BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-22_____

EXH. JRT-2

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

AVISTA

# 2021 Electric Integrated Resource Plan


# Safe Harbor Statement

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

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

# Production Credits

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# 2021 Electric IRP Introduction

***Avista has a 132-year tradition of innovation and a commitment to providing safe, reliable, low-cost, clean energy to our customers. We meet this commitment through a diverse mix of generation and demand side resources.***

The 2021 Integrated Resource Plan (IRP) continues our legacy by looking 24 years into the future to determine the energy needs of our customers. The IRP analyzes and outlines a strategy to meet projected demand and renewable portfolio standards through energy efficiency and a diverse mix of clean generation resources.

## Summary

The 2021 IRP shows Avista has adequate resources between owned and contractually controlled generation, when combined with conservation and market purchases, to meet customer needs through 2025. New renewable energy, energy storage, demand response, energy efficiency, and upgrades to existing hydropower and biomass plants are integral to our plan.

## Changes

Major changes from the 2020 IRP include:

- Retail sales and residential use per customer forecasts are slightly higher compared to the 2020 IRP projections.
- Return of new natural gas-fired peakers because long-term energy storage is not yet available or as cost effective as initially estimated in the 2020 IRP for the 2026 capacity need.
- Demand response programs begin in 2024 and grow to 71 MW by 2045.

## Highlights

Some highlights of the 2021 IRP include:

- The resource strategy meets nearly 78 percent of Avista's corporate clean energy goal to provide customers with 100 percent net clean energy by 2027 at competitive prices.
- A new chapter in this IRP addresses energy equity and details plans to form an Equity Advisory Group in 2021 to further engage Washington's vulnerable and highly impacted communities.
- New renewable energy is needed in 2023 and 2024 to meet Washington's clean energy targets. The most viable new resource option is 200 MW of wind from Montana. Another 100 MW of wind is added in 2028.

## IRP Process

Each IRP is a thoroughly researched and data-driven document identifying a Preferred Resource Strategy to meet customer needs while balancing costs and risk measures with environmental goals and mandates. Avista's professional energy analysts use sophisticated modeling tools and input from over 100 participants to develop each plan. The participants in the public process include customers, academics, environmental organizations, government agencies, consultants, utilities, elected officials, state utility commission stakeholders, and other interested parties.

## Conclusion

This document is mostly technical in nature. The IRP has an Executive Summary and chapter highlights at the beginning of each section to help guide the reader. Avista expects to begin developing the 2023 IRP in late 2021. Stakeholder involvement is encouraged and interested parties may contact John Lyons at (509) 495-8515 or irp@avistacorp.com for more information on participating in the IRP process.

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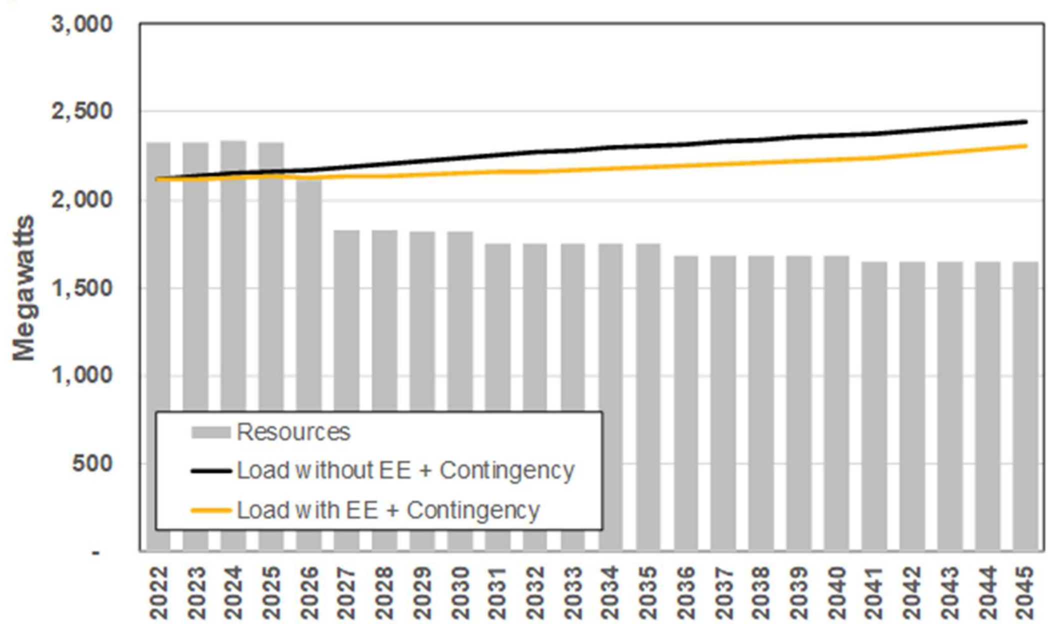
# 1. Executive Summary

The 2021 Electric Integrated Resource Plan (IRP) shapes Avista's resource strategy and planned procurements for the next 24 years. It provides a snapshot of existing resources and Avista's load forecast. The plan evaluates supply and demand-side resource options with multiple resource selection strategies over expected and possible future conditions to determine an optimal resource strategy to serve customers. The Preferred Resource Strategy (PRS) relies on modeling methods to balance cost, reliability, rate volatility as well as environmental goals and mandates. Avista's management and Technical Advisory Committee (TAC) guide the IRP development through input and feedback on modeling and planning assumptions while providing the public with information on future energy requirements. TAC members include customers, Commission staff, consumer advocates, academics, environmental groups, utility peers, government agencies, independent power producers and other interested parties.

## Resource Needs

Avista expects its highest peak load during winter cold snaps. Avista's peak planning methodology considers operating reserves, regulation, load following, wind integration and resource adequacy requirements. The Company has adequate resources and energy efficiency programs to meet both summer and winter peak load requirements through December 2025. Figure 1.1 shows Avista's annual resource position through 2045. Chapter 7 – Long-Term Position details Avista's projected resource needs. Load growth and the loss of Colstrip[1], Lancaster, Northeast, Boulder Park and expiring hydro contracts drive Avista's resource deficits.

**Figure 1.1: Load-Resource Balance—Winter Peak Load & Resource Availability**



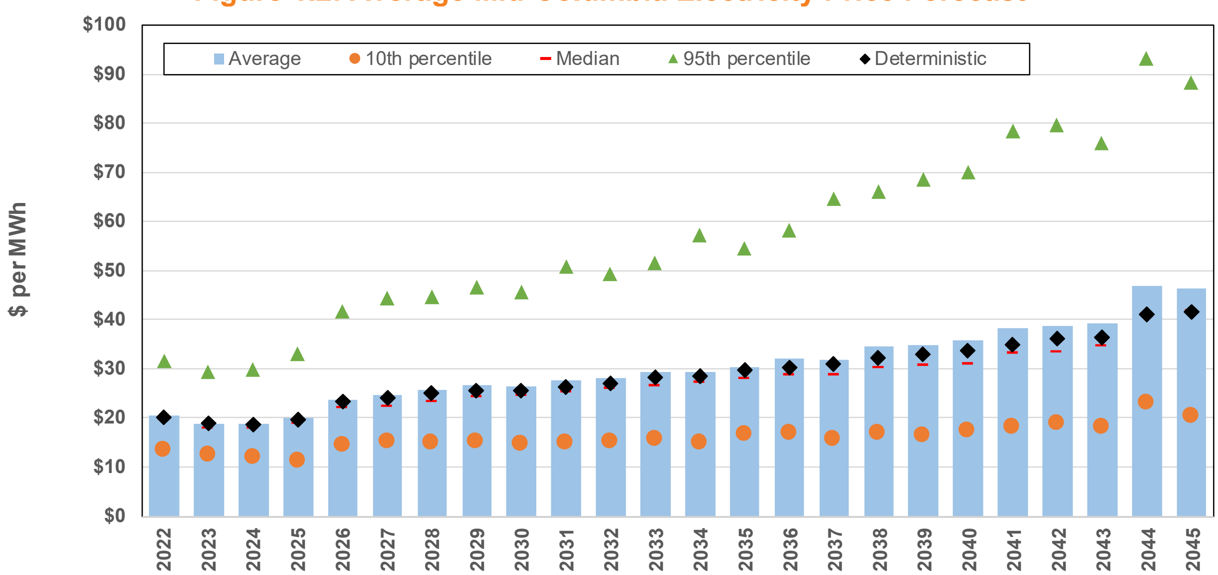

[1] This IRP assumes Colstrip no longer serves Washington customers after 2025, while portfolio modeling determines the economic end life for Idaho's portion of the plant. For planning purposes, Avista assumes the plant exits in 2025 as shown in Figure 1.1.

# Modeling and Results

Avista uses a multistep process to develop its PRS, beginning with a market analysis using the Aurora software by Energy Exemplar to identify and quantify the fundamental changes expected in the Western Interconnect between 2022 and 2045. The model uses the regional generation resources, load estimates and transmission links described in Chapter 10. The model adds new resources throughout the western region as loads transform to serve new uses and existing resources retire. Monte Carlo-style analyses vary hydro and wind generation, weather, forced outages and natural gas price data over 500 iterations of potential future market conditions to develop a forecast of wholesale Mid-Columbia electricity market prices through 2045. This forecast is used to value Avista's resource alternatives.

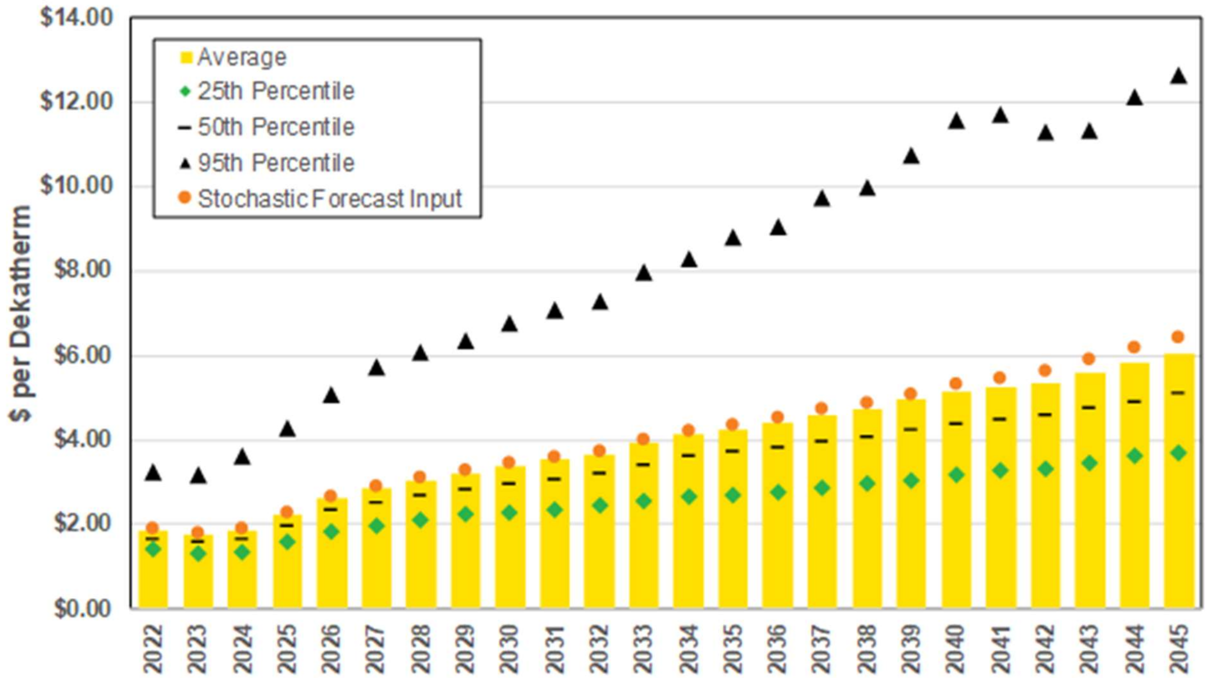
Figure 1.2 shows the 2021 IRP Mid-Columbia electricity price forecast for the Expected Case, including the range of prices from the 500 Monte Carlo iterations. The levelized price is $27.13 per MWh in nominal dollars over the 2022-2045 timeframe.

**Figure 1.2: Average Mid-Columbia Electricity Price Forecast**




Electricity and natural gas prices are highly correlated because natural gas fuels marginal generation in the Northwest during most of the year. Figure 1.3 presents nominal Expected Case natural gas prices at the Stanfield trading hub, located in northeastern Oregon, as well as the forecast range from the 500 Monte Carlo iterations performed for the Expected Case. The average natural gas price is $3.45 per dekatherm (Dth) over the next 24 years. See Chapter 10 – Market Analysis for natural gas and electricity price forecasts.

Figure 1.3: Stanfield Natural Gas Price Forecast

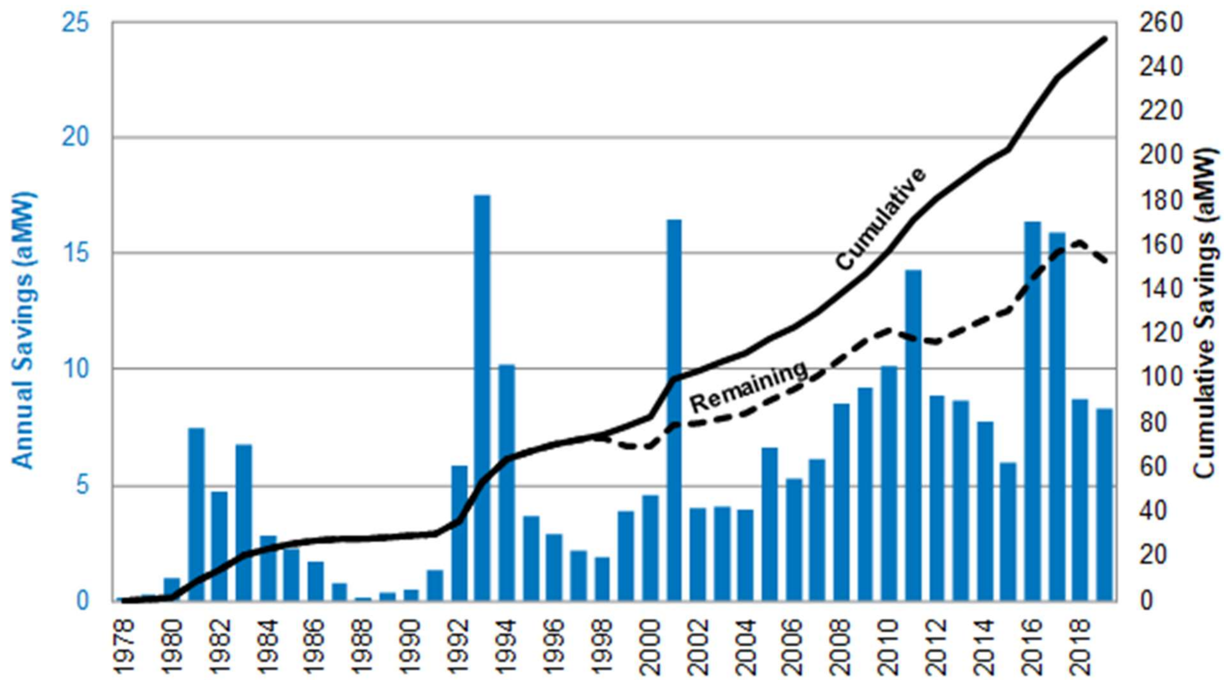



## Energy Efficiency and Demand Response

Avista commissioned a Conservation Potential Assessment (CPA) and a Demand Response potential study to estimate the potential for those applications in its service area. These studies provided Avista with approximately 7,000 potential energy efficiency measures and 16 Demand Response programs. Avista's commitment to energy efficiency is evident with a 14.5 percent reduction in average load since 1978 due to these efforts. Figure 1.4 illustrates the historical efficiency acquisitions as blue bars and the dashed line shows the amount of energy efficiency Avista estimates to remain on the system today.[2] Going forward, Avista expects energy efficiency to serve 68 percent of future load growth. See Chapter 5 – Energy Efficiency for more information. Demand Response programs will be integral to serving peak load using a variety of cost-effective programs and rate redesigns. See Chapter 6 – Demand Response for more information.

[2] Cumulative savings are lower than the summation of annual program savings due to the estimated 18-year average measure life.

**Figure 1.4: Avista's Annual and Cumulative Energy Efficiency Acquisitions**




## Preferred Resource Strategy

The PRS results from careful consideration and input by Avista's management, the TAC, and information gathered and analyzed through the IRP process. The PRS meets future reliability and clean energy requirements with upgrades at existing generation facilities (thermal and hydro), energy efficiency, natural gas peakers, energy storage, contracts, new renewable resources and demand response, as shown in Table 1.1. These resource selections are based on an economic decision-making process using both societal and resource cost estimates. Actual resource acquisition will occur through a competitive Request for Proposal (RFP) process where submitted resources will be evaluated to meet the Company's resource needs, such as Avista's 2020 Renewable RFP. This RFP may modify this plan if actual resource acquisition occurs and provides substitutes for planned resource needs.

The 2021 PRS is the lowest-reasonable cost plan to meet both reliability and environmental requirements given the resource inputs and need assessment. Major changes from the 2020 IRP include the return of new natural gas-fired peakers as long term energy storage is not cost effective as initially estimated in the 2020 IRP for the Company's initial 2026 capacity need. The plan also lowers the estimated demand response, wind acquisition and hydro upgrade quantities.

Each new supply- and demand-side resource option is valued against the Mid-Columbia electricity market forecast to identify its future energy value, as well as its inherent risk measured by year-to-year portfolio power cost volatility. These values, and associated capital and fixed operation and maintenance (O&M) costs, form the input into Avista's Preferred Resource Strategy Model (PRiSM). PRiSM assists Avista by mathematically determining optimal mixes of new resources. The resource plan may change over time depending on whether projects identified in the IRP remain cost competitive and available at the time of need.

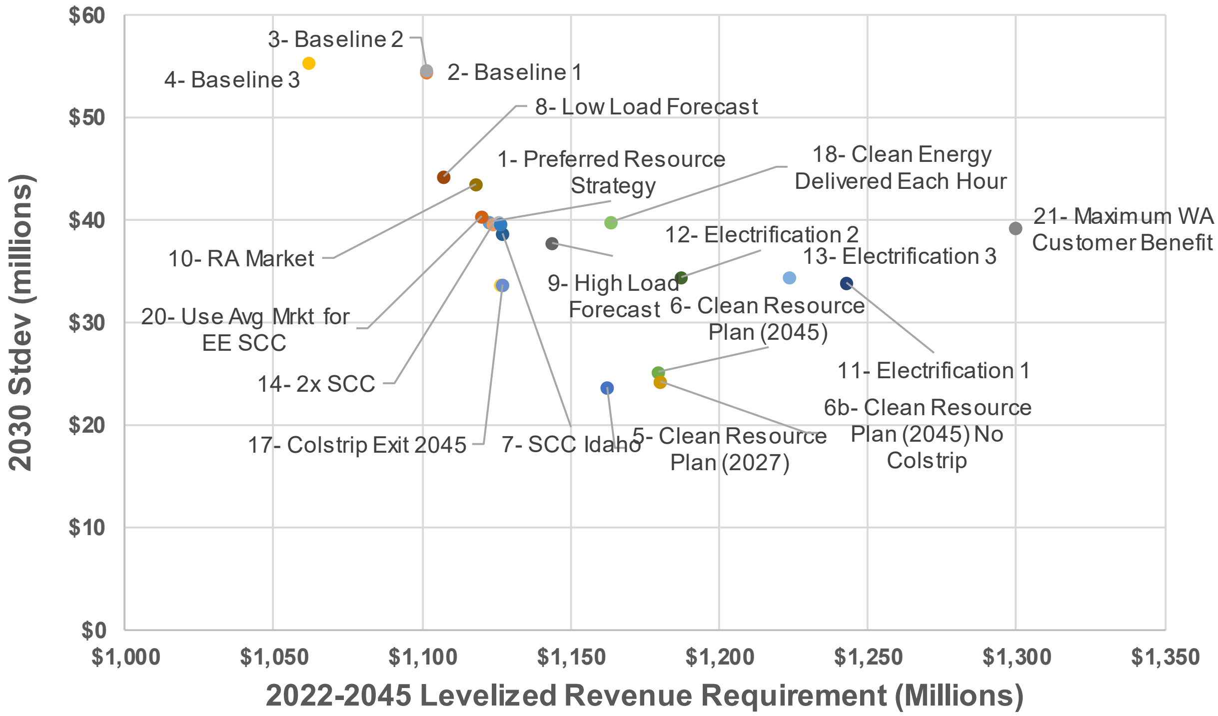
**Table 1.1: The 2021 Preferred Resource Strategy**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana wind | 2023 | WA | 100 |
| Montana wind | 2024 | WA | 100 |
| Lancaster | 2026 | WA/ID | (257) |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 85 |
| Natural Gas Peaker | 2027 | WA/ID | 126 |
| Montana wind | 2028 | WA | 100 |
| NW Hydro Slice | 2031 | WA | 75 |
| Rathdrum CT Upgrade | 2035 | WA/ID | 5 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 87 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Natural Gas Peaker | 2041 | ID | 36 |
| Montana wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 239 |
| 4-hr Storage for Solar | 2042-2043 | WA | 119 |
| Liquid Air Storage | 2044 | WA | 12 |
| Liquid Air Storage | 2045 | ID | 10 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 75 |
| | | | |
| Supply-side resource net total (MW) | | | 1,032 |
| Supply-side resource total additions (MW) | | | 1,589 |
| Demand Response 2045 capability (MW) | | | 71 |
| Cumulative energy efficiency (aMW) | | | 121 |
| Cumulative summer peak savings (MW) | | | 111 |
| Cumulative winter peak savings (MW) | | | 116 |

The PRS provides customers with the lowest-reasonable cost portfolio, minimizing future costs and risks within actual and expected environmental constraints. Similar to finding an optimal mix of risk and return in an investment portfolio, a preferred resource strategy is a balance between cost and risk. As potential returns increase, so do risks. Conversely, reducing risk generally increases overall cost. Figure 1.5 presents the change in cost and risk from the many portfolio scenarios compared to the PRS. Lower power cost variability comes from investments in more expensive, but less risky, resources such as wind and hydroelectric upgrades, with risk measured by lower cost volatility.

Chapter 12 – Portfolio Scenario Analysis includes scenarios and market sensitives illustrating how the PRS could change under different conditions and alternate market futures. It also evaluates the impacts of varying load growth, resource availability, market dynamics and greenhouse gas policies.

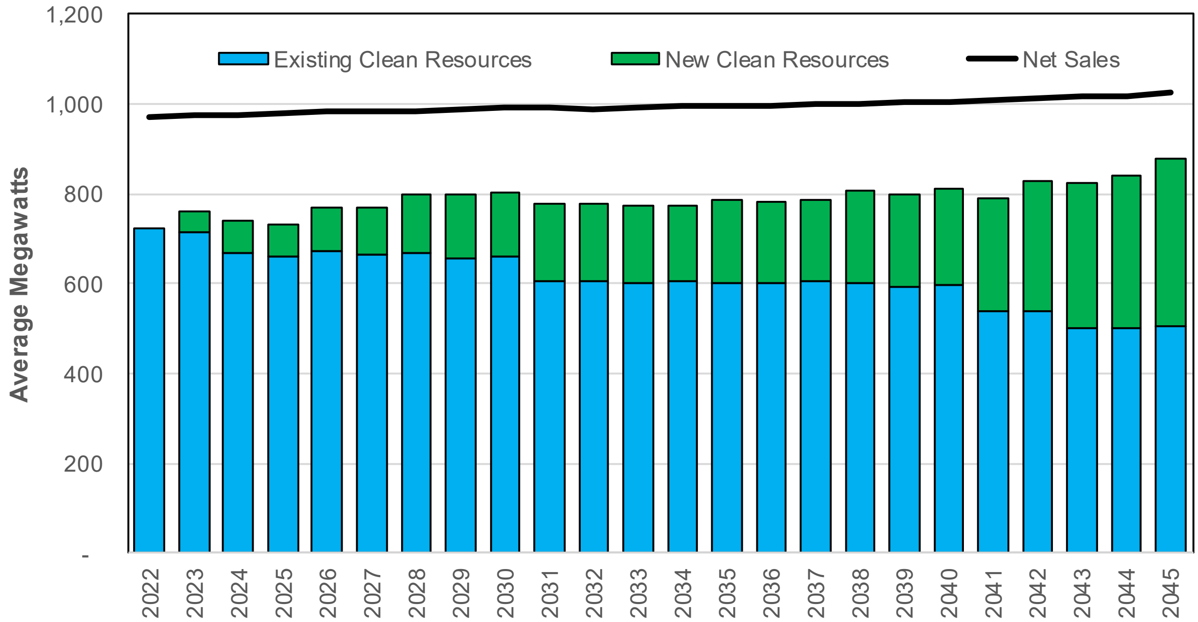
**Figure 1.5: Portfolio Scenario Analysis**




## Clean Energy Goals

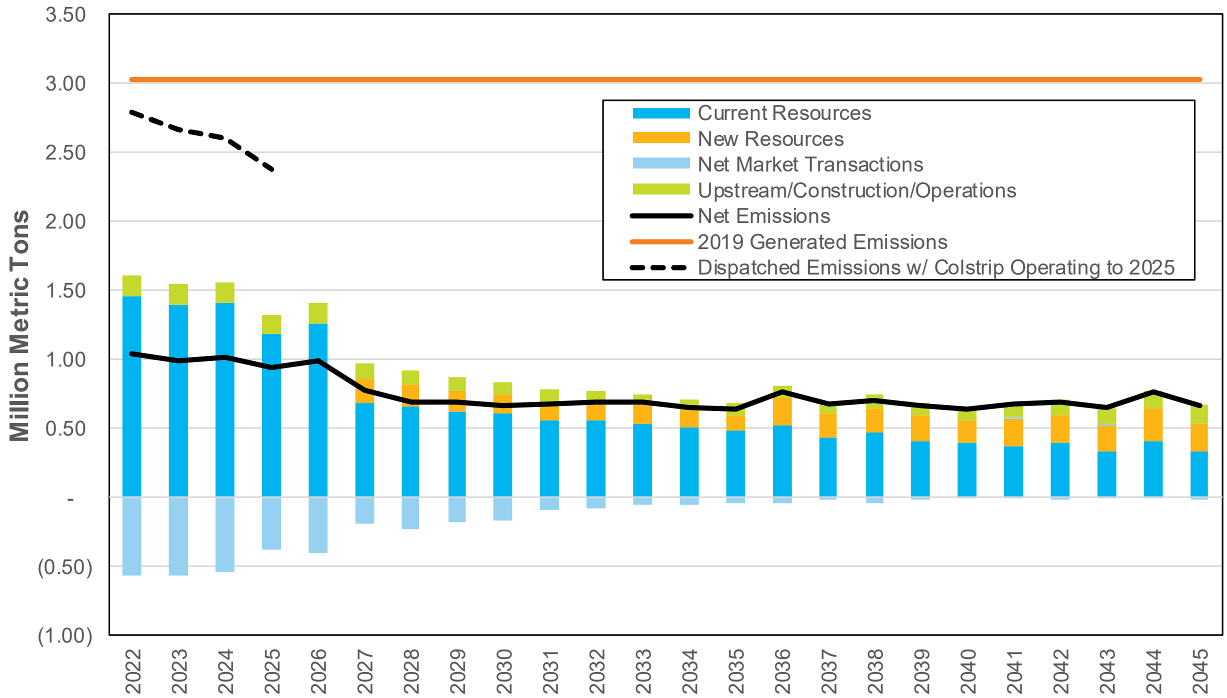
Acquiring an additional 375 MW (by 2031) of new clean energy resources along with upgrades to its hydroelectric and biomass facilities will position Avista to meet or exceed Washington's clean energy requirements. The PRS meets nearly 78 percent of Avista's corporate clean energy goal to provide customers with 100 percent net clean energy by 2027 at competitive prices. Figure 1.6 compares Avista's total energy retail sales (Idaho and Washington) and the annual average clean energy resources serving customers. Avista's plan also exceeds goals of Washington's Energy Independence Act (EIA), relying on output from the Palouse and Rattlesnake Flat Wind contracts, generation from the Kettle Falls biomass facility and upgrades to the Clark Fork and Spokane River hydroelectric developments.

**Figure 1.6: Avista's Clean Energy Acquisition Forecast**




The shift to clean energy will reduce Avista's greenhouse gas footprint significantly. Figure 1.7 shows how emissions will decrease from 2019 levels by 74 percent in 2030 or 2.2 million metric tons. Since the exact removal date of Colstrip from the Avista resource portfolio is not known, Figure 1.7 shows emissions including Colstrip through 2025 (dashed line) and with the removal of Colstrip starting in 2022 for comparison purposes. When accounting for Avista's contributions through incentives and programs to shift transportation fuel from petroleum to electricity, regional greenhouse gas reductions may be greater than those from the removal of coal- and natural gas-fired generation.

**Figure 1.7: Avista Greenhouse Gas Emissions Forecast**




## Energy Equity

Washington's Clean Energy Transformation Act (CETA) expands Avista's commitment to bring affordable energy to customers particularly those in Highly Impacted Communities and vulnerable populations. Avista began a process to identify vulnerable populations within its service territory to better understand the difference in energy burden and reliability for these populations. The Company is committed to finalizing a methodology and developing programs to increase energy affordability of these populations in the next IRP and Clean Energy Implementation Plan. This process will begin with the development of an Equity Advisory Group (EAG) described in Chapter 13 and a low-income energy efficiency pilot program.

## Action Items

The 2021 Action Items chapter provides a progress report on Action Items from the 2020 and 2017 IRPs, and outlines activities Avista intends to perform between the publication of this report and the next IRP. Action Items reflect input from staff at both state Commissions, Avista's management team and the TAC. Refer to Chapter 14 – Action Items for details about each of these categories.

# 2. Introduction and Stakeholder Involvement

Avista submits an Integrated Resource Plan (IRP) to the Idaho and Washington public utility commissions biennially.[1] Including its first plan in 1989, the 2021 IRP is Avista's seventeenth plan. The IRP identifies and describes a Preferred Resource Strategy to meet load growth, resource deficits and environmental requirements while balancing cost and risk measures.

Avista is statutorily obligated to provide safe and reliable electricity service to its customers at rates, terms and conditions that are fair, just, reasonable and sufficient. Avista assesses different resource acquisition strategies and business plans to acquire a mix of resources meeting resource adequacy requirements to maintain reliability while optimizing the value of its current portfolio. The IRP is a resource evaluation tool rather than a plan for acquiring specific assets. Actual resource acquisitions generally occur through competitive bidding processes and can result in different types or sizes of resource selections than previously indicated by the IRP process because acquisitions are based on the bids received.

## IRP Process

This IRP process follows up on the 2020 IRP filed in Idaho by incorporating new requirements and a modified schedule to comply with CETA legislation in Washington. The process is normally completed every two years but was shortened for this IRP cycle. In March 2019, Avista requested both Washington and Idaho approvals to delay the IRP filing by six months, effectively creating the 2020 IRP cycle. Ultimately the 2020 IRP was filed in Idaho, but it was only considered a Progress Report by Washington. This IRP filing, given the shortened schedule, is the first plan in the new process schedule under CETA. Avista intends to file the next IRP in Idaho and Washington[2] by January 1, 2023 unless a new date is required by either state commission.

The 2021 IRP is developed and written with the aid of a public process. Avista actively seeks input from many constituents through its Technical Advisory Committee (TAC) meetings. The TAC is a mix of over 100 external participants, including staff from the Idaho and Washington commissions, customers, academics, environmental organizations, government agencies, consultants, utilities and other interested parties who want to engage in the planning process. Avista distributed a draft of its work plan prior to submitting the final work plan on April 1, 2020. This shortened IRP process included five full meetings, two updates and one modeling workshop beginning with its first meeting on June 18, 2020. A public meeting to seek more customer level input was also held on February 24, 2021. Each TAC meeting covered different IRP activities. TAC members provided contributions to and assessed modeling assumptions, modeling processes and results of Avista studies. Table 2.1 lists TAC meeting dates and agenda items covered in each meeting.

[1] Washington IRP requirements are in WAC 480-100-238 Integrated Resource Planning. Idaho IRP requirements are in Case No. U-1500-165, Order No. 22299 and Case No. GNR-E-93-3, Order No. 25260.
[2] Washington does not require the next full IRP until 2025 and the 2023 filing is a biennial IRP update.

Appendix A, available on and Avista's website[3], includes the agendas, presentations and meeting notes from the 2021 IRP TAC meetings. The website also contains all of the past IRPs and TAC meeting presentations back to 1989. The final work plan, which incorporates changes in the schedule, is in Appendix B.

**Table 2.1: TAC Meeting Dates and Agenda Items**

| Meeting Date | Agenda Items |
|---|---|
| TAC 1 – June 18, 2020 | • TAC Meeting Expectations & IRP Process Review<br>• Review of 2020 IRP Idaho acknowledgement<br>• Update on CETA rulemaking process<br>• Modeling process and assumptions overview including Aurora, ARAM, ADSS and PRiSM<br>• Generation options (cost, assumptions, ELCC)<br>• Highly impacted community discussion (WA-CETA) |
| TAC 2 – August 6, 2020 | • Demand and economic forecast<br>• Conservation Potential Assessment (AEG)<br>• Demand Response Potential Assessment (AEG)<br>• Natural gas market overview and price forecast<br>• Regional energy policy update<br>• Gas/Electric coordinated studies<br>• Highly impacted community proposals |
| Load Forecast – August 18, 2020 | • Economic and Load Forecast |
| TAC 3 – September 29, 2020 | • IRP transmission planning studies<br>• Distribution planning within the IRP<br>• IRP Transmission Planning Studies<br>• Discuss market and portfolio scenarios<br>• Existing resource overview<br>• Electric market forecast and scenarios |
| TAC 4 – November 17, 2020 | • Final resource needs assessment and resource adequacy<br>• Ancillary services and intermittent generation analysis<br>• Review draft resource plans for each state and scenarios |
| PRiSM Workshop – December 4, 2020 | • Review of PRiSM Model |
| Scenario Review- December 16, 2020 | • Draft PRS<br>• Portfolio Scenario and Sensitivity Results |
| TAC 5 – January 21, 2021 | • Review draft IRP<br>• Final state resource plans and scenarios<br>• Draft Clean Energy Implementation Plan discussion<br>• 2021 IRP Action Items<br>• Initial comments from TAC participants<br>• Overview of ARAM model |
| Public Meeting – February 24, 2021 | • Overview of the 2021 IRP and public discussion<br>• Customer Q&A sessions |

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

Avista greatly appreciates the valuable contributions of its TAC members and wishes to acknowledge and thank the organizations and members who participated in this IRP. Table 2.2 lists organizations participating in the 2021 IRP TAC process.

**Table 2.2: External Technical Advisory Committee Participating Organizations**

| Organization | |
|---|---|
| 4Sight Energy Group | National Grid |
| 350.Org Spokane | New Sun Energy |
| AEG | NW Energy Coalition |
| Biomethane, LLC | Northwest Power and Conservation Council |
| Bonneville Power Administration | Northwest Renewables |
| Building Industry Association of Washington | Pacific Northwest Utilities Conference Committee |
| Carbon WA | Pera Inc |
| Chelan PUD | Perennial Power Holdings |
| City of Spokane | Phil Jones Consulting |
| Clenera | Pivotal Investments |
| Clear Result | Puget Sound Energy |
| Clearwater Paper | Pullman City Council |
| Climate Solutions | Renewable Northwest |
| Creative Renewable Solutions | Residential and Small Commercial Customers |
| Cyprus Creek Renewables | Shasta |
| Direct Energy | Sierra Club |
| Energy Keepers Inc. | Sovereign Power |
| GE Energy | Spokane Tribe of Indians |
| Heelstone Renewable Energy | SpokEnergy |
| Huntwood | Strata Solar |
| Idaho Conservation League | Tesla |
| Idaho Department of Environmental Quality | The Energy Authority |
| Idaho Office of Energy and Mineral Resources | Tollhouse Energy |
| Idaho Power | Tyr Energy |
| Idaho Public Utilities Commission | Wartsila |
| Inland Empire Paper | Washington State Department of Community, Trade and Economic Development |
| Inland Power & Light | Washington State Office of the Attorney General |
| Innovari | Washington State Department of Enterprise Services |
| Kiemle Hagood | Washington Utilities and Transportation Commission |
| McKinstry | Water Planet |
| Measure Meant | Western Grid Group |
| Mitsubishi Power Americas, Inc | Whitman County Commission |
| MRW Associates | |

### Future Public Involvement

Avista actively solicits input from interested parties to enhance its IRP process and continues to expand its TAC membership and diversity while maintaining the TAC meetings as an open public process. Anyone who would like to be added to the TAC, please email irp@avistacorp.com for more information.

## 2021 IRP Outline

The 2021 IRP consists of 15 chapters including the Executive Summary and this introduction. A series of technical appendices supplement this report.

### Chapter 1: Executive Summary

This chapter summarizes the overall results and highlights of the 2021 IRP.

### Chapter 2: Introduction and Stakeholder Involvement

This chapter introduces the IRP and details public participation and involvement in the IRP process.

### Chapter 3: Economic and Load Forecast

This chapter covers regional economic conditions, Avista's energy and peak load forecasts and load forecast scenarios.

### Chapter 4: Existing Supply Resources

This chapter provides an overview of Avista-owned generating resources and its contractual resources and obligations and environmental regulations.

### Chapter 5: Energy Efficiency

This chapter discusses Avista energy efficiency programs. It provides an overview of the conservation potential assessment and summarizes energy efficiency modeling results.

### Chapter 6: Demand Response

This chapter discusses the demand response potential study and an overview of demand response pilot programs.

### Chapter 7: Long-Term Position

This chapter reviews Avista reliability planning and reserve margins, resource requirements and provides an assessment of its reserves and resource flexibility.

### Chapter 8: Transmission & Distribution Planning

This chapter discusses Avista distribution and transmission systems, as well as regional transmission planning issues. It includes details on transmission cost studies used in IRP modeling and summarizes the Company's 10-year Transmission Plan. The chapter concludes with a discussion of distribution planning; including storage benefits to the distribution system.

### Chapter 9: Supply-Side Resource Options

This chapter covers the cost and operating characteristics of supply side resource options modeled for the IRP.

### Chapter 10: Market Analysis
This chapter details Avista IRP modeling and its analyses of the wholesale market.

### Chapter 11: Preferred Resource Strategy
This chapter details the resource selection process used to develop the 2021 PRS and resulting avoided costs.

### Chapter 12: Portfolio Scenarios
This chapter presents alternative resource portfolios and shows how each scenario performs under different energy market conditions.

### Chapter 13: Energy Equity
This chapter discusses the vulnerable population and highly impacted communities relative to Clean Energy Transformation Act (CETA).

### Chapter 14: Action Plan
This chapter discusses progress made on Action Items in the 2020 IRP. It details the areas Avista will focus on between publication of this plan and the 2023 IRP.

### Chapter 15: Clean Energy Action Plan
This chapter discusses action items for compliance with Washington State's CETA between publication of this plan and the 2023 IRP.

## Idaho Regulatory Requirements
The IRP process for Idaho has several requirements documented in IPUC Orders Nos. 22299 and 25260. Order 22299 dates back to 1989; this order outlines the requirement for the utility to file a "Resource Management Report". This report *recognize[s] the managerial aspects of owning and maintaining existing resources as well as procuring new resources and avoiding/reducing load*. *[The Commission's] desire is the report on the utility's planning status, not a requirement to implement new planning efforts according to some bureaucratic dictum*. *We realize that integrated resource planning is an ongoing, changing process. Thus, we consider the RMR required herein to be similar to an accounting balance sheet, i.e., a "freeze-frame" look at a utility's fluid process.*

The report should discuss any flexibilities and analyses considered during comprehensive resource planning such as:

1. Examination of load forecast uncertainties
2. Effects of known or potential changes to existing resources
3. Consideration of demand- and supply-side resource options
4. Contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead-time, reliability, risk, etc.) as future events unfold.

Avista outlines the order's requirements below for ease of readability for each of the Commission's requirements.

## Existing Resource Stack

Identification of all resources by category below[4]; including the utility shall provide a copy of the utility's most recent U.S. Department of Energy Form EIA-714 submittal and the following specific data, as defined by the NERC, ought to be included as an appendix[5]:

a) Hydroelectric;
   i. Rated capacity by unit;
   ii. Equivalent Availability Factor by month for most recent 5 years;
   iii. Equivalent Forced Outage Rate by month for most recent 5 years; and
   iv. FERC license expiration date.
b) Coal-fired;
   i. Rated Capacity by unit;
   ii. Date first put into service;
   iii. Design plant life (including life extending upgrades, if any);
   iv. Equivalent Availability Factor by month for most recent 5 years; and
   v. Equivalent Forced Outage Rate by month for most recent 5 years.
c) Oil or Gas fired;
   i. Rated Capacity by unit;
   ii. Date first put into service;
   iii. Design plant life (including life extending upgrades, if any);
   iv. Equivalent Availability Factor by month for most recent 5 years; and
   v. Equivalent Forced Outage Rate by month for most recent 5 years.
d) PURPA Hydroelectric;
   i. Contractual rated capacity;
   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
e) PURPA Thermal;
   i. Contractual rated capacity;
   ii. Five-year historic hours connected to system, by month (if known);
   iii. Five-year historic generation (kWh), by month;
   iv. Level of dispatchability, if any; and
   v. Contract expiration date.
f) Economy Exchanges;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
g) Economy Purchases;
   I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
   II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.
h) Contract Purchases;

[4] Resources less than three megawatts should be grouped as a single resource in the appropriate category.
[5] FERC Form 714 can be on-line at https://www.ferc.gov/docs-filing/forms/form-714/data.asp

I. For contract purchases & exchanges, key contract terms and conditions relating to capacity, energy, availability, price, and longevity.
II. For economy purchases and exchanges, 5-year historical monthly average capacity, energy, and prices.

i) Transmission Resources; and
   I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.
j) Other.
   I. Information useful for estimating the power supply benefits and limitations appurtenant to the resources in question.

### Load Forecast

Each RMR should discuss expected 20-year load growth scenarios for retail markets and for the federal wholesale market including "requirements" customers, firm sales, and economy (spot) sales. For each appropriate market, the discussion should:

a) identify the most recent monthly peak demand and average energy consumption (where appropriate by customer class), both firm and interruptible;
b) identify the most probable average annual demand and energy growth rates by month and, where appropriate, by customer class over at least the next three years and discuss the years following in more general terms;
c) discuss the level of uncertainty in the forecast, including identification of the maximum credible deviations from the expected average growth rates; and
d) identify assumptions, methodologies, data bases, models, reports, etc. used to reach load forecast conclusions.

This section of the report is to be a short synopsis of the utility's present load condition, expectations and level of confidence. Supporting information does not need to be included but should be cited and made available upon request.

### Additional Resource Menu

This section should consist of the utility's plan for meeting all potential jurisdictional load over the 20-year planning period. The discussion should include references to expected costs, reliability and risks inherent in the range of credible future scenarios.

- An ideal way to handle this section could be to describe the most probable 20-year scenario followed by comparative descriptions of scenarios showing potential variations in expected load and supply conditions and the utility's expected responses thereto. Enough scenarios should be presented to give a clear understanding of the utility's expected responses over the full range of possible future conditions.
- The guidance provided above is intended to ensure maximum flexibility to utilities in presenting their resource plans. Ideally, each utility will use several scenarios to demonstrate potential maximum, minimum and intermediate levels of new resource requirements and the expected means of fulfilling those requirements. For example,
  - A credible scenario requiring maximum new resources might be regional load growth exceeding 3% per year combined with catastrophic destruction (earthquake, fire, flood, etc.) of a utility's largest resource (i.e., Bridger coal

plant for IPCo and PP&L, Hunter coal plant for UP&L and Noxon hydro plant for WWP).
    - A credible scenario causing reduced utilization of existing resources might be regional stagflation combined with loss of a major industry within a utility's service territory. Analyses of intermediate scenarios would also be useful.
- To demonstrate the risks associated with various proposed responses, certain types of information should be supplied to describe each method of meeting load. For example,
    - If new hydroelectric generating plants are proposed, the lead time required to receive FERC licensing and the risk of license denial should be discussed.
    - If new thermal generating plants are proposed, the size, potential for unused capacity, risks of cost escalation and fuel security should be discussed and compared to other types of plants.
    - If off-system purchases are proposed, specific supply sources should be identified, regional resource reserve margin should be discussed with supporting documentation identified, potential transmission constraints and/or additions should be discussed, and all associated costs should be estimated.
    - If conservation or demand side resources are proposed, they should be identified by customer class and measure, including documentation of availability, potential market penetration and cost.
- Because existing hydroelectric plants could be lost to competing companies if FERC relicensing requirements are not aggressively pursued, relicensing alternatives require special consideration. For example,
    - If hydroelectric plant relicensing upgrades are proposed, their costs should be presented both as a function of increased plant output and of total plant output to recognize the potential of losing the entire site.
    - Costs of upgrades not required for relicensing should be so identified and compared only to actual increased capacity/energy availability at the unit, line, substation, distribution system, or other affected plant. Increased maintenance costs, instrumentation, monitoring, diagnostics, and capital investments to improve or maintain availability should be quantified.
- Because PURPA projects are not under the utility's control, they also require special consideration. Each utility must choose its own way of estimating future PURPA supplies. The basis for estimates of PURPA generation should be clearly described.

### Other provisions from Order 22299

- Because the RMR is expected to be a report of a utility's plans, and because utilities are being given broad discretion in choosing their reporting format, Least Cost Plans or Integrated Resource Plans submitted to other jurisdictions should be applicable in Idaho.
    - Utilities should use discretion and judgement to determine if reports submitted to other jurisdictions provide such emphasis, if adding an

appendix would supply such emphasis, or if a separate report should be prepared for Idaho.
  - The project manager responsible for the content and quality of the RMR shall be clearly identified therein and a resume of her/his qualifications shall be included as an appendix to the RMR.
- Finally, the Resource Management Report is not designed to turn the IPUC into a planning agency nor shall the Report constitute pre-approval of a utility's proposed resource acquisitions.
- The reporting process is intended to be ongoing-revisions and adjustments are expected. The utilities should work with the Commission Staff when reviewing and updating the RMRs. When appropriate, regular public workshops could be helpful and should be a part of the reviewing and updating process.
- Most parties seem to agree that reducing and/or avoiding peak capacity load or annual energy load has at least the equivalent effect on system reliability of adding generating resources of the same size and reliability. Furthermore, because conservation almost always reduces transmission and distribution system loads, most parties consider reliability effects of conservation superior to those of generating resources. Consequently, the Commission finds that electric utilities under its jurisdiction, when formulating resource plans, should give consideration to appropriate conservation and demand management measures equivalent to the consideration given generating resources.
- Therefore, we find that the parties should use the avoided cost methodology resulting from the No. U-1500-170 case for evaluating the cost effectiveness of conservation measures. The specific means for comparing No. U-1500-170 case avoided costs to conservation costs will initially be developed case-by-case as specific conservation programs are proposed by each utility. Prices to be paid for conservation resources procured by utilities are discussed later in this Order.
- Give balanced consideration to demand side and supply side resources when formulating resource plans and when procuring resources.
- Submit to the Commission, no later than March 15, 1989, and at least biennially thereafter, a Resource Management Report describing the status of its resource planning as of the most current practicable date.

### Order 25260 Requirements

This order documents additional requirements for resource planning including:

- Give full consideration to renewables, among other resource options.
- Investigate and carefully weigh the site-specific potential for particular renewables in their service area.
- Deviations from the integrated resource plans must be explained. The appropriate place to determine the prudence of an electric utility's plan or the prudence of an electric utility's following or failing to follow a plan will be in general rate case or other proceeding in which the issue is noticed.

## Washington Regulatory Requirements

Washington UTC recently completed its rule making process for Integrated Resource Planning. The rules are outlined below in Table 2.3 through Table 2.13. Avista also discusses where in the IRP document the rule requirement is covered or plans to address the rule requirement in the next IRP.

### Table 2.3: Timing & Plan Horizon

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-625 (1) and (4) | Integrated resource plan updated every four years, with a progress report at least every two years. | This IRP begins the new IRP cycle. |
| WAC 480-100-620 (1) | Unless otherwise stated, all assessments, evaluations, and forecasts comprising the plan should extend over the long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) planning horizon. | This IRP covers 2022 to 2045. |

### Table 2.4: Load Forecast

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (2) | Plan includes range of forecasts of projected customer demand that reflect effect of economic forces on electricity consumption.<br><br>Plan includes range of forecasts of projected customer demand that address changes in the number, type, and efficiency of electrical end-uses. | Chapter 3 covers the load forecast and Chapter 12 includes scenarios on alternative electrical end uses. |

## Table 2.5: Demand-Side Resources & DERs

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (3)(a)<br>WAC 480-109-100 (2) | Plan includes load management assessments that are cost-effective and commercially available, including current and new policies and programs to obtain:<br>• all cost-effective conservation, efficiency, and load management improvements;<br>• ten-year conservation potential used in the concurrent biennial conservation plan consistent with RCW 19.285.040(1);<br>• identification of opportunities to develop combined heat and power as an energy and capacity resource; and<br>• all demand response (DR) at the lowest reasonable cost (LRC). | Chapter 5 covers the energy efficiency potential assessment.<br><br>Chapter 6 covers the demand response potential assessment.<br><br>Chapter 11 covers the selected energy efficiency and demand response options. |
| WAC 480-100-620 (3)(b) | Plan includes assessments of distributed energy programs and mechanisms pertaining to energy assistance and progress toward meeting energy assistance need, including but not limited to the following:<br>• Energy efficiency and CPA,<br>• Demand response potential,<br>• Energy assistance potential.<br><br>Plan assesses a forecast of distributed energy resources (DER) that may be installed by the utility's customers via a planning process pursuant to RCW 19.280.100(2).<br><br>Plan includes effect of DERs on the utility's load and operations.<br><br>If utility engages in a DER planning process, which is strongly encouraged, IRP should include a summary of the process planning results. | Avista includes future customer DERs with the load forecast in Chapter 3, The Company includes DERs as resource options to meet future resource deficits. Lastly, Avista has not identified any DER opportunities in its Distribution Planning at this time as covered in Chapter 8.<br><br>Avista intends to develop a plan to integrate DERs in the 2025 IRP (Chapter 14). |

## Table 2.6: Supply-Side Resources

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620(4) | Plan assesses wide range of conventional generating resources. | Chapter 9 covers the full list of supply side resource options considered in this IRP. |
| WAC 480-100-620(5) | In making new investments, plan considers acquisition of existing and new renewable resources at LRC. | In Chapter 9, Avista considers extensions to existing resource contracts, but does not consider resources under contract by other utilities. These resources will typically be discovered through the RFP process as Avista has no way to accurately price these resources without an RFP.<br><br>Avista plans to further assess existing resource options as part of its Action Plan for this IRP. |
| UE-151069 & UE-161024 | Plan assesses energy storage resources. | Chapter 9 covers the full list of energy storage resources modeled in this plan. |
| WAC 480-100-620 (5) | Plan assesses nonconventional generating, integration, and ancillary service technologies. | Avista includes the value and cost of ancillary services for meeting the flexibility requirements of the system covered in Chapter 7. |

## Table 2.7: Regional Generation & Transmission

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (6) | Plan assesses the availability of regional generation and transmission capacity for purposes of delivery of electricity to customers.<br><br>Plan assesses utility's regional transmission future needs and the extent transfer capability limitations may affect the future siting of resources. | Avista assessed regional reliability in Chapter 7 and the market analysis in Chapter 10. Regional transmission planning efforts are discussed in Chapter 8 and Appendix G. |

## Table 2.8: Resource Evaluation

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (7) | Plan compares benefits and risks of purchasing power or building new resources.<br><br>Plan compares all identified resources according to resource costs, including:<br>• transmission and distribution delivery costs;<br>• risks, including environmental effects and the social cost of GHG emissions;<br>• benefits accruing to the utility, customers, and program participants (when applicable); and<br>• resource preference public policies adopted by WA State or the federal government.<br><br>Plan includes methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events. | Chapter 11 covers the selection process of new supply side and demand side resources considering the requirements of this rule. Additional planning requirements are also discussed in Chapter 7 and in Chapter 12. |

## Table 2.9: Resource Adequacy Metric Determination & Identification

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (8) | Plan assesses and determines resource adequacy metrics.<br><br>Plan identifies an appropriate resource adequacy requirement.<br><br>Plan measures corresponding resource adequacy metric consistent with prudent utility practice in eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030), attaining GHG neutrality by 1/1/2030 (RCW 19.405.040), and achieving 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050). | Avista discusses its resource adequacy assessment in Chapter 7 and the resulting resource adequacy of the PRS in Chapter 11. Avista also conducted a resource adequacy related scenario in Chapter 12. |

## Table 2.10: Economic, Health, Environmental Burdens and Benefits, and Equity

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (9) | Plan reflects the cumulative impact analysis conducted under RCW 19.405.140, and includes an assessment of:<br>• energy and nonenergy benefits;<br>• reduction of burdens to vulnerable populations and highly impacted communities;<br>• long-term and short-term public health and environmental benefits and costs;<br>• long-term and short-term public health and environmental risks; and<br>• energy security and risk. | Avista covers its current and future plan to meet this requirement in Chapter 12. |

## Table 2.11: Cases, Scenarios, & Sensitivities

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (10) | Utility should include a range of possible future scenarios and input sensitivities for testing the robustness of the utility's resource portfolio under various parameters, including the following required components. | Chapter 12 covers over 20 portfolio scenarios and four market scenarios. |
| | CETA counter factual scenario - describe the alternative LRC and reasonably available portfolio that the utility would have implemented if not for the requirement to comply with RCW 19.405.040 and RCW 19.405.050, as described in WAC 480-100-660(1). | Avista includes this portfolio as Portfolio #2, Baseline #1 as described in Chapter 12. |
| | Climate change scenario - incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change. | Avista includes a climate load forecast for this scenario in Chapter 3 and discusses effects of hydro production and resource analysis in Chapter 12. |
| | Maximum customer benefit sensitivity - model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals. | Avista has not conducted this scenario for the 2021 IRP due to the timing of this requirement. At this time, Avista still requires additional information to determine how to model this scenario and meet its intended purpose. |

## Table 2.12: Portfolio Analysis and Preferred Portfolio

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (11)<br>WAC 480-100-620 (11)(a) | Plan must integrate demand forecasts and resource evaluations into a long-range IRP solution.<br><br>IRP solution or preferred portfolio must describe the resource mix that meets current and projected needs.<br><br>Preferred portfolio must include narrative explanation of the decisions made, including how the utility's long-range IRP solution:<br>• achieves requirements for eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030);<br>• attains GHG neutrality by 1/1/2030 (RCW 19.405.040);<br>• achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050) at LRC; and<br>• achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050), considering risk. | Avista plans for many alternative long-term load forecasts besides the Expected Case; including lower and higher load growth and three electrification scenarios as discussed in Chapter 3 and in Chapter 12.<br><br>For each of these scenarios, Avista developed a PRS subject to the requirements of this rule. |
| WAC 480-100-620(11)(c) | Consistent with RCW 19.285.040(1), preferred portfolio shows pursuit of all cost-effective, reliable, and feasible conservation and efficiency resources, and DR. | See Chapter 11. |
| WAC 480-100-620(11)(d) and (e) | Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, insofar as doing so is at LRC.<br><br>Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, considering risks. | See Chapter 11. |
| WAC 480-100-620 (11)(f) | Preferred portfolio maintains and protects the safety, reliable operation, and balancing of the utility's electric system, including mitigating over-generation events and achieving identified resource adequacy requirements. | See Chapter 11. |
| WAC 480-100-620 (11)(g) | Preferred portfolio ensures all customers are benefiting from the transition to clean energy through the<br>• equitable distribution of energy and nonenergy benefits; reduction of burdens to vulnerable populations and highly impacted communities;<br>• long-term and short-term public health and environmental benefits; reduction of costs and risks; and<br>• energy security and resiliency. | Avista is developing an Equity Advisory Group to assure all customers benefit in the transition to clean energy. Avista's plan for this transition is covered in Chapter 13. |

| | | |
|---|---|---|
| WAC 480-100-620(11)(h)<br>WAC 480-100-620(11)(i)<br>WAC 480-100-620(11)(j) | Preferred portfolio: assesses the environmental health impacts to highly impacted communities,<br>• analyzes and considers combinations of DER costs, benefits, and operational characteristics (incl. ancillary services) to meet system needs.<br>• incorporates the social cost of GHG emissions as a cost adder. | At this time the full list of Highly Impacted Communities is not available, but it will be included in the planning efforts described in Chapter 13. |

## Table 2.13: Clean Energy Action Plan

| WAC Rule | Requirement | IRP Discussion |
|---|---|---|
| WAC 480-100-620 (12) | Utility must develop a ten-year clean energy action plan (CEAP) for implementing RCW 19.405.030 through 19.405.050 at LRC, and at an acceptable resource adequacy standard.<br><br>The CEAP will:<br>• identify and be informed by utility's ten-year CPA per RCW 19.285.040(1);<br>• demonstrate that all customers are benefiting from the transition to clean energy;<br>• establish a resource adequacy requirement;<br>• identify the potential cost-effective DR and load management programs that may be acquired;<br>• identify renewable resources, nonemitting electric generation, and DERs that may be acquired and evaluate how each identified resource may be expected to contribute to meeting the utility's resource adequacy requirement;<br>• identify any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities; and<br>• identify the nature and possible extent to which the utility may need to rely on alternative compliance options, if appropriate. | Avista includes a Clean Energy Action Plan in Chapter 15 of this IRP covering each of the requirements. |
| WAC 480-100-620 (12)(i) | Plan (both IRP and CEAP) considers cost of greenhouse gas emissions as a cost adder equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in Table 2, Technical Support Document: Technical update of the social cost of carbon (SCC) for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, as adjusted by the Commission to reflect the effect of inflation. | Avista includes these adders discussed in Chapters 9 - 12 and includes the calculation of these costs in Appendix I. |

## Table 2.14: Avoided Cost

| WAC Rule | Requirement | IRP Discussion |
| --- | --- | --- |
| WAC 480-100-620 (13) | Plan must include an analysis and summary of the estimated avoided cost for each supply- and demand-side resource, including (but not limited to):<br>• energy,<br>• capacity,<br>• transmission,<br>• distribution, and<br>• GHG emissions.<br>Listed energy and non-energy impacts should specify to which source party they accrue (e.g., utility, customers, participants, vulnerable populations, highly impacted communities, general public). | Avista estimates avoided cost including each of the factors for both supply and demand side resources. Chapter 5 includes the avoided costs for energy efficiency and Chapter 11 includes the avoided cost for supply side and demand response resources. |
| WAC 480-106-040 | Plan provides information and analysis used to inform annual purchases of electricity from qualifying facilities, including a description of the:<br>• avoided cost calculation methodology used;<br>• avoided cost methodology of energy, capacity, transmission, distribution, and emissions averaged across the utility; and<br>• resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost, including (but not limited to): cost assumptions, production estimates, peak capacity contribution estimates, and annual capacity factor estimates. | Qualifying Facility avoided costs calculations are included in Appendix F. |

## Table 2.15: Process

| WAC Rule | Requirement | IRP Discussion |
| --- | --- | --- |
| WAC 480-100-620 (14) | To maximize transparency, the utility should submit data input files supporting the plan in native file format (e.g., supporting spreadsheets in Excel, not PDF file format). | Avista includes all publicly available documentation electronically in Appendix I and confidential data and models in Appendix J. |
| WAC 480-100-620 (16) | Plan must summarize substantive changes to modeling methodologies or inputs that change the utility's resource need, as compared to the utility's previous IRP. | This information is included in Chapter 2. |
| Utility must summarize: | Utility must summarize:<br>• public comments received on the draft IRP,<br>• utility's responses to public comments, and<br>• whether final plan addresses and incorporates comments raised. | Comments and responses are covered in Appendix C. |

## Summary of 2021 IRP Changes from the 2017 and 2020 IRPs

This summary provides an overview of major changes in the analyses since the 2017 and 2020 IRPs. This section does not describe all the specific changes, but rather provides a summary of the significant or major methodological changes.

### Capacity and Energy Position, Including Load Forecasting

- Loads and resources are divided using the Production-Transportation (PT) ratio and resources must be selected to meet individual state requirements.
- This IRP uses a 16 percent planning margin in the winter rather than the 2017 IRP's 14 percent. The 7 percent summer planning margin remains the same. This change retains the 5 percent LOLP threshold assuming 330 MW of market availability to Avista (compared to 250 MW in the 2017/2020 IRPs).
- The load forecast includes adjustments for natural gas penetration.
- Assumes Colstrip exits Avista's portfolio by the end of 2025 for Washington customers and allows the plant to remain in the Idaho portfolio in any year it is economic.
- Assumes the Northeast CT retires in 2035 and Boulder Park retires in 2040.

### Energy Efficiency and Demand Response

- Idaho energy efficiency analysis uses the Utility Cost Test (UCT) for program selection rather than the Total Resource Cost (TRC) test.
- Washington energy efficiency analysis includes savings from associated greenhouse gas emissions priced at the social cost of carbon using the 2.5 percent discount rate prescribed in CETA. The emissions savings assumes the annual incremental emission rate within the regional power system. Avista used average regional emissions in the 2020 IRP and a portfolio scenario was conducted to test this difference in this IRP.
- Estimates for non-energy impacts are included in the avoided cost.
- The 2021 IRP estimated energy savings for DR programs and includes the energy savings in the portfolio analysis.

### Supply-Side Resource Options

- Avista modeled several energy storage options in this IRP including specific regional projects and representative pumped hydro storage projects. Transmission and Distribution scale lithium-ion storage along with vanadium flow, zinc bromide flow, and liquid air storage options were also modeled for this IRP.
- Hydrogen fuel is considered using both fuel cells and turbines with on-site storage.
- This IRP models wind, solar, pumped hydro storage, nuclear and geothermal as purchase power agreements; whereas the IRPs prior to 2020 assumed these resources were Avista-owned.
- Avista assigned peak credits to renewable and storage resources depending on a resource's ability to meet peak loads determined using its ARAM model.
- The 2021 plan, for the first time, uses levelized energy or capacity cost rather than annual cost estimates for all resource options.
- This IRP includes upstream greenhouse gas emissions from the natural gas-fired projects priced with the social cost of carbon for Washington's share of resources.

- Construction and operational greenhouse gas emissions are considered and priced using the social cost of carbon for Washington's share of resources.
- The IRP analysis does not use a social cost of carbon price for market purchases and sales as in the 2020 IRP. A portfolio scenario was performed to test this sensitivity.

## Market Analysis

- Avista utilizes Energy Exemplar's (Aurora) database for most inputs into the price forecast with the exception of Avista's proprietary utility specific information.
- The Aurora capacity expansion study is required to meet the qualifications of state clean energy policies including CETA using both a national consulting database and Aurora's capacity expansion logic. The model must also meet a 5 percent LOLP threshold for reliability when selecting new resources.
- This IRP blends two consultant forecasts and the Energy Information System (EIA) long-term forecasts with market forward prices for the natural gas price forecast. The 2017 IRP used only one consultant forecast along with forward prices and the 2020 IRP did not include the EIA forecast.

## Portfolio Optimization Analysis

- The 2021 IRP optimizes a resource portfolio for 2022 to 2045. Moving to 24 years led to removing some of the cost estimates for resources beyond 20 years.
- The social cost of carbon is not included in the projected dispatch decision of resources in the Expected Case but is included in the optimization of resource decisions, which is the same methodology used in the 2020 IRP.
- This IRP models the clean energy requirements of CETA in Washington State the same as the 2020 IRP.
- Includes total customer rate estimates. IRPs prior to 2020 only showed power supply costs.
- Portfolio optimization allows new resources to be added for either state or the system to understand the drivers and responsibility of resource decisions.

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# 3. Economic & Load Forecast

Avista's loads and resources are an integral component of the IRP. This chapter summarizes customer and load projections; including high and low load growth scenarios; adjustments for customer-owned solar generation, electric vehicles and climate change, as well as recent enhancements to load and customer forecasting models and processes.

**Chapter Highlights**

- The 2021 energy forecast grows 0.3 percent per year, similar to the 0.3 percent annual growth rate in the 2020 IRP.
- Peak load growth is 0.38 percent in the winter and 0.44 percent in the summer.
- Retail sales and residential use per customer forecasts are slightly higher than the 2020 IRP projections.
- Avista expects a 39 aMW increase in residential load from electric vehicles and a decrease of 12 aMW due to residential rooftop solar by 2045.

## Economic Characteristics of Avista's Service Territory

Avista's core electric service area includes more than a half million people residing in Eastern Washington and Northern Idaho. Three metropolitan statistical areas (MSAs) dominate its service area: the Spokane-Spokane Valley, WA MSA (Spokane-Stevens counties); the Coeur d'Alene, ID MSA (Kootenai County); and the Lewiston-Clarkson ID-WA, MSA (Nez Perce-Asotin counties). These three MSAs account for just over 70 percent of both Avista's customers (i.e., meters) and load. The remaining 30 percent are in low-density rural areas in both states. Washington accounts for about two-thirds of customers and Idaho the remaining one-third. The IRP forecast period 2021-2025 includes the impacts of the COVID-19 shock since the forecast was completed following the national shut-down for the pandemic in the first quarter of 2020. By 2025, the IRP assumes both the U.S. and Avista service area economies will largely return to pre-COVID-19 long-run economic growth.

### Population

Population growth is increasingly a function of net migration within Avista's service area. Net migration is strongly associated with both service area and national employment growth through the business cycle. The regional business cycle follows the U.S. business cycle, meaning regional economic expansions or contractions follow national trends.[1] Econometric analysis shows when regional employment growth is stronger than U.S. growth over the business cycle, it is associated with increased in-migration and the reverse holds true. Figure 3.1 shows annual population growth since 1971 and highlights the recessions in yellow. During all deep economic downturns since the mid-1970s, reduced population growth rates in Avista's service territory led to lower load growth.[2] The

[1] *An Exploration of Similarities between National and Regional Economic Activity in the Inland Northwest*, Monograph No. 11, May 2006. http://www.ewu.edu/cbpa/centers-and-institutes/ippea/monograph-series.xml.
[2] Data Source: Bureau of Economic Development, U.S. Census, and National Bureau of Economic Research.

Great Recession reduced population growth from nearly 2 percent in 2007 to less than 1 percent from 2010 to 2013. Accelerating service area employment growth in 2013 helped push population growth to around 1 percent starting in 2014.

**Figure 3.1: MSA Population Growth and U.S. Recessions, 1971-2019**

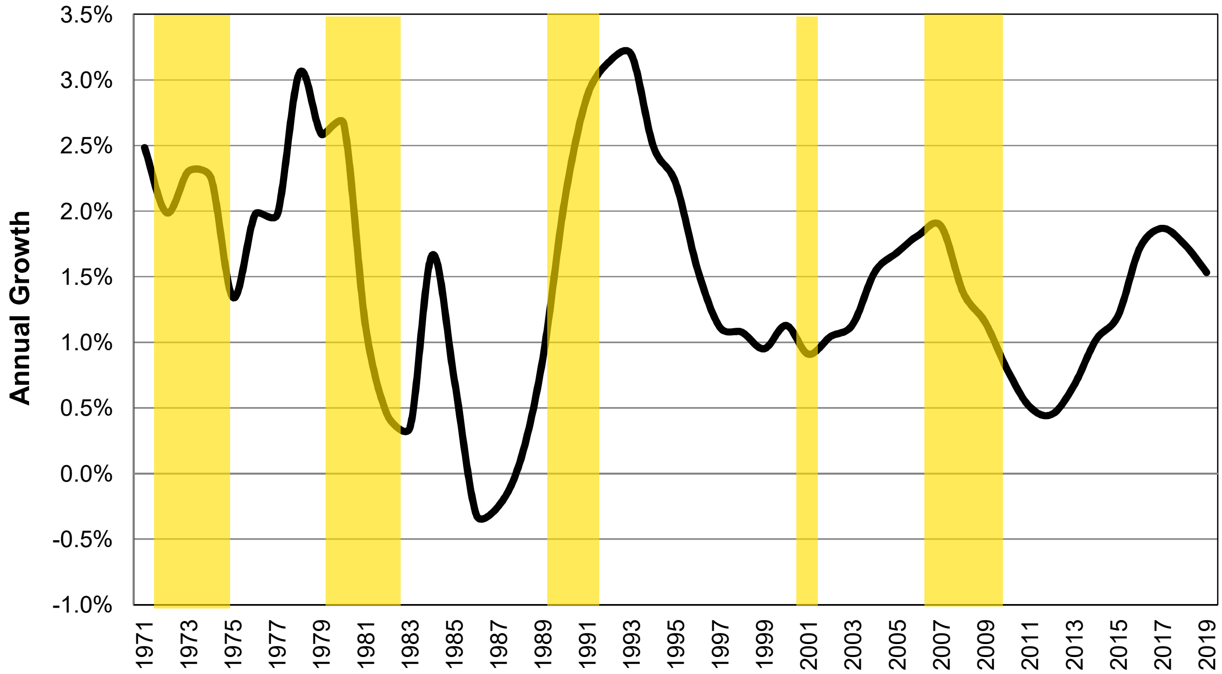
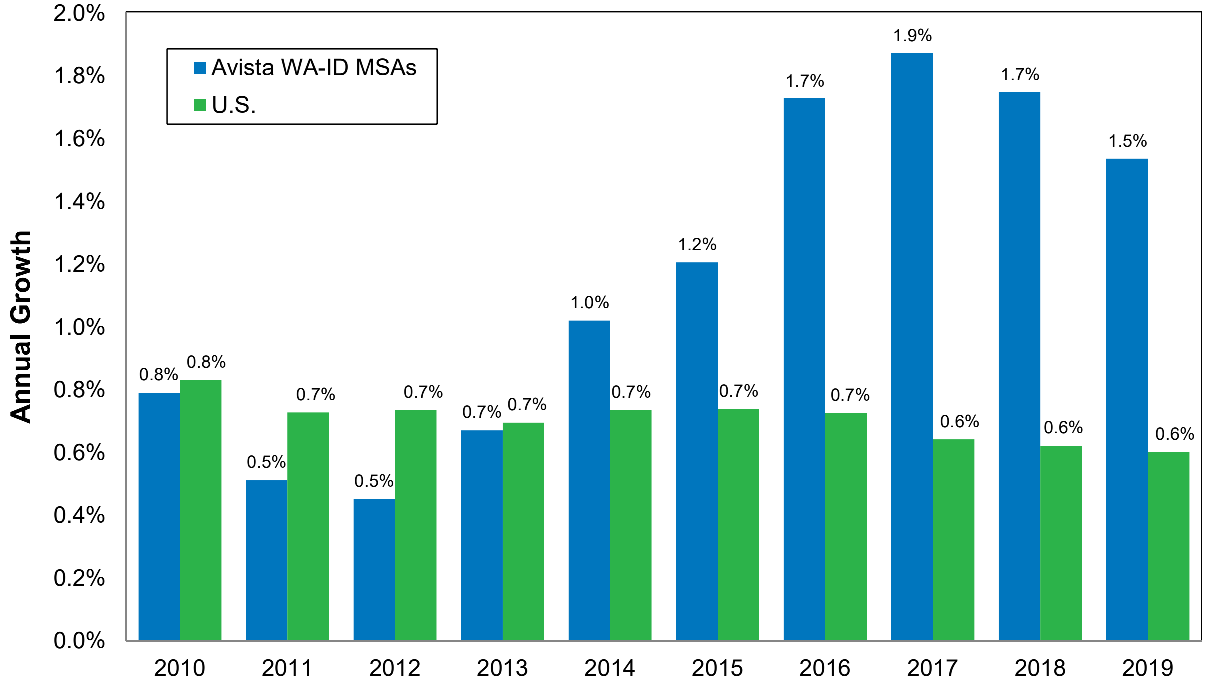



Figure 3.2 shows population growth since the start of the Great Recession in 2007.[3] Service area population growth over the 2010-2012 period was weaker than the U.S.; however, it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in service area population growth in 2014 relative to the U.S. population growth. The association of employment growth to population growth has a one-year lag. The relative strength of service area population growth in year “y” is positively associated with service area population growth in year “y+1”. Econometric estimates using historical data show when holding the U.S. employment-growth constant, every 1 percent increase in service area employment growth is associated with a 0.4 percent increase in population growth in the next year.

[3] Data Source: Bureau of Economic Analysis, U.S. Census, and Washington State OFM.

**Figure 3.2: Avista and U.S. MSA Population Growth, 2007-2019**

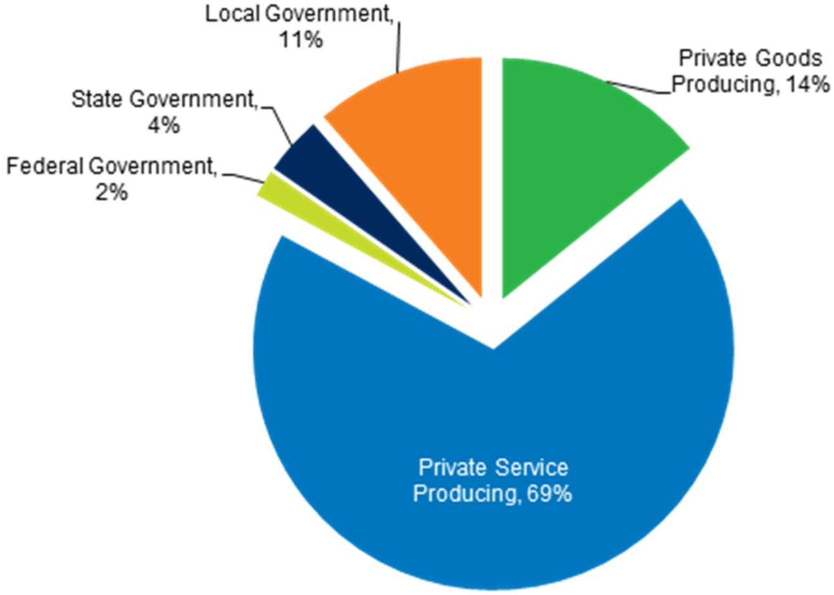



## Employment

It is useful to examine the distribution of employment and employment performance since 2007 given the correlation between population and employment growth. The Inland Northwest is now a services-based economy rather than its former natural resources-based manufacturing economy. Figure 3.3 shows the breakdown of non-farm employment for all three-service area MSAs.[4] Approximately 70 percent of employment in the three MSAs is in private services, followed by government (17 percent) and private goods-producing sectors (14 percent). Farming accounts for 1 percent of total employment. Spokane and Coeur d'Alene MSAs are major providers of health and higher education services to the Inland Northwest.

[4] Data Source: Bureau of Labor and Statistics.

**Figure 3.3: MSA Non-Farm Employment Breakdown by Major Sector, 2019**




Non-farm employment growth averaged 2.7 percent per year between 1990 and 2007. However, Figure 3.4 shows service area employment lagged the U.S. recovery from the Great Recession for the 2010-2012 period.[5] Regional employment recovery did not materialize until 2013, when services employment started to grow. Prior to this, reductions in federal, state and local government employment offset gains in goods producing sectors. Service area employment growth began to match or exceed U.S. growth rates by the fourth quarter 2014. It is worth noting the exact timing of Avista's service area's recovery from the COVID-19 recession is uncertain. However, the 2021 IRP forecast assumes a GDP decline of 6 percent in 2020, with a gradual recovery to pre-COVID-19 long-term economic growth by 2025. The steep decline in GDP in 2020 translates into an industrial load forecast that will not fully normalize until after 2025. In addition, the forecast includes statistical control variables assuming the large COVID-19 induced load shifts between residential and commercial customers will last into 2025, but with the large difference initially created in 2020 narrowing as economic activity normalizes. Avista will continue to monitor the post-recession load levels and distribution for future IRPs.

[5] Data Source: Bureau of Labor and Statistics.

**Figure 3.4: Avista and U.S. MSA Non-Farm Employment Growth, 2010-2019**

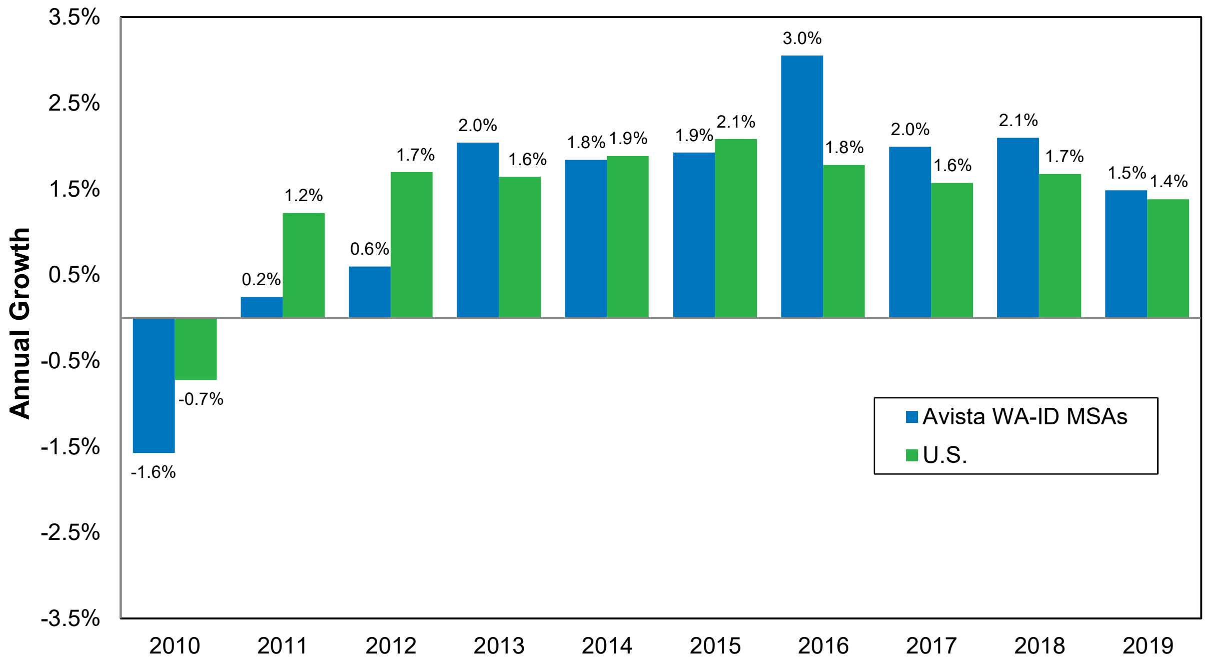



Figure 3.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[6] Regular income includes net earnings from employment, and investment income in the form of dividends, interest and rent. Personal current transfer payments include money income and in-kind transfers received through unemployment benefits, low-income food assistance, Social Security, Medicare and Medicaid.

Transfer payments in Avista's service area in 1970 accounted for 12 percent of the local economy. The income share of transfer payments has nearly doubled over the last 40 years to 22 percent. The relatively high regional dependence on government employment and transfer payments means transfer program reform may reduce future local economic growth. Although 57 percent of personal income is from net earnings, transfer payments still account for more than one in every five dollars of personal income. Recent years have seen transfer payments become the fastest growing component of regional personal income. This growth in regional transfer payments reflects an aging regional population, a surge of military veterans and the Great Recession; the latter significantly increased payments from unemployment insurance and other low-income assistance programs.

Figure 3.6 shows the real (inflation adjusted) average annual growth per capita income by MSA for Avista's service area and the U.S. overall. Note that in the 1980 – 1990 period, the service area experienced significantly lower income growth compared to the U.S. because of the back-to-back recessions of the early 1980s.[7] The impacts of these recessions were more negative in the service area compared to the U.S. as a whole, so the ratio of service area per capita income to U.S. per capita income fell from 93 percent

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[6] Data Source: Bureau of Economic Analysis.

[7] Data Source: Bureau of Economic Analysis.

in the 1970s to around 85 percent by the mid-1990s. The income ratio has not since recovered.

**Figure 3.5: MSA Personal Income Breakdown by Major Source, 2019**

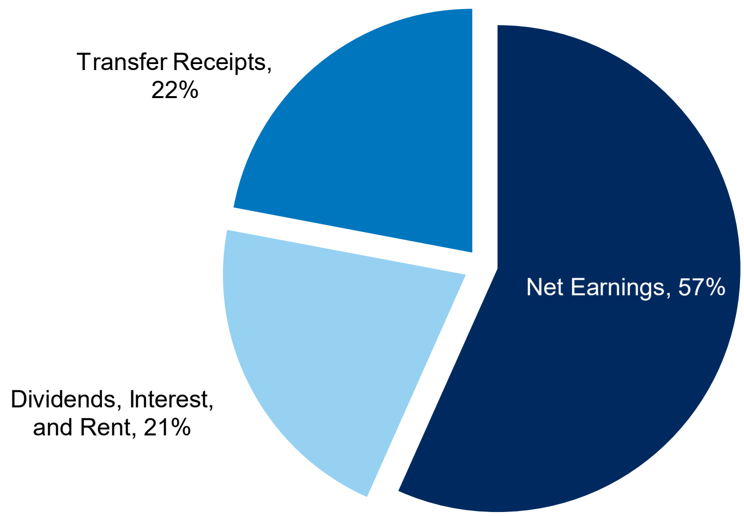
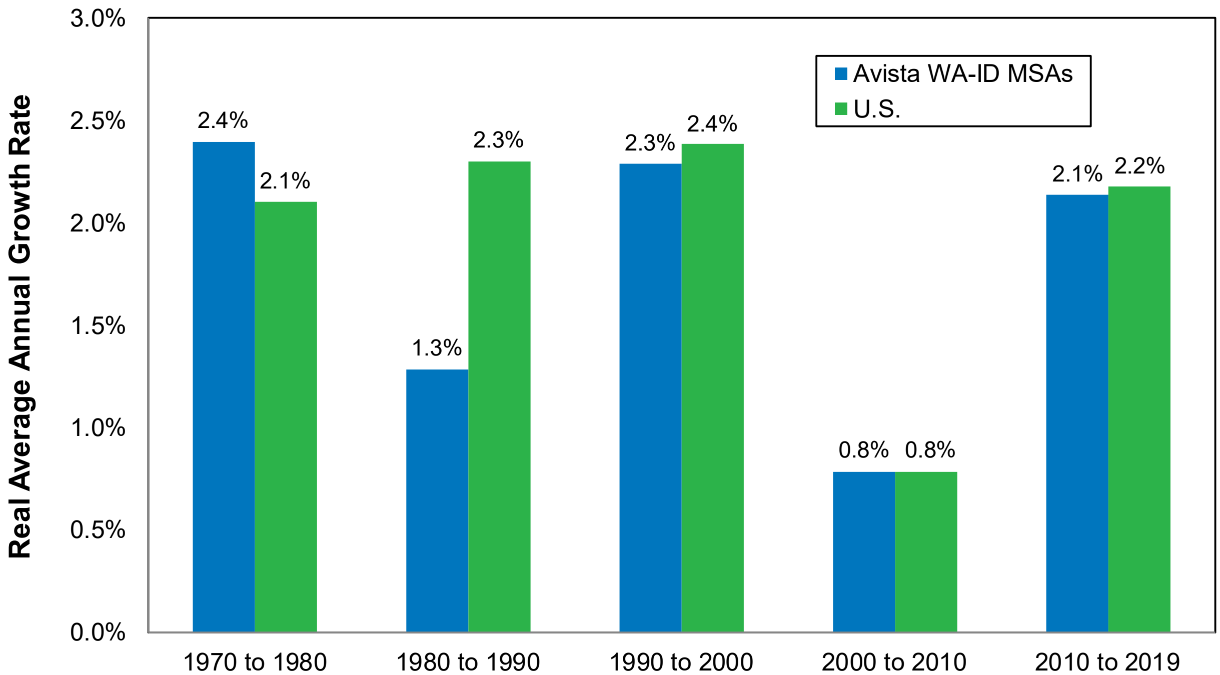



**Figure 3.6: Avista and U.S. MSA Real Personal Income Growth by Decade, 1970-2019**




## Overview of the Retail Load Forecast

The retail load forecast is a two-step process. The first step is a detailed five-year forecast described below and the second steps bootstraps years six through 25 by applying the growth assumptions discussed later in this chapter. For each customer class in most rate schedules, there is a monthly use per customer (UPC) forecast and a monthly customer forecast.[8] The load forecast results from multiplying the customer and UPC forecasts. The UPC and customer forecasts are generated using time-series econometrics, as shown in Equation 3.1.

**Equation 3.1: Generating Schedule Total Load**

$$F(kWh_{t,y_c+j,s}) = F(kWh/C_{t,y_c+j,s}) \times F(C_{t,y_c+j,s})$$

Where:

- $\mathrm{F}(\mathrm{kWh}_{\mathrm{t},\mathrm{y_c}+\mathrm{j},\mathrm{s}})$ = the forecast for month t, year j = 1,…,5 beyond the current year, $y_c$ ,for schedule s.
- $\mathrm{F}(\mathrm{kWh}/\mathrm{C}_{\mathrm{t},\mathrm{y_c}+\mathrm{j},\mathrm{s}})$ = the UPC forecast.
- $\mathrm{F}(\mathrm{C}_{\mathrm{t},\mathrm{y_c}+\mathrm{j},\mathrm{s}})$ = the customer forecast.

## UPC Forecast Methodology

The econometric modeling for UPC is a variation of the "fully integrated" approach expressed by Faruqui (2000) in the following equation:[9]

**Equation 3.2: Use Per Customer Regression Equation**

$$kWh/C_{t,y,s} = \alpha W_{t,y} + \beta Z_{t,y} + \epsilon_{t,y}$$

The model uses actual historical weather, UPC and non-weather drivers to estimate the regression in Equation 3.2. To develop the forecast, normal weather replaces actual weather (W) along with the forecasted values for the Z variables (Faruqui, pp. 6-7). Here, W is a vector of heating degree day (HDD) and cooling degree day (CDD) variables; Z is a vector of non-weather variables; and $\varepsilon_{t,y}$ is an uncorrelated N(0,σ) error term. For non-weather sensitive schedules, W = 0.

The W variables will be HDDs and CDDs. Depending on the schedule, the Z variables may include real average energy price (RAP); the U.S. Federal Reserve industrial production index (IP); residential natural gas penetration (GAS); non-weather seasonal dummy variables (SD); trend functions (T); and dummy variables for outliers (OL) and periods of structural change (SC). RAP is measured as the average annual price (schedule total revenue divided by schedule total usage) divided by the consumer price index (CPI), less energy. For most schedules, the only non-weather variables are SD, SC and OL. See Table 3.1 for the occurrence RAP and IP.

If the error term appears to be non-white noise, then the forecasting performance of Equation 3.2 can be improved by converting it into an autoregressive integrated moving average (ARIMA) "transfer function" model such that $\epsilon_{t,y}$ = ARIMA$\epsilon_{t,y}$(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

[8] For schedules representing a single customer, where there is no customer count and for street lighting, Avista forecasts total load directly without first forecasting UPC.

[9] Faruqui, Ahmad (2000). *Making Forecasts and Weather Normalization Work Together*, Electric Power Research Institute, Publication No. 1000546, Tech Review, March 2000.

of seasonal differencing, and $q_k$ is the seasonal order of MA terms. The seasonal values relate to “k,” or the frequency of the data. With the current monthly data set, k = 12.

Certain schedules, such as those related to lighting, use simpler regression and smoothing methods because they offer the best fit for irregular usage without seasonal or weather-related behavior, is in a long-run steady decline, or is seasonal and unrelated to weather. Avista defines normal weather for the load forecast as a 20-year moving average of degree-days taken from the National Oceanic and Atmospheric Administration’s Spokane International Airport data. Normal weather updates only occur when a full year of new data is available. For example, normal weather for 2018 is the 20-year average of degree-days for the 1998 to 2017 period; and 2019 is the average of the 1999 to 2018 period.

The choice of a 20-year moving average for defining normal weather reflects several factors. First, climate research from the National Aeronautics and Space Administration’s (NASA) Goddard Institute for Space Studies (GISS) shows a shift in temperature starting almost 30 years ago. The GISS research finds the summer temperatures in the Northern Hemisphere increased one degree Fahrenheit above the 1951-1980 reference period; the increase started roughly 30 years ago in the 1981-1991 period.[10] An in-house analysis of temperature in Avista’s Spokane-Kootenai service area, using the same 1951-1980 reference period, also showed an upward shift in temperature starting about 30-years ago. A detailed discussion of this analysis is provided in the peak-load forecast section of this chapter.

The second factor in using a 20-year moving average is the volatility of the moving average as a function of the years used to calculate the average. Moving averages of 10 and 15 years showed considerably more year-to-year volatility than the 20-year moving average. This volatility can obscure longer-term trends and leads to overly sharp changes in forecasted loads when applying the updated definition of normal weather each year. These sharp changes would also cause excessive volatility in the revenue and earnings forecasts.

As noted earlier, if non-weather drivers appear in Equation 3.2, then they must also be in the five-year forecast to generate the UPC forecast. The assumption in the five-year forecast for this IRP is for RAP to be constant out to 2025; increase at 1 percent from 2026 to 2029; and then increase 1.5 percent until 2045. RAP no longer appears explicitly in the regression equations for the five-year forecast. The coefficient estimates for RAP have become unstable and statistically insignificant. Therefore, the 2021 IRP assumes elasticity to be -0.3 percent, based on long-run estimates from academic literature.[11] This

[10] See Hansen, J.; M. Sato; and R. Ruedy (2013). *Global Temperature Update Through 2012*, http://www.nasa.gov/topics/earth/features/2012-temps.html.

[11] Avista is unable to produce reliable elasticity estimates using its own UPC data. It is difficult to obtain reliable elasticity estimates using data for an individual utility, so the Company relies on academic estimates using multiple regions and estimation methods. As theory predicts, the literature indicates that short-term elasticity is lower (less price sensitive) than long-term elasticity. Avista assumes the low end of the long-term range of academic elasticity estimates.

IRP generates IP forecasts from a regression using the GDP growth forecasts (GGDP). Figure 3.7 describes this process.

**Table 3.1: UPC Models Using Non-Weather Driver Variables**

| Schedule | Variables | Comment |
|---|---|---|
| **Washington:** | | |
| Residential Schedule 1 | GAS | Ratio of natural gas residential schedule 101 customers in WA to electric residential schedule 1 customers in WA. |
| Industrial Schedules 11, 21, and 25 | IP | |
| | | |
| **Idaho:** | | |
| Residential Schedule 1 | GAS | Ratio of natural gas residential schedule 101 customers in ID to electric residential schedule 1 customers in ID. |
| Industrial Schedules 11 and 21 | IP | |

The forecasts for GDP reflect the average of forecasts from multiple sources including the Bloomberg survey of forecasts, the Philadelphia Federal Reserve survey of forecasters, the Wall Street Journal survey of forecasters and other sources. Averaging forecasts reduces the systematic errors of a single-source forecast. This approach assumes macroeconomic factors flow through UPC in the industrial rate schedules. This reflects the relative stability of industrial customer growth over the business cycle.

**Figure 3.7: Forecasting IP Growth**

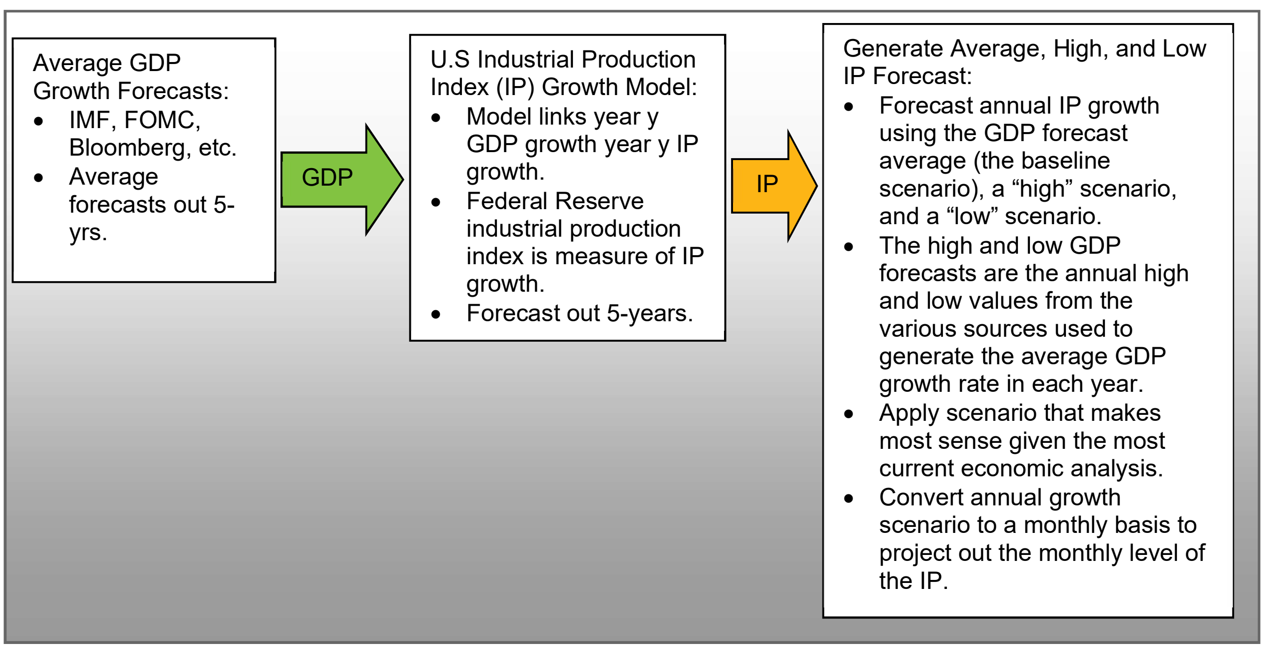
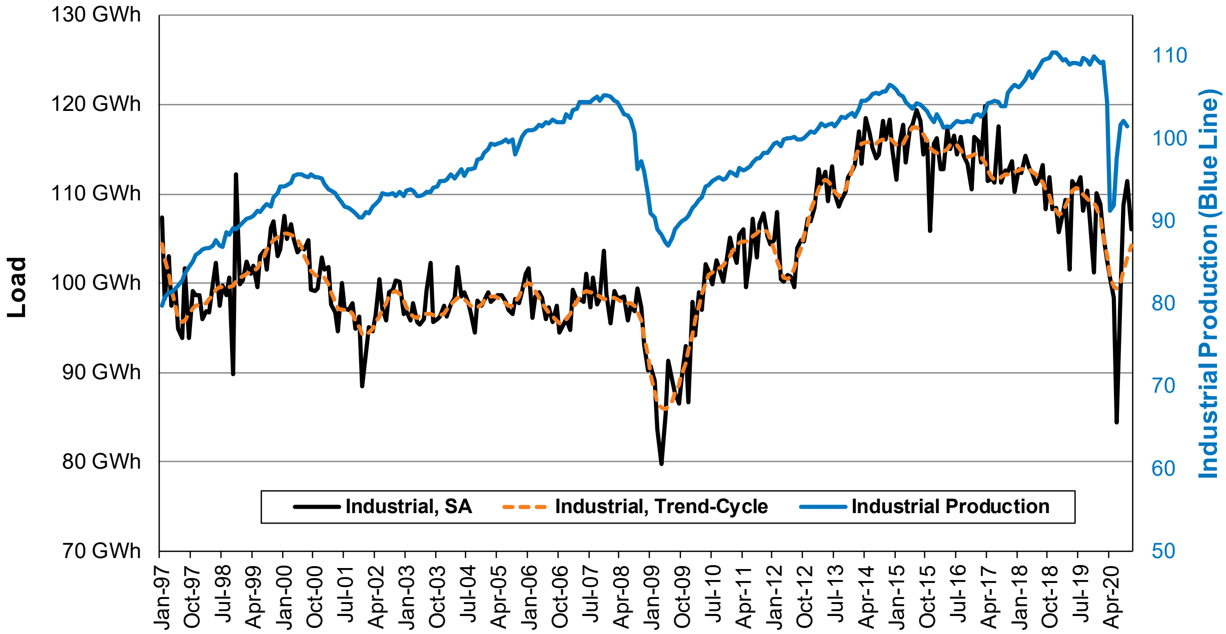


Figure 3.8 shows the historical relationship between the IP and industrial load for electricity.[12,13] The load values have been seasonally adjusted using the Census X11 procedure. The historical relationship is positive for both loads. The relationship is very strong for electricity with the peaks and troughs in load occurring in the same periods as the business cycle peaks and troughs.

**Figure 3.8: Industrial Load and Industrial (IP) Index**




## Customer Forecast Methodology

The econometric modeling for the customer models range from simple smoothing models to more complex ARIMA models. In some cases, a pure ARIMA model without any structural independent variables is used. For example, the independent variables are only the past values of the rate schedule customer counts, which is also the dependent variable. Because the customer counts in most rate schedules are either flat or growing in a stable fashion, complex econometric models are generally unnecessary for generating reliable forecasts. Only in the case of certain residential and commercial schedules is more complex modeling required.

For the main residential and commercial rate schedules, the modeling approach needs to account for customer growth between these schedules having a high positive correlation over 12-month periods. This high customer correlation translates into a high correlation over the same 12-month periods. Table 3.2 shows the correlation of customer growth between residential, commercial and industrial consumers of Avista electricity and natural gas. To assure this relationship in the customer and load forecasts, the models for the Washington and Idaho Commercial Schedules 11 use Washington and Idaho Residential Schedule 1 customers as a forecast driver. Historical and forecasted

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[12] Data Source: U.S. Federal Reserve and Avista records.

[13] Figure 3.8 excludes one large industrial customer with significant load volatility.

Residential Schedule 1 customers become drivers to generate customer forecasts for Commercial Schedule 11 customers.

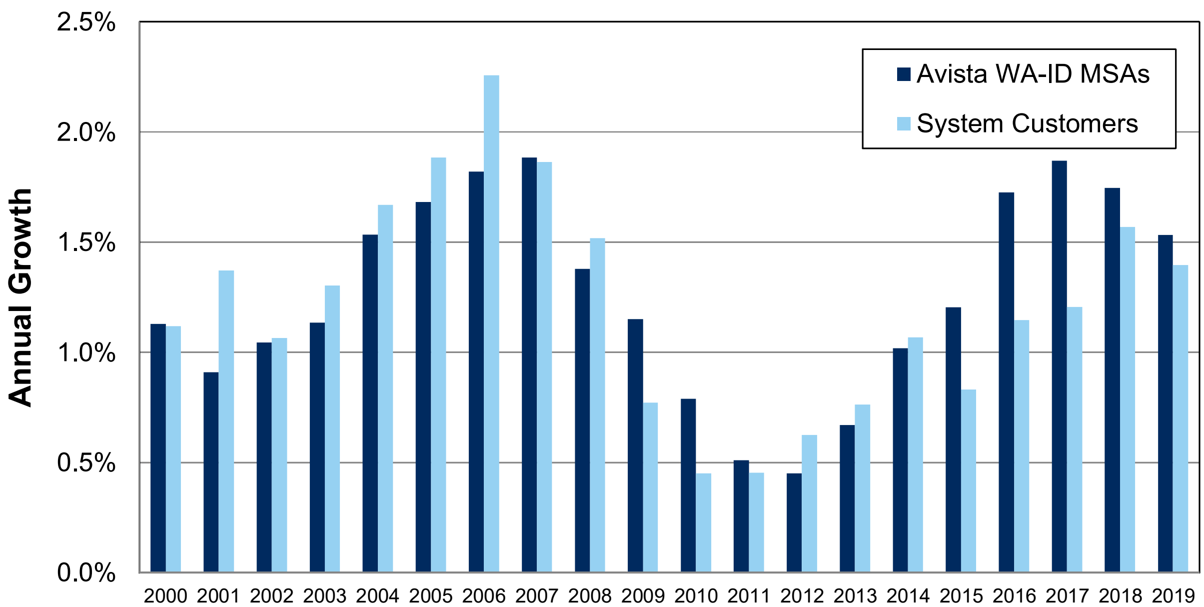
**Table 3.2: Customer Growth Correlations, January 2005 – October 2020**

| Customer Class (Year-over-Year) | Residential | Commercial | Industrial | Streetlights |
|---|---|---|---|---|
| Residential | 1 | | | |
| Commercial | 0.61 | 1.00 | | |
| Industrial | -0.06 | 0.12 | 1.00 | |
| Streetlights | -0.18 | -0.08 | 0.13 | 1.00 |

Figure 3.9 shows the relationship between annual population growth and year-over-year customer growth.[14] Customer growth has closely followed population growth in the combined Spokane-Kootenai MSAs over the last 20 years. Population growth averaged 1.3 percent over the 2000-2019 period and customer growth averaged 1.2 percent annually.

Figure 3.9 demonstrates how population growth is a proxy for customer growth. As a result, forecasted population is an adjustment to Residential Schedule 1 customers in Washington and Idaho. The forecast is made using an ARIMA times-series model for Schedule 1 customers in Washington and Idaho. If the growth rates generated from this approach differ from forecasted population growth, the forecast adjusts to match forecasted population growth.

**Figure 3.9: Population Growth vs. Customer Growth, 2000-2019**

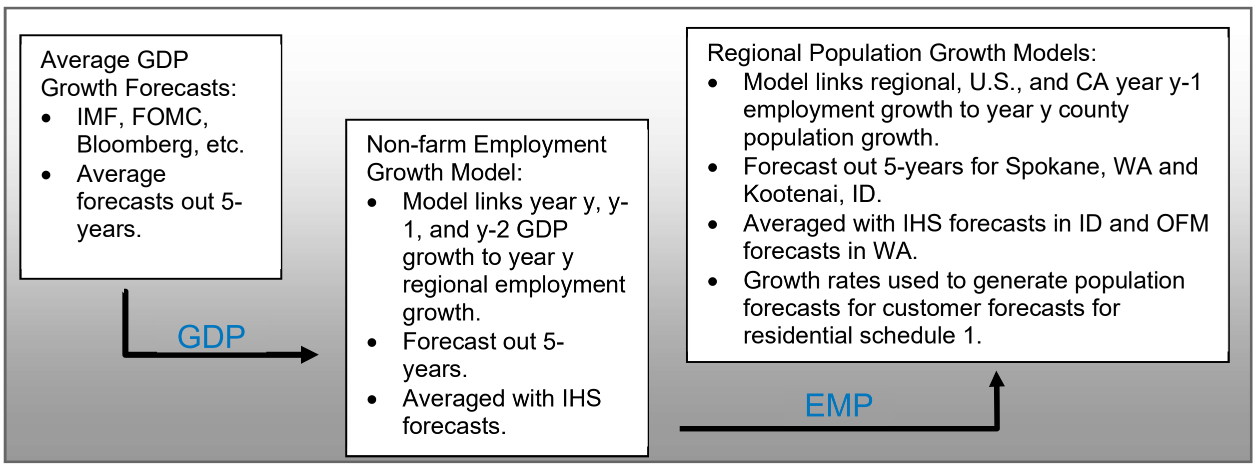



[14] Data Source: Bureau of Economic Analysis, U.S. Census, Washington State OFM, and Avista records.

Forecasting population growth is a process that links U.S. GDP growth to service area employment growth and then links regional and national employment growth to service area population growth.

The same average GDP growth forecasts used for the IP growth forecasts are inputs to the five-year employment growth forecast. Avista averages employment forecasts with IHS Connect's (formerly Global Insight) forecasts for the same counties. Averaging may reduce the systematic errors of a single-source forecast. The averaged employment forecasts become inputs to generate population growth forecasts. Figure 3.10 summarizes the forecasting process for population growth for use in estimating Residential Schedule 1 customers.

**Figure 3.10: Forecasting Population Growth**




The employment growth forecasts (the average of Avista and IHS forecasts) become inputs used to generate the population growth forecasts. The Kootenai forecast is averaged with IHS's forecasts for the same MSA. The Spokane forecast is averaged with Washington's Office of Financial Management (OFM) forecast for the same MSA. These averages produce the final population forecast for each MSA. These forecasts are then converted to monthly growth rates to forecast population levels over the next five years.

# IRP Long-Run Load Forecast

## The Basic Model

The long-run load forecast extends the intermediate term projection out to 2045. It includes the adjustments for electric vehicle (EV) fleet and residential rooftop photovoltaic (PV) solar. The long-run modeling approach starts with Equation 3.3.

**Equation 3.3: Residential Long-Run Forecast Relationship**

$$\ell_y = c_y + u_y$$

Where:

- $\ell_y$ = residential load growth in year y.
- $c_y$ = residential customer growth in year y.
- $u_y$ = UPC growth in year y.

Equation 3.3 sets annual residential load growth equal to annual customer growth plus the annual UPC growth.[15] $C_y$ is not dependent on weather, so where $u_y$ values are weather normalized, $\ell_y$ results are weather-normalized. Varying $c_y$ and $u_y$ generates different long-run forecast simulations. This IRP varies $c_y$ for economic reasons and $u_y$ for increased usage of PV, EVs and LED lighting.

## Expected Case Assumptions

The forecast makes the following assumptions about the long-run relationship between residential, commercial and industrial classes.

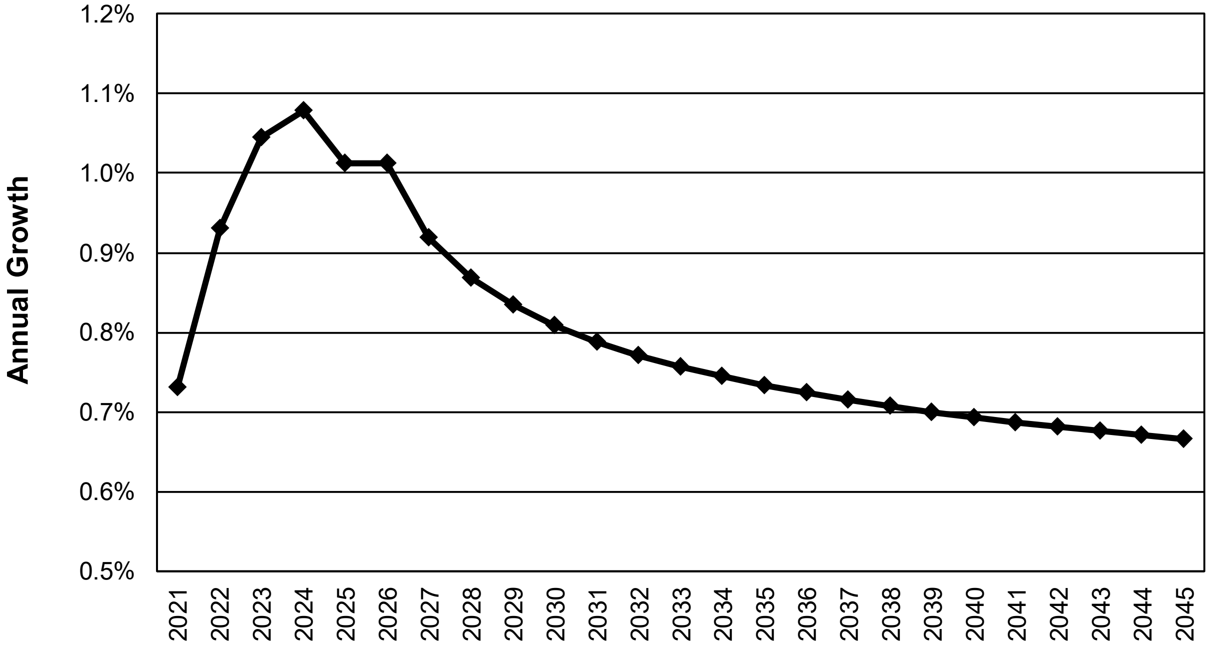
1. As noted earlier, long-run residential and commercial customer growth rates are linked, consistent with historical growth patterns with a positive correlation between the two (see Table 3.2). Figure 3.11 shows the time path of residential customer growth. The average annual growth rate after 2025 is approximately 0.8 percent, with a gradual decline out to 2045. The generated values shown in Figure 3.11 use the Employment and Population forecasts in conjunction with IHS's employment and population forecasts and Washington's OFM population forecasts. Starting in 2026, it assumes annual commercial customers increase 0.08 percent for each one percentage point increase in residential customer growth. This relationship is consistent with both long-run annual regression relationships and monthly ARIMA forecast models where residential customers are used as the forecast driver. The annual average growth rate of commercial customers after 2025 is approximately 0.66 percent. The annual industrial customer growth rate assumption is -0.66 percent after 2025, which is equivalent to a decline of seven industrial customers a year through 2045. This assumption reflects an ongoing long-run decline in industrial customers experienced by Avista since 2005.

2. Commercial load growth follows changes in residential load growth. This positive correlation assumption is consistent with the high historical correlation seen between residential and commercial load growth. The connection, based on a linear regression linking commercial UPC growth to residential UPC growth, assumes that for every 1 percent point change in residential UPC growth, commercial UPC will change by 0.23 percent.

3. Consistent with historical behavior, industrial and streetlight load growth projections do not correlate with residential or commercial load. Annual industrial load growth is near zero percent after 2025. This reflects the assumption that the annual -0.66 percent decline in industrial customer growth is offset by UPC growth driven by long-run economic growth. The streetlight load growth is zero percent after 2025 to reflect the assumption of slow customer growth being offset by the impact of LED lighting.

[15] Since UPC = load/customers, calculus shows the annual percentage change UPC ≈ percentage change in load - percentage change in customers. Rearranging terms, the annual percentage change in load ≈ percentage change in customers + percentage change in UPC.

**Figure 3.11: Long-Run Annual Residential Customer Growth**




4. As noted earlier, the assumption in the five-year forecast for this IRP is for the RAP to be constant through 2025; increase at 1 percent annually between 2026 and 2029; and then increase 1.5 percent yearly until 2045. RAP no longer appears explicitly in the regression equations for the five-year forecast. The coefficient estimates for the RAP have become unstable and statistically insignificant. Therefore, the 2021 IRP assumes own-price elasticity to be -0.3 percent, based on long-term estimates from the academic literature (See also footnote 11).

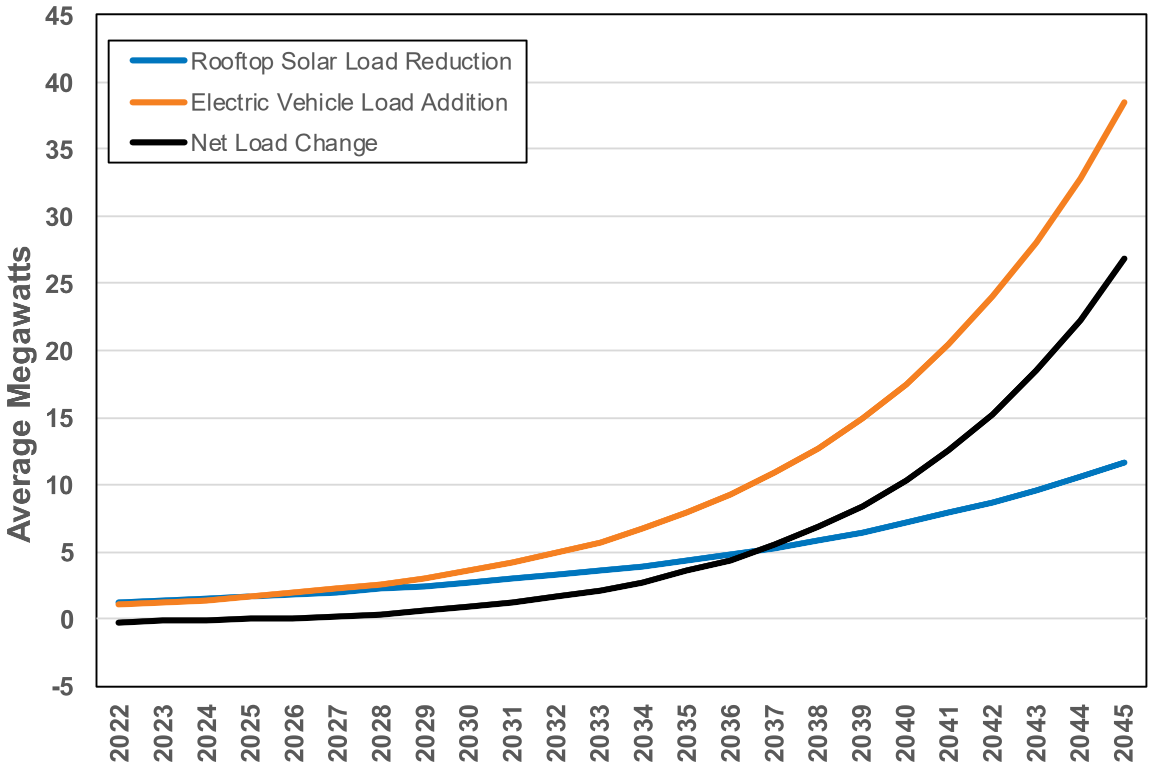
5. Avista estimates 2,000 Electric Vehicles (EV) are currently within its service area. The forecasted rate of adoption over the 2021-2045 period assumes 107,000 EVs will be in the service area by 2045. Between 2021 and 2045, the implied annual growth rate is 16 percent. The forecast assumes each EV uses 3,153 kWh per year, to be consistent with the value used in Avista's 2020 Transportation Electrification Plan. The EV forecast reflects residential light duty vehicles only. Based on the assumption of approximately two vehicles per residential customer (based on U.S. Census data for our service area), the EV penetration rate is forecasted to rise from 0.3 percent of residential customers today to just over 13 percent by 2045 for a total load of 39 aMW. See Figure 3.12.

   There are three significant barriers to the rapid, near-term accumulation of EVs. The first is consumer preferences related to model options (i.e., sedans, SUVs, and pickups) and battery range. Although these barriers are slowly shrinking, the gap with traditional internal combustion vehicles is still notable. This is important in Avista's service area given the significant number of rural and suburban households with strong preferences for pickup trucks and SUVs for both commuting, utility and recreational use. Second, there is consumer uncertainty about the evolution of the public charging infrastructure to support rapid adoption in the near term. Although improving, the public charging infrastructure remains significantly underdeveloped compared to traditional vehicles. Third is the willingness of consumers to rapidly abandon traditional vehicles, while still being relatively new, for EVs with similar characteristics that may require a higher upfront cost. Because of these barriers, this IRP, as with the 2017 and 2020 IRPs, assumes rapid adoption will not start until the early 2030s in Avista’s service area. This is reflected in the assumption that the number of EVs will follow an exponential growth function with a 16 percent growth rate. Finally, although not directly calculated, the impact of EVs on commercial usage is indirectly accounted for by the assumed positive correlation between residential and commercial UPC.

6. Rooftop solar penetration, measured as the share of residential solar customers to total residential customers, continues to grow at present levels in the forecast. The starting average solar system is set at 7 kW (DC) with a 13 percent capacity factor, or about 7,800 kWh per year per customer. These values reflect current Company data on customer installation size and system efficiency. The IRP assumes the starting system size will increase 1 percent annually to about 10,100 kWh per year per customer in 2045, with the capacity factor remaining constant at 13 percent. Company data on its residential customers show the system size is increasing over time. In the 2005-2008 period, when solar installs were just beginning, the median installed system size was about 1.8 kW. This IRP assumes the residential PV penetration rate will continue to follow a non-linear relationship between the historical penetration rate in year t and the historical number of residential customers in year t. Under this assumption, residential solar penetration will increase from 0.3 percent in 2019 to about 2.5 percent in 2045.This accumulation can be approximated by an exponential growth function. The base-line model assumes residential solar penetration will grow at approximately 8 percent annually through 2045 for approximately 12 aMW in load reduction- See Figure 13.12. Both the growth in solar system size and penetration are estimates and this information will be monitored for possible adjustment in future IRPs.

   There are several important barriers around the accumulation of residential PV systems in our service area. First, urban and rural forests surround many of the owner-occupied homes in our service area. Tree shade can significantly reduce solar generation. In the Spokane metro area, the largest metro area we serve, many of the areas with fewer trees are lower-income areas and/or are mainly composed of renter-occupied residences. Second, the heavy winter cloud cover also reduces solar generation. The Company recognizes future improvements in solar panels can reduce these barriers. For example, solar panels can be formed directly into roof top shingles or home siding. The assumed penetration of solar has increased in every IRP since 2015. Finally, as with EVs, the impact of solar penetration for commercial customers is indirectly accounted for by the assumed positive correlation between residential and commercial UPC.

**Figure 3.12: Electric Vehicle and Rooftop Solar Load Changes**




## Native Load Scenarios with Low/High Economic Growth

The load forecast for this IRP also considers futures with higher and lower loads. The high and low load scenarios use the population growth in Table 3.3, holding long-run U.S. employment growth constant at 0.4 percent (a Bureau of Labor Statistics forecast for the 2019-2029 period), but varying MSA employment growth at higher and lower levels to gauge the impacts on population growth and subsequent utility loads. This approach assumes customer growth, and not UPC, is most likely to be impacted by differences in economic growth rates between the Company's service area and the U.S.in general.

Historical evidence shows population growth (a proxy for customer growth) tends to increase as regional growth improves relative to the U.S. growth level. That is, as the regional economy gains strength relative to the U.S., in-migration accelerates. This is done using coefficient estimates from the Company's medium-term population growth forecast models referred to in Figure 3.10. The high/low range for growth in the service area reflects the impact on forecasted population growth by varying service area employment growth while holding U.S. employment growth constant at 0.4 percent. Simulated population growth is a proxy for residential customer growth in the long-run forecast model and produces the high and low native load forecasts in Figure 3.13.

**Equation 3.4: Residential Long-Run Forecast Relationship**

$$POPG = (0.005 + a_1 0.004_{US} + a_2 EMPG_{SPK}) \cdot W + (0.005 + b_1 0.004_{US} + b_2 EMPG_{KOOT}) \cdot (1 - W)$$

Where:

- POPG = predicted population growth rate for the combined Spokane-Kootenai metro area.
- a = the estimated regression coefficients from the Spokane metro population growth forecast equation used for the medium-term forecast. These reflect the sensitivities of a change in U.S. employment growth ($a_1$<0) and Spokane metro employment growth ($a_2$>0) on Spokane metro population growth. Note that 0.004 is the BLS forecast for long-run U.S. employment growth and $EMPG_{SPK}$ is the assumed high/low growth rate for Spokane metro.
- b = the estimated regression coefficients from the Kootenai metro population growth forecast equation medium-term forecast. These reflect the sensitivities of a change in U.S. employment growth ($b_1$<0) and Kootenai metro employment growth ($b_2$>0) Kootenai metro population growth. Note that 0.004 is the BLS forecast for long-run U.S. employment growth and $EMPG_{KOOT}$ is the assumed high/low growth rate for the Kootenai metro area.
- 0.005 = the intercept term replacing the original intercept from the medium-term regression equations. It reflects the long-term U.S. Census forecast for annual U.S. population growth (0.5 percent) over the IRP's forecast period. The assumption here is if annual service area employment growth and U.S. employment growth are the same, regional population growth will converge to the U.S. level over time. This assumes that if regional employment growth is the same as the U.S. (0.4% annually), the incentive for people to migrate to the combined metro region for economic reasons goes away.
- W = the share of population in the Spokane metro as a share of the total population the combined Spokane-Kootenai metro area. This provides a weight to produce a combined area population growth rate.

The high and low values in Table 3.3 were chosen based on the historical distribution of service area employment growth relative to the U.S. employment growth. From 1990 to 2019 (pre-COVID-19), annual service area employment growth exceeded U.S. growth by an average of 0.9 percent, which is statistically different from zero at the 95 percent level. The low growth scenario is set where the annual growth spread is zero percent and the high growth case is 1.5 percent. The historical distribution of the annual growth spread places a zero spread and 1.5 spread at *approximately* the 25$^{th}$ and 75$^{th}$ percentiles, respectively. It should be noted however, for 2021-2022, the high/low bounds shown in Figure 3.13 were widened beyond what was suggested by Equation 3.4 because of the Company's uncertainty over the shorter-term impacts COVID-19 on load behavior.

**Table 3.3: High/Low Economic Growth Scenarios (2021-2045)**

| Economic Growth | Annual U.S. Employment Growth (percent) | Annual Service Area Employment Growth (percent) | Annual Population Growth (percent) |
|---|---|---|---|
| Expected Case | 0.40 | 1.00 | 0.80 |
| High Growth | 0.40 | 1.90 | 1.20 |
| Low Growth | 0.40 | 0.40 | 0.50 |

**Figure 3.13: Average Megawatts, High/Low Economic Growth Scenarios**

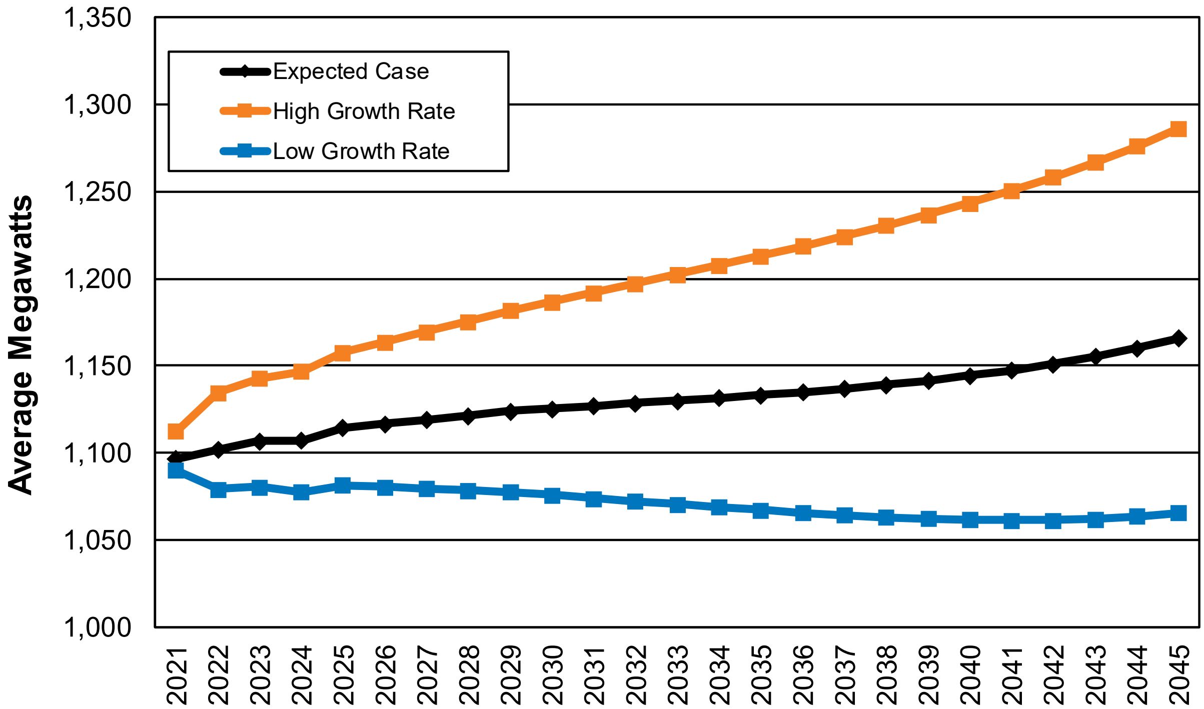



Table 3.4 shows the average annual load growth rate over the 2021-2045 period. The low growth scenario predicts a slight load decline over the 2025-2041 timeframe.

**Table 3.4: Load Growth for High/Low Economic Growth Scenarios (2021-2045)**

| Economic Growth | Average Annual Native Load Growth (percent) |
|---|---|
| Expected Case | 0.30 |
| High Growth | 0.70 |
| Low Growth | -0.10 |

## Long-Run Forecast Residential Retail Sales

Focusing on residential kWh sales, Figure 3.14 is the residential UPC growth plotted against the EIA's annual growth forecast of U.S. residential use per household growth. The EIA's forecast is from the 2020 Annual Energy Outlook. EIA's forecast shows positive UPC growth by the early 2030s, while Avista's growth does not become positive until the early 2040s. The higher EIA forecast reflects a population shift to warmer-climate states where air conditioning is typically required most of the year. In contrast, Avista's forecast of positive UPC growth in the 2040s reflects the impact of the growth of EVs in the region.

**Figure 3.14: UPC Growth Forecast Comparison to EIA**

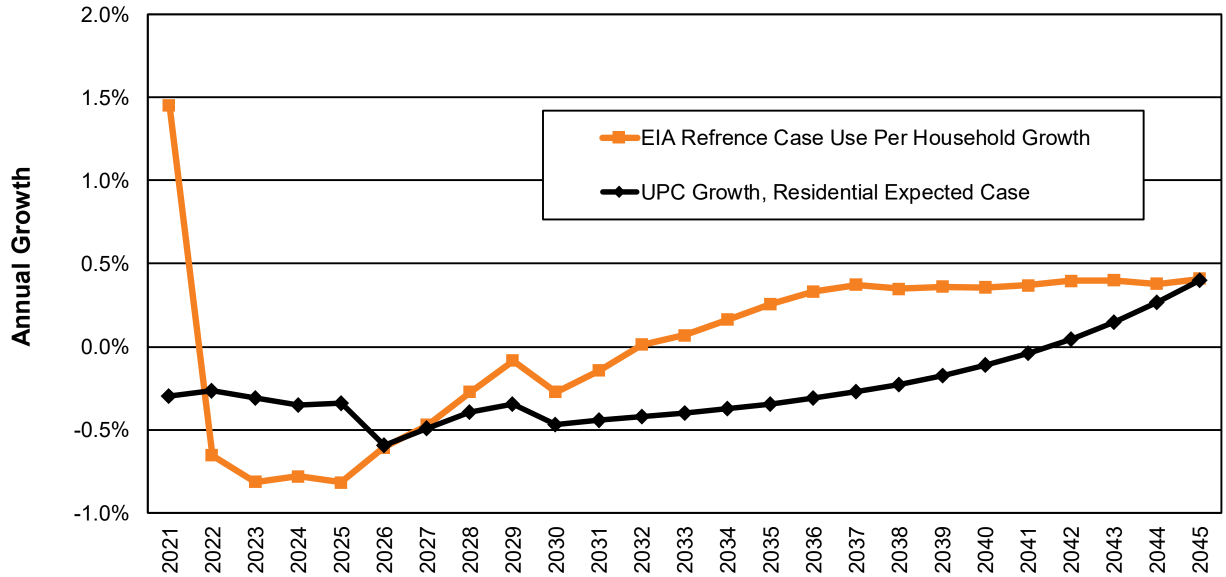
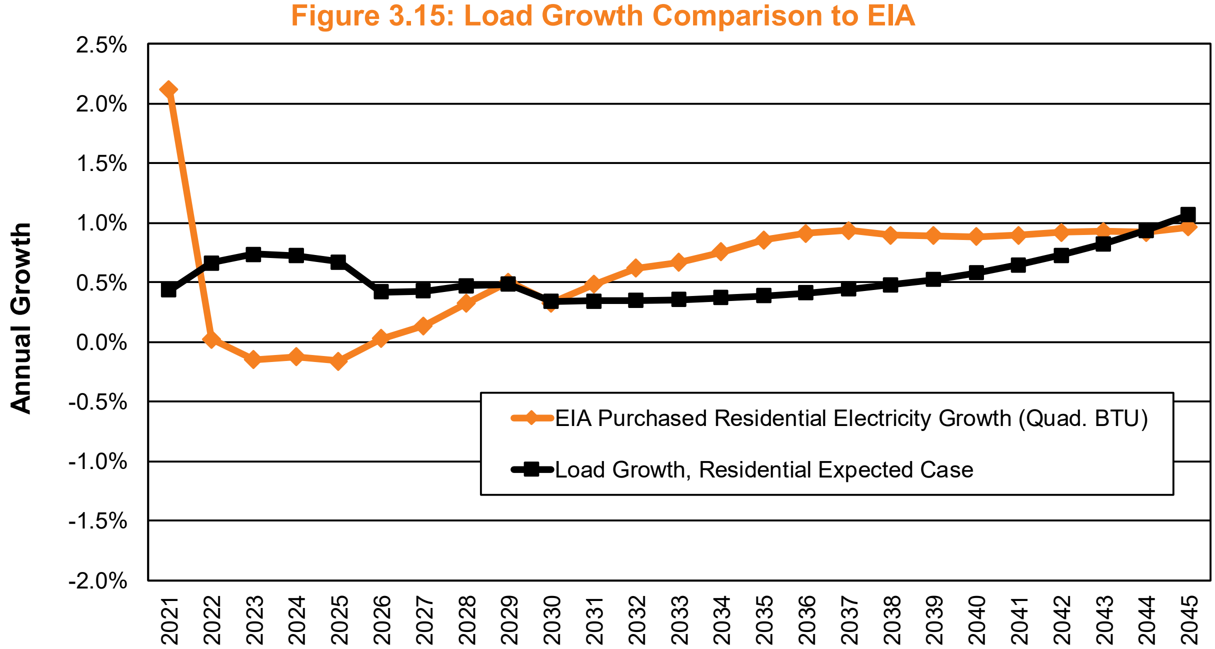



Figure 3.15 shows the EIA and the residential load growth forecasts. Avista's forecast is typically higher in the 2021-2028 period, reflecting an assumption that service area population growth will exceed the U.S. average; this is consistent with government and IHS forecasts for the far west and Rocky Mountain regions where Avista's service territory is located.

**Figure 3.15: Load Growth Comparison to EIA**



## Energy Forecast and Climate Change Scenarios

In addition to the base-line forecast discussed above, Avista also developed a climate change scenario. This scenario assumes the 20-year moving average (MA) trend is the definition of normal weather under the Expected Case shown above in Figure 3.13. Trending the moving average used two different approaches. The first approach relies on HDD and CDD data for Avista's service territory while the second relied on state-level HDD and CDD forecasts from the Northwest Power and Conservation Council (NPCC).

The first approach applies the long-run time-series trend observed in the historical 20-year MA for HDD and CDD. This historical trend shows HDD gradually declining and CDD gradually increasing. Therefore, this trend is projected forward to produce a trended moving average out to 2045. In Table 3.5, and Figures 3.16 and 3.17, this approach is called, "Avista Trended 20-yr MA." The exact analytical approach is provided in Appendix K.

The second approach was to use the trend in the annual HDD and CDD forecasts provided by the NPCC. These forecasts reflect recent NPCC efforts to model regional climate impacts at the state level. Since Avista serves both Washington and Idaho, the NPCC's HDD and CDD forecasts for Washington and Idaho are averaged for each year out to 2045 and then converted to a 20-year MA. This moving average is used as the basis for establishing the long-run trend in HDD and CDD. This approach is called, "NPCC Trended 20-yr MA."

Table 3.5 and Figure 3.16 show how climate change impacts the Expected Case for energy relative to the fixed 20-year MA. The climate effects are built-in after 2025, the end year of the intermediate term forecast. With load shifting from winter to summer, overall load levels and load growth are predicted to be lower with climate change. This reflects the net impact of declining HDD and increasing CDD over the forecast horizon. In addition, the difference between the Avista Trended Weather and the NPCC Trended weather forecasts reflects a much more aggressive warming trend than Avista's own historical weather data indicates. Figure 3.17 shows how the different methods shift the share of retail load across the months compared to the load shares of the fixed 20-year MA—that is, without trended weather. Both the Avista and NPCC trended weather show a shifting of load activity from winter to summer by 2045.

**Table 3.5: Load Growth for Climate Scenarios (2026-2045)**

| Climate Scenario | Average Annual Native Load Growth (percent) | Difference in aMW in 2045 Compared to Expected Case with fixed 20-yr MA |
|---|---|---|
| Fixed 20-yr MA | 0.23 | - |
| Avista Trended 20-yr MA | 0.21 | 4 |
| NPCC Trended 20-yr MA | 0.13 | 23 |

**Figure 3.16: Average Megawatts with Climate Scenarios**

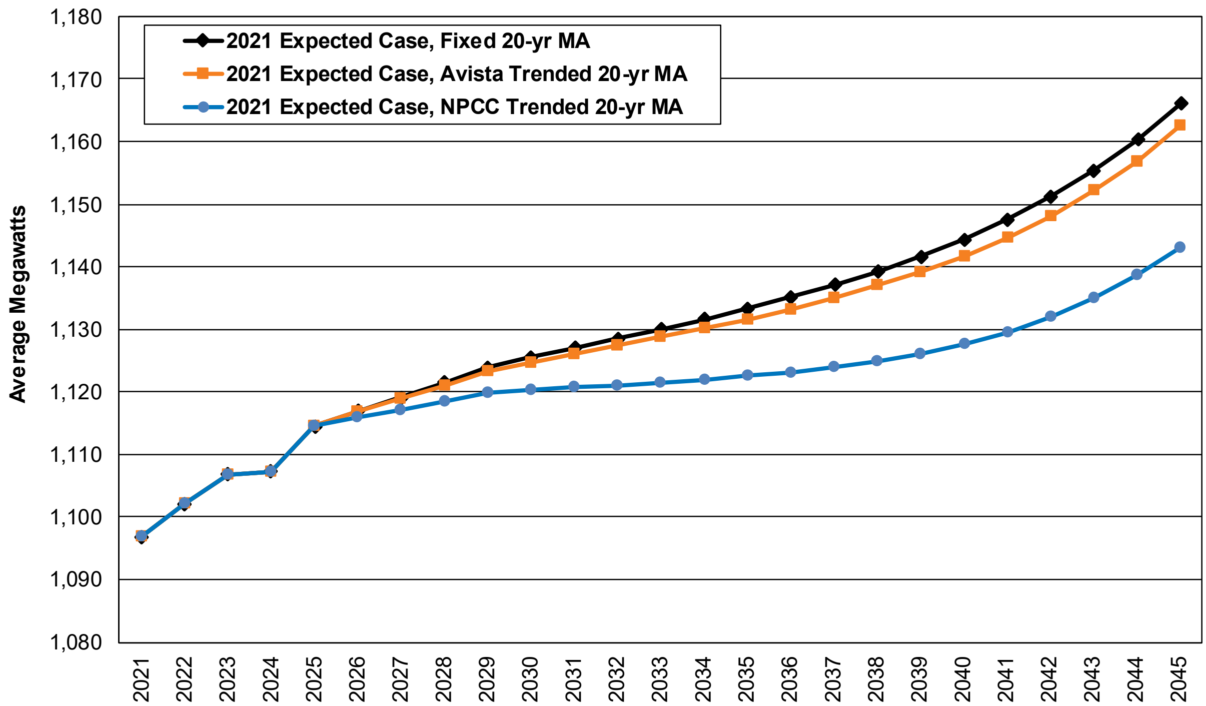
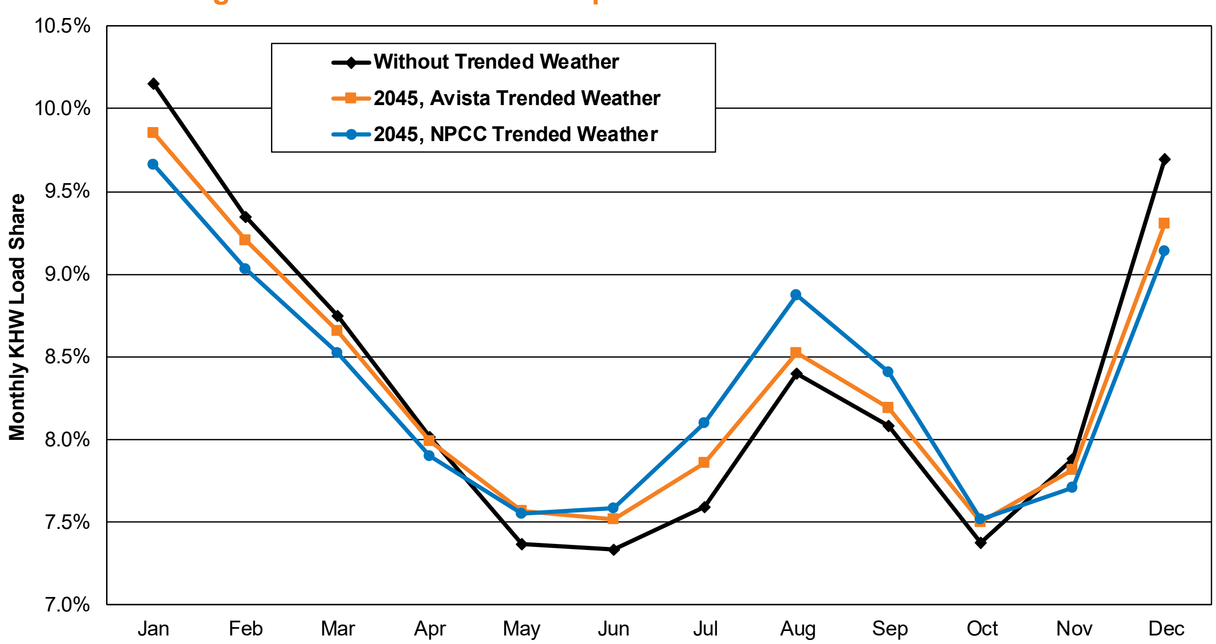



**Figure 3.17: Load Share Comparison with Climate Scenarios**



# Monthly Peak Load Forecast Methodology

## The Peak Load Regression Model

The peak load hour forecast is used to determine the amount of resources necessary to meet system peak demand. Avista must build generation capacity to meet winter and summer peak periods. Looking forward, the highest peak loads are still most likely to occur in the winter months, although in some years a mild winter followed by a hot summer could find the annual maximum peak load occurring in a summer hour. Equation 3.5 shows the current peak load regression model.

**Equation 3.5: Peak Load Regression Model**

$$hMW_{d,t,y}^{netpeak} = \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2$$
$$+ \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD_{d,t,y}^{HIGH} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{t.y-1}$$
$$+ \phi_2 (D_{SUM,2014\uparrow} * GDP_{t.y-1}) + \omega_{WD} D_{d,t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Mar\ 2005=1}$$
$$+ \epsilon_{d,t,y}\ for\ t,y = June\ 2004 \uparrow$$

Where:

- $\mathrm{hMW}_{\mathrm{d,t,y}}^{\mathrm{netpeak}}$ = metered peak hourly usage on day of week d, in month t, in year y, and excludes two large industrial producers. The data series starts in June 2004.
- $\mathrm{HDD}_{\mathrm{d,t,y}}$ and $\mathrm{CDD}_{\mathrm{d,t,y}}$ = heating and cooling degree days the day before the peak.
- $(\mathrm{HDD}_{\mathrm{d,t,y}})^2$ = squared value of $HDD_{d,t,y}$.$\mathrm{HDD}_{\mathrm{d-1,t,y}}$ and $\mathrm{CDD}_{\mathrm{d-1,t,y}}$ = heating and cooling degree days the day before the peak.
- $\mathrm{CDD}_{\mathrm{d,t,y}}^{\mathrm{HIGH}}$ = maximum peak day temperature minus 65 degrees.[16]
- $\mathrm{GDP}_{\mathrm{t.y-1}}$ = extrapolated level of real GDP in month t in year y-1.
- $(D_{SUM,2014\uparrow} * GDP_{t.y-1})$ is a slope shift variable for GDP in the summer months, June, July, and August.
- $\omega_{WD} D_{d,t,y}$ = dummy vector indicating the peak's day of week.
- $\omega_{SD} D_{t,y}$ = seasonal dummy vector indicating the month; and the other dummy variable control for an extreme outliers in March 2005.
- $\varepsilon_{d,t,y}$ = uncorrelated N(0, σ) error term.

## Generating Weather Normal Growth Rates Based on a GDP Driver

Equation 3.5 coefficients identify the month and day most likely to result in a peak load in the winter or summer. By assuming normal peak weather and switching on the dummy variables for day ($d_{MAX}$) and month ($t_{MAX}$) that maximize weather normal peak conditions in winter and summer, a series of peak forecasts from the current year, $y_c$, are generated out N years by using forecasted levels of GDP as shown in Equation 3.5.[17] All other

[16] This term provides a better model fit than the square of CDD.
[17] Forecasted GDP is generated by applying the averaged GDP growth forecasts used for the employment and industrial production forecasts discussed previously.

factors besides GDP remain constant to determine the impact of GDP on peak load. For winter, this is defined as the forecasted series W:

$$W = \{F(hMW^{WN,netpeak,W}_{d_{MAX},t_{MAX},y_c+1}), F(hMW^{WN,netpeak,W}_{d_{MAX},t_{MAX},y_c+2}), \ldots, F(hMW^{WN,netpeak,W}_{d_{MAX},t_{MAX},y_c+N})\}$$

For summer, this is defined as the forecasted series S:

$$S = \{F(hMW^{WN,netpeak,S}_{d_{MAX},t_{MAX},y_c+1}), F(hMW^{WN,netpeak,S}_{d_{MAX},t_{MAX},y_c+2}), \ldots, F(hMW^{WN,net\,peak,S}_{d_{MAX},t_{MAX},y_c+N})\}$$

Both S and W are convertible to a series of annual growth rates, GhMW. Peak load growth forecast equations are shown below as winter ($W_G$) and summer ($S_G$.):

$$W_G = \{F(GhMW^{WN,netpeak,W}_{d_{MAX},t_{MAX},y_c+1}), F(GhMW^{WN,netpeak,W}_{d_{MAX},t_{MAX},y_c+2}), \ldots, F(GhMW^{WN,netpeak,W}_{d_{MAX},t_{MAX},y_c+N})\}$$

$$S_G = \{F(GhMW^{WN,netpeak,S}_{d_{MAX},t_{MAX},y_c+1}), F(GhMW^{WN,netpeak,S}_{d_{MAX},t_{MAX},y_c+2}), \ldots, F(GhMW^{WN,netpeak,S}_{d_{MAX},t_{MAX},y_c+N})\}$$

## Simulated Extreme Weather Conditions with Historical Weather Data

In Equation 3.6, holding all else constant, growth rates are applied to simulated peak loads generated for the current year, $y_c$, for each month, January through December. These peak loads are generated by running actual extreme weather days observed since 1890. Equations 3.6 and 3.7 generate a series of simulated extreme peak load values for heating degree days and cooling degree days respectively.

**Equation 3.6: Peak Load Simulation Equation for Winter Months**

$$\widehat{hMW}^{W}_{t,y} = a + \widehat{\lambda_1} HDD_{t,y,MIN} + \widehat{\lambda_2}(HDD_{t,y,MIN})^2 \; for\; t = Jan, \ldots, Dec \; if\; maxium\; avg.temp < 65 \; and \; y = 1890, \ldots, y_c$$

Where:

- $\widehat{hMW}^{W}_{t,y}$ = simulated winter peak megawatt load using historical weather data.
- $HDD_{t,y,MIN}$ = heating degree days calculated from the minimum (MIN) average temperature (average of daily high and low) on day d, in month t, in year y if in month t the maximum average temperature (average of daily high and low) is less than 65 degrees.
- a = aggregate impact of all the other variables held constant at their average values.

Similarly, the model for cooling degree days is:

**Equation 3.7: Peak Load Simulation Equation for Summer Months**

$$\widehat{hMW}_{t,y}^{S} = a + \widehat{\lambda_4} CDD_{t,y,MAX} \ for\ t = Jan, \ldots, Dec\ if\ maxium\ avg.temp > 65\ and\ y = 1890, \ldots, y_c$$

Where:

- $\widehat{\mathrm{hMW}}_{\mathrm{t,y}}^{\mathrm{S}}$ = simulated winter peak megawatt load using historical weather data.
- $CDD_{t,y,MAX}$ = cooling degree days calculated from the maximum (MAX) average temperature. The average of daily high (H) and low (L) on day d, in month t, in year y if in month t if the maximum average temperature (average of daily high and low) is greater than 65 degrees.
- a = aggregate impact of all the other variables held constant at their average values.

With over 100 years of average maximum and minimum temperature data, Equations 3.6 and 3.7 applied to each month t will produce over 100 simulated values of peak load that can be averaged to generate a forecasted average peak load for month t in the current year, $y_c$. Equations 3.8 and 3.9 show the average for each month.

**Equation 3.8: Current Year Peak Load for Winter Months**

$$F\left(hMW_{t,y_c}^{W}\right) = \frac{1}{(y_c - 1890) + 1} \sum_{y=1890}^{y_c} \widehat{hMW}_{t,y}^{W}\ for\ each\ heating\ month\ t\ where\ maxium\ avg.temp < 65$$

**Equation 3.9: Current Year Peak Load for Summer Months**

$$F\left(hMW_{t,y_c}^{S}\right) = \frac{1}{(y_c - 1890) + 1} \sum_{y=18}^{y_c} \widehat{hMW}_{t,y}^{S}\ for\ each\ cooling\ month\ t\ where\ maxium\ avg.temp > 65$$

Forecasts beyond $y_c$ are generated using the appropriate growth rate from series $W_G$ and $S_G$. For example, the forecasts for $y_{c+1}$ for winter and summer are:

$$F\left(hMW_{t,y_{c+1}}^{WN,netpeak,W}\right) = F\left(hMW_{t,y_c}^{W}\right) * [1 + F(GhMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,W})]$$

$$F\left(hMW_{t,y_{c+1}}^{WN,netpeak,S}\right) = F\left(hMW_{t,y_c}^{S}\right) * [1 + F(GhMW_{d_{MAX},t_{MAX},y_c+1}^{WN,netpeak,S})]$$

The finalization of the peak load forecast occurs when the forecasted peak loads of two large industrial customers and EVs, excluded from the Equation 3.8 and 3.9 estimations, are added back in.

Table 3.6 shows estimated peak load growth rates with and without the two large industrial customers. Figure 3.17 shows the forecasted time path of peak load out to 2045, and Figure 3.18 shows the high/low bounds based on a 1-in-20 event (95 percent confidence interval) using the standard deviation of the simulated peak loads from Equations 3.8 and 3.9.

**Table 3.6: Forecasted Winter and Summer Peak Growth, 2021-2045**

| Peak Load Annual Growth | Winter (Percent) | Summer (Percent) |
|---|---|---|
| Including Large Industrial Customers | 0.35 | 0.42 |

Figure 3.18 shows how the summer peak forecast grows faster than the winter peak. Under current growth forecasts, the orange summer line in Figure 3.17 will get close to the blue winter line by 2045. Figure 3.19 shows that the winter high/low bounds considerably larger than summer and reflects a greater range of temperature anomalies in the winter months.

**Figure 3.18: Peak Load Forecast 2021-2045**

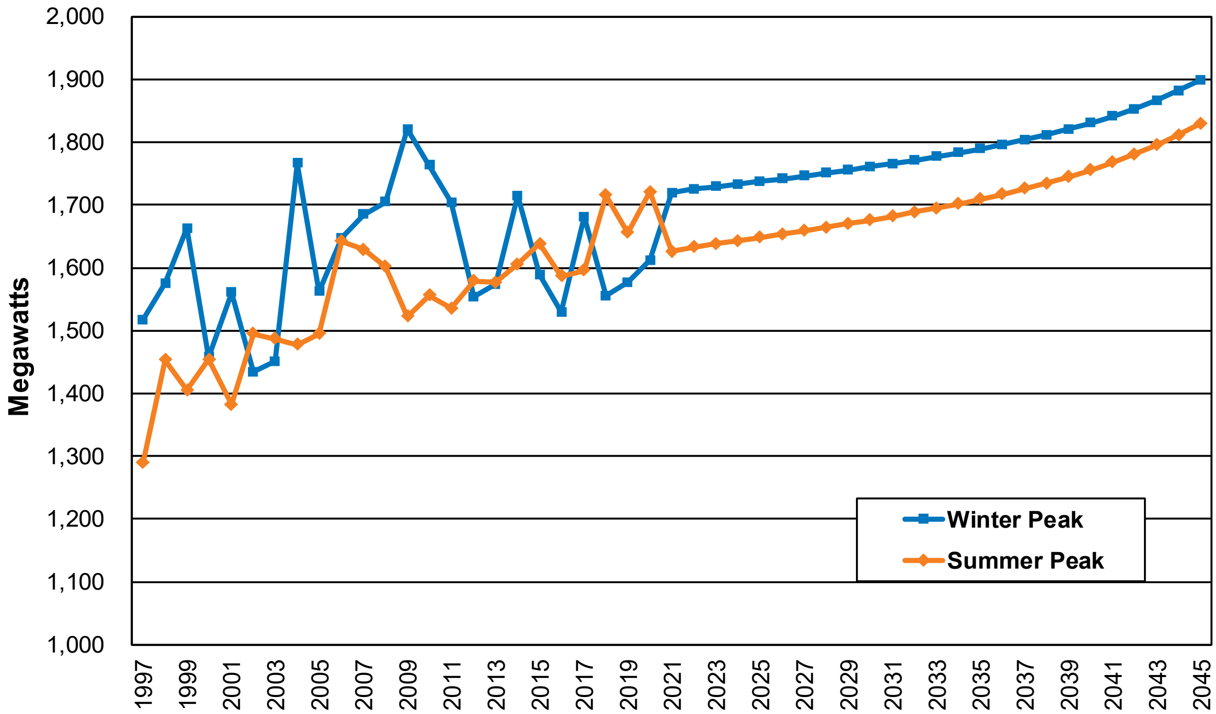
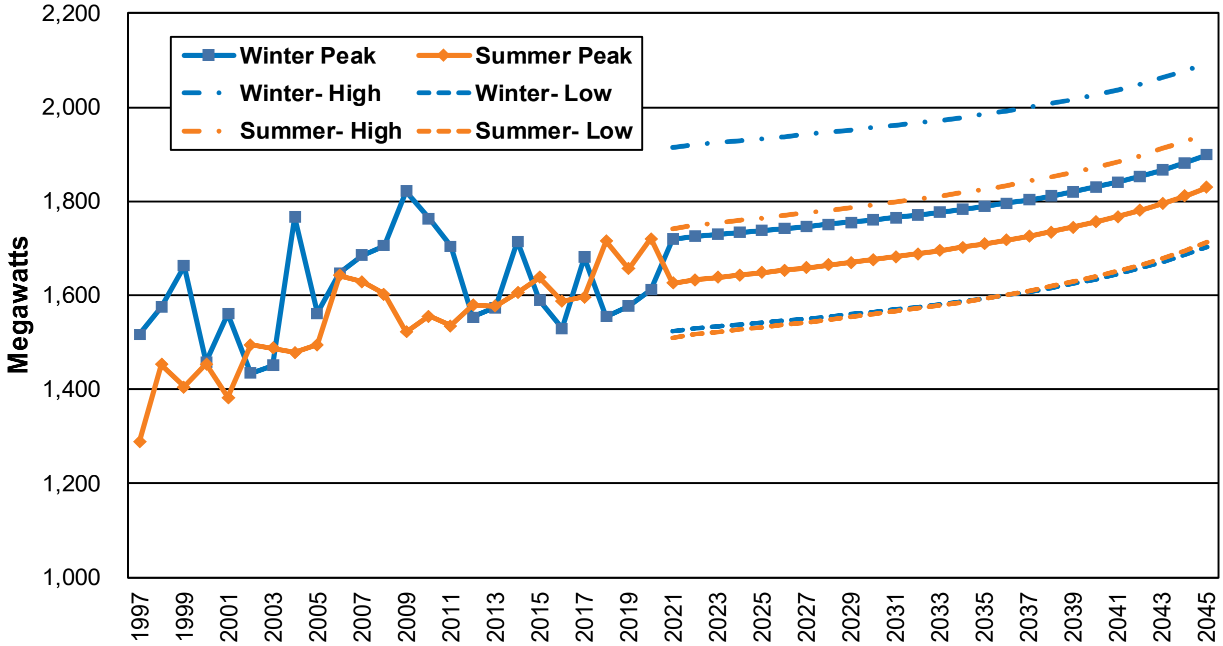


**Figure 3.19: Peak Load Forecast with 1 in 20 High/Low Bounds, 2021-2045**




## Peak Load Forecast and Climate Change

To simulate the impact of climate change on the peak load, the Expected Case's forecast assumes Avista Trended Weather as the basis for the forecast. The impact is shown in Table 3.7 and Figures 3.20, 3.21 and 3.22.

**Table 3.7: Forecasted Winter and Summer Peak Growth with Trended Climate, 2021-2045**

| Peak Load Annual Growth | Winter (Percent) | Summer (Percent) |
|---|---|---|
| Avista Trended 20-yr MA, Including Large Industrial Customers | 0.32 | 0.47 |
| NPCC Trended 20-yr MA, Including Large Industrial Customers | 0.22 | 0.53 |

Using the Avista trended weather lowers the winter growth rate and increases the summer growth rate. In addition, the level of peak-load starting in 2021 is lower in the winter and higher in the summer. The combined result is a shift from a winter peaking to a summer peaking by the early 2030s. However, Figure 3.21 shows that because of the distribution of possible winter temperatures relative to summer, the 1-in-20 high range still exceeds summer loads. This relationship changes notably with the NPCC Trended Weather as the basis for the forecast as shown in Figure 3.22. This figure shows Avista becomes summer peaking by the late 2020s and by the 2040s, the high range for summer exceeds winter's peak. The difference between the winter and summer growth rates also increases with NPCC trended weather.

Figure 3.20: Peak Load Forecast with Avista Trended 20-yr MA, 2021-2045

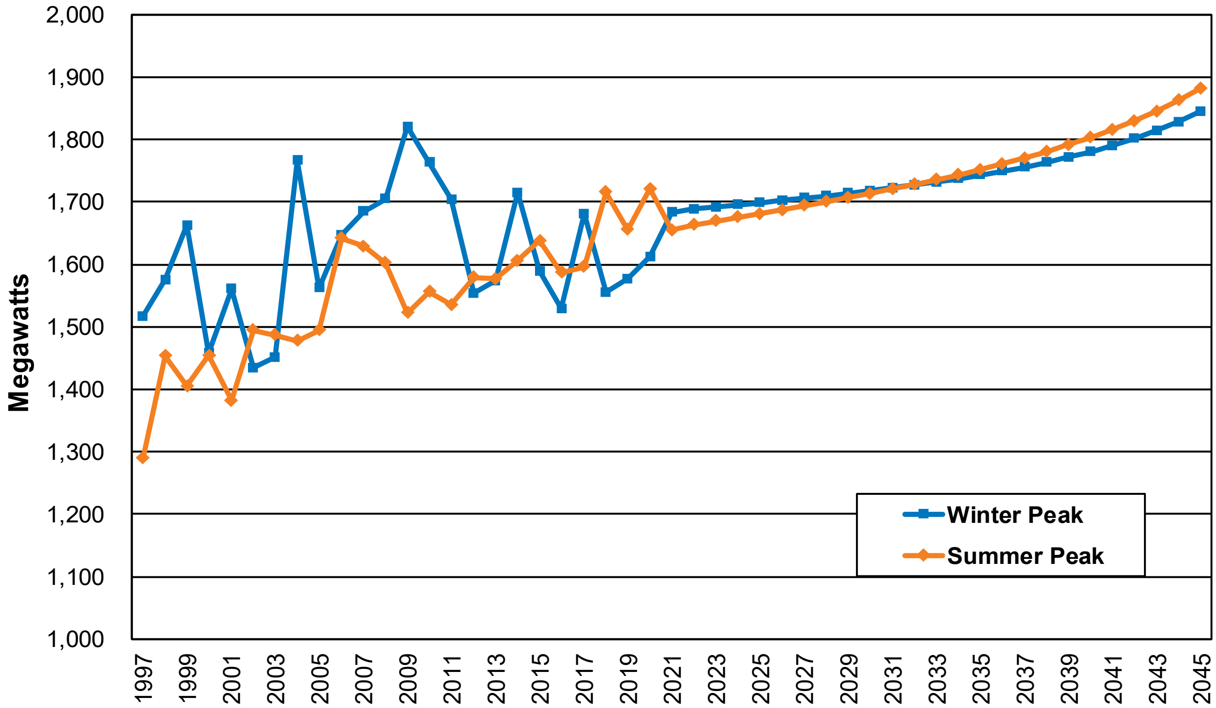



Figure 3.21: Peak Load Forecast with 1-in-20 High/Low Bounds and Avista Trended 20-yr MA, 2021-2045

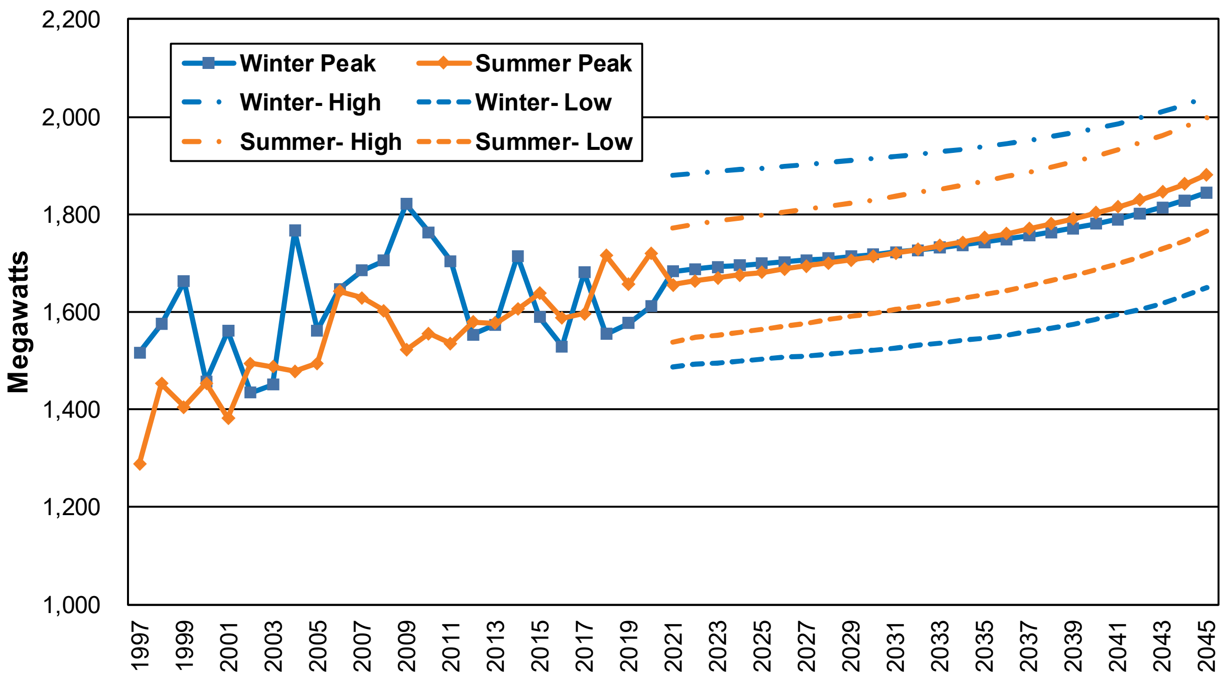
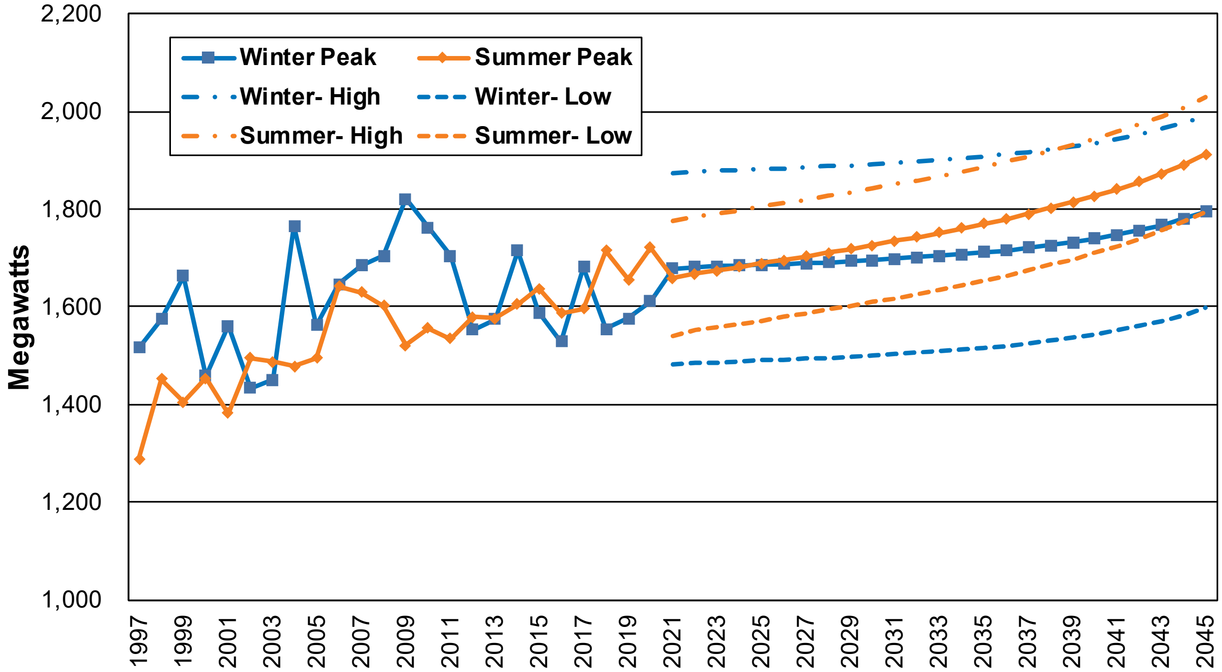


**Figure 3.22: Peak Load Forecast with 1 in 20 High/Low Bounds and NPCC Trended 20-yr MA, 2021-2045**



## Table 3.8: Energy and Peak Forecasts

| Year | Energy (aMW) | Winter Peak January (MW) | Summer Peak July (MW) |
|---|---|---|---|
| 2021 | 1,097 | 1,712 | 1,616 |
| 2022 | 1,102 | 1,719 | 1,626 |
| 2023 | 1,107 | 1,725 | 1,633 |
| 2024 | 1,107 | 1,729 | 1,638 |
| 2025 | 1,115 | 1,733 | 1,643 |
| 2026 | 1,117 | 1,738 | 1,648 |
| 2027 | 1,119 | 1,742 | 1,653 |
| 2028 | 1,122 | 1,746 | 1,659 |
| 2029 | 1,124 | 1,751 | 1,664 |
| 2030 | 1,125 | 1,756 | 1,670 |
| 2031 | 1,127 | 1,761 | 1,676 |
| 2032 | 1,129 | 1,766 | 1,682 |
| 2033 | 1,130 | 1,771 | 1,688 |
| 2034 | 1,132 | 1,777 | 1,695 |
| 2035 | 1,133 | 1,783 | 1,702 |
| 2036 | 1,135 | 1,789 | 1,710 |
| 2037 | 1,137 | 1,796 | 1,718 |
| 2038 | 1,139 | 1,804 | 1,726 |
| 2039 | 1,142 | 1,812 | 1,735 |
| 2040 | 1,144 | 1,821 | 1,745 |
| 2041 | 1,148 | 1,830 | 1,756 |
| 2042 | 1,151 | 1,841 | 1,768 |
| 2043 | 1,155 | 1,853 | 1,781 |
| 2044 | 1,160 | 1,867 | 1,795 |
| 2045 | 1,166 | 1,882 | 1,811 |

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# 4. Existing Supply Resources

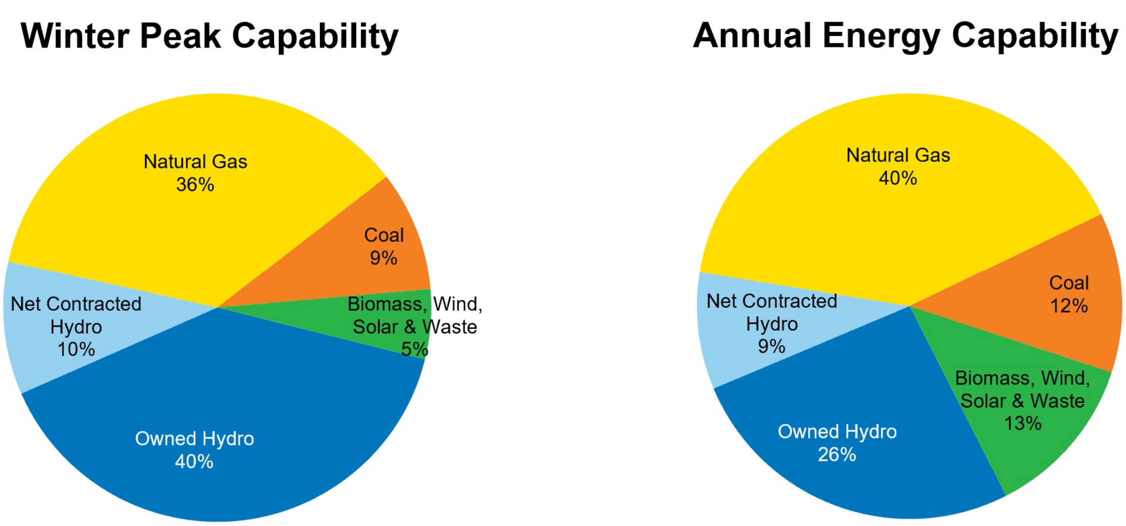
Avista relies on a diverse portfolio of assets to meet customer loads, including owning and operating eight hydroelectric developments on the Spokane and Clark Fork rivers. Its thermal assets include ownership of five natural gas-fired projects, a biomass plant, and partial ownership of two coal-fired units. Avista also purchases energy from several independent power producers (IPPs) and regional utilities.

**Section Highlights**

- Hydro represents about half of Avista's winter generating capability.
- Natural gas-fired plants represent the largest portion of Avista's thermal generation portfolio.
- The Rattlesnake Flat wind facility began operations in December 2020.
- Fifty-five percent of Avista's generating potential is hydro, biomass, wind, and solar.
- Avista's net metering program includes 1,345 customers with 14.1 megawatts of their own generation.

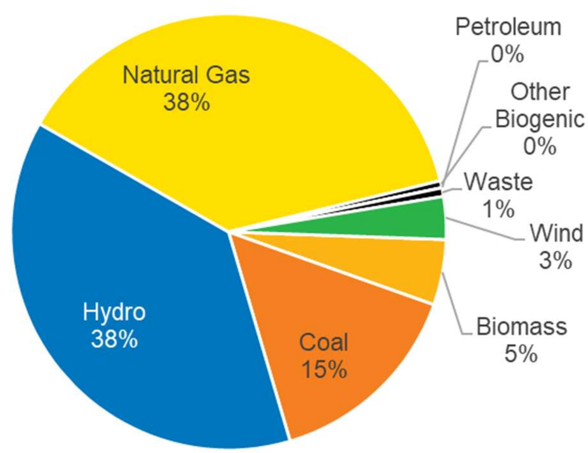
Figure 4.1 shows Avista's capacity and energy mixes. Winter capability is the share of total capability of each resource type the utility can rely upon to meet winter peak load. The annual energy chart represents the energy as a percent of total supply; this calculation includes fuel limitations (for water, wind, and wood), maintenance and forced outages. Avista's largest energy supply in the peak winter months is from hydro at 50 percent, followed by natural gas-fired resources at 36 percent. On an annual basis, natural gas-fired generation can produce more energy (40 percent) than hydroelectric (36 percent) because it is not constrained by fuel limitations. The resource mix changes each year depending on streamflow conditions and market prices.

**Figure 4.1: 2020 Avista Capability and Energy Fuel Mix**



Avista reports its fuel mix annually in the Washington State Fuel Mix Disclosure[1]. The State calculates the resource mix used to serve load, rather than generation potential, by adding regional[2] estimates for unassigned market purchases and Avista-owned generation minus net renewable energy credit (REC) sales[3]. Figure 4.2 shows Avista's 2019 fuel mix disclosure from the Washington State Department of Commerce. The Idaho fuel mix is nearly identical to Washington except for its allocation of PURPA generation. Each state receives RECs based on their share of the system (approximately 65 percent Washington and 35 percent Idaho). Avista may retain RECs, sell them to other parties or transfer them between states. Avista transfers RECs from Idaho to help comply with Washington's Energy Independence Act (EIA). Idaho customers are compensated for the value of RECs at market value.

**Figure 4.2: 2019 Washington State Fuel Mix Disclosure**




## Spokane River Hydroelectric Developments

Avista owns and operates six hydroelectric developments on the Spokane River. Five operate under a 50-year FERC operating license through June 18, 2059. The sixth, Little Falls, operates under separate authorization from the U.S. Congress[4]. This section describes the Spokane River developments and provides the maximum on-peak and nameplate capacity ratings for each plant. The maximum on-peak capacity of a generating unit is the total amount of electricity it can safely generate with its existing configuration and the current mechanical state of the facility. Unlike other generation assets, hydro capacity is often higher than nameplate because of plant upgrades and favorable head or streamflow conditions. The nameplate, or installed capacity, is the

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[1] Report 11-A Utility Fuel Mix Market Summary – 20200911 post adjust.pdf from Department of Commerce.

[2] For 2019, the region is approximately 54 percent hydroelectric, 13 percent unspecified, 12 percent natural gas, 11 percent coal, 5 percent nuclear, 4 percent wind and 1 percent other. When Avista sells RECs from its resources they are assigned an emissions level in the report equal to regional average emissions.

[3] In 2019, Avista sold 44 aMW of RECs, which lowers the percentage of renewable resources.

[4] Little Falls is not under FERC jurisdiction as it was congressionally authorized because of its location on the Spokane Indian Reservation. Avista operates Little Falls Dam in accordance with an agreement reached with the Tribe in 1994 to identify operational and natural resource requirements. Little Falls Dam is also subject to other Washington State environmental and dam safety requirements.

capacity of a plant as rated by the manufacturer. All six hydroelectric developments on the Spokane River connect directly to the Avista electrical system.

### Post Falls

Post Falls is the hydroelectric facility furthest upstream on the Spokane River. It is located several miles east of the Washington/Idaho border. The facility began operating in 1906 and during summer months maintains the elevation of Lake Coeur d'Alene. Post Falls has a 14.75 MW nameplate rating and is capable of producing up to 18.0 MW with its six generating units.

### Upper Falls

The Upper Falls development sits within the boundaries of Riverfront Park in downtown Spokane. It began generating in 1922. The project is comprised of a single 10.0 MW unit.

### Monroe Street

Monroe Street was Avista's first generation development. It began serving customers in 1890 in downtown Spokane near Riverfront Park. Following a complete rehabilitation in 1992, the single generating unit has a 15.0 MW maximum capacity rating.

### Nine Mile

A private developer built the Nine Mile development in 1908 near Nine Mile Falls, Washington. Avista purchased the project in 1925 from the Spokane & Inland Empire Railroad Company. Nine Mile has undergone recent substantial upgrades. The development has two new 8 MW units and two 10 MW units for a total nameplate rating of 36 MW. The incremental generation from the upgrades qualifies for Washington's EIA.

### Long Lake

The Long Lake development is located northwest of Spokane and maintains the Lake Spokane reservoir, also known as Long Lake. The project's four units have a nameplate rating of 81.6 MW and 88.0 MW of combined capacity. Chapter 9, Supply-Side Resource Options, provides modernization options under consideration at Long Lake.

### Little Falls

The Little Falls development, completed in 1910 near Ford, Washington, is the furthest downstream hydroelectric facility on the Spokane River. The facility's four units generate 35.2 MW.

## Clark Fork River Hydroelectric Development

The Clark Fork River Development includes hydroelectric projects located near Clark Fork, Idaho, and Noxon, Montana, 70 miles south of the Canadian border on the Clark Fork River. The plants operate under a FERC license through 2046 and connect directly to the Avista transmission system.

### Noxon Rapids

The Noxon Rapids development includes four generators installed between 1959 and 1960, and a fifth unit that entered service in 1977. Avista completed major turbine upgrades on units 1 through 4 between 2009 and 2012. The upgrades increased the capacity of each unit from 105 MW to 112.5 MW and added 6.6 aMW of additional energy. The total capability of the plant is 610 MW.

### Cabinet Gorge

Cabinet Gorge started generating power in 1952 with two units, and two additional generators were added the following year. Upgrades to units 1 through 4 occurred in 1994, 2004, 2001 and 2007, respectively. The current maximum on-peak plant capacity is 270.5 MW, modestly above its 265.2 MW nameplate. The incremental generation from the upgrades qualifies for the EIA. Chapter 9, Supply-Side Resource Options, provides modernization options under consideration at Cabinet Gorge.

## Total Hydroelectric Generation

In total, Avista's hydroelectric plants have 1,080 MW of capacity. Table 4.1 summarizes the location and operational capacities of Avista's hydroelectric projects, and the expected energy output of each facility based on an 80-year hydrologic record.

**Table 4.1: Avista-Owned Hydroelectric Resources**

| Project Name | River System | Location | Nameplate Capacity (MW) | Maximum Capability (MW) | Expected Energy (aMW) |
|---|---|---|---|---|---|
| Monroe Street | Spokane | Spokane, WA | 14.8 | 15.0 | 11.2 |
| Post Falls | Spokane | Post Falls, ID | 14.8 | 18.0 | 9.4 |
| Nine Mile | Spokane | Nine Mile Falls, WA | 36.0 | 32.0 | 15.7 |
| Little Falls | Spokane | Ford, WA | 32.0 | 35.2 | 22.6 |
| Long Lake | Spokane | Ford, WA | 81.6 | 89.0 | 56.0 |
| Upper Falls | Spokane | Spokane, WA | 10.0 | 10.2 | 7.3 |
| | | | | | |
| Noxon Rapids | Clark Fork | Noxon, MT | 518.0 | 610.0 | 196.5 |
| Cabinet Gorge | Clark Fork | Clark Fork, ID | 265.2 | 270.5 | 123.6 |
| **Total** | | | **972.4** | **1,079.9** | **442.3** |

## Thermal Resources

Avista owns seven thermal generation assets located across the Northwest. These assets provide dependable energy and capacity serving base and peak-load obligations. Table 4.2 summarizes these resources by fuel type, online year, remaining design life, book value at the end of 2019 and remaining accounting life. Appendix D provides operating details for these facilities between 2016 and 2020. Table 4.3 includes capacity information for each of the facilities along with the five-year historical forced outage rates used for modeling purposes. Plants with a number in parentheses indicates the number of equally sized units at each facility.

### Table 4.2: Avista-Owned Thermal Resources

| Project Name | Location | Fuel Type | Start Date | Remaining Design Life | Book Value (mill. $) | Book Life (years) |
|---|---|---|---|---|---|---|
| Colstrip 3 & 4 | Colstrip, MT | Coal | 1984[5] | 25 | 97.2 | See Note[6] |
| Rathdrum | Rathdrum, ID | Gas | 1995 | 40 | 34.2 | 11 |
| Northeast | Spokane, WA | Gas | 1978 | 15 | 0.2 | 5 |
| Boulder Park | Spokane, WA | Gas | 2002 | 20 | 16.0 | 18 |
| Coyote Springs 2 | Boardman, OR | Gas | 2003 | 25 | 117.2 | 19 |
| Kettle Falls | Kettle Falls, WA | Wood | 1983 | 20 | 53.1 | 11 |
| Kettle Falls CT | Kettle Falls, WA | Gas | 2002 | 40 | 3.3 | 12 |

### Table 4.3: Avista-Owned Thermal Resource Capability

| Project Name | Winter Maximum Capacity (MW) | Summer Maximum Capacity (MW) | Nameplate Capacity (MW) | Forced Outage Rate (%) |
|---|---|---|---|---|
| Colstrip 3 | 111 | 111 | 123.5 | 9.3 |
| Colstrip 4 | 111 | 111 | 123.5 | 9.3 |
| Rathdrum (2 units) | 176 | 130 | 166.2 | 5.0 |
| Northeast (2 units) | 66 | 42 | 61.8 | 5.0 |
| Boulder Park (6 units) | 24.6 | 24.6 | 24.6 | 13.7 |
| Coyote Springs 2 | 317.5 | 286 | 306.5 | 2.6 |
| Kettle Falls | 47 | 47 | 50.7 | 2.4 |
| Kettle Falls CT | 11 | 8 | 7.2 | 5.0 |
| **Total** | **864.1** | **759.6** | **864.0** | |

## Colstrip Units 3 and 4

The Colstrip plant, located in eastern Montana, consists of the two remaining coal-fired steam plants connected to a double-circuit 500 kV line owned by each of the participating utilities. The utility-owned segment extends from Colstrip to Townsend, Montana. BPA's ownership of the 500 kV line starts in Townsend and continues west. Energy moves across both segments of the transmission line under a long-term wheeling arrangement. Talen Energy Corporation operates the facilities on behalf of the six owners. Avista owns 15 percent of Units 3 and 4. Unit 3 began operating in 1984 and Unit 4 was finished in 1986. Avista's share of Colstrip has a maximum net capacity of 222 MW, and a nameplate rating of 247 MW.

## Rathdrum

Rathdrum consists of two identical simple-cycle combustion turbine (CT) units. This natural gas-fired plant located near Rathdrum, Idaho connects to the Avista transmission system. It entered service in 1995 and has a maximum combined capacity of 176 MW in the winter and 126 MW in the summer. The nameplate rating is 166.5 MW. Chapter 9, Supply-Side Resource Options, provides details about modernization options under consideration at Rathdrum.

[5] Colstrip unit 3 began in 1984 and Colstrip 4 began in 1986.
[6] Avista is modeling Colstrip Units 3 and 4 with a depreciable life ending in 2025 in Washington and 2027 in Idaho, as approved by the Washington and Idaho Commissions.

### Northeast

The Northeast plant, located in Spokane, has two identical aero-derivative simple-cycle CT units completed in 1978. It connects to Avista's transmission system. The plant is capable of burning natural gas, but current air permits preclude the use of fuel oil. The combined maximum capacity of the units is 68 MW in the winter and 42 MW in the summer, with a nameplate rating of 61.2 MW. The plant air permit limits run hours to 100 hours per year, limiting its use primarily to reliability events. Avista assumes this plant will retire in 2035 for modeling purposes of this IRP.

### Boulder Park

The Boulder Park project entered service in the Spokane Valley in 2002. It connects directly to the Avista transmission system. The site uses six identical natural gas-fired internal combustion reciprocating engines to produce a combined maximum capacity and nameplate rating of 24.6 MW. Avista assumes this plant will retire in 2040 for modeling purposes of this IRP.

### Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine (CCCT) located near Boardman, Oregon. The plant connects to the BPA 500 kV transmission system under a long-term agreement. The plant began service in 2003 and has a maximum capacity of 317.5 MW in the winter and 285 MW in the summer with duct burners operating. The nameplate rating of the plant is 287.3 MW.

### Kettle Falls Generation Station and Kettle Falls Combustion Turbine

The Kettle Falls Generating Station entered service in 1983 near Kettle Falls, Washington. It is among the largest biomass generation plants in North America and connects to Avista on its 115 kV transmission system. The open-loop steam plant uses waste wood products (hog fuel) from area mills and forest slash but can also burn natural gas on a limited basis. A 7.5 MW combustion turbine (CT), added to the facility in 2002, burns natural gas and increases overall plant efficiency by sending exhaust heat to the wood boiler when operating in combined-cycle mode.

The wood-fired portion of the plant has a maximum capacity of 50 MW and a nameplate rating of 50.7 MW. Varying fuel moisture conditions at the plant causes correlated variation between 45 and 50 MW. The plant's capacity increases from 55 to 58 MW when operated in combined-cycle mode with the CT. The CT produces 8 MW of peaking capability in the summer and 11 MW in the winter. The CT can be limited in the winter when the natural gas pipeline is capacity constrained. The CT is not available when temperatures fall below zero[7]. This operational assumption reflects natural gas availability limits in the area. Chapter 9, Supply-Side Resource Options, provides details about modernization options under consideration at Kettle Falls.

[7] Avista is reviewing its policies and may restrict the CT use when the pipeline is at lower pressures then the current standard. This change could further restrict the plant from producing power in winter months. For this IRP, Avista assumes no winter Kettle Falls CT capacity after 2023.

## Small Avista-Owned Solar

Avista operates three small solar projects. The first solar project is three kilowatts located on its corporate headquarters as part of its Solar Car initiative. Avista installed a 15 kilowatt solar system in Rathdrum, Idaho to supply its My Clean Energy™ (formerly Buck-A-Block) voluntary green energy program. The 423-kW Avista Community Solar project, located at the Boulder Park property, began service in 2015.

**Table 4.4: Avista-Owned Solar Resource Capability**

| Project Name | Project Location | Project Capacity (kW-DC) |
|---|---|---|
| Spokane Headquarters Solar | Spokane, WA | 3 |
| Rathdrum Solar | Rathdrum, ID | 15 |
| Boulder Park Solar | Spokane Valley, WA | 423 |
| **Total** | | **441** |

## Power Purchase and Sale Contracts

Avista uses purchase and sale arrangements of varying lengths to meet a portion of its load requirements. These contracts provide many benefits by including environmentally low-impact from low-cost hydro and wind power to the Company's resource mix. This chapter describes the contracts in effect during the timeframe of the 2021 IRP. Tables 4.4 through 4.6 summarize Avista's contracts.

### Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, Public Utility Districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was large compared to loads served by the PUDs. Long-term contracts with public, municipal and investor-owned utilities throughout the Northwest assisted with project financing by providing a market for the surplus power. The contract terms obligate the PUDs to deliver power to Avista points of interconnection.

Avista originally entered into long-term contracts for the output of five projects "at cost". Avista now competes in capacity auctions to retain the rights of these contracts as they expire. The Mid-Columbia contracts in Table 4.5 provide clean energy, capacity and reserve capabilities; in 2020, the contracts provided approximately 247 MW of capacity and 148 aMW of energy.

The timing of the power received from the Mid-Columbia projects is a result of agreements including the 1961 Columbia River Treaty and the 1964 Pacific Northwest Coordination Agreement (PNCA). Both agreements optimize hydroelectric project operations in the Northwest U.S. and Canada. In return for these benefits, Canada receives return energy under the Canadian Entitlement. The Columbia River Treaty and the PNCA manage storage water in upstream reservoirs for coordinated flood control and power generation optimization. The Columbia River Treaty may end on September 15, 2024. Studies are underway by U.S. and Canadian entities to determine possible post-2024 Columbia River operations. Federal agencies are soliciting feedback from stakeholders and ongoing negotiations will determine the future of the treaty. This IRP does not model alternative outcomes for the treaty negotiations, because they likely will not affect long-term resource acquisitions and this IRP does not speculate on future wholesale electricity market impacts of the treaty at this time.

**Table 4.5: Mid-Columbia Capacity and Energy Contracts[8]**

| Counter Party | Project(s) | Percent Share (%) | Start Date | End Date | 2020 Estimated On-Peak Capability (MW) | 2020 Annual Energy (aMW) |
|---|---|---|---|---|---|---|
| Grant PUD | Priest Rapids | 3.79 | Dec-2001 | Dec-2052 | 30 | 19.5 |
| Grant PUD | Wanapum | 3.79 | Dec-2001 | Dec-2052 | 32 | 18.7 |
| Chelan PUD | Rocky Reach | 5.0 | Jan-2016 | Dec-2030 | 57 | 35.9 |
| Chelan PUD | Rock Island | 5.0 | Jan-2016 | Dec-2030 | 19 | 18.4 |
| Douglas PUD | Wells | 12.76[9] | Oct-2018 | Dec-2028 | 107 | 57.0 |
| Canadian Entitlement | | | | | -14 | -5.6 |
| **2020 Total Net Contracted Capacity and Energy** | | | | | **230** | **143.9** |

## Public Utility Regulatory Policies Act (PURPA)

The passage of PURPA by Congress in 1978 required utilities to purchase power from resources meeting certain size and fuel criteria. Avista has many PURPA contracts, as shown in Table 4.6. The IRP assumes renewal of these contracts after their current terms end based on our experience with these contracts and ongoing communications with the project owners. Appendix D includes operating details of these projects. Avista takes the energy as produced, does not control the output of any PURPA resources and does not receive the RECs from these projects.

## Lancaster Power Purchase Agreement

Avista acquired output rights to the Lancaster CCCT, located in Rathdrum, Idaho, after the sale of Avista Energy in 2007. Lancaster directly interconnects with the Avista transmission system at the BPA Lancaster substation. Under the tolling contract, Avista pays a monthly capacity payment for the sole right to dispatch the plant through October 2026. In addition, Avista pays a variable energy charge and arranges for all of the fuel needs of the plant.

## Palouse Wind Power Purchase Agreement

Avista signed a 30-year PPA in 2011 with Palouse Wind for the entire output of its 105 MW project starting in December 2012. Avista has the option to purchase the project after 2022. The project is EIA-qualified and directly connects to Avista's transmission system between Rosalia and Oaksdale, Washington in Whitman County.

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[8] For purposes of long-term transmission reservation planning for bundled retail service to native load customers, replacement resources for each of the resources identified in Table 4.5 are presumed and planned to be integrated via Avista's interconnection(s) to the Mid-Columbia region.

[9] Percent share varies each year depending on Douglas PUD's load growth, although the 10 percent share expires in 2023.

**Table 4.6: PURPA Agreements**

| Contract | Fuel Source | Location | Contract End Date | Size (MW) | 5 year avg. Gen. History (aMW) |
|---|---|---|---|---|---|
| Meyers Falls | Hydro | Kettle Falls, WA | 12/2025 | 1.30 | 1.10 |
| Spokane Waste to Energy | Waste | Spokane, WA | 12/2022 | 22.70 | 13.54 |
| Spokane County Digester | Biomass | Spokane, WA | 8/2021 | 0.26 | 0.13 |
| Plummer Saw Mill | Wood Waste | Plummer, ID | 12/2021 | 5.80 | 3.81 |
| Deep Creek | Hydro | Northport, WA | 12/2022 | 0.41 | 0.01 |
| Clark Fork Hydro | Hydro | Clark Fork, ID | 12/2037 | 0.22 | 0.13 |
| Upriver Dam[10] | Hydro | Spokane, WA | 12/2024 | 14.50 | 5.16 |
| Big Sheep Creek Hydro | Hydro | Northport, WA | 6/2021 | 1.40 | 0.89 |
| Ford Hydro LP | Hydro | Weippe, ID | 6/2022 | 1.41 | 0.41 |
| John Day Hydro | Hydro | Lucile, ID | 9/2022 | 0.90 | 0.33 |
| Phillips Ranch | Hydro | Northport, WA | n/a | 0.02 | 0.01 |
| City of Cove | Hydro | Cove, OR | 10/2038 | 0.80 | 0.28 |
| Clearwater Paper | Biomass | Lewiston, ID | 12/2023 | 90.20 | 51.68 |
| **Total** | | | | **139.92** | **78.49** |

## Rattlesnake Flat Wind Power Purchase Agreement

Between the 2017 and 2020 IRPs, Avista identified an opportunity to procure low-cost wind energy at prices close to the energy market. This opportunity maintains Avista's lower power costs and assists in meeting CETA and corporate clean energy targets. Rattlesnake Flat was selected as the preferred project in our 2018 request for proposals (RFP) for 50 aMW of renewable energy. It is a 160.5 MW (limited to 144 MW) 20-year PPA with an expected net output of 469,000 MWh (53.5 aMW) each year. Located east of Lind, Washington in Adams County, the project went online in December 2020.

## Adams-Nielson Solar Power Purchase Agreement

Avista signed a 20-year PPA for the Adams-Nielson solar project in 2017. The 80,000 panel, single axis, solar facility is capable of delivering 19.2 MW of alternating current (AC) power entered service in December 2018. The project is located north of Lind, Washington in Adams County. The project provides energy for Avista's Solar Select program. Solar Select allows commercial customers to voluntarily purchase solar energy attributes from the project at no additional cost through a combination of tax incentives from the State of Washington and offsetting power supply expenses.

## Sales Contracts

Avista has intermediate power sales contracts used to optimize Avista's energy position on behalf of customers. Avista currently has three sales contracts extending through 2023. These contracts include Nichols Pumping, a sale of power at Colstrip; Douglas PUD which is part of an exchange agreement tied to the 10 percent purchase of Wells hydro project; and the Morgan Stanley contract to facilitate the sale of Clearwater Paper's

[10] Energy estimate is net of the City of Spokane's pumping load.

generation. For resource planning purposes, Avista does not assume contract sale extensions.

**Table 4.7: Other Contractual Rights and Obligations**

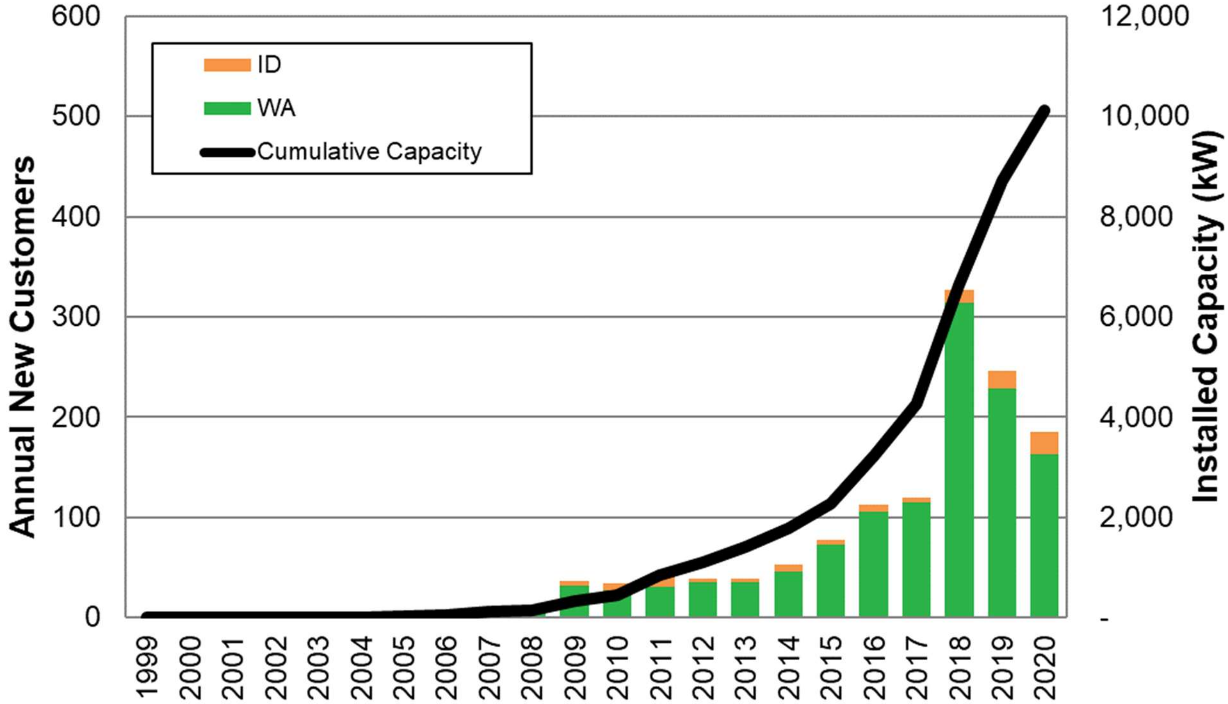
| Contract | Type | Fuel Source | End Date | Winter Capacity Contri-bution (MW) | Summer Capacity Contri-bution (MW) | Annual Energy (aMW) |
|---|---|---|---|---|---|---|
| Lancaster | Purchase | Natural Gas | 2026 | 283.0 | 231.0 | 218.0 |
| Palouse Wind | Purchase | Wind | 2042 | 5.3 | 5.3 | 36.2 |
| Rattlesnake Flat | Purchase | Wind | 2040 | 7.2 | 7.2 | 53.5 |
| Adams-Nielson | Purchase | Solar | 2038 | 0.4 | 10.2 | 5.6 |
| Nichols Pumping | Sale | System | 2023[11] | -5.0 | -5.0 | -5.0 |
| Morgan Stanley | Sale | Clearwater Paper | 2023 | -46.0 | -46.0 | -44.9 |
| Douglas PUD | Sale | System | 2023 | -48.0 | -48.0 | -48.0 |
| **Total** | | | | **196.9** | **154.7** | **215.4** |

## Customer-Owned Generation

Avista had 1,345 customer-installed net-metered generation projects on its system in early December 2020, representing a total installed capacity of 14.1 MW direct current (DC). Ninety-one percent of installations are in Washington; most are located in Spokane County. Figure 4.3 shows annual net metering customer additions since 1999. Solar is the primary net metered technology; the remaining are wind, combined solar and wind systems, and biogas. The average size of the customer installations is 7.65 kilowatts. Solar additions are falling due to the expiration of production incentives for new installations in Washington prior to the end of 2020. In Idaho, solar installation rates continue to increase each year without a major subsidy, but total only 117 customers compared to Washington's 1,200 plus customer installations. If net-metering customers continue to increase, Avista may need to adjust rate structures for these customers. Much of the cost of utility infrastructure to support reliable energy delivery is recovered in energy rates. Net metering customers continue to benefit from this infrastructure but are no longer purchasing as much energy, thereby transferring costs to customers not generating their own power.

[11] This obligation operates pumping loads in Colstrip. The end date reflects the energy sold to other Colstrip participants, Avista's obligation is approximately one megawatt and will end when Avista exits the plant.

Figure 4.3: Avista's Net Metering Customers




## Natural Gas Pipeline Rights

Avista transports natural gas to its natural gas-fired generators using the GTN pipeline owned by TC Energy (formally TransCanada). The pipeline runs between Alberta, Canada and the California/Oregon border at Malin. Avista holds 60,592 dekatherms per day of capacity from Alberta to Stanfield[12], and another 26,388 dekatherms per day from Stanfield to Malin. Figure 4.4 illustrates Avista's natural gas pipeline rights. Also included in this figure is the theoretical capacity if the plant runs at full capacity for the entire 24 hours in a day on the system. The maximum burn by Avista is 136,326 dekatherms in one day based on the average of the top five historical natural gas burn days of 2019 and 2020, as shown in Table 4.8.

As discussed above, Avista does not have firm transportation rights for the entirety of its natural gas generation capacity. Avista relies on short-term transportation contracts to meet needs above our firm contractual rights. Adequate surplus transportation has historically been available because the GTN pipeline was not fully subscribed. Natural gas producers have recently purchased all remaining rights on the system to transport their supply south and take advantage of higher prices in the U.S. compared to Canada. However, these suppliers do not appear to have firm off-takers of their product, and therefore a lack of transportation likely will not lead to a lack of fuel for our natural gas plants. This becomes a pricing rather than a supply issue when suppliers control the pipeline. Avista will continue acquiring natural gas delivery beyond our firm rights through the daily market. When the market begins to tighten, or the premiums paid for delivery

[12] Beginning on November 1, 2023, Avista will have transportation rights to 69,388 Dekatherms from Alberta to the U.S. border (Kingsgate) to match its rights to Stanfield.

through suppliers increases greatly, Avista will revisit its options. These options include procurement through pipeline capacity expansions and investment in onsite fuel storage.

**Figure 4.4: Avista Firm Natural Gas Pipeline Rights**

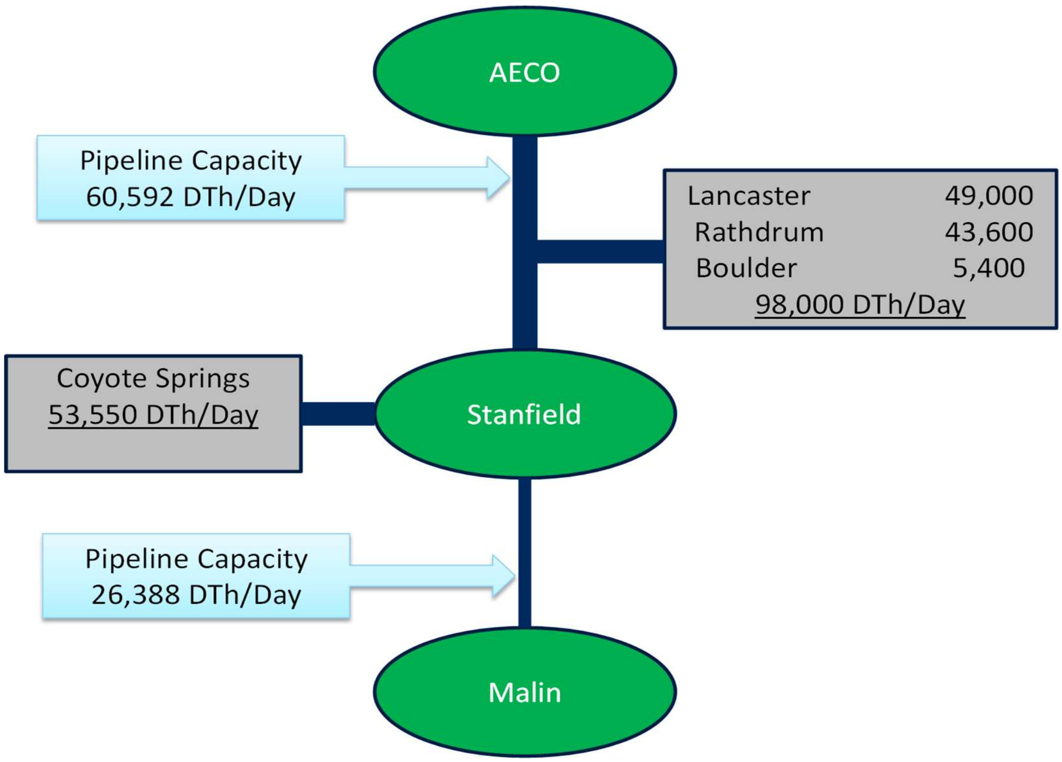



**Table 4.8: Top Five Historical Peak Natural Gas Usage (Dekatherms)**

| Date | Boulder Park | Coyote Springs 2 | Lancaster | Rathdrum | GTN Total | Firm Rights |
|---|---|---|---|---|---|---|
| 3/2/2019 | 5,361 | 45,855 | 48,889 | 43,614 | 143,719 | 60,592 |
| 3/1/2019 | 4,641 | 44,585 | 47,340 | 43,298 | 139,864 | 60,592 |
| 4/12/2020 | 4,427 | 45,651 | 44,150 | 44,106 | 138,333 | 60,592 |
| 4/5/2020 | 4,555 | 45,629 | 43,505 | 43,357 | 137,046 | 60,592 |
| 4/8/2020 | 4,498 | 45,411 | 43,625 | 42,792 | 136,326 | 60,592 |

## Resource Environmental Requirements and Issues

Electricity generation creates environmental impacts subject to regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities Avista has ownership interests in are designed, operated and monitored to maintain compliance with applicable environmental laws. Avista conducts periodic reviews and audits of its facilities and operations to ensure continued compliance. To respond to or anticipate emerging environmental issues, Avista monitors legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to impact the operation and productivity of our generating plants and other assets.

Generally, environmental laws and regulations have the following impacts while maintaining and enhancing the environment:

- Increase operating costs of generation;
- Increase the time and costs to build new generation;
- Require modifications to existing plants;
- Require curtailment or retirement of generation plants;
- Reduce the generating capability of plants;
- Restrict the types of plants that can be built or contracted with;
- Require construction of specific types of generation at higher cost; and
- Increase the cost to transport and distribute natural gas.

The following sections describe applicable environmental regulations in more detail.

### Clean Air Act (CAA)

The CAA is a federal law setting requirements for thermal generating plants. States are typically authorized to implement CAA permitting and enforcement. States have adopted parallel laws and regulations to implement the CAA. Some aspects of its implementation are delegated to local air authorities. Colstrip, Coyote Springs 2, Kettle Falls and Rathdrum CT all require CAA Title V operating permits. Boulder Park and the Northeast CT require minor source permits or simple source registration permits to operate. These requirements can change as the CAA or other regulations change and agencies review and issue new permits. A number of specific regulatory programs authorized under the CAA impact Avista's generation, as reflected in the following sections.

### Hazardous Air Pollutants (HAPs)

On April 16, 2016, the Mercury Air Toxic Standards (MATS), an EPA rule under the CAA for coal and oil-fired sources, became effective for all Colstrip units. Colstrip performs quarterly compliance assurance stack testing to meet the MATS site-wide limitation for Particulate Matter (PM) emissions (0.03 lbs./MMBtu) a measure used as a surrogate for all HAPs.

On May 22, 2020, EPA published its reconsideration of the "appropriate and necessary" finding and concluded that it is not "appropriate and necessary" to regulate electric utility steam generation units under section 112 of the CCA. EPA also took final action on the residual risk and technology review that is required by CAA section 112 and determined that emissions from HAP have been reduced such that residual risk is at acceptable levels. There are no developments in HAP emission controls to achieve further cost-effective reductions beyond the current standards and, therefore, no changes to the MATS rule are warranted.

### Montana Mercury Rule

Montana established a site wide Mercury cap in 2010, requiring Mercury to be below 0.9 lbs. per trillion Btu. Colstrip installed a mercury oxidizer/sorbent injection system to comply with the cap. The Montana Department of Environmental Quality (MDEQ) recently reviewed the equipment and concurred with the plant's assessment that units 3 and 4 operate at 0.8 lb. per Tbtu range. There is no indication mercury requirements will change in the IRP time horizon.

### Regional Haze Program

EPA set a national goal in 1999 to eliminate man-made visibility degradation in national parks and wilderness areas by 2064. Individual states must take actions to make "reasonable progress" through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In the absence of state programs, EPA may adopt Federal Implementation Plans (FIPs). On September 18, 2012, EPA finalized the Regional Haze FIP for Montana. In November 2012, several groups petitioned the U.S. Court of Appeals for the Ninth Circuit for review of Montana's FIP. The Court vacated portions of the Final Rule and remanded back to EPA for further proceedings on June 9, 2015. MDEQ is in the process of retaking control of the program from EPA after issuing a Regional Haze Program progress plan for Montana in 2017 and Montana's plan for the 2018 – 2028 period is expected to be submitted to EPA by July 31, 2021. A combination of LoNOx burners, overfire air, and SmartBurn currently control NOx emissions at Colstrip. Regional coal plant shutdowns indicate the NOx emissions are below the glide path. This progress demonstrates reasonable progress; therefore, Avista anticipates no additional NOx pollution controls Colstrip at this time.

### Coal Ash Management/Disposal

In 2015, EPA issued a final rule on coal combustion residuals (CCRs), also known as coal combustion byproducts or coal ash. The rule has been subject to ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations expressed largely through a 2012 Administrative Order on Consent (AOC). These requirements continue despite the 2018 federal court ruling.

In addition, under the AOC, the Colstrip owners must provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro rata share of various anticipated closure and remediation obligations. The amount of financial assurance required may vary due to the uncertainty associated with remediation activities. Please refer to the Colstrip section for additional information on the AOC/CCR related activities.

### Particulate Matter (PM)

Particulate Matter (PM) is the term used for a mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to see with the naked eye. Others are so small they are only detectable with an electron microscope. Particle pollution includes:

- $PM_{10}$: inhalable particles, with diameters that are generally 10 micrometers and smaller; and
- $PM_{2.5}$: fine inhalable particles, with diameters generally 2.5 micrometers and smaller.

There are different standards for $PM_{10}$ and $PM_{2.5}$. Limiting the maximum amount of PM to be present in outdoor air protects human health and the environment. The CAA requires EPA to set National Ambient Air Quality Standards (NAAQS) for PM, as one of the six criteria pollutants considered harmful to public health and the environment. The law also requires periodic EPA reviews of the standards to ensure that they provide adequate health and environmental protection and to update standards as necessary.

Avista owns and/or has operational control of the following generating facilities that produce PM: Boulder Park, Colstrip, Coyote Springs 2, Kettle Falls, Lancaster, Northeast and Rathdrum. Table 4.9 shows each of plants, their location, status of the surrounding area with NAAQS for $PM_{2.5}$ and $PM_{10,}$ operating permit, and PM pollution controls.

Appropriate agencies issue air quality operating permits. These operating permits require annual compliance certifications and renewal every five years to incorporate any new standards including any updated NAAQS status.

### Threatened and Endangered Species and Wildlife

A number of species of fish in the Northwest are listed as threatened or endangered under the Federal Endangered Species Act (ESA). Efforts to protect these and other species have not significantly affected generation levels at our facilities. Avista is implementing fish protection measures at our Clark Fork hydroelectric project under a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana, consistent with requirements of our FERC license.

Various statutory authorities, including the Migratory Bird Treaty Act, have established penalties for the unauthorized take of migratory birds. Some of our facilities can pose risks to a variety of such birds. We have and follow avian protection plans for these facilities.

**Table 4.9: Avista Owned and Controlled PM Emissions**

| Thermal Generating Station | $PM_{2.5}$ NAAQS Status | $PM_{10}$ NAAQS Status | Air Operating Permit | PM Pollution Controls |
|---|---|---|---|---|
| Boulder Park | Attainment | Maintenance | Minor Source | Pipeline Natural Gas |
| Colstrip | Attainment | Non-Attainment | Major Source Title V OP | Fluidized Bed Wet Scrubber |
| Coyote Springs 2 | Attainment | Attainment | Major Source Title V OP | Pipeline Natural Gas, Air filters |
| Kettle Falls | Attainment | Attainment | Major Source Title V OP | Multi-clone collector, Electrostatic Precipitator |
| Lancaster | Attainment | Attainment | Major Source Title V OP | Pipeline Natural Gas, Air filters |
| Northeast | Attainment | Maintenance | Minor Source | Pipeline Natural Gas, Air filters |
| Rathdrum | Attainment | Attainment | Major Source Title V OP | Pipeline Natural Gas, Air filters |

## Climate Change - Federal Regulatory Actions

In June 2019, the EPA released the final version of the Affordable Clean Energy (ACE) rule, the replacement for the Clean Power Plan (CPP). The final ACE rule combined three distinct EPA actions. First, EPA finalized the repeal of the CPP. The CPP was comprised of three "building blocks" identified by the EPA as follows:

- Reducing $CO_2$ emissions by undertaking efficiency projects at affected coal-fired power plants (i.e., heat-rate improvements);
- Reducing $CO_2$ emissions by shifting electricity generation from affected power plants to lower-emitting power plants (e.g., natural gas plants); and
- Reducing $CO_2$ emissions by shifting electricity generation from affected power plants to new renewable energy generation.

Notably, the second and third building blocks, responsible for the majority of projected emission reductions, were premised on "beyond the fence" measures to reduce emissions. Second, the EPA finalized the ACE rule, which comprised the EPA's determination of the Best System of Emissions Reduction (BSER) for existing coal-fired power plants and procedures that would govern States' promulgation of standards of performance for such plants within their borders. EPA set the final BSER as heat rate efficiency improvements based on a range of "candidate technologies" that can be applied to a plant's operating units and requires that each State determine which apply to each coal-fired unit based on consideration of remaining useful plant life. Contrary to the CPP, ACE relied solely on emission reductions from the specific source, or "inside the fence." Lastly, the ACE rule included implementing regulations for State plans.

In January 2021, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the ACE Rule and remanded the record back to the EPA for further consideration consistent with its opinion, finding that the EPA misinterpreted the CAA when it determined that the language of Section 111 barred consideration of emissions reduction options that were not applied at the source. The Court also vacated the repeal of the CPP. The EPA will now act on remand, and it is unclear what next steps the EPA will take. Given the complex and uncertain legal record with respect to the CPP, and the confirmation testimony of the incoming EPA Administrator that the Court's ruling was an opportunity for the EPA to "take a clean slate" in this area, we expect new rulemaking in the future.

### Climate Change - State Legislation and State Regulatory Activities

Washington and Oregon both adopted non-binding targets to reduce greenhouse gas emissions with an expectation of reaching the targets through a combination of renewable energy standards, eventual carbon pricing mechanisms (such as cap and trade regulation or a carbon tax), and assorted "complementary policies." Neither state has yet mandated specific reductions, but instead have enacted other targets to reduce greenhouse gas emissions. Washington State enacted Senate Bill 5116, the Clean Energy Transformation Act (CETA). As stated elsewhere in this IRP, CETA aims to reduce greenhouse gas emissions from specific sectors of the economy through direct regulation including electricity generation. CETA requires utilities to eliminate coal-fired resources from Washington retail rates by the end of 2025, achieve carbon neutrality by 2030 with no more than 20 percent of load met by alternative compliance means, and serve all retail load with renewable and non-emitting resources by 2045. Additional legislation with goals to reduce greenhouse gas emissions through a variety of measures have been proposed in both states. Any legislation that becomes law will be incorporated into future IRPs.

Washington and Oregon apply greenhouse gas emissions performance standards (EPSs) to electric generation facilities used to serve retail loads in their jurisdictions, whether the facilities are located within those respective states or elsewhere. The EPS prevents utilities from constructing or purchasing generation facilities or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that, in any case, have emission levels higher than 1,100 $CO_2$ equivalency ($CO_2e$) pounds per MWh. The Washington State Department of Commerce reviews this standard every five years. The last review was in September 2018 where it adopted a new rate of 925 pounds $CO_2e$ per MWh.

### Energy Independence Act (EIA)

The EIA in Washington requires electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits equal to 15 percent of the utility's total retail load in Washington in 2020 and beyond. Utilities under EIA regulation must also meet biennial energy conservation targets. Failure to comply with renewable energy and efficiency standards result in penalties of as much as $50 per MWh of deficiency. Avista meets the requirements of the EIA through a combination of hydro upgrades, wind, biomass, and renewable energy credits. Beginning in 2030, if a utility is compliant with CETA, the utility is deemed to meet the requirements of the EIA.

## Colstrip

Colstrip was built as a four-unit coal plant in Eastern Montana. Avista is 15 percent owner in Units 3 and 4. A complete list of the ownership shares and sizes of the plant is in Table 4.10. Units 1 and 2 retired in early 2020. Washington's CETA prohibits utilities from charging and using coal resources for Washington retail customers after 2025.

**Figure 4.5: Colstrip Plant**

**Table 4.10: Colstrip Ownership Shares**

| | Unit 3 | Units 4 |
|---|---|---|
| Operating Capacity (MW) | 740 | 740 |
| Year On-Line | 1984 | 1986 |
| | | |
| Owners | | |
| Avista | 15% | 15% |
| Northwestern Energy | 0% | 30% |
| PacifiCorp | 10% | 10% |
| Portland General Electric | 20% | 20% |
| Talen Energy, LLC | 30% | 0% |
| Puget Sound Energy | 25% | 25% |

### Coal Supply

Colstrip is supplied from an adjacent coal mine under coal supply and transportation agreements. Avista, along with the other owners agreed to an extension of this agreement through 2025 with extension options. The specific terms of the agreement are confidential.

### Water and Waste Management

Colstrip uses water from the Yellowstone River for steam production, air pollution scrubbers and cooling purposes. The water travels through a 29-mile pipeline to Castle

Rock Lake, a surge pond and water supply source for the plant and the Town of Colstrip. From Castle Rock Lake, water moves to holding tanks as needed throughout the plant site. The water recycles until it is ultimately lost through evaporation, also known as zero-discharge. An example of this reuse is how the plant removes excess water from the scrubber system fly ash, creating a paste product similar to cement. The paste flows to a holding pond while clear water is reused. Similarly, the bottom ash flows to a holding pond, where it is dewatered and the water is reused.

The plant uses three major areas for water and waste management. The first are at-plant facilities, in which all four units, including the now-retired Units 1 and 2, shared use of the ponds. The second major area, supporting Units 3 and 4 operations, is the Effluent Holding Pond (EHP). This area is 2.5 miles to the south east of the plant site. Avista is responsible for its proportional share of the EHP Area. The third storage area is the Stage One Effluent Pond (SOEP)/Stage Two Effluent Pond (STEP); these ponds dispose fly ash from the scrubber slurry/paste from Units 1 and 2. These ponds are nearly two miles to the northwest of the plant. Avista does not have ownership or responsibility in this area. Avista is therefore responsible for its share of the plant site area and EHP facilities. Figure 4.6 shows a map of the different storage areas at Colstrip.

Colstrip will covert to dry ash storage in 2022. The master plan for site wide ash management is filed with the MDEQ-AOC[13] and additional information on CCRs is available at Talen's website[14]. This plan includes removing Boron, Chloride and Sulfate from groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system along with a dry ash storage facility. Each of the new facilities are required, regardless of the length of the plant's continuing operations. Avista has posted bonds for nearly $6 million in 2018 for cost assurance and an additional $7 million in 2019 related to Units 3 and 4 closure. These amounts are updated annually, increasing as clean-up plans are finalized and approved in the coming years and then decreasing over time as remediation activities are completed.

### Post 2025 Considerations

Three primary drivers affect operational and financial risks defining the future viability of the Company's share of Colstrip Units 3 and 4. These include the ownership and operating agreement, the coal contract and Washington CETA law.

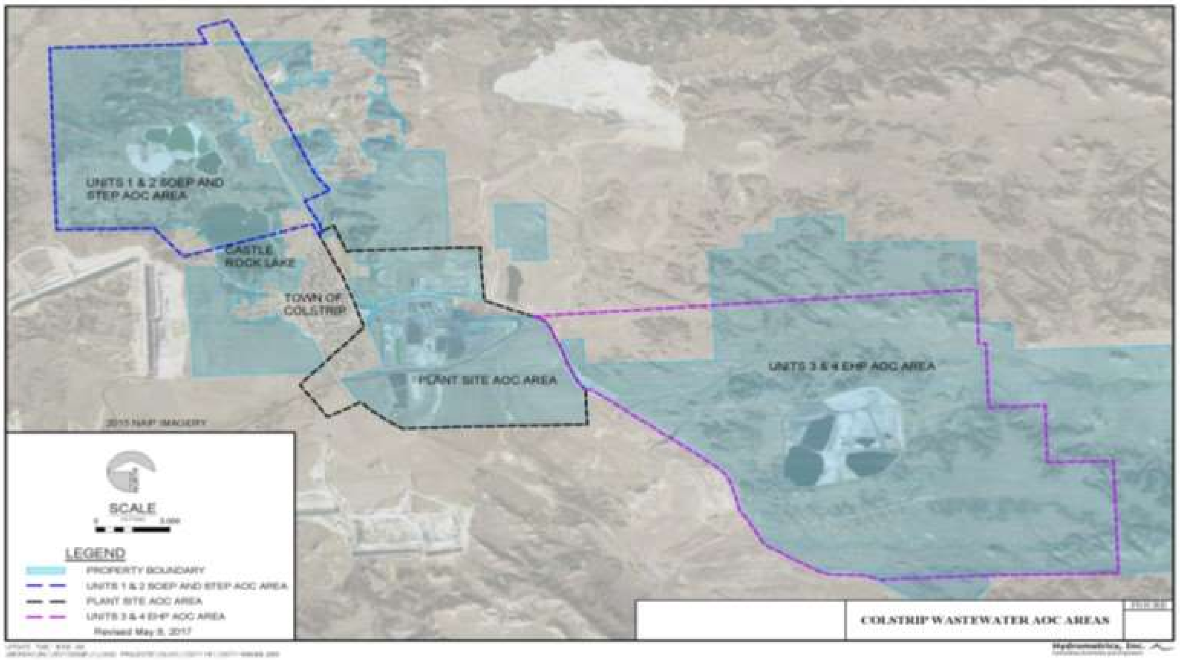
The ability to shut down Colstrip Units 3 and 4 is governed by the ownership and operation agreement. No decisions have been made by the ownership group regarding whether Colstrip Unit 3 and/or Unit 4 will continue to operate to the December 31, 2025 date imposed by CETA or if the units will continue to operate beyond 2025.

Avista obtains its share of the coal for Colstrip Units 3 and 4 pursuant to a coal supply agreement with Westmoreland Rosebud Mining, LLC. The coal supply agreement expires on December 31, 2025 but could be extended up to December 31, 2029. If the coal supply

[13] http://deq.mt.gov/DEQAdmin/mfs/ColstripSteamElectricStation.
[14] https://www.talenenergy.com/ccr-colstrip/.

agreement is extended beyond December 31, 2025, the parties will need to negotiate a new price for coal for the extended term.

**Figure 4.6: Map of Colstrip Water Storage**




Section 3 of CETA states: "On or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity."[15] That is, after December 31, 2025, the costs and benefits associated with coal-fired resources (except for decommissioning and remediation costs), including costs and benefits associated with Avista's share of Colstrip Units 3 and 4, cannot be included in Avista's Washington retail electricity rates.[16] Coal-fired resources must be fully depreciated under the law by December 31, 2025.[17]

It is difficult to speculate on all potential Colstrip scenarios; however, in general, there are three likely outcomes:

- one or more of the units will continue to operate with the same ownership;
- one or more of the units will continue to operate, but the ownership in the units will change; or
- both units will be shut down.

[15] "Allocation of electricity" means, for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity customers that are located in this state.
[16] *See* Clean Energy Transformation Act at Section 2 (defining "electric utility"); Clean Energy Transformation Act at Section 3.
[17] Clean Energy Transformation Act at Section 3.

If units continue to operate after December 31, 2025, and Avista remains an owner, a number of items will need to be addressed. First, Avista will need to evaluate its contractual obligations under the existing ownership and operation agreement. Second, because Avista is contractually required to supply its share of coal to operate the unit(s), Avista will need to either join in extending the existing coal supply agreement or make other arrangements. Finally, Avista will need to determine how it is going to comply with the requirements of any applicable laws, including the Washington CETA.

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# 5. Energy Efficiency

Avista's energy efficiency programs provide cost-effective opportunities for customers to save energy by replacing old equipment with better performing, energy efficient equipment. The energy efficiency programs offer a wide array of low-cost measures to our customers. Current programs with the highest impacts on energy savings include non-residential lighting, residential home measures and direct install programs. Avista's energy efficiency programs regularly meet or exceed regional shares of the efficiency targets outlined by the Northwest Power and Conservation Council (NPCC).

**Section Highlights**

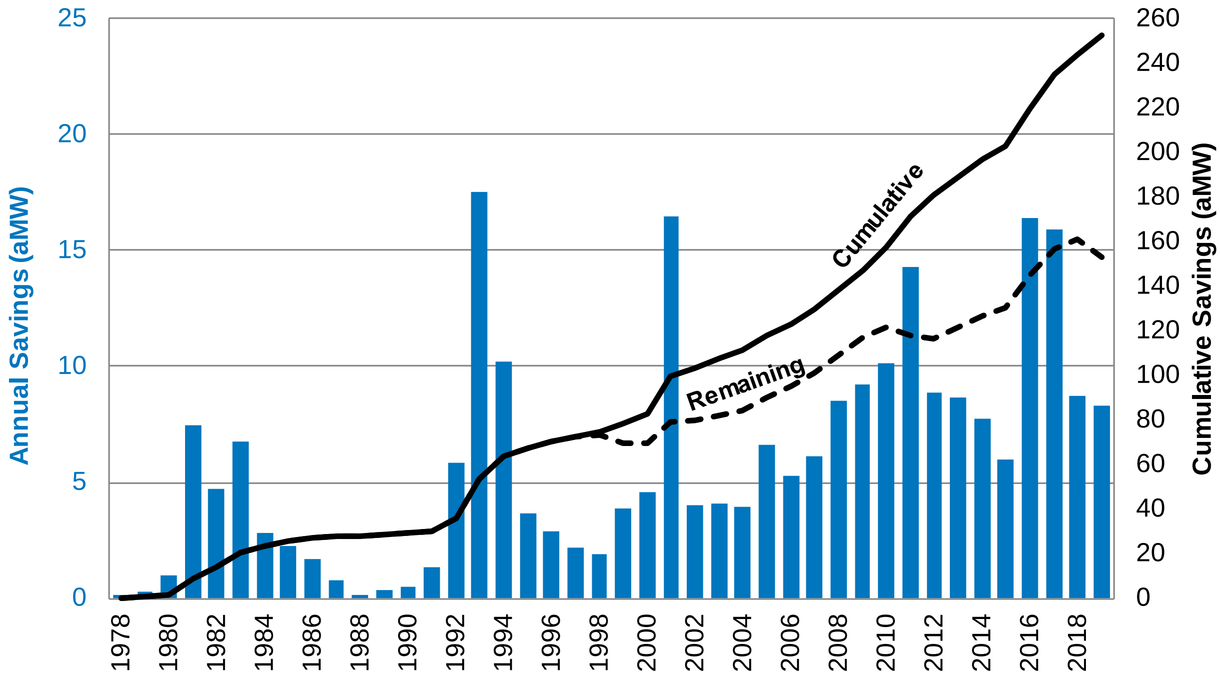
- Avista's energy efficiency programs reduce loads by nearly 14.5 percent, or 160 aMW.
- This IRP evaluated over 7,300 measure options covering all major end use equipment, as well as devices and actions to reduce energy consumption for this IRP.
- The 2022-23 Washington EIA penalty threshold is 88,889 MWh.

Figure 5.1 illustrates Avista's historical electricity conservation acquisitions. Avista has acquired 252 aMW of energy efficiency since 1978; however, the 18-year average measure life of the conservation portfolio means some measures are no longer reducing load as the measure has either became code or standard practice. The 18-year measure life accounts for the difference between the cumulative and online trajectories in Figure 5.1. Currently 160 aMW of energy efficiency serves customers, representing nearly 14.5 percent of 2019 load.

Avista's energy efficiency programs provide energy efficiency and education offerings to the residential, low income, commercial and industrial customer segments. Program delivery mechanisms include prescriptive, site-specific, regional, upstream, behavioral, market transformation and third-party direct install options. Prescriptive programs provide fixed cash incentives based on an average savings assumption for the measure across the region. Prescriptive programs work best where uniform measures or offerings apply to large groups of similar customers. Examples of prescriptive programs include the installation of qualifying high-efficiency heating equipment or replacement of T8 florescent strip lighting with a high-efficiency LED lamp.

Site-specific programs, or customized offerings, provide cash incentives for cost-effective energy saving measures or equipment that are analyzed and contracted but do not meet prescriptive rebate requirements. Site-specific programs require customized approaches for commercial and industrial customers because of the unique characteristics of each premise and/or process. Other delivery methods build off these offerings with up- and mid-stream retail buy-downs of low-cost measures, free-to-customer direct install programs or coordination with regional market transformation efforts. In addition to developing and delivering incentive offerings, Avista also provides technical assistance to help educate and inform customers about various types of efficiency measures.

**Figure 5.1: Historical Conservation Acquisition (system)**

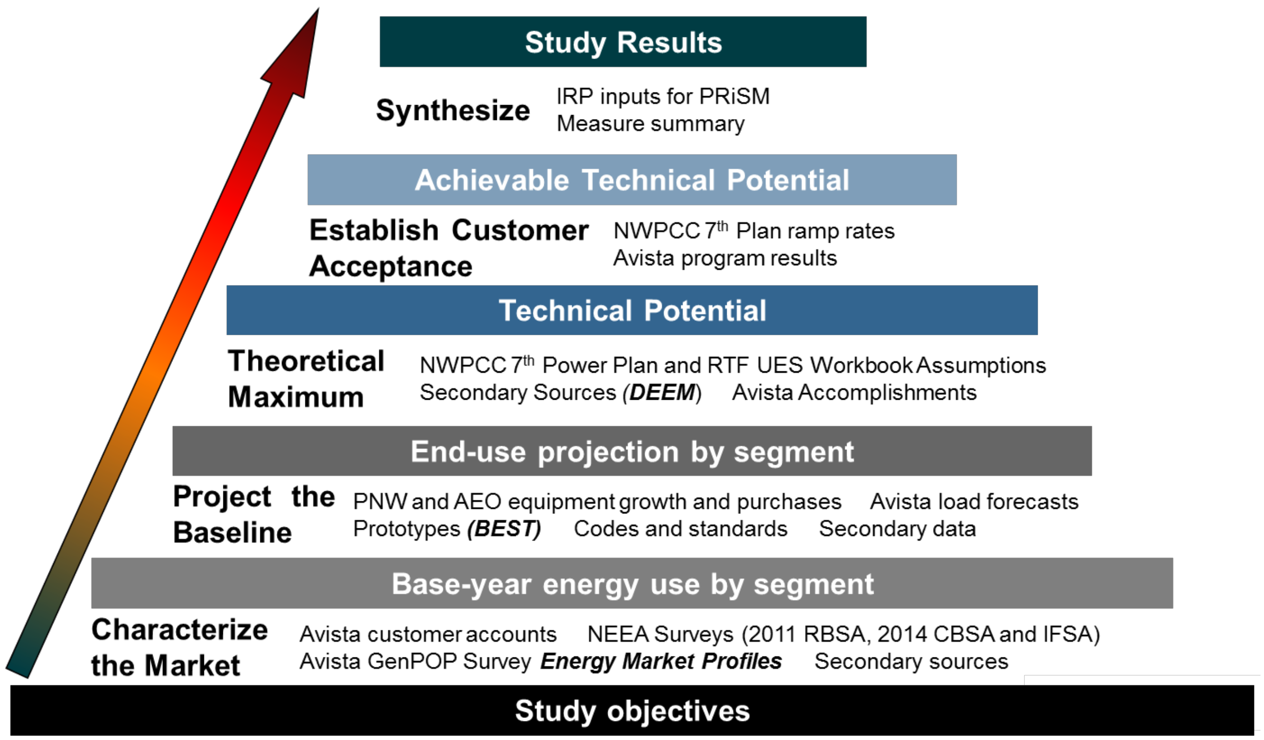



## The Conservation Potential Assessment

Avista retained Applied Energy Group (AEG) as an independent consultant to assist in developing a Conservation Potential Assessment (CPA) for this IRP. The CPA is the basis for the energy efficiency portion of this plan. The CPA identifies the 24-year potential for energy efficiency and provides data on resources specific to Avista's service territory for use in the resource selection process and in accordance with the Energy Independence Act's (EIA) energy efficiency goals. The potential assessment considers the impacts of existing programs, the influence of known building codes and standards, technology developments and innovations, changes to the economic influences and energy prices. The CPA report is included in Appendix E of this IRP and the list of energy efficiency measures are in Appendix I.

AEG first developed estimates of *technical potential*, reflecting the adoption of all conservation measures, regardless of cost-effectiveness or customers' likeliness to participate. The next step identified the *achievable technical potential*; this measure modifies the technical potential by accounting for customer adoption constraints by using the Power Council's 2021 Plan ramp rates. The estimated achievable technical potential, along with associated costs, feed into the PRiSM model to select cost-effective measures. AEG took the following steps shown in Figure 5.2 to assess and analyze energy efficiency and potential within Avista's service territory.

**Figure 5.2: Analysis Approach Overview**




In short, the potential assessment performed by AEG included the following steps:

1. Perform a market characterization to describe sector-level electricity use for the residential, commercial and industrial sectors for the 2019 base year.
2. Develop a baseline projection of energy consumption and peak demand by sector, segment and end use for 2019 through 2045.
3. Define and characterize several hundred conservation measures to be applied to all sectors, segments and end uses.
4. Estimate Technical Potential and Achievable Technical Potential at the measure level in terms of energy and peak demand impacts from conservation measures for 2019-2045.

## Market Segmentation

The CPA considers Avista customers by state and by sector. The residential sector includes single-family, multi-family, manufactured home and low-income customers[1] and is based on Avista's customer data and U.S. Census data from the American Community Survey (ACS). For the residential sector, AEG utilized Avista's customer data and prior CPA ratios developed from census information. AEG incorporated information from the Northwest Energy Efficiency Alliance's (NEEA) Commercial Building Stock Assessment to assess the commercial sector by building type, installed equipment and energy consumption. Avista analyzed the industrial sector as a whole for each state because of their unique energy needs. AEG characterized energy use by end use within each

[1] The low-income threshold for this study is 200 percent of the federal poverty level. Low-income information is available from U.S. census data and the American Community Survey data.

segment in each sector, including space heating, cooling, lighting, water heat or motors; and by technology, including heat pump and resistance-electric space heating.

The baseline projection is a “business as usual” metric without future utility conservation or energy efficiency programs. It estimates annual electricity consumption and peak demand by customer segment and end use absent future efficiency programs. The baseline projection includes the impacts of known building codes and energy efficiency standards as of 2018 when the study began. Codes and standards have direct bearing on the amount of energy efficiency potential due to the reduction in remaining end uses with potential for efficiency savings. The baseline projection accounts for market changes including:

- customer and market growth;
- income growth;
- retail rates forecasts;
- trends in end use and technology saturation levels;
- equipment purchase decisions;
- consumer price elasticity;
- income; and
- persons per household.

For each customer class, AEG compiled a list of electrical energy efficiency measures and equipment, drawing from the NPCC’s 2021 Power Plan, the Regional Technical Forum and other measures applicable to Avista. The 7,300 individual measures included in the CPA represent a wide variety of end use applications, as well as devices and actions able to reduce customer energy consumption. The AEG study includes measure costs, energy and capacity savings and estimated useful life.

Avista, through its PRiSM model, considers other performance factors for the list of measures and performs an economic screening on each measure for every year of the study to develop the economic potential of Avista’s service territory and individually by state.

Avista supplements energy efficiency activities by including potentials for distribution efficiency measures consistent with EIA conservation targets and the NPCC 2021 Power Plan.

## Overview of Energy Efficiency Potential

AEG’s approach adhered to the conventions outlined in the National Action Plan for Energy Efficiency Guide for Conducting Potential Studies.[2] The guide represents comprehensive national industry standard practice for specifying energy efficiency potential. Specifically, two types of potential were included in this study, as discussed below. Table 5.1 shows the CPA results for Technical and Achievable Technical Potential by state.

[2] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. www.epa.gov/eeactionplan.

**Table 5.1: Cumulative Potential Savings (Across All Sectors for Selected Years)**

| | 2022 | 2023 | 2024 | 2031 | 2041 |
|---|---|---|---|---|---|
| Technical Potential (GWh) | 150.4 | 310.3 | 480.6 | 1,798.5 | 2,620.6 |
| Washington (GWh) | 95.6 | 197.7 | 307.5 | 1,179.8 | 1,723.7 |
| Idaho (GWh) | 54.9 | 112.6 | 173.1 | 618.7 | 896.9 |
| Total Technical Potential (aMW) | 18.0 | 36.0 | 54.9 | 205.3 | 299.0 |
| | | | | | |
| Technical Achievable Potential (GWh) | 84.2 | 180.7 | 287.6 | 1,245.0 | 1,867.5 |
| Washington (GWh) | 53.0 | 114.5 | 183.5 | 821.2 | 1,238.4 |
| Idaho (GWh) | 31.2 | 66.2 | 104.1 | 423.8 | 629.1 |
| Total Technical Achievable Savings (aMW) | 9.5 | 20.8 | 33.1 | 141.9 | 212.9 |

### Technical Potential

Technical Potential is defined as the theoretical upper limit of conservation potential. It assumes customers adopt all feasible measures regardless of 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 relative to applicable codes and standards. Non-equipment measures, which may be realistically installed apart from equipment replacements, are implemented according to ramp rates developed by the NPCC for its 2021 Power Plan, applied to 100 percent of the applicable market. The Technical Potential case is a theoretical construct and is provided primarily for planning and informational purposes.

### Achievable Technical 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 affecting market penetration of energy efficiency measures. AEG used ramp rates from the Council's 2021 Power Plan in development of the Achievable Technical Potential.

For the Achievable Technical Potential case, a maximum achievability multiplier of 85 to 100 percent is applied to the ramp rate, per Council methodology. This achievability factor represents an achievable potential, which can reasonably be acquired through available mechanisms, regardless of how conservation is achieved. Thus, the market applicability assumptions utilized in this study include savings outside of utility programs.

### PRiSM Co-Optimization

Avista's identifies achievable economic conservation potential by concurrently evaluating supply- and demand-side resources together in Avista's PRiSM model. In PRiSM, the energy efficiency resources compete with supply- and demand resource options to meet Avista resource deficits. Energy efficiency measures benefit from additional value streams, such as 10 percent more energy and capacity from the Power Act Preference in Washington, as compared to other resources. Energy efficiency also receives additional financial benefits by including financial savings from reducing line losses and avoided transmission and distribution costs. For Washington, an additional credit is included based on regional greenhouse gas emissions reductions priced at the social cost of carbon and financial benefits for non-energy impacts.

## Energy Efficiency Targets

Cost effective energy efficiency will lower system sales by 113 aMW by 2041; this translates into a 9.6 percent savings. Of the total energy efficiency savings estimates, Idaho saves 23 percent of the saving potential compared to Washington's 77 percent. Washington receives a larger percentage of the savings because of the higher avoided costs. These higher avoided costs include greenhouse gas emissions benefits priced at the social cost of carbon, non-energy impacts, and the 10 percent Power Act preference adder. Figure 5.3 shows the total savings by state for selected years. Commercial and Residential customers contribute to most of the savings of the three major customer classes. Savings for each class are shown by state in Figure 5.4

**Figure 5.3: Conservation Potential Assessment - 20-Year Cumulative GWh**

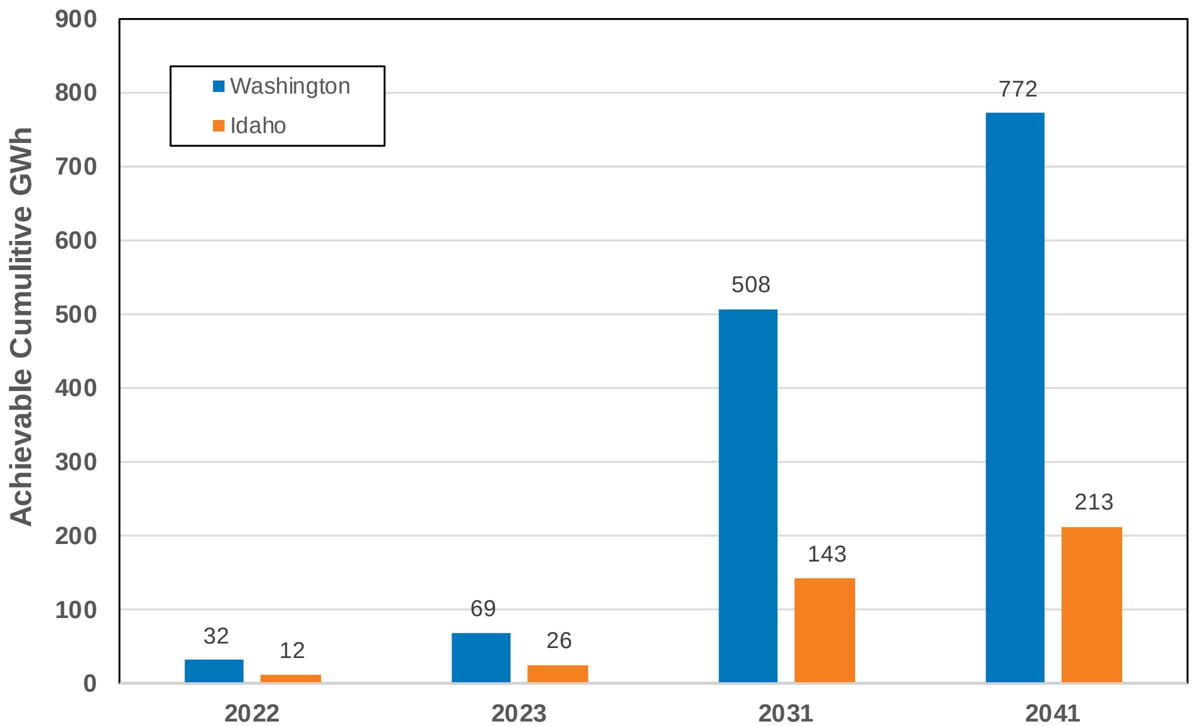
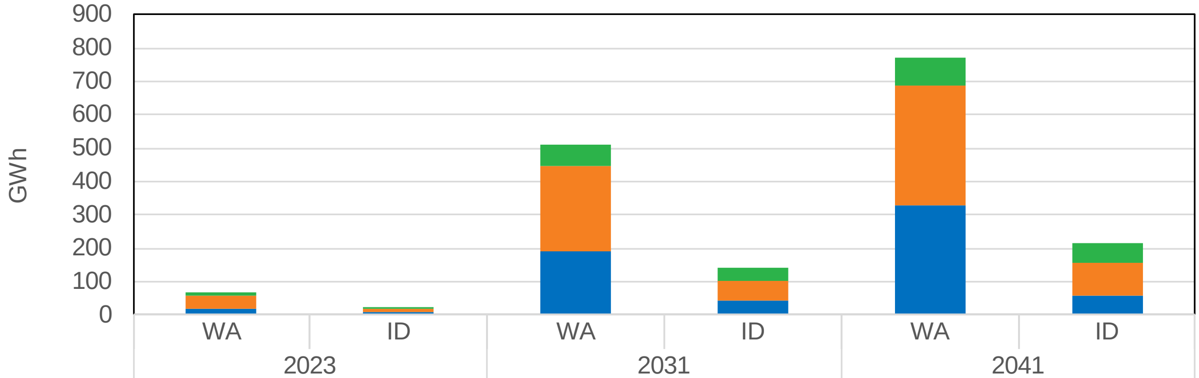


**Figure 5.4: Energy Efficiency Savings by Segment**




| | 2023 WA | 2023 ID | 2031 WA | 2031 ID | 2041 WA | 2041 ID |
|---|---|---|---|---|---|---|
| Industrial | 12.0 | 8.4 | 62.5 | 42.8 | 86.4 | 59.1 |
| Commercial | 39.3 | 10.0 | 255.3 | 57.4 | 359.2 | 95.3 |
| Residential | 17.9 | 7.2 | 190.0 | 42.6 | 326.8 | 58.8 |
| Total | 69.2 | 25.6 | 507.8 | 142.9 | 772.4 | 213.2 |

## Washington Biennial Conservation Plan

The IRP process provides the energy efficiency targets for Washington's EIA Biennial Conservation Plan. Pursuant to requirements in Washington, the biennial conservation target must be no lower than a pro rata share of the utility's ten-year conservation potential. In setting the Company's target, both the two-year achievable potential and the ten-year pro rata savings are determined with the higher value used to inform the EIA Biennial target. Figure 5.5 shows the annual selection of new energy efficiency compared to the 10-year pro-rata share methodology.

For the 2022-2023 CPA, the two-year achievable potential is 69,174 MWh for Washington electric operations. The pro-rata share of the utility's ten-year conservation potential is 102,566 MWh which is used in the calculation of the biennial target. Table 5.2 contains achievable conservation potential for 2022-2023 using the PRiSM methodology. Also included is the energy savings expected from the 2022 and 2023 feeder upgrade projects shown below in Table 5.3.

**Figure 5.5: Washington Annual Achievable Potential Energy Efficiency (Gigawatt Hours)**

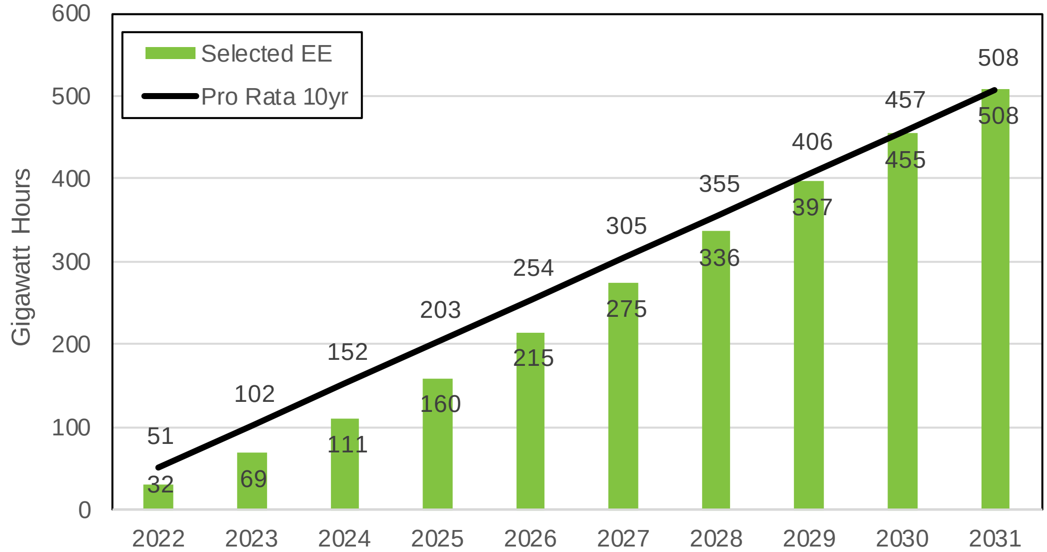



**Table 5.2: Biennial Conservation Target for Washington Energy Efficiency**

| 2022-2023 Biennial Conservation Target (MWh) | |
|---|---|
| CPA Pro-Rata Share | 101,566 |
| Distribution and Street Light Efficiency | 219 |
| **EIA Target** | **101,785** |
| Decoupling Threshold | 5,119 |
| **Total Utility Conservation Goal** | **106,904** |
| Excluded Programs (NEEA)[3] | -12,896 |
| **Utility Specific Conservation Goal** | **94,008** |
| Decoupling Threshold | -5,119 |
| **EIA Penalty Threshold** | **88,889** |

**Table 5.3: Annual Achievable Potential Energy Efficiency (Megawatt Hours)**

| Year | Methodology | Washington | Idaho | Total |
|---|---|---|---|---|
| 2022 | Feeder Upgrades | 218.8 | 0 | 218.8 |
| 2023 | Feeder Upgrades | 0 | 245.6 | 245.6 |

[3] NEEA yet to be determined for the 2022-2023 Biennium

## Energy Efficiency Related Financial Impacts

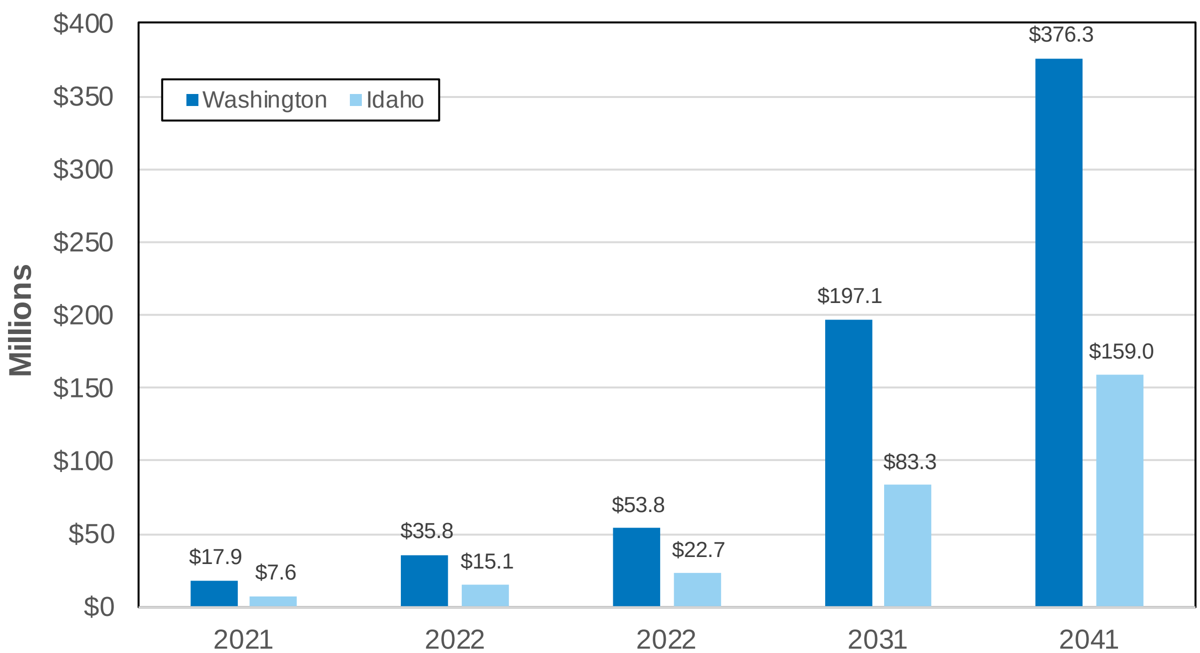
The Washington EIA requires utilities with over 25,000 customers to acquire all cost-effective and achievable energy conservation.[4] For the first 24-month period under the law, 2010-2011, this equaled a ramped-in share of the regional 10-year conservation target identified in the Seventh Power Plan. Penalties of at least $50 per MWh exist for utilities not achieving EIA targets.

The EIA requirement to acquire all cost-effective and achievable conservation may pose significant financial implications for Washington customers. Based on CPA results, the projected 2021 conservation acquisition cost to Washington electric customers is approximately $17.9 million. This amount grows to $35.8 million by 2022 totaling to $197 million over this 10-year period. Costs are projected to continue increasing after 2031 to over $376 million in 2041. In total, the levelized price for Washington's savings is 3.5 cents per kWh.

For Idaho, Avista continues to pursue all cost-effective and achievable energy efficiency. Based on CPA results, the projected 2021 Idaho conservation acquisition cost to electric customers is approximately $7.6 million. This amount is projected to grow to $15 million by 2022 totaling to $83 million over this 10-year period. Costs are projected to continue to increase after 2031 to more than $159 million in cumulative costs by 2041. In total, the levelized price for Idaho's energy efficiency is 3.4 cents per kWh.

Figure 5.6 shows the annual cost in millions of nominal dollars for the utility to acquire the projected electric achievable potential and administer the programs for each state.

**Figure 5.6: Cumulative Energy Efficiency Costs**




[4] The EIA defines cost effective as 10 percent higher cost than a utility would otherwise spend on energy acquisition.

## Integrating Results into Business Planning and Operations

The CPA and IRP energy efficiency evaluation processes provide high-level estimates of conservation cost-effectiveness and acquisition opportunities. Results establish baseline goals for continued development and enhancement of energy efficiency programs, but do not provide enough detail to form an actionable acquisition plan. Avista uses results from both processes to establish a budget for energy efficiency measures, determine the size and skillsets necessary for future operations and identify general target markets for energy efficiency programs. This section discusses recent operations of the individual sectors and energy efficiency business planning.

The CPA is used for implementing energy efficiency programs in the following ways:

- Identifying conservation resource potentials by sector, segment, end use and measure of where energy savings may come from. Energy efficiency staff uses CPA results to determine the segments and end uses/measures to target.
- Identifying measures with the highest benefit-cost ratios to help the utility acquire the highest benefits for the lowest cost. Ratios evaluated include total resource cost (TRC) in Washington and utility cost test (UCT) in Idaho.
- Identifying and targeting measures with large potential but significant adoption barriers that the utility may be well-positioned to address through innovative program design or market transform efforts.
- Optimizing the efficiency program portfolio by analyzing cost effectiveness, potential of current measures and programs, determining potential new programs, ideal program changes and necessary program sunsets.

The CPA illustrates potential markets and provides a list of cost-effective measures to analyze through the ongoing energy efficiency business planning process. This review of both residential and non-residential program concepts and sensitivity to more detailed assumptions feed into program planning.

### Residential Sector Overview

The Company's residential portfolio of efficiency programs uses several approaches to engage and encourage customers to consider energy efficiency improvements for their home. Prescriptive rebate programs are the main component of this portfolio, augmented with other interventions. Other interventions include select distribution of low-cost lighting and weatherization materials, direct-install programs as well as multi-faceted, multichannel outreach and customer engagement.

Residential customers received over $7.7 million in rebates in 2019 to offset the cost of implementing these energy efficiency measures. All programs within the residential portfolio contributed over 28,295 MWh to the 2019 annual energy savings.

### Low-Income Sector Overview

The Company leverages the infrastructure of several network Community Action Agencies (CAA) and one tribal weatherization organization to deliver energy efficiency programs for the Company's low-income residential customers in Avista's service territory. CAAs have resources to income qualify, prioritize and treat clients' homes based upon several characteristics that are not available to Avista. Beyond Avista's annual funding, the agencies have other monetary resources to leverage for home weatherization and other energy efficiency measures. The agencies have both in-house and/or contract crews available to install many of the efficiency program measures.

Avista's general outreach for this sector is a "high touch" customer experience for vulnerable customer groups including seniors and those with limited incomes. Each outreach encounter includes information about bill payment options and energy management tips, along with the distribution of low-cost weatherization materials. Many events are coordinated each year, including Avista-sponsored energy fairs, and the energy resource van. Avista also partners with community organizations to reach these customers through other means such as area food bank/pantry distribution sites, senior activity centers, or affordable housing developments. Low-income energy efficiency programs contributed 898 MWh of electricity savings in 2019.

### Non-Residential Sector Overview

Non-residential energy efficiency programs deliver energy efficiency through a combination of prescriptive and site-specific offerings. Any measure not offered through a prescriptive program is eligible for analysis through the site-specific program, subject to the criteria for program participation. Prescriptive paths for the non-residential market are preferred for small and uniform measures, but larger measures may also fit where customers, equipment and estimated savings are reasonably non-homogenous.

In 2019, more than 1,687 prescriptive and site-specific nonresidential projects received funding. Avista contributed over $8 million for energy efficiency upgrades to offset costs in nonresidential applications. Non-residential programs realized over 43,799 MWh in annual first-year energy savings in 2019.

## Other Energy Efficiency Analysis

### Conservation's Transmission & Distribution Deferral Analysis

Cost-effective energy efficiency programs require a review of cost versus potential benefits. One benefit is the avoidance or deferral of generation and distribution system investments. Avoided generation investments are straightforward but avoided transmission and distribution (T&D) system components tend to be less straightforward as the investments are lumpy, location specific and may or may not include energy efficiency due to the thermal limitations of the system.

The 2017 IRP Washington acknowledgement letter requested Avista determine whether to move the T&D benefits estimates to a forward-looking value versus a historical value. With many changes occurring in energy efficiency in the future, there is merit in exploring the deferral value on the future use of T&D systems. A forward-looking T&D deferral value could provide better alignment between the expected use of the Company's T&D system and the valuation of customer benefits. Conversely, estimates on future T&D values can be more difficult to quantify and are subject to many iterations throughout the T&D planning process.

The NPCC's methodology divides the estimated capital investment over a 5 to 10-year period by the estimated capacity gained by that investment. Note that this value is refined by applying a capital growth investment ratio, a power factor, a regionally set discount rate and the assumption that the average measure has a life of 35 years. The result of these calculations is deferred values of $13.01 per kW-year and $12.37 per kW-year for transmission and distribution respectively and a combined value of $25.38 per kW-year. Table 5.4 illustrates the values calculated for the Company's T&D deferred benefits for energy efficiency.

**Table 5.4: Transmission and Distribution Benefits (System)**

| | Transmission | Distribution |
|---|---|---|
| Capital Investment (est.) | $57,400,000 | $ 651,706,715 |
| Capacity Gained (est. MW) | 275 | 512 |
| Capital Growth Investment Ratio | 100% | 26% |
| Power Factor | 0.98 | 0.98 |
| Discount rate | 5% | 5% |
| Asset lifetime (Years) | 35 | 35 |
| T&D Carrying Charge | 6.1% | 6.1% |
| Results Separate ($/kW-year) | 13.01 | 12.37 |
| Result Combined ($/kW-year) | | 25.38 |

The impact of implementing a forward-looking T&D deferral value attempts to better align with known future activity; however, data on future T&D investments as they relate to energy efficiency is less reliable as it is not a primary consideration for many T&D projects. While the overall impact of the T&D deferral methodology used is minimal, Avista remains open to exploring alternative methodologies as they become available.

## Non-Energy Impacts

Avista will partner with a third-party consultant to identify non-energy impact (NEI) benefits or costs within its service territory that have historically not been quantified. In order to provide the IRP with an estimate for the benefits, Avista is using an interim value of $8.90 per MWh as a proxy for the yet to be identified impacts until more robust estimates can be determined later in 2021. The interim NEI values are based on a 2019 EPA report entitled "Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report". This report identifies NEI values for regions throughout the U.S. including the Pacific Northwest. NEI values identified are not tied to specific measures, but rather are applicable to all generated energy, which allows the values to be easily applied. However, the report has inherent limitations when applying the values to a specific utility, as the study does not identify each county in the Pacific Northwest but takes an aggregated approach by selecting counties across Washington, Oregon, Idaho, Montana, Wyoming and Nevada. This aggregation limits the ability to derive unique NEI values for Avista and its own fuel mix.

To address this limitation, Avista's energy efficiency team used the AVERT calculator, a tool used in the report to identify each region's NEI values, to determine emissions rates for each state within the Pacific Northwest region. The results of that analysis show Washington accounted for only 20 percent of the generation and about half of the emissions rate compared to the aggregated Pacific Northwest data. Avista imported the AVERT data into the COBRA Model, also utilized by the EPA study to replicate the health benefits from the region. The resulting NEI value range was between $5.46 and $12.34 per MWh which is about half of the range for the Pacific Northwest region. While this NEI value range is closer to Avista's emissions rate and fuel mix, the actual NEI value for Avista's service territory is unknown because Washington data included only Clark, Cowlitz, Grays Harbor, Klickitat, Lewis, Pierce, Skagit, and Whatcom counties. King and Spokane counties were excluded in the report. Based on a comparison of Avista's wood smoke study conducted in 2018, Avista had a NEI cost of $4.00 to $9.00 per MWh. Using the $5.46 to $12.34 per MWh range is close to this amount and is a reasonable approximation. The midpoint of this range is $8.90 per MWh, which was applied uniformly to account for non-energy impacts within the 2021 IRP. The NEI values estimates used do not take the expectation of Avista's increasingly cleaner generation mix into consideration. This is an area for further consideration in the more detailed Avista NEI study described above.

### Social Cost of Carbon

For Washington programs, energy efficiency benefits economically from an adjustment to include the benefit from regional greenhouse gas emission reductions. Avista estimated the incremental amount of greenhouse emissions reductions per MWh of energy efficiency for the northwest and applied this savings to each MWh of potential program savings valued at the social cost of carbon. Details regarding the market impacts of energy efficiency are included in Chapter 10 and the net economic benefit from including the social cost of carbon for energy efficiency is in the avoided cost shown in Figure 5.7.

### Combined Heat and Power

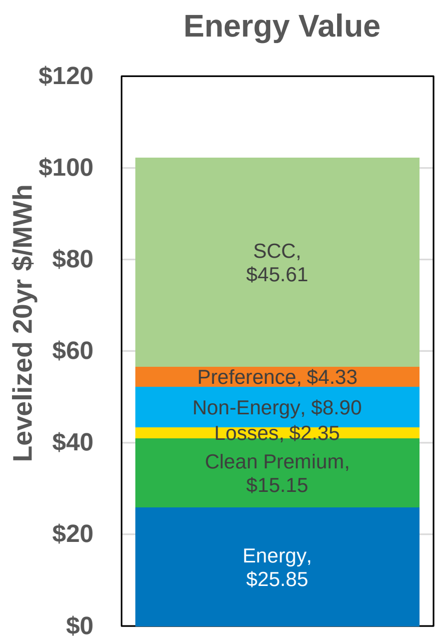
Avista has not identified any combined heat and power opportunities within its service territory for this plan. Currently, Avista has one combined heat and power customer in Idaho selling power to Avista under a PURPA contract and one customer in Washington that is exploring the feasibility of a project. Due to the uncertainty of a future project, no additional analysis is required at this time.

## Energy Efficiency Avoided Costs

The energy efficiency avoided cost is useful for the energy efficiency evaluation and acquisition team to conduct financial analysis of potential programs in between IRP analyses. The process to estimate avoided cost calculates the marginal cost of energy and capacity of the resources selected in the PRS. The calculation process is similar to the generation resources discussed in Chapter 11 but differs in the case of energy efficiency for the capacity and clean energy calculation by removing energy efficiency as a resource option to determine its avoided capacity and energy costs.

The energy efficiency avoided costs include additional premium components depending on whether the program is being evaluated for Washington or Idaho. The Washington analysis (Figure 5.7) includes additional societal costs such as non-energy impacts, social cost of carbon and the Power Act's 10 percent premium adder. Washington programs also reduce the need for premium priced clean energy resources and this benefit is also factored into the analysis. The total energy avoided cost is $105.83 per MWh and $151.25 per kW-year for capacity. For Idaho (Figure 5.8) the costs considered include the avoided energy, capacity, T&D losses and avoided T&D capital. The total of these avoided costs for Idaho is $29.63 per MWh and $137.50 per kW-year for capacity[5].

**Figure 5.7: Washington Energy Efficiency Avoided Cost**



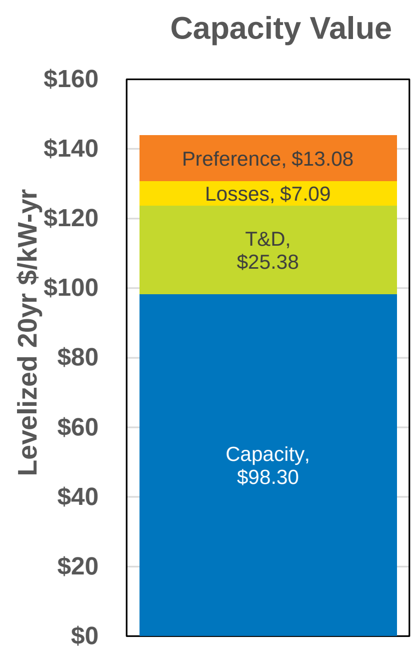
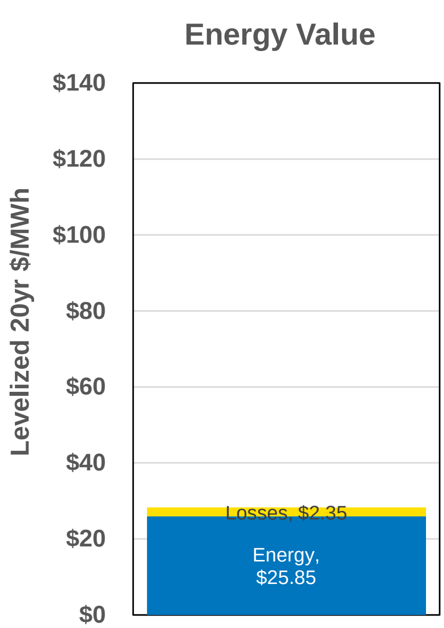
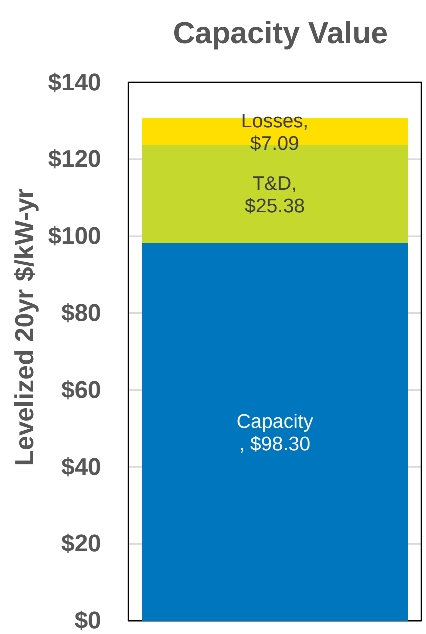




**Figure 5.8: Idaho Energy Efficiency Avoided Cost**




[5] Avista previously included the Northwest Power Act 10 percent premium for Idaho energy efficiency avoided costs. Avista chose not to include this adjustment to align all assumptions of this plan to only include measurable utility cost avoided by the utility.

# 6. Demand Response

Historically, demand response (DR) programs provide capacity at times when wholesale prices are unusually high, when a shortfall of generation or transmission occurs, or during an emergency grid-operation situation. Traditional DR, time-of-use rates, peak time rebates, direct load control programs or bi-lateral agreements are programs to incent load reductions to specific enrolled customers during such periods until the load event is over or the customer has met the contracted commitment. More recently, DR driven initiatives are providing reliable ancillary service support in wholesale markets with future expectations of providing additional services to the modern grid, becoming especially important in supporting clean energy goals.

**Section Highlights**

- Avista's demand response experience began in 2001.
- Avista contracted AEG to perform a residential and commercial demand response potential assessment for this IRP.
- This IRP studied 16 demand response programs.
- An 8-hour demand response event receives a 60 percent peak credit against peak demand.

Avista's experience with DR dates back at least to the 2001 Western Energy Crisis. Avista responded with all-customer and irrigation customer buy-back programs and bi-lateral agreements with its largest industrial customers. These programs, along with enhanced commercial and residential energy efficiency programs, reduced the need for purchases in very high-cost wholesale electricity markets. A July 2006 multi-day heat wave prompted Avista to request DR voluntarily through media outlets by asking customers to conserve energy due to the extreme regional and local temperatures not seen to that point in the Spokane Area since 1961. Avista also initiated short-term agreements with large industrial customers to curtail loads. Avista estimated those DR projects reduced loads by 50 MW during the 2006 event. After the 2006 event, Avista implemented additional short-term bi-lateral DR agreements with its largest customers for use during grid emergencies.

## 2007-2009 Residential Demand Response Pilot

The 2006 heat wave event led to Avista conducting a two-year residential load control pilot between 2007 and 2009 to study specific DR technologies and examine cost-effectiveness and customer acceptance. The DR pilot tested scalable Direct Load Control (DLC) devices based on installations in approximately 100 volunteer households in Sandpoint and Moscow, Idaho. The sample allowed Avista to test DR with the benefits of a larger-scale project, but in a controlled, measurable and customer-friendly manner. Avista installed DLC devices on residential heat pumps, water heaters, electric forced-air furnaces and air conditioners to control operation during 10 scheduled events at peak times ranging from two-to-four hours each. A separate group, within the same communities, participated in an in-home-display device study as part of the pilot. The program provided Avista and its customers experience with "near-real time" energy-usage feedback equipment. Information gained from the pilot is summarized in a report filed with the Idaho Public Utilities Commission[1].

### 2009-2014 Smart Grid Demonstration Project

Following the North Idaho DR pilot program, Avista engaged in a DR program as part of the Northwest Regional Smart Grid Demonstration Project (SGDP) with Washington State University (WSU) and approximately 70 residential customers in Pullman and Albion, Washington participated. Residential customer assets including forced-air electric furnaces, heat pumps and central air-conditioning units received a Smart Communicating Thermostat provided and installed by Avista. The DLC approach was non-traditional, meaning the DR events were not prescheduled, but rather Avista controlled customer loads through an automated process based on utility or regional grid needs while using predefined customer preferences (no more than a two degree offset for residential customers and an energy management system at WSU with a console operator). More importantly, the technology used in the DR portion of the SGDP predicted if equipment was available for participation in the control event, which provided real time feedback of the actual load reduction due to the DR event. Additionally, WSU facility operators had instantaneous feedback due to the integration between Avista and their building management system. Residential customer notifications of the DR event occurred via their smart thermostat. The SGDP began in 2009 and concluded in 2014. Avista reported information gained from this project to the prime sponsor for use in the SGDP's final project report and compilation with other SGDP initiatives[2].

Experiences from both DLC pilots showed participating customer engagement is high; however, recruiting participants was challenging. Avista's service territory has a high level of natural gas penetration meaning many customers cannot participate in typical DLC electric space and water heat programs. Additionally, customers did not seem overly interested in the DLC programs as offered. BPA found similar challenges in gaining customer interest in their regional DLC programs[3]. A 2019 Avista quantitative survey, conducted by the Shelton Group, also found customer interest to participate in DR programs to be low.

Avista paid customers direct incentives for program participation in both DLC pilots. Incentive levels were a premium to recruit and retain customers and were not intended to be scalable. Avista will need to conduct additional analysis to determine cost effective payment strategies beyond pilots to mass-market DLC programs. Where Avista is not able to harness adequate customer interest at cost-effective incentive levels, the future of DR could be more limited than assumed in this IRP.

Avista will evaluate and consider DR programs to meet future load requirements where cost effective compared to other alternatives and does not adversely influence reliability or customer satisfaction with service. To fulfill this commitment, Avista sponsored several DR potential assessment studies to identify the 20-year DR potential specific to Avista's

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[1] https://puc.idaho.gov/fileroom/cases/elec/AVU/AVUE0704/company/20100303FINAL%20REPORT.pdf
[2] https://www.smartgrid.gov/files/OE0000190_Battelle_FinalRep_2015_06.pdf.
[3] BPA's partnership with Kootenai Electric Coop, https://www.bpa.gov/EE/Technology/demand-response/Documents/20111211_Final_Evaluation_Report_for_KEC_Peak_Project.pdf.

service territory for use in its resource selection process. The first DR study occurred for the 2015 IRP in response to a 2013 IRP Action Item, and subsequent DR studies were performed for the 2017, 2020 and this IRP.

## Demand Response Potential Assessment Study

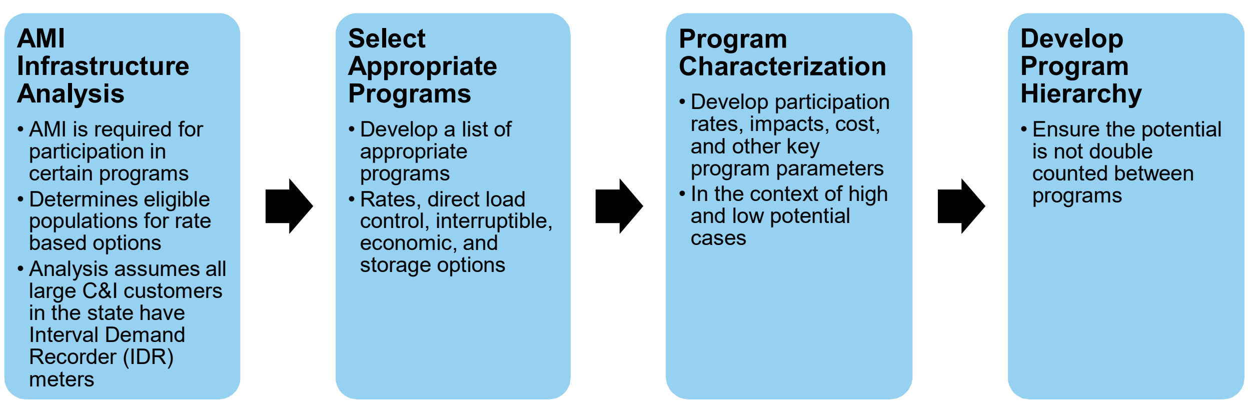
Avista retained AEG to study the potential of DR for all of Avista's service territory for the 2022–2045 planning horizon. The study primarily sought to develop reliable estimates of the magnitude, timing and costs of DR resources likely available to Avista for meeting both winter and summer peak loads. The study's focus was on resources assumed achievable during the planning horizon, recognizing market dynamics may hinder DR acquisition.

Figure 6.1 outlines AEG's approach to determine potential DR programs in Avista's service territory. Many DR programs require Advanced Metering Infrastructure (AMI) for settlement purposes. All DR pricing programs, behavioral and third-party contract DR programs included in this study require AMI as an enabling technology. AMI deployment is nearly complete in Washington at the time of this writing. AEG broadly assumed that Avista would follow with AMI metering in Idaho beginning in 2022 and assumed a two-year ramp rate for full deployment, finishing in 2024.

As with the CPA study for energy efficiency, AEG looked at Avista's customer accounts and rates schedules to characterize the market. This became the basis for customer segmentation to determine the number of eligible customers in each market segment for potential DR program participation.

The study compared Avista's market segments to national DR programs to identify relevant DR programs for analysis.

**Figure 6.1: Program Characterization Process**




This process identified several DR program options shown in Table 6.1. The different types of DR programs include two broad classifications: curtailable/controllable DR and rate design programs. Except for the behavioral program, curtailable/controllable DR programs represent firm, dispatchable and reliable resources to meet peak-period loads. This category includes Direct Load Control (DLC), Firm Curtailment (FC), thermal and battery storage and ancillary services. Avista added large industrial curtailment that was not part of the AEG study. Rate design options offer non-firm load reductions that might not be available when needed, but rather create a reliable pattern of potential load reduction. Pricing options include time-of-use and variable peak pricing. Each option requires a new rate tariff for each state in Avista's service territory.

**Table 6.1: Demand Response Program Options by Market Segment**

| DR Program | | Participating Market Segment | | | | Season Impacted | |
|---|---|---|---|---|---|---|---|
| Program Type | Program Option | Res. | Sm. Com. | Large. Com./ Ind. | Extra Large Com./ Ind. | Winter | Summer |
| Curtailable/ Controllable DR | DLC Central AC | X | X | | | | X |
| | DLC Smart Thermostat – Cooling | X | X | | | | X |
| | DLC Smart Thermostat – Heating | X | X | | | X | |
| | DLC CTA-2045 Water Heating | X | X | | | X | X |
| | DLC Water Heating | X | X | | | X | X |
| | DLC Vehicle Charging | X | | | | X | X |
| | DLC Smart Appliances | X | X | | | X | X |
| | Third Party Contracts | | | X | X | X | X |
| | Thermal Energy Storage | | X | X | X | | X |
| | Battery Energy Storage | X | X | X | X | X | X |
| | Behavioral | X | | | | X | X |
| | Ancillary Services | X | X | X | X | X | X |
| | Large Industrial Curtailment | | | | X | X | X |
| Rates | Time-of-Use Opt-in | X | X | X | X | X | X |
| | Time-of-Use Opt-out | X | X | X | X | X | X |
| | Variable Peak Pricing Rates | X | X | X | X | X | X |

# Demand Response Program Descriptions

## Direct Load Control

A DLC program targeting Avista's Residential and General Service customers in Idaho and Washington would directly control electric space heating load in winter, space-cooling load in the summer, and water heating load throughout the year with a load control switch or programmable thermostat. Central electric furnaces, heat pumps and central air-conditioners would cycle on and off during high-load events. Water heaters would completely turn off during the DR event period. Tank style, domestic electric water heaters of all sizes are eligible for control. Smart appliances included in the analysis include refrigerators, clothes washers and dryers. Typically, DLC programs take five years to ramp up to maximum participation levels.

## Third Party Contracts - Firm Curtailment

Customers participating in a firm curtailment program agree to reduce demand by a specific amount or to a pre-specified consumption level during the event in exchange for fixed incentive payments. Customers receive payments while participating in the program even if they never receive a load curtailment request while enrolled in the program. The capacity payment typically varies with the firm reliability-commitment level. In addition to fixed capacity payments, participants receive compensation for reduced energy consumption. Because the program includes a contractual agreement for a specific level of load reduction, enrolled loads have the potential to replace a firm generation resource. Financial penalties are a possible component of a firm curtailment program.

Customers with maximum demand greater than 200 kW and operational flexibility are attractive candidates for firm curtailment programs. Examples of customer segments with high participation possibilities include large retail establishments, grocery chains, large offices, refrigerated warehouses, water- and wastewater-treatment plants and industries with process storage (e.g. pulp and paper, cement manufacturing). Customers with operations requiring continuous processes, or with relatively inflexible obligations, such as schools and hospitals, generally are not good candidates for curtailment programs.

Third parties often administer firm curtailment programs and are responsible for all aspects of program implementation, including program marketing and outreach, customer recruitment, technology installation and incentive payments. Avista could also contract with a third party to deliver a fixed amount of capacity reduction for a specified number of events over a certain specified timeframe. The contracted capacity reduction and the actual energy reduction during DR events is the basis of payment to the third-party administrator.

## Thermal Energy Storage

Thermal energy storage technologies draw electricity during low demand periods and store it as ice sealed inside the unit. A variable speed fan can automatically circulate the cool air throughout a room using the stored energy (ice) rather than having to draw energy from the grid during peak times to chill the air.

This emerging technology has been primarily used in non-residential buildings and applications but may have the potential to be used in the future for residential applications as the technology advances.

### Battery Energy Storage

Battery energy storage technologies draw electricity during low demand periods and store it for use later during peak times. This study assumes energy is stored using electrochemical processes as found with lithium-ion battery equipment.

### Behavioral

A behavioral program is a voluntary reduction in response to digital behavioral messaging. These programs typically occur in conjunction with energy efficiency behavioral reporting programs and communicate the request to customers to reduce usage via text or email messages. AMI technology is needed to evaluate and measure the impact of the program for events.

### Ancillary Services

For DR providing ancillary (spinning, non-spinning, regulation) and load following services, loads need to respond within a very short notification period, typically less than 10 minutes. These “Fast DR” programs providing load following services are relevant for integrating intermittent renewable resources such a solar and wind. A subset of participants from other DR programs including Smart Thermostats – Heating/Cooling, DLC Water Heating, CTA-2045 Water Heating, Electric Vehicle Charging and Battery Energy Storage could supply these services if called upon.

### Time of Use Rates (Opt-In or Opt-Out)

A Time of Use (TOU) rate is a time-varying rate. Relative to a revenue-equivalent flat rate, the rate during on-peak hours is higher, while the rate during off-peak hours is lower. This provides customers with an incentive to shift consumption out of the higher-price on-peak hours to the lower cost off-peak hours. TOU is not a demand-response option, per se, but rather a permanent load shifting opportunity. Large price differentials are generally more effective than smaller differentials for TOU programs.

The DR study considered two types of TOU pricing options. In an opt-in rate, participants voluntarily enroll in the rate. An opt-out rate places all customers on the time-varying rate, but they may opt-out and select another rate later.

### Variable Peak Pricing

Similar to TOU pricing, variable peak pricing changes prices daily to reflect system conditions and costs. Under a variable peak pricing program, on-peak prices for each weekday are made available the previous day. Variable peak pricing bills customers for their actual consumption during the billing cycle at these prices. Over time, establishment of event-trigger criteria enables customers to anticipate events based on extreme weather or other factors. System contingencies and emergency needs are good candidates for variable peak pricing events. Variable peak pricing program participants are required to be enrolled in a TOU rate option.

### Large Industrial Curtailment

This IRP includes a 25 MW large industrial curtailment program to approximate the DR potential with one of Avista's larger industrial customers. Program sizes are likely to be around 25 MW, but there is the potential for additional load reduction depending on customers' flexibility. The concept of this program is to develop parameters for customer curtailment and compensate customers with a fixed or per curtailment amount.

For additional detail on the various DR program characteristics, see chapter 6 of the 2020 CPA. AEG's DR potential assessment is also included in Appendix E.

## Demand Response Program Participation

The steady-state participation assumptions rely on an extensive database of existing program information and insights from market research results and represent "best-practices" estimates for participation in these programs. The industry commonly follows this approach for arriving at achievable potential estimates. However, practical implementation experience suggests that uncertainties in factors such as market conditions, regulatory climate, economic environment and customer sentiments are likely to influence customer participation in DR programs.

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

Table 6.2 shows the steady-state participation rate assumptions for each DR program option. Space cooling is split between DLC Central AC and Smart Thermostat options.

**Table 6.2: DR Program Steady-State Participation Rates (% of eligible customers)**

| DR Program | Residential Service | General Service/ Small Commercial | Large General Service | Extra Large General Service |
|---|---|---|---|---|
| Direct Load Control (DLC) of central AC | 10% | 10% | - | - |
| DLC of domestic hot water heaters (DHW) | 15% | 5% | - | - |
| Smart Thermostats DLC Heating | 5% | 3% | - | - |
| CTA-2045 hot water heaters | 50% | 50% | - | - |
| Smart Thermostats DLC Cooling | 20% | 20% | - | - |
| Smart Appliances DLC | 5% | 5% | - | - |
| Third Party Contracts | - | 15% | 22% | 21% |
| Electric Vehicle DLC Smart Chargers | 25% | - | - | - |
| Time-of-Use Pricing Opt-in | 13% | 13% | 13% | 13% |
| Time-of-Use Pricing Opt-out | 74% | 74% | 74% | 74% |
| Variable Peak Pricing | 25% | 25% | 25% | 25% |
| Thermal Energy Storage | - | 0.5% | 1.5% | 1.5% |
| Battery Energy Storage | 0.5% | 0.5% | 0.5% | 0.5% |
| Behavioral | 20% | - | - | - |

## Demand Response Potential and Cost Assumptions

Each DR program used in this evaluation was assigned an average load reduction per participant per event, an estimated duration of each event, and a total number of event hours per year. Costs were also assigned to each DR program for annual marketing, recruitment, incentives, program development and administrative support. These resulted in potential demand savings and total cost estimates for each program independently or on a standalone basis.

This approach does not account for participation overlaps among DR options targeted at the same customer segment and therefore savings and cost results for individual DR programs are not additive. The standalone analysis results provide a comparative assessment of individual DR program demand savings and costs and are useful for selecting programs for a DR portfolio.

If Avista offers more than one program, then the potential for double counting exists. To address this possibility, a participation hierarchy was assumed and defines the order customers take the programs for an integrated approach. These savings and costs results were then used in Avista's modeling. For additional detail on DR resource assumptions used in developing potential savings and cost results, see Chapter 6 of the 2020 CPA.

## Achievable Potential Estimates

Two DR potential programs for TOU were reviewed for Avista's load. The first is Time of Use (TOU) rates as opt-in. This means customers sign up for a time-based rate schedule versus the second potential study where customers must opt out of the new potential rate schedule. Because TOU rates change customer behavior, the amount of DR savings differs between how many customers have this rate schedule. For this IRP, the potential study results use the TOU Opt-in scenario in the integrated savings and costs since it is more likely Avista may offer a TOU Opt-in program rather than a TOU Opt-out program should a pricing program be implemented. Figures 6.2 and 6.3 show demand savings from all available individual DR programs from DR options in Avista's Idaho and Washington service territories.

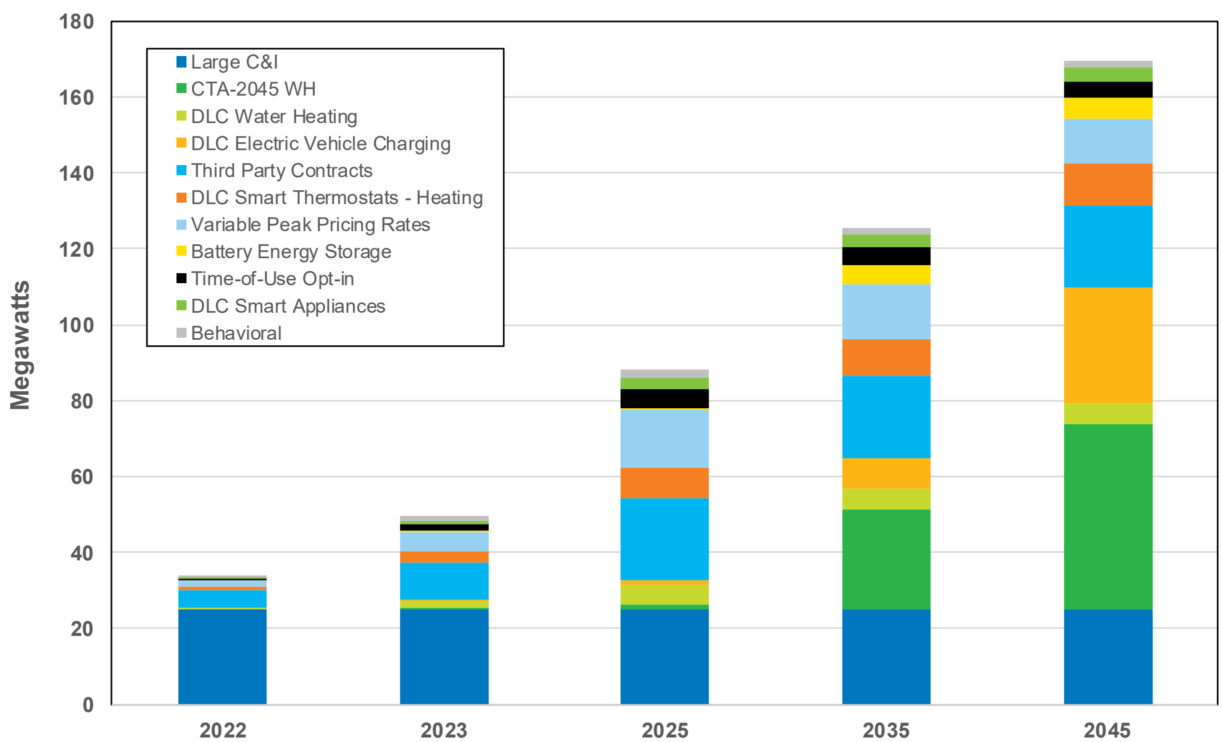
Additional detail for these programs including specific cost and savings is included in Tables 6.3 and 6.4. The cost of the programs within these tables represent the on-going operations and capital cost required to start and maintain these programs. The capital costs are amortized and recovered over a 10-year period. The costs included are the first 10 years levelized as if the program begins in 2022. These tables include the estimated potential megawatt savings for 2031 and 2045. These estimates are the expected amount of demand reduction from all program participants. Although, Avista will require a higher amount of contracted load to achieve these savings. The Maximum Impact Percentage column is the amount of additional MW shown as a percentage of additional load required to meet the expected demand reduction. For example, to achieve the 4.3 MW of reduction from Time of Use rates would require nearly three times the amount of capacity under contract.

## Winter Demand Response Savings Potential

Key findings:

- The highest potential option is the CTA-2045 WH water heater program which is expected to reach a savings potential of 48.9 MW by 2045.
- The next three biggest potential DR options in winter include DLC Electric Vehicle Charging (30.2 MW in 2045), Third Party Contracts (21.9 MW) and Variable Peak Pricing Rates (12.5 MW).
- Since most of the participants are likely to be on the VPP rate in the TOU Opt-in scenario, the TOU potential (4.3 MW in 2045) is significantly lower than in the TOU Opt-out case where 17.8 MW of winter peak load would be reduced by this program.
- The total potential savings in the winter TOU Opt-in scenario are expected to increase from 9.3 MW in 2022 to 145 MW by 2045. The respective increase in the percentage of system peak goes from 0.7 percent in 2022 to 10.0 percent by 2045.

**Figure 6.2: Demand Response Achievable Potential (Winter MW)**




## Winter Demand Response Costs

In addition to levelized costs, 2031 savings potential from DR options are represented for reference.

Key findings:

- The third-party contracts option delivers the highest savings in 2031 at approximately $96/kW-year cost. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option. All O&M and administrative costs are expected to be incurred by the representative third-party contractor.

- The Variable Peak Pricing (VPP) option has the lowest levelized cost among all the DR options. It delivers 15.5 MW of savings in 2031 at $33/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of VPP deployment costs.

**Table 6.3: DR Program Costs and Potential – Winter TOU Opt-In**

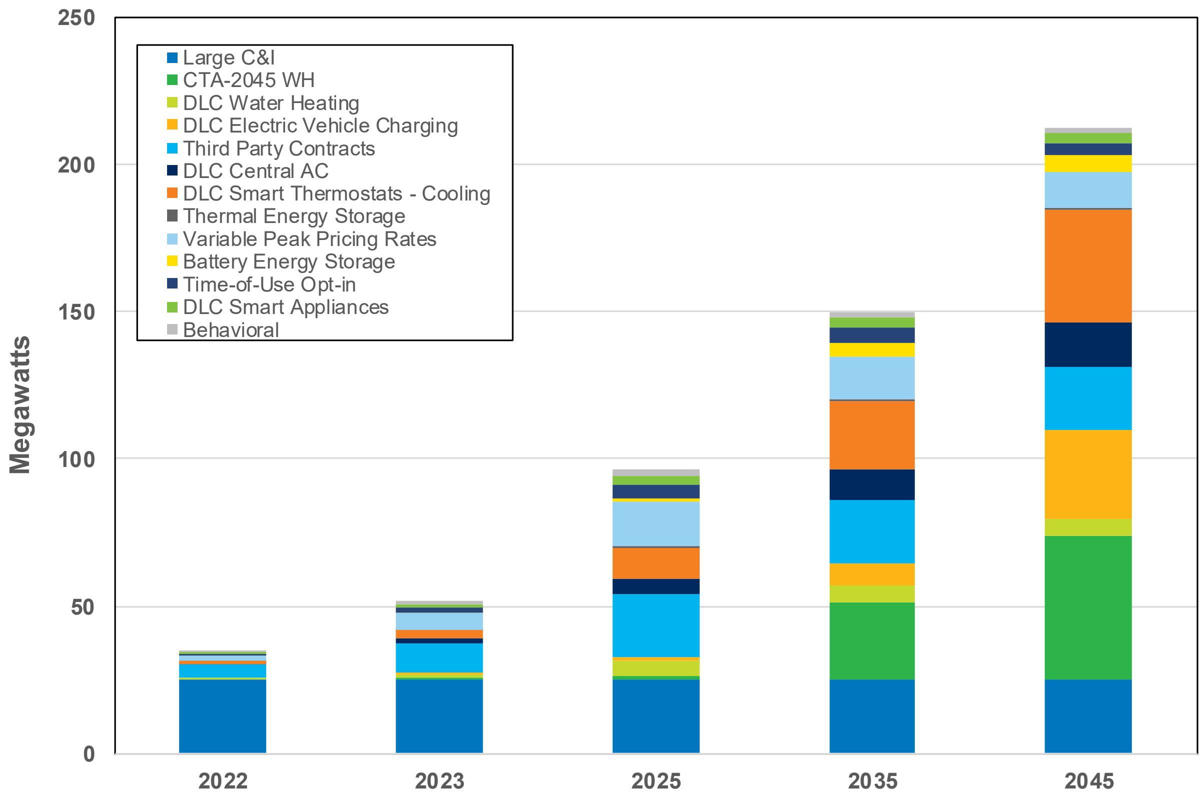
| DR Option | Levelized $/kW (2022-2031) | System Winter Potential MW in 2031 | System Winter Potential MW in 2045 | Maximum Impact Potential |
|---|---|---|---|---|
| Battery Energy Storage | $483 | 2.8 | 5.6 | 100% |
| Behavioral | $210 | 2.2 | 1.7 | 101% |
| CTA-2045 WH | $122 | 17.6 | 48.9 | 144% |
| DLC Electric Vehicle Charging | $353 | 3.9 | 30.2 | 137% |
| DLC Smart Appliances | $295 | 3.2 | 3.7 | 101% |
| DLC Smart Thermostats - Heating | $92 | 9.5 | 10.9 | 286% |
| DLC Water Heating | $213 | 5.5 | 5.5 | 144% |
| Third Party Contracts | $96 | 21.9 | 21.9 | 101% |
| Time-of-Use Opt-in | $83 | 5.2 | 4.3 | 300% |
| Variable Peak Pricing Rates | $33 | 15.5 | 12.5 | 282% |

## Summer Demand Response Savings Potential

Key findings:

- The highest potential option is DLC Smart Thermostats, which is expected to reach savings potential of 61 MW by 2045.
- The next two biggest potential options in summer include CTA-2045 WH (48.9 MW in 2045), DLC Electric Vehicle Charging (30.2 MW) and DLC Central AC (24.5 MW).
- Two space cooling options- DLC Smart Thermostat and DLC Central AC – are expected to contribute a combined 86 MW by 2045.
- Total potential savings in the summer TOU Opt-in scenario are expected to increase from 11.3 MW in 2022 to 220 MW by 2045. The respective increase in the percentage of system peak increases from 0.8 percent in 2022 to 15.4 percent by 2045.

**Figure 6.3: Demand Response Achievable Potential (Summer MW)**




## Summer Demand Response Costs

In addition to levelized costs, 2031 savings potential from DR options are represented for reference.

Summer DR Key findings:

- DLC Smart Thermostats deliver the highest savings in 2031 (28.68 MW) at approximately $159/kW-year. Capacity-based and energy-based payments to the third-party constitutes the major cost component for this option. All O&M and administrative costs are expected to be incurred by the representative third-party contractor.
- The Variable Peak Pricing (VPP) option has the lowest levelized cost among all the DR options. It delivers 15.5 MW of savings in 2031 at $33/kW-year system wide. Enabling technology purchase and installation costs for enhancing customer response is a large part of VPP deployment costs.

**Table 6.4: DR Program Costs and Potential – Summer TOU Opt-In**

| DR Option | Levelized $/kW (2022-2031) | System Summer Potential MW in 2031 | System Summer Potential MW in 2045 | Maximum Impact Potential |
|---|---|---|---|---|
| Battery Energy Storage | $483 | 2.8 | 5.6 | 100% |
| Behavioral | $210 | 2.2 | 1.7 | 101% |
| CTA-2045 WH | $122 | 17.6 | 48.9 | 144% |
| DLC Central AC | $83 | 12.7 | 24.5 | 492% |
| DLC Electric Vehicle Charging | $353 | 3.9 | 30.2 | 137% |
| DLC Smart Appliances | $295 | 3.2 | 3.7 | 101% |
| DLC Smart Thermostats - Cooling | $159 | 28.7 | 61.0 | 494% |
| DLC Water Heating | $213 | 5.5 | 5.5 | 144% |
| Thermal Energy Storage | $800 | 0.7 | 0.6 | 101% |
| Third Party Contracts | $96 | 21.9 | 21.9 | 101% |
| Time-of-Use Opt-in | $73 | 5.2 | 4.3 | 300% |
| Variable Peak Pricing Rates | $33 | 15.5 | 12.5 | 274% |

The value of these programs in meeting Avista's capacity needs is calculated in the Avista IRP modeling process using the magnitude of DR program potential and the estimated costs provided by AEG. In addition, Avista assigns a DR peak credit as described below.

## Demand Response Peak Credit

For reliability planning, Avista translates the peak savings identified by AEG into a peak credit, meaning the percentage of the capacity each option contributes to meeting Avista reliability criteria in peak load periods. An Effective Load Carrying Capability (ELCC) analysis is performed to determine the peak credit. Refer to Chapter 9 for a more in-depth discussion of Avista's ELCC methods. A DR program's assigned peak credit will differ depending on its duration. Programs interrupting loads for longer periods will receive larger peak credits, but the peak credit depends on if there is a "snap back" effect when the DR event is over. Loads without a snap back effect shed load permanently whereas loads exhibiting the snap back effect are higher later due to recovery from the earlier reduction from the DR program. Avista only had adequate time to conduct generic DR programs assuming up to eight hours of load reduction. This analysis results in a 60 percent peak credit for a continuous 8-hour DR load reduction. Avista concludes this is a result of limited energy reduction when Avista needs winter energy in addition to winter peak reductions. Avista will need to conduct further DR peak credit analysis in future IRPs.

# 7. Long-Term Position

This chapter describes the analytical framework used to develop Avista's net load and resource position. It describes reserve margins held to meet peak loads, risk-planning metrics used to meet hydro variability and plans to meet renewable goals set by Washington's Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA).

Avista has unique attributes affecting its ability to meet peak load requirements. While it connects to several neighboring utility systems across its large service territory, it comprises only 5 percent of the total Northwest regional load. Annual peaks can occur either in the winter or in the summer; but Avista is still winter peaking on a planning basis due to periods of extreme cold weather conditions. The winter peaks generally occur in December or January but may also occur in November or February. As described in Chapter 4 – Existing Supply Resources, Avista's resource mix contains roughly equal amounts of hydro and thermal generation. Hydro resources meet most of Avista's flexibility requirements needed for load and intermittent generation, though thermal generation is playing a larger role as load growth and intermittent generation increase flexibility requirements.

**Section Highlights**

- Avista's first long-term capacity deficit net of energy efficiency is in 2026 at 12 MW, increasing to 301 MW in 2027; the first energy deficit is also in 2026.
- By 2022, clean resource generation meets 75 percent of retail sales.
- The regional resource adequacy situation is at risk due to planned coal plant retirements and load growth without the addition of new capacity resources.

## Reserve Margins

Planning reserves accommodate situations when load exceeds and/or resource output falls below expectations due to adverse weather, forced outages, poor water conditions or other unplanned events. Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves because of the cost of carrying rarely used generating capacity. Reserve resources have the physical capability to generate electricity, but most have high operating costs that limit normal dispatch and revenue.

There is no industry standard reserve margin level, as it is difficult to enforce standardization across systems with varying resource mixes, system sizes and transmission interconnections. NERC defines reserve margins as 15 percent for predominately thermal systems and 10 percent for predominately hydro systems[1], but does not provide an estimate for energy-limited hydro systems like Avista.

Since Avista and the region's hydro system is energy constrained, the 10 or 15 percent metrics suggested by NERC do not adequately account for the Company's load and

[1] http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

resource variations. Beyond planning margins defined by NERC, a utility must maintain operating reserves to cover generator forced outages to maintain grid stability. Avista includes operating reserves in addition to a planning margin. Per Western Electric Coordinating Council (WECC) requirements, Avista must maintain 3 percent for balancing of area load and 3 percent for on-line balancing area generation. Within this quantity, 24 megawatts must also qualify as Frequency Response Reserve (FRR). Avista must also maintain reserves to meet load following and regulation requirements of within-hour load and generation variability equivalent to 16 MW at the peak hour.

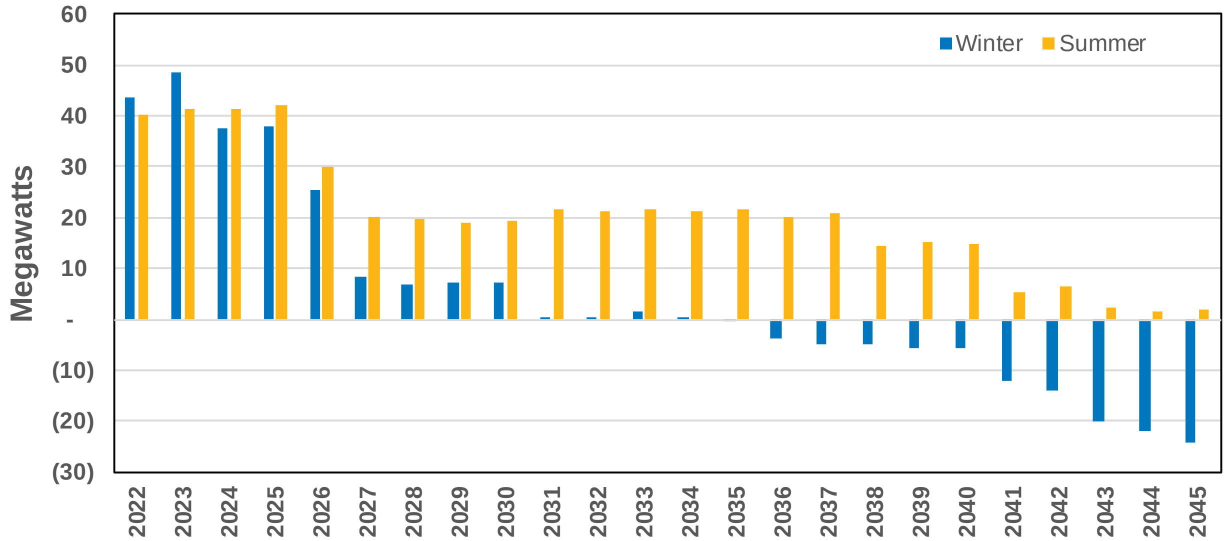
Avista's planning margin in the 2020 IRP was 16 percent[2] in the winter (October through April) and 7 percent in the summer (May through September). Adding operating and load following reserves increased the totals to 24.6 and 15.6 percent, respectively. This was a result of a study of Avista resources and loads using 1,000 simulations varying weather for loads and thermal generation capability, forced outage rates on generation, water conditions for hydro plants and wind generation. The reserve levels ensured Avista's system could meet all expected load in 95 percent of the simulations, a 5 percent loss of load probability (LOLP).

The northwest region began investigating a resource adequacy program in 2019. As part of this effort, a consultant (E3) developed tools to identify planning margins each utility should be meeting absent a regional resource adequacy program and planning margins with a resource adequacy program. Avista used this analysis to validate its current planning margin. This independent analysis suggests utilities use a 1-in-2 load forecast, as Avista does, a 16 percent planning margin on this load forecast, and then derate resources using a peak credit to account for forced outages and energy limitations. The only difference between the E3 methodology and Avista's current method is Avista assumes a higher planning reserve margin to account for operating reserves rather than derating its facility's peak credit. A comparison between the two methods is shown in Figure 7.1. Avista's method shows the system longer in the early years, but shorter in the winter and nearly the same in the summer by the end of the study. Given Avista peak load is near 1,800 MW, the differences between the two methods are relatively small.

The intent of the proposed Regional Resource Adequacy Program is to allow for lower planning margins to reduce customer cost while ensuring the region is building adequate resources to meet expected load plus contingencies. Avista conducted a scenario to show the financial benefit of this program in Chapter 12. Given this information, Avista's planning margin criteria is within standard utility practice; but it is at risk as regional market power may not be available in quantities required if other utilities do not also provide their share of capacity to the region. Avista models up to 330 MW of market reliance to satisfy its 5 percent LOLP.

[2] Avista's PRS used an 18 percent planning margin to overcome peak credits for storage and intermittent resources that were too low.

**Figure 7.1: Stand Alone Northwest Utility vs. Avista's L&R Methodology**




## Balancing Loads and Resources

The single-hour future load and resource projection is a simple method to identify shortages when adjusted by a planning reserve margin. It is used in Avista's resource selection model, but also to provide a review of system resource adequacy. The one-hour peak does not consider sustained peaking events where Avista's hydro system or a future storage system cannot continually deliver energy over multiple peak hours, such as a week of extreme cold weather. To ensure reliance on a one-hour metric does not compromise system reliability, Avista conducts a detailed hourly reliability study to validate whether the planning margin also satisfies other potential resource shortfalls. This analysis informs the creation of a planning reserve margin to include in the single peak hour analysis. Avista's single hour peak winter load and resource position are shown in Figure 7.2. In this illustration, Avista includes Colstrip Units 3 and 4 through the end of 2025, though Avista is uncertain when Colstrip will exit its portfolio under the current ownership agreement. With this assumption, the first significant winter capacity deficit occurs in January 2026 with a 12 MW deficit and quickly escalates to 301 MW in 2027 after the Lancaster contract expires in October 2026.

Avista plans to meet summer peak load with a smaller planning margin than in the winter. Summer months include operating reserve and regulation obligations in addition to a 7 percent planning margin (see Figure 7.3). Avista uses a smaller planning margin in the summer months due to less variation in summer peak load levels and reliability planning analysis showing no summer adequacy issues when Avista addresses its larger winter peak requirements. Market purchases should satisfy any weather-induced load variation or generation forced outage that otherwise would be included in the planning margin as is the case with the higher winter planning margin. In this comparison, Avista's first summer deficit occurs in 2027 at 171 MW.

Figure 7.2: Winter One-Hour Peak Capacity Load and Resources Balance

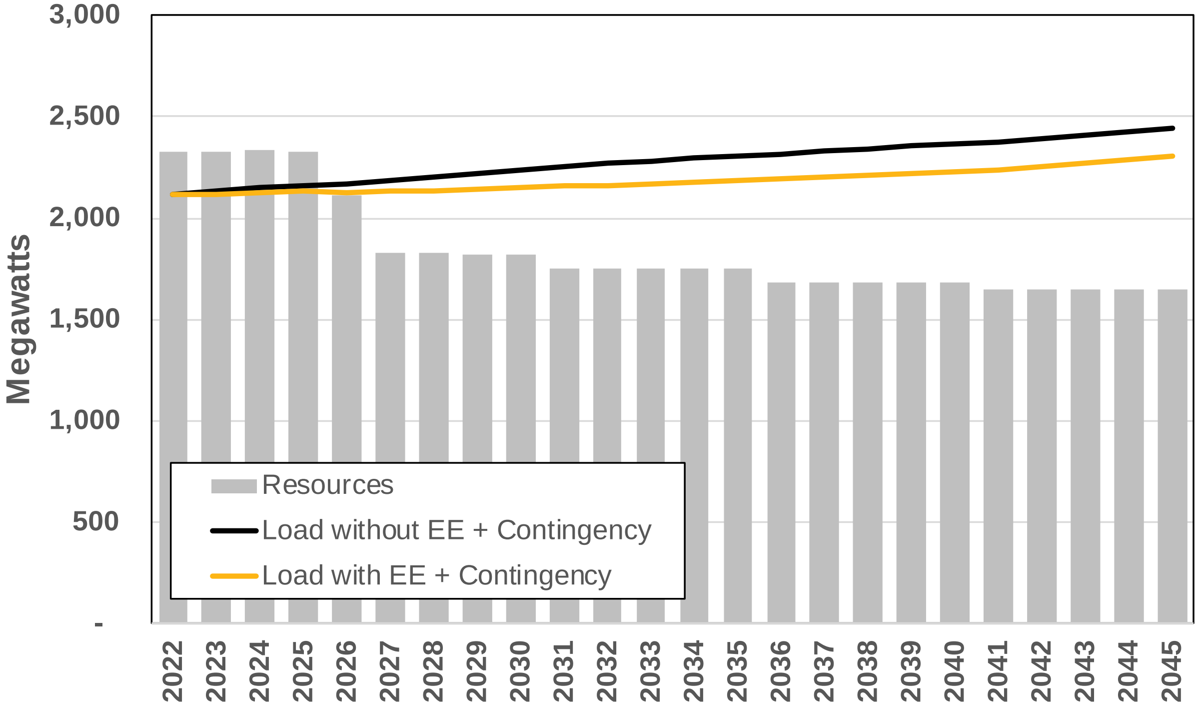
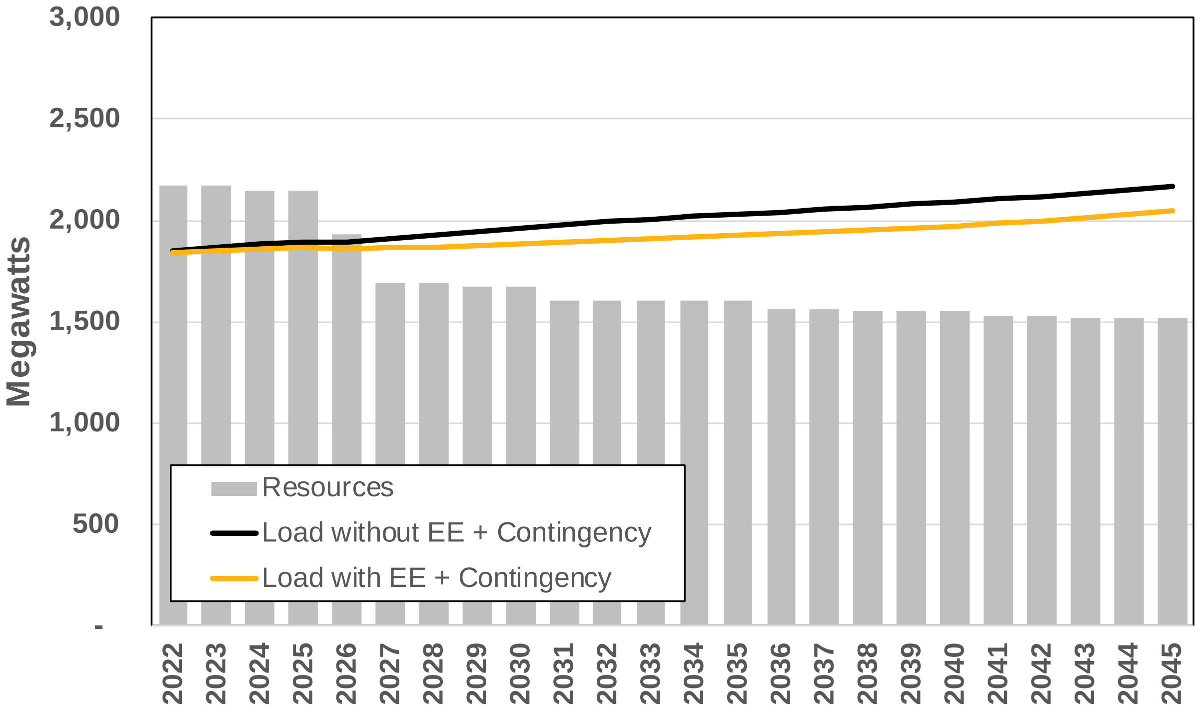



Figure 7.3: Summer One-Hour Peak Capacity Load and Resources Balance

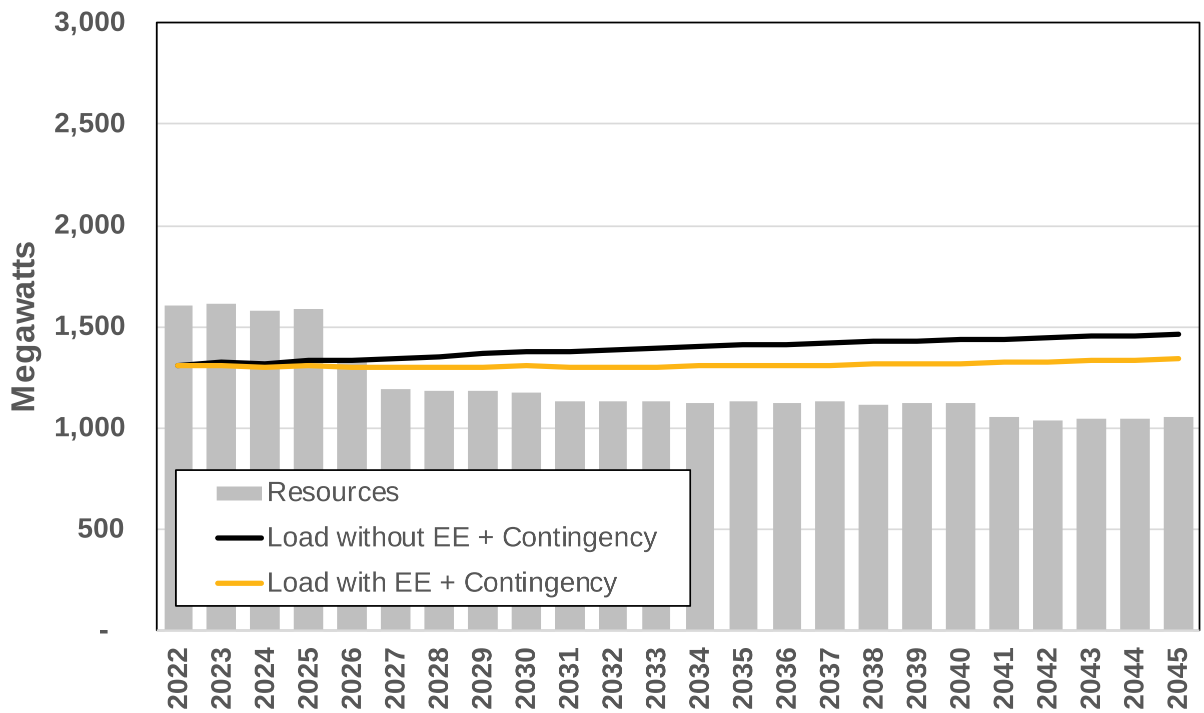


## Energy Planning

For energy planning, resources must be adequate to meet customer requirements even when loads are high for extended periods, or sustained outages limit the contribution of one or more resources. Where generation capability is inadequate to meet these variations, customers and the utility must rely on the short-term electricity market. In addition to load variability, Avista holds energy-planning margins for variations in month-to-month hydro generation.

As with capacity planning, there are no defined methods for establishing an energy-planning margin. Many utilities in the Northwest base their energy planning margins on the amount of energy available during the "critical water" period of 1936/37.[3] The critical water year of 1936/37 is low on an annual basis, but it does not represent a low water condition in every month of that hydro year. The IRP could target resource development to reach a 99 percent confidence level to deliver energy to its customers to significantly decrease the frequency of market purchases. However, this strategy requires investments in approximately 200 MW of generation in addition to the capacity planning margins included in the Expected Case. Investments to support this high level of reliability would increase pressure on retail rates for a modest reliability benefit. Avista plans to the 90th percentile for hydro generation. Using this metric, there is a one-in-ten chance of needing to purchase energy from the market in any given month over the IRP timeframe due solely to a shortage of available generation from its hydro resources. Avista uses the annual average of the monthly position shown in Figure 7.4 to set a minimum energy acquisition target.

Figure 7.4: Annual Average Energy Load and Resources

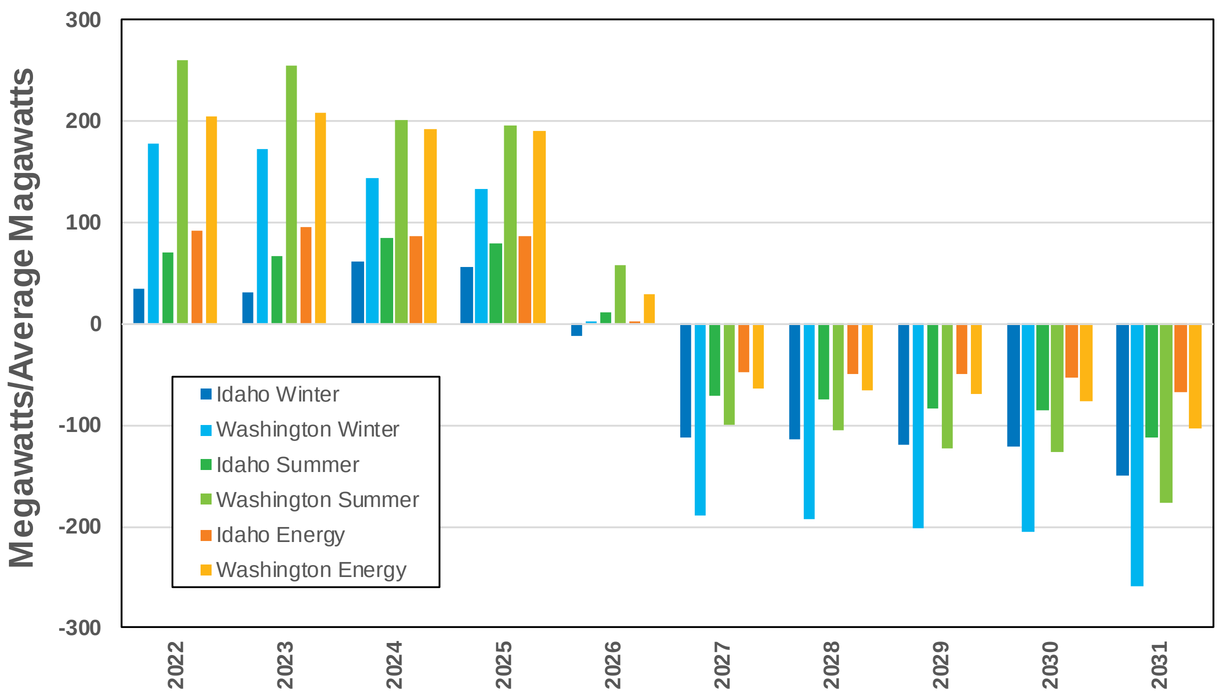



[3] The 1936/37 critical water year represents the lowest historical generation level in the streamflow record.

### State Level Planning

Avista separates capacity and energy targets in the 2021 IRP between Idaho and Washington. This split ensures Avista acquires new resources to meet specific state goals when needed and allows for tracking of costs to be assigned to each state as necessary to meet its goals. This methodology extends to reliability targets. Avista split loads and costs for resources using the Production-Transportation ratio (PT ratio) for resources planned for use by both states. The PT ratio is approximately 65 percent Washington and 35 percent Idaho. The method excludes a large PURPA facility and its load which are directly assigned to Idaho. All PURPA generation is assigned to the state where its contract was approved. The portfolios identified in Chapters 11 and 12 show how each resource is assigned to either or both states. Figure 7.5 shows each state's position for winter, summer and annual energy. The state level data follows the system level data as presented earlier, though a small difference exists due to the unique arrangement of the Idaho large load and associated PURPA generation identified above.

**Figure 7.5: State Level Load and Resource Position by State**




## 2021 IRP Resource Adequacy Assessment

Serving customers with an adequate resource supply is challenging without new capacity resources. Table 7.1 shows the probability of load loss in each month absent resource additions based on 1,000 simulations. Each "simulation" not able to serve all load with existing resources plus up to 330 MW of market purchases expected to be available to Avista is considered a loss of load event. This methodology is termed a Loss of Load Probability (LOLP) analysis. With Colstrip included through 2025, Avista is resource adequate, but without the two coal units the Company exceeds the 5 percent LOLP limit. The table shows a 21 percent probability of lost load in 2030 to represent the additional loss of Lancaster in 2026. By 2040, this shortfall increases to 81.4 percent.

Table 7.1: LOLP Reliability Study Results without New Resources

| Month | 2025 with Colstrip | 2025 without Colstrip | 2030 | 2040 |
|---|---|---|---|---|
| Jan | 0.6% | 2.7% | 10.5% | 32.7% |
| Feb | 0.1% | 0.6% | 4.2% | 15.0% |
| Mar | 0.0% | 0.0% | 0.5% | 2.9% |
| Apr | 0.0% | 0.0% | 0.0% | 0.0% |
| May | 0.0% | 0.0% | 0.0% | 0.0% |
| Jun | 0.0% | 0.0% | 0.0% | 0.1% |
| Jul | 0.0% | 0.3% | 1.7% | 33.0% |
| Aug | 0.0% | 0.1% | 0.6% | 30.5% |
| Sep | 0.0% | 0.0% | 0.0% | 0.9% |
| Oct | 0.0% | 0.0% | 0.0% | 0.5% |
| Nov | 0.0% | 0.0% | 0.7% | 5.0% |
| Dec | 0.8% | 3.2% | 7.1% | 17.1% |
| Annual | 1.4% | 6.3% | 21.2% | 81.4% |

To resolve the lost load, the IRP identifies the addition of 333 MW of winter capability, or a 16 percent planning margin, would reduce the LOLP to 5 percent on an annual average basis by 2030. This analysis assumes Avista could acquire up to 500 MW from the market in non-regionally stressed hours and 330 MW in regionally stressed hours recognizing that the market is not unlimited. Regionally stressed hours occur when Avista's average daily temperature exceeds the 99$^{th}$ percentile. This happens in days where the average temperature is 2 degrees Fahrenheit or lower in the winter, and 83 degrees or higher in the summer. Placing limits on market reliance is a difficult exercise and may seem arbitrary given the difficultly in its quantification due to regional load diversity and the surplus capability of each regional utility or independent power producer. Avista revised its market reliance in this IRP up to 330 MW from 250 MW used in previous IRPs. This market assumption change ensures the 16 percent winter planning margin achieves a 5 percent LOLP. While this change assumes greater market reliance, it also results in lower customer cost. The change is informed by regional work discussed in other parts of this report indicating that higher market reliance is possible under a regional capacity planning effort.

## Resource Adequacy Risk Assessment

Future planning of resource adequacy requires consideration of many risks. Avista is utilizing the risks identified by the November 2020 paper Implications of Regional Resource Adequacy Program on Utility Integrated Resource Planning[4] to detail how Avista manages these risks. While Avista's identified 2026 resource deficit is not likely to change since the deficit is driven by the expiration of a purchase power agreement, the risks outlined below will impact the ultimate resource need.

[4] Implications of a regional resource adequacy program on utility integrated resource planning https://www.westernenergyboard.org/wp-content/uploads/11-2020-LBNL-WIEB-regional-resource-adequency-and-utility-integrated-resource-planning-final-paper.pdf.

### Peak Demand Forecast

Avista uses a 1--in-2 peak load forecast, meaning half of the time the load will be above and half the time load will be below the peak forecast. The forecast is based on historical weather conditions. These same weather conditions are used in reliability planning that drives the planning margin used to account for these risks. While weather is considered in the unknown nature of future loads, there are also other load risks the Company considers in scenario analysis. These potential changes are from economic impacts, electrification and increased customer owned generation. Avista conducted analysis on portfolio changes for these risks in Chapter 12 of this IRP to understand the implication to load and the resources needed.

### Demand-Side Resource Contribution

Avista includes demand-side resources as options when determining the amount and type of resources needed to meet future demand, but demand side resources may also impact the net demand of the system prior to this inclusion. For example, roof top solar may reduce Avista's summer energy needs, but have limited impact on winter loads. To address this risk, Avista includes an estimate of new customer owned generation in its load forecast and performed scenario analysis in prior IRPs. The greatest risk to uncertainty regarding demand-side resources is whether they will impact winter peak load requirements and given today, most additions are solar, this risk is low. If customers begin to install a winter load impacting resources, Avista will need to reconsider the risk at that time.

### Power Plant Retirement

To address the uncertainty of power plant retirements, Avista conducted two scenarios to understand the reliability implications of Colstrip exiting the portfolio along with including other potential resource retirements in long run reliability studies.

### Renewable Contribution

Increasing renewable penetrations will impact the reliability of the power system if utilities estimate their contributions too high. Avista found in the 2020 IRP it needed additional resources to maintain the 5 percent LOLP when relying on renewable resources to meet its peak loads. This concept can also be related to the Peak Credit analysis or Effective Load Carrying Capability (ELCC) analysis discussed in Chapter 9. The issue is if increasingly correlated intermittent resources are added to the system, the value they contribute to reliability "peak credit" declines. Other ELCC studies have shown this same effect[5]. Avista found this was an issue in the last IRP for Montana wind and conducted further analysis in this IRP to have a reducing peak credit as more resources are added to the system. While this is an issue for other resources evaluated, the Montana wind resource is more impactful due to the high peak credit it receives compared to other resources.

### Storage Efficiency

Avista sees two risks for storage efficiency. The first risk is similar to the renewable contribution described above where short duration resources may help reliability in small

[5] Such as E3's Resource Adequacy in the Pacific Northwest Study.

increments, but the reliability benefit is reduced as more storage is added to the system due to the need to recharge the storage device after use. The second risk of storage is the efficiency to recharge the device. Not all storage technologies have the same recharging ability based on energy losses and time to recharge; therefore, each of these considerations should be included in determining each device's peak credit. Avista has begun this analysis as shown in Chapter 9, but due to the multitude of storage configurations and technologies, this analysis will be an ongoing exercise.

## Market Availability

Avista found market availability to be the greatest risk in resource adequacy absent a resource adequacy market or program. As described earlier, Avista limits market purchases to 330 MW in critical time periods to avoid placing significant reliance on a market that may or may not have enough resources available. Part of this risk is not only resource availability, but also load diversity with the region as loads are not perfectly correlated across the northwest.

Avista conducted an analysis to understand the benefits of regional load diversity, as shown in Figure 7.6. Regional load is compared to Avista Balancing Authority (BA) load for the top 98$^{th}$ percentile daily peak loads since 2010. This data showed an increasing relationship between Avista load and regional loads, but the R-squared is low at 36 percent, indicating a weak correlation. In addition, when the maximum regional load was nearly 34,884 MW, Avista's BA load was approximately 10 percent below its maximum. Avista found in these top load hours the regional load range is 3,835 MW. When considering only Avista's 99$^{th}$ percentile load and above the regional range is 3,027 MW. This analysis illustrates the current load diversity in the region and indicates Avista can rely on market purchases for a share of its peak load needs if the region has adequate resources to meet the regional coincident peak load.

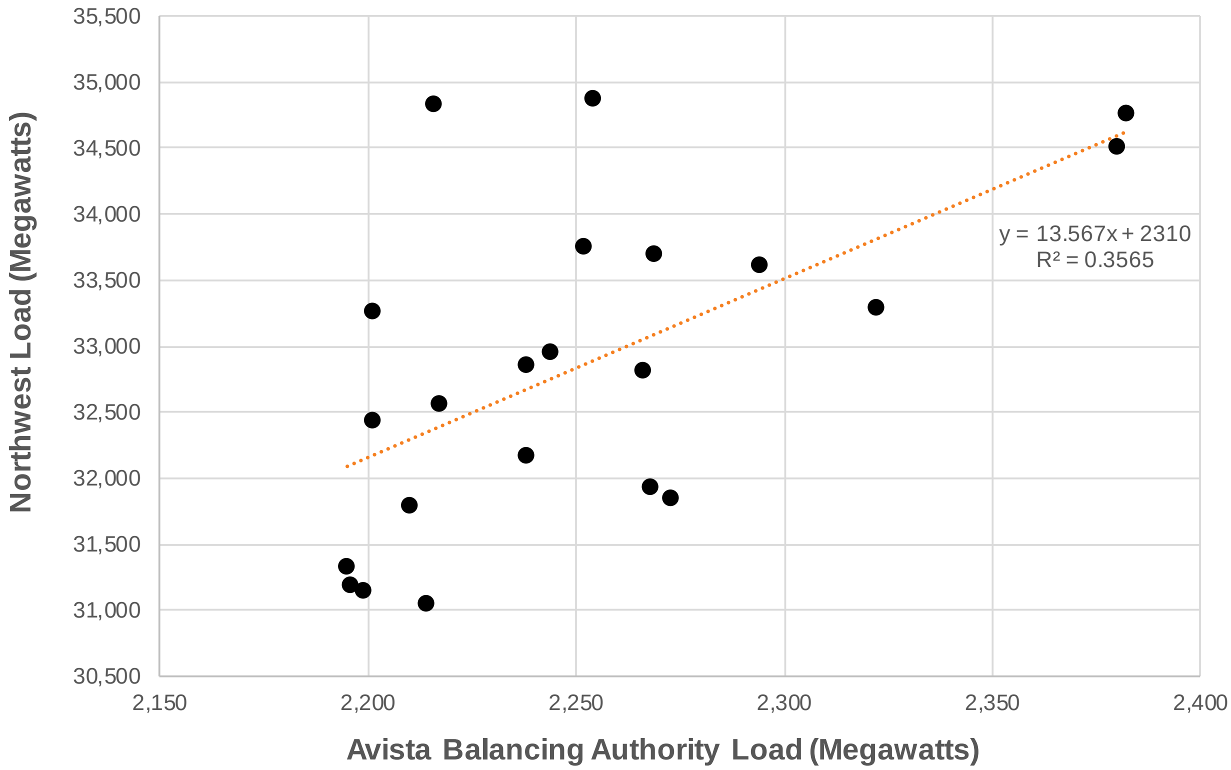
The issues presented here show why the region is pursuing a resource adequacy program to ensure the region has adequate resource capability and that each utility is providing its fair share of capacity. Another benefit from an IRP planning perspective is the identification of a clear and regionally consistent planning margin requirement and peak credits.

## Resource Acquisition

When utilities have a need for new supply-side resources, the utility has two paths to add generation. The utility can add existing generation owned by other utilities or independent power producers if available or it can acquire new resources through either a PPA or ownership. Given the timelines for construction and permitting, Avista plans to issue RFPs to acquire new resources with enough time to overcome any potential obstacles of new generation construction and allow for the potential purchase of existing generation with prior off-taker agreements ending. The results of an RFP may cause timing differences between the forecasted need and the acquisition date. While acquiring a resource ahead of need may cause rate pressure, it may also eliminate risks such as construction delays. If the existing resource is available after the need, the Company will have to find a short-term solution to meet the resource deficit prior to a new resource becoming available.

This short-term solution may increase risk to customers but may be at a lower cost alternative then building resources at the time of need.

**Figure 7.6: Avista versus Regional Loads (98th percentile)**




# Washington State Renewable Portfolio Standard

Washington's EIA promotes the development of regional renewable energy by requiring utilities with more than 25,000 customers to source 15 percent of their energy from qualified renewables by 2020. Utilities must also acquire all cost-effective conservation as explained in Chapter 5 – Energy Efficiency. In 2011, Avista signed a 30-year PPA with Palouse Wind to help meet the EIA goal. In 2012, an amendment to the EIA allowed Avista's Kettle Falls project to qualify toward the EIA goals beginning in 2016. More recently Avista acquired the Rattlesnake Flat wind project and Adams Nielson Solar[6] project, both of which qualify for EIA and CETA compliance.

Table 7.2 shows the forecasted renewable energy credits (RECs)[7] Avista needs to meet the EIA renewable requirement and the amount of qualifying resources already in Avista's generation portfolio. This table does not reflect the additional flexibility available for the REC banking provision in the EIA. Avista uses this banking flexibility as needed to

[6] Adams Neilson will be used for the EIA after the Solar Select program ends.
[7] These RECs are qualifying RECs within Avista's system. For state compliance purposes the Company may transfer RECs between a state's allocation shares at market prices. Avista may also sell excess RECs to reduce customer rates.

manage variation in renewable generation. After 2030, the renewable energy obligation to meet the EIA is met, as long as Avista is compliant with the requirements of CETA.

**Table 7.2: Washington State EIA Compliance Position Prior to REC Banking (aMW)**

| | 2022 | 2025 | 2030 |
|---|---|---|---|
| Two-Year Rolling Average WA Retail Sales Estimate | 632.8 | 651.5 | 660.7 |
| | | | |
| Renewable Goal | 94.9 | 97.7 | 99.1 |
| Incremental Hydro | 14.4 | 14.4 | 14.4 |
| **Net Renewable Goal** | 80.5 | 83.3 | 84.7 |
| | | | |
| ***Other Available RECs*** | | | |
| Palouse Wind with Apprentice Credits | 45.9 | 45.9 | 45.9 |
| Kettle Falls | 33.4 | 33.4 | 33.4 |
| Rattlesnake Flat[8] | 55.2 | 55.2 | 55.2 |
| Adams Neilson Solar | - | - | 5.5 |
| **Net Renewable Position (before rollover RECs)** | **54.1** | **51.2** | **55.4** |

## Washington State Clean Energy Transformation Act (CETA)

Washington State's CETA requires serving 100 percent of state retail sales with clean energy by 2045. In 2030, up to 20 percent of this clean energy may use an alternative compliance mechanism to satisfy the requirement. Since final rules were not in place to define all potential programs qualifying for this designation except for unbundled RECs, Avista did not model all alternative compliance options for this plan. For this IRP, Avista made assumptions on how compliance would work and how to manage the renewable energy for a multi-state utility. The following is a list of the assumptions included to develop the clean energy need assessment in Figure 7.7.

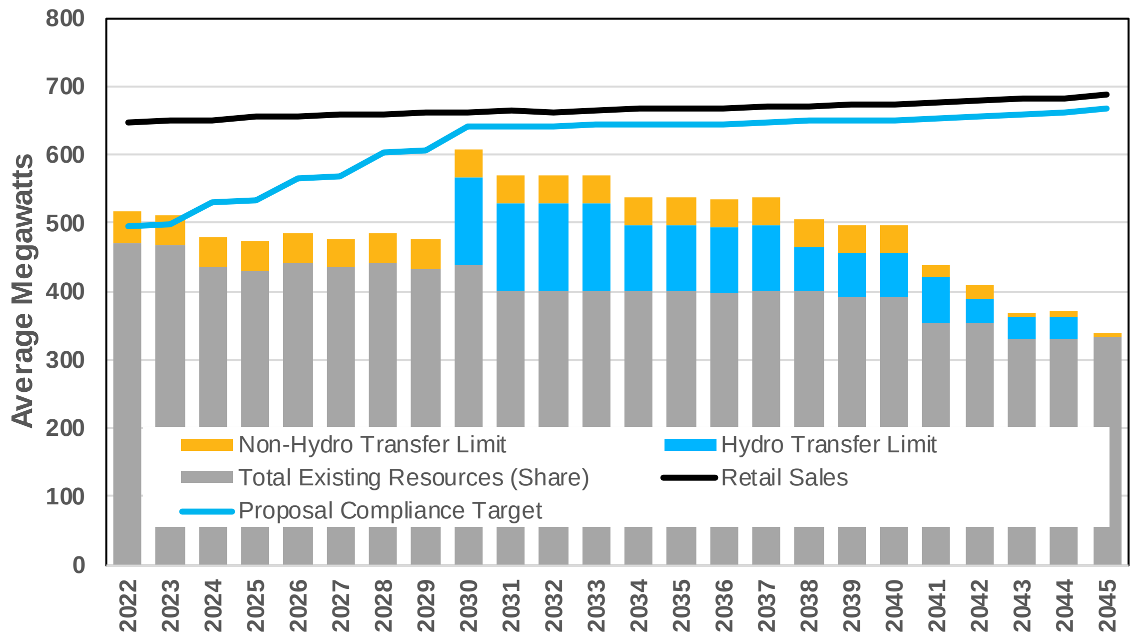
- Qualifying clean is determined by procurement and delivery of clean energy to Avista's system for all years.
- The clean energy goal is applied to retail sales *less* in-state PURPA generation constructed prior to 2019 *plus* voluntary customer programs such as Solar Select.
- Customer voluntary REC programs, such Avista's My Clean Energy™ program, do not qualify toward the CETA standard.
- Interim targets of 80 percent of net Washington retail sales are met with clean energy and unbundled RECs in 2022 and 2023, 85 percent in 2024 and 2025, 90 percent in 2026 and 2027, 95 percent in 2028 and 2029, and 100 percent clean energy in 2030 with an allowance of up 20 percent from unbundled RECs .
- All existing clean energy resources within the Avista portfolio are allocated between Idaho and Washington customers using the PT ratio.

[8] Rattlesnake Flat wind may also qualify for the apprentice credits, creating a 20 percent adder to the REC amount available for EIA compliance. This table does not include the 20 percent adder.

- Avista may transfer qualifying non-hydro clean energy generated for Idaho loads to Washington if needed by compensating Idaho at a forecasted REC price of $7.50 per MWh escalating at 5 percent per year[9].
- While CETA allows for up to 20 percent of compliance from unbundled RECs in 2030, Avista intends to meet this requirement between 2030 and 2033 purchasing Avista Idaho customer's share of the hydro system as unbundled RECs and then up to 15 percent between 2034 and 2037, 10 percent between 2038 and 2041, and 5 percent between 2042 and 2044.
- Avista is not planning to use Idaho's hydro RECs prior to 2030 for planning purposes to incent clean energy acquisitions, however actual compliance may include them due to variability in clean resource availability.
- Avista anticipates final rules regarding the "use" of clean energy for compliance purposes in late 2021. Depending upon the final adoption of the CETA rules for compliance, Avista may change its needs assessment for future IRPs accordingly.

Based on this plan of acquisition and normal water conditions, Avista has enough qualifying resources to meet its internal 80 percent target in 2022 and 2023 but will need to acquire up to 51 aMW by 2024 and up to 132 aMW of clean energy by 2029. The 2045 goal will require 326 aMW of additional clean energy.

**Figure 7.7: Washington State CETA Compliance Position**

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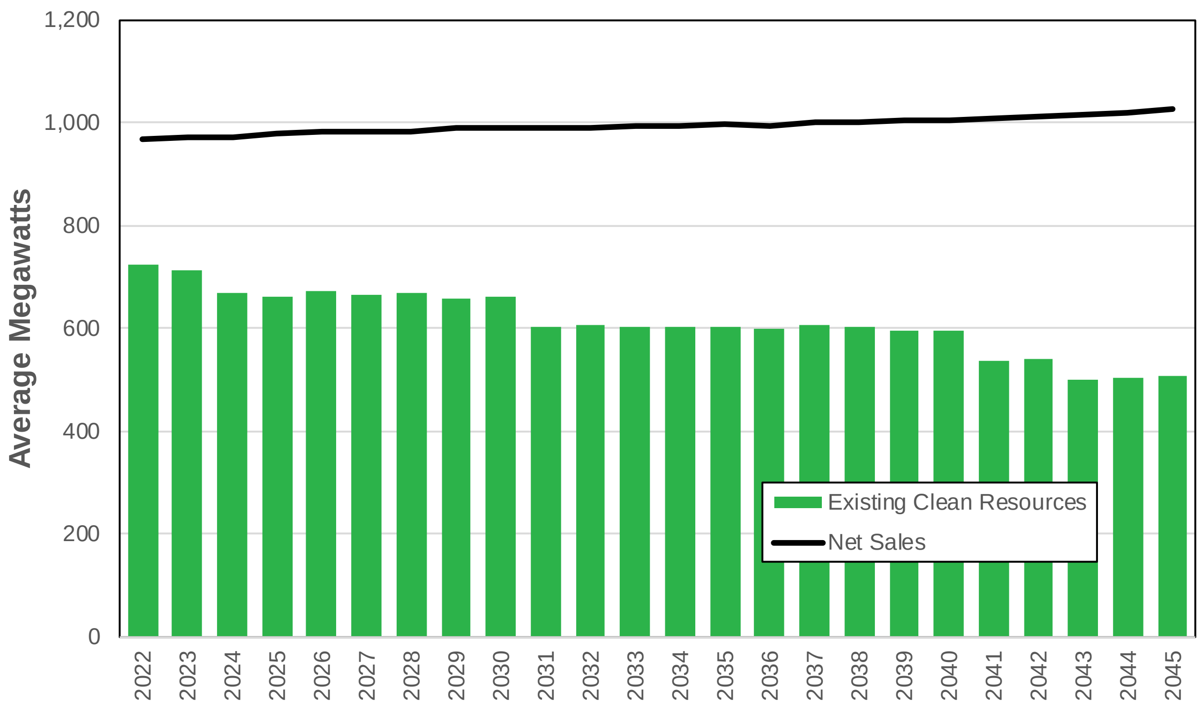
[9] In operations, transfers of RECs between states shall be market price based. Avista uses $7.50 per MWh for this IRP based on transactions Avista has made at the time of the development of the IRP.

## Avista's Company-Wide Clean Energy Goal

Avista set a corporate goal to serve all retail customers with 100 percent carbon neutral energy by 2027 and deliver 100 percent clean energy by 2045 for the entire system while maintaining reliability and affordability for its customers. From a resource planning perspective, the 2027 goal entails ownership or control of renewable resources or RECs equal to retail sales by 2027 and phasing out all fossil fuel producing generation by 2045. Each of these goals must carefully consider cost implications and technical feasibility balanced to ensure customer affordability. Avista is still working out the details of what would be acceptable to customers regarding affordability; whether this is a dollar threshold, a percentage increase or an energy burden level for different customer groups. Avista will seek customer input on these and other issues as described in Chapter 13 – Energy Equity. This section discusses the amount of energy and capacity necessary to meet the Company's system-wide clean energy goals. By 2022, Avista will have enough clean generation over the course of the year to meet 75 percent of retail sales. Avista would need to acquire an additional 318 aMW of clean energy or RECs to achieve its 2027 goal. The clean energy deficit grows to nearly 520 aMW by 2045. In addition to the additional clean energy need in 2045, the Company will also need to add 659 MW of winter capacity to meet the current resource deficiency and replace the 494 MW of remaining thermal resources providing capacity on a winter peak day for a 1,153 MW total. This potential new capacity will need to operate in cold winters for a sustained period to meet Avista's 5 percent LOLP reliability threshold.

Figure 7.8: Avista Clean Energy Goal



# Regional Resource Adequacy

Avista relies on 330 MW of market power in its reliability study. If Avista chose not to rely on this level of available market power, its planning margins would need to be over 30 percent. However, Avista is not an electrical island, and other entities should be able to assist Avista when loads peak due to load and resource diversity. Collectively, utilities should plan as a system and optimize resources to meet regional needs to increase system reliability and minimize system costs for all customers and utilities in the region. This may be an optimistic goal, as some utilities do not always make their excess capacity available to the marketplace when needed to meet peak load events. To gain a better understanding of the market and the region's ability to provide adequate power, Avista participates in the Northwest Power and Conservation Council's (NPCC) resource adequacy forum. In addition to this process, Avista contributed funding for a recent Northwest Power Pool resource adequacy study performed by the consulting firm E3. This study provided regional resource builds and costs for future clean energy scenarios. The last method Avista uses to review regional resource adequacy is part of its market price forecast.

## Northwest Power and Conservation Council

The NPCC released its Pacific Northwest Power Supply Adequacy Assessment for 2024[10] on October 31, 2019. It highlights potential resource adequacy risks to the regional power system. The NPCC estimates the regional 2021 LOLP to be 7.5 percent, exceeding the region's current 5 percent threshold due primarily to announced coal plant retirements without commensurate replacement of capacity resources. The likelihood of lost load increases to 8.2 percent by 2024, equaling a regional 800 MW capacity shortage. When additional thermal resources retire in 2026, the regional LOLP increases to 17 percent. Using the results from this study equates to a regional planning margin of 13.4 percent[11].

The regional analysis also contained sensitivities on load and extra-regional imports. Table 7.3 shows the range in analysis provided by the NPCC for the regional LOLP in the first three rows and the megawatts of required generation (or load reduction) in the bottom three rows. This analysis shows the region is at risk without new resources unless loads fall or the region can acquire reliable winter capacity from other regions. The import limit of 2,500 MW and medium load are the expected cases shown in bold.

[10] https://www.nwcouncil.org/sites/default/files/2024%20RA%20Assessment%20Final-2019-10-31.pdf.
[11] This assumes the BPA's White Book average peak capacity for regional hydro generation and 2,500 MW of imports.

**Table 7.3: NPCC 2024 Resource Adequacy Analysis**

| | Import (MW) | 1,500 | 2,000 | 2,500 | 3,000 | 3,500 |
|---|---|---|---|---|---|---|
| LOLP % | High Load (3% higher) | 21.1 | 18.0 | 16.0 | 14.4 | 12.0 |
| LOLP % | Medium Load | 12.5 | 10.2 | **8.2** | 6.9 | 5.2 |
| LOLP % | Low Load (3% lower) | 7.0 | 5.2 | 4.0 | 3.1 | 2.0 |
| | | | | | | |
| Required MW | High Load (3% higher | 2,800 | 2,300 | 1,700 | 1,200 | 800 |
| Required MW | Medium Load | 1,900 | 1,400 | **800** | 400 | 0 |
| Required MW | Low Load (3% lower) | 900 | 200 | 0 | 0 | 0 |

The greatest chance of regional load loss occurs in the winter months, primarily in January. The study found 27 percent of events occur in January and 19 percent in December. The summer had a collective LOLP of 26 percent.

The NPCC presented its preliminary 2025 resource adequacy assessment in December 2020. This assessment included their assumptions on climate change impacts using limited potential datasets for expected variation of load and hydro. This assessment also included more coal retirements than in its 2024 study completed in 2019. The assessment indicated a LOLP three times the maximum threshold (15 percent) in 2025 for the region, with summer months driving the deficits if hydro conditions increase along with lower peak loads in the winter and higher loads in the summer along with lower generation. Avista has concerns with the limited input data sets used to derive the range in potential climate adjusted load and hydro conditions but agrees there are great risks for maintaining regional resource adequacy in the future in this area.

### Energy and Environmental Economics (E3) Study

Avista participated in a regional study sponsored by the Northwest Power Pool to understand resource adequacy needs under different clean energy legislation options. This study was included as Appendix F of the 2020 IRP. The first year reviewed in the study was 2018 to test the model with the existing system. The study also reviewed 2030 and 2050 under multiple resource acquisition strategies. The footprint of this study included the four northwest states, Wyoming and Utah. This is a larger footprint then Avista's traditional energy trading partners. The 2018 study determined the region meets its 5 percent LOLP with a value of 3.7 percent; but does not have enough capacity to meet a goal of less than 2.4 outage hours per year (6.5 hours)[12]. E3 estimated the larger region needs an "effective" planning reserve margin of 12 percent to meet the goal of less than 2.4 outage hours per year, which would require an additional 1,200 MW of resources. By 2030, the study estimates a need for an additional 5,000 MW of capacity to maintain reliability due to expected resource retirements and load growth.

### Avista's Market Study

Avista details its market price forecast in Chapter 10. It contains a forecast of the needs of the region to maintain resource adequacy and estimates generation needs using an approximation of system load and resources. It models the entire northwest as one entity

[12] As discussed on page 36 of 2020 IRP Appendix F.

and ignores potential power transfer limits within the region. The following capacity additions were required by 2030: 1,400 MW of demand response, 1,500 MW of storage, and 2,300 MW of natural gas-fired combustion turbines. These additions are required over and above the capacity benefits included for the wind and solar required to meet state clean energy goals. Although given transfer limitations the actual required new generation is likely to be higher.

### Regional Resource Adequacy Conclusions

Avista is concerned the region is not adding enough capacity resources needed to maintain regional resource adequacy due to resource retirements, increases in intermittent resources and load growth. While Avista's resource plan shows significant planning margin requirements meeting standard utility practice, these requirements may not be enough to provide certainty for Avista's customers if the other regional utilities do not also add new capacity to maintain higher planning margins.

Avista is in a good current position since the Company is long capacity and exceeds its planning margin requirements through 2025. After 2025, Avista and many other regional utilities must acquire new dependable capacity resources to ensure customers have adequate power to sustain both extended cold winter and hot summer periods. Given the concern of regional resource adequacy, Avista is hopeful the regional resource adequacy program currently being designed is successfully implemented.

# 8. Transmission & Distribution Planning

This chapter introduces the Avista Transmission and Distribution (T&D) systems and provides a brief description of how Avista studies these systems and recommends capital investments to keep the systems functioning reliably while accommodating future growth. Avista's Transmission System is only one part of the networked Western Interconnection with specific regional planning requirements and regulations. This chapter summarizes planned transmission projects and generation interconnection requests currently under study and provides links to documents describing these studies in more detail. This section also describes how distribution planning is incorporated in the IRP and Avista's merchant transmissions system rights.

**Section Highlights**

- Avista actively participates in regional transmission planning forums.
- Avista develops annual transmission and distribution system plans.
- Transmission Planning estimates costs of locating new generation on the Avista system for the IRP.

## Avista Transmission System

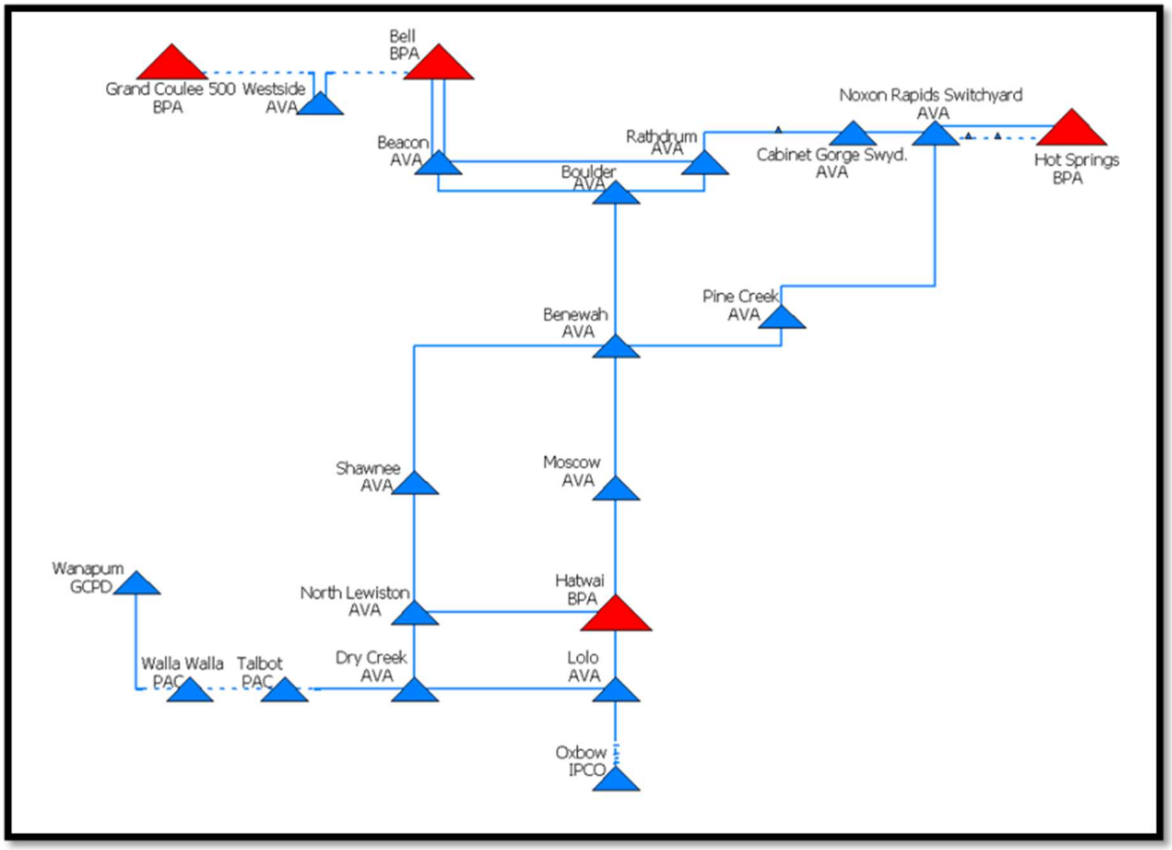
Avista owns and operates a system of over 2,200 miles of electric transmission facilities including approximately 700 miles of 230 kV transmission lines and 1,570 miles of 115 kV transmission lines (see Figure 8.1).

**Figure 8.1: Avista Transmission System**

### 230 kV Transmission System

The backbone of the Avista Transmission System operates at 230 kV. Figure 8.2 shows a station-level drawing of Avista's 230 kV Transmission System including interconnections to neighboring utilities. Avista's 230 kV Transmission System is interconnected to the BPA 500 kV transmission system at the Bell, Hot Springs and Hatwai Stations.

**Figure 8.2: Avista 230 kV Transmission System**




## Transmission Planning Requirements and Processes

Avista coordinates transmission planning activities with neighboring interconnected transmission owners. Avista complies with FERC requirements related to both regional and local area transmission planning. This section describes several of the processes and forums important to Avista's transmission planning.

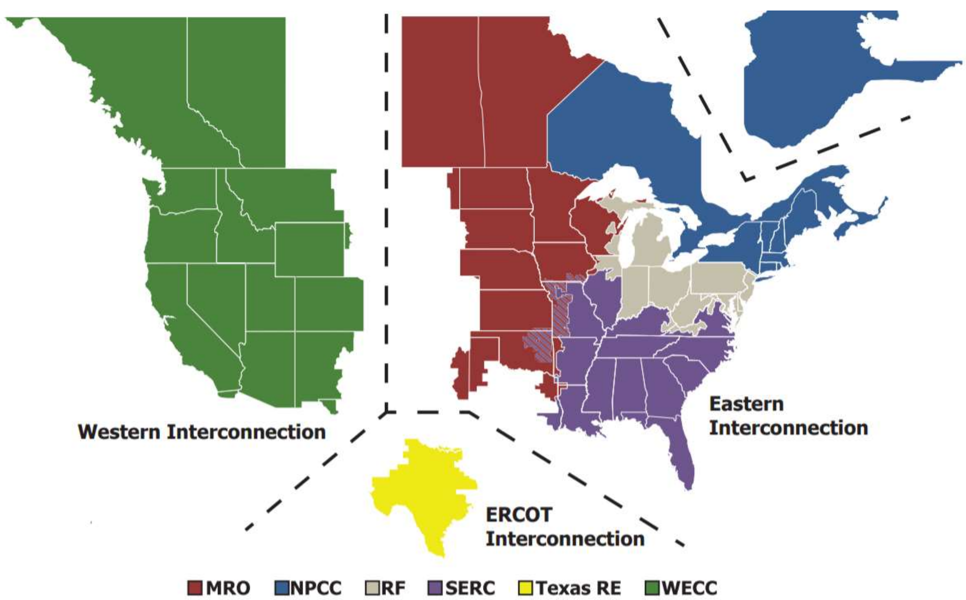
### Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is the group responsible for promoting bulk electric system reliability, compliance monitoring and enforcement in the Western Interconnection. This group facilitates development of reliability standards and helps coordinate interconnected system operation and planning among its membership. WECC is the largest geographic territory of the regional entities with delegated authority from the National Electric Reliability Council (NERC) and the Federal Energy Regulatory Commission (FERC). It covers all or parts of 14 Western states, the provinces of Alberta and British Columbia and the northern section of Baja, Mexico.[1] See Figure 8.3 for the map of NERC Interconnections including WECC.

## RC West

California ISO's RC West performs the federally mandated Reliability Coordinator function for a portion of the Western Interconnection. While each transmission operator within the Western Interconnection operates its respective transmission system, RC West has the authority to direct specific actions to maintain reliable operation of the overall transmission grid.

**Figure 8.3: NERC Interconnection Map**




## Northwest Power Pool

Avista is a member of the Northwest Power Pool (NWPP), an organization formed in 1942 when the federal government directed utilities to coordinate river and hydro operations to support wartime production. The NWPP serves as a northwest electricity reliability forum, helping to coordinate present and future industry restructuring, promoting member cooperation to achieve reliable system operation, coordinating power system planning and assisting the transmission planning process. NWPP membership is voluntary and includes the major generating utilities serving the Northwestern U.S., British Columbia and Alberta. The NWPP operates several committees, including its Operating Committee, the Reserve Sharing Group Committee, the Pacific Northwest Coordination Agreement (PNCA) Coordinating Group and the Transmission Planning Committee (TPC).

## NorthernGrid

NorthernGrid formed on January 1, 2020. Its membership includes thirteen utility organizations within the northwest and many external stakeholders. NorthernGrid aims to enhance and improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. Consistent with FERC requirements issued in Orders

[1] https://www.wecc.biz/Pages/About.aspx.

890 and 1000, NorthernGrid provides an open and transparent process to develop sub-regional transmission plans, assess transmission alternatives (including non-wires alternatives) and provide a decision-making forum and cost-allocation methodology for new transmission projects. NorthernGrid is a new regional planning organization created by combining the members of ColumbiaGrid and the Northern Tier Transmission Group.

## System Planning Assessment

Development of Avista's annual System Planning Assessment (Planning Assessment) encompasses the following processes:

- The Avista Local Transmission Planning Process – as provided in Attachment K, Part III of Avista's Open Access Transmission Tariff (OATT);
- The NorthernGrid transmission planning process – as provided in the NorthernGrid Planning Agreement; and
- The requirements associated with the preparation of the annual Planning Assessment of the Avista portion of the Bulk Electric System.

The Planning Assessment, or Local Planning Report, is prepared as part of a two-year process as defined in Avista's OATT Attachment K. The Planning Assessment identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources, serve the forecasted loads of Avista's Network Customers and Native Load Customers, and meet all other Transmission Service and non-OATT transmission service requirements, including rollover rights, over a 10-year planning horizon. The Planning Assessment process is open to all interested stakeholders, including, but not limited to Transmission Customers, Interconnection Customers and state authorities.

Avista's OATT is located on its Open Access Same-time Information System (OASIS) at http://www.oatioasis.com/avat. Additional information regarding Avista's System Planning work is in the Transmission Planning folder on Avista's OASIS. The Avista System Planning Assessment is posted on OASIS. Avista's most recent transmission planning document highlights several areas for additional transmission expansion work including:

- **Big Bend** - Transmission system capacity and performance will significantly improve upon completion of the Benton – Othello Switching Station 115 kV Transmission Line rebuild project and the Saddle Mountain 230 kV Station project, which adds a fourth source into the load area. The addition of communication aided protection schemes and other reconductor projects will improve reliability and lessen the impacts of system faults. This project is needed for continued integration of utility scale renewable generation.

- **Coeur d'Alene** - The completion of the Coeur d'Alene – Pine Creek 115 kV Transmission Line Rebuild project and Cabinet – Bronx – Sand Creek 115 kV Transmission Line Rebuild project improved transmission system performance in northern Idaho. The addition and expansion of distribution substations and a reinforced 115 kV transmission system are needed in the near-term planning horizon to support load growth and ensure reliable operations in this.

- **Lewiston/Clarkston** - Load growth in the Lewiston/Clarkson area contributed to heavily loaded distribution facilities. Additional performance issues have been identified related to the ability for bulk power transfer on the 230 kV transmission system. A system reinforcement project is under development to accommodate the load growth in this area.

- **Palouse** - Completion of the Moscow 230 kV Station rebuild project in 2014 mitigated several performance issues. The remaining issue is a potential outage of both the Moscow and Shawnee 230/115 kV transformers. An operational and strategic long-term plan is under development to best address a possible double transformer outage in this area.

- **Spokane** - Several performance issues exist with the present state of the transmission system in the Spokane area and are expected to worsen with additional load growth. The Westside 230 kV station rebuild is near completion and the rebuild at the Irvin 115 kV station is ongoing. The staged construction of new 230 kV facilities at the Garden Springs 230 kV station is under development. Dependency on the 230 kV Beacon station leaves the system susceptible to performance issues for outages related to transmission lines that terminate at the station.

IRP Generation Interconnection Options (Table 8.1) shows the projects and cost information for each of the IRP-related studies where Avista evaluated new generation options. These studies provide a high-level view of generation interconnection costs and are similar to third-party feasibility studies performed under Avista's generator interconnection process. In the case of third-party generation interconnections, FERC policy requires a sharing of costs between the interconnecting transmission system and the interconnecting generator. Accordingly, Avista anticipates all identified generation integration transmission costs will not be directly attributable to a new interconnected generator.

## Large Generation Interconnection Requests

Third-party generation companies may request transmission studies to understand the cost and timelines required for integrating potential new generation projects. These requests follow a strict FERC process to estimate the feasibility, system impact and facility requirement costs for project integration. After this process is completed, a contract offer to integrate the project may occur and negotiations can begin to enter into a transmission agreement if necessary. Table 8.2 lists information associated with potential third-party resource additions currently in Avista's interconnection queue.[2]

[2] https://www.oasis.oati.com/woa/docs/AVAT/

## Table 8.1: 2021 IRP Generation Study Transmission Costs

| Station | Request (MW) | POI Voltage | Cost Estimate ($ million)[3] |
|---|---|---|---|
| Kootenai County (GF) | 100 | 230 kV | 4 |
| Kootenai County (GF) | 200/300 | 230 kV | 80-100 |
| Rathdrum | 25/50/100 | 115 kV | <1 |
| Rathdrum | 200 | 115 kV | 55 |
| Rathdrum | 50/100 | 230 kV | <1 |
| Rathdrum | 200 | 230 kV | 60 |
| Benewah | 100/200 | 230 kV | <1 |
| Tokio | 50/100 | 115 | <1, 20 |
| Othello/Lind | 50/100/200 | 115 kV | Queue Issues[4] |
| Lewiston/Clarkston | 100/200 | 230 kV | <1 |
| Northeast | 10 | 115 kV | <1 |
| Kettle Falls | 12 | 115 kV | <1 |
| Kettle Falls | 24/100/124 | 115 kV | <20 |
| Long Lake | 68 | 115 kV | 33 |
| Monroe Street | 80 | 115 kV | 2 |
| Post Falls | 10 | 115 kV | <1 |
| Cabinet Gorge | 110 | 230 kV | <14 |

[3] Cost estimates are in 2019 dollars and use engineering judgment with a 50 percent margin for error.
[4] This area of the system has several projects in the transmission request process, in total these projects exceed the local area's ability to integrate new resources and the issue is currently being studied.

## Table 8.2: Third-Party Large Generation Interconnection Requests

| Project | Size (MW) | Type | Interconnection Location | Proposed Date |
|---|---|---|---|---|
| #46 | 126 | Wind | Big Bend (WA) | December 2018 |
| #47 | 750 | Wind | Colstrip 500kV (MT) | September 2018 |
| #50 | 450 | Pumped Hydro | Colstrip 500kV (MT) | December 2020 |
| #51 | 300 | Solar | Broadview (MT) | December 2020 |
| #52 | 100 | Solar | Big Bend (WA) | July 2020 |
| #59 | 116 | Solar & Storage | Big Bend (WA) | June 2021 |
| #60 | 150 | Solar & Storage | Lewiston/Clarkston | December 2022 |
| #62 | 123 | Wind | Big Bend (WA) | November 2021 |
| #63 | 26 | Hydro | Post Falls (ID) | February 2023 |
| #66 | 71 | Wood Waste | Kettle Falls (WA) | July 2023 |
| #67 | 80 | Solar | Big Bend (WA) | June 2023 |
| #68 | 750 | Wind | Colstrip 500kV (MT) | |
| #69 | 750 | Wind | Colstrip 500kV (MT) | |
| #70 | 2.5 | Storage | Liberty Lake (WA) | |
| #71 | 7 | Solar | Big Bend (WA) | August 2020 |
| #72 | 80 | Solar | Big Bend (WA) | June 2021 |
| #73 | 100 | Solar | Big Bend (WA) | June 2020 |
| #74 | 0.1 | Storage | Spokane (WA) | |
| #76 | 200 | Solar | Big Bend (WA) | December 2020 |
| #79 | 5 | Solar | Spokane (WA) | June 2020 |
| #80 | 19 | Solar | Spokane (WA) | June 2020 |
| #81 | 94 | Solar | Big Bend (WA) | June 2020 |
| #82 | 600 | Wind | Colstrip 500kV (MT) | December 2021 |
| #83 | 300 | Wind | Colstrip 500kV (MT) | October 2022 |
| #84 | 5 | Solar | Kettle Falls (WA) | August 2020 |
| #85 | 5 | Solar | Big Bend (WA) | August 2020 |
| #90 | 5 | Solar | Big Bend (WA) | August 2021 |
| #94 | 5 | Solar | Big Bend (WA) | August 2021 |
| #95 | 600 | Wind | Colstrip 500kV (MT) | December 2022 |
| #96 | 400 | Wind | Colstrip 500kV (MT) | December 2022 |
| #97 | 100 | Solar & Storage | Lewiston/Clarkston | December 2021 |
| #99 | 200 | Solar & Storage | Big Bend (WA) | December 2021 |
| #100 | 100 | Solar & Storage | Palouse (WA) | December 2021 |
| #101 | 500 | Solar & Storage | Lewiston/Clarkston | September 2024 |
| #103 | 58 | Solar | Big Bend (WA) | July 2021 |
| #104 | 120 | Wind | Palouse (WA) | December 2023 |
| #105 | 5 | Solar | Big Bend (WA) | June 2021 |
| #106 | 180 | Solar | Big Bend (WA) | December 2022 |
| #107 | 500 | Storage | Colstrip 500kV (MT) | December 2023 |
| #108 | 750 | Wind | Colstrip 500kV (MT) | October 2023 |

# Distribution Planning

Avista continually evaluates its distribution system for continued reliability and level of service requirements for current and future loads. The distribution system consists of approximately 350 feeders covering 30,000 square miles, ranging in length from three to 73 miles. For rural distribution, feeder lengths vary widely to meet electrical loads resulting from the startup and shutdown of customers in the timber, mining and agriculture industries. The distribution evaluation determines if there are capacity limitations on the system to serve current and future projected load for each individual feeder. The analysis also considers if the system meets reliability and level of service requirements including voltage and power quality. When a potential constraint is identified, an action plan is prepared and compared against other options, and the best course of action is budgeted for implementation.

Electric distribution planning identifies system capacity and service reliability constraints, and subsequently determines the best and lowest life-cycle cost solution for those constraints. Solutions traditionally center on infrastructure upgrades such as poles, wire and cable. New technologies are emerging and may impact system analysis, including storage, photovoltaic (solar) and demand response. As these alternatives mature and evolve, they are likely to play a growing role in Avista's investment portfolio either as primary solutions or as capital deferment solutions. Avista has deployed several distribution level pilot projects to determine the best means to meet customer needs while maintaining a high degree of reliability now and in the future.

Load and system data are required to properly evaluate each feeder for new technologies. Quality load data is not available for all the Avista feeders beyond monthly data logs recording peak load and energy usage. Avista has 200 of 347 feeders with three-phase Supervisory Control and Data Acquisition (SCADA) data available. Avista adds SCADA capability to more feeders as resources and budgeting within our substation work schedule allows. Evaluating new technologies is limited to portions of the system with the available data until new sources of data are developed and brought online. Detailed data is required to validate whether new technologies solve current system constraints or just defer the constraint for a period of time. Avista is installing automated meters for customers in Washington and plans to install these meters in Idaho in the next few years. When complete, the new meters will be able to collect additional data needed to improve the distribution planning process.

New load forecasting techniques such as spatial load forecasting will be required for distribution planning. This new forecasting method uses Geographic Information System (GIS) based information associated with feeder location and can help forecast specific feeder load growth by considering zoning, demographics, land availability and specific parcel information. With additional investment in both technology and human capital, Avista will be prepared to quickly study and implement new technologies on its distribution system.

## Deferred Capital Investment Analysis

New technologies such as storage, photovoltaics and demand response programs could help the electrical system by deferring or eliminating future capital investments. This is dependent on new technologies to solve system constraints and meet customer expectations for reliability. An advantage in using these technologies may be additional benefits incorporated into the overall power system. For example, storage may help meet overall power supply peak load needs, but it may also provide voltage support and defer capital investment on the distribution feeder or at the distribution substation in the right conditions (discussed below).

This section discusses the analysis for determining the capital investment deferment value for distributed energy resources (DERs). Capital investment deferment is not the same for all locations on the system. Feeders differ by whether they are summer or winter peaking, the time of day when the peaks occur, whether they are at or near capacity, and the speed of local load growth. It is not practical to have an estimate for each feeder in an IRP, but it is prudent to have a representative estimate included in the IRP resource selection analysis.

In order to fairly evaluate and select the most cost-effective solutions for system deficiencies, the planning process needs to identify the deficiency well in advance of becoming a problem. Longer evaluation periods provide for a more comprehensive evaluation so the solution can take a holistic approach to include system resource needs. A shorter period requires immediate action and does not lend itself to a stacked value analysis due to time constraints for acquiring and constructing a non-wire alternative.

Identifying future deficiencies in a timely matter has become the focus of System Planning. As previously mentioned, spatial forecasting, load data, time series analysis and accurate modeling are critical to making decisions as early as possible. Although DER opportunities will continue to be evaluated, System Planning needs the tools, process and time to evaluate whether DERs are the preferred solution in any given situation.

At this time, Distribution Planning has not identified any projects meeting the criteria for an economic non-wire alternative. The near-term distribution projects require capacity increases and duration requirements due to load growth exceeding the distributed energy resources (DERs) capability. Avista is starting a public distribution planning process in 2022 to identify and plan for future distribution needs.

### Reliability Impact of Distributed Energy Storage

Utility-scale batteries may offer benefits to grid operations. Reliability is one benefit often associated with batteries. This is particularly true in situations where the battery system is commissioned as a mitigation solution on the distribution system.

There is an industry trend to broaden the list of remedies available to alleviate grid deficiencies beyond traditional wires-based solutions. The solutions are typically called “non-wire” alternatives but it may be more informative to call them non-traditional alternatives. The motivation behind the trend is reasonable as non-traditional approaches may be less expensive than legacy options and may also incorporate other ancillary benefits, such as in the case of batteries. Utilities should consider all viable options to arrive at a least cost and reliable solution to distribution issues. In addition to solving grid issues, some non-wire alternatives may also serve as a system resource. Typically, these are referred to as a Distributed Energy Resource. Batteries, the subject of this section, are one such non-wire alternative with other benefits.

It is often presumed batteries increase system reliability. This may be true in some applications, but in the narrow sense of non-wire alternatives, this would not typically be the case. In the simplest of terms, reliability can decrease with the addition of a battery because the battery and its control system are additional failure points in the existing system chain. It is difficult to identify a case where this reduction in reliability from the added potential failure points is not true.

To demonstrate this point, a typical battery use case is presented as a thought experiment. A common issue on the distribution grid is feeder capacity constraints. A constrained feeder typically approaches the operational constraint during the daily peak load. The historical mitigation for this type of constraint is to increase the capacity of the constraining element by installing a larger conductor, different regulators, a larger transformer, or building a new substation. With the advent of utility-scale batteries, utilities have another option to mitigate these types of feeder constraints. Employing battery storage to, in effect, shift load from the daytime when limited and expensive resources are the norm, to the nighttime when relatively more abundant and less expensive resources are readily available.

When used to fix a constraint in this manner the battery (or generating resource such as a DER) is added to existing distribution facilities. It does not replace existing facilities, and this is a key point. The probability of failure of the existing facilities remains. The probability of failure of the battery or other non-wire alternative system is now an additional failure point. Think of a feeder as a chain where each link is a potential failure point. If the chain consists of 100 links, there are 100 points of possible failure along the entire chain. In the same manner, adding a battery to a feeder to mitigate an issue simply adds another link, and another possible failure point, in the chain. Instead of 100 possible points of failure, there are now 101 possible points of failure. Granted, there are temporal aspects to this as well. The battery will not always be needed to fix a constraint that does not occur at all times. If a failure occurs in the battery when there is no constraint, the feeder can continue operating as normal with no adverse impacts to the system. But there will be times when the battery is needed to meet that peak event and during those times the battery becomes an additional failure point with the expanded system. The annual net effect on the feeder is reduced reliability.

The shift in reliability is more significant if a traditional solution was chosen. Existing, older links in the failure chain would be replaced with new and often more robust and more reliable links. To take the chain analogy even further, if a new substation is built, links are removed from the failure chain as each affected feeder becomes shorter and has less environmental exposure. In addition, there is increased resiliency due to added operational flexibility and the ability to serve load from different directions. The net effect of a traditional solution is increased reliability and it facilitates future DER resource additions because traditional solutions make the grid better able to accept the additional DERs.

Quantifying the real effect of a grid-fixing battery, or similar resource, on reliability is difficult and situational. Indeed, it may not rise to a level of concern given the temporal nature of the decrease in reliability. The benefit of the resource may outweigh the short period of time it increases failure probability. However, if it increases failure probability for a significant period an alternate solution may be warranted. From an IRP perspective, the notion that fixing a distribution grid deficiency while simultaneously providing a system resource is an intriguing one. It is worthy of consideration, but one can't assume system reliability will not be negatively impacted by doing so.

# Merchant Transmission Rights

Avista has two types of transmission rights. The first rights include Avista's owned transmission. This transmission is reserved and purchased by Avista's merchant department to serve Avista customers. Avista owned transmission is also available to other utilities or power producers. FERC separates utility functions between merchant and transmission functions to ensure fair access to the Avista transmission system. The merchant department dispatches and controls the power generation for Avista and purchases transmission from the Avista transmission operator to ensure energy can be delivered to customers. Avista must show a load serving need to reserve transmission on the Avista owned transmission system to ensure equitable access to the transmission capacity. Appendix H shows the projected need and future use of the Avista transmission system.

Avista also purchases transmission rights from other utilities to serve customers. This transmission is procured on behalf of the merchant side of Avista. The merchant group has transmission rights with BPA, PGE and a few smaller local electric utilities. Table 8.4 shows the third-party transmission rights contracted by Avista's merchant group.

**Table 8.3: Merchant Transmission Rights**

| Counterparty | Path | Quantity (MW) | Expiration |
|---|---|---|---|
| BPA | Lancaster to John Day | 100 | 6/30/2026 |
| BPA | Coyote Springs 2 to Hatwai | 97 | 8/1/2026 |
| BPA | Coyote Springs 2 to Benton | 50 | 8/1/2026 |
| BPA | Garrison to Hatwai | 196 | 8/1/2026 |
| BPA | Coyote Springs 2 to Vantage | 125 | 10/31/2022 |
| BPA | Townsend to Garrison | 210 | 9/30/2027 |
| PGE | John Day to COB | 100 | 12/31/2023 |
| Northern Lights | Dover to Sagle | As needed | n/a |
| Kootenai Electric | Rockford to Worley | As needed | 12/31/2028 |

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# 9. Supply-Side Resource Options

Avista evaluates several different generation, storage and hybrid solar/storage supply-side resource options to meet future resource deficits. The resource categories evaluated for this IRP included upgrading existing resources, building and owning new generation facilities and contracting with other energy companies. This section describes the costs and characteristics of resource options Avista considered in the 2021 IRP. The options are mostly generic, as actual resources are typically acquired through competitive processes such as an RFP. This process may yield resources that differ in size, cost and operating characteristics due to siting, engineering or financial requirements, it also may reveal existing resource options.

**Section Highlights**

- Solar, wind and other renewable resource options are modeled as Purchase Power Agreements (PPA) instead of utility ownership.
- Upgrades to Avista's hydro, natural gas and biomass facilities are included as resource options.
- Future competitive acquisition processes might identify different technologies available to Avista at a different cost, size or operating characteristics and may include existing generation options.
- Renewable resource costs assume no extensions of current state and federal tax incentives.
- Avista models several energy storage options including pumped storage hydro, lithium-ion, vanadium flow, zinc bromide flow, liquid air and hydrogen.
- In addition to industry sources, Avista's recent Renewable RFP informed IRP inputs on solar, wind and hybrid solar/storage resource options.

## Assumptions

Avista models only commercially available resources with well-known costs and generation profiles priced as if Avista developed and owned the generation or acquired generation from Independent Power Producers (IPPs) through a Purchase Power Agreement (PPA). Resources using PPAs rather than ownership include pumped hydro storage, wind, solar (with and without storage), geothermal and nuclear resources. Avista modeled these resource types as PPAs since IPPs financially capture tax benefits for these resources earlier, reducing the cost to customers. Resource options assuming utility ownership include natural gas-fired combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), natural gas-fired reciprocating engines, hydrogen-fired SCCT, energy storage, hydrogen fuel cell, biomass, hydroelectric upgrades, hydroelectric contracts and thermal unit upgrades. Upgrades to coal-fired units were not included or considered in this IRP. Modeling resources as PPAs or ownership does not preclude the utility from acquiring new resources in other manners but serves as an appropriate cost estimate for the new resources. Several other resource options described later in the chapter are not included in the portfolio analysis but are discussed here as potential resource options since they may appear in a future request for resource acquisition.

It is difficult to accurately model potential contractual arrangements with other energy companies as an option in the plan specifically for existing units or system power, but such arrangements may offer a lower customer cost when a competitive acquisition process is completed. Avista plans to use competitive RFP processes for resource acquisitions where possible to ensure the lowest cost resource is acquired for customers. However, another acquisition process may yield better pricing on a case-by-case basis, especially for existing resources available for shorter time periods. When evaluating upgrades to existing facilities, Avista uses the IRP, RFPs and market intelligence to determine and validate its upgrade assumptions. Upgrades typically require competitive bidding processes to secure contractors and equipment.

The costs of each resource option within this chapter do not include the cost related to upgrading the transmission or distribution system described in Chapter 8 – Transmission & Distribution Planning or third-party wheeling costs. All costs are considered at the bus bar. Avista excludes these costs in this chapter to allow for cost comparison as resource costs at specific locations are highly dependent on the location chosen in relation to Avista's system. These costs are included when Avista evaluates the resources for selection in an RFP and within the IRP's portfolio analysis. All costs are levelized by discounting nominal cash flows by the 6.70 percent-weighted average cost of capital approved by the Idaho and Washington Commissions in recent rate case filings. All costs in this section are in 2020 nominal dollars unless otherwise noted. All cost and operating characteristic assumptions for generic resources and how PPA pricing were calculated are available in Appendix I.

Avista relies on several sources including the NPCC, press releases, regulatory filings, internal analysis, publicly available studies, developer estimates and Avista's experience with certain technologies to develop its generic IRP resource assumptions. In addition to the above, Avista's 2020 Renewable RFP was utilized to ensure assumed IRP costs for solar, wind and solar/storage resource options were in line with pricing available from actual projects.

Levelized resource costs illustrate the differences between generator types. The values show the cost of energy if the plants generate electricity during all available hours of the year. In actual operation, plants do not operate to their maximum generating potential because of market and system conditions. Costs are separated between energy in $/MWh and capacity in $/kW-year to better compare technologies[1]. Without this separation of costs, resources operating infrequently during peak-load periods would appear more expensive than baseload CCCTs, even though peaking resources are lower total cost when operating only a few hours each year. Avista levelizes the cost using the production capability of the resource. For example, a natural gas-fired turbine is available 92 to 95 percent of the time when accounting for maintenance and forced outage rates. Avista divides the cost by the amount of megawatt hours the machine can produce. For resources that are available but may not have the fuel available, such as a wind project, the resource costs are divided by its expected production.

[1] Storage technologies use a $ per kWh rather than $ per kW because the resource is both energy and capacity limited.

Tables at the end of this section show incremental capacity, heat rates, generation capital costs, fixed O&M, variable costs and peak credits for each resource option.[2] Table 9.1 compares the levelized costs of different resource types over a 30-year asset life.

## Distributed Energy Resources (DERS)

This IRP includes several distributed energy resource options. DERs are both supply and demand side resources located at either the customer location or at a utility-controlled location on the distribution system. For demand side DERs other than energy efficiency, the resource assumptions are typically demand response. Avista included these program options in Chapter 6. Specific programs with physical DER assets include EV charging and customer-owned battery and thermal storage along with many other options to lessen customer load during peak events. In addition to these modeled demand-side DER options, Avista included forecasts for customer-owned solar and EVs as part of its load forecast discussed in Chapter 3.

In addition to demand-side DERs, supply-side resource options include small scale solar and battery storage. Avista includes specific cost estimates for smaller scale projects described later in this chapter along with the energy, capacity and ancillary services benefits traditional utility scale projects offer. Due to the location, additional benefits such as line loss savings over alternative utility scale projects are also included. Other locational benefits may also be credited to the project if it alleviates distribution constraints. Projects on the customer system may also provide reliability benefits to the specific customer. At this time, Avista has not determined any specific locational value or reliability benefits for these resources, but additional information can be found regarding effects of DERs under distribution planning in Chapter 8. Avista also plans to include non-energy impacts of DERs and utility scale resources in the next IRP.

## Natural Gas-Fired Combined Cycle Combustion Turbine

Natural gas-fired CCCT plants provide reliable capacity and energy for a relatively modest capital investment. The main disadvantages of a CCCT are generation cost volatility due to reliance on natural gas, unless utilizing hedged fuel prices, and the plant emissions. This IRP models CCCTs as “one-on-one” (1x1) configurations, using hybrid air/water cooling technology and zero liquid discharge. The 1x1 configuration consists of a single gas turbine with a heat recovery steam generator (HRSG) and a duct burner to gain more generation from the steam turbine. The plants have nameplate ratings between 311 MW and 586 MW each depending on configuration and location. A three-on-two (3x2) CCCT plant configuration is possible with three turbines and two HRSG, generating up to 249 MW.

Cooling technology is a major cost driver for CCCTs. Depending on water availability, lower-cost wet cooling technology could be an option, similar to Avista’s Coyote Springs 2 plant. However, absent water rights, a more capital-intensive and less efficient air-cooled technology may be used. For this IRP, Avista assumes water is available for plant cooling based on its internal analysis, but only enough water rights for a hybrid system utilizing the benefits of combined evaporative and convective technologies.

[2] Peak credit is the amount of capacity a resource contributes at the time of system one-hour peak load.

This IRP models three types of CCCT plants, ranging in size from 235 MW to 480 MW as 1x1 configuration. Avista reviewed many CCCT technologies and sizes and selected these plants due to the range in size to have the potential for the best fit for the needs of Avista's customers. If Avista pursues a CCCT, a competitive acquisition process will allow analysis of other CCCT technologies and sizes at both Avista's preferred and other locations. It is also possible Avista could acquire an existing CCCT resource from one of the many units in the Pacific Northwest.

The most likely location for a new CCCT is in Idaho, mainly due to Idaho's lack of an excise tax on natural gas consumed for power generation, a lower sales tax rate relative to Washington and no state taxes or fees on the emission of carbon dioxide.[3] CCCT sites likely would be on or near our transmission system to avoid third-party wheeling costs. Another advantage of siting a CCCT resource in Avista's Idaho service territory is access to relatively low-cost natural gas on the GTN pipeline. Avista already secured a site with these potential connection points in the event it needs to add additional capacity from either a CCCT or other technology.

Combined cycle technology efficiency has improved since Avista's current CCCT generating fleet entered service with heat rates as low as 6,400 Btu/kWh for a larger facility and 6,700 for smaller configurations. Duct burners can add additional capacity with heat rates in the 7,200 to 8,400 Btu/kWh range.

The anticipated capital costs for the modeled CCCTs, located in Idaho on Avista's transmission system with AFUDC on a greenfield site, range between $813 to $1,453 per kW in 2020 dollars. A likely configuration of the modern technology is $1,048 per kW. These estimates exclude the cost of transmission and interconnection. Table 9.1 shows levelized plant cost assumptions split between capacity and energy for both the combined cycle options discussed here, and the natural gas peaking resources discussed in the next section. The costs include firm natural gas transportation, fixed and variable O&M and transmission. Table 9.2 summarizes key cost and operating components of natural gas-fired resource options. With competition from alternative technologies and the need for additional flexibility for intermittent resources, it is likely to put downward pressure on future CCCT costs.

### Natural Gas-Fired Peakers

Natural gas-fired SCCTs and reciprocating engines, or peaking resources, provide low-cost capacity capable of providing energy as needed. Technological advances coupled with a simpler design relative to CCCTs allow them to start and ramp quickly, providing regulation services and reserves for load following and variable resources integration.

This IRP modeled frame, hybrid-intercooled, reciprocating engines and aero-derivative technologies. Peakers have different load following abilities, costs, generating capabilities and energy-conversion efficiencies. Table 9.2 shows cost and operational characteristics

[3] Washington state applies an excise tax on all fuel consumed for wholesale power generation, the same as it does for retail natural gas service, at approximately 3.875 percent. Washington also has higher sales taxes and carbon dioxide mitigation fees for new plants.

based on internal engineering estimates. Peaking plants assume 0.1-0.5 percent annual real dollar cost decreases and forced outage and maintenance rates. The levelized cost for each of the technologies is in Table 9.1.

Firm natural gas fuel transportation is an electric generation reliability issue with FERC and is also the subject of regional and extra-regional forums. For this IRP, Avista continues to assume it will not procure firm natural gas transportation for peaking resources and will use its current supply or short-term transportation for peaking needs. Firm transportation could be necessary where pipeline capacity becomes scarce during utility peak hours. Where non-firm transportation options become inadequate for system reliability, four options exist: contracting for firm natural gas transportation rights, purchasing an option to exercise the rights of another firm natural gas transportation customer during times of peak demand, on-site fuel oil or nearby storage such as liquefied natural gas.

**Table 9.1: Natural Gas-Fired Plant Levelized Costs**

| Plant Name | Total $/MWh | $/kW-Yr (Capability) | Variable $/MWh | Winter Capacity (MW) |
|---|---|---|---|---|
| Advanced Small Frame CT | 60 | 132 | 44 | 96 |
| Frame/Aero Hybrid CT | 52 | 138 | 36 | 93 |
| Large Reciprocating Engine Facility | 52 | 142 | 35 | 184 |
| Small Reciprocating Engine Facility | 57 | 170 | 36 | 91 |
| Modern Small Frame CT | 58 | 147 | 40 | 56 |
| Aero CT | 60 | 171 | 39 | 49 |
| 1x1 Large CCCT | 41 | 114 | 27 | 615 |
| 1x1 Modern CCCT | 48 | 161 | 28 | 329 |
| 3x2 Small CCCT | 57 | 219 | 30 | 267 |

**Table 9.2: Natural Gas-Fired Plant Cost and Operational Characteristics[4]**

| Item | Capital Cost with AFUDC ($2020/kW) | Fixed O&M ($2020 / kW-yr) | Heat Rate (Btu/ kWh) | Variable O&M ($/MWh) | Total Project Size (MW) | Total Cost (Mil$-2020) |
|---|---|---|---|---|---|---|
| Advanced Small Frame CT | 1,040 | 4.80 | 11,352 | 4.00 | 84 | 87 |
| Frame/Aero Hybrid CT | 1,097 | 4.40 | 8,956 | 4.00 | 92 | 101 |
| Large Recip. Engine Facility | 1,145 | 4.30 | 8,382 | 5.00 | 184 | 211 |
| Small Recip. Engine Facility | 1,333 | 8.80 | 8,146 | 7.00 | 91 | 122 |
| Modern Small Frame CT | 1,137 | 7.90 | 9,817 | 5.00 | 51 | 58 |
| Aero CT | 1,319 | 9.10 | 9,512 | 5.00 | 44 | 58 |
| 1x1 Modern CCCT | 1,048 | 13.60 | 6,765 | 4.00 | 311 | 326 |
| 1x1 Large CCCT | 813 | 25.70 | 6,411 | 3.50 | 587 | 477 |
| 3x2 Small CCCT | 1,453 | 32.10 | 6,779 | 5.00 | 249 | 362 |

## Wind Generation

While wind resources benefit from having no direct emissions or fuel costs, they are not typically dispatchable to meet load. Avista modeled four general wind location options in this plan: Montana, Eastern Washington, the Columbia River Basin and offshore. Configurations of wind facilities are changing given transmission limitations in the region, benefits of tax credits, low construction prices and the potential for storage. These factors allow for sites being built with higher capacity levels than the transmission system can currently integrate. When the wind facilities generate additional MWh above the physical transmission limitations[5], the generators typically feather or store energy using onsite energy storage. At this time, Avista is not modeling wind with onsite storage or wind facilities with greater output capabilities then can be integrated on the transmission system. Since storage at a wind facility does not benefit from tax incentives, Avista's modeling process allows for storage to be sited at a wind facility if cost effective.

Onshore wind capital costs in 2020, including construction financing, are $1,300 per kW for Washington on-system projects, off-system projects including locations in Oregon and Montana are $1,268 per kW, and offshore wind is $2,950 per kW. The annual fixed O&M costs of $32.30 per kW-year is for onshore wind and $95.00 per kW-year for offshore wind. Fixed O&M does not include indirect charges to account for the inherent variation in wind generation often referred to as wind integration. The cost of wind integration depends on the penetration of wind resources in Avista's balancing authority and the market price of power.

Wind capacity factors in the Northwest range between 25 and 40 percent depending on location and in the 45 to 55 percent range in Montana and offshore locations. This plan assumes Northwest wind has a 35 percent average capacity factor. A statistical method, based on regional wind studies, derives a range of annual capacity factors depending on

[4] Costs based on Idaho. Washington's costs would be slightly higher due to higher sales tax rate of 8.9% compared with Idaho's 6.0% rate.

[5] If transmission is limited due to contractual reasons, an additional option is to buy non-firm transmission to move the power.

the wind regime in each year (see stochastic modeling assumptions section for details in Chapter 10).

This IRP estimated potential costs for offshore wind. Offshore wind has the potential for higher capacity factors (55 percent), but development and operating costs are higher. At the time of this IRP, developers have not been offering an offshore product in the Pacific Northwest. The pricing and costs are estimates based on other proposals in North America and were not directly modeled in this IRP as a resource option.

As discussed above, levelized wind costs change substantially due to the capacity factor but can change even more from tax incentives and the ownership structure of the facility. Table 9.3 shows the nominal levelized prices with different start dates for each modeled location. These price estimates assume the facility is acquired using a 20-year PPA with a flat pricing structure, the intermittent generation integration charge for the first 100 MW added to Avista's system, and includes costs associated with the cost of the PPA, excise taxes, commission fees, and uncollectables to customers. These costs do not include the transmission costs for either capital investment or wheeling purchases. If a PPA is selected in Avista's preferred resource strategy (Chapter 11), the model assumes the PPA will extend through the 24-year time period.

### Photovoltaic Solar

Photovoltaic (PV) solar generation technology costs have fallen substantially due to low-cost imports and from increased demand driven by renewable portfolio standards. Solar systems are often built with more generating capacity than the transmission interconnect allows to take advantage of those limited times when full energy production can be utilized. To help with integration of intermittent production, some systems have storage connected to the system to avoid curtailment by storing excess energy or shifting energy to higher priced hours. Solar plus storage has an advantage, compared to other renewable systems, because storage may qualify for investment tax credits when paired with solar if the stored energy is generated by solar. Since both systems use DC power, they can utilize the same power inverters. Other renewable resources may not benefit from this tax provision because production, rather than capital spending, drive the tax credits for those resources. It is possible future solar incentives will be similar to the Production Tax Credit rather than the Investment Tax Credit (ITC).

Avista models three solar systems for this IRP. The first is an on-system solar facility in 25 MW (AC) increments, modeled as a facility with at least 100 MW to take advantages of economies of scale. Solar costs can change significantly depending on the size of the project; to address this issue, a smaller 5 MW (AC) on-system solar option is also included. The third solar option includes a 100 MW facility to be wheeled to Avista from higher solar production areas such as southern Idaho or Oregon. While any location can participate in a future RFP, transmission charges and availability will determine if a project moves forward with Avista.

**Table 9.3: Levelized Wind Prices ($/MWh)**

| Year | On-System Wind | Off-System Wind | Montana Wind | OffShore Wind |
|---|---|---|---|---|
| 2022 | 37 | 36 | 25 | 68 |
| 2023 | 44 | 41 | 31 | 72 |
| 2024 | 55 | 53 | 42 | 82 |
| 2025 | 56 | 53 | 42 | 81 |
| 2026 | 56 | 54 | 43 | 80 |
| 2027 | 57 | 55 | 43 | 79 |
| 2028 | 57 | 55 | 44 | 78 |
| 2029 | 58 | 56 | 44 | 77 |
| 2030 | 58 | 56 | 44 | 77 |
| 2031 | 59 | 57 | 45 | 77 |
| 2032 | 59 | 57 | 45 | 77 |
| 2033 | 60 | 58 | 46 | 77 |
| 2034 | 61 | 59 | 47 | 78 |
| 2035 | 62 | 60 | 47 | 78 |
| 2036 | 63 | 61 | 48 | 78 |
| 2037 | 63 | 62 | 49 | 79 |
| 2038 | 64 | 63 | 50 | 79 |
| 2039 | 65 | 64 | 50 | 79 |
| 2038 | 66 | 64 | 51 | 79 |
| 2039 | 67 | 66 | 52 | 79 |
| 2040 | 68 | 67 | 53 | 80 |
| 2041 | 69 | 68 | 54 | 81 |
| 2042 | 70 | 69 | 54 | 81 |
| 2043 | 71 | 70 | 55 | 82 |
| 2044 | 37 | 36 | 25 | 83 |
| 2045 | 44 | 41 | 31 | 83 |

Solar capital costs have been rapidly declining despite increasing tariffs costs. Technological improvements such as bi-facial panels make solar more efficient at delivering energy per square meter. For this IRP, larger systems assume a cost of $1,000 per kW (AC) for a single axis tracking system; by 2030, these costs are expected to rise to $1,219 per kW and $1,486 per kW by 2040 from inflation. While these costs increase in nominal dollars, real solar costs are likely to fall. Smaller systems assume premium prices due to a lack of economies of scale with a price of $2,347 per kW in 2030 with similar price changes as larger systems in the future. The cost to operate solar depends on the size of the facility and location due to property taxes and lease payments; given these varying costs, Avista assumes $11 per kW-year for larger systems and $14 per kW-year for smaller systems.

Table 9.4 shows the levelized prices for 20-year flat PPAs with additional costs to integrate the first 100 MW of intermittent generation, excise taxes, commission fees and uncollectables. These costs do not include transmission costs associated with either new construction or wheeling purchases.

## Table 9.4: Levelized Solar Prices

| Year | On-system | Southern NW | On-system (Distributed) |
|---|---|---|---|
| 2022 | 32 | 29 | 63 |
| 2023 | 32 | 28 | 62 |
| 2024 | 40 | 36 | 80 |
| 2025 | 40 | 35 | 79 |
| 2026 | 38 | 34 | 76 |
| 2027 | 37 | 34 | 74 |
| 2028 | 37 | 33 | 73 |
| 2029 | 36 | 33 | 72 |
| 2030 | 36 | 32 | 71 |
| 2031 | 36 | 33 | 71 |
| 2032 | 36 | 33 | 71 |
| 2033 | 36 | 33 | 72 |
| 2034 | 37 | 33 | 72 |
| 2035 | 37 | 33 | 72 |
| 2036 | 37 | 33 | 72 |
| 2037 | 37 | 33 | 72 |
| 2038 | 37 | 33 | 72 |
| 2039 | 37 | 33 | 72 |
| 2040 | 37 | 33 | 73 |
| 2041 | 38 | 34 | 73 |
| 2042 | 38 | 34 | 73 |
| 2043 | 38 | 34 | 74 |
| 2044 | 38 | 34 | 74 |
| 2045 | 39 | 34 | 74 |

### Solar Energy Storage (Lithium-Ion Technology)

As previously discussed, storage paired with solar takes advantage of federal tax credits, lowers transmission costs, shifts energy deliveries, manages intermittent generation, uses common equipment, increases peak reliability and can prevent energy oversupply. Avista must study each potential benefit to see its value and the amount of storage duration that is cost effective for each potential project. While the solar plus storage system receives tax incentives (approximately six years) it must be only supplied with solar energy. This limits the value of the storage asset due to its inability to assist with larger system variations.

Lithium-ion technology prices are declining and will likely continue to fall. Avista estimates the additional cost for more hours of storage in Table 9.5 for solar PPAs[6]. Avista modeled two two-hour duration and one four-hour duration options; although, 15 to 30 minutes would be considered if the technology is limited to assist with integrating intermittent generation rather than reliability. Avista's experience with solar generation from its 19.2 MW Adams Neilson PPA shows significant energy variation due to cloud cover. For this IRP, Avista considers the benefits for reducing the variable generation integration costs

[6] This table includes the values used in the IRP's PRiSM model, due to the complexity of these arrangements the costs within Appendix I may differ than those shown here due to modeling changes.

and enhanced resource adequacy of the storage device. Currently, due to the complexity and range of potential storage configurations, the IRP limits the storage options to a four-hour and two-hour designs. In addition, Avista's modeling of solar plus storage allows the storage device to use grid power as it may when tax incentives end after six years.

**Table 9.5: Storage Cost w Solar System ($/kW-month)**

| Year | 100 MW/ 400 MWh | 100 MW/ 200 MWh |
|---|---|---|
| 2022 | 8.2 | 7.3 |
| 2023 | 8.1 | 7.4 |
| 2024 | 6.2 | 5.7 |
| 2025 | 6.2 | 5.8 |
| 2026 | 6.4 | 6.2 |
| 2027 | 6.3 | 6.3 |
| 2028 | 6.2 | 6.4 |
| 2029 | 6.2 | 6.5 |
| 2030 | 6.1 | 6.7 |
| 2031 | 6.1 | 6.7 |
| 2032 | 6.1 | 6.8 |
| 2033 | 6.1 | 6.9 |
| 2034 | 6.1 | 7.0 |
| 2035 | 6.1 | 7.1 |
| 2036 | 6.1 | 7.2 |
| 2037 | 6.1 | 7.3 |
| 2038 | 6.2 | 7.4 |
| 2039 | 6.2 | 7.5 |
| 2040 | 6.2 | 7.6 |
| 2041 | 6.2 | 7.7 |
| 2042 | 6.3 | 7.9 |
| 2043 | 6.3 | 8.0 |
| 2044 | 6.3 | 8.1 |
| 2045 | 6.4 | 8.2 |

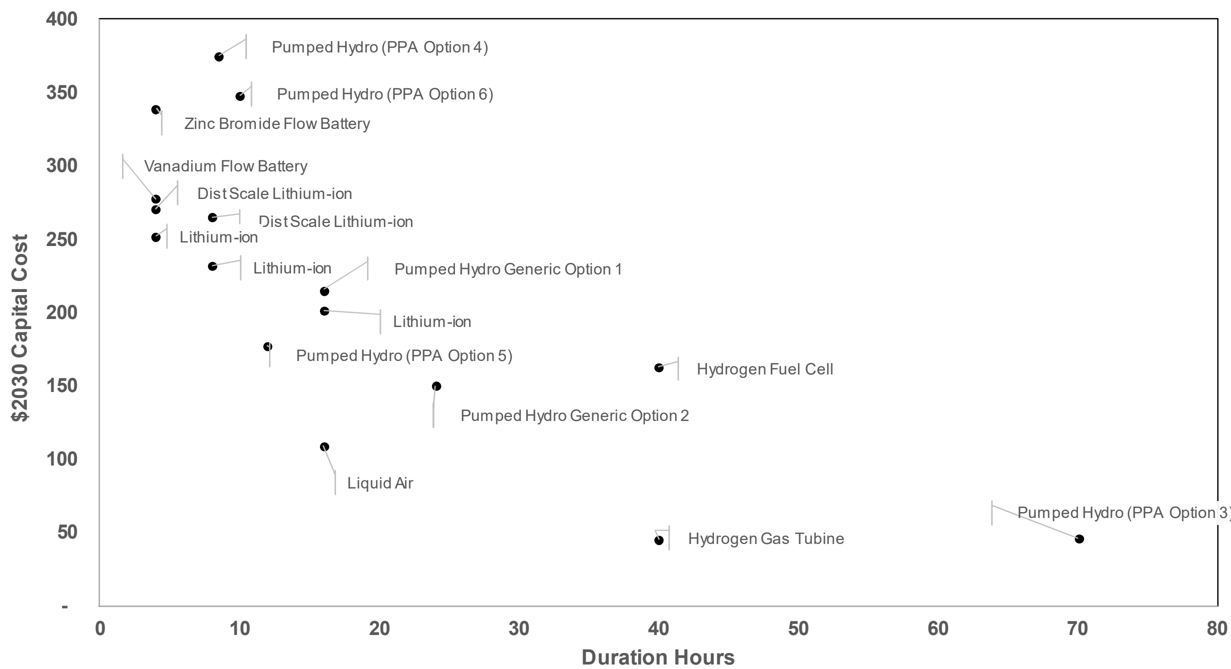
## Stand-Alone Energy Storage

Energy storage resources are gaining significant traction as a resource of choice in the western U.S. While energy storage does not create energy, it shifts it from one period to another in exchange for a portion of the energy stored. Avista modeled several energy storage options including pumped hydro storage, lithium-ion, vanadium flow, zinc bromide flow, liquid air and hydrogen. In addition to the technology differences, Avista also considers different energy storage durations for each technology. Pricing for energy storage is also rapidly changing due to the technology advancements currently taking place. In addition to changing prices for existing technologies, new technologies are entering the storage space. The rapid change in pricing and new available technologies justifies the need for frequent updates to the IRP analysis.

Another challenge with storage concerns pumped hydro technology where costs and storage duration can be substantially different depending on the geography of the proposed project. Storage is also gaining attention to address transmission and distribution expansion, where the technology can alleviate conductor overloading and short duration load demands rather than adding physical line/transformation capacity.

The storage costs discussed in this chapter are shown as the levelized cost for the duration capability of the storage resources. This means the cost of capital and operations are levelized then divided by the duration in kilowatt-hours of the resource. Storage cannot be shown in $ per MWh as with other generation resources because they do not create energy, only store it with losses. This analysis shows the cost differences between the technologies but does not consider the efficiency of the storage process or the cost of the energy stored. This analysis is performed in the resource selection process. Figure 9.1 summarizes the storage technologies based on upfront capital cost and duration using costs in 2030 dollars

**Figure 9.1: Storage Upfront Capital Cost versus Duration**




## Pumped Hydro Storage

The most prolific energy storage technology currently used in both the U.S. and the world is pumped hydro storage. This technology requires the use of two or more water reservoirs with different elevations. When prices or load are low, water is pumped to a higher reservoir and released during higher price or load periods. This technology may help with meeting system integration issues from intermittent generation resources. Currently only one of these projects exists in the northwest and several more are in various stages of the permitting process. An advantage with pumped hydro is the technology has a long service life and is a technology Avista is familiar with as a hydro generating utility. The greatest disadvantages are large capital costs and long-permitting cycles.

The technology has good round trip efficiency rates (Avista assumes 81 percent for most options). When projects are developed, they are designed to utilize the amount of water storage in each reservoir and the generating/pump turbines are sized for how long the capacity needs to operate. For the IRP resource analysis, Avista models the technology with six different durations: 8.5, 10, 12, 16, 24 and 70 hours. These durations indicate the number of hours the project can run at full capacity. The pricing and durations of these facilities are based on projects currently being developed in the northwest. Modeling different duration times are required since in an energy-limited system, Avista requires resources with enough energy to provide reliable power over an extended period in addition to meeting single hour peaks. This study used the ELCC analysis discussed later in the chapter to determine the Peak Credit for pumped hydro storage. Avista bases its pricing for pumped hydro using a PPA financing methodology with fixed and variable payments for four of the modeled options (3 through 6) to replicate current pumped hydro opportunities in the northwest. Avista also modeled two potential ownership projects in the event of future developments (options 1 and 2). The complete range in levelized cost for pumped hydro is shown in Table 9.6. PPA options also include a $5 per MWh (escalating with inflation) variable payment for each MWh generated.

**Table 9.6: Pumped Hydro Company-Owned Options**

| Year | Option 1 (16 hr) | Option 2 (24 hr) | Option 3 (70 hr) | Option 4 (8.5 hr) | Option 5 (12 hr) | Option 6 (10 hr) |
|---|---|---|---|---|---|---|
| | $/kW-Year | $/kW-Year | $/kW-Month | $/kW-Month | $/kW-Month | $/kW-Month |
| 2022 | 420.2 | 437.8 | 21.76 | 23.28 | 15.19 | 25.15 |
| 2023 | 426.6 | 444.4 | 22.07 | 23.62 | 15.42 | 25.53 |
| 2024 | 433.0 | 451.1 | 22.39 | 23.98 | 15.64 | 25.91 |
| 2025 | 439.6 | 457.9 | 22.72 | 24.34 | 15.88 | 26.30 |
| 2026 | 446.2 | 464.8 | 23.05 | 24.70 | 16.11 | 26.69 |
| 2027 | 453.0 | 471.9 | 23.39 | 25.07 | 16.35 | 27.09 |
| 2028 | 459.8 | 479.0 | 23.73 | 25.45 | 16.60 | 27.50 |
| 2029 | 466.8 | 486.3 | 24.07 | 25.83 | 16.84 | 27.91 |
| 2030 | 473.9 | 493.6 | 24.42 | 26.22 | 17.09 | 28.32 |
| 2031 | 481.0 | 501.1 | 24.78 | 26.61 | 17.35 | 28.75 |
| 2032 | 488.3 | 508.7 | 25.13 | 27.01 | 17.61 | 29.18 |
| 2033 | 495.7 | 516.4 | 25.50 | 27.42 | 17.87 | 29.61 |
| 2034 | 503.2 | 524.2 | 25.87 | 27.83 | 18.14 | 30.06 |
| 2035 | 510.8 | 532.1 | 26.25 | 28.24 | 18.41 | 30.50 |
| 2036 | 518.6 | 540.2 | 26.63 | 28.67 | 18.68 | 30.96 |
| 2037 | 526.4 | 548.4 | 27.01 | 29.10 | 18.96 | 31.42 |
| 2038 | 534.4 | 556.7 | 27.41 | 29.53 | 19.24 | 31.89 |
| 2039 | 542.5 | 565.1 | 27.80 | 29.98 | 19.53 | 32.37 |
| 2040 | 550.7 | 573.6 | 28.21 | 30.43 | 19.82 | 32.85 |
| 2041 | 559.1 | 582.3 | 28.62 | 30.88 | 20.11 | 33.34 |
| 2042 | 567.5 | 591.1 | 29.03 | 31.35 | 20.41 | 33.84 |
| 2043 | 576.1 | 600.1 | 29.45 | 31.82 | 20.71 | 34.35 |
| 2044 | 584.9 | 609.2 | 29.88 | 32.29 | 21.02 | 34.86 |
| 2045 | 593.7 | 618.4 | 30.31 | 32.78 | 21.34 | 35.38 |

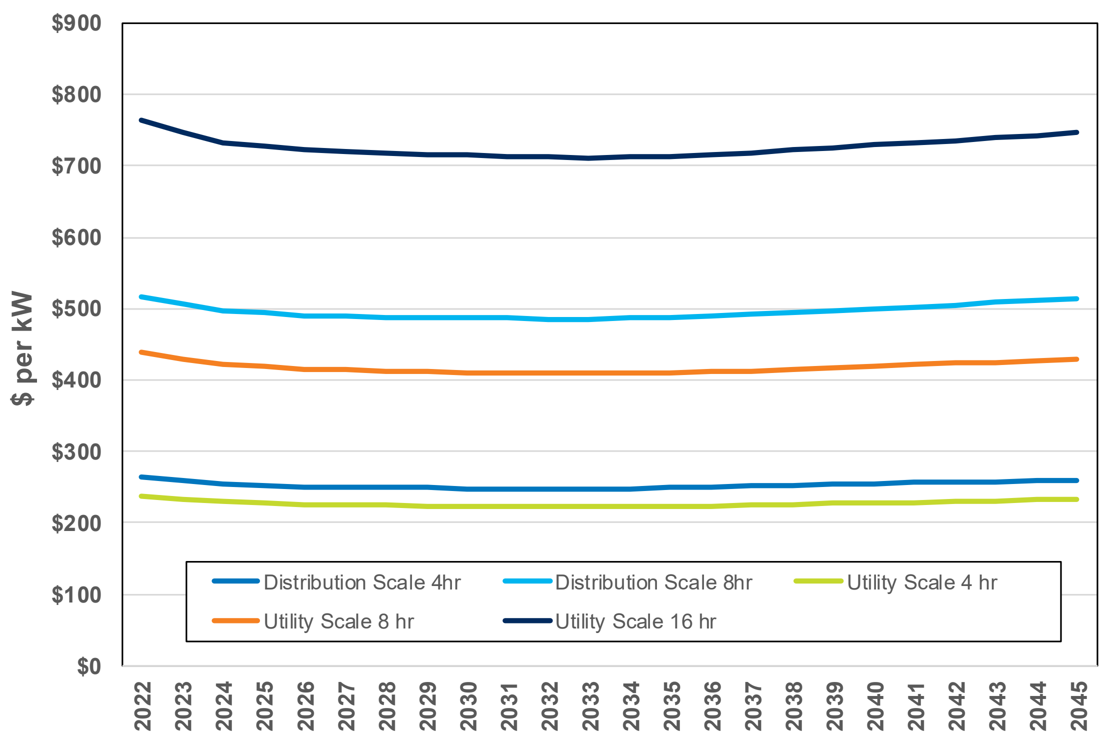
## Lithium-Ion

Lithium-ion technology is one of the fastest growing segments of the energy storage space. When coupled with solar, both tax advantages and economies of scope can reduce the upfront pricing. This discussion focuses on using energy storage as a stand-alone resource rather than coupled with solar. Stand-alone lithium-ion assumes a utility owned asset for modeling purposes, but it could be acquired through a PPA as well with two 10-year cycles for a 20-year life. Fixed O&M costs include replacement cells to maintain the energy conversion efficiency and capacity for this storage option.

The lithium-ion technology is an advanced battery using ionized lithium atoms in the anode to separate their electrons. This technology can carry high voltages in small spaces making it a preferred technology for mobile devices, power tools and electric vehicles. The large manufacturing sector of the technology is driving prices lower permitting the construction of utility scale projects.

Avista modeled five conceptual stand-alone configurations for lithium-ion batteries. Two DER small-scale sizes (5 MW) with four- and eight-hour durations for modeling the potential for use on the distribution system and three larger systems (25 MW) including four- and eight-hour durations as well as a theoretical 16-hour configuration were derived from publicly available energy consultant sources. Figure 9.1 show the forecast for each of the sizes and durations considered. Avista classifies the 4-hour battery as the standard technology with a capital cost of $1,288 per kW in 2020 dollars. Fixed O&M costs are also expected to decline; Avista assumed for the 4-hour technology an annual cost of $238.60 per kW-year in 2022 and falling to $222.50 per kW-year by 2032.

**Figure 9.2: Lithium-ion Capital Cost Forecast**



Storage technology is often displayed in many methods to illustrate the cost because it is not a traditional capacity resource. Table 9.7 shows levelized cost per kW for each configuration. This calculation factor levelizes the cost for the capital, O&M and regulatory fees including capital reinvestments over 20 years divided by the capacity duration. These costs do not consider the variable costs, such as energy purchases.

**Table 9.7: Lithium-ion Levelized Cost $/kW**

| Year | Distribution Scale 4 hour | Distribution Scale 8 hour | Utility Scale 4 hour | Utility Scale 8 hour | Utility Scale 16 hour |
|---|---|---|---|---|---|
| 2022 | 238 | 378 | 173 | 318 | 552 |
| 2023 | 242 | 374 | 171 | 314 | 546 |
| 2024 | 246 | 372 | 169 | 312 | 542 |
| 2025 | 250 | 370 | 169 | 310 | 539 |
| 2026 | 254 | 369 | 168 | 309 | 538 |
| 2027 | 258 | 369 | 168 | 309 | 537 |
| 2028 | 262 | 369 | 168 | 308 | 536 |
| 2029 | 266 | 369 | 168 | 308 | 536 |
| 2030 | 271 | 370 | 168 | 309 | 537 |
| 2031 | 275 | 371 | 168 | 309 | 538 |
| 2032 | 280 | 372 | 169 | 310 | 539 |
| 2033 | 284 | 374 | 169 | 311 | 542 |
| 2034 | 289 | 377 | 170 | 313 | 544 |
| 2035 | 294 | 379 | 171 | 315 | 548 |
| 2036 | 298 | 382 | 172 | 317 | 551 |
| 2037 | 303 | 385 | 174 | 319 | 555 |
| 2038 | 308 | 388 | 175 | 322 | 559 |
| 2039 | 313 | 391 | 176 | 324 | 563 |
| 2040 | 319 | 394 | 177 | 326 | 567 |
| 2041 | 324 | 397 | 178 | 328 | 571 |
| 2042 | 329 | 400 | 180 | 331 | 575 |
| 2043 | 335 | 403 | 181 | 333 | 579 |
| 2044 | 340 | 406 | 182 | 335 | 583 |
| 2045 | 346 | 409 | 183 | 337 | 587 |

## Flow Batteries

This IRP modeled vanadium and zinc bromide flow batteries. Other technologies are beginning to enter the marketplace, including iron. Flow batteries have the advantage over lithium-ion of not degrading over time leading to longer operating lives. The technology consists of two tanks of liquid solutions that flow adjacent to each other past a membrane and generate a charge by moving electrons back and forth during charging and discharging. Avista assumed an acquisition size of 25 MW of capacity with 4-hours in duration for each technology.

Capital costs are $1,633 per kW for the vanadium in 2020 and costs fall 44 percent by 2030. Zinc bromide’s capital cost are $1,837 per kW in 2020 falling 39 percent by 2030. Fixed O&M costs are $57 per kW-year for vanadium and $64 per kW-year for zinc bromide and increase with inflation. Round-trip efficiency for the vanadium is 70 percent and for the zinc bromide is 67 percent. Given Avista's recent experience with vanadium flow batteries, these efficiency rates are highly dependent on the battery's state of charge and how quickly the system is charged or discharged. Table 9.8 shows the levelized cost per kWh of capacity.

### Table 9.8: Flow Battery Levelized Cost $/kWh of Capacity

| Year | Vanadium | Zinc Bromide |
|---|---|---|
| 2022 | 227 | 246 |
| 2023 | 222 | 244 |
| 2024 | 217 | 243 |
| 2025 | 217 | 242 |
| 2026 | 213 | 242 |
| 2027 | 213 | 242 |
| 2028 | 212 | 242 |
| 2029 | 212 | 242 |
| 2030 | 212 | 243 |
| 2031 | 211 | 243 |
| 2032 | 211 | 244 |
| 2033 | 211 | 245 |
| 2034 | 212 | 247 |
| 2035 | 213 | 248 |
| 2036 | 214 | 250 |
| 2037 | 215 | 251 |
| 2038 | 217 | 253 |
| 2039 | 219 | 255 |
| 2040 | 221 | 256 |
| 2041 | 222 | 258 |
| 2042 | 224 | 260 |
| 2043 | 226 | 261 |
| 2044 | 228 | 263 |
| 2045 | 229 | 265 |

## Liquid Air

A new technology with promise to provide long duration and long service life is liquid air storage. This is similar to compressed air storage, but rather than compressing the air, the air is cryogenically frozen and stored in a tank to increase storage duration capability. The conversion process requires a liquefier to liquefy the air for storage. It is possible to use waste heat from existing natural gas-fired turbines to increase the efficiency of liquefying the air molecules. This increases round-trip efficiencies from 65 percent to 75 percent. After the air is stored, it can later be used by pushing the air through an air turbine.

Liquid air has not been widely used in the electric sector but relies on common technology from other industries requiring liquefaction of gases. This experience in the technology gives promise as a new technology that could benefit from short commercialization periods. Avista assumed a 25 MW unit capacity with 400 MWh hours of storage (16 hours). Another advantage of this technology is the ability to add storage capacity by adding more tanks while using the same turbine and liquefaction systems.

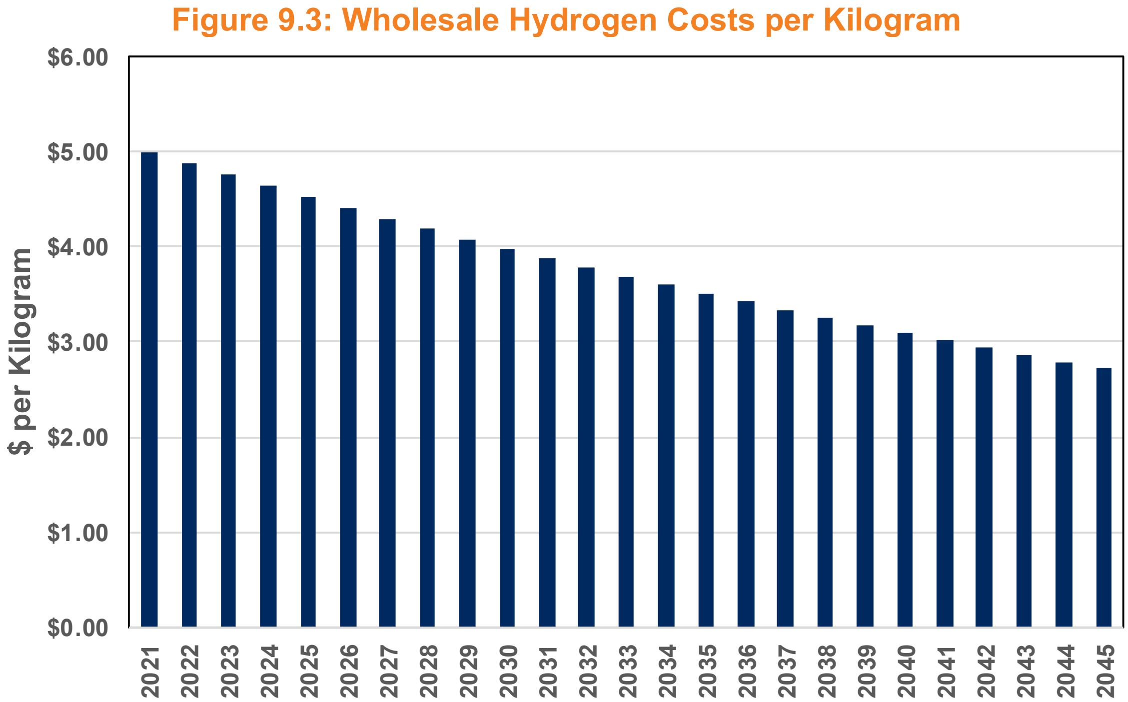
Avista estimates liquid air storage capital costs at $1,429 per kW (2020 dollars) and increases with inflation due to the use of mature industrial technology. Fixed O&M is $26 per kW-year and carries a $3.06 per MWh variable charge. The levelized cost of the storage is estimated to be $233 per kW for 2022 and future years increase with inflation.

### Hydrogen/ Fuel Cell

The idea of using hydrogen in the energy sector has been a perennial option for the distant future. Avista recognizes this technology as an avenue for long-duration energy storage with the potential to store power to continuously run for up to several days. Hydrogen would be delivered by pipeline, truck or rail and stored in tanks and then converted back to power (and water) when needed using a fuel cell or hydrogen-fueled turbine. This process would result in a 34 percent round trip efficiency. The ability to store hydrogen in tanks similar to liquid air means medium term duration times can be obtained. Significant R&D is being dedicated to hydrogen technologies in transportation and other sectors which may result in reduced costs or increased operating efficiency. It is also possible transportation and other sectors could utilize the electric power system to create a cleaner form of hydrogen to offset gasoline, diesel, propane or natural gas. The concept of offsetting natural gas led Avista to engage Black and Veatch to provide estimates for renewable hydrogen options for the Natural Gas IRP. These assumptions and discussion resulted from this study.

Most hydrogen today uses methane-reforming techniques to remove hydrogen from natural gas or coal. This technology is primarily used in the oil and natural gas industries but results in similar levels of greenhouse gas emissions from the combustion of the underlying fuels absent sequestration or carbon capture. If green hydrogen is obtained from “clean” energy through electrolysis, the amount of greenhouse gas emissions can be greatly reduced. If renewable energy prices fall and there is an available water supply, the operating cost of creating green hydrogen could also fall, however capital costs would remain steady with significant technology enhancements.

Converting hydrogen back into power could be done by using a hydrogen fuel cell or direct burning in a combustion turbine similar to natural gas-fired generation. Figure 9.2 shows the forecasted delivered price of hydrogen to a potential green hydrogen fuel facility in Avista’s service territory. The development and delivery of green hydrogen is estimated based on the projected cost of electrolyzer technology with reduction in costs due to scaling and access to low cost renewable electric power.




The second step in the hydrogen concept is to convert the hydrogen back to power. For this conversion, a 25 MW fuel cell would be assembled for utility scale needs. The estimated capital cost for a fuel cell is $5,356 per kW with a forty-hour storage vessel plus fixed O&M at $160 per kW-year. Table 9.9 shows the all-in levelized cost of hydrogen including the fuel cell.

There are significant safety concerns relative to hydrogen that would have to be mitigated. Hydrogen ignites more easily than gasoline or natural gas. Therefore, adequate ventilation and leak detection are important elements in the design of a safe hydrogen storage system. Hydrogen burns with a nearly invisible flame which requires special flame detectors. Some metals become brittle when exposed to hydrogen, so selecting the appropriate metal is important to the design of a safe storage system. Finally, appropriate training in safe hydrogen handling would be necessary to ensure safe use. Appropriate engineering along with safety controls and guidelines could mitigate the safety risk of hydrogen but add to the high capital and operating costs of this resource option.

### Hydrogen Turbine

Another hydrogen generation technology studied in this IRP is a hydrogen gas-fired turbine with above ground storage. Avista assumes an 84 MW capacity with 3,356 MWh hours of compressed storage (40 hours). An advantage of this technology is the ability to add storage capacity by adding additional tanks and using the same turbine.

Avista estimates hydrogen gas turbine capital costs at $1,490 per kW (2020 dollars) and increases with inflation due to the use of mature technology. Fixed O&M is $5 per kW-year and carries a $4 per MWh variable charge. The levelized cost of the storage is estimated to be $176 per kW for 2022 and future years increase with inflation.

### Table 9.9: Hydrogen Storage, Fuel Cell and Turbine Levelized Cost $/kWh

| Year | Fuel Cell (40-hour Storage) | Turbine (40-hour Storage) |
|---|---|---|
| 2022 | 837 | 176 |
| 2023 | 840 | 177 |
| 2024 | 844 | 177 |
| 2025 | 848 | 177 |
| 2026 | 853 | 177 |
| 2027 | 857 | 177 |
| 2028 | 861 | 177 |
| 2029 | 865 | 177 |
| 2030 | 870 | 177 |
| 2031 | 874 | 178 |
| 2032 | 879 | 178 |
| 2033 | 884 | 178 |
| 2034 | 889 | 178 |
| 2035 | 894 | 178 |
| 2036 | 899 | 178 |
| 2037 | 904 | 178 |
| 2038 | 909 | 179 |
| 2039 | 914 | 179 |
| 2040 | 920 | 179 |
| 2041 | 925 | 179 |
| 2042 | 931 | 179 |
| 2043 | 937 | 179 |
| 2044 | 943 | 180 |
| 2045 | 949 | 180 |

## Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest management and are considered renewable. In the biomass generation process, a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale level generation. Avista's 50 MW Kettle Falls Generation Station consumes over 350,000 tons of wood waste annually or about 48 semi-truck loads of wood chips per day. It typically takes 1.5 tons of wood to make one megawatt-hour of electricity, but the ratio varies with the moisture content of the fuel. The viability of another Avista biomass project depends on the long-term availability, transportation needs and cost of the fuel supply. Unlike wind or solar, woody biomass can be stockpiled and stored for later use. Many announced biomass projects fail due to the lack of a reliable long-term fuel source.

Based on market analysis of fuel supply and expected use of biomass facilities, a new facility could be envisioned as a wood-fired peaker. With high levels of intermittent renewable generation, a wood-fired peaker could be constructed to generate during low renewable output months or days. The capital cost for this type of facility would be $2,500 per kW plus O&M amounts of $26 per kW-year for fixed costs and $3.30 per MWh of variable costs (2020 dollars). The levelized cost per MWh is $115 per MWh for a 2022 project.

## Geothermal Generation

Geothermal energy provides predictable capacity and energy with minimal CO2 emissions (zero to 200 pounds per MWh). Some forms of geothermal technology extract steam from underground sources to run through power turbines on the surface while others utilize an available hot water source to power an Organic Rankine Cycle installation. Due to the geologic conditions of Avista's service territory, no geothermal projects are likely to develop locally. Geothermal energy often struggles to compete economically due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust with no guarantee of reaching useable geothermal resources. Ongoing geothermal costs are low, but the capital required for locating and proving a viable site are significant. In Avista's 2018 RFP, one geothermal project was bid, leading Avista to reconsider this option as a possible resource in its IRPs. The 2020 RFP did not receive any geothermal options. While a project was bid in the past, geothermal resources must overcome the hurdles previously discussed. This IRP estimates a future geothermal PPA at $81 per MWh in 2022 at the busbar.

## Nuclear

Avista studies nuclear power options in IRP, but given the uncertainty of their economics, regional political issues with the technology, U.S. nuclear waste handling policies and Avista's modest needs relative to the size of modern nuclear plants Avista is unlikely to select a nuclear project in its preferred portfolio even if economic. Nuclear resources could be in Avista's future only if other utilities in the Western Interconnect incorporate nuclear power into their resource mix and offer Avista a PPA or if cost effective small-scale nuclear plants become commercially available.

The viability of nuclear power could change as national policy priorities focus attention on decarbonizing the nation's energy supply. The limited amount of recent nuclear construction experience in the U.S. makes estimating construction costs difficult. Cost projections in the IRP are from industry studies, recent nuclear plant license proposals and the small number of projects currently under development. Modular nuclear design could increase the potential for nuclear generation by shortening the permitting and construction phase and making these traditionally large projects a better fit to the needs of smaller utilities. Given this possibility, Avista included an option for small scale nuclear power. The estimated cost for nuclear per MWh on a levelized basis in 2030 is $94 per MWh assuming capital costs of $4,544 per kW (2020 dollars) as a PPA.

## Other Generation Resource Options

Resources not specifically included as options in this IRP include cogeneration, landfill gas, anaerobic digesters and central heating districts. This plan does not model these resource options explicitly but continues to monitor their availability, cost and operating characteristics to determine if state policies change or the technology becomes more economically viable.

Exclusion from the PRS analysis does not automatically exclude non-modeled technologies from Avista's future resource portfolio. The non-modeled resources can compete with resources identified in the PRS through competitive acquisition processes that always occur when a resource shortage is indicated, and the Company seeks resources to fill those needs. Competitive acquisition processes identify technologies to displace resources otherwise included in the IRP strategy. Another possibility is acquisition through a PURPA contract. PURPA provides developers the ability to sell qualifying power to Avista at set prices and terms[7] outside of the RFP process.

## Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane gas collected at landfills. The costs of a landfill gas project depend on the site specifics of a landfill. The Spokane area had a project at one of its landfills, but it was retired after the fuel source depleted to an unsustainable level. Much of the Spokane area uses the Spokane Waste to Energy Plant instead of landfills for solid waste disposal. Nearby in Kootenai County, Idaho, the Kootenai Electric Cooperative developed the 3.2 MW Fighting Creek Project. Using publicly available costs and the NPCC estimates, landfill gas resources are economically promising, but are often limited in their size, quantity and location. Many landfills are considering cleaning the landfill gas to create pipeline quality gas due to low wholesale electric market prices. This form of renewable natural gas has become an option for utilities to offer a renewable gas alternative to customers. This form of gas and the duration of the supply depends on the on-going disposal of trash, otherwise the methane could be depleted in six to nine years.

## Anaerobic Digesters (Manure or Wastewater Treatment)

The number of anaerobic digesters is increasing in the Northwest. These plants typically capture methane from agricultural waste, such as manure or plant residuals, and burn the gas in reciprocating engines to power generators or directly inject a cleaned fuel into the natural gas pipeline. These facilities tend to be significantly smaller than most utility-scale generation projects and are often less than five megawatts. Most digester facilities are located at large dairies and cattle feedlots. A survey of Avista's service territory found no large-scale livestock operations capable of implementing this technology.

Wastewater treatment facilities can host anaerobic digesting technology. Digesters installed when a facility is initially constructed helps the economics of a project significantly, although costs range greatly depending on system configuration. Retrofits to existing wastewater treatment facilities are possible but tend to have higher costs. Many projects offset energy needs of the facility, so there may be little, if any, surplus generation capability. Avista currently has a 260-kW wastewater system under a PURPA contract with a Spokane County wastewater facility.

## Small Cogeneration

Avista has few industrial customers with loads significantly large enough to support a cogeneration project. If an interested customer developed a small cogeneration project, it could provide benefits including reduced transmission and distribution losses, shared

[7] Rates, terms, and conditions are available at www.avistautilities.com under Schedule 62.

fuel, capital and emissions costs, as well as credit toward Washington's EIA efficiency targets.

Another potentially promising option is natural gas pipeline cogeneration. This technology uses waste-heat from large natural gas pipeline compressor stations. Few compressor stations exist in Avista's service territory, but the existing compressors in our service territory have potential for this generation technology. Avista has discussed adding cogeneration with pipeline owners, but no project has been deemed feasible. A big challenge in developing any new cogeneration project is aligning the needs of the cogenerator with the utility need for power. The optimal time to add cogeneration is during the creation or retrofit of an industrial process, but the retrofit may not occur when the utility needs new capacity. Another challenge to cogeneration within an IRP is estimating costs when host operations drive costs for a project. The best method for the utility to acquire this technology is through the PURPA process or through a future RFP.

### Coal

The coal generation industry is at a crossroads. In many states, like Washington, new coal-fired plants are extremely unlikely due to current policy, emission performance standards and the shortage of utility scale carbon capture and storage projects. The risks associated with future carbon legislation and projected low natural gas and renewables costs make investments in this technology highly unlikely. It is possible in the future there will be permanent carbon capture and sequestration technology at price points to compete with alternative fuels. Avista will continue to monitor this development for future IRPs.

### Heating Districts

Historically heating districts were preferred options to heat population dense city centers. This concept relies on a central facility to either create steam or hot water then distribute via a pipeline to buildings to provide end use space and water heating. Historically, Avista provided steam for downtown Spokane using a coal-fired steam plant. This concept is still used in many cities in the U.S. and Europe including Seattle, WA. Developing new heating districts requires the right circumstances, partners and long-term vision.

These requirements recently came together in a new concept of central heating districts being tested by a partnership between Avista and McKinstry in the Spokane University District, also called the Eco-District. The Hub facility contains a central energy plant to generate, store and share thermal and electrical energy with a combination of heat pumps, boilers, chillers, thermal and electrical storage. The Hub controls all electric consumption for the campus and balances this against the needs of both the development and the grid. Future buildings within the district will be served by the Hub's central energy plant, expanding the district's shared energy footprint. A part of the Eco-District development will involve studying the costs and benefits of this configuration. The success of the district will determine how it will be implemented in the future for Avista's customers.

### Bonneville Power Administration

For many years, Avista received power from the Bonneville Power Administration (BPA) through a long-term contract as part of the settlement from WNP-3. Most of the BPA's power is sold to preference customers or in the short-term market. Avista does not have access to power held for preference customers but engages BPA on the short-term market. Avista has two other options for procuring BPA power. The first is using the New Resource NR rate. BPA's power tariff outlines a process for utilities to acquire power from BPA using this rate for one year at a time. As of the publishing of this IRP, the NR rate is $79.80 per MWh[8]. Since this offering is short-term and variable, Avista does not consider it a viable long-term option for planning purposes, however, it is a viable alternative for short-run capacity needs. The other option to acquire power from BPA is to solicit an offer. BPA is willing to provide prices for periods of time when it believes it has excess power or capacity. This process would likely parallel an RFP process for future capacity needs and likely take place after current agreements with public power customers end in 2027.

### Existing Resources Owned by Others

Avista has purchased long-term energy and capacity from regional utilities in the past, specifically the Public Utility Districts in Mid-Columbia region and has a tolling agreement for the Lancaster Generating Station. Avista contracts are discussed in Chapter 4, but extensions or new agreements could be signed. If utilities are long on capacity, it is possible to develop agreements to strengthen Avista's capacity versus load position. Since these potential agreements are based on existing assets, prices are dependent on future markets. Avista is modeling for this IRP the possibility of an up to 75 MW extension of existing hydro agreements, but the cost and actual quantities available in the future are unknown. Avista could acquire or contract for energy and capacity of other existing facilities without long term agreements. Avista anticipates these resources will be offered into future RFPs and may replace any resources selected in this IRP.

### Renewable Natural Gas

Avista did not model the option to use renewable natural gas (RNG) for electric generation in this IRP. RNG is methane gas sourced from waste produced by dairies, landfills, wastewater treatment plants and other facilities. The amount of RNG is limited by the output of the available processes. The amount of greenhouse gas emissions the RNG offsets differs depending upon the source of the gas and the duration of the methane abatement used. Avista considers the cost-effective use of this fuel type in its Natural Gas IRP and believes its best use is to reduce emissions from the direct use of natural gas rather than use as a fuel in natural gas-fired turbines due to higher end-use efficiency in customers' homes.

## Hydro Project Upgrades and Options

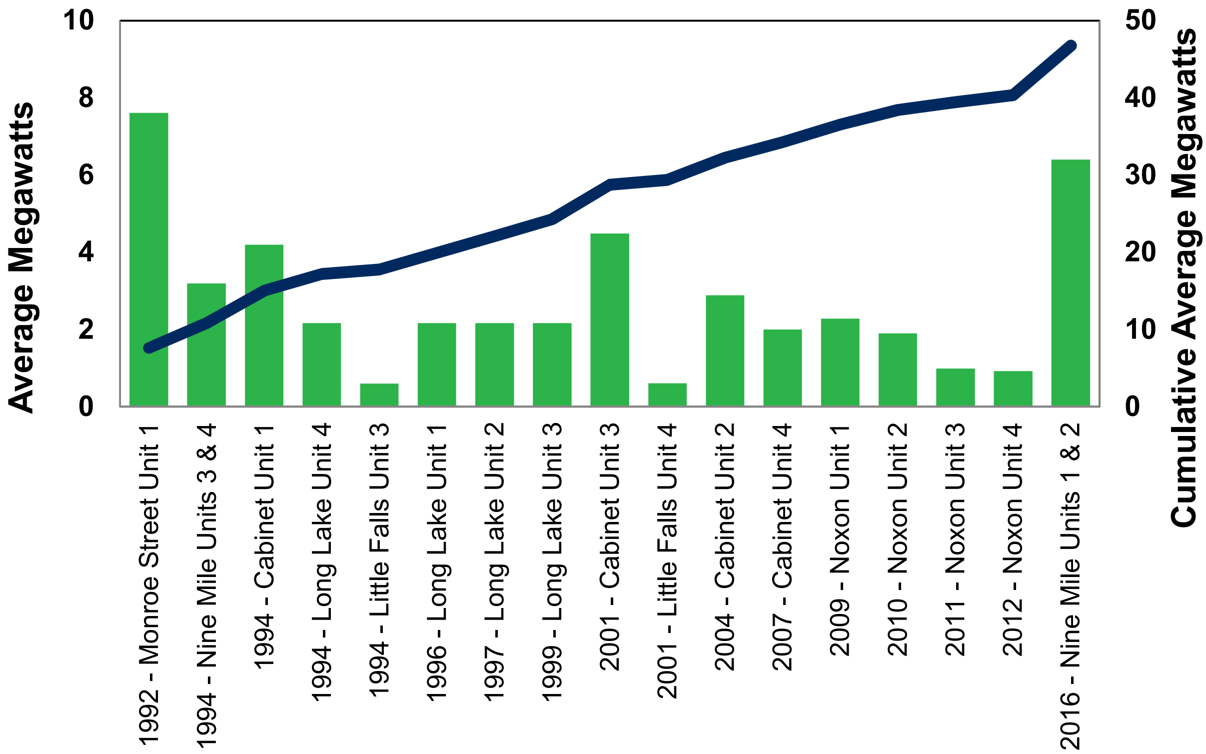
Avista continues to upgrade its hydro facilities as shown in Figure 9.3. The latest hydro upgrade added 10 megawatts to the Nine Mile Falls Development in 2016. Avista added 46.8 aMW of incremental hydro energy between 1992 and 2016. Upgrades completed after 1999 can qualify for the EIA, thereby reducing the need for additional renewable

[8] https://www.bpa.gov/Finance/RateInformation/Pages/Current-Power-Rates.aspx.

energy options. Further, any upgrade can qualify for CETA if it meets the requirements as a clean energy resource.

Construction of the Spokane River hydro project occurred in the late 1800s and early 1900s, when the priority was to meet then-current loads. The developments using the technology of the time do not capture most river flows. In 2012, Avista reassessed its Spokane River Project to evaluate opportunities to capture more of the streamflow. The goal was to develop a long-term strategy and prioritize potential facility upgrades. Avista evaluated five of the six Spokane River hydro developments and estimated costs for generation upgrade options. Each upgrade option would qualify for the EIA renewable energy goal. These studies were part of the 2011 and 2013 IRP Action Plans and results appear below. Each of these upgrades are major engineering projects, taking several years to complete and requiring major changes to the FERC licenses and the project's non-consumptive water rights. The upgrades will compete against other renewable options when more renewables are required or developed as Avista considers the most effective management plans for these existing projects.

**Figure 9.4: Historical and Planned Hydro Upgrades**




## Post Falls

This IRP assumes a refurbishment of Post Falls by 2026. Avista studied this upgrade in the 2020 IRP and it was found to be cost effective. Avista is continuing to engineer and plan for this refurbishment and assumptions will likely change over time, but for planning purposes Avista assumes an additional 3.8 MW of incremental winter capacity and 4 aMW of incremental clean energy from this upgrade.

## Long Lake Second Powerhouse

Avista studied adding a second powerhouse at Long Lake over 30 years ago by using the small arch or saddle dam located on the south end of the project site. This project would be a major undertaking and require several years to complete, including major changes to the Spokane River FERC license and water rights. In addition to providing customers with a clean energy source, this project could help reduce total dissolved gas levels by reducing spill at the project and providing incremental capacity to meet peak load growth.

The 2012 study considered three alternatives. The first involved replacing the existing four-unit powerhouse with four larger units totaling 120 MW, increasing capacity by 32 MW. The other two alternatives considered development of a second powerhouse with a penstock from a new intake structure located downstream of the existing saddle dam. One powerhouse option was a single 68 MW turbine project. The second option was a two-unit 152 MW project. The best alternative in the study was to add the single 68 MW unit. Table 9.10 shows upgrade costs and characteristics. Avista does not believe this upgrade will meet the requirements of a qualifying clean energy project for CETA, consequently the upgrade is not included in this resource plan as it was in the 2020 IRP.

## Cabinet Gorge Second Powerhouse

Avista is exploring the addition of a second powerhouse at the Cabinet Gorge site to mitigate total dissolved gas and produce additional electricity. A new 110 MW underground powerhouse would benefit from an existing diversion tunnel around the dam built during original construction. Unfortunately, this resource would not have any peak capacity credit due to the water right limitations of the license. The resource only creates additional energy during spring runoff.

### Table 9.10: Hydroelectric Upgrade Options

| Resource | Long Lake | Cabinet Gorge |
|---|---|---|
| Incremental Capacity (MW) | 68 | 110 |
| Incremental Energy (MWh) | 202,531 | 161,885 |
| Incremental Energy (aMW) | 23.1 | 9.2 |
| Peak Credit (Winter/ Summer) | 100/100 | 0/0 |
| Capital Cost ($2020 Millions) | $162 | $255 |
| Levelized Energy Cost ($2022/MWh) | $98 | $186 |

# Thermal Resource Upgrade Options

For the last several IRPs, Avista investigated opportunities to add capacity at existing facilities. These projects have been implemented when cost effective. Avista is modeling three potential options at Rathdrum CT and an option at Kettle Falls Generating Station. Since pricing is sensitive to third-party suppliers, concept overviews with no costs are presented in this section. Estimated costs including the portfolio modeling is discussed in Chapter 11.

### Rathdrum CT Supplemental Compression

Supplemental compression is a new technology to increase airflow through the CT compressor thereby increasing machine output. This upgrade could increase Rathdrum CT capacity by 24 MW.

### Rathdrum CT 2055 Uprates

By upgrading certain combustion and turbine components, the firing temperature can increase to 2,055 degrees from 2,020 degrees providing a 5 MW increase in output.

### Rathdrum CT Inlet Evaporation

Installing a new inlet evaporation system could increase the Rathdrum CT capacity by 17 MW on a peak summer day, but no additional energy is expected during winter months.

### Kettle Falls Turbine Generator Upgrade

The Kettle Falls plant began operation in 1983. In 2025, the generator and turbine will be 42 years old and at the end of its expected life. Avista could spend additional capital and upgrade the unit by 12 megawatts rather than replace it with in-kind technology.

# Intermittent Generation Costs

Intermittent generation resources such as wind and solar require other resources to help balance the unpredictable energy supply. This results in a cost required by shifting from otherwise more efficient operations. This is challenging for Avista because the cost could be the difference of running stored water hours later compared to now. Avista began studying these costs on its system in 2007. This analysis created the methodology the ADSS model now uses to not only study the costs of the intermittent resources, but also better equip our real-time operations team with information to use in managing when to dispatch resources. For this IRP, wind adds approximately $5 per MWh in operating cost inefficiencies and solar $1.80 per MWh based on the 2007 study. Avista's 2007 study[9] is still relevant due to scenario analysis performed resulting in pricing similar to today's prices along with a similar resource portfolio. Avista believes these costs will increase with additional generation on the system and plans to update its intermittent cost study in 2021 and incorporate results in future IRPs. . Participation in an Energy Imbalance Market (EIM) can reduce these costs by up to 40 percent based on information provided by the CAISO.

[9] Avista engaged a third-party to update these studies as well as determine how these integration costs will be impacted in the future by EIM.

Another cost to consider when adding intermittent generation is the capacity value for reliability. Intermittent resources add additional load following requirements when operating in the event the resource loses power. For this additional requirement, Avista's ELCC studies require a 10 percent increase in held reserves for the produced energy each hour.

## Sub Hourly Resource and Ancillary Services Benefits

Many of the resources discussed in this chapter may provide reliability benefits to the electrical system beyond traditional energy and capacity due to intra hour needs and system reliability requirements. Some resources can provide reserve products such as frequency response or contingency reserves. Avista is required to hold generating reserves of 3 percent of load and 3 percent of on-line generation. This means resources need to be able to respond in 10 minutes in the event of other resource outages on the system. Within the reserve requirement, 24 MW must be held as frequency response to provide instantaneous response to correct system frequency variations. In addition to these requirements, Avista must also hold capacity to help control intermittent resources and load variance, this is referred to as load following and regulation. The shorter time steps minute-to-minute is regulation and longer time steps such as hour-to-hour is load following. Together these benefits consist of ancillary services for the purposes of this IRP.

Many types of resources can help with these requirements, specifically storage projects, natural gas peakers and hydro generation. Some DR options may help in the future as well. The benefits these projects bring to the system greatly depend on many external factors including other "capacity" resources within the system, the amount of variation of both load and generation, market prices, market organization (i.e. EIM) and hydro conditions. Internal factors also play a role, such as the ability for the resource to respond in speed and quantity. Avista conducted a study on its Turner Energy Storage project along with the Pacific Northwest National Lab to understand the operating restrictions of the technology. For example, if the battery is quickly discharged, the efficiency lowers and depending on the current state of charge the efficiency is also affected. These nuances make it more difficult to model in existing software systems.

Avista will continue studying the benefits of energy storage by modeling additional scenarios including price, water year and level of renewable penetration. It will also need to study the benefits of using a sub-hourly model rather than using variability estimates within the hour. Avista is refining the ADSS model to provide this complete analysis although Avista does not expect more detailed analysis to change the current results of these studies. Avista presented results from two studies regarding the potential analysis with the ADSS system. These analyses were completed using existing markets and showed the potential to provide benefits from new resources with flexibility. Although, as Avista enters a future with additional on-system renewables and an EIM, these estimates will need to be revised. Table 9.11 outlines the assumed values for Ancillary Service or within hour benefits for new construction projects. These estimates also apply to distributed energy resources in the event they are able to respond to utility signals.

**Table 9.11: Ancillary Services & Sub-hourly Value Estimates (2020 dollars)**

| Resource | $/kW-yr |
|---|---|
| Natural gas-fired CT/reciprocating engine | 1.00 |
| Lithium-ion battery | 4.74 |
| Lithium-ion battery connected to solar | 1.50 |
| Pumped hydro | 4.74 |
| Flow battery | 1.74 |
| Liquid Air | 0.50 |

## Resource Peak Credit and ELCC Analysis

Avista conducted substantial research and spent considerable time studying the impact of the effect of different resources on resource adequacy for this IRP and the 2020 IRP. Avista uses an Equivalent Load Carrying Capability (ELCC) analysis to determine the appropriate reliability benefit each resource provides to the system. Avista uses a peak credit to show the equivalent value of a resource to its "surrogate" natural gas turbine resource. Avista learned the quantity, location and mixture of resources has a substantial impact on the benefit each resource provides. For example, 4-hour duration storage can provide high levels of resource adequacy in small quantities because it has other resources to assist in its recharging; but as the proportion of storage gets larger, there is not enough energy to refill the storage device for later dispatch as shown in the E3 study for resource adequacy for the northwest[10]. When coupled with renewable energy storage, the combined resources may increase Avista's resource adequacy, but this depends on how much energy can be stored and the amount produced in critical periods. Higher levels of penetrations for renewables may lower their effect on resource adequacy.

To complete the analysis, Avista used 1,000 simulations of hydro, load, wind and forced outage rates to estimate the contribution for different types of resources available to meet its peak. This is measured by the resources ability to reduce Loss of Load Probability (LOLP) using the Avista Reliability Assessment Model (ARAM). ARAM simulates Avista's system on an hourly basis for a future year where resource deficits occur (i.e. 2030). Each of the simulations use a different potential configuration of the system assumptions to account for uncertainty of weather conditions and resource availability. For example, historical weather years are randomly input into the model to change loads and resource capability such as hydro availability and the maximum generation capability of thermal units. The model's objective is to determine if there are adequate resources available from the Avista resource stack to meet load and reserve requirements each hour. The model also has the ability to purchase energy from the wholesale market. This market is limited to 330 MW in days with weather conditions exceeding the 99$^{th}$ percentile, otherwise the model assumes 500 MW of market availability. Any hour that cannot meet its load or reliability requirements is considered a loss of load event.

Given the 2030 year is a resource deficit year, the model includes additional new natural gas-fired CTs to meet future load obligations. In total between existing and "new" CTs, the system has sufficient resources equal to meet the 16 percent planning margin needed

[10] 2020 IRP Appendix F, Resource Adequacy in the Pacific Northwest, page 54.

above the expected peak load. To determine the peak credit, the "new" gas-fired turbines are removed in total or in part and replaced with each of the resources in Table 9.12 individually. The model runs through iterative cycles to determine the amount of a resource needed to achieve equal reliability as the natural gas-fired CTs from a LOLP perspective. This means each resource is added to the model until the LOLP returns to the same level as the CT resource alternative. The percentage shown in the table is the percent of natural gas turbines assumed offset by the replacement resource. For example, if a northwest wind resource replaced a natural gas CT resource, it would not be replaced one for one, but rather each 5 MW reduction in natural gas CTs would require 100 MW of the additional wind resource to equal the same LOLP. The lower values of peak capacity credits are due to the resource either not reliably providing energy during times of system need or the resource running out of energy over the duration of the high load event, such as with storage. In the case of the storage resource, during a peak load event when all resources are needed to respond to load during the day, the storage resource may be able to provide energy for four hours, but fails to continue energy delivery once the battery is drained and may not be able to recharge until either system or market energy is available. Due to Avista's load profile of not only winter peaking, but significantly higher daily winter loads, storage resources require longer durations to replace traditional energy resources able to serve loads throughout the day.

**Table 9.12: Peak Credit or Equivalent Load Carrying Capability Credit**

| Resource | Peak Credit (percent) |
|---|---|
| Northwest solar | 2 |
| Northwest wind | 5 |
| Montana wind[11] 100-200 MW | 35 to 28 |
| Hydro w/ storage | 60-100 |
| Hydro run-of-river | 31 |
| Storage 4 hr duration | 15 |
| Storage 8 hr duration | 30 |
| Storage 12 hr duration | 58 |
| Storage 16 hr duration | 60 |
| Storage 24 hr duration | 65 |
| Storage 40 hr duration | 75 |
| Storage 70 hr duration | 90 |
| Demand response | 60 |
| Solar + 4 hr Storage[12] | 17 |
| Solar + 2 hr Storage[13] | 12 |

[11] Net of transmission losses. Montana wind peak credits decline with additional capacity, the first 200 MW is 35 percent, the next 100 MW is 30 percent, and another 100 MW is 28 percent. Avista does not assume any Montana wind beyond 400 MW.

[12] This assumes the storage resource may only charge with solar. This specific option was not modeled within the PRS and is shown as a reference only. Avista only modeled solar plus storage where the storage resource could be charged with non-solar as well to reflect long-term utility operations.

[13] Avista limited solar plus storage to these two scenarios; many other options are likely including different durations and storage to solar ratios. Specific configurations would need to be studied to validate peak credits for those configurations.

# Other Environmental Considerations

All generating resources have an associated greenhouse gas emissions profile, either when it produces energy, during operations, when constructed, retired, or all of the above. For this IRP, Avista modeled associated emissions with the production of energy as well as emissions associated with the manufacturing and construction of the facility where emissions information was available, such as from the National Renewable Energy Laboratory (NREL) data for greenhouse gas emissions related to construction and operations.

This IRP also includes upstream greenhouse gas emissions from natural gas. Natural gas is assumed to directly emit 119 pounds of equivalent greenhouse gases per dekatherm when including the other gases within the supply. In addition to those emissions, there could be upstream emissions from the drilling process and the transportation of the fuel to the plant also known as fugitive emissions. While not required by the final CETA rules, this IRP includes these emissions priced at the social cost of carbon for the Washington customer portion of resource optimization. The additional emissions are assumed to be 9.8 percent added to the emissions from dispatch. This percentage accounts for both upstream methane leakage and combusted natural gas in the supply chain. The combusted upstream natural gas is estimated to be 0.77 percent[14] assuming a Canadian sourced natural gas supply. The remaining percentage is derived from estimated methane releases using a 34-year conversion factor from methane to CO2 equivalent emissions.

## Social Cost of Carbon

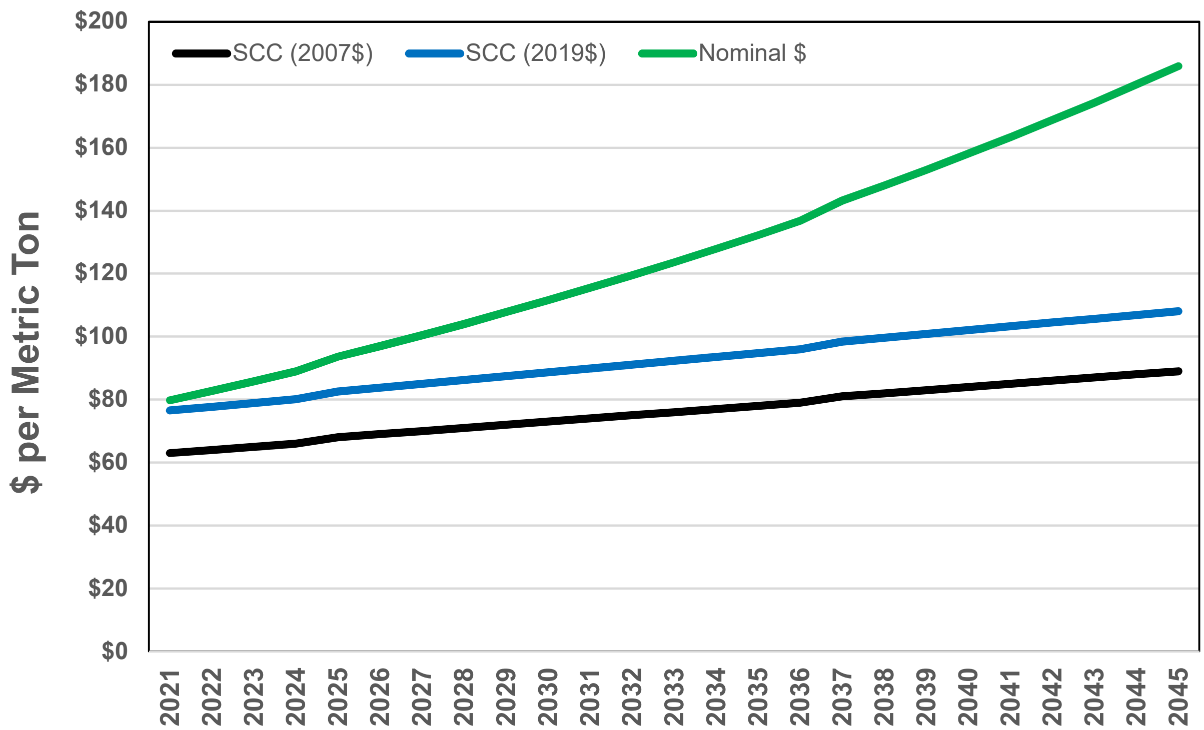
The social cost of carbon is included for thermal resource project additions along with projected emissions reduction from energy efficiency for Washington's load obligations. The social cost of carbon pricing is shown in Figure 9.4. Avista uses the pricing method and the 2.5 percent discount rate identified by the Washington Commission for CETA. The prices are inflated from 2007 to 2020 using the Bureau of Economic Analysis inflation data and then inflated at 2.11 percent each year thereafter.

PRiSM, Avista's portfolio optimization model, uses the social cost of carbon as a cost adder to Washington's share of greenhouse emitting resources for both existing and new resource options and the associated regional emission reductions from energy efficiency. Any emissions associated with the operations and construction is also included in the social cost of carbon analysis. Avista does not use the social cost of carbon pricing for market transactions including purchases for storage as it had done in the 2020 IRP per the CETA requirements only targeting these costs for intermediate and long-term resources. After review of Section 14 of the CETA, focusing on these costs shall be included for evaluating energy efficiency programs and evaluating intermediate term and long-term resource options. Given this section of the law excludes short term transactions, Avista chose not to include this cost for market transactions although a

[14] The emission rate is from recent environment impact studies for the PSE Tacoma LNG plant, Kalama Manufacturing and Export Facility.

scenario is included in Chapter 12 of this IRP to reflect the difference in the plan if these costs were included.

**Figure 9.5: Social Cost of Carbon**




## Other Environmental Considerations

There are other environmental factors involved when siting and operating power plants. Avista considers these costs in the siting process. For example, new hydro projects or modifications to existing facilities must be made in accordance with their operating license. If new or upgraded facilities require operations outside this license, the license would be reopened. When siting solar and wind facilities, developers must have solicit and receive approvals from local, state and federal governing boards or agencies to ensure all laws and regulations are met.

If Avista sites a new natural gas-fired facility, it will have to meet all state and local air requirements for its air permit. Requirements are at levels these governing bodies find appropriate for their communities. Currently, Avista is not evaluating emissions costs outside of these considerations.

# 10. Market Analysis

Energy policy in the Western Interconnect is shifting toward clean generation. Several states, including Washington and California, already have 100 percent clean energy goals. These policy changes dramatically impact the wholesale power market. Previous IRPs focused on carbon pricing methodologies driving wholesale power prices upward. At this time, it does not appear policymakers will pursue direct carbon mitigation policies. Rather energy policies now focus on 100 percent clean energy to achieve carbon reductions. This approach drives wholesale prices lower and may lead to the build-out of storage resources although traditional natural gas-fired generation is still needed to prevent significant price volatility and prevent reliability events.

Fundamental market analysis is important to support the resource strategy selected to serve Avista's customers over the next 20 plus years. Avista uses forecasts of future market conditions to optimize its resource portfolio options. The Company uses electric price forecasts to evaluate the net operating margin of each supply- and demand-side option for comparative analysis between each resource type. The model tests each resource in the wholesale marketplace to understand its profitability, dispatch, fuel costs, emissions, curtailment and other operating characteristics.

**Section Highlights**

- Solar and wind dominate future generation across the west while natural gas and increasing amounts of storage will ensure resource adequacy as more coal plants shut down.
- By 2045, 91 percent of generation in the Pacific Northwest will be carbon free, up from approximately 70-80 percent today depending on hydro conditions.
- Greenhouse gas emissions will fall to historic lows with the expansion of renewables and continued coal plant retirements. By 2045, expected emissions will be 64 percent less than in 1990.
- The 24-year wholesale electric price forecast (2022-2045) is $27.13 per MWh. Expansion of renewables reduces mid-day prices, but evening and nighttime prices will be at a premium compared to today's pricing.
- Natural gas prices continue to remain low; for example, the levelized price at Stanfield (2022-2045) is $3.45 per dekatherm.

Avista conducts the wholesale market analysis using the Aurora model by Energy Exemplar. The model includes generation resources, load estimates and transmission links within the Western Interconnect. This chapter outlines the modeling assumptions and methodologies for this IRP and includes Aurora's primary function of electric market pricing (Mid-Columbia for Avista), as well as operating results from the analysis. The Expected Case is a forecast defined using the best available information on policies, regulations and resource costs under average conditions. This chapter also presents the results of four additional pricing scenarios to better understand changes to the electric market if natural gas prices significantly increase or decrease from the forecast, climate change impacts to loads and hydro conditions, and the effects of a national greenhouse gas pricing mechanism.

## Electric Marketplace

Avista simulates the entire Western Interconnect electric system for its IRP planning; shown as WECC[1] in Figure 10.1. The rest of the U.S. and Canada are in separate electrical systems. The Western Interconnect includes the U.S. system west of the Rocky Mountains plus two Canadian provinces and the northwest corner of Mexico's Baja peninsula.

The Aurora market simulation model represents each operating hour between 2022 and 2045. It simulates both load and generation dispatch for sixteen regional areas or zones within the west. Avista's load and most of its generation is in the Northwest zone identified in Table 10.1. Each of these zones include connections to other zones via transmission paths or links. These links allow generation trading between zones and reflect operational constraints of the underlying system, but do not model the physics of the system as a power flow model. Avista focuses on the economic modeling capabilities of the Aurora platform to understand resource dispatch and market pricing effects resulting in a wholesale electric market price forecast for the Northwest zone or Mid-Columbia marketplace.

The Aurora model estimates its electric prices using an hourly dispatch algorithm to match the load in each zone with the available generating resources. Resources are selected to dispatch after considering fuel availability, fuel cost, operations and maintenance cost, dispatch incentives/disincentives and operating constraints. The marginal cost of the last generating resource needed to meet area load becomes the electric price. The IRP uses these prices to value each resource (both supply and load side) option and select from among them to achieve a least reasonable cost plan meeting all load and reliability obligations. Avista also conducts stochastic analyses for its price forecasting, where certain assumptions are drawn from 500 distributions of potential inputs. For example, each forecast randomly draws from an equally weighted probability distribution of the 80-year hydro record.

The next several sections of this chapter discuss the assumptions used to derive the wholesale electric price forecast, resulting dispatch and greenhouse gas emissions profiles for the west for the 500 stochastic studies.

[1] WECC is the Western Electrical Coordinating Council. It coordinates reliability for the Western Interconnect.

Figure 10.1: NERC Interconnection Map

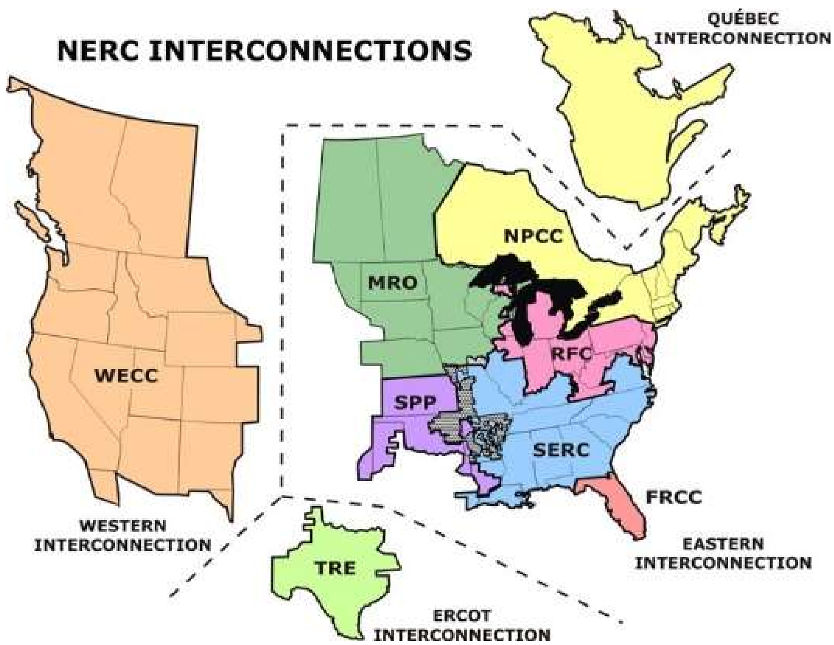



Table 10.1: AURORA Zones

| | |
|---|---|
| Northwest- OR/WA/ID/MT | Southern Idaho |
| Utah | Wyoming |
| Eastern Montana | Southern California |
| Northern California | Arizona |
| Central California | New Mexico |
| Colorado | Alberta |
| British Columbia | South Nevada |
| North Nevada | Baja Mexico |

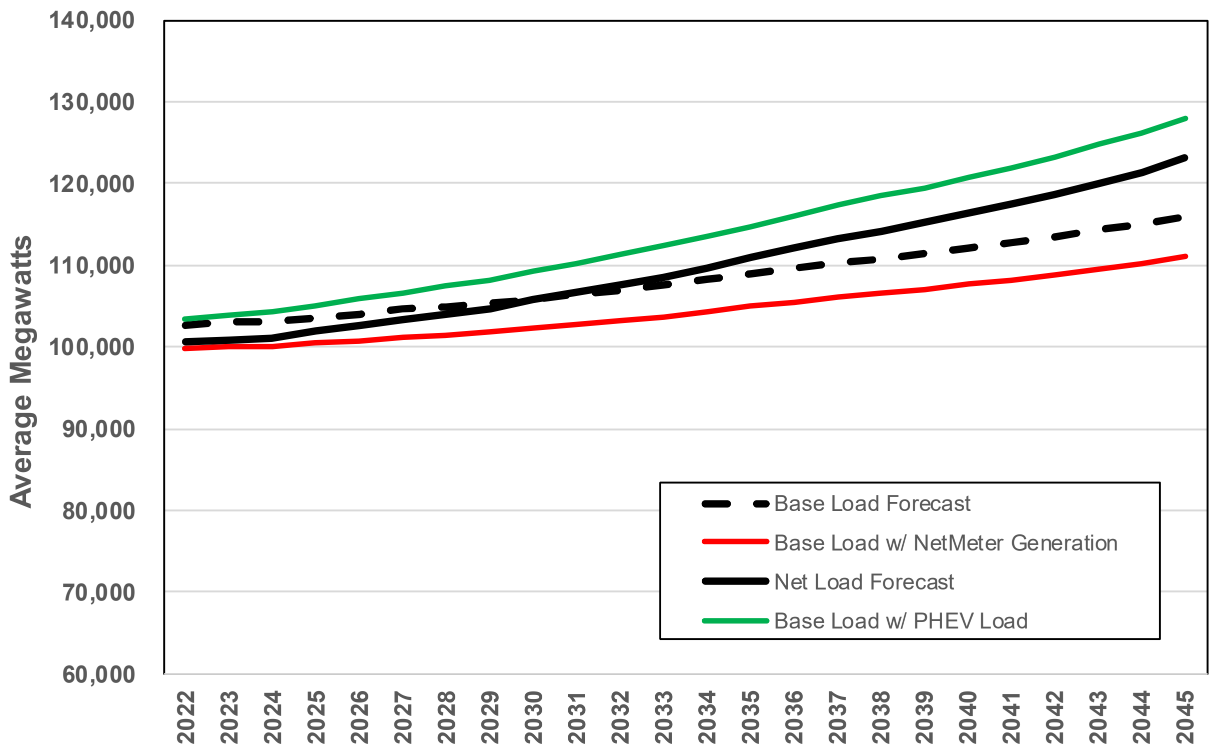
## Western Interconnect Loads

Each of the sixteen zones in Aurora require hourly load data for all 24 years of the forecast plus 500 different stochastic studies for weather variation. Future loads may not resemble past loads from an hourly shape point of view due to the continual increase in EVs and rooftop solar. Changes in energy efficiency, demand curtailment/demand response, population migration and economic activity increase the complexity. While each of these drivers are important to the forecast of power pricing, it takes a large amount of analytical time to estimate or track these macro effects over the region. Avista uses the following methods to derive its regional load forecast for power price modeling to account for these complexities.

Avista begins with Energy Exemplar's demand forecast included with the Aurora software package. This forecast includes an hourly load shape for each region along with annual changes to both peak and energy values. The hourly load shape uses historical data for each balancing area and the growth rates from publicly available forecast information for each region. Figure 10.2 shows this base forecast as the black dotted line. Western

Interconnect load grows 0.51 percent per year. Avista adjusts this initial forecast to account for changes in EV penetration and net-metered generation, including rooftop solar. Annual EV load grows at 12.5 percent and net-metered generation grows at 2.4 percent[2]. These adjustments increase the load forecast growth rate to approximately 0.85 percent per year. Within the year, the hourly load shapes adjust to reflect charging patterns of both residential and commercial vehicles in addition to most net-metered generation being modeled as fixed roof mount solar panels.

**Figure 10.2: 24-Year Annual Average Western Interconnect Load Forecast**




## Regional Load Variation

Several factors drive load variability. The largest short-run driver is weather. Long-run economic conditions, like the Great Recession, tend to have a larger impact on the load forecast. IRP loads increase on average at the levels discussed earlier in this chapter, but risk analyses emulate varying weather conditions and base load impacts. Avista continues with its previous practice of modeling load variation using FERC Form 714 load data from 2015 to 2019. To maintain consistent west coast weather patterns, statistically significant correlation factors between the Northwest and other Western Interconnect load areas represent how electricity demand changes together across the system. This method avoids oversimplifying Western Interconnect loads. Absent the use of correlations, stochastic models may offset changes in one variable with changes in another, virtually eliminating the possibility of broader load excursions witnessed by the electricity grid. The additional accuracy from modeling loads this way is crucial for understanding wholesale electricity market price variation as well as the value of peaking

[2] Avista uses forecasts provided by IHS Markit to assist in the development of these forecasts.

resources and their use in meeting system variation. The load correlation values are summarized in Tables 10.2 through 10.5. Data reported as "Mix" or "Not Sig" in the tables indicates data for that region and time period either was not statistically correlated with Northwest loads or the annual correlations varied between correlated and inversely correlated. In either case, no correlation was used for results with "Mix" or "Not Sig". These load variations form the basis for load changes in each of the 500 simulations of the electric price forecast.

### Table 10.2: January through June Load Area Correlations

| Area | Jan | Feb | Mar | Apr | May | Jun |
|---|---|---|---|---|---|---|
| Alberta | Mix | Mix | 28% | Mix | Mix | Mix |
| Arizona | Not Sig | 28% | Not Sig | Not Sig | 9% | Not Sig |
| Avista | 95% | 96% | 92% | 78% | 50% | 90% |
| British Columbia | 87% | 91% | 93% | 67% | Mix | 67% |
| California | 8% | Not Sig | Not Sig | Not Sig | Mix | Not Sig |
| CO-UT-WY | 61% | Not Sig | Not Sig | Not Sig | Mix | Mix |
| Montana | 64% | 75% | 66% | 8% | Mix | 16% |
| New Mexico | Mix | Mix | Mix | Mix | Not Sig | Mix |
| North Nevada | Not Sig | 83% | 64% | Mix | Mix | 18% |
| South Idaho | 67% | 85% | 69% | Mix | Mix | 35% |
| South Nevada | Not Sig | 10% | Mix | Not Sig | 9% | Not Sig |

### Table 10.3: July through December Load Area Correlations

| Area | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|
| Alberta | Mix | Mix | Mix | Mix | 10% | Mix |
| Arizona | Mix | Mix | 26% | -8% | Mix | Mix |
| Avista | 89% | 81% | 86% | 88% | 89% | 92% |
| British Columbia | 77% | 72% | 37% | 76% | 87% | 85% |
| California | 36% | 8% | 50% | -33% | Mix | Not Sig |
| CO-UT-WY | Mix | Mix | 9% | Not Sig | Not Sig | Not Sig |
| Montana | Not Sig | 8% | 9% | 54% | 30% | 49% |
| New Mexico | Not Sig | Mix | Mix | 8% | 19% | Mix |
| North Nevada | Not Sig | Not Sig | 59% | 65% | 72% | Not Sig |
| South Idaho | Not Sig | 57% | 59% | 62% | 73% | 65% |
| South Nevada | Mix | Mix | 20% | -17% | Mix | Mix |

**Table 10.4: Area Load Coefficient of Determination (Standard Deviation/Mean)**

| Area | Jan | Feb | Mar | Apr | May | Jun |
|---|---|---|---|---|---|---|
| Alberta | 2.9% | 2.4% | 2.9% | 1.8% | 4.0% | 4.8% |
| Arizona | 6.6% | 7.6% | 4.9% | 7.5% | 11.0% | 10.2% |
| Avista | 8.6% | 9.2% | 7.9% | 5.9% | 4.7% | 7.1% |
| British Columbia | 5.8% | 7.3% | 6.9% | 5.6% | 3.7% | 4.2% |
| California | 5.8% | 5.6% | 5.8% | 6.6% | 8.2% | 11.3% |
| CO-UT-WY | 4.3% | 6.4% | 5.2% | 4.1% | 5.0% | 9.3% |
| Montana | 6.0% | 11.3% | 9.8% | 7.2% | 6.5% | 6.0% |
| New Mexico | 5.5% | 5.9% | 4.4% | 5.2% | 7.9% | 9.3% |
| Northern Nevada | 3.8% | 6.2% | 5.6% | 4.8% | 4.5% | 7.0% |
| Pacific Northwest | 9.1% | 9.7% | 8.4% | 5.2% | 4.0% | 5.4% |
| South Idaho | 8.4% | 8.2% | 7.4% | 7.3% | 10.2% | 11.7% |
| South Nevada | 4.5% | 6.1% | 4.4% | 9.9% | 14.3% | 13.2% |

**Table 10.5: Area Load Coefficient of Determination (Standard Deviation/Mean)**

| Area | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|
| Alberta | 3.0% | 2.2% | 2.2% | 2.8% | 3.1% | 3.6% |
| Arizona | 7.7% | 7.2% | 12.2% | 7.6% | 3.3% | 5.1% |
| Avista | 8.1% | 7.6% | 5.7% | 6.6% | 7.0% | 7.0% |
| British Columbia | 4.7% | 4.7% | 3.4% | 4.4% | 5.5% | 6.0% |
| California | 9.7% | 7.9% | 10.7% | 7.5% | 5.6% | 5.4% |
| CO-UT-WY | 6.8% | 6.7% | 7.9% | 5.4% | 5.7% | 4.4% |
| Montana | 7.0% | 8.3% | 7.7% | 8.8% | 8.6% | 5.0% |
| New Mexico | 6.6% | 7.5% | 8.3% | 7.8% | 5.3% | 5.3% |
| Northern Nevada | 6.1% | 5.4% | 6.9% | 4.5% | 5.8% | 4.0% |
| Pacific Northwest | 6.4% | 6.4% | 4.9% | 5.8% | 7.3% | 7.1% |
| South Idaho | 7.0% | 7.3% | 15.0% | 6.7% | 7.9% | 6.8% |
| South Nevada | 8.8% | 8.3% | 15.5% | 9.4% | 3.2% | 3.9% |

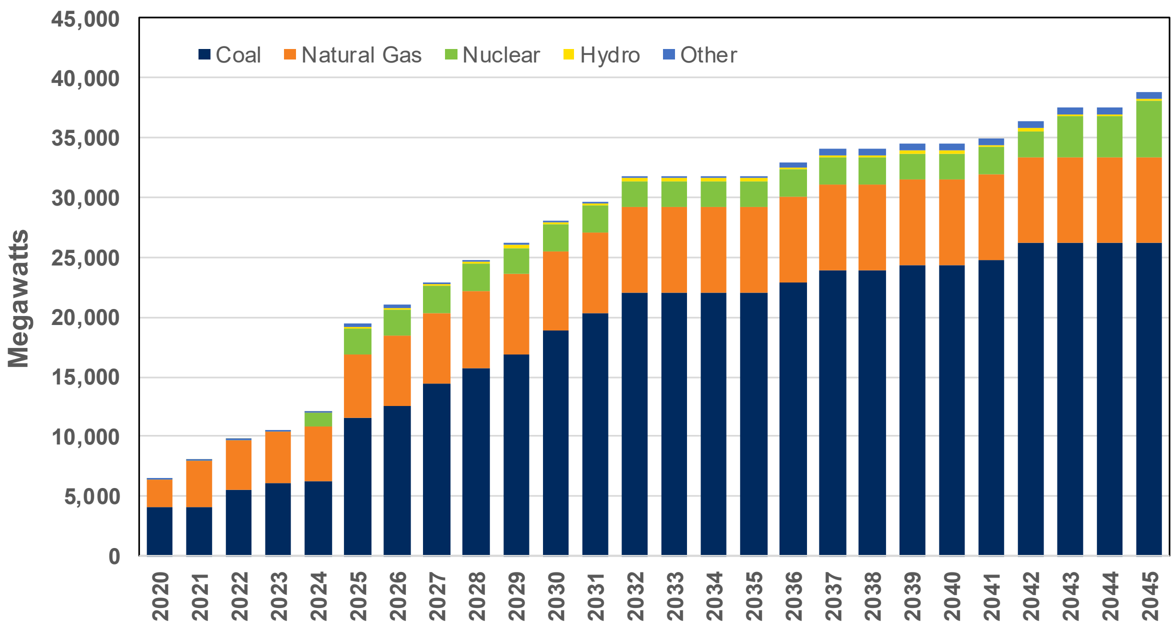
## Generation Resources

The Aurora model needs a forecast of generation resources to compare and dispatch against the load forecast for each hour. A generation availability forecast includes the following mean components:

- Resources currently available;
- Resources retiring;
- New resources for capacity and load service;
- New resources for renewable energy compliance; and,
- Fuel prices, fuel availability and operating availability.

Aurora contains a database of existing generating resources with the location, size and estimated operating characteristics for each resource. When a resource has a publicly scheduled retirement date or is part of an approved provincial phase-out plan, it is retired for modeling purposes on the expected date. Avista does not project retirements beyond those with publicly stated retirement dates or phase out plans. Rather, plants that become less economic in the forecast dispatch fewer hours. Several coal plant retirements have or are expected to occur in the Northwest during this IRP, including Boardman, Colstrip Units 1 and 2, North Valmy and Centralia. Figure 10.3 shows the total retirements included in the electric price forecast. Approximately 26,000 MW of coal, 7,000 MW of natural gas, 4,758 MW of nuclear, and 750 MW of other Western Interconnect resources including biomass, hydro and geothermal are known to retire by the end of 2045.

**Figure 10.3: Cumulative Resource Retirement Forecast**



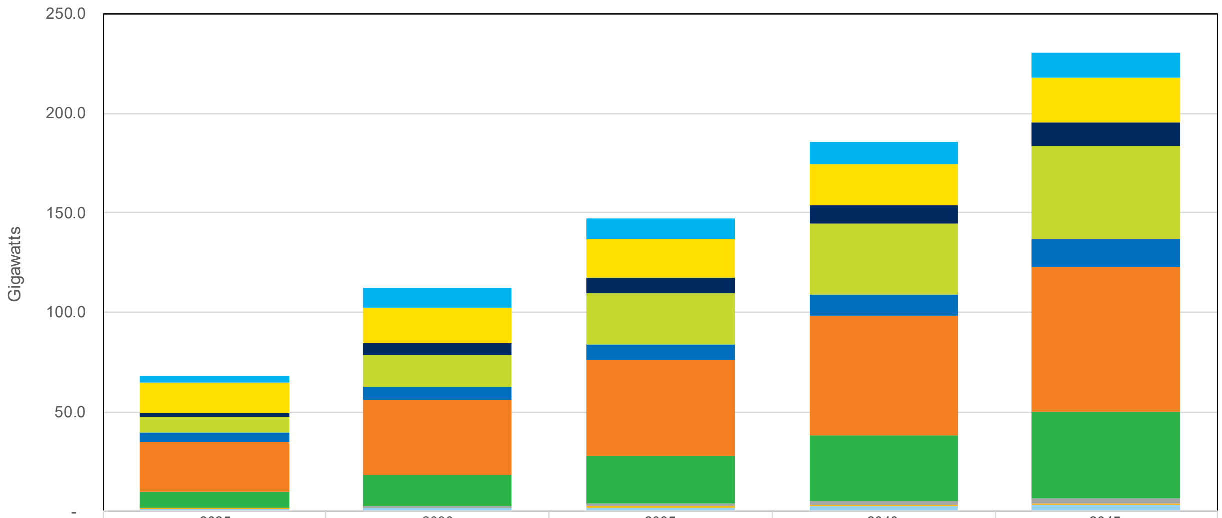

## New Resource Additions

In order to meet future load growth, considering state-defined clean energy goals and replacement of retired generation, a new generation forecast must include enough resources to meet peak load. Furthermore, some states include emission constraints or require emission pricing for new resource additions. Avista uses a resource adequacy-based forecast for new resource additions along with data estimates provided by a third-party consultant. The process begins with a forecast of new generation by resource type from a third-party consultant. Consultants with multiple clients and dedicated staff can, and more efficiently than Avista, research new resource costs and operating characteristics on likely resource construction in the West, especially in areas where Avista has no market presence or local market knowledge. These forecasts for new generation account for environmental policies and localized cost analysis of resource choices to develop a practical new resource forecast.

The next step in this process adjusts the clean energy additions to reflect changes in state policies for additional renewable energy requirements to ensure the new renewable resource build out matches requirements given the load forecast for each region. The last step runs the model for 500 simulations to see if each area can meet a resource adequacy test. The goal is for each area to serve all load in at least 475 of the 500 iterations, a 95 percent loss-of-load threshold measuring reliability.

Figure 10.4 shows the 230 GW of added generation included in this forecast. The added resources include 73 GW of utility-scale solar, 43 GW of wind, 13 GW of natural gas combined cycle CTs, 12 MW of storage[3], 23 GW of natural gas CTs and 20 GW of other resources including hydro, biomass, geothermal and net-metering.

**Figure 10.4: Western Generation Resource Additions (Nameplate Capacity)**




| | 2025 | 2030 | 2035 | 2040 | 2045 |
|---|---|---|---|---|---|
| CCCT | 3.3 | 9.9 | 10.7 | 11.6 | 12.8 |
| SCCT | 15.4 | 17.8 | 19.3 | 20.2 | 22.7 |
| DR | 2.1 | 6.0 | 7.6 | 9.5 | 11.5 |
| Storage | 7.9 | 16.2 | 25.7 | 35.5 | 47.1 |
| Net-Meter | 4.5 | 6.5 | 8.5 | 10.8 | 13.9 |
| Solar | 25.5 | 37.5 | 47.8 | 59.7 | 73.0 |
| Wind | 7.8 | 15.7 | 24.1 | 33.4 | 43.3 |
| Geothermal | 0.3 | 0.7 | 1.2 | 1.9 | 2.9 |
| Biomass | 0.2 | 0.4 | 0.6 | 0.7 | 0.9 |
| Hydro | 1.3 | 1.6 | 1.9 | 2.4 | 2.8 |

## Generation Operating Characteristics

Several changes are made to the resources available to serve future loads to account for Avista's specific expectations such as fuel prices and to reflect potential variation of resource supply such as wind and hydro generation.

### Natural Gas Prices

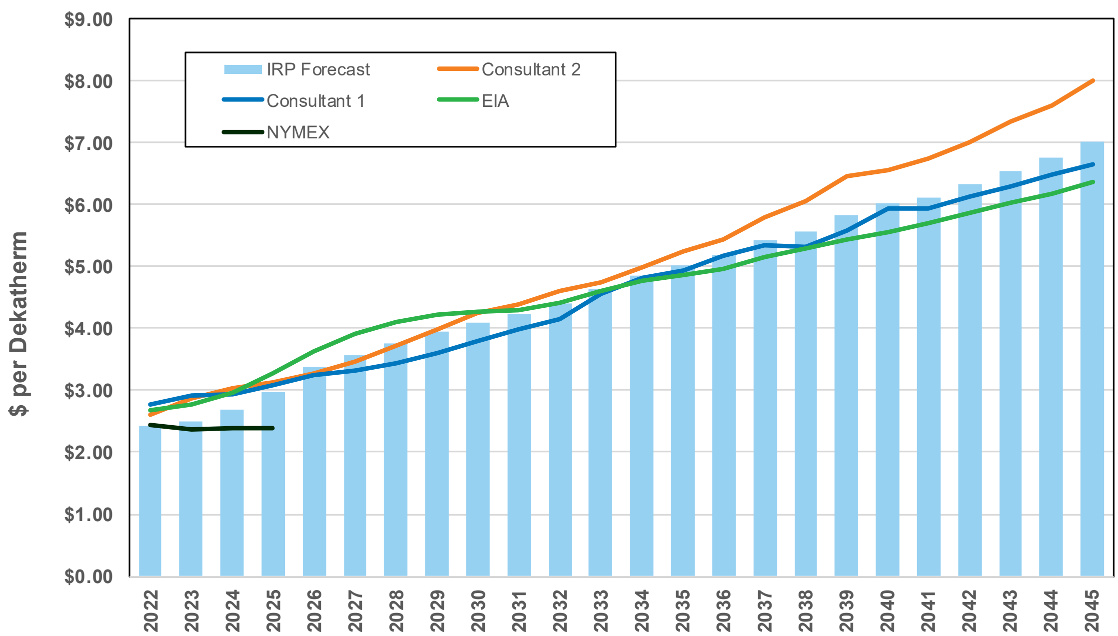
Historically, natural gas prices were the greatest indicator of electric market price forecasts. Between 2003 and 2019 the correlation ($R^2$) between natural gas and on-peak Mid-Columbia electric prices was 0.90, indicating a strong connection between the two prices. Natural gas-fired generation facilities were typically the marginal resource in the northwest except for times when hydro generation was high due to water flow. In addition, natural gas-fired generation met 31 percent of the load in the U.S. Western Interconnect in 2019. With the large increases in new solar and wind generation in the west, the

[3] Storage energy to capacity ratio averages 3 hours in 2022 and increases to 6 hours by 2045. This change assumes technological advances in the duration of batteries and other storage technologies.

number of hours where natural gas-fired facilities will set the marginal market price is expected to decline.

For modeling purposes, Avista uses a baseline of monthly natural gas prices and varies prices based on a distribution for each of the 500 stochastic forecasts. The forecasts begin with the Henry Hub forecast. Since Avista is not equipped with fundamental forecasting tools, nor is it able to track natural gas market dynamics across North America and the world, it uses a blend of market forward prices, consultant forecasts and the Energy Information Administration (EIA) forecast. The EIA forecast is compared below in Figure 10.5 against forecasted Henry Hub prices from two consultants with the capability to follow the fundamental supply and demand changes of the industry. The 24-year nominal levelized price of natural gas is $4.11 per dekatherm; the 20-year nominal levelized price is $3.90 per dekatherm[4].

**Figure 10.5: Henry Hub Natural Gas Price Forecast**




Natural gas generation facilities in the West do not use Henry Hub as a fuel source, but natural gas contracts are priced based on the Henry Hub index. Northwest basins include Sumas for coastal plants on the Northwest pipe system. Power plants on the GTN pipeline obtain fuel at prices based on AECO, Stanfield or Malin depending on contracted delivery rights. Table 10.6 shows these basin differentials as a percent change from Henry Hub. This table also includes basin nominal levelized prices for both 20 and 24 years for selected basins.

[4] The natural gas pricing data is available on the IRP website as “Natural Gas Prices”.

**Table 10.6: Natural Gas Price Basin Differentials from Henry Hub**

| Year | Stanfield | Malin | Sumas | AECO | Rockies | Southern CA |
|---|---|---|---|---|---|---|
| 2022 | 77.7% | 84.4% | 83.1% | 57.8% | 81.3% | 90.8% |
| 2025 | 76.2% | 81.0% | 79.4% | 61.1% | 82.1% | 88.4% |
| 2030 | 83.6% | 87.2% | 81.1% | 67.5% | 87.7% | 92.2% |
| 2035 | 86.4% | 89.5% | 83.6% | 70.1% | 91.0% | 95.0% |
| 2040 | 87.8% | 90.7% | 85.4% | 74.1% | 93.6% | 96.9% |
| 2045 | 91.2% | 93.9% | 88.7% | 77.5% | 96.9% | 100.6% |
| ***24 yr*** | ***$3.45*** | ***$3.61*** | ***$3.43*** | ***$2.82*** | ***$3.66*** | ***$3.86*** |
| ***20 yr*** | ***$3.23*** | ***$3.39*** | ***$3.23*** | ***$2.63*** | ***$3.43*** | ***$3.62*** |

As described earlier, natural gas prices are a significant predictor of electric prices. Due to this significance, the IRP analysis studies prices described on a stochastic basis for the 500 iterations. The methodology to change prices uses an autocorrelation algorithm allowing prices to experience excursions, but to not move randomly. The methodology works by focusing on the monthly change in prices. The forecast's month-to-month Expected Case change in prices is used as the mean of a lognormal distribution; then for the stochastic studies, a monthly change in natural gas price is drawn from the distribution. The lognormal distribution shape and variability uses historical monthly volatility. Using the lognormal distribution allows for the large upper price excursions seen in the historical dataset.

The average of the 500 stochastic prices are similar to the inputted expected price forecast described earlier in this chapter. Figure 10.6 illustrates the simulated data for the stochastic studies compared to the input data for the Stanfield price hub. The stochastically derived nominal levelized price for 20 years is $3.17 per dekatherm compared to the average price of $3.71 per dekatherm. These values likely would converge with a sample size much larger than 500. The median price is lower at $2.78 per dekatherm. Another component of the stochastic nature of the forecast is the growth in variability. In the first year, prices vary 39 percent around the mean, or the standard deviation as a percent of the mean. By 2040, this value is 58 percent, rising to 60 percent in 2045. Avista uses higher variation in later years because the accuracy and knowledge of future natural gas prices becomes less certain.

**Figure 10.6: Stochastic Stanfield Natural Gas Price Forecast**

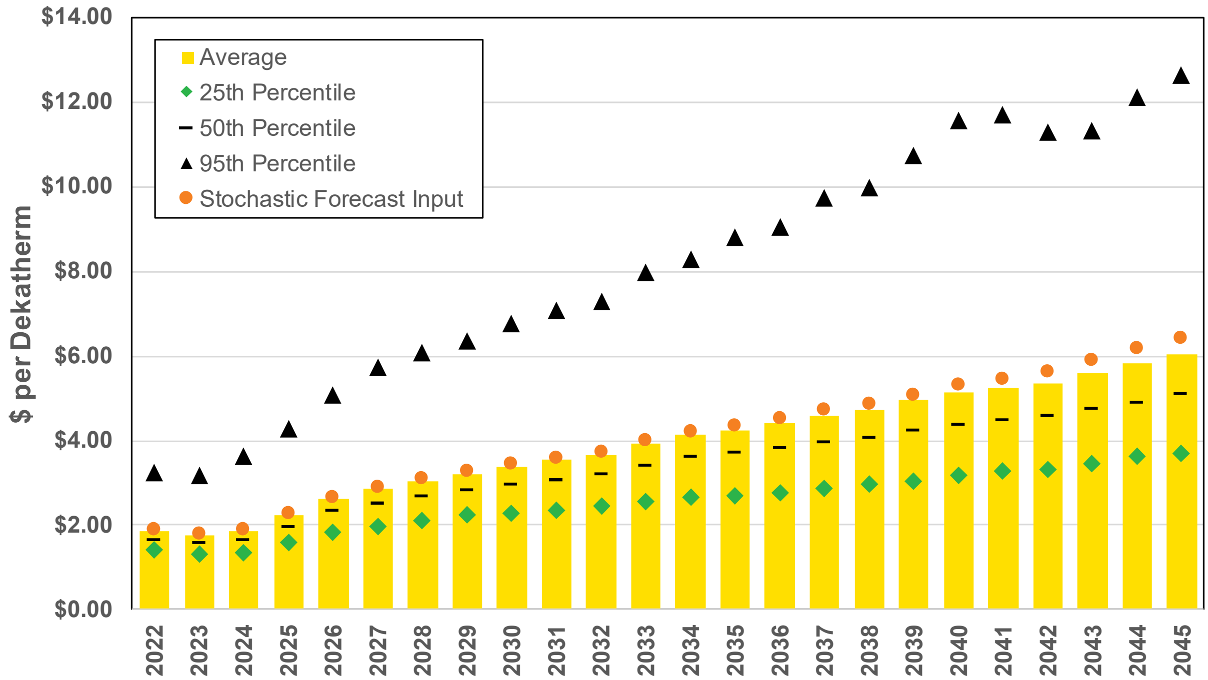
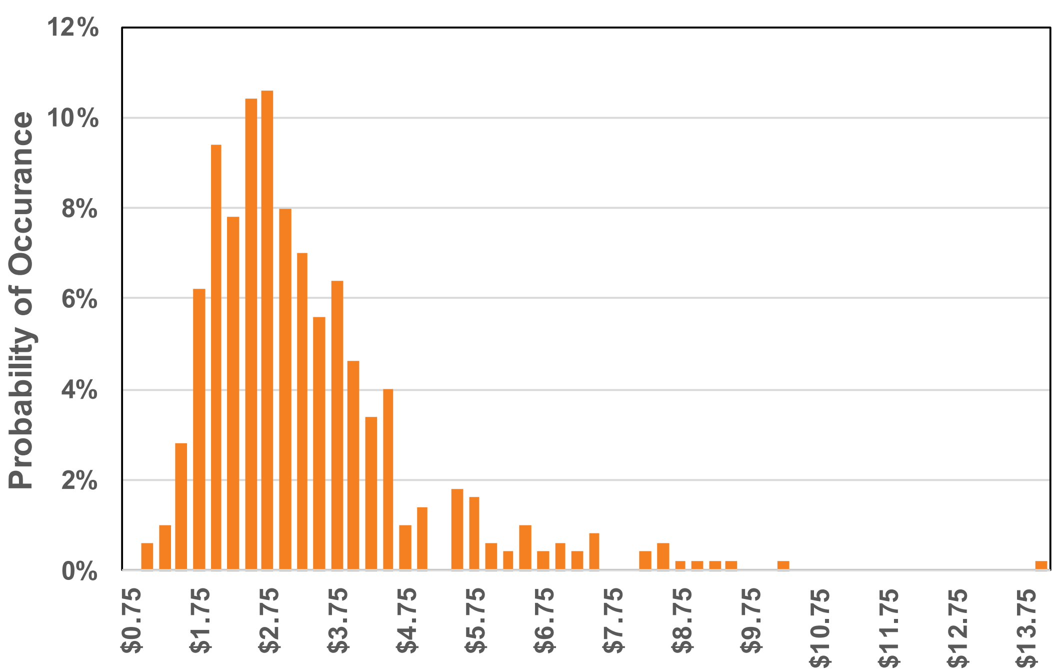



Figure 10.7 shows another way to visualize Avista's natural gas price forecast assumptions. This chart shows the 24-year nominal levelized prices for Stanfield as a histogram to demonstrate the skewness of the natural gas price forecast.

**Figure 10.7: Stanfield Nominal 20-Year Nominal Levelized Price Distribution**



## Regional Coal Prices

Coal-fired generation facilities are still an important part of the Western Interconnect. In 2019, coal met 18 percent of Western Interconnect loads, falling from 34 percent in 2001. Coal pricing is typically different from natural gas pricing, providing diversification and mitigating price volatility risk. Natural gas is delivered by pipeline, whereas coal delivery is by rail, truck or conveyor. Coal contracts are typically longer term and supplier specific. Avista uses the coal price forecast contained in Aurora. The software's forecast is based on FERC filings for each of the coal plants and used to determine historical pricing. Future prices are based on the EIA Annual Energy Outlook.

Coal price forecasts have uncertainty like natural gas prices, yet the effect on market prices is less because coal-fired generation rarely sets marginal prices in the Western Interconnect. While labor, steel cost and transportation costs drive some portion of coal price uncertainty, transportation is its primary driver. There is also uncertainty in fuel suppliers as the coal industry is restructuring. Given the relatively small effect on Western Interconnect market prices, Avista chose not to model this input stochastically.

## Hydro

The Northwest U.S., British Columbia and California have substantial hydro generation capacity. Hydro resources were 54 percent of Northwest generation in 2019, although hydro generation is only 22 percent of generation in the Western Interconnect. A favorable characteristic of hydro power is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. Hydro generation is valuable for meeting peak load, following general intra-day load trends, storing and shaping energy for sale during higher-valued hours and integrating variable generation resources. The key drawback to hydro generation is its variability and limited fuel supply.

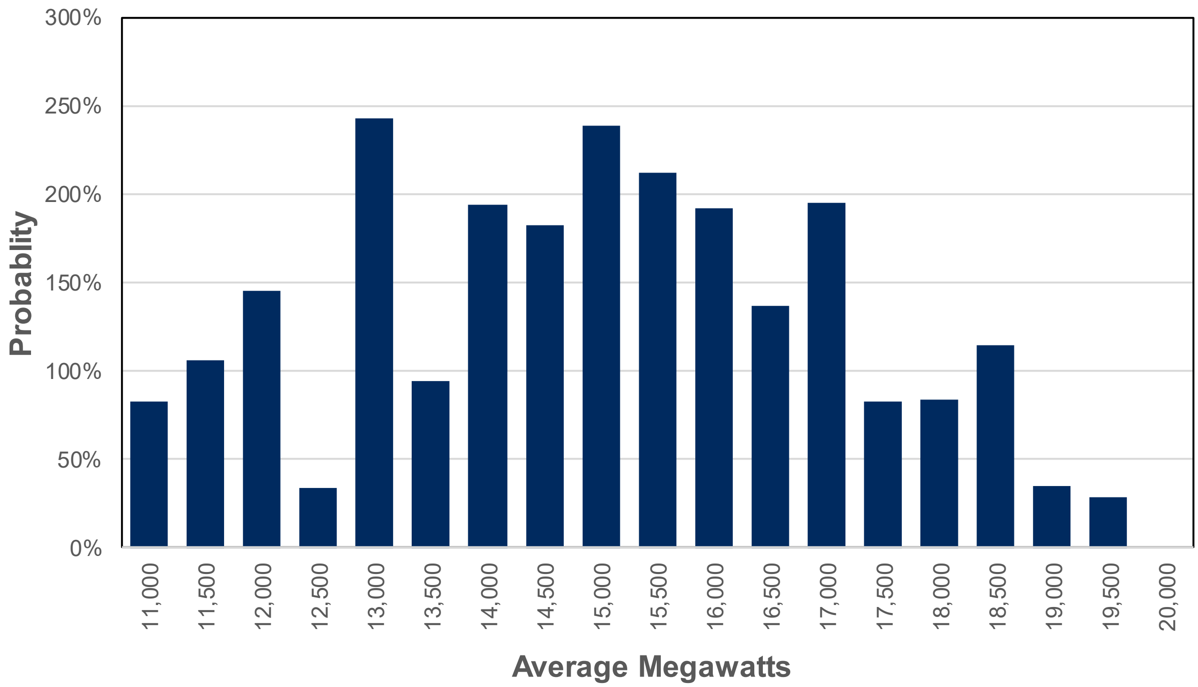
This IRP uses an 80-year study of the hydro data record. The study provides monthly energy levels for the region over an 80-year hydrological record spanning 1929 to 2008[5]. Many IRP studies use an average of the hydro record, whereas stochastic studies randomly draw from the record, as the historical distribution of hydro generation is not normally distributed. Avista uses both methodologies. Figure 10.8 shows the average hydro energy as 14,719 aMW (median 14,813 aMW) in the northwest over the 24-year study, defined here as Washington, Oregon, Idaho and western Montana. The chart also shows the range in potential energy used in the stochastic study, with a 10$^{th}$ percentile water year of 11,558 aMW (-22 percent) and a 90$^{th}$ percentile water year of 17,587 aMW (+19 percent). The EIA reports contain details about hydro generation back to 2001. This was a historically low hydro year with 11,098 aMW generated, but in 2019, another low year, 13,041 aMW was generated. Over the 18-year period, not reflected in the 80-year hydroelectric study, the average was 14,779 aMW, which is in line with the 80-year average.

Aurora maps each hydro plant to a load zone creating a similar energy shape for all plants in the load zone. Aurora uses the output from Avista's proprietary software with a more accurate representation of the operating characteristics and capabilities of hydro plants.

[5] BPA provides the underlying data used for regional hydro data.

Aurora represents hydro plants using annual and monthly capacity factors, minimum and maximum generation levels, and sustained peaking generation capabilities. The model's objective, subject to constraints, shifts hydro generation into peak load hours to maximize system value consistent with actual plant operations.

**Figure 10.8: Northwest Expected Energy**




## Wind Variation and Pricing

Wind is a growing generation source to meet customer load. As of 2019, 8 percent[6] of Western Interconnect generation was wind, up from nearly zero in 2001. Capturing the variation of wind generation on an hourly basis is important in fundamental power supply models due to the volatility of its generation profile and the effect of this volatility on other generation resources and electric market prices. Energy Exemplar recently made significant progress populating a larger database of historical wind data points throughout North America. The IRP leverages this work but takes it one step further by including a stochastic component to change the wind shape for each year. Avista uses the same methodology for developing its wind variation as discussed in previous IRPs. The technique includes an auto correlation algorithm with a focus on hourly generation changes. It also reflects the seasonal variation of generation.

To keep the problem manageable, Avista developed 15 different annual hourly wind generation shapes that are randomly drawn for each year of the 24-year forecast. By capturing volatility this way, the model can properly estimate hours with oversupply compared with using monthly average generation factors.

[6] Wind represented 9.4 percent of Northwest generation in 2019.

## Solar

Like wind, solar is quickly increasing its market share in the Western Interconnect. In 2019 solar was 6 percent[7] of the total generation, up from 2 percent in 2014 (both estimates exclude behind the meter solar). The Aurora model includes multiple solar generation shapes with multiple configurations, including fixed and single-axis technologies, along with multiple locations within an area. As solar continues to grow, additional data will become available and it will be incorporated into future IRP modeling. One of these new techniques may include multiple hourly solar shapes like those used with wind, so the model can account for solar variation from cloud cover.

## Other Generation Operating Characteristics

Avista uses the Energy Exemplar database assumptions for all other generation types not detailed here, except for Avista owned and controlled resources. For Avista's resources, more detailed confidential information is used to populate the model.

Forced outage and mechanical failure is a common problem for all generation resources. Typically, the modeling for these events is through de-rating generation. This means the available output is reduced to reflect the outages. Avista uses this method for solar, wind, hydro and small thermal plants; but uses a randomized outage technique for larger thermal plants where the model randomly causes an outage for a plant based on its historical outage rate, keeping the plant offline for its historical mean time to repair.

## Negative Pricing and Oversupply

Avista includes adjustments in the Aurora model to account for oversupply in the Mid-Columbia market, including negative price effects. Negative pricing occurs when generation exceeds load. This occurs most often in the Northwest when much of the hydro system is running at maximum capacity in the spring months due to high runoff and wind projects are also generating and lacking an economic incentive to shut off due to their requirement to generate for the Production Tax Credit (PTC), environmental attributes (e.g., RECs) or sale obligations. Hydro resources are dispatchable, but they may not be able to dispatch off due to total dissolved gas issues when forced to spill water instead of generating. This phenomenon will likely increase as wind and solar generation is added to the system where there are tax credits in place or where environmental attributes are needed for clean energy requirements. To model this effect in Aurora, Avista changes the economic dispatch prices for several resources that have dispatch drivers beyond fuel costs.

The first change Avista made is to the hydro dispatch order. This makes hydro resources a "must run" resource or last resource to turn off. To do this, hydro generation is assigned a negative $10 per MWh price (2020 dollars)[8]. The next change assigns an $8 per MWh (2020$) reduction in cost for qualifying renewable resources to reflect a preference for meeting state renewable portfolio standards (RPS); this price adjustment accounts for the

[7] Solar represented 0.6 percent of Northwest generation in 2019.

[8] These plants cannot be designated with a "must run" designation due to the "must run" resources requiring resources to dispatch at minimum generation and for modeling purposes, hydro minimum generation is zero in the event of low flows.

intrinsic value of the REC. The last adjustment is to include a PTC for resources with this benefit. After these adjustments, the model turns off resources in a fashion similar to periods of excess generation seen today. In an oversupply condition such as this, the last resource turned off sets the marginal price.

There could be potential solutions to reduce the amount of negative pricing hours going forward. One method would reduce the incentive to generate when the power is not needed. This would mean counting the “spilled” generation toward clean energy requirements or providing eligibility for tax credits. Other solutions include developing load-based options to take advantage of low wholesale market prices and increase requirements. The third method is storage. As storage costs decrease and oversupply costs increase, storage resources may alleviate oversupply if storage becomes a large enough resource. For IRP purposes, Avista includes the negative pricing effects so that load or storage-based options experience the pricing effects in the market for its economic analysis. Without these adjustments, expected generation from renewable resources may be overestimated by not including the hours of the year it will be curtailed.

### Greenhouse Gas Pricing

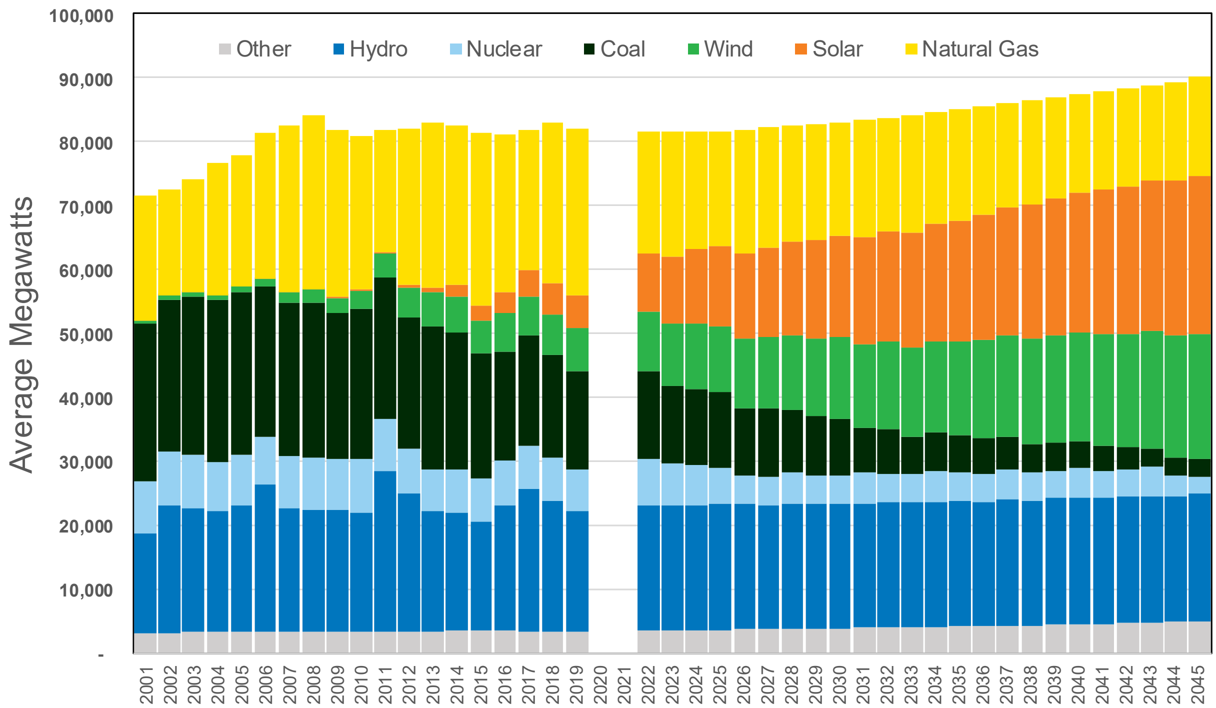
Many states and provinces have enacted greenhouse gas emissions reduction programs with others considering such programs. Some states have emissions trading mechanisms while others chose clean energy targets. Aurora can model either policy, but different policy choices can result in dissimilar impacts to electric wholesale pricing. Clean energy target programs, such as Washington’s CETA, generally depress prices due to the bias for increasing the incentives to construct low marginal-priced resources. California’s cap and trade program has the opposite effect and pushes wholesale prices upwards. Avista includes known programs in California[9], British Columbia and Alberta in its modeling as a carbon tax. The carbon tax approach means the model includes a specified price on emissions.

## Electric Resource and Emissions Forecast

Avista forecasts a major shift to clean energy resources across the Western Interconnect over the next 24 years. Figure 10.9 shows the historical and forecast generation for the U.S. portion of the Western Interconnect. In 2019, 42 percent of load is served by clean energy, increasing to 63 percent by 2030, and 77 percent by 2045. To achieve this shift in energy, while also serving new loads, solar and wind production will displace coal and natural gas. Absent significant new storage technologies, thermal resources are required to help meet system needs during peak weather events, especially in Northwest winters.

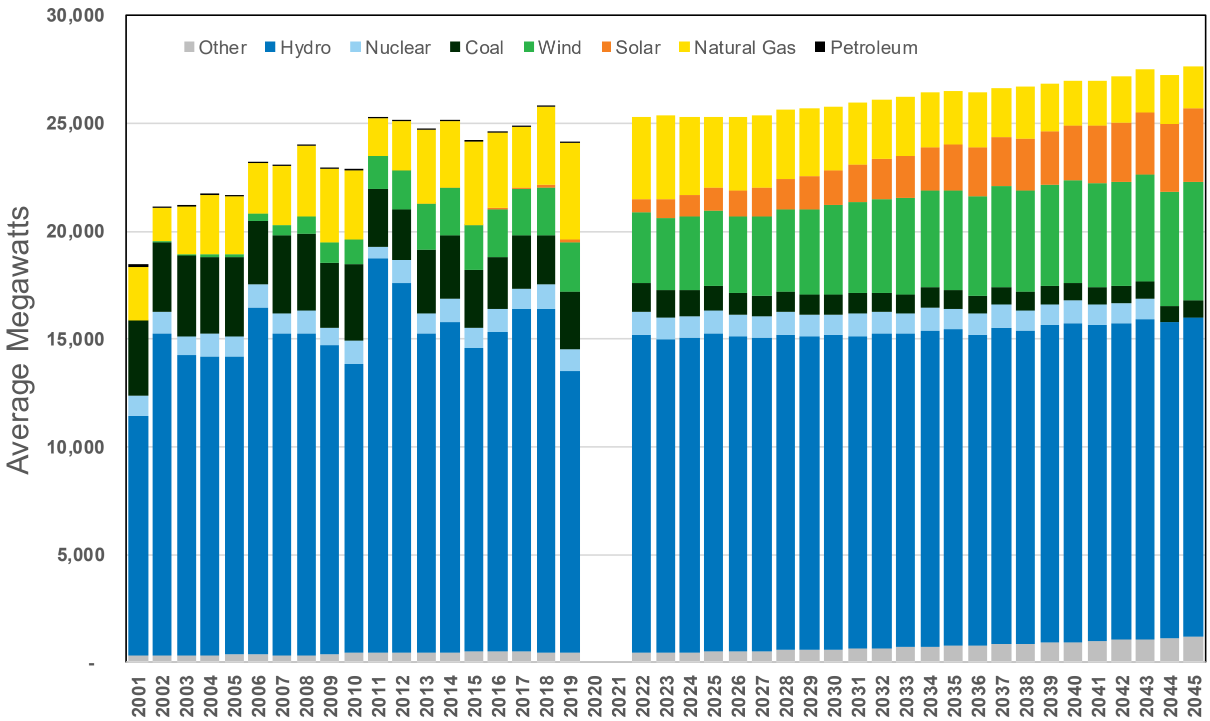
[9] Pricing used in California uses the low price/high demand scenario from the revised 2019 IEPR carbon price projects; e.g. $19.20/metric ton in 2022, $33.73/metric ton in 2030, and $67.95/metric ton in 2040.

Figure 10.9: Generation Technology History and Forecast




The northwest will undergo significant changes in future generation. This forecast expects coal, natural gas and nuclear generation to be limited by 2045; and the remaining generation requirements will be met with solar, wind and hydro generation. As of 2019, 70 percent of the northwest generation was clean, increasing to 84 percent in 2030 and 91 percent by 2045 as shown in Figure 10.10. Achieving these ambitious clean energy goals will require a more than doubling of wind generation and a 23-fold increase in solar energy from the 2019 generation levels. This results in solar providing 12 percent of future generation and wind 20 percent. Avista expects solar generation will be the renewable resource of choice in the northwest as quality wind sites are developed and costly transmission constraints will prohibit new wind in other locations due to the price competitiveness of solar.

Figure 10.10: Northwest Generation Technology History and Forecast




## Regional Greenhouse Gas Emissions

Greenhouse gas emissions are likely to significantly decrease with the retirement of coal generation and solar/wind resources displacing additional natural gas-fired generation. Avista estimates greenhouse gas emissions for plants within the U.S. Western Interconnect at approximately 235 million metric tons in 2019, which is close to the 1990 emissions level of 234 million metric tons. Avista obtained historical data back to 1980; the emissions minimum since 1980 was 161 million metric tons in 1983.

Avista's market modeling only tracks emissions at their source and does not estimate assignment to each state from energy transfers, such as emissions generated in Utah for serving customers in California. Figure 10.11 shows the percent totals for 2019. The largest emitters by state are Arizona and California, followed by Colorado, Utah and Wyoming. The four northwest states generate 17 percent of the total emissions in the Western Interconnect.

Avista expects emissions to decline 20 percent by 2022 compared to 2019 due to coal plant retirements. By 2045, emissions fall 63 percent compared to 1990 levels as shown in Figure 10.12. All states will have a reduction in emissions in this forecast except for modest growth in Idaho. The greatest reductions by percentage are Utah (83 percent), New Mexico (82 percent), Washington (80 percent), and California (76 percent). The greatest reductions by tons are California (27 MMT), Utah (24 MMT), Arizona (21 MMT), and Wyoming (19 MMT).

**Figure 10.11: 2019 Greenhouse Gas Emissions**

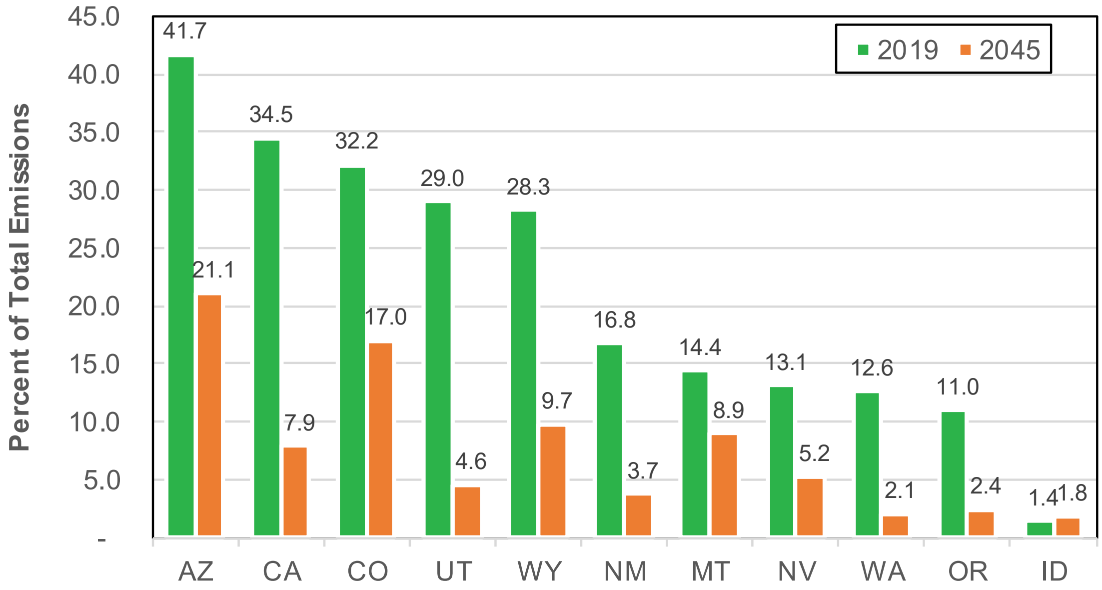
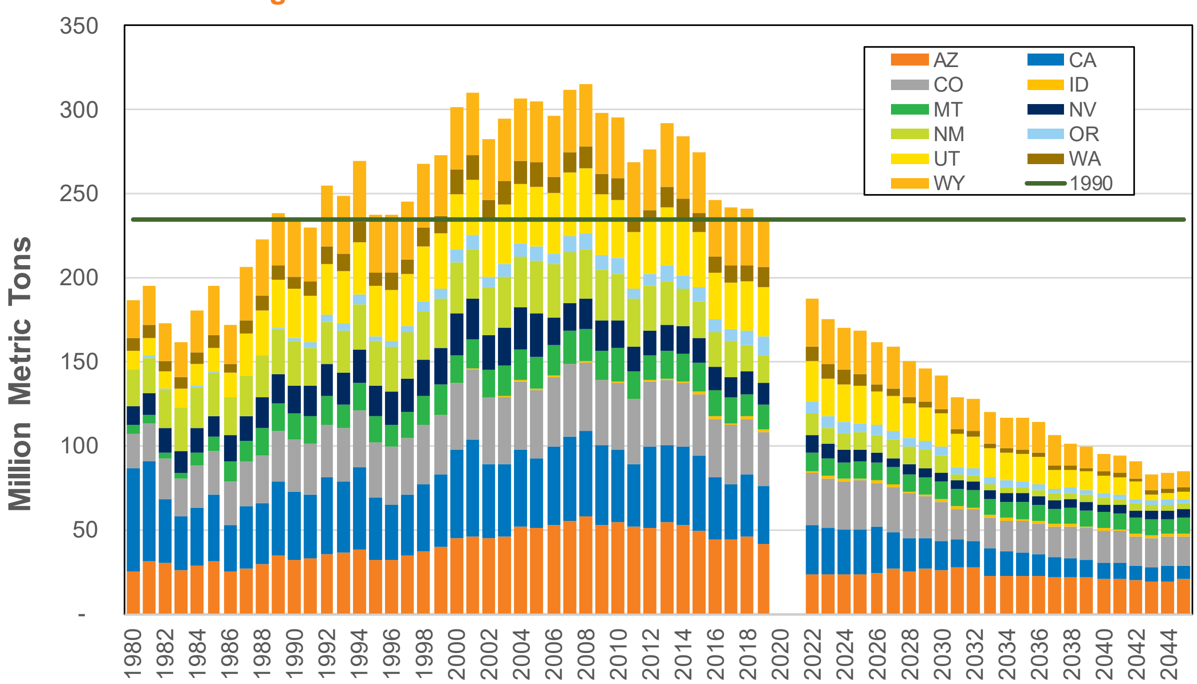


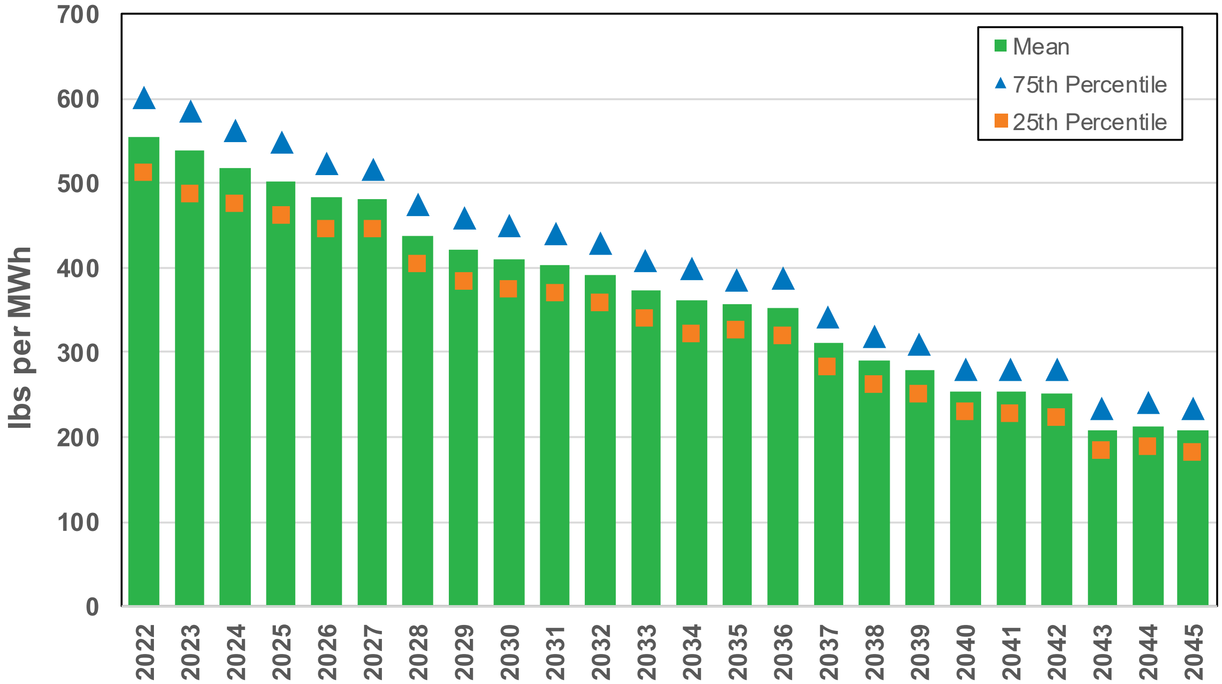

**Figure 10.12: Greenhouse Gas Emissions Forecast**




## Regional Greenhouse Gas Emissions Intensity

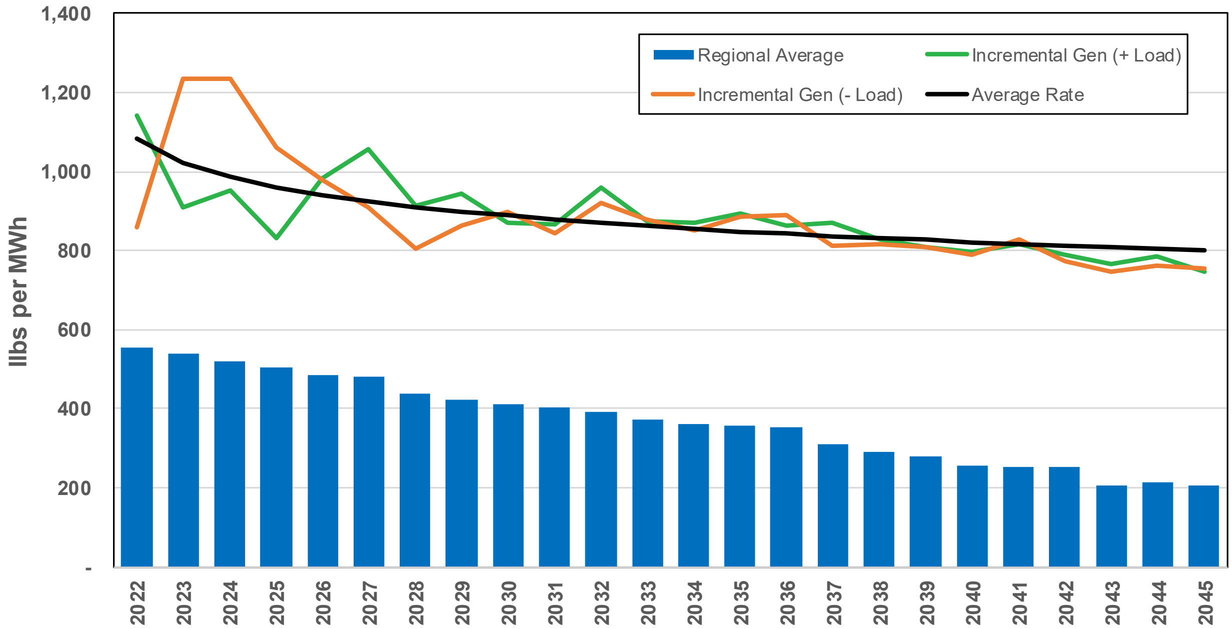
To understand the greenhouse emissions from Avista's market purchases, Avista uses regional emissions intensity per MWh to estimate the associated emissions from these short-term acquisitions. Avista uses the mean values shown in Figure 10.13 for each of the 500 simulations. The chart below shows the mean, 25th percentile and 75th percentile for regional emissions intensity. The emissions are included from Washington, Oregon, Idaho, Montana, Utah and Wyoming. Emissions intensity falls as renewables are added and coal plants retire, but the intensity rate depends on the variation in hydro production. The locations for Avista's potential market purchase radius are consistent with Washington's energy and emissions intensity report but is higher than Avista's likely counter parties for market purchases.

**Figure 10.13: Northwest Regional Greenhouse Gas Emissions Intensity**




When evaluating energy efficiency programs in PRiSM a different regional greenhouse gas emissions intensity is calculated to determine the emission reduction benefits. In this case, Avista determines the incremental regional emission per MWh. These amounts are used for determining the avoided societal greenhouse gas emissions using the social cost of carbon for Washington customers. This is done with two scenarios, the first increases load and the second decreases load in the Northwest. Loads change by the approximate amount of energy efficiency Avista may pursue in the future. Avista chose to look at both load adjustment methods rather than the higher load method due to the higher load method requiring new generation and this generation may influence the incremental emissions rate. Conducting both scenarios and averaging the results approximates the incremental reductions in regional emissions. To estimate the savings, the change in regional emissions was divided by the change in generation. The results of the two analyses show the annual incremental emissions intensity in Figure 10.14. The black line is the fitted curve of the average of the two scenarios and it is used in Avista's portfolio modeling for energy efficiency selection. As a comparison, the blue bar is the average emission rates as shown in Figure 10.13.

**Figure 10.14: Northwest Incremental Greenhouse Gas Emissions Intensity Rates**




# Electric Market Price Forecast

## Mid-Columbia Price Forecast

Deterministic and stochastic analysis methodologies of the Expected Case are studied for the IRP. Each study uses hourly time steps between 2022 and 2045 for a simulation of over 210,000 hours. This process is time consuming when conducted 500 times. Running the Expected Case 500 times took one week of continuous processing on 33 separate processor cores to complete. Time constraints limit the number of market scenarios Avista is ultimately able to explore in each IRP.

The annual average of all hourly prices from both studies are shown in Figure 10.15. This chart shows the annual distribution of the prices using the 10$^{th}$ and 95$^{th}$ percentiles compared to the mean, median and deterministic prices. The pricing distribution is lognormal as prices continue to be highly correlated with the lognormally distributed natural gas prices. The 24-year nominal levelized price of the deterministic study is $26.05 per MWh and $27.13 per MWh for the stochastic study. See Tables 10.7 and 10.8. Table 10.8 includes the super peak evening (4 to 10 p.m.) period to illustrate how prices behave during this high-demand period where solar output is falling, and rising prices encourage dispatching of other resources.

Figure 10.15: Mid-Columbia Electric Price Forecast Range

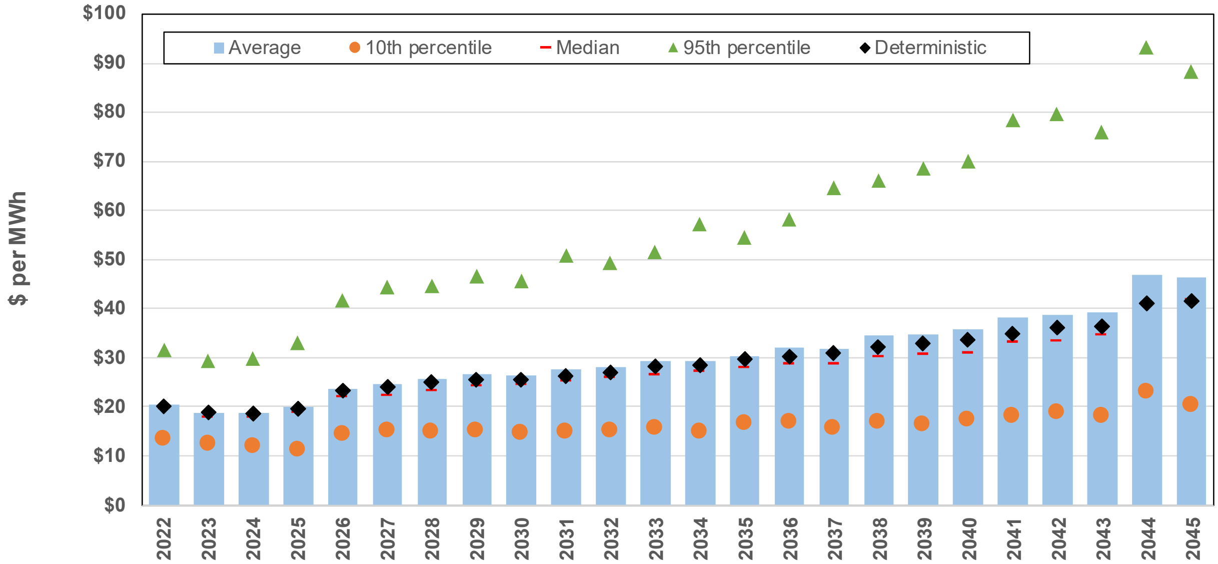



Table 10.7: Nominal Levelized Flat Mid-Columbia Electric Price Forecast

| Metric | 2022-2041 Levelized ($/MWh) | 2022-2045 Levelized ($/MWh) |
|---|---|---|
| Deterministic | $24.98 | $26.05 |
| Stochastic Mean | $25.82 | $27.13 |
| 10th Percentile | $17.54 | $18.14 |
| 50th Percentile | $23.62 | $24.84 |
| 95th Percentile | $42.95 | $44.35 |

Average on-peak prices between 7 a.m. and 10 p.m. on weekdays plus Saturday have historically been higher than the remaining off-peak prices. However, this forecast shows off-peak prices outpacing on-peak prices on an annual basis beginning in 2026 due to increasing quantities of solar generation placed on the system depressing on-peak prices. As more solar is added to the system, this effect spreads into the shoulder months. Only in the winter season, where solar production is lowest, does the traditional relationship of today's on- and off-peak pricing continue.

Depending on the future level of storage and its duration, price shapes could flatten out rather than inverting the daytime spread. Mid-day pricing will be low in all months going forward, driving on-peak prices lower. Super peak evening prices after 4 p.m., when other resources will need to dispatch to serve load, can be high if startup costs effect market pricing as expected in this forecast.

**Table 10.8: Annual Average Mid-Columbia Electric Prices ($/MWh)**

| Year | Flat | Off-Peak | On-Peak | Super Peak Evening |
|---|---|---|---|---|
| 2022 | $20.37 | $18.65 | $21.66 | $27.31 |
| 2023 | $18.71 | $17.89 | $19.34 | $23.69 |
| 2024 | $18.73 | $18.32 | $19.04 | $23.90 |
| 2025 | $19.99 | $19.92 | $20.05 | $25.07 |
| 2026 | $23.74 | $23.82 | $23.68 | $29.31 |
| 2027 | $24.63 | $25.12 | $24.27 | $30.37 |
| 2028 | $25.67 | $26.58 | $24.99 | $31.97 |
| 2029 | $26.65 | $27.83 | $25.77 | $33.21 |
| 2030 | $26.46 | $27.78 | $25.48 | $33.03 |
| 2031 | $27.63 | $29.15 | $26.48 | $34.44 |
| 2032 | $28.02 | $29.57 | $26.86 | $35.21 |
| 2033 | $29.30 | $31.08 | $27.96 | $36.88 |
| 2034 | $29.42 | $31.33 | $27.98 | $37.26 |
| 2035 | $30.47 | $32.68 | $28.81 | $39.10 |
| 2036 | $32.10 | $34.41 | $30.38 | $42.19 |
| 2037 | $31.95 | $34.45 | $30.08 | $42.57 |
| 2038 | $34.46 | $37.39 | $32.26 | $46.92 |
| 2039 | $34.77 | $38.04 | $32.31 | $47.99 |
| 2040 | $35.67 | $39.01 | $33.15 | $50.67 |
| 2041 | $38.23 | $41.52 | $35.77 | $56.03 |
| 2042 | $38.71 | $41.79 | $36.40 | $58.32 |
| 2043 | $39.27 | $42.40 | $36.92 | $61.88 |
| 2044 | $46.82 | $50.34 | $44.18 | $73.63 |
| 2045 | $46.45 | $49.28 | $44.31 | $75.47 |
| **Levelized 2022-2041** | **$25.82** | **$26.68** | **$25.18** | **$33.28** |
| **Levelized 2022-2045** | **$27.13** | **$28.16** | **$26.35** | **$35.90** |

Figures 10.16 through 10.19 show the average prices for each hour of the season for every five years of the price forecast. The spring and summer prices generally stay flat throughout the 24 years as these periods have large quantities of hydro and solar generation to stabilize prices, but mid-day prices decrease over time while prices for the other time periods increase. The winter and autumn prices will have larger price increases due to less available solar energy to shift unless enough long-term storage materializes. With this analysis, current on/off-peak pricing will need to change into different products such as a morning peak, afternoon peak, mid-day and night. Pricing for holidays and weekends likely will be less impactful on pricing except for the morning and evening peaks. Future pricing for all resources will need to reflect these pricing curves so they can be properly valued against other resources.

Figure 10.16: Winter Average Hourly Electric Prices (December - February)

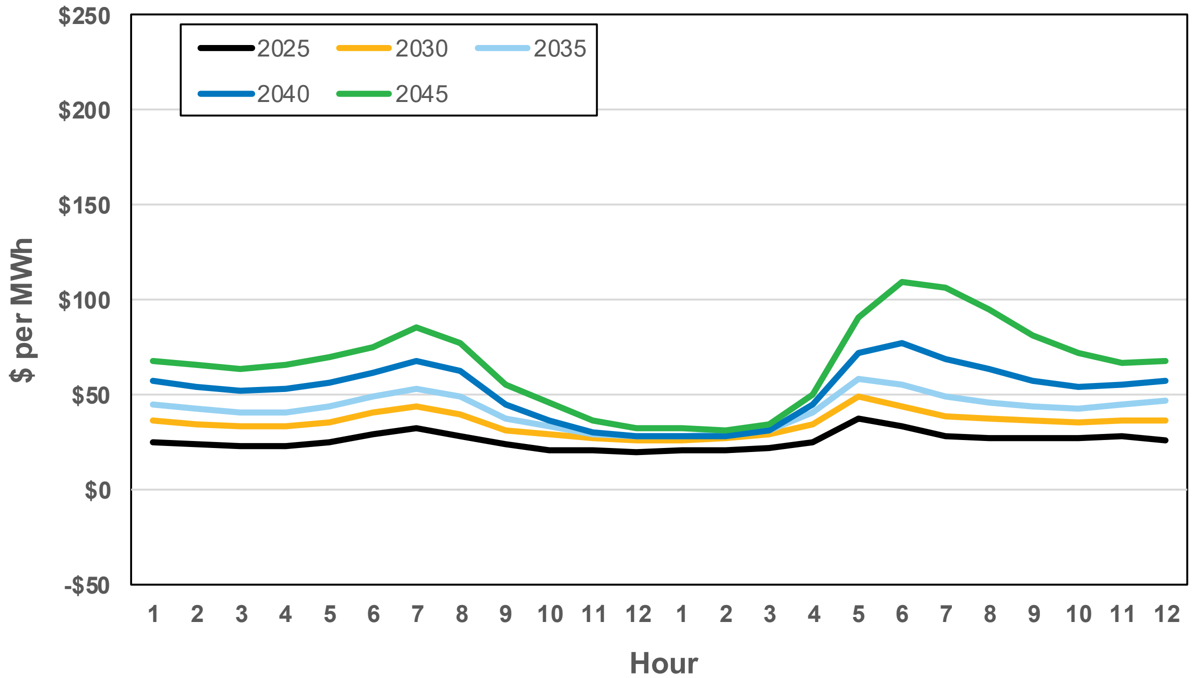



Figure 10.17: Spring Average Hourly Electric Prices (March - June)

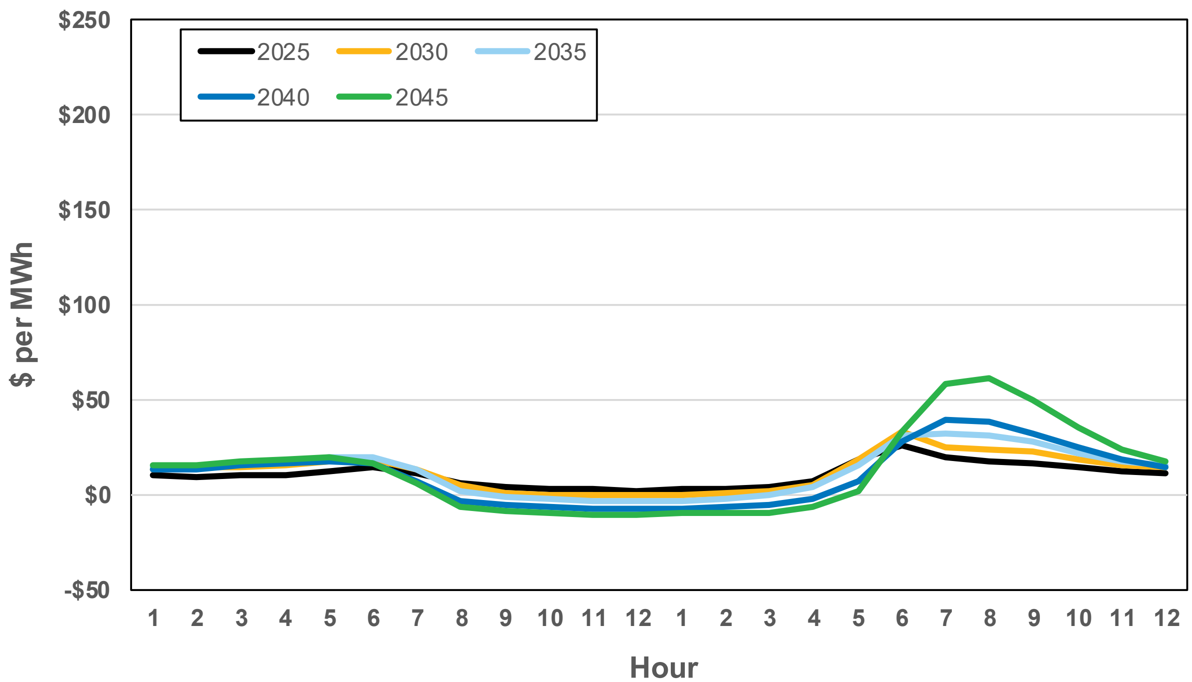


**Figure 10.18: Summer Average Hourly Electric Prices (July - September)**

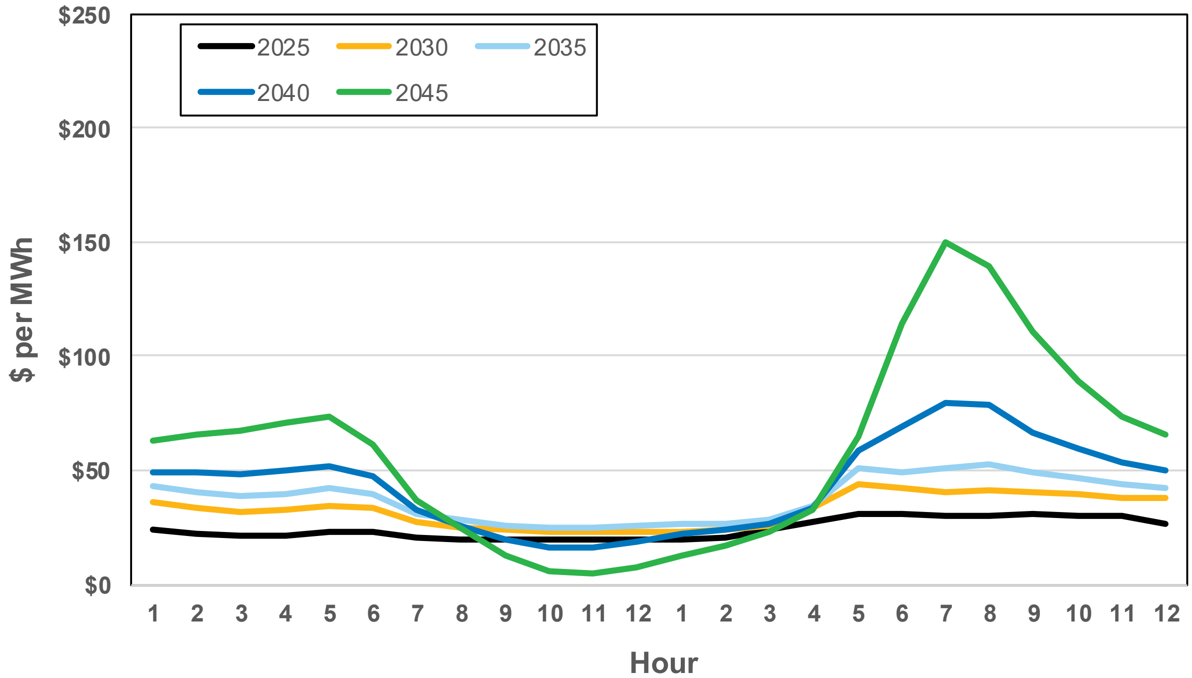
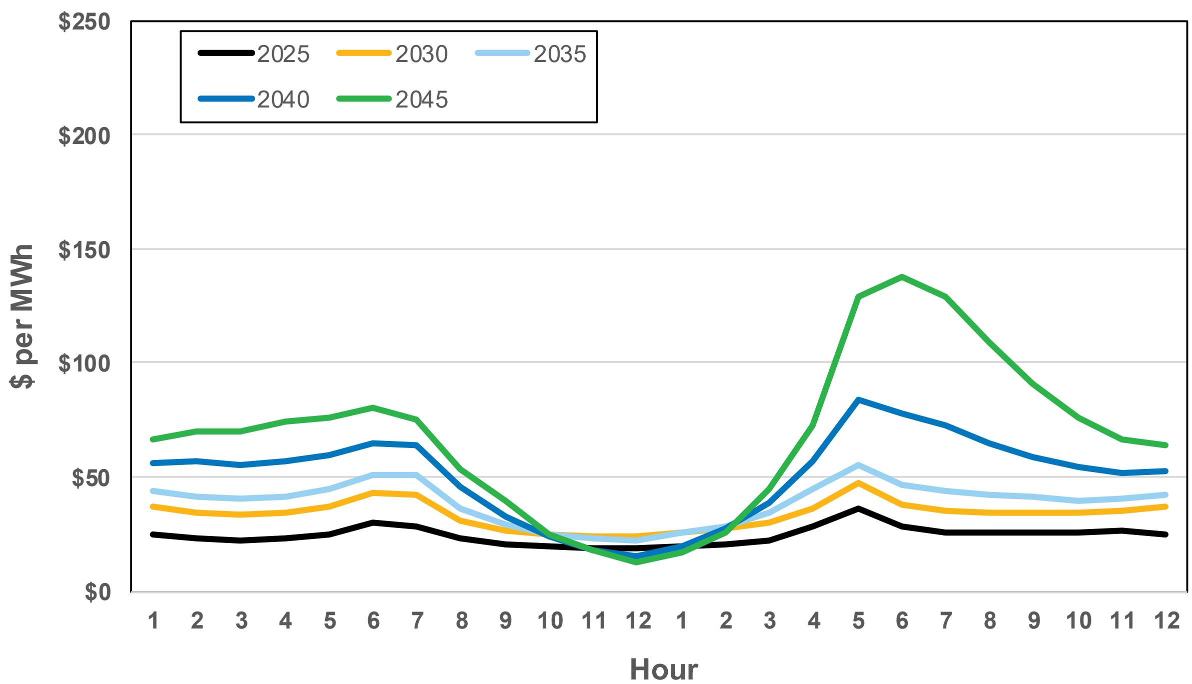



**Figure 10.19: Autumn Average Hourly Electric Prices (October - November)**



# Scenario Analyses

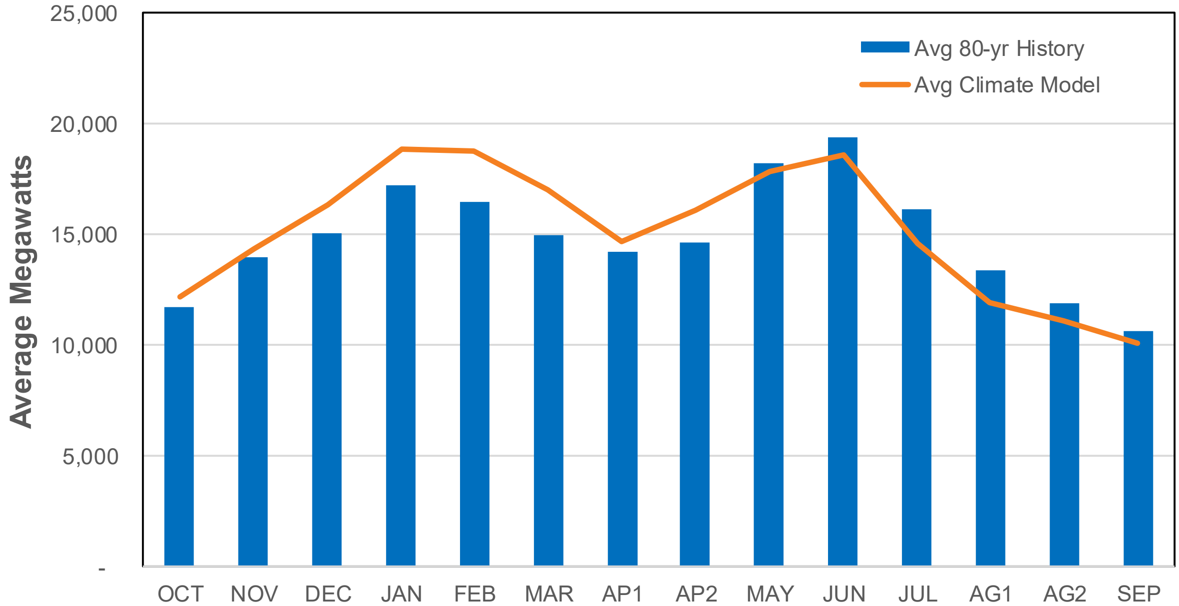
Electric wholesale market prices will have an impact on this resource plan depending on how each resource option performs compared to other resources. This comparison uses market prices along with how each resource performs when customers need them (e.g., winter sustained peak). As discussed earlier, market price forecasts can be rather computer processor and time intensive. However, understanding specific effects on the marketplace are important to understand the risks involved with resource choice. Avista studied four additional scenarios beyond the 500 simulations of the Expected Case. Avista modeled each scenario deterministically. Deterministic studies are sufficient because the objective of the scenario is to understand the effect of the underlying change in assumption on the plan. The portfolio sensitivities and market scenarios conducted for this IRP are discussed below.

## Climate Shift Scenario

To understand the effects of increasing future regional temperatures, this study increases summer loads and decreases winter loads to reflect warming temperatures. This scenario reflects anticipated climate change impacts to hydro production levels from changes in streamflow patterns and reduced natural gas plants maximum capabilities in hotter temperatures.

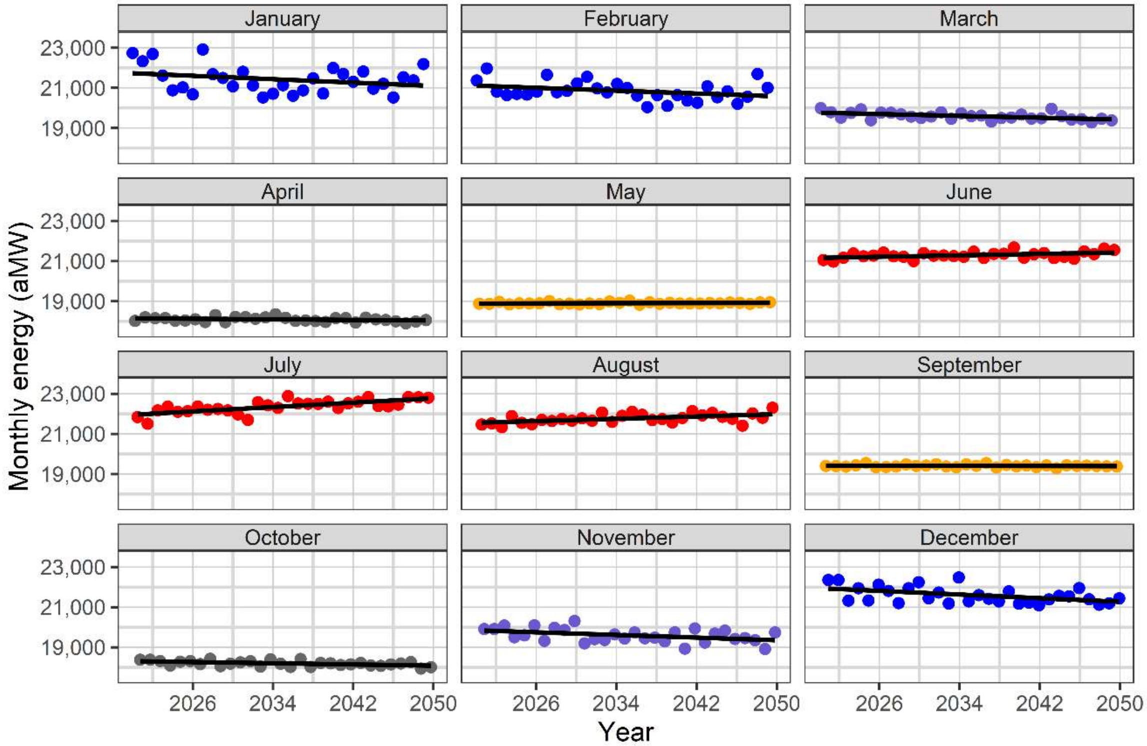
Avista used data from the Northwest Power and Conservation Council (NPCC) to estimate the impacts to load and hydro conditions for this market study. For the hydro changes, Figure 10.20 shows average generation from climate case A, C, and G (orange line) which is the NPCC's change scenario compared to their 80-year average northwest generation quantities. The resulting change is additional hydro generation in the winter months and less in the spring and summer. Avista assumes climate model results for 2045 in this scenario and linearly interpolates the 80-year average data to the 2045 change from 2021.

Figure 10.20: Change in Hydroelectric Generation




To estimate the climate impacts on load, Avista uses the July 2020 NPCC's load iteration climate change scenario to estimate the trending changes in load due to warming temperatures. In this case, the NPCC took the 2024 operating year load forecast and estimated how that operating year's load would perform using predicted temperatures between 2020 and 2045 from the three different climate change studies A, C and G. Avista, with assistance from the Pacific Northwest Utility Conference Committee (PNUCC), created linear changes in load by month given the data provided by the NPCC. This data is shown in Figure 10.21 and illustrates the monthly impact of warming temperatures on Northwest loads. Avista used this linear trend to increase or decrease each monthly load for the Northwest in this scenario.

Figure 10.21: Forecast Change in Monthly Northwest Load Due to Climate Change




## Social Cost of Carbon (SCC) Scenario

This scenario shows the implications of a national carbon policy using the SCC as a “tax” on the entire electric system. In this scenario, power plants are burdened by this cost when making dispatch decisions. This scenario starts with a lower price of $10 per metric ton in 2022 escalating to the SCC by year three. By 2030, the price is $112 per metric ton, $158 in 2040, and $186 in 2045. The levelized price per ton of this scenario is $108.95 per metric ton. Avista chose to ramp in the SCC pricing to reflect a more probable climate policy objective then to shock the energy marketplace. Price elasticity effects due to higher electric prices were not represented in this scenario. This study includes an updated capacity expansion study to reflect the impacts of the carbon tax on the economics of thermal generation.

## Natural Gas Pricing Scenario

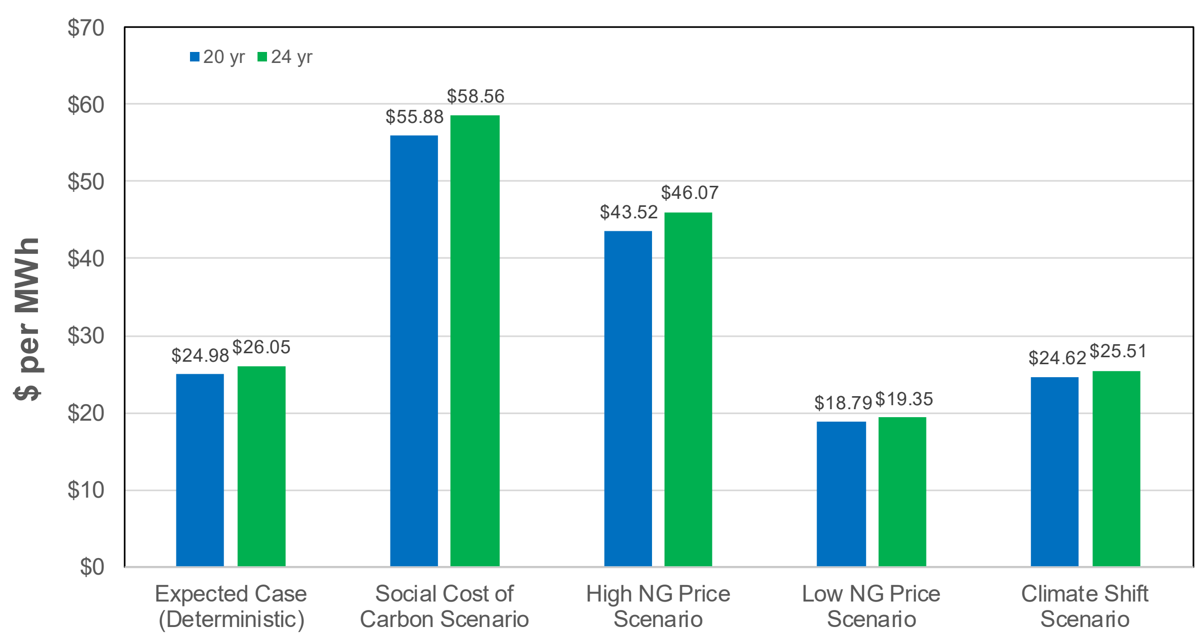
Prevailing low natural gas prices will impact resource selection by lowering electric prices. This scenario assumes 25$^{th}$ percentile natural gas prices from the Expected Case stochastic study. The high pricing scenario uses the 95$^{th}$ percentile of the same Expected Case data set. Both scenarios rely on the Expected Case capacity expansion study. Figure 10.22 compares the levelized cost of these scenarios to the Expected Case at the Henry Hub price. The high price scenario is 200 percent above while the low-price scenario is 35 percent below the Expected Case. This scenario is useful in determining the viability of future resource options given the change in natural gas prices. For example, low natural gas price scenarios will make coal and renewable projects less economic while the high natural gas scenarios will make them relatively more economic.

Figure 10.22: Change in Henry Hub Natural Gas Prices


## Scenario Electric Price Results

The results of these studies show a variety of market price impacts from changes in key assumptions. Figure 10.23 presents the nominal levelized prices for each scenario on a 20- and 24-year basis compared with the Expected Case's deterministic study. The deterministic study is shown in the comparison to eliminate other factors for the comparative analysis. For example, the only change in the study assumptions is the specific input rather than stochastic assumptions. The annual prices used to estimate the levelized costs for each scenario is shown in Figure 10.24.

Figure 10.23: Mid-Columbia Nominal Levelized Prices Scenario Analysis

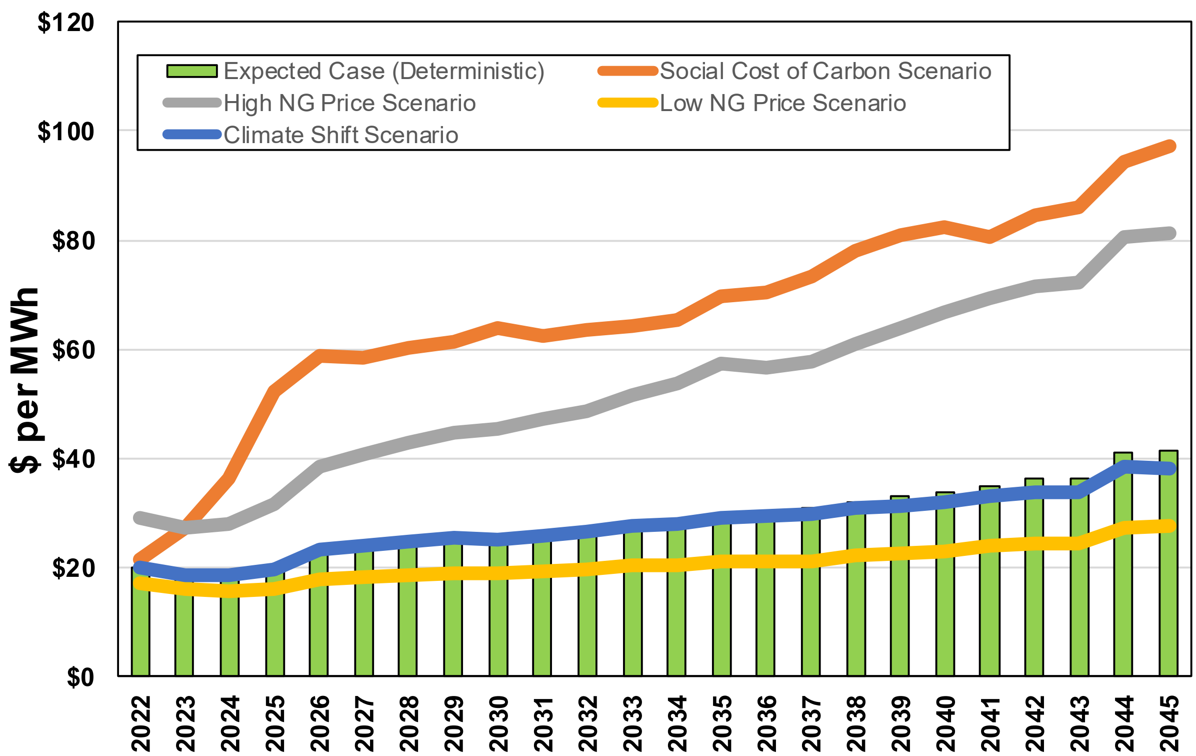


The scenario results show with warming temperatures the wholesale prices are lower over the 24-year period, with 2045 prices 8 percent lower than the Expected Case. The change in price is due to hydro generation more closely matching higher loads in the winter; while worse hydro conditions in the summer have only a small effect on summer prices due to already low hydro generation levels.

The natural gas pricing scenarios show how a 200 percent increase in natural gas prices causes a 77 percent increase in electric market prices. When natural gas prices are 35 percent lower than the expected case the resulting electric prices are 26 percent lower.

The SCC scenario models the adder as a tax, meaning the marginal price of thermal unit dispatch increases based upon its carbon content. In this case, prices increase 225 percent compared to the Expected Case or $32 per MWh levelized. This equates to a $0.30 per MWh impact per $1 of metric ton of greenhouse gas pricing.

**Figure 10.24: Mid-Columbia Annual Electric Price Scenario Analysis**

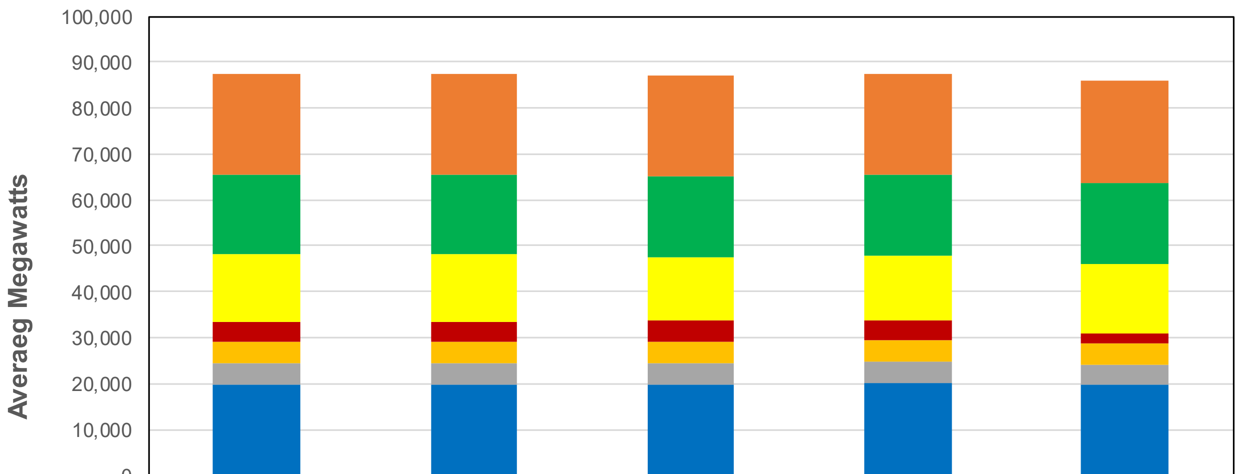



## Scenario Generation Dispatch Results

Each scenario assumption influences the type of generation dispatched in the Western Interconnect. Figure 10.25 highlights generation dispatch in each scenario for 2040, and Table 10.9 shows the percent change in dispatch compared to the Expected Case. The biggest change in dispatch is in the SCC scenario, where the tax on coal and natural gas decreases coal-fired generation and increases natural gas and solar generation. Natural gas dispatch does not significantly change in the natural gas price sensitivities due to the available resources being the same in each scenario. The major impact of the higher and lower gas price scenarios is an overall increase or reduction in market prices. In the climate change scenario, increases to winter hydro production reduces overall coal and natural gas-fired generation.

Greenhouse gas emissions vary across the scenarios. Figure 10.26 presents the results for the first and last year of the study, along with the average emissions rate for the 24-year period. Higher natural gas prices modestly increase emissions in the short term due to additional coal dispatch, but emissions are slightly less in the long term. Emissions fall with lower natural gas prices in all years due to less coal dispatch. The climate shift scenario slightly reduces emissions due to increased hydro generation. The SCC scenario reduces emissions 20 percent over the course of the study.

**Figure 10.25: 2040 Western Interconnect Generation Forecast**

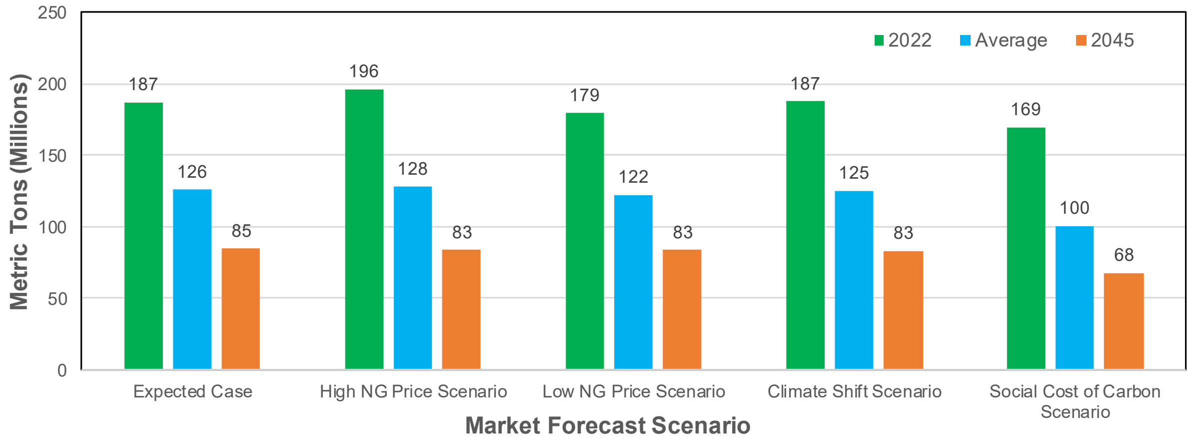



| | Expected Case | Low NG Price Scenario | High NG Price Scenario | Climate Shift Scenario | Social Cost of Carbon Scenario |
|---|---|---|---|---|---|
| Solar | 22,059 | 22,040 | 22,071 | 22,033 | 22,550 |
| Wind | 17,477 | 17,461 | 17,498 | 17,455 | 17,367 |
| Natural Gas | 14,489 | 14,782 | 13,997 | 14,255 | 15,309 |
| Coal | 4,477 | 4,251 | 4,535 | 4,410 | 2,069 |
| Nuclear | 4,729 | 4,713 | 4,740 | 4,714 | 4,727 |
| Other | 4,605 | 4,550 | 4,632 | 4,585 | 4,295 |
| Hydro | 19,726 | 19,726 | 19,726 | 20,028 | 19,726 |

**Table 10.9: Change in 2040 Regional Generation**

| Scenario | Coal | Natural Gas | Hydro | Nuclear | Other | Wind | Solar |
|---|---|---|---|---|---|---|---|
| Low NG Price Scenario | -5% | 2% | 0% | 0% | -1% | 0% | 0% |
| High NG Price Scenario | 1% | -3% | 0% | 0% | 1% | 0% | 0% |
| Climate Shift Scenario | -1% | -2% | 2% | 0% | 0% | 0% | 0% |
| Social Cost of Carbon Scenario | -54% | 6% | 0% | 0% | -7% | -1% | 2% |

## Figure 10.26: Scenario Greenhouse Gas Emissions



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# 11. Preferred Resource Strategy

Avista needs to acquire additional reliable sources of power to meet peak planning requirements for both summer and winter peak loads while also identifying clean generation resources to meet state and corporate clean energy goals. To achieve these goals, Avista must maintain system reliability at affordable rates, while meeting the regulatory and legal obligations of Idaho and Washington, including the new requirements of Washington State's Clean Energy Transformation Act (CETA) requiring service of its state's retail loads with 100 percent non-emitting resources by 2045. This chapter outlines a potential path for Avista to meet its future resource needs under these objectives.

Avista generally acquires new resources through a competitive request for proposal (RFP) process. Avista shortlisted proposals from its 2020 Renewable RFP and is in contract negotiations to acquire new clean energy and any associated capacity for the Company's resource portfolio. Potential additions from the RFP are not included in this plan since contracts were not completed prior to the required IRP filing date. Any resources acquired from that RFP will result in changes to the Preferred Resource Strategy (PRS). While the IRP indicates a resource acquisition plan, it does not include final pricing, resource availability or account for existing resource opportunities.

**Section Highlights**

- The 2020 Renewable RFP may displace some resources selected in this plan.
- It is economic to exit the Colstrip coal-fired facility; however, an exit strategy has yet to be agreed upon by all the owners.
- 200 MW of Montana wind is the most economic new resource to meet the CETA requirements beginning in 2024.
- 211 MW of natural gas CTs are needed for reliability by November 1, 2026 to offset Colstrip and expiring power contracts. Existing resource options may allow for a more economic replacement than constructing new facilities.
- Energy efficiency meets 68 percent of customers' new energy requirements.
- Demand response programs begin in 2024 and provide 71 MW of capacity by 2032.

The IRP acquisition strategy identified as the PRS uses the best information available at the time of its analyses, including Avista's interpretation of CETA requirements. However, some rules for CETA are still incomplete. The IRP uses a least-cost planning methodology using specific social costs specified by the law's planning requirements. Avista did not assume alternative compliance options in meeting its CETA goals. Final rules for CETA may change future resource assumptions and plans.

Avista's PRS describes the lowest reasonable cost portfolio of resources given Avista's need for new capacity, energy and clean non carbon emitting resources, while accounting for social and economic factors prescribed by state policies. This analysis also considers energy market risks as alternative portfolios. The analysis tests sensitivities against the preferred portfolio to measure impacts from critical external factors such as higher and lower load growth. Portfolio sensitivities are discussed in Chapter 12 – Portfolio Scenarios.

The resource strategy includes supply-side resources, energy efficiency and demand response measures. The IRP compares resource options to find the lowest-cost portfolio to meet capacity deficits in both the winter and summer, annual energy and clean energy/CETA requirements.

## Resource Selection Process

Avista uses three models to evaluate resources in its PRS. Aurora, the first model discussed in detail in Chapter 10, determines the economic value of each resource option using its electricity price forecast. For each resource, Aurora defines the following key pieces of data: resource dispatch, greenhouse gas emissions, operating costs and market revenue. Aurora also estimates the market value of our contract obligations.

The second model is Avista's Reliability Assessment Model (ARAM). ARAM first estimates resource peak credits or the amount of reliable capacity a resource provides to Avista's system during the critical peak hours. The second purpose of ARAM is testing various resource acquisition strategies to ensure when new resources are combined with the existing portfolio, Avista can meet system planning requirements with a 5 percent loss of load probability (LOLP). Chapters 6 and 9 discuss this topic in more detail.

A third model, PRiSM (Preferred Resource Strategy Model), aids resource selection using information from the Aurora and ARAM models. PRiSM evaluates each resource option's capital recovery and fixed operation costs relative to their operating margins and capability to serve energy, peak loads and clean energy obligations. PRiSM then determines the lowest-cost mix of resources meeting Avista's resource needs (see Chapter 6). The model can also measure and optimize the risk of various portfolio additions when informed by Monte Carlo data. For the PRS, Avista includes its forecast of 500 Monte Carlo market futures to inform PRiSM. PRiSM is publicly available on Avista's IRP website. No known model, either commercially available or at Avista, can combine hourly or sub-hourly economic dispatch, resource selection and reliability results into one streamlined model. To ensure Avista's portfolio is optimal for customers absent a more granular model, Avista uses an iterative process where the resource selections of one PRiSM optimization are re-evaluated in the Aurora and ARAM models to determine the impacts of the PRiSM run on value (Aurora) and system reliability (ARAM).

### PRiSM

Avista staff developed the first version of PRiSM in 2002 to support resource decision making in the 2003 IRP. The model continues to support the IRP as enhancements improved the model over time. PRiSM uses a mixed integer programming routine to support complex decision making with multiple objectives. Its results ensure optimal values for variables given system constraints. The model uses an add-in function to Excel from Lindo Systems named *What's Best* along with the Gurobi solver. Excel then becomes PRiSM's user interface. PRiSM simultaneously solves to meet system reliability obligations and clean energy standards in Washington while minimizing costs.

The 2021 IRP PRiSM model analyzes resource need for the entire Avista system and by state to ensure each state will be assigned the appropriate incremental costs (if any) of new resource choices. PRiSM includes state-level load and resource balances, and resources must be added to satisfy deficits for both the system and for each state[1]. The model can also retire existing resources when they become uneconomic[2]. Avista employs these modeling changes to better understand the impacts of Washington State policies effect on Idaho. These changes also make it easier to account for social costs included for Washington but are not applicable to Idaho.

The model solves using the net present value of resource costs given the following inputs:

1. Expected future deficiencies for each state and the system
   - Summer Planning Margin from ARAM (16 percent, October through April)
   - Winter Planning Margin from ARAM (7 percent, May through September)
   - Annual energy
   - Clean energy requirements
2. Costs to serve future retail loads as if served by the wholesale marketplace (from Aurora)
3. Existing resource and energy efficiency contributions
   - Operating margins
   - Fixed operating costs
   - Capital Costs
   - Greenhouse gas (GHG) emission levels
   - Upstream GHG emission levels
   - Operating GHG emissions
4. Supply-side resource, energy efficiency and demand response options
   - Fixed operating costs
   - Return on capital
   - Interest expense
   - Taxes
   - Power Purchase Agreements
   - Peak Contribution from ARAM
   - Generation levels
   - GHG emission levels
   - Upstream GHG emission levels
   - Construction and operating GHG emissions
   - Transmission costs

[1] State level constraints are included in the PRiSM model after 2026.
[2] Resources can only be retired at the system level. PRiSM cannot "retire" a resource from serving only one state and transferring the output to the other state.

5. Constraints
   - Must meet energy, capacity and clean energy shortfalls without market reliance for each state
   - Resource quantities available to meet future deficits

The model's operation is characterized by the following objective function:

Minimize: (WA "Societal" $NPV_{2022\text{-}45}$) + (ID $NPV_{2022\text{-}45}$)

Where:

- WA $NPV_{2022\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Social Cost of Carbon + Energy Efficiency Total Resource Cost

- ID $NPV_{2022\text{-}45}$ = Market Value of Load + Existing & Future Resource Cost/Operating Margin + Energy Efficiency Utility Resource Cost

Subject to:

- Generation availability and timing
- Energy efficiency potential
- Demand response potential
- Winter peak requirements
- Summer peak requirements
- Annual energy requirements
- Clean energy goals
- T&D constraints

## The Preferred Resource Strategy

To meet future customer load and emission reduction requirements, Avista plans to acquire energy efficiency, participate in demand response programs, make upgrades to its existing thermal and hydro generation fleet, contract for new renewable energy, and add electricity storage. Avista might acquire resources other than those identified as preferred due to lower costs or the actual capabilities of resources found when acquiring new resources through an RFP or similar competitive process. As discussed earlier, this strategy will also be affected by any new contracted resource resulting from the Company's 2020 Renewables RFP.

Avista's resource strategy relies on available information at the time of the IRP analysis, and may change based on how Avista's customers use energy in the future, changes in projected resource costs, development of new technology and the influences of market price conditions on analysis and future acquisition. The strategy uses Avista's interpretation of CETA requirements since CETA rules were not final when this IRP was written. Therefore, Avista's portfolio may change depending on the final CETA requirements. None of these potential changes due to CETA are expected to alter the short-term resource decisions being made prior to the development of the 2023 IRP.

Resource selections consider economics and environmental objectives while maintaining customer reliability. Avista's first major resource adequacy shortfall is expected to occur in 2026, but it may occur earlier if a resource exits the portfolio prior to that date or loads grow faster than forecasted.

Avista's interpretation of CETA allows for the financially compensated transfer of clean energy attributes from Idaho to Washington customers. Avista limits these transfers in earlier years of the plan to ensure compliance with renewable energy targets. A complete description of these assumptions is provided in Chapter 7 – Long-Term Position.

The PRS is separated between the first decade (2022-2031), second decade (2032-2041) and after 2041. The next several sections of this chapter detail the expected resource acquisitions summarizing demand response and energy efficiency projections separately.

### 2022-2031 Supply-Side Resource Selections

Avista must acquire new energy and capacity resources to meet clean energy goals and capacity deficits. Table 11.1 shows a complete list of new generation selections and exiting resources for the 2022 to 2031 period. The first planned resource change is an economically driven exit of Colstrip. Avista, like other Washington utilities with an ownership share in Colstrip, is unable to recover costs of coal-fired generation in Washington rates after 2025. While the fate of the plant will depend on a joint decision between all owners based on their own economic circumstances, Avista's most economic decision based on modeling in this IRP would be exiting both Units 3 and 4 as soon as possible. Additional scenario analysis on Colstrip is presented in Chapter 12 – Portfolio Scenarios, showing an exit prior to 2025 modestly benefitting both Idaho and Washington customers compared with later dates. Given the difficulty of exiting ownership of this facility, Avista cannot commit to a specific exit or retirement date at this time, but Avista continues to work toward the optimal exit from the resource.

Avista's first new resource additions include 200 MW of wind from Montana in 2023 and 2024. The PRS includes wind due to it generating during higher-priced hours compared to solar, and the potential for Montana wind projects to provide generation during winter peak load conditions. Another 100 MW of Montana wind is added in 2028.

Avista is investigating the possibility of increasing the capacity of its Kettle Falls biomass plant by up to 12 MW before 2026. The 35-year old plant is reaching a point where major equipment replacements are required and repowering at a higher generation level may be justified given CETA requirements.

In the 2020 IRP, Avista found it to be cost effective to modernize the Post Falls hydro facility, including increasing the capacity by 8 MW for an energy increase of 4 aMW. Avista included this upgrade as an assumed upgrade in the plan, meaning the PRiSM model includes this resource as a fixed resource.

With the exit of Colstrip and the expiration of the Lancaster PPA in October 2026, the PRS adds 211 MW of natural gas-fired CTs. The 2020 IRP assumed the capacity lost from Colstrip and Lancaster could be met with long duration pumped hydro, but the updated cost and construction schedule information for pumped hydro caused this resource to not be selected in this IRP. This modeling result is consistent with a scenario analysis performed in the 2020 IRP showing natural gas CTs would be required if low-cost long-duration pumped hydro was not available by 2026. Avista will continue to follow pumped hydro developments for future consideration and developers can respond to any capacity RFP issued by the Company. The natural gas-fired facility is split between Idaho and Washington unevenly. Idaho requires 142 MW and Washington only needs 92 MW for winter peaking capacity. Washington requires less of the natural gas-fired CT due to its earlier selection of Montana wind. It may be possible to design a new CT with the ability to co-fire hydrogen or biofuels to meet CETA's 100 percent clean energy goals by 2045 if the Company cannot acquire an existing facility or alternative clean energy capacity resource in a future RFP.

Avista anticipates contracting for 75 MW of existing regional hydro capacity to replace its expiring Mid-Columbia hydro contracts. Existing hydro generation will likely be competitive given 2031 is within the timing of the 80 percent CETA requirement. Although hydro capacity should be available, it will be a competitive process with other utilities to acquire the generation and it will need to be compared against alternative resource options.

**Table 11.1: 2021 Preferred Resource Strategy (2022-2031)**

| Resource | State | Time Period | ISO Conditions (MW) | Equivalent Winter Peak Capacity (MW) | Energy Capability (aMW) |
|---|---|---|---|---|---|
| Colstrip 3 & 4 | WA/ID | TBD | -222 | -222 | -206 |
| Montana wind | WA | 2023 | 100 | 33 | 45 |
| Montana wind | WA | 2024 | 100 | 33 | 45 |
| Post Falls modernization | WA/ID | 2026 | 8 | 4 | 4 |
| Kettle Falls modernization | WA/ID | 2026 | 12 | 12 | 10 |
| Natural gas CT | WA/ID | 2027 | 211 | 234 | 191 |
| Montana wind | WA | 2028 | 100 | 28 | 45 |
| Mid-Columbia Hydro Extension | WA | 2031 | 75 | 44 | 33 |
| **Total New Resources** | | | **606** | **388** | **373** |
| **Net of Removed Resources** | | | **384** | **166** | **167** |

## 2032-2041 Supply-Side Resource Selections

The second decade of the PRS continues to replace existing resource capacity, meet future load growth and maintain resource adequacy while adding renewable energy to meet CETA requirements. A complete list of resource additions for this decade is in Table 11.2. The first resource addition for this decade is a 5 MW Rathdrum CT upgrade in 2035. The Northeast CT is also expected to retire in 2035, if not earlier. The Northeast CT was constructed in 1978 and Avista forecasts its retirement in 2035 due to the age of the resource and the lack of availability of parts to maintain the equipment. To replace this lost capacity and meet load growth, a natural gas-fired CT was selected to serve the capacity needs of both Washington and Idaho customers.

The first 100 MW solar acquisition occurs in 2038, along with 50 MW of on-site lithium-ion batteries with four hours of storage for both states. Additional load and the expected retirement of Boulder Park in 2041 drives the addition of 36 MW of new natural gas-fired reciprocating engines for Idaho and 100 MW of Montana wind for Washington. The Montana wind replaces expiring wind contracts while contributing toward CETA goals.

**Table 11.2: 2021 Preferred Resource Strategy (2032-2041)**

| Resource | State | Time Period | ISO Conditions (MW) | Equivalent Winter Peak Capacity (MW) | Energy Capability (aMW) |
|---|---|---|---|---|---|
| Rathdrum upgrade | WA/ID | 2035 | 5 | 5 | 4 |
| Northeast CT | WA/ID | 2035 | -62 | -43 | 0 |
| Natural gas CT | WA/ID | 2036 | 87 | 96 | 79 |
| Adams-Neilson Solar | WA | 2037 | -19.2 | 0 | -5 |
| Solar w/ storage | WA/ID | 2038 | 100 | 2 | 26 |
| 4-hour storage (lithium-ion) | WA/ID | 2038 | 50 | 7 | -2 |
| Rattlesnake Flat | WA/ID | 2040 | -145 | -7 | -55 |
| Boulder Park | WA/ID | 2041 | -25 | -25 | -14 |
| Montana wind | WA | 2041 | 100 | 26 | 45 |
| Natural gas reciprocating engine | ID | 2041 | 36 | 35 | 33 |
| **Total New Resources** | | | **378** | **171** | **185** |
| **Net of Removed Resources** | | | **127** | **96** | **111** |

## 2042-2045 Supply Side Resource Selections

The IRP typically does not forecast resource additions beyond 20 years but given the CETA requirement to be 100 percent clean by 2045 Avista extends modeling resources to 24 years into the future for certain scenario analyses (see Chapter 12). The final four years of the plan, while relatively uncertain at this time, identifies the replacement of existing renewable PPAs with both renewable and storage technologies, including lithium-ion and liquid air energy storage (LAES). Table 11.3 outlines these additions. No major resources are expected to leave Avista’s portfolio during this time period absent expiring PPAs.

**Table 11.3: 2021 Preferred Resource Strategy (2042-2045)**

| Resource | State | Time Period | ISO Conditions (MW) | Equivalent Winter Peak Capacity (MW) | Energy Capability (aMW) |
|---|---|---|---|---|---|
| Palouse Wind | WA/ID | 2042 | -105 | -5 | -36 |
| Solar w/ storage | WA | 2042 | 117 | 2 | 31 |
| 4-hour storage (lithium-ion) | WA | 2042 | 58 | 9 | -2 |
| Solar w/ storage | WA | 2043 | 122 | 2 | 31 |
| 4-hour storage (lithium-ion) | WA | 2043 | 61 | 9 | -2 |
| Liquid Air Energy Storage (LAES) | WA | 2044 | 12 | 7 | -1 |
| Solar w/ storage | WA | 2045 | 149 | 3 | 40 |
| 4-hour storage (lithium-ion) | WA | 2045 | 75 | 11 | -2 |
| Liquid Air Energy Storage (LAES) | ID | 2045 | 10 | 6 | -1 |
| **Total New Resources** | | | **604** | **49** | **94** |
| **Net of Removed Resources** | | | 499 | 44 | 58 |

## Demand Response Selections

Demand Response (DR) resources are integral to Avista's strategy to meet customer peak load requirements with non-emitting resources. Avista does not currently offer any load management programs, although it has piloted programs in the past[3]. To understand the potential for new DR programs, Avista contracted with Applied Energy Group (AEG) to estimate the amount of DR available in our Idaho and Washington service territories. Chapter 6 – Demand Response provides an overview of DR programs, their potential and expected costs. The DR estimate includes 16 programs to reduce as much as 169 MW of winter peak load and 245 MW of summer peak load. Some programs offer reductions in both winter and summer, while others only in one season or the other. Avista's primary needs are for winter peak reduction, and several programs were found cost effective. The 2021 PRS incorporates the first DR programs in 2024, ramping up to include all cost-effective DR options by 2027. Table 11.4 shows each DR program selected as part of the PRS. Figure 11.1 illustrates when DR enters the system and how the penetration of DR programs increase through 2045.

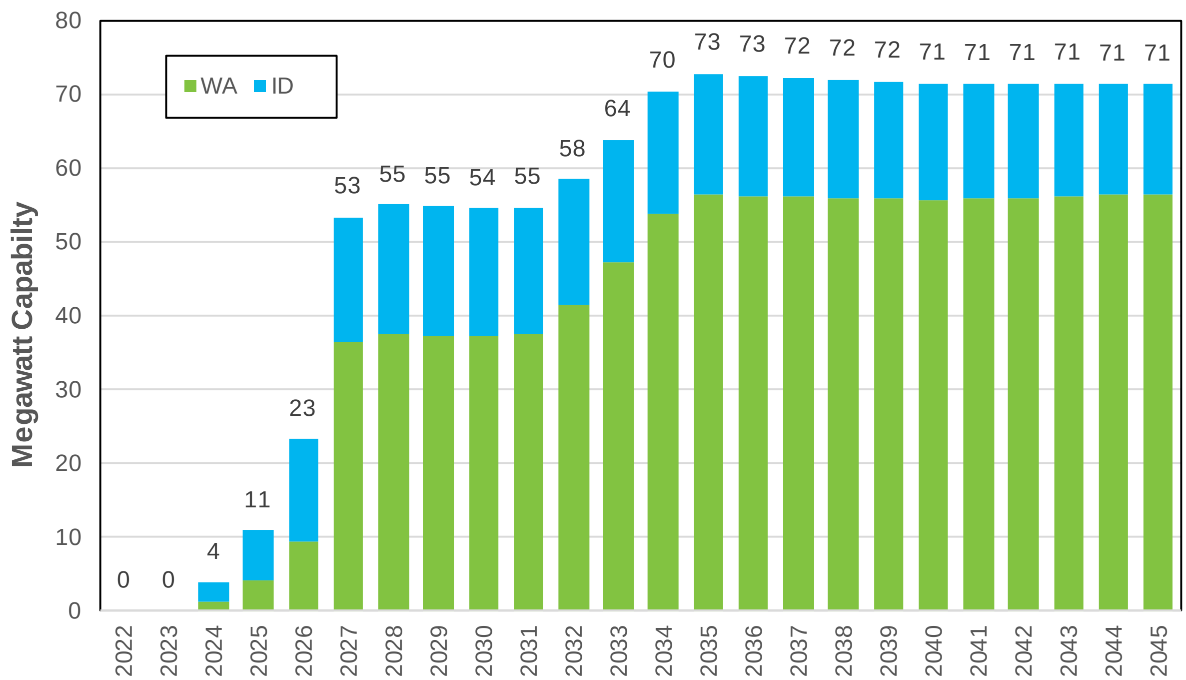
Meeting reliability targets with DR depends on the length of time each program can reduce loads. Avista assumes a 60 percent on-peak capacity credit for DR. Due to the limited duration of the DR programs, Avista's ARAM model demonstrates these programs achieve 60 percent of the reliability benefits of a natural gas-fired CT. Actual experience and program design will ultimately determine the amount of reliable capacity contribution from these resources.

[3] Avista does not have any current plans to institute DR programs specifically for low income energy assistance and has not performed an assessment of low-income DR programs. If the Company elects to perform such an assessment, it would be coordinated through the Energy Assistance Advisory Group or the Equity Advisory Group.

**Table 11.4: PRS Demand Response Programs**

| Program | Washington | Idaho |
|---|---|---|
| Time of Use Rates | 2 MW (2024) | 2 MW (2024) |
| Variable Peak Pricing | 7 MW (2024) | 6 MW (2024) |
| Large C&I Program | 25 MW (2027) | n/a |
| DLC Smart Thermostats | 7 MW (2031) | n/a |
| Third Party Contracts | 14 MW (2032) | 8 MW (2024) |
| Behavioral | 1 MW (2041) | n/a |
| Total | 56 MW | 16 MW |

**Figure 11.1: Annual PRS Demand Response Capability**




## Energy Efficiency Selections

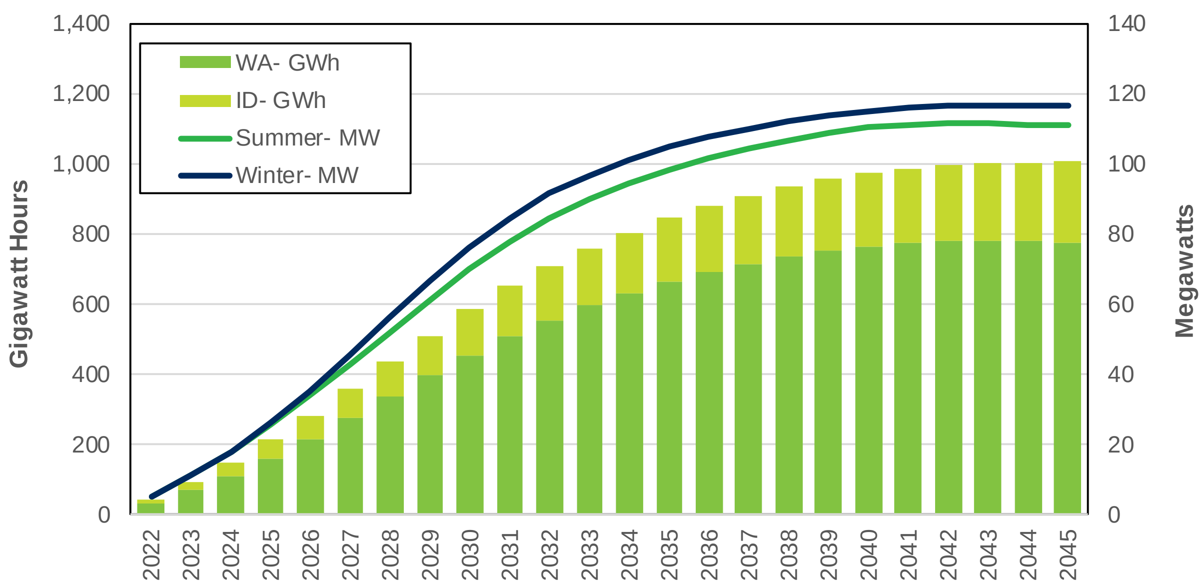
Energy efficiency meets more than two-thirds of all future load growth. This IRP studied over 7,300 energy efficiency programs and measures. Avista models energy efficiency programs individually to ensure each program's capacity and energy contributions are valued in detail for the system. This method ensures an accurate accounting of peak savings that is not possible if programs were bucketed or simply compared to a levelized price of energy. As described in Chapter 3, long-term energy and peak demand forecasts already include the benefits of energy efficiency. This requires adjusting the load forecast used in PRiSM to exclude projected energy efficiency additions so specific program selections can occur. An iterative process with PRiSM ensures maximum cost-effective energy efficiency quantities are included in the PRS. PRiSM adds both supply- and demand-side resources to the PRS. Selected energy efficiency is then reinserted into the model by increasing the amount of load forecast by the selected energy efficiency program or resource. The process repeats until the amount of energy efficiency selected and the amount of energy efficiency added to the load forecast is similar[4].

Over the course of the plan, 1,005 cumulative gigawatt-hours are saved through energy efficiency. When considering transmission and distribution losses, loads are 121 aMW less with these programs. In total, energy efficiency meets 68 percent of load growth between 2022 and 2045. Figure 11.2 shows total energy and peak hour savings by state for both winter and summer. Winter peaks are reduced by nearly 118 MW and summer peaks are reduced by 111 MW. Over the IRP planning horizon, 23 percent of new energy efficiency comes from Idaho customers and 77 percent from Washington customers. Washington has more energy efficiency savings than Idaho relative to load because of the higher avoided costs driven by CETA and other regulations in Washington.

Most energy efficiency savings are from commercial customers (47 percent), followed by residential customers (37 percent), with the remainder from industrial customers. The greatest sources of energy efficiency, at nearly 60 percent, are from lighting, space and water heating measures. Figure 11.3 shows the program type by share of the total savings.

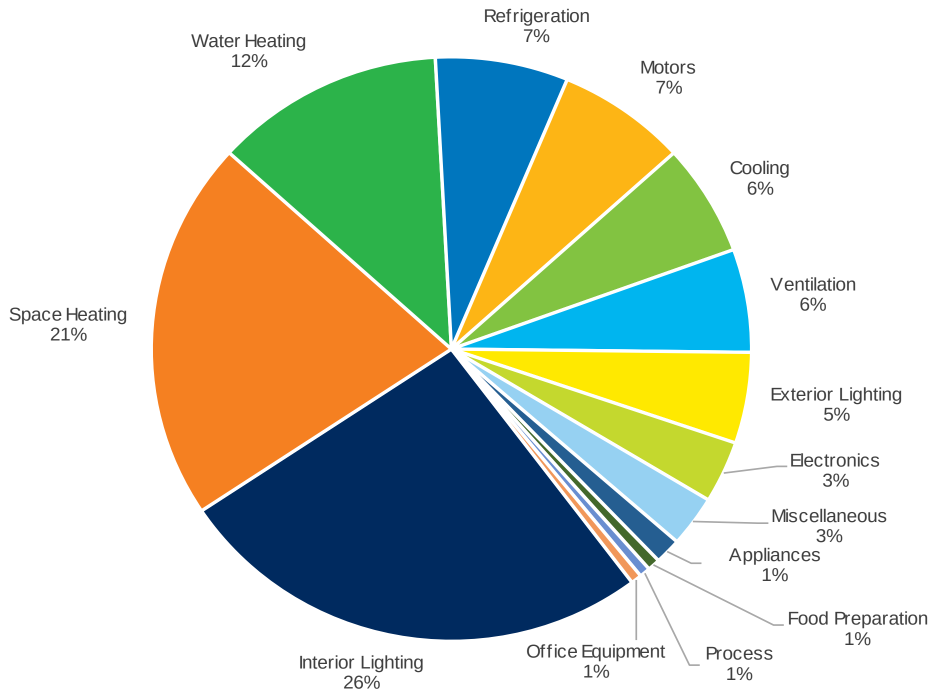
The amount of energy efficiency identified in the PRS will lead to specific program creation in Washington and Idaho. The IRP informs the Avista energy efficiency team in determining cost-effective solutions and potential new programs for business planning, budgeting and program development.

**Figure 11.2: Energy Efficiency Annual Forecast**




[4] The difference in this IRP is 1 aMW for energy and 1 MW for capacity through 2045.

**Figure 11.3: Energy Efficiency Savings Programs**




## Reliability Analyses

This plan uses a LOLP metric to ensure future system reliability. Due to the large computational effort associated with completing reliability assessments, not all years are able to be evaluated for IRPs. Reliability is assessed in 2025, 2030 and 2040 using ARAM for this IRP. ARAM simulates 1,000 potential scenarios with different loads, wind estimates, hydro conditions and forced outage rates for each hour of each year studied. This analysis includes the resources expected to remain in Avista's portfolio along with resource selections from PRiSM associated with the PRS.

The resource adequacy objective of the plan is to have a LOLP at or below 5 percent. This means up to 5 percent of the 1,000 simulations do not meet all load requirements over the year. The methodology is similar to the concept of experiencing one resource adequacy issue in 20 years. The LOLP is measured by any event where loads or reserves are not met in the simulation. Table 11.5 shows reliability metrics for the PRS for 2025, 2030 and 2040. For comparison, a 333 MW CT addition in 2030 is modeled and included in the table. This scenario is used as the basis for determining the market reliance requirements to maintain the 5 percent LOLP. This analysis also assumes the ability to purchase short-term market power but is limited to 330 MW in high-load periods, meaning temperatures below 2 degrees Fahrenheit or above 83 degrees (daily average)[5]; all other periods are limited to 500 MW.

[5] Both temperatures are 99th percentile events.

The PRS in 2030 is slightly above the 5 percent LOLP target, although Avista is not proposing additional capacity at this time due to its similarity to the natural gas-fired alternative and having lower values for the other industry benchmark reliability metrics as shown in Table 11.5. By 2040, the PRS is resource insufficient and will require more analysis to determine if the peak credits for different resources are appropriate or if additional planning reserve margin is required at the end of the study period. The other reliability metrics shown are Loss of Load Hours (LOLH), which is the average duration of outages and the Loss of Load Expectation (LOLE) which is the number of days with an outage event divided by the 1,000 simulations. The LOLE measure is similar to the LOLP but includes a frequency component. Another way of showing this is the "Total Events" line item, meaning in the 2030s PRS, 148 events occur in 1,000 simulations. These events occur in only 5.4 percent of the simulations, meaning simulations with reliability issues can have more than one event per simulation. The final reliability measurement is Expected Unserved Energy (EUE), this is a measurement of the average quantity of MWh the system cannot meet.

**Table 11.5: Reliability Metrics**

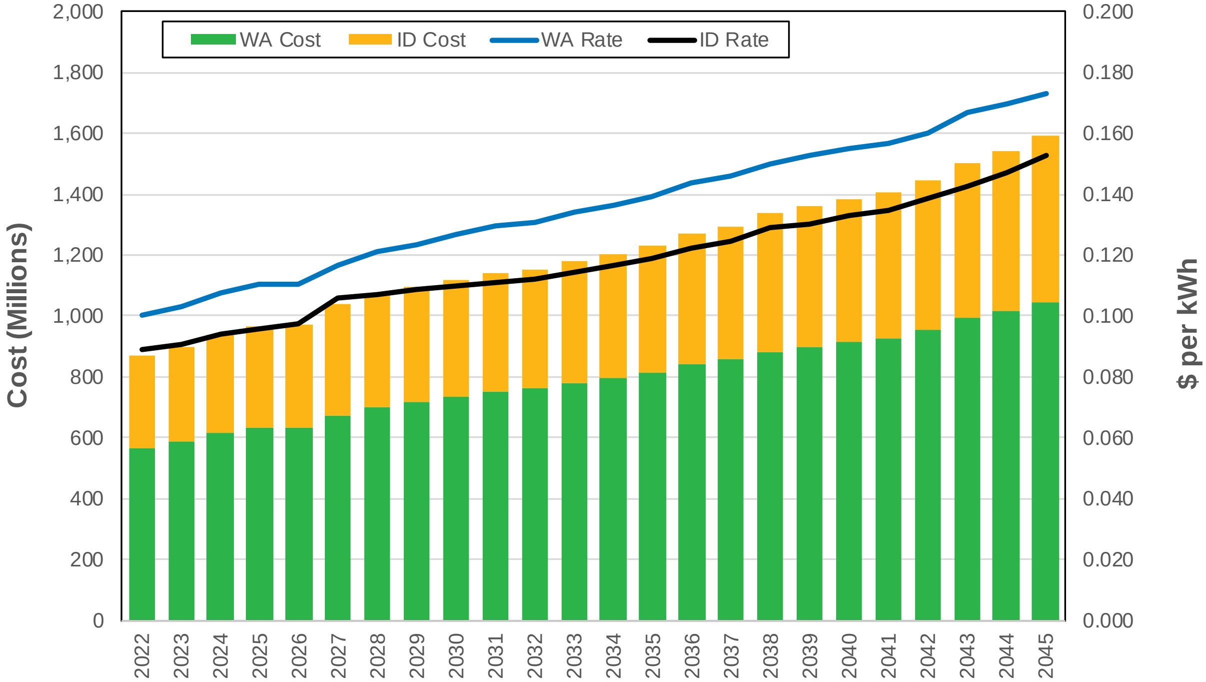
| Year | 2025 (PRS) | 2030 (PRS) | 2040 (PRS) | 2030 (333 MW NG CT) |
|---|---|---|---|---|
| LOLP | 4.6% | 5.4% | 8.8% | 5.2% |
| LOLH | 1.45 hours | 1.74 hours | 2.89 hours | 1.89 hours |
| LOLE | 0.12 | 0.14 | 0.21 | 0.15 |
| EUE | 233 MWh | 266 MWh | 548 MWh | 316 MWh |
| Total Events | 126 | 148 | 228 | 160 |

## Cost and Rate Projections

The IRP rate projection does not include detailed transmission[6], distribution, administrative and O&M cost recovery costs of the hydro system. Avista assumes these non-generation costs increase by 2 percent per year to approximate an annual average customer rate estimate. By 2022, there is an expected difference between Idaho and Washington rates of nearly one cent per kWh, but over the IRP time horizon these differences increase to two cents. Annual projected rates are shown in Figure 11.4. Rate impacts are an important consideration when comparing the portfolio alternatives found in Chapter 12.

[6] Unrelated to specific generation acquisition.

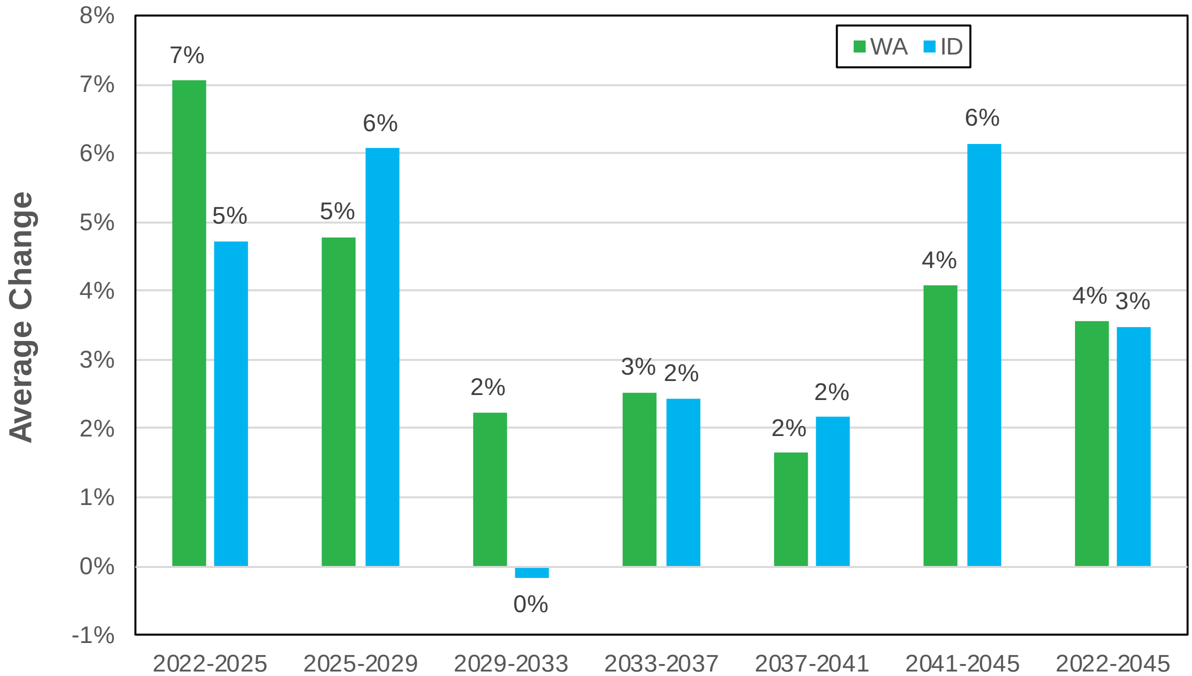
**Figure 11.4: Revenue Requirement and Rate Forecast by State**




To help understand costs in more context without scenario comparisons, Figure 11.5 shows the annual rate increase by state for each four-year period of the IRP using only generation-related costs. Over the first four years of the plan, power and new power acquisition rates increase nearly 5 percent in Idaho and 7 percent in Washington. Washington's increases are from renewable energy and DR program acquisitions, with nearly half of the costs due to existing resource/load power supply cost and market price increases. Cost increases in Idaho are mostly from existing resource/load power supply cost increases along with modest DR costs.

In the next four-year period (2025-2029), cost increases are due to increases in the market price of electricity and new resource acquisitions. Where Washington acquires part of its needs earlier to meet CETA, resource acquisitions for Idaho are delayed until actual capacity needs occur in this four-year period. By 2030, resource acquisition is limited and power costs stabilize. Idaho has a small cost decrease from selling RECs and clean energy to Washington. As 2040 approaches, new resource acquisitions and lower REC sales for Idaho lead to cost increases in both states. Overall power-related costs increase nearly 4 percent per year in Washington and 3 percent in Idaho.

**Figure 11.5: Percent Change in Resource Related Rates**




Avista conducted an incremental cost analysis for Washington-related CETA costs using the incremental cost methodology provided by rule. Between 2022 and 2025, Washington customers are likely to pay $99 million[7] more for the CETA clean energy requirement for this period. Avista estimates CETA spending must exceed $131 million before qualifying for an exemption from fully meeting clean energy goals. The spending target is calculated by summing the cumulative 2 percent annual increases of the weather adjusted Washington revenue requirement over a four-year period. The cost cap provision is retrospective and will be based on actual cost from the period. Avista estimated the difference in expected costs and the CETA cap to forecast would be under its cost cap during the first four-year compliance period.

Although under the cost cap, the average rate increases from these power-supply acquisitions alone cause rates to increase 3.7 percent per year more than rates would rise absent the clean energy legislation. In the remaining years through 2044, Washington rate increases from power generation additions are approximately 3 percent more per year compared to the baseline analysis. These figures are below the cap due to generation cost increases being averaged into the overall utility rate. Beyond 2044, compliance costs, even when blended with non-power supply related costs, are likely to exceed the CETA cost cap depending on the methodology used to comply with the 100 percent clean energy requirement.

[7] Assumes social cost of carbon in the baseline analysis, baseline analysis is Scenario 2- Baseline 1 in Chapter 12.

**Table 11.6: 2022-2024 Cost Cap Analysis (millions $)**

| | 2021 | 2022 | 2023 | 2024 | 2025 | Total |
|---|---|---|---|---|---|---|
| Revenue Requirement w/ SCC | 655 | 655 | 675 | 710 | 716 | |
| Baseline | | 650 | 657 | 672 | 678 | |
| Annual Delta | | 5 | 18 | 38 | 38 | 99 |
| Percent Change | | 0.7% | 2.7% | 5.6% | 5.7% | 3.7% |
| **Four Year Max Spending** | | **33** | **33** | **33** | **33** | **133** |
| Comparison vs Annualized Cost Cap | | -28 | -15 | 5 | 5 | -34 |

## Environmental Analyses

Avista has a Company-wide goal to serve all customers with clean energy. This goal includes meeting 100 percent of retail sales with a combination of clean energy and emission offsets by 2027 and meeting all retail sales with clean energy by 2045. Avista is committed to meeting this goal, but must balance it with state policies, affordability and reliability. Affordability is important to Avista's customers, most of whom have lower than state-median household income. In addition, Avista customers live in areas subject to more extreme winter and summer temperatures than those west of the Cascades, meaning their energy bills are often higher and are a higher portion of their income.

Avista's PRS meets 78 percent of its 2027 corporate goal, meaning nearly 80 percent of energy delivered to all customers is from clean resources including hydro, biomass, wind and solar prior to any additional clean energy or REC market purchases. Figure 11.6 shows annual amounts of clean energy for the system. By 2045, 86 percent of sales are provided by clean energy if the PRS is implemented. This means Avista will create or acquire clean energy over the course of the year to equal 86 percent of retail sales. This estimate includes existing (shown in blue) and new (shown in green) clean energy resources. Figures 11.7 and 11.8 illustrate dedicated clean energy for Washington and Idaho. Washington must acquire clean energy and/or RECs equal to retail sales by 2030. Idaho's share of clean energy ranges between 37 and 60 percent depending on the quantity of annual REC sales to Washington but is still expected to acquire up to 38 aMW of new clean energy over the 24-year IRP horizon.

**Figure 11.6: Annual Clean Energy for the System Sales**

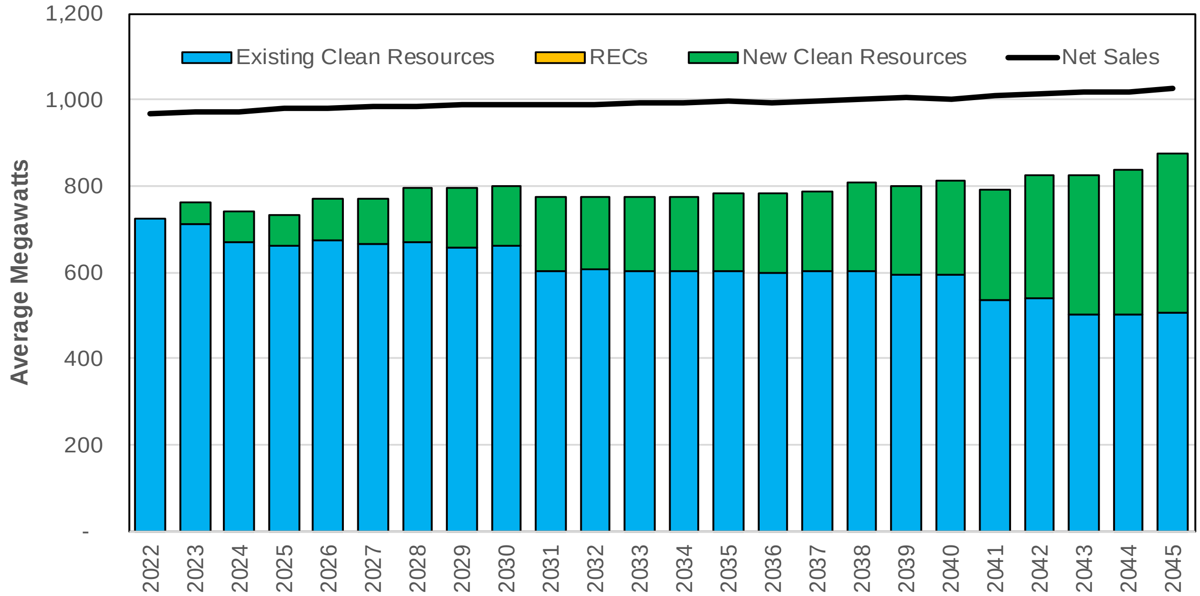



**Figure 11.7: Annual Clean Energy for Washington Portion of Sales**

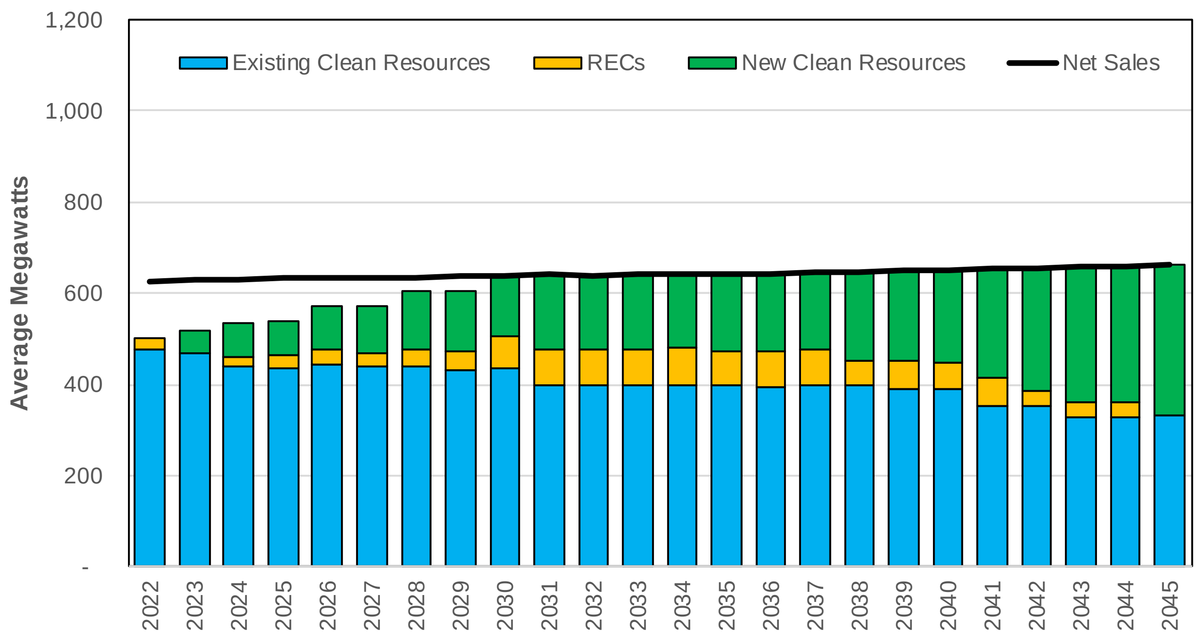
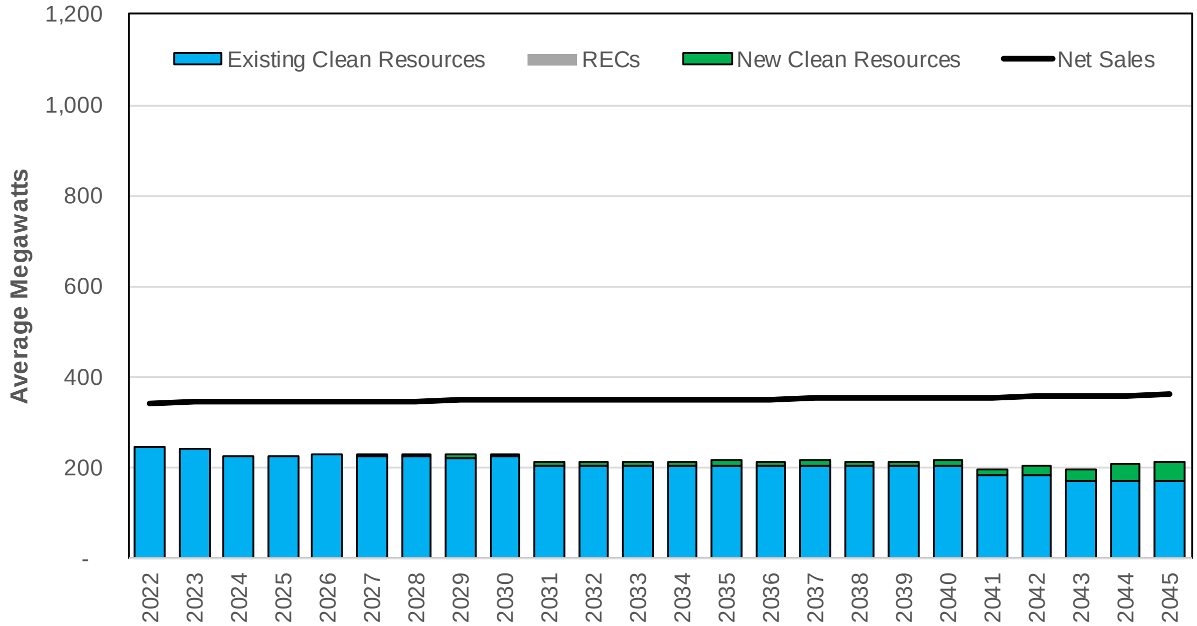


**Figure 11.8: Annual Clean Energy for Idaho Portion of Sales**




With the resource changes of this plan, Avista's greenhouse gas emissions fall below 2019 levels. In 2019, greenhouse gas emissions from our generating fleet were nearly three million metric tons prior to any adjustments for market transactions or upstream emissions. This level declines even if Colstrip remains in the portfolio through 2025, as shown in the dotted line in Figure 11.9. Emission reductions are largely due to reduced Colstrip dispatch as low natural gas prices and larger quantities of renewables push wholesale prices lower. If Colstrip is removed from the portfolio, direct emissions fall to 1.5 million metric tons. Comparing 2030 to 2019, direct emissions drop 2.2 million tons or 74 percent (total of the blue and orange bars).

Avista included estimates from upstream emissions in its IRP analyses. The natural gas estimate includes between 80,000 and 150,000 metric tons per year from upstream emissions, as shown in the green bars. Net emissions from market transactions are shown in the light blue bars and are netted with total emissions in the black line. The chart assumes the transactions use the annual average northwest regional emissions rate. As shown, Avista is a net seller of energy through 2026, continuing as a net seller in smaller increments afterward. This net sales position may reduce emissions using this average annual rate factor.

Avista's emissions intensity continues to decline over the course of the IRP. Current emissions intensity rates are nearly 730 lbs per MWh. The rate is expected to fall below 700 if Colstrip remains in the portfolio and drops to nearly 350 lbs per MWh when it exits. After the Lancaster PPA expires, emissions rates drop to 200 lbs per MWh and continue declining as more clean energy resources enter the portfolio. These estimates assume gross dispatched emission levels compared to retail sales.

**Figure 11.9: Greenhouse Gas Emissions**

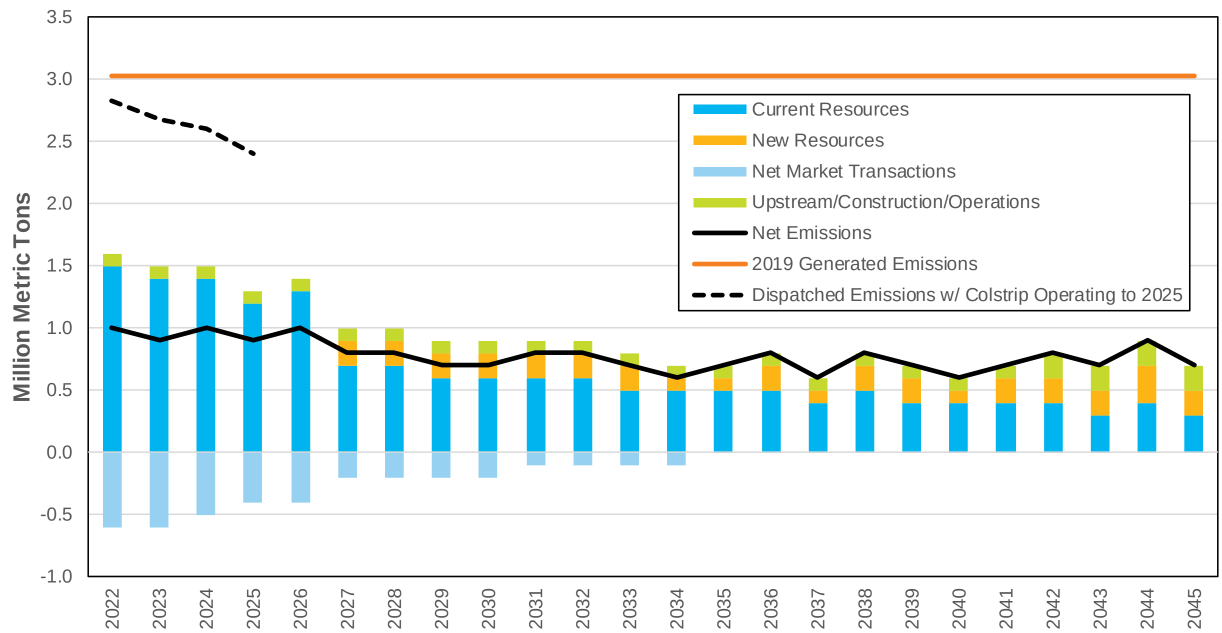
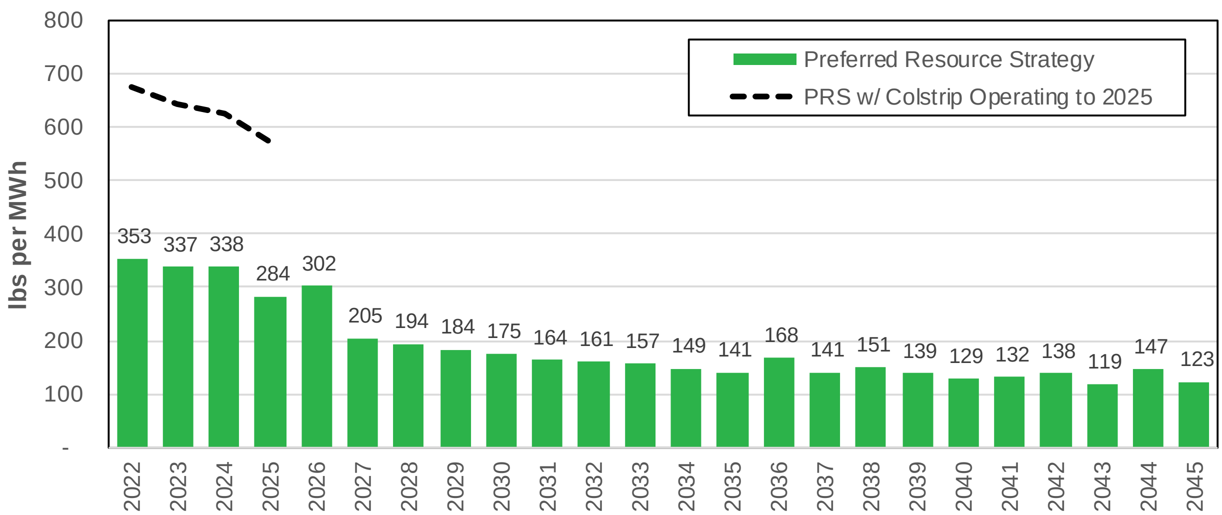



**Figure 11.10: Total Net Greenhouse Gas Emissions Intensity**




## Avoided Cost

Avista calculates the avoided, or incremental cost, to serve customers by comparing the PRS cost to alternative portfolios. Additional avoided cost estimates for specific resource types are available in Appendix F for Washington PURPA calculations, and energy efficiency avoided cost details are in Chapter 5 – Energy Efficiency.

## New Resource Avoided Costs

Table 11.7 includes the 2021 IRP avoided costs. However, avoided costs change as Avista's loads and resources change, as well as with changes in the wholesale power marketplace. Avoided costs are a best-available estimate at the time of analysis. Specific project characteristics will likely change the value of a resource. The prices shown in Table 11.7 represent energy and capacity values for different periods and product types, including renewable energy projects. For example, a new generation project with equal annual deliveries in all hours has an energy value equal to the flat energy price shown in Table 11.7. The table also includes traditional on- and off-peak pricing compared to the flat price. In addition to the energy prices, these theoretical resources receive capacity value for production at the time of system peak. This value begins in 2026, the first year of forecasted resource deficiency, for resources that can dependably meet winter peak requirements.

Capacity value is the resulting average cost of capacity each year. Specifically, the calculation compares the least cost portfolio building to meet capacity requirements against a lower cost portfolio with no capacity requirements. This is done by comparing the annual costs of Baseline Portfolio 2 to Baseline Portfolio 3 (shown in Chapter 12). Avista uses these annual cash flow differences to create annualized costs of capacity beginning in the first year of a major resource deficit. Recognizing cash flows are lumpy by nature, the variability in annual values are levelized and tilted using a 2 percent inflation rate. The next step divides the costs by added capacity amounts during the winter peak. This value is the cost of capacity per MW or cost per kW-year. The capacity payment applies to the capacity contribution of the resource at the time of the winter peak hour.

Transmission costs associated with new resources are included within the capacity cost. These include the interconnection of the resource to the system and the cost to wheel power to Avista's customers.

The resource must generate 100 percent of its capacity rating at the time of system peak to obtain a full capacity payment. For example, solar receives a 2 percent credit based on Equivalent Load Carrying Capability (ELCC) analysis and would receive 2 percent of the capacity payment compared with its nameplate capacity. For wind resources, location determines the capacity credit received. Northwest wind contributes 5 percent of its operational capacity to meeting Avista winter peaks, while Montana wind contributes 28 to 35 percent. No matter the resource, Avista will need to conduct an ELCC analysis for any specific project it evaluates to determine its peak credit.

Variable Energy Resources (VER) consume ancillary services because their output cannot be forecasted with great precision. VER resources seeking avoided cost pricing may receive reduced payments to compensate for ancillary service costs if the resource is different than proposed in the PRS. The clean energy premium includes the VER cost as part of the estimated value

The clean energy premium calculation is similar to the capacity credit but estimates the cost to comply with CETA by comparing the PRS to a portfolio without CETA requirements (see the Baseline 2 scenario in Chapter 12). Avista uses annual cash flow differences to create an annualized cost of clean energy beginning with the first year of clean energy acquisition with an annual price adjustment of 2 percent per year. This new annual cost is divided by the incremental megawatt hours of generation and the resulting value shows the amount of extra cost per MWh needed to meet clean energy requirements. This benefit includes the cost associated with changing to cleaner capacity resources, but also adding clean energy resources. Clean energy premiums assume no change to renewable energy tax incentives but will include any tax incentives if they are extended.

Avista believes the best method for estimating avoided costs of new clean energy resources is through an RFP process. This ensures resources are competing with other options. Table 11.7 presents avoided costs from IRP analyses and the present mix of resources in Avista's portfolio. As Avista acquires new resources, including resources for CETA compliance, avoided costs will likely fall to reflect the lesser need for clean energy resources.

**Table 11.7: New Resource Avoided Costs**

| Year | Energy Flat (MWh) | Energy On-Peak (MWh) | Energy Off-Peak (MWh) | Clean Premium (MWh) | Capacity ($/kW-Yr) |
|---|---|---|---|---|---|
| 2022 | $20.37 | $21.66 | $18.65 | $0.00 | $0.00 |
| 2023 | $18.71 | $19.34 | $17.89 | $13.27 | $0.00 |
| 2024 | $18.73 | $19.04 | $18.32 | $13.54 | $0.00 |
| 2025 | $19.99 | $20.05 | $19.92 | $13.81 | $0.00 |
| 2026 | $23.74 | $23.68 | $23.82 | $14.09 | $0.00 |
| 2027 | $24.63 | $24.27 | $25.12 | $14.37 | $115.10 |
| 2028 | $25.67 | $24.99 | $26.58 | $14.65 | $117.40 |
| 2029 | $26.65 | $25.77 | $27.83 | $14.95 | $119.80 |
| 2030 | $26.46 | $25.48 | $27.78 | $15.25 | $122.20 |
| 2031 | $27.63 | $26.48 | $29.15 | $15.55 | $124.60 |
| 2032 | $28.02 | $26.86 | $29.57 | $15.86 | $127.10 |
| 2033 | $29.30 | $27.96 | $31.08 | $16.18 | $129.70 |
| 2034 | $29.42 | $27.98 | $31.33 | $16.50 | $132.20 |
| 2035 | $30.47 | $28.81 | $32.68 | $16.83 | $134.90 |
| 2036 | $32.10 | $30.38 | $34.41 | $17.17 | $137.60 |
| 2037 | $31.95 | $30.08 | $34.45 | $17.51 | $140.30 |
| 2038 | $34.46 | $32.26 | $37.39 | $17.86 | $143.10 |
| 2039 | $34.77 | $32.31 | $38.04 | $18.22 | $146.00 |
| 2040 | $35.67 | $33.15 | $39.01 | $18.58 | $148.90 |
| 2041 | $38.23 | $35.77 | $41.52 | $18.96 | $151.90 |
| 2042 | $38.71 | $36.40 | $41.79 | $19.34 | $154.90 |
| 2043 | $39.27 | $36.92 | $42.40 | $19.72 | $158.00 |
| 2044 | $46.82 | $44.18 | $50.34 | $20.12 | $161.20 |
| 2045 | $46.45 | $44.31 | $49.28 | $20.52 | $164.40 |
| 20 yr. Levelized | **$25.85** | **$25.20** | **$26.72** | **$14.04** | **$80.3** |
| 24 yr. Levelized | **$27.18** | **$26.39** | **$28.22** | **$14.50** | **$86.6** |

There are other non-energy impacts (cost or benefits) that are included when determining the avoided cost of resources. For example, resources with greenhouse gas emissions have a social cost of carbon implication for Washington customers. The $ per MWh impact of this cost is shown in Table 11.8 for three example natural gas-fired resource for each MWh generated. Further information regarding the social cost of carbon used in the analysis is provided in Chapter 9 along with workbook details included in Appendix I.

**Table 11.8: Natural Gas Social Cost of Carbon Impacts ($/MWh)**

| Year | Modern 1x1 CCCT | Large Reciprocating Engine | Modern Small Frame |
|---|---|---|---|
| | 6,779 btu/kWh | 8,382 btu/kWh | 9,817 btu/kWh |
| 2022 | $30.28 | $37.44 | $43.85 |
| 2023 | $31.40 | $38.83 | $45.47 |
| 2024 | $32.56 | $40.26 | $47.15 |
| 2025 | $34.25 | $42.35 | $49.60 |
| 2026 | $35.49 | $43.88 | $51.39 |
| 2027 | $36.76 | $45.45 | $53.23 |
| 2028 | $38.07 | $47.07 | $55.13 |
| 2029 | $39.42 | $48.74 | $57.09 |
| 2030 | $40.81 | $50.46 | $59.10 |
| 2031 | $42.24 | $52.23 | $61.17 |
| 2032 | $43.71 | $54.05 | $63.31 |
| 2033 | $45.23 | $55.93 | $65.50 |
| 2034 | $46.79 | $57.86 | $67.76 |
| 2035 | $48.40 | $59.84 | $70.09 |
| 2036 | $50.05 | $61.89 | $72.48 |
| 2037 | $52.40 | $64.79 | $75.88 |
| 2038 | $54.17 | $66.97 | $78.44 |
| 2039 | $55.98 | $69.22 | $81.07 |
| 2040 | $57.85 | $71.53 | $83.78 |
| 2041 | $59.77 | $73.91 | $86.56 |
| 2042 | $61.75 | $76.35 | $89.42 |
| 2043 | $63.79 | $78.87 | $92.37 |
| 2044 | $65.88 | $81.46 | $95.40 |
| 2045 | $68.03 | $84.12 | $98.52 |
| **20 yr. Levelized** | **$40.60** | **$50.20** | **$58.79** |
| **24 yr. Levelized** | **$42.51** | **$52.56** | **$61.56** |

Avista recognizes there are other benefits and costs associated with new resources such as economic, health, reliability, resiliency, energy security and others. Each of these categories may impact customers differently depending on if they are located in a highly impacted community or are part of a vulnerable population. Avista was unable to address these costs and benefits for resources for this IRP but plans to engage a consultant to estimate these values in the next IRP for Washington resource selection. Many of these benefits or costs will be either borne by customers or people within the local area of the resource location. If Avista uses these benefits within its resource selection, customers are at risk to pay additional costs for potential benefits of others.

# 12. Portfolio Scenario Analysis

The 2021 Preferred Resource Strategy (PRS) is Avista's 24-year strategy to meet future loads and replace generation resources. Because the future is often different from the IRP's Expected Case forecast, the future resource strategy needs to be flexible enough to serve customers under a range of plausible outcomes. This IRP identifies permutations of potential resource strategies due to resource availability and pricing. Resource decisions may change depending on how customers use electricity, how the economy changes and how carbon emission policies evolve. This chapter investigates the cost and risk impacts to the PRS under different futures the utility might face as well as alternative resource portfolios.

**Chapter Highlights**

- 2021 IRP analysis shows Colstrip's removal from Avista's portfolio earlier than 2025 is more economic for the whole system, while retaining the plant through 2025 reduces power supply cost risk.
- A Northwest Resource Adequacy (i.e. reliability) Program lowers system cost by 0.4 percent or $4.4 million per year.
- Portfolios with higher levels of clean energy reduce risk if a future national carbon tax is enacted.
- Supplying all customers with clean energy equal to 100 percent of sales and retiring Avista's natural gas-fired plants by 2045 increases rates by 20 percent in Washington and by 28 percent in Idaho compared to the Preferred Resource Strategy.
- Warming regional temperatures result in higher winter hydro production while shifting loads from winter to summer. These changes reduce customers' cost by 1.1 percent.

The 2021 PRS is Avista's preferred resource plan, but plans may change as alternative pricing and resource availability is determined in future RFPs. Avista's IRP is a roadmap of potential resource acquisition strategies using currently known information. For example, Avista's resource strategy might change if a resource adequacy program develops, if electrification becomes policy for Washington State or if the Company pursues clean energy at a faster rate. This analysis can also test modeling assumptions regarding the social cost of carbon for energy efficiency, demand response and other resource acquisitions. Avista uses two methods to understand cost effects. The first is the Present Value of Revenue Requirement (PVRR) or the discounted cost customers pay to serve load and the second method is the average energy rates. The rates calculation is the year's revenue requirement divided by energy sales.

In addition to alternative portfolio choices, Avista tested the portfolios under alternative market futures or sensitivities. These sensitivities show how the portfolios perform with a carbon tax and with higher or lower natural gas prices. Avista also studied how its portfolio and cost would change if regional temperatures increase leading to changes in hydro operations and load.

## Portfolio Scenarios

Avista studied many alternative portfolios to compare cost, risk and emissions to the PRS for the Expected Case market forecast. The Company also reviewed two portfolios with fundamental changes to the marketplace requiring a re-optimization of the resource strategy. The PRS is Portfolio #1 on all tables and charts in this chapter. The remaining portfolios change assumptions to arrive at a portfolio to meet a specific objective. The next section outlines each of the portfolio objectives and resource selection. The resource selections included in the PRS are in Table 12.1.

**Table 12.1: Portfolio #1- Preferred Resource Strategy Resource Selection**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana wind | 2023 | WA | 100 |
| Montana wind | 2024 | WA | 100 |
| Lancaster | 2026 | WA/ID | (257) |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 85 |
| Natural Gas Peaker | 2027 | WA/ID | 126 |
| Montana wind | 2028 | WA | 100 |
| NW Hydro Slice | 2031 | WA | 75 |
| Rathdrum CT Upgrade | 2035 | WA/ID | 5 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 87 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Natural Gas Peaker | 2041 | ID | 36 |
| Montana wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 239 |
| 4-hr Storage for Solar | 2042-2043 | WA | 119 |
| Liquid Air Storage | 2044 | WA | 12 |
| Liquid Air Storage | 2045 | ID | 10 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 75 |
| Supply-side resource net total (MW) | | | 1,032 |
| Supply-side resource total additions (MW) | | | 1,589 |
| Demand Response 2045 capability (MW) | | | 71 |
| Cumulative energy efficiency (aMW) | | | 121 |
| Cumulative summer peak savings (MW) | | | 111 |
| Cumulative winter peak savings (MW) | | | 116 |

### Portfolio #2: Baseline Portfolio #1

The objective for this scenario is to understand how the utility would plan its portfolio without the clean energy targets required under CETA while retaining the social cost of carbon assumption. Absent this change, this portfolio represents a traditional pre-CETA clean energy target IRP least cost strategy. This portfolio allows Avista to identify the incremental cost and develop the 2 percent rate cap analysis used for alternative compliance within CETA. The specific resource selection for this portfolio is in Table 12.2. The major differences between this portfolio and the PRS are higher levels of natural gas-fired turbines and removal of wind and solar projects. An interesting result of this study is the model selecting additional storage resources including hydrogen and liquid air energy storage necessary to meet capacity requirements due to the model limitations on additional generation in the Rathdrum area without an expensive transmission enhancement. Avista recognizes it should model off-system natural gas-fired turbines to compare against building new transmission or non-natural gas-fired resources elsewhere in the system. Absent this analysis, the financial results from a present value perspective are not likely to vary significantly.

Overall, this scenario reduces levelized system cost by 1.9 percent versus the PRS, although 2045 tail risk increases by 69 percent, meaning a significantly riskier portfolio for cost volatility and potential for higher cost outcomes. By 2045, the Washington energy rate would be 3.3 percent lower and Idaho's rate would be 0.7 percent lower than the PRS. Idaho's expected rate increases are higher than Washington's in this portfolio due to the elimination of REC sales to Washington customers.

**Table 12.2: Portfolio #2- Baseline Portfolio #1 Resource Selection**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Lancaster | 2026 | WA/ID | (257) |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | WA | 144 |
| Liquid Air Storage | 2034 | WA | 10 |
| Northeast | 2035 | WA/ID | (54) |
| Liquid Air Storage | 2039 | WA | 14 |
| Boulder Park | 2040 | WA/ID | (25) |
| Liquid Air Storage | 2042-2045 | WA | 44 |
| Natural Gas Peaker | 2027 | ID | 97 |
| Hydrogen Turbine with 40 Hrs Storage | 2041 | ID | 50 |
| 4hr Lithium-Ion | 2045 | ID | 20 |
| Kettle Falls Upgrade | 2025 | WA/ID | 5 |
| Rathdrum Upgrade | 2026 | WA/ID | 12 |
| NW Hydro Slice | 2031 | WA/ID | 75 |
| Natural Gas Peaker | 2031 | WA/ID | 48 |
| Natural Gas Peaker | 2036 | WA/ID | 84 |
| | | | |
| Supply-side resource net total (MW) | | | 53 |
| Supply-side resource total additions (MW) | | | 611 |
| Demand Response 2045 capability (MW) | | | 123 |
| Cumulative energy efficiency (aMW) | | | 123 |
| Cumulative summer peak savings (MW) | | | 111 |
| Cumulative winter peak savings (MW) | | | 121 |

## Portfolio #3: Baseline Portfolio #2

This portfolio estimates Avista's premiums for both clean energy and capacity for the avoided cost calculations. It uses the same assumption as the Baseline #1 portfolio but also removes the social cost of carbon. This is the least cost strategy given system constraints. The results are similar to the Baseline Portfolio #1 with slight reductions in DR and a slight increase in natural gas-fired CTs. This scenario, like the Baseline Portfolio #1 scenario, reaches the Rathdrum area transmission constraint. Energy efficiency acquisition and resource removal assumptions remain unchanged in this scenario from the PRS to keep the load forecast constant to measure cost changes in resource acquisition. The full resource selection for this portfolio is in Table 12.3.

This scenario reduces levelized system cost by 1.9 percent versus the PRS although the 2045 tail risk increases by 69 percent. By 2045, the Washington energy rate would be 3.1 percent lower and Idaho's rate would be 0.9 percent lower than the PRS. Idaho rate increases in this portfolio are higher due to the elimination of REC sales to Washington customers.

### Table 12.3: Portfolio #3- Baseline Portfolio #2 Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Kettle Falls Upgrade | 2025 | WA/ID | 5 |
| Lancaster | 2026 | WA/ID | (257) |
| Rathdrum Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 97 |
| Natural Gas Peaker | 2027 | WA | 147 |
| NW Hydro Slice | 2031 | WA/ID | 75 |
| Natural Gas Peaker | 2031 | WA/ID | 48 |
| Liquid Air Storage | 2034 | WA | 10 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 84 |
| Liquid Air Storage | 2039 | ID | 10 |
| Liquid Air Storage | 2039 | WA | 14 |
| Liquid Air Storage | 2042-2045 | WA | 44 |
| Hydrogen Turbine w\ 40 Hrs Storage | 2041 | ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| 4hr Lithium-Ion | 2045 | ID | 23 |
| | | | |
| Supply-side resource net total (MW) | | | 68 |
| Supply-side resource total additions (MW) | | | 626 |
| Demand Response 2045 capability (MW) | | | 117 |

## Portfolio #4: Baseline Portfolio #3

This scenario is not a reliable plan to serve customers, but it is used to compare costs of other portfolios to determine the change in capacity avoided costs. The social cost of carbon, clean energy requirements as well as capacity and energy requirements are removed. Both energy efficiency and resource removals are with the same as the PRS. This allows the model to only select cost-effective supply-side resources based on energy benefits. The Company can estimate the avoided cost of capacity and the avoided cost of clean energy by comparing other baseline portfolios to this baseline. The full resource selection for this portfolio is in Table 12.4.

While this portfolio is not a reliable plan to meet future load, this scenario reduces levelized system cost by 5.4 percent and increases tail risk by 84 percent. The Washington energy rate would be 8.9 percent lower and Idaho's rate would be 7.3 percent lower by 2045 under this strategy.

### Table 12.4: Portfolio #4- Baseline Portfolio #3 Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Lancaster | 2026 | WA/ID | (257) |
| Northeast | 2035 | WA/ID | (54) |
| Boulder Park | 2040 | WA/ID | (25) |
| | | | |
| Supply-side resource net total (MW) | | | (550) |
| Supply-side resource total additions (MW) | | | 8 |
| Demand Response 2045 capability (MW) | | | 4 |

## Portfolio #5: Clean Resource Plan (2027)

Avista created a corporate goal of transitioning to 100 percent net clean energy by 2027 and 100 percent clean energy by 2045 subject to the availability of technology and affordability for Avista's customers. This portfolio assists the Company with understanding the resource needs and the costs to meet the 2027 corporate goal. The strategy shows a need of an additional 500 MW of wind and solar by 2027 to achieve the system-wide clean energy goal. With these additional resources, natural gas-fired acquisitions fall by 55 MW. The full resource selection for this portfolio is in Table 12.5.

This scenario increases levelized system cost by 3.5 percent versus the PRS and the 2045 tail risk decreases by 33 percent. The Washington energy rate would be 1.7 percent higher and Idaho's rate would be 9.0 percent higher than the PRS by 2045; both of these increases are due to additional renewable acquisition specifically for Washington where it would no longer be able to access lower cost Idaho RECs and Idaho would pay more to add wind and solar to meet its 100 percent requirement while also losing the financial benefits of REC sales to Washington.

### Table 12.5: Portfolio #5- Clean Resource Plan (2027) Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023 | ID | 194 |
| Montana Wind | 2023 | WA | 100 |
| Montana Wind | 2025 | WA | 100 |
| Solar Photovoltaic | 2026-2027 | ID | 200 |
| Lancaster | 2026 | WA/ID | (257) |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 20206 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 111 |
| Montana Wind | 2027 | WA | 200 |
| Natural Gas Peaker | 2027 | WA | 48 |
| NW Hydro Slice | 2031 | WA | 75 |
| Solar w/ storage (4 hours) | 2031 | WA/ID | 100 |
| 4-hr Storage for Solar | 2031 | WA/ID | 50 |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 84 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Solar w/ storage (4 hours) | 2041-2043 | WA/ID | 349 |
| 4-hr Storage for Solar | 2041-2043 | WA/ID | 175 |
| Geothermal | 2041 | WA/ID | 20 |
| Natural Gas Peaker | 2043 | ID | 36 |
| Liquid Air Storage | 2044-2045 | WA | 24 |
| Solar Photovoltaic | 2045 | WA | 26 |
| | | | |
| Supply-side resource net total (MW) | | | 1,509 |
| Supply-side resource total additions (MW) | | | 2,018 |
| Demand Response 2045 capability (MW) | | | 71 |
| Cumulative energy efficiency (aMW) | | | 135 |
| Cumulative summer peak savings (MW) | | | 133 |
| Cumulative winter peak savings (MW) | | | 128 |

## Portfolio #6: Clean Resource Plan (2045)

This portfolio builds on Portfolio #5, but also requires the exiting of all fossil fuel thermal plants by 2044 with no new natural gas facilities being added. The model assumes Colstrip can exit at any time based on economics and ignoring the ownership requirements. This resulted in one unit shutting down and the other remaining online throughout the study due to the limited capacity options available to replace it. The result illustrates an interesting conclusion about the plant for Idaho indicating it is economic to maintain the plant if only expensive options are available to replace it.

The resulting portfolio selection is over 1,149 MW of solar and 500 MW of attached storage along with an additional 200 MW of wind above the 2027 goal scenario. To meet capacity needs, 307 MW of hydrogen turbines and 332 MW of storage replace the lost natural gas-fired peaking capacity. The full resource selection for this portfolio is in Table 12.6.

This ambitious scenario relies on a liquid energy market which comes at a cost. The levelized system cost increases 5.1 percent compared to the PRS and the 2045 tail risk reduces by 68 percent. The Washington energy rate would be 20.3 percent higher and Idaho's rate would be 28.2 percent higher than the PRS by 2045.

### Portfolio #6b: Clean Resource Plan (2045) without Colstrip

While Portfolio #6 allows fossil fueled thermal plants to exit when economic, this scenario removes Colstrip while keeping everything else constant. This scenario shows the cost and resource changes necessary to drive the utility to zero carbon resources by 2045. This single change increases the amount of renewable resources by approximately 50 MW and increases storage by approximately 30 MW. The full list of resource changes is shown in Table 12.7. The costs are similar to Portfolio #6, where total cost changes are also 5.1 percent although 2045 tail risk is 67 percent lower.

### Portfolio #7: Social Cost of Carbon for Idaho

CETA requires a social cost of carbon for energy efficiency and fossil fuel resource selection in Washington. The TAC requested this portfolio to examine the impacts of this same requirement on Idaho load. The resulting portfolio reduces natural gas acquisition from 335 MW in the PRS to 280 MW. Energy efficiency increases in Idaho from 27 aMW to 44 aMW, leading to an additional 13 MW of winter peak load reduction. The full resource selection for this portfolio is in Table 12.8.

This change in the planning process increases levelized system cost 0.4 percent above the PRS and reduces the 2045 tail risk by 4.5 percent. The Washington energy rate increases 0.8 percent and Idaho's rate is 5.7 percent higher than the PRS portfolio. This change to the Idaho customer portfolio also leads to a small potential change in resource acquisition for Washington customers.

## Table 12.6: Portfolio #6- Clean Resource Plan (2045) Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip (Unit 4) | 2021 | WA/ID | (111) |
| NW Wind On System | 2023 | ID | 100 |
| Montana Wind | 2023 | WA | 100 |
| NW Wind On System | 2023 | WA/ID | 100 |
| Montana Wind | 2025 | ID | 100 |
| Lancaster | 2026 | WA/ID | (257) |
| Montana Wind | 2026 | WA/ID | 100 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Geothermal | 2027 | ID | 20 |
| Montana Wind | 2027 | WA | 100 |
| Liquid Air Storage | 2027 | WA | 56 |
| Kettle Falls Upgrade | 2027 | WA/ID | 12 |
| Solar w/ storage (4 hours) | 2027 | WA/ID | 115 |
| 4-hr Storage for Solar | 2027 | WA/ID | 58 |
| Liquid Air Storage | 2029-31 | WA | 27 |
| NW Hydro Slice | 2031 | WA/ID | 75 |
| Solar w/ storage (4 hours) | 2031 | WA/ID | 111 |
| 4-hr Storage for Solar | 2031 | WA/ID | 55 |
| Liquid Air Storage | 2033 | WA | 13 |
| Northeast | 2035 | WA/ID | (54) |
| Hydrogen Turbine with 40 Hrs Storage | 2036 | ID | 50 |
| Hydrogen Turbine with 40 Hrs Storage | 2036 | WA | 75 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Liquid Air Storage | 2041-2043 | ID | 20 |
| Solar w/ storage (4 hours) | 2040-2043 | WA/ID | 423 |
| 4-hr Storage for Solar | 2040-2043 | WA/ID | 212 |
| Liquid Air Storage | 2041 | WA | 10 |
| Colstrip (Unit 3) | 2044 | WA/ID | (111) |
| Coyote Springs 2 | 2044 | WA/ID | (302) |
| Kettle Falls CT | 2044 | WA/ID | (9) |
| Rathdrum | 2044 | WA/ID | (153) |
| Solar w/ storage (4 hours) | 2044 | ID | 100 |
| 4-hr Storage for Solar | 2044 | ID | 50 |
| Hydrogen Turbine with 40 Hrs Storage | 2045 | ID | 182 |
| Liquid Air Storage | 2044-2045 | WA | 206 |
| Solar Photovoltaic | 2045 | ID | 150 |
| Cabinet Gorge Upgrade | 2045 | ID | 68 |
| NW Wind On System | 2045 | WA | 200 |
| Small Nuclear (share) | 2045 | WA | 71 |
| Wood Biomass | 2045 | WA | 25 |
| Solar w/ storage (4 hours) | 2045 | WA/ID | 150 |
| 4-hr Storage for Solar | 2045 | WA/ID | 75 |
| | | | |
| Supply-side resource net total (MW) | | | 2,346 |
| Supply-side resource total additions (MW) | | | 3,367 |
| Demand Response 2045 capability (MW) | | | 124 |
| Cumulative energy efficiency (aMW) | | | 140 |
| Cumulative summer peak savings (MW) | | | 138 |
| Cumulative winter peak savings (MW) | | | 136 |

## Table 12.7: Portfolio #6b- Clean Resource Plan (2045) Resource Selection without Colstrip

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip (Unit 4) | 2021 | WA/ID | (222) |
| Montana Wind | 2023 | ID | 100 |
| NW Wind On System | 2023 | WA | 192 |
| Montana Wind | 2025 | ID | 100 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Lancaster | 2026 | WA/ID | (257) |
| Montana Wind | 2026 | WA/ID | 100 |
| Geothermal | 2027 | ID | 20 |
| Montana Wind | 2027 | WA | 100 |
| Liquid Air Storage | 2027 | WA | 83 |
| Kettle Falls Upgrade | 2027 | WA/ID | 12 |
| Solar w/ storage (4 hours) | 2027 | WA/ID | 128 |
| 4-hr Storage for Solar | 2027 | WA/ID | 64 |
| Liquid Air Storage | 2029 | WA | 12 |
| NW Hydro Slice | 2031 | WA | 75 |
| Solar w/ storage (4 hours) | 2031 | WA/ID | 112 |
| 4-hr Storage for Solar | 2031 | WA/ID | 56 |
| Pumped Hydro | 2031 | ID | 27 |
| Liquid Air Storage | 2033 | WA | 13 |
| Northeast | 2035 | WA/ID | (54) |
| Hydrogen Gas Turbine with 40 Hrs Storage | 2036 | ID | 50 |
| Hydrogen Gas Turbine with 40 Hrs Storage | 2036 | WA | 75 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Solar w/ storage (4 hours) | 2040 | WA/ID | 100 |
| 4-hr Storage for Solar | 2040 | WA/ID | 50 |
| Solar w/ storage (4 hours) | 2041 | ID | 120 |
| 4-hr Storage for Solar | 2041 | ID | 60 |
| Liquid Air Storage | 2041 | WA | 23 |
| Solar w/ storage (4 hours) | 2042-43 | WA/ID | 231 |
| 4-hr Storage for Solar | 2042-43 | WA/ID | 115 |
| Coyote Springs 2 | 2044 | WA/ID | (302) |
| Kettle Falls CT | 2044 | WA/ID | (9) |
| Rathdrum | 2044 | WA/ID | (153) |
| Liquid Air Storage | 2044 | ID | 13 |
| Liquid Air Storage | 2044-2045 | WA | 210 |
| Hydrogen Gas Turbine with 40 Hrs Storage | 2045 | ID | 195 |
| Solar Photovoltaic | 2045 | ID | 150 |
| Cabinet Gorge Upgrade | 2045 | WA/ID | 68 |
| NW Wind On System | 2045 | WA | 322 |
| Wood Biomass | 2045 | WA | 39 |
| Solar w/ storage (4 hours) | 2045 | WA/ID | 150 |
| 4-hr Storage for Solar | 2045 | WA/ID | 75 |
| | | | |
| Supply-side resource net total (MW) | | | 2,377 |
| Supply-side resource total additions (MW) | | | 3,398 |
| Demand Response 2045 capability (MW) | | | 100 |
| Cumulative energy efficiency (aMW) | | | 139 |
| Cumulative summer peak savings (MW) | | | 128 |
| Cumulative winter peak savings (MW) | | | 129 |

### Table 12.8: Portfolio #7- Idaho Social Cost of Carbon Portfolio Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Lancaster | 2026 | WA/ID | (257) |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 57 |
| Montana Wind | 2027 | WA | 100 |
| Natural Gas Peaker | 2027 | WA/ID | 88 |
| Kettle Falls Upgrade | 2027 | WA/ID | 12 |
| Rathdrum Upgrade | 2029 | WA/ID | 5 |
| NW Hydro Slice | 2031 | WA/ID | 75 |
| Natural Gas Peaker | 2031 | WA/ID | 48 |
| Liquid Air Storage | 2034 | WA | 10 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 87 |
| Solar w/ storage (4 hours) | 2038 | WA | 107 |
| 4-hr Storage for Solar | 2038 | WA | 54 |
| Boulder Park | 2040 | WA/ID | (25) |
| Hydrogen Turbine with 40 Hrs Storage | 2041 | ID | 50 |
| Montana Wind | 2041 | WA | 100 |
| Liquid Air Storage | 2044 | WA | 12 |
| Liquid Air Storage | 2045 | ID | 10 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 74 |
| Montana Wind | 2023-2024 | WA | 200 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 239 |
| 4-hr Storage for Solar | 2042-2043 | WA | 120 |
| | | | |
| Supply-side resource net total (MW) | | | 1,048 |
| Supply-side resource total additions (MW) | | | 1,602 |
| Demand Response 2045 capability (MW) | | | 75 |
| Cumulative energy efficiency (aMW) | | | 139 |
| Cumulative summer peak savings (MW) | | | 135 |
| Cumulative winter peak savings (MW) | | | 131 |

## Portfolio #8: Low Load Forecast

Chapter 3 outlines Avista's forecast for future expected and alternative load growth. This portfolio studies negative 0.11 percent load growth. The negative load growth scenario still requires significant new resources, specifically 248 MW of natural gas-fired generation over the planning period which is a reduction of 87 MW from the PRS. Wind selection remains the same, but solar and storage are significantly less than the PRS. The full resource selection for this portfolio is in Table 12.9. For this scenario, energy efficiency selection remains constant since Avista has not conducted a conservation potential assessment for a low load forecast scenario. The intent of this scenario is to understand changes in resource selections if a low load growth future materializes.

Lower loads should reduce cost, but not necessarily rates. The levelized system cost decreases by 1.3 percent compared to the PRS and the 2045 tail risk increases 18.8

percent. The 2045 Washington energy rate increases 7.4 percent and Idaho's rate is 6.8 percent higher than the PRS portfolio. Rates increase with less energy consumption to spread costs across compared to the higher load levels in the PRS. It is possible non-modeled costs would change in the future negating some or all of these rate effects.

### Table 12.9: Portfolio #8 Low Load Forecast Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | -222 |
| Montana Wind | 2023 | WA | 100 |
| Lancaster | 2026 | WA/ID | -257 |
| Montana Wind | 2026 | WA | 100 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 98 |
| Natural Gas Peaker | 2027 | WA | 48 |
| Kettle Falls Upgrade | 2027 | WA/ID | 12 |
| Solar Photovoltaic | 2029 | WA | 28 |
| NW Hydro Slice | 2031 | WA | 75 |
| Rathdrum Upgrade | 2031 | WA/ID | 5 |
| Northeast | 2035 | WA/ID | -54 |
| Natural Gas Peaker | 2036 | WA/ID | 65 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 104 |
| 4-hr Storage for Solar | 2038 | WA/ID | 52 |
| Boulder Park | 2040 | WA/ID | -25 |
| Montana Wind | 2041-2042 | WA | 200 |
| Natural Gas Peaker | 2041 | ID | 36 |
| Solar Photovoltaic | 2045 | WA | 102 |
| | | | |
| Supply-side resource net total (MW) | | | 476 |
| Supply-side resource total additions (MW) | | | 1,034 |
| Demand Response 2045 capability (MW) | | | 56 |

## Portfolio #9: High Load Forecast

As with the low load forecast scenario, the high load growth scenario assumptions are discussed in Chapter 3. Loads in this scenario grow at 0.73 percent compared to the 0.31 percent growth rate assumed in the PRS. Additional load growth requires minor natural gas-fired resource additions due to transmission limitations described in earlier scenarios. Although an additional 114 MW of wind and 192 MW of other capacity resources, such as hydrogen CTs and storage, are required. The full resource selection for this portfolio is in Table 12.10. The energy efficiency selection is the same as the PRS for this scenario since Avista has not conducted a CPA for a higher load scenario.

Higher loads increase cost, but not necessarily rates. The levelized system cost increases by 1.9 percent compared to the PRS and the 2045 tail risk decreases 19 percent. Washington's 2045 energy rate decreases 5.2 percent and Idaho's rate is 7.1 percent lower than in the PRS portfolio. Rates decrease in this scenario with the costs being spread out over higher retail sales than the PRS. Non-modeled costs may change in the future negating these rate effects.

## Table 12.10: Portfolio #9 High Load Forecast Resource Selection

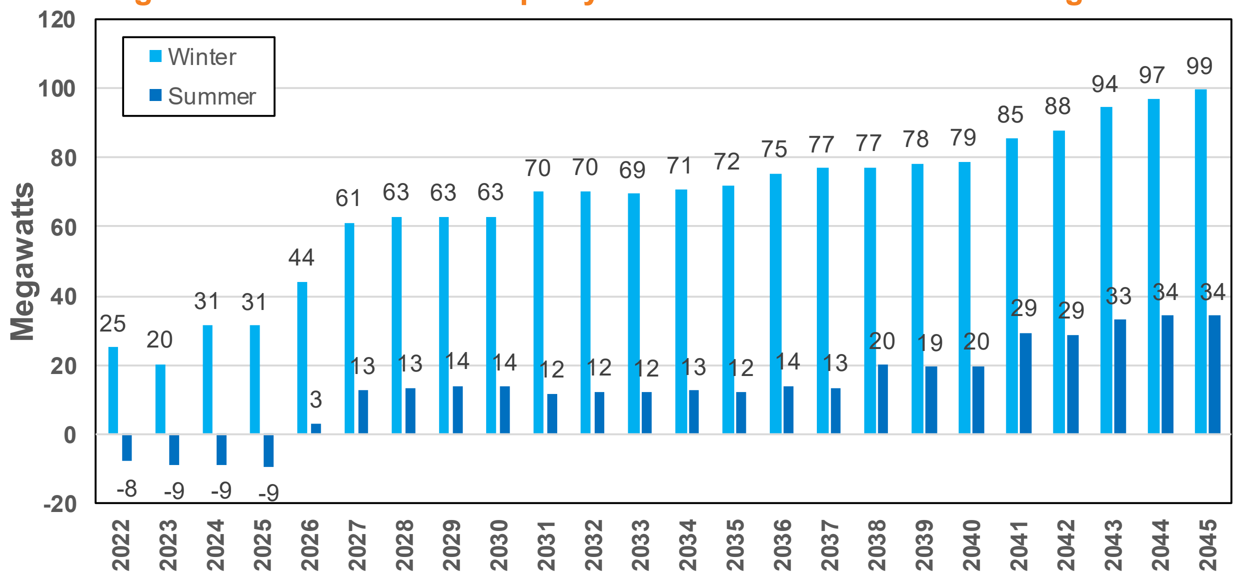
| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip 3 | 2021 | WA/ID | (111) |
| Colstrip 4 | 2022 | WA/ID | (111) |
| Lancaster | 2026 | WA/ID | (257) |
| Natural Gas Peaker | 2026 | ID | 55 |
| Geothermal | 2026 | WA | 20 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 84 |
| Natural Gas Peaker | 2027 | WA | 92 |
| Kettle Falls Upgrade | 2027 | WA/ID | 12 |
| Rathdrum Upgrade | 2027 | WA/ID | 5 |
| Montana Wind | 2028 | WA | 100 |
| Natural Gas Peaker | 2031 | ID | 55 |
| NW Hydro Slice | 2031 | WA | 75 |
| Rathdrum Upgrade | 2035 | WA/ID | 4 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 84 |
| Montana Wind | 2038 | WA | 100 |
| Boulder Park | 2040 | WA/ID | (25) |
| Hydrogen Gas Turbine with 40 Hrs Storage | 2041 | ID | 50 |
| Liquid Air Storage | 2041 | WA | 22 |
| NW On System Wind | 2045 | WA | 114 |
| Montana Wind | 2023-2024 | WA | 200 |
| Liquid Air Storage | 2031-2035 | WA | 54 |
| Solar w/ storage (4 hours) | 2040-2043 | WA | 493 |
| 4-hr Storage for Solar | 2040-2043 | WA | 246 |
| Liquid Air Storage | 2043-2045 | WA | 37 |
| Liquid Air Storage | 2044-2045 | ID | 28 |
| | | | |
| Supply-side resource net total (MW) | | | 1,381 |
| Supply-side resource total additions (MW) | | | 1,939 |
| Demand Response 2045 capability (MW) | | | 64 |

## Portfolio #10: Resource Adequacy (RA) Program

The northwest is investigating a regional program to require a specified planning methodology including planning margins for load and resource balancing, and to take advantage of regional load and resource diversity. Specific changes for this scenario include movement to a 12 percent planning margin for winter and summer peak loads and specified peak credits for each resource technology. An annual summary of the changes to the load and resource position are in Figure 12.1. For most years, Avista sees reductions in capacity requirements except for modest summer additions in the first four years. The reduction in capacity requirements leads to 50 MW fewer natural gas turbines and more solar generation. Solar increases due to higher peak credits in a regional RA program. The RA program assigns solar a 19.2 percent peak credit in the winter and Avista assumes this benefit is only 2 percent without the RA program. The initial solar capacity credit assumption may be adjusted in the final program design as additional solar is added to the system, which would change the results of this scenario. The full resource selection for this portfolio is in Table 12.11. The actual peak credits and planning margin of the program are subject to change if the program moves forward.

The RA program should improve regional resource reliability and ultimately reduce costs for Avista customers because of lower planning reserve requirements. The results of this study show levelized system cost decreases 1.9 percent compared to the PRS and the 2045 tail risk increases 13.9 percent due to greater market dependence. The Washington energy rate increases 0.6 percent by 2045 and Idaho's rate is 0.7 percent lower than in the PRS portfolio. The mismatch in rate change effects is likely due to Idaho's greater benefit from reduced capacity needs compared to Washington's large amount of renewable requirements. Overall, Washington benefits by $40 million PVRR, but in the year 2045, timing of resource acquisition shows a minor increase in rates.

**Figure 12.1: Resource Adequacy Load Resource Position Changes**



## Table 12.11: Portfolio #10: Resource Adequacy Program Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | -222 |
| Solar Photovoltaic | 2023 | WA | 108 |
| Montana Wind | 2023 | WA | 100 |
| Lancaster | 2026 | WA/ID | -257 |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 91 |
| Solar w/ storage (2 hours) | 2027 | WA | 101 |
| 2-hr Storage for Solar | 2027 | WA | 25 |
| Natural Gas Peaker | 2027 | WA/ID | 88 |
| Solar Photovoltaic | 2028 | WA | 100 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | -54 |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Natural Gas Peaker | 2036 | ID | 56 |
| Natural Gas Peaker | 2036 | WA | 49 |
| Boulder Park | 2037 | WA/ID | -25 |
| Solar w/ storage (4 hours) | 2038 | WA | 137 |
| 4-hr Storage for Solar | 2038 | WA | 69 |
| Montana Wind | 2041-2042 | WA | 200 |
| Solar w/ storage (4 hours) | 2043 | WA/ID | 100 |
| 4-hr Storage for Solar | 2043 | WA/ID | 50 |
| 4hr Lithium-Ion | 2045 | ID | 49 |
| Solar Photovoltaic | 2045 | WA | 106 |
| | | | |
| Supply-side resource net total (MW) | | | 972 |
| Supply-side resource total additions (MW) | | | 1,530 |
| Demand Response 2045 capability (MW) | | | 54 |
| Cumulative energy efficiency (aMW) | | | 123 |
| Cumulative summer peak savings (MW) | | | 123 |
| Cumulative winter peak savings (MW) | | | 116 |

## Portfolio #11: Electrification Portfolio #1 (Existing Technology)

Avista uses three scenarios to identify impacts to the power system if space and water heating is electrified in the Washington service area. This scenario is a larger effort than typically studied in an IRP, but it is included to begin the discussion and considerations of this potential future. First, the results of this study do not include the cost to homeowners to convert equipment. Second, this analysis does not consider the significant transmission or distribution grid impacts due to added load as this analysis only focuses on the resource impacts[1] of the additional load. Third, 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 this issue may be best suited for a non-IRP analysis on a regional level.

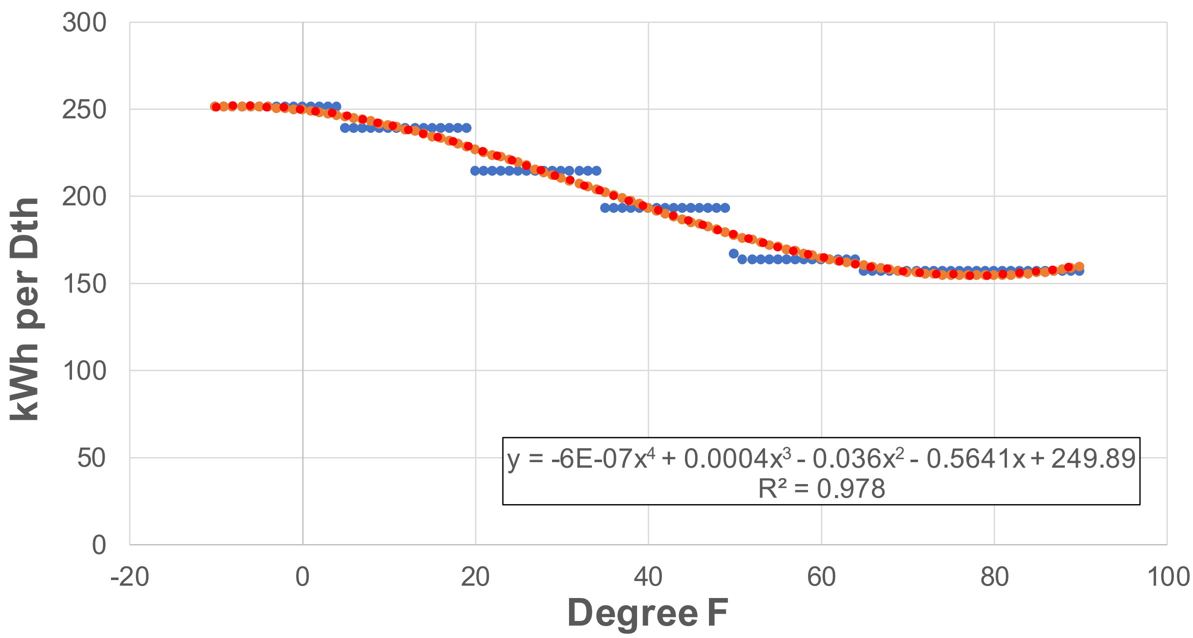
Given this study focuses on the additional resources to meet this added load from electrification, the current natural gas load forecast was addressed. To estimate the

[1] This analysis includes the transmission interconnect costs discussed in Chapter 8 for resource integration.

added electric load, Avista converted the natural gas load forecast to electric load by using the relationship shown in Figure 12.2. This load conversion assumes currently available technology including a mixture of centralized heat pumps and to a lesser extent ductless heat pumps for space heating, and heat pump water heaters and conventional technologies for water heating. In warmer temperatures, fewer kWhs are required due to the efficiency of the heat pump technology. In colder temperatures, the centralized heat pump technology provides no efficiency benefit over resistance heating at Avista's typical winter peak temperature of less than 5 degrees Fahrenheit.

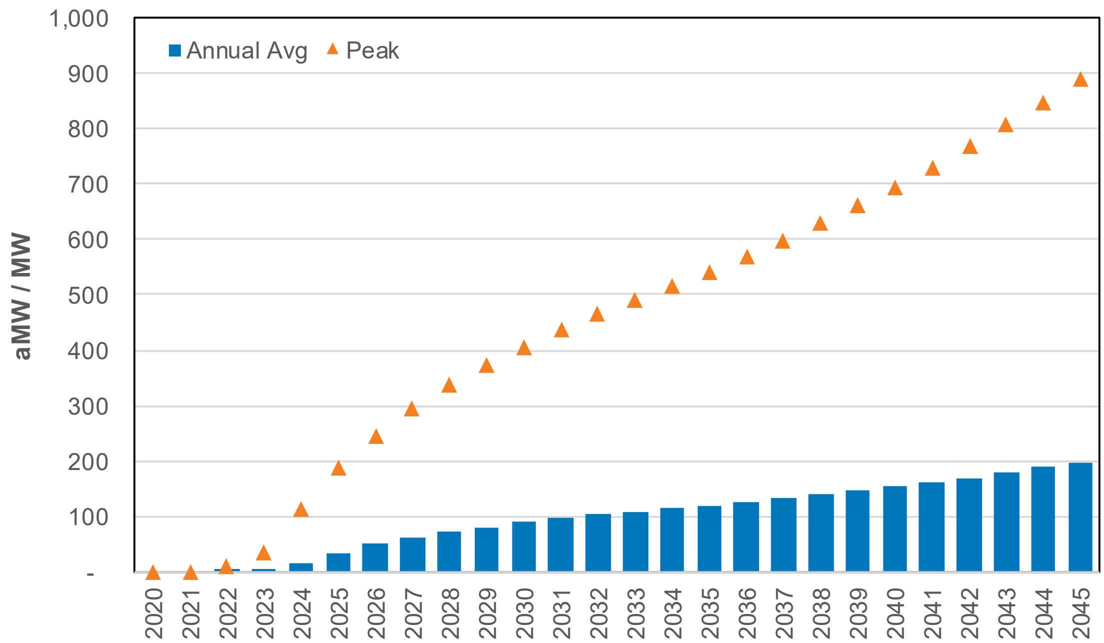
The conversion from natural gas to electric load assumes a 50 percent reduction in natural gas load by 2030 and an 80 percent reduction by 2045. Of the converted natural gas load, Avista assumes 75 percent of these conversions will be on the Avista electric system, while the remaining conversions will be in other electric providers' service territories within Avista's gas-only service territory. The added load is estimated to be 893 MW to the winter peak hour by 2045, but only 409 MW by 2030 to the same winter peak hour. Energy needs increase from 89 aMW in 2030 to 197 aMW by 2045. See Figure 12.3. The challenge with natural gas conversions is the timing of the load which is predominantly in the winter and is very temperature sensitive. Figure 12.4 illustrates the timing of the load for 2030, showing both peak and energy increases with 50 percent[2] of Washington customers converting to electric.

**Figure 12.2: Natural Gas to Electric Load Relationship**

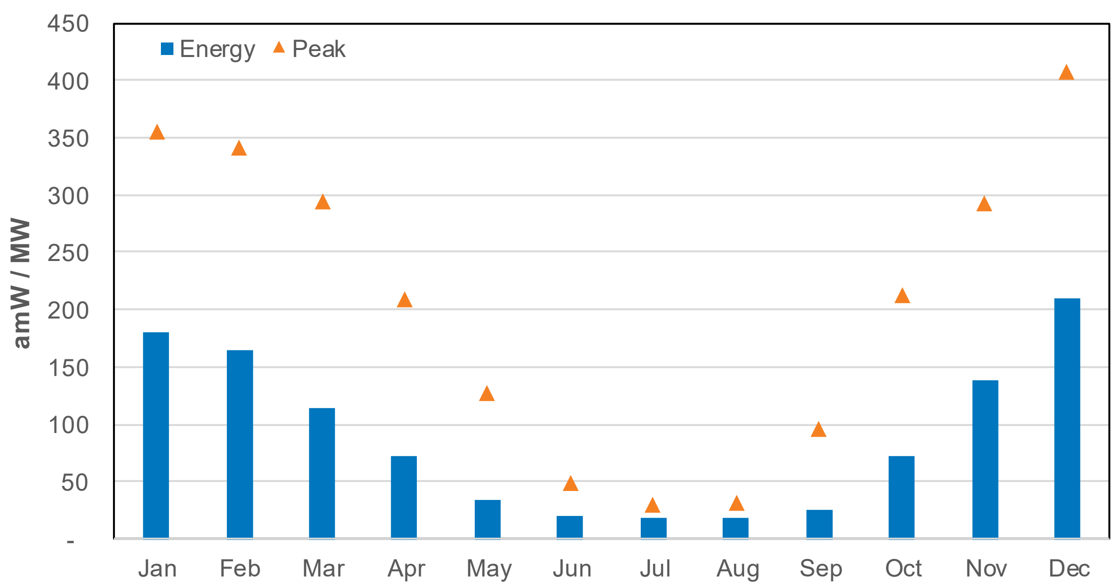



[2] Seventy-five percent of those customers are represented here on the Avista electric system.

## Figure 12.3: Electrification Scenario #1 Additional Load




## Figure 12.4: Electrification Scenario #1 Monthly Load




Avista selected resources to meet this added load for both capacity and energy requirements including clean energy. This scenario does not assume a match between delivery of clean energy and the load at the same time. Table 12.12 indicates only a modest increase in natural gas generation capacity and meets most of the new load with nearly 500 MW of hydrogen-fired turbines and nearly 1,000 MW of additional wind and solar resources. These results also include more energy efficiency from additional customer opportunities that were previously natural gas customers. As mentioned earlier, Avista has not updated the electric market simulation for this study and the cost for this study will not include the full cost of running hydrogen turbines at greater capacity factors then assumed in the Expected Case. The estimated marginal fuel cost for hydrogen in 2040 is $155 per MWh assuming hydrogen is $3.00 per kilogram. Therefore, if the hydrogen plant was required to operate in 22 percent of the hours (the load factor of the new load), the cost increases by $150 million for the hydrogen gas or an additional two cents per kWh to Washington customers. Currently the modeling only shows the hydrogen CT running less than 1 percent of the hours due to the availability of lower cost natural gas market options. It is unknown if Avista would be able to procure the amount of clean hydrogen necessary without either a massive storage or delivery system. Without this needed infrastructure, these turbines would need to run on natural gas to serve load.

The limited financial results of this study show the levelized system cost increasing by 10.7 percent over the PRS with the 2045 tail risk decreasing by 12 percent due to greater amounts of clean energy required. Since this market analysis was not updated, this risk and cost measurement is unreliable and may be underestimated. By 2045, the Washington energy rate increases 8.3 percent not including all the other infrastructure costs or potential hydrogen operation costs, and Idaho’s rate also increases by 3.5 percent due to resource selection timing and the PVRR is only 0.05 percent higher.

It should be noted that the economics of these electrification scenarios do not include the significant costs related to the stranding of natural gas assets (i.e. the undepreciated, unrecovered capital investment costs relative to natural gas transmission and distribution). In addition, determining who might bear that cost. The electric rate payers, the natural gas rate payers, shareholders or some combination would need to be determined between several regulatory commissions and Avista.

## Table 12.12: Portfolio #11- Electrification Portfolio #1 Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023-2024 | WA | 200 |
| Liquid Air Storage | 2025-2028 | WA | 130 |
| Rathdrum Upgrade | 2025 | WA/ID | 5 |
| Lancaster | 2026 | WA/ID | (257) |
| Montana Wind | 2026 | WA | 100 |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 91 |
| Natural Gas Peaker | 2027 | WA | 200 |
| Montana Wind | 2028 | WA | 100 |
| Natural Gas Peaker | 2029 | WA/ID | 84 |
| Liquid Air Storage | 2030-2035 | WA | 190 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Geothermal | 2035 | WA | 20 |
| Hydrogen Turbine with 40 Hrs Storage | 2036-2037 | WA | 153 |
| Hydrogen Turbine with 40 Hrs Storage | 2036 | ID | 50 |
| Liquid Air Storage | 2038-2039 | WA | 59 |
| NW On System Wind | 2038 | WA | 114 |
| Solar w/ storage (4 hours) | 2039 | WA | 127 |
| 4-hr Storage for Solar | 2039 | WA | 63 |
| Hydrogen Turbine with 40 Hrs Storage | 2040-2043 | WA | 244 |
| Boulder Park | 2040 | WA/ID | (25) |
| Hydrogen Turbine with 40 Hrs Storage | 2041 | ID | 50 |
| Solar w/ storage (4 hours) | 2041 | WA | 150 |
| 4-hr Storage for Solar | 2041 | WA | 75 |
| NW On System Wind | 2042-2043 | WA | 241 |
| Liquid Air Storage | 2044-2045 | WA | 107 |
| 4hr Lithium-Ion | 2045 | ID | 26 |
| NW On System Wind | 2045 | WA | 139 |
| | | | |
| Supply-side resource net total (MW) | | | 2,256 |
| Supply-side resource total additions (MW) | | | 2,813 |
| Demand Response 2045 capability (MW) | | | 68 |
| Cumulative energy efficiency (aMW) | | | 148 |
| Cumulative summer peak savings (MW) | | | 144 |
| Cumulative winter peak savings (MW) | | | 158 |

## Portfolio #12: Electrification Scenario #2 (Hybrid Natural Gas/Electric System)

To overcome some of the winter peak challenges with the previous scenario, this scenario lessens the financial impact of electrification by using homeowner natural gas heat only during colder temperatures. This scenario uses the same assumptions regarding the number of customers converting to electric but changes the relationship of kilowatt-hours to dekatherms to account for less additional electric load on the system in colder temperatures. The relationship used in this scenario is shown in Figure 12.5. This scenario assumes most customers retain their natural gas furnace but add an electric heat pump and heat pump water heaters. In this scenario, peak loads reduce 208 MW in 2030 and 442 MW in 2045 from Electrification Scenario #1. Winter peak loads are still 201 MW higher in 2030 and 451 MW higher in 2045 compared to the PRS. Given these load increases, additional generation will be needed for both the peak requirements, and 147 aMW of additional energy will be needed by 2045.

### Figure 12.5: Hybrid Scenario Natural Gas to Electric Load Relationship

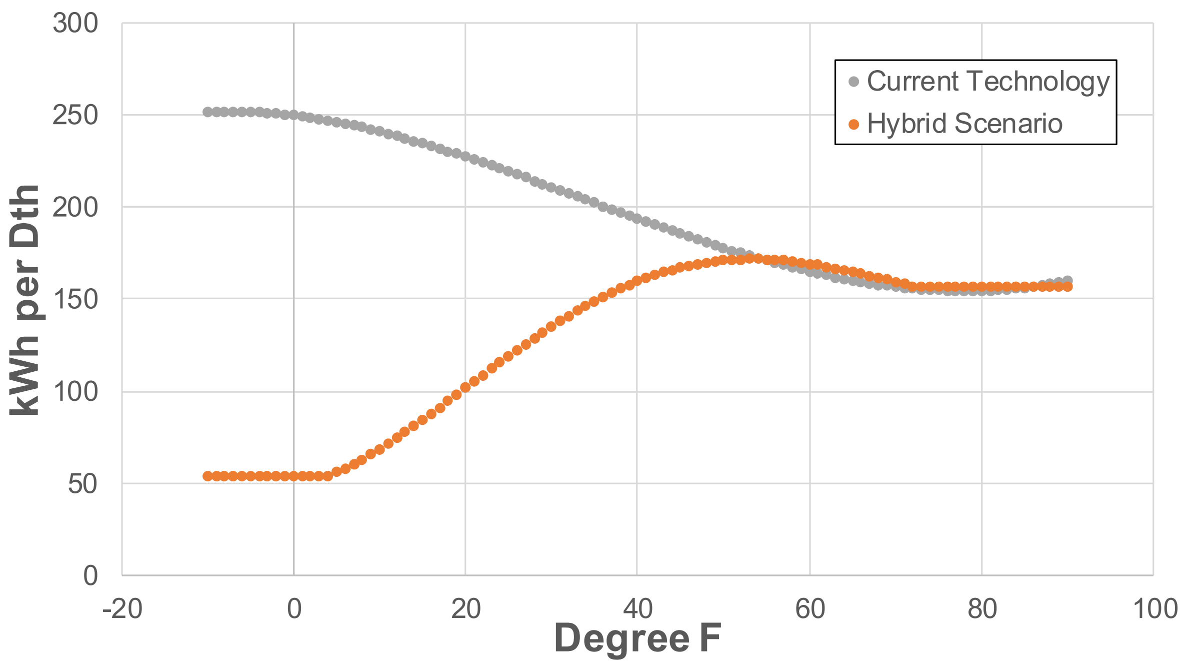
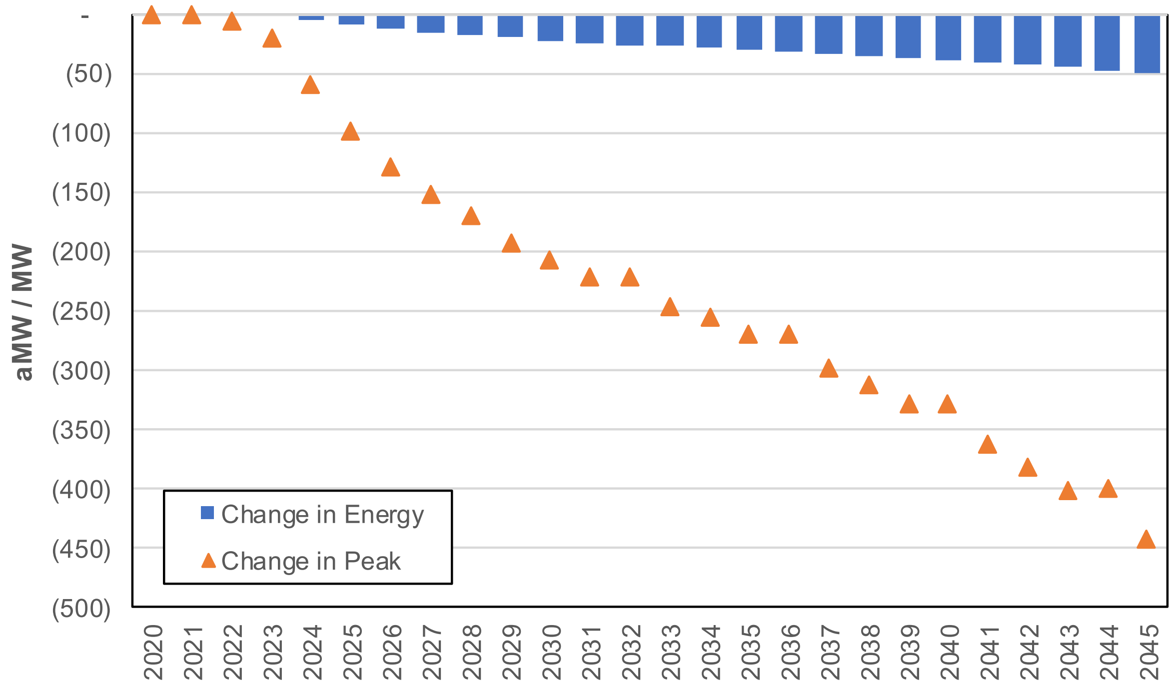


**Figure 12.6: Electrification Scenario #2 Load Change from Electrification Scenario #1**




As expected, the cost to meet this additional load is 5.7 percent higher than the PRS. Although using natural gas during cold temperatures costs 4.5 percent less than a full conversion to electric (not including T&D costs). Rates are also modestly higher in 2045 compared to the PRS with a 1.4 percent increase in Washington and a 1.6 percent increase in Idaho. It is worth noting while the energy rate in Idaho is slightly higher, the PVRR is 0.15 percent lower with the small rate increase due to resource timing and selection changes.

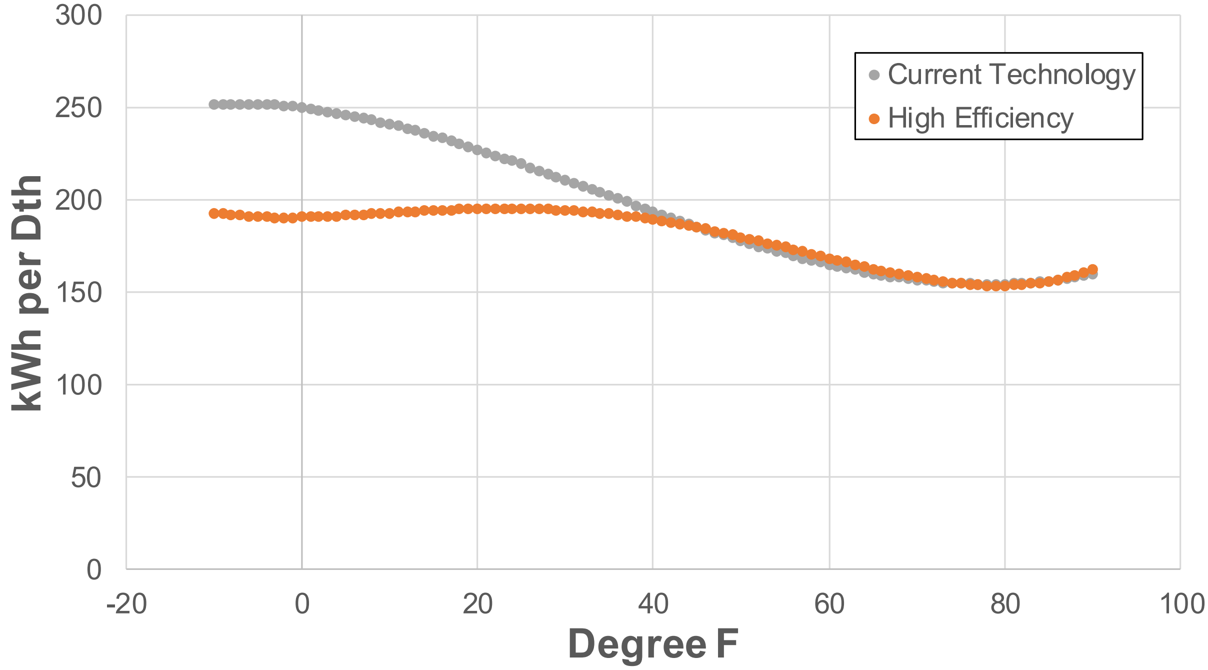
## Table 12.13: Portfolio #12- Electrification Scenario #2 Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023-2024 | WA | 200 |
| Rathdrum Upgrade | 2025 | WA/ID | 5 |
| Lancaster | 2026 | WA/ID | (257) |
| Montana Wind | 2026 | WA | 100 |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 95 |
| Natural Gas Peaker | 2027 | WA | 159 |
| Liquid Air Storage | 2027 | WA | 12 |
| Montana Wind | 2028 | WA | 100 |
| Liquid Air Storage | 2029-2030 | WA | 50 |
| NW Hydro Slice | 2031 | WA | 75 |
| Natural Gas Peaker | 2031 | WA/ID | 84 |
| Liquid Air Storage | 2034-2035 | WA | 35 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | ID | 36 |
| Hydrogen Gas Turbine with 40 Hrs Storage | 2036 | WA | 84 |
| Liquid Air Storage | 2037-2041 | WA | 105 |
| NW On System Wind | 2038 | WA | 101 |
| Solar w/ storage (4 hours) | 2039 | WA | 109 |
| 4-hr Storage for Solar | 2039 | WA | 54 |
| Boulder Park | 2040 | WA/ID | (25) |
| Solar w/ storage (4 hours) | 2041-2043 | WA | 428 |
| 4-hr Storage for Solar | 2041-2043 | WA | 214 |
| Hydrogen Gas Turbine with 40 Hrs Storage | 2041 | ID | 50 |
| Geothermal | 2042 | WA | 20 |
| Liquid Air Storage | 2043-2045 | WA | 78 |
| 4hr Lithium-Ion | 2045 | ID | 16 |
| NW On System Wind | 2045 | WA | 127 |
| | | | |
| Supply-side resource net total (MW) | | | 1,799 |
| Supply-side resource total additions (MW) | | | 2,356 |
| Demand Response 2045 capability (MW) | | | 68 |
| Cumulative energy efficiency (aMW) | | | 138 |
| Cumulative summer peak savings (MW) | | | 116 |
| Cumulative winter peak savings (MW) | | | 152 |

### Portfolio #13: Electrification Scenario #3 (High Efficiency)

The previous electrification scenarios provide context for additional load using existing technology and a hybrid system conversion. This third scenario considers whether electric heating technology improves enough to minimize the cold weather effects of heating with electric heat pumps. This scenario uses the same assumptions as the previous two electrification scenarios except it uses a flatter curve to remove most of the cold temperature effects on electric heat. In this case, in cold weather periods the relationship is 50 less kWh per dekatherm of natural gas as shown in Figure 12.7. This change in efficiency leads to lower loads, but not to the extent seen in Portfolio #12 as shown in Figure 12.8. The effects on the electric system will be significant even with more efficient electric heating technology for colder weather applications.

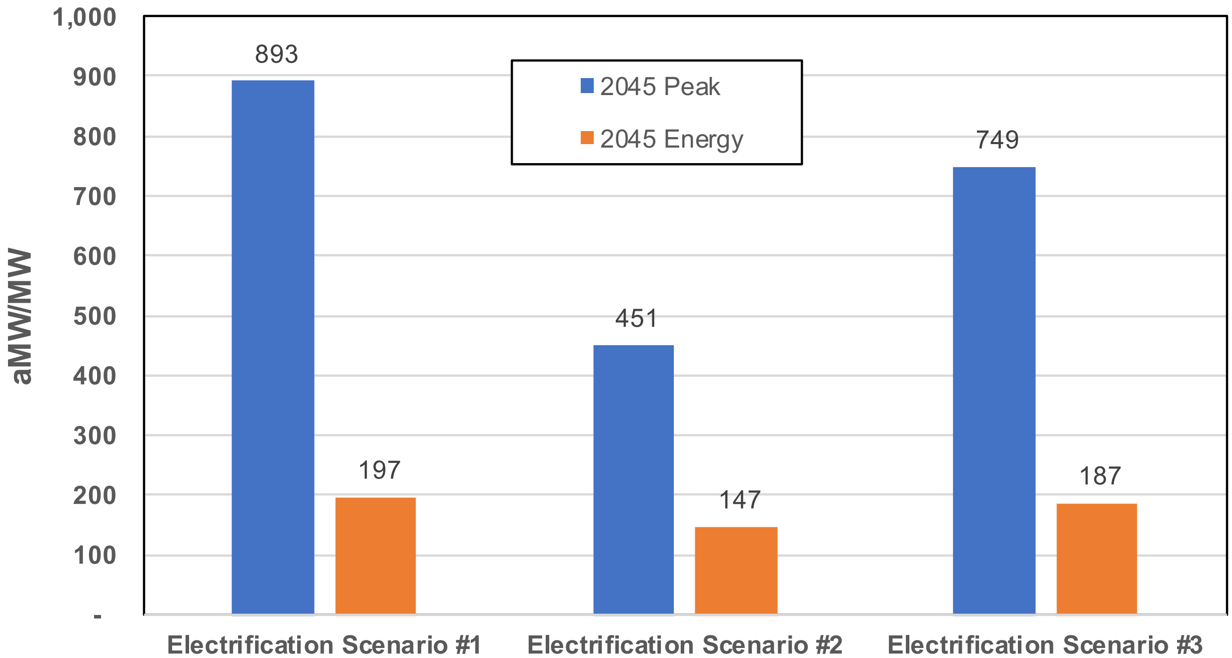
**Figure 12.7: High Efficiency Scenario Natural Gas to Electric Load Relationship**




The resources added in this scenario are similar to Portfolio #11, but with lower quantities due to lower peak load and lower energy needs. Results are shown in Table 12.14. Costs in this scenario are 9 percent higher than the PRS. Idaho costs remain unchanged, but the 2045 Idaho rate is 3.2 percent higher due to portfolio resource changes.

The cost to electrify the Washington residential and commercial heating system range between $0.8 to $1.4 billion PVRR and does not include the required T&D investments and customer equipment needed and the unknown amount of hydrogen or other storage alternative needed to meet load during the winter. With these costs, there are savings in natural gas purchases on the distribution side and lower direct greenhouse gas emissions. While these studies provide some information on potential impacts of electrification, additional work needs to be done to answer the issues discussed above. The IRP is not the best vehicle for this type of analysis due to the quantity of analyses required to complete the IRP and the information needed from T&D planning and therefore should be studied separately using information informed by regional IRPs.

**Figure 12.8: Electrification Load Increase Comparison**




## Portfolio #14: 2x Social Cost of Carbon

CETA requires a social cost of carbon for energy efficiency and fossil fuel resource selection in Washington using a cost of $82.80 per metric ton in 2022 and rising to $185.90 per metric ton by 2045. This portfolio examines the impacts of doubling these prices to better understand changes in portfolio selection and cost to the system. The resulting portfolio, shown in Table 12.15, slightly reduces the overall natural gas build out and slightly increases storage and energy efficiency selection. Making this change in the planning process will change system costs. This scenario stress tests the model to see how resource decisions change.

The levelized system cost increases 0.1 percent over the PRS and reduces the 2045 tail risk reduces by 2 percent. By 2045, the Washington energy rate increases 0.5 percent and Idaho's rate is 0.1 percent lower than the PRS portfolio. From a state-by-state PVRR point of view, Washington cost increases by $15 million and Idaho cost increases by less than $1 million over 24 years.

## Table 12.14: Portfolio #13- Electrification Scenario #3 Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023-2024 | WA | 200 |
| Liquid Air Storage | 2025-2028 | WA | 76 |
| Rathdrum Upgrade | 2025 | WA/ID | 5 |
| Lancaster | 2026 | WA/ID | (257) |
| Montana Wind | 2026 | WA | 100 |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 91 |
| Natural Gas Peaker | 2027 | WA | 200 |
| Montana Wind | 2028 | WA | 100 |
| Natural Gas Peaker | 2029 | WA/ID | 84 |
| Liquid Air Storage | 2030-2035 | WA | 156 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Geothermal | 2035 | WA | 20 |
| Hydrogen Turbine with 40 Hrs Storage | 2036 | ID | 50 |
| Hydrogen Turbine with 40 Hrs Storage | 2036 | WA | 92 |
| Liquid Air Storage | 2037-2039 | WA | 81 |
| NW On System Wind | 2038 | WA | 114 |
| Solar w/ storage (4 hours) | 2039 | WA | 125 |
| 4-hr Storage for Solar | 2039 | WA | 62 |
| Boulder Park | 2040 | WA/ID | (25) |
| Hydrogen Turbine with 40 Hrs Storage | 2040-2041 | WA | 107 |
| Hydrogen Turbine with 40 Hrs Storage | 2041 | ID | 50 |
| Solar w/ storage (4 hours) | 2041 | WA | 150 |
| 4-hr Storage for Solar | 2041 | WA | 75 |
| Liquid Air Storage | 2042-2045 | WA | 161 |
| NW On System Wind | 2042 | WA | 145 |
| Solar w/ storage (4 hours) | 2043 | WA | 150 |
| 4-hr Storage for Solar | 2043 | WA | 75 |
| 4hr Lithium-Ion | 2045 | ID | 26 |
| NW On System Wind | 2045 | WA | 137 |
| | | | |
| Supply-side resource net total (MW) | | | 2,169 |
| Supply-side resource total additions (MW) | | | 2,727 |
| Demand Response 2045 capability (MW) | | | 68 |
| Cumulative energy efficiency (aMW) | | | 141 |
| Cumulative summer peak savings (MW) | | | 121 |
| Cumulative winter peak savings (MW) | | | 154 |

### Table 12.15: Portfolio #14- 2x Social Cost of Carbon Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023-2024 | WA | 200 |
| Lancaster | 2026 | WA/ID | (257) |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 91 |
| Natural Gas Peaker | 2027 | WA/ID | 110 |
| Montana Wind | 2028 | WA | 100 |
| NW Hydro Slice | 2031 | WA | 75 |
| Rathdrum Upgrade | 2033 | WA/ID | 5 |
| Liquid Air Storage | 2034 | WA | 10 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 86 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Natural Gas Peaker | 2041 | ID | 36 |
| Montana Wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 230 |
| 4-hr Storage for Solar | 2042-2043 | WA | 115 |
| Liquid Air Storage | 2044 | WA | 13 |
| 4hr Lithium-Ion | 2045 | ID | 29 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 75 |
| | | | |
| Supply-side resource net total (MW) | | | 1,035 |
| Supply-side resource total additions (MW) | | | 1,593 |
| Demand Response 2045 capability (MW) | | | 75 |
| Cumulative energy efficiency (aMW) | | | 124 |
| Cumulative summer peak savings (MW) | | | 114 |
| Cumulative winter peak savings (MW) | | | 119 |

## Portfolio #15: Colstrip Exit in 2025

Regardless of Avista's preference, the Company does not have unilateral control of Colstrip's eventual shutdown date due to the structure of the ownership agreement. Avista's PRiSM model, used to develop optimized resource strategies, allows the plant to exit the portfolio in any year to avoid future costs if it is economic to do so. This portfolio, along with the next two scenarios, is used to understand the cost if the Colstrip units remain on-line for different lengths of time. In this scenario, the 2025 date is used to coincide with the CETA requirement to remove coal from rates in Washington State. The model in this scenario requires the plant to maintain operation through 2025 before exiting the portfolio.

Since the plant was determined by the model to be economic to exit in 2022, the cost of this scenario is higher. The levelized system cost increases 0.3 percent over the PRS and tail risk remains the same since the final resource mix is the same as the PRS. This portfolio is shown in Table 12.16. From a PVRR cost perspective, Washington's cost increases by $22 million (0.3 percent) and Idaho's increase by $12 million (0.3 percent) compared to the PRS.

### Table 12.16: Portfolio #15- Colstrip Exit in 2025 Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Montana Wind | 2023-2024 | WA | 200 |
| Colstrip | 2025 | WA/ID | (222) |
| Lancaster | 2026 | WA/ID | (257) |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 85 |
| Natural Gas Peaker | 2027 | WA/ID | 126 |
| Montana Wind | 2028 | WA | 100 |
| NW Hydro Slice | 2031 | WA | 75 |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas Peaker | 2036 | WA/ID | 87 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Natural Gas Peaker | 2041 | ID | 36 |
| Montana Wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 239 |
| 4-hr Storage for Solar | 2042-2043 | WA | 119 |
| Liquid Air Storage | 2044 | WA | 12 |
| Liquid Air Storage | 2045 | ID | 10 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 75 |
| Montana Wind | 2023-2024 | WA | 200 |
| | | | |
| Supply-side resource net total (MW) | | | 1,032 |
| Supply-side resource total additions (MW) | | | 1,589 |
| Demand Response 2045 capability (MW) | | | 71 |
| Cumulative energy efficiency (aMW) | | | 121 |
| Cumulative summer peak savings (MW) | | | 111 |
| Cumulative winter peak savings (MW) | | | 116 |

### Portfolio #16: Colstrip Exit in 2035

As with Portfolio #15, this scenario requires Colstrip to maintain operation, but increases the length of operations through 2035, before exiting the portfolio to understand the cost impacts of an additional 10 years of operating the Idaho share of the plant. This scenario assumes the former Washington portion of the plant's cost or benefit is borne by shareholders and is not included in this study. The cost of this scenario is higher as expected from the result of the PRS. The resource mix shown in Table 12.17 is slightly different than the PRS because the Colstrip capacity is replaced at different times. The levelized system cost increases 0.3 percent above the PRS and tail risk is 1.2 percent less due to resource selection changes. From a PVRR cost perspective, Washington's cost increase by $31 million (0.4 percent) and Idaho by $15 million (0.3 percent) compared to the PRS. These results show that the additional 10 years of Colstrip operation are only expected to increase Idaho's PVRR by $3 million, but Washington's cost increase by $9 million. Even though Washington is not receiving any of the Colstrip power beyond 2025 due to portfolio resource changes in Idaho, Washington cannot share resources with Idaho as optimally as in the PRS.

**Table 12.17: Portfolio #16- Colstrip Exit in 2035 Resource Selection**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Montana Wind | 2023-2024 | WA | 200 |
| Natural Gas Peaker | 2026 | WA | 51 |
| Lancaster | 2026 | WA/ID | (257) |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | WA/ID | 125 |
| Kettle Falls Upgrade | 2027 | WA/ID | 12 |
| Montana Wind | 2028 | WA | 100 |
| Natural Gas Peaker | 2031 | ID | 36 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Colstrip | 2035 | WA/ID | (222) |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Natural Gas Peaker | 2036 | ID | 92 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Liquid Air Storage | 2039 | WA | 10 |
| Boulder Park | 2040 | WA/ID | (25) |
| Natural Gas Peaker | 2041 | ID | 36 |
| Montana Wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 239 |
| 4-hr Storage for Solar | 2042-2043 | WA | 119 |
| 4hr Lithium-Ion | 2045 | ID | 24 |
| Liquid Air Storage | 2045 | WA | 12 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 75 |
| | | | |
| Supply-side resource net total (MW) | | | 1,062 |
| Supply-side resource total additions (MW) | | | 1,620 |
| Demand Response 2045 capability (MW) | | | 64 |
| Cumulative energy efficiency (aMW) | | | 120 |
| Cumulative summer peak savings (MW) | | | 109 |
| Cumulative winter peak savings (MW) | | | 114 |

## Portfolio #17: Colstrip Exit in 2045

This scenario requires Colstrip to maintain operation throughout the entire IRP. This scenario also assumes the Washington share of the plant's ongoing operational costs or benefits are borne by shareholders after 2025. As expected, the cost of this scenario is higher than the PRS. The resource mix as shown in Table 12.18 reduces the amount of new natural gas resources due to Colstrip not being replaced. The levelized system cost increases by 0.4 percent above the PRS and the 2045 tail risk is 15.4 percent less due to a less variable generation and fuel supply. From a PVRR cost perspective, Washington's cost increases $27 million (0.3 percent) and Idaho's cost increases by $24 million (0.5 percent) compared to the PRS. These results show the additional 20 years of operation compared to a 2025 exit increase Idaho's PVRR by $12 million, but Washington's cost increase by $5 million because of other portfolio changes.

Overall, the three Colstrip portfolios show the 76 MW Idaho portion of the Colstrip plant modestly increases costs with the plant continually operating compared to it exiting the portfolio. Due to the small change in costs and the unknown future of both the market and operating cost, it is clear continuing the plant operation or exiting the plant has similar cost when considering this uncertainty. Avista also recognizes other utilities with ownership shares may reach different outcomes for the facility depending on whether an immediate replacement for the resource is needed. For example, if Avista were not currently long on capacity of similar quantities as the Colstrip plant, it is likely the plant would be economic to continue operations through 2025.

### Portfolio #18: Clean Energy Delivered Each Hour

The compliance method for meeting the CETA goals have yet to be determined regarding the intent to be 100 percent net clean by 2030 and 100 percent by 2045. The PRS assumes Avista must acquire clean energy equaling 100 percent of adjusted Washington retail sales with an allowance for 20 percent unbundled RECs in 2030 and transitioning to no unbundled RECs by 2045. This means if the Company acquires the clean energy, it does not need to be delivered to the customer in the same hour or instantaneously. This scenario attempts to understand the consequences of meeting a 100 percent delivery requirement. Currently, Avista's modeling tools are not designed for this scenario. In order to meet this scenario's objective, it requires a look at likely generation profiles of both existing and new resource options in order to see if and how generation can be re-shaped to meet load profiles.

Avista studied 2030, 2040 and 2045 generation profiles to first see if the resources from the PRS met the 100 percent clean delivery goal using expected delivery shapes of renewables. The analysis showed the PRS likely would meet the delivery goal in 2030, although 81 aMW of its generation is in excess of load and would be unbundled RECs in an average water year. By 2040, where it is expected the amount of allowed unbundled RECs should decline to 10 percent the PRS would not meet the delivery requirement in an average water year due to exceeding the limit of unbundled RECs. To overcome this constraint Avista would need to add more clean energy resources such as 100 MW of wind and 150 MW of solar to increase the probability of generation being available at the hourly time of load.

**Table 12.18: Portfolio #17- Colstrip Exit in 2045 Resource Selection**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Montana Wind | 2023-2024 | WA | 200 |
| Lancaster | 2026 | WA/ID | (257) |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | WA/ID | 125 |
| Kettle Falls Upgrade | 2027 | WA/ID | 12 |
| Montana Wind | 2028 | WA | 100 |
| Natural Gas Peaker | 2031 | ID | 36 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Natural Gas Peaker | 2036 | WA/ID | 86 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Natural Gas Peaker | 2041 | ID | 36 |
| Montana Wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 238 |
| 4-hr Storage for Solar | 2042-2043 | WA | 119 |
| 4hr Lithium-Ion | 2045 | ID | 24 |
| Liquid Air Storage | 2044 | WA | 13 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 75 |
| | | | |
| Supply-side resource net total (MW) | | | 1,216 |
| Supply-side resource total additions (MW) | | | 1,552 |
| Demand Response 2045 capability (MW) | | | 64 |
| Cumulative energy efficiency (aMW) | | | 119 |
| Cumulative summer peak savings (MW) | | | 108 |
| Cumulative winter peak savings (MW) | | | 113 |

The 2045 goal of 100 percent of delivered clean energy is too difficult to model as it is unknown what clean resources will be available in the market each hour to serve load when Avista is short clean energy in addition to the intermittent nature of renewables and the hydro variability. While it is impractical for the utility to plan to be a clean energy electrical island, studying these complexities assists in understanding potential storage and renewable needs for this future. The challenge is to find the additional amount of storage and renewables to balance load and generation without using market purchases or thermal resources to meet Washington's hourly load assuming average hydro conditions. This scenario is not optimized for cost, but rather optimized to minimize additional MWh of storage to renewable generation. Beyond the PRS, 300 MW of wind, 400 MW of solar and 100 MW of biomass is required. This results in 240 aMW in excess generation compared to load and some of the additional renewables would need to be curtailed or sold assuming Avista was able to procure an additional 500 MW of storage capability with 27,000 MWh of storage. For context, this level of storage requirement is nearly equal to the total system load for an entire day. The resource selection in Table 12.19 demonstrates how these requirements could be met with the resource options, but

Avista would still need to conduct additional hydro variability and market studies to determine the feasibility of resource selection along with an optimized cost analysis. In this case, 2045 rates are 19.6 percent higher than the PRS in Washington and 1.5 percent higher in Idaho. For the 2045 goal, Avista anticipates, absent new low-cost storage technology, to exceed the CETA cost cap for 2045 obligations due to the cost increases of storage and additional clean energy requirements under this scenario.

**Table 12.19: Portfolio #18- Clean Energy Delivered Each Hour Resource Selection**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023-2024 | WA | 200 |
| Lancaster | 2026 | WA/ID | (257) |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 85 |
| Natural Gas Peaker | 2027 | WA/ID | 126 |
| Montana Wind | 2028 | WA | 100 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Natural Gas Peaker | 2036 | ID | 73 |
| Pumped Hydro Storage | 2036 | WA | 500 |
| NW On System Wind | 2038 | WA | 100 |
| Solar w/ storage (4 hours) | 2038 | WA | 150 |
| 4-hr Storage for Solar | 2038 | WA | 75 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 100 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | (25) |
| Montana Wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2045 | WA | 538 |
| 4-hr Storage for Solar | 2042-2045 | WA | 269 |
| NW On System Wind | 2042 | WA | 100 |
| NW Off System Wind | 2042 | WA | 100 |
| Solar w/ storage (2 hours) | 2042 | WA | 100 |
| 2-hr Storage for Solar | 2042 | WA | 25 |
| Liquid Air Storage | 2044 | WA | 12 |
| Liquid Air Storage | 2045 | ID | 10 |
| Wood Biomass | 2045 | WA | 100 |
| | | | |
| Supply-side resource net total (MW) | | | 2,456 |
| Supply-side resource total additions (MW) | | | 3,014 |
| Demand Response 2045 capability (MW) | | | 71 |
| Cumulative energy efficiency (aMW) | | | 121 |
| Cumulative summer peak savings (MW) | | | 111 |
| Cumulative winter peak savings (MW) | | | 116 |

## Portfolio #19: Social Cost of Carbon Cost on Purchases/Sales

Avista uses a social cost of carbon in its portfolio optimization of energy efficiency and fossil fuel generation options. Avista did not assign any social cost of carbon for short-term market purchases or benefits of market sales. This portfolio tests the impact of the resource strategy adding this cost to the model. In the current modeling process, Avista is unable to separate purchases and sales and, therefore, uses the net purchases and sales for this study. For the carbon content of market transactions, the study uses the annual average emissions rate included in the market price forecast as described in Chapter 9. Table 12.20 describes the resource selection for this scenario. Compared to the PRS, the model selection for this scenario is biased toward wind and selects less solar and storage. This is likely due to the potential carbon content in storage inherent with using market purchases used to recharge the storage resources.

The levelized system cost increases with this change by 0.3 percent compared to the PRS and reduces 2045 tail risk by 1.6 percent. By 2045, the Washington energy rate increases 0.6 percent and Idaho's rate increase 0.4 percent relative to the PRS portfolio due to resource selection changes.

### Table 12.20: Portfolio #19- SCC on Purchases/Sales Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023-2024 | WA | 200 |
| Lancaster | 2026 | WA/ID | (257) |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 92 |
| Montana Wind | 2027 | WA | 100 |
| Natural Gas Peaker | 2027 | WA/ID | 95 |
| NW Hydro Slice | 2031 | WA | 75 |
| Montana Wind | 2031 | WA | 100 |
| Northeast | 2035 | WA/ID | (54) |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Natural Gas Peaker | 2036 | WA/ID | 92 |
| Boulder Park | 2039 | WA/ID | (25) |
| Natural Gas Peaker | 2040 | WA/ID | 63 |
| NW On System Wind | 2041 | WA | 116 |
| Liquid Air Storage | 2043-2045 | ID | 34 |
| Solar w/ storage (4 hours) | 2043 | WA | 120 |
| 4-hr Storage for Solar | 2043 | WA | 60 |
| Liquid Air Storage | 2044-2045 | WA | 22 |
| NW On System Wind | 2045 | WA | 100 |
| | | | |
| Supply-side resource net total (MW) | | | 737 |
| Supply-side resource total additions (MW) | | | 1,295 |
| Demand Response 2045 capability (MW) | | | 64 |
| Cumulative energy efficiency (aMW) | | | 123 |
| Cumulative summer peak savings (MW) | | | 111 |
| Cumulative winter peak savings (MW) | | | 121 |

### Portfolio #20: Average Market Emissions Intensity Used for Energy Efficiency

This scenario tests the sensitivity of the social cost of carbon to the cost of energy efficiency. The CETA legislation requires using a social cost of carbon for energy efficiency acquisition, but it is unclear regarding what emissions rate to assign to energy efficiency or how it should be derived. From an operational perspective, reducing Avista's load with energy efficiency will not likely have any significant impact on the operations of its fossil fuel generation as these plants dispatch to wholesale market prices which do not include a social cost of carbon component. Energy efficiency will reduce the need for new resources with lower loads. Avista indirectly modeled these benefits by requiring energy efficiency to be co-optimized with supply side resources. The next question is whether Avista's operational emissions change with energy efficiency, as less load will likely lead to less emissions in the marketplace. For the PRS, Avista uses the annual incremental emissions rate described in Chapter 9 per a request from the WUTC staff. This amount is higher than the average market emissions rate Avista used in the 2020 IRP. The purpose of this scenario is to understand the difference in energy efficiency acquisition between the two methods. It is unclear to Avista if the legislature intended for a utility to increase its energy efficiency programs for emissions reduction for other utilities in the region.

Resource selection changes in this scenario due to energy efficiency changes shown in Table 12.21. Annual energy efficiency savings are 10 aMW less by 2045 or 12 percent due to this assumption change. Given this change since the last IRP, Avista's energy efficiency goals are higher along with making Washington customers' PVRR $32 million higher than the PRS due to this change and average customer rates are 0.7 percent higher than the PRS. Idaho rates are also 0.3 percent higher due to resource selection changes.

## Table 12.21: Portfolio #20- Average Market Emissions Intensity for Energy Efficiency Resource Selection

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | -222 |
| Montana Wind | 2023-2024 | WA | 200 |
| Lancaster | 2026 | WA/ID | -257 |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Natural Gas Peaker | 2027 | ID | 96 |
| Natural Gas Peaker | 2027 | WA | 84 |
| Montana Wind | 2028 | WA | 100 |
| Natural Gas Peaker | 2031 | ID | 37 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | -54 |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Natural Gas Peaker | 2036 | WA/ID | 86 |
| Solar w/ storage (4 hours) | 2038 | WA/ID | 101 |
| 4-hr Storage for Solar | 2038 | WA/ID | 50 |
| Boulder Park | 2040 | WA/ID | -25 |
| Natural Gas Peaker | 2041 | ID | 36 |
| Montana Wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 239 |
| 4-hr Storage for Solar | 2042-2043 | WA | 120 |
| Liquid Air Storage | 2044 | WA | 12 |
| Liquid Air Storage | 2045 | ID | 10 |
| Solar w/ storage (4 hours) | 2045 | WA | 149 |
| 4-hr Storage for Solar | 2045 | WA | 75 |
| | | | |
| Supply-side resource net total (MW) | | | 1,038 |
| Supply-side resource total additions (MW) | | | 1,595 |
| Demand Response 2045 capability (MW) | | | 75 |
| Cumulative energy efficiency (aMW) | | | 111 |
| Cumulative summer peak savings (MW) | | | 98 |
| Cumulative winter peak savings (MW) | | | 112 |

## Cost and Rate Comparison

Avista chose two different metrics to illustrate the cost differences among the portfolios. The first metric is total revenue requirement and the second is average customer rates. This is a simple rate calculation of total revenue requirement divided by retail sales. The full 24-year term along with intermediate time steps for each of the methodologies is in Table 12.22. The table shows the results of the portfolios including present value of revenue requirements (PVRR) and the effective average energy rate for 2030 and 2045 for both states over 24 years.

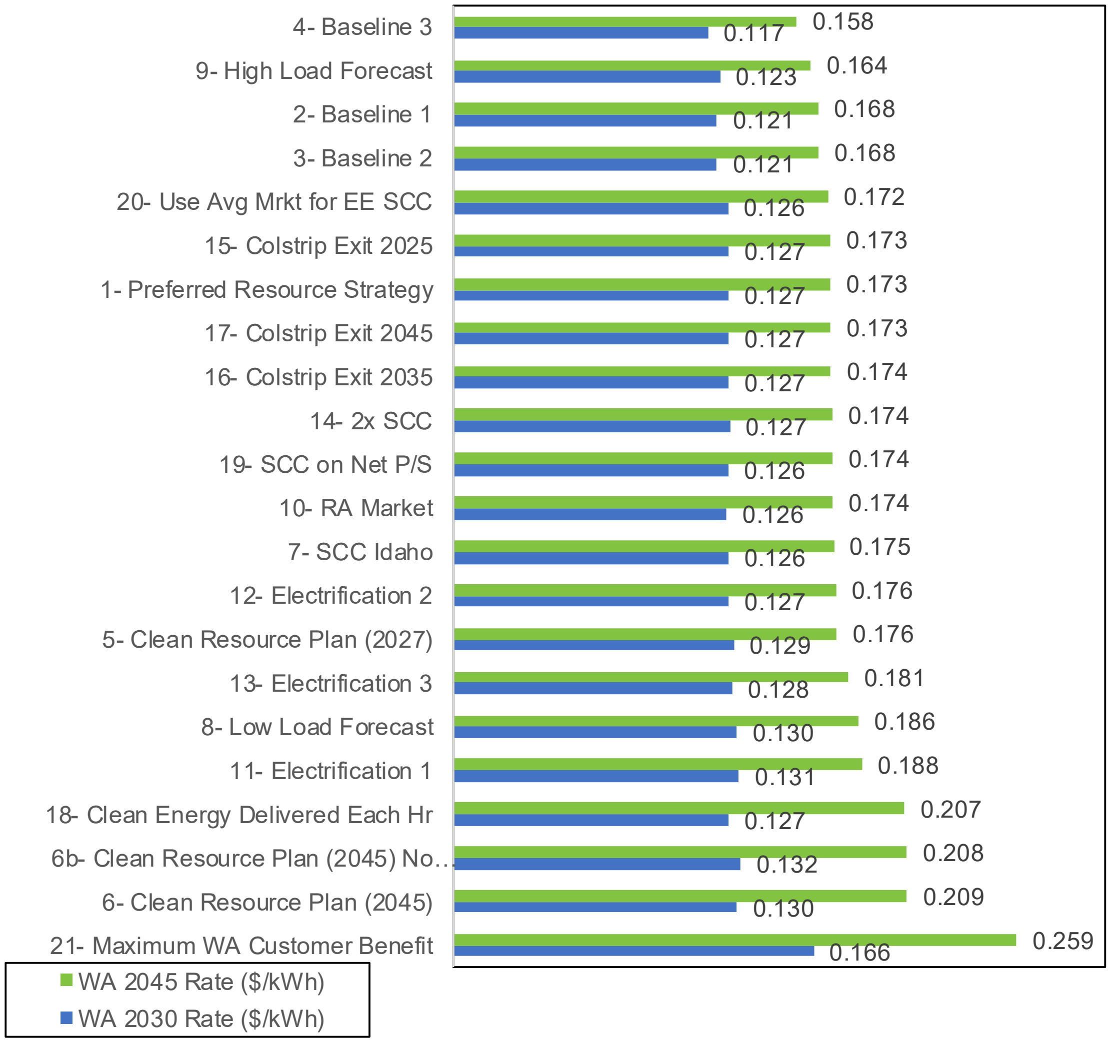
### Table 12.22: Portfolio Costs and Rates

| Scenario | WA-PVRR ($ Mill) | ID-PVRR ($ Mill) | WA 2030 Rate ($/kWh) | WA 2045 Rate ($/kWh) | ID 2030 Rate ($/kWh) | ID 2045 Rate ($/kWh) |
|---|---|---|---|---|---|---|
| 1- Preferred Resource Strategy | 8,703 | 4,543 | 0.127 | 0.173 | 0.110 | 0.153 |
| 2- Baseline 1 | 8,418 | 4,578 | 0.121 | 0.168 | 0.110 | 0.152 |
| 3- Baseline 2 | 8,418 | 4,580 | 0.121 | 0.168 | 0.110 | 0.151 |
| 4- Baseline 3 | 8,125 | 4,405 | 0.117 | 0.158 | 0.106 | 0.141 |
| 5- Clean Resource Plan (2027) | 8,800 | 4,910 | 0.129 | 0.176 | 0.121 | 0.166 |
| 6- Clean Resource Plan (2045) | 8,965 | 4,951 | 0.130 | 0.209 | 0.122 | 0.196 |
| 6-b Clean Resource Plan (2045) | 9,004 | 4,918 | 0.132 | 0.208 | 0.120 | 0.190 |
| 7- SCC Idaho | 8,732 | 4,568 | 0.126 | 0.175 | 0.112 | 0.161 |
| 8- Low Load Forecast | 8,575 | 4,492 | 0.130 | 0.186 | 0.113 | 0.163 |
| 9- High Load Forecast | 8,916 | 4,576 | 0.123 | 0.164 | 0.104 | 0.142 |
| 10- RA Program | 8,663 | 4,531 | 0.126 | 0.174 | 0.109 | 0.152 |
| 11- Electrification 1 | 10,117 | 4,545 | 0.131 | 0.188 | 0.109 | 0.158 |
| 12- Electrification 2 | 9,471 | 4,536 | 0.127 | 0.176 | 0.109 | 0.155 |
| 13- Electrification 3 | 9,894 | 4,543 | 0.128 | 0.181 | 0.109 | 0.158 |
| 14- 2x SCC | 8,718 | 4,544 | 0.127 | 0.174 | 0.110 | 0.152 |
| 15- Colstrip Exit 2025 | 8,725 | 4,555 | 0.127 | 0.173 | 0.110 | 0.153 |
| 16- Colstrip Exit 2035 | 8,734 | 4,558 | 0.127 | 0.174 | 0.108 | 0.153 |
| 17- Colstrip Exit 2045 | 8,729 | 4,567 | 0.127 | 0.173 | 0.108 | 0.154 |
| 18- Clean Energy Deliver by Hr. | 9,162 | 4,567 | 0.127 | 0.207 | 0.110 | 0.155 |
| 19- SCC on Net P/S | 8,726 | 4,561 | 0.126 | 0.174 | 0.110 | 0.153 |
| 20- Use Avg Market for EE SCC | 8,671 | 4,543 | 0.126 | 0.172 | 0.108 | 0.153 |
| 21- Max. WA Customer Benefit | 10,764 | 4,569 | 0.166 | 0.259 | 0.110 | 0.151 |

The lowest overall cost and the lowest energy rate portfolios are different due to the inclusion of net energy sales in the rate calculation. Portfolios with less energy sales may have higher rates due to fewer kWhs over which to spread total costs. Figure 12.9 shows the energy rates by portfolio sorted from lowest to highest for Washington and Figure 12.10 shows the same information for Idaho. The portfolios are sorted by the lowest 2045 rate on top. The lowest rate portfolios include the baseline scenarios for Washington as they do not include the clean energy targets. High economic growth also has lower rates as more energy is available to spread costs over and it is also a lower rate portfolio. The higher rate portfolios have additional energy requirements. For Idaho, most of the portfolios have similar rates due to the nature of most of the portfolio scenarios affecting

Washington, but for portfolios requiring Idaho to add additional clean energy directly or indirectly increase cost.

**Figure 12.9: Washington Portfolio Average Energy Rates**




Avista's optimization model does not select new resources based on the rate of power, but rather the PVRR of the total system with societal costs for Washington. The resulting revenue requirements for each state and the system are shown in Figure 12.11. The data is sorted by system PVRR in billions of dollars. The Idaho and Washington values shown illustrates the effects on each state given the changes in the portfolio requirements. The chart also shows the benefits or costs in relative impacts to each portfolio. It is worth noting the average rate methodology compared to the PVRR method illustrates the change in order of portfolio costs; for example, low load growth is one of the lower PVRR cost but on the higher end of the rate comparison. This is similar when looking at the electrification scenarios where the added sales dampens the rate impact (absent non-modeled costs).

**Figure 12.10: Idaho Portfolio Average Energy Rates**

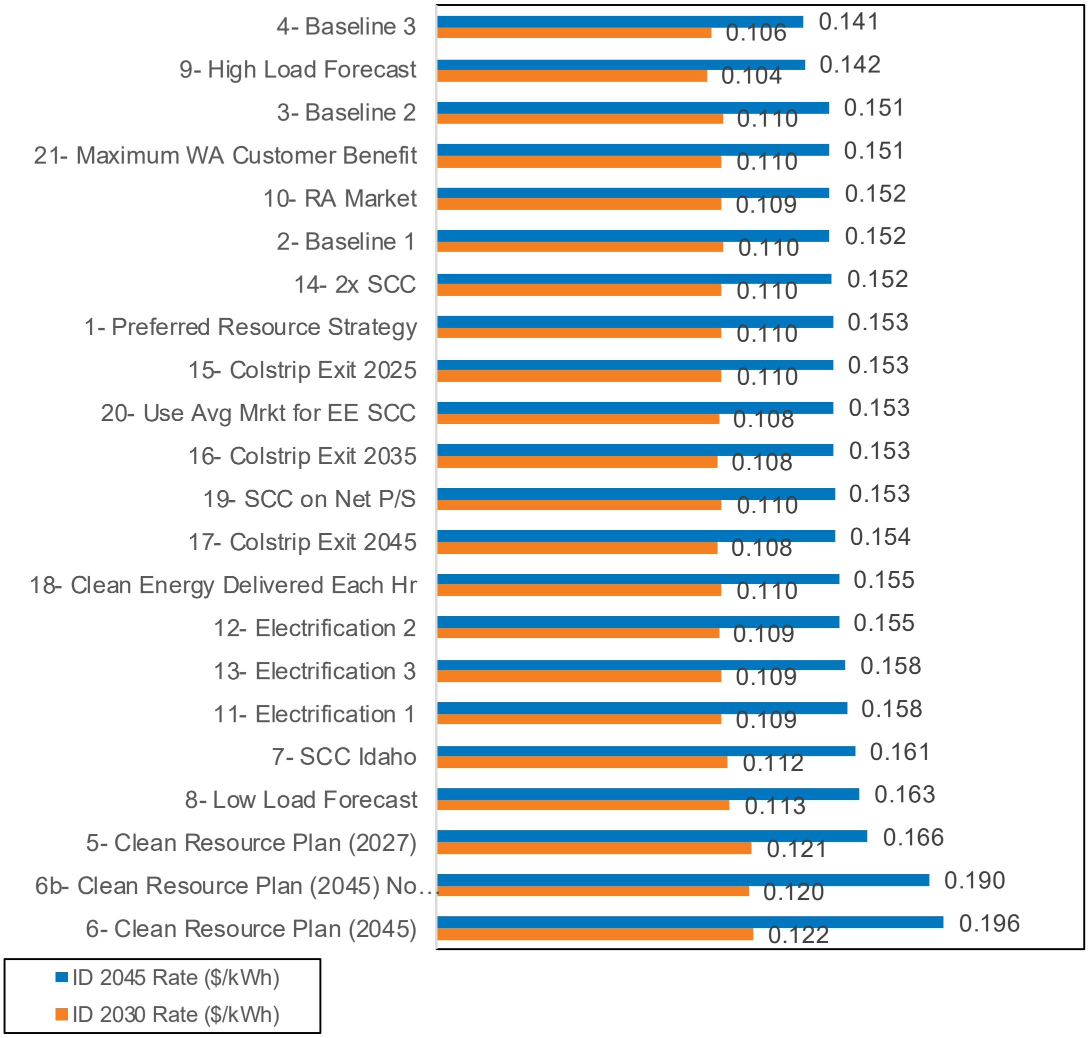
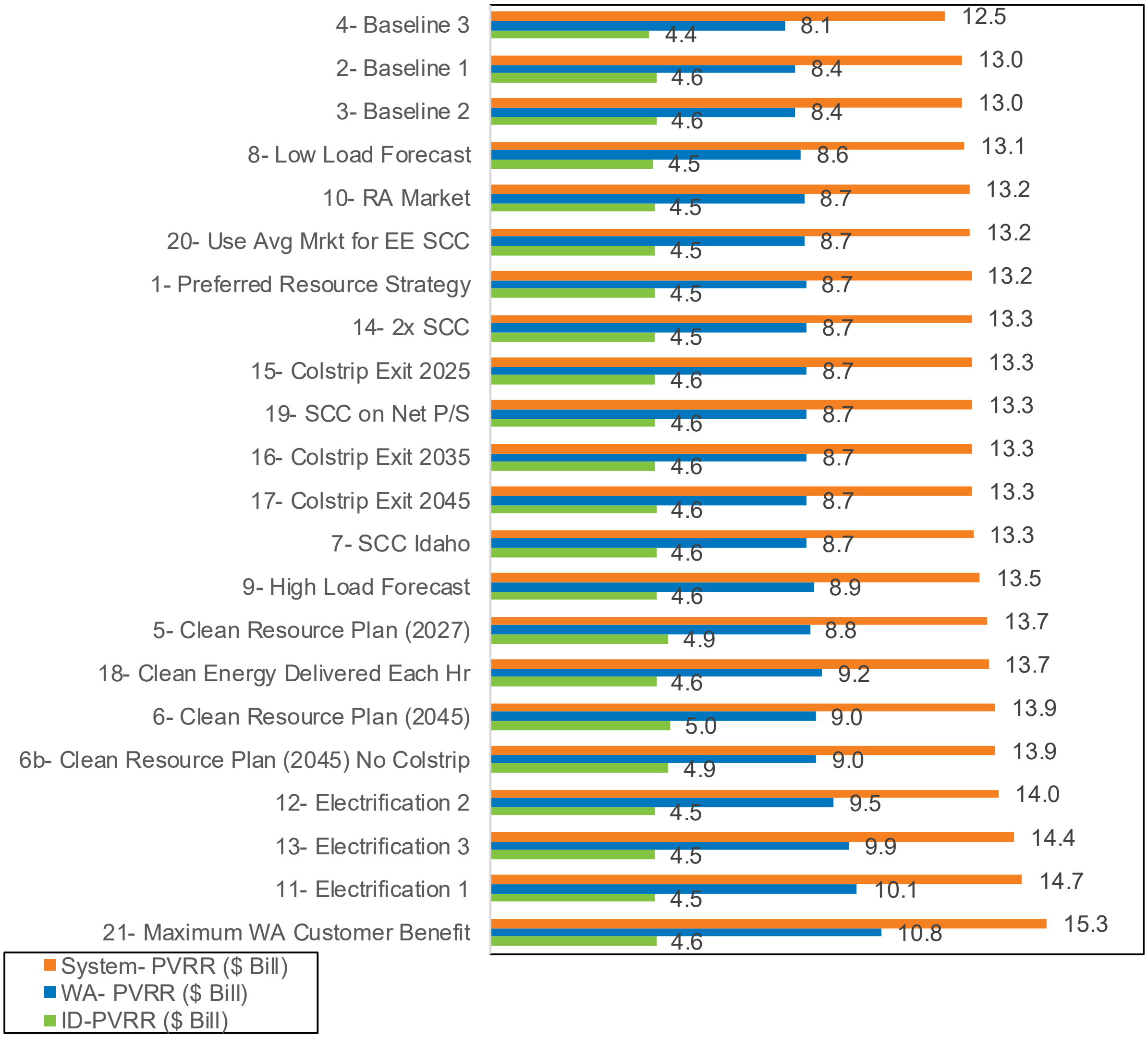


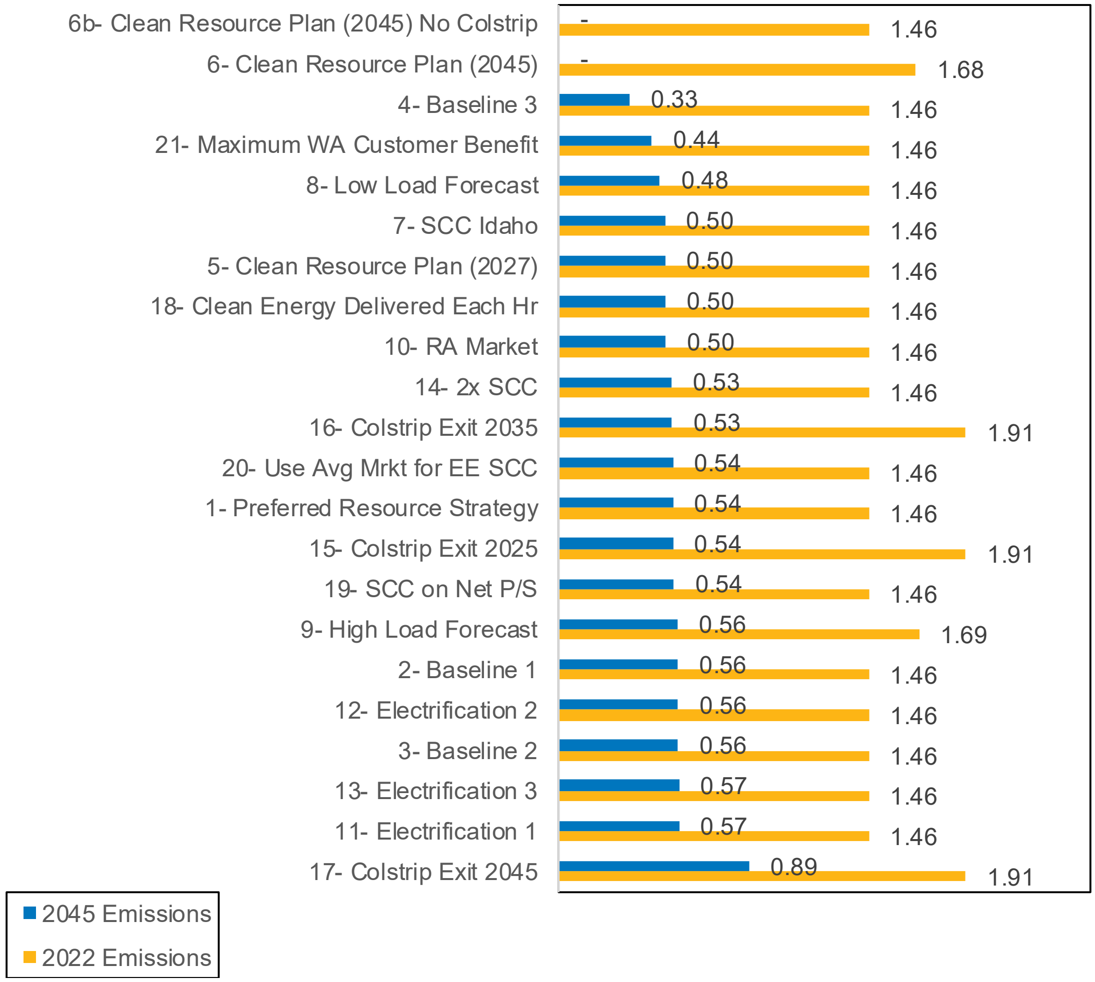
**Figure 12.11: Portfolio Average Energy Levelized Revenue Requirement**




## Greenhouse Gas Analysis

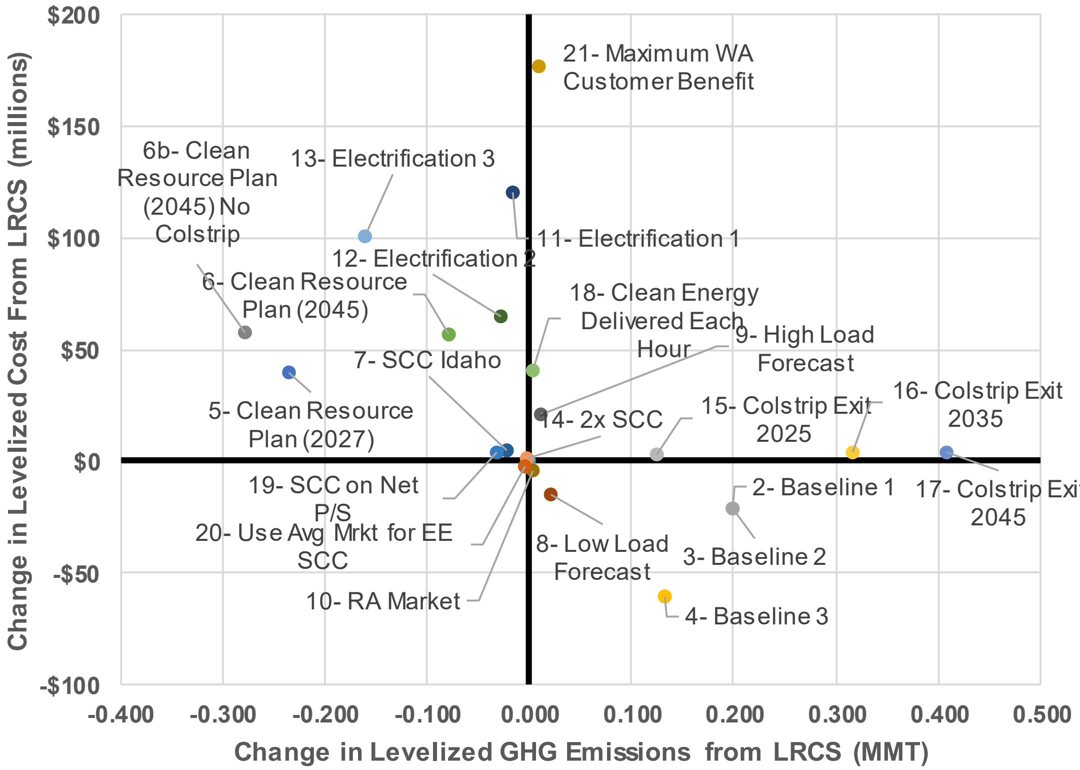
The portfolios studied in the chapter show a net reduction of greenhouse gas emissions. Emissions are lower due to the exit of Colstrip and the electric marketplace's large amount of clean energy driving dispatch of remaining coal and natural gas plants lower. Figure 12.12 shows the differences in greenhouse gas emissions from the alternative portfolios in 2022 and 2045. This methodology shows Avista's emissions at the beginning and end of the IRP. The emissions included in this chart are direct emissions of greenhouse gases. This methodology clearly displays known emission levels based on forecasts of expected run hours for thermal resources and excludes impacts of upstream emissions and estimates market emissions. Most portfolios end with the same emissions range due to similar levels of natural gas-fired facilities.

**Figure 12.12: Levelized Greenhouse Gas Emissions**




Another way to look at emission reductions is to compare the reduction to the PRS and how the portfolio cost changes. Figure 12.13 is a complex chart showing this effect where each point is a portfolio showing the relative change in cost and emissions compared to the PRS (at the center of the chart). In this case, the emissions are the levelized net emissions with market impacts and cost is the levelized cost of the system. A way to test whether the PRS stands up against other portfolios in this measurement is to identify if any portfolios with lower cost and less emissions exist. In this example, Portfolio #20 marginally achieves this criterion. This portfolio uses the average market emission rate for the energy efficiency calculation. The reason it performs better in this measurement is that costs are lower due to using fewer high cost energy efficiency measures and emissions are lower due to slightly higher clean energy purchases.

Figure 12.13: Change in Greenhouse Gas Emissions Compared to Change in Cost




## Risk Analysis

Avista's 500 simulations of market prices allow Avista to study the portfolio cost in different market conditions in order to understand the power cost risk of these potential futures. For this risk analysis Avista looks at standard deviation, which measures variability in cost, this can be either positive or negative risk. Avista's measure of tail risk is the difference between the mean cost of the 500 simulations and the 95$^{th}$ percentile.

Avista typically shows its cost versus risk metrics graphically with cost on the x-axis and risk on the y-axis to show the tradeoff between cost and risk. The best portfolios are in the bottom left of the chart with low risk and low cost. In past IRPs, Avista developed an efficient frontier to show the best cost versus risk portfolios. Given the new complexities of CETA and splitting each of the portfolio cost between states to show which is driving the actual cost, Avista did not have time to conduct this analytical comparison. Figure 12.14 shows the 2030 standard deviation of power cost in the y-axis compared to the levelized revenue requirement of the system in the x- axis. The PRS is in the upper middle and the remaining portfolios are labeled to show their relative comparison.

The tail risk analysis using the same cost versus risk metric is shown in Figure 12.15. This method of reviewing risk uses the same x-axis for cost but uses the 2045 Tail95 risk on the y-axis. These two methods produce similar results although the Tail95 measurement illustrates higher relative risk for the baseline scenarios. Also, since this is a view of 2045, the differences can illustrate portfolio differences between 2030 and 2045.

**Figure 12.14: Portfolio's Standard Deviation versus Portfolio's Levelized PVRR**

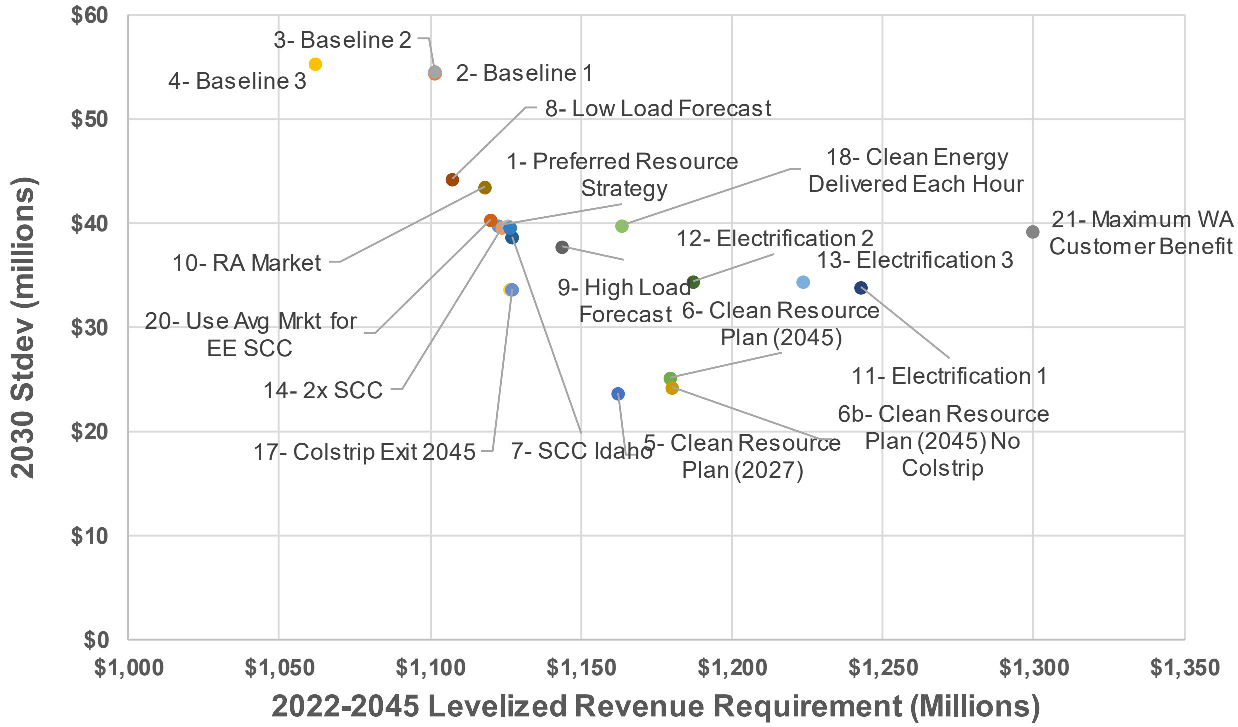
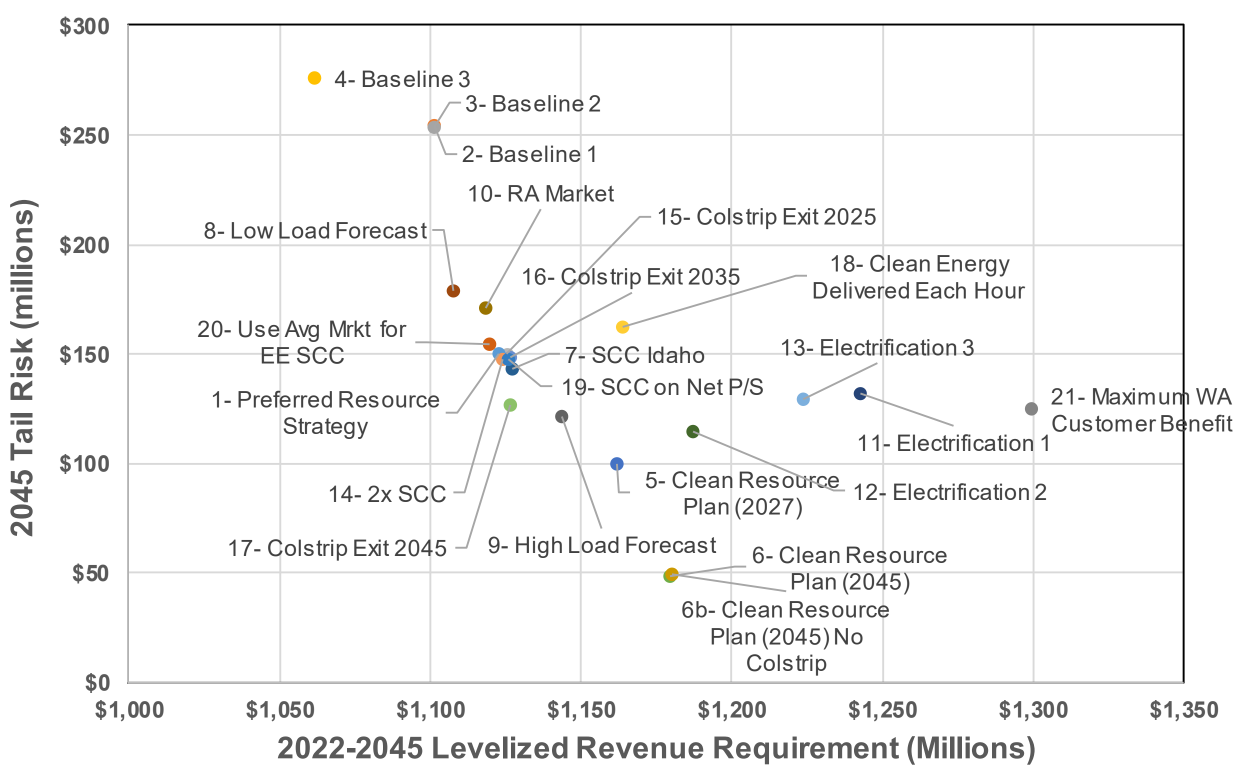
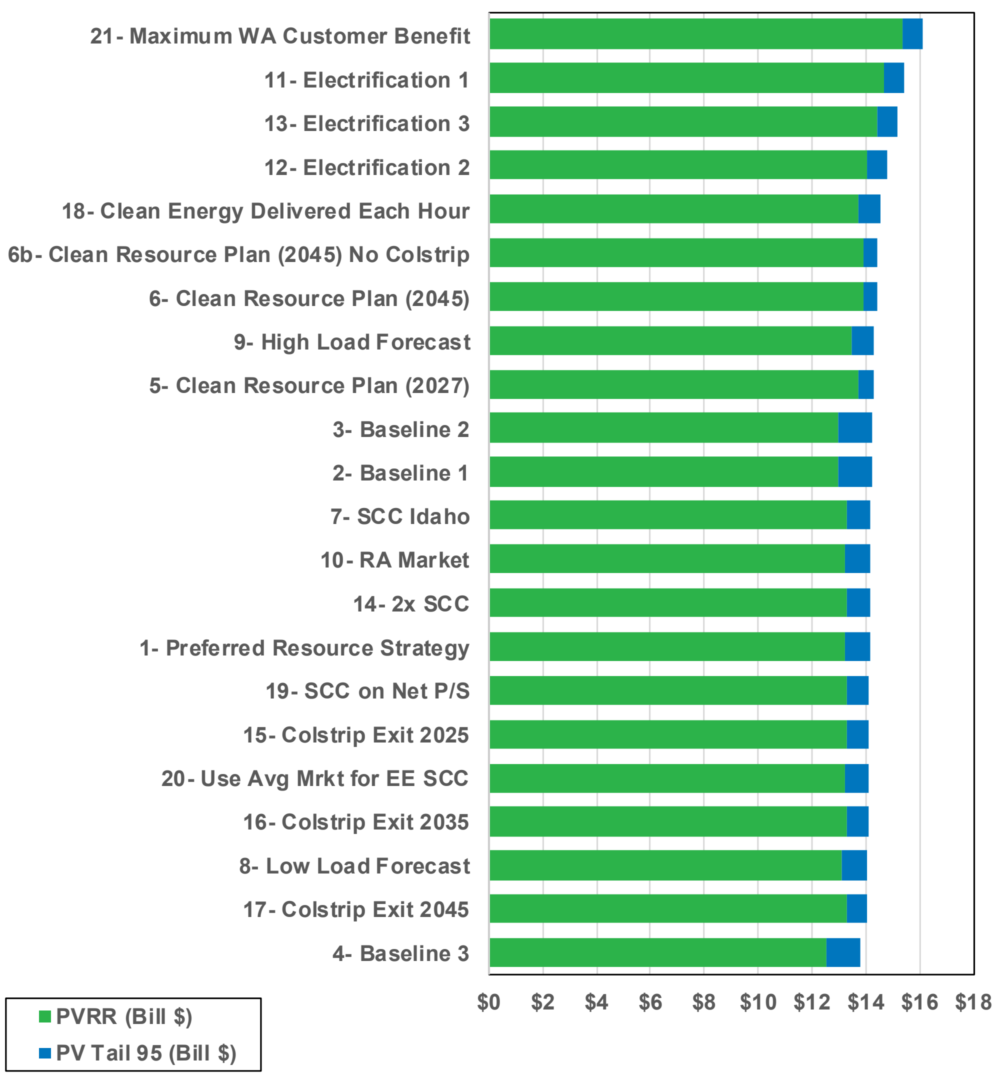



**Figure 12.15: Portfolio's Tail Risk vs Portfolio's Levelized PVRR**



Considering total cost with risk, Figure 12.16 shows the lowest cost portfolio with risk included. In this measurement, the PVRR of the Tail95 risk is added to the PVRR. The risk component is included in blue and the expected cost is in green. The method shows the lowest risk adjusted cost is Portfolio #4, although this portfolio does not meet capacity or clean energy requirements. The next best portfolio meeting all requirements is Portfolio #17 with Colstrip exiting in 2045 for Idaho and 2025 for Washington. This portfolio has lower risk than exiting Colstrip early and this lower risk offsets the higher expected cost. It is worth noting this analysis does not include risk metrics on the future cost of capital or operations to operate the Colstrip plant through 2045. The other portfolios with direct comparison to the PRS with lower risk adjusted cost are both extending Colstrip beyond 2022 (#14 & #16) and two of the social cost of carbon assumption changes (#19 & #20). Given these results, there could be merit in using the average market (or lower) emissions rate for energy efficiency's social cost of carbon and potentially using market emissions for purchases/sales.

**Figure 12.16: Portfolio PVRR with Risk Analysis**



## Reliability Analysis

Each of the portfolios discussed in this chapter use planning margins to determine the quantity of new resources required to have a reliable system. In addition to planning margins, resources are also assigned a peak credit to estimate each resource's contribution to meeting the system planning margin. Many of the scenarios change existing resources and have high amounts of intermittent renewable energy so the peak credits assumed in this study may not apply when larger quantities of the resource are deployed or as Avista's resource mix changes such as any new contracted resources signed at the conclusion of the 2020 Renewable RFP. While it may be of interest to study the reliability by year of each of the portfolios studied in this IRP, the time needed to perform such an analysis would be unachievable in time to release the final IRP. Although certain portfolios and certain years warrant further study, Avista selected the scenarios and years shown in Table 12.23 to represent the appropriate areas of focus to determine the validity of the 16 percent planning margin and the peak credits used in this IRP.

Based on this reliability analysis, high renewable penetrations show either the planning margin is too low or peak credits are too high to maintain a reliable system. This is demonstrated by the 2040 analysis of the Portfolio 6 Clean Resource Plan with a 7.5 percent LOLP versus 5.4 percent in the PRS. Analysis shows if Colstrip is retained through 2030, the LOLP is slightly higher than the PRS is in 2030 without the plant. This demonstrates the utility will have similar, if not slightly improved, reliability without Colstrip in the portfolio. The last insight from this study is the RA program analysis. In this case, lowering the planning margin and changing peak credits to a regional level, would increase the LOLP. This analysis illustrates the level of market reliance created in the RA program would not be materially different than Avista's current assumption for market availability by only yielding a change in LOLP by 1 percent.

**Table 12.23: Portfolio Scenario's Reliability Analysis**

| Scenario | Year Studied | LOLP | LOLH | LOLE | EUE |
|---|---|---|---|---|---|
| 1- Preferred Resource Strategy | 2030 | 5.4% | 1.74 | 0.14 | 266 |
| 5- Clean Resource Plan (2027) | 2030 | 5.7% | 1.66 | 0.13 | 250 |
| 6- Clean Resource Plan (2045) | 2040 | 7.5% | 2.98 | 0.22 | 643 |
| 10- RA Program | 2030 | 6.4% | 2.67 | 0.20 | 510 |
| 16- Colstrip Exit 2035 | 2030 | 5.7% | 1.77 | 0.14 | 287 |

## Market Price Sensitivities

Another way to measure risk for each portfolio is to compare each portfolio's cost under different specific market conditions rather than relying on the stochastic study. This section compares each portfolio using the electric price scenarios described in Chapter 10. The scenarios include a deterministic study of the Expected Case (Sensitivity 1), while fixing the major risk variables such as hydro conditions and natural gas prices at expected averages. Sensitivity 2 is low natural gas prices; Sensitivity 3 is high natural gas prices; and Sensitivity 4 is the SCC as a tax across the entire Western Interconnect. Avista only conducted these market scenarios on portfolios with implications of changes in market prices to understand the sensitivity to major assumption changes.

The following tables show the change in cost (PVRR) and levelized emitted greenhouse emissions given these pricing sensitivities. Table 12.24 shows the cost changes compared to the Expected Case revenue requirements from the deterministic price forecast. In all portfolios, higher natural gas prices lead to higher costs, but portfolios with either more renewables or more coal are less cost sensitive. For the fuel price sensitivity with low natural gas prices, all portfolios have lower costs and portfolios with more coal and renewables are less cost sensitive. The SCC as a tax sensitivity changes the least cost portfolio results. In this case, a high price national carbon tax places the #5 and #6 Clean Resource Portfolios as the best options. From a greenhouse gas reduction perspective, the results perform as expected. Where higher natural gas prices occur, Avista's natural gas dispatch is reduced and where natural gas prices are lower, Avista's natural gas fleet operates more. The SCC scenario reduces all emissions as intended.

The second view of these market scenarios (Table 12.25) compares the alternative portfolios to the PRS to see if any portfolios perform better with these price sensitivities. In an alternative future, retaining Colstrip performs better in a higher natural gas price environment, but the Portfolio #3 Baseline 2 where no clean energy is added performs better in a lower natural gas price future, illustrating the cost of clean energy. In the case of the national SCC tax future, the Portfolio #5 2027 Clean Resource Plan performs best. The greenhouse gas analysis of this comparison shows marginal changes compared to the PRS except for when Colstrip exits the portfolio. The Portfolio #6 Clean Resource Plan (2045) scenario emissions are higher due to one Colstrip unit staying on-line as described earlier in this chapter. Otherwise emissions would be similar to Portfolio #5.

**Table 12.24: Change in Cost (PVRR) Compared to Expected Case**

| | Change in PVRR vs Expected Case | | | | Change in Levelized GHG MT vs Expected Case | | |
|---|---|---|---|---|---|---|---|
| Portfolio | High NG Prices | Low NG Prices | SCC | | High NG Prices | Low NG Prices | SCC |
| 1- Preferred Resource Strategy | 6.1% | -2.1% | 5.5% | | -18% | 16% | -18% |
| 3- Baseline 2 | 8.8% | -3.0% | 11.5% | | -18% | 17% | -18% |
| 5- Clean Resource Plan (2027) | 3.6% | -1.3% | -0.1% | | -18% | 16% | -18% |
| 6- Clean Resource Plan (2045) | 2.6% | -0.9% | 0.0% | | -12% | 6% | -25% |
| 15- Colstrip Exit 2025 | 5.7% | -2.0% | 5.7% | | -14% | 11% | -23% |
| 16- Colstrip Exit 2035 | 5.2% | -1.8% | 6.6% | | -11% | 5% | -30% |
| 17- Colstrip Exit 2045 | 4.8% | -1.7% | 7.3% | | -10% | 3% | -31% |

**Table 12.25: Levelized Greenhouse Gas Emissions vs. Expected Case**

| | Change in PVRR vs PRS | | | | Change in Levelized GHG MT vs PRS | | |
|---|---|---|---|---|---|---|---|
| Portfolio | High NG Prices | Low NG Prices | SCC | | High NG Prices | Low NG Prices | SCC |
| 3- Baseline 2 | 0.7% | -2.7% | 3.8% | | 1% | 1% | 1% |
| 5- Clean Resource Plan (2027) | 1.3% | 4.7% | -1.8% | | -1% | -2% | -1% |
| 6- Clean Resource Plan (2045) | 2.0% | 6.8% | 0.0% | | 33% | 13% | 13% |
| 15- Colstrip Exit 2025 | -0.1% | 0.4% | 0.4% | | 23% | 13% | 11% |
| 16- Colstrip Exit 2035 | -0.5% | 0.7% | 1.4% | | 59% | 32% | 25% |
| 17- Colstrip Exit 2045 | -0.8% | 0.8% | 2.1% | | 75% | 41% | 34% |

## Social Cost of Carbon Portfolio Optimization

The previous section comparing the portfolios to a future with the SCC as a national tax is interesting, but they may not lead to the best portfolio if the carbon tax is considered when optimizing the portfolio. Avista conducted an analysis to determine the optimal portfolio with this SCC assumption. In this case, the cost can be improved by 2.5 percent over the PRS and 0.8 percent better than Portfolio #5 with similar greenhouse gas emissions. The selected portfolio in this future is shown in Table 12.26 This portfolio uses 88 MW less natural gas than the PRS, 77 MW less solar and replaces the capacity with storage and wind generation in addition to higher amounts of energy efficiency.

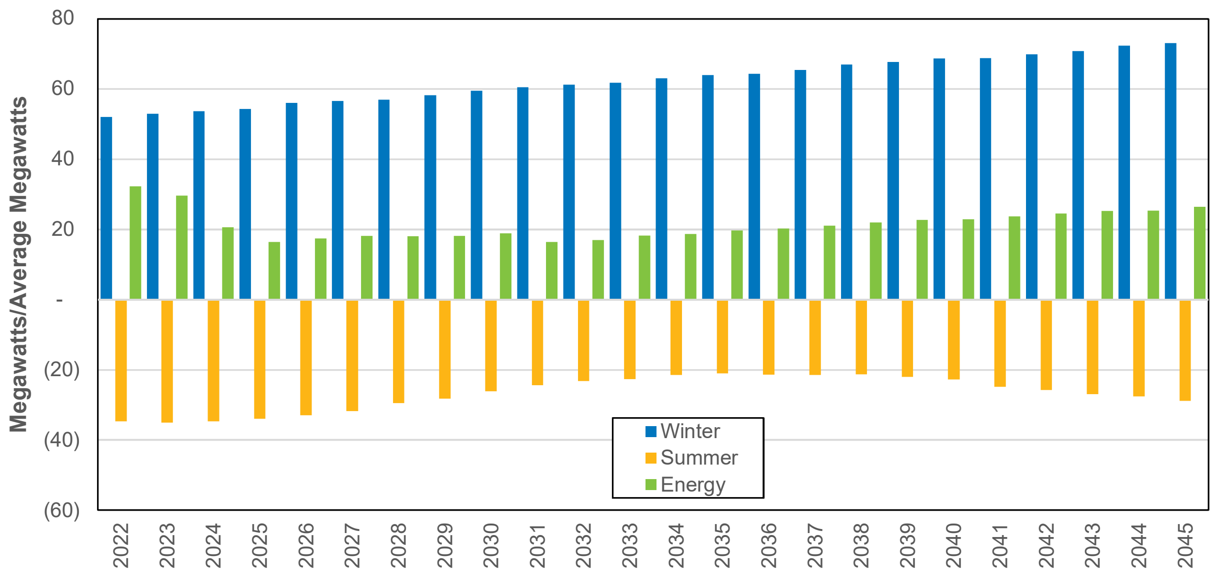
**Table 12.26: Optimized Social Cost of Carbon Future Portfolio**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| NW Off System Wind | 2023 | WA | 250 |
| Montana Wind | 2023 | WA | 100 |
| Montana Wind | 2025 | ID | 100 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Lancaster | 2026 | WA/ID | (257) |
| Montana Wind | 2026 | WA/ID | 200 |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Natural Gas Peaker | 2027 | WA/ID | 125 |
| Rathdrum Upgrade | 2029 | WA/ID | 5 |
| Natural Gas Peaker | 2031 | WA/ID | 55 |
| NW Hydro Slice | 2031 | WA/ID | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Solar w/ storage (4 hours) | 2035 | WA/ID | 100 |
| 4-hr Storage for Solar | 2035 | WA/ID | 50 |
| Natural Gas Peaker | 2036 | WA/ID | 66 |
| Solar w/ storage (4 hours) | 2037 | WA/ID | 111 |
| 4-hr Storage for Solar | 2037 | WA/ID | 56 |
| Solar w/ storage (4 hours) | 2039 | WA/ID | 100 |
| 4-hr Storage for Solar | 2039 | WA/ID | 50 |
| 4hr Lithium-Ion | 2040-2043 | ID | 176 |
| 4hr Lithium-Ion | 2040-2045 | WA | 824 |
| Boulder Park | 2040 | WA/ID | (25) |
| Solar w/ storage (4 hours) | 2041 | WA/ID | 100 |
| 4-hr Storage for Solar | 2041 | WA/ID | 50 |
| NW Off System Wind | 2044-2045 | ID | 227 |
| Distribution Scale 4hr Lithium-Ion | 2044-2045 | WA | 41 |
| NW Off System Wind | 2044 | WA/ID | 123 |
| Distribution Scale 4hr Lithium-Ion | 2045 | WA/ID | 9 |
| | | | |
| Supply-side resource net total (MW) | | | 2,456 |
| Supply-side resource total additions (MW) | | | 3,014 |
| Demand Response 2045 capability (MW) | | | 42 |
| Cumulative energy efficiency (aMW) | | | 152 |
| Cumulative summer peak savings (MW) | | | 177 |
| Cumulative winter peak savings (MW) | | | 133 |

## Climate Shift Portfolio Optimization

Avista conducted a study to determine the effects to and cost of the Avista portfolio with temperatures continuing to warm and changing Avista's historical load and hydro profiles. These changes are discussed earlier in Chapter 3 for load and Chapter 10 for hydro conditions. In summary, average annual loads levels do not significantly vary, but winter peak loads are 63 MW lower by 2045 and summer peak loads are 55 MW higher respectively. As for hydro conditions, Avista's production is expected to increase 15 aMW for the Clark Fork and Spokane River systems over the year with lower expected hydro production in the spring and summer and higher hydro production in the winter months. From a hydro production point of view, these changes will reduce the cost to serve customers. Figure 12.17 demonstrates the changes in Avista load and resource balance given these potential future weather conditions. The warmer temperatures on a net basis decrease the need for more winter resources but increase the need for summer resources. Even with these changes, by 2045 Avista will still require more winter capacity than summer capacity due to higher winter planning margins. The gap of seasonal need goes from 129 MW to 27 MW by 2045. Although, Avista may find with these weather changes a higher planning margin may be required for summer which could increase the need for summer resource acquisitions.

**Figure 12.17: Climate Shift Land and Resource Position Change**




Given these changes, a re-optimized portfolio was developed, and it is shown in Table 12.27. This portfolio is like the PRS, but with 43 MW less natural gas CTs, less solar generation, but the model selects more summer peaking energy efficiency programs. From a cost perspective, the average system costs decline by 1.1 percent over the 24-year period. Currently, Avista is unable to conduct a reliability study of the portfolio due to the complexity of the future distributions of hydro and load. Avista plans to conduct such a study in a future IRP.

**Table 12.27: Optimized Social Cost of Carbon Future Portfolio**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Montana Wind | 2023 | WA | 100 |
| Montana Wind | 2025 | WA | 100 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Lancaster | 2026 | WA/ID | (257) |
| Natural Gas Peaker | 2027 | ID | 84 |
| Natural Gas Peaker | 2027 | WA/ID | 85 |
| Montana Wind | 2028 | WA | 100 |
| NW Hydro Slice | 2031 | WA | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Rathdrum Upgrade | 2035 | WA/ID | 5 |
| Natural Gas Peaker | 2036 | ID | 36 |
| Kettle Falls Upgrade | 2036 | WA/ID | 12 |
| Rathdrum Upgrade | 2036 | WA/ID | 4 |
| Natural Gas Peaker | 2036 | WA/ID | 87 |
| Solar Photovoltaic | 2039-2040 | WA | 10 |
| Boulder Park | 2040 | WA/ID | (25) |
| Montana Wind | 2041 | WA | 100 |
| Solar w/ storage (4 hours) | 2042-2043 | WA | 222 |
| 4-hr Storage for Solar | 2042-2043 | WA | 111 |
| Liquid Air Storage | 2044-2045 | WA | 21 |
| Solar Photovoltaic | 2045 | ID | 5 |
| Solar Photovoltaic | 2045 | WA | 140 |
| | | | |
| Supply-side resource net total (MW) | | | 748 |
| Supply-side resource total additions (MW) | | | 1,306 |
| Demand Response 2045 capability (MW) | | | 64 |
| Cumulative energy efficiency (aMW) | | | 127 |
| Cumulative summer peak savings (MW) | | | 139 |
| Cumulative winter peak savings (MW) | | | 116 |

## Washington Maximum Customer Benefit Scenario

The maximum customer benefit scenario is a limited economic optimization study to help understand the cost of adding or removing resources from the portfolio to maximize non-energy benefits to Washington customers. Non-energy benefits include societal benefits such as health, local economic development, improved reliability, customer satisfaction among others. To better understand these societal benefits, Avista will identify these benefits or costs to its customers and system in the next IRP. While the customer value of non-energy benefits is yet to be determined, this scenario takes resource selection to the extreme where customers may benefit without fully taking cost into account.

This scenario assumes new resources provide economic benefits if located in Washington rather than other locations and ignores the cost of the selection decision. It only considers if the choice to locate a resource in Washington has more benefits than locating the resource in another state. In the end, the total portfolio cost of all the decisions could then be weighed against the theoretical customer benefit if known and the alternative resource portfolio such as the PRS.

This analysis also assumes customers benefits by maximizing local distributed energy resources (DERs) given the system's ability to integrate such systems. The analysis does not however determine if DERs provide benefit to customers from a reliability or resiliency point of view since Avista does not find additional DERs will increase customer reliability or resiliency unless these systems are behind the customer's meter under customer control or if a separately controlled micro grid facilitates system operations for a limited number of customers[3]. The scenario does not consider the additional distribution systems cost to facilitate a change in grid operations for supporting additional DERs.

The scenario takes two approaches for determining resource selection. The first approach adds demand-side resources such as energy efficiency and demand response to the maximum potential. The next step adds DERs to the maximum capability of the system such as customer owned solar and utility owned distributed solar and storage. The last step allows the PRiSM model to optimize the remaining portfolio with resource choices beneficial to Washington customers such as no new natural gas, resource acquisitions in Washington only and limiting REC purchases from Idaho customers. Table 12.28 shows a description of each of these assumptions and the potential customer benefits.

As previously discussed, the value to Avista's customers for the resource selection choices is not known, but the incremental value of all these choices are known compared to the PRS. The PVRR of costs increases from $8.70 billion in the PRS to $10.76 billion in this scenario. The energy rate also increases to customers from 12.7 cents/kWh to 16.6 cents/kWh in 2030. By 2045, this rate increases to 25.9 cents/kWh compared to the PRS's 17.3 cents/kWh. This scenario provides annual power cost risk reduction compared to the PRS by reducing annual standard deviation from $87 million to $73 million. In addition to this risk reduction, direct greenhouse gas emissions fall from 0.54 million metric tons in 2045 to 0.44 million metric tons with the scenario assumptions.

[3] See system reliability of DERs in chapter 8 for more information.

## Table 12.28: Customer Benefits

| Assumption | Energy/ Non-Energy Impacts | Public Health/ Environmental Health/ Cost and Risks | Reliability/ Resilience |
|---|---|---|---|
| Increased energy efficiency by 57 aMW through 2045[4]. | • Comfort & Productivity<br>• Increase local employment<br>• Customer engagement<br>• Acts as hedge against price volatility | • Customer health<br>• Reduction in employee sick days.<br>• Reduction of power plant emissions.<br>• Decreased water use | • Heat & cooling retention in outages.<br>• System and local peak reductions to lower new resource requirements. |
| Increase demand response by 124 MW[5] . | • Customer engagement and loyalty<br>• Increase local employment<br>• Bill savings for participation | • Unknown changes in regional power plant emissions. | • System and local peak reductions to lower new resource requirements.<br>• Aid in managing frequency and regulation |
| 400 MW of 8-hour duration distribution level storage by 2045. | • Potential for deferred distribution investments<br>• Increase local employment<br>• Increase local tax base | • Potential for reduced wildfire risk by temporarily shutting down Transmission lines. | • Potential for decreased power outage length in microgrid or behind meter installation. |
| 400 MW (AC) of utility distributed small scale solar. | • Increase local employment<br>• Increase local tax base | • Potential for regional power plant emission reductions. | • Benefits are yet to be determined. |
| 620 MW (AC) of roof-top solar[6] . | • Increase local employment<br>• Increase local tax base | • Potential for regional power plant emission reductions. | • Potential for customer reliability benefits if coupled with customer storage. |
| No new natural gas facilities[7]. | • Increase capital investment in other resources. | • Reduction of power plant emissions | • Less reliance on single natural gas supply line. |
| No hydro renewable energy credit transfers from Idaho customers. | • Increase local employment<br>• Increase local tax base | • Potential for regional power plant emission reductions. | • Benefits are yet to be determined. |
| No out of state renewables including solar, wind, or geothermal. | • Local job creation<br>• Increase tax base | • Benefits are yet to be determined. | • Benefits are yet to be determined. |
| No new nuclear resources. | • Elimination of nuclear waste storage | • Elimination of catastrophic failure risk | • Benefits are yet to be determined. |

[4] Assumes up to $1000 per MWh for avoided cost.
[5] Includes all demand response options under $1000 per kW-year.
[6] Modeled as utility scale rather than a load reduction using pricing for utility scale distributed solar.
[7] Includes upgrades to existing resources.

**Table 12.29: Optimized Social Cost of Carbon Future Portfolio**

| Resource Type | Year | State | Capability (MW) |
|---|---|---|---|
| Colstrip | 2021 | WA/ID | (222) |
| Small Scale Solar | 2022-2030 | WA | 403 |
| NW Wind | 2023 | WA | 143 |
| 8 hr Lithium-Ion (Distribution) | 2022-2030 | WA | 100 |
| Post Falls Upgrade | 2026 | WA/ID | 8 |
| Rathdrum Upgrade | 2026 | WA/ID | 5 |
| Kettle Falls Upgrade | 2026 | WA/ID | 12 |
| Liquid Air Storage | 2027 | WA | 110 |
| Natural Gas CT | 2027 | ID | 113 |
| Small Scale Solar | 2031-2040 | WA | 495 |
| 8 hr Lithium-Ion (Distribution) | 2031-2040 | WA | 200 |
| NW Hydro | 2031 | WA/ID | 75 |
| Northeast | 2035 | WA/ID | (54) |
| Natural Gas CT | 2036 | ID | 59 |
| Boulder Park | 2040 | WA/ID | (25) |
| Small Scale Solar | 2041-2045 | WA | 104 |
| 8 hr Lithium-Ion (Distribution) | 2041-2045 | WA | 100 |
| Liquid Air Storage | 2043-2045 | ID | 34 |
| Solar w/ storage (4 hours) | 2045 | WA | 100 |
| 4-hr Storage for Solar | 2045 | WA | 50 |
| | | | |
| Supply-side resource net total (MW) | | | 1,810 |
| Supply-side resource total additions (MW) | | | 1,509 |
| Demand Response 2045 capability (MW) | | | 179 |
| Cumulative energy efficiency (aMW) | | | 179 |
| Cumulative summer peak savings (MW) | | | 244 |
| Cumulative winter peak savings (MW) | | | 142 |

## Expected Case Portfolio Summary

A summary of the total new resources selected between 2022 and 2045 is shown in Table 12.30 for all portfolios using the Expected Case market forecast. In addition to this summary, all PRiSM models and summary information is available in Appendix I.

## Table 12.30: 2022-2045 Portfolio Selection Summary

| | 1- Preferred Resource Strategy | 2- Baseline 1 | 3- Baseline 2 | 4- Baseline 3 | 5- Clean Resource Plan (2027) | 6- Clean Resource Plan (2045) | 6b- Clean Resource Plan (2045) No Colstrip | 7- SCC Idaho | 8- Low Load Forecast | 9- High Load Forecast | 10- RA Market |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Washington** | | | | | | | | | | | |
| NG CT | 140 | 230 | 233 | - | 103 | - | - | 146 | 91 | 147 | 107 |
| Solar | 454 | - | - | - | 386 | 590 | 538 | 496 | 199 | 493 | 618 |
| Storage Added to Solar | 227 | - | - | - | 180 | 295 | 269 | 248 | 34 | 246 | 127 |
| Wind | 400 | - | - | - | 400 | 531 | 680 | 400 | 400 | 514 | 300 |
| Storage | 12 | 68 | 68 | - | 24 | 312 | 341 | 22 | - | 113 | - |
| Hydrogen | - | - | - | - | - | 75 | 75 | - | - | - | - |
| Other- (Clean Capacity) | - | - | - | - | 13 | 96 | 39 | - | - | 20 | - |
| Thermal Upgrade | 11 | 11 | 11 | - | 11 | 8 | 8 | 11 | 11 | 14 | 11 |
| Hydro | 75 | 49 | 49 | - | 75 | 49 | 120 | 49 | 75 | 75 | 75 |
| DR Capability | 56 | 104 | 97 | 3 | 56 | 104 | 104 | 57 | 49 | 49 | 34 |
| EE- Winter Capacity | 86 | 85 | 86 | 86 | 89 | 92 | 92 | 86 | 86 | 86 | 85 |
| EE- Summer Capacity | 92 | 92 | 92 | 92 | 100 | 101 | 101 | 93 | 92 | 92 | 96 |
| | | | | | | | | | | | |
| **Idaho** | - | - | - | - | - | - | - | - | - | - | - |
| NG CT | 195 | 143 | 142 | - | 176 | - | - | 134 | 157 | 223 | 178 |
| Solar | 34 | - | - | - | 389 | 559 | 552 | - | 36 | - | 34 |
| Storage Added to Solar | 17 | - | - | - | 94 | 204 | 201 | - | 18 | - | 17 |
| Wind | - | - | - | - | 194 | 269 | 234 | - | - | - | - |
| Storage | 10 | 20 | 33 | - | - | 20 | 41 | 10 | - | 28 | 49 |
| Hydrogen | - | 50 | 50 | - | - | 232 | 245 | 50 | - | 50 | - |
| Other- (Clean Capacity) | - | - | - | - | 7 | 20 | 20 | - | - | - | - |
| Thermal Upgrade | 6 | 6 | 6 | - | 6 | 4 | 4 | 6 | 6 | 7 | 6 |
| Hydro | - | 26 | 26 | - | - | 94 | 23 | 26 | - | - | - |
| DR Capability | 15 | 18 | 20 | 2 | 16 | 20 | 20 | 19 | 8 | 16 | 19 |
| EE- Winter Capacity | 24 | 29 | 24 | 24 | 31 | 37 | 37 | 38 | 24 | 24 | 24 |
| EE- Summer Capacity | 13 | 13 | 13 | 13 | 26 | 30 | 27 | 35 | 13 | 13 | 20 |

| | 11- Electrification 1 | 12- Electrification 2 | 13- Electrification 3 | 14- 2x SCC | 15- Colstrip Exit 2025 | 16- Colstrip Exit 2035 | 17- Colstrip Exit 2045 | 18- Clean Energy Delivered Each Hour | 19- SCC on Net P/S | 20- Use Avg Mrkt for EE SCC | 21- Maximum WA Customer Benefit |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Washington** | | | | | | | | | | | |
| NG CT | 255 | 214 | 255 | 128 | 140 | 133 | 138 | 83 | 164 | 141 | - |
| Solar | 277 | 536 | 425 | 444 | 454 | 454 | 453 | 854 | 120 | 455 | 1,120 |
| Storage Added to Solar | 138 | 268 | 212 | 222 | 227 | 227 | 227 | 402 | 60 | 228 | 50 |
| Wind | 894 | 628 | 796 | 400 | 400 | 400 | 400 | 700 | 616 | 400 | 143 |
| Storage | 486 | 279 | 474 | 23 | 12 | 22 | 13 | 512 | 22 | 12 | 510 |
| Hydrogen | 397 | 84 | 199 | - | - | - | - | - | - | - | - |
| Other- (Clean Capacity) | 20 | 20 | 20 | - | - | - | - | 100 | - | - | - |
| Thermal Upgrade | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Hydro | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 49 |
| DR Capability | 49 | 49 | 49 | 57 | 56 | 56 | 56 | 56 | 49 | 56 | 180 |
| EE- Winter Capacity | 118 | 114 | 114 | 88 | 86 | 86 | 86 | 86 | 85 | 81 | 117 |
| EE- Summer Capacity | 121 | 97 | 99 | 94 | 92 | 92 | 92 | 92 | 92 | 79 | 231 |
| | | | | | | | | | | | - |
| **Idaho** | - | - | - | - | - | - | - | - | - | - | - |
| NG CT | 120 | 161 | 120 | 194 | 195 | 208 | 145 | 201 | 178 | 198 | 172 |
| Solar | - | - | - | 34 | 34 | 34 | 34 | 34 | - | 35 | - |
| Storage Added to Solar | - | - | - | 17 | 17 | 17 | 17 | 17 | - | 17 | - |
| Wind | - | - | - | - | - | - | - | - | - | - | - |
| Storage | 26 | 16 | 26 | 29 | 10 | 24 | 24 | 10 | 34 | 10 | 34 |
| Hydrogen | 100 | 50 | 100 | - | - | - | - | - | - | - | - |
| Other- (Clean Capacity) | - | - | - | - | - | - | - | - | - | - | - |
| Thermal Upgrade | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Hydro | - | - | - | - | - | - | - | - | - | - | 26 |
| DR Capability | 19 | 18 | 19 | 18 | 15 | 9 | 9 | 15 | 15 | 19 | 19 |
| EE- Winter Capacity | 32 | 29 | 32 | 25 | 24 | 22 | 21 | 24 | 29 | 25 | 24 |
| EE- Summer Capacity | 15 | 13 | 15 | 13 | 13 | 11 | 11 | 13 | 13 | 13 | 13 |

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# 13. Energy Equity

Washington's Clean Energy Transformation Act (CETA) requires utilities to ensure an equitable distribution of energy and non-energy benefits and a reduction of burdens on vulnerable populations and highly impacted communities. Avista has a history of demonstrated commitment to easing the energy burden for vulnerable customers through several programs and community partnerships. This is evident from the Company's robust outreach program, with multiple modalities, designed to equip customers with conservation education information and resources along with raising awareness of assistance programs among vulnerable customers including low-income, senior and disabled. Avista's commitment is also demonstrated through bill assistance and weatherization programs in place to help customers with affordability and energy efficiency. The equity components of CETA provides the Company with an opportunity to dig deeper into its commitment to ensure safeguards are in place for marginalized groups of customers impacted by Avista resource plan, giving these customers a voice and access to benefits as we move toward a cleaner power supply.

In addition to specific initiatives for vulnerable customers, Avista has many other indirect programs to serve all customer groups including park development, the energy pathway career experience program for high school students, wildlife land purchases, transportation electrification and public access to Avista recreational properties to name a few. The CETA guidelines will expand these efforts with enhanced funding for additional low-income programs, higher energy efficiency targets and other specific targeted programs and projects developed with input from the Equity Advisory Group discussed in this chapter.

**Section Highlights**

- A preliminary methodology for determining vulnerable communities within Avista's service territory is complete.
- A baseline process and analysis are complete to assess energy use, energy burden, air emissions and community reliability and resiliency.
- Avista is forming an Equity Advisory Group in early 2021 to enhance the Vulnerable Population and Highly Impacted Community Action Plan.
- Avista plans to engage the public about the needs of both vulnerable and highly impacted communities with the assistance of the Equity Advisory Group for refining the future planning process.

Avista is in the early stages of developing a plan for addressing the new CETA equity goals. The Company started by conducting an analysis to identify potential geographically based communities using vulnerable population data. The analysis compares energy use in the communities to other customers along with the percent of annual income consumed by energy costs. Lastly, the Company compared reliability and resilience data of these communities to customers outside of these areas. These analyses provided an initial point of reference to measure success of future programs and to understand whether the correct geographic areas or population groups identified as vulnerable are accurate. This will be an ongoing analysis to identify the locations of Vulnerable Populations in our service area as demographics shift. At this time, the analysis and requirements discussed in this section only apply to Washington

State, but future IRPs may expand this work to include Idaho customers.

## CETA Requirements

Specifically, CETA Section 1(6) requires:

> *The legislature recognizes and finds that the public interest includes, but is not limited to:*
>
> - *The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities;*
> - *long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks;*
> - *and energy security and resiliency.*
>
> *It is the intent of the legislature that in achieving this policy for Washington, there should not be an increase in environmental health impacts to highly impacted communities.*

The requirements are further defined for integrated resource planning in Section 14*(k):*

> *An assessment, informed by the cumulative impact analysis conducted under section 24 of this act, of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security and risk;*

An Equity Advisory Group is being formed to help define the customers qualifying as vulnerable populations. This group will develop an outreach plan to engage with these customer groups to determine the energy needs of these communities and to develop a long-term strategy with the interim steps the utility will take to equitably distribute energy and non-energy benefits and reduce burdens for highly impacted communities and vulnerable populations.

The two types of qualifying customer communities for equity considerations under CETA are Highly Impacted Communities and Vulnerable Populations. The Highly Impacted Communities are communities *designated by the department of health based on cumulative impact analyses or a community located in census tracts that are fully or partially on "Indian country" as defined in 18 U.S.C. Sec. 1151*. At the time of this IRP, the Department of Health had not released these areas[1]. Avista has two known qualifying census tracks within its Washington service territory that are identified as “Indian country” including the Colville and Spokane reservations.

The second qualifying group for equity considerations are Vulnerable Populations. These are *communities that experience a disproportionate cumulative risk from environmental burdens due to: (a) Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and (b) Sensitivity factors, such as low birth weight and higher rates of hospitalization.* Avista assumes the identification of vulnerable populations will be determined by the utility with

[1] Avista received the list of Highly Impacted Communities from the Department of Health on March 16, 2021. Avista is reviewing the selected areas for inclusion in the 2023 IRP.

guidance by the Equity Advisory Group using the above factors.

This IRP is limited in the inclusion of these public interest requirements mainly due to the newly developing public interaction process, as well as the complexity and timing of the CETA rulemaking process. Additional energy efficiency for customers is not included in this IRP to avoid double-counting due to the inclusion of non-energy benefits and the economic test analysis for the social cost of carbon. In addition, the Company is committed to an energy efficiency pilot project in 2021 to help vulnerable populated communities along with continuing to provide and expand current efficiency and economic programs to its low-income communities. Lastly, Avista is committed to conducting an analysis for nonenergy impacts of generation alternatives for the next IRP with the aid of a specialist in this area.

## Community Identification

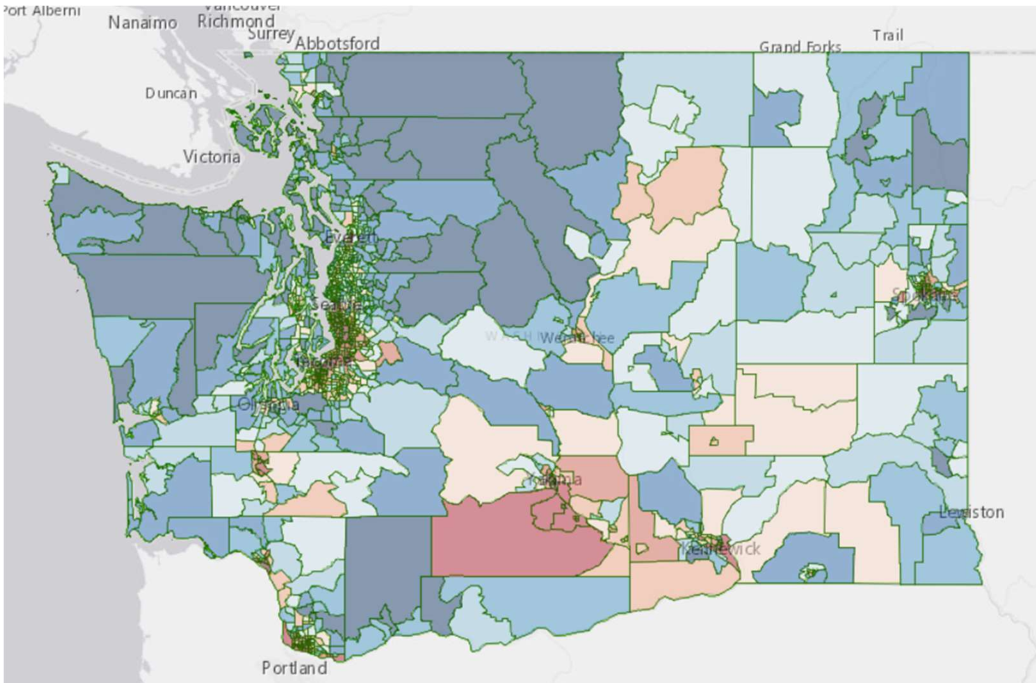
Early in this IRP development, Avista found it beneficial to start a process to distinguish vulnerable populations based upon the CETA definition. The challenge with this requirement that remains unclear is whether these populations are based on geographic or individual considerations.

A focus on geographic considerations allows the Company to resolve potential issues with projects improving reliability/resiliency or economic stimulus from the location of future power generation. It can also help identify equity concerns related to emissions. The downside to this methodology, and benefit of identifying these communities on an individual basis, allows for customers who live in areas not determined to be vulnerable to also be considered for programs. Regardless of their geographic location, customers who meet the vulnerable definition would still be eligible for income-qualified assistance programs.

At this time, and subject to future agreement by the Equity Advisory Group, Avista chose to use a geographic method to identify these communities. Avista leveraged the Environmental Health Disparities Map[2] analysis conducted by the Washington Department of Health (DOH). Avista chose this methodology as it coincides with CETA's definition of Vulnerable Populations. The DOH map divides Washington into local areas using Federal Information Processing Standards (FIPS) codes; which are generally areas within counties or cities representing neighborhoods. Figure 13.1 illustrates the boundaries of these areas based on the scoring of the final composite score between pollution burden and population characteristics (used for illustration purposes only).

[2] https://fortress.wa.gov/doh/wtn/wtnibl/

**Figure 13.1: Washington Department of Health Disparities Map**




A rating between 1 and 10 is given for Pollution Burdens and Population Characteristics in each of these areas. The ratings are based on a score of 5 being median within the state and the higher or lower scores are based on a percentile of the population. Avista chose to use the Population Characteristics metrics as these are defined with a scoring of 1 to 10 for both Sensitive Population considerations including cardiovascular disease and low birth weight infants as well as Socioeconomic Factors such as poor educational attainment, housing burden, linguistic isolation, poverty, race, transportation expense and unemployment. These definitions of scoring are consistent with the definition of Vulnerable Populations from CETA. Other considerations to enhance these selections will be discussed and considered with the Equity Advisory Group.

The next step in identifying Vulnerable Populations is to align the DOH health disparities map with Avista's service territory using its Geographic Information System (GIS). Avista chose to include any area with a score of 8 or higher in either the Sensitive Population or Socioeconomic Factor rating as a Vulnerable Population. This score indicates a population base with characteristics exceeding the $70^{th}$ percentile in the category. Avista plans to refine this selection with guidance from the Equity Advisory Group. Avista expects this will be an ongoing requirement as local demographics change. The vulnerable areas are shown in Figure 13.2 for eastern Washington and in Figure 13.3 for the Spokane area.

## Figure 13.2: Vulnerable Population Areas within Avista Service Territory

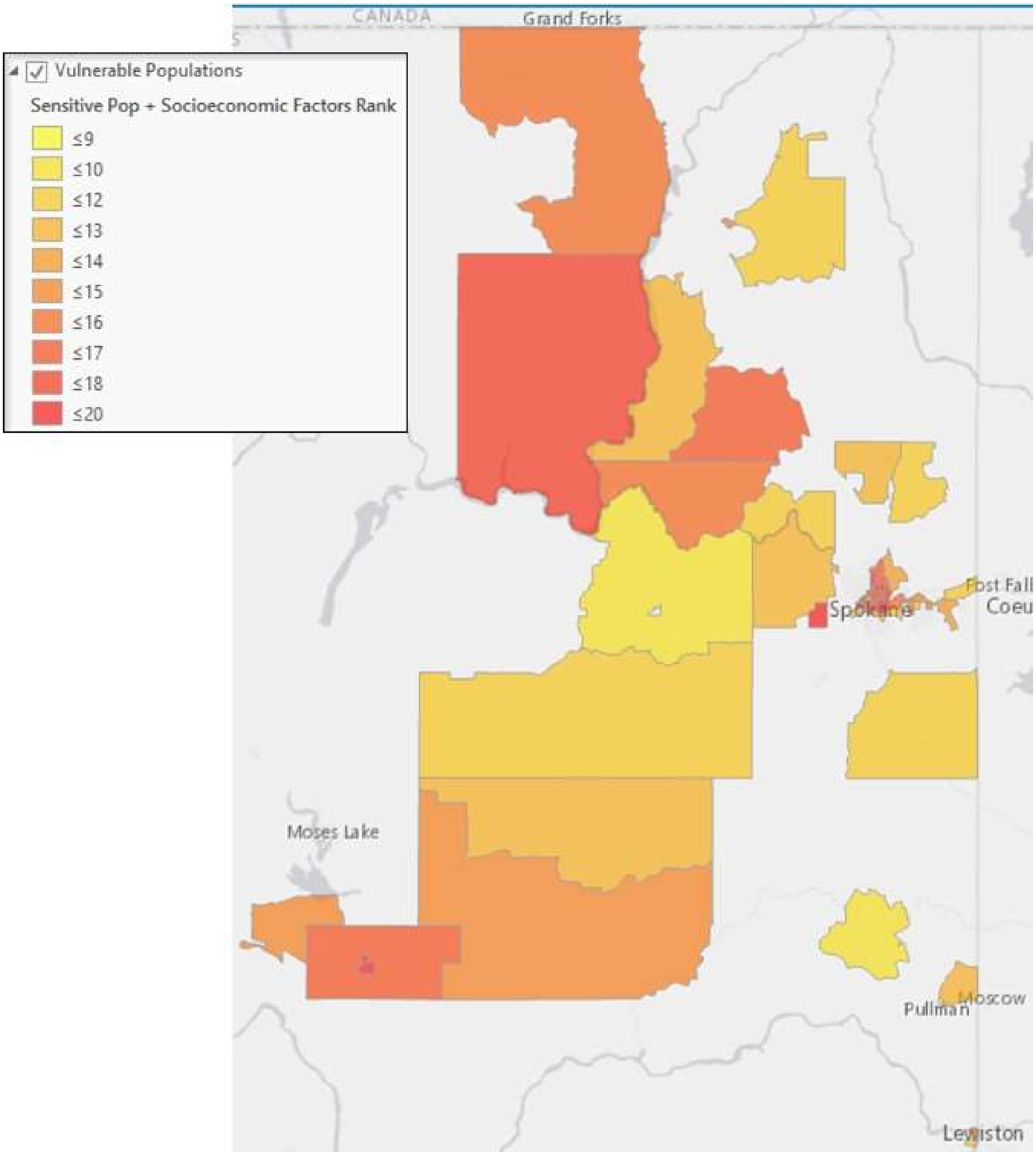
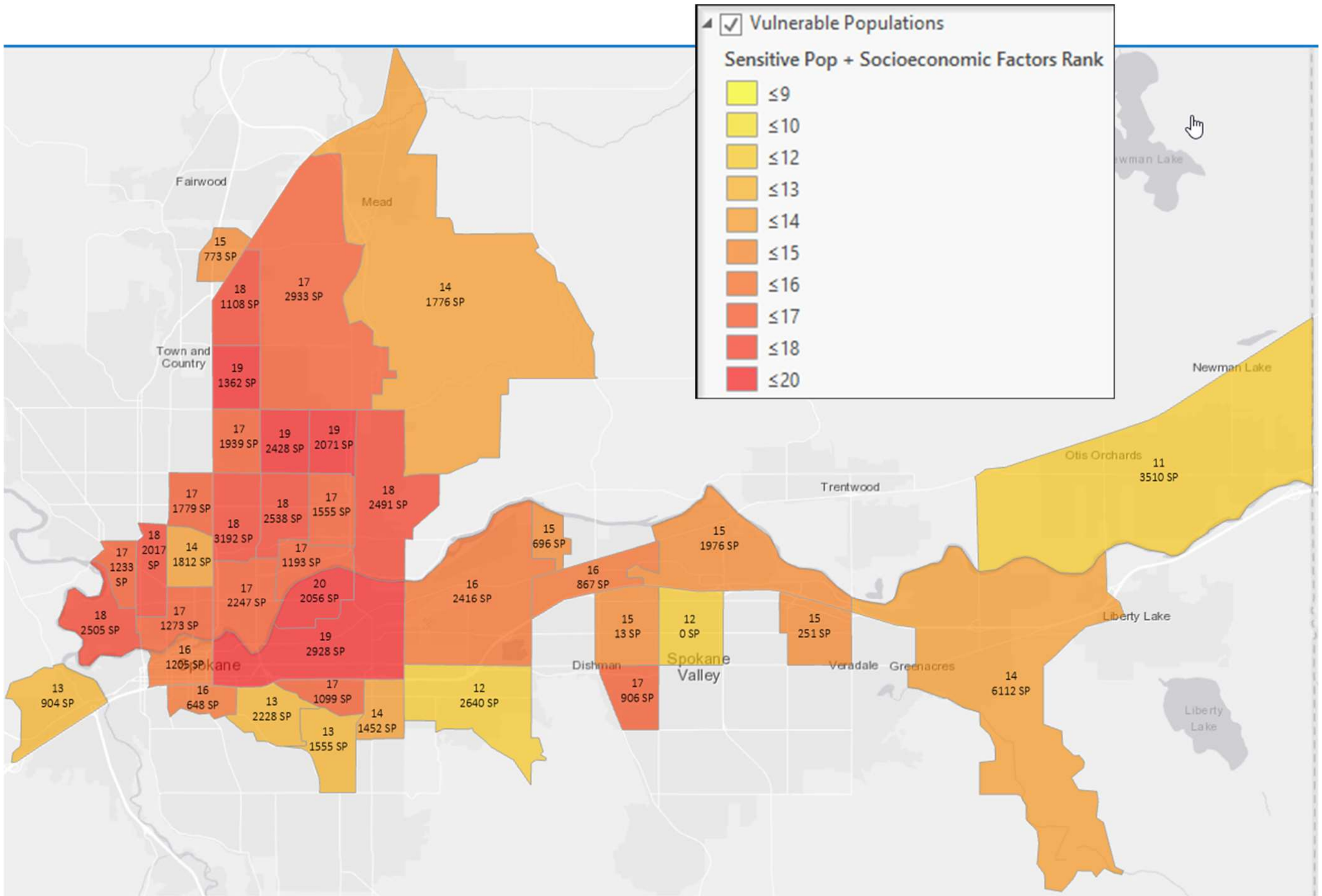


**Figure 13.3: Vulnerable Population Areas within Spokane Area**




Avista’s Washington electric service territory serves either the entirety or a portion of 145 communities using the FIPS code methodology. Of Avista’s 145 communities, 35 (24 percent) score 8 or higher in the Sensitive Population category and 55 (38 percent) have Socioeconomic Factors communities scores of 8 or higher. When combining either area with a score of 8 or higher, 67 (46 percent) of communities within Avista’s service territory qualify as Vulnerable Populations. This compares to the statewide statistics of 43 percent of the 1,458 communities qualifying as vulnerable. Avista’s service territory has a higher density of lower Socioeconomic areas with a score of 8 or higher (28 percent) than the state average but higher Sensitive Population scores (30 percent) than the state average. Given the large amount of areas qualifying, the Equity Advisory Group may need to consider narrowing the qualifications for consideration.

Table 13.1 compares the number of areas qualifying as vulnerable or Highly Impacted based on different metrics of scoring from the DOH methodology. The table shows how many areas would be affected if levels other than scores of 8 or above were used.

**Table 13.1: Percent of Service Territory Area Above the DOH score**

| Score | Socioeconomic | Sensitive Populations | Either Category |
|---|---|---|---|
| 6+ | 45% | 60% | 68% |
| 7+ | 33% | 49% | 57% |
| 8+ | 24% | 38% | 46% |
| 9+ | 13% | 22% | 29% |
| 10 | 6% | 12% | 16% |

Another method might consider total score of both categories. This methodology could narrow the areas to high levels of both areas of focus rather than just one area. While there are many ways to use this data and potentially other data sources, Avista plans to address the final selection of a methodology with guidance from the Equity Advisory Group.

# Baseline Analysis

Avista developed a baseline analysis of the selected areas to determine where there are significant differences in energy use, energy cost, reliability, resiliency and higher densities of locational power plant emissions. These analyses can be useful for multiple purposes. The first benefit can be using this baseline to measure success of future programs to ensure a positive change. The other benefit of the baseline could be to provide additional criteria for the Equity Advisory Group to narrow or expand areas for inclusion in future program development.

## Energy Use, Cost and Burden Analysis

The results of the usage and energy burden analysis are available in Tables 13.2 and 13.3 using data between 2015 and 2019. The income estimates use census level income information for each area. The usage and utility bill costs are from Avista's customer database. The first table of electric only customers show the areas with DOH scores above 8 use slightly less electric energy then other areas; therefore, their bills are also lower. However, as a comparison of energy bills as a percent of income, these areas spend more of their income on energy, which is known as energy burden. What is not distinguished in this information is whether other heating fuels influence these amounts, along with home types, square footage or home location which may be included in future analyses.

**Table 13.2: Electric Energy Use and Energy Burden Comparison**

| Area | Fuel Type | Monthly Energy Use (Kwh) | Monthly Avg Bill | Annual Household Income | % Income or Energy Burden |
|---|---|---|---|---|---|
| Vulnerable Population Areas | Electric | 997.7 | $98.40 | $42,730 | 2.8% |
| Other Areas | Electric | 1,009.7 | $100.20 | $58,834 | 2.0% |

Table 13.3 includes analysis on customers with both electric and natural gas usage as part of the calculation as it is more likely to estimate a total household energy cost compared to income and the home types are likely to be similar, meaning a lower probability of multi-family houses

with more than two units. In this scenario, energy use as a percent of income is higher. It is noteworthy this total measurement shows higher cost percent of income, but not over a typical 6 percent threshold for energy burden. Some of these communities may have other reasons to identify them with higher ratings using the DOH metric other than low income.

**Table 13.3: Electric & Natural Gas Energy Use and Energy Burden Comparison**

| Area | Fuel Type | Energy Use | Average Monthly Bill $ | Annual Household Income $ | Income % or Energy Burden |
|---|---|---|---|---|---|
| Vulnerable Population Areas | Electric | 820.4 kWh | $80.40 | | |
| Other Areas | Electric | 875.5 kWh | $84.50 | | |
| | | | | | |
| Vulnerable Population Areas | Natural Gas | 51.6 Dth | $47.40 | | |
| Other Areas | Natural Gas | 62.3 Dth | $55.90 | | |
| | | | | | |
| Vulnerable Population Areas | Total | | $127.80 | 44,889 | 3.4% |
| Other Areas | Total | | $140.30 | 68,250 | 2.5% |

While the summary level information is useful, drilling down into the individual areas is just as important. Figure 13.4 illustrates the electric only customer scoring for areas with DOH scores 8 and above. In this case the darker color areas have higher energy cost compared to income; but as a total area no electric only customers exceed 4.27 percent of energy cost compared to income. Other studies show many individual customers exceed these amounts for energy burden.

The combined electric and natural gas customer information is in Figure 13.5. This figure, with the inclusion of total energy and total energy cost, shows areas within Spokane and Pullman whose costs exceed the 6 percent threshold. This information may help identify areas where the Equity Advisory Committee may want to focus programs for energy assistance or targeted energy efficiency programs.

## Figure 13.4: Electric Customer Energy Cost versus Income

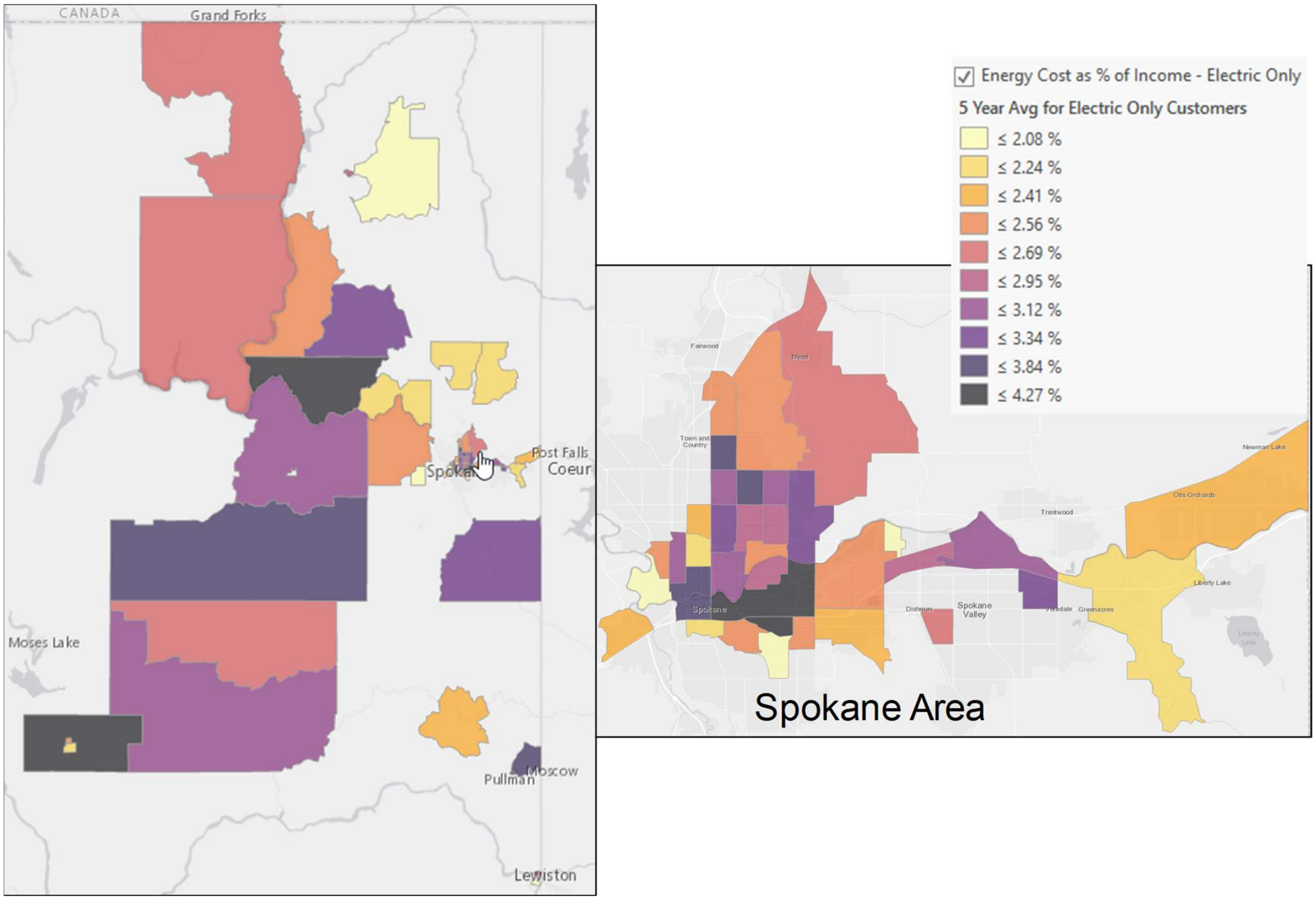
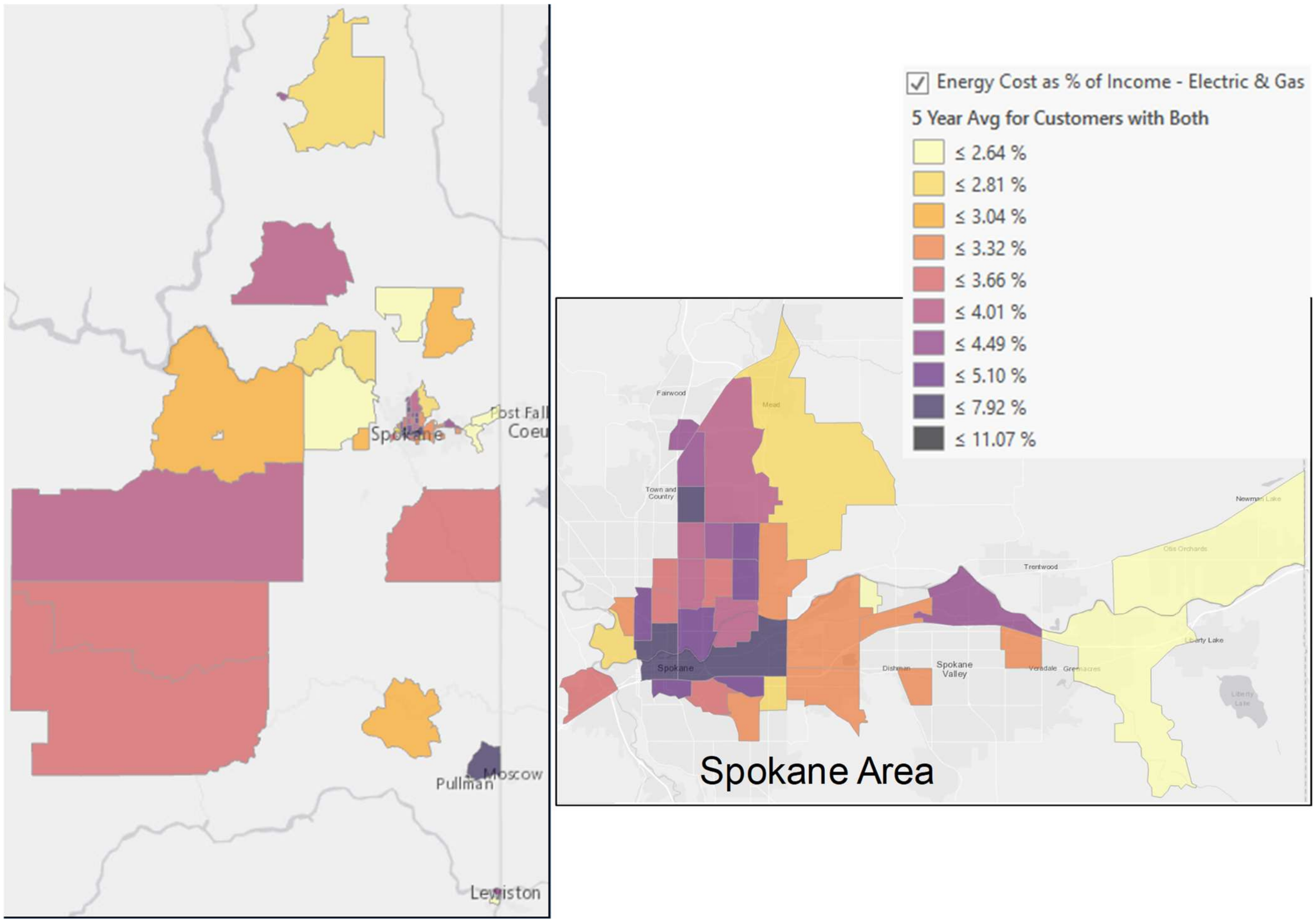


**Figure 13.5: Electric/Natural Gas Customer Cost versus Income**




## Reliability and Resiliency Analysis

As with the initial analysis regarding cost for the selected communities, Avista looked at reliability to determine a baseline of areas within the service territory with reliability or resiliency issues. The Company views resiliency and reliability as related terms. Measuring resiliency as when an outage occurs and considers how long it takes to return service to customers. If reliability is 100 percent, the system is also resilient as there are no outages to return service from. The data presented in this section look at occurrences of outages and the time to return to service for areas with the DOH score of 8 or above versus other customers.

Overall, Avista found that areas in the vulnerable areas have shorter outages over the five-year period between 2015 and 2019. This is shown in Figure 13.6 for the Customer Average Interruption Duration Index (CAIDI). CAIDI is a measure of resiliency to determine the average number of minutes customers are offline during an outage. In the case of this historical period, the duration is only slightly shorter. Response times for vulnerable customers could be shorter due to the fact many are located in suburban areas where Avista is able to respond to outages faster than in rural areas.

Figure 13.6: CAIDI Historical Comparison

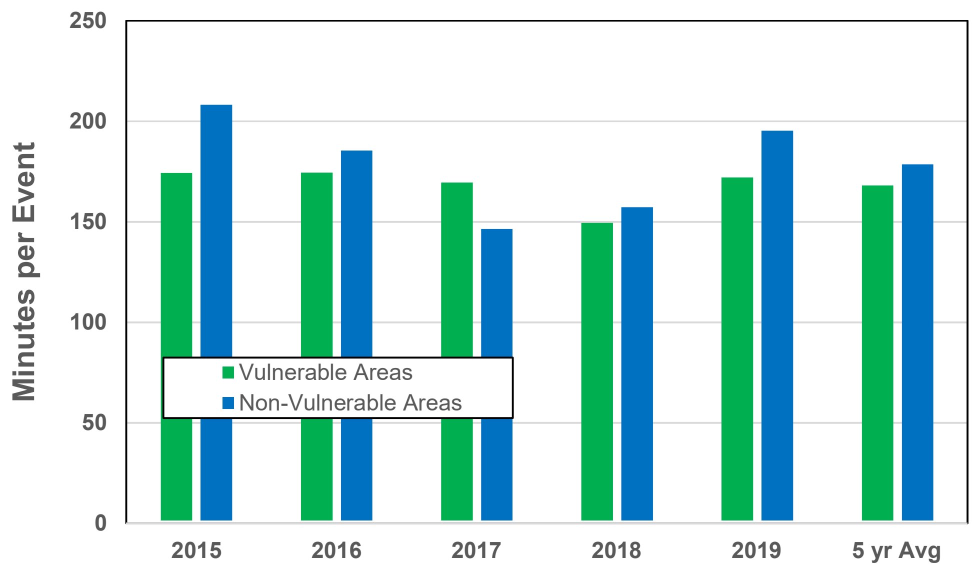
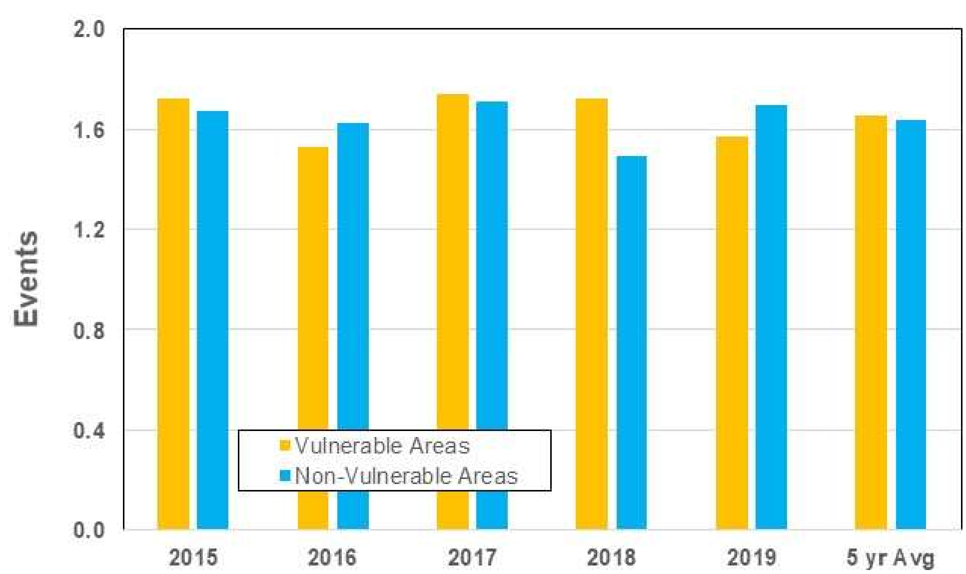



Figure 13.7 shows the Customers Experiencing Multiple Interruptions (CEMI) metric and it is a measure of reliability. This metric indicates the number of outages on average that occurred in these areas over the historical period. These results show there are slightly more outages in the vulnerable areas then other areas of the system. Additional research of these results showed the number of outages for vulnerable areas is likely due to a higher number of outages in rural areas. In this case, vulnerable rural areas have 40 percent more outages (about one more per year) than other rural areas, and the time to restore rural vulnerable customers is 11 percent longer or 25 minutes with the extra time needed to get crews out to the outage locations.

Figure 13.7: CEMI Historical Comparison



The detailed outage rates for the five-year average period is shown in map form in Figure 13.8 for the resiliency measurement of CAIDI and in Figure 13.9 for the reliability measurement CEMI. It is clear in the map that rural areas to the north of Spokane are at a potential disadvantage compared to other customers for reliability due to the local environment, distance between customers and more extreme weather. Avista anticipates this exercise may help determine the issues customers face in these areas and could lead toward identifying solutions to resolve these concerns.

**Figure 13.8: 5-year Average CAIDI Map**

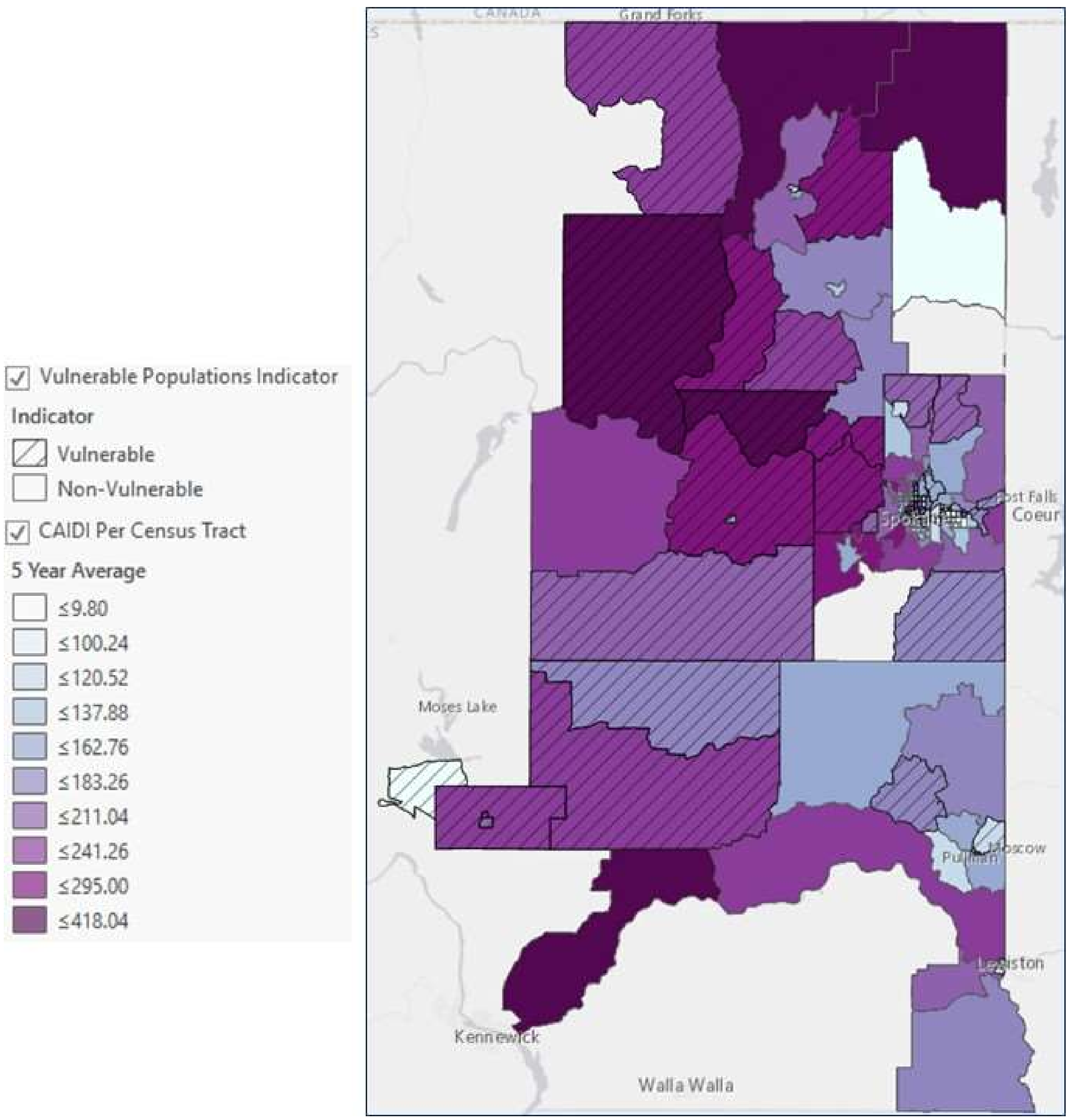
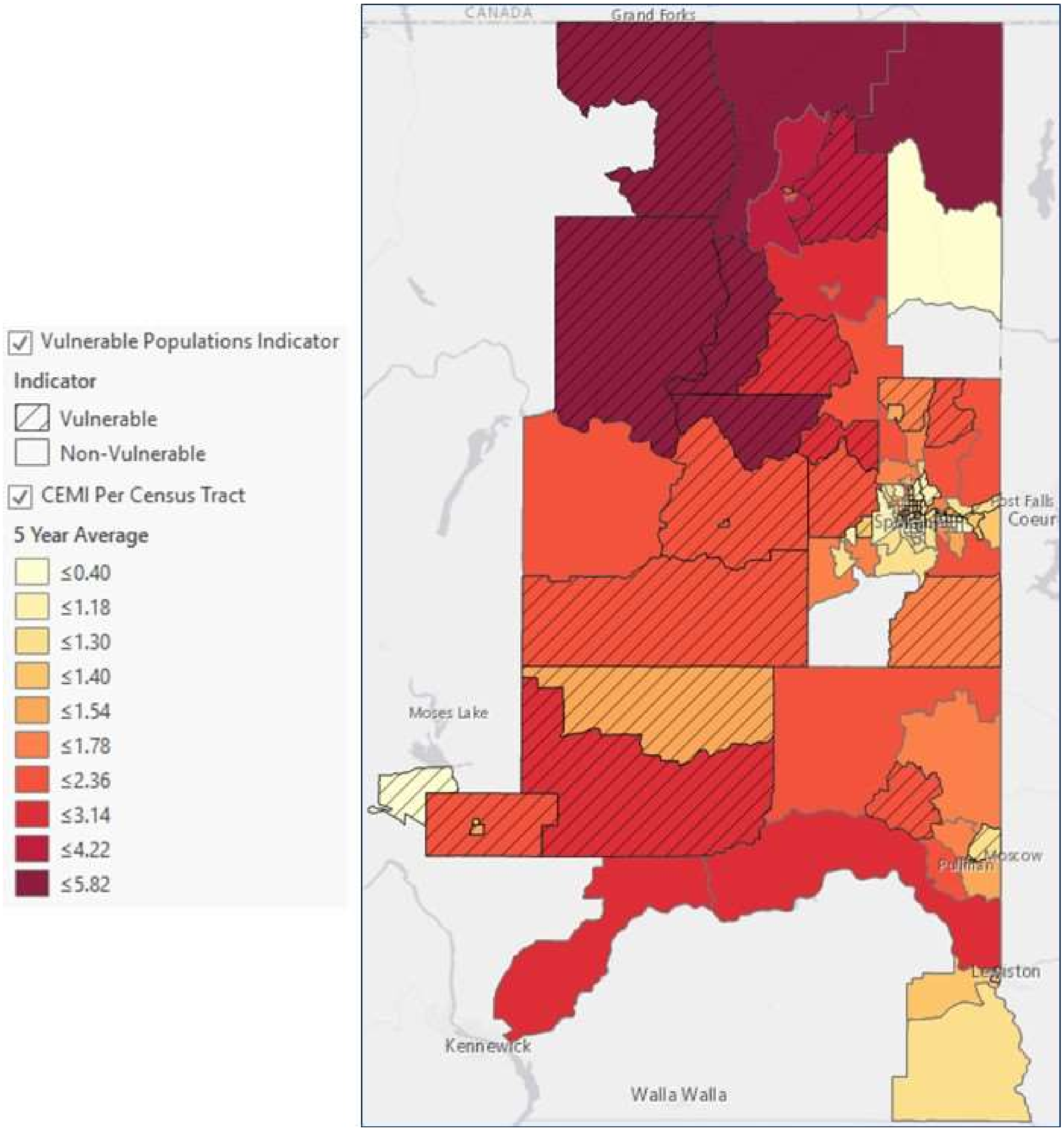


**Figure 13.9: 5-year Average CEMI Map**




## Power Plant Locational Discussion

CETA objectives regarding equity provisions highlight concerns about the location of power plants in areas with Vulnerable Populations and Highly Impacted Communities. Many of the Avista-owned and contracted power plants are within the boundaries of the identified communities with scores of 8 or higher as described above. Locating power plants in these areas may have both positive and negative effects. Positive effects include economic opportunities for job creation, added local tax base, greater energy security, and the potential for increased resiliency. The negative impacts can be from air emissions, increased traffic from construction and operations and visual concerns from transmission lines or other power facilities. Table 13.4 highlights the facilities Avista owns or contracts[3] for in the areas identified with DOH scores above 8.

**Table 13.4: Existing Facilities within Identified Areas**

| Facility | Fuel Type | Control | County |
|---|---:|---:|---:|
| Little Falls | Water | Own | Stevens/Lincoln |
| Long Lake | Water | Own | Spokane |
| Nine Mile | Water | Own | Spokane |
| Upper Falls | Water | Own | Spokane |
| Monroe Street | Water | Own | Spokane |
| Northeast | Natural Gas | Own | Spokane |
| Boulder Park | Natural Gas | Own | Spokane |
| Adams Neilson | Solar | Contract | Adams |
| Rattlesnake Flat | Wind | Contract | Adams |
| Boulder Park Solar | Solar | Own | Spokane |
| Upriver | Water | Contract | Spokane |

Even if a facility is not located in a vulnerably populated area, air emissions may have effects on neighboring communities. Avista's thermal facilities in the State of Washington meet state level requirements for each emission type in their air permits, such as particulate matter and nitrogen oxides. In addition, the retirement of two natural gas-fired facilities located in Washington are being planned within the time horizon of this IRP; specifically, Northeast by 2035 and Boulder Park by 2040. Both facilities are "peaking" plants meaning they only run when demand is extremely high and therefore have low annual emissions. The Northeast facility is limited to 100 hours of operation per year and often runs less than 100 hours. Additional information regarding emissions from Avista facilities is available in Appendix I. A future analysis of the economic and health impacts of these facilities is being planned for the next IRP as part of the non-energy impacts study for supply-side resources.

While IRPs are useful planning documents, actual resource selection and locational analysis is determined through the Request for Proposal (RFP) process. Avista's 2020 Renewables RFP included additional scoring criteria for projects enhancing the economic viability of identified vulnerable communities and projects located within the Avista Transmission system that may enhance energy security and resiliency.

## Vulnerable Population Action Plan

Avista's Vulnerable Population Action Plan supports the objectives of the equitable distribution of benefits and the reduction of health, economic and/or environmental burdens with the following tactics:

1) Form an Equity Advisory Group to guide and prioritize community and individual outreach and engagement and to assist with the establishment of indicators and strategies.

[3] Avista is only highlighting facilities generating greater than 5 MW in Washington State in this table.

2) Develop targeted energy assistance programs and funding for low income customers in identified areas.
3) Conduct a non-energy impacts study for supply and demand-side resources.

## Equity Advisory Group

Requirement: **WAC 480-100-655 Public participation in a clean energy implementation plan (CEIP).**

*WAC 480-100-655 (2) – A utility must maintain and engage an external equity advisory group of stakeholders to advise the utility on equity issues including, but not limited to, vulnerable populations designation, equity indicator development, data support and development, and recommended approaches for the utility's compliance within WAC 480-100-610 (4)(C)(i).*

- *Participation to include environmental justice and public health advocates, tribes, and representatives from highly impacted communities and vulnerable populations in addition to other relevant groups.*
- *Meet regularly with Equity Advisory Group during the CEIP development and implementation.*
- *Must provide reasonable advance notice of all equity advisory group meetings.*
- *CEIP draft review with advisory groups 2 months before filing with the Commission.*

**Intent:** to advise the utility on equity issues including, but not limited to, vulnerable population designation, equity indicator development, data support and development, and recommended approaches for the utility's compliance with WAC 480-100-610 (4)(c)(i). The utility must encourage and include the participation of environmental justice and public health advocates, tribes, and representatives from highly impacted communities and vulnerable populations in addition to other relevant groups.

Avista is forming an Equity Advisory Group (EAG) responsible to review the indicators and vulnerable populations identified by the previously described analysis in this section along with the DOH's cumulative impact analysis in order to identify weighting factors for compliance with WAC 480-100-610 (4)(c)(i). Additionally, the EAG will help guide the design of the Vulnerable Population outreach and engagement that will be used to distinguish and prioritize additional indicators and solutions, as well as the development of the Clean Energy Implementation Plan (CEIP). The EAG's work will be conveyed to the Technical Advisory Committee (TAC), the Energy Assistance Advisory Group (EAAG) and Energy Efficiency Advisory Group (EEAG) for use in their respective work.

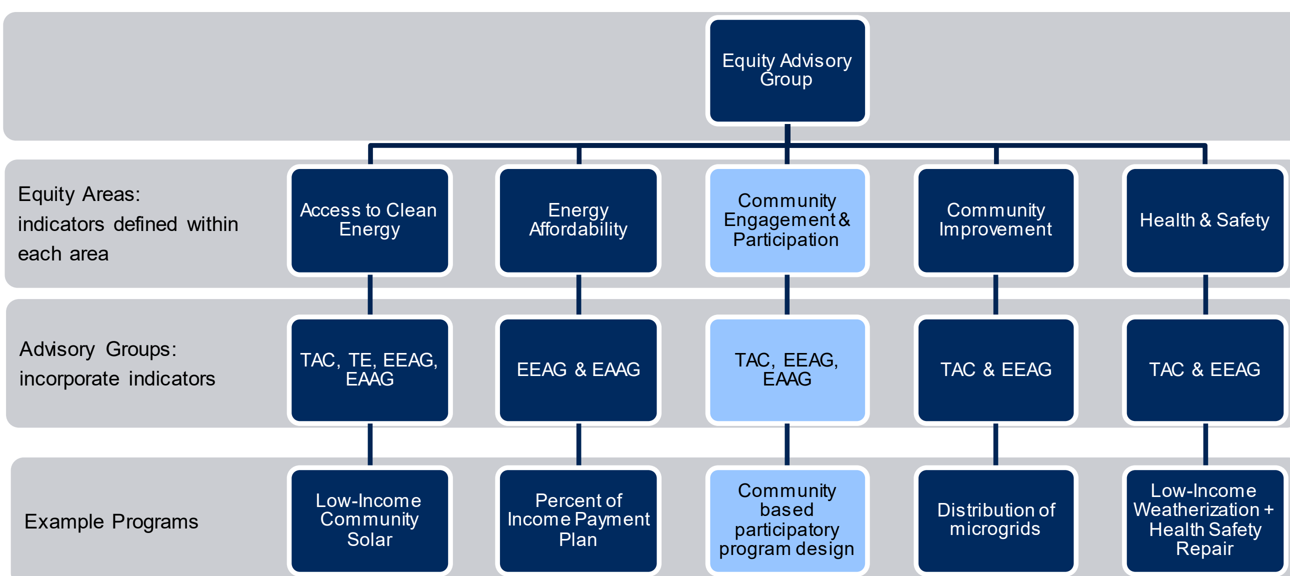
Avista began preliminary work to determine a framework including membership for our EAG towards the end of 2020. Along with official representation from stakeholders from the community, clean energy, equity and public health, the Company is committed to obtaining representation for individuals from highly impacted communities. The anticipated DOH analysis will be critical for identifying the communities for which representation will be sought. Avista plans to engage community organizations who reach across the service territory as well as tribal organizations, but also include specific individuals within identified communities. It is anticipated the group will start small and will expand as the group gains shared understanding and determines direction and approach.

Prior to recruitment, and with guidance from the EAAG and community partners, Avista will design the role and expectations for the advisory group participants including the group's objectives and meeting frequency.

Avista plans to have the first Equity Advisory Group meeting in the first half of 2021. With an advisory group in place, the work will begin to refine the Vulnerable Population determinates based on the preliminary analytical work conducted by Avista and the DOH. Also, for 2021, the group will advise the Company on an outreach and engagement campaign to obtain information and determine needs of vulnerable customers for each community. Avista staff are researching and learning about processes and methods that have demonstrated results in effective outreach and engagement in other jurisdictions that will be helpful for the design and facilitation of a needs assessment of the targeted vulnerable populations. In addition to helping to confirm health, economic and/or environmental burdens, partnership with local public health organizations that have experience in successfully engaging marginalized, hard to reach populations will be essential.

This group will also contribute to the review of future IRPs, Clean Energy Action Plans and Clean Energy Implementation Plans. One area of focus will discern how to implement equity-based solutions while maintaining traditional least cost planning methodologies. Figure 13.10 illustrates how the Equity Advisory Group's work will inform the Company's other stakeholder groups while supporting community engagement and participation for the IRP's TAC process.

**Figure 13.10: Equity Advisory Group Chart**



# 14. Action Items

The IRP is an ongoing and iterative process balancing regular publication timelines while pursuing the best resource strategy for the future as the market, laws and customer needs evolve. The biennial publication date provides opportunities to document ongoing improvements to the modeling and forecasting procedures and tools, as well as enhance the process with new research as the planning environment changes. This section provides an overview of the progress made on the 2017 and 2020 IRP Action Plans and discusses plans for the 2023 IRP. This discussion reviews the past two IRPs due to only officially filing the 2020 IRP in Idaho, but not Washington. Avista considers the Action Plan for the 2020 IRP to also apply to this plan and intends to complete these items for the 2023 IRP and beyond.

## Summary of the 2017 IRP Action Plan

The 2017 Action Plan included three categories: generation resource related analysis, energy efficiency and transmission planning.

### Generation Resource Related Analysis

- Continue to review existing facilities for opportunities to upgrade capacity and efficiency.

  *Avista included an upgrade to the Post Falls facility based on economics of the upgrade in the 2020 IRP. Avista also included options for Rathdrum and Kettle Falls facilities. This IRP also evaluated the potential for significant upgrades at Long Lake, Monroe Street, Upper Falls and Cabinet Gorge. After additional review, Avista no longer considers these upgrades to qualify for Washington's clean energy requirements as these changes are beyond efficiency improvements and make substantial changes to capacity and water use. Although, Avista may still consider these plans to continue to enhance existing resources where possible to help meet future resource needs. Additional information regarding resource upgrades is included in Chapter 9.*

- Model specific commercially available storage technologies within the IRP; including efficiency rates, capital cost, O&M, life cycle and the ability to provide non-power supply benefits.

  *This IRP includes a range of storage resource technologies and durations as well as considering Avista-owned and PPA options. The IRP studied the reliability benefits of storage options with different durations. Avista included pumped hydro, liquid-air and lithium-ion technologies. During this IRP cycle, energy storage costs and technologies continued to change and develop. Avista will continue to analyze new storage options and costs as a resource in addition to continuing its process in optimizing the transmission and distribution systems to utilize storage when beneficial to the local system. A full list of the storage resource options and descriptions is available in Chapter 9.*

- Update the TAC regarding the EIM study and Avista plan of action.

*Avista's officers approved joining the EIM on April 15, 2019 and the Company plans to go live with the EIM on March 2, 2022. Avista shared this update at the fifth TAC meeting of the 2020 IRP on October 15, 2019. As part of joining the EIM, Avista expects to spend approximately $32 million to enter the market and an additional $4.0 million each year thereafter. The EIM will require at least 17 new employees to support ongoing market operations. The benefits of the EIM range from $2 to $12 million per year but are likely to be nearly $6 million per year. The EIM presentation shared with the 2020 IRP TAC is available in Appendix A of the 2020 IRP.*

- Monitor regional winter and summer resource adequacy, provide TAC with additional Avista LOLP study analysis.

*The 2020 IRP's second TAC meeting included a presentation regarding Avista's resource adequacy methodology and preliminary results of the system for 2030. Avista also presented the TAC with ELCC calculations for each resource used for resolving Avista capacity shortfalls. In the sixth TAC meeting, Avista shared results from the PRS's reliability analysis. The 2020 IRP Appendix A includes the slides presented to the TAC and Chapters 9 and 11 include results from Avista's reliability studies. Avista used this same analysis for the 2021 IRP.*

- Update the TAC regarding progress on the Post Falls Hydroelectric Project redevelopment.

*Avista concluded in the 2020 IRP PRS analysis that the most cost-effective plan for Post Falls was to redevelop the site by 2027 to maintain its Spokane River License. The project scope includes replacing turbines and generators with more efficient units that will generate additional capacity and energy. Avista compared this option against replacing the equipment with similar sized technology. Avista shared this progress at the second, fifth and sixth TAC meetings of the 2020 IRP. Those presentations are available in the 2020 IRP Appendix A. Avista includes this upgraded resource in its resource balance in the 2021 IRP.*

- Perform a study to determine ancillary services valuation for storage and peaking technologies using intra-hour modeling capabilities. Further, use this technology to estimate cost to integrate variable resources.

*Avista conducted studies regarding the benefits of pumped hydro storage and flow batteries and shared results with the 2020 TAC at its fifth meeting. Avista believes this analysis is important to meet future needs of the system and it requires tools to correctly identify the costs and benefits. Avista plans to conduct additional analyses once sub-hourly modeling is available in the ADSS system with the assistance of intra-hour reserve requirements provided by EnerNex Consulting. Avista has not completed this work and it will be an Action Item for the 2023 IRP.*

- Monitor state and federal environmental policies affecting Avista's generation fleet.

  *Avista continues to monitor and participate in the development of state and federal environmental policies affecting Avista's generation fleet. Updates about the ongoing impacts and changes to these policies are available in Chapter 4.*

## Energy Efficiency and Demand Response

- Determine whether to move the Transmission and Distribution (T&D) benefits estimate to a forward-looking value versus a historical value.

  *Avista uses the Northwest Planning and Conservation methodology for evaluating the benefits of energy efficiency to the Transmission and Distribution system. The discussion of this methodology is in Chapter 5 of this plan.*

- Determine if a study is necessary to estimate the potential and cost for a winter and summer residential demand response (DR) program and along with an update to the existing commercial and industrial analysis.

  *Applied Energy Group (AEG) conducted a DR potential study for Avista's service territory. The study included residential, commercial and industrial programs. AEG presented the DR programs at the third TAC meeting in April 2019 for the 2020 IRP and the September 2020 meeting for the 2021 IRP. Chapter 6 includes an overview of these DR programs. Avista identified many of these programs as cost effective and they are included in the PRS described in Chapter 11.*

- Use the utility cost test (UCT) methodology to select conservation potential for Idaho program options.

  *Avista included the UCT methodology for evaluating energy efficiency in Idaho. Avista continues to use the TRC method in Washington. Details about energy efficiency cost methodologies are in Chapter 5.*

- Share proposed energy efficiency measure list with Advisory Groups prior to CPA completion.

  *Avista provided a list of energy efficiency measures for the IRP to TAC members on its website. This information is also available in Appendix I.*

## Transmission and Distribution Planning

- Work to maintain Avista's existing transmission rights, under applicable FERC policies, for transmission service to bundled retail native load.

  *Avista has maintained its existing transmission rights on its system and any transmission system it purchases rights from to serve native load.*

- Continue to participate in BPA transmission processes and rate proceedings to minimize costs of integrating existing resources outside of Avista's service area.

    *Avista continues to actively participate in BPA transmission rate proceedings.*

- Continue to participate in regional and sub-regional efforts to facilitate long-term economic expansion of the regional transmission system.

    *Avista staff participates in and leads many regional transmission efforts including the newly formed Northern Grid, which replaced Columbia Grid and the Northern Tier Transmission Group.*

- IRP and T&D planning will coordinate on evaluating opportunities for alternative technologies to solve T&D constraints.

    *Avista conducted a pilot project to determine if a distribution project could be modeled within PRiSM to co-optimize the power system along with the needs of the T&D system. Chapter 8 of the 2020 IRP discusses this analysis. Avista plans to continue this analysis in future IRPs. The 2021 IRP concluded that no projects met the criteria for inclusion in the IRP.*

## 2020 IRP Two Year Action Plan

Avista's 2020 PRS provided direction and guidance for the type, timing and size of future resource acquisitions in 2020. The 2020 Action Plan highlights the activities for development in the 2021 IRP. These activities include resource acquisition processes, regulatory filings and analytical efforts for the next IRP. This Action Plan includes input from Commission Staff, Avista's management team and members of the TAC. Avista is expanding this Action Items section to be included in the 2023 IRP for any uncompleted items from the 2020 IRP due to the short 2021 IRP schedule.

### Resource Acquisition Action Items

- Determine the plan for Long Lake Development expansion. This includes a filing with the appropriate agencies to determine if the project upgrades identified in this plan meet CETA requirements. Begin discussions with agencies who are part of the Spokane River license to discuss expansion options. Lastly determine if the project should include a new second powerhouse, a new combined powerhouse including existing generation capacity or leave the project unchanged. This Action Item will begin in 2020 and will be an ongoing item for the 2021 IRP. Any updates will be shared with the TAC when available.

    *Avista completed a legal review of the requirements to qualify the Long Lake Development expansion as a qualifying clean energy resource and does not believe this upgraded resource would qualify. Therefore, Avista will not pursue this resource expansion option at this time. If Long Lake expansion clearly qualifies as a qualifying future resource, Avista may include it as a new resource option in the future.*

- Avista identifies long duration pumped hydro storage as the capacity resource to meet future long duration deficits. Avista will continue engaging with pumped hydro developers regarding this resource type. Avista will investigate the potential for pumped hydro in or near its service territory for long-term potential. This Action Item will continue through future IRPs and TAC updates will be provided as new information is available.

  *The Company met with developers of regional pumped hydro projects on multiple occasions. The 2021 IRP resource options include the most viable pumped hydro options along with the costs and timelines as informed by these discussions. Long duration pumped hydro is likely available later than the timelines used in the 2020 IRP and at higher costs. Although other shorter duration pumped hydro projects are expected to be feasible to meet the capacity needs of the Company, these projects will be further evaluated to determine if they are economic in a future RFP process.*

- The resource analysis identifies a natural gas CT to replace resource deficits if pumped hydro is not feasible to meet the 2026 shortfall. Avista will conduct transmission and air permitting studies to prepare for this contingency. Avista expects this process to take at least two years.

  *Avista is currently investigating the transmission availability for natural gas-fired CT and/or storage resource options. It has filed an interconnect study request and it is at queue number 109. Air permitting studies have not been initiated at this time.*

- Avista will consider releasing a renewables RFP in the second quarter of 2020 for new resources meeting the CETA requirements. Projects are preferred to be online by 2022 and 2023, but other start dates may be acceptable depending on cost effectiveness and other considerations, including final CETA rule making requirements.

  *Avista issued an RFP on June 26, 2020 and concluded the process in October 2020. It is currently negotiating with short listed bidders. Any contracts signed may alter the near-term results of the PRS and the updated PRS will be made available after this IRP is filed.*

- To meet the January 2026 capacity shortfall and to validate Avista's preferred choice of long duration pumped hydro to meet this deficit, Avista may release a capacity RFP as early as 2021. Avista will evaluate the appropriate timing of this RFP in 2020. Potential projects will need to have a clear ability to serve Avista's customers during winter peaks. Avista anticipates existing resources, DR, renewable, thermal, and storage resources to respond.

  *Avista is still committed to releasing a capacity RFP in the near future subject to the adjusted needs resulting from the acquisition from the 2020 Renewable RFP.*

- This IRP forecasts the Northeast CT will retire in 2035. Avista will continue to evaluate this retirement date as it operates the facility and will provide the TAC with additional analysis and information regarding the preferred retirement date.

  *Avista is maintaining the 2035 retirement date for the 2021 IRP. In addition to retiring the Northeast CT, the Company's engineering department has also identified Boulder Park to likely retire by 2040.*

- This IRP's economic analysis determines Colstrip is best to shut down after 2025 compared to alternative scenarios, such as a 2035 closure or operating a single unit through 2035. As discussed in Chapter 12 – Portfolio Scenarios, the inclusion or exclusion of the social cost of carbon regarding Colstrip does not change the economically optimal closure date. Avista will continue evaluating this analysis and work with the other owners for the best course of action to meet state objectives and the needs of all of Avista's customers.

  *Avista's analysis for the 2021 IRP is consistent with the 2020 IRP analysis. Although the 2021 IRP indicates earlier removal than the 2020 IRP. The IRP analysis is consistent with the plant's exit from the Company's resource portfolio by the end of 2025, if not sooner, provided agreement can be reached with the owners of Units 3 and 4.*

## Analytical and Process Action Items

- Avista will continue to study the costs of intermittent resources and understand the financial benefits and capability of resources such as storage, natural gas-fired peakers and hydroelectric resources to meet the intermittent characteristics of variable resources. Studies will continue when sub-hourly modeling is functional in Avista's ADSS software. Avista's timeline for this analysis is to be completed in 2021.

  *As discussed in the response to the 2017 IRP, Avista is still developing new assumptions for valuing the sub-hourly costs and benefits of resources. Avista is optimistic it will have updated analysis completed in time for inclusion in the 2023 IRP. A public process to evaluate these costs will begin in the second quarter of 2021*

- Avista intends to include greenhouse gas emissions from resource construction, manufacturing and operations where available. This research will begin in 2020 and will be shared with the TAC members at a future meeting. Avista prefers this to be a collaborative effort with the TAC members as there is clearly no accepted standard for this area of research.

  *Avista included estimates of these emissions in its resource portfolio optimization using data from the National Renewable Energy Lab (NREL). A resources option spreadsheet including these emissions estimates was provided to the TAC members and is as also available on the Company's IRP website and Appendix I. Further, Avista included these assumptions with its PRiSM model that is available for review on the Company's IRP website and Appendix I.*

- The time and resource commitment to produce the electric market price forecast is extensive and difficult to complete internally. To make the best use of staff time and customer's resources, Avista will investigate early in 2020 whether using a third-party forecast, along with an internally developed dispatch model, is a better approach to inform the resource planning effort.

  *Avista used an internally developed market price forecast for the 2021 IRP. While Avista has concerns with continued staffing for this function, it did not have time to introduce a new process or partner between the 2020 and 2021 IRP filing requirements and will reevaluate this need for the 2023 IRP.*

- Washington State will issue rules for CETA and IRP planning over the next two years. Avista will be an active participant in this rulemaking process. The timeline is 2020-2023.

  *Avista participated in both Commerce and Washington Utility and Transportation Commission processes for CETA rulemaking and has implemented guidance for developing the 2021 IRP from these processes as they became available.*

- Avista will continue to support and participate in regional resource adequacy discussions and market developments by the Northwest Power Pool and the CAISO respectively. Avista will report back to the TAC when further information is available.

  *Avista actively participates in the regional resource adequacy effort including both the trial program over the summer of 2020 and the development of a future program. Further, it has conducted a scenario analysis in this IRP to identify the benefits of this future program. The Company is committed to participating in this regional program if there is support to implement it.*

## 2021 IRP Action Items

Due to the short period between the 2020 IRP and this IRP, the Company considers all incomplete Action Items from the 2020 IRP to continue as Action Items for this IRP. In addition to the 2020 IRP Action Items that are still in process, the Company identified the following items for the 2023 IRP.

- Investigate and potentially hire a consultant to develop both a hydro and load forecast to include a shift in climate in the Inland Northwest. This analysis would include a range in new hydro conditions and temperatures so the Company can utilize the new forecast for resource adequacy planning and baseline planning.

- Investigate streamlining the IRP modeling process to integrate the resource dispatch, resource selection and reliability verification functions.

- Study options for the Kettle Falls CT regarding potential reductions of the natural gas supply in winter months. The Company will investigate alternatives for this resource including fuel storage, retirement or relocation of the asset.
- Determine how to best implement the Washington Commission's strong encouragement

under WAC 480-100-620 (3) regarding distribution energy resource planning as a separate process or in conjunction with the 2025 IRP.

- Form an Equity Advisory Group to ensure a reduction in burdens to vulnerable populations and highly impacted communities and to ensure benefits are equitably distributed in the transition to clean energy in the state of Washington. This group will provide guidance to the IRP process on ways to achieve these outcomes.

- Avista will conduct an existing resource market potential to estimate the amount and timing of existing resources available through 2045.

- Conduct further peak credit analysis to understand the reliability benefits of all resources including demand response options with different duration and call options of the wide range of DR program options.

- Avista will partner with a third-party consultant to identify non-energy impacts that have not historically been quantified for both energy efficiency and supply side resources.

- Formalize the process for public to submit IRP-related comments and questions and for Avista to share responses to those requests.

- Develop a transparent methodology to include pricing data and consider available options for new renewable generation and energy storage options.

# 15. Washington Clean Energy Action Plan

Avista will file an amended Clean Energy Action Plan with the Washington Utility and Transportation Commission after any resource acquisition is complete from the 2020 Renewable RFP. No contracts were signed from the 2020 RFP in time to be included in this Clean Energy Action Plan.

On May 7, 2019, the Clean Energy Transformation Act (CETA) was signed into law committing Washington to an electricity supply free of greenhouse gas emissions by 2045. Consequently, each utility must incorporate the social cost of greenhouse gas emissions as a cost adder for all relevant inputs when developing IRPs, Clean Energy Action Plans (CEAP) and evaluating and selecting resource options. RCW 19.280.030 states that for an Investor-Owned Utility, the CEAP must (a) identify and be informed by the utility's ten-year cost-effective conservation potential assessment; (b) if applicable, establish a resource adequacy requirement; (c) identify the potential cost-effective demand response and load management programs that may be acquired; (d) identify renewable resources, non-emitting electric generation and distributed energy resources that may be acquired and evaluate how each identified resource may be expected to contribute to meeting the utility's resource adequacy requirement; (e) identify any need to develop new, or expand or upgrade existing bulk transmission and distribution facilities; and (f) identify the nature and possible extent to which the utility may need to rely on alternative compliance options, if appropriate.

Avista's 10-year CEAP is a lowest reasonable cost plan of resource acquisition given societal cost, clean energy and reliability requirements. Avista developed this CEAP in conjunction with its Technical Advisory Committee with the intent to meet the capacity, energy and clean energy needs of both Idaho and Washington. The resources described in this plan are specific to the Washington portion of Avista's system needs in compliance with CETA. The discussion of the plan below describes the important considerations as required by the WUTC. Details regarding the methodology and assumptions regarding this plan are found within the chapters of the 2021 IRP. This CEAP will be the basis for the upcoming 2021 Clean Energy Implementation Plan (CEIP).

Table 15.1 illustrates annual capacity additions of all planned resources, including demand response and energy efficiency, for 2022 through 2031.

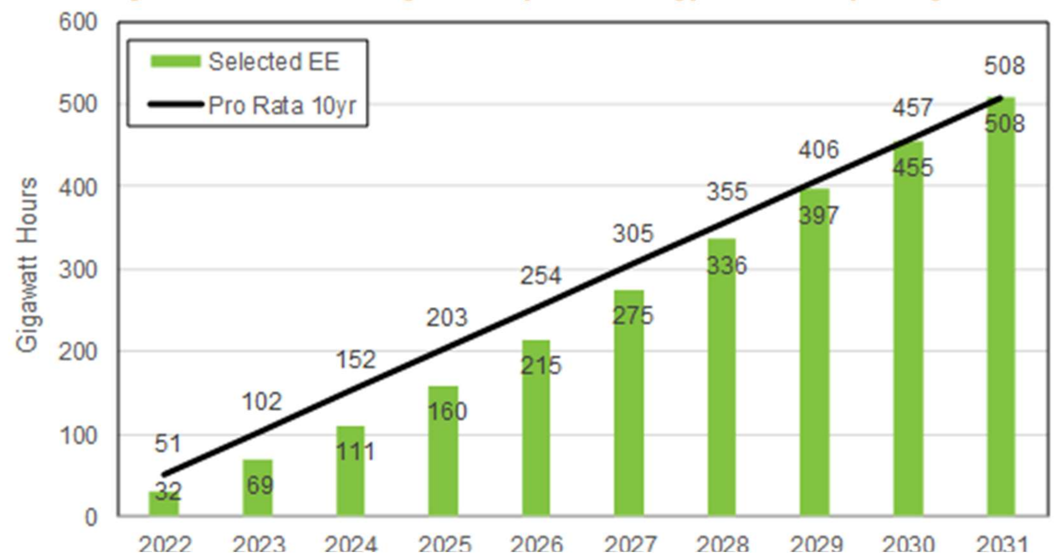
## Energy Efficiency Savings

Avista plans to acquire 508 GWh of cumulative energy efficiency over the next 10 years based on this IRP analysis. This represents 61.3 aMW when accounting for transmission and distribution line loses. These programs reduce winter peak loads by 64.3 MW and summer peak loads by 69.5 MW. Information on energy efficiency targets, and detailed results, are available in IRP chapters 5 and 11, Energy Efficiency and the Preferred Resource Strategy respectively. Figure 15.1 illustrates the energy efficiency selected for the 2021 PRS as well as the 10-year pro rata share of both annual and cumulative efficiency. For more information on the biennial conservation target and the EIA penalty threshold see Table 5.2 in Chapter 5.

**Table 15.1: Washington Annual Capacity by Resource Type**

| | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Supply Resources (MW)** | | | | | | | | | | |
| Wind | 0 | 100 | 100 | 0 | 0 | 0 | 100 | 0 | 0 | 0 |
| Kettle Falls GS upgrade | 0 | 0 | 0 | 0 | 7.9 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas CT | 0 | 0 | 0 | 0 | 0 | 82.9 | 0 | 0 | 0 | 0 |
| NW Hydro Slice | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 75 |
| **Total Resources** | **0** | **100** | **100** | **0** | **7.9** | **82.9** | **100** | **0** | **0** | **75** |
| | | | | | | | | | | |
| **Demand Response (MW)** | | | | | | | | | | |
| Variable Peak Pricing | 0 | 0 | 1 | 2.1 | 4.2 | 1.3 | 0.6 | -0.1 | -0.1 | -0.1 |
| Time of Use Rates | 0 | 0 | 0.3 | 0.7 | 1.0 | 0.9 | 0.3 | 0 | 0 | 0 |
| Large C&I | 0 | 0 | 0 | 0 | 0 | 25.0 | 0 | 0 | 0 | 0 |
| DLC Smart Thermostats | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.6 |
| **Total Demand Response** | **0** | **0** | **1.3** | **2.8** | **5.2** | **27.2** | **0.9** | **-0.1** | **-0.1** | **0.5** |
| | | | | | | | | | | |
| **Energy Efficiency** | | | | | | | | | | |
| Energy Savings (GWh)[1] | 33.5 | 39.6 | 43.9 | 52.1 | 58.3 | 62.9 | 65.5 | 64.0 | 61.2 | 56.1 |
| Winter Peak Reduction | 3.6 | 4.4 | 5.1 | 6.1 | 7.0 | 7.8 | 8.1 | 8.0 | 7.5 | 6.6 |
| Summer Peak Reduction | 4.5 | 5.3 | 5.9 | 7.0 | 7.5 | 8.1 | 8.3 | 8.1 | 8.1 | 6.8 |
| | | | | | | | | | | |
| **Total MW[2]** | **3.6** | **104.4** | **106.4** | **8.9** | **20.2** | **117.9** | **109.0** | **7.9** | **7.3** | **82.0** |

**Figure 15.1: Washington 10-year Energy Efficiency Target**




## Resource Adequacy

Avista must ensure its resources are adequate to serve its customers. Because of the benefits of regional coordination, Avista is participating in the development of a potential regional resource adequacy program. The Company's participation in regional resource adequacy efforts is important because the choices of other utilities affect the amount of resources that

[1] Includes estimated line losses.
[2] Uses winter peak savings for energy efficiency.

must be constructed. Avista currently targets a 16 percent planning margin to meet winter peaks, and 7 percent planning margin for summer peaks. This is in addition to meeting operating reserves and regulation requirements. Avista estimates participation in a resource adequacy program may reduce its needs for new capacity by up to 70 MW in 2031 based on the current draft program design. These savings will potentially allow the utility to require lower future resource acquisitions if the program is successfully developed and implemented.

Avista's 2021 IRP calls for 83 MW of natural gas-fired capacity for Washington customers by November 1, 2026, replacing the Lancaster PPA, to maintain reliability targets for Washington customers during peak load hours however, a total of 211 MW is needed for all of Avista's customers. A future RFP may identify a lower cost clean resource to meet this reliability shortfall, but the current IRP modeling results selected a natural gas-fired resource in 2026.

## Demand Response and Load Management Programs

Avista does not have any demand response or load management programs today, but this CEAP identifies new programs with the potential to reduce load by 37.6 MW by 2031. Load management programs are projected to begin in 2024 with time of use and variable peak pricing opt-in programs. Savings are estimated to be 12 MW by 2031. A 25 MW large commercial customer program offering is selected before the Lancaster PPA ends in 2026. Another program, starting in 2031, encourages the adoption of smart thermostats to control heating and cooling load. The program expects to achieve 0.6 MW of savings in the first year and grow to over 6 MW by 2045. Future all-source RFPs may find additional opportunities from demand response aggregators or others.

**Table 15.2: Demand Response and Load Management Programs**

| Program | Washington |
|---|---:|
| Time of Use Rates | 3.1 MW (2024) |
| Variable Peak Pricing | 8.9 MW (2024) |
| Large C&I Program | 25.0 MW (2027) |
| DLC Smart Thermostats | 0.6 MW (2031) |
| Total | 37.6 MW (2031 Total) |

## Planned Clean Energy Acquisitions

Avista developed CEAP targets to ensure 100 percent of Washington retail sales by 2030 are served with clean energy options including up to 20 percent from offsets such as RECs. Table 15.3 outlines the requirements and projected new resources to meet the goals. The 2021 IRP identifies a need for 180 aMW of clean energy by 2031[3] along with 41 aMW of clean energy purchases from Avista's Idaho customers and 20 aMW of RECs from Idaho customers under median hydro conditions. Depending on the determination of the WUTC's decision regarding compliance with the 100 percent goal, Avista may need additional clean energy and/or RECs if renewable and non-emitting energy must be delivered to customers instantaneously. Chapter 12 – Portfolio Scenarios of the 2021 IRP outlines the cost and energy acquisition impacts of

[3] The owned hydro energy forecast includes Washington customers' share of additional energy from an upgrade to the Post Falls hydro facility.

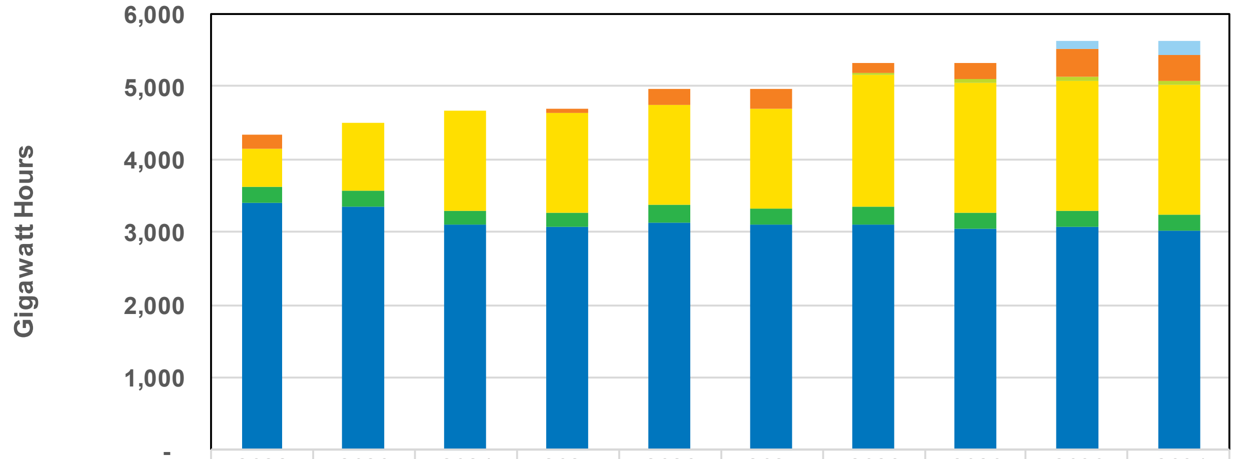
this scenario.
The new resources identified to meet CETA include 300 MW (144 aMW) of Montana Wind, 5 aMW from a 12 MW upgrade to the Kettle Falls Generating Station in 2026 and 31 aMW from renewing a 75 MW long-term hydro purchase power agreement in 2031. Avista's Washington customers may need to rely on the purchase of additional Idaho-shares of hydro energy in years of poor water or wind output.

Avista does not anticipate pursuing any transformational energy projects at this time. If CETA rule adoptions change from our current understanding of the law, the Company will revisit the matter. Figure 15.2 summarizes the annual clean energy serving Washington each year and by resource type in gigawatt-hours. The 10-year cumulative summary of clean energy is split by resource type in Figure 15 in gigawatt-hours.

### Table 15.3: 2022-2031 Washington Clean Energy Targets (aMW)

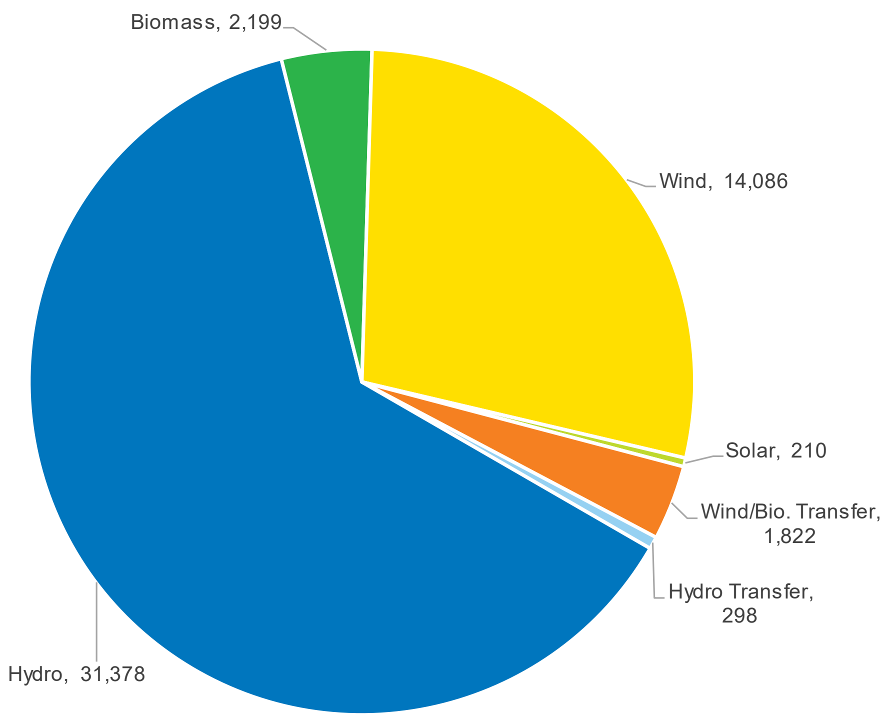
| | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|
| Retail Sales | 647 | 650 | 651 | 655 | 657 | 658 | 658 | 661 | 662 | 663 |
| PURPA | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| Solar Select | 6 | 6 | 6 | 6 | 6 | 6 | 0 | 0 | 0 | 0 |
| **Net Requirement** | **619** | **623** | **624** | **628** | **629** | **631** | **636** | **640** | **641** | **642** |
| | | | | | | | | | | |
| Target Clean % | 80 | 80 | 85 | 85 | 90 | 90 | 95 | 95 | 100 | 100 |
| **Clean Energy Goal** | **496** | **498** | **530** | **534** | **567** | **568** | **604** | **608** | **641** | **642** |
| | | | | | | | | | | |
| Owned Hydro | 292 | 288 | 288 | 285 | 292 | 289 | 292 | 289 | 291 | 291 |
| Contract Hydro | 96 | 95 | 65 | 66 | 65 | 64 | 63 | 58 | 59 | 23 |
| Kettle Falls | 24 | 23 | 23 | 21 | 23 | 21 | 22 | 20 | 21 | 19 |
| Palouse Wind | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| Rattlesnake Flat Wind | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 | 36 |
| Adams Neilson Solar | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 6 | 6 | 6 |
| **Available Resources** | **473** | **466** | **436** | **431** | **439** | **434** | **441** | **433** | **436** | **399** |
| | | | | | | | | | | |
| **Shortfall** | **23** | **33** | **94** | **103** | **127** | **134** | **163** | **174** | **204** | **242** |
| | | | | | | | | | | |
| **Resource Forecast** | | | | | | | | | | |
| Montana Wind | 0 | 48 | 96 | 96 | 96 | 96 | 144 | 144 | 144 | 144 |
| Kettle Falls Upgrade | 0 | 0 | 0 | 0 | 6 | 6 | 6 | 6 | 5 | 5 |
| Regional Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 31 |
| ID AVA Ren. Purchase | 23 | 0 | 0 | 7 | 25 | 32 | 13 | 25 | 42 | 41 |
| ID AVA Hydro Purchase | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 21 |
| **Total Energy/RECs** | **23** | **48** | **96** | **103** | **127** | **134** | **163** | **175** | **204** | **242** |
| | | | | | | | | | | |
| **Net Position** | **0** | **15** | **2** | **0** | **0** | **0** | **0** | **1** | **0** | **0** |
| | | | | | | | | | | |
| **Total Clean Resource Need** | **23** | **48** | **96** | **103** | **127** | **134** | **163** | **175** | **191** | **180** |

## Figure 15.2: Washington Annual Clean Energy Acquisition




| | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|---|---|---|
| Hydro Transfer | - | - | - | - | - | - | - | - | 114 | 184 |
| Wind/Bio. Transfer | 201 | - | - | 61 | 219 | 280 | 114 | 219 | 368 | 359 |
| Solar | - | - | - | - | - | - | 53 | 53 | 53 | 53 |
| Wind | 526 | 946 | 1,367 | 1,367 | 1,367 | 1,367 | 1,787 | 1,787 | 1,787 | 1,787 |
| Biomass | 210 | 201 | 201 | 184 | 254 | 237 | 245 | 228 | 228 | 210 |
| Hydro | 3,399 | 3,355 | 3,092 | 3,075 | 3,127 | 3,092 | 3,110 | 3,040 | 3,066 | 3,022 |

## Figure 15.3: Cumulative Clean Energy Acquisition for Washington



## Transmission & Distribution Improvements

Avista's resource acquisition plan does not include significant transmission or distribution improvements as acquired resources are likely to be off system or utilize existing transmission assets and not require significant new transmission investment. Avista plans future transmission investment following its 10-year plan described in Appendix G.

This IRP resulted in two interconnection requests to Avista's transmission department to evaluate future resource opportunities. The first is up to 200 MW in the Rathdrum area and the second is to integrate the additional capacity at Kettle Falls for the upgrade opportunity. So far, the Kettle Falls interconnection request does not require any significant improvements. Rathdrum area results will not be available until later in 2021 after the publication of this IRP.

Avista continues to upgrade its distribution system as customer load grows. Avista conducted a review of potential resource acquisitions that could defer distribution investments, but none were selected in this IRP based on economic analysis of the alternatives. Avista will begin designing a public process for distribution planning in 2021.

## Energy Equity

Avista is developing a plan to ensure an equitable distribution of benefits and reduced burdens on highly impacted communities and vulnerable populations through the IRP process. At the time of drafting this plan, the state had not yet defined the highly impacted communities nor provided guidance on acceptable cost premiums associated with an energy equity plan. Even so, Avista began development of a methodology to identify vulnerable populations in 2020; but, Avista will not finalize these populations groups until formation of its Equity Advisory Group (EAG) in 2021. The EAG will guide the determination of these communities as well as assist in designing the outreach and engagement that will be used to distinguish and prioritize indicators and solutions. Avista recently committed to an energy efficiency program pilot focused on vulnerable populations starting in 2021. Options on how to design and implement a program to meet this commitment to help with the identification of any barriers or missing data to make sure that these groups are receiving their fair share of energy and non-energy benefits continue to be assessed.

This IRP includes analytical enhancements to its energy efficiency cost effectiveness test to include non-energy benefits. These enhancements should ultimately benefit vulnerable communities. Avista also includes provisions in its energy acquisition process to prioritize projects that may improve resiliency and increase energy security in these communities. The priority evaluation also includes preference to renewable projects located in vulnerable population areas to further develop those economies. The plan does not include new generation facilities in Washington[4] except for an upgrade to the Kettle Falls wood-fired facility[5].

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[4] A future request for proposals of renewable energy may yield local resources more beneficial than those identified in this plan.

[5] The Kettle Falls plant is not located in a vulnerable populated area.

## Cost Analysis

The 2021 IRP includes an analysis comparing the cost of the PRS to a baseline portfolio without CETA clean energy requirements. This modeling exercise determines whether alterative compliance mechanisms such as the 2 percent cost cap will be required. For the first two of the four-year compliance periods under CETA, Avista expects to be under the cap by $64 and $61 million, respectively, absent any future equity-related program costs. Yet Avista found the simple average rate increase over the first four-year period is actually 2.5 percent as shown in Table 15.4. Table 15.5 shows the plan is also under the cost cap by $61 million over the second four-year compliance period. The final two years of the 10-year plan are not shown as they are part of a four-year period extending beyond this CEAP timeline. Those costs are also expected to remain under the cost cap.

**Table 15.4: 2022-2024 Washington Cost Cap Analysis (millions $)**

| | 2021 | 2022 | 2023 | 2024 | 2025 | Total |
|---|---|---|---|---|---|---|
| Revenue Requirement w/ SCC | 651 | 651 | 669 | 700 | 705 | |
| Baseline | | 650 | 657 | 672 | 678 | |
| Annual Delta | | 1 | 11 | 28 | 27 | 67 |
| Percent Change | | 0.2% | 1.7% | 4.2% | 4.0% | 2.5% |
| **Four Year Max Spending** | | 33 | 33 | 33 | 33 | 132 |
| Comparison vs Annualized Cost Cap | | (32) | (22) | (5) | (6) | (64) |

**Table 15.5: 2025-2028 Washington Cost Cap Analysis (millions $)**

| | 2024 | 2025 | 2026 | 2027 | 2028 | Total |
|---|---|---|---|---|---|---|
| Revenue Requirement w/ SCC | 705 | 714 | 718 | 744 | 755 | |
| Baseline | | 688 | 709 | 721 | 731 | |
| Annual Delta | | 26 | 9 | 23 | 23 | 81 |
| Percent Change | | 3.8% | 1.3% | 3.2% | 3.2% | 2.9% |
| **Four Year Max Spending** | | 36 | 36 | 36 | 36 | 143 |
| Comparison vs Annualized Cost Cap | | (10) | (27) | (13) | (12) | (61) |

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