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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-17-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 4
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	SCOTT J. KINNEY
______________________________	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

AVISTA

2015

Electric Integrated Resource Plan

August 31, 2015

Exhibit No. 4
Case No. AVU-E-17-01
S. Kinney, Avista
Schedule 1, Page 1 of 212

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 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.

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2015 Electric IRP Introduction

Avista has a 125-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 2015 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 2015 IRP shows Avista has adequate resources between owned and contractually controlled generation, combined with conservation and market purchases, to meet customer needs through 2020. In the longer term, plant upgrades, energy efficiency measures, and additional natural gas-fired generation are integral parts of Avista's 2015 Preferred Resource Strategy.

Changes

Major changes from the 2013 IRP include:

- Average annual load growth reduced to 0.6 percent from just over 1 percent in 2013. This combined with a short term purchase power agreement delays the need for a new natural gas-fired resource by one year.
- Less contribution from natural gas-fired peakers due to lower projected loads.
- The elimination of demand response (temporarily reducing the demand for energy) due to higher estimated costs.

Highlights

Some highlights of the 2015 IRP include:

- Population and employment growth is starting to recover from the Great Recession.
- Natural gas-fired plants represent the largest portion of generation potential.
- The first anticipated resource acquisition is a natural gas-fired peaker by the end of 2020 to replace expiring contracts and to serve load growth.
- Colstrip remains a cost effective and reliable source of power to meet future customer needs.
- Energy efficiency offsets more than half of projected load growth through the 20-year IRP timeframe.

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 mandates. Avista's professional energy analysts use sophisticated modeling tools and input from over 75 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 2017 IRP in early 2016. 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.

1. Executive Summary

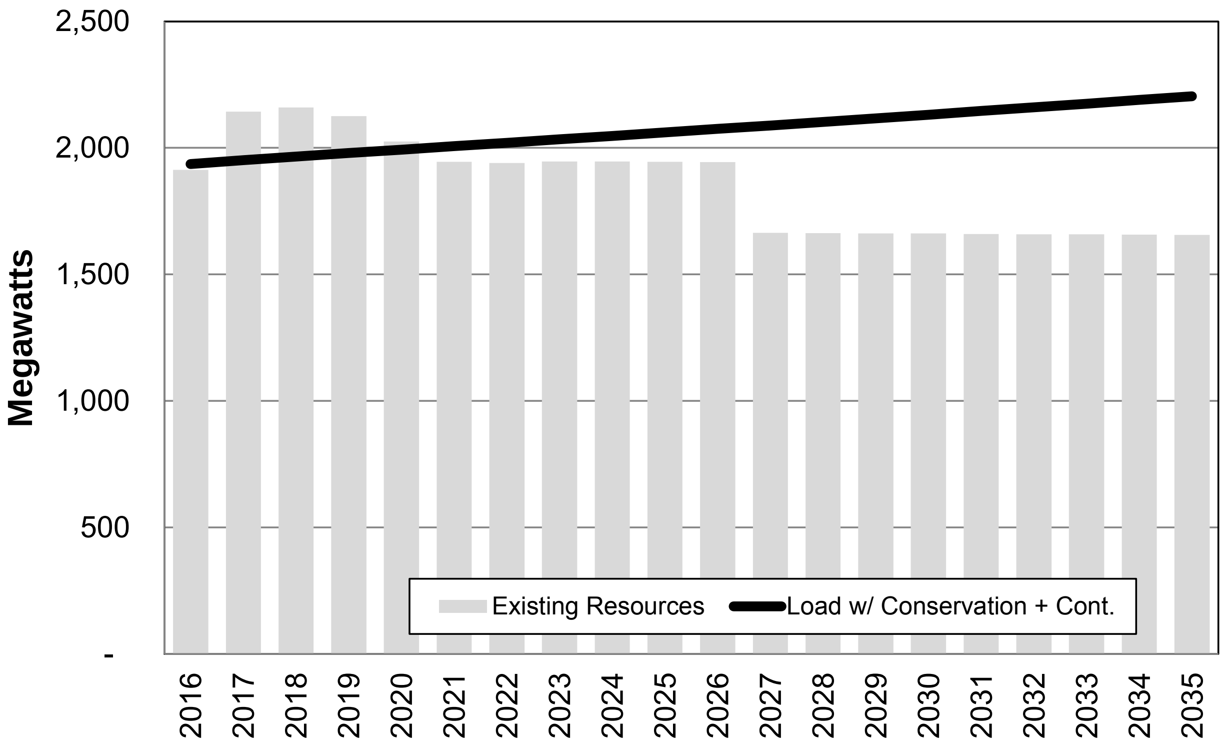
Avista's 2015 Electric Integrated Resource Plan (IRP) guides its resource strategy over the next two years and resource procurements over the next 20-years. It provides a snapshot of existing resources and loads and evaluates acquisition strategies over expected and possible future conditions. The 2015 Preferred Resource Strategy (PRS) includes energy efficiency, generation upgrades, and new natural gas-fired generation.

PRS development depends on modeling techniques to balance cost, reliability, rate volatility, and renewable resource requirements. Avista's management and the Technical Advisory Committee (TAC) guide its development and the IRP document by providing 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 experiences its highest peak loads in the winter. Its peak planning methodology includes operating reserves, regulation, load following, wind integration, and a 14 percent planning margin over winter-peak load levels. The company has adequate resources, combined with conservation and market purchases, to meet peak load requirements through 2020. Figure 1.1 shows Avista's resource position through 2035.

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



A short-term capacity need exists in the winter of 2015-2016, but is short-lived due to a 150 MW capacity sale contract ending in 2016. Avista addressed this deficit with market purchases; so, the first long-term capacity deficit begins in 2021. Resources acquired to meet projected winter deficiencies will provide capacity in excess of summer needs. Chapter 6 – Long Term Position details Avista's resource needs.

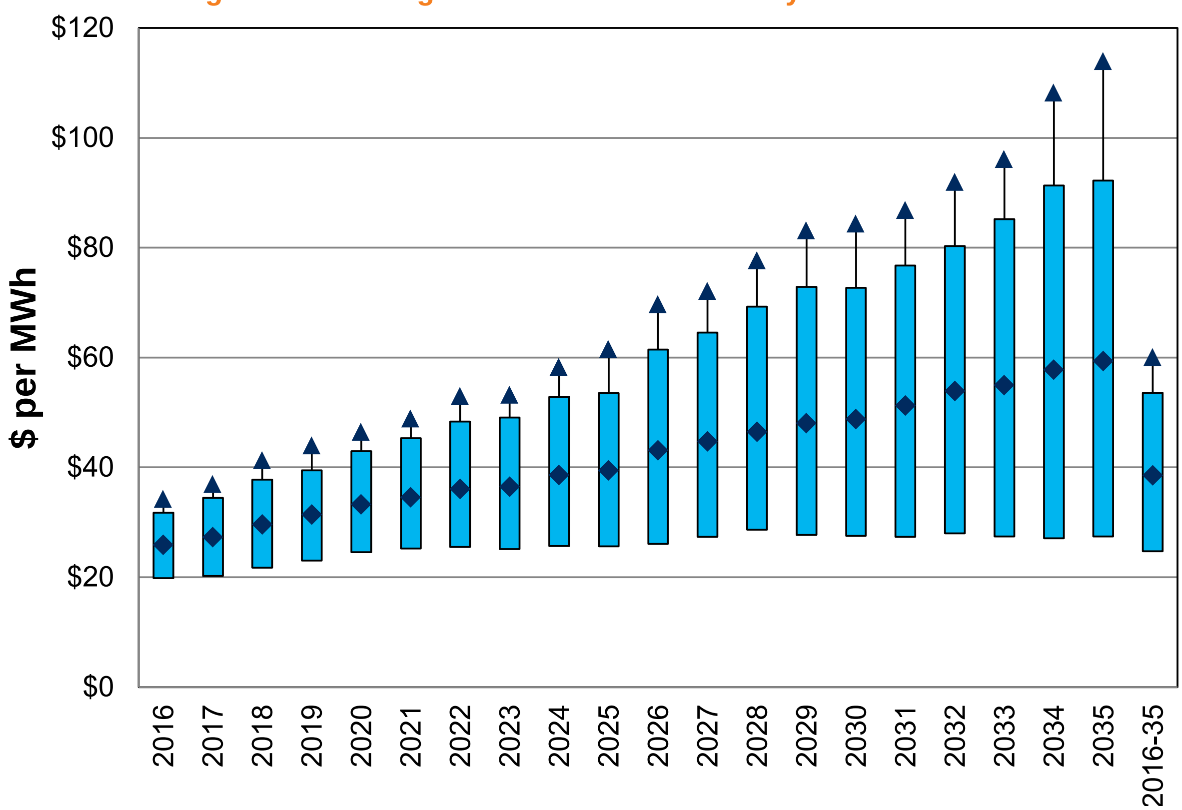
Modeling and Results

Avista uses a multiple-step approach to develop its PRS. It begins by identifying and quantifying potential new generation resources to serve projected electricity demand across the West. This Western Interconnect-wide study determines the impact of extra-regional markets on the Northwest electricity marketplace of which Avista is a part. It then maps existing Avista resources to the transmission grid in a model simulating hourly operations for the Western Interconnect from 2016 to 2035, the IRP study timeframe. The model adds new resources and transmission to the Western Interconnect as regional loads grow and older resources are retired. 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 2035.

Electricity and Natural Gas Market Forecasts

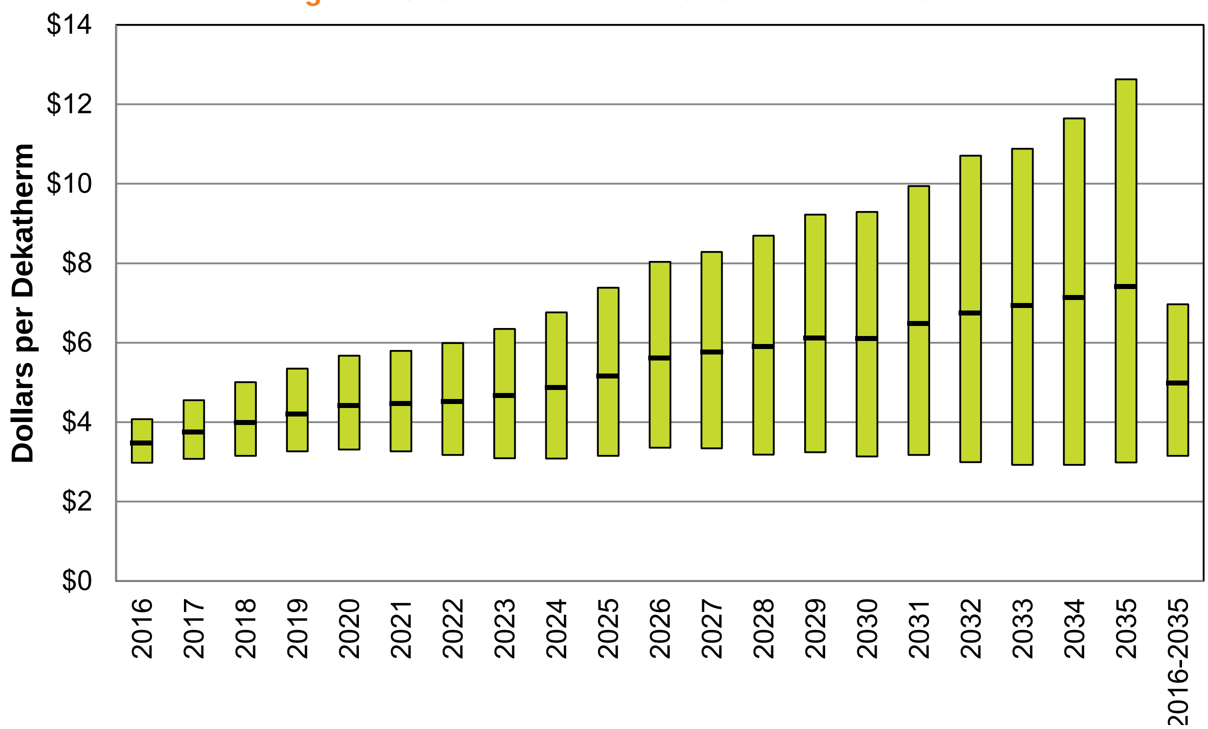
Figure 1.2 shows the 2015 IRP Mid-Columbia electricity price forecast for the Expected Case, including the range of prices resulting from 500 Monte Carlo iterations. The levelized price is $38.48 per MWh in nominal dollars over the 2016-2035 timeframe.

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 $4.97 per dekatherm over the next 20 years. See Chapter 10 – Market Analysis for details on the natural gas and electricity price forecasts.

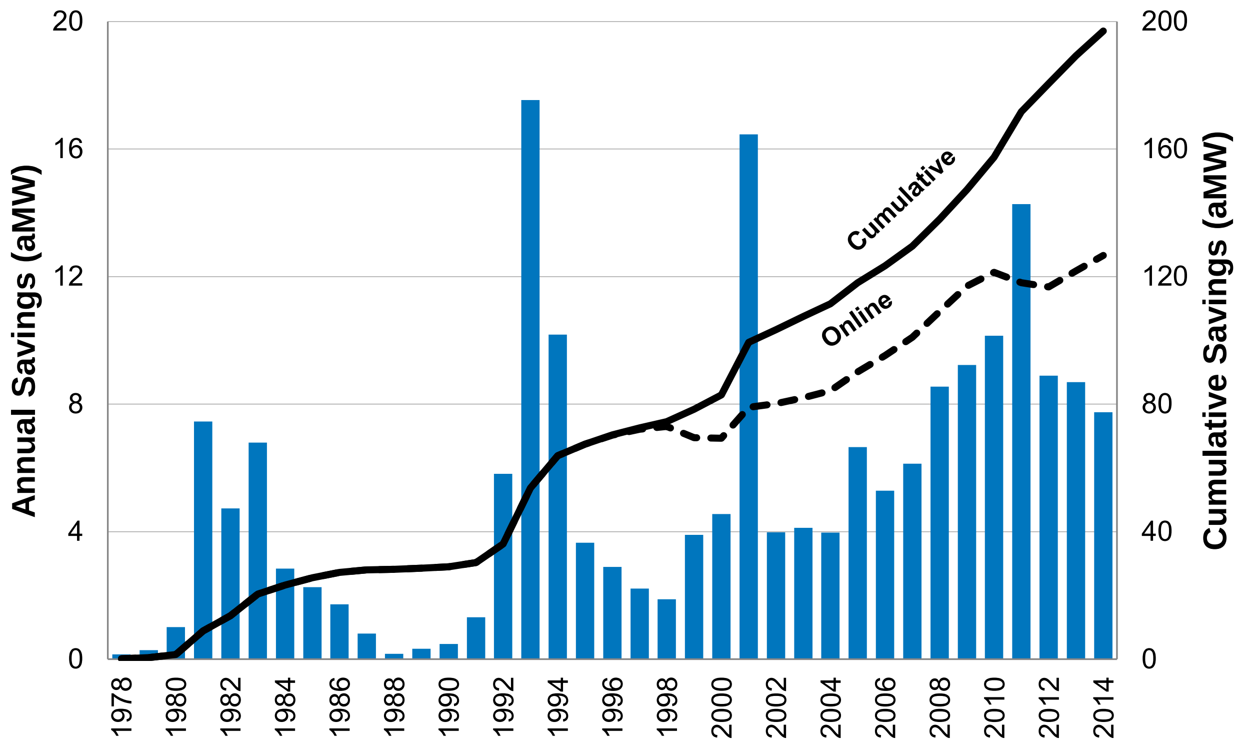
Figure 1.3: Stanfield Natural Gas Price Forecast



Energy Efficiency Acquisition

Avista commissioned a 20-year Conservation Potential Assessment in 2015. The study analyzed over 3,000 equipment and 2,300 measure options for residential, commercial, and industrial energy efficiency applications. Data from this study formed the basis of the IRP conservation potential evaluation. Figure 1.4 shows how historical efforts in energy efficiency have decreased Avista's load requirements by 127 aMW, or approximately eleven percent of its total load in 2014. The cumulative line shows the summation of all efficiency acquisitions and the online 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 by Avista's management and the TAC of information gathered and analyzed in the IRP process. It meets future load growth with upgrades at existing generation facilities, energy efficiency, and natural gas-fired technologies, as shown in Table 1.1.

Table 1.1: The 2015 Preferred Resource Strategy

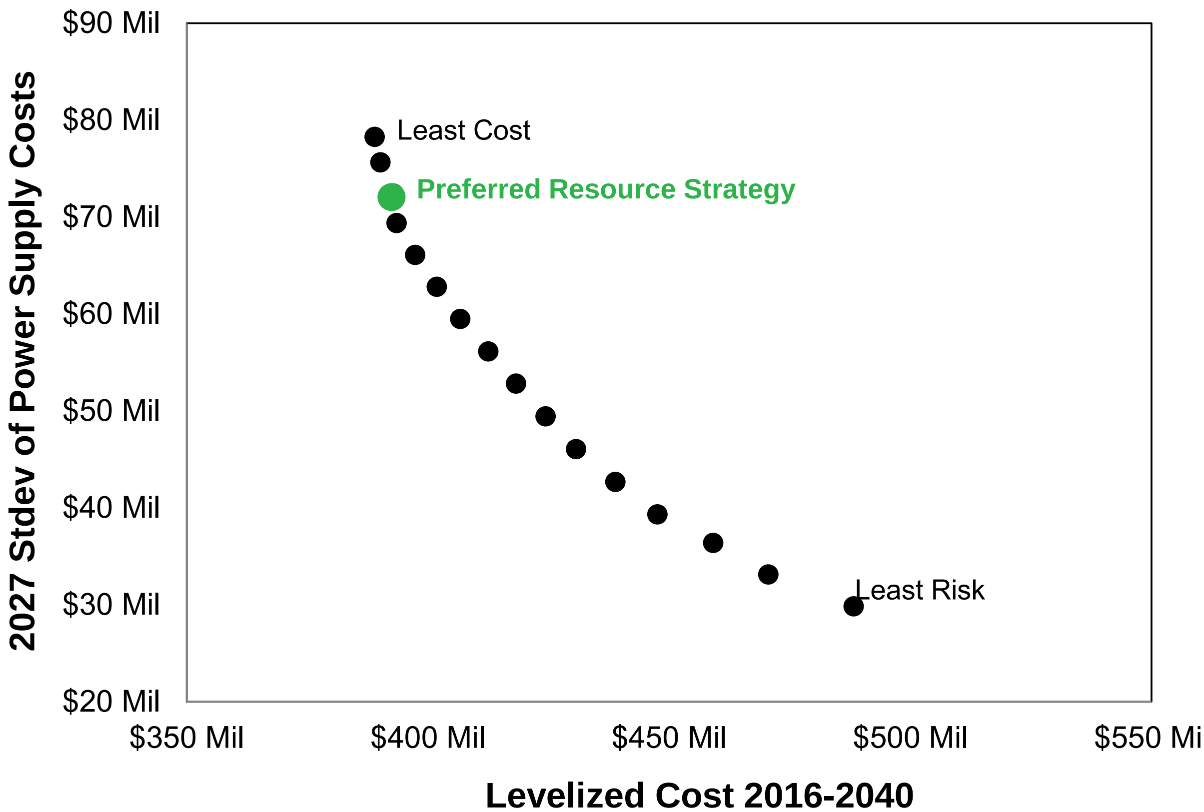
Resource	By the End of Year	ISO Conditions (MW)	Winter Peak (MW)	Energy (aMW)
Natural Gas Peaker	2020	96	102	89
Thermal Upgrades	2021-2025	38	38	35
Combined Cycle CT	2026	286	306	265
Natural Gas Peaker	2027	96	102	89
Thermal Upgrades	2033	3	3	3
Natural Gas Peaker	2034	47	47	43
Total		**565**	**597**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

The 2015 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 2013 IRP include a reduced contribution from natural gas-fired peakers and the elimination of demand response because of lower projected load growth, more thermal plant upgrades and higher demand response costs.

Each new resource and energy efficiency option is valued against the Expected Case Mid-Columbia electricity market to identify its future value, as well as its inherent risk measured by year-to-year portfolio 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 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. An 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 expected 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

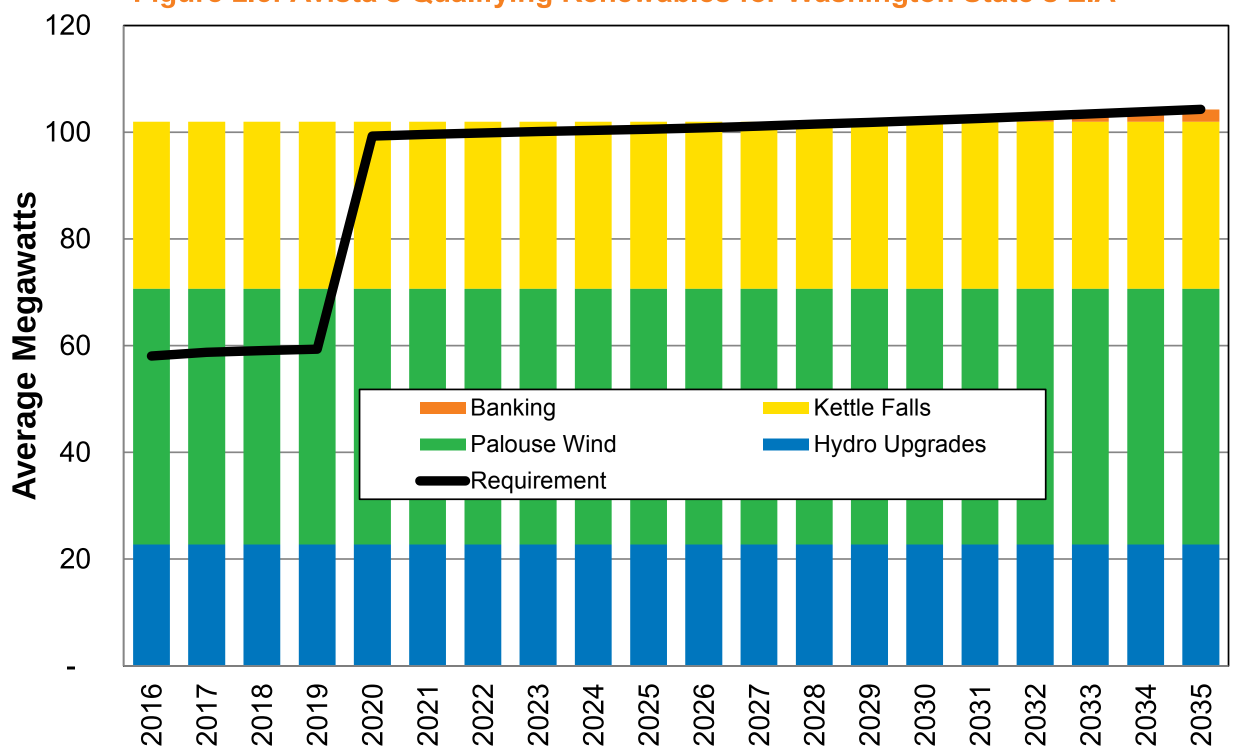


Chapter 12 – Portfolio Scenarios, includes several scenarios identifying tipping points where the PRS could change under different conditions from the Expected Case. It also evaluates the impacts of, among others, varying load growth, resource capital costs, and greenhouse gas policies.

Energy Independence Act Compliance

Washington voters approved the Energy Independence Act (EIA) through Initiative 937 in the November 2006 general election. The EIA requires utilities with over 25,000 customers to meet three percent of retail load from qualified renewable resources by 2012, nine percent 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, Kettle Falls Generating Station output and renewable energy certificate (REC) purchases. Figure 1.6 shows Avista's EIA-qualified generation; Chapter 6 – Long-Term Position includes a more in-depth discussion of this topic.

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



Greenhouse Gas Emissions

The regulation of greenhouse gases, or carbon emissions, is in various stages of development and implementation throughout the country. Some states have active cap and trade programs, emissions performance standards, renewable portfolio standards, or a combination of active and proposed regulations affecting emissions from electric generation resources. The Environmental Protection Agency's (EPA) June 2014 Clean Power Plan (CPP) draft proposal aimed to reduce greenhouse gas emissions from existing fossil-fueled electric generating units by establishing state-by-state emission rate targets calculated based on four building blocks. The EPA issued the final CPP rule on August 3, 2015, which was after modeling for this IRP was completed. The analysis of the final CPP rule, and subsequent state implementation plans, will occur in the 2017 IRP. The 2015 IRP reduces emissions consistent with the EPA draft rule. All active regulations affecting generation in the Western Interconnect are included in the IRP, including a $12 per metric ton carbon cost that escalates over time. Figure 1.7 shows Avista's projected greenhouse gas emissions for its existing and new generation assets.

Figure 1.7 shows that Avista emissions will increase modestly over the IRP timeframe. Figure 1.8 shows that, unlike Avista, western-region emissions likely will fall from historic levels. This discrepancy occurs because Avista does not own any of the less-cost-effective coal and natural gas-fired plants projected to retire over the IRP timeframe. More details on state and federal greenhouse gas policies are in Chapter 7. Results of greenhouse-gas policy scenarios are in Chapter 12.

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

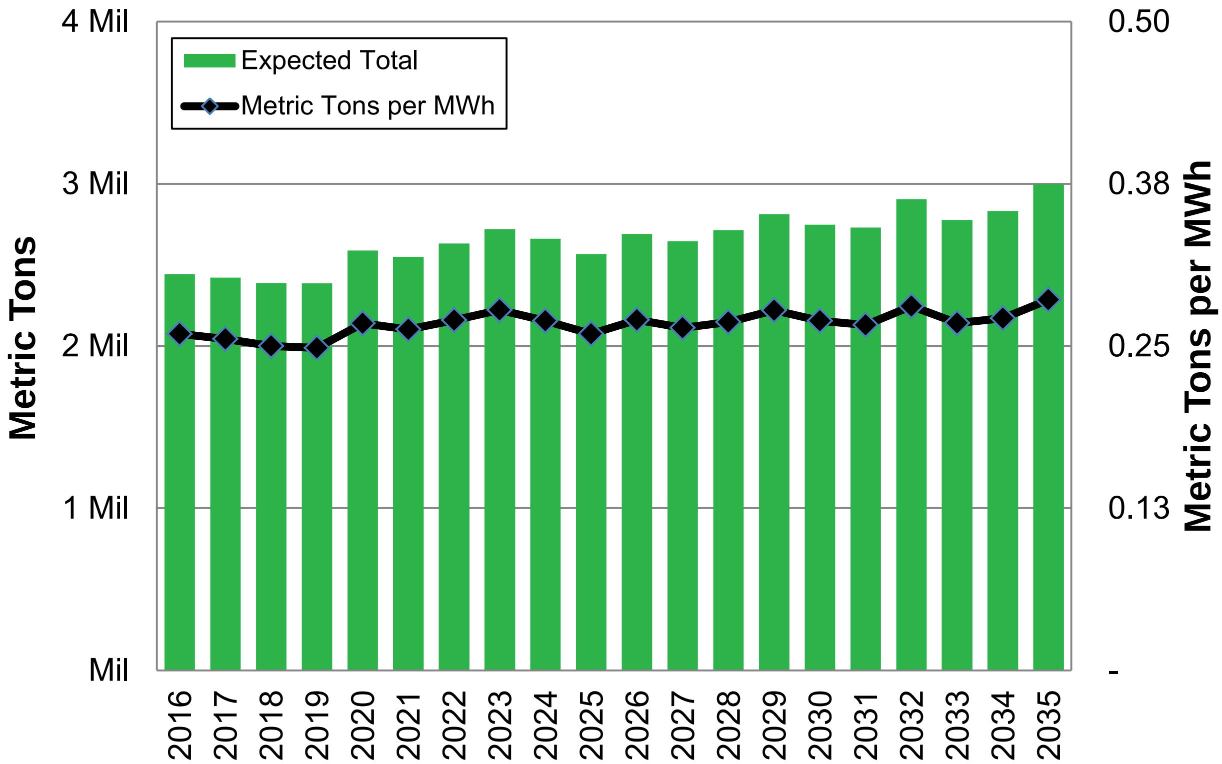
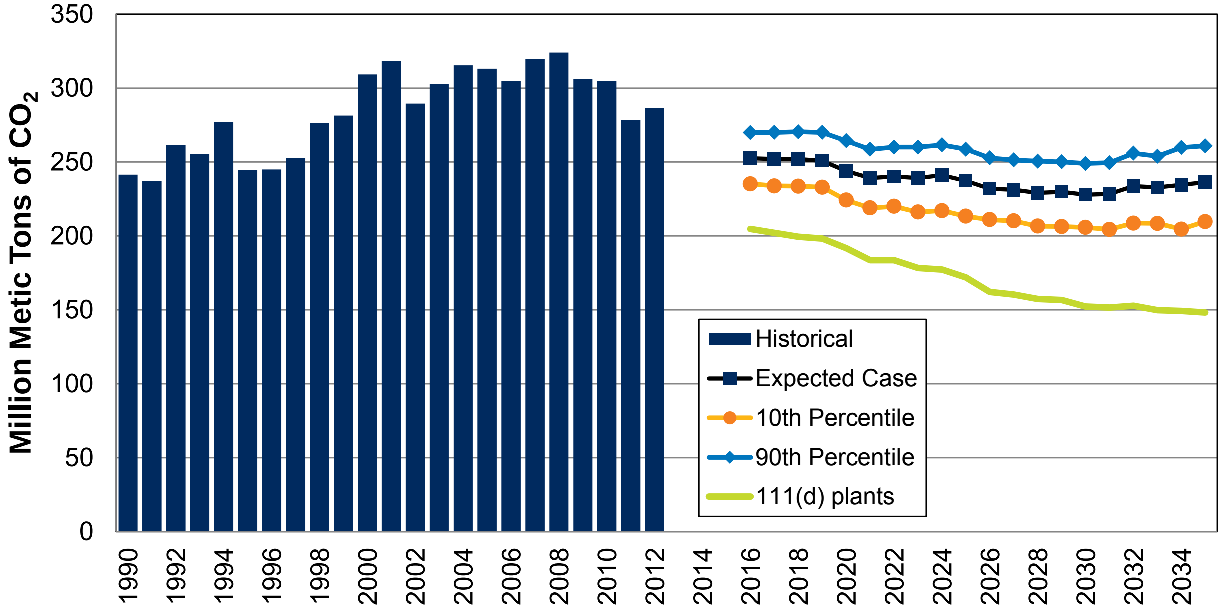


Figure 1.8: U.S. Western Interconnect Greenhouse Gas Emissions



Action Items

The 2015 Action Items chapter updates progress made on Action Items in the 2013 IRP and outlines activities Avista intends to perform between the publication of this report and publication of the 2017 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 2015 IRP is Avista's fourteenth 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 2015 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 more than 75 invited 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 2015 IRP. The first meeting was on May 29, 2014; the last occurred on June 24, 2015. 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 http://www.avistautilities.com/inside/resources/irp/electric. 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, Case No. GNR-E-93-1, Order No. 24729, 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 – May 29, 2014	• TAC Meeting Expectations • 2013 IRP Commission Acknowledgements • 2013 Action Plan Update • Energy Independence Act Compliance • Pullman Energy Storage Project • Demand Response Study Discussion • Draft 2015 Electric IRP Work Plan
TAC 2 – September 23, 2014	• Introduction & TAC 1 Recap • Conservation Selection Methodology • Load and Economic Forecast • Shared Value Report • Generation Options • Clean Power Plan Proposal Discussion
TAC 3 – November 21, 2014	• Introduction & TAC 2 Recap • Planning Margin • Colstrip Discussion • Cost of Carbon • IRP Modeling Overview • Conservation Potential Assessment
TAC 4 – February 24, 2015	• Introduction & TAC 3 Recap • Demand Response Study • Natural Gas Price Forecast • Electric Price Forecast • Resource Requirements • Interconnection Studies • Market Scenarios and Portfolio Analysis
TAC 5 – May 19, 2015	• Introduction & TAC 4 Recap • Review of Market Futures • Ancillary Services Valuation • Conservation Potential Assessment • Draft 2015 PRS & Portfolio Analysis
TAC 6 – June 24, 2015	• Introduction & TAC 5 Recap • Avista Community Solar • 2015 Action Plan • Final 2015 PRS • 2015 IRP Document Introduction

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 2015 IRP TAC process.

Table 2.2: External Technical Advisory Committee Participating Organizations

Organization
AEG
As You Sow
Birch Energy Economics
City of Spokane
Clearwater Paper
Earth Justice
Eastern Washington University
Eugene Water & Electric Board
GE Energy
Gonzaga University
Grant PUD
Idaho Department of Environmental Quality
Idaho Public Utilities Commission
Inland Empire Paper
Montana Environmental Information Center
NW Energy Coalition
PacifiCorp
Pend Oreille PUD
Puget Sound Energy
Pullman City Council
Renewable Northwest
Residential and Small Commercial Customers
Resource Development Associates
Sierra Club
Spokane Neighborhood Action Partners
The Energy Authority
Washington State Office of the Attorney General
Washington Department of Enterprise Services
Washington State Department of Commerce
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.

2015 IRP Outline

The 2015 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 2015 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 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.

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 2015 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 2013 IRP. It details the action items Avista will focus on between publication of this plan and the next one.

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 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
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

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, 2014; 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 Chapter 11- Preferred Resource Strategy
WAC 480-100-238(2)(a) – Plan describes conservation supply.	Chapter 5- Energy Efficiency & Demand Response
WAC 480-100-238(2)(a) – Plan addresses supply in terms of current and future needs of utility ratepayers.	Chapter 3- Economic & Load Forecast
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 Chapter 11- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers demand side uncertainties.	Chapter 5- Energy Efficiency & Demand Response Chapter 11- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers resource dispatchability.	Chapter 9- Generation Resource Options Chapter 10- Market Analysis
WAC 480-100-238(2)(b) – LRC analysis considers resource effect on system operation.	Chapter 10- Market Analysis Chapter 11- Preferred Resource Strategy
WAC 480-100-238(2)(b) – LRC analysis considers risks imposed on ratepayers.	Chapter 7- Policy Considerations Chapter 9- Generation Resource Options Chapter 10- Market Analysis Chapter 11- Preferred Resource Strategy 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 Chapter 4- Existing Supply Resources Chapter 7- Policy Considerations 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 Chapter 11- Preferred Resource Strategy 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 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 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 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 Chapter 5- Energy Efficiency & Demand Response 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 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 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 Chapter 11- Preferred Resource Strategy 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 Chapter 8- Transmission & Distribution
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 Chapter 8- Transmission & Distribution Chapter 9- Generation Resource Options Chapter 12- Portfolio Scenarios
WAC 480-100-238(3)(g) – Plan includes a two-year action plan that implements 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. (Description not required)	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 Chapter 10- Market Analysis
RCW 19.280.030-1(f) – The integration of the 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 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 2015 Expected Case energy forecast grows 0.6 percent per year, replacing the 1.0 percent annual growth rate in the 2013 IRP.
- Peak load growth is higher than energy growth, at 0.74 percent in the winter and 0.85 percent in the summer.
- Retail sales and residential use per customer forecasts continue to decline from 2013 IRP projections.
- Testing performed for this IRP shows that historical extreme weather events are valid for peak load modeling.

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 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 explains that when regional employment growth is stronger than U.S. growth over the business cycle, its cause is increased in-migration. The reverse holds true. Figure 3.1 shows annual population growth since 1971. 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

[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

to 2013. Accelerating service area employment growth in 2013 helped push population growth above one percent in 2014.

Figure 3.1: MSA Population Growth and U.S. Recessions, 1971-2014

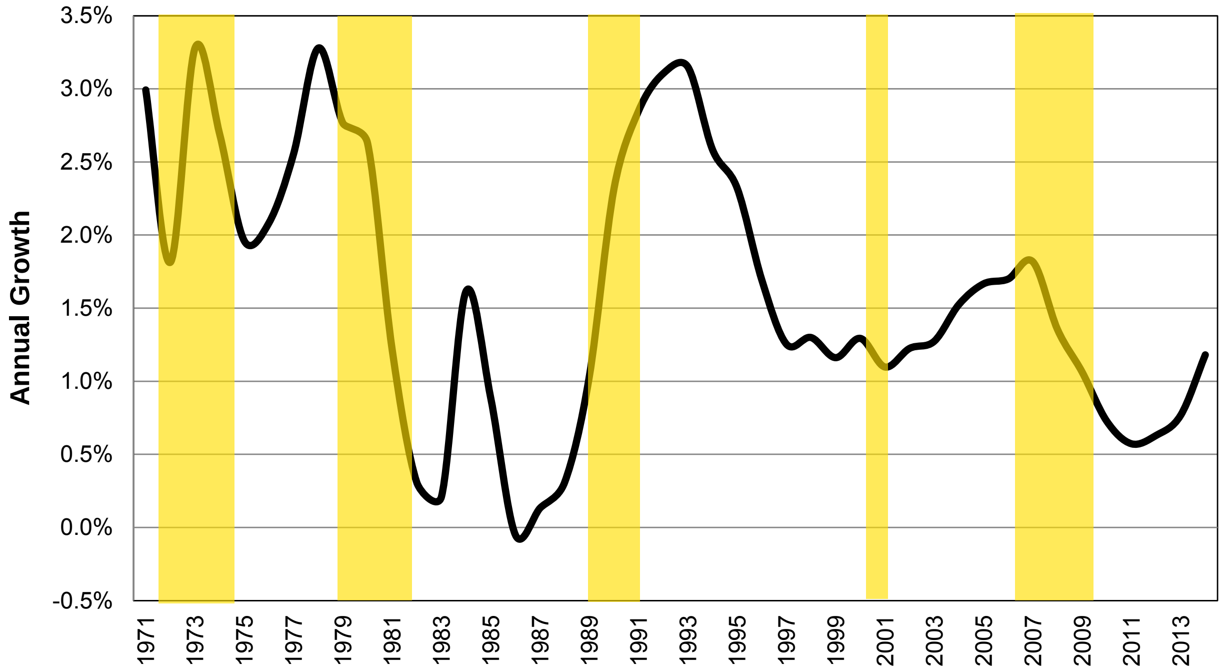
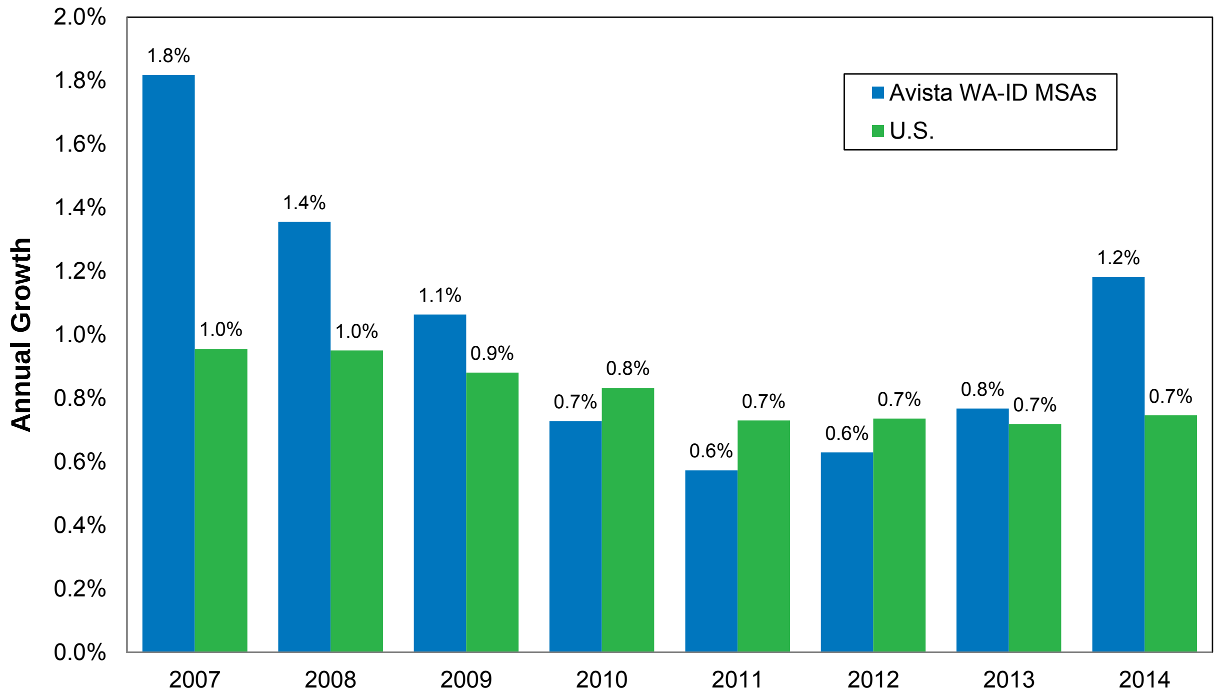


Figure 3.2 shows population growth since the start of the Great Recession in 2007.[3] Service area population growth over the 2010-2012 period was weaker than the U.S.; it was closely associated with the strength of regional employment growth relative to the U.S. over the same period. The same can be said for the increase in population growth in 2014 relative to the U.S. The association of employment growth to population growth has a one year lag. That is, 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.

[3] Data Source: Bureau of Economic Analysis and U.S. Census.

Figure 3.2: MSA Population Growth, 2007-2014



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 MSAs.[4] Approximately 70 percent of employment in the three MSAs is in private services, followed by government (18 percent) and private goods-producing sectors (13 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.

Between 1990 and 2007 non-farm employment growth averaged 2.7 percent per year. 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. By the fourth quarter 2014, service area employment growth began exceeding U.S. growth rates.

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

Figure 3.3: MSA Non-Farm Employment Breakdown by Major Sector, 2014

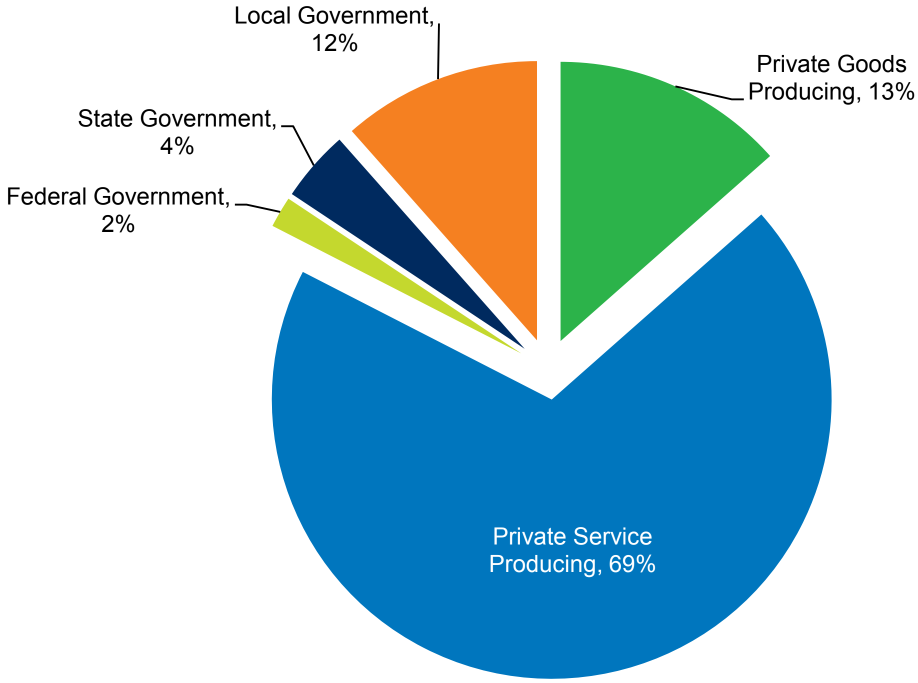


Figure 3.4: MSA Non-Farm Employment Growth, 2007-2014

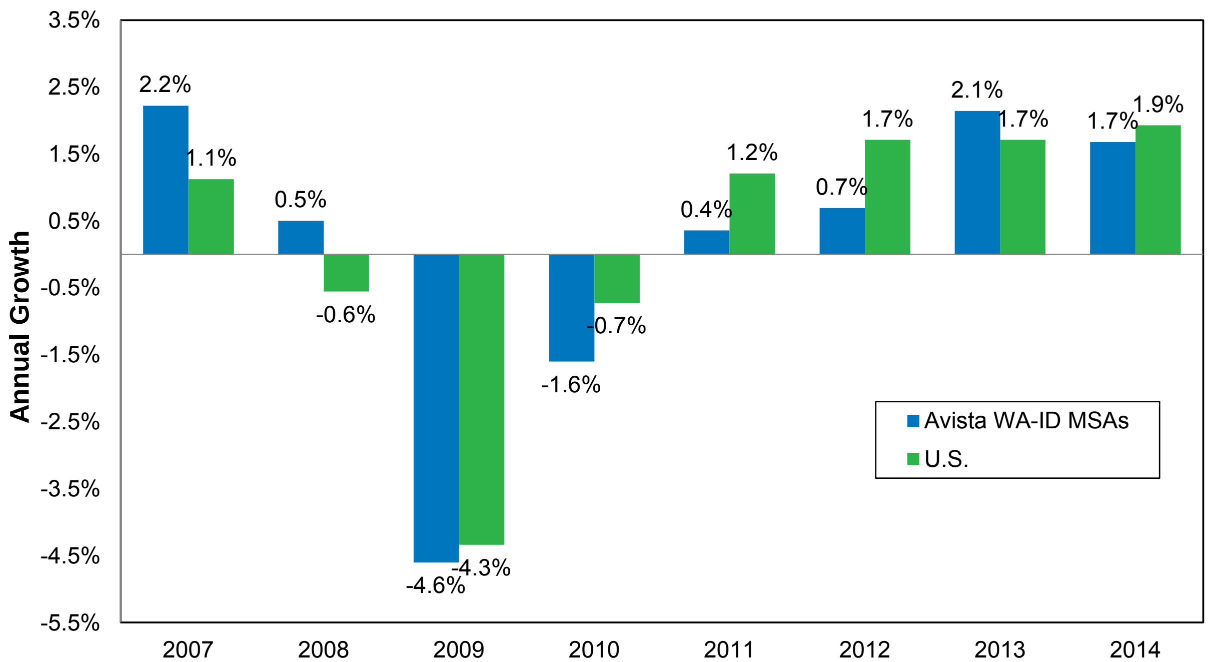
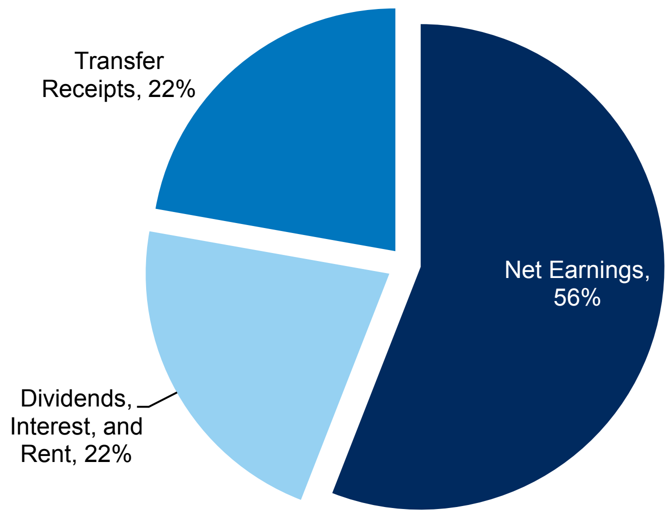


Figure 3.5 shows the distribution of personal income, a broad measure of both earned income and transfer payments, for Avista's Washington and Idaho MSAs.[6] Regular income includes net earnings from employment, and investment income in the form of

[6] Data Source: Bureau of Economic Analysis.

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.

Figure 3.5: MSA Personal Income Breakdown by Major Source, 2013

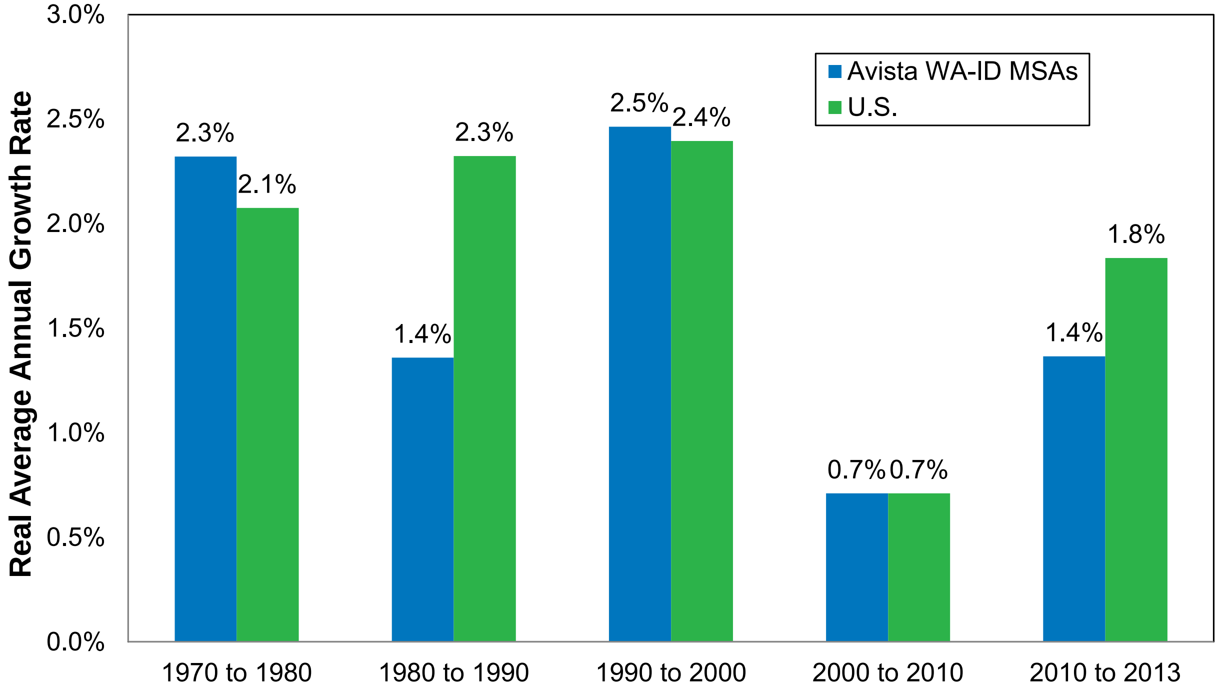


Transfer payments in Avista's service area in 1970 accounted for 12 percent of the local economy. The income share of transfer payments has nearly doubled over the last 40 years, to 22 percent. The relatively high regional dependence on government employment and transfer payments means continued federal fiscal consolidation and transfer program reform may reduce future growth. Although roughly 60 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 for Avista's service area and the U.S. Note that in the 1980-90 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. As a result, 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: 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 a set of 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.

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

Equation 3.1: Generating Schedule Total Load

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

Where:

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

UPC Forecast Methodology

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

Equation 3.2: Use Per Customer Regression Equation

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

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

The W variables will be HDDs and CDDs. Depending on the schedule, the Z variables may include real average energy price (RAP); average household size (AHS); 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.

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.

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

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.

The choice of a 20-year moving average for defining normal weather reflects several factors. First, recent climate research from the National Aeronautic 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 that summer temperatures in the Northern Hemisphere have increased about 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 1951-1981 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 10 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, AHS, and IP appear in Equation 3.2, then they must also be forecasted for five years to generate the UPC forecast. The assumption in the five-year forecast for this IRP is that RAP will increase two percent annually. This rate reflects the average annual real growth rate for the 2005-2013 period. AHS is constant at the 2012 level.[11] This reflects the relative stability of AHS over the 2006-2013 period. Table 3.1 shows the schedules using these three drivers.

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

[11] AHS only appears in the forecast equation for Washington Schedule 1 UPCAHS is not a statistically significant predictor of UPC and the sign on the estimated regression coefficient is not stable for Idaho Schedule 1.

Table 3.1: UPC Models Using Non-Weather Driver Variables

Schedule	Variables	Comment
Washington:		
Residential Schedule 1	RAP, AHS	
Commercial Schedule 31	RAP	Commercial pumping schedule
Industrial Schedule 31	RAP	
Industrial Schedules 11, 21, and 25	IP	
Idaho:		
Residential Schedule 1	RAP	AHS not a statistically significant or stable driver
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.

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.
- ε_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.[12,13] 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.

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

Figure 3.7: Forecasting IP Growth

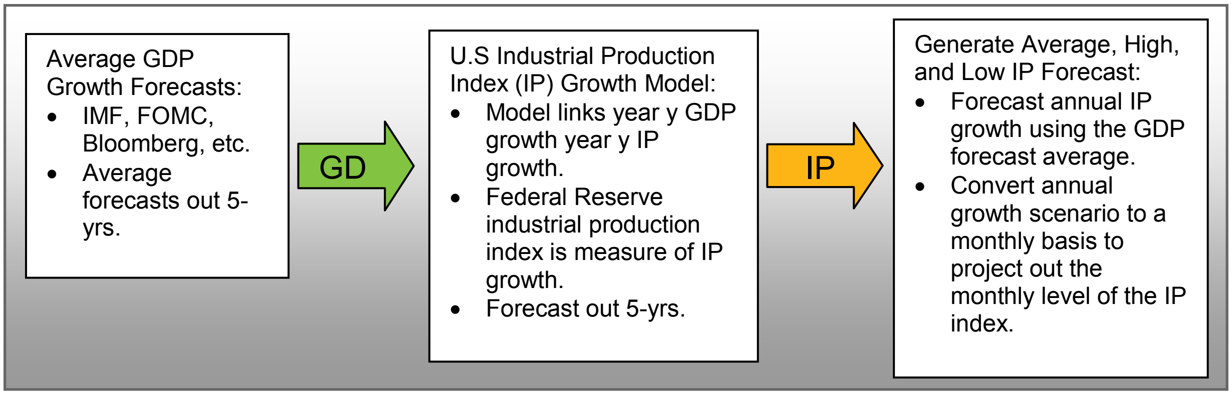
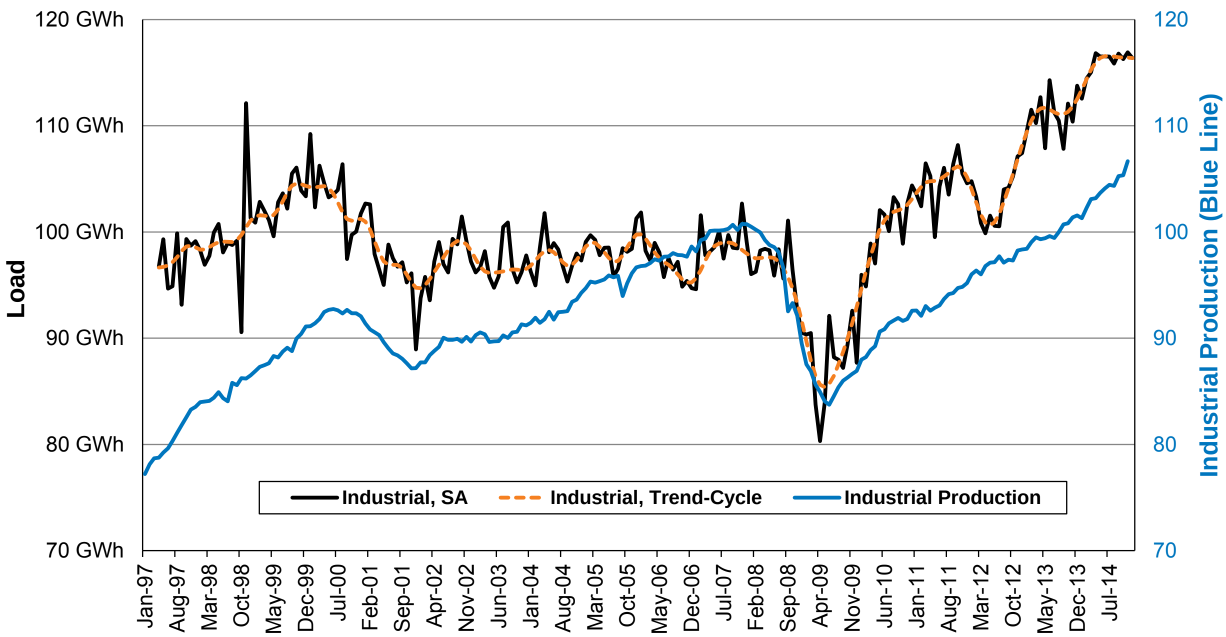


Figure 3.8: Industrial Load and Industrial (IP) Index



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 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.

Table 3.2: Customer Growth Correlations, January 2005-December 2013

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

Figure 3.9 shows the relationship between annual population growth and year-over-year customer growth.[14] For the last 15 years electricity customer growth has closely followed population growth in the combined Spokane-Kootenai MSAs. Both population and customer growth have averaged 1.2 percent annually over the 2000-14 period.

Figure 3.9: Population Growth vs. Customer Growth, 2000-2014

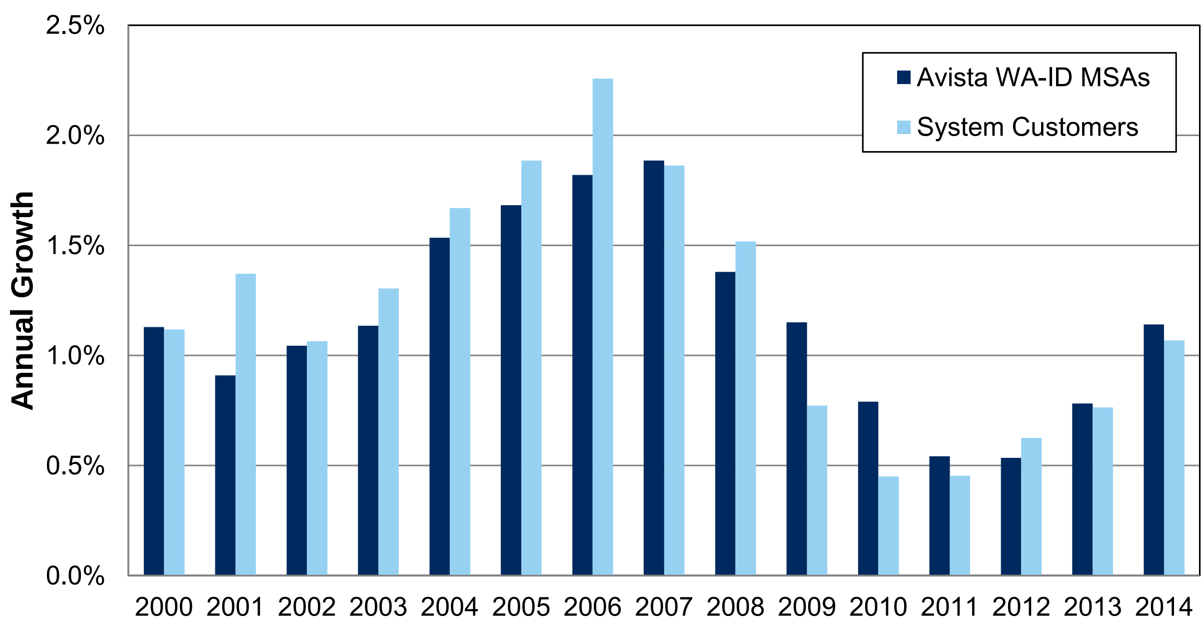
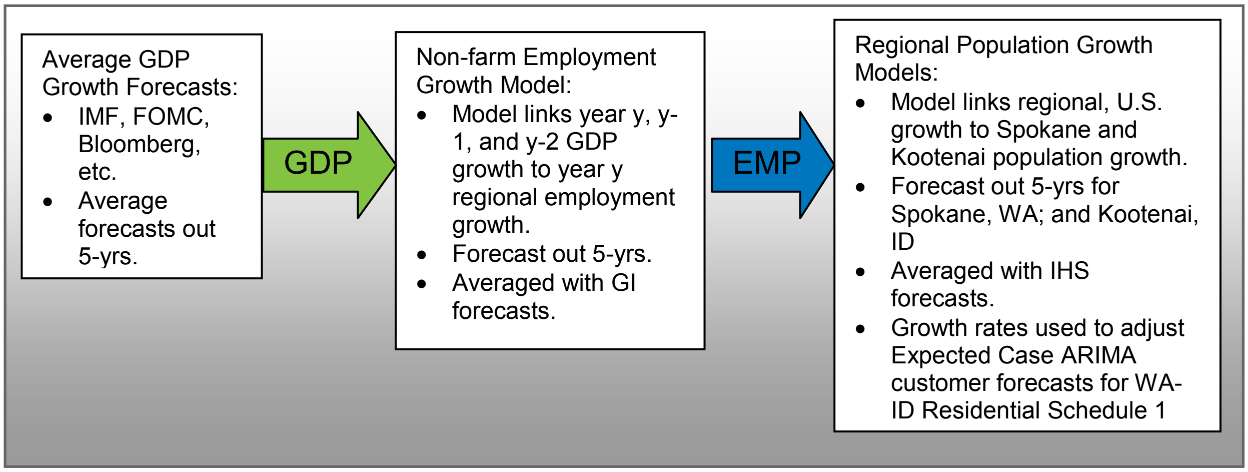


Figure 3.9 demonstrates that population growth can be used as a proxy for customer growth. As a result, forecasted population is an adjustment to Expected Case forecasts of Residential Schedule 1 customers in Washington and Idaho. That is, for schedule 1

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

in Washington and Idaho, an Expected Case forecast is made using an ARIMA times-series model. 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 3.10: 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.
- GEMPy = employment growth in year y.
- GGDPy,US, GGDPy-1,US, and GGDPy-2,US = U.S. real GDP growth in years y, y-1, and y-2.

- DKC and DHB = structural change (SC) dummy variables for the closing of Kaiser Aluminum in Spokane.
- For the housing bubble, specific to each region.
- D1994=1 and D2009=1 = outlier (OL) dummy variables for 1994 and 2009 in Kootenai.
- εy= a random error term.

The same average GDP growth forecasts used for the IP growth forecasts are inputs to generate five-year employment growth forecasts. Employment forecasts are averaged with IHS Connect's (formerly Global Insight) forecasts for the same counties. Averaging reduces 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.
- GPOPy = 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 HIS forecasts) become inputs to Equations 3.6 and 3.7 to generate population growth forecasts. These forecasts, averaged with IHS's forecasts for the same MSAs, produce a final population forecast. This population growth forecast is used to adjust the Expected Case ARIMA generated forecasts for Residential Schedule 1 customers. This adjustment reconciles forecasted growth with forecasted population growth.

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 a growing electric vehicle (EV) and residential rooftop photovoltaic solar (PV) fleets. 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:

- ℓ_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.[15] C_y is not dependent on weather, so where u_y values are weather normalized, ℓ_y results are weather-normalized. Varying c_y and u_y generates different long-run forecast simulations. This IRP pays attention to varying c_y for economic reasons and u_y due to increased PV penetration.

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 2020 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 2019 is approximately 1 percent, assuming a gradual decline starting in 2020. This value was generated with the Employment and Population forecast Equations 3.4, 3.5, 3.6, and 3.7 in conjunction with IHS Connect's employment and population forecasts for the 2020-2024 period. The Expected Case assumes long-run U.S. employment growth of approximately 1.4 percent and service area employment growth of approximately 1.5 percent. These numbers result from assumed U.S. long-run GDP growth of approximately 2.4 percent. 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 assumption of high correlation is consistent with the high historical correlation between residential and commercial load growth. The 0.5

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

percent spread is in 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. For 2020-2035, annual industrial load growth is set at 0.5 percent and streetlight load growth at 0.1 percent. 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 2026. Up to 2026, this is the same as the nominal price increasing 4 percent a year assuming a non-energy inflation rate of 2 percent. The real price increase assumption is zero starting in 2026. 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 -0.20. 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. The AHS-elasticity of UPC is set at 2.3. This assumes AHS is constant up to 2025, then starts to slowly decline through 2040. AHS-elasticity estimates are from the five-year UPC forecast equations for Residential Schedule 1 in Washington and Idaho, using the customer-weighted average between Washington and Idaho.

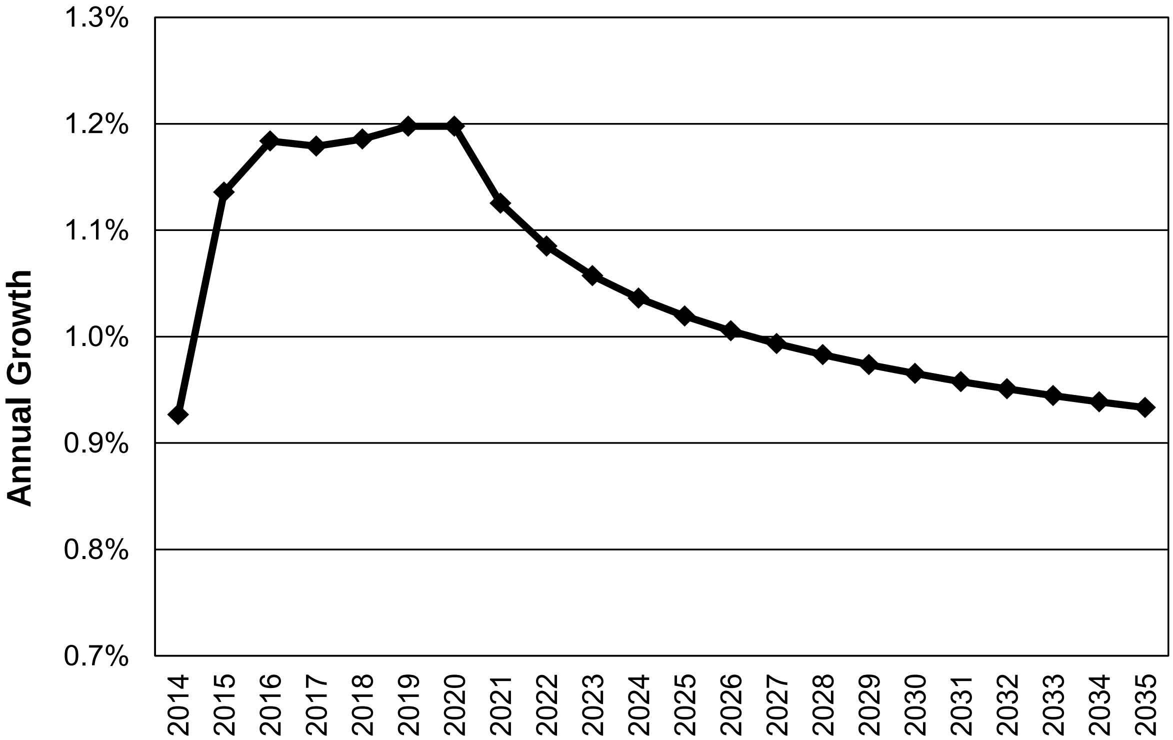
7. From 2020 to 2023, depressed UPC growth results from new lighting and other efficiency standards. The impact is more gradual than the Energy Information Administration's (EIA) modeling assumptions in its 2014 Annual Energy Outlook. The EIA assumes a large decline in UPC growth in 2020 with a subsequent sharp rebound in 2021 that Avista believes is too volatile.

8. Electric vehicles grow at a rate consistent with present adoption rates. Using Electric Power Research Institute data, Avista estimates that as of 2015 there are around 400 EVs registered in its service area. The forecasted rate of adoption over the 2020-2035 period is a function of forecasted residential customer growth over the same period. The EV adoption rate assumption uses historical data for the 2010-2013 period to establish the relationship between residential customers and EVs. This analysis shows that for every 100 residential customers added, approximately three new registered EVs are added to the Avista service area. However, since Avista does not serve 100 percent of all loads in the counties it serves, so this adoption rate is reduced by 50 percent. Each EV uses 2,500 kWh per year in the forecast.

9. 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 3.0 kilowatts and a 13 percent capacity factor. As of 2014, residential PV penetration was about 0.06 percent. The growth assumption is approximately 0.01 percent per year to 2040, resulting in a 2035 penetration rate of 0.29 percent. This slow rate of PV penetration growth is consistent with recent history.

Figure 3.11: Long-Run Annual Residential Customer Growth



Load Scenarios with PV

In addition to the Expected Case forecast, three alternatives illustrate the impacts of varying PV penetration by 2025: 1 percent (low shock scenario); 5 percent (medium shock scenario); and 10 percent (high shock scenario). In each scenario, the penetration rate is constant after 2025. Each shock case assumes that the PV system size grows each year so that by 2035 the typical system size equals 5 kilowatts. All remaining assumptions in the PV penetration cases remain unchanged from the Expected Case. Figure 3.12 presents results of the Expected Case and shock scenarios. Figure 3.13 shows the annual growth rate in the load shown in Figure 3.12. In all PV scenarios, load growth returns to the Expected Case by 2026 when the penetration rate stabilizes. Table 3.3 shows the average annual PV scenario growth rates in native load for the five-year forecast and long-run forecast.

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Figure 3.12: Load Scenarios with PV Shocks

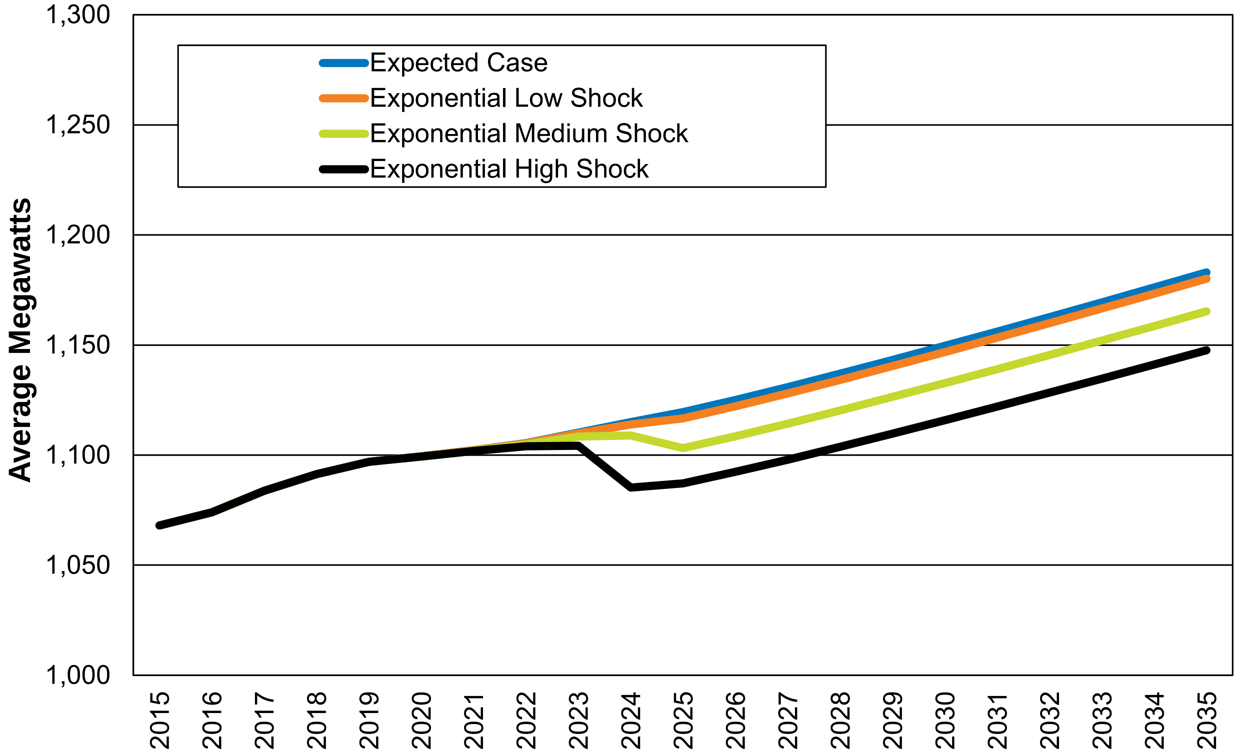


Figure 3.13: Load Growth Scenarios with PV Shocks

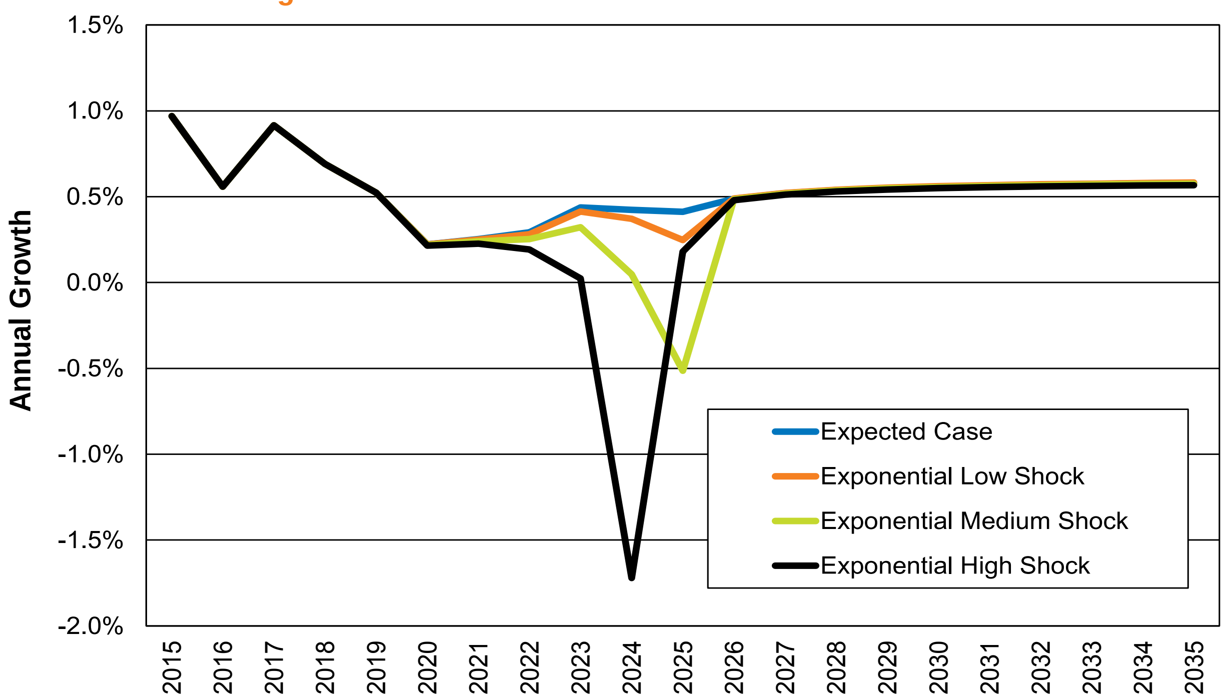


Table 3.3: Average Annual PV Scenario Load Growth for Selected Periods

PV Scenario	2015-2019 (Percent)	2020-2035 (Percent)	2015-2035 (Percent)
Expected Case (0.1%)	0.73	0.47	0.53
Low Shock (1%)	0.73	0.46	0.52
Medium Shock (5%)	0.73	0.38	0.46
High Shock (10%)	0.73	0.28	0.39

The model suggests that with PV penetration between 0.3 percent and 1 percent, load growth after 2020 averages around 0.5 percent, a slight decrease from the 0.6 percent assumption in the Expected Case. Penetration rates 5.0 percent and higher result in noticeable load growth declines.

Native Load Scenarios with Low/High Economic Growth

Native load changes in the PV scenarios because of varying PV growth assumptions. For load growth scenarios, Expected Case PV assumptions remain constant while regional economic growth levels vary. The high and low scenarios use population growth Equations 3.6 and 3.7, holding U.S. employment growth constant at 1.4 percent, but varying MSA employment growth at higher and lower levels gauges the impacts on population growth and utility loads. See Table 3.4. 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 3.14.

Table 3.4: High/Low Economic Growth Scenarios (2015-2035)

Economic Growth	Annual U.S. Employment Growth (percent)	Annual Service Area Employment Growth (percent)	Annual Population Growth (percent)
Expected Case	1.4	1.5	1.0
High Growth	1.4	2.3	1.6
Low Growth	1.4	0.7	0.8

Figure 3.14: Average Megawatts, High/Low Economic Growth Scenarios

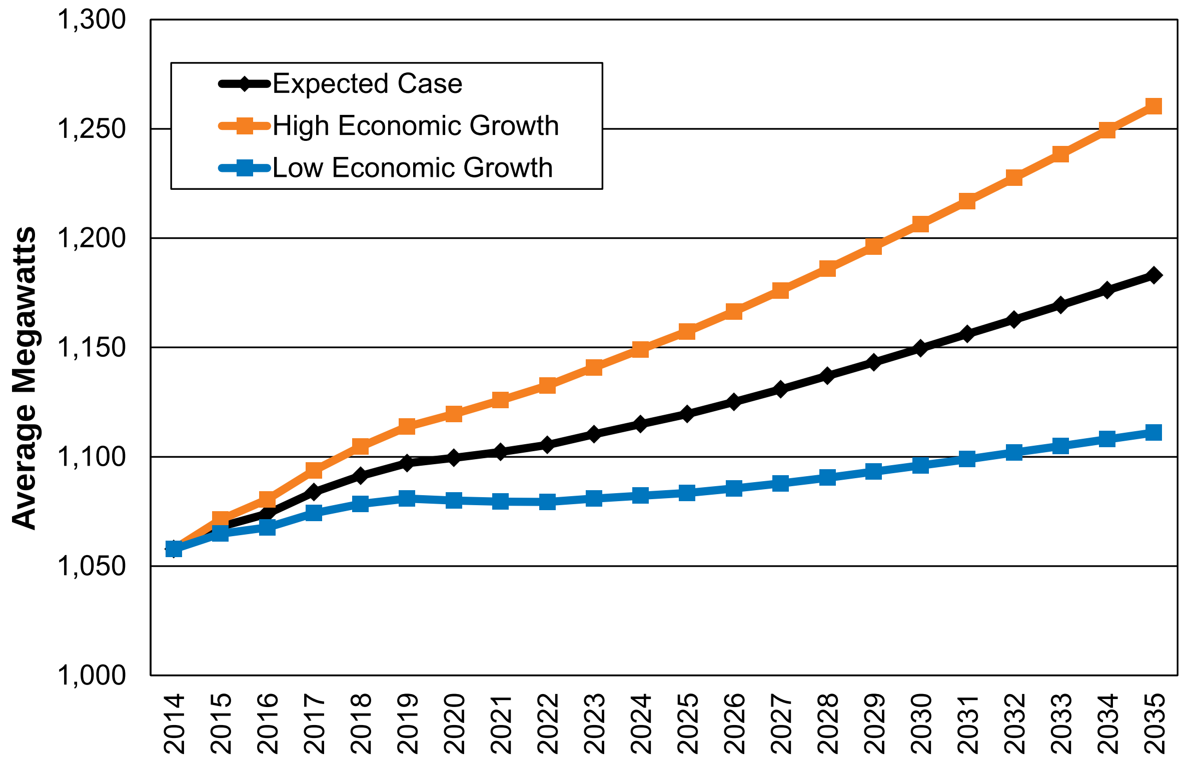


Table 3.5 is the average annual load growth rate over the 2015-2035 period. The low growth scenario predicts a slight load decline over 2020-2022 due to the impact of the phased-in efficiency standards discussed in Item 7 of the Expected Case Assumptions listed above.

Table 3.5: Load Growth for High/Low Economic Growth Scenarios (2015-2035)

Economic Growth	Average Annual Native Load Growth (percent)
Expected Case	0.53
High Growth	0.83
Low Growth	0.23

Long-Run Forecast Residential Retail Sales

Focusing on residential kWh sales, Figure 3.15 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 2014 Annual Energy Outlook. Avista's forecast never shows positive UPC growth; in contrast, the EIA forecasts positive UPC growth returning in 2033. The EIA forecast reflects a population shift to warmer-climate states where air conditioning is typically required most of the year.

Figure 3.15: UPC Growth Forecast Comparison to EIA

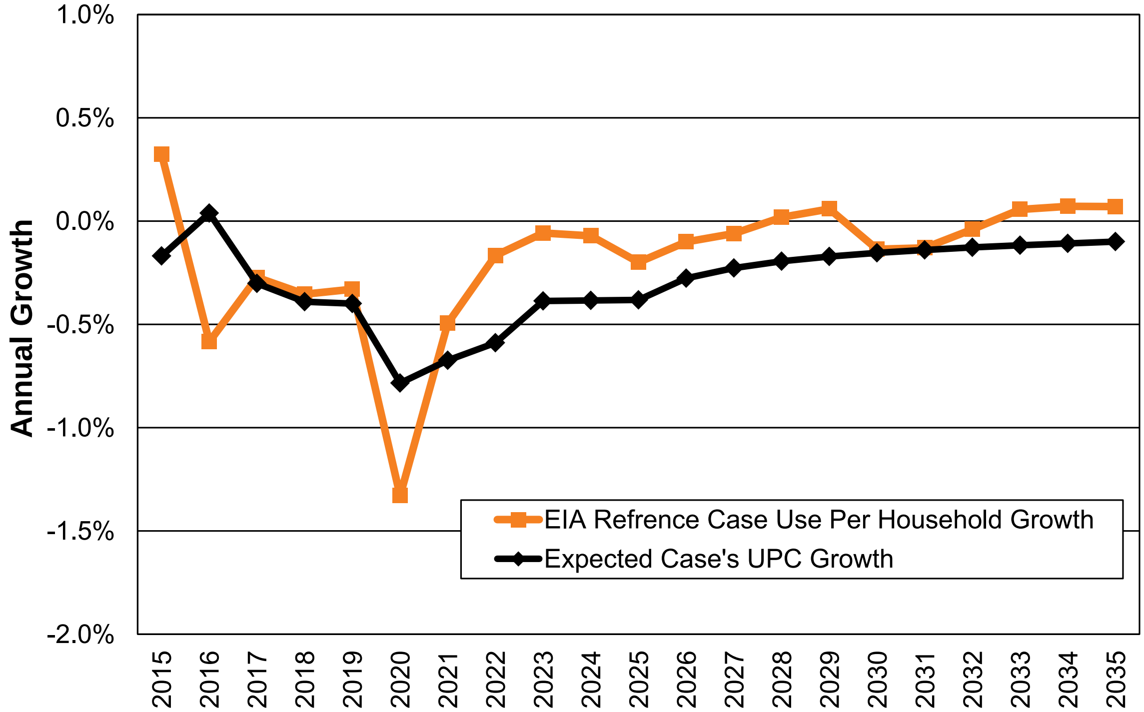
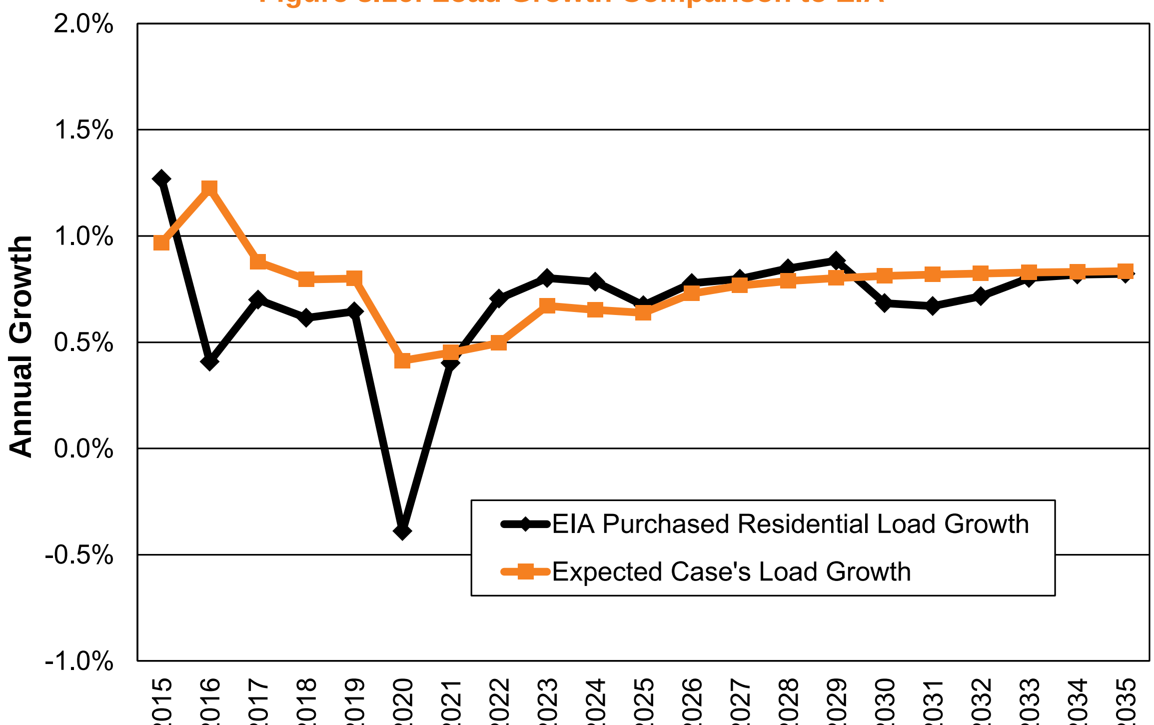


Figure 3.16 shows the EIA and Expected Case residential load growth forecasts of residential load growth. Avista's forecast is higher in the 2015-2020 period, reflecting an assumption that service area population growth will be stronger than the U.S. average.

Figure 3.16: Load Growth Comparison to EIA



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. This said, 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

$$\begin{aligned} hMW^{netpeak}_{d,t,y} &= \lambda_0 + \lambda_1 HDD_{d,t,y} + \lambda_2 (HDD_{d,t,y})^2 \\ &+ \lambda_3 HDD_{d-1,t,y} + \lambda_4 CDD_{d,t,y} + \lambda_5 CDD^{HIGH}_{d,t,y} + \lambda_6 CDD_{d-1,t,y} + \phi_1 GDP_{q(t).y-1} \\ &+ \omega_{WD} D_{d,t,y} + \omega_{SD} D_{t,y} + \omega_{OL} D_{Mar\ 2005=1} + \omega_{OL} D_{Feb\ 2012=1} + \epsilon_{d,t,y} \end{aligned}$$

Where:

- $\mathrm{hMW}^{\mathrm{netpeak}}_{\mathrm{d,t,y}}$ = 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.
- $\mathrm{CDD}^{\mathrm{HIGH}}_{\mathrm{d,t,y}}$ = maximum peak day temperature minus 65 degrees. This term provides a better model fit than the square of CDD.
- $\mathrm{GDP}_{\mathrm{q(t).y-1}}$ = level of real GDP in quarter q covering month t in year y-1.
- $\omega_{WD}D_{d,t,y}$ = dummy vector indicating the peak's day of week.
- $\omega_{SD}D_{t,y}$ = seasonal dummy vector indicating the month; and the other dummy variables control for outliers in March 2005 and February 2012.
- $\varepsilon_{d,t,y}$ = uncorrelated N(0, σ) 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 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.

Similarly, the model for cooling degree days is:

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

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.
- $CDD_{t,y,MAX}$ = cooling degree days calculated from the maximum (MAX) average temperature. The average of daily high (H) and low (L) on day d, in month t, in year y if in month t if the maximum average temperature (average of daily high and low) is greater than 65 degrees.
- a = aggregate impact of all the other variables held constant at their average values.

Given 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

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

Equation 3.13: Current Year Peak Load for Summer Months

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

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 3.6 shows estimated peak load growth rates with and without the two large industrial customers. Figure 3.17 shows the forecasted time path of peak load out to

2040, and Figure 3.18 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 3.6: Forecasted Winter and Summer Peak Growth, 2015-2035

Category	Winter (Percent)	Summer (Percent)
Excluding Large Industrial Customers	0.74	0.85
Including Large Industrial Customers	0.68	0.79

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 3.17 will converge with the blue winter line in approximately year 2100. Figure 3.18 shows that the winter high/low bound considerably larger than summer, and reflects a greater range of temperature anomalies in the winter months. Table 3.7 shows the energy and peak forecasts.

Figure 3.17: Peak Load Forecast 2015-2035

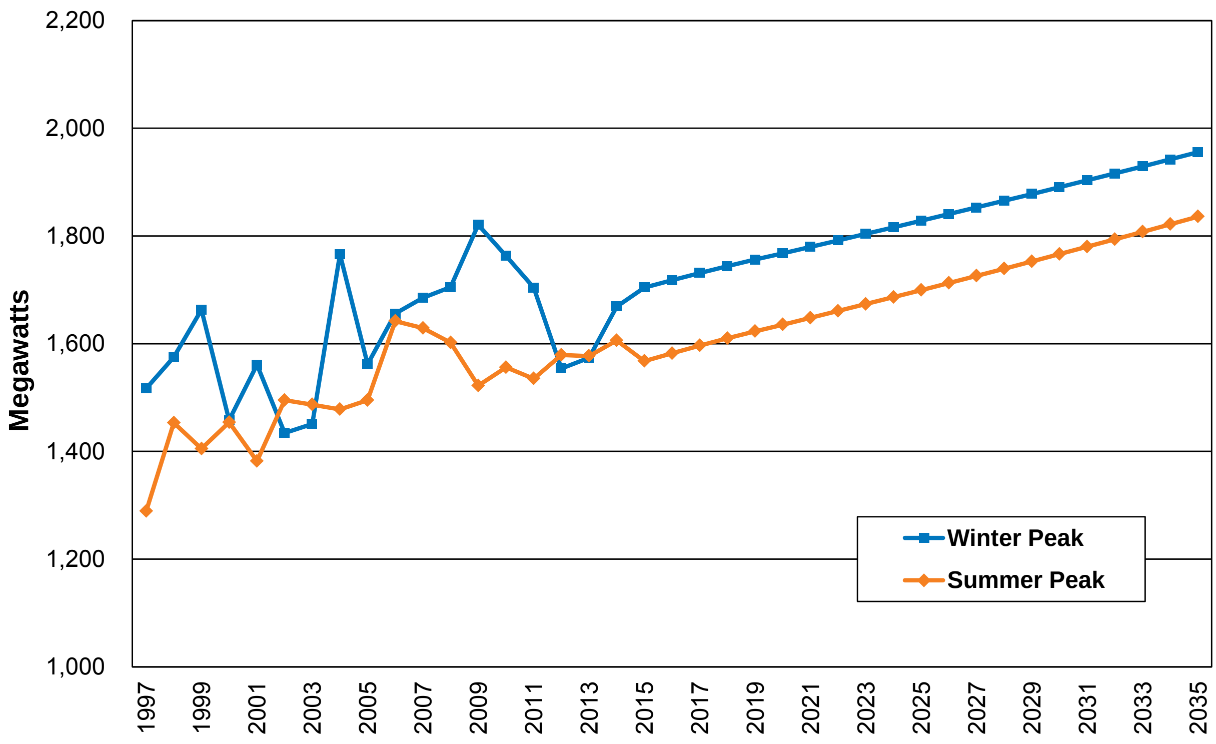


Figure 3.18: Peak Load Forecast with 1 in 20 High/Low Bounds, 2015-2035

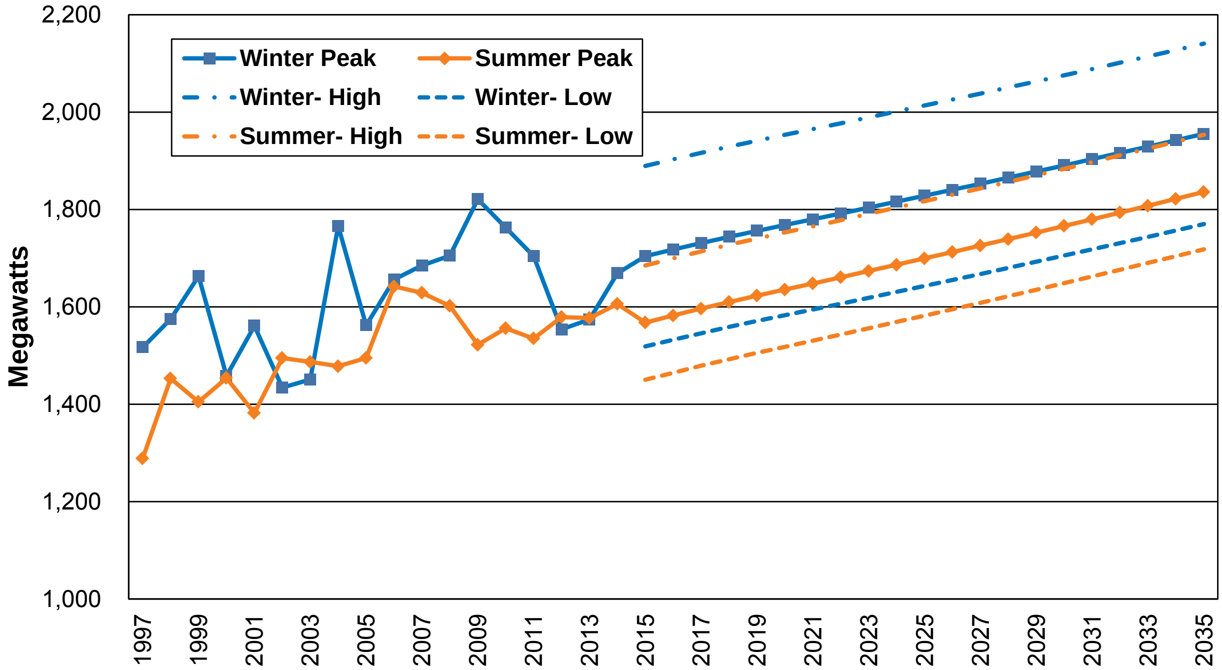


Table 3.7: Energy and Peak Forecasts

Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)
2016	1,074	1,718	1,582
2017	1,084	1,731	1,596
2018	1,091	1,744	1,610
2019	1,097	1,756	1,623
2020	1,099	1,768	1,635
2021	1,102	1,780	1,648
2022	1,105	1,792	1,661
2023	1,110	1,804	1,674
2024	1,115	1,816	1,686
2025	1,120	1,828	1,699
2026	1,125	1,840	1,713
2027	1,131	1,853	1,726
2028	1,137	1,865	1,739
2029	1,143	1,878	1,753
2030	1,150	1,891	1,766
2031	1,156	1,903	1,780
2032	1,163	1,916	1,794
2033	1,169	1,929	1,808
2034	1,176	1,942	1,822
2035	1,183	1,955	1,836

Testing for Changes in Extreme Temperature Behavior

The impacts of global warming and the relevance of historical temperature data when forecasting future peak loads, drives much of the recent load forecasting debates. To validate the use of historical temperatures in the peak load forecast, an analysis was conducted using the same GISS methodology and reference period referenced in the UPC forecast methodology section. In particular, using 1951-1981 as the reference period, Avista examined daily temperature anomalies using daily temperature data from the Spokane International Airport going back to 1947. The analysis focused on the core summer months (June, July, and August) and winter months (December, January, and February). The GISS study only considered 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 1951 to 1981 reference period. In contrast, while Avista analysis shows increased average temperatures compared to the reference period, 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

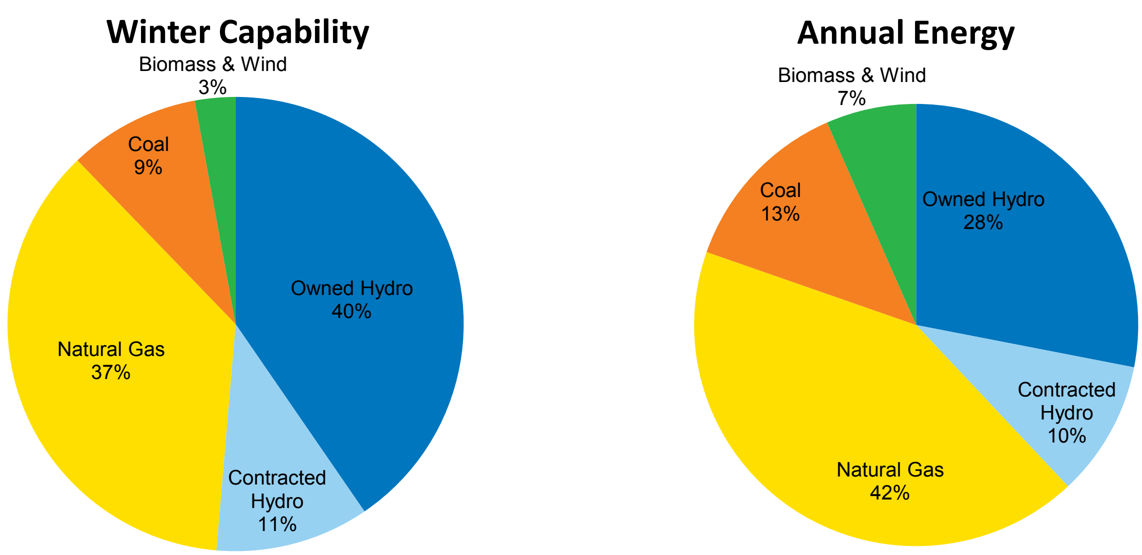
Avista relies on a diverse portfolio of assets to meet customer loads, including owning and operating eight hydroelectric developments on the Spokane and Clark Fork rivers. Its thermal assets include partial ownership of two coal-fired units, five natural gas-fired projects, and a biomass plant. Avista purchases energy from several independent power producers (IPPs), including Palouse Wind 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 generation potential.
- Seven percent of Avista's generating potential is biomass and wind.
- A major rehabilitation project for Nine Mile Falls ends in 2016.
- 280 of Avista customers net meter 1.8 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 42 percent, than hydroelectric at 37 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: 2016 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 stripped of 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 a separate license authorized by 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. 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 transmission grid.

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. Avista redeveloped the Huntington Park area around this facility in 2014 in honor of the company's 125th anniversary.

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 is undergoing substantial upgrades scheduled for completion in 2016. Two 8-MW units will replace its existing 3-MW units. Once operational, the new units will add 1.4 aMW of energy beyond the plant’s original configuration and bring total operating capability to 32 MW. The nameplate rating of the facility will rise to 36 MW. In addition to capacity upgrades, the facility will receive new hydraulic governors, static excitation systems, switchgear, station service, control and protection packages, ventilation, rehabilitation of intake gates and sediment bypass system, and other investments.

Long Lake

The Long Lake development is located northwest of Spokane and maintains the Lake Spokane reservoir, also known as Long Lake. The plant received new runners in the 1990s, bringing the project’s four units to 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. A new runner upgrade in 2001 added 0.6 aMW of energy generation to the project. 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. Current projects include replacing station service equipment, updating the powerhouse crane, and developing new control schemes and panels. After the preliminary work is completed, replacing 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.

Cabinet Gorge

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

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.

Total Hydroelectric Generation

Avista's hydroelectric plants have 1,065.4 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 the 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	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
Cabinet Gorge	Clark Fork	Clark Fork, ID	265.2	270.5	123.6
Noxon Rapids	Clark Fork	Noxon, MT	518.0	610.0	196.5
Total			**962.4**	**1,065.4**	**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.

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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	Boardman, OR	Gas	2003	312.0	277.0	287.3
Kettle Falls	Kettle Falls, WA	Wood	1983	47.0	47.0	50.7
Kettle Falls CT[1]	Kettle Falls, WA	Gas	2002	11.0	8.0	7.5
Total				**858.6**	**750.6**	**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. The Avista 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 near Rathdrum, Idaho connects to the Avista transmission system. It entered service in 1995 and has a maximum capacity of 178.0 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 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 is limited to run no more than approximately 550 hours 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.

[1] The Kettle Falls CT numbers include output of the natural gas-fired turbine plus the benefit of its steam to the main unit's boiler.

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 with a maximum capacity of 285 MW in the winter and 250 MW in the summer, with duct burners providing additional capacity of up to 27 MW. The plant nameplate rating of the plant is 287.3 MW.

Recent upgrades to Coyote Springs 2 include cooling optimization and cold day controls. The cold day controls remove firing temperature suppression that occurs when ambient temperatures are below 60 degrees. The upgrade improves the heat rate by 0.5 percent and output by approximately 2.0 MW during cold temperature operations. The cooling optimization package improves compressor and natural gas turbine efficiency, resulting in an overall increase in plant output of 2.0 MW. In addition to these upgrades, Coyote Springs 2 now has a Mark VIe control upgrade, a new digital front end on the EX2100 gas turbine exciter, and model-based control with enhanced transient capability. Each of these upgrades allows Avista to maintain high reliability, reduce future O&M costs, maintain compliance with WECC reliability standards, and help prevent damage to the machine during electrical system disturbances.

Kettle Falls Generation Station and Kettle Falls Combustion Turbine

The Kettle Falls Generating Station, a biomass facility, entered service in 1983 near Kettle Falls, Washington. It is among the largest biomass 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 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. 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 2015 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 when 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 2015, the contracts provide approximately 160 MW of capacity and 96 aMW of energy. The Douglas PUD (2018) and Chelan PUD (2020) contracts expire over the next five years. Avista may extend these contracts or even gain additional capacity in auctions; however, there are no guarantees to extend contract rights. Due to this uncertainty around future availability and cost, the IRP does not include these contracts in the resource mix beyond their expiration dates.

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 in earnest to decide whether the current treaty will continue, should be ended, or if a new agreement will be reached. 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, as part of 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

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	16.9
Grant PUD	Wanapum	3.7	Dec-2001	Dec-2052	34.5	27.2
Chelan PUD	Rocky Reach	5.0	Jan-2016	Dec-2020	58.1	18.4
Chelan PUD	Rock Island	5.0	Jan- 2016	Dec-2020	20.1	25.7
Douglas PUD	Wells	3.3	Feb-1965	Aug-2018	27.9	16.5
Canadian Entitlement					-10.1	-5.7
2016 Total Net Contracted Capacity and Energy					**155.3**	**99.0**

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.

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 further discussion of this obligation, and how Avista plans to account for it, is contained 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 4.4: PURPA Agreements

Contract	Owner	Fuel Source	Location	End Date	Size (MW)	Annual Energy (aMW)
Meyers Falls	Hydro Technology Systems Inc.	Hydro	Kettle Falls, WA	12/2013	1.30	1.05
Spokane Waste to Energy	City of Spokane	Municipal Waste	Spokane, WA	12/2017	18.00	16.00
Spokane County Digester	Spokane County	Municipal Waste	Spokane, WA	8/2016	0.26	0.14
Plummer Saw Mill	Stimson Lumber	Wood Waste	Plummer, ID	11/2016	5.80	4.00
Deep Creek	Deep Creek Energy	Hydro	Northpoint, WA	12/2016	0.41	0.23
Clark Fork Hydro	Clark Fork LLC.	Hydro	Clark Fork, ID	12/2017	0.22	0.12
Upriver Dam[2]	City of Spokane	Hydro	Spokane, WA	12/2019	17.60	6.17
Sheep Creek Hydro	Sheep Creek Hydro Inc.	Hydro	Northpoint, WA	6/2021	1.40	0.79
Ford Hydro LP	Ford Hydro Ltd Partnership	Hydro	Weippe, ID	6/2022	1.41	0.39
John Day Hydro	David Cereghino	Hydro	Lucille, ID	9/2022	0.90	0.25
Phillips Ranch	Glenn Phillips	Hydro	Northpoint, WA	n/a	0.02	0.01
Total					**47.32**	**29.15**

Table 4.5: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity (MW)	Summer Capacity (MW)	Annual Energy (aMW)
PGE Capacity Exch.	Exchange	System	12/2016	-150	-150	0
Douglas Settlement	Purchase	Hydro	9/2018	2	2	3
Energy America	Sale	CEC RECs[3]	12/2019	50	50	50
WNP-3	Purchase	System	6/2019	82	0	42
Lancaster	Purchase	Natural Gas	10/2026	279	228	215
Palouse Wind	Purchase	Wind	12/2042	0	0	40
Nichols Pumping	Sale	System	n/a	-1	-1	-1
Total				**262**	**129**	**349**

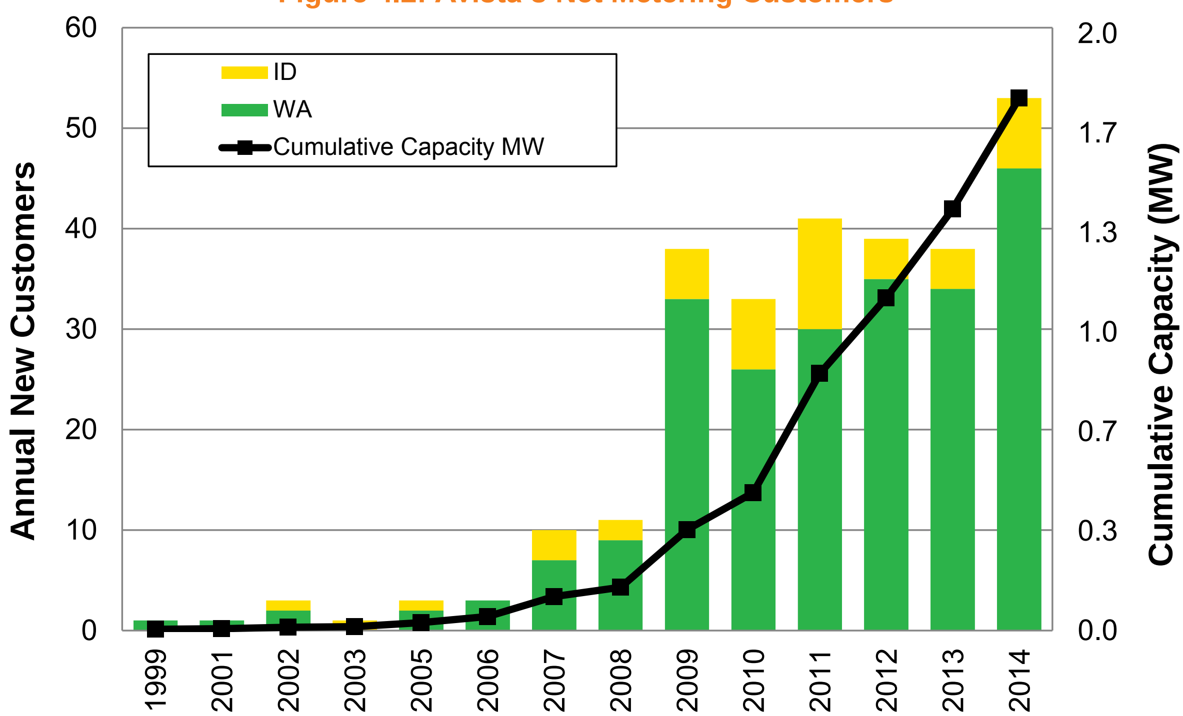
[2] Energy estimate is net of the city's pumping load.
[3] CEC RECs are renewable resources based on approval of the California Energy Commission. Kettle Falls, Palouse Wind, Nine Mile Falls, Post Falls, Monroe Street, and Upper Falls are CEC certified.

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 increased to 38 per year. The increase likely was in response to 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 2020. The Washington utility taxes credit finances these incentives that rise to as much as $1.08 per kWh.

Avista had 208 customer-installed net-metered generation projects on its system at the end of 2014 representing a total installed capacity of 1.8 MW. Eighty-four percent of 2014 installations are in Washington, with most located in Spokane County. In that year, Avista credited customers $245,884 for the energy created via the Washington state tax incentive–an average of $281 per MWh. Figure 4.2 shows annual net metering customer additions. 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 current tax incentives are nearing optimal payback, the number of new net-metered systems rose in 2014. If tax subsidies end without a significant reduction in technology cost, the interest in net metering likely will return to pre-tax incentive levels. 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. 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 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 will utilize approximately $600,000 each year in state tax incentives.

Boulder Park Community Solar Project

5. Energy Efficiency & Demand Response

Introduction

Avista began offering energy efficiency programs to its customers in 1978. Recent programs include the distribution in the summer of 2011 of 2.3 million compact fluorescent lights (CFLs) to residential and commercial customers for an estimated energy savings of 39,005 MWh. The 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).

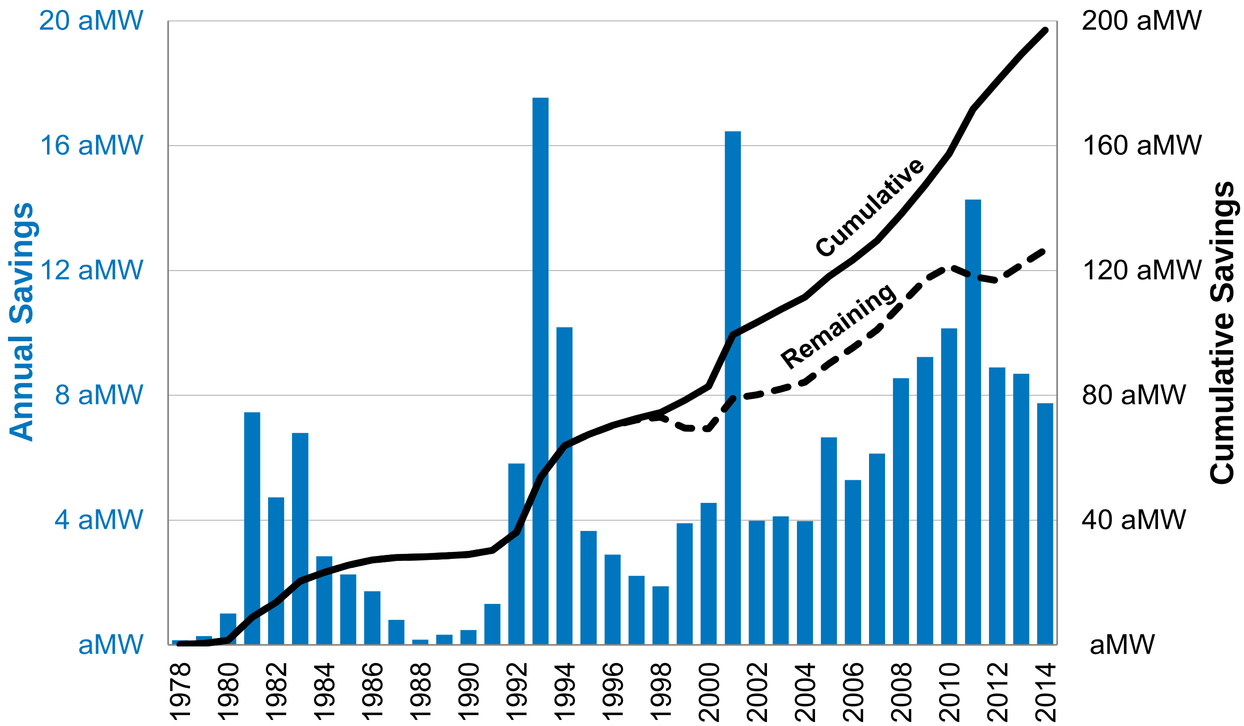
Section Highlights

- Current Avista-sponsored conservation reduces retail loads by nearly 11 percent, or 127 aMW.
- This IRP evaluated over 3,000 equipment options and over 2,300 measure options covering all major end use equipment, as well as devices and actions to reduce energy consumption for this IRP.
- This 2015 IRP is the first to co-optimize conservation and demand response options with generation resource options using our PRiSM model.

Figure 5.1 illustrates Avista's historical electricity conservation acquisitions. Avista has acquired 197 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 assumed measure life accounts for the difference between the cumulative and online trajectories in Figure 5.1. Currently 127 aMW of conservation serves customers, representing nearly 11 percent of loads.

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 and Forecast Conservation Acquisition (system)



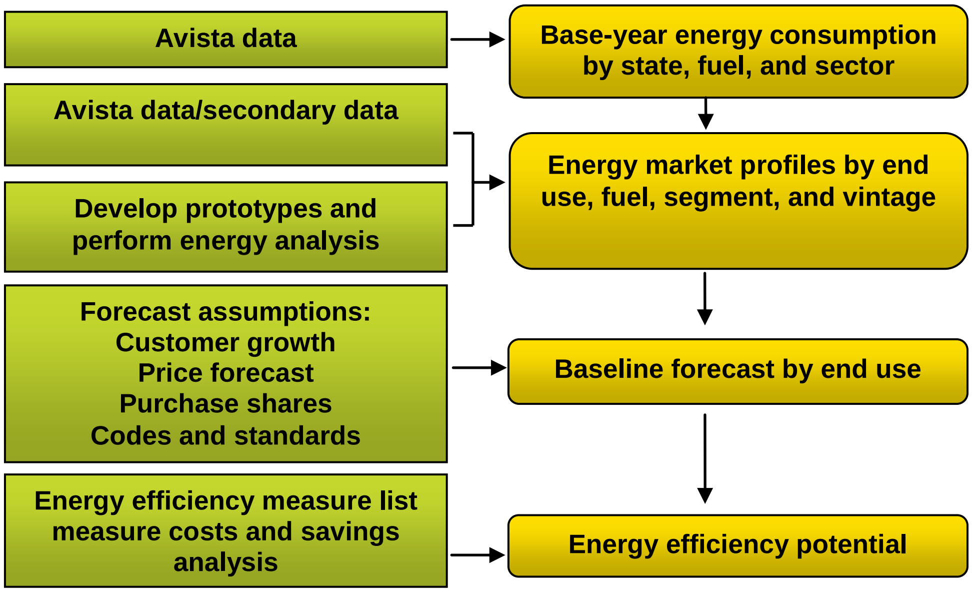
Efficiency programs with economic paybacks of less than one year are not eligible for incentives, although Avista assists in educating and informing customers about these types of efficiency measures. Site-specific programs require customized services for commercial and industrial customers because of 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) to develop an independent 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 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 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. **Market Assessment:** 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, economic, and achievable 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.

[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.

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 2013 when the study began. Codes and standards have direct bearing on the amount of energy efficiency potential that exists 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 Sixth Power Plan, the Regional Technical Forum, and other measures applicable to Avista. The approximately 6,000 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 CPA includes measure costs, energy and capacity savings, estimated useful life, and other performance factors identified for the list of measures and economic screening performed 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 Sixth 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, three types of potential are in this study, as discussed below. Table 5.1 shows the CPA results for technical, economic, and achievable potential.

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

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

	2016	2017	2020	2025	2035
Cumulative (GWh)					
Achievable Potential	34	74	236	575	1,090
Economic Potential	68	138	360	733	1,292
Technical Potential	173	344	837	1,581	2,506
Cumulative (aMW)					
Achievable Potential	3.9	8.5	26.9	65.6	124.5
Economic Potential	7.7	15.9	41.1	83.7	147.5
Technical Potential	19.8	39.3	95.5	180.5	286.1

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 that would result 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 the only considered portion of current equipment stock is that reaching the end of its useful life 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.

Economic Potential

Economic potential includes the purchase of the most efficient cost-effective option available for each given equipment or non-equipment measure.[3] Cost effectiveness is determined by applying the Total Resource Cost (TRC) test using all quantifiable costs and benefits, regardless of who accrues them, and inclusive of non-energy benefits as identified by the NPCC.[4] Measures passing the economic screen represent aggregate economic potential. As with technical potential, economic potential calculations use a phased-in approach. Economic potential is a hypothetical upper-boundary of savings potential representing only economic measures; it does not consider customer acceptance and other factors.

Achievable Potential

Achievable potential refines economic potential, accounting for expected program participation, customer preferences, and budget constraints. It estimates achievable savings attainable through Avista energy efficiency programs when considering market

[3] The Industry definition of economic potential and the definition of economic potential referred to in this document are consistent with the definition of "realizable potential for all realistically achievable units".
[4] There are other tests to represent economic potential from the perspective of stakeholders (e.g., Participant or Utility Cost), but the TRC is generally accepted as the most appropriate representation of economic potential because it tends to represent the net benefits of energy efficiency to society. The economic screen uses the TRC as a proxy for moving forward and representing achievable energy efficiency savings potential for measures that are most cost-effective.

maturity and barriers, customer willingness to adopt new technologies, incentive levels, as well as whether the program is mature or represents the addition of a new program.

During this stage, AEG applied market acceptance rates based upon NPCC-defined ramp rates from the Sixth Power Plan, taking into account market barriers and measure lives. However, AEG adjusted the ramp rates for the measures and equipment to reflect Avista's market-specific conditions and program history. In some cases Avista ramp rates exceed the NPCC's, illustrating a mature energy efficiency program reaching a greater percentage of the market than estimated by the now five-year-old Sixth Power Plan. In other cases, where a program does not currently exist, a ramp rate could be less than the NPCC's ramp rate, acknowledging the additional design and implementation time necessary to launch a new program. Other examples of ramp rate changes include measures or equipment where the regional market shows lower adoption rates than historically estimated by the NPCC, such as heat pump water heaters. AEG's CPA forecasts incremental annual achievable potential for all sectors at 3.9 aMW (34,106 MWh) in 2016, increasing to cumulative savings of 124.5 aMW through 2035.

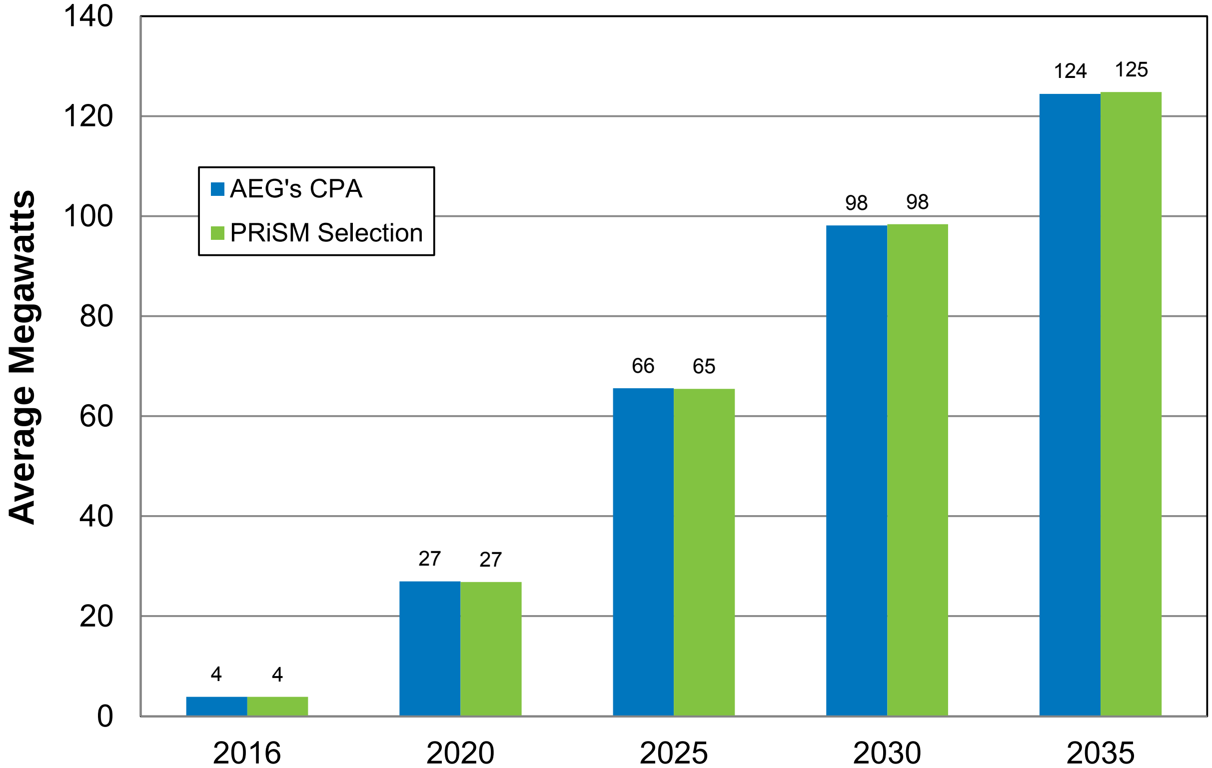
PRiSM Co-Optimization

For the first time, this IRP used a second methodology to identify achievable conservation potential. This method selects conservation measures concurrently with supply side resources in Avista's PRiSM model. This methodology was the result of a 2013 IRP Action Item to streamline the process of selecting conservation in conjunction with the efficient frontier modeling process. See Chapter 11 for more details about the PRiSM model. The method inputs all measures with TRCs less than 130 percent of the avoided cost rate, adjusted for ramp rates used for achievable potential. The 130-percent threshold ensures that conservation options are available in the lower-risk region of the efficient frontier, just as PRiSM includes higher-cost supply-side options that help mitigate risk. The conservation resources compete with supply- and demand response options to meet Avista resource deficits. Each conservation program's winter and summer peak contribution, plus the value of its energy savings are considered.

Given the change to evaluating conservation directly in PRiSM, results were also compared to the historical method. Figure 5.3 shows both CPA and PRiSM conservation estimates. The results were very similar, with PRiSM selecting 0.4 aMW more conservation than the CPA over the 20-year horizon. The similar result is evidence that the avoided cost method used for previous IRPs was accurate. However, using PRiSM for program selection allows conservation selections to change with differing resource strategies across the efficient frontier.[5] Previously a change in resource selection required a feedback loop with AEG to re-run the CPA with new avoided costs. With the new approach, no feedback loop is required. Given the results of this methodology, Avista will likely use this method in future IRPs for conservation selection.

[5] For example, pursuing a least-cost strategy might have less conservation resource than pursuing a least-cost strategy where more costly supply-side resources are being avoided through conservation.

Figure 5.3: Cumulative Conservation Potentials CPA versus PRiSM



Conservation Targets

The IRP process provides conservation targets for the 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. Table 5.2 contains achievable conservation potential for 2016-2017 using both the AEG and PRiSM methodologies. Also included is the energy savings expected from the 2016 and 2017 feeder upgrade projects. See Chapter 8 – Transmission and Distribution Planning for more information.

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

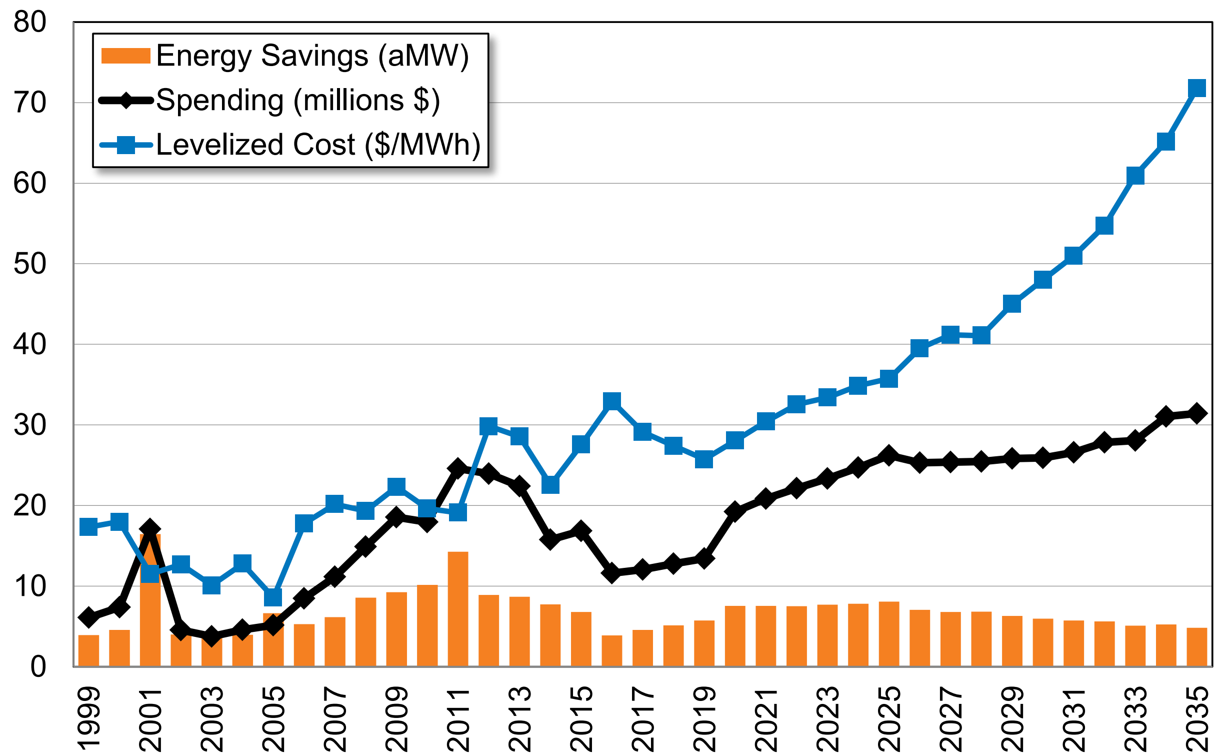
Year	Methodology	Washington	Idaho
2016	AEG CPA	22,863	11,243
2016	PRiSM Selection	22,747	11,213
2017	AEG CPA	26,930	13,217
2017	PRiSM Selection	26,799	13,186
2016	WA Feeder Upgrades	485	1,118
2017	WA Feeder Upgrades	0	0
2016	Facility Efficiencies	0	300
2017	Facility Efficiencies	151	0

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.[6] 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 Sixth 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 2016 conservation acquisition cost to electric customers is $11.6 million. This amount grows by 224% to $26 million by 2026, a total of $186 million over this 10-year period. Costs continue increasing after 2026 to more than $31 million in 2035. Figure 5.4 shows the annual cost in millions of nominal dollars for the utility to acquire the projected electric achievable potential.

Figure 5.4: Existing & Future Energy Efficiency Costs and Energy Savings



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

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

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. 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

Avista offers most residential energy efficiency programs through prescriptive or standard offer programs targeting a range of end uses. Programs offered through this prescriptive approach during 2014 included space and water heating conversions, ENERGY STAR® homes, space and water equipment upgrades, and home weatherization. The appliance programs offered by ENERGY STAR® phased out in 2013 due to results of a Cadmus net-to-gross study indicating market transformation to a point that incentives are no longer required. Other non-appliance ENERGY STAR® programs continue.

Avista offers its remaining residential energy efficiency programs through other channels. For example, JACO, a third party administer, operates a refrigerator/freezer recycling program. UCONS administers a manufactured home duct-sealing program. CFL buy-downs at the manufacturer level provide customers access to lower-priced lamps. Home energy audits, subsidized by a grant from the American Recovery and Reinvestment Act (ARRA), ended in 2012. This program offered home inspections including numerous diagnostic tests and provided a leave-behind kit containing CFLs and weatherization materials. ARRA funds also helped support another program aimed at helping to remove the financial roadblocks to implementing energy efficiency for customers. This program used ARRA funds to buy down the interest rate on loans geared directly towards installing energy efficiency measures in the home. This loan program ended December 31, 2014, after helping fund 269 projects.

Avista processed 5,300 residential energy efficiency rebates in 2014, benefiting approximately 4,000 households. Rebates of over $2.3 million offset customer conservation-implementation costs. Third-party contractors implemented a second appliance-recycling program and a manufactured home duct-sealing program. Avista participated in a regional upstream buy-down program called Simple Steps Smart Savings to provide customers reduced cost lighting and showerheads through participating retailers. Finally, Avista distributed over 7,700 CFLs, and provided expert advice, at various community events throughout the service territory. Residential programs contributed 25,397 MWh and 355,443 therms of energy savings in 2014.

Avista successfully launched a three-year cost-effective behavioral program in June 2013 using the Opower Home Energy Report platform, where participating customers receive a peer-comparison report in the mail every two months. Since launch of the program, Avista has seen a higher than expected ramp rate of energy savings for participating customers as measured in the statistically valid Randomized Control Trial method. Uptake in other energy efficiency programs increased as well. The Opower Home Energy Report contributed 8,131 MWh of savings in 2014.

Low-Income Sector Overview

During 2014, six community action agencies administered Avista low-income programs, targeting a range of end-uses including space and water heating conversions, ENERGY STAR® refrigerators, and weatherization improvements. Beyond direct energy efficiency measures, Avista funding goes towards health and safety improvements considered necessary to ensure the habitability of low-income homes and protect the efficiency measures. The funding also allows the agencies to receive an administration fee for program delivery.

Avista processed approximately 1,400 low-income sector rebates in 2014, benefitting 360 households.[7] During 2014, Avista reimbursed the six agencies over $2.6 million for energy efficiency upgrades where some measures were fully subsidized and others capped based on avoided costs. The agencies spent nearly $394,000 on health and human safety, or 13 percent of their total expenditures–within their 15 percent allowance for this spending category. The low-income energy efficiency programs contributed 400 MWh of electricity savings and 14,944 therms of natural gas savings in 2014.

Non-Residential Sector Overview

Marketing and the new energy efficiency program development starts with measures highlighted in the CPA. All electric-efficiency measures with simple paybacks exceeding one year, but less than eight years for lighting measures or 13 years for other

[7] Washington agencies had up to $2.0 million available for energy efficiency improvements. Idaho had $700,000 available for energy efficiency improvements and $50,000 for conservation education.

measures, automatically qualify for the non-residential portfolio. The IRP provides account executives, program managers/coordinators, and energy efficiency engineers to support program implementation. However, characteristics of a non-residential facility override any high-level program prioritization.

For the non-residential sectors, including multi-family, Avista offers energy efficiency programs on a site-specific or custom basis. Avista offers prescriptive approaches when treatments result in similar savings and the technical potential is high. As an example, the prescriptive lighting program is not purely prescriptive in the traditional sense, such as with residential applications where homogenous programs are provided for all residential customers. It is a more prescriptive approach applied for these similar applications.

Non-residential prescriptive programs offered by Avista include, but are not limited to, space and water heating conversions and equipment upgrades, appliance and cooking equipment upgrades, personal computer network controls, commercial clothes washers, lighting, motors, refrigerated warehouses, traffic signals, and vending controls. Also included are residential program offerings, including site-specific multi-family measures and multi-family market transformation.

Avista processed 1,100 energy efficiency projects resulting in the payment of over $4.6 million in rebates paid directly to non-residential customers to offset the cost of their energy efficiency projects in 2014. These projects contributed 24,400 MWh of electricity and 262,000 therms of natural gas savings.

PECI's Energy Smart Grocer is a regional turnkey program administrated for several years in the Avista service territory. It will approach saturation levels during the early part of the IRP 20-year planning horizon. The Energy Smart Grocer program contributed 3,275 MWh of the 24,400 MWh of non-residential program savings in 2014.

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. Avista intends to study converting decorative lighting and larger-wattage (200 watt and 400 watt) streetlights in the future.

Demand Response

Over the past decade, demand response (DR) gained growing attention as an alternative for meeting peak load growth. Demand response reduces load to specific customers during peak demand periods. Enrolling customers allows the utility to modify their usage pattern in exchange for bill discounts. National attention focuses on residential programs to control water heaters, space heating, and air conditioners. A 2013 Action Item suggested further study of the DR potential based on its selection as a

PRS resource from 2022 to 2027 in that plan. Avista retained AEG to study the potential of future commercial and industrial programs.

Past Programs

Avista's experience with DR dates back to 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 rely on 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 that uncovered a control board in a customer's heat pump that caused 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 STP 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.

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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, which might limit customer interest.

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 2016–2035. 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 that may hinder acquisition.

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. Table 5.3 details achievable demand response potential for the programs studied by AEG.

Table 5.3: Commercial and Industrial Demand Response Achievable Potential (MW)

Program	2016	2020	2025	2030	2035
Direct Load Control	0.6	6.5	6.7	6.9	7.2
Firm Curtailment	5.8	17.5	17.4	17.4	17.5
Opt-in Critical Peak Pricing	0.1	1.4	4.3	4.3	4.4
Opt-out Critical Peak Pricing	6.3	4.4	12.9	13.0	13.1

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 that 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. An opt-in rate that 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.

Studies show that dynamic pricing programs such as critical peak pricing 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 demand response implemented through energy management and control systems.

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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 hours. The AEG DR study included standby generation in its firm curtailment section. 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 their use during peak hours. 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 20 MW of standby generation resources are available for utility use over a five-year acquisition period. To test the concept, a pilot using Avista backup generation facilities is likely. The pilot would provide a cost estimate and illustrate the engineering necessary to bring a standby generation program to fruition. The IRP assumes a standby generation program would cost $50 to $85 per kW in upfront investments, plus $10 to $15 per kW-year in O&M costs.

In May 2015, the federal courts overturned rules limiting the availability of standby generation resources. This ruling creates uncertainty around using standby generation to serve utility requirements. The ruling requires new rules to be developed to determine the amount of hours and environmental conditions these units could be used.

Generation Efficiency Audits of Avista Facilities

A 2013 IRP Action Item was the study of potential for energy efficiency opportunities at company generation facilities. During 2015, Avista performed preliminary energy efficiency audits at all of its hydroelectric dams and most thermal generation facilities Avista owns or is a partial owner in, excluding Colstrip. The preliminary scoping audits focused on lighting, shell, heating ventilation and air conditioning (HVAC), and motor controls on processes. Table 5.4 summarizes these potential projects, Table 5.5 summarizes the planned projects for 2016 – 2017, and Appendix D contains a complete description of the study findings. A discussion of some of the major identified categories follows. Studies will continue into 2016 and the findings reported in the 2017 IRP.

Lighting Projects

Avista's generation 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 that has completed a lighting retrofit. Little Falls, Nine Mile, Cabinet Gorge and Long Lake lighting upgrades are planned in 2016 and 2017.

Shell Projects

Shell projects include measures keeping conditioned air within buildings. A generation facilities review found no capital shell measures with significant savings potential. However, small maintenance weatherization efforts could improve occupant comfort.

Table 5.4: 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
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

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

Table 5.5: Planned Generation Facility Efficiency Upgrades 2016 – 2017

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

HVAC Projects

Noxon Rapids is the only hydroelectric project with heating and cooling equipment. Its water-source heat pump system includes air handlers and hydronic unit heaters. In addition to efficiency gains, replacing this system would reduce annual maintenance.

Cabinet Gorge does not have active heating or cooling systems. Ducted hydronic coils flush air outside during spring and summer nights. A water-source heat pump would increase overall heating and cooling efficiency.

In most cases waste heat from the hydroelectric generating equipment supplies heat to facilities in winter months. When idle, facilities typically motor a unit during the winter months to keep the facility above freezing. Unit heaters could provide a more efficient heat source, and the control room could be thermally isolated from the rest of the plant to ensure only required areas are heated.

Given the relative efficiency of existing thermal facilities heating systems, HVAC equipment improvements make sense only when each unit reaches the end of its useful life.

Controls on Process Motors

Most motor loads at the hydroelectric facilities operate limited hours, often less than 30 hours per year. They do not consume enough electricity to justify the cost of installing new variable speed drives. Coyote Springs 2 has potential for variable-speed motors in its compressed-air systems. The Little Falls exhaust fan could benefit from the installation of variable speed drives.

6. Long-Term Position

Introduction & Highlights

This chapter describes the analytical framework used to develop Avista's net 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.

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 regional load. Annual peaks can occur either in the winter or in the summer; but on a planning basis using extreme weather conditions, Avista is winter peaking. The winter peak generally occurs in December or January, but may happen in November or February where weather events occur in these months. As described in Chapter 4 – Existing Resources, Avista's resource mix contains roughly equal splits between 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 2021; the first energy deficit is in 2026.
- Including operating reserves, Avista plans to a 22.6 percent planning margin.
- The 2015 IRP meets all EIA mandates over the next 20 years with a combination of qualifying hydroelectric upgrades, purchased 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 contingencies. Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves because of the additional 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 revenues.

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'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 therefore includes operating reserves in its definition of planning margin. Per Western Electric Coordinating Council (WECC) requirements, Avista must maintain 1.5 percent of current load and 1.5 percent of on-line generation as spinning reserves and 1.5 percent of current load and 1.5 percent of on-line generation as standby reserves.[2] Avista must also hold load regulation reserves to meet load following and regulation requirements of within-hour load and generation variability.

Avista participates in regional Energy Imbalance Market (EIM) studies and committees. An EIM, where adopted, would create a trading market for regulation services, among other products. While the new market may not reduce the amount of required capacity, it may lower customer rates by providing Avista another market to buy and sell short-term capacity products and services.

Planning Margin

Utility capacity planning begins with identifying the broader regional capacity position, as regional surpluses can offset 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 6,000 MW of natural gas-fired generation, about 3,500 MW was constructed immediately after the crisis. During this same time, Oregon and Washington added 7,850 MW of wind generation. With recent wind additions in the mix, due to wind's lack of on-peak capacity contribution, the region is approaching load-resource capacity balance, while retaining an energy surplus.

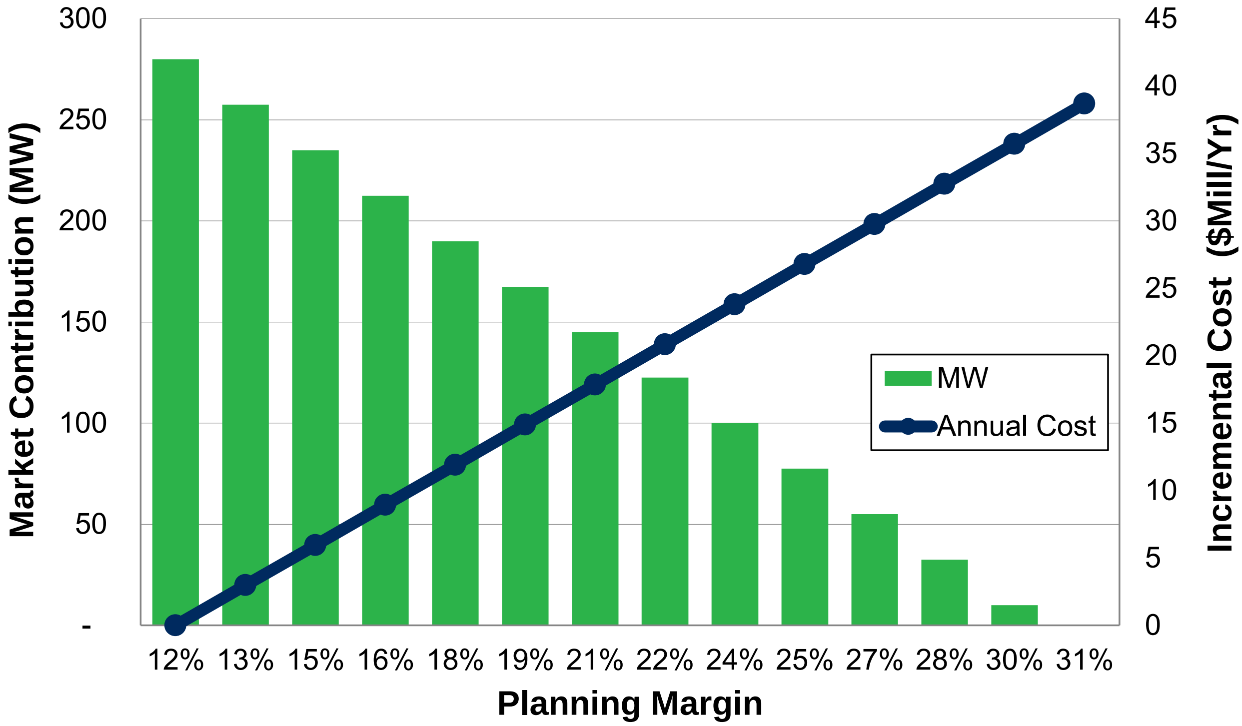
[1] http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx
[2] Spinning reserves sync to the system while stand-by reserves must be available within 10 minutes.

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 5 percent LOLP threshold. Five percent LOLP means utilities meet all customer demand in all hours of the year in 19 of 20 years; one loss-of-load event is allowed in a 20-year period. Regional LOLP analysis is beyond the scope of an IRP. Fortunately, the NPCC conducts regional LOLP studies. Based on their work, the Northwest begins to fail the five-percent LOLP measure in the winter of 2020-21 when three major coal generators retire.[3] The NPCC identifies a need of 1,150 MW of natural gas-fired capacity to eliminate potential 2021 resource shortfalls. The projected shortages occur primarily in the winter, with a small chance of shortage in the summer. At the time of writing, the NPCC had not translated its LOLP study results into a regional planning margin statistic. Absent NPCC translation to planning margin level, Avista made its own estimate using NPCC data and historical methodology to perform the translation. Including operating reserves, the Northwest planning margin is between 23 and 24 percent.

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 with 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 target a lower planning margin. The harder question is how much reliance it should place on the wholesale market. Previous IRPs have shown charts like Figure 6.1, the tradeoff between added resources, i.e., planning margin, and higher system costs and wholesale market reliance. For example, were Avista an electrical island like AELP, a 5 percent LOLP would require a 31 percent planning margin, adding nearly $40 million annually to rates. On the opposite end of the spectrum, if the marketplace had 275 megawatts available, a 12 percent planning margin would meet the 5 percent LOLP for no added cost. Figure 6.1 also explains that in 2020, absent any resource additions or market reliance, Avista projects a 12 percent reserve margin.

[3]John Fazio, NPCC, http://www.nwcouncil.org/media/7149183/may-1-2015-raac-steer-2020-21-adequacy-assessment.pdf. The 8.3 percent LOLP result primarily is due to the retirements of the Boardman and Centralia coal-fired plants, and to a lesser extent regional load growth.

Figure 6.1: 2020 Market Reliance & Capacity Cost Tradeoffs



Avista reviewed planning margins used by transmission organizations and utilities across the country. The results varied depending on the depth and breadth of their interconnections and the types and quantities of resources within their systems. One challenge in comparing planning margins across utilities is determining whether they include ancillary service, or operating reserve, obligations in their planning margins. Figure 6.2 illustrates the findings of our review of utility 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 metric to consider 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 met 16 percent of weather-adjusted peak load in 2014, a high statistic relative to our Western Interconnect peers. Figure 6.3 illustrates the single largest contingencies for selected utilities in the West. Excluding Avista, the average percentage of peak load is 11 percent; the high is 33 percent for Sierra Pacific (553 MW Tracy CCCT), and the low is 5 percent for BC Hydro.

Some resource planners argue planning margins should be no smaller than a utility's single largest contingency on the basis that where your 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 load reductions.

Figure 6.2: Planning Margin Survey Results

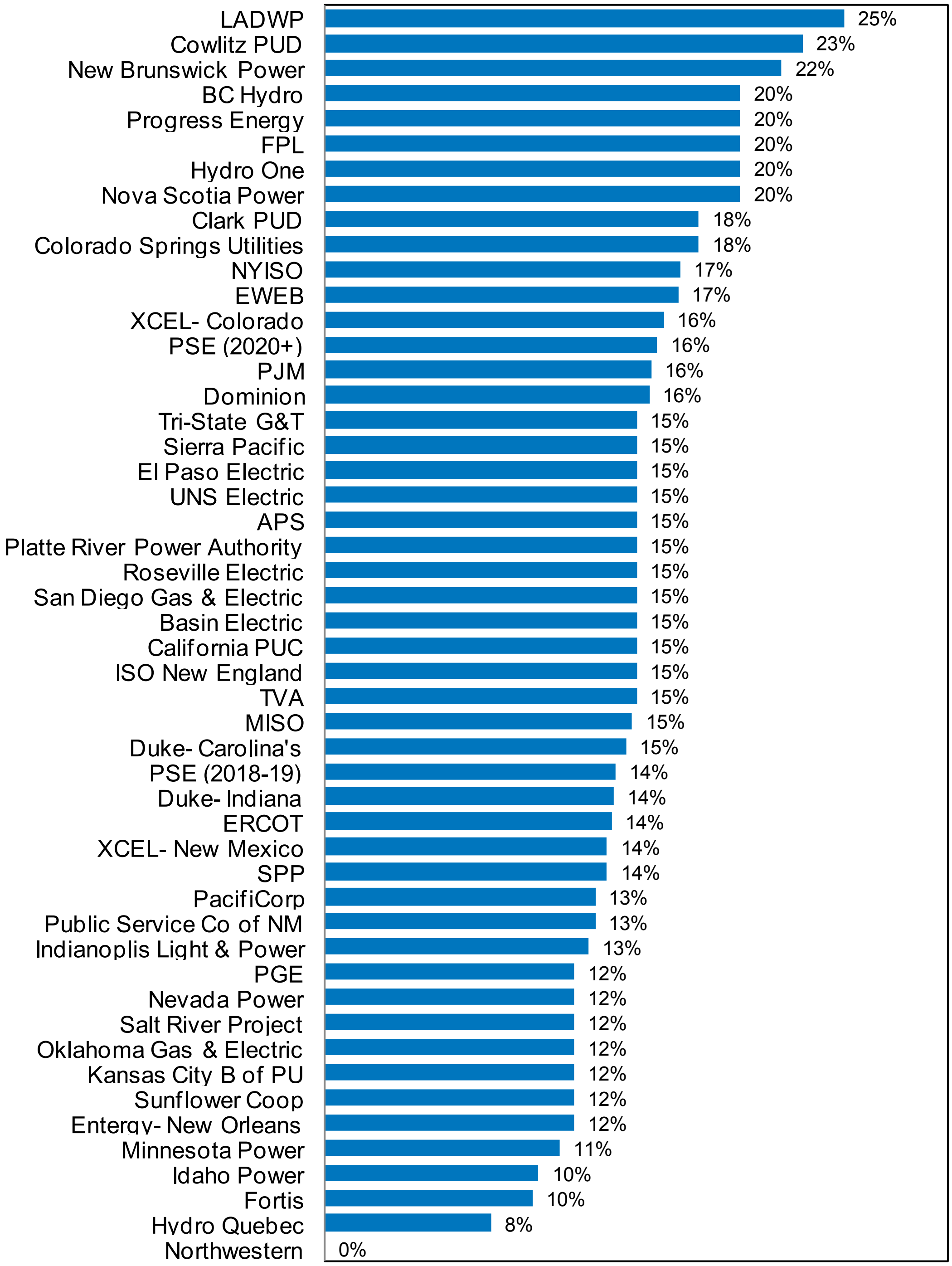


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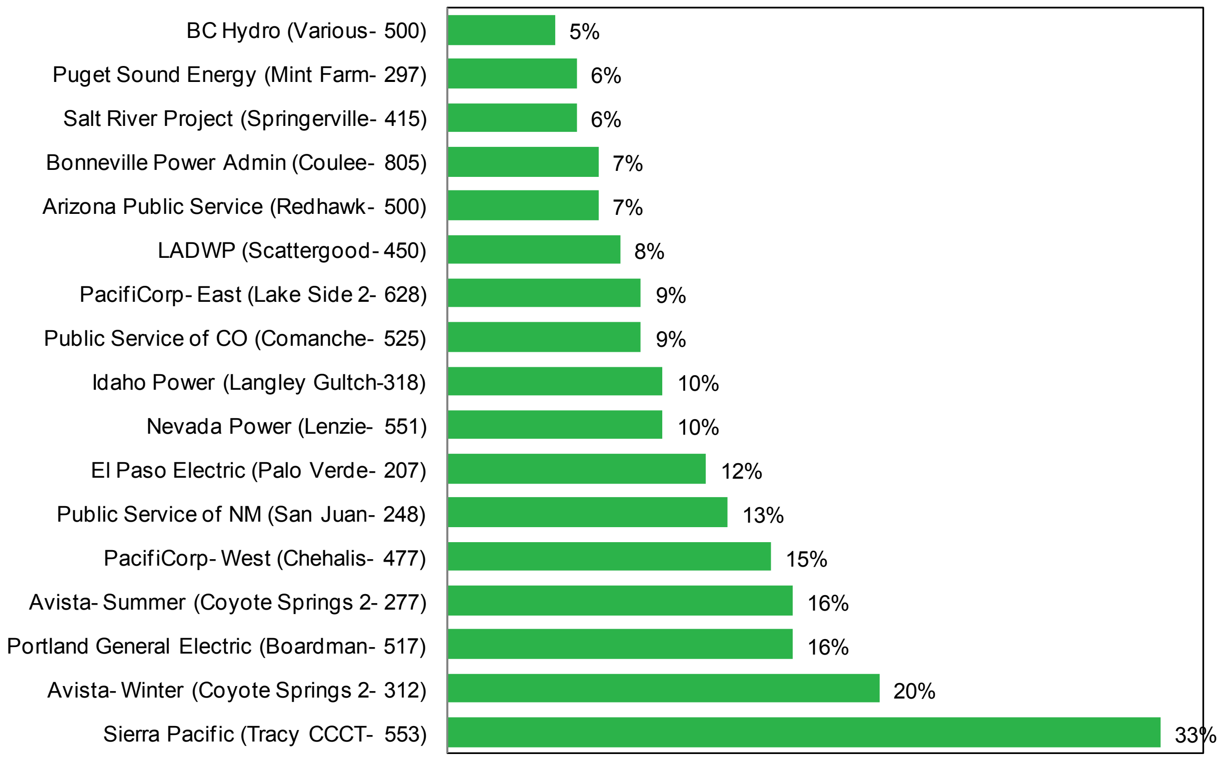
Figure 6.3: Single Largest Contingency Survey Results (2014 Peak Load)



Flexibility Requirements

Renewable portfolio standards, large federal and state subsidies, high feed-in tariff and PUPRA prices, and falling equipment and installation costs have led to more intermittent wind and solar generation installations in the Northwest. Unlike traditional generation resources, intermittent generation variability consumes system capacity. This is similar to holding generation capacity for unknown changes in load, but differs because changes in renewable generation output are much larger and more volatile than load changes on a per-MW of capacity basis. Avista and many of its peer utilities have conducted studies to ensure they have enough flexible capacity to support intermittent resources. However, analytical methods contained in these studies are not fully mature because it is a relatively new concept for the industry.

Avista has identified an initial analytical process to study flexibility requirements for this IRP. The first step looks at system variation on different time horizons. The analysis looks at the five-, 10-, 15- and 60- minute periods in calendar year 2013. The study estimated the amounts of capacity reserves required in the 95th and 99th percentile, or 8,322 and 8,672 hours of the 8,760 hours of a year. While Avista will need to meet all needs during the calendar year, some reliance on the wholesale marketplace is appropriate. Figures 6.4 and 6.5 outline the amount of capacity required to meet load and wind variation, and operating reserve requirements, at the 95th and 99th percentiles. Over the five-minute time range, Avista needs 100 MW to 107 MW of flexible resources. Extending the time horizon to 10 minutes, 110 MW to 122 MW are required. Between 120 MW and 137 MW are required for 15-minute interval variation. Over an hour, total needs are 196 MW to 260 MW. Regulation-capable resources are required to meet much of the variation under 15 minutes, though the 44 MW of non-spinning reserve can be met with stand-by ready resources. For the hour, incremental capacity requirements over the five- to 15-minute intervals increases, but standby resources meet the requirement.

Figures 6.4 and 6.5 identify the requirements for flexible resources on the system, but they do not identify the resources available to meet them. Avista outlines in Chapter 4 resources currently meeting its flexibility requirement. We typically use a combination of Mid-Columbia contracts and Clark Fork generators to provide regulation and load following services, but natural gas-fired peaking resources sometimes meet non-spin or supplemental operating requirements. Recently added controls at Coyote Springs 2 allow it to provide regulation services, taking advantage of its flexibility when online. Figure 9.5 in Chapter 9 shows the excess reserves by month available to meet flexibility requirements.

Figure 6.4: 95th Percentile Capacity Requirements

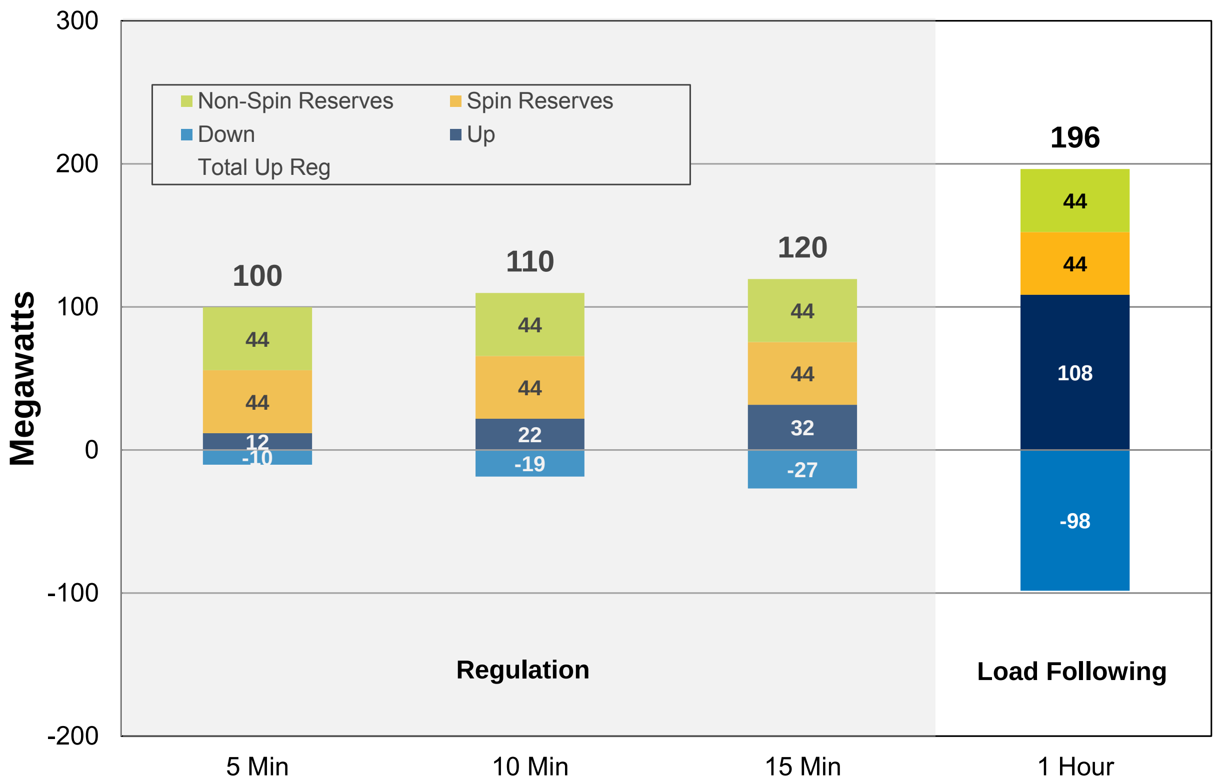
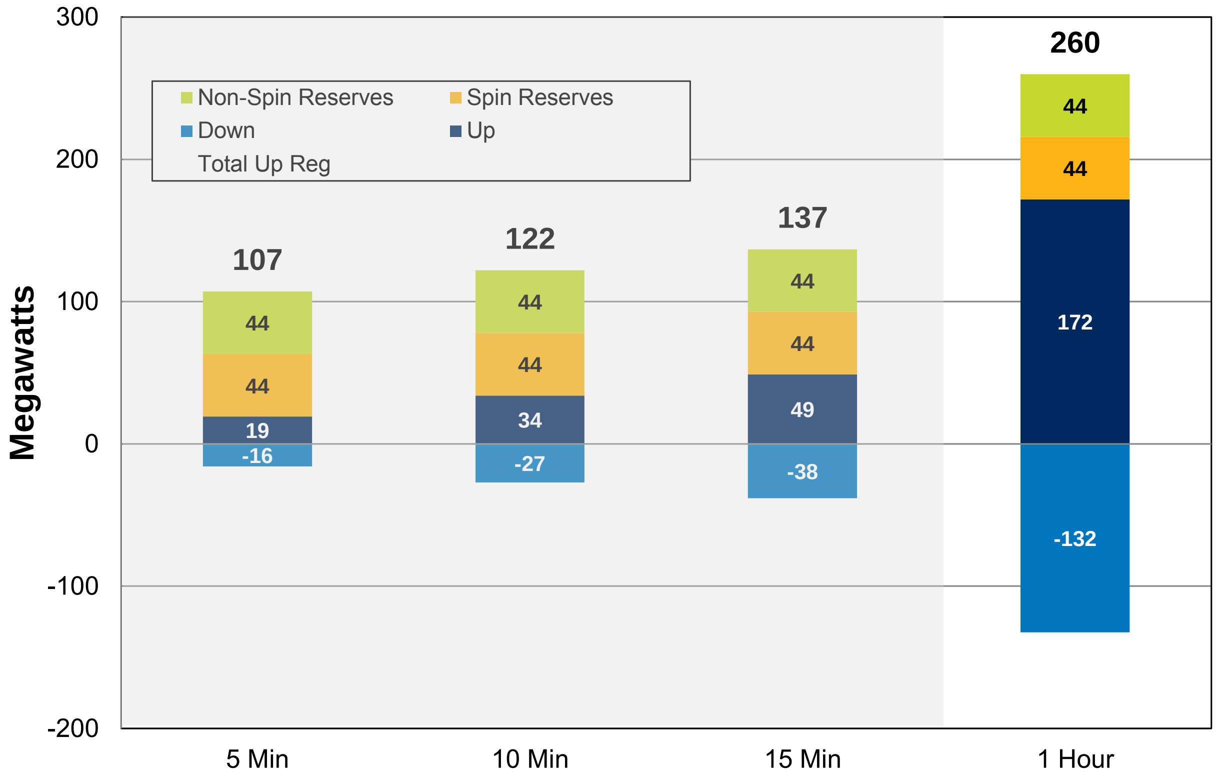


Figure 6.5: 99th Percentile Capacity Requirements



Avista's Planning Margin and Flexibility Reserve Levels

The NPCC Draft Seventh Power Plan finds the region is surplus capacity through 2020. Avista will not acquire additional capacity until its expected peak loads, plus reserve margins, exceed resources beyond 2020 either on a single-hour or on a sustained 3-day basis. To meet customer loads in a reliable and cost-effective manner, Avista retains resources capable of a minimum of 114 percent of its one-in-two winter peak load forecast.[4] Further, it plans to meet spin- and non-spin requirements, as set by the WECC. Lastly, Avista retains an additional 16 MW of regulation to serve load and wind generation variation within the peak hour. The winter total requirement equates to a 22.6 percent planning margin. This level is in line with NPCC estimates for an adequate supply, as described earlier in this chapter.

The NPCC study shows the region has a minimal chance of a load loss event in summer months. Given this low probability, Avista's summer planning margin is comprised only of balancing area reserve requirements and 16 MW of regulation. Avista will monitor the summer market depth and will revise its planning margin assumption if regional capacity surpluses fall due to load growth or exports.

Energy Imbalance Market

Avista is participating 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

[4] One-in-two load is the peak load day during an average coldest winter day.

(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.

The MC Initiative's core goal is to lower overall load serving costs by voluntarily re-dispatching resources. Balancing Authorities (BA) can collectively reduce within-hour balancing resources and maintain their systems if the EIM captures regional load and resource diversity and BAs agree on protocols for allocating reserves and ramping capability obligations among participants. The EIM does this by executing a security-constrained economic dispatch process every five minutes instead of the current one-hour term. The process accounts for the capabilities and prices of the volunteered and committed generating resources for re-dispatch, and the real-time capability of the transmission system to accommodate flows resulting from a central market-instructed re-dispatch.

The name "energy imbalance market" implies the core function is managing intra-hour imbalances – such as load forecast error, generator station error – particularly from variable energy resources – or both. While covering these imbalances is an integral part of the EIM, it is not the main objective of the overall economic optimization process. The market allows BAs to use lower-cost third-party generation when sufficient real-time transmission exists available to replace their higher-cost generation resources.

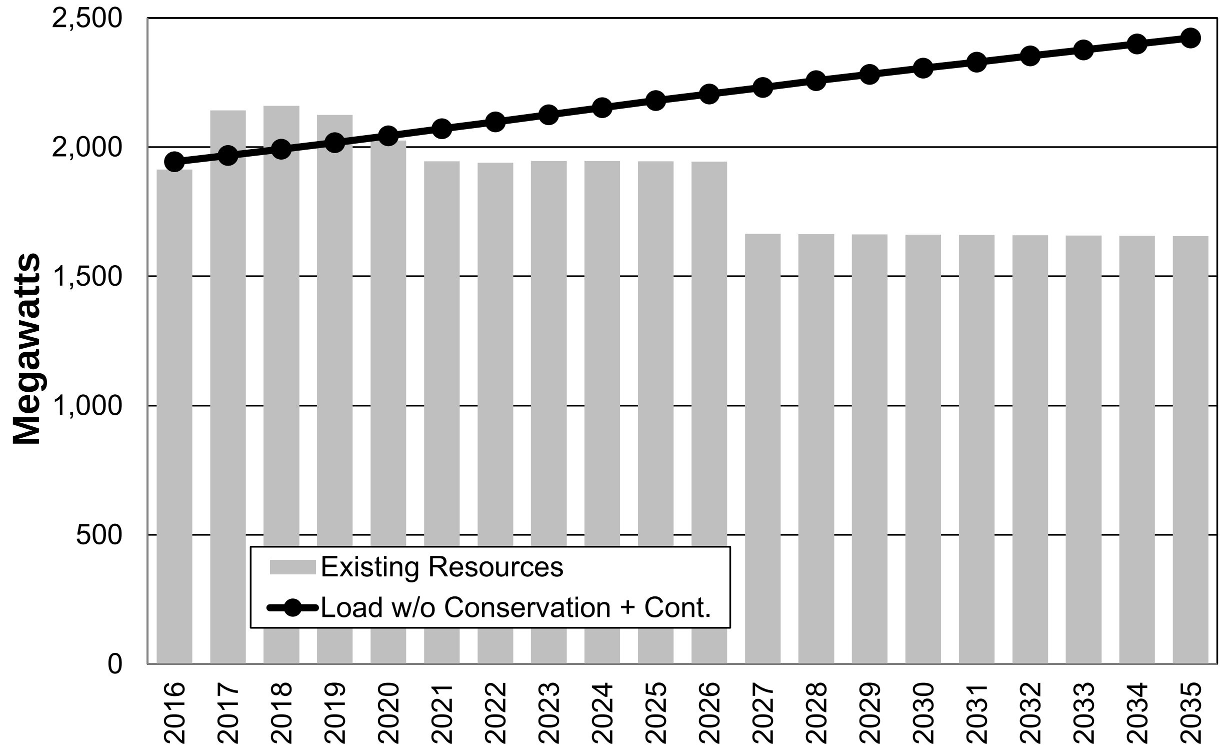
The MC Initiative formed an Analytical Team to evaluate the potential production cost savings within the Northwest Power Pool area. An Executive Committee instructed the Analytical Team to identify a minimum high-confidence range of potential savings, using a production cost model with updated grid assumptions provided by members. The base case results range from approximately $40 million to $90 million per year in regional gross annual savings. Additional sensitivities resulted in savings of $70 to $80 million dollars to the region. This analysis indicates Avista would conservatively observe approximately 5 percent of the total regional benefits, or $2 to $5 million. The Executive Committee currently is evaluating implementation costs to determine if they are lower than expected savings.

Savings estimates do not reflect significant additional benefits of reducing reserve requirements in the region. These benefits may add $100 million or more to expected annual benefit.

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 months than is 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 6.6 illustrates the winter balance of loads and resources; the first year Avista identifies a significant winter capacity deficit is January 2021. The load resource comparison removes conservation from the load forecast to show the total resource need. Conservation will lower this need, but the plan requires new generating resources to meet remaining shortfalls. At the time of the IRP analysis, Avista had small short-term deficits in 2015 and 2016, but those positions have been filled with market purchases. Chapter 11 – Preferred Resource Strategy provides more details about the short-term position.

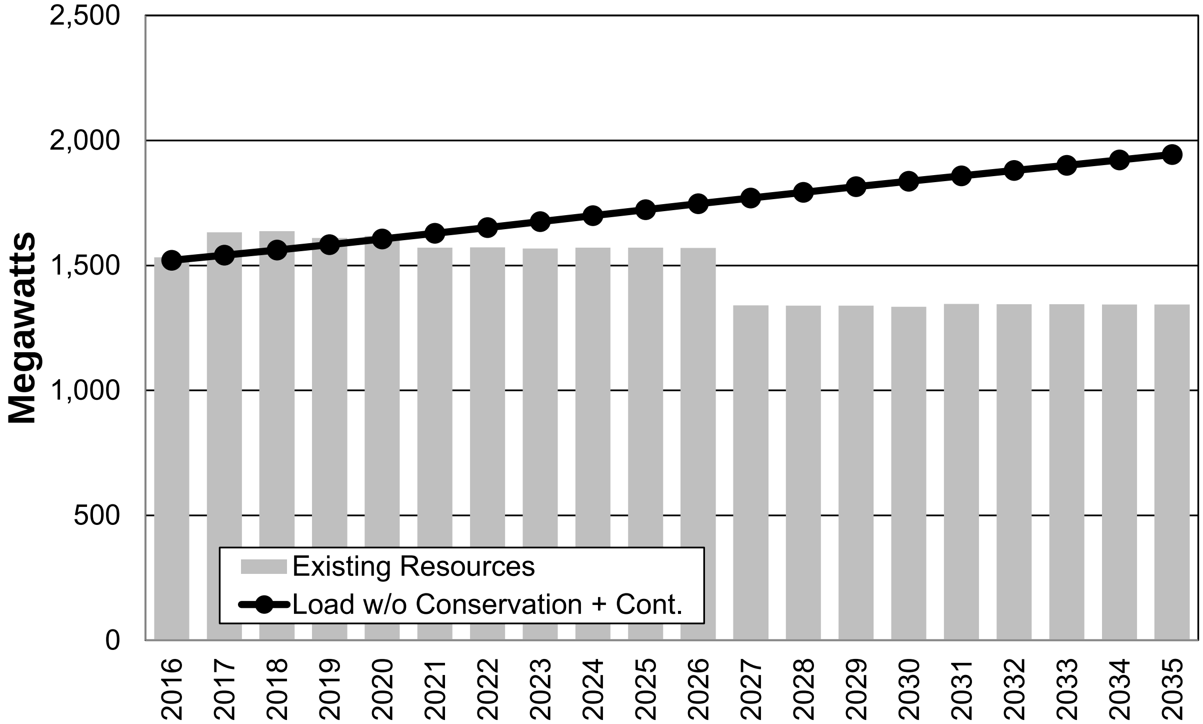
Figure 6.6: Winter 1 Hour Capacity Load and Resources



Avista plans to meet its summer peak load with a smaller planning margin than in the winter. During summer months, only operating reserve and regulation obligations are included in the planning margin. Market purchases in the deep regional market will satisfy any weather-induced load variation or generation forced outage that otherwise would be included in the planning margin. Resource additions serving winter peaks meet smaller summer deficits as well.

Figure 6.7 shows Avista's summer resource balance. This chart differs from the winter load and resource balance by using an 18-hour sustained peak rather than the single-hour peak. Longer-term sustained peaks are more constraining in summer months due to reservoir restrictions and lower river flows, reducing the amount of continuous hydroelectric generation available to meet loads.

Figure 6.7: Summer 18-Hour Capacity Load and Resources



Energy Planning

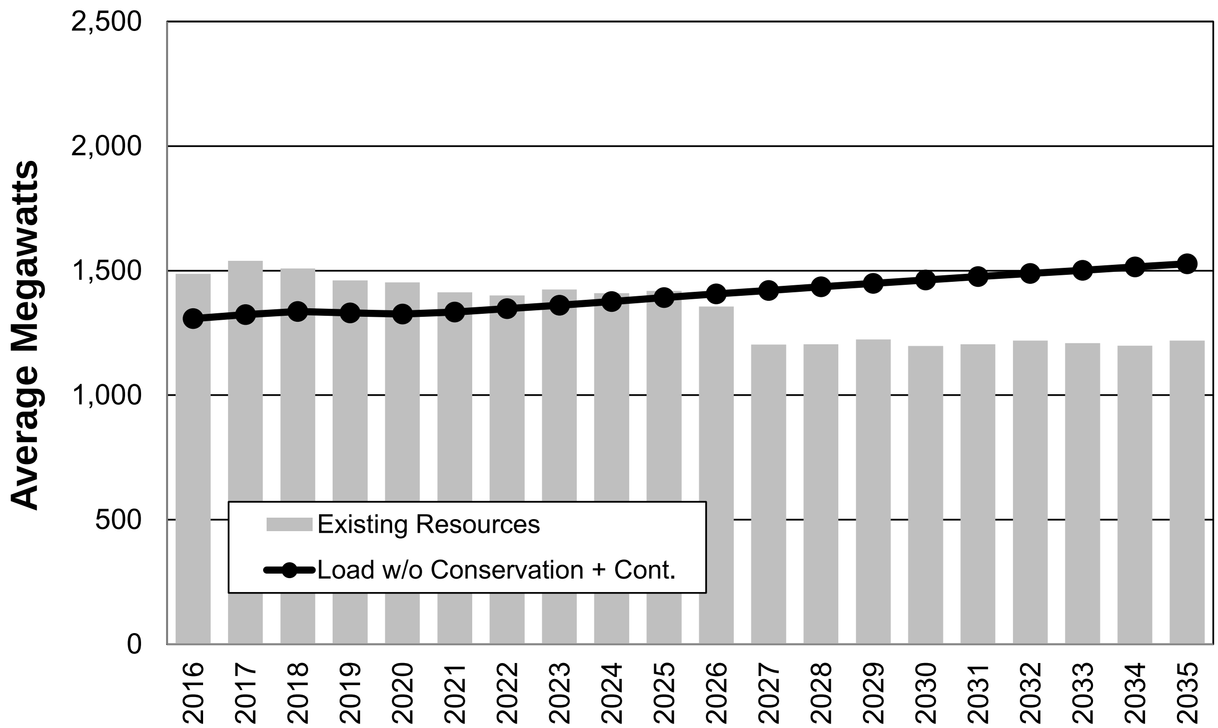
For energy planning, resources must be adequate to meet customer requirements even when loads are high for extended periods, or a sustained outage limits the contribution of a resource. Where generation capability is not adequate to meet these variations, customers and the utility must rely on the short-term 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 planning on the amount of energy available during the "critical water" period of 1936/37.[5] 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 2015 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 instead plans to the 90th 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.

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

Beyond load and hydroelectric variability, Avista's 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 194 aMW in 2016. See Figure 6.8 for the summary of the annual average energy load and resource net position.

Figure 6.8: Annual Average Energy Load and Resources



Washington State Renewable Portfolio Standard

In the November 2006 general election, Washington voters approved the EIA. The EIA requires utilities with more than 25,000 customers to source 3 percent of their energy from qualified renewables by 2012, 9 percent by 2016, and 15 percent by 2020. Utilities also must acquire all cost effective conservation and energy efficiency measures. In 2011, Avista acquired the output from the Palouse Wind project through a 30-year power purchase agreement to help meet the EIA goal. In 2012, an amendment to the EIA allowed some biomass facilities built prior to 1999 to qualify under the law beginning in 2016. This amendment allows Avista's 50-MW Kettle Falls project to qualify and help meet EIA goals.

Table 6.1 shows the forecast amount of RECs Avista needs to meet Washington state law 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 2030. With this ability, Avista does not need additional EIA resources over the planning horizon of this IRP. It may have surplus renewables depending upon the qualifying output of Kettle Falls. Kettle Falls qualifying output may vary depending upon the quantity of fuel meeting the EIA old growth provision, the availability of fuel, and 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

	2016	2020	2025	2030	2035
Percent of Washington Sales	9%	15%	15%	15%	15%
2-Year Rolling Average Washington Retail Sales Estimate	645	662	671	682	696
Renewable Goal	-58	-99	-101	-102	-104
Incremental Hydroelectric	23	23	23	23	23
Net Renewable Goal	**-35**	**-77**	**-78**	**-79**	**-82**
Other Available REC's					
Palouse Wind with Apprentice Credits	48	48	48	48	48
Kettle Falls (67% Capacity Factor)	31	31	31	31	31
Net Renewable Position (before rollover RECs)	**44**	**3**	**1**	**0**	**-2**
Net Renewable Position with Kettle Falls at 90% Capacity Factor	**55**	**14**	**12**	**11**	**8**

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 continue to evolve since publication of the last IRP; most recently, EPA released the Clean Power Plan in August 2015. Current and proposed regulations by the EPA, among other agencies, coupled with political and legal efforts, have particular implications for coal generation, as they involve regional haze, coal ash disposal, mercury emissions, water quality, and greenhouse gas emissions. This chapter discusses pertinent public policy issues relevant to the IRP.

Chapter Highlights

- The 2015 IRP reduces carbon emissions with existing carbon costs, the goals of the Clean Power Plan proposal, and a carbon tax.
- Scenario analyses address the impacts of the Clean Power Plan proposal if implemented individually by state and if implemented as a regional solution.
- Avista's Climate Policy Council monitors greenhouse gas legislation and environmental regulation issues.

Environmental Issues

The evolving nature of environmental regulation creates unique resource planning challenges. If avoiding certain air emissions were the only issue facing electric utilities, resource planning would only require a determination of the amounts and types of renewable generating technology and energy efficiency to acquire. However, the need to maintain system reliability, acquire resources at least cost, mitigate price volatility, meet renewable generation requirements, manage financial risks, and meet changing environmental requirements sometimes creates conflict. Each generating resource has distinctive operating characteristics, cost structures, and environmental regulatory challenges that can change significantly based on timing and location.

Traditional thermal generation technologies, like coal and natural gas-fired plants, provide reliable capacity and energy. Mine-mouth coal-fired units, like Avista's shares in Colstrip Units 3 and 4, have high capital costs and long permitting and construction lead times, and relatively low and stable fuel costs. New coal plants are difficult, if not impossible, to site today due to state and federal laws and regulations, local opposition, their relatively high costs when compared to natural gas-fired plants, and additional environmental concerns. Remote locations increase costs from either the transportation of coal to the plant or the transportation of the generated electricity by the plant to load centers.

Compared to coal, natural gas-fired plants have low capital costs, can typically be located closer to load centers, can be constructed in relatively short time frames, emit less than half the greenhouse gases of conventional coal generation, have fewer other emissions and waste product issues, and are often the only utility-scale baseload resource available. Higher fuel price volatility has historically affected the economics of natural gas-fired plants, their performance decreases in hot weather conditions, it is increasingly difficult to secure sufficient water rights for their efficient operation, and they emit significant greenhouse gases relative to renewable resources.

Renewable energy technologies, including wind, biomass, and solar generation, have different challenges. Renewable resources are attractive because they have low or no fuel costs and few, if any, direct emissions. However, solar and wind-based renewable generation resources have limited or no capacity value for the operation of Avista's system, and their variable output presents integration challenges requiring additional non-variable capacity investments. Even with significant decreases in equipment and installation costs, renewables are high-cost and suffer from integration challenges.

Renewable projects also draw the attention of environmental groups interested in protecting visual aspects of landscapes and wildlife populations. Similar to coal plants, renewable resource projects are often located to maximize their capability rather than to be near load centers. The need to site renewable resources in remote locations often requires significant investments in transmission interconnection and capacity expansion, as well as mitigating possible wildlife and aesthetic issues. Some of these issues may be alleviated with distributed resources, but the price differentials of distributed resources make them more difficult to develop at utility scale. Unlike coal or natural gas-fired plants, the fuel for non-biomass renewable resources may not be transportable from one location to another to utilize existing transmission facilities 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 is uncertain for several reasons. Federal investment and production tax credits begin expiring for projects starting construction after 2013. The continuation of credits and grants cannot be relied upon in light of the impact such subsidies have on the finances of the federal government, and the relative maturity of wind and solar technologies. Many relatively unpredictable factors affect the costs of renewable technologies, such as renewable portfolio standard goals, construction and component prices, international trade issues, and currency exchange rates. Capital costs for wind and solar have decreased over the last several IRPs, but future costs remain uncertain.

Uncertainty still exists about final design and scope of greenhouse gas regulation. Pockets of strong regional and national support to address climate change exist, but little political will at the national level to implement significant new laws exists beyond the regulations proposed by the EPA and is unpredictable going forward. However, since the 2013 IRP publication, changes in the approach to greenhouse gas emissions regulation have occurred, including:

- The EPA proposed actions to regulate greenhouse gas emissions under the CAA through the proposed CPP; and

- California's cap and trade regulation continues scheduled expansion throughout the economy and includes new linkages with Quebec, and an October 2013 compact to link future programs with British Columbia, Oregon, and Washington.

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 of Avista participate on certain topics as needed. The monthly meetings for this group include work divided into immediate and long-term concerns. The 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 data requests about climate change issues. Longer-term issues involve emissions tracking and certification, considering the merits of different greenhouse gas policies, actively participating in the development of 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.

Greenhouse Gas Emissions Concerns for Resource Planning

Resource planning in the context of greenhouse gas emissions regulation raises the relationships between Avista's obligations for environmental stewardship and cost implications for customers. Resource planning considers the cost effectiveness of resource decisions, as well as the need to mitigate the financial impact of potential future emissions risks. Although some parties advocate for the immediate reduction or elimination of certain resource technologies, such as coal or even natural gas-fired plants, there are economic and reliability limitations among concerns related to pursuing this type of policy. Technologically, it is possible to replace fossil-fueled generation with renewables, but this approach results in increased cost to customers and results in reliability challenges.

State and Federal Environmental Policy Considerations

The CPP is the focus of federal greenhouse gas emissions policies in the 2015 IRP. In the 2013 plan, Avista did not include a specific dollar amount for cap and trade or a carbon tax on the modeling of the Western Interconnect. Modeling for jurisdictions with existing costs, such as California and British Columbia, included the appropriate costs. The 2013 IRP had an implied cost from the replacement of retired coal capacity. The Expected Case in this IRP includes the probability of a cost of carbon. Details about the cost of carbon and the modeling results are in Chapter 10 – Market Analysis. The Expected Case also includes proposed regulatory mechanisms through sections 111(b) for new sources and 111(d) for existing sources of the Clean Air Act (CAA) as described below.

The President's Climate Action Plan, released on June 25, 2013, outlined the Obama administration's three pillars of executive action regarding climate change. The pillars include:

- Reducing U.S. carbon emissions through the regulation of emissions from power plants, increased use of renewables and other clean energy technologies, and stronger energy efficiency standards (reflected in the CPP);
- Making infrastructure preparations to mitigate the impacts of climate change; and
- Working on efforts to reduce international greenhouse gas emissions and prepare for the impacts of climate change.

A presidential memo with several climate related policies went to the EPA Administrator on the same day as the Climate Action Plan. It directed the EPA to:

- Issue new proposed greenhouse gas emissions standards for new electric generation resources by September 30, 2013.
- Issue new proposed standards for existing and modified sources by June 1, 2014, final standards by June 1, 2015, and require state implementation plans by June 30, 2016.

The EPA answered the administration by issuing a new proposal to limit carbon dioxide emissions from new and modified coal and natural gas-fired electric generating units in late 2013, and from existing sources in June 2014. Details of these proposals are later in this chapter.

The federal Production Tax Credit (PTC), Investment Tax Credit (ITC), and Treasury grant programs are key federal policy considerations for incenting the development of renewable generation. The current PTC and ITC programs are available for non-solar projects that began construction before the end of 2013 and for solar projects before the end of 2016. Avista did not model an extension of these tax incentives because of the uncertainty of their continuation. This situation may change and would affect modeling assumptions for the 2017 IRP. Extension of the PTC may accelerate the development of some regional renewable energy projects. This may affect the development of renewable projects in the Western Interconnect, but not necessarily for Avista, because the current resource mix and low projected load growth do not necessitate the development of new renewables in this 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 that 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.

Promulgated PSD permit rules may affect Avista's thermal generation facilities in the future. These rules can affect the amount of time it takes to obtain permits for new generation and 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. The Title V operating permit for Colstrip Units 3 and 4 expires in 2017. The Coyote Springs 2 permit expires in 2018. A new Title V operating permit for the Kettle Falls generating station is expected in 2016, and the Rathdrum CT expires in 2016. 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 will guide modeling assumptions for the 2017 IRP.

Clean Power Plan Proposal

The EPA issued the draft CPP on June 2, 2014. The modeling for this IRP was based on the CPP proposal. This plan aims to reduce national greenhouse gas emissions from covered fossil-fueled electric generating units by 30 percent by 2030 from a 2005 baseline, with an interim goal in 2020. The draft rule calculated emission rate targets for each state using a combination of four building blocks:

1. Heat rate improvements at coal plants up to 6 percent;
2. Displacement of coal-fired and oil-fired steam generation by increasing utilization of natural gas-fired combined cycle plants up to a 70 percent capacity factor;
3. Use of more low- or zero-carbon emitting generation resources (including 6 percent of nuclear capacity); and
4. Increase demand side efficiency by 1.5 percent per year between 2020 and 2029.

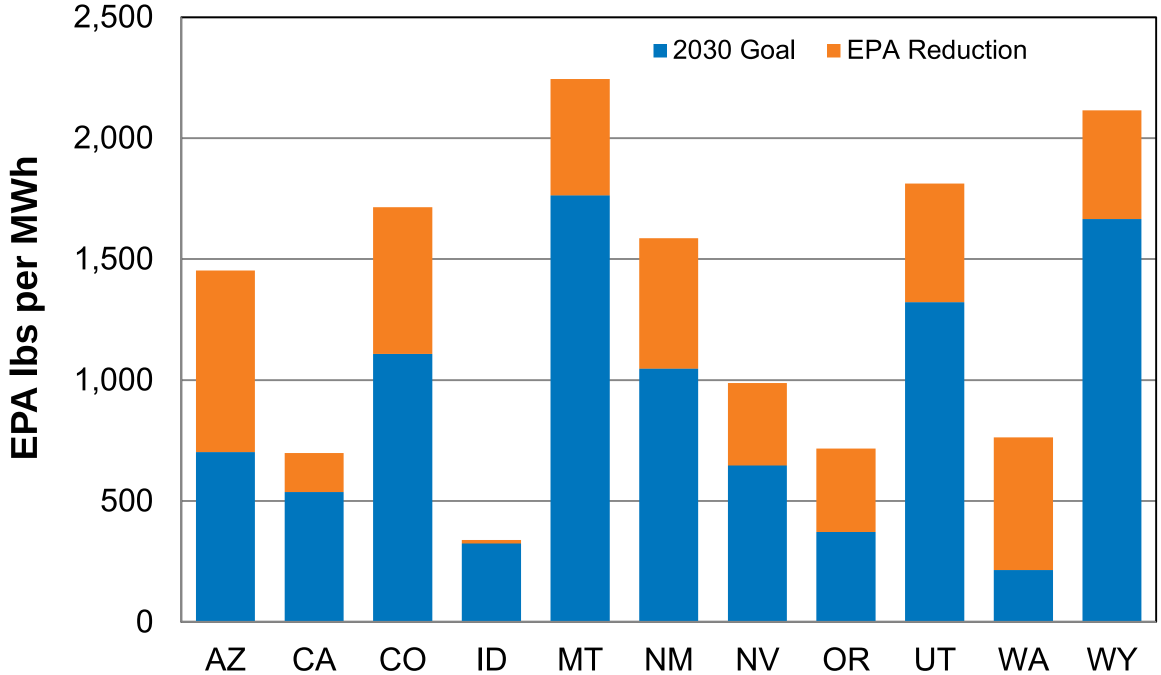
The EPA used 2012 data for the baseline for each state. The building blocks could constitute the best system of emission reduction a state could propose in its compliance plan. However, states might also propose to comply through other measures, including a cap and trade form of regulation. The state of Washington, through the provisions of the EIA (Chapter 19.285 RCW), currently applies renewable energy and energy efficiency standards to Avista's electric operations. The state also imposes an emissions performance standard under Chapter 80.80 RCW to long-term financial commitments made by electric utilities when acquiring new baseload generation or upgrading existing fossil-fueled baseload generation.

Several aspects of the proposed CPP are problematic. The TAC discussed these issues in several of its meetings. Issues include the impact of the 2012 baseline year on hydroelectric generation, the affect on combined cycle resources in Idaho, the immediate impact of the first two building blocks on the 2020 interim goal, and the short time to develop regional solutions in light of the interim goal and legislation that may be required from some of the states. Some adjustments to modeling for the 2015 IRP attempt to alleviate some of these issues to make them into a workable plan. Updates to 2017 IRP modeling assumptions will account for changes made in the final CPP and subsequent state implementation plans. The EPA issued the final CPP on August 3, 2015. The final rule differs from the proposed rule in many ways including the removal of the fourth building block (energy efficiency), movement of the start date from 2020 to 2022, and adjusted goals for many states. The 2017 IRP will account for these changes, since modeling for the 2015 concluded in early 2015.

Figure 7.1 includes the IRP's adjusted 2030 goal in comparison to the 2012 baseline.

The orange portion of the bar shows the proposed reduction. Washington State has the highest percentage reduction, followed by Arizona. Idaho has the lowest reduction after an assumed adjustment for 2012 partial year of operations at Langley Gulch.

Figure 7.1: Draft Clean Power Plan 2030 Emission Intensity Goals



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 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 and 4's existing emission control systems should be sufficient to meet mercury limits. For the remaining portion of the rule specifically addressing air toxics (including metals and acid gases), the joint owners of Colstrip are currently evaluating what type of new emission control systems will be required to meet MATS compliance in 2016. Avista is unable to determine to what extent, or if there will be any, material impact to Colstrip Units 3 and 4 at this time.

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.

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. The state of Washington requires mandatory greenhouse gas emissions reporting similar to the EPA requirements. Oregon has similar reporting requirements.

Coal Ash Management and Disposal

On December 19, 2014, the EPA issued a final rule regarding coal combustion residuals (CCR). This will affect 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 final rule has not yet been published in the Federal Register. 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 at this 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 an emissions performance standard 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 jurisdictions where Avista operates 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 a renewable portfolio standard (RPS). There is no indication that Idaho is moving toward the active regulation of greenhouse gas emissions beyond the CPP. The Idaho Department of Environmental Quality will administer greenhouse gas standards under its CAA delegation from the EPA.

Montana Policy Considerations

Montana has a non-statutory goal to reduce greenhouse gas emissions to 1990 levels by 2020. Montana's RPS law, enacted through Senate Bill 415 in 2005, requires utilities to meet 10 percent of their load with qualified renewables from 2010 through 2014, and 15 percent beginning in 2015. Avista is exempt from the Montana RPS and its reporting requirements beginning on January 2, 2013, with the passage of SB 164 and its signature by the Governor.

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 meeting Montana's mercury emissions goal.

Oregon Policy Considerations

The State of Oregon has a history of considering 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 not adopted any comprehensive requirements. 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 paying into the Climate Trust of Oregon. Senate Bill 838 created a renewable portfolio standard requiring large electric utilities to generate 25 percent of annual electricity sales with renewable resources by 2025. Intermediate term goals include 5 percent by 2011, 15 percent by 2015, and 20 percent by 2020. Oregon ceased being an active member in the Western Climate Initiative in November 2011. The Boardman coal plant is the only active coal-fired generation facility in Oregon; by the end of 2020, it will cease burning coal. The decision by Portland General Electric to make near-term investments to control emissions from the facility and to discontinue the use of coal, serves as an example of how regulatory, environmental, political, and economic pressures can culminate in an agreement that results in the early closure of a coal-fired power plant.

[1] http://www.dsireusa.org/rpsdata/index.cfm

Washington State Policy Considerations

Similar circumstances leading to the closure of the Boardman facility in Oregon encouraged TransAlta, the owner of the Centralia Coal Plant, to agree to shut down one unit at the facility by December 31, 2020, and the other unit by December 31, 2025. The confluence of regulatory, environmental, political, and economic pressures brought about its scheduled closure. The state of Washington 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. Washington's EIA, passed in the November 2006 general election, established a requirement for utilities with more than 25,000 retail customers to use qualified renewable energy or renewable energy credits to serve 3 percent of retail load by 2012, 9 percent by 2016, and 15 percent by 2020. Failure to meet these RPS requirements results in at least a $50 per MWh fine. The initiative also requires utilities to acquire all cost-effective conservation 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.

A utility can also comply with the renewable energy standard by investing in at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable energy resources and/or renewable energy credits. In 2012, Senate Bill 5575 amended the EIA to define Kettle Falls Generating Station and other legacy biomass facilities that commenced operation before March 31, 1999, as EIA qualified resources beginning in 2016. A 2013 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 beginning in 2016. The 2015 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 (Commerce) has commenced a process expected to adopt a lower emissions performance standard in 2013; a new standard would not be applicable until at least 2017. Commerce filed a final rule with 970 pounds per MWh for greenhouse gas emissions on March 6, 2013, with rules becoming effective on April 6, 2013.[2]

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 did 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 regulatory program will not itself include the establishment of an emissions trading market, but other entities could develop such a system to facilitate trading.

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

8. Transmission & Distribution Planning

Introduction

Avista delivers electricity from generators to customer meters through a network of conductors and ancillary equipment. Avista categorizes its energy delivery systems between transmission and distribution voltages. Avista's transmission system operates at 115 and 230 kV nominal voltages; the distribution system operates between 4.16 and 34.5 kV, but typically at 13.2 kV in urban service centers. In addition to voltages, the transmission system operates distinctly from the distribution system. For example, the transmission system is a network linking multiple sources with multiple loads, while the distribution system configuration uses radial feeders to link a single source to multiple loads.

Chapter Highlights

- Avista actively participates in regional transmission planning forums.
- Avista develops a transmission plan annually.
- Projects completed since the last IRP include new transmission line segments, and rebuilds and upgrades through the grid modernization project.
- Planned projects include reconductoring and station rebuilds and reinforcements.
- Lind Substation interconnection study work continues.

Coordinating transmission system operations and planning activities with regional transmission providers maintains reliable and economic transmission service for our customers. Transmission providers and interested stakeholders coordinate regional planning, construction, and operations under Federal Energy Regulatory Commission (FERC) rules and guidance from state and local agencies. This chapter complies with Avista's FERC Standards of Conduct compliance program governing communications between Avista merchant and transmission functions.

This chapter describes Avista's completed and planned distribution feeder upgrade program, the transmission system, completed and planned upgrades, and estimated costs and issues of new generation resource integration.

FERC Transmission Planning Requirements and Processes

Avista coordinates its transmission planning activities on a voluntary basis with neighboring interconnected transmission operators. Avista complies with a number of FERC requirements related to both regional and local area transmission planning. This section describes several of these processes and forums important to Avista transmission planning.

Local Transmission Planning Report

Avista's local planning report is the product of both a local transmission planning process and an annual planning assessment. Attachment K to Avista's Open Access Transmission Tariff (OATT) FERC Electric Volume No. 8 outlines the local transmission planning process. This process identifies single-system projects needed to mitigate future reliability and load-service requirements for the Avista transmission system.

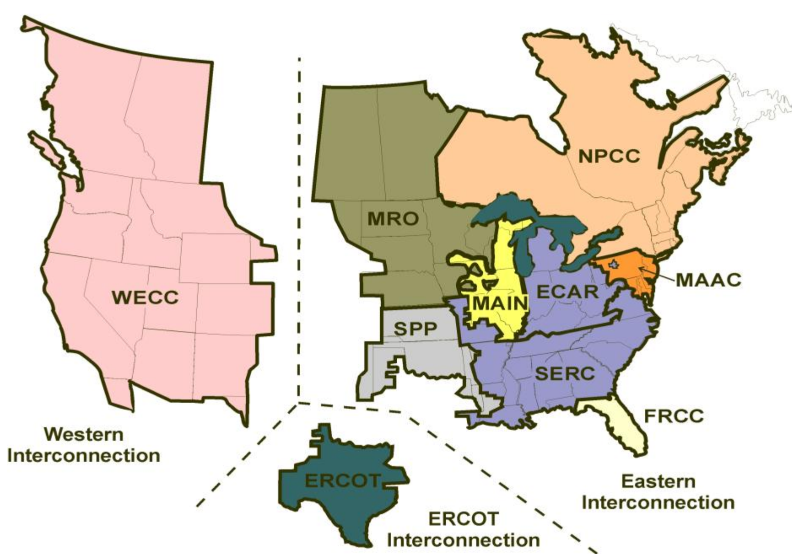
The annual planning assessment is outlined by North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4. The planning assessment determines where the system may have the inability to meet performance requirements as defined in the NERC Reliability Standards and identifies corrective action plans addressing how to meet the performance requirements. The planning assessment includes performing steady state contingency analysis, voltage collapse, and transient technical studies.

The local planning report supports compliance with the local transmission planning process and applicable NERC reliability standards. The local planning report, with its associated collection of single-system projects and corrective Action Plans, provides a 10-year transmission system expansion plan by including all transmission system facility improvements.

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 also 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 8.1.

Figure 8.1: NERC Interconnection Map



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

Peak Reliability

The Peak Reliability (Peak) organization took over the role of reliability coordinator from WECC on February 12, 2014. Peak is wholly independent of WECC, performing the reliability coordinator and interchange authority functions for the Western Interconnection.[2]

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. Smaller, principally non-generating utilities participate in an indirect manner through their member systems, such as the BPA.

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). The TPC exists as a forum addressing northwest electric planning issues and concerns, including a structured interface with external stakeholders.

ColumbiaGrid

ColumbiaGrid began 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.

[2] https://www.peakrc.com/aboutus/Pages/History.aspx

BPA Transmission System

BPA owns and operates over 15,000 miles of transmission-level facilities and owns over three-quarters of the region's high voltage (230 kV or higher) transmission grid. Avista uses BPA transmission to transfer output from its remote generation sources to Avista's transmission system, including its share in Colstrip Units 3 and 4, Coyote Springs 2, and its WNP-3 settlement contract. Avista also contracts for BPA transmission to transfer power to several delivery points on the BPA system serving portions of our retail load and for selling surplus power to other parties in the region.

Avista participates in BPA transmission rate case processes and in BPA's Business Practices Technical Forum to ensure charges remain reasonable and support system reliability and access. Avista works with BPA and other regional utilities to coordinate major transmission facility outages.

Future electric grid expansion likely will require transmission expansion by federal and other entities. BPA is developing several transmission projects in the Interstate-5 corridor and in southern Washington to maintain reliable system operation and integrate regional wind generation resources. Each project has the potential to increase BPA transmission rates and thereby affect Avista's costs.

Avista's Transmission System

Reliability and Operations

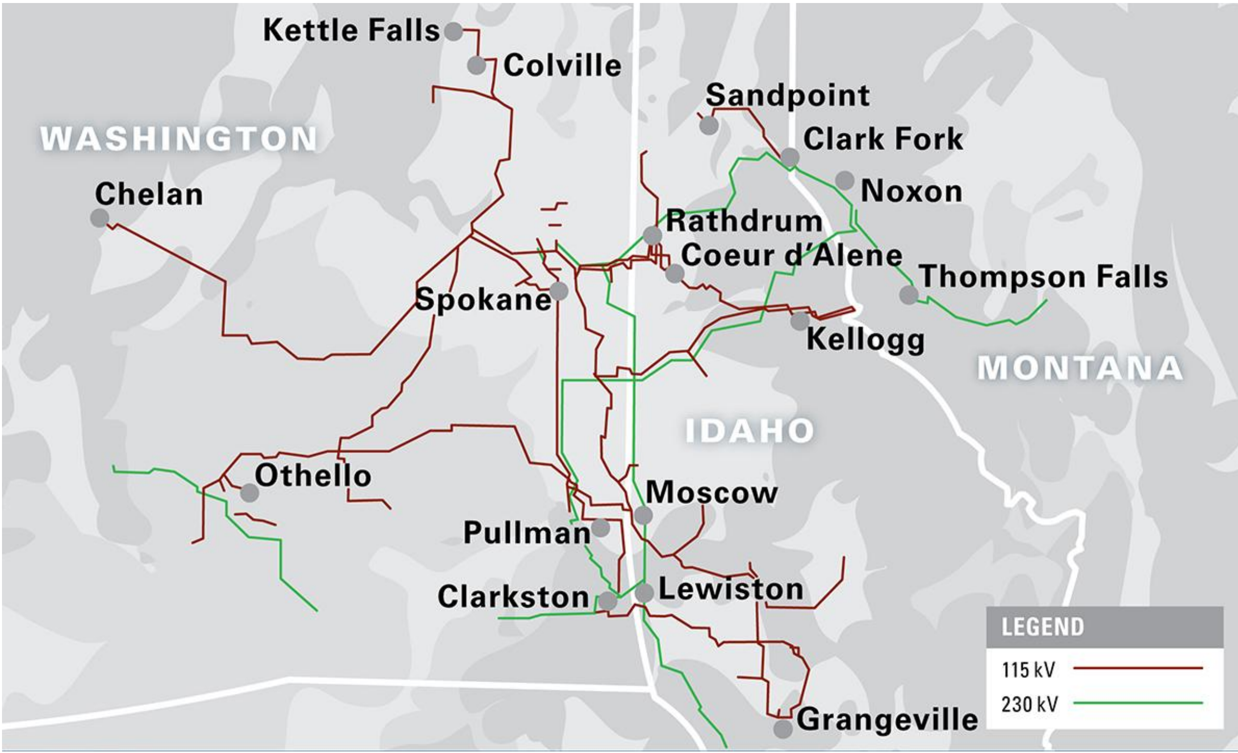
Avista plans and operates its transmission system pursuant to applicable criteria established by the NERC, WECC, and NWPP. Through involvement in WECC and NWPP standing committees and sub-committees, Avista participates in developing new and revised criteria while coordinating transmission system planning and operation with neighboring systems. Mandatory reliability standards promulgated through FERC and NERC subject Avista to periodic performance audits through these regional organizations.

Avista's transmission system provides reliable and efficient transmission service from the company's generation resources to its retail and wholesale customers. Transmission capacity surplus to retail load service needs is available to other parties pursuant to FERC regulations and the terms and conditions of Avista's OATT. Avista markets its unsold surplus transmission capacity on a long-term (greater than one year) basis and short-term basis to other parties as part of Avista's overall resource optimization efforts.

System Topology

Avista owns and operates over 2,200 miles of electric transmission facilities. This includes approximately 685 miles of 230 kV line and 1,527 miles of 115 kV line. Figure 8.2 illustrates Avista's transmission system.

Figure 8.2: Avista Transmission Map



Avista owns an 11 percent interest in 495 miles of double circuit 500 kV lines between Colstrip and Townsend, Montana. The transmission system includes switching stations and high-voltage substations with transformers, monitoring and metering devices, and other system operation-related equipment. The system transfers power from Avista's generation resources to its retail load centers. Avista has network interconnections with the following utilities:

- BPA
- Chelan County PUD
- Grant County PUD
- Idaho Power Company
- NorthWestern Energy
- PacifiCorp
- Pend Oreille County PUD

Transmission System Information

Since the 2013 IRP, Avista completed several transmission projects to support new generation, increase reliability, and provide system voltage support.

Transmission Line Upgrades

- Chelan – Stratford 115 kV: line reconductor
- Garden Springs to Hallet & White section of South Fairchild 115 kV Tap: line reconductor

- Irvin – Opportunity 115 kV line: new line section
- Burke to Montana border section of Burke – Thompson Falls A&B 115 kV lines
- Southern half of Bronx – Cabinet Gorge 115 kV line: line reconductor

Stations

- Stratford 115 kV – station rebuild
- Odessa 115 kV – capacitor bank installed
- Lancaster 230 kV station interconnection
- Lind 115 kV – capacitor bank installed
- Moscow 230/115 kV – station rebuild
- Blue Creek 115 kV – station rebuild
- Beck Road 115 kV – new station
- Clearwater 115 kV – station upgrade
- Lewiston Mill Road 115 kV – new station
- North Lewiston 115 kV Distribution Substation

Planned Projects

Avista plans to complete several re-conductor projects throughout its transmission system over the next decade. These projects focus on replacing decades-old small conductor with new conductor capable of greater load-carrying capability and fewer electrical losses. The following list gives an example of planned transmission projects:

Transmission Lines

- Addy – Devil's Gap 115 kV
- Bronx – Cabinet Gorge 115 kV (2011-2017)
- Burke – Pine Creek 115 kV (2012-2015)
- Benton – Othello 115 kV (2014-2016)
- Devils Gap – Lind 115 kV (2014-2016)
- Devil's Gap – Stratford 115 kV (2019)
- Coeur d'Alene – Pine Creek 115 kV (2014-2018)
- Spokane Valley Reinforcement Project (2011-2016)

Stations

- Irvin 115 kV Switching Station [Spokane Valley Reinforcement] (2016)
- Millwood 115 kV Distribution Substation [Spokane Valley Reinforcement] (2013)
- Harrington 115 kV Distribution Substation (2014)
- Noxon 230 kV Switching Station (2013-2018)
- 9th & Central 115 kV Distribution Substation (2015)
- Greenacres 115 kV Distribution Substation (2014)
- Beacon 230/115 kV Station Partial Rebuild (2017+)
- Saddle Mountain 115 kV Station (new, 2018)
- Westside 230/115 kV transformer (2016)

IRP Generation Interconnection Options

Table 8.1 shows the projects and cost information for each of the IRP-related locational studies where Avista evaluated new generation options. The study details for each project, including cost and integration options, are in Appendix E. These studies provide a high-level view of the generation interconnect requests, and are similar to third-party feasibility studies performed under Avista's generator interconnection process. Because the FERC does not allow complete charging of integration costs benefiting the overall transmission system to the new generator, it is unlikely that the entirety of these figures will actually be charged to a new interconnected generator. There are cost ranges for each proposed generation project because there are alternate solutions to reinforce the transmission system to support the proposed interconnected generation levels.

Table 8.1: 2015 IRP Requested Transmission Upgrade Studies

Project	Size (MW)	Cost Estimate (Millions)[3]
Kootenai County	100	$16 to $20.1
Kootenai County	350	$47.2
Rathdrum Station (115 kV)	26	$2.8 to $10.9
Rathdrum Station (115 kV)	50	$10.7 to $18.7
Rathdrum Station (115 kV)	200	$10.3 to $48.5
Rathdrum Station (230 kV)	50	$7 to $16.8
Rathdrum Station (230 kV)	200	$15.5 to $21.5
Thornton Station	100	$0.4
Othello Station	25	$2.0
Northeast Station (Spokane)	10	$0.0
Kettle Falls Station	10	$0.0
Long Lake	68	$19.7
Monroe Street	80	$7.0

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. The studies typically take at least one year to complete. 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. Each of the proposed projects becomes public to some degree, but customer names remain anonymous. Table 8.2 lists major projects currently in Avista's interconnection queue.

Table 8.2: Third-Party Large Generation Interconnection Requests

Project	Size (MW)	Type	Interconnection
#43	150	Wind	Lind 115 kV Substation
#44	600	Pumped Hydro	Colstrip 500 kV System

[3] Cost estimates are in 2014 dollars and use engineering judgment with a 50 percent margin for error.

Distribution System Efficiencies

Avista's distribution system consists of approximately 330 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.

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 the summer of 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 both 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.

Grid Modernization

Building on a 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 8.3 contains a list of completed and planned feeder upgrades.

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 work of 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.

Figure 8.3 illustrates the reliability advantages and reasons for the Grid Modernization Program. Prior to the 2009 feeder rebuild pilot program, 39 outages per year were expected. After the project, outages declined significantly to an average of 20 unique outages. In the past two years, only one outage occurred. The program is in its second year of regular funding and is realizing its intended purpose of capturing energy savings through reduced losses, increased reliability, and decreased O&M costs. Table 8.3 shows the feeders addressed through this program to date and projects currently in progress. The total energy savings from both re-conductor and transformer efficiencies for all completed feeders is approximately 7,479 MWh annually.

Figure 8.3: Spokane's 9th and Central Feeder (9CE12F4) Outage History

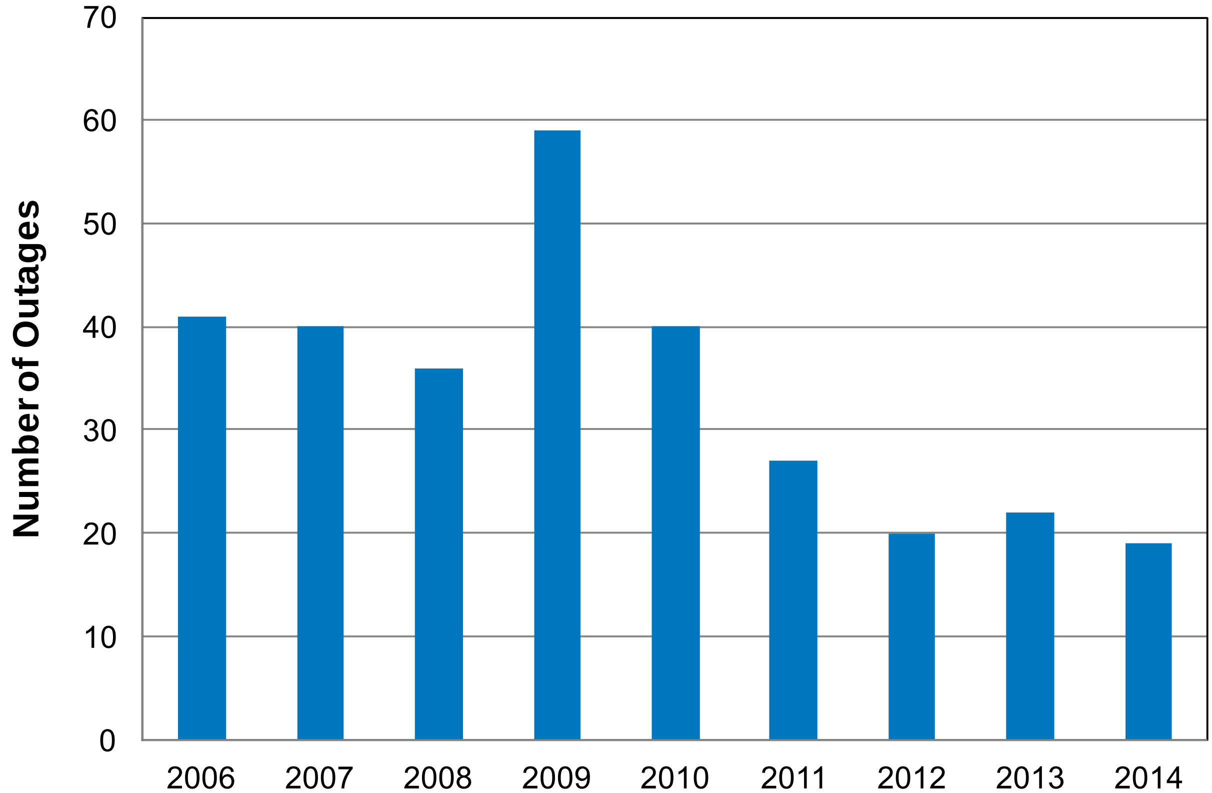


Table 8.3: Completed and Planned Feeder Rebuilds

Feeder	Area	Year Complete	Annual Energy Savings (MWh)
9CE12F4	Spokane, WA (9th & Central)	2009	601
BEA12F1	Spokane, WA (Beacon)	2012	972
F&C12F2	Spokane, WA (Francis & Cedar)	2012	570
BEA12F5	Spokane, WA (Beacon)	2013	885
WIL12F2	Wilbur, WA	2013	1,403
CDA121	Coeur d'Alene, ID	2013	438
OTH502	Othello, WA	2014	21
RAT231	Rathdrum, ID	2014	0
M23621	Moscow, ID	2015	413
WIL12F2	Wilbur, WA	2015	1,403
WAK12F2	Spokane, WA (Waikiki)	2016	175
RAT233	Rathdrum, ID	2019	471
SPI12F1	Northport, WA (Spirit)	2019	127
		Total	**7,479**

9. Generation Resource Options

Introduction

Several generating resource options are available to meet future load growth. 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 2015 IRP to meet future needs. The resources described in this chapter are mostly generic, as actual resources identified through a competitive process may differ in size, cost, and operating characteristics due to siting or engineering requirements.

Section Highlights

- Only resources with well-defined costs and operating histories are options to meet future resource needs.
- Wind, solar, and hydroelectric upgrades represent renewable options available to Avista.
- Upgrades to Avista's hydroelectric and thermal 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 only considers 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 wind, energy storage, photovoltaic solar, hydroelectric upgrades, and thermal unit upgrades. Several other resource options described later in the chapter were not included in the PRS analysis, but discussed as potential resource options that may respond to a future RFP. The IRP excludes potential contractual arrangements with other energy companies as an option in the plan, but such arrangements may be an option when Avista seeks new resources through a competitive acquisition process.

The resource costs of each resource option include transmission expenses, as described in Chapter 8 – Transmission & Distribution Planning. Levelized costs result from discounting nominal cash flows by a 6.58 percent-weighted average cost of capital approved by the states of Idaho and Washington in recent rate case filings. All costs in this section are in 2015 nominal dollars unless otherwise noted.

Many renewable resources are eligible for federal and state tax incentives. Federal solar tax benefits fall by two-thirds after 2016; 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. The IRP amortizes investment tax credits over the life of the asset per regulatory accounting rules.

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 characteristic and cost information from Thermoflow.

Levelized resource costs illustrate the cost 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 the facilities. 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 planned to operate only a few hours each year. Levelized energy costs fairly compare renewable resources to the energy component of natural gas-fired resources because renewable technologies are not dispatchable.

The following cost items are in the levelized cost calculations 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, a cash grant, or an investment tax credit (ITC), available to qualified generation options.
- *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 that are not based on generation levels.
- *Variable O&M:* Costs per MWh related to incremental generation.
- *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.

- *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.[1] Table 9.1 compares the levelized costs of different resource types.

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	$58	$130	220
Modern Large Frame CT	$57	$124	186
Advanced Small Frame CT	$64	$151	102
Frame/Aero Hybrid CT	$46	$164	106
Small Reciprocating Engine Facility	$41	$159	93
Modern Small Frame CT	$59	$188	49
Aero CT	$54	$202	45
1 x 1 Advanced CCCT	$37	$211	362
1 x 1 Modern CCCT	$37	$210	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 600 MW. Avista would need to share the plant with one or more utilities 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 some water is available for plant cooling, but only enough for a hybrid system utilizing the benefits of combined evaporative and convective technologies.

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

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 being commonly used technologies in the Northwest. Where 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.[2] 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 machine's heat rate is 6,720 Btu/kWh in 2016.[3] The larger machine is 6,631 Btu/kWh. The plants include duct firing for 7 percent of rated capacity at a heat rate of 7,912 and 7,843 Btu/kWh, respectively.

The IRP includes a 3 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 anticipated capital costs for the two CCCTs, located in Idaho on Avista's transmission system with AFUDC on a green field site, are $1,177 per kW for the smaller machine and $1,120 per kW (2016$) 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 allow the plants to start and ramp quickly, providing regulation services and reserves for load following and to integrate variable resources such as wind and solar.

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 and operational estimates based on internal engineering estimates. All

[2] 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.
[3] Heat rates shown are the higher heating value.

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	$638	$2.08	9,931	$3.65	1	203	203	$129
Modern Large Frame CT	$667	$2.08	10,007	$2.60	1	170	170	$114
Advanced Small Frame CT	$853	$3.13	11,265	$2.60	1	96	96	$82
Frame/Aero Hybrid CT	$1,016	$3.13	8,916	$3.13	1	101	101	$103
Small Reciprocating Engine Facility	$546	$8.33	7,700	$3.13	10	9.3	93	$51
Modern Small Frame CT	$1,265	$4.17	10,252	$2.60	1	45	45	$57
Aero CT	$1,316	$6.25	9,359	$2.60	1	42	42	$56
1 x 1 Modern CCCT	$1,120	$18.75	6,771	$3.91	1	341	341	$382
1 x 1 Advanced CCCT	$1,177	$15.63	6,845	$3.13	1	286	286	$336

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 its 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, three options exist: contracting for firm natural gas transportation rights, on-site oil, or liquefied natural gas storage.

Wind Generation

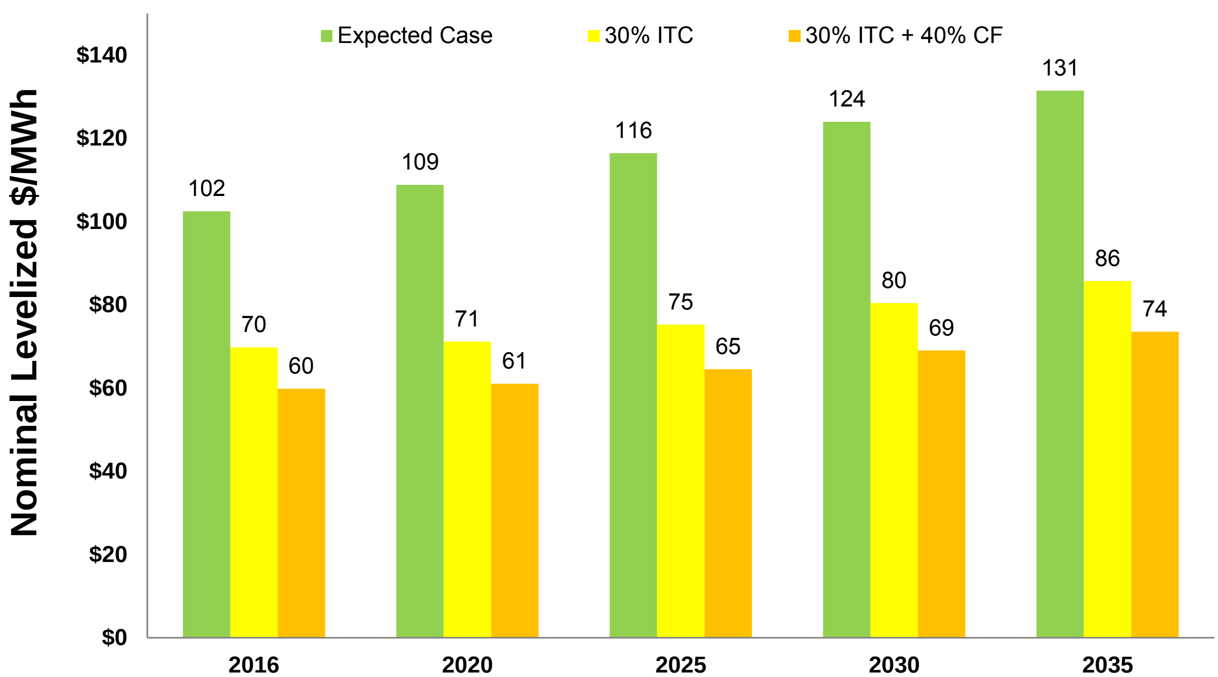
Governments promote wind generation with tax benefits, renewable portfolio standards, carbon emission restrictions, and stricter controls on existing non-renewable resources. The 2013 “Fiscal Cliff” deal in the U.S. Congress extended the PTC for wind through December 31, 2013, with provisions allowing projects to qualify after 2013 if construction began in 2013. This IRP does not assume the PTC extends beyond this term, but does assume the preferential five-year tax depreciation remains.

Wind resources benefit from having no emissions or fuel costs, but they are not dispatchable, and have high capital and labor costs on a per-MWh basis when compared to most other resource options. Wind capital costs in 2016, including AFUDC, are $2,234 per kW, with annual fixed O&M costs of $46 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 $4.30 per kW-year in 2016. 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 35 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 impacts 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 2016, the estimated "all-in" cost is $102 per MWh; but, direct cost to customers would be $70 per MWh with the ITC. This plan assumes wind resources selected in the PRS include the 20 percent REC apprenticeship adder for the EIA. Qualification for the adder requires 15 percent of construction labor by state-certified apprentices.

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 that 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.

Where a substantial amount of PV solar is added to a summer peaking utility system, such as one located in the Desert Southwest, the peak hour recorded prior to the installation will be reduced, but the peak hour will shift 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 that solar does not reduce Avista’s winter peak, reduces the summer peak, and is less effective at reducing peak as more solar is installed.

Table 9.3: Solar Capacity Credit by Month

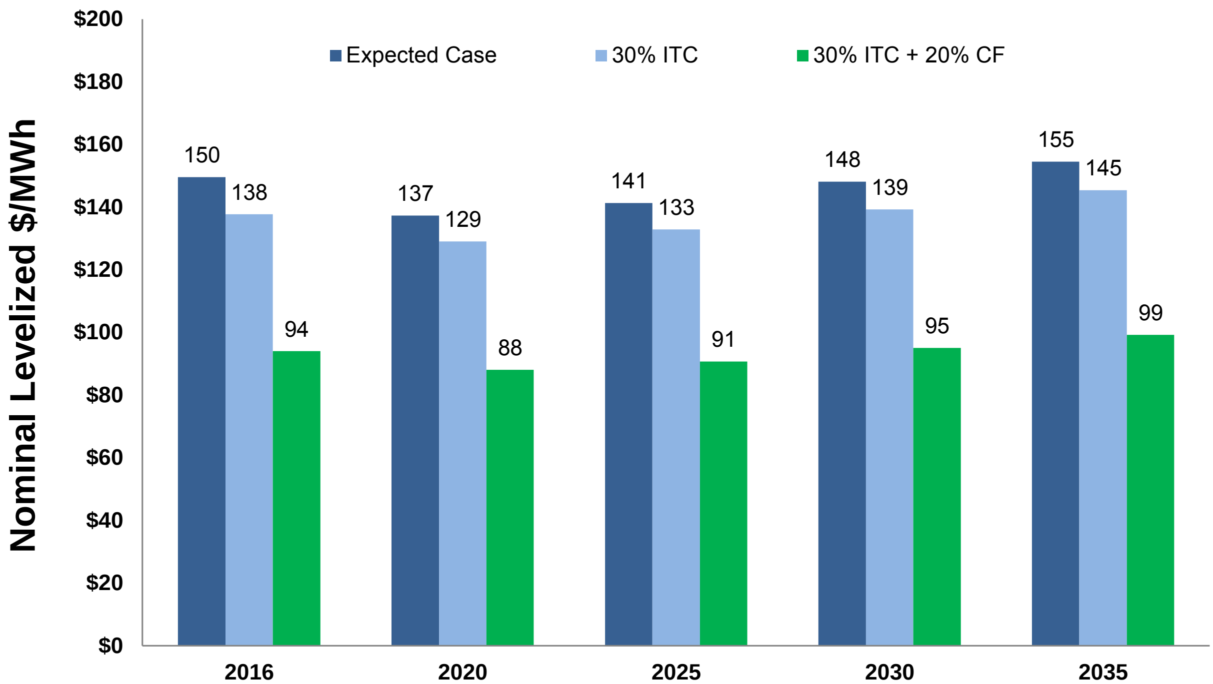
Month	5 MW	25 MW	50 MW	100 MW	150 MW	200 MW	300 MW
Jan	0%	0%	0%	0%	0%	0%	0%
Feb	0%	0%	0%	0%	0%	0%	0%
Mar	0%	0%	0%	0%	0%	0%	0%
Apr	28%	15%	11%	8%	6%	5%	3%
May	46%	46%	37%	26%	17%	13%	9%
Jun	39%	39%	36%	31%	25%	22%	19%
Jul	52%	49%	45%	43%	33%	27%	22%
Aug	40%	40%	40%	34%	32%	30%	24%
Sep	0%	0%	0%	0%	0%	0%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

Solar-thermal technologies can produce capacity factors as much as 30 percent higher than PV solar projects and can store energy for several hours 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 the IRP.

Utility-scale PV solar capital costs in the IRP, including AFUDC, are $1,500 per kW for fixed panel and $1,600 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 to account for panel degradation.

Figure 9.2 shows the levelized costs of solar resources, including applicable federal and state incentives, on-line dates, and capacity factors. The costs are specific to Avista acquisition and ownership. The State of Washington offers a number of incentives for solar installations. First, 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.

Figure 9.2: Solar Nominal Levelized Cost ($/MWh)



Energy Storage

Increasing solar and wind generation on the electric grid makes energy storage technologies attractive from an operational perspective. Storage could be an ideal way to smooth out renewable generation variability, 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 over supply 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, flow batteries, flywheels, and compressed air.

Storage may become an important part of the nation's electricity grid if the technology overcomes a number of large 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 high, at near $3,455 per kW, or nearly three times the initial cost of a natural gas-fired peaking plant that can provide many of the same capabilities without the electricity consumption characteristics of storage. Storage costs will decline over time, and Avista continues to 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. Finally, early technology adoption can be risky, with industry examples of battery fires and financial issues.

To learn more about storage technology and its potential, Avista recently installed a vanadium flow battery in Pullman, Washington. This installation, known as the Turner Energy Storage Project, will provide insight about the technology's reliability, its potential benefit to the transmission and/or distribution systems, and potential power supply benefits including oversupply events. The battery has one megawatt of power capability and three megawatt-hours of energy storage. A Washington state grant for research and development partially funded this storage project.

Turner Energy Storage Project, Pullman, WA

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 fall.

In addition to capital costs, storage projects O&M costs are $20 per kW-year, and recharge costs use off-peak Mid-Columbia energy prices. Levelized storage project costs are highly 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.

The nominal levelized capacity cost for storage is approximately $580 per kW-year and energy costs $35/MWh.

Other Generation Resource Options

A thorough IRP analyzes generation resources not readily available in large quantities, not commercially available, not economically ready for utility-scale development, or prohibited by state policy. Several emerging technologies, like energy storage, are attractive from an operational or environmental perspective, but are significantly higher-cost than other technologies providing similar capabilities at lower cost. The resources include biomass, geothermal, co-generation, nuclear, landfill gas, and anaerobic digesters. This plan does not model these resource options explicitly, but continues to monitor their viability.

Exclusion from the PRS is not the last opportunity for non-modeled technologies to be part of Avista's future portfolio. The resources compete with those included in the PRS through competitive acquisition processes. Competitive acquisition processes identify technologies that might displace resources otherwise included in the IRP strategy. Another possibility is acquisition through federal PURPA mandates. PURPA provides non-utility developers the ability to sell qualifying power to Avista at set prices and terms.[4]

Woody Biomass Generation

Woody biomass generation projects use waste wood from lumber mills or forest restoration processes. 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 project, Avista will consider it for a future acquisition.

Geothermal Generation

Northwest utilities have shown increased interest in geothermal energy over the past several years. It 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 projects are likely to be developed.

Geothermal energy struggles to compete due to high development costs stemming from having to drill several holes thousands of feet below the earth's crust; each hole can

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

cost over $3 million. Ongoing geothermal costs are low, but the capital required locating and proving a viable site is significant. Costs shown in this section do not account for the dry-hole risk associated with sites that do not prove to be viable after drilling has taken place.

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 it 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 has 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.

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 fewer than five megawatts. Most facilities are located at large dairies and feedlots. A survey of Avista's service territory found no large-scale livestock operations capable of implementing this technology.

Wastewater treatment facilities can also 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 waste water system under a PURPA contract with a Spokane County facility.

Small Cogeneration

Avista has few industrial customers capable of developing cost-effective cogeneration projects. 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.

A big challenge in developing any new cogeneration project is aligning the needs of the cogenerator and the utility's 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.

Nuclear

Avista does not include nuclear plants as a resource option in the IRP given the uncertainty of their economics, the apparent lack of regional political support for 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 a reality.

The viability of nuclear power could change as national policy priorities focus attention on de-carbonizing the nation's energy supply. The lack 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. New smaller, and more modular, nuclear design could increase the potential for nuclear by shortening the permitting and construction phase, and make these traditionally large projects better fit the needs of smaller utilities.

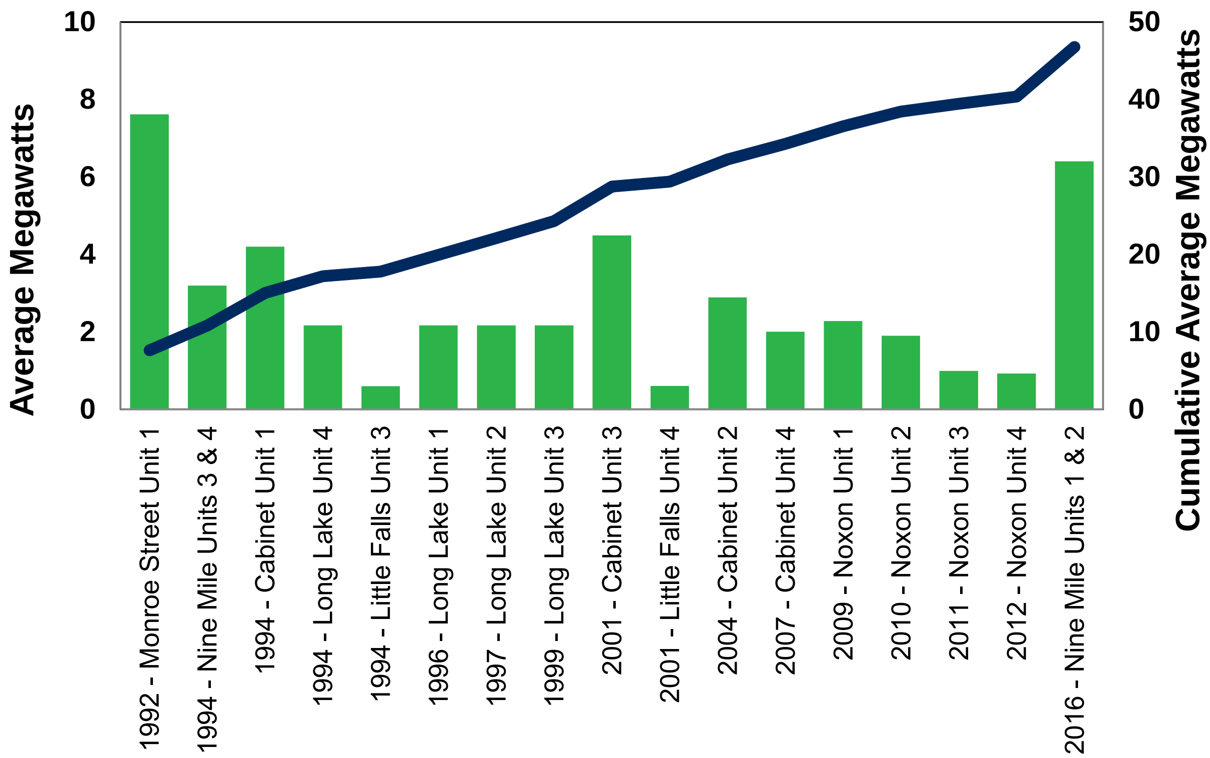
Coal

The coal generation industry is at a crossroads. In many states, like Washington, new coal-fired plants are unlikely due to emission performance standards and the shortage of utility scale carbon capture and storage projects. Federal guidelines under section 111(b) of the CAA and the CPP likely prevent or restrict the construction of new coal generation. The final rule was not available at the time this section's drafting. The risks associated with future carbon legislation and projected low natural gas costs make investments in this technology challenging.

Hydroelectric Project Upgrades and Options

Avista continues to upgrade its hydroelectric facilities. The latest hydroelectric upgrade added nine megawatts to the Noxon Rapids Development in April 2012. Figure 9.3 shows the history of upgrades to Avista's hydroelectric system. Avista added 40.1 aMW of incremental hydroelectric energy between 1992 and 2012. 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



Avista is currently upgrading the Nine Mile powerhouse, replacing two of its four turbine generator units. Avista removed the last two original 1908 units in 2013 and began a project to replace the 107-year old technology with new turbine generators, generator step-up transformer, switchgear, exciters, governors and controls in 2014. Avista expects to complete the project in 2016.

The Spokane River hydroelectric construction occurred in the late 1800s and early 1900s, when the priority was to meet then-current loads. The developments currently do not capture a majority of the river flow as their original designs only met then-current loads and not river capacity. In 2012, Avista reassessed its Spokane River developments to evaluate opportunities to take advantage of 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 at each. Each upgrade option should qualify for the EIA, meeting the Washington state 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. A summary of the upgrade options is in Table 9.4. The upgrades will compete against other renewable options when more renewables are required in future.

Table 9.4: Hydroelectric Upgrade Options

Resource	Post Falls	Monroe Street/Upper Falls	Long Lake	Cabinet Gorge
Incremental Capacity (MW)	22	80	68	110
Incremental Energy (MWh)	90,122	237,352	202,592	161,571
Incremental Energy (aMW)	10.3	27.1	23.1	9.2
Peak Credit (Winter/ Summer)	24/0	31/0	100/100	0/0
Capital Cost ($ Millions)	$136	$193	$179	$286
Levelized Energy Cost ($/MWh)	$159	$93	$112	$197

Long Lake Second Powerhouse

Avista studied adding a second powerhouse at Long Lake over 20 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 provide incremental capacity to meet peak load growth.

The 2012 study focused on three alternatives. The first replaces the existing four-unit powerhouse with four larger units to total 120 MW, increasing capacity by 32 MW. The other two alternatives develop a second powerhouse with a penstock beginning from a new intake structure just 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.

Post Falls Refurbishment

The Post Falls hydroelectric development is 109 years old. Three alternatives could increase the existing capacity from 18 MW up to 40 MW. The first option is a new two-unit 40 MW powerhouse on the south channel that replaces the existing powerhouse. Alternative 2 retrofits the existing powerhouse with five 8.0 MW units (40 MW total). The last alternative retrofits the existing powerhouse with six 5.6-MW units (33.6 MW total). The cost differences between developing a new powerhouse in the south channel and the smaller plant refurbishment is small. Studies of alternatives to address the aging infrastructure of the plant will continue over the next decade.

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 1952 construction.

Thermal Resource Upgrade Options

The 2013 IRP identified several thermal upgrade options for Avista's fleet. 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 PowerPhaseLLC, the technology increases airflow through a combustion turbine compressor increasing machine output. This upgrade increases 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 2020 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 will be at the end of its expected life. At this time, Avista could spend additional capital and upgrade the unit by 12 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 3 percent of load and 3 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 10 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 10 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

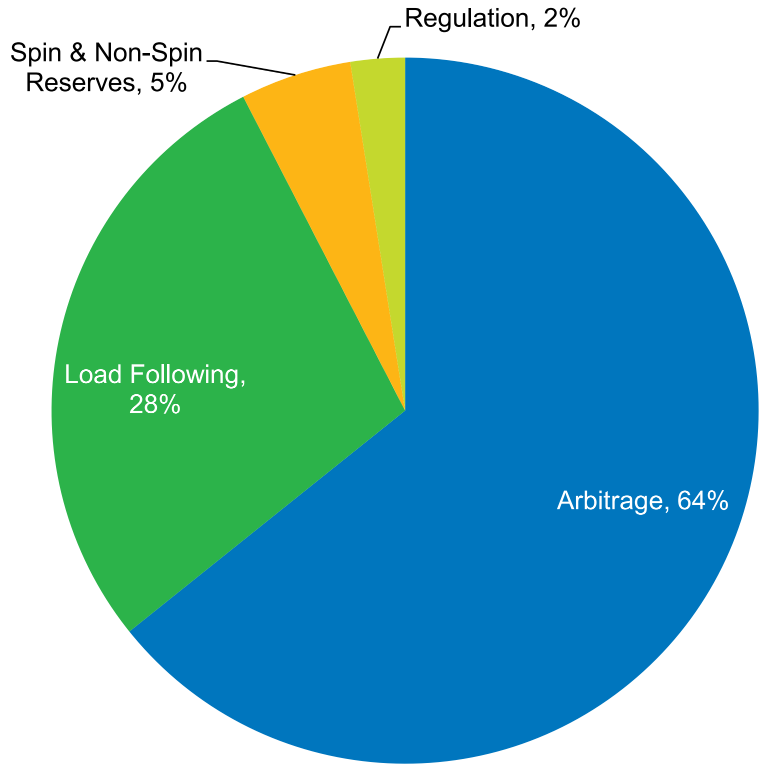
As intermittent resources grow in size, there is potential for the existing system not being robust enough to integrate the resources and handle oversupply of renewable energy. To address this concern, governments and utilities are investing in storage technology. Today storage has a limited role due to cost and technology infancy. This analysis studies the potential financial value storage brings to Avista's power supply costs based on 2012 actual data and average hydroelectric conditions. The study includes several storage capacities with storage to peak ratio of three to one and 85 percent efficiency. Table 9.5 is the value 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 is optimizing the battery to charge in low prices and discharging 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

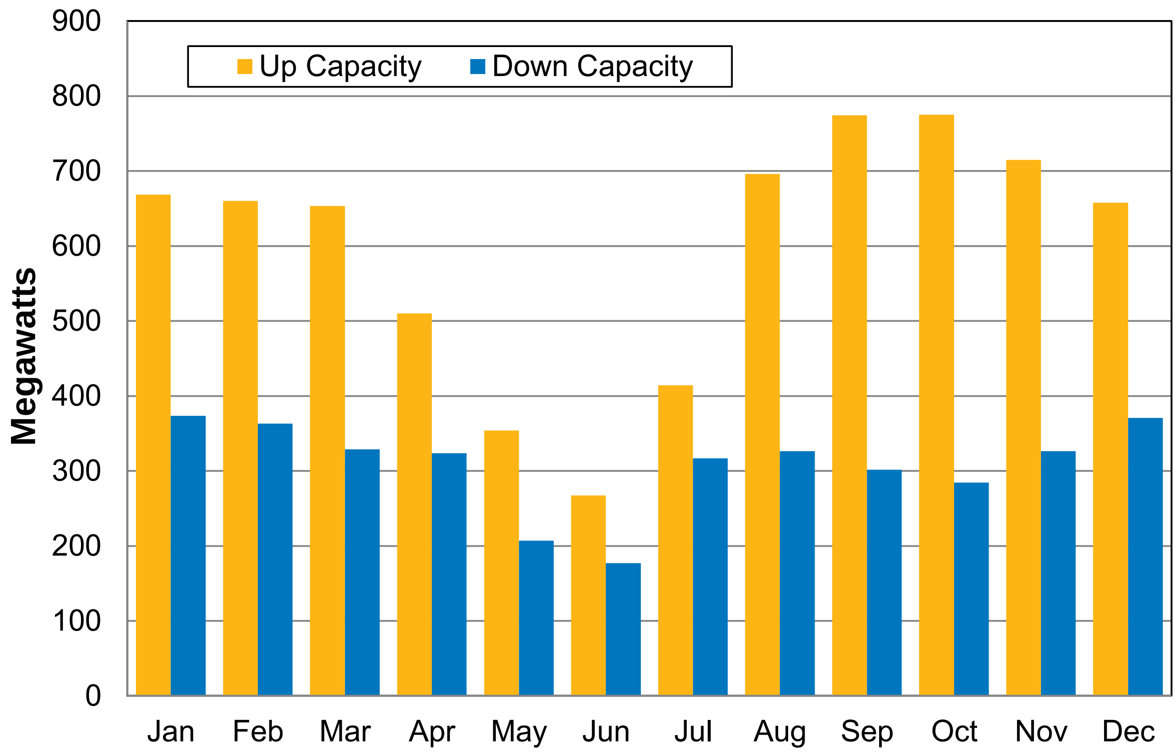
Natural gas-fired facilities can provide energy and ancillary services. This study looks at their incremental ancillary services value to the system. The values do not represent the value for current resources of similar technology, but only the incremental value of a new facility. This study assumes 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 this type of resource. 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[5], 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

Currently, there is not a mature ancillary services market in the Northwest, so ancillary service values are the costs of operating Avista's system differently to provide more ancillary services relative to traditional wholesale energy sales. The ancillary service values of both storage and natural gas-fired technology were less than expected prior to the analysis. Avista concluded that the results were reasonable for one primary reason: having a large hydroelectric system, Avista's system has a significant amount of flexibility relative to its load variability in most periods. With as the addition of more variable generation resources, the value of ancillary services capacity should rise. Figure 9.5 details the significant surplus of ancillary service generation Avista's system contains. While the system can become constrained during peak load periods, the large value in these periods is not as significant when averaged over the entire year.

Figure 9.5: Avista's Monthly Up/Down Regulation Surplus



5 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 2015 IRP. It contains price risks Avista considers to meet customer demands at the lowest reasonable cost. The analytical foundation for the 2015 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 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 various sub-markets within the Western Interconnect and the changing 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 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), resource dispatch costs and values, and greenhouse gas emissions.

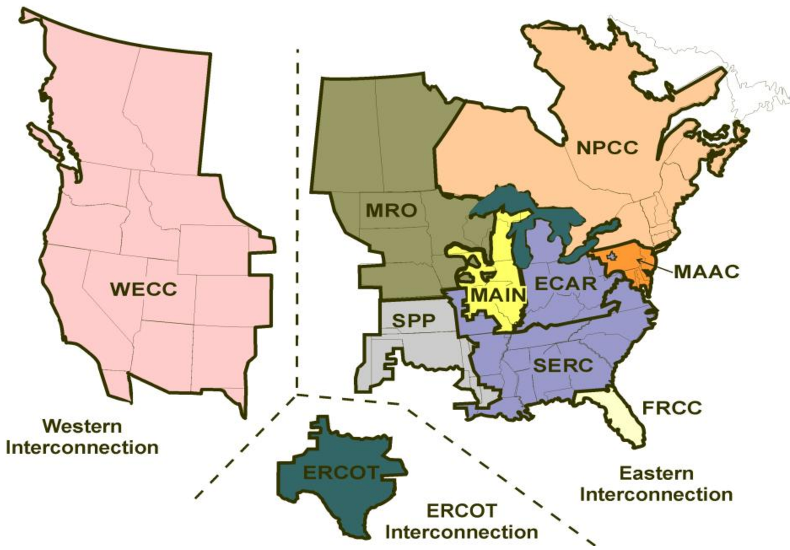
Section Highlights

- Natural gas, solar, and wind resources dominate new generation additions in the Western Interconnect.
- Clean Power Plan regulation could cause large price and costs swings, but without a final rule and state compliance plans, the impacts are unknown at this time.
- 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.

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 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

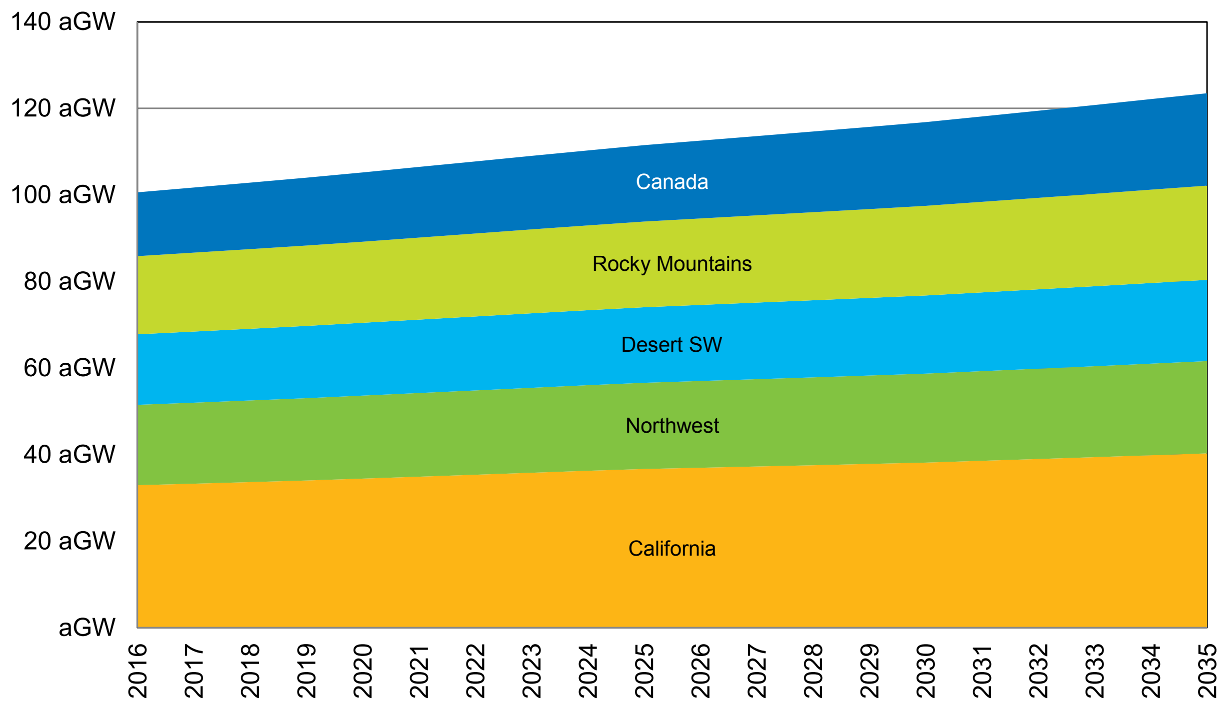
Northwest- OR/WA/ID/MT	Southern Idaho
COB- OR/CA Border	Wyoming
Eastern Montana	Southern California
Northern California	Arizona
Central California	New Mexico
Colorado	Alberta
British Columbia	South Nevada
North Nevada	Baja, Mexico
Utah	

Western Interconnect Loads

The 2015 IRP relies on a load forecast for each zone of the Western Interconnect. Avista uses other utilities' resource plans and regional plans to quantify load growth across the west. These estimates include energy efficiency, customer-owned generation, plug-in electric vehicles, and demand response reductions within the trajectory. 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 1.1 percent annually over the next 20 years. On a regional basis, the Northwest will grow at 0.73 percent, California at 1 percent, the Rocky Mountain States at 1 percent, and the desert Southwest region is lower than previous forecasts at 0.75 percent. The strongest projected growth area in the region comes from Canada at 2 percent. From a system reliability perspective, regional peak loads grow at similar levels.

Figure 10.2: 20-Year Annual Average Western Interconnect Energy



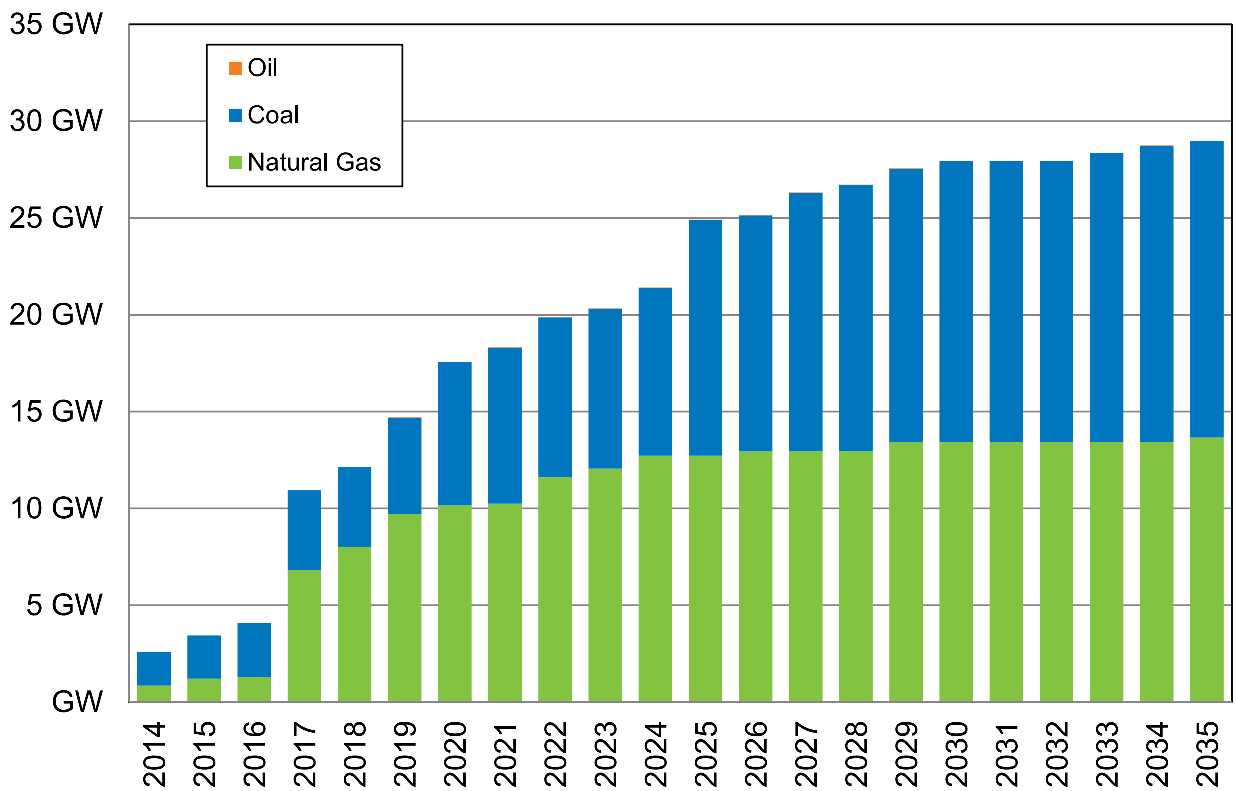
Resource Retirements

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 future 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 that cannot economically meet stricter air emissions standards and compete with lower-cost natural gas-fired facilities.

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. Remaining OTC natural gas-fired and nuclear facilities with more favorable economics are candidates for retrofitting with new cooling technology. The IRP models the closure of OTC plants with identified shutdown dates from their utility owners' IRPs and news releases. 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 a more modern and efficient generation fleet will serve customers.

Coal-fired facilities face increasing regulatory scrutiny. In the Northwest, the Centralia and Boardman coal plants will retire by the end of calendar years 2020 and 2025 respectively, for a reduction of 1,961 megawatts. Other coal-fired plants throughout the Western Interconnect have announced plant closures, including Four Corners, Carbon, Arapahoe, San Juan, Reid Gardner, and Corette. The Nevada legislature successfully placed into law a plan to retire all in-state coal plants, and PacifiCorp appears poised to retire many plants as indicated in its most recent IRP. Over the next 20 years, roughly 45 percent of the 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 29 gigawatts by 2035. Avista does not forecast any additional large coal facility retirements in its Expected Case.

Figure 10.3: Resource Retirements (Nameplate Capacity)



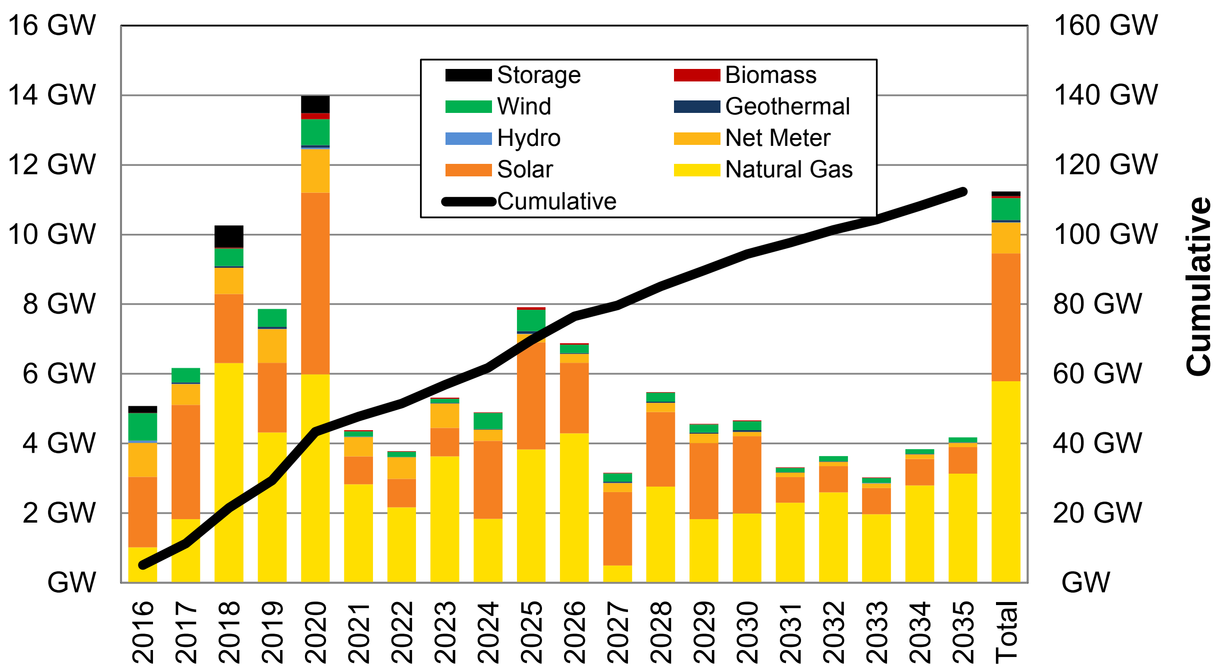
New Resource Additions

New resource capacity is required to meet future load growth and replace retired power plants over the next 20 years. To fill the gap, the model adds new resources in each region to maintain a 5 percent Loss of Load Probability (LOLP). This means meeting all system demand in 95 percent of simulated forecasts. The generation additions meet capacity, energy, ancillary services, and renewable portfolio mandates. Only natural gas-fired peaking and CCCT plants, solar plants, and wind plants are in the plan. The IRP does not include new nuclear or coal plants over the forecast horizon.

Many states have RPS requirements promoting renewable generation to reduce greenhouse gas emissions, provide jobs, and diversify their 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^{XMP} cannot model RPS levels explicitly. Instead, Avista inputs RPS requirements into the model at levels sufficient to satisfy state laws based on resource selection trends. Figure 10.4 illustrates new capacity and RPS additions made in the modeling process. Nearly 112 GW will be required to meet the renewable and capacity requirements for the system. Wind and solar facilities meet most renewable energy requirements.

Geothermal, biomass, and hydroelectric resources provide limited RPS contributions. Due to its low capacity factor, large quantities of solar capacity are necessary to make a meaningful contribution. Renewable resource choices differ depending on state laws and the local availability of renewable resources. For example, the Southwest will meet RPS requirements with solar given policy choices by those states. The Northwest will use a combination of wind, solar, and hydroelectric upgrades because the costs of these resources are the lowest for the region. Rocky Mountain States will meet RPS requirements predominately with wind.

Figure 10.4: Cumulative Generation Resource Additions (Nameplate Capacity)



In total, 45,000 MW of new utility and consumer-owned renewable generation will put downward pressure on afternoon peak pricing 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 forecast finds wind generation is no longer the largest contributor of new renewable resources in the Western Interconnect; it represents 6,000 MW, or 13 percent, of new renewable capacity. The largest resource addition expected in the west is natural gas-fired generation. The technology likely will be a combination of peakers and flexible combined cycle plants. A new entrant into the resource forecast is storage technology. Given increasing government intervention in the energy storage market in California, 1,300 MW of storage capacity is included in the forecast. 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 2021. Utility resource size requirements determine if the new plants are CCCTs or peakers. Based on market simulation results, a 24 percent regional planning margin (including operating reserves) is necessary to meet the 5 percent LOLP. The Northwest likely will continue to develop wind to meet RPS requirements, but given the lower cost of solar, Avista expects some utilities to move to solar to meet renewable requirements beginning in 2020. Table 10.2 shows the amount of new renewables added to the Northwest by the end of 2035 in the Expected Case.

Table 10.2: Added Northwest Generation Resources

Resource Type	Capacity (MW)
Wind	2,340
Utility- Solar	1,140
Customer- Solar	1,884
Other Renewables	225

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 limited siting opportunities.

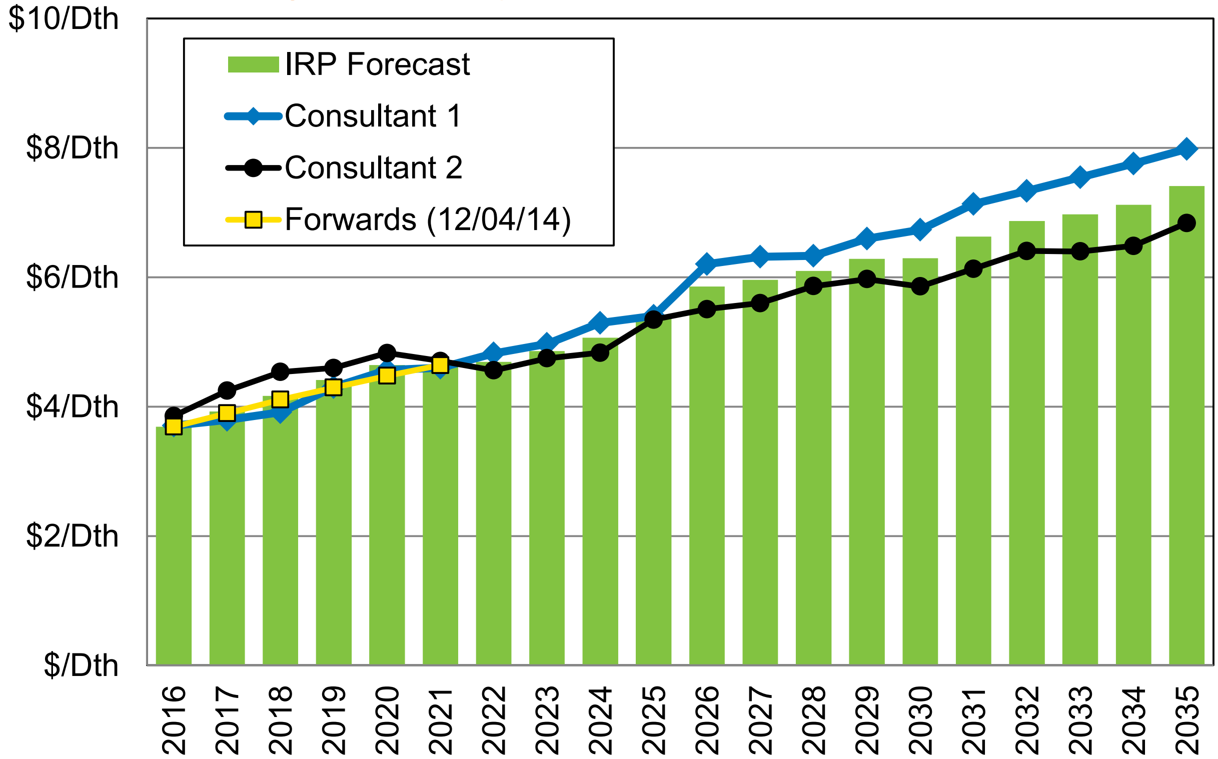
Natural Gas

The natural gas industry continues its fundamental shift away from conventional gas to hydraulic fracturing, or fracking. As fracking continues to become more efficient, production increases at record pace. At the same time, growth in the residential, commercial, and industrial markets is flat. Natural gas used for power generation is growing due to its flexibility to support the variable output from renewable energy and as a replacement resource for coal plant retirements caused by state and federal regulations. Additionally, forecast adoption of natural gas for transportation and LNG exports increases demand in later years of the forecast.

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. Unconventional sources reduce overall price levels and volatility, although it is unknown how much volatility will exist in the future, as technology plays out against regulatory pressures and the potential for new demand created by falling prices. Avista uses forward market prices and a combination of two forecasts from prominent energy industry consultants to develop the natural gas price forecast for this IRP. Based on these forecasts, the levelized nominal price is $5.13 per dekatherm (Dth) at Henry Hub (shown in Figure 10.5 as the green bars). The pricing methodology to create a fundamental price forecast is below, as follows:

- 2016: 100 percent market;
- 2017: 75 percent market, 25 percent consultant average;
- 2018: 50 percent market, 50 percent consultant average; and
- 2019-21: 25 percent market, 75 percent consultant average.

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. One change in recent years is the new Ruby pipeline. It provides the west coast access to historically cheaper natural gas supplies located in the Rocky Mountains. 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	2016	2020	2025	2030	2035
Stanfield	93%	94%	95%	97%	100%
Malin	98%	98%	98%	99%	101%
Sumas	90%	93%	93%	97%	100%
AECO	81%	83%	87%	92%	94%
Rockies	97%	96%	97%	98%	99%
Southern CA	103%	102%	102%	102%	103%

Table 10.4: Monthly Price Differentials for Stanfield from Henry Hub

Month	2016	2020	2025	2030	2035
Jan	97%	97%	98%	99%	103%
Feb	97%	96%	97%	98%	102%
Mar	96%	95%	96%	98%	101%
Apr	92%	94%	95%	96%	100%
May	91%	92%	93%	95%	99%
Jun	87%	88%	92%	94%	98%
Jul	87%	90%	93%	93%	98%
Aug	91%	93%	94%	95%	99%
Sep	93%	95%	95%	97%	100%
Oct	93%	95%	96%	98%	100%
Nov	95%	97%	97%	100%	102%
Dec	96%	97%	96%	99%	102%

Coal

This IRP models no new coal plants in the Western Interconnect, so coal price forecasts affect only existing facilities. The average annual price increase over the IRP timeframe is 3.6 percent based on data from the Energy Information Administration. For Colstrip Units 3 and 4, Avista used escalation rates based on expectations from existing contracts.

Hydroelectric

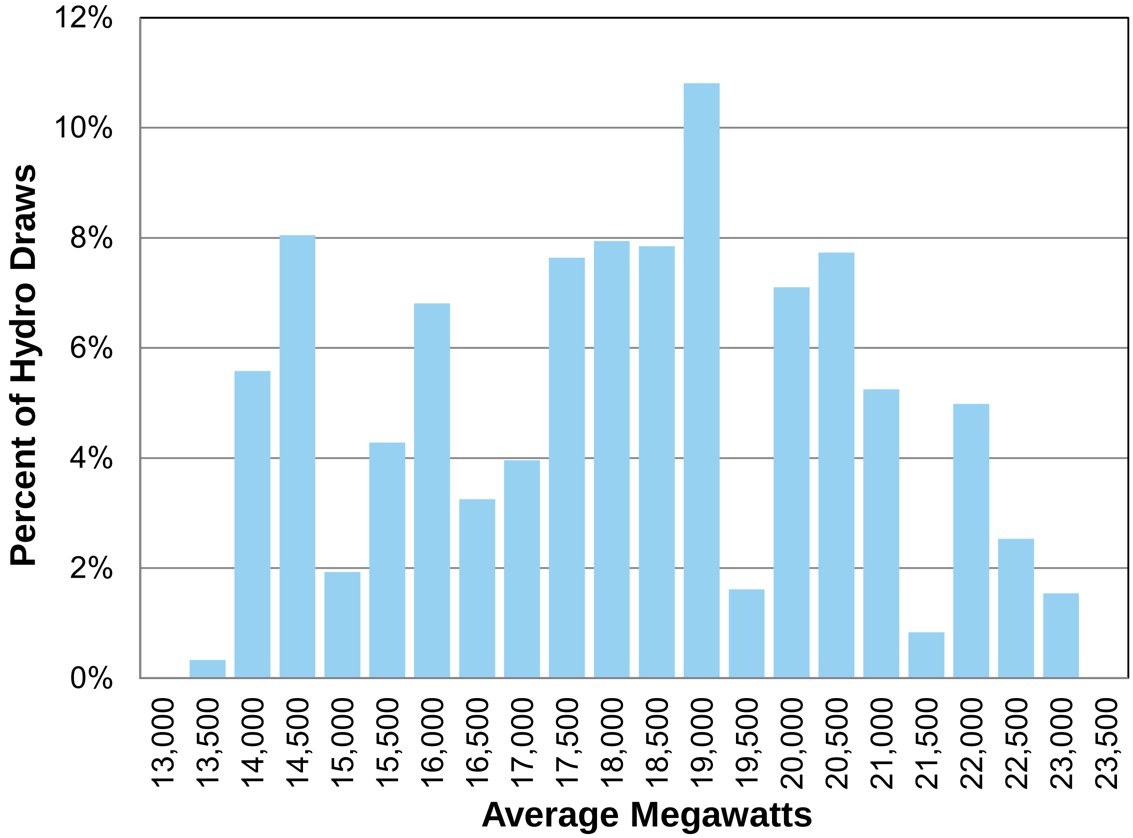
The Northwest U.S., British Columbia, and California have substantial hydroelectric generation capacity. A favorable characteristic of hydroelectric power is its ability to provide near-instantaneous generation up to and potentially beyond its nameplate rating. This characteristic is valuable for meeting peak load, following general intra-day load trends, shaping energy for sale during higher-valued hours, and integrating variable 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. This IRP also includes BPA hydroelectric estimates for the 80-year record for British Columbia and California.

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 17,370 aMW in 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 13,735 aMW (-21 percent) and a 90th percentile water year of 20,340 aMW (+17 percent).

AURORA^{XMP} maps each hydroelectric plant to a load zone, creating a similar energy shape for all plants in that load zone. For Avista's hydroelectric plants, AURORA^{XMP} uses the output from its own proprietary software with a better representation of operating characteristics and capabilities. AURORA^{XMP} 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 move hydroelectric generation into peak load hours; this maximizes the value of the system consistent with actual operations.

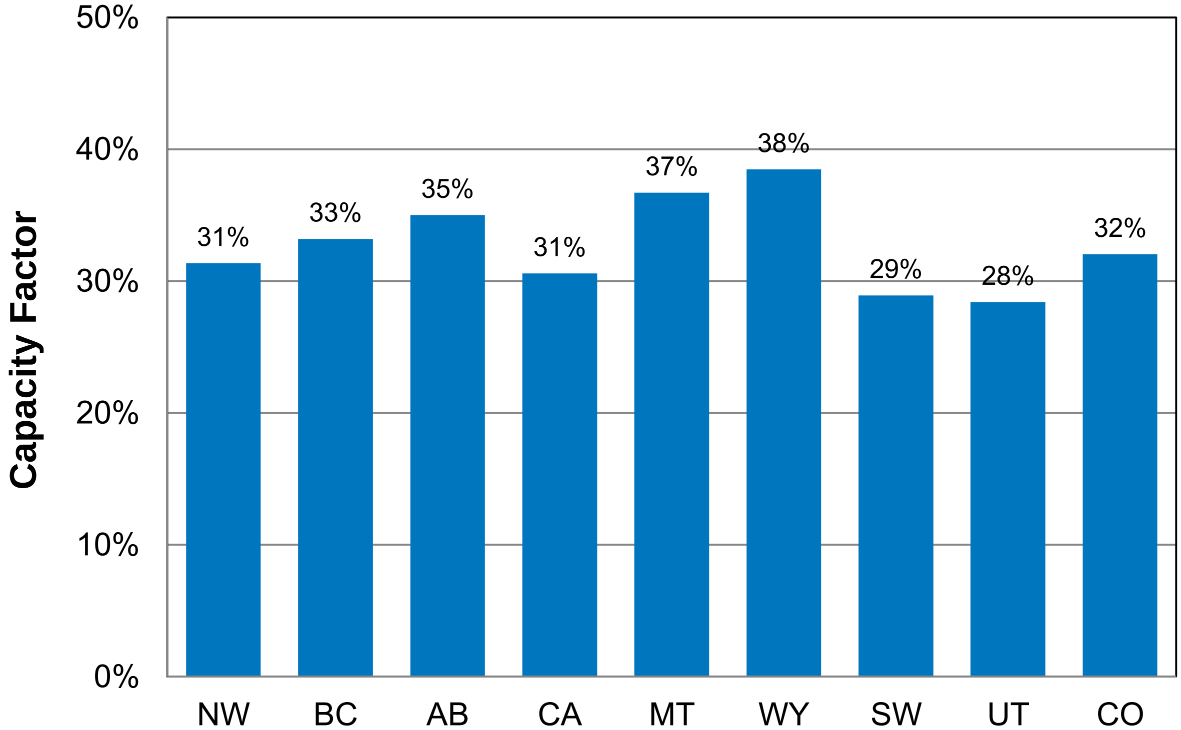
Figure 10.6: Northwest Expected Energy



Wind

New wind resources satisfy renewable portfolio standards over the IRP timeframe. These additions increase competition for the remaining higher-quality wind sites. Similar to how AURORA^{XMP} 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

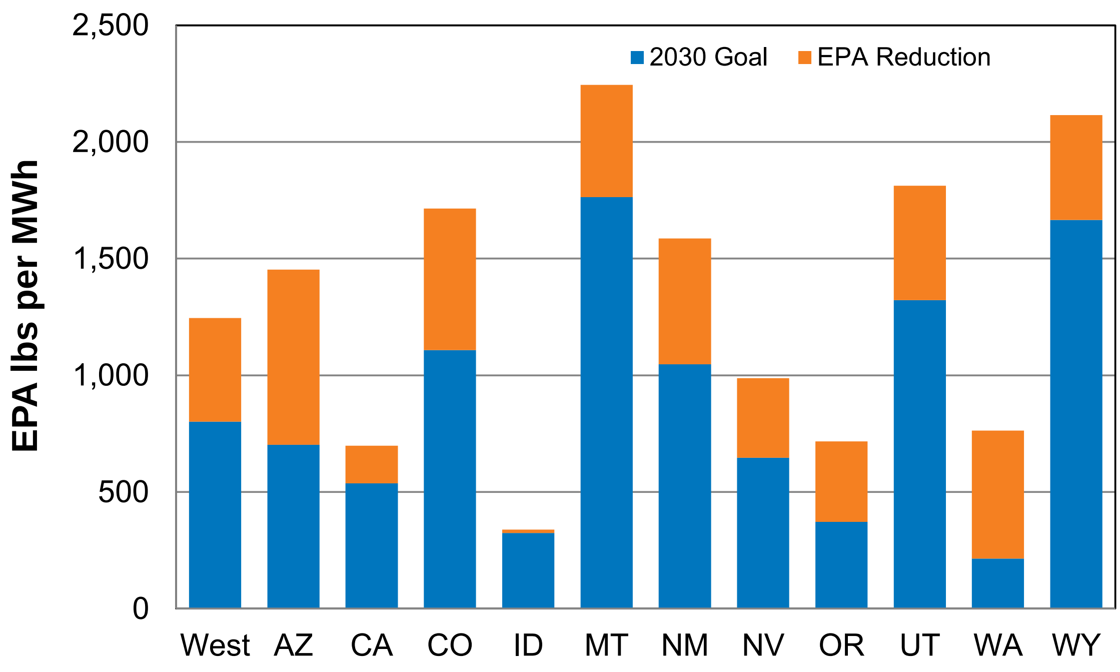
Greenhouse gas, or carbon emissions, regulation is a significant risk for the electricity industry because of its reliance on carbon-emitting power generation. Regulation may require the reduction of carbon emissions at existing power plants, the construction of low- and non-carbon-emitting technologies, and changes to existing resource operations. Between 2008 and 2012, carbon emissions from electricity generation have fallen by nearly 12 percent due to reduced loads and lower coal generation levels.

Future carbon emissions could fall due to fundamental market changes. In 2014, the EPA released the draft CPP under section 111(d) of the CAA to reduce emissions from existing plants. A description of the draft CPP is in Chapter 7 – Policy Considerations. Use of compliance measures that do not rely on emission reductions solely from covered fossil-fueled electric generating units, such as renewable energy and energy efficiency standards, would not necessarily preclude emission increases from certain sources, just an overall reduction in a statewide emission rate. If emissions from plants covered under section 111(d) and newly constructed plants subject to section 111(b) are not both subjected (at some point) to the same emission rate target established under section 111(d), then newly constructed thermal facilities may increase emissions even when complying with 111(b)'s emission performance standard.

The Expected Case makes assumptions about state and federal greenhouse gas emissions policies. Avista's 2013 IRP acknowledgement from the WUTC directed the company to include a non-zero cost of carbon in the 2015 IRP. The acknowledgement indicated that by not including a risk factor for this potential cost, the portfolio decision does not include the potential risk of the added costs. The Expected Case in this IRP includes a 10 percent probability of $12 per metric ton beginning in 2020. Beyond 2020, the price increases 5 percent per year. This results in a levelized 2016-2035 cost of $11.45 per metric ton, applied randomly in 10 percent of the modeled iterations.

The second carbon reduction assumption in the Expected Case is the Western Interconnect meeting draft CPP goals by 2030. The CPP proposal was in draft form at the time of IRP development. This regulation received the most comments on a proposed rule in EPA history. The final rule, issued after the modeling was complete for this IRP, differs from the draft. The IRP assumes meeting CPP state-by-state goals as a whole in the Western Interconnect by 2030. The IRP assumes certain modifications to the goals to conform to this modeling effort, including adjustments for plants located outside the Western Interconnect, and adjusting Idaho's goal to account for partial-year operation of the Langley Gulch plant. The IRP assumes the Western Interconnect must be below 801 pounds per MWh by 2030. Figure 10.8 shows adjusted state and regional carbon intensity goals for CPP-regulated plants compared to the 2012 baseline.

Figure 10.8: 2030 Adjusted State Carbon Intensity CPP Goals



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 developed 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 among the most volatile of any traded commodity. Daily Stanfield prices ranged between $1.72 and $24.36 per Dth between 2004 and 2014. Figure 10.9 shows average Stanfield monthly prices since January 2004. Prices retreated from 2008 highs to a monthly price of $2.26 per Dth in April 2015. Prices since 2009 are lower than the previous five years, but continue to show volatility.

There are several methods to stochastically model natural gas prices. This study retains the method from the 2011 IRP, with mean prices shown in Figure 10.5 as the starting point. Prices vary using historical month-to-month volatility and a lognormal distribution.

Figure 10.9: Historical Stanfield Natural Gas Prices (2004-2015)

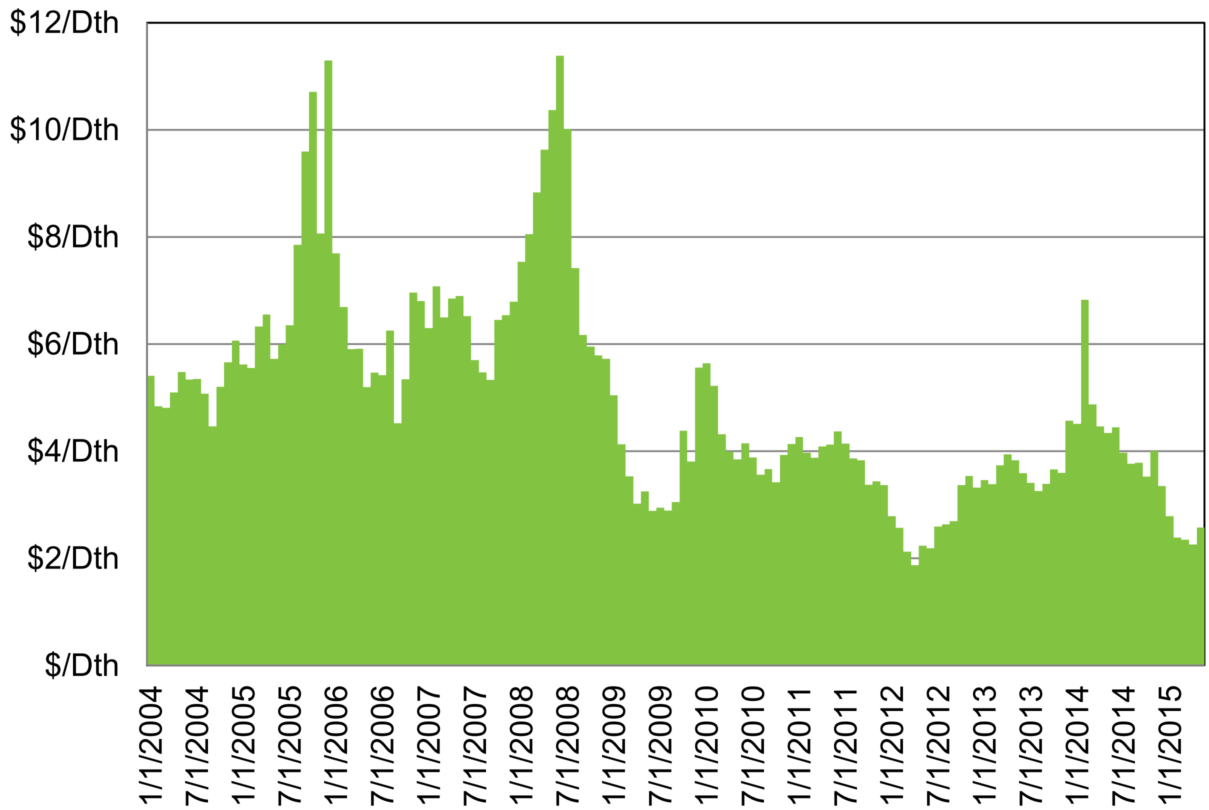


Figure 10.10 shows Stanfield natural gas price duration curves for 2016, 2025, and 2035. The chart illustrates a larger price range in the later years of the study, reflecting less forecast certainty over time. Shorter-term prices are more certain due to additional market information and the quantity of near term natural gas trading. Figure 10.11 shows another view of the forecast. The mean price in 2016 is $3.47 per Dth, represented by the horizontal bar, and the levelized price over the 20 years is $4.97 per MWh. The bottom and top of the bars represent the 10th and 90th percentiles. The bar length indicates price uncertainty.

Figure 10.10: Stanfield Annual Average Natural Gas Price Distribution

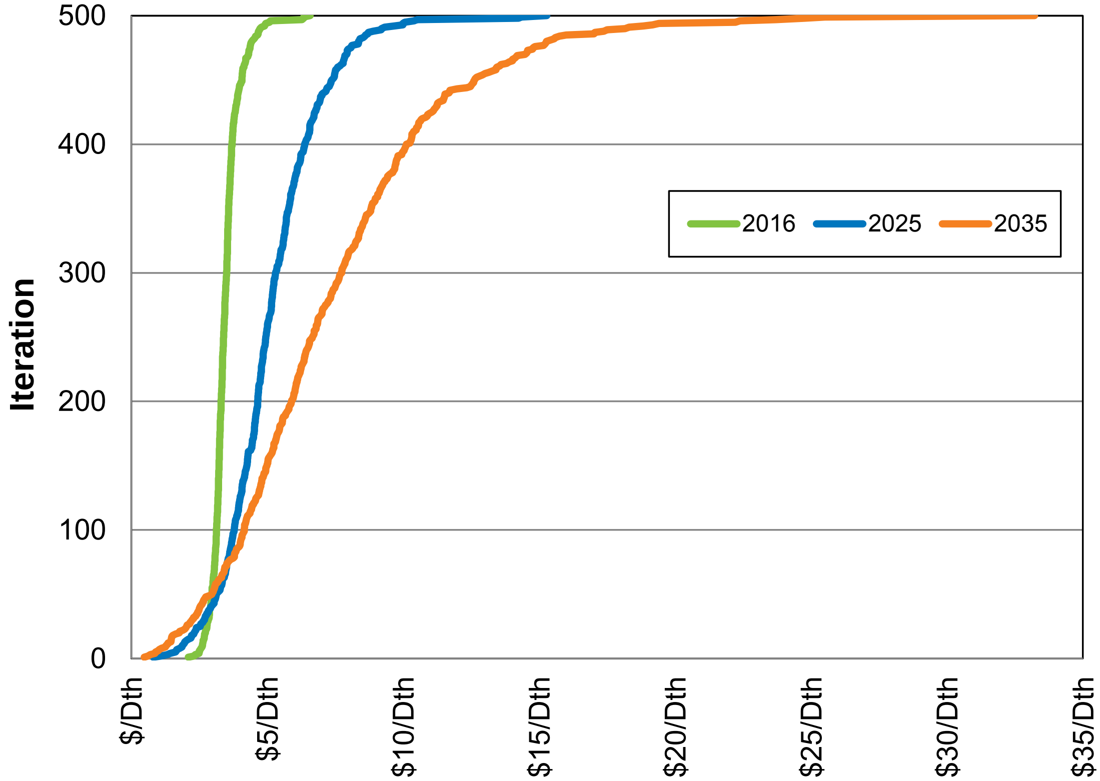
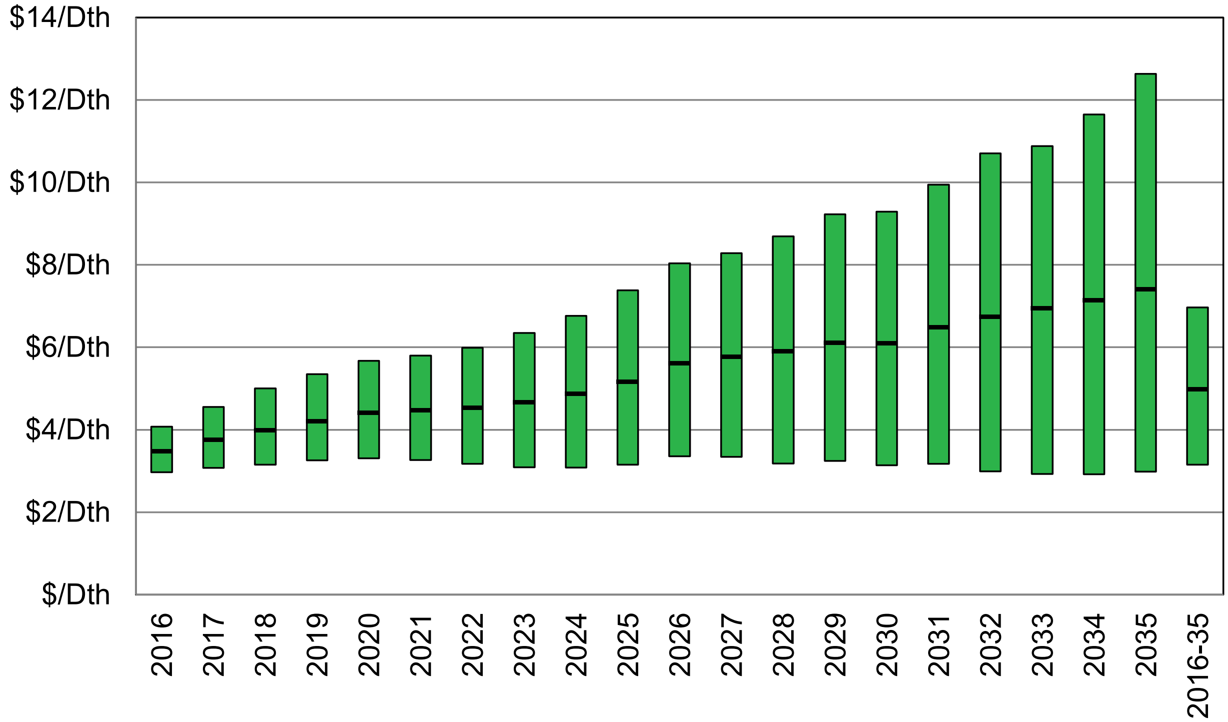


Figure 10.11: Stanfield Natural Gas Distributions



Regional Load Variation

Several factors drive load variability. The largest short-run driver is weather. Long-run economic conditions like the recent 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 2013 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 2015 IRP. Statistics are relative to the Northwest load area (Oregon, Washington, and Idaho). “NotSig” indicates that no statistically valid correlation existed in the data. “Mix” indicates the relationship was not consistent across the 2007 to 2013 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.[1]

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

Table 10.5: January through June Load Area Correlations

Area	Jan	Feb	Mar	Apr	May	Jun
Alberta	Not Sig	Not Sig	Not Sig	Mix	Mix	Mix
Arizona	14%	34%	Mix	Not Sig	Mix	7%
Avista	89%	82%	81%	80%	43%	51%
British Columbia	87%	86%	72%	78%	50%	31%
California	Not Sig	Not Sig	Mix	Mix	Mix	30%
CO-UT-WY	-16%	Mix	Mix	-24%	-3%	-6%
Montana	50%	43%	65%	57%	Mix	7%
New Mexico	Not Sig	Mix	Mix	Mix	Mix	Not Sig
North Nevada	62%	22%	7%	Not Sig	Mix	25%
South Idaho	77%	75%	67%	Mix	Mix	32%
South Nevada	37%	59%	Mix	Not Sig	Mix	7%

Table 10.6: July through December Load Area Correlations

Area	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig
Arizona	Not Sig	Not Sig	Mix	-7%	Mix	8%
Avista	66%	75%	65%	77%	92%	92%
British Columbia	67%	47%	18%	80%	89%	84%
California	5%	Not Sig	Mix	Not Sig	Mix	Not Sig
CO-UT-WY	-9%	Mix	-2%	-1%	19%	Mix
Montana	14%	15%	8%	7%	76%	76%
New Mexico	Not Sig	Not Sig	Mix	-21%	36%	Not Sig
North Nevada	48%	61%	32%	Not Sig	75%	63%
South Idaho	40%	63%	32%	Mix	86%	88%
South Nevada	7%	37%	Mix	-22%	Mix	63%

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

Area	Jan	Feb	Mar	Apr	May	Jun
Alberta	5.4%	4.6%	5.2%	5.0%	5.5%	6.1%
Arizona	8.8%	8.3%	8.1%	12.3%	16.5%	18.6%
Avista	10.1%	8.8%	10.2%	9.8%	9.7%	11.1%
British Columbia	9.7%	8.7%	9.4%	9.3%	9.7%	9.9%
California	10.6%	10.5%	10.5%	10.8%	12.5%	14.2%
CO-UT-WY	8.6%	8.1%	8.6%	8.6%	10.0%	14.8%
Montana	8.5%	7.3%	8.0%	7.9%	8.2%	10.5%
New Mexico	9.4%	9.1%	9.3%	10.9%	14.5%	15.9%
Northern Nevada	6.3%	6.2%	6.3%	6.4%	7.6%	10.2%
Pacific Northwest	11.0%	9.8%	10.6%	10.1%	9.6%	9.9%
South Idaho	9.5%	8.6%	9.9%	10.5%	11.6%	16.3%
South Nevada	7.3%	6.6%	7.2%	12.5%	17.8%	20.1%

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

Area	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	6.5%	6.2%	5.8%	5.6%	5.6%	5.5%
Arizona	16.4%	16.9%	18.1%	15.0%	8.7%	8.3%
Avista	13.9%	13.6%	11.5%	10.1%	11.1%	10.7%
British Columbia	10.8%	10.6%	10.3%	10.3%	11.3%	10.3%
California	14.9%	15.9%	16.0%	12.7%	11.2%	11.0%
CO-UT-WY	14.7%	14.3%	13.1%	9.5%	9.1%	9.3%
Montana	11.1%	10.9%	9.3%	8.4%	8.9%	9.0%
New Mexico	15.0%	14.7%	15.7%	12.2%	10.3%	10.0%
Northern Nevada	11.3%	10.9%	9.8%	6.8%	6.9%	7.3%
Pacific Northwest	11.8%	11.7%	10.8%	10.5%	12.0%	12.0%
South Idaho	12.2%	12.9%	13.5%	9.6%	10.4%	9.9%
South Nevada	17.9%	18.3%	20.0%	14.1%	7.8%	7.8%

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). There is some debate in the Northwest over whether the hydroelectric record has year-to-year correlation. Avista does not model year-to-year correlation after studying the data and finding a modest 35 percent year-to-year correlation over the 80-year record.

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 is varying. 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 it 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 it 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 meeting several conditions:

1. Data correlated between areas using historical data.
2. Data within load areas is auto-correlated.[2]
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, attempts to adhere to 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, hour type (night or day), 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 four 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 2014 generation recorded by BPA Transmission; in 2014, the average wind fleet in BPA's balancing authority had a 28.1 percent capacity factor.

[2] Adjoining hours or groups of hours are correlated to each other.

Figure 10.12: Wind Model Output for the Northwest Region

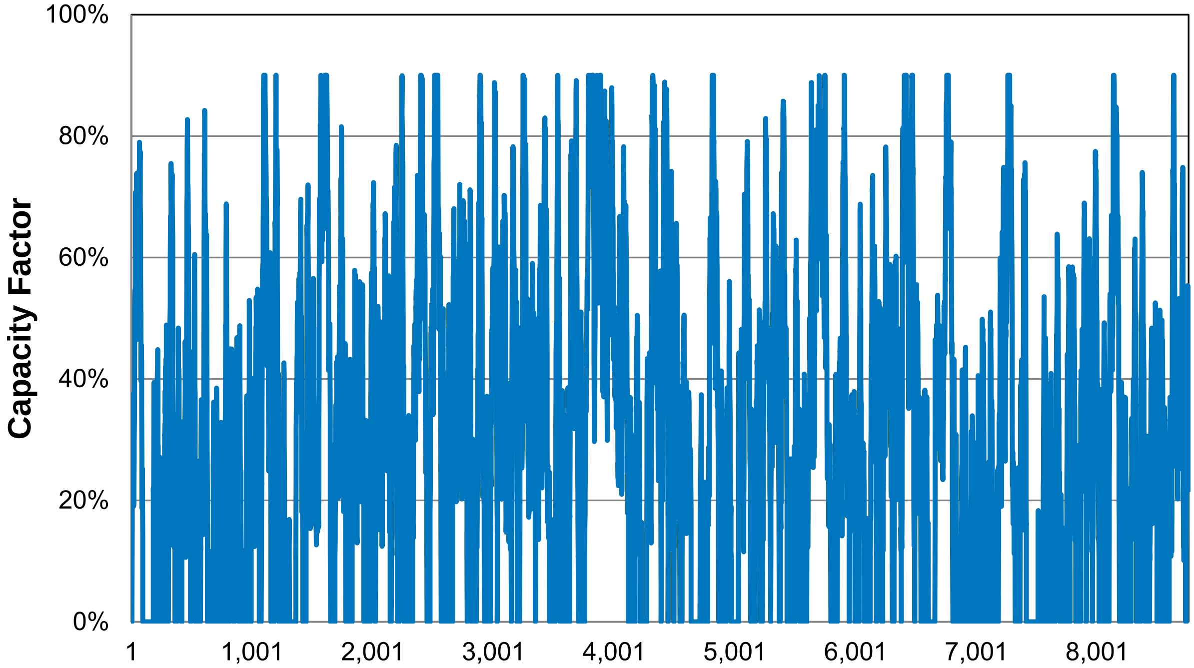
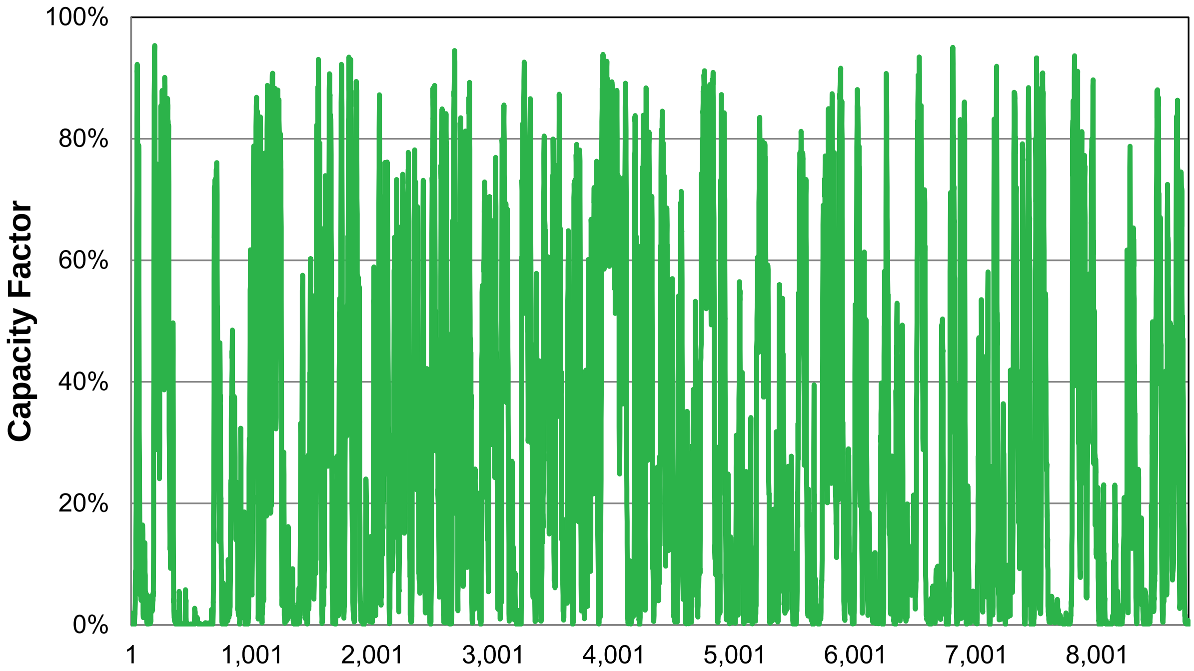


Figure 10.13: 2014 Actual Wind Output BPA Balancing Authority[3]



There is speculation a correlation exists between wind and hydroelectric generation, especially outside of the winter months where storm events bring both rain to the river

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

system and wind to the wind farms. This IRP does not correlate wind and hydroelectric generation due to a lack of any historical wind data set large enough to test this hypothesis. If correlation exists, it would be optimal to run the model using a large dataset of historical wind and water years.

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 have a material impact on market prices and therefore 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.

Market Price Forecast

An optimal resource portfolio cannot ignore the extrinsic value inherent in its resource choices. The 2015 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 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 individual utilities in the region. This reflects the fact that Western regions can 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^{XMP} assigns market values to each resource alternative available to Avista, but the model does not itself select PRS resources. 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 analyses 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.

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 Western Interconnect also has major trading hubs at the California/Oregon Border (COB), Four Corners, in the northwestern corner of New Mexico, Palo Verde in central Arizona, SP-15 in southern California, NP-15 in northern California, and Mead in southern Nevada. The Mid-Columbia market is usually the lowest cost because of the significant amount of hydroelectric generation assets at the hub, though other markets can be less expensive when Rocky Mountain-area natural gas prices are low and natural gas-fired generation is setting marginal power prices.

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 others. Each study simulates the entire Western Interconnect hourly between 2016 and 2035. The analysis used 29 central processing units (CPUs) linked to a SQL server, creating over 45 GB of data in 3,000 CPU-hours.

Figure 10.14 shows the Mid-Columbia stochastic market price results with horizontal bars representing the 10th to 90th percentile range for annual prices, the diamonds show the average prices, and the arrows represents the 95th percentile. The 20-year nominal levelized price is $38.48 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 $7.78 per MWh over 20 years. The 2013 IRP annual average nominal price was $44.08 per MWh. The reduction in pricing is a result of lower natural gas prices, lower loads, and higher percentages of new lower-heat-rate natural gas plants.

Figure 10.14: Mid-Columbia Electric Price Forecast Range

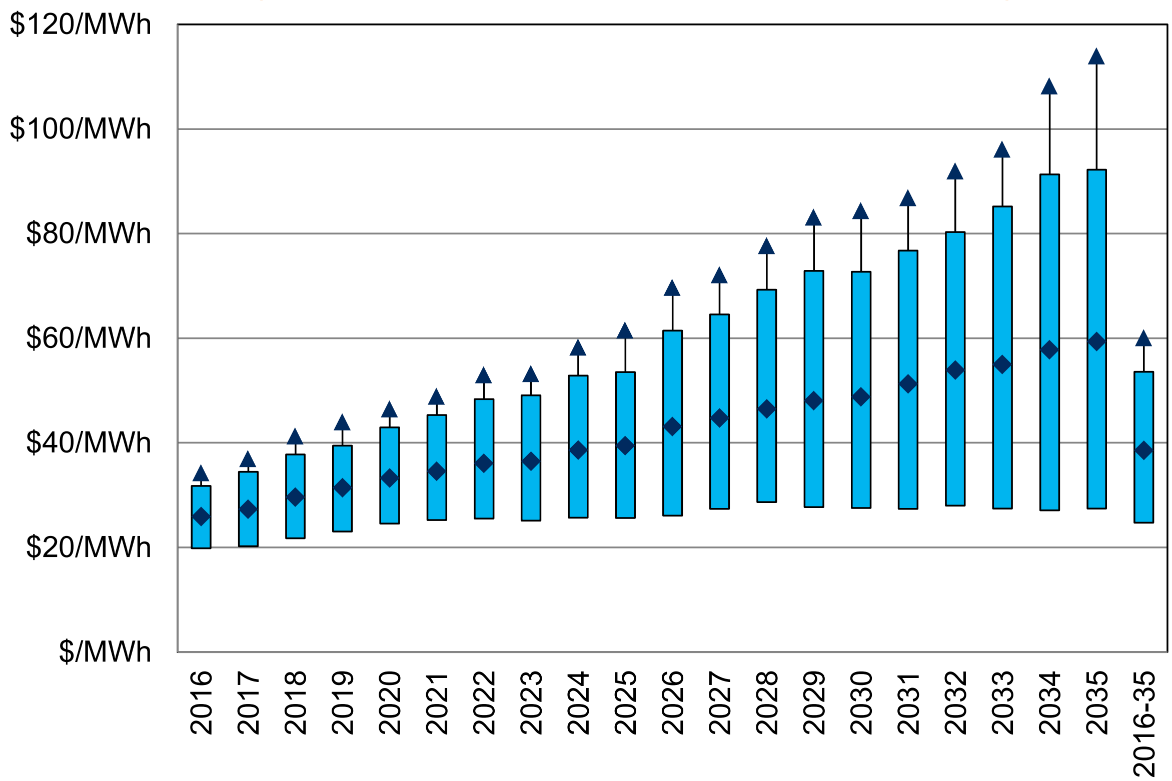


Table 10.9: Annual Average Mid-Columbia Electric Prices ($/MWh)

Year	Flat	Off-Peak	On-Peak
2016	25.87	21.62	29.05
2017	27.27	23.03	30.47
2018	29.59	25.18	32.90
2019	31.40	26.83	34.82
2020	33.25	28.94	36.48
2021	34.54	30.21	37.79
2022	36.05	31.70	39.30
2023	36.43	32.17	39.64
2024	38.60	34.27	41.85
2025	39.42	35.18	42.59
2026	43.12	38.80	46.36
2027	44.72	40.23	48.08
2028	46.48	42.09	49.79
2029	48.01	43.51	51.39
2030	48.79	44.32	52.14
2031	51.23	46.52	54.76
2032	53.90	48.98	57.58
2033	54.98	49.95	58.74
2034	57.77	52.65	61.64
2035	59.33	54.12	63.24
Levelized	**$38.48**	**$34.03**	**$41.81**

Greenhouse Gas Emission Levels

Greenhouse gas levels decline as natural gas prices decrease and coal plants react by dispatching for fewer hours in the year or retire. This IRP includes a 10 percent probability of a carbon price and includes reductions consistent with EPA's CPP goal for 2030. This forecast also includes cap-and-trade costs in California and carbon taxes in the Canadian provinces. Further discussion of carbon policy is in Chapter 7 – Policy Considerations. Figure 10.15 shows historic and expected greenhouse gas emissions for the Western Interconnect. Greenhouse gas emissions from electricity generation decrease 6.4 percent between 2016 and 2035, and 2016 is 12 percent lower than 2012. The figure also includes 10th and 90th percentile statistics from the 500-iteration dataset. The higher and lower bands show where emissions could land depending on changes in hydroelectric generation, load, resource availability, and other factors. The reduction drivers are lower load forecasts, lower natural gas prices, higher RPS requirements in some states, and forecasted coal-fired generation retirements due to federal and state regulations, and carbon pricing. Further, emissions from plants covered under the CPP fall by 28 percent as shown in the green line, but new plants emissions covered under the CPP offset much of this reduction.

Figure 10.15: Western States Greenhouse Gas Emissions

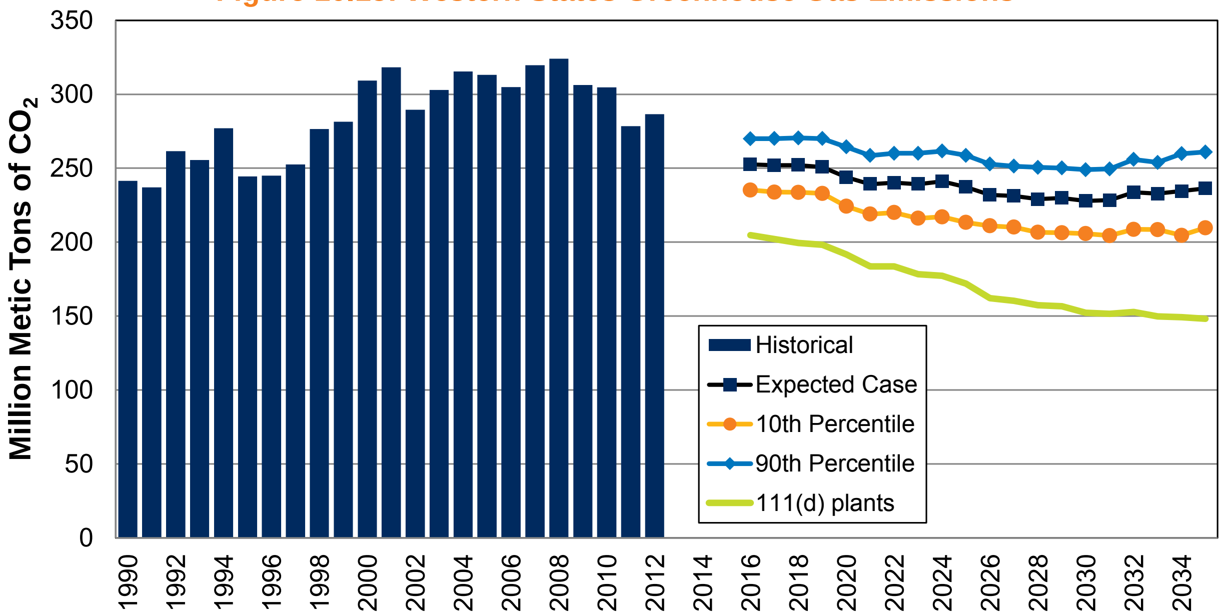


Figure 10.16 illustrates the Expected Case emissions rate for EPA regulated plants compared to EPA's draft CPP goal for each year. The Expected Case estimates the west will meet the 2030 goal by 2026; by 2035, the 681 lbs/MWh result is well below the 801 lbs/MWh CPP draft goal. Certain states, including Arizona, Colorado, Washington, and Wyoming, likely will exceed the goal while other states witness falling emissions. See Figure 10.17. If the final rule implements as the draft proposal, these state will need to take additional action, as described later in this chapter.

Figure 10.16: EPA's CPP Annual Emissions Intensity for the West

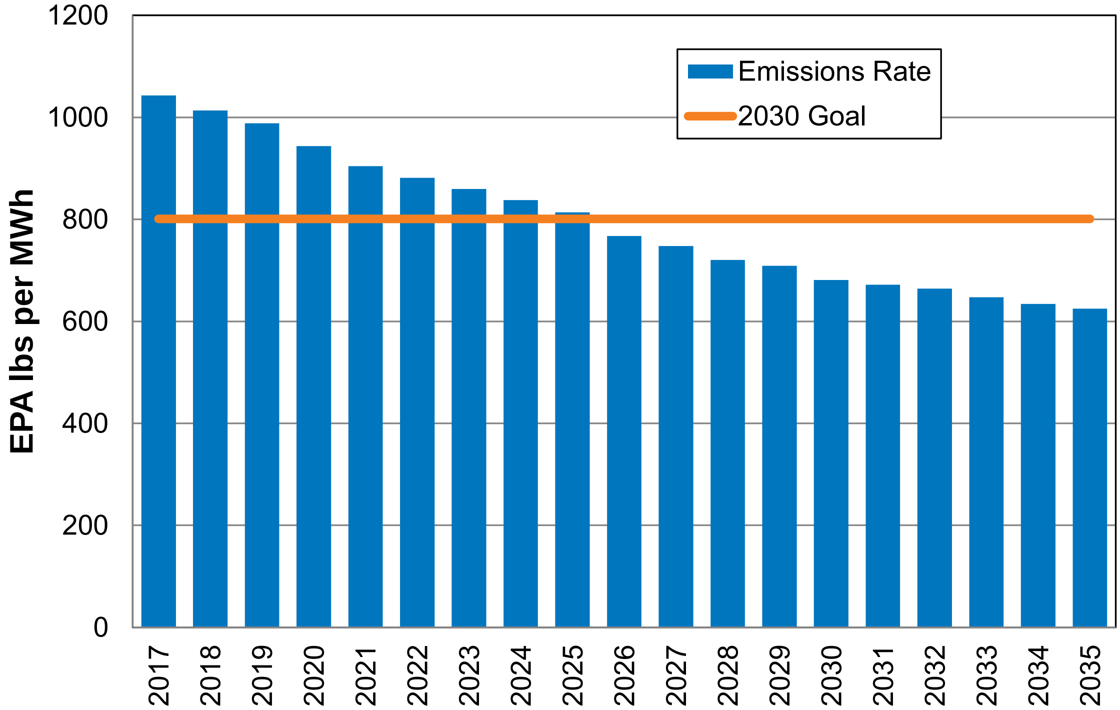
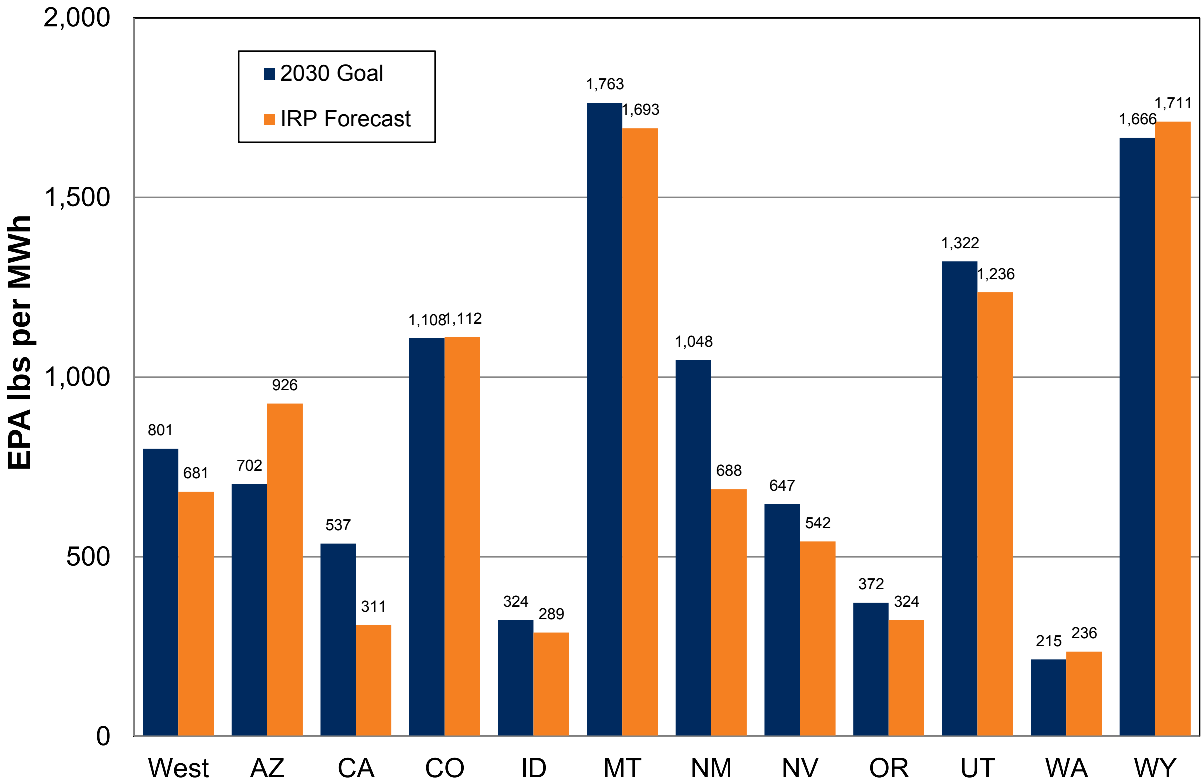


Figure 10.17: EPA's CPP 2030 State Goal vs. Modeling Result

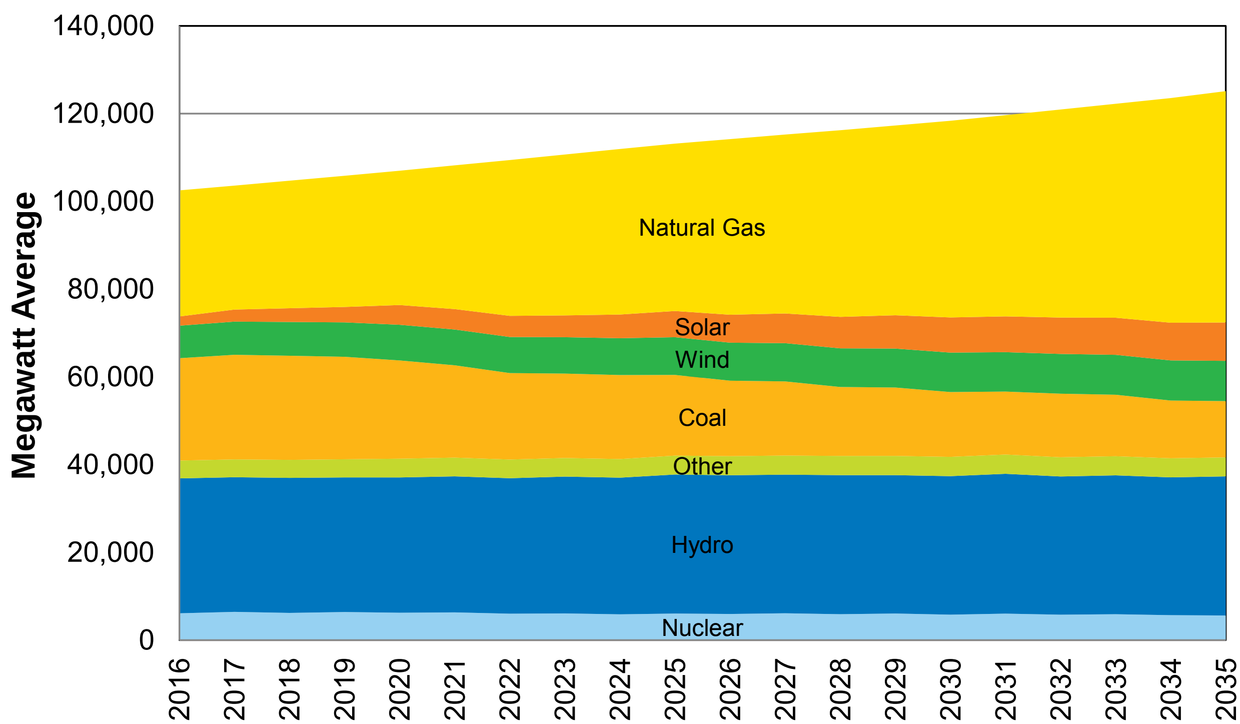


Resource Dispatch

State-level RPS goals and greenhouse gas regulations change resource dispatch decisions and affect future power prices. The Northwest already is witnessing the market-changing effects of a more than 7,750 MW wind fleet. Figure 10.18 illustrates how natural gas will increase its contribution as a percentage of Western Interconnect generation, from 28 percent in 2016 to 42 percent 2035. The increase offsets coal-fired generation, with coal dropping from 22 percent in 2016 to 10 percent in 2035. Utility-owned solar and wind generation increase from 9 percent in 2016 to 14 percent by 2035. New renewable generation sources also reduce coal-fired generation, but natural gas-fired generation is the primary resource meeting load growth.

Public policy changes encouraging renewable energy development may reduce greenhouse gas emissions on a market scale, but they also change electricity marketplace fundamentals. On the present trajectory, policy changes are likely to move the generation fleet toward natural gas, with its currently low but historically volatile prices. These policies will displace low-cost coal-fired generation with higher-cost renewables and natural gas-fired generation having lower capacity factors (wind) and higher marginal costs (natural gas). Stranded coal plant investments may increase the overall cost of electricity. Further, wholesale prices likely will increase with the effects of the changing resource dispatch driven by carbon emission limits and renewable generation integration. New environmental policy-driven investments, combined with higher market prices, will necessarily lead to higher than otherwise retail rates absent greenhouse gas reduction policies.

Figure 10.18: Base Case Western Interconnect Resource Mix



Scenario Analysis

Scenario analysis evaluates the impact of changes in underlying market assumptions, Avista's generation portfolio and new generation resource options' values. In addition to the Expected Case, this IRP includes three stochastic analyses. The Benchmark Case removes the carbon price and relaxes assumptions on meeting draft CPP goals. This scenario provides data to calculate the impact of the environmental policies in the Expected Case. The second scenario assumes all four Colstrip units retire by the end of 2026. This scenario uses a portfolio study to estimate impacts of an early closure at Colstrip. The third scenario looks at the added costs and associated reductions in greenhouse gas emissions if the social cost of carbon was included in the market price analysis. Deterministic studies model impacts of state-by-state draft CPP compliance.

Benchmark Scenario

The Benchmark Scenario removes the carbon adder in 2020 and relaxes assumptions in meeting the draft CPP targets. The flat levelized price for this scenario is $38.12 per MWh, or a reduction of $0.39 per MWh from the Expected Case. Figure 10.19 shows annual flat prices compared to the Expected Case. This scenario's prices are similar to the Expected Case. The levelized cost of the carbon adder in the Expected Case is $1.15 per metric ton. While the emissions penalty was small in this case, Western Interconnect emissions increase 2.3 percent by 2035. This scenario shows that the lower emissions of the Expected Case are relatively modest, at a levelized $30 million each year for the Western Interconnect. Figure 10.20 shows annual greenhouse gas emissions for the Western Interconnect in the Benchmark Scenario.

Figure 10.19: Annual Mid-Columbia Flat Price Forecast Benchmark Scenario

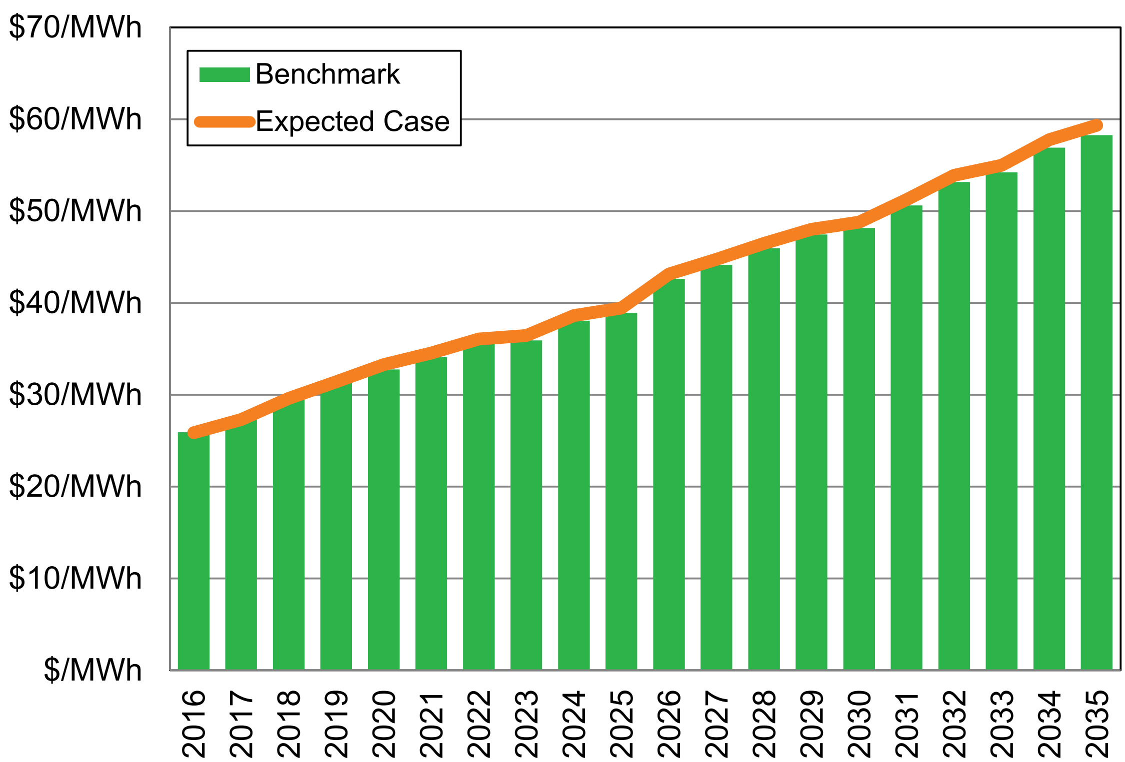
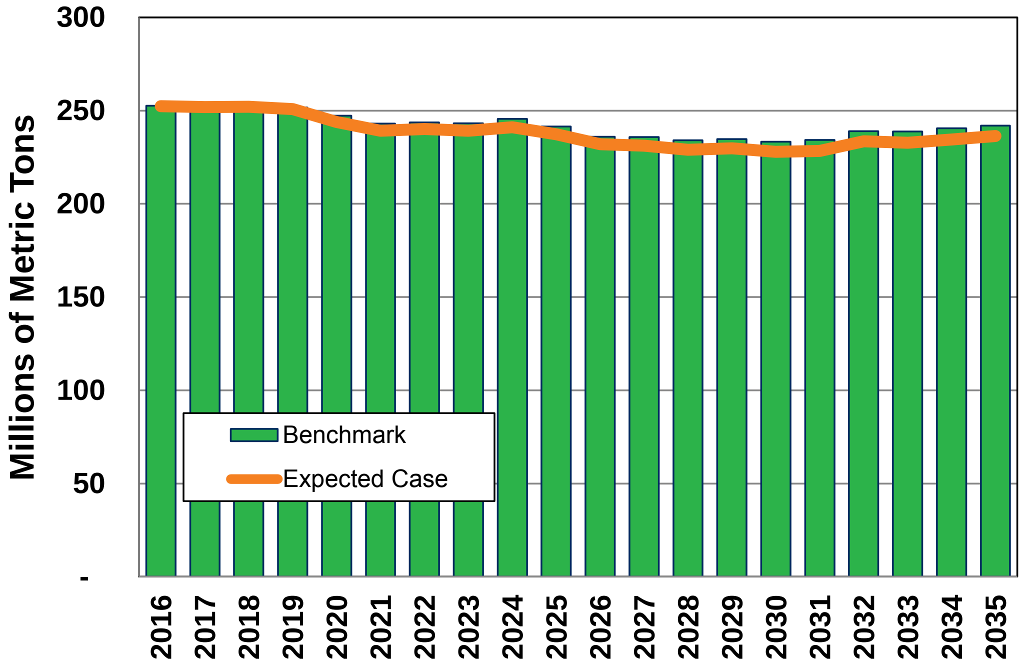


Figure 10.20: Benchmark Scenario Annual Western U.S. Greenhouse Gas Emissions



No Colstrip Scenario

The No Colstrip Scenario models the implications of retiring Colstrip. 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 the site redevelops with several large CCCT plants upon retirement in 2026. It does not attempt to represent the feasibility of this assumption, but rather helps understand the impacts to the overall market place by replacing Colstrip with a CCCT. Without Colstrip, regional market prices increase slightly as shown in Figure 10.21. There are small differences beginning in 2027 with a $0.93 per MWh annual average price difference. 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. Further, without replacement capacity, price impacts and reliability concerns increase. Beginning in 2027, the annual cost to all western customers increases by $651 million with the closure of Colstrip, or 2.6 percent, in the No Colstrip scenario. Without Colstrip, greenhouse gas emissions should decrease; in 2035 emissions in this scenario were 3.2 percent lower, or nearly 9.3 million metric tons per year, as shown in Figure 10.22. Given the increased cost and associated emissions reductions, the implied price of carbon reduction at Colstrip is $74.17 per metric ton in 2027; the average price between 2027 and 2035 is $73.18 per metric ton.

Figure 10.21: Annual Mid-Columbia Flat Price Forecast Colstrip Retires Scenario

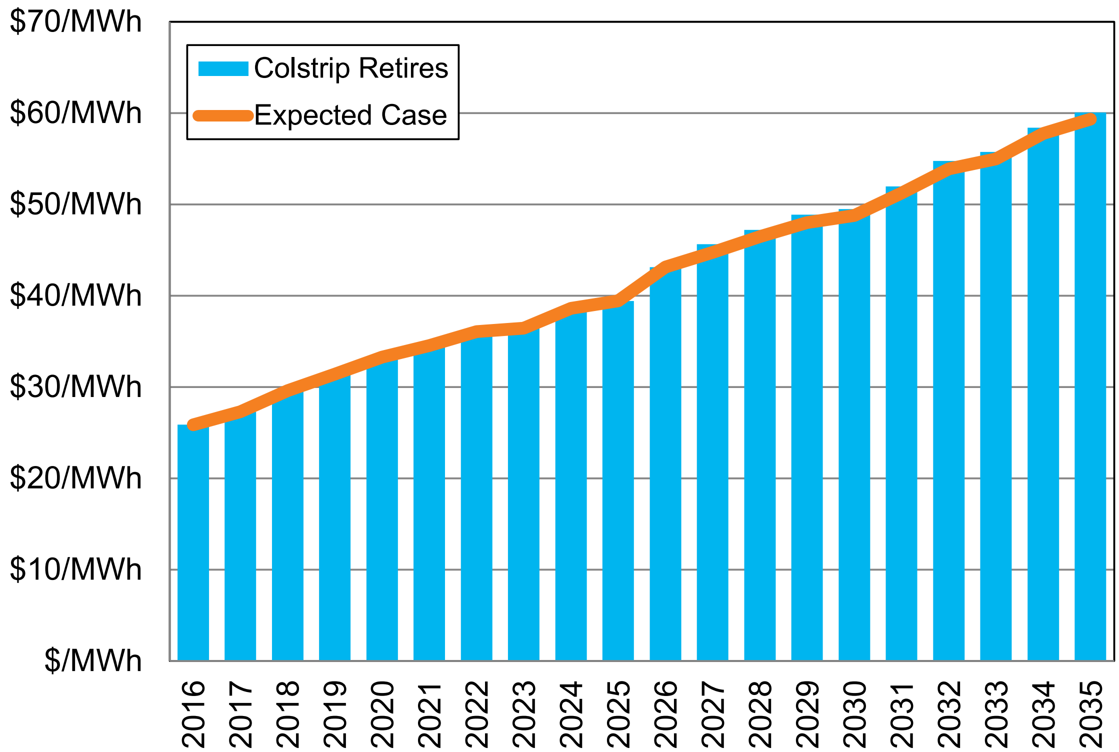
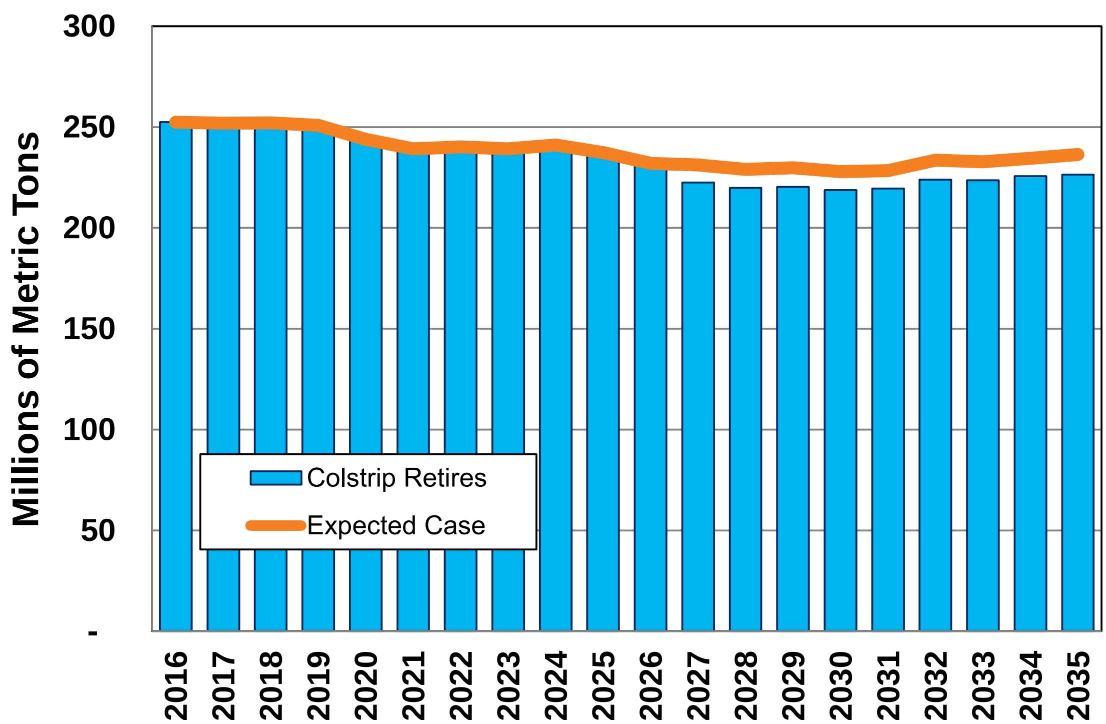


Figure 10.22: No Colstrip Scenario Annual Western U.S. Greenhouse Gas Emissions



Social Cost of Carbon Scenario

For the past several IRPs Avista has conducted carbon emission pricing scenarios. For this IRP, the TAC recommended a Social Cost of Carbon case. The Social Cost of Carbon study uses data from an EPA study. The prices from this study have different ranges depending on the discount rate assumed and the point on the probability curve. Avista chose the 5 percent discount rate study with a starting price of $11 per metric ton in 2010 (2007 dollars). Figure 10.23 shows the nominal prices per metric ton. The levelized price is $19.31 per metric ton, approximately 18 times the carbon cost assumed in the Expected Case. These prices do not vary in each of the 500 iterations.

With a Social Cost of Carbon adder, the impact to Mid-Columbia prices is more apparent. The levelized price increases to $45.46 per MWh, or 18 percent higher than the Expected Case, as shown in Figure 10.24. The added pricing to emissions also increases power costs by $3.6 billion annually (17.2 percent) across the U.S. west. In exchange for the added costs, emissions fall 9.6 percent or 25 million metric tons by 2035. See Figure 10.25.

Figure 10.23: Social Cost of Carbon Scenario Emission Prices

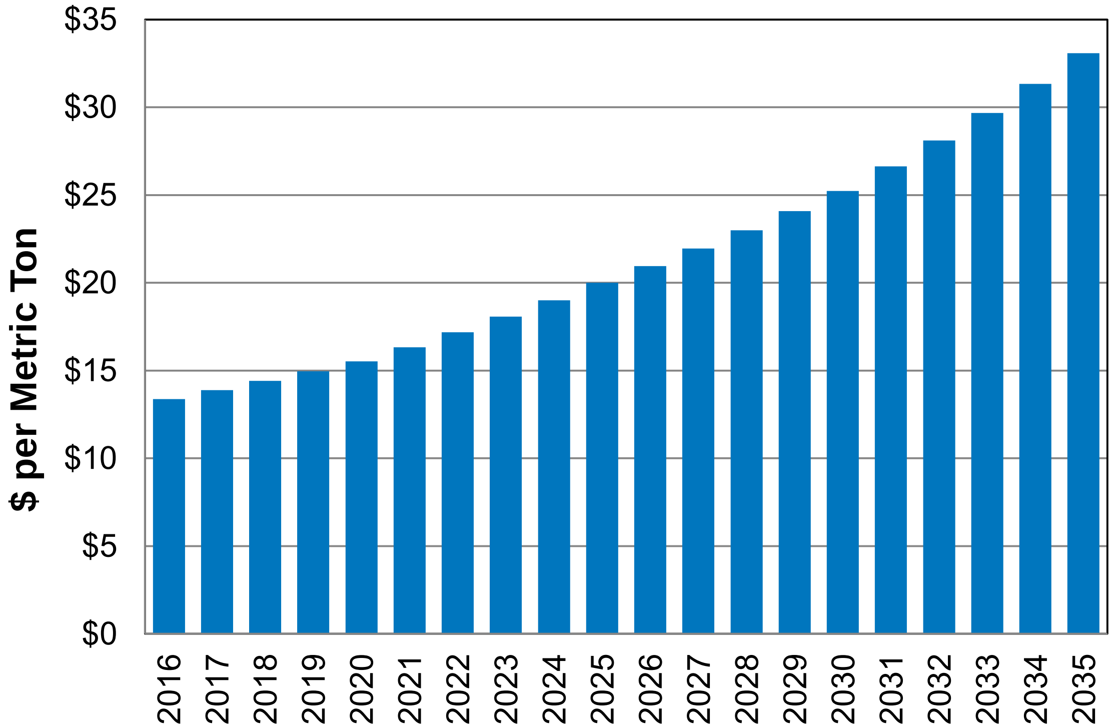


Figure 10.24: Annual Mid-Columbia Flat Price Forecast Social Cost of Carbon Scenario

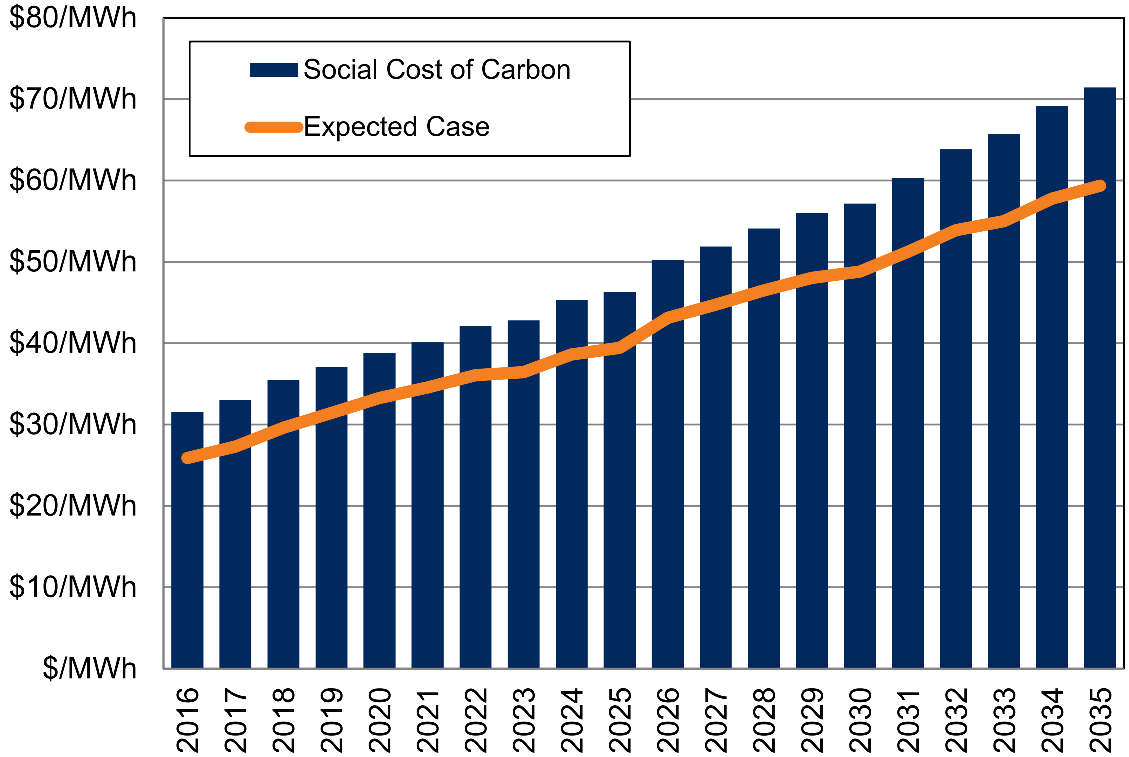
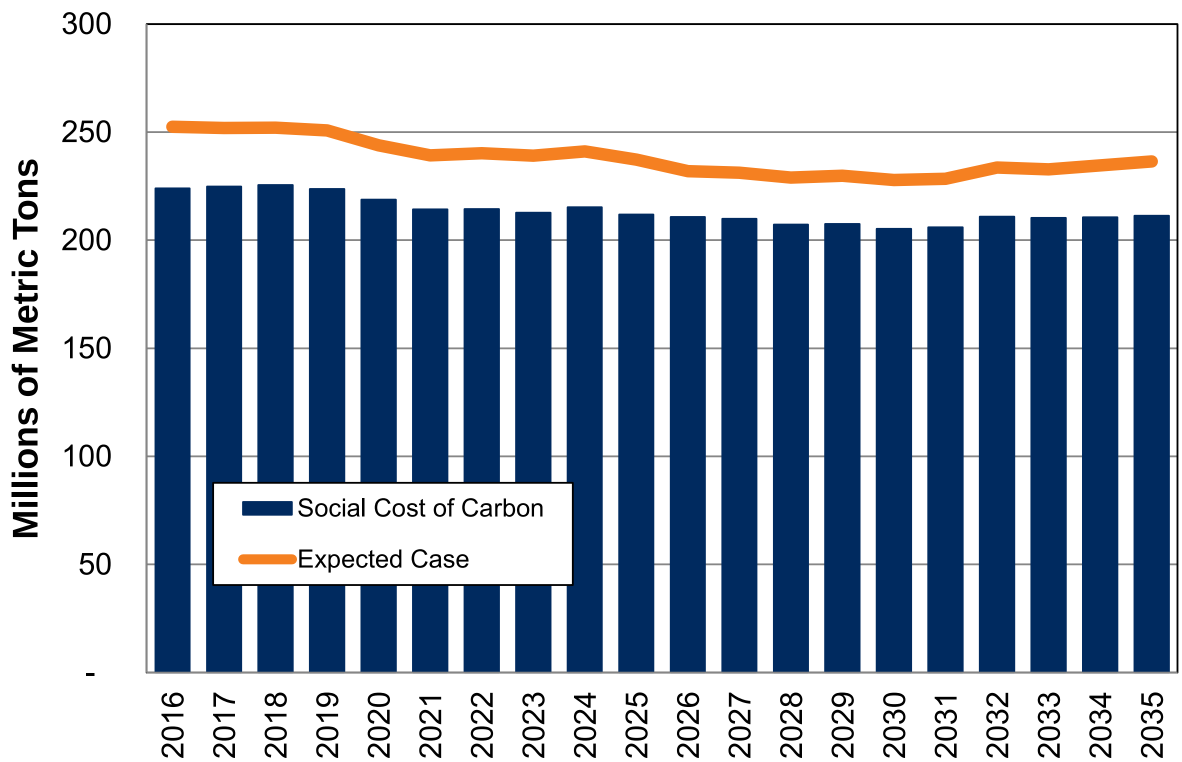


Figure 10.25: Social Cost of Carbon Scenario Western US Greenhouse Gas Emissions



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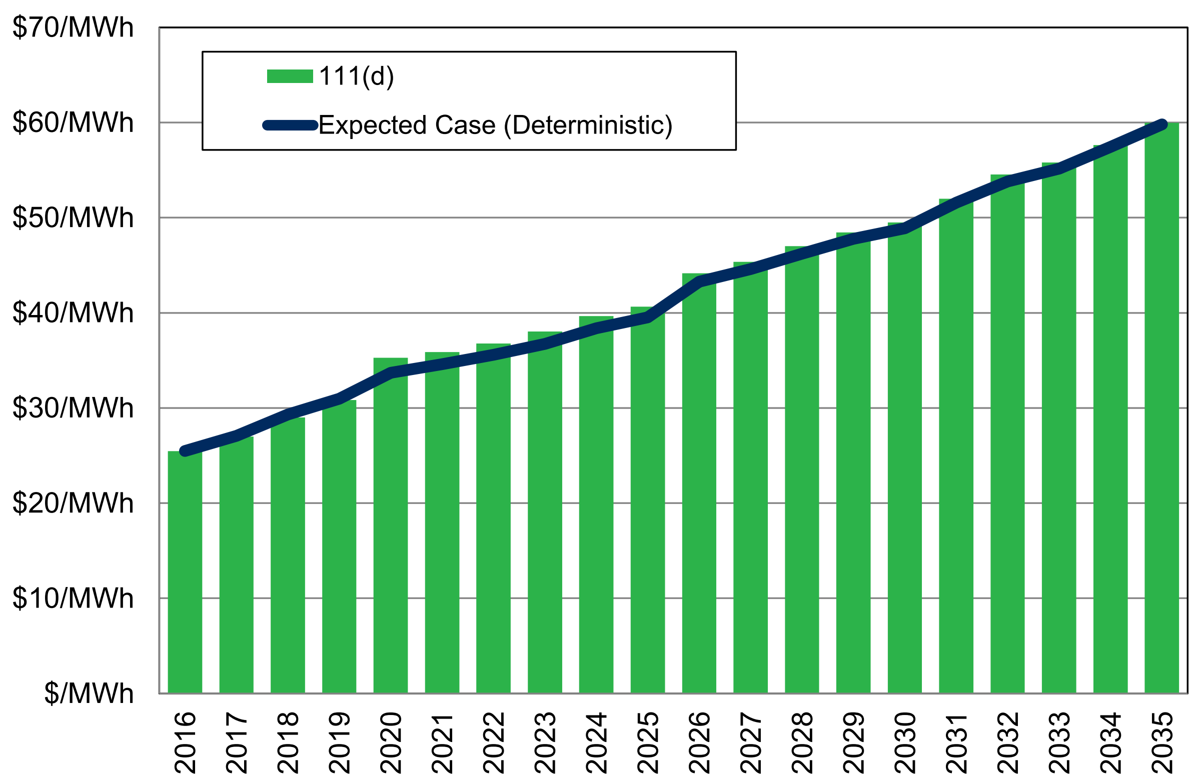
Clean Power Plan Scenarios

The 2015 IRP analyzes implications of the draft CPP by first looking at its requirements on a state-by-state compliance basis instead of a regional basis as is assumed in the Expected Case. This scenario was studied on a deterministic basis rather than the full 500 stochastic iterations, because some of the stochastic variables have a large impact on emissions. Because emissions are highly dependent on some of the stochastic assumptions – for example, streamflows affect hydroelectric generation – a low water year is tested. To meet the 2020 draft CPP goal, each state would have to change its system. Any planned coal retirement beyond 2020 would accelerate to 2019. Some states would need to increase conservation and renewable resource acquisitions. Many states may need to implement a carbon emissions price. Northwest states would require a carbon price of $1.25 per short ton in an average water year to reduce emissions, even with the early closure of Centralia 1 & 2 and Boardman by the end of 2019. Other states, such as Colorado and Arizona, would require prices near $20 per short ton.

Figure 10.26 shows the Mid-Columbia flat annual price in the state-by-state compliance scenario. The levelized price is $39.06 per MWh, 1.6 percent higher than the Expected Case's deterministic study. This is not a large increase because the average price of carbon across the west is actually lower than in the Expected Case, but since fewer coal resources are available, the price is higher. In 2020, the year with the largest price change, the difference is $1.59 per MWh, an increase of 4.7 percent.

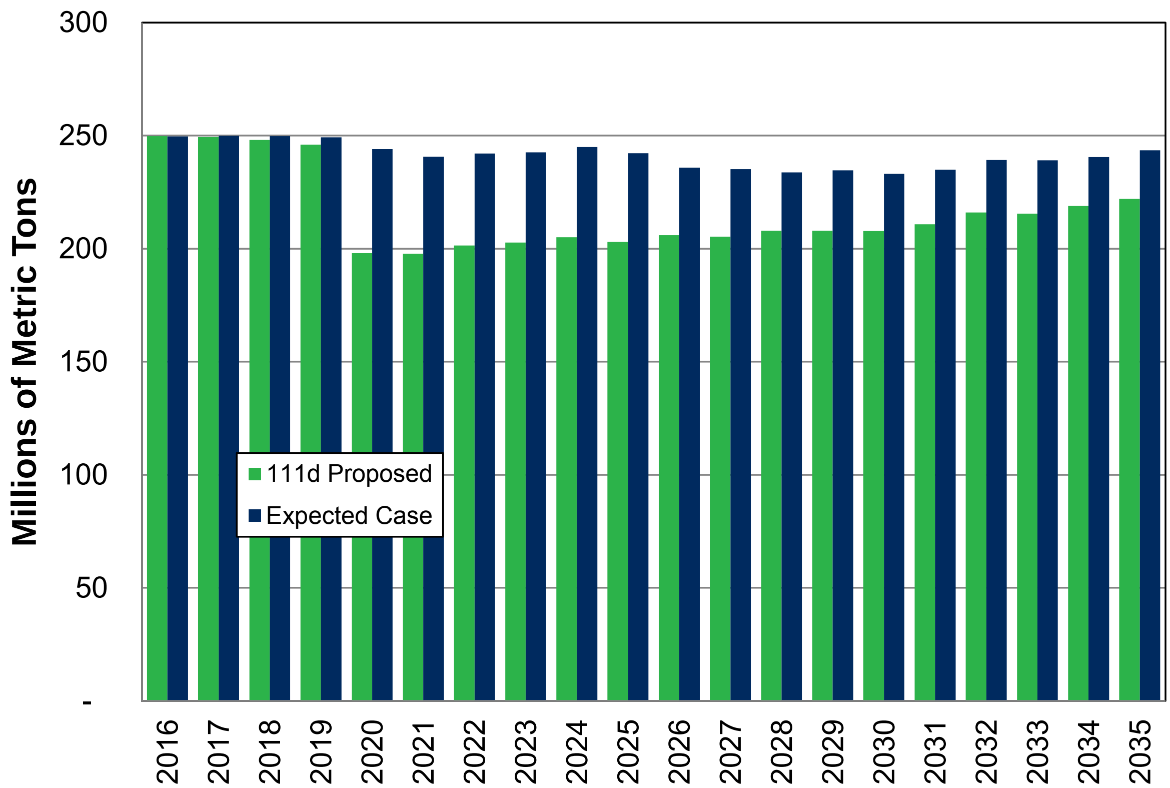
Figure 10.26: Draft CPP as Proposed Scenario Flat Mid-Columbia Electric Prices



The cost of the Western electrical system requires review to understand the impacts of a state-by-state draft CPP scenario. Levelized cost increases $342 million per year (1.7 percent), and cost is $1.2 billion (7.6 percent) in 2020. This added cost reduces emissions from the Expected Case by 19 percent in 2020 and 9 percent in 2035, as shown in Figure 10.27. The reduction from the Expected Case comes from earlier retirement of coal resources. Reductions toward the end of the study are from additional renewable resources and higher carbon emission prices. Emissions increase because increased conservation offsets the need to reduce emissions from generation.

The draft CPP significantly affects the timing of new resources to replace retired coal plants. It would require carbon pricing unless using other CPP building blocks. These issues are minimal compared to a low water year in the Northwest. In low water years, decreased hydroelectric production requires the region’s natural gas and coal-fired resources to dispatch more and reduces regional exports and associated revenues.

Figure 10.27: Draft CPP as Proposed Scenario Western Greenhouse Gas Emissions



A low water year environment requires higher carbon prices to reduce emissions compared to the average water year. To test this hypothesis, this study uses the water conditions from 1941 to represent a lower 10th percentile water year. In this case, the carbon prices required for the Northwest states are:

- Washington: $18/ton (2020), $18/ton (2030)
- Oregon: $19/ton (2020), $15/ton (2030)
- Idaho: $23/ton (2020), $14/ton (2030)

The required carbon price changes as the amount of conservation increases, lowering the reliance on the remaining generating fleet to meet the draft CPP goal. The cost impact of this regulation in a lower water year can also be very high if the water conditions are less than average beginning in 2020. For example, Figure 10.28 demonstrates the financial impact of the low water year; in 2020, the costs are $1.6 billion higher, or 9 percent, as compared to a low water year without the draft CPP requirement. In 2030, as conservation ramps up and if a poor water year occurs, the added costs decrease to $137 million or 0.4 percent higher. Electricity market prices at the Mid-Columbia also have similar impacts. Figure 10.29 illustrates the increases of the draft CPP in the 1941 water year and illustrates increases in prices compared to the average water year from the Expected Case. In 2020, the added regulation increases prices by $6.10 per MWh, or 17 percent, compared to the case without the regulation in the poor water year. The impact decreases to approximately 5 percent in 2035. Given that the future timing of low water years is unknown, the levelized price impact of $4.76 per MWh (10.3 percent) is the best indicator of the added price to the Northwest market.

Figure 10.28: Draft CPP as Proposed Scenario 1941 Water Year Annual Costs

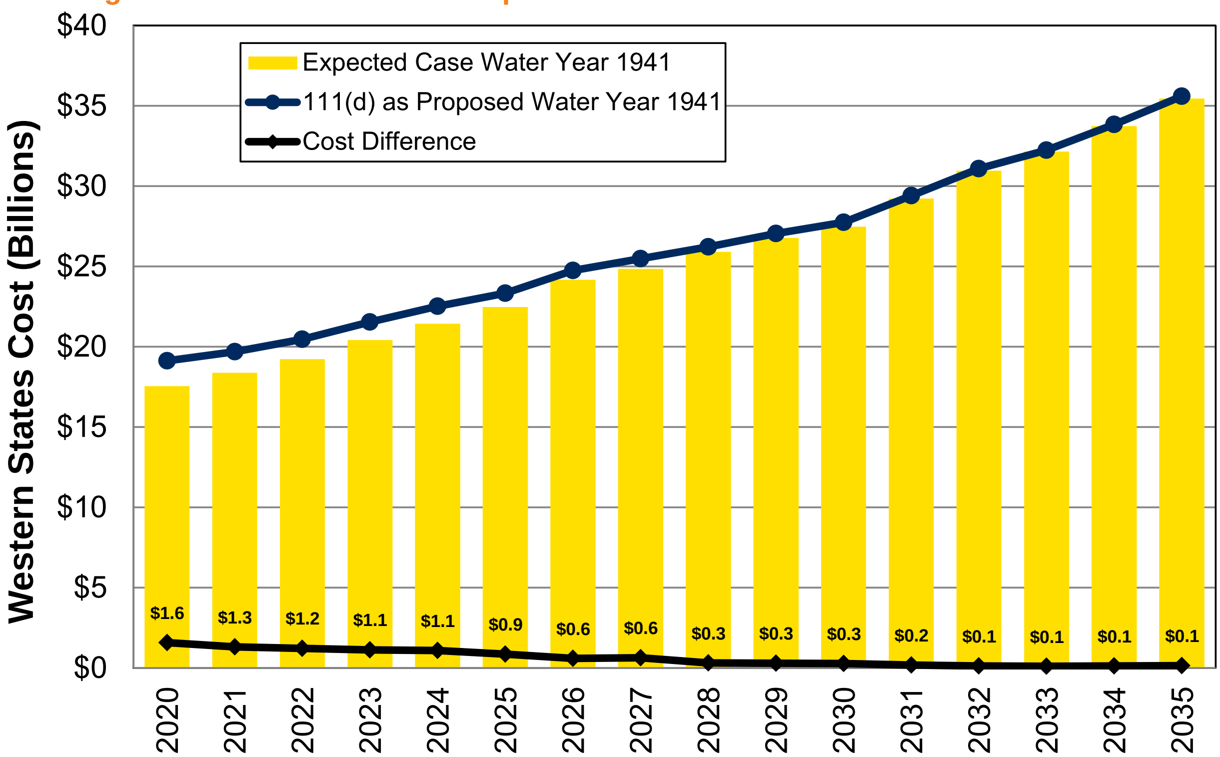
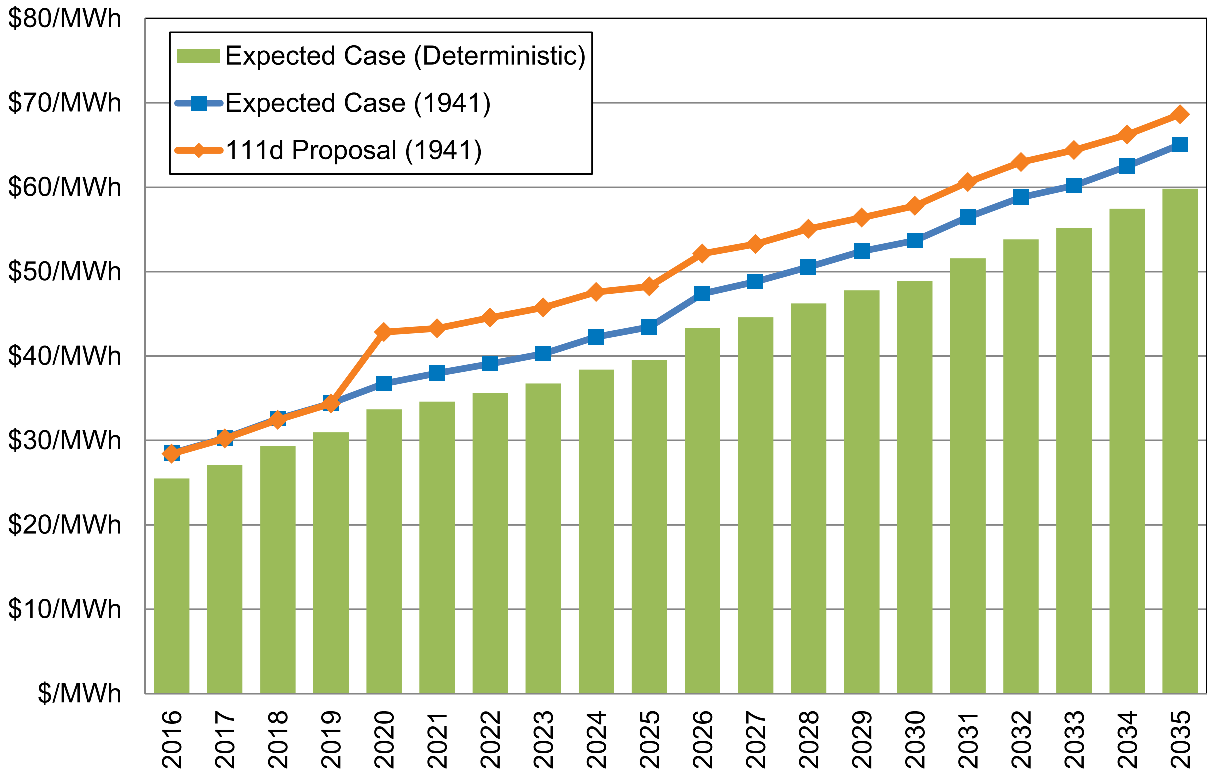


Figure 10.29: CPP as Proposed 1941 Water Year Scenario Mid-Columbia Electric Prices



11. Preferred Resource Strategy

Introduction

This chapter describes potential costs and financial risks of the new resource and conservation strategy Avista plans to meet future requirements over the next 20 years. It explains the decision making process used to select the PRS, and the resulting avoided costs used to target future conservation.

The 2015 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 2013 plan include modestly less energy efficiency, the elimination of demand response, and the elimination of a natural gas-fired peaking plant. The plan also calls for upgrades to Avista's thermal generating fleet. The strategy's lower energy efficiency acquisition is due to lower market prices and increased codes and standards reducing some of the need for utility-sponsored acquisition. The reduction in natural gas-fired resources results primarily from a lower retail load forecast. Demand response is no longer in the PRS, as a third-party study found costs to be much higher than estimated in the 2013 IRP. Like the prior plan, upgrades at certain existing facilities look attractive as a resource alternative. Overall, the 2015 PRS performs better against the efficient frontier than the 2013 strategy.

Section Highlights

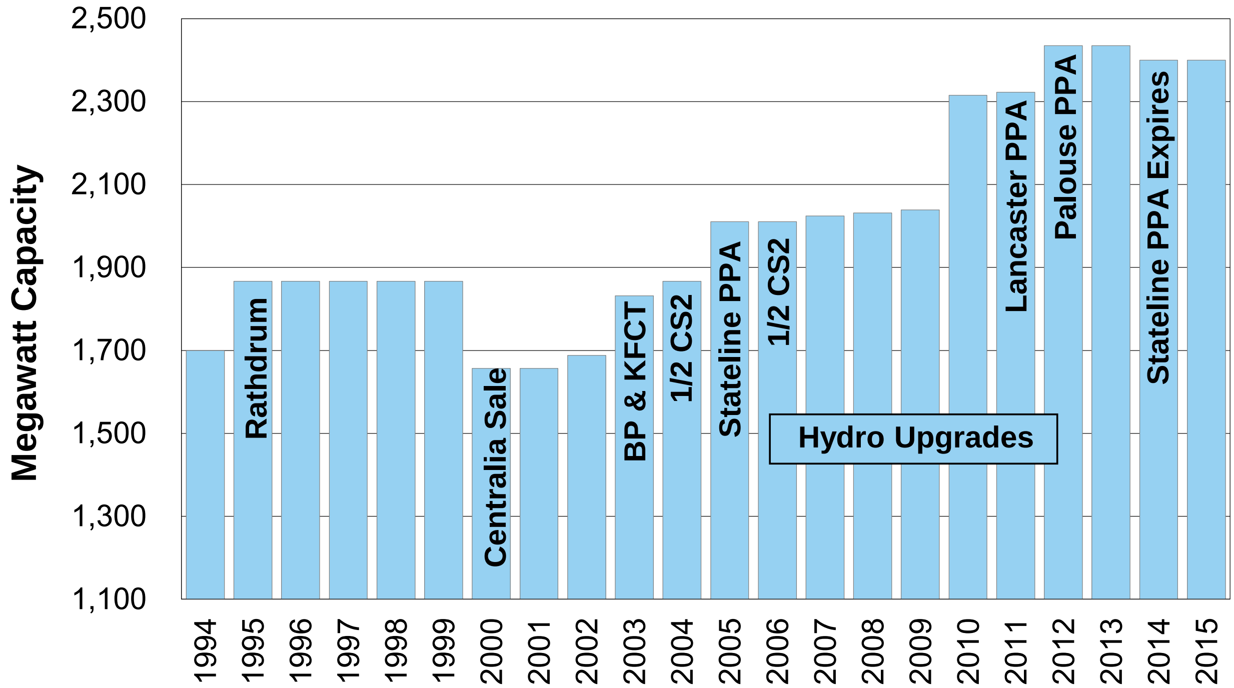
- The first anticipated resource acquisition is a natural gas-fired peaking plant by the end of 2020 to replace expiring contracts and serve growing loads.
- Replacement of the Lancaster Facility with a CCCT occurs in 2026.
- Upgrades to existing facilities help meet resource deficits.
- Energy efficiency offsets 52 percent of projected load growth through the 20-year IRP timeframe.

Supply-Side Resource Acquisitions

Avista began its shift away from coal-fired resources with the sale of its 210 MW share of the Centralia coal plant in 2000. Natural gas-fired plants replaced it. See Figure 11.1. Since the Centralia sale, Avista has made several generation acquisitions and upgrades, including:

- 25 MW Boulder Park natural gas-fired reciprocating engines (2002);
- 7 MW Kettle Falls natural gas-fired CT (2002);
- 35 MW Stateline wind power purchase agreement (2004 – 2014);
- 56 MW (total) hydroelectric upgrades (through 2012);
- 270 MW natural gas-fired Lancaster Generation Station tolling agreement (2010 – 2026);
- 105 MW Palouse Wind power purchase agreement (2012 – 2042); and
- 16 MW Nine Mile Falls Upgrade (2016)

Figure 11.1: Resource Acquisition History



Resource Deficiencies

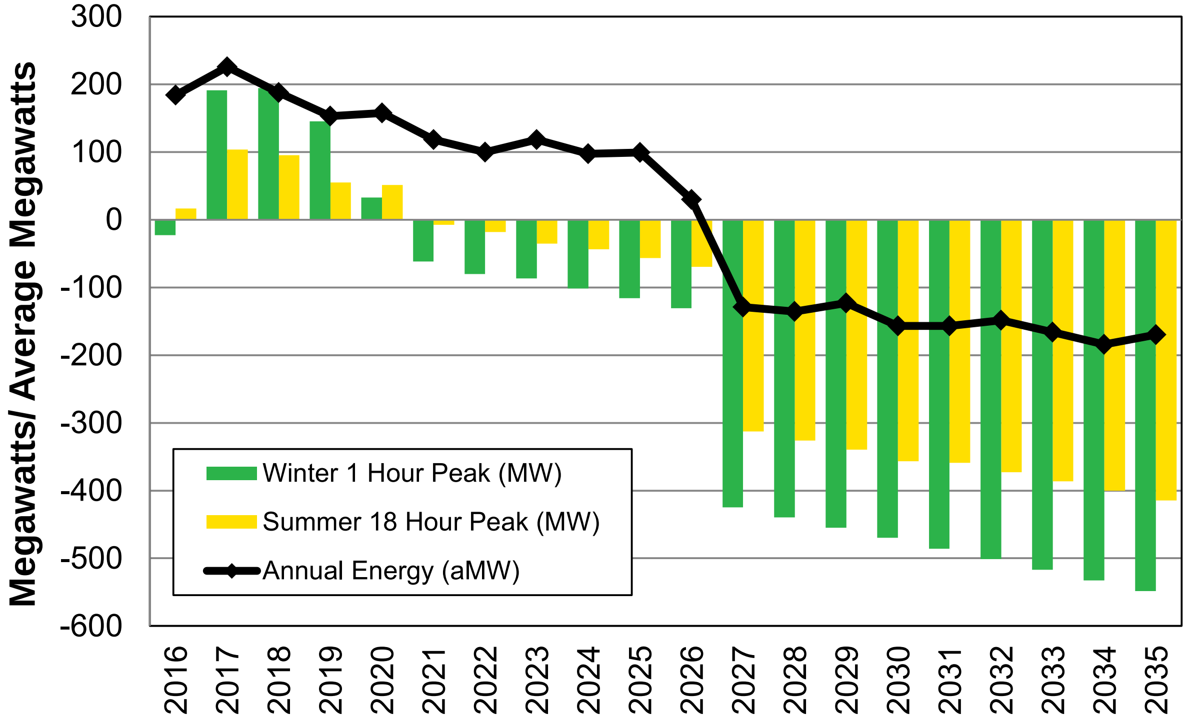
Avista uses a single-hour and an 18-hour peak event methodology to measure resource adequacy. The 18-hour methodology assures energy-limited hydroelectric resources can meet multiday extreme weather events.

Avista considers the regional power surplus in its planning, consistent with the NPCC's forecast, and does not intend to acquire long-term generation assets while the region is significantly surplus. Current NPCC research indicates the region is long on capacity through 2020 during the winter and forecasts no summer resource deficits.

Avista's peak planning methodology includes operating reserves, regulation, load following, wind integration, and a planning margin. Even with this planning methodology, Avista currently projects having adequate resources between owned and contractually controlled generation to meet physical energy and capacity needs until 2021.[1] See Figure 11.2 for Avista's physical resource positions for annual energy, summer capacity, and winter capacity. This figure accounts for the effects of new energy efficiency programs on the load forecast. Absent energy efficiency, Avista would be deficient earlier.

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

Figure 11.2: Physical Resource Positions (Includes Energy Efficiency)



Renewable Portfolio Standards

Washington voters approved the EIA in the November 2006 general election. The EIA requires utilities with over 25,000 customers to meet 3 percent of retail load from qualified renewable resources by 2012, 9 percent by 2016, and 15 percent by 2020. The initiative also requires utilities to acquire all cost-effective energy efficiency.

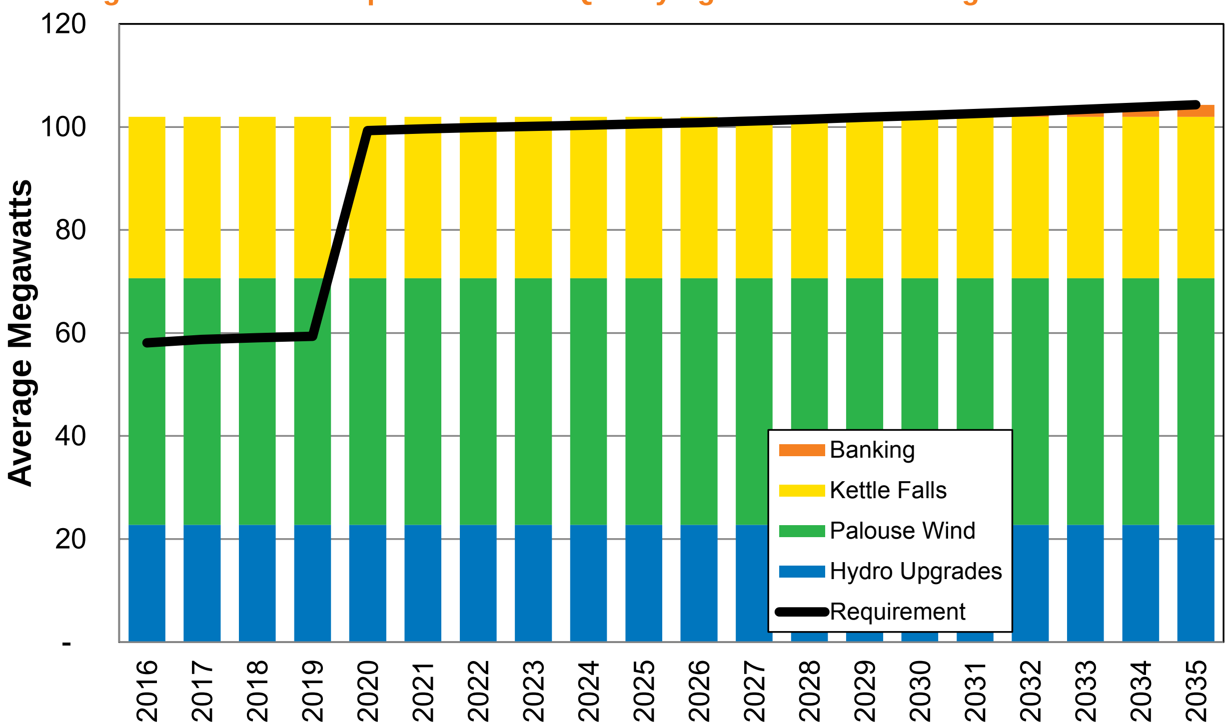
Avista expects to meet or exceed its EIA renewable energy requirements through the 20-year plan with a combination of qualifying hydroelectric upgrades, the Palouse Wind project, the Kettle Falls Generating Station and selective REC purchases.[2] Table 11.1 provides a list of the qualifying generation projects and the associated expected output. Figure 11.3 shows the forecast REC positions. The flexibility included in 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.

[2] The RECs from Wanapum are not in WREGIS and are currently ineligible under the EIA requirements for investor-owned utilities, but Avista is working with Grant County PUD to qualify the energy.

Table 11.1: Qualifying Washington EIA Resources

Resource	Resource Type	On-line Year	Nameplate Capacity	Expected MWh	Expected RECs
Kettle Falls GS[3]	Biomass	1983	47.0	374,824	281,118
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	17.0	45,808	45,808
Cabinet Gorge 2	Hydro	2004	17.0	29,008	29,008
Cabinet Gorge 4	Hydro	2007	9.0	20,517	20,517
Wanapum	Hydro	2008	0.0	22,206	22,206
Noxon Rapids 1	Hydro	2009	7.0	21,435	21,435
Noxon Rapids 2	Hydro	2010	7.0	7,709	7,709
Noxon Rapids 3	Hydro	2011	7.0	14,529	14,529
Noxon Rapids 4	Hydro	2012	7.0	12,024	12,024
Palouse Wind	Wind	2012	105.0	349,726	419,671
Nine Mile 1 & 2	Hydro	2016	4.0	11,826	11,826
Total			**236.0**	**928,671**	**904,910**

Figure 11.3: REC Requirements vs. Qualifying RECs for Washington State EIA



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

[3] The Kettle Falls Generation Station becomes EIA qualified beginning in 2016. Clarification about old growth fuel is required to determine the amount of energy to qualify for the law.

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 the 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, RPS, and other requirements.

PRiSM

Avista staff developed the first version of PRiSM in 2002 to support resource decision making in the 2003 IRP. Various 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.

Overview of the PRiSM model

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
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
    - The level of market reliance (surplus/deficit limits on energy, capacity and RPS)
    - Resources quantities available to meet future deficits

PRiSM uses these inputs to develop an optimal resource mix over time at varying levels of risk. 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.

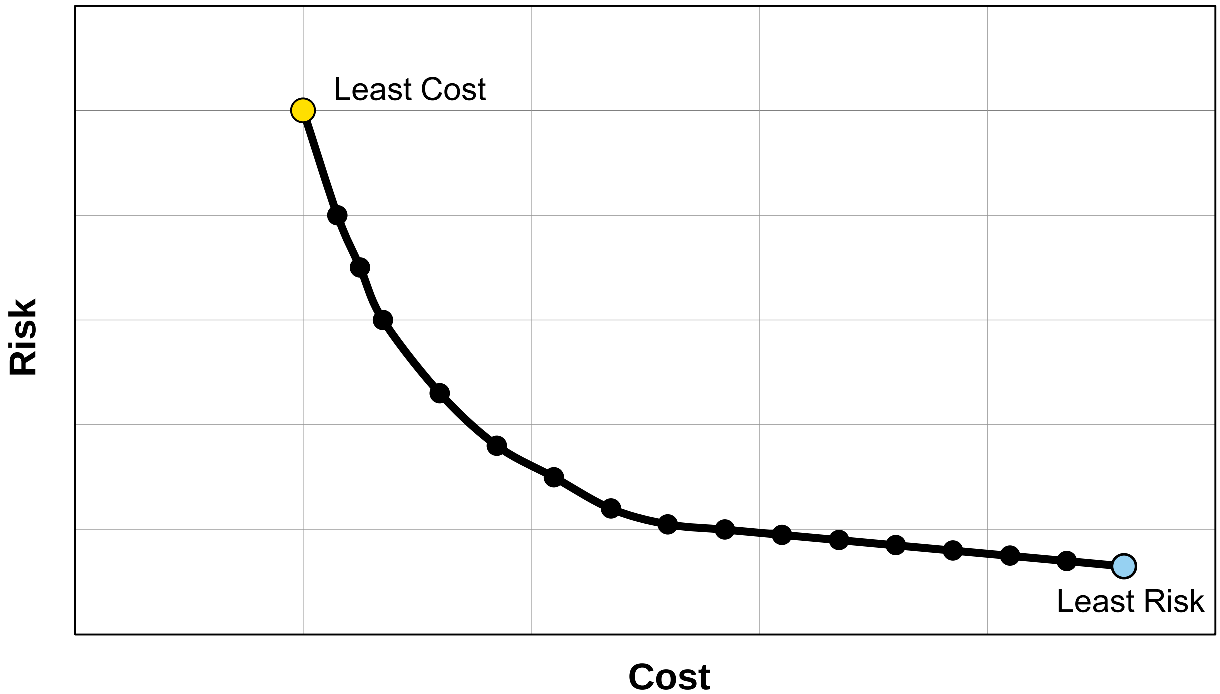
Equation 11.1: PRiSM Objective Function

Minimize: $(X_1 * NPV_{2016\text{-}2040}) + (X_2 * NPV_{2016\text{-}2065})$

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.[4]

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 risk Avista and its customers are willing to accept. No best point on the curve exists, but Avista prefers points where small incremental cost additions offer large 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 limit utility-scale resource options. Portfolios to the right of the curve are less efficient as they have higher costs than a portfolio with the same level of risk. The model does not meet deficits with market purchases or allow the construction of resources in any incremental size.[5] Instead, it uses the market to balance short-term gaps and adds resources in sizes equal to the project sizes Avista could actually obtain.

[4] 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.
[5] Market reliance, as identified in Section 2, is determined prior to PRiSM's optimization.

Constraints

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 societal. The major resource constraints are capacity and energy needs, Washington's EIA, and greenhouse gas emissions performance standard.

The PRiSM model selects from conservation, combined- and simple-cycle natural gas-fired combustion turbines, natural gas-fired reciprocating engines, wind, solar, storage batteries, and upgrades to existing thermal and hydroelectric resources.

Before the addition of an RPS obligation, the efficient frontier contained a least-cost strategy on one axis, the least-risk strategy on the other axis, and all of the points in between. Management used the efficient frontier to help determine where they wanted to be on the cost-risk continuum. The least-cost strategy consists of natural gas-fired peaking resources. Portfolios with less risk replace some of the natural gas-fired peaking resources with wind generation, other renewables, combined cycle natural gas-fired plants and/or coal-fired resources. Past IRPs identified resource strategies including all of these risk-reducing resources. Added environmental and legislative constraints reduce the number of resource choices available to reduce future costs and/or risks.

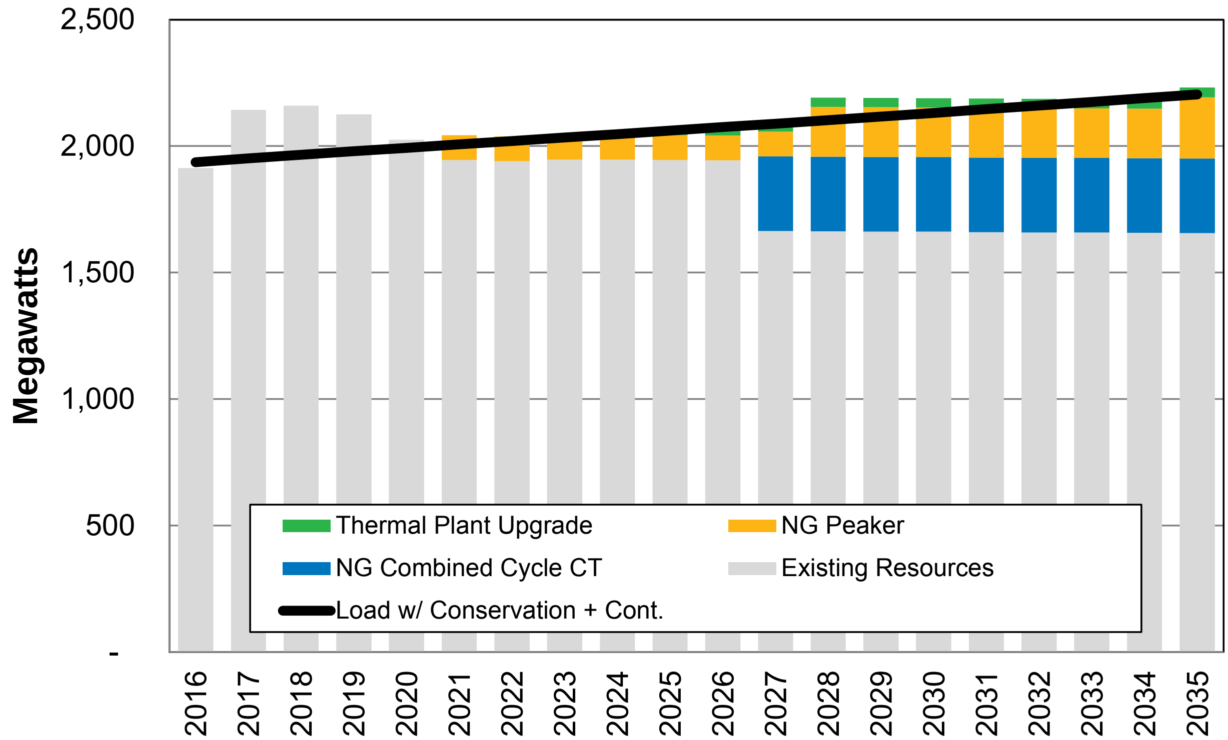
Preferred Resource Strategy

The 2015 PRS consists of existing thermal resource upgrades, energy efficiency, natural gas-fired peakers, and a natural gas-fired CCCT. A list of planned acquisitions is in Table 11.2 and a graphic is in Figure 11.5. The first resource acquisition is 96 MW of natural gas-fired peaking technology by the end of 2020. This resource acquisition fills the capacity deficit created by the expiration of the 82-MW WNP-3 contract with the BPA, the expiration of a 28 MW Douglas County PUD contract for a portion of its Wells hydroelectric facility, and load growth. In this IRP evaluation, frame technology CTs are the preferred gas-fired peaking technology. Given the relatively small cost differences between the evaluated natural gas-fired peaker technologies, the future technology decision will be determined in an RFP. Technological changes in efficiency and flexibility may mean the Avista will need to revisit this resource choice closer to the actual need. Since the long-term need is more than five years out, Avista will not release an RFP in the next two years, but will begin a process to evaluate technologies and potential locations prior to a RFP release, likely following the 2017 IRP.

Table 11.2: 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	2016-2035		193	132
Distribution Efficiencies			<1	<1
Total			**193**	**132**

Figure 11.5: New Resources Meets Winter Peak Loads



The next resource acquisitions in the PRS are upgrades to Avista's thermal fleet. These upgrades may be cost effective earlier depending upon negotiations with vendors. The proposed 286 MW CCCT replaces the Lancaster tolling agreement expiring in October 2026. Avista could renegotiate the current agreement or find other mutual terms to retain the plant for customers. If Avista does not retain Lancaster, it would need to build or procure a similar-sized natural gas-fired unit. The new plant size could meet future load growth needs and delay or eliminate the need for later additional resource acquisitions in this plan. Due to the uncertainty surrounding replacing Lancaster, this IRP assumes the replacement is a new facility of similar size. More information and replacement costs will be discussed in future IRPs as 2026 approaches.

The 2015 PRS is moderately different from the 2013 resource strategy shown in Table 11.3. Avista's capacity needs have changed since the prior plan. The first need for new resources has moved out one year, as Avista won an auction to purchase a share of the output from Chelan County PUD's hydroelectric projects. Lower loads compared to the prior plan and new upgrade options eliminate the need for one of the peakers forecasted in the prior plan.

Table 11.3: 2013 Preferred Resource Strategy

Resource	By the End of Year	ISO Conditions (MW)	Winter Peak (MW)	Energy (aMW)
Simple Cycle CT	2019	83	86	76
Simple Cycle CT	2023	83	86	76
Combined Cycle CT	2026	270	281	248
Simple Cycle CT	2023	83	86	76
Rathdrum CT Upgrade	2028	6	2	5
Simple Cycle CT	2032	50	52	46
Total		**575**	**594**	**527**
Efficiency Improvements	**Acquisition Range**		**Winter Peak Reduction**	**Energy (aMW)**
Energy Efficiency	2014-2033		221	164
Demand Response	2022-2027		19	0
Distribution Efficiencies	2014-2017		<1	<1
Total			**240**	**164**

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 energy efficiency at below 110 percent of generation alternative costs. Avista now models energy efficiency and supply side options in a single optimization, a change from prior practice. This enhancement allows PRiSM to select different conservation amounts along the efficient frontier instead of one acquisition strategy across the entire curve.

Figure 11.6 shows the annual PRS conservation additions from the optimization compared to the third party CPA. The PRiSM model selected nearly identical conservation quantities each year and in total (132.5 aMW with PRiSM versus 132.1 with the CPA). Figure 11.7 shows the difference between the load forecast with and without conservation. The 132 aMW of energy savings (including losses) represents 52 percent of potential load growth. Please refer to Chapter 5 – Energy Efficiency and Demand Response for a detailed discussion of energy efficiency resources. That chapter identifies 124.5 aMW, which is the 132 aMW minus 6 percent for losses.

Figure 11.6: Energy Efficiency Annual Expected Acquisition Comparison[6]

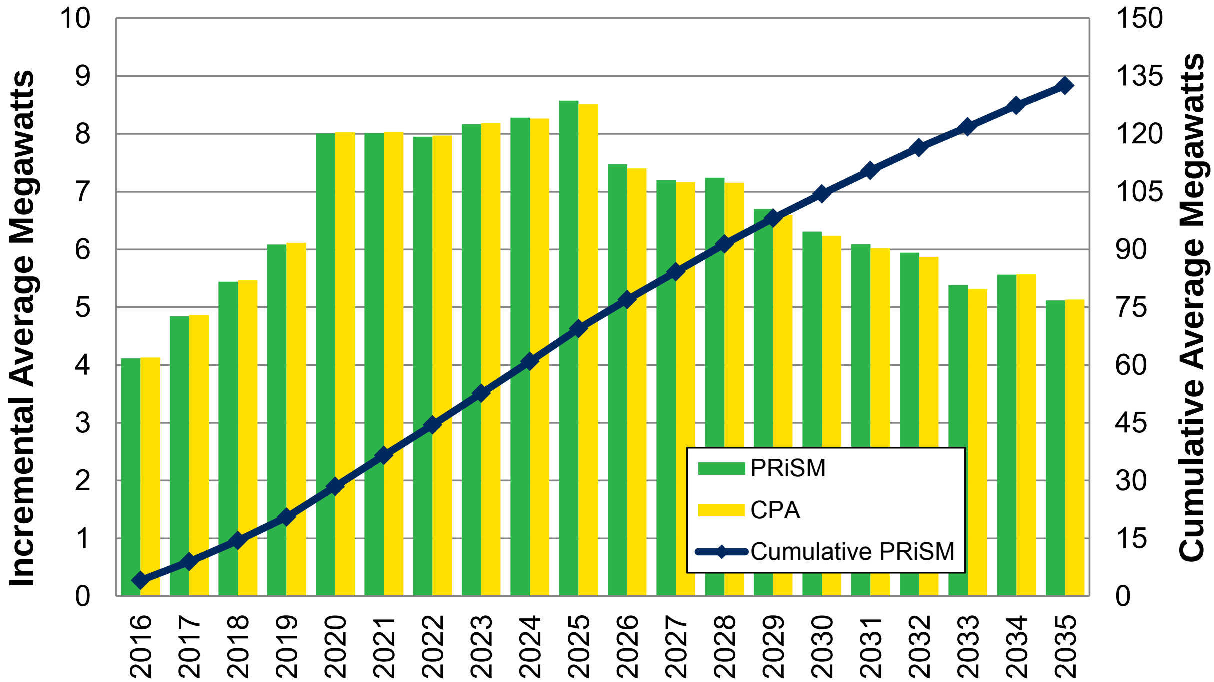
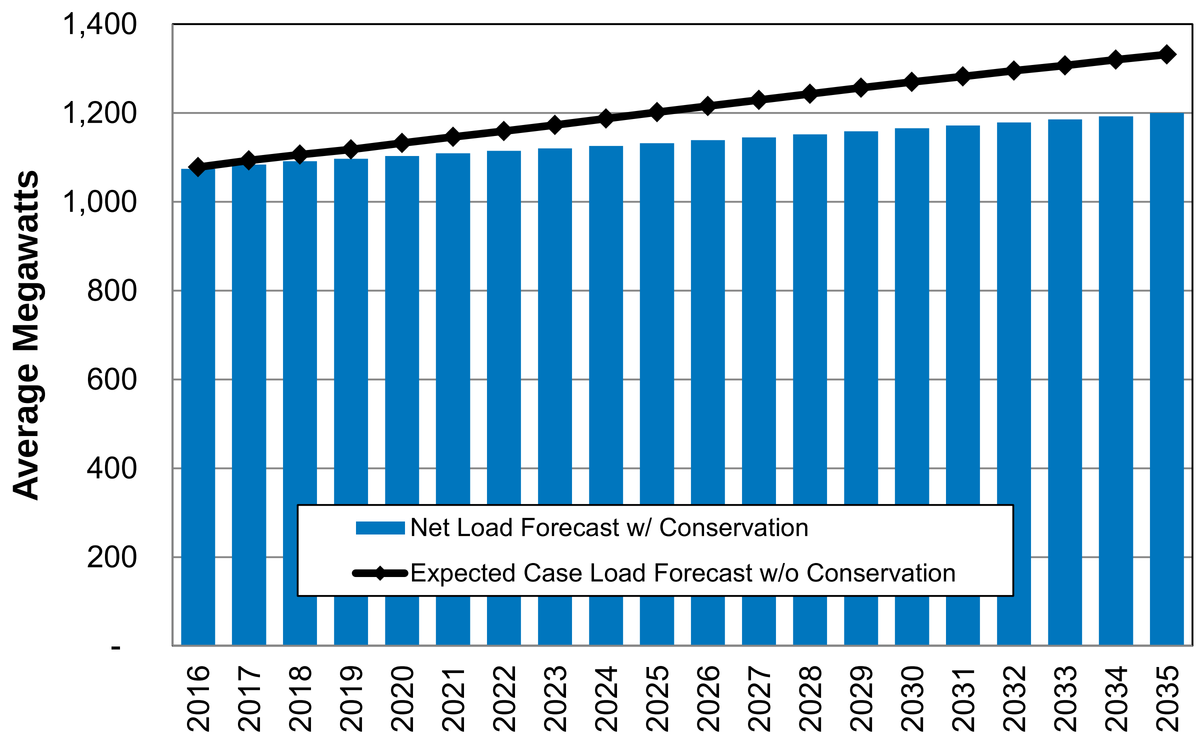


Figure 11.7: Load Forecast with and without Energy Efficiency



[6] Figure 11.6 includes 6.1 percent energy losses.

Grid Modernization

Distribution feeder upgrades entered the PRS for the first time in the 2009 IRP. The grid modernization process began with the Ninth and Central feeder in Spokane. The decision to rebuild a feeder considers energy, operation and maintenance savings, the age of installed equipment, reliability indexes, 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 resource option in PRiSM. A broader discussion of Avista's feeder rebuild program is in Chapter 8.

Natural Gas-Fired Peakers

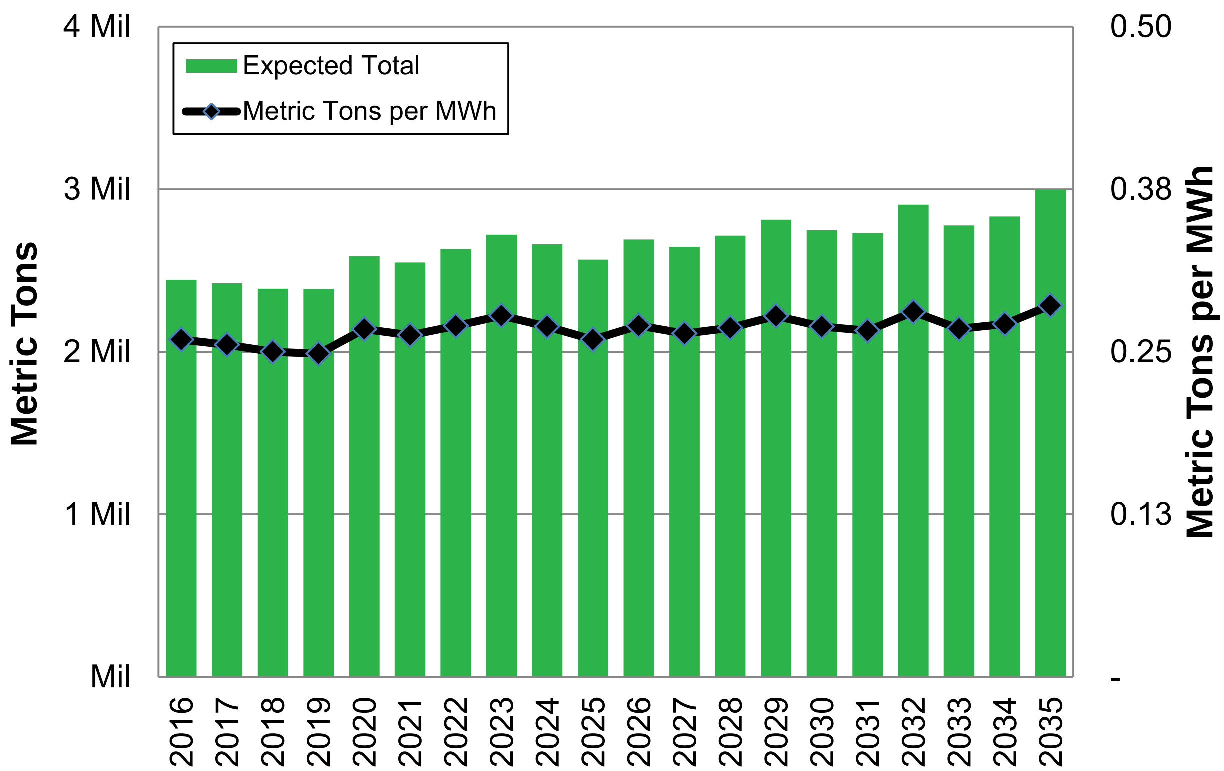
Avista plans to locate potential sites for new natural gas-fired generation capacity within its service territory ahead of an anticipated need. Avista's service territory has areas with different combinations of benefits and costs for gas-fired generation. Locations in Washington have higher generation costs because of natural gas fuel taxes and carbon mitigation fees. However, Washington locations may benefit from their proximity to natural gas pipelines and Avista's transmission system, lower project elevations with higher on-peak capacity contributions per investment dollar, and potential for water rights to cool the facility more efficiently relative to air-cooled options. In Idaho, lower taxes and fees decrease the cost of a potential facility, but fewer locations exist to site a facility near natural gas pipelines, fewer low cost transmission interconnection points are available, and fewer sites have available rights for cooling water. A 2013 IRP Action Item was identification of a location for a future natural gas resource. Avista has studied potential locations and concluded a site in Northern Idaho best fits customer needs. Avista has yet to determine if a brownfield or a greenfield site is best. Given Avista's extended surplus position until the end of 2020, it will defer the decision while continuing to pursue and evaluate sites.

Avista is not specifying a preferred peaking technology until a competitive bidding process is completed. Given current assumptions, the resource strategy would include a Frame CT machine. 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 has 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 low heat rates, and are highly flexible, but they can be more expensive than other technologies. Given the expected number of operating hours, the lowest cost option is the less efficient and less flexible Frame CT. Increased flexibility requirements and greenhouse gas emissions costs could make a hybrid plant or reciprocating engines preferable. Avista has enough resource flexibility to meet customer needs to drive the strategy towards a lower cost peaker option, but energy imbalance markets may provide enough revenues for a flexible peaker to offset the higher costs.

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 due to current or proposed environmental regulations. The only significant carbon emitting lost resource is the expiration of the Lancaster PPA in 2026. Figure 11.8 presents Avista's expected greenhouse gas emissions (excluding Kettle Falls Generating Station) with the addition of 2015 PRS resources. Emissions should not change significantly prior to 2019 other than from year-to-year fluctuations resulting from maintenance outages, market fluctuations, and regional hydroelectric generation levels. Beginning in 2019, additional emissions will come from new peaking resources, but these resources will not affect overall emissions levels much due to low projected use. The estimates in Figure 11.8 do not include emissions from purchased power or a reduction in emissions for off-system sales. Avista expects its greenhouse gas emissions intensity from owned and controlled generation to remain around 0.27 metric tons per MWh with the current resource mix and the new generation identified in the PRS.

Figure 11.8: Avista Owned and Controlled Resource's Greenhouse Gas Emissions



Capital Spending Requirements

This IRP assumes Avista will finance and own all new resources. This may or may not be the result of competitive acquisition processes, but the overall result is unchanged by assumed ownership structure. Using this assumption, and the resources identified in the 2015 PRS, the first capital addition to rate base is in 2021 for the first natural gas-fired peaker. The development is likely to begin years earlier, but would likely enter rate base

January 1, 2021. Avista may begin making major capital investments for the addition in 2018 or earlier. The capital cash flows in Table 11.4 include AFUDC, transmission investments for generation, tax incentives, and sales taxes. Over the 20-year IRP timeframe, $682 million (nominal) in generation and related transmission expenditure is required to support the PRS. A separate tariff rider funds energy efficiency.

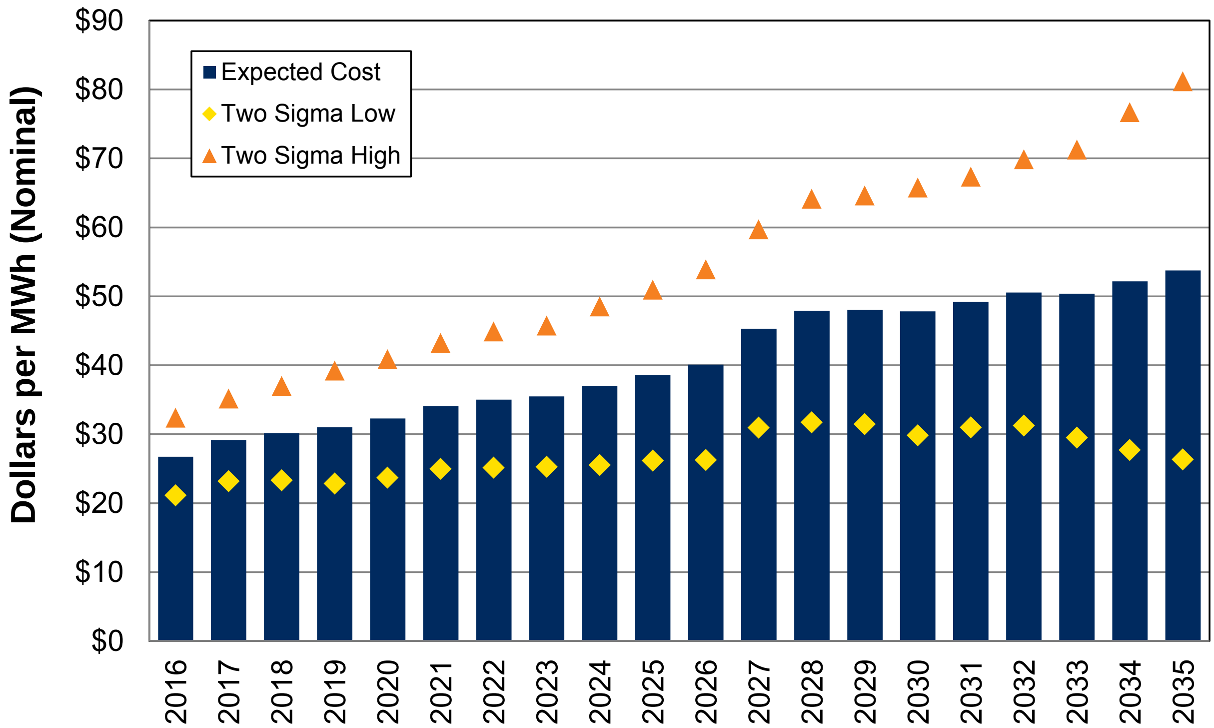
Table 11.4: PRS Rate Base Additions from Capital Expenditures (Millions of Dollars)

Year	Investment	Year	Investment
2016	0.0	2026	8.2
2017	0.0	2027	398.9
2018	0.0	2028	98.7
2019	0.0	2029	0.0
2020	0.0	2030	0.0
2021	89.4	2031	0.0
2022	0.0	2032	0.0
2023	0.0	2033	0.0
2024	3.0	2034	4.2
2025	12.1	2035	68.1
2016-25 Total	**104.5**	**2026-35 Totals**	**578.0**

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 11.9 shows expected PRS costs through 2035 as the blue bar. In 2016, costs are $26 per MWh. The chart shows a two-sigma cost range. Yellow diamonds represent the lower range and orange triangles represent the upper range. The main driver increasing power supply costs and volatility in future years is natural gas prices and weather, which affects both hydroelectric generation levels and load variability. Avista increases the volatility assumption of future natural gas prices, as the commodity price has unknown future risks and a history of volatility.

Figure 11.9: Power Supply Expense Range



Near Term Load and Resource Balance

Under Washington regulation (WAC 480-107-15), utilities expecting supply deficits within three years of an IRP filing must file a RFP with the WUTC within 135 days after filing the IRP. After WUTC approval, bids to meet the anticipated capacity shortfall are issued within 30 days. In the 2013 IRP, an Action Item committed Avista to develop a short-term capacity load and resource balance tool to monitor temporarily short positions. Shortly after the filing of the 2013 plan, a Capacity Report was completed and is consulted prior to the heating and cooling seasons. Chapter 6 – Long-term Position discussed small deficits in 2015 and 2016. The company's power supply department filled those deficits due to monitoring of the Capacity Report. Table 11.5 shows the latest position with the 2016 short-term capacity positions closed with market purchases. In Table 11.6, the summer position is long in each of the next four years. As described in Chapter 6, the region is long on summer capacity. Given this circumstance, Avista is not planning to hold capacity for a planning margin and will utilize the surplus in the wholesale market to meet load in extreme weather conditions or extended plant outages.

Table 11.5: Avista Medium-Term Winter Peak Hour Capacity Tabulation

	2016/17	2017/18	2018/19	2019/20
Load Obligations	1,718	1,725	1,737	1,748
Other Firm Requirements	239	89	59	8
Reserves Planning	376	374	376	381
Total Obligations	**2,333**	**2,188**	**2,172**	**2,137**
Firm Power Purchases	206	164	162	31
Owned & Contracted Hydro	1,014	1,029	996	1,001
Thermal & Storage Resources	1,137	1,142	1,142	1,141
Wind (at Peak)	0	0	0	0
Total Resources	**2,357**	**2,335**	**2,300**	**2,173**
Net Position	**24**	**147**	**128**	**36**

Table 11.6: Avista Medium-Term Summer 18-Hour Sustained Peak Capacity Tabulation

	2016	2017	2018	2019
Load Obligations	1,515	1,529	1,542	1,554
Other Firm Requirements	189	89	89	59
Reserves Planning	165	164	166	166
Total Obligations	**1,869**	**1,782**	**1,797**	**1,779**
Firm Power Purchases	68	68	51	49
Owned & Contracted Hydro	823	818	806	781
Thermal Resources	984	988	988	988
Wind (at Peak)	0	0	0	0
Total Resources	**1,875**	**1,874**	**1,845**	**1,818**
Net Position	**6**	**92**	**48**	**39**

Efficient Frontier Analysis

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 met with sets of intermediate portfolios between the least risk and least cost options.

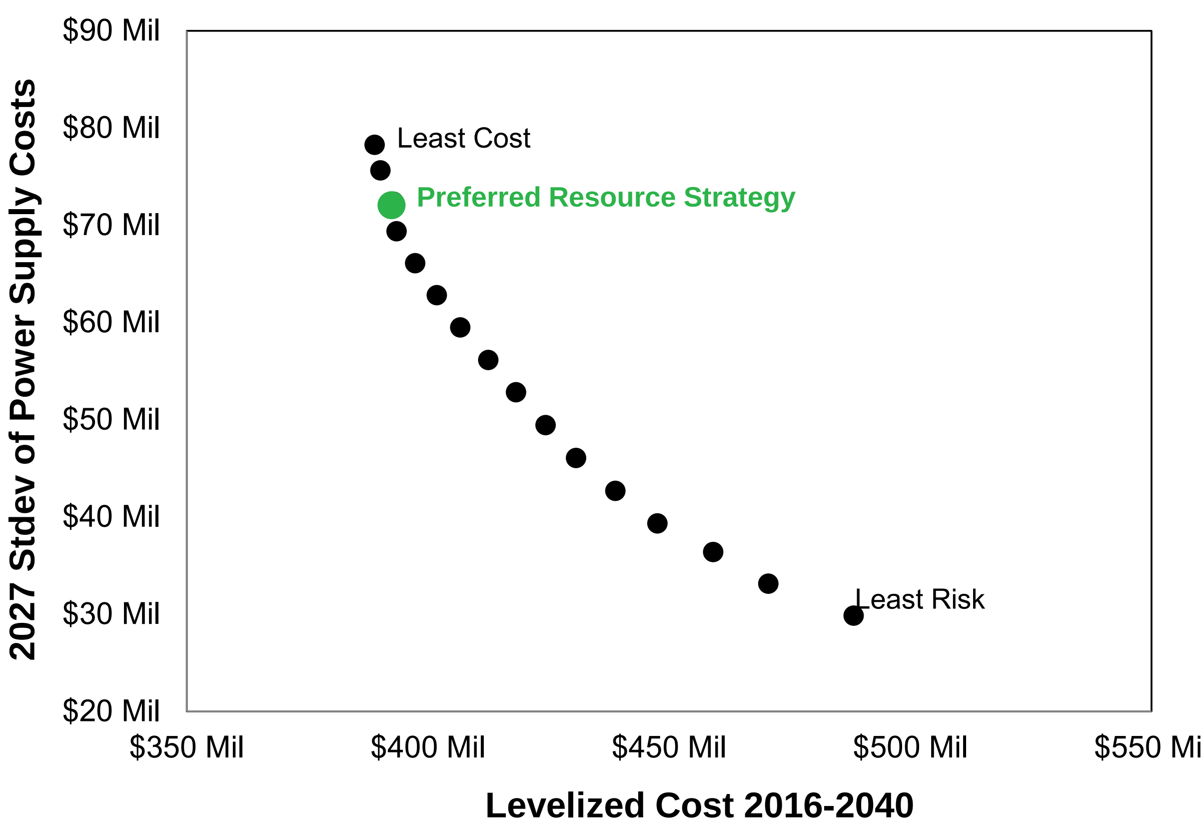
Given the resource assumptions, no resource portfolio can be at a better cost and risk combination than these portfolios.

- **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 given current information.

Figure 11.10 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 the standard deviation of power supply costs in 2027. It is necessary to move far enough into the future so load growth provides PRiSM the opportunity to make new resource decisions. The year 2027 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 is not choosing to pursue the absolute least cost strategy in this IRP, as it relies exclusively on natural gas-fired peaking facilities. A peakers-only strategy would include more market risk than exists in the present portfolio because the portfolio would trade diversity of the Lancaster CCCT for another peaker. Selecting the appropriate point on the efficient frontier is not solvable through a mathematical formula.

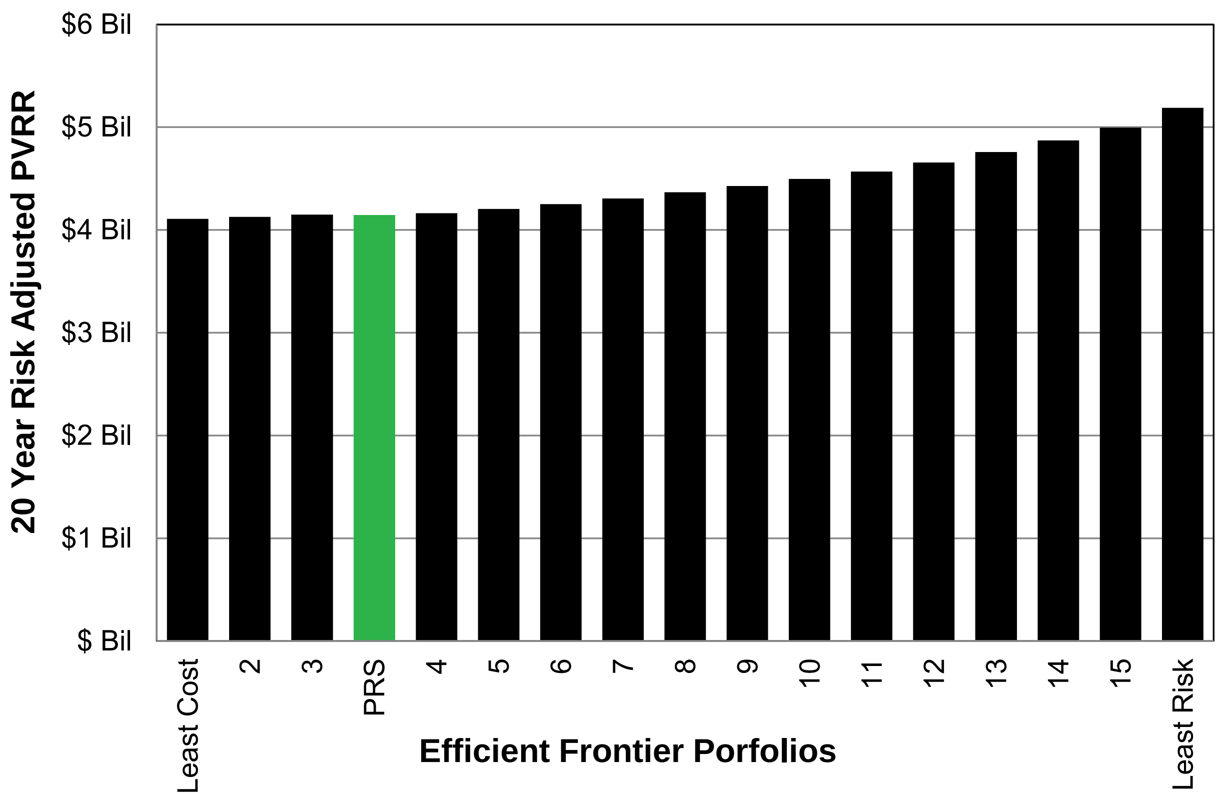
Figure 11.10: Expected Case Efficient Frontier



In the WUTC's 2013 IRP acknowledgement, the Commission asked Avista to evaluate the value of risk mitigation among competing resource strategies and provide justification for its selection of the PRS over other portfolios along the efficient frontier. Avista investigated several methods of measuring the benefits and costs of each portfolio along the efficient frontier. Economic theory indicates all points on the curve are the best portfolio for a given level of risk. Academic research suggests users of efficient frontiers develop indifference curves to overlay against the efficient frontier to help select the appropriate portfolio strategy. After researching this concept, it is no different from finding what level of risk reduction a manager is accepting for each level of risk. Avista investigated two other analytical methodologies to evaluate each portfolio along the efficient frontier: risk adjusted PVRR and point-to-point derivatives.

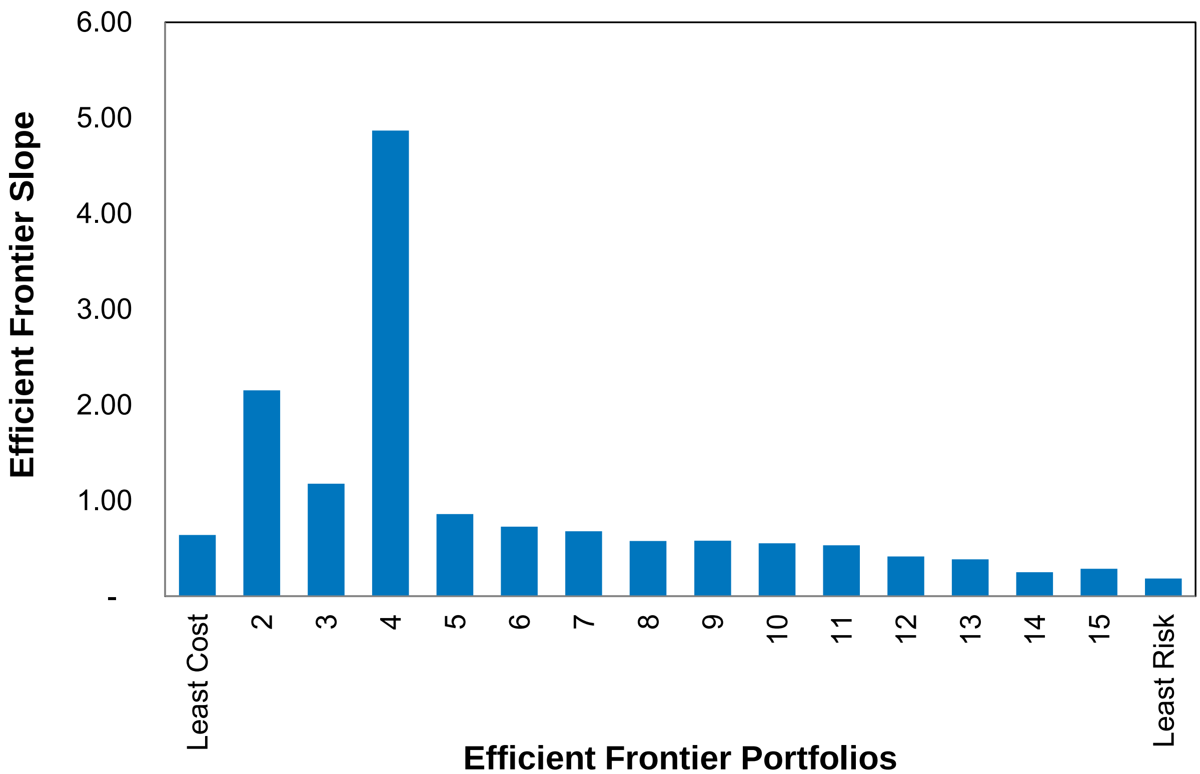
The first step calculates risk adjusted PVRR for each portfolio. This calculation is the net present value of the future revenue requirements, plus the present value of taking each of the future year's tail risk, calculated by 5 percent of the 95th percentile's increase in costs. This methodology assumes the lowest NPV should yield the best strategy. Figure 11.11 shows the results of this study of the efficient frontier. The lowest cost scenario, including tail risk, is the Least Cost portfolio. This Risk-Adjusted PVRR methodology suggests the Least Cost strategy would be the best choice. Before making this decision, Avista considered additional analyses, given that this strategy built 527 MW of 11,000 Btu/kWh heat rate peakers. The strategy increases exposure to a potentially volatile power and natural gas market as compared to today's portfolio.

Figure 11.11: Risk Adjusted PVRR of Efficient Frontier Portfolios



To illustrate this risk and the benefits of the PRS, Avista employed a second method. It calculates point-to-point derivatives by analyzing the slope of the change in cost relative to the change in costs. In this case, a greater slope indicates increasing benefits for trading off risk reduction for higher portfolio costs; a higher slope indicates a better tradeoff between cost and risk. Figure 11.12 illustrates the results of this study. The PRS selected by PRiSM falls between Portfolios 3 and 4, indicating its results are valid. Avista prefers the PRS relative to Portfolio 4 because it includes more efficiency upgrades to its generation assets and a CCCT technology more closely aligned with our expiring Lancaster CCCT facility contract.

Figure 11.12: Risk Adjusted PVRR of Efficient Frontier Portfolios



Other Efficient Frontier Portfolios

In addition to the PRS, the efficient frontier contains 16 additional resource portfolios. The lower cost and higher risk portfolios contain primarily natural gas peakers, as portfolio risk decreases, CCCT capacity increases. The amount of conservation varies in these portfolios as it lowers risk, and as it fills deficiency gaps depending on the resource selection. 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 larger needs with conservation in order to meet the load requirement. This discussion continues in Chapter 12 – Portfolio Scenarios.

Toward the middle of the efficient frontier, PRiSM favors wind and solar to reduce 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.

Table 11.7: Alternative Resource Strategies along the Efficient Frontier (MW)

Portfolio	NG Peaker	NG CCCT	Wind	Solar	Thermal Upgrade	Energy Efficiency
Least Cost	527	-	-	-	38	128
2	524	-	-	-	41	135
3	239	286	-	-	38	128
PRS	239	286	-	-	41	132
4	143	341	-	-	38	138
5	189	341	50	10	41	139
6	140	341	100	20	41	143
7	189	341	200	-	38	141
8	140	341	250	20	41	142
9	186	341	300	70	38	141
10	186	341	400	30	38	141
11	140	341	450	80	38	144
12	140	341	500	150	41	142
13	186	341	500	290	38	143
14	93	627	500	270	38	140
15	93	627	500	480	38	141
Least Risk	186	683	500	600	23	144

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 energy efficiency is within PRiSM, the prior IRP method of calculating avoided costs is no longer required; but estimating these values is helpful in selecting conservation measures in future 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 an hourly energy price to ensure matching between savings and value. If the savings were the same each hour of the year, it would receive the flat energy price, but if it were only saving energy in on-peak hours, it would receive a higher price. In addition to energy prices, the 10 percent Power Act adder and the value of loss savings are included.[7] Reducing customer loads saves future distribution and transmission capital and O&M costs, and is included in the

[7] The Power Act adder refers to one aspect of federal law enacted in 1980 along with the creation of the Northwest Power and Conservation Council.

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 commodity energy sales in the wholesale marketplace.

Equation 11.2 describes the avoided costs to evaluate conservation measures. This equation is slightly different from the 2013 IRP. In prior IRPs, the capacity value received the 10 percent Power Act benefit. Now with energy efficiency included in the PRiSM model, the 10 percent adder cannot be included in the linear program as it would create a non-linear solution. This change is consistent with the NPCC's methodology.

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 \$38.48 per MWh assuming a flat load shape.

PCR = New resource capacity savings for the PRS selection point is estimated to be \$102 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 6.1 percent based on Avista's estimated system average losses.

DC = Distribution capacity savings. This value is approximately \$12.30 per kW-Year

Determining the Avoided Cost of New Generation Options

Avoided costs change as market prices, loads, and resources change. Table 11.8 shows avoided costs derived from the 2015 PRS, but they will change as Avista's loads and resources change. The prices represent the value of energy from a project making equal deliveries over the year in all hours. In this case, a new resource, such as a PURPA qualifying project, would not qualify for capacity payments until 2021. This is because Avista does not need capacity resources until then. The capacity payments included are tilted and levelized, meaning the actual capacity costs are linear and increasing each year rather than the PRS's actual declining cost curve for capacity. This is similar to typical pricing in the marketplace.

Table 11.8: Updated Annual Avoided Costs ($/MWh)

Year	Flat Energy $/MWh	On-Peak Energy $/MWh	Off-Peak Energy $/MWh	Capacity $/kW-Yr
2016	25.87	29.05	21.62	0.00
2017	27.27	30.47	23.03	0.00
2018	29.59	32.90	25.18	0.00
2019	31.40	34.82	26.83	0.00
2020	33.25	36.48	28.94	0.00
2021	34.54	37.79	30.21	145.00
2022	36.05	39.30	31.70	148.32
2023	36.43	39.64	32.17	151.72
2024	38.60	41.85	34.27	155.19
2025	39.42	42.59	35.18	158.75
2026	43.12	46.36	38.80	162.38
2027	44.72	48.08	40.23	166.10
2028	46.48	49.79	42.09	169.90
2029	48.01	51.39	43.51	173.80
2030	48.79	52.14	44.32	177.78
2031	51.23	54.76	46.52	181.85
2032	53.90	57.58	48.98	186.01
2033	54.98	58.74	49.95	190.27
2034	57.77	61.64	52.65	194.63
2035	59.33	63.24	54.12	199.09

12. Portfolio Scenarios

Introduction

The PRS is Avista's strategy to meet future loads. In case the future is different from the IRP forecast, the strategy needs to be flexible enough to benefit customers under the new future. 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 load forecasts, determines the impact of unit sizing, and the selection of portfolios to the right of the efficient frontier. This chapter also identifies the capital cost tipping points for solar, storage, and demand response options.

Chapter Highlights

- Lower or higher future loads do not materially change the resources strategy.
- Colstrip remains a cost-effective and reliable source of power to meet future customer loads.
- Without Colstrip in 2027, customer bills increase $58 million.
- A $19 per metric ton social cost of carbon scenario increases customers' costs by $67 million per year levelized.
- Tipping point analysis suggests utility scale solar costs would need to decline 48 percent to be included in the PRS.

Mixed Integer versus Linear Programming

PRiSM is a mixed integer model that meets utility power supply deficits over the IRP timeframe from a pre-defined set of resource options. The integer model selects only commercially available resources. For example, if Avista is short 45.3 MW, the integer model cannot select a 45.3 MW resource. Rather it must choose among unit sizes actually for sale in the marketplace. This methodology creates lumpy resource additions, meaning that by selecting a commercially available resource capable of fully meeting the deficit, Avista likely will have some level of surplus. Figure 12.1 shows the impact of lumpy resource acquisitions on the efficient frontier relative to a linear solution not requiring lumpy additions. In this case, costs in the integer model average 0.5 percent higher than were Avista able to purchase resources exactly matching its deficits in a linear model. In addition to higher costs, resources mixes on the efficient frontier change when choices must match actual resources available in the marketplace. The resources selected across the efficient frontier under a linear programming model are in Table 12.1. This methodology creates a smoother transition of peakers to CCCTs and energy efficiency increases at a smoother rate than the more realistic integer-based model.

Figure 12.1: Linear versus Integer Efficient Frontier Difference

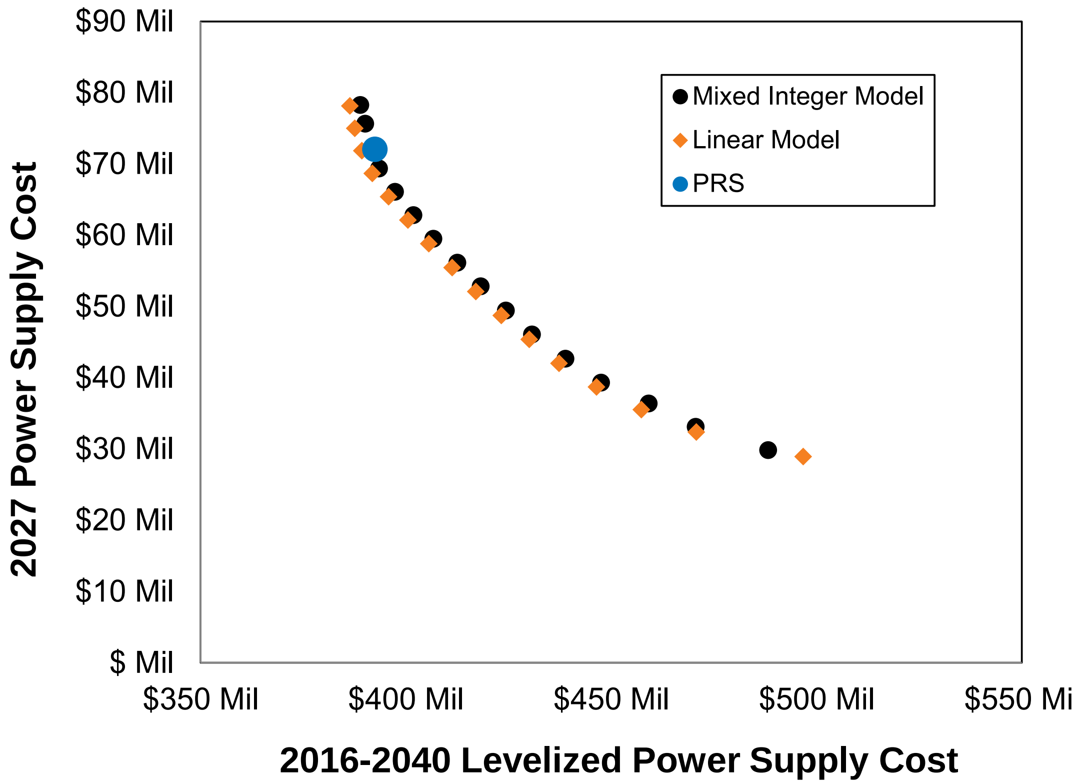


Table 12.1: Efficient Frontier with Linear Programming

Portfolio	NG Peaker	NG CCCT	Wind	Solar	Thermal Upgrade	Hydro Upgrade	Energy Efficiency
Least Cost	500	-	-	-	41	-	130
2	367	129	-	-	41	-	133
3	222	274	-	-	41	-	133
4	79	414	-	-	41	-	135
5	58	429	60	-	41	-	139
6	56	431	132	-	41	-	139
7	48	439	202	-	41	-	139
8	41	445	276	-	41	-	139
9	41	445	352	-	41	-	140
10	30	456	400	46	40	-	140
11	29	458	478	50	38	-	141
12	6	480	500	143	38	-	141
13	-	515	500	282	38	-	141
14	-	549	500	446	38	-	141
15	-	674	500	523	12	-	144
Least Risk	-	855	500	600	12	57	147

Load Forecast Scenarios

The PRS meets the Expected Case energy load growth of 0.6 percent and winter peak demand growth of 0.68 percent over the next 20 years. Chapter 3 – Economic and Load Forecast provides details about three alternative load forecasts. Table 12.2 summarizes the alternative growth assumptions. The high and low load scenarios use different population growth assumptions than the Expected Case. The Increased DG Solar scenario uses the same economic growth rate as the Expected Case, but assumes 10 percent of residential customers install rooftop solar with up to a 6 kW system by 2040.

Table 12.2: Load Forecast Scenarios (2016-2035)

Scenario	Energy Growth (%)	Winter Peak Growth (%)	Summer Peak Growth (%)
Expected Case	0.6	0.7	0.8
High Load	0.8	0.9	1.1
Low Load	0.2	0.6	0.7
Increased DG Solar	0.4	0.7	0.6

Table 12.3 shows changes to the PRS for each load scenario. In the High Load scenario, 97 MW of additional natural gas-fired peakers meet added load growth, while the Low Load scenario reduces peakers by 46 MW. The changes between the High and the Low Load scenarios are not significant because expiring contracts is more of a driver of Avista's resource needs than load growth.

Table 12.3: Resource Selection for Load Forecast Scenarios

Resource	Expected Case's PRS	High Loads	Low Loads	Increased DG Solar
NG Peaker	239	335	192	239
NG Combined Cycle CT	286	286	286	286
Wind	0	0	0	0
Solar	0	0	0	0
Demand Response	0	0	0	0
Thermal Upgrades	41	41	41	41
Hydro Upgrades	0	0	0	0
Total	**565**	**662**	**519**	**565**

The Increased DG Solar scenario provides interesting results. In this scenario, where customer-supplied generation increases during summer peak-load periods, the PRS does not change. The winter peak load drives Avista's resource acquisition needs, so this scenario does not change the resource strategy, as DG solar does not produce energy between the hours of 5:00 pm and 7:00 pm in the winter. This results in the same resource build, but with lower retail energy sales.

Load forecast changes can also come in the form of new large loads or the loss of an existing large load. In both cases, the change will likely be short notice. Avista likely would meet these events by utilizing the energy market.

Colstrip Retirement Scenarios

The 2013 IRP acknowledgement letter from the Washington Commission (Docket UE-121421) requested Avista continue assessing the impacts of a hypothetical portfolio without Colstrip and provide the overall impacts on rates. TAC members requested another scenario to analyze higher operating costs and shorter EPA compliance timelines. Avista evaluated both continued operation and retirement of Colstrip under each of these scenarios.

Modeling results for Colstrip in the Expected Case indicate Avista ownership interests in the plant will remain cost effective for the next 20 years. The IRP assumes certain capital investments will satisfy future state and federal regulations over the IRP timeframe. The type, amount, and timing of capital expenditures are estimates used for modeling purposes because exact dates and costs are unknown at this time. Future IRPs will update assumptions as more and better information is available. The potential capital investments include emerging requirements related to coal combustion residuals (CCR) and Regional Haze-related controls. Other environmental regulations may drive future investment requirements, such as ash pond improvements and the installation of a system for NO_X control. IRP modeling assumes that a default control system of a selective catalytic reduction (SCR) will be required by the end of 2026, but the specific target date or control type is unknown at this time.

Colstrip Retires in 2026 Scenario

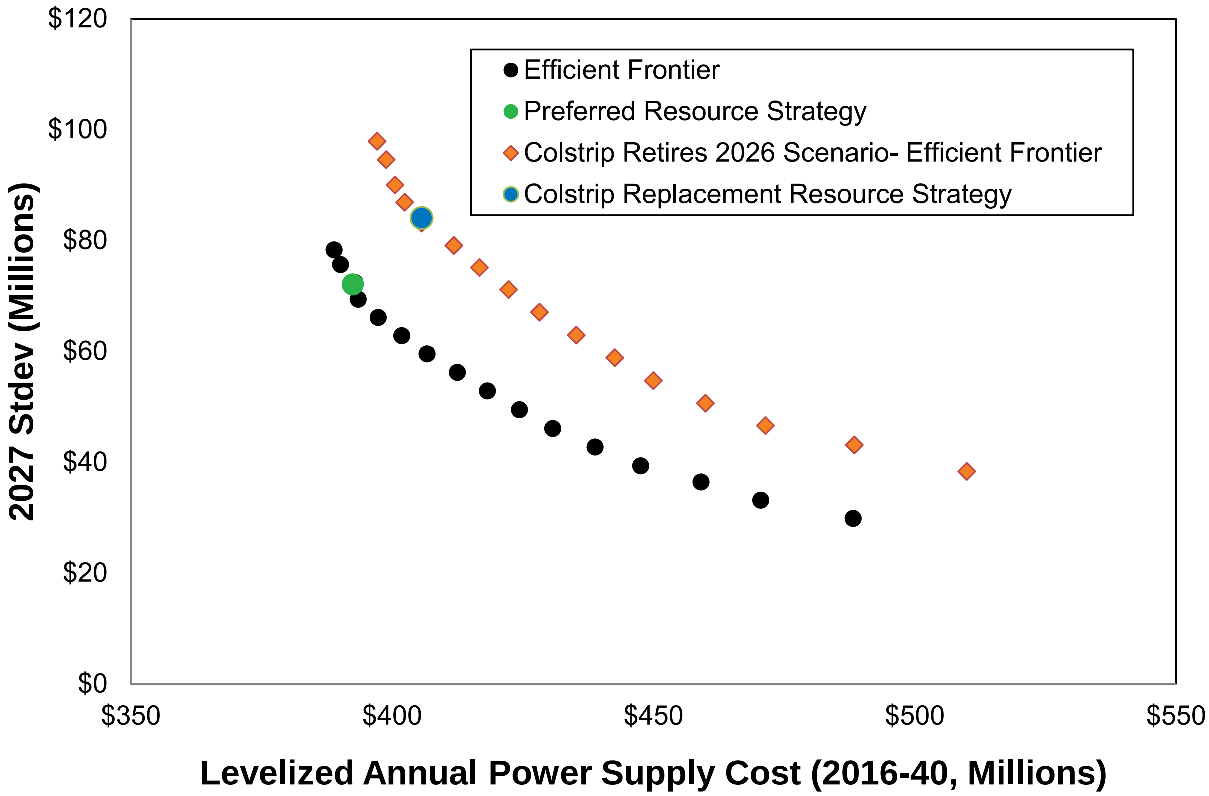
This scenario assumes plant closure at the end of 2026 under the Expected Case's market forecast. This closure date eliminates capital spending for the SCR, accelerates ash pond decommissioning, and alters ongoing capital and O&M spending at the plant. This scenario assumes all costs related to existing and future capital spending would fully depreciate five years after closure. It also assumes capital spending for ash pond closure and no additional shutdown costs beyond the amount included in current depreciation schedules for the plant. The scenario does not include any costs related to employee retraining or relocation costs, payments to other owners, or costs to decommission the plant beyond those included in current rates.

The results of the 2026 year-end closure scenario require 208 MW of new winter capacity, assuming a replacement resource in Avista's balancing area. Table 12.4 provides details about the resource strategy in this scenario. The strategy for this scenario adds a second CCCT to replace the Colstrip capacity and serve future load growth. Figure 12.2 shows a full efficient frontier analysis for this scenario. Levelized power supply costs increase by $13.2 million or 3.6 percent per year across all years of the IRP study. Portfolio risk increases by $12 million in 2027, or 16.6 percent. While the 3.6 percent cost impact appears to be modest due to the IRP's method of levelizing large future costs across the 20-year study timeframe, the annual cost increases in Figure 12.3 are significant beginning in 2027.

Table 12.4: Colstrip Retires in 2026 Scenario Resource Strategy

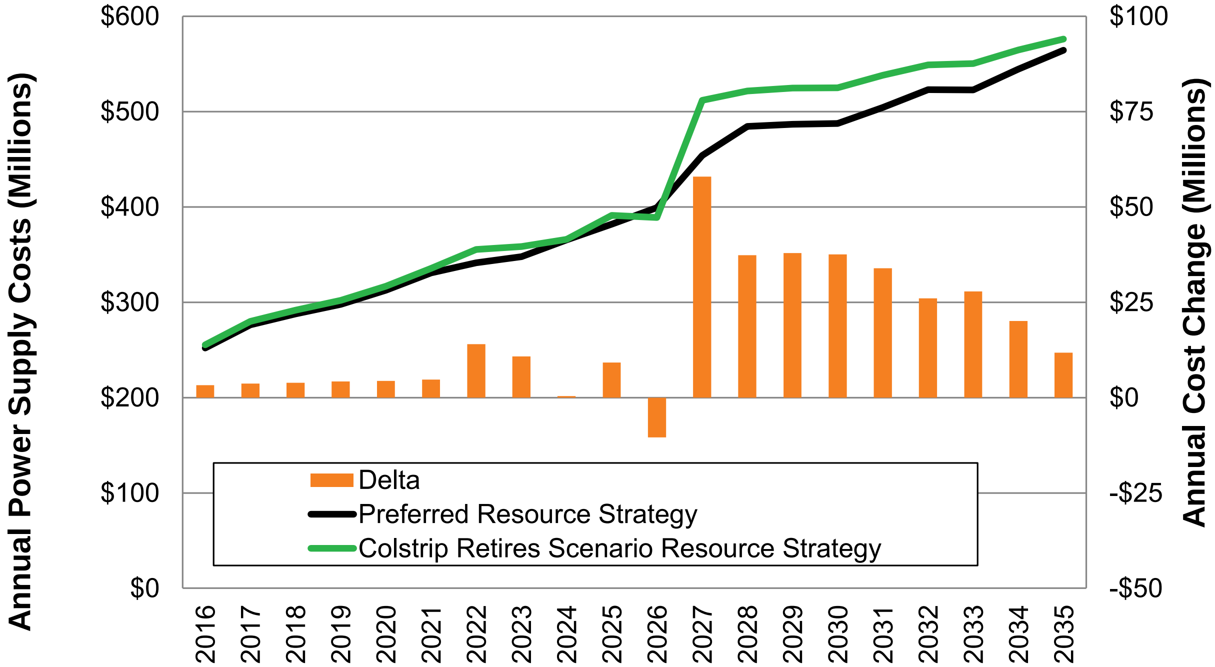
Resource	By End of Year	ISO Conditions (MW)
Natural Gas-Fired Peaker	2020	96
Thermal Upgrades	2021-2025	38
Natural Gas-Fired CCCTs	2026	627
Total		**761**
Conservation (w/ T&D losses)	2016-2035	130.7

Figure 12.2: Colstrip Retires Scenario Efficient Frontier Analysis



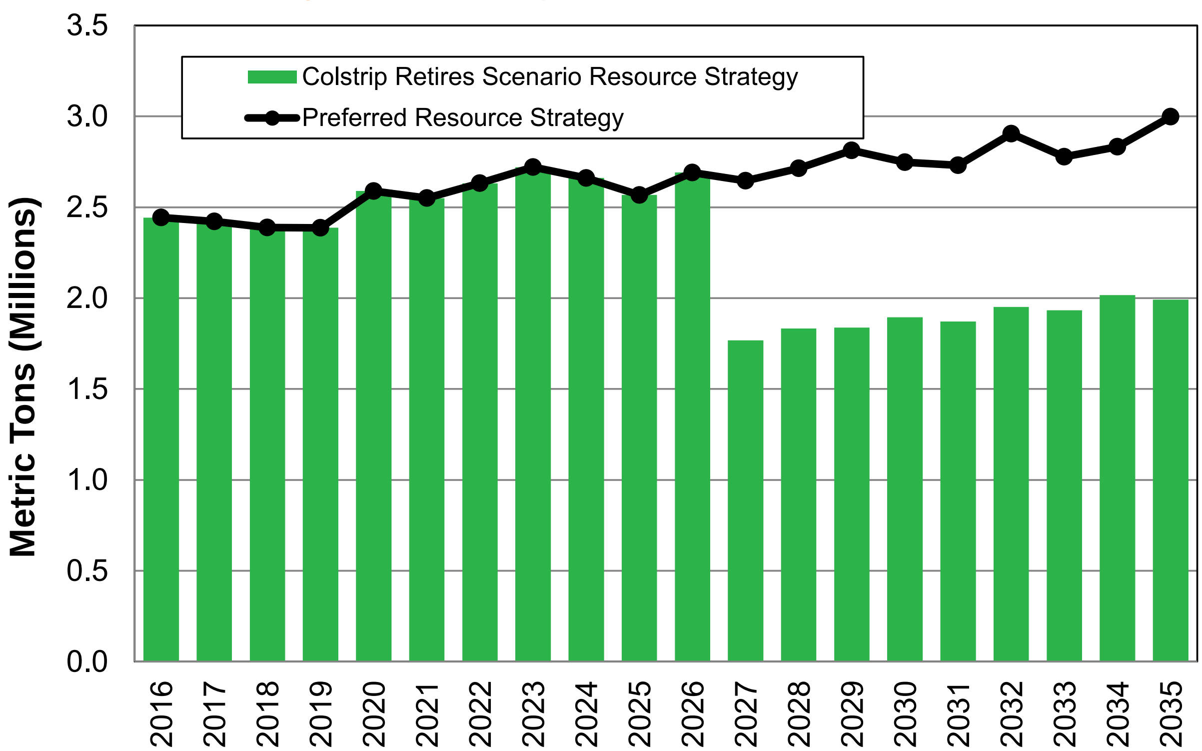
Between 2016 and 2021, customer costs increase due to accelerated recovery of existing capital investments in the plant. In 2022-2026, the model assumes spending to maintain and improve the plant continues at a lower rate, but most costs typically classified as capital spending are expensed, leading to an earlier recovery of spending. The elimination of the SCR offsets and lowers recovered Colstrip costs as high cost investments are removed. The biggest cost to customers is replacement capacity. In 2027, this amounts to $58 million in added costs, or 13 percent. To put this into perspective, Avista's 2015 electric revenue requirement in that year is $900 million. Assuming non-power supply costs increased at the rate of load growth, closing Colstrip alone would increase customer rates by 5.7 percent the first year of closure.

Figure 12.3: Colstrip Retires in 2026 Scenario Power Supply Cost Impact



Avista greenhouse gas emissions decline by an estimated 0.9 million metric tons per year, or 32 percent. Figure 12.4 shows the change in emissions by year. In 2027, the first year of closure in the scenario, the cost per saved metric ton of carbon is $66.

Figure 12.4: Colstrip Retires in 2027 Emissions



High-Cost Colstrip Retention Scenario

The TAC proposed a second Colstrip case. The High-Cost Colstrip Retention scenario assumes replacing existing SO_2 scrubbers, converting the plant to dry ash handling, landfill replacement, acceleration of SCR installation to 2022, and added O&M costs due to the assumed closure of Colstrip Units 1 and 2 in 2017. While offering to perform an analysis of High-Cost Colstrip Retention, Avista does not believe this scenario represents a likely future for Colstrip and therefore has not vetted these assumptions closely. The scenario provides a very high and unlikely case to test the viability of the plant under much higher costs. A third scenario evaluates closing the plant in 2022 to avoid the higher ongoing costs associated with the High-Cost Colstrip Retention case. The resource strategy selected by PRiSM for this scenario is in Table 12.5; it is very similar to the portfolio scenario with the plant retiring in 2027, but the scenario offsets other plant requirements differently causing a small increase in capacity need (770 MW versus 761 MW).

The High-Cost Colstrip scenario in Figure 12.5 uses the efficient frontier methodology to measure cost and risk. It increases fixed costs by $18 million per year levelized between 2016 and 2040 and risk levels do not change. Where Colstrip retires in 2022 to avoid High-Cost Colstrip Retention costs, overall system cost increases $2 million per year; risk increases by $11 million in 2027. The annual costs for the Colstrip scenarios are in Figure 12.6 in 2023. The first year without Colstrip costs increase by $19 million compared to the plant operating with the higher costs. This scenario shows with higher operating costs, the plant is still marginally economic to continue operating.

Table 12.5: Colstrip Retires in 2022 Scenario Resource Strategy

Resource	By End of Year	ISO Conditions (MW)
Natural Gas Peaker	2020	56
Thermal Upgrades	2021-2035	41
Combined Cycle CTs	2023-2026	627
Natural Gas Peaker	2035	47
Total		**770**
Conservation (w/ T&D losses)	2016-2035	131

Figure 12.5: High-Cost Colstrip Retention Scenario Efficient Frontier

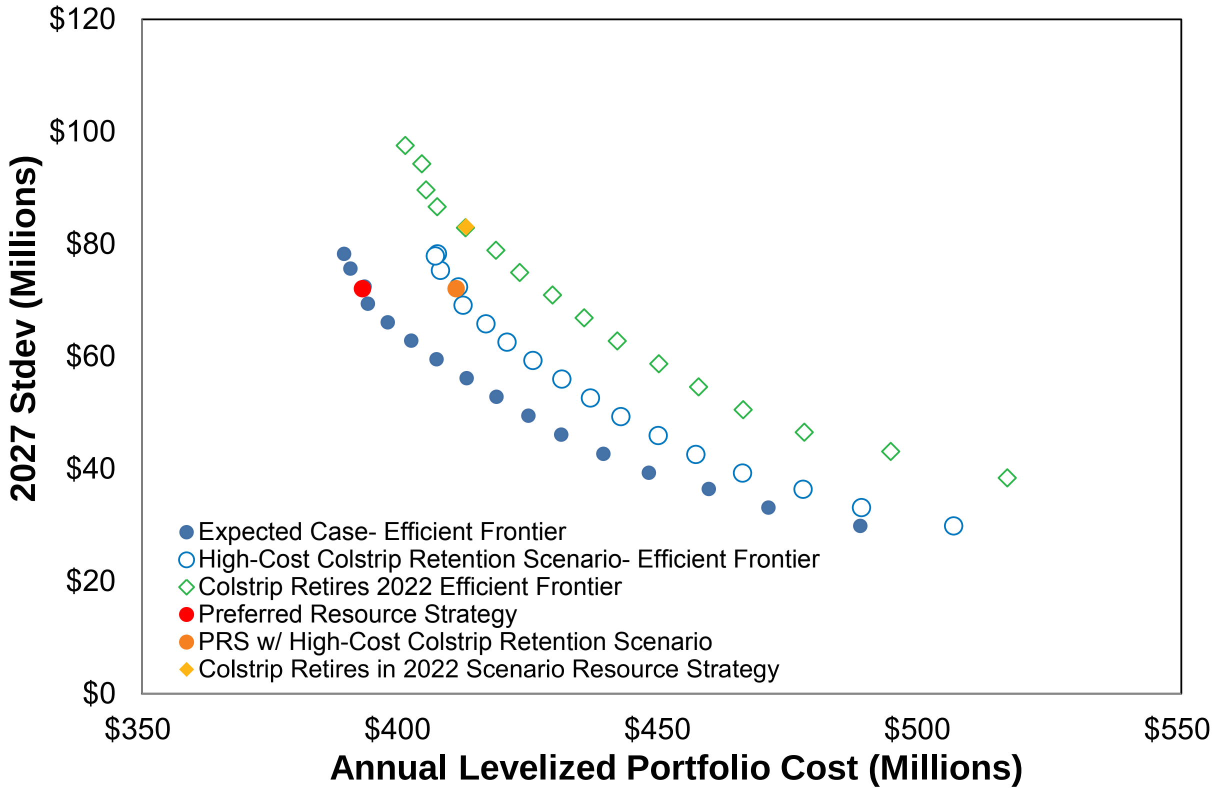
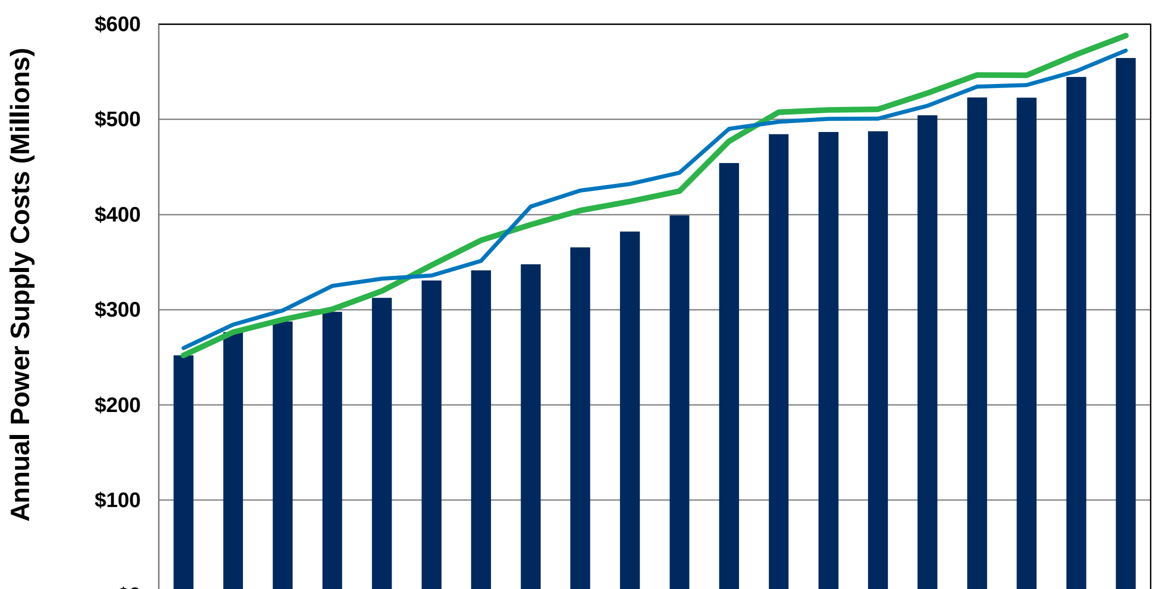


Figure 12.6: High-Cost Colstrip Scenarios Annual Cost

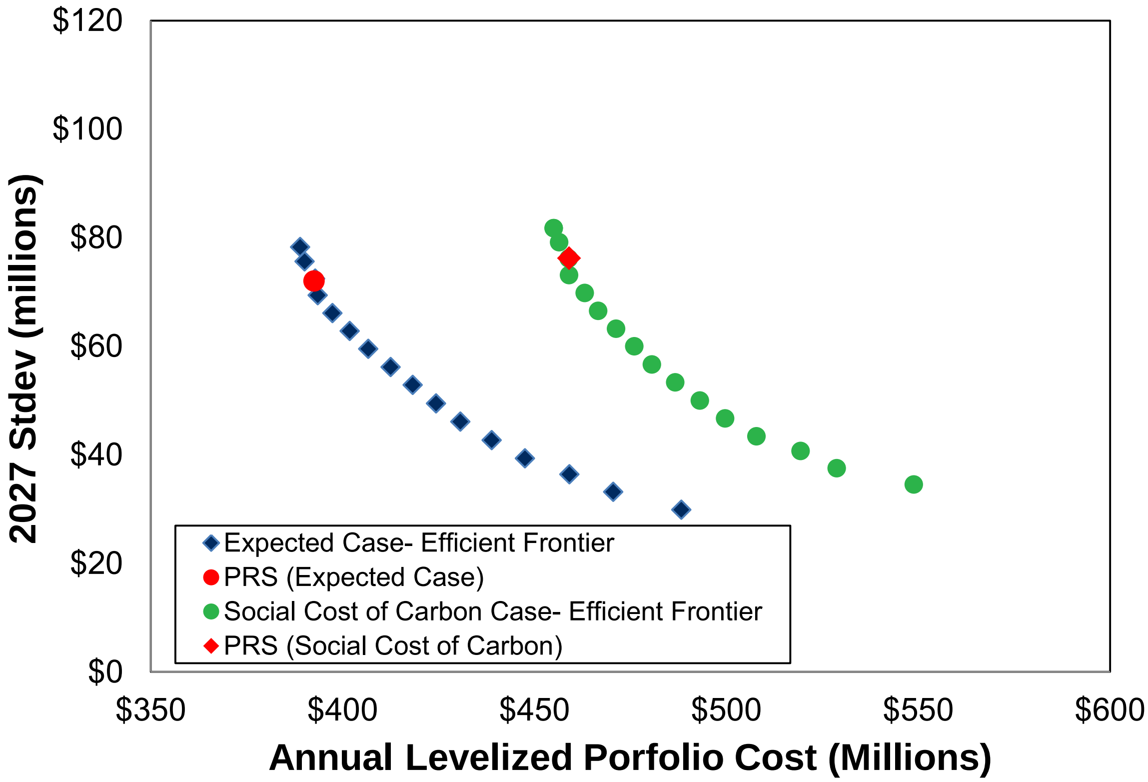


	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PRS	252	276	288	298	313	331	341	348	366	382	399	454	484	487	488	504	523	523	545	564
PRS High Colstrip Costs	252	276	290	301	320	347	373	389	404	414	425	477	507	510	511	528	547	546	568	588
PRS Colstrip Retires 2022	260	284	299	325	333	336	351	408	425	432	444	490	498	500	501	514	534	536	551	572

Social Cost of Carbon Market Scenarios

Chapter 10 describes alternative market scenarios. One modeled scenario was the market impact of a social cost of carbon added to all carbon emissions. This section describes the cost and portfolio impacts of such a market environment to Avista. Figure 12.7 is the efficient frontier of the Expected Case compared to the efficient frontier developed for the Social Cost of Carbon market scenario. With the social cost of carbon, the cost of the PRS increases by $67 million per year, or 17 percent. Risk also increases by $4 million or 6 percent in 2027 for the same portfolio as the PRS.

Figure 12.7: Social Cost of Carbon Impact to Efficient Frontier



Colstrip Retires in 2027 with Social Cost of Carbon

Adding a fee to emit carbon will increase portfolio costs. This scenario analyzes the cost effectiveness of keeping Colstrip open with the Social Cost of Carbon adder. The cost of retiring Colstrip is approximately $6 million higher per year with the plant closed compared to operating with the additional carbon pricing. Not only are system costs higher with the closure of Colstrip in this scenario, but risk increases by 15 percent. See Figure 12.8. This indicates Colstrip is still economic even with carbon pricing approximately 10 times higher than in the Expected Case. The combination of the Social Cost of Carbon with the assumptions from the High-Cost Colstrip Retention scenario would find the plant marginally uneconomic, but as explained earlier, Avista does not believe the assumptions of the High-Cost Colstrip Retention scenario are realistic. The Social Cost of Carbon case reduces carbon emissions without Colstrip retiring. In this scenario, emissions decline by 12 percent; if Colstrip retires, emissions fall 24 percent in total (See Figure 12.9).

Figure 12.8: Colstrip Retires in 2027 Portfolio Efficient Frontier

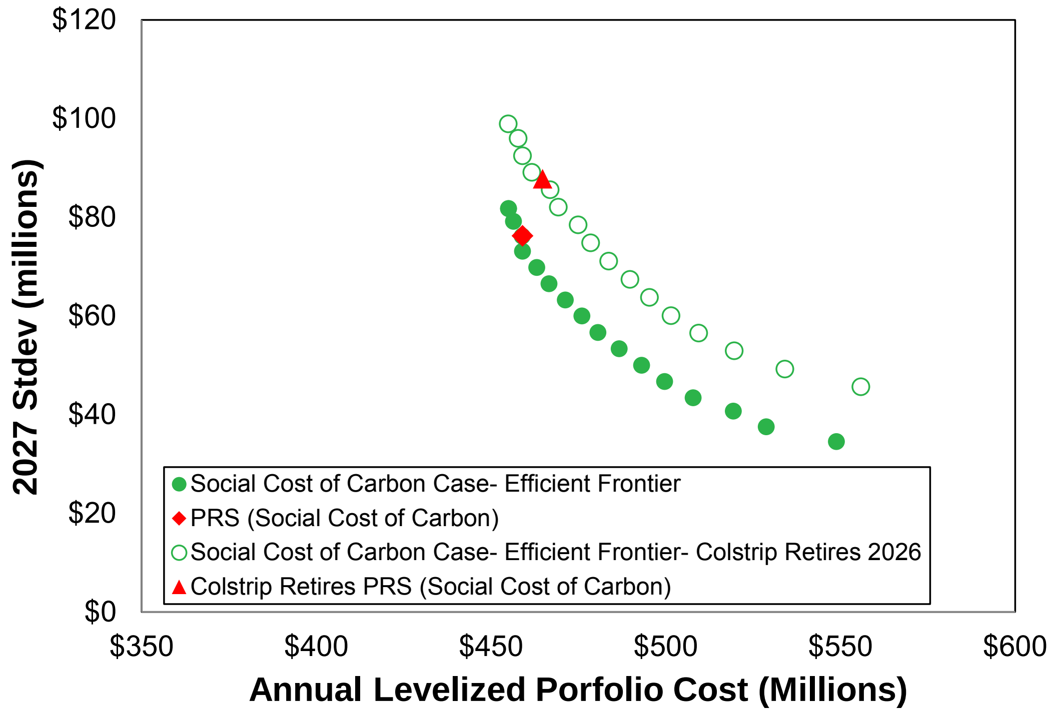
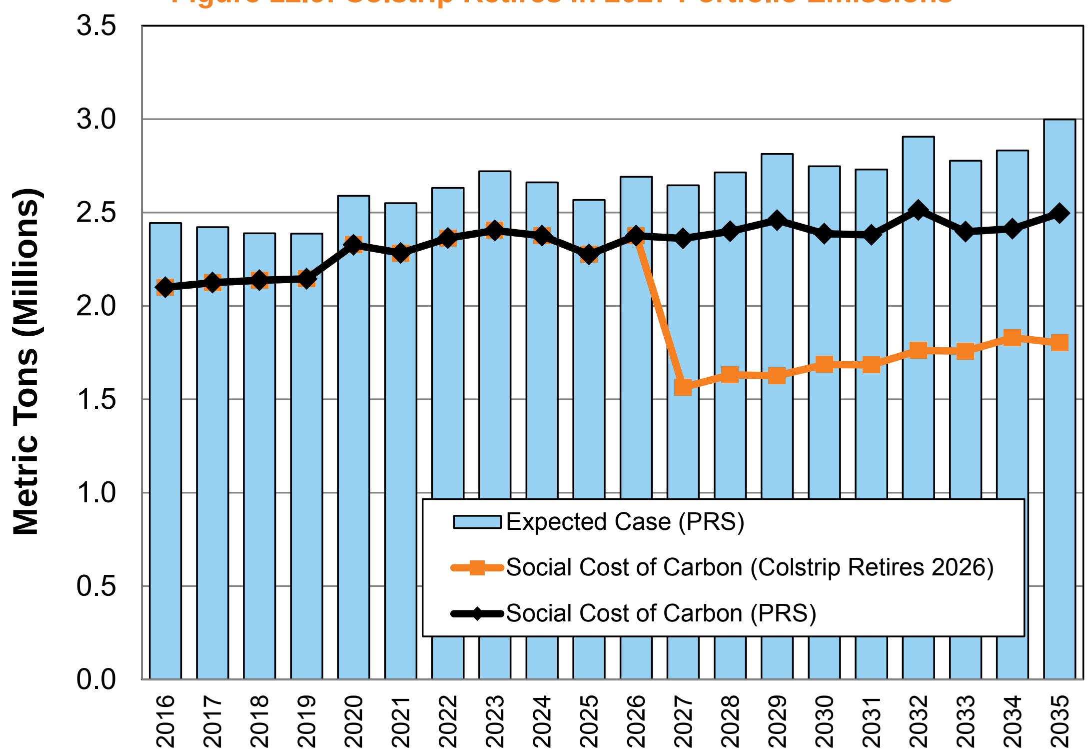


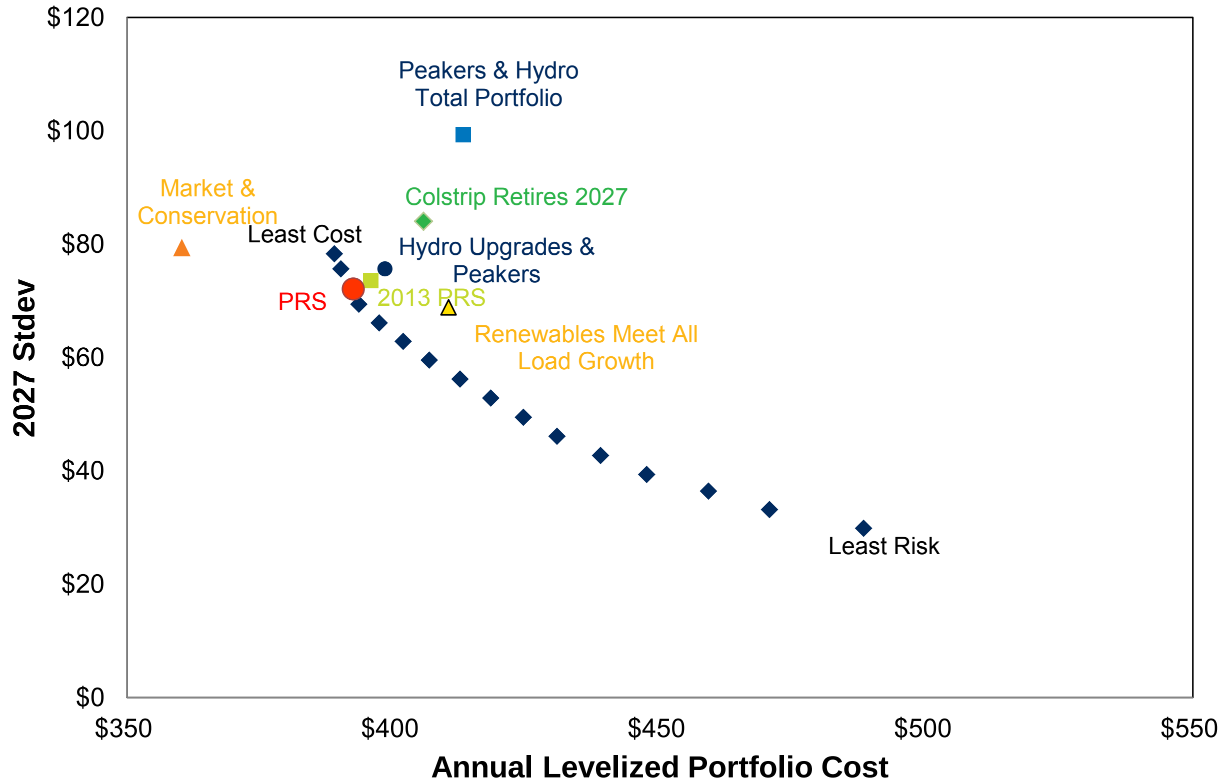
Figure 12.9: Colstrip Retires in 2027 Portfolio Emissions



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. They are similar to how Avista selected resource strategies prior to its 2003 IRP and the adoption of more sophisticated modeling tools such as PRiSM and Monte Carlo risk analysis. Figure 12.10 shows the levelized cost and 2027 risk compared to the efficient frontier.

Figure 12.10: Other Resource Strategy Portfolio Cost and Risk (Millions)



Market and Conservation

The Market and Conservation portfolio shows the cost and risk if the utility chose not to fill its capacity need with generation assets, instead dependeding on the wholesale market for its future needs. This portfolio helps estimate the value of capacity in the PRS. It assumes the same amount of conservation as the PRS. This portfolio's cost is $28 million per year levelized lower than the least cost portfolio, and the risk is $1 million higher in 2027. The cost difference between this portfolio and the least cost represents the cost of capacity or the added cost of reliability. Given this strategy does not meet reliability targets, it is not an acceptable portfolio. Utilities may lean toward this type of portfolio when the market place is long on resources, which is not the case beginning in 2021.

2013 Preferred Resource Strategy

This portfolio emulates the strategy selected in the 2013 IRP. The 2013 PRS portfolio includes the resources described in Chapter 11, predominantly natural gas-fired peakers, a CCCT, and demand response. The portfolio reflects the current lower load growth trajectory by eliminating a peaker from the previous strategy. This strategy's levelized cost is $3 million higher than the PRS, and risk is $1.5 million higher in 2027. With the exception of the demand response, this portfolio is similar to the current PRS results with similar metrics for cost and risk.

Renewables Meet All Load Growth

The Renewables Meet All Load Growth scenario is similar to a higher RPS scenario. The objective is to meet all energy load growth with renewables along with meeting capacity requirements. This scenario meets energy needs with newly acquired renewable resources and natural gas-fired generation for capacity needs. The model selected 250 MW of wind (87 aMW) with a 20 percent apprentice REC credit, plus an upgrade to the Kettle Falls plant; with rollover ability, these renewables meet the 126 aMW requirement each year.

The added renewables, in addition to the capacity resources, add $18 million per year to power supply expenses relative to the Expected Case, and lower risk in 2027 by $3 million. Avista could get the same amount of risk reduction by selecting a portfolio on the efficient frontier with an annual $15 million reduction in cost.

Hydroelectric Upgrades and Peakers

This scenario uses a combination of peakers and hydroelectric upgrades to meet future capacity needs. The scenario completes major upgrades at Long Lake and Monroe Street during the IRP timeframe; natural gas-fired peakers meet all remaining capacity needs. Costs increase by $6 million per year in this scenario, and risk increases by $4 million. An interesting result from the scenario is the increased risk metric. Typically, more renewables reduce risk, but since hydro is highly correlated with the Northwest marketplace, the upgrades actually increase risk relative to the PRS.

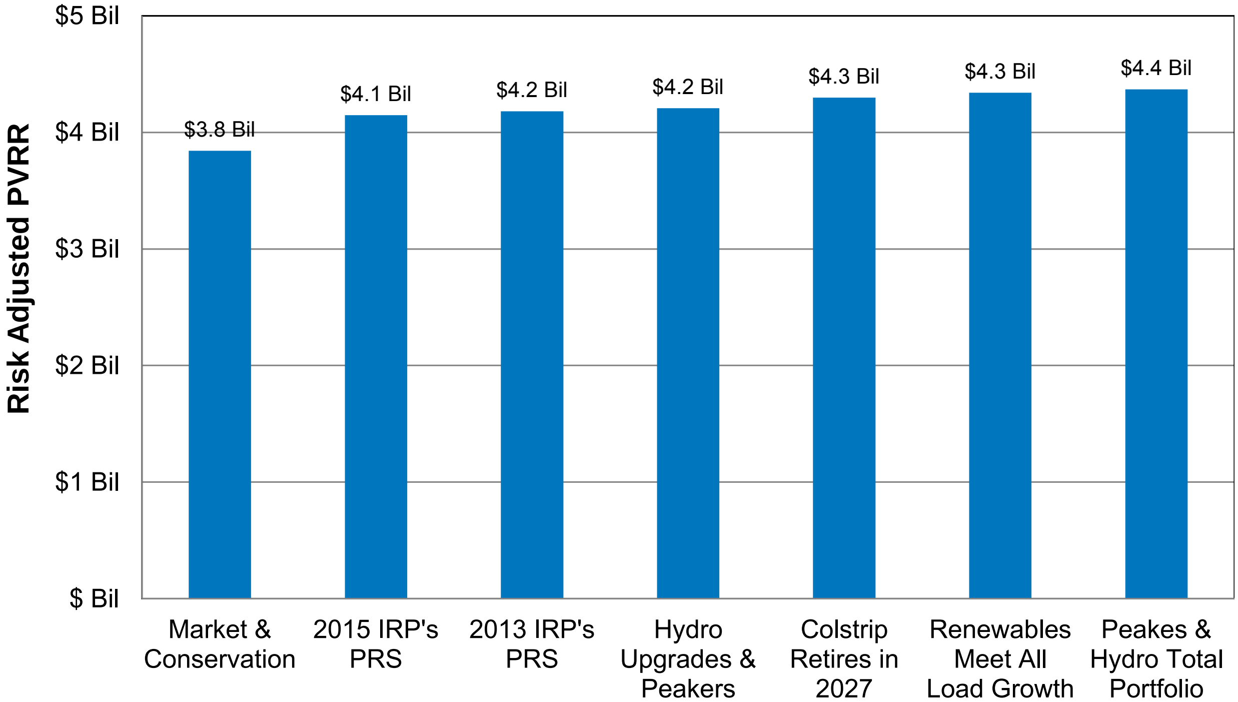
Peakers and Hydro Total Portfolio

A future with no coal or baseload natural gas resources is the premise of this scenario. It retires Avista's CCCTs and coal by 2027, replacing them with upgrades at hydroelectric facilities and the construction of natural gas-fired peaking plants. In 2027, when the retirements occur, the risk metric increases by $27 million; costs are $80 million higher compared to the PRS.

Risk-Adjusted PVRR

Avista believes efficient frontier analysis paired with robust analytics and data is a superior method to measure tradeoffs between average costs and risk. Chapter 11 details the risk-adjusted PVRR methodology used to analyze the efficient frontier. Risk-adjusted PVRR is helpful with measuring risk in handpicked portfolios that that do not fall on the efficient frontier, or where the efficient frontier is not part of the IRP process. Figure 12.11 shows the risk-adjusted PVRR analysis results for the other resource strategy scenarios in this section. The portfolio with the lowest cost is the Market and Conservation portfolio. This portfolio does not meet reliability objectives of the IRP, and is not an acceptable option. The next lowest cost portfolio is the PRS, followed by the 2013 PRS.

Figure 12.11: Risk Adjusted PVRR (2016- 2035)



Resource Tipping Point Analyses

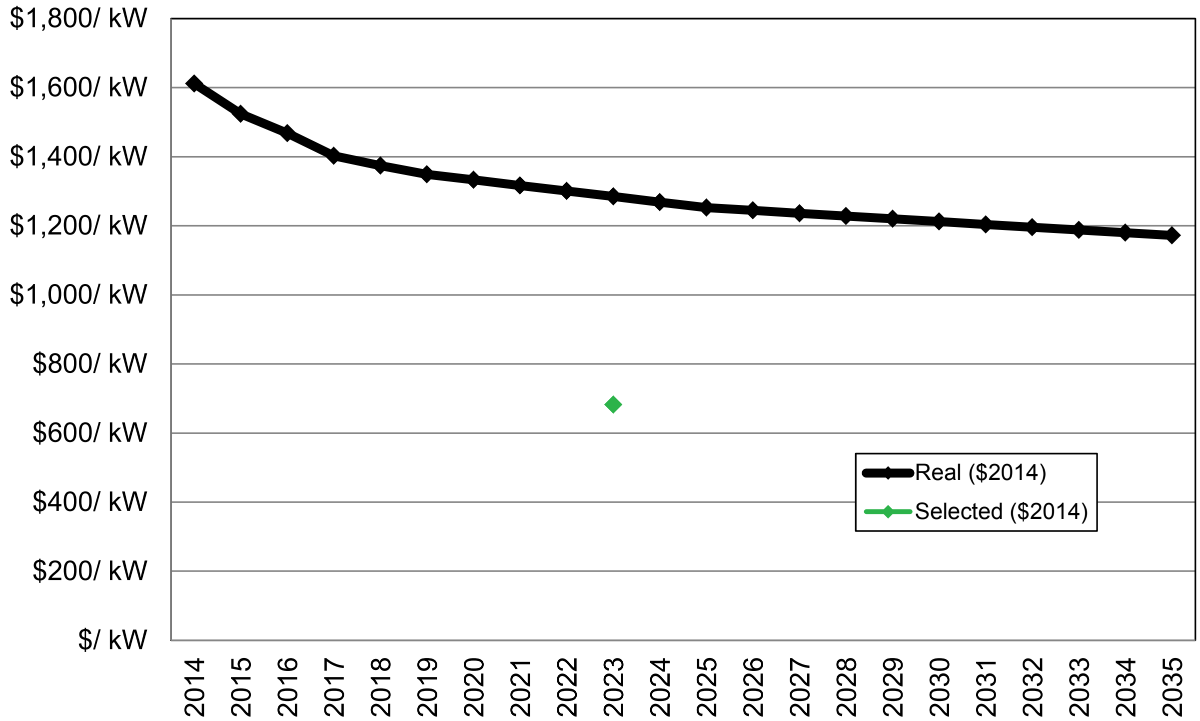
Recent Avista IRPs studied through tipping point analyses show how much capital costs needed to change before different resource selections occurred in the PRS. The 2013 IRP included solar, nuclear, and IGCC coal tipping point analyses. This IRP includes tipping point analyses for solar, energy storage, and demand response. As emerging technology costs generally do not follow typical inflation, tipping point analyses are important to understand at what point such technologies might affect the PRS.

Utility Scale Solar

The IRP assumes utility scale solar has a $1,500 per kW capital cost for fixed panel and $1,600 per kW (2014 dollars) for single-axis tracking panel facilities. Avista estimates solar costs will decline in real dollars by 27 percent over the 20-year planning horizon and the 10 percent federal investment tax credit is available after 2016. Solar does not provide winter on-peak capability. Therefore, the resource must be cost competitive with wholesale market commodity prices.

The analysis decreases single axis solar capital costs in PRiSM until the model selects the resource in the PRS. PRiSM selects solar in 2023 when its price falls 47 percent below current projections, to $682 per kW in 2014-year dollars. Figure 12.11 shows the solar cost curve and the point where solar becomes economic to Avista.

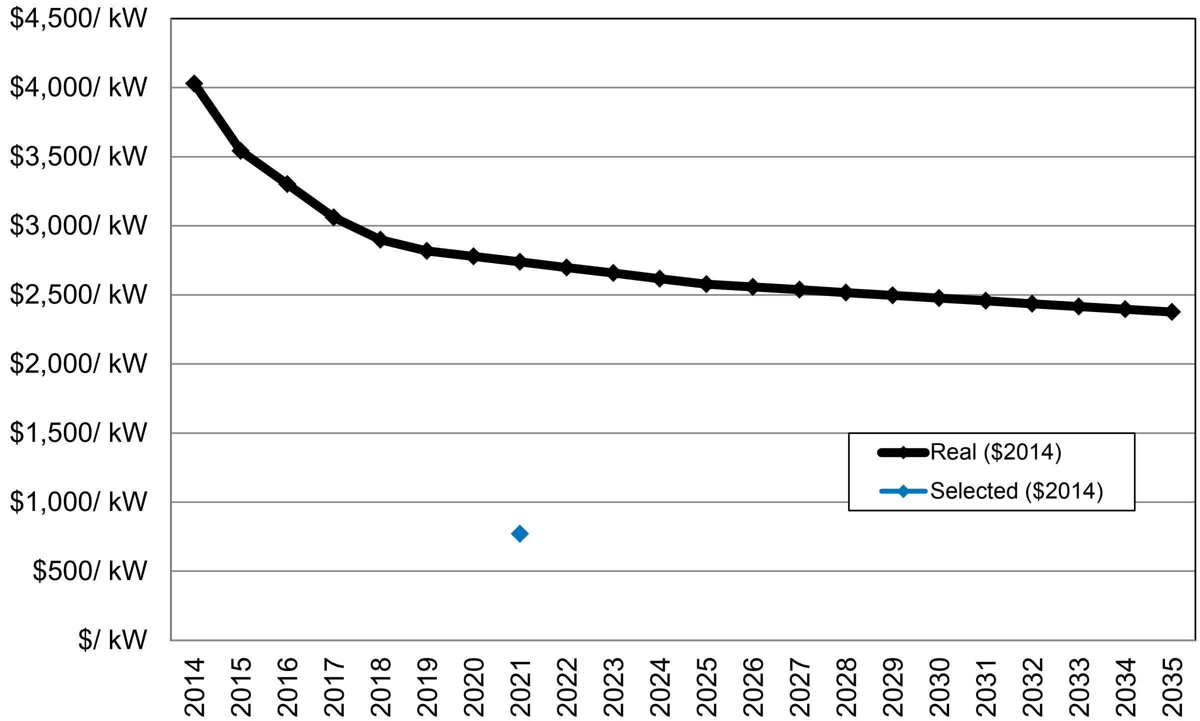
Figure 12.12: Utility Scale Solar Tipping Point Analysis (2014 $)



Utility Scale Energy Storage

Energy storage might become a commercial-scale resource for utilities and their customers in the future. As the amount of intermittent generation grows, many believe energy storage will help integrate these resources into the electricity grid. There are many types of energy storage technologies, but this study remains agnostic to the technology and only looks at how costs change, as long as each technology performs similarly. Similar to solar generation, energy storage costs should decline as the technology becomes more common. Unlike solar, energy storage can meet on peak needs, but it consumes significant amounts of energy in the form of losses in the process. The Expected Case assumes storage at $4,000 per kW in 2014. By the first capacity need in 2021, utility scale energy storage is expects to be $2,736 per kW (2014$) or $3,201/kW nominal. PRiSM first selects storage in 2021 with a price $770 per kW in 2014-year dollars, a 72 percent reduction in capital costs.

Figure 12.13: Utility Scale Storage Tipping Point Analysis (2014 $)



Demand Response

Demand response was part of the PRS in Avista's 2013 IRP. At that time, the costs were preliminary internal estimates; since then, Avista sponsored a study to determine the demand response costs and quantities available. The results of the study showed higher prices than the 2013 plan, and the higher costs meant demand response is not in this plan. To make demand response attractive, costs must fall to $117 per kW-year levelized between 2023 and 2035. This is a reduction of 46 percent.

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 2013 IRP Action Plan and provides the 2015 Action Plan.

Summary of the 2013 IRP Action Plan

The 2013 Action Plan included three categories: generation resource related analysis, energy efficiency, and transmission planning.

2013 Action Plan and Progress Report

Generation Resource Related Analysis

- Consider Spokane and Clark Fork River hydroelectric upgrade options in the next IRP as potential resource options to meet energy, capacity, and environmental requirements.
    - This IRP continues incorporating hydroelectric upgrades as resource options in the PRS and scenario analysis. Chapter 9 – Generation Resource Options provides details about the hydroelectric upgrades evaluated for this IRP.

- Continue to evaluate potential locations for natural gas-fired resources identified to be online by the end of 2019, including environmental reviews, transmission studies, and potential land acquisition.
    - The natural gas-fired peaker options included in this IRP assume both greenfield and brownfield sites in Northern Idaho. Avista is currently negotiating the purchase of property for a greenfield site. Information about this site will not be available publically until after the close of the potential transaction.

- Continue participation in regional IRP and regional planning processes, monitor regional surplus capacity, and continue to participate in regional capacity planning processes.
    - Avista continues to monitor and review other Northwest IRP processes.
    - The company continues to participate in regional processes including the development of the Seventh Regional Power Plan, PNUCC studies, and work by the Western Governors Association on energy issues.

- Commission a demand response potential and cost assessment of commercial and industrial customers per its inclusion in the middle of the PRS action plan.
    - Avista retained the services of AEG to study the amount and cost of different types of demand response programs available in the service

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territory. A discussion about the scope of this study occurred with the TAC during the first meeting on May 29, 2014, and the results presented at the fourth TAC meeting on February 24, 2015. Both of these presentations are available in Appendix A.
- The complete AEG demand response study is available in Appendix C.

- Continue monitoring state and federal climate change policies and report work from Avista's Climate Change Council.
  - Several developments concerning state and federal climate change policies have occurred since publication of the 2013 IRP. Most notably, the CPP at the federal level and Washington Governor Inslee's Executive Order 14-04 concerning climate change and subsequent proposed legislation concerning a cap and trade program at the state level.
  - Details about the CPP proposal and Governor Inslee's Executive Order are available in Chapter 7 – Policy Considerations. Studies concerning these areas are included in chapter 12 – Portfolio Scenarios. The original presentations made to the TAC about these issues are in Appendix A.

- Review and update the energy forecast methodology to better integrate economic, regional, and weather drivers of energy use.
  - Please refer to Chapter 3 – Economic and Load Forecast for a detailed account of changes made to the energy forecast methodology to better integrate economic, regional, and weather drivers of energy use. Avista's chief economist presented the forecasting methodology updates at the second TAC meeting on September 24, 2014. The presentation is available in Appendix A

- Evaluate the benefits of a short-term (up to 24-months) capacity position report.
  - Avista implemented a short-term capacity model in late 2013. The tool assists in closing short capacity positions. An updated version of this tool added long-term functionality to develop resource positions for this plan.

- Evaluate options to integrate intermittent resources.
  - Avista completed development of the Avista Decision Support System (ADSS); this tool can model the costs and benefits of intermittent resources. A presentation about the model and the results of the value of thermal resources assisting with ancillary services study occurred at the May 19, 2015, Technical Advisory Committee meeting. This presentation is located in Appendix A.

Energy Efficiency

- Work with NPCC, the UTC, and others to resolve adjusted market baseline issues for setting energy efficiency target setting and acquisition claims in Washington.
  - Avista hired AEG to conduct the biannual CPA. The study complied with accepted NPPC methodologies where possible by using measure savings

identified by the RTF or estimated by AEG. Where RTF unit energy savings are utilized those savings will be symmetrically applied when Avista claims the energy savings for the biennium. AEG is currently in the process of updating inputs for the CPA to include indexing the CPA to the forecast and other economic factors to address changing market conditions.

- Study and quantify transmission and distribution efficiency projects as they apply to EIA goals.
  - Avista continues to invest in transmission and distribution projects including efficiency upgrades. Chapter 8 contains details about completed and announced projects.

- Assess energy efficiency potential on Avista's generation facilities.
  - Avista completed an energy audit on owned generating facilities. Chapter 5 – Energy Efficiency and Demand Response summarizes the results and Appendix D includes the audit reports.

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.

2013 Action Plan and Progress Report – Supplemental

Avista submitted eight updated Action Items on January 27, 2014 in response to comments made at the January 9, 2014 hearing with the WUTC. This section highlights the work done in this IRP concerning the additional Action Items.

Generation Resource Related Analysis – Additional Updates

- Continue to evaluate scenarios related to Colstrip and how each scenario may impact power supply costs.
  - The 2015 IRP includes several Colstrip scenarios in Chapter 10 – Market Analysis and Chapter 12 – Portfolio Scenarios.

- Evaluate and explicitly document various options for quantifying carbon costs in the IRP.
    - Avista discussed different options concerning the quantification of the cost of carbon in the Expected Case and in scenarios for the 2015 IRP. The presentations made to the TAC are in Appendix A and the results of the analyses are in chapters 10, 11 and 12.
- Work with TAC to determine which carbon quantification method should be employed in the Expected Case of the 2015 IRP.
    - Avista's discussions with the TAC about different options for the quantification of the cost of carbon in the Expected Case for the 2015 IRP are in the presentations made to the TAC in Appendix A. The Expected Case analysis concerning carbon emissions are in chapters 10 and 11.
- Use Avista's new modeling capabilities to further evaluate the benefits of storage resources to its generation portfolio, including the impacts on ancillary services needs.
    - Chapter 9 – Generation Resource Options and chapter 12 – Portfolio Scenarios discuss the results of the evaluation of energy storage to Avista's generation portfolio.
- Revisit with the TAC the benefits and costs of the Company's 2013 IRP planning margin target to determine if a different level is warranted in the 2015 IRP.
    - Avista discussed the planning margin target with the TAC. The presentations concerning those discussions are in Appendix A. Chapter 6 – Long-Term Position has an extensive discussion about the choice of the appropriate planning margin for the 2015 IRP.
- Evaluate with the TAC the impacts of different points along the efficient frontier.
    - Avista discussed the evaluation of the impacts of choosing different points along the efficient frontier with the TAC. The presentations concerning those discussions are in Appendix A and details about the results in this IRP are located in chapters 11 – Preferred Resource Strategy and 12 – Portfolio Scenarios.

Energy Efficiency – Additional Updates

- Evaluate the impacts of targeting individual or groups of energy efficiency options within PRiSM instead of targeting quantities using avoided cost.
    - Avista developed and used a secondary methodology for identifying the amount of achievable conservation potential using the PRiSM model. Details about PRiSM co-optimization are in Chapter 5 – Energy Efficiency and Demand Response.
- Work with TAC to determine if 2015 IRP should continue the historical method of conservation quantification or if PRiSM should be used instead.
    - The TAC meetings included discussions about the PRiSM co-optimization methodology for identifying the amount of energy efficiency potential for the 2015 IRP. Appendix A contains the presentation materials.

2015 IRP Two Year Action Plan

Avista's 2015 PRS provides direction and guidance for the type, timing, and size of future resource acquisitions. The 2015 IRP Action Plan highlights the activities planned for possible inclusion in the 2017 IRP. Progress and results for the 2015 Action Plan items are reported to the TAC and the results will be included in Avista's 2017 IRP. The 2015 Action Plan includes input from Commission Staff, Avista's management team, and the TAC.

Generation Resource Related Analysis

- Analysis of the continued feasibility of the Northeast Combustion Turbine due to its age.
- Continue to review existing facilities for opportunities to upgrade capacity and efficiency.
- Increase the number of manufacturers and sizes of natural gas-fired turbines modeled for the PRS analysis.
- Evaluate the need for, and perform if needed, updated wind and solar integration studies.
- Participate and evaluate the potential to join a Northwest EIM.
- Monitor regional winter and summer resource adequacy.
- Participate in state level implementation of the CPP.

Energy Efficiency

- Continue to study and quantify transmission and distribution efficiency projects as they apply to EIA goals.
- Complete the assessment of energy efficiency potential on Avista's generation facilities.

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.

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Production Credits

Primary Avista 2015 Electric IRP Team

Individual	Title	Contribution
Clint Kalich	Manager of Resource Planning & Analysis	Project Manager
James Gall	Senior Power Supply Analyst	Analysis/Author
John Lyons	Senior Resource Policy Analyst	Research/Author/Editor
Grant Forsyth	Senior Forecaster & Economist	Load Forecast
Richard Maguire	System Planning Engineer	Transmission & Distribution

2015 Electric IRP Contributors

Name	Title
Thomas Dempsey	Manager, Generation Joint Projects
Leona Doege	DSM Program Manager
Tom Pardee	Natural Gas Planning Manager
Shane Pacini	Manager Network Engineering
Eric Scott	Natural Gas Resources Manager
Mike Dillon	DSM Planning and Analytics Manager
Jeff Schlect	Senior Manager of FERC Policy and Transmission Services
Dave Schwall	Senior Engineer
Darrell Soyars	Manager of Corporate Environmental Compliance
Xin Shane	Power Supply Analyst
Debbie Simock	Senior External Communications Manager
Jason Graham	Mechanical Engineer

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Avista Utilities Energy Resources Risk Policy

Pages 1 through 35

Generation / Production Capital Projects - Index of Business Case Justification Narratives

* The transfers to plant associated with this business case represent investment of four thousand dollars ($4,000) associated with trailing charges following the completion of the project, which is not unusual for this type of major project. Given that the project is complete, with the exception of these trailing charges, a business case justification narrative in the new format was not completed for this project.

1 GENERAL INFORMATION

Requested Spend Amount	$650,000.00
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Kristina Newhouse
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

The controls engineering team identified the need to address the risk of aging and failing control equipment. The Distributed Control Systems (DCS) and Programmable Logic Controllers (PLC) are aging and are introducing an increase in hardware and software failures. Discussions with the Director of GPSS, the Manager of Operations Analytics, the Electrical Engineering Manager, and the Protection Control Meter Technician Foreman concluded that a planned replacement program was needed.

The controls engineering manager will provide ongoing oversight and monthly tracking of the ongoing work within the program. The advisory group for ongoing vetting includes the Director of GPSS, the Controls Engineering Manager, the Protection Control Meter Technician Foreman, the Manager of Hydro Operations and Maintenance, and the Manager of Thermal Operations and Maintenance.

2 BUSINESS PROBLEM

The major driver for the Automation Replacement business case is Reliability. This program aligns with Avista's Safe & Reliable Infrastructure strategy. Upgrading our control systems within our generating facilities allows us to provide reliable energy. The Distributed Controls Systems (DCS) and Programmable Logic Controllers (PLC) are used to control and monitor Avista's generating units as well as each generating facility. For many facilities the operation of the generating units is performed remotely with the use of the DCSs and the PLCs. These aging devices use unsupported operating systems and modules that are no longer available. Failing software and hardware introduces risk and limits Avista's ability to operate generating facilities reliably.

The DCS and PLC work is needed now to reduce the higher risk of failure due to the aging equipment. The DCSs are no longer supported and spare modules are limited. The modules in service have a high risk of failure as they are over 20 years old. The computer drivers that are needed to communicate to the DCSs will not fit in new computers with Windows 10 operating systems. This creates a Cyber Security issue.

The software needed to view and modify the logic programs only runs on Windows 95. Avista has a very limited supply of Windows 95 laptops and they also continue to fail.

Replacing aging DCSs and PLCs will reduce unexpected plant outages that require emergency repair with like equipment. A planned approach will allow engineers and technicians to update logic programs more effectively and replace hardware with current standards.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Upgrade DCS and PLCs	$6.5M	1/2017	12/2025
Option 2 - Spare Parts Refurbishment / Do nothing	$100k/year	1/2017	NA
Option 3 - Software Upgrade	$2.5M	1/2017	12/2025

Option 1 is to replace all aging DCSs and PLCs proactively on a schedule that takes into account resources and outage availability. This option addresses aging hardware and software concerns as well as the cyber security vulnerabilities. Additional resources are required in order to maintain a schedule and consistently meet the objectives. Engineering will require a designer to develop new logic programs and designs for installations. The Protection Control Meter Shop will need a resource to install and commission the PLC programs.

Option 2 is to maintain existing Bailey DCSs and Modicon PLCs as we currently do today. This includes replacing modules as they fail with old spare parts or refurbish third party parts. Maintaining spare parts allows us to continue using existing infrastructure and logic programs but it does not resolve the long term issue which is aging equipment that will eventually no longer be available. The risk of outages at undesirable times to replace failed parts becomes more likely the longer the aging hardware is in service. This alternative also does not resolve the issue with computers that have unsupported operating systems and are considered a cyber-security risk.

Option 3 is to upgrade software on the DCSs and PLCs. This would include replacing each system's software that runs on Windows 95 and Windows XP with a separate software for each platform that runs on Windows 7. This will mitigate the software and cyber security issue but not the aging hardware issue. Outages would be required and the new logic programs would need to be rewritten and fully commissioned. Upgrading the Bailey software and the Modicon software do not align with our standard PLC platform that our engineers and technicians are trained on. This would introduce two new software applications. Efficiency to troubleshoot and resolve issues in a timely manner could be impacted.

Option 1 is the proposed option because it addresses the issues with aging hardware and software and it resolves the cyber security vulnerabilities. This option addresses the identified issues in a more controlled and planned manner where designs can be well thought out and plant outages for construction can be scheduled and ideally limited. The requested spend amount is based on Option 1 and takes into account resources needed to perform designs and installations. Is also takes into consideration feasibility of plant outages as projects are spread out over time.

See attached timeline titled *Timeline Estimate - Automation Replacement Business Case.pdf*

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Automation Replacement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Kristina Newhouse Date: 4/17/2017
Print Name: Kristina Newhouse
Title: Controls Engineering Manager
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Kristina Newhouse	04/05/2017	Andy Vickers	04/11/2017	Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$2,941,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

As generating plants are managed by the Generation, Production, and Substation support group, they provide energy and other services used by Power Supply. The steering committee for this project includes members from both groups: Director Power Supply; Director GPSS; Manager Hydro Ops and Manager Project Delivery. This team receives monthly project status updates but meets only in the event that a decision is needed.

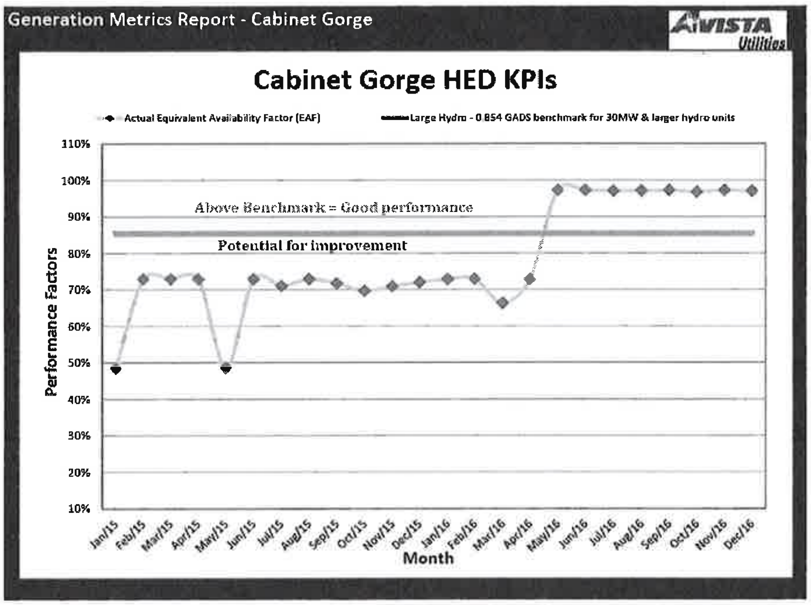
The project/stakeholder team meets on a more regular basis (at least monthly) to work on the project's scope and planning. The project/stakeholder team is comprised of representatives from the various engineering groups (electrical, controls, mechanical) and plant operations.

2 BUSINESS PROBLEM

This plant was designed for base load operation. Today, Cabinet Gorge is called on to not only provide load, but to quickly change output in response to the variability of wind generation, to adjust to changing customer loads, and other regulating services needed to balance the system load requirements and assure transmission reliability. The controls necessary to respond to these new demands include speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system. In addition to reducing unplanned outages, these systems will provide the ability for Avista to maximize these services from within the pool of its own assets on behalf of its customers rather than having to procure them from other providers.

As part of the designated "Regulating Hydro" class of assets. The key metric for these plants is their Equivalent Availability Factor or EAF.

Chart 1 – Equivalent Availability Factor



Equivalent Availability Factor (EAF) measures the amount of time that the Unit is able to produce electricity in a certain period, divided by the amount of time in that period. In this case, Cabinet Gorge has averaged below 85% EAF for the twelve month rolling period ending September 2016. The internal company target for this measure is 85%

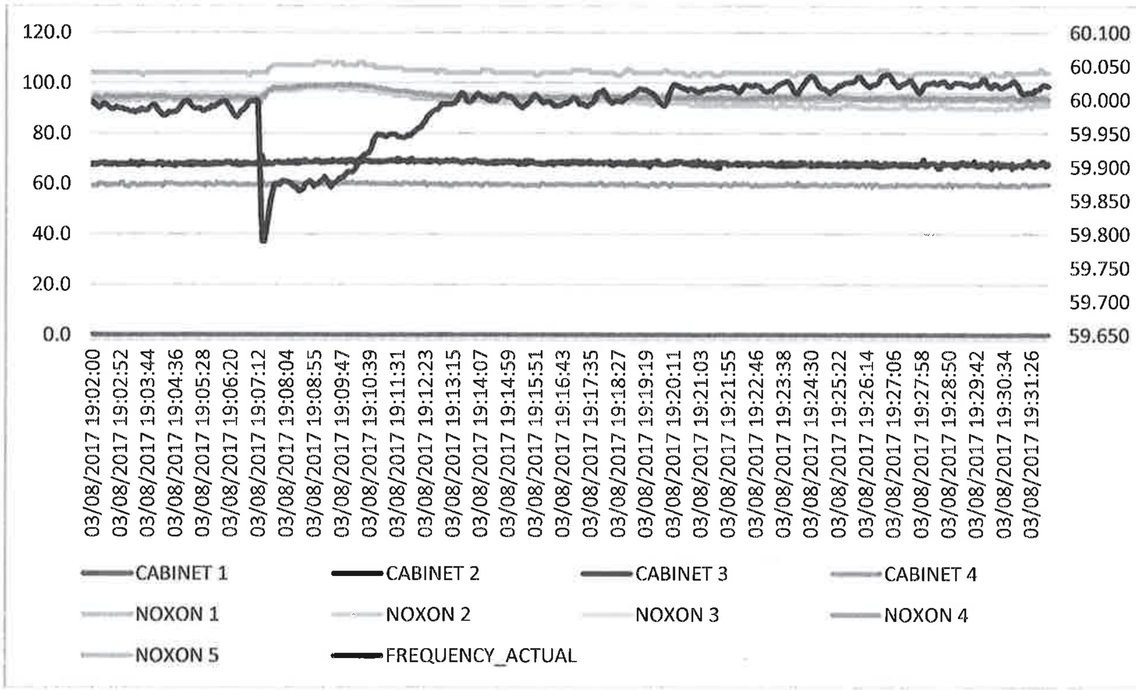
Some of the outages that cause the EAF to fall below the target include forced and maintenance outages associated with the control and protection systems described. Some recent events captured are attached to this document for reference[1].

An additional problem with the existing speed controls (governors) is the lack of response in a system frequency event. The graph below shows a significant frequency "excursion" (the dark blue line) and the response of the machines at Noxon Rapids HED to this excursion. Those are the lines that move upward on the top of the chart. The response of the Cabinet Units is shown in the lines in the

[1] See "18 Maximo Work Orders related to CG Controls."

middle of the chart should have bumped up like the Noxon, but instead were non-responsive.

Chart 2 – Lack of Frequency Response



A similar chart showing voltage control issues at Cabinet Gorge can be found in Appendix A.

There are several NERC Reliability standards against which the existing equipment performs at a sub-standard level. One of these standards involves frequency response as describe above. The related NERC standards are attached to this document along with some technical explanation if more information is needed.

Last, there have been several unit outages that were specifically taken to address problems associated with the existing control and protection equipment. This equipment is at the end of its intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability. More details of these events are can be found in the attached "18 Maximo Work Orders related to CG Controls" document.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing / Continue to Repair	$0	ongoing	ongoing
Replace Unit Control, Monitoring, and Protection Systems	$2,136,194	12/2015	12/2018
Mechanical, Controls, Electrical upgrades and Stator Re-wedging	$2,936,194	12/2015	12/2018

Avista's Safe & Reliable Infrastructure strategic initiative seeks to leverage technology and innovative products and services offered to existing and new customers. The work proposed for Cabinet Gorge will include equipment and component replacement geared at increasing reliability and unit control/monitoring. Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products.

To accomplish project objectives to improve unit response, operating flexibility, and reliability, the following components will be considered: governor and governor controls, generator excitation system and AVR, protective relays, and unit controls. The extended outage will provide an opportunity to address other issues including, insulating the generator housing roof, cooling water upgrade, unit flow meter and other items to improve overall reliability. The objective is to ensure system compatibility with current standards and improve system reliability.

Do Nothing / Continue to Repair: While the generator is capable of producing energy with existing systems, the present equipment does not provide the system support abilities needed to meet today's requirements (see graph above). This solution requires maintenance of old systems that are no longer supported by the original manufacturer and there is some question on parts availability. Additionally, trained personnel available to work on these older systems are becoming scarce and formal training is no longer available. For reasons of obsolescence, inadequate system performance, and increasing maintenance demands, this option is not the preferred option.

Replace Unit Control, Monitoring, and Protection Systems: In addition to addressing issues of obsolescence and increased likelihood of unplanned outages, replacement of these key systems addresses the performance needs to work with the new dynamics of the systems today. This includes integration of intermittent resources, reserves, frequency and voltage response, and the ability to adapt these controls and protection devices as the larger grid continues to evolve.

Installation of new controls and protection will also provide increased visibility into the systems allowing better remote monitoring and troubleshooting. New systems are also configured so compliance with NERC standards is much easier to achieve. As this option addresses the primary issues, this is considered the minimal preferred option.

Mechanical, Controls, Electrical upgrades and Stator Re-wedging: This option is the same as the *Replace Unit Controls, Monitoring, and Protection Systems* described above except this also includes addressing additional items related to the reliability of the generating unit. This may include replacing the insulation system on the generator rotor, re-wedging the generator stator, replacing and updating auxiliary system motor controls, and other items identified as necessary to both extend the life of the asset and improve the reliability. This option would allow for work that would be necessary in the near future to be performed now therefore avoiding future outages and improving the near and long term reliability of the units. While this is the preferred option, it cannot be selected at this time due to the gantry crane's limitations[2].

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -
2014		$ -	$ -	$ -
2015	$ 13,025	$ -	$ -	$ 30,000
2016	$ 316,000	$ -	$ -	$ 316,000
2017	$ 1,561,000	$ -	$ -	$ 1,561,000
2018	$ 532,000			$ 532,000
Total	$ 2,422,025	$ -	$ -	$ 2,439,000

[2] The gantry crane is needed to pick the rotor in order to perform the re-wedging work. The gantry crane is in a state of disrepair which is being addressed by a separate business case.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Automation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 20170417
Print Name: JACOB REIDT
Title: MGR CONTRACTS & PM
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	04/14/17	Steve Wenke	04/14/17	Initial version

Template Version: 03/07/2017

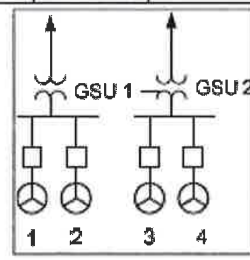
APPENDIX A

AVISTA Utilities

Page 1 of 1

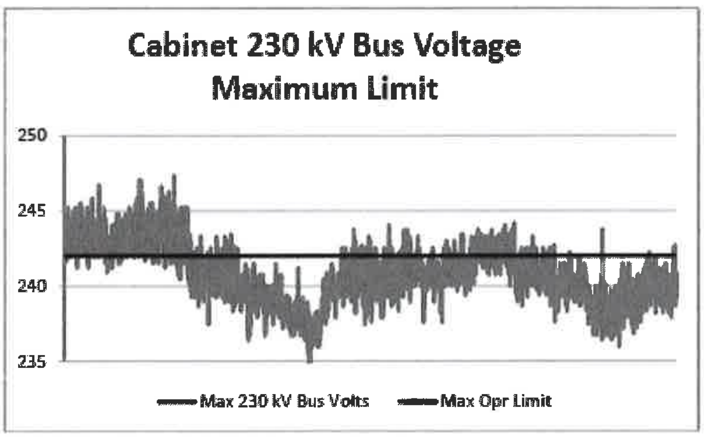
Project:	Cabinet Gorge HED - 230 kV Bus			Date:	03/29/17
Subject:	Bus Operating Voltage Analysis			By:	SEW
				Rev:	1
Proj No.:	09801545	Task:	535000	Ck'd:	

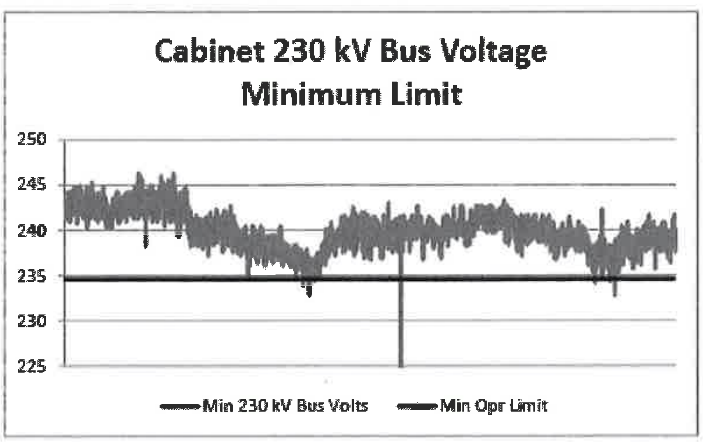
Generating Units Connected
Units 3 and 4



	from:	to:
Period Covered:	1/1/2016	12/31/2016

Number of Hours Voltage Exceeded Max Limits:	2275	hrs
Number of Hours Voltage Exceeded Min Limits:	32	hrs





Printed: 3/29/2017
Q:\G&P Files\Budget\Capital Budget\2017 Capital Budget\Cabinet Automation\Cabinet Voltage Schedule Report.xlsx

1 GENERAL INFORMATION

Requested Spend Amount	$4,275,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The advisory group for this project consists of members from the Generation Production and Substation support department including: Director – GPSS, Manager Hydro Operations & Maintenance and Manager Electrical Engineering. Steering committee members receive monthly project status update reports but are convened only in the event of a decision point.

The project/stakeholder team meets on a more regular basis (at least monthly) to work on the project's scope and planning. The project/stakeholder team is comprised of representatives from the various engineering groups (electrical, controls, mechanical) and operations.

2 BUSINESS PROBLEM

All generation facilities require Station Service to provide electric power to the plant. Station Service components include Transformers, Power Centers, Motor Control Centers, Load Centers, Emergency Load Centers and various breakers. Station Service is an elaborate system with multiple built-in redundancies designed to protect the plant's electrical operation.

The Cabinet Gorge Station Service equipment is original from 1951. The station service is a typical redundant Main-Tie-Main Service with some components added over time to accommodate changes to the Units and Balance of Plant needs. The Main-Tie-Main has multiple power sources which provides various switching alternative to bypass systems so that power is never lost. Station Service transformers no longer have the capacity to provide the needed load and could be subject to overload. The current Motor Control Centers (MCC) lack monitoring and indication. Replacement of these MCCs would create operational efficiencies by providing visibility into how station service is performing. The cables require evaluation due to age of insulation and the wet conditions they have been subject to over the years. The weight due to the number of cables in the tray cause concern for potential failure (see photo below). Due to control and other additions that have occurred over time, the existing 26 year old Emergency Generator no longer meets the load critical requirements for the plant. The only components of Station Service that have been recently replaced are the Intake Motor Control Center in 2010 and the single high voltage circuit breaker serving the plant in 2015.

If no action is taken, there is a risk of individual component failure that could force load shedding under certain operational scenarios. Should a catastrophic failure occur with switchgear and/or power cables, it could result in generator unit and/or plant wide forced outages potentially lasting as long as eight months. This is due to the long manufacturing lead time for some types of specialized equipment.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Alternative #1 - Replace identified components	$4,275,000	02/2017	02/2020
Alternate #2 - New external source	$4,765,381	02/2017	02/2020

Do Nothing: doing nothing is an option. However, if components do fail, due their age, replacements are not available. Addressing such failures in an emergency/ad hoc situation would increase the cost and extend the outage time. This option does not provide any capacity for future loads.

Alternative #1 would replace the following components:

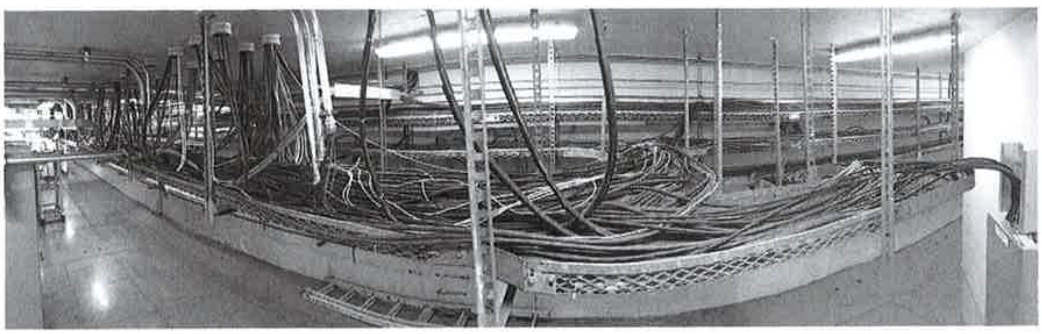
- Station Service Transformers 1 & 2
- Power Center A & B.
- Load Center 1, 2 & 4 would be replaced with Motor Control Centers with provisions for future capacity.
- Power cables
- Emergency Generator and controls to accommodate additional emergency load.
- Address arc flash rating and improve load flow analysis and coordination.
- Add metering to each Station Service Power Center and Emergency Generator.

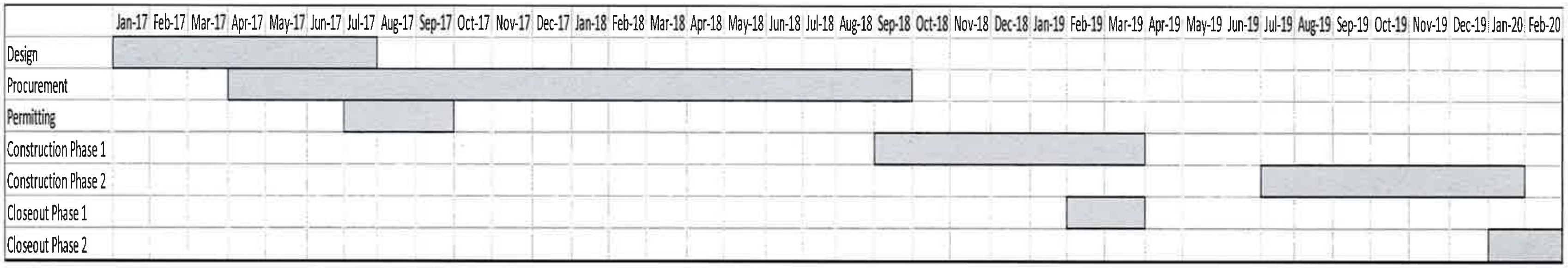
Alternative #2: Add a second emergency generator with appropriate transformation to add capacity in the event of a failed Station Service transformer. This alternative would require the addition of another Power Center that when tied in with the others would significantly increase the complexity of the system. The additional environmental risk in the form of containment and risk of release of the Emergency Generator fuel would need to be addressed. This alternative does not address the risks associated with the overloaded cable trays and Motor Control Centers. When the costs of procuring a new generator, power center and associated cables are factored in, alternative #2 exceeds the cost of alternative #1 by $490k.

The recommended approach is alternative #1. This project aligns with both Avista's Safe and Reliable Infrastructure goal through investment to achieve optimum life-cycle performance and operational safety and Reliable Resources goal to control a portfolio of resources that responsibly meet our long term energy needs. Additionally, alternative #1 provides an avenue for prudent procurement of capital components by engaging in the competitive bid process.

This project impacts our external customers by ensuring they have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders. Finally, unscheduled outages force hydro plants to spill water which represents a FERC license violation.

Overloaded Cable Trays





Alternative #1 Program Cost Flows

	Year (xxxx)	Capital Cost	O&M Cost	Other Costs	Approved
Previous		$ -	$ -	$ -	$ -
Year 1	2017	$ 500,000	$ -	$ -	$ 500,000
Year 2	2018	$ 2,100,000	$ -	$ -	$ 2,100,000
Year 3	2019	$ 1,475,000	$ -	$ -	$ 1,475,000
Year 4	2020	$ 200,000	$ -	$ -	$ 200,000
Year 5		$ -	$ -	$ -	$ -
Year 6		$ -	$ -	$ -	$ -
	Total	$ 4,275,000	$ -	$ -	$ 4,275,000

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Station Service Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 20170417
Print Name: Jacob Reidt
Title: Mgr Contract & Project Mgmt
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andy Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	4/14/17	Steve Wenke	4/14/17	Initial version

Template Version: 03/07/2017

Generation DC Supplied System Update

1 GENERAL INFORMATION

Requested Spend Amount	$1,315,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Glen Farmer
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Steering Committee for this project consists of members from the Generation Production and Substation Support Department including the Hydro Operations & Maintenance Manager, the Thermal Operations & Maintenance Manager, and the Generation Electrical Engineering Manager. Steering committee members receive project status updates when there are proposed changes to the program plan and are convened only in the event of a decision point.

The project stakeholder teams meet on a regular basis to work on the project scope and planning the project. The stakeholder teams are comprised of the representatives from Project Management, Engineering (Electrical, Controls, Mechanical & Civil), Operations, Maintenance and Compliance.

2 BUSINESS PROBLEM

This program supersedes a previous program that was identified for Battery Bank replacements only.

Traditionally, the Direct Current (DC) system, (aka Battery System) at each generation plant is used for protection and monitoring of the plant. All the protection relays, breaker control circuits and monitoring circuits are fed from this source. The source is assumed to always be on-line and able to supply the critical load for a predetermined length of time.

As technology has evolved, other standalone DC systems that were installed at different times. Typical plants now have standalone DC Systems for: general station, Uninterruptible Power Supplies (UPS), governors (electronic turbine speed controllers), communications and control systems. Each of these systems have a battery bank, battery charger, converters to supply different voltages, and distribution panels and circuits. As things have changed on the generating units or in the balance of plant systems, the DC load requirement has significantly increased and the time duration for the systems to supply this critical load has increased. Our current practice is to replace the battery banks per manufactures life cycle recommendations. This practice is not addressing the additional load added to the systems.

Some of the other issues we have had on the DC systems are the failing of battery cells due to inconsistent temperature and environmental control needed to maintain these present battery systems. The system life cycle is 20 years at its normal operating temperature of 77 degrees F. For temperatures fifteen degrees F over the normal operating temperature the life cycle is decreased by 50 percent. Component failure, utilization from multiple extended outages and manufactures quality are other problems we have experienced on these systems.

Finally there are compliance requirements from the North American Electric Reliability Corporation (NERC) for inspections, maintenance and testing of the battery banks to make sure they are in good working order and will perform when called upon. In order to perform these inspections and maintenance, and testing needs, it requires either unit or plant outages to comply with the requirements for multiple DC systems that are now present in our stations.

To address these multiple issues, a new Generation Plant DC Standard was developed by the engineering group. The new Generation Plant DC Standard System provides for layers of back up and redundancy to address current and future capacity needs as well as addressing maintenance and testing requirements. This Program will replace existing DC systems at Avista's owned and operated generation plants with a system that meets this new design standard. The Generation Plant DC Standard will be used as a guide for defining the base scope of the project.

The activity objectives is to order the plant replacements in a time line that will allow for stages of a project to happen and use our engineering and construction staffing. At each plant the DC System will be updated to meet the current Generation Plant DC System Standard and the following:

1. Comply with NERC requirements for inspection and testing.
2. Address battery room environmental conditions to optimize battery life.
3. Replace any legacy UPS systems with an invertor system.
4. Address auxiliary equipment based on life cycle.
5. Hydrogen sensing and fire alarm, eyewash station and lighting.
6. Wall separation of batteries and auxiliary equipment.
7. Install Programmable logic controller monitoring and new operating screens to provide visibility for operations and maintenance purposes.
8. Provide new distribution panels, disconnect switches, voltage conversion devices for communications equipment that operate at different voltages.
9. Establish current drawings, construction documents, I/O list, plans, schedules, manuals and as-builts.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
1. Do nothing – no action	$0		
2. Address the DC system standards as we are doing other system or unit upgrades.	$1,315,000/yr	01/2017	12/2030
3. Replace parts as they fail with the goal of making it like our standard over time.	$200,000/yr	01/2017	12/2037

4. Establish an independent DC system replacement program to bring plants to a standard as quickly as possible.	1,315,000/yr	1/20/2017	12/20/26

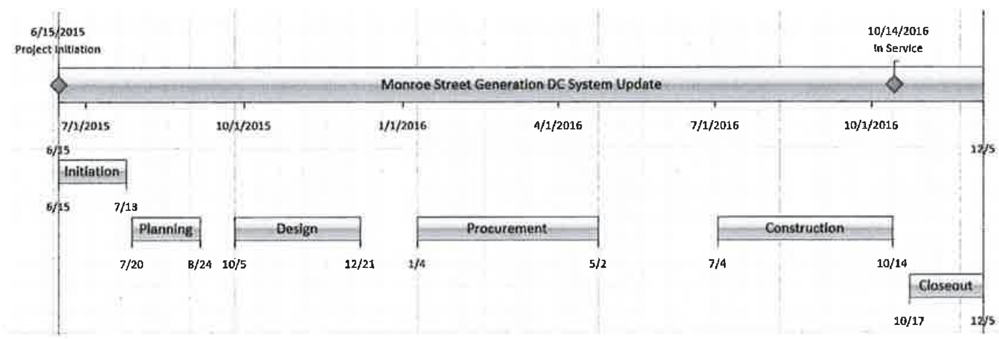
The "no action" alternative fails to address the issues associated with our current DC system. It allows for the scope of any maintenance work to balloon into a large project so if a problem arises there is not defined plan to address it. This can extend outages and leave the plant exposed for extended time frames for repairs and/or replacement parts. Upon failure we would temporarily restore the system back to working condition with the knowledge that we have to address it later. It places plant equipment at risk if a key element of the DC system were to fail, particularly the battery system. It also does not provide a means to perform required NERC testing and does not provide a means to plan for replacements costly. Also, critical AC loads served from the UPS have increased to the point where we can no longer get a UPS that is of necessary size. We would have to install more UPS systems, creating more maintenance work and increasing the NERC testing requirements. It also does not address any other issues that our design standard is intending to address. While it is a much higher life cycle cost and operationally impactful option.

Alternative 2 is to address the DC system as part of another capital project. In this case the scope of the DC system upgrade project is often a lower level effort and is subordinated to the primary project. The table below shows the current upgrade plans. While planning and scoping management can manage the concerns about making sure the DC Supplied Systems can be fully addressed, we do not have plans to work through all of the plants. This would leave the program incomplete.

Year	Plant	Comments	Cost
2014	Little Falls	DC system was built to our standard, example to follow.	$700k
2015	Nine Mile	Being addressed by Units 1&2 project	$650k
2015	GCC	Just battery bank replacement.	$250k
2016	Monroe Street	Doing design in 2015. Basis of design done. Install in 2016.	$700k
2017	Cabinet Gorge	Address existing problems with UPS system.	$700k
2018	Long Lake	Do design in conjunction with Unit Upgrades.	$700k
2019	Post Falls	Do design with plant rebuild.	$700k
2020	Kettle Falls	Steam Turbine & Gas Turbine DC System.	$700k

Alternative 3 to replace parts as they fail doesn't address any of the requirements for Standards, NERC inspection and testing, or the room itself. The parts fail at different time and we are subject to more outages. This also requires reaction to a critical system failure. Clearly replacing failed parts and components is a more costly item than performing planned work and without a planned effort, deployment of that new Generation Plant DC Standard would likely take decades. Replacing as components fail and gradually build out to our standard has the benefit of minimizing the costs of this program. However, it would be unpredictable would make labor planning impossible. This would also place the plant at a higher likelihood of forced outages and equipment damages if we wait for failure.

Alternative 4 is to construct new systems as part of a programmatic effort. This would allow for prioritized and planned series of projects to upgrade the existing station DC systems to the Generation Plant DC Standard. This will save time and expense over the life cycle of the station with the flexibility it provides to address future capacity and maintenance needs, and the ability to perform NERC required testing. It also has the benefit allowing a schedule to be established for both the engineering and the installation. Both of these resources are constrained and it would allow options of contracting or in-house consideration. A typical schedule to execute is given below. Each planned project would take approximately 16 to 18 months. Added complexity, cost, and time may be needed if extensive work is required to address the temperature and other environmental issues with the location of the new battery system.



Alternative 4 is the recommended approach. This program aligns with Avista's Safe and Reliable Infrastructure goal through investment to achieve optimum life-cycle performance and operational safety. In addition, it helps Avista meet its corporate compliance goals.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Generation DC Supplied System Update Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Glen A Farmer Date: 4/17/17
Print Name: GLEN FARMER
Title: GENERATION Electrical/Eng. MANAGER
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Dr Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Glen Farmer	4/7/2017	Steve Wenke	4/10/2017	Initial Version

Template Version: 03/07/2017

Solar Combustion Turbine Controls Upgrade

1 GENERAL INFORMATION

Requested Spend Amount	$ 660,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Greg Wiggins
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The plant uses a plant Budget Committee to evaluate, prioritize, and oversee project work at the station. This group consists of the Plant Manager, General Foreman, Plant Mechanic and a Plant Technician.

This project was first identified by plant technicians and plant control operators. Using past maintenance logs along with an assessment on the current status of the controls system a Project Request was submitted to the plant Budget Committee for a rebuild on the major components.

The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix. The review process focuses around Personnel and Public Safety, Environmental Concerns, Regulatory/Insurance Mandates, Ongoing Maintenance Issues, Decreasing Future Operating Costs, Increasing Efficiency, Managing Obsolete Equipment and Assessing the Risk of Equipment Failure.

The Maintenance Project Review scoring matrix revealed risks around Ongoing Maintenance, Decreasing Future Operating Costs, Obsolete Equipment and Equipment Failure.

The project request and detailed estimate was brought forward to Corporate Finance and Planning Analyst for further analysis. The project was then presented to the Thermal Operations and Maintenance Manager for plant budget approval.

Approved projects are assigned a project Lead from the plant staff depending on discipline. Large complex projects may be assigned Engineering staff and/or a Project Manager from Generation Production and Substation Support Department to oversee. Project status and updates are discussed at the weekly plant maintenance meetings.

2 BUSINESS PROBLEM

In 2002 Kettle Falls Generating Station added a second generating unit at the facility. The new unit was a skid mounted package combustion turbine Solar Taurus 70 and (HRSG) Heat Recovery Steam Generator. The 7MW natural gas fired turbine that can be operated in simple cycle or combined cycle modes depending on energy supply needs.

When operating in simple cycle mode the unit can be started quickly and ramped up to full load to help meet load demand within 30 minutes. When operating in combined cycle mode the hot exhaust from the gas turbine is converted to steam by directing the exhaust to a heat recovery steam generator (HRSG). The HRSG creates medium pressure steam which is used to preheat water for the wood fired boiler. This increases overall plant by a 3MW increase in power output on the wood fired steam turbine generator or through an efficiency improvement by a reduction in wood consumption if the wood fired unit is already operating at full load.

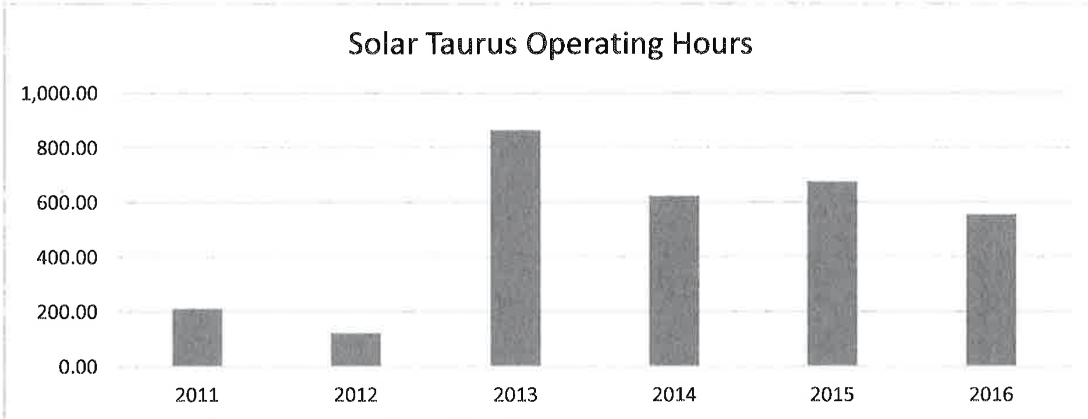
Operation of the combustion turbine, HRSG and fire protection for the combustion turbine is done remotely through the Solar TTX controls system. The controls platform is legacy equipment and the control program is no longer supported by Solar. Additionally, the installed version of the Allen Bradley control network has not been supported for a number of years. The Human Machine Interface (HMI) control system used by operations functions on Windows 2000 software, which is no longer available for replacement equipment. The desktop operating computer recently failed and the plant is now operating without a spare. With this failed HMI, the HRSG cannot be operated from the local control panel at the turbine enclosure. If the one remaining HMI were to fail, the combustion turbine would only be able to be operated in the simple cycle mode as there would not be any communication with the HRSG system.

The fire protection system is no longer supported from the vendor or Solar Turbines. The unit will not operate without the fire protection system in service due to insurance requirements. The unit posted its third and fourth highest forced outage rates in the past 15 years in 2013 and 2014. The higher forced outage rate was mostly attributed to components failing within the fire protection system. The trend to the higher forced outage rate from the fire protection system is expected to continue higher.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
1. Replace fire protection system	*$228,000*	*04 2018*	*06 2018*
2. Replace turbine control hardware	*$74,000*	*04 2018*	*06 2018*
3. Upgrade turbine controls	*$400,000*	*04 2018*	*06 2018*
4. Replace turbine controls and fire protection	*$660,000*	*04 2018*	*06 2018*

The Solar Taurus 70 combustion turbine has been in commercial operation for 15 years and has run an average of 700 hours annually the past four years. The times in which the unit operates is mostly during the high load demand times in the winter and summer.



With an increase in plant operations and increasing forced outage rate, mostly attributed to control devices failing on the fire protection system, five options were discussed.

Doing nothing will eventually put the combustion turbine in an unreliable and unsafe mode.

Option 1 to replace the fire protection system hardware and controls was identified as a safety and reliability issue. The unit will not operate without the fire protection system in service due to insurance requirements. While trying to work with the fire protection system manufacture we have constantly been re-directed back to Solar for support as the fire protection manufacture no longer supports the system. Solar has stated the fire protection system upgrade would not integrate into the outdated control system without significant programing. They estimate a cost savings of nearly $60,000 if the fire protection system is upgraded with the controls system. Total estimated costs $228,000

Option 2 to replace the HMI with new hardware and newer operating system. Solar has known documented cases of our outdated operating system failing on newer than Windows 2000 systems. Solar will not guarantee the controls system will operate if we lose our only computer and try to deploy the system on a newer computer. Total estimated cost $74,000

Option 3 to replace the turbine controls software and hardware. The Solar Taurus 70 utilizes proprietary turbine controls. We have reached out to a number of third party vendors and have been told they can do controls upgrades on Solar units just not the Taurus 70. The turbine controls interface with the fire protection system and although they are separate systems they are very much integrated with each other. Solar has estimated an additional $60,000 in programing the new controls system to our fire protection system. Total estimated cost $400,000

Option 4 is to install new software and hardware in conjunction with upgrading the fire protection system with the newest turbine controls. Transfer to plant is scheduled to be June 2018 with an estimated cost of $660,000. The project would be sole sourced to Solar and would have minimal impact on internal resources.

It is recommended we pursue Option 4. Completion of the project would bring unit reliability up while maintaining safe operations. Detailed scope of work and estimates from Solar attached.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Solar Combustion Turbine Controls Upgrade Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Greg Wiggins Date: 3/29/17
Print Name: Greg Wiggins
Title: Kettle Falls Plant Manager
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andy Vickers
Title: Director of GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Greg Wiggins	04/12/2017	Steve Wenke	04/12/2017	Initial version

Template Version: 03/07/2017

Kettle Falls Stator Rewind

1 GENERAL INFORMATION

Requested Spend Amount	$7,930,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Steering Committee is comprised of the Manager of Thermal Operations & Maintenance, the Kettle Falls Plant Manager, the Manager of Contracts & Project Management, and the Manager of Electrical Engineering for GPSS.

Monthly project status updates will be distributed via email indicating the status of the scope, schedule and budget of the project.

Steering committee meetings will be coordinated if decisions need to be made, due to significant changes to the scope, schedule or budget based on unforeseen circumstances and/or risk identification.

1.2 Customers & Stakeholders:

This projects impacts internally the Thermal Operations & Maintenance teams, including the crews at Kettle Falls, Electrical Engineering and Power Supply. By providing these stakeholders with a properly maintained generator we are providing them with reliability of the system.

This project impacts our external customers by ensuring they have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders.

2 BUSINESS PROBLEM

Major Driver:

The General Electric (GE) generator at the Kettle Falls Generating Station is 32 years old (as of 2015, the time of the original funding request) and near the end of its design life. Field inspections performed by GE and by Avista using industry standard megger tests have shown a decline in the winding insulation resistance. These condition reports are attached to this document for information.

A 2014 report prepared by the Asset Management group (attached to this document) demonstrated the prudency of replacing the winding before it fails in service. Failing in service would significantly extend the outage time and the cost to repair. Scheduled work to rewind the stator is a proactive measure to ensure uninterrupted and efficient operations.

Risks:

The consequences of a stator winding failure include lost generation, loss of renewable energy credits[1], long term interruption of fuel supply, possible collateral damage to the core and hydrogen cooling system with resulting safety hazards.

Driving Metrics:

During the outage of 2007, GE completed a "Generator Inspection Report" (attached) that found through the High Voltage DC Leakage test:

- Excessive leakage in the "right phase"
  - The leakage had doubled from the year 2000 test to the year 2007 test.
  - Industry analysis has found that when the current leakage more than doubles in a particular step, it is considered a warning sign that the leakage may be approaching the point of failure. The leakage jumped from 4 micro Amps (μA) to 22 μA between these test periods. (See following graph.)

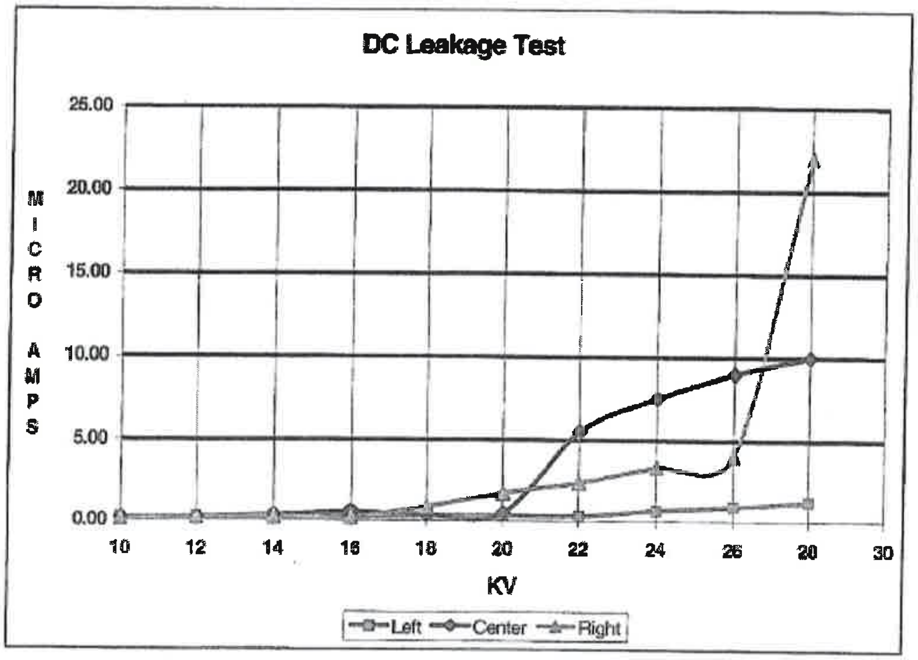
Figure 1

[1] We rely on the "green tags" produced from Kettle Falls to meet our I-937 "The Clean Energy Initiative" requirements. An unplanned outage due to a system failure could prolong the outage and put us at risk of having to incrementally procure additional Renewable Energy Credits (REC's) to meet our I-937 energy targets.

2007 GE Generator Megger Test Results

Armature Insulation DC Leakage Test

Date(m/d/y)	6/7/2007	Generator Serial No.	316X456	Prepared by	Jonathan Bellas
Customer	Avista K.Falls	Turbine Serial No.	197891		Greg Phillips
Manufacture	GE			FSR No.	94WC0587



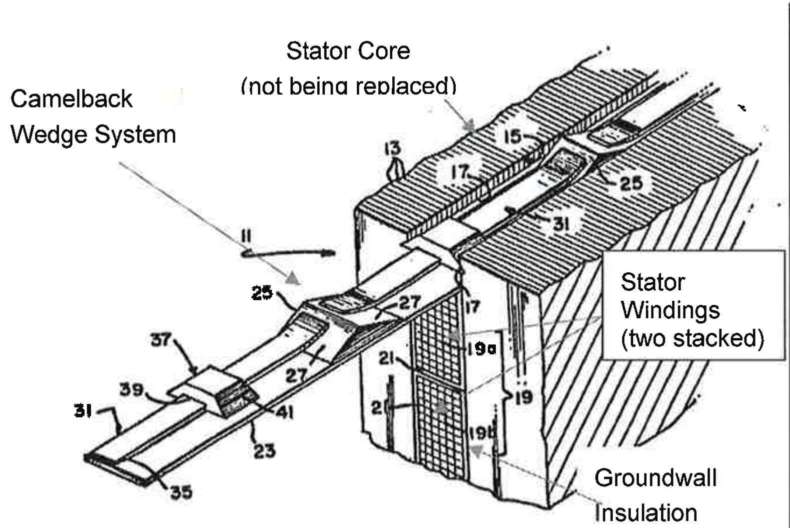
GE recommended that further DC High Potential (Hi-Pot) testing should not be conducted due to the risk of potential damage and no preparations made for the repairs necessary if the unit were to fail the test.

During the outage of 2015 an industry standard Polarization Index (PI) "Megger" test (attached) was conducted. The results shows the PI falling below 2.0 indicating problems of winding contamination, moisture ingress (leakage) and/or bulk insulation damage (conduction).

<u>Success Measures:</u>

Replacement of the existing stator windings and generator wedge system (sketch shown below) will improve the groundwall insulation resistance, reduce losses, and will allow the generator stator to operate at a cooler temperature. This will be validated by a successful completion of a Hi Pot test, and PI readings in excess of 6.0 for all three phases of the generator during commissioning. In addition, the operating temperatures of the unit as measured by the generator stator temperature monitors will show a lower average operating temperature.

Figure 2
Generator Coil Illustration show Winding and Camelback Wedge System
This is the general configuration for Kettle Falls.



GE has been commissioned to conduct the work and guarantees the MVA rating at a given power factor. This guarantee will be validated by a one-time test to be performed at an appropriate time after completion of the stator rewind and the unit is capable of full electrical production, but not less than 90 days after the completion of the stator rewind.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
1. Do nothing	$0		
2. Stator Rewind (recommended)	$7.93M	05 2015	06 2017
3. Generator Upgrade	Unidentified	05 2015	06 2017

Impacts:

The impacts are improved reliance on the system for the Kettle Falls operators and the Power Supply department. No additional O&M costs will be incurred as a result of this project nor will any O&M costs be reduced and/or eliminated.

Alternatives:

Option 1 to "do nothing" would increase our risk of an unplanned and potentially catastrophic outage. As described, test results conducted over time show a continuing decline in the winding condition and provides reasonable doubt about the ability of the present stator winding to continue to operate reliably for any duration of time.

Option 2 to perform a Stator Rewind has been demonstrated by a study from the Asset Management group to be a preferred option. This alternative minimizes outage time and removes the concerns of the failing stator insulation system and the potential for a catastrophic failure of the generator.

The Option 3 alternative to "upgrade" the generator to produce additional MWH output was determined to be unfeasible, based on a "Feasibility Analysis" (attached) conducted by contractor H2E in May 2015.

Risk Mitigation:

This project significantly reduces our risk of an unplanned, and possible catastrophic, outage by replacing the existing stator winding.

The risk of an unplanned outage increases the cost of the outage and the length of the outage due to the long lead time for stator bar order, construction and delivery. By proactively scheduling the rewind of the stator we are reducing the risk of an unplanned and potentially catastrophic outage. Firm costs and schedules can be achieved working with suppliers and installers to minimize the costs and time within acceptable windows.

Timeline:

- Design – 2015
- Request For Proposal (RFP), Contract Awarded, Planning – 2016
- Construction, In Service – 2017

Alignment with Strategic Initiatives:

Safe and reliable infrastructure. This project will improve the ability to sustain safe systems that deliver energy effectively and efficiently at all times. In addition, the Kettle Falls Generating Station, as a biomass fueled generating station, is one of the responsible resources in Avista's diverse generating portfolio for our customers. This project will allow for the safe and continued operation of this key resource.

Budget:

The rough +/- 50% estimate for the project began at $7.93M. The current estimate with +/- 10% accuracy is $5.43M.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Stator Rewind Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	20170417
Print Name:	Jacob Reidt		
Title:	Mgr. Contracts & Project Management		
Role:	Business Case Owner		

Signature:		Date:	4/19/2017
Print Name:	Andy Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Tara Moses	3/28/2017	Steve Wenke	4/6/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$56,100,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

This program is comprised of two layers of Steering Committee Oversight. One layer of oversight is at the program level and the other layer is at the project level.

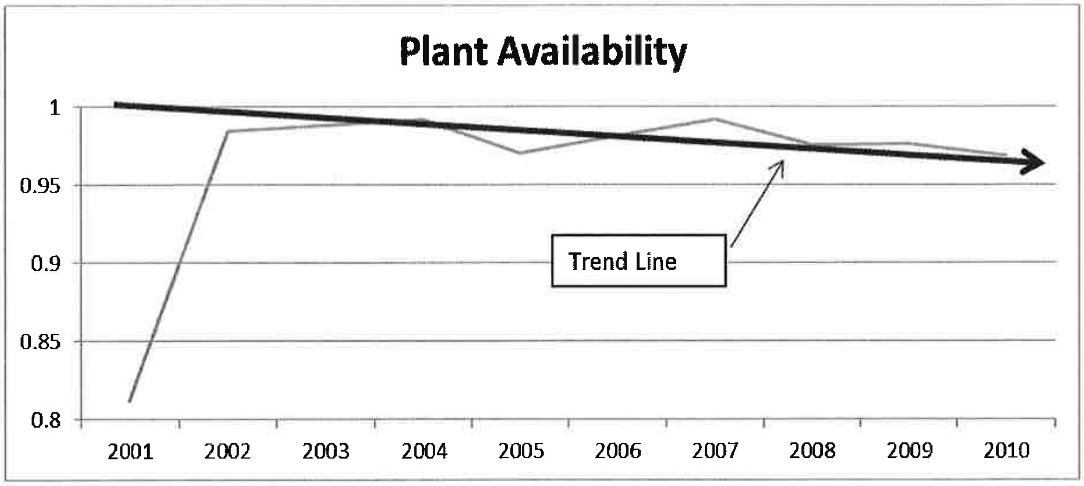
The Program Steering Committee is responsible for vetting and approving the objective, scope and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee on a semi-annual basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee. The Program Steering Committee is composed of the Director of GPSS and the Director of Power Supply. This committee meets semi-annually or as major events create a change order request.

The Project Steering Committee oversees the deliverables of the individual projects. Each member of the steering committee represents a major stakeholder in the project. The members are dependent on the respective project but will include representatives from hydro operations, central shops and engineering. The Project Steering Committee will approve and changes to the schedule, scope and budget of the individual project. They also are responsible for approving the necessary personnel for the completion of the project. This group is engaged on a quarterly basis.

2 BUSINESS PROBLEM

The existing Little Falls equipment ranges in age from 60 to more than 100 years old. Little Falls experienced an increase in forced outages over the past six years, increasing from about 20 hours in 2004 to several hundred hours in the past several years, due to equipment failures on a number of different pieces of equipment.

The major drivers for the Little Falls Plant Upgrade are available and reliability. See the graph below that illustrates the trend line for availability at Little Falls.



Once the business case is complete, a study of forced outages at the plant over a 5 year period could be taken and measured against the pre-construction outage numbers to determine if plant availability has increased and the business case objective met.

3 PROPOSAL AND RECOMMENDED SOLUTION

Below is a breakdown of the capital construction cost associated with each alternative and any ongoing maintenance costs associated with each alternative.

	Capital Cost	O&M Cost
Status Quo	$0	$150,000/yr +
Alternative 1	$5,000,000	$20,000/yr +
Alternative 2	$83,000,000	$0
Proposed Alternative	$56,100,000	$0

Summary of alternatives:

Status Quo: Forced outages and emergency repairs would continue to increase, reducing the reliability of the plant. Each time a generator goes down for an emergency repair, Avista is forced to replace this energy from the open market which leads to higher energy costs.

It is expected that the O&M costs would continue to climb as more failures occurred. This may also require personnel to be placed back in the plant to man the plant 24/7 in order to respond to failures. Again, increasing expenses for the project with no benefit in performance.

Alternative 1: Replace Switchgear and Exciter: This would replace the two items that are currently responsible for the majority of the forced outages, and then continue to use the remaining equipment.

This alternative is a temporary fix. One of the generators has a splice and is expected to fail in the next few years. If this generator fails before a new generator is ordered, this generator will be out of service for 2 years. The control system is a vintage system and is on the verge of a total failure and spare parts are not available (a few minor system failures occurred in the past 2 years). If a total system failure is encountered, it is expected the plant to be down for a year as the control system is designed, procured and installed.

Alternative 2: Replace all generating units with larger, vertical units capable of additional output. Avista's Power Supply group evaluated the present value of larger, vertical units at Little Falls. The increase in present value from larger units was $20M over a 30 year analysis. The capital construction cost increase from in-kind replacement to vertical units was $27M.

This present value calculation of benefit did not include risk. Installing new vertical units would require modification of the powerhouse foundation and presents serious construction risk. Due to the high construction costs, high risk, and low payoff NPV, this alternative was abandoned.

Alternative 3 and Proposed Alternative: Replace nearly all of the older and less reliable equipment with new equipment. This includes replacing two of the turbines, all four generators, all generator breakers, three of the four governors, all of the AVR's, removing all four generator exciters, replacing the unit controls, replacing the unit protection system, and replacing and modernizing the station service. All major equipment would be procured through a competitive bid process to help keep construction costs low. Equipment would also be purchased for all four units at once to help keep costs down.

Additional Justification for Proposed Alternative:

Because of the age and condition of all of the equipment at the plant, all of the equipment has been qualified as obsolete in accordance with the obsolescence criteria tool. The Asset Management tool has been applied to Little Falls and also supports this project. The Asset Management studies that have been done to date are still subject to further refinements, but the general conclusions support this project. There are many items in this 100 year old facility which do not meet modern design standards, codes, and expectations. This project will bring Little Falls to a place where it can be relied on for another 50 to 100 years. Finally, this project will need to be worked in coordination with our Indian Relations group as the Little Falls project is part of a settlement agreement with the Spokane Tribe.

Milestone Schedule:

January 2010	Program Begins
March 2012	Exciter & Generator Breaker Replacement Complete
January 2014	Warehouse Construction Complete
January 2014	Bridge Crane Overhaul Complete

February 2015	Station Service Replacement Complete
February 2016	Unit 3 Modernization Complete
April 2017	Unit 1 Modernization Complete
October 2017	Backup Generator Install Complete
May 2018	Unit 2 Modernization Complete
May 2019	Unit 4 Modernization Complete
October 2019	Headgate Replacement Complete

Yearly Transfer to Plant:

2013	$3,100,000
2014	$2,000,000
2015	$4,000,000
2016	$16,300,000
2017	$10,400,000
2018	$9,000,000
2019	$13,000,000
Total	$57,800,000

Strategic Alignment:

The Little Falls Plant Upgrade aligns with the Safe and Reliable Infrastructure company strategy. The program will address safety and reliability issues while looking for innovative, economical ways to deliver the projects.

Customers and Stakeholders:

Mike Magruder	Manager, Hydro Operations and Maintenance
Alexis Alexander	Manager, Spokane River Hydro Operations
Kevin Powell	Chief Operator, Long Lake and Little Falls HED

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Little Falls Plant Upgrade Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Jacob Reidt	Date:	20170417
Print Name:	Jacob Reidt		
Title:	Mgr Contract & Project Mgmt		
Role:	Business Case Owner		

Signature:		Date:	4/19/2017
Print Name:	Andy Vickers		
Title:	Dir Gen Prod Sub Support		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Brian Vandenburg	02/14/2017	Steve Wenke	04/10/2017	Initial Creation

Template Version: 02/24/2017

Exhibit No. 4
Case No. AVU-E-17-01
S. Kinney, Avista
Schedule 3, Page 37 of 108

1 GENERAL INFORMATION

Requested Spend Amount	$46,000,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

This program is comprised of two layers of Steering Committee Oversight. One layer of oversight is at the program level and the other layer is at the project level.

The Program Steering Committee is responsible for vetting and approving the objective, scope and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee on a semi-annual basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee. The Program Steering Committee is composed of the Director of GPSS, Director of Environmental Affairs, and the Director of Power Supply. This committee meets semi-annually or as major events create a change order request.

The Project Steering Committee oversees the deliverables of the individual projects. Each member of the steering committee represents a major stakeholder in the project. The members are dependent on the respective project but will include representatives from hydro operations, central shops and engineering. The Project Steering Committee will approve and changes to the schedule, scope and budget of the individual project. They also are responsible for approving the necessary personnel for the completion of the project. This group is engaged on a quarterly basis.

2 BUSINESS PROBLEM

The existing Long Lake equipment ranges in age from 20 to more than 100 years old. We have experienced an increase in forced outages at Long Lake over the past six years, almost zero in 2011 and increasing every year since then. This is caused by equipment failures on a number of different pieces of equipment. Specifically, the turbines are thrusting too much (a sign of significant wear), including a failure in 2015. The 1990 vintage control system is failing and only secondary markets can support this equipment.

The original generators consist of a stator frame, stator core, stator winding, and rotor field poles. They were originally rated at 12 MW's. In the late 1940's, the height of the dam was raised 16 feet which resulted in more operating head for the generating units. A forced air cooling system for the generators was added to the plant at that time to accommodate the increase in output from 12 to 17 MW's due to the increased head. In the 1960's, the stator windings on all of the units were replaced and the rating of the generators, along with the forced air system allowed for the units to operate at the higher 17 MW output.

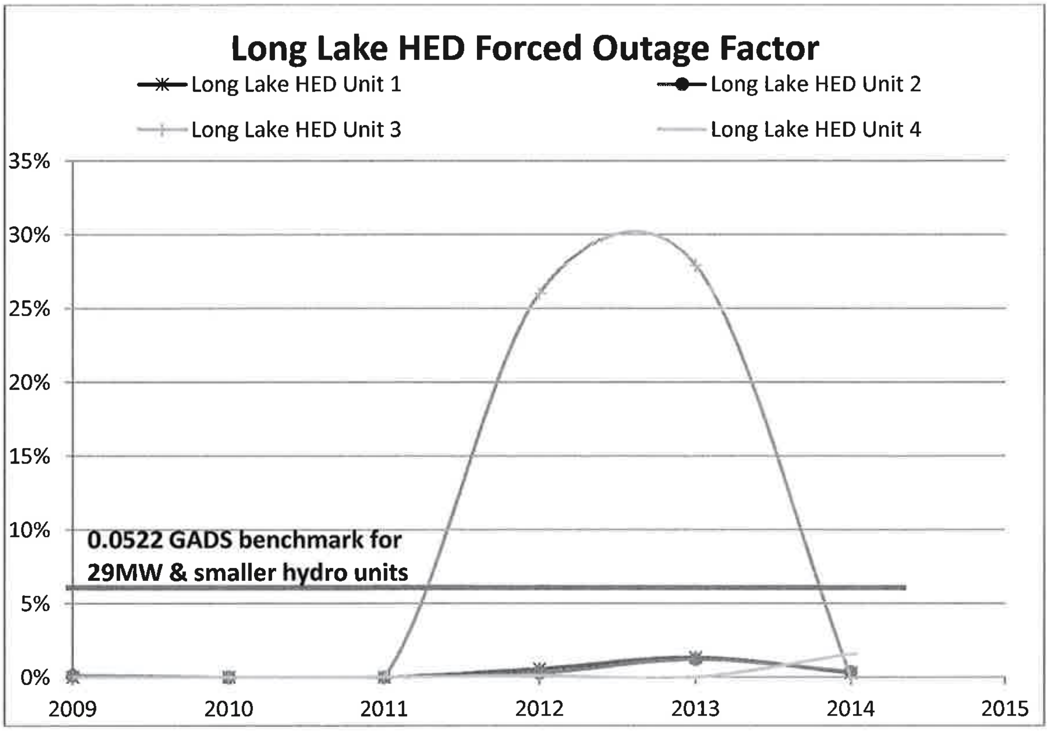
In the 1990's, the original turbine runners were replaced and upgraded. The improvement in turbine runner efficiency resulted in still another increase in unit output. Since the mid-1990's, the generators have been operating with a maximum output of 22 to 24 MW's. The generators are currently operated at their maximum temperature which stresses the life cycle of the already 50+-year-old winding.

Inspections of other components of the generator show the stator core is "wavy". The core lamination steel should be in straight. The "wave" pattern is a strong indication of higher than expected losses are occurring in the generator. Finally, maintenance reports have identified that the field poles on the rotor have shifted from their designed position very slightly over the years. While there can be several causes of this movement, it is speculated that it is due to the high operating temperatures of the generator. This highlights the first driver for the program, reliability.

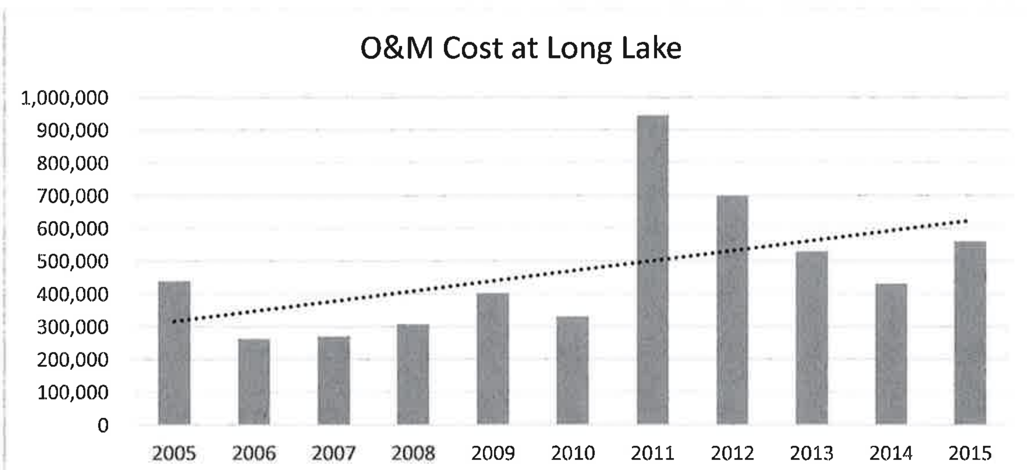
With the increase in generator output, the output of the generator step up transformer (GSU) has also increased to its rating. These GSU's are now running at the high 65C temperature which is a concern. As these GSU's are more than 30 years old and operating at the high end of their design temperature, these are now approaching their end of useful life and need to be replaced proactively rather than wait for a failure.

The other major driver for the program is safety. The switching procedure for moving station service from one generator to the other resulted in a lost time accident and a near miss in the past 5 years. In addition, the station service disconnects represent the greatest arc-flash potential in the company. This area is roped off and substantial safety equipment is required to operate the disconnects. This project will reconfigure this system to eliminate requiring personnel to perform this operation and avoid the arc-flash potential area.

Below is a graph of Forced Outage Factor for Long Lake HED from Avista's Asset Management Plan.



The below graph shows the O&M cost at Long Lake for the past 11 years. The trendline is increasing due to increasing repairs to aging equipment.



The above graph shows the O&M cost at Long Lake for the past 11 years. The trendline is increasing due to increasing repairs to aging equipment.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete
Do nothing	$0	N/A	
Recommended: Replace Units In-Kind	$46M	05/2018	06/2024
Alternative 1: Install four new 60MW vertical units	$173M	05/2018	04/2023
Alternative 2: Construct one unit powerhouse	$144M	05/2018	07/2021
Alternative 3: Construct two unit powerhouse	$276M	05/2018	11/2021
Alternative 4: Replace Units In-Kind	$46M	05/2018	06/2024

Do Nothing: Continue to run plant and repair as necessary

The Long Lake powerhouse would continue to operate as it has for the past 10 years. O&M costs would continue to rise. In an additional 10 years, if the trend continues, average O&M costs will rise from $285k in 2005 to $590 in 2014 and projected to be $900k in 2024. Due to the condition of the generators, it is likely that one of the generators or another piece of major equipment will fail and permanently disable equipment, increasing forced outage numbers.

Alternative 1: Install four new 30MW vertical units

This alternative would be to replace the four existing units in the powerhouse with four new 30 MW Kaplin units. Significant civil, electrical and mechanical work would be required, in addition to powerhouse access.

The increased yearly generation would be 114,000MWh. Using $30/MWh (extremely conservative number) the rough yearly benefit to Avista is $3.4M. The payoff period is greater than 30 years and therefore this alternative was abandoned.

Alternative 2: Construct one unit powerhouse

Instead of upgrading the current powerhouse, this alternative is to construct a new powerhouse with a single, 68MW next to the existing powerhouse, using the saddle dam (also referred to as the "arch dam") as an intake. This alternative would only use the old powerhouse during high flows, when flows exceeded the new unit's capacity. Additional funds would be required to upgrade, even at a minimum level, to address some of the failing components.

The increased yearly generation would be 170,000MWh. Again, using $30/MWh the rough yearly benefit to Avista is $5.1M. The payoff for this is 30 years. Again, since this cost does not include the additional work required in the plant and the cost of the risk associated with modifying the saddle dam, this alternative was abandoned.

Alternative 3: Construct two unit powerhouse

Another option to build a new powerhouse is to construct a new powerhouse with two, 76MW units next to the existing powerhouse. This alternative would also use the saddle dam as an intake. This alternative would only use the old powerhouse during extreme high flows, minimizing the need to perform any upgrades to the old plant.

The increased yearly generation would be 258,000MWh. Using $30MWh, the rough yearly benefit to Avista is $7.7M. The payoff would be greater than 30 years and therefore the alternative was abandoned.

Alternative 4 and Recommended Alternative: Replace units in-kind

This alternative would replace the existing major unit equipment (generator, field poles, governors, exciters, generator breakers) with new equipment.

Over the past 11 years, the average O&M spend at Long Lake was $470k, with the low being $262k and the high year being $944k. In addition, the O&M cost is trending upward. After the upgrade, the expected O&M cost is $200k/year, an average reduction of $270k/year.

Milestone Schedule:

May 2017	Project Kickoff
Sept 2018	Vertical Elevator Replacement Complete
Dec 2018	Bridge Crane Replacement Complete
Nov 2018	Sewer System Overhaul
Oct 2019	Access Road Overhaul
Dec 2019	Facility Upgrades
Oct 2019	Station Service Replacement
Apr 2021	Unit 1 Overhaul
Oct 2020	Air System Overhaul
Apr 2022	Unit 2 Overhaul
Apr 2023	Unit 3 Overhaul
Sep 2022	Sump System Overhaul
Sep 2022	Spillway Controls Replacement
Apr 2024	Unit 4 Modernization
Aug 2024	Control Room Remodel

Yearly Transfer to Plant:

2018	$3,750,000
2019	$5,500,000
2020	$250,000
2021	$21,100,000
2022	$8,050,000
2023	$7,600,000
2024	$8,300,000
Total	$45,750,000

Strategic Alignment:

The Long Lake Plant Upgrade aligns with the Safe and Reliable Infrastructure company strategy. The program will address safety and reliability issues while looking for innovative, economical ways to deliver the projects.

Customers and Stakeholders:

Manager, Hydro Operations and Maintenance

Manager, Spokane River Hydro Operations

Chief Operator, Long Lake and Little Falls HED

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Long Lake Plant Upgrade Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 20170417

Print Name: Jacob Reidt

Title: Mgr Contract & Project Mgmt

Role: Business Case Owner

Signature: Date: 4/19/2017

Print Name: Andy Vickers

Title: Dir Gen Prod Sub Support

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Brian Vandenburg	03/22/2017	Steve Wenke	04/10/2017	Initial Creation

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$ 119,044,755
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

The Steering Committee for the Nine Mile Rehabilitation governs the scope, schedule, and budget requests made by the stakeholder group when creating the deliverables and requirements for any sub projects. Each project may have the same, partial, or different members as selected by the Program Steering Committee. In general, Power Supply is represented by its Direction, Generation is represented by its Director, and Hydro Licensing & Environmental is represented by its Director.

2 BUSINESS PROBLEM

Both Units 1 and 2 at Nine Mile have mechanically failed, and are no longer able to generate electricity per our FERC license. These issues are a result of aging equipment, reservoir sedimentation, and damage to submerged equipment from the sediment. A FERC license amendment has been received to replace these units. In addition to the loss of generation for customers, failure to return the units to service may put the existing Spokane River License at risk. Requirements for Renewable Energy Credits (RECs) as part of Avista's Resource portfolio make this an opportune time increase REC availability, restore the powerhouse to full capacity and rehabilitate the surrounding facility.

3 PROPOSAL AND RECOMMENDED SOLUTION

Following the failure of Unit 1, Unit 2, and the subsequent turbine failure in Unit 4, an assessment of the Spokane River Plants was performed to establish the prudency of work within the Spokane River, prior to commencing work at Nine Mile. Many alternatives were generated, including:

- Rehabilitation or new construction of powerhouse at Post Falls
- Construction of new powerhouse at Upper Fall
- Construction of new powerhouse or spillway modification at Monroe Street
- Rehabilitation or new construction of powerhouse at Nine Mile
- Rehabilitation or new construction of powerhouse at Long Lake

A Likert Scale was developed by the team to evaluate each alterative against the following criteria.

- Alternative Development
- Financial
- Energy
- Regulatory Influences
- Operation and Maintenance
- Transmission System Impact
- Stakeholders
- Risk Identification
- Customer and Community Impact

Following the group evaluation of all proposed alternatives, the Project Team determined the only plant that warranted further evaluation at that time was Nine Mile due to the failed equipment, and ongoing operational and maintenance issues at the 100 year old facility. Focusing on the Nine Mile plant allowed for further evaluation of and reduced the number of fully evaluated alternatives to two:

Option	Cost	Start	Complete
Do nothing	$ 0		
Replace Units 1 and 2, rehabilitate Units 3 and 4, and modify the Sediment Bypass System	$ 70.8	2012	2019
A new five-unit 60 MW powerhouse located on the same footprint as the existing powerhouse, which would be demolished.	$ 192.7	2012	2027

Based on the criteria used by the Project Team to evaluate the Nine Mile Alternatives, Replacement of Units 1 and 2, rehabilitation of Units 3 and 4, and modify the Sediment Bypass System received the best score primarily due to project economics and likelihood of regulatory agency approval. Do nothing was eliminated due to the risk to our licenses.

The recommended alternative consists of a series of steps or phases, beginning in November 2012 and continuing through 2019. The key elements are:

Unit 1 and 2 Upgrade to Seagull Turbines:

- Units, including Turbines, Bulkheads, Generators, Switchgear
- Control and Protection Package including Excitation and Governors
- Powerhouse including Station Service, Ventilation, Intakes
- Substation and Communications work
- Site Work including cottages and warehouse
- Rehabilitate Intake Gates and Trash Rack

Unit 3 and 4 Overhaul:

- Overhaul including Runners, Thrust Bearings, Switchgear

- Control and Protection Package including Excitation and Governors
- Rehabilitate Intake Gates and Trash Rack

Plant Rehab

- Sediment Bypass and Debris Handling System
- Rehabilitation of the existing 100 year old Powerhouse Building

At completion, the powerhouse production capacity will be increased, units will experience less outages and reduced damaged from the sediment, and the failing control components will be replaced. Spending is expected to occur between 2012 and 2019.

2012	$10,758,313
2013	$10,794,355
2014	$26,059,264
2015	$26,890,094
2016	$13,628,862
2017	$11,800,000
2018	$8,575,000
2019	$7,322,000

A complete evaluation of this alternative's review, the analysis process, and the risks associated with the each is available in the attached material. Construction of a new powerhouse was eliminated due to lengthy permitting efforts, and increased risk surrounding unknown construction efforts.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Rehabilitation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jacob Reidt Date: 20170417

Print Name: Jacob Reidt

Title: Mgr Contract & Project Mgmt

Role: Business Case Owner

Signature: Andy Vickers Date: 4/19/2017

Print Name: Andy Vickers

Title: Dir Gen Prod Sub Support

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Nathan Fletcher	03/28/17	Steve Wenke	04/07/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$3,810,118
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The advisory group for this project consists of members from the Generation Production and Substation support department including the Director of GPSS, the Manager of Hydro Operations & Maintenance, and the Manager of Electrical Engineering for GPSS. Advisors are provided with monthly project status reports but, are only convened in the event of a necessary decision point.

The project/stakeholder team meets on a more regular basis (at least monthly) to work on the project's scope, schedule and budget. The project/stakeholder team is comprised of representatives from the various engineering groups (electrical, controls, mechanical) and operations.

2 BUSINESS PROBLEM

All generation facilities require Station Service to provide electric power to the plant. Station Service components include Motor Control Centers, Load Centers, Emergency Load Centers and various breakers. Station Service is an elaborate system with multiple built-in redundancies designed to protect the plant's electrical operation.

Upgrades and replacement of some of the Noxon 480V Station Service equipment have occurred since the late 1990s. However, some of the planned projects were never completed. In the fall of 2013, both an overcurrent coordination and load flow study[1] were completed for the Noxon 480V Station Service in response to an electrical overcurrent coordination issue. These studies found that a majority of the components require replacement due to electrical capacity and rating issues stemming from the added loads at the plant and the growth of the electric system in the 50 years of service.

[1] These studies can be made available upon request.

This project seeks to create a more reliable Station Service system in order to avoid forced outages and to modernize the electrical delivery system in the plant. Additionally, this effort will provide remote operation and monitoring capabilities, incorporate previously incomplete service expansions, support future system expansion, improve operator safety and ensure regulatory compliance.

If no action is taken, there is a risk of catastrophic switch gear failure and generator unit forced outages for up to a year. Additionally, forced load shedding under certain operational scenarios could be necessary.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Alternative 1 - Replace overrated and marginal function equipment and cables	$3,110,118	12/2013	10/2017
Alternative 2 Install Current Limiting Reactors	$800,000	12/2013	10/2017
Alternative 3 Install a new station service source from outside the plant (feeder extension)	$4,000,000	12/2013	10/2017

Do Nothing: doing nothing is an option. However, if components do fail, due their age, replacements are not available. Addressing such failures in an emergency/ad hoc situation would increase the cost and extend the outage time. This option does not provide any capacity for future loads.

<u>Alternative #1</u> would replace the following components:

- Station Service Transformers A & B
- 2000A Bus Ducts from Station Service transformers to Power Distribution Centers A & B
- Power Distribution Centers A & B
- Tie Bus that connects Power Distribution Centers A & B
- Main supply breakers to Motor Control Center 1, 2 and 3 and installing new monitoring and control of Motor Control Center starters
- Complete replacement of Motor Control Center 4
- Install a Programmable Logic Controller (PLC) to monitor and control Station Service from a central operating room.
- Integration of 1000 kVA Emergency Generator into Programmable Logic Controller monitoring and control

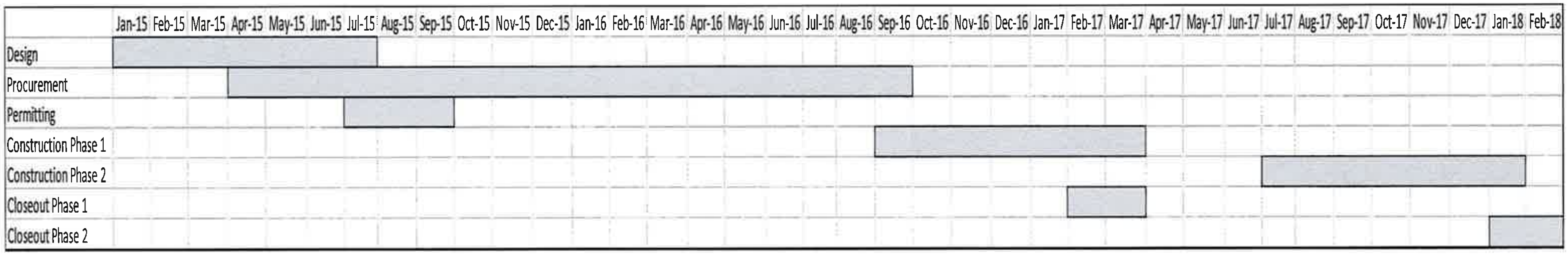
- Upgrade the existing Emergency Load Center to integrate with the balance of the station service system
- Address arc flash rating and improve load flow analysis and coordination Add metering to each Station Service Power Center and Emergency Generator.

Alternative #2 involves the installation of current limiting reactors on the transformers which would address the breaker sizing issues but, would not address the reliability and expansion components required by the project objectives. As such, it was dropped from consideration.

Alternative #3 would bring in an external source for Station Service which would achieve the reliability objective, but would not address the anticipated future load requirement on MCC4. As such, it was dropped from consideration.

The recommended approach is alternative #1. This project aligns with both Avista's Safe and Reliable Infrastructure goal through investment to achieve optimum life-cycle performance and operational safety and Reliable Resources goal to control a portfolio of resources that responsibly meet our long term energy needs. Additionally, alternative #1 provides an avenue for prudent procurement of capital components by engaging in the competitive bid process.

This project impacts our external customers by ensuring they have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders.



Alternative #1 Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ -	$ -	$ -	$ -
2015	$ 343,228	$ -	$ -	$ 343,228
2016	$ 2,177,106	$ -	$ -	$ 1,477,106
2017	$ 1,171,577	$ -	$ -	$ 1,171,577
2018	$ 118,208	$ -	$ -	$ 118,208
2019	$ -	$ -	$ -	$ -
2020+	$ -	$ -	$ -	$ -
Total	$ 3,810,118	$ -	$ -	$ 3,110,119

NOTE: $700k in additional funds requested in Q4 2016.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Noxon Station Service Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	20170417
Print Name:	Jacob Reidt		
Title:	Mgr Contract & Project Mgmt		
Role:	Business Case Owner		

Signature:		Date:	4/19/2017
Print Name:	Andy Vickers		
Title:	Director - GPSS		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	4/14/17	Steve Wenke	4/14/17	Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$500,000 per year
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Thomas Dempsey
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

This business case request is for Avista's Peaking Generation thermal plants, Boulder Park Generating Station, Northeast Combustion Turbine and Rathdrum Combustion Turbines. The purpose of this program is for these plants to keep their operating expenses as low as possible and to ensure start and operating reliability is achieved by providing funding for specific efforts to allow the plants to accomplish that objective.

Smaller and emergent projects planned for these facilities are identified and prioritized during monthly maintenance meetings, and approved by the Manager of Thermal Operations and Maintenance.

2 BUSINESS PROBLEM

Various projects for Boulder Park Generating Station, Northeast Combustion Turbine and Rathdrum Combustion Turbines are necessary to ensure continued safe, low cost, reliable and compliant electrical generation for Avista's electric customers. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. At times these plants are needed by Avista's Power Supply and System Operations group to start and operate in an emergency situation, where the electrical output is needed in a short amount of time. There have been times that have been identified by plant operations and tracked by Avista's asset management metrics reports, where start reliability and forced outages occur on a higher than acceptable occurrance. Some projects under this business case are completed to improve the start reliability of these facilities. As this program proceeds, it is expected that forced outage rates and forced derates of these facilities will decrease to a level one standard deviation less than the current average resulting in more economic benefits for the project.

The projects that are opened under this business case are not known in advance. Most of the individual projects are small in nature and are required due to regulatory or environmental requirements, emergent safety items, or for continued reliable operation. Examples of recent expenditures under this program include:

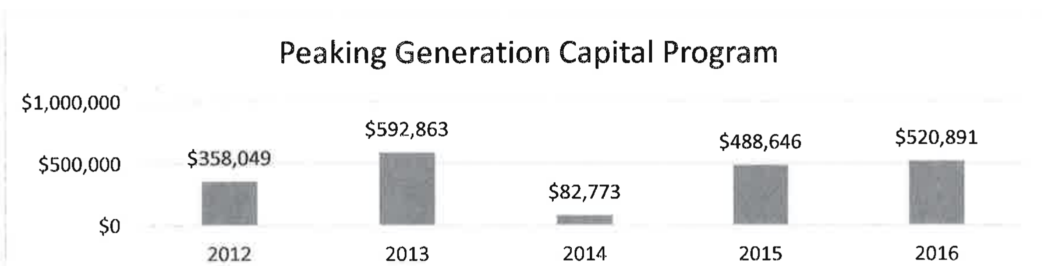
- Boulder Park – Emission Programmable Logic Controller replacement – allows remote monitoring of air emission to remain compliant with permit. (regulatory or environmental)
- Boulder Park – Replace the start air compressors – air used for start up of the engines (reliable operation)
- Northeast Combustion Turbine – Replace start system air compressors – air used for start up of the turbine (reliable operation)
- Northeast Combustion Turbine – Add sewage holding tank – replace antiquated sewage management system (regulatory or environmental)
- Rathdrum Combustion Turbines – Replace the Carbon Dioxide fire extinguishing system controllers – system utilized in case of an emergency in the combustion turbine area (safety)
- Rathdrum Combustion Turbines – Continuous Emission Monitoring System replacement – used to monitor and record air emission when the combustion turbines are on line (regulatory or environmental)

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
As proposed	$500,000	Ongoing, required for operation		
Unfunded Program				

This program is necessary to sustain or improve the existing operating costs for Boulder Park Generating Station, Northeast Combustion Turbine and Rathdrum Combustion Turbines. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. The Peaking Generation Business Case is reassessed for adjustments on a 5 year cycle.

A 5 year historical graph of expenditures is attached to help assess future capital funding for the Peaking Generation plants. This spending pattern indicates the diligence that is applied to capital request as managed by the Peaking Generation management team. As mentioned above, there is opportunity to adjust this amount every five years.



4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Peaking Generation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Thomas C. Dempsey Date: 04/21/2017
Print Name: Thomas Dempsey
Title:
Role: Business Case Owner

Signature: Andy Vickers Date: 4/19/2017
Print Name: Andy Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Mecham	04/07/2017	Jacob Reidt	04/17/2017	Initial version

Template Version: 02/24/2017

Post Falls HED Redevelopment Program

1 GENERAL INFORMATION

Requested Spend Amount	$58,100,000- +/- 30%
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Post Falls HED Redevelopment program is monitored by a steering committee consisting of the Director of Environmental Affairs, the Director of Generation Production and Substation Support, the Director of Power Supply, and the Vice President of Energy Resources. This group is provided quarterly updates on project cost and schedule status. This group is also included in decisions on significant changes in scope.

The program is actively overseen by a stakeholder group that consists of representatives from Power Supply, Ass6et Management, Licensing and Environmental, and Generation & Production. This group meets at least monthly to receive progress reports, cost and schedule updates, and is presented with project risks and proposed mitigations to those risks. This group is also included on decisions on significant and modest changes in scope.

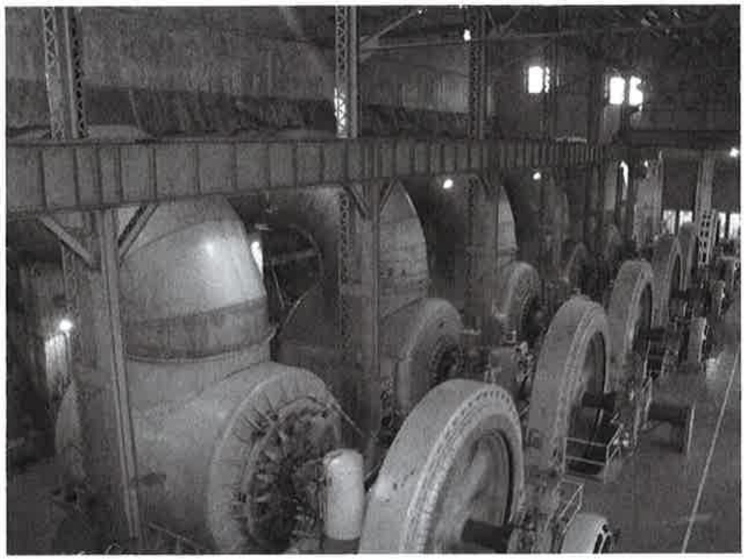
The project is led by a Project Manager. The Project Manager (PM) has a team of subject matter experts (SME) in a variety of areas to help them execute the project plan. Under the management of the PM and SME's, weekly and daily decisions are made to determine the most prudent course of action and to actively monitor progress of the project.

This PM is also assisted by an Advisory Group consisting of GPSS Engineering Managers, Maintenance Managers, and other administrative GPSS support personnel.

2 BUSINESS PROBLEM

The Post Falls HED started operation in 1906 and has been operating continually since that time. The generators, turbines, and governors (turbine speed controller) are original equipment and are still in service. The brick powerhouse with riveted steel superstructure is has not changed since the plant was constructed. Over time, it has been re-roofed and the intake area has had some major work, but the appearance of the project remains largely the same as when it started operation more than 110 years ago.

Photo showing interior of present Powerhouse



While the plant is still producing, the generating equipment, protective relaying, unit controls, and many other components of the operating equipment are mechanically and functionally failing. The turbines are estimated to be 50% efficient contrasted to modern turbines which can exceed 90% efficient. The existing governors have had patchwork repairs due to lack of replacement parts and while they do allow for unit control, they are ineffective in their response to system disturbances. Generator voltage controllers, protective relays, and unit monitoring systems all have a similar story of marginal functionality.

The units are exhibiting signs of failure. Attached are recent reports for Unit 1, Unit 4 and Unit 6 that describe some of the problems encountered during last maintenance on Unit 1, and the current operational directive to de-rate Unit 4 and Unit 6 due to their mechanical condition.

Because of the age of the plant, it presents some safety issues that have evolved over time. The access port for crews to access and maintain the turbine runners is too small to allow for any type of backboard or stretcher to exit the turbine area in the event a worker would be injured. The castings used to create the turbine water case do not allow the opening to be increased without risk of permanently damaging the water case and leaking. For this reason, crews can no longer access the turbines to maintain the runners. This has been the case for nearly a decade.

Photo showing safety issue due to restricted access to turbine area
The opening will not allow a backboard or stretcher to the area for emergency evacuation

Additionally, control modifications done in the late 1940's place the primary generator breakers inside the control room. This presents and unacceptable arc flash hazard to operating and maintenance personnel. While either the operation desk or the switchgear can be relocated to address this issue, this work would cost several million dollars and would not address some of the other issues associated with the plant.

Photo showing proximity of switchgear to Operators Station
(Operator Chair is indicated by arrow)

Finally, the Post Falls project has a number of critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements. The Post Falls dam must provide minimum flows during summer months to support fishery habitat downstream. It is also subject to restrictions on how fast the flows through the project can change in order to meet downstream flow requirements. The present plant controls marginally provide the precision needed for this control.

To address water quality issues during high river flow seasons, unit and spillway controls must follow certain procedures to minimize Total Dissolved Gas creation in the river system. In addition, flows through the project provide water at the recreational site known as Trailer Park Wave. Upstream of the dam is the Spokane River and Lake Coeur d'Alene which are significant regional recreational resources that rely on the water control at Post Falls to maintain the water levels during the summer months.

Finally, there is a City Park and boat launch that is integral with the immediate upstream reservoir. Safety requirements have been implemented that require all spillgates at the project be closed before boaters are allowed to use the boat launch and recreate in the reservoir immediately upstream. Flows that would normally go through the plant need to be passed through the spillgates instead because of the unreliability of the generating units, extended maintenance outages, unit de-rates, and forced outages. This requires the boat launch opening to be delayed or in some cases closed on an emergency basis until flows subside or the generating unit can be returned to service.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
1. Remove the existing six generating units and equipment and replace them with new units, control and monitoring equipment, and balance of plant equipment. This is to be done within the present building structure.	$58.1M	2017 and going forward		

The estimates in the above table for capital costs should be construed to be +/- 30% for each of the options.

In an effort to determine a prudent course of action to address the Post Falls project, a significant Assessment Study was performed. This assessment considered a number of different options that might address the issues described above. The report of this assessment is attached to this document. This assessment concluded that the most prudent course of action was to redevelop the site by keeping the existing powerhouse and location.

Subsequently, a Feasibility Study was undertaken to evaluate different alternatives that could be done to redevelop the existing powerhouse. These include replacement of the present units with some new parts and pieces and modernizing the plant to the extent possible. It also considered a full redevelopment which would effective remove all of the existing equipment and replace it with new – still retaining the existing powerhouse structure. This Feasibility Study recommended that the project be redeveloped by shutting down the plant, removing the old equipment, and replacing it with new. This report on the Feasibility Workshop is attached to this document.

Finally, a team of Avista made up of personnel from the GPSS department, Licensing and Environmental, Power Supply, Asset Management, and Procurement convened a series of meetings to analyze the results of the Feasibility Study recommendation and explore its conclusions and assessed how the recommended solution addressed the issues such as equipment reliability, personnel safety, and risks associated with potential disruption of fishery and recreational needs. Significant financial analysis was performed by the Power Supply group in support of this effort to ascertain the most attractive alternative that addressed the issues. This was summarized in a final presentation in April of 2016. This was presented to the steering committee identified above. That presentation is attached to this document.

The final conclusion of all of this effort recommended that a full replacement of the existing units and other powerhouse equipment be replaced in their entirety with new equipment. It was estimated that the project would cost $58,100,000 (+/- 30%). It was also demonstrated that due to a shorter construction period, it is more beneficial to shut down the plant during this reconstruction. It was estimated the entire project would take five years once it was initiated. This decision was recorded in a summary message to a group of stakeholders and is attached to this document.

This work will replace the existing six 110 year old generating units with six new variable blade turbine generator units. Work will also include needed ancillary replacements and powerhouse remediation to attain a 50 year lived project. In addition, the efficiency of the new generating equipment will result in an improvement in output capacity and energy. This project will result in an estimated 40% increase in capacity and 15% increase in energy and reduce future major maintenance costs.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Post Falls HED Redevelopment Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: _[signature]_ Date: 20170419

Print Name: Jacob Reidt

Title: MGR CONTRACTS & PM

Role: Business Case Owner

Signature: _[signature]_ Date: 4/19/2017

Print Name: Andy Vickers

Title: Director, GPSS

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Steve Wenke	04/19/2017	Jacob Reidt	04/19/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$ 700,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Greg Wiggins
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The plant uses a plant Budget Committee to evaluate, prioritize, and oversee project work at the station. This group consists of the Plant Manager, General Foreman, Plant Mechanic and a Plant Technician.

This project was first identified by plant mechanics and equipment operators. Using past maintenance logs along with an assessment on the current status of the machine a Project Request was submitted to the plant Budget Committee for a rebuild on the major components.

The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix. The review process focuses around Personnel and Public Safety, Environmental Concerns, Regulatory/Insurance Mandates, Ongoing Maintenance Issues, Decreasing Future Operating Costs, Increasing Efficiency, Managing Obsolete Equipment and Assessing the Risk of Equipment Failure.

The Maintenance Project Review scoring matrix revealed risks around Safety, Ongoing Maintenance, Decreasing Future Operating Costs and Equipment Failure.

The project request and detailed estimate was brought forward to Corporate Finance and Planning Analyst for further analysis. The project was then presented to the Thermal Operations and Maintenance Manager for plant budget approval.

Approved projects are assigned a project Lead from the plant staff depending on discipline. Large complex projects may be assigned Engineering staff and/or a Project Manager from Generation Production and Substation Support Department to oversee. Project status and updates are discussed at the weekly plant maintenance meetings.

2 BUSINESS PROBLEM

Kettle Falls Generation Station utilizes two D10 CAT dozers to move nearly 500,000 green tons of waste wood around the storage area each year. Two primary tasks the Fuel Equipment Operators use the dozers throughout the day for is moving new material out into the inventory storage area and bringing in waste wood fuel to be burned for the plant operations.

The fuel yard operates 24-7 receiving wood waste from over 20 contracted sawmills. Semi-trucks move product out of the mills to the plant where the wood waste is moved via a conveyor system. The dozers move the material out from underneath the conveying system to the storage pile. If the dozers break down and material is not moved out from the conveying system, trucks will begin to back up in the yard and possibly create issues on HWY 395. On average the plant receives 60-80 semi-truck loads of fuel each day from area sawmills. Maintaining the waste wood receiving equipment at the plant is critical to the plant overall operations. Other markets are available for waste wood such as beauty bark, wood pellets and press board. Having a highly reliable waste wood system keeps transportation costs down which benefits the customer in lower fuel costs to the plant.

The Fuel Equipment Operators also use the dozers throughout the day to move wood into the reclaiming system to be burned for the plant operations. The 53MW facility cannot operate on wood waste without the use of a dozer. The plant may be operated on natural gas at 50% capacity but is not classified as a renewable source and the REC's are lost when operating in that mode. The unit is less efficient and not designed to operate on natural gas for extended periods of time.

Normally one dozer is operating while the other is in standby until the 250 hour service is needed then the standby machine it put into service while the other sits in standby. Typically the dozer is operated 10-12 hours each day. On average each machine operates 2,000 hours per year.

Major overhauls require the dozer to be shipped over 80 miles to the nearest service center in Spokane. This work is planned and schedule around the annual maintenance outage in the Spring to reduce the risk to plant availability due to the loss of the standby dozer from an unexpected breakdown.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
1. Rebuild the engine and transmission	*$230,000*	*05 2017*	*06 2017*
2. Purchase Certified Rebuilt CAT D10R	*$700,000*	*05 2017*	*06 2017*
3. Purchase New CAT D10 Dozer or equivalent	*$1,800,000*	*06 2017*	*06 2017*

The plant has been operating and maintaining D10 dozers for over 30 years and has kept maintenance records of the equipment. Historical data on record over the past 20 years shows the engine on the D10R has never reached 9,000 hours of operation between failures. The transmission has never reached 10,000 hours of operation between failures. The CAT D10R dozer has over 36,000 operating hours on the machine chassis. Major components have been rebuilt over the years including the motor, transmission and final drives. The major rebuilds are planned on a time base maintenance plan. Minor components found in the auxiliary systems including radiators, coolers, hoses, belts, seals, gaskets, bearings, wiring, switches, gauges, tracks, pads, pins and blade are basically ran until failure.

Discussions with the equipment manufacture service representative identified three options to consider, major rebuild of critical components, a complete certified rebuild and purchase of new equipment.

The four options were discussed and doing nothing was not an option as the motor had failed and the transmission will fail at some point.

Option 1 is rebuilding the engine and transmission were identified as time based maintenance projects and funded as a Major Maintenance O&M project for 2017. There were uncertainties around what other issues we would find as we pulled the motor and transmission. There was risks the costs and scope could increase as auxiliary equipment including the final drives, steering clutches, brakes and minor equipment were removed and inspected.

The engine failed last Fall with 8,600 hours. We were given options of rebuilding our engine if the head was able to be machined down, purchase an already rebuilt engine or purchase a new engine. Rebuilding our engine would increase the time in which the plant would be operating with only one dozer available putting plant operations and fuel contracts at risk. Working with Western States we were able to negotiate a new engine with warranty for the same price of a rebuilt engine. A new engine was installed in October of 2016 for $119,000.

Option 2 is purchase the Certified Rebuilt CAT D10R dozer. The rebuilt dozer, which is currently an Avista Kettle Falls asset, will be completely disassembled down to the machine frame. All hoses, belts, seals, gaskets, bearings, wiring, switches and gauges will be new. The frame will be reconditioned to original performance of new machine. Engine and transmission will be reconditioned and updated to Caterpillar Certified Rebuild Standards. The dozer will be issued a new serial number and carry like new machine warranty.

Recommendation is to pursue option 2 to purchase a Certified Rebuilt CAT D10R dozer. The rebuild will be completed during the schedule annual maintenance outage and will be complete two weeks prior to the plant startup. Transfer to plant is scheduled to be June 2017. Because of the engine failure in $119k was spent in 2016, $500k will be spent in 2017. $230,000 will be reduced from K07 O&M for 2017 by eliminating the Major Maintenance project of the engine and transmission rebuild.

The Certified Rebuild on our existing D10R will reset the time based maintenance of the major and minor equipment. Reliability on the D10R will be increased as it will be back to like new condition. Steering and brakes will be like new making for safer operation on the fuel pile.

Western States Equipment has experience rebuilding equipment. The scope of work and costs for 2017 are attached.

Option 3 is purchasing a new D10 CAT dozer or equivalent was considered but cost, long lead time and issues around operating our current D10T we eliminated this option. A new D10T was purchased in 2012 at the cost of $1.6 million for a new machine. Working with Western States a new CAT D10T dozer would now cost around $1.8 million. The D10T has newer emissions equipment which increased the exhaust temperature compared to the D10R. The extremely high manifold temperatures cause sawdust to catch on fire in the engine compartment throughout the hot summer months. Modifications to the D10T over the past years include large blowers moving sawdust off the top of the engine and ceramic coating the intake manifolds have reduced the fires on the D10T but not eliminated the problem.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Certified Rebuild D10R CAT Dozer Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Greg Wiggins Date: 4/17/2017

Print Name: Greg Wiggins

Title: Kettle Falls Plant Manager

Role: Business Case Owner

Signature: Date: 4/19/2017

Print Name: Andy Vickers

Title: Director of GPSS

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Greg Wiggins	04/12/2017	Jacob Reidt	04/17/2017	Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$3,530,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Steering Committee members are comprised of: Director – GPSS, Manager, Hydro Operations & Maintenance and Manager - Project Delivery. Steering Committee members are provided a monthly project status report but, meet only in the event a decision point is needed.

Other key stakeholders include: Manager, Clark Fork River Hydro; Manager, Mechanical Engineering. Additional Cabinet Gorge Hydro Electrical Development mechanical staff that more directly represent the interests of the plant itself are consulted regularly.

2 BUSINESS PROBLEM

The gantry crane at Cabinet Gorge Hydro Electrical Development was used in the original construction of the plant in 1952-53. The crane is rated at 275 tons but can perform lifts as heavy as 330 tons on an occasional basis given that a certified test has been performed. As the asset has aged, various upgrades and updates have been made to prolong the crane's usefulness. However, it has become apparent that the crane is unable to perform the duties required of it in a dependable manner.

The gantry crane is of the only means of moving the large machinery found at Cabinet Gorge Hydro Electric Development such as moving/placing transformers, tailgates and generators. It is also the only way other equipment can be moved into and out of the plant. Its inability to function reliably impacts the work that is able to be performed at the plant and presents a safety risk to personnel if the crane fails to control the load. There is also a risk of not being able to accomplish repairs in the event of an emergency related to any one of the four generating units. In essence, the gantry crane is a bottle neck preventing both annual maintenance work and capital improvements alike.

The crane has a long history of breakdowns and operational problems. Most recently, during the Cabinet Gorge Unit #1 rehabilitation project spanning from 2014 to 2016, problems with the crane caused significant delays. Some examples include:

Relay/Contactor control problem – approx. 6 days

Gear/bearing problem – approx. 3 weeks

Brake problem – approx. 2 days

Additional problems experienced with the crane during the Unit #1 rehabilitation are documented in a memo by Ryan Bean, dated November 13, 2015, attached as Appendix A below.

Inspections performed by Professional Crane Inspections in the years 2010, 2012, 2015 and 2016 each give the crane an overall condition level 3 indicating that "Minor to moderate performance issues exist. PCI recommends repair or adjustment as soon as practical." Copies of these inspection reports can be made available upon request. A summarized list of foreman reports dating back to 1966 can be found in Appendix B below.

The successful outcome of this project would be to deliver a state-of-the-art crane capable of safely and reliably providing rated lifting capabilities for the likes of draft tube bulkheads, Generation Step-Up transformers and any one of the four generators.

A properly functioning crane at Cabinet Gorge Hydro Electric Development enables Avista to tend to the aging assets and maintenance needs of plant machinery to ensure that they run safely and reliably.

Customers benefit in the ability to adequately and safely maintain this equipment to continue to provide low cost and reliable energy.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Estimated Capital Cost	Start	Complete
Do nothing	$0		
Alternative 1: Full Replacement	$5,308,449	03/2017	12/2018
Alternative 2: Replacement w/extended reach	$7,272,000	03/2017	12/2018
Alternative 3: Refurbishment	$3,894,173	03/2017	12/2018

Do Nothing: doing nothing is an option however, given the criticality of this asset, doing nothing would leave the plant at risk should an emergency arise necessitating the crane's use

Alternative #1: Full Replacement. Advantages of this option include new structure designed and rated for 330T from conception, modernized controls utilizing current technology, reduced maintenance costs, elimination of as-building the existing crane structure, full archived drawing and product data set and removal of any lead-based paint and asbestos contamination risks.

Alternative #2: Replacement w/Extended Reach. This alternative expands on alternative #1 by utilizing extended reach to enable reach to the transformers and leg pass-through design enabling access to the draft tube bulkheads. Replacement with extended reach represents a modest increase (comparatively) in price but will provide savings in terms of usability for the foreseeable future in terms of lifting capability. The estimated capital cost of $7,272,000 represents a very high level estimate at this point.

Alternative #3: Refurbishment. Advantages of refurbishment included lower up-front costs resulting from retaining the majority of the steel structure and a reduced level of demolition and installation work. However, this alternative would require lead-based paint and asbestos abatement and without X-ray examination of each rivet, it would be impossible to accurately and definitively assess the true condition of the structure.

A final decision has yet been made with regard to selection of Alternatives 1, 2, or 3. However, with any option we anticipate construction will take upwards of four months, following dismantling of the existing crane. Due to weather conditions inherent in north Idaho, it would be optimal to construct the new crane during the months of June to September. Given the long lead time expected in the manufacturing of a new crane (upwards of twelve months), we anticipate that all construction will be completed and the project placed in service no later than December 31, 2018.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Gantry Crane Replacement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 20170417
Print Name: JACOB REIDT
Title: MGR CONTRACTS & PM
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director GPSS
Role: Business Case Sponsor

VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	4/14/2017	Steve Wenke	4/14/2017	Initial version

Template Version: 03/07/2017

APPENDIX A

DATE: NOVEMBER 13TH, 2015

TO: FILE, JACOB REIDT, RANDY PEIRCE, BOB WEISBECK, MIKE SHOFF

FROM: RYAN BEAN

SUBJECT: CABINET GORGE UNIT 1 – GANTRY CRANE ROTOR PICK PROBLEMS

Background

The scope of work during the Unit 1 rehabilitation included two picks of the generator rotor complete with field poles installed. The first pick removed the rotor from the stator and placed it in the shop for field pole removal. The rotor was then moved to the rotor storage building until the field poles were returned after being refurbished by RPR Hydro (subcontractor to GE). The field poles were reinstalled in the rotor storage building and the rotor was then placed back in the stator.

An Engineered Pick Plan was produced in accordance with ASME Code Section B30.2-3.1.7 that allows for occasional picks for loads exceeding rated limits up to 125% of the nameplate rating. The crane nameplate is 275 tons with an occasional pick of up to 343.8 tons. The rotor with lifting device weighs approx 330 tons. The cranes ability to lift this load was confirmed by Bedford Crane during the initial installation. The code allows an occasional pick not to exceed two occurrences in a 12 month period provided the crane manufacturer or other qualified person has reviewed the crane design to handle the load.

Inconsistencies During Operation

During the initial removal of the rotor from the stator, the micro drive and main hoist motor were used. The micro drive operated as expected, however the main hoist motor appeared to struggle when initially engaged. While returning the rotor to the stator on September 22nd, 2015, an issue was experienced where the main hoist did not operate as expected during raising. This was a repeatability issue with the main hoist where the hoist may raise, stall, or lower the rotor when the control lever was taken back into the same notch repeatedly. The lift was stopped and an investigation followed.

Investigation and Troubleshooting

With assistance from PCI and K&N Electric, an investigation and troubleshooting of the power and control systems followed. Components checked included the control lever, overloads, contactors, resistors, motor currents, brakes, and micro-drive operation. Everything appeared to be operating correctly, albeit in an overloaded condition due to the above nameplate load. The micro-drive operated reliably throughout testing. This lead us to believe the problem resides downstream of the control system, potentially with either the motor output or mechanical drive system. The gear train was visually inspected via available access ports and appeared to be in good shape and operated smoothly.

Original records of the hoist motor test data indicate the existing hoist motor reaches its nameplate current of 160 amps at a load of approximately 205 tons. This limits the service cycle at 240 amps with a load of approx. 320 amps to approximately one to two minutes without overheating resistor banks. This would require several lifting and cooling off periods to complete the lift. This reflects what we experienced in the field with tripping of the overload relays during sustained lifting at approx. 250 amps.

The crane micro-drive arrangement was also inspected, which consists of an additional motor and speed reducer that can be clutched in or out as necessary. The arrangement utilizes the same main hoist drivetrain and brakes (with an additional motor brake) without using the main hoist motor. Per Mark Oney's crane evaluation dated May 10, 1994 and design drawings, the micro-drive is rated for continuous duty without overheating. Hoisting speed is reduced during operation to slightly less than 0.5 feet per minute.

Conclusion

This has historically been a difficult pick for this crane and the system appears to have reached an impasse where the main hoist is no longer capable of producing the power to function at 100%. We suspect the issue lies in either the motor output, which has been operated above its nameplate current a number of times in the past, or due to an increase in mechanical drag in the gear train.

Per the results of our initial investigation and a stakeholder meeting on October 5th, 2015, (Ryan Bean, Andy Vickers, Mike Gonnella, Bob Weisbeck, Brand McNamara, Rob Selby, and Jeremy Winkle in attendance) and in agreement with the project Foreman Mike Shoff, the rotor pick was completed using the installed micro-drive system, without the use of the main hoist motor.

References

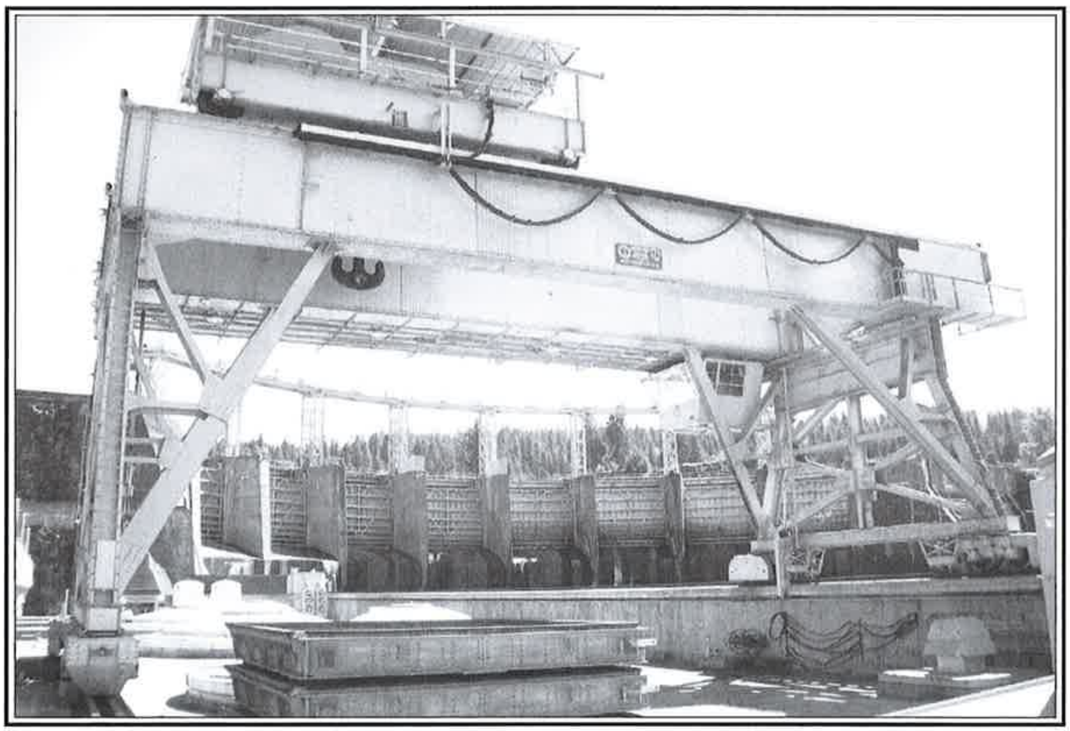
1. CG 1 Rotor Pick Plan Oct 2015 Rev1
2. ASME Crane code for CG1
3. Crane Report by Mark Oney, May 10 994
4. D-15701s001c1952 – Gantry Clearance Diagram with notes
5. 304E-25-040-01-01, 02, 03, 04, 05, 08 – Micro Drive Arrangement Drawings
6. 1952 Load Test Data
7. 1993 Load Test Data

APPENDIX B: SUMMARIZED FOREMAN REPORTS

Job Title	Begin date	End date	Description
Gantry Crane - Mechanical Maintenance	5/23/1966	7/1/1966	Replaced sheaves and greased bearings on large hook. Applied oil to bearings on trolley. Drained and cleaned gear cases. Checked brakes.
Repair Gantry Crane	3/31/1969	4/9/1969	Large bevel gear was removed. New bushing was installed and the drive reassembled. Wheel guards were repaired and installed.
Re-reeve Gantry Crane Main Hook - Cabinet Gorge Station	12/2/1976	12/14/1976	Old cable was removed and new cable added to the drums.
Crane Maintenance	11/14/1988	11/14/1988	Main hoist gear box inspected. Friction brake assembly was seized together.
Redo Crane Track Splices	4/5/1993	5/13/1993	Weld holding rails together were repaired.
Gantry Crane - Bridge Drive Motor	1/23/1997	2/11/1997	The bridge drive motor on the Gantry Crane was removed and sent in for repair. Report includes repair details.
Crane Maintenance	6/28/1999	7/29/1999	The bridge motor, brake and gearbox were inspected. Trolley motor removed and sent to K&N for maintenance.
Annual Safety Inspection for Gantry Crane	7/12/2000	7/12/2000	Mechanical and Electrical inspection of crane components.
Crane Maintenance	5/1/2000	7/13/2000	Crane was pressure washed. Full structural inspection completed. Rusting areas noted. The main and auxiliary hoists were load tested.
Gantry Crane Maintenance "03"	6/16/2003	8/26/2003	Replaced all races and several bearings, and repaired sheaves of the main hoist block. Replumbed bridge brake system and repaired/replaced several brake components. Maintained the trolley controller (electricians), main and auxiliary hoist cables, and open

Job Title	Begin date	End date	Description
275 Ton Gantry Crane Load Test	6/5/2006	6/8/2006	Components of the main hoist had been modified necessitating a load test (Report from load test on the 275 ton gantry cane).
Crane Maintenance 2010	9/15/2010	9/15/2010	Abbreviated maintenance on the gantry crane. See report for details.
Gantry Crane Oil Analysis	4/19/2011	4/19/2011	Oil Analysis results for Gantry Crane components.
Gantry Crane Maintenance 2011	4/11/2011	4/20/2011	Report includes details on maintenance of the gantry crane, checklist included. Report state the crane in in dire need of a paint job.
Annual Maintenance Gantry Crane	4/9/2012	5/3/2012	Crane condition regarding many items is not satisfactory, see report for details

detailed Foreman reports can be found here > c01m114/G://Foremanreports.accdb



1 GENERAL INFORMATION

Requested Spend Amount	$1,149,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Mike Magruder
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

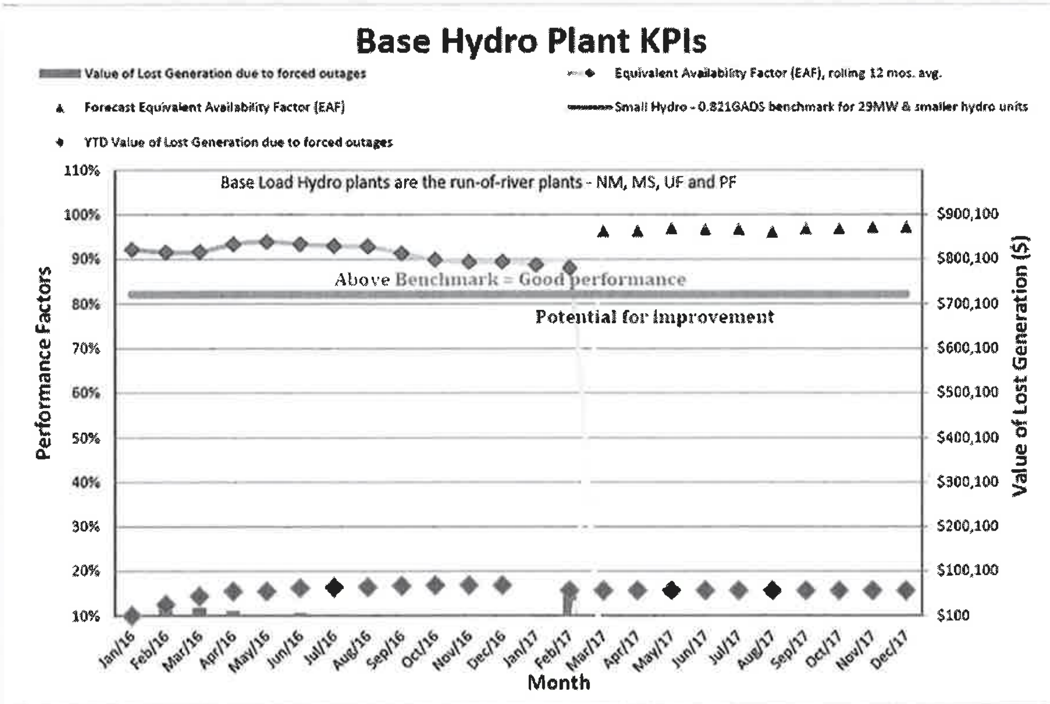
Most projects are proposed through Operations and Engineering. The projects are vetted holistically by Operations and Engineering to evaluate the issue, determine available options, confirm prudency, and bring the potential solutions forward for discussion with the Advisory Group consisting of the Plant Managers and the Manager of Hydro Operations. A similar vetting process is followed for funding emergency projects with the impacted stakeholders included.

Over the course of the year, the program funding is actively managed by the Manager of Hydro Operations through monthly analysis and reporting for end of year expected spend.

2 BUSINESS PROBLEM

Avista's Base Load Hydro (or Base Hydro) program includes the Post Falls, Upper Falls, Monroe Street, and Nine Mile Hydroelectric Developments. These are all located on the upper Spokane River and are "run of river" plants which require them to have a constant water level in their forebay. It also includes minor capital projects at the Generation Control Center and on the Generation Control Network. It can also include some projects at the Post Street 115kV Substation where the two downtown hydro plants are tied into the grid.

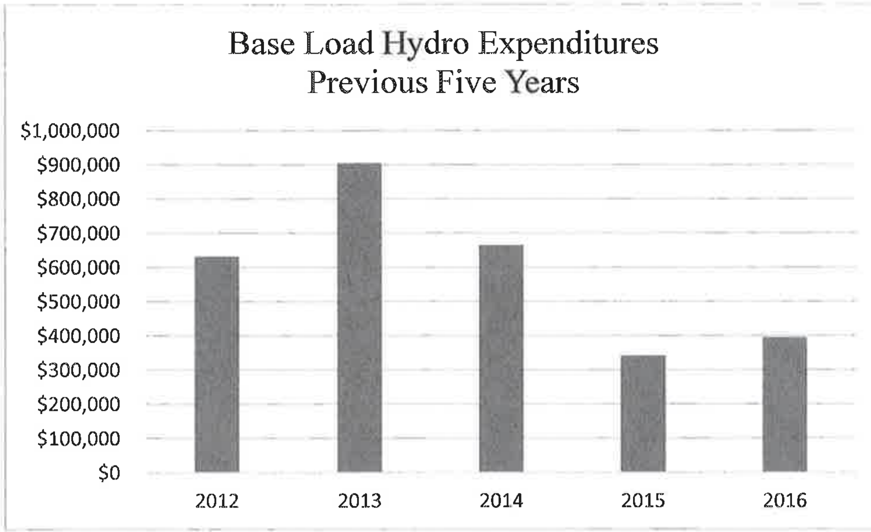
The purpose of this program is provide funding for these plants to accomplish the objectives of keeping operating expenses as low as possible and maintain a level of reliability as indicated by the Equivalent Availability Factor (EAF) in the graph below. This program covers the smaller capital expenditures and upgrades required to safely and reliably operate the Upper Spokane River plants and continue their low cost. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business driver for this program is a combination of Asset Condition, Failed (or Failing) Plant, and addressing operations deficiencies.. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operations issues.



Examples of projects completed in 2016 or in progress under this business case include:

- Monroe St. – Water Drain and Diversion Installation. This project captured high flows on the site that were washing away some of the visitor amenities.
- Nine Mile – Replace Failed Spillway Gate Controls. This project will replace failed controls that allow the spillway to automatically adjust to maintain a forebay level.
- Upper Falls – Upgrade Headgate Camera. This replaced a non-functioning camera used for some area surveillance and to observe the trash rake operation on the intake.
- Post Falls – Replace Switch Building Drain Field. This project is to move ponding of water away from the foundation structure to maintain the integrity of the building.
- Nine Mile – Install Roof Safety Handrail. This addresses a personnel safety item.
- Post Falls – Install N. Channel Downstream Warning System. This is a system that warns the public in the event of a start of a spill or a significant increase in spill at the site.

The Program funding requests are submitted to the Capital Planning Group (CPG) through the business case review process. The business case expenditures over the last 5 years are shown below.



2012	2013	2014	2015	2016
$631,961	$905,557	$664,783	$342,194	$394,849

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Maintain Existing Base Hydro Program Business Case	*$350k - $1.15M*	*Annual*	*Annual*
Make all small projects as standalone projects	*$3.1M - $5.9M*	*Annual*	*Annual*

These base load hydro plants are among the oldest plants in Avista's generating fleet. The option to "Do Nothing" is impractical in that existing machinery and systems periodically fail and are required to be replaced. Having no costs allocated to address those concerns is impractical.

The second proposal is to continue with the Base Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Base Hydro program, or a specific project business case.

The last proposal to eliminate funding for this program introduces greater risk to the ongoing operation of the plants by reducing the efficiency of operations and administration to set up and execute the required projects, especially for failed plant and operations. The program gives us the flexibility to respond quickly and prudently.

The recommended option to pursue is the second proposal to continue with the Base Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Base Hydro program, or a specific project business case. The program offers greater efficiency to manage "drop-in" or emergency projects allowing for better response time.

The annual requested budget amount is conservative to cover potential large expenditures that do not require a new project business case to be developed. The annual amount is reasonable, especially given that the program is actively managed and there is a means to release or request funds through the CPG.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Base Load Hydro Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Michael A. Magruder Date: 4/19/2017
Print Name: Michael Magruder
Title: Mgr. Hydro Ops & Maintenance
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Magruder	03/17/17	Jacob Reidt	04/19/2017	Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$3,100,000 per year
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Thomas Dempsey
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

This business case request is for Avista's base load thermal plants, Kettle Falls and Coyote Springs 2. The purpose of this program is for these plants to keep their operating expenses as low as possible by providing funding for specific efforts to allow the plants to accomplish that objective.

Smaller and emergent projects planned for Kettle Falls are identified and prioritized through their plant Budget Committee. The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix.

Projects planned specifically for Coyote Springs 2 are identified and prioritized during the Annual Budgeting process, with emergent projects discussed during the Monthly Owners committee meetings between Avista management and Coyote Springs management. Some of the projects that fall within this business case are joint projects between Portland General Electric (PGE) and Avista. Those "common" projects are also reviewed in an owner committee setting during meetings at the plant that take place on a monthly basis.

Individual projects are identified and approved by the Manager of Thermal Operations and Maintenance, specific plant managers and/or GPSS management. Some specific jobs under this program may require additional financial analysis if they are sufficiently large or there are several options that can be chosen to meet the objective. These projects are reviewed with finance personnel to make sure that they are in the best interest of our customers.

2 BUSINESS PROBLEM

Various projects for Coyote Springs 2 and Kettle Falls Generating Station are necessary to ensure continued safe, low cost, reliable and compliant electrical generation for Avista's electric customers. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. As this program proceeds, it is expected that forced outage rates and forced de-rates of these facilities will decrease to a level one standard deviation less than the current average resulting in more economic benefits for the Program. The projects that are opened under this business case are not known in advance. Most of the individual projects are small in nature and are required due to regulatory or environmental requirements, emergent safety items, or for continued reliable operation. Examples of recent expenditures under this Program include:

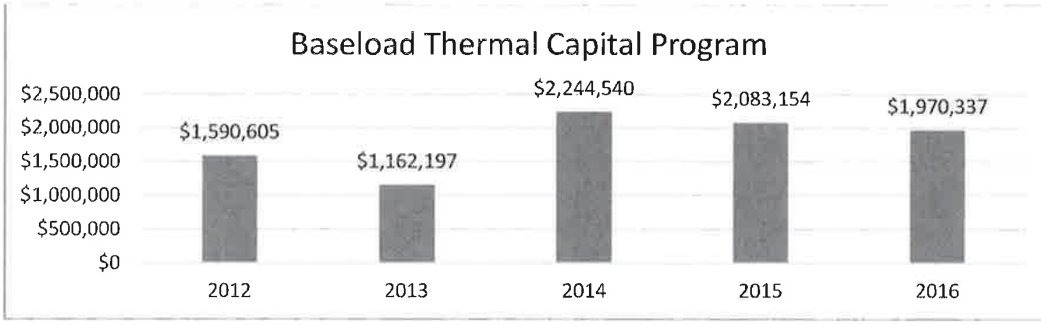
- Kettle Falls - Replace the Furnace Grate Drive System, part of the system that moves the burned fuel from the boiler to the ash disposal system (Reliability)
- Kettle Falls – Replace Furnace Forced Draft Fan motor, the fan that blows the wood waste fuel into the boiler where it is burned (Reliability)
- Kettle Falls – Diesel Fueling System, providing additional containment and system to improve the onsite diesel fuel handling system (Regulatory or Environmental)
- Kettle Falls – Replace the Turbine/Generator fire system (Safety)
- Coyote Springs 2 – Replace the Reheat Steam Attemperator, the system used to control the steam temperature in the boiler (Reliability)
- Coyote Springs 2 – Upgrade the Medium Pressure steam control valves (Safety and Reliability)
- Coyote Springs 2 – Upgrade the NOx analyzer, part of the plant emission monitoring system that monitors the Nitrous Oxide emissions (Regulatory or Environmental)
- Coyote Springs 2 – Improve physical site security, addition of key card access door locks on critical facility doors. (Regulatory, Safety)

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
As proposed	$3,100,000	Ongoing, required for operation		
Unfunded Program				

This program is necessary to sustain or improve the existing operating costs for Coyote Springs 2, the Coyote Springs Common Facilities, and Kettle Falls Generating Station. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. The Capital Retirement Unit Catalog for Kettle Falls and “Other” became effective January 1, 2017. Due to this Retirement Unit Catalog update, $900,000 in additional funds are necessary for 2017, in order to cover capital projects that were previously identified as Operation and Maintenance. The Base Load Thermal Business case is reassessed for adjustments on a 5 year cycle.

A 5 year historical graph of expenditures is attached to help assess future capital funding for the Base Thermal Plant. This spending pattern indicates the diligence that is applied to capital requests as managed by the Kettle Falls plant Budget Committee and the joint owners of Coyote Springs during their monthly meetings. As mentioned above, there is opportunity to adjust this amount every five years if needed.



4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Baseload Thermal Program Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Thomas L. Dempsey Date: 4/21/2017

Print Name: Thomas Dempsey

Title:

Role: Business Case Owner

Signature: Date: 4/19/2017

Print Name: Andy Vickers

Title: Director, GPSS

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Mecham	04/05/2017	Jacob Reidt	04/14/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$3,533,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Mike Magruder
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

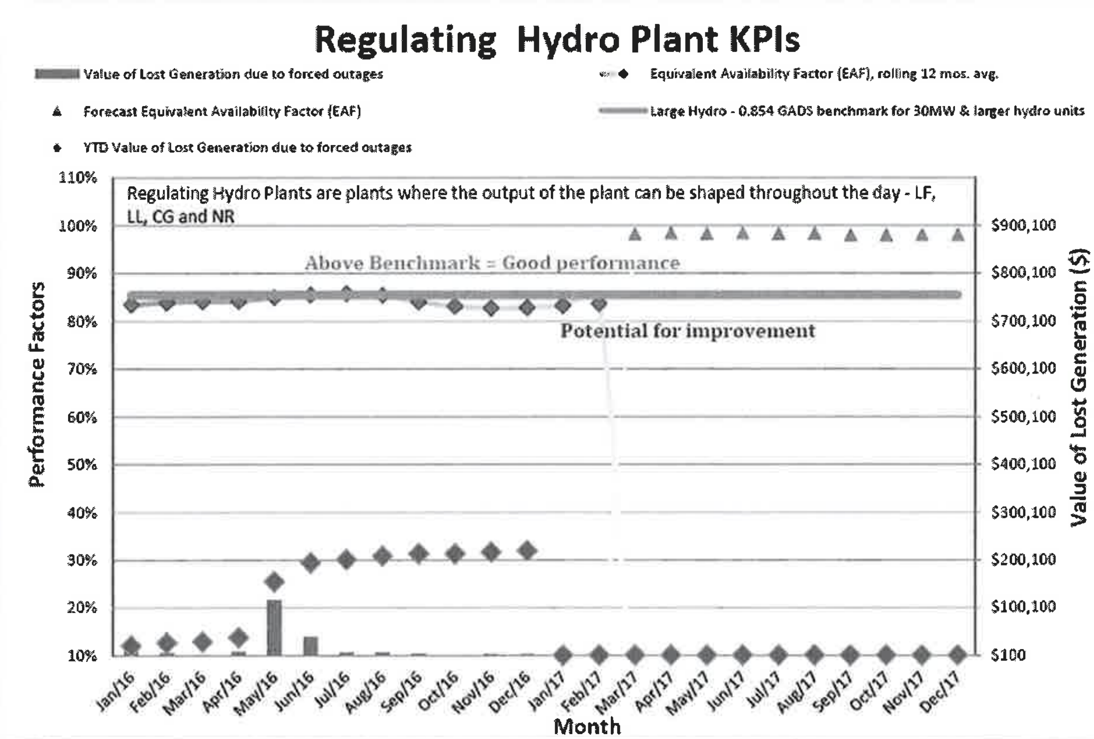
Most projects are proposed through Operations and Engineering. The projects are vetted holistically by Operations and Engineering to evaluate the issue, determine available options, confirm prudency, and bring the potential solutions forward for discussion with the Advisory Group consisting of the Plant Managers and the Manager of Hydro Operations. A similar vetting process is followed for funding emergency projects with the impacted stakeholders included.

Over the course of the year, the program funding is actively managed by the Manager of Hydro Operations through monthly analysis and reporting for end of year expected spend.

2 BUSINESS PROBLEM

Avista's Regulating Hydro program includes the Cabinet Gorge (Idaho) and Noxon Rapids (Montana) Hydroelectric Developments on the Clark Fork River and the Long Lake (WA) and Little Falls (WA) Hydroelectric Developments on the lower Spokane River. Because of the storage available in their reservoirs, these plants are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers. These plants are the four largest hydro plants on Avista's system representing more than 950 MW of power.

Because these plants are used to provide a wide variety of grid services, energy and power supply, and other types of electric grid support services, the availability for the generating units in these plants is paramount. The purpose of this program is to provide funding to achieve availability targets (Equivalent Availability Factor or EAF) of 85% or higher.



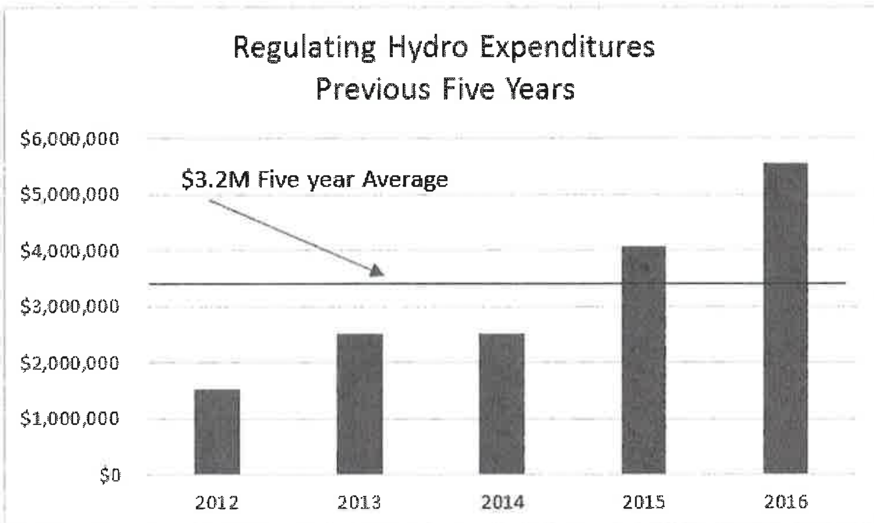
This program covers the smaller capital expenditures and upgrades required to safely and reliably operate four largest hydro plants and to achieve the EAF target. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business driver for this program is a combination of Asset Condition, Failed (or Failing) Plant, and addressing operations deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operations issues.

Examples of projects completed in 2016 or in progress under this business case include:

- Cabinet Gorge – Tunnel Access Improvement; this work removed loose rock along the access road and installed protective metal netting to address the hazard of falling rocks on personnel and equipment. (Rock Scaling/Netting)
- Noxon – Install Dam Pressure Monitoring System; this work provided specialized instrumentation so that operators and engineers can monitor the structural stability of the dam.
- Long Lake – Spillway Improvements; this project replaced and enhanced some areas of the Long Lake spillway section by removing and replacing areas of the decaying 100 year old concrete. (Rebuild Parapet Wall/Extend Spillway Walkway)

- Little Falls – Replace Spillway Log Boom; this is a plant safety system that diverts floating debris from the generating units and can provide a boundary to keep the public away from the hazardous intake area of the dam.
- Noxon – Replace Unit 5 Turbine Bearing Cooling System
- Long Lake – Install Redundant Spillgate Hoist System; this work added a FERC required secondary system so that in the event of a failure of one system, the spillgates could still be operated with a second power source to assure ability to manage river flows at the project and provide safe operation of the spillway.

The Program funding requests are submitted to the Capital Planning Group (CPG) through the business case review process. The business case expenditures over the last 5 years are shown below.



2012	2013	2014	2015	2016
$1,514,577	$2,517,815	$2,519,775	$4,073,698	$5,558,100

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing – not a viable option.	$0		
Maintain Existing Regulating Hydro Program Business Case	*$1.5M - $5.5M*	*Annual*	*Annual*
Make all small projects as standalone projects	*$3.1M - $5.9M*	*Annual*	*Annual*

The plants that make up the Regulating Hydro group provide the most flexibility of any of the generating assets owned by Avista. As such, they provide a wide variety of critical and economical services that allows Avista to optimize the entire energy portfolio. Consequently, the option of doing nothing to maintain these units is a poor economic choice on behalf of Avista's customers and shareholders.

The second option is to continue with the Regulating Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Regulating Hydro program, or a specific project business case.

The last option to eliminate funding for this program introduces greater risk to the ongoing operation of the plants by reducing the efficiency of operations and administration to set up and execute the required projects, especially for failed plant and operations. The program gives us the flexibility to respond quickly and prudently.

The recommended option to pursue is the second proposal to continue with the Regulating Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Regulating Hydro program, or a specific project business case. The program offers greater efficiency to manage "drop-in" or emergency projects allowing for better response time.

The annual requested budget amount is conservative to cover potential large expenditures that do not require a new project business case to be developed. The annual amount is reasonable, especially given that the program is actively managed and there is a means to release or request funds through the CPG.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Regulating Hydro Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Michael A. Magruder Date: 4/19/2017
Print Name: Michael A. Magruder
Title: Mgr. Hydro Ops & Maintenance
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Magruder	03/17/17	Jacob Reidt	04/19/2017	Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$10-$20 Million per year
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Thomas C Dempsey
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

This Business Case request is for Colstrip 3&4 capital projects. Avista does not operate the facility nor does it prepare the annual capital budget plan. The current operator provides the annual business plan and capital budgets to the owner group every September. They also provide individual project summaries which characterize the work using categories similar in concept the Avista business case drivers. Avista reviews these individual projects. Some of them are reclassified to O&M if the work does not conform to our own capitalization policy. Avista does not have a "line item veto" capability for individual projects but it can present concerns during the September owners' meeting. Ultimately, the business plan is approved in accordance with the Ownership and Operation Agreement for units 3&4 that six companies are party too. This Business case represents the final approved budget after subtracting items that we will expense instead of charging to capital.

2 BUSINESS PROBLEM

This Business Case represents the entire body of capital work performed in a calendar year at Colstrip. This includes a variety of types of projects that Talen (current operator) characterizes using the following categories:

- ENVMD- Environmental Must Do
- Sustenance
- Regulatory
- Reliability Must Do

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Ongoing Operations (Yes/No Vote)	$10-$20M		N/A	

Colstrip Capital is required as part of ongoing operations of the facility.

- *The operator (Talon) reviews each proposed project. Discretionary items are reviewed in a hurdle rate analysis.*
- *The operator reviews the risk mitigation for each alternative using the business risk worksheet as well as describe the nature of the risks for each alternative.*
- *Those that meet the criteria are submitted as part of an overall budget to the owner committee,*
- *This process is repeated annually*
- *The annual business plan is available on request.*
- *Although alternatives are not available for consideration at this level, individual projects are reviewed and considered by all the joint owners. Projects may be delayed and changed per committee recommendation to the operator of the facility.*

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Colstrip 3&4 Capital Projects Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 4/21/2017
Print Name:
Title:
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Mecham	04/17/2017	Steve Wenke	04/17/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$ 17,725,513
Requesting Organization/Department	Clark Fork License Implementation
Business Case Owner	Tim Swant
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

In mid-1996, stakeholders were invited to meet with a neutral facilitator to develop a process for participating in the relicensing of these projects. There evolved a Clark Fork Relicensing Team, which included representatives from nearly 40 organizations, including representatives from federal, state, and local government agencies, five Indian tribes, special interest groups, conservation groups, property owners, and Avista Corporation. The Relicensing Team established five technical working groups, covering: 1) fisheries; 2) water resources; 3) wildlife, botanical, and wetlands; 4) land use, recreation, and aesthetics; and 5) cultural resources management. The team developed protection, mitigation, and enhancement (PM&E) measures that were the basis for the comprehensive Settlement Agreement filed with Avista's license application. The Settlement Agreement establishes processes and includes 26 PM&E measures to resolve a wide range of complex and conflicting natural resource interests. Avista led this collaborative effort and signed the Agreement, making commitments for the 45-year term of the license. FERC incorporated the Settlement Agreement into the new license. Under the Settlement Agreement and license, the licensee works through a Management Committee (MC), comprised of one representative of each of the 27 parties to the Agreement, to implement the PM&E measures. In addition, the Clark Fork Settlement Agreement (CFSA) and license require Avista to provide funding for PM&E implementation over the course of the term.

All proposed PM&E activities and associated budgets are developed through one of the three technical working groups identified in the settlement agreement and approved by the MC, which strives to make all decisions, including approval of planned activities and expenditures, by consensus. FERC reviews and approves annual work plans to implement license requirements.

2 BUSINESS PROBLEM

Avista owns and operates the Noxon Rapids and Cabinet Gorge hydroelectric developments (Clark Fork Project No. 2058). The operation of the Clark Fork Project is conditioned by the Clark Fork Settlement Agreement, signed in 1999, and FERC

License No. 2058, effective date of March 1, 2001. Avista evaluated whether to proceed with a traditional licensing process in the 1990s, which typically led to conflict and litigation, or pursue a different strategy. The Company elected to pursue an agreement through a collaborative effort. During the negotiations, Officers and Directors of the company were informed and engaged, and officer approval was required for the Settlement. This business case represents the ongoing resolution of these issues and the means by which Avista fulfills its obligations under the CFSA and the FERC License.

The License was issued to Avista Corporation for a period of 45 years to operate and maintain the Clark Fork Project No. 2058. The License, and associated Code of Federal Regulation, includes hundreds of specific legal requirements, many of which are reflected in License Articles 404-430. These Articles derived from a comprehensive settlement agreement between Avista and over 20 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non-Governmental Organizations. We are required to develop, in consultation with the Management Committee, an annual implementation plan and report, addressing all PM&E measures of the License. In addition, implementation of these measures is intended to address ongoing compliance with Montana and Idaho Clean Water Act requirements, the Endangered Species Act (fish passage), and state, federal and tribal water quality standards as applicable. License articles also describe our operational requirements for items such as minimum flows, and reservoir levels, as well as dam safety and public safety requirements.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	0	N/A	
Fund the annual request	$17,725,513	01/2017	12/2017

Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC license and CFSA for permission to continue to own and operate the hydro-electric facilities. This commitment was made in 2001, and is ongoing. At that time, Avista determined that the Settlement was in the best interest of Avista, our customers, our shareholders, and the communities we serve. These decisions were documented throughout the process at that time.

If the PM&Es and license articles are not implemented and/or funded, we would be in breach of an agreement and in violation of our License. There would be high risk for penalties and fines, new license requirements, higher mitigation costs, and loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydro Electric Facilities. Ultimately, FERC has the authority to revoke our operating license and we could risk a competing license or even losing the facility. Loss of operational flexibility, or, in the extreme, of these generation assets, would create substantial new costs, to the detriment of our customers and the company.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clark Fork Settlement Agreement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ____________________ Date: ____________

Print Name: ____________________

Title: ____________________

Role: Business Case Owner

Signature: [signature] Date: 4/17/17

Print Name: BRUCE F HOWARD

Title: DIRECTOR, ENV. AFFAIRS

Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/29/17	Bruce Howard	03/29/17	Initial version

Template Version: 02/24/2017

flexibility, or, in the extreme, of these generation assets, would create substantial new costs, to the detriment of our customers and the company.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clark Fork Settlement Agreement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 04/19/2017
Print Name: Timothy J Swant
Title: Clark Fork Licensee Manager
Role: Business Case Owner

Signature: [signature] Date: 4/19/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV-AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/29/17	Bruce Howard	03/29/17	Initial version

Template Version: 02/24/2017

Hydro Safety Minor Blanket

1 GENERAL INFORMATION

Requested Spend Amount	$350,000.00
Requesting Organization/Department	Hydro Compliance
Business Case Owner	Michele Drake
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Funded projects are identified in several ways. During periodic site inspections, FERC staff may identify a new specific concern or point out an existing item that is deficient or in need of repair. In other cases, Avista has assessed the condition of safety items at our dams, and proactively plans replacement or addition of a new safety measure. Replacement can be driven by physical condition/age/function, changing standards in FERC guidance, industry practice, or emergent public safety needs. All projects are subject to the conceptual approval of the Chief Dam Safety Engineer and to additional internal review and oversight.

2 BUSINESS PROBLEM

Section 10(c) of the Federal Power Act authorizes the Federal Energy Regulatory Commission (FERC) to establish regulations requiring owners of hydro projects under its jurisdiction to operate and properly maintain such projects for the protection of life, health, and property. FERC's Division of Dam Safety and Inspections establishes national guidance and policy, and Regional Offices implement this responsibility. 18 CFR Part 12 delegates to the Regional Engineer the authority to require safety devices, where necessary. Section 12.42 of the Regulations states that, "To the satisfaction of, and within a time specified by the Regional Engineer, an applicant or licensee must install, operate, and maintain any signs, lights, sirens, barriers, or other safety devices that may reasonably be necessary or desirable to warn the public of fluctuations in flow from the project or otherwise, to protect the public in the use of the project lands and waters."

In addition to the broad regulatory discretion given to FERC, Avista is subject to liability should we not maintain safety-related equipment at our hydro facilities. This work is aimed at reducing both regulatory and liability risks. Some of the projects under this budget are planned, but others are opportunistic. We take advantage of other planned work to coordinate dam safety actions, and at times, we have to replace equipment that has been damaged due to flow conditions. [1]

Projects identified for 2017 include replacement of the boater safety cable at Noxon Rapids and replacement of a boater safety sign at Post Falls.

1. The boater safety cable at Noxon Rapids is more than 30 years old, and has begun to show visual signs of failure, including listing, rusted floats and deteriorating concrete. Operators and hydro safety staff identified the item as in need of repair or replacement.
2. The boater safety sign at Post Falls was installed in 1994 and utilizes neon, molded bulb lighting. A FERC inspector identified that the sign was becoming difficult to read, and informally suggested replacement. Upon investigation, some of the individual letters fail to illuminate.

In both cases, repair of the existing item was considered. However the age and condition of the items and improvements in technology have made repair moot.

1. "Guidelines for Public Safety at Hydropower Project" https://www.ferc.gov/industries/hydropower/safety/guidelines/public-safety.pdf

2. Avista's Hydro Public Safety Plans for each of it hydro facilities.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	0		
Fund annual request	$350,000	01 2017	12 2017

Funding of these activities protect employees, contractors, and the general public, and reduces financial risk to Avista.

Non-Funding activity would ultimately result in total failure of safety equipment, subjecting Avista to additional liabilities due to possible regulatory penalties, injuries or loss of life, and is therefore not a recommended option.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Hydro Safety Minor Blanket Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________ Date: ____________

Print Name: ______________________

Title: ______________________

Role: Business Case Owner

Signature: ______________________ Date: 4/17/17

Print Name: Bruce F Howard

Title: Director, Env. Affairs

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/17/17	Bruce Howard	04/03/17	Initial version

Template Version: 03/07/2017

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Hydro Safety Minor Blanket Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Michele M. Drake Date: 4/17/17
Print Name: Michele M. Drake
Title: supervisor, hydro compliance services
Role: Business Case Owner

Signature: [signature] Date: 4/17/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/17/17	Bruce Howard	04/03/17	Initial version

Template Version: 03/07/2017

1 GENERAL INFORMATION

Requested Spend Amount	$4,750,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Steering committee is comprised of the Manager of Thermal Operations & Maintenance, the Kettle Falls Plant Manager, the Manager of Contracts & Project Management, the Manager of Corporate Environmental Compliance, and the Manager of Mechanical Engineering for GPSS.

Monthly project status updates will be distributed via email indicating the status of the scope, schedule and budget of the project.

Steering committee meetings will be coordinated if decisions need to be made, due to significant changes to the scope, schedule or budget based on unforeseen circumstances and/or risk identification.

1.2 Customers & Stakeholders:

This projects impacts internally the Thermal Operations & Maintenance teams, including the crews at Kettle Falls, Mechanical Engineering and Environmental Compliance. By providing these stakeholders with a properly maintained water treatment system we are providing them with reliability of the system and regulatory compliance assurance.

This project impacts our external customers by ensuring we are in compliance with environmental regulations and protecting the public safety of ground water. We are also ensuring our customers have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders.

2 BUSINESS PROBLEM

Major Driver:

The water effluent discharged from the plant contains trace levels of mercury. To abate the mercury in the effluent, an expensive high quality food grade acid is added to the boiler water supply. With this treatment, mercury levels are not detectable.

In 2015, the water source for the plant was moved from the City of Kettle Falls to a new well system owned by Avista to reduce the water supply costs and to provide the City with needed additional capacity for their system. When this new water source was used for the plant, the water chemistry was different than the City Water source, leading to trace levels of mercury again. As with the previous effort, more of the expensive food grade acid was added to the treatment system. This again resulted in effluent with no detectable level of mercury.

While the current system meets the source and environmental needs, Kettle Falls Generating Station needs a more cost effective, long-term solution to achieve environmental permit compliance and to improve the water treatment process.

Kettle Falls is subject to the following regulatory drivers surrounding water treatment:

- Washington State Department of Ecology
    - National Pollutant Discharge System (NPEDS), 126 priority pollutants
    - Discharge water limits (into the Columbia River)

Currently, two intended short term solutions have been deployed to ensure environmental compliance with increasing and unsustainable operating costs. These two solutions have been evaluated to determine which best meets the cost effective, environmentally sound, long term solution being sought to best manage costs.

1. Use of high quality food grade acid
2. Rental/Test Reverse Osmosis (RO) system in place at one fourth (¼) of full operating capacity

Secondary Driver:
The present water treatment system has been in service since the plant went on line in 1983. The original water treatment demineralization system is aging. The two (2) demineralizer trains in service are controlled by the original automated control system or Programmable Logic Controllers (PLC's). Mechanical valves that control the water treatment are failing. The control system needs to be upgraded to a modern platform and the programming needs to be rewritten. Because of glitches with the existing control program, the system can get locked in step until it is reset which uses more chemicals and water, increasing operating expenses. The panel board for controlling the system has hardwired buttons/indicators that need to be replaced to allow soft control from a touch panel. The analyzers used are from a company that is no longer in business and replacement parts cannot be purchased. There is also a Caustic/Acid dilution rack that is seeing increasing corrosion on piping and valves need to be replaced. Overall the existing water treatment system needs an overhaul or replacement.

Risks:
The continued use of the food grade acid does abate the mercury in the effluent, but significantly increases O&M costs to run the unit. This treatment does not mitigate the performance risk associated with an aging/obsolete demineralization water treatment system. The current demineralization system requires a substantial amount of Plant Operator and Technicians time and effort to reset the system due to component and controls malfunctions. The system also requires corrective actions to fix pump, hose and valve leaks (see attached work order history).

Driving Metrics:

Through routine internal environmental testing we found that we were discharging trace amounts of mercury into the Columbia River due to acid and caustic chemicals injected into the cooling tower and boiler water purification treatment processes. The system is intended to bring these down to non-detectable levels of mercury.

Success Measures:

The Nalco DMS model will be run for any proposed water treatment system to ensure the system will meet our environmental requirements. The Nalco DMS model projects the outcome of water treatment solutions based on the quality and quantity of the incoming source water, and the quantity of chemicals introduced in the water purification process.

References/Studies:

- Department of Ecology – Self reported "Violation Letter", 1/20/2015
- URS Corporation – Mercury Source Review & Strategy Development, 2/12/2015
- Nalco, DMS – Water Treatment System Review, 7/16/2015
- Avista Maximo Water Treatment Work Order History

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Do nothing	$0	N/A		
Option 1 - Full Scale RO/EDI water treatment system	*$4.75M*	*02.2016*	*06.2018*	
Option 2 - Full Scale Water Treatment System TBD by vendor during RFP process	*$4.75M*	*02.2016*	*06.2018*	
Option 3 - Upgrade current demineralizer train	*unknown*	*02.2016*	*06.2018*	

Impacts:

While the Operations staff at Kettle Falls will need to be trained to operate the new water treatment system, no additional staff will be needed to meet the operational requirements. The water treatment system placed in service will be chosen based on O&M costs for treatment and other costs to repair or replace the existing water treatment system.

Alternatives:

1. The present system of food acid treatment only adds $30,000/ month incremental O&M expense to supply and manage this treatment. This can continue, however this option does not address the issues associated with the existing water treatment plant.
2. Installation of a new Reverse Osmosis (RO) and Electrodionization (EDI) water treatment system to replace much of the existing water treatment system, OR

3. Installation of an alternative water treatment system TBD by vendors during an RFP process that would replace much of the existing water treatment system, OR
4. Upgrade the current demineralizer train. Re-write the programming and move the control and monitoring to the existing plant control system. This option would also replace worn and non-performing valves and analyzers with new ones.

Risk Mitigation:

This project will improve the reliability of the treated water that is required for the boiler. It will also provide environmental compliance assurance by addressing mercury levels and other point source pollutants by upgrading or replacing or enhancing the water treatment system. Failure to find a long term, cost effective means to treat and provide water for the boiler could result in environmental compliance violations that could result in significant penalties and/or changes in permitting regulations with increased operating and capital costs to meet compliance.

Selected Alternative:

A selected alternative has not been determined at this time. The alternatives will be evaluated and a final solution will be determined.

Timeline:

- 2016 – Preliminary Analysis for RO/EDI Water Treatment System
- 2017 – Request for Proposal Process
- 2018 – In Service

Alignment with Strategic Initiatives:

Mandatory and compliance. The water treatment process needs to adhere to environmental regulations.

Safe and reliable infrastructure. The water treatment system is an essential operating system of the plant, failure of the system impacts operations.

Budget:

The rough +/- 25% estimate for the project is currently at $4.75M based on initial review conducted by Nalco for water treatment solution alternatives.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Water Treatment System Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 2017.04.17

Print Name: Jacob Reidt

Title: Mgr. Contracts & Project Management

Role: Business Case Owner

Signature: Date: 4/19/2017

Print Name: Andy Vickers

Title: Dir. GPSS

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Tara Moses	4/5/2017	Steve Wenke	4/10/2017	Initial version

Template Version: 02/24/2017

I. GENERAL INFORMATION

Requested Spend Amount	$2,033,063
Requesting Organization/Department	Spokane River License Implementation
Business Case Owner	Speed Fitzhugh
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Decisions related to annual implementation activities are reviewed and approved by technical working groups (i.e., fish, aquatic weeds, water quality, recreation, land use, and cultural) comprised of Avista, Tribal, local, state (Idaho and Washington), and federal agency staff. The activities are specific to the Federal Energy Regulatory Commission (FERC)-approved resource and operational plans that were developed to address Spokane River Project License conditions. Capital projects are undertaken only to meet the requirements of the Spokane River License.

II. BUSINESS PROBLEM

Avista must have a license from FERC to operate the Spokane River Project. The Spokane River Project consists of the Post Falls Hydroelectric Development (HED), Upper Falls HED, Monroe Street HED, Nine Mile HED and Long Lake HED. Avista's prior license expired in 2007; Avista undertook a relicensing effort beginning formally in 2002 to secure a new license, consisting of a collaborative process with over 200 stakeholders. The process ultimately resulted in FERC's issuance of a 50-year license to Avista to operate and maintain the Spokane River Project, No 2545, effective June 18, 2009. This License defines how Avista shall operate the Spokane River Project and includes several hundred requirements, through license conditions, that we must meet.

The License was issued pursuant to the Federal Power Act (FPA) and embodies requirements of a wide range of other laws (The Clean Water Act, The Endangered Species Act, The National Historic Preservation Act, etc.). These requirements are also expressed through specific license articles (known as Protection Mitigation and Enhancement Measures (PME)), relating to fish, terrestrial, water quality, recreation, land use, education, cultural and aesthetic resources.

Avista also entered into additional two-party agreements with local state, and federal agencies and the Spokane Tribe. Avista's FERC license and agreements include mandatory conditions issued by the Idaho Department of Environmental Quality (401 Water Quality Certification, issued June 5, 2008), the Washington Department of Ecology (401 Certification, issued May 8, 2009), the U.S. Forest Service (Federal Power Act 4(e), issued May 4, 2007), U.S. Bureau of Land Management, as well as commitments joined in with the Idaho Department of Fish and Game, Idaho Department of Parks and Recreation, City of Coeur d'Alene, and the City of Post Falls, Kootenai County Parks and Waterways, Washington Parks and Recreation Commission, the Washington Department of Natural Resources, and articles set forth in Form L-1 (entitled "Terms and Conditions of License for Constructed Major project Affecting Lands of the United States"). During the seven-year relicensing process, we engaged stakeholders in direct negotiations and we also engaged in litigation to challenge some proposed conditions. Avista's officers and Board were updated regularly during these efforts, and officers were engaged at key decision points. Ultimately, FERC retains oversight jurisdiction for license compliance; however, other entities, such as state agencies, assert their authority to independently enforce license terms. The FERC license ensured Avista's ability to operate the Spokane River project on behalf of our customers for another 50 years.

III. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Fund the annual request	$2,033,063	01 2017	12 2017

Complying with our license is mandatory to continued permission to operate the Spokane River Project. Funding the implementation activities for the Spokane River Project License is essential to remain in compliance with the FERC license. There are no practicable alternatives to meet compliance. Avista evaluated the potential of surrendering the Spokane River license at the beginning of the relicensing process, determining that this option would be detrimental to our customers, the company, and the communities we serve.

If the PM&Es, license articles and settlement agreements are not implemented and/or funded, we would be out of compliance with and/or in violation of our License. This would lead to penalties and fines, new license requirements, court costs, higher mitigation costs, and loss of operational flexibility. Ultimately, FERC has the authority to revoke our License if we do not comply with the terms and conditions required by it. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers and no benefits.

IV. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Spokane River License Implementation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Speed Fitzhugh Date: 4/19/17
Print Name: Speed Fitzhugh
Title: Spokane River License Manager
Role: Business Case Owner

Signature: Bruce Howard Date: 4/17/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

V. VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/15/17	Bruce Howard	3/30/17	Initial version

Template Version: 03/07/2017