B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2013 Resource Program

February 2013

Table of Contents

Tables

Figures

Executive Summary

Bonneville Power Administration's (BPA) 2013 Resource Program updates the 2010 Resource Program, released in September 2010. The 2013 Resource Program is abbreviated and primarily provides updates to key inputs and analysis. The 2013 Resource Program focuses on two study periods, fiscal years (FY) 2016 and 2021.

BPA has prepared an updated 2013 Resource Program Action Plan to highlight the following key areas of action:

- Evaluate the contribution of conservation to meeting capacity needs.
- Further develop the definitions of system and resource flexibility, including how flexibility might be measured and possible adequacy metrics.
- Continue to evaluate demand response and Keys Pumped Generation Station.
- Explore the application of Peak Net Requirements provisions described in Regional Dialogue contracts.
- Monitor the emerging drivers that influence the potential Above-High Water Mark load placed on BPA post-FY 2019.
- Continue to evaluate how traditional thermal generation resources could supplement the capacity of, and provide flexibility and seasonal energy to, the existing Federal Columbia River Power System (FCRPS).
- Monitor factors that could reduce the capability or output of the FCRPS.
- Collaborate with the Northwest Power and Conservation Council (Council) to prepare for the Seventh Power Plan and BPA's next Resource Program.

From now on, BPA plans to publish its Pacific Northwest Loads and Resources Study (the White Book) every two years. The biennial White Book will include the Needs Assessment, which is the foundation for defining the power supply obligation needs for the Resource Program. As a result of this addition to the White Book, BPA expects to update the Resource Program roughly every two years. It is anticipated that BPA's next Resource Program will be prepared in conjunction with the Council's Seventh Power Plan and BPA's 2014 White Book.

Energy:

The 2012 Needs Assessment shows that, under a variety of conditions and timeframes, BPA could need to supplement the existing Federal system generation to meet existing and projected obligations. These conclusions reflect additional limitations on the projected capability of the FCRPS to meet BPA's load obligations since the 2010 Needs Assessment. Specifically, updates to the hydro modeling assumptions have, in general, decreased the expected annual and winter FCRPS forecast generation. The 2012 Needs Assessment projects more significant deficits in the January-February timeframe, some improvement to the second half of August, and increased deficits in September relative to the 2010 Resource Program.

Under the expected case, modest annual energy deficits are projected under critical water. However, in studying the 10th percentile (P10) for each month, there are significant deficits (both heavy load hour and all hours), notably in January and February (winter), the second half of August, and September (summer). These deficits would be larger if BPA were to lose any current generating capability. For example, the 2012 Needs Assessment assumes 2008 Biological Opinion (BiOp) hydro operation requirements, which, based on an average of historical fish migration at the Snake River dams, typically end juvenile bypass spill by mid-August. If spill were required through the end of August, the additional spill would correspond to a loss of about 400 average megawatts (aMW) of generating capability in the second half of August under all water conditions.

BPA plans to address the energy need by:

- Achieving the Sixth Power Plan conservation targets, which would greatly reduce BPA's need for additional power to meet energy needs (both seasonally and on an annual average basis).
- Continuing to utilize wholesale power market purchases.

Any residual needs are expected to be small and very seasonal in nature (winter and summer) and could be met with minimal incremental market purchases above those assumed in the studies.

Capacity:

The Needs Assessment results show that the 18-hour capacity metric is minimal to no longer capacity surplus in either the winter or summer. The winter capacity numbers changed significantly from the 2010 Needs Assessment, largely as a result of extreme weather load differences, the expiration of winter purchases, and changes in FCRPS generation forecasts.

BPA plans to address the 18-hour capacity need by:

- Achieving the Sixth Power Plan conservation targets. This will have the effect of reducing the load and thus help to supplement the existing capacity of the FCRPS. BPA is concerned that not all the conservation may occur during times of extreme loads, and hence further study is warranted.
- Making market purchases. As with the energy needs, market purchases during heavy load hours supplement BPA's ability to meet capacity needs.
- Further exploring additional Non-Treaty storage, demand response, and the application of customer non-Federal resource peaking capacity (Peak Net Requirements). These promising areas need further evaluation to determine the effects on BPA's capacity needs. BPA also plans to continue to evaluate Keys pumped storage.

Balancing Reserves:

The Needs Assessment reflects that the FCRPS resources are insufficient to meet the forecast 99.5 percent level of service for balancing reserve requirements in FY 2016 and FY 2019 (proxy for FY 2021). There are many processes occurring in the region to address the issue of balancing reserves, including:

- Ancillary and Control Area Services (ACS) Practices Forum
- BP-14 rate case
- Northwest Power Pool Market Committee and the Joint Initiative

Balancing reserve service requests are made every two years and for a period of only two years. This timing creates much uncertainty regarding the amount of balancing reserves BPA may be requested to provide. BPA's current strategy is to make short-term purchases of additional balancing reserves, if needed, in the wholesale market.

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Chapter 1. Introduction

The Resource Program outlines Bonneville Power Administration's (BPA) proposed approach to meeting the power supply needs established in the 2012 Needs Assessment in a manner consistent with the Pacific Northwest Power and Conservation Council's (Council) Sixth Power Plan.

Historically, BPA has published the Pacific Northwest Loads and Resources Study, known more commonly as the "White Book," on an annual basis. The White Book is a ten-year forecast of Pacific Northwest regional and Federal loads and resources. From now on, every two years BPA will publish a White Book that includes Federal Resource Adequacy and Needs Assessment studies in addition to the other studies the White Book has traditionally included.[1] The Needs Assessment is the foundation for defining and identifying the potential power supply obligation needs for the Resource Program. With this change to the White Book schedule and inclusion of the Needs Assessment in the White Book, BPA plans to update the Resource Program roughly every two years to correspond with the White Book release.

In the years in which BPA publishes the White Book and the Council is not publishing a Power Plan, such as 2013, BPA anticipates that its Resource Program will be abbreviated and provide only an update to key inputs and analysis. In the years when the Council does publish a Power Plan, the Resource Program will take a much more comprehensive and in-depth approach.

1.1 Purpose of the Resource Program

Under the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), any Northwest utility that is a qualified BPA customer can contract with BPA to supply its firm power needs to the extent that those needs are not met by its own resources. BPA supplies roughly one-third of the Northwest's wholesale electric power. To meet these needs and other statutory obligations, BPA must plan a reliable and adequate supply for its expected power needs.

BPA markets the output of the Federal Columbia River Power System (FCRPS), which consists of 31 hydroelectric projects and one nuclear power plant. The Northwest Power Act authorizes BPA to acquire resources to meet its contractual obligations. BPA does not own generating resources, so when BPA uses the term "acquire resources," it refers to contract purchases, not project ownership.

To be in a position to meet future supply obligations placed on BPA by its power and transmission users, it is prudent that BPA develop a Resource Program. BPA's Resource Program evaluates resource options and identifies potentially optimal resource choices for meeting its obligations. Decisions regarding the acquisition of any specific resource will be made in a separate process, however, and not in the Resource Program. The

[1] During the odd-numbered years, BPA will publish a summary of major changes to the Federal and regional obligations and resources.

Resource Program provides information BPA can use to make informed resource acquisition decisions in the future, when such decisions are needed.

1.2 Uncertainties Drive BPA Resource Planning

Beginning with the Regional Comprehensive Review and the Power Subscription Strategy and continuing through development of the Regional Dialogue (Contract High Water Mark) contracts and the Tiered Rate Methodology, BPA's goal has been to provide its customers information they can use to choose their power supplier. As highlighted in the 2010 Resource Program, section 1.4, one result of BPA customers having opportunities to make resource elections is that BPA faces load uncertainties that can affect its resource planning. Those load uncertainties include:

- The amount of Above-High Water Mark load customers will elect to have BPA serve
- The amount of Resource Support Services customers will need to support their non-Federal resources
- The potential for new publicly owned utilities to form and buy power from BPA
- The amount of direct-service industrial customer (DSI) load BPA will serve in the future
- Whether the Department of Energy (DOE) Richland vitrification plant construction will be completed on time and increase electricity consumption by up to 70 megawatts as is contractually possible
- The amount of balancing reserves BPA will need to provide to wind power generators in the BPA balancing authority area

As discussed in section 1.5 of the 2010 Resource Program, BPA faces uncertainties beyond customer choice that also affect resource planning. Some of these uncertainties specific to BPA are:

- Operational effects of the Biological Opinion
- Hydro operational requirements
- Natural variations in water supply and timing
- Operational uncertainties of the Columbia Generating Station (CGS) nuclear plant

BPA also shares numerous market and planning uncertainties with other utilities across the Northwest and the Western Interconnection, the area of 13 U.S. states and two Canadian provinces in which BPA buys power and sells surplus power. These include:

- The effects of Renewable Portfolio Standards (RPS) on location and timing of renewable resource development
- Amounts and locations of load growth within the Western Electricity Coordinating Council (WECC) area

- The effects of regulatory body restrictions and penalties on greenhouse gas emissions
- The effects on loads of emerging technologies such as Smart Grid and electric vehicles
- Variability of fuel prices for natural gas
- The effect of financing uncertainties on capital costs and availability of financing for generating projects

In sum, electric utilities in general and BPA in particular face a wide range of power supply, demand, and market uncertainties. The 2013 Resource Program examines these uncertainties and determines their relevance for BPA's resource acquisition decisions.

1.3 Resource Program Objectives

The objectives for the 2013 Resource Program are:

1. To define the types, amounts, and timing of resource acquisitions that can best meet the demands placed on BPA by customers, consistent with the Council's Power Plan and BPA's strategic objectives
2. To inform customers' decisions as they make their Above-High Water Mark load elections by providing information about BPA's likely resource acquisitions
3. To build understanding of BPA's likely resource acquisition choices and timing
4. To build BPA's resource planning and analytical capability to support future decisionmaking

1.4 Consistency with the Northwest Power Act

The Council publishes its Northwest Conservation and Electric Power Plan at least once every five years in accordance with the Northwest Power Act. BPA develops its Resource Program to be consistent with the Council's Power Plan. To ensure consistency, BPA works closely with the Council staff throughout preparation of the Council's Power Plan and the BPA Resource Program.

Recently the Council released a draft Sixth Power Plan Mid-Term Assessment. BPA coordinated with the Council during development of both this Resource Program and the Council's Mid-Term Assessment.

The Northwest Power Act requires that BPA follow specific procedures if it proposes to acquire the output of a "major resource." A major resource is defined as one with a planned capability greater than 50 aMW and that is acquired for more than five years. If BPA were to propose to acquire a major resource, BPA would review the proposed acquisition for consistency with the Council's Power Plan then in effect, in a public process as required under section 6(c) of the Northwest Power Act.

1.5 National Environmental Policy Act

BPA will conduct National Environmental Policy Act (NEPA) analyses as appropriate prior to any future decision to acquire specific power resources to meet future resource needs. The NEPA documentation to be prepared will depend on the nature of each specific acquisition and the circumstances at that time, as information about any proposed acquisition becomes available.

For some such actions, BPA may tier its decision to BPA's Business Plan Final Environmental Impact Statement, DOE/EIS-0183, June 1995 (Business Plan EIS), and Business Plan Record of Decision (ROD), August 15, 1995, if the specific acquisition is considered to be within the scope of that EIS and ROD. The Business Plan EIS and its Supplement Analysis of April 26, 2007, were prepared to support a number of BPA decisions, including plans for BPA resource acquisitions and power purchase contracts. The Business Plan EIS and ROD would still be applicable should BPA decide to acquire resources to meet its obligations under its Regional Dialogue contracts. For other acquisitions that do not fall within the scope of the Business Plan EIS and ROD, BPA may prepare a project-specific EIS or other appropriate NEPA documentation.

1.6 2013 Resource Program

The 2013 Resource Program occurs in a year in which the Council is not publishing a Power Plan but BPA is publishing a White Book. Thus, the 2013 Resource Program focuses on updates to certain key inputs and analysis. For this Resource Program, the following assumptions and conclusions are updated:

- Load forecasts
- Needs Assessment
- Market Assessment, including scenarios
- Resource characteristics and cost information, focusing on natural gas plants
- Resource assessment and conclusions
- Action Plan

1.7 Public Involvement

The 2013 Resource Program is an update to the 2010 Resource Program. BPA coordinated throughout the development of the 2013 Resource Program with the Council as it prepared its Sixth Power Plan Mid-term Assessment. BPA did not anticipate, which was confirmed by the results of the Needs Assessment analysis, a substantial change in the results of the 2013 Resource Program compared to the 2010 Resource Program. As such, and given the level of activity occurring in the region on other topics, BPA did not conduct a public process for this Resource Program. BPA does anticipate conducting a public process for the development of the next full Resource Program.

Chapter 2. Market Assessment

2.1 Introduction

Chapter 1 lists a number of demand, supply, and market uncertainties BPA faces. This Market Assessment examines how some of these uncertainties might influence long-term trends in market prices.

Market prices are significant factors in resource planning in a number of ways. The wholesale power market is inextricably linked with the generating resource mix in the Pacific Northwest, with each constantly determining outcomes for the other through the dynamics of supply and demand. The outlook for power market prices helps determine the amount and types of resources that are built and retired. Relatively high market prices may indicate that the region is short on energy, while persistently low market prices might indicate the opposite. In an even more direct sense, wholesale power prices determine the value of BPA's surplus power and the costs of meeting BPA's obligations when BPA is short of power. Hence, a significant portion of BPA's revenue and risk exposure hinges on market outcomes. The Resource Program reviews wholesale prices in the region and evaluates how market prices relate to the costs of generating power to help determine the most cost-effective means for BPA to meet its needs.

2.2 Methodology

To analyze market uncertainties, BPA developed an expected case and four scenarios to represent a range of possible future outcomes (see sections 2.3.1 to 2.3.5). BPA then determined the most relevant variables to analyze within those scenarios and performed a stochastic analysis. Instead of modeling a variable as a discrete value, stochastic analysis allows a variable to take on a range of possible values, each with an associated probability. The uncertainty for each variable is represented by a probability distribution, which is repeatedly sampled. The Resource Program uses both scenario and stochastic analysis with the goal of capturing as much of the uncertainty BPA faces as possible in its modeling.

To quantify the impacts of the scenarios, BPA used the AURORAxmp® price forecast model. AURORAxmp, owned and licensed by EPIS, Inc., is commonly used in the utility business to produce electricity price forecasts. BPA used AURORAxmp in the Power Risk and Market Price Study for the BP-14 initial proposal, BP-14-E-BPA-04; for further information, see sections 2.2.2, 2.3, and 2.4 of that Study.

2.3 Scenarios

The four scenarios used in the Resource Program were developed based on two main drivers—economic growth and the regional policy stance involving "clean" or "green" energy—with each driver being modeled as either aggressive or restrained. Economic growth was selected as a main driver because of its direct impact on load growth and many other planning factors. Regional economic indicators such as GDP, employment, and demand for power would be expected to increase more quickly in a high economic growth scenario than in a lower growth scenario. Regional clean energy policy stance was selected as a main driver because it will influence many of the major issues that can be expected to shape the power industry sector and BPA over the next decade. Perhaps most importantly, the regional policy stance toward clean energy will have a significant impact on the pace and direction of generating resource development for the foreseeable future. Throughout this text, the word "green" is used to refer to a subset of the scenarios. In this sense, green can be taken to mean that regional policy decisions are made with environmental concerns as a top priority. Heightened Renewable Portfolio Standards, renewable production and investment tax credits, and penalties to discourage emissions of pollutants such as CO_2 and SO_2 would be associated with an aggressively "green" policy stance.

Taking the combinations of the two main drivers produces four scenarios. Within each of the four scenarios, BPA varied the values of several key market drivers to perform the stochastic analysis. Table 2-1 summarizes the scenarios and the key variables that were modeled. A brief description of each of the scenarios follows Table 2-1.

Table 2-1: Description of Variables and Scenarios

Variable	Scenario 1: Less Green – High Economic Growth	Scenario 2: More Green – High Economic Growth	Scenario 3: Less Green – Low Economic Growth	Scenario 4: More Green – Low Economic Growth
RPS Build	Expected	High	Expected	High
Load	High	High	Low	Low
Natural Gas $	High	High	Low	Low
CO_2	Expected	High	Expected	Expected

2.3.1 Expected Case

BPA modeled an expected case in addition to the four scenarios. The expected case contains all of the "expected" values for the market drivers that are varied in the scenarios. This market price forecast was based on the BP-14 initial proposal forecast and was trended out through FY 2021 by using the average rate of growth in nominal prices for heavy load hours (HLH) and light load hours (LLH) independently.

- The hydroelectric generation forecast is the same one used in the BP-14 initial proposal, an 80-historical-water-year (1929-2008) forecast.

- The price of carbon emissions is assumed to be $0 per megawatthour (MWh).[2]
- The preliminary resource build forecast, including RPS-qualifying facilities, was provided by the Council and was developed in preparation for the Council's Sixth Power Plan Mid-Term Assessment.
- The WECC-wide load forecast was developed by BPA in 2012.
- The expected case bears one distinction from the AURORAxmp run for the BP-14 initial proposal: the long-term AURORAxmp run for the 2013 Resource Program assumes that wind generates a flat monthly amount of energy, whereas the BP-14 AURORAxmp run assumes a distribution of hourly wind profiles. While an hourly wind profile through the two-year BP-14 rate period is appropriate, the Resource Program AURORAxmp run is ten years long. The assumed amount of wind generation capacity installed in the region in the later years is much larger than in the earlier years. Modeling the wind generation on an hourly basis introduces a large amount of uncertainty and variability toward the end of the study that may not be realistic.

The bullets below highlight the rationale behind the attributes of the scenarios. Descriptions are relative to the expected case.

2.3.2 Scenario 1: Less Green – High Economic Growth

- There is no development of renewable resources beyond those required to meet current RPS standards. Development of conventional generation is accelerated.
- State and Federal entities impose no price on greenhouse gas emissions.
- A strong economy causes high electricity load growth in the region.
- Construction costs increase due to increased demand in the strong economy. The exception might be the cost of renewable resources, as demand for these would be less than in the expected case.
- Higher demand for natural gas causes an increase in natural gas prices.
- Natural gas-fired resources make up the bulk of new generating facilities added in the Northwest.

2.3.3 Scenario 2: More Green – High Economic Growth

- Clean energy measures and State and Federal greenhouse gas (GHG) and RPS regulations are accelerated.

[2] California's Global Warming Solutions Act (AB-32) is currently in effect, and carbon prices do currently exist in California. However, as of this writing, there is still uncertainty regarding whether all imported power will be treated as an unspecified resource with respect to AB-32, or whether California will permit asset-controlling suppliers such as BPA to benefit from different tariff rates. For this reason, the 2013 Resource Program has chosen not to model a carbon price in its expected case. This is consistent with the BP-14 initial proposal assumptions. For more information, please see BP-14-E-BPA-14, page 11.

- The strong economy causes high load growth.
- Construction costs increase due to increased demand in the strong economy. Renewable resource costs may especially increase due to upward pressures caused by aggressive green policies.
- High demand and aggressive regulation against fossil fuels create a high natural gas price scenario.
- New resources added in the Northwest are primarily a mix of renewable, storage, and demand response, with some natural gas.

2.3.4 Scenario 3: Less Green – Low Economic Growth

- There is no development of renewable resources beyond those required to meet current RPS standards. Development of conventional generation is accelerated.
- State and Federal entities impose no price on greenhouse gas emissions.
- The weak economy causes low load growth.
- Construction costs decrease due to decreased demand in a weak economy.
- Low demand, coupled with little fossil fuel regulation, results in low natural gas prices.

2.3.5 Scenario 4: More Green – Low Economic Growth

- Clean energy measures are extended and accelerated.
- State and Federal GHG and RPS regulations are accelerated. RPS requirements and government incentives drive renewable resource development.
- The weak economy causes low load growth, although it is increased by electric vehicle adoption due to aggressive green policies.
- Even though aggressive regulation of fossil fuels persists, low demand for gas keeps prices on a low trajectory.

2.4 Description of Key Variables in the Scenarios

2.4.1 Natural Gas Prices

The preceding section outlines some of the theories behind the creation of each scenario. Below is a more-detailed look at the assumptions that led to the "low" and "high" natural gas price forecasts.

BPA developed three natural gas price scenarios to support the Resource Program Market Assessment (see Figure 2-1). The expected case forecast is the same as that used in the BP-14 initial proposal. Annual figures for the high and low forecasts were developed by the Council in preparation for its Sixth Power Plan Mid-Term Assessment; BPA applied its monthly shapes to create monthly values.

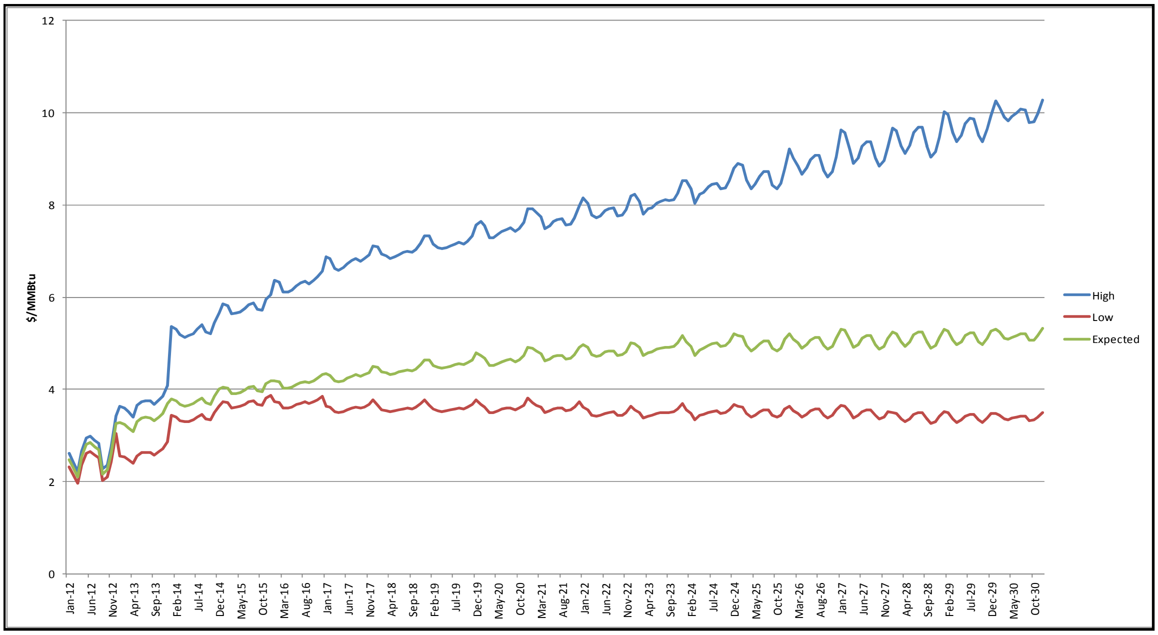
The expected case forecasts that prices will increase from their current levels due to a slow rebalancing of the gas market from its current supply glut. However, there are limitations to both upside and downside risks for prices. This forecast assumes no extreme weather events, such as the record mild winter of 2011-2012, which brought gas prices down to sub-$2 per million British thermal units (MMBtu) levels. Despite recent drops in rig counts, gas production is forecast to remain robust, limiting some potential upside risk. Associated gas from the production of oil is forecast to remain strong, and advances in drilling technology can be expected to provide a quicker supply response than the market has been accustomed to recently. In the long term, sustained additional demand will come from new sources of gas consumption and likely not from coal-to-gas switching. The most concrete potential source is the exportation of liquefied natural gas (LNG), for which a few projects in the United States and Canada are on track to begin in 2016. The pace and direction of hydraulic fracturing ("fracking") regulation at the State and Federal levels remain uncertain, as do the price effects of such regulation on the gas market.

The low gas price outlook is brought about by a continued global economic downturn. No new LNG export terminals are approved for the U.S., and the country faces a continued situation of low demand and cheap supply. A lack of environmental regulation means that coal-fired generation retains its cost advantage over natural gas and thus its prominence in the U.S. generation mix. At the same time, demand from residential/commercial, industrial, and transportation sectors is assumed to stagnate over the next decade.

The high gas price outlook reflects strong economic growth. LNG imports decline over the next three to four years, with the U.S. becoming a net exporter of LNG by 2016. LNG projects currently in development are granted regulatory approval. Financial backing and global market forces continue to encourage export. Residential/commercial/ industrial demand sees increases over the next five years as these customers abandon fuel oil and propane. Industrial activity increases due to economic growth. The transportation sector also increases its demand for natural gas. Cross State Air Pollution Rule (CSAPR)/Utility Mercury and Air Toxics Standards (MATS) Rule/GHG rule(s) all are implemented, raising prices for both coal and gas but favoring gas. As a result, nearly all of the incremental power demand over the next five to ten years is met with new gas-fired generation.

Figure 2-1 reflects the high, expected, and low natural gas prices. The low and high forecasts were sourced from the Council, and the expected case was developed by BPA for the BP-14 initial proposal. The large increase in prices between 2013 and 2014 in both the low and the high forecasts is attributable to two factors: the forecasting process and expectations for higher prices in 2014. The low and high case forecasts were influenced by futures prices for natural gas, which showed 2014 prices markedly higher than 2013 prices at the time the forecast was created.

Figure 2-1: Natural Gas Price Scenarios (real 2008 $)

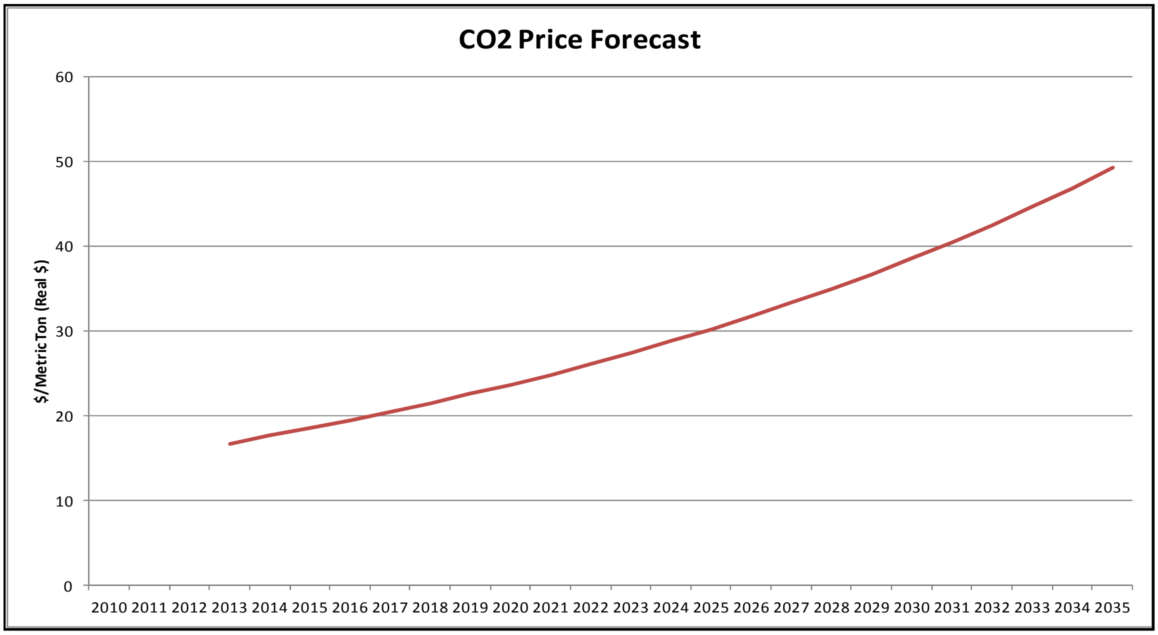


2.4.2 CO_2 Assumptions

The CO_2 scenarios are reflected in Figure 2-2.

- High CO_2 Cost: For the high case, BPA is using futures prices for CO_2 under the California Cap and Trade Program, sourced from the Chicago Mercantile Exchange. Those prices are applied to all generators in the WECC to represent the cost of emitting CO_2.
- Expected: BPA assumed CO_2 costs of zero due to increased uncertainty surrounding both state and national carbon legislation (see section 2.3.1).

Figure 2-2: CO_2 Scenario (Real 2012 $)



2.4.3 WECC Loads

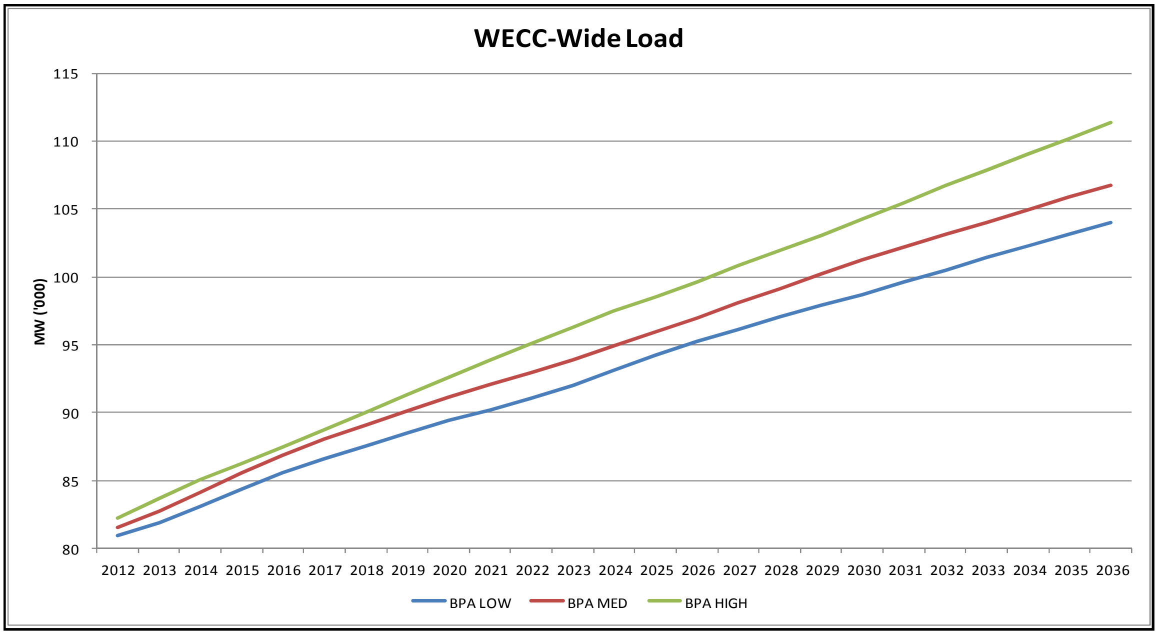
Scenarios regarding annual average load growth were developed for expected, high, and low cases.

The expected case is consistent with the 2012 White Book load growth forecast, with an average annual load growth rate for 25 years of approximately 1.13 percent. This includes some conservation that is embedded in the load forecast, discussed in Chapter 4.

The high case forecast includes a robust increase in economic growth due to increased spending (consumer and Federal), followed by an expanding, demand-driven economy. It includes additional demographic migration into the Pacific Northwest to meet employment needs, as well as additional demand for electricity from increased industrial activity. The average annual load growth rate for the high case is approximately 1.27 percent.

The low case forecast includes a double-dip recession stemming from current European economic conditions, which would be followed by slow employment growth in the region. This case does not anticipate closures of specific industries or prolonged demographic out-migration from the Pacific Northwest. The average annual load growth rate for the low case is about 1.05 percent.

Figure 2-3: WECC-Wide Load Forecasts



2.4.4 RPS Builds

Figures 2-4 and 2-5 show the two cases BPA modeled for the build-out of renewable resources to fulfill state RPS requirements across the entire WECC. See 2010 Resource Program Appendix G for details of state RPS requirements. Percentages cited below are percentages of retail load provided by renewable resources in the year specified.

The expected case forecast was provided to BPA by the Council, along with a forecast of all resources to be built in the WECC over the study period. It assumes California meets the 33 percent-by-2020 RPS standard; large utilities in Oregon meet a 25 percent-by-2025 RPS standard; and Washington meets a 15 percent-by-2019 RPS standard. It also assumes the expected load growth case.

The high case is a modification of the expected RPS case that uses high load growth instead of expected load growth, which would increase the amount of renewable generation required. In addition, instead of stopping when the current RPS standard goals are met, all WECC states extend their current trends of RPS growth through 2030.

Figure 2-4: Expected WECC RPS Resource Build

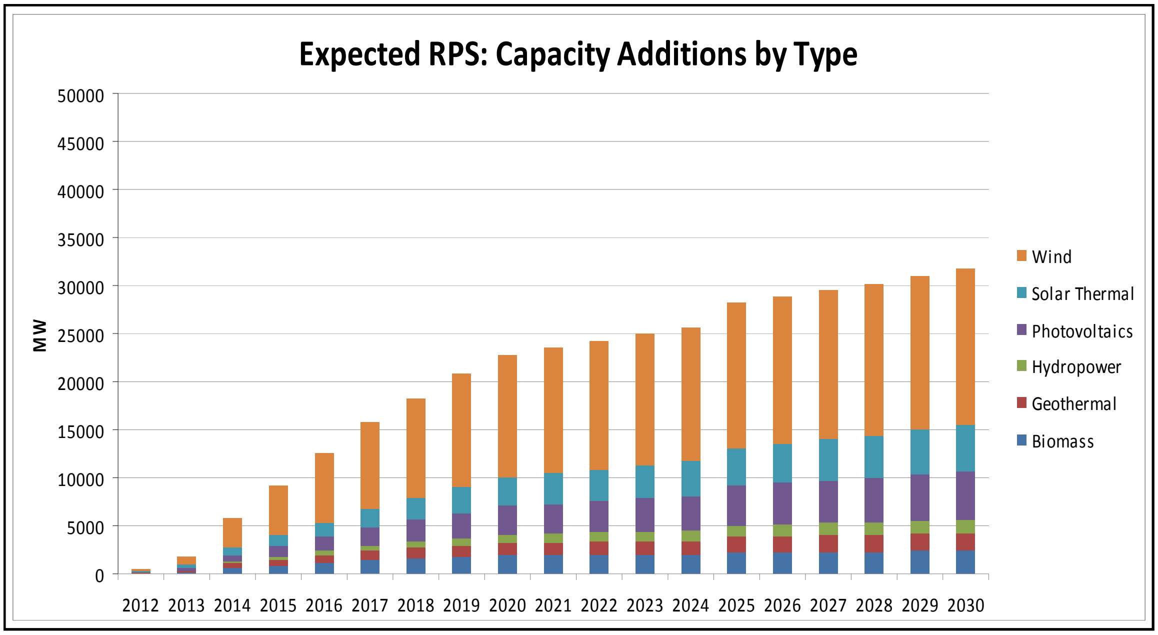
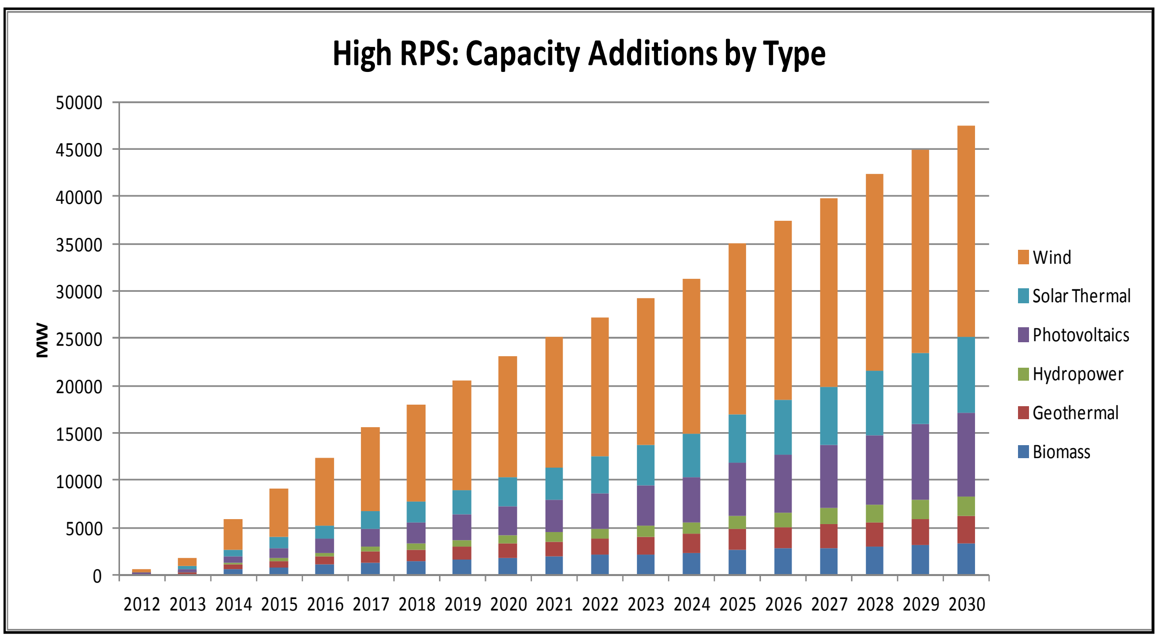


Figure 2-5: High WECC RPS Resource Build



2.4.5 Hydro Variability

BPA and the region can experience a wide variability in monthly and annual hydroelectric generation due to the high variability in streamflows experienced in the Columbia River Basin. One hydro regulation study was used for all the scenarios. To model the variability in hydro generation, BPA used 80 historical water years, 1929-2008.

2.5 AURORAxmp Overview and Results

BPA used AURORAxmp to forecast Mid-Columbia (Mid-C) electricity prices using the variables that resulted from the assumptions made in the expected case and the four scenarios. AURORAxmp produced separate price forecasts for each of the scenarios. Each price forecast comprises monthly HLH and LLH Mid-C electricity prices from October 2013 through September 2021. Flat prices shown in Figure 2-6 represent the average price for all hours by month or year. In the year 2013, several factors are behind the noticeably higher prices. Most importantly, CO_2 pricing is assumed to begin in scenarios where this is applicable, and natural gas prices in the high case increase significantly.

Figure 2-6: Mid-C Price Forecasts under the Different Scenario Assumptions

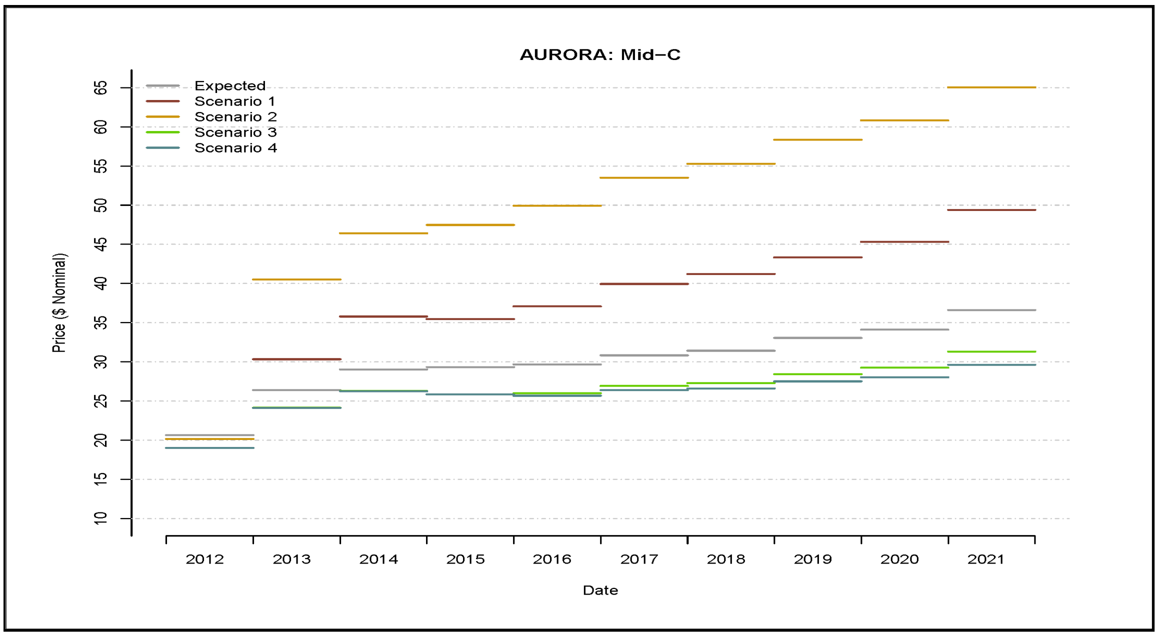


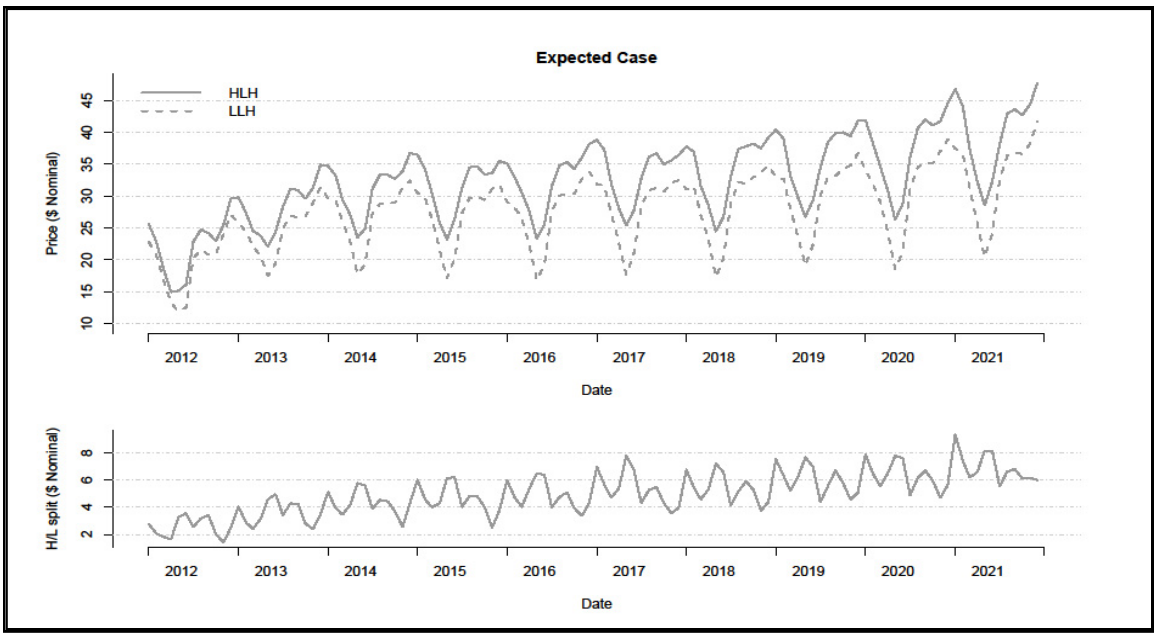
Table 2-2: Annual Average Flat Mid-C Prices

Date	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Scenario 1	20.16	30.34	35.79	35.46	37.08	39.94	41.21	43.32	45.32	49.39
Scenario 2	20.15	40.50	46.51	47.54	50.12	53.71	55.53	58.55	61.03	65.27
Scenario 3	19.03	24.14	26.28	25.87	26.00	26.93	27.29	28.44	29.25	31.31
Scenario 4	19.02	24.12	26.26	25.86	25.68	26.40	26.60	27.52	28.04	29.63
Expected Case	20.66	26.41	29.04	29.34	29.68	30.83	31.42	33.06	34.11	36.62

Each scenario results in changes to the price forecast that are consistent with the corresponding assumptions. Scenario 1, which incorporates high loads and a high natural gas forecast, results in substantially higher prices than the expected case. The rate of change in prices is mitigated beginning in 2014 by the addition of new resources, particularly renewable resources outside the Pacific Northwest. The addition of a CO_2 cost in Scenario 2 results in markedly higher prices immediately. Because this policy applies to all carbon-emitting resources, it results in a more obvious effect on prices than a carbon policy in a single region.

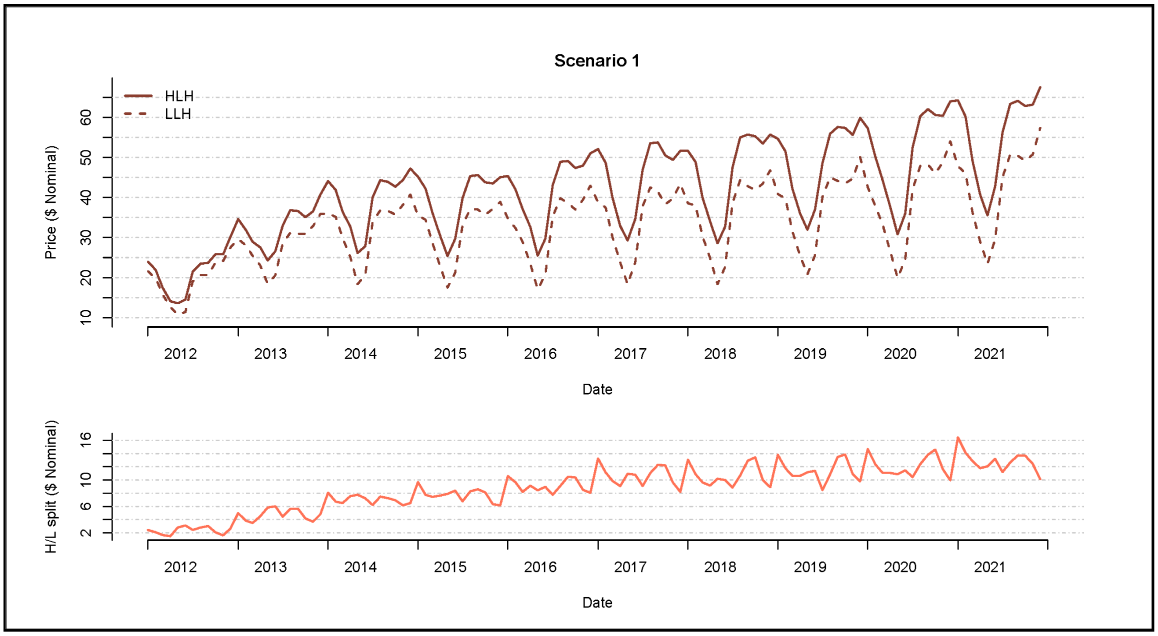
Low loads and low natural gas prices contribute to reduced price forecasts in Scenarios 3 and 4. The addition of an aggressive renewable resource build further depresses prices in Scenario 4 because supply tends to exceed demand for electricity. Generally speaking, the resulting prices are reasonable with respect to the assumptions in each scenario. However, it is worth noting that there seems to be limited downside risk to prices, even though the inputs in the various scenarios are symmetrical relative to the expected case. That is, the high and low load scenarios both represent 10 percent departures relative to the expected case. Upside price risk is substantially more evident, as can be seen in Figure 2-6. This is expected given the properties of risk model distributions when input variables take on larger values. The risk models introduce variability as proportional relative to the forecast. Higher forecast values result in higher standard deviations of output distributions, which exert upward pressure on the average of the distribution of prices.

Figure 2-7: Monthly Price Forecast – Expected Case



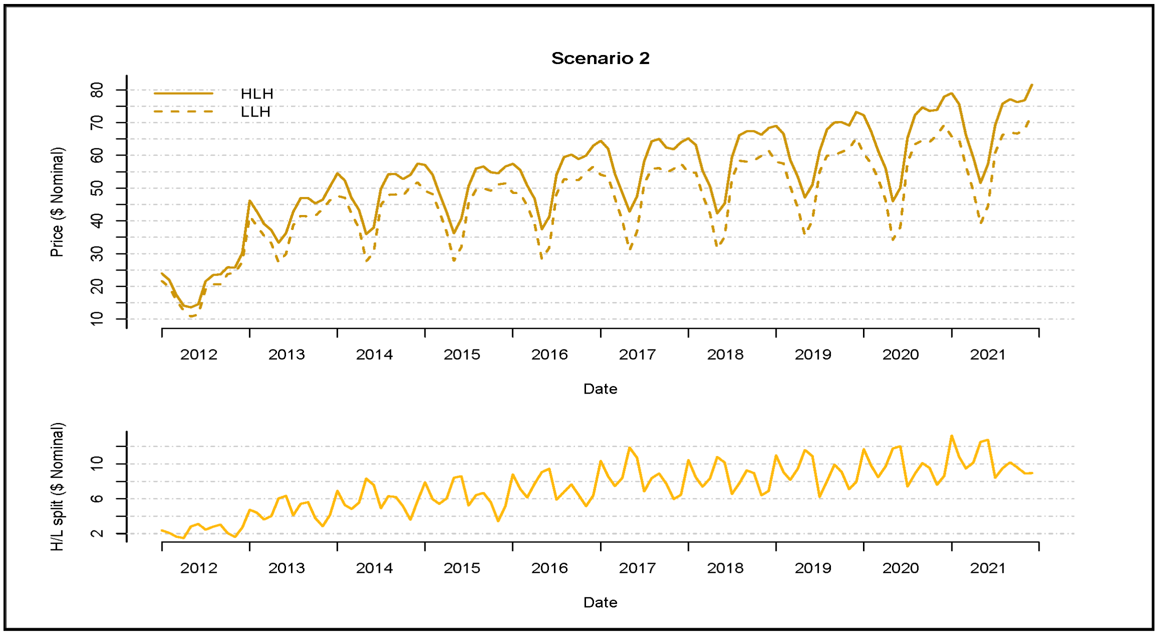
Figures 2-8, 2-9, 2-10, and 2-11 present the monthly prices for each scenario. Relative to the expected case, Scenario 1 (Figure 2-8) has much larger HLH to LLH spreads. Because Scenario 1 assumes high load growth and high natural gas prices with no change in the resource base, prices are substantially higher. In addition, these conditions have a disproportionate impact on HLH prices because of the implied pressure on load-resource balance during those hours. LLH prices are affected also, though to a lesser extent.

Figure 2-8: Monthly Price Forecast – Scenario 1



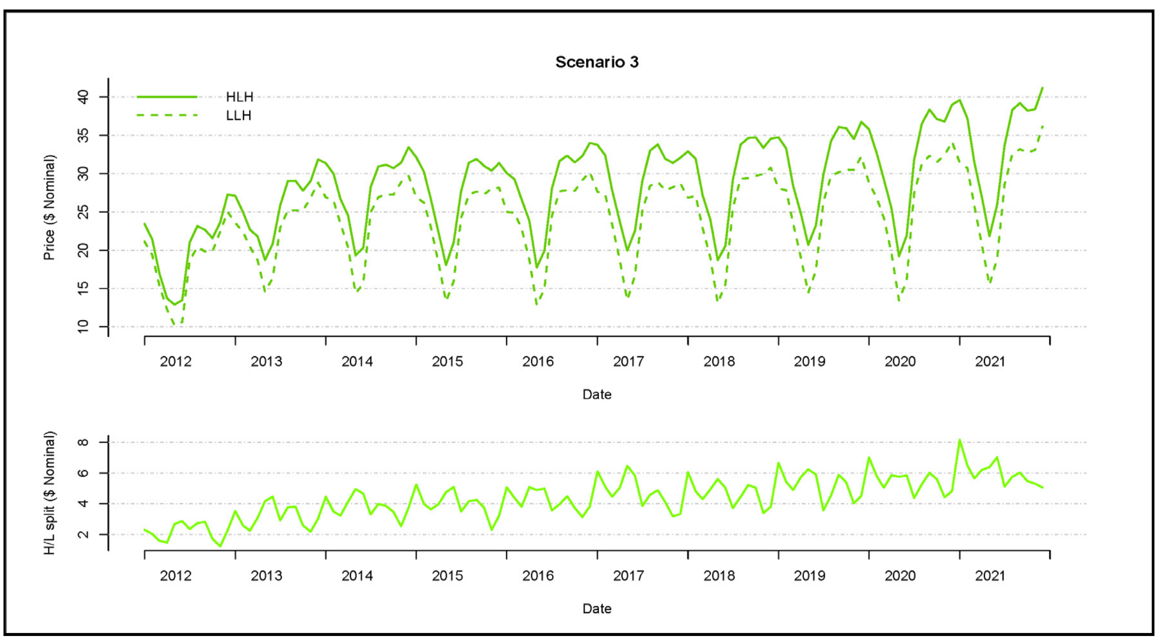
Scenario 2 (Figure 2-9), which assumes high load growth, high natural gas prices, a national CO_2 tax, and an aggressive build of renewable resources to comply with RPS, results in the highest price forecast of the four scenarios. In order of predominance, natural gas prices, the CO_2 price, and higher load growth contribute to producing the aggressive price trajectory. Largely because of the aggressive renewable resource build, however, the HLH to LLH price spread is less pronounced than in Scenario 1. Note that it is still substantially higher than in the expected case or Scenarios 3 and 4, however, which is largely a result of the marked changes in loads without a corresponding change in baseload resources.

Figure 2-9: Monthly Price Forecast – Scenario 2



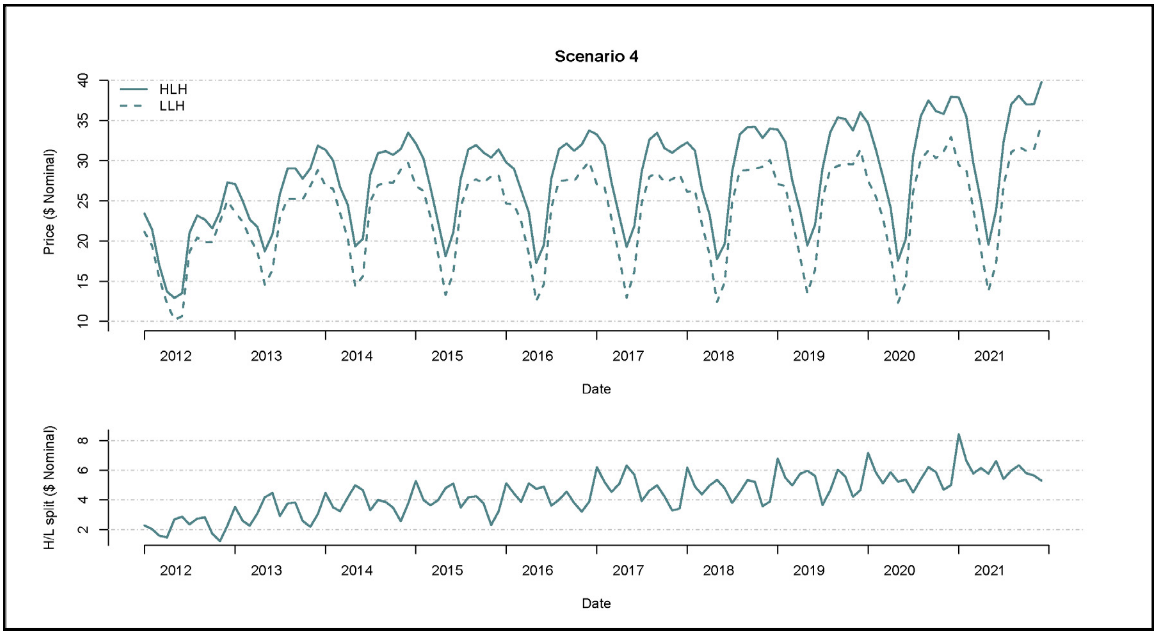
Scenario 3 (Figure 2-10), which assumes low load and low natural gas prices, shows expected prices that are slightly below those in the expected case. These circumstances do not imply fundamental changes in HLH to LLH price spreads. When conditions in AURORAxmp show a surplus of resources over loads, HLH to LLH price splits tend not to deviate substantially.

Figure 2-10: Monthly Price Forecast – Scenario 3



Scenario 4 (Figure 2-11), which assumes low load, low natural gas prices, and a higher than expected renewable resource build, generates prices that are only slightly lower than Scenario 3. This similarity in prices is largely because the majority of the change in renewable resource additions applies to areas beyond the Pacific Northwest. The largest changes are in the Desert Southwest and California and thus do not produce dramatic effects on Pacific Northwest energy prices.

Figure 2-11: Monthly Price Forecast – Scenario 4



2.6 Conclusions to the Market Assessment Analysis

BPA conducted the analysis in this chapter to quantify the potential impacts of a number of market uncertainties currently facing BPA and other utilities. The results of this analysis are used throughout the rest of the document and specifically in Chapters 4 and 5.

Chapter 3. 2012 Needs Assessment

The Needs Assessment measures the expected generation capability of the existing Federal system resources to meet projected load obligations under a range of conditions and timeframes. The 2012 Needs Assessment examines the potential needs associated with FY 2016 and FY 2021. This chapter has been excerpted from the 2012 White Book; please see the 2012 White Book for detail not included here.

3.1 Federal System Needs Assessment Assumptions

BPA's existing resource capability is forecast using two BPA models: Hydrosystem Simulator (HYDSIM) for monthly, seasonal, and annual energy, and Hourly Operating and Scheduling Simulator (HOSS) for hourly energy and capacity. The models assess the resource capability to meet loads under expected conditions and extreme temperature events, over a range of possible water conditions.

The HYDSIM study used for the 2012 Needs Assessment is the same study used for the 2012 White Book and the BP-14 initial proposal. As part of the 2012 Needs Assessment, BPA has made specific changes to forecasts and certain model assumptions, which are detailed below, including using stochastic load variability to simulate load uncertainty and stochastic unit performance for CGS to simulate unplanned outages. This assessment does not model any internal or regional transmission constraints that may limit the ability to match system generation to load.

Three load obligation scenarios were developed and analyzed for study years FY 2016 and FY 2021.[3] These scenarios were produced by BPA's Agency Load Forecast (ALF) system. The low and high scenarios were constructed by applying a growth percentage to the aggregate load obligation forecast in the expected case to simulate the potential range of uncertainty of the overall load obligation forecast. It does not identify changes to specific categories of load (*e.g.,* DSIs, Tier 2, New Large Single Loads).

ALF's load obligation forecast methodology automatically includes projections of programmatic conservation savings that continue at the level established under current BPA conservation programs. For the 2012 Needs Assessment scenarios, the historical estimate of embedded conservation savings is approximately 56 aMW throughout the study period. An additional 4 aMW of annual incremental conservation is included in the forecast as new planned conservation. It does not include the incremental amount of conservation needed to meet the Council's Sixth Power Plan targets.

The load forecast methodology projects load growth for Load Following and Slice/Block customers. In September 2011, customers elected how they would serve their Above-High Water Mark load for the FY 2015–2019 period. The resulting percentages from those elections were used to estimate the potential load obligations in the expected scenario that BPA would be serving in the outyears. There is additional uncertainty to the load obligations across all three scenarios from the impact of the various BPA Tier 2

[3] 2016 is a non-refueling year for CGS; 2021 is a refueling year for CGS.

products as well as how customers may change their elections for the FY 2020–2024 period.

For a more detailed description of the underlying hydro modeling and load obligation assumptions, please see Section 2 of the 2012 White Book.

3.2 Federal System Needs Assessment Load Scenarios

Figure 3-1 illustrates the expected case, high economy, and low economy load scenarios.

Expected Case: The expected load case is consistent with the 2012 White Book forecast, with an average annual growth rate of approximately 0.8 percent over the next 25 years.

This scenario includes a data warehouse load forecast based on generation plants that are highly likely to start production in the next 10 years. The expected Tier 2 load is approximately 128 aMW in FY 2016 and approximately 255 aMW in FY 2021. For the 18-hour capacity study only, the expected case is adjusted to include a three-day extreme weather event in each of February and August.

High Economy Scenario: The high economy case forecasts a robust increase in the economy due to increased spending (Federal and consumer). The expected average annual growth rate for 25 years from 2012 is approximately 2.4 percent.

This scenario anticipates higher load growth that could be caused by a number of factors such as additional population in-migration to the region to meet employment needs; additional Federal spending on military facilities and growth at local Naval facilities; clean-up activity at DOE-Richland; and increased aluminum production in the region. The forecast of data warehouses is aggressive but still could occur in the next ten years. The Tier 2 load obligation could be as high as 550 aMW in FY 2021.[4]

Low Economy Scenario: The low economy forecast includes a double-dip recession due to current regional, national, and international economic conditions, including the potential impacts of Federal government funding sequestration. This economic condition would be followed by slow employment growth in the region. The expected average annual load growth rate for 25 years from 2012, in the low economy scenario, is approximately 0.1 percent.

This scenario anticipates lower load growth that could be caused by a number of factors such as reduced growth at local Naval facilities because of reduced Federal spending on military facilities or postponed funding of clean-up activity at DOE-Richland. It does not anticipate closures of specific industries or out-migration from the region. The data warehouse forecast includes only plants that are in service this year.

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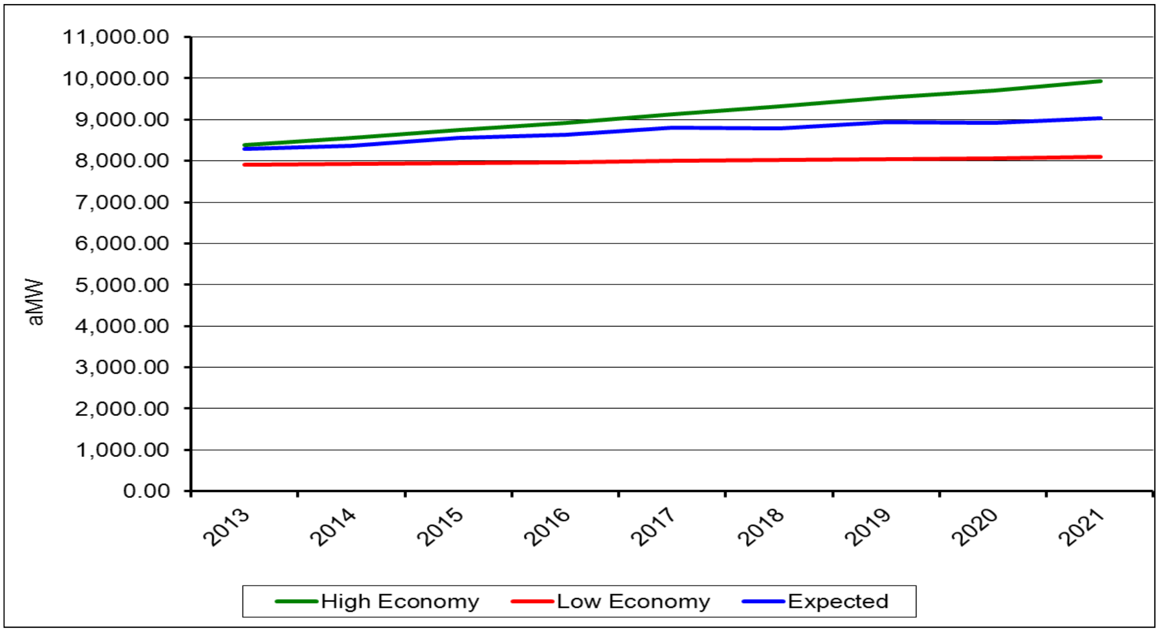
[4] This maximum amount assumes that all Regional Dialogue customers elect to have BPA serve their Above-High Water Mark load in FY 2021.

Figure 3-1: Federal System Needs Assessment Load Scenarios



Average Annual Growth Rates 2013-21: Low Economy 0.1%, Expected .8%, High Economy 2.4%

3.3 Major Changes from the 2010 Needs Assessment

Several updates to the key study assumptions were made in preparing the 2012 Needs Assessment. These include the following:

Change in study years: Study years FY 2013 and FY 2019 were examined in the 2010 Needs Assessment; study years FY 2016 and FY 2021 are examined for the 2012 Needs Assessment.

Hydro modeling updates: Seventy water years were modeled in the 2010 Needs Assessment; 80 water years (update to 2010 Level Modified Streamflows) were modeled in the 2012 Needs Assessment.

The 2010 Needs Assessment used the 2010 Assured Operating Plan (AOP), while the 2012 Needs Assessment uses the 2015 AOP. The 2015 AOP updates the forecast amount of monthly discharges from the Canadian reservoirs and results in higher August flows and lower September flows.

Balancing Reserves: In the 2010 Needs Assessment, BPA modeled balancing reserves based on the forecast requirement assuming 30-minute wind persistence and the 99.5 percent level of service. For the 2012 Needs Assessment, BPA modeled a FCRPS reserve limit of 900 MW incremental and 1,100 MW decremental and used the delta between those and the forecast requirement to calculate the need.

3.4 Federal System Needs Assessment Metrics

Similar to the 2010 Needs Assessment, BPA analyzed the following metrics for the 2012 Needs Assessment to assess the possible needs of the Federal system for meeting its obligations:

- **Annual energy deficit under critical water:** Annual average energy under 1937 critical water conditions, analyzed under the expected, high, and low load scenarios.

- **Seasonal/monthly heavy load hour (10th percentile by month):** Tenth-lowest percentile (P10) of surplus/deficit by month (which is roughly comparable to the fifth lowest surplus/deficit percentile (P5) by season) under the expected load scenario. Months are analyzed independently.

- **120-hour capacity (also known as superpeak):** Capacity inventory to meet load peaks day after day throughout the month (6 hours per day times 5 days per week times 4 weeks per month = 120 hours) under the expected load scenario.

- **18-hour capacity:** Capacity inventory to meet the 6 peak load hours for 3 consecutive days under the "expected" load case with 3-day extreme weather events assuming median water supply and hydro generation. Loads for the 3-day event are increased to reflect additional heating or cooling load, and wind generation is assumed to be zero. The maximum take of Canadian Entitlement is also assumed. Cold snap analysis includes a 10 percent reduction in streamflows to account for icing effects. Heat wave analysis includes a 10 percent reduction in CGS generating capability to account for heat impacts on generation.

- **Reserves for ancillary services:** The difference between what the FCRPS can supply and the forecast need.

3.5 Federal System Needs Assessment Results

As shown in Table 3-1, the 2012 Needs Assessment shows a wide range of potential annual needs under critical water conditions, depending on which load scenario is studied, as well as needs on a monthly and hourly basis under 10th percentile conditions. Energy and capacity results are rounded to the nearest 50 aMW. In general, the trends are similar to those discussed in the 2010 Needs Assessment, with modest deficits in annual energy and medium to significant energy deficits in certain winter and summer months. One notable change in this analysis is the reduction of the winter 18-hour capacity for both FY 2016 and FY 2021, discussed further below.

Table 3-1: Federal System Needs Assessment Summary of Results

(positive numbers indicate surplus)

Metric	FY 2016	FY 2021
Annual energy deficit (critical water)	Expected Case: -200 aMW High Economy: -550 aMW Low Economy: 250 aMW	Expected Case: -500 aMW High Economy: -1,450 aMW Low Economy: 50 aMW
Seasonal/monthly (10th percentile by month)	Significant HLH deficits in January, February, and September	Significant HLH deficits in October, January–February, second half of August, and September
Superpeak or 120-hour capacity (10th percentile by month)	HLH deficits greater than superpeak deficits except for second half of August	HLH deficits greater than superpeak deficits except for second half of August
18-hour capacity, positive (extreme weather scenarios)	Winter: 100 MW Summer: 250 MW	Winter: 0 MW Summer: 0 MW
Reserves for ancillary services	Inc: -390 MW Dec: -484 MW	Inc: -642 MW Dec: -817 MW

Looking at the results by month and by season shows a more serious deficit picture than the annual view. While the monthly metric is for HLH and superpeak, we also display the average and LLH deficits for additional information.

The assessment shows that BPA typically experiences substantial energy surpluses in May and energy deficits in other months, in years with poor water conditions or other reductions in generation. Water in reservoirs is BPA's form of energy storage, and FCRPS hydrosystem storage is limited to approximately 35 percent of an average year's runoff. Use of this storage is further constrained by operating requirements, such as flood control and BiOp requirements. As a result, the system has limited ability to store water from season to season, month to month, and even hour to hour.

Accordingly, as shown in Figures 3-2 and 3-3, BPA faces deficits for HLH energy in FY 2016 during the winter months, the second half of August, and September under the 10th percentile of surplus/deficit scenarios. This trend is seen again in the FY 2021 analysis. This implies that there is a 1 in 10 chance that BPA will need to acquire additional energy during the heavy load hours—the 16 highest load hours each day (except Sundays)—during the winter, and additional energy over the remaining hours. During the summer, demand is not quite as high as in the winter, but the water supply is considerably more limited. Furthermore, the LLH deficits for FY 2016 and FY 2021 are significant in the winter and summer months. This suggests that there is not enough water in the system to generate sufficient energy to meet load obligations for the majority of the year.

Figure 3-2: Federal System Needs Assessment FY 2016 10th Percentile Monthly Energy Deficits

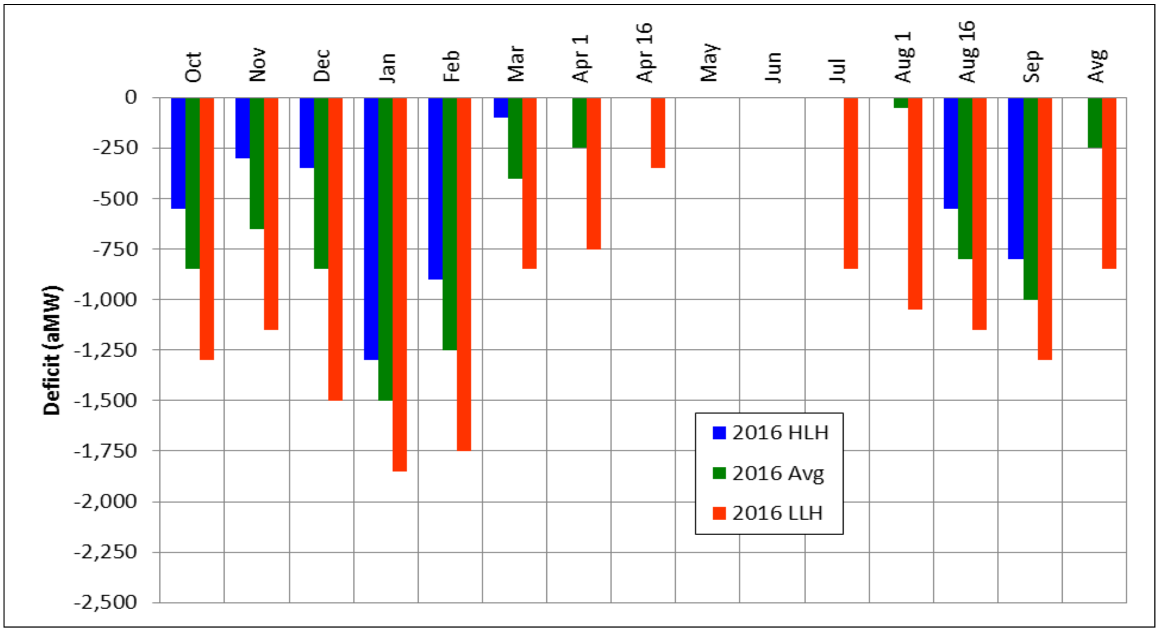
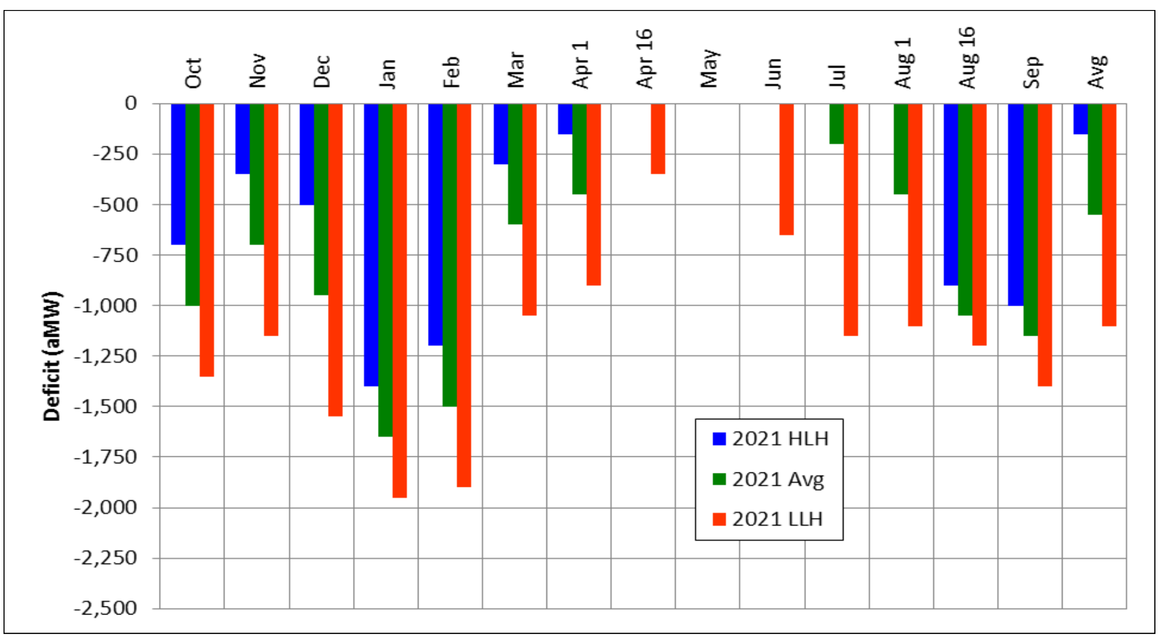


Figure 3-3: Federal System Needs Assessment FY 2021 10th Percentile Monthly Energy Deficits



Tables 3-2 and 3-3 illustrate the 120-hour superpeak analysis, which shows that the deficit for superpeak hours is less than the deficit for heavy load hours for both FY 2016 and FY 2021 except for the second half of August. This result indicates that there is enough flexibility for the model to shape generation into the superpeak hours except in the second half of August.

Table 3-2: Federal System Needs Assessment FY 2016 10th Percentile Monthly Surplus/Deficits

	Spk	HLH	Avg	LLH
Oct	-400	-550	-850	-1,300
Nov	50	-300	-650	-1,150
Dec	-50	-350	-850	-1,500
Jan	-800	-1,300	-1,500	-1,850
Feb	-700	-900	-1,250	-1,750
Mar	700	-100	-400	-850
Apr 1	250	100	-250	-750
Apr 16	750	750	300	-350
May	3,650	3,150	2,400	1,500
Jun	2,550	1,750	1,100	300
Jul	950	750	100	-850
Aug 1	650	650	-50	-1,050
Aug 16	-900	-550	-800	-1,150
Sep	-750	-800	-1,000	-1,300
Avg	450	150	-250	-850

Table 3-3: Federal System Needs Assessment FY 2021 10th Percentile Monthly Surplus/Deficits

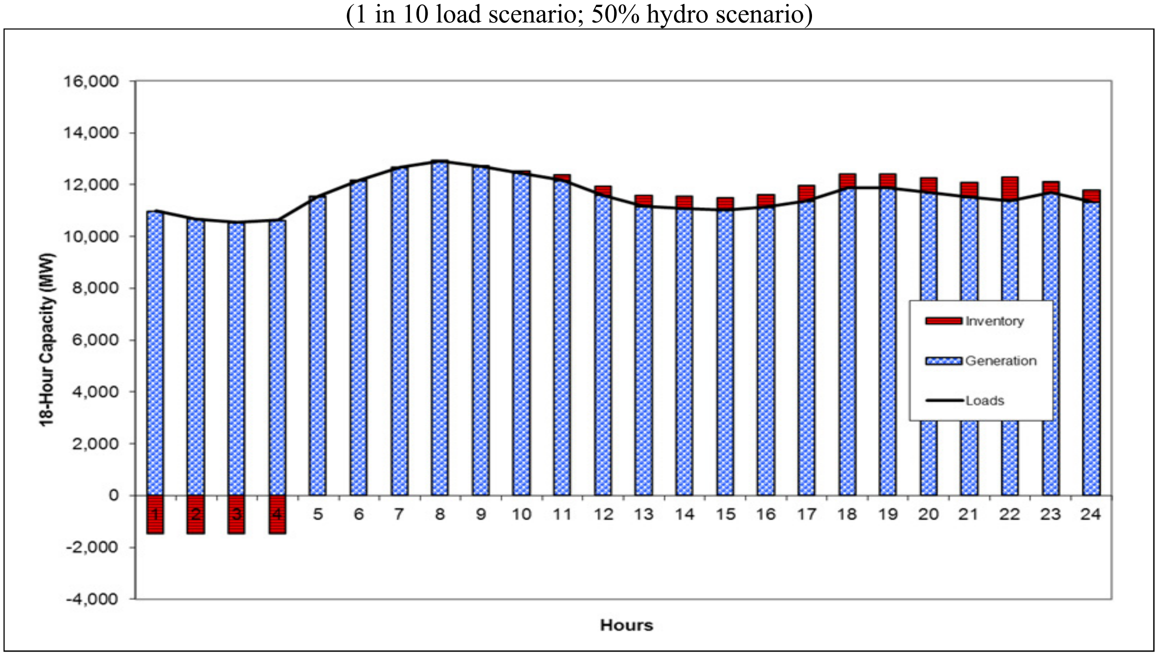
	Spk	HLH	Avg	LLH
Oct	-600	-700	-1,000	-1,350
Nov	-50	-350	-700	-1,150
Dec	-250	-500	-950	-1,550
Jan	-1,000	-1,400	-1,650	-1,950
Feb	-950	-1,200	-1,500	-1,900
Mar	450	-300	-600	-1,050
Apr 1	0	-150	-450	-900
Apr 16	650	700	250	-350
May	3,000	2,500	1,850	950
Jun	1,300	700	150	-650
Jul	550	500	-200	-1,150
Aug 1	0	50	-450	-1,100
Aug 16	-1,250	-900	-1,050	-1,200
Sep	-850	-1,000	-1,150	-1,400
Avg	100	-150	-550	-1,100

The energy metrics described in section 3.4 measure the capability of the Federal system during expected conditions. Under an extreme weather event, the hydro system could flex as much as possible to handle the additional loads from a cold snap or heat wave event, but only for a limited amount of time. The water used to meet load demands during the extreme event may be taken out of the rest of the month (or perhaps subsequent months). For example, meeting peak loads in a February cold snap reduces BPA energy for the rest of February by an estimated 425 aMW (sliced). For an August heat wave, the water needed to meet peak loads for a three-day event reduces the energy available for the rest of the month by an estimated 300 aMW (sliced).

The 18-hour capacity metric shows BPA just adequate to meet daily peak power needs during a three-day extreme cold snap in February or extreme heat wave in August. As seen in Figures 3-4, 3-5, 3-6, and 3-7, the system has minimal to zero surplus 18-hour capacity during a cold snap or heat wave in either FY 2016 or FY 2021. The reduction in the winter capacity from the 2010 Needs Assessment is significant[5] and largely results from the differences in the extreme weather load forecast, expiration of winter purchases, and changes in winter FCRPS generation forecasts from HYDSIM. A major input to the 2010 Needs Assessment load forecast was calculated incorrectly, and its correction is the largest driver of the three drivers mentioned. Due to changes in BPA's load forecasting database, systems, and procedures, BPA is unable to determine the exact causes for the error in the 2010 Needs Assessment load forecast. From the data available from the last analysis, it appears that the 2010 Needs Assessment included an incorrect (low) Slice Right to Power forecast, which resulted in a higher 18-hour capacity surplus. The 2012 Needs Assessment corrects that error, and combined with the other updates, shows a more realistic picture of the winter capacity amounts. However, changes to load from either marketing or load uncertainty could result in either higher or lower 18-hour capacity amounts.

Figure 3-4: Federal System Needs Assessment February 2016 Extreme Weather 18-Hour Capacity Surplus/Deficits

(1 in 10 load scenario; 50% hydro scenario)



[5] In the 2010 Needs Assessment, the winter 18-hour capacity amounts for FY 2013 and 2019 were 1,600 MW and 1,050 MW, respectively.

Figure 3-5: Federal System Needs Assessment Second Half of August 2016 Extreme Weather 18-Hour Capacity Surplus/Deficits

(1 in 10 load scenario; 50% hydro scenario)

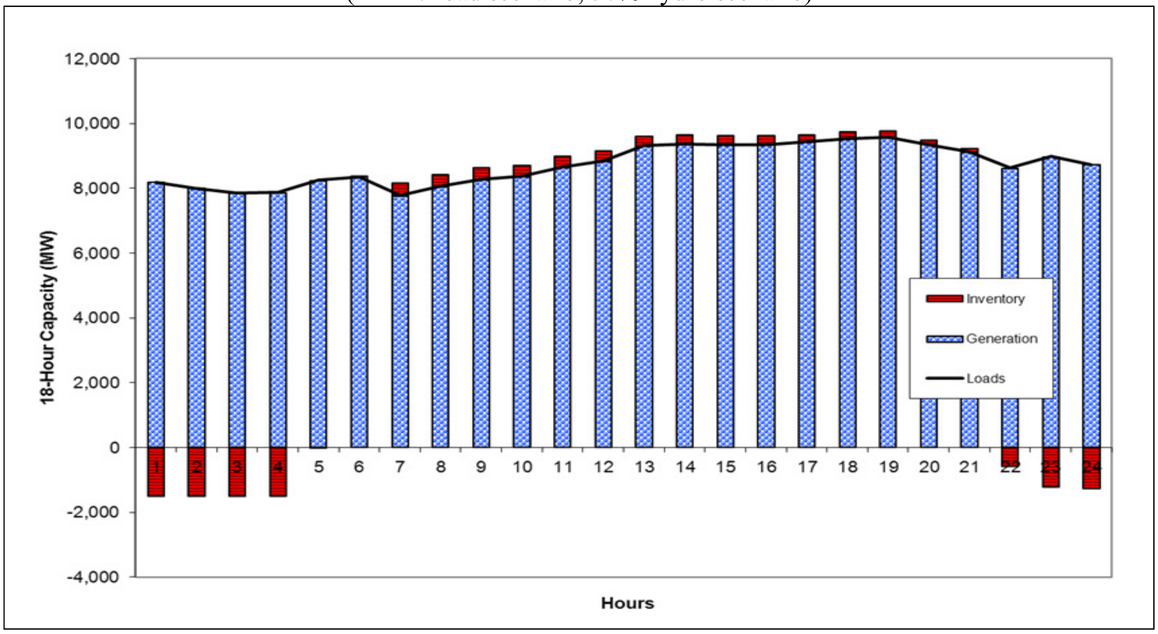


Figure 3-6: Federal System Needs Assessment February 2021 Extreme Weather 18-Hour Capacity Surplus/Deficits

(1 in 10 load scenario; 50% hydro scenario)

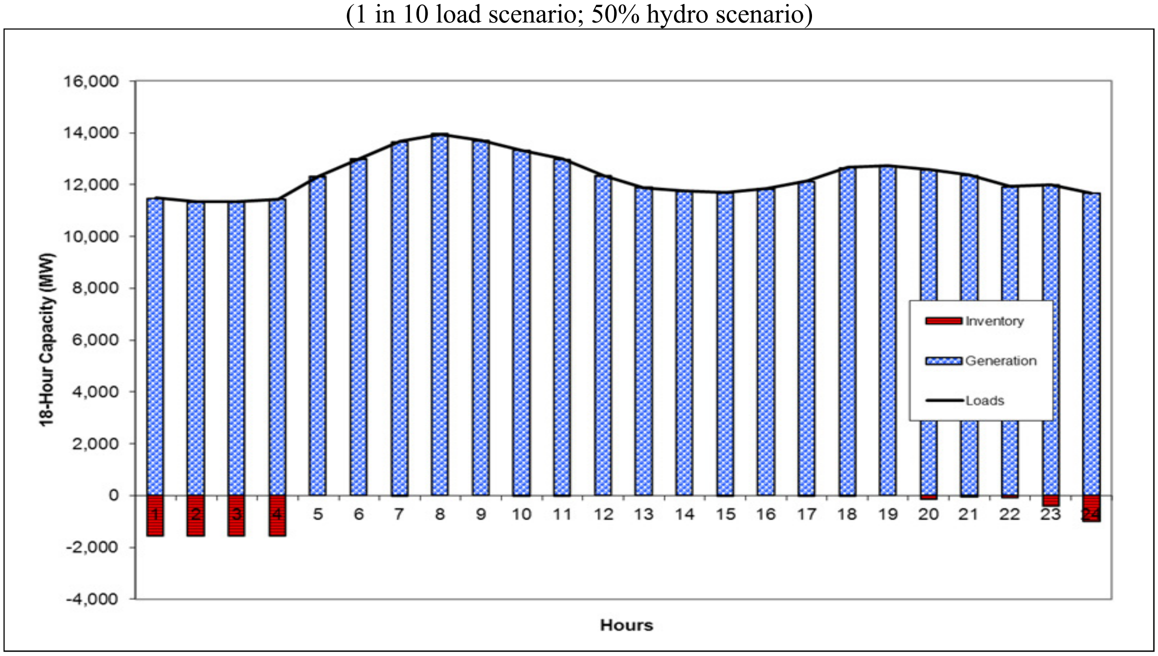
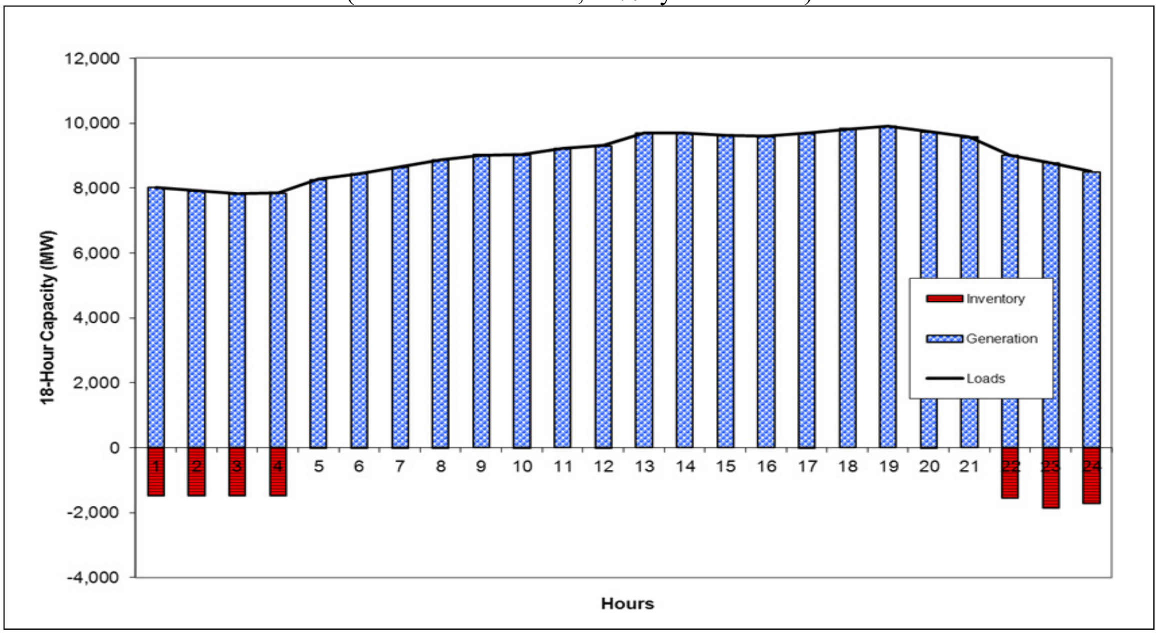


Figure 3-7: Federal System Needs Assessment Second Half of August 2021 Extreme Weather 18-Hour Capacity Surplus/Deficits

(1 in 10 load scenario; 50% hydro scenario)



Currently the FCRPS can supply up to 900 MW of incremental and 1,100 MW of decremental balancing reserves. The ancillary reserves analysis compared the forecast of balancing reserves required for the end of FY 2016 and end of FY 2019 (as the proxy for FY 2021), to the FCRPS established limits. The forecast for both study years shows that the required balancing reserves exceed the limit of what the FCRPS can supply.

3.6 Federal System Needs Assessment Conclusions and Next Steps

The analysis shows that under a variety of conditions and timeframes, BPA could need to supplement the existing Federal system generation to meet existing and projected obligations in the time period. These conclusions reflect additional limitations on the projected capability of the FCRPS to meet BPA's load obligations since the 2010 Needs Assessment analysis was performed. Specifically, updates to the hydro modeling assumptions have, in general, decreased the expected annual and winter FCRPS forecast generation. Hydro modeling updates included incorporating the 2010 Level Modified Streamflows, changing Canadian project operations, and limiting Grand Coulee's draft during winter operations to better reflect likely in-season management decisions. This updated analysis projects more significant deficits in the January-February timeframe, some improvement to the second half of August, and increased deficits in September.

Under the expected case, modest annual energy deficits are projected under critical water. However, in the high economy and low economy load scenarios, there is a wide range of uncertainty in the load obligations forecast, and the deficits could be erased or become significantly higher. There are also significant deficits (both heavy load hour and all hours) in several of the 10th percentile months, notably January and February (winter) and the second half of August and September (summer). These deficits would be larger if the FCRPS were to lose any current generating capability. For example, the 2012 Needs Assessment assumes 2008 BiOp hydro operation requirements, which, based on an average of historical fish migration at the Snake River dams, typically ends juvenile bypass spill by mid-August. If spill were required through the end of August, the additional spill would correspond to a loss of about 400 aMW of generating capability in the second half of August under all water conditions.

Under the extreme weather scenario, BPA is minimally surplus to no longer capacity surplus in either the winter or summer. The winter capacity numbers changed significantly from the 2010 Needs Assessment, largely as a result of the extreme weather load forecast differences, the expiration of winter purchases, and changes in FCRPS generation forecasts,. This capacity metric can be similarly affected by variations in the load and generating capability uncertainties.

The Federal system resources are insufficient to meet the forecast 99.5 percent level of service for balancing reserve requirements in FY 2016 and FY 2019 (proxy for FY 2021). These deficits could increase if BPA adopts higher levels of service. There are many efforts underway to address this issue, including the BP-14 initial proposal.

BPA will continue to evaluate and update this analysis as part of the next formal Needs Assessment, scheduled to be completed as part of the 2014 White Book process.

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Chapter 4. Resource Assessment

4.1 Introduction

This chapter discusses the criteria BPA used for evaluating the alternative options to meet its resource needs. The chapter then presents the merits of the options relative to the criteria.

4.2 Resource Program Evaluation Criteria

As discussed in Chapter 1, BPA is not conducting a full Resource Program in 2013. As such, BPA is using the same evaluation criteria it used in the 2010 Resource Program. At the time of the next full Resource Program, BPA will reassess and update the evaluation criteria as appropriate. Chapter 5 of the 2010 Resource Program presents the full evaluation criteria; an abbreviated version appears below.

4.2.1 Northwest Power Act Resource Priorities

The Northwest Power Act of 1980 (section 4(e)) provides that the Council's Power Plan give priority to the following resources the Council determines to be cost-effective:

1. Conservation
2. Renewable resources
3. Generating resources using waste heat or of high fuel-conversion efficiency
4. All other resources

The Act directs BPA, in acquiring resources, to act consistent with the Council's Plan.

4.2.2 BPA Strategy

BPA chose resources for consideration in the Resource Program by considering how each potential resource best meets BPA's statutory requirements and BPA's commitment to providing Regional Accountability, System Reliability, Environmental Stewardship, and Low Rates, as explained below.

Regional accountability:

- Consistency with the Council's Power Plan.
- Meet targets for customer, constituent, and tribal satisfaction.

System reliability, based on the following metrics:

- **Annual energy deficit under critical water:** Annual average energy under 1937 critical water conditions, analyzed under the expected, high, and low load scenarios.

- **Seasonal/monthly heavy load hour (10th percentile by month):** Tenth-lowest percentile (P10) of surplus/deficit by month (which is roughly comparable to the fifth lowest surplus/deficit percentile (P5) by season) under the expected load scenario. Months are analyzed independently.

- **120-hour capacity (also known as superpeak):** Capacity inventory to meet load peaks day after day throughout the month (6 hours per day times 5 days per week times 4 weeks per month = 120 hours) under the expected load scenario.

- **18-hour capacity:** Capacity inventory to meet the 6 peak load hours for 3 consecutive days under the "expected" load case with 3-day extreme weather events assuming median water supply and hydro generation. Loads for the 3-day event are increased to reflect additional heating or cooling load, and wind generation is assumed to be zero. The maximum take of Canadian Entitlement is also assumed. Cold snap analysis includes a 10 percent reduction in streamflows to account for icing effects. Heat wave analysis includes a 10 percent reduction in CGS generating capability to account for heat impacts on generation.

- **Reserves for ancillary services:** The difference between what the FCRPS can supply and the forecast need.

Environmental stewardship, based on the following indicators:

- Accomplish conservation targets

- Enable renewable resource integration.

- Limit growth of greenhouse gas emissions.

- Other environmental impacts of resource choices.

Low Power and Transmission rates:

- Resource cost-effectiveness, including volatility of costs and how costs could vary across future scenarios.

4.3 Resources Considered

This section focuses on resource options that could meet the system reliability metrics described above. The resources described here are not an all-inclusive list of possible resources. The 2013 Resource Program does not consider any types of resources different from those in the 2010 Resource Program. BPA has reduced the list to those resources that are consistent with the Sixth Power Plan, resources BPA believes to be potentially economically viable during the study period, and resources that pass a high-level screening to meet BPA's needs. For the purpose of screening resources, BPA considers various costs (fixed, variable, and levelized), characteristics, risks, and environmental factors. For this analysis, the primary generator characteristics include their ability to provide energy, capacity, and flexibility services, as well as heat rates and emissions. Following are some definitions of these considerations.

Heat Rate. A heat rate is a measure of the efficiency of a plant to convert fuel into electricity. The lower the heat rate, the more efficient a plant is at producing power. Heat rates are a crucial factor in assessing the variable cost of a plant.

Fixed Costs. Fixed costs are those that must be recovered to pay for a resource whether it operates or not; they typically do not vary from year to year. These costs include plant capital costs, financing costs, and fixed operating and maintenance costs. Fixed costs also are referred to as capacity costs.

Variable Costs. Variable costs are associated with operating the plant to generate power. They typically vary from year to year depending on the amount and cost of the fuel used. Variable costs also are referred to as energy costs.

Levelized Costs. These are intended to include all of the costs (expressed in constant dollars per megawatthour) over the entire operating life of the plant, including the costs associated with building and operating a power plant. The primary purpose of estimating levelized costs is to facilitate a side-by-side comparison of resources with different capital, fuel, operational, and environmental costs.

Levelized cost figures for all of the thermal plants and wind projects were calculated using the Microfin spreadsheet model developed by BPA and the Council. As its main input, the model takes an assumption for power plant capital cost. Using other input parameters such as assumed capacity factor, discount and interest rates, and economic life, the model produces a levelized cost figure as its main output.

Capital cost figures for the thermal and wind plants in this study are identical to those used by the Council in its Sixth Power Plan. However, the 2013 Resource Program used a different natural gas price forecast and CO_2 price forecast from those in the Sixth Plan. All of the thermal plant costs were levelized using a 30-year measure life, a discount rate of 12 percent (consistent with the official BPA agency discount rate for Power Services), and BPA's long-term expected gas price forecast, as discussed in Chapter 2.

Environmental Considerations. All thermal generating plants produce emissions as a byproduct of the combustion process. Ratings for plant emissions are typically expressed in terms of total volume (tons or pounds) emitted or by volume per megawatt of energy produced. In recent years, more attention has been given specifically to plant emissions of CO_2, which is a greenhouse gas. Natural gas-fired plants emit 117.1 lbs of CO_2 per MMBtu of fuel. Coal, as a reference point, emits 212.7 lb of CO_2 per MMBtu of fuel.

Heat rates also play a role in the amount of CO_2 emitted, as a heat rate is a measure of the fuel efficiency of a power plant. For example, a combined-cycle plant with a heat rate of 6,900 Btu/kWh would produce 811 lb of carbon per one unit of electricity (MWh) (*i.e.,* 117.7*(6,900/1000)). A simple-cycle plant with an average heat rate of 9,400 Btu/kWh would produce 1,097 lb/MWh. A reciprocating engine with a heat rate of 8,900 would emit 1,036 lb/MWh.

Once emissions rates are known, a carbon price can then be applied to determine the incremental cost of production. Using the combined-cycle example that produces 811 lb, if a carbon price is assumed to be $20/metric ton, the incremental cost of production would be $7.38/MWh higher due to an emissions price (*i.e.,* 811/2200*20). This same math can be applied to the other thermal plants described above. The amount of carbon emitted and the associated price comprise only one aspect for environmental consideration. Other factors, such as water contamination, siting impacts on wetlands or protected species, NEPA mitigation issues, site rehabilitation after decommissioning, and spent fuel disposal, are also important considerations.

Baseload. Baseload resources provide energy at consistent and reliable levels. Baseload generating plants are usually larger in size than other types of generation and have relatively high capital costs. These plants are also more fuel-efficient, which translates into lower variable (energy) cost. Examples of baseload resources are nuclear, coal, hydroelectric, and combined-cycle natural gas.

Capacity (Peaking Generation). Capacity resources are brought on-line intermittently to meet peak demand for electricity (*e.g.,* during adverse weather conditions to meet peak demands or during unforeseen resource outages). Traditional peaking generation plants are generally smaller in size than other types of generation and have a lower capital cost. However, they are usually less efficient and more costly to operate due to higher variable costs. Examples are simple-cycle combustion turbines, reciprocating engines, and some storage technologies.

Flexibility. For purposes of the 2013 Resource Program, BPA is using the following preliminary definition of resource flexibility: Resource Flexibility is the capability of a power source to respond to bi-directional changes in load, variable generation, and system contingencies at intra-minute, intra-hour, and intra-day time intervals by ramping output within operational constraints.

Following are some constraints and contributing factors:

- Start Time (amount of time needed to synchronize to the grid)
- Efficient Control Range (minimum and maximum power limits)
- Ramp Rate (upward and downward across various time intervals)

- Efficient Cycling Frequency (minimum run time and off time)
- Fuel Scheduling and Availability (fuel deliveries vs. on-site storage; seasonal and diurnal availability constraints; competing fuel uses)
- Non-Power Constraints (emissions limits, discharge limits, draft limits)

Variable Energy Resources (VER). These generating resources produce electrical output that varies directly with the availability of fuel. They are usually powered by renewable fuels, with wind and solar plants being the two most common VERs. Variable energy resources cannot be dispatched to meet load, though output can usually be decreased as needed. Variable energy resources are considered to have no capacity value, and they usually require a grid operator to use balancing and other types of reserves to maintain grid stability when large amounts of VERs are installed.

The rest of this chapter consists of three sections. Section 4.4 describes non-thermal generation options BPA considered for the Resource Program. Section 4.5 describes thermal generation options BPA considered. Section 4.6 describes other options.

4.4 Non-Thermal Options

4.4.1 Conservation

As stated earlier, conservation is the highest-priority resource for BPA under the Northwest Power Act. Also, as detailed in section 4.4.1.3, conservation is the most cost-effective resource. The Council's Sixth Power Plan established a regional cost-effective conservation target for cost-effective and achievable savings. BPA, together with public power, is committed to ensuring achievement of the public power share (42 percent) of the Council's regional conservation targets in the Sixth Power Plan, and thus the current analysis is centered on those targets. The upcoming Seventh Power Plan will likely feature new conservation targets.

4.4.1.1 Sixth Power Plan Conservation Targets

BPA is committed to achieving the conservation targets from the Sixth Power Plan. Table 4-1 summarizes the Council's targets for the region as well as the public power share.

Table 4-1: Sixth Power Plan Annual Conservation Targets

Fiscal Year	2013	2014	2015	2016	2017	2018	2019	2020	2021
Council Targets - Annual Targets (aMW)	260	280	290	320	340	350	360	365	365
Public Power Share - Annual Targets (aMW)	109	118	122	134	143	147	151	153	153
Public Power Share – Cumulative (aMW)*	386	504	626	760	903	1,050	1,201	1354	1507

*Cumulative aMW start in 2010.

In the Sixth Power Plan Action Plan, page AP-2, the Council noted that conservation has an inherent level of uncertainty based on "the pace of anticipated economic recovery, power market conditions, carbon control requirements, technology evolution, the success or failure of acquisition mechanisms or strategies, progress on research and development and the adoption of codes and standards." Therefore, the Council recommends a range of conservation savings from 1,100 to 1,400 average megawatts for the timeframe of 2010-2014 (*i.e.,* between 92 percent and 117 percent of the Council's specified target). Table 4-2 applies this range to public power's share of the target for FY 2016 and FY 2021.

Table 4-2: Public Power's Share of Council Range of Cumulative Conservation Savings

Scenarios:	FY 2016	FY 2021
Low Conservation (1,100 for 2010-2014)	697 aMW	1,439 aMW
High Conservation (1,400 for 2010-2014)	887 aMW	1,831 aMW

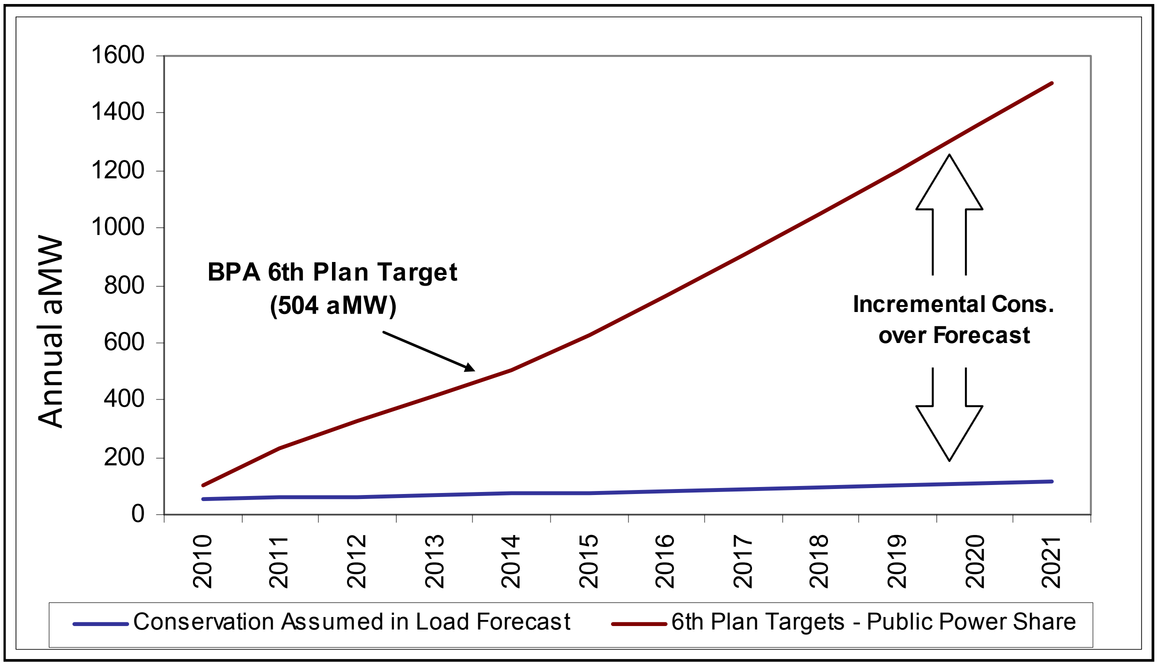
To analyze the impacts of conservation acquisition on loads in the 2013 Resource Program, the Council's hourly load shapes were used based on the distribution of sector savings in the Sixth Power Plan, although the shape of BPA's conservation achievements may differ based on programmatic achievements.

4.4.1.2 Conservation in the Load Forecast

In the Resource Program analysis, some of this potential conservation appears in the BPA Total Supply Obligations Forecast used in the Needs Assessment, and the balance is considered additional conservation to be achieved. The BPA Total Supply Obligations Forecast for the Resource Program assumes a current conservation amount of about 60 average megawatts (see section 3.1), which persists through FY 2021. Additional conservation to meet public power's share of the Council's Sixth Power Plan target is shown as an incremental resource available to meet needs.

Figure 4-1 reflects the cumulative annual conservation savings using the Council's targets in its Sixth Power Plan and the conservation assumed in the Needs Assessment load obligation forecast.

Figure 4-1: BPA Conservation Targets and Portion Subsumed within BPA Total Supply Obligations Forecast



Even though the Resource Program assumes that conservation exhibits slight hourly, daily, monthly, and yearly shapes, the service that conservation provides is widely considered to be baseload energy. By its nature, its capacity factor is high, and the energy savings provided tend to be continuous and constant.

4.4.1.3 Cost of Conservation

In its analysis BPA corroborated the Council's findings that conservation is the most cost-effective energy resource currently available to the region. BPA examined its customers' energy efficiency (EE) acquisitions for 2012 from capitalized and expensed programs and levelized the costs using the assumed 12-year average measure life for energy efficiency. At an estimated $15.89/MWh, conservation is significantly more cost-effective than other alternatives.

The levelized costs mentioned above vary slightly from those reported in the EE Action Plan[6] due to differences in savings and costs included in the calculations. The Resource Program uses both capital- and expense-related savings and dollars to calculate levelized cost, while the EE Action Plan uses only capitalized conservation savings and costs. The EE Action Plan focuses on the annual budgets and cost of savings acquisition and was not intended to represent a full cost of the resource. The EE Action Plan also uses a

[6] Bonneville Power Administration 2012 Update to the 2010-2014 Action Plan for Energy Efficiency, March 1, 2012: http://www.bpa.gov/Energy/N/pdf/BPA_Action_Plan_FINAL_20120301.pdf

slightly different discount rate in order to align with the levelized cost calculations used by the Council and other regional utilities for energy efficiency-related costs.

4.4.2 Hydropower

Investment opportunities in the existing Federal hydroelectric system (section 4.4.2.1) are likely the primary and most-effective means BPA has to extend the life of existing hydroelectric projects and to increase their efficiency, capacity, and energy production.

Investing in the John W. Keys Pumped Generating Station beyond the basic maintenance (section 4.4.2.2) could increase the amount of balancing reserves BPA could provide and could enhance the ability of the FCRPS to provide peaking capacity.

4.4.2.1 Improvements to Existing Federal Hydroelectric Projects

BPA partners with the U.S. Army Corps of Engineers and the Bureau of Reclamation to identify, prioritize, and complete hydropower improvements and capital equipment replacements at Pacific Northwest Federal dams. Between now and 2019, BPA plans to invest approximately $250 million per year in capital projects to:

- maintain and extend the life of existing Federal hydroelectric generating units
- enhance generation efficiency
- increase the capacity of some units

Most investments are made to maintain the reliability of power generation equipment by replacing old, degraded equipment at the 31 Federal plants. Less frequently, "opportunity investments" are made that improve generation efficiency, typically through new turbine runner design. Runner replacements for 18 units at Grand Coulee Dam have been completed, and replacements for runners on 16 units at Chief Joseph Dam were recently initiated. All told, the projects initiated to date will result in about 100 aMW of increased generation, worth around $50 million annually. An added benefit of higher-efficiency runners is the reduction of greenhouse gases that would otherwise be produced by a thermal generation alternative.

Capital investments are also frequently made to improve safety and provide environmental benefits, including enhanced fish passage.

4.4.2.2 John W. Keys Pumped Generating Station

The John W. Keys III Pump-Generating Plant pumps water vertically 280 feet from Franklin D. Roosevelt Lake to Banks Lake. This water is used to irrigate approximately 670,000 acres of farmland in the Columbia Basin Project. Congress authorized Grand Coulee Dam in 1935, with its primary purpose to provide water for irrigation. Six pumps with a total capacity of 300 megawatts were installed in 1951. In the 1960s, investigations revealed the potential for power generation at the Keys plant. Between

1973 and 1984, six pump-generators were installed with a total capacity of 314 megawatts.

Much of the equipment at the Keys plant is worn or obsolete. Over the years, several of the pumps have been refurbished by in-kind replacement of the pump impellers; some of the motor stators have been rewound; and minor enhancements have been made to the controls and protection systems. The pump-generators have not yet undergone similar refurbishment and still have the original pump-turbines and generator-motors, governors, and static exciters. Since the plant has not yet been called on for significant load balancing or to meet reserves, repairs and upgrades to the pump-generators have not been addressed with urgency. As a result, the pump-generating units have experienced extended unit outages over the past several years.

In order to maintain the irrigation reliability of the Keys facility and to stem any further deterioration of the pumping plant, BPA has approved $61.4 million to fund the power share of approximately $90 million in capital investment over the next nine years for continued refurbishment of pumping units 1-6. This project's progress is contingent upon the board of the Columbia Basin Project agreeing to fund its current 31.7 percent share of costs. That approval process is underway.

The need to refurbish or improve the six pump-generating units at the Keys plant for generation reliability or provision of balancing services is being evaluated and will be decided upon at a future date.

4.4.3 Demand Response

Demand response has emerged as a reliable, cost-effective tool on the national level, but due to a number of factors has not been adopted as readily in the Pacific Northwest. Over the last four years, BPA and regional utilities have conducted several demand response pilots to assess the technical feasibility and programmatic requirements of building demand response programs in the region.

Demand response can be part of the solution to increasing challenges in the Pacific Northwest, providing opportunities to reduce load and to provide energy storage to address unique variable generation and hydro system operations (*e.g.,* providing additional balancing reserves or increasing load during light load hours). Demand response opportunities include managing load for wind integration and enhancing the value and flexibility of the FCRPS, including BPA's transmission system.

There are many types of demand response programs in the nation, with a focus on reliability and economics. In particular, BPA is interested in demand response for:

- Reliability – as a peak capacity resource, or for ancillary services, particularly a portion of contingency requirements

- Flexibility – to meet a variety of needs in the Pacific Northwest (*e.g.,* this flexibility aspect can help manage the FCRPS to help meet fish requirements and FCRTS to avoid or defer transmission investment)

According to the February 2011 FERC staff report *Assessment of Demand Response and Advanced Metering,* the potential demand response resource contribution from all U.S. demand response programs is estimated to be more than 58,000 MW, or about 7.6 percent of U.S. peak demand. This is an increase of about 17,000 MW from the 2008 FERC survey. BPA conducted research to determine progress in other regions with regard to implementing demand response projects, including the California Independent System Operator, the New England Independent System Operator, the PJM Independent System Operator, and the Tennessee Valley Authority. Available demand response is an average of 5-10 percent of these entities' peak load. The organizations typically have a specific amount of guaranteed dispatchable (pre-arranged, contracted) load for use with meeting economic needs and an additional amount that is used only for emergency/ reliability situations.

All these entities have several methods or programs for acquiring and dispatching demand response. Some include third party suppliers ("aggregators") working directly with utilities and dispatching directly served industrial consumers. None of the entities focuses on only one method of dispatchable demand response. The entities use third-party aggregators extensively to build scale quickly and leverage existing tools and relationships.

BPA has finished four years of demand response field tests, pilots, modeling, and analysis. BPA tested a large number of technologies, including commercial and public building load control, residential and commercial space heating energy storage, water heating energy storage and load control, industrial process load control and energy storage, large farm water management system load control and storage, small scale battery energy storage, and load shifting using aquifer recharge opportunities.

BPA has learned that demand response is diverse, available in generally predictable and reliable quantities and time periods, available from many end uses, and variable in its cost. The next phase of BPA demand response development will identify and implement some larger-scale commercial demonstration projects. These projects will test the appropriate mechanisms to contract for demand response (working with utilities and any third parties) and investigate the availability and reliability of demand response to help address multiple regional requirements.

BPA is also launching several new demand response-related pilot projects as part of the FY 2013 Technology Innovation portfolio. These proof-of-concept research and development projects are focused on data centers, municipal wastewater treatment plants, and energy storage. The BPA Energy Efficiency group is also implementing several technology innovation projects, four of which involve the testing and modeling of the demand response potential of heat pump water heaters.

There is still a need to continue testing emerging and next-generation demand response technologies, communication protocols, and new uses for the growing amounts of "smart" data becoming available from new metering and communication systems. There is also a need to understand how to more effectively integrate demand response with Energy Efficiency measures and program implementation, as well as how to address possible regional and BPA capacity shortages with demand response measures.

BPA's national and regional benchmarking work shows a consistent range of deployed demand response costs of about $3.50 to $7.00 per kilowatt-month. Based on the demand response pilot outcomes and this benchmarking, BPA believes there is significant cost-competitive demand response available in the region.

4.4.4 Market Purchases

Since deregulation of the wholesale power industry in the mid-1990s, BPA, like many utilities, has relied primarily on wholesale market purchases to meet its additional power needs. Historically, BPA has relied on market purchases in two ways: (1) short-term market purchases and sales are used to manage within-year hydro generation variability and market price uncertainty; and (2) longer-term purchases are used to meet growing seasonal and annual electricity demand and to offset reductions in firm generating capability.

BPA's energy position is heavily influenced by impacts of climate and hydrological variability on hydro generation. This generation uncertainty means that BPA can be significantly long or short on energy in the spot markets (day-ahead and real-time). For any given month, on a forecast basis, BPA might have excess energy in an "average" hydro year but might have a large deficit position in a low hydro year. This is particularly true for summer and winter peak demand periods. These low hydro conditions have a low probability of occurrence, so acquiring firm energy resources on a long-term sustained basis to meet this potential exposure would mean that BPA would have large amounts of excess power to market. This approach could expose BPA to significant market price risk, given the potential for wholesale spot market energy price volatility.

BPA believes that continued reliance on short-term to mid-term (less than five-year) markets to manage up to 1,000 MW of HLH deficits in the winter and up to 500 MW of HLH deficits in the summer is sound business practice given the current wholesale power market in the Western Interconnection. These winter and summer market threshold guidelines are based on past operating practices and experience. BPA will continue to monitor and evaluate these guidelines in light of evolving wholesale market conditions.

BPA uses short-term market purchases to balance within-year variations in generation availability and customer loads. BPA also uses short-term to mid-term market-based purchases to meet sustained seasonal and annual needs. Historically, BPA has made short-term to mid-term market purchases up to five years in duration to provide energy for all or most of the year. A short-term to mid-term market purchase can be attractive to avoid the risks associated with long-term resource acquisitions based on the output of a specific generating unit. Short-term to mid-term market purchases can also be attractive to fill diurnal and seasonal needs.

4.4.5 Wind Generation

Wind power plants convert wind energy into electrical power by using specially designed turbines. Though several different designs exist, the vast majority of these plants feature tower-mounted horizontal-axis turbines. Nearly all wind turbines have an upwind rotor and three blades. In the U.S., most applications are based on land, though many offshore plants exist worldwide. Wind plants usually consist of many individual turbines, sometimes numbering in the hundreds for a single project, and often covering thousands of acres.

The Pacific Northwest, and in particular, the Columbia Basin, have proven to be successful sites for wind power development over the past decade. This success is due to a confluence of factors, including powerful and relatively consistent winds, readily available transmission capacity, RPS requirements in regional and neighboring states, and government tax credits for building and generating power from wind plants. According to the Council, nearly 7,500 MW (nameplate) of wind generating capacity has been built in the region as of 2012. Over 4,700 MW of that was developed within BPA's balancing authority area, mostly since 2006.

Wind plants are considered to be non-dispatchable or semi-dispatchable, in that they can produce energy only if the wind is blowing. In the case where wind is blowing and power generation is not needed, the turbines' power output can be reduced. Annual capacity factors can range from 20 to 50 percent; Columbia Basin plants average a 32 percent capacity factor, according to the Council's Sixth Power Plan.

BPA's calculated levelized cost for wind in the region, with no transmission costs, is $90.66/MWh. This figure uses the $2,100/kW capital cost assumption used in the Council's Sixth Power Plan. According to the Internal Revenue Service, the Production Tax Credit available to wind projects is $22/MWh. In addition, according to the U.S. Department of Energy, the value of Renewable Energy Credits is currently about $2/MWh. These incentives, when factored into the cost of the project, lower the overall levelized cost to $74.61/MWh.[7] However, in order for wind power to be considered on the same basis as the firm energy output from a thermal resource, the 2013 Resource Program assumes that the costs of BPA's Variable Energy Resource Balancing Service (VERBS) and Resource Support Service (RSS) products would need to be factored into the cost of the wind project (see Figure 4-5). The VERBS and RSS products are sold by BPA for firming energy within-hour (VERBS), and on a longer-term basis (RSS). Even

[7] Note: The Production Tax Credit ($22/MWh) and Renewable Energy Credit ($2/MWh) are modeled to decrease only the variable cost component of the levelized cost, not the fixed cost component. For this reason, they do not decrease the levelized cost of wind by $24/MWh. The Production Tax Credit was modeled to provide benefits for 10 years, not the full 20-year life of the wind project.

with these adjustments, it is still difficult to compare the costs of wind generation with those of a dispatchable resource.

Wind plants may provide energy at the assumed 32 percent annual capacity factor, but monthly, daily, and hourly output can vary dramatically. BPA also assumes that wind cannot provide capacity, as there is no guarantee of the availability of wind. Wind plants also cannot provide balancing reserves and typically increase the need for balancing reserves held by the grid operator to maintain grid stability. Due to BPA's specific needs for monthly HLH energy, capacity, and balancing reserves, wind plants were not chosen as a resource option in this study.

4.5 Thermal Generation

Natural gas-fired generators produce energy from the combustion of this fossil fuel. The typical measurement of fuel efficiency of this combustion is referred to as a heat rate and is measured in Btu/kWh. A plant with a lower heat rate tends to be more efficient at converting natural gas to electricity than a plant with a higher heat rate. Natural gas plants are available either in a turbine configuration or, less commonly, as a reciprocating engine. Though gas-fired projects are sometimes referred to as "thermal" plants, they are mechanically driven directly from the natural gas combustion process, and in most applications, heat is a byproduct from which little or no energy is harnessed.

Gas-fired generators have several advantages over other types of plants. They are suitable for a broad range of applications: baseload (energy), peaking (capacity), and most recently in the integration of variable generating resources (flexibility). Emissions from gas-fired plants are significantly lower than those from coal-burning facilities, and a recent boom in gas production from shale formations has brought natural gas prices down to levels that are competitive with coal on a dollars per million Btu basis. As a result, in recent years, the United States has seen utilities temporarily shutting down or retiring coal-fired facilities and replacing the generation with cheaper natural gas-fired power, a phenomenon known as coal-to-gas switching.

Nearly 16 percent of the Northwest's generating capacity, or about 9,600 MW, is gas-fired. Three major types of natural gas-fired plants will be covered in this section: simple-cycle combustion turbines, combined-cycle combustion turbines, and reciprocating engines.

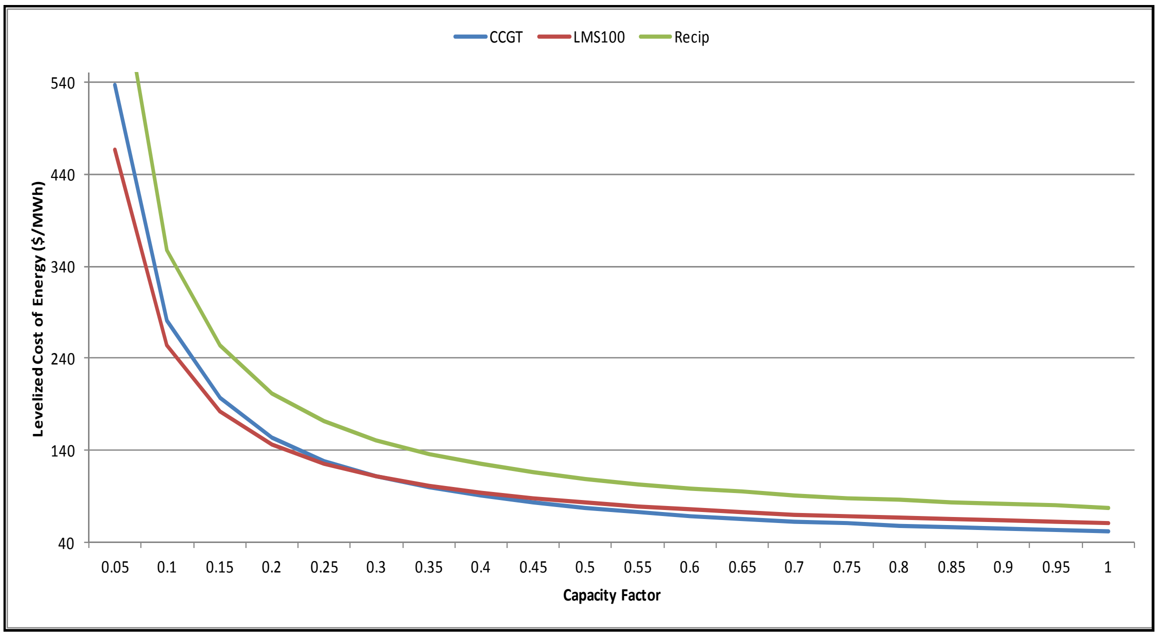
4.5.1 Simple-Cycle Natural Gas-Fired Combustion Turbine

4.5.1.1 Overview and Characteristics

Simple-cycle combustion turbines employ combustion turbines, derived from similar units commonly used on commercial airliners to drive an electric generator. Models include frame, aero-derivative, and intercooled designs. Though usually deployed in configurations of one or two turbines, four-unit and even eight-unit plants exist. Due to their combination of relatively high heat rates, high variable costs, and low capital costs, simple-cycle plants have historically been employed in peaking capacity applications. However, recently, utilities and merchants have also taken advantage of the flexibility and quick ramping capability of single-cycle turbines in balancing the energy produced from variable-generation renewable resources.

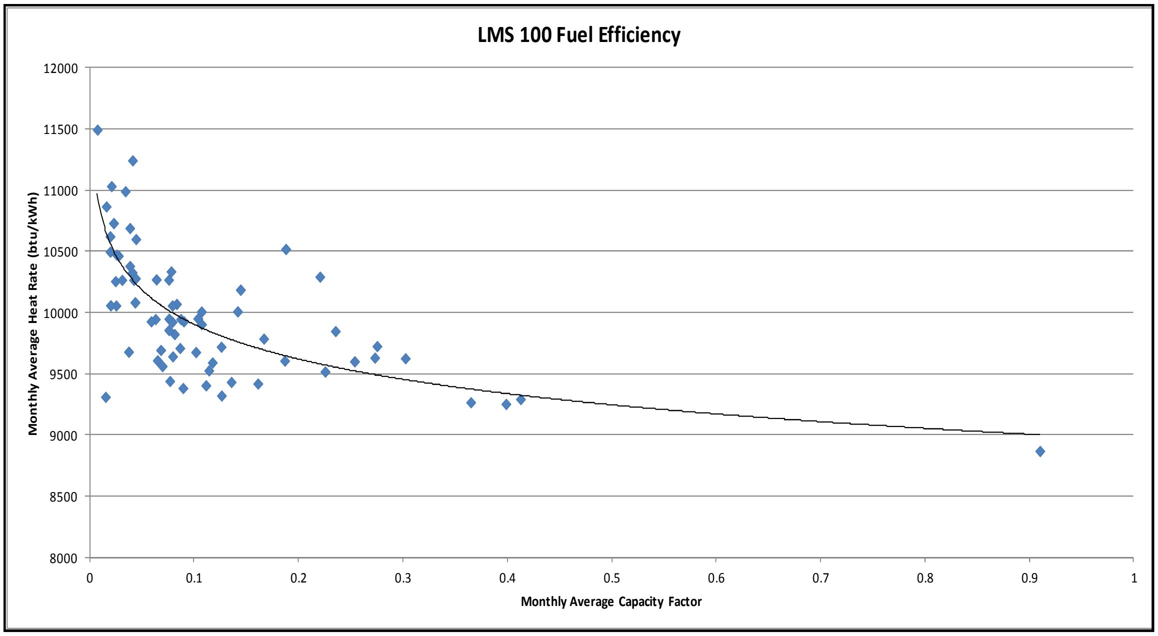
Figure 4-2 shows that the levelized cost of a combustion turbine varies with the number of megawatthours that the plant produces over its lifetime. However, due to their low capital cost, simple cycle plants tend to be cheaper than alternative natural gas-fired plants (combined-cycle or reciprocating engine) on a levelized cost basis if they are run below about a 30 percent capacity factor. Above the 30 percent capacity factor threshold, the relatively high heat rate (low efficiency) of the simple-cycle plant makes it less cost-effective than a combined-cycle combustion turbine plant. Data from the EIA, reflected in Figure 4-3, indicate that plant operators generally deploy simple-cycle (LMS 100) plants at less than a 30 percent capacity factor.

Figure 4-2: Screening Curves



Though the designs of most simple-cycle gas plants are fairly similar, the slight differences in their operational and cost characteristics allow a plant owner to tailor its purchase to the specific need at hand. The intercooled turbine, often represented by GE's LMS100, tends to exhibit relatively low heat rates and is a common choice for new simple-cycle applications greater than 100 MW. Figure 4-3 shows fuel efficiency data for actual simple-cycle GE LMS100 power plants in operation in the U.S.

Figure 4-3: LMS 100 Fuel Efficiency



4.5.1.2 Application

Simple-cycle plants are not best suited to providing baseload energy, but they are a top choice where firm capacity and flexibility are needed. Many modern designs are small, modular, and quick to construct, and feature 10-minute start times and quick ramping capability. In California, simple-cycle plants will likely fill an even broader niche over the next decade than they already do. The need for new firm capacity resulting from expected plant retirements associated with California's "Once-Through Cooling Rule,"[8] along with the need for balancing reserves in the face of increasing renewable portfolio standards, have already encouraged planned simple-cycle projects across California. The Panoche Energy Center in California features four 100 MW LMS100s, and the planned CPV Sentinel Project would feature eight 100 MW turbines.

4.5.1.3 Environmental and Fuel Risks

The two major drawbacks to simple-cycle natural gas combustion turbines are environmental impacts and fuel price risk. All gas-fired power plants require construction of a gas pipeline if they are not sited adjacent to an existing pipeline. Though gas is considered to be a "clean-burning" fossil fuel, there are still emissions from the combustion process. Mitigating emissions adds to the cost of operating the resource and can directly affect the operational flexibility of the plant. In addition, natural gas as a commodity has historically been exposed to high price volatility. High volatility will not only affect the cost of running the plant, it will also change an operator's decision whether to dispatch the plant within a given system. Relatively high

[8] California's Once-Through Cooling Rule would require generators along the coast to either implement best available technologies for mitigating effects on local marine life, or shut down.

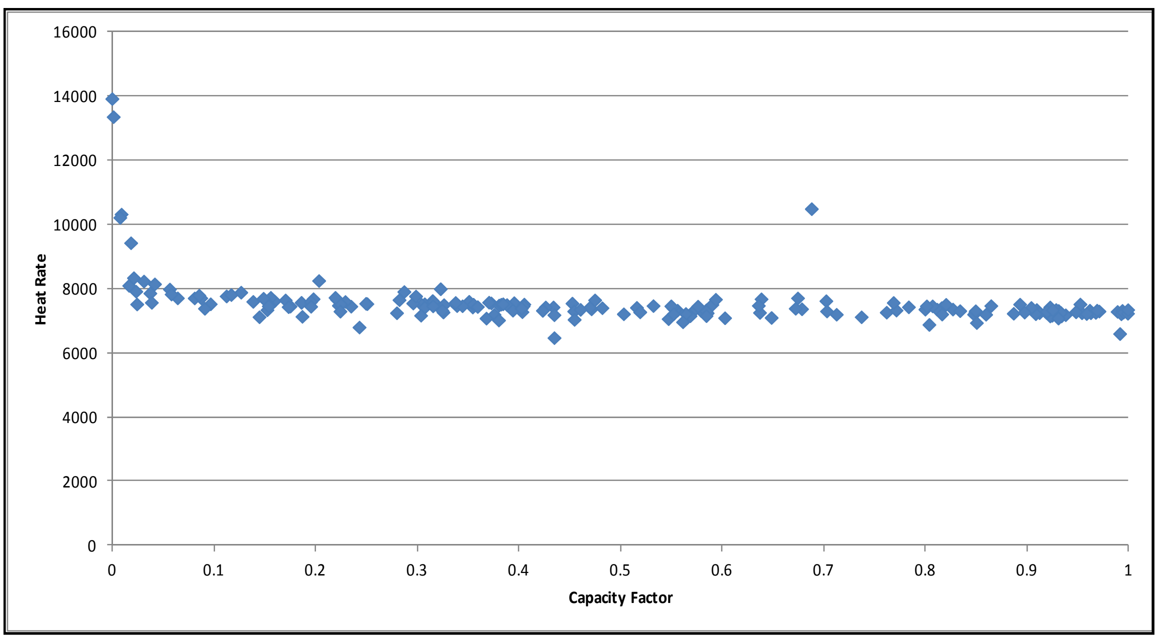
natural gas prices for a gas-fired plant within a system of hydroelectric facilities such as the FCRPS would likely mean less deployment.

4.5.2 Combined-Cycle Combustion Turbine

4.5.2.1 Overview and Characteristics

A natural gas-fired combined-cycle plant operates similarly to a simple-cycle plant, with the addition of heat recovery steam generators. The steam generators capture the waste heat of the gas turbine combustion process to create pressurized steam. The steam drives a steam turbine generator, adding to the amount of power produced from the overall thermal cycle. This increased generation does not require any additional fuel and effectively results in heat rates significantly lower than those achieved in a simple-cycle configuration. Unlike simple-cycle plants, combined-cycle gas turbine (CCGT) plants are designed with baseload energy service as their primary product, though in practice, many are relatively flexible and can be cycled, as Figure 4-4 suggests. Even though the capital cost for a combined cycle plant exceeds that of a simple-cycle plant, the lower heat rate (higher efficiency) for the combined-cycle plant, especially at higher capacity factors, results in lower overall cost for baseload energy service. Note that the combined-cycle plant exhibits lower heat rates in operation than simple-cycle plants. Also note that the combined-cycle plants are run at higher capacity factors than simple-cycle plants; the combined-cycle plant is run throughout the range of capacity available to the plant, maintaining a near-constant heat rate throughout.

Figure 4-4: CCGT Fuel Efficiency



4.5.2.2 Application

When run as baseload units, combined-cycle plants exhibit some of the lowest levelized costs of energy of all generators. Figure 4-2 reflects that at about a 30 percent capacity factor and above, the lower heat rate and variable cost of the combined-cycle plant begin to make it an overall cheaper choice than the simple-cycle plant. For this reason, most of the non-renewable power generation development over the past decade in the West has been combined-cycle natural gas-fired plants. If natural gas remains a low-cost fuel, and environmental or political concerns make new coal and nuclear facilities unattractive, this pattern can be expected to continue.

Though there are several manufacturers and models of combined-cycle plants, combined-cycle plants do not differ from each other as much as the simple-cycle designs do. Capital costs for most of these fall into the same range, along with heat rates and typical size configuration.

One possible exception is GE's latest design, which it refers to as the FlexEfficiency 50. These plants run using GE's 9FB gas turbine, with some modifications, including hollowed-out compressor blades that circulate cool air to increase efficiency. GE rates the plant at 61 percent thermal efficiency, overtaking GE's previous milestone of 60 percent achieved with the H Class turbine in 2000. GE is also advertising over 50 MW/minute ramp rates, 30-minute starts, and the ability to turn down to 40 percent of full load while maintaining emissions guarantees. Because of these features, GE is advertising the plant as being tailored more for integrating renewable generation and less for baseload duty. As of late 2012, there have been several global orders placed for the FlexEfficiency 50. However, unless the need is for a large plant, 500 MW or above, simple cycle plants, which can be scaled down to 50-100 MW applications, will likely be the choice where flexibility is required. The FlexEfficiency 50, like most combined cycle plants, is available only in relatively large sizes (300-600 MW), which allows for increased economies of scale and efficiency.

4.5.2.3 Environmental and Other Risks

Combined-cycle plants share with simple-cycle plants the same major drawbacks in the form of fuel price volatility and environmental concerns. Even though the combined-cycle plant may emit less on a per-megawatt basis, fuel costs for a combined-cycle plant will typically represent a greater portion of overall lifecycle cost than in a simple-cycle plant due to the higher capacity factors. For this reason, combined-cycle plants are somewhat less insulated from fuel price risk than simple-cycle facilities.

4.5.3 Reciprocating Engine

4.5.3.1 Overview and Characteristics

Unlike gas-fired power plants driven by combustion turbines, the reciprocating engine design is based on the internal combustion engine. Individual generators range in size from about 4 MW to just under 20 MW and generally are deployed in banks of multiple units, with plant sizes ranging from 10 MW to nearly 400 MW in newer applications.

4.5.3.2 Application

While not the most cost-effective for baseload applications, reciprocating engine plants are some of the most flexible in other areas. In their smallest increments, combustion turbines can be deployed in batches of about 50 MW, with many single turbines rated at around 100 MW. In contrast, with their small and modular design, reciprocating engines can be deployed in finer increments, tailored to the specific need at hand. Also, due to the modular design, reciprocating engines tend to see a flatter heat rate curve (better partial load efficiency) than simple-cycle combustion turbines. A prominent manufacturer, Wartsila, boasts 5-minute starts, lower cooling water consumption than a typical combustion turbine, lower gas fuel pressure requirement, and significantly better performance at high altitude and severe temperature conditions. This flexibility does not come without extra cost, though, as the levelized cost of energy from reciprocating engines can be nearly $10/MWh higher than that of comparably sized combustion turbines.

4.5.3.3 Environmental and Other Risks

Reciprocating engine power plants share many of the same environmental and fuel price risks as combustion turbine plants. Their modular nature gives reciprocating engines an advantage as far as flexibility, with a drawback being higher cost. That higher cost is evident in the variable operation and maintenance (O&M) costs of the plant throughout its lifecycle. The Council estimated such costs to be about $10/MWh in the Sixth Power Plan (Appendix I, p. 84), nearly double the variable O&M costs of the LMS100 intercooled gas turbine.

4.5.4 Conclusions

Tables 4-3 and 4-4 outline the power plants described here, their costs, and the capabilities they would provide to BPA’s system.

Table 4-3: Natural Gas Plant Characteristics

Reference Plant	Plant Size (MW)	Reference Plant	Heat Rate (HHV Btu/kWh)	Maximum Annual Capacity Factor	Services	Black Start Capability
NG Frame Gas Turbine	85	GE MS7001EA	11,960	91%	NG Frame Gas Turbine	No
NG Aero Gas Turbine	2x47/unit	LM6000PD Sprint	9,370	91%	NG Aero Gas Turbine	Yes
NG Intercooled Gas Turbine	99	GE LMS100	9,053	91%	NG Intercooled Gas Turbine	Yes
NG Reciprocating Engine Plant	12x8.3/unit	Wartsila 20V34SG	8,850	93%	NG Reciprocating Engine Plant	Yes
NG Combined Cycle	Baseload - 390 Peak Incr - 25	Mitsubishi MHI 501G	7,132 Pk Incr - 9,500	89%	NG Combined Cycle	No

Reference Plant	10-Minute Start	Max Ramp Rate (%/Minute)	Minimum Load	Minimum Run Time	Minimum Down Time	Proj Dev / Construction (mos)	Earliest Service	Developable Potential (MWa)
NG Frame Gas Turbine	No (85% load in 10 Minutes	20%	25%	1 Hour	1 Hour	18/15	2015	NA
NG Aero Gas Turbine	Yes	20%	25%	1 Hour	1 Hour	18/15	2015	NA
NG Intercooled Gas Turbine	Yes	20%	25%	1 Hour	1 Hour	18/15	2015	NA
NG Reciprocating Engine Plant	100% load in 10 minutes from warm start, not cold	20%	40%	1 Hour	1 Hour	18/15	2015	NA
NG Combined Cycle	10-20 Minutes	5-10%	70%	6 Hours	12 Hours	24/30	2015	NA

Table 4-4: Costs of Natural Gas Plants

Reference Plant	Levelized Cost Energy ($/MWh)	Levelized Cost Capacity ($/kw/mo)	NPVRR ($1,000/MW)	Total Plant Cost ($/kW)	Total Variable Cost ($/MWh)	Fixed O&M ($/kW/mo)	Variable O&M ($/MWh)
NG Frame Gas Turbine	$71	$12	$5,485	$610	$54	$0.84	$1.11
NG Aero Gas Turbine	$68	$15	$5,285	$1,050	$45	$1.01	$4.43
NG Intercooled Gas Turbine (LMS100)	$68	$15	$5,295	$1,134	$45	$0.62	$5.53
NG Reciprocating Engine Plant	$75	$16	$5,915	$1,150	$51	$1.02	$11.07
NG Combined Cycle	$58	$15	$3,972	$1,120	$34	$1.05	$1.88

Figure 4-5 is a graphical depiction of the resource cost information broken out by cost category. The chart shows that the majority of the levelized cost of a thermal plant is its variable fuel cost. Conservation uses no fuel, which contributes to its cost-effectiveness as a resource. Even though wind also has no fuel cost, the bulk of the levelized cost of wind is in its capital cost. As described above, RSS and VERBS have been included in the levelized cost of wind calculation.

Figure 4-5: Levelized Cost of Energy from Various Resource Options

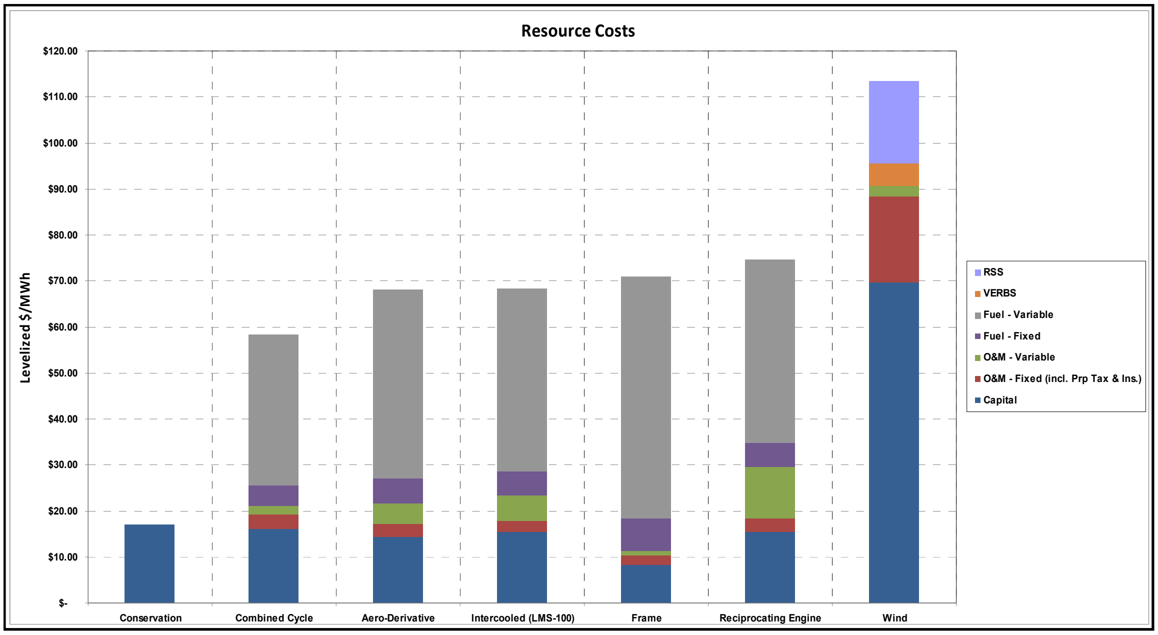
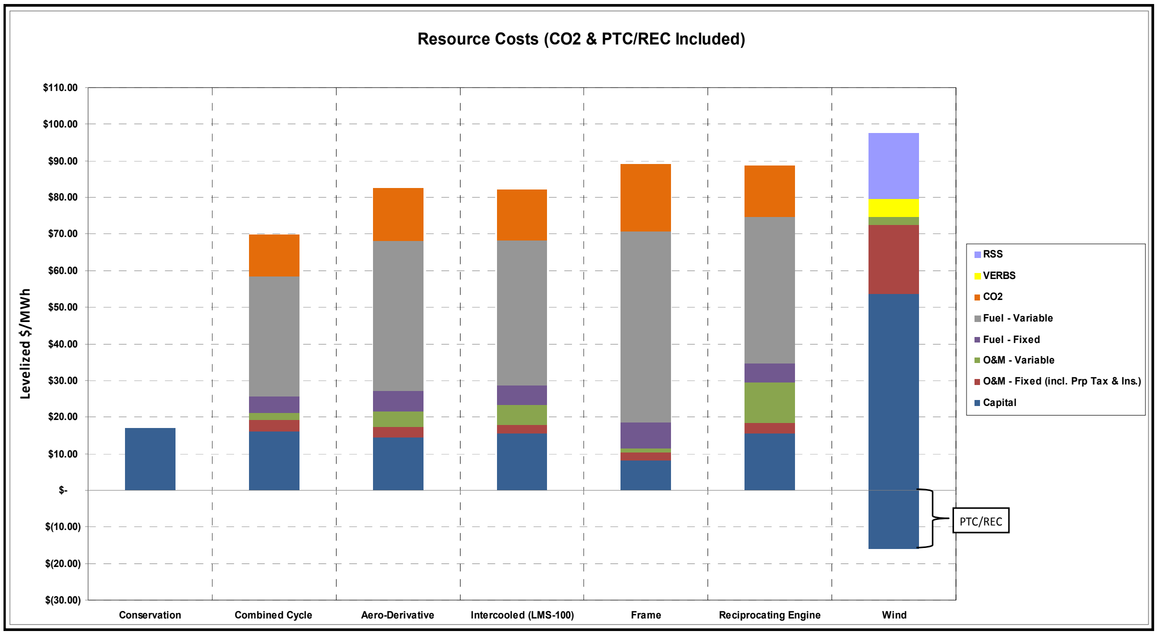


Figure 4-6 shows the same costs as Figure 4-5 but with a carbon cost included. All natural gas plants emit carbon. Figure 4-6 uses the heat rate associated with reference plants and the carbon price forecast from the Market Assessment to determine the incremental cost of production. Figure 4-6 also incorporates the value of both Production Tax Credits and Renewable Energy Credits, which reduces the cost of a wind resource.

Figure 4-6: Levelized Cost of Energy with Carbon Costs, Production Tax Credits and Renewable Energy Credits



As highlighted earlier in this chapter, there are many uncertainties in the costs of these resources. Uncertainties include capital costs, emissions costs, and natural gas cost. To highlight the impact of these uncertainties, BPA developed the following charts. Figure 4-7 represents the range of levelized costs of energy due to only the capital costs. Data used for Figure 4-7 was derived from a variety of information sources including reported as-built costs within the region, and planned plant costs. Variation can likely be attributed mostly to site-specific capital needs, *i.e.,* brownfield (land previously in industrial use and potentially contaminated) or greenfield (land not previously developed) construction.

Figure 4-7: Ranges of Levelized Cost of Energy – Capital Cost Sensitivity

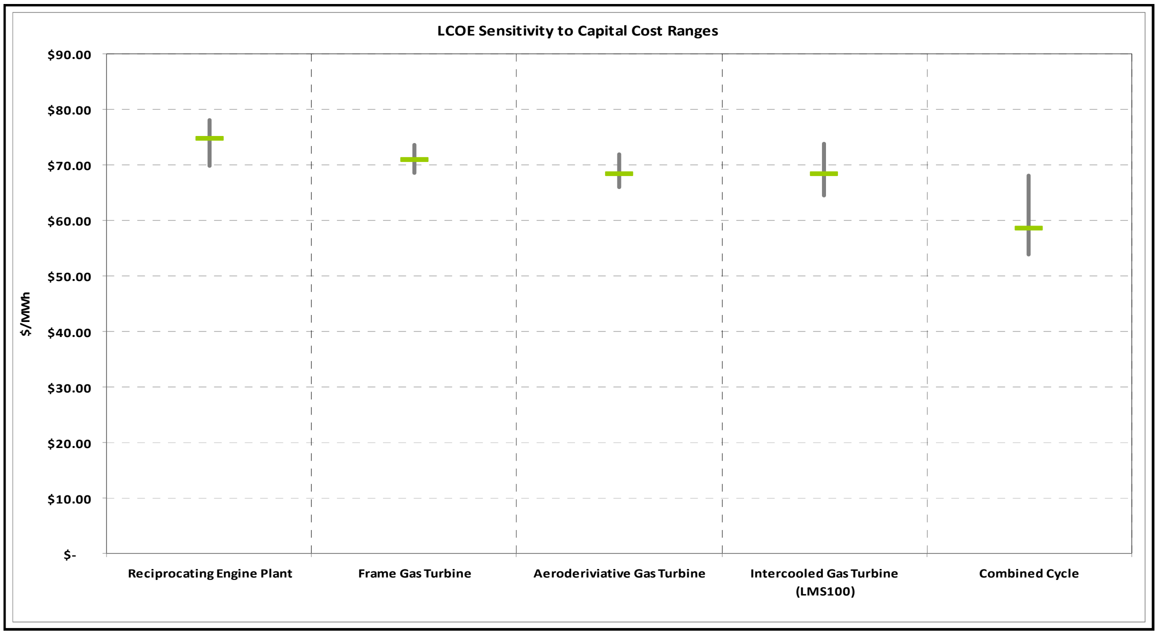
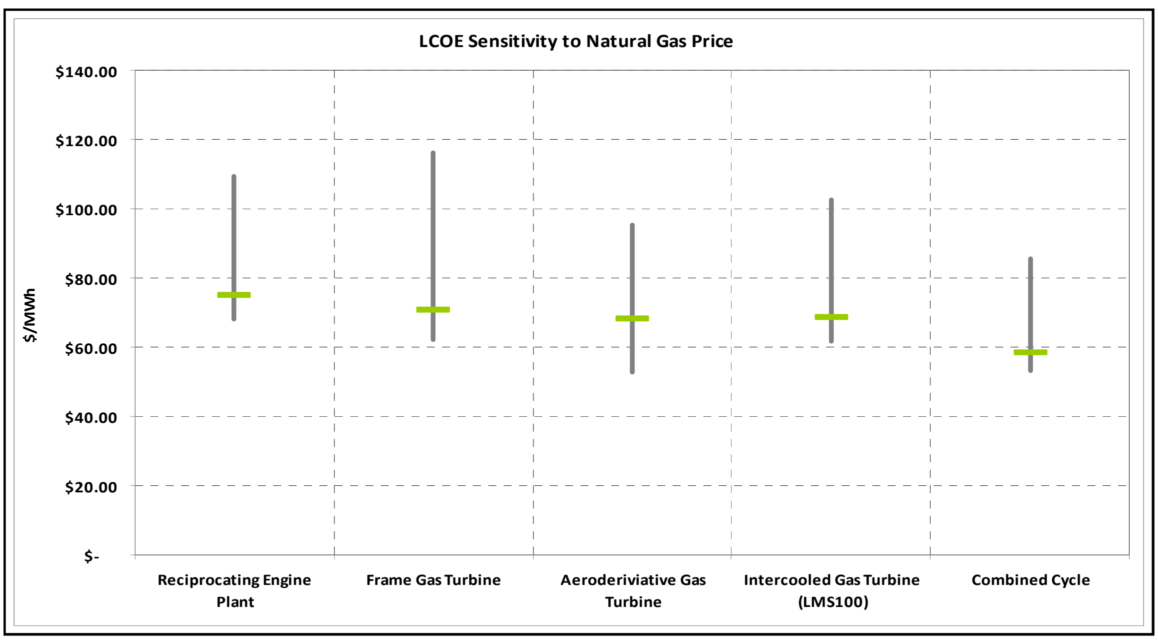


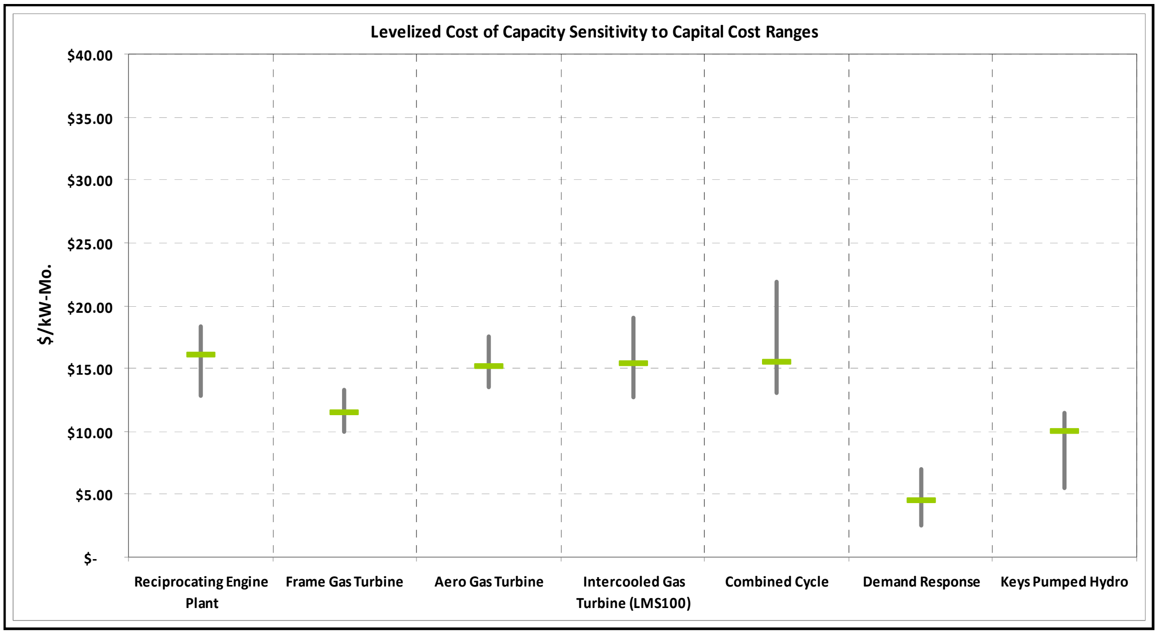
Figure 4-8 reflects the range of levelized electricity costs due to only natural gas price levels. The gas price scenarios, described in Chapter 2, were used in this analysis to determine the ranges.

Figure 4-8: Ranges of Levelized Cost of Energy – Natural Gas Price Sensitivity



For calculating ranges for the levelized cost of capacity, only capital cost ranges were varied. This is due to the way the cost of capacity is calculated, which excludes the energy (or variable) costs in the calculation. Figure 4-9 shows the results of the capacity sensitivity analysis.

Figure 4-9: Ranges of Levelized Cost of Capacity



As these figures illustrate, there is much uncertainty in the cost of new thermal generation. Furthermore, and not factored into the calculations, location can play a key role in determining which type of thermal generation is the most cost-effective. Other factors, such as elevation and location relative to natural gas pipelines and transmission facilities, also play an important role. As such, the Resource Program does not select the most cost-effective thermal resource. If BPA were to decide to acquire the output of a major thermal generating plant, the cost-effectiveness analysis would have to consider the case-specific factors (described above) at that point in time.

The figures highlight that conservation is the most cost-effective resource for energy for BPA. Figure 4-9 also shows that demand response and Keys pumped hydro appear to be cost-effective sources for capacity. However, as discussed in section 4.4, there are still some outstanding questions regarding these two alternatives that need to be addressed.

4.6 Other Resource Options

Two areas BPA is currently researching and monitoring are Compressed Air Energy Storage (CAES) and Solar Photovoltaic (PV) generation.

4.6.1 Compressed Air Energy Storage

CAES is a form of energy storage that uses electrical energy to compress and store atmospheric air at high pressure in an underground reservoir. The stored air, which is usually compressed when electricity prices are low, is withdrawn and directed through an expansion turbine to generate electricity at times when the value of electricity is higher. Though it carries net energy losses of 20-40 percent, CAES is capable of providing a number of benefits.

CAES technology comes in two forms, adiabatic and diabatic. Adiabatic CAES captures and stores heat energy generated during the air compression cycle and later reuses it to heat the air as it is expanded in the turbine during the generation cycle. Diabatic CAES loses heat energy from the compression cycle and instead burns fuel (typically natural gas) to reheat the air before it is expanded through the turbine.

Depending on the length of compression-generation cycle used, CAES has the ability to provide firm capacity, peaking energy, or both. A CAES air reservoir can be continuously compressed for days or weeks until a reservoir is full and capable of providing firm capacity for a sustained period (6-24 hours). Alternatively, CAES resources can be operated on shorter cycles, with a plant being switched from compression to generation on a within-day basis that matches a diurnal load pattern.

CAES can also be used as an effective balancing resource. Fast ramping capabilities (up to 10 megawatts per minute), good partial-load efficiency, and the ability to create load when in compression mode make CAES resources flexible in both the incremental and decremental directions.

Grid-scale CAES could prove especially valuable to the Northwest, where rapidly growing wind capacity has led to more frequent oversupply events during the coincident high wind and high water conditions of the spring season. Energy storage during such events could avoid costs associated with current oversupply management solutions involving wind curtailment and hydro spill.

Infrequent occurrence of the salt dome formation used for the only two currently operating CAES plants in the world has prompted investigations into the viability of using porous rock aquifers or hard rock cavern formations as air reservoirs. BPA recently commissioned the Pacific Northwest National Laboratory (PNNL) to conduct the first-ever techno-economic feasibility study for CAES in the porous rock aquifers embedded in the flood basalts in the Northwest.

Preliminary results of the PNNL study indicate with high probability that numerous areas in Eastern Washington have suitable geology to support cost-effective CAES facilities capable of storing more 100,000 MWh of electric energy and to support the flexible dispatch of greater than 200 MW of storage and generation capacity. The final PNNL study report is expected to be released in March 2013.

4.6.2 Solar Photovoltaic

Utility-scale solar PV installations use panels of semiconductors to convert the sun's radiation into direct-current electricity. Inverters then convert the direct-current output to alternating current before the electricity is transmitted to the grid. Capacity factors for PV arrays vary widely based on geography, with the economics being more favorable for projects based in sunny locations. Passing clouds as well as seasonal and daily variations in the amount of available daylight can make PV output highly intermittent and in need of balancing services. Current trends in solar generation have strongly favored PV arrays over solar thermal ones, which concentrate solar radiation to heat a synthetic oil that transfers the heat to develop steam to drive a steam turbine-driven generator.

Sustained growth coupled with global oversupply in the residential, commercial, and utility-scale sectors have continued to reduce the costs of PV installations nationwide. However, while the number of new utility-scale solar PV projects installed nationally in 2011 nearly tripled the number installed in 2010, large solar PV projects have been slow to develop in the Northwest. Only two installations in Oregon account for the 4 MW of utility-scale solar capacity currently operating in all of the Northwest.

Idaho's Snake River plateau and the inter-mountain basins of central and eastern Oregon are considered to be the best locations for Northwest solar generation. Roughly 40 MW of photovoltaic capacity is currently under development in these two regions combined. It is expected that solar generation profiles in the Northwest would line up well with the region's summer load profile; maximum photovoltaic output should often coincide with summer superpeak and heavy load hours caused by cooling needs.

California leads the nation in new solar installations. The large amount of utility-scale solar projects coming on-line in California may have significant effects on western reliability coordination and electricity markets as solar output ramps occurring in the middle part of the day increase in size.

Though solar generation in the Northwest is not currently as economically viable as other generation alternatives, growth in solar markets is expected to continue, driving down the cost of solar projects. BPA will continue to monitor the developments and the economics of solar resources.

4.6.3 Other Types of Generation

BPA is also monitoring developments for other classes of generation resources, including geothermal and biofuels. These two renewable generation types have the distinction that they are dispatchable and produce consistent generation output with a high capacity factor, and thus, can act as baseload resources.

Geothermal

Geothermal energy resources, which use thermal energy from the latent heat in the Earth's crust to drive steam turbine generators, have been developed in California, Utah, Nevada, Wyoming, Idaho, and Oregon. The volcanic geology of the Cascade mountain region is expected to contain rich geothermal potential, but its resources are largely precluded from development by existing land uses. The most promising region for geothermal generation potential in the Northwest is the basin and range land of southeastern Oregon and southern Idaho, where vertical faults allow upward movement of heated water to depths less than 10,000 feet.

Idaho is home to the Northwest's first utility-scale geothermal energy project, the 13 MW Raft River Project, which came on-line in 2008. Oregon's first utility-scale geothermal power plant, the 22-megawatt Neal Hot Springs Project, began operation in the fourth quarter of 2012 and will deliver its power to Idaho Power Company. The Geothermal Energy Association's 2012 annual report ranks Oregon third in the nation (behind California and Nevada) in geothermal development, with 16 geothermal energy projects currently under development, totaling 285–330 MW of potential capacity. One such project is the Newberry Volcano site, long proposed for development, where the Bureau of Land Management recently authorized a geothermal demonstration project.

Assessments by the U.S. Geological Survey have indicated that 1,369 aMW of geothermal potential exist in the Northwest. However, much of that energy is believed to be unrecoverable due to prohibitively high initial capital costs and risk associated with exploration and well configuration. The Council has therefore adopted a tempered estimate of 416 potential megawatts of capacity delivering 375 aMW of energy.

Biofuels

Biofuel-based generation resources can include (1) steam-turbine generators driven directly by combusted biomass; (2) coal-fired power plants replacing a portion of coal with biomass; and (3) gas-fired turbines fueled by methane derived from biomass.

Common biofuel sources available for power generation in the Northwest include wood residues, agriculture field residues, pulping (black) liquor, animal manure, landfill gas, and waste water gas. Over 500 MW of utility-scale biomass generating capacity is currently installed in Oregon, Washington, and Idaho. Roughly 390 MW of this capacity is fueled using wood residues, with the rest split between woody biomass (90 MW) and municipal solid waste (40 MW).

While biofuel generation technology is relatively mature, associated air quality controls are continually evolving. Nationally, almost 80 percent of wood-fired biomass plants violated emissions standards in 2012, and development of a proposed 26 MW Iberdrola biomass plant in Lakeview, Oregon, is currently being delayed in part because of concerns over particulate matter emissions. Research regarding the use of torrified (a process that turns plant matter into a charcoal-like pellet) woody biomass in existing coal plants is also being conducted. For example, Portland General Electric is currently funding technical research on the conversion of its 585 MW Boardman coal plant to the use of a torrified fast-growing cane plant in place of coal.

The Council indicates that there is roughly 800 aMW of bio-fueled energy potential available for development in Oregon, Washington, Idaho, and Montana. Additionally, the Council cites 50–110 aMW of development potential for animal manure biofuels, 70 aMW of development potential for landfill gas biofuels, and 7–14 aMW of development potential for wastewater treatment energy recovery.

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Chapter 5. Resource Assessment Results

5.1 Introduction

This chapter presents the recommended approaches to meeting potential needs identified in the Needs Assessment. As stated earlier, conservation is BPA's highest priority resource option, and BPA is committed to ensure that public power's share of the conservation targets established in the Sixth Power Plan is met. BPA also has extensive experience with transacting in the wholesale market. Thus, as a starting point, BPA gave the highest priority to these two resource types for meeting potential needs.

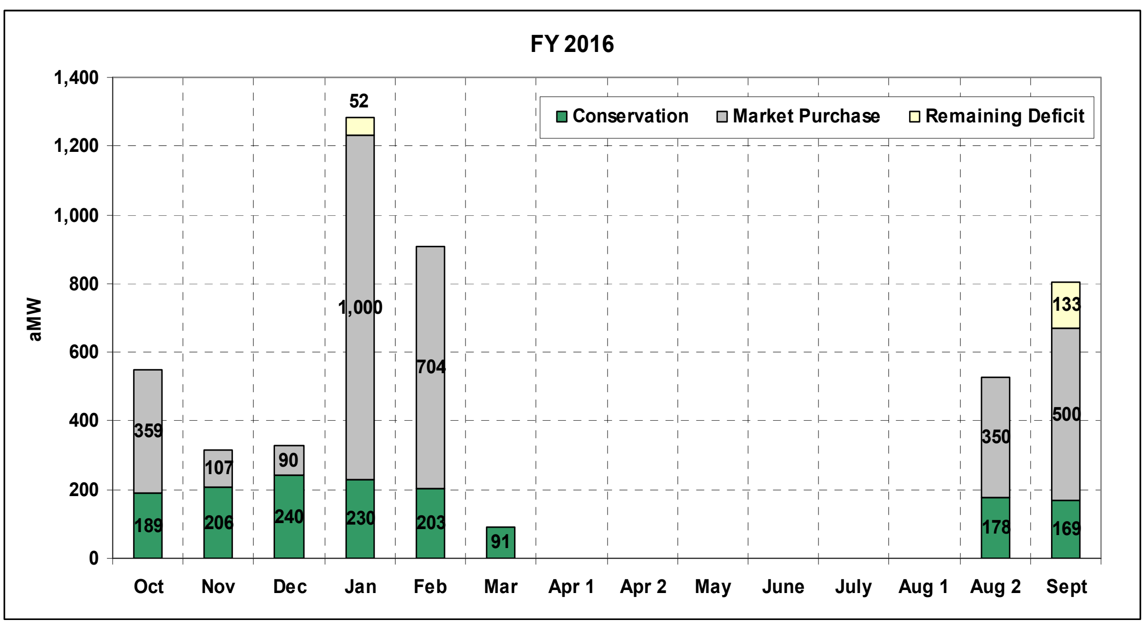
5.2 Energy Conclusions

As discussed in Chapter 3, BPA has forecast energy needs through FY 2021. The metrics used for energy needs are annual energy under critical water and monthly/seasonal HLH energy at the 10th percentile, varying both load and water. Meeting the Sixth Power Plan conservation targets would greatly reduce BPA's need for additional power resources for energy purposes. BPA also intends to continue to utilize wholesale power market purchases to meet system needs. Market purchases and their threshold limits are described in Chapter 4.

5.2.1 Monthly Energy

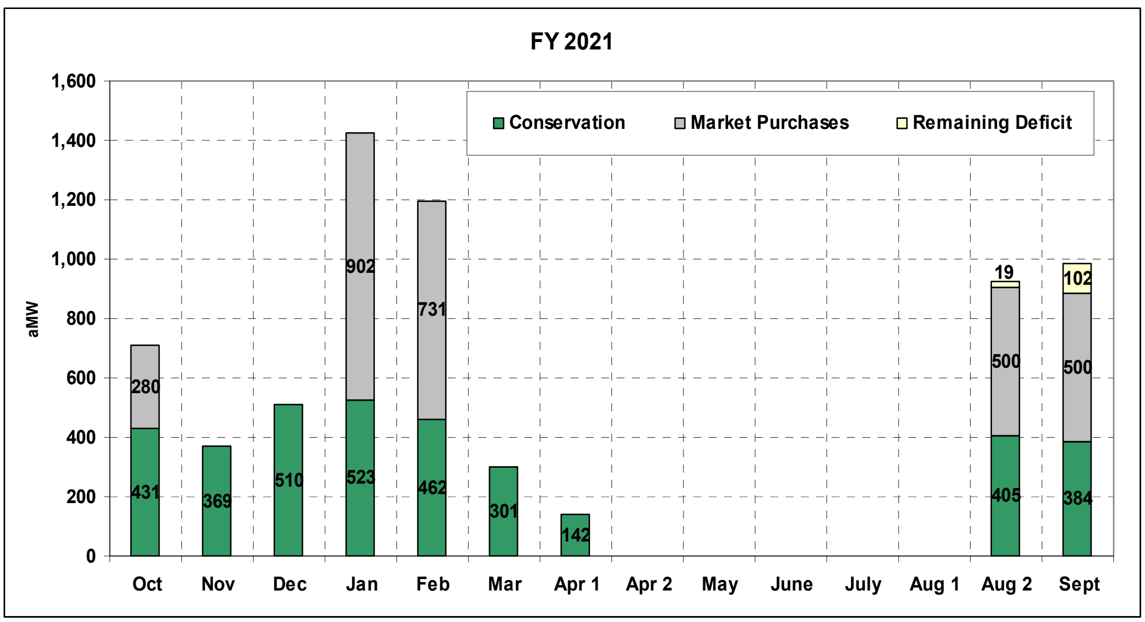
Figure 5-1 reflects the results of applying the conservation targets and the market purchase thresholds to the monthly energy needs for FY 2016.

Figure 5-1: Conservation and Market Purchases for FY 2016



The green bars in Figure 5-1 reflect achievement of the incremental amount of conservation to meet the Sixth Power Plan conservation targets. As discussed in Chapters 3 and 4, roughly 60 aMW of conservation is already included in the load forecasts. The conservation amounts are assumed to have monthly shapes that are consistent with those in the Sixth Power Plan. Conservation does not appear on the charts in the months in which BPA does not project deficits. The gray bars reflect the reliance on market purchases up to the market threshold limits. Any remaining amount of the needs not met is shown in yellow. As the figure suggests, there are only very minor needs left in January and September. It is anticipated that these remaining small deficits can be managed using market purchases above those assumed in the studies. As noted earlier, the hydro modeling uses BiOp spill assumptions. In years where fish migration continues later than normal, spill may continue through the end of August and lead to higher second half of August deficits (up to 400 aMW less generating capability). This applies to FY 2021 as well. Figure 5-2 reflects the results for FY 2021.

Figure 5-2: Conservation and Market Purchases for FY 2021

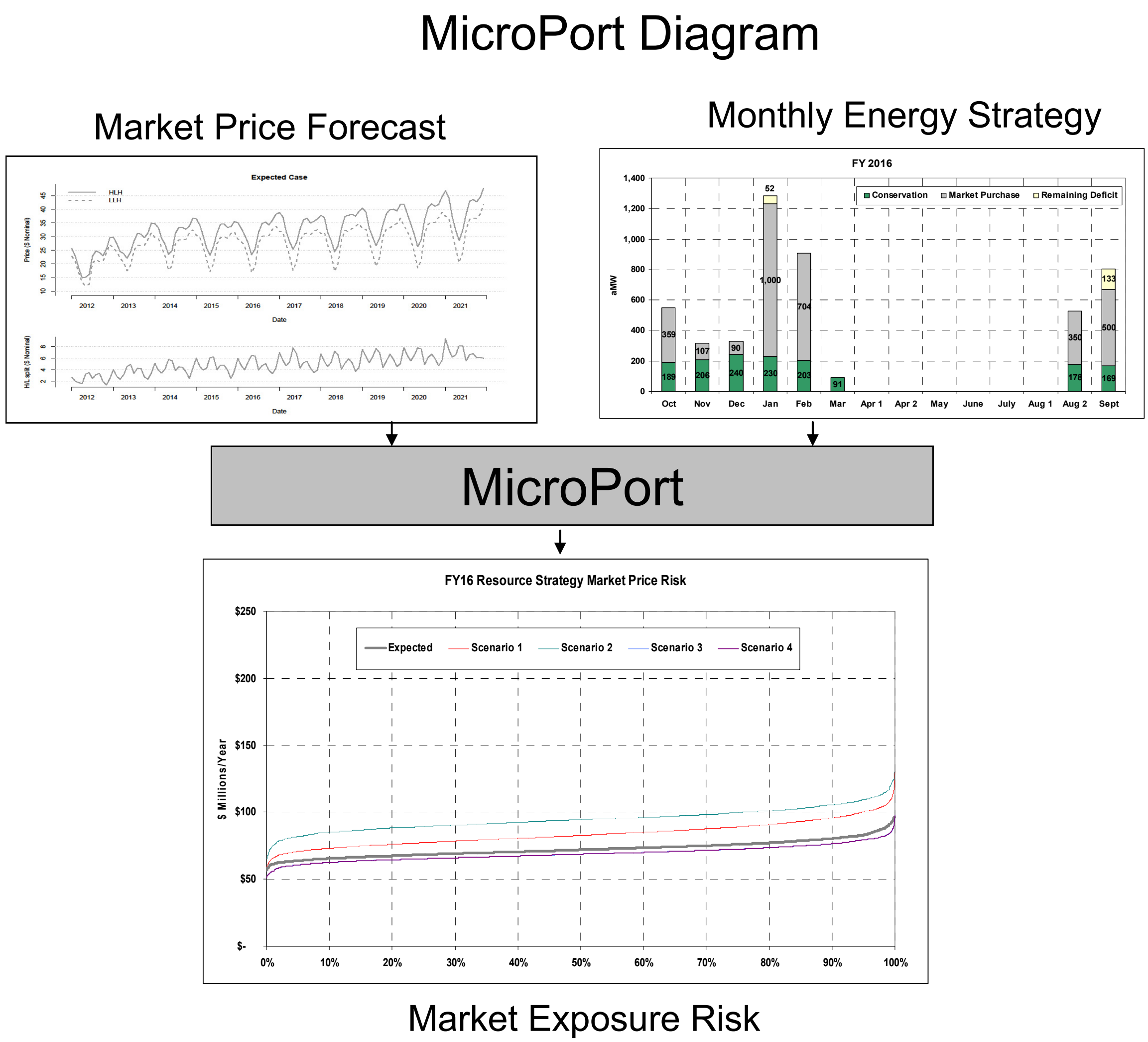


For FY 2021, the only month that shows need not met with conservation and market purchases, beyond the small deficits in late August, is September. Again, it is anticipated that these remaining deficits can be managed using additional market purchases above those assumed in the studies.

5.2.1.1 Risks of Monthly Energy Strategy

As described in section 4.4, there are risks associated with market purchases. BPA has addressed these risks, in part, by assuming a maximum amount of market purchases of 1,000 aMW per month in the winter and 500 aMW per month in the summer. However, as highlighted in Chapter 2, there are other risks associated with wholesale market purchases. In Chapter 2, BPA forecast electricity prices under various scenarios to attempt to quantify uncertainty in wholesale electricity prices. The next step is to quantify the market price risk associated with the monthly energy strategy. To do this, BPA has developed a tool named MicroPort. A detailed description of MicroPort can be found in Appendix A. MicroPort combines the results of the Market Assessment with the monthly energy strategy described above and reports costs. The costs are associated with the acquisition of conservation (assumed at a constant cost) and market purchases given various levels of market prices. Figure 5-3 is a graphical depiction of the process.

Figure 5-3: MicroPort Diagram



The base case and all four scenarios were run through MicroPort. Figures 5-4 and 5-5 reflect the results.

Figure 5-4: Conservation and Market Purchases Strategy for FY 2016 – Cost Risks

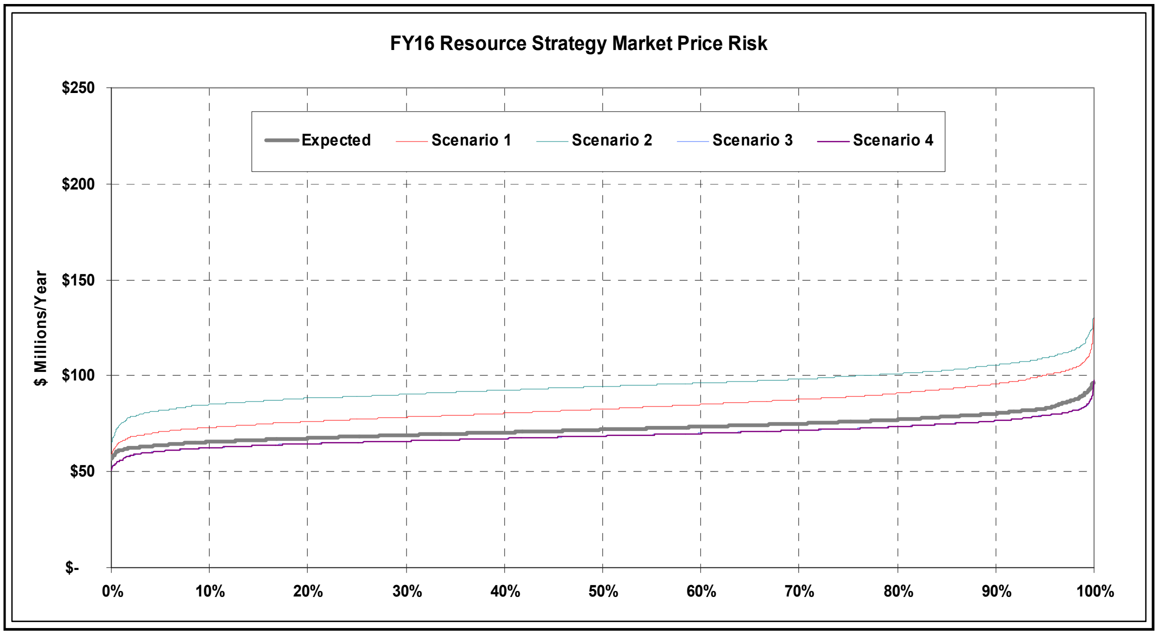


Figure 5-5: Conservation and Market Purchases Strategy for FY 2021 – Cost Risks

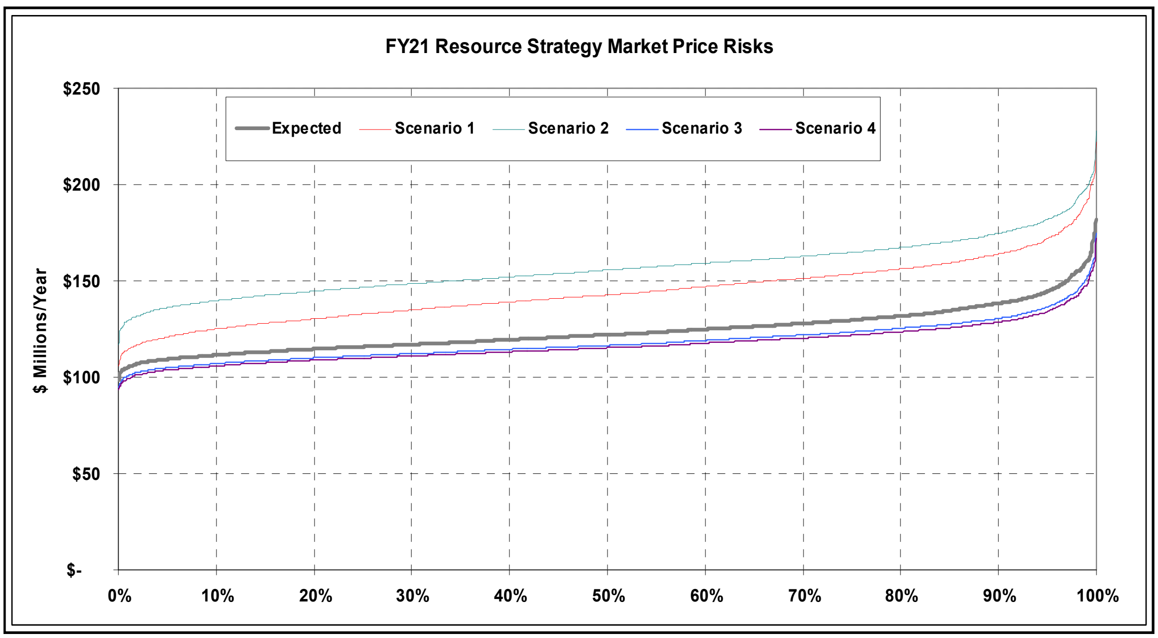


Figure 5-4 depicts a fairly flat cost curve for FY 2016, which corresponds to the conclusions in the Market Assessment that market prices for FY 2016 are fairly low and stable over the various scenarios and even within the scenarios. Figure 5-5 depicts that by FY 2021 there is a much wider range in expected outcomes over the scenarios as well as within each of the scenarios. The FY 2021 chart also reflects some very costly outcomes above the 90th percentile.

5.2.1.2 Monthly High and Low Economy Scenarios

As discussed in Chapter 3, BPA also analyzed the impacts of various load growth scenarios. For the low economy scenario, BPA has concluded that it could meet all of its needs with conservation and market purchases. The high economy scenario shows greater deficits that need to be met and is represented in Figures 5-6 and 5-7 below.

Figure 5-6: Conservation and Market Purchases for FY 2016 – High Load Growth

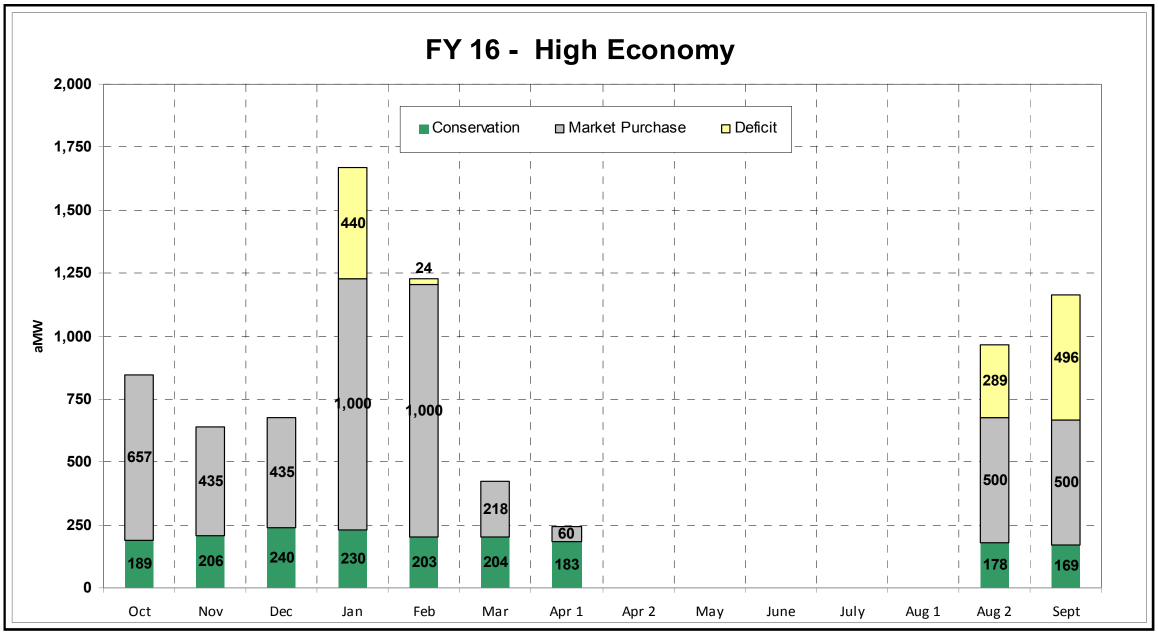
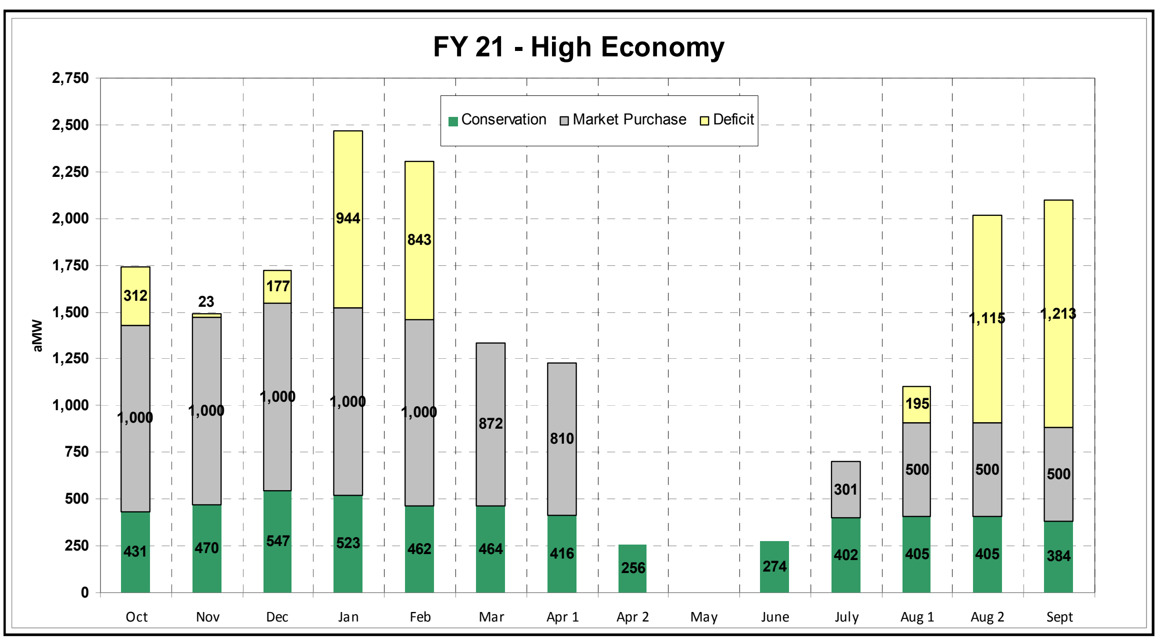


Figure 5-7: Conservation and Market Purchases for FY 2021 – High Load Growth



Results for both years show that BPA would not be able to meet its forecast needs with only conservation and market purchases. FY 2021 also shows considerable deficits across the winter and summer months. To recognize and address such an outcome, it is prudent to monitor the factors that could lead to this scenario. These factors are described in Chapter 6.

5.2.2 Annual Energy

Annual energy needs are determined by the deficit under load-resource balance with critical water expressed in annual average megawatts. Table 5-1 reflects the expected annual needs for the study years and the results after the conservation targets are applied (netted against the expected needs).

Table 5-1: Annual Needs after Conservation Targets are Met

Scenario	Study Year FY 2016	Study Year FY 2021
Expected Need	-200 aMW	-500 aMW
Incremental Conservation	197 aMW	446 aMW
Net Need	-3 aMW	-64 aMW

As with the monthly energy needs, achieving the conservation targets would eliminate the majority of the annual energy need. The remaining small deficits could be eliminated if the monthly energy purchase strategy was implemented**.** As indicated in Chapter 3, annual energy needs were assessed not only under expected loads, but also under high and low loads. In a high economy scenario, after the acquisition of incremental conservation, BPA has a net need (deficit) of 353 aMW in FY 2016 and 1004 aMW in FY 2021. A low economy scenario would result in no net need for either FY 2016 or FY 2021. As described in the monthly energy strategy section, BPA plans to monitor some key factors it believes could lead to the high load growth scenario.

5.3 Capacity Conclusions

As discussed in Chapter 3, capacity need is measured two ways. The first is 18-hour capacity, which is the capacity inventory needed to meet the six peak load hours for three consecutive days under loads expected for extreme temperature events, assuming median water supply and hydro generation. Table 5-2 represents the results of the 18-hour capacity study. Positive numbers indicate a surplus.

Table 5-2: 18-Hour Capacity Results

Winter 2016	Summer 2016	Winter 2021	Summer 2021
+100 aMW	+250 aMW	0 aMW	0 aMW

The 18-hour capacity results show minimal surplus in both winter and summer in FY 2016, while the FY 2021 results show load-resource balance. The following are measures that could help to supplement the FCRPS capacity:

1. Sixth Power Plan Conservation Targets. Achievement of the targets will have the effect of reducing load. This approach is consistent with the Council modeling for the Regional Resource Adequacy study. However, there is concern, based on the lack of accurate hourly information, as to how firm the load reductions would be during times of extreme weather conditions. The estimated impact is 200 MW in the summer and winter in FY 2016 and 400 MW in the summer and winter in FY 2021.

2. Market Purchases. As with conservation, HLH market purchases would also help supplement the amount of capacity available. There is some concern about the monthly market thresholds of 1,000 aMW in winter and 500 aMW in summer. For example, if an extreme weather event were to occur with a lead time short enough that it would preclude BPA from participating in any markets other than the real-time market, the market thresholds assumed in the capacity studies may be overstated. The estimated impact is that a market purchase would translate into a one-for-one capacity benefit; *i.e.,* a 100 aMW HLH purchase would add 100 MW to the capacity metric.

3. Additional Non-Treaty Storage (NTS). BPA analyzed the effect of releasing additional 10,000 cubic feet per second (kcfs) of water out of Canada as a potential means to supplement the FCRPS capacity. However, due to the current arrangement with Canada, this additional water from the NTS should be viewed as non-firm for planning purposes. The estimated impact, based on a 10 kcfs release over the study period, is an additional 400 MW in the winter (FY 2016 and FY 2021), 300 MW in the summer of 2016, and 350 MW in the summer of 2021.

4. Keys Pumped Generation Station is not assumed to be available on a planning basis for the 18-hour capacity study. However, it is probable that during times of extreme weather events Keys could provide some additional capacity. There are many questions and uncertainties about the future of Keys. If Keys is available, it would have an estimated impact of 150 MW and could potentially be as high as 300 MW.

5. Demand response is an area that holds promise and appears to offer some level of cost-effective capacity. As such, BPA is continuing to explore demand response.

6. The application of customer non-Federal resource peaking capacity (Peak Net Requirements) to serve customer Total Retail Load will be explored. Under the Slice and Block contract, BPA agreed that it would conduct a public process to develop a methodology for determining non-Federal resource capacity prior to taking any steps to change customer resource amounts currently listed under the customers' BPA contracts.

7. Acquisition of the output of a thermal generation plant, described in further detail below.

The second unit of capacity need measurement is the 120-hour superpeak capacity, which is defined as the capacity inventory needed to meet load peaks day after day throughout the month (6 hours per day times 5 days per week times 4 weeks per month = 120 hours). The results of the 120-hour capacity analysis reflect that HLH energy is more limiting than the 120-hour capacity in all months except the second half of August. Thus, it is anticipated that the monthly energy strategy would mostly eliminate the 120-hour capacity need, and the small remaining balancing could be met with market purchases.

5.4 Balancing Reserves Conclusions

The results of the Needs Assessment reflect that the FCRPS will not be able to provide the level of balancing reserves potentially required by the time of the first study period (FY 2016). There are many processes occurring in the region and within BPA to address this issue, including:

- Ancillary and Control Area Services (ACS) Practices Forum
- BP-14 rate case
- Northwest Power Pool Market Committee and the Joint Initiative

There is much uncertainty regarding what level of balancing reserves BPA may be requested to provide, since requests are made every two years for a period of only two years. As such, BPA's current strategy is to purchase additional balancing reserves, if needed, in the wholesale market from existing resources.

5.5 Overall Conclusions

When the strategy of conservation and market purchases is applied to the results of the Needs Assessment, it appears BPA's resulting energy and capacity needs are minimal. The minimal needs appear to be seasonal in nature and occur in only a few specific months of winter and summer.

Given the results described above, BPA will continue to evaluate sources of seasonal energy, flexibility, and capacity. Sources that provide both capacity and seasonal energy would likely provide the greatest benefit, given BPA's needs. A capacity purchase targeted at a specific transmission-constrained location could also provide additional benefits. One such location could be in the Southern Idaho area, where the capacity could supplement that of the Federal system while also providing a seasonal energy source to serve BPA preference loads in that location. Another use of additional capacity could be to help supplement the ability of the Federal system to provide balancing reserves. This type of capacity resource would need to be flexible and have operational characteristics necessary to provide seasonal energy needs under low-probability events.

5.6 Summary of Resource Options

As discussed in Chapter 4, there are additional options beyond conservation and market purchases that BPA is evaluating to address its future capacity and seasonal energy needs. Some of these options are actions that BPA can take, while others fall more into the category of resource acquisitions. Table 5-3 reflects these options for the various "need" metrics.

Table 5-3: Summary of Resources Options by Metric

Metric	**Resource Options (in no specific order)**
Annual Energy	• Conservation • Market purchases • Combined-cycle combustion turbine • Federal hydro system improvements

Monthly/Seasonal HLH Energy	• Conservation
	• Market purchases
	• Combined-cycle combustion turbine
	• Simple-cycle combustion turbines
	  o Frame
	  o Aeroderivative
	  o Intercooled
	• Reciprocating Engine

Capacity and Flexibility	• Demand response
	• Combined-cycle combustion turbine
	• Simple cycle combustion turbines
	  o Frame
	  o Aeroderivative
	  o Intercooled
	• Reciprocating Engine
	• Keys Pumped Storage Plant
	• Federal hydro system improvements
	• Capacity net requirements
	• Additional Non-Treaty storage
	
	❖ BPA will be exploring the contribution of conservation to meeting capacity needs.

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Chapter 6. Action Plan

Even though no decisions concerning the acquisition of any specific resource are made in the Resource Program, the Resource Program provides information BPA will use to make informed resource acquisition decisions in the future, if needed.

BPA sees the following as areas to focus on:

- Evaluating the contribution of conservation to meeting capacity needs.
- Further developing the definitions of system and resource flexibility, including how flexibility might be measured and possible adequacy metrics.
- Continuing to evaluate demand response and Keys Pumped Generation Station.
- Exploring the application of Peak Net Requirements provisions described in Regional Dialogue contracts.
- Monitoring the emerging drivers that influence the potential Above-High Water Mark load placed on BPA post-FY 2019.
- Reviewing the metrics and tools used in the Needs Assessment.
- Continuing to evaluate how traditional thermal generation resources might help supplement the capacity of, and provide flexibility and seasonal energy to, the existing FCRPS.
- Considering the evolving relationship between power, gas, and transmission planning.
- Collaborating with the Council to prepare for the Seventh Power Plan and BPA's next Resource Program.

The action items from the 2010 Resource Program (Action Plan, Chapter 9) continue to be relevant and are largely incorporated here, although in an abbreviated version. The action items have been updated to reduce redundancy, condense language, and remove items no longer relevant.

6.1 Action Items

6.1.1 Conservation

- Work with customers and regional stakeholders to achieve all cost-effective conservation measures necessary to meet public power's share of the Council's Sixth Power Plan regional conservation targets.
- Participate in and support conservation infrastructure development.
- Conduct demand response pilot programs and technology demonstrations.

- Support improved processes for the acquisition and verification of conservation measure data reported to BPA to ensure the validity of lowest-cost savings with the least intrusion on customers' business practices.
- Work with the Council and regional stakeholders to develop a plan to collect end-use load shape data.

6.1.2 Market Purchases

- Continue to consider the reliance on market transactions to meet low-probability within-year seasonal needs as an alternative to committing to long-term resource acquisitions.

6.1.3 Variable Energy Resource Integration and Acquisition

- Preserve and enhance the performance of the hydroelectric generating capability of the FCRPS through the Asset Management Strategy, Capital Investment Review, and Integrated Program Review processes.
- Complete existing Wind Integration Team Work Plan projects.
- Continue to participate in the Northwest Wind Integration Forum and work with regional entities and stakeholders to develop a long-term wind integration strategy.
- Pursue further evaluation of potential benefits associated with cooperative, collaborative, and/or joint balancing authority functions.
- Actively participate in Western Electricity Coordinating Council west-wide transmission and power planning efforts and in development of national North American Electric Reliability Corporation adequacy standards for variable generation.
- Explore and assess small-scale, cost-effective renewables such as waste heat and bioresidue energy recovery, biomass generation, cogeneration, geothermal, and new small hydro.

6.1.4 Natural Gas-Fired Generation

- Further evaluate natural gas-fired flexible resources.
- Continue to track, evaluate, and appropriately pursue natural gas-fired generation to supply future reserve requirements, seasonal/monthly energy, and annual energy needs.

6.1.5 Sources of Flexibility and Energy Storage

- Evaluate flexibility augmentation options as appropriate.

- Evaluate pumped storage and other energy storage options and pursue cost-effective alternatives.

6.1.6 Emerging Technologies

- Continue to support research, development, and demonstration projects to foster technologies that may improve FCRPS cost-effectiveness, including new conservation and demand response techniques and methods to encourage consumer participation.
- Continue to monitor progress in development of relevant technologies for potential application to future Resource Programs.

6.1.7 Improving methodologies

- Continue to further develop tools and analytical methods to enhance BPA's capability to evaluate system needs and resource options.

6.2 Factors to Monitor

For BPA, as for many utilities and agencies, planning for the wide range of uncertainty, given the current status of the regional, national, and global economy, is challenging. Historically, BPA's business practices have been focused on managing a portfolio of resources that, even under very dry water years, provide enough surplus energy and capacity to meet reasonable ranges in uncertainty. However, the range of possible futures and potential impacts to BPA's load-resource balance is wide. BPA will monitor, at a minimum, the following:

- National and regional economic growth indicators and impacts on loads, including Above-High Water Mark loads
- Natural gas supplies and market trends
- Power market liquidity and trends, including increased volatility and frequency of negative prices
- Climate change legislation
- Carbon legislation implementation
- Regional capacity constraints through the Regional Adequacy Forum
- Implementation of renewable portfolio standards in the Pacific Northwest and California
- Emergence and cost-effectiveness of new technologies

In summary, the timing and amount of BPA's resource needs beyond those to be supplied from conservation and market purchases will depend in large part on the outcome of uncertainties in customer load placement and power supply preferences for FY 2020 and beyond, climate change legislation, economic recovery, and many other uncertain future outcomes. This uncertain situation motivates BPA to commit to actions that can help better prepare to meet a wide range of possible outcomes at lowest economic and environmental cost. In this quickly evolving environment, traditional distinctions between transmission planning, conservation program development, resource planning, and load forecasting are also changing. BPA's Resource Program will continue to evolve with these changes.

APPENDIX A

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Appendix A

MicroPort Model Description

Introduction

MicroPort is a linear program model designed to evaluate resource alternatives for meeting BPA's energy needs. It was developed by BPA Resource Program staff during 2012, and though it is still in the process of development, preliminary results from the model were used in the 2013 Resource Program. The model was developed in R (www.r-project.org), an open-source statistical software environment that compiles on several platforms. R is released under the GNU GPL (GNU General Public License) and is free software.

MicroPort evaluates the costs of different resource types in meeting BPA's projected energy needs. The calculation takes into account the fixed costs of generators as well as variable costs and distinguishes between peaking and baseload plants, conservation, and market purchases. The model does this calculation under many different hydroelectric generation, load, gas price, and power price conditions. In its current state, MicroPort is aligned with both the HOSS and AURORAxmp models, also used at BPA.

Long-term goals for MicroPort include developing the model into a full portfolio evaluator for BPA that can plan for not only energy needs, but also different types of reserves and flexibility needs. In addition, there have been preliminary discussions regarding how MicroPort can be configured to interact with output from the Genesys model, which BPA currently uses for loss of load probability calculations. This coordination may enable the Resource Program to integrate potential resources with the existing Federal hydro system in its models. MicroPort is also currently being adapted to perform hourly analysis by incorporating constraints on the hourly operation of plants.

Inputs

As its primary input, MicroPort uses the results of the Needs Assessment, specifically monthly average HLH energy deficits at the P10 level, although it retains the ability to use nearly any of the Needs Assessment results. The 2012 Needs Assessment produces this data for two selected future years.

MicroPort treats the deficits produced by the Needs Assessment as "load" that it needs to meet by using a set of resources the user makes available to it. Currently, the model has the ability to use conservation, the wholesale market, a combined-cycle natural gas combustion turbine (CT), and a simple-cycle CT to meet these deficits. The user can specify any combination of those resource options (portfolio). The model also contains information on the cost characteristics of those resources, including both total variable cost and total fixed costs. Cost information for the thermal plants and conservation is sourced directly from the BPA Resource Program, which uses the MicroFin spreadsheet model for generating resource costs and BPA's Conservation Resource Energy Data report (the RED Book) for conservation costs. Market purchases are valued at the most-recent BPA long-term price forecast from the AURORAxmp production cost model consistent with the Market Assessment forecast.

Linear Program

The linear program in the model has an objective function to minimize the total variable cost of eliminating deficits, subject to these constraints: resources have to meet load, and each resource can be used only up to its maximum specified capacity (set by the user; this can be thought of as the resource's capacity or the market depth if the resource is a market purchase).

The model examines each month independently, first taking the resource with the lowest variable cost and using it either up to its maximum specified capacity or until the deficit for that month is met. If after applying the lowest variable cost resource up to its capacity the deficit is still not met, the model moves to the next available resource with the lowest variable cost. It does this until the deficit for the month is met. At the end of this stage of the model, one can imagine that for each month in the study, there is a resource "stack" with the lowest-cost resources at the bottom of the stack and the most-expensive resource to run at the top.

In the next step, the model calculates the total variable cost of meeting all of the deficits in the study and adds the fixed costs associated with the particular set of resources the user specified. In this way, the model produces a total yearly cost for eliminating deficits using whatever resource strategy the user set before running the program.

Portfolio Selection

MicroPort can perform the above process for several different potential portfolios, calculating total costs for each. For example, the user may be interested in the cost of using only market purchases and conservation, but the user may also be interested in whether adding a 100 MW simple-cycle CT can lower the overall costs of meeting deficits. In other words, will the fixed costs associated with a simple-cycle CT be worth the investment if the plant has a lower variable cost than the market or conservation? One can imagine two portfolios: (a) one containing only conservation and market purchases, and (b) another containing conservation, market purchases, and a simple-cycle CT. MicroPort will run the linear program for each, "dispatching" both (a) and (b) in the most optimal manner. The model will calculate a total (variable plus fixed) cost for each portfolio. Comparing the total costs from each portfolio will determine whether adding the gas plant to the portfolio decreased the overall cost as hypothesized. If multiple portfolios are input, MicroPort will run through all of them and perform the linear program repeatedly in order to determine the total cost of each.

In this way, the user can view a group of different portfolios, the way in which each is used to meet the particular deficits found by the Needs Assessment, and the costs associated with each portfolio.

Stochastic Gas and Power Prices

The above examples assume that the price forecasts for power market purchases and for natural gas as a fuel for the CT were discrete. That is, each study was done using one market price forecast and one gas forecast. MicroPort can also treat gas and power prices as stochastic variables coming from a distribution of prices and sampled many times (sometimes referred to as "games"). This capability can be desirable, as prices for both commodities have historically been volatile, and relying solely on either would carry cost uncertainty for BPA. BPA already models this uncertainty in forecasting both prices as distributions in the AURORAxmp model. AURORAxmp takes a distribution of natural gas prices as one of its inputs, and its primary output is a distribution of power prices. MicroPort can use both of these distributions as inputs in repeated games, with gas and power prices fully correlated with each other. Thus, if a certain MicroPort game uses a low gas price, it will also use the low power price that was associated with it in AURORAxmp originally.

Costs and Risk

As part of the above processes, the model calculates the costs of meeting needs and can report costs in a variety of ways—by year, by month, and for fixed and variable costs. Types of costs can be taken whole or specified by resource type. Currently MicroPort has two different risk metrics built in: the simple standard deviation in costs for a portfolio (under different price scenarios), and the TailVar90. The Northwest Power and Conservation Planning Council uses the average of the worst 10th percentile outcomes in its planning as its risk metric.

Graphics and Charts

MicroPort contains code that produces graphics at several points, including the following:

- Monthly charts showing deficits and makeup of the resource stack
- Yearly charts showing exposure to market price risk under a full distribution of games (2,400 games)
- An "efficient frontier" chart showing how each portfolio of resources performed concerning both costs and risk (standard deviation or TailVar90)

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