BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

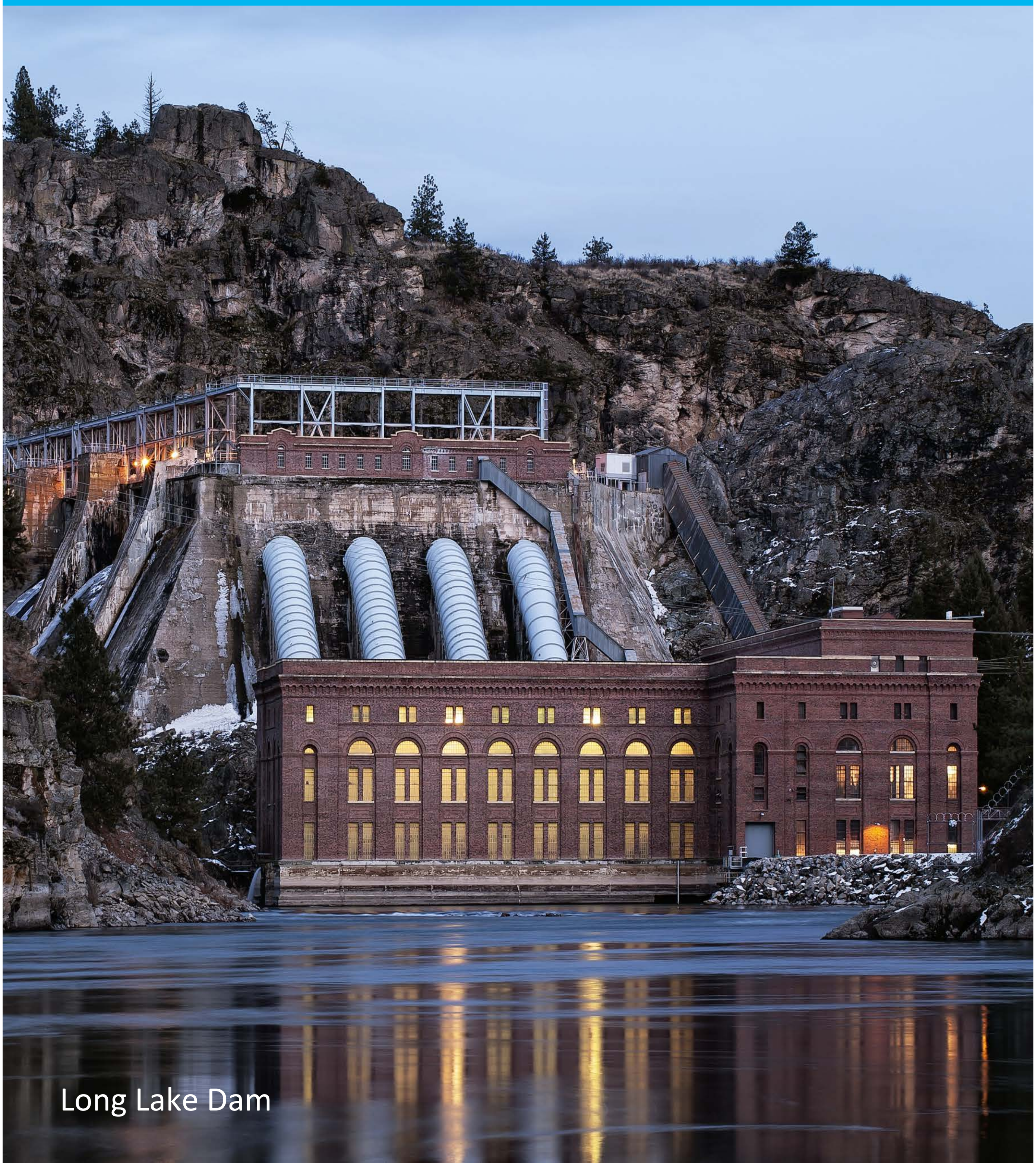
DOCKET NO. UE-19________

EXH. JRT-2

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

# 2017 Electric Integrated Resource Plan



Long Lake Dam

# Safe Harbor Statement

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

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

## Production Credits

### *Primary Avista 2017 Electric IRP Team*

| Individual | Title |
|---|---|
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| James Gall | IRP Manager |
| John Lyons | Senior Resource Policy Analyst |
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| Richard Maguire | System Planning Engineer |

### *2017 Electric IRP Contributors*

| Name | Title |
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# 2017 Electric IRP Introduction

***Avista has a 128-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 resources.***

The 2017 Integrated Resource Plan (IRP) continues this legacy by looking 20 years into the future to determine the energy needs of our customers. The IRP, updated every two years, analyzes and outlines a strategy to meet the projected demand and renewable portfolio standards through energy efficiency and a diverse mix of renewable and traditional energy resources.

## Summary

The 2017 IRP shows Avista has adequate resources between owned and contractually controlled generation, combined with conservation and market purchases, to meet customer needs through 2026. In the longer term, plant upgrades, energy efficiency measures, solar, demand response, energy storage and additional natural gas-fired generation are integral parts of Avista's 2017 Preferred Resource Strategy.

## Changes

Major changes from the 2015 IRP include:

- The 2017 Expected Case energy forecast grows 0.47 percent per year, replacing the 0.6 percent annual growth rate in the last IRP.
- Peak load growth is lower than energy growth, at 0.42 percent in the winter and 0.46 percent in the summer.
- Lower expected load growth combined with recent Mid-Columbia hydroelectric contracts, energy efficiency, and demand response delay the need for additional resources from the end of 2020 until 2026.
- The return of demand response (temporarily reducing the demand for energy) and the addition of energy storage and solar.
- Lower expected emissions from Avista owned and controlled resources with fewer natural-gas fired peaking plants and no new combined-cycle plants.

## Highlights

Some highlights of the 2017 IRP include:

- Avista's current generation resources remain cost effective and reliable sources of power to meet future customer needs over the next 20 years.
- Energy storage costs are significantly lower than the last IRP which for the first time makes the technology operationally attractive in meeting energy needs in the 20-year timeframe of the 2017 IRP.
- Avista is working to construct a 15 MW (DC) solar facility for the company's new Solar Select Program for commercial and industrial customers.
- This study estimates conservation will serve 53.3 percent of future load growth.

## IRP Process

Each IRP is a thoroughly researched and data-driven document that identifies and describes a Preferred Resource Strategy to meet customer needs while balancing costs and risk measures with environmental and other policy mandates. Avista's professional energy analysts use sophisticated modeling tools and input from over 100 invited 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 2019 IRP in mid-2018. Stakeholder involvement is encouraged and interested parties may contact John Lyons at (509) 495-8515 or john.lyons@avistacorp.com for more information on participating in the IRP process.

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# 1. Executive Summary

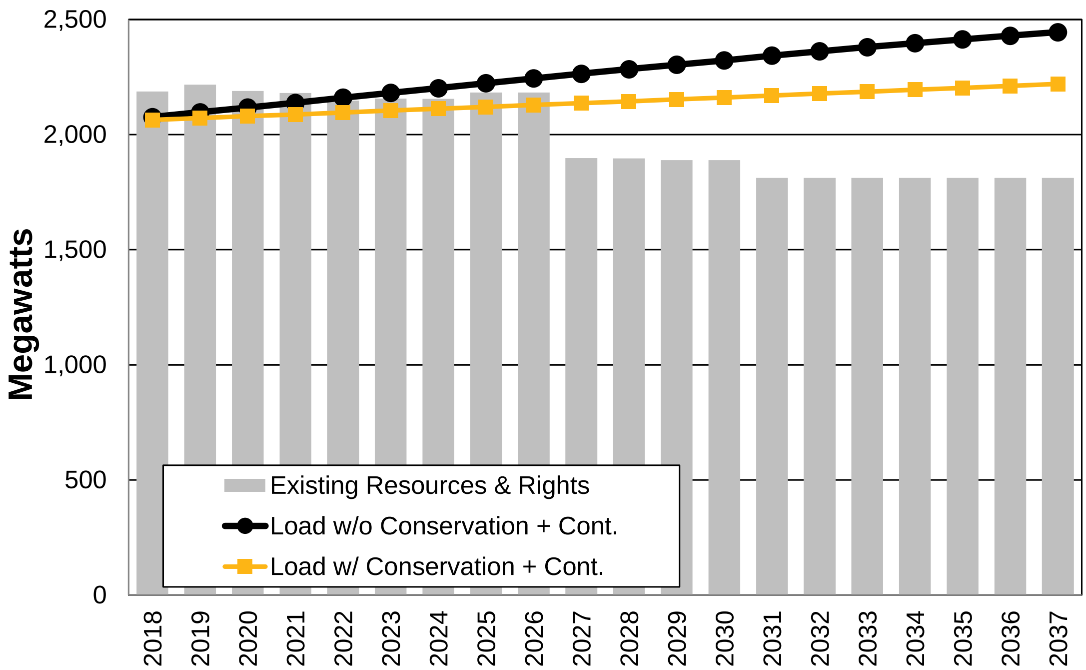
Avista's 2017 Electric Integrated Resource Plan (IRP) shapes its resource strategy over the next two years and procurements over the next 20 years. It provides a snapshot of existing resources and loads and evaluates acquisition strategies over expected and possible future conditions. The 2017 Preferred Resource Strategy (PRS) includes a mix of solar, demand response, energy efficiency, storage, upgrades to existing assets, and new natural gas-fired generation.

The PRS relies on modeling methods to balance cost, reliability, rate volatility, and renewable requirements. Avista's management and the Technical Advisory Committee (TAC) guide IRP development through their input on modeling and planning assumptions. TAC members include customers, Commission staff, the Northwest Power and Conservation Council, consumer advocates, academics, environmental groups, utility peers, government agencies, and other interested parties.

## Resource Needs

Under extreme weather conditions, Avista expects its highest peak loads in the winter. Its peak planning methodology includes operating reserves, regulation, load following, wind integration, a 14 percent planning margin over winter-peak load levels, and a seven percent planning margin over summer-peak load levels. The company has adequate resources combined with conservation to meet peak load requirements through October 2026. Figure 1.1 shows Avista's resource position through 2037. Chapter 6 – Long-Term Position details Avista's resource needs.

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



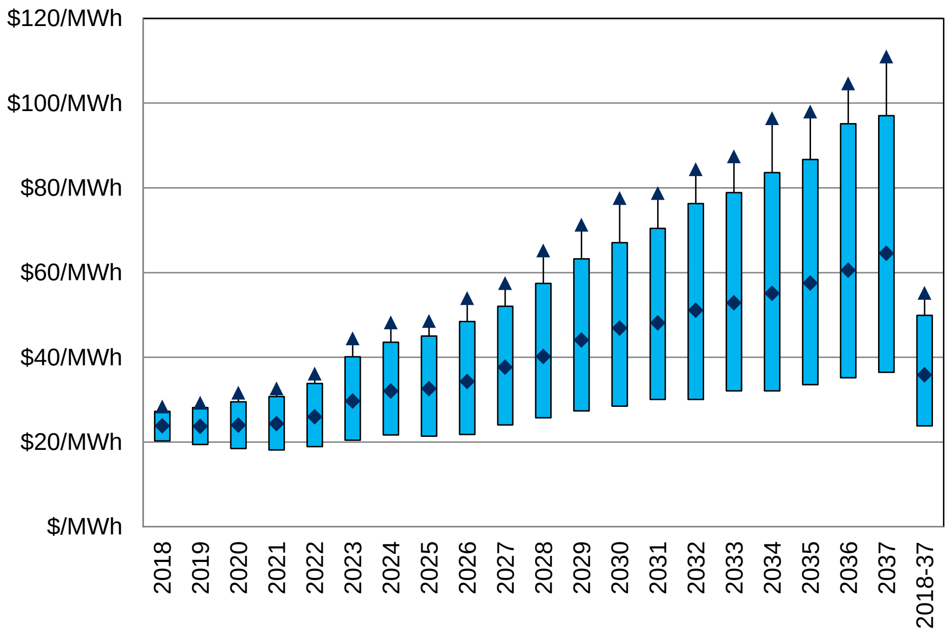
## Modeling and Results

Avista uses multiple steps to develop its PRS; beginning with identifying and quantifying potential new generation resources to serve projected electricity demand across the Western Interconnect. This study determines the impact of external markets on the Northwest electricity marketplace. It then maps existing Avista resources to the transmission grid in a model simulating hourly operations for the Western Interconnect in the 2018 to 2037 IRP timeframe. The model adds new resources and transmission to the Western Interconnect as regional loads grow and resources retire. Monte Carlo-style analyses vary hydroelectric and wind generation, loads, forced outages and natural gas price data over 500 iterations of potential future market conditions to develop the Mid-Columbia electricity marketplace through 2037.

## Electricity and Natural Gas Market Forecasts

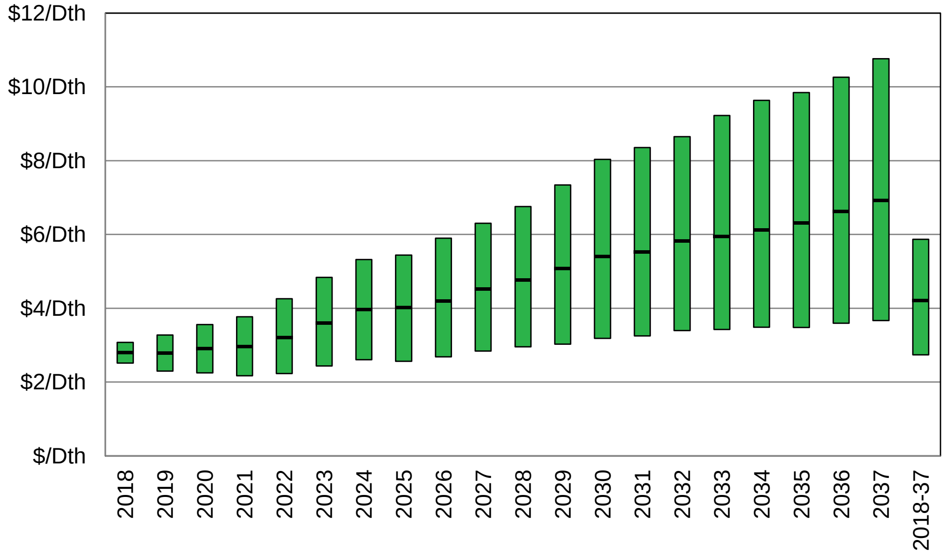
Figure 1.2 shows the 2017 IRP Mid-Columbia electricity price forecast for the Expected Case, including the range of prices resulting from 500 Monte Carlo iterations. The levelized price is $35.85 per MWh in nominal dollars over the 2018-2037 timeframe.

**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 is $4.20 per dekatherm (Dth) over the next 20 years. See Chapter 10 – Market Analysis for natural gas and electricity price forecasts.

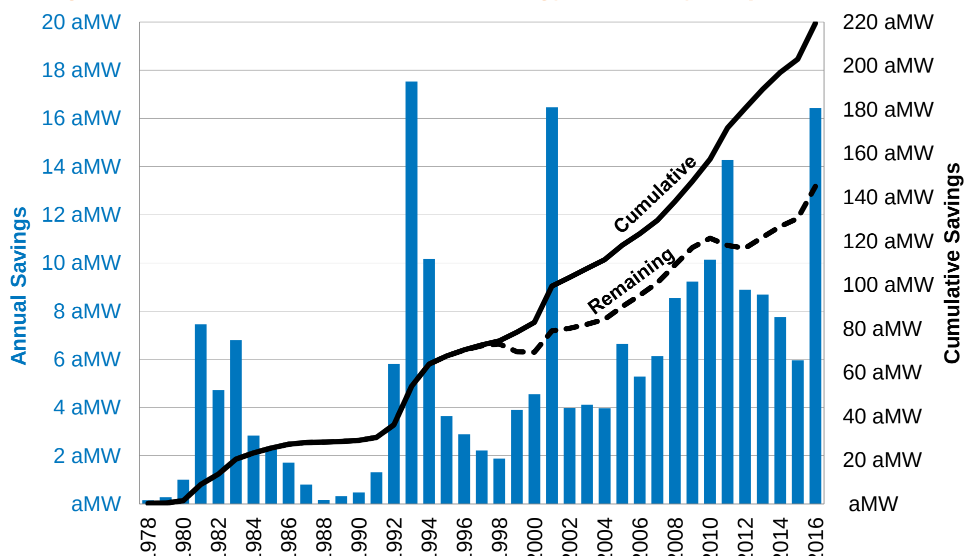
Figure 1.3: Stanfield Natural Gas Price Forecast




# Energy Efficiency Acquisition

Avista commissioned a 20-year Conservation Potential Assessment (CPA) to determine potential residential, commercial and industrial energy efficiency applications. Data from this study formed the basis of the IRP's conservation analysis. This study estimates conservation will serve 53.3 percent of future load growth. Since 1978, Avista's load is 12.3 percent lower due to conservation. Figure 1.4 illustrates the historical efficiency acquisitions as blue bars and the dashed line shows the amount of energy efficiency still reducing loads due to the 18-year assumed measure life. See Chapter 5 – Energy Efficiency and Demand Response for details.

Figure 1.4: Annual and Cumulative Energy Efficiency Acquisitions



## Preferred Resource Strategy

The PRS results from careful consideration and input by Avista's management, the TAC, and from the information gathered and analyzed in the IRP process. It meets future load growth with upgrades at existing generation facilities, energy efficiency, natural gas-fired technologies, storage, energy efficiency, and demand response, as shown in Table 1.1.

**Table 1.1: The 2017 Preferred Resource Strategy**

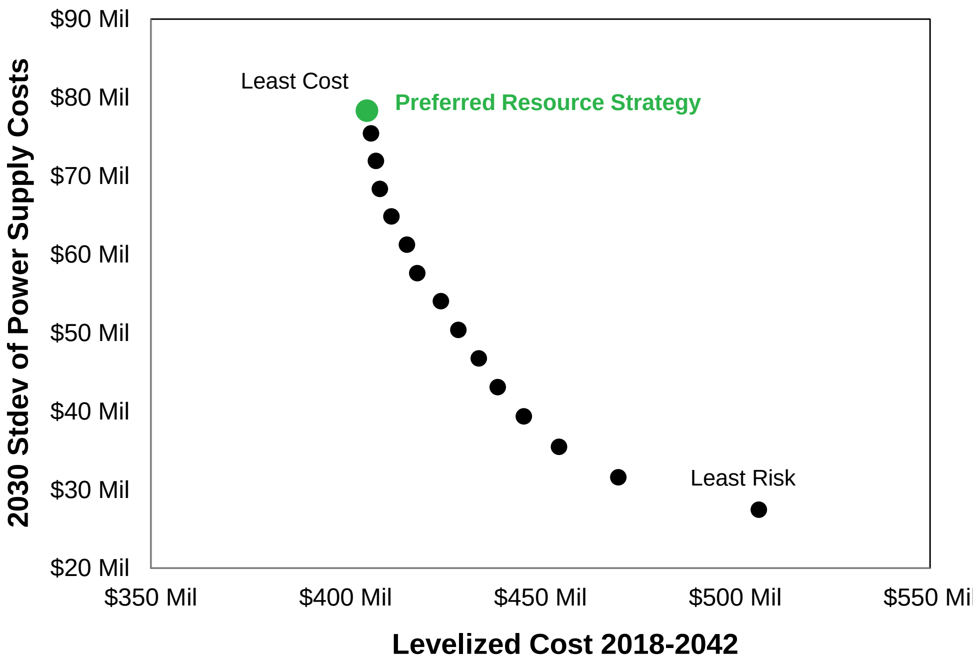
| Resource | By the End of Year | ISO Conditions (MW) | Winter Peak (MW) | Energy (aMW) |
|---|---|---|---|---|
| Solar | 2018 | 15 | 0 | 3 |
| Natural Gas Peaker | 2026 | 192 | 204 | 178 |
| Thermal Upgrades | 2026-2029 | 34 | 34 | 31 |
| Storage | 2029 | 5 | 5 | 0 |
| Natural Gas Peaker | 2030 | 96 | 102 | 89 |
| Natural Gas Peaker | 2034 | 47 | 47 | 43 |
| **Total** | | **389** | **392** | **344** |
| **Efficiency Improvements** | **Acquisition Range** | | **Winter Peak Reduction (MW)** | **Energy (aMW)** |
| Energy Efficiency | 2018-2037 | | 203 | 108 |
| Demand Response | 2025-2037 | | 44 | 0 |
| Distribution Efficiencies | | | <1 | <1 |
| **Total** | | | **247** | **108** |

The 2017 PRS describes a reasonable low-cost plan along the Efficient Frontier of potential resource portfolios accounting for fuel supply and price risks. Major changes from the 2015 IRP include a lower contribution from natural gas-fired peakers and inclusion of demand response, solar and storage resources.

Each new generation resource and energy efficiency option is valued against the Expected Case's 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 their associated capital and fixed operation and maintenance (O&M) costs, form the input into Avista's Preferred Resource Strategy Linear Programming Model (PRiSM). PRiSM assists Avista by developing optimal mixes of new resources along an efficient frontier. Chapter 11 – Preferred Resource Strategy provides a detailed discussion of the efficient frontier concept.

The PRS provides a least reasonable-cost portfolio, minimizing future costs and risks within actual and expected environmental constraints. The Efficient Frontier helps determine the tradeoffs between risk and cost. The approach is similar to finding an optimal mix of risk and return in an investment portfolio, as potential returns increase, so do risks. Conversely, reducing risk generally reduces overall returns. Figure 1.5 presents the change in cost and risk from the PRS on the Efficient Frontier. Lower power cost variability comes from investments in more expensive, but less risky, resources such as wind and hydroelectric upgrades. The PRS is the portfolio selected on the Efficient Frontier where reduced risk justifies the increased cost.

**Figure 1.5: Efficient Frontier**

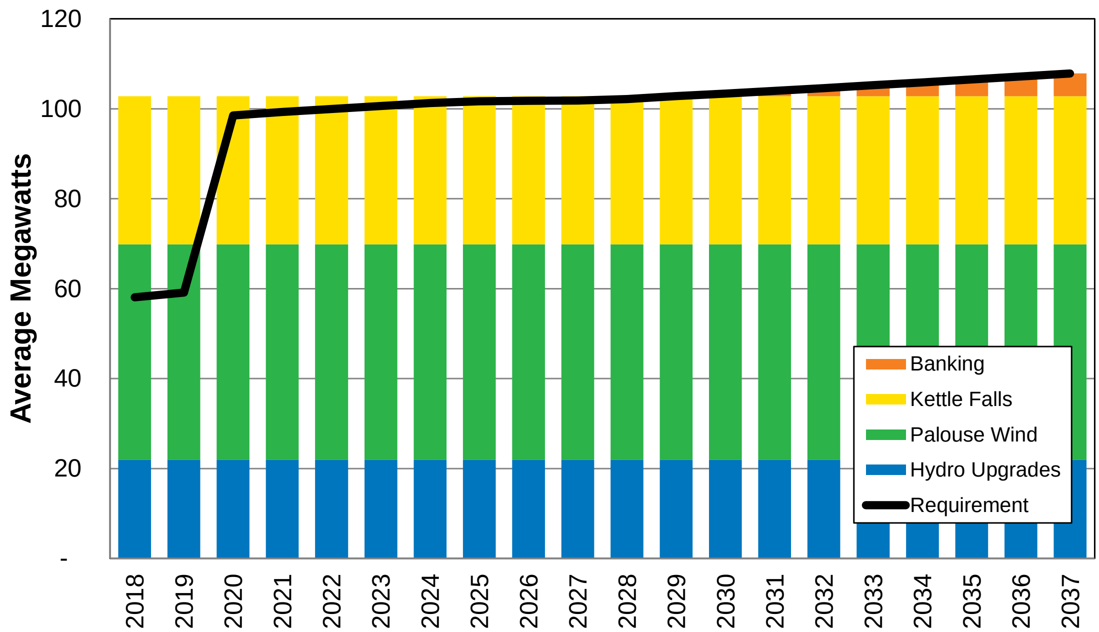



Chapter 12 – Portfolio Scenarios, includes several scenarios identifying tipping points where the PRS could change under different conditions from the Expected Case. It also evaluates the impacts of, among others, varying load growth, resource capital costs, and greenhouse gas policies.

## Energy Independence Act Compliance

Washington's Energy Independence Act (EIA), or Initiative 937, requires utilities with over 25,000 customers to meet nine percent of retail load from qualified renewable resources by 2016 and 15 percent by 2020. The initiative also requires utilities to acquire all cost-effective conservation and energy efficiency measures. Avista will meet or exceed its EIA requirements through the IRP timeframe with a combination of qualifying hydroelectric upgrades, the Palouse Wind project, and Kettle Falls Generating Station output. Figure 1.6 shows Avista's EIA-qualified generation; Chapter 6 – Long-Term Position covers this topic in-depth.

Figure 1.6: Avista's Qualifying Renewables for Washington State's EIA




## Greenhouse Gas Emissions

The regulation of greenhouse gases, or carbon emissions, has changed since the 2015 IRP with the change in presidential administrations, resulting in evolving federal and additional state-driven regulation. Some states have active cap and trade programs, emissions performance standards, renewable portfolio standards, or a combination of current and proposed regulations affecting emissions from electric generation resources.

Figure 1.7 shows that Avista emissions will decrease over the IRP timeframe. The 2017 IRP's emissions forecast is 29 percent lower for 2035 than the 2015 IRP's forecast. Figure 1.8 shows the western-region emissions likely will fall from historic levels. Regional emissions fall below 1990 levels by the end of the study period due to coal retirements and potential state and federal policies. More details on state and federal greenhouse gas policies are in Chapter 7 – Policy Consideration. Results of greenhouse-gas policy scenarios are in Chapter 10 – Market Analysis and Chapter 12 – Portfolio Scenarios.

Figure 1.7: Avista Owned and Controlled Resource's Greenhouse Gas Emissions

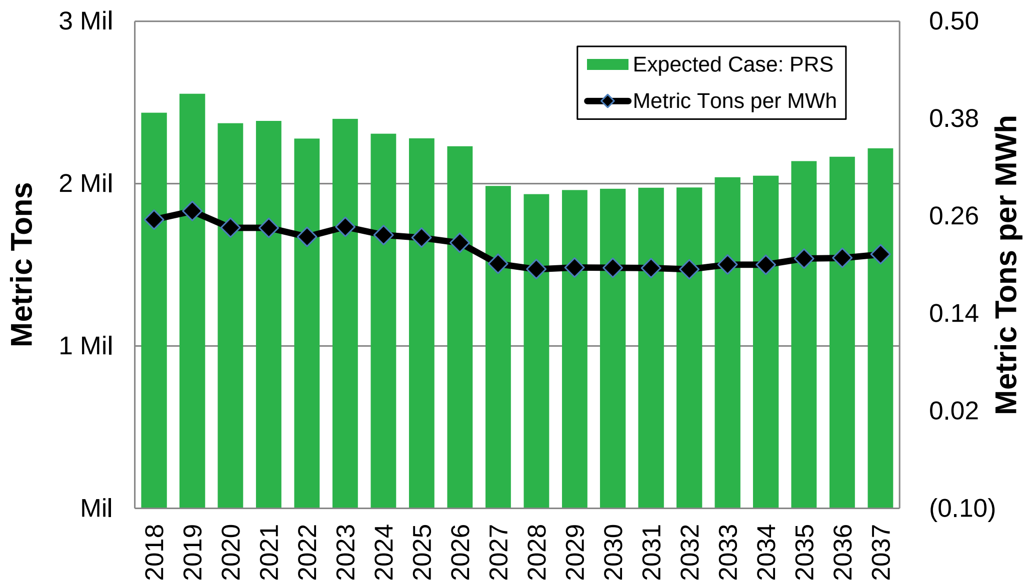
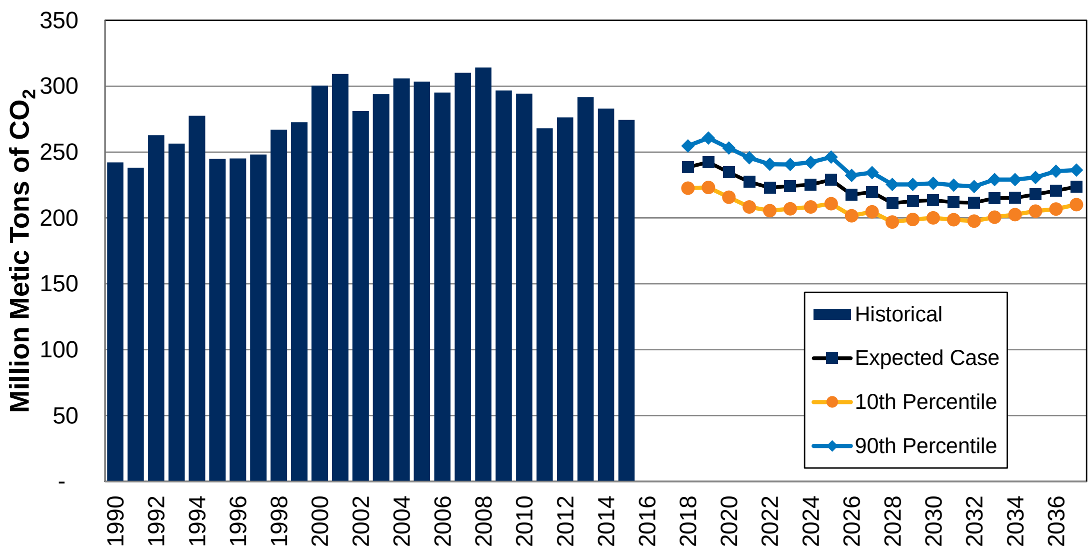



Figure 1.8: U.S. Western Interconnect Greenhouse Gas Emissions




## Action Items

The 2017 Action Items chapter updates progress made on Action Items in the 2015 IRP and outlines activities Avista intends to perform between the publication of this report and publication of the 2019 IRP. It includes input from Commission Staff, Avista's management team, and the TAC. Action Item categories include generation resource-related analysis, energy efficiency, and transmission planning. Refer to Chapter 13 – Action Items for details about each of these categories.

# 2. Introduction and Stakeholder Involvement

Avista submits an IRP to the Idaho and Washington public utility commissions biennially.[1] Including its first plan in 1989, the 2017 IRP is Avista's fifteenth plan. It identifies and describes a PRS for meeting load growth while balancing cost and risk measures with environmental mandates.

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 and optimizing the value of its current portfolio. The IRP is a resource evaluation tool, not a plan for acquiring a particular set of assets. Actual resource acquisition generally occurs through competitive bidding processes.

## IRP Process

The 2017 IRP is developed and written with the aid of a public process. Avista actively seeks input from a variety of constituents through the TAC. The TAC is a mix of over 100 invited external participants, including staff from the Idaho and Washington commissions, customers, academics, environmental organizations, government agencies, consultants, utilities, and other interested parties, who joined the planning process.

Avista sponsored six TAC meetings for the 2017 IRP. The first meeting was on June 2, 2016 and the last occurred on June 20, 2017. Each TAC meeting covers different aspects of IRP planning activities. At the meetings, members provide contributions to, and assessments of, modeling assumptions, modeling processes, and results of Avista studies. Table 2.1 contains a list of TAC meeting dates and the agenda items covered in each meeting.

Agendas and presentations from the TAC meetings are in Appendix A and on Avista's website at https://www.myavista.com/about-us/our-company/integrated-resource-planning. The website link contains all past IRPs and TAC meeting presentations back to 1989.

[1] Washington IRP requirements are contained 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.

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

| Meeting Date | Agenda Items |
| --- | --- |
| TAC 1 – June 2, 2016 | • TAC Meeting Expectations<br>• 2015 IRP Commission Acknowledgements<br>• 2015 Action Plan Update<br>• Energy Independence Act Compliance<br>• Energy Efficiency Modeling Discussion<br>• Resource Adequacy – Preliminary Results<br>• Draft 2017 Electric IRP Work Plan |
| TAC 2 – September 28, 2016 | • Introduction & TAC 1 Recap<br>• TAC 1 Action Item Update<br>• Electrification Update<br>• Load and Economic Forecasts<br>• Supply Side Options<br>• Clean Energy Fund 2 Grant Project |
| TAC 3 – November 8, 2016 | • Introduction & TAC 2 Recap<br>• Colstrip Discussion<br>• Clean Power Plan and Clean Air Rule<br>• IRP Modeling Overview<br>• Cost of Carbon<br>• Avista's Power Planner Simulator |
| TAC 4 – February 15, 2017 | • Introduction & TAC 3 Recap<br>• Resource Needs Assessment<br>• Natural Gas Price Forecast<br>• Electric Price Forecast<br>• Transmission Planning<br>• Market and Portfolio Scenarios |
| TAC 5 – March 28, 2017 | • Introduction & TAC 4 Recap<br>• Updated Electric Price Forecast<br>• Energy Storage and Ancillary Services<br>• Conservation Potential Assessment<br>• Distribution Planning<br>• Draft Preferred Resource Strategy |
| TAC 6 – June 20, 2017 | • Introduction & TAC 5 Recap<br>• Conservation Assessment<br>• Final 2017 Preferred Resource Strategy<br>• Scenario Analysis<br>• C&I Solar Select Program<br>• 2019 IRP Action Items<br>• 2017 IRP Document Overview |

Avista greatly appreciates the valuable contributions of its TAC members and wishes to acknowledge and thank the organizations that allow their attendance. Table 2.2 is a list of the organizations participating in the 2017 IRP TAC process.

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

| Organization |
|---|
| AEG |
| City of Spokane |
| Clearwater Paper |
| Eastern Washington University |
| GE Energy |
| Idaho Conservation League |
| Idaho Department of Environmental Quality |
| Idaho Power |
| Idaho Public Utilities Commission |
| Inland Empire Paper |
| NW Energy Coalition |
| Northwest Power and Conservation Council |
| PacifiCorp |
| Pend Oreille PUD |
| Puget Sound Energy |
| Renewable Northwest |
| Residential and Small Commercial Customers |
| Sierra Club |
| Snake River Alliance |
| Spokane Neighborhood Action Partners |
| The Energy Authority |
| Washington State Office of the Attorney General |
| Washington Department of Enterprise Services |
| Washington Utilities and Transportation Commission |
| Whitman County Commission |

## Issue Specific Public Involvement Activities

In addition to TAC meetings, Avista sponsors and participates in several other collaborative processes involving a range of public interests. A sampling is below.

### *Energy Efficiency Advisory Group*

The energy efficiency Advisory Group provides stakeholders and public groups biannual opportunities to discuss Avista's energy efficiency efforts.

### *FERC Hydro Relicensing – Clark Fork and Spokane River Projects*

Over 50 stakeholder groups participated in the Clark Fork hydro-relicensing process beginning in 1993. This led to the first all-party settlement filed with a FERC relicensing application, and the eventual issuance of a 45-year FERC operating license in February 2003. This collaborative process continues in the implementation of the license and Clark Fork Settlement Agreement, with stakeholders participating in various protection, mitigation, and enhancement efforts. Avista received a 50-year license for the Spokane

River Project following a multi-year collaborative process involving several hundred stakeholders. Implementation began in 2009 with a variety of collaborating parties.

#### *Low Income Rate Assistance Program*
This program is coordinated with four community action agencies in Avista's Washington service territory. The program began in 2001, and quarterly reviews ensure changing administrative issues and needs are met.

### Regional Planning
The Pacific Northwest generation and transmission system operates in a coordinated fashion. Avista participates in the efforts of many regional planning processes. Information from this participation supplements Avista's IRP process. A partial list of the regional organizations Avista participates in includes:

- Western Electricity Coordinating Council
- Peak Reliability
- Northwest Power and Conservation Council
- Northwest Power Pool
- Pacific Northwest Utilities Conference Committee
- ColumbiaGrid
- Northern Tier Transmission Group
- North American Electric Reliability Corporation

### Future Public Involvement
Avista actively solicits input from interested parties to enhance its IRP process. We continue to expand TAC membership and diversity, and maintain the TAC meetings as an open public process.

## 2017 IRP Outline
The 2017 IRP consists of 13 chapters plus an 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 2017 IRP.

### Chapter 2: Introduction and Stakeholder Involvement
This chapter introduces the IRP and details public participation and involvement in the IRP planning 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.

### Chapter 5: Energy Efficiency and Demand Response

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

### Chapter 6: Long-Term Position

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

### Chapter 7: Policy Considerations

This chapter focuses on some of the major policy issues for resource planning, including state and federal greenhouse gas policies and environmental regulations.

### Chapter 8: Transmission & Distribution Planning

This chapter discusses Avista distribution and transmission systems, as well as regional transmission planning issues. It includes detail on transmission cost studies used in IRP modeling and provides a summary of our 10-year Transmission Plan. The chapter concludes with a discussion of distribution efficiency and grid modernization projects; including storage benefits to the distribution system.

### Chapter 9: Generation Resource Options

This chapter covers the costs and operating characteristics of the generation 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 2017 PRS, including the efficient frontier and resulting avoided costs.

### Chapter 12: Portfolio Scenarios

This chapter discusses the portfolio scenarios and tipping point analyses.

### Chapter 13: Action Items

This chapter discusses progress made on Action Items contained in the 2015 IRP. It details the action items Avista will focus on between publication of this plan and the 2019 IRP.

## Regulatory Requirements

The IRP process for Idaho has several requirements documented in IPUC Orders Nos. 22299 and 25260. Table 2.3 summarizes them.

**Table 2.3: Idaho IRP Requirements**

| Requirement | Plan Citation |
|---|---|
| Identify and list relevant operating characteristics of existing resources by categories including: hydroelectric, coal-fired, oil or gas-fired, PURPA (by type), exchanges, contracts, transmission resources, and others. | Chapter 4- Existing Supply Resources |
| Identify and discuss the 20-year load forecast plus scenarios for the different customer classes. Identify the assumptions and models used to develop the load forecast. | Chapter 3- Economic & Load Forecast<br>Chapter 12- Portfolio Scenarios |
| Identify the utility's plan to meet load over the 20-year planning horizon. Include costs and risks of the plan under a range of plausible scenarios. | Chapter 11- Preferred Resource Strategy<br>Chapter 12- Portfolio Scenarios |
| Identify energy efficiency resources and costs. | Chapter 5- Energy Efficiency & Demand Response |
| Provide opportunities for public participation and involvement. | Chapter 2- Introduction and Stakeholder Involvement |
| Explain the present load/resource position, expected responses to possible future events, and the role of conservation in those responses. | Chapter 6- Long-Term Position<br>Chapter 12- Portfolio Scenarios<br>Chapter 5- Energy Efficiency & Demand Response |
| Discuss any flexibilities and analyses considered, 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, and (4) contingencies for upgrading, optioning and acquiring resources. | Chapter 3- Economic & Load Forecast<br>Chapter 4- Existing Supply Resources<br>Chapter 9- Generation Resource Options<br>Chapter 11- Preferred Resource Strategies |

The IRP process for Washington has several requirements documented in Washington Administrative Code (WAC). Table 2.4 summarizes where in the document Avista addressed each requirement.

**Table 2.4: Washington IRP Rules and Requirements**

| Rule and Requirement | Plan Citation |
|---|---|
| WAC 480-100-238(4) – Work plan filed no later than 12 months before next IRP due date. Work plan outlines content of IRP. Work plan outlines method for assessing potential resources. | Work plan submitted to the UTC on August 31, 2016; see Appendix B for a copy of the Work Plan. |
| WAC 480-100-238(5) – Work plan outlines timing and extent of public participation. | Appendix B |

| | |
|---|---|
| WAC 480-100-238(2)(a) – Plan describes mix of energy supply resources. | Chapter 4- Existing Supply Resources<br>Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(a) – Plan describes conservation supply. | Chapter 5- Energy Efficiency & Demand Response<br>Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(a) – Plan addresses supply in terms of current and future needs of utility ratepayers. | Chapter 3- Economic & Load Forecast<br>Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(b) – Plan uses lowest reasonable cost (LRC) analysis to select mix of resources. | Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(b) – LRC analysis considers resource costs. | Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(b) – LRC analysis considers market-volatility risks. | Chapter 10- Market Analysis<br>Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(b) – LRC analysis considers demand side uncertainties. | Chapter 5- Energy Efficiency & Demand Response<br>Chapter 12- Portfolio Scenarios |
| WAC 480-100-238(2)(b) – LRC analysis considers resource dispatchability. | Chapter 9- Generation Resource Options<br>Chapter 10- Market Analysis |
| WAC 480-100-238(2)(b) – LRC analysis considers resource effect on system operation. | Chapter 10- Market Analysis<br>Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(b) – LRC analysis considers risks imposed on ratepayers. | Chapter 7- Policy Considerations<br>Chapter 9- Generation Resource Options<br>Chapter 10- Market Analysis<br>Chapter 11- Preferred Resource Strategy<br>Chapter 12- Portfolio Scenarios |
| WAC 480-100-238(2)(b) – LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government. | Chapter 3- Economic & Load Forecast<br>Chapter 4- Existing Supply Resources<br>Chapter 7- Policy Considerations<br>Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(2)(b) – LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide. | Chapter 7- Policy Considerations<br>Chapter 11- Preferred Resource Strategy<br>Chapter 12- Portfolio Scenarios |
| WAC 480-100-238(2)(c) – Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution. | Chapter 5- Energy Efficiency & Demand Response<br>Chapter 11- Preferred Resource Strategy |
| WAC 480-100-238(3)(a) – Plan includes a range of forecasts of future demand. | Chapter 3- Economic & Load Forecast<br>Chapter 12- Portfolio Scenarios |
| WAC 480-100-238(3)(a) – Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity. | Chapter 3- Economic & Load Forecast<br>Chapter 12- Portfolio Scenarios |
| WAC 480-100-238(3)(a) – Plan develops forecasts using methods that address changes in the number, type and efficiency of end-uses. | Chapter 3- Economic & Load Forecast<br>Chapter 5- Energy Efficiency & Demand Response<br>Chapter 8- Transmission & Distribution |

| | |
|---|---|
| WAC 480-100-238(3)(b) – Plan includes an assessment of commercially available conservation, including load management. | Chapter 5- Energy Efficiency & Demand Response<br>Chapter 8- Transmission & Distribution |
| WAC 480-100-238(3)(b) – Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. | Chapter 5- Energy Efficiency & Demand Response<br>Chapter 8- Transmission & Distribution |
| WAC 480-100-238(3)(c) – Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies. | Chapter 9- Generation Resource Options<br>Chapter 11- Preferred Resource Strategy<br>Chapter 12- Portfolio Scenarios |
| WAC 480-100-238(3)(d) – Plan includes an assessment of transmission system capability and reliability (as allowed by current law). | Chapter 8- Transmission & Distribution |
| WAC 480-100-238(3)(e) – Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC. | Chapter 5- Energy Efficiency & Demand Response<br>Chapter 8- Transmission & Distribution<br>Chapter 11- Preferred Resource Strategy |
| WAC-480-100-238(3)(f) – Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition. | Chapter 5- Energy Efficiency & Demand Response<br>Chapter 8- Transmission & Distribution<br>Chapter 9- Generation Resource Options<br>Chapter 12- Portfolio Scenarios |
| WAC 480-100-238(3)(g) – Includes a two-year action plan implementing the long range plan. | Chapter 13- Action Items |
| WAC 480-100-238(3)(h) – Plan includes a progress report on the implementation of the previously filed plan. | Chapter 13- Action Items |
| WAC 480-100-238(5) – Plan includes description of consultation with commission staff and public participation | Chapter 2- Introduction and Stakeholder Involvement |
| WAC 480-100-238(5) – Plan includes description of work plan. | Appendix B |
| WAC 480-107-015(3) – Proposed request for proposals for new capacity needed within three years of the IRP. | Chapter 10- Preferred Resource Strategy |
| RCW 19.280.030-1(e) – An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio; | Chapter 9- Generation Resource Options<br>Chapter 10- Market Analysis |
| RCW 19.280.030-1(f) – Integration of demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events, at the lowest reasonable cost and risk to the utility and its ratepayers. | Chapter 9- Generation Resource Options<br>Chapter 10- Market Analysis |

# 3. Economic & Load Forecast

## Introduction & Highlights

An explanation and quantification of Avista's loads and resources are integral to the IRP. This chapter summarizes Expected Case customer and load projections, load growth scenarios, and recent enhancements to our forecasting models and processes.

**Chapter Highlights**

- Population and employment growth are recovering from the Great Recession.
- The 2017 Expected Case energy forecast grows 0.47 percent per year, replacing the 0.6 percent annual growth rate in the 2015 IRP.
- Peak load growth is lower than energy growth, at 0.42 percent in the winter and 0.46 percent in the summer.
- Retail sales and residential use per customer forecasts continue to decline from 2015 IRP projections.

## Economic Characteristics of Avista's Service Territory

Avista's core service area for electricity includes a population of 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 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.

### 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 that when regional employment growth is stronger than U.S. growth over the business cycle, it is associated with increased in-migration. The reverse holds true. Figure 3.1 shows annual population growth since 1971 and highlights the recessions. 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 Great Recession reduced population growth from nearly two percent in 2007 to less than one percent from 2010 to 2013. Accelerating service area employment growth in 2013 helped push population growth to around one percent starting in 2014.

[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.

**Figure 3.1: MSA Population Growth and U.S. Recessions, 1971-2016**

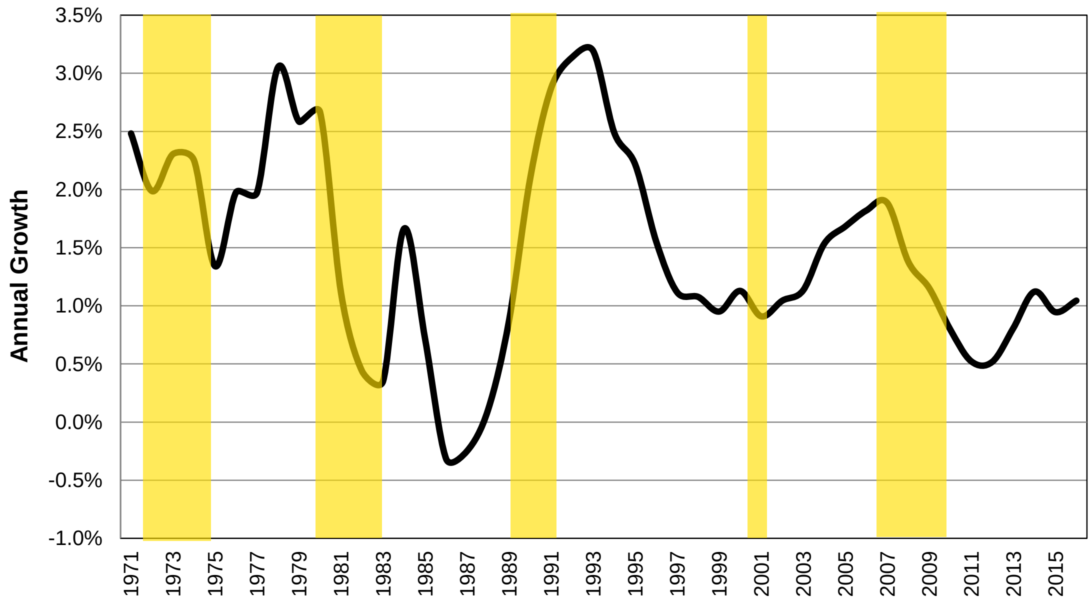



Figure 3.2 shows population growth since the start of the Great Recession in 2007.[3] Service area population growth over the 2010-2012 period was weaker than the U.S.; it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in service area population growth in 2014 relative to the U.S. 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 based on historical data show that, holding U.S. employment-growth constant, every one percent increase in service area employment growth is associated with a 0.4 percent increase in population growth in the next year.

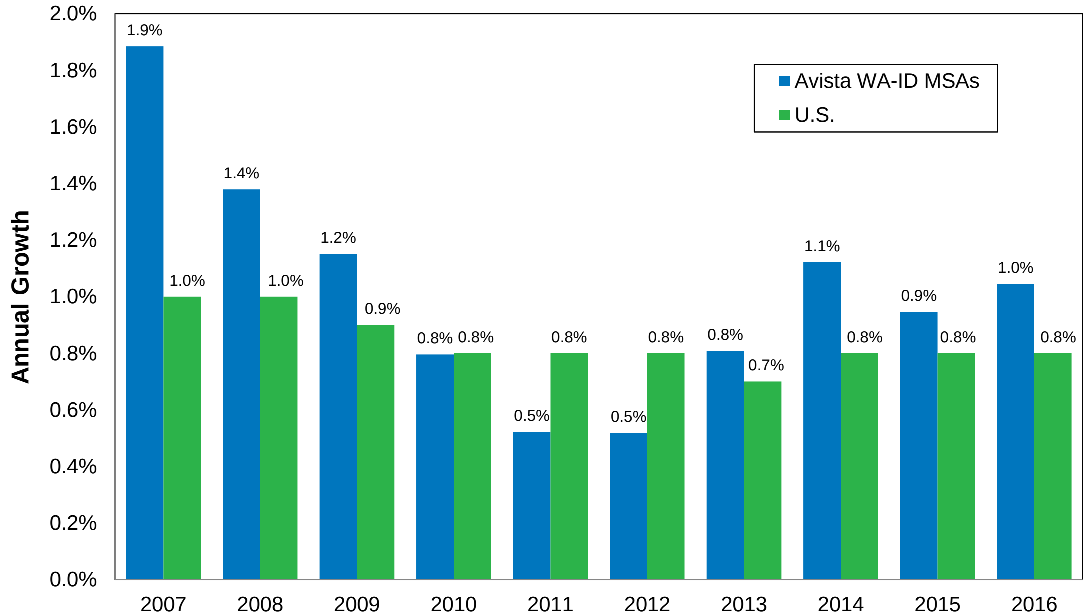
## Employment

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 has transitioned from a natural resources-based manufacturing economy to a services-based 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 one percent of total employment.

Spokane and Coeur d'Alene MSAs are major providers of health and higher education services to the Inland Northwest. A recent addition to these sectors is approval from Washington's legislature for Washington State University to open a medical school in Spokane, Washington.

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

**Figure 3.2: Avista and U.S. MSA Population Growth, 2007-2016**




Non-farm employment growth averaged 2.7 percent per year between 1990 and 2007. However, Figure 3.4 shows that 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.

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.

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

**Figure 3.3: MSA Non-Farm Employment Breakdown by Major Sector, 2016**

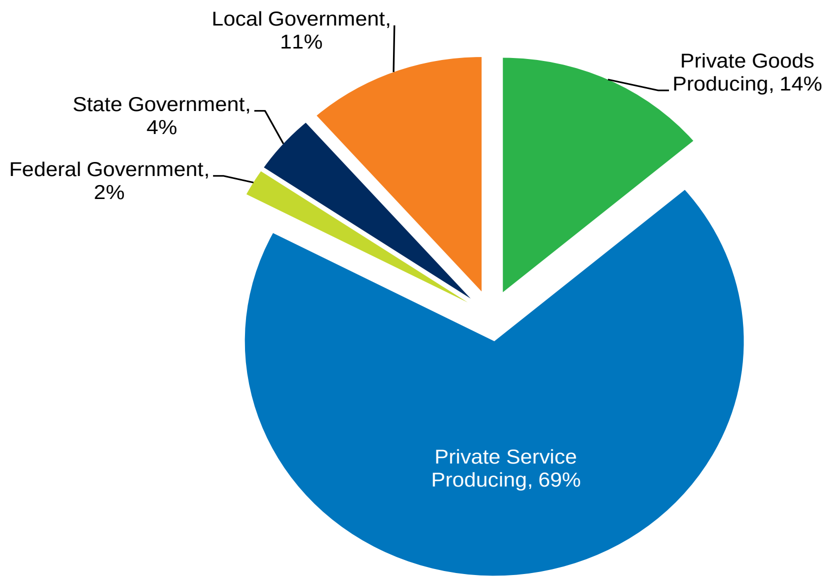



**Figure 3.4: Avista and U.S. MSA Non-Farm Employment Growth, 2007-2016**

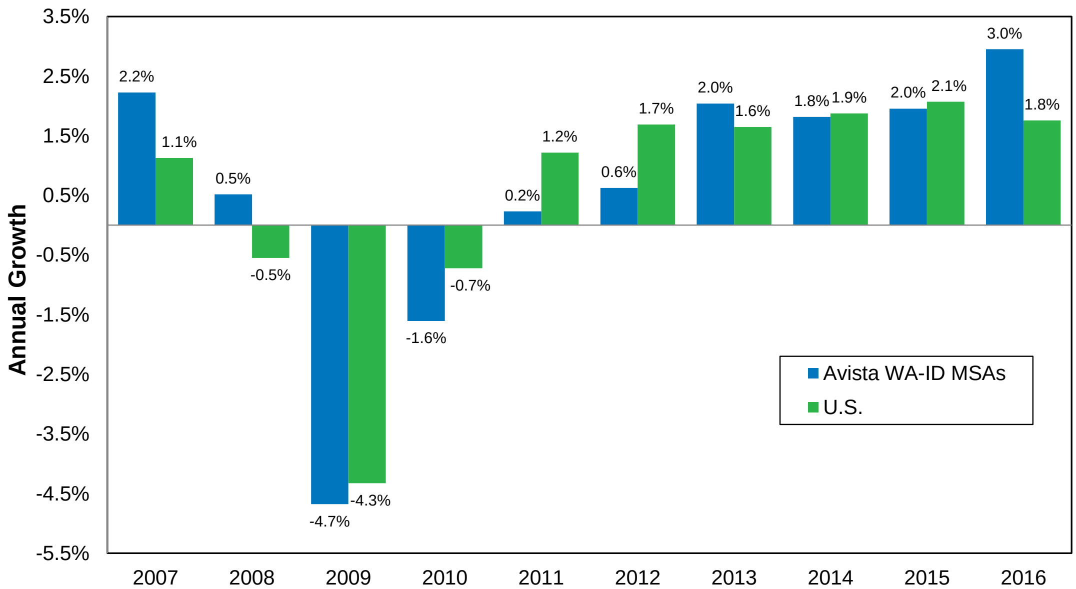
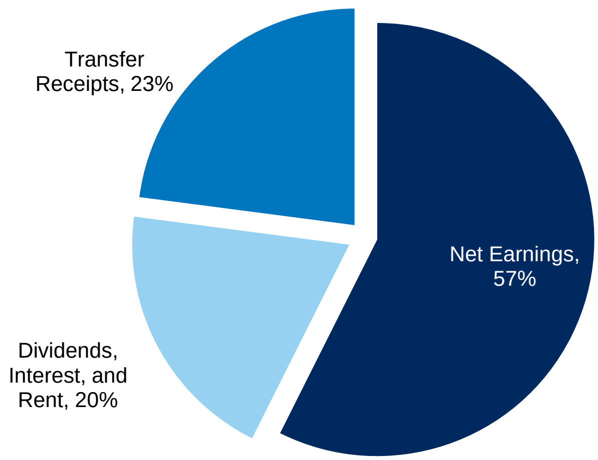


**Figure 3.5: MSA Personal Income Breakdown by Major Source, 2015**

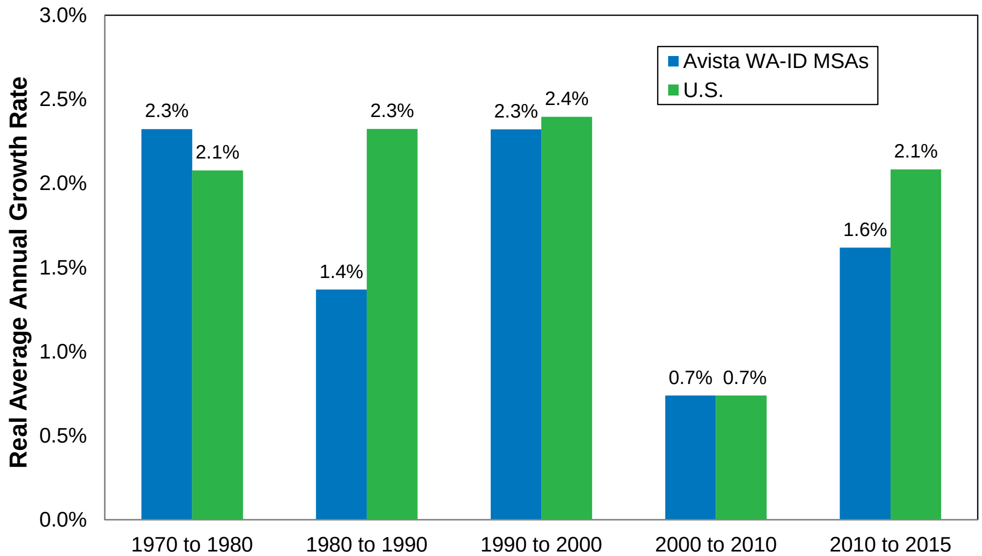



Transfer payments in Avista's service area in 1970 accounted for 12 percent of the local economy. The income share of transfer payments has nearly doubled over the last 40 years to 23 percent. The relatively high regional dependence on government employment and transfer payments means continued federal fiscal consolidation and transfer program reform may reduce future growth. Although 57 percent of personal income is from net earnings, transfer payments 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 reflects an aging regional population, a surge of military veterans, and the Great Recession; the later 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. as a result 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 in the previous decade to around 85 percent. The income ratio has not since recovered.

[7] Data Source: Bureau of Economic Analysis.

**Figure 3.6: Avista and U.S. MSA Real Personal Income Growth, 1970-2013**




## Five-Year Load Forecast Methodology

In non-IRP years, the retail and native load forecasts have a five-year time horizon. Avista conducts the forecasts each spring with the option of second forecast in the winter if changing economic conditions warrant a new forecast. The results are fed into Avista's revenue model, which converts the load forecast into a revenue forecast. In turn, the revenue forecast feeds Avista's earnings model. In IRP years, the long-term forecast boot-straps off the five-year forecast by applying growth assumptions beyond year five.

## Overview of the Five-Year Retail Load Forecast

The five-year retail load forecast is a two-step process. For most schedules in each class, there is a monthly use per customer (UPC) forecast and a monthly customer forecast.[8] The load forecast is generated by 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:

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

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

## 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); 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 3.3 can be improved by converting it into an 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 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.

For certain schedules, such as those related to lighting, simpler regression and smoothing methods are used 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.

Normal weather for the forecast is defined 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 when a full year of new data is available. For example, normal weather for 2015 is the 20-year average of degree-days for the 1995 to 2014 period; and 2016 is the 1996 to 2015 period.

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

The choice of a 20-year moving average for defining normal weather reflects several factors. First, recent climate research from the National Aeronautics and Space Administration's (NASA) Goddard Institute for Space Studies (GISS) shows a shift in temperature starting about 20 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 20 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 shows an upward shift in temperature starting about 20-years ago. A detailed discussion of this analysis is 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 function of the years used to calculate the average. Moving averages of ten and 15 years showed considerably more year-to-year volatility than the 20-year average. This volatility can obscure longer-term trends and lead to overly sharp changes in forecasted loads when the updated definition of normal weather is applied each year. These sharp changes would also cause excessive volatility in the revenue and earnings forecasts.

As noted earlier, if RAP and IP appear in Equation 3.2, then they must also be in the forecast for five years to generate the UPC forecast. The assumption in the five-year forecast for this IRP is the RAP will increase two percent annually. This rate reflects the average annual real growth rate for the 2005-2013 period.

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

| Schedule | Variables | Comment |
|---|---|---|
| **Washington:** | | |
| Residential Schedule 1 | RAP | |
| Commercial Schedule 31 | RAP | Commercial pumping schedule |
| Industrial Schedule 31 | RAP | |
| Industrial Schedules 11, 21, and 25 | IP | |
| **Idaho:** | | |
| Residential Schedule 1 | RAP | |
| Commercial Schedule 31 | RAP | Commercial pumping schedule |
| Industrial Schedules 11 and 21 | IP | |

IP forecasts generate from a regression using the GDP forecast. Equation 3.3 and Figure 3.7 describes this process.

[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.

**Equation 3.3: IP Regression Equation**

$$GIP_{y,US} = \nu_0 + \nu_1 GGDP_{y,US} + \epsilon_y$$

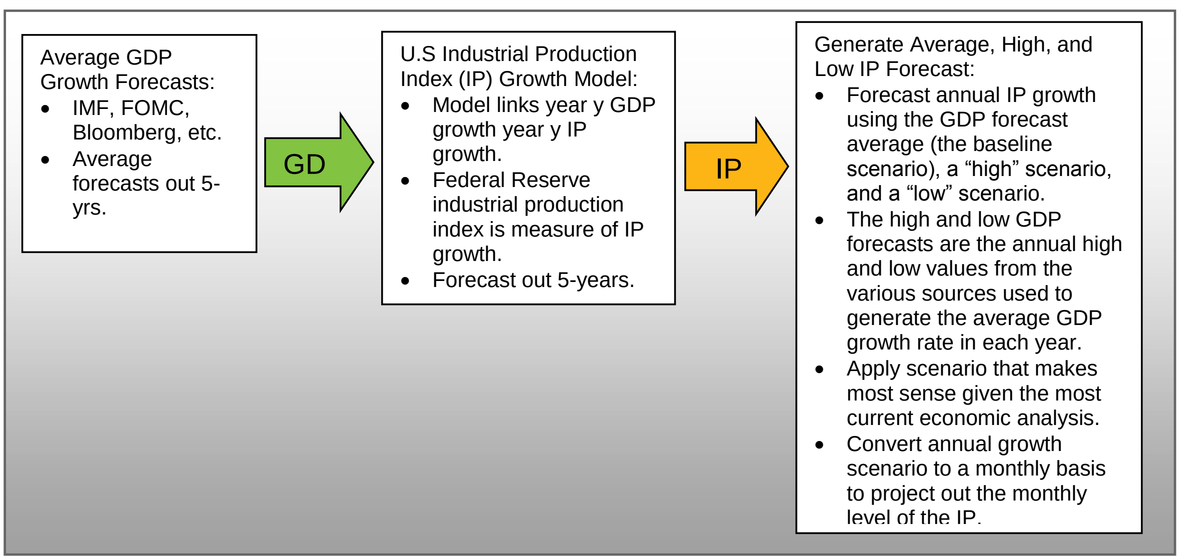
Where:

- $GIP_{y,US}$ = the annual growth in IP in year y.
- $GGDP_{y,US}$ = the annual growth in real GDP in year y.
- $\varepsilon_y$ = a random error term.

Equation 3.3 uses historical data and incorporates forecasts for GDP to forecast GIP over five years. GIP is an input for the generation of a forecast for the level of the IP index. The forecasts for GGDP reflect the average of forecasts from multiple sources. Sources include 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 that macroeconomic factors flow through UPC in the industrial schedules. This reflects the relative stability of industrial customer growth over the business cycle.

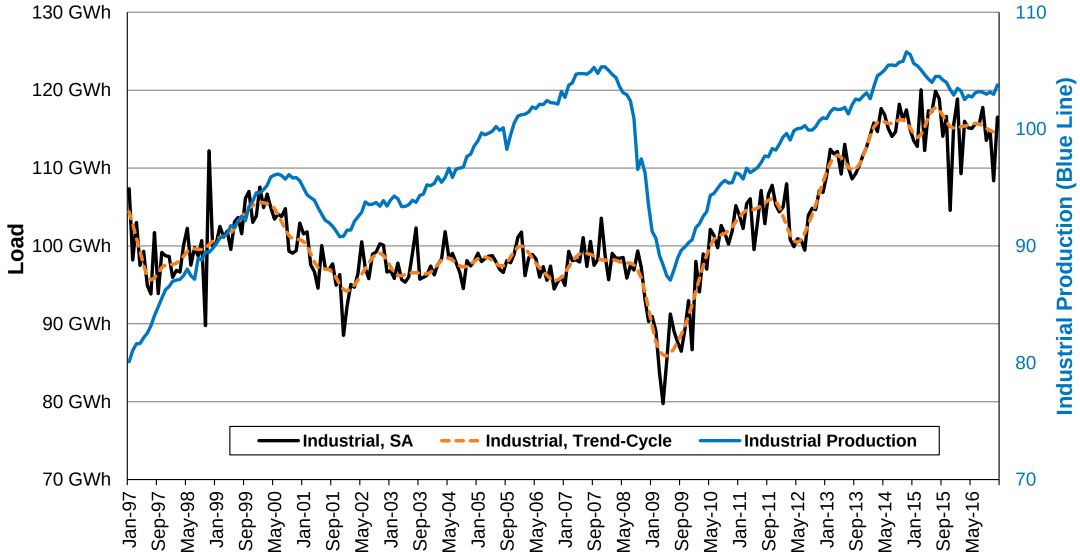
Figure 3.8 shows the historical relationship between the IP and industrial load for electricity.[11,12] The load values have been seasonally adjusted using the Census X12 procedure. The historical relationship is positive for both loads. The relationship is very strong for electricity with the peaks and troughs in load occurring in the same periods as the business cycle peaks and troughs.

**Figure 3.7: Forecasting IP Growth**




[11] Data Source: U.S. Federal Reserve and Avista records.
[12] Figure 3.8 excludes one large industrial customer with significant load volatility.

**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 autoregressive integrated moving average (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 schedule customer counts, the dependent variable. Because the customer counts in most 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 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 users 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 Residential Schedule 1 customers become drivers to generate customer forecasts for Commercial Schedule 11 customers.

Figure 3.9 shows the relationship between annual population growth and year-over-year customer growth.[13] Customer growth has closely followed population growth in the combined Spokane-Kootenai MSAs over the last 15 years. Population growth averaged 1.2% over the 2000-2016 period, and customer growth averaged 1.1 percent annually.

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

**Table 3.2: Customer Growth Correlations, January 2005 – December 2013**

| Customer Class (Year-over-Year) | Residential | Commercial | Industrial | Streetlights |
|---|---|---|---|---|
| Residential | 1 | | | |
| Commercial | 0.892 | 1 | | |
| Industrial | -0.285 | -0.167 | 1 | |
| Streetlights | -0.273 | -0.245 | 0.209 | 1 |

Figure 3.9 demonstrates population growth can be used as a proxy for customer growth. As a result, forecasted population is an adjustment to Expected Case forecasts of Residential Schedule 1 customers in Washington and Idaho. An Expected Case forecast is made using an ARIMA times-series model, for Schedule 1 in Washington and Idaho. If the growth rates generated from this approach differ from forecasted population growth, the Expected Case forecasts are adjusted to match forecasted population growth. Figure 3.10 summarizes the forecasting process for population growth for use in Residential Schedule 1 customers.

**Figure 3.9: Population Growth vs. Customer Growth, 2000-2016**

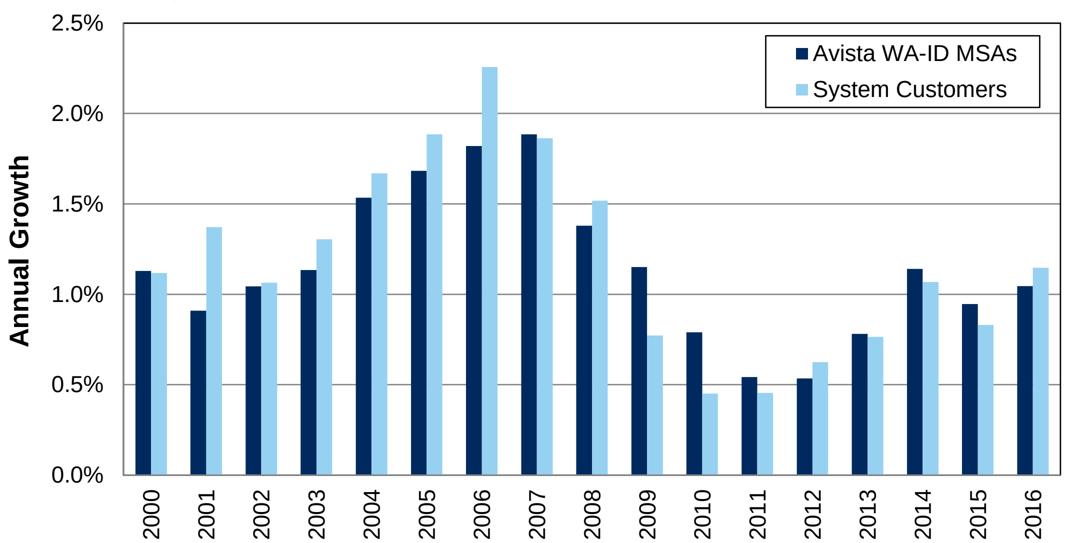
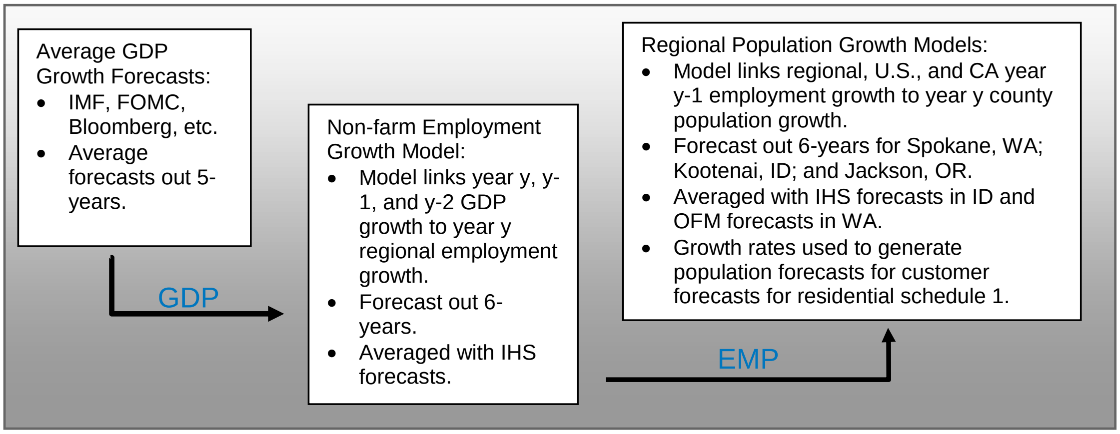


**Figure 3.10: Forecasting Population Growth**




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 forecasting models for regional employment growth are:

**Equation 3.4: Spokane Employment Forecast**

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

**Equation 3.5: Kootenai Employment Forecast**

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

Where:

- SPK = the Spokane, WA MSA.
- KOOT = the Kootenai, ID MSA.
- $GEMP_y$ = employment growth in year y.
- $GGDP_y$,US, $GGDP_{y-1}$,US, and $GGDP_{y-2}$,US = U.S. real GDP growth in years y, y-1, and y-2.
- DKC = structural change (SC) dummy variables for the closing of Kaiser Aluminum in Spokane.
- DHB = for the housing bubble, specific to each region.
- $D_{1994=1}$ and $D_{2009=1}$ = outlier (OL) dummy variables for 1994 and 2009 in Kootenai.
- $\varepsilon_y$ = a random error term.

The same average GDP growth forecasts used for the IP growth forecasts are inputs to the five-year employment growth forecast. Employment forecasts are averaged 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. The forecasting models for regional population growth are:

**Equation 3.6: Spokane Population Forecast**

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

**Equation 3.7: Kootenai Population Forecast**

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

Where:

- SPK = the Spokane, Washington MSA.
- KOOT = the Kootenai, Idaho MSA.
- $GPOP_y$ = employment growth in year y.
- $GEMP_{y-1}$ and $GEMP_{y-2}$ = employment growth in y-1 and y-2.
- $D_{1994=1}$, $D_{2001=1}$, and $D_{2002=1}$ = outlier (OL) dummy variables for recession impacts
- $D_{HB,2007\uparrow=1}$ = structural change (SC) dummy variable that adjusts for the after effects of the housing bubble collapse in the Kootenai, Idaho MSA.

Equations 3.6 and 3.7 are estimated using historical data. Next, the GEMP forecasts (the average of Avista and IHS forecasts) become inputs to Equations 3.6 and 3.7 to generate 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 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 five-year projection out to 2035. It includes the impacts from growing electric vehicle (EV) fleets and residential rooftop photovoltaic solar (PV). The long-run modeling approach starts with Equation 3.8.

**Equation 3.8: 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 3.8 sets annual residential load growth equal to annual customer growth plus the annual UPC growth.[14] $C_y$ 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 Expected Case forecast makes assumptions about the long-run relationship between residential, commercial, and industrial classes, as documented below.

1. Long-run residential and commercial customer growth rates are the same for 2022 to 2040, consistent with historical growth patterns over the past decade. Figure 3.11 shows the Expected Case time path of residential customer growth. The average annual growth rate after 2021 is approximately 0.8 percent, assuming a gradual decline starting in 2022. The values shown in Figure 3.11 were generated with the Employment and Population forecast Equations 3.4, 3.5, 3.6, and 3.7 in conjunction with IHS's employment and population forecasts and Washington's OFM population forecasts. The annual industrial customer growth rate assumption is zero, matching historical patterns for the past decade.

2. Commercial load growth follows changes in residential load growth, but with a spread of 0.5 percent. This high correlation assumption is consistent with the high historical correlation between residential and commercial load growth. The 0.5 percent spread is within the range of historical norms and the forecasted growth spread from the five-year model.

3. Consistent with historical behavior, industrial and streetlight load growth projections are not correlated with residential or commercial load. Annual industrial load growth is set at 0.5 percent and streetlight load growth at 0.1 percent for 2022-2037. Both growth rates are in the range of historical norms and forecasted growth trends from the five-year model.

4. The real residential price per kWh increases at 2 percent per year until 2027. Up to 2027, this is the same as the nominal price increasing 4 percent per year assuming a

[14] 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.

non-energy inflation rate of 2 percent. The real price increase assumption is zero starting in 2027. This assumption means the nominal price is increasing at the same rate as consumer inflation, excluding energy. This assumption relies on historical trends in residential prices and current capital spending plans.

5. The own-price elasticity of UPC is set at -0.11. Own price elasticity was estimated from the five-year UPC forecast equations for Residential Schedule 1 in Washington and Idaho. Specifically, the own-price elasticity calculation uses the customer-weighted average between Washington and Idaho.

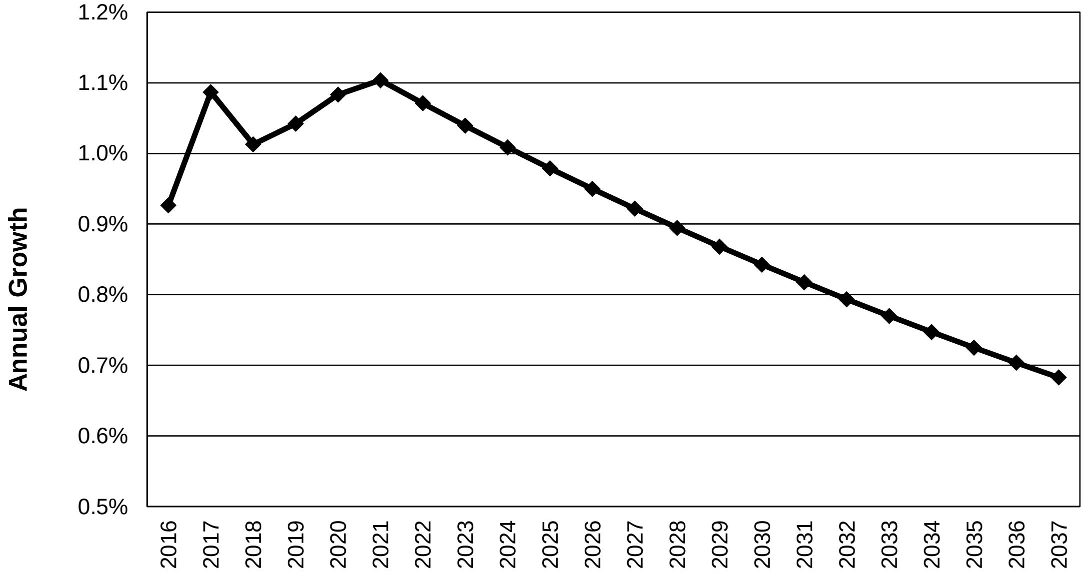
6. From 2022 to 2024, depressed UPC growth results from new lighting and other efficiency standards. The impact is more gradual than the Energy Information Administration's (EIA) modeling assumptions in its 2016 Annual Energy Outlook. The EIA assumes a large decline in UPC growth in 2020 with a subsequent sharp rebound in 2021 that Avista believes is too volatile.

7. Electric vehicles (EVs) grow at a rate consistent with present adoption rates. Using Electric Power Research Institute data, Avista estimates that as of 2015 there were around 400 EVs registered in its service area. The forecasted rate of adoption over the 2020-2040 period is a function of and EV forecast provided by Avista's EV management team. This forecast reflects a low, middle, and, high forecast for EVs in our electric service area. The low forecast predicts 20,000 EVs by 2040; the middle predicts 70,000; and the high predicts 118,000. The final 2040 forecast used for the IRP weights the low forecast at 70 percent, the middle a 20 percent weight; and the high with a 10 percent weight. Therefore, the IRP forecast for 2040 is 0.70 x 20,000 + 0.20 x 70,000 + 0.10 x 118,000 = 39,800 EVs. Between 2016 and 2040, the implied growth rate is 19 percent, which puts total EVs in 2037 as 22,395. The forecast assumes each EV uses 2,500 kWh per year.

8. Rooftop PV penetration, measured as the share of PV residential customers to total residential customers, continues to grow at present levels in the forecast. The average PV system is forecast at the current median of 5.0 kW (DC) and a 13 percent capacity factor, or about 5,578 kWh per year per customer. It assumed that this median system size will increase annually to 6.0 kW (DC) by 2040, or about 6,694 kWh per year per customer. This is equal to an annual growth rate in PV kWh of about 0.8 percent per year. In addition, the IRP assumes the penetration rate (share of residential customers) will follow the historical regression relationship between the historical penetration rate in year t and the historical number of residential customers in year t for the 2008-2015 period. Using this relationship, residential PV penetration will increase from 0.09 percent in 2016 to about 0.42 percent in 2037. Residential solar adoption in Avista's service area continues at a very modest pace even though solar prices have fallen significantly and state subsidies for solar are still in place. One important factor restricting solar adoption in our service territory is the stable real price of residential electricity. Adjusting the average residential price for CPI inflation, less energy, shows that real prices have been largely flat since 2009. The IRP assumes the real price of residential power will continue to rise at a very modest pace which, in

turn, will keep solar adoption in line with the historical data used to forecast future solar adoption. Clarity on federal energy policy would help make possible adjustments to the forecast now based on historical behavior alone.

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




## Native Load Scenarios with Low/High Economic Growth

The high and low load scenarios use population growth Equations 3.6 and 3.7, holding U.S. employment growth constant at 1.1 percent, but varying MSA employment growth at higher and lower levels to gauge the impacts on population growth and utility loads. See Table 3.3. The high/low range for service area employment growth reflects historical employment growth variability. Simulated population growth is a proxy for residential and customer growth in the long-run forecast model, and produces the high and low native load forecasts shown in Figure 3.12.

**Table 3.3: High/Low Economic Growth Scenarios (2017-2037)**

| Economic Growth | Annual U.S. Employment Growth (percent) | Annual Service Area Employment Growth (percent) | Annual Population Growth (percent) |
|---|---|---|---|
| Expected Case | 1.1 | 1.3 | 0.9 |
| High Growth | 1.1 | 2.0 | 1.6 |
| Low Growth | 1.1 | 0.1 | 0.8 |

**Figure 3.12: Average Megawatts, High/Low Economic Growth Scenarios**

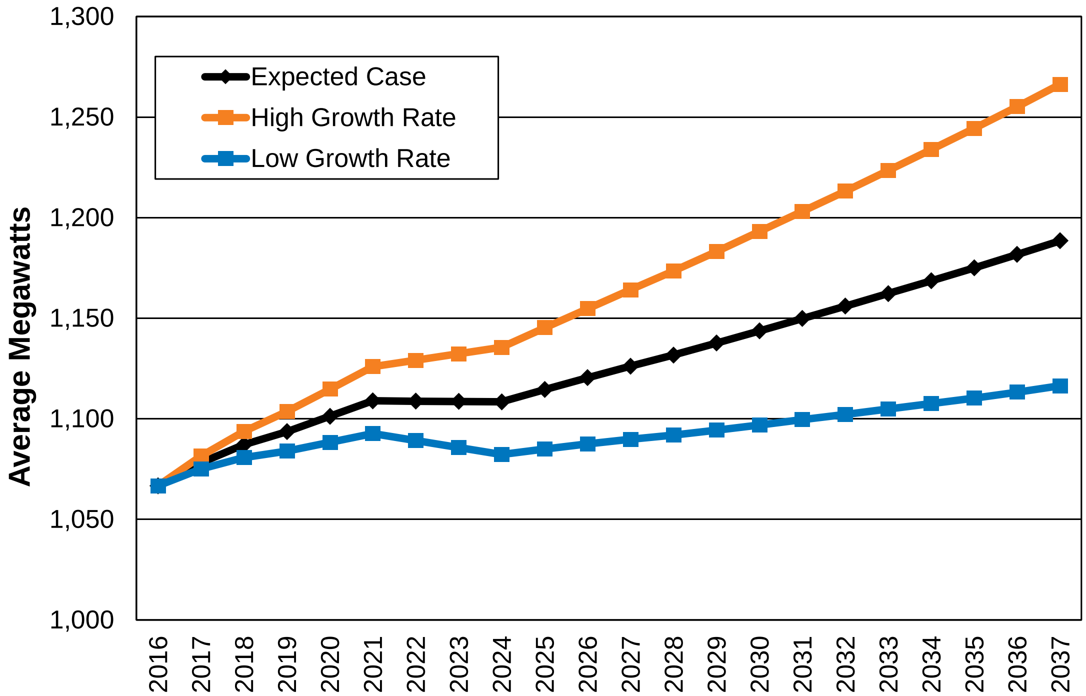



Table 3.4 is the average annual load growth rate over the 2017-2037 period. The low growth scenario predicts a slight load decline over 2022-2024 due to the impact of the phased-in efficiency standards discussed in Item 6 of the Expected Case's assumptions listed above.

**Table 3.4: Load Growth for High/Low Economic Growth Scenarios (2018-2037)**

| Economic Growth | Average Annual Native Load Growth (percent) |
|---|---|
| Expected Case | 0.47 |
| High Growth | 0.82 |
| Low Growth | 0.19 |

## Long-Run Forecast Residential Retail Sales

Focusing on residential kWh sales, Figure 3.13 is the Expected Case 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 2016 Annual Energy Outlook. Both Avista's and EIA's forecasts show positive UPC growth returning around 2035. The 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 reflects the impact of EVs.

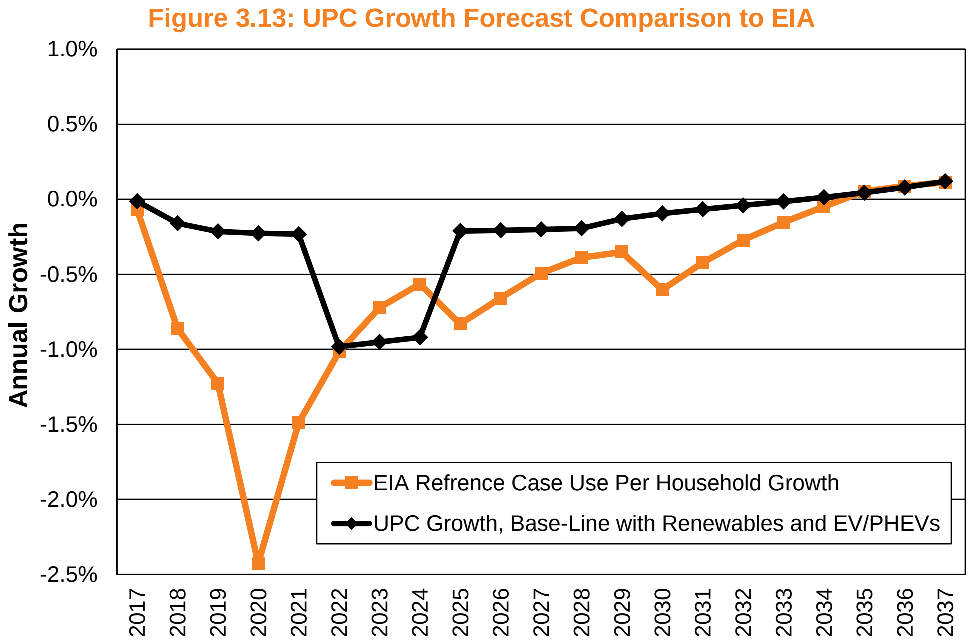
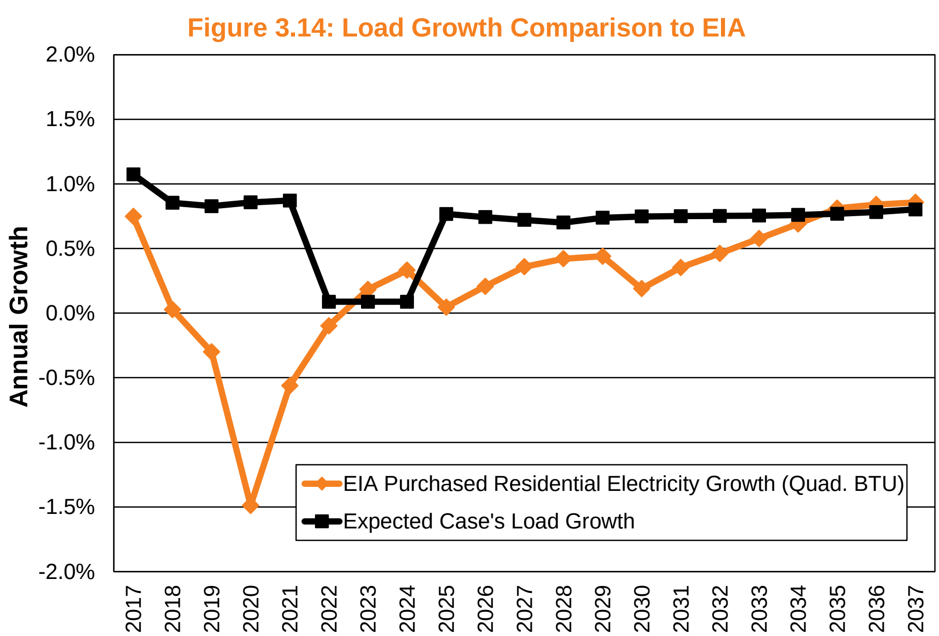



Figure 3.14 shows the EIA and Expected Case residential load growth forecasts of residential load growth. Avista's forecast is higher in the 2015-2020 period, reflecting an assumption that service area population growth will be stronger than the U.S. average, consistent with government and consultant's forecasts for the far west and Rocky Mountain regions where Avista's service territory is located.



# Monthly Peak Load Forecast Methodology

## The Peak Load Regression Model

The peak load forecast helps Avista determine the amount of resources necessary to meet peak demand. In particular, Avista must build generation capacity to meet winter and summer peak periods. Looking forward, the highest peak loads are 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. On a planning basis where extreme weather is expected to occur in the winter, peak loads occur in the winter throughout the IRP timeframe. Equation 3.9 shows the current peak load regression model.

**Equation 3.9: Peak Load Regression Model**

$$hMW_{d,t,y}^{netpeak} = \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2 \\ + \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD_{d,t,y}^{HIGH} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{q(t).y-1} \\ + \omega_{WD} D_{d,t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Mar\ 2005=1} + \omega_{OL} D_{Feb\ 2012=1} + \omega_{OL} D_{Jan\ 2015=1} \\ + \omega_{SC} D_{Winter\ 2016} + \omega_{SC} D_{Summer\ 2016} + \epsilon_{d,t,y}$$

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 $\mathrm{HDD}_{\mathrm{d,t,y}}$.$\mathrm{HDD}_{\mathrm{d-1,t,y}}$ 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.[15]
- $\mathrm{GDP}_{\mathrm{q(t).y-1}}$ = level of real GDP in quarter q covering month t in year y-1.
- $\omega_{\mathrm{WD}}\mathrm{D}_{\mathrm{d,t,y}}$ = dummy vector indicating the peak's day of week.
- $\omega_{\mathrm{SD}}\mathrm{D}_{\mathrm{t,y}}$ = seasonal dummy vector indicating the month; and the other dummy variables control for outliers in March 2005, February 2012, and January 2015.
- $\omega_{\mathrm{SD}}\mathrm{D}_{\mathrm{Winter\ 2016}}$ and $\omega_{\mathrm{SD}}\mathrm{D}_{\mathrm{Summer\ 2016}}$ = dummy variables to control for the extreme La Nina effects on peak load.
- $\varepsilon_{\mathrm{d,t,y}}$ = uncorrelated $\mathrm{N}(0, \sigma)$ error term.

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

Equation 3.9 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

[15] This term provides a better model fit than the square of CDD.

out N years by using forecasted levels of GDP as shown in Equation 3.3.[16] All other factors besides GDP remain constant to determine the impact of GDP on peak load. For winter, this is defined as the forecasted series W:

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

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

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

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 ($S_G$.):

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

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

In Equation 3.10, 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. The following section describes this process.

### Simulated Extreme Weather Conditions with Historical Weather Data

Equation 3.10 generates a series of simulated extreme peak load values for heating degree days.

**Equation 3.10: Peak Load Simulation Equation for Winter Months**

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

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.

[16] Forecasted GDP is generated by applying the averaged GDP growth forecasts used for the employment and industrial production forecasts discussed previously.

Similarly, the model for cooling degree days is:

**Equation 3.11: 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.
- $\mathrm{CDD}_{\mathrm{t,y,MAX}}$ = 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 3.10 and 3.11 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, $y_c$. The average for each month are shown by Equations 3.12 and 3.13.

**Equation 3.12: Current Year Peak Load for Winter Months**

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

**Equation 3.13: Current Year Peak Load for Summer Months**

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

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 peak load forecast is finalized when the loads of two large industrial customers excluded from the Equation 3.12 and 3.13 estimations are added back in.

Table 3.5 shows estimated peak load growth rates with and without the two large industrial customers. Figure 3.15 shows the forecasted time path of peak load out to 2040, and Figure 3.16 shows the high/low bounds based on a one-in-20 event (95 percent confidence interval) using the standard deviation of the simulated peak loads from Equations 3.12 and 3.13.

**Table 3.5: Forecasted Winter and Summer Peak Growth, 2017-2037**

| Category | Winter (Percent) | Summer (Percent) |
|---|---|---|
| Excluding Large Industrial Customers | 0.42 | 0.46 |
| Including Large Industrial Customers | 0.38 | 0.42 |

Table 3.6 shows the summer peak is forecast to grow faster than the winter peak. Under current growth forecasts, the orange summer line in Figure 3.15 will converge with the blue winter line in approximately year 2100. Figure 3.16 shows that the winter high/low bound considerably larger than summer, and reflects a greater range of temperature anomalies in the winter months. Table 3.6 shows the energy and peak forecasts.

**Figure 3.15: Peak Load Forecast 2017-2037**

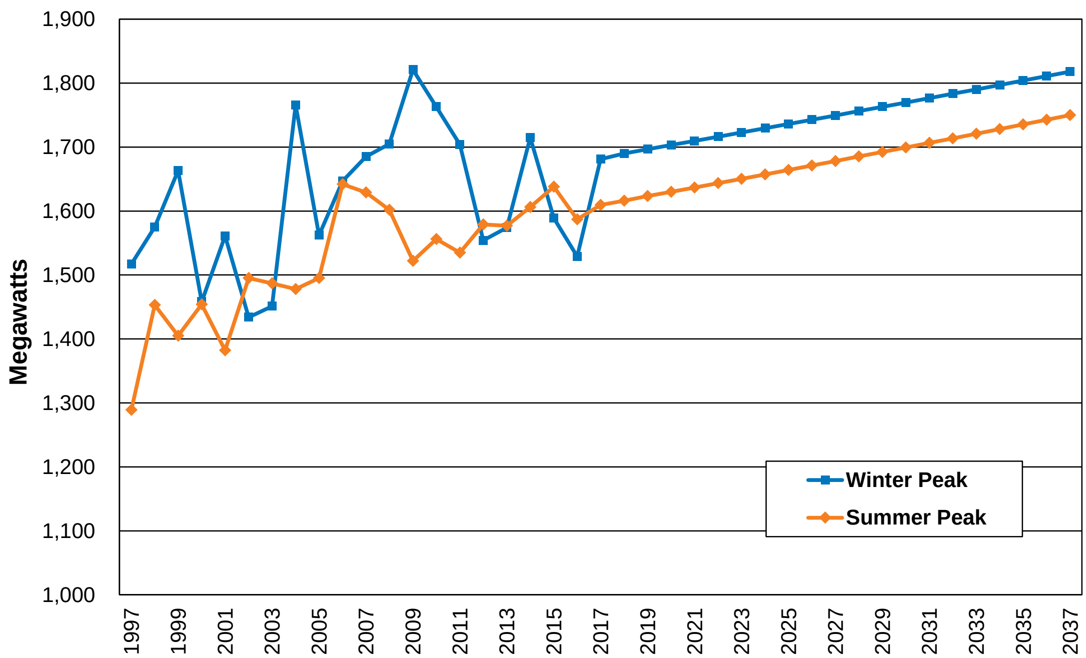


**Figure 3.16: Peak Load Forecast with 1 in 20 High/Low Bounds, 2017-2037**

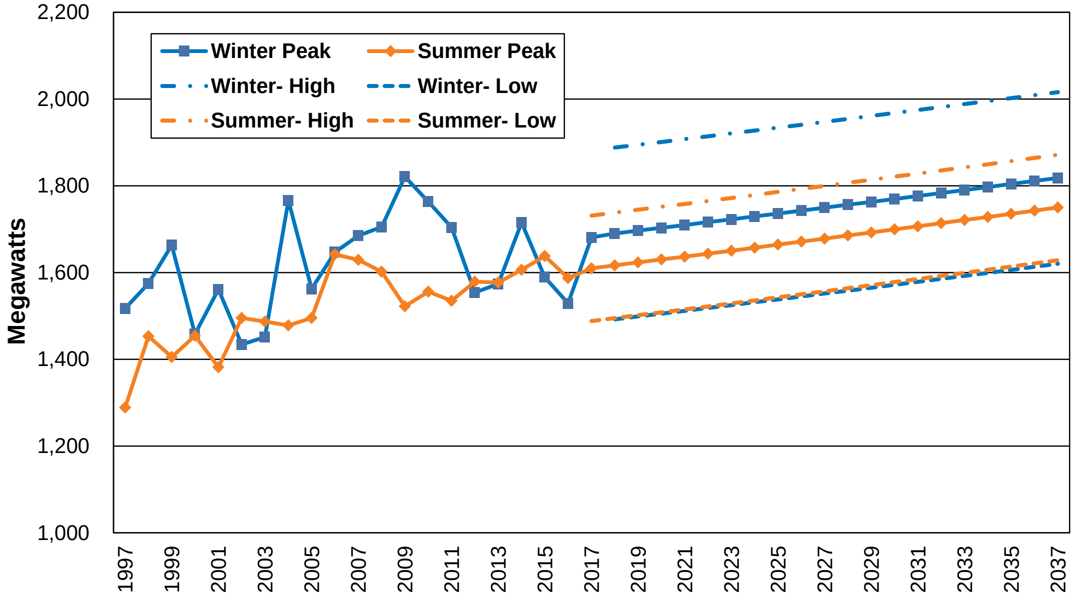



**Table 3.6: Energy and Peak Forecasts**

| Year | Energy (aMW) | Winter Peak (MW) | Summer Peak (MW) |
|---|---|---|---|
| 2018 | 1,087 | 1,690 | 1,616 |
| 2019 | 1,094 | 1,697 | 1,623 |
| 2020 | 1,101 | 1,703 | 1,630 |
| 2021 | 1,109 | 1,710 | 1,637 |
| 2022 | 1,109 | 1,716 | 1,643 |
| 2023 | 1,109 | 1,723 | 1,650 |
| 2024 | 1,108 | 1,729 | 1,657 |
| 2025 | 1,114 | 1,736 | 1,664 |
| 2026 | 1,120 | 1,743 | 1,671 |
| 2027 | 1,126 | 1,749 | 1,678 |
| 2028 | 1,132 | 1,756 | 1,685 |
| 2029 | 1,138 | 1,763 | 1,692 |
| 2030 | 1,144 | 1,770 | 1,699 |
| 2031 | 1,150 | 1,776 | 1,707 |
| 2032 | 1,156 | 1,783 | 1,714 |
| 2033 | 1,162 | 1,790 | 1,721 |
| 2034 | 1,169 | 1,797 | 1,728 |
| 2035 | 1,175 | 1,804 | 1,735 |
| 2036 | 1,182 | 1,811 | 1,743 |
| 2037 | 1,189 | 1,818 | 1,750 |

### Extreme Temperature Analysis

The impact of temperature changes and the relevance of historical temperature data drives much of the recent load forecasting debates regarding peak load forecasts. To validate the use of historical temperatures in the peak load forecast, an analysis using the same GISS methodology and reference periods referenced in the UPC forecast methodology section. In particular, using 1951-1980 as the reference period, Avista examined daily temperature anomalies using daily temperature data from the Spokane International Airport going back to 1947.

The analysis focuses on the core summer months (June, July, and August) and winter months (December, January, and February). The GISS study only considers summer months and found, in addition to an increase in the average temperature in the summer, the variance around the average increased. Specifically, the frequency of extreme temperature anomalies three or more standard deviations above the summer average increased compared to the 1950-1981 reference period. In contrast, Avista's analysis shows average temperature increases compared to the reference period, but there was no significant shift in the frequency of extreme temperature events. This finding supports continued use of historical temperature extremes for peak load forecasting.

# 4. Existing Supply Resources

## Introduction & Highlights

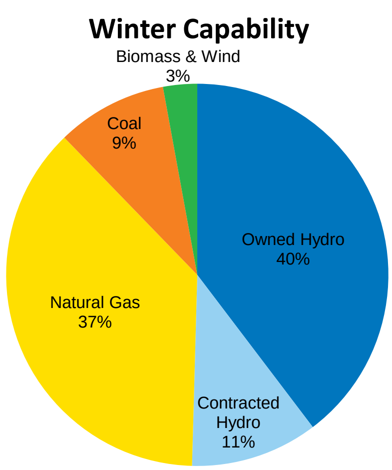
Avista relies on a diverse portfolio of assets to meet customer loads, including owning and operating eight hydroelectric developments on the Spokane and Clark Fork rivers. Its thermal assets include partial ownership of two coal-fired units, five natural gas-fired projects, and a biomass plant. Avista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

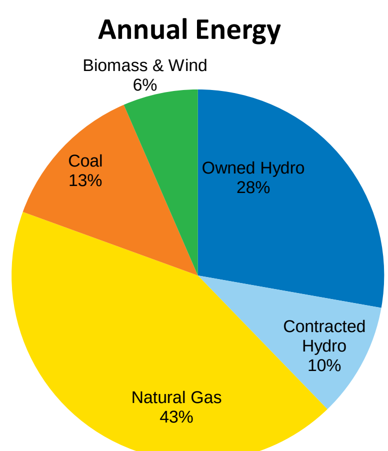
**Section Highlights**

- Hydroelectric represents about half of Avista's winter generating capability.
- Natural gas-fired plants represent the largest portion of Avista's thermal generation portfolio.
- Six percent of Avista's generating potential is biomass and wind.
- A major rehabilitation project for Nine Mile Falls is ongoing; the capacity upgrade was complete in 2016.
- 490 of Avista customers net meter a total of 3.5 megawatts of their own generation.

Figure 4.1 shows Avista capacity and energy mixes. Winter capability is the share of total capability of each resource type the utility can rely upon to meet peak load absent outages. 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 supply in the peak winter months is hydroelectric at 51 percent, followed by natural gas. On an energy capability basis, natural gas-fired generation can produce more energy, at 43 percent, than hydroelectric at 38 percent, because it is not constrained by fuel limitations. In any given year, the resource mix will change depending on streamflow conditions and market prices.

**Figure 4.1: 2018 Avista Capability & Energy Fuel Mix**



Avista reports its fuel mix annually in the Washington State Fuel Mix Disclosure. The State calculates the resource mix used to serve load, rather than generation potential, by adding regional estimates for unassigned market purchases and Avista-owned generation minus environmental attributes from renewable energy credit (REC) sales.

## Spokane River Hydroelectric Developments

Avista owns and operates six hydroelectric developments on the Spokane River. Five operate under 50-year FERC operating licenses issued in June 2009. The sixth, Little Falls, operates under separate authorization from the U.S. Congress. 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 state of the facility. This capacity is often higher than the nameplate rating for hydroelectric developments because of plant upgrades and favorable head or flow conditions. The nameplate, or installed capacity, is the 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 facility furthest upstream on the Spokane River. It is located several miles east of the Washington/Idaho border. It 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 nameplate unit with a 10.26-MW maximum capacity rating.

### Monroe Street

Monroe Street was Avista's first generation development. It began serving customers in 1890 in downtown Spokane near Riverfront Park. Rebuilt in 1992, the single generating unit has a 14.8-MW nameplate rating and a 15.0-MW maximum capacity rating.

*Monroe Street Development and Huntington Park, Downtown Spokane, WA*

### 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.

### 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.

### 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 of on-peak capacity and have a 32.0 MW nameplate rating. Avista is carrying out a series of upgrades to the Little Falls development. Much of the new electrical equipment and the installation of a new generator excitation system are complete. Projects include replacing station service equipment, updating the powerhouse crane, and developing new control schemes and panels are complete. Work is now ongoing to replace generators, turbines, and unit protection and control systems on the four units will start.

## 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. The plants operate under a FERC license through 2046. Both hydroelectric projects on the Clark Fork River connect to the Avista transmission system.

### Noxon Rapids

The Noxon Rapids development includes four generators installed between 1959 and 1960, and a fifth unit 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.

### Cabinet Gorge

Cabinet Gorge started generating power in 1952 with two units, and added two additional generators the following year. Upgrades to units 1 through 4 occurred in 1994, 2004, 2001, and 2007. The current maximum on-peak plant capacity is 270.5 MW; it has a nameplate rating of 265.2 MW.

## Total Hydroelectric Generation

Avista's hydroelectric plants have 1,080 MW of on-peak 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. Based on IRP analyses, Avista expects each plant to continue operation through the 20-year IRP horizon. The resources provide dependable energy and capacity serving base- and peak-load obligations. A summary of their capabilities is in Table 4.2.

**Table 4.2: Avista-Owned Thermal Resources**

| Project Name | Location | Fuel Type | Start Date | Winter Maximum Capacity (MW) | Summer Maximum Capacity (MW) | Nameplate Capacity (MW) |
|---|---|---|---|---|---|---|
| Colstrip 3 (15%) | Colstrip, MT | Coal | 1984 | 111.0 | 111.0 | 123.5 |
| Colstrip 4 (15%) | Colstrip, MT | Coal | 1986 | 111.0 | 111.0 | 123.5 |
| Rathdrum | Rathdrum, ID | Gas | 1995 | 176.0 | 130.0 | 166.5 |
| Northeast | Spokane, WA | Gas | 1978 | 66.0 | 42.0 | 61.2 |
| Boulder Park | Spokane, WA | Gas | 2002 | 24.6 | 24.6 | 24.6 |
| Coyote Springs 2[1] | Boardman, OR | Gas | 2003 | 317.5 | 286.0 | 287.3 |
| Kettle Falls | Kettle Falls, WA | Wood | 1983 | 47.0 | 47.0 | 50.7 |
| Kettle Falls CT[2] | Kettle Falls, WA | Gas | 2002 | 11.0 | 8.0 | 7.5 |
| **Total** | | | | **864.1** | **759.6** | **844.8** |

### Colstrip Units 3 and 4

The Colstrip plant, located in eastern Montana, consists of four coal-fired steam plants connected to a double-circuit 500 kV BPA transmission line under a long-term wheeling agreement. Talen Energy Corporation operates the facilities on behalf of the six owners. Avista has no ownership interest in Units 1 or 2, but 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 222.0 MW, and a nameplate rating of 247.0 MW.

### Rathdrum

Rathdrum consists of two 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 capacity of 176.0 MW in the winter and 126.0 MW in the summer. The nameplate rating is 166.5 MW.

### Northeast

The Northeast plant, located in Spokane, has two aero-derivative simple-cycle CT units completed in 1978. It connects to Avista's transmission system. The plant is capable of burning natural gas or fuel oil, but current air permits preclude the use of fuel oil. The

[1] For purposes of long-term transmission reservation planning for bundled retail service to native load customers, replacement resources for Coyote Springs 2 is presumed and planned to be integrated via Avista's interconnection(s) to the Mid-Columbia region.
[2] The Kettle Falls CT capacity quantities include output of the natural gas-fired turbine plus the benefit of its steam to the main unit's boiler.

combined maximum capacity of the units is 68.0 MW in the winter and 42.0 MW in the summer, with a nameplate rating of 61.2 MW. The plant permit limits run hours to 100 per year.

### Boulder Park

The Boulder Park project entered service in the Spokane Valley in 2002 and connects directly to the Avista transmission system. The site uses six natural gas-fired internal combustion reciprocating engines to produce a combined maximum capacity and nameplate rating of 24.6 MW.

### 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; it has a maximum capacity of 317.5 MW in the winter and 285 MW in the summer, with duct burners. The nameplate rating of the plant is 287.3 MW. In 2016, the Advanced Hot Gas Path is the latest upgrade to the plant increasing both the unit's capacity and efficiency.

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

The Kettle Falls Generating Station, a woody biomass facility, 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 biomass steam plant uses waste wood products from area mills and forest slash, but can also burn natural gas. 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.

The wood-fired portion of the plant has a maximum capacity of 50.0 MW, and its nameplate rating is 50.7 MW. The plant typically operates between 45 and 47 MW because of fuel conditions that change depending on the moisture content of the fuel. The plant's capacity increases to 55.0 to 58.0 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 resource can be limited in the winter when the natural gas pipeline is capacity constrained. For IRP modeling, the CT does not run when temperatures fall below zero. This operational assumption reflects natural gas availability limits on the plant when local natural gas distribution demand is highest.

## Power Purchase and Sale Contracts

Avista uses purchase and sale arrangements of varying lengths to meet a portion of its load requirements. Contracts provide many benefits, including environmentally low-impact and low-cost hydroelectric and wind power. This chapter describes the contracts in effect during the timeframe of the 2017 IRP. Tables 4.3 through 4.5 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 then served by the PUDs. Long-term contracts with public, municipal, and investor-owned utilities throughout the Northwest assisted with project financing and ensured 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 four of these projects “at cost.” Avista now competes in capacity auctions to retain the rights of these expiring contracts. The Mid-Columbia contracts in Table 4.3 provide energy, capacity and reserve capabilities; in 2017, the contracts provide approximately 154 MW of capacity and 101 aMW of energy. Recently, Avista successfully negotiated an extension of the Chelan PUD contract. However, there are no guarantees to extend contract rights beyond this term. Due to the uncertainty around future availability and cost, the IRP does not include these contracts in the resource mix beyond their current expiration dates. Avista was also able to extend its legacy Douglas PUD contract set to expire in 2018. The new contract provides capacity and energy through September 2028 at a decreasing portion each year until it expires.

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. On September 16, 2024, the Columbia River Treaty may end. 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 soon negotiations will begin to determine the future of the treaty. This IRP does not model alternative outcomes for the treaty negotiations, because it will not likely affect long-term resource acquisition and we cannot speculate on future wholesale electricity market impacts of the treaty.

### 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.

**Table 4.3: Mid-Columbia Capacity and Energy Contracts[3]**

| Counter Party | Project(s) | Percent Share (%) | Start Date | End Date | Estimated On-Peak Capability (MW) | Annual Energy (aMW) |
|---|---|---|---|---|---|---|
| Grant PUD | Priest Rapids | 3.7 | Dec-2001 | Dec-2052 | 34.8 | 19.5 |
| Grant PUD | Wanapum | 3.7 | Dec-2001 | Dec-2052 | 34.5 | 18.7 |
| Chelan PUD | Rocky Reach | 5.0 | Jan-2016 | Dec-2030 | 58.1 | 35.8 |
| Chelan PUD | Rock Island | 5.0 | Jan- 2016 | Dec-2030 | 20.1 | 18.4 |
| Douglas PUD | Wells | 3.3[4] | Feb-1965 | Sep-2028 | 27.9 | 14.3 |
| Canadian Entitlement | | | | | -10.1 | -5.7 |
| **2018 Total Net Contracted Capacity and Energy** | | | | | **165.3** | **101.0** |

## 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 4.4. The IRP assumes renewal of these contracts after their current terms end.

**Table 4.4: PURPA Agreements**

| Contract | Fuel Source | Location | End Date | Size (MW) | Annual Energy (aMW) |
|---|---|---|---|---|---|
| Meyers Falls | Hydro | Kettle Falls, WA | 12/2019 | 1.30 | 1.05 |
| Spokane Waste to Energy | Waste | Spokane, WA | 12/2017 | 18.00 | 16.00 |
| Spokane County Digester | Biomass | Spokane, WA | 8/2021 | 0.26 | 0.14 |
| Plummer Saw Mill | Wood Waste | Plummer, ID | 12/2019 | 5.80 | 4.00 |
| Deep Creek | Hydro | Northpoint, WA | 12/2017 | 0.41 | 0.23 |
| Clark Fork Hydro | Hydro | Clark Fork, ID | 12/2017 | 0.22 | 0.12 |
| Upriver Dam[5] | Hydro | Spokane, WA | 12/2019 | 17.60 | 6.17 |
| Big Sheep Creek Hydro | Hydro | Northpoint, WA | 6/2021 | 1.40 | 0.79 |
| Ford Hydro LP | Hydro | Weippe, ID | 6/2022 | 1.41 | 0.39 |
| John Day Hydro | Hydro | Lucille, ID | 9/2022 | 0.90 | 0.25 |
| Phillips Ranch | Hydro | Northpoint, WA | n/a | 0.02 | 0.01 |
| **Total** | | | | **47.32** | **29.15** |

[3] 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 4.3 are presumed and planned to be integrated via Avista's interconnection(s) to the Mid-Columbia region.
[4] The share from Wells is dependent on Douglas PUD's load growth.
[5] Energy estimate is net of the city of Spokane's pumping load.

### Bonneville Power Administration – WNP-3 Settlement

Avista signed settlement agreements with BPA and Energy Northwest on September 17, 1985, ending its nuclear plant construction delay claims against both parties. The settlement provides an energy exchange through June 30, 2019, with an agreement to reimburse Avista for WPPSS – Washington Nuclear Plant No. 3 (WNP-3) preservation costs and an irrevocable offer of WNP-3 capability under the Regional Power Act.

The energy exchange portion of the settlement contains two basic provisions. The first provision provides approximately 42 aMW of energy to Avista from BPA through 2019, subject to a contract minimum of 5.8 million megawatt-hours. Avista is obligated to pay BPA operating and maintenance costs associated with the energy exchange as determined by a formula that ranges from $16 to $29 per megawatt-hour in 1987-year constant dollars. The second provision provides BPA approximately 32 aMW of return energy at a cost equal to the actual operating cost of Avista's highest-cost resource. A discussion of this obligation, and how Avista plans for it, is in Chapter 6.

### Palouse Wind – Power Purchase Agreement

Avista signed a 30-year power purchase agreement in 2011 with Palouse Wind for the entire output of its 105-MW project. Avista has the option to purchase the project after 10 years. Commercial operation began in December 2012. The project is EIA-qualified and directly connected to Avista's transmission system.

**Table 4.5: Other Contractual Rights and Obligations**

| Contract | Type | Fuel Source | End Date | Winter Capacity (MW) | Summer Capacity (MW) | Annual Energy (aMW) |
|---|---|---|---|---|---|---|
| Douglas Settlement | Purchase | Hydro | 9/2018 | 2 | 2 | 3 |
| Energy America | Sale | CEC RECs[6] | 12/2019 | 50 | 50 | 50 |
| WNP-3 | Purchase | System | 6/2019 | 82 | 0 | 42 |
| Lancaster | Purchase | Natural Gas | 10/2026 | 283 | 233 | 218 |
| Palouse Wind | Purchase | Wind | 12/2042 | 0 | 0 | 40 |
| Nichols Pumping | Sale | System | n/a | -1 | -1 | -1 |
| **Total** | | | | **416** | **284** | **352** |

## Customer-Owned Generation

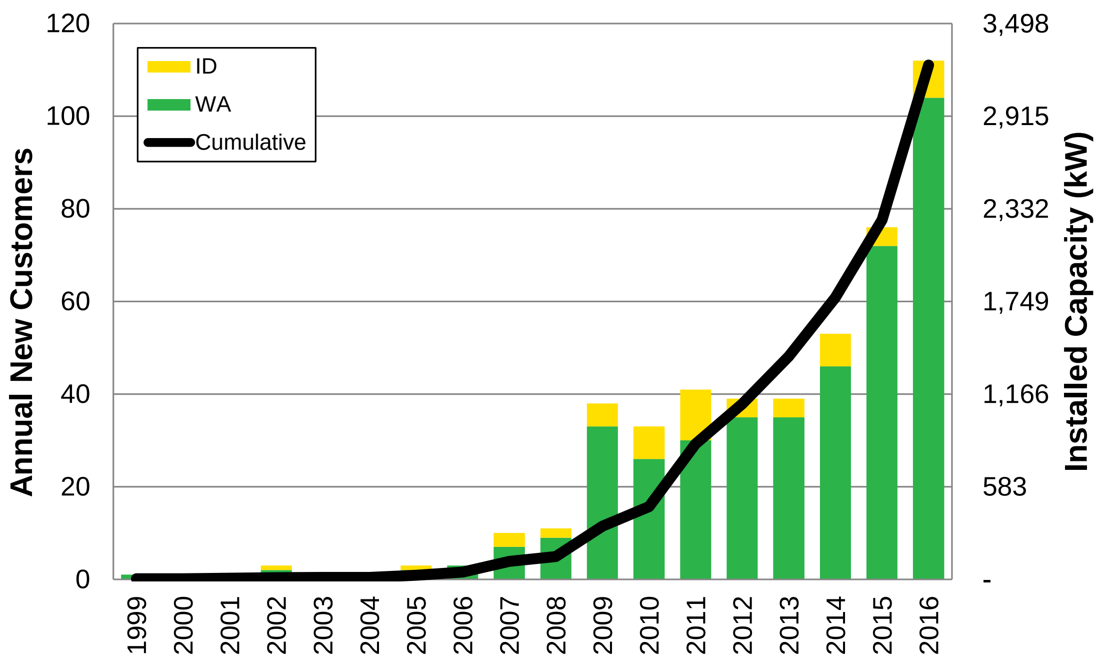
A small but growing number of customers install their own generation systems. In 2007 and 2008, the average number of new net-metering customers added was 10 yearly; and between 2009 and 2014, the average is 41 per year, but over the last two years, an increasing amount, 76 in 2015, and 112 in 2016. The recent increase likely driven by solar price reductions and the near term expiring of the generous federal and new state tax incentives. Certain renewable projects qualify for the federal government's 30 percent tax credit and Washington tax incentives of up to $5,000 per year through July

[6] CEC RECs are renewable resources based on approval of the California Energy Commission. Kettle Falls, Palouse Wind, Nine Mile Falls, Post Falls, Monroe Street, and Upper Falls are CEC certified.

2020. The Washington utility taxes credit finances these incentives that rise to as much as $1.08 per kWh.

Avista had 490 customer-installed net-metered generation projects on its system in early June 2017 representing a total installed capacity of 3.5 MW. Eighty-eight percent of installations are in Washington, with most located in Spokane County. Figure 4.2 shows annual net metering customer additions through 2016. Solar is the primary net metered technology; the remaining is a mix of wind, combined solar and wind systems, and biogas. The average annual capacity factor of the solar facilities is 13 percent. Small wind turbines typically produce at less than a 10 percent capacity factor, depending on location. Given the current tax incentives when the IRP modeling occurred were nearing optimal payback, the number of new net-metered systems rose significantly in 2016. The signature of SB 5939 on July 7, 2017 established a new solar incentive program from October 1, 2017 through 2029 at a lower rate than the current subsidy. If the number of net-metering customers continues to increase, Avista may need to adjust rate structures for customers who rely on the utility's infrastructure, but do not contribute financially for infrastructure costs.

**Figure 4.2: Avista's Net Metering Customers**



## Solar

As solar equipment and installation prices have decreased, the nation's interest and development of the technology has increased dramatically. Avista has three small projects of its own and is working with a developer to construct a fourth. The first was three kilowatts on its corporate headquarters as part of the Solar Car initiative. The solar production helped power two electric vehicles in the corporate fleet. Avista installed a 15-kilowatt solar system in Rathdrum, Idaho to supply Buck-A-Block, a voluntary program allowing customers to purchase green energy. The 423-kW Avista Community Solar project entered service in 2015. The project takes advantage of federal and state subsidies. The $1,080/MWh Washington solar subsidy allows customers to purchase individual solar panels within the facility and receive payments that more than offset their upfront investment. The program utilizes approximately $600,000 each year in state tax incentives. SB 5939, signed by Governor Inslee on July 7, 2017, updates the solar incentive program for residential, commercial and shared commercial projects starting on or after October 1, 2017. The new solar program pays an incentive for eight years with projects starting later receiving a smaller incentive.

In April 2017, the company released a Request for Proposals to develop up to a 15 MW (DC) solar facility for the company's new Solar Select Program. This project will voluntarily allow commercial and industrial customers to assign the solar costs and production of the facility to their bill as a substitute for the utility's regular power supply cost. The participating customer will continue to pay their regular bill, but get a rate credit for the variable power supply portion of their rate and then substitute a "lock-in" solar rate for up to 20 years and the rate will not increase beyond its rate schedule for the term. This new rate schedule once approved by state Commissions will allow participating customers to acquire renewable energy and hedge power supply costs from future increases. Avista plans to file this tariff by the end of 2017.

*Boulder Park Community Solar Project*

# 5. Energy Efficiency & Demand Response

## Introduction

Avista began offering energy efficiency programs to its customers in 1978. These programs pursue all cost-effective energy efficiency and operate within the prevailing market and economic conditions. Recent programs with the highest impacts on energy savings include residential and non-residential prescriptive lighting, residential fuel efficiency, site-specific lighting, and small business projects. In addition, the Oracle (formerly Opower) Home Energy Report program began sending peer-comparison reports to participating customers every two months beginning in June 2013. Conservation programs regularly meet or exceed regional shares of the energy efficiency gains outlined by the Northwest Power and Conservation Council (NPCC).

**Section Highlights**

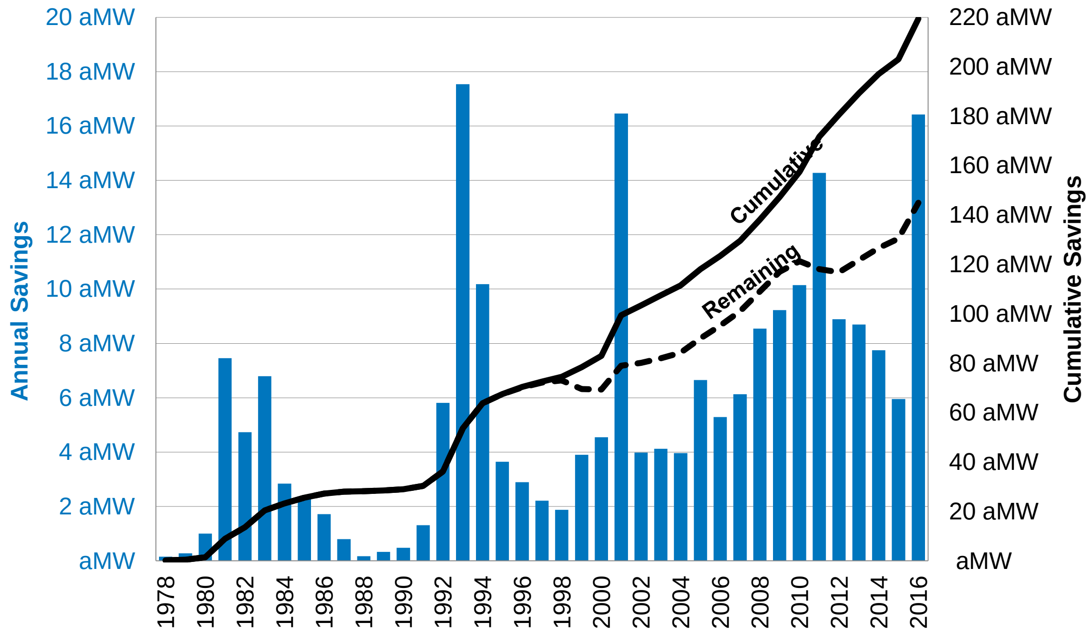
- Current Avista-sponsored conservation reduces retail loads by nearly 12.3 percent, or 145 aMW.
- This IRP evaluated over 8,700 measure options covering all major end use equipment, as well as devices and actions to reduce energy consumption for this IRP.
- In 2016, Non-residential interior lighting produced savings of over 43,000 MWh, accounting for over half of all non-residential electric energy savings.
- The 2018-19 Washington biennium goal is 71,479 MWh.
- The PRiSM model now selects conservation programs individually rather than as an input into the model.

Figure 5.1 illustrates Avista's historical electricity conservation acquisitions. Avista has acquired 219 aMW of energy efficiency since 1978; however, the 18-year average measure life of the conservation portfolio means some measures no longer are reducing load. The 18-year measure life accounts for the difference between the cumulative and online trajectories in Figure 5.1. Currently 145 aMW of conservation serves customers, representing nearly 12.3 percent of 2016 load.

Avista energy efficiency programs provide conservation and education options to the residential, low income, commercial, and industrial customer segments. Program delivery includes prescriptive, site-specific, regional, upstream, behavioral, market transformation, and third-party direct install options. Prescriptive programs, or standard offerings, provide cash incentives for standardized products such as the installation of qualifying high-efficiency heating equipment. Prescriptive programs work in situations where uniform products or offerings are applicable for large groups of homogeneous customers and primarily occur in programs for residential and small commercial customers.

Site-specific programs, or customized offerings, provide cash incentives for any cost-effective energy saving measure or equipment with an economic payback greater than one year and less than eight years for non-LED lighting projects, or less than 13 years for all other end uses and technologies. Other delivery methods build off these approaches but may include upstream buy downs of low cost measures, free-to-customer direct install programs, and coordination with regional entities for market transformation efforts.

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



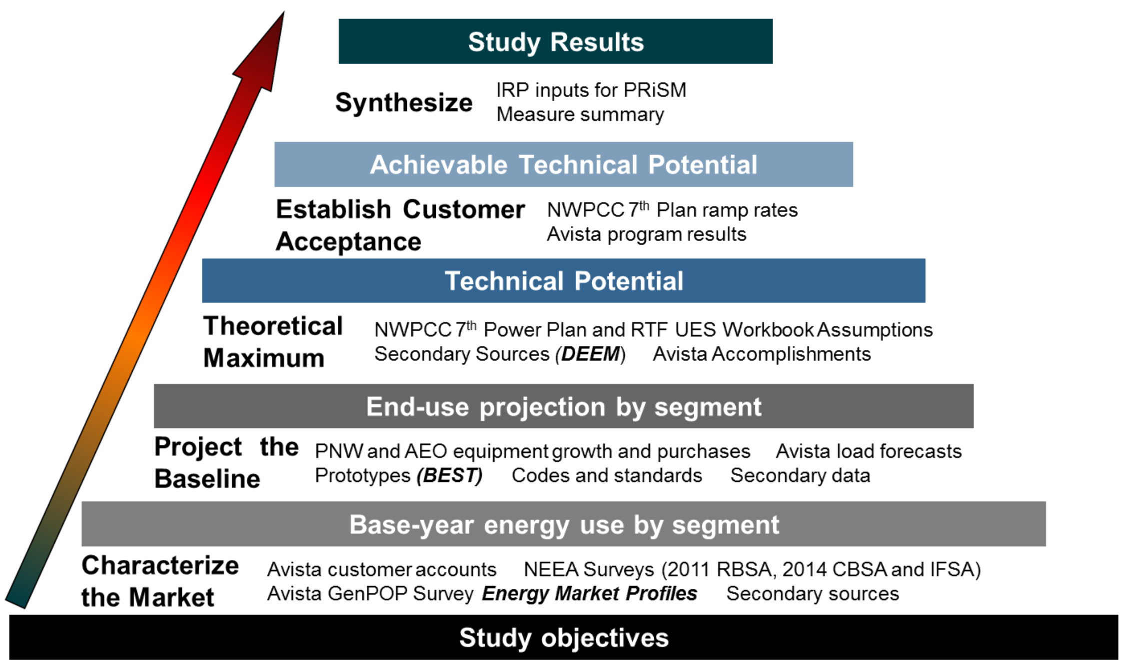

Efficiency programs with economic paybacks of less than one year are not eligible for incentives, although Avista assists in educating and informing customers about these types of efficiency measures. Site-specific programs require customized services for commercial and industrial customers because of the unique characteristics of each of their premises and processes. In some cases, Avista uses a prescriptive approach where similar applications of energy efficiency measures result in reasonably consistent savings estimates in conjunction with a high achievable savings potential. An example is prescriptive lighting for commercial and industrial applications.

## The Conservation Potential Assessment

Avista retained Applied Energy Group (AEG) as an independent third party to assist in developing a Conservation Potential Assessment (CPA) for this IRP. The study forms the basis for the conservation portion of this plan. The CPA identifies the 20-year potential for energy efficiency and provides data on resources specific to Avista's service territory for use in the resource selection process in the PRiSM model, in accordance with the EIA's energy efficiency goals. The energy efficiency potential 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.

AEG implemented several changes to its current study including a regionally specific categorization of savings potential. In the 2015 IRP, AEG provided three levels of potential: technical, economic, and achievable. This approach first considered the economic screening of measures in the CPA then applied ramp rates in order to arrive at the achievable potential. For the 2015 plan, Avista compared using this methodology versus its new methodology utilizing a technical and achievable technical approach and using PRiSM to select measures. Both methodologies arrived at similar results in the 2015 study, but the inclusion in the PRiSM model allows conservation to dynamically reduce portfolio risk. In the 2015 IRP Washington acknowledgement, Washington agreed Avista should make the methodology change. In the new method, AEG first develops estimates of technical potential, reflecting the adoption of all conservation measures, regardless of cost-effectiveness. Achievable Technical Potential modifies the technical potential by accounting for customer adoption constraints, using the Council's Seventh Plan ramp rates. The estimated achievable technical potential for each individual measure, along with associated costs, feed into the PRiSM model to select the cost-effective measures on a measure-by-measure basis rather than by bundling. AEG took the following steps to assess and analyze energy efficiency and potential within Avista's service territory. Figure 5.2 illustrates the steps of the analysis.

**Figure 5.2: Analysis Approach Overview**




1. **Characterize the Market:** Categorizes energy consumption in the residential (including low-income customers), commercial, and industrial sectors. This assessment uses utility and secondary data to characterize customers' electricity usage behavior in Avista's service territory. AEG uses this assessment to develop energy market profiles describing energy consumption by market segment, vintage (existing or new construction), end use, and technology.

2. **Baseline Projection:** Develops a projection of energy and demand for electricity, absent the effects of future conservation by sector and by end use for the entire 20-year study.
3. **Measure Assessment:** Identifies and characterizes energy efficiency measures appropriate for Avista, including regional savings from energy efficiency measures acquired through Northwest Energy Efficiency Alliance efforts.
4. **Potential:** Analyzes measures to identify technical and achievable technical conservation potential.

### Market Segmentation

The CPA divides Avista customers by state and class. The residential class segments include single-family, multi-family, manufactured home, and low-income customers.[1] AEG incorporated information from the Commercial Building Stock Assessment to break out the commercial sector by building type. Avista analyzed the industrial sector as a whole for each state. AEG characterized energy use by end use within each 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 the "business as usual" metric without future utility conservation 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 2016 when the study began. Codes and standards have direct bearing on the amount of energy efficiency potential existing beyond the impact of these efforts. The baseline projection accounts for market changes including:

- customer and market growth;
- income growth;
- retail rates forecasts;
- trends in end use and technology saturations;
- 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 Seventh Power Plan, the Regional Technical Forum, and other measures applicable to Avista. The 3,400 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.

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

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. Many measures initially do not pass the economic screen of supply side resource options, but some measures may become part of the energy efficiency program as contributing factors evolve during the 20-year planning horizon.

Avista supplements energy efficiency activities by including potentials for distribution efficiency measures consistent with EIA conservation targets and the NPCC Seventh Power Plan. Details about the distribution efficiency projects are in Chapter 8 – Transmission and Distribution Planning.

## 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 the most credible and comprehensive national industry standard practice for specifying energy efficiency potential. Specifically, two types of potential are in this study, as discussed below. Table 5.1 shows the CPA results for technical and achievable technical potential.

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

| | 2018 | 2019 | 2022 | 2027 | 2037 |
|---|---|---|---|---|---|
| Cumulative (GWh) | | | | | |
| Achievable Technical Potential | 88.0 | 186.8 | 468.3 | 927.1 | 1,516.3 |
| Technical Potential | 190.1 | 376.7 | 771.7 | 1,370.9 | 1,937.0 |
| | | | | | |
| Cumulative (aMW) | | | | | |
| Achievable Technical Potential | 10.0 | 21.3 | 53.5 | 105.8 | 173.1 |
| Technical Potential | 21.7 | 43.0 | 88.1 | 156.5 | 221.1 |

### Technical Potential

Technical potential finds the most energy-efficient option commercially available for each purchase decision regardless of its cost. This theoretical case provides the broadest and highest definition of savings potential because it quantifies savings if all current equipment, processes, and practices in all market sectors were replaced by the most efficient and feasible technology. Technical potential in the CPA is a "phased-in technical potential," meaning only the current equipment stock at the end of its useful life is considered and changed out with the most efficient measures available. Non-equipment measures, such as controls and other devices (e.g., programmable thermostats) phase-in over time, just like the equipment measures.

### Achievable Technical Potential

Achievable Technical Potential is a subset of technical potential representing the portion of technically feasible reductions in load associated with applicable end-uses.

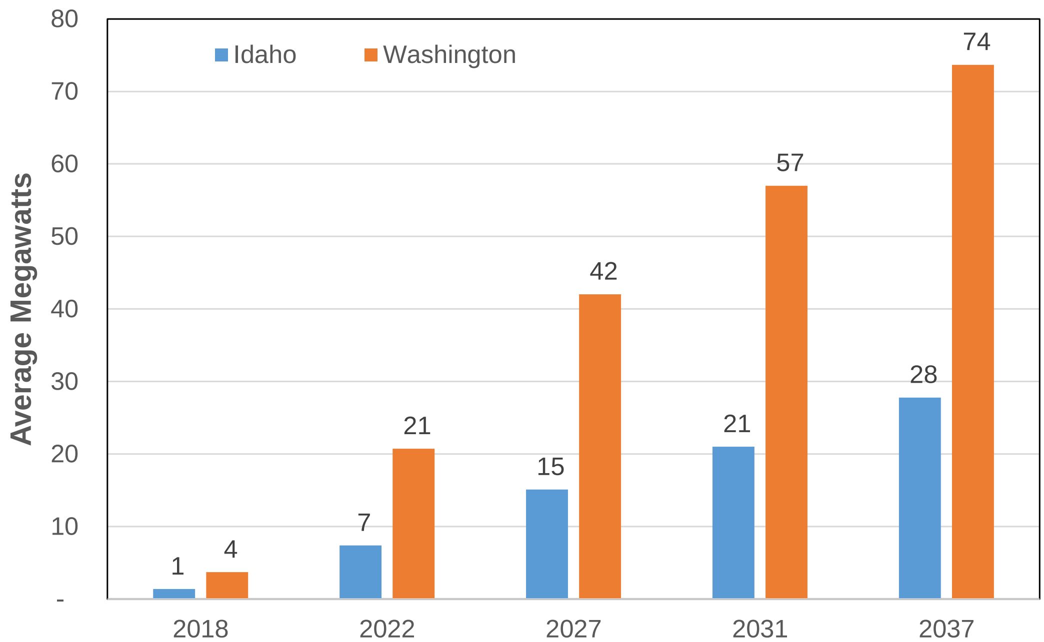
[2] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025:* Developing a Framework for Change. www.epa.gov/eeactionplan.

It refines technical potential by applying customer participation rates to account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of efficiency measures. The customer participation rates use the NPCC Seventh Plan ramp rates.

### PRiSM Co-Optimization

Avista's identifies achievable economic conservation potential by concurrently evaluating supply side and over 8,700 demand side resources in PRiSM. This methodology was the result of a 2013 IRP Action Item to streamline the process of selecting conservation in conjunction with the Efficient Frontier. The 2015 IRP tested this method by comparing the traditional methodology with the co-optimization. The co-optimization resulted in similar savings, and portfolios further down the Efficient Frontier selected additional energy efficiency to reduce risk at a higher cost. The Washington 2015 IRP acknowledgement asked Avista to make this change for the 2017 IRP. Now in PRiSM, the individual energy efficiency resources compete with supply- and demand response options to meet resource deficits, although, energy efficiency measures benefit by receiving 10 percent more value compared to the supply-side resources. This methodology does not change the amount of conservation selected in the PRS, but provides information regarding conservation selection if Avista choses different portfolios in the Efficient Frontier analysis or other scenario analysis. Each program's winter and summer peak contribution (including line loss benefit), plus the value of its energy savings are considered. Figure 5.3 shows the combined Washington and Idaho CPA for 2018 through 2037.[3]

Figure 5.3: Achievable Conservation Potential Assessment (20-Year Cumulative)

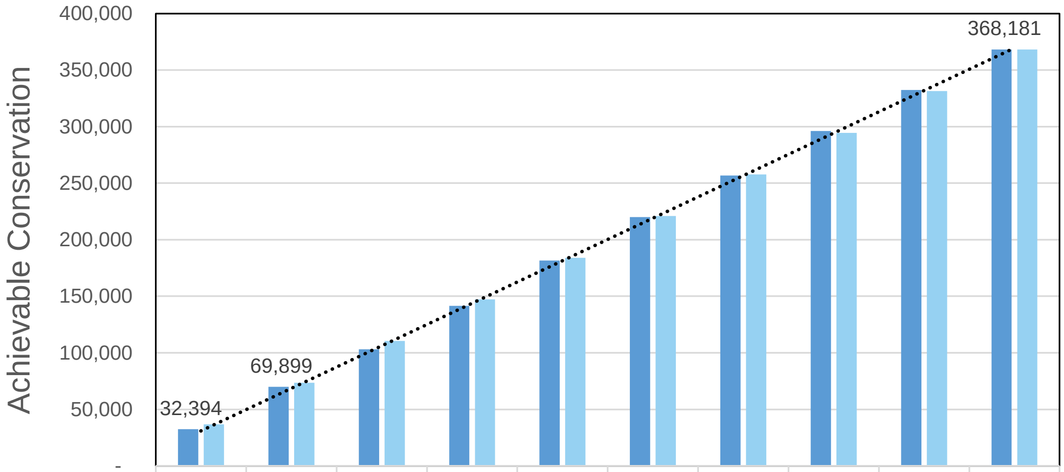



[3] The achievable conservation does not include savings from T&D losses. Chapter 11 conservation totals include losses.

## Conservation Targets

The IRP process provides conservation targets for the Washington EIA Biennial Conservation Plan. Other components, including conservation from distribution and transmission efficiency improvements, combine with energy efficiency targets to arrive at the full Biennial Conservation Plan target for Washington. 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 5.4: Washington Annual Achievable Potential Energy Efficiency (Megawatt Hours)**




| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| PRiSM | 32,394 | 69,899 | 103,108 | 141,532 | 181,537 | 219,967 | 256,765 | 296,068 | 332,472 | 368,181 |
| 10-yr Prorata | 36,818 | 73,636 | 110,454 | 147,272 | 184,091 | 220,909 | 257,727 | 294,545 | 331,363 | 368,181 |

For the 2018-2019 CPA, the two-year achievable potential is 69,899 MWh for Washington Electric operations. The pro rata share of the utility's ten-year conservation potential of 73,636 MWh is the basis for calculating the biennial target. Table 5.2 contains achievable conservation potential for 2018-2019 using the PRiSM methodology.

In addition to traditional efficiency programs, Avista is replacing approximately 21,640 high-pressure sodium fixtures in Washington and Idaho with comparable LED fixtures. The expected completion of this project is late 2019; efficiency savings are not available at this time to include in the achievable target. Also included is the energy savings from feeder upgrade projects. These projects, described in Chapter 8 – Transmission and Distribution Planning, reduce system losses.

**Table 5.2: Annual Achievable Potential Energy Efficiency (Megawatt Hours)**

| 2018-2019 Biennial Conservation Target | Savings (MWh) |
|---|---|
| Pro Rata Share of CPA | 73,636 |
| Behavioral Program | 15,386 |
| Less: NEEA | (21,812) |
| End-Use Efficiency Measures Subtotal | 67,210 |
| Plus: Distribution Efficiency | 714 |
| Plus: Generation Efficiency | 151 |
| **Total** | **68,075** |
| Plus: Decoupling Commitment | 3,404 |
| **Proposed Biennial Conservation Target + Decoupling (EIA) (Subject to Penalties)** | **71,479** |
| Plus: NEEA Projection | 21,812 |
| **Total Conservation Commitment** | **93,291** |

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

| Year | Methodology | Washington | Idaho | Total |
|---|---|---|---|---|
| 2018 | Feeder Upgrades | 233 | TBD | 233 |
| 2019 | Feeder Upgrades | 481 | 472 | 953 |
| | | | | |
| 2018 | LED Street Lighting | TBD | TBD | TBD |
| 2019 | LED Street Lighting | TBD | TBD | TBD |
| | | | | |
| 2018 | Facility Efficiencies | 0 | 300 | 300 |
| 2019 | Facility Efficiencies | 151 | 0 | 151 |

For conservation efforts in Idaho, the Idaho Public Utilities Commission asked Avista to pursue cost effective measures and set conservation goals based on the Utility Cost Test (UCT). While the conservation identified in this IRP uses the Total Resource Cost (TRC) in terms of power planning over twenty years, the amount of conservation the Company will pursue in Idaho beginning in 2018 will use the UCT.

Using the UCT as the basis for conservation, Avista identifies achievable potential conservation in Idaho of 15,370 MWh in 2018. The company determined this savings amount by applying an adjustment factor of 1.28 to Avista's TRC goal of 12,008 MWh. The 1.28 adjustment factor is the ratio of the TRC to the UCT from the Company's 2016 Idaho DSM Annual Report. In this report, Avista obtained a TRC of 2.13 and a UCT of 2.73 with the UCT being 1.28 times higher than the TRC.

## NPCC's Seventh Power Plan Benchmarking

Figure 5.5 illustrates the comparison between Avista's CPA Achievable Conservation and its estimated allocation of the Seventh Power Plan's regional savings. Commercial and Industrial sectors have been combined into a single category titled "non-residential."

It is important to note that the value for from the Seventh Power Plan represents a single point within a range of values. The comparison relies on the assumption that Avista's share of the region is 3.5 percent (Sixth Power Plan assumption). A 0.5 percent variance in this allocation would increase or decrease Avista's allocation of the Seventh Power Plan by approximately 12 aMW.

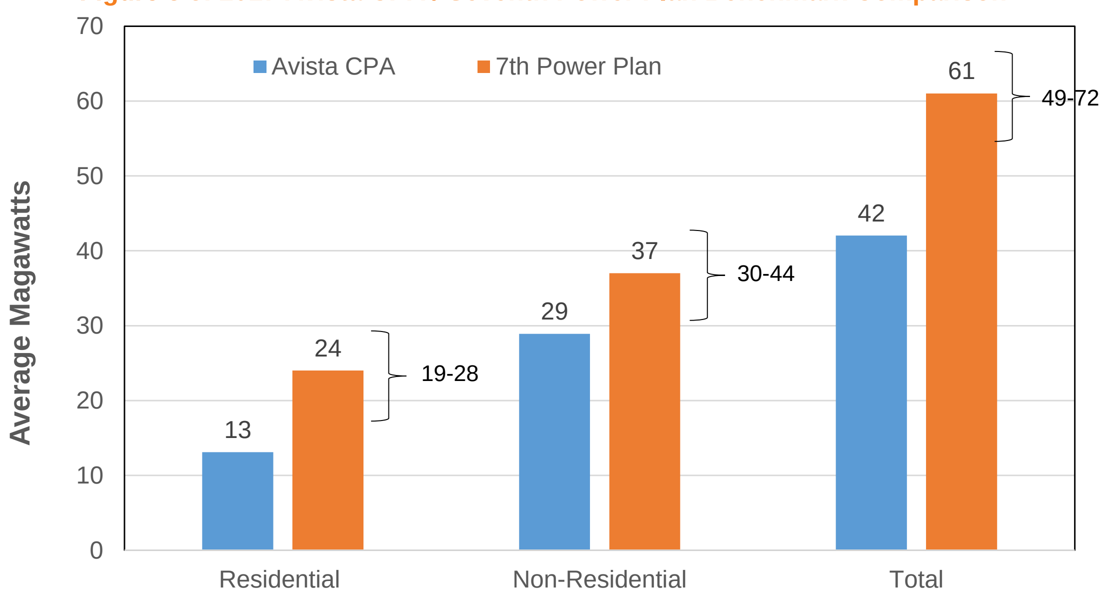
### Comparing Avista's CPA to the Seventh Power Plan

The Washington 2015 IRP acknowledgement asked Avista to compare its IRP conservation and demand response (DR) results to the Seventh Power Plan. Avista's Washington Electric CPA identifies 42 aMW of savings for the 2018-2027 period with 13 aMW from Residential and 29 aMW from Non-Residential saving. Avista's allocation of the Seventh Power Plan's regional savings is approximately 61 aMW, with 24 aMW from Residential and 37 aMW from Non-Residential. See Figure 5.5.

The comparison of Avista's CPA and its share of the Seventh Power Plan considers several factors. Avista's avoided cost is lower than the costs used to calculate average regional energy costs. Because avoided cost is a primary factor in determining cost-effectiveness, some regional portfolio measures are not cost effective in Avista's CPA.

Avista calculated the 61 aMW using the highest Levelized Cost Bins for Conservation[4]. While information that is more granular is available, complications exist depending on end use customers and the type of individual measures considered. For consistency, the comparison uses the highest Cost Bin in calculating Avista's share of the Seventh Power Plan. This approach provides the most conservative estimates on cost.

**Figure 5.5: 2017 Avista CPA / Seventh Power Plan Benchmark Comparison**




[4] Seventh Power Plan Appendix G, Table G-7: Levelized Cost Bins for Conservation.

## Consistency with the Seventh Power Plan

AEG's methodology to develop the electric CPA is consistent with the Council's Seventh Power Plan methodology and fulfills the requirements of the utility analysis option as specified in WAC 194-37-070 subsection (6),(a)(i) through (xv).[5] This CPA, like the Seventh Plan, uses an end-use model to distinctly consider and account for the following:

- Building characteristics that reflect Avista's service territory;
- Fuel and equipment saturations based on the knowledge of Avista's customers;
- Measure life;
- Stock accounting;
- Existing and new construction;
- Lost-and non-lost opportunities;
- Measure saturation and applicability;
- Measure savings, including contribution to system peak;
- Customer growth; and
- Federal and state standards for appliances and technologies.

Like the Seventh Plan, the Avista CPA uses a frozen-efficiency approach assuming equipment efficiency purchase decisions are fixed, with the exception of changes due to the phase-in of new codes and standards.

For this CPA, AEG develops estimates of Technical Potential and Achievable Technical Potential.[6] The Economic Achievable Potential was determined by running the Achievable Technical Potential through PRiSM. The Power Act's 10 percent adder for conservation is added to the avoided energy costs within the PRiSM model.

In terms of conservation measures, the CPA includes all measures incorporated in the Seventh Plan, as well as additional measures. However, the CPA analyzes each measure individually, whereas the Seventh Plan bundles measures in some cases. All measures were characterized using data from the Seventh Plan and RTF workbooks, when available. If a measure was not characterized using the Seventh Plan or RTF workbooks, AEG relied upon its database of energy efficiency measures (DEEM) that is developed by incorporating measures encountered throughout the country and characterized using sources typically cited by the NPCC in its analyses. Similar to the Council's approach, AEG removes measures with market saturation, such as LED TVs, while at the same time includes and updates commercially available technologies.

To develop Technical Potential, AEG's LoadMAP model includes all technically feasible potential conservation. The model choses the most efficient option at the time of equipment turnover. The market acceptance rates used to develop Achievable Technical potential are based upon the new, simplified Seventh Plan ramp rates. AEG mapped each of the individual measures to a Seventh Plan ramp rate and compared the results to historical achievements. AEG then adjusted the 2018 achievable technical potential for

[5] http://apps.leg.wa.gov/WAC/default.aspx?cite=194-37&full=true

[6] AEG provided estimates of Technical Potential, Economic Potential, and Achievable Potential in previous CPAs. For this study, the ramp rates were applied to the Technical Potential and provided to Avista to run through PRiSM to estimate the cost-effective conservation potential.

those specific measures to line up with 2018. This provided a starting point for 2018 potential aligned to historic results. AEG provided the individual measure characteristics at the Achievable Technical level to Avista to run through PRiSM to determine which measures are cost-effective and included in the Economic Achievable Potential or targets.

## Energy Efficiency-Related Financial Impacts

The EIA requires utilities with over 25,000 customers to obtain a fixed percentage of their electricity from qualifying renewable resources and acquire all cost-effective and achievable energy conservation.[7] 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 Washington 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 2018 conservation acquisition cost to electric customers is $14.5 million. This amount grows by 200% to $29 million by 2027, a total of $214 million over this 10-year period. Costs continue increasing after 2027 to more than $40 million in 2037.

## 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 the results are not detailed enough to form an actionable plan. Avista uses both processes' results to establish a budget for energy efficiency measures, help determine the size and skill sets necessary for future operations, and identify general target markets for energy efficiency programs. This section provides an overview of recent operations of the individual sectors, as well as energy efficiency business planning.

The CPA is useful 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 TRC benefit-cost ratios, resulting in the lowest cost resources, brings the greatest amount of benefits to the overall portfolio.
- By identifying measures with great adoption barriers based on the economic versus achievable results by measure, staff can develop effective programs for measures with slow adoption or significant barriers.
- By improving the design of current program offerings, staff can review the measure level results by sector and compare the savings with the largest-saving measures currently offered. This analysis may lead to the addition or elimination of programs.

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

> Additional consideration for lost opportunities can lead to offering greater incentives on measures with higher benefits and lower incentives on measures with lower benefits.

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

### Residential Sector Overview

The Company's residential portfolio is composed of several approaches to engage and encourage customers to consider energy efficiency improvements within their home. Prescriptive rebate programs are the main component of the portfolio, but augment variety of other interventions. These include: upstream buy-down of low-cost lighting and water saving measures, select distribution of low-cost lighting and weatherization materials, direct-install programs and a multi-faceted, multichannel outreach and customer engagement effort.

Washington and Idaho residential customers received over $10.2 million in rebates to offset the cost of implementing these energy efficiency measures. All programs within the residential portfolio contributed over 83,400 MWh and over 669,800 therms to the 2016 annual energy savings.

Avista launched a Home Energy Reports program in June 2013, targeting 73,501 Idaho and Washington customers with high electric use. As of December 2015, Avista had 48,800 customers still in the Home Energy Reports program. In January of 2016, Avista 'refilled' their existing Home Energy Reports Program by 24,706 customers bringing total distribution to approximately 73,506 electric customers in Idaho and Washington. Eligibility for treatment includes several criteria such as sufficient (two year) billing history, enough peers to build comparison group, not in the control group, not a 'do not solicit' customer and high enough electric use to be cost-effectively treated. In an effort to reduce energy usage through behavioral changes, Home Energy Reports show personalized usage insights and energy saving tips. Customers also see a ranking of similar homes, comparison to themselves and a personal savings goal on the Reports. In addition to closely matching usage curves, the similar home comparisons use the following four criteria: square footage, home type, heat type and proximity. The Oracle Home Energy Report contributed 12,131 MWh of savings in 2016.

### Low-Income Sector Overview

The Company leverages the infrastructure of six network Community Action Program (CAP) agencies and one tribal weatherization organization to deliver energy efficiency programs for the Company's low-income residential customers in the Washington service territory. CAP agencies have resources to income qualify, prioritize and treat client homes based upon a number of characteristics. In addition to the Company's annual funding, the agencies have other monetary resources to leverage when treating a home with weatherization or other energy efficiency measures. The agencies either have in-house or contract crews to install many of the efficiency measures of the program. The low-income energy efficiency programs contributed 830 MWh of electricity savings and 19,183 therms of natural gas savings in 2016 to Avista's system.

The general outreach programs provide energy management information and resources at events (such as resource fairs) and through partnerships to reach target populations. These programs also include bill payment options and assistance resources in senior and low-income publications. In 2016, Avista participated in 193 events in Idaho and Washington including workshops, energy fairs, mobile outreach events, and general outreach partnerships and events reaching over 16,500 individuals.

### Non-Residential Sector Overview

The non-residential energy efficiency market delivers through a combination of prescriptive and site-specific offerings. Any measure not offered through a prescriptive program is automatically eligible for treatment 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.

In 2016, more than 2,900 prescriptive and site-specific nonresidential projects received funding. Additionally, the Small Business program installed over 27,500 measures. Avista contributed more than $14.8 million for energy efficiency upgrades in nonresidential and small business applications. Non-residential programs realized over 73,900 MWh and 196,875 therms in annual first-year energy savings.

Program changes made at the beginning of 2016 to the non-residential programs include the addition of new program offerings and changes to eligibility or incentive levels. Avista communicates the majority of program changes after the Business Plan is final and the changes become effective at the beginning of the year. In addition, some program's change throughout the year as necessary but these are less typical.

For non-residential programs, changes effective January 1, 2016 to rebates reflect new information regarding new unit energy savings (UES) and cost values. Avista accepted rebate applications through March 31, 2016 for 2015 measures and amounts. This 90-day grace period allows for a smooth transition when rebate programs change to allow enough time for customers in the pipeline to complete their projects yet close out changes in a timely but balanced approach.

After years of review, Avista began converting a large portion of its high-pressure sodium (HPS) street light system to LED units in 2015. Advancements in LED technology and lower product costs make early replacements cost effective. LEDs consume about half of the energy as their conventional counterparts for the same light output. Other non-energy benefits include improved visibility and color rendering relative to HPS lighting, and longer product life. The initial focus of the program is replacing 26,000 100-watt cobra-head style streetlights.

## Conservation's T&D Deferral Analysis

Cost-effective energy efficiency programs require a review of cost versus its potential benefits. One benefit is the generation and delivery system investments *avoided* or *deferred*. Generation avoided investments are fairly 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 be reduced by energy efficiency due to the thermal limitations of the system.

Utilities use a number of methods to estimate avoided T&D costs and there is no one “best” approach to developing these estimates. There is a wide range of estimates for avoided T&D, underscoring the diverse nature of the methods used to calculate avoided costs. For the past several IRPs, Avista used $10 per kW-yr (2006 dollars), based on a study for the 2007 IRP, this out of date study is driving the need for a new methodology as part of the 2015 IRP action plan.

For this IRP, Avista chose to value these benefits using the current values approach. The current values approach considers the amount of current investment in both T&D from a revenue requirement reference point, then divided by the peak load of the system, to estimate a $/kW-yr. value (see Table 5.2). This method’s strength is its simplicity, lending itself to frequent updates, but does not accurately portray the amount of deferred future T&D investment due to new conservation programs. Avista will consider moving to another methodology to account for this benefit in the next IRP. Further, in Chapter 8, there is a discussion of a storage facility’s benefit to the distribution system by deferring new capital investment using three feeders as case studies. Given, T&D deferments importance, Avista will evaluate alternative methods to value these benefits to future investment.

**Table 5.4: Transmission and Distribution Benefit**

| | Transmission Net Book Value | Distribution Net Book Vale |
|---|---:|---:|
| Washington | $294,988,593 | $675,072,411 |
| Idaho | $153,799,772 | $348,486,297 |
| Total | $448,788,365 | $1,023,558,708 |
| Revenue Requirement | $448,859,497 | $1,099,186,748 |
| | | |
| Peak Load (MW) | 1,693 | 1,693 |
| Current $/kW | $265 | $649 |
| Levelized Cost | $13.77 | $15.95 |
| Total Levelized cost | | $29.72 |

## Generation Efficiency Audits of Avista Facilities

Avista engineers performed energy efficiency audits at all of Avista’s hydroelectric dams and most of thermal generation facilities where Avista wholly owns or is a partial owner, excluding Colstrip Generating station in Colstrip, Montana. The scoping audits focused on lighting, shell, HVAC and motor controls on processes. Table 5.5 shows efficiency potential and Table 5.6 shows the efficiency projects for Avista generation facilities planned for 2017 and 2018.

**Table 5.5: Preliminary Generation Facility Efficiency Upgrade Potential**

| Facility | Description | Measure Life (years) | Electric Savings (kWh) |
|---|---|---|---|
| Boulder Park | Control Room Lighting | 15 | 3,931 |
| | Generating Floor Lighting High Bays | 15 | 16,099 |
| | Replacing Engine Bay Lights | 15 | 6,736 |
| | Replace Exterior Wall Packs | 15 | 16,054 |
| | Instrument Air Cycling Air-Dryers | 12 | 10,074 |
| | Oil Reservoir Heater Fuel Conversion[8] | 15 | 525,600 |
| Coyote Springs | Control Room Lighting | 15 | 6,368 |
| | Generating Floor Lighting High Bays | 15 | 85,778 |
| | Roadway Lighting | 15 | 1,085 |
| | Air-Compressor VFD | 12 | 130,000 |
| | Retrofit Air-Dryer with Dew-Point Controls | 12 | 25,000 |
| Kettle Falls | Plant Lighting | 15 | 150,190 |
| | Plant Lighting Controls | 15 | 183,058 |
| | Yard Lighting | 15 | 48,180 |
| | Forced Draft Boiler Fan VSD | 12 | 700,000 |
| Little Falls | Speed Controls Cooling/Exhaust Fans | 12 | 247,909 |
| Long Lake | Variable Speed Stator Cooling Blowers | 12 | 135,000 |
| | Exterior Wall Packs | 15 | 2,084 |
| Northeast CT | Halogen Pole Lights | 15 | 5,146 |
| Noxon Rapids | Full LED Lighting Upgrade (Completed) | 15 | 382,115 |
| Post Falls | Control Room T12s | 15 | 1,776 |
| | Generating Floor HPS | 15 | 3,312 |
| Upper Falls | Utility Men Break Room Lighting | 15 | 2,151 |
| | Control Room Lighting | 15 | 4,340 |
| | Network Feeder Tunnel Lighting | 15 | 8,344 |
| Rathdrum CT | Roadway Lighting | 15 | 16,273 |
| | Halogen Pole Lights | 15 | 3,200 |

### Lighting Projects

The facilities have a mixture of T12, T8 and some T5 linear fluorescent fixtures as well as many incandescent bulbs. The proposed replacement fixtures from the lighting audits are primarily linear, high bay, and screw in LED fixtures. Noxon Rapids is the only facility with a completed a lighting retrofit.

### Shell Projects

No shell measures are cost effective due to negligible savings and cost prohibitive nature of the measure due to the size of the facilities and large internal heat gain of the equipment in the facilities. However, small maintenance weatherization are available to improve occupant comfort.

[8] Also saves 23,911 therms of natural gas per year.

### HVAC Projects

There are no recommendations to replace current HVAC equipment but there are recommendations to replace equipment with more efficient technology when each unit reaches the end of its' useful life.

### Controls on Process Motors

There are a number of air compressors, fans and pumps driven by electric motors in Avista's facilities. These motors could use variable speed drives to match the current process needs and reduce the energy consumption of the motors as opposed to the current control systems.

**Table 5.6: Planned Generation Facility Efficiency Upgrades 2017 – 2018**

| Facility | Description | Measure Life (years) | Electric Savings (kWh) |
|---|---|---|---|
| Cabinet Gorge | Lighting Retrofit | 15 | 300,000 |
| Little Falls | Lighting Retrofit | 15 | 62,266 |
| Long Lake | Lighting Retrofit | 15 | 17,441 |
| Nine Mile | Lighting Retrofit | 15 | 71,455 |

## Demand Response

Over the past decade, demand response or DR gained attention as an alternative to new generation to meet peak load growth. DR reduces load to specific customers during peak demand periods until the load event is over or the customer has met its commitment. Enrolling customers allows the utility to modify customer usage in exchange for bill discounts. National attention focuses on residential programs to control water heaters, space heating, and air conditioners. A 2013 IRP Action Item suggested further study of the DR potential based on its selection as a PRS resource from 2022 to 2027. Avista retained AEG to study the potential of future commercial and industrial programs for both the 2015 IRP and 2017 IRPs.

### Previous Demand Response Programs

Avista's first DR experience began in the 2001 Energy Crisis. Avista responded with an 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 again led Avista to request DR through a media request for customers to conserve and short-term agreements with large industrial customers. During the 2006 event, Avista estimates DR reduced loads by 50 MW.

Avista conducted a two-year residential load control pilot between 2007 and 2009 to study specific technologies and examine cost-effectiveness and customer acceptance. The pilot tested scalable Direct Load Control (DLC) devices based on installation 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 and customer-friendly manner. Avista installed DLC devices on 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. 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 in the report filed with the Idaho Public Utilities Commission.

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. 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 control approach was non-traditional in several ways. First, the DR events were not prescheduled, but Avista controlled customer loads defined by pre-defined 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. Lastly, value quantification extended beyond demand and energy savings and explored bill management options for customers with whole house usage data analyzed in conjunction with smart thermostat data.

Inefficient homes identified through this analysis prompted customer engagement. For example, an operational anomaly prompted an investigation uncovering a control board in a customer’s heat pump causing the system to draw warm air from inside the home during the heating season. This in turn caused the auxiliary heat to come on prematurely and cycle too frequently, resulting in high customer bills. The repair saved the customer money and allowed them to be more comfortable in their home. Lessons learned from the SGDP program helped craft Avista’s new Smart Thermostat rebate program (an efficiency-only program) implemented in October 2014. The Smart Grid demonstration project concluded December 31, 2014.

Experiences from both residential DLC pilots (North Idaho Pilot and the SGDP) show participating customer engagement is high; however, recruiting participants is challenging. Avista’s service territory has high natural gas penetration for typical DLC space and water heat applications. Customers who have interest may not have qualifying equipment, making them ineligible for participation in the program. Secondly, customers did not seem overly interested in the DLC program offerings. BPA has found similar challenges in gaining customer interest in their recent regional DLC programs. Finally, Avista is unable at this time to offer pricing strategies other than direct incentives to compensate customers for participation in the program.

Avista is committed to evaluating and considering DR to meet future load requirements if it cost effective compared to other alternatives and does not influence the customer’s reliability or satisfaction with service. To fulfill this commitment, Avista will determine if a study is needed to evaluate the residential DR potential for the next IRP to meet its winter and summer peak requirements as part of this IRP’s action plan.

## Demand Response Comparison to the Seventh Power Plan

For DR, Avista reviewed the NPCC's Seventh Plan and found some differences between Avista's DR analysis and the NPCC's including 1) the NPCC's analysis includes residential and agricultural programs, 2) specific summer and winter programs, and 3) the NPCC excludes standby generator programs. Further, the NPCC models these programs in bins, rather than specific programs. Avista will determine if it is necessary to include residential DR programs in the 2019 IRP, but agricultural programs will be limited due to Avista's limited irrigation pumping load, although other agricultural process were included in the industrial portion of the existing study. Avista only includes winter C&I programs in its study, as at the time of the analysis Avista's capacity requirements are winter peaking rather than summer peaking.

The NPCC estimates 600 MW[9] of DR for the region; using Avista's 3.5 percent share of the region[10], equates to 21 MW of DR. Avista's PRS, as described in Chapter 11, includes 9 MW of winter C&I DR and 35 MW of standby generation, for 44 MW[11] of total peak load reduction. This more than doubles the amount of DR the NPCC includes as cost effective in the Seventh Power Plan.

## Demand Response Potential Assessment Study

Avista retained AEG to study the potential for commercial and industrial DR in Avista's service territory for the 20-year planning horizon of 2018–2037. It primarily sought to develop reliable estimates of the magnitude, timing, and costs of DR resources likely available to Avista for meeting winter peak loads. The study focuses on resources assumed achievable during the planning horizon, recognizing known market dynamics may hinder acquisition. Avista includes in the DR analysis savings from avoiding T&D losses, but does not include T&D capital deferral benefits as it is not determined whether or not a system peak DR program will actually defer any specific T&D investment.

The IRP incorporates DR study results, and the study will affect subsequent DR planning and program development efforts. A full report outlining the DR potential for commercial and industrial customers is in Appendix C from the 2015 IRP. AEG updated the costs and savings for this IRP, but the report showing the amount of DR in Avista's service territory is the same. Table 5.3 details achievable DR potential for the programs studied by AEG.

**Table 5.7: Commercial and Industrial Demand Response Achievable Potential (MW)**

| Program | 2018 | 2019 | 2020 | 2037 | 2037 |
|---|---|---|---|---|---|
| Direct Load Control | 0.4 | 1.1 | 2.2 | 3.9 | 4.2 |
| Firm Curtailment | 5.8 | 11.6 | 17.5 | 17.7 | 18.2 |
| Opt-in Critical Peak Pricing | 0.1 | 0.4 | 0.9 | 4.4 | 4.6 |

[9] NPCC's Seventh Power Plan, page 3-4.
[10] Avista's estimate share of the region per the NPCC Sixth Power Plan, this calculation is not available for the Seventh Power Plan at this time.
[11] The 44 MW figure does not include additional savings from transmission and distribution loses.

### *Direct Load Control*

A DLC program targeting Avista General and Large General Service customers in Washington and Idaho would directly control electric space heating load in winter, and water heating load throughout the year, through a load control switch or programmable thermostat. Central electric furnaces, heat pumps, and water heaters would cycle on and off during high-load events. Typically, DLC programs take five years to ramp up to maximum participation levels.

### *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 return, they receive fixed incentive payments. Customers receive payments even if they never receive a load curtailment request. 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. Penalties are a possible component of a firm curtailment program.

Industry experience indicates customers with loads greater than 200 kW participate in firm curtailment programs. However, there are a few programs where customers with 100-kW maximum demand participate. In Avista’s case, the study lowered the demand threshold level to include Large General Service customers with an average demand of 100 kW or more.

Customers with 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 obligations such as schools and hospitals, generally are not good candidates.

Third parties generally administer firm curtailment programs for utilities and are responsible for all aspects of program implementation, including program marketing and outreach, customer recruitment, technology installation and incentive payments. Avista could contract with a third party to deliver a fixed amount of capacity reduction 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.

### *Critical Peak Pricing*

Critical peak pricing programs set prices much higher during short critical peak periods to encourage lower customer usage at those times. Critical peak pricing is usually offered in conjunction with time-of-use rates, implying at least three periods: critical peak, on-peak and off-peak. Utilities offer heavy discounts to participating customers during off-peak periods, even relative to a standard time-of-use rate program. Event days generally are a day ahead or even during the event day. Over time, establishment of event-trigger criteria enables customers to anticipate events based on hot weather or other factors.

System contingencies and emergencies are candidates for Critical peak pricing. Critical peak pricing differentials between on-peak and off-peak in the AEG study are 6:1, and available to all three commercial and industrial classes.

There are two ways to offer critical peak pricing. The opt-in rate allows voluntary enrollment in the program or the utility enrolls all customers in an opt-out program, requiring them to select another rate program if they do not want to participate. Avista is only modeling the opt-in program. The success of the critical peak pricing program will vary according to whether customers have enabling technology to automate their response. For General and Large General Service customers, the enabling technology is a programmable communicating thermostat. For Extra Large General Service customers, the enabling technology is automated DR implemented through energy management and control systems.

Critical peak pricing programs require formal rate design based on customer billing data to specify peak and off-peak price levels and periods the rates are available. Rate design was outside the scope of the AEG study. Further, new metering technology is required. Given these requirements, critical peak pricing was not an option for the IRP.

### Standby Generation Partnership

Few utilities have contracted with large industrial customers to use their standby generation resources during peak load events or to provide non-spinning reserves. Avista studied a standby generation option similar to the Portland General Electric program where existing customers use their standby generation. Portland General Electric dispatches, tests, and maintains the customer generation resources in exchange for control of the resource in non-emergency situations. It uses customer generators for limited hours for peak requirements, operating reserves, and potentially for voltage support on certain distribution feeders.

Environmental regulations limit the use of backup generation facilities unless they meet strict emission guidelines. To provide more operating hours a program could introduce natural gas blending to improve the emissions and operating costs. Avista estimates approximately 40 MW[12] of standby generation resources are available for utility use over 20-year acquisition period. The IRP assumes a standby generation program would cost $50 per kW in upfront investments, and $10 to $15 per kW-year in O&M costs.

In May 2015, the federal courts overturned Reciprocating Internal Combustion Engine (RICE) rule limiting the availability of standby generation resources. The RICE rule was remanded to EPA and remains in its 2013 form the former rule. Under clarification of this rule, the EPA allows generators to dispatch 50 hours per year in non-emergency conditions. Local air authorities may further restrict qualifying generators to new technologies. In the event this program is part of Avista’s plans to meet resource deficits, additional environmental and potential studies will begin.

[12] The AEG DR study included standby generation in its firm curtailment section, in the event both programs are cost effective, firm curtailment will include a 50 percent reduction in its capability.

# 6. Long-Term Position

## Introduction & Highlights

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

Avista has unique attributes affecting its ability to meet peak load requirements. It connects to several neighboring utility systems, but is only 5 percent of the total regional load. Annual peaks can occur either in the winter or in the summer; but Avista is winter peaking on a planning basis using extreme weather conditions. The winter peak generally occurs in December or January, but may happen in November or February when extreme weather events may occur. As described in Chapter 4 – Existing Supply Resources, Avista's resource mix contains roughly equal amounts of hydroelectric and thermal generation. Hydroelectric resources meet most of Avista's flexibility requirements for load and intermittent generation, though thermal generation is playing a larger role as load growth and intermittent generation increase flexibility demands.

**Section Highlights**

- Avista's first long-term capacity deficit net of energy efficiency is in 2026; the first energy deficit is also in 2026.
- Expected conservation programs defer resource needs five years.
- Avista's peak hour planning margin is 14 percent in the winter and 7 percent in the summer; including operating reserves, Avista plans to a 22.6 percent planning margin in the winter and a 15.6 percent planning margin in the summer.
- The 2017 IRP meets all EIA mandates over the next 20 years with a combination of qualifying hydroelectric upgrades, purchased renewable energy credits (RECs), Palouse Wind, and Kettle Falls.

## 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 their dispatch and revenue.

There is no industry standard reserve margin level; standardization across systems with varying resource mixes, system sizes, and transmission interconnections, is difficult. NERC defines reserve margins as follows:

*Generally, the projected demand is based on a 50/50 forecast. Based on experience, for Bulk Power Systems that are not energy-constrained, reserve margin is the difference between available capacity and peak demand, normalized by peak demand shown as a percentage to maintain reliable operation while meeting unforeseen increases in demand (e.g. extreme weather) and unexpected outages of existing capacity. Further, from a planning perspective, planning reserve margin trends identify whether capacity additions are keeping up with demand growth. As this is a capacity based metric, it does not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources. Data used here is the same data that is submitted to NERC for seasonal and long-term reliability assessments. Figures above shows forecast net capacity reserve margin in US and Canada from 2008 to 2017.*

*NERC's Reference Reserve Margin is equivalent to the Target Reserve Margin Level provided by the Regional/subregional's own specific margin based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigned 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems. As the planning reserve margin is a capacity based metric, it does not provide an accurate assessment of performance in energy limited systems, e.g., hydro capacity with limited water resources.*[1]

Avista and the region's hydroelectric system is energy constrained, so the 10 or 15 percent metrics from NERC do not adequately define our planning margin. Beyond planning margins, as defined by NERC, a utility must maintain operating reserves to cover forced outages on the system. Avista includes operating reserves in addition to a planning margin. Per Western Electric Coordinating Council (WECC) requirements, Avista must maintain 1.5 percent of control area load and 1.5 percent of on-line control area generation as spinning reserves.[2] Then an additional 1.5 percent of control area load and 1.5 percent of on-line control area generation as non-spinning reserves. Avista must also maintain reserves to meet load following and regulation requirements of within-hour load and generation variability, this amount equals 16 MW at the peak hour. Recently, the WECC began experimenting with changing the reserve rules. The current proposal is to keep three percent of load and three percent of generation as operating reserves, but to remove the requirement to hold half the reserves as spinning reserve. In lieu of spinning reserves is a requirement to hold 24 MW (for Avista) as Frequency Response Reserves (FRR). FRR can instantaneously respond to changes in frequency. Avista has sufficient FRR resource capability; but will require operational changes to insure the units with this capability are available. Avista will not acquire additional capacity until its expected peak loads plus reserve margins exceed resources beyond 2026 either on a single-hour or on a sustained three-day basis.

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

[2] Spinning reserves synchronize to the system while stand-by reserves must be available within 10 minutes.

## Planning Margin

Utility capacity planning begins with identifying the broader regional capacity position, as regional surpluses can offset high planning margins and utility investments. The Northwest has a history of capacity surpluses and energy deficits because of its hydroelectric generation base. Since the 2000-2001 energy crisis, the Northwest added nearly 6,400 MW of natural gas-fired generation. During this same time, Oregon and Washington added 7,890 MW of wind generation. Northwest load growth projections are lower as compared to history, but with announced coal plant retirements and wind's lack of on-peak capacity contribution, the region is approaching load-resource capacity balance, while retaining an energy surplus.

Given the interconnected landscape of the Northwest power market, selecting a planning margin target is not straightforward. One approach is to conduct a regional loss of load probability (LOLP) study calculating the amount of capacity required to meet a five percent LOLP threshold. Five percent LOLP means a utility meets all customer demand in all hours of the year in 19 of 20 years; this allows one loss-of-load event in a 20-year period. Regional LOLP analysis is beyond the scope of an IRP. Fortunately, the NPCC conducts regional LOLP studies.

The NPCC analyzes northwest resource adequacy. Based on their work, the northwest begins to fail the five percent LOLP measure in the winter of 2021-22 when major coal generators retire.[3] The NPCC identifies a loss of load probability after conservation is 7.2 percent, assuming the region can import 2,500 MW of power from southern neighbors. The projected shortages occur primarily in the winter, but now the summer as well, the same periods when Avista would expect its peak loads to occur. The summer LOLP is new to the Council's analysis prompting Avista to consider a summer planning margin. In prior studies during the 2015 IRP cycle, the Council concluded the region had enough capacity to meet summer demand. The recent change is due to additional coal plant retirement announcements.

Avista is an interconnected utility, an advantage over its sister utility Alaska Electric Light & Power (AELP). AELP is an electrical island and must meet all loads instantaneously using its own resources without relying on its neighbors. AELP retains large reserve margins to account for avalanche danger – typically 115 percent of peak load. Avista, as an interconnected utility, can rely on its neighbors (and the neighbors can rely on Avista) to lower planning margins. The harder question is how much reliance it should place on the wholesale market. Wholesale markets are important to help meet load when controlled resource dispatch is not available from factors such as economic dispatch, forced or planned outages, low renewable energy production (such as wind/hydro), or higher than normal loads. In the 2013 IRP, Avista found a 30 percent planning margin (in addition to operating reserves) would be required to meet the 5 percent LOLP without connecting to the wholesale market. This higher planning margin is due to Avista's large resources as compared to its load. Since Avista is an interconnected utility, a lower planning margin of 14 percent (winter) and seven percent (summer) is included in the plan to balance the reliance on the marketplace when large

[3]https://www.nwcouncil.org/media/7491213/2017-5.pdf.

resources have forced outages or other combination of events. This difference results in Avista requiring 270 MW less winter peak generation in 2018 than if Avista was an electrical island, a similar amount to its largest contingencies. The total requirement for planning margin and other reserves equates to a 22.6 percent planning margin.

Avista studied planning margins used by transmission organizations and utilities across the country as part of the 2015 IRP. The results varied depending on the amount and size of their interconnections and the resource mix within their systems. One challenge in comparing planning margins across utilities is determining if they include ancillary service, or operating reserve, obligations in their planning margins. Utilities with minimal interconnections or a large hydroelectric system have higher planning margins than better-interconnected and/or thermal-based systems. Avista and its neighbors generally meet a large portion of their load obligations with hydroelectric resources, implying that their planning margins might need to be higher than NERC's 15 percent recommendation.

Another consideration when selecting the appropriate planning margin is the utility's largest single contingency relative to peak load. Avista's largest single unit contingency is Coyote Springs 2. This plant is 18.8 percent of weather-adjusted peak load in 2018, a high statistic relative to Western Interconnect peers. Some resource planners argue planning margins should be no smaller than a utility's single largest contingency on the basis that if the largest resource fails, other resources may not be able to replace it. Given the Northwest's contingency reserve sharing agreement, lower reserve levels are required for the first hour following a qualifying generation outage. Signatories to the contingency reserve sharing agreement can call on assistance from neighboring utilities for up to 60 minutes to help meet shortages. Beyond the first hour, utilities are responsible for replacing the lost power themselves, either from other utility resources, from purchases from other generators, or from load reductions.

In Avista's prior LOLP studies, both summer and winter capacity shortages are possible due to high peak loads. Past IRPs planned to utilize the wholesale market for summer capacity due to the amount of available surplus market capacity. As this capacity surplus shrinks, Avista is changing its summer planning margin to seven percent plus operating reserves and regulation. Avista chose the seven percent planning margin by comparing the standard deviation of potential loads in the summer (69 MW) to winter peak load standard deviation (138 MW).[4] Avista concluded the summer planning margin should be half of the winter planning margin because the standard deviation of summer potential peak loads is half of the winter peak loads. Avista will continue to analyze planning margins using its loss of load model to validate or update this requirement as part of the 2019 IRP. Avista will monitor the summer market depth and may revise the planning margin standard from after reviewing work by the NPCC. The addition of a seven percent summer planning margin for this IRP does not add additional resources requirements above the winter peak requirement due to our dual peaking load profile, but it will require the selection of resources than can provide both winter and summer

[4] Peak winter loads can occur from the last two weeks of November through the second week of February. The standard deviation of all the monthly peak loads in this period is 138 MW.

peaking capabilities. Avista intends on meeting this requirement using owned resources or power purchase agreements (PPAs) as identified in Chapter 11 – Preferred Resource Strategy. Avista does not plan to use short-term market purchases to meet the 14 and seven percent planning margin requirements.

### Northwest Power and Conservation Council Operating Reserve Planning Data

The NPCC's Seventh Plan and the Washington Commission's 2015 IRP acknowledgment letters request utilities to provide additional documentation regarding reserves:

> *Utilities should include their planning assumptions for the provision of operating reserves in their Integrated Resource Plans and Bonneville in its Resource Program. These assumptions should emphasize reliability ahead of economic operations, that is, reasonable estimates for times of power system stress. The following should also be included:*
>
> - *An estimate of the utility's or Bonneville's requirement for operating reserves*
> - *Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on hydropower generation and which projects should be assigned in power system models to provide these reserves*
> - *Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on thermal plants and which plants should be assigned in power system models to provide these reserves*
> - *Reasonable planning assumptions for any third-party provision of reserves*[5]

In response to this request, Avista provides the following:

- Avista includes operating reserves as part of its planning criteria; these operating reserves are not included in the 14 percent winter or the seven percent summer planning margin calculations. For the 2018 winter peak hour estimated load, the operating reserves sum to 122 MW.[6] An additional 16 MW[7] of capacity is for within hour requirements such as regulation. Regulation is typically met with Avista's hydroelectric facilities. Avista tends to hold out of the money thermal resources as non-spinning reserve resources and the remaining requirements at its hydroelectric facilities. The amounts held at the hydroelectric system versus thermal facilities depends on water conditions and plant economics. For example, it is possible to hold all these reserves on the hydroelectric system in summer months due to lower flows and Avista's storage at both the Noxon Rapids and Mid-Columbia projects.
- Avista has several hydroelectric units with the ability to provide operating reserves; these include Noxon Rapids, Cabinet Gorge, Long Lake and contracted Mid-Columbia projects. These facilities provide both spinning and

[5] Northwest Power and Conservation Council's Seventh Power Plan, Chapter 4, Page 7, REG-4

[6] Avista holds operating reserves for the entire control area, including non-Avista generation and loads.

[7] Avista typically holds 20 MW for both increases and decreases during normal operating conditions (non-peak event), but may vary depending on wind forecasts.

non-spinning reserves. Under the new FRR rules, only four units at Noxon Rapids and one of Cabinet Gorge's units can provide this capacity.

- Avista can also provide operating reserves with its thermal fleet. Rathdrum CT, and Northeast CT can provide non-spinning reserves. Coyote Springs 2 and Lancaster can provide non-spin, spinning, and FRR reserves when the units are not at full capacity.
- Avista on occasion will contract to sell reserves to other control areas under short-term agreements, but this information is proprietary.

## Energy Imbalance Market

Avista recently participated in a regional effort to evaluate the viability of an intra-hour Energy Imbalance Market (EIM) in the Northwest Power Pool area. The Market Coordination (MC) Initiative officially launched on March 19, 2012 to explore alternatives to address the growing operational and commercial challenges to integrate variable energy resources affecting the regional power system. In December 2015, the MC evaluation effort concluded. The agreement ended after the group could not agree to a final market design and several participants decided to join the California Independent System Operator (CAISO) Western EIM.

Avista is conducting a cost/benefit analysis associated with joining the CAISO EIM. This analysis will be complete in the fall of 2017. Avista is also evaluating other factors influencing the decision to join the CAISO EIM. These include the reduction of near term market liquidity as other utilities join the EIM and the additional integration of renewable resources in our service territory. Avista will use the cost/benefit analysis and evaluation of other market factors to inform its decision to participate in the Western EIM.

## Balancing Loads and Resources

Both single-hour and sustained-peaking requirements compare future load and resource projections to identify any shortages. The single peak hour is a larger concern in the winter than the three-day sustained 18-hour peak. During winter months, the hydroelectric system can sustain generation levels for longer periods than in the summer due to higher inflows. Figure 6.1 illustrates the winter balance of loads and resources. The first year Avista has a significant winter capacity deficit is November 2026 when including future conservation acquisitions. If all conservation programs ended, the first capacity deficit would occur in January 2022. Until recently, the capacity position was short beginning in 2022, but the extension of a PPA from the Mid-Columbia PUDs filled this deficiency.

Avista plans to meet its summer peak load with a smaller planning margin than in the winter. During summer months, operating reserve and regulation obligations are included in addition to a seven percent planning margin. Market purchases in the deep regional market should satisfy any weather-induced load variation or generation forced outage that otherwise would be included in the planning margin as is the case in the higher 14 percent winter planning margin. Resource additions to serve winter peaks meet smaller summer deficits as well. Figure 6.2 shows Avista's summer resource balance. Like the winter, Avista expects its first summer deficit in 2027 after the expiration of the Lancaster PPA in October 2026.

**Figure 6.1: Winter One-Hour Capacity Load and Resources**

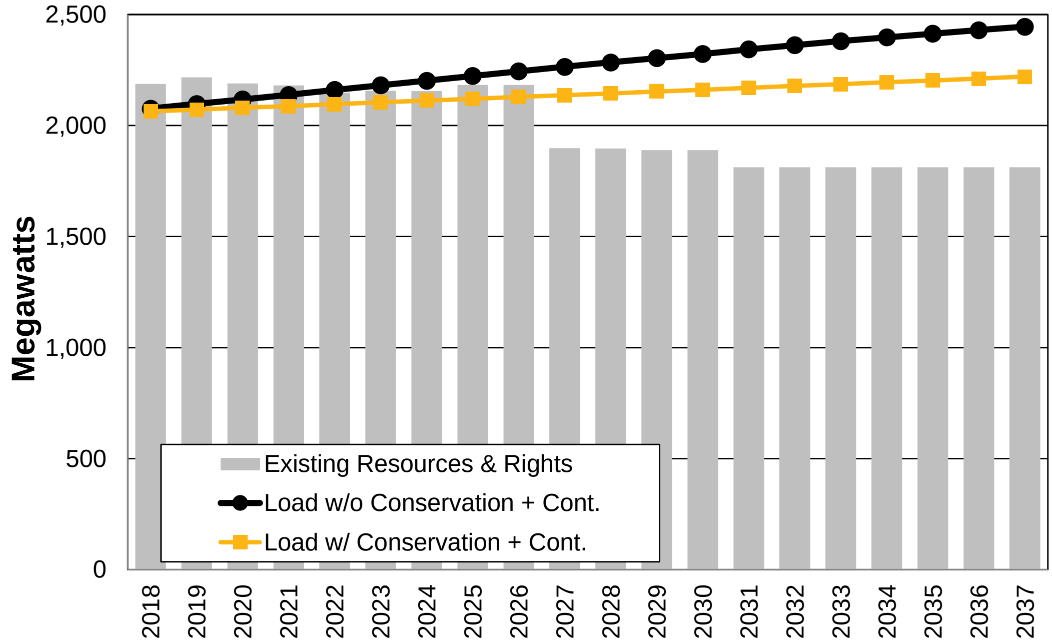
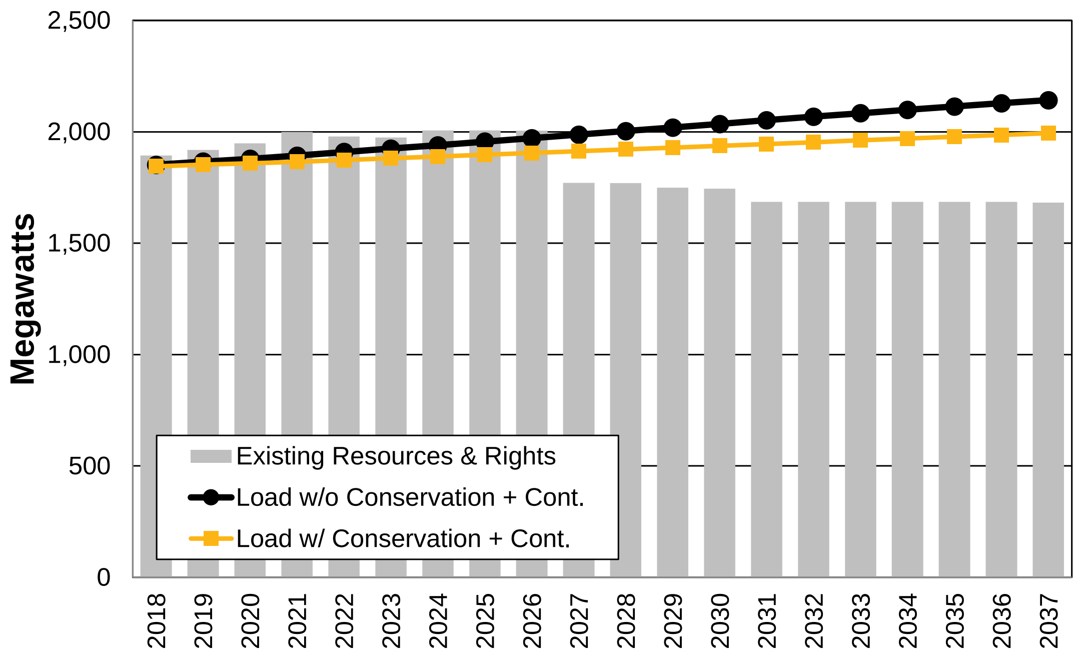



**Figure 6.2: Summer One-Hour Capacity Load and Resources**



## Energy Planning

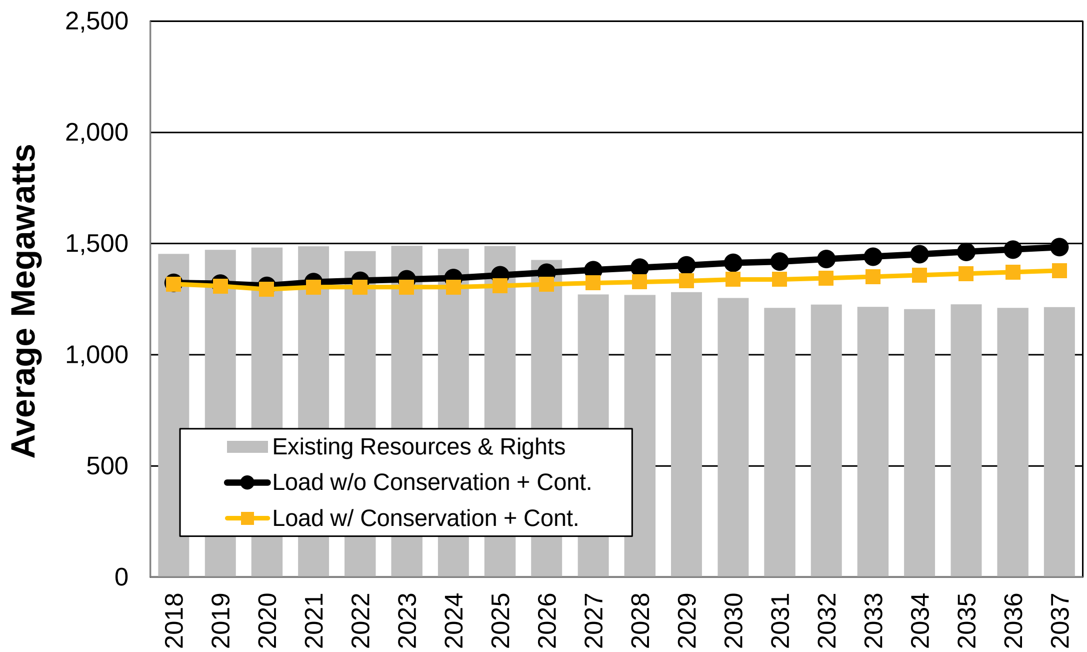
For energy planning, resources must be adequate to meet customer requirements even when loads are high for extended periods, or a sustained outage limits the contribution of a resource. Where generation capability is not adequate to meet these variations, customers and the utility must rely on the short-term electricity market. In addition to load variability, Avista holds energy-planning margins accounting for variations in month-to-month hydroelectric generation.

As with capacity planning, there are differences in regional opinions on the proper method for establishing energy-planning margins. Many utilities in the Northwest base their energy planning margins on the amount of energy available during the "critical water" period of 1936/37.[8] 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. The IRP could target resource development to reach a 99 percent confidence level on being able to deliver energy to its customers, and it would significantly decrease the frequency of its 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 of the 2017 IRP to cover a one-in-one-hundred year event. Investments to support this high level of reliability would increase pressure on retail rates for a modest benefit. Avista plans to the 90$^{th}$ percentile for hydroelectric generation. Using this metric, there is a one-in-ten-year chance of needing to purchase energy from the market in any given month over the IRP timeframe.

Beyond load and hydroelectric variability, Avista's legacy WNP-3 contract with BPA contains supply risk. The contract includes a return energy provision in favor of BPA that can equal 32 aMW annually. Under adverse market conditions, BPA almost certainly would exercise this right, as it did during the 2001 Energy Crisis. To account for this contract risk, the energy contingency increases by 32 aMW until the contract expires in 2019. With the addition of WNP-3 contract contingency to load and hydroelectric variability, the total energy contingency amount equals 231 aMW in 2018. See Figure 6.3 for the summary of the annual average energy load and resource net position.

[8] The critical water year represents the lowest historical generation level in the streamflow record.

**Figure 6.3: Annual Average Energy Load and Resources**




## Washington State Renewable Portfolio Standard

Washington's EIA requires utilities with more than 25,000 customers to source 9 percent of their energy from qualified renewables through 2019 and 15 percent by 2020. Utilities also must acquire all cost effective conservation as explained in Chapter 5 – Energy Efficiency and Demand Response. 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 50-MW Kettle Falls project to qualify for the EIA goals beginning in 2016.

Table 6.1 shows the forecast amount of RECs Avista needs to meet the EIA renewable requirement and the amount of qualifying resources already in Avista's generation portfolio. Without the ability to roll RECs from previous years, Avista would require additional renewables in 2026. With this ability, Avista does not need additional EIA resources over the planning horizon of this IRP. The company may have surplus RECs depending upon the qualifying output of Kettle Falls and Palouse Wind. Kettle Falls qualifying output varies depending upon the availability of qualifying fuel and the economics of the facility. Given its expected renewables surplus until 2020, Avista will market the excess RECs until 2019. Beginning in 2019, surplus RECs will roll into 2020, allowing the banking provision to delay additional renewable resource investment.

**Table 6.1: Washington State EIA Compliance Position Prior to REC Banking (aMW)**

| | 2018 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| Percent of Washington Sales | 9% | 15% | 15% | 15% | 15% |
| Two-Year Rolling Average Washington Retail Sales Estimate | 644 | 658 | 683 | 699 | 720 |
| | | | | | |
| Renewable Goal | -58 | -99 | -103 | -105 | -108 |
| Incremental Hydroelectric | 22 | 22 | 22 | 22 | 22 |
| **Net Renewable Goal** | -36 | -77 | -81 | -83 | -86 |
| | | | | | |
| ***Other Available REC's*** | | | | | |
| Palouse Wind with Apprentice Credits | 48 | 48 | 48 | 48 | 48 |
| Kettle Falls | 33 | 33 | 33 | 33 | 33 |
| **Net Renewable Position (before rollover RECs)** | **45** | **4** | **0** | **-2** | **-5** |

# 7. Policy Considerations

Public policy affects Avista's current generation resources and the resources it can pursue. Each resource option presents different cost, environmental, operational, political, regulatory, and siting challenges. Regulatory environments regarding energy topics such as renewable energy and greenhouse gas regulation continue to evolve since publication of the last IRP. Current and proposed regulations by federal and state agencies, coupled with political and legal efforts, have implications for the development and continued use of coal and natural gas-fired generation. This chapter discusses pertinent public policy issues relevant to the IRP.

**Chapter Highlights**

- Active cap and trade programs, emissions performance standards, and combinations of current and proposed regulations affect emissions levels.
- Avista's Climate Policy Council monitors greenhouse gas legislation and environmental regulation issues.
- The Washington State Clean Air Rule affects generation in Washington, but does not directly impact any of Avista's generating fleet.

## Environmental Issues

The evolving and sometimes contradictory nature of environmental regulation from state and federal perspectives creates challenges for resource planning. The IRP cannot add renewables or reduce emissions in isolation from topics such as system reliability, least cost requirements, price mitigation, renewable portfolio standards, financial risk management, and meeting changing environmental requirements. Each generating resource has distinctive operating characteristics, cost structures, and environmental regulatory challenges that can change significantly based on timing and location. All resource choices have costs and benefits requiring careful consideration of the utility and customer needs being fulfilled, their location, and the regulatory and policy environment at the time of procurement.

Traditional thermal generation technologies, like coal and natural gas-fired plants, provide reliable capacity and energy. New coal plants as compared to natural gas-fired resources have environmental and economic disadvantages. It is unlikely without major technological improvements any new coal-fired resources will be developed in the U.S. Existing coal-fired resources are also under increasing pressure from lower-cost resources and increasing regulatory constraints and costs.

Natural gas-fired plants have relatively low capital costs, can typically be located closer to load centers, have relatively short construction time frames, lower emissions and fewer waste issues than coal, and are often the only available utility-scale baseload resource. On the other hand, higher fuel price volatility historically affected natural gas-fired plant economics. In addition, their performance decreases in hot weather, they are difficult to site with sufficient water rights for their efficient operation, and they emit greenhouse gases.

Renewable energy technologies such as wind, biomass, geothermal, and solar have different benefits and challenges. Renewable resources have low or no fuel costs and few, if any, direct emissions. However, solar and wind-based generation have limited or no capacity value, their own unique siting limitations, and their variable output can present integration challenges requiring additional capacity investments. Renewable resources are often located to maximize capability rather than proximity to load centers. The need to site renewable resources in remote locations often requires significant investments in transmission and capacity expansion, as well as mitigating possible wildlife and aesthetic issues. Distributed resources may alleviate some of these issues, but the price differentials of distributed resources make them more difficult to develop at utility scale. Unlike fossil fuel-fired plants, the fuel for non-biomass renewables may not be transportable to utilize existing transmission or to minimize opposition to project development. Dependence on the health of the forest products industry and access to biomass materials, often located in publicly owned forests, poses challenges to biomass facilities. Transportation costs and logistics also complicate the location of biomass plants.

The long-term economics of renewable resources also faces some uncertainties. Federal investment and production tax credits are set to expire. The extension credits and grants may not be sustainable given their impact on government finances and the maturity of wind and solar technologies. Many relatively unpredictable factors affect renewables, such as renewable portfolio standards (RPS), construction and component prices, international trade issues and currency exchange rates. Decreasing capital costs for wind and solar may slow or stop.

The design and scope of greenhouse gas regulation is in a state of flux due to legal challenges and evolving political realities. As a result, greenhouse gas policy-making is shifting from the federal to the state and local level. Since the 2015 IRP publication, changes in the approach to greenhouse gas emissions regulation and supporting programs, include:

- The EPA proposed actions to regulate greenhouse gas emissions under the Clean Air Act (CAA) through the proposed Clean Power Plan (CPP) were stayed by the U.S. Supreme Court on February 9, 2016;
- The President signaled a shift in federal priorities through Executive Orders as well as proposed budgets.
- EPA plans to reevaluate the CPP and submit a new CPP proposal to the Office of Management and Budget;
- California failed to pass an extension to its cap-and-trade program beyond 2020, but did raise its RPS to 50 percent and expanded energy storage requirements; and
- The State of Washington implemented the Clean Air Rule

### Natural Gas System Emissions

The physical makeup of the natural gas system includes extraction rigs, pipelines and storage; each of these facilities have fugitive emissions. Fugitive emissions are the unintended or irregular releases of natural gas as part of the production cycle. The EPA introduced the Natural Gas STAR Program in 1993 in response to these emissions concerns. This Natural Gas STAR Program is a voluntary program allowing the self-reporting of emission reduction technologies and practices and includes all of the major industry sectors. In May 2016, the EPA finalized rules to reduce methane emissions from wells under the CAA. The program requires natural gas well owners to find and repair leaks at the well site no less than twice per year and four times per year at compressor stations. The EPA placed a 90-day delay on portions of the rule to allow additional comments.

Natural gas wells utilizing shale deposits have a high production curve at the beginning of the extraction process and then dramatically levels off. If not constructed properly, there is a risk of leakage that may lower the return on investment. In addition, risk of increased regulation incentivizes producers to manage emissions as effectively as possible as more regulations generally increase costs and reduce return on investments. Over time a smaller return on investment could mean the difference in survival outcomes for each producer.

## Avista's Climate Change Policy Efforts

Avista's Climate Policy Council is an interdisciplinary team of management and other employees that:

- Facilitates internal and external communications regarding climate change issues;
- Analyzes policy impacts, anticipates opportunities, and evaluates strategies for Avista Corporation; and
- Develops recommendations on climate related policy positions and action plans.

The core team of the Climate Policy Council includes members from Environmental Affairs, Government Relations, External Communications, Engineering, Energy Solutions, and Resource Planning groups. Other areas participate for topics as needed. The meetings for this group include work for both immediate and long-term concerns. Immediate concerns include reviewing and analyzing proposed or pending state and federal legislation and regulation, reviewing corporate climate change policy, and responding to internal and external requests about climate change issues. Longer-term issues involve emissions measurement and reporting, different greenhouse gas policies, actively participating in legislation, and benchmarking climate change policies and activities against other organizations.

Membership in the Edison Electric Institute is Avista's main vehicle to engage in federal-level climate change dialog, supplemented by other industry affiliations. Avista monitors regulations affecting hydroelectric and biomass generation through its membership in other associations.

### State and Federal Environmental Policy Considerations

The CPP was the focus of federal greenhouse gas emissions policies in the 2015 IRP and the starting point for this IRP emission reduction assumptions. Details about greenhouse gas emissions modeling are in Chapter 10 – Market Analysis. As explained above, the application and form of the future CPP is uncertain as this IRP is being written. However, a form of federal regulation will be put in place. As explained in Chapter 10, this IRP does not include specific carbon pricing with the exception of states and provinces with existing carbon trading and taxing regulations. This IRP does include regional emission reduction goals leading to a shadow price of carbon pricing, rather than an arbitrary carbon price. If a carbon tax or cap and trade program develops in the future, it will require alternative analysis in a later IRP.

### EPA Regulations

EPA regulations, or the States' authorized versions, directly, or indirectly, affecting electricity generation include the CAA, along with its various components, including the Acid Rain Program, the National Ambient Air Quality Standard, the Hazardous Air Pollutant rules, and Regional Haze Programs. The U.S. Supreme Court ruled the EPA has authority under the CAA to regulate greenhouse gas emissions from new motor vehicles and the EPA has issued such regulations. When these regulations became effective, carbon dioxide and other greenhouse gases became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program. Both of these programs apply to power plants and other commercial and industrial facilities. In 2010, the EPA issued a final rule, known as the Tailoring Rule, governing the application of these programs to stationary sources, such as power plants. EPA proposed a rule in early 2012, and modified in 2013, setting standards of performance for greenhouse gas emissions from new and modified fossil fuel-fired electric generating units and for existing sources through the draft CPP in June 2014. The EPA released the final CPP rules and the Carbon Pollution Standards (CPS) as published in the Federal Register on October 23, 2015, when they were both challenged thorough a series of lawsuits. Standards under Section 111(d) of the CAA are currently stayed by the Supreme Court. The EPA also finalized new source performance standards (NSPS) for new, modified and reconstructed fossil fuel-fired generation under CAA section 111(b).

Promulgated PSD permit rules may affect Avista's thermal generation facilities in the future. These rules can affect the amount of time to obtain permits for new generation, major modifications to existing generating units, and the final limitations contained in permits. The promulgated and proposed greenhouse gas rulemakings mentioned above have been legally challenged in multiple venues so we cannot fully anticipate the outcome or extent our facilities may be impacted, nor the timing of rule finalization.

### Clean Air Act Operating Permits

The CAA, originally adopted in 1970 and modified significantly since, intends to control covered air pollutants to protect and improve air quality. Avista complies with the requirements under the CAA in operating our thermal generating plants. Title V operating permits are required for our largest generation facilities and are renewed every five years. Title V operating permit renewal applications are in process for Colstrip Units 3 and 4, Coyote Springs 2 and Kettle Falls. Boulder Park, Northeast CT, and other small facilities require only minor source operating or registration permits based on their limited operation and emissions. Discussion of some major CAA programs follows.

### New Source Proposal

After receiving over 2.5 million comments on the April 2012 proposal for new resources under section 111(b) of the CAA, the EPA withdrew that proposal and submitted a new proposal on September 20, 2013. This proposal covers new fossil fuel-fired resources larger than 25 MW for the following resource types:

- Natural gas-fired stationary combustion turbines: 1,000 pounds $CO_2$ per MWh for units burning greater than 850 mmBtu/hour and 1,100 pounds $CO_2$ per MWh units burning less than or equal to 850 mmBtu/hour.
- Fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units: 1,100 pounds $CO_2$ per MWh over a 12-operating month period or 1,000–1,500 pounds $CO_2$ per MWh over a seven-year period.

The EPA finalized the new source standard on August 3, 2015. The final rule differs from the proposal, which was the basis for the development of this IRP. The final rule guided modeling assumptions for the 2017 IRP.

### Acid Rain Program

The Acid Rain Program is an emission-trading program for reducing nitrous dioxide by two million tons and sulfur dioxide by 10 million tons below 1980 levels from electric generation facilities. Avista manages annual emissions under this program for its ownership interest in Colstrip Units 3 and 4, Coyote Springs 2, and Rathdrum.

### National Ambient Air Quality Standards

EPA sets National Ambient Air Quality Standards for pollutants considered harmful to public health and the environment. The CAA requires regular court-mandated updates to occur for nitrogen dioxide, ozone, and particulate matter. Avista does not anticipate any material impacts on its generation facilities from the revised standards at this time.

### Hazardous Air Pollutants (HAPs)

HAPs, often known as toxic air pollutants or air toxics, are pollutants that may cause cancer or other serious health effects. EPA regulates toxic air pollutants from a published list of industrial sources referred to as "source categories". These pollutants must meet control technology requirements if they emit one or more of the pollutants in significant quantities. EPA finalized the Mercury Air Toxic Standards (MATS) for the coal and oil-fired source category in 2012. Colstrip Units 3 & 4's existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule that utilized Particulate Matter as a surrogate for air toxics (including metals and acid gases), the Colstrip owners reviewed recent stack testing data and expected that no additional emission control systems would be needed for Units 3 & 4 MATS compliance.

### Regional Haze Program

EPA set a national goal to eliminate man-made visibility degradation in Class I areas by the year 2064. Individual states are to 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. The FIP includes both emission limitations and pollution controls for Colstrip Units 1 and 2. Colstrip Units 3 and 4 are not currently affected, although the units will be evaluated for Reasonable Progress at the next review period in September 2017. Avista does not anticipate any material impacts on Colstrip Units 3 and 4 at this time. 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.

### EPA Mandatory Reporting Rule

Any facility emitting over 25,000 metric tons of greenhouse gases per year must report its emissions to EPA. Colstrip Units 3 and 4, Coyote Springs 2, and Rathdrum currently report under this requirement. The Mandatory Reporting Rule also requires greenhouse gas reporting for natural gas distribution system throughput, fugitive emissions from electric power transmission and distribution systems, fugitive emissions from natural gas distribution systems, and from natural gas storage facilities. Washington requires mandatory greenhouse gas emissions reporting similar to the EPA requirements and Oregon has similar reporting requirements.

### Coal Ash Management and Disposal

The EPA issued a final rule regarding coal combustion residuals (CCR) in 2014. This affects Colstrip since it produces CCR. The rule establishes 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 CCR rule became effective October 2015. The owners of Colstrip are developing a multi-year plan to comply with the new CCR standards. Any financial or operational impacts to Colstrip from the CCR are still estimates, but are included in this IRP.

### Particulate Matter

Particulate Matter (PM or particle pollution) is the term 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 be seen with the naked eye. Others are so small they can only be detected using 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 that are 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 EPA to periodically review the standards to ensure that they provide adequate health and environmental protection, and to update those standards as necessary.

Avista has ownership and/or operational control for the following thermal electric generating stations: Boulder Park, Colstrip, Coyote Springs, Kettle Falls, Lancaster, Northeast and Rathdrum that produce PM. Table 7.1 shows each of these generating stations, location, status of the surrounding area with NAAQS for $PM_{2.5}$ and $PM_{10}$, operating permit and PM pollution controls.

**Table 7.1: Avista Owned and Controlled PM Emissions**

| Thermal Generating Station | Location County, City, State | $PM_{2.5}$ NAAQS Status | $PM_{10}$ NAAQS Status | Air Operating Permit | PM Pollution Controls |
|---|---|---|---|---|---|
| Boulder Park | Spokane Co., Spokane, WA | Attainment | Maintenance | Minor Source | Pipeline Natural Gas |
| Colstrip | Rosebud Co., Lame Deer, MT | Attainment | Non-Attainment | Major Source Title V OP | Fluidized Bed Wet Scrubber |
| Coyote Springs | Morrow Co., Boardman, OR | Attainment | Attainment | Major Source Title V OP | Pipeline Natural Gas, Air filters |
| Kettle Falls | Lincoln Co., Kettle Falls, WA | Attainment | Attainment | Major Source Title V OP | Multi-clone collector, Electrostatic Precipitator |
| Lancaster | Kootenai Co., Rathdrum, ID | Attainment | Attainment | Major Source Title V OP | Pipeline Natural Gas, Air filters |
| Northeast | Spokane Co., Spokane, WA | Attainment | Maintenance | Minor Source | Pipeline Natural Gas, Air filters |
| Rathdrum | Kootenai Co., Rathdrum, ID | Attainment | Attainment | Major Source Title V OP | Pipeline Natural Gas, Air filters |

Our generating stations are issued air quality operating permits from the appropriate EPA delegated air quality agency under the authority of the Federal CAA. These operating permits require annual compliance certifications and are fully renewed every five years to incorporate any new standards including any updated NAAQS status. If warranted, EPA would issue specific requirements to protect human health and the environment at that time.

## State and Regional Level Policy Considerations

The lack of a comprehensive federal greenhouse gas policy encouraged states, such as California, to develop their own climate change laws and regulations. Climate change legislation takes many forms, including economy-wide regulation under a cap and trade system, a carbon tax, and emissions performance standards for power plants. Comprehensive climate change policy can include multiple components, such as renewable portfolio standards, energy efficiency standards, and emission performance standards. Washington enacted all of these components, but other Avista jurisdictions have not. Individual state actions produce a patchwork of competing rules and regulations for utilities to follow and may be particularly problematic for multi-jurisdictional utilities such as Avista. There are 29 states, plus the District of Columbia, with active renewable portfolio standards, and eight additional states have adopted voluntary standards.[1]

### Idaho Policy Considerations

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

### Montana Policy Considerations

Montana's RPS law requires covered utilities to meet 15 percent of their load with qualified renewables since 2015. Montana implemented a mercury emission standard under Rule 17.8.771 in 2009. The standard exceeds the most recently adopted federal mercury limit. Avista's generation at Colstrip Units 3 and 4 have emissions controls currently meeting Montana's mercury emissions goal.

### Oregon Policy Considerations

The State of Oregon has a history of greenhouse gas emissions and renewable portfolio standards legislation. The Legislature enacted House Bill 3543 in 2007, calling for, but not requiring, reductions of greenhouse gas emissions to 10 percent below 1990 levels by 2020 and 75 percent below 1990 levels by 2050. Compliance is expected through a combination of the RPS and other complementary policies, like low carbon fuel standards and energy efficiency measures. The state has been working towards the adaptation of comprehensive requirements to meet these goals. Oregon's SB 1547, enacted in March 2016, ends the use of coal to serve Oregon loads by 2030 and increases the RPS to 50 percent by 2040. HB 2135, or the cap and trade bill, is under consideration at the time this chapter is being written. This bill would repeal the greenhouse gas emissions goals stated above and would require the Environmental Quality Commission to adopt greenhouse gas emissions goals for 2025, and set limits for years 2035 and 2050.

These reduction goals are in addition to a 1997 regulation requiring fossil-fueled generation developers to offset carbon dioxide ($CO_2$) emissions exceeding 83 percent of the emissions of a state-of-the-art gas-fired combined cycle combustion turbine by funding offsets through the Climate Trust of Oregon.

### Washington State Policy Considerations

The State of Washington has enacted several fossil-fueled generation emissions and resource diversification measures. A 2004 law requires new fossil-fueled thermal electric generating facilities of more than 25 MW of generation capacity to offset $CO_2$ emissions through third-party mitigation, purchased carbon credits, or cogeneration. An agreement with the State of Washington requires the Centralia Coal Plant to shut down one unit by December 2020 and the other unit by December 2025.

Washington's EIA requires utilities with more than 25,000 retail customers to use qualified renewable energy or renewable energy credits to serve nine percent of retail load by 2012 and 15 percent by 2020. Failure to meet RPS requirements results in at least a $50 per MWh fine. The initiative also requires utilities to acquire all cost-effective conservation

[1] http://www.dsireusa.org/resources/detailed-summary-maps/

and energy efficiency measures up to 110 percent of avoided cost. Additional details about the energy efficiency portion of the EIA are in Chapter 6 – Long-Term Position.

In 2012, Senate Bill 5575 amended the EIA to define Kettle Falls Generating Station and other legacy biomass facilities commencing operation before March 31, 1999 as EIA-qualified resources beginning in 2016. A 2013 EIA amendment allows multistate utilities to import RECs from outside the Pacific Northwest to meet renewable goals and allows utilities to acquire output from the Centralia Coal Plant without jeopardizing alternative compliance methods.

Avista will meet or exceed its renewable requirements in this IRP planning period through a combination of qualified hydroelectric upgrades, wind generation from the Palouse Wind PPA, and output from its Kettle Falls generation facility. The 2017 IRP Expected Case ensures that Avista meets all EIA RPS goals.

Former Governor Christine Gregoire signed Executive Order 07-02 in February 2007 establishing the following GHG emissions goals:

- 1990 levels by 2020;
- 25 percent below 1990 levels by 2035;
- 50 percent below 1990 levels by 2050 or 70 percent below Washington's expected emissions in 2050;
- Increase clean energy jobs to 25,000 by 2020; and
- Reduce statewide fuel imports by 20 percent.

The Washington Department of Ecology adopted regulations to ensure that its State Implementation Plan comports with the requirements of the EPA's regulation of greenhouse gas emissions. We will continue to monitor actions by the Department as it may proceed to adopt additional regulations under its CAA authorities. In 2007, Senate Bill 6001 prohibited electric utilities from entering into long-term financial commitments beyond five years for fossil-fueled generation creating 1,100 pounds per MWh or more of greenhouse gases. Beginning in 2013, the emissions performance standard is lowered every five years to reflect the emissions profile of the latest commercially available CCCT. The emissions performance standard effectively prevents utilities from developing new coal-fired generation and expanding the generation capacity of existing coal-fired generation unless they can sequester emissions from the facility. The Legislature amended Senate Bill 6001 in 2009 to prohibit contractual long-term financial commitments for electricity deliveries that include more than 12 percent of the total power from unspecified sources. The Department of Commerce filed a rule adopting a standard of 970 pounds per MWh for greenhouse gas emissions on March 6, 2013, with rules becoming effective on April 6, 2013.[2] Commerce announced that work for the next update would begin in the summer of 2017.

[2] http://www.commerce.wa.gov/Programs/Energy/Office/Utilities/Pages/EmissionPerfStandards.aspx

April 29, 2014, Washington Governor Jay Inslee issued Executive Order 14-04, "Washington Carbon Pollution Reduction and Clean Energy Action." The order created a "Climate Emissions Reduction Task Force" tasked with providing recommendations to the Governor on designing and implementing a market-based carbon pollution program to inform possible legislative proposals in 2015. The order also called on the program to "establish a cap on carbon pollution emissions, with binding requirements to meet our statutory emission limits." The order also states that the Governor's Legislative Affairs and Policy Office "will seek negotiated agreements with key utilities and others to reduce and eliminate over time the use of electrical power produced from coal." The Task Force issued a report summarizing its efforts, which included a range of potential carbon-reducing proposals. Subsequently, in January 2015, at Governor Inslee's request, the Carbon Pollution Accountability Act was introduced as a bill in the Washington legislature. The bill includes a proposed cap and trade system for carbon emissions from a wide range of sources, including fossil-fired electrical generation, "imported" power generated by fossil fuels, natural gas sales and use, and certain uses of biomass for electrical generation. The bill was not enacted during the 2015 legislative session. After the conclusion of the 2015 legislative sessions, Governor Inslee directed the Department of Ecology to commence a rulemaking process to impose a greenhouse gas emission limitation and reduction mechanism under the agency's CAA authority to meet the future emissions limits established by the Legislature in 2008. This resulted in Washington's Clean Air Rule (CAR).

The CAR imposes new compliance obligations on sources identified by Ecology. The rule imposes caps and requirements to reduce or offset emissions on large emitting facilities, fuel providers and natural gas distribution companies. It initially applies to 29 entities. Compliance obligations for energy-intensive trade-exposed industries, including pulp and paper manufacturers, steel and aluminum manufacturers and food processors, are deferred for three years. When fully implemented, the CAR could cover as many as 70 emitters who account for about two-thirds of Washington's emissions. The CAR caps emissions for facilities emitting more than 100,000 metric tons per year, and reduces the emissions threshold by 5,000 metric tons per year, until covering all entities emitting over 70,000 metric tons by 2035. The Washington Commission may implement rules regarding RCW 70.235, from the Executive Order 07-02. The CAR became effective January 1, 2017 and is currently under legal challenge. Avista does not have any generating facilities under the CAR rule.

# 8. Transmission & Distribution Planning

## Introduction

This chapter introduces the Avista Transmission and Distribution systems and provides a brief description of how Avista studies these systems and recommends projects that keep the systems functioning reliably. Avista's Transmission System is only one part of the networked Western Interconnection, so a discussion of regulations and regional planning is also provided. This chapter includes a brief summary of planned transmission projects and generation interconnection requests currently under study, and provides links to documents describing these studies in more detail. Further, this section describes how distribution planning is now playing a role in the IRP.

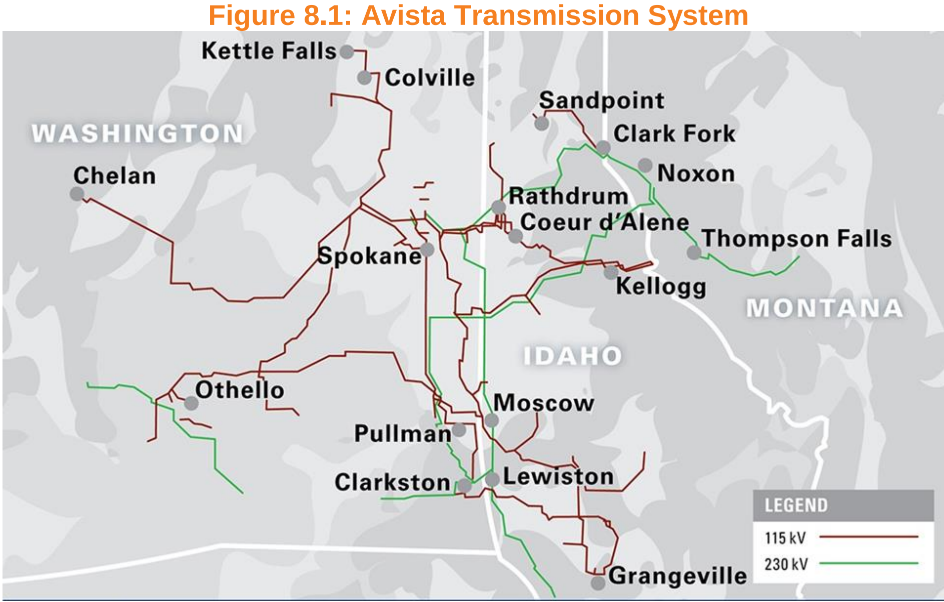
**Section Highlights**

- Avista actively participates in regional transmission planning forums.
- Avista develops a transmission and distribution system plan annually.
- Planned projects include reconductoring, station rebuilds and reinforcements.
- Transmission planning estimates costs for locating new generation on the Avista system.
- Distribution planning evaluates potential storage opportunities that may allow deferment of new distribution capital as part of the IRP process.

## Avista Transmission System

Avista owns and operates a system of over 2,200 miles of electric transmission facilities including approximately 660 miles of 230 kV transmission lines and 1,550 miles of 115 kV transmission lines (see Figure 8.1).

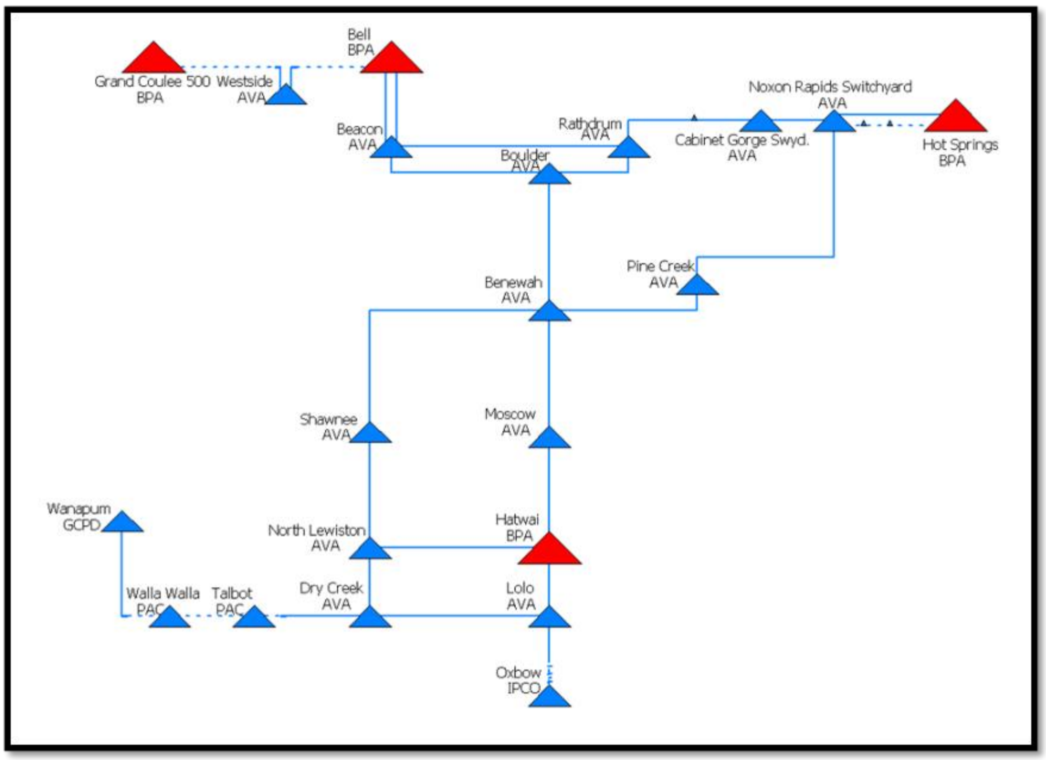
Figure 8.1: Avista Transmission System



### 230 kV Backbone

The backbone of the Avista Transmission System functions 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**



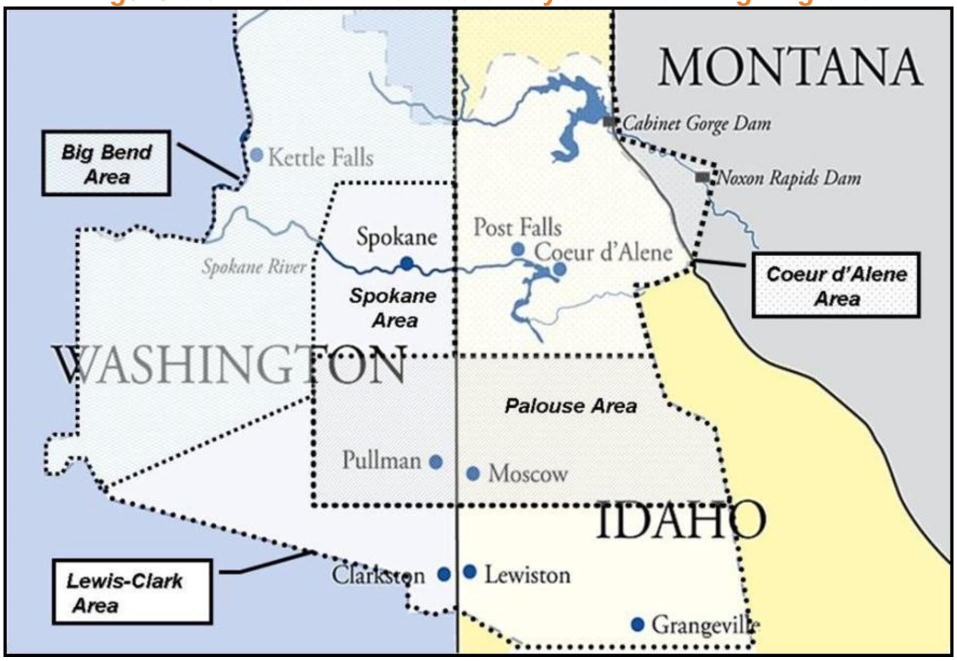

### Transmission System Areas

Avista separates its Transmission System into five geographical study areas:

1. Big Bend
2. Coeur d'Alene
3. Lewiston-Clarkston
4. Palouse
5. Spokane

Figure 8.3 shows the approximate boundaries of the study areas and these areas are referenced individually in Avista's Local Planning Report.

**Figure 8.3: Avista Transmission System Planning Regions**




## Transmission Planning Requirements and Processes

Avista coordinates its transmission planning activities with neighboring interconnected transmission operators. 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 transmission planning.

### Western Electricity Coordinating Council

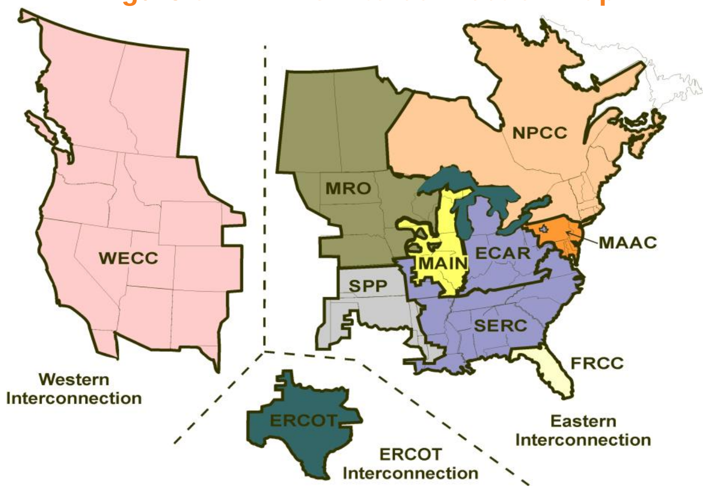
The Western Electricity Coordinating Council (WECC) is the group responsible for promoting bulk electric system reliability, compliance monitoring, and enforcement in the Western Interconnection. This group facilitates development of reliability standards and helps coordinate operating and planning among its membership. WECC is the largest geographic territory of the regional entities with delegated authority from the NERC and the 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 8.4 for the map of WECC.

### Peak Reliability

Peak Reliability (Peak) performs the federally mandated reliability coordinator function for a majority of the Western Interconnection. While each transmission operator within the Western Interconnection operates its respective transmission system, Peak has the authority to direct specific actions to maintain reliable operation of the overall transmission grid.

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

**Figure 8.4: 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 operations in support of 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 a number of committees, including its Operating Committee, the Reserve Sharing Group Committee, the Pacific Northwest Coordination Agreement (PNCA) Coordinating Group, and the Transmission Planning Committee (TPC).

### ColumbiaGrid

ColumbiaGrid formed on March 31, 2006. Its membership includes Avista, BPA, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. ColumbiaGrid 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 890 and 1000, ColumbiaGrid provides an open and transparent process to develop sub-regional transmission plans, assess transmission alternatives (including non-wires alternatives), and provides a decision-making forum and cost-allocation methodology for new transmission projects.

### Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) formed on August 10, 2007. NTTG members include Deseret Power Electric Cooperative, Idaho Power, Northwestern Energy, PacifiCorp, Portland General Electric, and Utah Associated Municipal Power Systems. These members rely upon the NTTG committee structure to meet FERC's coordinated transmission planning requirements. Avista's transmission network has a number of strong interconnections with three of the six NTTG member systems. Due to the geographical and electrical positions of Avista's transmission network related to NTTG members, Avista participates in the NTTG planning process to foster collaborative relationships with our interconnected utilities.

## Annual Transmission Planning Report

Avista's Local Planning Report is the end product of both the Local Transmission Planning Process and the annual Planning Assessment. The Local Transmission Planning Process (Process) is outlined in Attachment K to Avista's Open Access Transmission Tariff, FERC Electric Volume No. 8. The Process identifies single system projects needed to mitigate future reliability and load-service requirements for the Avista Transmission System. The Planning Assessment is outlined in the NERC Reliability Standard TPL-001-4.

The Planning Assessment determines where the Transmission System may not meet performance requirements as defined in the NERC Reliability Standards, and identifies Corrective Action Plans addressing how the performance requirements will be met. The Planning Assessment includes steady state contingency analysis, analysis of potential voltage collapse, and transient technical studies. Development of the Local Planning Report supports compliance with applicable NERC Reliability Standards as well as satisfying necessary steps in the Local Transmission Planning Process.

The Local Planning Report provides a 10-year Transmission System expansion plan by including all Transmission System facility improvements. The following sections summarize information from this report and other studies done by the Transmission Planning group in the 2016 Assessment.

### Transmission System Study Results

#### *Big Bend Area*

The Big Bend area transmission system performance will significantly improve upon completion of the Benton – Othello Station 115 kV Transmission Line Rebuild project. Improvements are made with reconductor projects, the Saddle Mountain 230 kV Station project, and the addition of communication aided protection schemes.

#### *Coeur d'Alene Area*

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 will improve transmission system performance in the near and long term planning horizons. The Sandpoint Reinforcement Project and installation of capacitor banks at the St. Maries Substation are part of the long range plan for the area.

#### *Lewiston/Clarkston Area*

The transmission system in the Lewiston/Clarkston area performs well. Issues are limited primarily to N-1-1 outages[2] on the 230 kV system and voltage exceeding facility ratings

[2] Failure of two separate facilities.

during light loading conditions. Installation of shunt reactors is recommended to mitigate these issues.

### *Palouse Area*

Completion of the Moscow 230 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.

### *Spokane Area*

Several performance issues exist with the present state of the transmission system in the Spokane area and worsen with additional load growth. The staged construction of new 230 kV facilities at the Garden Springs 230 kV and Ninth and Central 230 kV Stations to reinforce the area will be required. Dependency on Beacon Station leaves the system susceptible to performance issues for outages related to the station.

### *Short Circuit Study*

This study identified six undersized 230 kV breakers at Noxon and two undersized 115 kV breakers at Sunset. A list of corrective actions plans developed to mitigate performance issues observed during the assessment are in the 2016 Annual Assessment document.[3]

## 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, it is anticipated that 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 for integrating potential new generation projects. These requests follow a strict FERC process, including three study steps 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 major projects currently in Avista's interconnection queue.[4]

[3] http://www.oasis.oati.com/AVAT/AVATdocs/2016_Avista_System_Planning_Assessment.pdf
[4] http://www.oasis.oati.com/AVAT/AVATdocs/GIP_Queue-V83.pdf

**Table 8.1: 2017 IRP Generation Study Transmission Costs**

| Project | Size (MW) | Cost Estimate ($ Millions)[5] |
|---|---|---|
| Kootenai County | 100 | 2 |
| Kootenai County | 350 | 100 |
| Rathdrum Station (115 kV) | 26 | <1 |
| Rathdrum Station (115 kV) | 50 | <1 |
| Rathdrum Station (115 kV) | 200 | 55 |
| Rathdrum Station (230 kV) | 50 | <1 |
| Rathdrum Station (230 kV) | 200 | 56 |
| Thornton Station | 100 | <1 |
| Othello Station | 25 | <1 |
| Northeast Station (Spokane) | 10 | <1 |
| Kettle Falls Station | 10 | <1 |
| Long Lake | 68 | 33 |
| Monroe Street | 80 | 2 |
| Post Fall | 10 | <1 |
| Post Falls | 20 | <1 |

**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 |
| #49 | 144 | Wind | Big Bend (WA) | 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 |
| #53 | 12 | Solar | Big Bend (WA) | October 2018 |
| #54 | 40 | Solar | Big Bend (WA) | January 2019 |

## Distribution Planning

Avista continually evaluates its distribution system. The distribution system consists of approximately 347 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 the timber, mining, and agriculture industries. The goals of the distribution evaluation are to determine if there are capacity limitations on the system to serve current and future projected load for each individual feeder. The analysis also includes whether or not 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 then the best course of action is budgeted.

The primary role of electric distribution planning is to identify system capacity and service reliability constraints, and subsequently identify the best and lowest life-cycle cost

[5] Cost estimates are in 2017 dollars and use engineering judgment with a 50 percent margin for error.

solution. Traditionally this solution has centered on infrastructure upgrades such as poles, wire, and cable. New technologies are emerging that may impact system analysis, including storage, photovoltaic (solar) and demand response. As these alternatives mature and evolve they are likely to play a role in our investment portfolio either as primary solutions or capital deferment solutions. Avista has deployed several pilot projects with the intent of determining how best to meet customer needs and maintain a high degree of reliability now and in the future.

To properly evaluate each feeder for new technologies, load data and system data is required. Quality load data is not available for all Avista feeders beyond monthly data logs recording peak load and energy. Without detailed load data, evaluating new technologies is limited to portions of the system with the available data. Detailed data is required to validate whether new technologies solves current system constraint or just defers the constraint to a different time.

Currently, 195 of 347 feeders have three-phase SCADA (Supervisory Control and Data Acquisition) data available. We currently improve circuits as resource and budgeting allow within our substation work schedule. As more demands beyond traditional capacity constraints and level of service requirements are placed on the grid, an increased amount of data is required to analyze and enhance the electric distribution system.

Further, new load forecasting techniques such as spatial load forecasting will be required. This new forecasting method uses account GIS information regarding the feeder location and can help forecast specific feeder load growth taking into account 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 system.

### Deferred Capital Investment Analysis

New technologies such as storage, photovoltaics, and demand response programs could help the electrical system by deferring or eliminating other investments. This is dependent on the new technology 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 can help meet overall power supply peak load needs, but it may also improve local reliability by providing voltage support and deferring capital investment at the substation.

This section discusses the analysis for determining the capital investment deferment value for distributed energy resources (DERs). Unfortunately, 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 the peaks occur, whether they are near capacity or not, and how fast loads are growing in the area. It is not practical to have an estimate for each feeders in an IRP, but it is prudent to have a representative estimate to include in the resource selection analysis.

For this analysis, Avista uses three representative feeders on three substations; 1) Barker Road, 2) Liberty Lake, and 3) Hallet & White. Each of these substations need capital investment due to growth in the next several years. Each location was fitted with an applicable storage device to determine how long the next investment could be deferred. Then a financial analysis estimates the financial value to customers for deferring the investment. The value of deferred investment is determined by comparing the present value of the revenue requirement of the current plan versus the revenue requirement of the alternative investment need when the storage device is installed. See Table 8.3 for the results of the analysis.

The value of the deferment is a range as it depends when the storage device is installed. The storage device has the greatest value when installed right before the investment is needed rather than years before. For this plan, $10 per kW-year is assumed for the IRP analysis. If distribution planning has a specific application for storage to meet distribution needs, the IRP group can provide the power supply benefits to add to the specific capital deferment analysis.

**Table 8.3: Capital Deferment Analysis**

| Substation | Storage Capacity (MW) | Storage Energy (MWh) | Deferment Time (Years) | Value Range ($/kW-yr) |
|---|---|---|---|---|
| Barker Road | 3.4 | 9.0 | 16 | $5 - $16 |
| Liberty Lake | 6.0 | 43.0 | 21 | $1 - $10 |
| Hallet & White | 1.7 | 10.5 | 9 | $10 - $19 |

## Grid Modernization

In 2008, an Avista system efficiencies team of operational, engineering, and planning staff developed a plan to evaluate potential energy savings from transmission and distribution system upgrades. The first phase summarized potential energy savings from distribution feeder upgrades. The second phase, beginning in summer 2009, combined transmission system topologies with right sizing distribution feeders to reduce system losses, improve system reliability, and meet future load growth.

The system efficiencies team evaluated several efficiency programs to improve urban and rural distribution feeders. The programs consisted of the following system enhancements:

- Conductor losses;
- Distribution transformers;
- Secondary districts; and
- Volt-ampere reactive compensation.

The analysis combined energy losses, capital investments, and reductions in O&M costs resulting from the individual efficiency programs under consideration on a per feeder basis. This approach provided a means to rank and compare the energy savings and net resource costs for each feeder.

Building on the 2009 effort, a 2013 study assessed the benefits of distribution feeder automation for increased efficiency and operability. The Grid Modernization Program (GMP) combines the work from these system performance studies and provides Avista's customers with refreshed system feeders with new automation capabilities across the company's distribution system. Table 8.4 shows the feeders currently planned for rebuild and their associated energy savings. The total energy savings from both re-conductor and transformer efficiencies for all completed feeders is approximately 1,930 MWh annually.

The GMP charter ensures a consistent approach to how Avista addresses each project. This program integrates work performed under various Avista operational initiatives, including the Wood Pole Management Program, the Transformer Change-Out Program, the Vegetation Management Program, and the Feeder Automation Program. The Distribution Grid Modernization Program includes replacing undersized and deteriorating conductors, and replacing failed and end-of-life infrastructure materials including wood poles, cross arms, fuses, and insulators. It addresses inaccessible pole alignment, right-of-way, under-grounding, and clear-zone compliance issues for each feeder section, as well as regular maintenance work including leaning poles, guy anchors, unauthorized attachments, and joint-use management. This systematic overview enables Avista to cost-effectively deliver a modernized and robust electric distribution system that is more efficient, easier to maintain, and more reliable for our customers.

**Table 8.4: Planned Feeder Rebuilds**

| Feeder | Area | Year Complete | Annual Energy Savings (MWh) |
|---|---|---|---|
| MIL12F2 | Millwood, WA | 2017 | 186 |
| ORO1280 | Orofino, ID | 2017 | 112 |
| PDL1201 | Clarkston, WA | 2017 | 189 |
| TUR112 | Pullman, WA | 2018 | 233 |
| HOL1205 | Lewiston, ID | 2018 | TBD |
| RAT233 | Rathdrum, ID | 2019 | 472 |
| SPI12F1 | Northport, WA (Spirit) | 2019 | 115 |
| SPR761 | Sprague, WA | 2019 | 106 |
| F&C12F1 | Spokane, WA (Francis & Cedar) | 2019 | 260 |
| MIS431 | Kellogg, ID | 2023 | 257 |
| | | **Total** | **1,930** |

# 9. Generation Resource Options

## Introduction

Several generating resource options are available to meet future resource deficits. Avista can upgrade existing resources, build new facilities, or contract with other energy companies to meet its load obligations. This section describes resources Avista considered in the 2017 IRP to meet future needs. They mostly are generic, as actual resources identified through a competitive process may differ in size, cost, and operating characteristics due to siting, engineering, or financial requirements.

**Section Highlights**

- The IRP only models resources with well-defined costs and operating histories as options to meet future resource needs.
- Storage and solar resource costs are significantly lower than the last IRP.
- Wind, solar, and hydroelectric upgrades represent renewable options available to Avista.
- Upgrades to Avista's hydroelectric and natural gas and biomass facilities are included as resource options.
- Future competitive acquisition processes might identify different technologies.
- Renewable resource costs assume no extensions of current state and federal incentives.

## Assumptions

Avista models only commercially available resources with well-known costs, availability, and generation profiles priced as if Avista developed and owned the generation. Resource options include natural gas-fired combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), natural gas-fired reciprocating engines, large-scale onshore wind, energy storage, photovoltaic solar, hydroelectric upgrades, and thermal unit upgrades. Several other resource options described later in the chapter are not included in the PRS analysis, but discussed as potential resource options to respond to a future resource acquisition. The IRP excludes potential contractual arrangements with other energy companies as an option in the plan, but such arrangements may actually offer a lower customer cost when a competitive acquisition process is completed.

The costs of each resource option include the transmission expenses described in Chapter 8 – Transmission & Distribution Planning. Levelized costs result from discounting nominal cash flows by a 6.46 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 2018 nominal dollars unless otherwise noted.

Many renewable resources are eligible for federal and state tax incentives. Federal solar tax benefits begin to reduce beginning in 2020; federal production tax credits (PTCs) are no longer available unless meeting certain provisions. Incentives, to the extent they are available, are included in IRP modeling.

Avista relies on several sources including the NPCC, press releases, regulatory filings, internal analysis, developer estimates, and Avista's experience with certain technologies for its resource assumptions. The natural gas-fired plants use operating characteristics and cost information obtained from Thermoflow design software.

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 reality, 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 very infrequently during peak-load periods would appear more expensive than base-load CCCTs, even though peaking resources are lower cost when operating only a few hours each year. By allowing the expected costs to be divided by the expected amount of energy deliveries, levelized energy costs fairly compare non-dispatchable renewable resources to the energy component of natural gas-fired resources because renewable technologies are typically not dispatchable. It is more difficult to estimate levelized costs for dispatchable resources because the amount of MWh to levelize the costs over is debatable, such as its potential energy or economic dispatch.

The levelized cost calculations include the following cost items for both the capacity and energy cost components.

- *Capital Recovery and Taxes*: Depreciation, return of and on capital, federal and state income taxes, property taxes, insurance, and miscellaneous charges such as uncollectible accounts and state taxes for each of these items pertaining to a generation asset investment.
- *Allowance for Funds Used During Construction (AFUDC):* The cost of money associated with construction payments made on a generation asset during construction.
- *Federal Tax Incentives:* The federal tax incentive in the form of a PTC, or investment tax credit (ITC), available to qualified generation.
- *Fuel Costs*: The average cost of fuel such as natural gas, coal, or wood per MWh of generation. Additional fuel price details are included in the Market Analysis section.
- *Fuel Transport*: The cost to transport fuel to the plant, including pipeline capacity charges.
- *Fixed Operations and Maintenance (O&M):* Costs related to operating the plant such as labor, parts, and other maintenance services not based on production levels.
- *Variable O&M:* Costs per MWh related to incremental generation.

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

- *Transmission*: Includes depreciation, return on capital, income taxes, property taxes, insurance, and miscellaneous charges such as uncollectible accounts and state taxes for each of these items pertaining to transmission asset investments needed to interconnect the generator and/or third party transmission charges. Further information regarding interconnection cost are in Chapter 8.
- *Other Overheads:* Includes miscellaneous charges for non-capital expenses such as un-collectibles, excise taxes, and commission fees.

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.

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

| Plant Name | Variable $/MWh | Winter $/kW-Yr | Winter Capacity (MW) |
|---|---|---|---|
| Advanced Large Frame CT | $54 | $156 | 220 |
| Modern Large Frame CT | $53 | $154 | 186 |
| Advanced Small Frame CT | $60 | $142 | 102 |
| Frame/Aero Hybrid CT | $43 | $154 | 106 |
| Small Reciprocating Engine Facility | $38 | $230 | 47 |
| Modern Small Frame CT | $55 | $174 | 49 |
| Aero CT | $50 | $187 | 45 |
| 1 on 1 Advanced CCCT | $35 | $230 | 362 |
| 1 on 1 Modern CCCT | $34 | $233 | 306 |

### 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 disadvantage of a CCCT is generation cost volatility due to reliance on natural gas, unless utilizing hedged fuel prices. CCCTs modeled in the IRP are “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 250 MW and 350 MW each depending on configuration and location. A two-on-one (2x1) CCCT plant configuration is possible with two turbines and one HRSG, generating up to 650 MW. Avista would need to share a 2 x 1 plant to take advantage of the modest economies of scale and efficiency of a 2x1-plant configuration due to its large size relative to Avista’s needs.

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, if no water rights are available, a more capital-intensive and less efficient air-cooled technology may be used. For this IRP, Avista assumes water is

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

available for plant cooling based on its internal analysis, but only enough for a hybrid system utilizing the benefits of combined evaporative and convective technologies.

This IRP models two types of CCCT plants, first a smaller 285 MW machine, and a larger advanced 341 MW plant. Avista reviewed many CCCT technologies and sizes, and selected these plants due to their use in the Northwest. If Avista pursues a CCCT, a competitive acquisition process will allow analysis of other CCCT technologies and sizes. The most likely location 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 on the emission of carbon dioxide.[3] CCCT site or 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.

The smaller CCCT's heat rate is 6,720 Btu/kWh in 2016.[4] The larger machine is 6,631 Btu/kWh. The plants include duct firing for seven percent of rated capacity at a heat rate of 7,912 and 7,843 Btu/kWh, respectively.

The IRP includes a three percent forced outage rate for CCCTs and 14 days of annual plant maintenance. The smaller plant can back down to 62 percent of nameplate capacity, while the larger plant can ramp down to 30 percent of nameplate capacity. The maximum capability of each plant is highly dependent on ambient temperature and plant elevation. The plan assumes a 30-year life absent capital upgrades for life extension.

The anticipated capital costs for the two CCCTs, located in Idaho on Avista's transmission system with AFUDC on a greenfield site, are $1,174 per kW for the smaller machine and $1,122 per kW for the larger machine. These estimates exclude the cost of transmission and interconnection. Table 9.1 shows levelized plant cost assumptions split between capacity and energy. 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.

### Natural Gas-Fired Peakers

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

The IRP models frame, hybrid-intercooled, reciprocating engines, and aero-derivative peaking resource options. The peaking technologies have different load following abilities, costs, generating capabilities, and energy-conversion efficiencies. Table 9.2 shows cost

[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 has carbon dioxide mitigation fees for new plants.
[4] Heat rates shown are the higher heating value.

and operational characteristics based on internal engineering estimates. All peaking plants assume 0.5 percent annual real dollar cost decrease and forced outage and maintenance rates. The levelized cost for each of the technologies is in Table 9.1.

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

| Item | Capital Cost with AFUDC ($/kW) | Fixed O&M ($/kW-yr) | Heat Rate (Btu/ kWh) | Variable O&M ($/MWh) | Units at Site | ISO Unit Size (MW) | Total Project Size (MW) | Total Cost (Mil$) |
|---|---|---|---|---|---|---|---|---|
| Advanced Large Frame CT | $654 | $2.19 | 9,931 | $3.73 | 1 | 203 | 203 | $133 |
| Modern Large Frame CT | $684 | $2.19 | 10,007 | $2.67 | 1 | 170 | 170 | $117 |
| Advanced Small Frame CT | $875 | $3.28 | 11,265 | $2.67 | 1 | 96 | 96 | $84 |
| Frame/Aero Hybrid CT | $1,042 | $3.28 | 8,916 | $3.20 | 1 | 101 | 101 | $105 |
| Small Reciprocating Engine Facility | $1,229 | $8.76 | 7,700 | $3.20 | 5 | 9.3 | 47 | $57 |
| Modern Small Frame CT | $1,349 | $4.38 | 10,252 | $2.67 | 1 | 45 | 45 | $61 |
| Aero CT | $1,349 | $6.57 | 9,359 | $2.67 | 1 | 42 | 42 | $57 |
| 1 x 1 Modern CCCT | $1,148 | $19.71 | 6,771 | $4.00 | 1 | 341 | 341 | $392 |
| 1 x 1 Advanced CCCT | $1,207 | $16.42 | 6,845 | $3.20 | 1 | 286 | 286 | $345 |

Firm natural gas fuel transportation is an electric reliability issue with FERC and 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. Firm transportation could be necessary where pipeline capacity becomes scarce during utility peak hours. However, pipelines near evaluated sites are not presently full or expected to become full in the near future. 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, and liquefied natural gas storage.

### Wind Generation

Governments promote wind generation with tax benefits, renewable portfolio standards, carbon emission restrictions, and stricter controls on existing non-renewable resources. In the Consolidated Appropriations Act 2016, HR 2029, section 301, passed December 2016, the U.S. Congress extended the PTC for wind through December 31, 2016, with provisions allowing projects to qualify for a prorated credit after 2016 if commencing construction prior to 2019. For projects commencing construction in 2017, the PTC is reduced by 20 percent, 2018 is reduced by 40 percent, and 2019 reduced by 60 percent. This IRP does not assume the PTC extends beyond this term, but does assume preferential five-year tax depreciation remains.

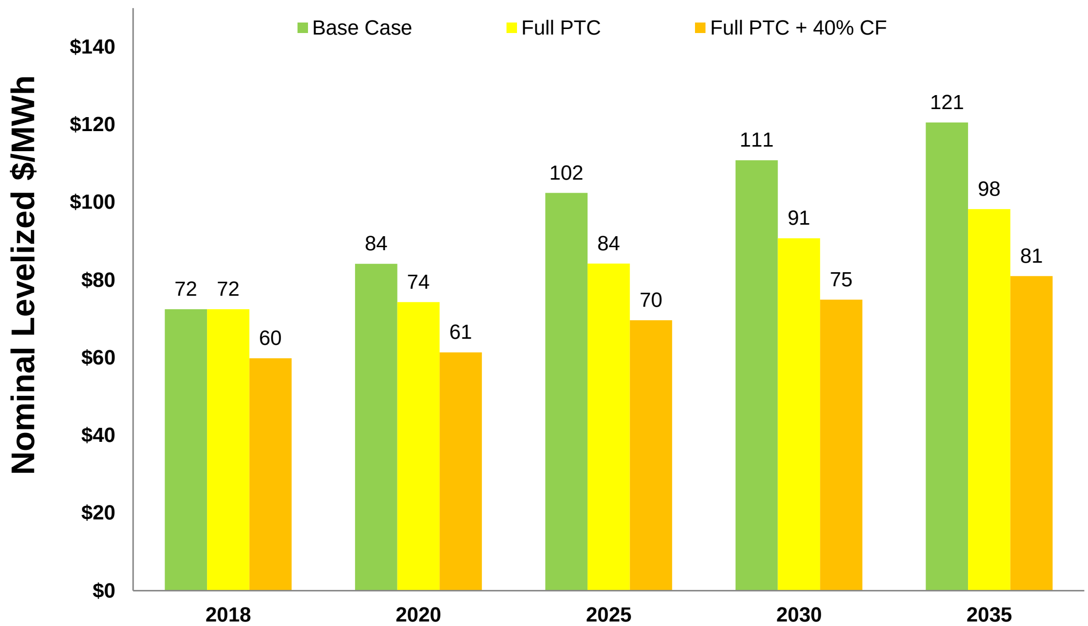
Wind resources benefit from having no emissions profile or fuel costs, but they are not typically dispatchable. On shore wind's capital costs in 2018, including AFUDC, are $1,798 per kW for Washington projects and $1,636 per kW in Montana, with annual fixed O&M costs of $42.70 per kW-yr. Fixed O&M includes indirect charges to account for the inherent variation in wind generation, oftentimes referred to as wind integration. The cost of wind integration depends on the penetration of wind in Avista's balancing authority and the market price of power. Wind integration in this IRP is $4.40 per kW-year in 2018. These estimates come from Avista's experience in the market and results from Avista's 2007 Wind Integration Study.

Wind capacity factors in the Northwest range between 25 and 40 percent depending on location. This plan assumes Northwest wind has a 37 percent average capacity factor. A statistical method, based on regional wind studies, derives a range of annual capacity factors depending on the wind regime in each year (see stochastic modeling assumptions for details). The expected capacity factor affects the levelized cost of a wind project. For example, a 30 percent capacity factor site could be $30 per MWh higher than a 40 percent capacity factor site holding all other assumptions equal.

As discussed above, levelized costs change substantially due to capacity factor, but can change more from tax incentives. Figure 9.1 shows nominal levelized prices with different start dates, capacity factors, and availability of the ITC. For a plant installed in 2018 with utility ownership, the estimated "all-in" cost is $72 per MWh for 25 years, including the 20 percent REC apprenticeship adder for the EIA. Qualification for the adder requires 15 percent of construction labor by state-certified apprentices. It is possible for third party to Independent Power Producers to develop a project at a lower cost for the PPA, depending on turbine agreements, site conditions, and cost of capital. Typical PPA prices do not include integration or transmission, and may reflect a different cost recovery period. If Avista plans to acquire new wind generation, an RFP will help identify the least cost option to meet customer needs.

This IRP includes analysis on wind projects located in Montana. Based on Avista's analysis, construction cost will be lower due to the absence of state sales tax and indications of higher quality wind speeds. Sites in Montana will require third party transmission wheeling. Adding Montana wind will be less costly to integrate due to its different generation profile as compared to Palouse Wind, and it may add up to a 7.5 percent capacity contribution when combined with Palouse Wind's expected output on to meet the single-hour winter peak. For summer, the plan assumes the combined resources would add 3 percent of its capability. Montana wind, with transmission to deliver it to Avista's system, costs $83 per MWh as compared to $72 per MWh with the same capacity factor in the Northwest.

**Figure 9.1: Northwest Wind Project Levelized Costs per MWh**




## Photovoltaic Solar

Photovoltaic (PV) solar generation technology costs have fallen substantially in the last several years partly due to low-cost imports and from demand driven by renewable portfolio standards and tax incentives. Even with large cost reductions, IRP analyses shows PV solar facilities still are uneconomic for winter-peaking utilities in the Northwest compared to other renewable and non-renewable generation options. This is due to its low capacity factor and lack of output during winter-peak periods. PV solar provides predictable daytime generation complementing the loads of summer-peaking utilities, though panels typically do not produce at full output during peak hours.

Adding a substantial amount of PV solar to a summer peaking utility system reduces the peak hour recorded prior to the installation, but the peak hour shifts toward sundown when PV solar output is lower. As more PV solar enters a system, the on-peak resource contribution falls precipitously. Table 9.3 presents the peak credit by month with different amounts of solar using output from the Rathdrum Solar Project. This table illustrates how solar does not reduce Avista's winter peak, reduces the summer peak, and is less effective at reducing peak with additional solar installations.

Solar-thermal technologies can produce capacity factors as much as 30 percent higher than PV solar projects and can store several hours of energy for later use in reducing peak loads. However, solar thermal technologies do not lend themselves well to the Northwest due to their lack of significant generation in the winter and higher overall installation and operation costs; therefore, only PV solar systems are considered for this IRP.

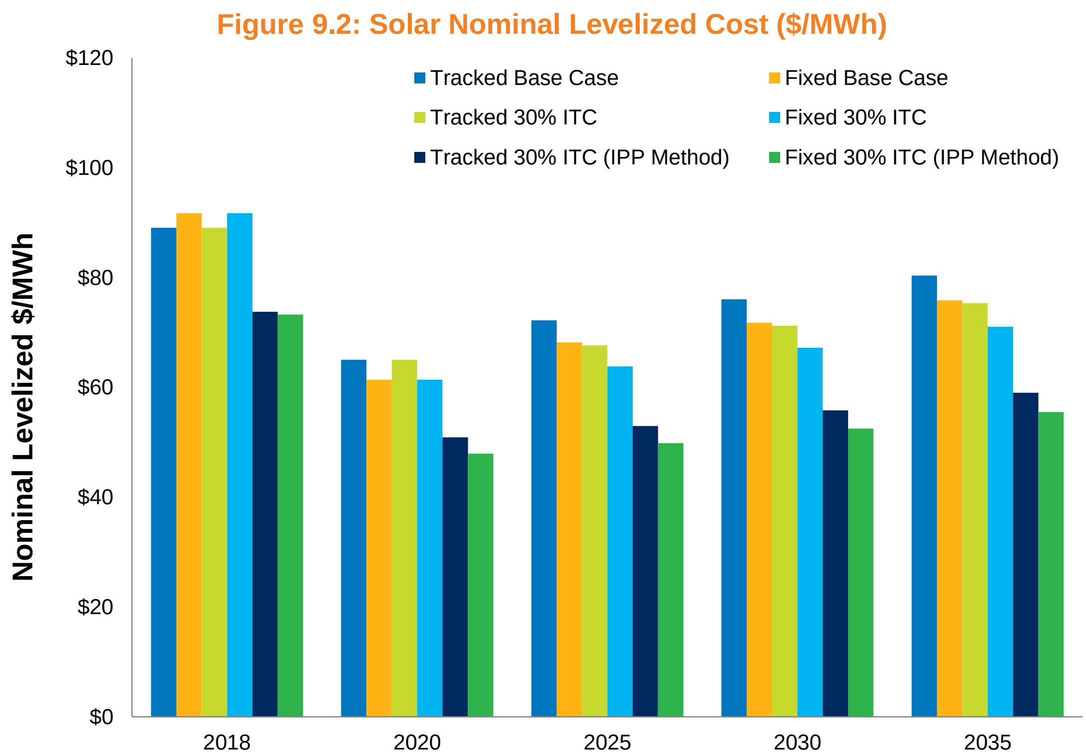
### Table 9.3: Solar Capacity Credit by Month

| Month | 5 MW | 25 MW | 50 MW | 100 MW | 150 MW | 200 MW | 300 MW |
|---|---|---|---|---|---|---|---|
| Jan | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Feb | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Mar | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Apr | 28% | 15% | 11% | 8% | 6% | 5% | 3% |
| May | 46% | 46% | 37% | 26% | 17% | 13% | 9% |
| Jun | 39% | 39% | 36% | 31% | 25% | 22% | 19% |
| Jul | 52% | 49% | 45% | 43% | 33% | 27% | 22% |
| Aug | 40% | 40% | 40% | 34% | 32% | 30% | 24% |
| Sep | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Oct | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Nov | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Dec | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

Utility-scale PV solar capital costs including AFUDC for a 50 MW (DC) system are $1,110 per kW for fixed panel and $1,165 per kW for single-axis tracking projects. A well-placed utility-scale single-axis tracking PV system located in the Pacific Northwest would achieve a first-year capacity factor of approximately 18 percent and a fixed panel system would achieve 15 percent. PV solar output degrades over time; the IRP de-rates solar generation output by one-half percent each year. The federal government's 30 percent tax credit begin phasing out after 2019. Projects starting construction in 2020 have a 26 percent ITC, 22 percent for 2021 projects, and 10 percent for any projects afterward.

Figure 9.2 shows the levelized costs of PV solar resources, including applicable federal and state incentives, on-line dates, and capacity factors. Like wind projects, independent power producers may have lower costs than utilities due to panel agreements, cost of capital and the ability to using federal incentives to directly lower upfront costs, rather than amortizing tax credits over the life of the asset. The costs in Figure 9.2 show the price advantage of IPP development as far as transferring benefits from the ITC directly to customers. IRP modeling in this IRP assumes the ITC would be a credit to the cost of the project rather than amortized over the life of the asset.

The State of Washington offers a number of incentives for solar installations. Plants less than five megawatts count double toward Washington's EIA. The state also offers substantial financial incentives for consumer-owned solar. Consumer-owned solar counts in reductions in Avista's retail load forecast.




## Energy Storage

Increasing solar and wind generation makes energy storage technologies attractive from an operational perspective. Storage could smooth out renewable generation variability, absorb oversupply, and assist in load following and regulation needs. The technology could help meet peak demand, provide voltage support, relieve transmission congestion, take power during oversupply events, and supply other non-energy needs for the system. The IRP considered several storage technologies, including pumped hydroelectric, lead-acid batteries, lithium-ion batteries, vanadium flow batteries, flywheels, compressed air, liquefied air, and gravity systems. For modeling purposes, the IRP uses two plant types: a 1x3-storage facility and a 1x6. Meaning, for each MW of capacity, it has three or six MWh of storage.

Modeling each storage technology would not provide additional insight as a comparison to other supply options because Avista's capacity needs are not urgent, the technology is changing rapidly, and each has different losses, lifespan and flexibility. Modeling of storage's non-power supply benefits is still in development. Although Avista is attempting to estimate as many of these values as possible. For example, Chapter 8 discusses the methodology to estimate the value of deferred distribution capital investment. The IRP includes a value for market arbitrage and providing ancillary services such as regulation, spinning, and non-spinning reserves. Avista is developing an evaluation for estimating the storage benefit for network services such as reliability, voltage support and frequency response (not all storage options can provide this service). Each of these benefits are part of the Clean Energy Funds/PNNL partnership to estimate values for storage. A report will be available in the spring of 2018.

Storage may become an important part of the nation's electricity grid if the technology overcomes a number of physical, technical, and economic barriers. First, existing technologies consume a significant amount of electricity relative to their output through conversion losses. Second, equipment costs are still high, but falling, at nearly three times the initial cost of a natural gas-fired peaking plant. Peaking plants provide many of the same capabilities without the electricity consumption characteristics of storage. Storage costs will decline over time and Avista will monitor the technologies as part of the IRP process. Third, the current scale of most storage projects is relatively small, limiting their applicability to utility-scale deployment.

Avista installed a vanadium flow battery in Pullman, Washington to learn more about storage technology. The Turner Energy Storage Project provides insight about the technology's reliability, potential benefit to the transmission and/or distribution systems, and potential power supply benefits including oversupply events. The battery has 1.2 megawatts of power capability and 3.5 megawatt-hours of energy storage. A Washington State research and development grant partially funded this project.


*Turner Energy Storage Project, Pullman, WA*

As part of the Clean Energy Funds 2 grants, Avista proposes to develop two additional storage projects in the University District of downtown Spokane. One 500 kW project with two MWh of storage and the other project 100 kW with 0.5 MWh of storage. At the time of this IRP's drafting these projects are out to bid and expected to begin operation in late 2018.

The Northwest might be slower in adopting storage technology relative to other regions in the country. The Northwest hydroelectric system already contains a significant amount of storage relative to the rest of the country. However, as more capacity consuming renewables enter the electric grid, new storage technologies might play a significant role in meeting the need for additional operational flexibility if upfront capital costs and operational losses continue to fall.

In addition to capital costs, storage project O&M costs are $20 per kWh-year levelized, and recharge costs use off-peak Mid-Columbia energy prices. Levelized storage project costs are inaccurate as storage projects do not create megawatt hours; in fact, they consume megawatt hours with 15 to 20 percent or more of their charge being lost. Avista's experience with vanadium flow storage has losses from 30 to 50 percent. This IRP assumes 17 percent losses over its 20 year expected life. Storage costs are typically shown in $/kWh due to the energy limitation of the project rather than $ per kW. The capital cost in 2018 dollars including AFUDC is $713 per kWh for the 1x3 project and $642 for the 1x6 project. By 2025, the costs fall to $573 and $516 per kWh respectively.

### Other Generation Resource Options

Many resources were not specifically included as resource options in this IRP. These resources include biomass, geothermal, co-generation, nuclear, offshore wind, landfill gas, and anaerobic digesters. 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 available.

Exclusion from the PRS does not necessarily exclude non-modeled technologies from Avista's future portfolio. The non-modeled resources can compete with resources identified in the PRS through competitive acquisition processes. Competitive acquisition processes identify technologies to displace resources otherwise included in the IRP strategy. Another possibility is acquisition through PURPA mandates. PURPA provides developers the ability to sell qualifying power to Avista at set prices and terms.[5]

### Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest management. In the generation process, a turbine converts boiler-created steam into electricity. A substantial amount of wood fuel is required for utility-scale generation. Avista's 50 MW Kettle Falls Generation Station consumes over 350,000 tons of wood waste annually, or 48 semi-truck loads of wood chips per day. It typically takes 1.5 tons of wood to make one megawatt-hour of electricity; the ratio varies with the moisture content of the fuel. The viability of another Avista biomass project depends on the availability and cost of the fuel supply. Many announced biomass projects fail due to lack of a long-term fuel source. If an RFP identifies a potential woody biomass project, Avista will consider it for a future resource.

### Geothermal Generation

Geothermal energy provides predictable capacity and energy with minimal carbon dioxide 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

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

projects are likely to develop. Geothermal energy struggles to compete economically due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust; each hole can cost over $3 million. Ongoing geothermal costs are low, but the capital required locating and proving a viable site is significant. Further, there are no good geothermal resource sites in or near Avista's service territory or transmission system.

### Landfill Gas Generation

Landfill gas projects generally use reciprocating engines to burn methane gas collected at landfills. The Northwest has developed many landfill gas resources. The costs of a landfill gas project depend on the site specifics of a landfill. The Spokane area had a project on one of its landfills, but was retired after the fuel source depleted to an unsustainable level. Much of the Spokane area no longer landfills its waste and instead uses the Spokane Waste to Energy Plant. Nearby in Kootenai County, Idaho, the Kootenai Electric Cooperative developed the 3.2 MW Fighting Creek Project. Using publically available costs and the NPCC estimates, landfill gas resources are economically promising, but are limited in their size, quantity, and location. Further, due to falling wholesale market pricing, many landfills are considering cleaning the gas to create pipeline quality gas. This form of renewable gas has become an option for natural gas utilities to offer a renewable gas alternative.

### 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. These facilities tend to be significantly smaller than utility-scale generation projects, at less than five megawatts. Most 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 greatly, though 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 facility. Anaerobic digesters may opt to clean the gas to make to pipeline quality to offer a clean gas alternative.

### Small Cogeneration

Avista has few industrial customers with loads significantly large enough to support a cogeneration project. If an interested customer was inclined to develop a small cogeneration project, it could provide benefits including reduced transmission and distribution losses, shared fuel, capital, and emissions costs, and 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. In Avista's service territory few compressor stations exist, 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 determined 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 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 particular project. The best method for the utility to acquire this technology is through the PURPA process.

### Nuclear

Avista does not include nuclear plants as a resource option in the IRP 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. Nuclear resources could be in Avista's future only if other utilities in the Western Interconnect incorporate nuclear power in their resource mix and offer Avista an ownership share 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 the needs of smaller utilities.

### Offshore Wind

Avista does not include offshore wind resources in this IRP due to the current availability of onshore wind resource options with lower prices and without third party transmission services. Offshore wind is a proven technology outside of the US, so far only one project is operational in the U.S. Avista will continue to monitor this technology as its cost and efficiency change.

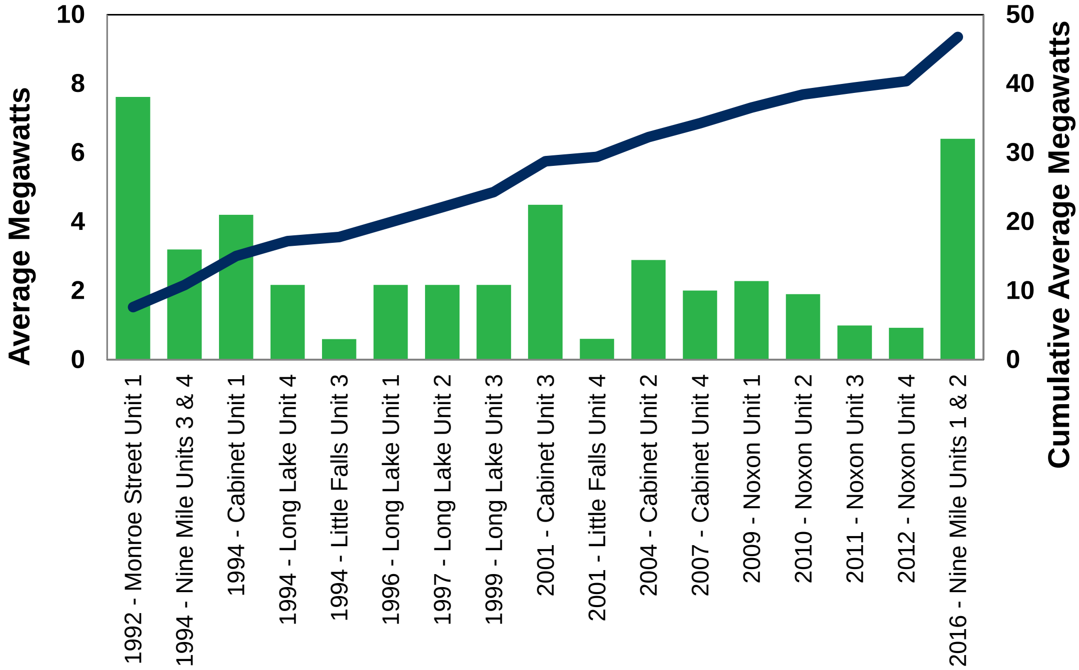
### Coal

The coal generation industry is at a crossroads. In many states, like Washington, new coal-fired plants are extremely unlikely due to emission performance standards and the shortage of utility scale carbon capture and storage projects. Federal guidelines regarding coal are uncertain given the current EPA administration's review of section 111(b) of the CAA and the CPP. The risks associated with future carbon legislation and projected low natural gas costs make investments in this technology highly unlikely.

## Hydroelectric Project Upgrades and Options

Avista continues to upgrade its hydroelectric facilities. The latest hydroelectric upgrade added ten megawatts to the Nine Mile Falls Development in 2016. Figure 9.3 shows the history of upgrades to Avista's hydroelectric system. Avista added 46.8 aMW of incremental hydroelectric energy between 1992 and 2016. Upgrades completed after 1999 can qualify for the EIA, thereby reducing the need for additional renewable energy options.

**Figure 9.3: Historical and Planned Hydro Upgrades**




Construction of the Spokane River hydroelectric project occurred in the late 1800s and early 1900s, when the priority was to meet then-current loads. The developments therefore do not capture a majority of 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 developments and estimated costs for generation upgrade options. Each upgrade option should 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 project water rights. Table 9.4 summarizes the upgrade options. The upgrades will compete against other renewable options when more renewables are required.

At the time of this IRP, the company is developing a long-term strategy for Post Falls. The current scope of the project is to replace the current generating equipment with newer technology. Part of this IRP's Action Plan will be to report on the redevelopment plan.

**Table 9.4: Hydroelectric Upgrade Options**

| Resource | Monroe Street/Upper Falls | Long Lake | Cabinet Gorge |
|---|---|---|---|
| Incremental Capacity (MW) | 80 | 68 | 110 |
| Incremental Energy (MWh) | 237,352 | 202,592 | 161,571 |
| Incremental Energy (aMW) | 27.1 | 23.1 | 9.2 |
| Peak Credit (Winter/ Summer) | 31/0 | 100/100 | 0/0 |
| Capital Cost ($2018 Millions) | $196 | $182 | $290 |
| Levelized Energy Cost ($2018/MWh) | $93 | $122 | $200 |

### 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 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 replaces the existing four-unit powerhouse with four larger units totaling 120 MW, increasing capacity by 32 MW. The other two alternatives develop a second powerhouse with a penstock beginning from a new intake structure downstream of the existing saddle dam. One powerhouse option was a single 68 MW turbine project. The second was a two-unit 152 MW project. The best alternative in the study was the single 68 MW option. Table 9.4 shows upgrade costs and characteristics.

### Monroe Street/Upper Falls Second Power House

Avista replaced the powerhouse at its Monroe Street development on the Spokane River in 1992. There are three options to increase its capacity. Each would be a major undertaking requiring substantial cooperation with the City of Spokane to mitigate disruption in Riverfront and Huntington parks and downtown Spokane during construction. The upgrade could increase plant capacity by up to 80 MW. To minimize impacts on the downtown area and the park, a tunnel drilled on the east side of Canada Island could avoid excavation of the south channel. A smaller option would add a second 40 MW Upper Falls powerhouse, but this option would require south channel excavation. A final option would add a second Monroe Street powerhouse for 44 MW.

### Cabinet Gorge Second Powerhouse

Avista is exploring the addition of a second powerhouse at the Cabinet Gorge development 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. This resource does not add any peak capacity credit due to the water right limitations of the license. The resource only creates additional energy during spring runoff.

## Thermal Resource Upgrade Options

The 2015 IRP identified several thermal upgrade options for Avista's fleet. Some options, such as the Cold Day Controls and Advanced Hot Gas Path at Coyote Springs 2, are already in service. This plan contains new ideas to increase generating capability at Avista's thermal generating resources. No costs are presented in this section, as pricing is sensitive to third-party suppliers.

### Northeast CT Water Injection

This is a water injected NOx control system allowing the firing temperature to increase and thereby increasing the capacity at the Northeast CT by 7.5 MW.

### Rathdrum CT Supplemental Compression

Supplemental compression is a new technology developed by PowerPhase LLC that increases airflow through a combustion turbine compressor 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 corresponding to a five MW increase in output.

### Rathdrum CT Inlet Evaporation

Installing a new inlet evaporation system will 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. At this time, Avista could spend additional capital and upgrade the unit by five megawatts rather than replace it with in-kind technology.

### Kettle Falls Fuel Stabilization

The wood burned at Kettle Falls varies in moisture content, and dryer fuel burns more efficiently. A fuel drying system added to the fuel handling system would allow the boiler to operate at a higher efficiency point, increasing plant capability by three megawatts.

## Ancillary Services Valuation

IRPs traditionally model the value of resources using hourly models. This method provides a good approximation of resource value, but it does not provide a value for the intra-hour or ancillary services needs of a balancing area. Ancillary services modeled in the IRP include spinning and non-spinning reserves, regulation, and load following. Spinning and non-spinning reserve obligations together equal three percent of load and three percent of on-line generation, as required by regional standards. Half of the reserves must synchronize to the system and half must be capable of synchronizing within ten minutes. Regulation meets instantaneous changes in load or resources with plants responding to the change using automatic generating control. Load following covers load changes within the hour, but for movements occurring across a timeframe greater than ten minutes.

Avista developed a new tool, called the Avista Decision Support System (ADSS), for use in operations and long-term planning. This model is a mixed-integer linear program simulating Avista's system. It optimizes a set of resources to meet system load and ancillary services requirements using real-time information. The tool uses both actual and forecasted information regarding the surrounding market and operating conditions to provide dispatch decisions, but can also use historical data to simulate benefits of certain system changes. ADSS uses historical data sets to estimate ancillary services values for storage and natural gas-fired resources.

### Storage

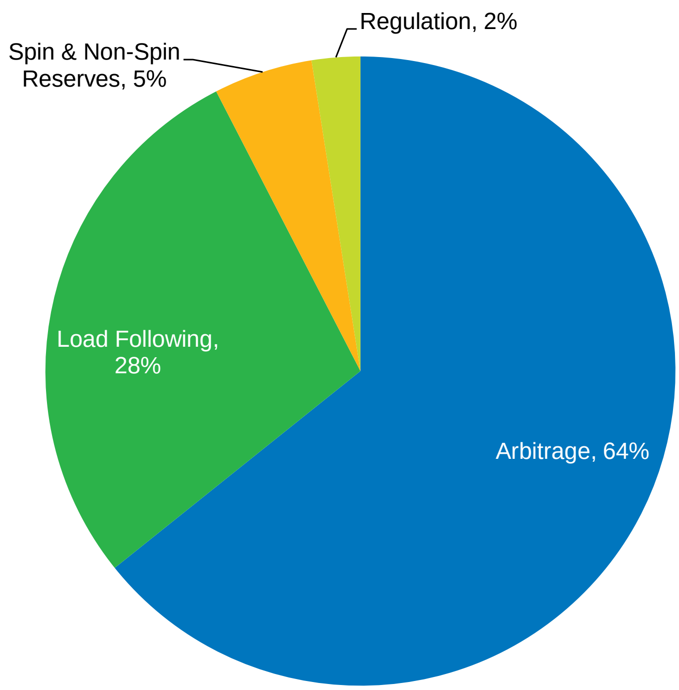
As intermittent resources grow in size, there is potential for the existing system not being robust enough to integrate the resources and handle oversupply of renewable energy. To address this concern, governments and utilities are promoting and investing in storage technology. Today storage has a limited role due to cost and technology development. This analysis uses the study competed for the 2015 IRP to determine the potential financial value storage brings to Avista's power supply costs. The study includes several storage capacities with storage to peak ratio of three to one and 85 percent efficiency. Table 9.5 shows the values brought to the power supply system for each storage capacity size. These values are to the Avista system only and do not represent the value to other systems or non-power supply benefits. Avista has a deep resource stack of flexible resources and adding additional flexible resources do not necessarily add value unless sold to third parties.

The values shown in Table 9.5 include margin from several value streams including operating reserves, regulation, load following, and arbitrage. Arbitrage optimizes the battery to charge in low price periods and discharge when prices are higher. Of the values shown in Table 9.5, arbitrage represents the largest value stream. Figure 9.4 shows the five value streams for power supply benefits. Load following and arbitrage represent 92 percent of the value to Avista.

**Table 9.4: Storage Power Supply Value**

| Storage Capacity (MW) | Annual Value | Annual $/kW Value |
|---|---|---|
| 35 | $1,201,590 | $34 |
| 30 | $1,024,569 | $34 |
| 25 | $923,291 | $37 |
| 10 | $381,407 | $38 |
| 5 | $189,000 | $38 |
| 1 | $36,862 | $37 |

**Figure 9.4: Storage's Value Stream**




## Natural Gas-Fired Facilities

Natural gas-fired facilities can provide energy and ancillary services. This study looks at their incremental ancillary services value to the system as prepared for the 2015 IRP. The values do not represent the value for current resources of similar technology, but only the incremental value of a new facility. This study assumes 100 MW resource increments in 2020. Table 9.6 shows the results of the analysis. The incremental values for these resources are marginal due to the limited need for these types of services. The study assumes each facility has different operating capabilities. For example, diesel back-up can only provide non-spin reserves as it is for emergency use only, while the LMS 100 may provide non-spinning reserves, spinning reserves, regulation, and load following if operating.

**Table 9.5: Natural Gas-Fired Facilities Ancillary Service Value**

| Resource Type | Capabilities | Annual $/kW Value |
|---|---|---|
| CCCT | Load Following/ Spin[6], Regulation | $0.00 |
| LMS 100 | Load Following/ Spin, Non-Spin/ Regulation | $1.12 |
| Reciprocating Engines | Load Following/Spin/Non-Spin | $0.61 |
| Diesel Back-Up | Non-Spin | $0.00 |

An action item from this IRP is to determine the intra hour valuation of these services for both storage and natural gas-fired peakers using historical data closer to the 2019 IRP release date and implementing new modeling techniques including intra hour modeling. Avista's DSS model at the time of the IRP is not capable of intra hour modeling, but it is in process of adding this functionality.

[6] Fast start CCCTs may have some non-spin reserve capability.

# 10. Market Analysis

## Introduction

This section describes the electricity, natural gas, and other markets studied in the 2017 IRP. It contains price risks Avista considers to meet customer demands at the lowest reasonable cost. The analytical foundation for the 2017 IRP is a fundamentals-based electricity model of the entire Western Interconnect. The market analysis evaluates potential resource options on their net value within the wholesale marketplace, rather than the summation of their installation, operation, maintenance and fuel costs. The Preferred Resource Strategy (PRS) analysis uses these net market values to select future resource portfolios.

Understanding market conditions in the Western Interconnect is important because regional markets are highly correlated due to large transmission linkages between load centers. This IRP builds on prior analytical work by maintaining the relationships between the sub-markets within the Western Interconnect and the changing energy market values of company-owned and contracted-for resources. The backbone of the analysis is an electricity market model. The model, AURORA^XMP, emulates the dispatch of resources to serve loads across the Western Interconnect given fuel prices, hydroelectric conditions, and transmission and resource constraints. The model's primary outputs are electricity prices at key market hubs (e.g., Mid-Columbia) and resource dispatch including the resources costs, market value and greenhouse gas emissions.

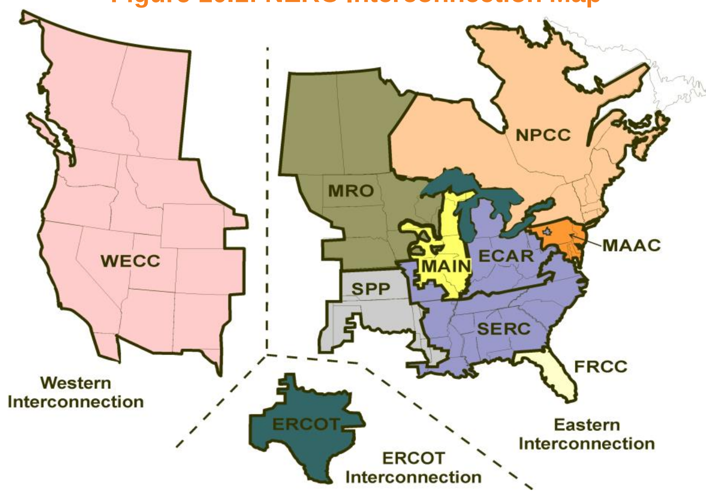
**Section Highlights**

- Natural gas, solar, wind and storage resources dominate new generation additions in the Western Interconnect.
- Greenhouse emissions constraints are in force for Washington, Oregon, and Montana. California includes carbon pricing and the remaining western states include regional emission caps based on a delayed Clean Power Plan.
- The Expected Case forecasts a continuing reduction of Western Interconnect greenhouse gas emissions due to coal plant closures brought on by federal and state regulations and low natural gas prices.
- The 20-year levelized price of Mid-Columbia energy is $35.85 per MWh (2018-2037).
- The 20-year levelized price of Stanfield natural gas is $4.20 per Dth (2018-2037).

## Marketplace

AURORA^XMP is a fundamentals-based modeling tool used by Avista to simulate the Western Interconnect electricity market. The Western Interconnect includes states west of the Rocky Mountains, the Canadian provinces of British Columbia and Alberta, and the Baja region of Mexico as shown in Figure 10.1. The modeled area has an installed resource base of approximately 240,000 MW.

**Figure 10.1: NERC Interconnection Map**




The Western Interconnect is separate from the Eastern and ERCOT interconnects to the east except for eight DC inverter stations. It follows operation and reliability guidelines administered by the Western Electricity Coordinating Council (WECC). Avista modeled the WECC electric system as 17 zones based on load concentrations and transmission constraints. After extensive study in prior IRPs, Avista models the Northwest region as a single zone because this configuration dispatches resources in a manner consistent with historical operations. Table 10.1 describes the specific zones modeled in this IRP.

**Table 10.1: AURORA XMP Zones**

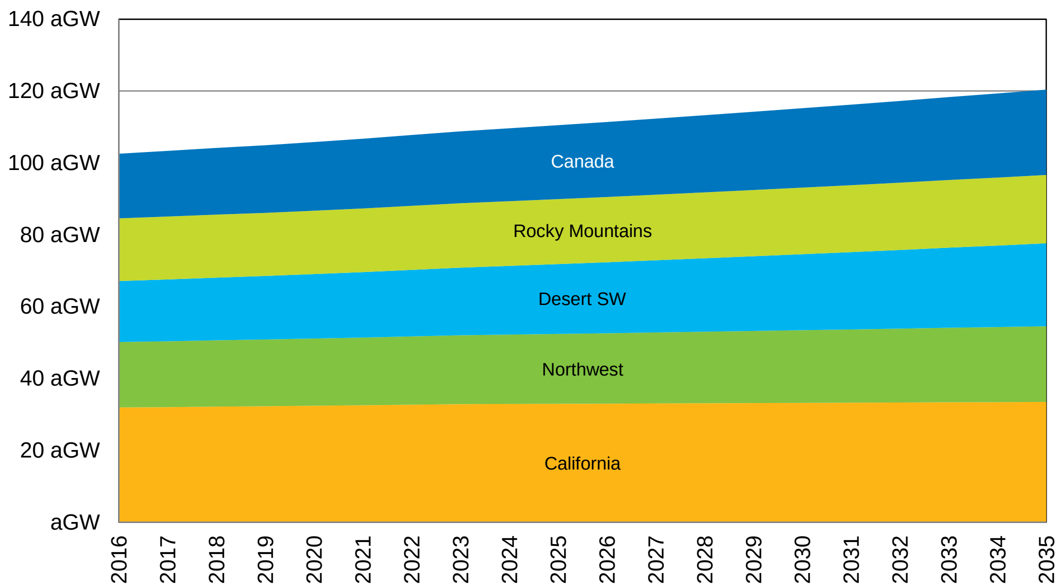
| | |
|---|---|
| Northwest- OR/WA/ID/MT | Southern Idaho |
| COB- OR/CA Border | Wyoming |
| Eastern Montana | Southern California |
| Northern California | Arizona |
| Central California | New Mexico |
| Colorado | Alberta |
| British Columbia | South Nevada |
| North Nevada | Baja, Mexico |
| Utah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

## Western Interconnect Loads

The 2017 IRP relies on a load forecast for each zone of the Western Interconnect. Avista uses utility resource plans and regional plans to quantify load growth across the west. These plans include estimates regarding energy efficiency, customer-owned generation, plug-in electric vehicles and demand response reductions. Forecasting future energy use is difficult because of large uncertainties with the long-term drivers of future energy use.

Figure 10.2 shows regional load growth estimates. The total of the forecasts show Western Interconnect loads rising nearly 0.85 percent annually over the next 20 years. On a regional basis, the Northwest grows at 0.77 percent, California at 0.25 percent, and the Rocky Mountain States at 1.63 percent. Canada is 1.5 percent. From a system reliability perspective, regional peak loads grow at similar levels.

**Figure 10.2: 20-Year Annual Average Western Interconnect Energy**



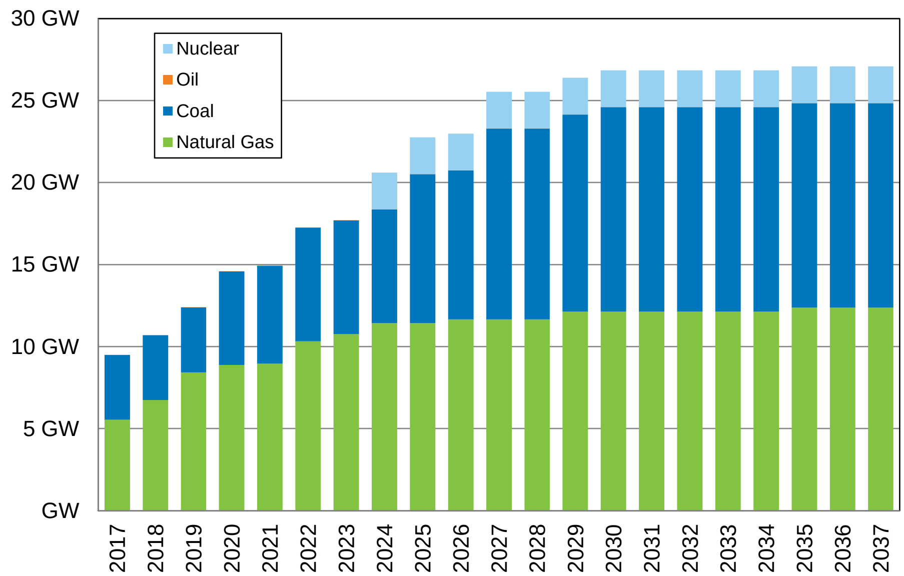

## Resource Retirements

The resource mix constantly changes as new resources start generating and older resources retire. In prior IRPs, much of the existing fleet continued to serve loads in combination with new resources. Many companies are now choosing to retire older plants to comply with environmental regulations and economic changes. Most plant closures are once-through-cooling (OTC) facilities in California and older coal technology throughout North America.

Several states are developing rules to restrict or eliminate certain generation technologies. In California, all OTC facilities require retrofitting to eliminate OTC technology or the plant must retire. Over 14,200 MW of OTC natural gas-fired generators in California likely will retire and need replacement in the IRP timeframe. The IRP assumes the closure of OTC plants with identified shutdown dates from their utility owners' IRPs and announcements. Elimination of OTC plants in California will eliminate older technology presently used for reserves and high demand hours. Replacement plants will be expensive for California customers, but they will have a more modern, efficient and flexible generation fleet.

Coal-fired facilities face increasing regulatory scrutiny. In the Northwest, the Boardman and Centralia coal plants will retire by the end of calendar years 2020 and 2025 respectively. Recently Colstrip 1 & 2 announced closure by 2022, for a reduction total of about 2,621 megawatts. Other coal-fired plants throughout the Western Interconnect have announced plant closures, including Four Corners, Carbon, Arapahoe, San Juan, Reid Gardner, Dave Johnson, North Valmy, and Intermountain. The Nevada legislature successfully placed into law a plan to retire all in-state coal plants, and other utilities appear poised to retire many plants as indicated in recent IRPs. Over the next 20 years, roughly 43 percent of the US Western Interconnection coal fleet retires in the Expected Case. In total, announced retirements for all generation technologies, as shown in Figure 10.3, equal approximately 25 gigawatts between 2017 and 2037. Avista did not forecast additional coal retirements beyond official announcements prior to development of the Expected Case.

**Figure 10.3: Resource Retirements (Nameplate Capacity)**



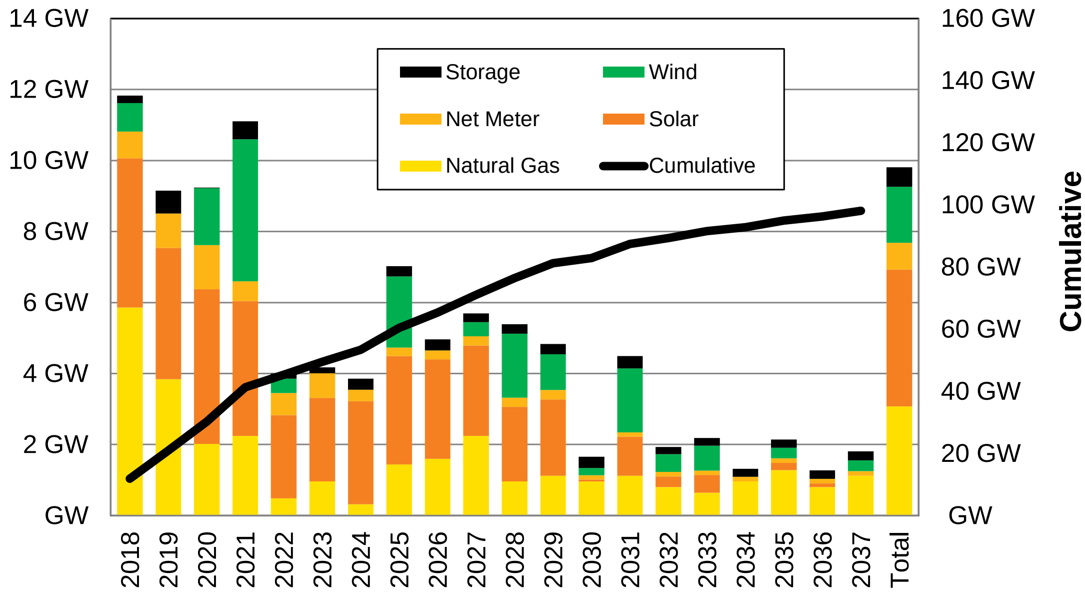

## New Resource Additions

New resource capacity is required to meet load growth and replace retiring power plants over the next 20 years. The generation additions meet capacity, energy, ancillary services and Renewable Portfolio Standards (RPS). Only natural gas-fired peaking and CCCT plants, storage, solar, and wind facilities are in the plan. The IRP does not include new nuclear or coal plants over the forecast horizon. The model objective is to meet capacity and renewable energy targets, but actual resources constructed may differ.

Many states have RPS requirements promoting renewable generation to reduce greenhouse gas emissions, provide jobs, and diversify energy mixes. RPS legislation generally requires utilities to meet a portion of their load with qualified renewable resources. No federal RPS mandate exists presently; therefore, each state defines RPS obligations differently. AURORA<u>XMP</u> now models RPS levels explicitly. The RPS requirements are loaded into the model and the model selects resources to satisfy state laws. Figure 10.4 illustrates new capacity and RPS additions made in the modeling process. Nearly 98 GW will be required to meet the renewable and capacity requirements for the US system. Wind and solar facilities meet most renewable energy requirements.

Geothermal, biomass, and hydroelectric resources provide limited RPS contributions; given their large range in costs and availability, these resources are not included in the capacity expansion study. Due to its low capacity factor, large quantities of solar capacity are necessary to make a meaningful contribution.

**Figure 10.4: Cumulative WECC Generation Resource Additions (Nameplate Capacity)**




In total, 61,000 MW of new utility and consumer-owned renewable generation will pressure afternoon peak pricing lower and move peak load requirements later in the day. Potential for oversupply in shoulder months in California will increase imports to the Northwest and other markets. The largest resource additions expected in the west are solar and natural gas-fired generation. Solar is the largest driver of new resource additions due to RPS requirements and the reduction in costs compared to alternative renewable resources. Most natural gas-fired technology will be peakers to provide a low cost flexible capacity to balance intermittent power generation and not burden customers with high capacity costs. Given the large amount of future renewables on the system, wholesale power prices will remain low and costs of larger baseload plants built to meet peak capacity requirements will be difficult to extract from the wholesale market, placing a burden on utility ratepayers or independent power producer's shareholders. Based on these market fundamentals and the requirement to have a reliable system where peakers rather than combined cycle plants will play a larger role in the future.

A new entrant into the resource forecast is storage technology. At the time of the IRP analysis, the capacity expansion model cannot model the economic additions of storage; current storage additions for the most part either are mandated or pilot projects. This forecast cautiously includes 5,500 MW of new storage capacity over the 20-year period. Given the changes in storage costs and policy, Avista will continue to monitor this technology to determine if a larger level of market penetration is likely.

The Northwest market needs new capacity resources in the 2021/22 period. This study includes nearly 7,000 MW of new natural gas-fired generation to meet load growth and replace retiring resources across the four Northwest states. As for renewable requirements, new generation will continue to consist of wind, but Avista expects movement to solar as costs decrease allowing solar to grow at a greater pace than wind energy. Table 10.2 shows the amount of new renewables added to the Northwest by the end of 2037. Also included in this analysis, is consumer driven renewables. These additions, amounting to one percent of load meet customer demand for renewables as part of a utility's renewable energy offerings.

**Table 10.2: Added Northwest Renewable Generation Resources**

| Resource Type | Capacity (MW) |
|---|---|
| Wind | 4,100 |
| Utility- Solar | 4,800 |
| Customer- Solar | 1,922 |

## Fuel Prices and Conditions

Fuel cost and availability are some of the most important drivers of the wholesale electricity marketplace and resource values. Some resources, including geothermal and biomass, have limited fuel options or sources, while natural gas has greater potential. Hydroelectric, wind, and solar resources benefit from free fuel, but are highly dependent on weather and siting opportunities.

### Natural Gas

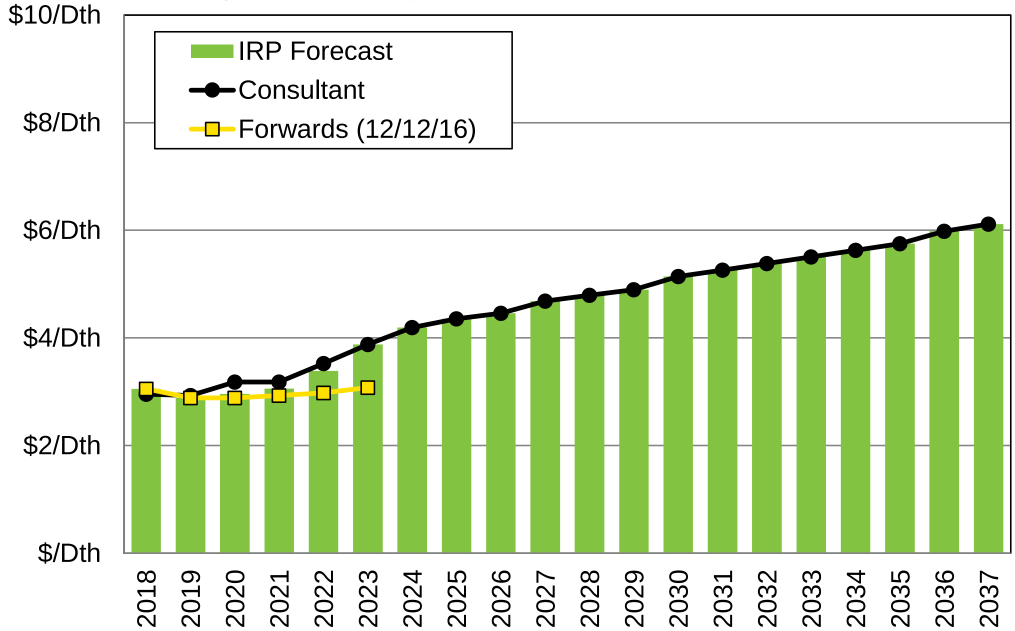
The natural gas industry continues its fundamental shift towards hydraulic fracturing and shale resources. New methods and technology continue to increase efficiency and production from wells. Over the next 25 years, demand in the residential, commercial, and industrial natural gas markets should slightly decline. At the same time, exports to Mexico and for LNG will ramp up as demand for natural gas-fired generation in Mexico and completion of LNG plants materialize.

Natural gas used for power generation is growing due to its ability to support variable output from renewable energy and as a replacement for coal plant retirements. The fuel of choice for new base-load and peaking generation continues to be natural gas. Natural gas has a history of significant price volatility, generally attributed to weather related demand and supply issues. The long-term forecasted supply for natural gas shows the average daily supply will increase to meet new demand through 2050.

Avista uses forward market prices and a forecast from a prominent energy industry consultant to develop the natural gas price forecast for this IRP. Based on these forecasts, the levelized nominal price is $4.20 per dekatherm (Dth) at Henry Hub (shown in Figure 10.5 as the green bars). The pricing methodology used to create a fundamental price forecast follows:

- 2018-2019: 100 percent market;
- 2020: 75 percent market, 25 percent consultant;
- 2021: 50 percent market, 50 percent consultant;
- 2022: 25 percent market, 75 percent consultant; and
- 2023-2037: 100 percent consultant.

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




Price differences across North America depend on demand at the major trading hubs and pipeline constraints existing between them. Table 10.3 presents western natural gas basin differentials from Henry Hub prices. Prices converge over the course of the study as new pipelines and sources of natural gas materialize. To illustrate the seasonality of natural gas prices, monthly Stanfield price shapes are in Table 10.4 for selected forecast years.

**Table 10.3: Natural Gas Price Basin Differentials from Henry Hub**

| Basin | 2018 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| Stanfield | 93% | 93% | 96% | 97% | 100% |
| Malin | 96% | 96% | 97% | 99% | 101% |
| Sumas | 90% | 89% | 92% | 97% | 100% |
| AECO | 73% | 74% | 84% | 91% | 92% |
| Rockies | 95% | 94% | 96% | 97% | 99% |
| Southern CA | 102% | 103% | 103% | 102% | 103% |

**Table 10.4: Monthly Price Differentials for Stanfield from Henry Hub**

| Month | 2018 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| Jan | 97% | 95% | 97% | 98% | 102% |
| Feb | 97% | 95% | 97% | 98% | 102% |
| Mar | 93% | 94% | 96% | 98% | 100% |
| Apr | 91% | 94% | 96% | 97% | 99% |
| May | 91% | 91% | 95% | 96% | 99% |
| Jun | 91% | 91% | 94% | 96% | 98% |
| Jul | 92% | 91% | 94% | 95% | 98% |
| Aug | 92% | 93% | 95% | 96% | 98% |
| Sep | 93% | 94% | 95% | 98% | 99% |
| Oct | 92% | 94% | 96% | 97% | 100% |
| Nov | 95% | 95% | 97% | 99% | 102% |
| Dec | 97% | 95% | 97% | 98% | 101% |

## Coal

This IRP assumes no new coal plants in the Western Interconnect, but models existing plants as part of the electric system unless scheduled for retirement. Existing coal facilities typically have medium to long-term fuel contracts in place and many have ties to oil prices due to transportation costs. These contracts are not publically available. For each coal plant, Avista uses publically available coal prices filed with FERC, and then uses an average annual price increase over the IRP timeframe of 1.2 percent for railed coal and 1.4 percent for mine mouth coal based on data from the Energy Information Administration[1]. For Colstrip Units 3 and 4, Avista used escalation rates based on expectations from existing and expectations of future contracts.

## Hydroelectric

The Northwest U.S., British Columbia and California have substantial hydroelectric generation capacity. A favorable characteristic of hydroelectric power is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. Hydro 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

[1] Energy Information Administration's Annual Energy Outlook 2016, reference case.

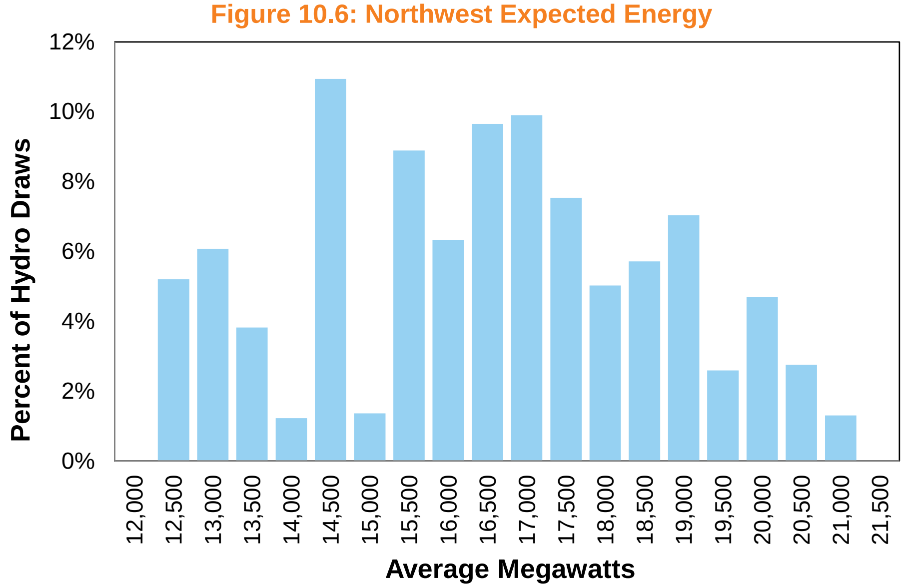
generation resources. The key drawback to hydroelectric generation is its variable and limited fuel supply.

This IRP uses an 80-year hydroelectric data record from the 2014 BPA rate case. The study provides monthly energy levels for the region over an 80-year hydrological record spanning 1928 to 2009.

Many IRP studies use an average of the hydroelectric record, whereas stochastic studies randomly draw from the record, as the historical distribution of hydroelectric generation is not normally distributed. Avista does both. Figure 10.6 shows the average hydroelectric energy of 15,720 aMW in the northwest, 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 10th percentile water year of 12,489 aMW (-21 percent) and a 90th percentile water year of 18,586 aMW (+18 percent).

AURORA<u>XMP</u> maps each hydroelectric plant to a load zone, creating a similar energy shape for all plants in the load zone. For Avista's hydroelectric plants, AURORA<u>XMP</u> uses the output from its own proprietary software with a more accurate representation of operating characteristics and capabilities. AURORA<u>XMP</u> represents hydroelectric plants using annual and monthly capacity factors, minimum and maximum generation levels, and sustained peaking generation capabilities. The model's objective, subject to constraints, is to shift hydroelectric generation into peak load hours to maximize the value of the system consistent with actual operations.

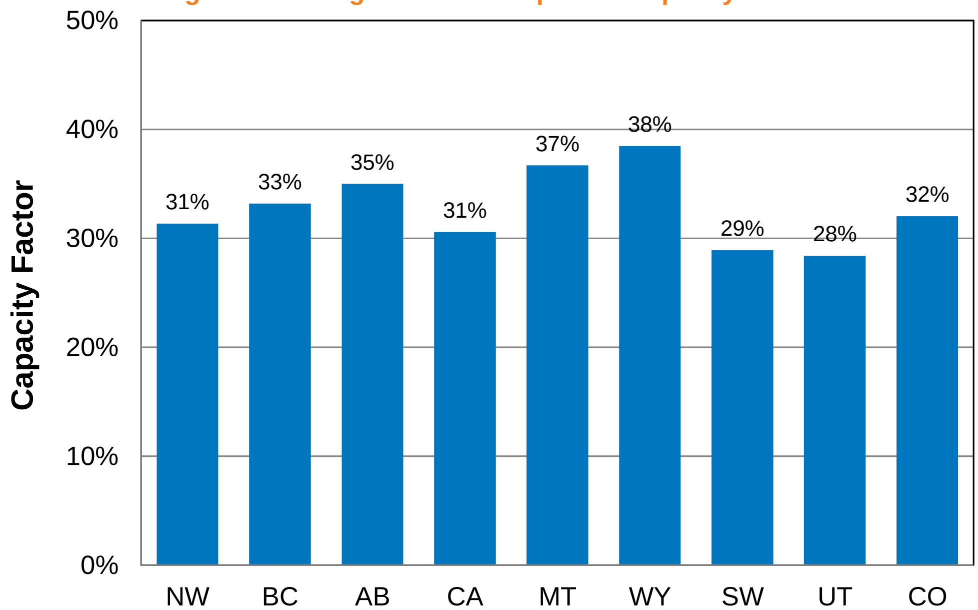
**Figure 10.6: Northwest Expected Energy**




## Wind

New wind resources satisfy a significant share of western renewable portfolio standards over the IRP timeframe. These additions increase competition for the remaining higher-quality wind sites. Similar to how AURORA<u>XMP</u> maps each hydroelectric plant to a load zone, the capacity factors in Figure 10.7 are averages for each zone. The IRP uses capacity factors from a review of the BPA and the National Renewable Energy Laboratory (NREL) wind data sets.

Figure 10.7: Regional Wind Expected Capacity Factors




## Greenhouse Gas Emissions and the Clean Power Plan

Greenhouse gas, or carbon emissions, regulation is a significant uncertainty for the electricity industry because of reliance on carbon-emitting generation and the potential of regulation to increase wholesale prices. Regulation may require the reduction of carbon emissions at existing power plants, the construction of low- and non-carbon-emitting technologies, and for changes to existing operations. Between 2008 and 2015, western states carbon emissions from generation dropped nearly 13 percent due to reduced loads and less coal generation.

Future carbon emissions could fall due to fundamental market changes or regulation. In 2014, the EPA released the draft Clean Power Plan (CPP) under section 111(d) of the CAA to reduce emissions from existing plants. With a new Federal Administration, the future of regulation under 111(d) may change; at the same time, state-level emission reduction policies may move forward. Washington's Clean Air Rule (CAR) caps emissions for facilities emitting more than 100,000 metric tons per year, and reduces the emissions threshold by 5,000 metric tons per year, until covering all entities emitting over 70,000 metric tons by 2035. The Washington Commission may implement rules regarding RCW 70.235, from the Executive Order 07-02. Other states, such as Oregon, are also considering carbon emissions limitations at the state legislature. Without final or specific rules and regulations, modeling the impact of future policies is difficult, but this plan includes specific assumptions. Due to uncertainty and the likelihood of greenhouse gas regulations, this IRP used the CPP goals to guide the development of the emission reduction forecast of this IRP.

For the Expected Case, the CAR limits plant level emissions in Washington. The Clean Air Rule identifies specific reductions to plants over a glide path by 2035. As an alternative to reductions, emission credits or RECs from Washington State may satisfy compliance obligations. The CAR monitors compliance at three-year intervals. Washington State may generate up to the cap each year based on the three-year average generation between 2012 and 2015. Each year the cap declines. For covered plants, the total allowance is for the group rather than the individual facility providing for allowance trading. The Department of Ecology intends to set baseline emission levels and reduction targets for new plants covered under the CAR.

The Oregon emissions policies, beyond the requirements in SB 1547 ending the use of coal to serve Oregon loads by 2030 and an increased RPS reaching 50 percent by 2040, are in development at the writing of this IRP. However, emissions are not likely to increase long term. This IRP assumes emissions fall by 30 percent compared to 2015 by 2025. The IRP assumes Idaho emissions follow the CPP emission intensity goals. Additional details about the state-level emissions reductions programs are in Chapter 7-Policy Considerations.

For the other states, outside of the current programs in California, carbon emissions will likely fall under federal policies. The current form of the CPP used to develop this IRP is not likely to remain in force under the current Federal Administration, but some form of regulation may replace it. The EPA sent information regarding CPP intent to the Office of Management and Budget on March 8, 2017, but had publically not released any proposal. This will require additional review and analysis in the next IRP. To consider this future affect to our facilities, Montana reduces electric generation carbon emissions following existing CPP targets with new source complement, but the start of this effort is delayed four years. For the remaining western states, an emission reduction goal is in place allowing each of the states to trade between each other based on the CPP target with new sources, but delayed until 2024.

This IRP does not include specific carbon pricing except for states and provinces with existing carbon trading and tax regulations. By modeling emission goals and constraints, the model estimates potential emission trading prices for each ton of emissions. This methodology is in line with current policy discussions using cap and trade markets rather than taxes or fees. Any future tax or price policy will require alternative analysis in a later IRP. Avista uses a different carbon reduction methodology in this IRP than in its prior plans. In this IRP, the model forces reductions in emissions and the model estimates the shadow price of the emission reduction. Past IRPs used an arbitrary carbon price not tied to a specific reduction level. Arbitrary carbon prices without a correlation to market fundamentals may not achieve desired emissions reductions. Without a tie to external factors, a “tax or fee” may not achieve a specific emission goal due to changing external factors such as natural gas prices or hydroelectric conditions. For example, a higher carbon price is required to reduce emissions when natural gas prices are high or hydroelectric conditions are unfavorable, as such, a lower carbon price will reduce emissions in a low natural gas price environment or favorable hydroelectric conditions. This phenomenon is shown later in this chapter regarding the Washington Clean Air Rule. Avista will monitor policy directives regarding greenhouse gas emissions to determine if the methodology is consistent with future policy objectives.

## Risk Analysis

A stochastic analysis, using the variables discussed earlier in this chapter, evaluates the market to account for future uncertainty. It is better to represent the electricity price forecast as a range because point estimates are unlikely to reflect underlying assumptions perfectly. Stochastic price forecasts develop more robust resource strategies by accounting for tail risk. The IRP uses 500 distinct 20-year market futures, providing a large distribution of the marketplace illustrating potential tail risk outcomes. The next several pages discuss the input variables driving market prices, and describe the methodology and the range in inputs used in the modeling process.

### Natural Gas

Natural gas prices are a volatile commodity in relation to its historical prices. Daily Stanfield prices ranged between $1.21 and $24.36 per Dth between 2004 and 2017. Figure 10.8 shows average Stanfield monthly prices since January 2004. Prices retreated from 2008 highs to a monthly price of $1.44 per Dth in March 2016. Prices since 2009 are lower than the previous five years, but continue to show volatility.

**Figure 10.8: Historical Stanfield Natural Gas Prices (2004-2015)**

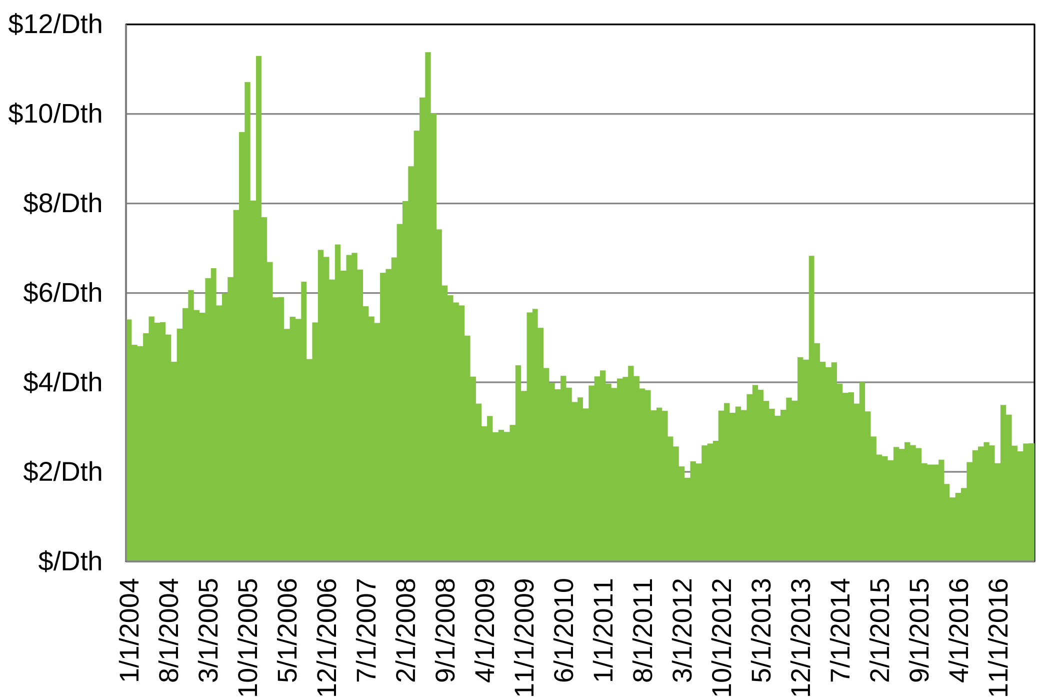
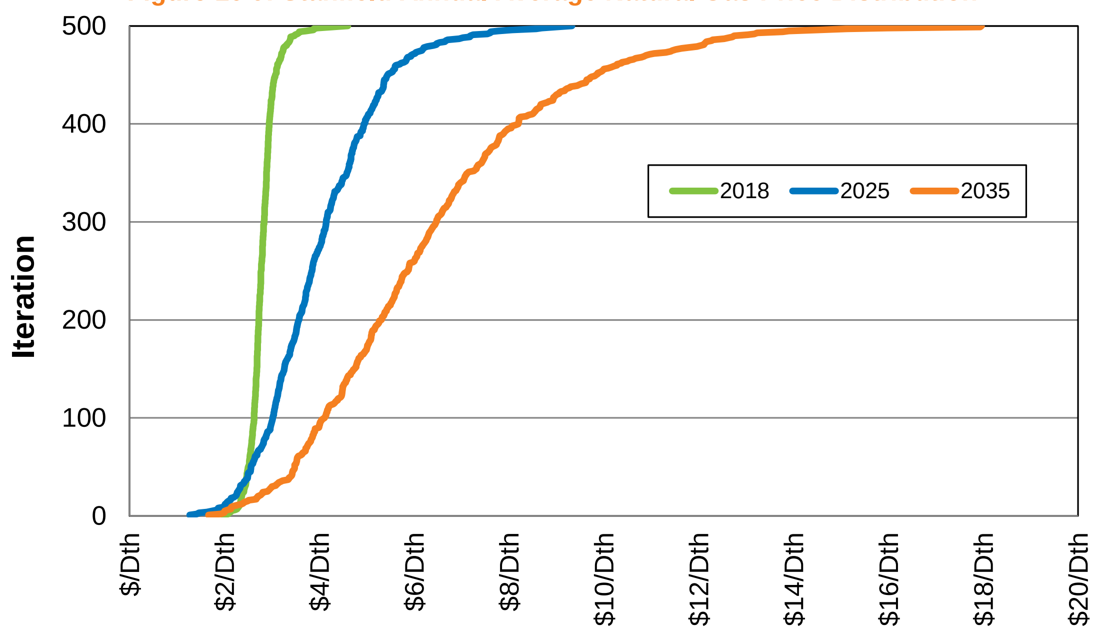


Figure 10.9 shows Stanfield natural gas price duration curves for 2018, 2025 and 2035. The chart illustrates a larger price range in the later years of the study, reflecting less forecast certainty. Shorter-term prices are more certain due to additional market information and the quantity of near term natural gas trading. Figure 10.10 shows another view of the forecast. The mean price in 2018 is $2.80 per Dth, represented by the horizontal bar, and the levelized price over the 20 years is $4.21 per Dth. The bottom and top of the bars represent the 10th and 90th percentiles. The bar length indicates price uncertainty. Figure 10.11 illustrates the difference in pricing between the deterministic case and the mean and median of the 500 simulations. On a levelized basis, the median and deterministic cases are $4.00 and $4.03 per Dth, while the mean is higher at $4.20 per Dth[2]. Due to the methodology of the stochastic model, the mean is greater than both the median and the starting deterministic. The model randomizes prices based on the lognormal distribution of the change in the deterministic monthly price forecast. Given a lognormal distribution, the mean prices trend higher than the median prices given the skewed distribution curve.

**Figure 10.9: Stanfield Annual Average Natural Gas Price Distribution**




[2] The 20-year levelized mean price at Henry Hub is $4.35 per dekatherm.

Figure 10.10: Stanfield Natural Gas Distributions

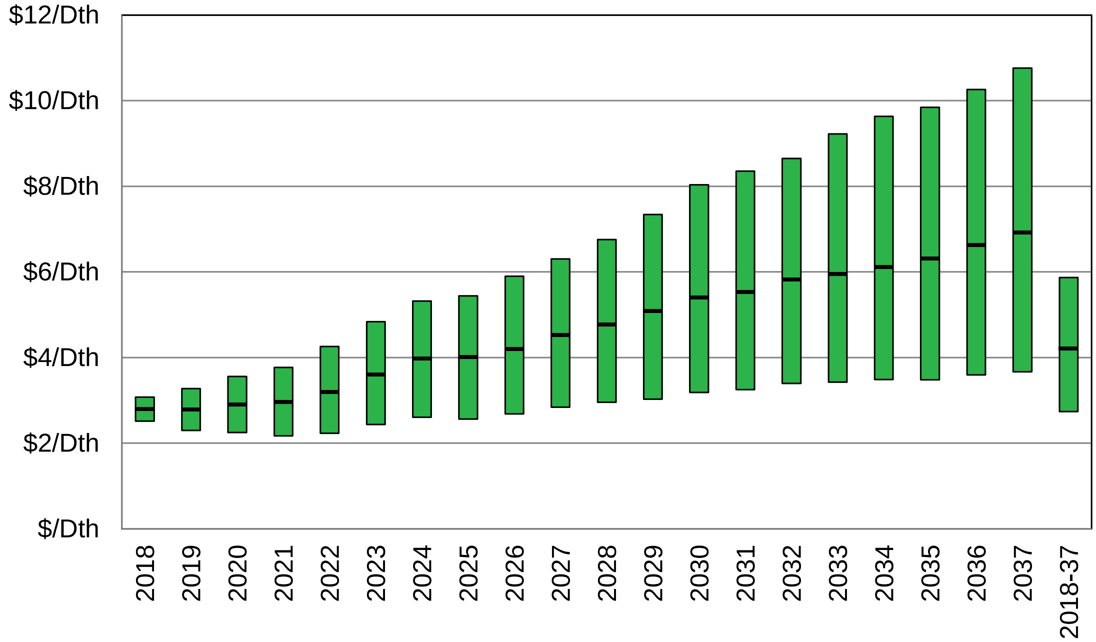
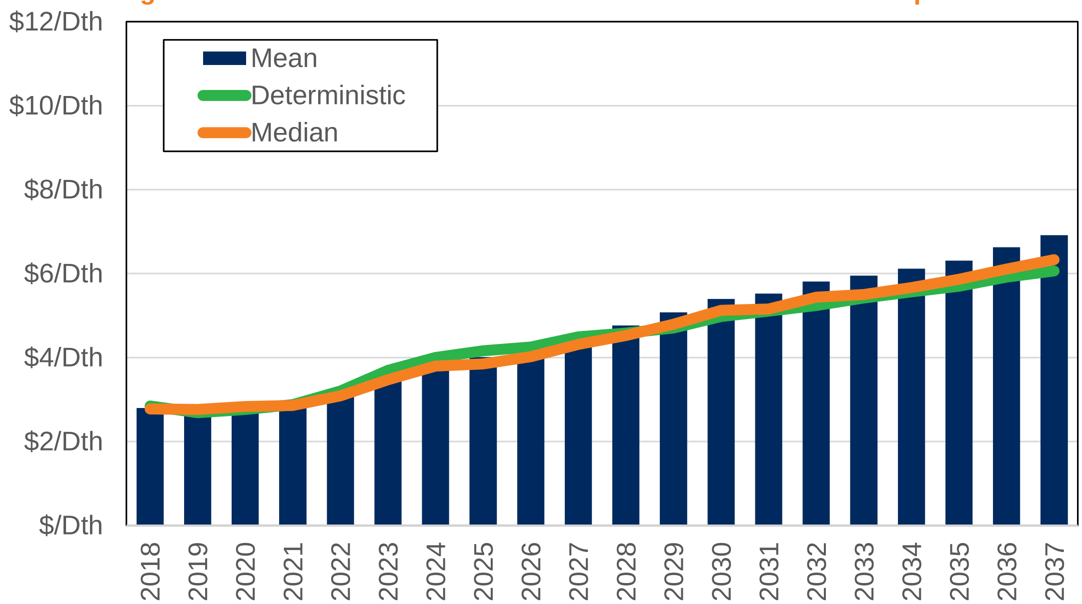



Figure 10.11: Stanfield Natural Gas Annual Price Statistical Comparison



## 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 data from 2007 to 2015 for the Western Interconnect as the basis for its analysis. Correlations 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 excursions witnessed by the electricity grid. The additional accuracy from modeling loads this way is crucial for understanding wholesale electricity market price variation. It is vital for understanding the value of peaking resources and their use in meeting system variation.

Tables 10.5 and 10.6 present load correlations for the 2017 IRP. Statistics are relative to the Northwest load area (Oregon, Washington and Idaho). “NotSig” indicates no statistically valid correlation existed in the data. “Mix” indicates the relationship was not consistent across the 2007 to 2015 period. For regions and periods with NotSig and Mix results, the IRP does not model correlations between the regions. Tables 10.7 and 10.8 provide the coefficient of determination values by zone.[3]

**Table 10.5: January through June Load Area Correlations**

| Area | Jan | Feb | Mar | Apr | May | Jun |
|---|---:|---:|---:|---:|---:|---:|
| Alberta | Mix | Mix | Mix | Mix | Not Sig | 20% |
| Arizona | 32% | 38% | Mix | Not Sig | Mix | Not Sig |
| Avista | 88% | 86% | 78% | 77% | 41% | 79% |
| British Columbia | 86% | 88% | 72% | 73% | 41% | 61% |
| California | Not Sig | Not Sig | Mix | Mix | 17% | Not Sig |
| CO-UT-WY | -23% | Mix | Mix | -26% | -3% | -18% |
| Montana | 55% | 65% | 63% | 52% | Mix | 46% |
| New Mexico | 6% | 6% | Mix | Mix | Mix | Mix |
| North Nevada | 58% | 22% | 6% | Mix | Mix | 51% |
| South Idaho | 79% | 76% | 69% | Mix | Mix | 49% |
| South Nevada | 52% | 42% | Mix | Not Sig | Mix | 19% |

[3] The coefficient of determination is the standard deviation divided by the average.

## Table 10.6: July through December Load Area Correlations

| Area | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|
| Alberta | 6% | Not Sig | Not Sig | Not Sig | 12% | Mix |
| Arizona | Mix | Mix | Mix | -21% | Mix | 27% |
| Avista | 76% | 78% | 67% | 79% | 92% | 92% |
| British Columbia | 73% | 56% | 23% | 75% | 87% | 83% |
| California | Not Sig | Not Sig | Not Sig | -12% | Mix | Not Sig |
| CO-UT-WY | -2% | Mix | -2% | -12% | 26% | Mix |
| Montana | 6% | 17% | 6% | 20% | 79% | 75% |
| New Mexico | Not Sig | Mix | Mix | Not Sig | 34% | 18% |
| North Nevada | 52% | 53% | 27% | Mix | 60% | 34% |
| South Idaho | 29% | 38% | 32% | 6% | 87% | 84% |
| South Nevada | Mix | 6% | Mix | -33% | Mix | 64% |

## Table 10.7: Area Load Coefficient of Determination (Standard Deviation/Mean)

| Area | Jan | Feb | Mar | Apr | May | Jun |
|---|---|---|---|---|---|---|
| Alberta | 4.9% | 4.3% | 4.8% | 4.5% | 4.9% | 5.5% |
| Arizona | 8.2% | 7.2% | 7.2% | 10.8% | 15.1% | 16.2% |
| Avista | 8.9% | 8.5% | 9.6% | 8.7% | 8.5% | 10.3% |
| British Columbia | 8.5% | 7.9% | 8.5% | 8.0% | 8.3% | 8.6% |
| California | 9.3% | 9.3% | 9.4% | 9.9% | 11.4% | 12.6% |
| CO-UT-WY | 7.8% | 7.7% | 7.9% | 7.5% | 8.7% | 13.2% |
| Montana | 7.8% | 7.1% | 7.7% | 7.1% | 7.3% | 9.6% |
| New Mexico | 8.3% | 8.4% | 8.0% | 9.5% | 13.0% | 13.6% |
| Northern Nevada | 5.6% | 5.6% | 5.6% | 6.4% | 6.0% | 9.4% |
| Pacific Northwest | 9.7% | 9.2% | 9.4% | 8.7% | 8.4% | 8.9% |
| South Idaho | 8.6% | 8.2% | 8.8% | 9.8% | 11.0% | 14.9% |
| South Nevada | 6.5% | 5.8% | 6.3% | 11.5% | 17.1% | 18.3% |

## Table 10.8: Area Load Coefficient of Determination (Standard Deviation/Mean)

| Area | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|
| Alberta | 5.8% | 5.5% | 5.8% | 4.6% | 5.0% | 4.8% |
| Arizona | 14.0% | 14.4% | 15.6% | 13.2% | 7.5% | 7.8% |
| Avista | 12.7% | 12.4% | 9.8% | 8.8% | 11.1% | 9.9% |
| British Columbia | 9.5% | 9.4% | 8.8% | 8.9% | 10.5% | 9.2% |
| California | 13.1% | 13.8% | 14.6% | 11.7% | 9.9% | 9.7% |
| CO-UT-WY | 12.8% | 12.4% | 11.4% | 8.3% | 8.6% | 8.4% |
| Montana | 9.8% | 10.1% | 8.1% | 7.2% | 8.6% | 8.1% |
| New Mexico | 12.8% | 12.5% | 13.8% | 10.8% | 9.1% | 8.8% |
| Northern Nevada | 10.0% | 9.3% | 8.7% | 5.9% | 6.2% | 6.5% |
| Pacific Northwest | 10.6% | 10.5% | 9.2% | 9.0% | 11.7% | 10.9% |
| South Idaho | 11.4% | 12.2% | 12.8% | 8.6% | 10.6% | 9.4% |
| South Nevada | 15.7% | 15.7% | 17.8% | 13.0% | 6.8% | 7.1% |

### Hydroelectric Variation

Hydroelectric generation is the most commonly modeled stochastic variable in the Northwest because historically it has a larger impact on regional electricity prices than other variables. The IRP uses an 80-year hydroelectric record starting with the 12-month water year beginning October 1, 1928. Every iteration starts with a randomly drawn water year from the historical record, so each water year repeats approximately 125 times in the study (500 scenarios x 20 years / 80 water year records).

### Wind Variation

Wind has the most volatile short-term generation profile of any utility-scale resource. This makes it necessary to capture wind volatility in the power supply model to determine the value of non-wind resources able to follow loads when wind production varies. Accurately modeling wind resources requires hourly and intra-hour generation shapes. For regional market modeling, the representation is similar to how AURORA<u>XMP</u> models hydroelectric resources. A single wind generation shape represents all wind resources in each load area. This shape is smoother than an individual wind plant, but closely represents the diversity of a large number of wind farms located across a zone.

This simplified wind methodology works well for forecasting electricity prices across a large market, but does not accurately represent the volatility of specific wind resources Avista might select as part of its PRS. Therefore individual wind farm shapes form the basis of wind resource options for Avista.

Fifteen potential 8,760-hour annual wind shapes represent each geographic region or facility. Each year contains a wind shape drawn from these 15 representations. The IRP relies on two data sources for the wind shapes. The first is BPA balancing area wind data. The second is NREL-modeled data between 2004 and 2006.

Avista believes an accurate representation of a wind shape across the West requires data meeting several conditions:

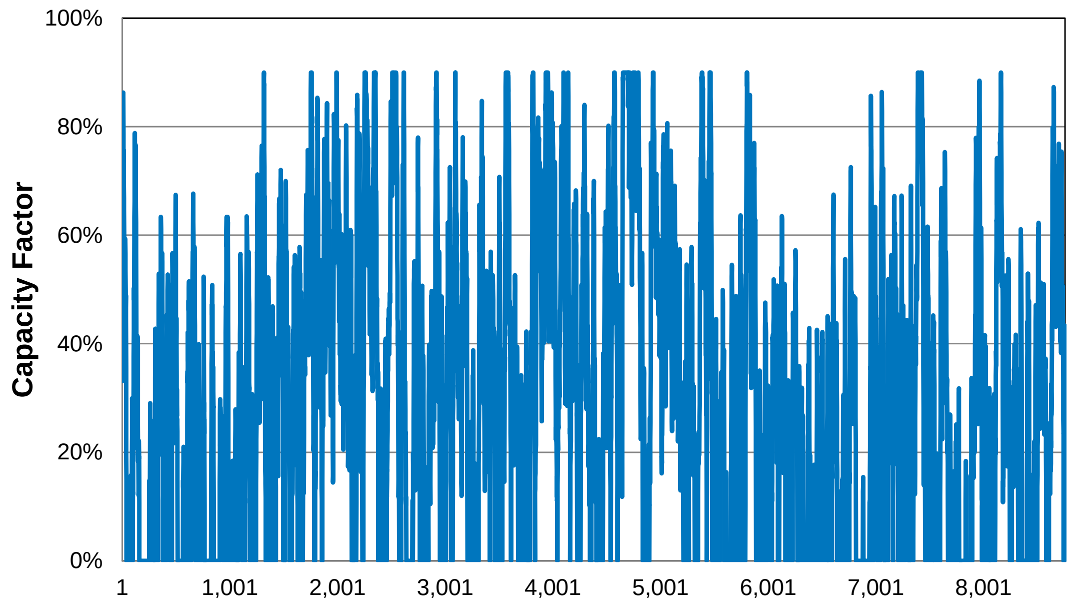
1. Data correlated between areas using historical data.
2. Data within load areas is auto-correlated.[4]
3. The average and standard deviation of each load area's wind capacity factor is consistent with the expected amount of energy for a particular area in the year and month.
4. The relationship between on- and off-peak wind energy is consistent with historic wind conditions. For example, more energy in off-peak hours than on-peak hours where this has been experienced historically.
5. Hourly capacity factors for a diversified wind region are never greater than 90 percent due to turbine outages and wind diversity within the area.

Absent these conditions, it is unlikely any wind study provides a level of accuracy adequate for planning efforts. Avista's methodology, first developed for its 2013 IRP,

[4] Adjoining hours or groups of hours correlate to each other.

attempts to meet the five conditions by first using a regression model based on historic data for each region. The independent variables used in the analysis were month, night or day hour type, and generation levels from the prior two hours. To reflect correlation between regions, a capacity factor adjustment reflects historic regional correlation using an assumed normal distribution with the historic correlation as the mean. After this adjustment, a capacity factor adjustment accounts for hours with generation levels exceeding a 90 percent capacity factor. Figure 10.12 shows a Northwest example of an 8,760-hour wind generation profile. This example, shown in blue, has a 31 percent capacity factor. Figure 10.13 shows actual 2016-wind generation recorded by BPA Transmission. The average wind fleet in BPA's balancing authority had a 27.3 percent capacity factor in 2016.

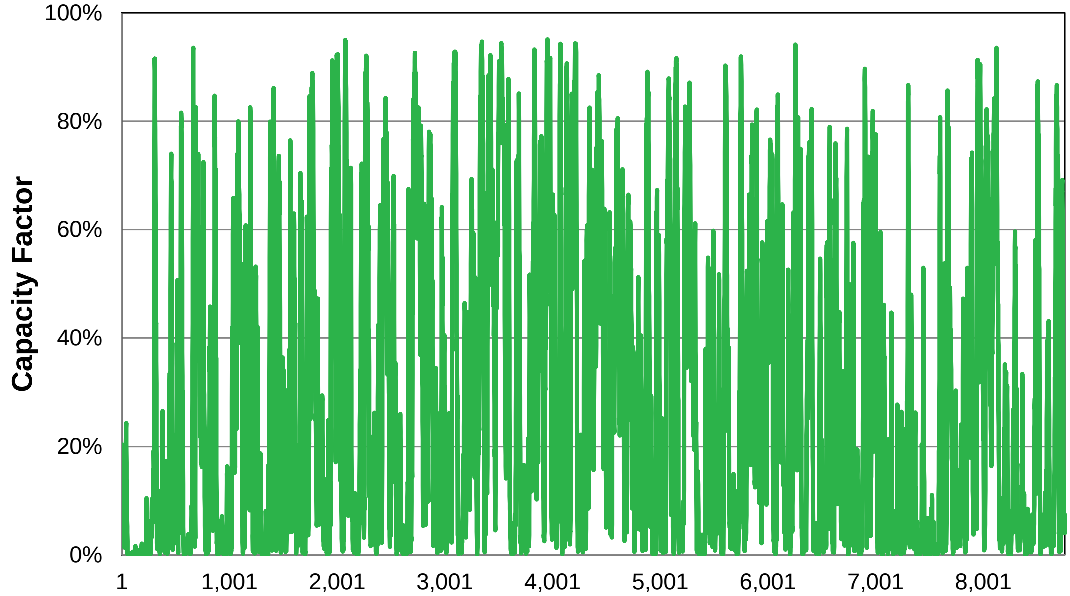
**Figure 10.12: Wind Model Output for the Northwest Region**




## Forced Outages

Most deterministic market modeling represents generator-forced outages with an average reduction to maximum capability. This over simplification represents expected values well; however, it is better to represent the system more accurately in stochastic modeling by randomly placing non-hydroelectric units out of service based on a mean time to repair and on an average forced outage rate. Internal studies show this level of modeling detail is necessary only for natural gas-fired, coal and nuclear plants with generating capacities in excess of 100 MW. Plants under 100 MW on forced outage do not materially affect market prices so their outages do not require stochastic modeling. Forced outage rates and mean time to repair data for the larger units in the Western Interconnect come from analyzing the North American Electric Reliability Corporation's Generating Availability Data System database, also known as GADS.

**Figure 10.13: 2016 Actual Wind Output BPA Balancing Authority[5]**




## Market Price Forecast

An optimal resource portfolio cannot ignore the extrinsic value inherent in its resource choices. To determine extrinsic value, the 2017 IRP simulation compares each resource's expected hourly output using forecasted Mid-Columbia hourly prices over 500 iterations of Monte Carlo-style scenario analysis.

Hourly zonal electricity prices are equal to either the operating cost of the marginal unit in the modeled zone or the economic cost to generate and move power from another zone to the modeled zone. A forecast of available future resources helps create an electricity market price projection. The IRP uses regional planning margins to set minimum capacity requirements rather than simply summing the capacity needs of regional utilities. This reflects how some regions have resource surpluses even where individual utilities are deficit. This imbalance can be due in part to ownership of regional generation by independent power producers and possible differences in planning methodologies used by utilities in the region.

AURORA$^{\underline{XMP}}$ assigns market values to each resource alternative available to Avista, but does not select Avista's PRS. Several market price forecasts determine the value and volatility of a resource portfolio. As Avista does not know what will happen in the future, it relies on risk analysis to help determine an optimal resource strategy. Risk analysis uses several market price forecasts with different assumptions from the Expected Case or with changes to the underlying statistics of a study. The modeling splits alternate cases into stochastic and deterministic studies.

[5] Chart data is from the BPA at: http://transmission.bpa.gov/Business/Operations/Wind/default.aspx.

A stochastic study uses Monte Carlo analysis to quantify the variability in future market prices, and the resultant impact on individual and portfolios of resources. These analyses include 500 iterations of varying natural gas prices, loads, hydroelectric generation, thermal outages, and wind generation shapes. The IRP includes three stochastic studies—the Expected Case, a case with the social cost of carbon, and a benchmarking case excluding a cost of carbon.

## Mid-Columbia Price Forecast

The Mid-Columbia market is Avista's primary electricity trading hub. The market is historically the lowest cost in the west due to the amount of hydroelectric generation at the hub and its proximity to Canadian gas supplies, though other markets can be less expensive at times when solar production is high and loads are low.

Fundamentals-based market analysis is critical to understanding the power industry environment. The Expected Case includes two studies. The first study is a deterministic market view using expected levels for the key assumptions discussed in the first part of this chapter. The second is a risk or stochastic study with 500 unique scenarios based on different underlining assumptions for natural gas prices, load, wind generation, hydroelectric generation, forced outages, and inflation. Each study simulates the entire Western Interconnect hourly between 2018 and 2037.

Figure 10.14 shows the Mid-Columbia stochastic market price results with horizontal bars representing the 10$^{th}$ and 90$^{th}$ percentile range for annual prices, diamonds show average prices, and arrows represent the 95$^{th}$ percentile. The 20-year nominal levelized price is $35.85 per MWh. Table 10.9 shows the annual averages of the stochastic case on-peak, off-peak and levelized prices. Spreads between on- and off-peak prices average $5.09 per MWh over 20 years. The 2015 IRP annual average nominal price was $38.48 per MWh. The market price reduction from the 2015 study results from lower natural gas prices, lower loads, higher percentages of new lower-heat-rate natural gas plants, and increased solar resources serving higher RPS requirements.

**Figure 10.14: Mid-Columbia Electric Price Forecast Range**

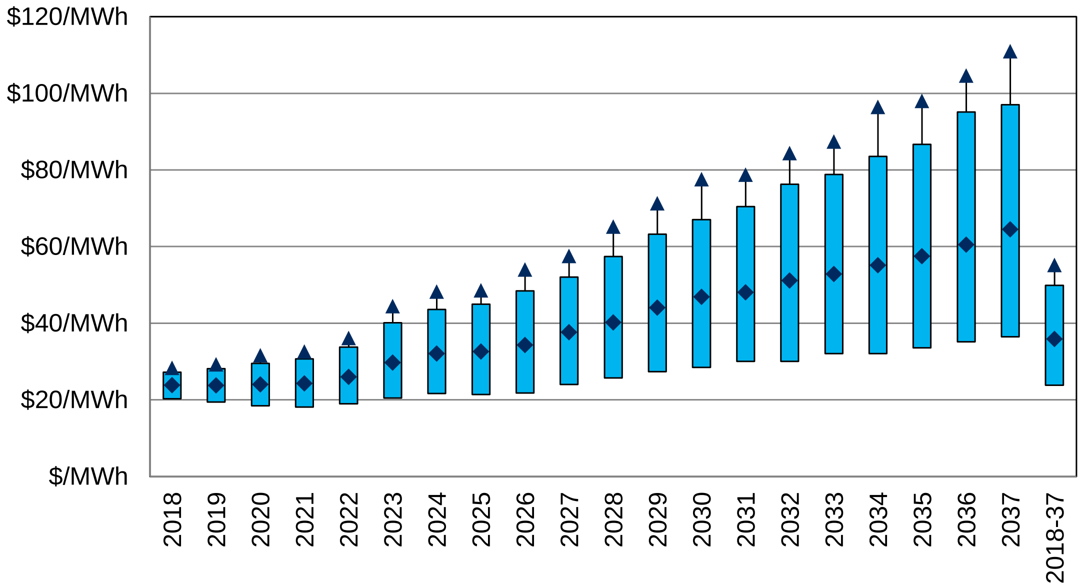



**Table 10.9: Annual Average Mid-Columbia Electric Prices ($/MWh)**

| Year | Flat | Off-Peak | On-Peak |
|---|---|---|---|
| 2018 | 23.79 | 19.48 | 27.02 |
| 2019 | 23.71 | 19.53 | 26.85 |
| 2020 | 23.99 | 20.16 | 26.85 |
| 2021 | 24.30 | 20.88 | 26.85 |
| 2022 | 25.95 | 22.59 | 28.47 |
| 2023 | 29.68 | 26.30 | 32.24 |
| 2024 | 32.03 | 28.90 | 34.38 |
| 2025 | 32.58 | 29.83 | 34.65 |
| 2026 | 34.27 | 31.77 | 36.13 |
| 2027 | 37.61 | 35.43 | 39.25 |
| 2028 | 40.18 | 38.28 | 41.60 |
| 2029 | 44.06 | 42.44 | 45.27 |
| 2030 | 46.86 | 45.15 | 48.15 |
| 2031 | 48.08 | 46.42 | 49.32 |
| 2032 | 51.10 | 49.17 | 52.55 |
| 2033 | 52.81 | 50.83 | 54.29 |
| 2034 | 55.09 | 53.07 | 56.61 |
| 2035 | 57.50 | 55.14 | 59.26 |
| 2036 | 60.52 | 58.24 | 62.22 |
| 2037 | 64.51 | 62.09 | 66.33 |
| **Levelized** | **$35.85** | **$32.94** | **$38.03** |

## Negative Electric Market Prices

The price forecast includes functionality to allow prices to go negative during oversupply events. In the past, oversupply events mostly occurred during spring periods when hydro was at high levels and wind was at full capacity. Traditionally these events occur at night when loads are lower. Given increasing solar penetration, negative pricing is now occurring during the mid-afternoon. Avista models this by changing the supply curve of the hydro resources to a negative marginal price. Whenever demand is higher than hydro resources and must run generation, the marginal price is negative. Without this change, prices would never go below zero. This change properly values new resource opportunities such as storage and peaking units, but is also important to avoid overvaluing solar and other non-dispatchable resources during oversupply events.

## Greenhouse Gas Emission Levels

Greenhouse gas levels are declining regionally and nationally as lower-cost natural gas resources displace coal-fired generation, or even forces coal plants into early retirement. This IRP includes emissions limits and pricing as described earlier in this chapter. Figure 10.15 shows historic and expected greenhouse gas emissions for the Western Interconnect. Greenhouse gas emissions from electricity generation decrease 6.2 percent between 2018 and 2037, and 2018 is 15 percent lower than 2015. The figure also includes 10$^{th}$ and 90$^{th}$ percentile statistics from the 500-iteration dataset. The higher and lower bands show emissions depending on changes in hydroelectric generation, load, resource availability and other factors. Lower load forecasts, lower natural gas prices, higher RPS requirements, coal-fired generation retirements and carbon limits drive the reductions. Once the majority of planned coal-fired plant retirements occur by 2032, emissions rise again reflecting new load met by a mixture of renewables and natural gas without coal retirements beyond current announcements.

**Figure 10.15: Western States Greenhouse Gas Emissions**

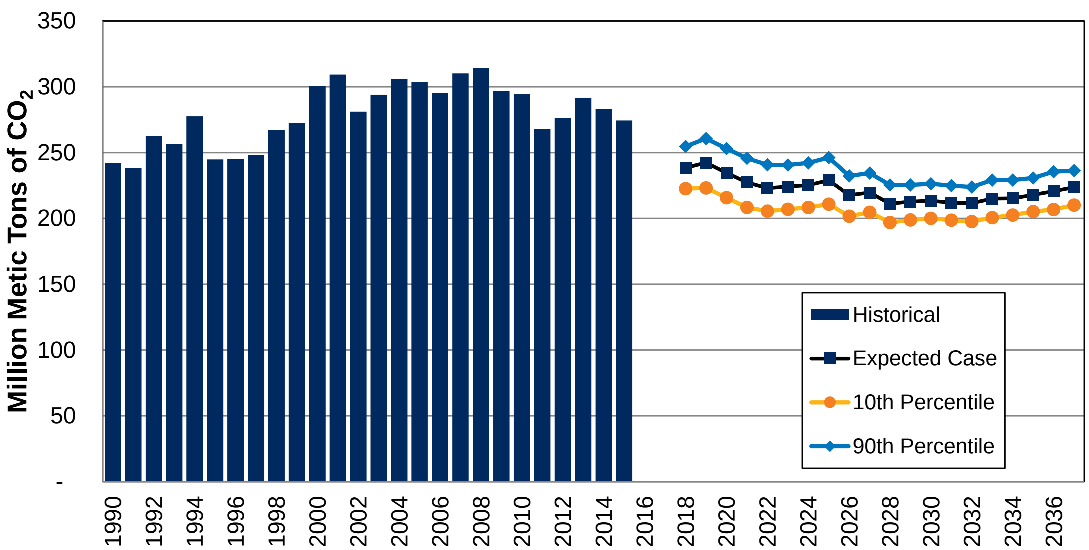


Figure 10.16 illustrates the Expected Case emissions intensity for the Western Interconnect. The CPP included an option for states to meet intensity goals for covered plants; this chart illustrates the reductions across the west to get a second look at the effectiveness of the emission constraints modeled. Between 2018 and 2037, the emission intensity falls 17.5 percent. Alternatively, Figure 10.17 illustrates the change in emission intensity from 2018 to 2037 by area. All areas show declining emissions intensity with the exception of southern Idaho. The Idaho area has few emitting resources (the region currently imports much of its baseload power) and the added natural gas increases its intensity. This chart shows the relationship of the emissions intensity of facilities in the area compared to the area's load. For example, Wyoming exports energy as its production is greater than its local load.

**Figure 10.16: Emission Intensity Metric**

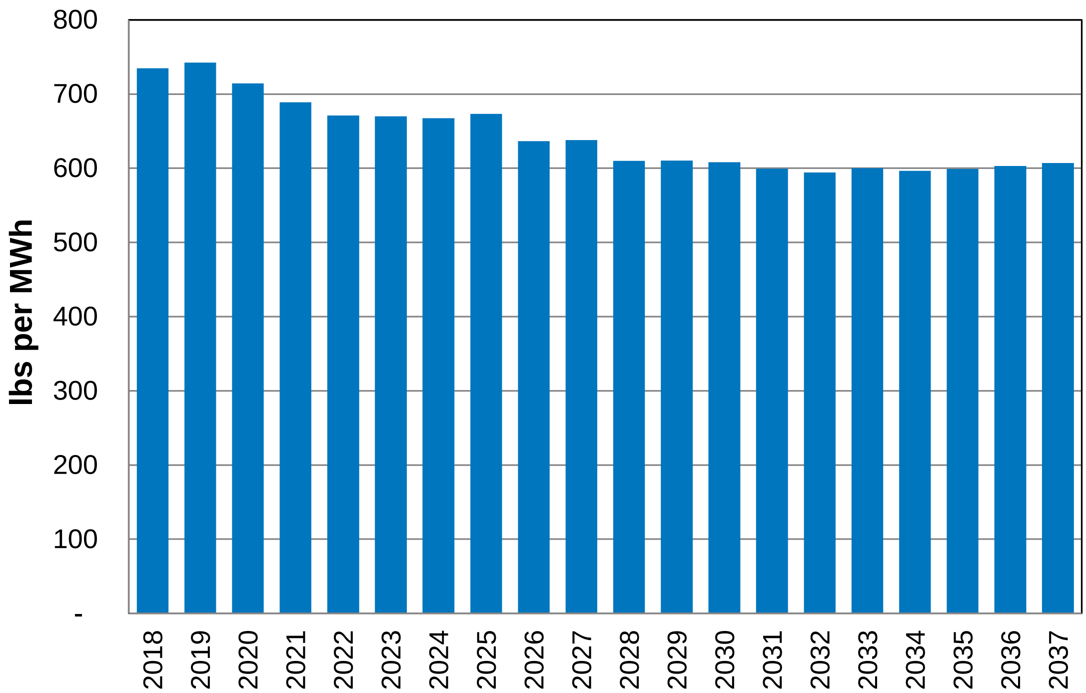
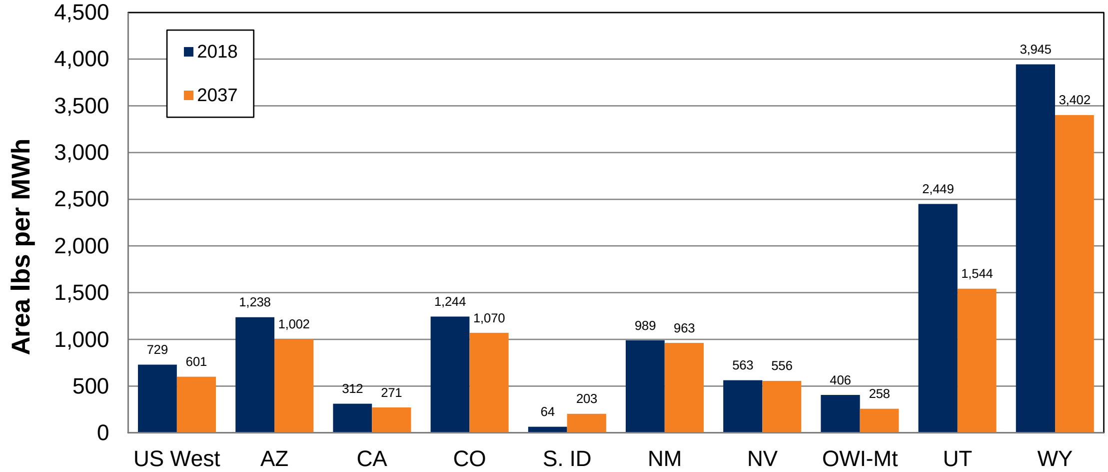


Figure 10.17: Instate Emission Intensity Change from 2018 to 2037




## Resource Dispatch

State-level RPS goals and greenhouse gas regulations change resource dispatch decisions and affect future power prices. The Northwest is witnessing the market-changing effects of more than 7,750 MW of wind. Figure 10.18 illustrates how natural gas will increase as a percentage of Western Interconnect generation from 29 percent in 2018 to 37 percent 2037. The increase offsets coal-fired generation, with coal dropping from 23 percent in 2018 to 13 percent in 2037. Utility-owned solar and wind generation increase from 11 percent in 2018 to 20 percent by 2037. New renewable generation also reduce coal-fired generation, but natural gas-fired generation is the primary resource meeting load growth due to economic dispatch and its addition to serve peak load growth. Figure 10.19, illustrates the resources meeting the reduction of coal and nuclear resources, and the increase in load. Natural gas meets 50 percent, while renewables meet the rest.

Figure 10.18: Base Case Western Interconnect Resource Mix

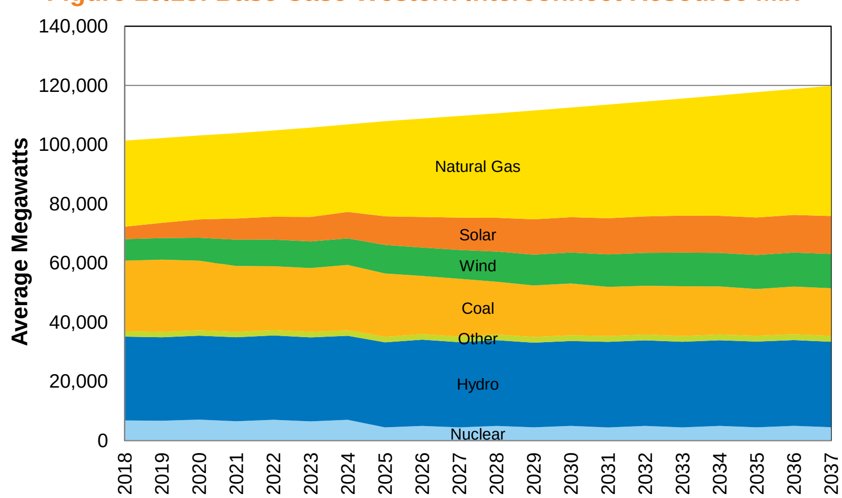
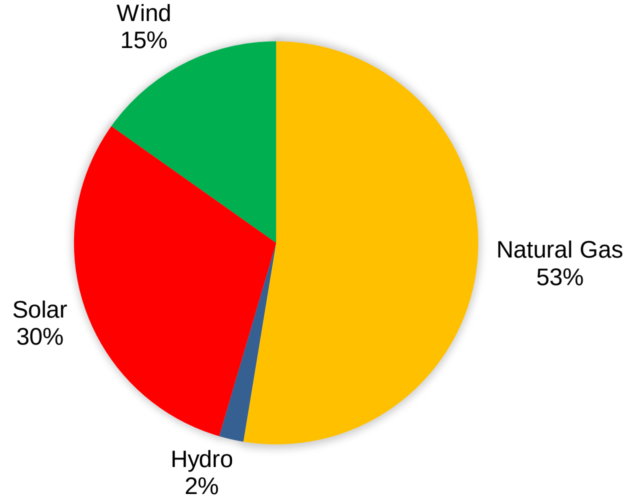


**Figure 10.19: Western Interconnect Resource Mix Changes**



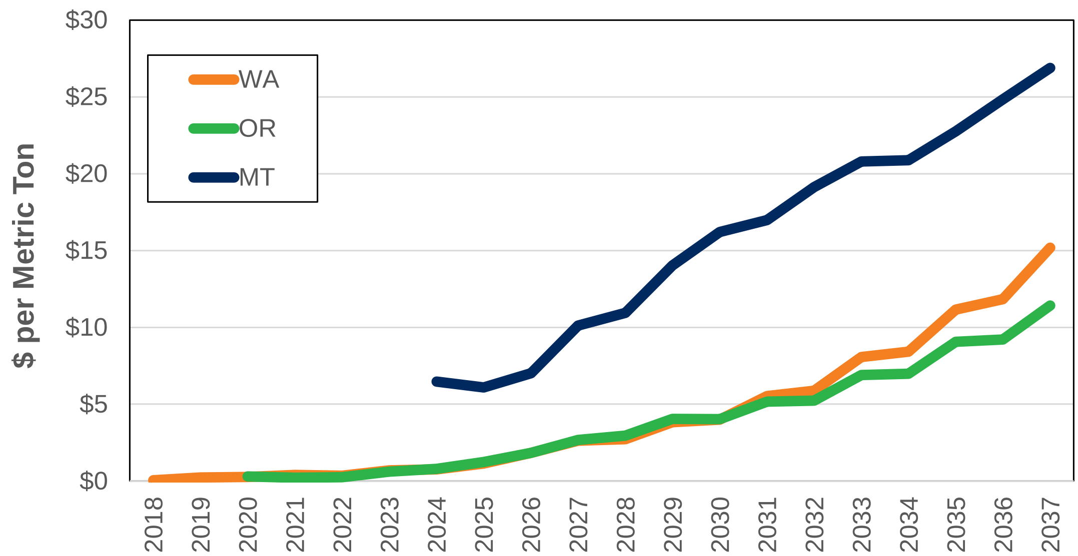

## Greenhouse Gas Emission Pricing

This IRP assumes the market will have emission caps; with this assumption, the AURORA$^{\underline{XMP}}$ model produces emission prices rather than a direct input as past IRPs. With this new constraint, the model produces a shadow price or hurdle rate for the plants with emission constraints. The resulting shadow prices as shown in Figure 10.20 affect the dispatch of plants in each area with reduction goals similar to models with a carbon "price". For Washington, the prices are near zero (depending on water year) until the early 2020s and remain below $5 per metric ton until 2030. These prices are a result of increasing renewables on the system and the type of regulations in place. Avista's facilities are not subject to these prices. The Washington projected emissions prices are lower than the prices required in coal regions as it is affecting natural gas resources rather than coal facilities. Natural gas prices need a lower financial disincentive to dispatch compared to coal as natural gas is on the margin most hours, while coal facilities are not.

In Washington, the emission policy only those plants identified by the Department of Ecology for the Clean Air Rule have constraints; therefore, the model may find cheaper ways to serve customers by running regulated plants only to the point of the regulation, or importing power. The prices shown are for the average price. Prices can be significantly higher, as shown in Figure 10.21 from the stochastic analysis. If hydroelectric production is low and there are few alternatives to serve load, then emissions prices could be significantly higher. Further analysis is required due to the baseline emissions were not yet available at the time of the analysis. The AURORA$^{\underline{XMP}}$ model is not able to produce prices based on a three-year compliance period; these prices assume a one-year compliance period. These prices do not represent the cost of compliance of this rule, but rather the implied cost for the electric sector to comply with the rule on a marginal basis. Non-electric participants subject to the rule could affect pricing if a future allowance market creates competition for scarce compliance options or where by building additional renewables driving down wholesale prices.

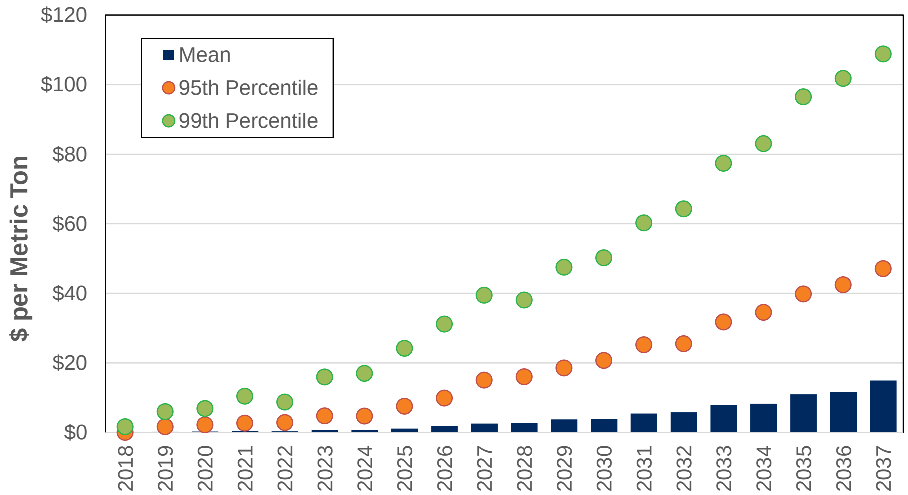
Prices in Oregon are important to Avista, as our Coyote Springs 2 is located there. At the time of the IRP analysis, Oregon had not identified a specific greenhouse gas policy. This IRP uses a 30 percent reduction goal from 2015 emissions by 2025. This amount is 10 percent lower than the Clean Power Plan new source complement mass based goal. The resulting prices of this assumption are similar to the Washington results, as the states have similar generation profiles after existing coal-fired facilities retire. In this state, the average prices increase to approximately $11 per metric ton by 2037. The resulting Montana prices are significantly higher than the coastal states, as emissions reductions must come from low marginal cost coal. The average price starts at $6.40 per metric ton in 2024 and escalates to $27 per ton in 2037.[6] Coal facilities have lower base dispatch costs and require a high price to reduce dispatch. These results illustrate the importance of policy making regarding emission reductions. For Avista, Colstrip is subject to this price adder for this analysis. This analysis illustrates how placing emission caps on individual states may drive in-state emissions lower, but will likely cause increasing imports (or decreasing exports). The analysis also shows lowering emissions from coal facilities requires higher pricing than areas with natural gas. For the northwest, a carbon pricing mechanism would be more effective and less burdensome on customers if it focused on coal rather than all resource types.

**Figure 10.20: Northwest Greenhouse Gas Emission Shadow Prices**




[6] At the 95th percentile, the 2024 price is $17 per metric ton and $60 per metric ton in 2037.

Figure 10.21: Washington Clean Air Rule Pricing




## Scenario Analysis

Scenario analysis evaluates the impact of changes in underlying market assumptions, Avista's generation portfolio, and new generation resource values. In addition to the Expected Case, this IRP includes two stochastic analyses. The first scenario is the case where Colstrip retires and the second scenario reduces dispatch at Colstrip to 50 percent of current levels. Both scenarios are required due to the nature of the portfolio studies they support (as described in Chapter 11).

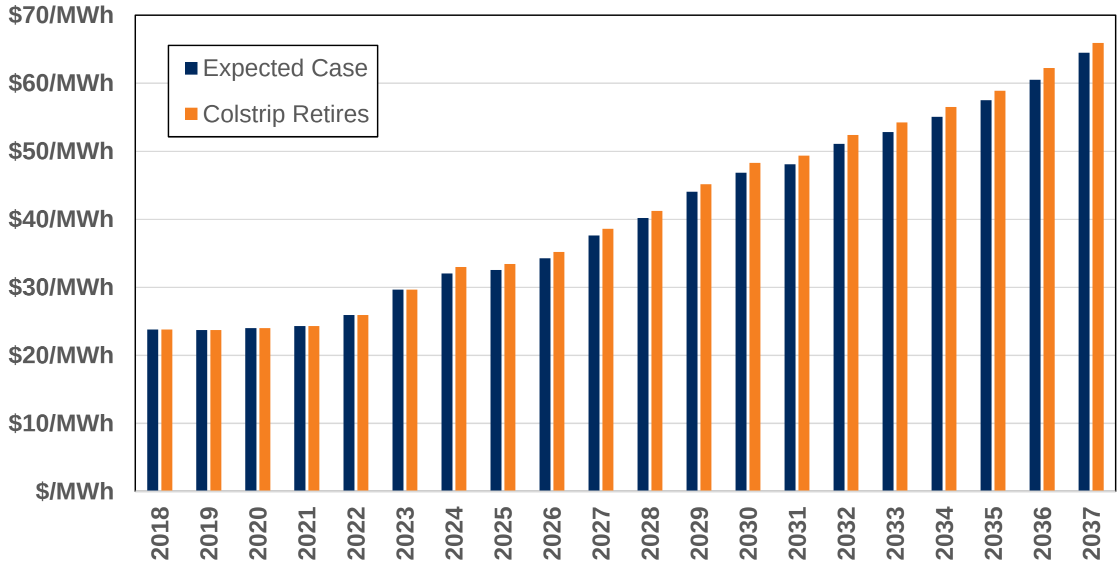
In past IRPs, several stochastic scenarios reviewed impacts on changes in environmental policy. These scenarios are important to consider for resource planning, but given uncertainty in policy, limited time for the analysis, and only minor changes from the 2015 IRP, these additional scenarios are only indicative until greenhouse gas policy becomes more certain. Therefore, most of the IRP scenarios focus on Avista's portfolio rather than the market. Per the TAC's request, a deterministic market scenario simulates how the energy market would change if total emissions decreased 50 percent by 2035. This is a market scenario only, and not part of the portfolio analysis. It is informative on the steps Avista's portfolio would need to take to achieve this goal.

### No Colstrip Scenario

The No Colstrip Scenario models the implications of retiring Colstrip Units 3 & 4 early. The scenario values new resource options and the remaining portfolio in a marketplace without Colstrip. In addition, this scenario provides data about the regional financial impacts of a Colstrip closure, rather than just the impact to Avista from divestment of its share. This scenario assumes 1,000 MW CCCT, 430 MW peakers, and 300 MW wind replace the units. It does not attempt to represent the feasibility of this assumption, but rather helps understand the impacts to the overall market place. To simulate all the portfolio scenarios implications, this market scenario assumes Colstrip retires by the end of 2023.

Without Colstrip, regional market prices increase slightly as shown in Figure 10.22. There are small differences beginning in 2024 with a $0.93 per MWh annual average price difference, overall prices are 2.7 percent higher without Colstrip. While these price changes are not large, it assumes the average price over a year in average water conditions. At times, the price impacts are much greater and without replacement capacity, price impacts and reliability concerns increase. Beginning in 2024, the annual production costs to all western customers' increases by $143 million with the closure of Colstrip, plus the capital recovery of the additional new resources to replace the capacity estimated to be $250 million (2023 dollars). Without Colstrip, greenhouse gas emissions decrease; in 2030 model emissions were 3.0 percent lower, or nearly 6 million metric tons per year, as shown in Figure 10.23.

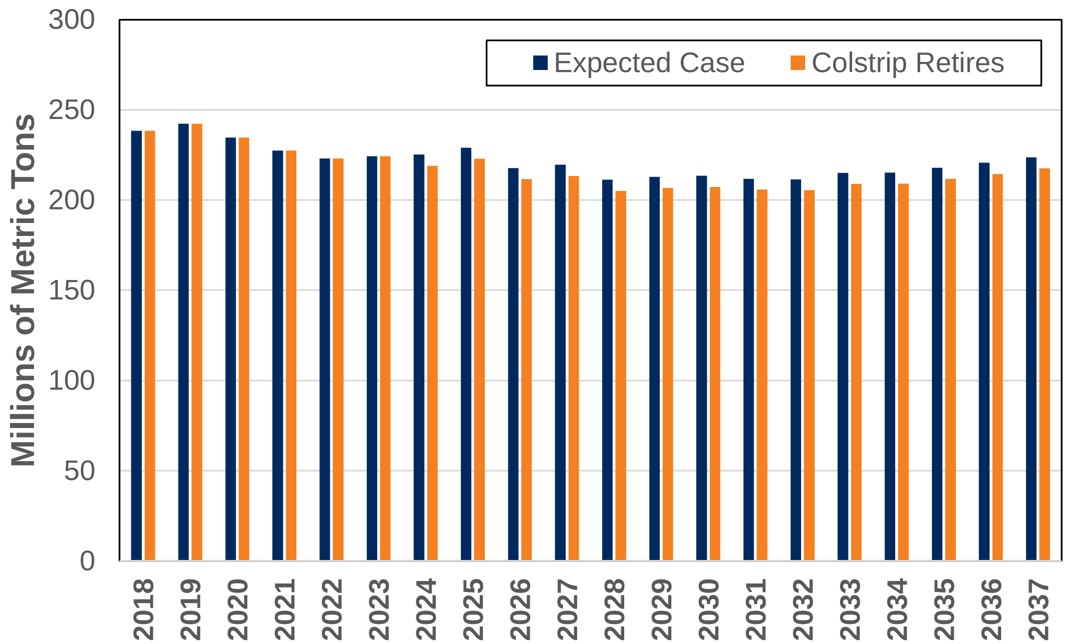
**Figure 10.22: Annual Mid-Columbia Flat Price Forecast Colstrip Retires Scenario**




## Colstrip Dispatch Reduction Scenario

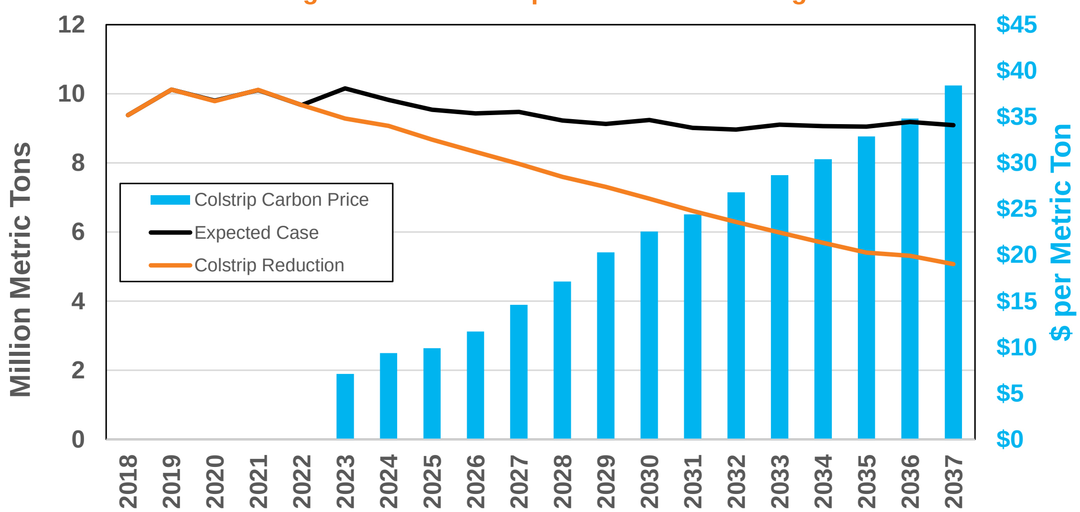
One of the methods to reduce emissions in the Northwest without closing Colstrip is to reduce its generation. This scenario shows the market implications if Colstrip dispatches less to meet policy objectives. Because the plants are not retired, the scenario does not require replacement of the generation capacity. Emissions at the plant decrease beginning in 2023 and continue until the reduction reaches 50 percent of its typical generation amount. This dispatch constraint lowers emissions and creates an emission price for the two units. Figure 10.24 provides the resulting emission prices and emission quantities. Colstrip emissions fall by up to 4 million metric tons annually by 2037. This is approximately two-thirds of the emission reduction achieved by the Colstrip retires scenarios. The emission price for this scenario starts around $7 per metric ton and escalates to $38 per metric ton by 2037. The prices shown are the mean of the 500 simulations. The 95$^{th}$ percentile price in 2037 is $75 per metric ton. Prices will vary depending on the level of hydro production among other factors such as load, wind production and natural gas prices.

Figure 10.23: No Colstrip Scenario Annual Western U.S. Greenhouse Gas Emissions




Mid-Columbia pricing in this scenario is nearly identical to the Expected Case because the marginal units driving prices do not change. With similar prices, total Western Interconnect emissions fall by one percent by 2035 or 2.3 million tons as the reduction in Colstrip operations is offset by increases in natural gas dispatch in other regions.

Figure 10.24: Colstrip Emissions & Pricing



## Western Interconnect is 50 Percent Below 1990 Greenhouse Gas Levels Scenario

In each IRP, Avista studies different fundamental shifts in the electric market to understand the impacts to the market place. Past studies included high solar penetration, the impact of electric vehicles, and high carbon prices. This IRP uses the new AURORA[XMP] constraint modeling functionality to develop a scenario that reduces Western Interconnect emissions by 50 percent compared to 1990 emission levels. Due to the uncertainty regarding regional conservation, load growth is the same as the Expected Case. This is a deterministic case similar to the Expected Case's deterministic study. This scenario does not consider variability to hydro, natural gas prices, or other inputs as described earlier in the chapter. Figure 10.25 illustrates the change in greenhouse gas emissions compared to the Expected Case. Emissions in the scenario start out lower due to changes in the new resource selection by the model because it anticipates significant future emission limits, so the model acquires renewables earlier.

Mid-Columbia prices are significantly higher in this scenario as significant emission prices drive emissions lower. Prices begin to deviate in 2029 when the price of carbon escalates at a higher rate, see Figure 10.26. Electric prices levelized for 20 years are 12 percent higher than the Expected Case, but 30 to 40 percent higher in the latter half of the study. See Figure 10.26. Carbon pricing shown below are for the entire Western Interconnect, as if the region was a cap and trade system. The levelized price for emission is $37.54 per metric ton between 2025 and 2037.

This aggressive reduction goal requires new renewables and more natural gas-fired generation. Figure 10.27 illustrates the change in production in 2037 between this scenario and the Expected Case. Natural gas generation increases 20 percent, solar 40 percent, and coal reduces 86 percent. Wind generation remains flat, as solar is a lower cost alternative with fewer limitations. New investment in renewables drives total annual cost to the system $15.3 billion higher than the Expected Case in the last 10 years of the study.

Figure 10.25: Greenhouse Gas Reduction

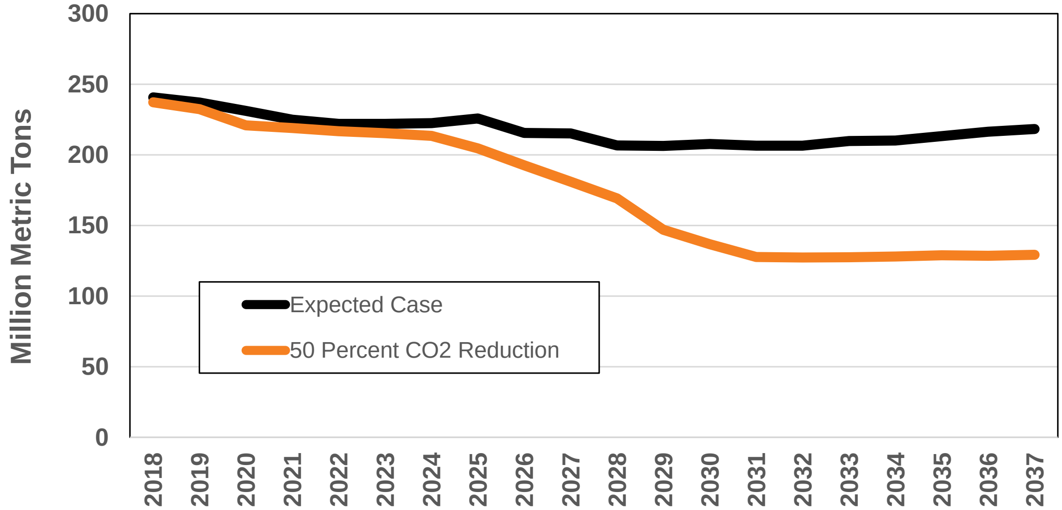



Figure 10.26: Mid-Columbia Electric Price Comparison

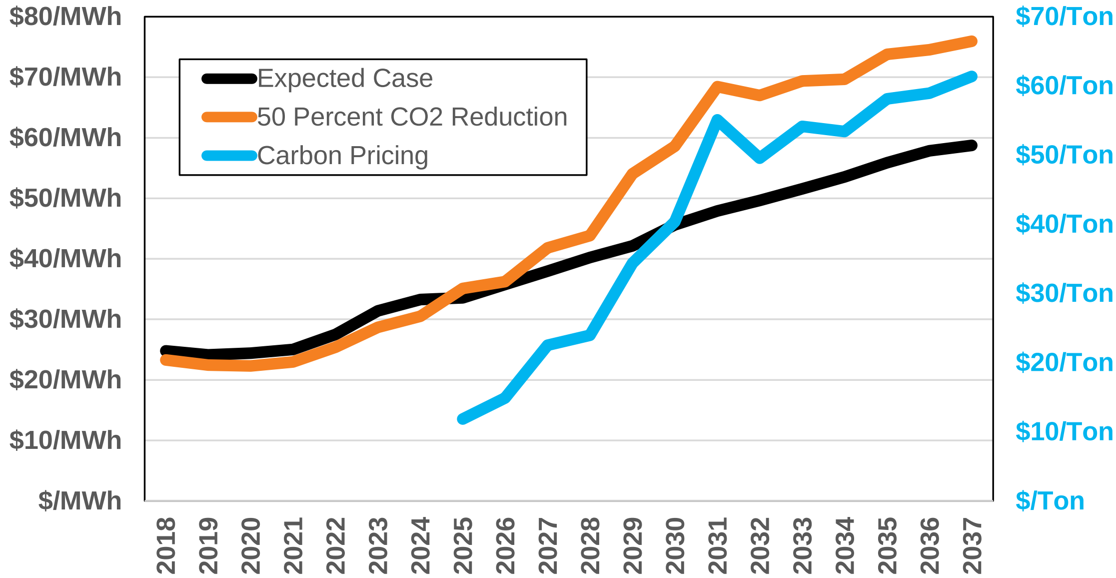
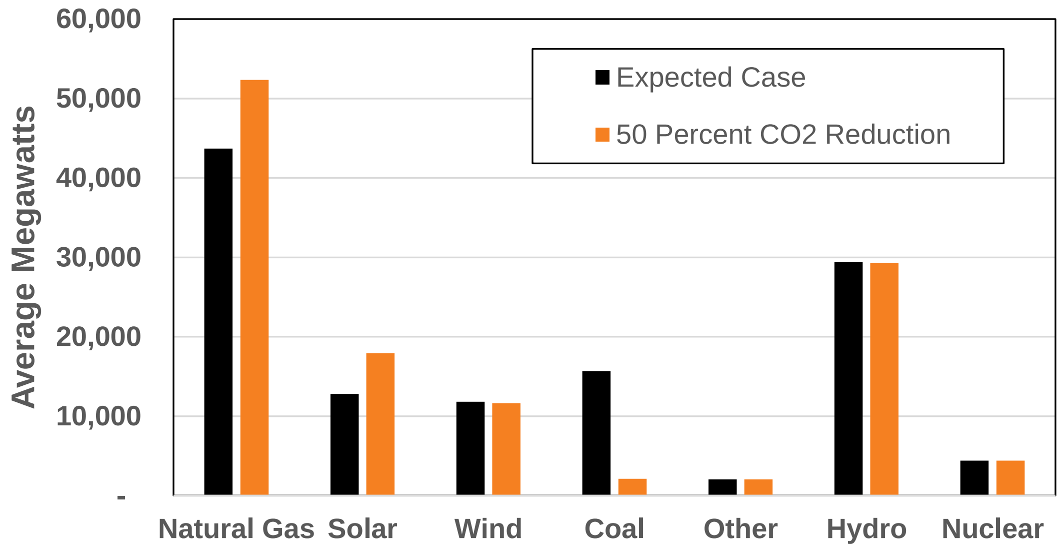


**Figure 10.27: 2037 Generation Mix Comparison**



# 11. Preferred Resource Strategy

## Introduction

This chapter describes potential costs and financial risks of Avista's new resource and conservation strategy to meet future requirements over the next 20 years. It explains the decision making process used to select the Preferred Resource Strategy (PRS), and the resulting avoided costs used to set targets for future conservation acquisitions and new resource alternatives.

The 2017 PRS describes a reasonable low-cost plan along the Efficient Frontier of potential resource portfolios accounting for fuel supply, regulatory and price risks. Major changes from the 2015 IRP include less energy efficiency (due to lower projected loads), the addition of demand response and storage resources, less natural gas-fired peaking capacity, and replacing the planned 2026 CCCT with natural gas-fired peakers.

Demand response returns to the PRS, as program options are more competitive compared to building new resources. Storage appears for the first time in the plan as projected costs decline and its modular sizing fits Avista's small load growth needs. Avista is also in the process of acquiring a 15 MW DC solar facility to sell to subscribing commercial and industrial customers of the Solar Select program (see Chapter 4 for further information). Due to a recent contract extension, Avista's first resource deficit is in the winter of 2026 after the expiration of the Lancaster PPA.

Avista will meet the Washington Energy Independence Act with current resources through the duration of the plan and Avista anticipates reduction in greenhouse gas emissions at its owned facilities given current policy direction at the state level.

**Section Highlights**

- Avista is acquiring a utility-scale solar facility for commercial and industrial customers voluntarily choosing solar for their power supply mix.
- The first anticipated resource acquisition is a demand response program beginning in 2025.
- Upgrades to existing thermal facilities begin prior to the 2026 deficit.
- Replacement of the Lancaster Facility with new natural gas peakers occurs in 2026 at the end of the power purchase agreement.
- Energy efficiency offsets 53.3 percent of projected load growth through the 20-year IRP timeframe.

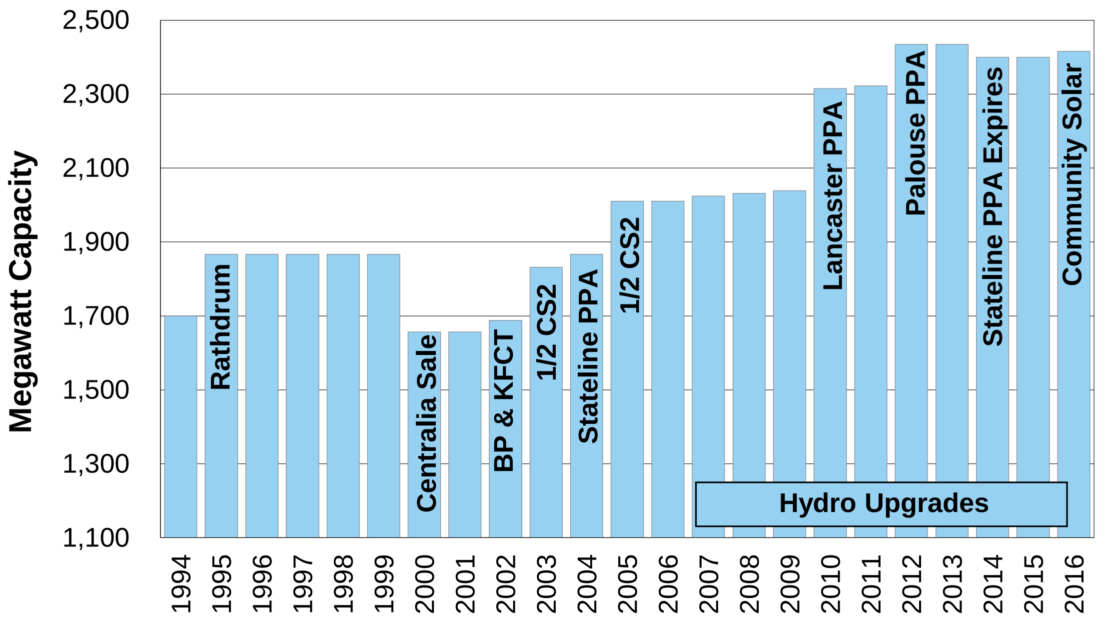
## Supply-Side Resource Acquisitions

As shown in Figure 11.1, Avista has made several generation acquisitions and upgrades over the last 15 years, including:

- 25 MW Boulder Park natural gas-fired reciprocating engines (2002);
- 7 MW Kettle Falls natural gas-fired CT (2002);

- 35 MW power purchase agreement with the Stateline Wind Project (2004 – 2014);
- 72 MW (total) hydroelectric upgrades (2007 – 2016);
- 270 MW natural gas-fired Lancaster Generation Station tolling agreement (2010 – 2026);
- 105 MW Palouse Wind power purchase agreement (2012 – 2042); and
- 423 kW Boulder Park Community Solar (2015)

**Figure 11.1: Resource Acquisition History**




## Resource Deficiencies

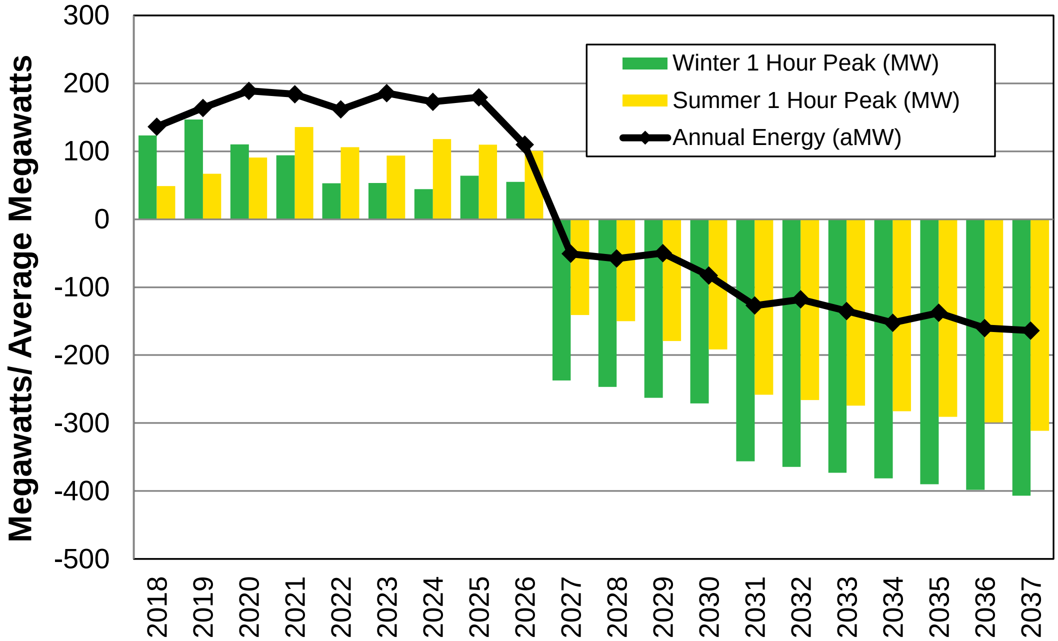
Avista uses both single-hour and 18-hour peak events (six hours per day spread over three consecutive days) to measure its projected resource adequacy. The single-hour event assures the system has enough machine capacity to meet an extreme load and/or outage event. The 18-hour methodology assures energy-limited hydroelectric resources can meet multiday extreme weather events. For this plan, both summer and winter deficits are slightly higher for the single-hour event than the 18-hour event.

Avista's peak planning methodology includes operating reserves, regulation, load following, variable generation (solar and wind) integration, and a planning margin. Avista currently projects having adequate resources between owned and controlled generation to meet physical energy and capacity needs until the end of 2026 when the Lancaster power purchase agreement expires.[1] See Figure 11.2 for Avista's physical resource positions for annual energy, summer capacity, and winter capacity. This figure accounts

[1] Chapter 6 – Long-Term Position contains details about Avista's peak planning methodology.

for the effects of energy efficiency programs on the load forecast. Absent energy efficiency, Avista would be deficient earlier.

Figure 11.2: Physical Resource Positions (Includes Energy Efficiency)




## Renewable Portfolio Standards

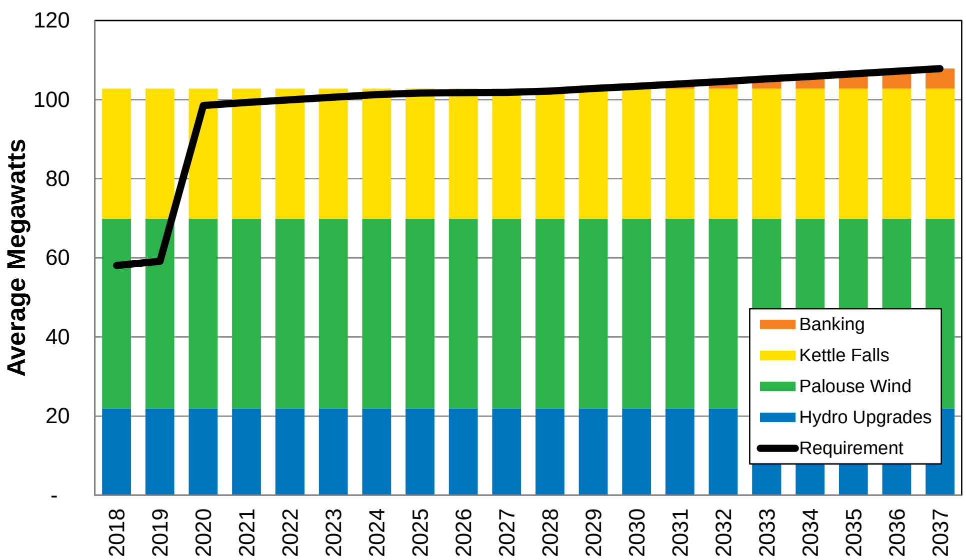
The Washington Energy Independence Act (EIA) requires utilities with over 25,000 customers to meet 9 percent of current retail load from qualified renewable resources and 15 percent by 2020. The initiative also requires utilities to acquire all cost-effective energy efficiency.

Avista expects to meet or exceed its EIA renewable energy requirements through the 20-year plan with a combination of qualifying hydroelectric upgrades, the Palouse Wind project, and the Kettle Falls Generating Station. Table 11.1 provides a list of the qualifying generation projects and associated generation and qualifying renewable energy credits (RECs). Figure 11.3 shows the REC position forecast. The flexibility within the EIA to use RECs from the current year, from the previous year, or from the following year for compliance, mitigates year-to-year variability in the output of qualifying renewable resources.

**Table 11.1: Qualifying Washington EIA Resources[2]**

| Resource | Resource Type | On-line Year | Nameplate Capacity | Expected MWh | Expected RECs |
|---|---|---|---|---|---|
| Kettle Falls GS | Biomass | 1983 | 47 | 374,824 | 355,607 |
| Long Lake 3 | Hydro | 1999 | 4.5 | 14,197 | 14,197 |
| Little Falls 4 | Hydro | 2001 | 4.5 | 4,862 | 4,862 |
| Cabinet Gorge 3 | Hydro | 2001 | 17 | 45,808 | 45,808 |
| Cabinet Gorge 2 | Hydro | 2004 | 17 | 29,008 | 29,008 |
| Cabinet Gorge 4 | Hydro | 2007 | 9 | 20,517 | 20,517 |
| Wanapum | Hydro | 2008 | 0 | 22,206 | 0 |
| Noxon Rapids 1 | Hydro | 2009 | 7 | 21,435 | 21,435 |
| Noxon Rapids 2 | Hydro | 2010 | 7 | 7,709 | 7,709 |
| Noxon Rapids 3 | Hydro | 2011 | 7 | 14,529 | 14,529 |
| Noxon Rapids 4 | Hydro | 2012 | 7 | 12,024 | 12,024 |
| Palouse Wind | Wind | 2012 | 105 | 349,726 | 419,671 |
| Nine Mile 1 & 2 | Hydro | 2016 | 4 | 21,950 | 21,950 |
| **Total** | | | **236** | **938,795** | **967,317** |

**Figure 11.3: REC Requirements versus Qualifying RECs for EIA**




[2] The forecasted REC's shown are based on project capability and may differ from the EIA report due to the EIA report may include economic dispatch. Palouse Wind receives a 20 percent bonus apprenticeship credit increasing the number of RECs. Wanapum has no qualifying RECs until the projects uses WREGIS.

## Resource Selection Process

Avista uses several decision support systems to develop its resource strategy, including AURORA$^{\underline{XMP}}$ and Avista's PRiSM model. The AURORA$^{\underline{XMP}}$ model, discussed in detail in the Market Analysis chapter, calculates the operating margin (value) of every resource option considered in each of the 500 Monte Carlo simulations of the Expected Case, as well as Avista's existing generation portfolio. The PRiSM model helps make resource decisions. Its objective is to meet resource deficits while accounting for overall cost, risk, capacity, energy, renewable energy requirements, and other constraints.

PRiSM evaluates resource values by combining operating margins with capital and fixed operating costs. The model creates an Efficient Frontier of resources, or least-cost portfolios, given a certain level of risk and constraints. Avista's management selects a resource strategy using this Efficient Frontier to meet all capacity, energy, renewable energy, and other requirements.

## PRiSM

Avista staff developed the first version of PRiSM in 2002 to support resource decision making in the 2003 IRP. Enhancements over the years have improved the model. PRiSM uses a mixed integer programming routine to support complex decision making with multiple objectives. These tools provide optimal values for variables, given system constraints.

## PRiSM Model Overview

The PRiSM model requires a number of inputs:

1. Expected future deficiencies
    - Greater of summer 1- or 18-hour capacity
    - Greater of winter 1- or 18-hour capacity
    - Annual energy
    - EIA requirements
2. Costs to serve future retail loads as if served by the wholesale marketplace
3. Existing resource and conservation contributions
    - Operating margins
    - Fixed operating costs
4. Resource and conservation options
    - Fixed operating costs
    - Return on capital
    - Interest expense
    - Taxes
    - Generation levels
    - Emission levels
5. Constraints
    - Must meet energy, capacity and RPS shortfalls without market reliance
    - Resources quantities available to meet future deficits

PRiSM uses these inputs to develop an optimal resource mix over time at varying levels of risk. PRiSM considers new resource costs over the next 50 years to consider long-term resource implications, but it weights the first 25 years more than the later years to highlight the importance of nearer-term decisions. Equation 11.1 shows a simplified view of the PRiSM linear programming objective function.

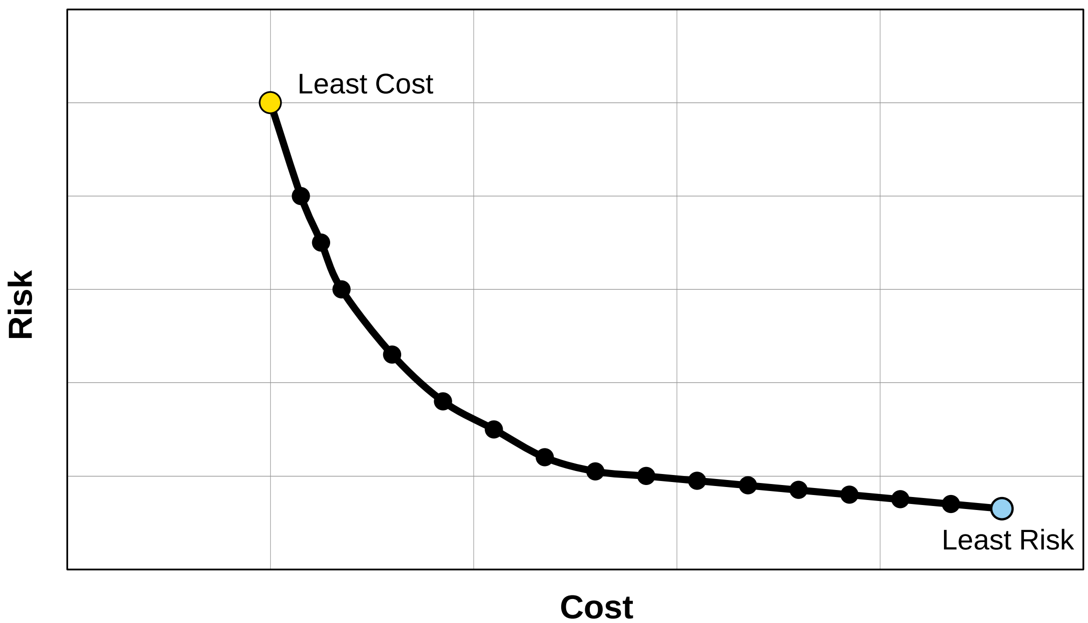
**Equation 11.1: PRiSM Objective Function**

**Minimize:** $(X_1 * NPV_{2018\text{-}2042}) + (X_2 * NPV_{2018\text{-}2067})$

**Where:** $X_1$ = Weight of net costs over the first 25 years (95 percent)
$X_2$ = Weight of net costs over the next 50 years (5 percent)
NPV is the net present value of total system cost.[3]

An efficient frontier captures the optimal resource mix graphically given varying levels of cost and risk. Figure 11.4 illustrates the efficient frontier concept.

**Figure 11.4: Conceptual Efficient Frontier Curve**




As you attempt to lower risk, costs increase. The optimal point on the Efficient Frontier depends on the level of acceptable risk. No best point on the curve exists, but Avista prefers points where small incremental cost additions offer larger risk reductions. Portfolios to the left of the curve are more desirable, but do not meet the planning requirements or resource constraints. Examples of these constraints include environmental costs, regulation, and the availability of commercially viable technologies. Portfolios to the right of the curve are less efficient as they have higher costs than a

[3] Total system cost is the existing resource marginal costs, all future resource fixed and variable costs, and all future energy efficiency costs, and the net short-term market sales/purchases.

portfolio with the same level of risk. PRiSM meets all deficit projections with new resources of the actual sizes available in the marketplace and does not use market purchases. As discussed earlier in this chapter, reflecting real-world constraints in the model is necessary to create a realistic representation of the future. Some constraints are physical and others are policy driven. The major resource constraints are capacity and energy needs, the EIA, and the greenhouse gas emissions performance standard.

## Preferred Resource Strategy

The 2017 PRS consists of existing thermal resource upgrades, energy efficiency, demand response, storage and natural gas-fired peakers (See Table 11.2 and Figure 11.5). The 15 MW (DC) solar facility for Avista's new voluntary Solar Select Program is also included in the resource plan[4]. Prior to the first capacity and energy need in 2026, the PRS shows Avista beginning two demand response programs to reduce loads at system peak. Both Solar Select and the DR programs will require commercial and industrial cooperation, regulatory approvals, permitting, and starting the program early to ensure enough participants are available when our deficit requires it.

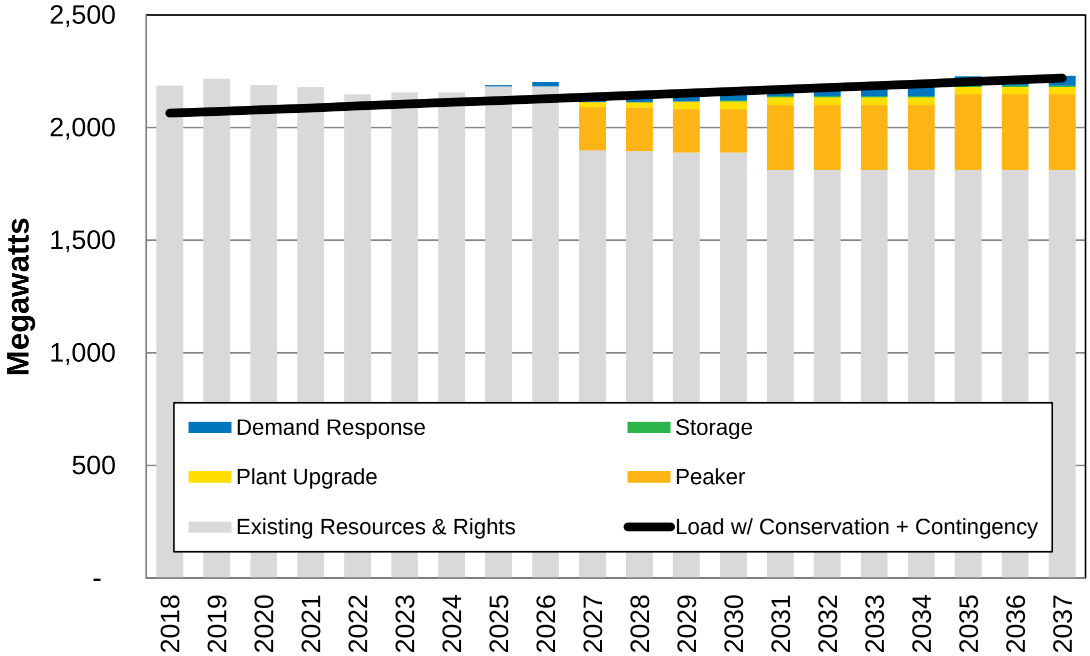
Additional thermal based resources meet the first large deficit created by the expiration of the Lancaster PPA. It is possible this resource could be re-acquired, or an alternative market resource may be available at a lower cost. Without an acquisition, the first new resource is a 192 MW of natural gas-fired peakers and upgrades at existing thermal facilities. Given the small cost differences between the evaluated natural gas-fired peaker technologies, the future technology decision likely will be refined in a Request for Proposals (RFP) process. Technological changes in efficiency and flexibility may lead Avista to revisit this resource choice closer to the actual need.

**Table 11.2: 2017 Preferred Resource Strategy**

| Resource | By the End of Year | ISO Conditions (MW) | Winter Peak (MW) | Energy (aMW) |
|---|---|---|---|---|
| Solar (Solar Select Program) | 2018 | 15 | 0 | 3 |
| Natural Gas Peaker | 2026 | 192 | 204 | 178 |
| Thermal Upgrades | 2026-2029 | 34 | 34 | 31 |
| Storage | 2029 | 5 | 5 | -0 |
| Natural Gas Peaker | 2030 | 96 | 102 | 89 |
| Natural Gas Peaker | 2034 | 47 | 47 | 43 |
| **Total** | | **389** | **392** | **344** |
| **Efficiency Improvements** | **Acquisition Range** | | **Winter Peak Reduction (MW)** | **Energy (aMW)** |
| Energy Efficiency | 2018-2037 | | 203 | 108 |
| Demand Response | 2025-2037 | | 44 | <0 |
| Distribution Efficiencies | | | <1 | <1 |
| **Total** | | | **247** | **108** |

[4] The size of the Solar Select facility may change from the RFP amount if program participation exceeds the initial 15 MW program.

**Figure 11.5: New Resources to Meet Winter Peak Loads**




After a combination of upgrades to existing thermal facilities, new peakers, and demand response, Avista's customers still will require additional capacity as loads grow and contracts expire. The next acquisition is a storage resource. The selected storage unit has a five-megawatt capacity rating, and 15 megawatt-hours of storage. Following the storage resource addition, a significant wholesale power contract expires at the end of 2030. To fill this gap, PRiSM selects a 96 MW natural gas fired peaker unless renewing the contract under favorable terms benefits customers. The last selected resource of the 20-year plan is a 47 MW natural gas-fired peaker by the end of 2034.

## 2015 IRP Comparison

The 2017 PRS differs from the 2015 PRS shown in Table 11.3. Lower load growth and contract changes push resource needs out to 2026 rather than by the end of 2020. New resource needs are 191 MW lower due to lower load growth, higher expected conservation at the time of system peak, and the addition of new demand response and storage programs. These factors further reduce the need for new fossil fuel resources. The 2015 PRS combined cycle plant is now too large relative to the projected need for replacing Lancaster with a new facility. Further, market conditions are changing due the amount of new renewable resources in the west, favoring flexible peaking resources over historically intermediate and baseload resources. Avista preformed a scenario, discussed in Chapter 12, showing if Avista continued assuming replacing Lancaster with a new CCCT plant to see the cost and risk impact to the portfolio.

**Table 11.3: 2015 Preferred Resource Strategy**

| Resource | By the End of Year | ISO Conditions (MW) | Winter Peak (MW) | Energy (aMW) |
|---|---|---|---|---|
| Natural Gas Peaker | 2020 | 96 | 102 | 89 |
| Thermal Upgrades | 2021-2025 | 38 | 38 | 35 |
| Combined Cycle CT | 2026 | 286 | 306 | 265 |
| Natural Gas Peaker | 2027 | 96 | 102 | 89 |
| Thermal Upgrades | 2033 | 3 | 3 | 3 |
| Natural Gas Peaker | 2034 | 47 | 47 | 43 |
| **Total** | | **565** | **597** | **524** |
| **Efficiency Improvements** | **Acquisition Range** | | **Winter Peak Reduction (MW)** | **Energy (aMW)** |
| Energy Efficiency[5] | 2016-2035 | | 193 | 132 |
| Distribution Efficiencies | | | <1 | <1 |
| **Total** | | | **193** | **132** |

## Energy Efficiency

Energy efficiency is an integral part of the PRS. It also is a critical component of the EIA requirement for utilities to obtain all cost-effective conservation. PRiSM considers energy efficiency and supply side options at the same time to ensure compliance with the EIA. PRiSM models each specific energy efficiency measure individually and does not bundle measures. This allows the selection of different conservation amounts at each point along the Efficient Frontier to capture changes in the risk profiles of additional conservation. This capability improves previous IRP evaluations assuming a constant conservation acquisition level along the entire curve.

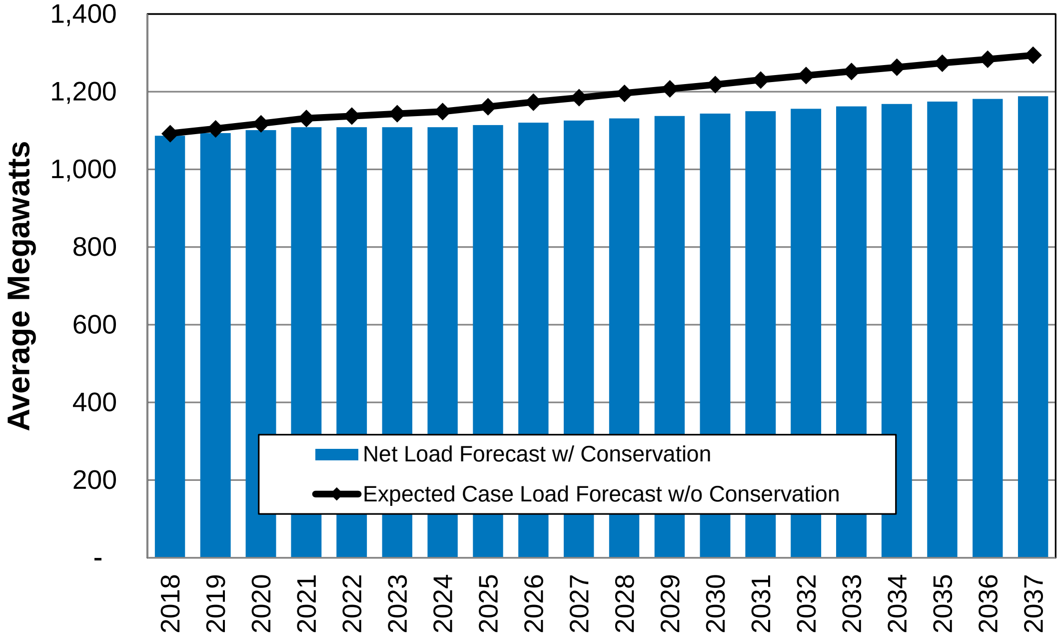
Conservation options inclusion within PRiSM requires a load forecast without future conservation. Due to industry-standard load forecasting methods, Avista’s load forecast is the load expectation net of future energy efficiency. Estimating the amount of conservation included in the forecast requires evaluating its economic potential. This requires an iterative process with PRiSM to validate if selected conservation is similar to the assumed conservation level in the load forecast. For example, if PRiSM selects less conservation than originally estimated, it runs again with a lower amount of conservation until the predetermined conservation is similar to the selected conservation on an annual energy basis. For this IRP, selected conservation is very similar to the levels in the forecast. The difference is three percent higher in the first 10 years, and two percent higher over 20 years, or 1.9 aMW.

Figure 11.6 illustrates the load forecast with and without conservation. The selected 108 aMW of savings represents 53.3 percent of expected load growth between 2018 and 2037. Please refer to Chapter 5 for a detailed discussion of energy efficiency resources.

[5] Total energy efficiency estimates include savings from transmission and distribution system losses.

Because portfolio analysis described in this chapter considers the impacts of transmission and distribution losses, savings in Chapter 5 are lower than shown here.

Figure 11.6: Load Forecast with and without Energy Efficiency




## Grid Modernization

Distribution feeder upgrades entered the PRS in the 2009 IRP and the grid modernization process began with the Ninth and Central feeder in Spokane. The decision to rebuild a feeder considers savings from reducing energy losses, operation and maintenance savings, the age of installed equipment, reliability indices, and the number of customers on the feeder. System reliability, instead of energy savings, generally drives feeder rebuild decisions. Therefore, feeder upgrades are no longer included as a resource option in PRiSM. A broader discussion of Avista's feeder rebuild program is in Chapter 8.

## Natural Gas-Fired Peakers

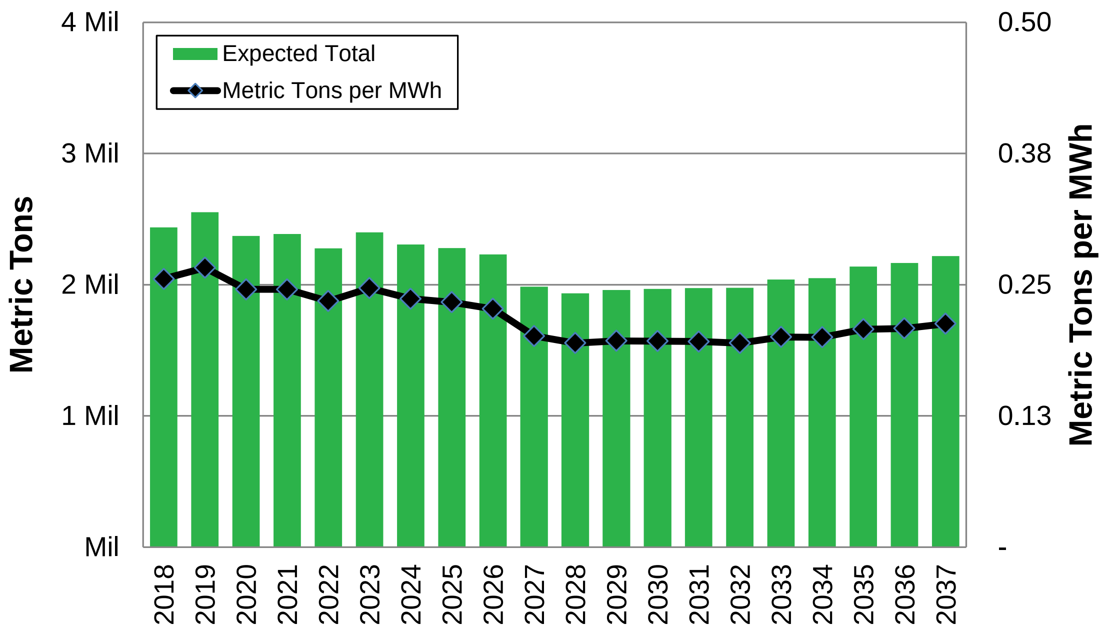
Avista plans to locate potential sites for new natural gas-fired generation capacity within its service territory ahead of an anticipated need. The option of having a utility-owned site is very low cost relative to the final acquisition cost of a natural gas-fired plant, and this strategy ensures customers will not pay a premium over the actual cost of building a new asset. A 2013 Action Item was to identify a utility-build natural gas resource site. Since then, Avista procured land in North Idaho in the event a greenfield site benefits customers. A second option for a smaller resource need is possible at the Rathdrum CT site.

Avista is not specifying a preferred peaking plant technology at this time. Tradeoffs will occur between capital costs, size, operating efficiency, and flexibility. Relative to other natural gas-fired peaking facilities, frame CT machines are a lower capital-cost option, but have higher operating costs and less flexibility, while the hybrid technology and aero turbines have higher capital costs, lower operating costs, and more operational flexibility. Advances in natural gas-fired reciprocating engines are also of interest. These resources utilize a group of smaller units to reduce the risk of a larger single plant breaking down, have lower heat rates, and are highly flexible, but can be more capital and O&M intensive than other technologies. Increased flexibility requirements and greenhouse gas emissions costs could make a hybrid plant or reciprocating engines preferable. Avista currently has enough resource flexibility to meet customer needs to drive the strategy towards a lower cost peaker option, but potential future participation in an energy imbalance markets may provide enough revenues for a flexible peaker to offset the higher costs. It is also possible other resource options such as CCCT, storage, or hydro could cost effectively compete against new peakers when procuring the new resource.

## Greenhouse Gas Emissions

Chapter 10 – Market Analysis, discusses how greenhouse gas emissions decrease due to coal plant retirements across the Western Interconnect. Avista's projected resource mix does not include any retirements. The only significant carbon emitting resource leaving the portfolio is the expiration of the Lancaster PPA in 2026. Figure 11.7 presents Avista's expected greenhouse gas emissions (excluding Kettle Falls GS) with the addition of 2017 PRS resources. The estimates in Figure 11.7 do not include emissions from purchased power or adjustments to reduce emissions for off-system sales. Emissions in 2037 are 11 percent lower than the 2018/19 average emissions and 18 percent lower on a per MWh basis. Emissions are 29 percent lower as compared to the 2015 IRP's estimate for 2035. The emissions reduction comes from adding natural gas-fired peaking units instead of building a new CCCT facility, and a reduction in the dispatch at Colstrip 3 & 4 due to modeled emission regulations.

**Figure 11.7: Avista Owned and Controlled Resource's Greenhouse Gas Emissions**



## Capital Spending Requirements

The IRP assumes Avista will finance and own all new resources for IRP planning purposes.[6] A competitive acquisition processes may hold different result, but under this assumption, and the resources identified in the 2017 PRS, the first capital addition to rate base is in 2025 as capital improvements are required for the stand-by generation DR program. In 2027, significant investment will be required for the first natural gas-fired peaker as a replacement for the Lancaster PPA. If a new facility replaces Lancaster, construction would begin prior to need, but the resource's capital cost would not enter rate base until after it is placed in service. The capital cash flows in Table 11.4 include AFUDC, generation capital costs, and transmission investments for generation, tax incentives, and sales taxes. Over the 20-year IRP timeframe, $538 million (nominal) in generation and related transmission expenditure is required to support the PRS.

**Table 11.4: PRS Rate Base Additions from Capital Expenditures (Millions of Dollars)**

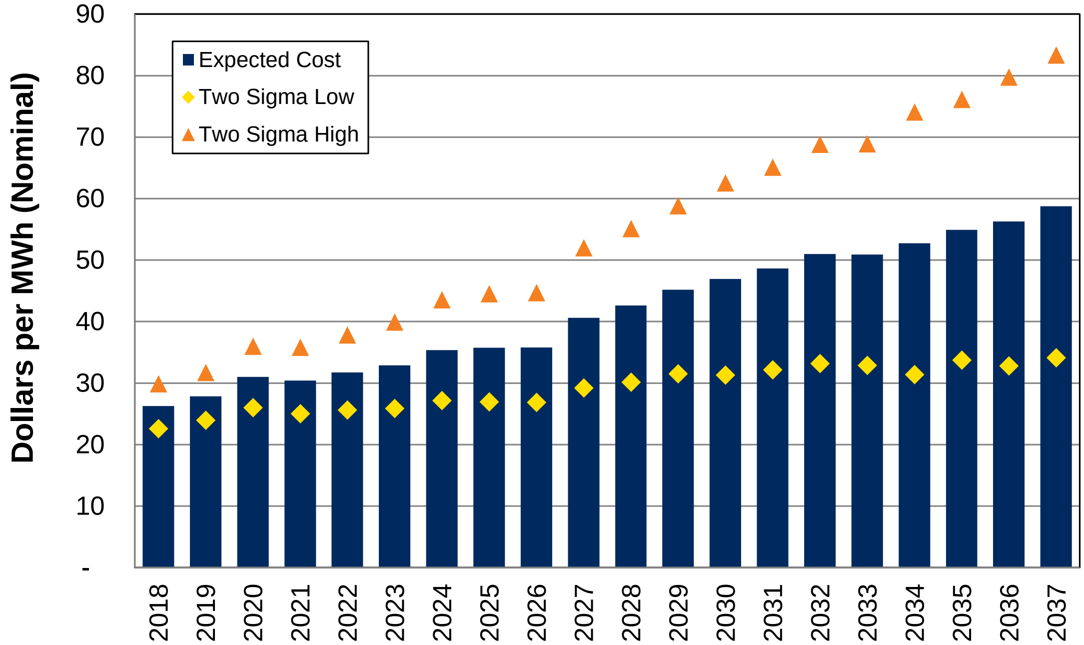
| Year | Investment | Year | Investment |
|---|---|---|---|
| 2018 | 0.0 | 2028 | 2.1 |
| 2019 | 0.0 | 2029 | 9.5 |
| 2020 | 0.0 | 2030 | 9.9 |
| 2021 | 0.0 | 2031 | 140.1 |
| 2022 | 0.0 | 2032 | 0.5 |
| 2023 | 0.0 | 2033 | 0.5 |
| 2024 | 0.0 | 2034 | 0.5 |
| 2025 | 2.3 | 2035 | 94.1 |
| 2026 | 2.0 | 2036 | 0.5 |
| 2027 | 275.7 | 2037 | 0.5 |
| **2018-27 Total** | **280.0** | **2028-37 Totals** | **258.2** |

## Annual Power Supply Expenses and Volatility

PRS variance analysis tracks fuel, variable O&M, emissions, and market transaction costs for the existing resource portfolio for each of the 500 Monte Carlo iterations of the Expected Case risk analysis. In addition to existing portfolio costs, new resource capital, fuel, O&M, emissions, and other costs provide a range of expected costs to serve future loads. Figure 11.8 shows expected PRS costs through 2037 as the blue bars. In 2018, portfolio costs average $26 per MWh. By 2037, costs approach $60 per MWh. The chart shows a two-sigma cost range with yellow diamonds representing the lower range and orange triangles representing the upper range. The main drivers increasing power supply costs and volatility are natural gas prices and weather, which affect both hydroelectric generation and load variability. Avista increases the volatility assumption of future natural gas prices because the commodity price has unknown future risks and a history of volatility.

[6] Except for resources taking advantage of the ITC, such as solar.

Figure 11.8: Projected Power Supply Expense Range




## Efficient Frontier Analysis

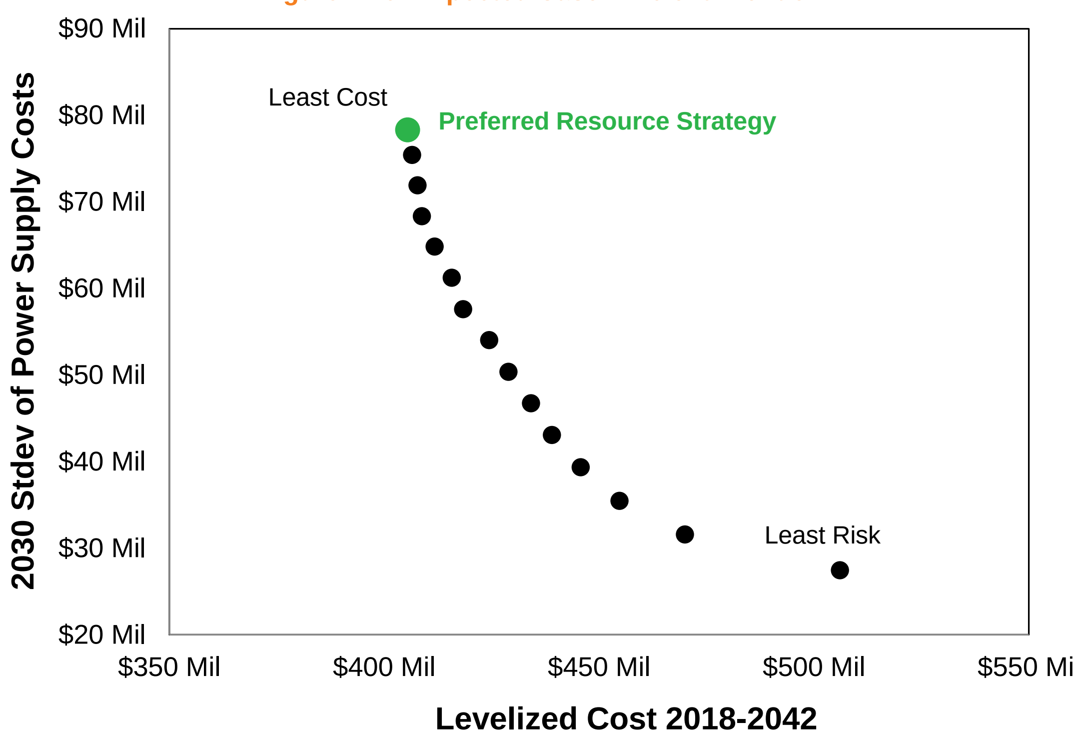
The Efficient Frontier analysis is the backbone of the PRS. The PRiSM model develops the efficient frontier by simulating the costs and risks of resource portfolios using a mixed-integer linear program. PRiSM finds an optimized least cost portfolio for a range of risk levels. The PRS analyses examined the following portfolios.

- **Least Cost**: Meets all capacity, energy and RPS requirements with the least-cost resource options. This portfolio ignores power supply expense volatility in favor of lowest-cost resources.
- **Least Risk**: Meets all capacity, energy, and RPS requirements with the least-risk mix of resources. This portfolio ignores the overall cost of the selected portfolio in favor of minimizing year-on-year portfolio cost variability.
- **Efficient Frontier:** Meets all capacity, energy, and RPS requirements with sets of intermediate portfolios between the least risk and least cost options. Given the resource assumptions, no resource portfolio can be at a better cost and risk combination than these portfolios.
- **Preferred Resource Strategy**: Meets all capacity, energy, and RPS requirements while recognizing both the overall cost and risk inherent in the portfolio. Avista's management chose this portfolio as the most reasonable strategy given current information.

Figure 11.9 presents the Efficient Frontier in the Expected Case. The x-axis is the levelized nominal cost per year for the power supply portfolio, including capital recovery, operating costs, and fuel expense; the y-axis displays standard deviation of power supply costs in 2030. It is necessary to move far enough into the future so load growth provides PRiSM the opportunity to make new resource decisions. The year 2030 is far enough into the future to account for the risk tradeoffs of several resource decisions. Using an earlier year to measure risk would have too few new resource decisions available to distinguish between portfolios.

Avista chose to use the least cost portfolio for this IRP. Past IRPs selected a portfolio with lower risk, but slightly higher cost. The main difference between this plan and prior plans is first the choice to replace Lancaster after the expiration of the PPA with peaking plants. Avista chose to move away from a baseload resource due to the lower capacity requirements upon its expiration. With the lower capacity requirement, adding a CCCT (without a partner) would increase customer's costs until the company could grow into the excess capacity. The second reason for the change is to take advantage of a low electric market price forecast by selecting natural gas-fired peakers and demand response. Avista's resource strategy meets reliability requirements and selects new resources to meet rapid changes in daily price volatility due to renewable resources in the region. If Avista maintains its strategy to replace Lancaster with a new CCCT, the costs would be 0.8 percent higher (PVRR) and the risk in 2030 would increase by 10 percent. While this scenario is similar to the portfolios on the Efficient Frontier analysis, there are other more optimal portfolios with similar risk, but at lower cost. More information regarding this scenario is in Chapter 12.

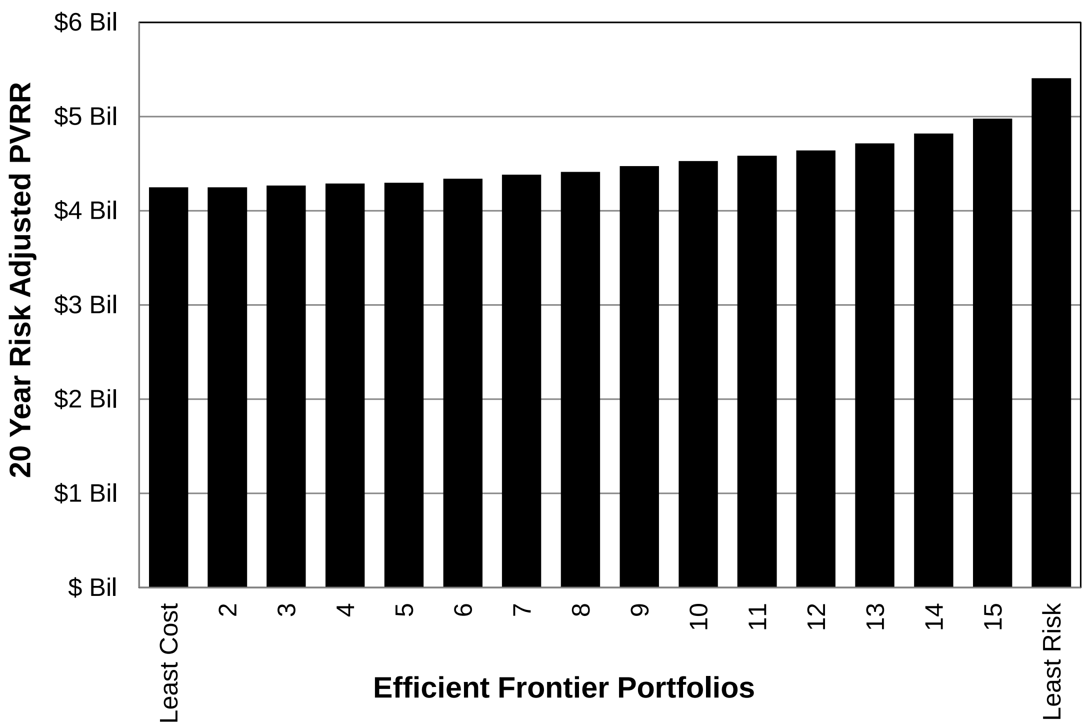
**Figure 11.9: Expected Case Efficient Frontier**



Selecting the appropriate point on the Efficient Frontier is not solvable through a mathematical formula. Portfolio selection along the Efficient Frontier is from a determination of management's judgment of cost versus risk. In prior IRPs, management selected lower heat rate facilities to protect the portfolio from wholesale market volatility by moving down the frontier curve. In this IRP, management is pursuing a modestly higher risk strategy by selecting peakers over CCCTs. Given the uncertainties in the marketplace today, including carbon mitigation policies, this choice gives more flexibility. Since our resource need is nine years away, multiple IRP's will be able to change course if needed when more information becomes available.

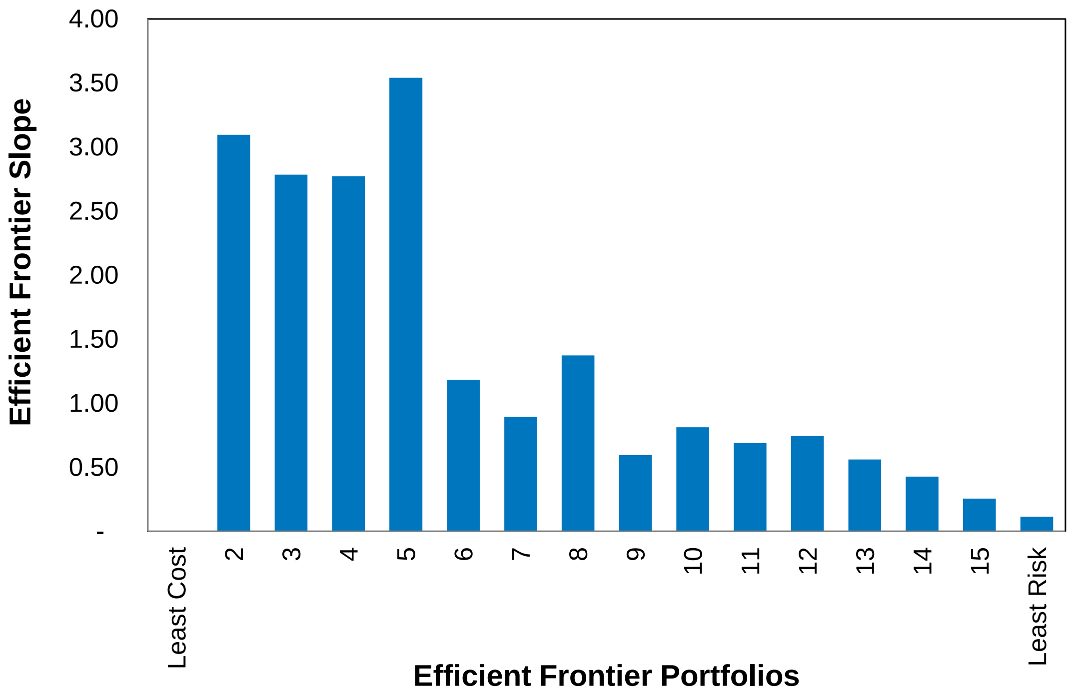
The 2015 IRP presented a method for reviewing portfolios along the Efficient Frontier as part of a request by the Washington Commission Staff. This method is a risk adjusted Present Value of Revenue Requirement, or PVRR, taking into account the tail risk. The first step calculates risk adjusted PVRR for each portfolio. This calculation is the net present value (NPV) of the future revenue requirements, plus the present value of taking each of the future year's tail risk, calculated by five percent of the 95$^{th}$ percentile's increase in costs. This methodology assumes the lowest NPV should yield the best strategy. Figure 11.10 shows the results of this study on the Efficient Frontier. The first two portfolios are the least cost adjusted for this risk calculation. The second portfolio is 0.003 percent lower cost than the PRS (Least Cost scenario), meaning the portfolios are essentially identical. The only difference is the resources selected are after 2035.

**Figure 11.10: Risk Adjusted PVRR of Efficient Frontier Portfolios**



To illustrate tradeoffs between the cost and risk of each portfolio along the Efficient Frontier, a point-to-point derivative of the slope of the change in cost relative to the change in absolute costs is useful. In this case, a greater slope indicates increasing benefits for trading risk reduction for higher portfolio costs. Figure 11.11 illustrates the results of this study. The PRS selected by PRiSM is the least cost portfolio, but moving down the frontier does provide good risk versus cost tradeoffs, as the slope of the Efficient Frontier is steeper until the sixth portfolio. As time passes, Avista may choose to move further down the Efficient Frontier given Avista's first resource need is not eminent.

**Figure 11.11: Risk Adjusted PVRR of Efficient Frontier Portfolios**




### Other Efficient Frontier Portfolios

In addition to the PRS, the Efficient Frontier contains 15 additional resource portfolios. The lower cost and higher risk portfolios contain primarily natural gas peakers and renewable resources to reduce risk. The amount of conservation varies in these portfolios as it lowers risk and fills deficiencies depending on the resources selected. For example, the model must select a resource size actually available in the marketplace. Given this "lumpiness", it may be more efficient to meet some needs with conservation rather than building a much larger generation asset. This discussion continues in Chapter 12 – Portfolio Scenarios.

Table 11.5 details the selected resource totals between 2018 and 2037 for each Efficient Frontier portfolio. Toward the middle of the Efficient Frontier, PRiSM favors wind and solar to reduce market risk as additional conservation resources become more expensive. The lower half of the Efficient Frontier includes portfolios with large capacity surpluses and renewable resources, meanwhile maxing out the amount of conservation included in the model. The least risk portfolio has no financial objective and selects as many resources as possible given the model's constraints to lower risk. A new natural gas CCCT does not appear anywhere on the Efficient Frontier for the first time since PRiSM was adopted in the 2003 IRP. This is because new CCCT units are too large relative to Avista's load requirements.

**Table 11.5: Alternative Resource Strategies (2035) along the Efficient Frontier (MW)**

| Portfolio | Levelized Cost | 2030 Stdev | NG Peaker | NG CCCT | Wind | Solar | Demand Respons | Thermal Upgrade | Storage | Hydro Upgrade | Energy Efficienc |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PRS | 405.5 | 78.3 | 335 | - | - | - | 44 | 34 | 5 | - | 108 |
| 2 | 405.5 | 78.1 | 288 | - | - | - | 48 | 34 | 15 | - | 111 |
| 3 | 406.5 | 75.4 | 332 | - | - | - | 44 | 34 | - | - | 108 |
| 4 | 407.7 | 71.9 | 329 | - | - | - | 35 | 31 | 5 | - | 114 |
| 5 | 408.7 | 68.4 | 326 | - | - | - | 41 | 34 | 10 | - | 109 |
| 6 | 411.7 | 64.8 | 372 | - | - | 70 | 15 | 31 | - | - | 115 |
| 7 | 415.7 | 61.2 | 372 | - | 100 | 10 | 13 | 31 | - | - | 114 |
| 8 | 418.4 | 57.6 | 372 | - | 150 | 50 | 3 | 31 | - | - | 118 |
| 9 | 424.4 | 54.0 | 372 | - | 250 | 20 | 15 | 31 | - | - | 113 |
| 10 | 428.9 | 50.4 | 372 | - | 300 | 70 | 3 | 31 | - | - | 118 |
| 11 | 434.1 | 46.8 | 372 | - | 350 | 150 | 3 | 31 | - | - | 118 |
| 12 | 439.1 | 43.1 | 372 | - | 450 | 90 | 3 | 31 | - | - | 120 |
| 13 | 445.7 | 39.4 | 326 | - | 550 | 130 | 26 | 31 | - | - | 123 |
| 14 | 454.8 | 35.5 | 279 | - | 650 | 160 | 38 | 31 | 15 | - | 130 |
| 15 | 470.0 | 31.6 | 231 | - | 750 | 400 | 49 | 34 | 30 | - | 134 |
| Least Risk | 506.1 | 27.5 | 93 | - | 900 | 590 | 57 | 40 | 30 | 68 | 153 |

## Determining the Avoided Costs of Energy Efficiency

The Efficient Frontier methodology determines the avoided cost of new resource additions included in the PRS. There are two avoided cost calculations for this IRP: one for energy efficiency and one for new generation resources. The energy efficiency avoided cost is higher because it includes benefits beyond generation resource value.

### Avoided Cost of Energy Efficiency

Since PRiSM selects energy efficiency, the prior IRP method of calculating avoided costs is no longer required; but estimating these values is helpful in selecting future conservation measures for more detailed analysis between IRPs. The process used to estimate avoided cost calculates the marginal cost of energy and capacity of the resources selected in the PRS. The energy value uses hourly energy prices to value more highly measures providing more contribution during system peak. The value of conservation measures includes the energy value, the ten percent Power Act adder and the value of loss savings.[7] Reducing customer loads saves future distribution and transmission capital and O&M costs, and is included in the conservation-avoided cost calculation. The final component of avoided cost accounts for the savings from avoided new capacity. This capacity value is the difference between the cost of a resource mix and the value the mix earns from energy sales in the wholesale marketplace. Equation 11.2 describes the avoided costs to evaluate conservation measures. This equation is the same as the 2015 IRP.

**Equation 11.2: Conservation Avoided Costs**

$$\{(E + (E * L) + DC) * (1 + P)\} + PCR$$

Where:

**E** = Market energy price. The price calculated by AURORA[XMP] is $35.85 per MWh assuming a flat load shape.

**PCR** = New resource capacity savings for the PRS selection point is estimated to be $120 per kW-year (winter savings only).

**P** = Power Act preference premium. This is the additional 10 percent premium given as a preference towards energy efficiency measures.

**L** = Transmission and distribution losses. This component is 6.0 percent based on Avista's estimated system average losses.

**DC** = Distribution capacity savings. This levelized value is approximately $34.41 per kW-Year.

## Determining the Avoided Cost of New Generation Options

The 2017 IRP's avoided costs are in Table 11.6. However, avoided costs will change as Avista's loads and resources change, as well with the wholesale power marketplace changes. The prices shown in the table represent energy & capacity values for different periods and product types. For example, for a new project with equal deliveries over the year in all hours has an energy value equal to the Flat Energy price shown in Table 11.6. Traditional on-peak and off-peak pricing is also included as a comparison to the flat price. In addition to the energy prices, this theoretical resource would also receive the capacity value as it produces power at the time of system peak. This system peak contributing value begins in 2027 for potential resources that can dependably meet winter peak requirements.

Capacity values shown below are the marginal cost of the most expensive significant resource from the PRS each year. The significant resources in this case are the natural gas-fired peakers. These resources set the avoided capacity cost, rather than smaller technologies, as the smaller technologies selected may not represent the marginal cost

[7] The Power Act adder refers to one aspect of federal law enacted in 1980 along with the creation of the NPCC. The NPCC includes the 10 percent adder to deferred capacity, given Avista's new conservation methodology using this 10 percent adder would not allow Avista's PRiSM model to solve, as it would be non-linear. Avista compared it's conservation method to the older method that calculates conservation outside PRiSM with the 10 percent adder in the 2015 IRP and both methods produced similar results.

if changes are made to loads or resources or if the PRiSM model is able to select resources to proper size requirement. The capacity payment applies to the capacity contribution of the resource at the time of the winter peak hour. To obtain a full capacity payment the resource must generate 100 percent of its capacity rating at the time of system peak. Solar receives no payment because it does not generate at the time of Avista's planned system peak (winter evenings or mornings when it is still dark). Wind resources may qualify for some contribution depending on the correlation and diversification of the resource. For example, this IRP assumes 7.5 percent winter capacity credit for Montana wind resources. The capacity cost methodology of this analysis is the same as the 2015 and prior plans by using the natural gas-fired resources as the avoided capacity unit. The only major difference from prior plans is the inclusion of specific avoided costs for renewables.

As an alternative to showing tipping point analysis to determine when a solar or wind resource is cost effective, the avoided energy value of these resources is part of this table. For solar, the levelized price to be economic for customers between 2017 and 2037, is $29.90 per MWh and for wind the economic price is $31.81 per MWh. These values do not include costs to integrate variable energy production, reserves, or interconnection costs, but represent the energy value of the resource's generation. The value attributed to these resources vary due to the time of expected delivery of the resources.

**Table 11.6: 2017 IRP Avoided Costs**

| Year | Flat Energy $/MWh | On-Peak Energy $/MWh | Off-Peak Energy $/MWh | Capacity $/kW-Yr | Example WA Solar $/MWh | Example WA Wind $/MWh |
|---|---|---|---|---|---|---|
| 2018 | 23.79 | 27.02 | 19.48 | 0 | 23.70 | 21.66 |
| 2019 | 23.71 | 26.85 | 19.53 | 0 | 23.28 | 21.71 |
| 2020 | 23.99 | 26.85 | 20.16 | 0 | 22.37 | 21.76 |
| 2021 | 24.30 | 26.85 | 20.88 | 0 | 21.67 | 21.63 |
| 2022 | 25.95 | 28.47 | 22.59 | 0 | 22.54 | 22.92 |
| 2023 | 29.68 | 32.24 | 26.30 | 0 | 25.36 | 26.35 |
| 2024 | 32.03 | 34.38 | 28.90 | 0 | 26.62 | 28.40 |
| 2025 | 32.58 | 34.65 | 29.83 | 0 | 26.66 | 28.85 |
| 2026 | 34.27 | 36.13 | 31.77 | 0 | 27.42 | 30.23 |
| 2027 | 37.61 | 39.25 | 35.43 | 171 | 29.51 | 33.25 |
| 2028 | 40.18 | 41.60 | 38.28 | 174 | 30.91 | 35.20 |
| 2029 | 44.06 | 45.27 | 42.44 | 178 | 33.84 | 38.65 |
| 2030 | 46.86 | 48.15 | 45.15 | 181 | 36.19 | 41.01 |
| 2031 | 48.08 | 49.32 | 46.42 | 185 | 36.88 | 41.98 |
| 2032 | 51.10 | 52.55 | 49.17 | 189 | 39.26 | 44.82 |
| 2033 | 52.81 | 54.29 | 50.83 | 192 | 40.73 | 46.13 |
| 2034 | 55.09 | 56.61 | 53.07 | 196 | 43.28 | 48.35 |
| 2035 | 57.50 | 59.26 | 55.14 | 200 | 45.96 | 50.51 |
| 2036 | 60.52 | 62.22 | 58.24 | 204 | 48.13 | 53.15 |
| 2037 | 64.51 | 66.33 | 62.09 | 208 | 51.98 | 57.14 |

# 12. Portfolio Scenarios

## Introduction

The Preferred Resource Strategy (PRS) is Avista's 20-year strategy to meet future loads. Because the future is often different from the IRP forecast, the strategy needs to be flexible enough to benefit customers under a range of plausible outcomes. This chapter investigates the cost and risk impacts to the PRS with different futures the utility might face. It reviews the impacts of losing a major generating unit, evaluates alternative loads, determines the impact of unit sizing, and the selection of portfolios to the right of the Efficient Frontier. All portfolios include the Solar Select project discussed in Chapter 11.

**Chapter Highlights**

- Lower or higher future loads do not materially change the resource strategy.
- Colstrip remains a cost-effective and reliable source of power to meet future customer loads.
- Without Colstrip in 2030, customer bills increase $50 million the first year.
- All load forecast scenarios require a new resource by the end of 2026.
- Avista has a pathway to reduce its emissions to 20 percent below 1990 levels.

### Load Forecast Scenarios

The PRS meets the Expected Case's load growth of 0.45 percent and winter peak growth of 0.39 percent over the next 20 years. Chapter 3 – Economic and Load Forecast provides details about the alternative load forecasts and Table 12.1 summarizes the alternative growth assumptions used to determine how the plan would change under different economic conditions.

**Table 12.1: Load Forecast Scenarios (2018-2037)**

| Scenario | Energy Growth (%) | Winter Peak Growth (%) | Summer Peak Growth (%) |
|---|---|---|---|
| Expected Case | 0.45 | 0.39 | 0.42 |
| High Load | 0.74 | 0.72 | 0.78 |
| Low Load | 0.16 | 0.03 | 0.04 |

Table 12.2 shows the changes to the PRS for each load growth scenario. In each scenario, a natural gas-fired CT is required by the end of 2026. Both the Low Load Growth case and the PRS add a 192 MW natural gas-fired CT by the end of 2026. The High Load Growth case requires 288 MW of additional capacity by the end of 2026. In all cases, the thermal upgrade selection is the same, but the timing of resources change, as the resource needs change. In both alternative scenarios, the storage facility is not cost effective, due to the size of selected resources needed to meet capacity needs. In the Expected Case, storage is the lowest cost resource for small incremental needs, but not for larger requirements. The portfolios for all three cases are similar with no scenario

requiring a different decision date for a new facility; the only major difference is the size of the addition. Near the 2026 requirement, Avista will have a greater understanding of its actual requirements.

**Table 12.2: Resource Selection for Load Forecast Scenarios**

| Resource | Expected Case's PRS | High Load Growth | Low Load Growth |
|---|---|---|---|
| NG Peaker | 335 | 477 | 192 |
| NG Combined Cycle CT | 0 | 0 | 0 |
| Wind | 0 | 0 | 0 |
| Solar | 0 | 0 | 0 |
| Demand Response | 49 | 49 | 49 |
| Storage | 5 | 0 | 0 |
| Thermal Upgrades | 34 | 34 | 34 |
| Hydro Upgrades | 0 | 0 | 0 |
| **Total** | **423** | **560** | **275** |

## Colstrip Scenarios

Coal-fired power plants are facing pressure from both policy requirements and economics to reduce their dispatch or to shut down. Avista's TAC and state commissions asked Avista to study the impacts of shuttering Colstrip prior to the end of its operating life. This IRP studies two alternative shutdown scenarios including coal-fired plant dispatch is limited due to more restrictive carbon reduction policies relative to the Expected Case's assumption.

In the Expected Case, Avista's ownership interests in the plant remains cost effective for the next 20 years, although it dispatches less due to carbon regulation projections. The Expected Case also includes Selective Catalytic Reduction (SCR) beginning service in 2028, significant capital expenses for Coal Combustion Residual (CCR) requirements and water management issues. Operating costs will increase when Units 1 & 2 close because there will be additional O&M costs and possible requirements for additional mercury controls.

### Colstrip Retirement Scenario

This IRP includes two scenarios with Colstrip retiring in 2030 and 2035. Both represent plausible early retirement dates when the plant could end service to customers. These scenarios assume both closure dates eliminate capital spending for the SCR and shorten capital recovery to current and future capital to five years after the retirement date. Future capital costs are lower than the Expected Case as certain capital improvements are cancelled. The CCR costs remain the same as in the Expected Case, but the time to complete the projects accelerates. The scenarios do not include costs related to employee retraining or relocation, payments to other owners, or decommissioning beyond those already included rates.

Table 12.3 shows the resource strategy for the Colstrip retirement scenarios. For the 2030 scenario, the table includes options for natural gas peakers and a CCCT. The 2035 scenario only shows replacement with peakers, although a CCCT could replace the plant, the cost illustration shown in 2030 represents this scenario. Figure 12.1 illustrates the costs and power supply risks of retiring Colstrip compared to the Efficient Frontier and the PRS. This chart shows the annual levelized costs between 2018 and 2042 on the x-axis and the 2037 standard deviation of power supply costs on the y-axis[1]. A separate scenario replacing Colstrip with energy storage and renewables appears later in this chapter. Retiring Colstrip early increases costs compared to the PRS, while pushing the retirement date out to 2035 is the least cost of the retirement scenarios, due to the added costs representing a smaller portion of the financial period. To understand the cost increases in the year of retirement, Figure 12.2 compares the annual cost of each scenario and the PRS.

The year following the plant retirement, power supply costs increase $50 to $60 million due to the cost of new capacity; this represents a 10 to 13 percent increase in power supply expenses as compared to the PRS. Reduced capital spending offsets some of the cost increases prior to the shutdown, but not enough to offset the increase. The CCCT option costs $1.8 million more per year (0.4 percent than the peaker option, but risk is 8 percent lower.

**Table 12.3: Colstrip Retires- Resource Strategy Options (ISO Conditions MW)**

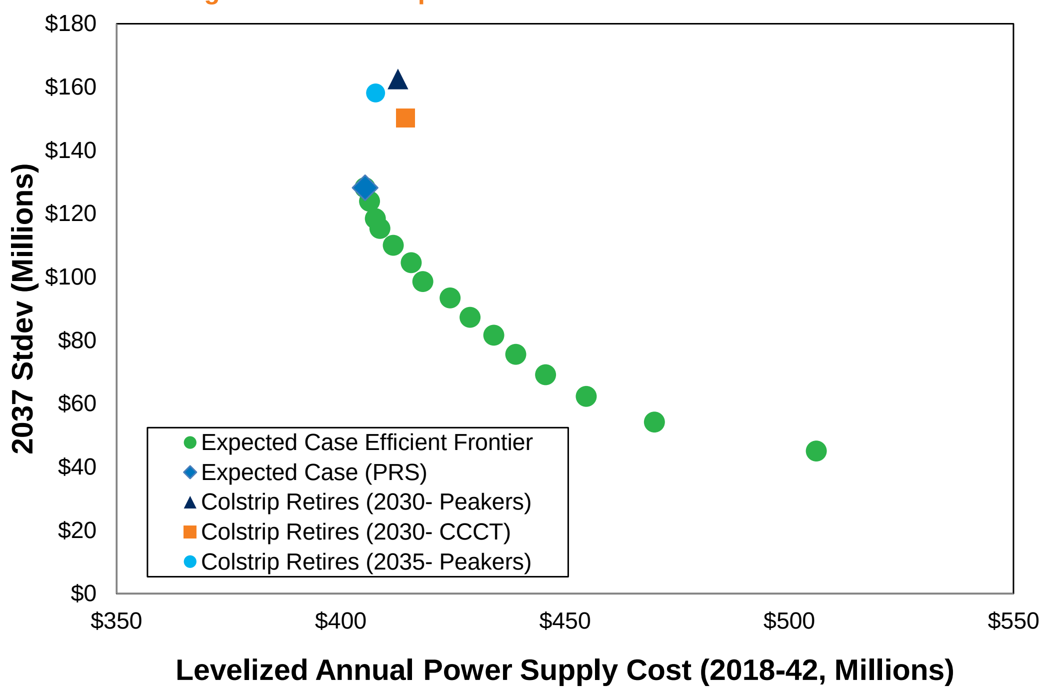
| Resource | By End of Year | 2030 Retirement with Peaker | 2030 Retirement with CCCT | 2035 Retirement with Peaker |
|---|---|---|---|---|
| Natural Gas Peaker | 2026 | 192 | 192 | 192 |
| Thermal Upgrades | 2027-2030 | 34 | 34 | 34 |
| Storage | 2028 | 5 | 5 | 5 |
| Natural Gas Peaker | 2030 | 288 | 0 | 96 |
| Natural Gas CCCT | 2030 | 0 | 286 | 0 |
| Storage | 2032 | 5 | 5 | 0 |
| Natural Gas Peaker | 2033 | 47 | 47 | 0 |
| Natural Gas Peaker | 2034 | 0 | 0 | 47 |
| Natural Gas Peaker | 2035 | 0 | 0 | 192 |
| **Total** | | **571** | **569** | **566** |
| | | | | |
| Demand Response | 2025-2037 | 44 | 44 | 48 |
| Conservation (w/ T&D losses) | 2018-2037 | 107 | 107 | 108 |

Early Colstrip retirement decreases direct greenhouse gas emissions as shown in Figure 12.3. In the natural gas-fired peaker scenario, direct emissions decrease 62 percent in

[1] The risk year is shifted to 2037 rather than 2030 used in other section to reflect change risk profile changes for portfolio choices late in the study period.

2037 compared to the PRS. If a CCCT replaces Colstrip, direct emissions fall 44 percent. The CCCT has higher direct emissions because it dispatches more hours than the less thermally efficient NG peaker. For the peaker scenario, Avista would rely on market purchases except when the peaker dispatch price is less expensive than purchasing from the market. Another method to review this scenario is the implied cost of carbon of shutting down the units. Using the average cost change between 2031 and 2037 and dividing by the average direct emissions reduction is an implied cost of $17.41 per metric ton, this with the pricing included in the market price forecast totals $38.78 per metric ton.[2]

**Figure 12.1: Colstrip Retires Scenario Cost versus Risk**




[2] This does not include indirect emissions from market purchases; depending on the methodology used to estimate these emissions the cost per ton could be higher. In the CCCT replacement scenario, the implied cost of carbon is $48.18 per metric ton using the same methodology.

**Figure 12.2: Annual Cost Impact with Colstrip Retirement versus PRS**

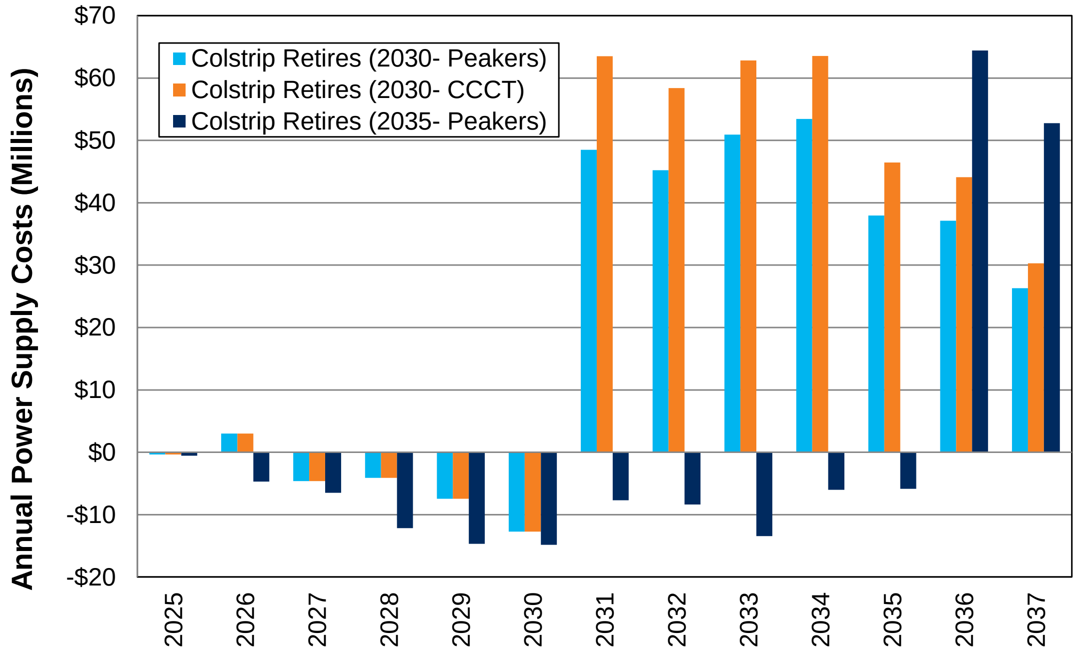
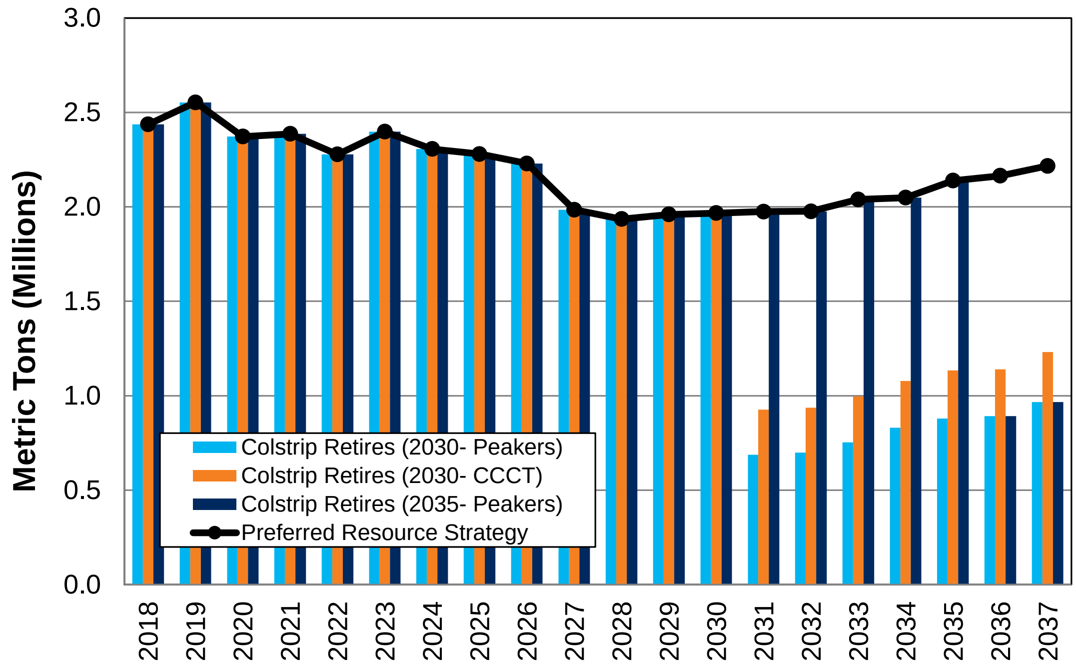



**Figure 12.3: Annual Greenhouse Gas Emissions with Colstrip Retirement**



## High-Cost Colstrip Retention Scenario

As part of the acceptance letter from the 2015 IRP, the Washington Commission requested a scenario with a higher than expected compliance costs to retain Colstrip and consult with the TAC regarding carbon pricing policies in the stochastic model. This scenario includes the following assumptions:

1) The SCR is required by the end of 2023 instead of 2028 to reflect an expansion of EPA regional air quality programs.
2) Units 1 & 2 shut down in 2018 rather than in 2022 and shift common facility costs earlier than in the Expected Case.
3) Adding a fabric filter (baghouse) system to enhance particulate removal by the end of 2023.
4) State of Montana to reduce carbon emissions beginning following the Clean Power Plan's mass based with new sources levels, but delayed until 2024.[3]

The annual cost between 2018 and 2037 is 3.7 percent higher in the High-Cost Colstrip scenario as compared to the PRS. Instead of paying these higher costs, the plant could retire by 2023. Table 12.4 shows the resource strategy for a 2023 Colstrip retirement to avoid the High Cost Colstrip scenario assumptions. Shutting down the plant as compared to the High Colstrip Cost scenario would save customers 0.35 percent over running the plant for the remainder of the IRP study period. Figure 12.4 illustrates the cost and risk of the portfolio compared to the PRS and the Expected Case's Efficient Frontier. Both the high cost and retirement scenarios result in higher customer costs, but early retirement exposes customers to more volatile power supply costs. Figure 12.5 shows the annual costs of the two scenarios compared to the PRS. Direct emissions for the PRS and the 2023 shutdown case are in Figure 12.6. Early retirement reduces emissions to 0.9 million metric tons if natural gas-fired peakers replace Colstrip and Lancaster and the wholesale market serves some customer energy needs. The implied carbon cost of shutting down the plant between 2024 and 2037 by selecting the new resource strategy is an additional $12.21 per metric ton using the change in cost and the change in Avista's direct emissions from this scenario. This in total with the pricing included in the market analysis, totals $23.88 per metric ton.

[3] The average shadow price of the stochastic studies is $11.67 per metric ton between 2024 and 2037. $6.47 in 2024 and $26.89 in 2037. The 95th percentile price in in 2024 is $16.94 per metric ton and $60.16 in 2037.

**Table 12.4: Colstrip Retires in 2023 Scenario Resource Strategy**

| Resource | By End of Year | ISO Conditions (MW) |
|---|---|---|
| Natural Gas Peaker | 2023 | 143 |
| Thermal Upgrades | 2023-2037 | 34 |
| Natural Gas Peaker | 2026 | 288 |
| Natural Gas Peaker | 2030 | 96 |
| Storage | 2035 | 5 |
| **Total** | | **566** |
| | | |
| Demand Response | 2025-2037 | 44 |
| Conservation (w/ T&D losses) | 2018-2037 | 107 |

**Figure 12.2: High-Cost Colstrip Retention Scenario Efficient Frontier**

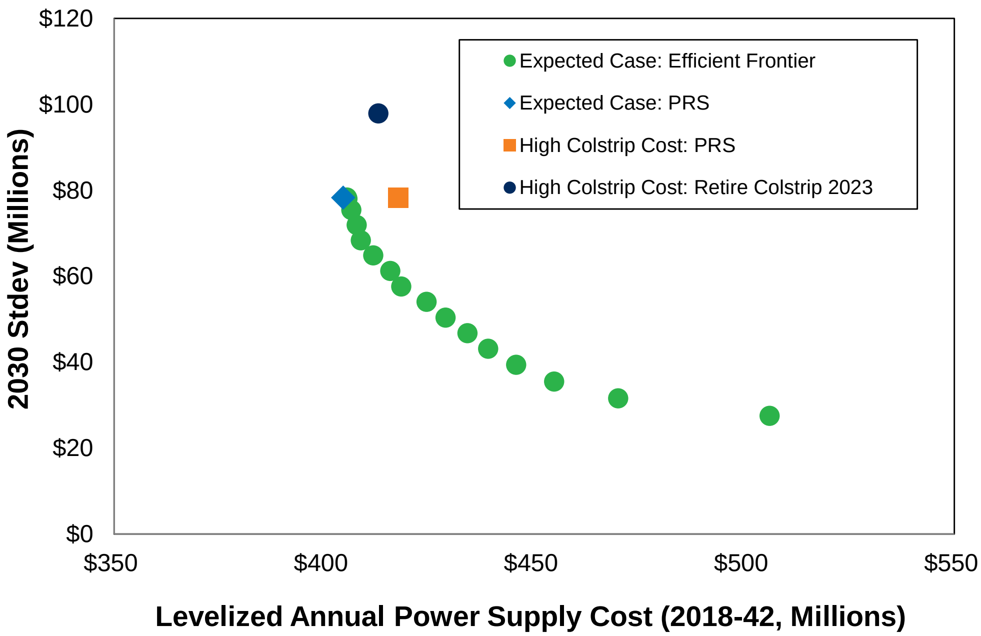


Figure 12.3: High-Cost Colstrip Scenarios Annual Cost

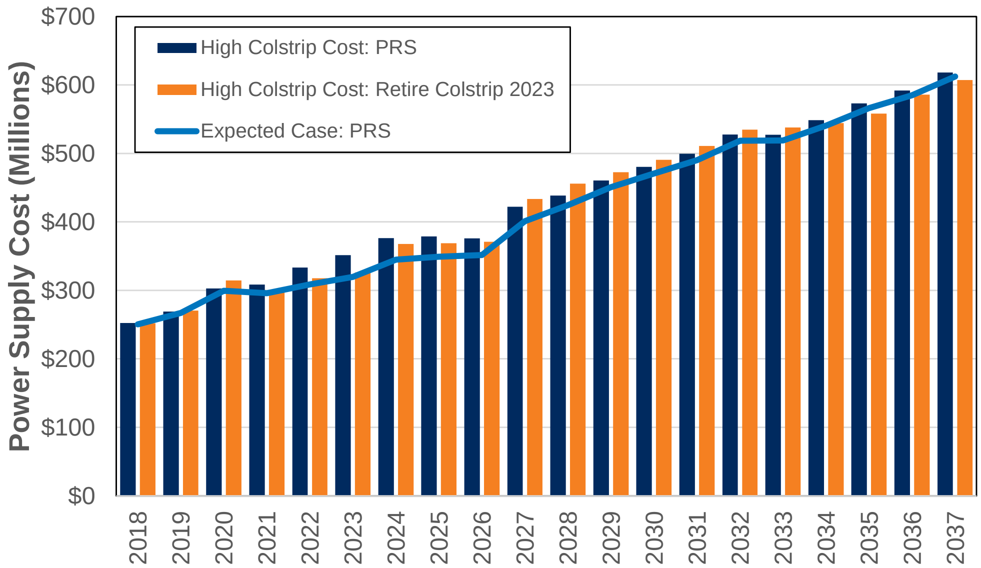
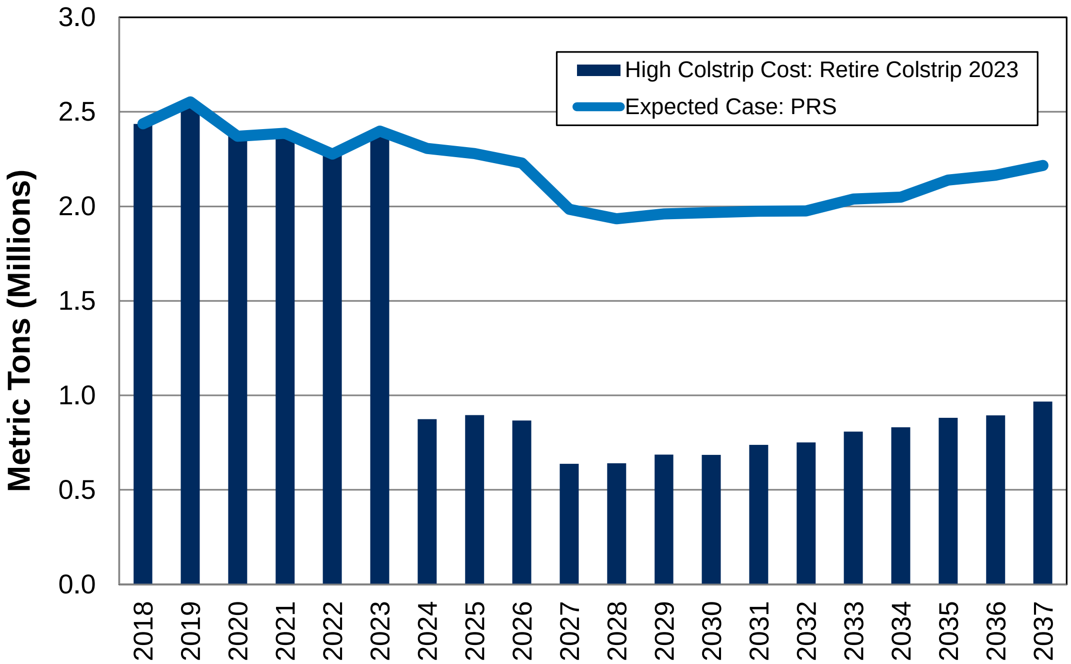



Figure 12.4: Greenhouse Gas Emissions: Retire Colstrip in 2023 versus PRS



## Colstrip Reduction Scenario

The major challenge with shutting down Colstrip prior to the end of its operational life is the cost to replace its generation capacity. An alternative to retiring Colstrip is reducing its dispatch. Each owner has dispatch rights and may not shut off all delivery, unless each owner agrees. If the owners could agree, or if a program's design could reduce dispatch within the constraints of each owner's control, then this scenario could be a lower cost approach to reduce emissions than plant closure.

For this scenario, a cap on emissions is set to 50 percent of Expected Case operations, and the plant is not able to purchase additional allowances. This methodology creates a carbon price for the emission reduction as described in Chapter 10. Figure 12.7, illustrates the cost and risk changes of this scenario compared to the PRS and retiring Colstrip in 2030. The cost of dispatching Colstrip at a 50 percent level is 2.2 percent higher than the Expected Case's PRS. Retiring the plant in 2030 and replacing it with peakers is a 1.8 percent increase and replacing the plant with a CCCT is a 2.2 percent increase. Figure 12.8 shows the change in greenhouse gas emissions. Reducing dispatch to 50 percent levels is nearly on par from the customer cost point of view of shutting down the resource, but if the plant needed to reduce operations less than 50 percent, then keeping the plant available is less costly.

**Figure 12.5: 50 Percent Colstrip Dispatch Reduction Scenario Cost & Risk Comparison**

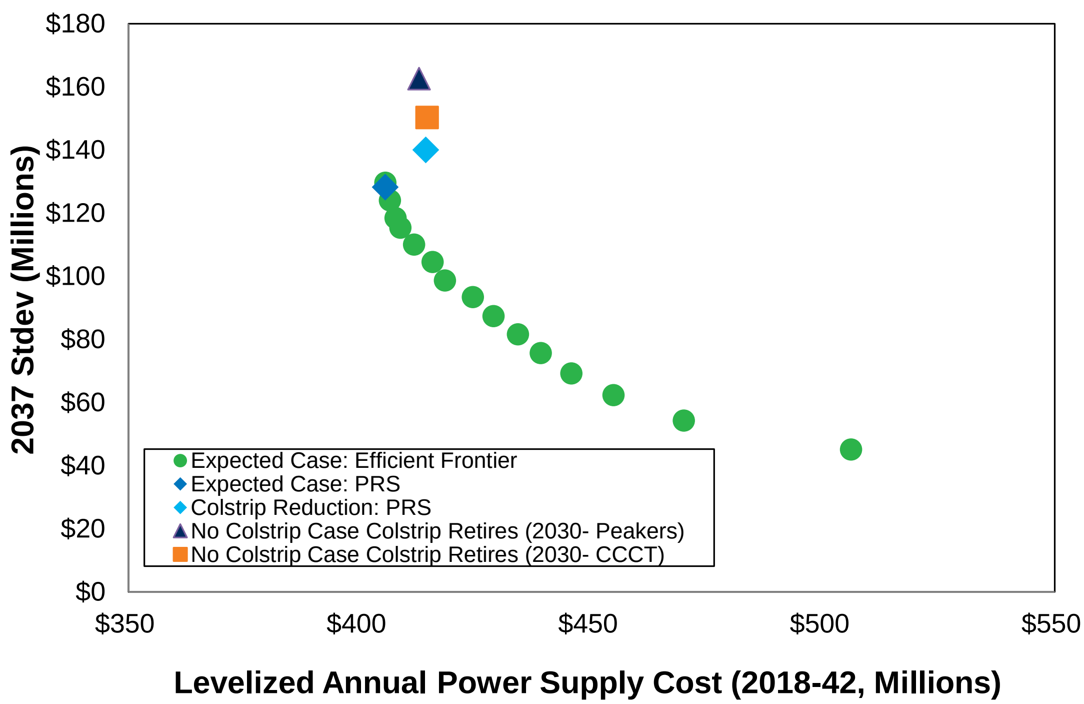
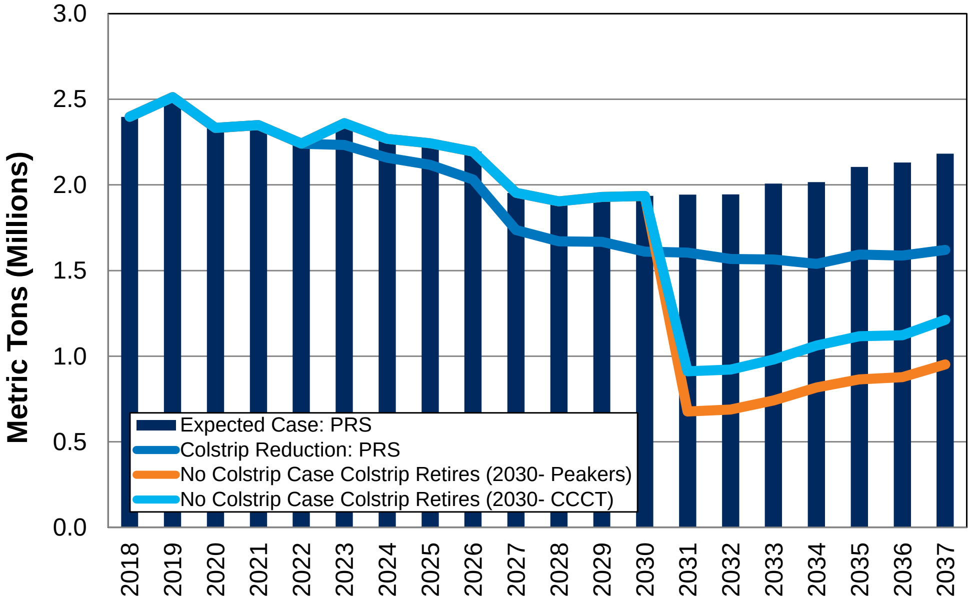


Figure 12.6: Colstrip Dispatch Reduction Scenario Greenhouse Gas Comparison




## Other Resource Scenarios

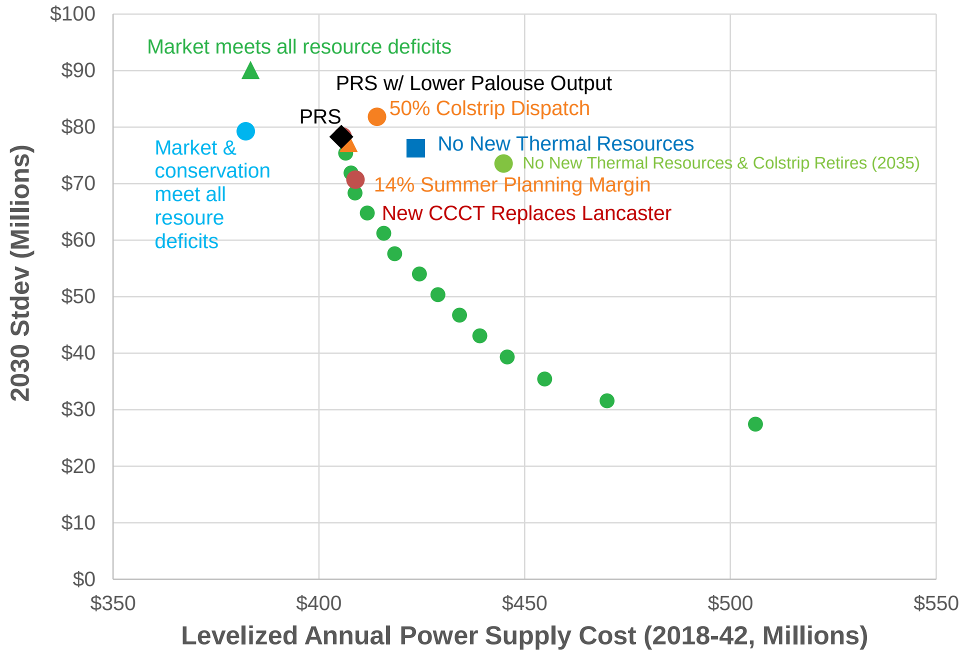
Several other resource portfolio studies using the Expected Case's market forecast formed the following analyses. The portfolios show the financial impact of different choices in meeting future resource deficits. Figure 12.9 shows the levelized cost and 2030 risk compared to the Efficient Frontier.

### Market Scenarios

This plan includes two wholesale market portfolio scenarios; the first uses wholesale market purchases to meet all resource deficits with a load adjustment assuming conservation programs end. This scenario illustrates the cost to serve the system with market resources. The second market scenario limits new resources to conservation and wholesale market purchases. These scenarios show the cost and risk if the utility chooses to depend on the wholesale market for its future needs. These portfolios estimate the value of capacity in the PRS.

If Avista ended conservation programs and used the wholesale power market for all future deficits, the cost to serve customers would be $22 million lower per year and market risk would be $12 million higher than the PRS. Offering conservation programs saves customers $23 million per year along with the market risk only being $1 million higher than the PRS. This analysis indicates that conservation is a cost effective method to reduce risk and cost to customers. It illustrates the cost to meet capacity requirements for a reliable system adds $23 million per year to customer costs over depending on the wholesale market place.

**Figure 12.7: Other Resource Strategy Portfolio Cost and Risk (Millions)**




## No New Thermal Resources Scenario

The No New Thermal Resources scenario meets future resource deficits without adding carbon-emitting resources. It requires a mix of new resource options adding both capacity and energy to the system. Table 12.5 outlines the resources selected to meet Avista capacity and energy requirements. If Avista could not construct or purchase new thermal resources, meeting capacity deficits would require new hydro and storage technologies, along with increased conservation and demand response. Wind and solar resources would meet energy requirements.

This scenario is 4.1 percent higher cost than the PRS per year over the IRP study period, but the 2030 market risk is 2.7 percent lower. Greenhouse gas emissions are 22 percent lower than the PRS, when taking into account the added renewables to the overall system. This scenario would require additional reliability work to determine if storage technology and the wholesale market could together meet reliability requirements. This scenario assumes over 10 percent of peak load is met by 215 MW of storage capacity and 645 MWh of storage capability. Avista will need to determine if current and large amounts of additional storage can adequately serve customer needs.

**Table 12.5: No New Thermal Resource Scenario**

| Resource | By End of Year | ISO Conditions (MW) |
|---|---|---|
| Storage | 2026 | 150 |
| Thermal Upgrades | 2026-2030 | 44 |
| Storage | 2026-2037 | 65 |
| Wind (on system) | 2030 | 50 |
| Hydro Upgrades | 2030 | 68 |
| Solar | 2030-2037 | 250 |
| **Total** | | **627** |
| | | |
| Demand Response | 2025-2037 | 47 |
| Conservation (w/ T&D losses) | 2018-2037 | 123 |

Extending the no new thermal resources scenario to the Colstrip shut down in 2035 scenario requires additional storage and renewable resources. Table 12.6 outlines the resources selected to meet deficits in this case. This scenario results in significant increases in storage, hydro upgrades and solar resources at a capital cost exceeding $3.1 billion through 2037 compared to the $538 million included in the PRS.

The cost, assuming Avista decisions do not affect market prices, is 9.7 percent higher than the PRS between 2018 and 2042. In 2036, the first full year of Colstrip retirement, costs are 45 percent higher than the PRS, and 31 percent higher than replacing Colstrip with natural gas-fired peakers. Power Supply Cost volatility is 25 percent lower in this scenario than the PRS and 8 percent lower than replacing Colstrip with natural gas-fired peakers in 2037. Greenhouse gas emissions are significantly lower. The direct greenhouse gas emissions from Avista facilities fall to 596,000 metric tons in 2037, but renewables added to the Avista system would offset these emissions.

Even though this scenario is attractive from an environmental point-of-view, it has significant cost implications and reliability concerns. Additional studies are required to validate if there are any reliability concerns with meeting loads without baseload generation as a backstop during both poor hydro years and in peak winter conditions.

**Table 12.6: No New Thermal Resource and Colstrip Replacement Scenario**

| Resource | By End of Year | ISO Conditions (MW) |
|---|---|---|
| Storage | 2026 | 155 |
| Thermal Upgrades | 2026-2030 | 44 |
| Storage | 2027-2037 | 225 |
| Wind (on system) | 2030-2037 | 250 |
| Solar | 2030-2037 | 550 |
| Hydro Upgrades | 2035 | 148 |
| Wind (Montana) | 2036 | 100 |
| **Total** | | **1,472** |
| | | |
| Demand Response | 2025-2037 | 49 |
| Conservation (w/ T&D losses) | 2018-2037 | 124 |

### Low Palouse Output Scenario

Currently, Avista does not anticipate needing additional renewables to meet the Washington EIA due to control of Palouse Wind and ownership of Kettle Falls Generation Station. Palouse Wind has delivered power for more than four years, but only one year has delivered the anticipated energy output. This scenario studies if Avista would require additional renewable energy if the generation continues to be below original expectations. The results of the scenario analysis warrant no change in resource strategy due to the inclusion of upgrades to Kettle Falls in the PRS. This analysis also indicates less REC sales (revenue) would be a result of lower Palouse Wind production. Given these conclusions, Avista will continue on its current EIA compliance path, but will continue to monitor production levels for any significant changes.

### Increased Summer Planning Margin Scenario

As explained earlier, in recent IRPs Avista has not included any summer planning margin beyond expected load expectation and reserve requirements. This IRP adds a seven percent summer planning margin to the mandatory reserve requirements based on the shrinking regional capacity associated with the shutdown of coal plants. The seven percent planning margin is half of the winter planning margin. This scenario tests the potential requirement and portfolio changes for a 14 percent summer planning margin. Although, Avista does not currently anticipate moving to a 14 percent summer margin until the wholesale market fails to provide adequate capacity as determined by internal or NPCC studies. This study shows no significant change to the resource strategy until after 2035. The minor changes accelerate thermal upgrades in the PRS, although after 2035 solar resources are cost effective to provide summer peak reduction.

### New CCCT Replaces Lancaster Scenario

Previous IRP's included a scenario regarding how the previous PRS compares to the new PRS. Since this plan's new resource acquisition is significantly different from prior plans in both timing and resource choice, the best way to represent this type of analysis is by including a new CCCT rather than CT's to replace Lancaster as this is the major change with this plan. The levelized cost for this scenario is higher than the PRS by 0.85 percent and 10 percent lower in 2030. In the Efficient Frontier analysis shown in Figure 12.7 above, the portfolio's cost and risk is to the right of the Efficient Frontier. Indicating there are more optimal portfolios to achieve similar risk savings. Table 12.7 shows the resource strategy selection for this scenario. It is possible the CCCT is lower cost compared to other alternatives so this portfolio option should be considered in future RFPs.

**Table 12.7: New CCCT Replaces Lancaster Scenario**

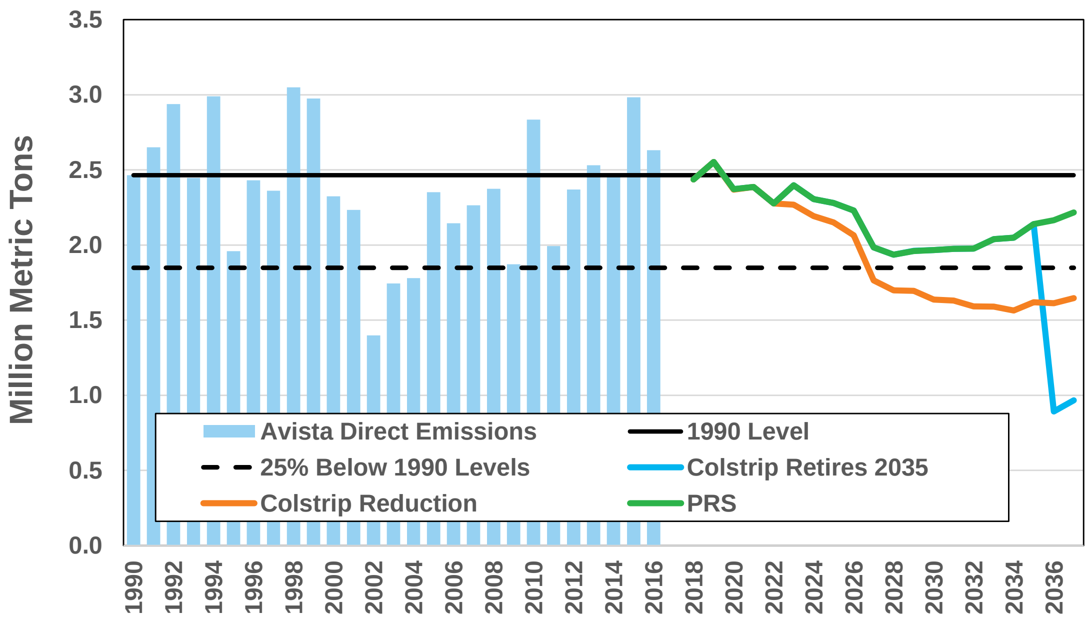
| Resource | By End of Year | ISO Conditions (MW) |
|---|---|---|
| CCCT | 2026 | 285 |
| Thermal Upgrades | 2026-2037 | 34 |
| Natural Gas Peaker | 2030 | 47 |
| Storage | 2036 | 5 |
| **Total** | | **371** |
| | | |
| Demand Response | 2032-2037 | 35 |
| Conservation (w/ T&D losses) | 2018-2037 | 103 |

## Washington State Emission Goal Analysis

The State of Washington has a goal to reduce greenhouse gas emissions to 20 percent below 1990 levels by 2035. No legislation or pathway to achieve this goal is set at the time of the 2017 IRP analysis. Details regarding how to account for emissions from market purchases have not been determined. Lastly, allocation between Washington and Idaho will need resolution. Ignoring these issues, Figure 12.10 shows Avista's total direct greenhouse gas emissions since 1990 and a 20-year forecast. Historical emissions are volatile due to hydro variability and resource changes. Avista significantly reduced its direct emissions in 2001 by selling its share of the Centralia coal plant, but emissions later rose due to Coyote Springs 2 and the Lancaster PPA. Hydro volatility needs addressing by any policy to reduce emissions because poor hydro years require thermal resources to meet load needs and they increase emissions in the regional power system.

Avista anticipates direct emissions to remain near 1990 levels and begin to decline under average water conditions, until reaching 20 percent below 1990 levels by 2035. After 2035, emissions begin to grow as Avista's natural gas-fired facilities increase production to meet load growth, unless future policies require changes to Avista's dispatch or require the purchase of allowances to comply with state regulations. The Colstrip Reduction scenario level meets emission reduction goals. Retiring Colstrip in 2035 could reduce emissions by 60 percent compared to 1990 levels.

**Figure 12.8: Avista Direct Greenhouse Gas Emissions**



# 13. Action Items

The IRP is an ongoing and iterative process balancing regular publication timelines with pursuing the best 20-year resource strategies. 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 2015 IRP Action Plan and provides the 2015 Action Plan.

## Summary of the 2015 IRP Action Plan

The 2015 Action Plan included three categories: generation resource related analysis, energy efficiency, and transmission planning.

### 2015 Action Plan and Progress Report

#### *Generation Resource Related Analysis*

- Analysis of continued feasibility of the Northeast Combustion Turbine due to its age.
    - Northeast is a 39 year old peaking unit permitted to run 100 run hours per year per unit. This action item is to determine if the unit should be available for the full 20-years of the IRP and if it should be considered for a capacity upgrade described in Chapter 9. Avista determined Northeast is a viable plant for the 20-year planning horizon. The plant has few operating run hours and it is not expected to reach its next maintenance cycle for hot gas path inspection due to run hour limitations. The unit is designed and used to meet extreme peak load conditions and to provide non-spinning reserves, it meets these needs at little cost to customers.

- Continue to review existing facilities for opportunities to upgrade capacity and efficiency.
    - Avista included several options to upgrade both hydro and thermal generating facilities in this IRP, these options are identified in Chapter 4. Further, Avista completed an upgrade to the Coyote Springs 2 facility in 2016, increasing winter peak capacity by 16 MW and increasing its efficiency by 0.8 percent by utilizing a hot gas path upgrade during its latest maintenance outage period.

- Increase the number of manufacturers and sizes of natural gas-fired turbines modeled for the PRS analysis.
    - Avista reviewed the thermal generation sizes and manufacturers when selecting resources to model for this IRP. Given Avista's new generation capacity need is not until 2026, additional resources beyond those identified in Chapter 4 are unnecessary at this time. Avista studied many alternative natural gas-fired resources and selected the lowest cost and sizeable resource to meet Avista's deficits.

- Evaluate the need for, and perform if needed, updated wind and solar integration studies.
  - Avista determined it is not necessary to update or develop variable integration study at this time. This is due to the fact the generation and pricing scenarios used from the previous study are still relevant. Further, Avista prefers to conduct these updated studies using intra hour modeling technology. This is currently being developed and may be available for the 2019 IRP.

- Participate and evaluate the potential to join a Northwest EIM.
  - Avista is conducting a cost/benefit analysis associated with joining the CAISO EIM. This analysis will be complete in the fall of 2017. Avista is also evaluating other factors influencing the decision to join the CAISO EIM. These include the reduction of near term market liquidity as other utilities join the EIM and the additional integration of renewable resources in our service territory. Avista anticipates making a decision on joining the CAISO EIM and the associated timing by the end of 2017.

- Monitor regional winter and summer resource adequacy.
  - Avista continues to monitor resource adequacy for both the Northwest and Avista. Avista is concerned the region may not have adequate resources given announcements of large baseload plants, further, new analysis shown by the Northwest Power and Conservation Council show summer peaking is starting to be a concern. Given this change, Avista implemented a 7 percent planning margin in the summer (in addition to operating reserves). Avista will continue to follow regional analysis by participating in the Resource Adequacy Advisory Committee.

- Participate in state level implementation of the CPP.
  - Since the 2015 IRP, the Clean Power Plan is on hold by the US Supreme Court. Further, the new Federal Administration has appeared to pause the Clean Power Plan. This IRP does assume many of the goals of the CPP will ultimately be implemented at a later date.

### Energy Efficiency and Demand Response

- Continue to study and quantify transmission and distribution efficiency projects as they apply to EIA goals.
  - This IRP includes new assumptions for T&D benefits based on new analysis, as discussed in Chapter 5.

- Complete energy efficiency potential assessment on Avista's generation facilities.
  - Since the 2015 IRP, Avista has completed additional analysis on owned generation facilities, further, the costs have come down as some projects are lighting related. An updated analysis is provided in Chapter 5.

### 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 to meet native customer load.

- Continue to participate in BPA transmission processes and rate proceedings to minimize the costs of integrating existing resources outside of Avista's service area.
    - Avista is actively participating in the BPA transmission rate proceedings.

- Continue to participate in regional and sub-regional efforts to establish new regional transmission structures to facilitate long-term expansion of the regional transmission system.
    - Avista staff participates in and leads many regional transmission efforts including the Columbia Grid and the Northern Tier Transmission Group Forums.

## 2017 IRP Two Year Action Plan

Avista's 2017 PRS provides direction and guidance for the type, timing, and size of future resource acquisitions. The 2017 IRP Action Plan highlights the activities planned for possible inclusion in the 2019 IRP. Progress and results for the 2017 Action Plan items are reported to the TAC and the results will be included in Avista's 2019 IRP. The 2017 Action Plan includes input from Commission Staff, Avista's management team, and the TAC.

### Generation Resource Related Analysis

- Continue to review existing facilities for opportunities to upgrade capacity and efficiency.
- Model specific commercially available storage technologies within the IRP; including efficiency rates, capital cost, O&M, life cycle, and ability to provide non-power supply benefits.
- Update the TAC regarding the EIM study and Avista plan of action.
- Monitor regional winter and summer resource adequacy, provide TAC with additional Avista LOLP study analysis.
- Update the TAC regarding progress regarding Post Falls Hydroelectric Project redevelopment.
- Perform a study to determine ancillary services valuation for storage and peaking technologies using intra hour modeling capabilities. Further, use this technology to estimate costs to integrate variable resources.
- Monitor state and federal environmental policies effecting Avista's generation fleet.

### Energy Efficiency and Demand Response

- Determine whether or not to move the T&D benefits estimate to a forward looking value versus a historical value.
- Determine if a study is necessary to estimate the potential and costs for a winter and summer residential demand response program and along with an update to the existing commercial and industrial analysis.
- Use the utility cost test methodology to select conservation potential for Idaho program options.
- Share proposed energy efficiency measure list with Advisory Groups prior to CPA completion.

### Transmission and Distribution Planning

- Work to maintain Avista's existing transmission rights, under applicable FERC policies, for transmission service to bundled retail 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.
- Continue to participate in regional and sub-regional efforts to facilitate long-term economic expansion of the regional transmission system.
- IRP & T&D planning will coordinate on evaluating opportunities for alternative technologies to solve T&D constraints.