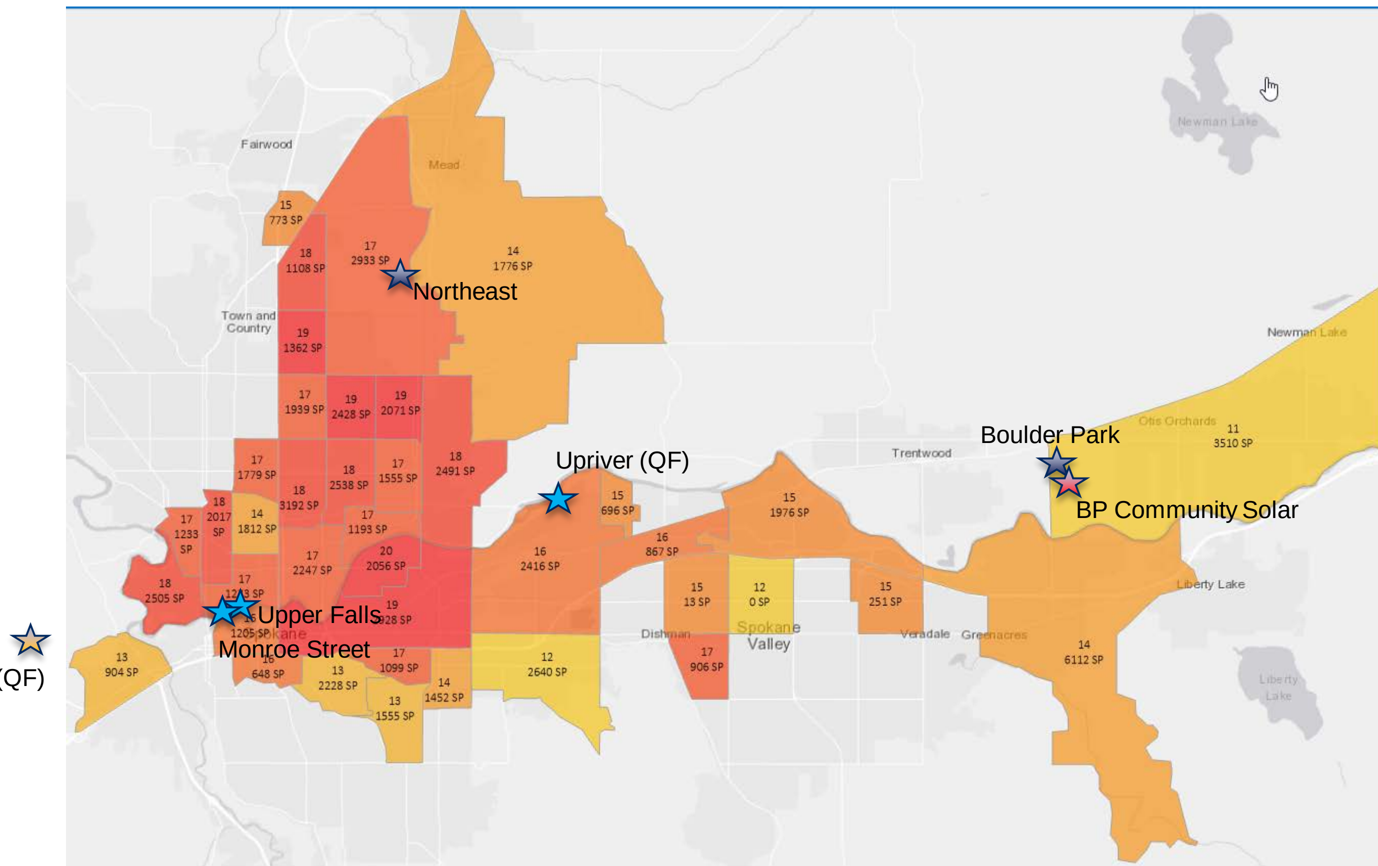
- Natural Gas
- Biomass/Other
- Hydro
- Wind
- Solar

Vulnerable Populations

Sensitive Pop + Socioeconomic Factors Rank

- ≤9
- ≤10
- ≤12
- ≤13
- ≤14
- ≤15
- ≤16
- ≤17
- ≤18
- ≤20

Data is shown by combined score



N

IRP Metrics *(From Last TAC Meeting)*

Metric	IRP Relationship
Energy Usage per Customer	• Expected change taking into account selected energy efficiency then compare to remaining population. • EE includes low income programs and TRC based analysis which includes non-economic benefits.
Cost per Customer	• Estimate cost per customer then compare to remaining population. • How do IRP results compare to above 6% of income?

Preference	• Should the IRP have a monetary preference?
	  • For example- should all customers pay more to locate assets (or programs) in areas with vulnerable populations or highly impacted communities?
	  • If so, how much more?

IRP Metrics *(From Last TAC Meeting)*

<table>
<tr><th>Metric</th><th>IRP Relationship</th></tr>
<tr><td>Reliability
SAIFI: System Average Interruption Frequency Index
MAIFI: Momentary Average Interruption Frequency Index</td><td rowspan="2">Calculate baseline for each distribution feeder and match with communities
Estimate benefits for area with potential IRP distribution projects
Compare to other communities as baseline
May be more appropriate in Distribution plan rather than IRP</td></tr>
<tr><td>Resiliency:
SAIDI: System Average Interruption Duration Index
CAIDI: Customer Average Interruption Duration Index
CELID: Customer’s Experiencing Long Duration Outages</td></tr>
<tr><td>Resource Analysis</td><td>Estimate emissions (NO_X, SO_2, PM2.5, Hg) from power projects located in/near identified communities
Identify new resource or infrastructure project candidates with benefit to communities; i.e. economic benefit, reliability benefit
Identify how resource can benefit energy security</td></tr>
</table>

Energy Use Analysis Results

- Uses five years of customer billing data
- Median income over the same period is used to estimate affordability
- Separated electric only vs electric/gas customers
  - Future enhancement include single/multi family homes, and manufactured homes

Energy/Cost Analysis

Electric Only Customers

Area	Fuel Type	Energy Use	Avg Bill	Income	% Income
Vulnerable Population Areas	Electric	998 KWh	$98	$42,730	2.8%
Other Areas	Electric	1,010 KWh	$100	$58,834	2.0%

Note: Mean energy use is statistically significantly different when removing energy use data below 100 kWh per month (1,049 kWh vs 1,082 kWh)

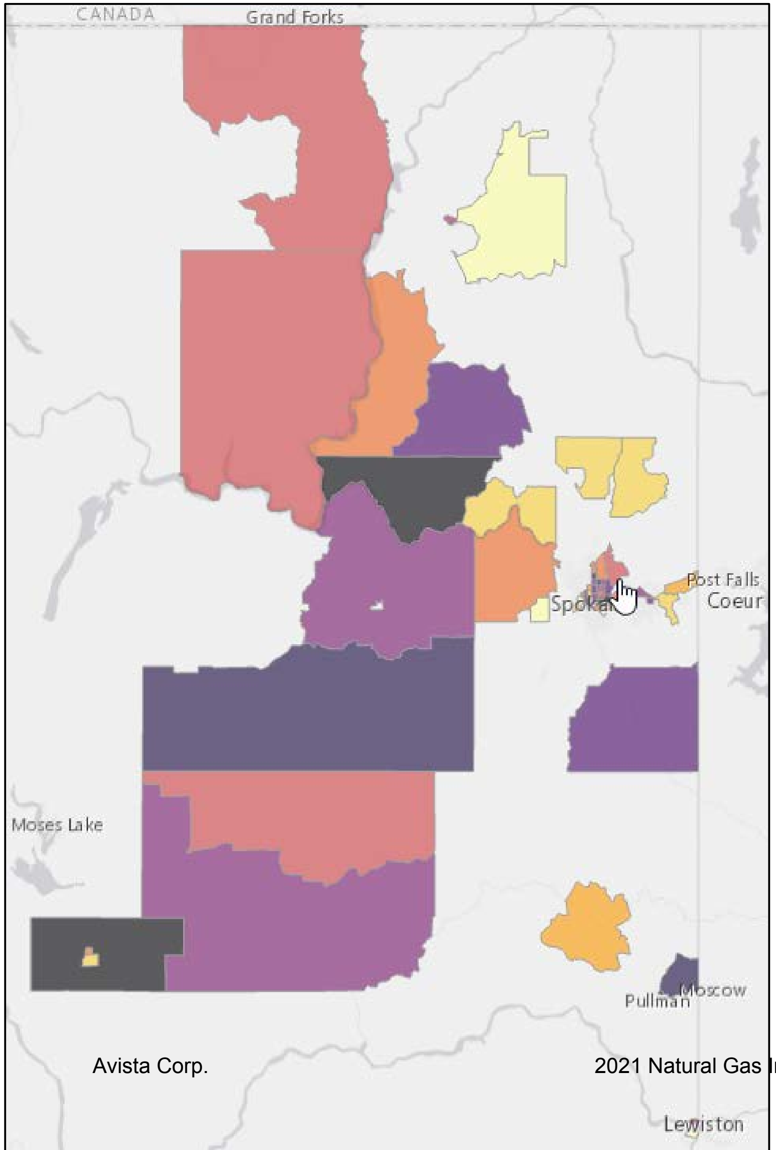
Natural Gas/Electric Customers

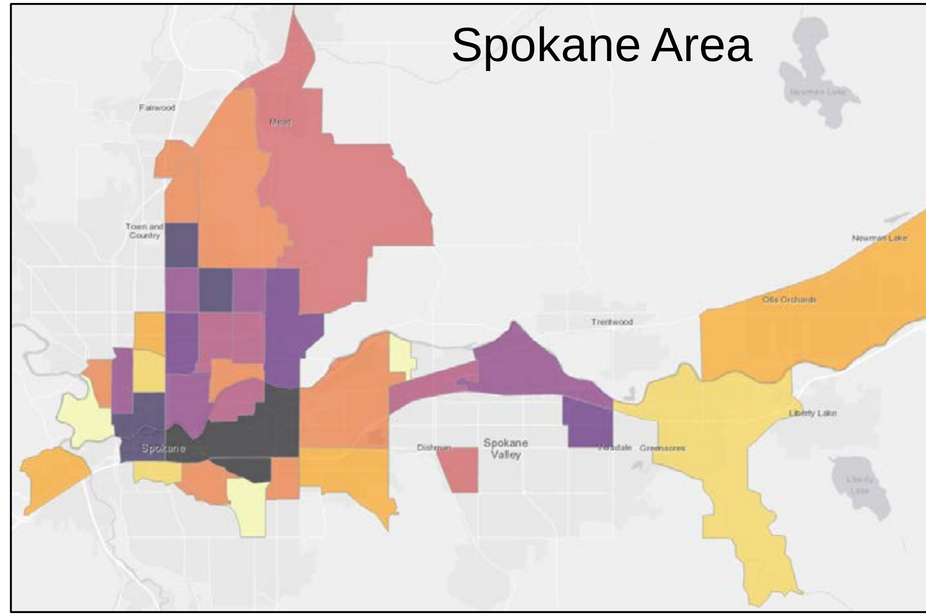
Area	Fuel Type	Energy Use	Avg Bill	Income	% Income
Vulnerable Population Areas	Electric	820 KWh	$80		
Other Areas	Electric	875 KWh	$84		
Vulnerable Population Areas	Gas	52 Therms	$47	$44,889	3.4%
Other Areas	Gas	62 Therms	$56	$68,250	2.5%

Note: Combined natural gas/electric homes have higher energy burden due to fewer multifamily homes included in the population or all electric home including homes with alternative heat such as wood, propane, oil, pellets. Future analysis needed to validate this hypothesis.

Vulnerable Populations

Electric Only Customers- Energy % of Income





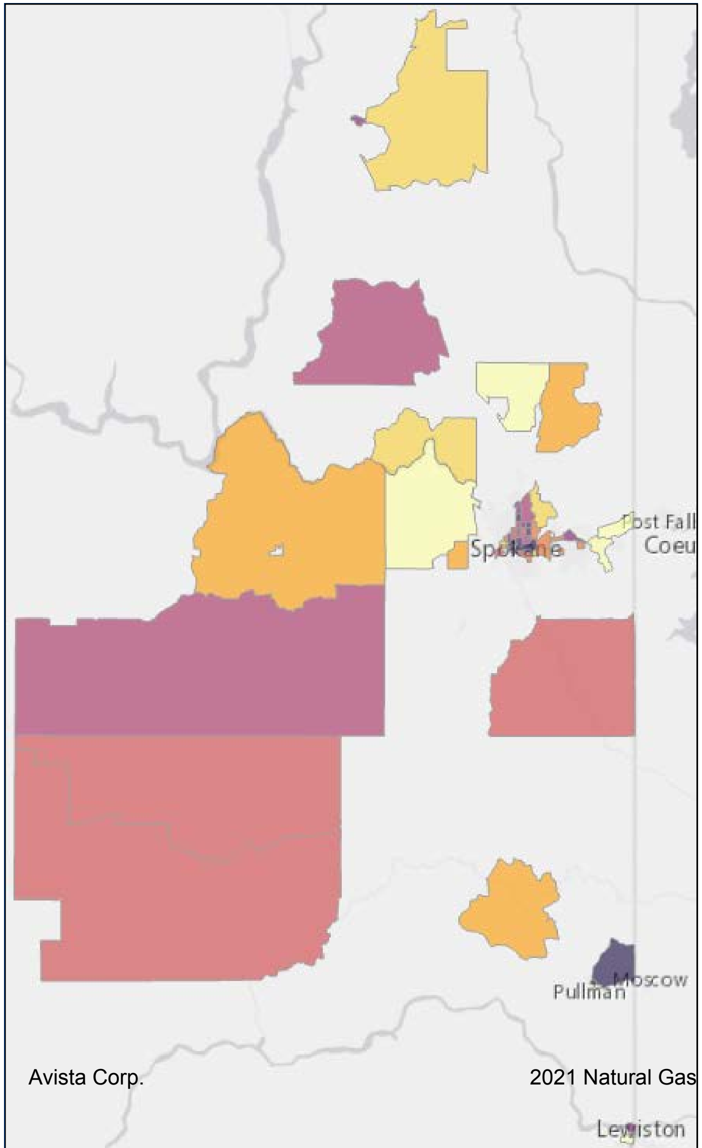
Energy Cost as % of Income - Electric Only

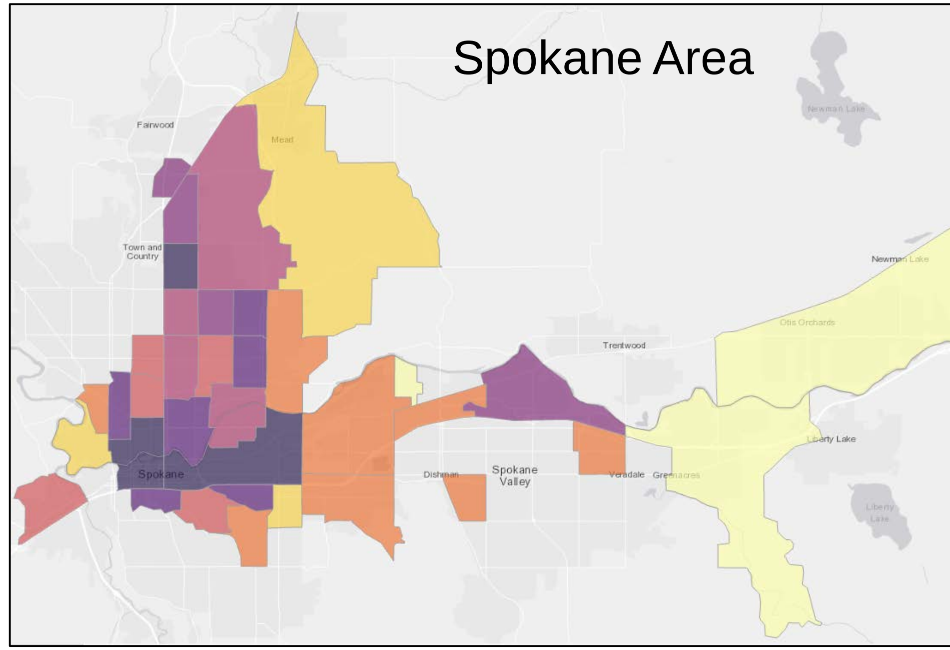
5 Year Avg for Electric Only Customers

- ≤ 2.08 %
- ≤ 2.24 %
- ≤ 2.41 %
- ≤ 2.56 %
- ≤ 2.69 %
- ≤ 2.95 %
- ≤ 3.12 %
- ≤ 3.34 %
- ≤ 3.64 %
- ≤ 4.27 %

Vulnerable Populations

Gas/Electric Only Customers- Energy % of Income





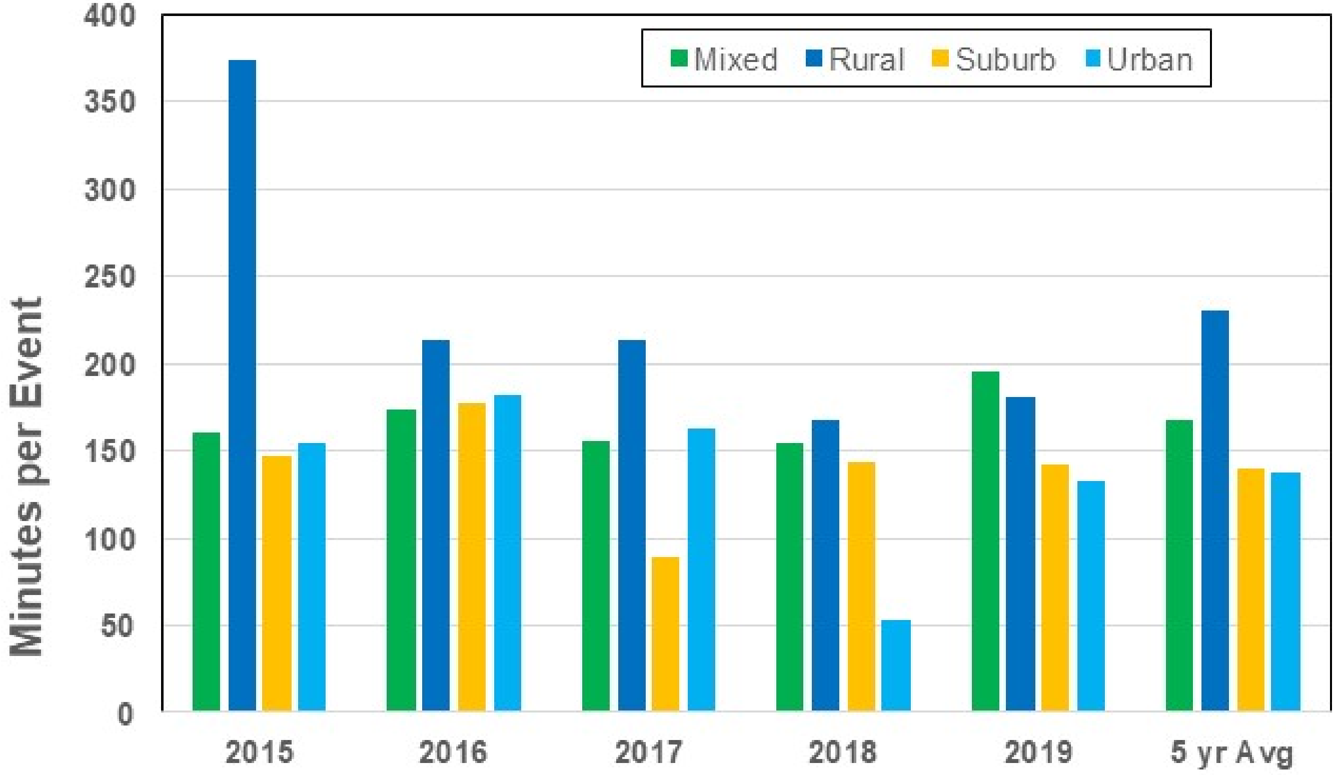
☑ Energy Cost as % of Income - Electric & Gas

5 Year Avg for Customers with Both

- ≤ 2.64 %
- ≤ 2.81 %
- ≤ 3.04 %
- ≤ 3.32 %
- ≤ 3.66 %
- ≤ 4.01 %
- ≤ 4.49 %
- ≤ 5.10 %
- ≤ 7.92 %
- ≤ 11.07 %

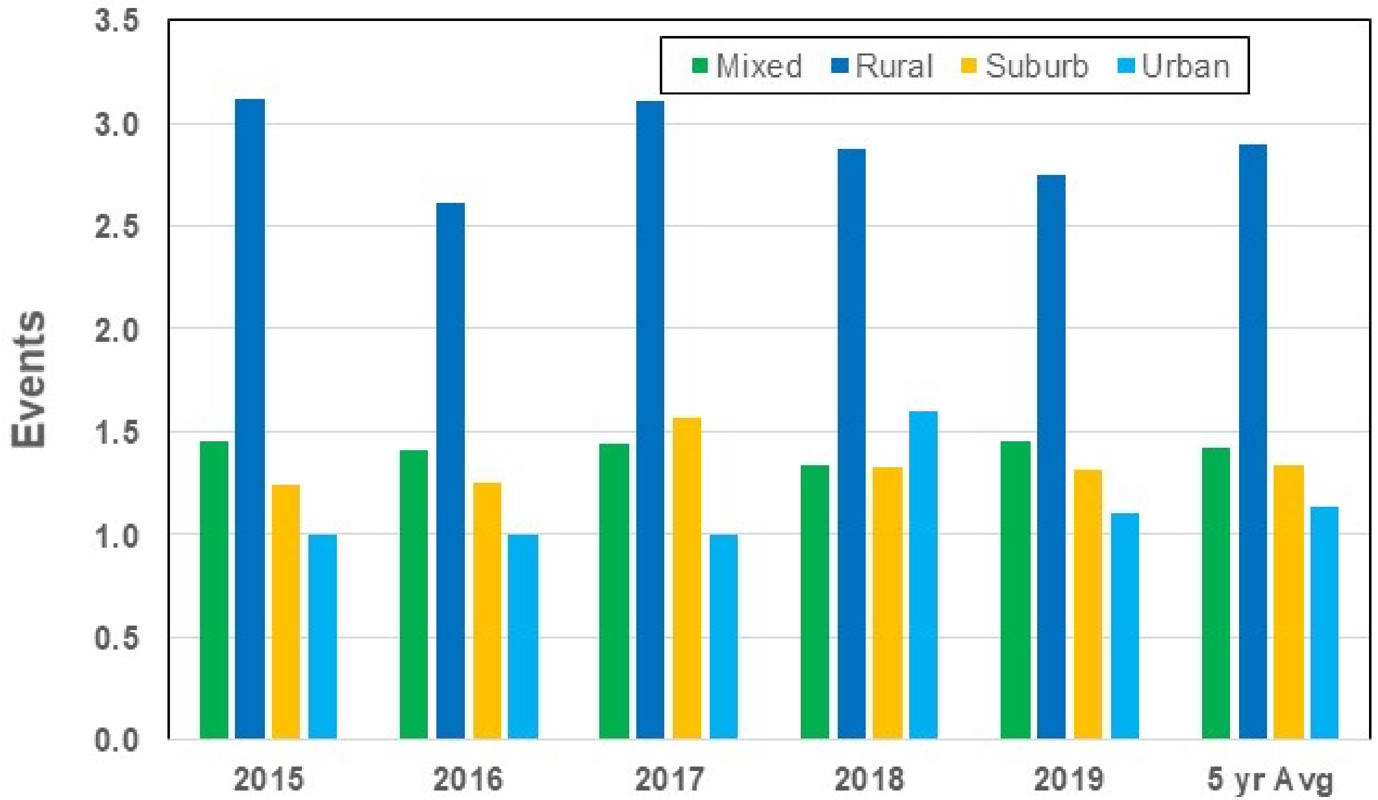
Reliability Data- CAIDI

Measure of resilience- minutes of outages per event
Excludes Major Event Days (MED)



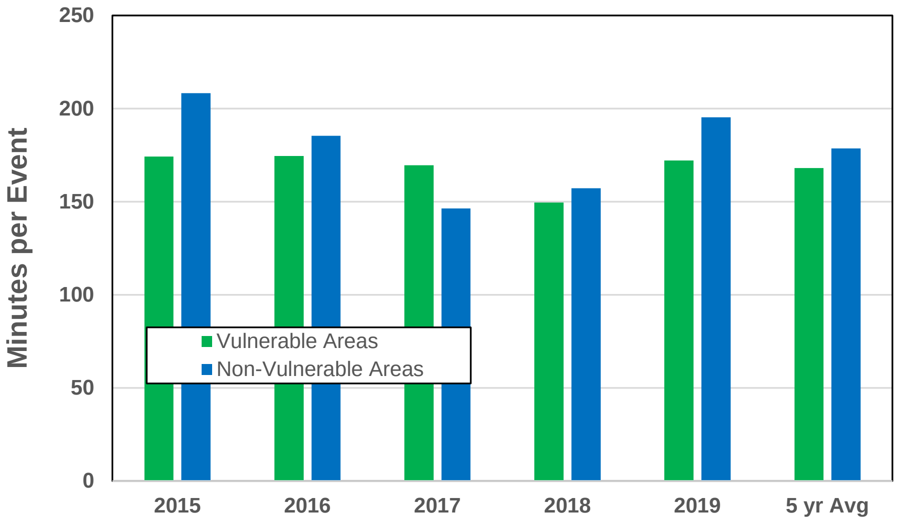
Reliability Data- CEMI

Measure of reliability- Events per Customer

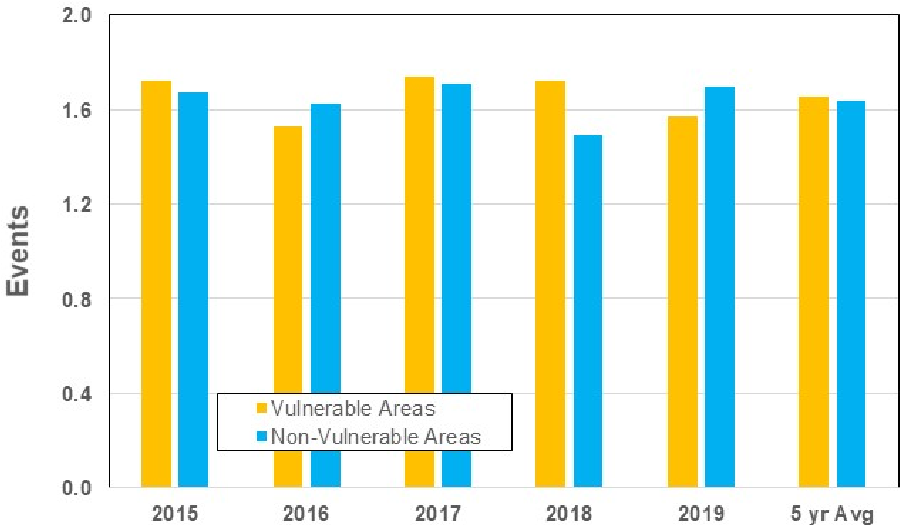


Vulnerable Area vs Non Vulnerable Areas

CAIDI

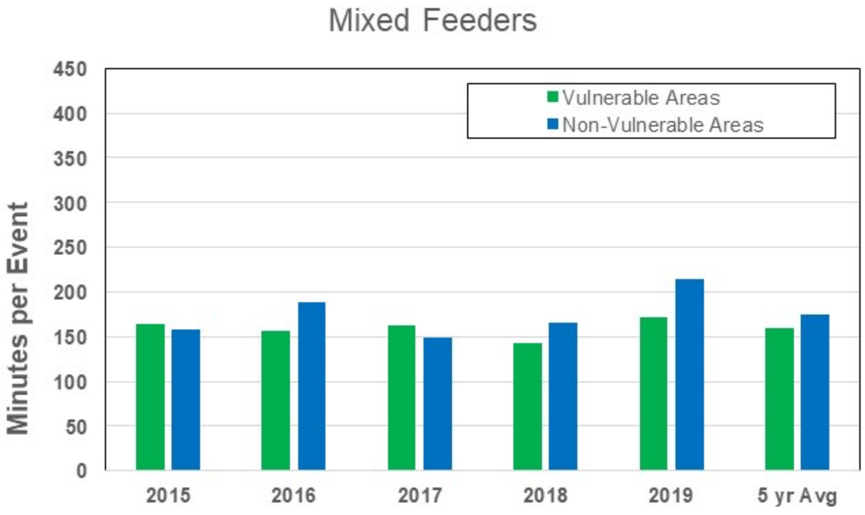


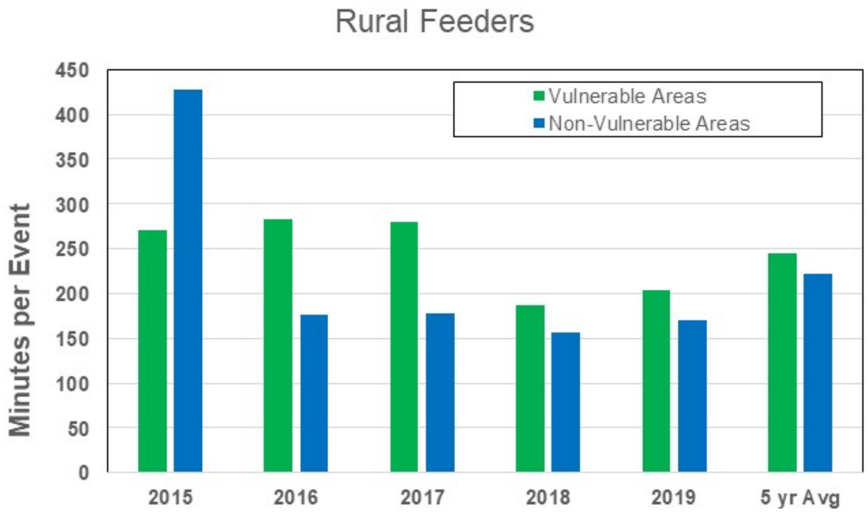
CEMI

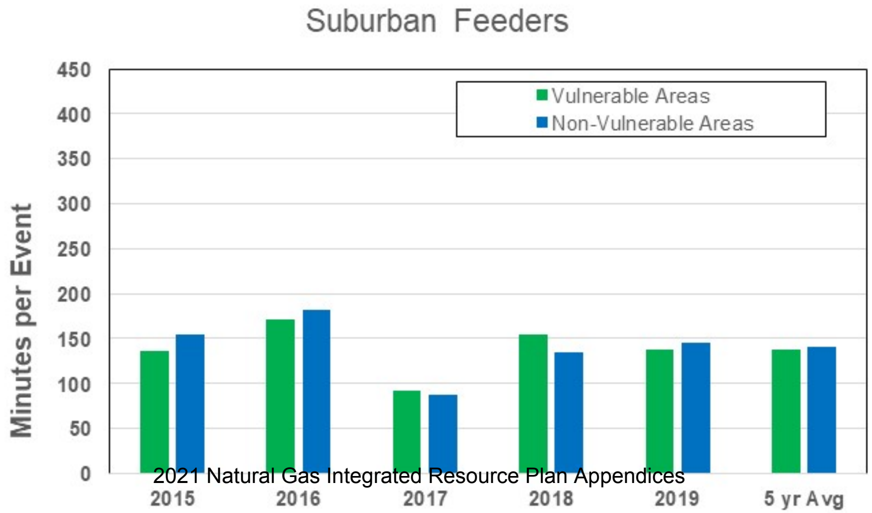


Note: 5 yr Average differences are statistically significantly different

CAIDI- By Feeder Type

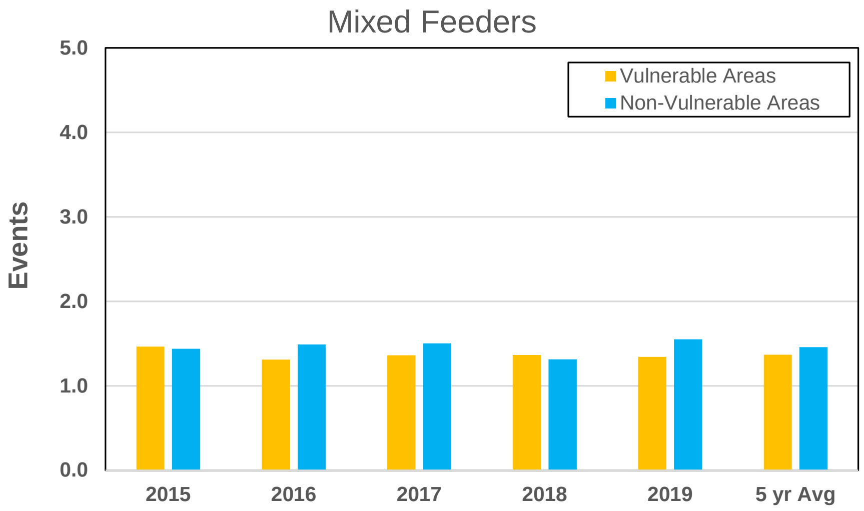


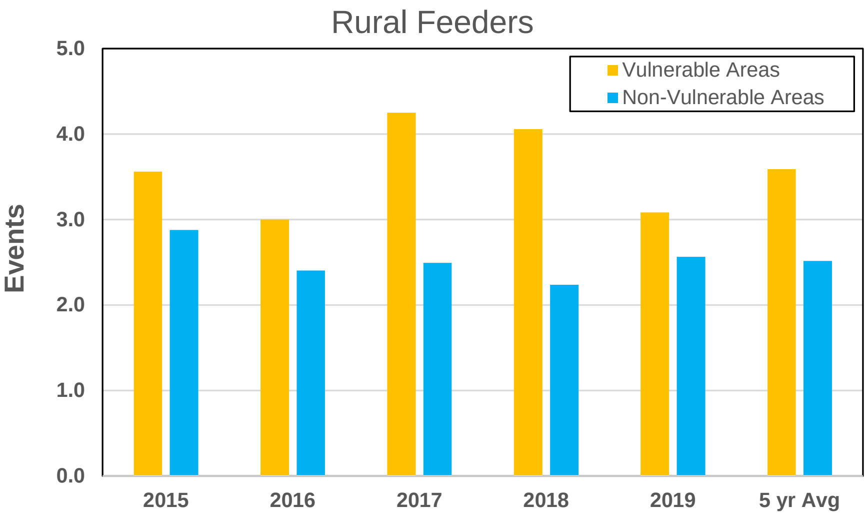


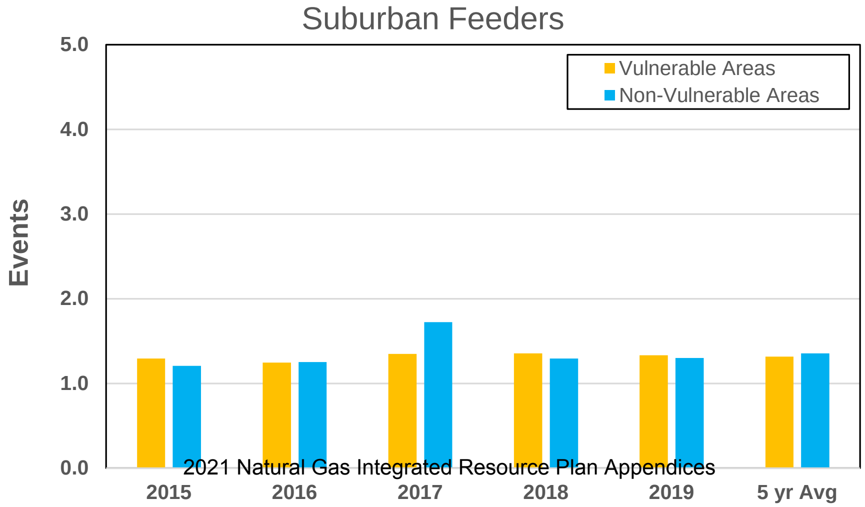


Note: Avista has no vulnerable areas with urban feeders

CEMI- By Feeder Type

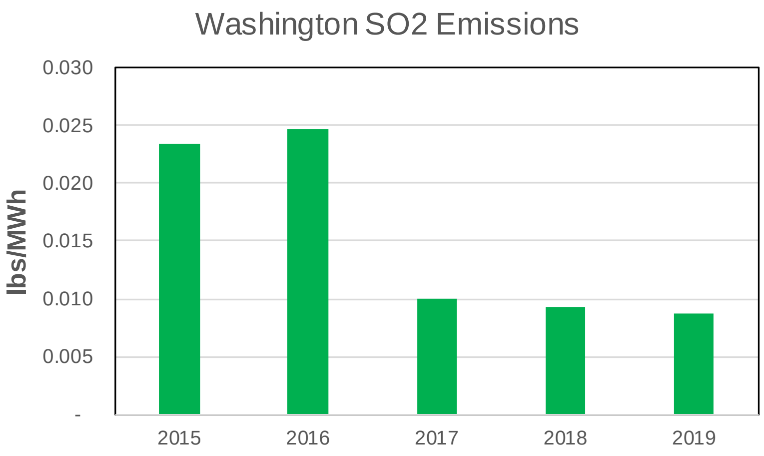


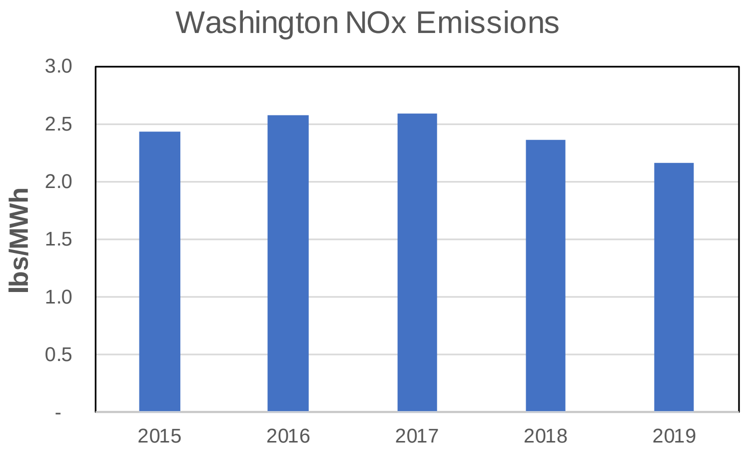


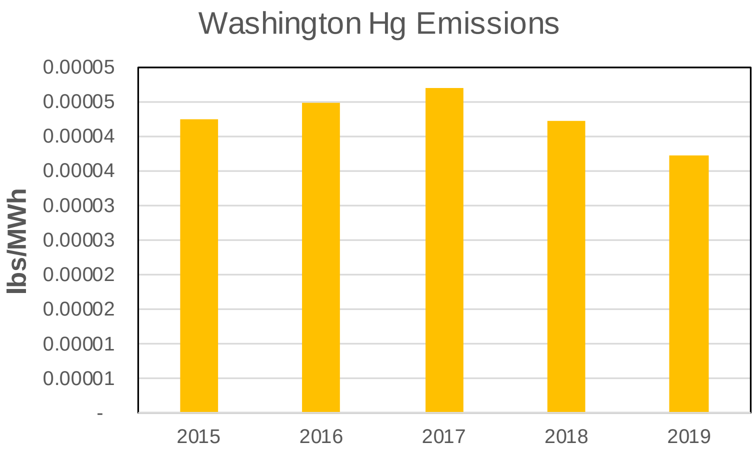


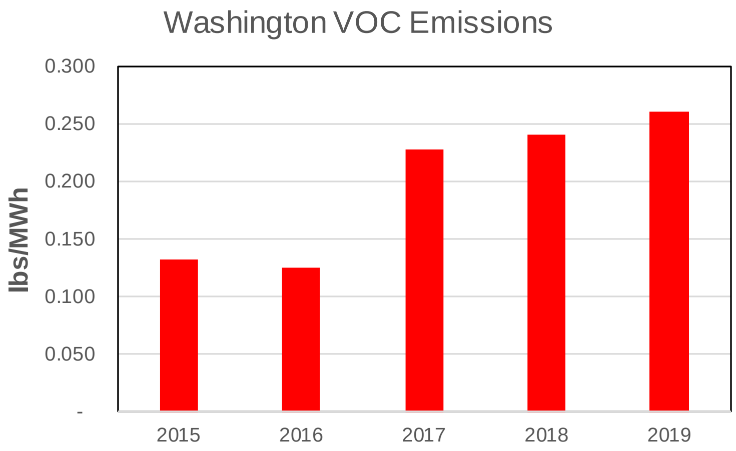
Note: Avista has no vulnerable areas with urban feeders

Avista's Washington Power Plant Air Emissions









TAC Input

- What other metrics can we provide in an IRP to show vulnerable populations and highly impacted communities are not harmed by the transition to clean energy

Economic, Load, and Customer Forecasts

Grant D. Forsyth, Ph.D.
Chief Economist
Technical Advisory Committee Meeting
August 18, 2020

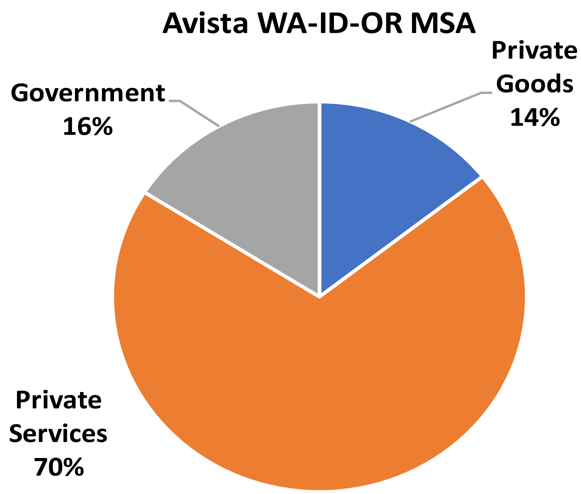
Main Topic Areas

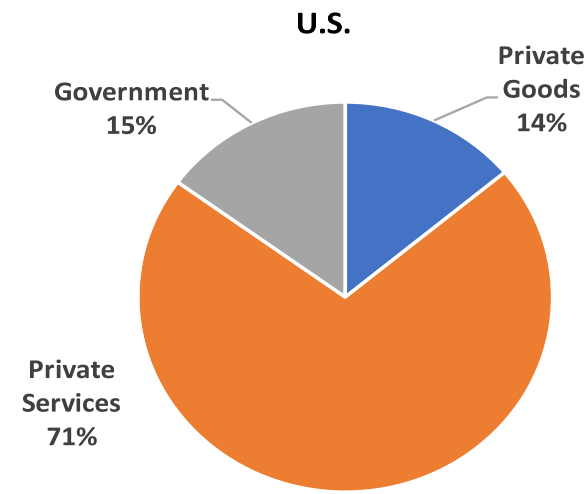
- Service Area Economy
- Long-run Energy Forecast
- Peak Load Forecast
- Long-run Gas Customer Forecast

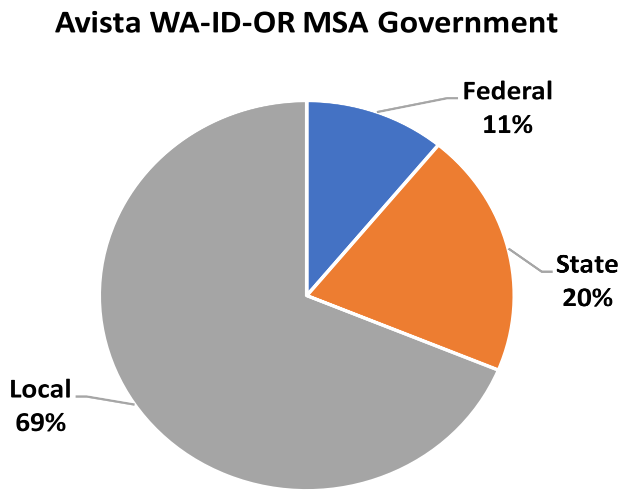
Service Area Economy

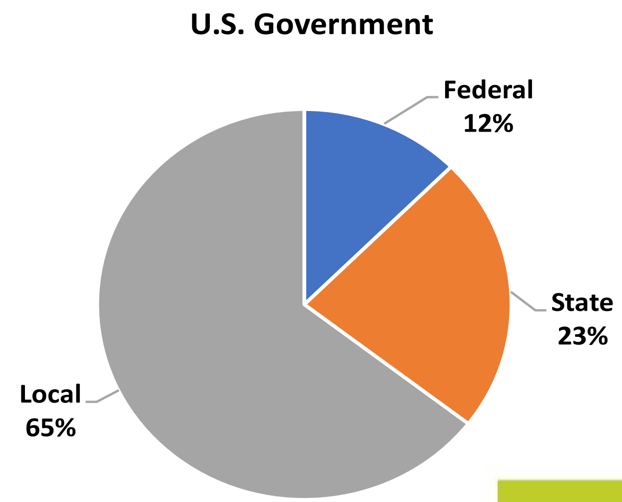
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Distribution of Employment, 2019



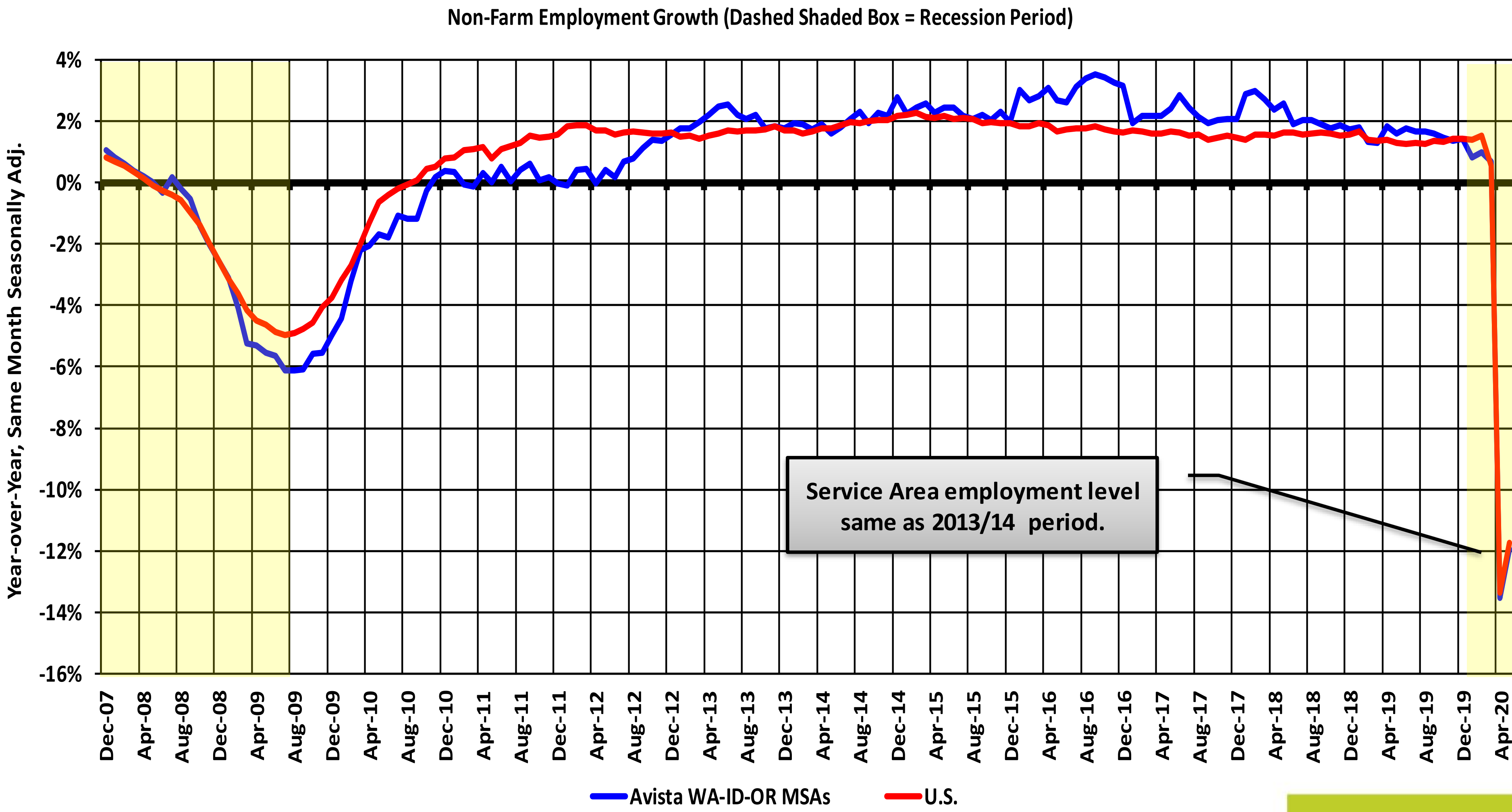






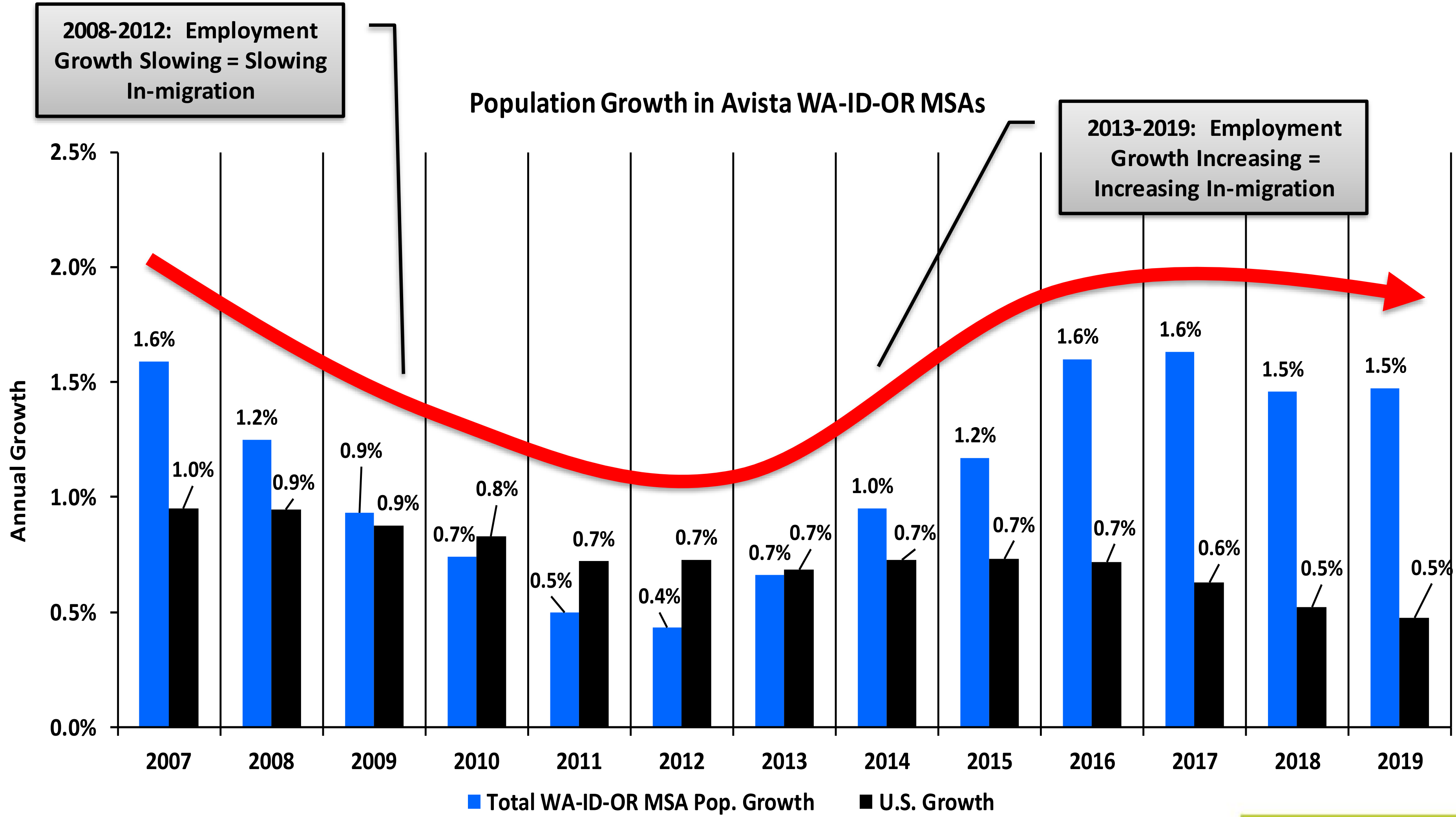
Source: BLS and author's calculations.

Non-Farm Employment Growth, 2009-2020



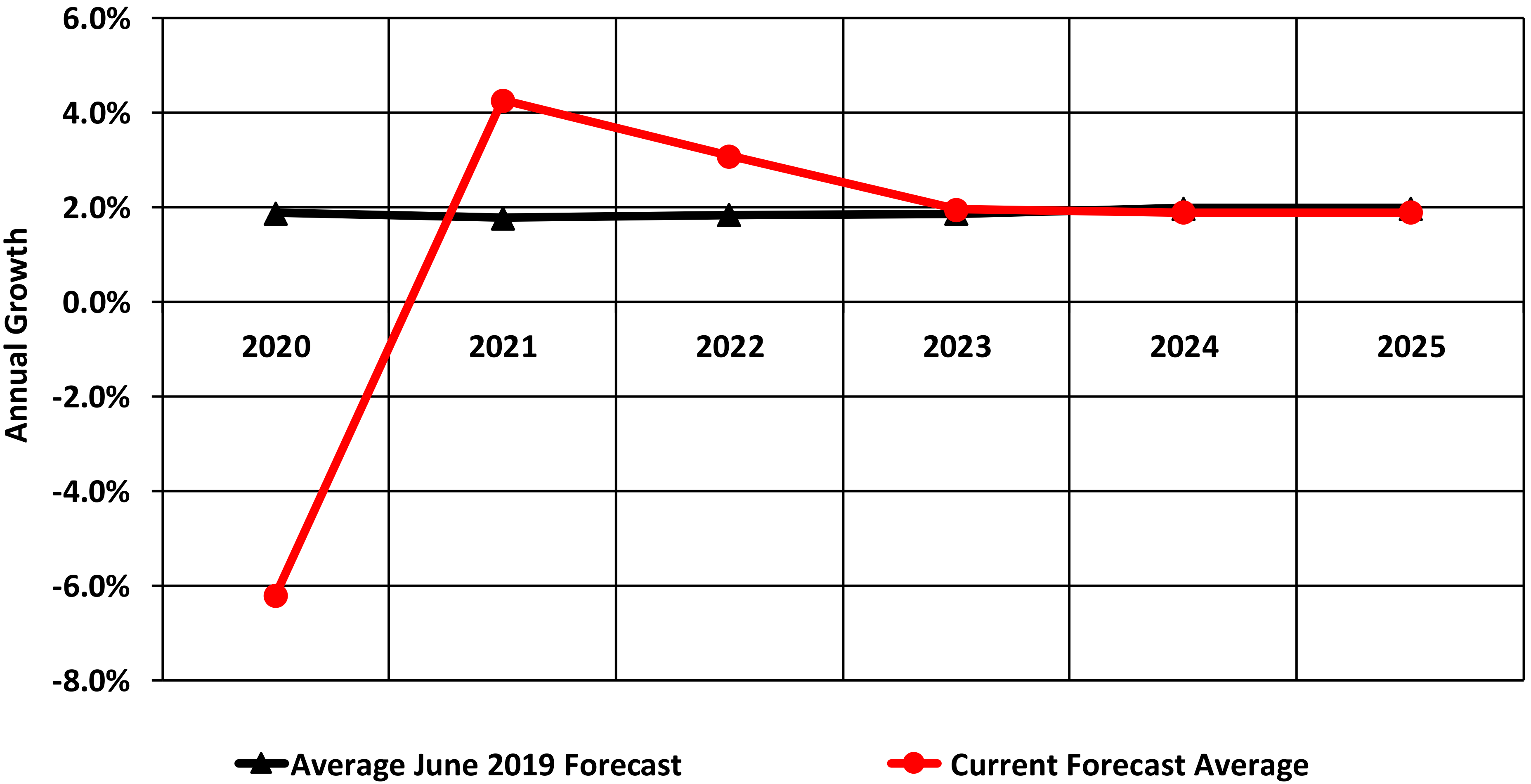
Source: BLS, WA ESD, OR ED and author's calculations.

MSA Population Growth, 2007-2019



Source: BEA, U.S. Census, and author's calculations.

GDP Growth Assumptions: 2021 IRP vs. 2020 IRP

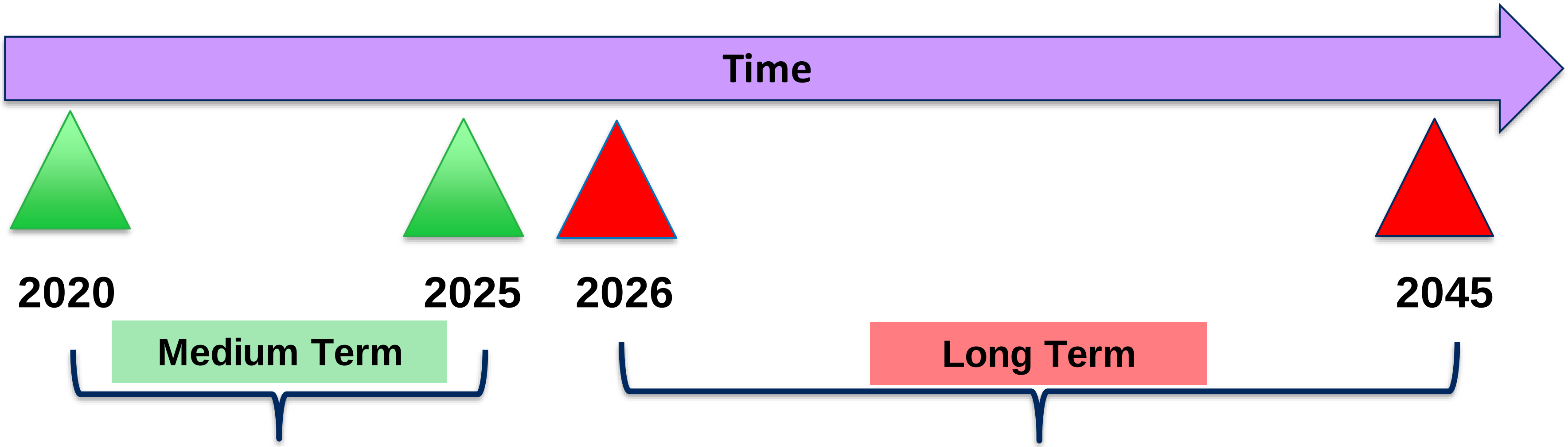


Source: Various and author's calculations.

Long-Term Energy Load Forecast

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Basic Forecast Approach



Medium Term

1) Monthly econometric model by schedule for each class.
2) Customer and UPC forecasts.
3) 20-year moving average for "normal weather."
4) Economic drivers: GDP, industrial production, employment growth, population, price, natural gas penetration, and ARIMA error correction.
5) Native load (energy) forecast derived from retail load forecast.
6) Current forecast is the "Summer/Fall Forecast" done in June.

Long Term

1) Boot strap off medium term forecast.
2) Apply long-run load growth relationships to develop simulation model for high/low scenarios.
3) Include different scenarios for renewable penetration with controls for price elasticity, EV/PHEVs, and natural gas penetration.

The Long-Term Relationship, 2021-2045

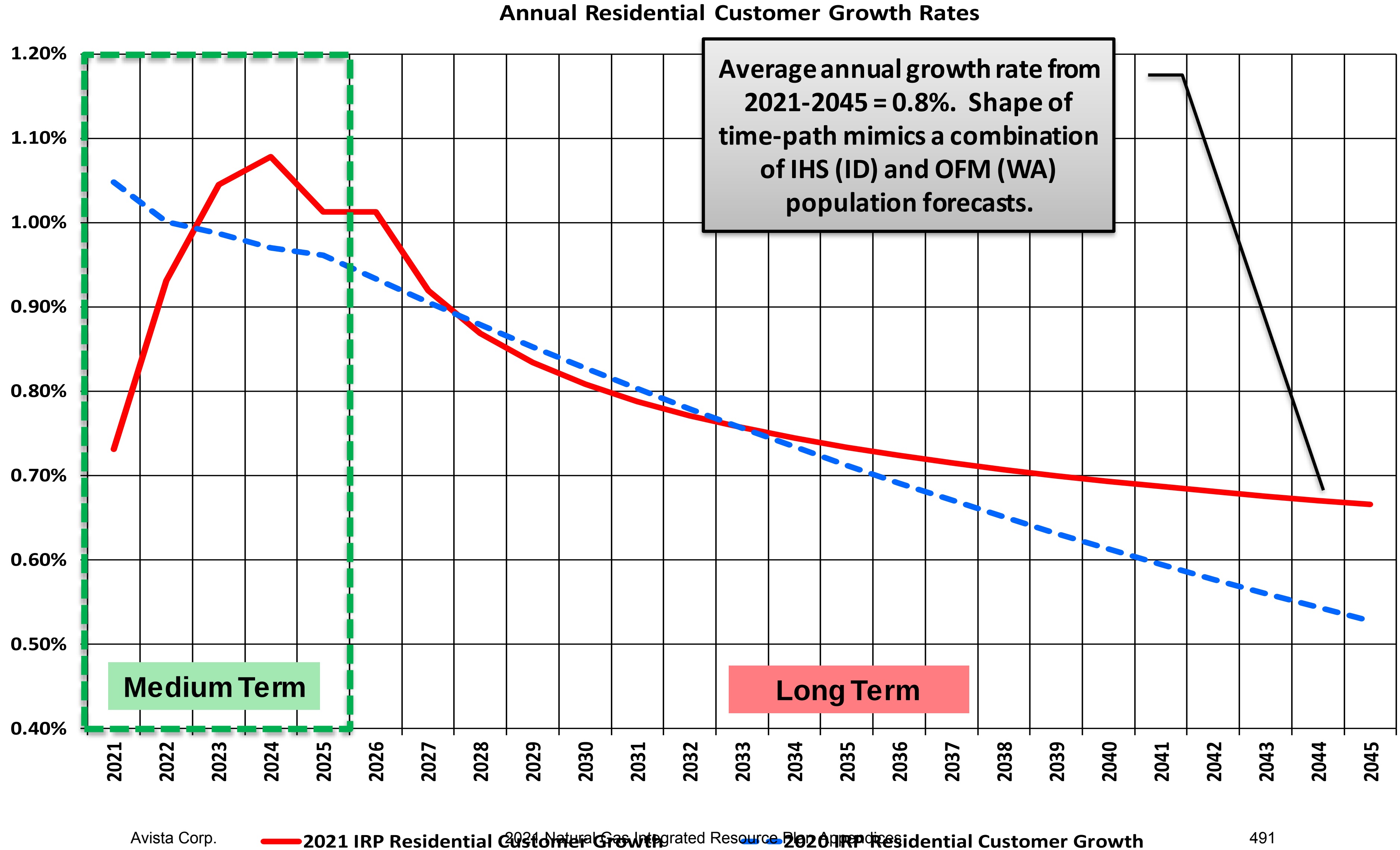
Load = Customers X Use Per Customer (UPC)

Load Growth ≈ Customer Growth + UPC Growth

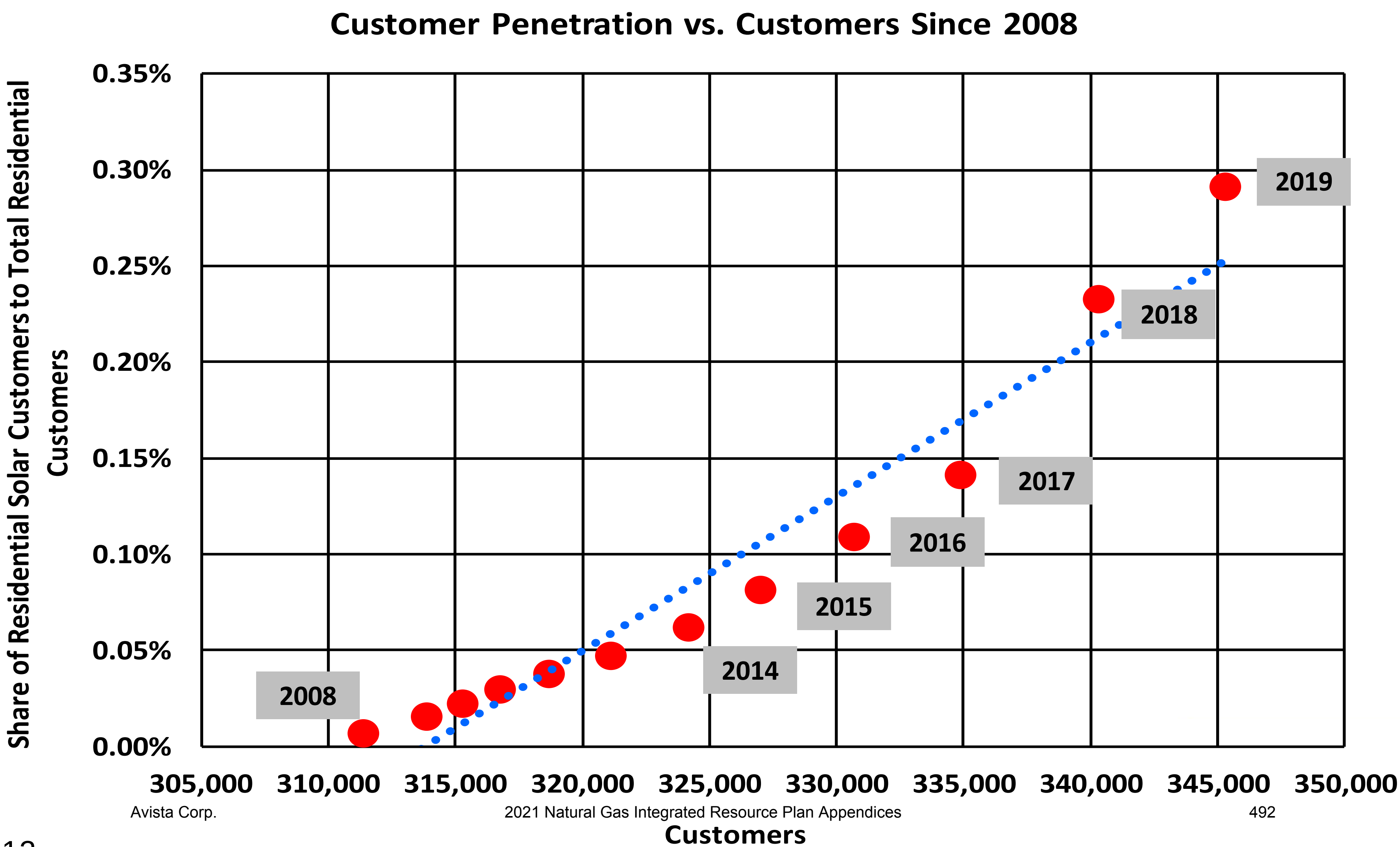
Assumed to be same as population growth for residential after 2025, commercial growth will follow residential, and slow decline in industrial.

Assumed to be a function of multiple factors including renewable penetration, gas penetration, and EVs/PHEVs.

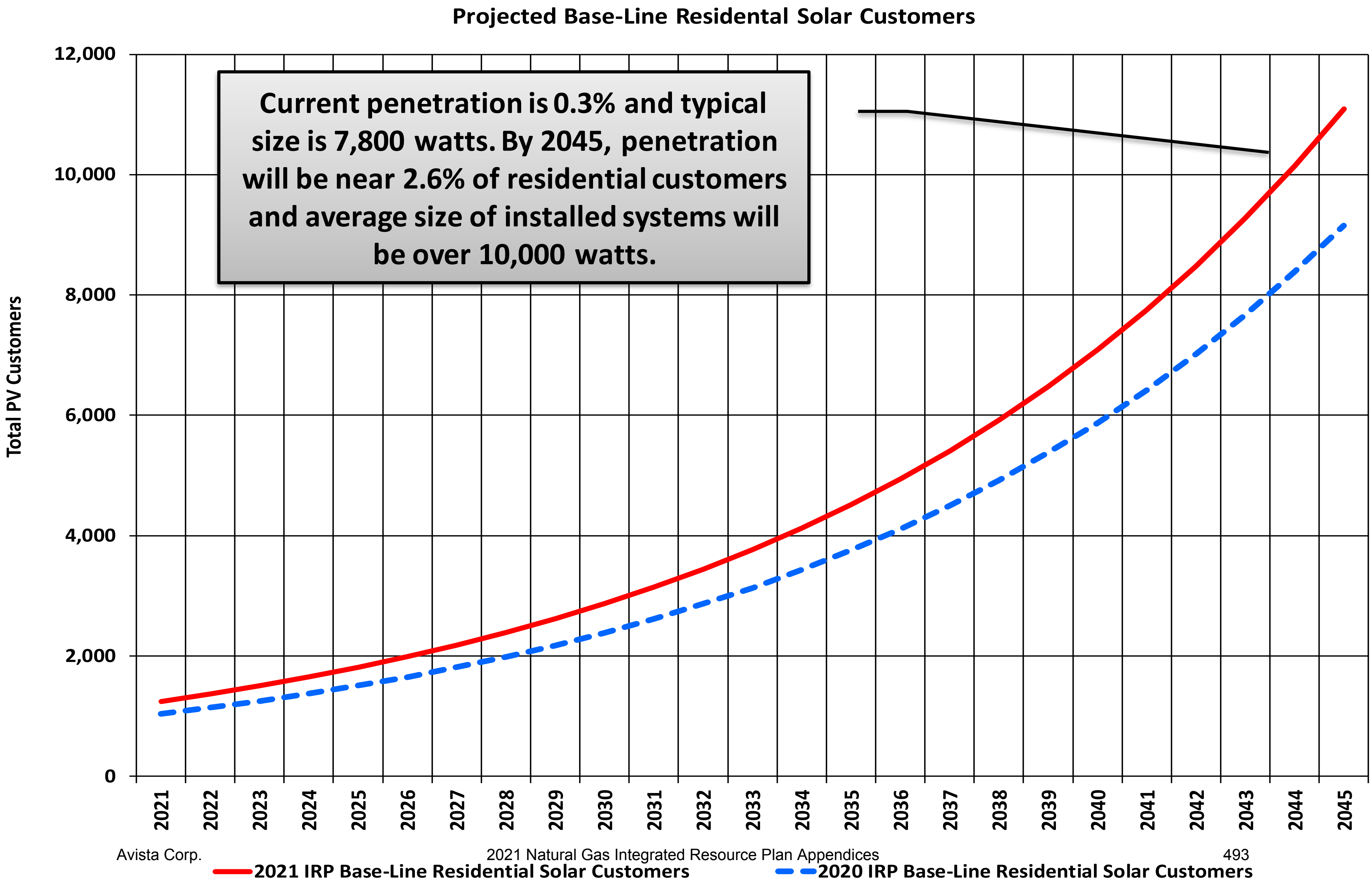
Residential Customer Growth, 2020-2045



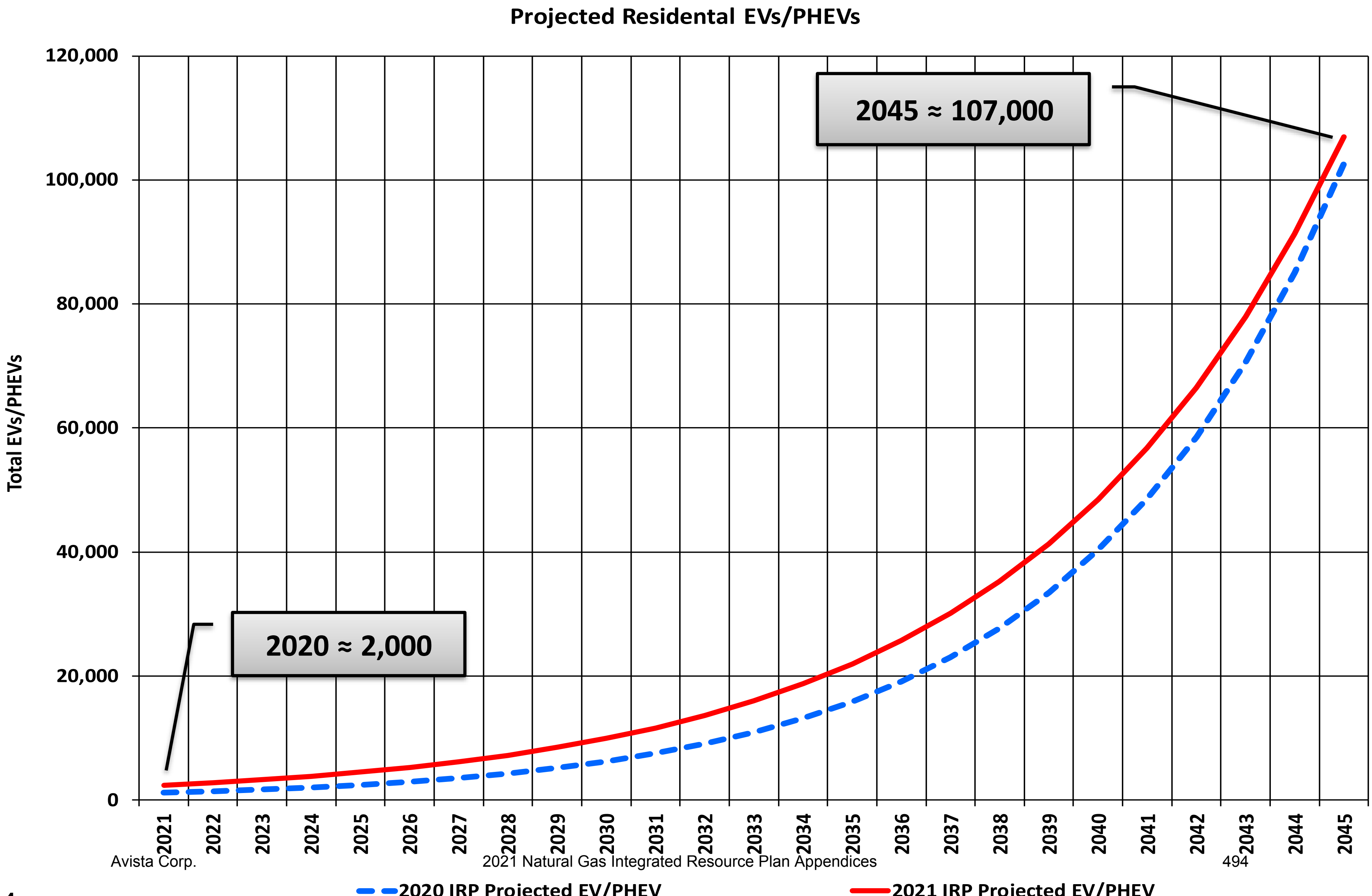
Residential Solar Penetration, 2008-2019



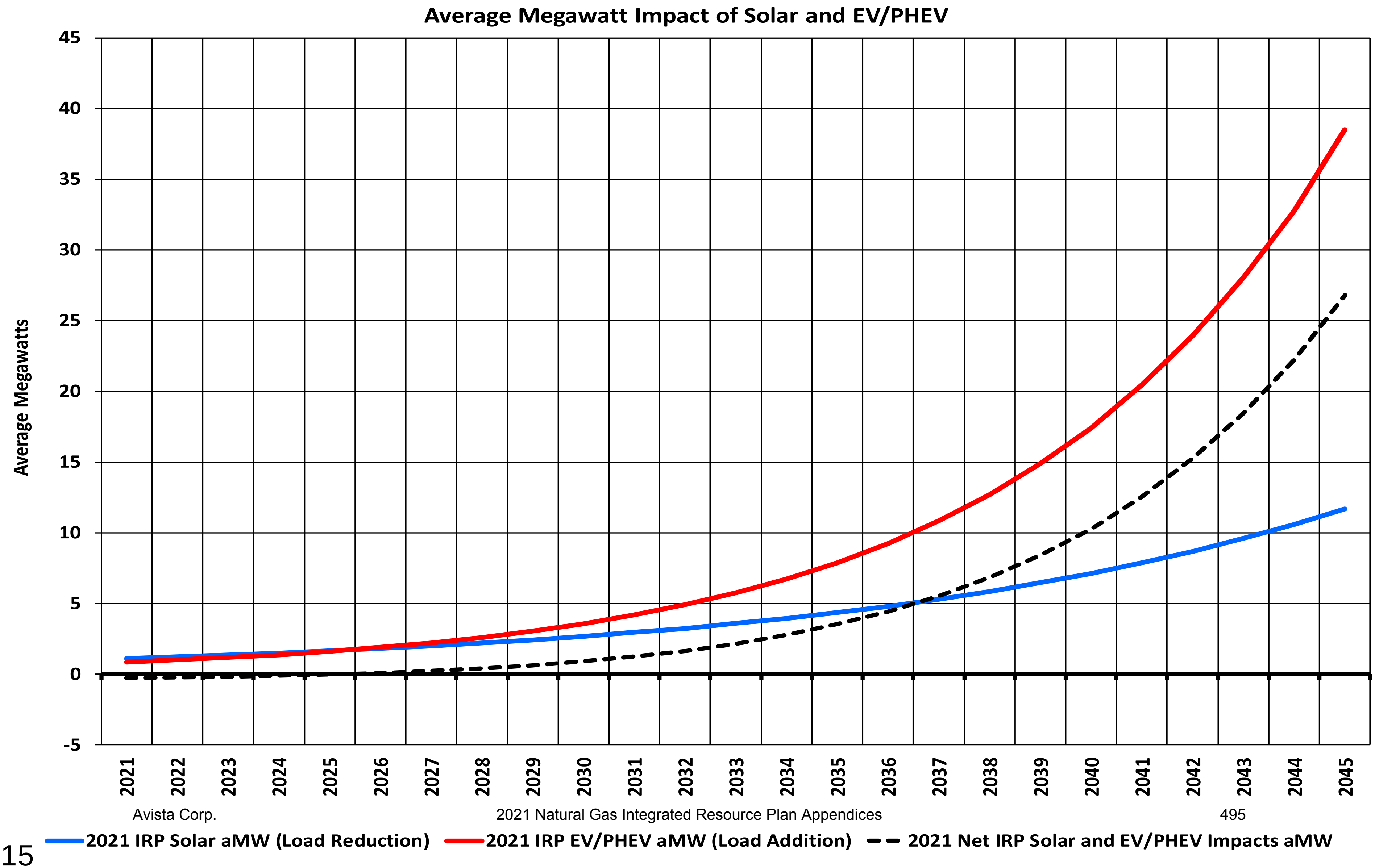
Residential Solar Penetration, 2021-2045



Residential EVs/PHEVs, 2021-2045

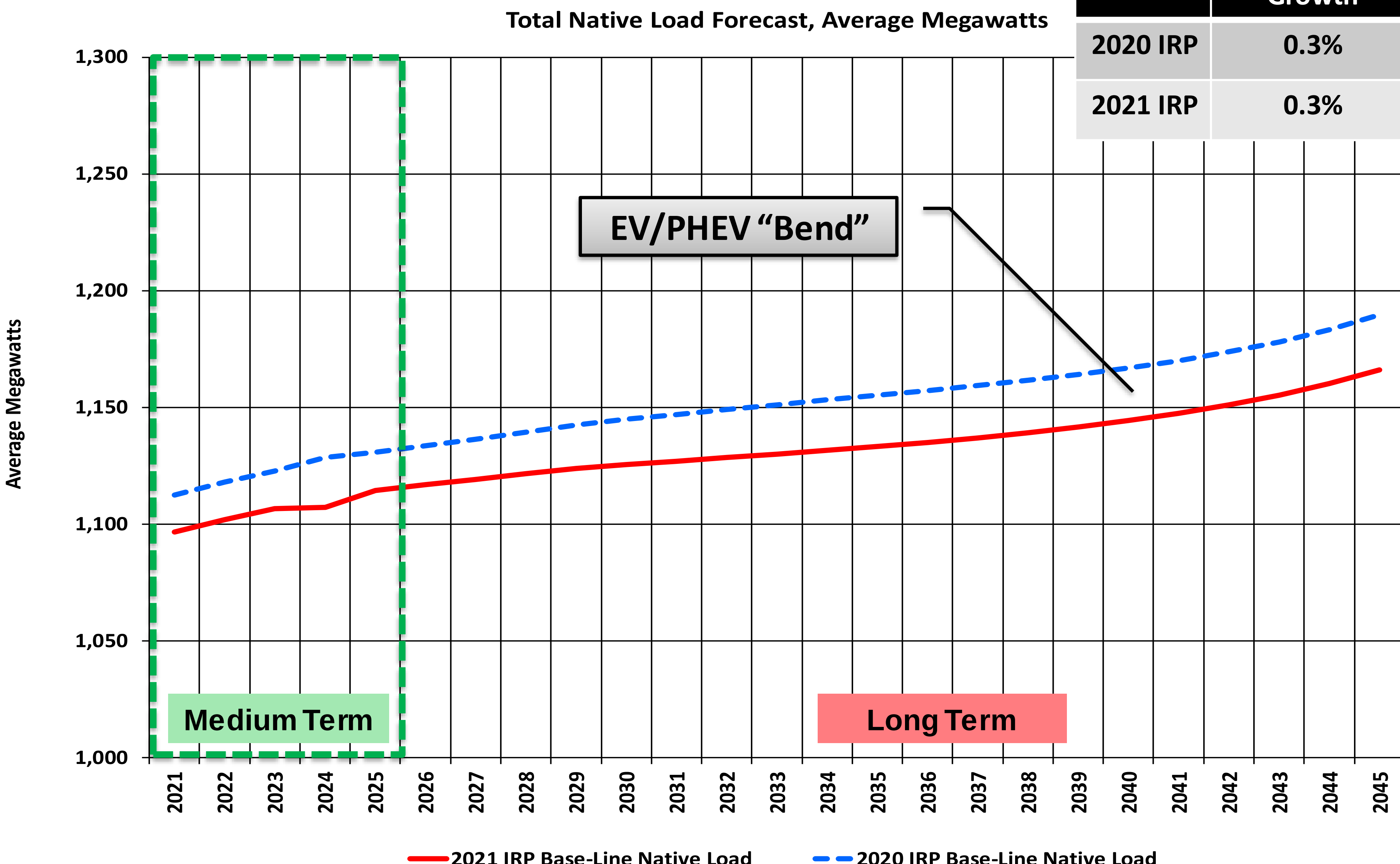


Net Solar and EV/PHEV Impact, 2021-2045



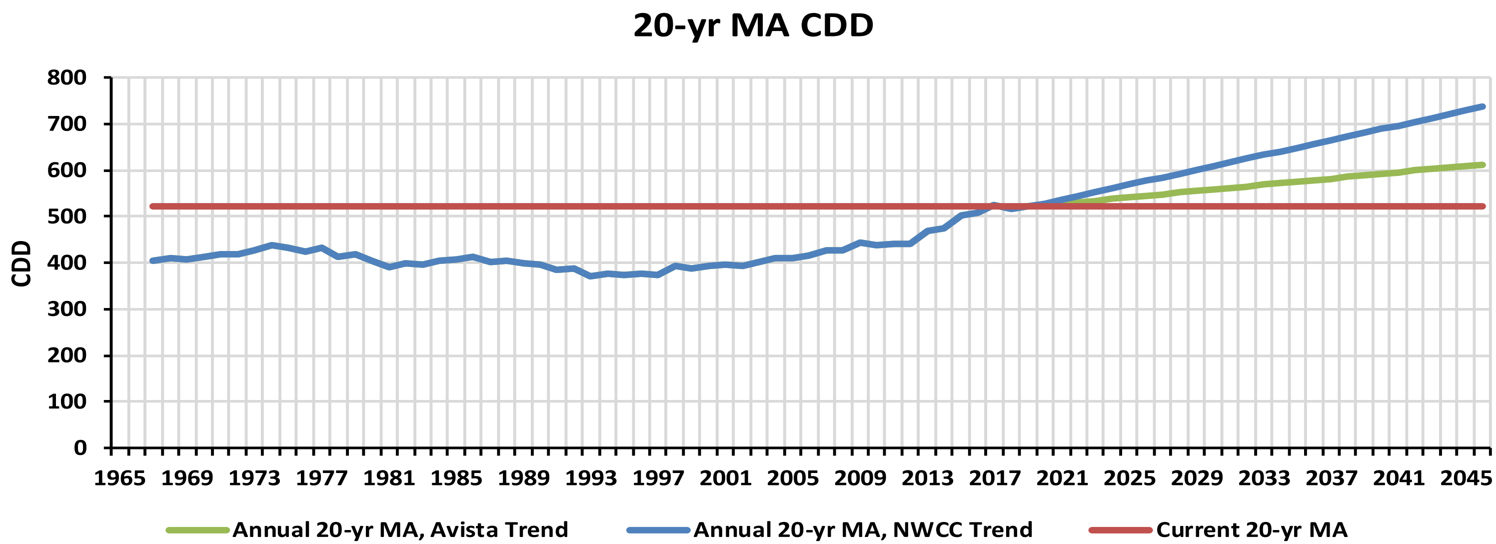
Native Load Forecast, 2021-2045

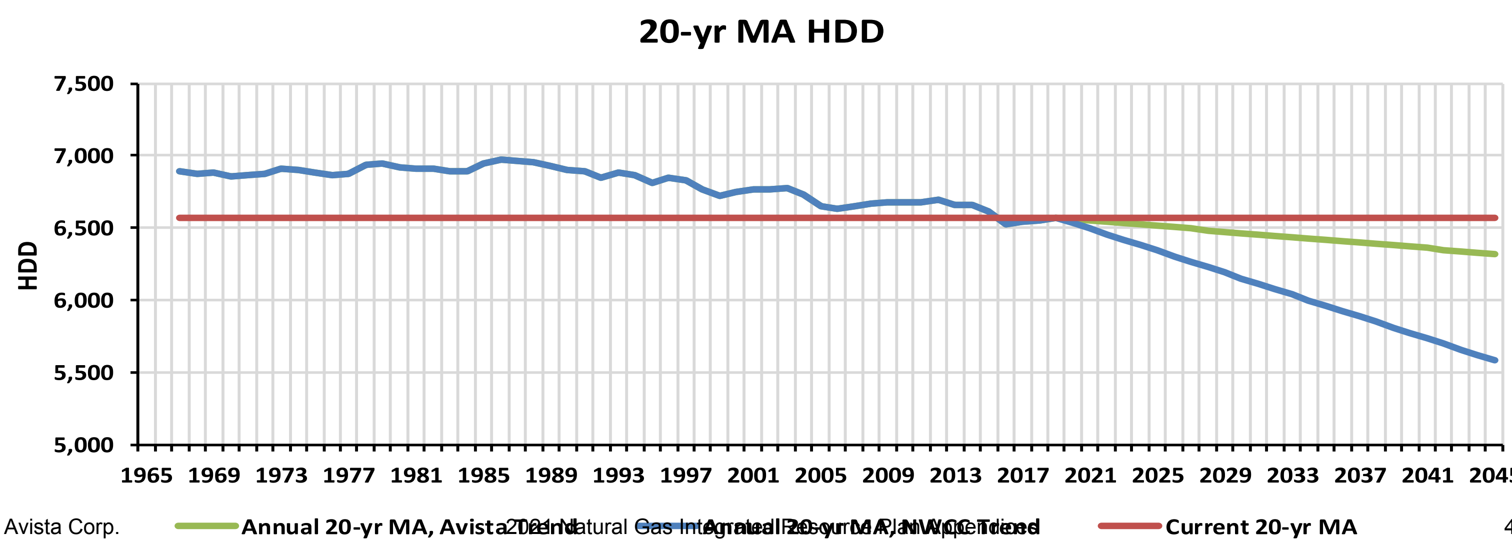
IRP	Avg. Annual Growth
2020 IRP	0.3%
2021 IRP	0.3%



16

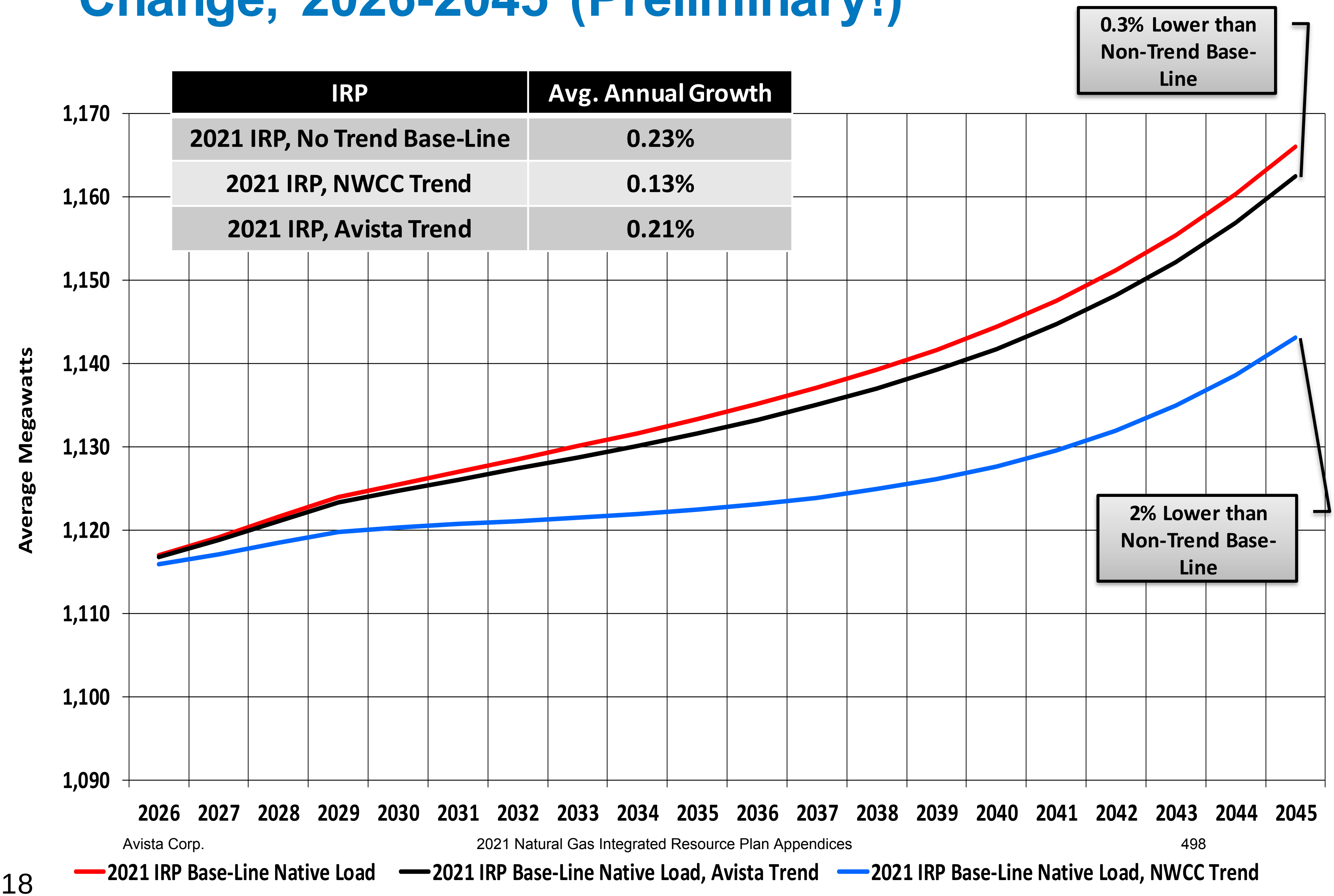
Climate Change: A Trended 20-year Moving Average (Preliminary!)



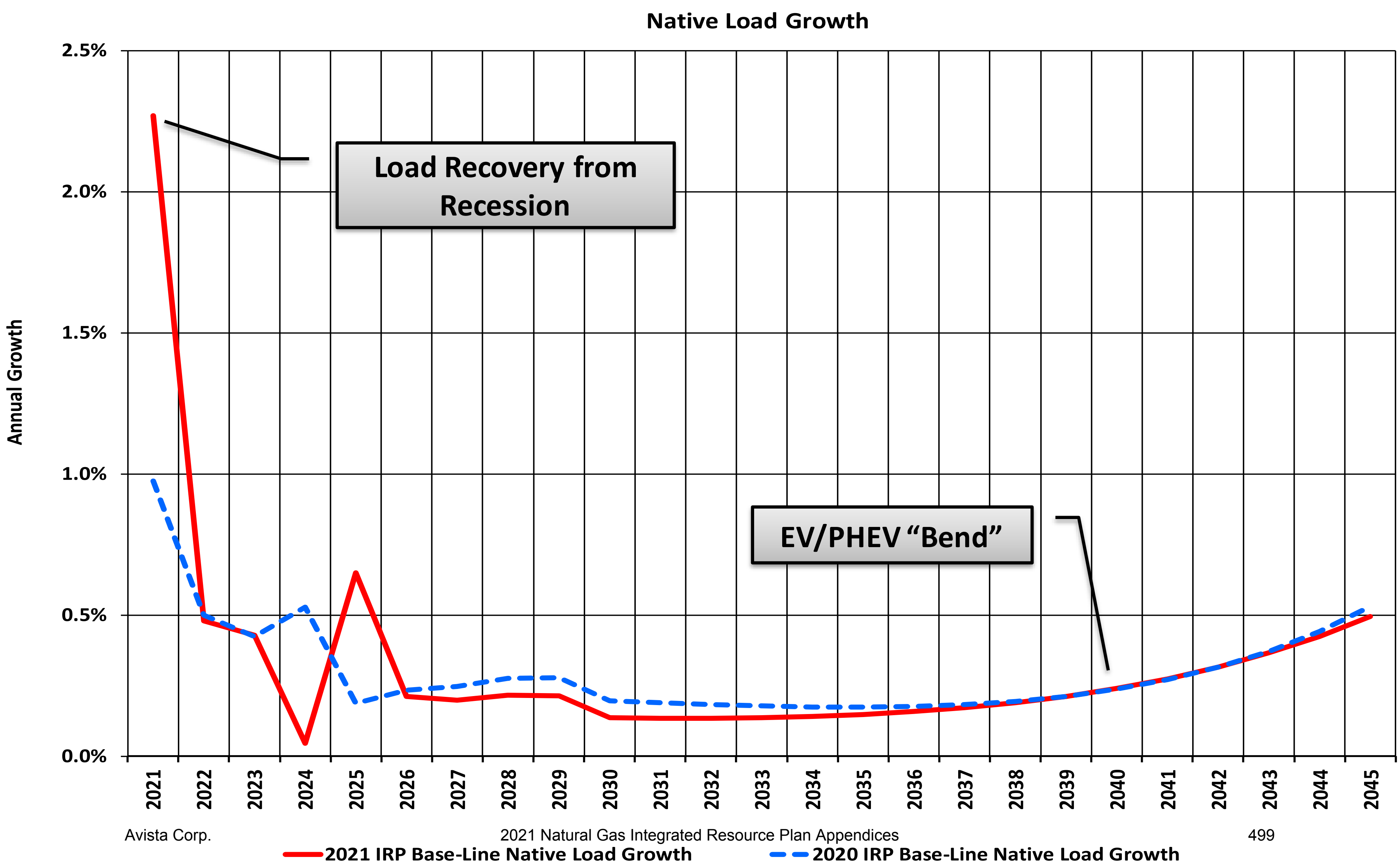


Annual Native Load Forecast with Climate Change, 2026-2045 (Preliminary!)

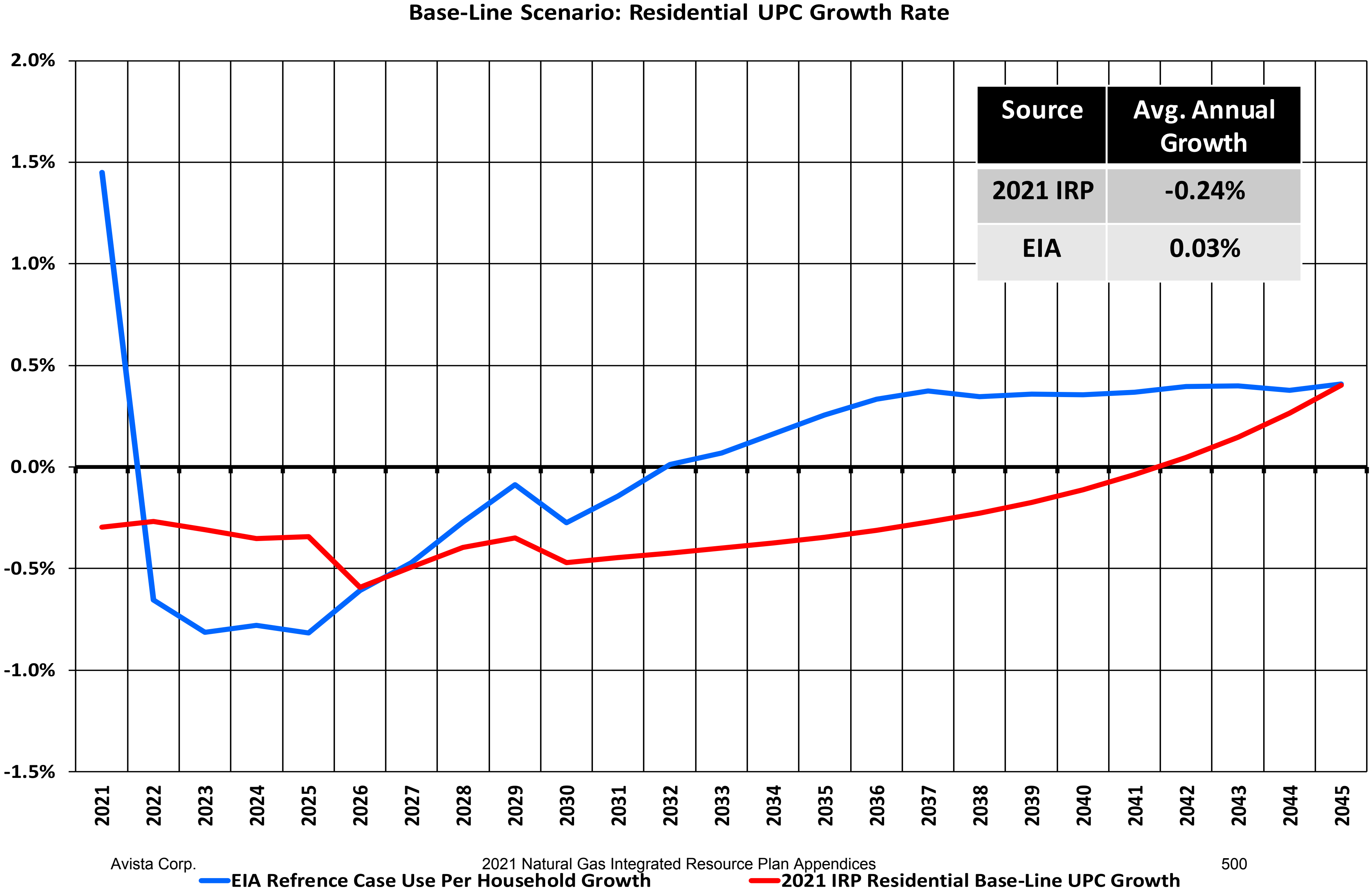
IRP	Avg. Annual Growth
2021 IRP, No Trend Base-Line	0.23%
2021 IRP, NWCC Trend	0.13%
2021 IRP, Avista Trend	0.21%



Native Load Growth Forecast, 2021-2045



Residential UPC Growth: 2021-2045

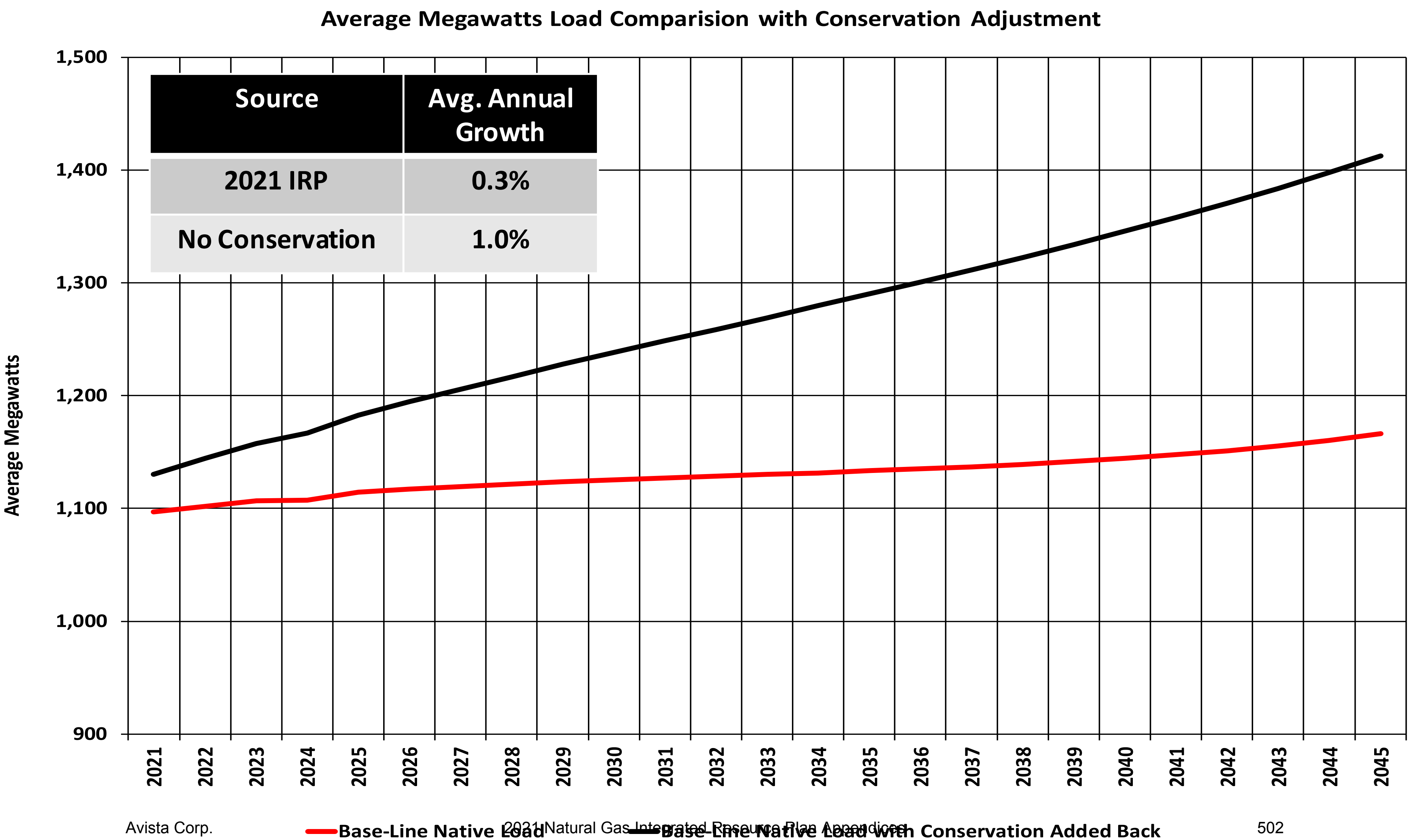


Source	Avg. Annual Growth
2021 IRP	-0.24%
EIA	0.03%

Long-Run Load Forecast: Conservation Adjustment

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Comparison of Native Load Forecasts, 2021-2045



Source	Avg. Annual Growth
2021 IRP	0.3%
No Conservation	1.0%

Peak Load Forecast

Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

The Basic Model

- **Monthly time-series regression model that initially excludes certain industrial loads and EVs (but those are added back in for the final forecast).**

- **Based on monthly peak MW loads since 2004. The peak is pulled from hourly load data for each day for each month.**

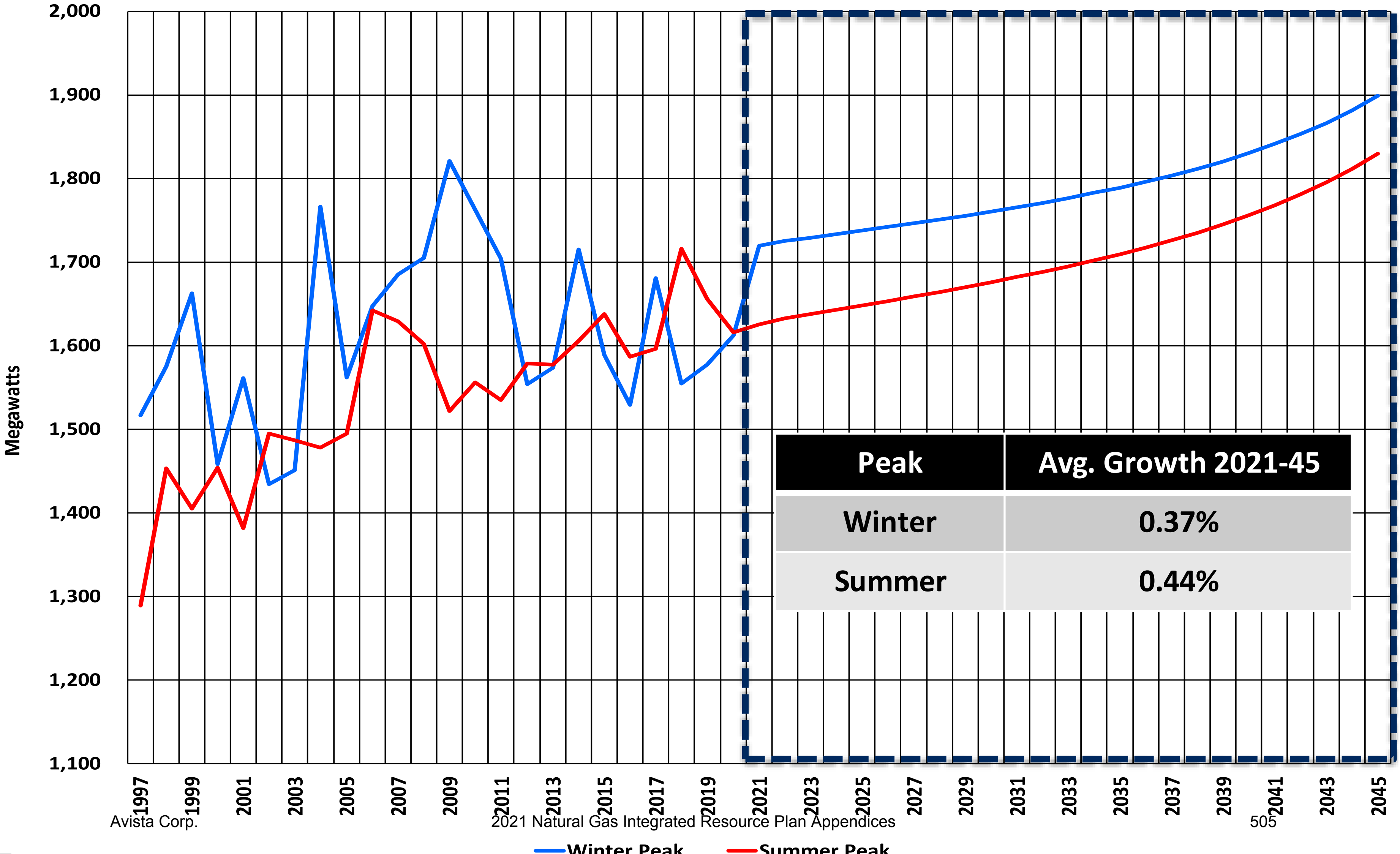
- **Explanatory variables include HDD-CDD and monthly and day-of-week dummy variables. The level of real U.S. GDP is the primary economic driver in the model—the higher GDP, the higher peak loads. *Model allows GDP impact to differ between winter and summer.***

- **The coefficients of the model are used to generate a distribution of peak loads by month based on historical max/min temperatures since 1890, holding GDP constant. A starting expected peak load is then calculated using the average peak load simulated for that month going back to 1890. Model shows Avista is a winter peaking utility for the forecast period; however, the summer peak is growing at a faster than the winter peak.**

- **For comparison in the 2021 IRP, peak load is also calculated by averaging simulated peak loads over the last 30 years and 20 years.**

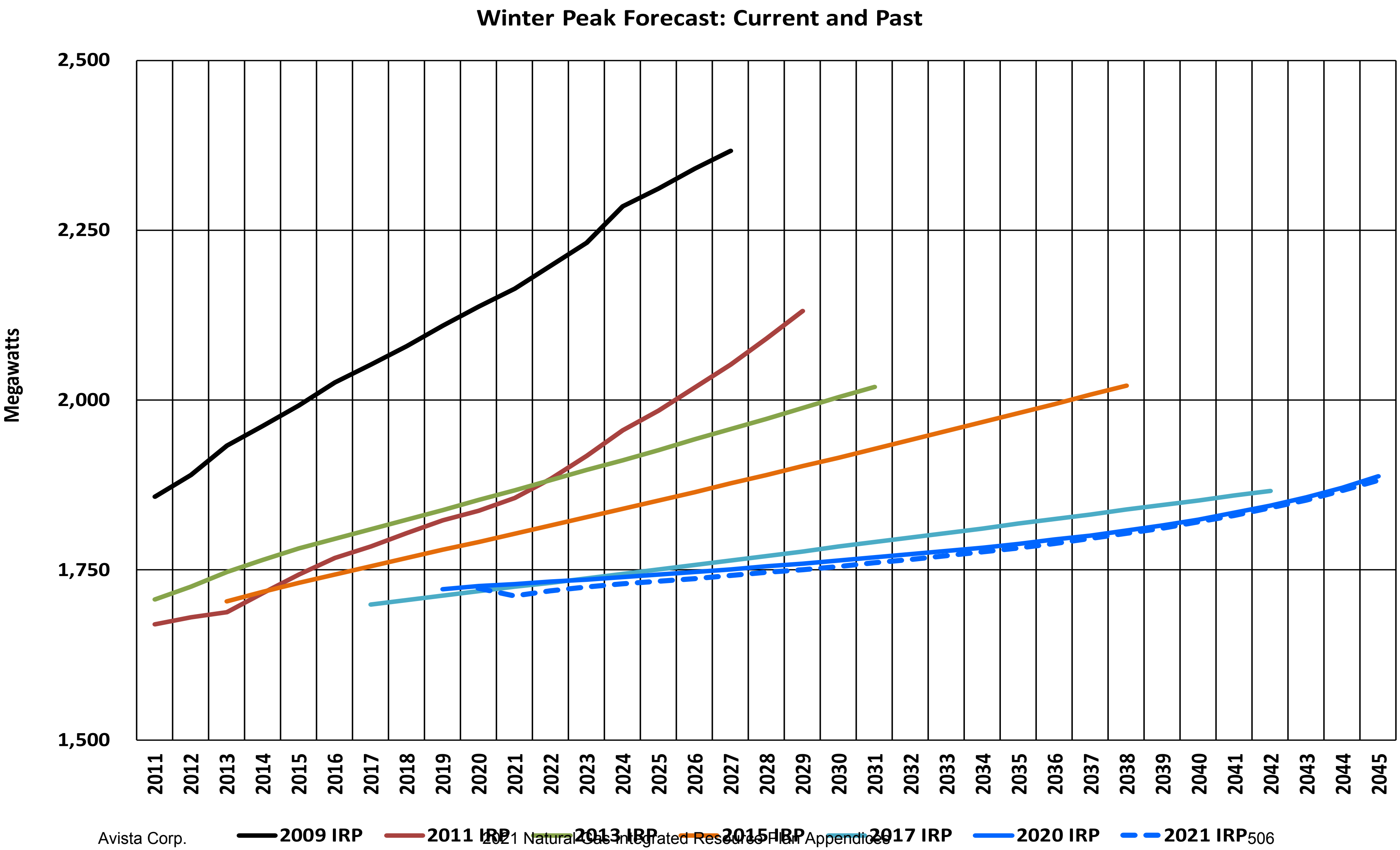
- **The model is also used to calculate the long-run growth rate of peak loads for summer and winter using a forecast of GDP growth under the "*ceteris paribus*" assumption for weather and other factors.**

Peak Forecasts for Winter and Summer, 2021-2045



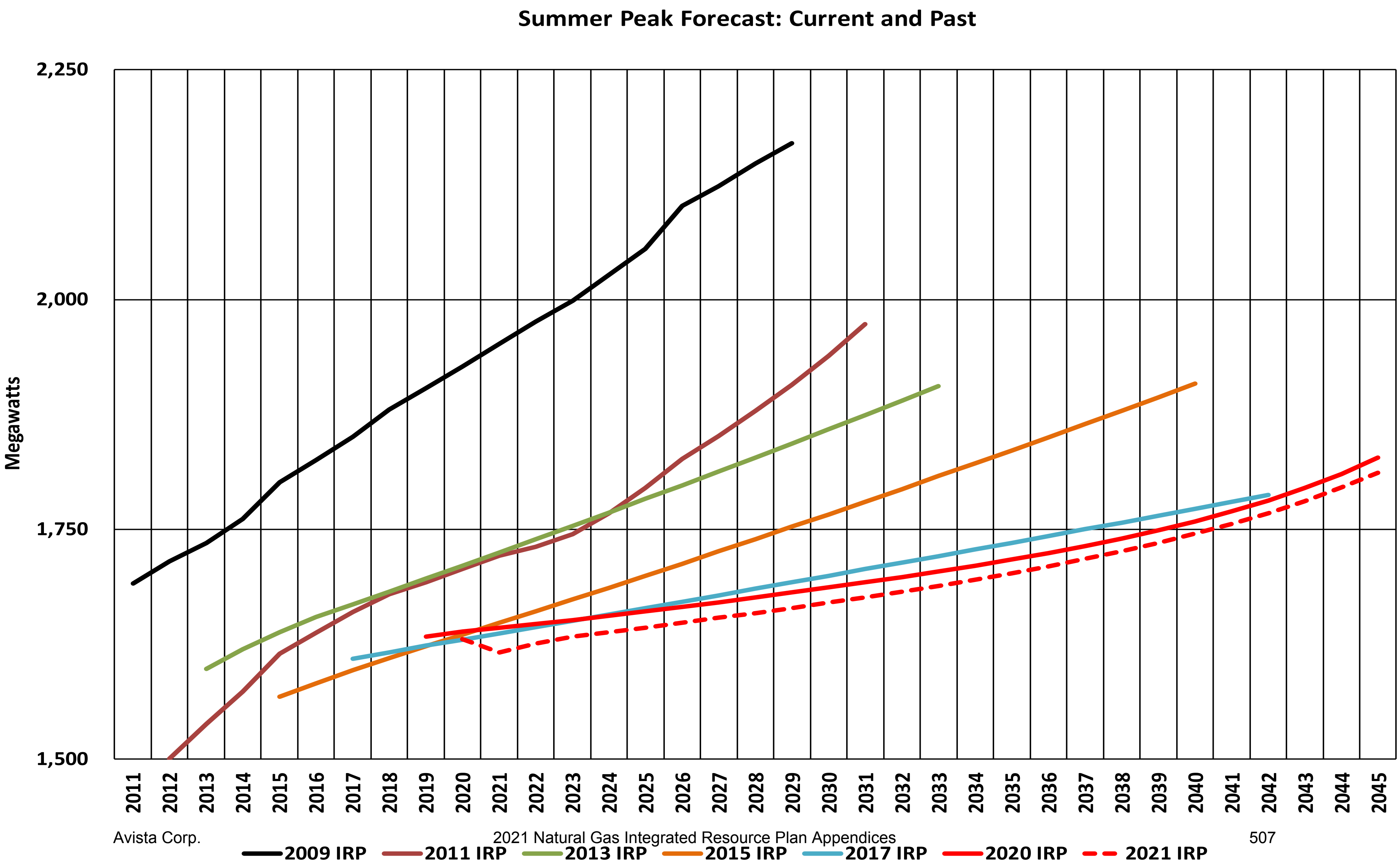
Peak	Avg. Growth 2021-45
Winter	0.37%
Summer	0.44%

Load Forecasts for Winter Peak, 2011-2043

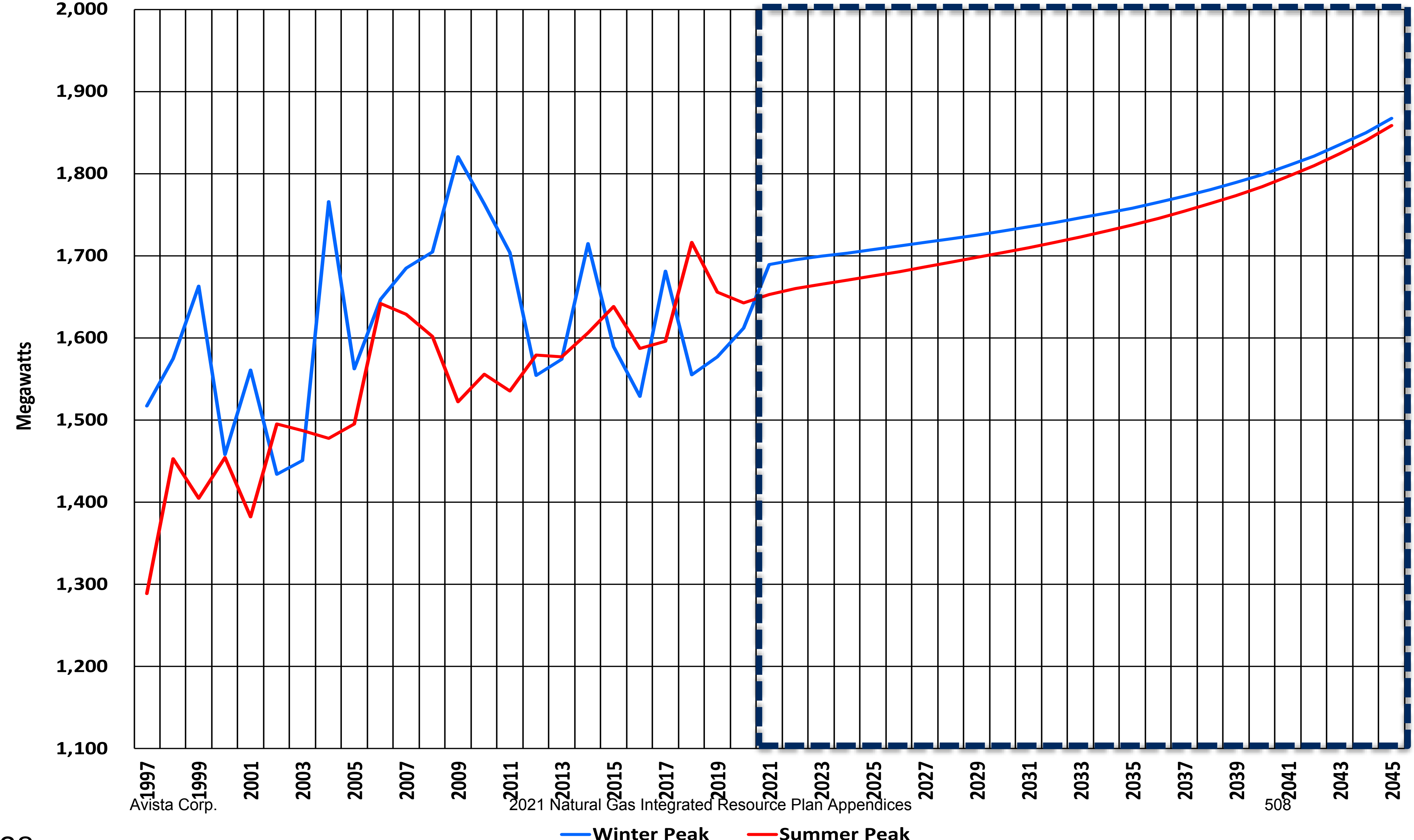


26

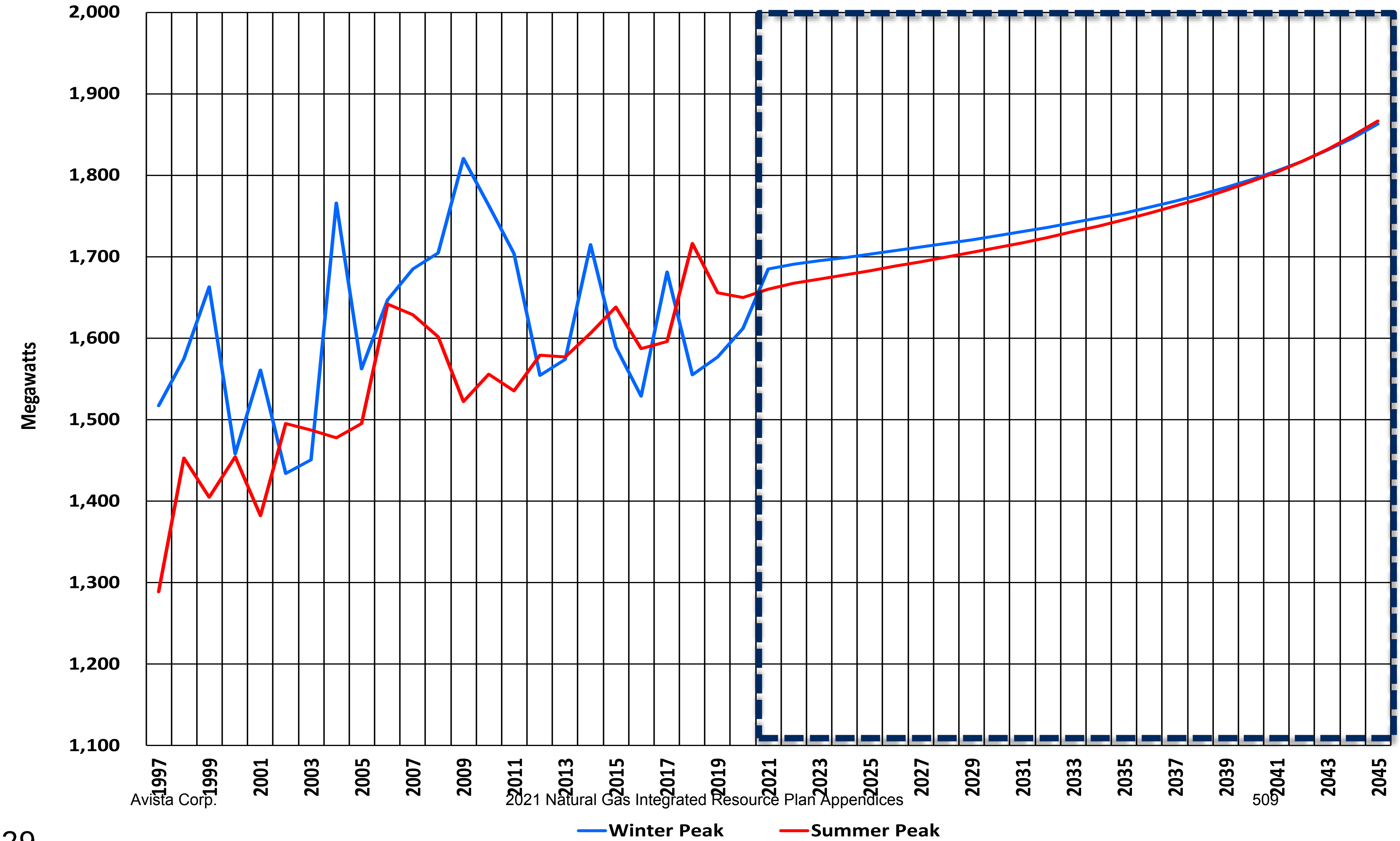
Load Forecasts for Summer Peak, 2011-2045



Peak Forecasts for Winter and Summer 30-Year Average Weather, 2021-2045



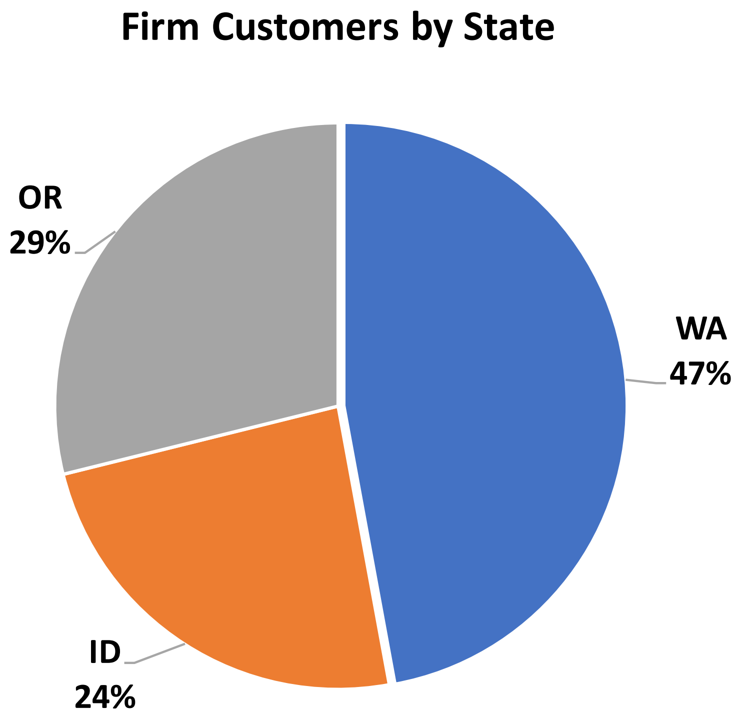
Peak Forecasts for Winter and Summer 20-Year Average Weather, 2021-2045

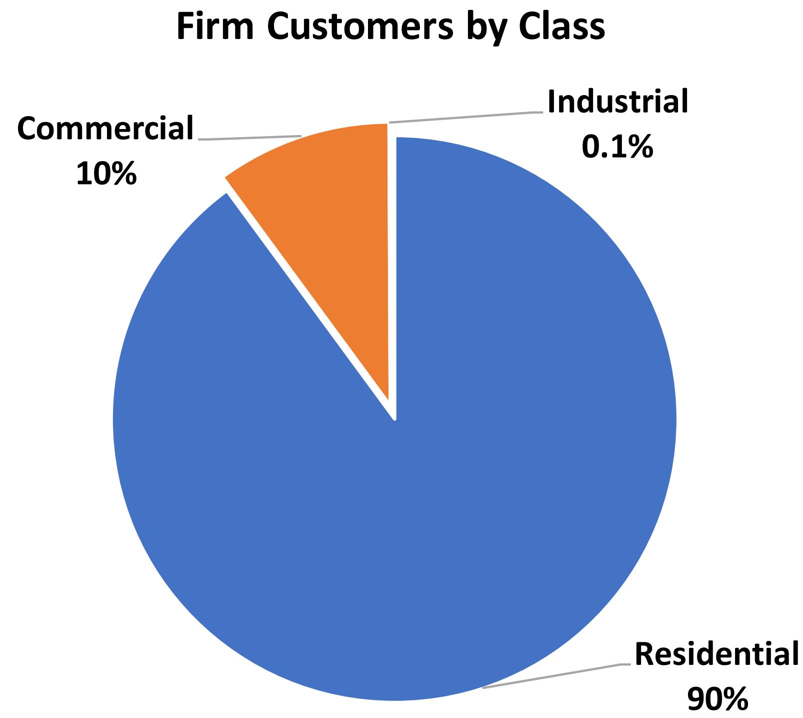


Long-Run Customer Forecast: Natural Gas

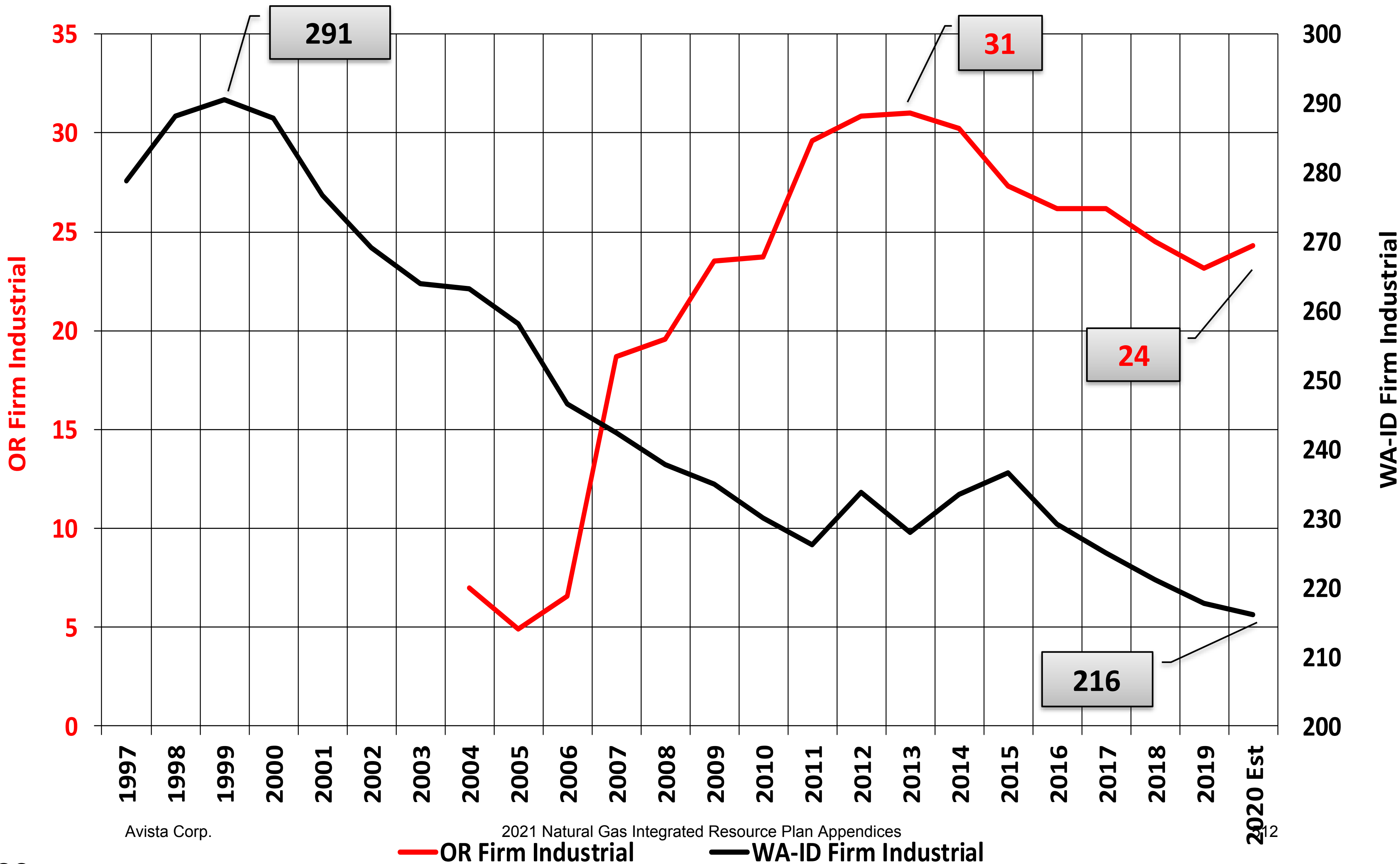
Grant D. Forsyth, Ph.D.
Chief Economist
Grant.Forsyth@avistacorp.com

Firm Customers (Meters) by State and Class, 2019





System All Types of Industrial Customers, 1997-2020



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 "Summer/Fall 2020" forecast completed in June.
- Customer forecasts are sent to Gas Supply for inclusion in the SENDOUT 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

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

Outlier Dummies (Interventions)

Error Correction Component

Getting to Population as a Driver, 2020-2025 & 2026-2045

2020-2025 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.

Deviation in the most recent forecast!

Kootenai and Jackson: IHS population growth forecasts for 2026-2045

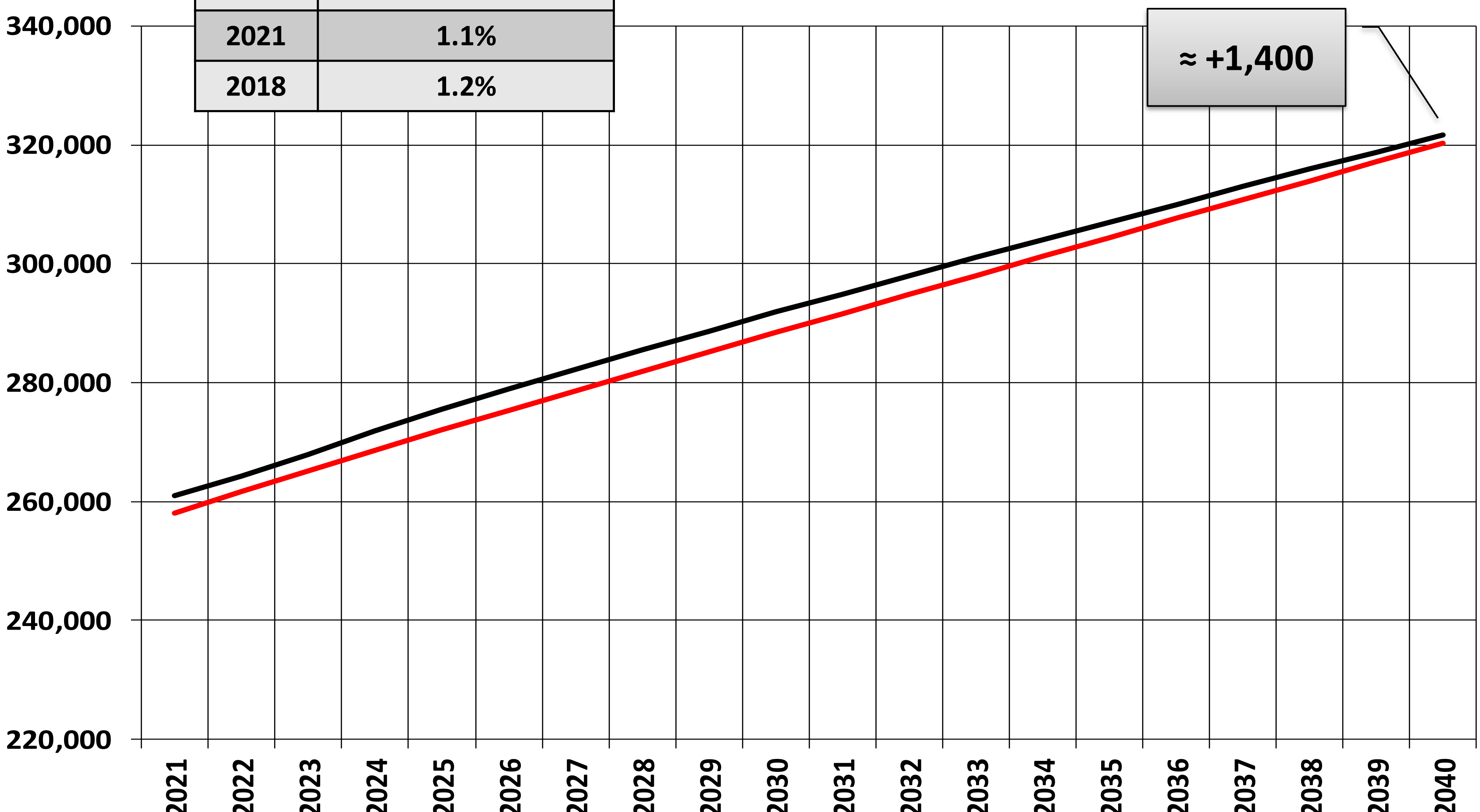
Spokane: OFM population growth forecasts for 2026-2045

OR Douglas, Klamath, and Union counties: IHS population growth forecasts for 2020-2045

Monlthly Interpolation assumes: $P_N = P_0e^{rN}$

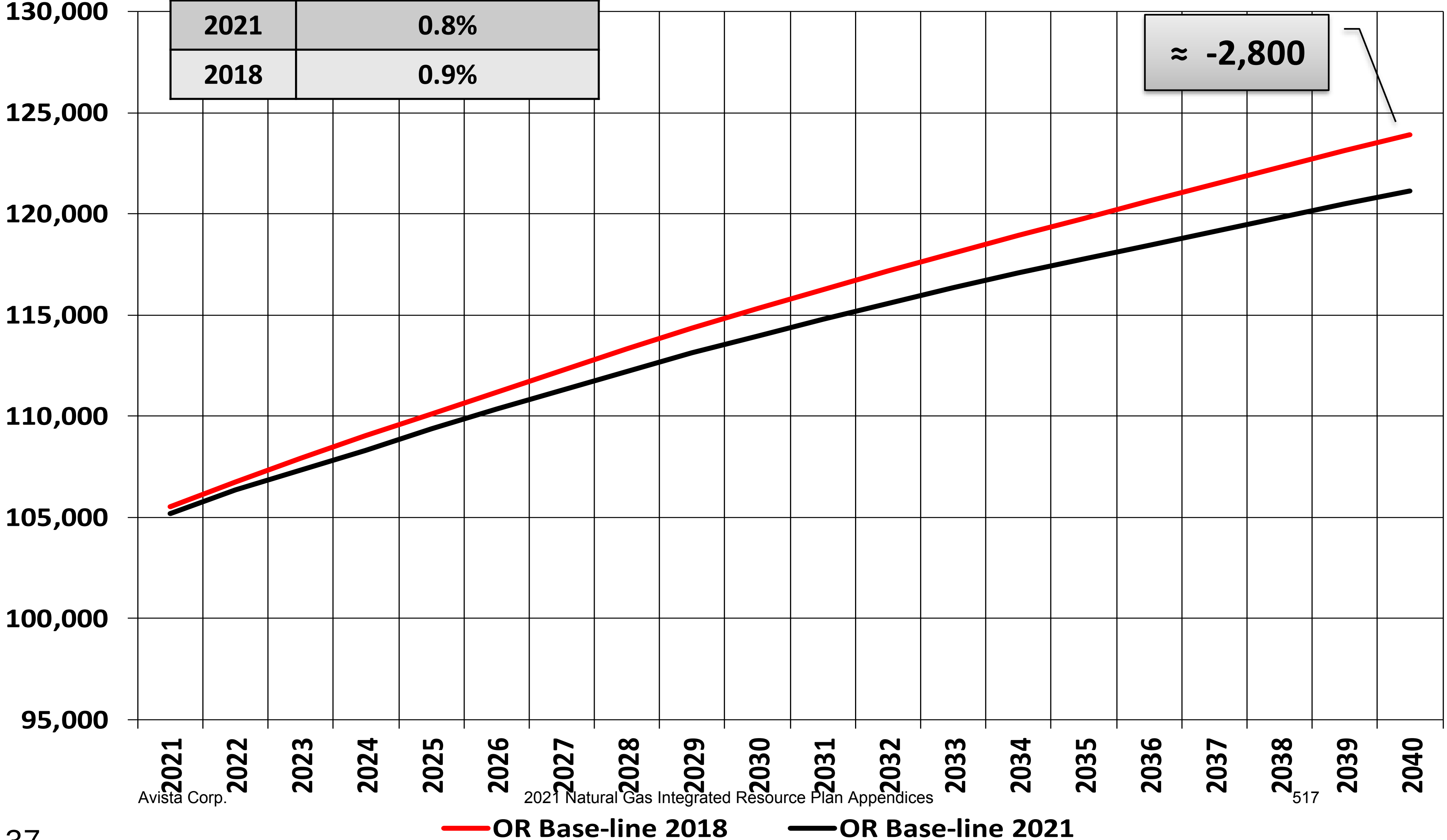
WA-ID Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	1.1%
2018	1.2%



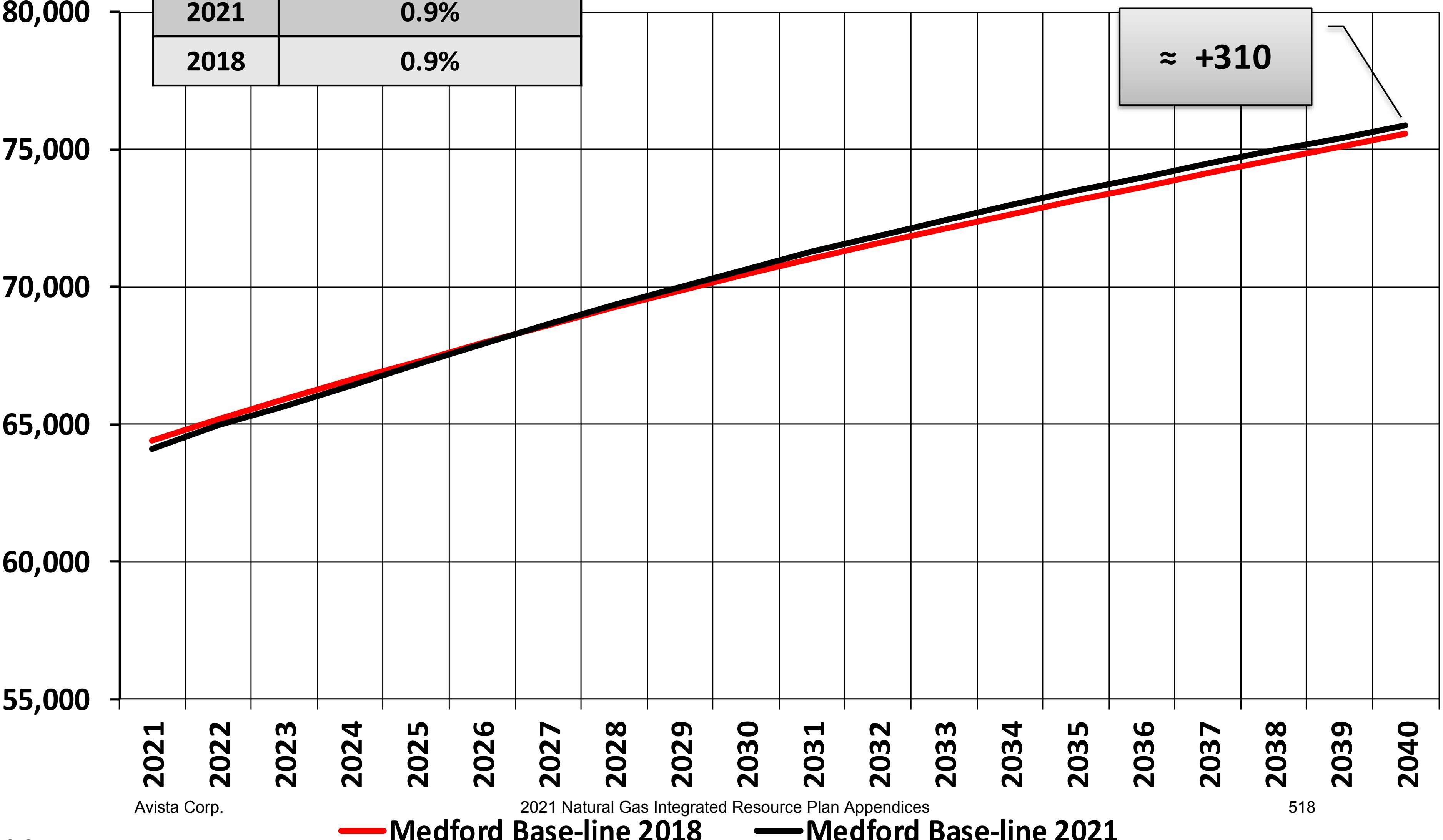
OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	0.8%
2018	0.9%

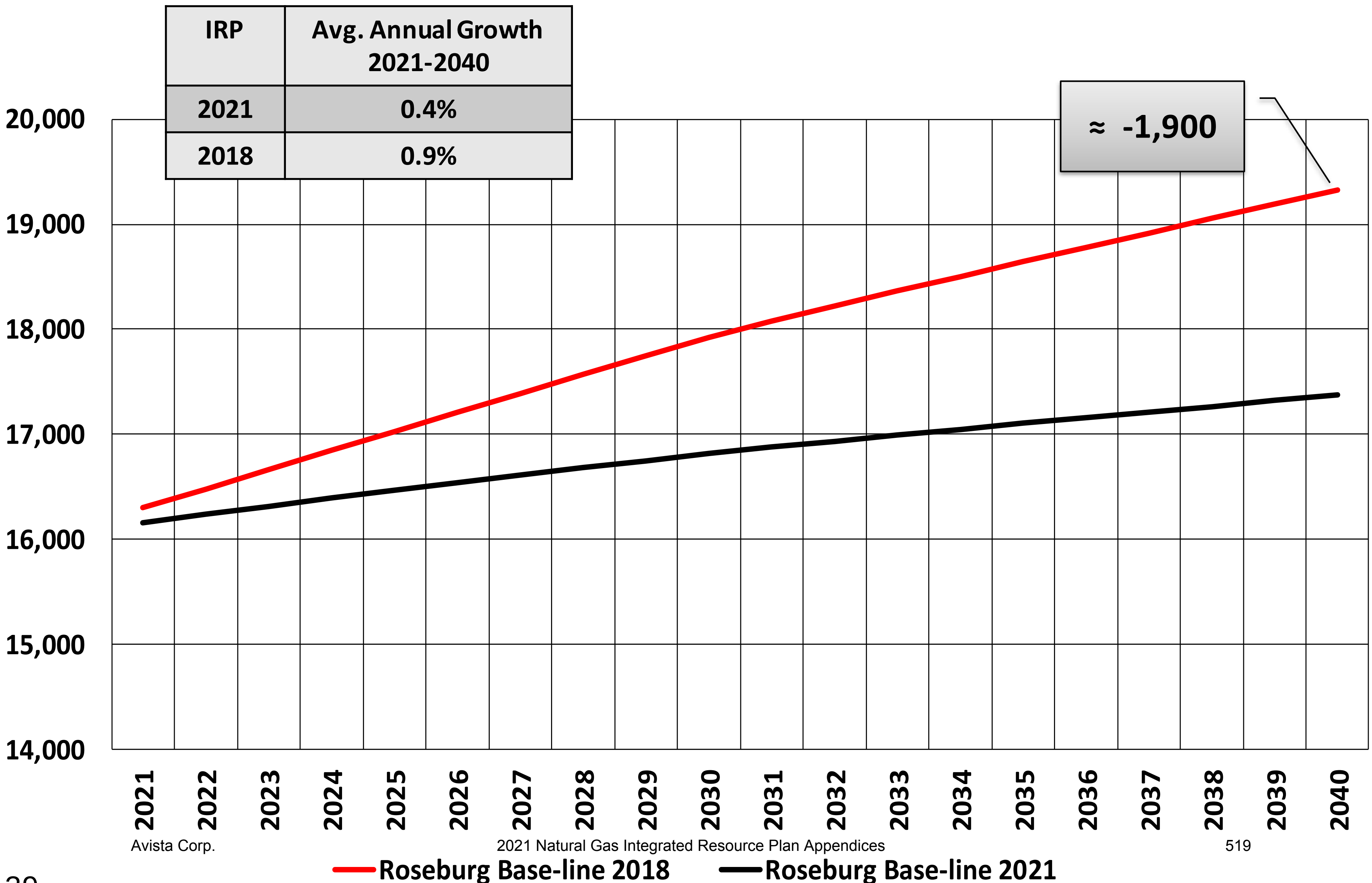


Medford, OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2037
2021	0.9%
2018	0.9%

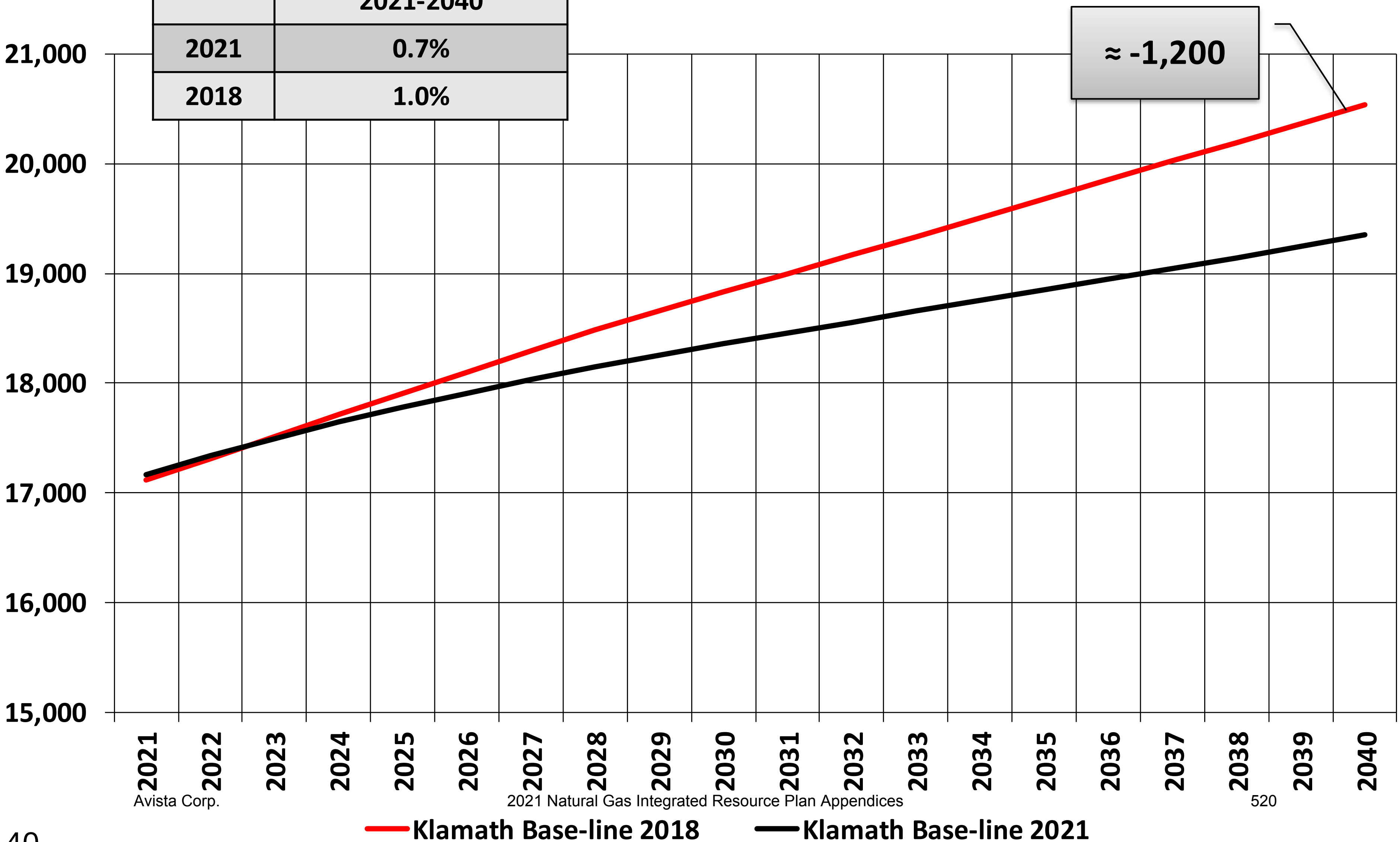


Roseburg, OR Region Firm Customers, 2021-2040 (2018 IRP)



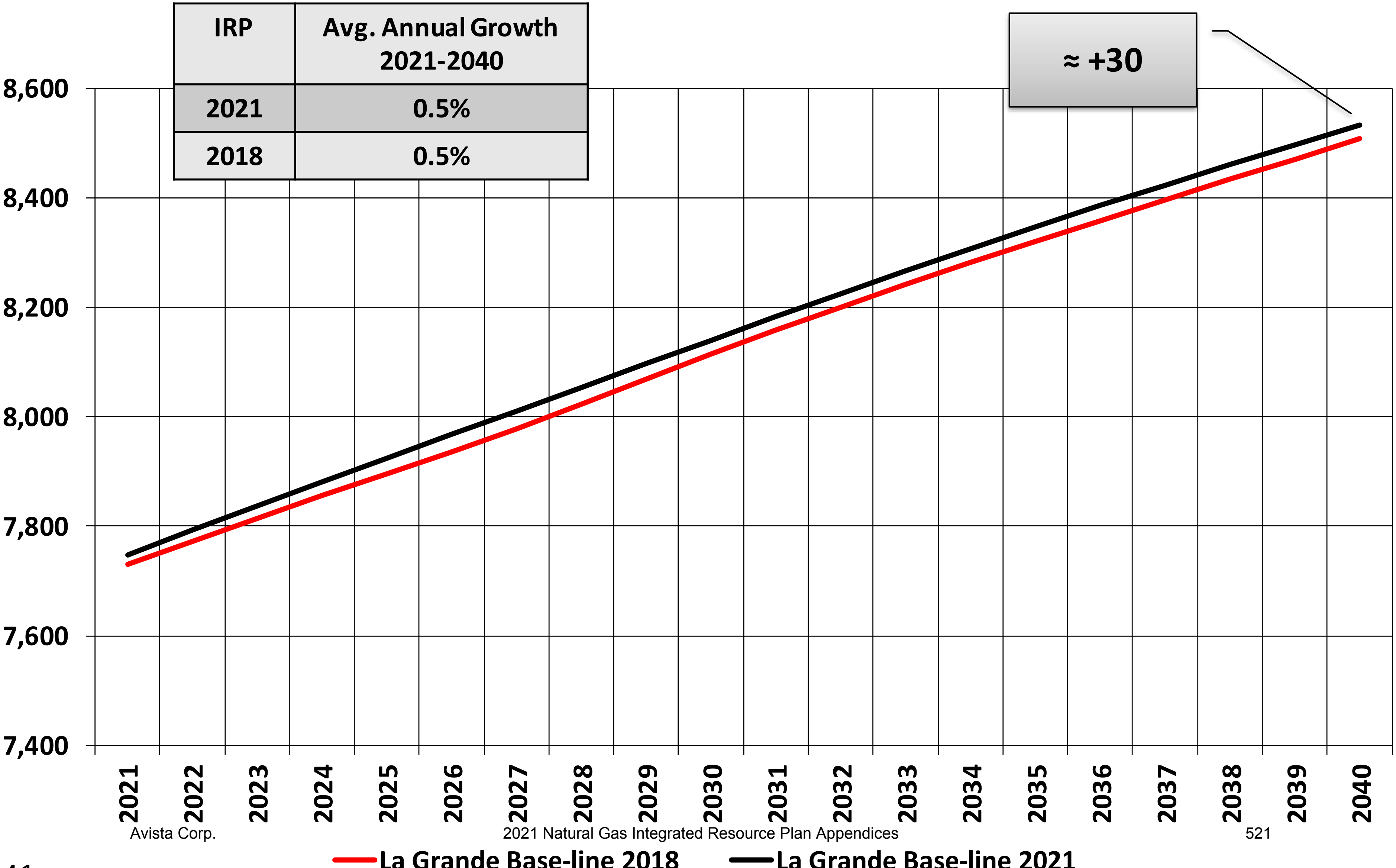
Klamath, OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	0.7%
2018	1.0%



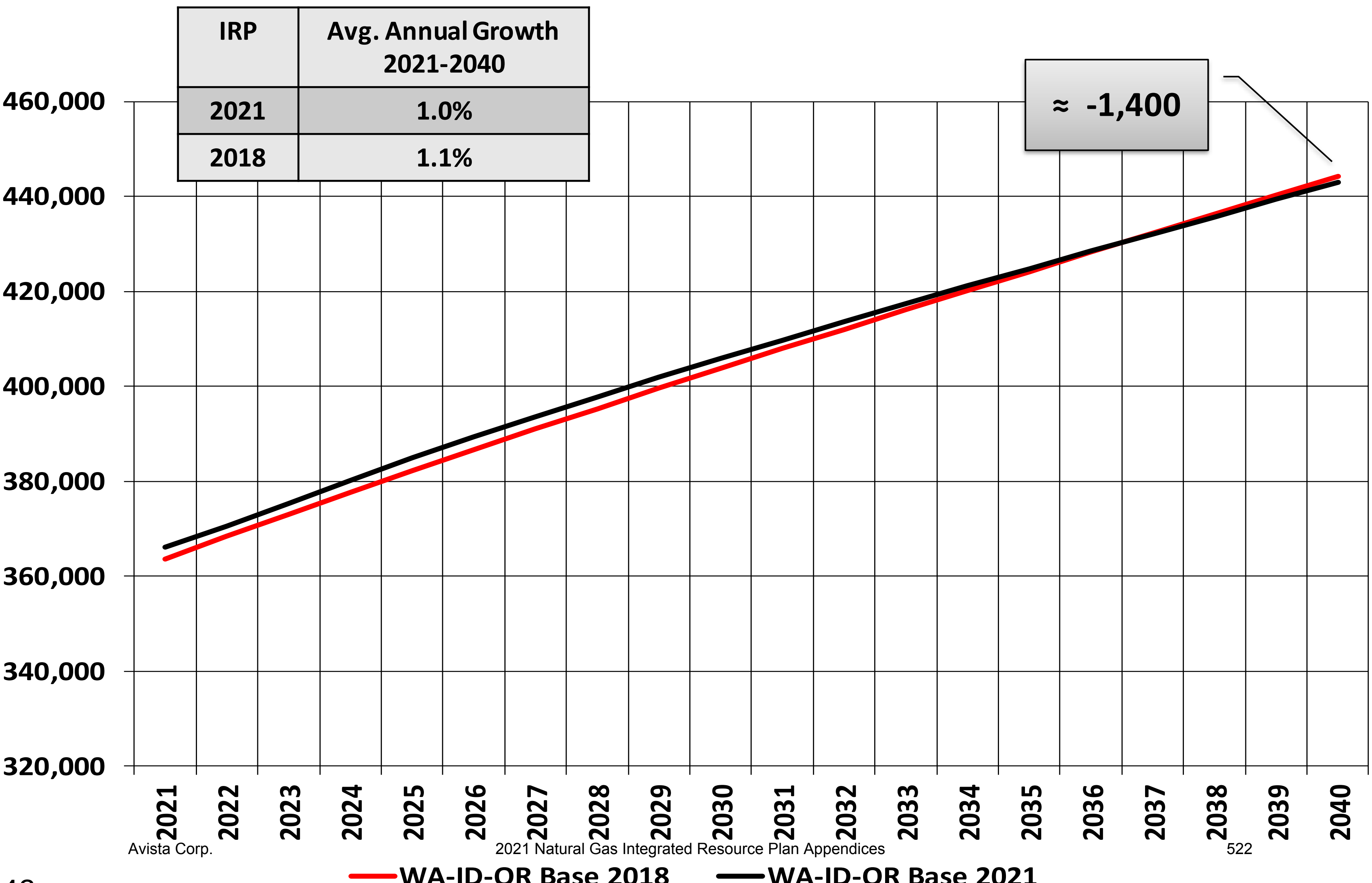
La Grande, OR Region Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	0.5%
2018	0.5%



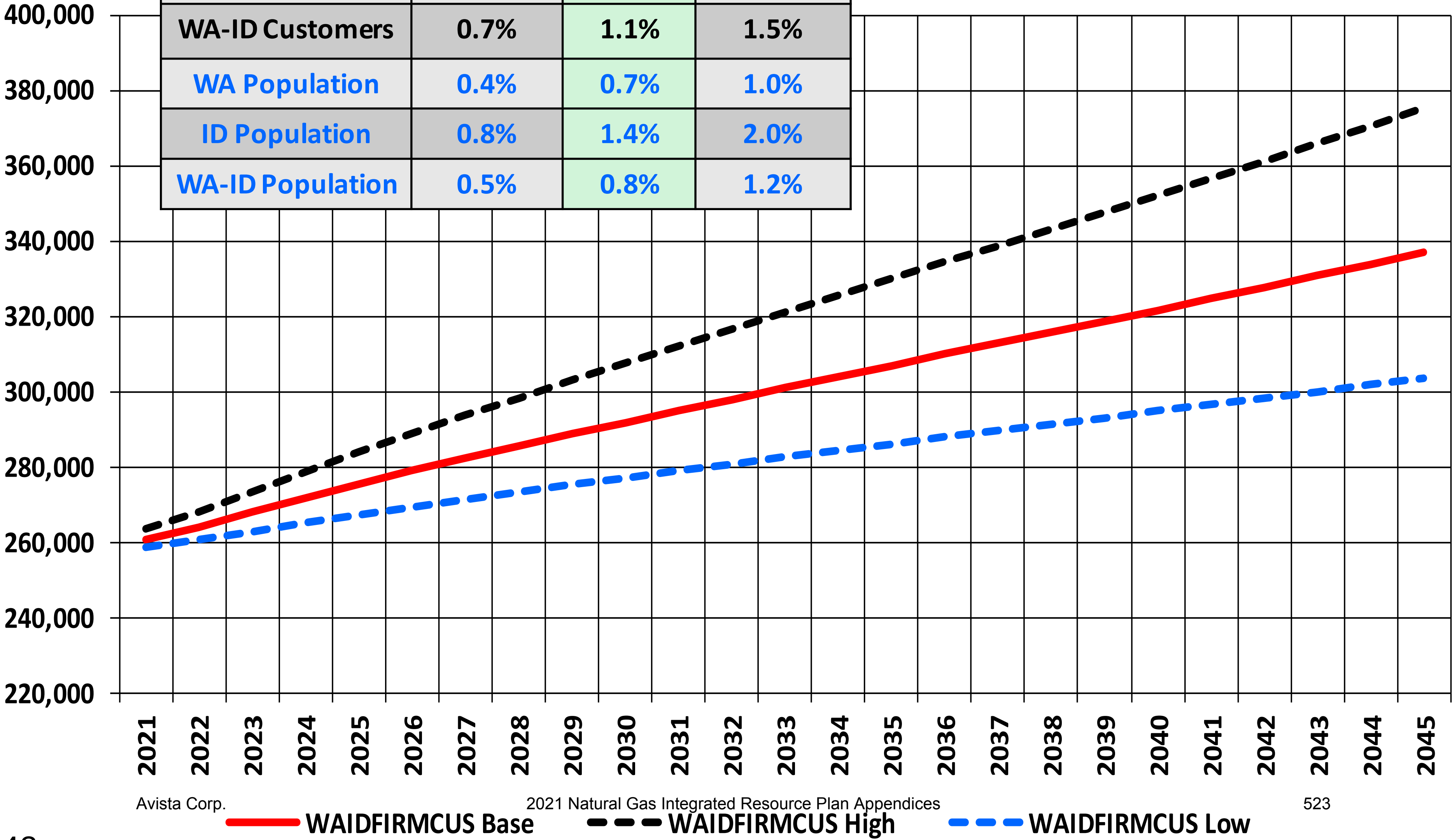
System Firm Customers, 2021-2040 (2018 IRP)

IRP	Avg. Annual Growth 2021-2040
2021	1.0%
2018	1.1%



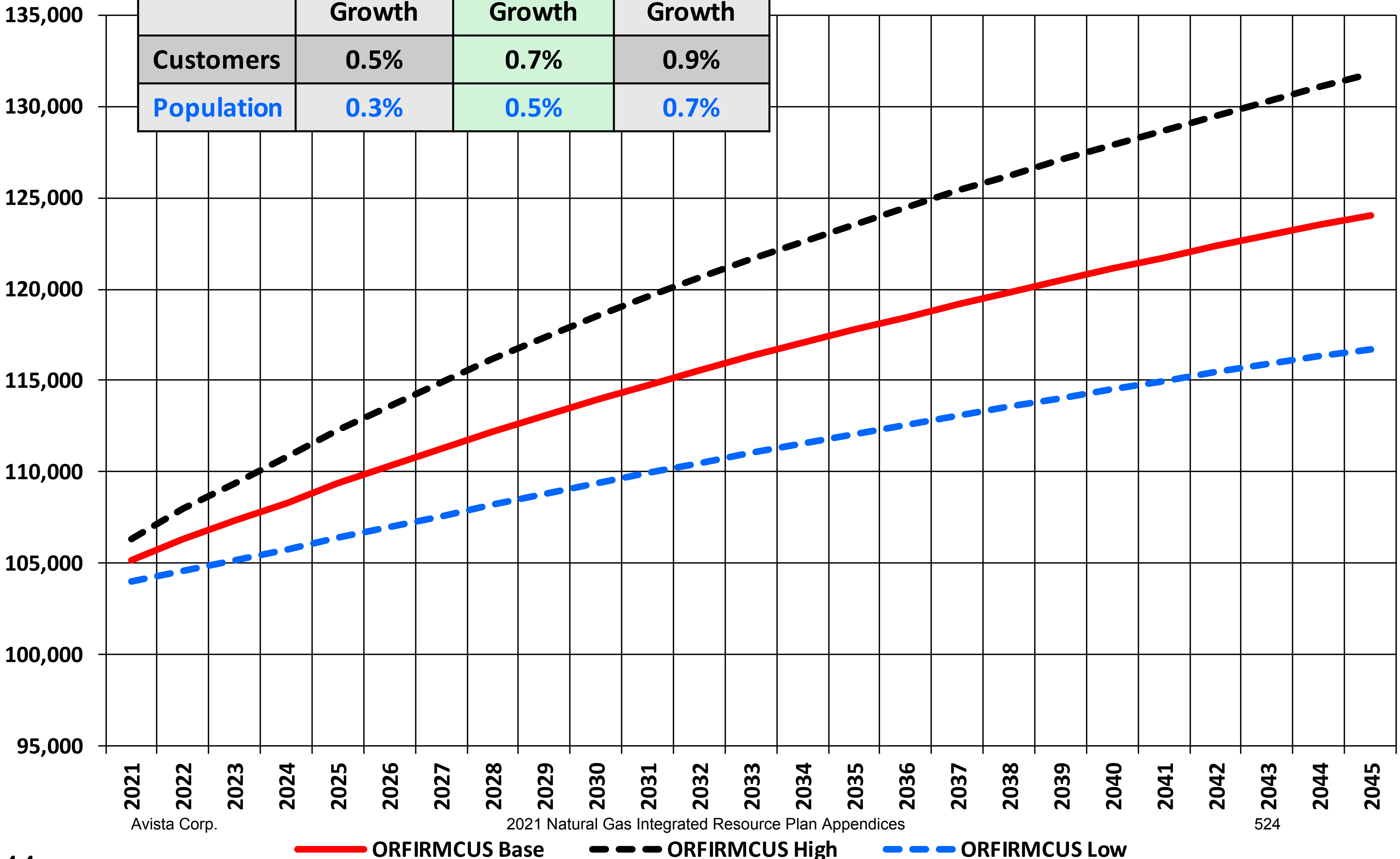
WA-ID Region Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
WA-ID Customers	0.7%	1.1%	1.5%
WA Population	0.4%	0.7%	1.0%
ID Population	0.8%	1.4%	2.0%
WA-ID Population	0.5%	0.8%	1.2%



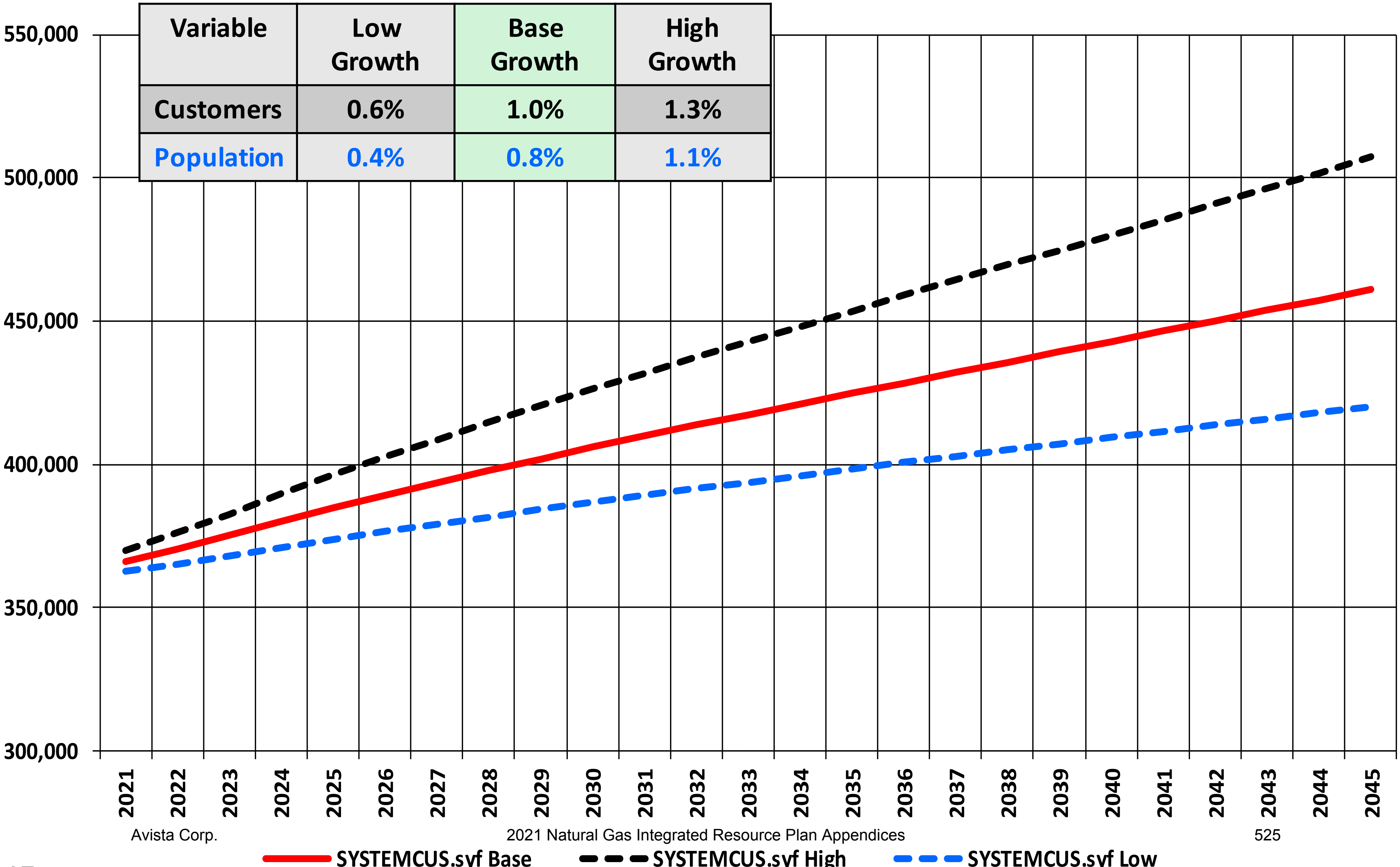
OR Region Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
Customers	0.5%	0.7%	0.9%
Population	0.3%	0.5%	0.7%



System Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
Customers	0.6%	1.0%	1.3%
Population	0.4%	0.8%	1.1%



Summary of Growth Rates

System	Base-Case	High	Low
Residential	1.0%	1.4%	0.7%
Commercial	0.5%	0.8%	0.1%
Industrial	-0.8%	2.2%	-3.8%
Total	1.0%	1.3%	0.6%
WA	Base-Case	High	Low
Residential	1.0%	1.3%	0.7%
Commercial	0.4%	0.7%	0.1%
Industrial	-0.8%	1.9%	-3.6%
Total	1.0%	1.3%	0.7%
ID	Base-Case	High	Low
Residential	1.4%	2.0%	0.8%
Commercial	0.4%	1.0%	-0.2%
Industrial	-1.0%	1.8%	-3.4%
Total	1.3%	1.9%	0.7%
OR	Base-Case	High	Low
Residential	0.7%	0.9%	0.5%
Commercial	0.6%	0.8%	0.4%
Industrial	0.0%	4.5%	-10.6%
Total	0.7%	0.9%	0.5%

Avista – 2020 Natural Gas Integrated Resource Plan

Technical Advisory Committee # 3

September 30, 2020

2020 Natural Gas IRP Schedule

TAC 1: Wednesday, June 17, 2020: TAC meeting expectations, 2020 IRP process and schedule, energy efficiency update, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits. fugitive Emissions, Weather Analysis, Weather Planning Standard

TAC 2 (Dual Meeting with Power side): Thursday, August 6, 2020: Market Analysis, Price Forecasts, Cost Of Carbon, Environmental Policies

- Demand Results and Forecasting – August 18, 2020

TAC 3: Wednesday, September 30, 2020: Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, Carbon cost, price elasticity, sensitivities and portfolio selection modeling.

TAC 4: Wednesday, November 18, 2020: CPA results from AEG & ETO, review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

Agenda

	Topic Length	Start Time – End Time
• Introductions/Agenda	30 minutes	9:00 AM – 9:30 AM
• Avista and Carbon Reduction	15 minutes	9:30 AM – 9:45 AM
• Current Supply Side Resources	30 minutes	9:45 AM – 10:15 AM
• **BREAK**	**15 minutes**	**10:15 AM – 10:30 AM**
• Renewable Natural Gas	60 minutes	10:30 AM – 11:30 AM
• Hydrogen	30 minutes	11:30 AM – 12:00 PM
• **LUNCH BREAK**	**60 minutes**	**12:00 PM – 1:00 PM**
• Distribution	60 minutes	1:00 PM – 2:00 PM
• Supply Side Resource Options	30 minutes	2:00 PM – 2:30 PM
• Carbon Costs/Price Elasticity	30 minutes	2:30 PM – 3:00 PM
• Sensitivities	30 minutes	3:00 PM – 3:30 PM

Avista and Carbon Reduction

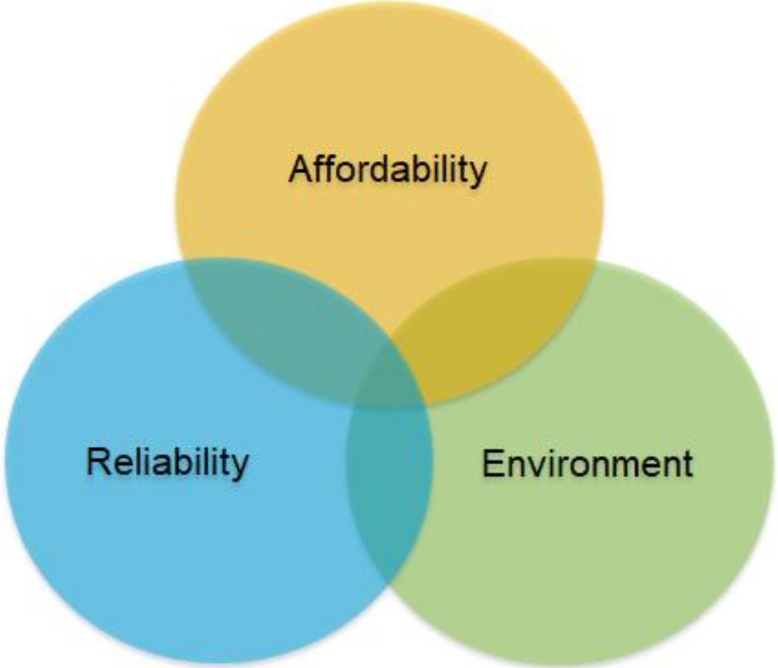
Jody Morehouse
Director – Natural Gas Supply

Planning for a Deeply Decarbonized Future

Active Energy Policy Environment

- Washington
  - Carbon reduction goal House Bill 2311
  - RNG/EE House Bill 1257

- Oregon:
  - RNG Senate Bill-98
  - Cap and Reduce Executive Order 20-04



Focus on solutions that balance carbon reduction, affordability, and reliability

Avista's Environmental Objectives

- Build further recognition of Avista’s continued commitment to environmental stewardship
- Acquire renewable supplies based on the demand of our customer base and/or policy direction
- Fully account for all costs of natural gas including carbon attributed to upstream emissions
- Continue to engage with state and local governments on all existing and future climate policy
- Increase understanding of how natural gas currently works as part of the energy ecosystem, ensuring that customers have choices for their energy needs that include access to reliable energy at affordable prices
- Demonstrate Avista’s leadership in responsibly managing a transition to a cleaner energy mix while being sensitive to customers’ and other stakeholders’ interests

Natural Gas is an Important Part of a Clean Energy Future

- 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
- Full electrification can lead to **unintended consequences**:
  - Creates new generation needs that may increase carbon footprint
  - Drives new investment in electric distribution, generation, and transmission infrastructure, causing bill pressure
  - Home and business conversion costs borne by customers
- Customers have paid for a vast pipeline infrastructure that can utilized for a cleaner future by **transitioning the fuel** and keeping the pipe
- A comprehensive view of the energy ecosystem leads to a **diversified approach to energy supply** that includes natural gas

Benefits of Natural Gas

- **For Customers.** Natural gas is affordable, resilient, and reliable.
- **For Society.** Natural gas is an abundant energy resource produced in North America, which helps lessen our dependency on foreign oil.
- **For Innovation.** Natural gas can play a supporting role in expanding the use of renewable energy sources.
- **For Environment.** Natural gas is the cleanest burning fossil fuel, so it helps reduce smog and greenhouse gas emissions.
- **For Economy.** Natural gas provides nearly a fourth of North America's energy today.

Current Supply Side Resources

Justin Dorr
Resource Manager, Natural Gas Supply

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 Contracting

Simply stated: The right to move (transport) a specified amount of gas from Point A to Point B

Contract Types

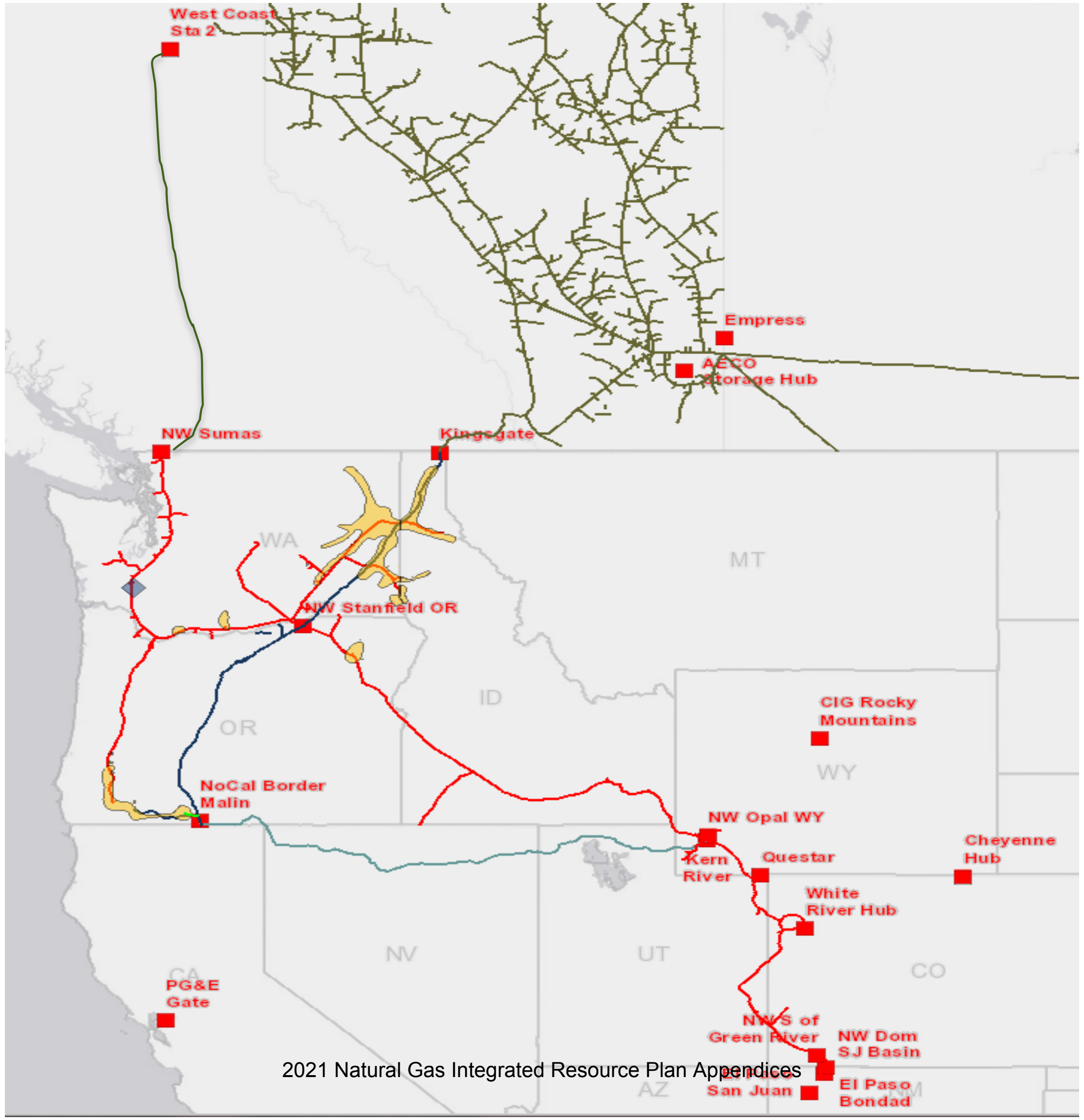
- Firm transport
  - Point A to Point B
- Alternate firm
  - Point C to Point D
- Seasonal firm
  - Point A to Point B but only in winter
- Interruptible
  - Maybe it flows, maybe it doesn't

Avista's Transportation Contract Portfolio

Avista holds firm transportation capacity on 6 interstate pipelines:

Pipeline	Expirations	Base Capacity Dth
Williams NWP	2025 – 2042 (2035)	290,000
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

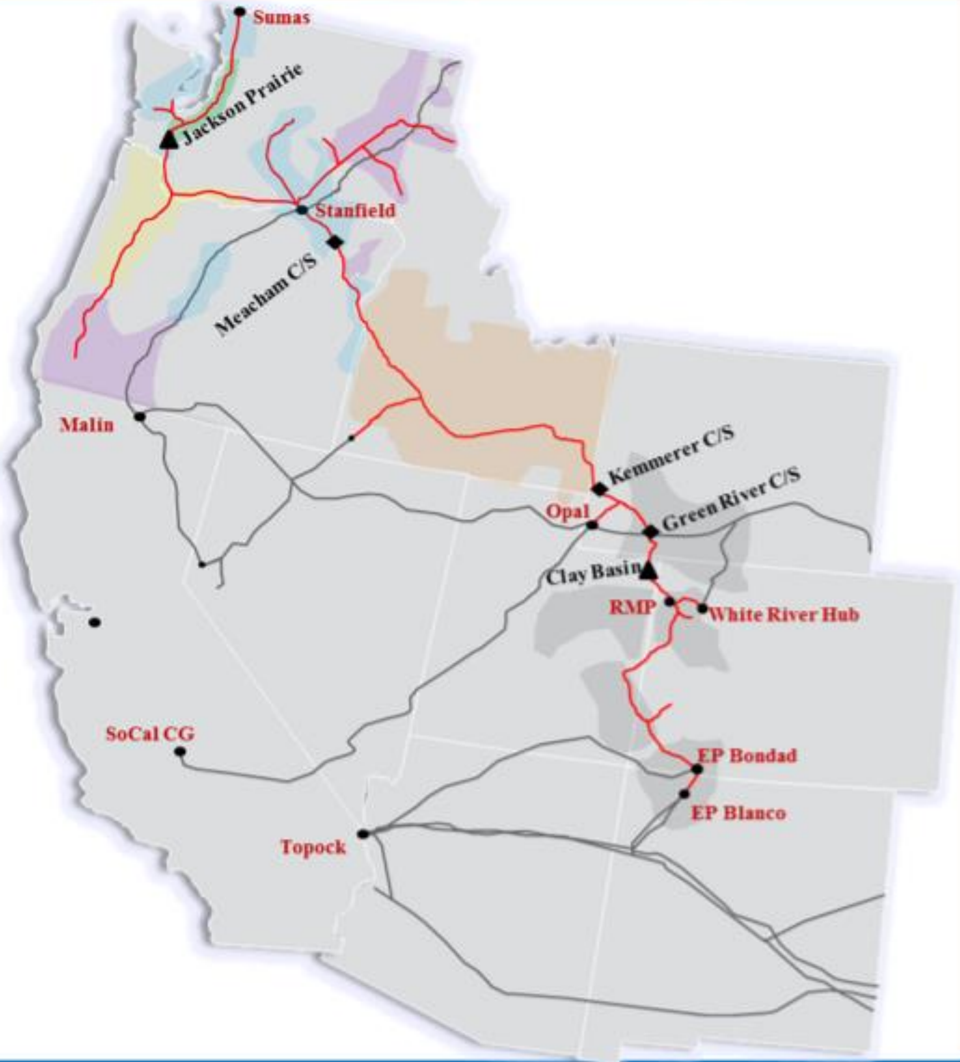
Pipeline Overview



Williams

Northwest System – Strategically Located

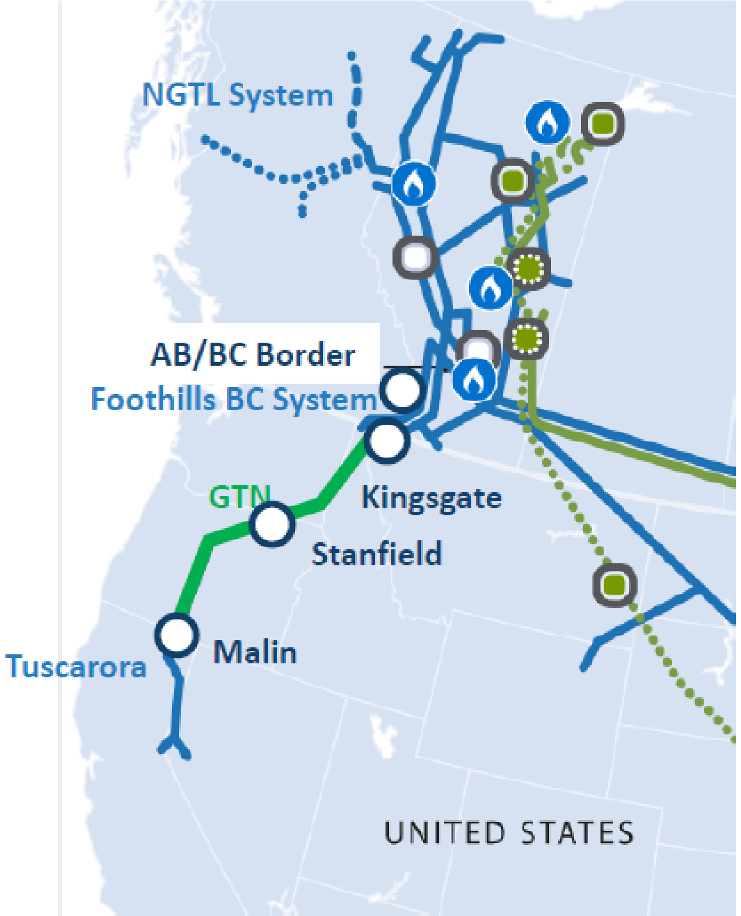
- Low-cost, primary service provider in the Pacific Northwest
  - 3,900-mile system with 3.8 Bcf/d peak design capacity
  - ~120 Bcf of access to storage along pipeline, with high injection and deliverability capability in market area
- Bi-directional design
  - Provides flexibility (Rockies to market 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

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:

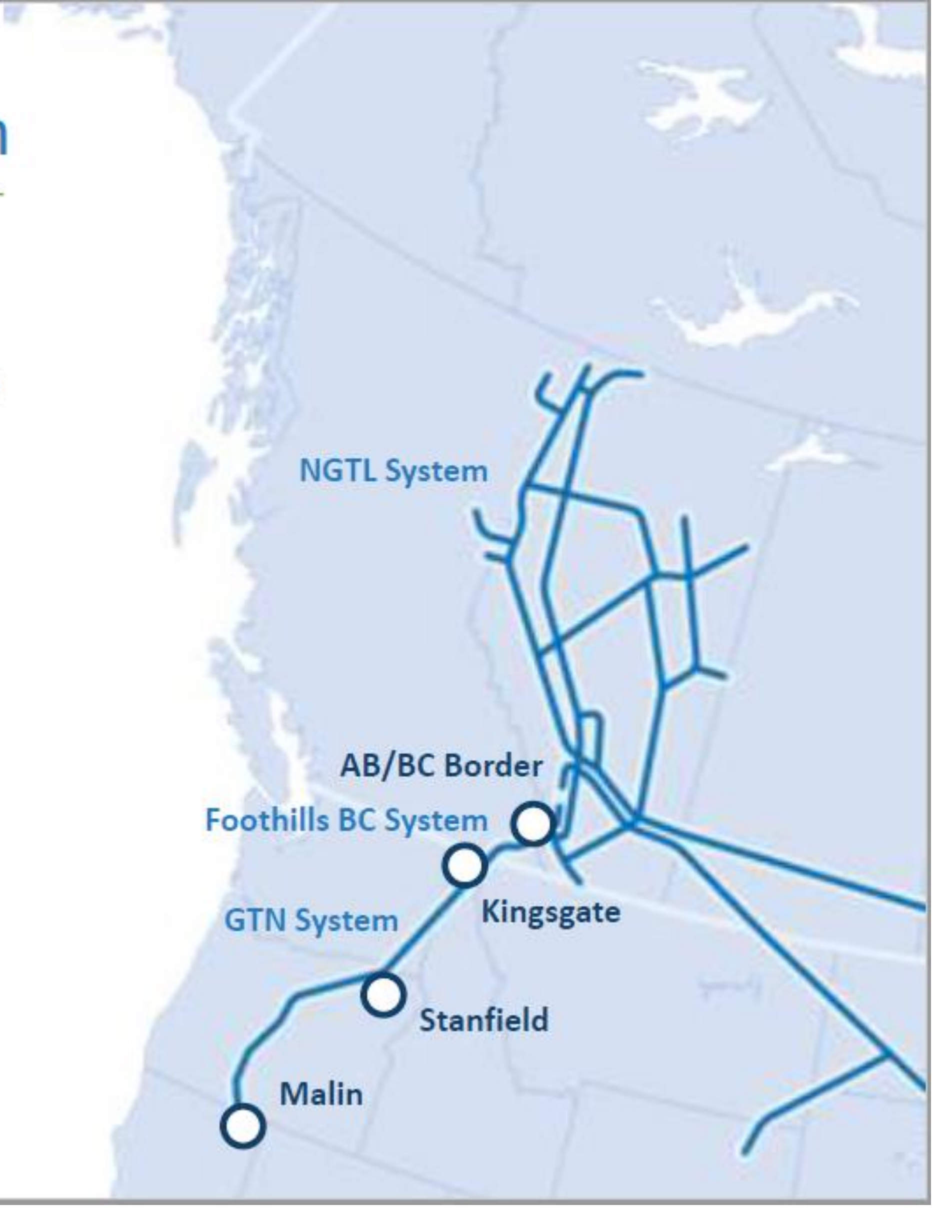
Tranche 1

- 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

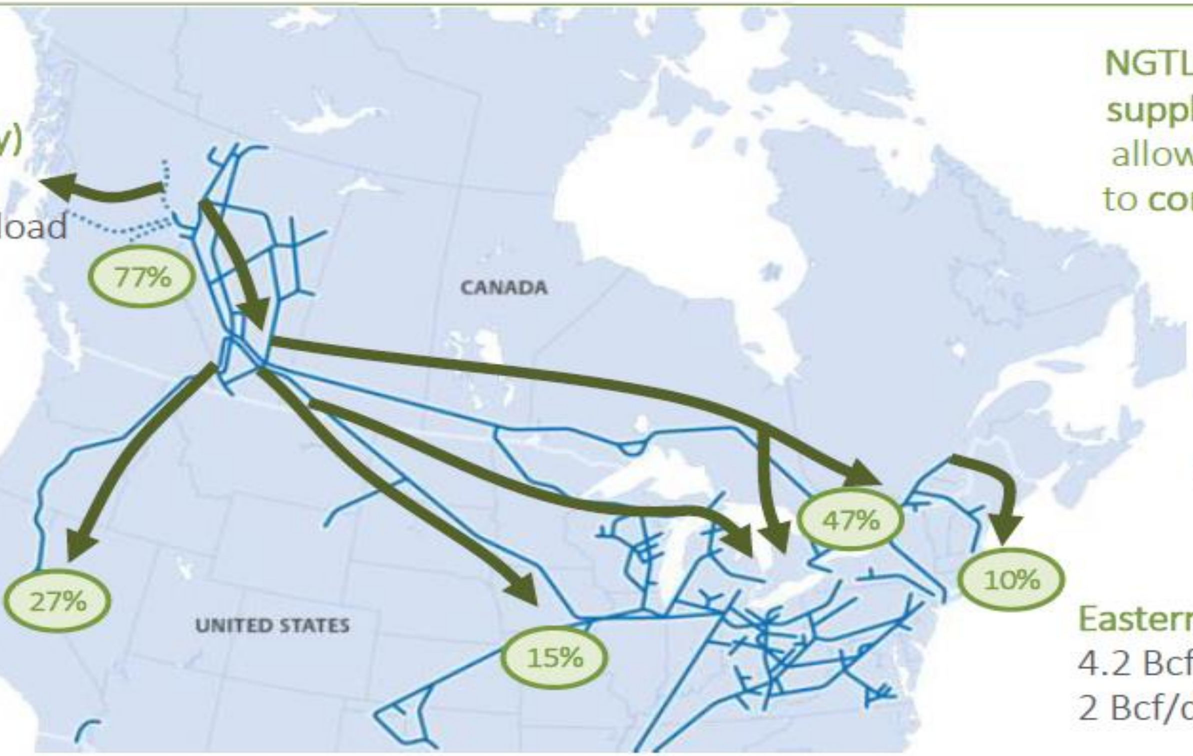


FOR DISCUSSION PURPOSES ONLY | SEPTEMBER 2020

WCSB gas is competitive in key markets,
Safety, Toll Competitiveness & Reliability is Our Focus

WCSB (77% TC Energy)
15.6 Bcf/d supply
7.1 Bcf/d intra basin load
8.7 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
8.3 Bcf/d market
2.2 Bcf/d via TC

U.S. Northeast
6.9 Bcf/d market
0.7 Bcf/d via TC

Eastern Canada
4.2 Bcf/d market
2 Bcf/d from WCSB via TC

Chicago (Mid-West)
12.7 Bcf/d end use market
1.6 Bcf/d from WCSB via TC

Flow data based on 2019 Calendar year

FOR DISCUSSION PURPOSES ONLY | SEPTEMBER 2020

TC Energy 1

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

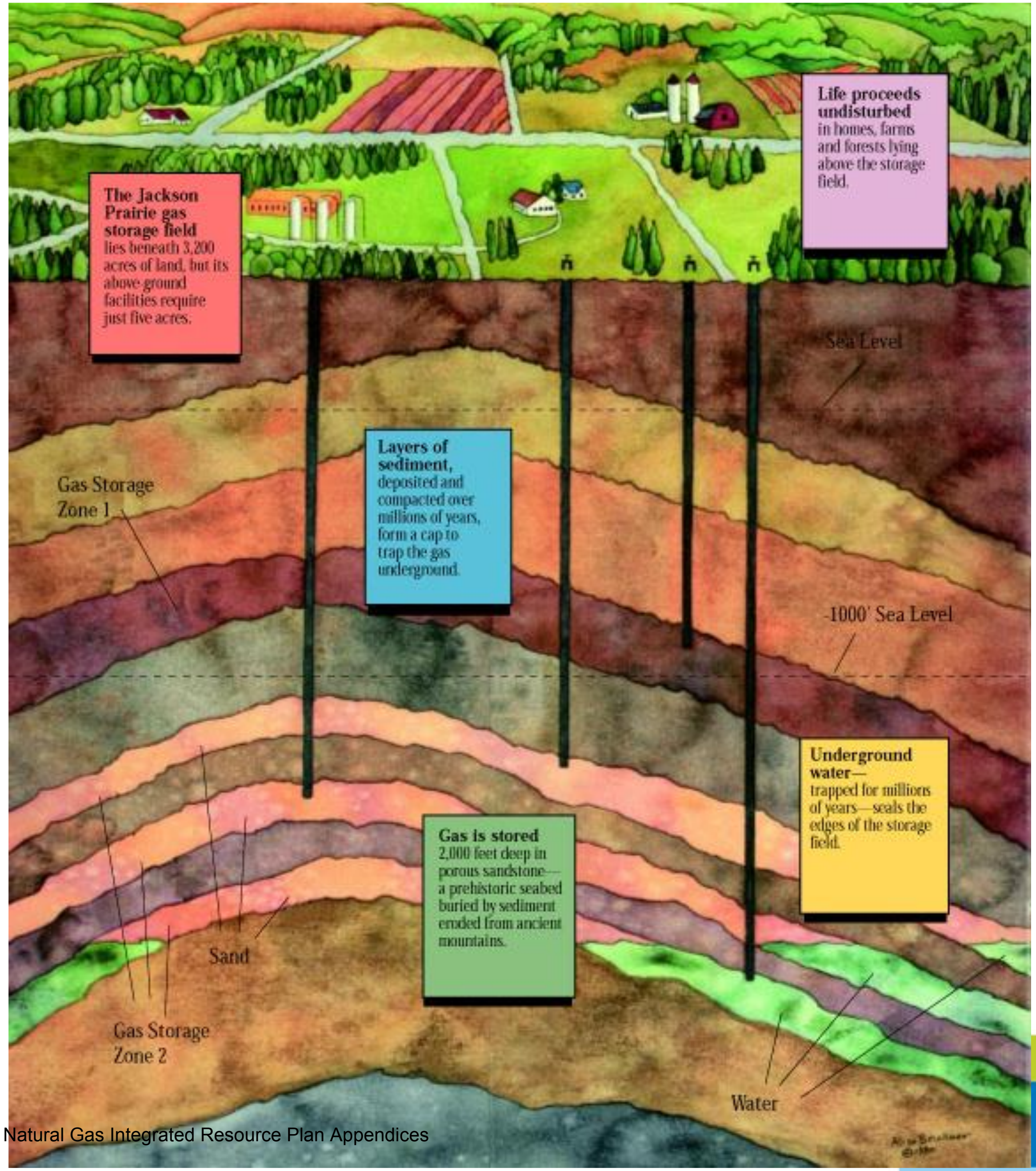
- 823,000 Dth of Capacity with approximately 52,000 Dth/d of deliverability

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.



Renewable Natural Gas (RNG)

Michael Whitby, RNG Manager

Advancing RNG at Avista

Avista has been actively preparing to participate in RNG. The following topics covered in this section of the presentation are as follows:

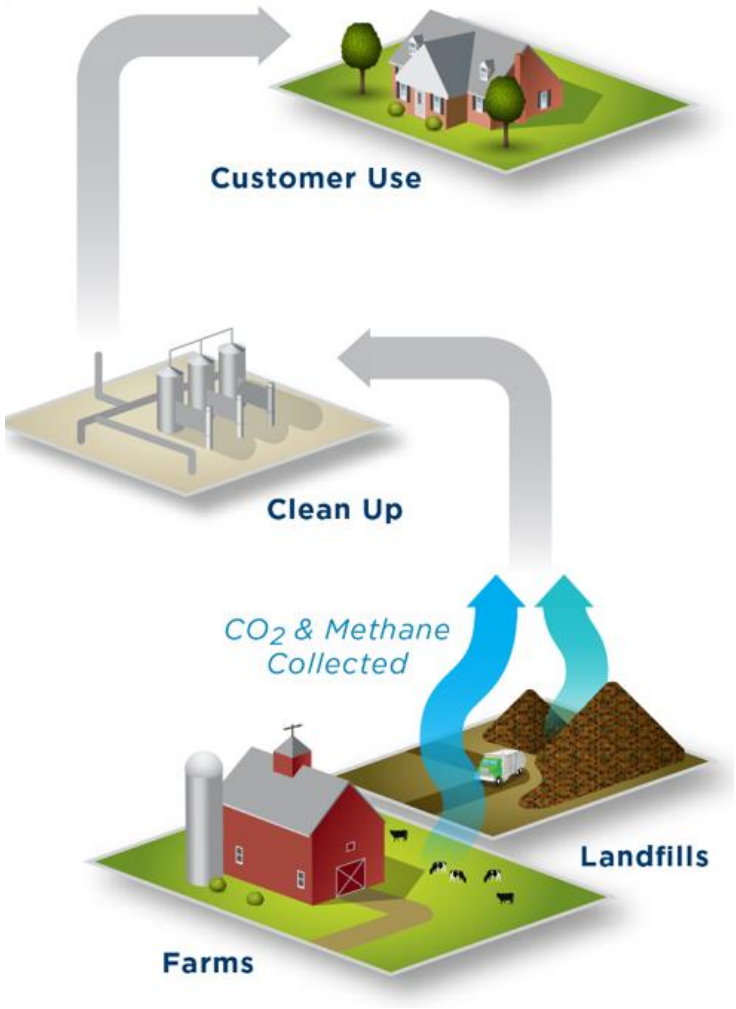
- Renewable Natural Gas (RNG) Explained
- RNG – A Climate Change Solution
- Policy & Regulation
- Industry Reports
- Avista's Commitment to Carbon Reduction
- Avista's RNG Program & Team
- Program Considerations
- RNG Market Studies & Voluntary Customer Program
- Pipeline Safety & Interconnection Requirements
- Environmental Attribute Tracking & Banking
- RNG Production Technologies & Project Types
- RNG Opportunities and Challenges
- Cost Effectiveness Evaluation Methodology

Renewable Natural Gas (RNG) Explained

Natural Gas is Critical to a Clean Energy Future

Renewable Natural Gas Explained

Renewable Natural Gas (RNG) is a non-fossil gas resource derived from various renewable waste stream sources including but not limited to landfills, wastewater treatment plants, food waste, and agriculture waste such as dairy farms, and other livestock farms. These feedstocks utilize anaerobic digestion to generate biogas, which in turn can be processed to meet pipeline quality RNG. Forest wood waste can also be converted to biogas via thermal gasification methods and made pipeline ready.



Viable feedstocks that are expected to continually operate and or expand will provide an opportunity for RNG to be produced in perpetuity, and shall serve to displace geologic gas volumes, and capture otherwise fugitive methane. As such, RNG can play an important role in decarbonizing our gas system through RNG customer programs and projects to reduce greenhouse gas (GHG) emissions, and the carbon footprint associated with geologic gas.

RNG is fully interchangeable with conventional natural gas and utilizes the existing natural gas distribution system network to seamlessly serve residential, commercial and industrial end users ***without any*** *additional building improvements, equipment, or special equipment requirements.*

RNG – A Climate Change Solution

Natural gas plays critical role for meeting aggressive green house gas (GHG) reductions goals, RNG even more so!

- Advantages of RNG
  - “De-carbonizes” gas stream
  - Gives customers another renewable choice
  - RNG is a strong pathway option for decarbonizing the thermal market
  - RNG utilizes existing infrastructure as it is fully interchangeable with conventional natural gas with no end user equipment modifications or replacement
  - RNG is a more economical solution than electrification which requires the procurement of added renewable electric resources, distribution system upgrades, and has a significant impact to end users due to the necessary replacement of building equipment and systems
  - 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

Policy & Regulation:

Washington HB 2580

- RNG study requested by legislature from WA Department of Commerce & WSU Energy Program

Washington HB 1257

- Building efficiency bill that includes RNG
- Requires utilities to offer voluntary RNG programs/products to customers
- Allows utilities to invest in RNG projects and recover the costs

Oregon SB 334

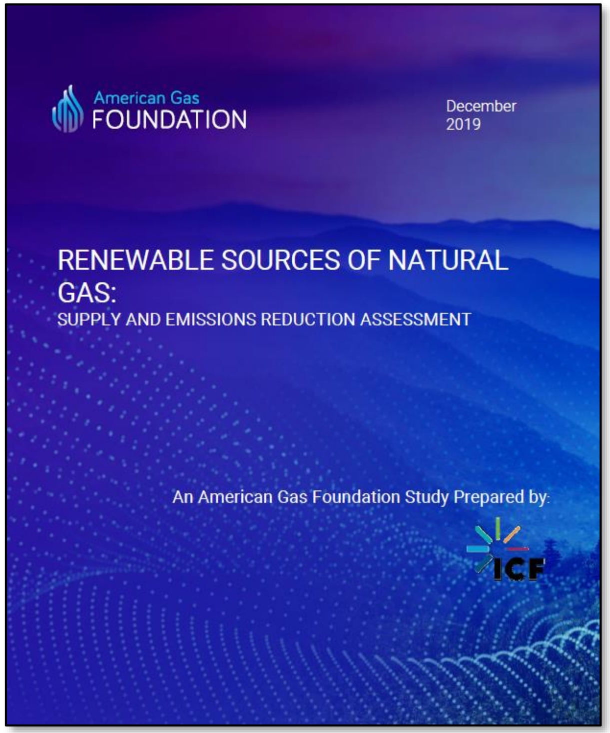
- Directs the Oregon Department of Energy to conduct a biogas and renewable natural gas inventory and prepare a report

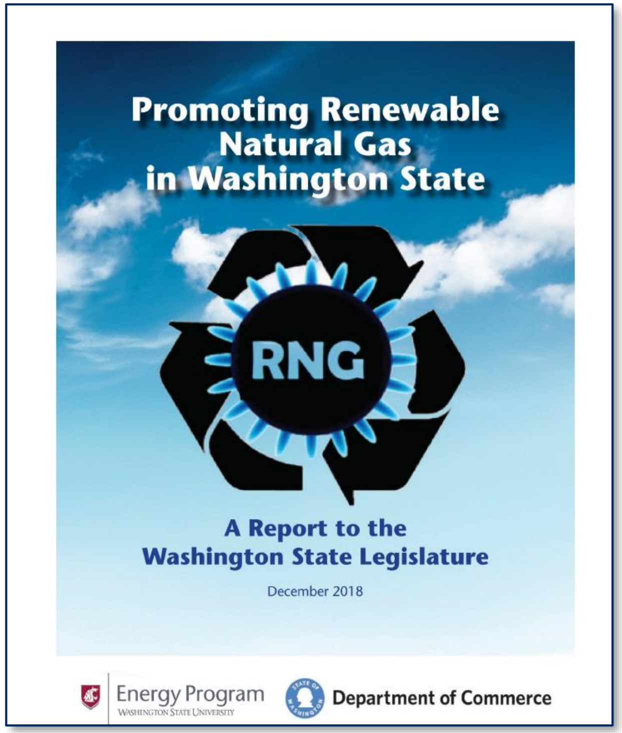
Oregon SB 98 & AR 632 Rule Making

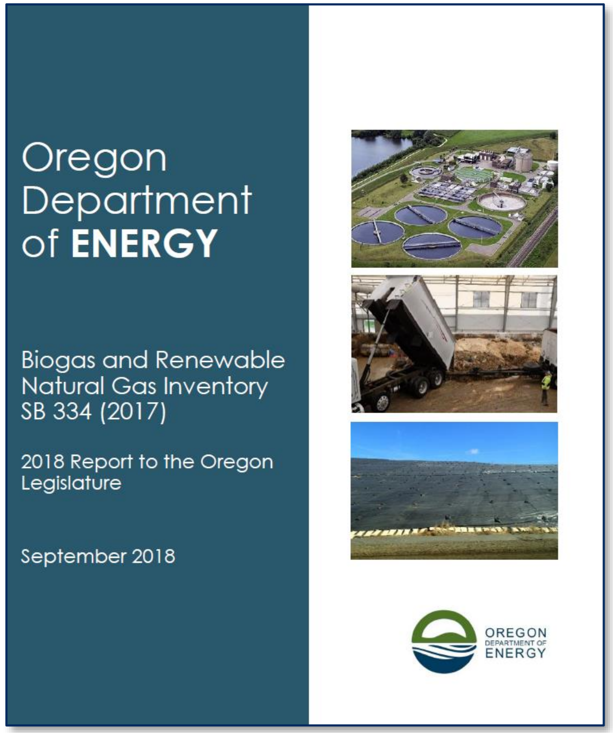
- Final rules effective on July 17th 2020
- Allows investment recovery, percent of revenue requirement per year to be determined based on potential project costs & timing, pending petition to participate
- Allows investment in gas conditioning equipment without RFP process

Industry Reports:

Avista is familiar with these relevant industry reports and has utilized them to understand the RNG industry in general as well as the potential in Washington & Oregon







Avista’s Commitment to Carbon Reduction

RNG is a Pathway to Decarbonizing the Natural Gas System

- By utilizing waste streams to create green fuel, RNG can play an important role in supporting Avista’s environmental strategy
- RNG provides Avista’s customers with a new environmentally friendly, low carbon fuel choice, delivered seamlessly via Avista’s existing natural gas system

Avista's RNG Program & Team

Avista has been assessing and planning for RNG

- Program Manager in place
- Program Charter in place
- Program Execution Plan drafted
- Participation in the regulatory and rule making process in OR & WA, informal and formal
- Business Development efforts in pursuit of multiple RNG projects continues
- Business Cases developed for consideration in Avista's five year capital planning cycle
- RNG Project accounting established
- Cross-functional team in place to support RNG:
    - Gas Engineering
    - Gas Supply
    - Legal
    - Governmental Affairs
    - Regulatory Affairs
    - Products & Services

Program Considerations

- Evaluate available RNG procurement options
- Pursue potential RNG development opportunities from local RNG feedstock resources under new legislation (Washington HB 1257 & Oregon SB 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 rule making and policy:
  - Participation in HB 1257 Policy development
  - Participation in SB 98 Policy Rulemaking via 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 WA LDC's

RNG Market Studies & Voluntary Customer Program

- RNG Commercial Market Study completed in 2019
- RNG Residential Market Survey concluded in September 2020
  - Customers lack understanding of RNG since it is a new concept
  - Customers like the environmental aspects of RNG
  - Customers like to choose their level of participation to manage costs predictably
- Voluntary customer RNG program design will advance based on the studies above
- Estimate voluntary customer program demands
- RNG to be added to Avista's renewables portfolio

Pipeline Safety & Interconnection Requirements

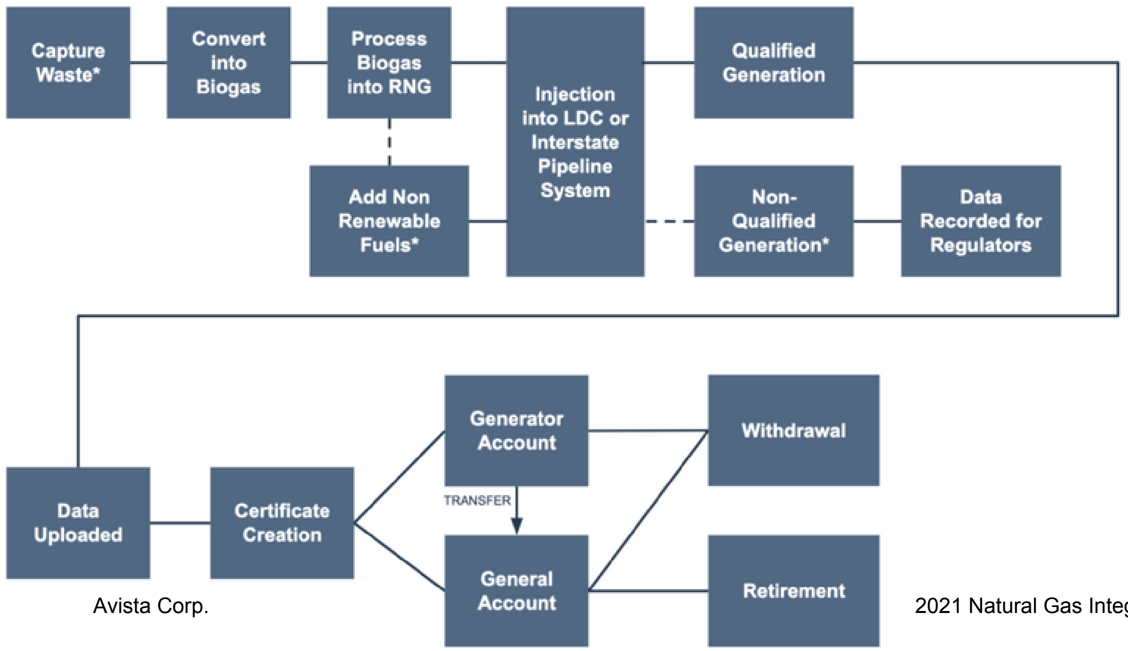
- Avista Gas Quality Specification developed
- Collaborative RNG Gas Quality Framework established across (4) WA LDC's
- Avista Interconnection Agreement template developed
- Avista Study Agreement and RNG Producer review process template developed

Environmental Attribute Tracking & Banking

Under OR SB 98 the M-RETS system has been selected to track RNG environmental attributes. Other jurisdictions including Washington may also select this system

- 1 Renewable Thermal Certificate (RTC) = 1 Dekatherm (Dth) of RNG
- Transparent electronic certificate tracking
- Not a certification entity

RTC Creation Process



What Does an RTC Look Like?

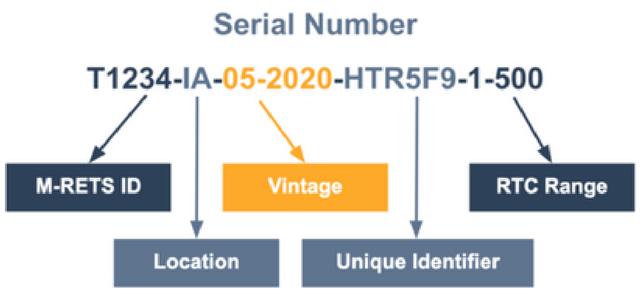
RTC Information

Dekatherm (Dth) Renewable Thermal = 1 Renewable Thermal Certificate

Certificate Details include:

- Serial Number (See Example)
- Account
- Project
- Thermal Resource
- Feedstock
- Vintage
- Location
- Quantity

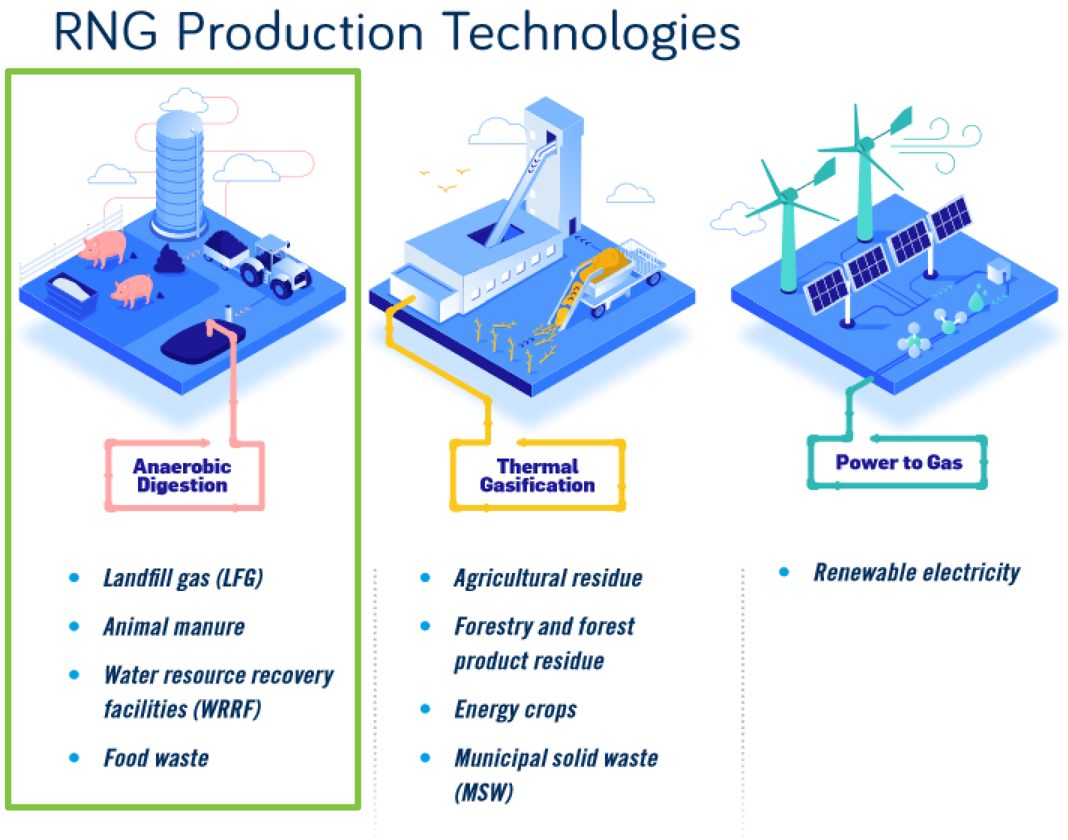
Carbon Pathways (If Applicable)
IRE Verification (If Applicable)



M-RETS Renewable Thermal

RNG Production Technologies & Project Types

Avista is actively evaluating a handful of potential Anaerobic Digestion Projects throughout Washington and Oregon.



RNG Technologies :

- Conventional RNG: Amine scrub, membrane separation, water wash, PSA
- Hydrogen blending

34

RNG Opportunities & Challenges

California RNG market ($30+/Dth v. $2/Dth)

- Vehicle emission incentives shut-out other potential end users
- Producers see the pot of gold in Federal RIN & California LCFS markets
- RNG supplier cost volatility

Financing for producers

- RIN market is volatile
- No forward pricing for RNG RTC’s in carbon market
- Vehicle market may be approaching saturation in CA
- Environmental attribute value for local markets is undefined

RNG Opportunities & Challenges

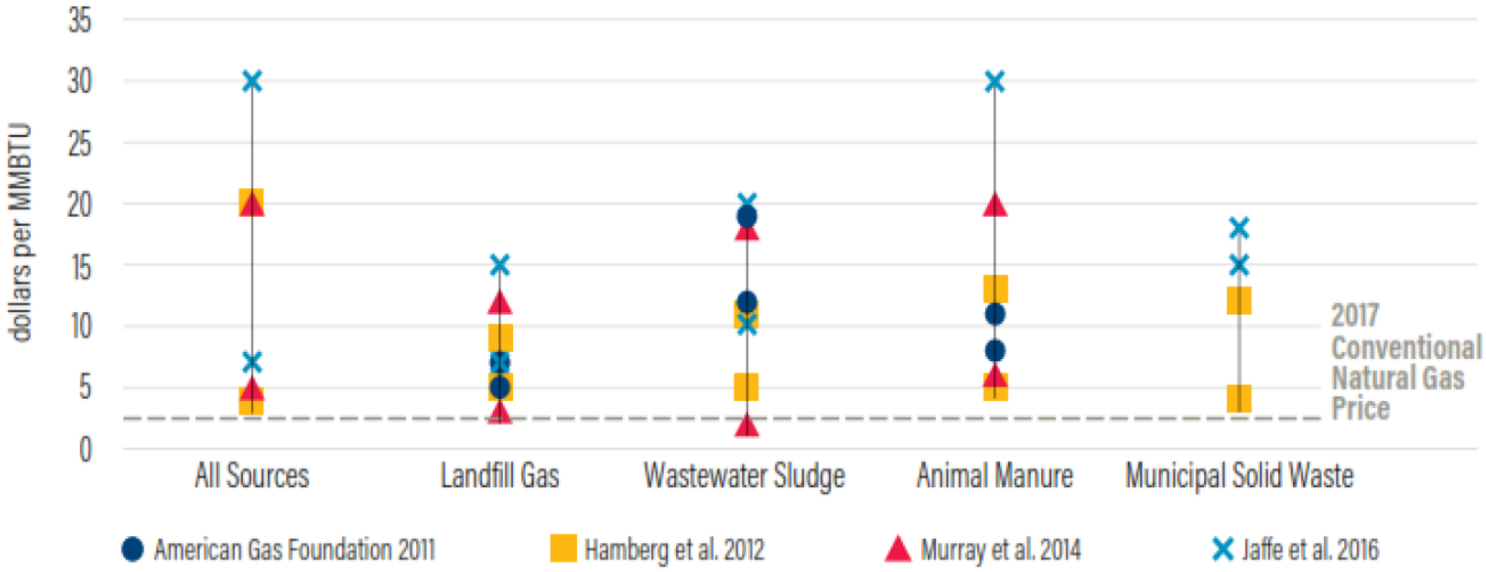
Utility RNG Projects

- Feedstock owners can now partner with LDC's to cultivate new RNG projects
- Feedstock owners wiliness to partner with the utility's cost of service model. This is a foreign concept to feedstock owners that seek highest value for their biogas
- 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
- Economies of scale – Low volume biogas opportunities face economic challenges
- New RNG Projects can take 2-3 years to develop
- Customers have paid for a vast pipeline infrastructure that can be utilized for a cleaner future by **transitioning the fuel** and keeping the pipe

RNG Opportunities & Challenges

RNG $ per Dth/MMBtu

Avista Owned and Operated	ID - WA 2035 Premium Estimate ($ / Dth)
RNG - Landfills	$7 - $10
RNG - Waste Water Treatment Plants (WWTP)	$12 - $22
RNG - Agriculture Manure	$28 - $53
RNG - Food Waste	$29 - $53



Source: Promoting RNG in WA State

RNG Opportunities & Challenges

Carbon Intensity will pay a role in how the environmental attributes / Renewable Thermal Certificate (RTC) values will be determined

Fuel Pathway	Carbon Intensity $\frac{gCO_{2}e}{MJ}$
Diesel*	102.01
Gasoline*	99.78
Fossil CNG†	78.37
Landfill CNG†	46.42
WWTP CNG*	19.34
MSW CNG*	-22.93
Dairy CNG‡	-276.24

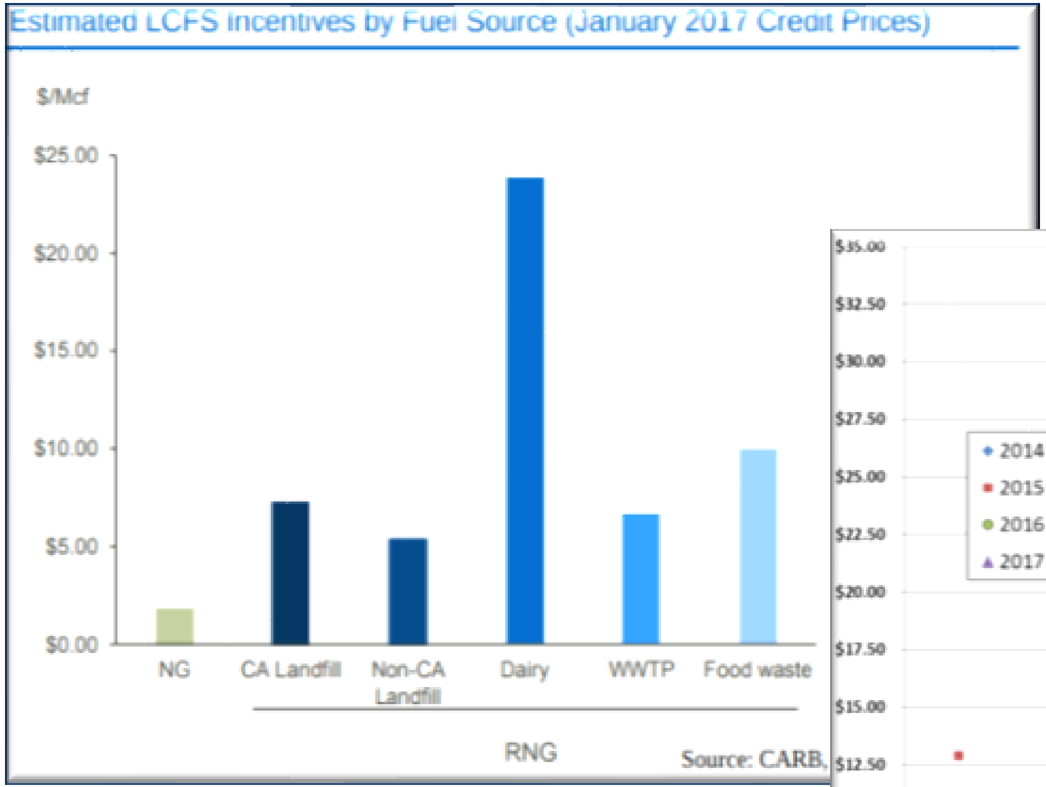
*California Code of Regulation Title 17, §95488, Table 6. Carbon intensity for WWTP is the average of two WWTP pathways.

†California Code of Regulation Title 17, §95488, Table 7.

†Method 2B Application CalBio LLC, Dallas Texas, Dairy Digester Biogas to CNG.

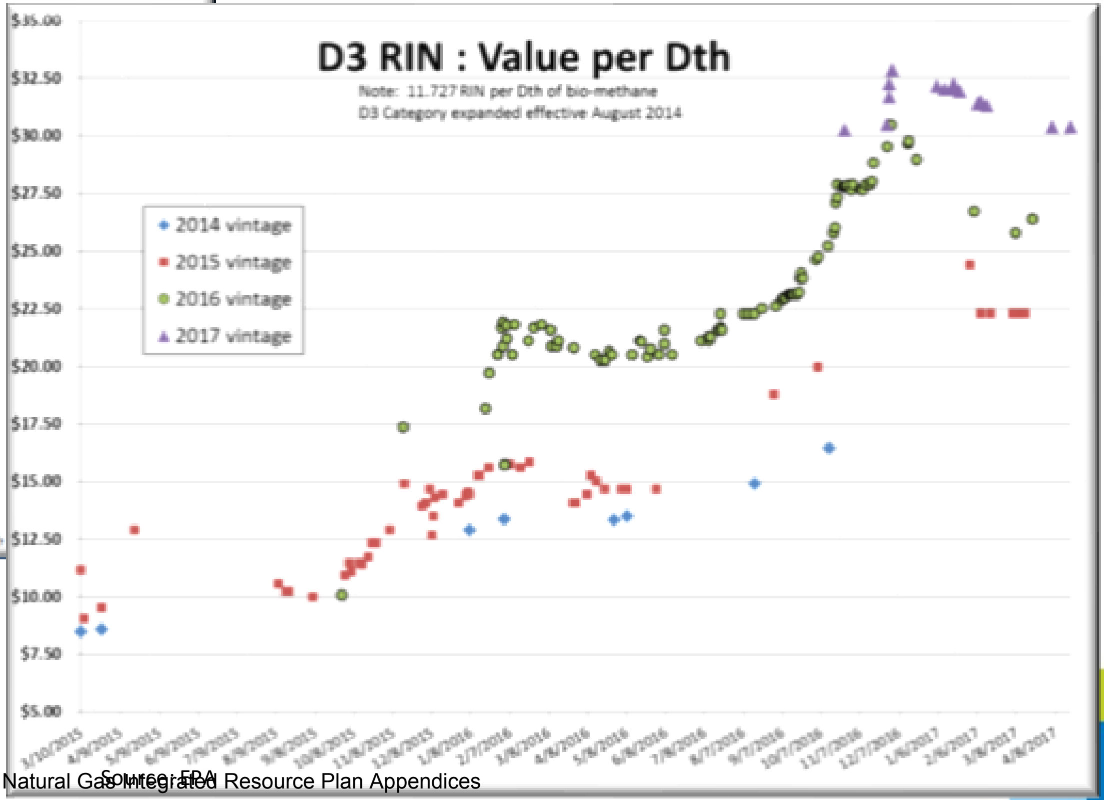
RNG Opportunities & Challenges

RNG RTC values within the utility construct cannot compete with the RNG values driven by the RFS RIN & LCFS markets



Source: CARB

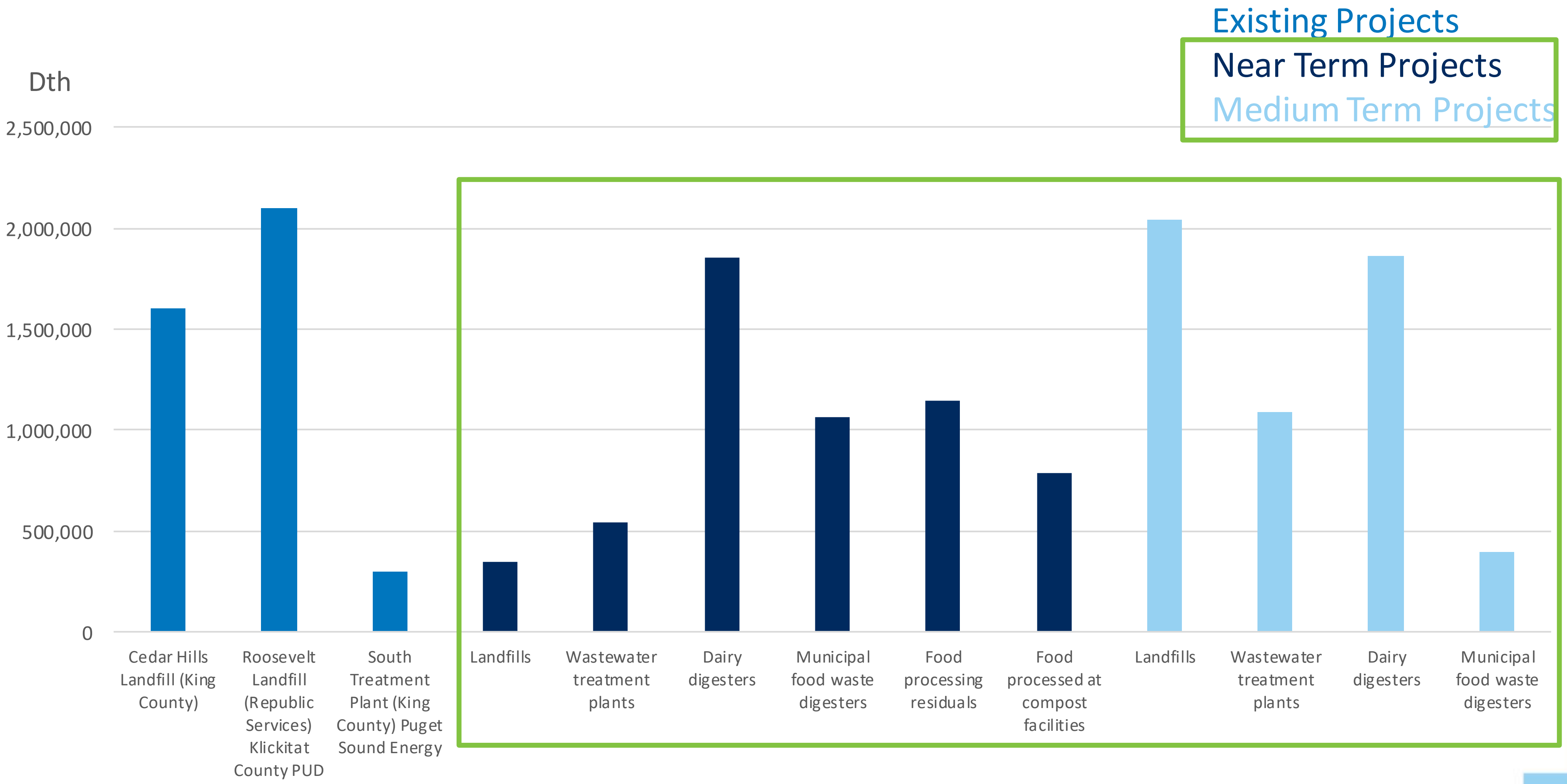
RIN = renewable identification number



Source: EPA

RNG Opportunities & Challenges

WA RNG Report (HB 2580) – Utility's have the opportunity to leverage the remaining RNG opportunities to decarbonize the natural gas system



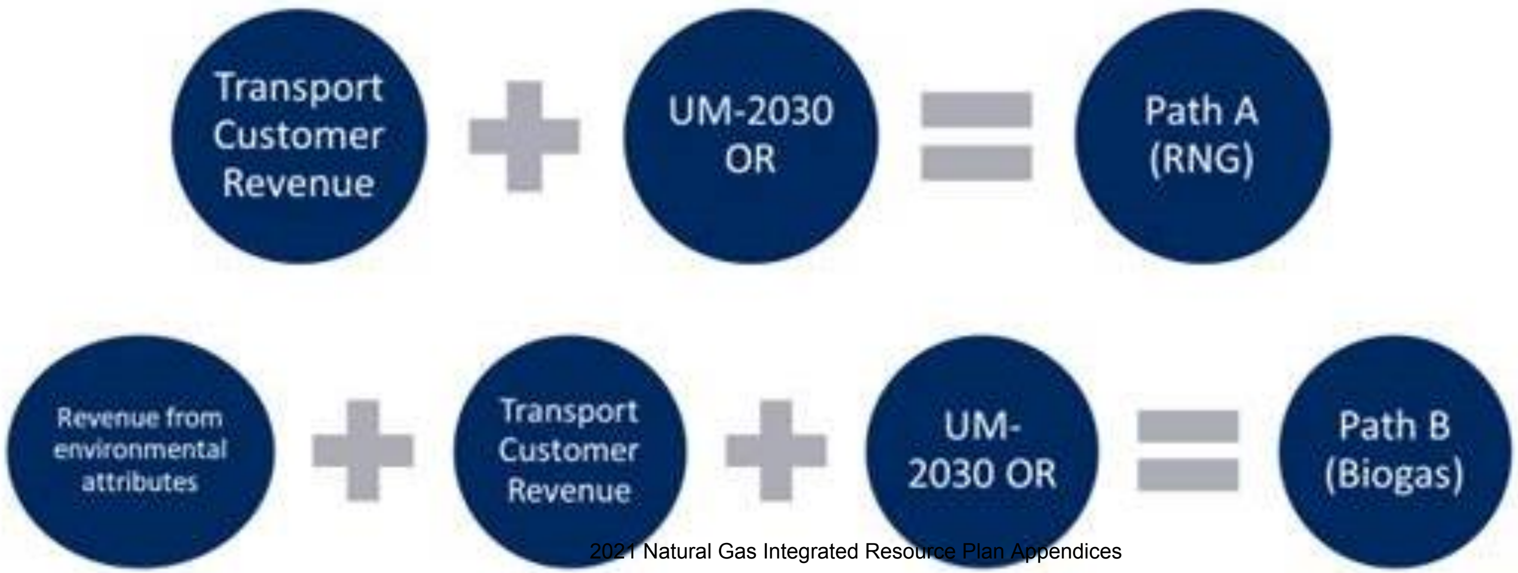
WSU Energy Program, Harnessing Renewable Natural Gas for Low-Carbon Fuel: A Roadmap for Washington State

*Released December 1, 2018

Cost Effectiveness Evaluation Methodology

Developing the Methodology….a work in process

- Avista is creating a cost effectiveness evaluation methodology for evaluating RNG projects. The following slides are a snapshot of Avista's work in progress.
- The methodology shown is derived from OPUC UM2030, also referenced in the OPUC SB 98 AR 632 Rulemaking
- The evaluation method shown herein is subject to input, refinement and reconsideration.



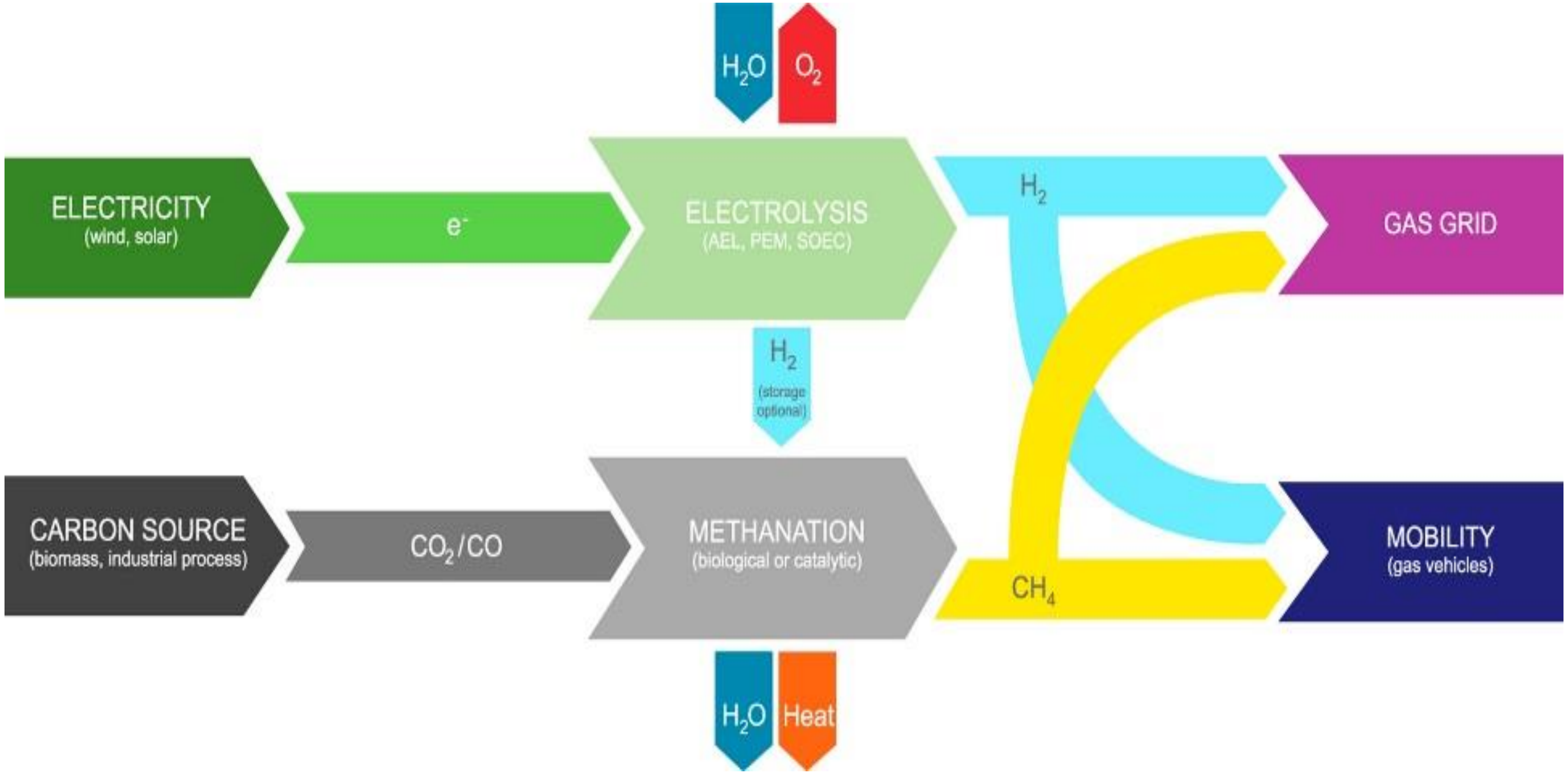
Hydrogen

Tom Pardee
Planning Manager, Natural Gas Supply

Hydrogen

- The energy factor of H2 Low Heating Value (LHV) is roughly equivalent to a gallon of gasoline or 114,000btu
  - This equates to 8.78 kg of H2LHV per Dth
- Most H2 is currently made from reforming natural gas
  - The energy can come from Nuclear (Pink), Renewables (Green) or Fossil fuels (Grey)
- High cost (currently) when compared to energy in a Dth combined with current prices of natural gas
- Hydrogen can only be stored in the pipeline as a % of gas or combined with a carbon source to produce methane.
- Hydrogen is lighter than air and diffuses rapidly (3.8x faster than natural gas) making it more difficult to contain

PtG Process



Source: http://www.europeanpowertogas.com/about/power-to-gas

Power to Gas

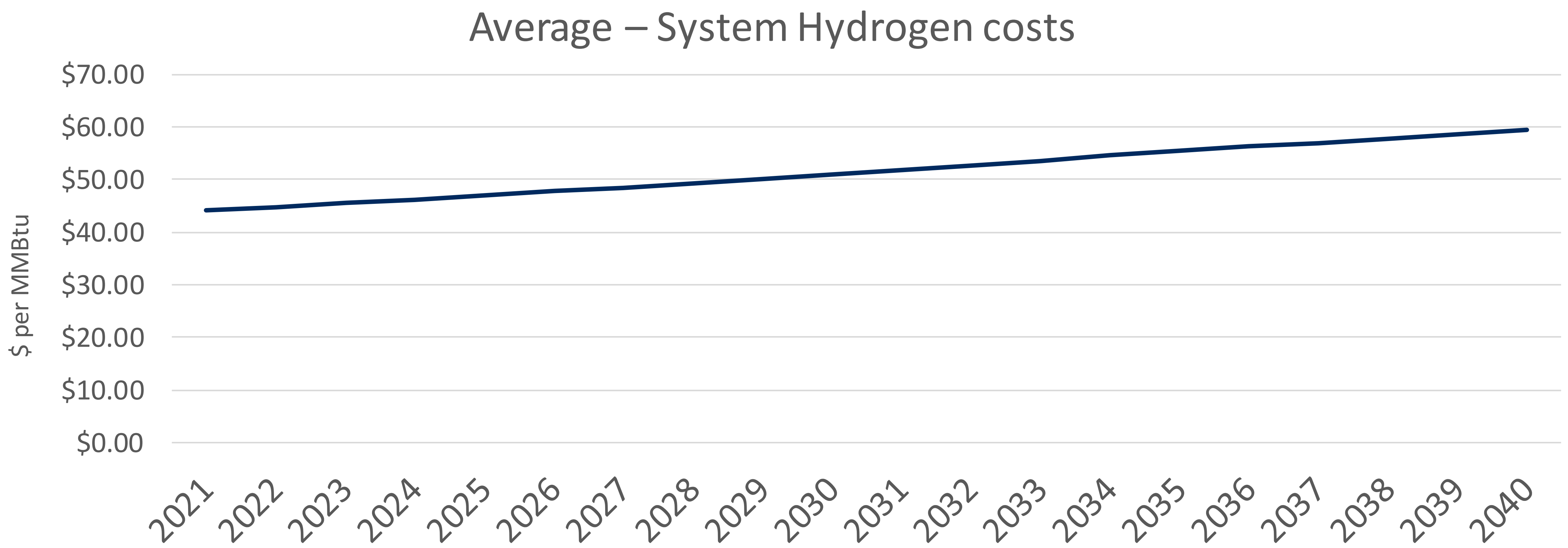
- Power to Gas (PtG) is a process using power to separate water into hydrogen and oxygen
- Hydrogen can be stored, as a % of gas, in the existing gas grid or used in the mobility sector (blend up to 20%)
- PtG can help to balance excess power from intermittent sources like wind and solar
- PtG can decarbonize the direct use of natural gas
- PtG economics will advance as more renewables are added and the technology matures
- Short term and seasonal energy storage
- Stored in the existing gas pipeline

PtG Benefits

Benefits

- Cleans up the grid using excess power
- Stores the energy for future use in the natural gas pipelines/infrastructure utilizing customer owned resources and are currently available
- Hydrogen is relatively safe as if it is released it quickly dilutes into a non-flammable concentration

Current Renewable Hydrogen Price estimates



*Assumes Avista owned resources

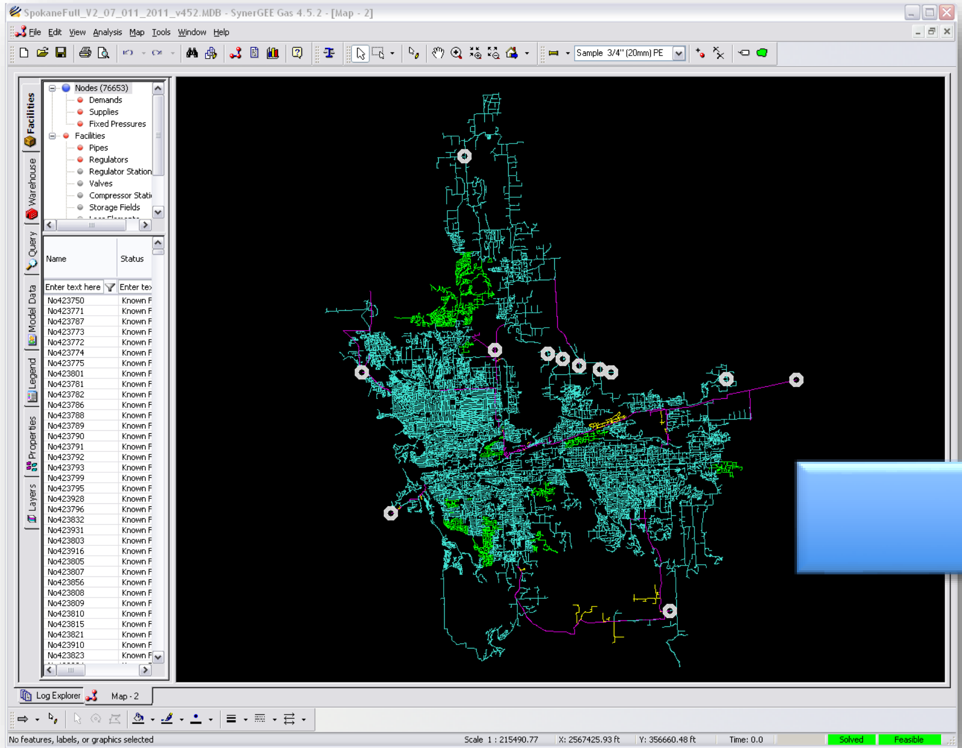
Distribution Overview

Terrence Browne

Sr. Gas Planning Engineer, Gas Engineering

Mission

- Using technology to plan and design a safe, reliable, and economical distribution system

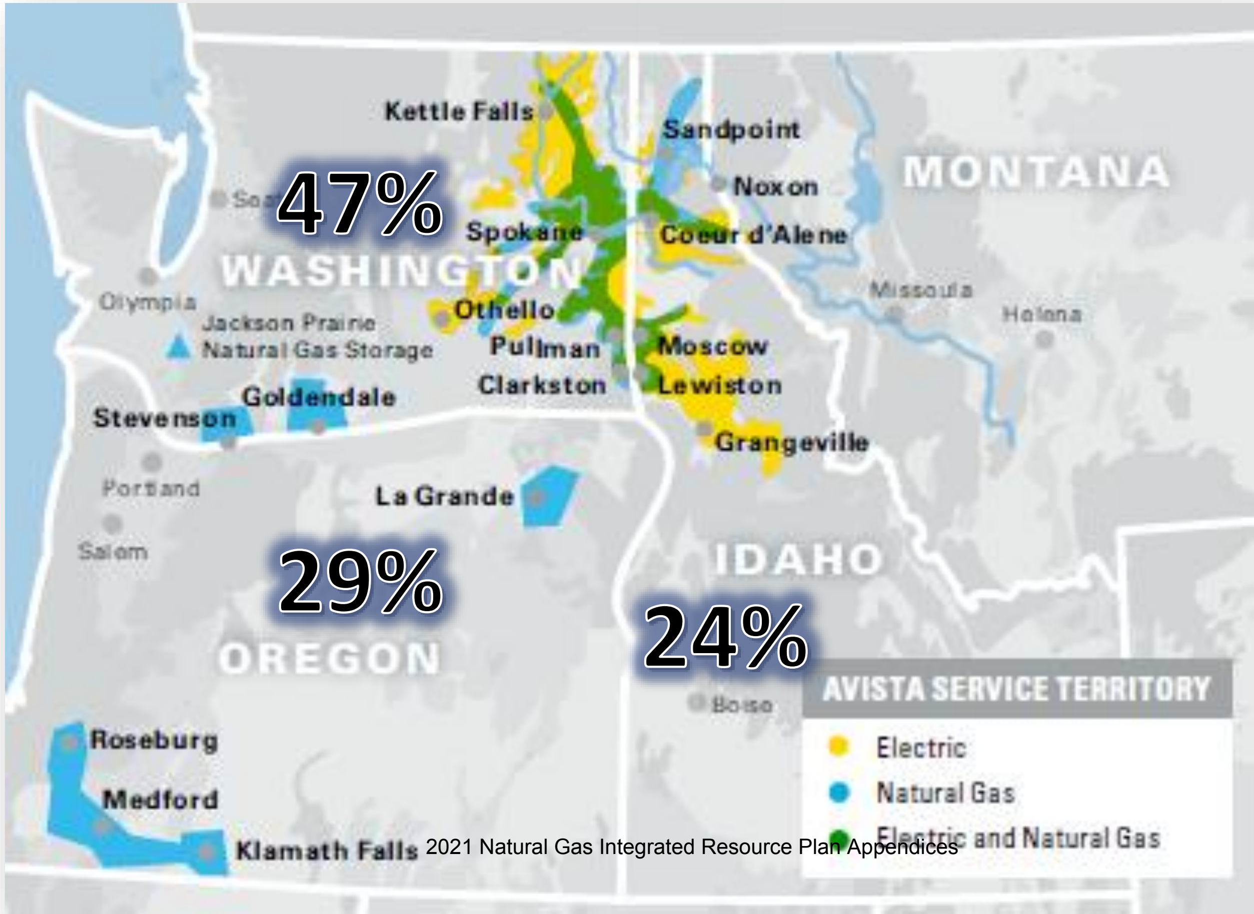


Gas Distribution Planning

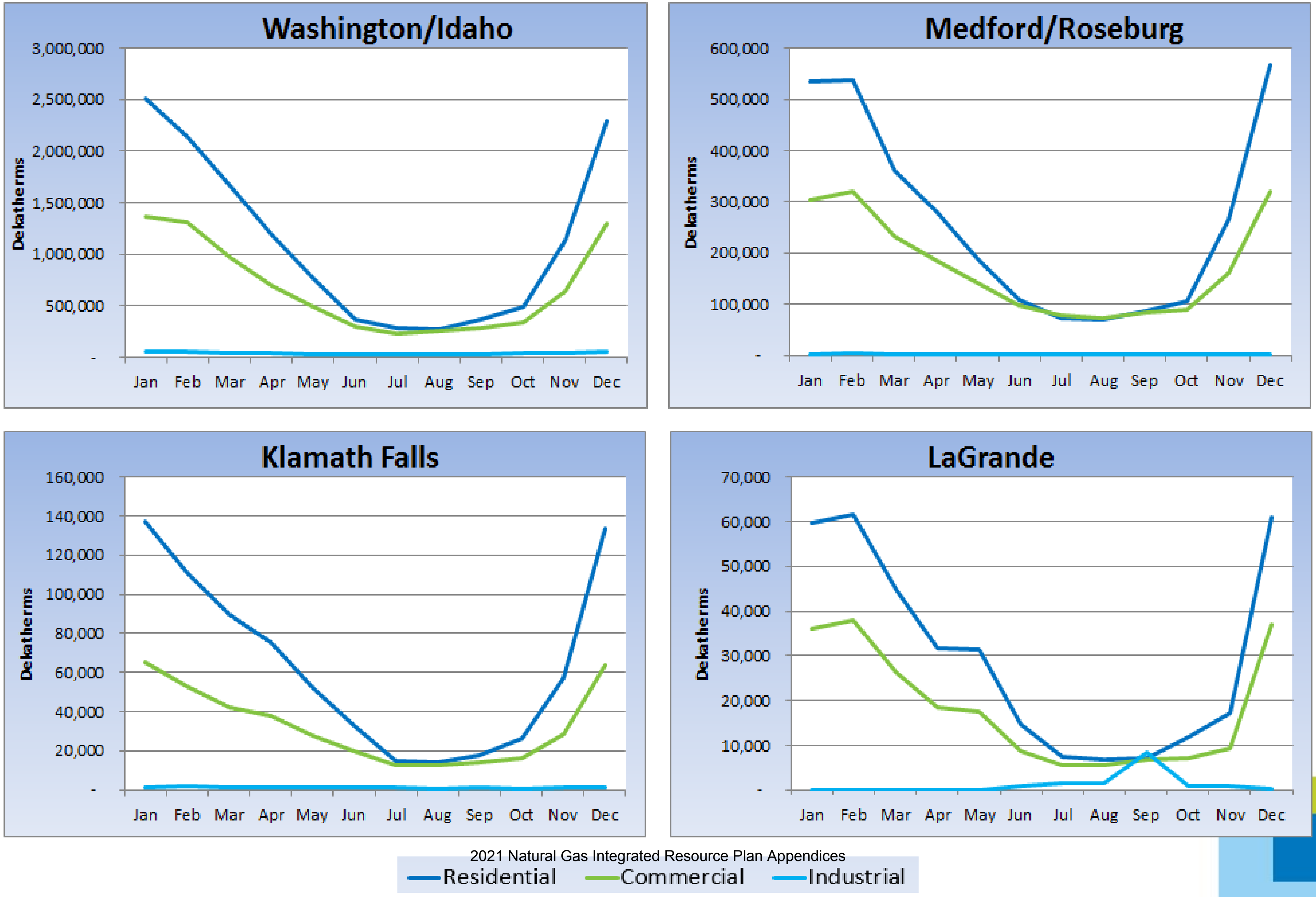
- Service Territory and Customers
- Scope of Gas Distribution Planning
- SynerGi Load Study Tool
- Planning Criteria
- Interpreting Results
- Long-term Planning Objectives
- Monitoring Our System
- Communicating Solutions
- Gate Station Capacity Review
- Project Examples

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 1.5 million
    - 385,000 electric customers
    - 360,000 natural gas customers

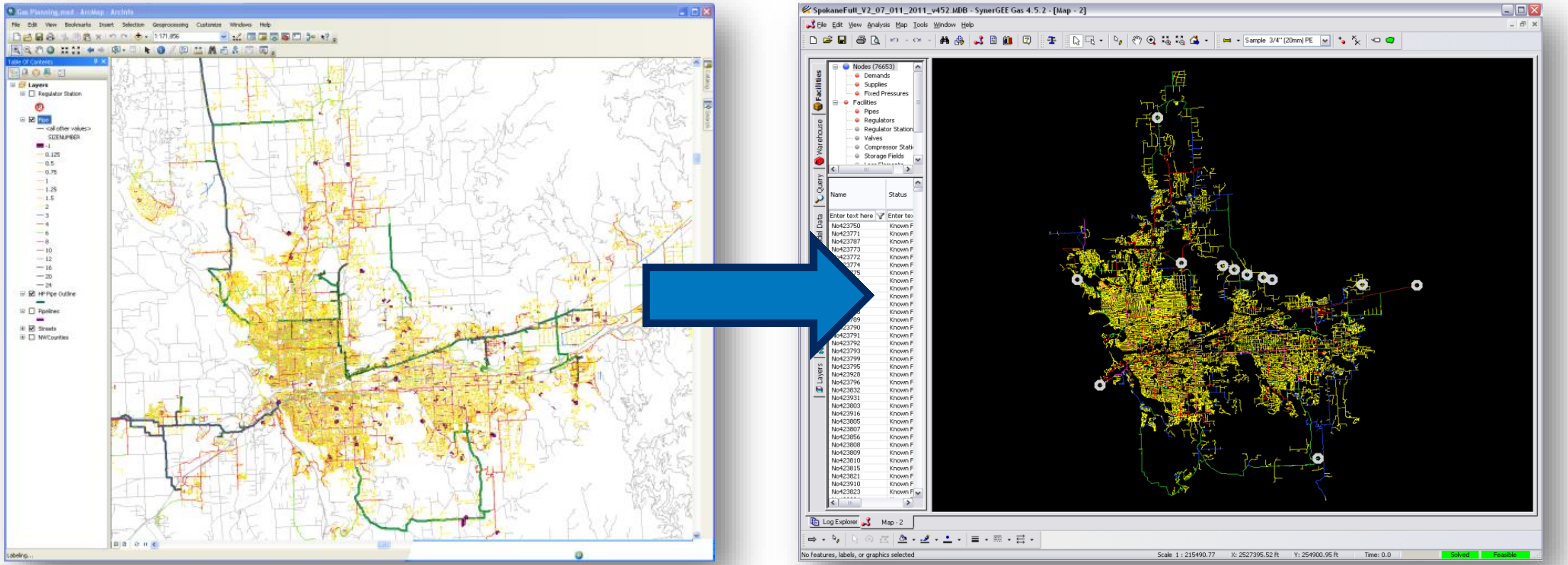


Seasonal Demand Profiles

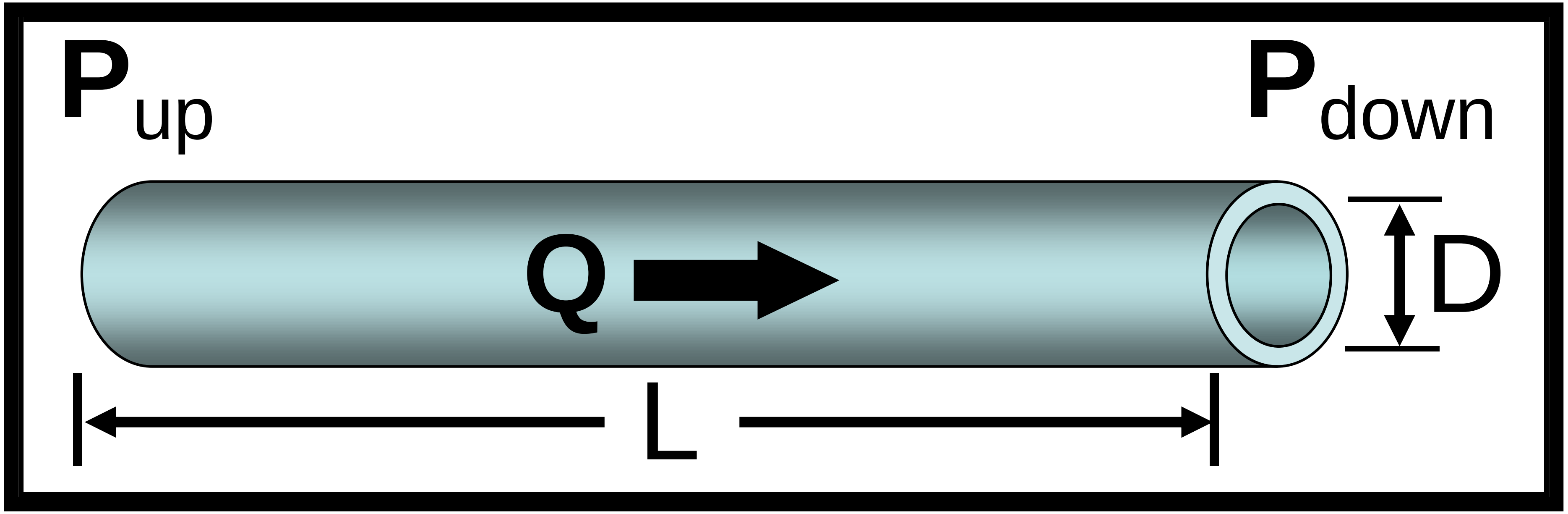


Our Planning Models

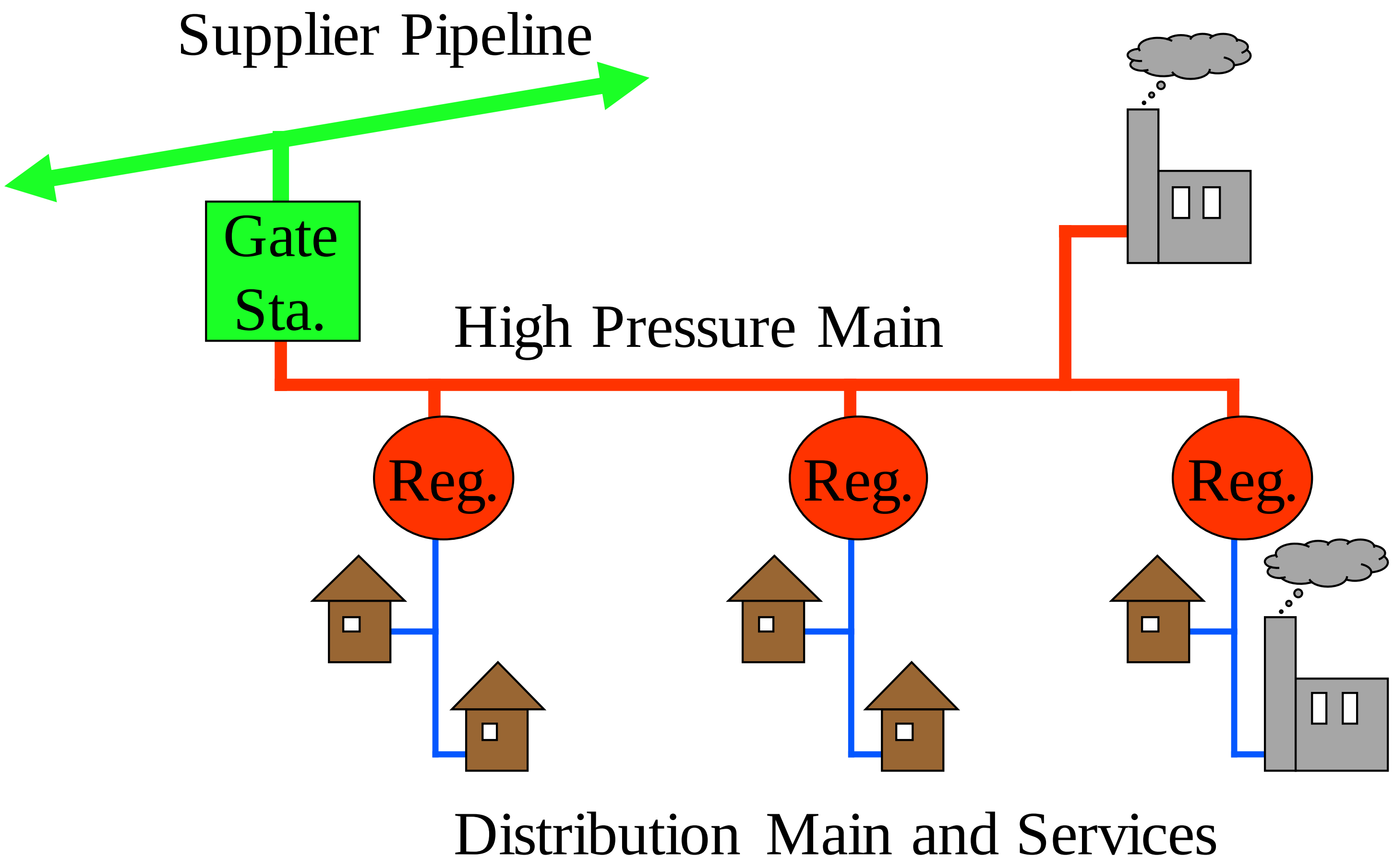
- 120 cities
- 40 load study models



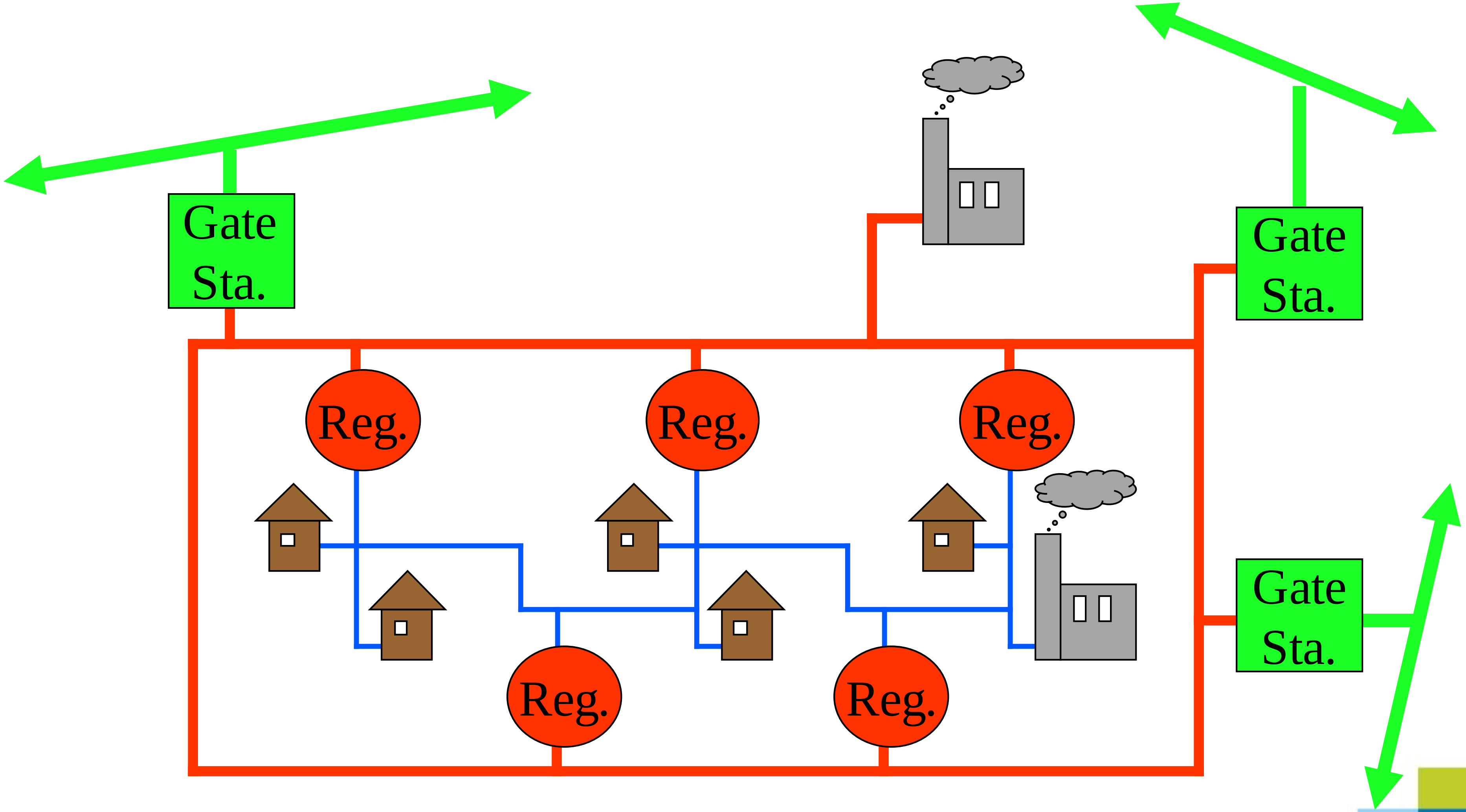
5 Variables for Any Given Pipe



Scope of Gas Distribution Planning

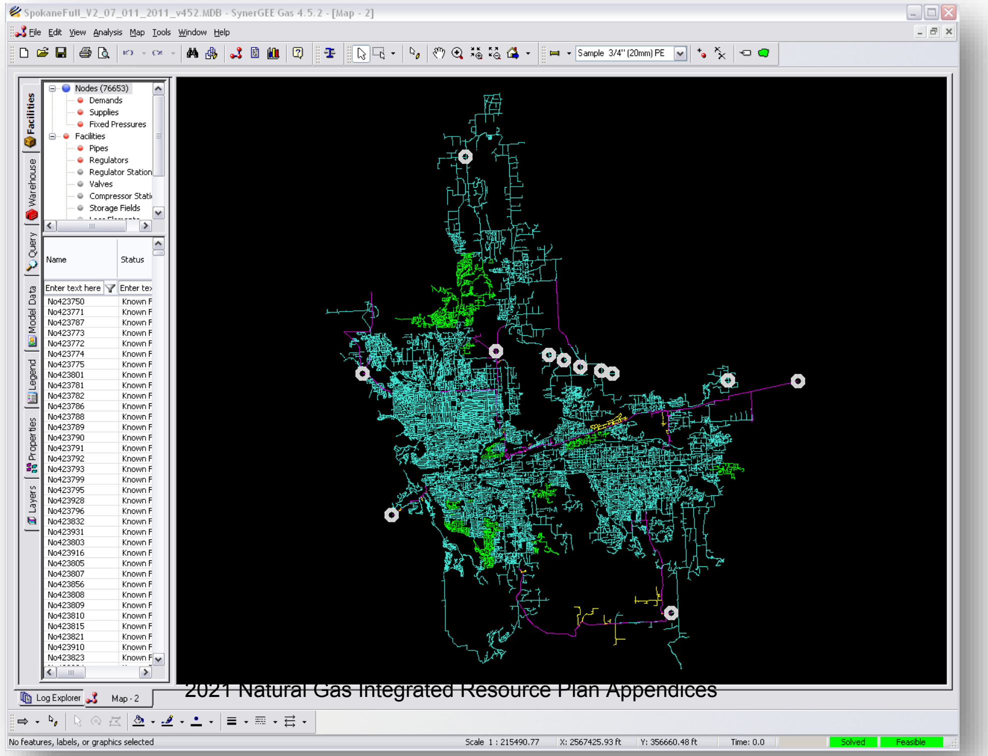


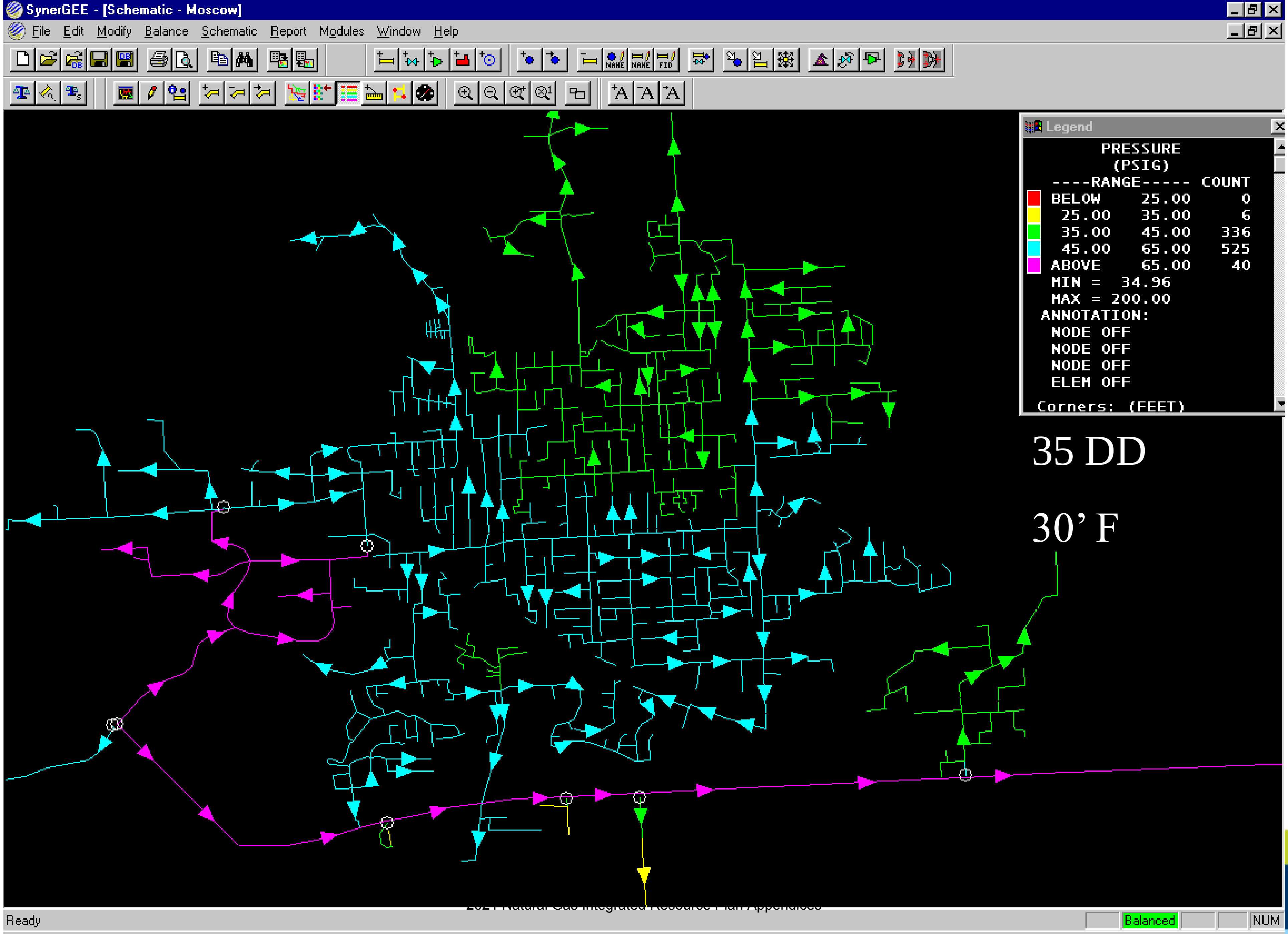
Scope of Gas Distrib. Planning cont.



SynerGi (SynerGEE, Stoner) Load Study

- Simulate distribution behavior
- Identify low pressure areas
- Coordinate reinforcements with expansions
- Measure reliability




SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 6
35.00 45.00 336
45.00 65.00 525
ABOVE 65.00 40
MIN = 34.96
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
Ready
Balanced
NUM

35 DD

30’ F

Preparing a Load Study

- Estimating Customer Usage
- Creating a Pipeline Network
- Join Customer Loads to Pipes
- Convert to Load Study

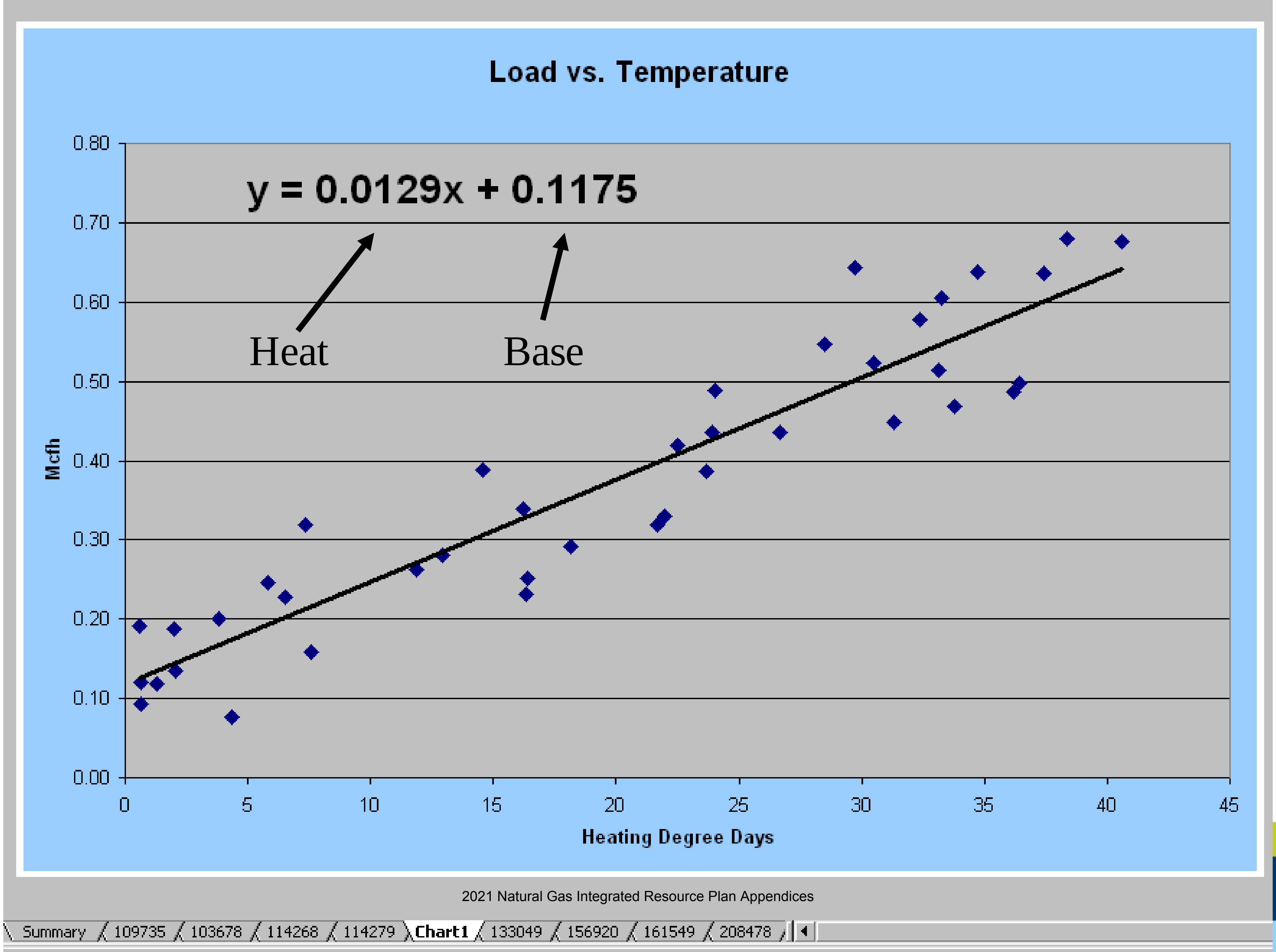
Estimating Customer Usage

- Gathering Data
  - Days of service
  - Degree Days
  - Usage
  - Name, Address, Revenue Class, Rate Schedule…

Estimating Customer Usage cont.

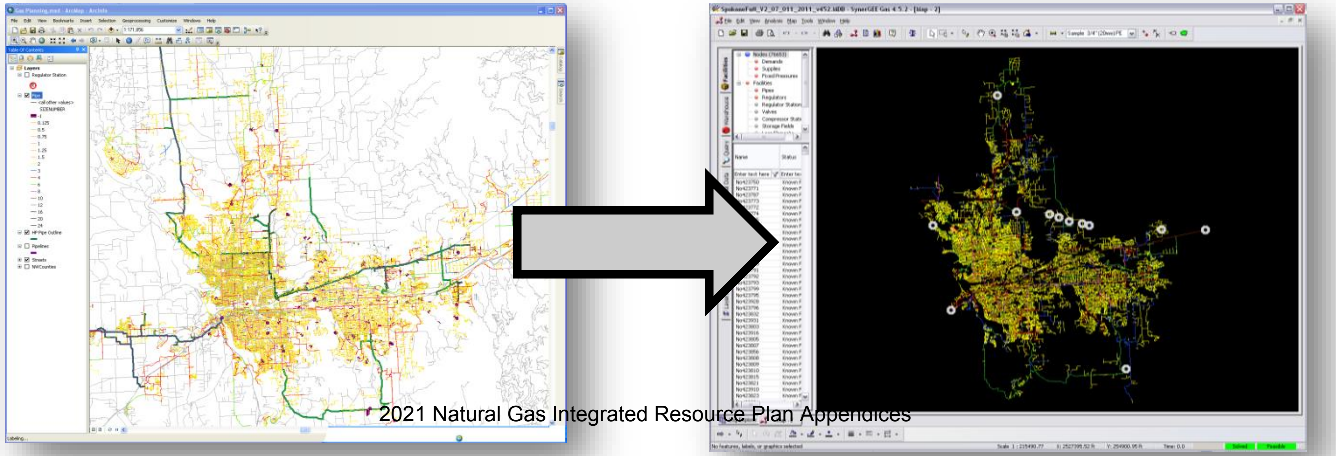
- Degree Days
  - Heating (HDD)
  - Cooling (CDD)
- Temperature - Usage Relationship
  - Load vs. HDD's
  - Base Load (constant)
  - Heat Load (variable)
  - High correlation with residential

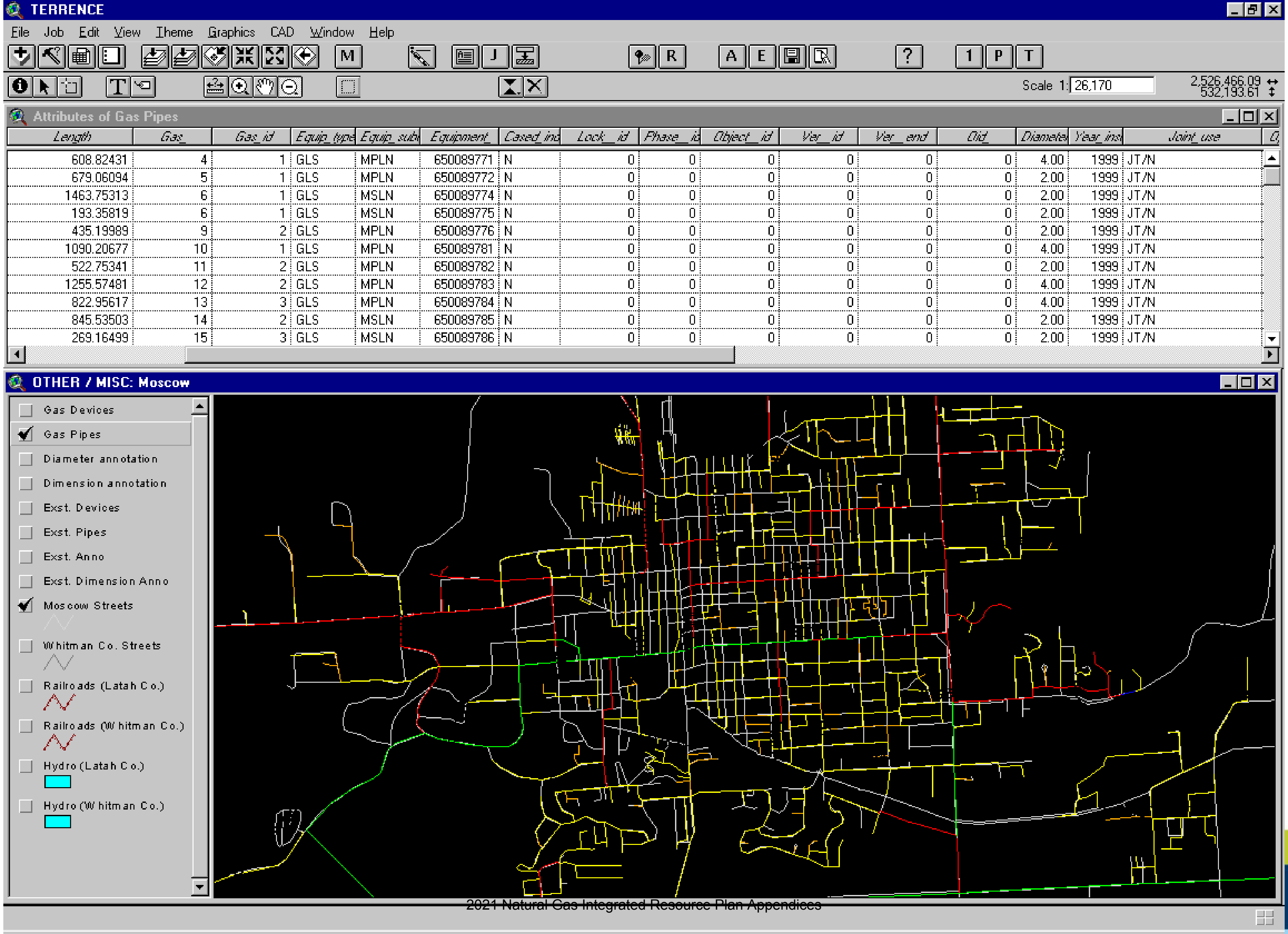
Avg. Daily Temperature ('Fahrenheit)	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
85		20
80		15
75		10
70		5
65	***0***	***0***
60	5	
55	10	
50	15	
45	20	
40	25	
35	30	
30	35	
25	40	
20	45	
15	50	
10	55	
5	60	
4	61	
0	65	
-5	70	
-10	75	
-15	80	


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

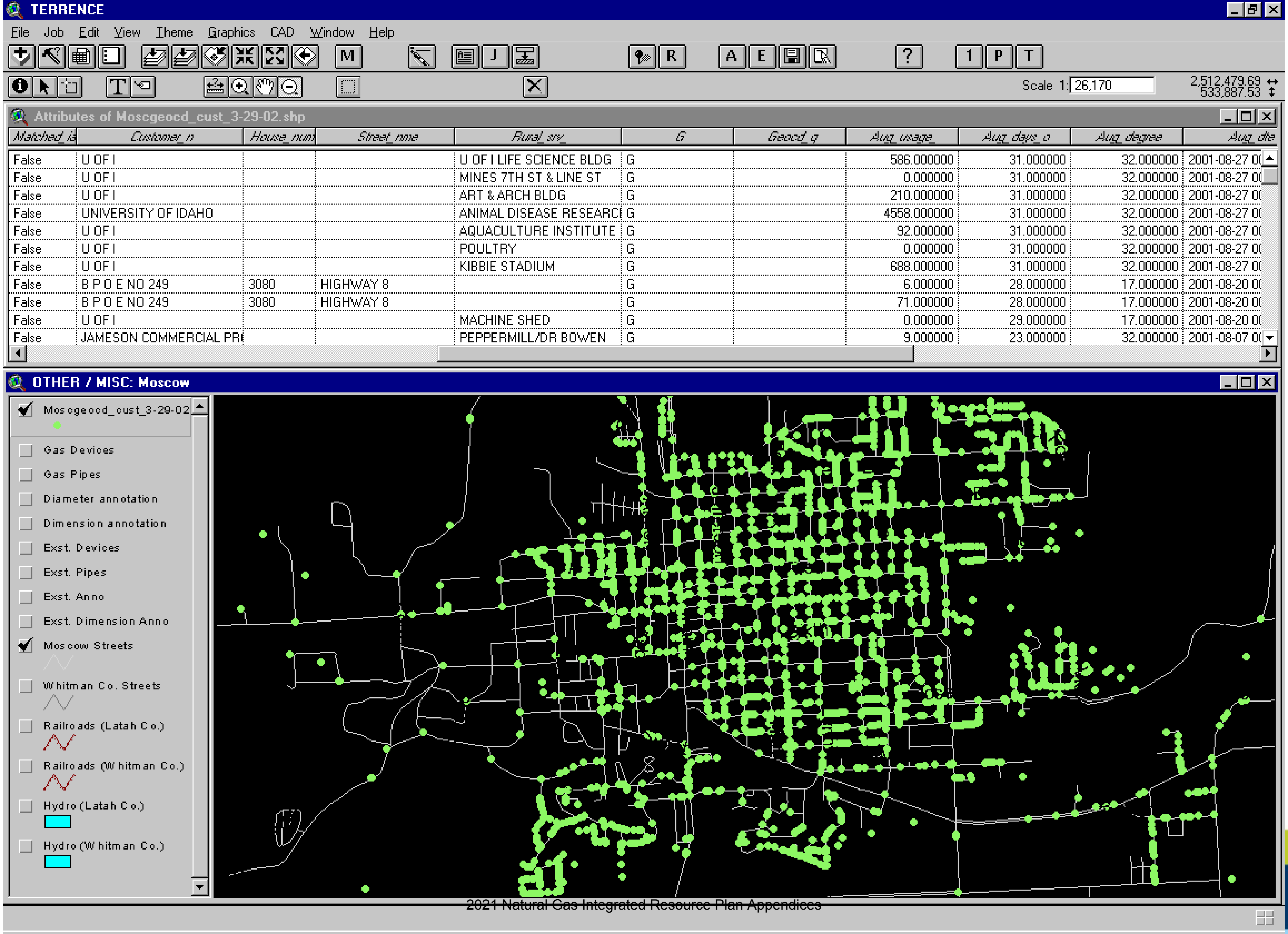
- Elements
  - Pipes, regulators, valves
  - Attributes: Length, internal diameter, roughness
- Nodes
  - Sources, usage points, pipe ends
  - Attributes: Flow, pressure



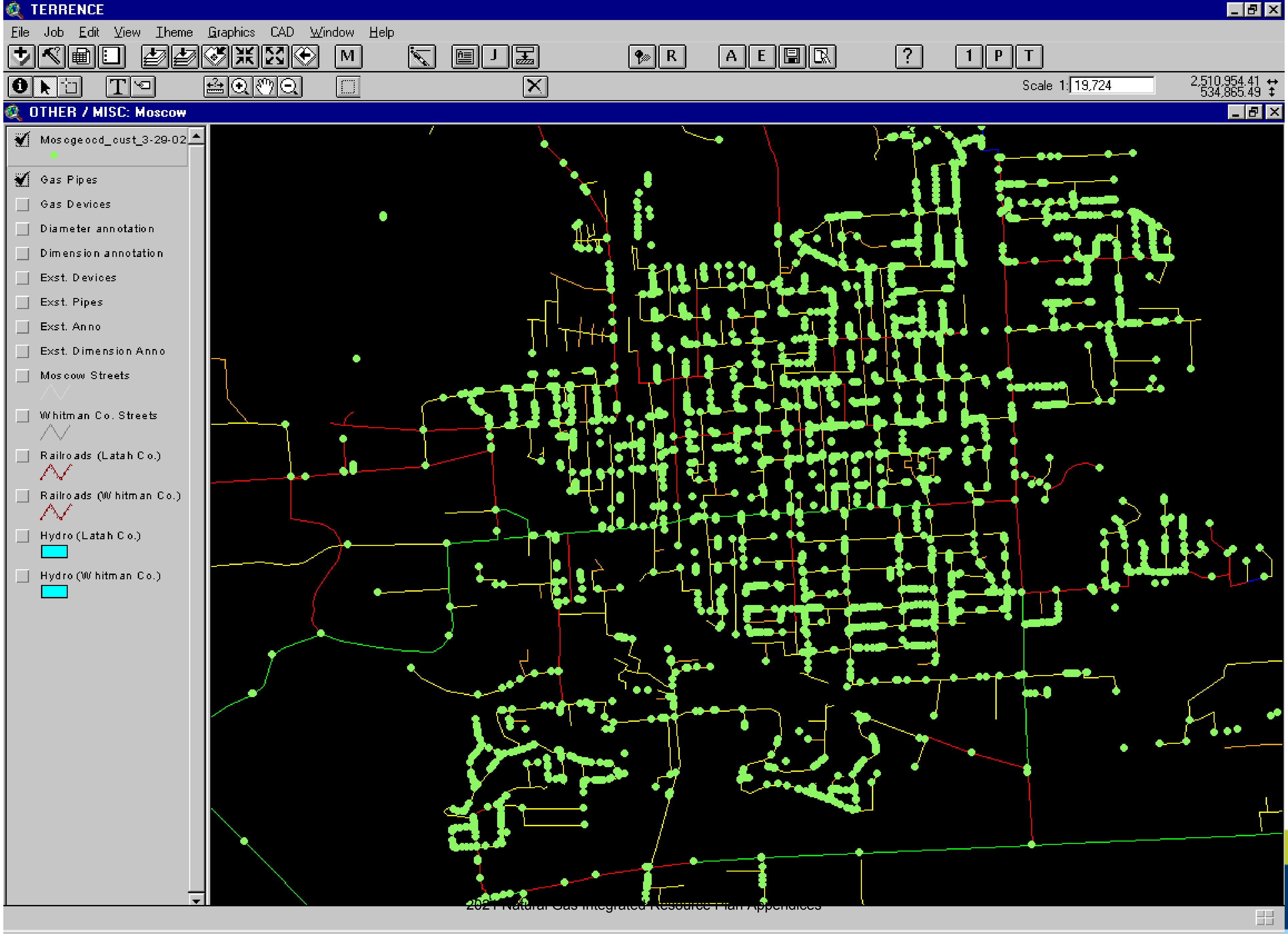

TERRENCE
File Job Edit View Theme Graphics CAD Window Help
Scale 1: 26,170
2,526,466.09
532,193.61
Attributes of Gas Pipes

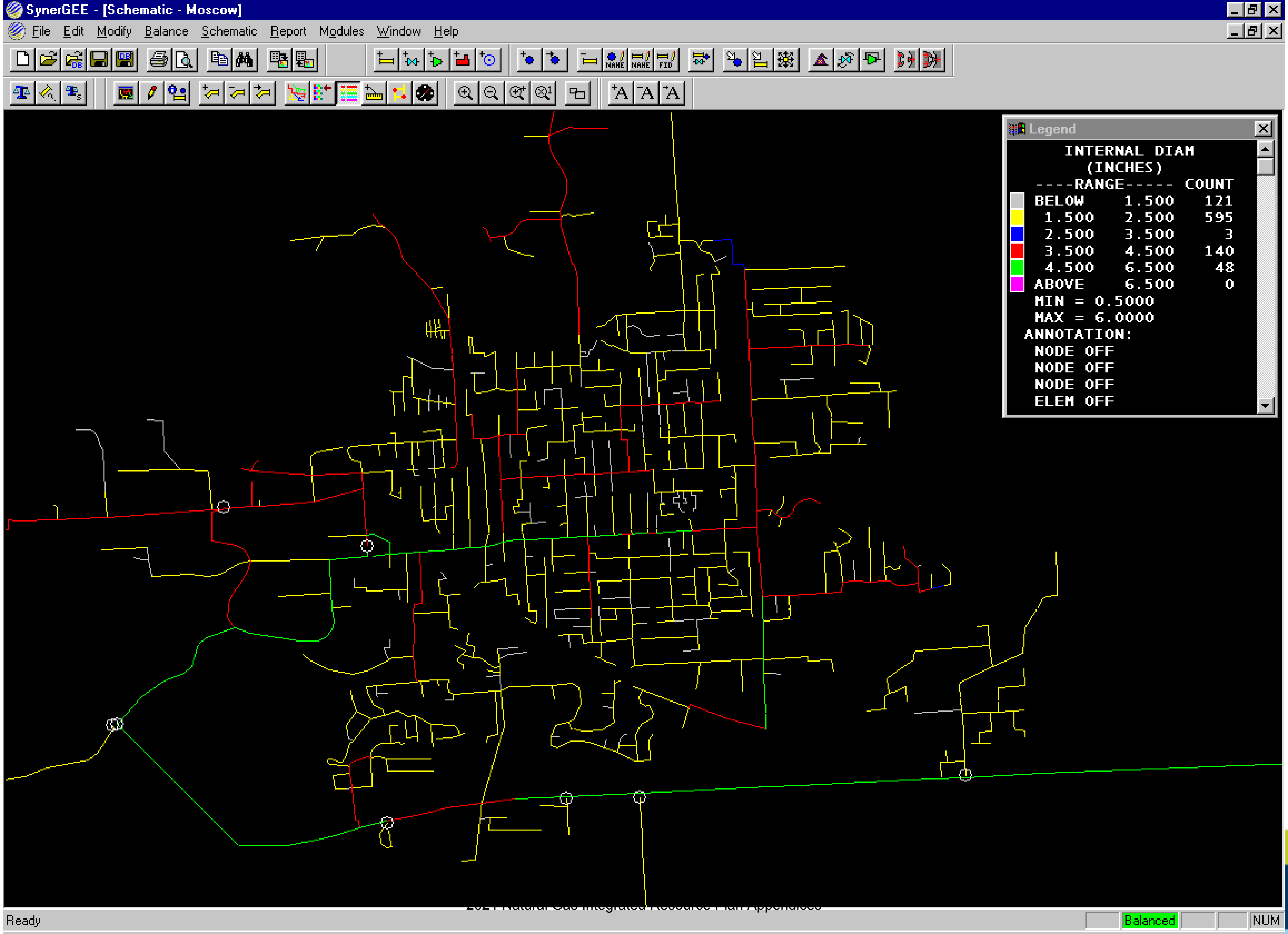
Length	Gas_	Gas_id	Equip_type	Equip_sub	Equipment	Cased_ind	Lock_id	Phase_id	Object_id	Ver_id	Ver_end	Oid	Diameter	Year_ins	Joint_use
608.82431	4	1	GLS	MPLN	650089771	N	0	0	0	0	0	0	4.00	1999	JT/N
679.06094	5	1	GLS	MPLN	650089772	N	0	0	0	0	0	0	2.00	1999	JT/N
1463.75313	6	1	GLS	MSLN	650089774	N	0	0	0	0	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

OTHER / MISC: Moscow
Gas Devices
Gas Pipes
Diameter annotation
Dimension annotation
Exst. Devices
Exst. Pipes
Exst. Anno
Exst. Dimension Anno
Moscow Streets
Whitman Co. Streets
Railroads (Latah Co.)
Railroads (Whitman Co.)
Hydro (Latah Co.)
Hydro (Whitman Co.)



Matched_is	Customer_n	House_num	Street_nme	Rural_srv_	G	Geocd_g	Avg_usage_	Avg_days_o	Avg_degree	Avg_dte
False	U OF I			U OF I LIFE SCIENCE BLDG	G		586.000000	31.000000	32.000000	2001-08-27 0(
False	U OF I			MINES 7TH ST & LINE ST	G		0.000000	31.000000	32.000000	2001-08-27 0(
False	U OF I			ART & ARCH BLDG	G		210.000000	31.000000	32.000000	2001-08-27 0(
False	UNIVERSITY OF IDAHO			ANIMAL DISEASE RESEARCI	G		4558.000000	31.000000	32.000000	2001-08-27 0(
False	U OF I			AQUACULTURE INSTITUTE	G		92.000000	31.000000	32.000000	2001-08-27 0(
False	U OF I			POULTRY	G		0.000000	31.000000	32.000000	2001-08-27 0(
False	U OF I			KIBBIE STADIUM	G		688.000000	31.000000	32.000000	2001-08-27 0(
False	B P O E NO 249	3080	HIGHWAY 8		G		6.000000	28.000000	17.000000	2001-08-20 0(
False	B P O E NO 249	3080	HIGHWAY 8		G		71.000000	28.000000	17.000000	2001-08-20 0(
False	U OF I			MACHINE SHED	G		0.000000	29.000000	17.000000	2001-08-20 0(
False	JAMESON COMMERCIAL PR			PEPPERMILL/DR BOWEN	G		9.000000	23.000000	32.000000	2001-08-07 0(

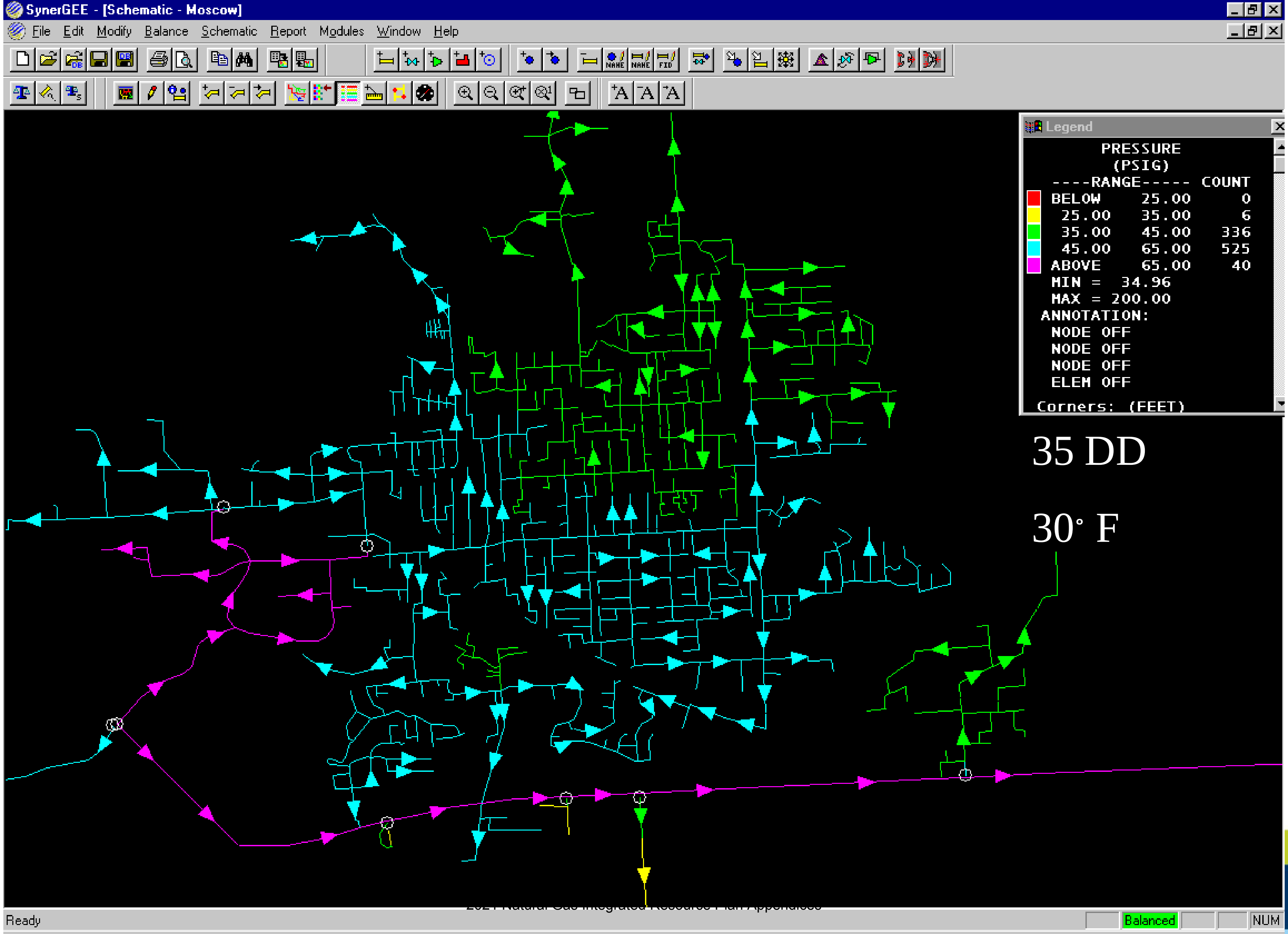

TERRENCE
File Job Edit View Theme Graphics CAD Window Help
Scale 1: 19,724
2,510,954.41
534,865.49
OTHER / MISC: Moscow
Moscgeocd_cust_3-29-02
Gas Pipes
Gas Devices
Diameter annotation
Dimension annotation
Exst. Devices
Exst. Pipes
Exst. Anno
Exst. Dimension Anno
Moscow Streets
Whitman Co. Streets
Railroads (Latah Co.)
Railroads (Whitman Co.)
Hydro (Latah Co.)
Hydro (Whitman Co.)


SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
INTERNAL DIAM
(INCHES)
----RANGE----- COUNT
BELOW 1.500 121
1.500 2.500 595
2.500 3.500 3
3.500 4.500 140
4.500 6.500 48
ABOVE 6.500 0
MIN = 0.5000
MAX = 6.0000
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Ready
Balanced
NUM

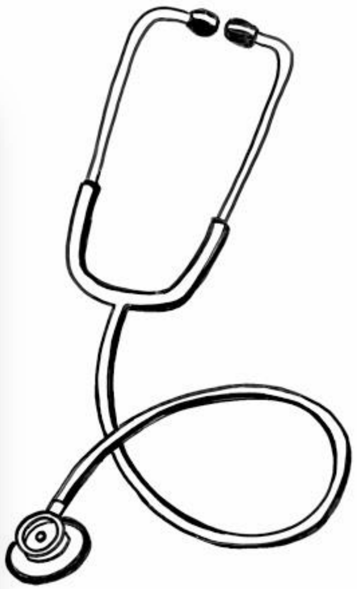
Avista Corp.

Balancing Model

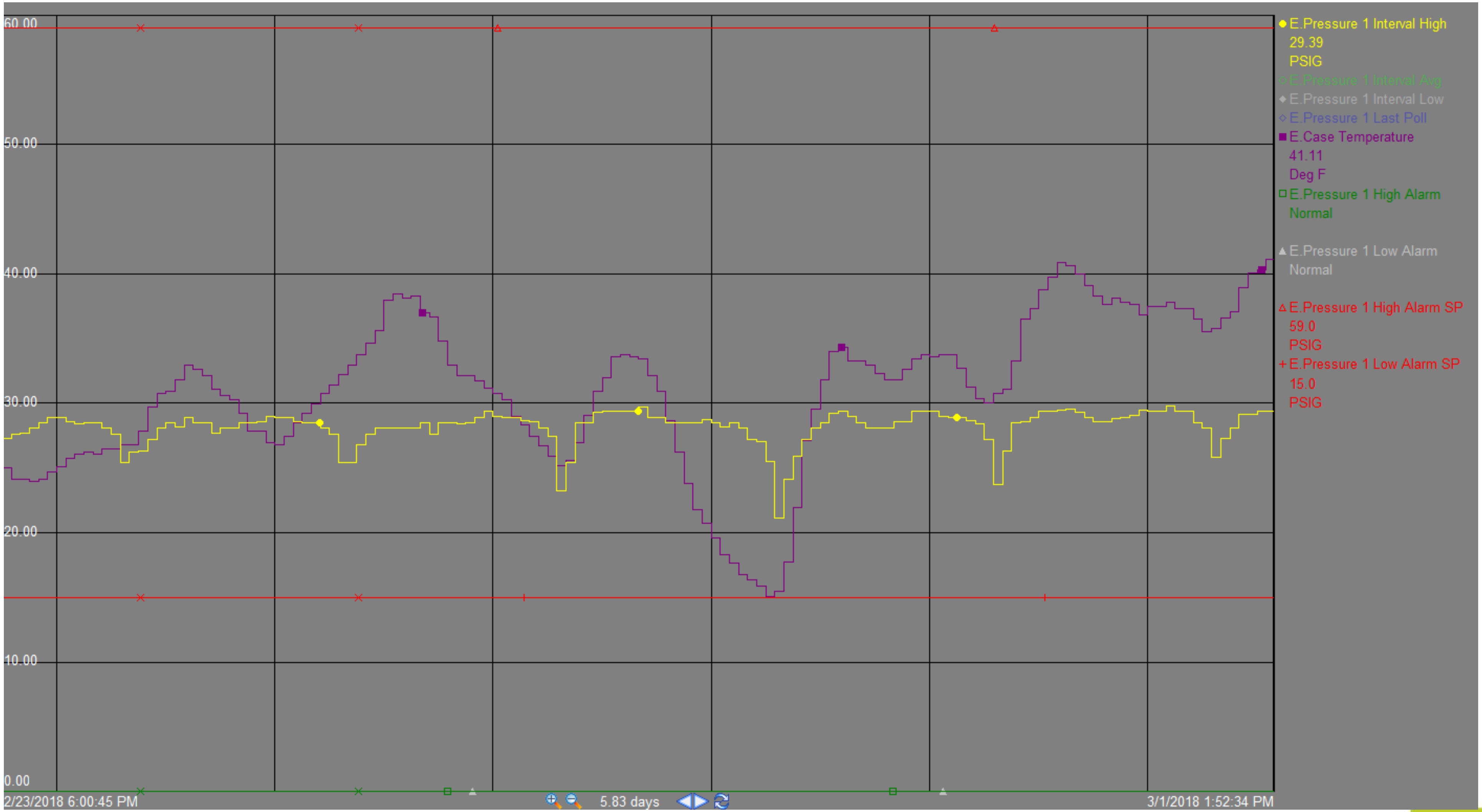
- Simulate system for any temperature
  - HDD's
- Solve for pressure at all nodes


SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 6
35.00 45.00 336
45.00 65.00 525
ABOVE 65.00 40
MIN = 34.96
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
35 DD
30° F
Ready
Balanced
NUM

Validating Model



Validating Model cont.



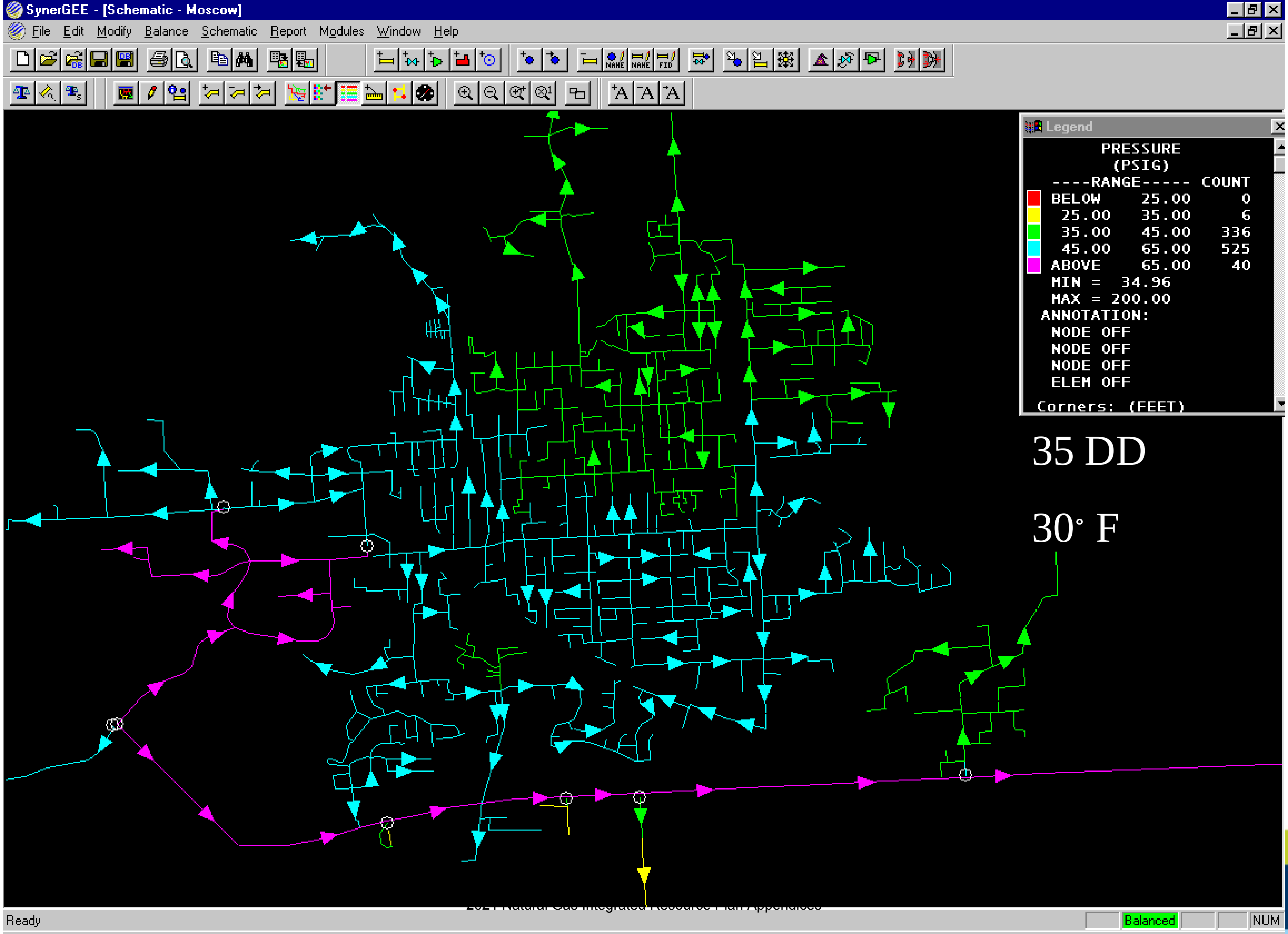
Validating Model cont.

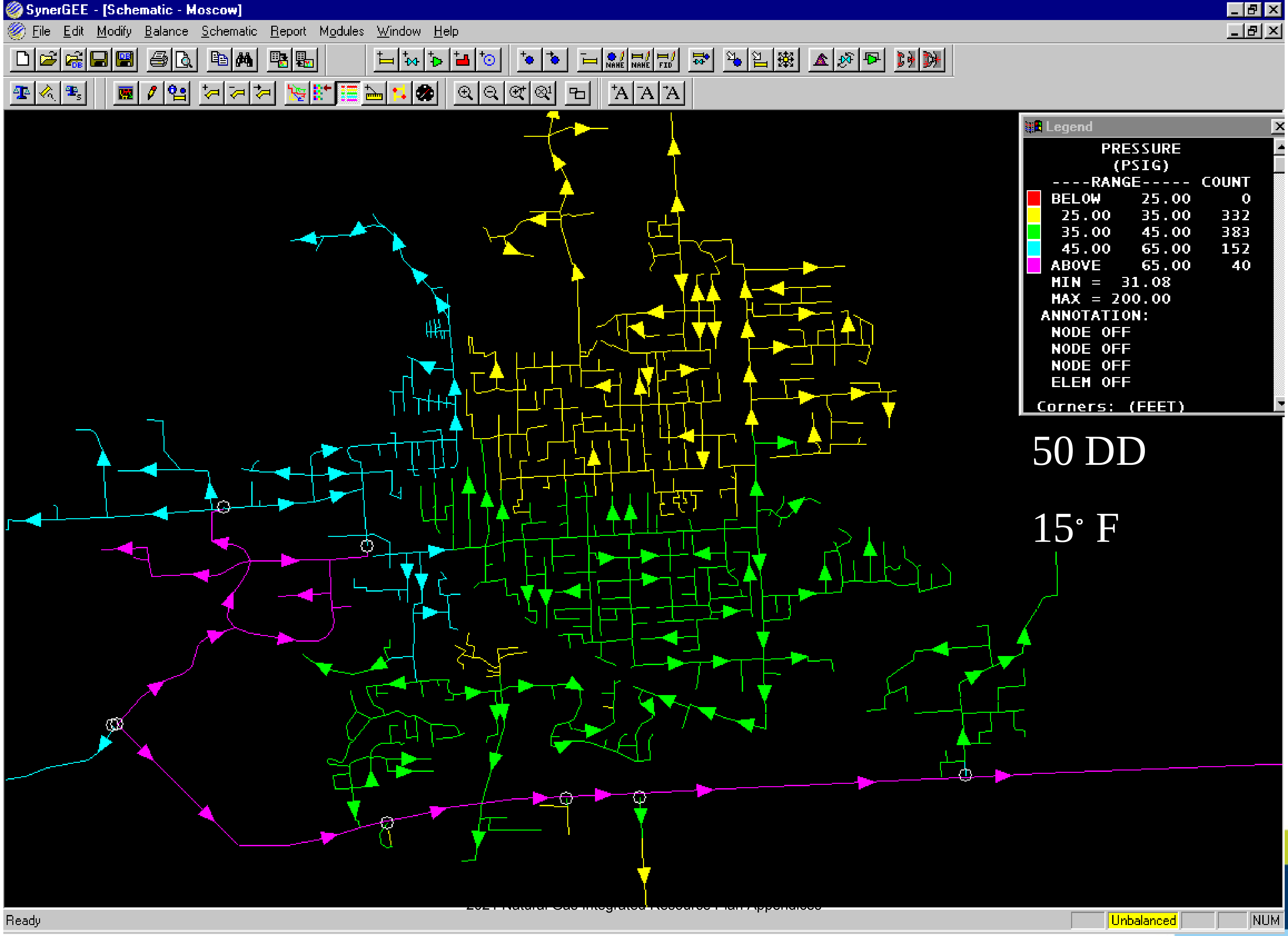
- Simulate recorded condition
- Electronic Pressure Recorders
  - Do calculated results match *field* data?
- Gate Station Telemetry
  - Do calculated results match *source* data?
- Possible Errors
  - Missing pipe
  - Source pressure changed
  - Industrial loads

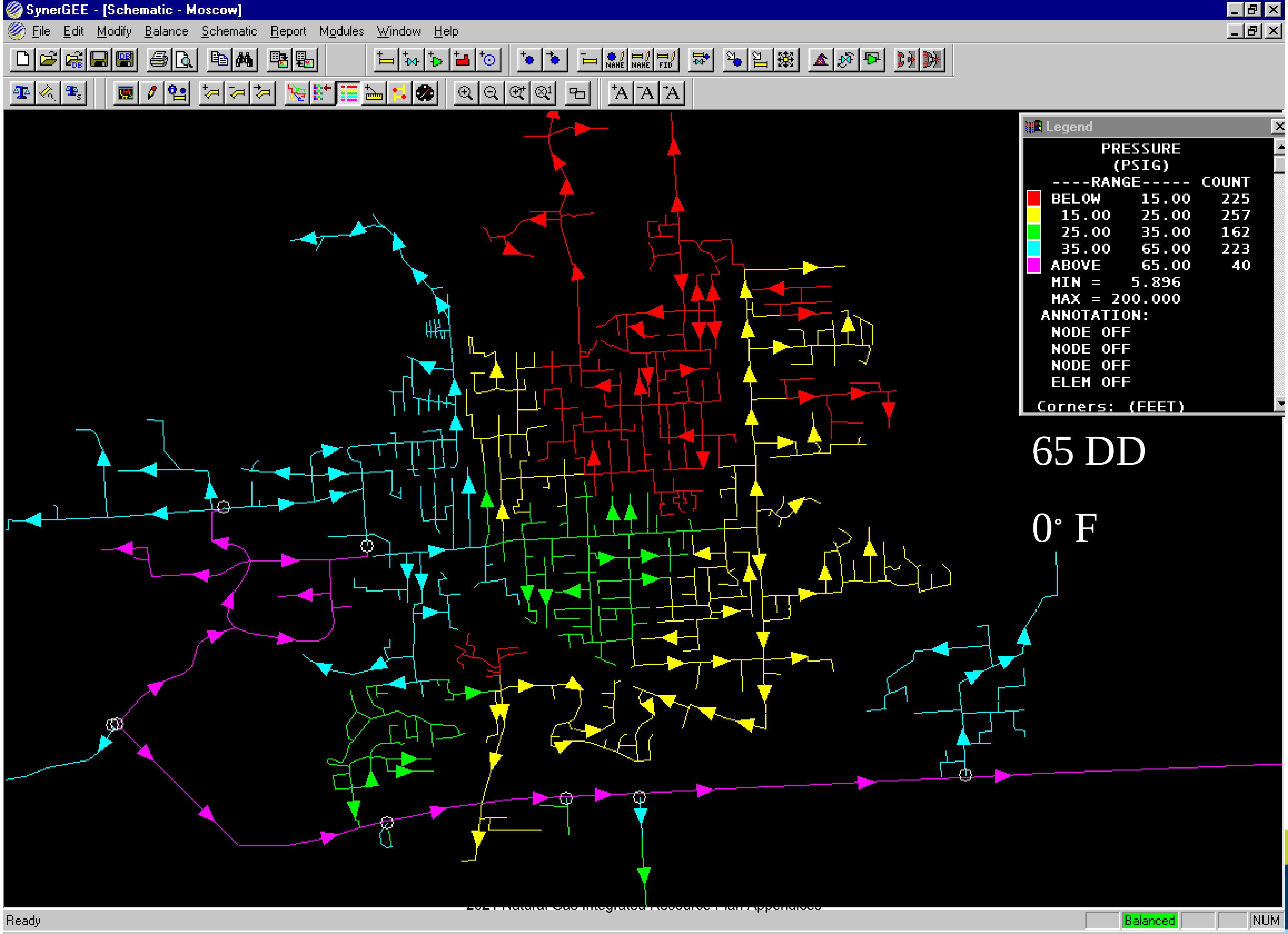
Planning Criteria

- Reliability during design HDD
  - Spokane **77 HDD** *(avg. daily temp. -12’ F)*
  - Medford **54 HDD** *(avg. daily temp. 11’ F)*
  - Klamath Falls **74 HDD** *(avg. daily temp. -9’ F)*
  - La Grande **76 HDD** *(avg. daily temp. -11’ F)*
  - Roseburg **51 HDD** *(avg. daily temp. 14’ F)*

- Maintain minimum of 15 psig in system at all times
  - 5 psig in lower MAOP areas

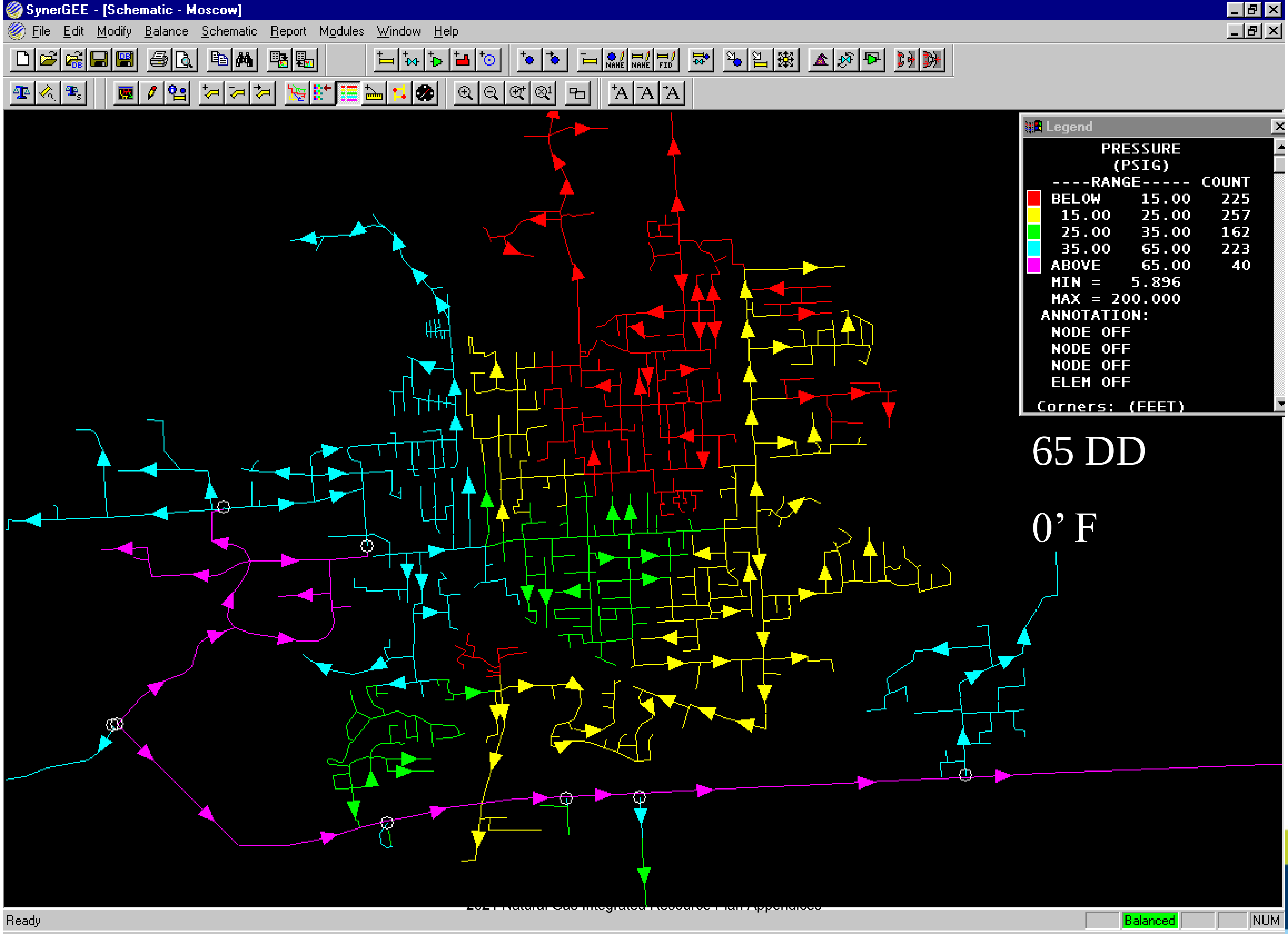

SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 6
35.00 45.00 336
45.00 65.00 525
ABOVE 65.00 40
MIN = 34.96
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
35 DD
30° F
Ready
Balanced
NUM

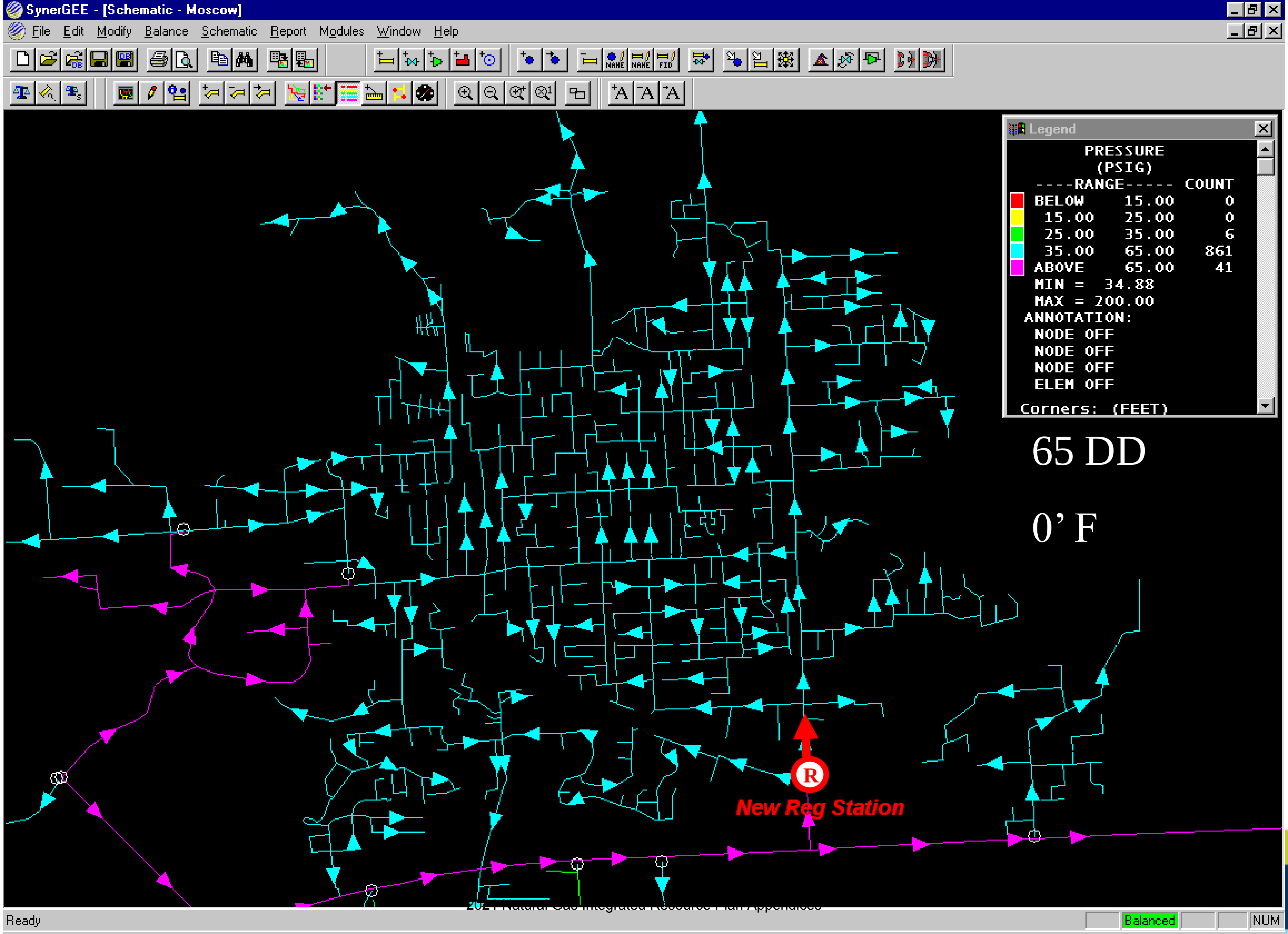

SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 25.00 0
25.00 35.00 332
35.00 45.00 383
45.00 65.00 152
ABOVE 65.00 40
MIN = 31.08
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
50 DD
15° F
Ready
Unbalanced
NUM

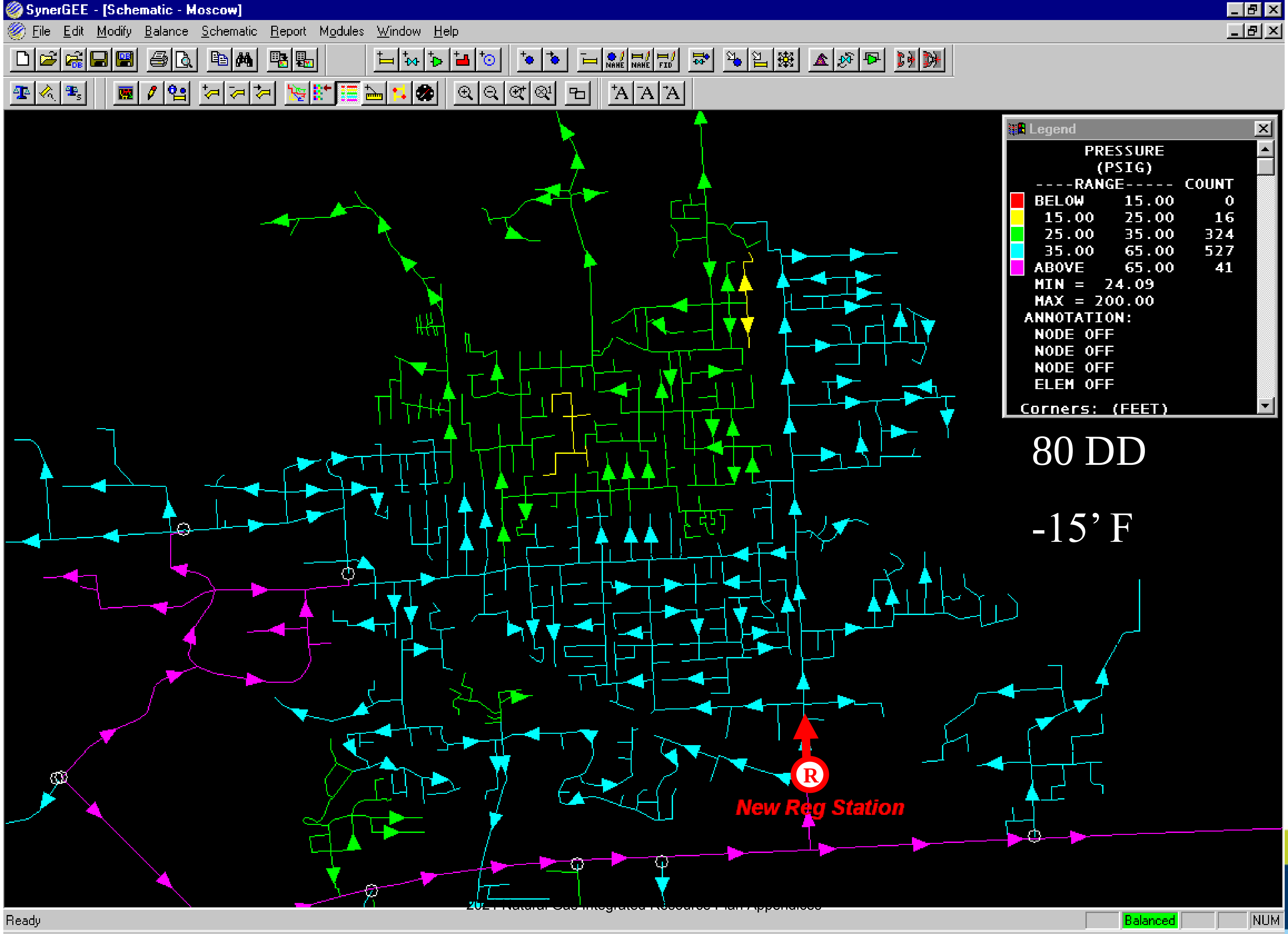

SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 225
15.00 25.00 257
25.00 35.00 162
35.00 65.00 223
ABOVE 65.00 40
MIN = 5.896
MAX = 200.000
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
65 DD
0° F
Ready
Balanced
NUM

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)


SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 225
15.00 25.00 257
25.00 35.00 162
35.00 65.00 223
ABOVE 65.00 40
MIN = 5.896
MAX = 200.000
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
65 DD
0’ F
Ready
Balanced
NUM


SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 0
15.00 25.00 0
25.00 35.00 6
35.00 65.00 861
ABOVE 65.00 41
MIN = 34.88
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
65 DD
0' F
R
New Reg Station
Ready
Balanced
NUM



SynerGEE - [Schematic - Moscow]
File Edit Modify Balance Schematic Report Modules Window Help
Legend
PRESSURE
(PSIG)
----RANGE----- COUNT
BELOW 15.00 0
15.00 25.00 16
25.00 35.00 324
35.00 65.00 527
ABOVE 65.00 41
MIN = 24.09
MAX = 200.00
ANNOTATION:
NODE OFF
NODE OFF
NODE OFF
ELEM OFF
Corners: (FEET)
80 DD
-15' F
R
New Reg Station
Ready
Balanced
NUM

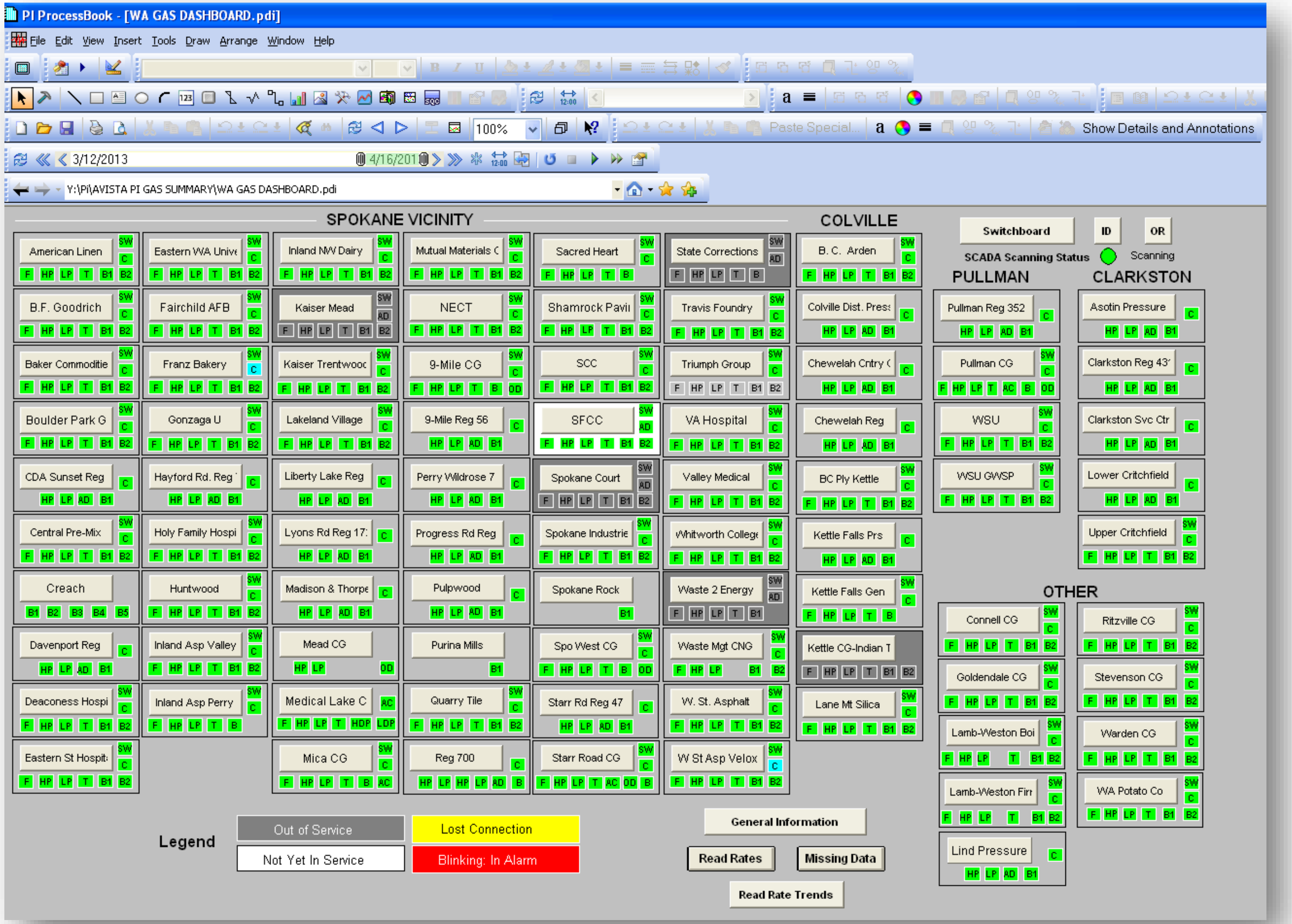
Long-term Planning Objectives

- Future Growth/Expansion
- Design Day Conditions
- Facilitate Customer Installation Targets

Monitoring Our System

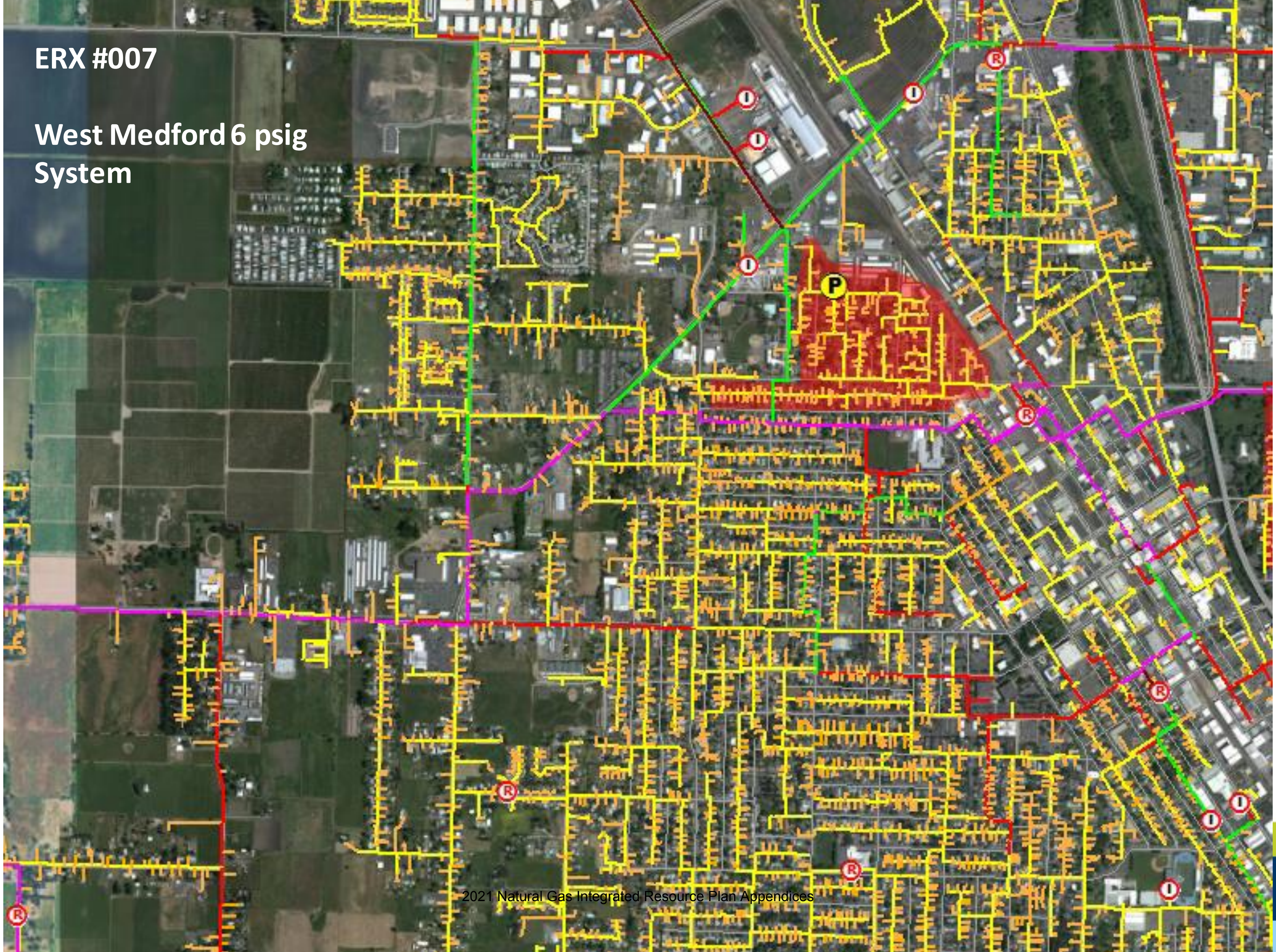
- Electronic Pressure Recorders
  - Daily Feedback
  - Real time if necessary
- Validates our Load Studies

Real-time Pressure & Flow Monitoring

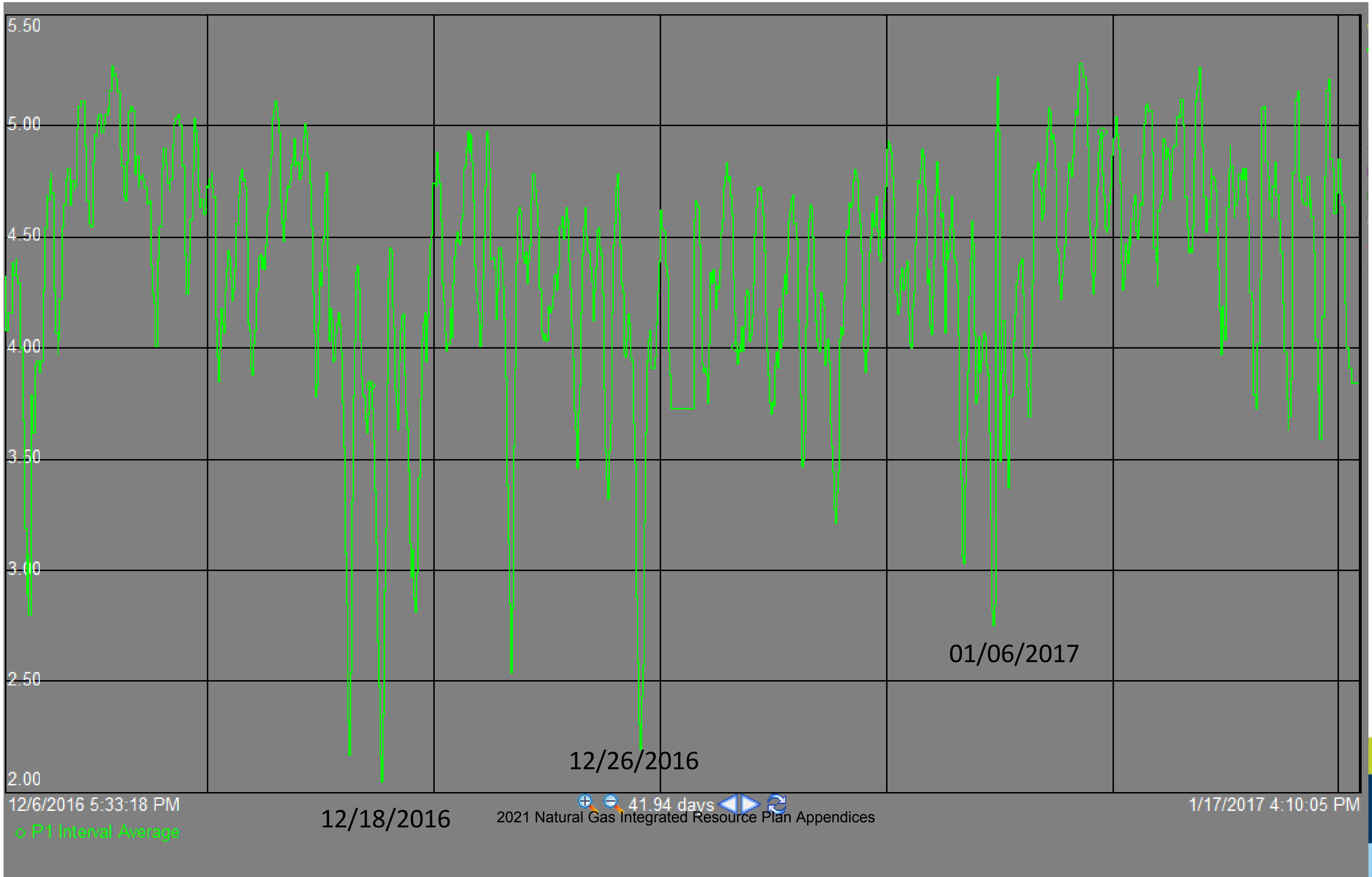


ERX #007

West Medford 6 psig System



ERX #007: West Medford 6 psig System, OR



2019-2020 Winter

AVISTA

Gas Load And Weather Forecast Report

Page: 1
Date: 01/08/20 01:00 PM
Database: NUCPRD
gs_fore_temp

Date: 01/08/2020

Area: LAGRANDE

	Date:	Hi	Lo	HDD	Load
SUN	01/05/20	39	29	30	3,827
MON	01/06/20	39	32	29	3,984
TUE	01/07/20	44	37	24	3,474
WED	01/08/20	41	30	30	3,636
THU	01/09/20	35	23	35	4,284
FRI	01/10/20	35	27	33	4,220
SAT	01/11/20	39	31	30	3,812
SUN	01/12/20	39	31	30	3,788
MON	01/13/20	33	26	34	4,241
TUE	01/14/20	27	15	43	5,177
			Average:		4,044

Area: KLAMATH FALLS

	Date:	Hi	Lo	HDD	Load
SUN	01/05/20	38	28	33	8,302
MON	01/06/20	45	20	35	7,822
TUE	01/07/20	47	21	29	7,345
WED	01/08/20	38	28	32	7,872
THU	01/09/20	36	21	37	8,027
FRI	01/10/20	39	24	31	7,783
SAT	01/11/20	38	28	32	7,650
SUN	01/12/20	38	30	31	7,617
MON	01/13/20	38	24	34	7,923
TUE	01/14/20	30	20	40	8,786
			Average:		7,913

Area: MEDFORD

	Date:	Hi	Lo	HDD	Load
SUN	01/05/20	47	34	25	27,581
MON	01/06/20	49	30	27	30,760
TUE	01/07/20	40	31	28	32,807
WED	01/08/20	45	38	25	30,458
THU	01/09/20	43	32	28	31,174
FRI	01/10/20	43	33	26	30,409
SAT	01/11/20	42	37	25	27,942
SUN	01/12/20	43	38	26	27,696
MON	01/13/20	40	33	28	31,906
TUE	01/14/20	37	30	31	34,882
			Average:		30,562

Area: ROSEBURG

	Date:	Hi	Lo	HDD	Load
SUN	01/05/20	49	41	20	7,334
MON	01/06/20	53	41	17	7,574
TUE	01/07/20	55	40	18	6,956
WED	01/08/20	48	41	21	7,363
THU	01/09/20	47	35	25	7,888
FRI	01/10/20	48	36	21	7,649
SAT	01/11/20	49	41	20	6,840
SUN	01/12/20	48	42	21	7,201
MON	01/13/20	46	37	23	7,942
TUE	01/14/20	46	35	26	8,553
			Average:		7,530

Area: SPOKANE

	Date:	Hi	Lo	HDD	Load
SUN	01/05/20	40	31	31	119,295
MON	01/06/20	44	33	24	108,349
TUE	01/07/20	45	36	24	99,618
WED	01/08/20	40	27	31	113,614
THU	01/09/20	33	26	36	130,326
FRI	01/10/20	34	27	33	127,052
SAT	01/11/20	35	31	32	120,468
SUN	01/12/20	32	23	38	132,989
MON	01/13/20	24	14	46	163,049
TUE	01/14/20	17	1	55	190,891
			Average:		130,565

Area: LEWISTON

	Date:	Hi	Lo	HDD	Load
SUN	01/05/20	46	34	24	15,796
MON	01/06/20	49	41	18	14,631
TUE	01/07/20	52	38	20	12,168
WED	01/08/20	47	36	24	14,115
THU	01/09/20	39	29	30	17,991
FRI	01/10/20	40	32	28	17,517
SAT	01/11/20	44	37	25	15,788
SUN	01/12/20	42	36	26	16,308
MON	01/13/20	38	31	30	18,342
TUE	01/14/20	31	18	40	22,165
			Average:		16,482

Area: OTHER

	Date:	Hi	Lo	HDD	Load
SUN	01/05/20	0	0	0	210
MON	01/06/20	0	0	0	207
TUE	01/07/20	0	0	0	207
			Average:		208

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

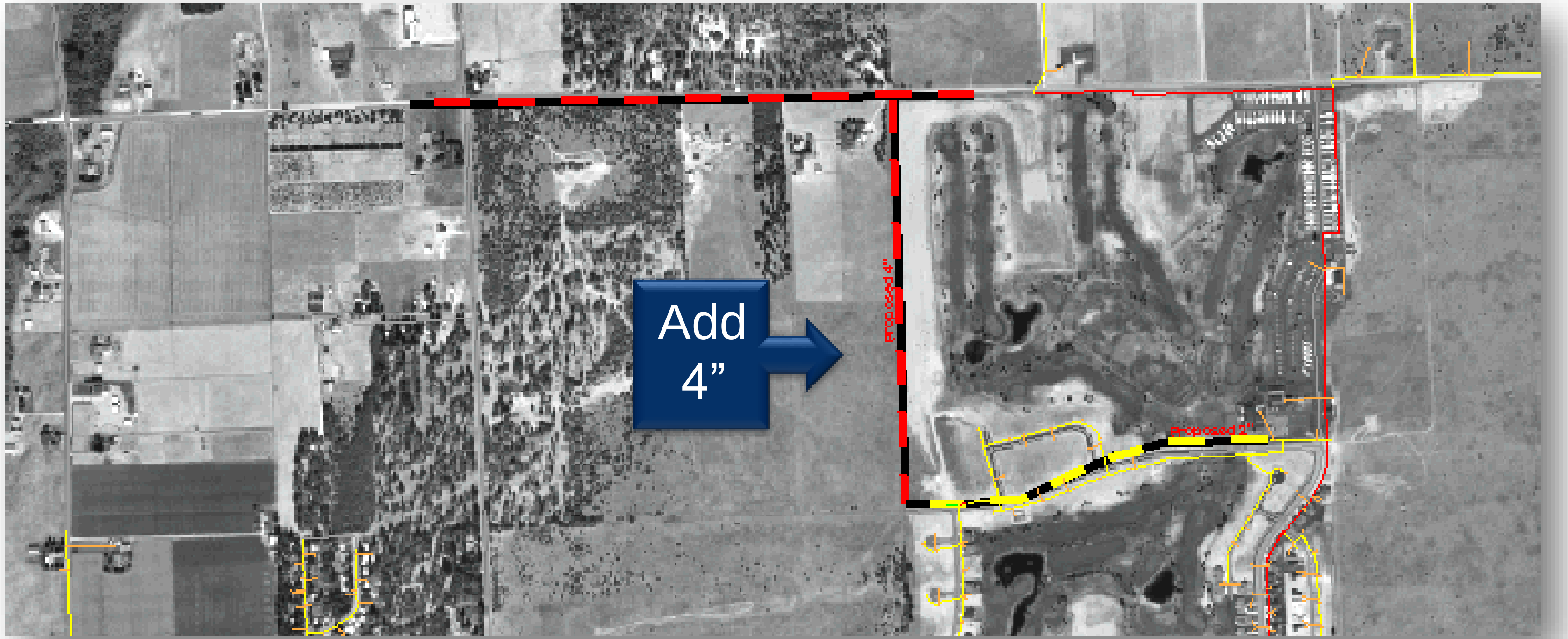
Area:	Spokane				
	Date	Hi	Lo	HDD	Load
SAT	12/7/2013	15	0	57	195,583
SUN	12/8/2013	15	-2	58	183,544
MON	12/9/2013	20	9	51	166,628
TUE	12/10/2013	25	12	46	156,433
WED	12/11/2013	29	15	43	145,441
THU	12/12/2013	31	20	39	134,506
FRI	12/13/2013	33	26	35	120,774
SAT	12/14/2013	35	27	34	114,257
SUN	12/15/2013	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

What I do when “things” look bad?

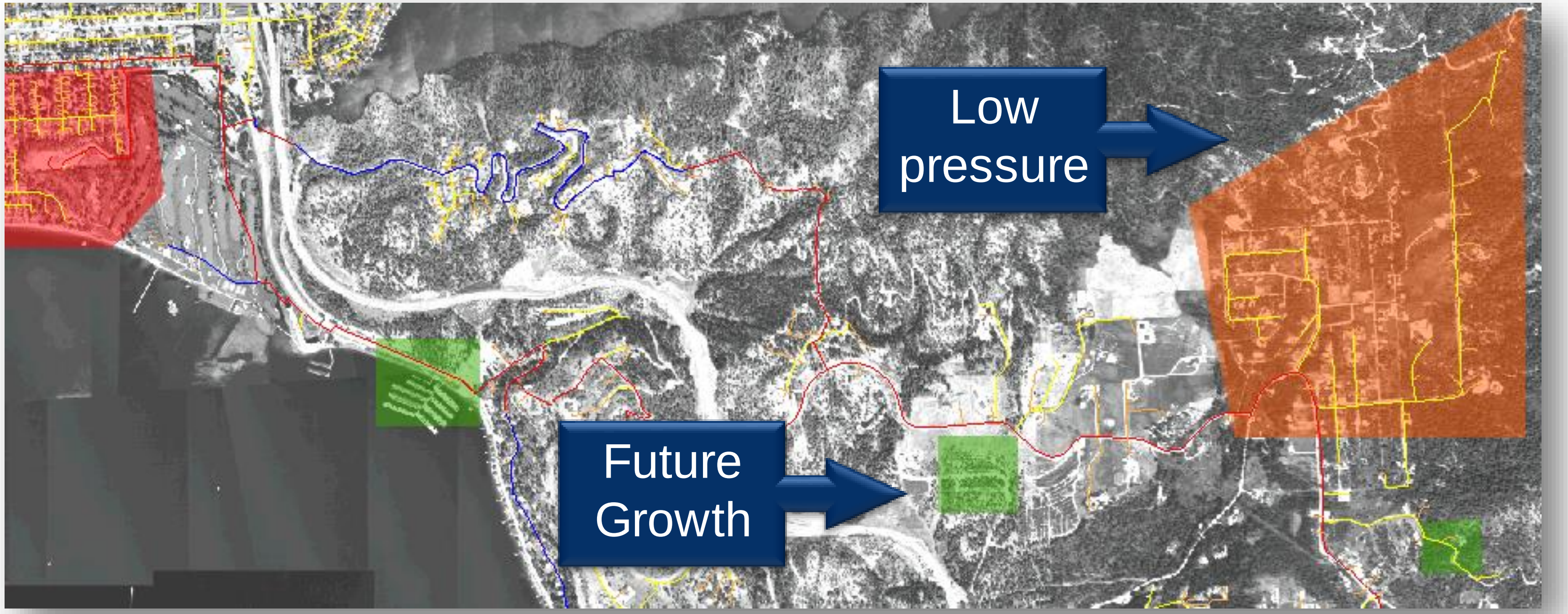
1) Notify service area manager
2) Show where and at what temperature we think we’ll have low pressure
3) Identify possible solutions like:
   - Curtailing interruptible customers
   - Ask schools & businesses to voluntarily lower thermostats
   - Bring out CNG trailers
4) Continue to monitor forecast to see if temperatures improve or get worse
5) Share plan with Gas Controllers
6) *Pray for warmer weather…*

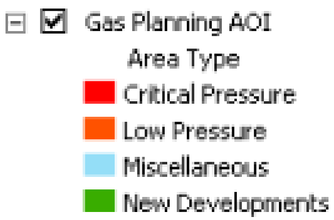
Communicating Solutions



Gas Planning Proposals
SIZENUMBER
2"
4"
6"
>6"

Gas Planning AOI

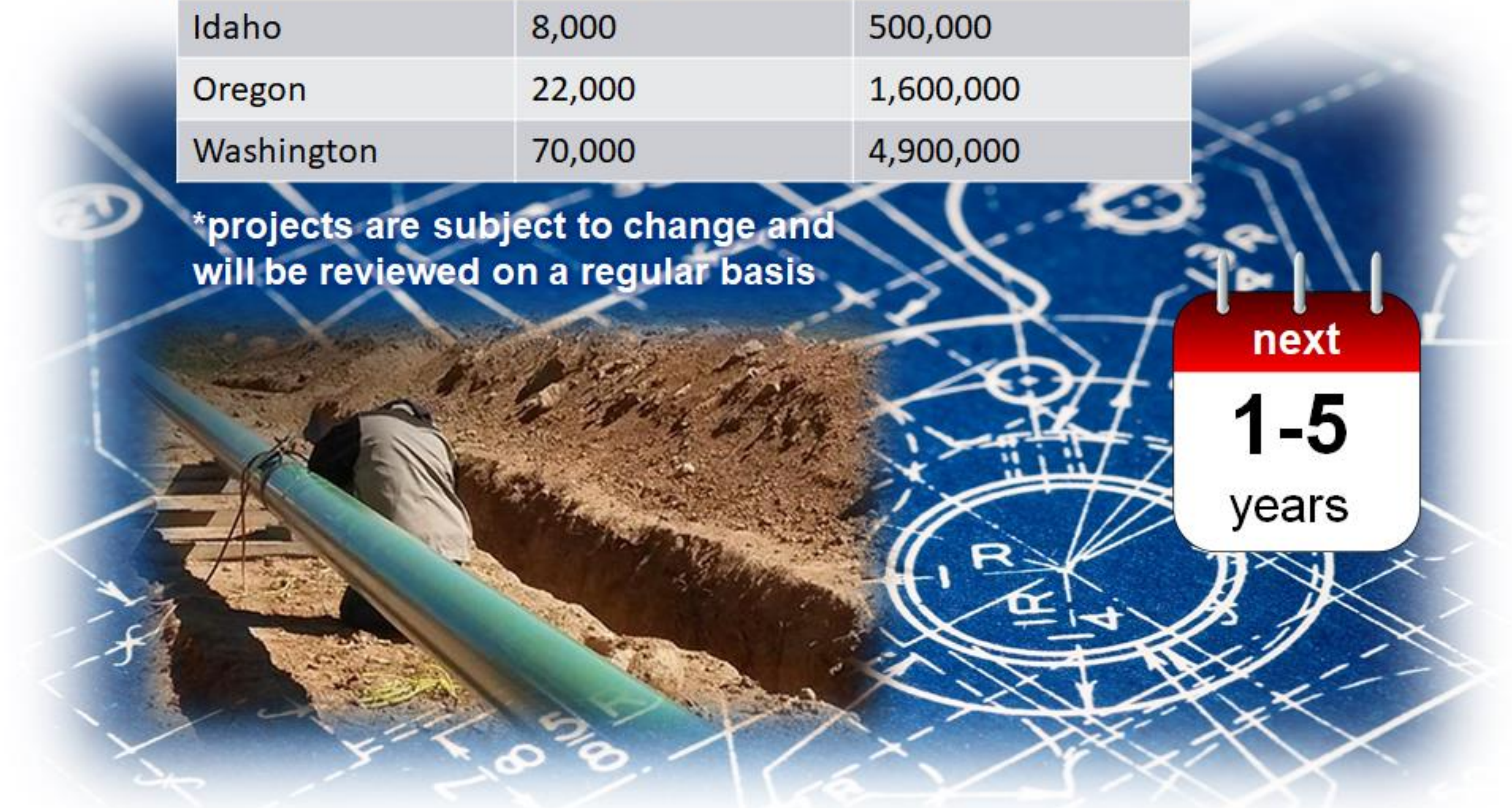




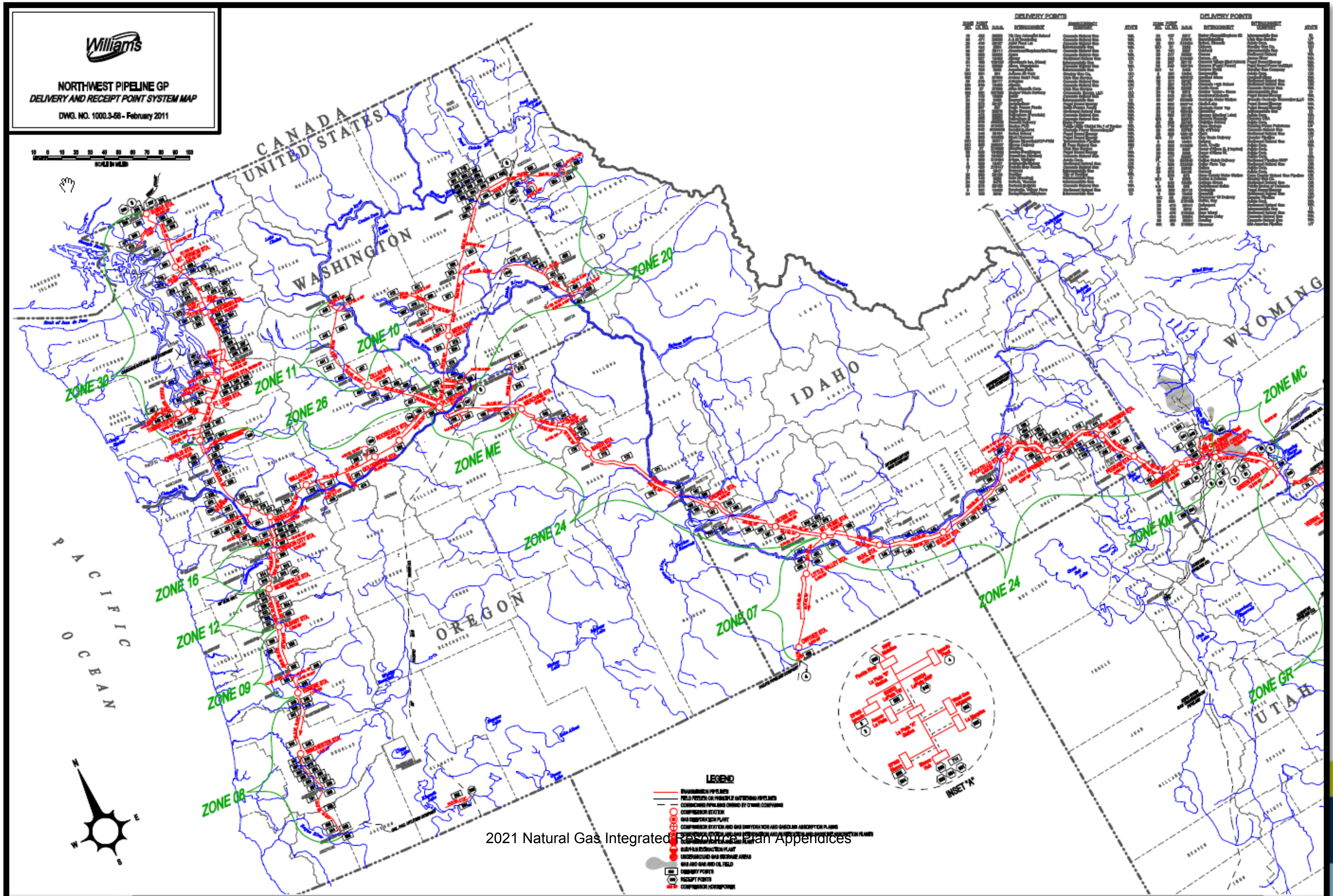
Solutions: long-term reinforcements

State	Feet of pipe*	Estimated Cost $*
Idaho	8,000	500,000
Oregon	22,000	1,600,000
Washington	70,000	4,900,000

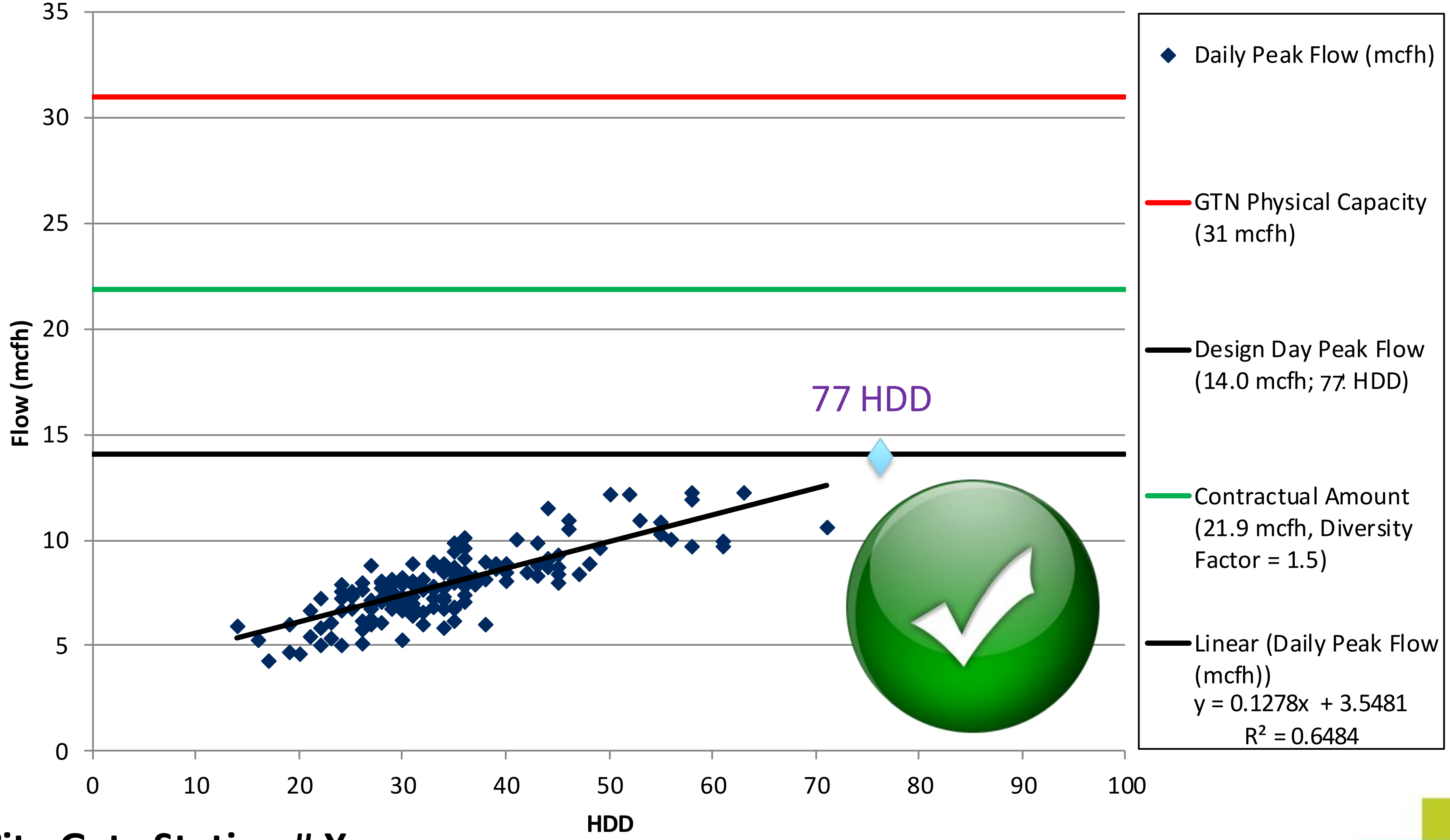
*projects are subject to change and will be reviewed on a regular basis



Gate Station Capacity Review

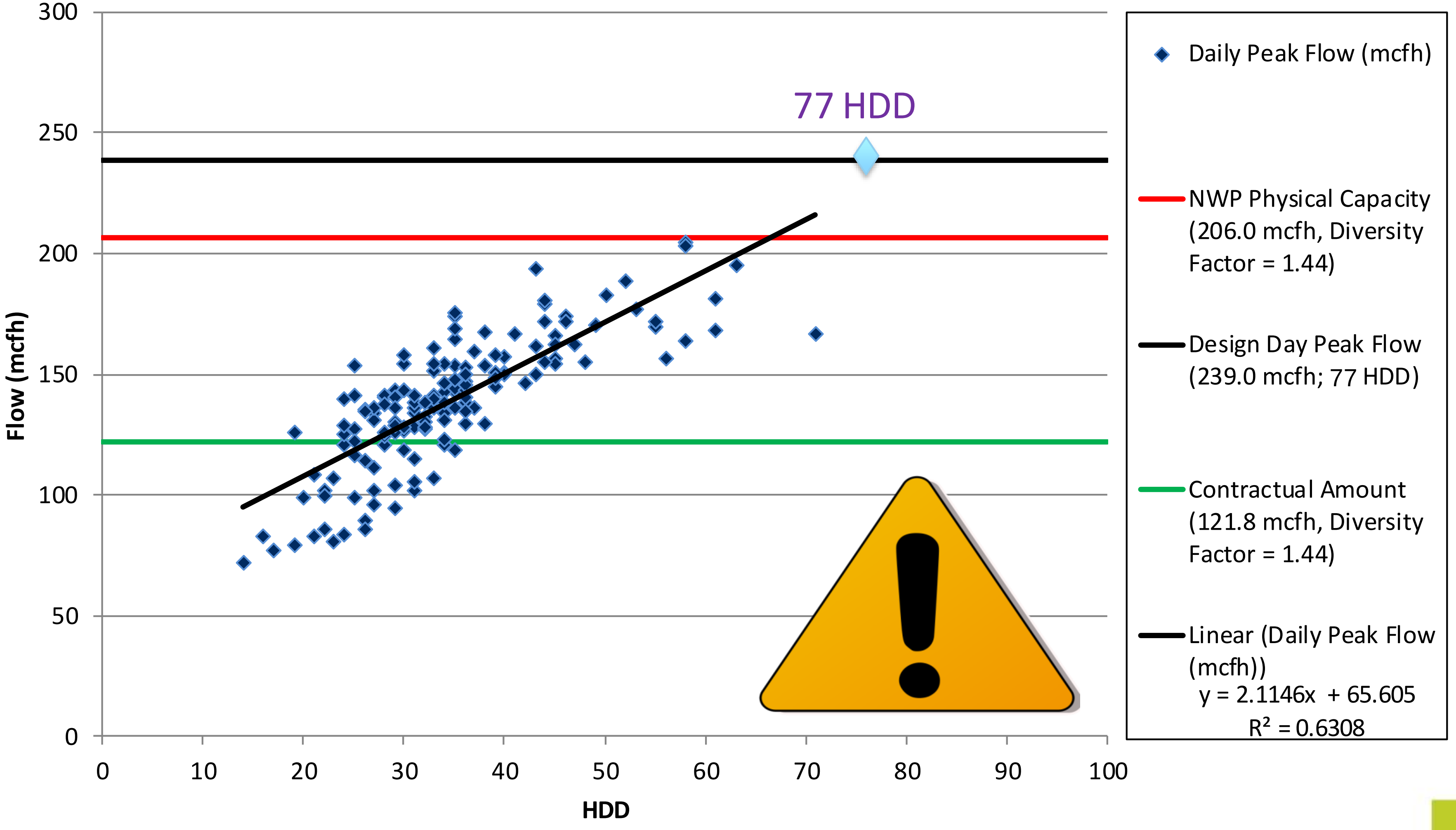


Gate Station Capacity Review (example)



City Gate Station # X

Gate Station Capacity Review (example)



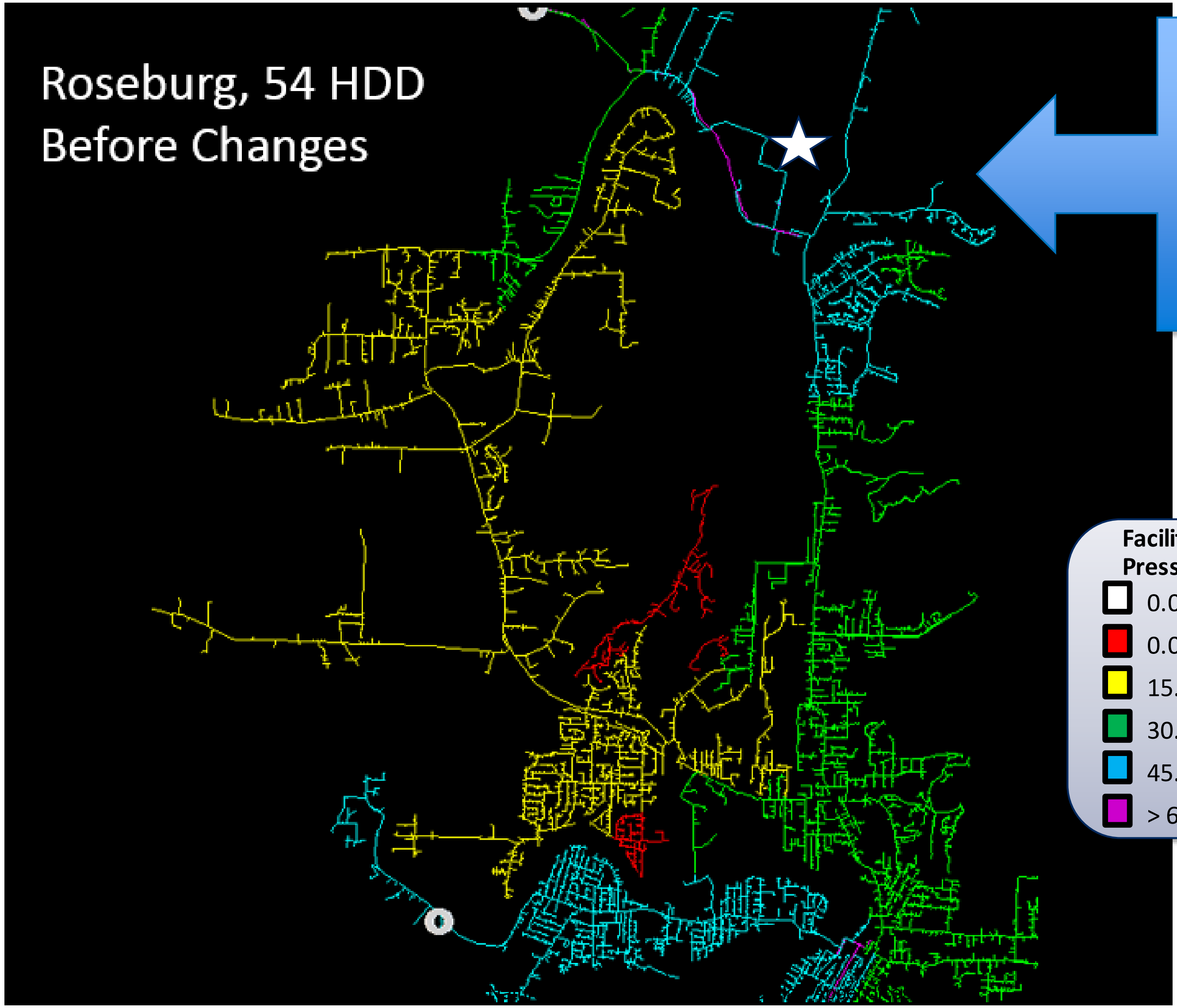
City Gate Station # Y

Recent Projects and Examples

New Agri-Industrial Customer Service Request

Roseburg, OR

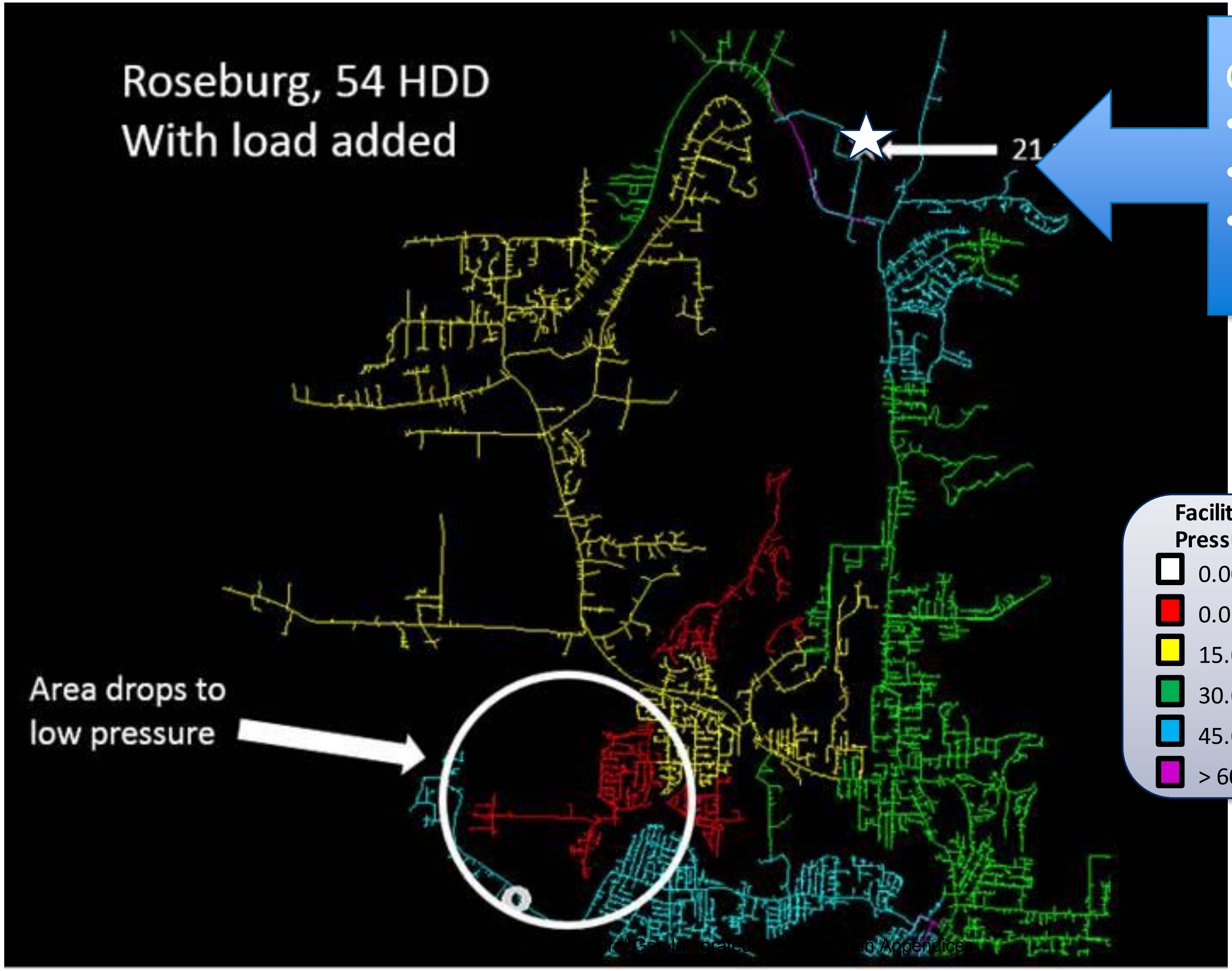
Agri-Industrial Customer Service Request



Conditions:
- 21 Mcfh
- 15 psig
- year-round
  - 51 HDD

Facilities Color By: Pressure (psig)
- 0.00
- 0.01 – 15.00
- 15.01 – 30.00
- 30.01 – 45.00
- 45.01 – 60.00
- > 60.01

Agri-Industrial Customer Service Request



Conditions:

- ~~21 Mcfh~~ 18 Mcfh
- 15 psig
- year-round
  - ~~51 HDD~~ 47 HDD

Facilities Color By:
Pressure (psig)

- 0.00
- 0.01 – 15.00
- 15.01 – 30.00
- 30.01 – 45.00
- 45.01 – 60.00
- > 60.01

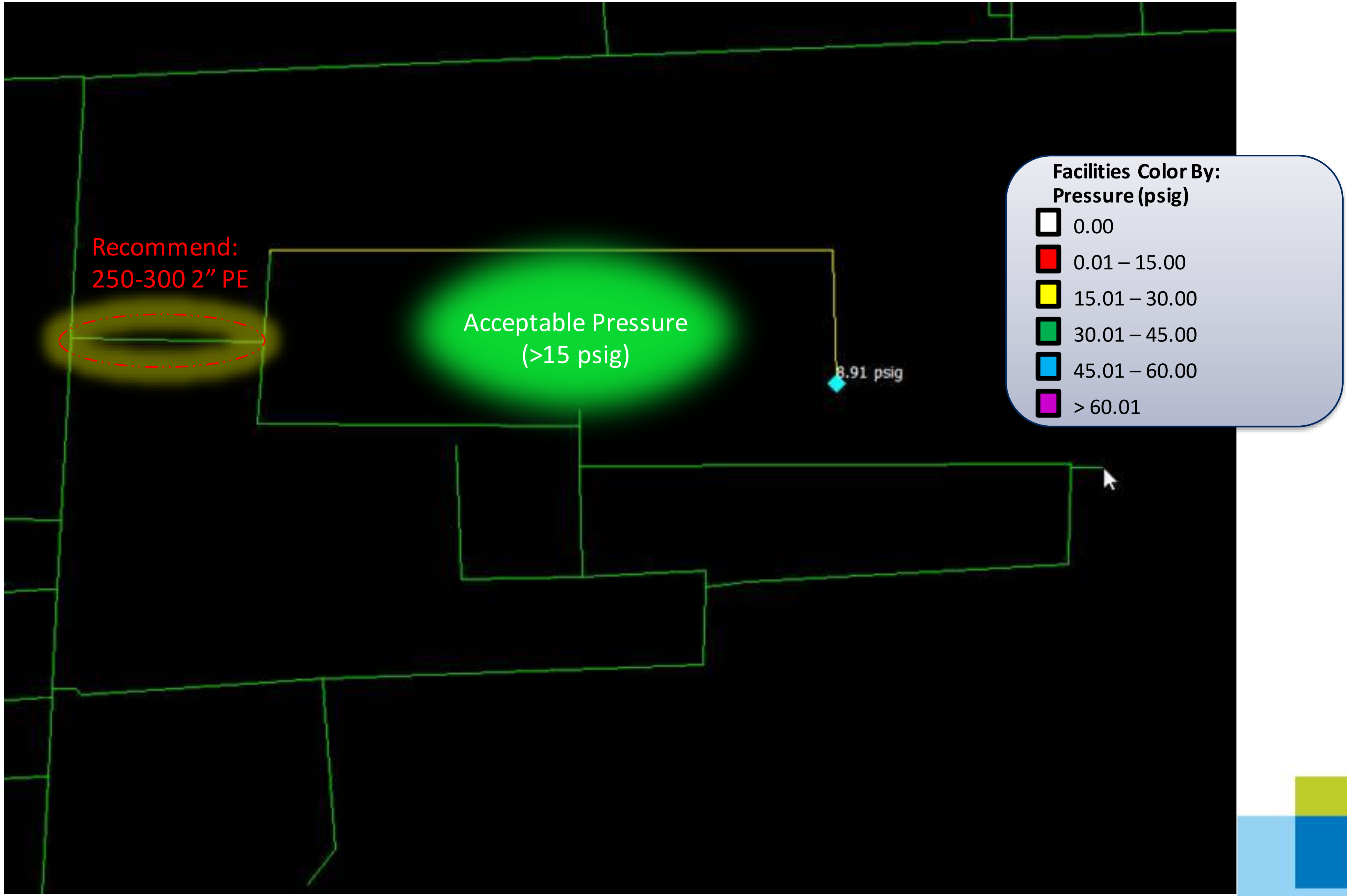
Residential Development Service Request

Deer Park, WA

Residential Development Study

Residential Development Study

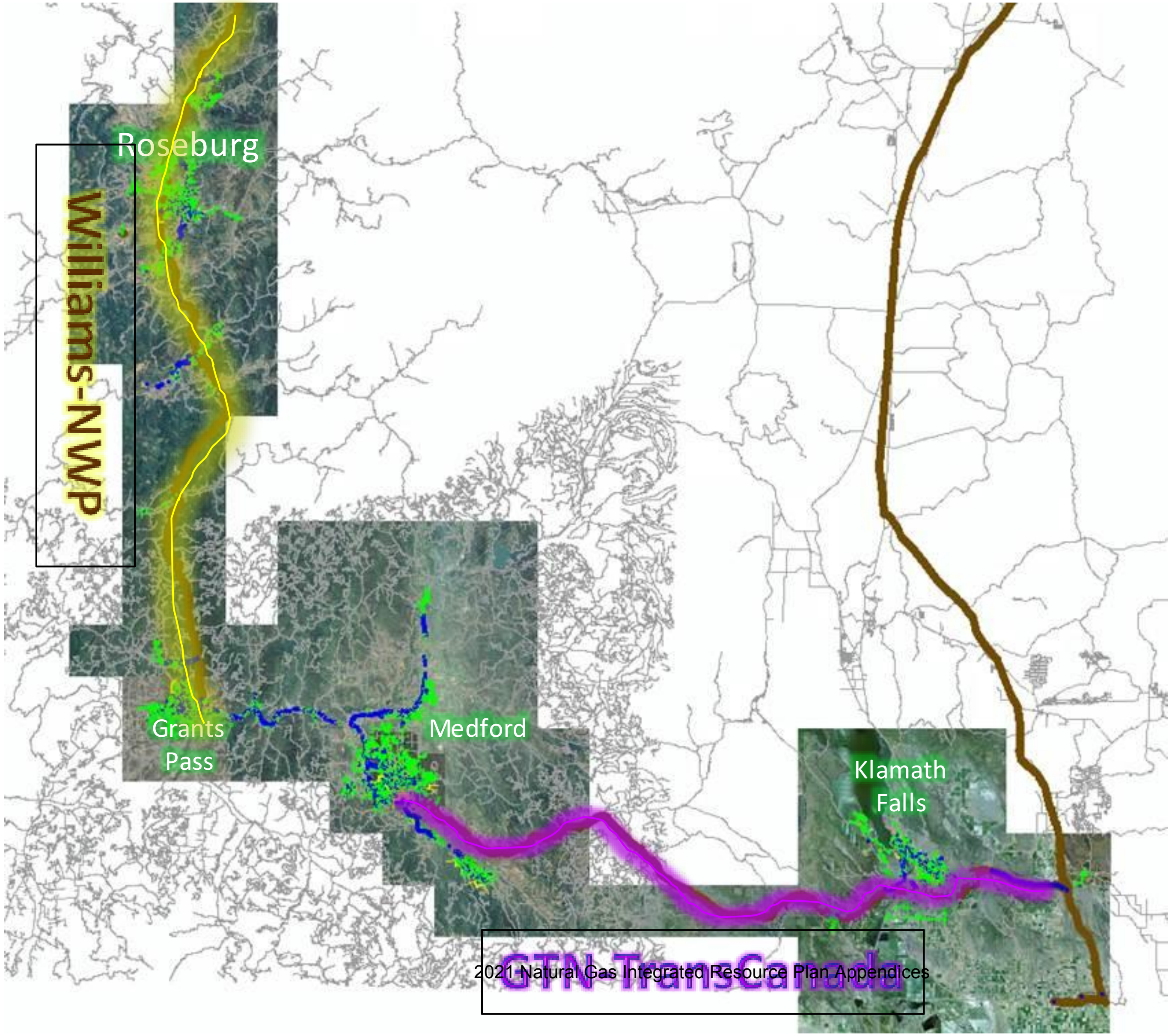
Residential Development Study



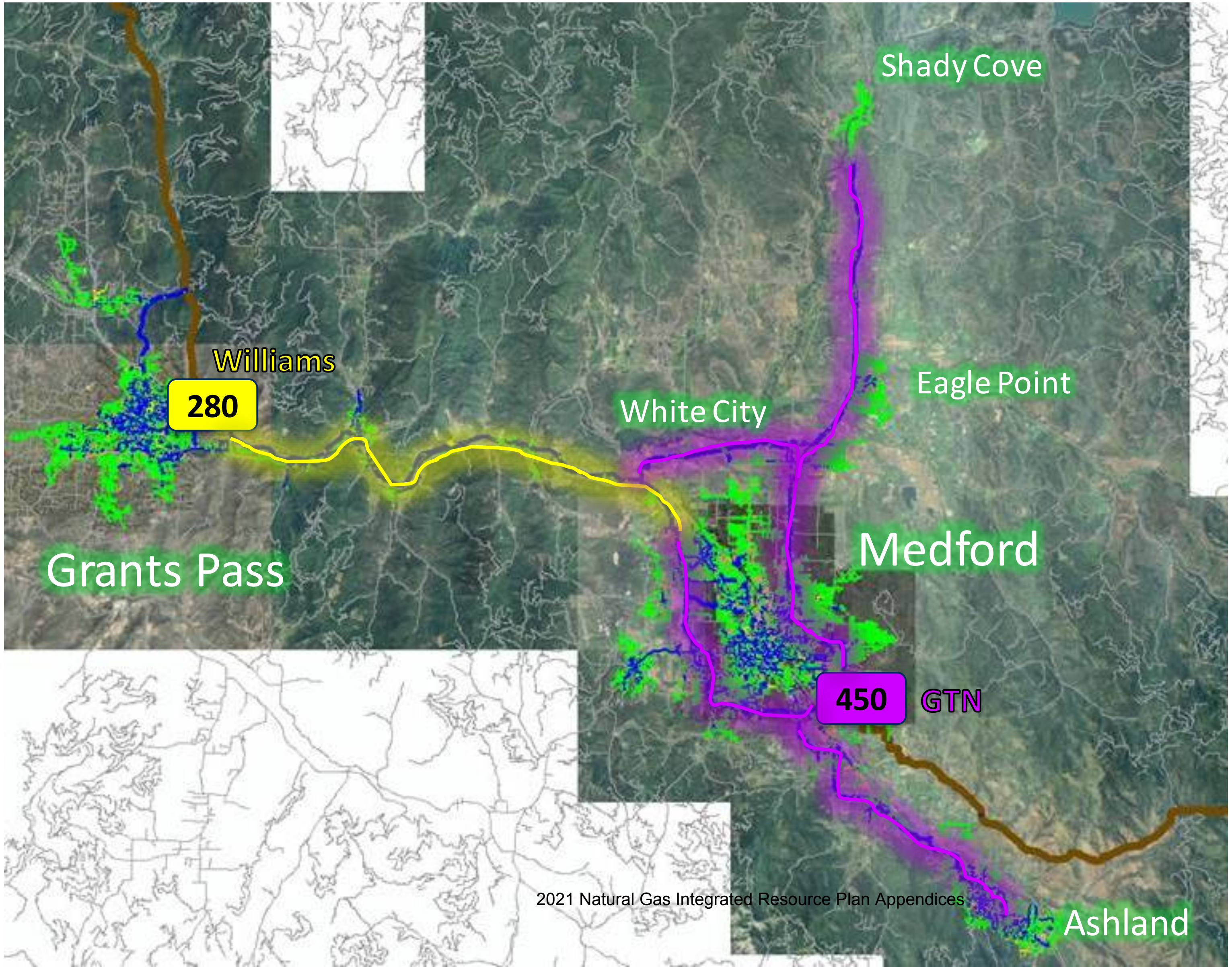
Enbridge Pipeline Rupture Effect on distribution

Medford, OR

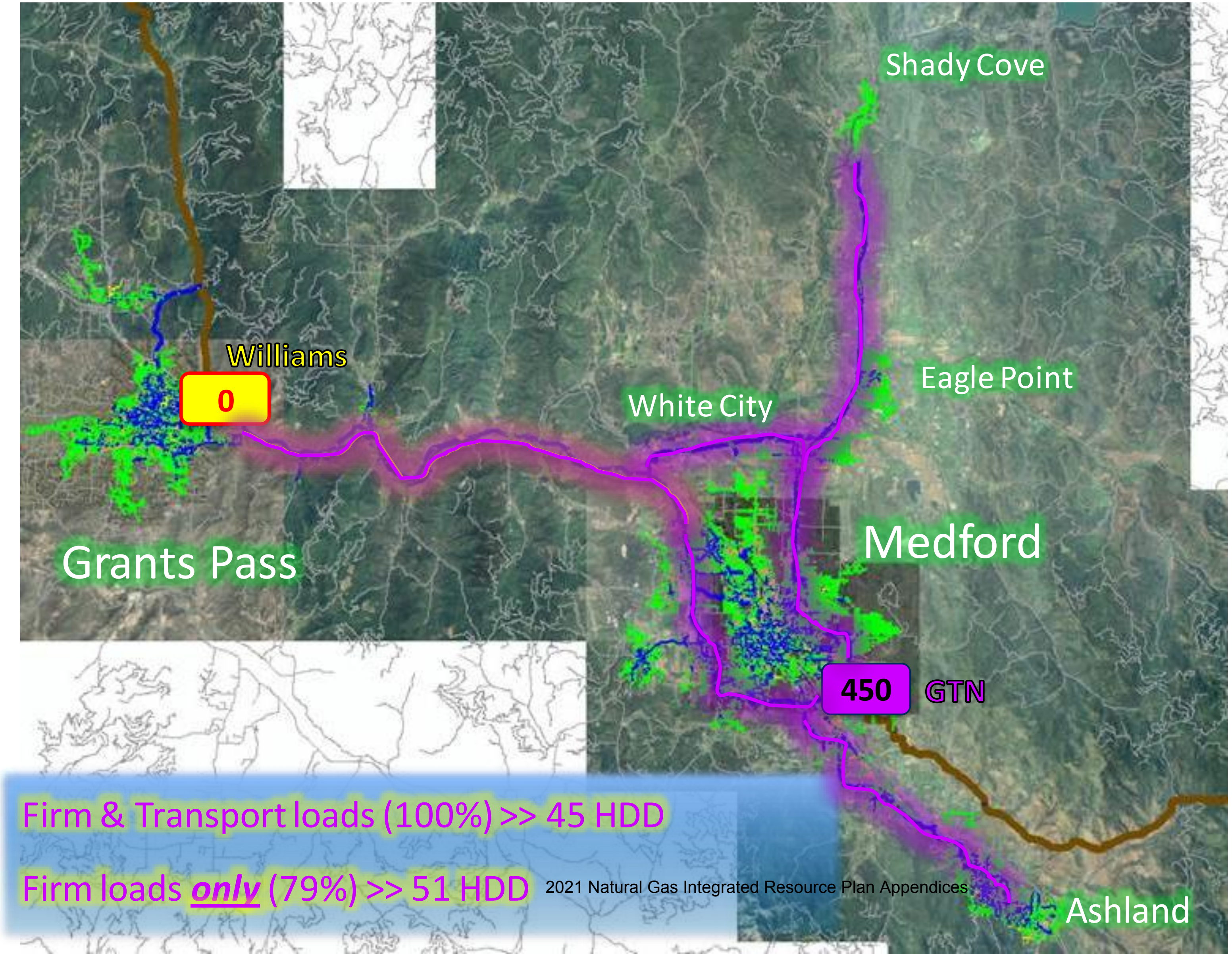
Enbridge Pipeline Rupture effect



Enbridge Pipeline Rupture effect



Enbridge Pipeline Rupture effect



Questions and Discussion

Mission

Using technology to plan and design a safe, reliable, and economical distribution system

Unserved Demand and Supply Side Resource Options

Tom Pardee
Planning Manager, Natural Gas Supply

When unserved demand does show up……

There are a few questions we need to ask:

1. Why is the demand unserved?
2. What is the magnitude of the short? (i.e Are we 1 Dth or 1000 Dth's short?)
3. What are my options to meet it?

When current resources don’t meet demand what could we consider?

- Transport capacity release recalls
- “Firm” backhauls
- Contract for existing available transportation
- Expansions of current pipelines
- Peaking arrangements with other utilities (swaps/mutual assistance agreements) or marketers
- In-service territory storage
- Satellite/Micro LNG (storage inside service territory)
- Large scale LNG with corresponding pipeline build into our service territory
- Structured products/exchange agreements delivered to city gates
- Biogas (assume it’s inside Avista’s distribution)
- Hydrogen blend (assume it’s inside Avista’s distribution)
- Avista distribution system enhancements
- Demand side management

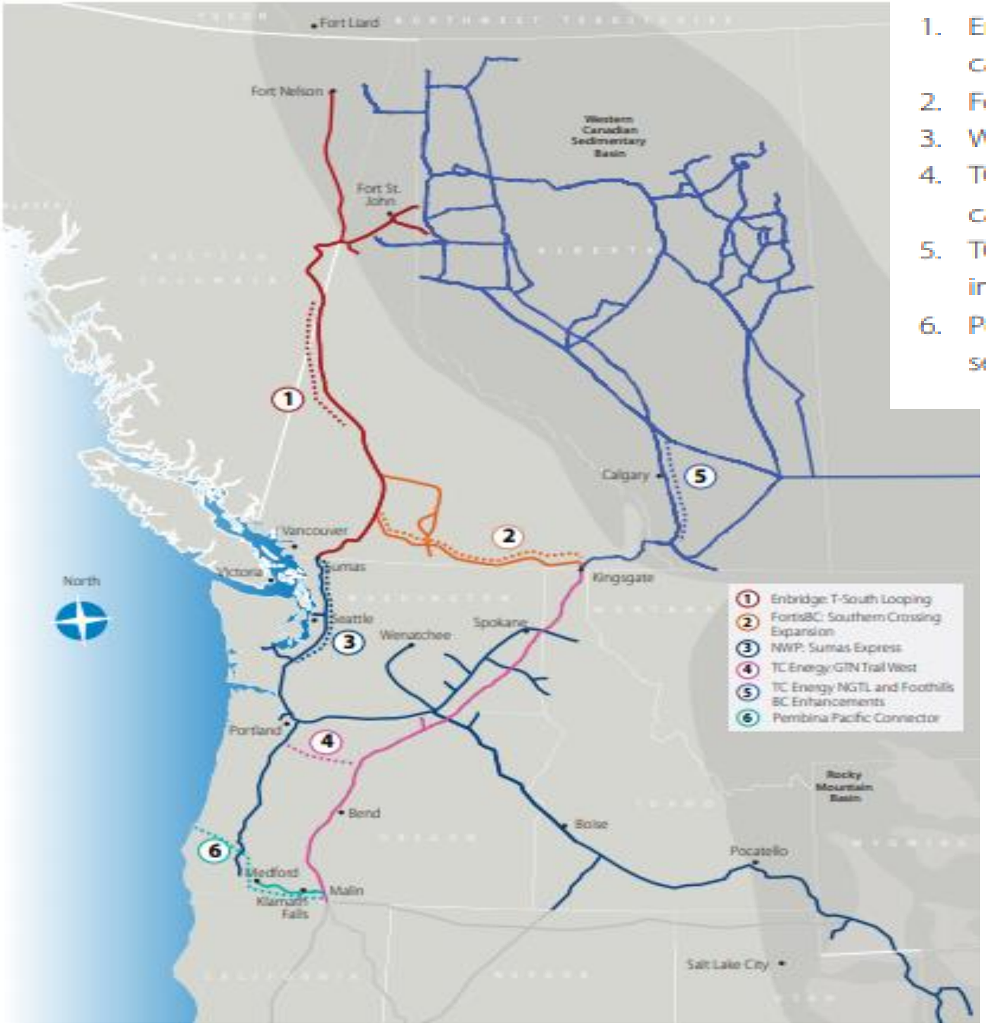
New Resource Risk Considerations

- Does is get supply to the gate?
- Is it reliable/firm?
- Does it have a long lead time?
- How much does it cost?
  - New build vs. depreciated cost
  - The rate pancake
- Is it a base load resource or peaking?
- How many dekatherms do I need?
- What is the "shape" of resource?
- Is it tried and true technology, new technology, or yet to be discovered?
- Who else will be competing for the resource?

Potential New Supply Resources Considerations

- Availability
  - By Region – which region(s) can the resource be utilized?
  - Lead time considerations – when will it be available?
- Type of Resource
  - Peak vs. Base load
  - Firm or Non-Firm
  - “Lumpiness”
- Usefulness
  - Does it get the gas where we need it to be?
  - Last mile issues
- Cost

Regional Infrastructure – Potential Projects



1. Enbridge T-South expansion: addition of 190 million cubic feet per day (MMcf/d) of firm capacity.
2. FortisBC Southern Crossing expansion: addition of 300-400 MMcf/d of bidirectional capacity.
3. Williams Northwest Pipeline (NWP) Sumas Express: still under assessment.
4. TC Energy Gas Transmission Northwest (GTN) Trail West/N-Max: addition of 500 MMcf/d capacity, expandable to 1,000 MMcf/d.
5. TC Energy other system enhancements: two projects to add a combined 525 MMcf/d of incremental firm transportation to the Alberta/BC export delivery point.
6. Pembina Pacific Connector Gas Pipeline (PCGP) Project: Addition of 1,000 MMcf/d capacity to serve proposed Coos Bay LNG export facility.

Supply Resources - Modeled

Additional Resource	Size	Cost/Rates			Availability	Notes
Unsubscribed GTN Capacity	Up to 50,000 Dth	GTN Rate			Now	Currently available unsubscribed capacity from Kingsgate to Spokane
Medford Lateral Exp	50,000 Dth / Day	$35M capital + GTN Rate			2022	Additional compression to facilitate more gas to flow from mainline GTN to Medford
Hydrogen	166 Dth / Day	WA	ID	OR	Varies	Cost estimates obtained from a consultant; levelized cost includes revenue requirements, expected carbon adder and assumed retail power rate
		$48 / Dth	$40 / Dth	$46 / Dth		
Renewable Natural Gas – Distributed Landfill	635 Dth / Day	WA	ID	OR	Varies	Costs estimates obtained from a consultant for each specific type of RNG; levelized costs include revenue requirements, distribution costs, and projected carbon intensity adder/(savings). This cost also includes any incentives from bills such as Washington House Bill 2580 or Oregon Senate Bill 334
		$13 / Dth	$13 / Dth	$13 / Dth		
Renewable Natural Gas – Centralized Landfill	1,814 Dth / Day	WA	ID	OR	Varies	
		$11 / Dth	$11 / Dth	$12 / Dth		
Renewable Natural Gas – Dairy	635 Dth / Day	WA	ID	OR	Varies	
		$34 / Dth	$39 / Dth	$33 / Dth		
Renewable Natural Gas – Waste Water	513 Dth / Day	WA	ID	OR	Varies	
		$19 / Dth	$18 / Dth	$19 / Dth		
Renewable Natural Gas – Food Waste to (RNG)	298 Dth / Day	WA	ID	OR	Varies	
		$38 / Dth	$39 / Dth	$38 / Dth		
Plymouth LNG	241,700 Dth w/70,500 Dth deliverability	NWP Rate			Now	Provides for peaking services and alleviates the need for costly pipeline expansions Pair with excess pipeline MDDO's to create firm transport

Future Supply Resources – Not Modeled

Other Resources to Consider

Additional Resource	Size	Cost/Rates	Availability	Notes
Co. Owned LNG	600,000 Dth w/ 150,000 of deliverability	$75 Million plus $2 Million annual O&M	2024	On site, in service territory liquefaction and vaporization facility
Various pipelines – Pacific Connector, Trails West, NWP Expansion, GTN Expansion, etc.	Varies	Precedent Agreement Rates	2022	Requires additional mainline capacity on NWPL or GTN to get to service territory
Large Scale LNG	Varies	Commodity less Fuel	2024	Speculative, needs pipeline transport
In Ground Storage	Varies	Varies	Varies	Requires additional mainline transport to get to service territory

Carbon Costs

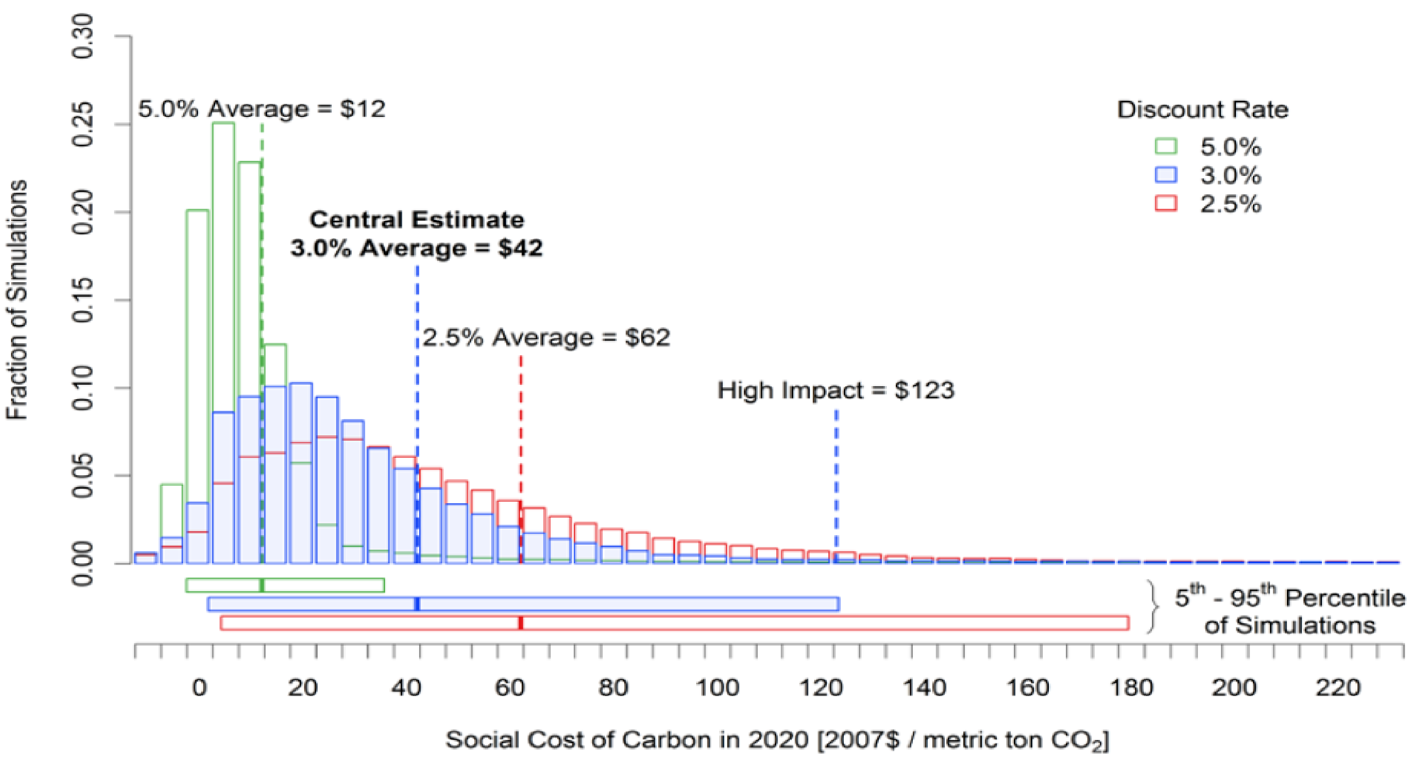
Tom Pardee
Planning Manager, Natural Gas Supply

Cost of Carbon and Sendout

- Monthly costs are loaded into SENDOUT
- These costs will differ based on the requirements or an expected program type by state
- These costs are input at the transportation level in order to correctly account for the cost of carbon in each area regardless of supply basin

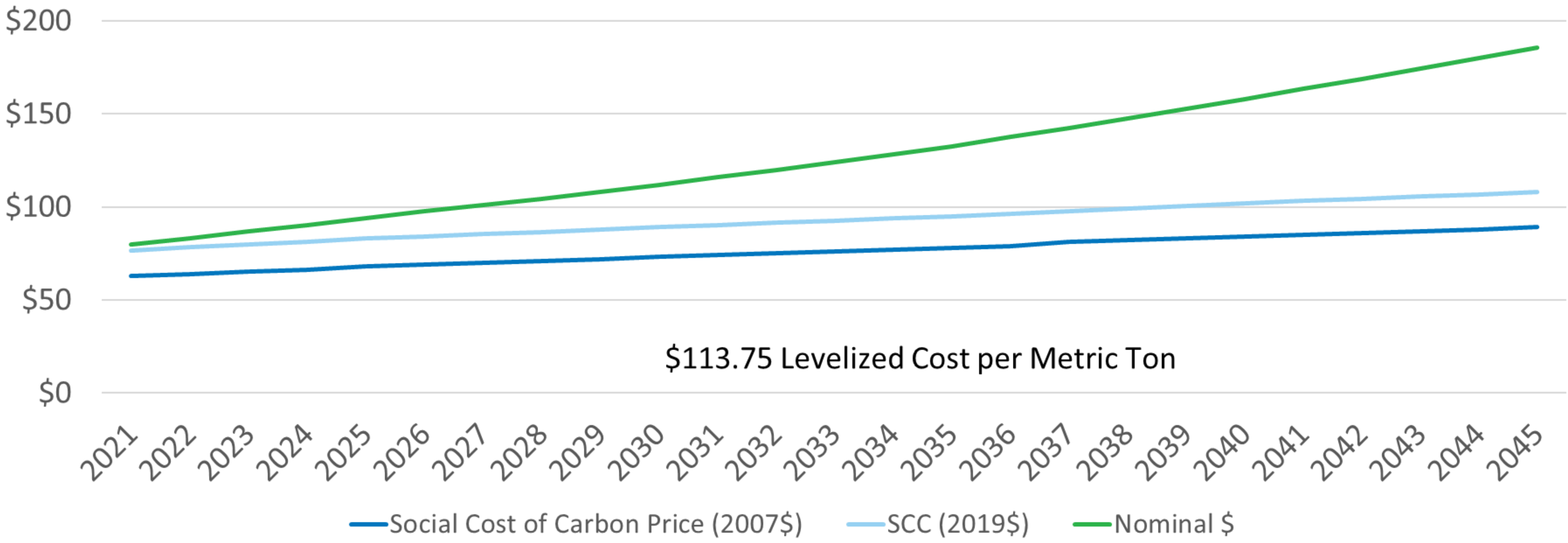
Social Cost of Carbon

Figure ES-1: Frequency Distribution of SC-CO_2 Estimates for 2020[3]



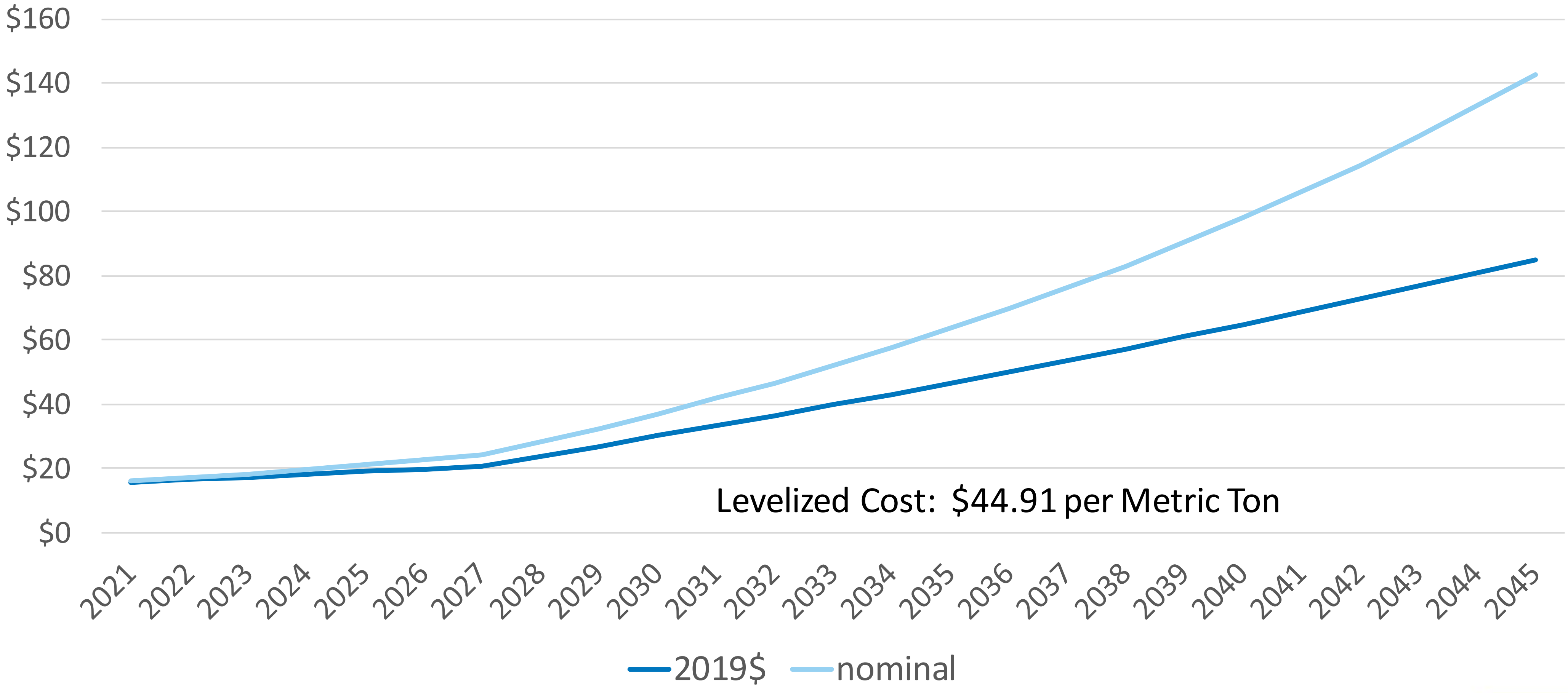
- Social cost of carbon dioxide in 2007 dollars using the 2.5% discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016.

Washington – Carbon adder



- Social cost of carbon dioxide in 2007 dollars using the 2.5% discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016.
- Adjust to 2019$ using Bureau of Economics GDP
- Adjust to Nominal $ using 2.11% annual inflation rate

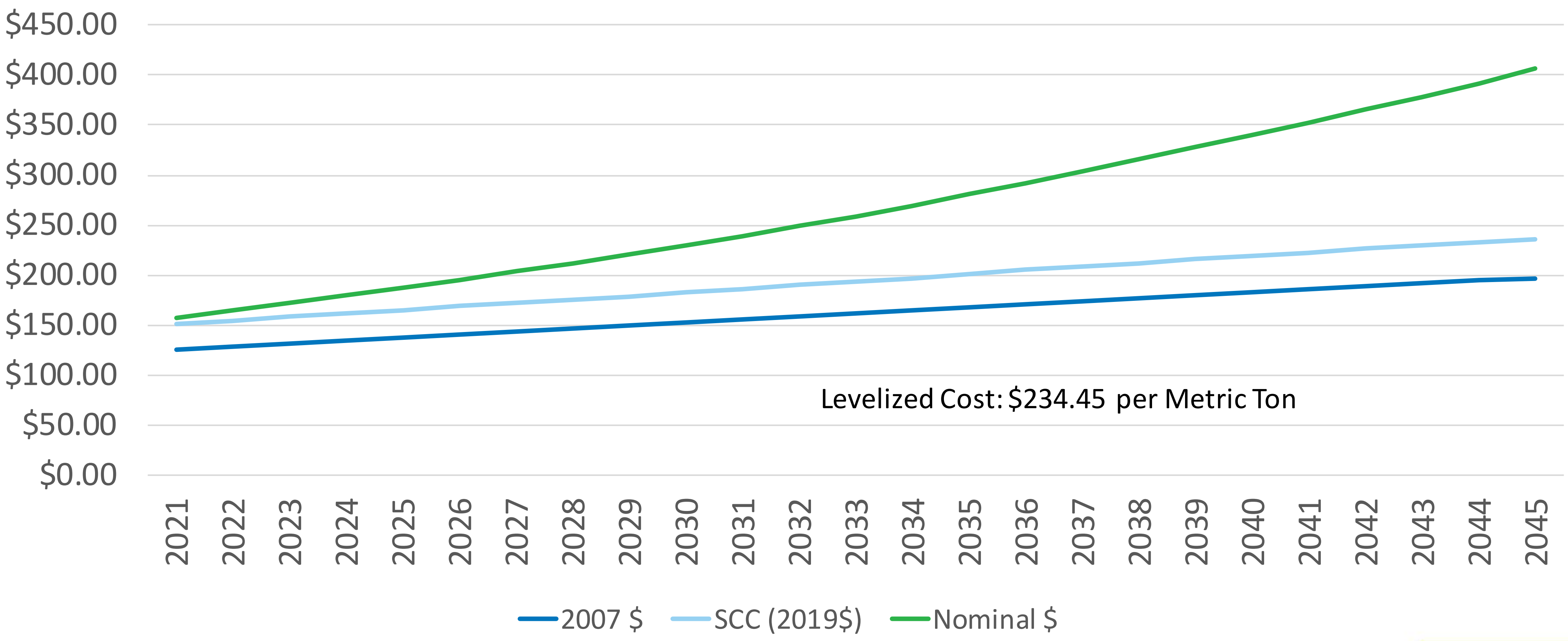
Oregon – Carbon adder



Source: Wood Mackenzie North America gas markets long-term outlook – H1 2020

***Modeled as an expected cost of California's cap and trade program**

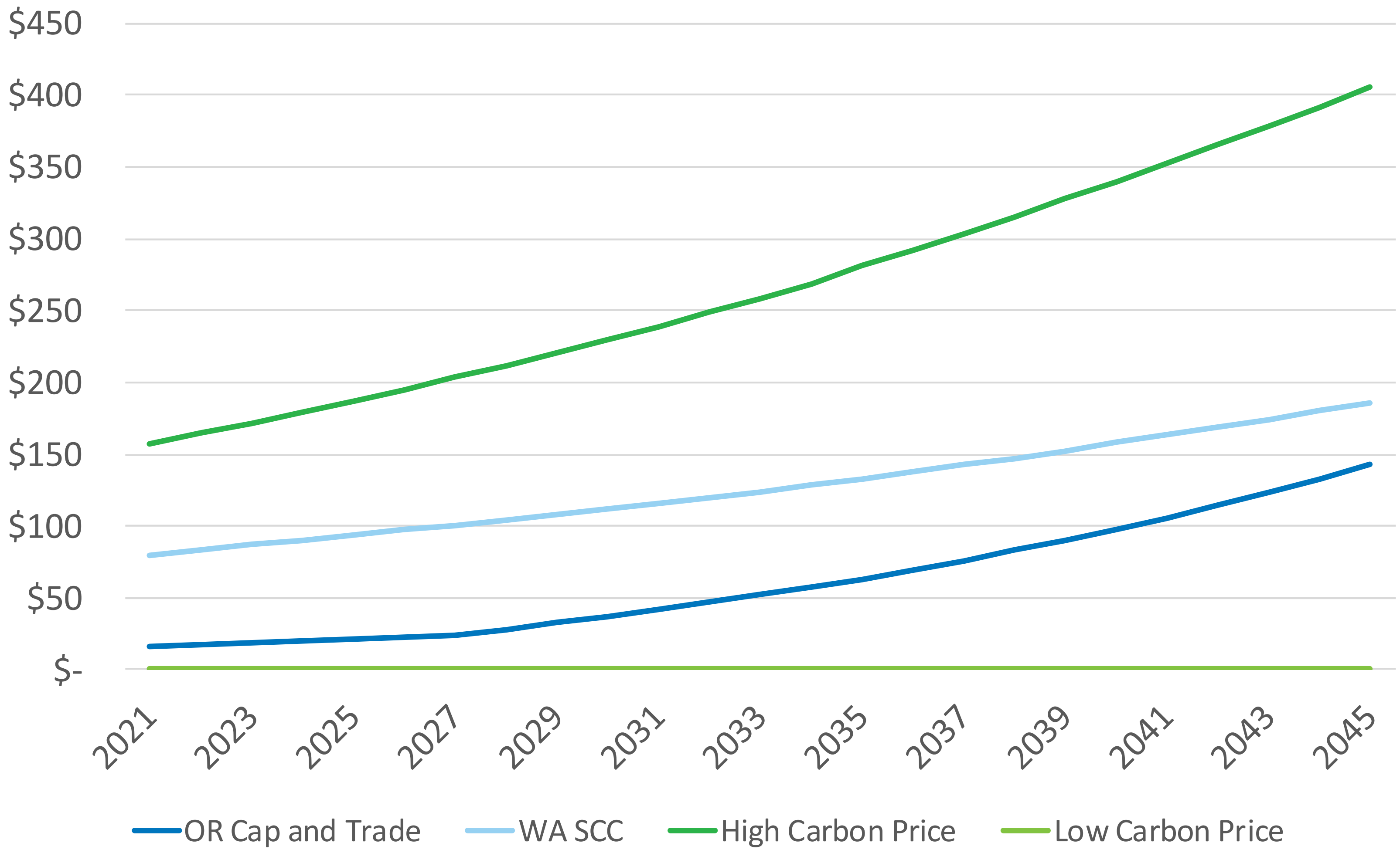
All jurisdictions - Carbon adder
High sensitivity



- EPA – Social Cost of Carbon
- Adjust to 2019$ using Bureau of Economics GDP
- Adjust to Nominal $ using 2.11% annual inflation rate

High Carbon Scenario - SCC @ 95% @ 3%

Carbon Costs



Levelized Cost per MTCO2e	$44.92	$113.75	$234.45	$0

Expected Case
Cost of Carbon by State - Summary

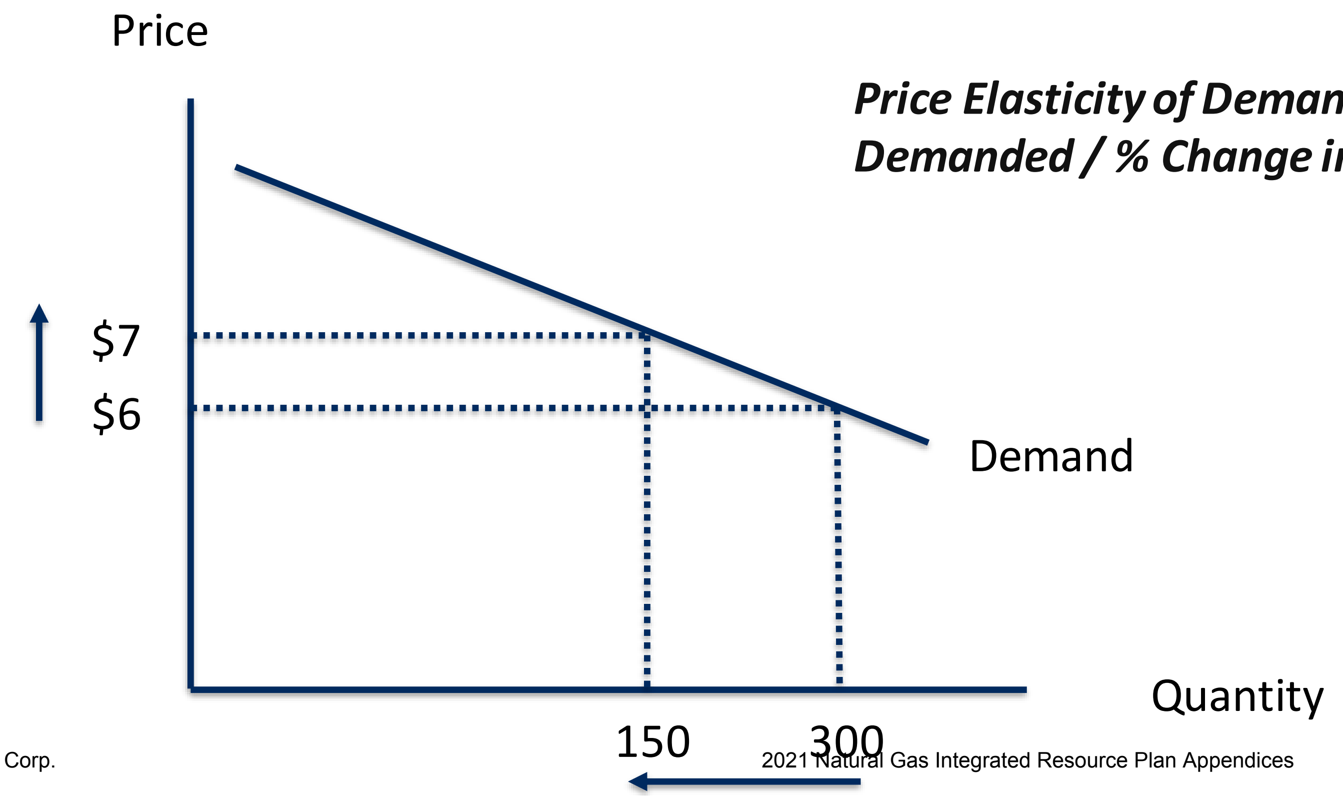
- Washington - Social cost of carbon @ 2.5% discount rate;
  - upstream emissions associated with natural gas drilling and transportation of natural gas to its end use.
- Oregon is based off a Wood Mackenzie estimate for Cap and Trade
- Idaho - carbon prices will not be included

Price Elasticity

Tom Pardee
Planning Manager, Natural Gas Supply

Price Elasticity

Price elasticity is a method used by economists to measure how supply or demand changes based on changes in price.



Price Elasticity of Demand = % Change in Quantity Demanded / % Change in Price

Price Elasticity Factors Defined

- Price elasticity is usually expressed as a numerical factor that defines the relationship of a consumer's consumption change in response to price change.

- Typically, the factor is a **negative** number as consumers normally **reduce** their consumption in response to **higher** prices or will **increase** their consumption in response to **lower** prices.
  - For example, a price elasticity factor of -0.081 means:
    - A 10% price **increase** will prompt a 0.81% consumption **decrease**
    - A 10% price **decrease** will prompt a 0.81%
    - consumption **increase**

Summary

- The elasticity as measured in the Medford and Roseburg areas will be used for the entire system as estimated elasticity.
- 0.81% decrease only for each price rise of 10%
- This elasticity is measured through heat coefficients and annual price changes

Sensitivities

Michael Brutocao
Analyst, Natural Gas Supply

Sensitivities Summary

Influence Type	Sensitivity	Customer Growth Rate	Use per Customer	Weather	Demand Side Management	Prices	Elasticity	First Year System Unserved	Location Unserved
DEMAND INFLUENCING - DIRECT	Reference	Reference	3 Year Historical	20 Year Average	None	Expected	None	-	-
	Reference Plus Peak			Planning Standard				2035	Washington
	Low Cust	Low Growth						-	-
	High Cust	High Growth						2029	Washington
	Alternate Weather Standard	Reference		Coldest in 20yrs				2035	Washington
	DSM			20 Year Average	Expected			-	-
	Peak plus DSM			Planning Standard				2039	Idaho
	80% below 1990 emissions – OR/WA only				None			-	-
	2 Year use per customer Alternate		2 Year Historical					2035	Washington
	5 Year use per customer Alternate		5 Year Historical					2035	Washington
	JP Outage Only (0% capacity)		3 Year Historical					2021	Washington
	AECO Outage Only (0% capacity)							2020	WA, ID
	Sumas Outage Only (0% capacity)							2020	Medford
	Rockies Outage Only (0% capacity)							2020	La Grande
	JP Outage Only (50% capacity)							2021	Washington
	AECO Outage Only (50% capacity)							2026	Washington
	Sumas Outage Only (50% capacity)							2025	Washington
	Rockies Outage Only (50% capacity)							2025	La Grande
	NWP Outage (0% capacity)							2020	WA, ID, La Grande
	GTN Outage (0% capacity)							2020	WA, ID, Klamath Falls
	NWP Outage (50% capacity)							2020	WA, La Grande
	GTN Outage (50% capacity)							2026	Washington

Sensitivities Summary (Continued)

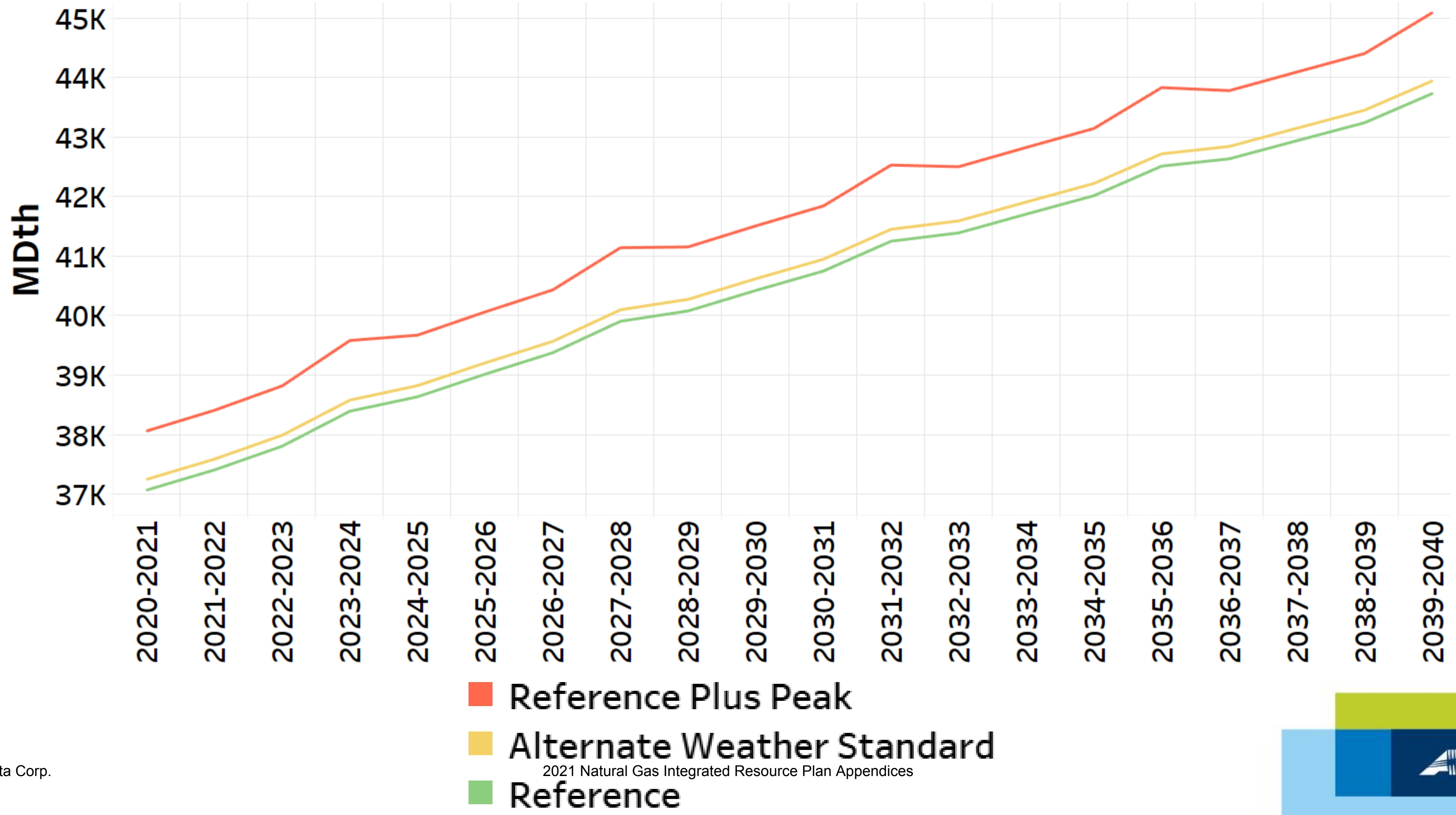
Influence Type	Sensitivity	Customer Growth Rate	Use per Customer	Weather	Demand Side Management	Prices	Elasticity	First Year System Unserved	Location Unserved
PRICE INFLUENCING - INDIRECT	Expected Prices	Reference	3 Year Historical	Planning Standard	None	Expected	Expected	-	-
	Low Prices					Low		-	-
	High Prices					High		-	-
	Carbon Cost - High (SCC 95% at 3%)					Expected		-	-
	Carbon Cost - Expected (SCC 2.5% (WA) & Cap&Red (OR))							-	-
	Carbon Cost - Low $0							-	-
EMISSIONS INFLUENCING	High Upstream Emissions 2.47% leakage (EDF study)							-	-
	Expected Upstream Emissions (0.79% leakage)							-	-
	No Upstream Emissions							-	-
	Expected Global Warming Potential (20 Years)							-	-
	Expected Global Warming Potential (100 Years)							-	-

First Year Peak Demand Unserved (11/1/2020 – 10/31/2040)

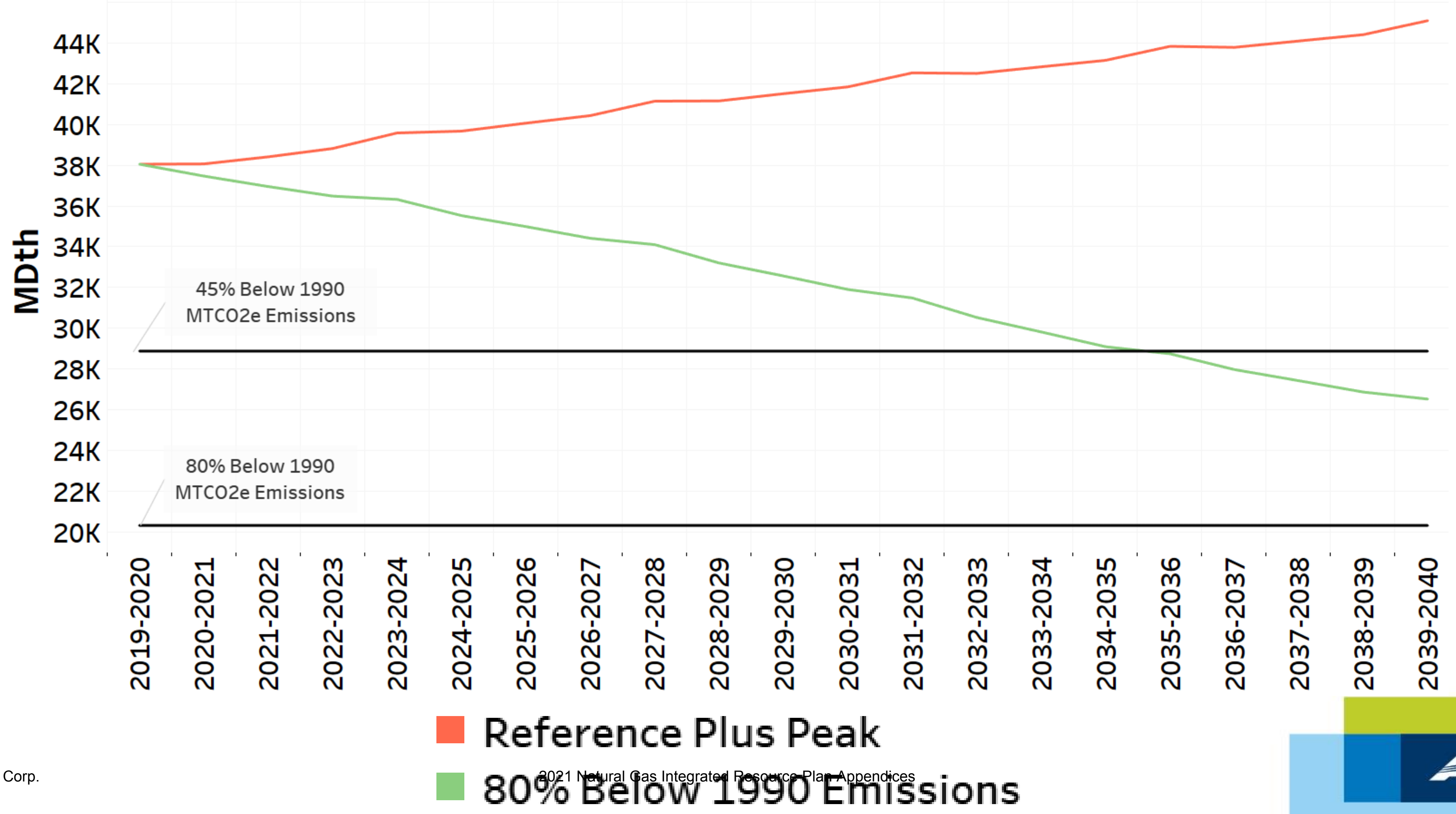
	Washington	Idaho	La Grande	Medford	Klam Falls	Roseburg
Reference Plus Peak	2035	2039				
High Customer Growth	2029	2038	2035			
Alternate Weather Standard	2035					
Reference Plus Peak Plus DSM		2039				
2-yr Use Per Customer	2035	2039				
5-yr Use Per Customer	2035					
Outage (JP - 0%)	2021	2022		2028		
Outage (JP - 50%)	2021					
Outage (AECO - 0%)	2020	2020				
Outage (AECO - 50%)	2026	2028				
Outage (Sumas - 0%)	2026	2021		2020		2032
Outage (Sumas - 50%)	2025	2038		2035		
Outage (Rockies - 0%)	2021	2023	2020	2031		2033
Outage (Rockies - 50%)	2028	2039	2025			
Outage (NWP - 0%)	2020	2020	2020	2021		2028
Outage (NWP - 50%)	2020	2023	2020	2029		
Outage (GTN - 0%)	2020	2020		2026	2020	2028
Outage (GTN - 50%)	2026	2028				

*Sensitivities not listed above have no unserved demand.

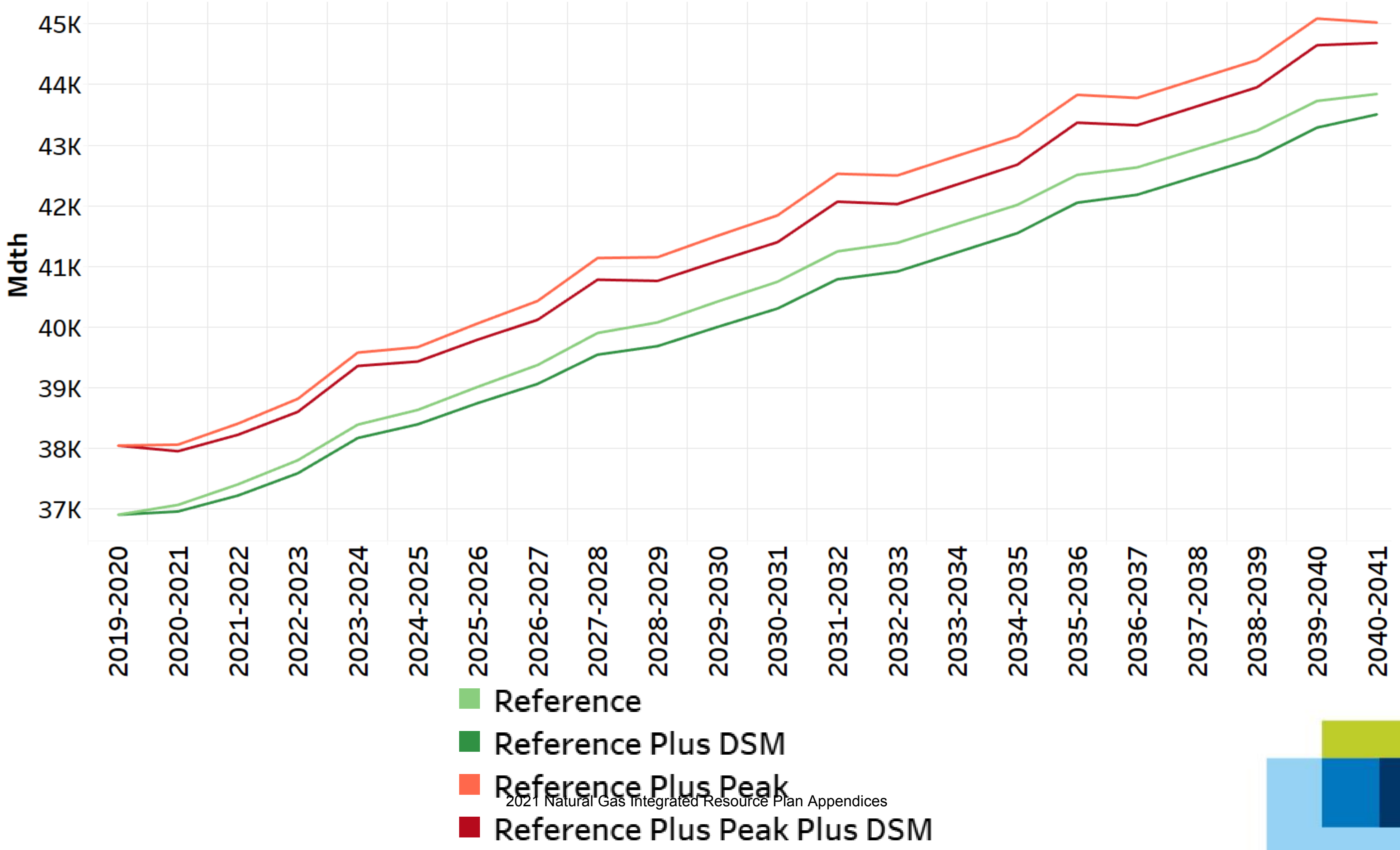
Demand Sensitivities: Weather



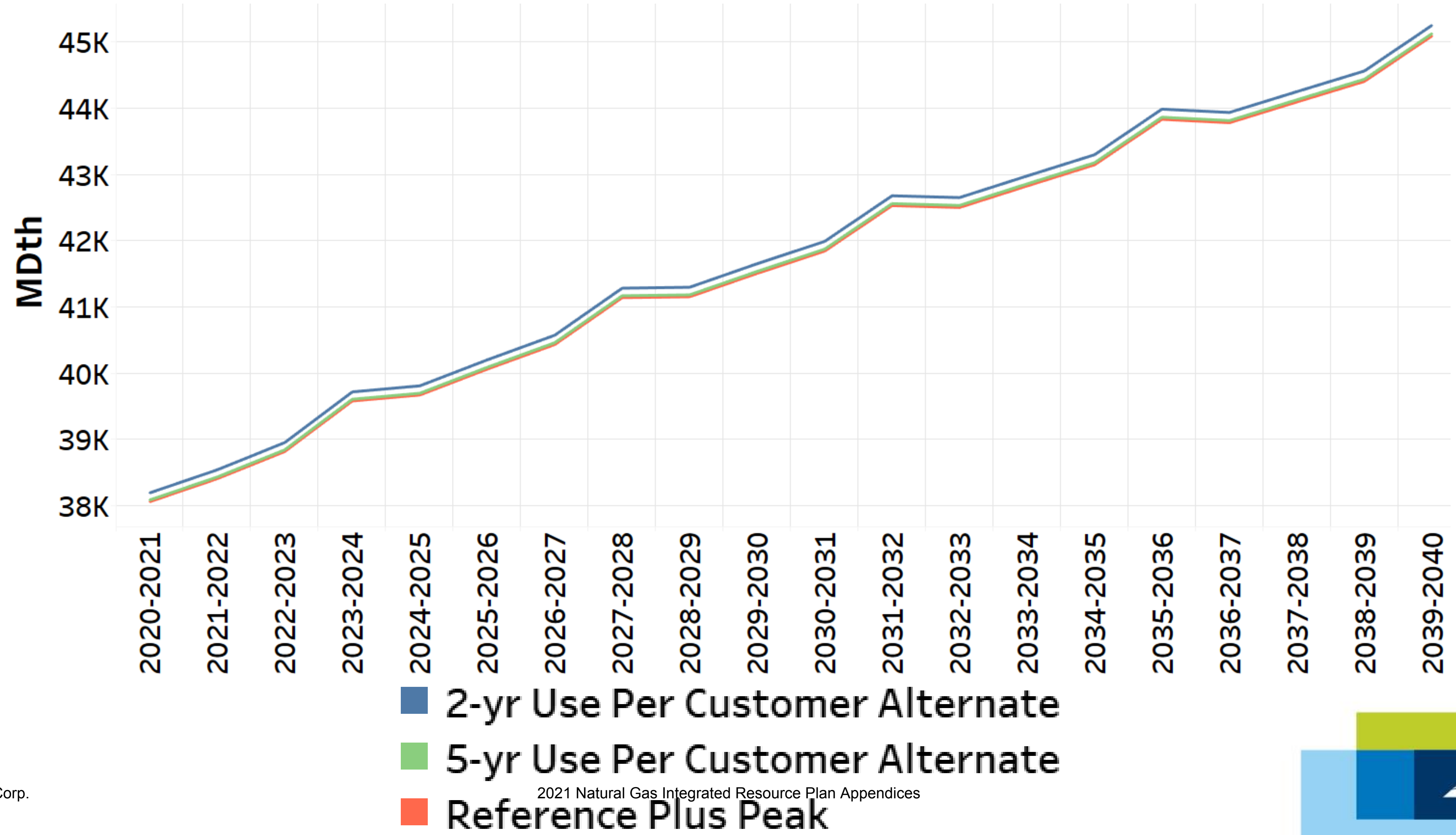
Demand Sensitivities: 80% Below 1990 Emissions



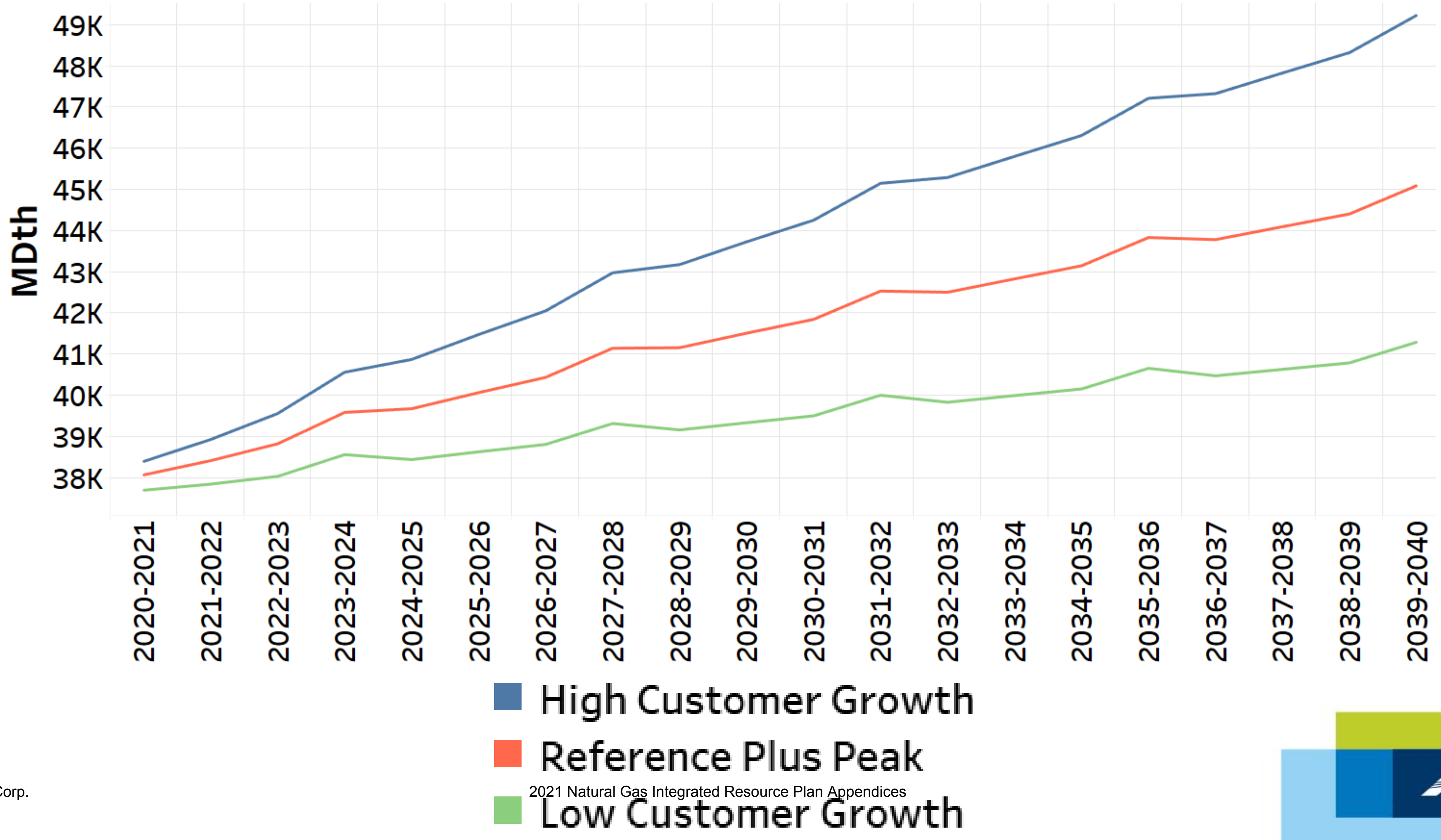
Demand Sensitivities: Demand Side Management



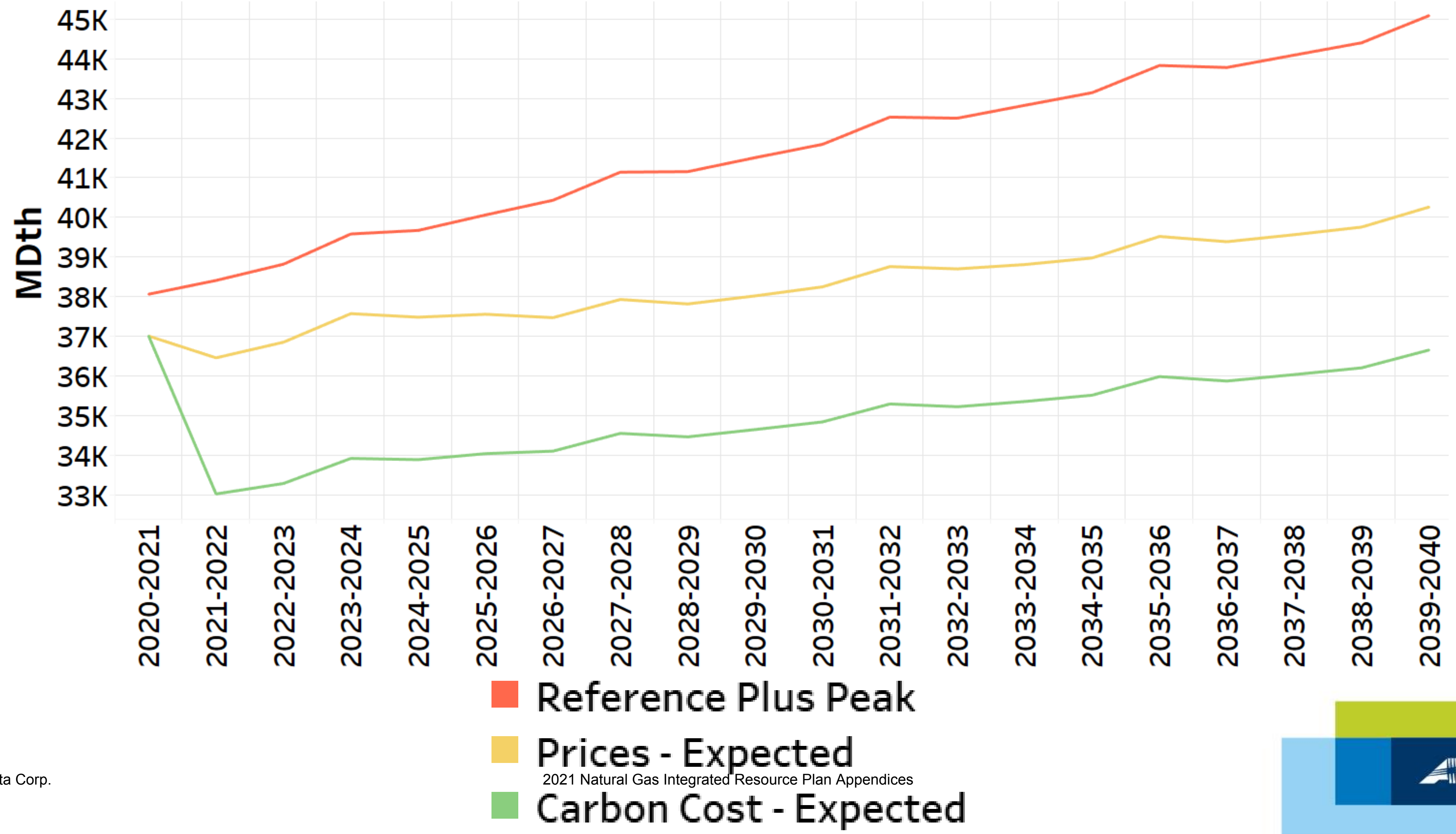
Demand Sensitivities: Use Per Customer



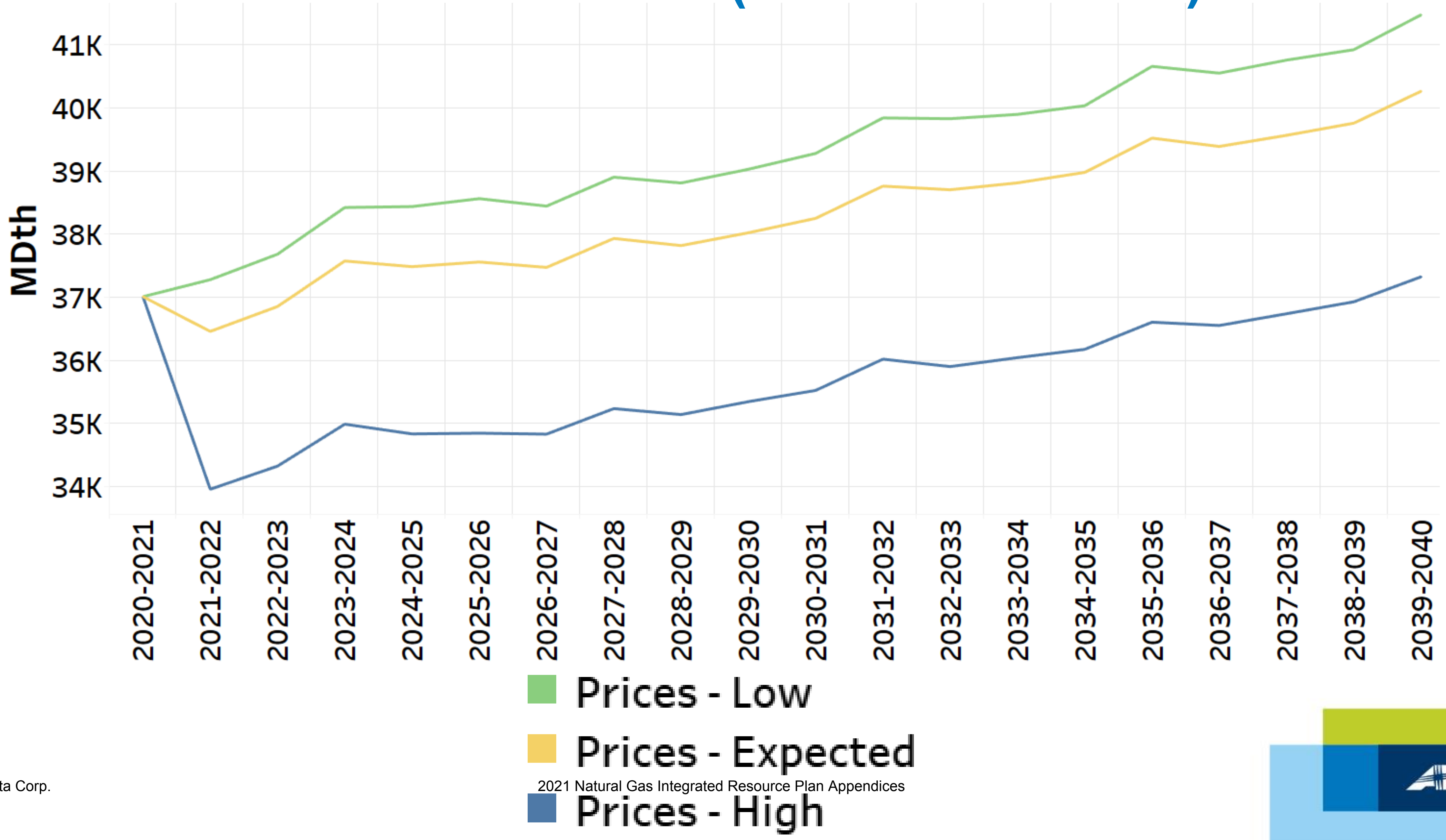
Demand Sensitivities: Customer Growth



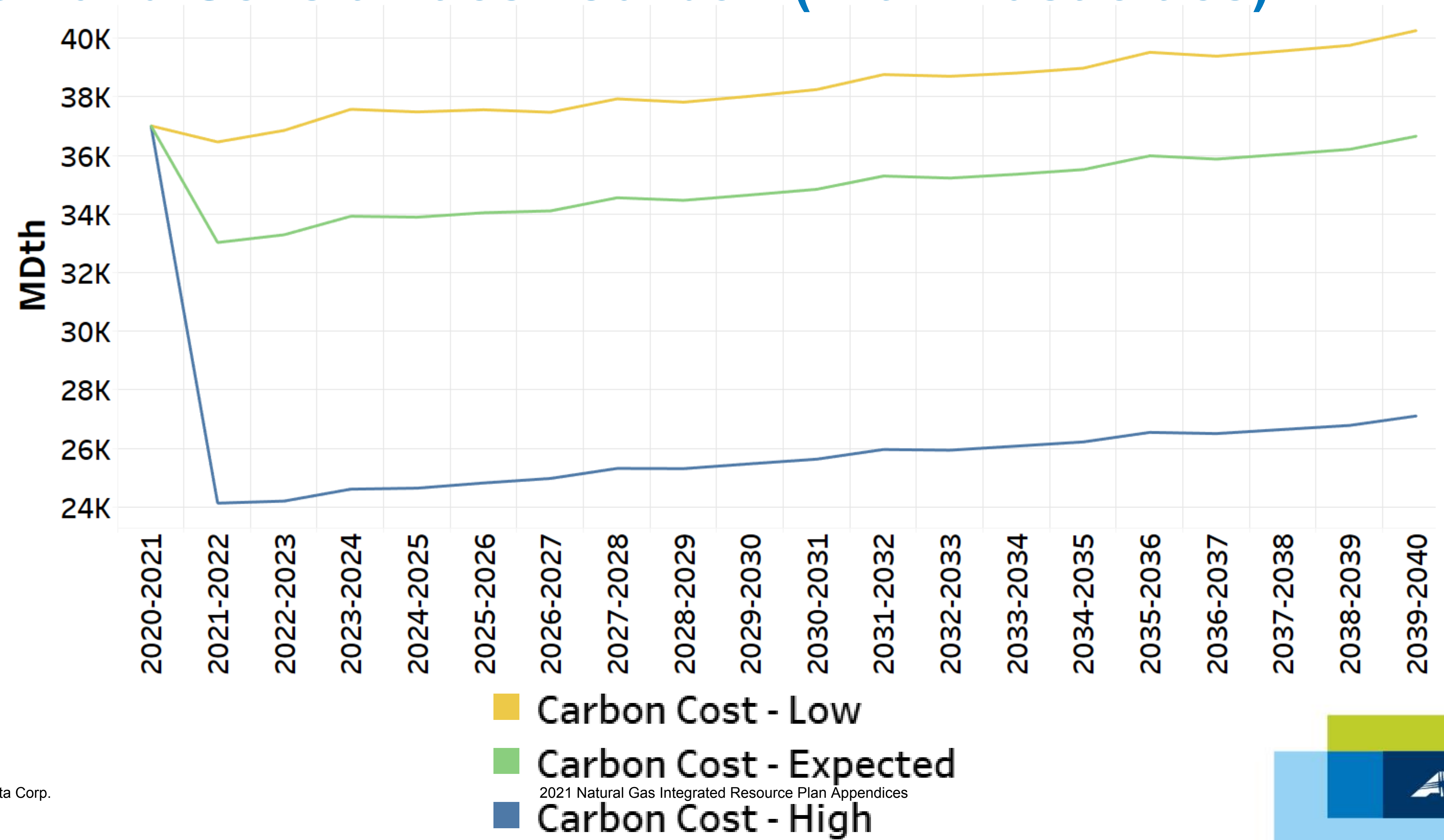
Demand Sensitivities: Price and Carbon Elasticities



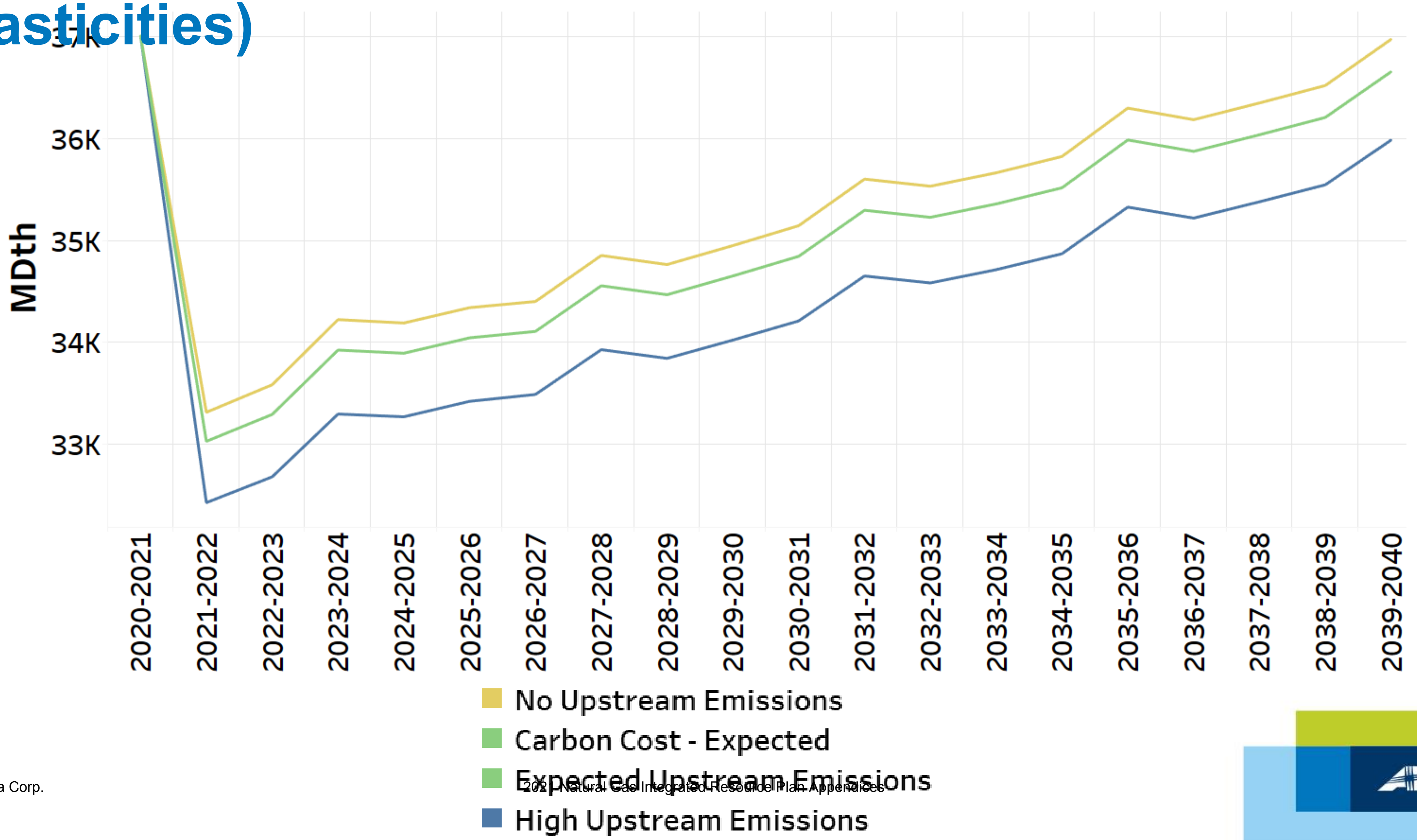
Demand Sensitivities: Price (with Elasticities)



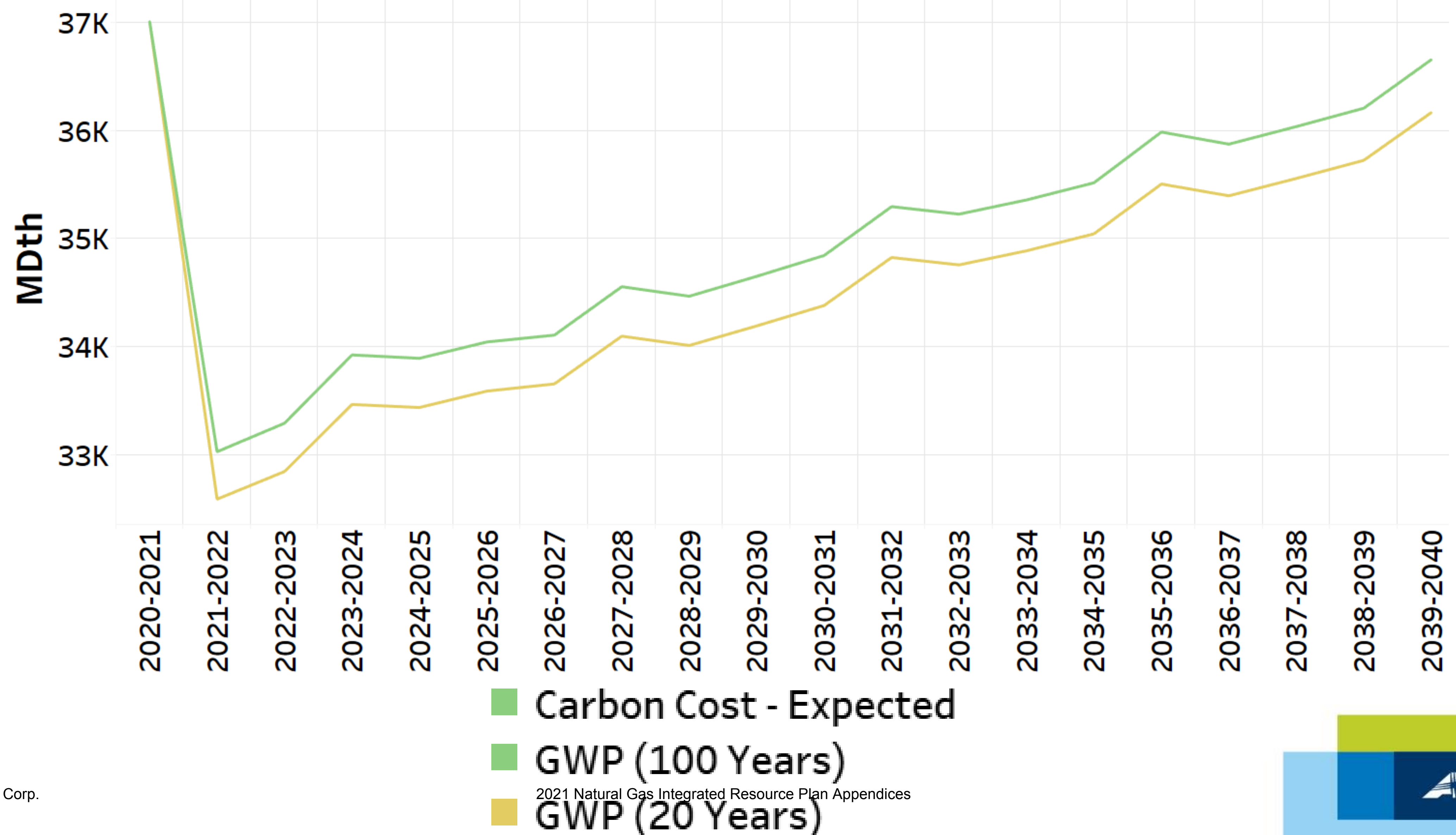
Demand Sensitivities: Carbon (with Elasticities)



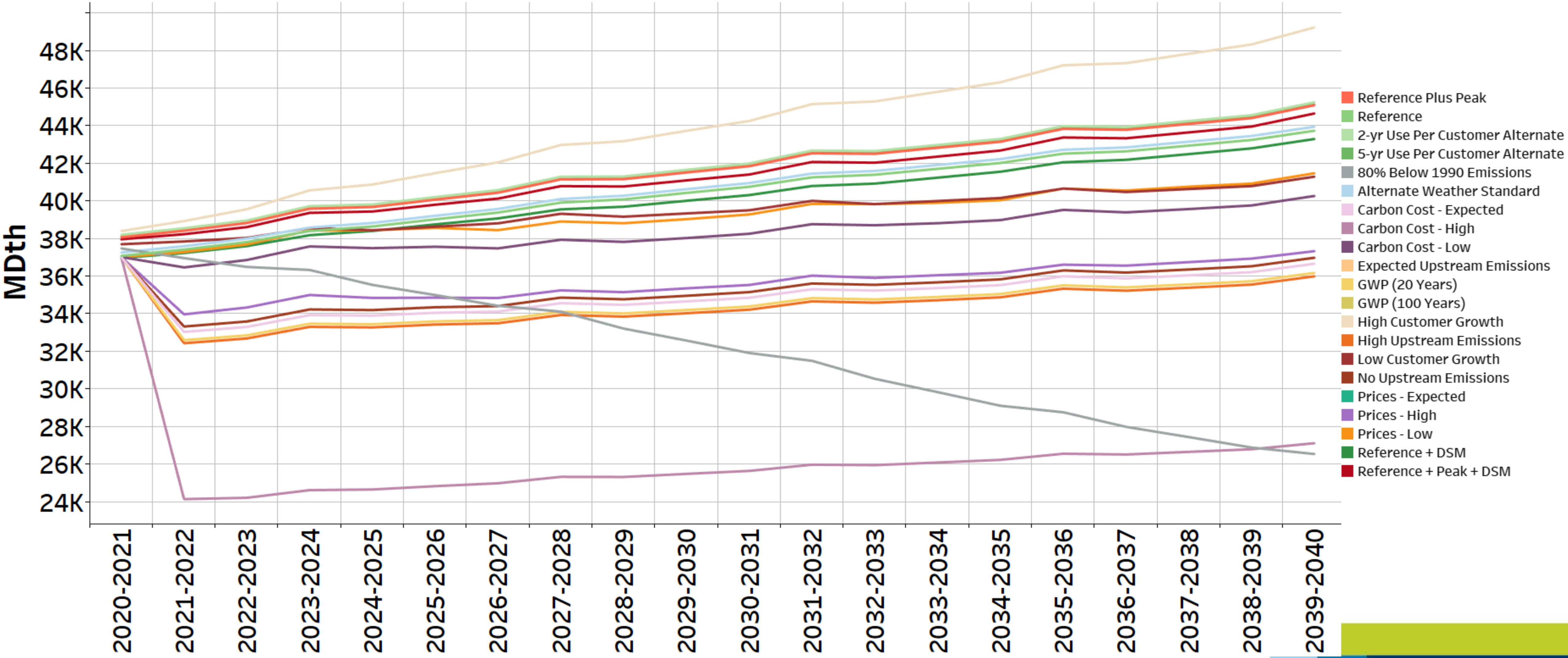
Demand Sensitivities: Upstream Emissions (with Elasticities)



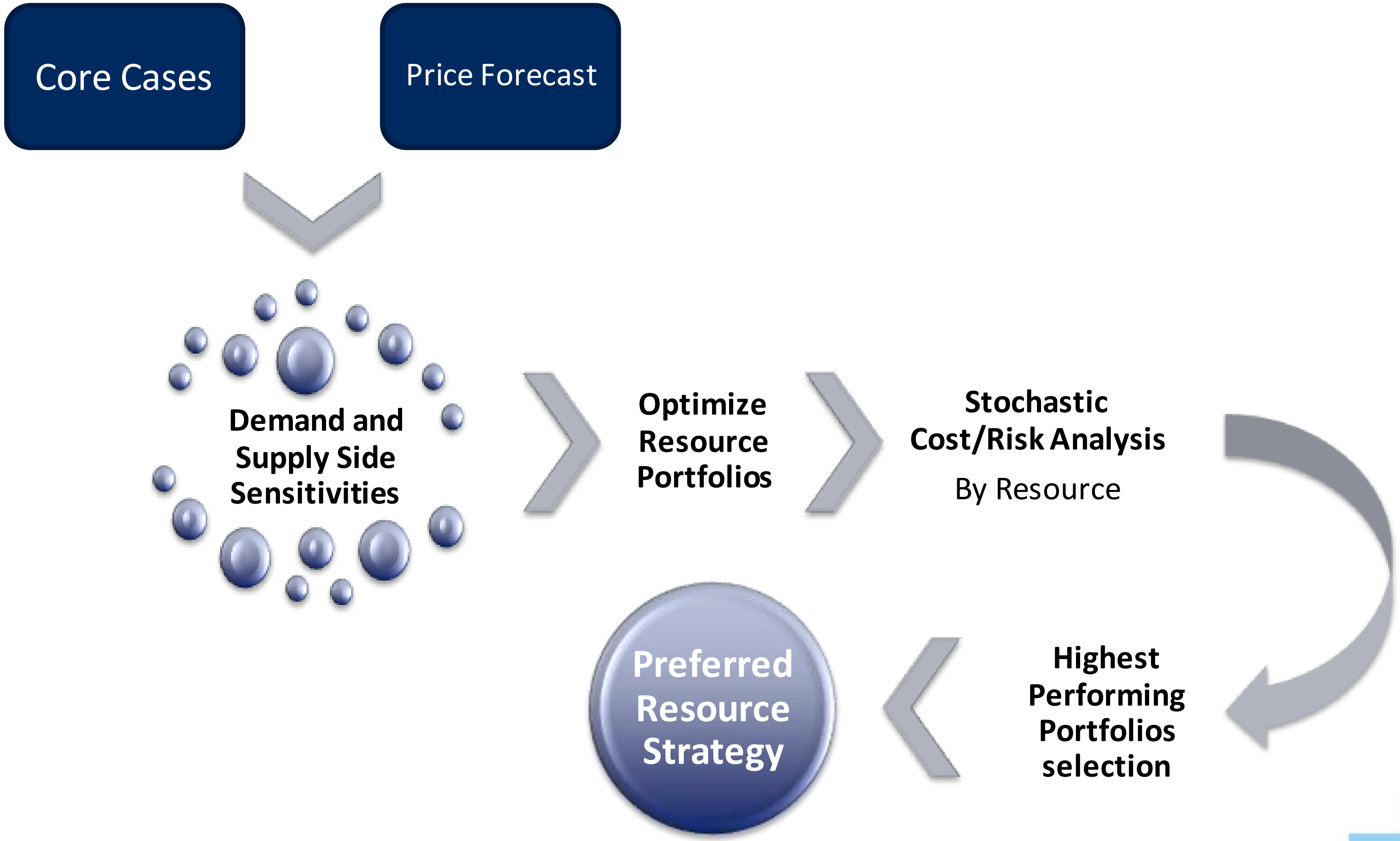
Demand Sensitivities: GWP (with Elasticities)



Demand (11/1/2020 – 10/31/2040)



Sensitivities, Scenarios, Portfolios



Proposed Scenarios

Proposed Scenarios INPUT ASSUMPTIONS	Expected Case	Average Case	Low Growth & High Prices	Carbon Reduction	High Growth & Low Prices
Customer Growth Rate	Reference Case Cust Growth Rates		Low Growth Rate	Reference Case Cust Growth Rates	High Growth Rate
Use per Customer	3 yr + Price Elasticity				
Demand Side Management	Expected Case CPA		High Prices DSM	Low Prices DSM	
Weather Planning Standard	99% probability of coldest in 30 years	20 year average	99% probability of coldest in 30 years		
GWP	100-Year GWP				
Prices Price curve	Expected		High	Low	
Carbon Legislation ($/Metric Ton)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID		Carbon Cost - High (SCC 95% at 3%)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID	$0
RESULTS					
First Gas Year Unserved					
Washington					
Idaho					
Medford					
Roseburg					
Klamath					
La Grande					
Scenario Summary					
	Most aggressive peak planning case utilizing Average Case assumptions as a starting point and layering in peak day 99% probability. The likelihood of occurrence is low.	Case most representative of our average (budget, PGA, rate case) planning criteria.	Stagnant growth assumptions in order to evaluate if a shortage does occur. Not likely to occur.	Reduction of the use of natural gas to 80% below 1990 targets in OR and WA by 2050. The case assumes the overall reduction is an average goal before applying figures like elasticity and DSM.	Aggressive growth assumptions in order to evaluate when our earliest resource shortage could occur. Not likely to occur.

*1,000 Draws per scenario will be run stochastically

2020 Natural Gas IRP Schedule

TAC 1: Wednesday, June 17, 2020: TAC meeting expectations, 2020 IRP process and schedule, energy efficiency update, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits. fugitive Emissions, Weather Analysis, Weather Planning Standard

TAC 2 (Dual Meeting with Power side): Thursday, August 6, 2020: Market Analysis, Price Forecasts, Cost Of Carbon, Environmental Policies

- Demand Results and Forecasting – August 18, 2020

TAC 3: Wednesday, September 30, 2020: Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, Carbon cost, price elasticity, sensitivities and portfolio selection modeling.

TAC 4: Wednesday, November 18, 2020: CPA results from AEG & ETO, review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

Natural Gas Integrated Resource Plan
TAC #4

November 18, 2020

Agenda

1. CPA results from AEG (60 minutes) – Ken Walter
2. CPA results from ETO (60 minutes) – Spencer Moersfelder, Ted Light
3. Break (15 minutes)
4. Sendout Model (15 minutes) – Tom Pardee
5. Review assumptions (30 minutes) – Tom Pardee
6. Lunch break (60 minutes)
7. Final modeling results for Expected Case (60 minutes) – Tom Pardee
8. Final modeling results for Other Scenarios (60 minutes) – Tom Pardee
9. Action Plan and Next Steps (30 minutes) – Tom Pardee

2020 Natural Gas IRP Schedule

TAC 1: Wednesday, June 17, 2020: TAC meeting expectations, 2020 IRP process and schedule, energy efficiency update, actions from 2018 IRP, and a Winter of 2018-2019 review. Procurement Plan and Resource Optimization benefits. fugitive Emissions, Weather Analysis, Weather Planning Standard

TAC 2 (Dual Meeting with Power side): Thursday, August 6, 2020: Market Analysis, Price Forecasts, Cost Of Carbon, Environmental Policies

- Demand Results and Forecasting – August 18, 2020

TAC 3: Wednesday, September 30, 2020: Distribution, Avista's current supply-side resources overview, supply side resource options, renewable resources, Carbon cost, price elasticity, sensitivities and portfolio selection modeling.

TAC 4: Wednesday, November 18, 2020: CPA results from AEG & ETO, review assumptions and action items, final modeling results, portfolio risk analysis and 2020 Action Plan.

AEG
Applied Energy Group



2020 CONSERVATION POTENTIAL ASSESSMENT – UPDATE

Prepared for the Avista Technical Advisory Committee

Energy solutions. Delivered.

November 18, 2020

AVISTA 2020 NATURAL GAS CPA

CPA Methodology Overview

- Review of AEG Approach
- Levels of Potential
- Economic Screening and IRP Integration
- Retained enhancements from 2018 Action Plan

Summary of Results

- Summary of Potential
  - High level potential
  - Technical Achievable compared to Economic potential
- Comparison to previous CPA

ABOUT AEG

AEG Applied Energy Group

Planning

- Baseline studies
- Market assessment studies
- Program design & action plans
- End-use forecasting

EM&V

- EE portfolio & targeted programs
- Demand response programs & dynamic pricing
- Pilot design & experimental design
- Behavioral programs

Implementation & Technical Services

- Engineering review, due-diligence, QA/QC
- M&V, modeling & simulation, onsite assessments
- Technology R&D and data tools (DEEM)
- Program admin, marketing, implementation, application processing

Market Research

- Program / service pricing optimization
- Process evaluations
- Market assessment / saturation surveys
- Market segmentation
- Customer satisfaction / customer engagement

VISION DSM™ Platform

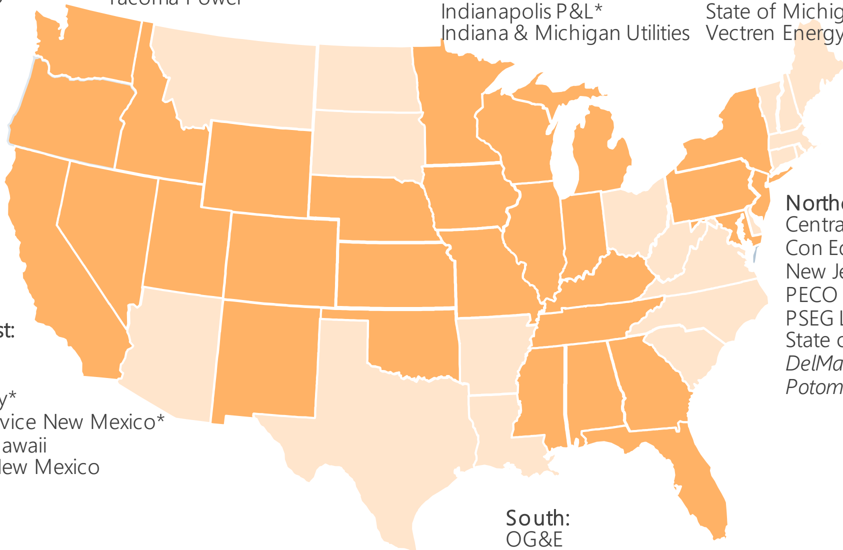
Full DSM lifecycle tracking & reporting

AEG EXPERIENCE IN PLANNING

Including Potential Studies and End-Use Forecasting

Northwest & Mountain:
Avista*
BPA*
Cascade Natural Gas
Chelan PUD
Cheyenne LFP
Colorado Electric*
Cowlitz PUD*
Inland P&L*
Oregon Trail EC
PacifiCorp*
PNGC
PGE*
Seattle City Light*
Tacoma Power*

Midwest:
Ameren Illinois*
Ameren Missouri*
Citizens Energy
Empire District Electric
Indianapolis P&L*
Indiana & Michigan Utilities
Kansas City Power & Light
MERC
NIPSCO*
Omaha Public Power District
State of Michigan
Vectren Energy*



Northeast & Mid Atlantic:
Central Hudson G&E*
Con Edison of NY*
New Jersey BPU
PECO Energy
PSEG Long Island
State of Maryland (*BG&E, DelMarva, PEPCO, Potomac Edison, SMECO*)

Southwest:
HECO
LADWP
NV Energy*
Public Service New Mexico*
State of Hawaii
State of New Mexico
Xcel/SPS

South:
OG&E
Kentucky Power
Southern Company (*APC, GPC, Gulf Power, MPC)*
TVA

Regional & National:
Midcontinent ISO*
EEI/IEE*
EPRI
FERC

* Two or more studies

AEG has conducted more than 60 planning studies for more than 40 utilities / organizations in the past five years.

AEG has a team of 11 experienced Planning staff plus support from AEG's Technical Services and Program Evaluation groups

Applied Energy Group

AEG CPA Methodology

CPA OBJECTIVES

The Avista Conservation Potential Assessment (CPA) supports the Company's regulatory filing and other demand-side management (DSM) planning efforts and initiatives.

The two <u>primary research objectives</u> for the 2020 CPA are:

- **Program Planning:** insights into the market for natural gas energy efficiency (EE) measures in Avista's Washington and Idaho service territories
  - For example, CPAs provide insight into changes to existing program measures as well as new measures to consider
- **IRP:** long-term forecast of future EE potential for use in the IRP
  - Economic Achievable Potential (EAP) for natural gas

AEG utilizes its comprehensive LoadMAP analytical models that are customized to Avista's service territory.

OVERVIEW OF AEG'S APPROACH

Overview – Natural Gas CPA

Market Characterization

- Avista control totals
- Customer account data
- Secondary data
- Avista market research

Identify Demand-Side Resources

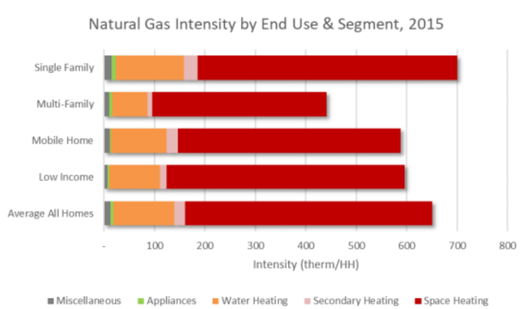
- EE technologies
- EE measures
- Emerging measures and technologies

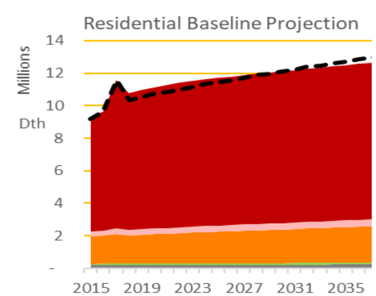
Baseline Projection

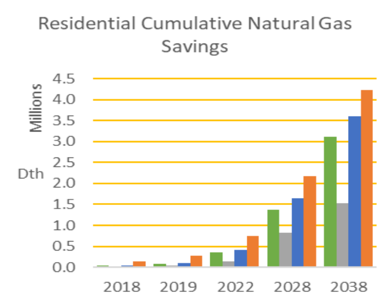
- Avista Load Forecast
- Customer growth
- Standards and building codes
- Efficiency options
- Purchase Shares

Potential Estimation

- Technical
- Technical Achievable
- Economic Screen *(TRC and UCT)*







KEY SOURCES OF DATA

Prioritization of Avista Data

Data from Avista was prioritized when available, followed by regional data, and finally well-vetted national data.

Avista sources include:

- 2013 Residential GenPop Survey
- Forecast data and load research
- Recent-year accomplishments and plans

Regional sources include:

- NEEA studies (RBSA 2016, CBSA 2019, IFSA)
- RTF and Power Council methodologies, ramp rates, and measure assumptions

Additional sources include:

- U.S. DOE's Annual Energy Outlook
- Technical Reference Manuals and California DEER
- AEG Research

BASELINE PROJECTION
Overview

"How much energy would customers use in the future if Avista stopped running programs now and in the absence of naturally occurring efficiency?"

- The baseline projection answers this question

The baseline projection is an independent end-use forecast of natural gas consumption at the same level of detail as the market profile

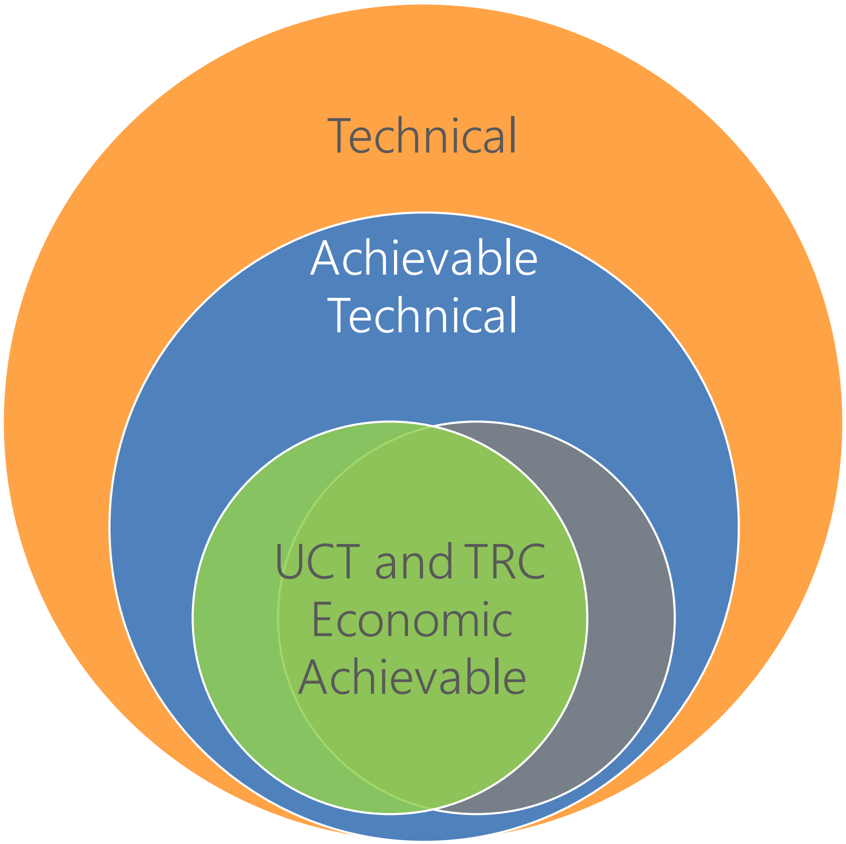
The baseline projection:

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) • Impacts of current and future demand-side management programs

LEVELS OF 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 <u>cost-effective</u> measures. Tests considered within this study include UCT, and TRC.



ECONOMIC SCREENING

Two Cost-Effectiveness Tests

In assessing cost-effective, achievable potential within Avista's Washington and Idaho territories, AEG utilized two cost tests:

- **Utility Cost Test (UCT):** Assesses cost-effectiveness from a utility or program administrator's perspective.
- **Total Resource Cost Test (TRC):** Assesses cost-effectiveness from the utility's <u>and</u> participant's perspectives. Includes non-energy impacts if they can be <u>quantified</u> and <u>monetized</u>.

Component	UCT	TRC
Avoided Energy	Benefit	Benefit
Non-Energy Benefits*		Benefit
Incremental Cost		Cost
Incentive	Cost	
Administrative Cost	Cost	Cost
Non-Energy Costs* (e.g. O&M)		Cost

*Council methodology includes monetized impacts on other fuels within these categories

ENHANCEMENTS RETAINED FROM 2018 CPA

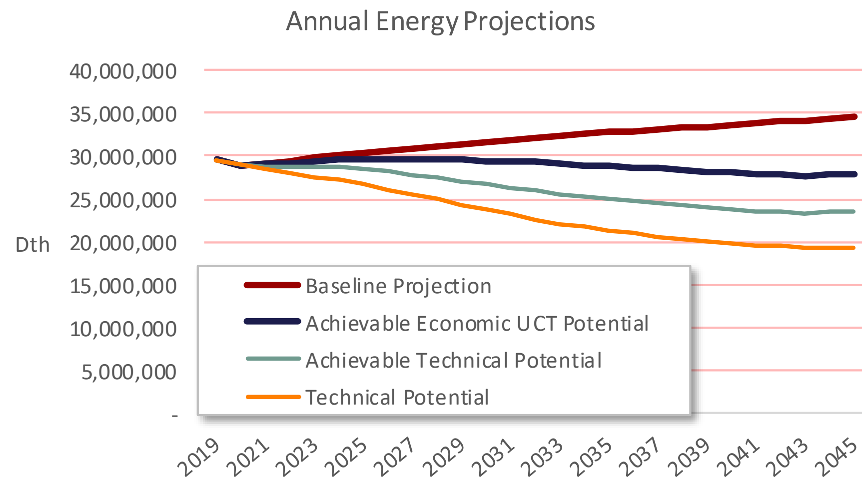
- The Measure Assumptions appendix is again available, containing UES data and other key assumptions and their sources
- **Fully Balanced TRC**. Using the same process developed in the 2018 CPA, the balanced TRC test includes an expanded scope of documentable and quantifiable impacts, including:
  1. 10% Conservation Credit in Washington
  2. Quantified and monetized non-energy impacts (e.g. water, detergent, wood)
  3. Projected cost of carbon in Washington
  4. Heating calibration credit for secondary fuels (12% for space heating, 6% for secondary heating)
  5. Electric benefits for applicable measures (e.g. cooling savings for smart thermostats, lighting and refrigeration savings for retrocommissioning)

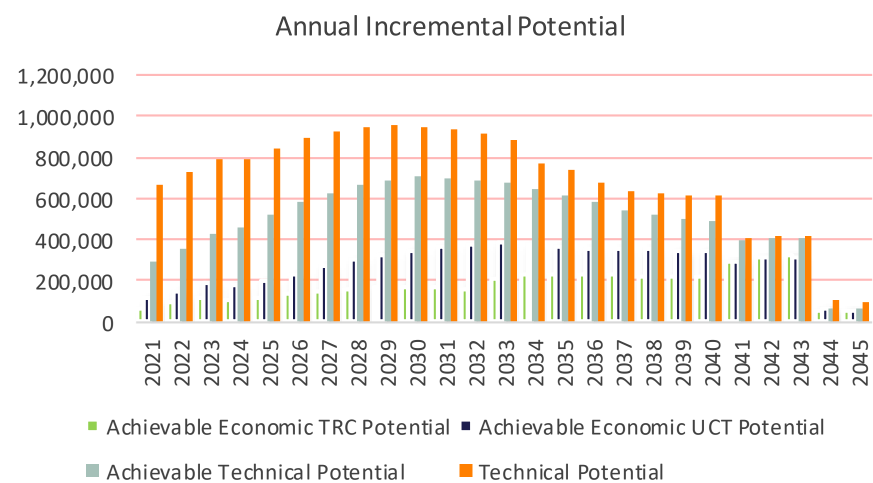
GAS ENERGY EFFICIENCY POTENTIAL

Potential Summary –WA & ID All Sectors

Projections indicate that gas savings of 1.5% of baseline consumption per year are Technically Achievable, and 0.8% per year is cost effective under the UCT test.

- TAP savings are 643,198 Dth in 2022, and 4,906,228 Dth in 2030
- UCT savings are 261,833 Dth in 2022 and 2,124,189 Dth in 2030
- Across the study period, ~46% of TAP savings are UCT cost-effective

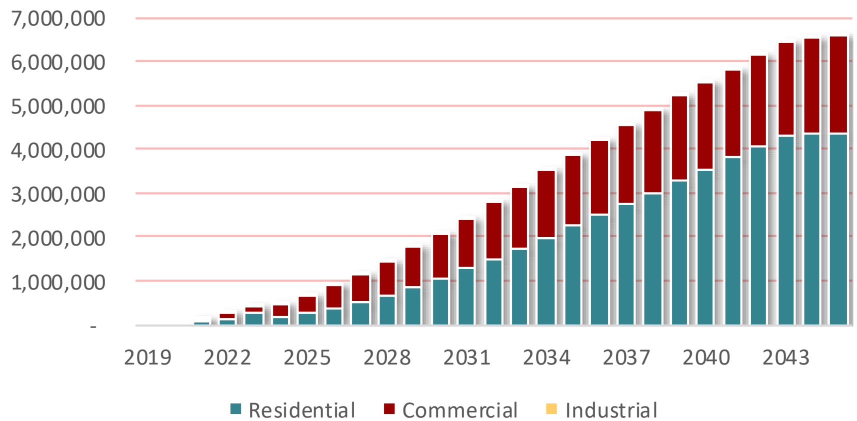




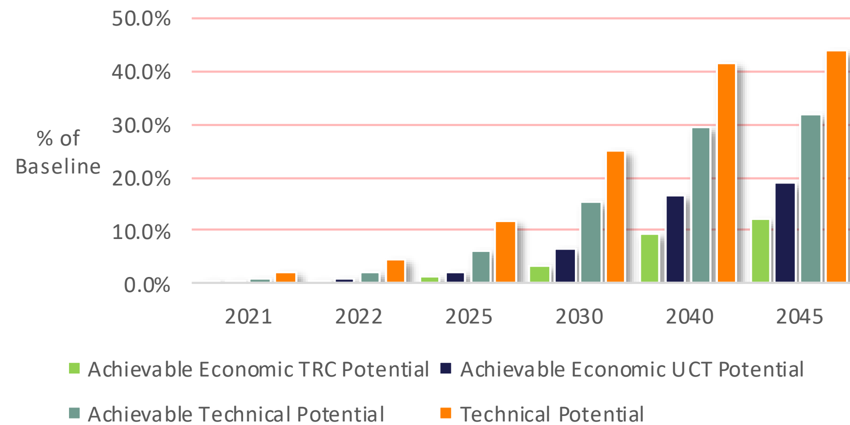
GAS EE POTENTIAL, CONTINUED

Potential Summary – WA & ID, All Sectors

Cumulative UCT Gas Savings (Dth) by Sector



Cumulative Gas Savings, Selected Years



Summary of Energy Savings (Dth), Selected Years	2021	2022	2025	2030	2040	2045
Reference Baseline	29,137,671	29,434,469	30,325,189	31,617,083	33,626,695	34,510,725
Cumulative Savings (Dth)						
Achievable Economic TRC Potential	68,091	163,156	364,805	1,125,806	3,188,178	4,257,057
Achievable Economic UCT Potential	111,637	261,833	686,706	2,124,189	5,585,922	6,625,682
Achievable Technical Potential	290,015	643,198	1,879,807	4,906,228	9,853,874	10,970,898
Technical Potential	662,737	1,387,924	3,587,536	7,862,508	13,922,189	15,068,864
Energy Savings (% of Baseline)						
Achievable Economic TRC Potential	0.2%	0.6%	1.2%	3.6%	9.5%	12.3%
Achievable Economic UCT Potential	0.4%	0.9%	2.3%	6.7%	16.6%	19.2%
Achievable Technical Potential	1.0%	2.2%	6.2%	15.5%	29.3%	31.8%
Technical Potential	2.3%	4.7%	11.8%	24.9%	41.4%	43.7%
Incremental Savings (Dth)						
Achievable Economic TRC Potential	68,091	95,046	117,484	165,797	218,288	49,635
Achievable Economic UCT Potential	111,637	150,478	202,477	345,896	343,741	56,935
Achievable Technical Potential	290,015	355,639	522,562	701,742	483,964	58,801
Technical Potential	662,737	730,524	845,047	950,617	611,563	98,433

AEG Applied Energy Group

GAS EE TOP MEASURES

Achievable Economic UCT Potential

Rank	Measure / Technology (Ranked by 1st year potential)	Achievable Economic UCT Potential (Dth) 2021	2022	2023	2030	% of Total
1	Residential - Furnace	35,602	81,473	134,334	136,211	6.4%
2	Residential - Gas Furnace - Maintenance	13,403	30,912	48,232	177,842	8.4%
3	Commercial - Water Heater	8,854	25,070	46,662	292,125	13.8%
4	Commercial - Space Heating - Heat Recovery Ventilator	7,569	15,162	22,499	65,615	3.1%
5	Commercial - Boiler	6,643	17,112	30,155	131,730	6.2%
6	Residential - Insulation - Ceiling, Installation	5,253	11,641	19,390	99,329	4.7%
7	Residential - ENERGY STAR Connected Thermostat	4,435	9,925	16,719	114,399	5.4%
8	Commercial - HVAC - Duct Repair and Sealing	3,777	7,461	11,046	33,252	1.6%
9	Commercial - Insulation - Wall Cavity	3,337	9,043	17,710	123,408	5.8%
10	Residential - Water Heater	2,954	9,266	19,112	162,884	7.7%
11	Industrial - Process Heat Recovery	2,849	5,670	8,461	21,943	1.0%
12	Commercial - Gas Boiler - Insulate Steam Lines/Condensate Tank	2,517	4,965	7,337	21,733	1.0%
13	Commercial - Insulation - Roof/Ceiling	2,507	6,823	13,348	89,849	4.2%
14	Commercial - Water Heater - Central Controls	1,901	3,766	5,585	13,155	0.6%
15	Commercial - Gas Boiler - Hot Water Reset	1,822	4,002	6,598	30,638	1.4%
16	Commercial - Gas Boiler - High Turndown	1,230	2,424	3,578	8,452	0.4%
17	Commercial - Fryer	1,210	2,946	5,199	29,424	1.4%
18	Commercial - Building Automation System	590	1,735	3,703	61,280	2.9%
19	Commercial - Water Heater - Faucet Aerator	581	1,269	2,079	9,046	0.4%
20	Commercial - Kitchen Hood - DCV/MUA	529	1,055	1,577	5,057	0.2%
	Total of Top 20 Measures	**107,565**	**251,718**	**423,324**	**1,627,371**	**76.6%**
	Total Cumulative Savings	**111,637**	**261,833**	**445,437**	**2,124,189**	**100.0%**

GAS EE TOP MEASURES

UCT & TRC Potential vs Technical Achievable

Rank	Measure / Technology (Ranked by 10-year TAP)	2030 Savings (Dth) TAP	UCT	TRC	% of TAP UCT	TRC
1	Residential - Windows - High Efficiency	670,667	905	0	*0.1%*	*0.0%*
2	Residential - Combined Boiler + DHW System (Storage Tank)	410,862	0	0	*0.0%*	*0.0%*
3	Residential - Combined Boiler + DHW System (Tankless)	338,983	0	0	*0.0%*	*0.0%*
4	Commercial - Water Heater	292,125	292,125	292,125	*100.0%*	*100.0%*
5	Residential - ENERGY STAR Homes	198,515	198,833	0	*100.2%*	*0.0%*
6	Residential - Gas Furnace - Maintenance	191,846	177,842	0	*92.7%*	*0.0%*
7	Residential - Water Heater	163,124	162,884	0	*99.9%*	*0.0%*
8	Residential - Insulation - Wall Cavity, Installation	162,690	8,840	0	*5.4%*	*0.0%*
9	Residential - Insulation - Ceiling, Installation	145,717	99,329	0	*68.2%*	*0.0%*
10	Residential - Furnace	136,211	136,211	136,211	*100.0%*	*100.0%*
11	Residential - ENERGY STAR Connected Thermostat	136,197	114,399	0	*84.0%*	*0.0%*
12	Commercial - Boiler	131,730	131,730	131,730	*100.0%*	*100.0%*
13	Residential - Insulation - Floor/Crawlspace	128,866	56,643	0	*44.0%*	*0.0%*
14	Commercial - Insulation - Wall Cavity	123,131	123,408	115,763	*100.2%*	*94.0%*
15	Commercial - Water Heater - Solar System	112,885	0	0	*0.0%*	*0.0%*
16	Residential - Windows - Low-e Storm Addition	108,983	0	121,262	*0.0%*	*111.3%*
17	Commercial - Insulation - Roof/Ceiling	97,447	89,849	31,527	*92.2%*	*32.4%*
18	Residential - Insulation - Ceiling, Upgrade	83,492	0	0	*0.0%*	*0.0%*
19	Residential - Insulation - Basement Sidewall	81,620	0	0	*0.0%*	*0.0%*
20	Commercial - Building Automation System	74,305	61,280	0	*82.5%*	*0.0%*
	Total of Top 20 Measures	**3,789,395**	**1,654,278**	**828,619**		
	Total Cumulative Savings	**4,906,228**	**2,124,189**	**1,125,806**	***43.3%***	***22.9%***

ACHIEVABLE POTENTIAL COMPARISON

Comparison with Prior Potential Study (2021-2038 **TAP**)

- The previous CPA included potential for 2018-2020, which is removed here
- For the 2021-2038 period, the current study shows quite a bit more **Technical Achievable** potential
- However, **UCT Cost Effective** potential is lower for this period.
  - Largest drop is in Residential water heating, due to a combination of factors:
    - Lower Water Heater unit savings
    - Removal or reduction in WA of HB-1444 affected water saving measures
    - New potential from measures like combination DHW+Boiler systems is expensive

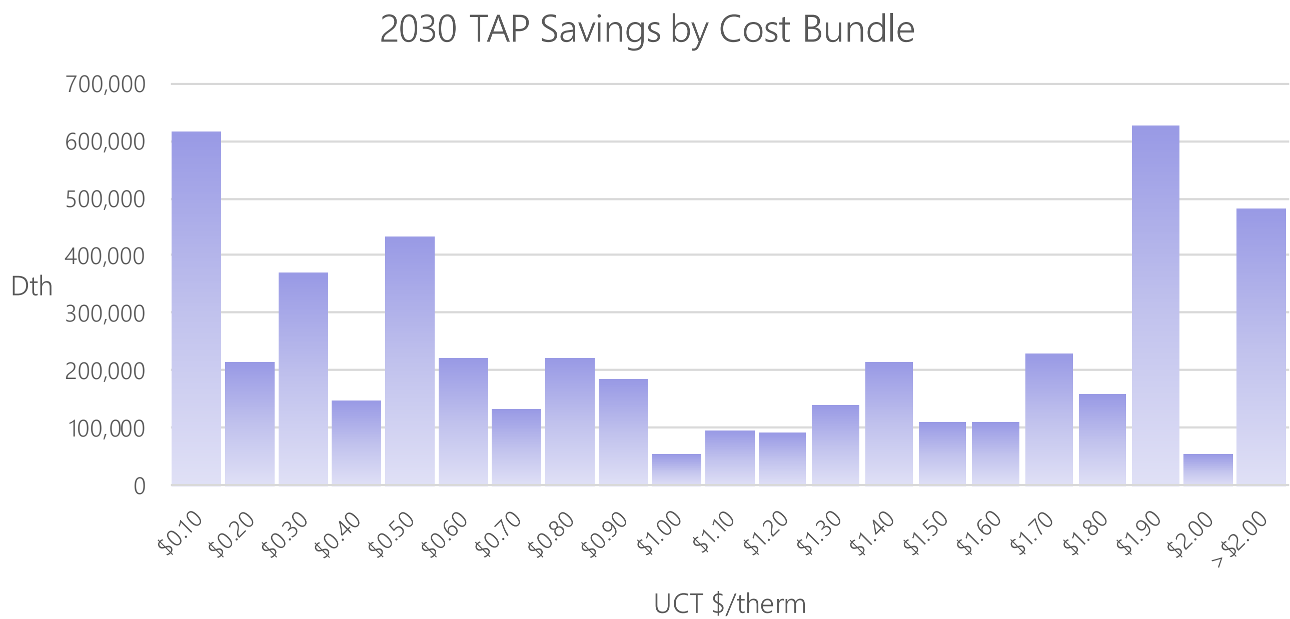
Sector (All States)	End Use	2038 TAP Savings (Dth) Prior CPA	2038 TAP Savings (Dth) Current Study	Diff.
Residential	Space Heating	2,879,487	4,019,918	1,140,431
	Secondary Heating	62,068	37,249	-24,819
	Water Heating	2,264,651	2,382,341	117,690
	Appliances	3,455	21,880	18,425
	Miscellaneous	2,682	3,172	490
Commercial	Space Heating	1,328,855	1,523,386	194,530
	Water Heating	268,621	903,545	634,924
	Food Preparation	136,388	139,204	2,816
	Miscellaneous	51	173	122
Industrial	Space Heating	7,145	8,125	980
	Process	15,435	40,310	24,875
	Miscellaneous	369	0	-369
Grant Total		**6,969,208**	**9,079,303**	**2,110,095**

Sector (All States)	End Use	2038 **UCT** Savings (Dth) Prior CPA	2038 **UCT** Savings (Dth) Current Study	Diff.
Residential	Space Heating	2,274,729	2,071,662	-203,067
	Secondary Heating	0	0	0
	Water Heating	2,223,975	943,071	-1,280,904
	Appliances	1,258	0	-1,258
	Miscellaneous	0	0	0
Commercial	Space Heating	1,131,121	1,088,143	-42,978
	Water Heating	135,582	638,616	503,033
	Food Preparation	136,388	139,204	2,816
	Miscellaneous	45	148	103
Industrial	Space Heating	1,747	6,906	5,159
	Process	14,367	34,395	20,028
	Miscellaneous	369	0	-369
Grant Total		**5,919,582**	**4,922,145**	**-997,437**

ACHIEVABLE POTENTIAL

2030 Savings (TAP) by UCT Cost Bundle – WA + ID All Sectors

UCT $/Therm	2030 TAP Savings (Dth)
$0.00 - $0.10	616,956
$0.10 - $0.20	213,315
$0.20 - $0.30	371,273
$0.30 - $0.40	146,027
$0.40 - $0.50	431,922
$0.50 - $0.60	219,860
$0.60 - $0.70	132,429
$0.70 - $0.80	222,526
$0.80 - $0.90	184,609
$0.90 - $1.00	55,730
$1.00 - $1.10	94,636
$1.10 - $1.20	91,213
$1.20 - $1.30	140,536
$1.30 - $1.40	215,089
$1.40 - $1.50	111,421
$1.50 - $1.60	109,370
$1.60 - $1.70	228,011
$1.70 - $1.80	158,836
$1.80 - $1.90	625,317
$1.90 - $2.00	54,020
$2 or more	483,133



AEG
Applied Energy Group

THANK YOU!

Ingrid Rohmund, Sr. Vice President, Consulting
irohmund@appliedenergygroup.com

Ken Walter, Project Manager
kwalter@appliedenergygroup.com

Kelly Marrin, Managing Director
kmarrin@appliedenergygroup.com

Tommy Williams, Lead Analyst
twilliams@appliedenergygroup.com

Energy Trust of Oregon

Energy Efficiency Resource Assessment Study

November 18, 2020

Energy Trust of Oregon

Agenda

- About Energy Trust
- 2019 Achieved Savings
- Resource Assessment Overview and Background
- Methodology
- Results
- Questions/Discussion

About us

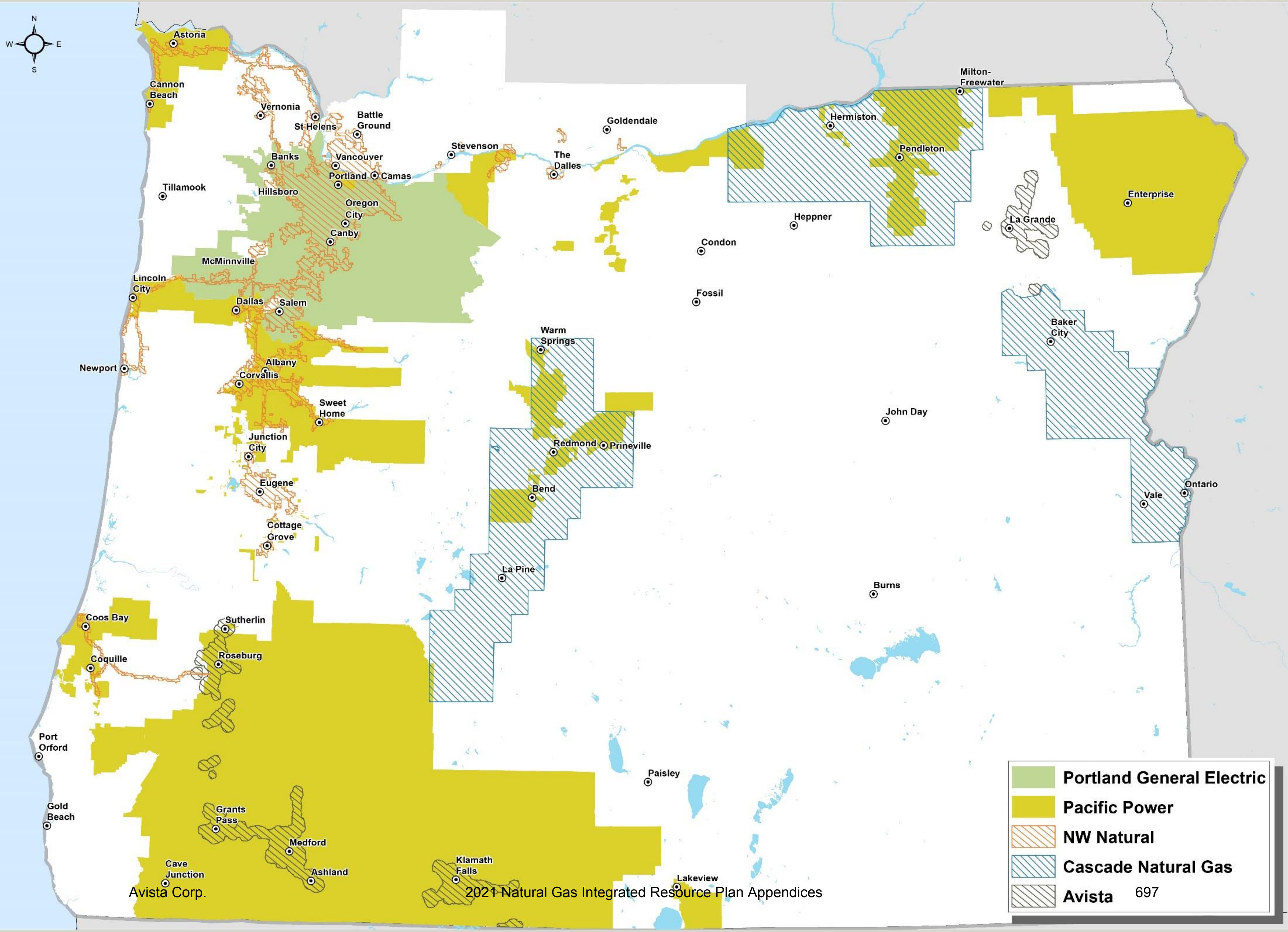
Independent nonprofit

Serving 1.6 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


Astoria
Cannon Beach
Vernonia
St Helens
Battle Ground
Banks
Vancouver
Portland
Camas
Stevenson
The Dalles
Goldendale
Tillamook
Hillsboro
Oregon City
Canby
McMinnville
Lincoln City
Dallas
Salem
Newport
Albany
Corvallis
Sweet Home
Junction City
Eugene
Cottage Grove
Coos Bay
Coquille
Sutherlin
Roseburg
Port Orford
Gold Beach
Grants Pass
Medford
Ashland
Cave Junction
Klamath Falls
Lakeview
Paisley
Burns
La Pine
Bend
Redmond
Prineville
Warm Springs
John Day
Fossil
Condon
Heppner
Hermiston
Pendleton
Milton-Freewater
La Grande
Enterprise
Baker City
Ontario
Vale
Portland General Electric
Pacific Power
NW Natural
Cascade Natural Gas
Avista

15 years of affordable energy

From Energy Trust's investment of $1.5 billion in utility customer funds:

Nearly 660,000 sites transformed into energy efficient, healthy, comfortable and productive homes and businesses

10,000 clean energy systems generating renewable power from the sun, wind, water, geothermal heat and biopower

$6.9 billion in savings over time on participant utility bills from their energy-efficiency and solar investments

20 million tons of carbon dioxide emissions kept out of our air, equal to removing 3.5 million cars from our roads for a year

A clean energy power plant

607 average megawatts saved

121 aMW generated

52 million annual therms saved

Enough energy to power **564,000** homes and heat **100,000** homes for a year

Avoided **20** million tons of carbon dioxide

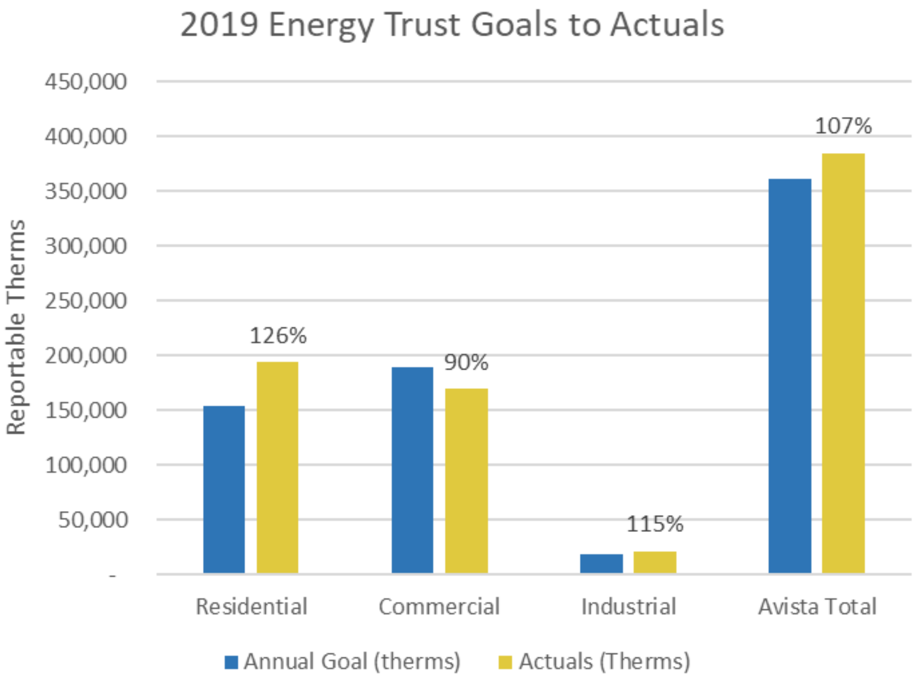
Energy Trust's 2019 Achievements for Avista

Energy Trust Savings Achievements – 2019

- Energy Trust began serving Avista customers in Oregon in 2016.

- Overall achieved 107% of goal
  - Goal 360k Therms
  - Achieved 384k Therms

- Anticipate continued success as we solidify trade ally and customers relationships.



Energy Trust achieved 107% of goal in Avista service territory

Resource Assessment:
Purpose, Overview and Background

Resource Assessment (RA) Purpose

- Provides estimates of energy efficiency potential that will result in a reduction of load on Avista's system for use in Avista's Integrated Resource Plan (IRP).

- The purpose is to help Avista strategically plan future investment in both supply side and demand side resources.

Resource Assessment Overview

- What is a resource assessment?
  - Model that provides an estimate of energy efficiency resource potential achievable over a 20-year period
  - 'Bottom-up' approach to estimate potential starting at the measure level and scaling to a service territory

- Energy Trust uses a model in *Analytica* that was developed by Navigant Consulting
  - The *Analytica m*odel calculates Technical, Achievable and Cost-Effective Achievable Energy Efficiency Potential.
  - Final program/IRP targets are established via ramp rates that are applied outside of the model.

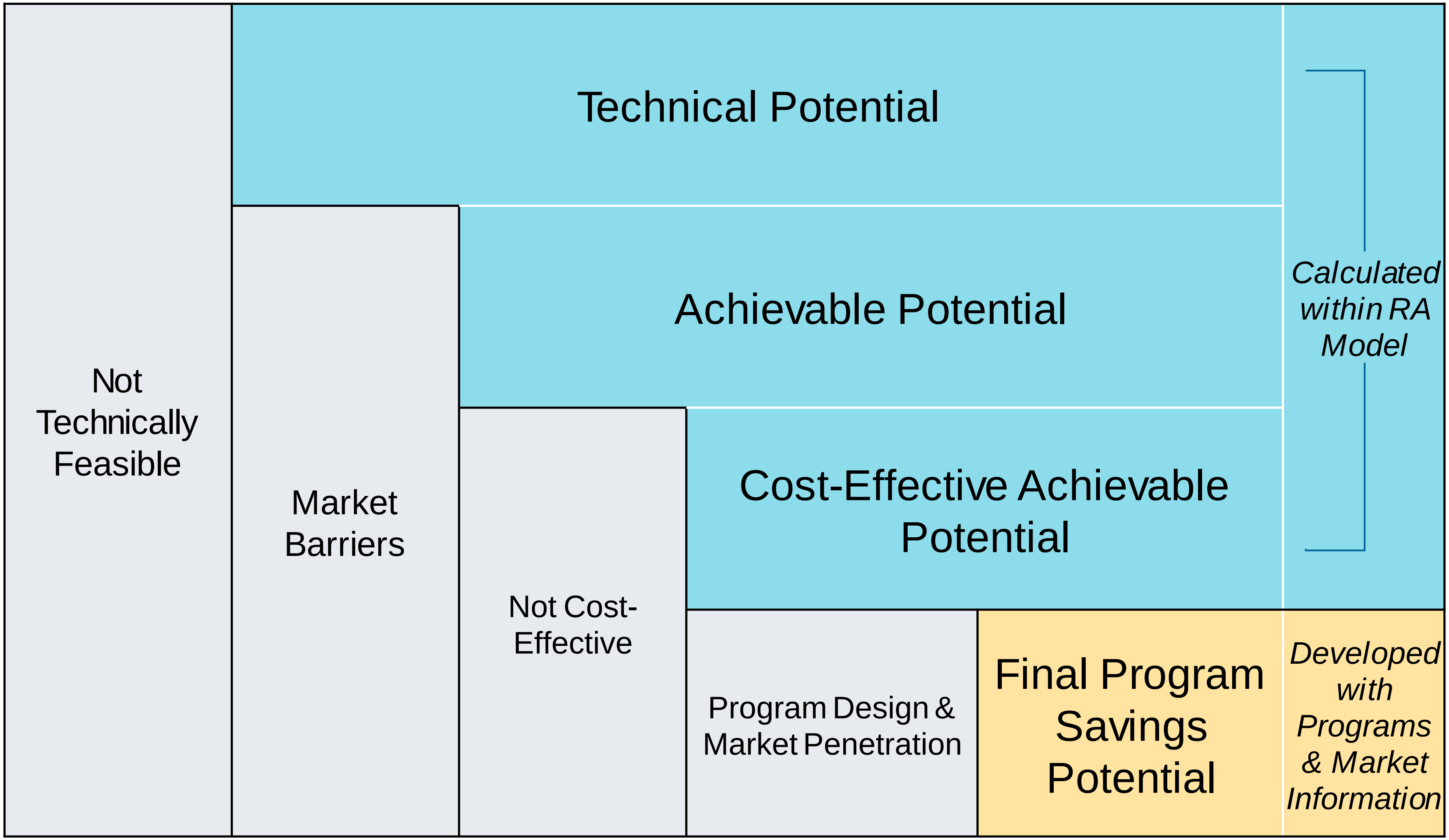
- Data inputs and assumptions in the model are updated in conjunction with IRP about every two years.

Additional Resource Assessment Background

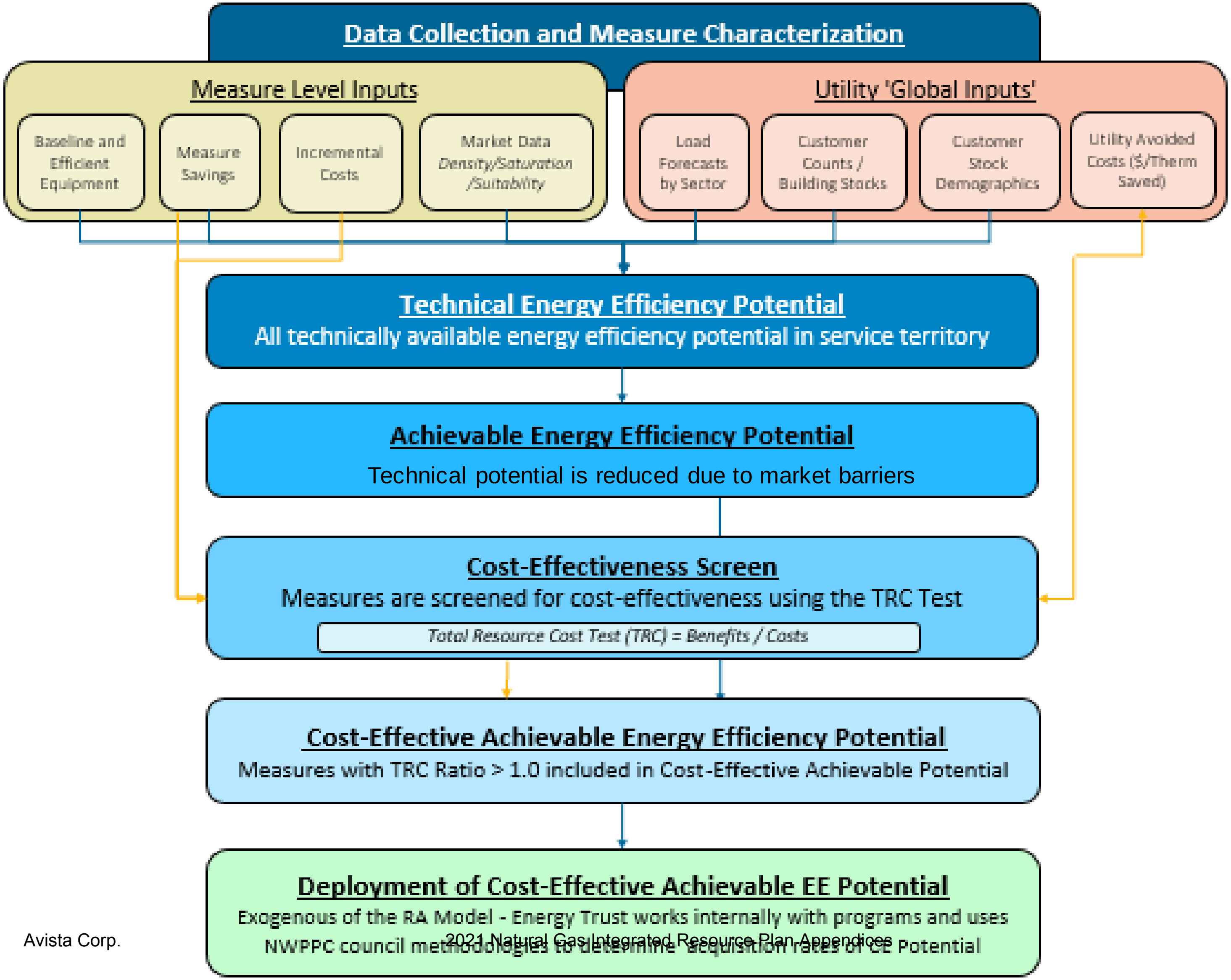
- Informs utility IRP work & Energy Trust strategic and program planning.
- Does not specify mechanism of savings acquisition (e.g. programs, market transformation, codes & standards)
- Does not dictate source or measure mix of annual energy savings acquired by programs
- Does not set incentive levels

20-Year Forecast Methodology

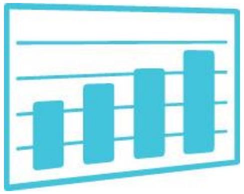
Forecasted Potential Types



20-Year IRP EE Forecast Flow Chart



RA Model inputs



Measure Inputs	Utility Inputs
Measure Definition: • Baseline & Efficient equipment • Applicable customer segments • Installation type* • Measure Life	**Customer and Load Forecasts** Used to scale measure level savings to a service territory • Residential Stock: Count of homes • Commercial Stock: Floor Area • Industrial Stock: Customer load
Measure Savings	**Avoided Costs**
Measure Cost • Incremental cost for lost opportunity measures • Full cost for retrofit measures	**Customer Stock Demographics:** • Heating fuel splits • Water heat fuel splits
Market Data • Density • Saturation of baseline equipment • Technical suitability	

**Retrofit, Replace on Burnout, or New Construction*

Model Updates

- The RA Model is a ‘living’ model and Energy Trust makes continuous improvements to it.

- Measure updates, new measures and new emerging technologies updated in model

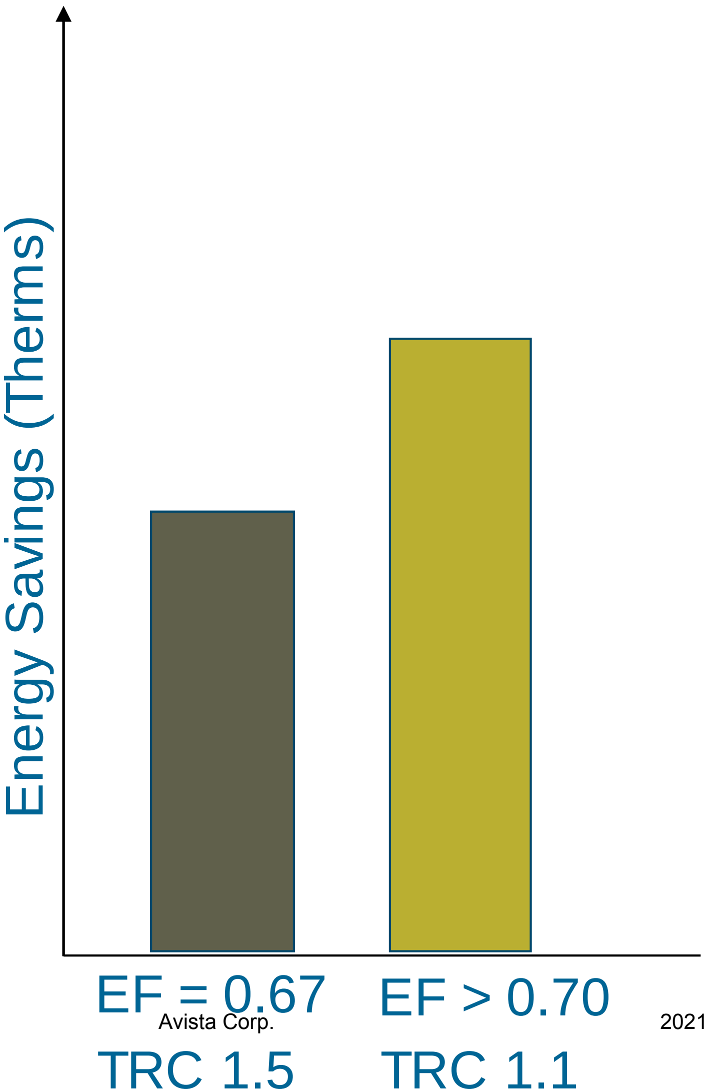
- Alignment with high-level NW Power Council Power Plan deployment methodologies to obtain cost-effective achievable savings within market sectors and replacement types.

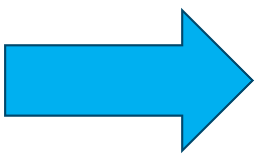
Example Measure: Residential Gas Tank Water Heater (>0.70 EF)

Key Measure Inputs:

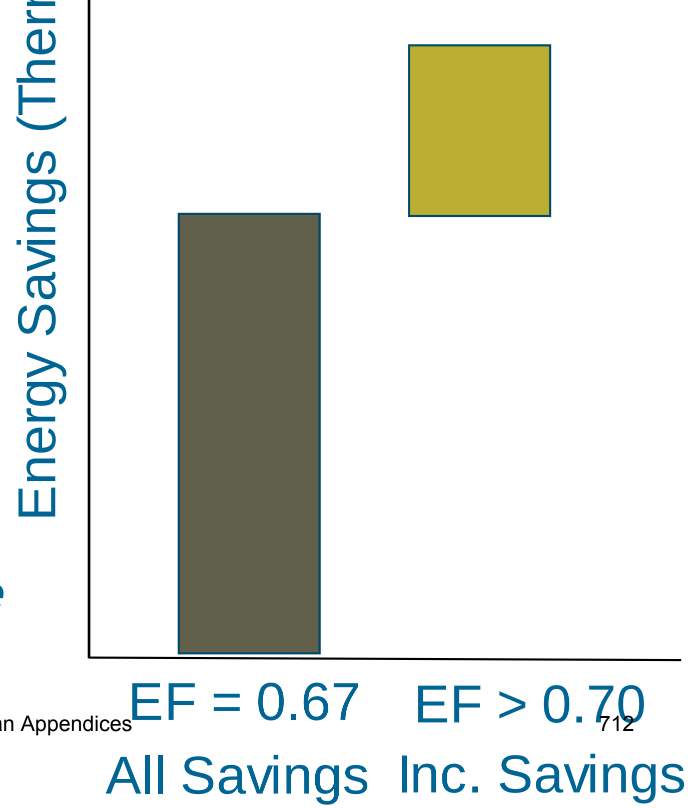
- Baseline: 0.60 EF gas water heater
- Replacement Type: Replacement on Burnout / New
- Measure Incremental Cost: $218
- Conventional (not emerging, no risk adjustment)
- Lifetime:13 years
- Savings: 31.6 therms (annual)
- Non-Energy Benefits: $5.34 per year
- Customer Segments: SF, MF, MH
- Density, Saturation, Suitability
- Competing Measures: All efficient gas water heaters

Incremental Measure Savings Approach (Competition group: Gas water heaters)





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

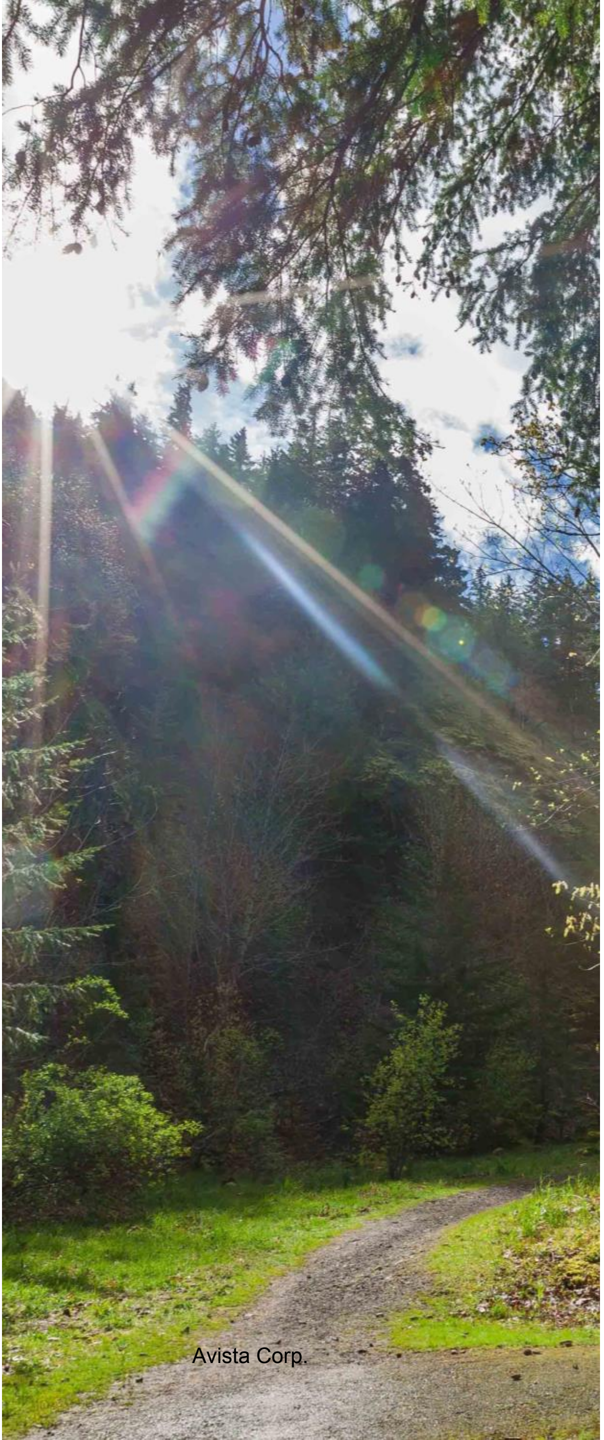
$$\mathrm{TRC} = \frac{\textit{Measure Benefits}}{\textit{Total Measure Cost}}$$

- If TRC is > 1.0, it is cost-effective

- Measure Benefits:
  - Avoided Costs (provided by Avista)
    - Annual measure savings x NPV avoided costs per therm
  - Quantifiable Non-Energy Benefits
    - Water savings, etc.

Total Measure Cost:

- The total cost of the EE measure (full cost if retrofit, incremental over baseline if replacement)



Cost-Effectiveness Override

Energy Trust applied this 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.

The following measures had the CE override applied (all under OPUC exception):

- Com Clothes Washers
- Res Insulation (ceiling, floor, wall)
- Res Clothes Dryers
- Res New Homes Packages

Emerging Technologies

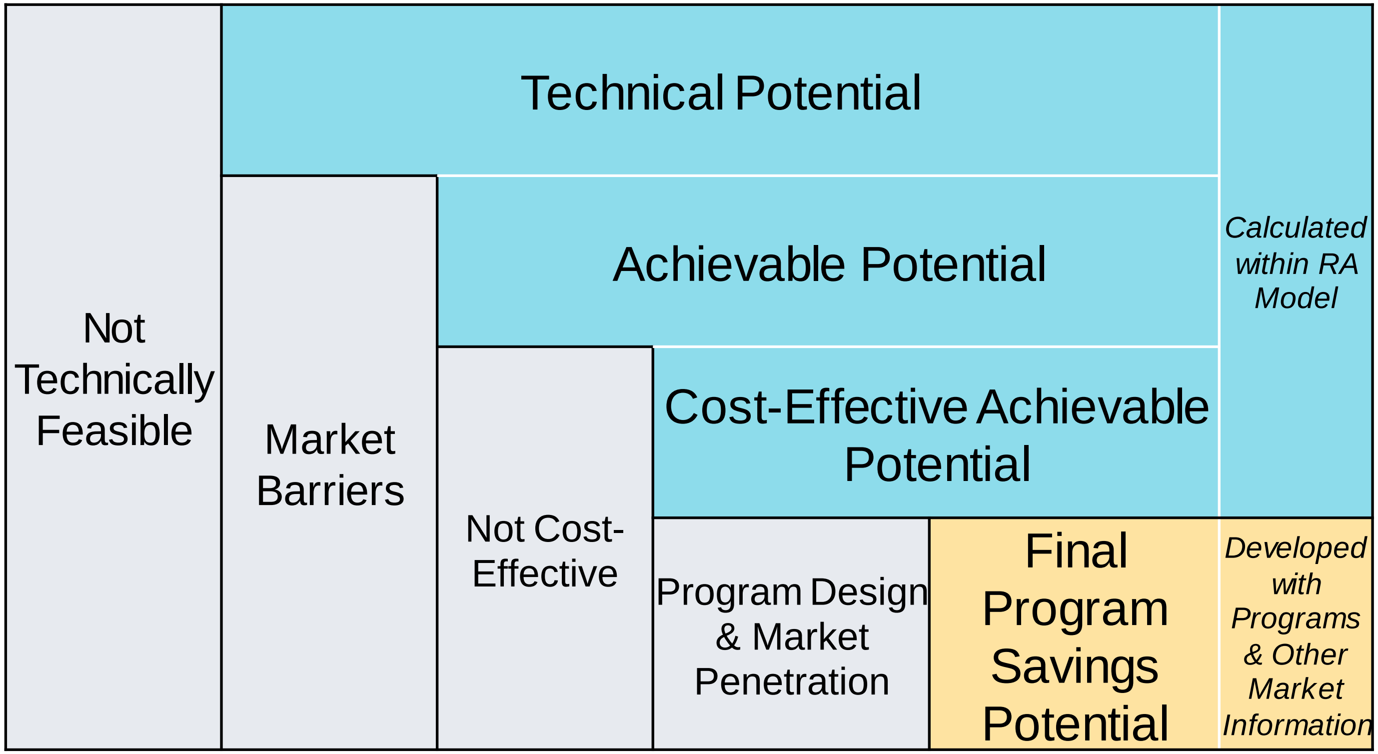
Residential	Commercial	Industrial
• Path 5 Emerging Super Efficient Whole Home • Window Replacement (U<.20), Gas SF • Absorption Gas Heat Pump Water Heaters • Advanced Insulation	• DOAS/HRV - GAS Space Heat • Gas-fired HP HW • Gas-fired HP, Heating • Advanced Windows	• Gas-fired HP Water Heater • Wall Insulation- VIP, R0-R35

- Model includes savings potential from emerging technologies
- Factors in changing performance, cost over time
- Use risk factors to hedge against uncertainty

	Risk Factors for Emerging Technologies				
Risk Category	**10%**	**30%**	**50%**	**70%**	**90%**
Market Risk (25% weighting)	Requires new/changed business model Start-up, or small manufacturer Significant changes to infrastructure Requires training of contractors. Consumer acceptance barriers exist.		Training for contractors available. Multiple products in the market.	Trained contractors Established business models Already in U.S. Market Manufacturer committed to commercialization	
Technical Risk (25% weighting)	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	Proven technology in target application. Multiple potentially viable approaches.
Data Source Risk (50% weighting)	Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	Evaluation results or multiple third party case studies

Results

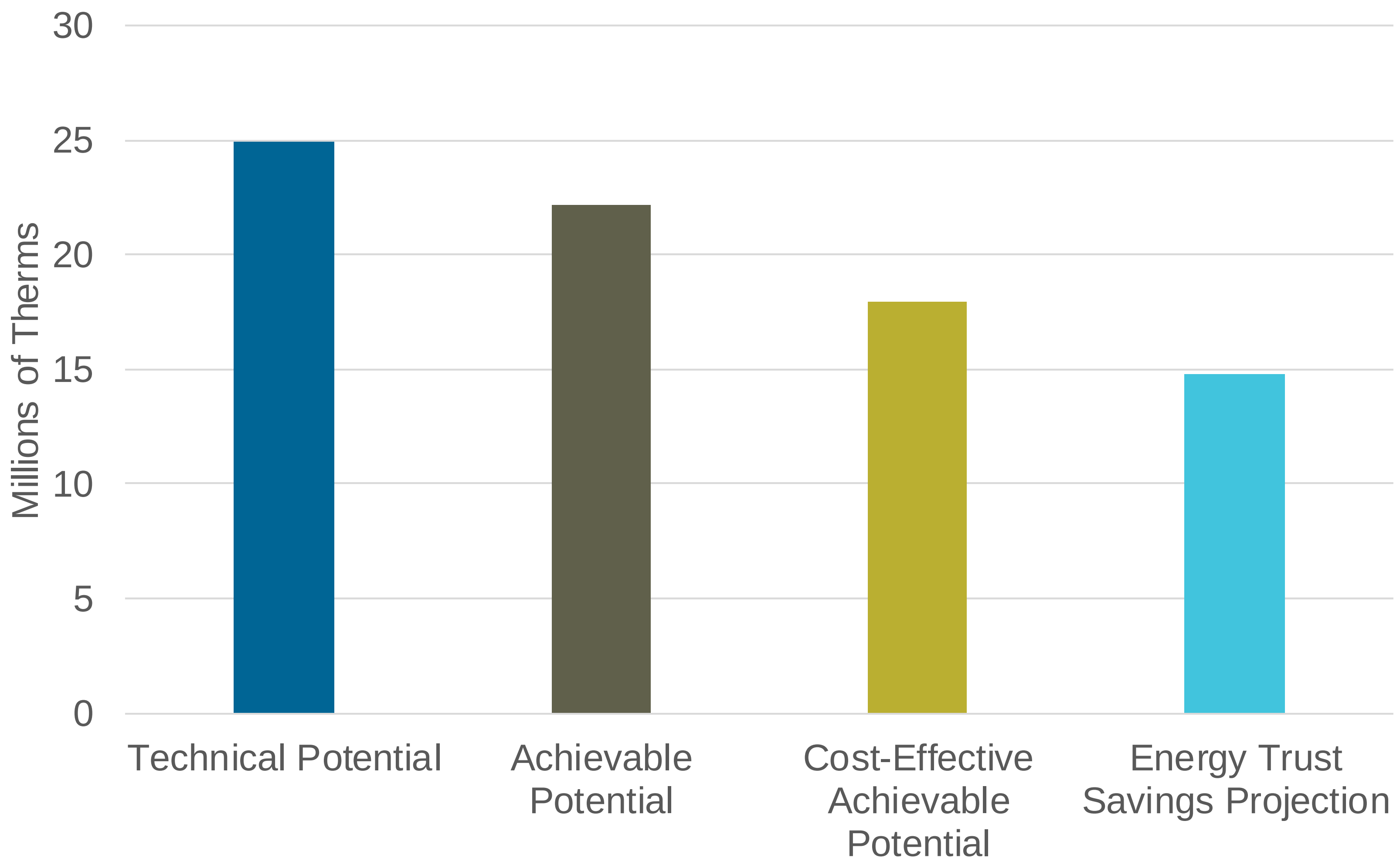
Outputs of Potential Type



The RA Model estimates the in Technical, Achievable and Cost-Effective Achievable potential

Final Program Savings Potential is deployed exogenously of the model using the Cost-Effective Achievable potential from the RA model in combination with program expertise on what can be achieved

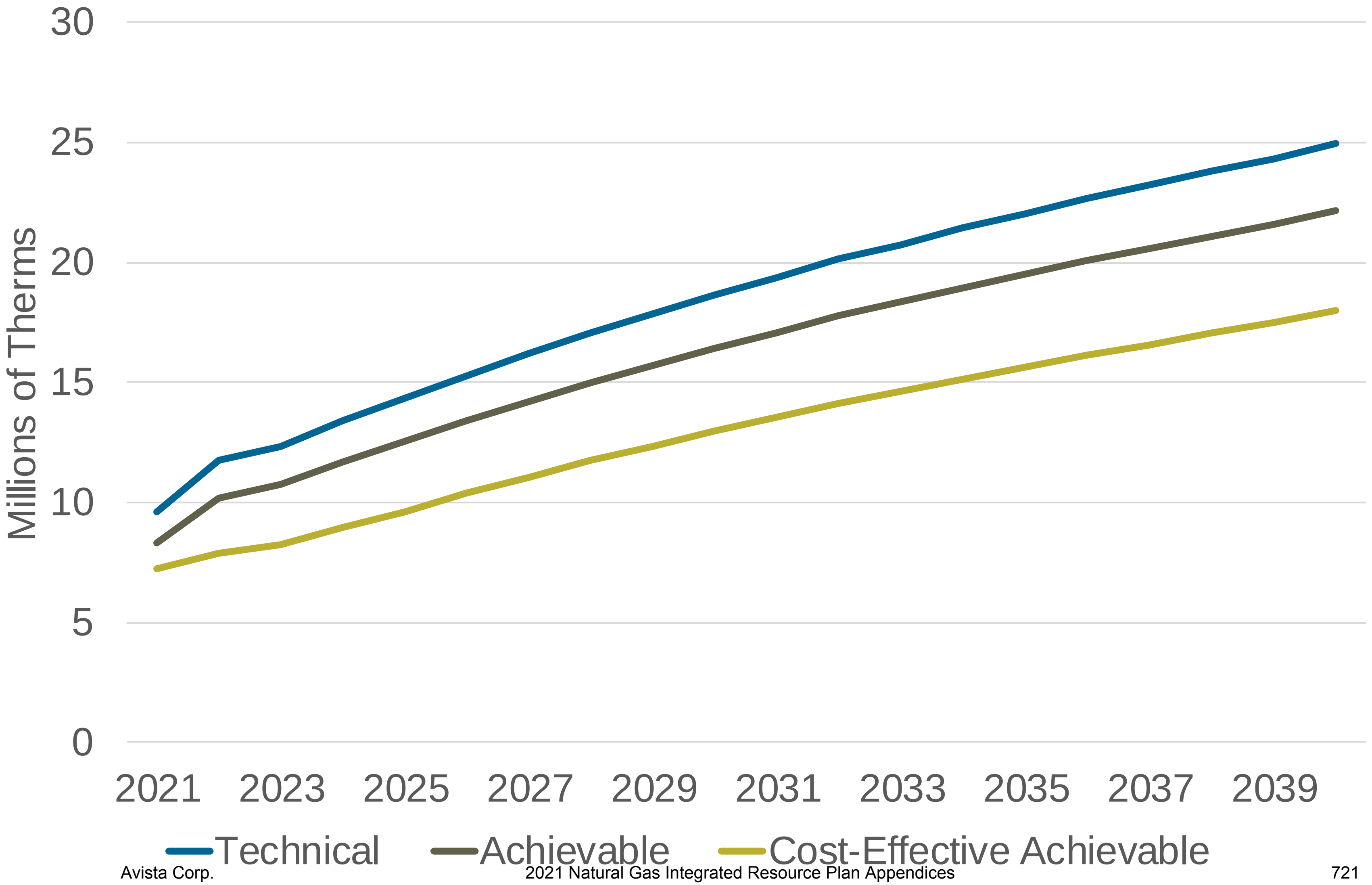
Overall Cumulative Savings Results



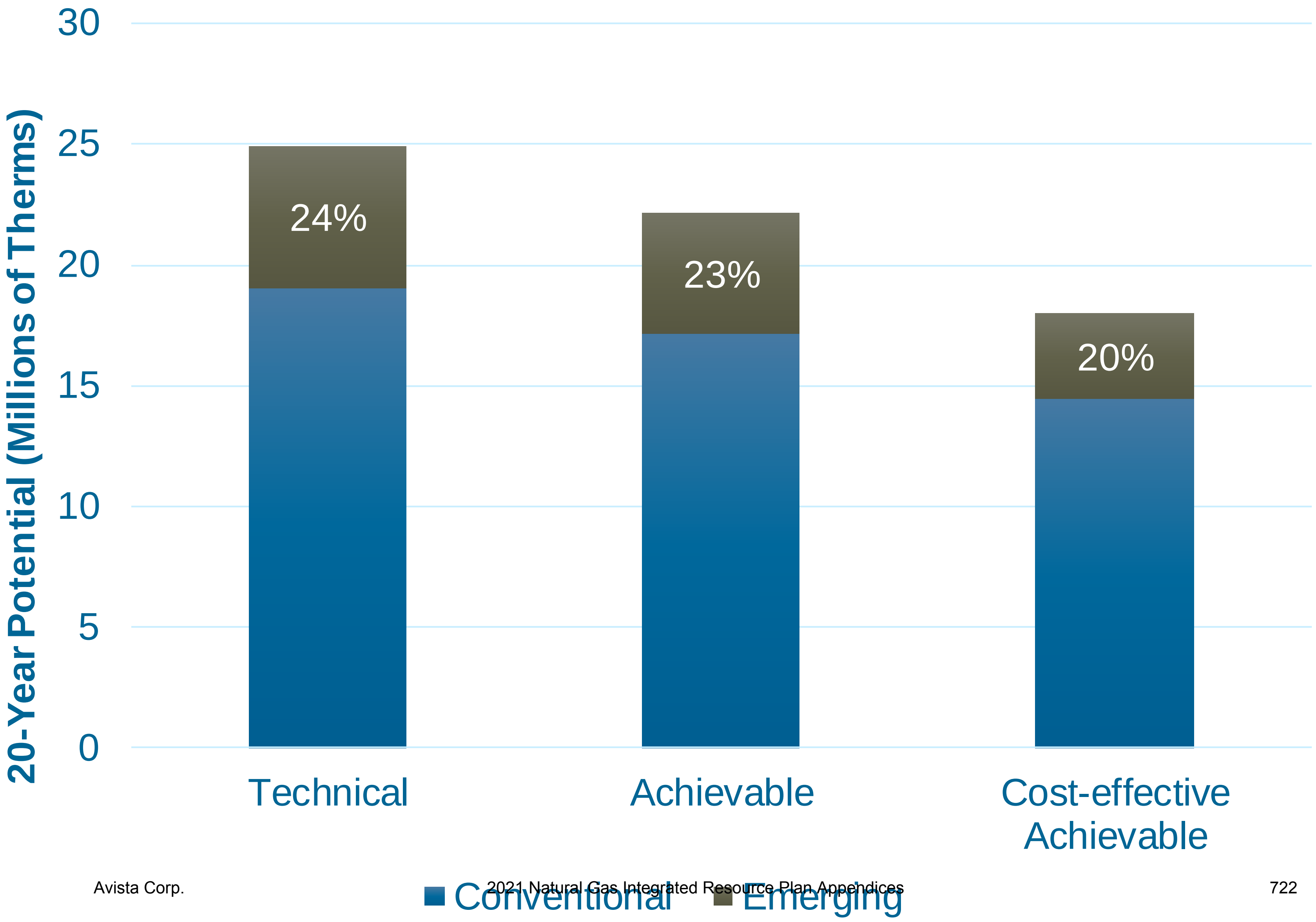
RA Model Results

Technical, Achievable, and Cost-Effective Achievable

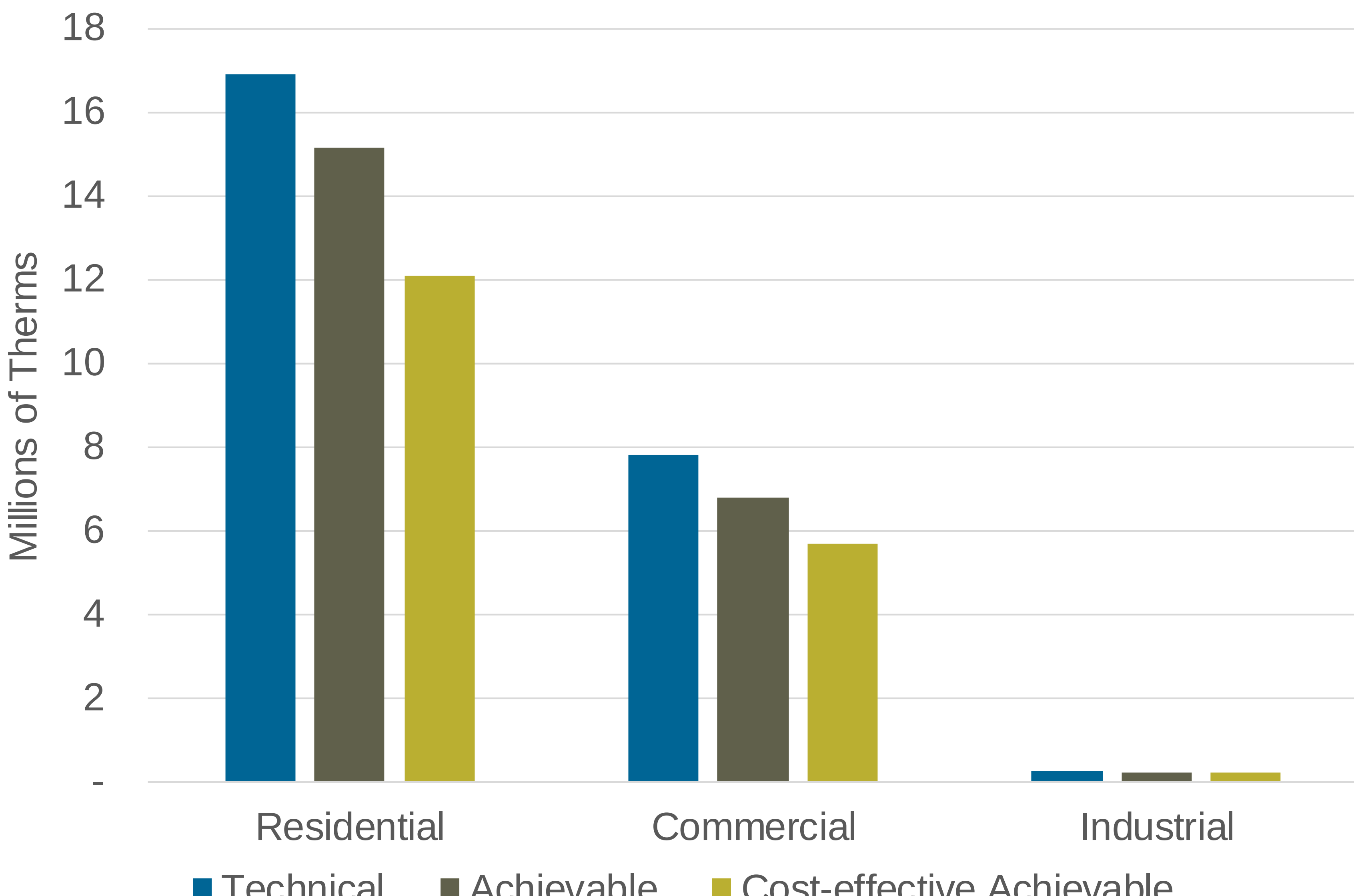
Cumulative Potential by Type and Year



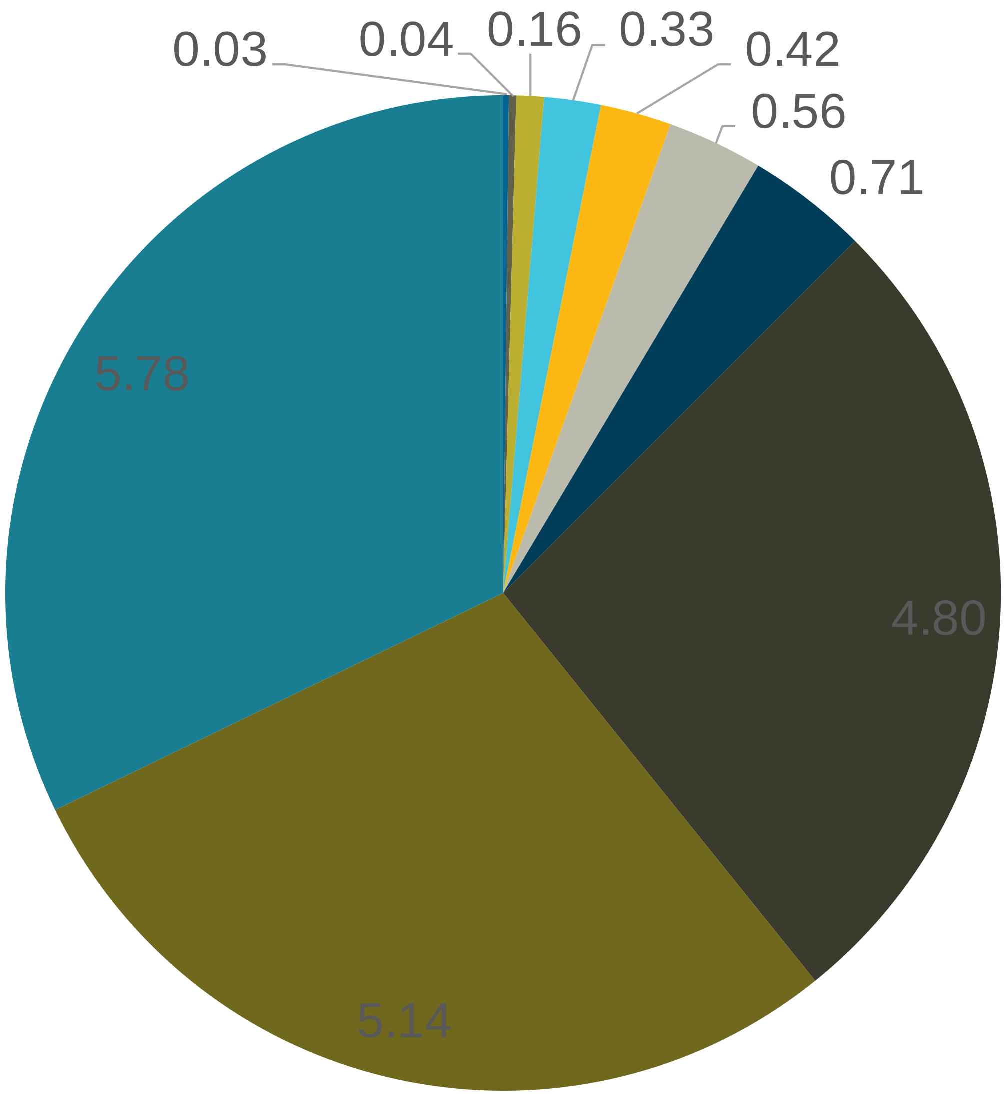
Contribution of Emerging Technology



Cumulative Potential by Sector and Type



Cost-effective Achievable Potential by End Use

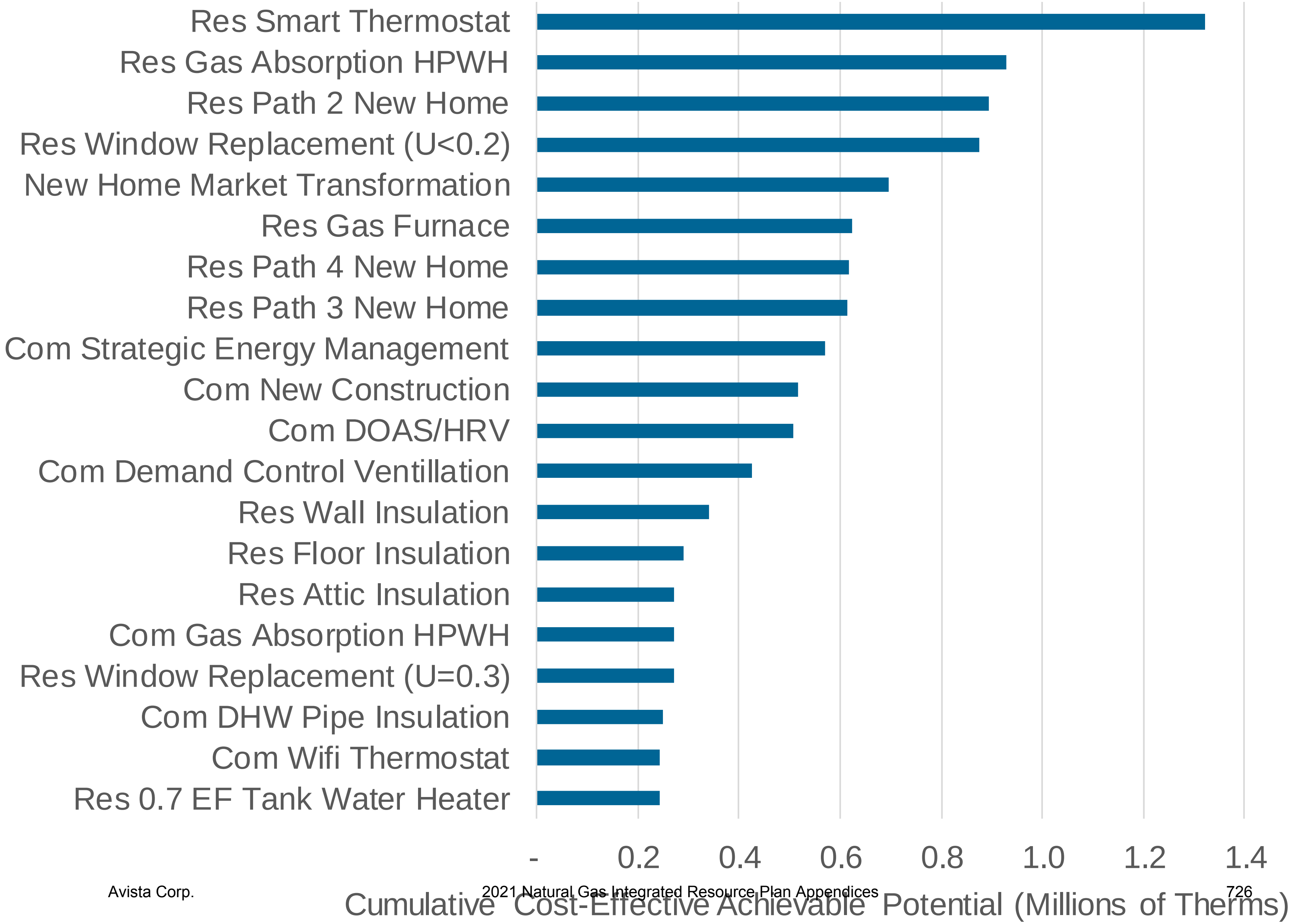


Cost-Effective Override Effect – (Millions of Therms)

Sector	Potential with Override	Potential without Override	Difference
Residential	12.1	10.9	1.2
Commercial	5.7	5.7	0.0
Industrial	0.2	0.2	0.0
Total	**18.0**	**16.8**	**1.2**

Measures with CE Override in Model:
- Res Insulation (ceiling, floor, wall)
- Res Clothes Dryers
- Res New Homes Packages
- Com Clothes Washers

Top-20 Measures



Final Savings Projections -
Deployed Results

Final Savings Projection Methodology

Energy Trust sets the first five years of energy efficiency acquisition to program performance and budget goals.

Years 1-2

- Program forecasts – they know what is happening short term best

Years 3-5

- Planning and Programs work together to create forecast

Years 6-20

- Planning forecasts long-term acquisition rate to generally align NWPCC

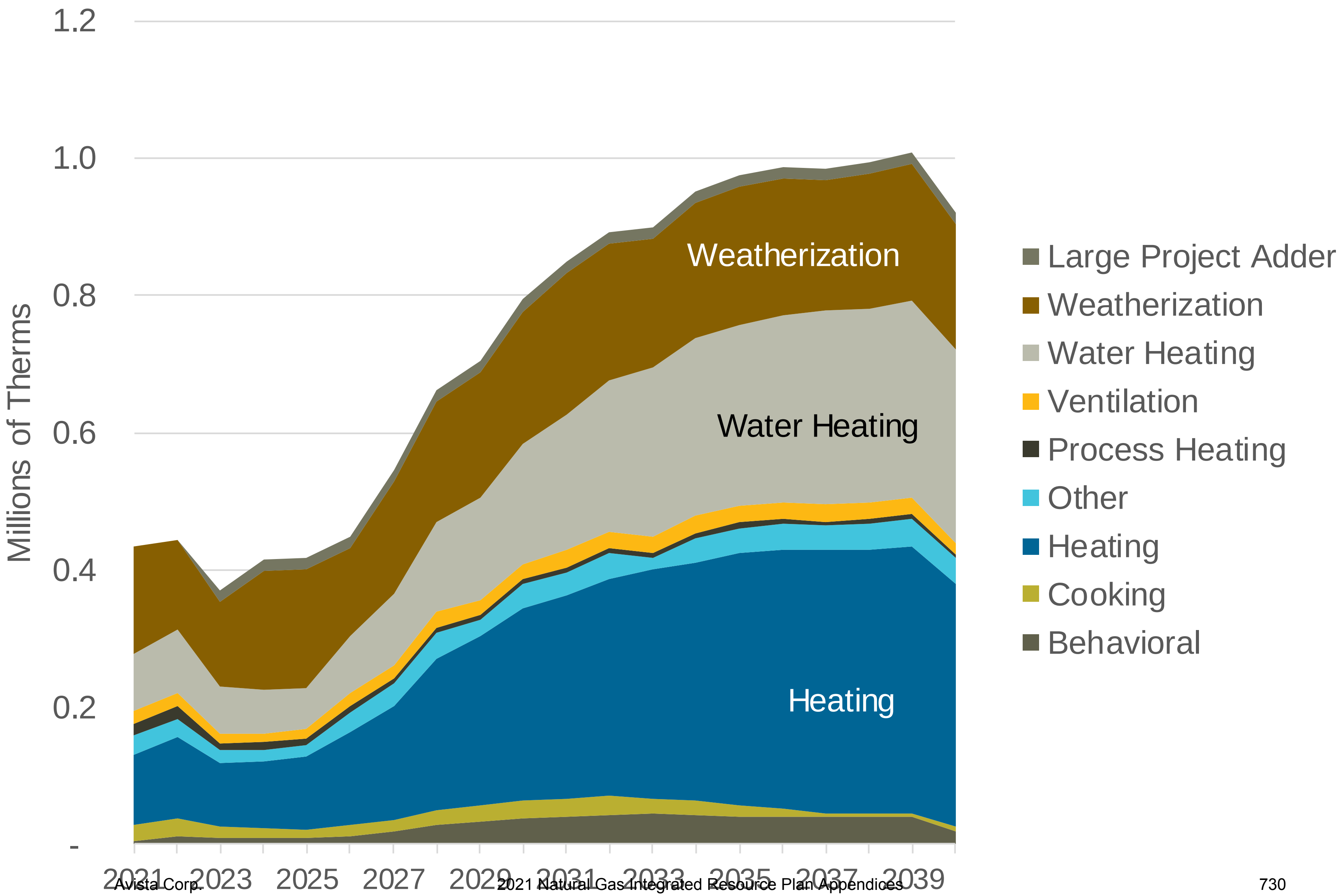
Cumulative Potential by Type – Millions of Therms

	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Energy Trust Savings Projection
Residential	16.9	15.2	12.1	8.2
Commercial	7.8	6.8	5.7	6.1
Industrial	0.3	0.2	0.2	0.5
All Sectors	**24.9**	**22.2**	**18.0**	**14.8**

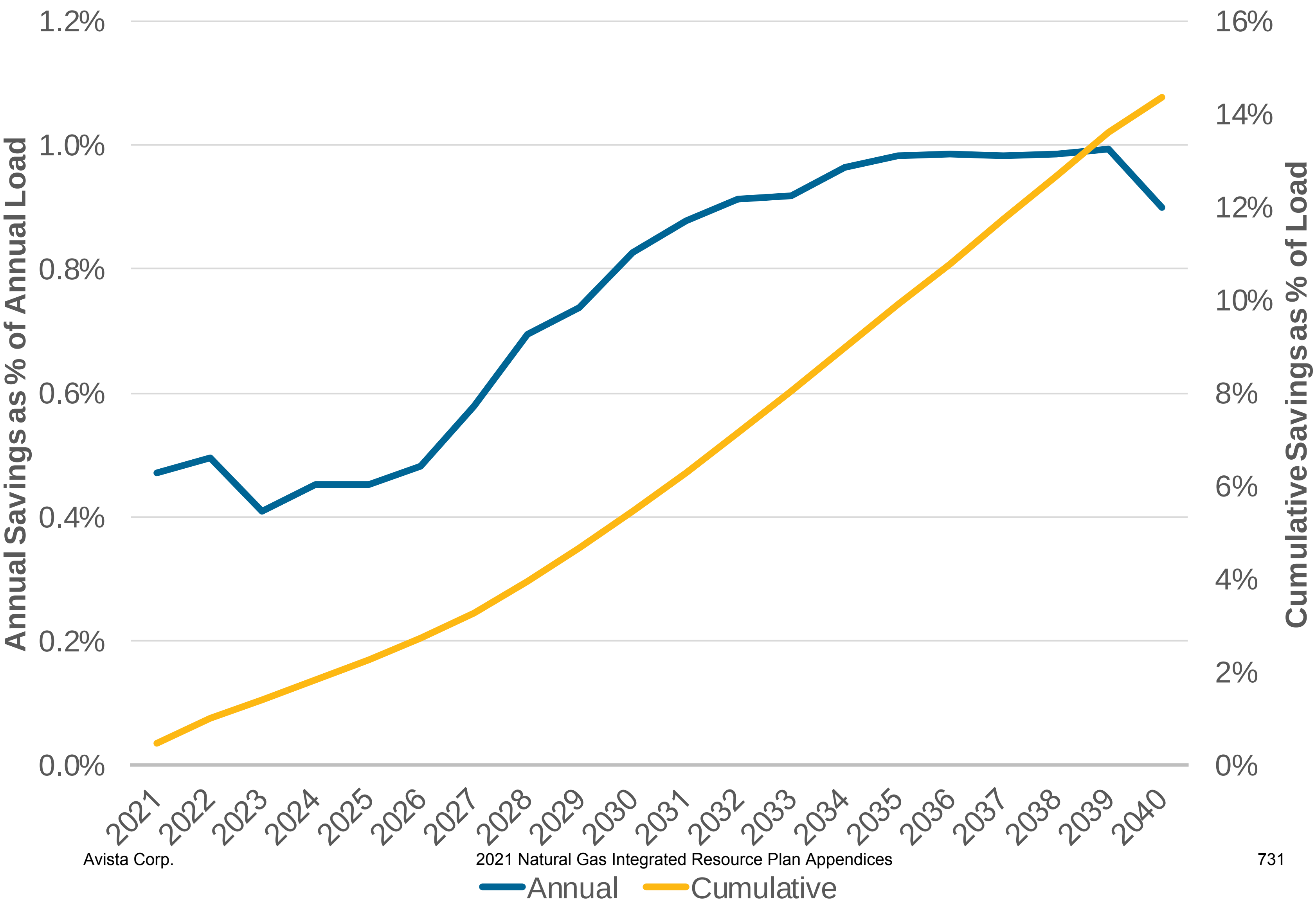
Not all Cost-Effective Potential is projected to be achieved because:

- Lost opportunity with 'Replacement' and 'New Constr.' measures
- Hard to reach measures (e.g. insulation)
- Other market barriers identified by programs & new service territory

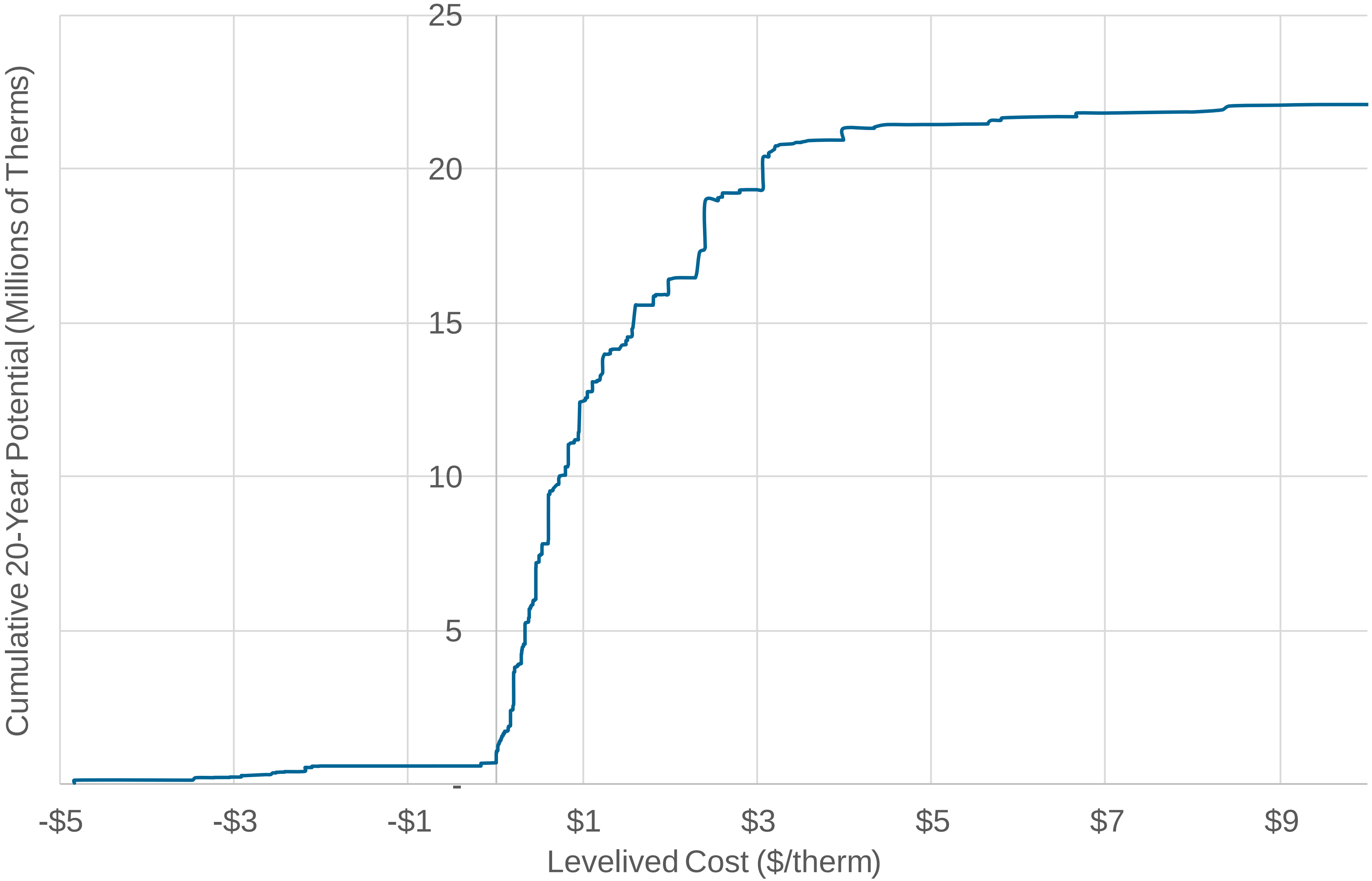
Cost-Effective Savings



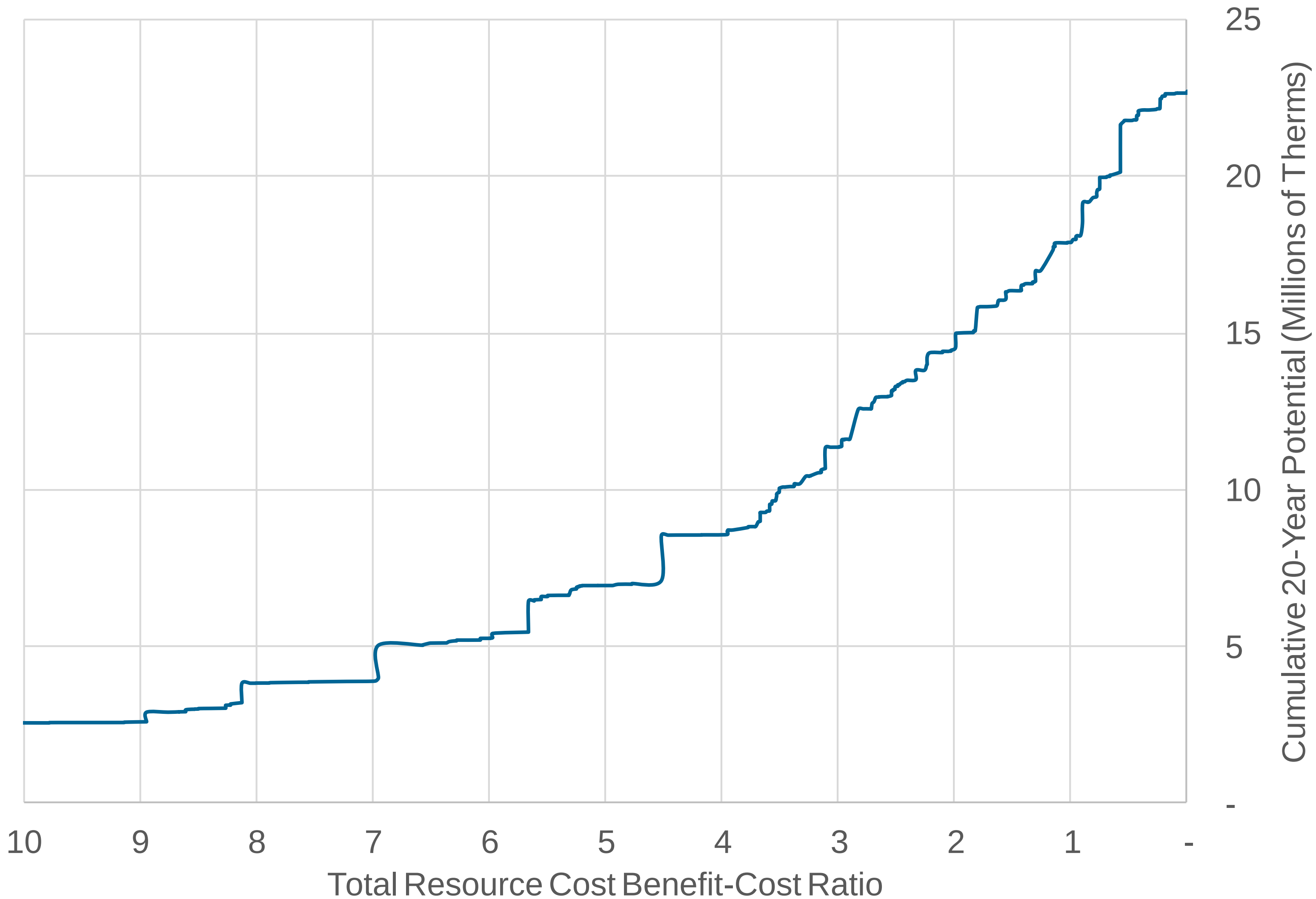
Projected Savings as Percent of Annual Load



Levelized Cost Supply Curve



Benefit Cost Ratio Supply Curve



Thank you

Spencer Moersfelder,

Planning Manager

spencer.moersfelder@energytrust.org

503.548.1596

Ted Light,

Lighthouse Energy Consulting

ted@lighthouseenergynw.com

503.395.5310

Sendout Model

Modeling Transportation In SENDOUT®

- Start with a point-in-time look at each jurisdiction's resources
  - Contracts – Receipt and Delivery Points
  - Rates
- Contractual vs. Operational
  - Contractual can be overly restrictive
  - Operational can be overly flexible
- Incorporating operational realities into our modeling can defer the need to acquire new resources
- Gas Supply's job is to get gas from the supply basin to the pipeline citygate
- Gas Engineering/Distribution's job is to take gas from the pipeline citygate to our customers
- The **major** limiting factor is receipt quantity – how much can you bring into the system?

Modeling Challenges

- Supply needs to get gas to the gate
- Contracts were created years ago, based on demand projections at that point in time
- Stuff happens (i.e. growth differs from forecast)
- Sum of receipt quantity and aggregated delivery quantity don't identify resource deficiency for quite some time however…..
- The aggregated look can mask individual city gate issues, and the disaggregated look can create deficiencies where they don't exist
- In many cases, operational capacity is greater than contracted
- Transportation resources are interconnected (two pipes can serve one area)
- WARNING – we need to be mindful of the modeling limitations

What is in SENDOUT®?

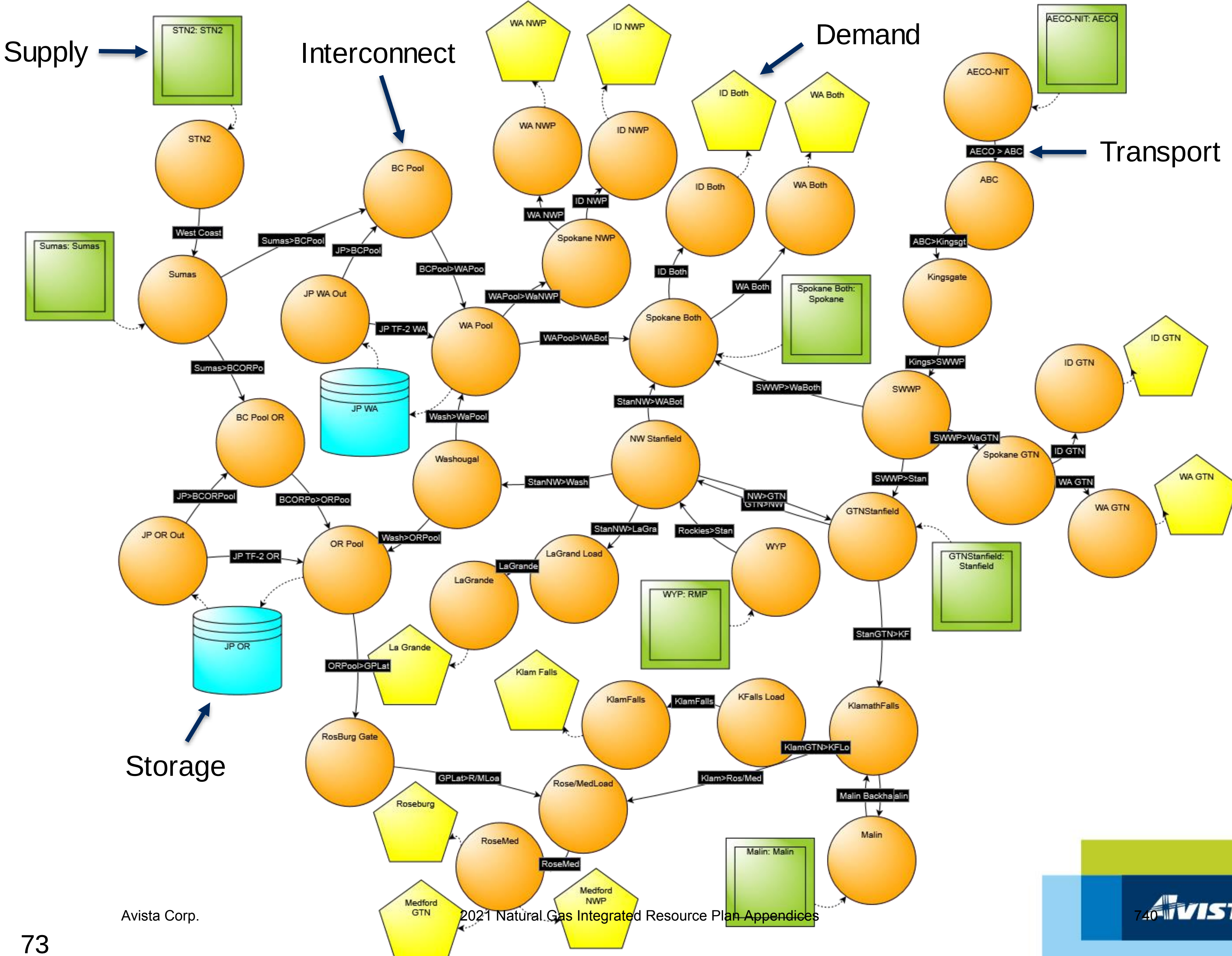
Inside:

- Demand forecasts at an aggregated level
- Existing firm transportation resources and current rates
  - Receipt point to aggregated delivery points/“zone”
  - Jurisdictional considerations
  - Long term capacity releases
- Potential resources, both supply and demand side

What is outside SENDOUT®?

Outside:

- Gate station analysis
  - Forecasted demand behind the gate
    - Growth rates consistent with IRP assumptions
    - Actual hourly/daily city gate flow data
  - Gate station MDDO’s
  - Gate station operational capacities

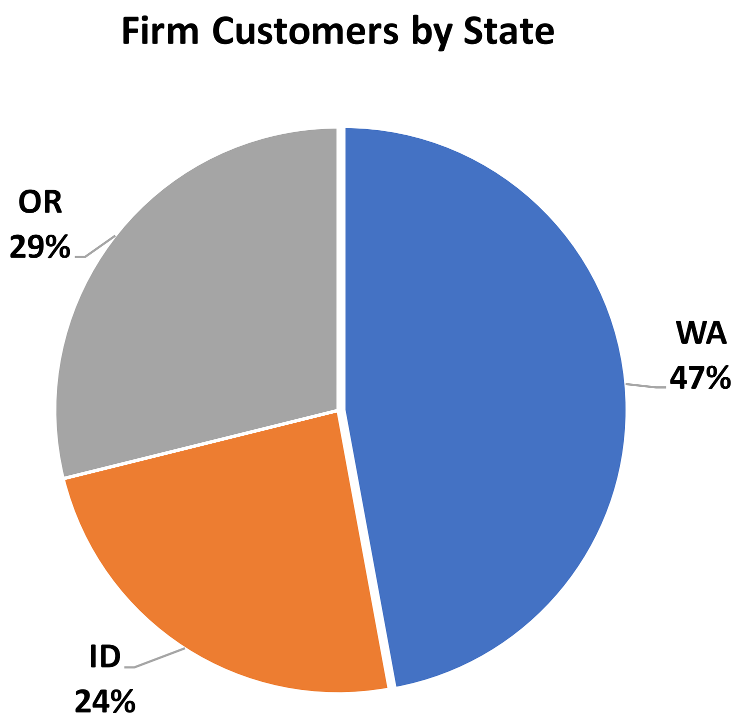

Supply
Interconnect
Demand
Transport
Storage
STN2: STN2
STN2
West Coast
Sumas: Sumas
Sumas
Sumas>BCPool
JP>BCPool
BC Pool
JP WA Out
JP TF-2 WA
JP WA
BCPool>WAPoo
WA Pool
Wash>WaPool
Sumas>BCORPo
BC Pool OR
JP>BCORPool
BCORPo>ORPoo
JP OR Out
JP TF-2 OR
JP OR
OR Pool
Wash>ORPool
Washougal
WA NWP
ID NWP
Spokane NWP
WAPool>WaNWP
WAPool>WABot
Spokane Both
ID Both
WA Both
Spokane Both: Spokane
StanNW>WABot
NW Stanfield
StanNW>Wash
StanNW>LaGra
LaGrand Load
LaGrande
Rockies>Stan
WYP
WYP: RMP
NW>GTN
GTN>NW
SWWP>WaBoth
AECO-NIT: AECO
AECO-NIT
AECO > ABC
ABC
ABC>Kingsgt
Kingsgate
Kings>SWWP
SWWP
SWWP>WaGTN
SWWP>Stan
Spokane GTN
ID GTN
WA GTN
GTNStanfield
GTNStanfield: Stanfield
StanGTN>KF
KlamathFalls
KlamGTN>KFLo
KFalls Load
KlamFalls
Klam Falls
Klam>Ros/Med
Malin Backha
alin
Malin
Malin: Malin
ORPool>GPLat
La Grande
RosBurg Gate
GPLat>R/MLoa
Rose/MedLoad
RoseMed
Roseburg
Medford GTN
Medford NWP

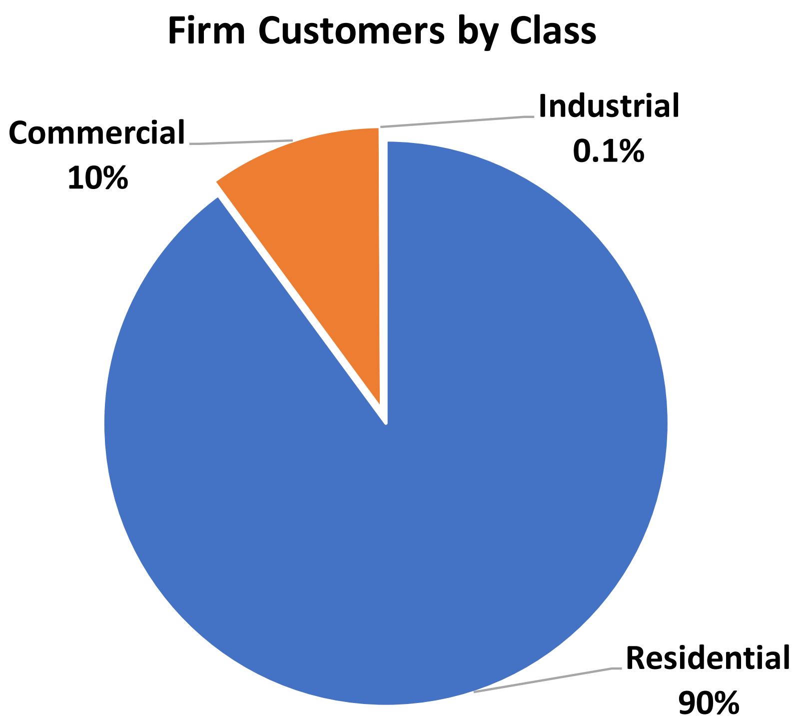
New Planning Software

- Avista is looking for a new software solution to model our natural gas system and the increasingly complex system with carbon reduction goals
- We hope to have this software available for the next round of Integrated Resource Planning (IRP) and to model it in parallel with Sendout

Assumptions Review

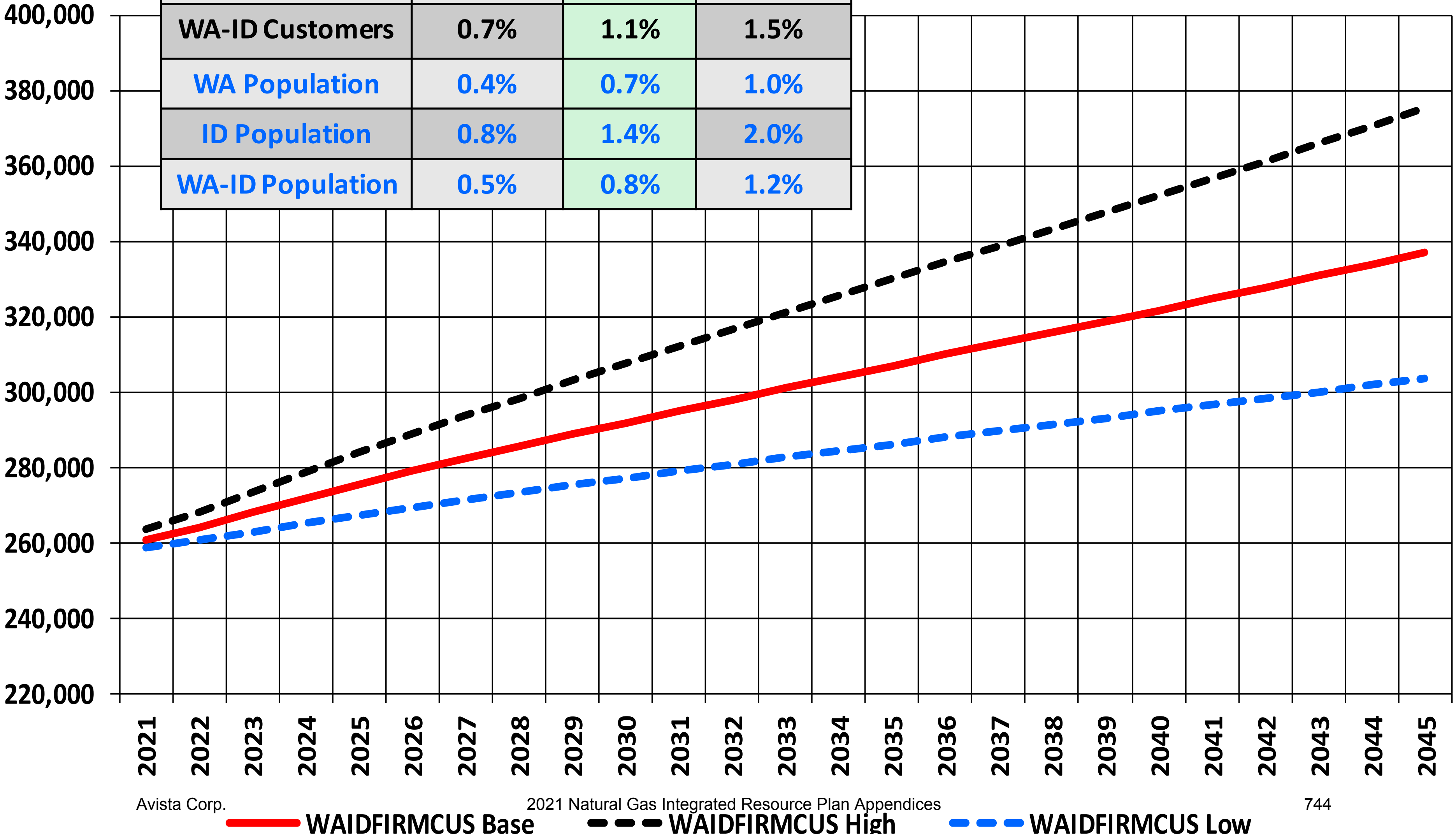
Firm Customers (Meters) by State and Class, 2019





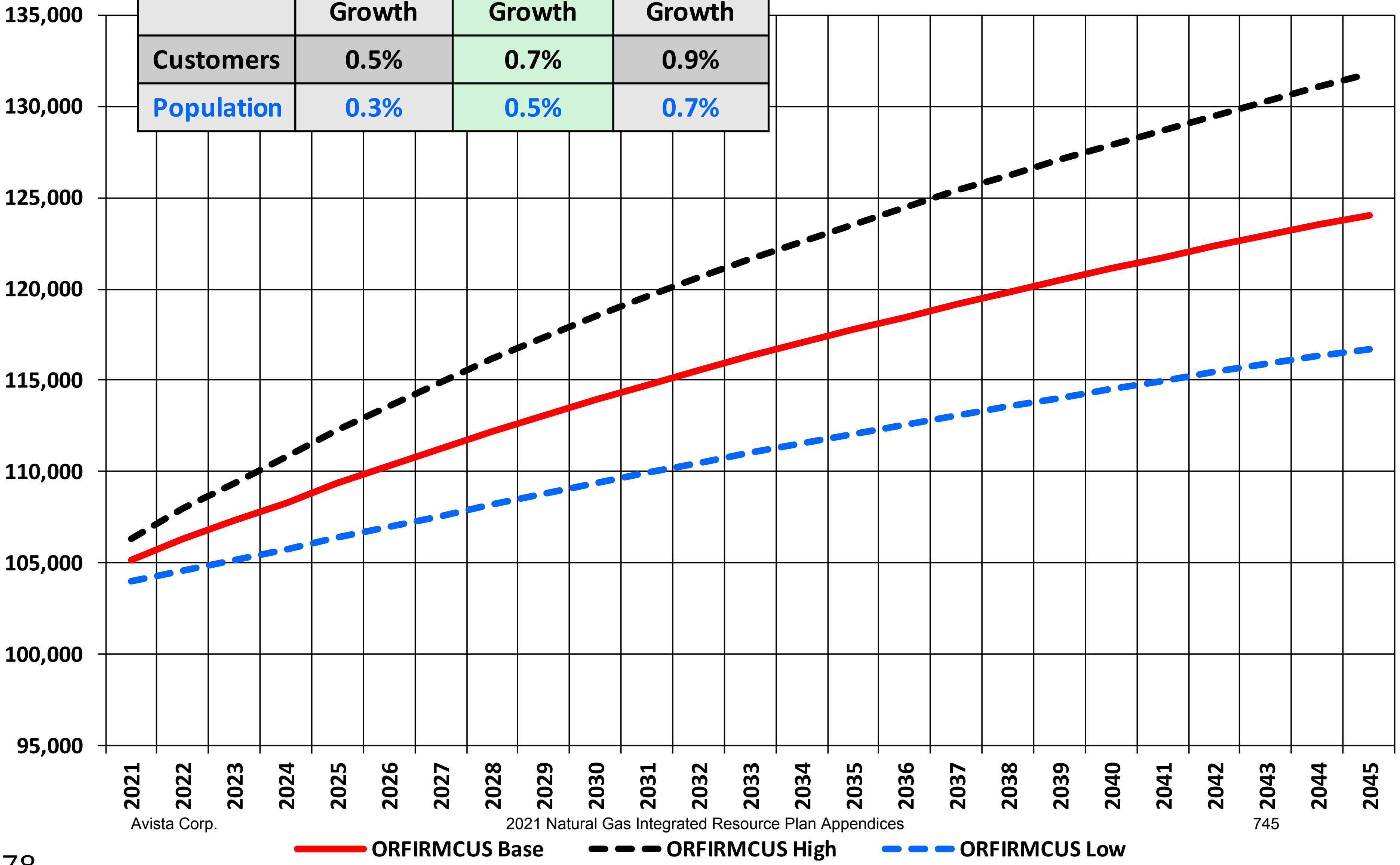
WA-ID Region Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
WA-ID Customers	0.7%	1.1%	1.5%
WA Population	0.4%	0.7%	1.0%
ID Population	0.8%	1.4%	2.0%
WA-ID Population	0.5%	0.8%	1.2%



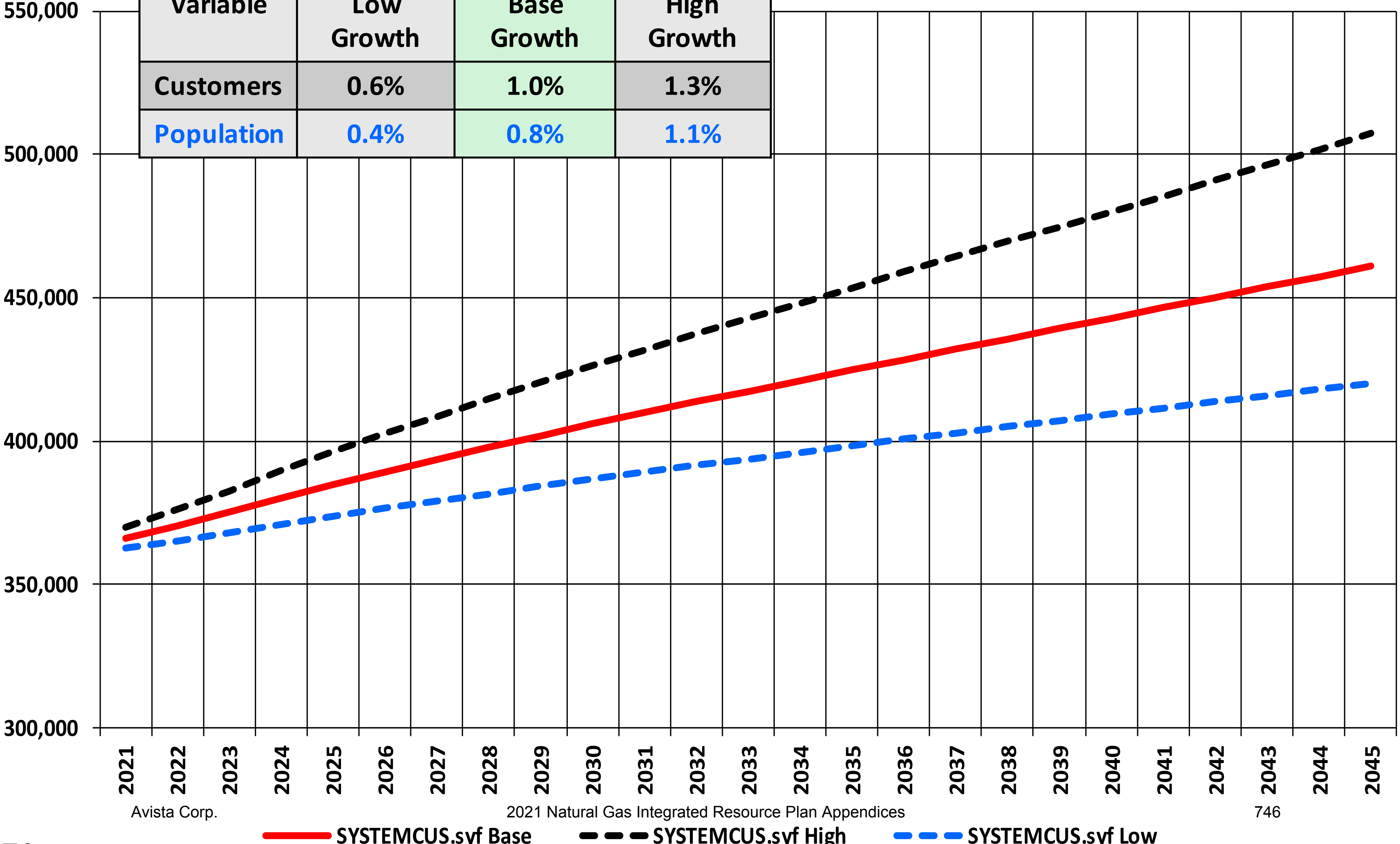
OR Region Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
Customers	0.5%	0.7%	0.9%
Population	0.3%	0.5%	0.7%



System Firm Customer Range, 2021-2045

Variable	Low Growth	Base Growth	High Growth
Customers	0.6%	1.0%	1.3%
Population	0.4%	0.8%	1.1%



Summary of Growth Rates

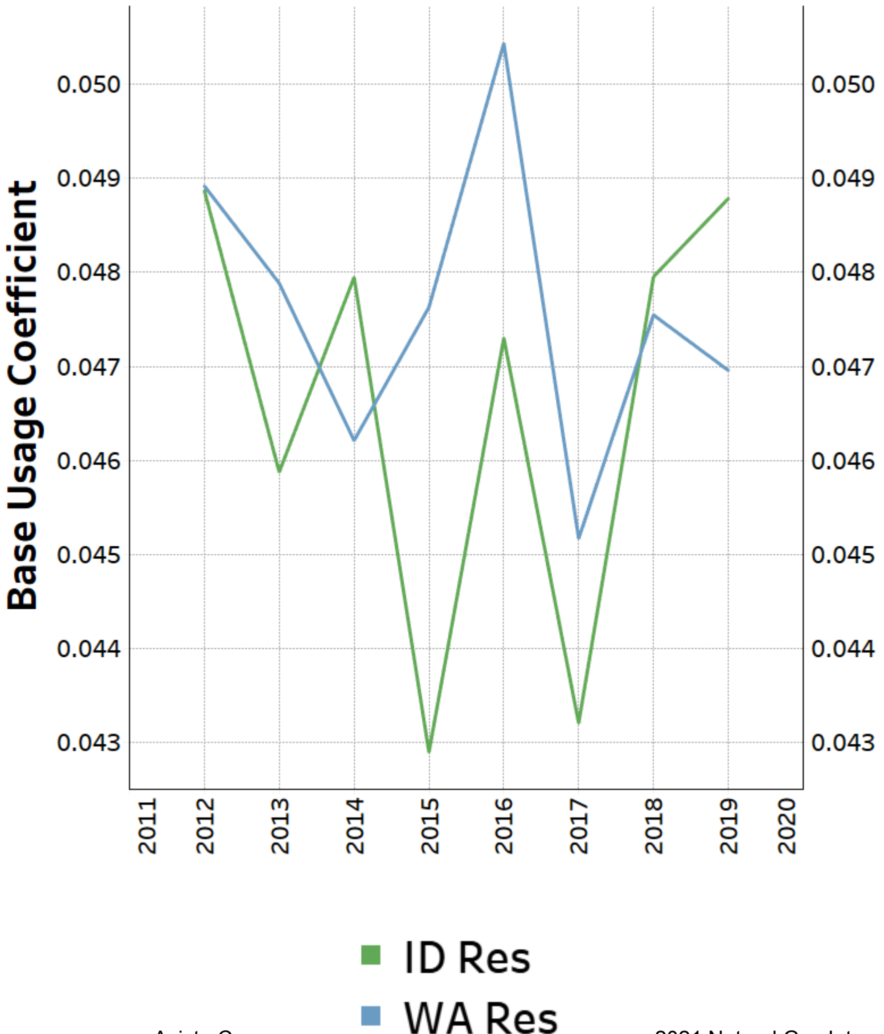
System	Base-Case	High	Low
Residential	1.0%	1.4%	0.7%
Commercial	0.5%	0.8%	0.1%
Industrial	-0.8%	2.2%	-3.8%
Total	1.0%	1.3%	0.6%

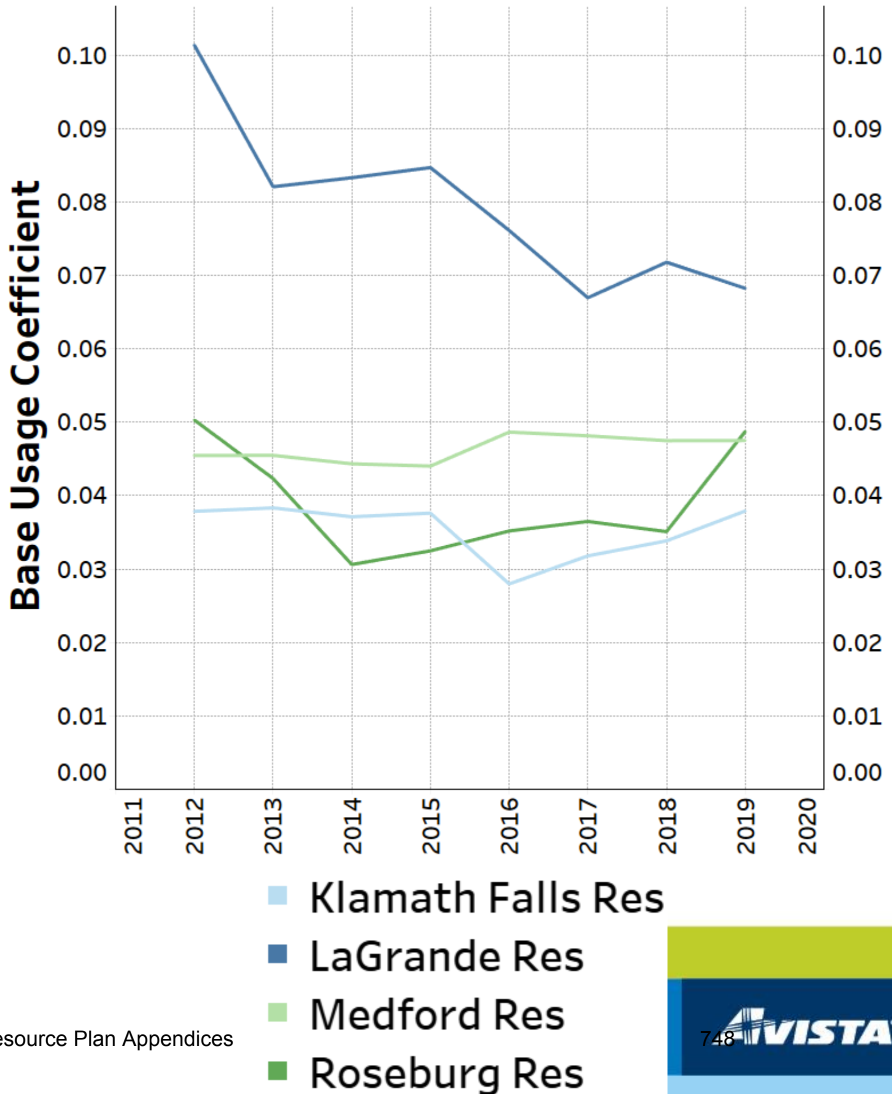
WA	Base-Case	High	Low
Residential	1.0%	1.3%	0.7%
Commercial	0.4%	0.7%	0.1%
Industrial	-0.8%	1.9%	-3.6%
Total	1.0%	1.3%	0.7%

ID	Base-Case	High	Low
Residential	1.4%	2.0%	0.8%
Commercial	0.4%	1.0%	-0.2%
Industrial	-1.0%	1.8%	-3.4%
Total	1.3%	1.9%	0.7%

OR	Base-Case	High	Low
Residential	0.7%	0.9%	0.5%
Commercial	0.6%	0.8%	0.4%
Industrial	0.0%	4.5%	-10.6%
Total	0.7%	0.9%	0.5%

Base Coefficients (July and August Averaged)





Heat Coefficients

Planning Area - Residential Class	2 Year	3 Year	5 Year
Roseburg (Oregon)	0.008829	0.008046	0.00699
Medford (Oregon)	0.00639	0.0065	0.006068
La Grande (Oregon)	0.006223	0.007297	0.00665
Klamath Falls (Oregon)	0.005284	0.005268	0.004902
Idaho	0.006445	0.006344	0.005896
Washington	0.006307	0.006313	0.005957

*Avg. of monthly heat coefficient

*Historic Data – adjusted by price elasticity and DSM

Price Elasticity

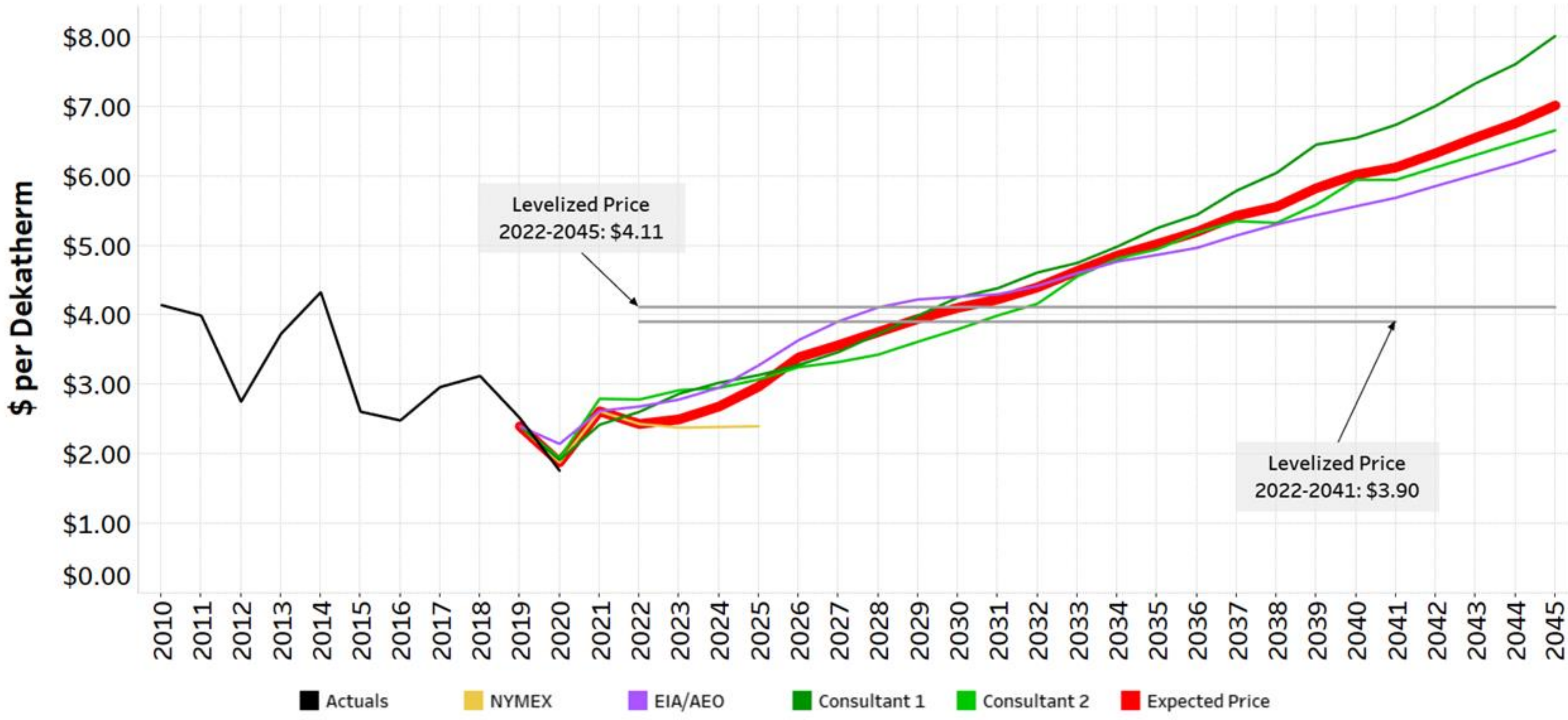
- The elasticity as measured in the Medford and Roseburg areas will be used for the entire system as estimated elasticity.
- 0.81% decrease only for each price rise of 10%
- This elasticity is measured through heat coefficients and annual price changes

Avista Weather Planning Standard

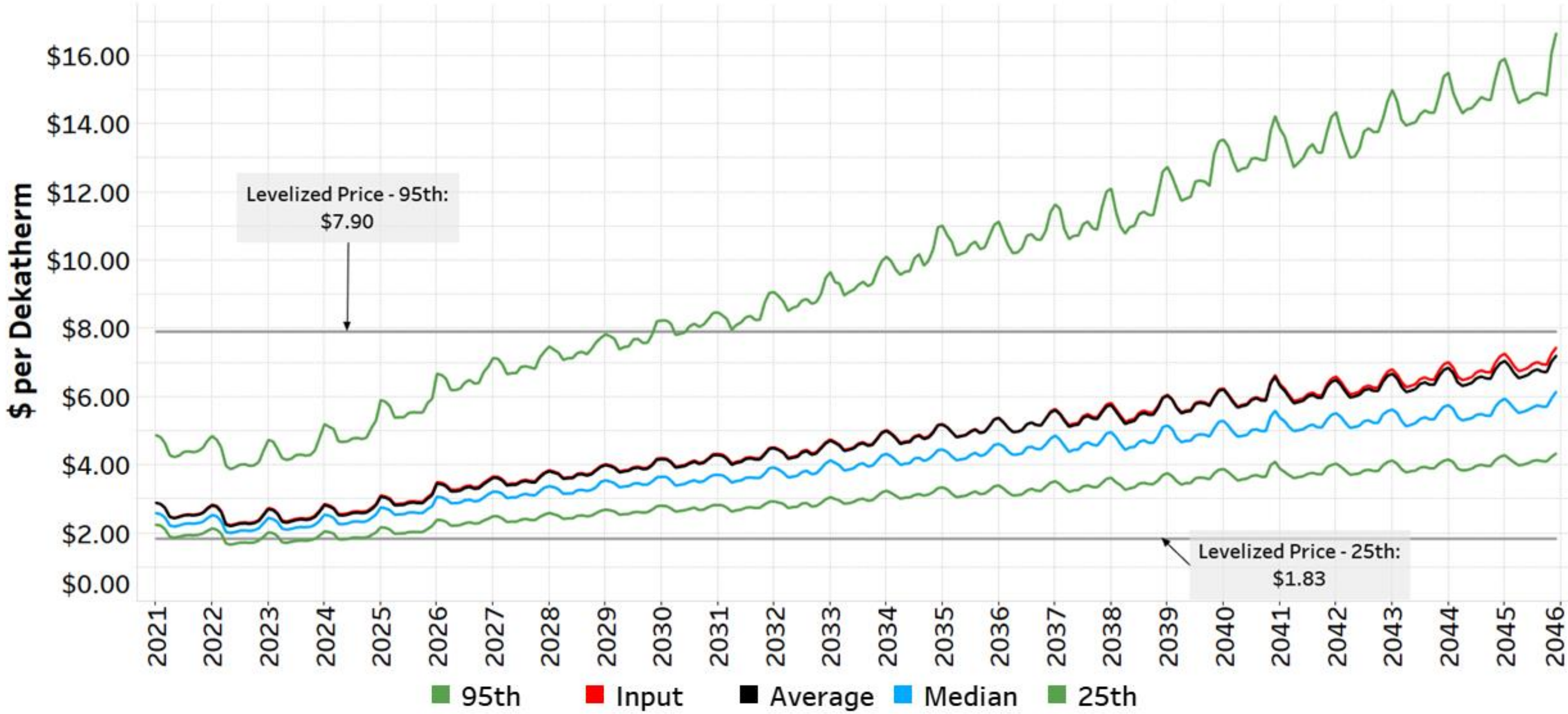
- Utilize coldest day for each of the past 30 years with a 99% probability supply can be fulfilled

Area	99% Probability Avg. Temp
La Grande	-11
Klamath Falls	-9
Medford	11
Roseburg	14
Spokane	-12

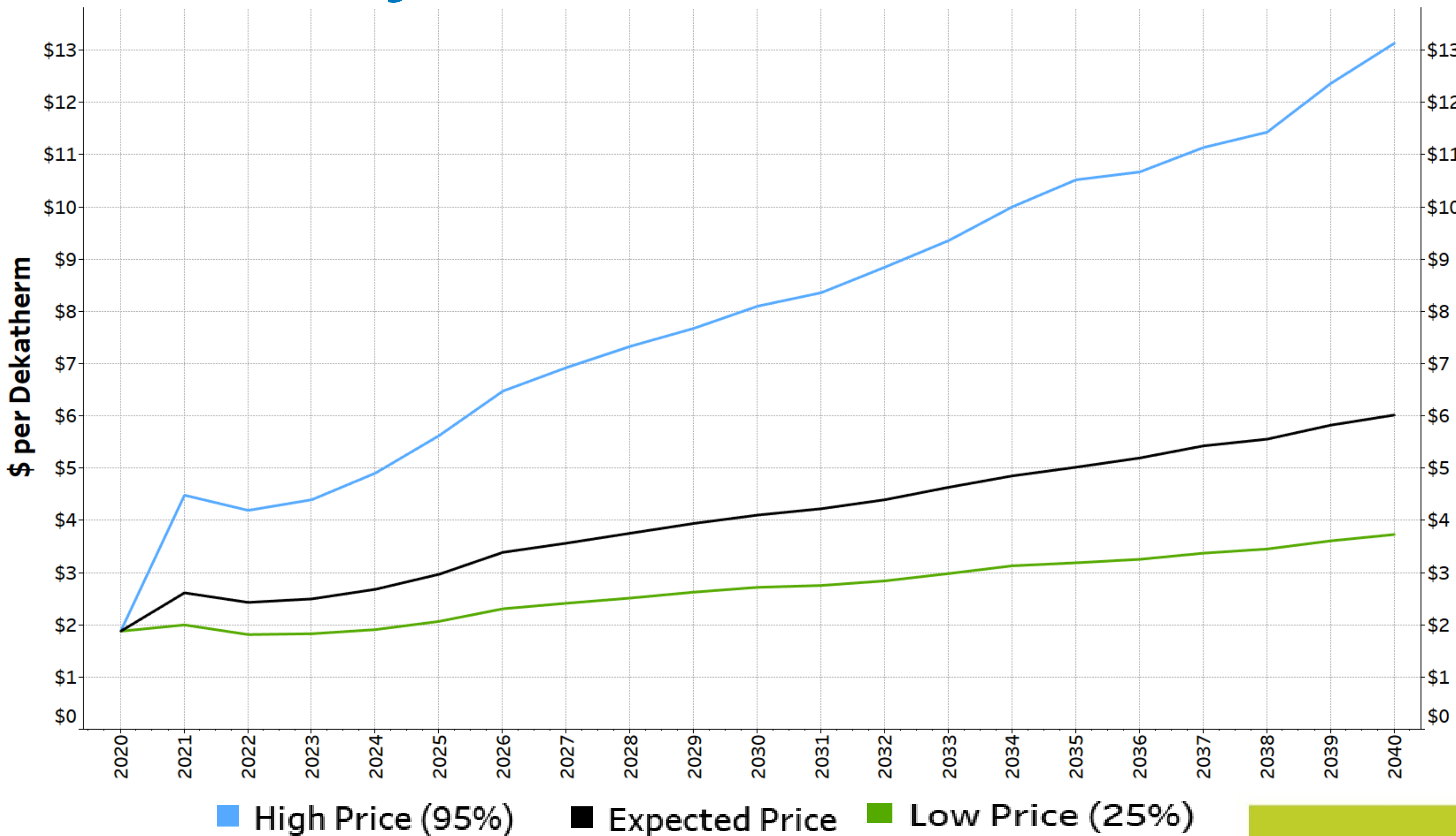
Henry Hub Expected Price and Average Annual Price Forecasts



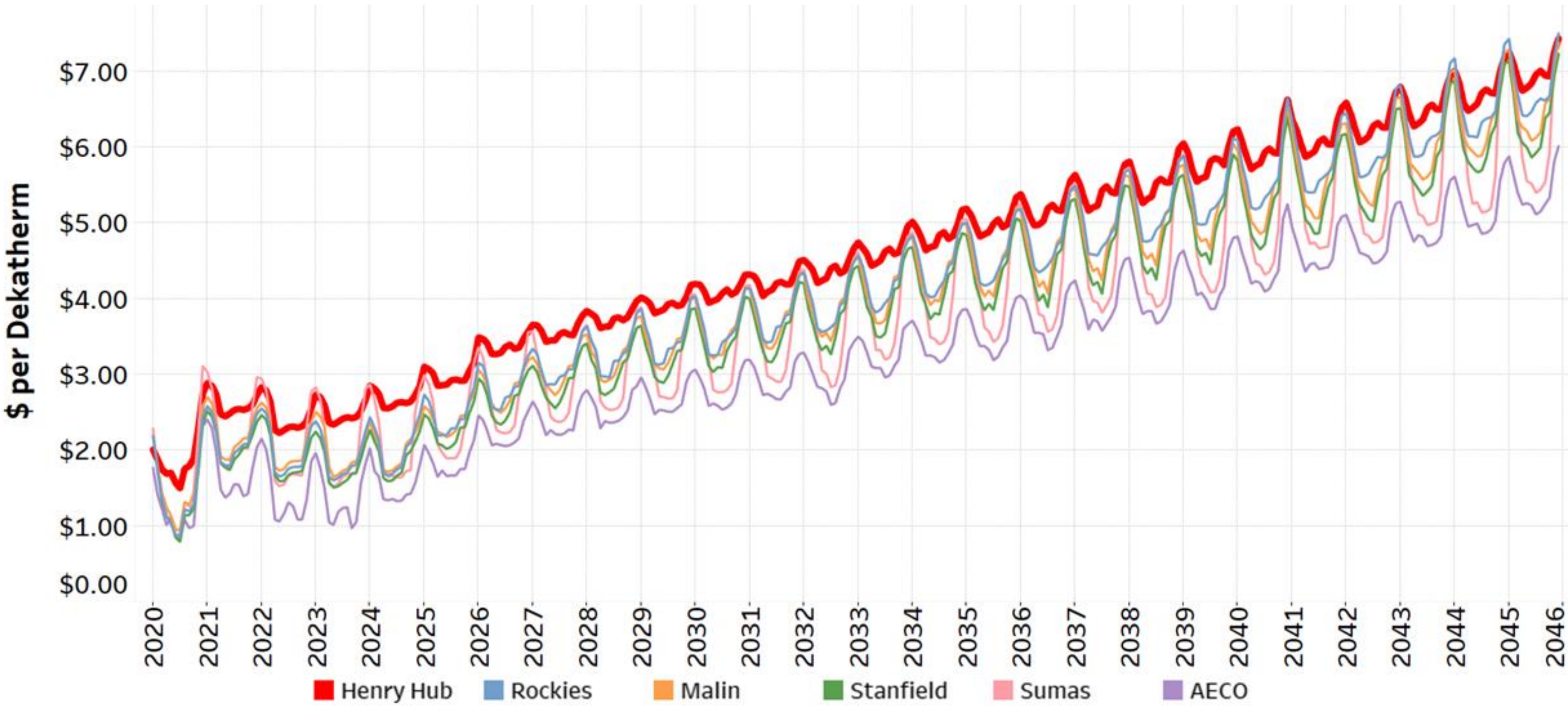
Stochastic Prices (Results from 1000 Draws)



2020 Henry Hub Prices - Nominal



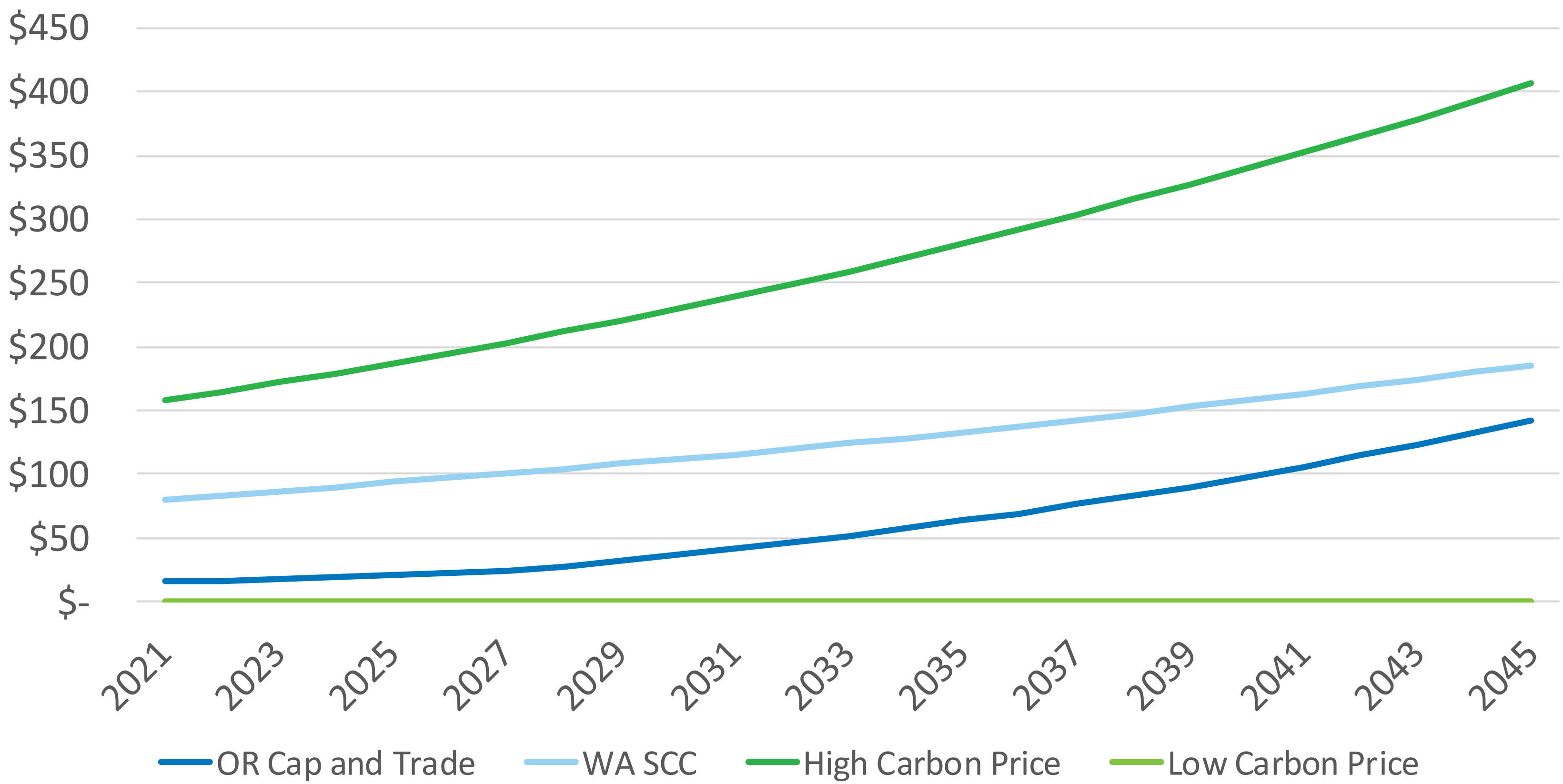
Prices by Gas Hub (Henry Hub Expected Price + Basis



Expected Case
Cost of Carbon by State - Summary

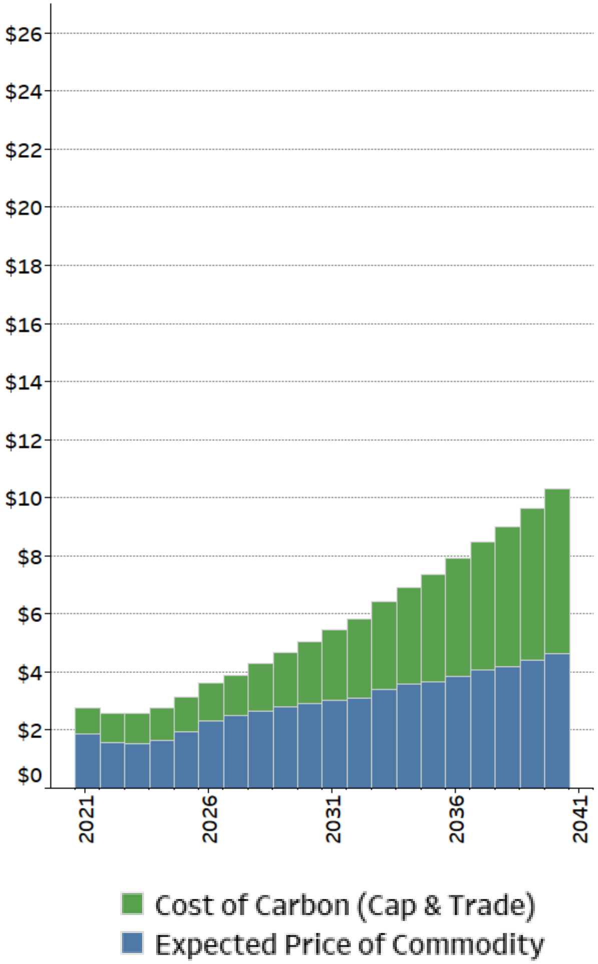
- Washington - Social cost of carbon @ 2.5% discount rate;
  - upstream emissions associated with natural gas drilling and transportation of natural gas to its end use.
- Oregon is based off a Wood Mackenzie estimate for Cap and Trade
- Idaho - carbon prices will not be included

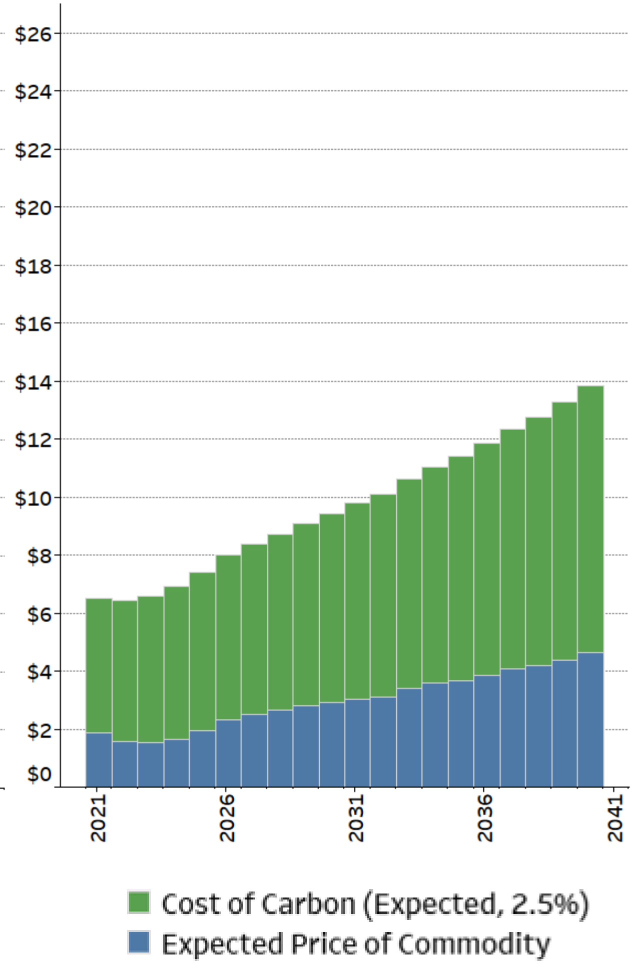
Carbon Costs

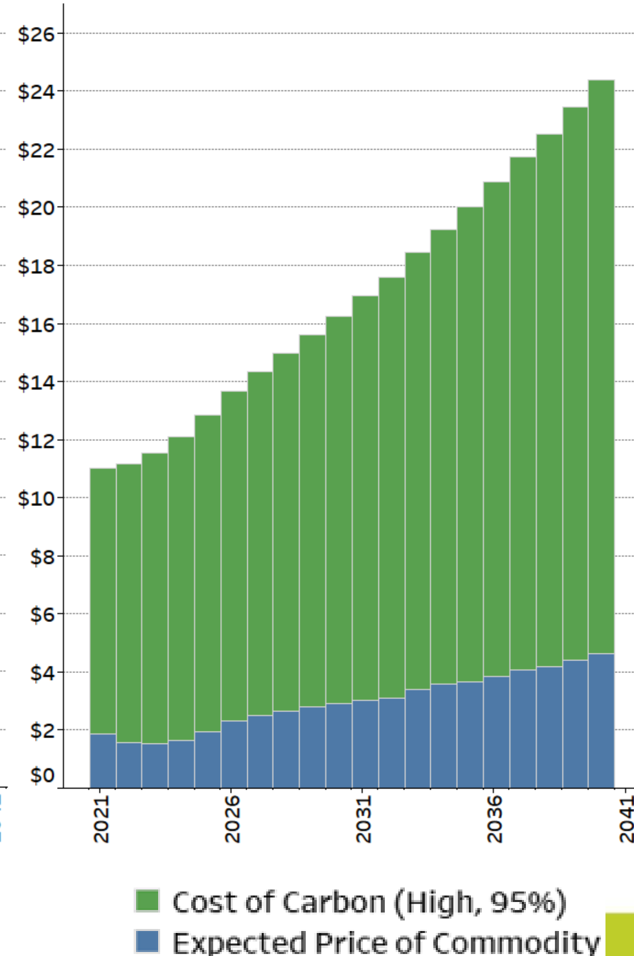


Levelized Cost per MTCO2e	$44.92	$113.75	$234.45	$0

Carbon Costs







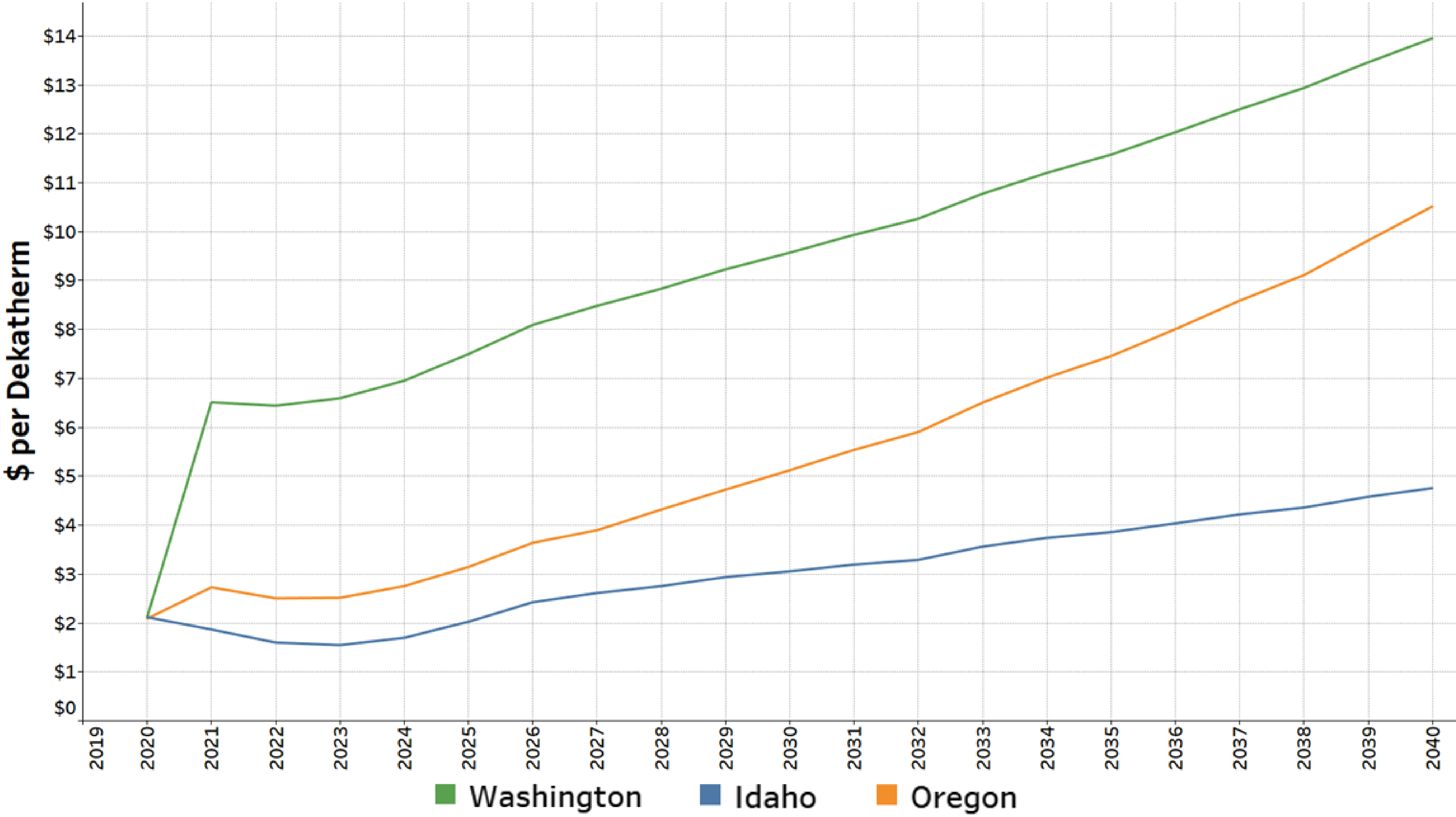
LDC Upstream Emissions

	Avista Specific Natural Gas	
Combustion	Lbs. GHG/MMBtu	Lbs. CO2e/Mmbtu
CO2	116.88	116.88
CH4	0.0022	0.0748
N2O	0.0022	0.6556
Total Combustion		117.61
Upstream		
CH4	0.313406851	10.66
Total		128.27
Upstream Emissions	Avista's Purchases	Emissions Location
0.77	89.72%	Canada
1.00	10.28%	Rockies
0.79		

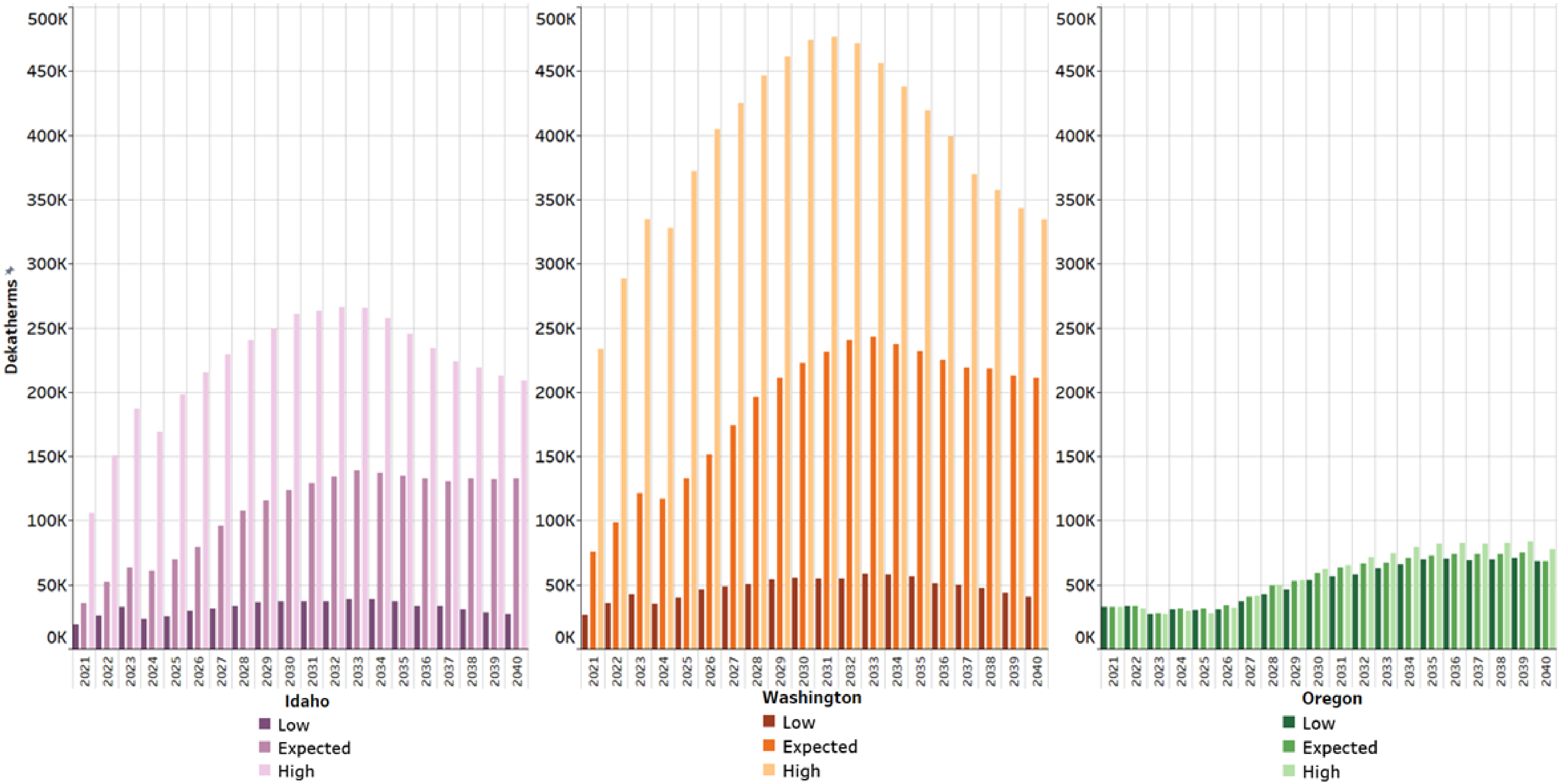
34 GWP

*Avista gas purchases
An average of the total volume purchased over
the past 5 years by emissions location

Avoided Cost Comparison



DSM


Dekatherms
500K
450K
400K
350K
300K
250K
200K
150K
100K
50K
0K
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
Idaho
Low
Expected
High
Washington
Low
Expected
High
Oregon
Low
Expected
High

Expected Case

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.

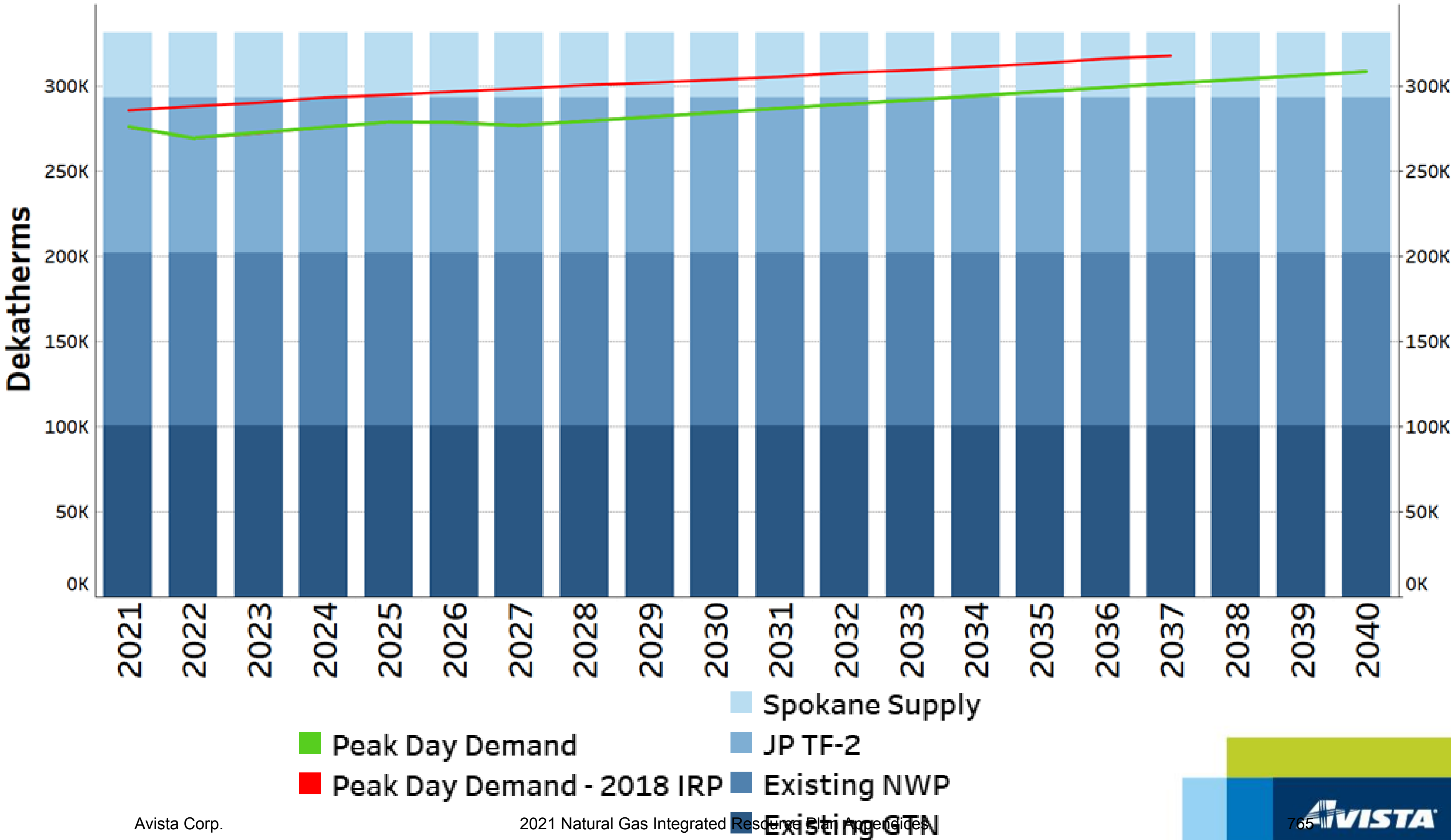
Proposed Scenarios

Proposed Scenarios INPUT ASSUMPTIONS	Expected Case	Average Case	Low Growth & High Prices	Carbon Reduction	High Growth & Low Prices
Customer Growth Rate	Reference Case Cust Growth Rates		Low Growth Rate	Reference Case Cust Growth Rates	High Growth Rate
Use per Customer	3 yr + Price Elasticity				
Demand Side Management	Expected Case CPA		High Prices DSM	Low Prices DSM	
Weather Planning Standard	99% probability of coldest in 30 years	20 year average	99% probability of coldest in 30 years		
GWP	100-Year GWP				
Prices Price curve	Expected		High	Low	
Carbon Legislation ($/Metric Ton)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID		Carbon Cost - High (SCC 95% at 3%)	SCC @ 2.5% WA; Cap and Trade forecast - OR; NO Carbon adder in ID	$0

*1,000 Draws per scenario will be run stochastically

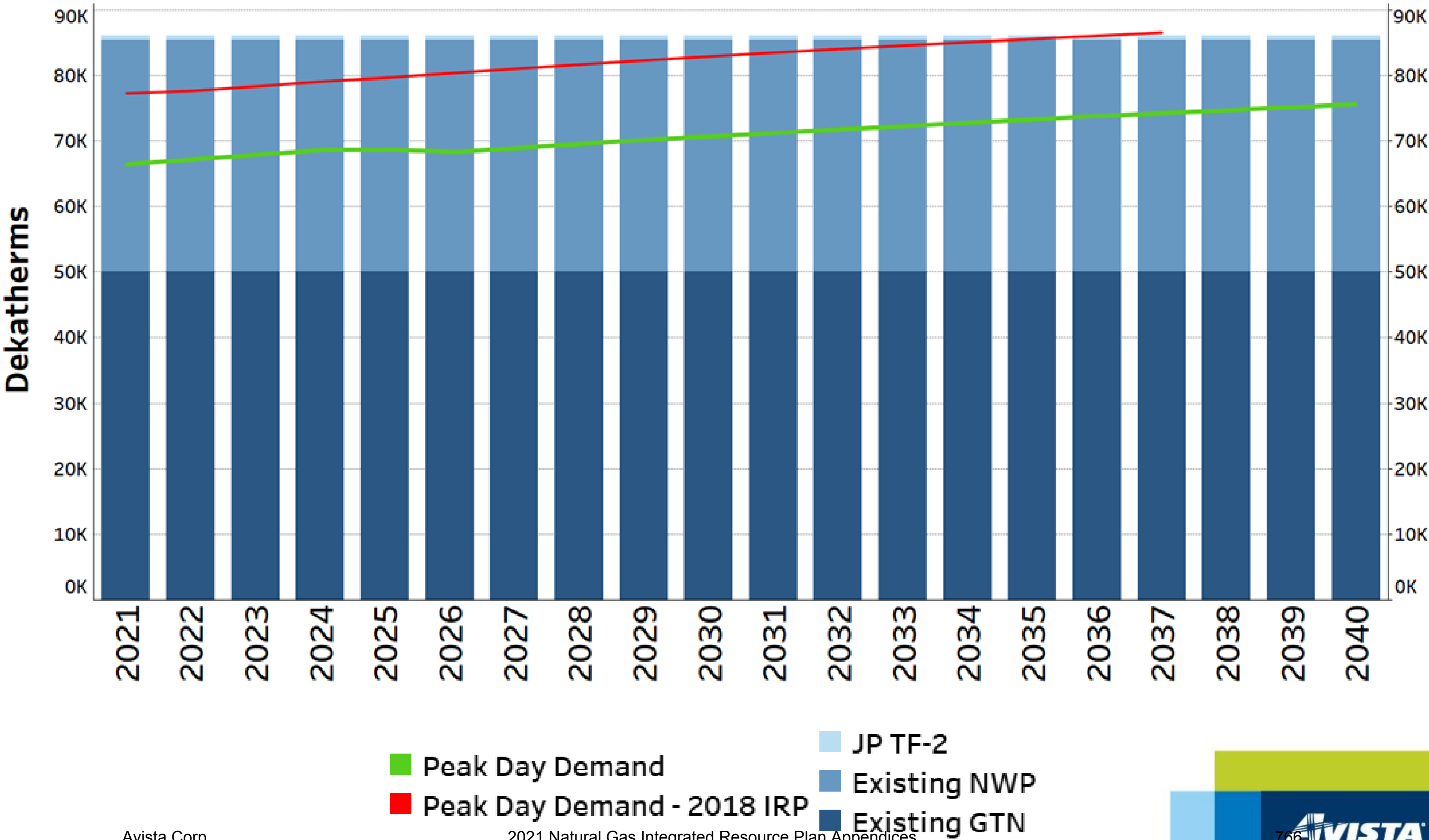
Existing Resources vs. Peak Day Demand

Expected Case – Washington/Idaho (DRAFT)



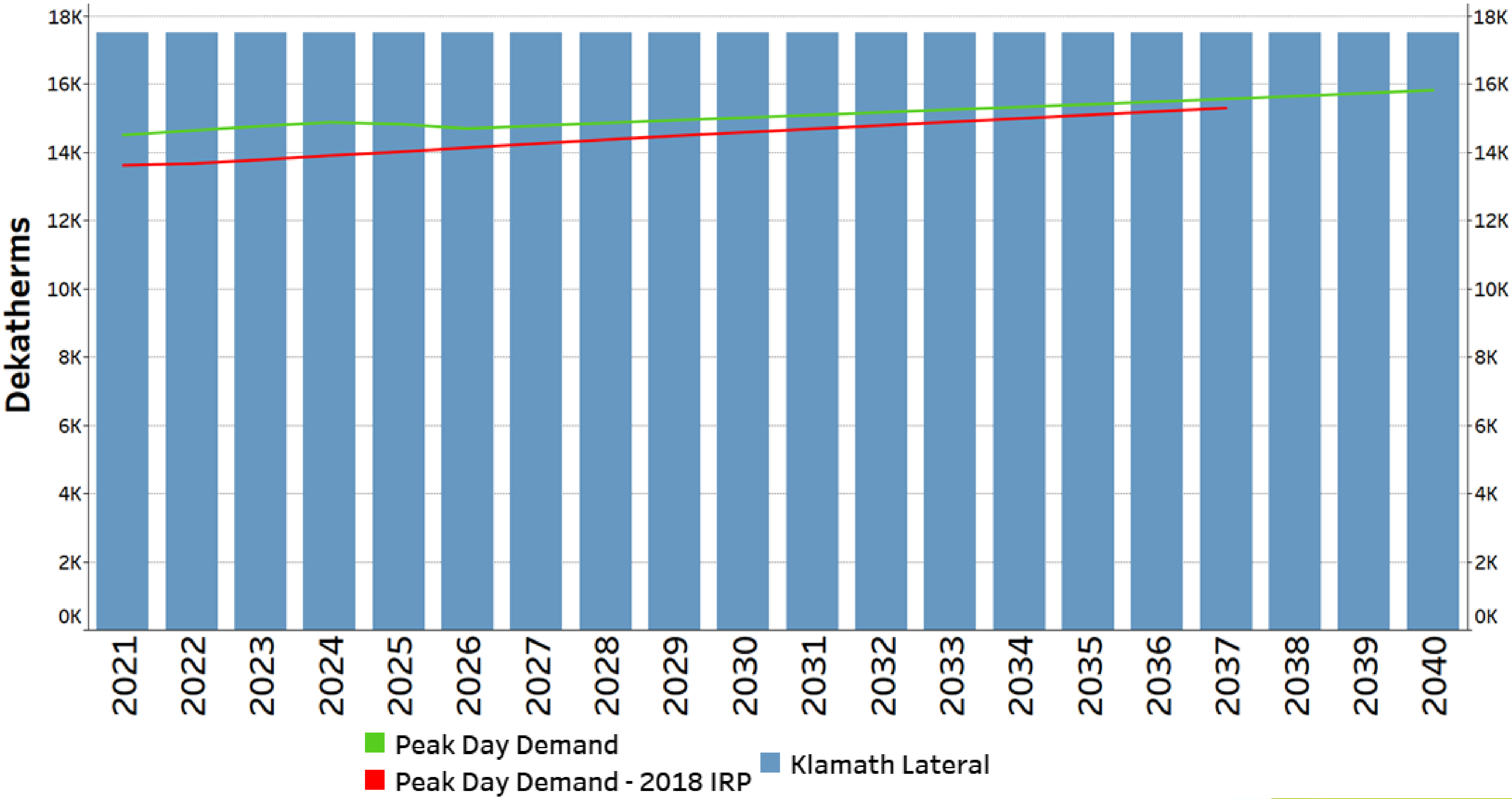
Existing Resources vs. Peak Day Demand

Expected Case – Medford/Roseburg (DRAFT)



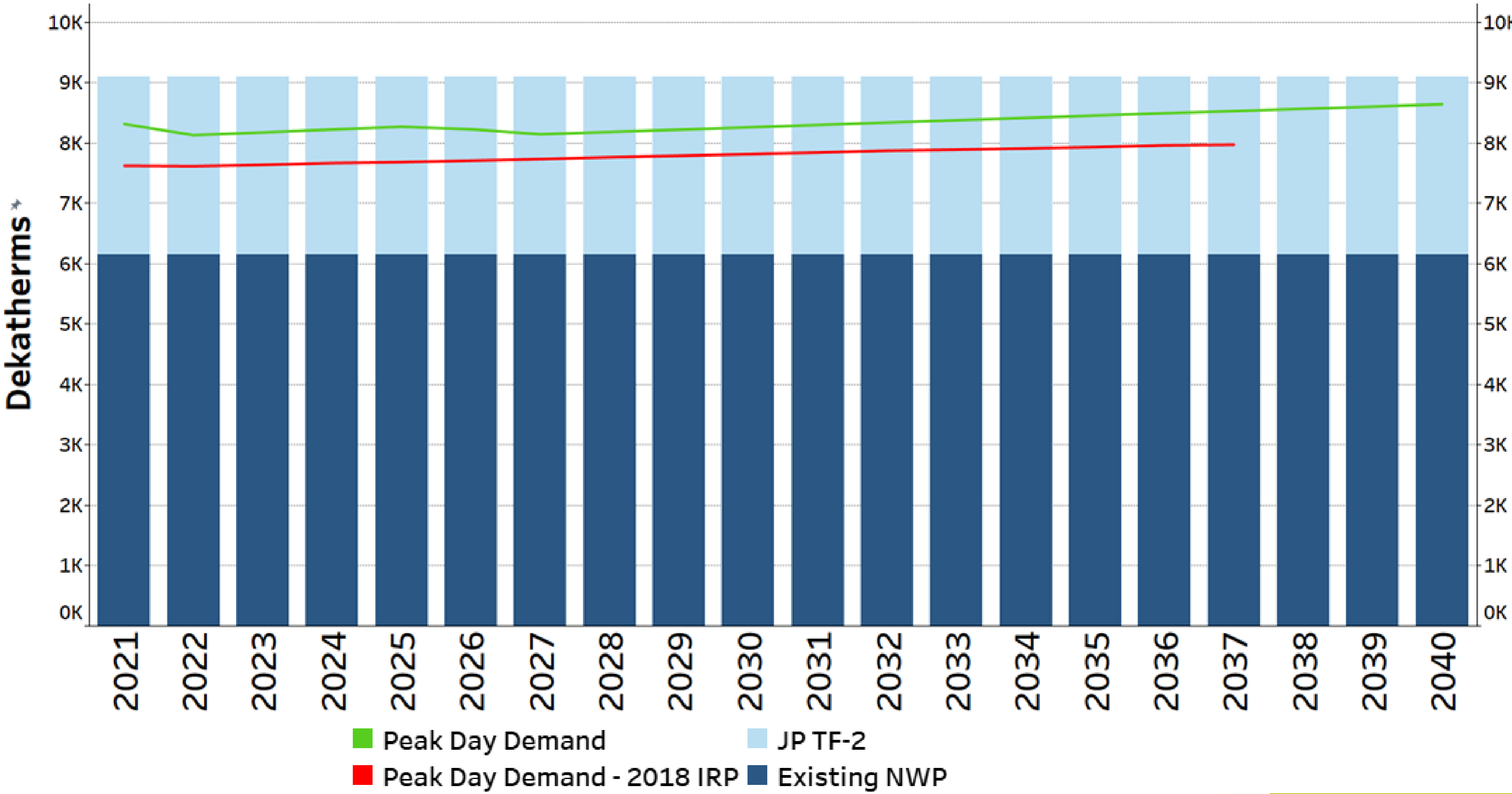
Existing Resources vs. Peak Day Demand

Expected Case – Klamath Falls (DRAFT)

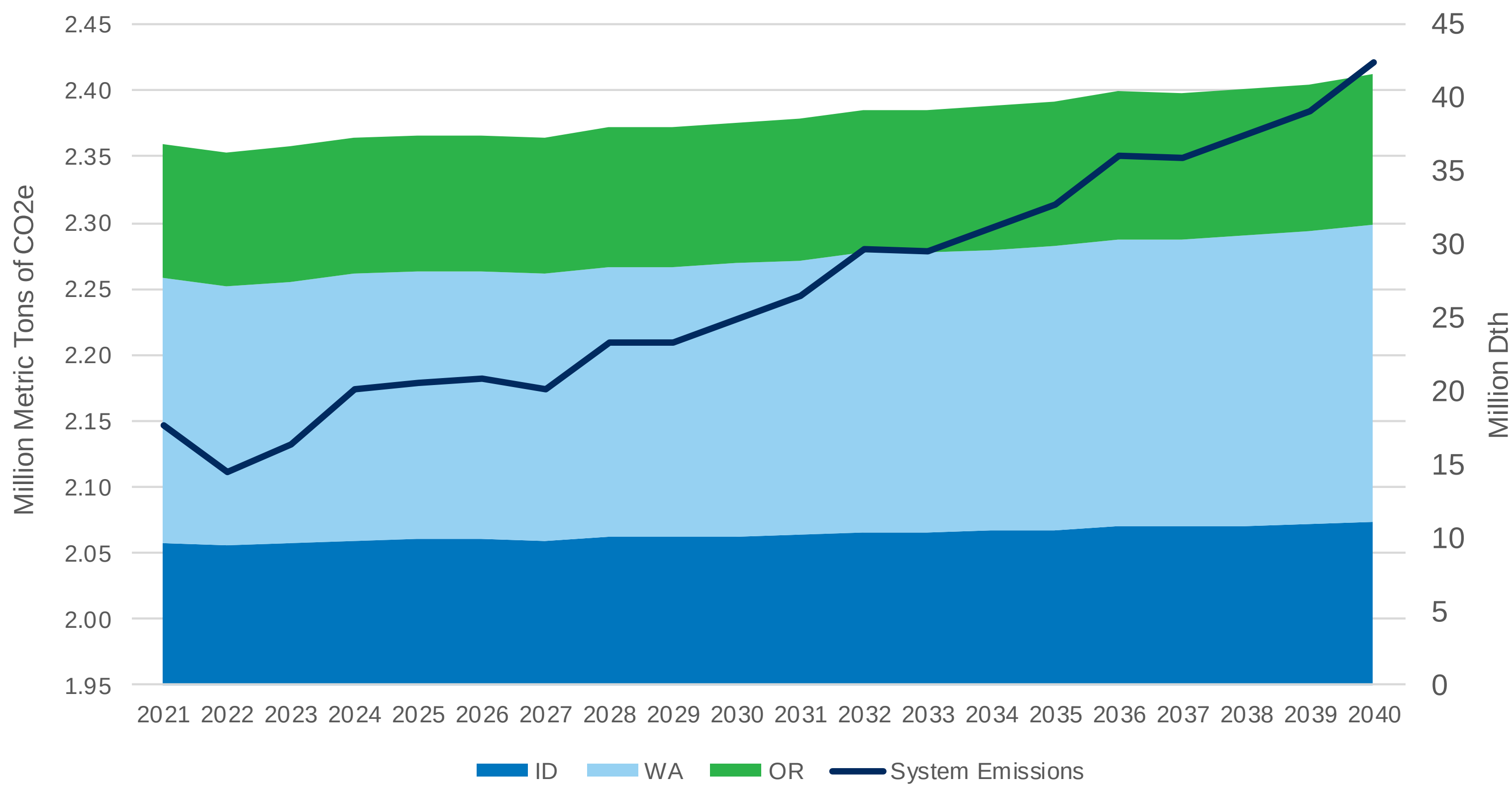


Existing Resources vs. Peak Day Demand

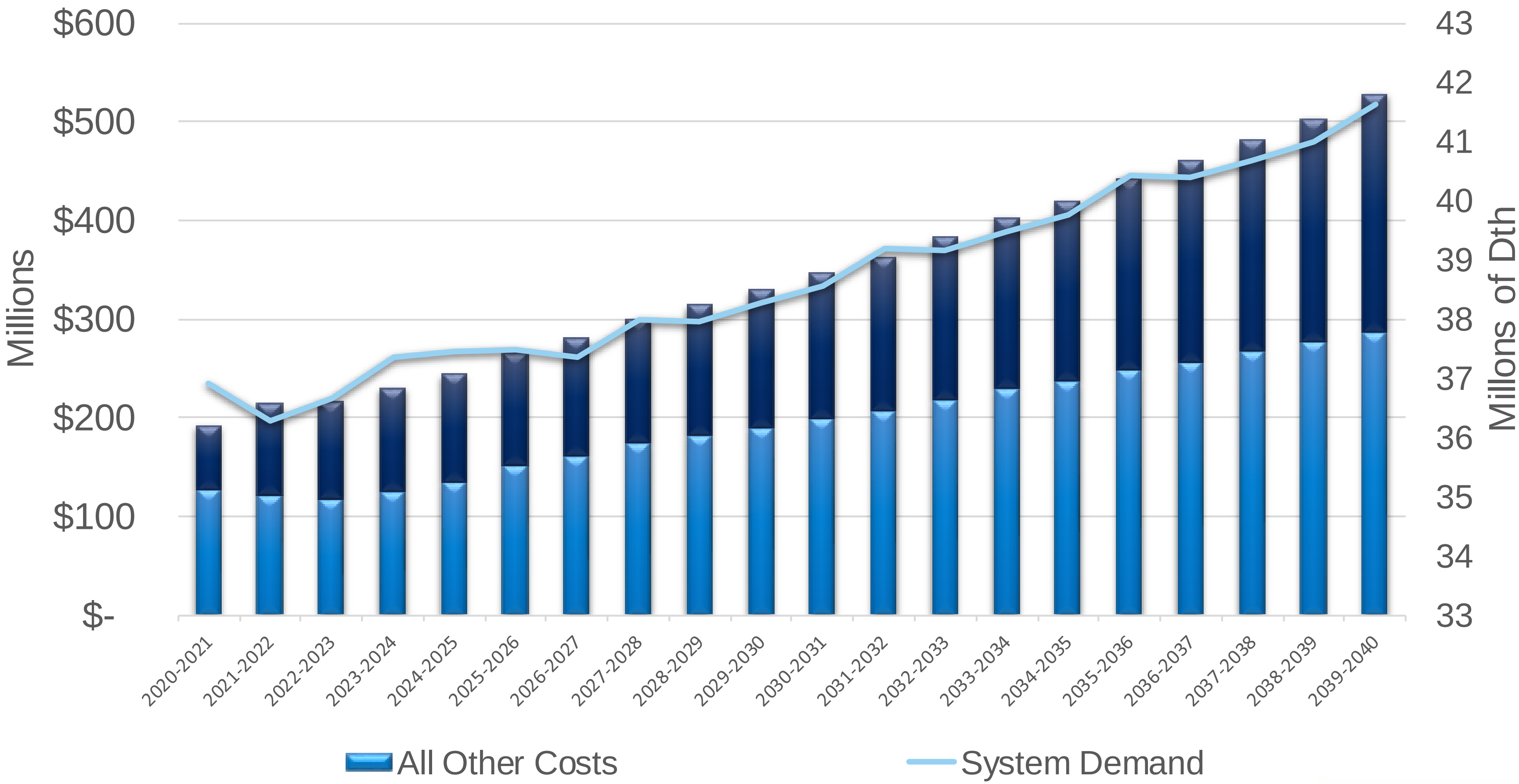
Expected Case – La Grande (DRAFT)



Expected Case - Emissions

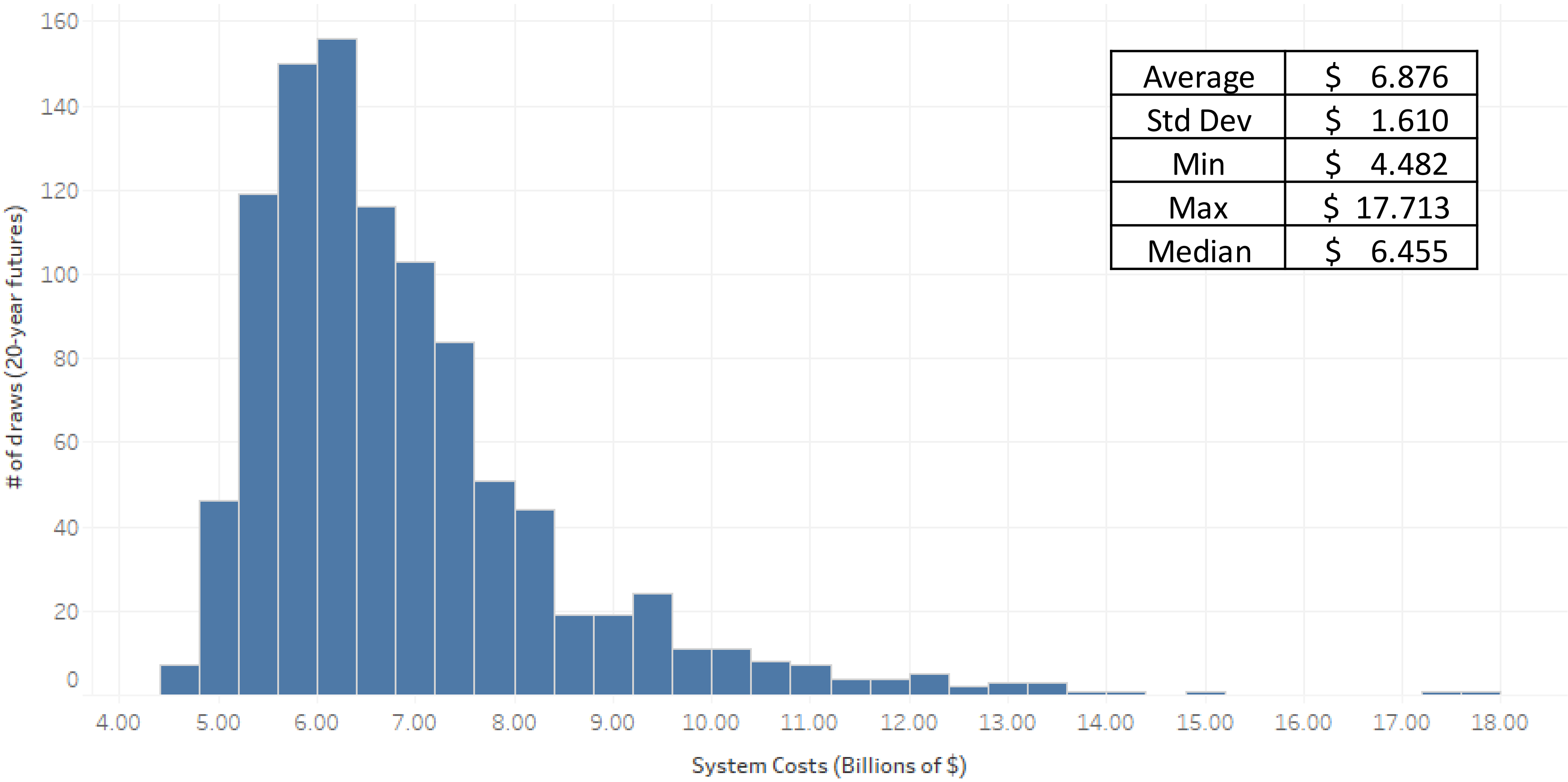


Expected Case Costs



$3.9B $3B

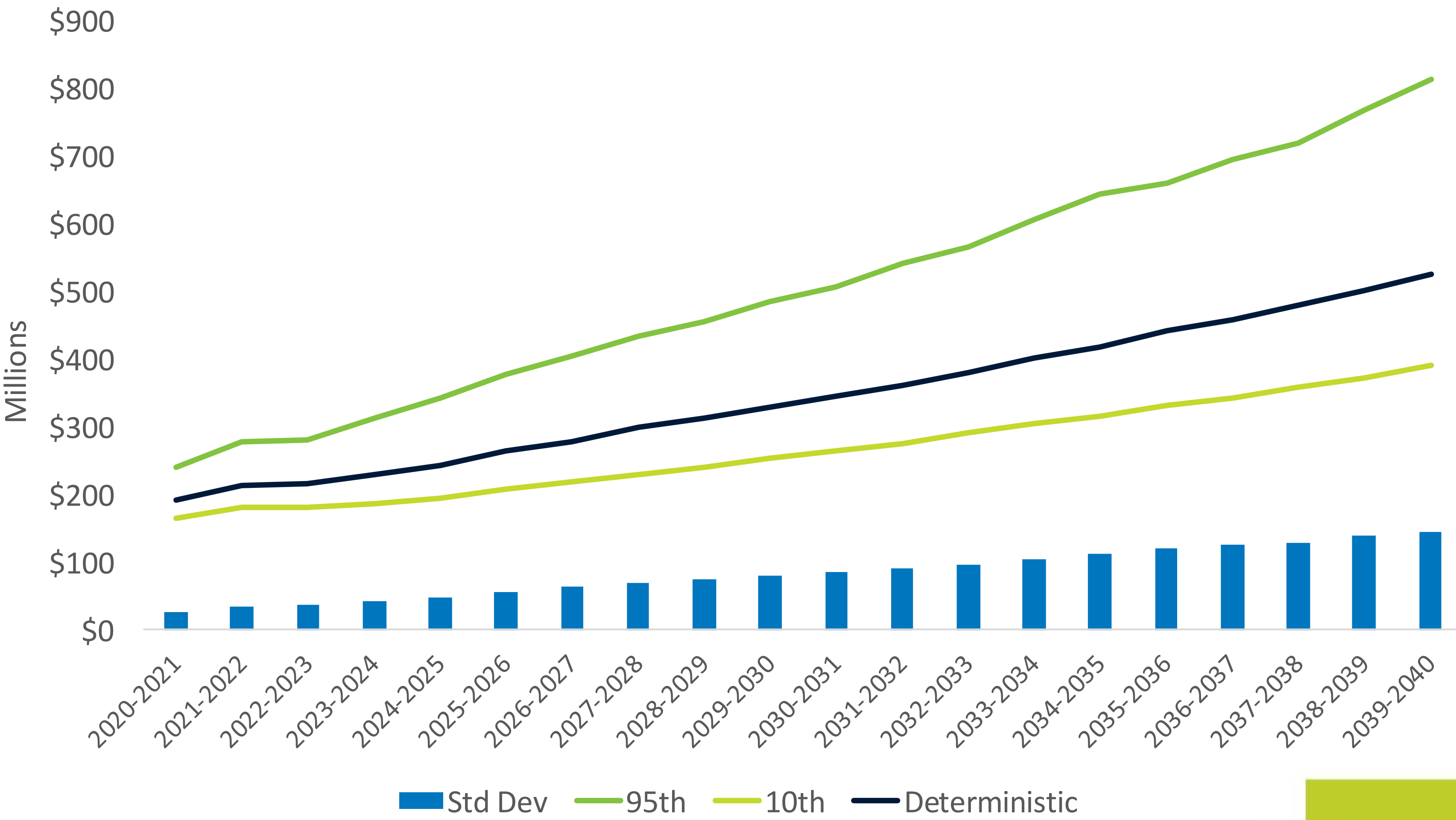
Expected Case distribution



Average	$ 6.876
Std Dev	$ 1.610
Min	$ 4.482
Max	$ 17.713
Median	$ 6.455

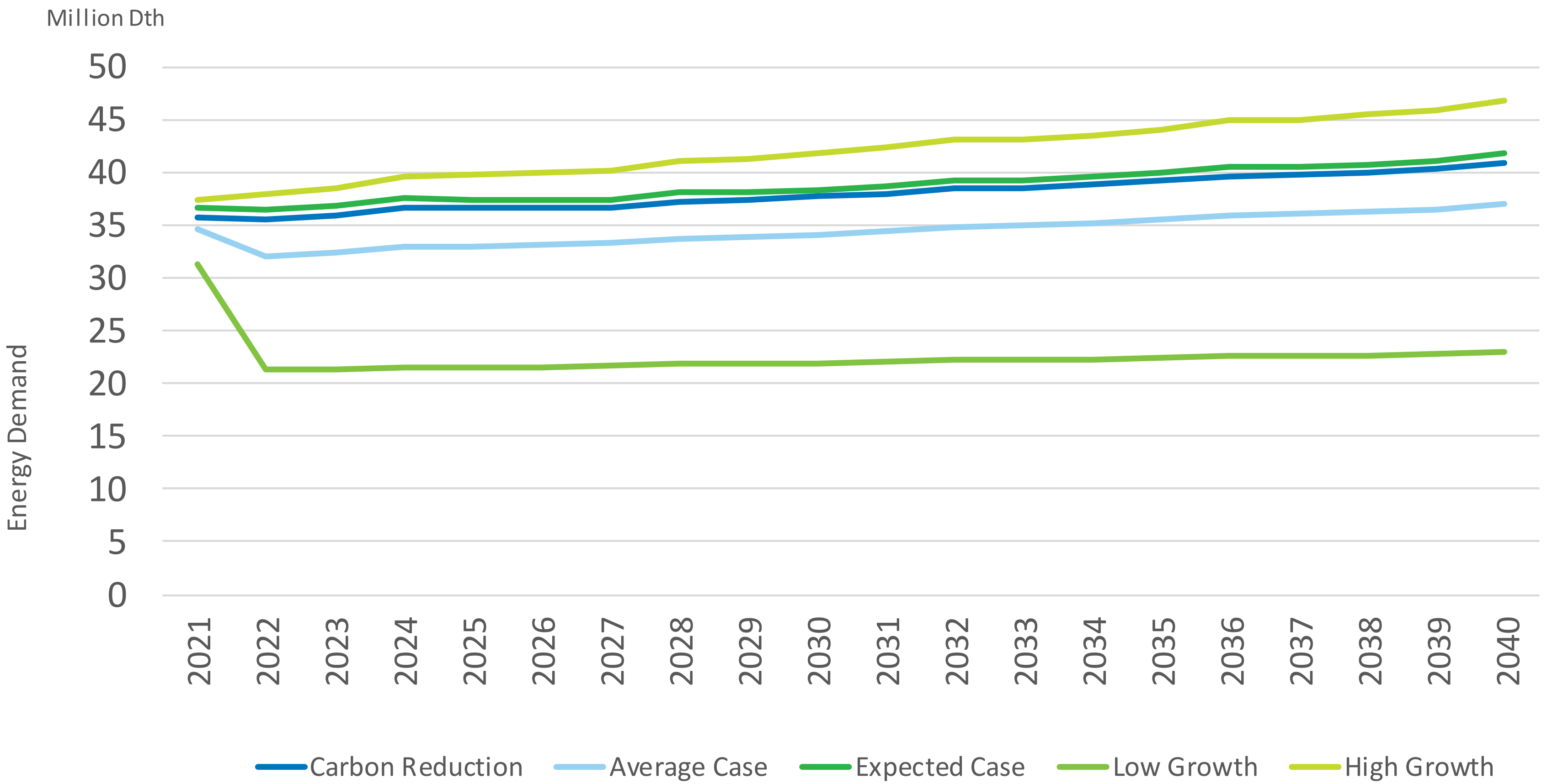
*1000 Simulations

Expected Case
1,000 Draws

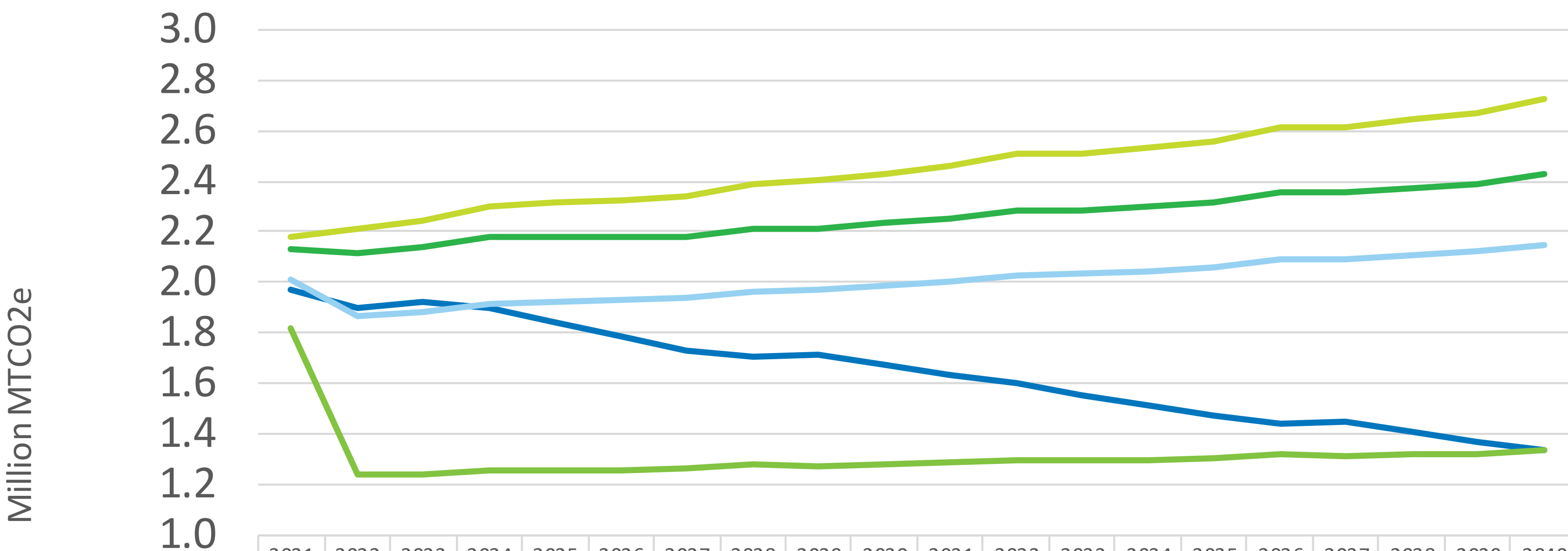


Other Scenarios

Energy Demand



Emissions

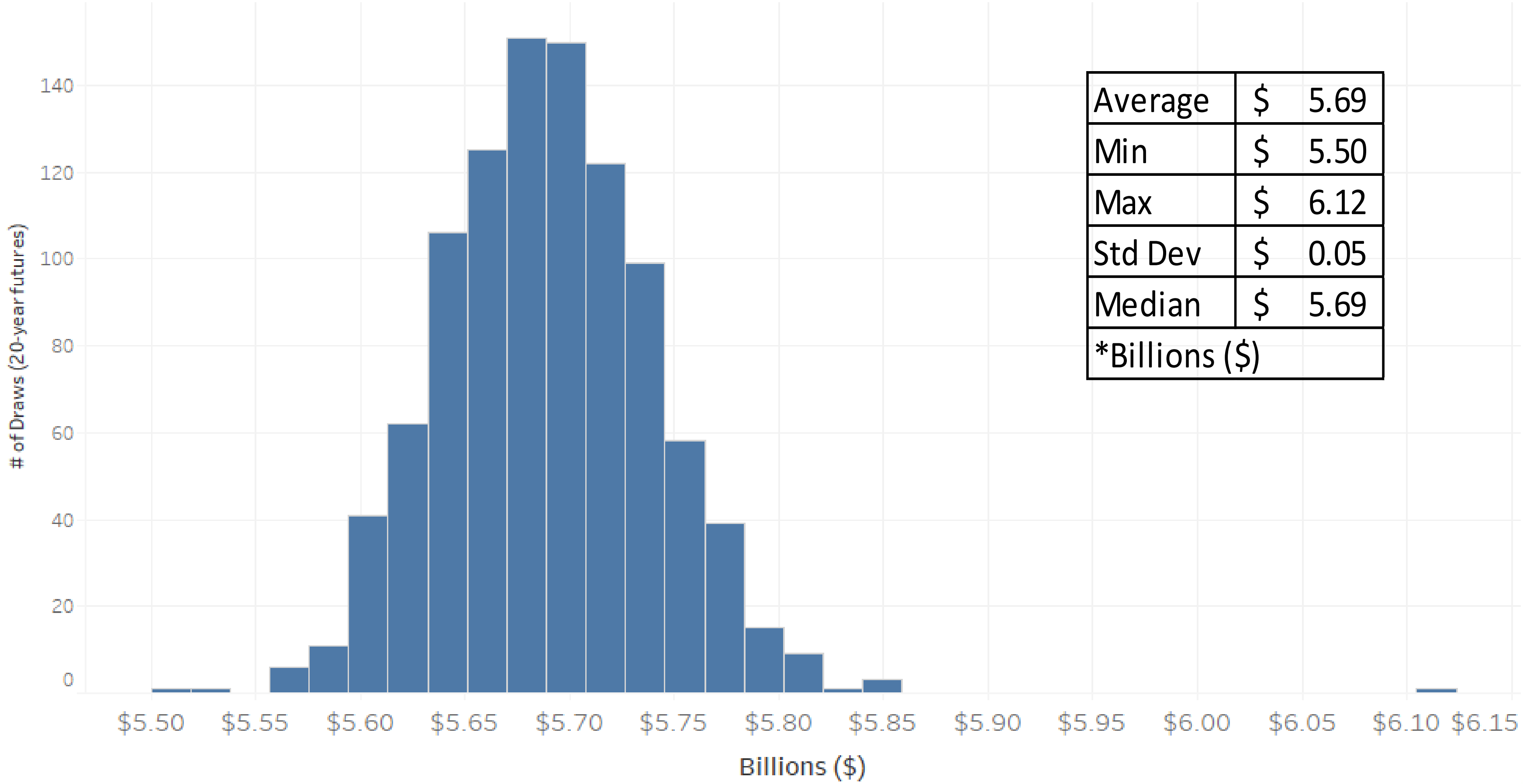


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Carbon Reduction	1,966	1,895	1,918	1,894	1,842	1,784	1,729	1,701	1,709	1,669	1,629	1,600	1,549	1,509	1,468	1,440	1,446	1,406	1,366	1,338
Average Case	2,011	1,868	1,883	1,913	1,921	1,929	1,938	1,961	1,968	1,984	1,999	2,023	2,030	2,045	2,061	2,086	2,093	2,109	2,124	2,149
Expected Case	2,132	2,117	2,138	2,181	2,178	2,178	2,178	2,214	2,214	2,232	2,249	2,284	2,283	2,301	2,319	2,356	2,355	2,372	2,389	2,426
Low Growth	1,820	1,237	1,237	1,251	1,249	1,255	1,260	1,274	1,271	1,276	1,282	1,295	1,292	1,297	1,301	1,315	1,311	1,316	1,321	1,334
High Growth	2,175	2,207	2,243	2,301	2,313	2,326	2,338	2,389	2,400	2,430	2,459	2,509	2,512	2,530	2,559	2,609	2,616	2,644	2,672	2,723

Carbon Reduction Average Case Expected Case Low Growth High Growth

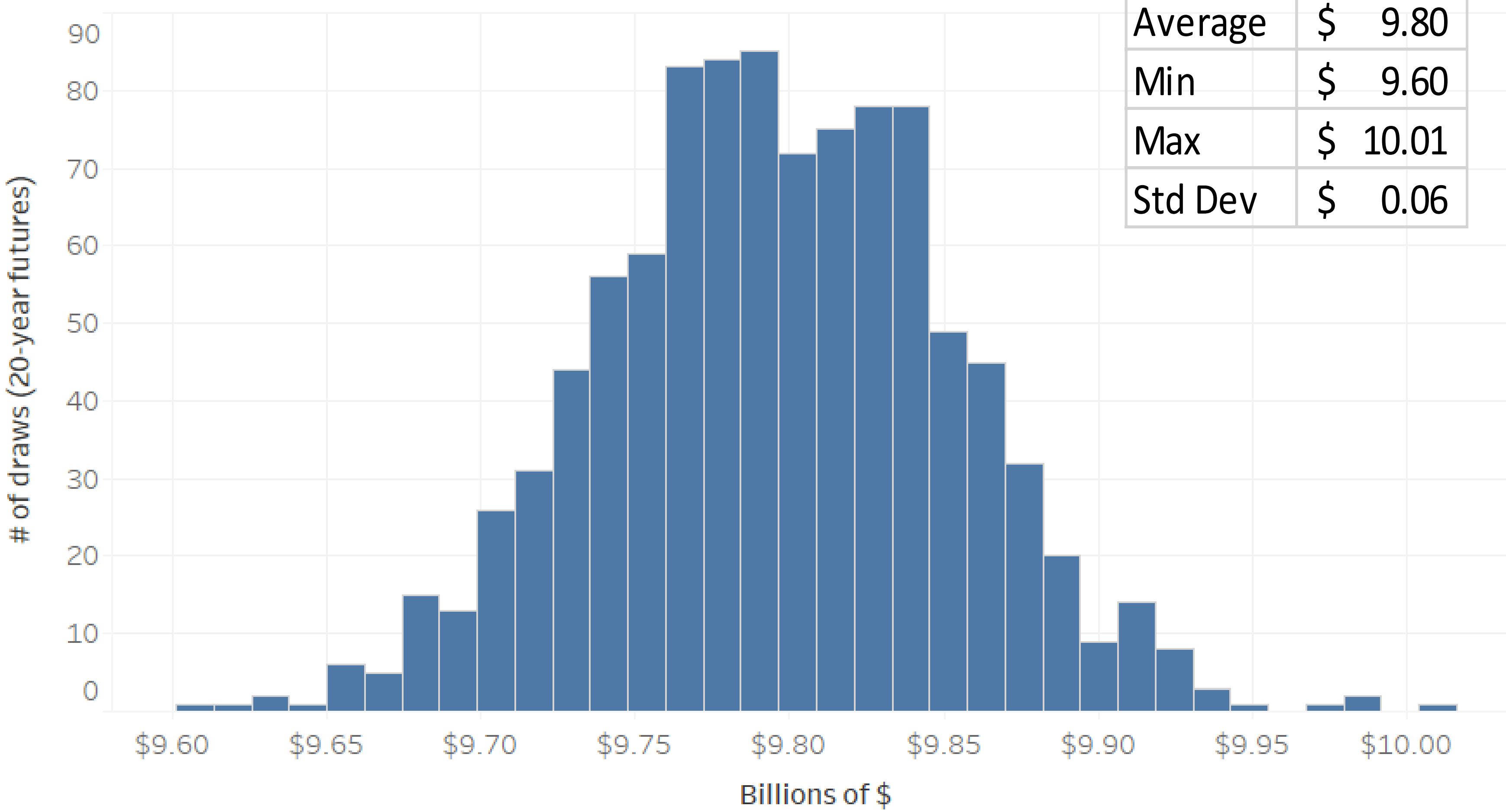
*Emissions assume carbon intensity of the supply resources

Average Case



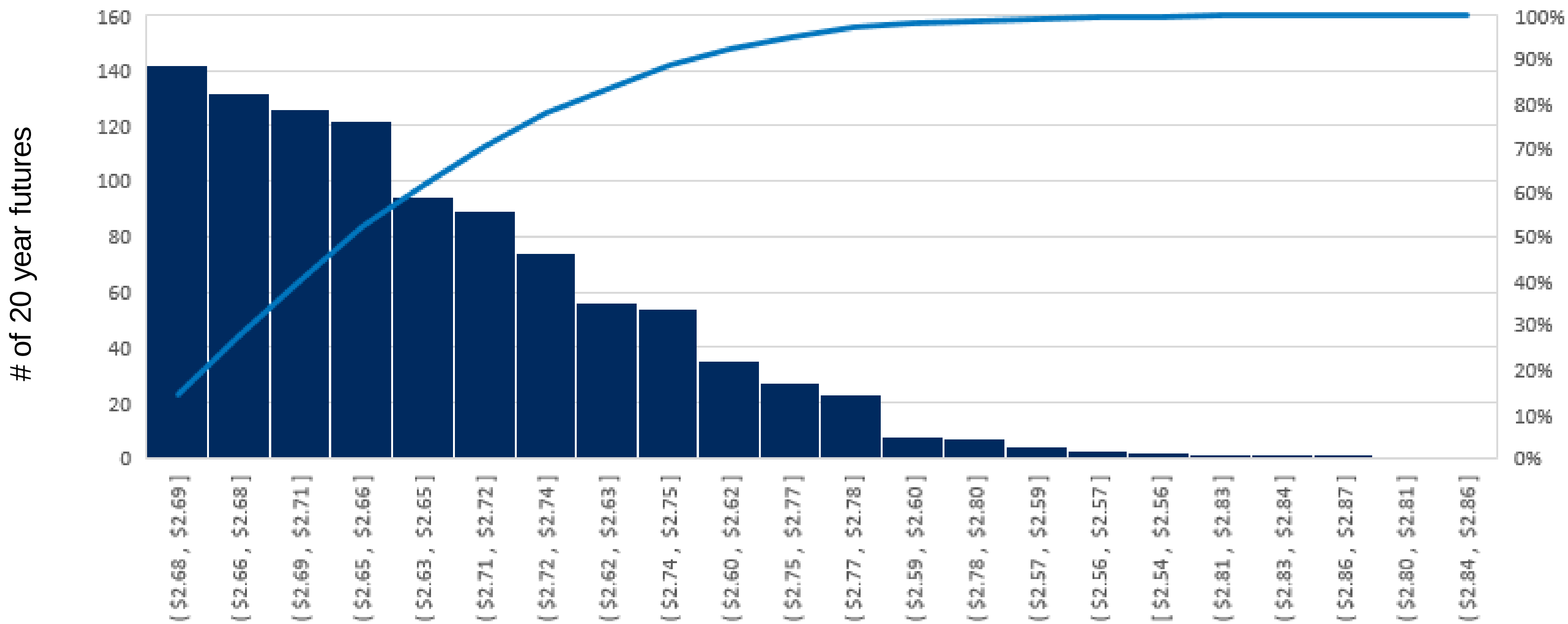
Average	$	5.69
Min	$	5.50
Max	$	6.12
Std Dev	$	0.05
Median	$	5.69
*Billions ($)		

Low Growth and High Prices



Average	$ 9.80
Min	$ 9.60
Max	$ 10.01
Std Dev	$ 0.06

High Growth & Low Prices
Least Cost/Risk - RNG solve



Solve - No Unserved	Average	Stdev	Median	Max	Min
RNG Resources Only	$ 2.683	$ 0.043	$ 2.681	$ 2.861	$ 2.542
Plymouth, RNG in La Grande	$ 2.721	$ 0.043	$ 2.719	$ 2.901	$ 2.580
GTN - RNG in La Grande	$ 2.734	$ 0.042	$ 2.675	$ 2.855	$ 2.540
Medford Lateral Expansion, RNG in La Grande	$ 2.734	$ 0.044	$ 2.731	$ 2.915	$ 2.600

*$ in Billions

**1,000 draws each scenario

Carbon Reduction Scenario

Carbon Reduction scenario

- Carbon reduction goals to meet 2035 targets of 45% below 1990 emissions and criteria are not known
- 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 costs and environmental attributes which 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

Resources Considered

Resource	Dth per year	Levelized Cost Per Dth (Year 1)
Distributed Renewable Hydrogen Production - WA	60,509	$47.25
Distributed Renewable Hydrogen Production - OR	60,509	$48.01
Distributed LFG to RNG Production - WA	231,790	$15.90
Centralized LFG to RNG Production - WA	662,256	$14.11
Dairy Manure to RNG Production - WA	231,790	$14.30
Wastewater Sludge to RNG Production - WA	187,245	$23.34
Food Waste to RNG Production - WA	108,799	$33.14
Distributed LFG to RNG Production - OR	231,790	$14.34
Centralized LFG to RNG Production - OR	662,256	$12.54
Dairy Manure to RNG Production - OR	231,790	$30.59
Wastewater Sludge to RNG Production - OR	187,245	$20.36
Food Waste to RNG Production - OR	108,799	$37.46

*Prices include carbon intensity, carbon costs, capital and overhead, and electricity and are considered Avista owned and operated
**Estimates are from a Black and Veach study

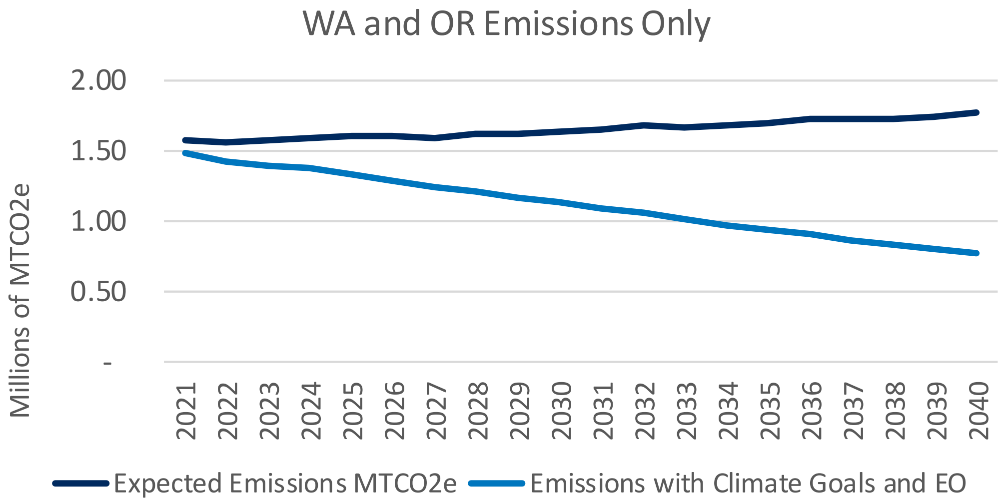
Carbon Intensity

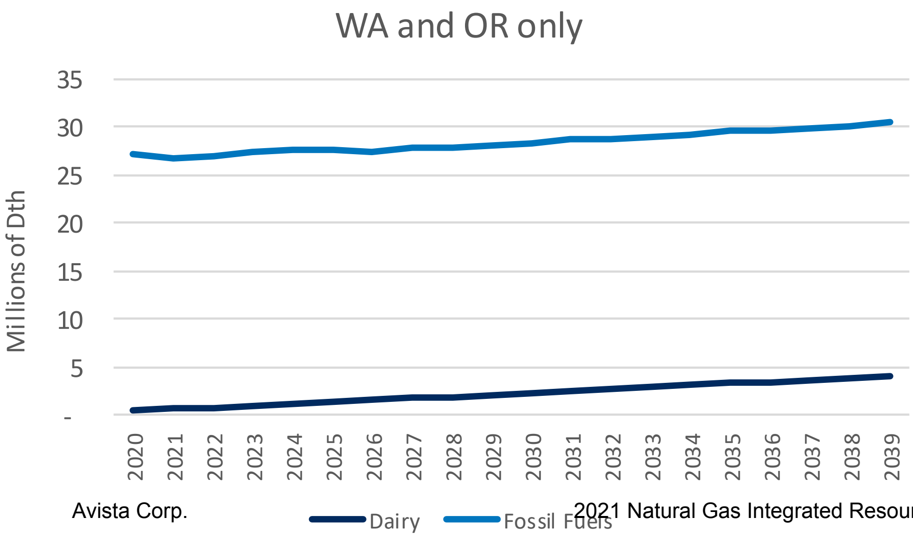
Source	Current Carbon Intensity (g CO2e/MJ)	Percent of estimated Carbon reduction as compared to natural gas (as base value)	lbs. per Dth
Natural Gas	78.37		128.27
Landfill	46.42	41%	75.98
Dairy	-276.24	-452%	(580.40)
WWT	19.34	75%	31.65
Solid Waste	-22.93	-129%	(165.80)

Source: California Air Resources Board

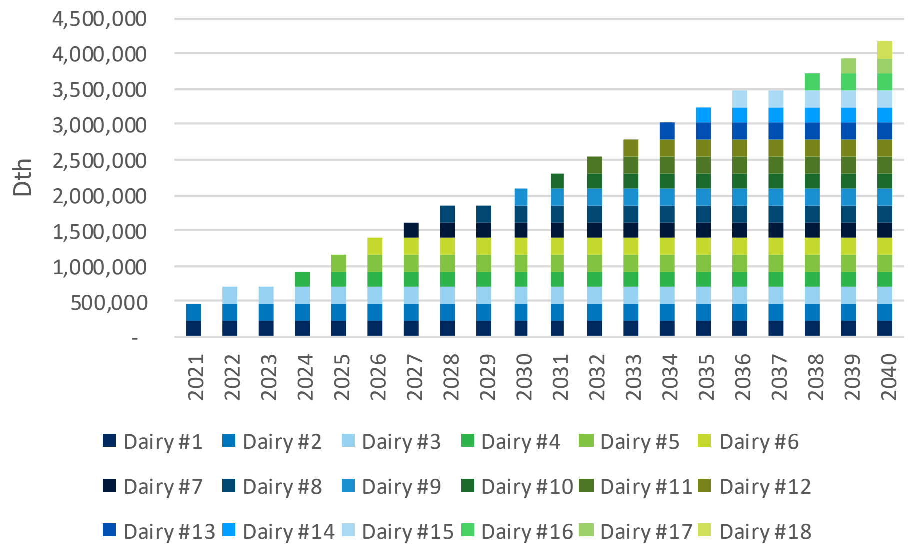
*Green H2 is considered to have no carbon or -128.27 lbs. per Dth as compared to Natural Gas

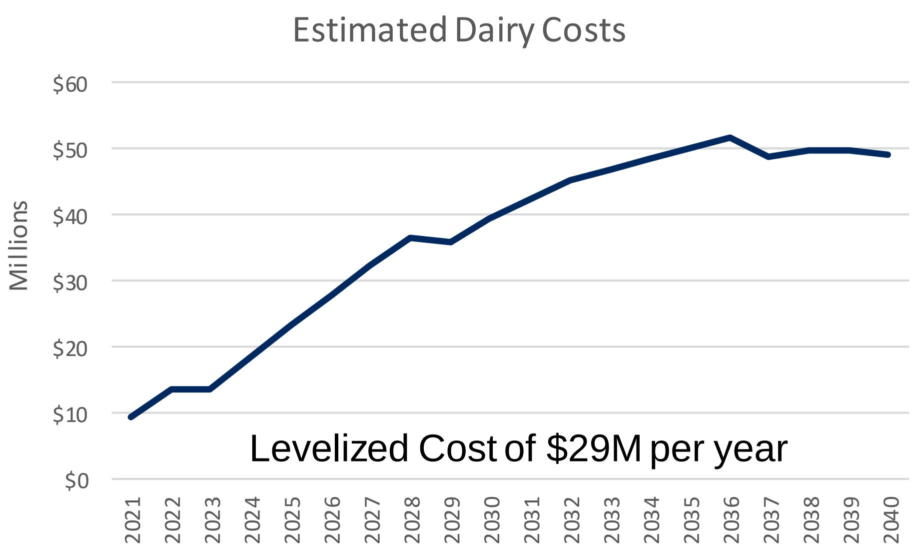
Climate Goals



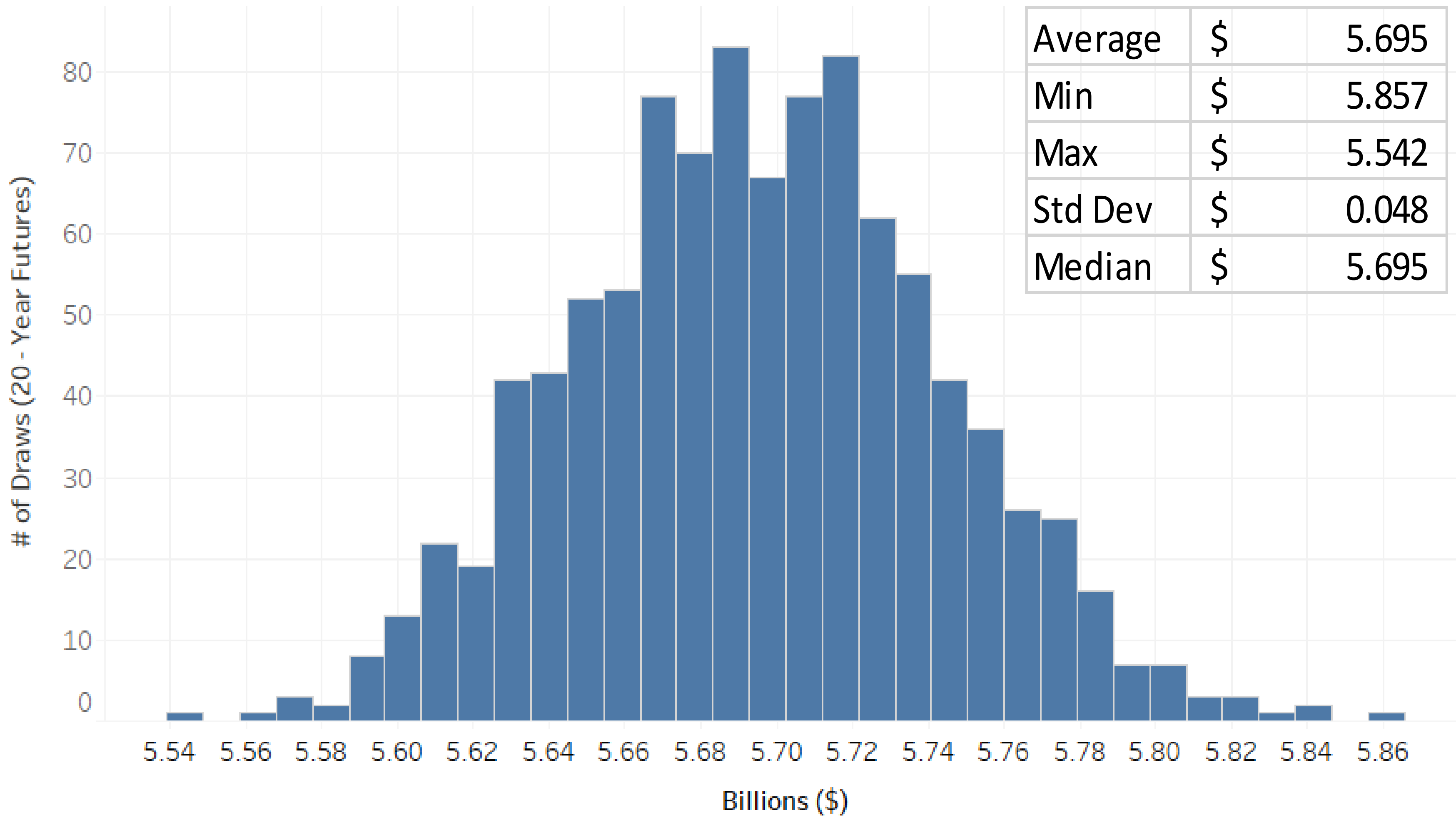


Resources Needed





Carbon Reduction



Average	$	5.695
Min	$	5.857
Max	$	5.542
Std Dev	$	0.048
Median	$	5.695

Carbon Reduction Summary

- Dairy
  - With a high carbon intensity and it's ability to reduce emissions dairy becomes the preferred resource in this IRP to reduce carbon
  - As the cost of carbon gets higher dairy becomes more economic as the carbon intensity combined with the SCC creates a low price
  - Unlike some other RNG resources a dairy farm has the potential to be reproduced unlike a landfill or waste water treatment plants
- Hydrogen
  - If the high carbon offset of dairy can be mitigated with a lower price of H2 this is both the primary and viable path
  - Green H2 has a large potential to offset emissions and provide the amount of energy demand forecasted
- Carbon offsets through allowances and the associated costs need to be considered to fully understand least cost and least risk
- Other RNG type programs will be modeled at a detailed level as projects are available and depending on costs and offsets could change least cost and least risk solution

Action Plan

- Further model carbon reduction
- Investigate new resource plan modeling software and integrate Avista's system into software to run in parallel with Sendout
- Model all requirements as directed in Executive Order 20-04
- Avista will ensure Energy Trust (ETO) has sufficient funding to acquire therm savings of the amount identified and approved by the Energy Trust Board

Next Steps

2020 Natural Gas IRP Draft Timeline

The following is Avista's tentative 2020 Natural Gas IRP timeline:

- June - November 2020 – Technical Advisory Committee meetings
- December 2020 – Prepare draft of IRP
- January 4, 2021 – Draft of IRP document sent to TAC
- February 1, 2021 – Comments on draft due back to Avista
- February 2021 – TAC final review meeting (if necessary)
- March 2021 – Final editing and printing of IRP
- April 1, 2021 – File IRP submission to Commissions and TAC