PUBLIC UTILITY DISTRICT NO.1 OF FRANKLIN COUNTY

INTEGRATED RESOURCE PLAN

2014

PREPARED IN COLLABORATION WITH

The Energy Authority®
The Strategic Partner for Public Power

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Executive Summary

Purpose

In 2006, the Washington State legislature enacted House Bill 1010, later codified in RCW 19.280, which mandates that electric utilities develop "comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers' electricity needs in both the long term and the short term." The law applies to utilities that have more than 25,000 customers and are not load-following customers of the Bonneville Power Administration. The law stipulates that qualifying utilities produce a full plan every four years, and provide an update to the full plan every two years.

Non-load-following customers of BPA with less than 25,000 customers, such as Franklin PUD (the District), are required to do a simpler, more streamlined document known as a resource analysis. The District submitted the required resource analyses to the Washington Department of Commerce in 2010 and 2012, but is preparing this more comprehensive IRP to help guide resource decisions.

Determining Factors

The environment in which the District finds itself predetermines many aspects of resource planning. The most important of these are identified below.

Energy Independence Act of Washington State

In 2006 Washington State voters approved the Energy Independence Act (hereinafter "the EIA" or "the Act" or "I-937"). The Act places renewable resource and conservation requirements on utilities with 25,000 or more customers (qualifying utilities). The EIA stipulates that each qualifying utility shall implement all available conservation that is "cost effective, reliable and feasible." In addition, the renewable portfolio standard (RPS) provision of the EIA says that in 2012, 3 percent of a qualifying utility's load must be served with eligible renewable resources. That percentage increases to 9 percent in 2016 and 15 percent in 2020. Utilities subject to the Act that fail to meet the either the renewable resource or conservation requirement will be assessed a $50 (2007 Dollars, adjusted for inflation) per MWh penalty.

Franklin PUD currently is not a qualifying utility as it has fewer than 25,000 customers. Thus, its expected compliance dates will be shifted out as discussed under "Energy Independence Act District Conservation Requirement" and "Energy Independence Act Renewable Portfolio (RPS) Requirement" in Chapter 1. It is currently projected that the EIA conservation mandate will apply to the District in 2019, and the first RPS requirement in 2021.

Load Forecast

Franklin County is one of the fastest growing counties in the nation, experiencing 54 percent population growth between 2003 and 2013, from 55,000 to 84,800. Commercial and industrial growth has occurred at a rapid pace as well. In all but two of those years when there were slight load losses of approximately .9 percent (2010) and .2 percent (2012), Franklin PUD experienced load growth ranging

from 1.7 percent to 5.5 percent, and an average annual growth rate during that ten-year period of 2.8 percent.

The economic downturn the state and nation faced between 2008 and 2012 was not as severe in the Tri-Cities region, which received a good deal of economic stimulus money from the federal government for work at the Hanford site. However, there was a delayed effect when the money was gone. While unemployment in the state and nation were decreasing, the Tri-Cities' unemployment was increasing. At the end of November, 2013, the Tri-Cities' unemployment rate was 8.1 percent, the State's was 6.8 percent, while the nation was slightly higher, at 7.0 percent.

Three load forecasts were developed for the IRP and indicate an overall slowing of growth from the rapid pace between 2003 and 2013. The medium scenario used an average annual growth rate of .35 percent, which translates to an increase of 3 aMW over the ten-year period 2013 through 2022 and 6 aMW over the 20-year period 2013 through 2032. The forecast also assumed that .8 aMW of conservation would be acquired each year. High and low forecasts were also produced for comparison. The high forecast assumed a 1.3 percent annual growth rate, and the low forecast assumed annual load loss of .70 percent. The high and low forecasts also include .8 aMW of new conservation each year. Figure 1 shows the high, medium and low forecasts on an average annual energy basis, and Figure 2 shows forecasts of peak loads by year.

Figure 1: Load Forecast Scenarios - Annual Average Energy

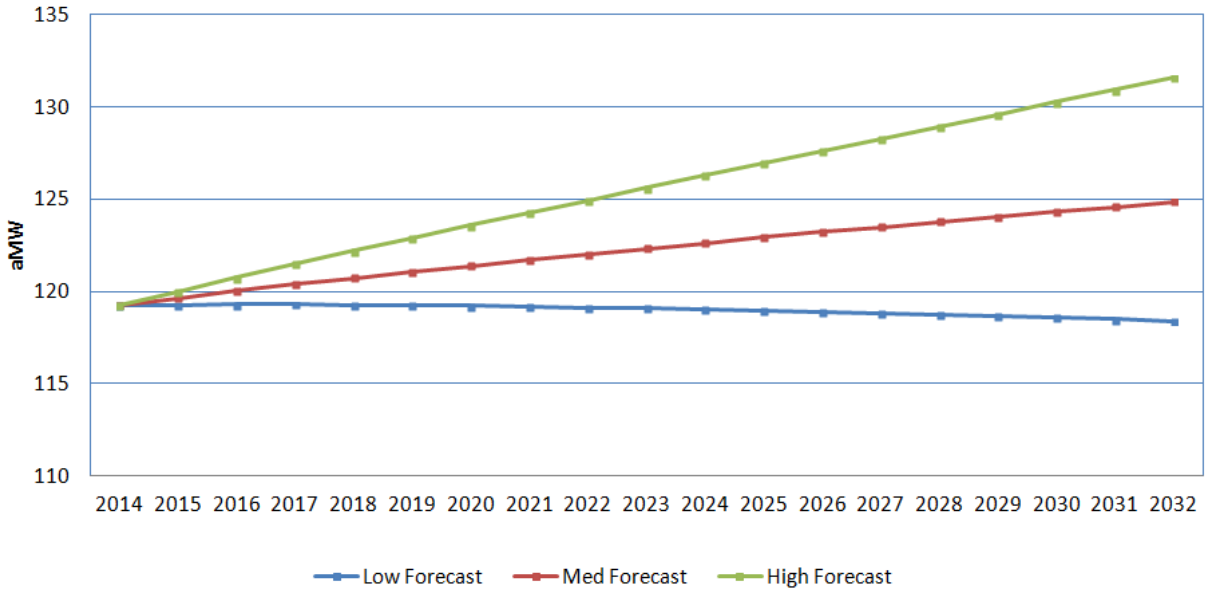
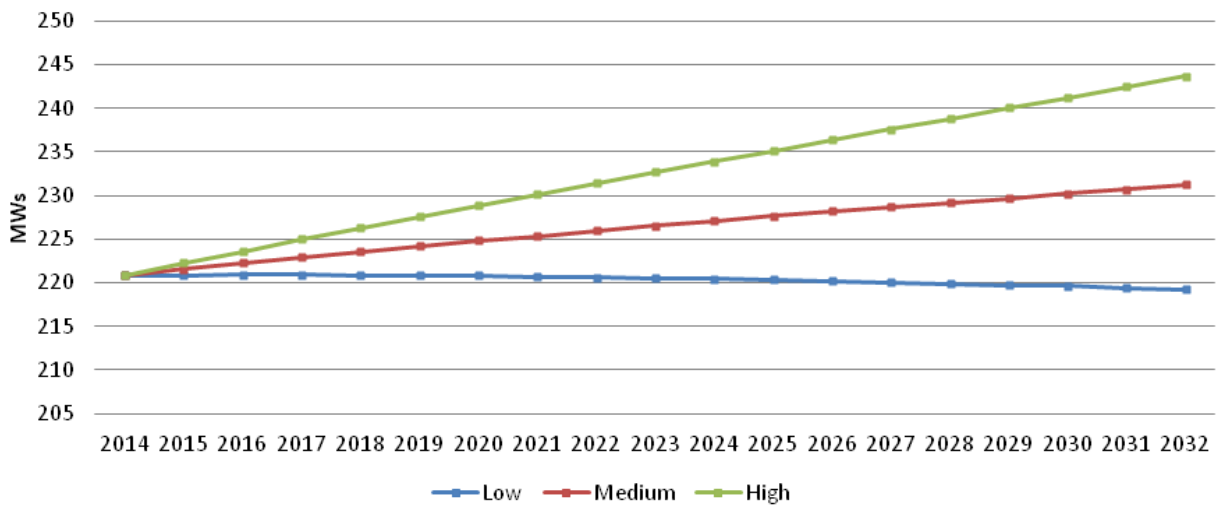


Figure 2: Load Forecast Scenarios - Annual Peak



Current Resources

Franklin PUD's existing resources consist of a Bonneville Power Administration (BPA) contract for the Slice/Block Product, output from the Frederickson Generating Station in Tacoma, contracts for wind from two projects, Nine Canyon and White Creek, contracts for power from two hydro projects, Packwood and Esquatzel, and energy efficiency, or conservation.

BPA Purchases

Under the Slice portion of the Slice/Block contract, BPA provides power indexed to the capability of the federal system and Franklin PUD is responsible for shaping its resources and additional purchases and sales to meet its loads.

The Slice/Block contract caps the amount of the Federal Base System (FBS) that can be sold through the Slice product. The District purchases a portion of its supply from BPA via monthly flat blocks shaped to its monthly net requirement. Approximately 48 percent of Franklin PUD's net BPA purchase is Slice and the other 52 percent is Block. Franklin PUD's maximum Slice percentage (or share of the FBS) is .78 percent.

Slice percentages were determined assuming FBS capability under critical water. If actual water conditions and associated FBS capability exceed critical water in a given year, the District may sell surplus energy on the market or displace other more costly resources. The amount of surplus energy in a given hour, day, month and year is dependent upon water conditions and the extent to which the resulting FBS capability exceeds utility load requirements.

As such, BPA's Slice Product has firm and non-firm components. The firm component is based on critical water firm load carrying capability. Because the timing of loads and firm output of FBS do not match perfectly within the year, the entire firm component may not be available in a shape that can meet the District's load requirements. Likewise, at other times part of the firm component may be surplus to its load requirements. The surplus firm component is likely to occur in spring months, when water

conditions are high and exceed BPA's planned firm requirements loads in the region. The non-firm component is surplus power above critical water and is delivered as available in other periods of an operating year.

Frederickson Generating Station

The Frederickson Generating station is a 249 MW natural gas-fired combined cycle combustion turbine plant. The District has a contract with Atlantic Power for 30 MW of capacity from the plant. Frederickson served about 4.9 percent, 5.7 aMW in 2013, of Franklin PUD's annual average load and can serve about 14 percent of its peak requirement. The plant is economically dispatched when it can serve load and/or produce energy below market price.

Nine Canyon Wind Project

The Nine Canyon Wind Project is an Energy Northwest-owned wind generation resource in Kennewick, WA. Developed in three phases, the aggregate capacity of the Project is 95.6 MW. Franklin PUD entered into a power purchase agreement with Energy Northwest for 10 MW of the generation capacity of the project, including the environmental attributes it produces, that extends through June 2030. These attributes will help Franklin PUD fulfill its future EIA renewable requirements. Nine Canyon has an expected capacity factor of 30 percent, also equating to an annual energy output of 3 aMW.

White Creek Wind Project

Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project has a total capacity of 205 MW, and Franklin PUD contracts for 10 MW of capacity, including environmental attributes, through 2027. With a capacity factor of around 30 percent, Franklin PUD receives an annual energy output of 3 aMW from the project.

Packwood Lake Hydro Project

The Packwood Lake Hydroelectric Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an annual output of approximately 10 aMW. It is owned and operated by Energy Northwest, but 12 Washington PUDs are participants in the project with "ownership-like" rights. Franklin PUD receives a 10.5% share of the output from the project, .7 aMW under critical water conditions, and approximately 1.3 aMW under average water. The project does not qualify as a renewable resource and will not help Franklin PUD meet its EIA obligations.

Esquatzel Hydro Project

Franklin PUD is purchasing all of the rights to the power and environmental attributes generated by the .9 MW Esquatzel Canal Hydroelectric Project in Pasco through 2031. The project generates power year-round – producing roughly 6,000 MWh annually. Esquatzel is an EIA eligible renewable resource, and because its generating capacity is less than 5 MW, it is also classified as "distributed generation," which will allow its environmental attributes (RECs) to count double. The Esquatzel project received California Energy Commission (CEC) certification as a qualifying renewable project effective December, 2012.

Conservation (Energy Efficiency)

Franklin PUD has had a conservation program since the early 1980s. In 2013, the District acquired approximately 1 aMW of new conservation. Programs for all customer classes are offered to help

reduce their energy consumption and thus their electricity bills. Conservation programs also help meet regional goals set by the Northwest Power & Conservation Council and BPA.

Loads and Resources

Existing resources and forecast requirements for new resources needed to meet load growth are shown in Figure 3 and Figure 4. The medium case forecast assumes that the District will continue to rely on a BPA power purchase agreement, Packwood, Esquatzel and Nine Canyon through the study period; the Frederickson plant until mid-2022; and White Creek through 2027. Although only a forecast, it provides the most reasonable basis for determining the amount of needed acquisitions.

Figure 3: Medium Case Load Forecast (Annual Average Energy) and Resource Stack

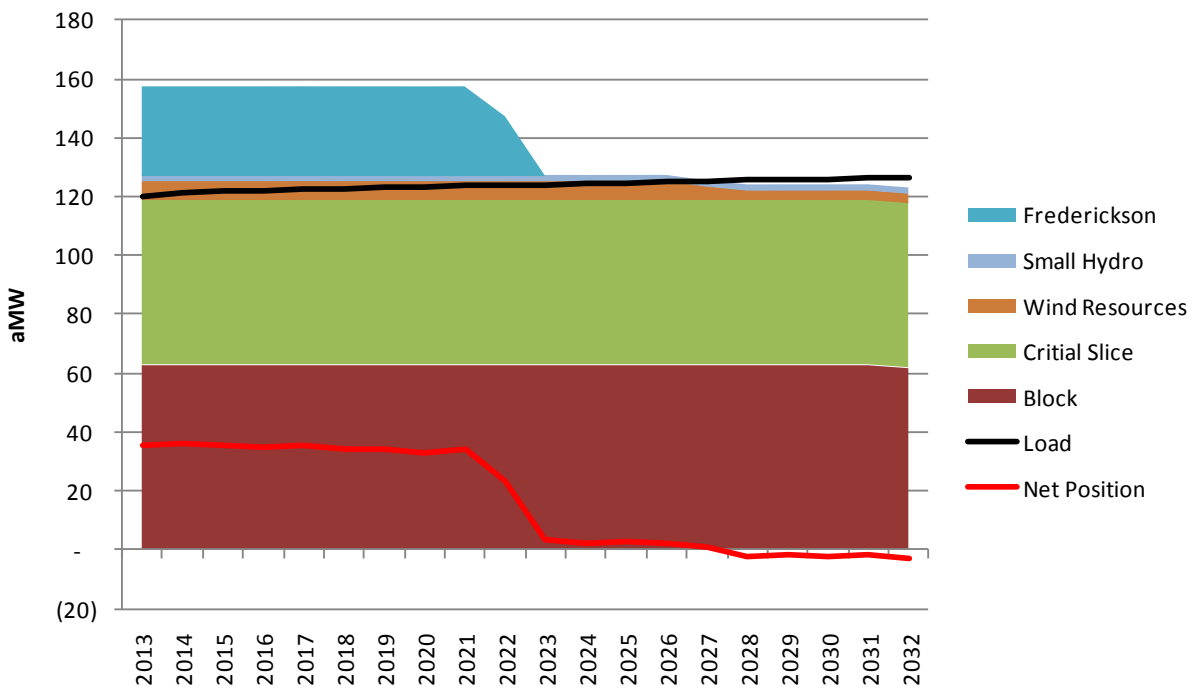
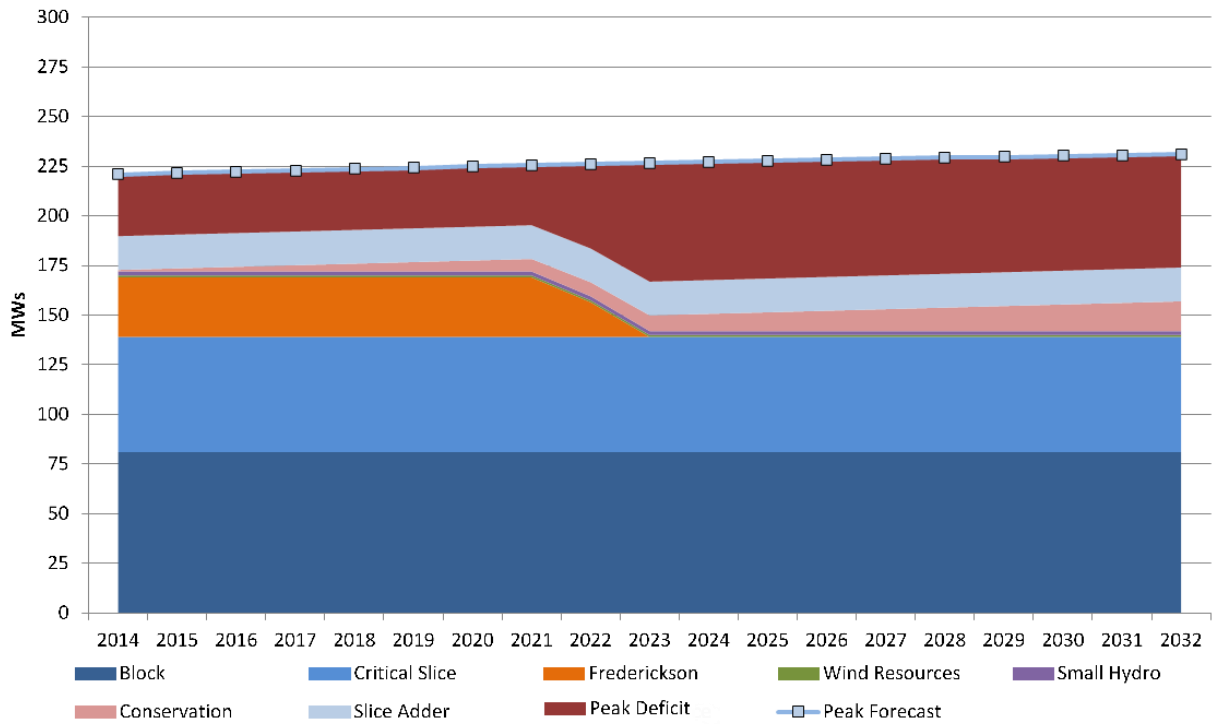


Figure 3 shows the District will be long on resources on an average annual basis until 2022 assuming Critical Slice, and thereafter loads and resources will be nearly equal through the planning period with small deficits beginning in 2028. Not included on the figure is additional Slice generation that would be expected under water conditions greater than Critical Slice.

Figure 4 shows estimated peak energy requirements, or the highest expected one-hour load during the year. The Peak Forecast line on Figure 4 is the "Medium" scenario depicted on Figure 2 and the District's peak requirement is compared to existing resources, which are shown on an average annual basis. This is somewhat of an "apples to oranges" comparison because just as there is variability in load by hour, day, month and season, there is also a difference in available resources because of the variability in hydro and wind. In addition to Critical Slice, this figure also includes a "Slice Adder" of 17 aMW, representing the difference between Slice generation expected to occur in an average year and Critical Slice. Even with this additional generation, the District will be short on capacity at times to meet

its peak load requirements, typically in the summer, and not often. As an example of the infrequency of loads exceeding resources, it is estimated that 2013 loads exceeded the average amount of expected generating resources available just 2% of the time, less than 200 hours. In 2022, when the Frederickson contract expires, that may increase to about 5%, or 500 hours. This capacity shortage can be handled with market purchases, resource development or contracted resources. With the Slice product, the District also often has the ability to shape generation as needed to meet a capacity shortage, thereby reducing market exposure to more expensive market purchases during heavy load hours. The options for meeting peak energy requirements are discussed in detail in the IRP.

Figure 4: Highest Expected One Hour Annual Peak Forecast (Medium Case) and Existing Resource Stack



Resources to Meet Future Growth

Peaking strategies are needed to meet current third-quarter summer peak shortages that will be exacerbated in 2022 when the Frederickson contract ends. The strategies examined in the IRP include market purchases, resource development, and continuing conservation programs even before EIA requirements are imposed. Under the mandates of the EIA, conservation should be the first resource used to meet load growth. Beyond conservation, supply side resources that could be chosen vary widely in their operating characteristics, cost, and availability. These aspects are covered in detail in the report.

Conservation Resources

The EIA requires utilities with 25,000 or more customers to acquire all available cost-effective, reliable and feasible conservation, consistent with the Northwest Power and Conservation Council's methodologies. Although Franklin PUD is not currently a qualifying utility under the EIA, it likely will be

by 2016. Franklin PUD's annual conservation target assumed in the IRP is .8 aMW, which is slightly above the Council's 5th Plan target amounts.

Supply Side Resources

Supply side resources can be divided into two categories—variable and non-variable. Most resources that are variable are also eligible renewable resources, such as wind and solar power. Some renewable resources are dispatchable, such as landfill gas and biomass. Non-renewable resources typically are non-variable, or dispatchable.

This will be an important distinction when Franklin PUD is required under the EIA to meet increasing eligible renewable requirements to serve customer loads. This requirement can be met by purchasing eligible renewable resource output directly or by purchasing non-eligible power and supplementing with the purchase of RECs. However, the uncertainty of relying on the future acquisition of RECs is that they may turn out to be unavailable or available only at highly inflated prices. The pricing uncertainty was captured in the resource portfolios modeled in Chapter 6. Figure 5 below shows Franklin PUD's current and forecast REC position.

Figure 5: Franklin PUD's REC Position through Study Period

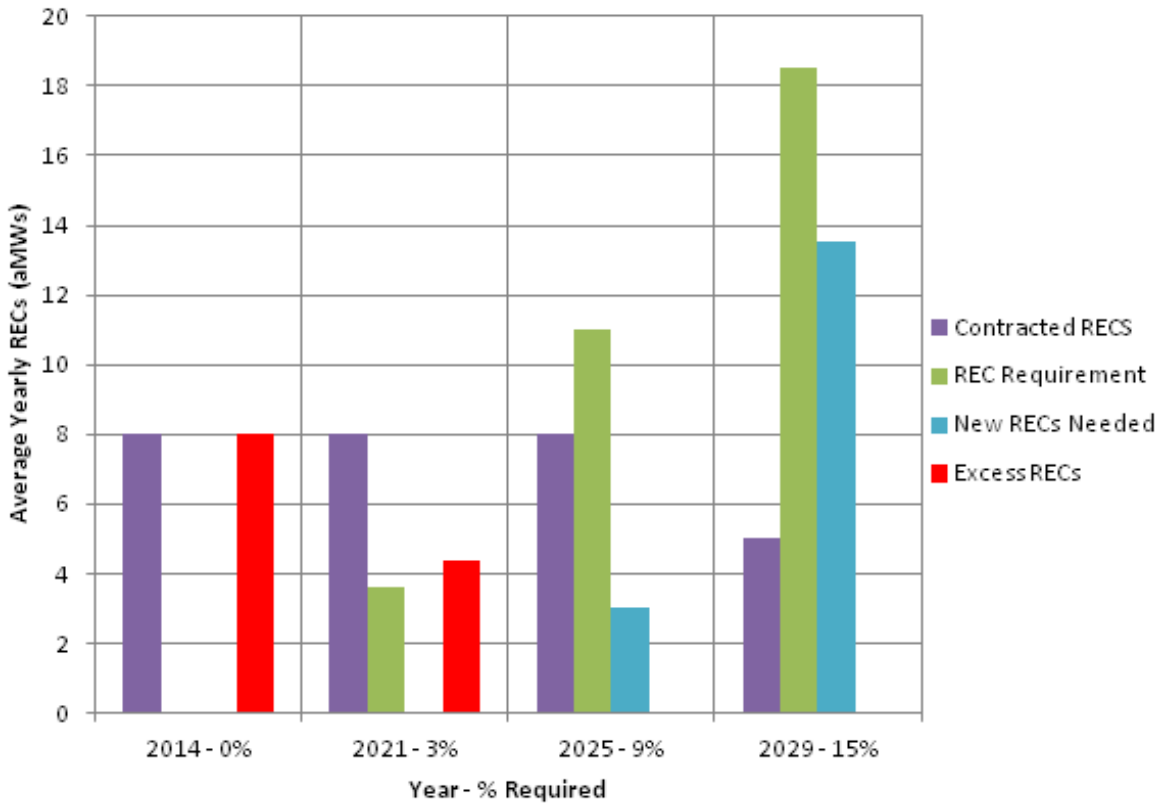
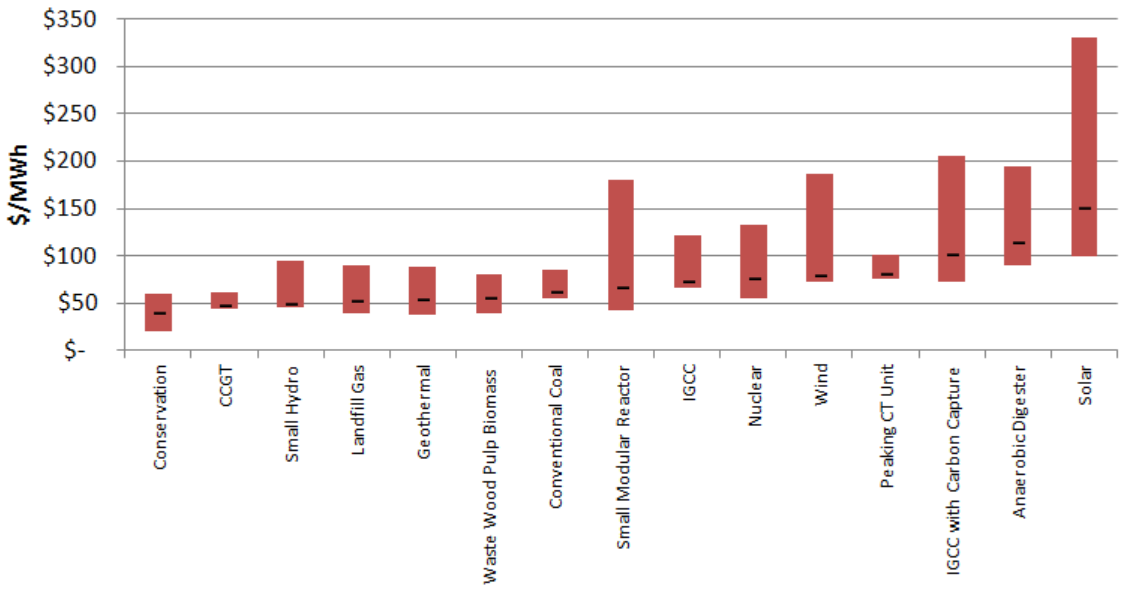


Figure 6 summarizes the resources that were considered in the IRP analysis and their approximate costs. The floating red bars represent the range of probable generation costs, and the black dash in each bar represents the expected levelized generation cost over the life of the resource. Those that are considered eligible renewable resources are geothermal, wind, biomass (waste wood and dairy

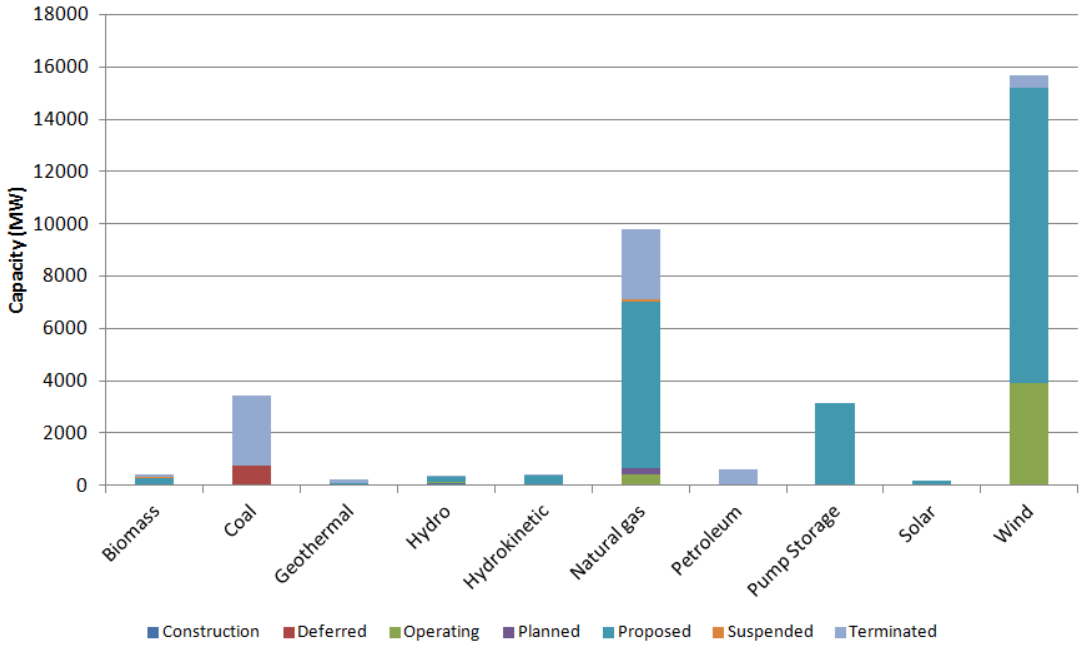
digester), small hydro, landfill gas and solar. Nonrenewable resource options are natural gas, nuclear, and coal (conventional and IGCC), and market purchases.

Figure 6: 20-Year Levelized Costs of Various Resources



In addition to cost, consideration is also given to availability of each resource. For example, landfill gas generation is low cost, renewable and reliable, but its supply is small because there are a limited number of landfills. Figure 7 shows the relative availability of various resources.

Figure 7: Power Plant Development Activity in the Pacific Northwest[1]



Source: *NWPCC PNW Power Plant Development*

[1]*Data displayed from 2010 to 2013.*

Strategies for Resource Consideration

Ten portfolios were modeled in the IRP that allowed the District to consider potential resource choices for both energy and RECs when needed. The portfolios included a range of dispatchable and non-dispatchable, renewable and non-renewable generation and contract resources, including market purchases of both energy and RECs. The selected resources that comprised the portfolios are listed below, grouped by four strategies for comparison.

Strategy 1: Keep the status quo

- Portfolio 1: Rely on the market to cover energy shortages and purchase RECs for renewable target deficits.

Strategy 2: Acquire resources to meet RPS and energy requirements

- Portfolio 2: Market purchases for 3rd Quarter seasonal deficits; additional wind to meet RPS
- Portfolio 3: Market purchases for 3rd Quarter seasonal deficits; biomass to meet RPS
- Portfolio 4: Market purchases for 3rd Quarter seasonal deficits; landfill gas to meet RPS

Strategy 3: Acquire resources to meet only energy deficits (Q3 and annual average)

- Portfolio 5: Acquire nuclear to meet energy shortage; RECs for RPS deficits
- Portfolio 6: Acquire combined cycle natural gas to meet energy shortage; RECs for RPS deficits

Strategy 4: Acquire resources to meet average annual energy, Q3 energy and RPS requirements

(District will be in energy load/resource balance under critical hydro conditions; surplus with average hydro conditions)

- Portfolio 7: Acquire single cycle CT for energy; landfill gas for RPS
- Portfolio 8: Acquire small hydro to meet energy and RPS needs; biomass for RPS
- Portfolio 9: Acquire single cycle CT for energy needs; landfill gas and solar for RPS
- Portfolio 10: Acquire biomass and landfill gas for both energy and RPS needs

The total power costs over a 20-year horizon were calculated for each portfolio. If a portfolio provided more power than needed in a given year, the excess was assumed to be sold on the market.

The results of the portfolio analysis showed a tradeoff between price, risk and resource availability. Resources that could fulfill both future energy and RPS requirements, such as landfill gas, tend to be in short supply. Wind, a fairly plentiful renewable resource, is less economical and cannot be depended on to supply capacity. Fossil-fueled resources have a combination of permitting, construction, and fuel-risk challenges.

Conclusions

- Based on the medium load forecast, Franklin PUD has sufficient annual average energy capability to meet its annual average energy requirements until 2028.
- Franklin PUD will not need peaking capability until 2022.

- With medium load growth assumed, the requirements of the EIA, coupled with sufficient annual average capability and a peak deficiency, dictate the purchase of RECs unless the cost cap under the EIA is triggered.
- Assuming Franklin PUD reaches 25,000 customers in 2015, the District will not need to purchase RECs to meet the EIA renewable requirement until 2025.
- All cost-effective conservation will be included in the resource plan.
- BPA Tier 1 power will be the lowest cost resource.
- Based on the District's current assumptions and positions, Strategy 1 will be adopted going forward.

Action Plan

The following actions summarize the recommended action plan in Chapter 7 of this IRP.

- The District is not expected to need additional energy generation resources until 2028, but currently projects REC deficits associated with Washington's RPS requirement beginning 2025.

- Based on the information available today, the preferred long-term portfolio would be to rely on the market to fulfill both energy and REC deficits.

- Energy deficits are most likely to occur in the 3rd quarter. The District should utilize short term market purchases to cover energy deficits, thereby reducing its market exposure.

- Continue to operate the Frederickson plant as cost-effectively as possible for its capacity contribution, and use it as a hedge against future prices. As the contract termination date approaches, plan for addition of another capacity resource.

- Monitor market conditions and the ongoing economic and technical viability of landfill gas, biomass, and other dispatchable resources that would satisfy the demand for both capacity and RECs. Also monitor conditions for small modular nuclear, a CO_2-free capacity resource with some dispatch capability.

- Complete a detailed conservation potential assessment to prepare for upcoming EIA requirements and to assess shorter term conservation (demand-side management) planning.

- Before any further REC or renewable acquisitions are made, it is important that the District fully understand the RPS "cost cap" alternative compliance mechanism.

- Monitor changes in the price and volatility of wholesale electricity, natural gas, and RECs that may require changes to the District's plan.

- Complete analysis on distributed generation and the potential effect it could have on future load growth if there is a significant increase in projects within the District's service territory due to State and Federal incentives and third party ownership options.

- The District should assess the economics of changing its BPA contract from Block/Slice to Load Following starting in FY2019. If the analysis indicates this is a preferred option, notice must be given to BPA no later than May 31, 2016.

This IRP examined renewable and energy needs based on District forecasts. While the forecasts were constructed using the best available information, the District will continue to monitor load growth, which can change and with it the energy and renewable requirements.

Chapter 1: Overview and Objectives

Franklin PUD Overview

Since its establishment in 1938, Franklin PUD (also referred to herein as "the District") has worked to improve the quality of life for the people who live in its service area. Franklin PUD has successfully provided its customers with outstanding customer service while meeting their electricity needs at cost in a reliable and sustainable manner. Today, Franklin PUD provides power to more than 24,000 customers, through 1,024 miles of transmission and distribution lines, in an area encompassing 435 square miles.

Maintaining a diverse resource portfolio helps Franklin PUD keep rates affordable. Franklin PUD is a preference customer of the Bonneville Power Administration, which provide access to one of the lowest cost resources in the Pacific Northwest. In addition, Franklin PUD has a contract for energy from a natural gas combined cycle combustion turbine and from a small conduit hydro project, has a 10% interest in another small hydroelectric project, and purchases output from two wind generation facilities. Franklin PUD also maintains a robust conservation program.

The current planning environment that confronts Franklin PUD is one of the most challenging in its history. These challenges include ever-changing state and federal regulations; state, national, and global economic volatility; and an increasingly constrained hydropower system. State mandated portfolio standards oblige utilities across the Western Interconnection, an area that includes all or parts of the 14 western US states, two Canadian provinces, and the northern part of Baja California in Mexico to acquire renewable resources and aggressively pursue conservation measures. Some utilities have dramatically altered their long term strategies based on expectations of federal carbon emission laws coming into effect. The District must balance its obligation to meet regulatory requirements with the duty to acquire resources that are "least cost" and help mitigate financial volatility.

This Integrated Resource Plan (IRP) establishes a strategic direction for Franklin PUD with flexibilities to make appropriate decisions as conditions change.

Resource Planning – House Bill 1010

In 2006, the Washington State legislature enacted House Bill 1010, later codified in RCW 19.280, which mandates that electric utilities develop "comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers' electricity needs in both the long term and the short term." The law applies to utilities that have more than 25,000 customers and are not load-following customers of the Bonneville Power Administration. The law stipulates that qualifying utilities must produce a full plan every four years, and provide an update to the full plan every two years.

Non-load-following customers of BPA with less than 25,000 customers, such as Franklin PUD, are required to do a simpler, more streamlined document known as a resource analysis. The District submitted the required resource analyses to the Washington Department of Commerce in 2010 and 2012, but has prepared this more comprehensive IRP to help guide resource decisions.

Energy Independence Act – Initiative 937

In 2006 Washington State voters approved the Energy Independence Act (hereinafter "the EIA" or "the Act" or "I-937"). The Act places renewable resource and conservation requirements on utilities with customers exceeding 25,000 (qualifying utilities). Qualifying utilities that fail to meet the either the renewable resource or conservation requirement will be assessed a $50 per MWh penalty (in 2007 Dollars, adjusted for inflation). Franklin PUD currently is not a qualifying utility as it has fewer than 25,000 customers. Thus, its expected compliance dates will be shifted out as discussed below.

Energy Independence Act Conservation Requirement

The Energy Independence Act stipulates that each qualifying utility shall implement all available conservation that is "cost effective, reliable and feasible." The law mandates that utilities evaluate conservation programs using the framework established by the Northwest Power and Conservation Council ("NWPCC" or "the Council") in its most recent power plan. Each utility is required to publish its conservation acquisition targets and plan over a 10 year time horizon.

Franklin PUD is expected to cross the 25,000 customer threshold in 2015 and thus become a qualifying utility on January 1, 2016. In 2020, it would then be required to publish and begin implementation of a 10-year conservation plan. Two years later, in 2022, and every two years thereafter, it would be audited by the Washington State Auditor for its conservation achievements, as well as for compliance with the renewable resource provisions of the Act. For additional detail, please see Chapter 3: Conservation.

Energy Independence Act Renewable Portfolio Standard (RPS) Requirement

The District has acquired or contracted the rights to three projects that are considered qualifying resources under the Act: the White Creek wind project, Nine Canyon wind project, and Esquatzel Canal hydroelectric project. It also receives a small number of RECs (.4 aMW) from its Tier 1 power purchases from BPA. Figure 8 shows the District's current qualifying resources. The BPA, Nine Canyon and Esquatzel RECs are assumed to remain in the District's portfolio for the balance of the study period, and after the current contracts expire on the dates shown in Figure 8. The White Creek contract will expire in 2027, however.

Figure 8: Current EIA Qualifying Resources

Resource	Size (Capacity)	Length of Contract	aMW RECs Generated
Nine Canyon Wind	10 MW	2030	3
White Creek Wind	10 MW	2027	3
Esquatzel Hydro	1 MW	2031	1
BPA RECs		2028	0.4

Assuming the District becomes a qualifying utility in 2016, it will be subject to a 3% RPS beginning in 2021 that it will be able to meet with its current renewable portfolio. When the RPS increases to 9% beginning in 2025, the District will need to acquire sufficient qualifying renewable resources to increase its average number of RECs by 3 per hour to fulfill its requirements. That deficit increases to roughly 14

average RECs needed per hour in 2029 when the requirement bumps up to 15%. This shortage is discussed in Chapter 2. Surplus RECs can be sold or banked for a 12-month period before they expire. REC deficits can also be covered through market purchases.

It is important to note that these estimates of the District's requirement ignore two important provisions of the Act that are discussed in the next section.

RCW 19.285 Alternate RPS Compliance

4% Cap on Incremental Expenditures on Renewable Resources

A utility can comply with the Act's renewable requirement without meeting the standard discussed in the previous section if it has invested 4% of its total annual retail revenue requirement on the incremental levelized cost of qualifying renewable resources. The intention of this provision is to limit the impacts of the law on retail rates. The law states*:*

> *"The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources where the resources being compared have the same contract length or facility life."*

Load Loss Limitation

The Act also allows for utilities not experiencing load growth to comply with the Act if they do not invest in any resources except renewables, and have invested at least one percent of their total annual retail revenue requirement on eligible renewable resources, renewable energy credits, or a combination.

A principal driver of resource acquisition for the District is achieving compliance with the Act. It is important that the District have a full understanding of the cost-cap and load loss mechanisms before it commits to further additions of resources. Franklin PUD is studying this issue and believes that it may comply with the Act by reaching the 4% target. Analysis is ongoing on this matter.

Objectives of the IRP

This document will serve as a road map to identify reliable, cost-effective, sustainable strategies to meet the electric power requirements of Franklin PUD's customers over the next 20 years.

An IRP serves as a means for a utility to study various long-term power supply portfolio strategies and provides an opportunity to test the robustness of various power supply portfolios under changing circumstances in the future. An IRP seeks to determine (1) the timing of when new resources are required, (2) the amounts of new resources, and (3) the types of new resources preferred within a portfolio. In addition, an IRP seeks to assess risks and risk management considerations for various resource planning options.

Although the time horizon of the study period is 20 years, an IRP is typically developed with an understanding that it needs to be continually reviewed, revised and updated to reflect changes in the utility industry. Over the past decade, utilities have been subject to increasing price volatility associated

with providing energy to retail customers and reduced certainty of supply. Looking forward, utilities face significant risks due to uncertainty of future wholesale natural gas and electricity prices, ongoing attempts by federal agencies and others to develop competitive electricity markets, and changing regulatory requirements.

Using a resource planning process to develop a roadmap for the future makes sense from a good business and utility planning perspective. Resource planning involves studying a broad range of alternative strategies including investments in energy conservation and demand-side options, and investments in renewable and non-renewable power generating resources.

IRP Approach

The approach to Franklin PUD's IRP modeling can be summarized in the following process:

1. Determine Resource Needs: Calculate the requirements for new resources under different load forecast assumptions.

2. Screen for Appropriate Resources: Identify the availability and cost of generic supply-side and demand-side resources.

3. Select Appropriate Strategies and Associated Portfolios: Select the preferred strategy and associated mix (or portfolio) of supply- and demand-side resource options for further analysis. Perform analysis to determine twenty-year power supply costs.

4. Perform Risk and Uncertainty Analyses: Perform sensitivity analyses on the preferred resource portfolios to determine the significance of changes in resource costs and capabilities, load forecasts and other variables. The analysis identifies the risks and uncertainties associated with the preferred resource portfolios.

5. Based on the results of the analysis, develop an action plan.

Organization of the Report

This report is divided into the following chapters:

Chapter 2 – Load Forecast and Incremental Power Requirements

Chapter 3 – Conservation

Chapter 4 – Federal Supply-Side Resource Options

Chapter 5 – Non-Federal Supply-Side Resource Options

Chapter 6 – Risk Analysis and Portfolio Selection

Chapter 7 – Action Plan

Chapter 2: Load Forecast and Incremental Power Requirements

Introduction

The cornerstone of the IRP is a forecast of incremental future electric power requirements. This forecast is obtained estimating gross future electric power requirements through the timeframe of the IRP, then subtracting owned and contracted resources amounts to determine the forecasted incremental electric power requirements. These incremental requirements can be met through a myriad of different demand and/or supply-side resource options.

These incremental requirements may be quite different for any hour depending upon time of year, day of week, and time of day. Standard industry practice has been to group the requirements into two distinct categories, Average and Peak. For the purposes of this IRP, three different requirements will be modeled and planned for; an annual average energy requirement, a typical annual peak requirement, and analysis of an extreme weather event. The annual average energy requirement is the average of all forecasted requirements over a calendar year. The annual peak requirement is the largest forecasted one-hour requirement within the calendar year. An extreme peak analysis was performed to plan for rather rare events that would cause load excursions. This IRP will use an approach that the District has successfully utilized for several years now to determine the requirements and resource forecasting necessary to maintain system reliability at an acceptable economic cost.

This section first examines the forecast of gross electric power requirements for the study period 2013 through 2032. Assumptions regarding existing resources will then be outlined.

Gross Power Requirements

Gross power requirements are the amounts of electric energy the District's customers require, as measured at its distribution substations, for heating, lighting, motors and other end-uses. These requirements are also known as system load. The District must be ready to supply the system load demands placed upon it from its customers at any time.

Low, medium and high case system load forecasts for the period 2013 through 2032 were developed for analysis in the IRP. The low and high cases provide a reasonable representation of a range of possible outcomes for the service area. The load forecasts provide projected monthly energy and peak demand requirements that are used to determine future resource requirements on an annual basis.

The conservation acquisition assumptions described in Chapter 3 are included in all three load forecast scenarios. Each scenario assumes .8 aMW of conservation will be acquired annually during the study period.

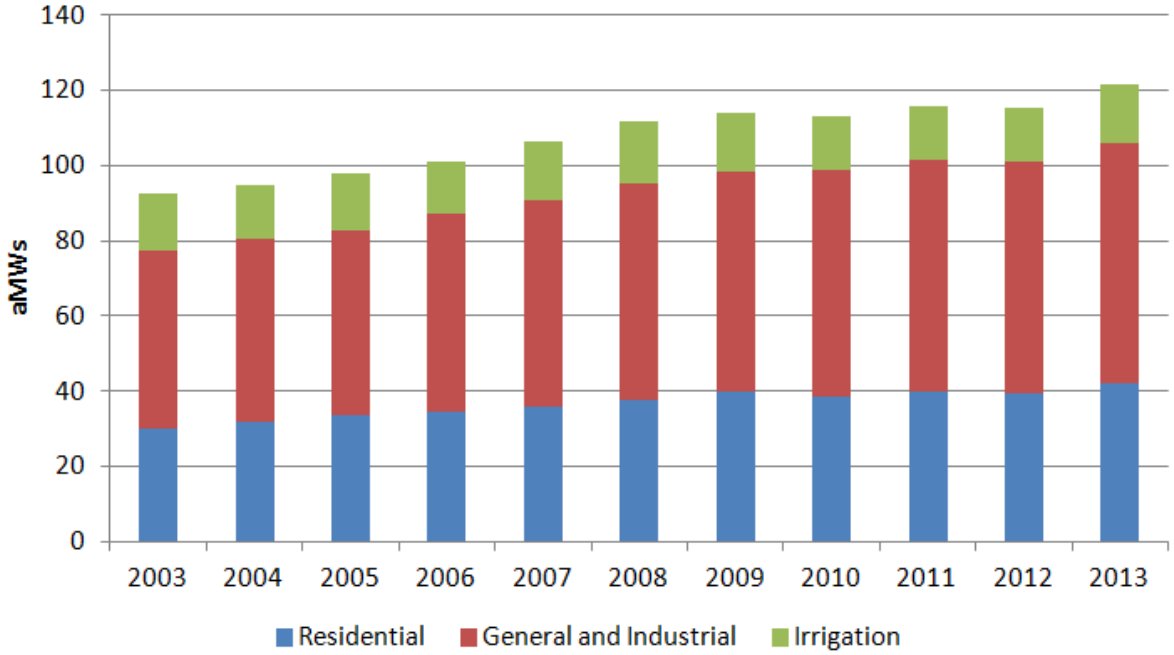
20-year Annual Load Forecast

Load forecasting is the process of estimating the amount of energy that the District's customers will use in the future. The load forecast is one of two key determinants used to identify the District's resource needs over a 20-year period, the other determinant being existing and committed resources. This section describes the forecast assumptions used in the IRP.

Franklin County was one of the fastest growing counties in the nation, with population increasing from 55,000 to 84,800, or 54 percent, between 2003 and 2013. The economic downturn the state and nation faced between 2008 and 2012 was not as severe in the Tri-Cities region, which received a good deal of economic stimulus money from the federal government for work at the Hanford site. However, there was a delayed effect when the money was gone. While unemployment in the state and nation were decreasing, the Tri-Cities' unemployment was increasing. At the end of November, 2013, the Tri-Cities unemployment rate was 8.1 percent, the State's was 6.8 percent, while the nation was slightly higher, at 7.0 percent.

During that 2003 through 2013 period, Franklin PUD's gross annual power requirements increased by 30 percent, from 93 aMW to 122 aMW. The load growth rate peaked in 2008, with a 5.5 percent annual increase, as residential, commercial and industrial growth in Pasco exploded. The load growth rate declined in 2010 and 2012 on account of a slowing economy, and weather-related factors. In 2013, loads increased by 5.1 percent over 2012 loads. Changes in retail sales by major customer class are illustrated in Figure 9 below.

Figure 9: Historical Retail Load by Customer Class



Average Energy Forecast

Looking at the 20-year IRP planning horizon, the medium load forecast is the base case, and includes a long-term growth rate of .35 percent, the high forecast includes a growth rate of 1.30 percent, while the low case shows a load loss of .70 percent. These forecasts include the .8 aMW annual conservation acquisition amount discussed in Chapter 3. The low and high forecasts will be used in this IRP to provide a range of reasonable future outcomes. Figure 10 shows the forecasts of annual system energy requirements in annual average megawatts. Low, medium and high forecast figures by year are provided in Figure 11.

Figure 10: Forecasted 2012-2032 Annual Average System Energy Requirements

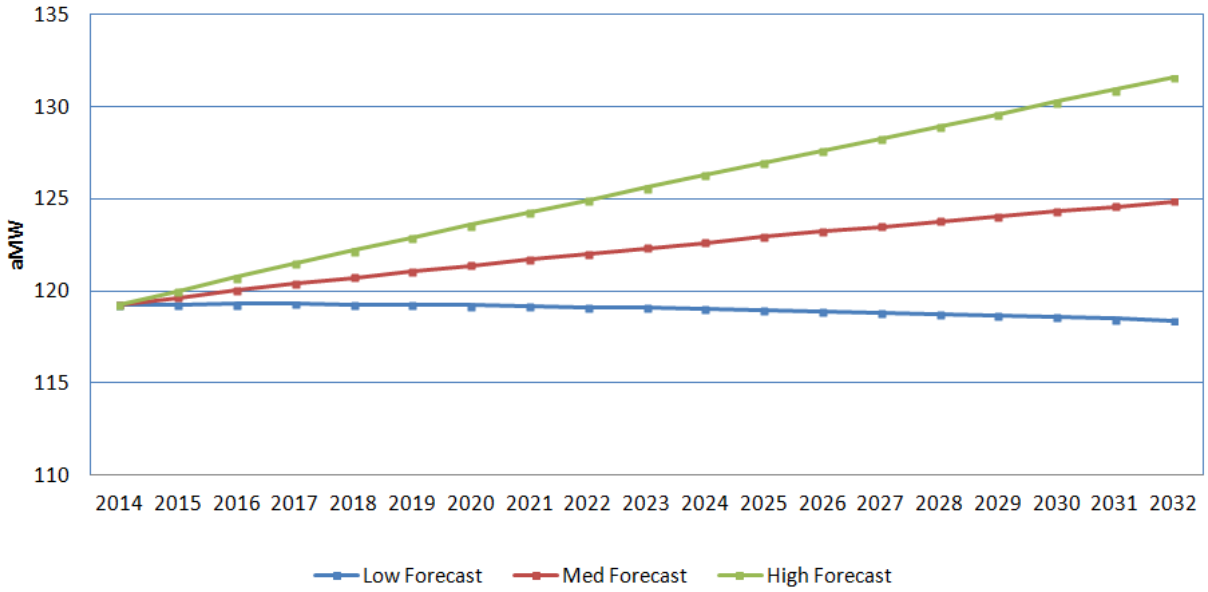


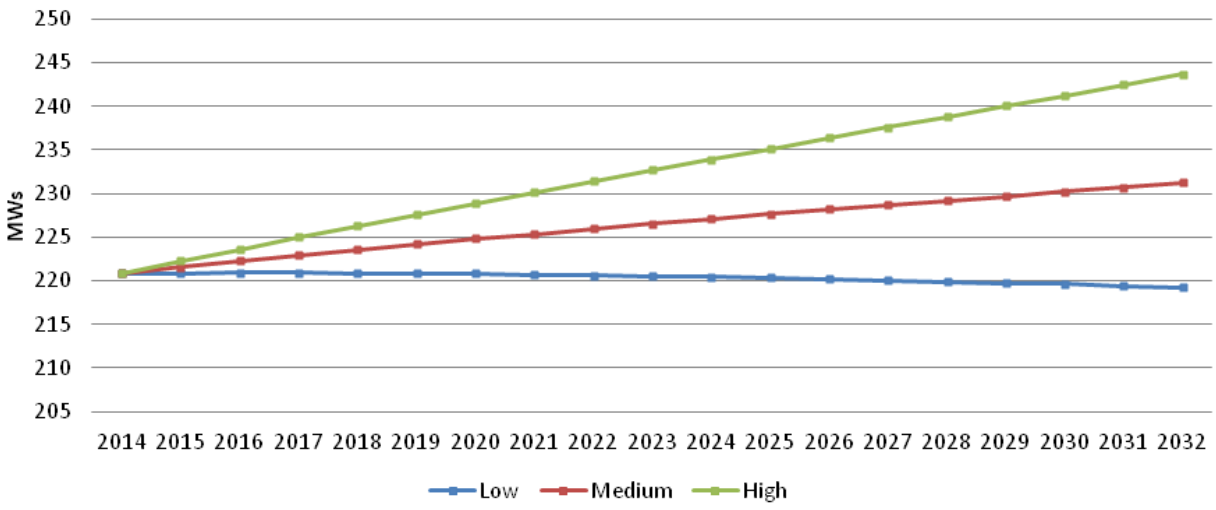
Figure 11: Low, Medium and High Loads Forecasts 2014 – 2032

	aMWs		
Year	Low	Med	High
2014	119.2	119.2	119.2
2015	119.3	119.6	120.0
2016	119.3	120.0	120.7
2017	119.3	120.4	121.5
2018	119.3	120.7	122.2
2019	119.3	121.1	122.9
2020	119.2	121.4	123.6
2021	119.2	121.7	124.3
2022	119.1	122.0	124.9
2023	119.1	122.3	125.6
2024	119.0	122.6	126.3
2025	119.0	122.9	127.0
2026	118.9	123.2	127.6
2027	118.8	123.5	128.3
2028	118.8	123.8	128.9
2029	118.7	124.0	129.6
2030	118.6	124.3	130.3
2031	118.5	124.6	130.9
2032	118.4	124.8	131.6

Annual Peak Forecast

Figure 12 shows three forecasts of gross electric power annual peak requirements used in this IRP. These forecasts are based on an average annual historical load factor of 54 percent.[1] Peak system requirements will be discussed in more detail later in this chapter.

Figure 12: Forecast of Annual Peak Energy Requirements



Medium Case

Forecasts of Franklin PUD's energy and peak system loads for selected years are shown in Figure 13. This medium system load forecast scenario assumes .35 percent annual load growth.

Figure 13: Medium Case Forecast of Gross Power Requirements

Medium Case: Forecast of Gross Power Requirements
2014 – 2032

Year	Annual Energy (MWh)	Annual Energy (aMW)	Annual Peak Demand (MW)	Annual Load Factor
2014	1,044,583	119	220	54%
2020	1,066,232	121	225	54%
2026	1,079,299	123	228	54%
2032	1,096,660	125	231	54%

Low Case

The low case load forecast can be seen in Figure 14. This forecast case accounts for scenarios where load growth is lower than currently expected. Factors leading to lower load growth could include economic slowdowns, especially from impacts at the nearby Hanford site, and a slowing housing market. The low case load forecast is based on an average annual decline in growth of .70 percent.

[1] The load factor is defined as the average load divided by the peak load in a specified time period. Its value is always less than one because maximum demand is always more than average demand. A high load factor means power usage is relatively constant. Low load factor shows that occasionally a high demand is set.

Figure 14: Low Case – Forecast of Gross Power Requirements

Low Case: Forecast of Gross Power Requirements
2014 - 2032

Year	Annual Energy (MWh)	Annual Energy (aMW)	Annual Peak Demand (MW)	Annual Load Factor
2014	1,044,583	119	220	54%
2020	1,047,197	119	220	54%
2026	1,041,641	119	220	54%
2032	1,039,992	118	219	54%

High Case

The high case load forecast can be seen in Figure 15. The high load forecast includes a 1.3 percent annual load growth rate. A higher growth rate could be attributed to greater than normal economic growth, greater population growth, increased consumption per customer, and industry shifts that bring more people into the area.

Figure 15: High Case – Forecast of Gross Power Requirements

High Case: Forecast of Gross Power Requirements
2014 – 2032

Year	Annual Energy (MWh)	Annual Energy (aMW)	Annual Peak Demand (MW)	Annual Load Factor
2014	1,044,583	119	220	54%
2020	1,085,570	124	229	54%
2026	1,118,053	128	236	54%
2032	1,155,850	132	244	54%

Existing Resources

Franklin PUD's resource mix is made up of hydroelectric, wind, nuclear and conservation (energy efficiency) resources with different delivery periods and shapes. To forecast Franklin PUD's incremental power requirements, the forecasted output from these resources will be subtracted from the forecasted gross power requirements. To forecast the output of these resources, both the average annual output plus the peak generation capability at the time of the gross power peak requirement must be modeled.

Existing Federal Resources

BPA Slice/Block Contract

Since 2001, Franklin PUD has been a BPA Slice/Block customer. The Slice product provides a percentage of output indexed to the actual production of the Federal Base System (FBS). The Block product provides a flat delivery of power across each month and is shaped throughout the year. Under critical water conditions, roughly half of the District's BPA power is provided by the Slice product and the other half comes from Block. The combination of the Slice/Block resource accounts for all of Franklin PUD's rights to Tier I power allocation or High Water Mark (HWM). Each utility's rate period HWM is recalculated for

each rate case (every two years) based on the forecast of Federal Base System output. For this study, it is assumed that Franklin PUD's HWM calculation will remain constant over the 20-year planning period. In addition, critical water conditions for the Slice product will be assumed, unless otherwise specified.

Existing Non-Federal Resources

White Creek Wind Project

Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project consists of 89 turbines, each with 2.3 MW of capacity, with a combined capacity of 205 MW. It came online and began generating electricity in November 2007. White Creek provides renewable energy and environmental attributes that will help Franklin PUD meet its EIA renewable requirements when its customer count exceeds 25,000 and it becomes a qualifying utility. Franklin PUD has contractual rights to a portion of the project's output, including all associated environmental attributes, through 2027.

With a capacity factor of around 30 percent, Franklin PUD receives an average energy output of 3 aMW from the project.

Nine Canyon Wind Project

The Nine Canyon Wind Project is an Energy Northwest-owned wind generation resource situated on dry land wheat farms approximately eight miles southeast of Kennewick in the Horse Heaven Hills. Phase I of the project consists of 37 wind turbines, with a total capacity of 48 MW. Phase II consists of an additional 12 wind turbines, totaling 15.6 MW of capacity. Phase III consists of 14 wind turbines with a total capacity of 32 MW. The aggregate capacity of the Project is 95.6 MW.

Franklin PUD entered into a power purchase agreement with Energy Northwest for a portion of the generation capacity of the project, including the environmental attributes it produces, that extends through June 2030, and the IRP assumes this contract will extend through the study period. These attributes will help Franklin PUD fulfill its EIA renewable requirements. Nine Canyon has an expected capacity factor of 30 percent, also equating to an average energy output of 3 aMW.

Frederickson Generation Project

Frederickson is a natural gas fueled combined cycle combustion turbine with a capacity of 249 MW. The power plant is located about 18 miles southeast of Tacoma, WA in Pierce County. Through a power purchase agreement that expires in August 2022, Franklin PUD controls 30 MW of the plant capacity. Each day, Franklin PUD has the right, but not the obligation, to purchase output from Frederickson at a heat rate of 7.1 MMBTU/MWh. The decision to buy output from Frederickson is based on the difference between the cost of Frederickson-generated power and the cost of power on the wholesale market. Generally speaking, Franklin PUD exercises the option when Frederickson-generated electricity is cheaper than what is available on the wholesale market. Conversely, if it makes economic sense to instead purchase power on the wholesale market, Franklin PUD does not exercise the right to purchase power from Frederickson.

Franklin PUD, along with Benton PUD and Grays Harbor PUD, are purchasing contract capacity under separate but virtually identical agreements. Together, the three PUD's have contract rights to 125 MW

of the plant's total 249 MW. Up to 40 percent of the plant capacity may be displaced regardless of the dispatch decisions of other purchasers; however, the heat rate may increase to a maximum of 7.952 MMBTU/MWh. The power purchase agreement is set up as a tolling arrangement. When the plant dispatches, Franklin PUD purchases and delivers gas to the fuel receipt point just across the Canadian border at Huntingdon. The plant is responsible for transporting the gas from Huntingdon, burning the gas and delivering power to the point of delivery on the BPA grid at the South Tacoma substation. TEA is Franklin PUD's appointed agent for fuel management services for this plant.

Packwood Hydroelectric Project

The Packwood Lake Hydroelectric Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an average output of approximately 10 aMW. It is owned and operated by Energy Northwest, but 12 Washington PUDs are participants in the project with "ownership-like" rights. It is located 5 miles east of Packwood, Washington in Gifford Pinchot National Forest. Franklin PUD receives a 10.5% share of the output from the project, .7 aMW under critical water conditions, and approximately 1.3 aMW under average water. The original 50 year license expired in February 2009. A new license application was filed in February 2008 and the project continues to operate under an annual license which automatically renews. It is expected that the new license will be issued within 24 months. The project does not qualify as a renewable resource and will not help Franklin PUD meet its obligations under the EIA.

Esquatzel Canal Hydroelectric Project

The Esquatzel Canal, which discharges into the Columbia River, is located about 5 miles north of Pasco, in Franklin County. In 2011, Green Energy Today, LLC installed a hydroelectric generation turbine at the confluence of the canal and the Columbia River to capture the kinetic energy of the flowing water and convert it into electricity. Franklin PUD purchased all of the rights to the power and environmental attributes generated by the .9 MW Esquatzel Canal Hydroelectric Project through 2031, and has an option to extend the contract. The IRP therefore assumes that Esquatzel will remain as a resource through the study period. The project generates power year-round – producing roughly 6,000 MWh of power annually.

Esquatzel is a run of the river project. Its generation cannot be turned on and off since neither Green Energy Today nor Franklin PUD controls the timing or quantity of water flows through the canal. The cost for Esquatzel's power is fixed at $65 per MWh for the first five years. In year six, the price increases to $70 per MWh. The price increases by 2% each year beginning in year 7. All environmental attributes from the project are included in the power price. Esquatzel is an EIA eligible renewable resource, and because its generating capacity is less than 5 megawatts, it is also classified as "distributed generation," which allows its environmental attributes (RECs) to count double. The Esquatzel project received CEC certification as a qualifying renewable project effective December, 2012.

Conservation

Franklin PUD has been actively engaged in conservation/energy efficiency resources for 30 years. Since 2002, the District's programs have resulted in the acquisition of nearly 9.6 aMW of conservation resources. More emphasis will be focused on conservation planning and acquisition in the future.

Along with a renewable portfolio requirement, the EIA requires that qualifying utilities pursue all cost-effective conservation. Franklin PUD will likely become a qualifying utility in 2016, and is positioning itself to manage its future compliance obligations.

The IRP load forecast assumes that conservation acquisition averages .8 aMW annually and is discussed in more detail in Chapter 3.

Monthly Load Profile and Existing Resource Comparison

The load forecasts summarized in this section are compared to the District's existing resources. The difference between these variables defines the District's requirement for new resources. The shape of the District's loads and resources is an important consideration for resource planning. Loads have historically been highest in the summer. Another peak season occurs in winter, although it is lower than the summer peak. Existing resources produce the most energy in spring and early summer months. The result is monthly energy surpluses and deficits that must be managed. Figure 16 illustrates the shape of Franklin PUD's 2013 load and resource stack by month. Surpluses typically occur from April to June, and under low water conditions (Critical Slice), resource deficits can occur in the 3rd quarter, when irrigators are pumping a lot of water and air conditioning loads are high.

Figure 16: 2013 Resources vs. Actual Monthly Load

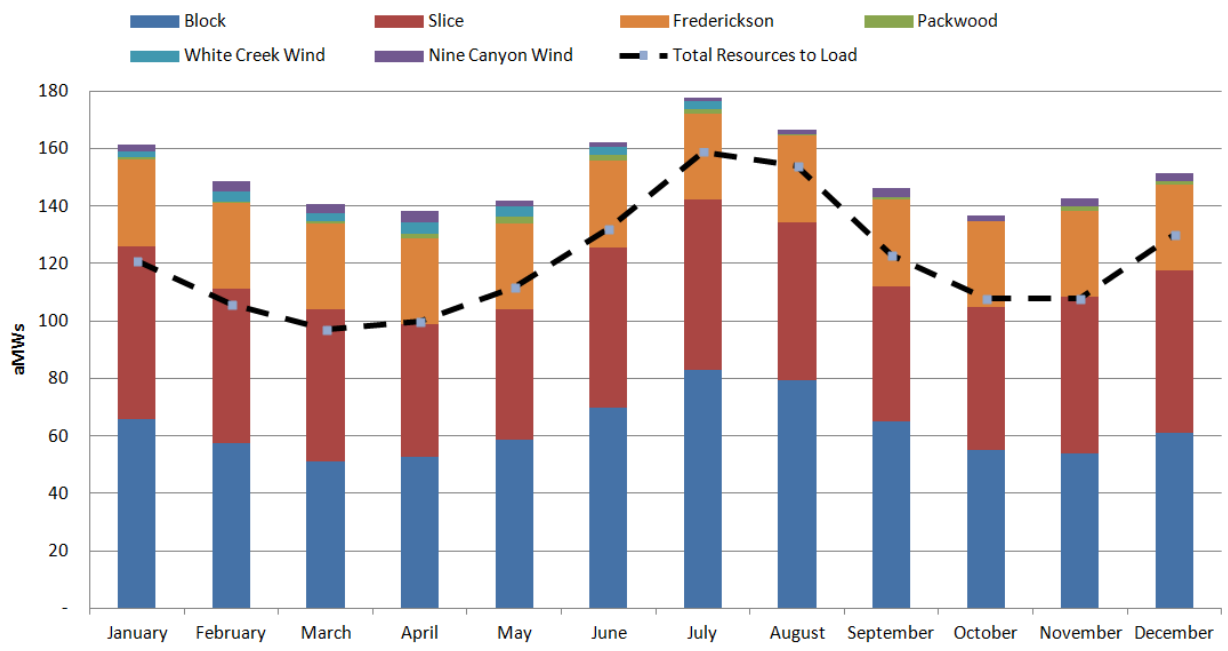
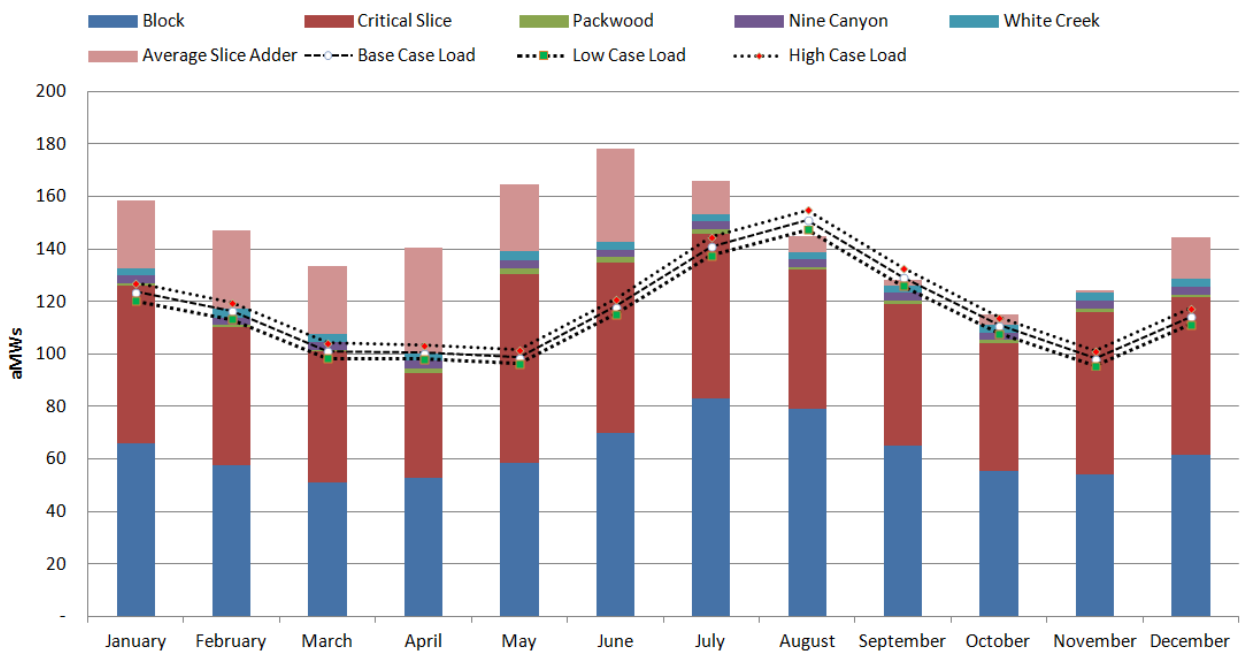


Figure 17 compares average load by month to the resource stack after the Frederickson contract terminates in mid-2022. Even assuming average Slice generation, the 3rd quarter need for a capacity resource is evident. Under a high load scenario, the need would be larger.

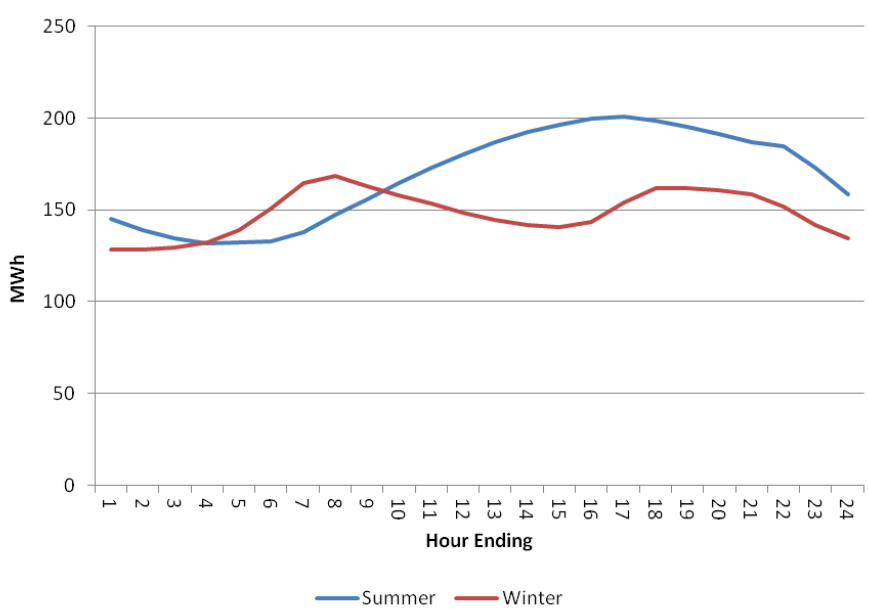
Figure 17: 2023 Resource Capacity vs. Forecasted Average Monthly Load (Med Case Load)



Peak Requirement Planning

Electricity usage is variable, affected by temperature, time of day, and economic activity, among other factors. Usage also follows a variable, but somewhat predictable, pattern. Hourly demand is dynamic; there are certain periods of the day when demand is higher than others. Figure 18 displays typical 24-hour winter and summer load profiles for Franklin PUD.

Figure 18: 24-Hour Summer and Winter Load Profiles



Demand is also very seasonal and temperature dependent. Figure 19 compares the 5-year daily temperature against the daily average load. It can be observed that Franklin PUD is a summer-peaking utility; its electricity usage on average is greater during the summer than any other period of the year. Temperature and demand are strongly correlated; the more extreme the temperature, high and low, the greater the electricity demand.

A utility with adequate resources to satisfy its average annual energy needs does not necessarily translate into the ability to fulfill its energy obligations during the highest electricity demand periods. Utilities must have access to, whether owned or purchased from the wholesale market, sufficient resources to serve above-average load. It is clear that the District needs enough resources to generate electricity in excess of the annual average load. What is less clear is how much surplus generating capability, or peaking capacity, is needed. Too little peaking capacity and the District may be unable to serve its load in a peak demand period; too much generation capacity can be costly to acquire and maintain.

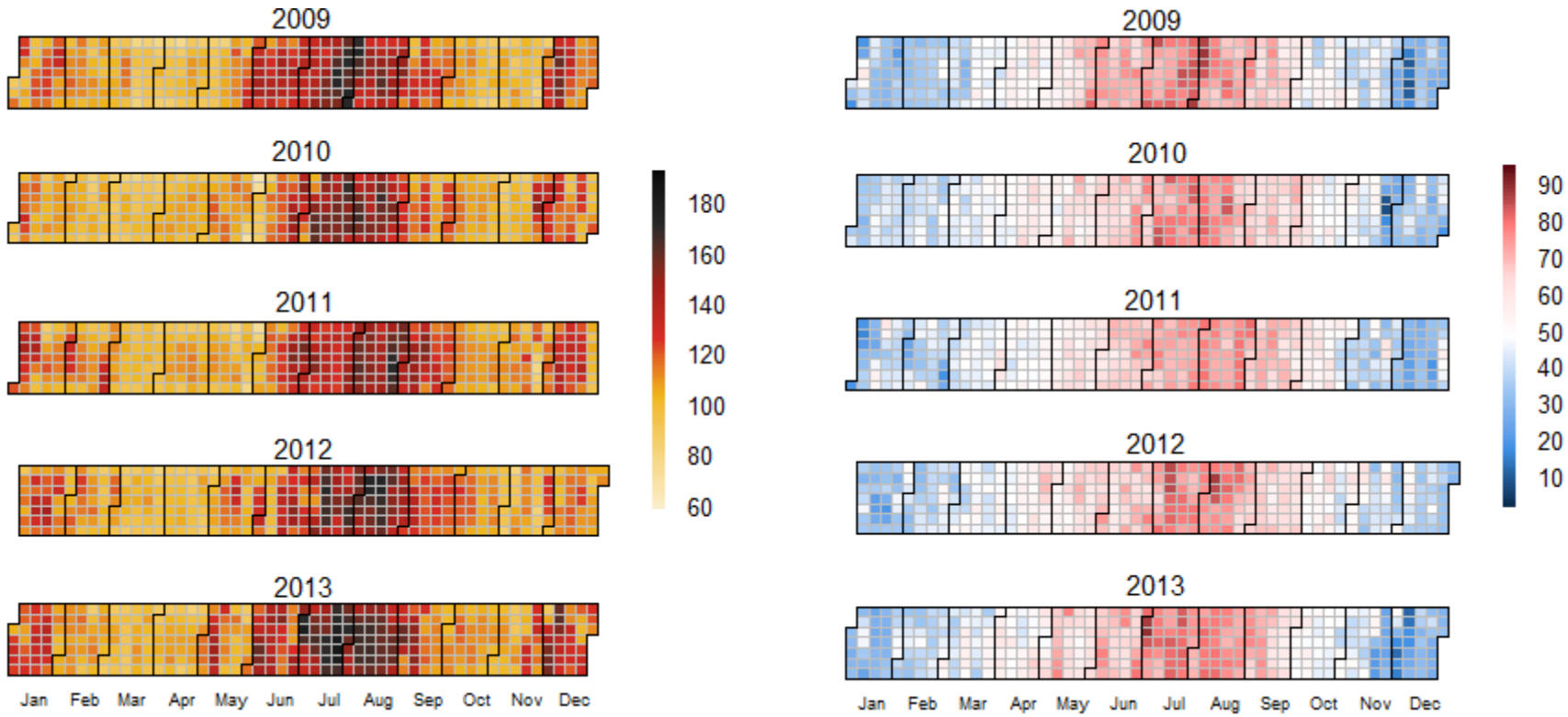
At the ends of the capacity acquisition spectrum are two opposite options. The first is to do nothing and rely on the wholesale market to serve any above average load. This eliminates the District's cost of acquiring and maintaining an additional resource. The market usually has enough energy to meet the District's needs as well. One issue with this strategy is that the same circumstances that cause a period of high demand for Franklin PUD affect the entire region equally. It is thus very likely that the entire region experiences a similar pattern of higher demand. With more load-serving entities competing for more power, it is possible, though not very likely, that market prices will double or triple during these periods. As a BPA Slice customer, the District can often shape generation as needed to meet a capacity shortage, thereby reducing exposure to higher-cost market purchases during heavy load hours.

The other extreme option is to acquire enough resources such that the District will never be energy deficit. This option eliminates any risk that the District will be unable to serve its load. However, there is a significant carrying cost to building and maintaining assets that are rarely used. It is not economically prudent to build more resources than needed in preparation for a once in a lifetime event. This section analyzes peak loads against peak resources to provide insight into that question. The process of determining the optimal available peaking capability at an economically acceptable cost is known as capacity adequacy.

Extreme Weather Event

A strict capacity adequacy standard for the Pacific Northwest does not currently exist. However, the NWPCC has a set of suggested best practices to which load serving entities such as Franklin PUD should adhere. It is also developing a capacity adequacy standard for the Pacific Northwest.

Figure 19: Average Daily Loads (Left) vs. Temperature (Right)



An analysis of extreme winter and summer resource needs during a 72-hour cold snap and heat wave was completed for this IRP (see Appendix A). The analysis indicated that at the present time, the District should have enough generation resources to meet summertime load although there could be some light load hour deficits in the winter. It also concluded that because of conservative hydro assumptions, the District should be able to maintain reliability at an acceptable financial cost through most weather events in the near future.

To assess needs 10 and 20 years out, the current seasonal peak requirements determined in the capacity portion of this study were inflated by the current load growth rate. Because the weather events used to determine the amount of required capacity during these extreme weather events are rare, the results of the capacity study are conservative by nature. The level of conservatism should be sufficient to address the variability in weather, resource performance, and economic conditions that are not easily accounted for in a deterministic approach to peak requirement planning.

If an emergency situation occurred that required the District to curtail customers, there is an established procedure so that essential services (e.g., hospitals, police and fire) are maintained if possible.

Incremental Power Requirements

With forecasts of gross electric power requirements and expected output from existing resources, the incremental electric power requirements can be forecast. In the annual average load and resource forecasts, critical water is assumed. In the annual peak scenarios, it is assumed that the Slice system will achieve well above critical generation, and that extreme measures could be taken to increase generation output in the event of a system emergency. That amount above critical is labeled "Slice Adder" in the peak planning scenarios in Figure 21, Figure 24 and Figure 26.

Medium Case Results

Figure 20 shows the results of these calculations on an annual energy basis. Under the medium load forecast, the District is surplus on an annual energy basis through the 20-year study period even with expiration of the Frederickson contract in 2022.

Figure 20: Medium Case Load Forecast – Annual Average MW

Medium Case Forecast* Annual Average Megawatts (aMW)								
	Gross Power Requirements	Production of Existing Resources						Incremental Power Requirements
Year		Conservation	Block	Critical Slice	Frederickson**	Wind Resources	Small Hydro***	Deficit/(Surplus)
2014	119	0.79	61	58	30	6	1.5	(38)
2020	121	5.52	61	58	30	6	1.5	(41)
2026	123	10.24	61	58	0	6	1.5	(14)
2032	125	14.97	61	58	0	3	1.5	(14)

* 0.35% average annual growth
** Contract expires August 2022
*** Packwood and Esquatzel

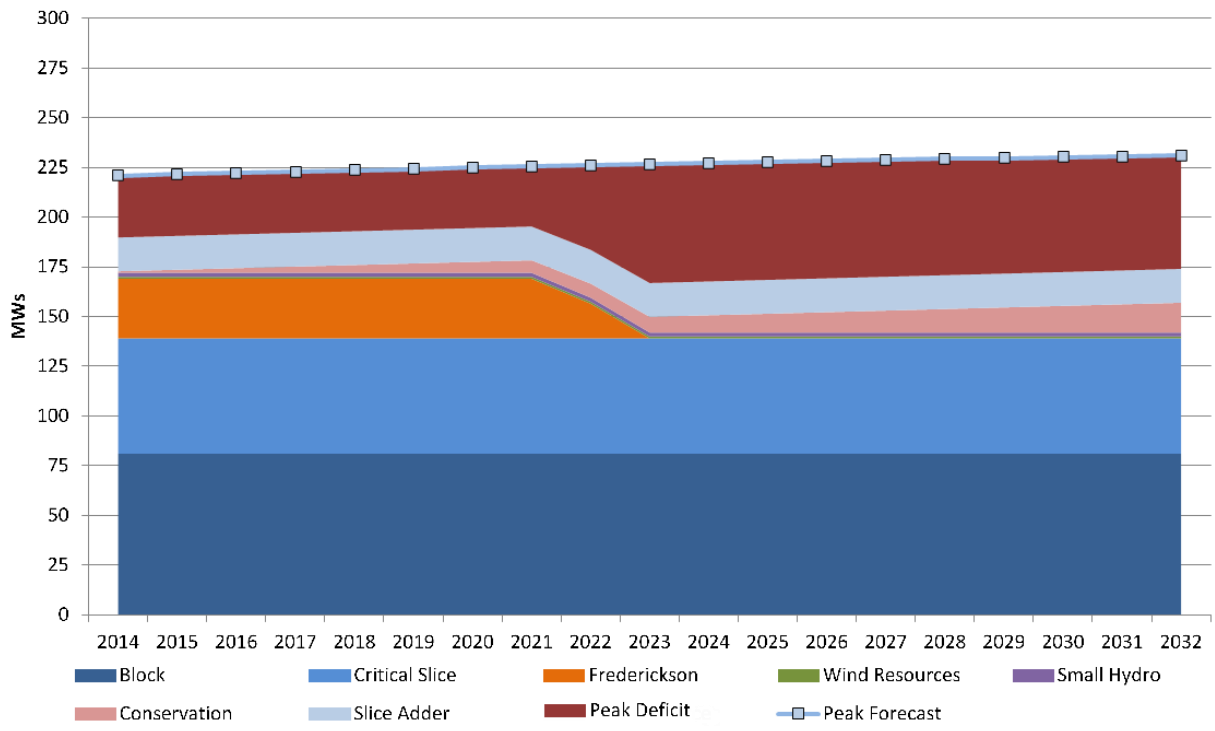
Figure 21 shows calculations of the incremental power requirements on an annual peak basis. Under the medium load forecast, Franklin PUD is deficient in meeting its annual peak requirement in 2022 and 2032. Figure 22 provides a graphical representation by year of the potential shortage of energy in a peak load situation.

Figure 21: Medium Case Forecast – Annual Peak MW

Medium Case Forecast* Peak Planning (MW)									
	Gross Power Requirements	Production of Existing Resources							Incremental Power Requirements
Year		Conservation	Block	Critical Slice	Slice Adder**	Frederickson***	Wind Resources	Small Hydro****	Deficit/(Surplus)
2022	226	7.09	81	58	17	18	1	2	42
2032	231	14.97	81	58	17	0	1	2	57

* 0.35% average annual growth
** Difference between Average and Critical Slice.
*** Contract expires August 2022
**** Packwood and Esquatzel

Figure 22: Highest Expected One Hour Annual Peak Forecast (Medium Case) & Existing Resource Stack



Low Case Results

Figure 23 and Figure 24 show the results for the low load forecast. Under this scenario, conservation achievements, combined with -.70 percent load growth rate, result in decreasing net energy requirements. As a result, Franklin PUD has surplus resources on an average annual basis. However, it remains peak deficit in the out years shown (2022 and 2032).

Figure 23: Low Case Load Forecast - Annual Average MW

Low Case Forecast* Annual Average Megawatts (aMW)								
	Gross Power Requirements	Production of Existing Resources						Incremental Power Requirements
Year		Conservation	Block	Critical Slice	Frederickson**	Wind Resources	Small Hydro***	Deficit/(Surplus)
2014	119	0.79	61	58	30	6	1.5	(38)
2020	119	5.52	61	58	30	6	1.5	(43)
2026	119	10.24	61	58	0	6	1.5	(18)
2032	118	14.97	61	58	0	3	1.5	(20)

* -0.70% average annual growth
** Contract expires August 2022
*** Packwood and Esquatzel

Figure 24: Low Case Forecast – Highest Expected One-Hour Annual Peak MW

Low Case Forecast* Peak Planning (MW)									
	Gross Power Requirements	Production of Existing Resources							Incremental Power Requirements
Year		Conservation	Block	Critical Slice	Slice Adder**	Frederickson***	Wind Resources	Small Hydro****	Deficit/(Surplus)
2022	221	7.09	81	58	17	18	1	2	37
2032	219	14.97	81	58	17	0	1	2	45

* -0.70% average annual growth
** Difference between Average and Critical Slice.
*** Contract expires August 2022
**** Packwood and Esquatzel

High Case Results

Figure 25 and Figure 26 show that under the high load forecast, the District remains surplus through 2032 on an average annual energy basis, and in a deficit position under the peak scenarios in 2022 and 2032.

Figure 25: High Case Load Forecast - Annual Average MW

High Case Forecast* Annual Average Megawatts (aMW)								
	Gross Power Requirements	Production of Existing Resources						Incremental Power Requirements
Year		Conservation	Block	Critical Slice	Frederickson**	Wind Resources	Small Hydro***	Deficit/(Surplus)
2014	119	0.79	61	58	30	6	1.5	(38)
2020	124	5.52	61	58	30	6	1.5	(38)
2026	128	10.24	61	58	0	6	1.5	(9)
2032	132	14.97	61	58	0	3	1.5	(7)

* 1.30% average annual growth
** Contract expires August 2022
*** Packwood and Esquatzel

Figure 26: High Case Forecast – Highest Expected One Hour Annual Peak MW

High Case Forecast* Peak Planning (MW)									
	Gross Power Requirements	Production of Existing Resources							Incremental Power Requirements
Year		Conservation	Block	Critical Slice	Slice Adder**	Frederickson***	Wind Resources	Small Hydro****	Deficit/(Surplus)
2022	231	7.09	81	58	17	18	1	2	48
2032	244	14.97	81	58	17	0	1	2	70

* 1.30% average annual growth
** Difference between Average and Critical Slice.
*** Contract expires August 2022
**** Packwood and Esquatzel

Although the District is expected to have sufficient generation resources on an average annual basis to meet its energy needs under critical water conditions, two things must be considered. Third quarter shortages are likely to occur every year, and additional renewable resources or RECs will be needed as EIA targets increase over time. The expected shortage of renewable resources or RECs under the medium load forecast is illustrated below in Figure 27 and Figure 28. Both resource needs are discussed further throughout this IRP.

Figure 27: Franklin PUD's Study Period REC Position

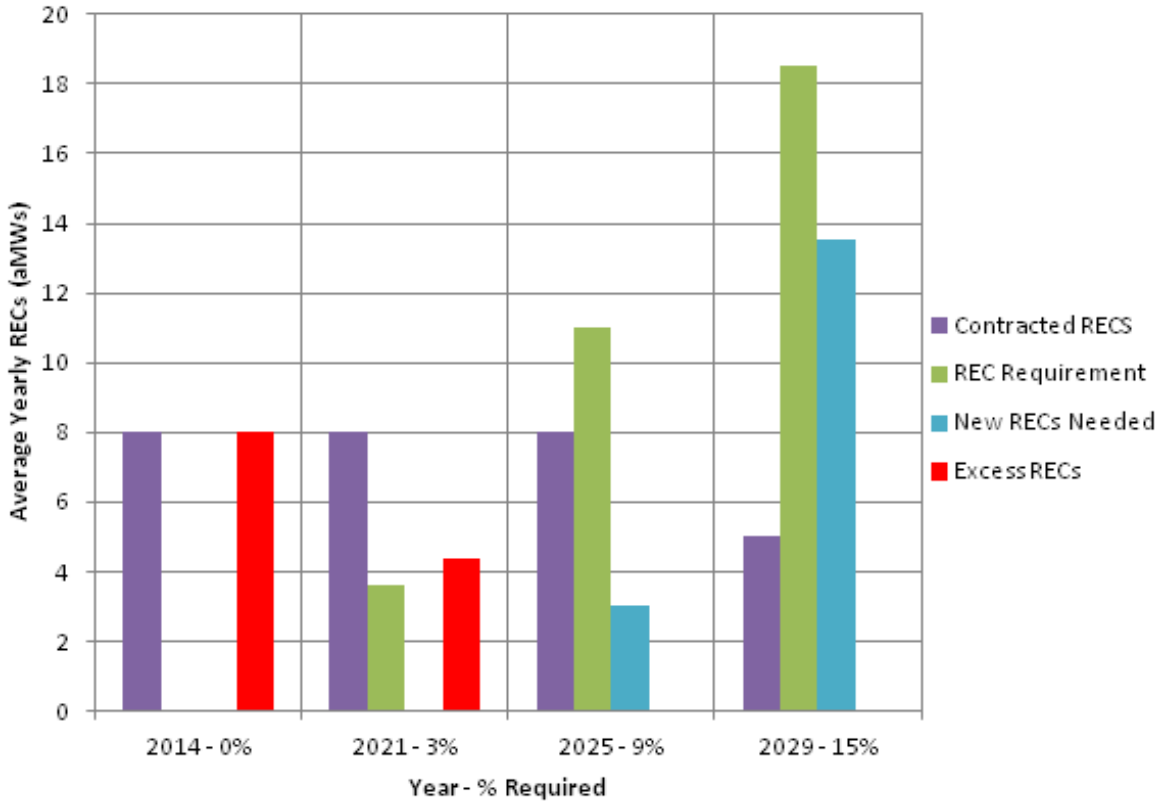


Figure 28: Franklin PUD's Study Period REC Position

Year - %	REC Requirement	Contracted RECS	New RECs Needed	Excess RECs
2014 - 0%	0.0	8.0	0.0	8.0
2021 - 3%	3.6	8.0	0.0	4.4
2025 - 9%	11.0	8.0	3.0	0.0
2026 - 9%	11.0	8.0	3.0	0.0
2027 - 9%	11.1	8.0	3.1	0.0
2028 - 9%	11.1	5.0	6.1	0.0
2029 - 15%	18.5	5.0	13.5	0.0
2030 - 15%	18.6	5.0	13.6	0.0
2031 - 15%	18.6	5.0	13.6	0.0
2032 - 15%	18.7	5.0	13.7	0.0

Chapter 3: Conservation

Introduction

Energy efficiency is a reduction in the amount of energy required to provide products and services. For example, a well-insulated home consumes less heating and cooling energy to achieve and maintain a comfortable temperature. Installing fluorescent lights or natural skylights reduces the energy required to attain the same level of illumination compared with using traditional incandescent light bulbs. Improvements in energy efficiency are most often achieved by adopting a more efficient technology. Although "conservation" is a broader term than "energy efficiency," the boundary between the two terms is fuzzy. In this document, both terms are used interchangeably, and included in a group of measures and activities aimed at controlling energy loads sometimes referred to as "demand side management."

By reducing the demand for electricity, energy efficiency programs lower District costs over time, decrease exposure to volatile power market prices, and defer the need for new generation, transmission and distribution capacity. For these and other reasons, it is an important resource for meeting future load growth.

Avoided Costs

Avoided cost forecasts are an important driver in resource planning because they provide the basis for comparing supply-side (generating) and conservation resources and determining which energy efficiency investments are cost-effective. Avoided costs are those costs a utility would incur to produce one more unit of electricity.

For Franklin PUD, energy savings from conservation programs defer the need for new power resources and in the near-term free up existing power supplies that can be used to serve new retail load or sold into the wholesale energy market. Conservation also defers the need for additional transmission and distribution capacity and reduces the number of renewable energy credits required under the EIA. The amount of renewable resources and/or RECs Franklin PUD must acquire under the EIA is reduced by every megawatt-hour of energy efficiency savings (reduction in load) that is achieved.

Historic and Current Conservation

An historical look at past conservation expenditures and acquisition by the District, as well as current programs, is covered in this section.

Franklin PUD has pursued conservation and energy efficiency resources since 1980, resulting in the cumulative acquisition of more than 10 aMW. Currently, the District offers several rebate programs for both residential and non-residential customers. These include energy efficient lighting rebates, residential weatherization programs, irrigation incentives, variable frequency drive incentives for agricultural and commercial use, freezer and refrigerator recycling, Energy Star appliance rebates, new construction programs for commercial and industrial customers, and audits for both residential and commercial customers. Figure 29 shows recent historic conservation achievements; and Figure 30 provides several program categories for each sector.

Figure 29: Conservation aMW Savings Acquired by Calendar Year

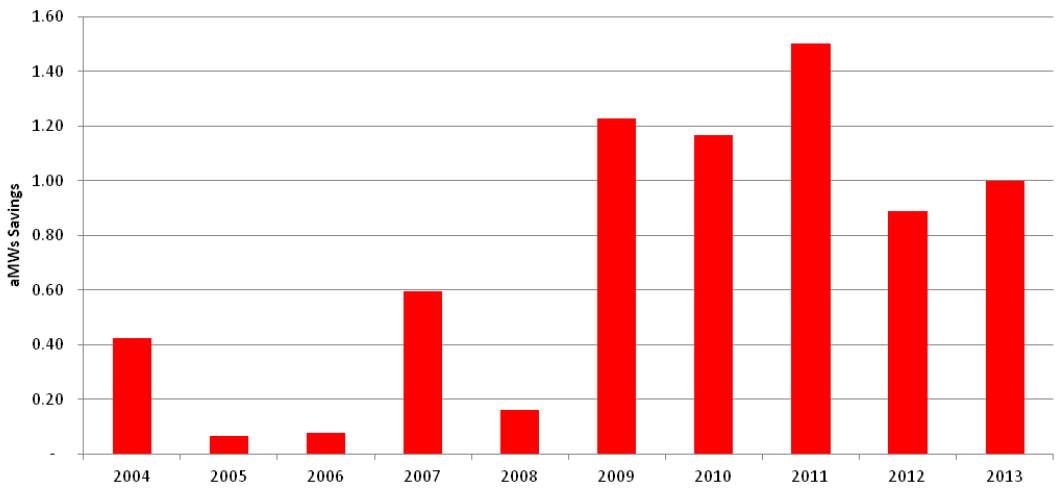


Figure 30: Franklin PUD Energy Services Programs

Program Description	Target Sector			
Residential	**Residential**	**Commercial**	**Industrial**	**Irrigation**
Single-Family Weatherization	X			
Multi-Family Weatherization	X			
Appliance Rebates	X			
Refrigerator/Freezer Recycling	X			
Compact Fluorescent Lighting	X			
New Home Construction	X			
Commercial & Industrial				
Custom Incentives-Existing Buildings		X		
Energy Smart Industrial			X	
Lighting Rebates – Existing Buildings		X	X	
Energy Smart Grocer		X		
Track and Tune			X	
Variable Frequency Drives			X	X
Agricultural				
Irrigation Water Management (SIS)				X
Variable Frequency Drives			X	X

Until FY2010, Franklin PUD only spent dollars provided by BPA as a credit on power bills on conservation rebate and incentive programs. Between 2004 and 2009, the average credit was approximately $400,000 per year. In FY2010, the amount and method of funding changed under the Energy Efficiency Incentive (EEI) program. BPA entered into Energy Conservation Agreements with its utility customers, and the monthly rate credit was replaced by a system wherein customers were reimbursed EEI dollars after eligible projects were completed.

During the FY2010-FY2011 rate period, utilities were not limited to a pre-determined rate credit amount as in past periods, and could increase their BPA reimbursement if they had eligible projects. Franklin PUD spent $5.4 million and acquired 3.2 aMW of energy efficiency, substantially exceeding previous amounts. Some very large industrial projects were completed during this period. The energy savings purchased through Simple Steps, Smart Savings™ residential program was significant, and an added benefit was the survey data collected at each home visited. The surveys provided statistics on home size, heating fuel source, weatherization characteristics, and other factors that have been and will be used to help determine the District's conservation potential.

Since FY2012, the District's Energy Efficiency Incentive from BPA, based on its Tier 1 Cost Allocator (TOCA), has been about $1.1 million[2] annually, and it is expected to remain near that level into the foreseeable future. The District paid out nearly $1.2 million in conservation incentives in 2013 and acquired 1.0 aMW of energy savings.

EIA Legal Framework

As discussed in Chapter 1, the District will need to comply with the State's Energy Independence Act after it reaches the 25,000 customer threshold and becomes a qualifying utility. The expected schedule and related requirements for the District related to conservation mandates in the Act are as follows:

- Early 2015	Customer count reaches 25,000
- January 2016	District becomes a "qualifying utility"
- January 2019	Identify ten-year achievable cost-effective[3] conservation potential, and establish biennial acquisition target as part of the ten-year assessment
- January 2021 and January in odd years thereafter	Review and update the ten-year achievable conservation potential, including the next biennial acquisition target
- June 2021 and each June thereafter	Submit annual report to the State Department of Commerce documenting progress in meeting the biennial target. In even years, the report must also include achievement in meeting the preceding biennial target; and current ten-year potential.

[2] In FY 2013 and FY 2014, EEI allocations were recalculated to accommodate for BPA not adequately tracking FY2011 EEI expenditures, and exceeding its budget by a significant amount. Since some of the "over-spend" included projects by Franklin PUD, BPA reduced the District's EEI budget to $433,787 in both FY2013 and FY2014.

[3] In order for a measure to be cost-effective it must produce savings at a lower cost to the utility than the next cheapest alternative resource. As a result, a utility can pay up to just less than the cost of alternative resources for energy efficiency even if this exceeds the incremental measure cost including program administration.

The Act provides three options for qualifying utilities to set their conservation targets:

- The NWPCC's ("the Council") conservation calculator;
- A modified version of the calculator; and
- The utility analysis option, using a methodology consistent with the Council's procedures.

The Council's conservation calculator is the simplest option for identifying a utility's conservation target. The calculator has three variations that produce slightly different target values. The first is based on the utility's share of total regional load. The second variation is similar to the first option except it is based on total retail sales by sector. The third variation expands the sector breakdown by allowing for input on irrigation loads for utilities with significant irrigated agriculture within their service territories.

The second option for setting conservation targets is to create a modified version of the conservation calculator. The results of the calculator can be adjusted by some of the Council's modeling assumptions, including: adding or removing measures, adjusting measure savings or cost values, changing the number or ratio of applicable units, changing growth rates, etc.

The third option is the utility analysis option, wherein conservation potential is estimated using methodologies consistent with the Council's most recent power plan. This includes analyzing a broad range of energy efficiency measures, a life-cycle cost analysis of measures or programs, a stringent cost-benefit analysis, and examining the results of multiple scenarios.

Comparison of NWPCC Plans and Methodologies

There are different opinions on which version of the Council's conservation calculator is to be used by qualifying utilities using the calculator or modified calculator options to establish their conservation potential. The calculator is contained in the Council's *Northwest Conservation and Electric Power Plan* ("the Plan")[4] that is updated every five years. When the Energy Independence Act was passed by the State's voters in 2006, the 5th Plan was in effect. In February 2010 the 6th Plan was formally adopted by the Council, and the conservation target calculator showed a significant increase in utility targets.[5] The following is a comparison of targets for the region and for the District in the 5th and 6th Plans based on the utility share of total regional retail sales:

	5th Plan	6th Plan
Region's 20-year target (aMW)	2,500	6,000
Region's 5-year target (aMW)	700	1,200
District's Annual Average 20-year Target (aMW)	.74	1.74
District's Annual Average 5-year Target (aMW)	.78	1.43

[4] The 1980 Northwest Power Act (Public Law 96-501) established the Pacific Northwest Electric Power and Conservation Planning Council, which was tasked with preparing and adopting a regional conservation and electric power plan to ensure an adequate, efficient, economical, and reliable power supply for the region.

[5] An opinion by the State Attorney General issued in December 2013 indicates that the conservation calculator referred to in WAC 194-37-070, and to be used for conservation targets that were to have been set by January 1, 2012, refers to the Sixth Power Plan.

As previously noted, there are variations on the calculator options for assessing potential, but the magnitude of the substantial increase in targets between the 5th and 6th Plans is similar.

Adding further uncertainty is the fact that the Council has indicated that its calculator was not developed for the purpose of determining individual utility targets for EIA compliance and does not want to maintain a calculator in the future. It has asked for an alternative solution, suggesting that BPA's conservation potential assessment tool can aid utilities in assessing their own potential.

The Utility Analysis Option should result in a more precise estimate of conservation potential, and most if not all qualifying utilities are doing conservation potential assessments (CPA) for that reason. There is some uncertainty about how the State Auditor is evaluating those CPAs and the resulting achievements. Out of eleven qualifying utilities surveyed, all met the 5th Plan targets for 2010-2011, and only three met or exceeded the 6th Plan targets. Six of the eleven that utilized the 6th Plan methodology in their CPAs had conservation potential lower than the 6th Plan calculator.[6]

While the District will have the option of relying on the Council's target calculator, comparing the calculator figures with its own utility analysis will be important. It is likely that calculator-derived targets will understate or overstate Franklin PUD's actual conservation potential even though the calculators allow some adjustments for local conditions. If the Plan's target is too high, it may be difficult or impossible to acquire the targeted amount, and a $50 (2007 Dollars adjusted for inflation) per MWh penalty for the shortfall will result. On the other hand, if the target is understated and more conservation is a viable option, avoidable costs in generating resources, transmission and distribution systems could be incurred.

Relevance to Franklin PUD

There are a number of reasons EIA conservation requirements are relevant to the District now, more than five years before its first ten-year potential must be submitted to the State. First, the amount of conservation acquired now and in the future will impact the amount of generating resources needed during the planning period. Secondly, current programs and conservation achievements should be compared to what will be required in the future to insure there is adequate infrastructure in place, including personnel, budget, program development and contractor support. Many projects and programs have long lead times, so if it is determined a significant increase in conservation acquisition will be required for compliance, a plan for ramping up those efforts must be put in place.

It would be prudent for the District to undertake a CPA at this time to help with the following issues and uncertainties:

- What is the estimated remaining potential for the District today?
- How does that potential compare to the Council's 5th and 6th Plan calculators? How does it compare to BPA's calculator that is expected to replace the Council's?

[6] The other five utilities either did not have CPAs or did not respond to the question.

- Does conservation acquired now reduce the potential in the future?
- Does the amount by which conservation costs erode retail energy sales exceed the savings from acquiring new generating assets (avoided cost)?
- What conservation measures are the most useful at reducing the District's peak loads?

Conservation Assumptions in the Integrated Resource Plan

In order to capture the expected impact of conservation acquisition on future loads and resource costs before EIA requirements are applicable, some assumptions and a rationale for the District's near-term conservation program are necessary. The assumptions in this analysis are as follows:

1. The District's annual conservation potential will be .8 aMW per year from 2014 through the study period, an average derived in its econometric load forecast that included figures for recent achievements. This amount is just over the 20-year average amount in the 5th Plan calculator which, based on a survey of qualifying utilities, should be achievable.

2. The average first-year cost of conservation is $0.19 per kWh ($190 per MWh), and the resulting levelized average cost is $15.83 per MWh. Unit acquisition costs were not inflated over the study period.

These assumptions were included in Chapter 2: Load Forecast and Incremental Power Requirements, and they are judged to be a reasonable representation of what the District can expect to achieve in the future. The conservation potential assessment previously discussed will be a useful tool for conservation planning and analysis as the District approaches the EIA qualifying utility threshold.

Chapter 4: Federal Supply-Side Resource Options

Introduction

Franklin PUD currently meets most of its average annual power requirements with its BPA Slice/Block contract. In order to serve loads in excess of its customer utilities' High Water Marks (HWMs), or Tier 1 allocations, BPA will need to acquire additional resources to augment its current resource stack. In addition, sufficient transmission needs to be available to bring the power to BPA's customers. BPA's proposed pricing methodology and the associated products for these additional resources are an important factor in determining whether to rely on BPA for above-HWM power supply requirements.

This section provides a BPA price forecast for HWM or Tier 1 loads based on BPA's existing resources. In addition, this section describes the products that BPA is offering to serve above-HWM loads and provides an evaluation and price forecast for these products. Also discussed is the option Franklin PUD has of switching to BPA's Load Following Product in 2019 to meet its Tier 1 loads.

BPA Rate Forecasts

The future price of BPA power is just one factor in evaluating the District's future resource options. BPA has two different pricing tiers. Tier 1 is intended to capture the costs of BPA's current resources and Tier 2 is intended to capture the costs of additional resources acquired by BPA to serve its customers' above-HWM loads. Rate forecasts have been developed for both Tier 1 and Tier 2 for the 20-year study period.

Tier 1 Rates and Forecast Methodology

The forecasts of BPA Tier 1 rates for purposes of this report were developed assuming that BPA's rates will escalate by 6 percent in each two-year rate period after FY2015. It should be noted that the forecast of Tier 1 rates extends through 2032 while the 20-year BPA contracts terminate in 2028. Unless there is a change in federal law, preference utilities will continue to have access to Tier 1 power from the Federal Base System. Prior to October 2028, preference customers will need new power contracts, which may or may not include a product design and rate structure similar to the 2011 contracts. They will most likely need to replace supplies used to serve above-HWM load. The uncertainty of the post-2028 products and rate alternatives not synchronizing with resource decisions made in the pre-2028 timeframe is faced by all preference customers as BPA's rate structure and the ability to integrate existing non-federal resources into a post-2028 portfolio are not fully understood at this time.

On an average annual basis, more than 98 percent of the District's power currently comes from BPA under a long-term contract. As a Slice/Block customer, it will purchase approximately .78% of the real-time capability of the Federal Base System (FBS) in addition to monthly flat blocks of energy that range from 50 to 81 MW. Scheduled output from the FBS, the Frederickson plant, Packwood and Esquatzel small hydro, the two wind projects, as well as market transactions, are used to serve load.

BPA's rate structure under the 2011 contracts was developed through a formal proceeding known as the Tiered Rate Methodology (TRM). Beginning in October 2011, BPA's rates became tiered with market-based rates serving above-HWM load. Under the TRM, total Tier 1 allocations roughly equal the capability of the FBS under critical water conditions. Under this approach, each BPA customer effectively

receives a share of output from the FBS. Power requirements above Tier 1 allocations may be purchased from BPA at Tier 2 rates or from alternative suppliers.

Franklin PUD's Slice/Block purchases are at Tier 1 rates, which include a composite customer charge, a Slice customer charge, a non-Slice customer charge and monthly and daily diurnal load shaping charges.

The basic premise of the Slice product is that BPA customers pay a fixed percent of BPA's power costs in exchange for a fixed percent of FBS generation and capabilities. Slice has firm and non-firm components. The firm component is based on critical water firm load carrying capability. Because the timing of loads and firm output of FBS do not match perfectly within the year, the entire firm component may not be available in a shape that can meet the customer's retail loads. At other times, part of the firm component may be surplus to the customer's load requirements. The surplus firm component is likely to occur in spring months, when water conditions are high. The non-firm component is surplus power above critical water firm load carrying capability. Slice purchasers must acquire additional resources during hours when their share of FBS resources is less that their load requirements and are free to sell surplus power in the market during hours when their share of FBS resources exceeds their load requirements.

As part of its Tier 1 allocation, the District receives RECs from BPA. The number of RECs received annually is expected to be approximately 3,500 throughout the study period. These RECs should be eligible to help meet EIA renewable requirement in the future. Should currently proposed state legislation pass that would allow federal incremental hydro improvements to qualify as renewable resources, the District would receive additional RECs from BPA.

Tier 2 Rates and Forecast Methodology

BPA offers a number of Tier 2 power rate alternatives and associated features during each rate period. Power sold at Tier 2 rates must be purchased in the shape of a flat annual block. Tier 2 rates are based on the marginal cost of new BPA purchases and resource acquisitions, including the costs of shaping and/or firming resources to a flat annual block. As discussed below, BPA customers that purchase power at Tier 2 rates may have the option of committing to pay for power at rates tied to the costs of specific resources.

The Tier 2 products that BPA has made available to customers are detailed below:

- Short-term Tier 2 – Rates are based on a portfolio of short- and mid-term (five years or less in duration) market power purchases. The minimum term for this product is two years. Short-Term Tier 2 rates are set each rate period according to the current market price forecast.

- Load Growth – Rates are based on a portfolio of short-, mid- and long-term market purchases and resource specific purchase power agreements. The term for this product is the full contract term.

- Vintage Renewable Tier 2 – Based on customer interest, BPA committed to exploring separate Tier 2 rates based on the cost associated with specific resources. Vintage rates include the renewable attributes of the resources.

The District is purchasing 1 MW of Short-term Tier 2 power from BPA in FY2014 at a cost of $35.59 per MWh, which is equivalent to the price of purchasing the power on the market. BPA rules for Tier 2 purchases on net requirement calculations, resource removal and remarketing are challenging, especially when the utility's total retail load is very close to its Tier 1 high water mark. For example, if a customer's net requirement is more than its Tier 1 power but less than Tier 1 and Tier 2 combined, the customer does not have the flexibility of marketing the surplus. BPA provides the remarketing services and credits the customer. This may make sense for a Load Following customer that is relying on BPA for all of its resource needs, but creates unnecessary complication for a Slice customer that is in the market anyway. This IRP assumes that BPA's Tier 2 product will not be used to meet resource needs after FY2014.

Future Option to Switch from Slice/Block to Load Following Contract

One option the District will have in beginning in FY2019 is to switch from BPA's Slice/Block contract to a Load Following contract where BPA is responsible for serving the customer's entire load, minus what is served by the customer's own resources. If the District wants to make this change, notice must be given to BPA no later than May 31, 2016.

The Regional Dialogue Load Following product gives customers more opportunities for applying new non-federal resources to serve their own load over time than they had under the previous Full Requirements Subscription contracts. Prior to FY2002, the District had the equivalent of a Full Requirements contract with BPA. The District will assess this possibility carefully in the near future.

Chapter 5: Non-Federal Supply-Side Resource Options

This section describes a number of non-federal supply side resource options available to Franklin PUD. The purpose of this section is to examine the alternatives for meeting Franklin's energy and peak demand load requirements. The supply side options explored are categorized according to thermal resources (gas, coal and nuclear), market resources, and eligible renewable resources.

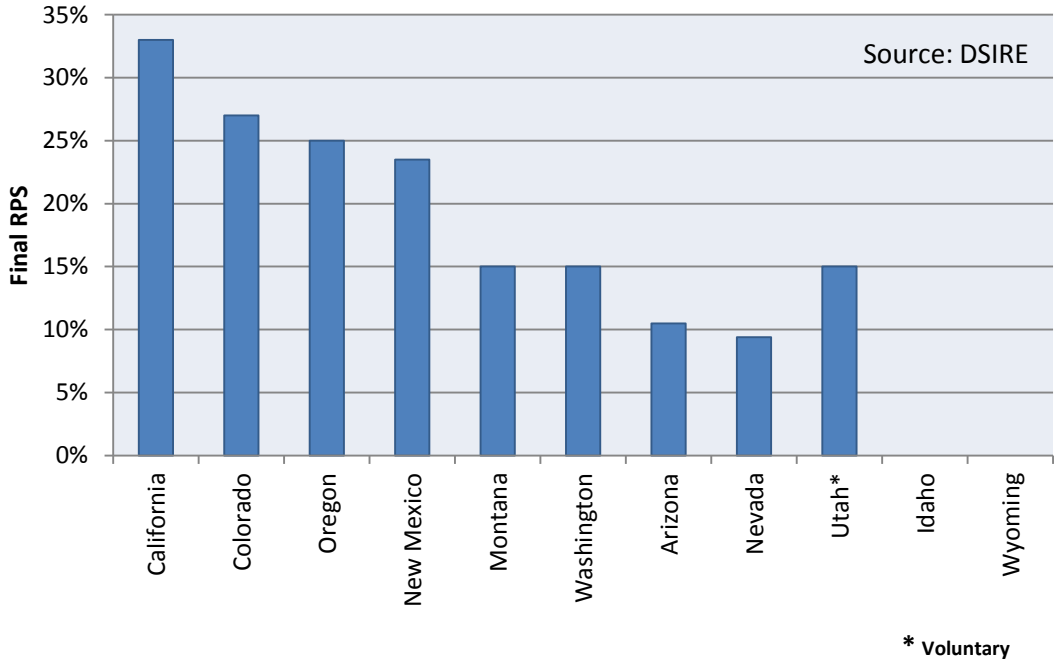
Legislation Affecting Supply-side Resources

There are several legislative mandates that will play key roles in the determination of new resource selections. While a wide range of supply side resource options are considered in the screening of resources included in this section of the report, many will be eliminated from further consideration due to the legislative mandates detailed below.

Renewable Portfolio Standards

Due to renewable portfolio standard (RPS) requirements in Washington and elsewhere in the region (Figure 31), there is currently high demand for eligible renewable resources. Franklin PUD is not currently obligated to purchase eligible renewable energy to comply with the EIA, but as discussed previously in Chapter 1, it will likely become a qualifying utility in 2016 with renewable resource requirements starting in 2021. The RPS requires large utilities (25,000 customers and greater) to obtain a percentage of their electricity from eligible renewable resources, such as solar and wind.

Figure 31: Western States with Renewable Portfolio Standards



State Greenhouse Gas Emission Legislation

In September 2007, Substitute Senate Bill 6001 enacted by Washington State established statewide greenhouse gas (GHG) emissions reduction goals and set an emissions performance standard on base

load electric generation. The law imposes significant restrictions on the procurement of fossil-fuel-fired base load generation. Conventional coal-fired generation (i.e., pulverized coal) produces GHG emissions in excess of the new emissions standard of 1,100 pounds of CO_2 per megawatt hour. The law thus effectively bars Washington utilities from entering into long term financial commitments for any pulverized coal-fired generation unless they use some form of carbon sequestration or unless they purchase coal transition power.[7] New coal combustion technologies such as Integrated Gasification Combined Cycle (IGCC) technology with the ability to capture carbon for sequestration may be feasible resource options in the future. However, a viable sequestration plan must be formulated which, to date, has not been demonstrated.

Other Carbon Regulation

Also on the horizon are significant changes that will influence how electric utilities deal with issues related to carbon emissions. A state or regional cap-and-trade system for carbon emissions could follow the same steps as other nationwide cap-and-trade programs. A nationwide cap-and-trade program to reduce sulfur dioxide (SO_2) emissions from the power sector has achieved dramatic SO_2 emission reductions at far lower than expected costs. A similar program to reduce nitrogen oxide (NO_X) emissions in the eastern US has achieved comparable success.

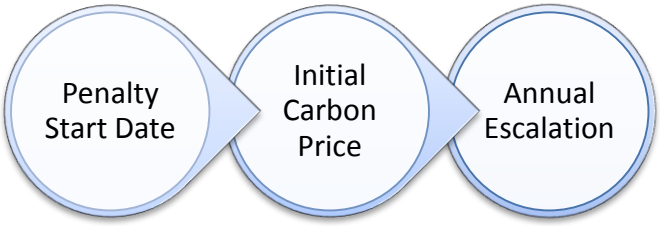
Over the past decade, the US Congress has considered several cap-and-trade proposals in various forms. The closest Congress came to passing cap and trade legislation came in 2008. Currently, with the state of the economy and Republican control over the House, it is unlikely that federal cap-and-trade legislation will be enacted in the next few years.

Industry professionals are confident that the US Congress will pass legislation in the future that will penalize the emission of CO_2 by power plants. This could take the form of a tax, enforced through a cap and trade system, or an alternative mechanism. In any case carbon regulation would exert a significant influence on the cost of power generated by emitting resources. It is important that the IRP address how carbon prices could impact resource economics. Similar to REC prices, predicting the future carbon emission penalty is highly speculative. To capture the cost and uncertainty associated with CO_2 prices, the IRP utilizes a Monte Carlo simulation. The simulation is divided into three processes as shown in Figure 32.

The first simulation step is to vary the penalty start date. In the IRP model, the starting date is set to range between 2013 and 2017 with a mean value of 2015.

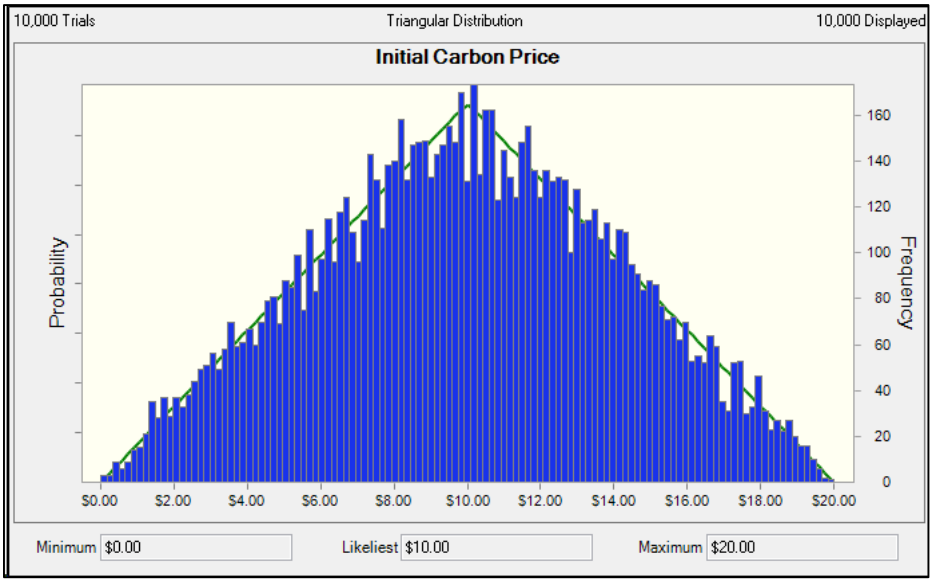
[7] E2SSB-5769 allowed utilities to contract for power from the TransAlta coal plant in Centralia, WA (referred to as "coal transition power"), in exchange for an MOA with the plant's owners to take it out of service by 2025.

Figure 32: Carbon Simulation Steps



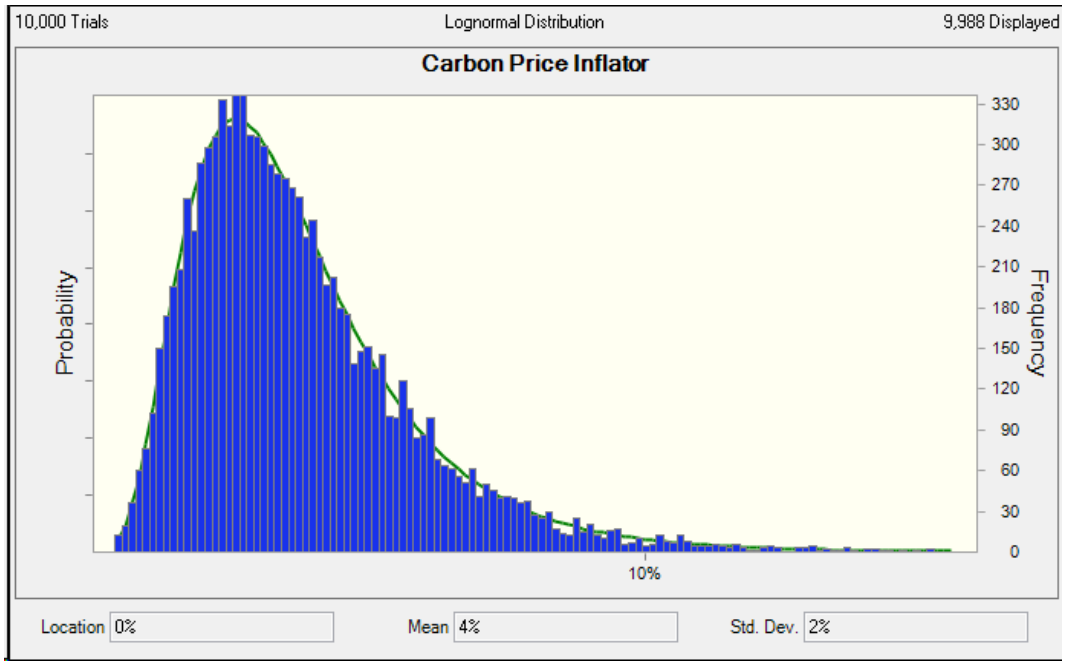
The second step in the simulation is to vary the initial carbon price level. The assumed distribution can be seen in Figure 33. The most likely outcome is $10/per ton, the minimum is zero and the maximum is $20/ton.

Figure 33: Initial Carbon Price Simulation



The final step in the simulation is to vary the escalation factor for the initial price. The assumed distribution is shown in Figure 34 below. The study assumes a lognormal distribution with a mean of 4% annual escalation and a standard deviation of 2%.

Figure 34: Carbon Price Inflator Simulation



The results of the simulation can be viewed in Figure 35. The chart shows five lines which represent probability percentile values from the simulation. For example, half of the simulation values will be above the 50th percentile and the other half below; 95% of the values will fall below the 95th percentile line, etc.

Figure 35: CO_2 Values Used in Study

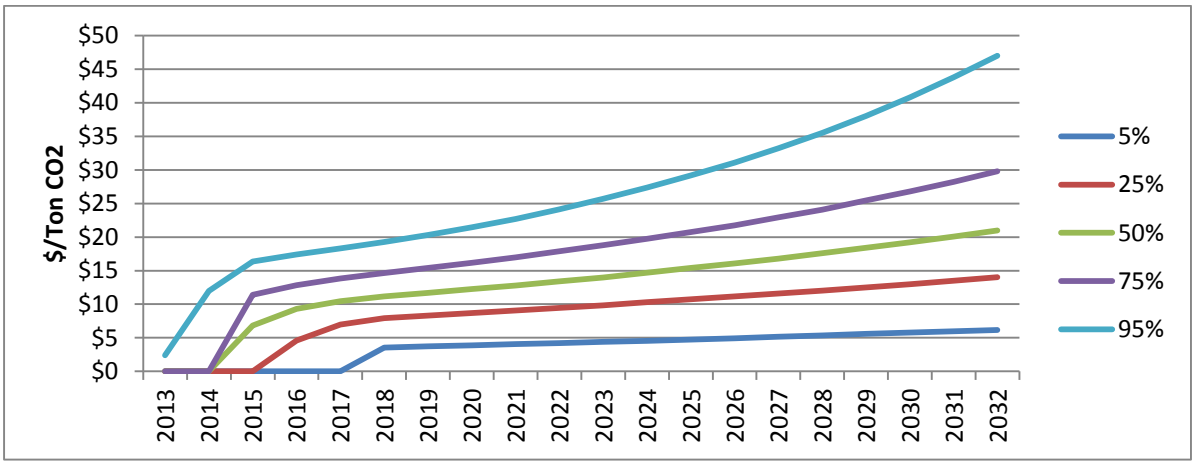
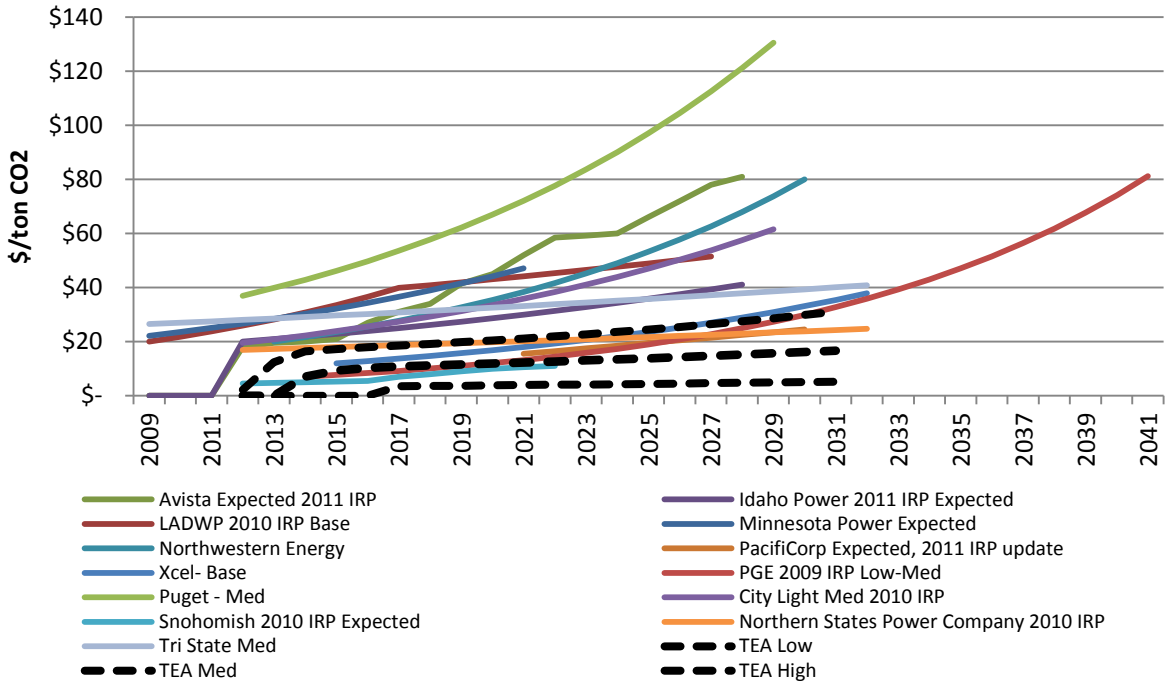


Figure 36 shows how the mean simulated value compares to a variety of external forecasts. The study assumption is represented by the black dashed line. Clearly, it is low relative to other forecasts. It should be noted that many of these forecasts were performed several years ago when the political climate seemed more favorable to this type of legislation. Given the subsequent political and economic changes, aggressive CO_2 legislation is less likely today than it was several years ago.

Figure 36: Survey of CO_2 Penalty Forecasts



Overview of Supply Side Resource Acquisition Alternatives

Franklin PUD has a number of options for purchasing power or acquiring output from generating resources to meet load requirements in excess of its existing resource mix both to meet RPS requirements and to meet the shortage of resources usually experienced during its 3rd quarter summer peak.

The costs associated with the various supply side resource alternatives included in this report are the same regardless of whether the District purchases a share of the output of a generating resource via a power purchase agreement or owns the resource outright. There are advantages to both options. The advantages to purchasing a share of the output from a generating resource rather than developing and owning a resource include:

- Economies of scale typically show that resources need to be fairly large (minimum of 70 to 100 MW) to be cost effective;

- Resource development contains significant risk, such as capital expenditure overruns and delays in the commercial operation date (COD); and

- Resource operation also includes significant risk, such as the potential for major unplanned outages and fuel price uncertainties.

The most significant risks associated with resource development include capital expenditure overruns and delays in the commercial operation date (COD). Capital expenditure overruns can be caused by increased costs associated with plant equipment, fuel transportation infrastructure (i.e., gas pipeline

interconnects) and transmission interconnections. Delays in the COD could require the utility to purchase market power to cover the months prior to the COD when the utility may be short resources due to the delay. This represents a significant risk because the utility would have no choice but to pay prevailing market prices. The complexity of arranging capital financing can also be very time consuming, complicated, and could lead to delays in the COD. The complexity and time required to set up financing is only exacerbated when multiple entities/utilities with different structures (municipalities, coops, public utilities, etc.) finance and build a resource together.

There are also significant risks associated with resource ownership after a project has achieved commercial operation. The most significant of these risks are fluctuating fuel prices and major plant outages. Both of these risks could leave a utility relying on fuel or power markets to provide power required to serve load.

There are also benefits to resource ownership including:

- The ability to economically dispatch the resource; and
- Fewer transmission constraints if the resource is sited within the utility's service territory;
- The ability to hedge market risks associated with fuel purchases;
- The ability to manage fuel transportation costs; and
- The likelihood of greater flexibility to use the resource as a load following resource, particularly with respect to meeting peak demands.

Supply Side Resources Considered in the IRP

The list of generation technologies examined is not exhaustive; only resources that can be developed within the timeframe of this IRP were considered. A project economics model was developed as a means to evaluate the different variables across the different generation resource options. The model was developed to compare the effect of the different variables across the generation technologies through a $/MWh levelized cost of energy (LCOE) metric that includes the average energy production costs, levelized throughout the lifecycle of the resource. LCOE includes the cost for capital, fixed O&M, and variable O&M.

Capital costs for new supply side resources have mostly held steady or decreased since completion of Franklin PUD's integrated resource analysis in 2010.[8] Improving technology and declining raw material costs are the primary drivers for this trend.

Thermal Resources

Despite the recent advances in renewable energy technology, fossil fuel generation sources are currently the most economical means to produce electricity. The statement holds true as long as the current fuel price and regulatory environment remains the same. Two of the most important drivers to

[8] Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report for US Energy Information Administration, February 2013

fossil fuel generation, though, are fuel price and regulatory environment.

Natural Gas Prices

Natural gas prices are at inflation-adjusted historical lows. Market and regulatory drivers are currently aligned in favor of reducing fossil fuel generation costs. A spike in natural gas prices or a reversal in one of the regulatory decisions has the potential to significantly drive up generation costs.

With prices historically very volatile and notoriously difficult to predict, the gas market is prone to periodic price spikes. However, the shale gas boom as of late has driven gas prices to near historical lows and reduced its volatility to below the historical average. Using the 20 year price forecasts in the cost calculations, natural gas generation is currently the most economically effective means of producing electricity. Price forecasts, however, are regularly off the mark and sometimes by wide margins. A risk metric was created to such that the fuel and regulatory uncertainty associated with fossil fuel generation was modeled and included in this analysis.

The use of hydraulic fracturing, which uses fluid under high pressure to propagate fractures in semi-permeable rock containing petroleum and natural gas, has led to a boom in the production of natural gas in the US from previously unrecoverable shale deposits. The US Energy Information Administration (US EIA) estimates there are over 827 trillion cubic feet of recoverable shale gas reserves in the US, and that prices will stay below $5/MMBTU through 2023. Due to this, natural gas generating units are likely to be the most significant form of new generating capacity in the foreseeable future. Hydraulic fracturing, however, has been criticized by some groups for polluting underground aquifers and contaminating drinking water. Scientists have not reached a consensus on this issue yet, and until they do, it appears that most states will continue to allow fracturing. The risk to natural gas power plants, however low that risk may be, is an outright ban that will certainly cause natural gas prices to rise.

The production cost of natural gas fueled generators depends heavily on natural gas prices, which are historically volatile and difficult to predict. Natural gas prices have fluctuated from a high of greater than $14/MMBtu in 2007 to a low of less than $2/MMBtu in 2013. Prices are forecast to average $3.90/MMBtu over the next 5 years. Every $1 increase in gas price equates to roughly a $10/MWh increase in production costs for a combined cycle combustion turbine (CCGT). Franklin PUD's current gas price forecast is illustrated in Figure 37.

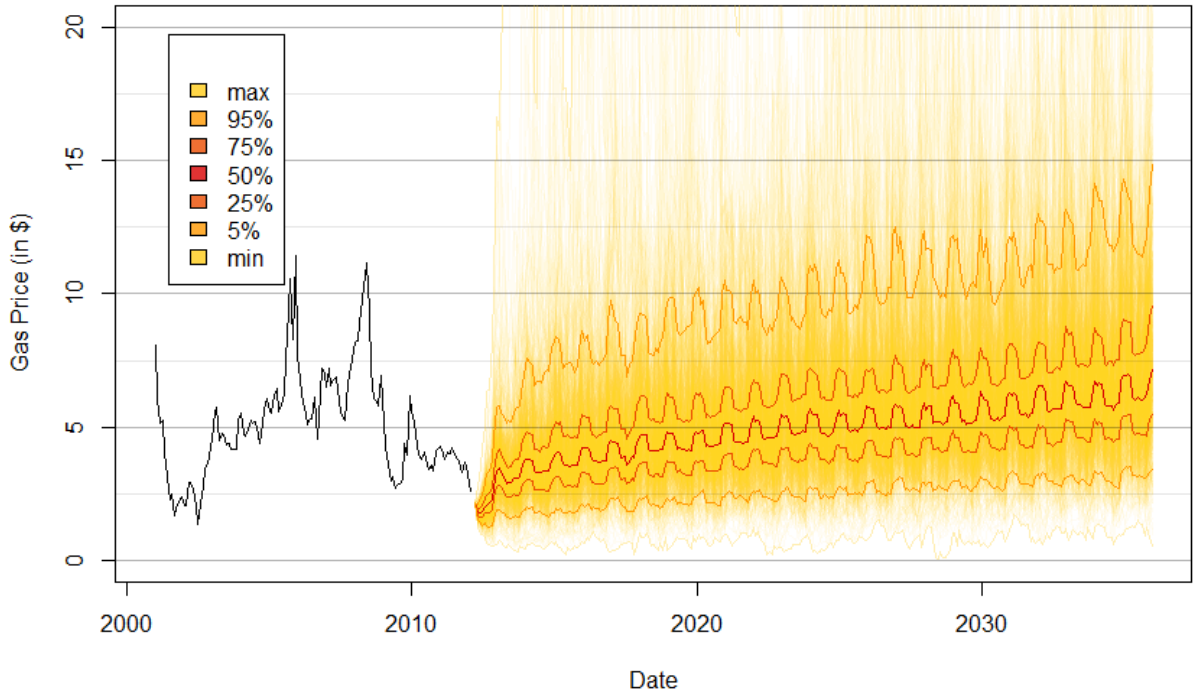
Natural Gas-Fired Combustion Turbines

Natural gas power plants are the single largest source of generation capacity in the US, comprising about 40 percent of total capacity and 30 percent of electricity generation in 2012. These plants are versatile, as they can be dispatched almost instantly and have the ability to generate electricity in high demand, capacity constrained periods.

General attributes of natural gas power plants include a small physical footprint, low capital investment, with a short construction period of less than one year. Compared to coal, natural gas produces significantly less pollution as it has lower sulfur, nitrogen, and soot content. It is also more than 40 percent less carbon intensive than coal. For the time being it is also cheaper than coal, though coal

prices are generally very stable, while natural gas prices are historically volatile. These attributes make natural gas power plants attractive to utilities.

Figure 37: 2012 – 2032 Long Term Gas Price Forecast



There are two common types of natural gas turbines: combustion gas turbines (CT) and combined cycle gas turbines (CCGT). A CT is effectively a jet engine that produces electricity. A CCGT is a CT with a steam turbine attached to the end of the process. It uses the hot exhaust from the CT cycle to make steam that is run through a turbine. CCGTs can be very efficient with heat rates ranging from 6,600-7,700 BTU/kWh. CTs have higher heat rates of 9,900-12,000 BTU/kWh and are generally used for capacity while CCGTs are more frequently used to serve base load.

In base load operations, a CCGT is preferred because of its greater thermal efficiency and lower cost on a per unit basis. A CT is more appropriate to ramp generation levels up and down to meet peak loads. Both the CCGT and CT considered in this section are assumed to produce GHG emissions less than the maximum of 1,100 pounds of CO_2 per MWh included in SSB 6001.

The lowest cost gas generators can produce at prices competitive with coal power. The most expensive generators are costlier than wind power. The average generator will likely fall somewhere in-between. Factors that will affect the further development of natural gas are fuel prices and the implementation of a carbon tax. Natural gas turbines have historically not encountered any major problems during siting or construction. Fuel represents about 75 percent of their total costs and puts a heavy dependence on the cost of fuel. However, natural gas is the least carbon intensive of all the fossil fuels and will be less affected by carbon pricing than its equivalent coal counterpart, which may spur a movement toward

natural gas generation. On the other hand, carbon and natural gas prices may rise above the threshold and make currently uneconomic renewable projects commercially viable.

Coal-Fired Projects

Coal combustion is one of the oldest and most well established methods of generating electricity. Nearly 40 percent of all electricity in the US is made from coal power. Coal fuels base load power plants that operate and generate electricity nearly continuously. Despite the large reserve base in the US, the current future of coal in the generation mix is uncertain.

Pulverized Coal-Fired Steam-Electric Power Plant

Pulverized coal (PC) plants are the dominant coal generation technology used in the US. The plant consists of a coal handling and preparation section, a boiler and a steam turbine generator. Raw fuel comes into the power plant where it is crushed and burned to turn water into steam. The steam expands and drives the turbine by pushing on its blades, which spins the generator, producing electricity. The steam is condensed back into water and returns to the boiler to begin the cycle once again. Exhaust gases are then passed through several pollution control devices installed to reduce emissions, such as sulfur, particulate matter, and nitrous oxides.

Coal is a unique fossil fuel because its prices are stable relative to the more volatile natural gas and crude oil prices. The price of coal at the mine is roughly $1/MMBtu compared to $4.00/MMBtu for natural gas and $15/MMBtu for crude oil. Most power plants, however, are not adjacent to the mine. Compared to natural gas or oil, coal has a relatively low energy density. Transporting coal from the mine to the power plant accounts for 50 percent of its cost. Since most is delivered by freight trains that run on diesel, the cost of coal is partially tied to the cost of oil.

Plans to build new PC-fired plants have decreased significantly over the past seven years. Nationally, since 2005, there have been more than 168 cancellations of planned coal plants. The cancellations have been due to escalating project costs (that have increased an estimated 15 to 20 percent between 2010 and 2013), permitting problems, and uncertainties regarding state and federal legislation that may influence coal-fired generation. Political pressure has accelerated the retirement schedule of the only two coal plants in the region in Boardman, OR and Centralia, WA with a total capacity of over 1,900 MW that are now slated for decommissioning in 2020 and 2025, respectively.

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) technology is a coal-fired, combined cycle electric power generation technology with post-combustion emission controls. The four major processes in an IGCC facility are: 1) converting coal into a fuel gas, 2) cleaning the fuel gas, 3) using the clean fuel gas to fire a gas turbine generator and the hot turbine exhaust to make steam that drives a steam turbine generator, and 4) treating waste streams. Gasification of coal allows pollutant carriers to be removed from the fuel before combustion in the power plant. Emissions of sulfur and nitrogen oxides and particulates from IGCC facilities are projected to be significantly lower than for traditional coal technologies.

IGCC is an emerging coal technology that will facilitate carbon capture and storage once it becomes technologically and economically viable. Currently there are only a handful of IGCC plants operating in

the US and none of them have the capacity to capture and store the carbon dioxide. However, this is the most promising technology to develop carbon capture and storage capabilities.

There are several barriers affecting the development of both PC and IGCC coal plants in Washington State that include public image, permitting issues, high and rising construction costs, state legislation limiting emissions for base load projects, and the possibility of carbon pricing in the near future. It was determined upon review that coal fired generation will not be a viable resource in the timeframe specified within this IRP.

Nuclear

The US is the world's largest producer of nuclear power and derives about 10 percent of its generation capacity from nuclear power plants. Nuclear energy gained prominence over half a century ago when it was labeled as a producer of electricity that would be "too cheap to meter." After a 20 year period of no nuclear growth, it is once again being considered as a viable technology that can provide abundant and emission-free electricity for the future.

Nuclear power has many advantages. Fuel is abundant; an MIT study on nuclear energy estimates that enough fuel exists worldwide to commission 1,000 x 1,000 MW nuclear power plants for the next 50 years. Nuclear power is a zero carbon emissions electric generation source that is commercially available on a large scale. Nuclear power has a long enough operational history that it has proven itself to be a reliable generator that can provide large amounts of electricity at predictable rates.

Nuclear power also has several disadvantages, namely perceived safety risks, cost, waste, and proliferation. While rare in occurrence, nuclear accidents are prominently featured and have far-reaching consequences. Meltdown of the Fukushima Dai'ichi plant prompted Japan and Germany, large consumers of nuclear power, to accelerate the decommissioning of their nuclear fleets. There is also the lingering question of how to safely and permanently dispose of nuclear waste. Despite spending $9 billion on building the Yucca Mountain nuclear waste repository slated to open in 1998, the project suffered a major setback when it was determined to no longer be a viable disposal site in 2009. However, in August 2013, the US Court of Appeals issued a decision ordering work to resume on a Department of Energy licensing application for the site.

Prior to the Fukushima accident, proliferation was cited by many as a concern to the continued use of nuclear power. Justified or not, it will continue to be a focus of attention during the siting and licensing process.

Finally, cost concerns have beleaguered the nuclear industry since its inception. Nuclear power plants in the US have not historically been delivered on-time or on-budget. The average final cost of 75 power plants operational in 1996 was 303 percent above the original budget. The nuclear industry has also not built a nuclear power plant in over 30 years. Given all of these variables, it is probably safe to say that the true economic cost of a new nuclear power plant will remain unknown until one is finally built. If US EIA estimates are correct, the current economics of nuclear power cannot compete with other generation sources such as coal or natural gas without subsidies or implementation of a carbon tax.

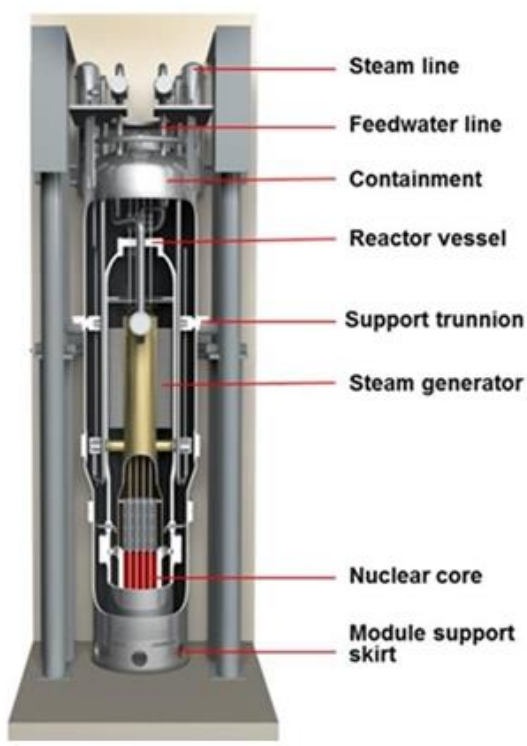
The nuclear power plant examined in this IRP is the small modular reactor (SMR) under development. SMRs are smaller, more economical, and safer than the conventional large-scale nuclear reactors. SMRs are not a single class of nuclear reactors, but a generic term to describe those with generation capacities of less than 300 MW, but that can generate as little as 25 MW. Columbia Generating Station, by contrast, is a typical conventional reactor with a 1,100 MW capacity. Both technical safety and protection against proliferation are always a concern with nuclear power; and enhanced safety features with SMRs will include further protections against technical failures, longer periods between refueling, and even the ability to be installed underground to limit potential tampering.

NuScale Power Small Modular Reactor

An SMR under development by NuScale Power of Corvallis, OR, has been selected by Energy Northwest as its technology of choice as an option to fill future energy needs. The District is engaged in Energy Northwest's efforts to move the NuScale design through licensing and construction. NuScale has identified Idaho Falls as the location for its first commercial plant, which is planned to be operational by 2024. The US Nuclear Regulatory Commission (NRC) is currently engaged in pre-application activities on this design.

The NuScale SMR, illustrated in Figure 38, is a pressurized-water reactor, and will consist of 45 MWe modules small enough to be fully built at the factory to minimize any on site construction. SMRs will also be more flexible than their conventional counterparts with the ability to ramp up production when needed and back off when it is not.

Figure 38 Cross-Section of NuScale Power Small Modular Reactor (SMR)



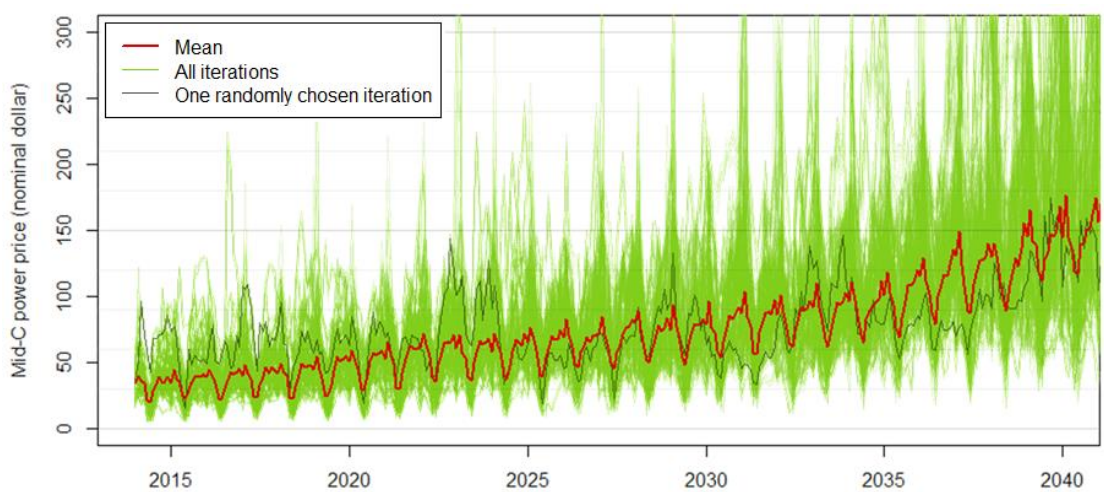
Market Power Purchases

Because the Mid-Columbia (Mid-C) power market was the assumed pricing mechanism for modeling market purchases, whether from a regional utility, a power marketer or under BPA's market based products for Tier 2 priced power, a single market forecast was developed. The AURORAxmp power market forecasting tool stochastically generates a long-term price forecast for the Mid-Columbia region using inputs on performance characteristics of supply resources, regional demand, and transmission constraints, regional operating units, fuel prices, demand forecasts, and other factors. AURORAxmp and the stochastic analysis are described in more detail in Appendix B.

In the Mid-C region, market prices have historically been among the lowest in the country due to the preponderance of cheap hydropower. Hydro output is not expected to increase throughout the period of this study, meaning that more expensive wind and natural gas generation will be used to meet increased demand. Prices in the region are forecast to steadily rise through 2035, with an average nominal price over the study period of $63.97.

Figure 39 shows an all-hours forecast of Mid-C power prices.

Figure 39: All-Hours Mid-C Price Forecast



If a power purchase agreement (PPA) for market power, or for a non-renewable resource, was entered into after the Frederickson contract terminates, the District would also need to purchase RECs in 2022-32 sufficient to meet its obligations under Washington's EIA. This would increase the costs associated with the PPA. Under this scenario, the District would be exposed to both Mid-C market price volatility and REC price volatility (as discussed in REC section below). In addition to price volatility, the impacts of which will be discussed in the "Risk Analysis" section, relying on a PPA would expose the District to uncertainty with respect to the availability of power that is shaped and has a contract term that meets its power requirements. The availability of market power is not guaranteed as most of the region's

current firm surplus is held by marketers who are free to sell the power to highest bidder, including the California market (assuming there are no transmission constraints).

Summary of Non-Renewable Resource Costs and Characteristics

Figure 40 summarizes the costs and characteristics of the non-renewable supply side resources discussed above.

Figure 40 - Supply-Side Resource Cost Assumptions

Summary of Medium Case Assumptions for Resources For Plants Entering Service in 2018 (2011 $)						
Resource	Plant Size (MW)	Heat Rate (Btu/kWh)	Capacity Factor	Total Plant Cost ($/kW)	Fixed O&M ($/MWh)	Variable O&M (including fuel)
Natural Gas (CCGT)	390	6900	87%	$ 1,120	$ 1.70	$ 48.40
Natural Gas - CT Peaking Unit	85	12000	30%	$ 610	$ 2.70	$ 80.00
Conventional Coal	450	9000	85%	$ 3,500	$ 4.10	$ 29.20
Coal (IGCC)	625	8700	85%	$ 3,600	$ 8.80	$ 37.20
Small Modular Reactor	50 - 500	10,700	90%	$ 5,000	$ 11.60	$ 12.30

Sources: NWPCC Sixth Power Plan, US Energy Information Administration

Figure 41 summarizes the levelized cost for utility-scale generation based on a 30-year cost recovery period, using a real after tax weighted average cost of capital of 6.6 percent. BPA's projected Tier 1 rate is included for comparison purposes.

Figure 41: US Average Levelized Costs for Plants Entering Service in 2018

U.S. Average Levelized Costs (2011 $/MWh) for Plants Entering Service in 2018	
Resource	Levelized Cost ($2011/MWH)
BPA Tier 1	$ 45.00
Market Forecast	$ 64.00
Natural Gas (CCGT)	$ 67.00
Conventional Coal	$ 100.00
Small Modular Reactor	$ 108.00
Natural Gas - CT Peaking Unit	$ 130.00
Coal (IGCC)	$ 135.00

Source: US Energy Information Administration

Renewable Resources

Eligible resources, as defined by the state Energy Independence Act, include wind, wave, and geothermal, landfill gas, biomass cogeneration, dairy-based anaerobic digesters, solar, and limited, narrowly-defined hydro. The benefit of eligible renewable energy lies in the expectation that most resource options have environmentally appealing aspects. In addition, eligible renewable projects can

provide protection against fuel price risk, future carbon costs, and provide diversification of fuel consumption, thereby limiting the risks associated with relying on one type of fuel and the volatile nature of specific fuel prices.

Impact of Renewable Portfolio Standards

Competition for eligible renewable projects in the region was heating up between 2007 and 2012 due to RPS requirements in Washington and elsewhere in the region (California, Oregon and Montana), but has slowed in recent months. Most utilities that must meet their near term RPS requirements have addressed their needs for the short term. However, there is risk that, due to the high RPS targets they must achieve, the IOUs in the region and in California may be purchasing much of the available supply of eligible renewable generation. This may make it difficult for small- and medium-size utilities to find enough megawatts to fulfill their RPS requirements. There are a great number of uncertainties surrounding renewable standards and the impact for eligible renewable generation in the market.

Renewable Energy Credits

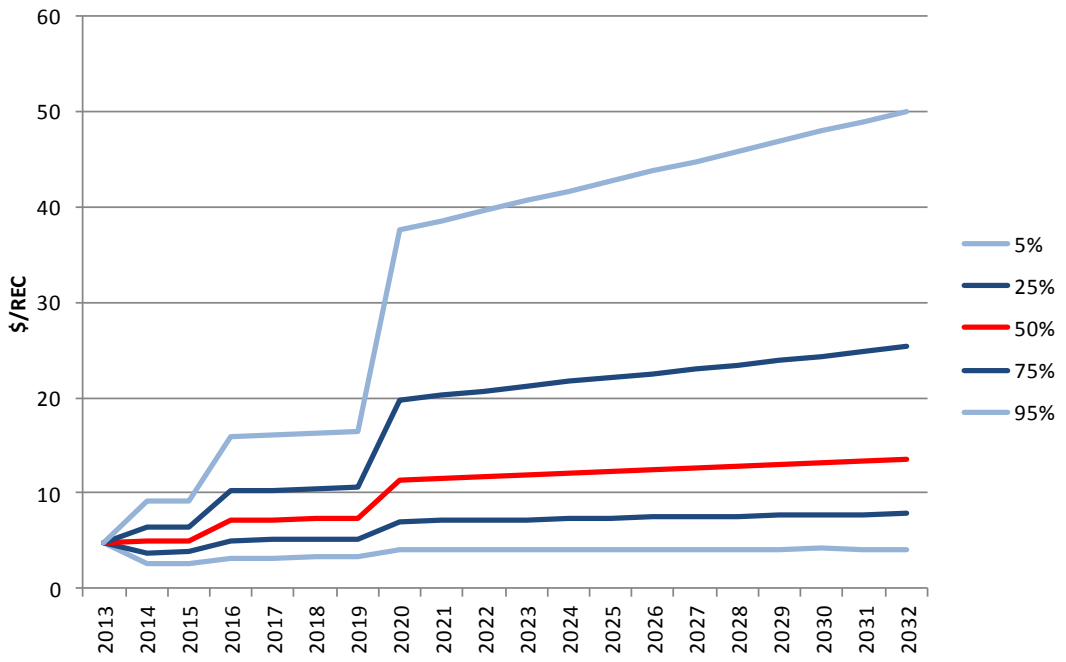
The value of the environmental attributes associated with eligible renewable resources is one of a myriad of issues driving the development of these resources. Renewable Energy Credits are market mechanisms that represent certain environmental benefits associated with generating electricity from eligible renewable resources. In states that have a REC program, eligible renewable energy providers are credited with one REC for every MWh of eligible renewable energy produced. A certifying agency (WREGIS in the Western Interconnection) assigns a unique identification number to each REC to make sure it is not double-counted. The eligible renewable energy is fed into the electrical grid, and the accompanying REC can then be sold on the open market.

A REC market has developed as an artifact of the creation of renewable standards by state legislatures. A utility with an eligible renewable resource that does not need to keep the environmental attributes associated with it has the option of marketing those environment attributes by selling RECs. These can be sold to other utilities that do not have sufficient eligible renewable resources in their portfolios. This allows utilities a means of including the environmental attributes of eligible renewable resources in their RPS portfolios.

Some utilities in the Pacific Northwest are not selling the environmental attributes of their eligible renewable resources but are instead using them to support their “green power” retail rate programs. These programs allow utilities’ retail customers to voluntarily purchase renewable energy at higher prices that reflect the increased costs associated with those resources.

The current wholesale value of a REC is in the range of $1.50/MWh to $20/MWh. The REC market is not liquid so it is difficult to estimate future prices. To account for this uncertainty, several REC pricing scenarios were developed and are shown in Figure 42. High, medium and low scenarios were constructed based on opinions collected from several energy traders. Each scenario has several “steps” that correspond to increases in the Washington State RPS. It is important to note that REC markets are highly illiquid and dependent on factors that are difficult to predict (regulation, legislation, etc.). As a result, actual future values could be dramatically different than what is assumed in the study.

Figure 42: REC Value Estimated Used in IRP



The EIA includes a penalty charge if a utility does not comply with the RPS targets. A $50/MWh charge (in 2007 dollars, adjusted for inflation) could be assessed on the difference between the target and the actual eligible REC purchased or generated. This penalty fee may set the maximum price for the REC market.

When it becomes a qualifying utility, Franklin PUD may claim RECs to meet future RPS requirements within a 3-year window of the eligible renewable energy generation. To the extent that the eligible renewable generation included in the portfolio analysis is greater than the RPS target on an annual MWh basis, the RECs will be banked and used to meet EIA requirements in subsequent year(s). Franklin PUD will be surplus RECs through 2024 and deficit beginning in 2025 when its RPS target jumps to 9 percent requiring, under most circumstances, REC purchases. This shortage will be increased by over 3 aMW after 2027 when the White Creek contract expires.

For the portfolios modeled in Chapter 6 that rely on non-eligible resources, it is assumed the District will purchase enough RECs (without energy) to meet the increase in the RPS target beginning in 2025 or may be able to use one of the cost cap alternatives in the EIA.

Tax Credits

Renewable generation development is also strongly dependent on both direct and indirect subsidies. Since 1992, various tax credits have been available for eligible renewable energy development. Each is discussed below. Because deadlines for tax credit eligibility vary across tax credit and type of resource, applicable renewable resources are evaluated both with and without tax credits.

Production Tax Credits

Originally enacted in 1992, the federal Production Tax Credit (PTC) is a per-kWh tax credit for electricity generated by qualified energy resources. The PTC provides a credit of 2.3 cents per kWh of actual energy generated applicable to the first 10 years of operation, which may be large enough to swing the pendulum from choosing a renewable over a fossil fuel generation resource. It is typically a program that needs to be renewed by Congress each year; Congress has a habit of waiting until the 11th hour to make a decision on whether to renew it or let it expire. As part of the Federal fiscal cliff deal at the end of 2012, this direct subsidy to the renewable industry was renewed and expanded. However, Congress failed to act on extending the PTC into 2014.

As it currently stands, construction of eligible facilities must have commenced by January 1, 2014. Congress' decision to let the PTC lapse will almost certainly adversely affect the future development of PTC dependent technologies. Wind power development has historically slowed in years when the PTC lapsed and accelerated again when the PTC was renewed.

Investment Tax Credits

The Investment tax credit (ITC) is similar to the PTC except that a share of project expenditures is available as a tax credit up front (rather than over the course of 10 years like the PTC). The ITC applies to solar, fuel cells, small wind turbines, geothermal, micro turbines, and combined heat and power (CHP). Depending on the technology and timing of investment, it may be more beneficial for developers to pursue the ITC rather than the PTC. Figure 43 summarizes the ITC for each eligible renewable energy technology.

Figure 43: Investment Tax Credit Summary

Investment Tax Credit Summary			
Technology	**Eligibility**	**Incentive**	**In-Service Deadline**
Solar	Solar for electricity, heating, cooling, plus hybrid solar lighting systems	30 percent	31-Dec-16
Fuel Cells	≥0.5 kW Efficiency ≥30 percent	30 percent up to $1,500/0.5kW	31-Dec-16
Small Wind Turbines	100 kW or less	30 percent	31-Dec-16
Geothermal Systems	Heat pumps and other equipment including utility scale	10 percent	December 31, 2016 for heat pumps, none otherwise
Microturbines	≤ 2 MWcapacity factor ≥26 percent	10 percent up to $200/kW	31-Dec-16
Combined Heat & Power	≤ 50 MW efficiency ≥60 percent	10 percent	31-Dec-16

Source: dsireusa.org

Renewable Energy Production Incentive

The federal Renewable Energy Production Incentive (REPI) had provided incentive payments similar to the PTC for electricity produced and sold by new qualifying renewable energy facilities owned by not-for-profit electrical cooperatives, public utilities and state governments. Qualifying systems are eligible for annual incentive payments for the first 10-year period of their operation just like the PTC; however, REPI benefits are subject to the availability of annual appropriations in each federal fiscal year of operation. Unfortunately, the REPI program has been under-funded in recent years, with appropriations so low that utilities have not been able to utilize the program. The Nine Canyon Wind Project, for example, has not received REPI benefits since FY2008.

Renewable Project Cost Estimates

Renewable resources have two common attributes: high capital expenses and low operating expenses. The primary advantage is a free and self-sustaining fuel source, which eliminates the volatility and uncertainty associated with fossil fuel prices. Resource acquisition decisions, however, are based on more than economics. Political incentives and constraints, such as renewable portfolio standards, carbon penalties, and other federal, state or local policies can encourage or discourage the development of certain resources. A number of commercially viable renewable resources are included in the IRP for screening, although some were not used in the candidate portfolios modeled for reasons discussed in the portfolio analysis chapter.

Capital costs, fixed and variable O&M costs and other costs associated with renewable resources are calculated based on data from regional and national resource planning studies.

Wind

Wind turbines convert wind energy into electricity by collecting kinetic energy generated when the blades that are connected to a drive shaft (rotor) turn a turbine generator. Individual wind turbine capacities of 2.5 MW are now commercially available. Wind generation facilities typically range in size from 50 MW to approximately 300 MW.

Generation output is cubically proportional to wind speed; e.g., if wind speed doubles, output increases by a factor of 8. When it comes to wind speed, however, more is not always better. Excessively high wind speeds can damage wind turbines. For this reason, turbines are engineered to turn into the wind during these periods, like a sailboat, so the rotors receive the least amount of wind. New turbine blades are also designed to bend when certain wind speeds are reached so that part of the wind spills off the turbine to minimize potential damage.

Wind turbines generally have high availability factors (close to 95 percent), but actual capacity factors are limited to approximately 25 to 40 percent[9]. By contrast, coal, nuclear, and combined cycle gas plants have capacity factors closer to 85 percent, while photovoltaic solar arrays have capacity factors between 14 to 20 percent.

[9] US Energy Information Administration, U.S. Wind Capacity Factors – 2012 from Form EIA-923 submitted by wind energy facilities nation-wide. The highest capacity factor state-wide was South Dakota at .429.

RPS policies nationwide have had a great impact on where wind facilities are being located. States with an RPS received 55 percent of the new wind development between 1999 and 2007. That figure increased to 75 percent in 2007. Being the least cost renewable resource available on a large scale, it is no surprise that utilities around the country disproportionately add wind energy to meet their renewable energy mandates. However, some utilities may be foregoing cheaper resources, or adding wind energy despite not having additional energy needs. The additional cost of wind energy over alternative, cheaper resources is ultimately passed onto consumers.

Subsidies can also promote adverse incentives. Most producers have an economic inventive to shut production down when market prices reach zero. Any lower, i.e., negative-priced markets, and buyers are getting paid to use electricity. Wind developers, however, do not have an incentive to curtail generation. Producers receive the PTC based on actual generation, not installed capacity. Their baseline for profitability is therefore not zero, but zero minus the amount of the subsidy, which comes to ($23)/MWh. Generating turbines also create RECs that have value in the market and for meeting RPS requirements, creating another disincentive to stop production.

Wind is being developed rapidly in the Pacific Northwest although there is some opposition to additional facilities in certain areas. Assuming that issues related to the availability of transmission service and the ability to manage the intermittency and unpredictability of the output can be resolved as more wind is developed, wind will be a viable and feasible renewable resource in the future. State RPS are applying pressure within the region to solve transmission, shaping/firming and integration issues as more and more utilities look to wind to provide eligible renewable generation.

Shaping/Firming and Integration of Wind Resources

Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. Electronics depend on a source of electricity that has a certain voltage and frequency. Variability in these two factors can lead to power surges or brownouts. The fact that wind power generation is variable, and not wholly predictable, means that electricity system operators must provide additional reserves to counter the additional risk in balancing power supply and demand. In addition, wind power output may not be sufficient when it is most needed such as during summer heat waves, or arctic outbreaks, when wind turbines are notorious for low generation levels due to reduced wind velocities.

Since wind output cannot be assumed to be available in all hours, other generating resources need to be on call to be ramped down when the wind resource provides generation and ramped up when the wind resource does not provide generation. Providing within-hour balancing services for variable wind power, including additional reserve capacity and shifting generation patterns, is known as wind integration. Typically this requires larger utilities that operate control areas with “dispatchable” resources (resources that can increase and decrease output as dictated by load requirements) to balance total generation and total load. Currently, the capacity and flexibility for balancing intermittent wind in BPA’s Balancing Authority Area (BAA) comes almost entirely from the FBS.

BPA Wind Integration Rates

The 2012 rate for wind integration (Variable Energy Resource Balancing Service, or VERBS) is $1.45/kW-month, which equates to $6.63/MWh for a wind project with a 31 percent capacity factor. These rates are levied on all wind generators in BPA's BAA. Furthermore, BPA also offers a firming and shaping service for entities that do not have the capability to integrate wind generation into their systems, though at a relatively high cost of roughly $19/MWh. For its existing wind resources, the District provides its own wind integration services with its Slice resource, though it is required to pay the VERBS charge.

Geothermal

Geothermal energy utilizes the Earth's natural underground heat for heating and electricity generation purposes. It has both similarities and differences with other renewable technologies. Like most renewable resources, geothermal is very site specific; there are few places with sufficient geothermal potential to commercially generate electricity and be used for other commercial purposes. Among the most valuable geothermal resources are those at a very high temperature and close to the surface that are easily accessible, such as hot springs and geysers, located in volcanically active areas. But unlike wind, solar, or hydro where actual generation is a function of the wind speed, sun intensity, or hydrological conditions, essentially forces beyond our control, geothermal is always available.

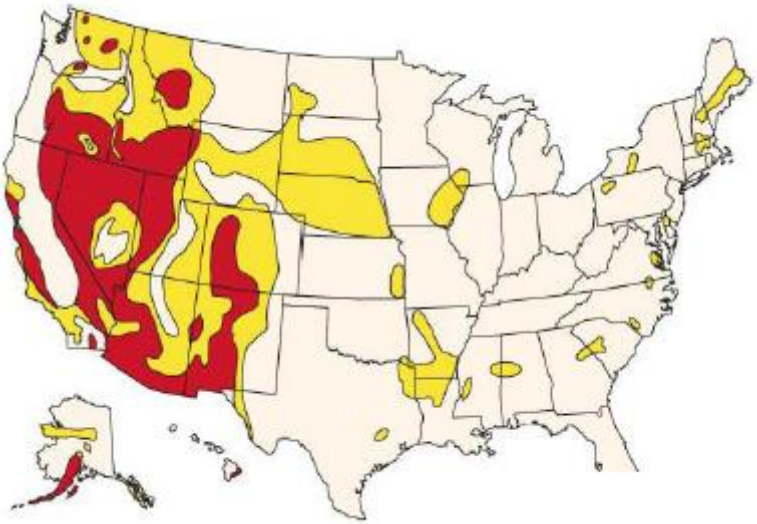
A developing geothermal technology is enhanced geothermal recovery. Research into the technology reveals a resource with enormous potential, estimated at 100,000,000 MW throughout the US. It involves utilizing the heat from deep within the Earth to sufficiently heat water to produce electricity. This technology is not commercially proven, and is not included among the resources evaluated for this IRP.

The development of conventional geothermal energy resources for utility-scale electricity production in the United States began in the 1960's. Since that time, the continual development of geothermal resources and technology has positioned the US as a leader in the global geothermal industry. The US currently has approximately 3,386 MW of installed geothermal capacity, more than any other country in the world. An estimated 175 projects are under development with approximately 5,000 – 5,500 of additional capacity.[10]

The 13 MW Raft River project in southern Idaho became the first commercially operational geothermal project in the Northwest when it began operations in January 2008. Other geothermal generation in the Northwest is still in the initial stages of commercial exploration and development. High development and exploration costs are substantial barriers to the future development of geothermal sources for power production. The location of potential geothermal sources in environmentally sensitive areas has been a barrier to siting geothermal power facilities in the Northwest. Potential geothermal resources in the Northwest include deep vertical faults in the Basin and Range geological province in southeastern Oregon and Southern Idaho and shallow magmatic intrusions associated with the volcanoes of the Cascade mountain range (Figure 44). Most of these locations are remote and could require significant transmission investments to facilitate transmitting the power to load centers.

[10] Geothermal Energy Association, 2013 Annual US Geothermal Power Production and Development Report

Figure 44: Conventional Geothermal Potential in the US



While there are no geothermal power plants currently operating in the State of Washington, one company, Gradient Resources, is in the early stages of developing its Mt. Baker project east of Bellingham.[11] Washington's RPS will provide incentive to development of other geothermal resources despite the State's complex geology. Additional potential commercially viable capacity is spread across five undeveloped sites, thermal springs in the Cascade mountain range and thermal wells located in the Columbia Basin of southeastern Washington. The NWPCC's 6th Plan indicated the development potential for geothermal resources was 375 aMW. Figure 45 shows the Geothermal Energy Association's estimate of projects in development in the western US.

Figure 45: Geothermal Energy Projects in Development by State

State	Total Projects	Planned Capacity Additions (MW)		Estimated Resources (MW)	
--	--	Low	High	Low	High
AK	6	50	50	95	95
AZ	2	2	2	102	102
CA	33	995	1,061	1,736	1,827
CO	3	20	40	60	60
HI	3	--	--	--	--
ID	11	83	83	439	514
ND	2	0.6	0.8	--	--
NM	1	15	15	--	--
NV	75	1,056	1,061	2,150	2,275
OR	18	73	77	208	270
TX	1	1	1	--	--
UT	19	215	215	260	280
WA	1	--	--	100	100
TOTAL	175	2,511	2,606	5,150	5,523

Source: Geothermal Energy Association

[11] Geothermal Energy Association

Biomass Energy

Biomass is made up mainly of the elements carbon and hydrogen. Several technologies can be employed to free the energy bound up in these chemical compounds. Biomass fuels include the following:

- Forest residue: log slash and forest thinning
- Paper mill residue: wood chips, shavings, sander dust and other wood waste
- Pulp chemical recovery: spent pulping liquor used in chemical pulping of wood
- Agricultural crop residues: obtained after harvesting cycle of commodity crops
- Energy crops: grown specifically for use as feedstocks in energy generation processes including hybrid poplar, hybrid willow and switchgrass
- Animal waste: combustible gas obtained by anaerobic decomposition of animal manure
- Municipal solid waste: organic component of municipal solid waste
- Landfill gas/wastewater treatment: combustible gas obtained by anaerobic decomposition of organic matter in landfills and wastewater treatment plants

Three biomass energy technologies are discussed in detail below.

Landfill Gas

Landfill gas consists mainly of methane and carbon dioxide and is produced when organic wastes in landfill sites decay. Landfill gas must be burned or flared in order to reduce the hazards associated with a large buildup of gas. Instead of being released directly into the atmosphere where it is a potent GHG, the methane can be used as fuel to power a turbine. For this reason, landfill gas generation is hailed for its potential reductions to GHG. It is estimated that methane has about 21 times the greenhouse warming potential of carbon dioxide. Aside from GHG reduction, landfill gas generation is also popular for reducing regional and local pollution. The PTC was expanded in the 2005 Energy Policy Act to include landfill gas generation.

According to the NWPCC's 6th Plan, the undeveloped potential for landfill gas generation in the Northwest is estimated to be capable of producing only 69 average megawatts of energy.

Waste Wood Pulp Biomass and Cogeneration

Cogeneration, sometimes referred to as combined heat and power or CHP, is the joint production of electricity and useful thermal or mechanical energy. Direct combustion (the burning of material by direct heat) is the simplest method of capturing the stored chemical energy in biomass.

Most existing biomass cogeneration facilities in the Northwest use the following fuels: wood residues, biogas or spent pulping liquor. Typical projects include pulp and paper mills that burn hog fuel to generate steam that is used in the paper drying process as well as to turn a steam turbine to generate electricity.

Reliability of fuel is a concern for biomass energy production. Power plants have a high heat rate (15,000+), meaning a great deal of fuel is burned per unit of electricity produced. The cost for the fuel itself is low, and can even be free, since much of the fuel has no other commercial application. Some mills pay third parties to remove and dispose of the waste. Transporting the fuel to the power plant can be costly though. The fuel is bulky, has a lower heating value than coal and because of its high water content, is quite heavy. The concern of fuel supply is not whether there is enough biomass available, but whether there is enough biomass available locally.

Estimated waste wood pulp biomass and cogeneration costs are included in this section of the report alongside other non-federal resource options for comparison purposes. Cogeneration will not be included in the portfolio analysis, however, due to the lack of economical fuel near the District's service territory.

Dairy-Based Anaerobic Digesters

Anaerobic digestion, similar to the process used at sewer treatment plants, is one method of handling manure that is likely to become more prevalent due to new standards that require large (700 cows or more) dairy operations to obtain discharge permits. The permits require that an approved method of managing manure be included in the dairies' practices. The Environmental Protection Agency favors anaerobic digestion for managing manure. Manure is fed into a tank in which bacteria break down volatile solids into methane gas and carbon dioxide. The gas can be used by reciprocating engines to produce electricity. This method of generating power falls under the "biomass" categorization and qualifies as an eligible renewable resource under Washington's RPS rules. There are currently eight operating digesters in Washington State, as shown in Figure 46.

Figure 46: Operating Anaerobic Dairy Digesters in Washington State

Farm/Project Name	City	Digester Type	Status	Year Opera-tional	Animal Type	Population Feeding Digester	Biogas End Use(s)	Installed Capacity (kW)	Baseline System	Receiving Utility
Edaleen Cow Power, LLC	Lynden	Mixed Plug Flow	Operational	2012	Dairy	2500	Electricity	750	Storage Lagoon	Puget Sound Energy
Farm Power Lynden	Lynden	Mixed Plug Flow	Operational	2010	Dairy	2000	Electricity	750	Storage Lagoon	Puget Sound Energy
Farm Power Rexville	Mount Vernon	Mixed Plug Flow	Operational	2009	Dairy	1500	Electricity	750	Storage Lagoon	Puget Sound Energy
G DeRuyter & Sons Dairy	Outlook	Mixed Plug Flow	Operational	2006	Dairy	4000	Electricity	1200	Storage Lagoon	Pacificorp
Qualco Energy	Monroe	Mixed Plug Flow	Operational	2008	Dairy	2000	Electricity	450	Storage Lagoon	Puget Sound Energy
Rainier Biogas	Enumclaw	Mixed Plug Flow	Operational	2012	Dairy	1500	Electricity	1000	Storage Lagoon	Puget Sound Energy
Van Dyk Dairy	Lynden	Complete Mix	Operational	2011	Dairy	1000	Electricity	400	Storage Tank or Pond or Pit	Puget Sound Energy
Vander Haak Dairy	Lynden	Mixed Plug Flow	Operational	2005	Dairy	1500	Electricity	600	Storage Lagoon	Puget Sound Energy

Source:
http://www.epa.gov/agstar/projects/#database

The 6th Plan estimates the development potential for animal manure digesters at dairies in the Northwest at 61 aMW, with a possible range of 51 to 108 aMW. Potentially feasible operations and mature head are reported by the EPA for operations of 500 head or more and employing slurry or liquid manure handling systems. A study commissioned by the EIA concluded that digesters with fewer than about 600 dairy cows were not viable and that maximum economy of scale is reached at about 2,300 dairy cows. The study estimated costs of digesters between $700 per dairy cow for a larger scale plant to $1,000 per dairy cow for a smaller plant.[12] The range of expected energy production potential is 2.6 to 3 kWh per mature head count per day.

There are at least two dairies in the District's service territory that may fit these criteria, and development of a digester has been explored with one farmer. A challenge is presented by the location of these dairies within the PUD's distribution system, and the need to provide expensive system protection should the generation exceed the load on a particular feeder.

Dairy-based anaerobic digesters should become more common place in the future as they will help utilities meet RPS requirements without incurring additional transmission expenses (except for possible distribution system protection). Like other renewable resources, the costs are very site specific and can easily overrun the stated estimates. The most comparable system would be the one built by Revolution Energy Solutions in Junction City, OR, equipped to handle 1,000 dairy cows at a cost of $2.2 million, or $2,200/dairy cow and roughly $12,500/kW capacity.[13] Using relatively aggressive assumptions, an unsubsidized levelized production cost of such a system in the $115 to $130/MWh range was calculated. The RECs from a digester would have double value as distributed generation because of their small (<5MW) size. Because of the need for eligible renewable resources, anaerobic digesters should receive further exploration by the District.

Solar

Solar energy is the direct harnessing of the sun's energy. The major issues to overcome with respect to solar energy are: (1) the intermittent and variable manner in which sun energy arrives at the earth's surface and, (2) the large area required to collect the sun's energy at a useful rate. In the case of solar photovoltaic (PV) systems, the process is direct, via silicon-based cells. In the case of concentrating solar power (CSP), the process involves heating a transfer fluid to produce steam to run a generator. Only PV technology will be discussed here as CSP requires high direct normal solar irradiation, like that found in the desert southwest, for efficient operation.

Photovoltaic Systems

PV systems (or solar electric systems) use PV cells to convert sunlight into direct current electricity. A group of panels mounted on a frame is called an array. To provide electricity reliably and safely, PV systems include several pieces of equipment in addition to the PV array, including a charge controller, an inverter, wiring, and a form of electricity storage (typically batteries).

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[12] AgSTAR. Anaerobic Digestion Capital Costs for Dairy Farms. May 2010. http://www.epa.gov/agstar/documents/digester_cost_fs.pdf

[13] http://sustainabililty.uoregon.edu/office-sustainability/news/dairy-dynamos-lochmead-cows-produce

There are two types of PV cells—silicon based and thin film. Silicon cells can reach an efficiency of about 16 percent while thin film cells presently have an efficiency of 10.6 percent. Higher efficiencies translate into smaller cells, fewer raw materials, fewer engineering requirements, and cheaper overall systems. Silicon cells are a very mature technology, while thin film has only recently reached the commercial phase. Solar generation capacity today consists mostly of silicon PV (92%).

The cost-range for PV installations is high. Solar costs have dropped more than twenty-fold since the technology's inception and continue to fall as technology improves. There are numerous large-scale PV projects installed around the world. These installations include all sizes of commercial and public facilities. Not surprisingly, most utility-scale installations in the US are located in the Southwest where the economics are improved because of the latitude.

Hydro Resources

Two primary types of hydro resources exist: large and small scale hydro. There are several differences between the two. Large scale projects typically include building a dam, which can affect the ecosystem and its surrounding environment. While hydropower is carbon-neutral by nature, most projects are not recognized as renewable resources and do not produce RECs precisely because of the impact they have on the environment. Grand Coulee is an example of a large scale hydro project. Lake Roosevelt is a creation of Grand Coulee Dam and because of the reservoir, operators can control the flow of water through the generators and dispatch the resource as needed.

A hydro generator is called such because of both its size (generation capacity) and method by which it generates electricity. Hydro generation facilities can qualify for the EIA as renewable resources in the State of Washington if they meet narrowly-defined criteria. One category of eligible hydro must be located in irrigation pipes and canals located in the Pacific Northwest and cannot result in new water diversions or impoundments. This type of hydro project is considered "run of the river," as it cannot be dispatched and generates energy as water flows down the canal or pipe. If it has a generation capacity not greater than 5MW, it is classified as "distributed generation," and the RECs it produces count double toward EIA RPS targets. Another type of qualifying hydro resource is incremental electricity resulting from efficiency improvements completed after March 31, 1999, to hydro projects owned by a qualifying utility.

Almost all large scale hydro plants in the US are legacy plants and were built prior to the 1950s. Permitting of a new large scale hydro plant today would be very difficult if not nearly impossible today due to more stringent environmental laws. For this reason, only small scale hydro plants will be considered as new resources in this IRP.

Summary of Eligible Renewable Resource Costs and Characteristics

It is important to note that the projected resource costs for the renewable resources previously discussed are only estimates. Whereas traditional fossil fuel generators consume a fuel with a known energy density, such as coal or natural gas, the efficiency and output from renewable resources depends heavily on the quality of the "fuel" that is available and the costs required to bring that energy to market. Geography presents several challenges for renewable resources. Solar panels in a sunny

locale such as Phoenix will generate more electricity than an identical installation located in a cloudy place such as Seattle. A slight change in capacity factor can have a significant impact on overall production costs. Many of the locations with the best resource potential are located in remote areas or present other challenges that would require significant investments in infrastructure, such as transmission lines, that add to the total project costs. Figure 47 provides a summary of costs and other characteristics for some of the plant types discussed herein.

Figure 47: Summary of Assumptions for Renewable Resources

Summary of Base Case Assumptions for Resources For Plants Entering Service in 2018 (2011 $)							
Resource	Plant Size (MW)	Heat Rate (Btu/kWh)	Capacity Factor	Total Plant Cost ($/kW)	Fixed O&M ($/MWh)	Variable O&M (including fuel)	Integration Cost ($/MWh)
Wind (OR/WA)	100	–	32%	$ 2,100	$ 13.10	$ 2.00	$ 7.98
Geothermal	39	28,500	90%	$ 4,800	$ 12.00	$ -	--
Solar - Tracking PV (E. WA)	5	–	24%	$ 9,000	$ 9.90	Inc. in Fixed	$ 7.98
Biomass							
Landfill Gas	3	10,100	85%	$ 3,000	$ 14.30	$ 0.73	--
Biomass Cogeneration (Wood)	25	19,300	90%	$ 5,000	$ 11.60	$ 12.30	--
Anaerobic Digester	1	10,250	75%	$ 5,000	$ 6.85	$ 19.00	--

Sources: NWPCC Sixth Power Plan, US Energy Information Administration

Figure 48 summarizes the nominal levelized costs of the supply side resources discussed above, both renewable and non-renewable. Forecast BPA Tier 1 rates are included for comparison purposes. Renewable resource costs are shown with and without the federal production tax credit. The PTC is a significant cost break for eligible generating resources.

Figure 48: 20-Year Levelized Cost of Supply Side Resources

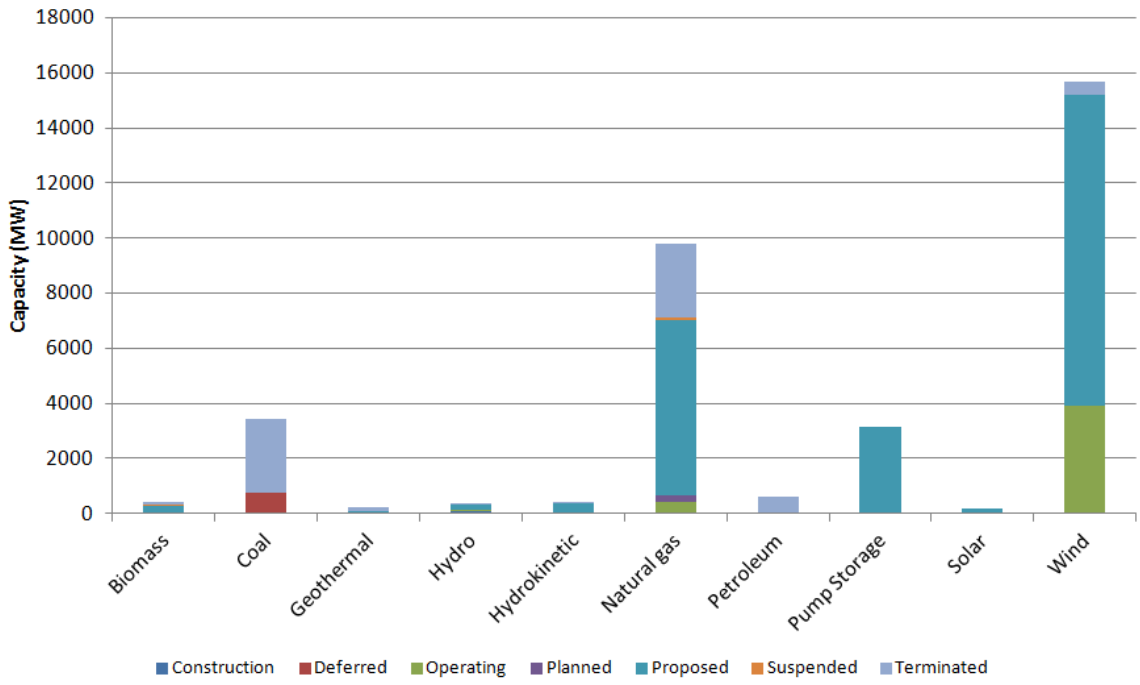
Resource	Nominal Levelized Cost ($2012/MWh)	Nominal Levelized Cost with PTC ($2012/MWh)
BPA Tier 1	$44	
Cogeneration	$74	
Combined Cycle Generating Turbine	$47	
Conventional Coal Plant	$62	
Integrated Gasification Combined Cycle	$73	
Geothermal	$54	$48
Market Forecast (3% annual inflation adjusted)	$43	
Nuclear	$77	
Wind I (Pacific NW, including wind integration)	$75	$83
Simple Cycle Combustion Turbine – Peaking unit	$103	
Solar (PV)	$208	$152
Small Hydro	$85	$78
Anaerobic Digester	$125	$118
Waste Wood Pulp Biomass	$55	$48
Small Modular Reactor	$67	

Source: *US Energy Information Administration*

In addition to cost, consideration is also given to availability of each resource. For example, landfill gas generation is low cost, renewable, and reliable, but the supply is small because there are a limited number of appropriate landfills.

Figure 49 shows the relative availability of various resources. Wind and natural gas-fired resources are the most readily available technologies.

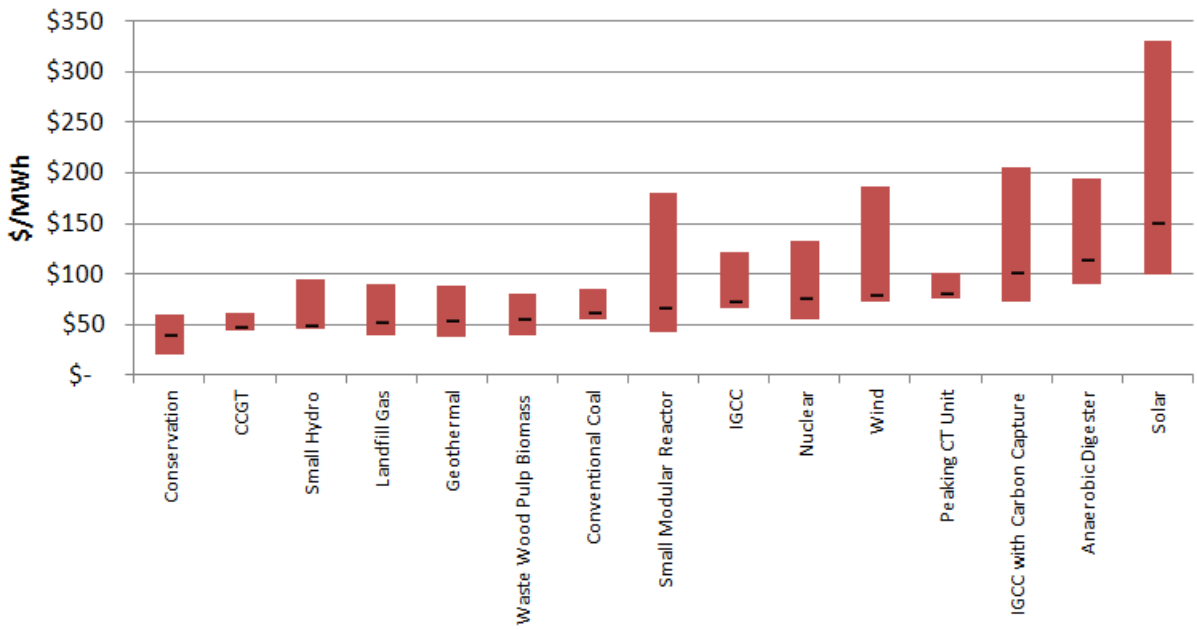
Figure 49: Power Plant Development Activity in the Pacific Northwest



Source: *NWPCC PNW Power Plant Development*
[1]Data displayed from 2010 to 2013.

The levelized cost of each resource examined in this IRP is displayed in Figure 50. The floating bars represent the range of probable generation costs on a levelized basis. The black dash in each bar represents the expected levelized generation cost over the life of the resource. In the next chapter, various portfolios containing some of the supply-side resources discussed in this chapter will be modeled.

Figure 50: Levelized Cost of Examined Supply Side Resources



Chapter 6: Risk Analysis and Portfolio Selection

Introduction

A long term integrated financial and energy position model was created to forecast the District's annual net power cost for the duration of the study period. The financial model used the results from previous sections, including forecasted loads, simulated hydro generation scenarios, forecasted output from generation resources, power price scenarios, market price scenarios, regulatory scenarios, and forecasted generation resources. The output from the model measured the impact of these different scenarios in a single metric: the 20 year net present value of net power costs. The methodology and assumptions used to create the market simulation used in the risk analysis are described in Appendix B.

Energy Net Position

As Figure 51 shows, under the medium load forecast and critical hydro scenario, the District will have a very small (less than 1 aMW) deficit beginning in 2030, which increases to 1.5 aMW in 2032. While the District is in load/resource balance on an annual average energy basis, it was previously discussed in Chapter 2 that neither loads nor resources are flat on an annual basis, but vary by month and season. Hydro and wind in particular have a great deal of variability.

Figure 51: Energy Net Position – Medium Load Forecast and Critical Hydro

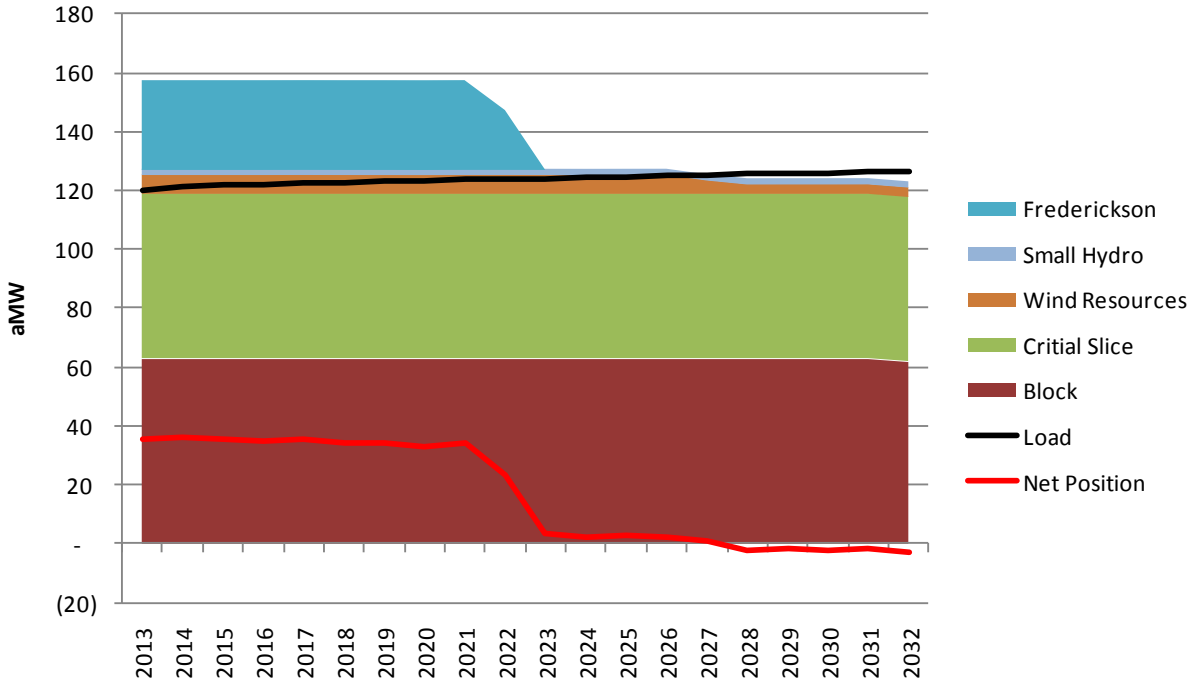
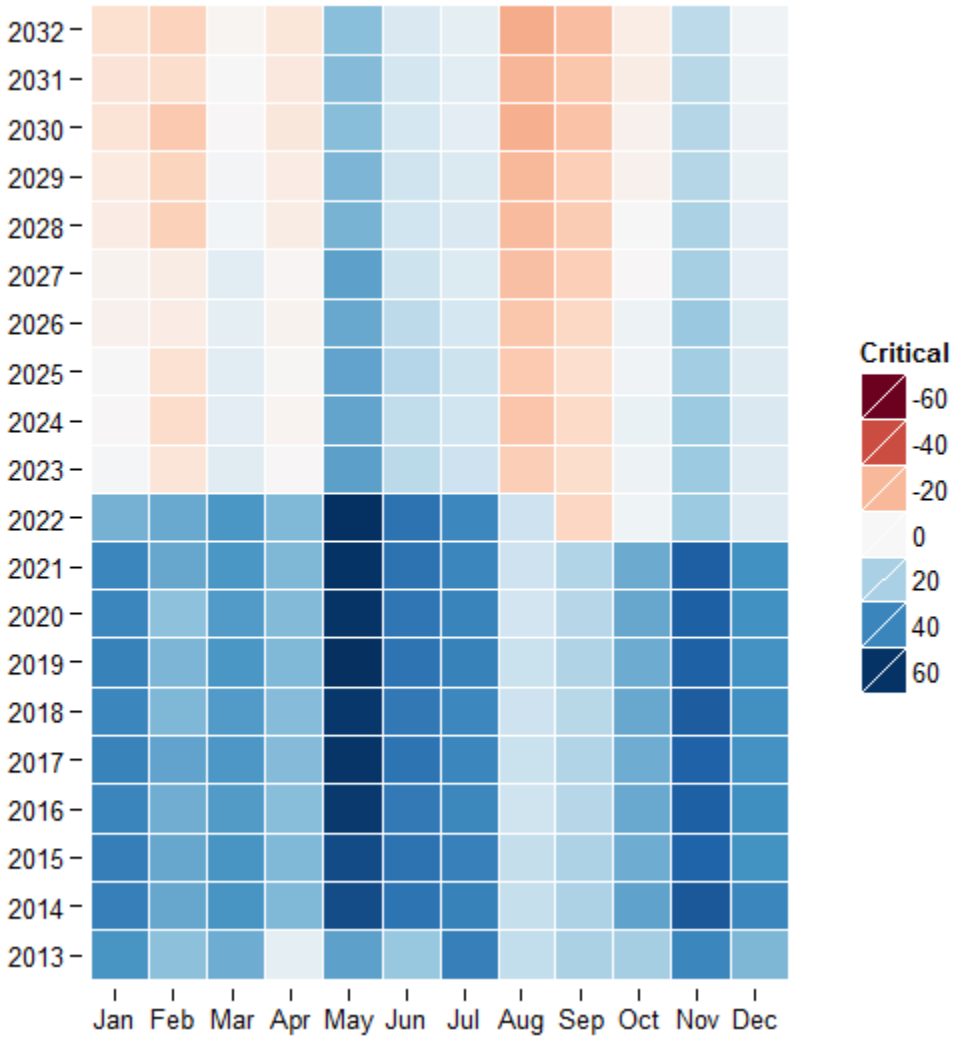


Figure 52 displays the District's average monthly net position in critical hydro conditions.

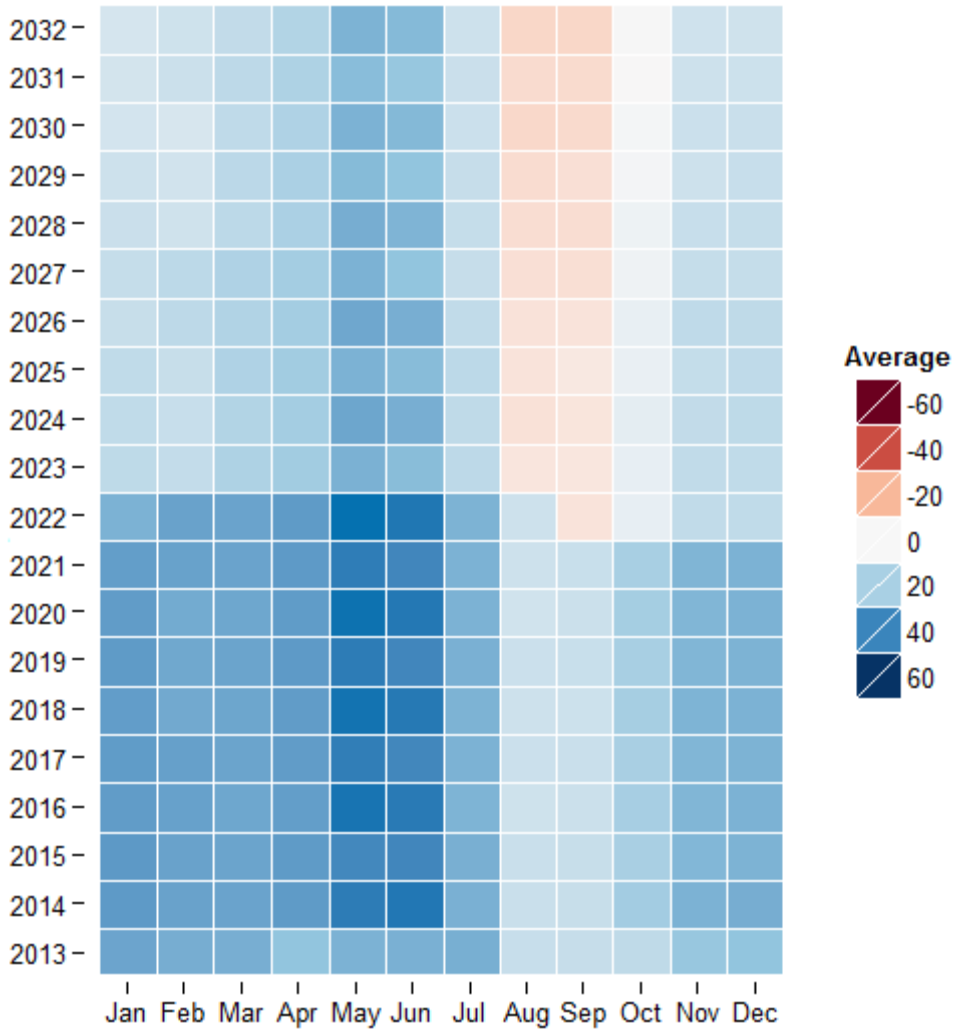
Figure 52: Monthly Net Positions, Medium Load Forecast and Critical Hydro (in aMW)



Even in critical conditions, the District is expected to be energy surplus on an average monthly basis until the Frederickson PPA expires in August 2022. Upon termination of the contract, deficits appear in the Q1 and Q3 timeframe, with the largest energy deficits occurring in August and September. These seasonal deficits were considered in the portfolio selection process.

In average hydro conditions, the District still anticipates August and September deficits after the Frederickson contract expires, although to a lesser magnitude (Figure 53). Regardless of the Slice and load scenario, the District can expect a seasonal deficit in the August and September months.

Figure 53: Monthly Net Positions in Average Megawatts, Medium Load Forecast, Average Hydro

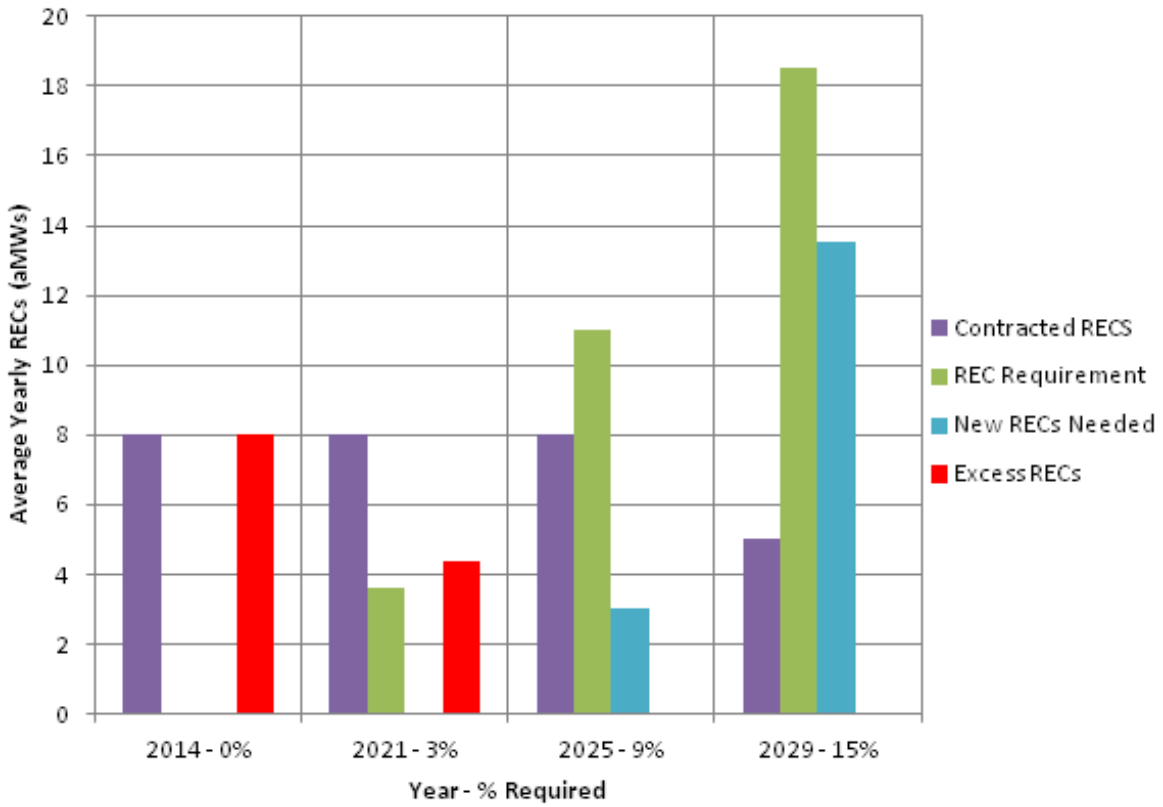


Renewable Portfolio Standard / REC Net Position

Although the District is expected to have sufficient generation resources to meet its energy needs on an average annual basis until 2028, the District also has an RPS standard to meet. With its current renewable assets, the District has sufficient resources to meet its RPS requirement through 2024. That surplus turns into a deficit beginning in 2025 when the RPS increases from 3% to 9%. In 2029, the deficit reaches about 18 MW when the RPS requires that 15% of load is served with renewable resources (Figure 54).

The District may fulfill RPS requirements with a renewable resource acquisition or by purchasing only the renewable attributes (RECs). Acquiring additional generation to meet the RPS requirements has both upside and downside effects. A renewable resource would help cover energy shortages; however, since shortages typically only occur in late summer, it would subject the District to additional market risk by adding surplus energy at other times of the year.

Figure 54: REC Net Position



Portfolio Strategies

Ten portfolios were analyzed, with each comprised of a different resource mix, to determine the optimal portfolio. The portfolios were constructed based on meeting the needs of Strategies 1 through 4 listed below. The colors and portfolio numbers (P1, P2, etc.) match the colors and numbers on Figure 58: Resources Considered in Portfolio Construction.

1. Keep the status quo (P1)
   - Rely on the market to cover energy shortages and RECs for RPS deficits

2. Acquire resources to meet RPS and market purchases for Q3 seasonal energy requirements(P2, P3 and P4)
   - District RPS requirements will be 3% of load in 2021, 9% in 2025 and 15% in 2029
   - Acquire sufficient resources to meet RPS needs through 2032
   - Rely on market to cover Q3 seasonal energy deficits

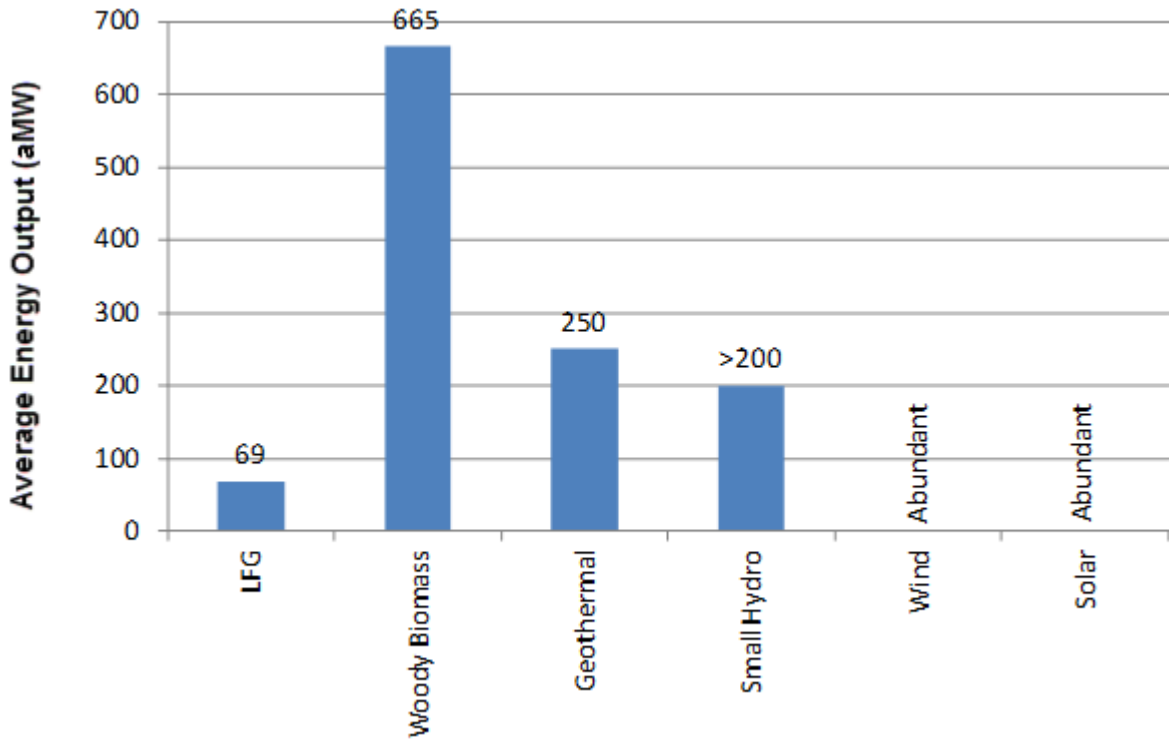
3. Acquire resources to meet only Q3 and annual average energy deficits (P5 and P6)
   - Acquire non-renewable resources to cover seasonal Q3 energy deficits
   - Use market to cover incremental REC deficits forecasted to begin 2025

4. Acquire sufficient resources to meet average annual energy, Q3 energy and REC requirements through 2032 (P7, P8, P9 and P10)

- District will be in energy L/R balance under **critical hydro conditions**
- District will be surplus with **average hydro conditions**
- Acquire sufficient REC generating resources to meet RPS needs through 2032.

While the amount of capacity built for each portfolio differs, the energy and renewable output of each portfolio within a particular strategy is consistent. For example, a landfill gas plant has a capacity factor of 80%. Solar arrays, on the other hand, have capacity factors of less than 15%, mainly because solar generators only produce energy when the sun is shining, and seldom reach maximum production. Therefore, a larger solar array must be built in order for it to produce an equal amount of energy as a landfill gas plant. IRP staff also took into consideration that development potential for certain resources are finite. While a natural gas generator only requires a flowing pipeline to receive its energy, a landfill gas plant needs a physical landfill from which it draws energy. There are a limited number of landfills in the region. Furthermore, each landfill has a maximum amount of energy that can be extracted from it. The regional development potential of specific resources is displayed in Figure 55.

Figure 55: Development Potential of Select Renewable Resources



Although 14 different resources were screened, the portfolios were constructed with only 10 of them. The other resources were eliminated from contention based on technical, economic, and political factors.

Nuclear was included in Portfolio 5 despite the economic and political challenges it faces. The District believes that if renewable resources are going to dominate the region's resource choices in the future, and if greenhouse gas reduction is the societal goal driving it, nuclear will have to play a future role as a base load resource.

The only conservation scenario modeled was that described in Chapter 3 and its load reduction impacts are reflected in all load forecasts. However, various conservation scenarios should be included in any future analysis once the District has completed a conservation potential assessment with a better estimate of remaining opportunities.

Figure 56: Resources Considered in Portfolio Construction

The portfolios examined in this IRP are outlined in Figure 58. Each group of portfolios was structured to accomplish different goals. Portfolio 1 was established as the baseline, "continue the status quo" portfolio in which the District does not acquire any resources and relies on the market to fill any energy or renewable deficits. Portfolios 2 through 4 fulfilled the RPS needs of the District, and relied on the market to fulfill any remaining energy deficits. The opposite scenario was examined in portfolios 5 and 6 wherein non-renewable resources are acquired to meet energy needs, but the market is relied on for RPS REC deficits. Both the energy and REC deficits were addressed in portfolios 7 to 10.

The portfolios were input into the long term financial model and then stress tested. Due to the large number of inputs in the financial model and all of the uncertainties surrounding each input, it was concluded that Monte Carlo simulation would produce the most comprehensive results. Figure 57 lists the variables and associated uncertainties. The stress test consisted of subjecting each portfolio to 1,000 random scenarios of each variable, which covered a large range of outcomes. The goal was not to simulate each mathematically possible scenario, but to simulate enough scenarios to put bookends

around worst case and best case, identify the most likely scenarios, and quantify the risk associated with each portfolio. The standard deviation of the 1,000 iteration simulation was chosen as the risk metric.

Figure 59 is a plot of each portfolio's average 20-year NPV net power cost on the x-axis vs. the standard deviation on the y-axis.

Portfolio evaluation involves assessing cost vs. risk. The ideal portfolios can be isolated by fitting a hyperbolic curve, known as the efficient frontier, through the points, as shown in Figure 60. Portfolios situated below the vertex, but still on the efficient frontier, have the least risk for a particular cost bucket. Portfolios that are high cost and high risk, such as Portfolios 5, 8, or 10, have undesirable characteristics and can be quickly eliminated. Portfolios 2, 4 and 7 are relatively low cost, and have similar risk. The ideal portfolio would have a low cost and low risk, but that is generally not achieved as there is usually a tradeoff between cost and risk. In this case, however, the choice is obvious as Portfolio 1 has the lowest cost and lowest risk.

Figure 57: Risk Drivers

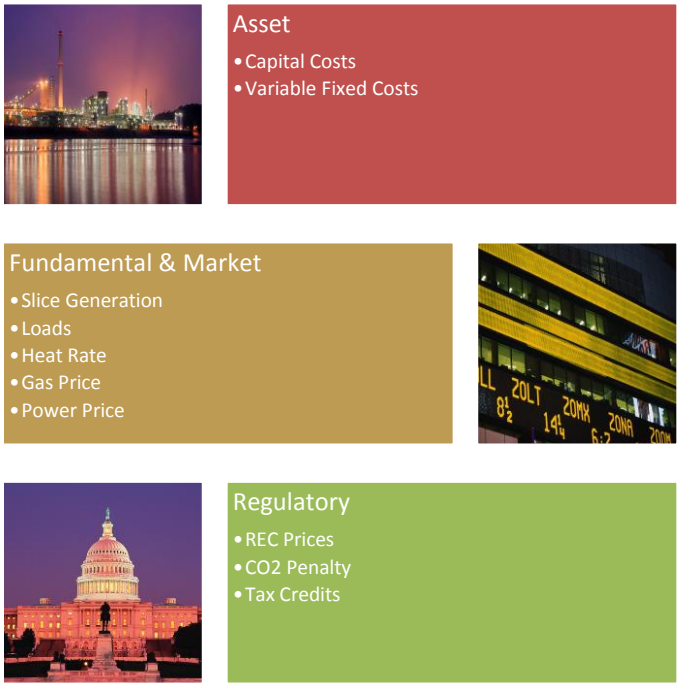
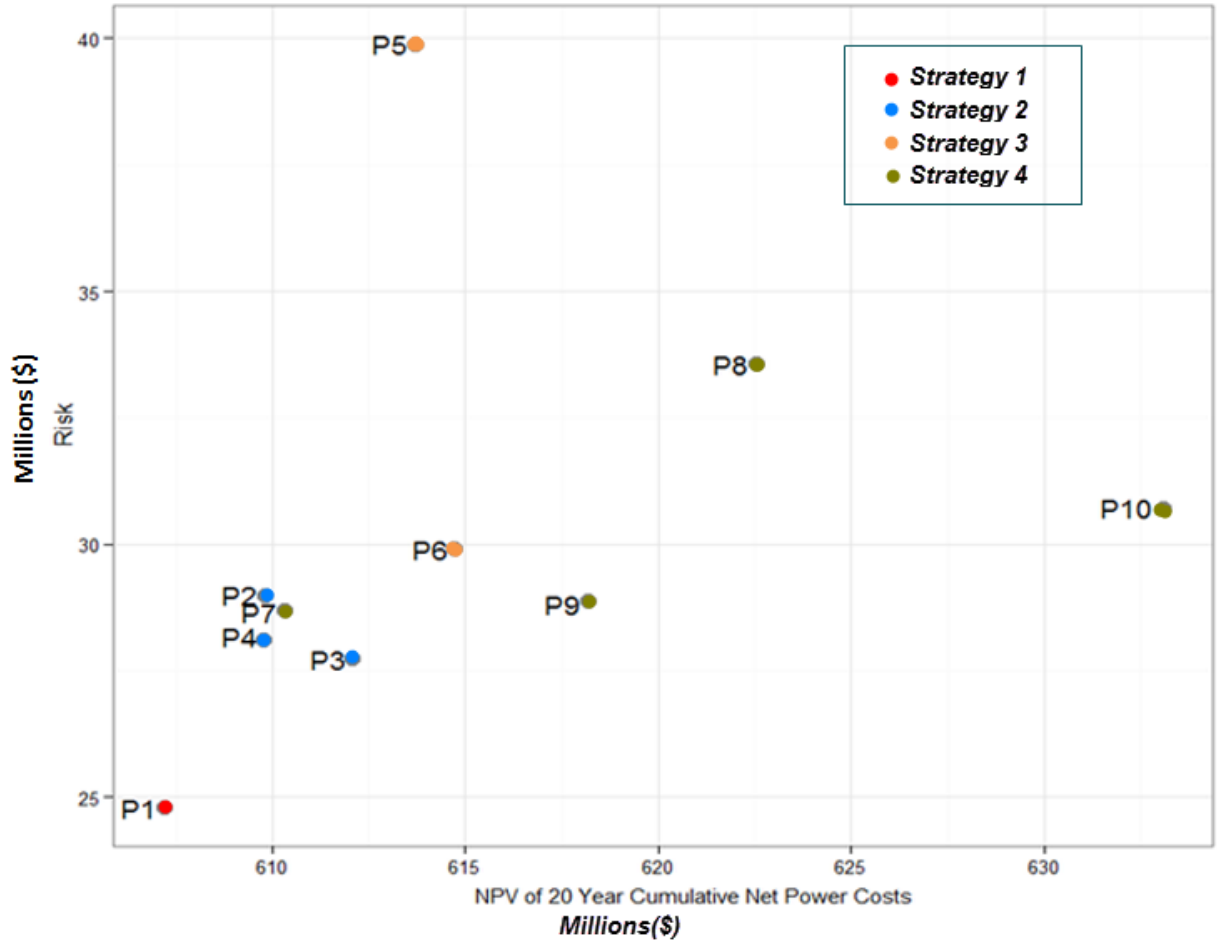


Figure 58: Resources Considered in Portfolio Construction

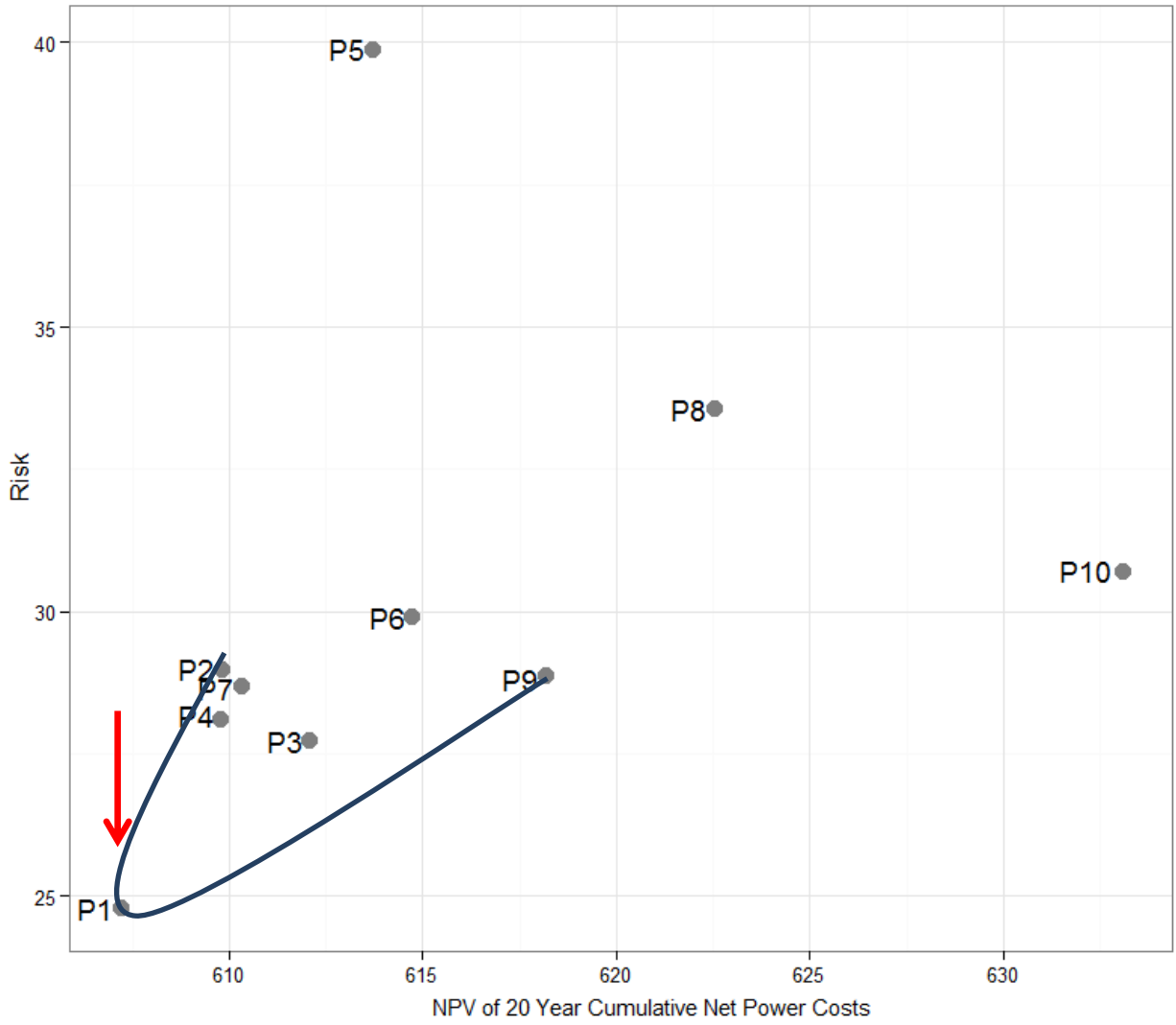
Portfolio			P1	P2	P3	P4	P5	P6	P7		P8		P9			P10	
Resource			Market	Wind	Biomass	LFG	SMR	CCCT	CT	LFG	Small Hydro	Biomass	CT	LFG	Solar	Biomass	Digester Gas
Capacity Factor			-	33%	80%	80%	85%	85%	60%	80%	52%	80%	60%	80%	15%	80%	80%
Strategy			Cover all Energy & RPS deficits with Market Purchases	Acquire Resoures to Meet RPS, Use Market to Cover Q3 Seasonal Energy Deficits	Acquire Resoures to Meet RPS, Use Market to Cover Q3 Seasonal Energy Deficits	Acquire Resoures to Meet RPS, Use Market to Cover Q3 Seasonal Energy Deficits	Acquire Resources to Meet Seasonal Q3 Energy Deficits	Acquire Resources to Meet Seasonal Q3 Energy Deficits	Acquire Resource to Meet Q3 Energy Deficits and RPS Requirements until 2032		Acquire Resource to Meet Q3 Energy Deficits and RPS Requirements until 2032		Acquire Resource to Meet Q3 Energy Deficits and RPS Requirements until 2032			Acquire Resource to Meet Q3 Energy Deficits and RPS Requirements until 2032	
Year	Gross Annual Energy Deficit (aMW)	Net Annual REC Requirement (aMW)	Cumulative Installed Generation Capacity														
2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	25	25	25	-	20	20	25	-	-	15	15
2024	-	-	-	-	-	-	25	25	25	-	20	20	25	-	-	15	15
2025	-	(4)	-	12	5	5	25	25	25	5	20	20	25	2	15	15	15
2026	-	(4)	-	12	5	5	25	25	25	5	20	20	25	2	15	15	15
2027	-	(5)	-	45	5	5	25	25	25	5	20	20	25	15	15	15	15
2028	(2)	(7)	-	45	20	20	25	25	25	20	20	20	25	15	15	15	15
2029	(2)	(14)	-	45	20	20	25	25	25	20	20	20	25	15	15	15	15
2030	(2)	(14)	-	45	20	20	25	25	25	20	20	20	25	15	15	15	15
2031	(2)	(14)	-	45	20	20	25	25	25	20	20	20	25	15	15	15	15
2032	(3)	(14)	-	45	20	20	25	25	25	20	20	20	25	15	15	15	15

Figure 59: Risk Efficiency Analysis



Summary of Stress-tested Portfolios			
Portfolio	Primary Resource Type	Resource Mix	Goal
P1	Market	Market	All needs met with Market
P2	Renewable	Wind	Cover Q3 Deficits/RPS needs
P3	Renewable	Biomass	Cover Q3 Deficits/RPS needs
P4	Renewable	Landfill Gas	Cover Q3 Deficits/RPS needs
P5	Thermal	Small Modular Nuclear	Cover Q3 Energy Deficits
P6	Thermal (Fossil)	CCGT	Cover Q3 Energy Deficits
P7	Thermal (Fossil)/Renewable	CT/LFG	Cover Q3 Deficits/RPS needs
P8	Renewable	Hydro/Biomass	Cover Q3 Deficits/RPS needs
P9	Thermal (Fossil)/Renewable	CT/LFG/Solar	Cover Q3 Deficits/RPS needs
P10	Renewable	Digester/LFG	Cover Q3 Deficits/RPS needs

Figure 60: Efficient Frontier and Preferred Portfolios



Preferred Portfolio

Results of the analysis suggest that the current least cost/risk option for the District is to rely on the market, or Portfolio 1, for all energy and REC deficits. These results make intuitive sense for several reasons:

1. Because of the low volatility in gas prices and flattening and even backwardation in the forward gas price curve, inflation-adjusted power prices are expected to remain under $50/MWh for the foreseeable future, lower than the levelized cost for any of the examined resources. Furthermore, there is always risk with building new resources, which include siting risks, regulatory risks, and construction risks, among others. With market purchases, the District can also eliminate some of that risk it faces through purchases from other entities in advance and locking in a price for the energy. The District will continue to monitor market conditions; any dramatic shift in the market may compel the District to revisit its preferred portfolio.

2. The viability of tax credits for renewable resources is also in flux in the current political climate, especially since Congress has demonstrated its willingness to let the PTC expire on December 31, 2013.

3. The District is expected to remain in load/resource balance under critical water conditions throughout the IRP study period. While there may be monthly or seasonal deficits, the District will carry energy surpluses on an average annual basis if even the worst water years on record occur.

4. Washington REC prices have remained low through the first compliance period from 2012-2015. The consequences of the RPS requirement step up in 2015 from 3% to 9% should increase REC prices, but the magnitude of the impact is currently unpredictable. It is an issue that will need to be revisited then. There is also proposed legislation that will exempt utilities from building renewable resources to meet the EIA requirements in excess of need. That is, unless a utility needs a resource to meet its load, it will not have to build renewable resources for the sole purpose of meeting its RPS target.

5. The portfolios containing landfill gas resources had a lower risk, but higher net cost. Unfortunately, the resource potential for LFG is limited in the area. The District, however, will continue to evaluate other resource options if/when the opportunity arises.

Figure 61 shows the impact of Portfolio 1 on the District's REC position. With this portfolio, RECs would be needed to satisfy RPS requirements in 2025 if the District did not qualify for one of the alternative compliance mechanisms discussed in Chapter 1.

Figure 61: RPS Position - Preferred Portfolio

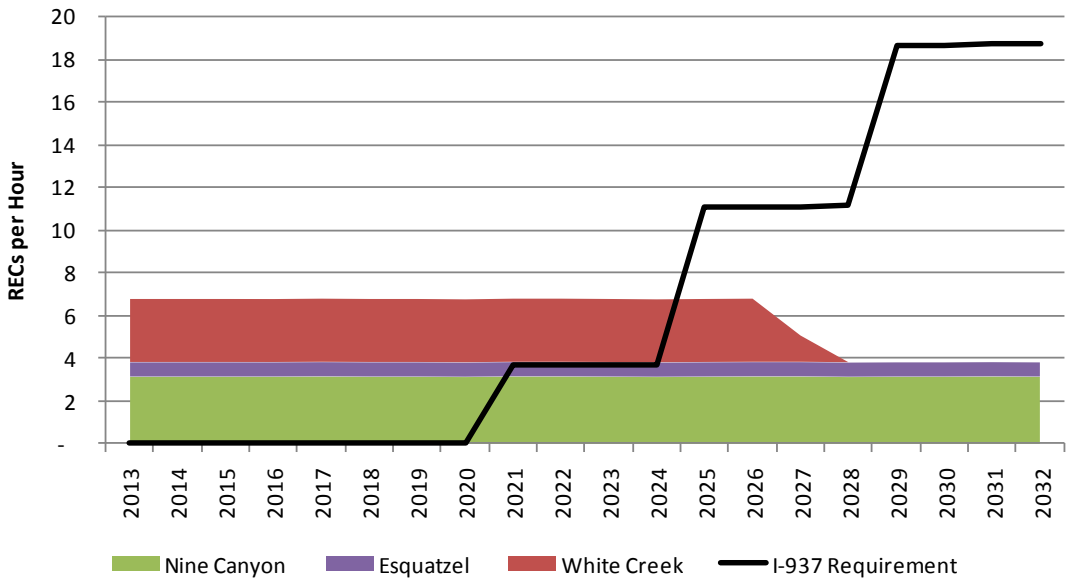
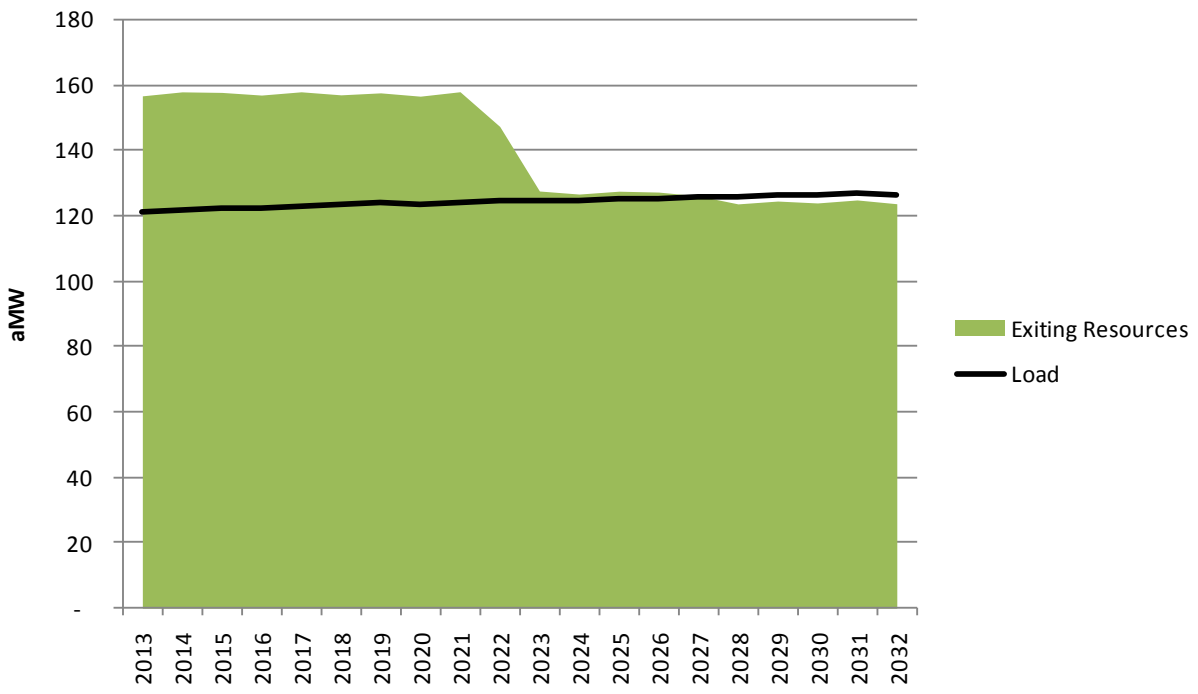


Figure 62 shows the impact of the preferred portfolio on the District's energy net position. The District should utilize shorter-term power purchases and other instruments to provide additional capacity and financial protection. The benefit of this approach is that the District can target the parts of the year that present the most challenges (summer and winter) while avoiding carrying costs during "lower risk" parts of the year (spring and fall). The District should regularly reevaluate this strategy. If there is a fundamental change to the volatility of the power market, the preferred portfolio could change.

Figure 62: Energy Net Position - Preferred Portfolio



Chapter 7: Action Plan

The District's IRP defines the District's need for new resources and investigates different generic resource types. The objective of the IRP is to present a quantitative and qualitative analysis of the benefits of pursuing different resource technologies to meet energy demand and RPS requirements. The District's action plan addresses both resource acquisitions and power supply related issues that will require additional investigation outside the IRP process:

- ✓ The District is not expected to need additional energy generation resources until 2028, but currently projects REC deficits associated with Washington's RPS requirement beginning 2025.

- ✓ Based on the information available today, the preferred long term portfolio would be to rely on the market to fulfill both energy and REC deficits.

- ✓ Energy deficits increase the District's market exposure and are most likely to occur in the 3rd quarter. Although there are no plans to acquire any resources for the next decade, the staff will monitor the District's monthly energy positions at monthly risk management meetings. The District may utilize short term market purchases to cover energy deficits, thereby reducing its market exposure.

- ✓ Continue to operate the Frederickson plant as cost-effectively as possible for its capacity contribution, and use it as a hedge against future prices. As the contract termination date approaches, plan for addition of another capacity resource.

- ✓ Because of the long lead time before the District needs to obtain any generation resources, it is important to understand that the findings and recommendations as a result of the planning process are not firm. Rather, this IRP provides the District staff with a framework to use when decisions on energy resource acquisitions need to be made.

- ✓ Monitor market conditions and the ongoing economic and technical viability of landfill gas, biomass, small modular nuclear and other dispatchable resources that would satisfy the demand for both capacity and RECs.

- ✓ Complete a detailed conservation potential assessment in preparation for upcoming EIA requirements. Use the CPA results to more thoroughly assess energy efficiency and demand-side management measures to help meet load growth. Implement all cost-effective conservation consistent with the requirements and any future amendments of the EIA

- ✓ Before any further REC or renewable acquisitions are made, it is critical that the District fully understand the RPS cost cap and load loss alternative compliance mechanisms and proposed legislation exempting utilities from building renewable resources ahead of need.

- ✓ The District will continue to monitor energy economic fundamentals to ensure that its resource strategy provides rate payers with low cost energy with a low level of risk. Major changes to price and volatility of wholesale electricity, natural gas, and REC s may require changes to the District's plan.

- ✓ This IRP examined renewable and energy needs based on District forecasts. While the forecasts were constructed using the best available information, the District will continue to monitor load growth, which can change and with it the energy and renewable requirements.

- ✓ The District should assess the possibility of changing its BPA contract from Block/Slice to Load Following starting in FY2019. If the analysis indicates this is a preferred option, notice must be given to BPA no later than May 31, 2016.

- ✓ Complete analysis on distributed generation and the potential effect it could have on future load growth if there is a significant increase in projects within the District's service territory due to State and Federal incentives and third party ownership options.

APPENDIX A

The goal of this study was to simulate a 3 day heat wave or cold snap, the periods during which the District needs the most capacity, and determine its ability to serve load during this period.

The sustained-peak period is defined as highest 6 load-hours of the day, over the highest 3 consecutive load-days during a particular period. These periods tend to coincide with unseasonably cold or hot spells, as extreme temperatures in either direction lead to greater energy usage. The expected-peak load is the average load over the sustained-peak period, based on normal temperatures.

Normal loads should reflect average or expected weather. For example, 2009 was a year that produced both a record high temperature-setting heat wave during the summer and a record low temperature-setting cold snap in the winter. On the other hand, 2010 was more temperate and saw milder weather in both the summer and winter. Examining either 2009 or 2010 in isolation would produce expected loads that are either too high or too low and would not conform to the NWPCC's guidelines. For that reason, the simulation examined the hottest and coldest 72 hour period for each year between 2001 and 2013. Using the temperature-load relationship, an algorithm to simulate the District's 3 day hourly loads using temperature inputs was developed. The median hot and cold period was selected and those temperatures were input into the load algorithm to simulate an expected-peak load for both the winter and summer. The analysis assumed these periods to stretch over a non-holiday work week. The average 72 hour temperature input was 18°F in the winter and 83.7°F in the summer. Results are displayed below in Figure 63.

The average 72-hour winter load in this algorithm-derived median scenario was 151 MW with a peak demand of 175 MW. The summer average was 172 MW with a peak of 209 MW.

The algorithm was validated by comparing algorithm-derived loads to actual loads for a comparable period. July 27-29, 2009 represented the hottest consecutive 3-day period since 2001, with an average temperature of 91°F, which is hotter than the sustained-peak temperature input of by 7.3°F. Several record high temperatures were also set during that period. A similar event occurred more recently in July 2013, but with lower temperatures and peak loads. For that reason, older historical data from 2009 was used in this analysis. Calculated extreme hot, actual, and calculated sustained-peak loads are displayed in Figure 64.

It appears that the algorithm introduces a bias that overestimates loads based on the temperature inputs. However, since it does not under forecast loads, the algorithm calculation was utilized since it adds an additional layer of conservatism into the analysis. A winter scenario was also tested, mimicking an extreme cold snap, with an average temperature of -1°F, well below the 18°F average used to compute the expected sustained-peak loads. The results of the study were compared against an actual cold snap during December 4 – 6, 2013 for validation. The mean temperature during this period was 16°F. Several cold-temperature records were also set during this period. The algorithm displays the same behavior for the winter scenario as well Figure 65.

Figure 63: Simulated 72 Hour Winter and Summer Peak Loads

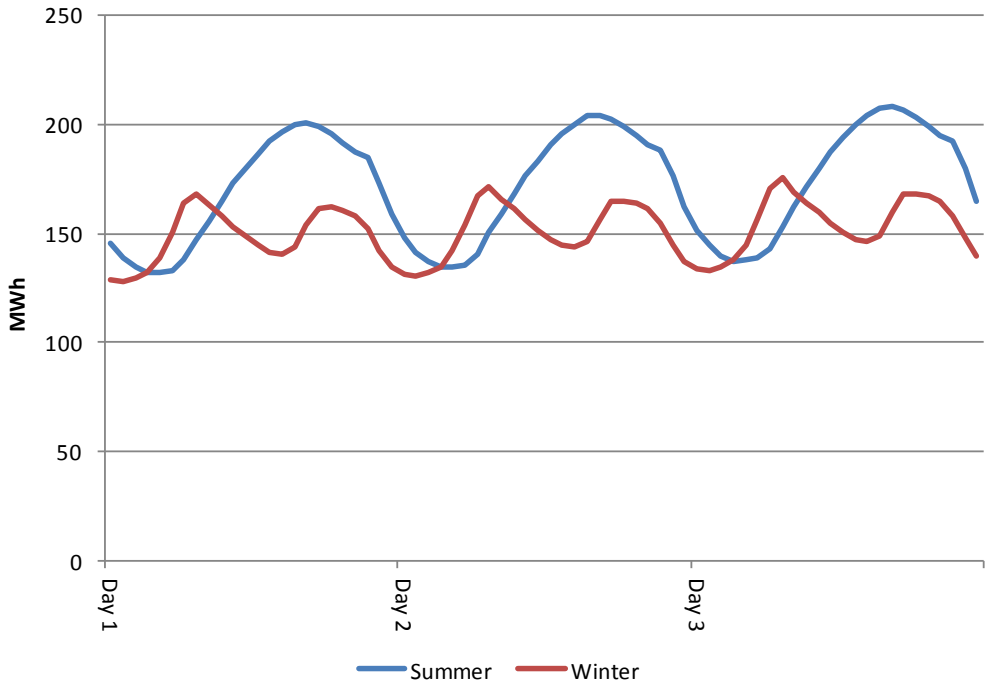


Figure 64: Simulated Extreme Peak, Expected Peak, and Observed Peak Summer Loads

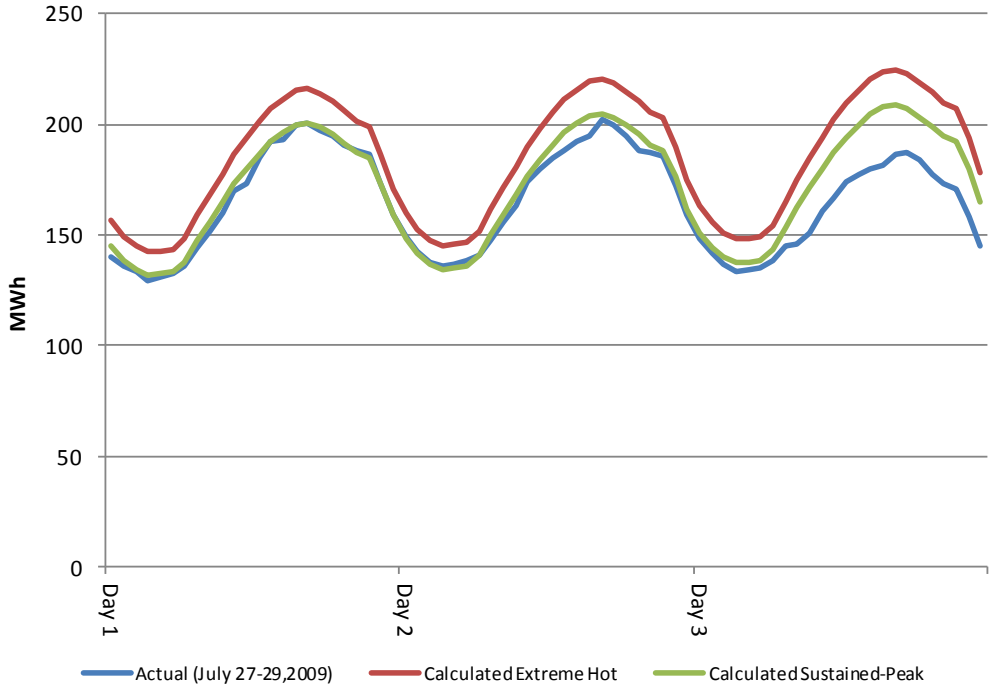
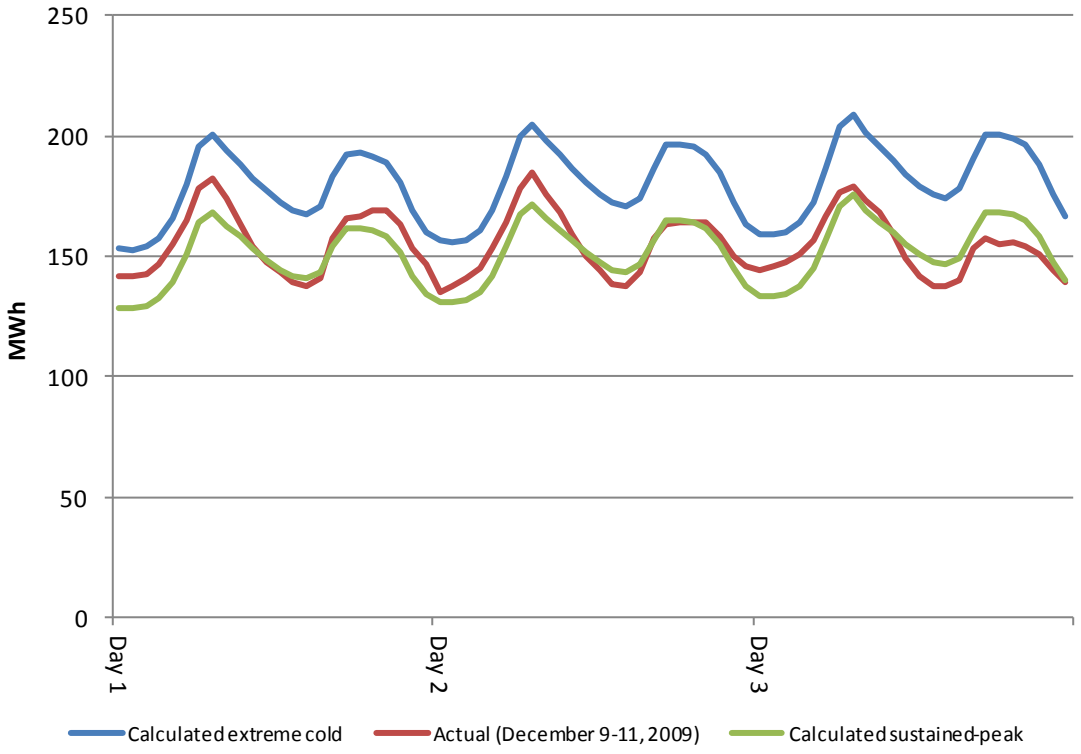


Figure 65: Simulated Extreme Peak, Expected Peak, and Observed Peak Winter Loads



If the District has sufficient reserves to meet the calculated sustained-peak loads, which mirror the observed loads during the heat wave and cold snaps of 2009 and 2013 that set multiple record heat and cold temperatures, it is probable that the District will have sufficient resources to meet load in most circumstances.

To assess needs 10 and 20 years out, the current seasonal peak requirements determined in the capacity portion of this study were inflated by the current load growth rate. Because the weather events used to determine the amount of required capacity during these extreme weather events are rare, the results of the capacity study are conservative by nature. The level of conservatism should be sufficient to address the variability in weather, resource performance, and economics that are not easily accounted for in a deterministic approach to peak requirement planning.

The results in Figure 66 through Figure 69 below display 20-year forecasted average loads through all of the heavy load hours for the 3 day period and the peak hour loads for the expected and extreme weather scenarios, as well as what would occur if there were a repeat of the weather events from Summer 2009 and Winter 2013.

Figure 66: Average HLH Load Projections in Expected and Extreme Winter Weather Conditions

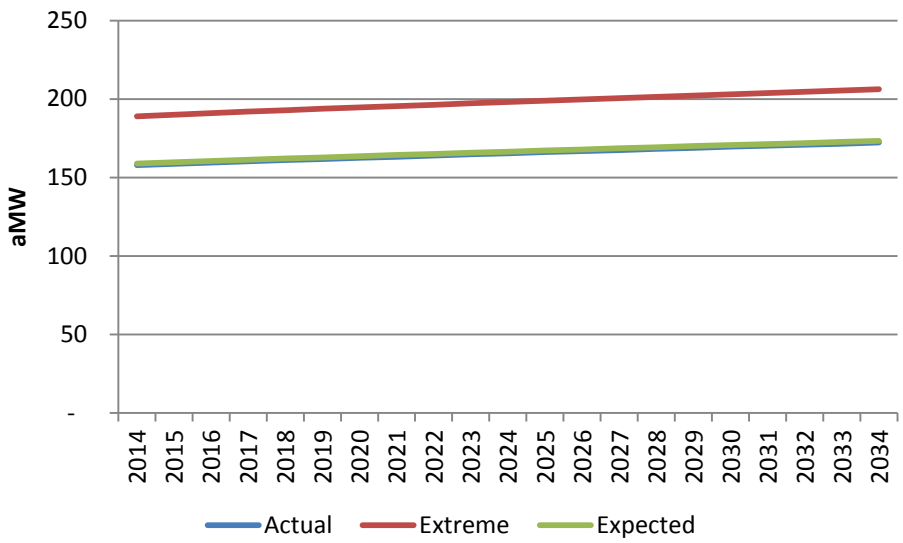


Figure 67: Peak Hourly Load Projections in Expected and Extreme Winter Weather Conditions

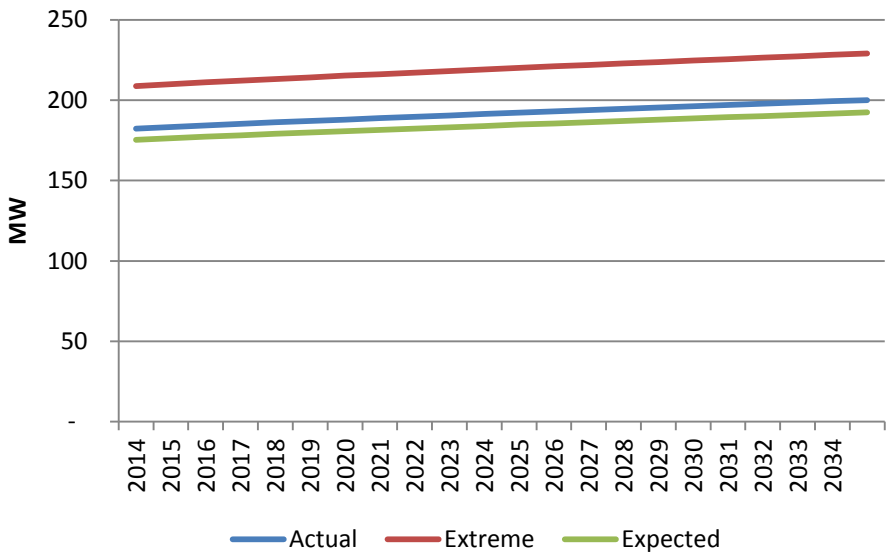


Figure 68: Average HLH Load Projections in Expected and Extreme Summer Weather Conditions

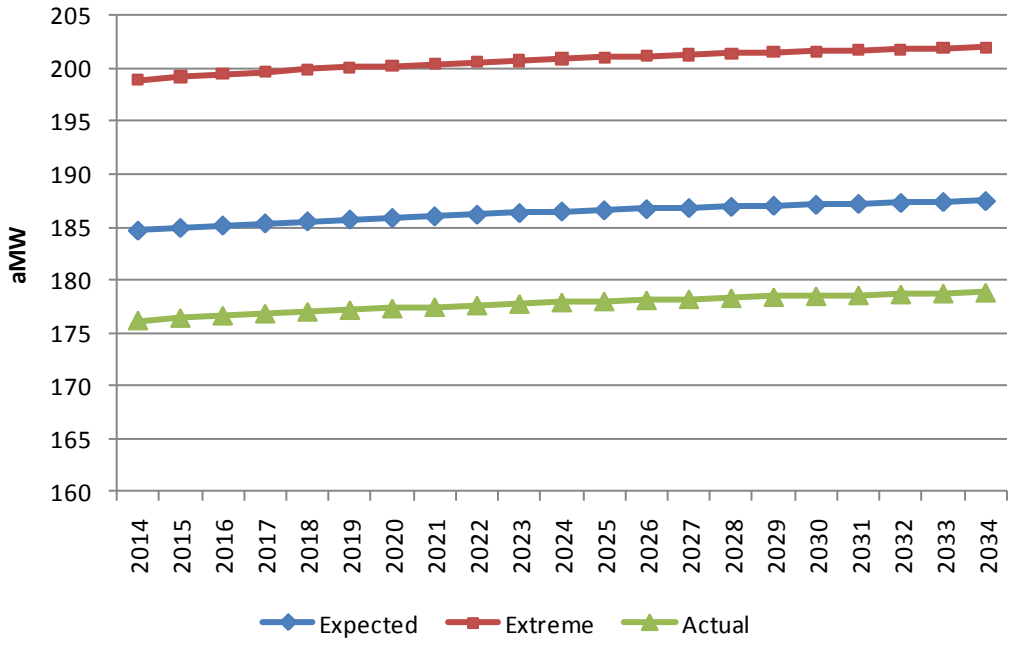
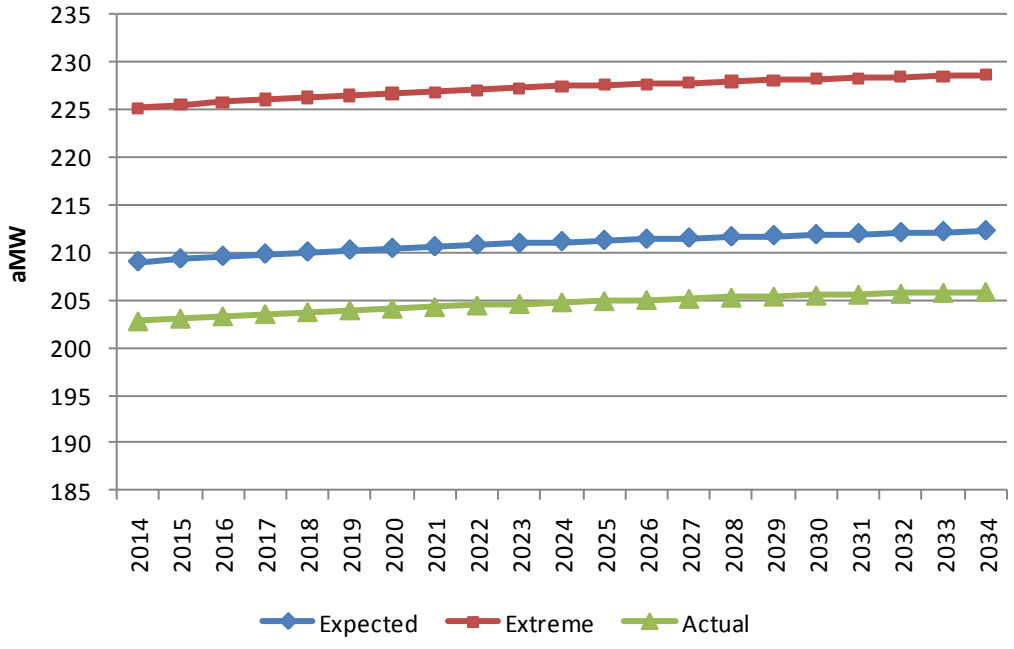


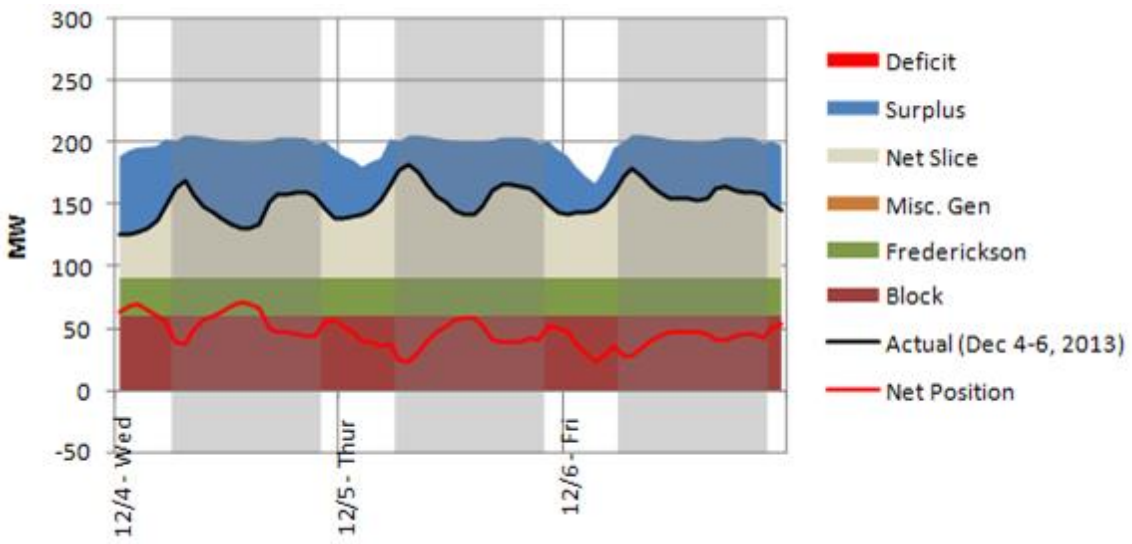
Figure 69: Peak Hourly Load Projections in Expected and Extreme Summer Weather Conditions



Determining the District's peaking capability, specifically its hydroelectric and wind plants, is particularly difficult. Because of the way weather patterns exist, it is a general rule of thumb that there is minimal wind generation during periods of extreme heat or cold. It was assumed in this analysis that the contribution of wind generation was negligible. Modeling the hydro peaking capability brings another

set of complications because the FCRPS is a mixed use system with multiple goals such as navigation, flood control, and fishery management. Therefore, many factors beyond the control of the utility go into its generation capacity, including the hydrological conditions leading up to the event. Each year brings a different set of circumstances that may or may not allow the District to generate as much power as needed to meet all of its needs. For example, in the most recent winter event in 2013, the Slice system was expected to be able to sustain a generation peak of slightly over 200MW through the heavy load hour period. This would generate sufficient resources such that the District would carry surpluses every hour through the event as displayed below in Figure 70.

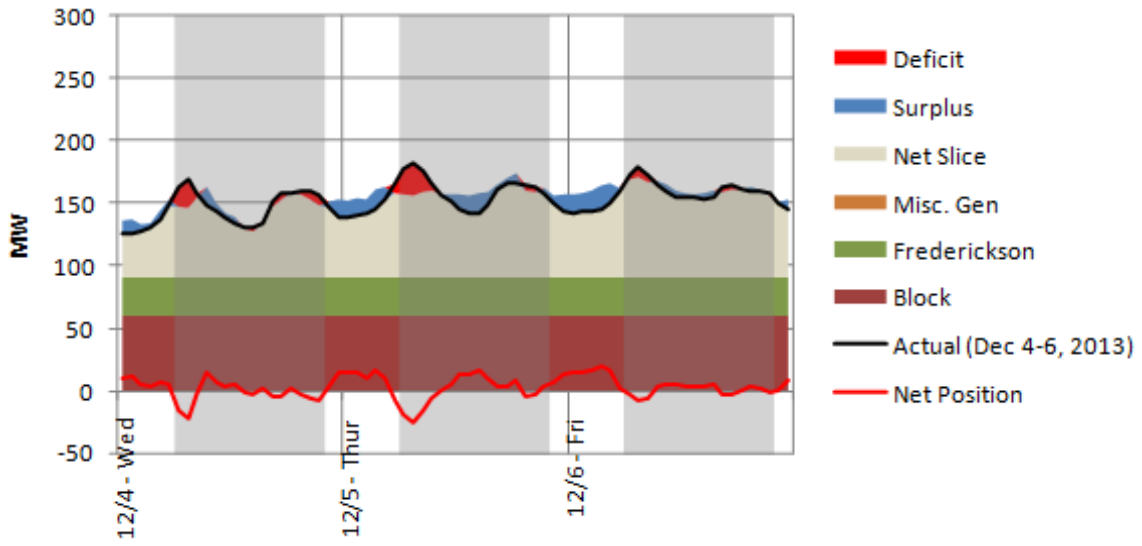
Figure 70: Modeled Slice System Capability in December 2013 Winter Event



However, due to constraints, the generation peaked only slightly above 150MW and the District instead carried deficits into morning and evening peak hours which can be observed in Figure 71.

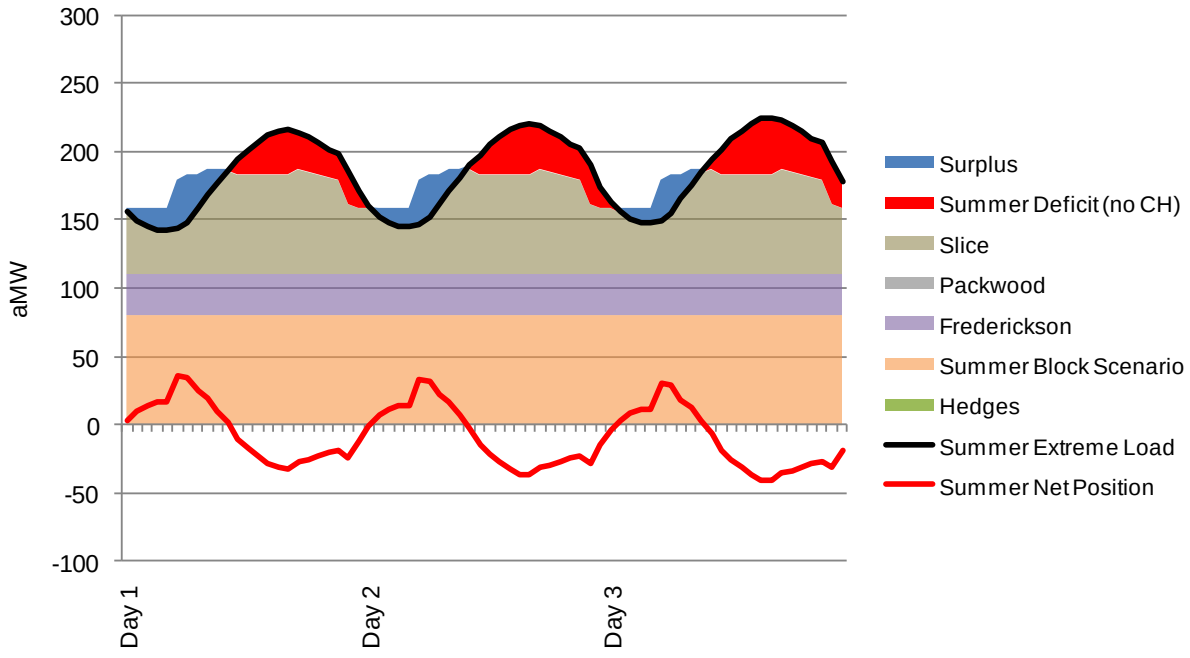
The discrepancies between the modeled and actual results can be attributed to many factors, but mainly because BPA did not declare a system emergency in which it would go to extraordinary lengths to ensure maximum Slice system generation. While prices were higher than average, they did not exceed $90/MWh on a day-ahead basis through the cold weather event and did not materially affect the District's finances. The District expects that in the event that either very cold or very hot weather settled into the region, BPA would lift many restrictions so that the system would be capable of additional generation.

Figure 71: Actual Slice System Capability in December 2013 Winter Event



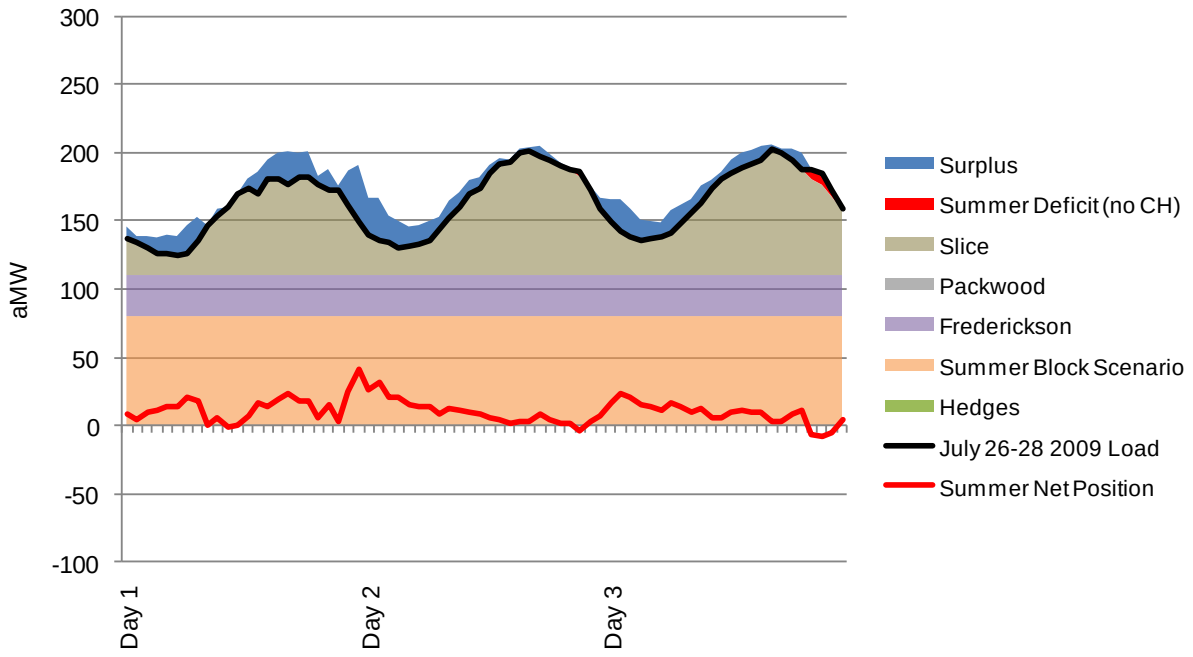
The District is typically a summer peaking utility and thus carries a seasonal energy deficit in the August/September timeframe. In the event of an extreme summertime event, the District could see deficits upwards of -35MW during the evening peak as displayed in Figure 72.

Figure 72: Modeled Load/Resource Balance in Extreme Summer Event



However, analyzing the load/resource balance from the last summer load excursion in July 2009, the loads were low enough and the District was able to generate enough from its Slice resource such that it was surplus almost throughout the 72 hour period as Figure 73 displays.

Figure 73: Actual Load/Resource Balance in July 26-28 Summer Event



The model shows that the total District resources will top out at about 200MW, which means that events which produce greater loads than the one in 2009 will exceed the District's resources at which point it will need to rely on the market to fill any deficits.

If the events of summer 2009 and winter 2013 replayed today, the District should have sufficient generation resources to meet its load. However, the District is beginning to approach the limit to which it can maintain load/resource balance without relying on outside resources. There are many options that can be explored to fill those short term seasonal deficits which range from procuring a new resource to purchasing annual physical call options to fill those requirements. Further, one benefit of the Slice system is its ramping capability and that it can increase its generation output when more resources are needed and ramp down when loads or market prices are lower. Shifting generation from lower priced to higher priced periods allows the District to take advantage of the market, purchasing energy at lower prices, and selling at higher prices.

Both summer and winter events set record high and record low temperatures. The simulated extreme peak loads in the capacity analysis represent are a more conservative forecast than the District has yet to experience. To reach those load figures would require new record breaking 72 hour temperatures. With modest load growth projections, along with very conservative hydro assumptions, it is likely that the District will be able to maintain reliability at an acceptable financial cost through most weather events in the near future. The District will continue to monitor its ability to navigate through capacity constrained periods and take action to mitigate the financial and physical impacts during these times.

APPENDIX B: Market Simulation

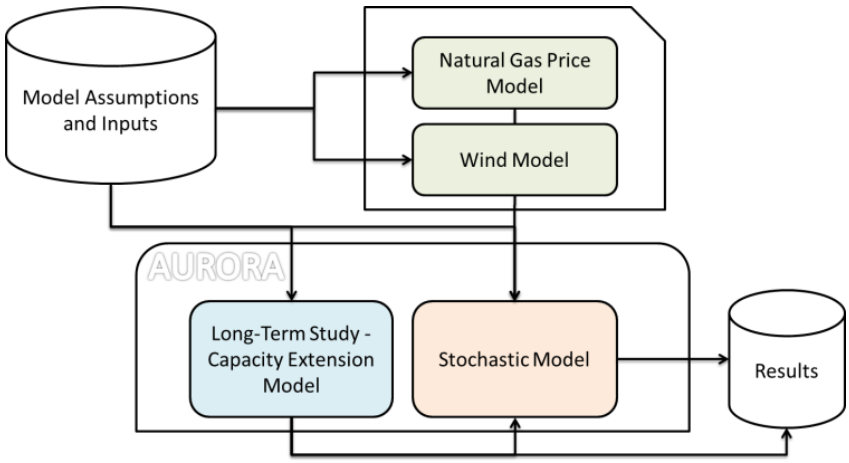
Introduction

This section provides an overview of the methodology and assumptions used in the long-term market simulation in the IRP. The values produced are integral to the evaluation as they describe a resource addition's expected performance and risk. Each potential resource is added to the existing portfolio and its cost is measured on a net present value basis over multiple simulations of electricity price.

Approach

The electricity price simulation is created by several fundamental models working in concert. Figure 74 provides an overview of the process used to create the price simulation. The progression can be broken down into three principle phases. In the first phase, fundamental and legislative factors were modeled and integrated. Examples include CO_2 penalty, regional renewable portfolio standard implementation, and fuel price models. The second part of the study uses the inputs from the first step to run a capacity expansion analysis. In this phase market prices are simulated for all of the Western Interconnection utilizing a production cost methodology. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 20 year time horizon. In the final phase, the modified supply stack is integrated back into a stochastic simulation of price, fuel and hydro variables. This section will describe the price simulation in further detail.

Figure 74: Modeling Approach



AURORA xmp

The main tool used to determine the long-term market environment is AURORA xmp also referred to as "Aurora". Developed by EPIS, Inc., Aurora simulates the supply and demand fundamentals of the competitive physical power market. Using factors such as the performance characteristics of supply resources, regional demand, and transmission constraints, Aurora simulates the WECC system to determine how generation and transmission resources operate to serve load. The model simulates resource dispatch that is used to create long term price and capacity expansion forecasts. The software

includes a database containing information on over 13,600 generating units, fuel prices, demand forecasts, and transmission constraints for 115 market areas in the United States.

Aurora was utilized for two main purposes. First, a deterministic look at expected capacity expansion in the WECC region was undertaken using expected values for natural gas prices, renewable energy requirements, demand escalation, and carbon prices. Using a multi-step process, Aurora determines an economically optimal resource expansion path within the given constraints. Using the results from this study, proprietary natural gas price and wind capacity factor models, and historical generation data, Aurora is then used to stochastically generate a long term price forecast for the Mid-Columbia (or Mid-C) region.

WECC Region Modeled

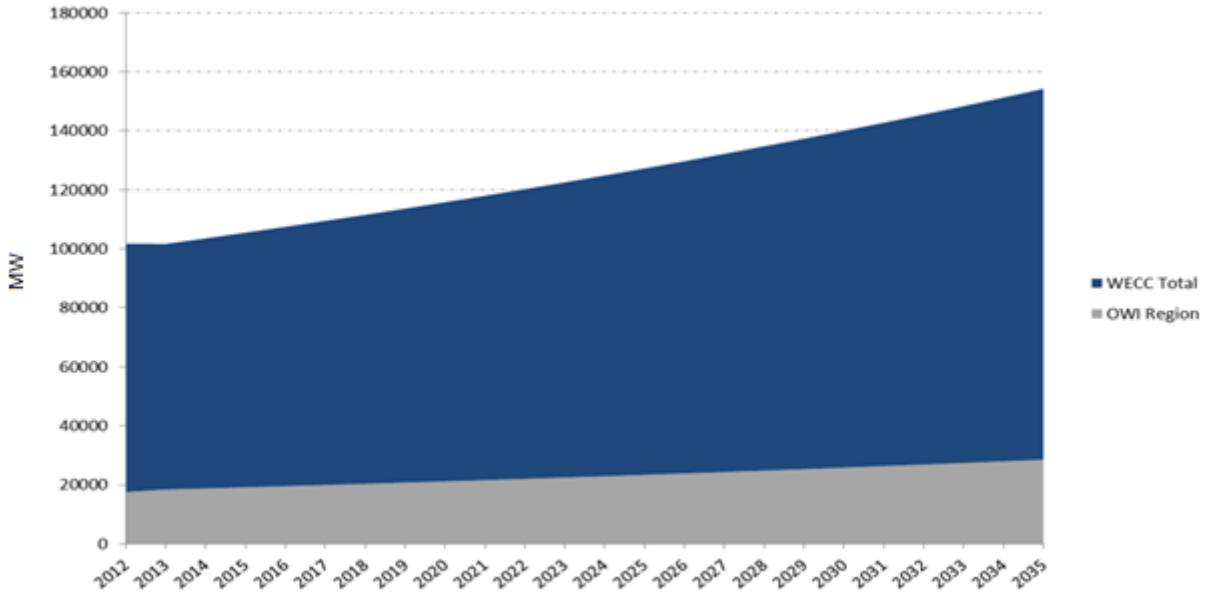
Aurora was used to model numerous zones within the Western Interconnection (the WECC region) based on geographic, load and transmission constraints. The WECC region is the most geographically diverse of the eight reliability coordination regions in the country. Much of the analysis in this IRP focuses specifically on the Northwest region, specifically Oregon, Washington and Idaho. Even though the IRP forecast focuses on the Mid-C electricity market, it is important to model the entire region. This is because fundamentals in other parts of the Western Interconnection exert a strong influence on the Pacific Northwest market. To create a credible Mid-C forecast it is imperative that the economics of the entire region are captured.

Principal Assumptions

WECC Region Load Included

Demand escalation forecasts for zones in the WECC region are based on US EIA and NERC data and are provided in the Aurora database. Based on these forecasts, overall load in the region is expected to rise by 51% through 2035, from 101,726 aMW in 2012 to 154,216 aMW in 2035. Increases in energy efficiency, slower economic growth, and decreased population growth contribute to less aggressive load growth when compared to the historical average. Loads in the Northwest region are expected to increase by 62% through 2035, from 17,542 aMW in 2012 to 28,506 aMW in 2035).

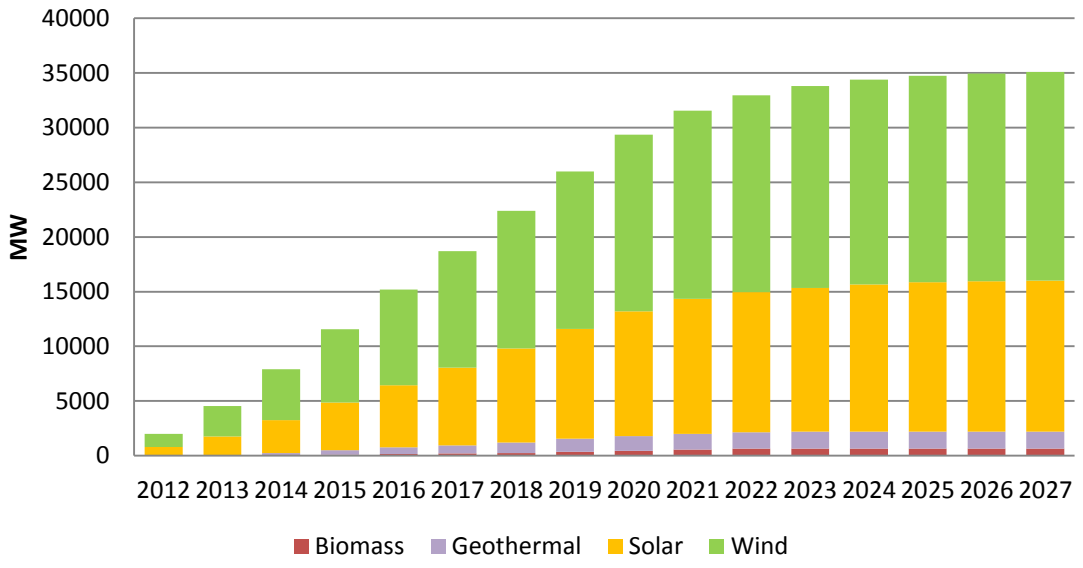
Figure 75 - Northwest Region Load Forecast through 2035



WECC Region Renewable Portfolio Standards

To capture the wholesale price impact of renewable portfolio standards in the WECC Region in the simulation, qualifying renewable resources were added to the supply stack prior to the capacity expansion analysis. An aggregate view of additions is shown below in Figure 76.

Figure 76: Resource Additions Added to Aurora



Regional Planning Reserve Margins

In order to ensure there will be sufficient generating capacity to meet demand in case of generator outages or demand spikes, a certain amount of generating reserve capacity is built into the market. These operating reserves are either extra generating capacity at already operating plants, or fast-start generators, usually natural gas fired, which can start-up and reach capacity within a short amount of time.

Planning reserve margins are long term measurements of the operating reserve capacity within a region, used to ensure there will be sufficient capacity to meet operating reserve requirements. The planning reserve margin is an important metric used to determine the amount of new generation capacity that will need to be built in the near future. For the capacity expansion analysis, the District used the planning reserve margins set by NERC in its 2011 Long Term Reliability Assessment, outlined below (Figure 77). Planning reserve margins in the Northwest are notably higher than the rest of the WECC due to a greater reliance on variable hydroelectric generation relative to other regions.

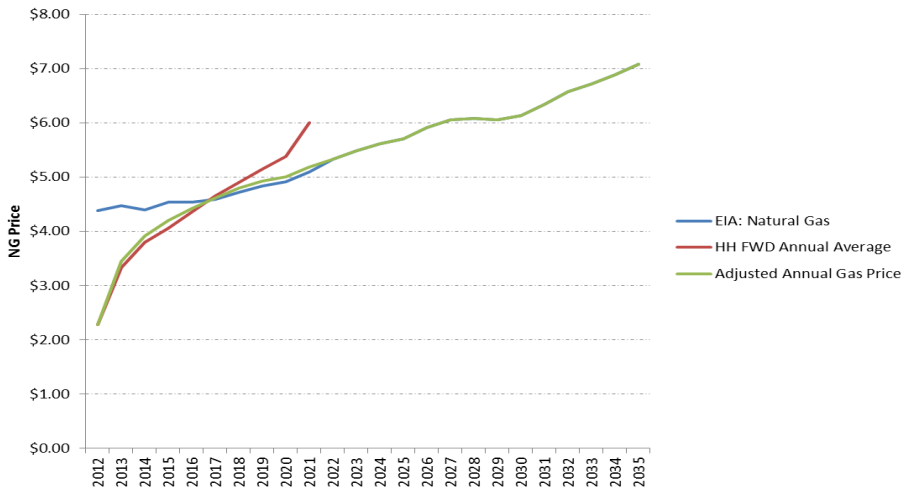
Figure 77 - WECC Regional Planning Reserve Margins

Zone	Planning Reserve Margin
AESO	14.1%
BC	14.1%
NORW	20.3%
BASN	12.6%
ROCK	13.9%
DSW	13.8%
CALN	14.2%
CALS	14.9%
MEXW	11.9%

Natural Gas Price Simulation

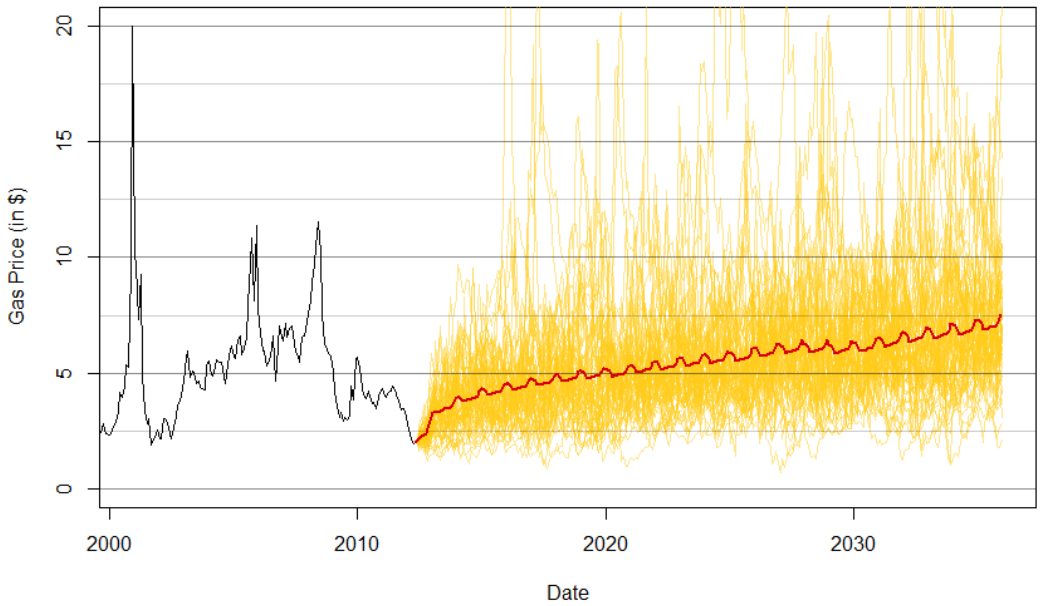
Natural gas prices are a key factor in the market simulation. It is challenging to forecast prices over a 20 year time period because market quotes do not exist for the full duration of the study period. As a result, the expected scenario was determined by combining several data points. The first part of the price curve uses Henry Hub forward pricing data through the year 2021. From the years 2022-2035 prices are normalized to US EIA natural gas price estimates. Figure 78 shows the natural gas prices used in this portion of the study.

Figure 78- Natural Gas Price Assumptions



A proprietary model was used to develop natural gas distributions for use in stochastically modeling electricity prices. The model is a statistical model which uses historical Henry Hub prices to generate an overall distribution of gas prices. A multi-factor mean-reverting Monte Carlo process is used to simulate the volatility of daily spot gas prices, and the model is seasonally adjusted to reflect historic seasonal trends in price and volatility, and is normalized to forward prices and US EIA price estimates. 70 iterations of this model were run, each generating daily spot gas prices through 2035, which were input into Aurora. The results of the gas price simulation are shown in the chart below (Figure 79).

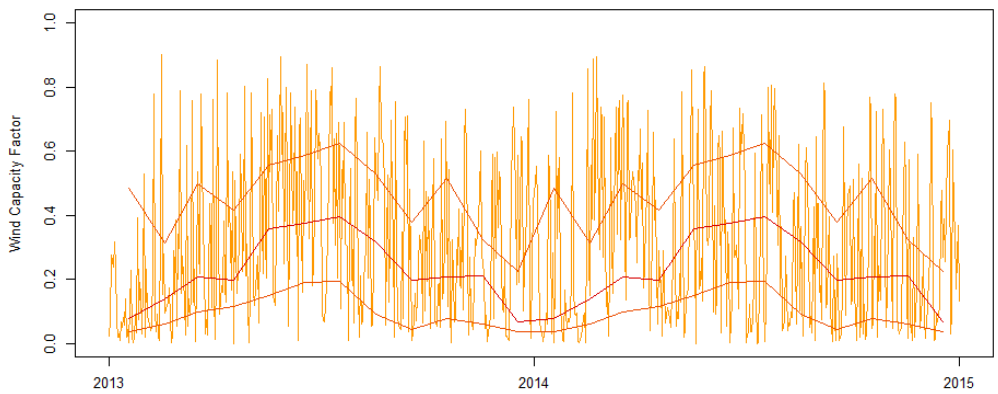
Figure 79: Gas Price Simulation



Wind Generation Simulation

Historical wind generation data from BPA was used to develop a Markov-chain based model that represents hourly wind capacity factors for the region. Historic wind generation data was analyzed to generate probabilities used to forecast daily wind capacity factors. These daily factors are then shaped into hourly capacity factors based on seasonal patterns. 70 years of hourly capacity factors were generated using this model. The forecasted 24 month wind simulation can be seen in Figure 80. The fitted curves within the chart represent percentiles (probabilities) of capacity factors. The line closest to the x-axis represents the 5th percentile (lowest) capacity factor. In the simulation, the capacity factor was less than the bottom boundary 5 percent of the time. Similarly, the line highest up on the y-axis represents the 95th percentile (highest) capacity factor. Capacity factor exceeded the upper bound 5 percent of the time. The middle line represents the mean.

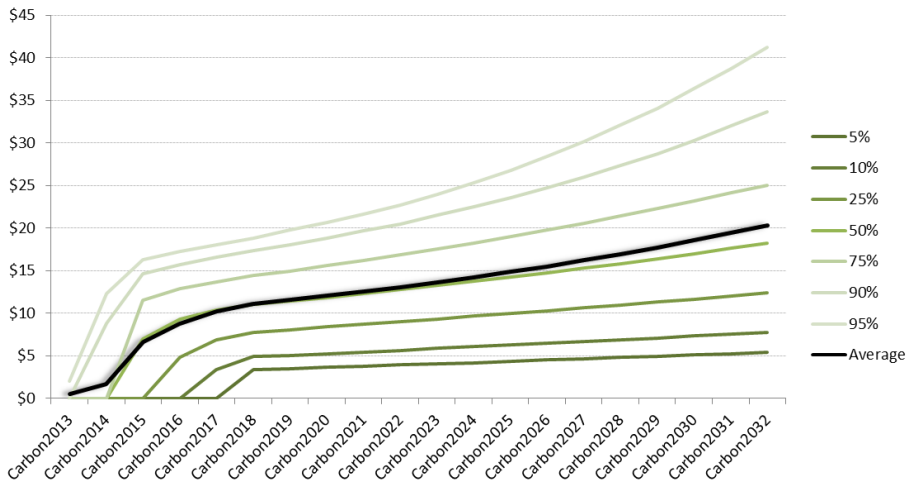
Figure 80: Wind Generation Simulation



Carbon Penalty Simulation

There is a high level of uncertainty regarding the regulation of CO_2 emissions, as well as the structure and creation of carbon trading markets. Currently in the western United States, the only state that prices carbon emissions is California with a cap and trade program that began in 2013. A large amount of the surplus generation from the Pacific Northwest is sold in California, and it is too soon to determine what kind of carbon premium will be priced into this power. A distribution of expected carbon prices for each year of this study is shown in Figure 81.

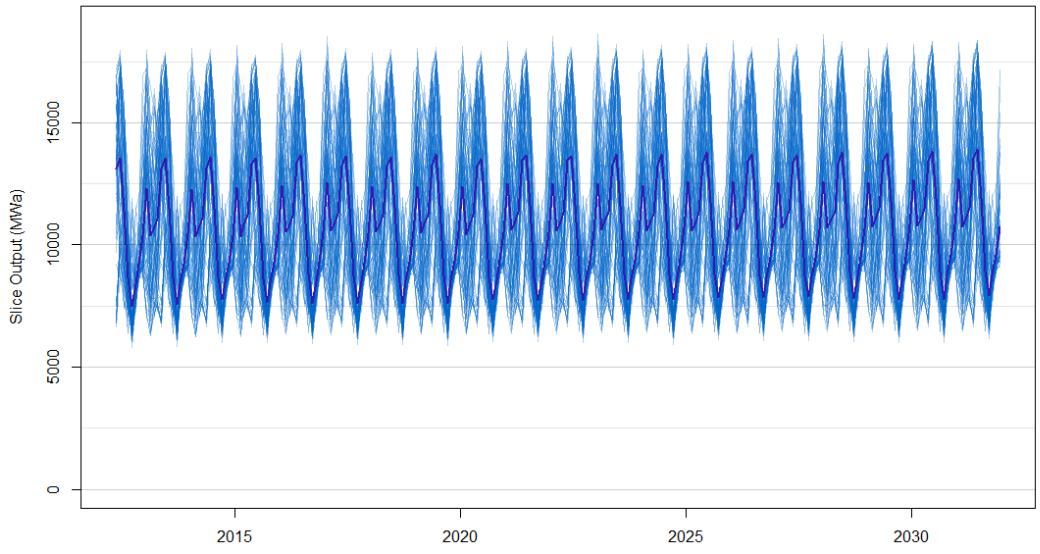
Figure 81: Carbon Penalty Assumption



Hydroelectric Generation Simulation

Hydro power currently accounts for approximately two-thirds of electricity generated in the Northwest US, and one-quarter of generation in the WECC Region. Hydroelectric power has a number of advantages, including the ability to shape generation to loads, and instantly stop and start generation depending on need. One of the challenges of hydro generation is its variability and uncertainty. Yearly hydroelectric output depends on a number of variables, including snowpack and environmental regulations. Historical hydro generating data was an input for the stochastic model, which randomly selects a water year from the 70-year data set. Figure 82 illustrates the hydro generation assumption used in the price simulation.

Figure 82: Hydro Simulation: Peak Hours



Long-Term Fundamental Simulation

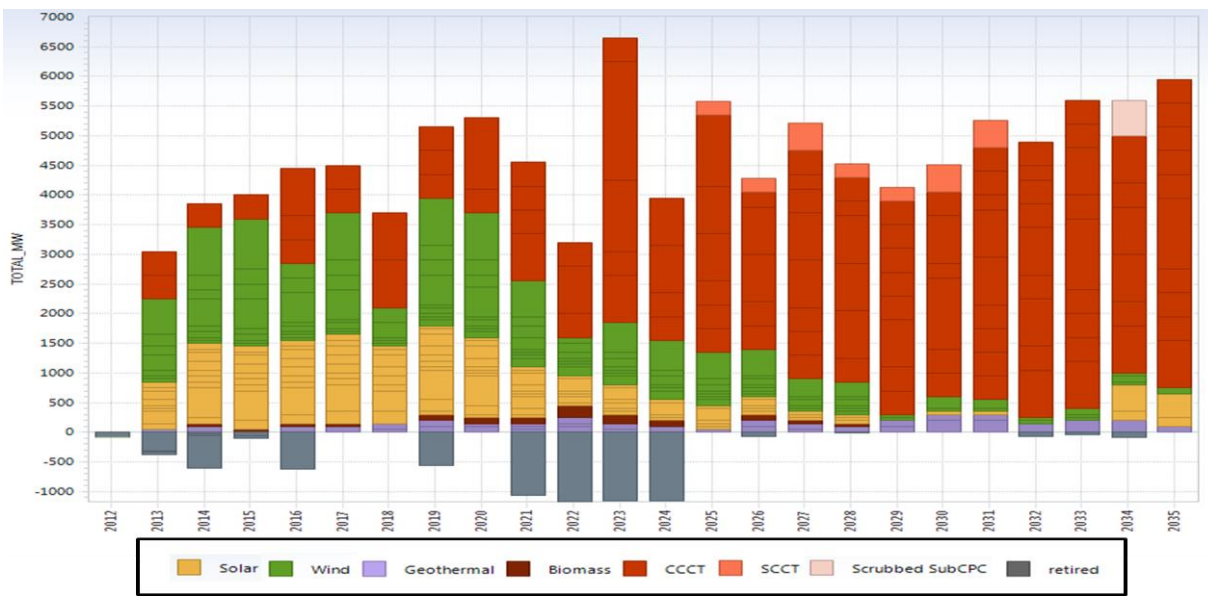
A vital part of the long-term market simulation is the capacity expansion analysis. AURORAxmp was used to determine what types of power plants will likely be added in the WECC over the next 20 years. To arrive at an answer requires an iterative process. In the first step, Aurora ran a 20 year dispatch study assuming that no new plants are built in the WECC. Over the course of the study period WECC loads escalate, which cause planning reserve margins to fall and prices to rise. In the second step Aurora adds resources progressively with load growth. The resources that are chosen are the best economic performers – i.e., provide the most regional benefit for the lowest price.

Capacity Expansion & Retirement

The generation options considered when modeling new resource additions in the region included coal, nuclear, simple and combined cycle natural gas, solar, wind, hydro, geothermal, and biomass. Costs for capital, variable operation and maintenance, fixed operation and maintenance, heat rate (thermal units), and capacity factor (wind and solar units) were inputs. Figure 83 illustrates the expected new resource expansion and retirement through 2035 throughout the entire Western Interconnection.

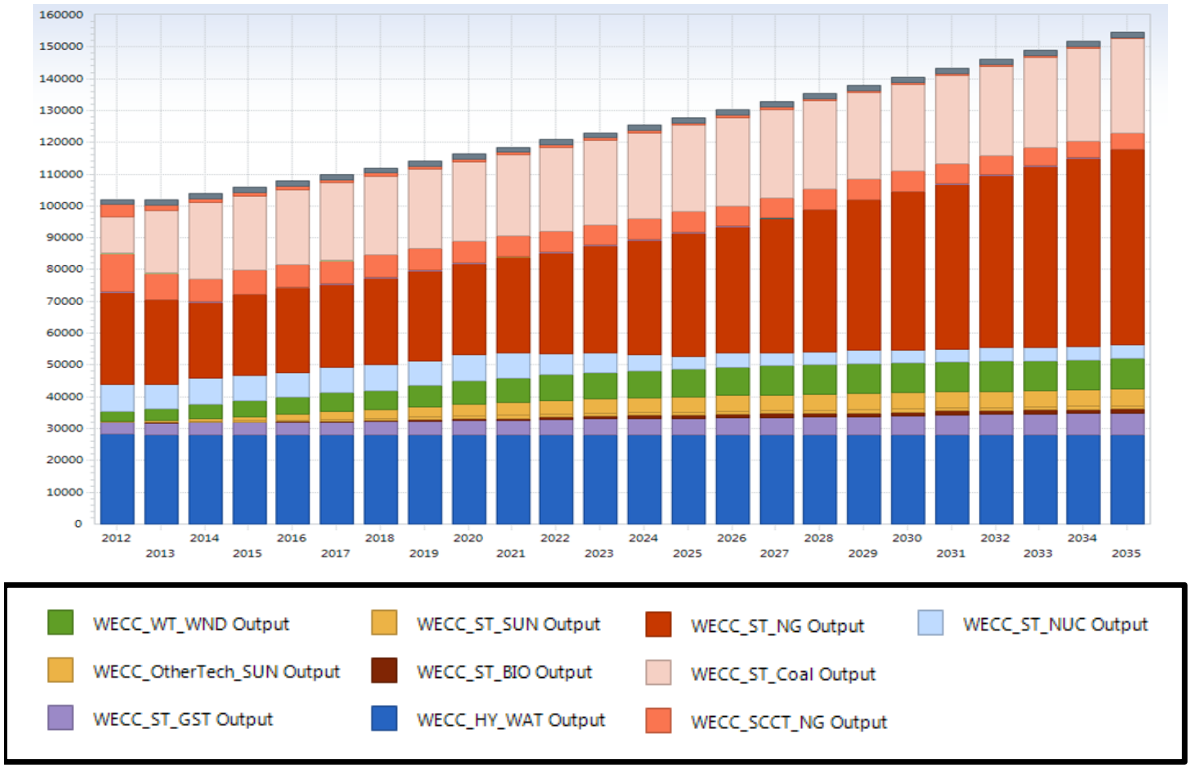
RPS requirements are one of the main drivers of new resource expansion over the next decade, as utilities develop mainly new wind and solar resources to meet state requirements. Combined cycle natural gas plants make up the majority of the additional capacity expansion, becoming the main source of new generation after 2020 when renewable resource expansion slows (Figure 83).

Figure 83 - Forecasted WECC Generation Capacity Additions through 2035



Coal output is forecasted to stay about constant, with new coal plants not being developed due to state and federal emissions regulations. Nuclear output will decline as aging units are taken off line, and hydro output will stay the same. The majority of the increasing load will be met with combined cycle natural gas plants, with smaller amounts of wind and other renewable resources. Figure 84 illustrates the outputs of all resources through 2035.

Figure 84 - Forecasted Total WECC Generation through 2035



Within the Oregon-Washington-Idaho region, the story is similar. Hydroelectricity will stay the largest single generating resource through 2035, with no projects being built or retired. Wind remains the renewable choice for fulfilling RPS requirements, and is expected to constitute the majority of new renewable generation built through the next decade. Along with wind, combined cycle natural gas plants make up the bulk of new generating capacity to meet increasing demand. Other renewables such as biomass, geothermal and solar are expected to be a growing portion of the resource stack.

Heat Rate Simulation

The capacity expansion analysis provides a realistic forecast of what resources will be added in the WECC over the next 20 years. These hypothetical resources are added to the existing resource stack to create a 20 year "stack forecast". This hypothetical supply stack is the foundation of the market heat rate simulation. Once these modifications are programmed into Aurora, all of the major factors are varied using Monte Carlo simulation. Major factors include WECC loads, WECC hydro generation, fuel prices, and CO_2 penalties. The result of the simulation is represented by Figure 85. Each blue dot represents an individual month from the simulation. The black trace represents the average of all of the iterations. Market heat rates are expected to stay relatively flat, although volatility will change slightly over time.

Figure 85: Heat Rate Simulation

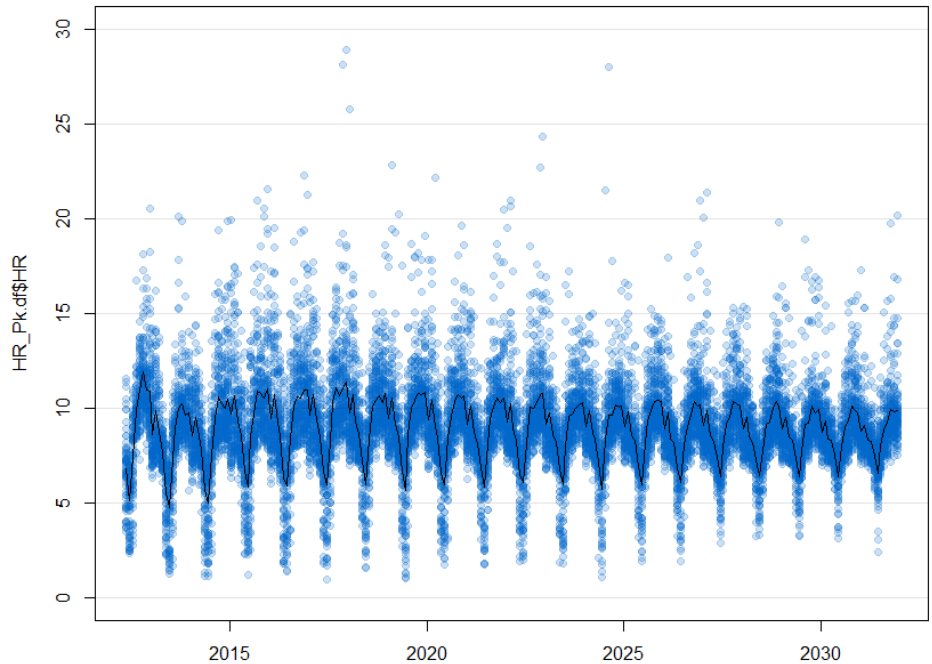
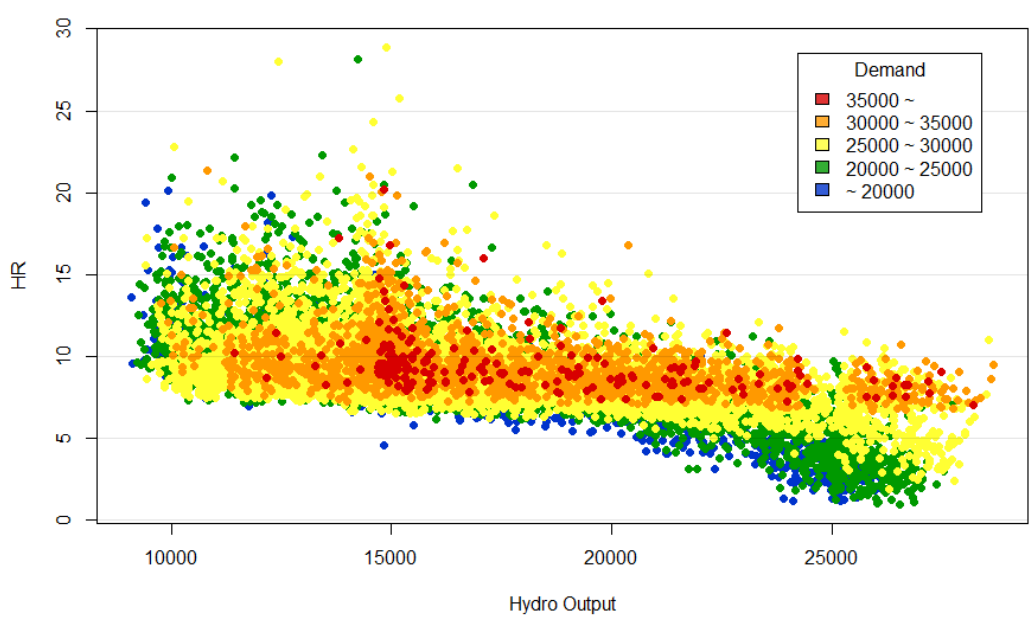


Figure 86 illustrates the relationship between WECC load, WECC hydro generation and forecasted market heat rate. Each dot represents a month from the simulation. The y-axis is market heat rate and the x-axis is WECC hydro generation. The simulation indicated in the future market heat rates will continue to be negatively correlated to hydro generation. The chart contains a second dimension that factors in the influence of WECC loads. Low load iterations are represented by "cooler" colors – i.e. blue and green. The higher load iterations are represented by "warmer" colors – i.e. orange and red.

Figure 86: Regional Heat Rates vs. Hydro & Demand



Power Price Simulation

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained over multiple iterations of Monte Carlo analysis. In the Mid-C region, prices have historically been among the lowest in the country due to the preponderance of cheap hydropower. Hydro output is not expected to increase throughout the period of this study, meaning that more expensive wind and natural gas generation will be used to meet increased demand. Prices in the region are forecasted to rise steadily over the study period about 7.5% each year, with an average increase of approximately 20% a year through 2016. The average price over the study period is $63.97 (Figure 87).

Figure 87 - Mid-Columbia On-Peak Price Simulation

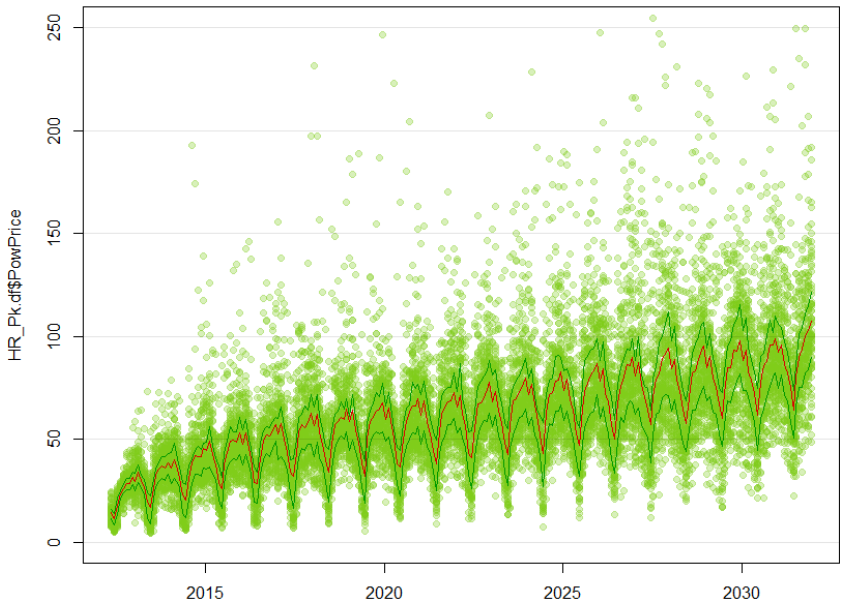


Figure 88 and Figure 89 show the forecast results for on-peak and off-peak prices, respectively. In each figure there are three traces. The middle trace represents the mean from the price simulation; the upper represents the 90th percentile and the lower represents the 10th percentile.

Figure 88: On Peak Price Forecast

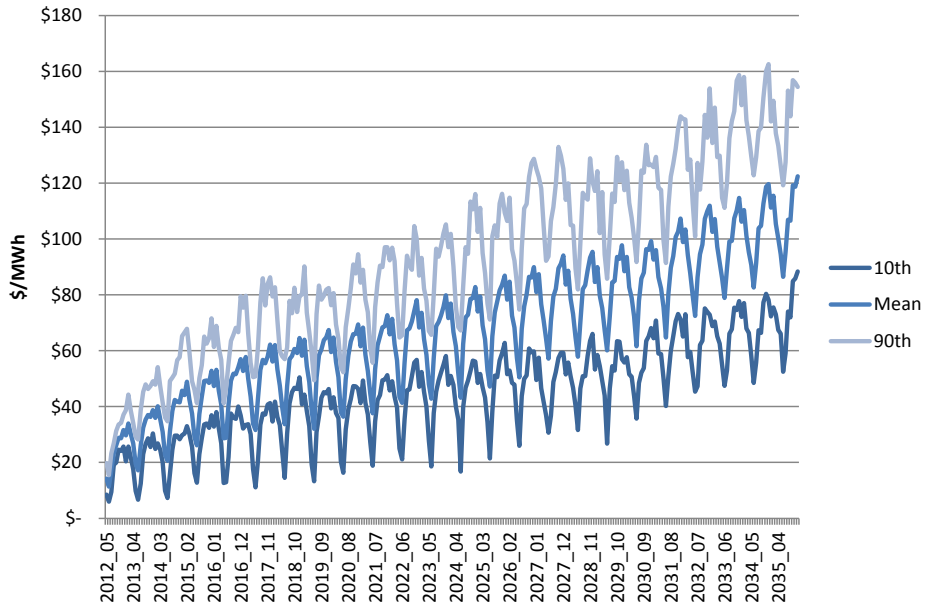


Figure 89: Off Peak Price Forecast