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

2010 Resource Program

September 2010

Cover photo of Klamath Cogeneration combustion turbines courtesy of Iberdrola Renewables.

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Road map to the Resource Program document

The Resource Program draws on many sources and computer models both within and outside BPA. This roadmap describes what may be found in each chapter and how the data relates and differs from one chapter to the next.

Chapter 1	**Background and Context:** Describes the purpose and objectives of the Resource Program.
Chapter 2	**Market Uncertainty:** Examines likely cost drivers in the wholesale power market of the Western Interconnection. The data and forecasts in this chapter pertain to the entire Western Interconnection market (not just BPA and not just the Northwest). Some of the information in this chapter comes from the Northwest Power and Conservation Council and some from other sources. This chapter displays a range of economic forecasts for the Western Interconnection to describe the scope of uncertainties in future power market and resource prices.
Chapter 3	**Total Supply Obligation Forecast:** Examines BPA's expected power supply obligations specific to the expected loads of BPA utility customers and other BPA contractual and legal obligations. This forecast is the basis for the forecast loads used in the Needs Assessment.
Chapter 4	**Needs Assessment:** Takes BPA's supply obligations and compares them to BPA's existing resource base to define any deficits. The resource base shown is consistent with the BPA 2010 White Book. There are annual energy deficits around 350 MW in 2013 and 400 MW in 2019. Winter Heavy Load Hour deficits are sizeable but are below the 1000 MW threshold for long-term purchasing. Late summer Heavy Load Hour deficits exceed the threshold for purchasing. There is surplus capacity to meet 3-day winter extreme cold snaps, but the capacity for summer heat waves is roughly in load-resource balance, with little buffer for load uncertainty. **Section 4.7 of the Needs Assessment:** Shows that conservation can help meet the resource deficits, but the impact of conservation on BPA's load obligation is not enough to change the findings of the Needs Assessment.
Chapter 5	**Resource Evaluation:** Describes factors BPA considers on a policy basis (in addition to legal requirements) in assessing resource alternatives.
Chapter 6	**Resource Descriptions:** Describes various resources using the Council's Sixth Power Plan and other sources. This chapter also describes planned federal hydro improvements and BPA energy conservation (including demand response), both of which are reviewed in other public processes and thus are outside the scope of the Resource Program.
Chapter 7	**Resource Assessment:** Discusses the relative merits of resource alternatives to meet BPA's remaining power supply needs after accounting for energy conservation and prudent market purchases. This discussion includes the resource levelized cost and availability assessments in the Council's Sixth Power Plan.

Chapter 8 **Conclusions:** General summary of results.
Chapter 9 **Action Plan:** Proposed actions**.**

Resource Program
Executive Summary

BPA has prepared a Resource Program to evaluate whether and what resources it may need to acquire to meet its power supply obligations, primarily to customers under Regional Dialogue contracts beginning in fiscal year 2012. The planning horizon extends through 2019. During preparation of the Resource Program, BPA coordinated closely with the Northwest Power and Conservation Council as it developed its draft and final Sixth Power Plan.

Recent events, including the current economic recession, have decreased BPA's near-term resource need. BPA expects to be able to meet most of its anticipated needs over the next few years through conservation—as called for by the Council's Sixth Power Plan—and short- and mid-term power purchases from the market. BPA, in partnership with public power, is committed to meeting public power's share of the Council's final conservation targets.

How much more power supply, if any, BPA will need to secure after achieving conservation targets will depend in large part on the outcome of a number of uncertainties about loads placed on BPA:

- Preference customer choices of power supplier(s) for their above-High Water Mark load beyond the initial election period
- Potential formation of new public utilities or tribal utilities that can place load on BPA
- Increased load service to DOE-Richland
- Long-term service to the region's direct-service industrial customers
- Wind power integration needs in the BPA balancing authority area

Other uncertainties that could affect BPA's need for additional resources include timing and strength of economic recovery, the rate of long-term load growth, fish requirements that impact hydro generation, success of conservation efforts, and others.

Depending on the outcomes of these uncertainties, BPA's largest and likeliest power needs after conservation are for:

- Energy for seasonal and monthly Heavy Load Hour power demands in winter and late summer
- Balancing reserves to replace flexibility that has been lost in the system and to help support variable energy resources, such as wind power
- Annual energy, which may be met largely by purchases for seasonal needs

BPA is working with regional utilities to develop technologies and operating techniques that could help meet these potential power supply needs. This area includes efforts to:

- Increase the flexibility of transmission grid operation to accommodate wind and other variable energy resources, through efforts such as the projects outlined in BPA's Wind Integration Team Work Plan
- Develop Smart Grid technologies, which also will increase transmission flexibility
- Directly involve electricity users through demand response programs

BPA is actively pursuing all these areas. The Resource Program analysis reinforces the importance of these efforts.

To support development of renewable and high-efficiency resources, BPA also will assess and identify cost-effective small-scale renewable and cogeneration resources in the Northwest considering customer interests and BPA's resource need.

In addition to relying on conservation as its highest priority resource, as a matter of sound business practice and to ensure reliability, BPA will continue to:

- Rely on wholesale power market purchases
- Monitor the areas of uncertainty, noted above, in order to adapt resource acquisition strategies as necessary
- Track, evaluate, and appropriately pursue availability of pumped storage and natural-gas-fired resources, such as combustion turbines, simple cycle turbines, and/or reciprocating engines, to provide seasonal Heavy Load Hour energy and/or balancing reserves

Currently BPA does not foresee the need to acquire any major resources. There is need to begin rebuilding BPA's ability to acquire resources so that BPA is ready to move quickly to acquire power resources in the event additional energy and/or capacity are needed as the current load and regulatory uncertainties are resolved.

Chapter 1. Background and Context

1.1 Introduction

The 2010 Resource Program includes a forecast of Bonneville Power Administration's expected needs for additional power supplies to meet its total supply obligations over the next 10 years. The Resource Program outlines BPA's proposed approach to meeting those needs. It also expresses how BPA plans to implement relevant portions of the Northwest Power and Conservation Council's Sixth Power Plan.

BPA expects to update the Resource Program periodically as load forecasts, the Council's Power Plan, customer requirements, and resource opportunities evolve.

1.2 Purpose of the Resource Program

BPA markets the output of the Federal Columbia River Power System, which consists of 31 hydroelectric projects and one nuclear power plant. BPA does not own generating resources. When BPA uses the term "acquire resources," BPA is referring to contract purchases, not project ownership.[1]

Under the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), any Northwest utility that is a qualified 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 now supplies roughly one-third of the Northwest's wholesale electric power. Also under the Northwest Power Act, BPA has the authority to acquire resources to meet its contractual obligations. To meet these needs and other statutory obligations, BPA must plan a reliable and adequate supply for all its expected power needs.

In 2008 BPA executed long-term Regional Dialogue power sales contracts for fiscal years 2012-2028 with 135 Northwest publicly owned utilities, federal agencies, tribal utilities, and a port authority. Under these contracts, customers have the option to make resource decisions that increase the amount of federal power BPA is obligated to supply.

BPA is statutorily obligated to offer contracts to supply the firm power loads of the region's utilities net of the non-federal resources they use to serve their loads, i.e., net requirements. BPA also has the obligation to provide generation inputs that support transmission grid stability in the BPA balancing authority area and services that support BPA's open-access transmission marketing function. Thus, there may be a need for additional generation inputs to support BPA transmission services, including transmission capacity and balancing services.

To be in a position to meet future power supply demands placed on BPA by its power and transmission users, it is prudent that BPA develop a Resource Program.

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[1] A BPA purchase obligation can include responsibilities similar to ownership-type rights if it includes the purchase of total life-time output of a power plant and the assumption of development and operational risks.

1.3 Background on Regional Dialogue contracts

BPA's Long-term Regional Dialogue Policy of 2007 provides the policy basis for the new Regional Dialogue power sales contracts. BPA worked with its regional customers to develop new long-term power sales contracts and an accompanying new Priority Firm Power (PF) rate design, the Tiered Rate Methodology. Together, the Regional Dialogue contracts and Tiered Rate Methodology are intended to distinguish the costs of existing federal power supplies from the costs of additional new resources. As such, the Resource Program will provide customers with information to guide their power purchase decisions as they choose whether to meet their load growth through BPA or other sources.

The Regional Dialogue power sales contracts, covering fiscal years 2012-2028, were executed in December 2008. At that time, 118 Northwest publicly owned utilities, tribal utilities, federal agencies, and a port authority chose to have BPA provide load following services to meet variations in their load.

The remaining 17 publicly owned utilities signed Slice/Block contracts, thereby choosing to meet load variations themselves. No customer chose to purchase the Block product without Slice. Under the Slice product, the amount of firm and non-firm energy a customer is eligible to purchase is indexed to the capability of the Tier 1 System, after all Tier 1 system obligations and operating constraints are met. (The Tier 1 System, as defined in the Tiered Rate Methodology, is made up of the resources and contract purchases that comprise the Tier 1 System Resources and the contract loads and obligations that comprise the Designated BPA System Obligations.) Collectively, Slice customers will purchase about 27 percent of the annual Tier 1 System power output. Under the Block product, customers can purchase a defined annual amount of firm power at Tier 1 or Tier 2 rates.

A fundamental tenet of the Regional Dialogue Policy is to limit BPA's sales of firm power at the lowest cost-based rates to approximately the firm capability of the existing federal system (i.e., the Tier 1 System). BPA will sell each preference customer an amount of firm power at Tier 1 rates up to the lower of its net requirements load or a maximum amount known as the customer's High Water Mark.[2]

Additional loads may be served by each customer's own resources or by BPA net requirements power sales that are subject to Tier 2 rates, which will reflect the costs of the resources BPA uses to serve that additional amount of load. Firm power sales under the Regional Dialogue contracts and tiered rates set under the Tiered Rate Methodology will begin in fiscal year 2012, which starts October 1, 2011. Investor-owned utilities, if they choose to purchase from BPA to meet their net requirements, would buy under BPA's New Resource rate.

[2] The term High Water Mark is used generically in the Resource Program document to encompass the various forms of High Water Marks customers will experience, including transitional, provisional, contract, and rate period High Water Marks.

By clarifying utilities' responsibilities and choices for meeting their load growth and separating the costs of resources added to the federal system, the Regional Dialogue contracts and tiered rate structure will promote better-informed development of electric infrastructure in the Northwest.

1.4 Customer choice drives BPA resource planning

Giving its customers a real choice in their power supplier is a primary BPA goal, with the intention to reflect the direction of the region and ensure timely resource infrastructure construction. In providing customers with opportunities to make these resource election choices, BPA opens itself up to significant load obligation and timing uncertainties. Uncertainties about the service choices BPA customers might make over a 10-year planning period and a 17-year contract period have resulted in a different Resource Program from previous plans. Likewise, this Resource Program is different from the integrated resource plans developed by other utilities. BPA and other utilities all face uncertainties about load growth and the performance of existing resources. BPA is unique, however, in that it also has many customers that can choose whether to buy from BPA or from some other supplier or build and operate their own generation. The range of choices customers may make creates a wide range of uncertainty about the timing and level of BPA's acquisition needs.

Preference customers made their resource elections under the Regional Dialogue contracts through the first commitment period, 2012-2014, on November 1, 2009. These initial customer choices are reflected in the Needs Assessment and determined the size, type, and timing of BPA's power supply obligations in those years. In 2011 customers will make resource elections for the next commitment period, 2015-2019. This pattern will repeat two more times: once for a five-year interval and once for a four-year interval during the term of the Regional Dialogue power sales contracts, as outlined in Table 1-1.

Table 1-1 – Notice deadlines for electing above-RHWM service from BPA

Notice Deadline		Purchase Period
November 1, 2009	for	FY 2012 – FY 2014
September 30, 2011	for	FY 2015 – FY 2019
September 30, 2016	for	FY 2020 – FY 2024
September 30, 2021	for	FY 2025 – FY 2028

<u>Preference customer load uncertainties</u>

- Existing preference customers may elect to have BPA serve all, a portion, or none of their above-High Water Mark load.
- If customers choose to use non-federal sources to serve all or part of their loads above their High Water Marks, they may purchase Resource Support Services from BPA for resource shaping and balancing reserves to integrate this generation. This last choice should not place a significant net annual

energy burden on BPA, but it could create seasonal or diurnal energy and capacity obligations for BPA. Commitments to purchase Resource Support Services are made for 3-5 year periods that correspond with the resource election commitment periods. Customers elected only very small amounts of RSS for the first commitment period.

Additional load uncertainties[3]

- Prospective new publicly owned utilities have a choice about whether to form a utility and buy power from BPA. In each 2-year rate period, up to 50 average megawatts of augmentation can be made to serve new publicly owned utility load to be served at Tier 1 rates, up to a total of 250 average megawatts over the duration of the Regional Dialogue contracts. BPA will augment the Tier 1 System by these amounts, as needed, and meld those costs into Tier 1 rates. New publicly owned utility load over and above these amounts may materialize, but any power supplied by BPA beyond these limits would be priced at Tier 2 rates. BPA has a signed contract with one new publicly owned utility, which plans to start taking power from BPA July 1, 2013. For more detail on new public and tribal utility loads, see section 4.6.3.
- Currently, BPA's power sales contracts with its direct-service industrial customers are being litigated. For the Needs Assessment, BPA included one contract extending through September 30, 2016, in the base case and included two other possible DSI contracts in the high case. See Chapter 4 for details.
- The Department of Energy (DOE-Richland) has a contractual right to up to 70 average megawatts of power within its High Water Mark for a nuclear waste vitrification plant on the Hanford Reservation in Washington. This load is expected to come on line in increments, but the timing is highly uncertain.
- Wind developers have a choice about whether to locate in BPA's balancing authority area. Within the next year or two, they may receive a choice of whether to supply their own balancing reserves or rely on BPA for these services. By October 1, 2010, BPA intends to initiate a pilot project to allow a wind generator located inside the BPA balancing authority to supply its own balancing reserves from non-federal resources.

To supply above-HWM loads, BPA may determine the need to acquire power. As such, BPA may make shorter-term acquisitions from the market for meeting its Tier 2 Short-term Rate load obligation. BPA will combine shorter-term and longer-term acquisitions from the market and resources for meeting its Tier 2 Load Growth Rate load obligation. If BPA offers a Tier 2 Vintage Rate to customers, the type of acquisition made to meet the obligation this creates will be driven by customer interest and BPA's need. The resource attributes and cost cap for acquisitions made to meet the Tier 2 Vintage Rate load obligations will be set and defined when such a rate is offered.

[3] See section 4.6 for further discussion of load uncertainties.

Each of these options or any combination of them would create a different resource need scenario for BPA. For the Needs Assessment, BPA assumed that customers would make Tier 2 elections in future commitment periods in the same proportions as in the first commitment period. Chapters 3 and 4 discuss high and low load scenarios as well, to address economic and contractual load uncertainty.

BPA has been working with its preference customers on the choices they face in structuring their new business relationship with BPA under the Regional Dialogue contracts and tiered rates. The draft Resource Program analysis helped inform this process and customers' first resource elections in November 2009, and this 2010 Resource Program will continue to inform the process, including customers' next resource elections in September 2011.

1.5 Additional planning uncertainties

BPA faces uncertainties beyond customer choice that also affect resource planning. Some of these uncertainties are specific to BPA.

> BiOp requirements: The 2008 Biological Opinion on FCRPS operations to protect salmon and steelhead listed under the Endangered Species Act is under litigation, and the outcome is not yet known.
>
> Balancing reserves: As a balancing authority operator, BPA Transmission Services is required to sell ancillary services, including balancing reserves, to support all generation in its balancing authority area. Transmission Services purchases generation inputs from BPA Power Services to support balancing reserves and other ancillary services. A key uncertainty is to what extent BPA may need to acquire additional resources to provide these balancing reserves. This uncertainty is driven by both the uncertainty of the amount of wind generation development in BPA's balancing authority area and to what degree efforts to reduce balancing reserve requirements will be successful. BPA will continue to work with the utility and wind communities to improve scheduling accuracy and devise new transmission operating techniques, business practices, and institutional arrangements that can help reduce overall reserve requirements for variable generation and better define BPA's future obligation.
>
> Hydro supply: Variations in monthly, seasonal, and annual Columbia River water supply are a significant, fundamental, and familiar uncertainty in BPA power planning. The techniques for addressing these variations are well established, and begin with basing resource planning on critical water, the expected output of the Columbia River System under extremely poor water conditions.

BPA also shares numerous 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:

> Load growth: Any utility faces uncertainties about load growth, even during stable economic times, due to temperature fluctuations, population demographics, and changing power use patterns. The current economic condition creates

uncertainty around the timing and extent of economic recovery and levels of load growth following recovery.

Greenhouse gas emission constraints: Regulatory bodies at the local, regional, national, and international levels are responding to global climate change with restrictions and/or penalties on greenhouse gas emissions. All of these efforts, if and when implemented, will change the economics of generation options and increase the cost of fossil-based power generation. While the future imposition of some form of carbon emission costs is almost certain, the timing and magnitude of these increased costs are not known. In the Resource Program, BPA uses existing state Renewable Portfolio Standard requirements as the basis for its analysis and analyzes the wholesale power market price impacts of three CO_2 price scenarios.

Emerging technologies: The electric power industry is undergoing a paradigm shift. Examples are Smart Grid, conservation innovations, and the potential for plug-in electric vehicles to serve as both a power load and a form of power storage.

Natural gas price uncertainty: In recent years, with the addition of many new natural gas burning plants, natural gas prices have become instrumental in setting the price of electricity on the margin in the Western Interconnection. The volatility in natural gas prices has caused electricity prices to average between $30 and $60 per megawatt-hour in recent years. Historically, even greater price ranges have been seen in spot market prices, with prices of thousands of dollars per megawatt-hour during the West Coast power crisis to occasional negative pricing (paying a purchaser to take power).

Financing uncertainties: The health of financing markets can affect capital costs and availability of financing for generating projects; this uncertainty is especially relevant given the current economic conditions.

In sum, electric utilities in general and BPA in particular now face an exceptionally wide range of power supply, demand, and market uncertainties.

1.6 Resource Program objectives

BPA's objectives for the 2010 Resource Program are to:

1. Assess BPA's need to make acquisitions by means of BPA's Needs Assessment, including defining the range of needs that could be created by high and low load scenarios.
2. 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.
3. Inform customers' decisions as they make their above-High Water Mark load elections by providing information about BPA's likely resource acquisitions.

4. Involve stakeholders and build external stakeholders' understanding of BPA's likely resource acquisition choices and timing.
5. Build analytical capability. Build BPA's resource planning and analytical capability to support future decisionmaking.

1.7 Consistency with the Council's Plan

The Northwest Power and Conservation Council publishes a Northwest Power Plan at least once every five years in accordance with the Northwest Power Act. BPA developed the 2010 Resource Program to be consistent with the Sixth Power Plan. BPA worked closely with Council staff throughout preparation of the Council's draft Sixth Power Plan and the draft Resource Program and provided comments to the Council on its draft power plan. Chapter 9 of this Resource Program reflects how BPA intends to implement relevant aspects of the Council's Sixth Power Plan.

In most cases, BPA has used Council information in BPA's resource analysis and assumptions. Differences are articulated and explained in the relevant sections. The differences largely reflect BPA-specific requirements, such as the expected high penetration rate of wind power on the BPA grid and the need to ensure sufficient operating reserves to support this variable energy resource.

The Northwest Power Act requires specific procedures if BPA proposes to acquire the output of a "major resource," one with a planned capability greater than 50 average megawatts acquired for more than five years. BPA would review any proposed major resource acquisition for consistency with the Council Power Plan then in effect, as required under section 6(c) of the Northwest Power Act.

1.8 National Environmental Policy Act

BPA's Resource Program is a vehicle for evaluating resource options and identifying potentially optimum resource choices, but no decision concerning the acquisition of any resource is made in the Resource Program. The Resource Program provides information BPA can use to make informed resource acquisition decisions in the future, if needed.

BPA will conduct National Environmental Policy Act 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 unique circumstances presented 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, 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 are still 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.

1.9 Preparation of the 2010 Resource Program

BPA began planning for its Resource Program in early 2008 because, at that time, forecasts suggested BPA likely would need to acquire resources to augment the FCRPS for initial power sales at Tier 1 rates in 2012 and meet customers' load growth served at Tier 2 rates as early as 2013. BPA delayed completion of the draft Resource Program until 2009 to focus on completing the Regional Dialogue contracts.

In March 2009, BPA held two public workshops and requested public comments on a Preliminary Needs Assessment and various new BPA analytical tools. The Preliminary Needs Assessment examined BPA's power needs from several perspectives, including BPA's existing load-resource balance; potential effects of customers' load placement choices under the Regional Dialogue contracts, which will take effect beginning in 2012; and requirements to support the growing amount of wind generation being connected to BPA's transmission grid. For the FY 2013 load forecast the 2010 Needs Assessment incorporates customer elections for the first commitment period, and for the FY 2019 load forecast assumes customers will make similar choices in the future.

The draft Resource Program included a draft Needs Assessment that reflected much-lower potential resource needs due to revised economic projections. That Needs Assessment also reflected comments received on the Preliminary Needs Assessment and new approaches to reducing the need for balancing reserves for integration of variable energy resources, such as wind power. The results of the draft Needs Assessment and BPA's approach to the Resource Program were presented at a public workshop on August 25, 2009. That workshop also addressed the Resource Program approach and next steps.

BPA released the draft Resource Program on September 30, 2009, and made it available for public comment until November 30, 2009. BPA held a workshop on October 14, 2009, that provided an overview of the draft Resource Program and encouraged public input. Appendix H summarizes the public comments, grouped by topic. As an informational tool that will, by its nature, evolve over time to reflect changes in BPA load supply obligations, resources, and other variables, the Resource Program does not represent a final decision or action of the Administrator.

Chapter 2. Market Uncertainties

2.1 Introduction

In Chapter 1 of this Resource Program, BPA listed a number of planning uncertainties that it faces. To further consider implications to future power market conditions, in this chapter BPA examines how some of these planning uncertainties might impact long-term trends in market prices. These planning uncertainties include a range of alternative future scenarios for:

- Economic growth (both load growth and natural gas prices)
- Potential costs of carbon emissions associated with power production
- Pacific Northwest hydroelectric generation variability

As discussed later in this chapter and in Appendix B, BPA used AURORAxmp® to model the effects of these planning uncertainties on electricity market prices. For the Resource Program, BPA did not take the next step of quantifying the benefits, costs, and risks of different types of resources under the different market uncertainties. To quantify the benefits, costs, and risks associated with power purchases from resources to meet a specified need, BPA would need to employ a more complete modeling method. One possible screening tool is described in Appendix F.

2.2 Methodology and basic assumptions

The Resource Program reflects a simplified market price analysis. BPA developed a set of scenarios to analyze a range of possible future outcomes instead of performing a stochastic analysis. BPA used the AURORAxmp® price forecast model, which is commonly used in utility business, to produce electricity price forecasts from the different scenario inputs. Many of the assumptions underlying BPA's AURORAxmp® analysis are consistent with those of the AURORAxmp® analysis the Council used in preparing its Sixth Power Plan. Significant changes include natural gas price forecasts, carbon price forecasts, hydroelectric generation forecasts, and use of high and low load growth rates derived by BPA. These changes were made primarily to reflect using a scenario approach to modeling specific uncertainties rather than a stochastic analysis.

2.2.1 <u>Scenario tree approach</u>

BPA used a set of scenarios—referred to as a scenario tree—to analyze future electricity market conditions. The scenario tree displays different possible market futures as branches to provide a range of possible economic growth and carbon cost futures. BPA varied the values of several key electricity market drivers within the scenario tree's economic and CO_2 scenarios.

The economic scenarios represent a combination of Western Electricity Coordinating Council load growth rates, forecasts of natural gas prices, and future carbon dioxide emission price scenarios. CO_2 scenarios represent various CO_2 prices that could result from future legislation and/or regulatory action. These different scenarios were then evaluated under different hydroelectric generation or water conditions.

Note that, while CO_2 prices are varied over the scenario tree, Renewable Portfolio Standards that may be required of utilities are not varied. Throughout the analysis, existing state Renewable Portfolio Standards requirements were held constant with the standards assumed in the Council's AURORAxmp®-based analysis for its Sixth Power Plan. Three of four Northwest states have existing Renewable Portfolio Standards requirements. California increased its Renewable Portfolio Standards requirement to 33 percent by 2020 through executive order and determined that it will seek to import renewable energy from other states. This increase in California's Renewable Portfolio Standards requirement and its potential effects on the Western market for renewable resources are not reflected in this analysis.

Modeling of the scenarios uses the following assumptions (see Figure 2-1):

- In the "Boom" scenario, BPA assumed a rapid, robust economic recovery and an average annual load growth rate of 2.79 percent through 2019 in the Pacific Northwest. This scenario assumed Henry Hub natural gas prices would average $8.50 per million British Thermal Units in nominal dollars during calendar years 2012-2019. For this scenario, BPA also assumed that CO_2 prices would match the Council's Sixth Power Plan's "central tendency" estimate, which tops out at $57/ton in 2019.[4]
- In the "Recovery and Modest Growth" scenario, BPA assumed a moderate economic recovery with an average annual load growth rate of 1.53 percent in the Pacific Northwest. BPA assumed Henry Hub natural gas prices would average $6.26 per million BTU in nominal dollars during calendar years 2012-2019. BPA used three CO_2 price assumptions for the "Recovery and Modest Growth" scenario:
    - High: Reaches $57/ton in 2019 (2019 $) (using the Council's Sixth Power Plan's central tendency CO_2 price estimate).[5]
    - Medium: Rises to $32/metric ton in 2019 (2019 $) (based on the Energy Information Administration's base-case estimate of the cost of implementing HR 2454, the Waxman-Markey Bill[6]).
    - Low CO_2 price (zero).
- In the "Prolonged Recession" scenario, BPA assumed a slow economic recovery and an average load growth rate of 0.88 percent in the Pacific Northwest. BPA assumed Henry Hub natural gas prices would average $4.41 per million BTU in

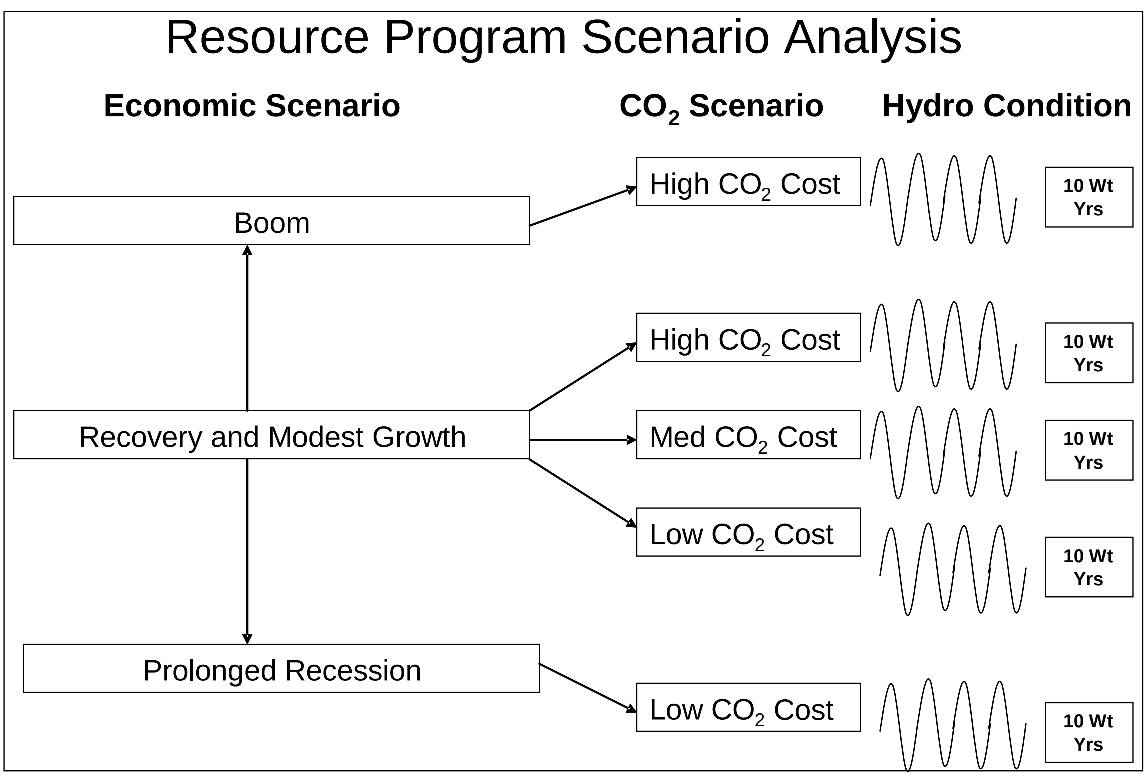
[4] Note: Council central tendency price estimates were pushed out by two years, to reflect regulatory delay that was not apparent at the time the Sixth Plan analysis was conducted.
[5] Note: Council central tendency price estimates were pushed out by two years, to reflect regulatory delay that was not apparent at the time the Sixth Plan analysis was conducted.
[6] As with the Council's estimate, the EIA's estimates of CO_2 prices were pushed out by two years to reflect regulatory delay.

nominal dollars during calendar years 2012-2019. BPA assumed a CO_2 price of zero for this scenario.

To address hydroelectric generation variability under different water supply conditions, all three scenarios use 10 different 10-year continuous water strips of hydro conditions. To develop the water year strips, BPA identified the 10-year subsets of 70 historical water years (water years 1929-1998) that represent a range of historically observed 10-year average energy outputs from the FCRPS hydro system. Analyzing results from all 70 historical water years is the preferred approach. However, BPA needed to reduce the substantial amount of computational time required by the software model. Therefore, BPA incorporated hydroelectric generation risk into the Resource Program with the 10-year subset.

The base case load forecast for the Recovery and Modest Growth scenario is a regional load forecast that is consistent with the Council's regional forecast. This load forecast is used only in the AURORAxmp® model and not in any other analysis in the Resource Program. However, the Recovery and Modest Growth load forecast is similar to the results of the BPA regional forecast, which is further discussed in Appendix C, section C.3. The sources of the Boom and Prolonged Recession load growth rates are historical load growth rates analyzed by BPA staff and are intended to provide a reasonable range for future outcomes. These growth rates are applied to the Recovery and Modest Growth scenario load forecast.

Figure 2-1 – Resource Program scenario analysis

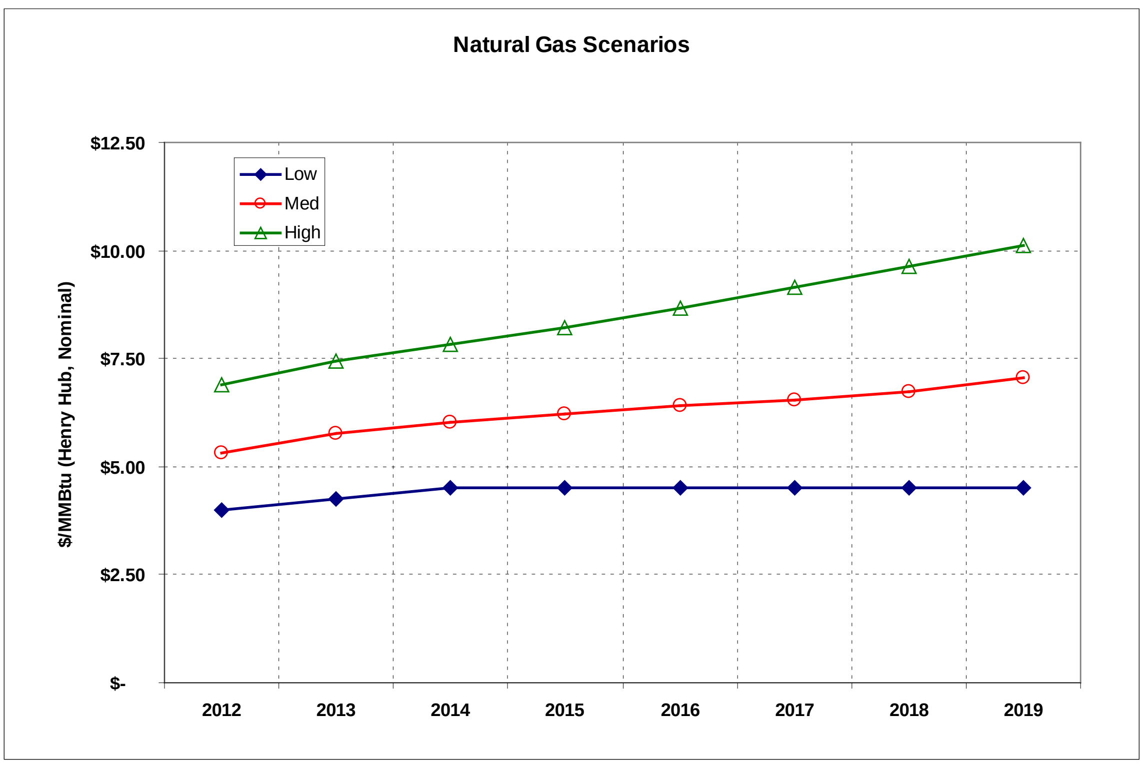


2.2.2 Natural gas price scenarios

BPA developed three natural gas price scenarios to support the economic scenarios (see Figure 2-2). These price scenarios are not based on the Council's gas price forecast and are updated from the draft Resource Program. They can be described as the following:

- A high natural gas price scenario assuming strong economic recovery with dramatically increased demand and upward pressure on natural gas prices.
- A medium natural gas price scenario assuming a short-term economic recovery. This recovery, in combination with cyclical natural gas patterns, was assumed to lead to a short-term increase in prices. The mid-/long-term price path assumed moderate growth with upside power sector demand growth met by increased global liquefied natural gas capacity and production of natural gas from unconventional resources in North America such as shale oil deposits.
- A low natural gas price scenario assuming long-term slow load growth in the economy leading to weak natural gas demand. The prices in the low scenario are based on downward resistance levels for natural gas prices. The resistance levels are based on the cost of natural gas production displacing coal on a long-term basis, which essentially sets a floor for natural gas prices.

Figure 2-2 – Natural gas price scenarios (nominal $)

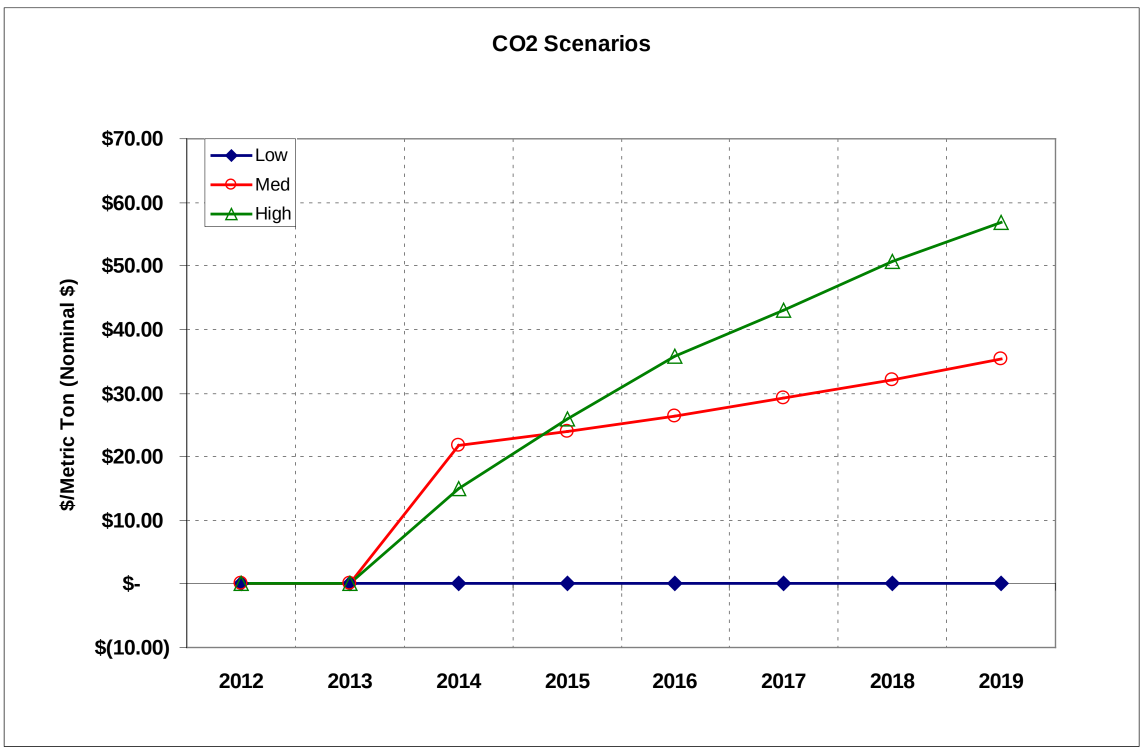


2.2.3 CO_2 scenarios

The CO_2 scenarios can be described by the following (see Figure 2-3):

- High CO_2 cost: Potential carbon costs are assumed to rise to about $57 per metric ton[7] of CO_2 by 2019 in nominal dollars. This is consistent with the "central tendency" CO_2 emissions cost path of the range of CO_2 costs in the Council's regional portfolio modeling for its Sixth Power Plan.
- Medium CO_2 cost: Potential carbon costs are assumed to rise to about $32 per metric ton of CO_2 by 2019 in nominal dollars. This scenario is based on an August 2009 Energy Information Administration base case forecast of the cost of implementing H.R. 2545, the Waxman-Markey Bill.
- Low CO_2 cost. For sensitivity comparison purposes, BPA assumed CO_2 costs of zero.

Figure 2-3 – CO_2 scenarios (nominal $)



2.2.4 Hydro variability

BPA has a wide variation in its monthly and annual hydroelectric generation due to the high variability in streamflows experienced in the Columbia Basin. In an effort to reduce

[7] The Council expresses CO_2 costs in U.S. tons. BPA converted the prices to metric tons for consistency with EIA figures. See also footnote 5.

model run-time, ten 10-year continuous water strips that ranged from the 5th percentile to the 95th percentile in terms of average 10-year hydroelectric energy produced were identified and used.

2.2.5 AURORAxmp® overview

BPA used AURORAxmp® to forecast Mid-Columbia electricity prices that result from the assumptions made in the different braches of the scenario tree. AURORAxmp® is owned and licensed by EPIS, Incorporated. AURORAxmp® is described in Appendix B.

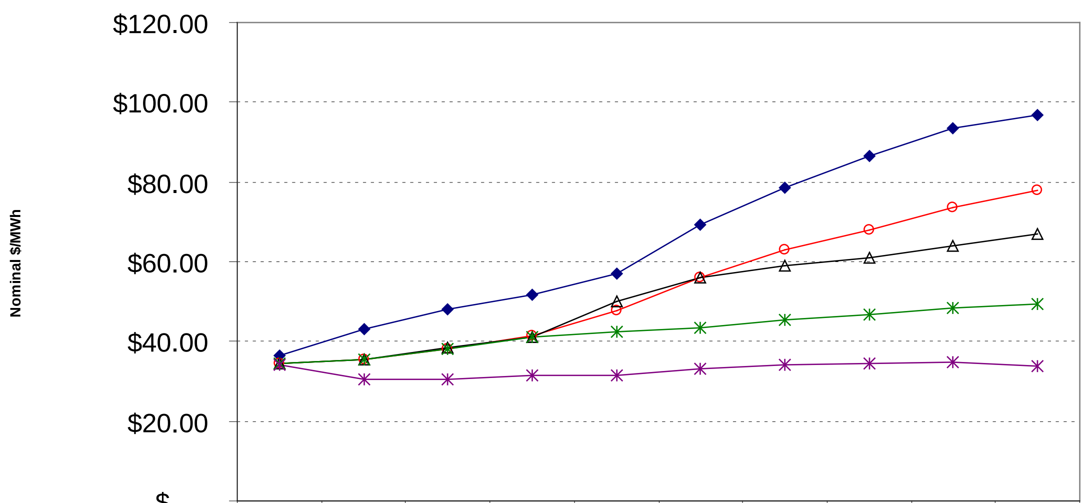
2.2.6 Application of AURORAxmp® for the Resource Program and price results

BPA produced separate price forecasts from AURORAxmp® for each of the scenario tree's five branches. To account for the wide variability in potential hydroelectric generation and the resulting potential effect on power prices, each of these five price forecasts consisted of an expected forecast, assuming average hydroelectric generation from the water year samples, plus 10 additional forecasts that resulted from the different hydroelectric generation values in the 10-year continuous water strips described above. Each of the resulting price forecasts resulted in monthly Heavy Load Hour and Light Load Hour Mid-C electricity prices from October 2010 through September 2019. Flat prices shown on the figures below represent the average price for all hours by month or year. Flat prices were derived by weighting the Heavy Load Hour prices by 57 percent and the Light Load Hour prices by 43 percent, consistent with the percentages of Heavy Load Hours and Light Load Hours in a year.

Figure 2-4 shows how Mid-Columbia power price forecasts vary under BPA's scenario assumptions.

- Mid-C annual prices averaged $33.89 per megawatt-hour in 2019 under the forecast for the Prolonged Recession scenario (low loads, low natural gas prices, and zero CO_2 costs).
- The three Recovery and Modest Growth scenarios isolated the impact of CO_2 costs, since the loads and natural gas prices were the same medium price outlook for all three scenarios. For FY 2019, the net power prices were as follows:
  - $49.48 per megawatt-hour in the zero CO_2 cost scenario
  - $66.93 per megawatt-hour in the medium CO_2 cost scenario
  - $77.88 per megawatt-hour in the high CO_2 cost scenario
- Prices averaged $96.78 per megawatt-hour in 2019 under the Boom scenario (high loads, high natural gas prices, and high CO_2 costs).

Figure 2-4 – Flat FY expected Mid-C price forecast (nominal $)



	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Boom	$36.30	$42.99	$48.21	$51.73	$57.10	$69.14	$78.69	$86.55	$93.32	$96.78
Recovery High CO2	$34.36	$35.58	$38.18	$41.37	$47.75	$56.07	$63.00	$68.06	$73.73	$77.88
Recovery Med CO2	$34.36	$35.58	$38.35	$41.13	$50.18	$55.97	$58.90	$61.09	$64.13	$66.93
Recovery Low CO2	$34.36	$35.58	$38.01	$41.25	$42.29	$43.55	$45.36	$46.64	$48.25	$49.48
Prolonged Recession	$34.07	$30.51	$30.66	$31.49	$31.58	$33.29	$34.06	$34.42	$34.76	$33.89

It is also useful to review the relationship between Heavy Load Hour and Light Load Hour prices. As stated above, the middle "Recovery and Modest Growth" economic scenario is analyzed with the three different CO_2 prices. Figure 2-5, Figure 2-6, and Figure 2-7 display the monthly Heavy Load Hour and Light Load Hour price relationships resulting from the Modest Growth scenario under different CO_2 price assumptions.

In the figures below, as the CO_2 price increased, the price difference between Heavy Load Hour and Light Load Hour prices decreased. This is due to the decrease in energy production from coal-fueled resources. From the low to high CO_2 price scenarios within the Modest Growth economic scenario, energy produced from coal-fueled generating resources declined. For example, in calendar year 2019, energy produced from coal-fueled generating resources fell from 3,227 average megawatts at the zero CO_2 price to 2,480 average megawatts at the high CO_2 price. Coal power plants were dispatched for fewer hours in the high CO_2 price scenario, while natural gas-fueled generating resources were dispatched during more Heavy Load Hours and Light Load Hours. The increased dispatch of natural gas-fueled generating resources in all hours decreased the price spread between Heavy Load Hours and Light Load Hours.

Figure 2-5 – Price forecast from modest growth/low CO_2 scenario

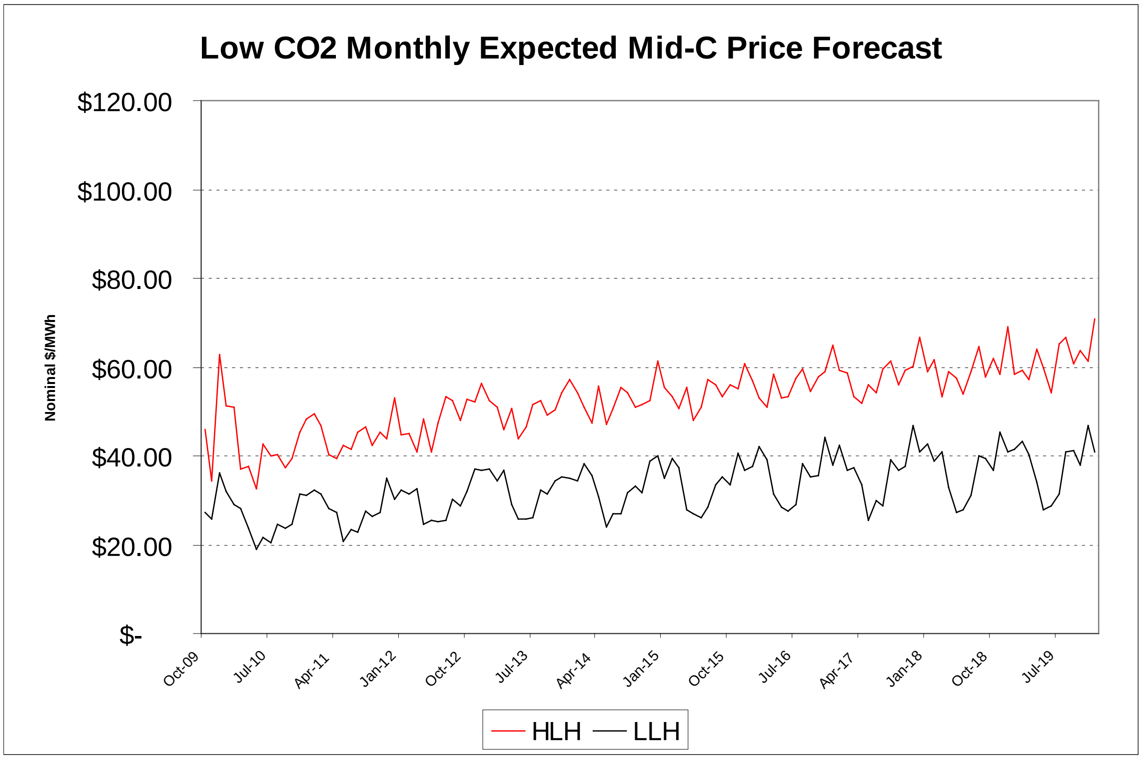


Figure 2-6 – Price forecast from modest growth/medium CO_2 scenario

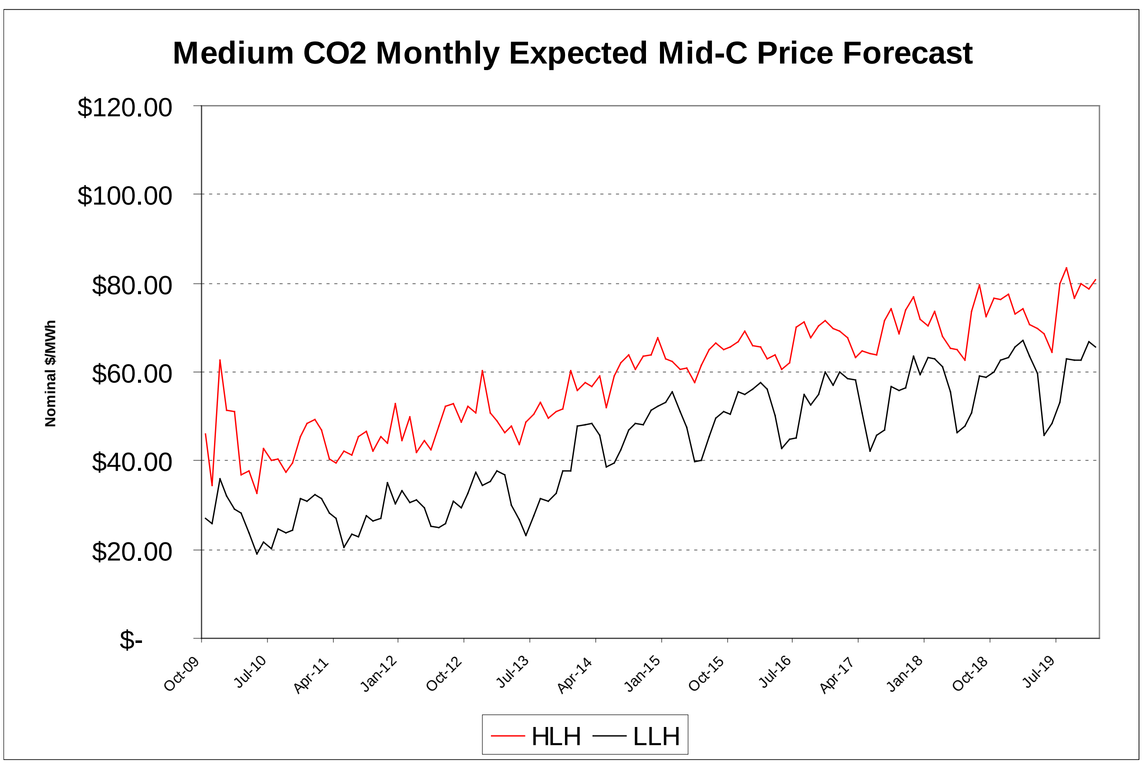
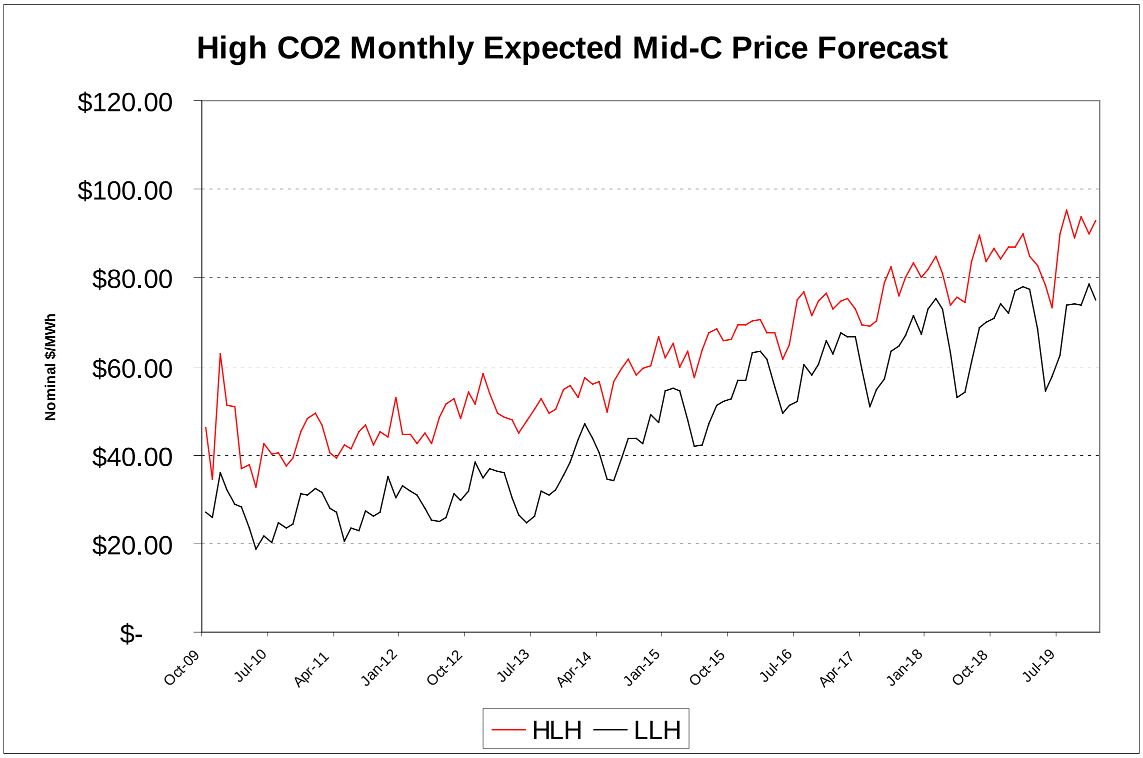


Figure 2-7 – Price forecast from modest growth/high CO_2 scenario



The prices in all the figures above are reflected in nominal dollars. The information, as well as the CO_2 prices, can also be found in real 2006 dollars in Appendix B. Also in Appendix B, information can be found on the effects that hydroelectric generation variability can have on the expected price forecast.

2.3 Limitations to the Market Uncertainty Analysis

For this Resource Program, several AURORAxmp® modeling compromises and limitations needed to be made:

- Renewable Portfolio Standards: Renewable Portfolio Standard requirements are typically based on a percentage of retail sales. If the assumed Pacific Northwest load forecast increases or decreases, it is appropriate to assume that retail loads change and the Renewable Portfolio Standard requirements should adjust accordingly. BPA produced price forecasts from three different load forecasts but did not account for the relationship between changes in retail loads and Renewable Portfolio Standard requirements. For this analysis, BPA used one set of Renewable Portfolio Standard requirements for all of the modeled scenarios. BPA's price forecast relied on the Council's Renewable Portfolio Standard forecast for all generating resource additions that were not selected by the AURORAxmp® long-term optimization logic. This assumption means that the forecast for installed wind capacity used in the price forecasts is less than the wind capacity assumptions made in the Needs Assessment.

- Reserves: For this analysis, BPA forecast Heavy Load Hour and Light Load Hour electricity prices. Relying on this type of forecast does not account for some of the impacts that variable energy resources have on reserve requirements. These impacts most likely will affect how resources operate and the resulting market prices.
- Load forecast: The load forecast used in this analysis accounts for the impact of the recession on Pacific Northwest loads only. The recession's impacts on the other WECC areas were not factored into the analysis. Since BPA markets power in the WECC, demand in other areas within the WECC also influences the market.
- The 10-year water hydroelectric data set developed to reduce the number of model runs is based on estimates of federal hydroelectric generation. These federal hydroelectric generation data are then translated into Pacific Northwest hydroelectric generation data for use in AURORAxmp®.

BPA conducted the analysis in this chapter to try to quantify the potential impacts of a number of planning uncertainties currently facing BPA and other utilities. Changes to the modeling approaches or limitations in this analysis would likely change the resulting electricity price forecasts.

Chapter 3. BPA Total Supply Obligation Forecast

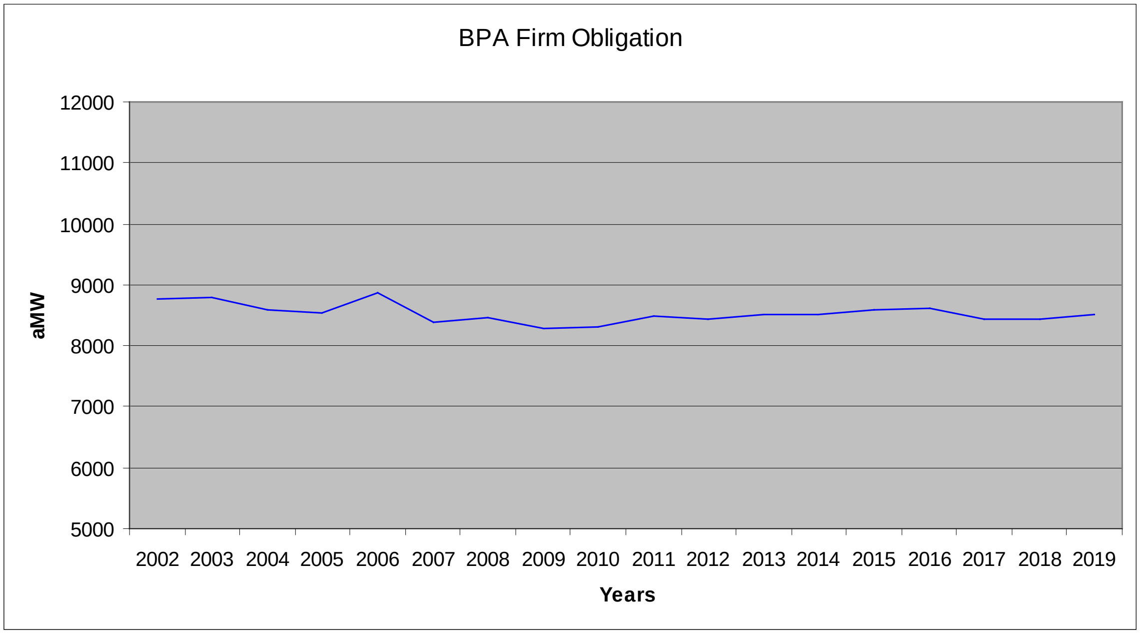
The load forecast discussed in the previous chapter was used to assess the potential effects of a number of uncertainties that bear on future power market conditions. For BPA's Needs Assessment, BPA produced a forecast of BPA's expected net load obligation, a subset of the total load forecast, which is the subject of this chapter.

The Resource Program is based on a forecast of BPA's expected contractual load obligations under Regional Dialogue contracts. This BPA firm power sales load forecast is produced by examining BPA's historical loads under existing Subscription contracts, comparing those contract obligations with upcoming Regional Dialogue contract obligations, and then estimating future loads under the new contracts and forecast economic growth.

Other BPA supply obligations, such as Canadian Entitlement power returns to Canada, station service at power plants, irrigation pumping load, and other obligations of the FCRPS, are included within the forecast. Uncertain loads, such as loads of BPA's direct-service industrial customers beyond current contracts, new publicly owned utilities, and additional DOE-Richland load, are excluded from the forecast and treated as separate variables. For the Resource Program, BPA completed high and low load growth forecasts for BPA supply obligations. These forecasts are consistent with the assumptions of the "Boom" and "Prolonged Recession" forecasts presented in the previous chapter.

The firm obligation for BPA is expected to grow in the future as energy consumption for the retail consumers of BPA customers grows. Figure 3-1 shows the net effect of this growth on BPA's firm obligation forecast. The growth rate for the base case scenario averages 0.3 percent from 2009 through 2019. The BPA firm obligation forecast forms the basis of the Needs Assessment for the Resource Program.

Figure 3-1 – BPA obligations forecast



3.1 BPA firm power sales load forecast

The BPA firm power sales in the supply obligations forecast include BPA's obligations to supply firm power under the Regional Dialogue contracts. This forecast is produced by adjusting forecasts of customer utilities' loads under existing Subscription contracts to reflect terms of the Regional Dialogue contracts, as follows.

BPA forecasts several types of load obligations under existing Subscription contracts. For full requirements customers, all load is included, because BPA is obligated to supply all the customers' firm power needs. For partial requirements contracts, under which customers meet their load partially from non-federal sources, customer-owned generation and/or non-federal power purchases are subtracted from customers' forecast total retail loads to produce a BPA firm power requirement load forecast. BPA sales obligations to customers with Slice/Block contracts and Block contracts are those planned power sales designated by contract; for these customers, their total retail load is subtracted and the contractual obligation is added in. For utilities that have not contracted with BPA to provide energy, none of their total retail load is included in the BPA firm power sales load forecast.

Under the Regional Dialogue contracts, there are three types of firm power sales: Load Following, Slice/Block, and Block. (As noted in Chapter 1, no customer chose to take a Block-only contract.) The variant under these contracts, in contrast to the Subscription contracts, is that BPA's supply obligation to serve customers' load can be changed based on customers' load placement elections during the contract period. The BPA firm power sales load forecast used in the Resource Program reflects the customers' elections during the first election period (October 2011-September 2014) and builds upon that forecast for future BPA need to serve customers' above-High Water Mark load under Regional

Dialogue contracts. In November 2009, customers identified how much of their future growth they expected BPA to supply through 2014. Based on customer elections through 2014, BPA assumed that customers' existing selection of BPA as their supplier will continue into the future. For example, if a customer declared that BPA will be the sole supplier of its above-High Water Mark load during the first election period, BPA assumed that the customer would continue with that declaration throughout the future. If a customer declared that BPA would supply 35 percent of its above-High Water Mark load during the first election period, BPA assumed that the customer would continue with that declaration throughout the future. In total, this forecast assumes that BPA will supply approximately 50 percent of the above-High Water Mark load in the region.

Customers' total retail loads will grow differently for the customer categories. We expect the load following customers to grow more slowly than they have for the last several years and the non-load following entities to grow at a pace similar to recent years. Table 3-1 shows the total retail load levels for several years covering historical and forecast time periods. Table 3-2 shows the historical and forecast average annual growth rates for the BPA load following and non-load following customer categories. Because BPA expects the economy to grow more rapidly in the recovery years immediately after the current national economic downturn, a more typical load growth rate, called the stable forecast period, is shown in Table 3-2. The "stable" rate is more representative of the long-term growth BPA is forecasting for its customers.

BPA forecasts continuation of some power use trends in the consumer base that makes up BPA's contract obligation forecast. BPA expects to see continued load increases in the residential sector as use of electricity for home electronics grows. BPA also expects to see an increase in electricity use by the health care industries of the commercial sector of the economy as the population ages. BPA expects to see a return to growth in the travel and hospitality industries as the economy improves and the Northwest resumes its spot as a favorable travel destination. Some industries in the industrial sector are likely to retrench in the future, while others grow. We expect to see some increased growth in the information industries as data centers and the digital economy grow.

Table 3-1 – Historical and expected forecast total retail load (average megawatts)

	BPA Load Following Entities	Non-Load Following Entities
Historical:		
1999	3,115	5,060
2003	3,355	4,899
2007	3,810	5,391
2009	3,854	5,285
Forecast:		
2013	4,097	5,729
2019	4,476	6,029

Table 3-2 – Historical and expected forecast period average annual growth rates

	BPA Load Following Entities	Non-Load Following Entities
1999 to 2008	2.6%	0.9%
Stable forecast period - 2014 to 2019	1.5%	1.3%

The BPA contract supply obligations forecast has a normal forecast uncertainty of ±250 megawatts by 2013. This forecast does not include the uncertainties of economic recovery or long-term load growth. In addition, BPA is seeing increasing seasonal, temperature-related volatility in customer load of up to +750 megawatts in summer. As a result, the forecast has a total peak load uncertainty of up to 1,000 megawatts during extreme weather events.

Trends in air conditioning penetration in the Northwest indicate that over time more consumers are choosing to install air conditioning. Modeling improvements recently incorporated allow BPA to model changing growth rates for each customer on summer and winter peak values. As the trends show greater differentiation in the growth of winter and summer peaks, our models will further incorporate them into the forecasts. Currently, winter peaks show the greater growth, but at some point in the future we do expect that trend to reverse; uncertainty on the timing of this change is great.

One of the major uncertainties at this time is the timing of an economic recovery. Economic reports vary on the duration of the recession and the pace of recovery. The current obligation forecast contains BPA's view on the recovery. Uncertainties about the speed of economic recovery or the long-term load growth rate are not covered in the forecast quantities mentioned above.

3.2 Other obligations

BPA provides federal power to customers under a variety of contractual arrangements. Existing contractual obligations other than Regional Dialogue contracts are included in the BPA firm power sales load forecast. These include power commitments under the Columbia River Treaty, capacity sales, capacity for energy exchanges, and others. Included in the base forecast is the contractual obligation for the existing DSI customers. We include only the contractual amount, and when the contract terminates we assume in this forecast that all obligations will terminate for these customers. We recognize that service to the DSIs is a great uncertainty and have elected to apply different assumptions for this group of contracts in the scenarios to account for the possible range of load from this group of contracts.

3.3 Treatment of conservation in the obligations forecast

The BPA supply obligations forecast methodology automatically includes projections of programmatic conservation savings that continue at the level established under current BPA conservation programs. Accordingly, the forecast assumes conservation savings at about 55 average megawatts per year from ongoing conservation efforts. Over the Resource Program planning horizon, these annual savings grow to more than 500 megawatts of cumulative efficiency achievements. Additional conservation expected under the Sixth Power Plan is assumed to reduce BPA's projected need in the Resource Program analysis. In evaluating resource alternatives, BPA recognizes that all conservation acquired in 2012-2019 will accrue from programs and initiatives operating in that time frame, including portions shown here as included in the load forecast. (See also conservation discussion in Chapter 6.) The reduction in load associated with a customer's conservation achievements will be accounted for in the load forecasts used to establish its Above-RHWM load. As such, either the amount of power BPA is obligated to supply at Tier 2 rates or the amount of non-federal resource the customer is obligated to apply would be reduced.

3.4 Forecast development

The multi-year load forecast used in the Needs Assessment for the Resource Program was developed in March 2010 using BPA's Agency Load Forecasting tool. Forecast updates are done annually in March unless there are unusual economic changes that would result in significant changes from planning assumptions, in which case updates are done more frequently.

3.5 Load scenario development

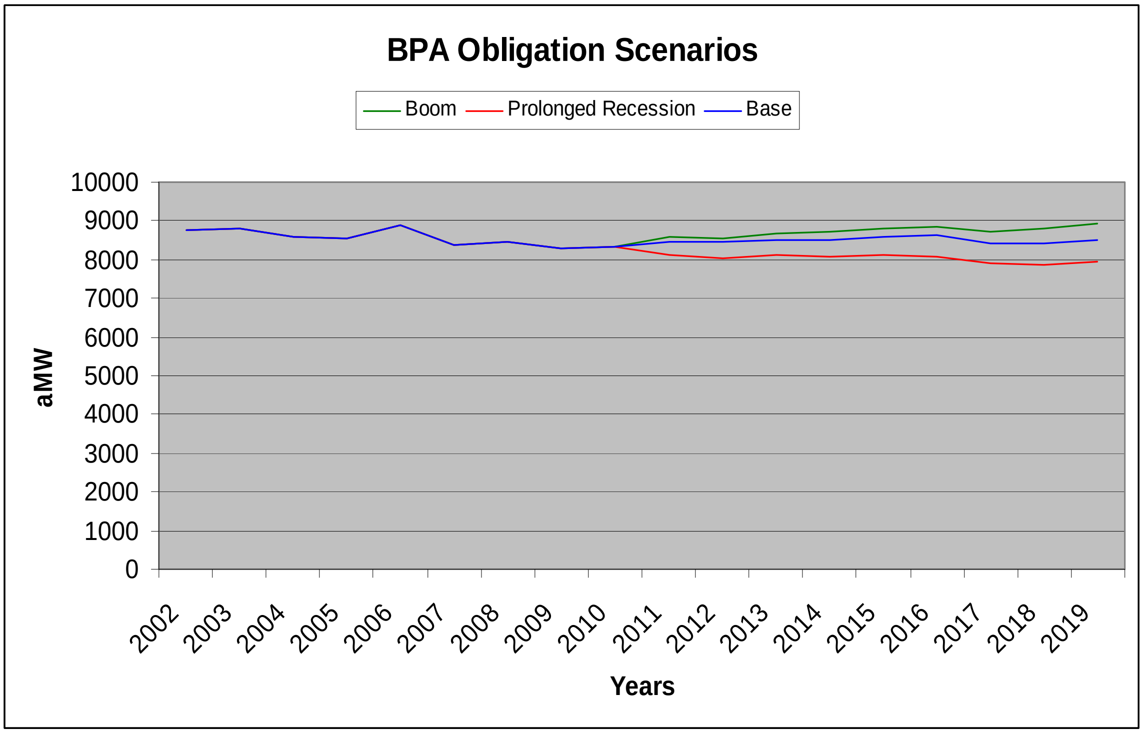
To complete the Needs Assessment for the Resource Program, BPA completed high and low load growth forecasts for BPA obligations. These scenarios are consistent with the assumptions of the "Boom" and "Prolonged Recession" forecasts presented in the previous chapter.

- In the "Boom" scenario, BPA assumed a rapid, robust economic recovery and used the above-average annual load growth rate of 2.79 percent for the load following customers and obligations of BPA. This is load growth in the tail of the distributions of load growth amounts experienced in the Pacific Northwest existing historically. Additionally, BPA assumed that BPA would continue to serve DSI loads at near fully operational levels indefinitely into the future. For the customers with Slice-Block Regional Dialogue contracts, BPA assumed that the Block portion of the contract would not increase.
- In the "Prolonged Recession" scenario, BPA assumed a lackluster economic recovery and used the below-average annual load growth rate of 0.88 percent for the load following customers and obligations of BPA. This is load growth in the tail of the distributions of load growth amounts experienced in the Pacific

Northwest historically. Additionally, BPA assumed that BPA would serve no DSI load. For the customers with Slice-Block Regional Dialogue contracts, BPA assumed that the Block portion of the contract would not increase.

Figure 3-2 shows the high and low scenarios along with the base BPA firm obligation forecast.

Figure 3-2 – Load growth scenarios



Chapter 4. Needs Assessment

4.1 Introduction

The Needs Assessment identifies the timing and the amount of resources BPA may need to acquire or plan for to reliably meet its obligations. It analyzes the range of BPA's potential resource needs in FY 2013 and FY 2019, which are early and late years in the Resource Program timeframe.

The Needs Assessment measures the expected capability of existing Federal Columbia River Power System (FCRPS) resources to meet projected load obligations. In evaluating FCRPS capabilities, the assessment assumes non-power requirements of the hydro system are met first; only remaining hydro capability is assumed to be available to meet power demand. Potential resource needs are assessed for the ability of the FCRPS to meet:

A. Annual energy

B. Seasonal/monthly energy and Heavy Load Hour energy

C. 120-hour "superpeak" loads

D. 18-hour peak capacity loads

E. Balancing reserve needs, including wind integration needs

BPA has updated the Needs Assessment in the Resource Program compared to the draft Needs Assessment of September 2009. The current edition reflects an updated load forecast, described in Chapter 3; updated requirements for operating reserves for wind power; and consideration of public comments received on the September 2009 version.

To reflect the impact of customer choices for Tier 2 rate service and Resource Support Services beyond the initial election period (October 2011-September 2014), the above-High Water Mark load was allocated to BPA service and self-supply in the same proportion as customers chose in the first election period. See section 3.1. DSI load service is defined according to the contracts. The effects of potential additional loads, including additional DSI loads, new publicly owned utilities, and additional DOE-Richland load for a nuclear waste vitrification plant, are then assessed in a high load scenario. The possible range of service—given remaining uncertainty in service for above-High Water Mark load plus these additional potential loads—creates a wide range of potential obligations for BPA.

The Needs Assessment is produced by analyzing BPA's existing resource supply against its forecast load obligations using two BPA models: the Hydrologic Simulator Model (HYDSIM) and the Hourly Operating and Scheduling Simulator (HOSS) for hourly, monthly, seasonal and annual energy needs. Appendix D describes the Needs Assessment in greater detail.

4.2 Inputs

4.2.1 Loads

The Needs Assessment is based on BPA's forecast of Total BPA Supply Obligations, described in the previous chapter and Appendix C, which reflects the most recent information on individual expected load growth for BPA's regional power customers. The total load that BPA must meet is the sum of BPA's load from the BPA's firm power sales plus other obligations, such as Canadian Entitlement delivery, station service (power consumed at the generating projects), irrigation pumping load, and transmission losses. As described in section 3.3, this load forecast is net of conservation at about 55 average megawatts per year based on recent conservation trends. Thus, the results reflected in this Needs Assessment are based on continued efforts by BPA and the region to achieve this level of conservation. Increases in conservation efforts are addressed in section 4.7 and Chapter 6. Service to Alcoa's Intalco smelter at 320 megawatts is included in the analysis for 2013 because BPA has a signed contract for such service contingent on the outcome of litigation regarding DSI service.

Note that the Total BPA Supply Obligations Forecast includes a normal range of uncertainty amounting to about ±250 average megawatts. This range does not include the uncertainty of the rate of load growth in the forecast. BPA faces additional uncertainties related to other types of load service requests that may be made in the future. BPA may serve additional DSI loads, may extend existing DSI contracts, may serve new public agencies, and may serve increased load at the DOE-Richland vitrification plant. These possibilities are discussed in more detail near the end of this chapter. These additional potential loads are sufficiently uncertain that they were not modeled as forecast loads in the Needs Assessment. One could easily adjust the results of the Needs Assessment for these additional potential loads, however.

4.2.2 Resources

BPA's primary resource base consists of the 31 hydroelectric dams of the FCRPS and the 1,100 megawatt capacity Columbia Generation Station nuclear plant. BPA has acquired a number of long-term contracts for additional resources. Thus, BPA's existing resource supply under 1937 water conditions is roughly 8,500 average megawatts of firm annual output, with a 1-hour January peak output around 18,000 megawatts. The hydro project resources include planned improvements to the hydrosystem, notably runner replacements at Chief Joseph and Grand Coulee Dams.

The Columbia Generating Station nuclear plant is scheduled for biennial refueling outages in both 2013 and 2019; therefore, the analysis represents years with slightly less energy in BPA's power supply inventory than alternate years. Columbia Generating Station performance was varied stochastically in the HOSS modeling for the Needs Assessment. Energy Northwest is currently focusing on performance and reliability, rather than performance increases. Therefore, the 2010 Needs Assessment is not including CGS performance increases at this time.

4.2.3 Reserves

The type and quantity of resources chosen in the Resource Program must generate enough power to meet BPA's firm load obligations under both expected and extreme conditions. In addition to meeting BPA's forecast deficits, planned resource additions must provide capability to address BPA's peak loads.

Given their various physical or mandated operational limitations, there is a fundamental question of whether or not the combined generators of the FCRPS have enough flexibility to meet all operating reserve and load demands placed on the system in a given hour. Therefore, the Needs Assessment examined the ability of the FCRPS to provide sufficient operating reserves on an hourly basis. Operating reserves consist of contingency reserves and balancing reserves, both of which are included in the analysis.

For 2013, the analysis includes 300 megawatts of Heavy Load Hour balancing purchases BPA has made from November through April. These purchases were made for 2009-2013 and 2009-2014. Further, there are two purchases targeted for serving load under Tier 2 rates that total 58 megawatts through September 2013 (this is a change from the draft Resource Program). System losses were set at 2.82 percent for normal weather and 3.59 percent for extreme weather.

Contingency reserves

Under current Western Electricity Coordinating Council (WECC) rules, each regional power pool must maintain contingency reserves of 5 percent of hydro resources and 7 percent of thermal resources operating in each power pool participant's balancing authority area. The Needs Assessment used contingency reserves of 3 percent of generation and 3 percent of load, however, as this is the proposed WECC standard currently pending approval at FERC. BPA is part of the Northwest Power Pool (NWPP), and because of BPA's large generating capacity, it frequently holds 80 percent of the contingency reserve obligation in the NWPP. This is a longstanding requirement. The hydroregulation models are designed to require unloaded turbines to meet this reserve requirement.

Balancing reserves

Reserve requirements for balancing reserves have been growing and changing rapidly in recent years and are becoming a much more significant aspect of BPA's resource needs. Large amounts of new variable energy resources such as wind interconnecting to the BPA balancing authority are significantly increasing BPA reserve obligations for BPA balancing reserve services: regulation, load following, and generation imbalance.

The Needs Assessment analyzes balancing reserve requirements assuming wind generation schedules as accurate as if the schedule were based on persistence of actual wind generation 30 minutes before the hour. This is known as 30-minute persistence scheduling accuracy. The Needs Assessment in the draft Resource program assumed 60-minute persistence accuracy for wind generation schedules.

The 2010 rate case discussed the issue of persistence accuracy at length. The BPA Administrator decided for ratesetting purposes to assume 30-minute persistence accuracy. For details of that discussion, please see the preface and also section 13.3.2.3 of the Administrator's Record of Decision for the 2010 rate case, WP-10-A-02. The decision determined that wind projects will attain 30-minute scheduling accuracy and reflects new operating protocols limiting wind project reserve requirements. This Needs Assessment used preliminary reserve estimates available at the time of the analytical study in spring 2010.

The 30-minute persistence study assumes that the following reserves are needed for the mid-range forecast of 6,122 megawatts of wind power in BPA's balancing authority by the end of FY 2013:

- Incremental reserves *(inc)* = 1,390 megawatts
- Decremental reserves *(dec)* = 1,827 megawatts

There is a significant amount of uncertainty around the rate of wind power development. This study used the same level of reserves in 2019 as in 2014, namely 1,564 megawatts *inc* and 2,063 megawatts *dec,* because in the HYDSIM and HOSS models, the hydro system could not handle any more reserves.

BPA is engaged in a number of efforts, largely through its Wind Integration Team, to reduce the amount of reserves that the FCRPS will be required to carry. These include working with the wind community to improve the accuracy in wind forecasting, which has already resulted in a change from 2-hour reserves in the Preliminary Needs Assessment and 60-minute reserves in the 2009 draft Needs Assessment to 30-minute reserves in the 2010 rate case and therefore in the Needs Assessment. Additional efforts such as dynamic scheduling, self-supply, intra-hour scheduling, and reserve sharing may further reduce the amount of reserves placed on the FCRPS.

4.3 Methodology

The studies focused on assessing the needs over a range of timescales from annual energy down to hourly. The studies used the HYDSIM and HOSS models to examine load-resource balance both during expected conditions and when loads were unusually high during extreme temperature events.

4.3.1 Energy: annual

The energy studies use a set of 70 historical water years to show the range of possible performance of the FCRPS resource base under forecast loads and obligations. The annual energy analysis is based on critical water (1937 runoff). This has been BPA's historical measure, and it is the basis against which firm power is sold.

In addition to water variation, the analysis used stochastic variability of unit performance, primarily Columbia Generating Station, to simulate unplanned outages. Load was also varied slightly around the expected forecast through stochastic modeling. The final reported result is the average of several runs of critical water with stochastic generator outages and fluctuating load. The annual energy needs assessment is simply a measure of the surplus or deficit of the current FCRPS capability to meet the forecast load in 2013 and 2019 under critical water conditions.

4.3.2 Energy: seasonal, monthly

The modeling runs that measure annual average energy surplus or deficit also report results by month and time of day. These studies are used to assess how the current system is projected to perform against the monthly and seasonal shape of the load, where winter and summer Heavy Load Hours cause the most concern for planning. As these studies use 70 water years with stochastic generation outages and load variation, they produce a large set of outputs with differing results. The Heavy Load Hour analysis displays results for the 10^{th} lowest percentile (P10) of generation by month or by the roughly comparable 5^{th} lowest generation percentile (P5) by season (winter, late summer). The critical water year is not the best measure of potential need on a monthly basis—while 1937 was a low-water year overall, low water conditions did not occur in every month of 1936-1937.

The model produces results for 14 periods, which are composed of 10 complete months plus April and August split into two half-months. April and August are each divided in half because key changes in operating constraints, such as flood control targets and fish migration flows, occur during the middle of these months, and hydro system capability differs significantly between the beginning and end of these months. For simplicity in reading, the Resource Program refers to these results as "monthly."

Not surprisingly, the winter months, December, January, and February, are somewhat correlated. The monthly P10 results correspond to about P5 for the winter season. Similarly, using P10 by period for late summer (August I, August II, and September) yields about a P5 measure for the late summer.

Deficits shown in the Needs Assessment would be bigger if BPA were to lose generating capability. For example, the Needs Assessment assumes 2008 Biological Opinion (BiOp) hydro operation requirements, which, based on an average of historical fish migration indices at the Snake River dams, typically would end juvenile bypass spill by mid-August. If spill were required through the end of August in any year, the additional spill would correspond to a loss of about 400 average megawatts of generating capability in the second half of August. (The 2008 BiOp with Obama Administration enhancements would end spill when few fish are in the river, so spill could continue throughout August in years of late downstream fish migration.)

4.3.3 Capacity studies: 120-hour superpeak and 18-hour studies

Historically, ensuring resource adequacy for the BPA system has focused on energy because the predominately hydro-based FCRPS is energy limited. Faced with steady load growth and significant changes to the operation of the hydro system, BPA is now also considering potential capacity needs. The question is still whether sufficient water will be available when needed to run through FCRPS turbines. The difference is that the ability of the FCRPS to meet short-term peak loads is of increased concern, in addition to the concern about its ability to meet sustained energy needs.

BiOp requirements to protect salmon and steelhead under the Endangered Species Act have severely limited the use of the FCRPS to meet winter and summer loads. BiOp provisions also impose significant seasonal reservoir operation requirements and spill requirements that impact system capability in those periods.

To assess capacity, BPA is interested in the ability of the system to meet peak loads during rare extreme-temperature events as well as to meet loads throughout a typical month. Such rare events are called the "super-peak" or 120-hour capacity. That approach is a measure of the system's ability 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 modeling discussed above for annual energy and monthly/seasonal Heavy Load Hour energy also reports results for the 120-hour superpeak. It, too, is based on 70 water years with stochastic generator outages and load, and the Needs Assessment focuses on the 10^{th} percentile, P10.

The 18-hour capacity study measures the capacity inventory over 6 peak load hours for 3 consecutive days under loads expected for extreme temperature events assuming median water supply and hydro generation. This 18-hour metric is a measure of the system's ability to meet extreme load events that are not encountered every year. The likelihood of a 1 in 10 year cold snap or heat wave occurring during extremely low (1 in 10 year) water is likely a 1 in 100 year event. The 18-hour capacity adequacy standard is to meet a 1 in 10 year event, so the study assumes median generation. Meeting these events is a critical measure of system reliability.

The Needs Assessment assumed British Columbia would exercise its right under the Columbia River Treaty to ask BPA to deliver the maximum amount of the Canadian Entitlement power during these peak-load hours. BPA makes these power deliveries as required under Canadian Entitlement contracts. The Needs Assessment did not assume BPA would be able to use extra water from Canadian dams which, if physically available, would require special arrangements. The study assumes the Bureau of Reclamation would permit additional drafting of water from Grand Coulee Dam above normal operating limits for a summer event, a dispensation that is generally granted for such rare extreme events.

Flexing the hydro system to meet an extreme temperature event involves borrowing a significant amount of water from other days and weeks. Thus, the 18-hour metric is a good measure of reliability under duress, but it does not measure the ability of the system to meet peak events beyond three days. Therefore, the Needs Assessment evaluates the 120-hour super-peak and Heavy Load Hour system capabilities in addition to the 18-hour capacity measurement.

4.3.4 Reserves

For this Needs Assessment, contingency reserves were handled by the model directly. Contingency reserves are longstanding requirements that are already built into the HYDSIM and HOSS models.

Balancing reserves were so small in the past that there was little need to build them into the model. That now has changed due to wind integration. In the studies for the Needs Assessment, incremental balancing reserves were modeled by reducing the maximum amount of generation at several projects, reserving some of the generation for reserves in case generation needs to increase when incremental reserves are called upon. Decremental balancing reserves require that the system be able to decrease generation on command, and thus the system must generate above its normal minimum generation level. Therefore, decremental reserves were modeled as an increase to the minimum generation level at the projects that might carry these reserves.

As the energy and capacity assessments discussed above were run in the model, the hydrosystem reached a point where it was not able to carry any additional decremental reserves. Any reserve requirement beyond the level that the system could produce is deemed a need for reserves in the context of the Resource Program.

The HYDSIM and HOSS models give only a rough estimate of the amount of reserves that the hydrosystem can provide. Low flows in April and high flows in June 2010 have made it clear that events can stress the hydro system to the brink with the current wind fleet and current reserve requirements. Studies are ongoing to look more closely at high and low flow scenarios with larger wind fleets with a goal of providing a definitive assessment of the ability of the FCRPS to integrate wind.

BPA acknowledges that current modeling and data inputs are limited with regard to fully depicting the complex interaction of variables, which can result in mismatches between non-power constraints, load service, transmission congestion, and balancing reserve provision. BPA is in a rapidly developing environment with regard to the flexibility demands that variable energy resources place on the generation and transmission systems—the demand for these services is growing, new interactions are regularly being identified and addressed, and new tools are being put in place to reduce balancing needs. All of these changes will need to be tested and verified to understand how to reflect them in system modeling. Because of this acknowledged uncertainty, BPA has maintained the ability to limit balancing reserve availability when it conflicts with other system obligations.

4.4 The need: BPA's resources compared to its potential obligations

4.4.1 Annual energy

As shown on Table 4-1, the Needs Assessment shows annual energy needs in the range of 350 megawatts in 2013 and 400 megawatts in 2019 with critical water. The trend is not a steady increase that one might expect from normal load growth because there are several major discrete changes that happen during this timeframe through the expiration of several purchase and sales agreements at different times.

Table 4-1 – BPA deficits (average megawatts) for critical water

Fiscal Year	2013	2019
Expected deficit	-350	-400
Low load scenario deficit	0	-300
High load scenario deficit	-550	-950
Expected surplus with median water	1200	1150

Table does not reflect load growth uncertainty; see Chapter 3.

These results include a continuation of the historical trend of conservation. If that trend did not continue, annual deficits would be about 150 megawatts higher in 2013 (about 55 megawatts cumulative for three years) and dramatically higher in 2019. If conservation efforts are accelerated, then these deficits would be lower, as discussed in section 4.7.

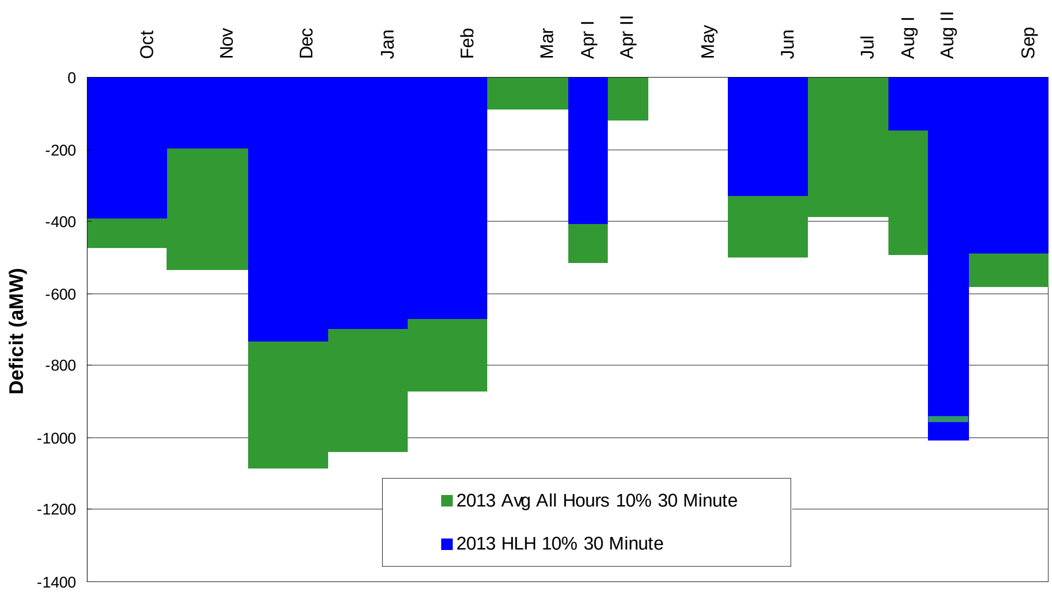
Conversely, BPA may see additional load from DSIs, new public agencies, and DOE-Richland, and faster economic growth, which could increase load and increase deficits by roughly 200 megawatts in 2013 and 550 megawatts in 2019, according to the high and low load scenarios discussed in sections 3.5 and 4.6.6. In a year with average generation conditions, both years are substantially surplus, as shown in Table 4-1.

4.4.2 Seasonal and monthly energy

Looking at the results by month and by season shows a different deficit picture from the annual view. BPA 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 hydro system storage is limited to 40 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.

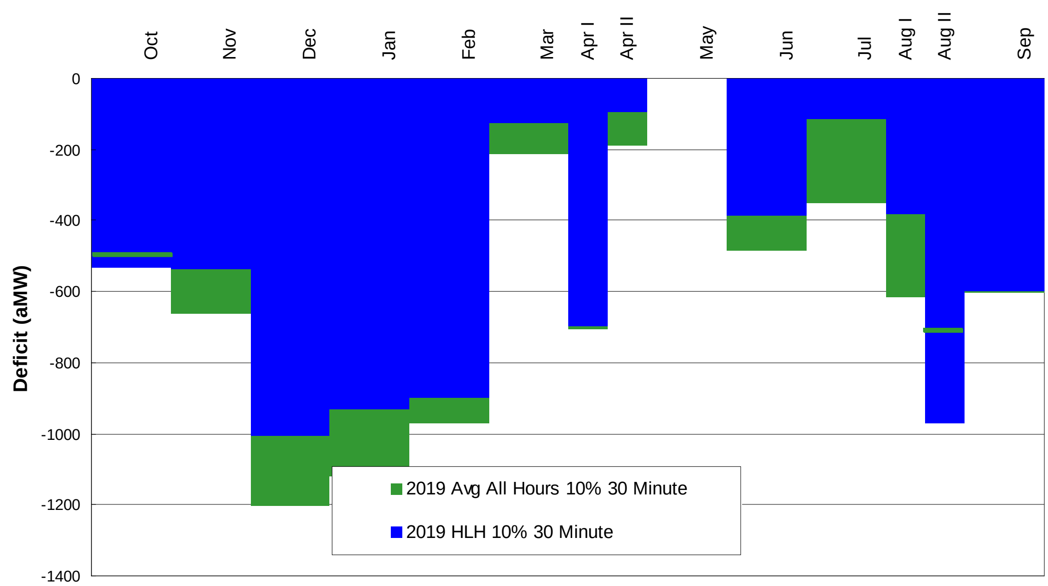
Accordingly, as shown in Figure 4-1, BPA faces deficits for Heavy Load Hour energy in FY 2013 during winter months under the 10^{th} percentile of generation (P10), generally the driest years. Monthly Heavy Load Hour deficits are around 700 megawatts in December to February and exceed 1000 megawatts for an average of all hours in these winter months. This means that there is a 1 in 10 chance that BPA will need to buy 700 megawatts during the 16 highest load hours each day (except Sundays) during the winter and additional energy for the remaining hours. The large deficits in the winter result largely from high demand for electricity for heating loads. During the summer, demand is not quite as high as in the winter (although it is growing significantly), but the water supply is considerably more limited. In the latter half of August (denoted as August II on the graph), Heavy Load Hour deficits reach 1,000 megawatts. Additional load (from DSIs, new public utilities, and load growth uncertainty, discussed in section 4.6 below) could increase the FY 2013 deficits by about 200 megawatts in the high load scenario.

Figure 4-1 – 2013 Heavy Load Hour and all-hour deficits by month



For 2019, as shown in Figure 4-2, the deficits for the winter are larger than in 2013, nearing 1,000 megawatts in Heavy Load Hours assuming BPA customers place about the same proportion of above-High Water Mark load on BPA as they have done for the first election period of the Regional Dialogue contracts. The deficit for late August in FY 2019 is similar to that in FY 2013, near 1,000 megawatts in Heavy Load Hours, with slightly smaller deficits in average of all hours of the month. Additional load (from DSIs, new public utilities, DOE-Richland, and higher load growth, as discussed in section 4.6 below) could increase the 2019 deficits by about 550 megawatts in the high-load scenario.

Figure 4-2 – 2019 Heavy Load Hour and all-hour deficits by month



The deficits in the Heavy Load Hour periods are generally accompanied by deficits in the Light Load Hours that are often slightly larger than the Heavy Load Hour deficits; thus, the analysis shows that deficits for all hours of each month (green area) are generally slightly larger than the Heavy Load Hour deficits (in blue). This finding suggests that the deficit is a combination of an energy deficit and a deficit in the ability to shape generation into Heavy Load Hours. Note that the all-hour deficit for the second half of August is noticeably smaller than for Heavy Load Hours, due to the low amount of water in the system, which cannot be shaped sufficiently into Heavy Load Hours. The all-hour deficits imply that BPA must acquire energy, some of which must be Heavy Load Hour energy, for the winter and summer. See Table D.7, Appendix D.

4.4.3 Capacity

120-hour superpeak is met

The 120-hour superpeak analysis shows that the deficit for superpeak hours is less than the deficit for Heavy Load Hours. This result indicates that there is enough flexibility for the model to shift sufficient water into the superpeak hours so that there is no need for BPA to buy any extra energy for the superpeak period beyond the purchases that it would need to make for all Heavy Load Hours.

18-hour capacity metric is met

The 18-hour capacity metric shows BPA slightly surplus in winter and just adequate in summer to meet daily peak power needs during a three-day extreme cold snap in

February or extreme heat spell in August. However, the combination of forecast error and the possibility of larger temperature effects on load cause an additional 1,000 megawatts of load uncertainty, which could cause BPA to become capacity deficit in summer. Additional loads, such as new public agency loads or additional DSI loads, and faster load growth also could reduce the capacity margin. Conversely, purchases made to alleviate the summer Heavy Load Hour deficits could create some surplus in summer 18-hour capacity.

Unlike in the other Needs Assessment metrics, 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 would reduce energy for the rest of February by about 100 average megawatts. 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 about 50 average megawatts.

4.4.4 Reserves

More reserves are needed, but when is uncertain

BPA has recently produced hourly reserve requirements with updated forecasts of the expected wind fleet, using a methodology described in the TR-10 rate case. The Needs Assessment analysis includes a wind fleet in BPA's balancing authority of 6,120 megawatts by the end of FY 2013 (mid-range forecast). For 30-minute persistence accuracy in wind generation scheduling, this equates to 1,390 megawatts of incremental and 1,827 megawatts of decremental reserves.

The FY 2013 results indicate, however, that the system is reaching its limits. In the study, the system was not consistently able to meet the decremental reserve requirements for wind generation beyond about 2014 with the 7,322-megawatt nameplate wind fleet expected in the BPA balancing authority area by the end of FY 2014. Thus, the studies identify the point at which reserve sources other than the FCRPS will be needed to maintain reliability. It also is important to state, however, that the models used in the Needs Assessment are not the most appropriate model for analyzing reserves.

Low flows in April and high flows in June 2010 have made it clear that events can stress the hydro system to the brink with the current wind fleet. Studies are ongoing to look more closely at high- and low-flow scenarios with larger wind fleets, with a goal of providing a definitive assessment of the ability of the FCRPS to integrate wind.

The need for decremental reserves appears primarily during Light Load Hours in drier years and drier months. To be able to decrease generation at night (such as when the wind fleet picks up unexpectedly and decremental reserves are called upon), the hydro system must be generating above its minimum level by the amount of the decremental reserves. The Needs Assessment shows that in drier years, there often would not be enough flow in the river to meet each hydro project's minimum flow plus the flow requirement for decremental reserves. Maintaining generation at higher levels at night to provide decremental reserves would necessitate moving energy out of Heavy Load Hours into the Light Load Hour/graveyard period. An increase in decremental reserves would affect the system primarily in low flow periods. Insufficient decremental reserves could create unacceptable reliability issues or violations of non-power system operation requirements.

Higher incremental reserves would shift some energy out of Heavy Load Hours by increasing the amount of turbine capacity that must remain unloaded in case it is needed to provide generation should wind generation drop off. In high flow periods, the reduced turbine availability would limit the amount of water that can be shaped into the Heavy Load Hour period. This in turn would shift energy into the Light Load Hour period and in very high flows could lead to increased spill.

For FY 2019, the study capped reserve requirements at the level projected for the end of FY 2014 because the FCRPS in the hydro models was not able to handle more reserves at the 30-minute reserve level. The study thus gives an indication of the need for additional sources of reserves or alternative solutions, which are discussed in Chapter 7.

A number of efforts in the region, coordinated at BPA largely through the Wind Integration Team (WIT), may reduce the amount of reserves that the FCRPS will be required to carry. The results indicated by these HYDSIM and HOSS models are not definitive quantitative measurements of the need to acquire resources for ancillary resources. Rather, they are an affirmation that there is a need to acquire resources and/or to reduce the amount of reserves that the FCRPS would be required to provide. WIT efforts and other work by the wind power community and Northwest utilities will help enable wind integration at the quantities projected for the BPA balancing authority area.

4.5 Summary of basic Needs Assessment

Given the multiple variables considered, the revised Needs Assessment shows that for the 10-year Resource Program study period and on a critical water basis, there may be a need to acquire 350 average megawatts of annual average energy to meet load in FY 2013, including 1,000 megawatts in late summer and winter and smaller amounts for the rest of the year. For FY 2019, this need would grow to 400 average megawatts, also with about 1,000 megawatts in late summer and winter and smaller amounts for the rest of the year.

Monthly energy including Heavy Load Hour energy is needed for monthly and seasonal deficits in late summer and winter. These needs approach and exceed 1,000 megawatts.

Table 4-2 summarizes the needs identified in the Needs Assessment. Additional load not yet under contract, such as new public utilities (discussed below), could increase deficits around 200 megawatts for 2013 and 550 megawatts for 2019.

Table 4-2 – Needs summary

Need type	2013	2019
Annual energy deficit (critical water)	350 MW	400 MW
Seasonal/monthly (10th percentile by month)	Winter: HLH deficits around 700 MW and all-hour energy deficits around 1,000 MW. Summer: HLH deficits around 1,000 MW and all-hour deficits at 900 MW in second half of August.	Winter: HLH deficits of almost 1,000 MW and all-hour energy deficits around 1,100 MW. Summer: HLH deficits just under 1,000 MW and all-hour deficits at 750 MW in second half of August.
Superpeak or 120-hour sustained peaking (10th percentile by month)	Not as large as HLH deficits.	Not as large as HLH deficits.
18-hour capacity (1 in 10 year cold snaps and heat spells)	Winter: Surplus (unless load is much bigger due to outcomes of current load uncertainties and new load). Summer: Essentially Load/Resource balance with current load.	Winter: Slightly smaller surplus compared to FY 2013. Summer: Similar to FY 2013.
Ancillary services for balancing reserves*	Adequate with 30-minute persistence accuracy wind forecasts (but other analyses suggest possible need before 2014).	System is unable to supply additional reserves beyond those required in 2014. Exact need is evolving as region is learning to integrate wind.

Table is based on BPA's expected load forecast; does not reflect load growth uncertainty.
* Studies are ongoing to look more closely at high and low flow scenarios with larger wind fleets with a goal of providing a more-definitive assessment of the ability of the FCRPS to integrate wind.

4.6 Potential changes to the needs

4.6.1 Resource Support Services

Under the Regional Dialogue contracts, BPA has committed to provide Resource Support Services to customers with specified resources dedicated to serve their total retail load. Resource Support Services are tailored to each specific resource and provide a financial and physical leveling of the variable generation of a resource. This could affect BPA's need for monthly/seasonal Heavy Load Hour energy and balancing reserves. However, this impact will not exceed the annual energy requirements above levels needed to serve all above-High Water Mark load. This is because Resource Support Services rely on capacity to shape a customer's non-federal resources; by definition, Resource Support Services do not place more load on BPA than would serving all customers' above-High Water Mark load. Based on customer elections during the first election period of the Regional Dialogue contracts, the amount of Resource Support Services requested is likely to continue to be relatively small.

4.6.2 DSI loads

Two BPA direct-service industrial customers remain active: Port Townsend Paper Corporation and an Alcoa aluminum smelter. Another, Columbia Falls Aluminum Company, is inactive. Currently, BPA has a contract with Alcoa that may include power deliveries in 2013, which are included in our analyses for that year. There is no other contract with Alcoa, Columbia Falls Aluminum Company, or Port Townsend Paper Corporation presently affecting this analysis, as the prevailing contract with Port Townsend is set to expire before 2013. To the extent any additional contract(s) is executed, DSI loads are generally flat, so additional DSI load on the BPA system would impact annual and seasonal energy needs and capacity needs. We also note that under the DSI contracts, unlike Regional Dialogue contracts, DSIs are required to supply reserves to assist BPA in meeting other firm power load obligations.

4.6.3 New public agency loads

The Regional Dialogue contracts allow for the addition of up to 50 average megawatts of new public agency load per rate period to receive power at Tier 1 rates, not to exceed 250 average megawatts total through the contract period. Specific accommodations for tribal utilities and small utilities under 10 average megawatts could result in rate period additions in excess of the 50 average megawatt limit. New publics could request additional service from BPA at rates designed to recover the marginal cost of energy, such as Tier 2 rates, to the extent the loads requesting service exceed the rate period limits. When necessary, BPA would acquire power to meet the amount of new public load.

Based on these limits, new public agency load in FY 2013 could be approximately 50 average megawatts and in FY 2019, 200 average megawatts. An increase in public agency loads would increase BPA's need for annual and seasonal energy and for capacity based on the seasonal shape of the loads being added.

The certainty, timing, and amounts of load that will be forecast as new public agency load each rate period will become known 15 months before each rate period based on the timelines established in the Tiered Rate Methodology. Jefferson County PUD is the only new public that made a request by the deadline for the FY 2012-2013 rate period. Jefferson's load is expected to be around 38 average megawatts beginning July 1, 2013. The amount of additional service to new publics in future rate periods will not be known until future deadlines, the next being July 1, 2012.

4.6.4 DOE-Richland

Current BPA customer DOE-Richland was provided an adjustment to its High Water Mark for an increase in demand for the operation of a vitrification plant on the Hanford Reservation in Washington. Vitrification combines nuclear waste with glass to create solid waste to be housed in steel canisters, thus preventing leakage, reducing possible contamination, and allowing for easier handling. The process is electricity intensive. The load is likely to increase 5 average megawatts in FY 2013, reaching 70 average megawatts by FY 2019.

Table 4-3 below summarizes these loads that are uncertain due to contract decisions.

Table 4-3 – Uncertain BPA loads (MW)

	2013	**2019**
DSI load	160	480
New publics	38	200
DOE-Richland	5	70
Total contractual load uncertainty	203	750

Table is based on BPA's expected load forecast; does not reflect load growth uncertainty

4.6.5 Potential changes to BPA's need for incremental reserves

As explained earlier, with the development and operation of significant amounts of wind generation within its balancing authority area, BPA must ensure it has adequate resources to provide balancing reserves. To that end, BPA is working with regional entities and wind developers to develop a number of business practices and structural changes that could reduce the need for reserves. Although the level of wind power development is uncertain, BPA expects that much of this need may be met through improved wind scheduling accuracy, new transmission operating protocols, and other efforts now in progress through the Wind Integration Team rather than through resource acquisition. For more on the WIT projects, go to http://www.bpa.gov/corporate/WindPower/WIT.cfm

4.6.6 Estimated low and high load scenarios

The previous sections described a number of contractual options that may increase load service for BPA. In addition, there is uncertainty in the load growth, as discussed in the previous chapter. While all of these uncertainties may materialize together and to the full extent, some are more likely than others. BPA estimates that the high load scenario for FY 2013 would add about 200 megawatts to BPA's load obligation, and in FY 2019 the high load scenario increases load by about 550 megawatts. Conversely, a low load scenario would reduce loads in FY 2013 by 350 megawatts and the 2019 load by 80 megawatts.

4.7 Needs net of conservation and short-term market purchases

4.7.1 Power 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 to manage within-year hydro generation and market price uncertainty, and 2) longer-term purchases to meet growing seasonal and annual electricity demand and to offset reductions in firm generating capability.

BPA's energy position is heavily influenced by climate and hydrological variability impacts 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 very 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 to meet this potential exposure on a long-term sustained basis 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.

Fortunately, the Western wholesale power market for purchases and sales with deliveries within one year continues to be robust. BPA routinely makes short-term market purchases and sales in the wholesale power market as needed to manage its daily, monthly, and seasonal power supplies. In this way, BPA can manage position exposure in the shorter-term markets, buying or selling to balance positions as hydro and market conditions become clearer. These transactions are typically made from one year in advance to within the current month.

From time to time, BPA uses mid-term or longer-term customized market purchases to reduce reliance on short-term markets for managing within-year hydro generation variability, as it has done with a number of purchases for FY 2013.

Use of short- and mid-term market purchases from the wholesale power market further reduces remaining seasonal energy needs that would otherwise be served by long-term resource acquisitions. BPA believes that continued reliance on short- to mid-term (less than 5-year) markets to manage up to 1,000 megawatts of Heavy Load Hour deficits in the winter and up to 500 megawatts of Heavy Load Hour deficits in the summer is sound business practice given the current wholesale power market in the Western Interconnection. These deficit thresholds are applied to the Heavy Load Hour need at the P10 (10^{th} percentile) level, reflecting the fact that, under average hydro conditions, the system does not anticipate such deficits. The annual energy is surplus by over 1,000 average megawatts in average years. 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.

Given the current situation, including the uncertainties related to BPA's load obligations, it would not be prudent to commit to purchases longer than 5 years at this time. Therefore, BPA views these as reasonable thresholds for the short and mid term. These amounts are guidelines for a prudent reliance on short-term market purchases. BPA may make long-term acquisitions that reduce its deficits at the P10 level below these thresholds and may deem it prudent to rely on the wholesale market for short-term purchases in some months above these thresholds.

4.7.2 Conservation

Conservation is the highest-priority resource choice of the Northwest Power Act, and it is the lowest-cost resource for the Northwest under the Council's Sixth Power Plan. Conservation measures can decrease energy consumption, including Heavy Load Hour and peak demand, lessening the need to construct new transmission to reduce transmission capacity constraints, as well as the need to acquire physical power.

4.7.3 Additional step in the Needs Assessment

With limited and highly uncertain resource needs and high expected forecast contributions from conservation, BPA took an additional step, to add the expected effect of the higher conservation targets of the Council's Sixth Power Plan, before analyzing potential long-term generating resource alternatives. BPA assumes that:

1) BPA, together with its public utility customers, will achieve the public power share of Northwest conservation called for in the Council's Sixth Power Plan.
2) BPA will continue to rely on short- and mid-term market purchases for Heavy Load Hour energy up to 1,000 megawatts in winter and up to 500 megawatts in summer to address seasonal deficits at the P10 level. These winter and summer market threshold guidelines are based on past operating practices and experience. BPA intends to continue evaluating these guidelines as wholesale market conditions evolve.

The needs discussed in this chapter so far and summarized in Table 4-2 include conservation continued at the same level as in recent years (about 55 megawatts per year, based on the average of the past five years' achievements). Without a continuation of this level of conservation programs, the deficits identified in the Needs Assessment would be higher.

The figures below add the expected effect of the higher conservation targets of the Council's Sixth Power Plan. The hatched area indicates the amount of additional conservation expected from the new targets, beyond the amount of conservation embedded in the load forecast used for the Needs Assessment. The values used here are estimates of not only the public power share of conservation, but more specifically only the conservation that will affect BPA's obligation. Since many BPA customers are choosing to meet their own load growth, much of the regional conservation will reduce the customers' overall load obligation, with only about a third of the public power's share of regional conservation reducing BPA's load obligation. This additional conservation reduces the deficit in 2013 by approximately 50 megawatts and in 2019 by approximately 200 megawatts. Though the Council's target acknowledges and encompasses a range, for simplicity purposes these figures depict the expected case target. The range of uncertainty in conservation levels does not significantly impact the conclusions because the total impact in 2013 is very small, and even in 2019, changes in the amount of conservation would not change the fact that winter deficits are smaller than the long-term purchase threshold or that late summer deficits exceed the long-term purchase threshold. In addition, Council data on hourly load shapes by sector (e.g., residential, commercial) and end use (e.g., lighting, heating/cooling) were used to develop the shape of the conservation. Although this method is consistent with the Council methodology, the distribution of conservation by sector and equipment type achieved by public power customers may differ from the Council's assumptions, and therefore the actual shape of the savings may differ. (See section 6.1 for more details on conservation.)

The horizontal lines in Figure 4-3 and Figure 4-4 at -1,000 megawatts in the winter and -500 megawatts in the summer mark the current thresholds BPA is using for long-term purchasing, as described in section 4.7.1. Therefore, the figures show that, with electricity demand reduced through conservation and 1,000 megawatts winter and 500 megawatts summer short-term purchasing allowance, the net need for long-term purchasing beyond the horizontal lines still exists in late summer in FY 2013. In FY 2019, there is a large net deficit in late summer but no net deficit beyond the market thresholds in winter, even after the additional conservation is subtracted. In an average water year, the system does not have deficits in monthly Heavy Load Hour energy; instead, annual energy is surplus by over 1,000 average megawatts in average years.

Figure 4-3 – Effect of additional conservation on BPA's monthly HLH need for 2013

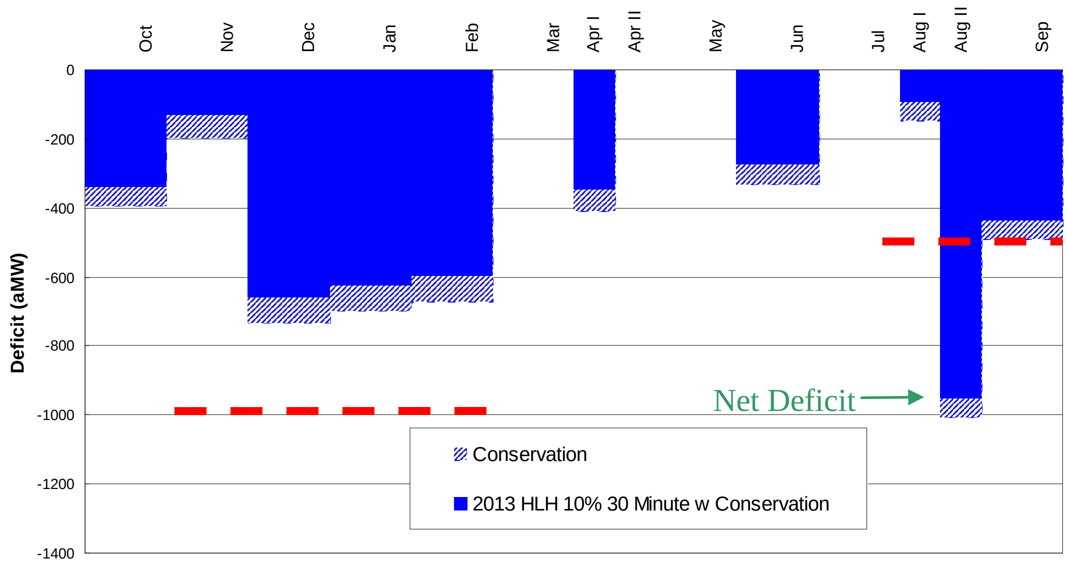
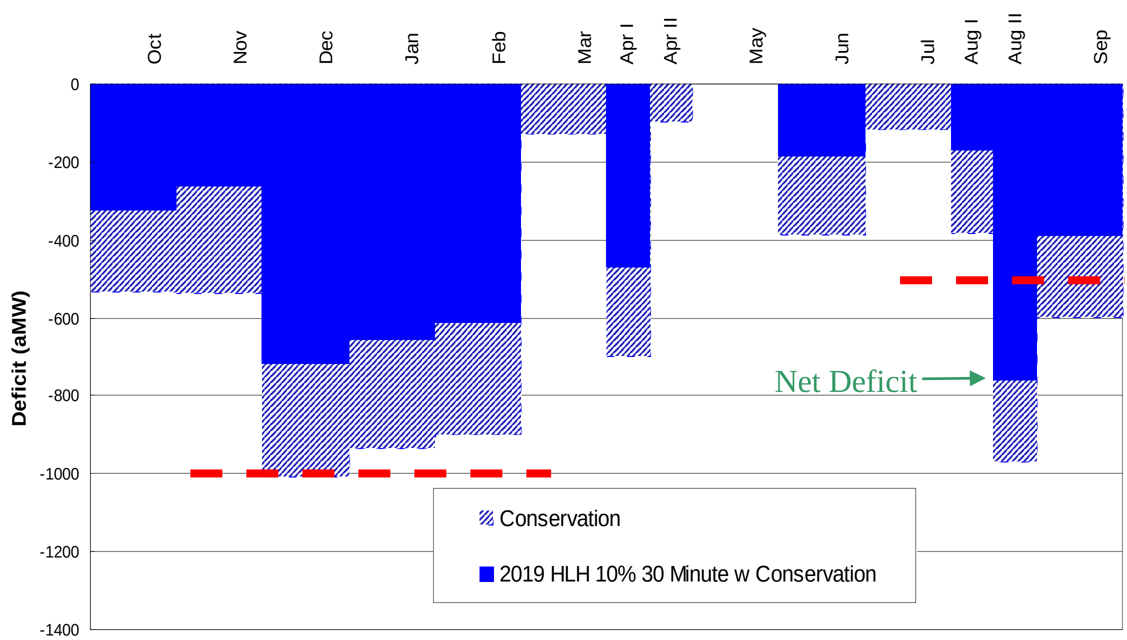


Figure 4-4 – Effect of additional conservation on BPA's monthly HLH need for 2019



4.7.4 Needs summary

The largest and most certain power needs are for seasonal Heavy Load Hour energy and Light Load Hour energy, which are based on low water or other low-generation conditions, particularly in winter and in late summer. BPA faces some annual energy needs through the Resource Program planning horizon, some or most of which may be met through expected conservation and seasonal market purchases.

Chapter 5. Resource Evaluation

This section discusses how BPA evaluated the resource alternatives in the Resource Program analysis. BPA began with resources considered in the Northwest Power and Conservation Council's Sixth Power Plan. The Council initially considered a broad range of possible resources, applied planning criteria, and identified those resources for further analysis. BPA took the same approach. The Resource Program first assessed known potential resources according to broad criteria. Resources that passed this initial screening were further evaluated.

5.1 Evaluation criteria

BPA evaluated potential resource alternatives using a combination of quantitative analysis and qualitative assessment, subject to specific constraints and evaluation criteria.

5.1.1 Northwest Power Act resource priorities

The Northwest Power Act of 1980 (section 4(e)) defines specific resource priorities for cost-effective resources that the Council's Power Plan is to consider and BPA may acquire. The resource priorities are as follows:

1. Energy conservation (weighted with an extra 10 percent cost advantage)
2. Renewable resources
3. Generating resources using waste heat or of high fuel-conversion efficiency
4. All other resources

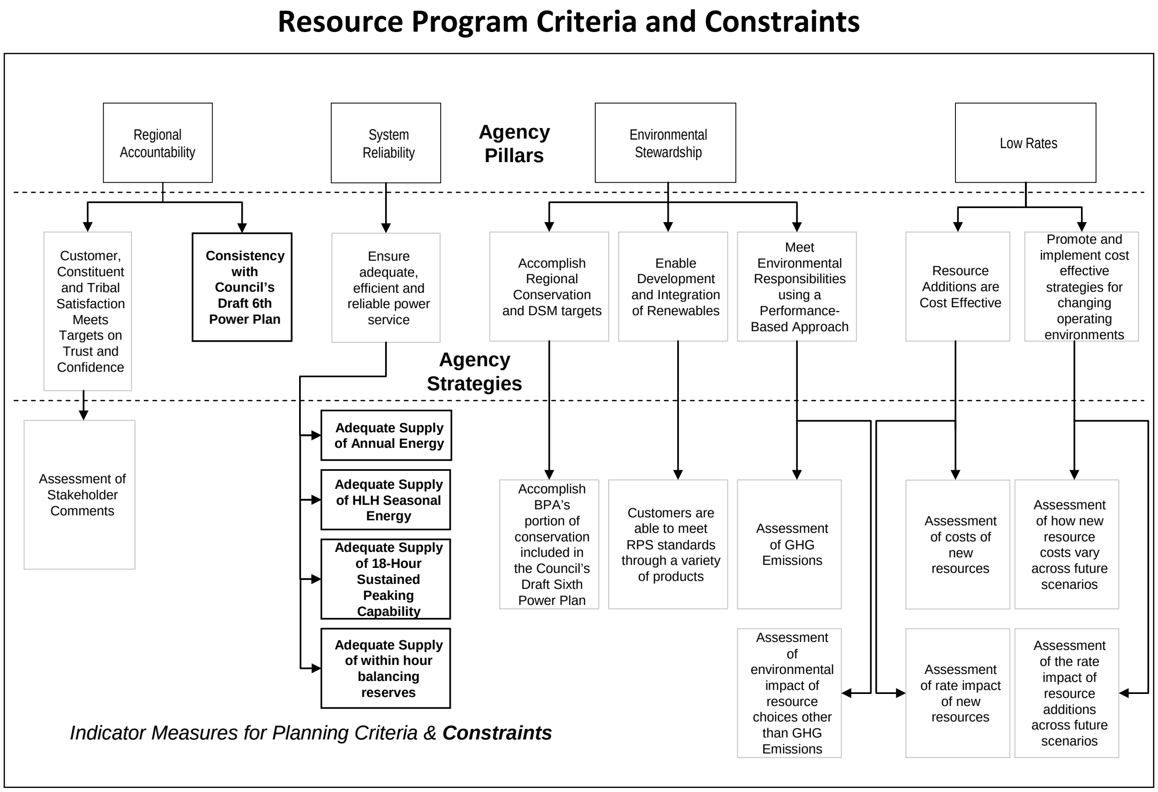
5.1.2 BPA strategy

BPA chose resources for consideration in the Resource Program by evaluating how each potential resource best meets statutory requirements and BPA's commitment to providing four benefits, displayed as Pillars in Figure 5-1:

1. Regional accountability
2. High power and transmission system reliability
3. Responsible environmental stewardship
4. Low power and transmission rates

BPA evaluated the extent to which each resource meets these requirements using the criteria shown in Figure 5-1.

Figure 5-1 – Resource Program criteria and constraints



5.2 Regional accountability

Consistency with Northwest Power and Conservation Council's Power Plan: A starting point for determining which resources to evaluate in BPA's Resource Program is consistency with the Council's Sixth Power Plan. For example, conventional coal generation is excluded from the Council's Sixth Power Plan and therefore not included for potential acquisition under BPA's Resource Program.

Meet targets for customer, constituent, and tribal satisfaction: BPA considered comments received on the draft Resource Program in preparing the 2010 Resource Program. In particular, customers have a choice about whether to buy from BPA or not, so their views on resource choices are important. See Appendix H.

5.3 System reliability

The portfolio of resources chosen in the Resource Program must generate enough power to meet BPA's firm load obligations under both expected and extreme conditions. In addition to meeting BPA's forecast deficits, planned resource additions must provide capability to address BPA's peak load and balancing reserve needs and be consistent with both the Council's regional resource adequacy standard established by the Pacific Northwest Resource Adequacy Forum[8] and WECC adequacy guidelines.[9]

The following metrics measure how well resource alternatives meet the goal of system reliability:

Annual energy: BPA's ability to serve expected annual load under critical water conditions.

Monthly and seasonal Heavy Load Hour energy: BPA's ability to serve peak load in winter and summer months under multiple hydro conditions measured at the 5th percentile of seasonal inventory positions (this is roughly equivalent to the 10th percentile of monthly inventory positions).

18-hour and 120-hour superpeak capacity: BPA's ability to serve peak load with expected hydro conditions under extreme weather for three consecutive days and for the monthly 120-hour superpeak periods.

Balancing reserves: The ability of FCRPS resources to provide sufficient reserves to support transmission reliability requirements. A qualitative assessment of dispatchability and flexibility is conducted to discern which resources might best support this need.

The Pacific Northwest Resource Adequacy Forum has provided only limited guidance on how utilities can ensure that they are aligned with the regional standard. On an energy basis, BPA's indicators are aligned with the regional standard. WECC's October 2009 Power Supply Assessment specifies a summer peak-hour planning margin of 18.6 percent and a winter peak-hour planning margin of 20 percent for the Northwest sub-area. This assessment shows that the Northwest is adequate on a regional basis. A regional study is underway to ensure that hydro utilities report their adverse hydro capacities using consistent assumptions. Although BPA's metrics do not include a peak-hour capacity indicator, it is likely that the other indicators provide sufficient assurance that BPA meets WECC's single peak-hour resource adequacy guideline. Once complete, the regional study will allow confirmation of BPA's alignment with WECC's resource adequacy guidelines.

5.4 Environmental stewardship

BPA's strategy for responsible environmental stewardship involves achieving conservation targets, evaluating demand response programs, considering renewable

[8] A forum created by the Council and BPA to develop a consensus-based resource adequacy framework for the Pacific Northwest to provide a means of assessing whether the region has sufficient deliverable resources to meet its electricity demands reliably and to establish an effective implementation approach to ensure an adequate supply for future years. The Council-adopted NW Resource Adequacy Standard is found at the following link: http://www.nwcouncil.org/library/2008/2008-07.pdf .

[9] WECC's adequacy guidelines is found at the following link: http://www.wecc.biz/committees/StandingCommittees/PCC/LRS/111507/Lists/Minutes/1/PSAP.doc.

resources for resource acquisitions, and limiting greenhouse gas emissions in resource acquisitions, as evaluated by the following indicators:

Accomplish conservation targets: The Resource Program calls for BPA to actively facilitate and jointly pursue, with customers, acquisition of public power's share of the regional conservation target included in the Council's Sixth Power Plan.

Enable renewable resource integration: BPA assists in the integration of the output of renewable resources into its balancing authority area by ensuring BPA can provide operating reserves as necessary.

Limit growth of greenhouse gas emissions: The Resource Program provides a qualitative assessment of resources' relative emissions.

Consider other environmental impacts of resource choices: In evaluating resource types and, eventually, specific resource choices, BPA considers all potential environmental effects and tradeoffs, including land use, impacts on fish and wildlife, visual impacts, and others.

5.5 Cost effectiveness

BPA is committed to maintaining low rates over the planning horizon while also meeting objectives for reliability, environmental stewardship, and regional accountability. Therefore, one of the ways BPA evaluates potential resources for acquisition is cost effectiveness. For example, in the base case a resource may have the lowest cost today, but that same resource may have a different cost structure in a future with a high carbon cost. BPA will assess the costs of new resources, including volatility and how costs could vary across future scenarios and acquire those generating resources that are cost effective and best meet the planning criteria.

Chapter 6. Resources Considered

This chapter describes each resource type BPA considered in the Resource Program and estimates the energy and capacity commercially available for each resource type within the 10-year Resource Program study horizon. Levelized life cycle costs for each resource type are used in the Resource Program to provide a qualitative comparison of each of the resources.[10]

6.1 Conservation

Conservation is the first priority resource for the Pacific Northwest under the Northwest Power Act. The Northwest Power and Conservation Council included in its Sixth Power Plan all cost-effective conservation measures as defined in the Council's portfolio model of economic resource choices. The Council established conservation targets to achieve all of these cost-effective measures. BPA, in partnership with public power, is committed to ensuring achievement of the public power share of the conservation targets in the Council's Sixth Power Plan, as specified in the Northwest Power Act.

In the Sixth Power Plan, the five-year conservation target for the region is 1,200 average megawatts by 2014, within a range of 1,100 to 1,400 average megawatts. In 10 years, the Council's portfolio model acquires 2,860 average megawatts of conservation. This Resource Program uses the Council's estimate of achievable conservation as the best available estimate. BPA is aware that there is uncertainty and risk associated with acquiring conservation and is working with others to quantify and address these factors. BPA's Energy Efficiency Post-2011 process has been discussing mechanisms that may help inform a more-accurate forecast of conservation acquisition. The post-2011 framework was developed in close collaboration with customers to provide a robust and flexible system to achieve savings. The framework will allow utilities to take advantage of regional programs as well as to design and implement local utility offerings to maximize implementation flexibility. Phase 2 of the post-2011 process began in July 2010. Also, the Council's ongoing Conservation Resources Advisory Committee plans to meet in 2012 for open meetings to review the Sixth Power Plan "near-term and long-term achievability [of savings amounts]."

BPA, in partnership with public power, is committed to ensuring achievement of the public power share of the conservation targets in the Council's Sixth Power Plan. The public power share of regional load is 42 percent,[11] based on EIA Form 861 data for 2007. Accordingly, the public power share of the Council's conservation targets is 386 average megawatts by 2013 and 1,201 average megawatts by 2019, as shown on Table 6-1. BPA is taking part in collaborative conversations with customers and the Council to develop and provide infrastructure and programs to achieve these aggressive targets at the lowest cost possible.

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[10] All references to levelized costs and development potential, and general descriptions of the resources available to the region, are from the Council's Sixth Power Plan. For a description of how levelized costs are estimated and the limitations on the use of those estimates, see section 7.4.1.

[11] Total MWh load of public power utilities served by BPA divided by total MWh regional load.

Table 6-1 – Sixth Power Plan annual conservation targets

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Council Targets - Annual Targets (aMW)	200	220	240	260	280	290	320	340	350	360
Public Power Share - Annual Targets (aMW)	84	92	101	109	118	122	134	143	147	151
Public Power Share – Cumulative (aMW)	84	176	277	386	504	626	760	903	1,050	1,201

The Resource Program analysis assumed annual conservation additions (achievements) at the levels shown in Table 6-1. Since the draft Resource Program, BPA has completed a five-year plan for energy efficiency based on public power infrastructure and recent achievements; the expected additions are shown in Table 6-2.

Table 6-2 – Estimated future savings, 2010-2014

	2010	**2011**	**2012**	**2013**	**2014**	**Total**
All sectors (aMW)	90	111	96	99	106	504

To analyze the monthly energy and capacity (see Figure 4-3 and Figure 4-4), 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. Table 6-3 shows the distribution of the 2013 and 2019 conservation potential by sector as outlined in the Sixth Power Plan supply curves.

Table 6-3 – Public power share of cumulative regional total conservation potential

	2013 aMW	2019 aMW
Residential	197	609
Commercial	84	261
Industrial	70	216
Distribution Efficiency Improvements	16	67
Agriculture	19	48
Total	**386**	**1,201**

In the Action Plan in its Sixth Power 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 time frame of 2010-2014 (i.e., between 92 percent and 117 percent of the Council's specified target). Table 6-4 applies this range to public power's share of the target in 2013 and 2019.

Table 6-4 – Public power's share of Council range of cumulative conservation savings

Scenarios:	2013 aMW	2019 aMW
Low Conservation (1,100 for 2010-2014)	354	1,101
High Conservation (1,400 for 2010-2014)	451	1,401

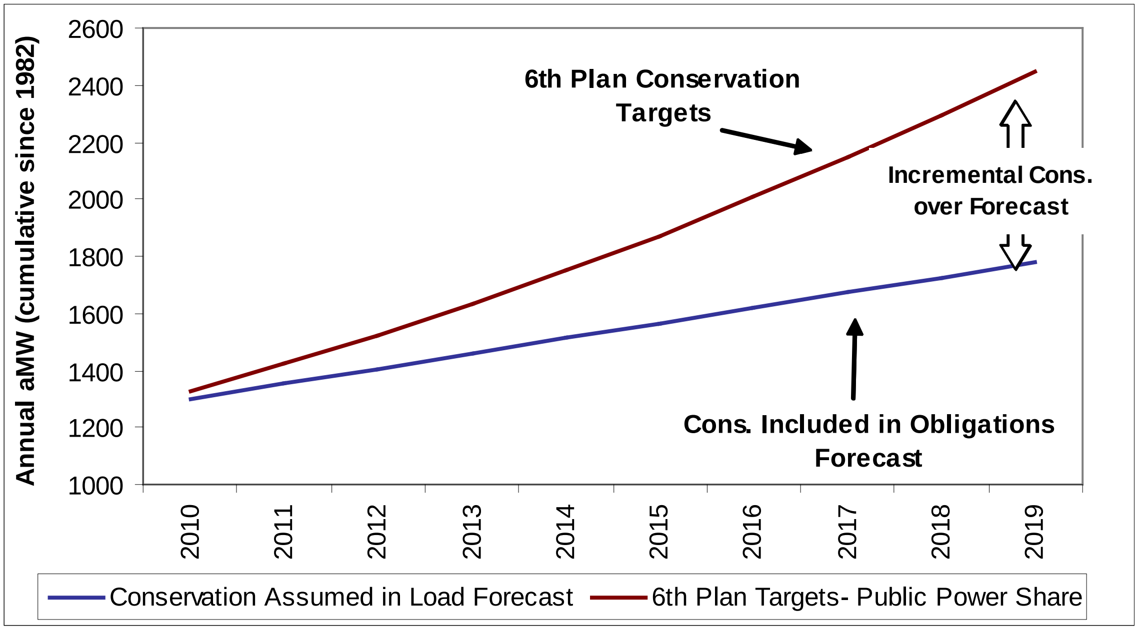
The results of the Needs Assessment for 2013 and 2019 indicate that if the region achieved only the low range of conservation, the amount of deficit would change, but it would not change enough to eliminate the annual deficits or move the winter Heavy Load Hour deficit beyond the threshold for long-term purchases. Achieving the high range of conservation would reduce deficits further, but still not enough to eliminate annual deficits or to reduce August Heavy Load Hour deficits beyond the long-term purchasing threshold.

6.1.1 Some conservation is embedded 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 as additional energy savings to be achieved. The BPA Total Supply Obligations Forecast for the Resource Program assumes a current conservation amount of about 55 average megawatts per year. Additional conservation to meet public power's share of the Council's Sixth Power Plan target is shown as an incremental resource. However, all future megawatts from conservation are included in BPA's share of the region's conservation target set by the Council and are part of BPA's conservation targets. The full public power share of the Council's target is assumed to be achieved. The expected impact on BPA's projected need is described in Chapter 4.

Figure 6-1 shows the cumulative annual conservation savings using the Council's targets in its Sixth Power Plan and the conservation assumed in the BPA Resource Program load forecast.

Figure 6-1 – BPA conservation targets and portion subsumed within BPA Total Supply Obligations Forecast



BPA expects to achieve public power's 42 percent share of the Council's conservation targets, through both achievements that would have resulted from continuation of existing efficiency programs and additional achievements under efficiency strategies now being developed with BPA customers.

6.2 Demand response

Smart Grid, Demand Response, and grid-scale storage technologies have the potential to transform the relationship between the utility and the end-use consumer. Smart Grid technologies involve two-way communications between the utility and end-use consumers, allowing consumers and autonomously responsive end-uses to play an active role in grid management. Demand response technologies and strategies can reduce load during peak times or reliability events. Load shifting strategies can move consumption out of peak hours. Storage technologies have the potential to store renewable energy during off-peak hours, returning it when demand is high.

BPA is exploring how demand response programs might contribute to meeting monthly/seasonal Heavy Load Hour and balancing reserve needs.

BPA has analyzed the costs and potential peak reductions of several potential demand-response programs, described below and quantified in Table 6-5.

> **Residential and small commercial direct load control:** Utility remotely shuts down or cycles a customer's electrical equipment on short notice.

Emergency demand response: Large customer reduces load during events triggered by either reliability needs or high market prices. Participation is voluntary. Targets medium and large commercial and industrial loads.

Capacity market: Participants commit to provide pre-specified load reductions when system contingencies occur. Participation in specific events is mandatory once a participant commits to the program. Targets medium and large commercial and industrial loads.

Ancillary services: End-use customers bid curtailments into the market as operating reserves. Accepted bids are paid market price for committing to be on standby. Targets large commercial and industrial loads.

Irrigation Direct Load Control: This is a voluntary program under which utility dispatchers can interrupt irrigation pumping during summer peak days.

Table 6-5 shows the results of BPA's demand response program options analysis and the Council's demand response inputs. It displays summer and winter demand reductions for 2013 and 2019 as well as the levelized costs of the program option.

Table 6-5 – BPA estimates of demand response programs' peak load reduction potential and costs

	2013 MW		2019 MW		Levelized Costs ($/kW-year)
	Summer	Winter	Summer	Winter	Average
Residential direct load control	24	21	54	49	$100
Small Commercial direct load control	3	3	9	8	$100
Emergency demand response	6	5	21	19	$120
Capacity market demand response	9	8	30	28	$150
Ancillary services demand response	1	0	2	2	$400
Irrigation direct load control	5	0	21	0	$80

6.3 Generating resources considered

6.3.1 <u>New hydropower opportunities</u>

New hydropower opportunities include improvements to existing federal and non-federal projects, and new hydroelectric generation development.

Improvements to existing Federal Base System 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 Northwest federal dams. Between now and 2019, BPA plans to invest $250 million per year in projects to:

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

Most of the investments are for replacing old, degraded equipment at the 31 federal plants. The remaining investment is for improving generation efficiency by designing and installing new turbine runners. Re-design and installation of new generating facilities is currently being conducted at Grand Coulee Dam and was recently initiated at Chief Joseph Dam. All told, the projects initiated to date have resulted in about 100 average megawatts of generation increase, worth $50 million annually. Also, BPA continues to assess the feasibility of increasing unit generation capacity at a number of facilities, which may increase net generation and capacity by 96 average megawatts. These investments will be pursued if rigorous engineering and economic analyses suggest the work to be cost-effective and if approved by BPA's internal capital review boards.

In some cases, capital investments also provide added environmental benefits, including enhanced fish passage and avoidance of greenhouse gas emissions from power plants using fossil fuel combustion.

Improvements to existing Federal Base System projects

Improvements to existing non-Federal Base System projects include renovations to restore original capacity and energy, and upgrades to increase capacity potential and energy production.

New hydropower development includes adding generation facilities to existing dams that are used for irrigation, flood control, and other non-power uses; adding generation to existing hydropower projects with streamflow available for more power generation; and building new facilities at currently undeveloped sites.

The Sixth Power Plan asserts that there are limited and small-scale opportunities for new hydro projects, with a total inventory of about 200 MW of capacity potentially available in the region. Council Plan, page 6-19. This estimate is based on a comprehensive assessment conducted in support of the Council's Fourth Power Plan. The Council believes this capacity remains representative of the current development opportunities.

According to the Council's research, new hydro project development costs are highly variable depending on project size, design, physical characteristics of the project site, and transmission location and availability. Levelized costs, with a project start date of 2015, are projected to range from $60 to $88 per megawatt-hour.

6.3.2 Geothermal

Geothermal power plants produce electricity by converting the thermal energy of below-ground reservoirs into steam or a condensed vapor to drive a steam turbine generator. A steam turbine generator is driven by steam either drawn directly from the ground or generated using a flash-steam process or a binary loop process. The flash-steam process is used where high-temperature ground water is available. The ground water is injected into a low-pressure boiler and a portion of the water flashes to steam. Since the steam is created directly from the ground water, impurities in the water may create corrosion issues.

For lower-temperature geothermal resources, a binary loop system consisting of closed primary and secondary loops is used. The ground water heats a working fluid that has a low temperature flash point to produce steam. Both the ground water and working fluid are in separate closed loops and, as a result, there are no emissions and the effect of ground water impurities is limited.[12]

Flashed steam plants release small amounts of naturally occurring carbon dioxide, a greenhouse gas. Binary cycle technology, since it is a closed loop system, emits no carbon dioxide emissions. Geothermal energy is available 24 hours a day, 365 days a year. Geothermal power plants have average availabilities of 90 percent or higher.

The 15.8-megawatt Raft River project in Idaho is the first commercial geothermal power plant in the Northwest. It came on line in 2008. Several geothermal projects are under development in Oregon, including Neal Hot Springs, Newberry Crater, Linskey Farms, and Crump Geysers. Most integrated resource plans of major Northwest utilities include the development of geothermal resources. The Council's Sixth Power Plan indicates (page 6-23) that a recent U.S. Geological Survey assessment found an average geothermal potential in the Northwest of 1,369 average megawatts, with the caveat that development historically has been challenged by high capital cost for exploring a potential resource and for configuring the optimal production well configuration. Therefore, the Council has adopted a provisional estimate of 416 megawatts, yielding about 375 average megawatts of energy. The levelized cost from the Council is $81 per megawatt-hour, which does not include the cost and associated risk of geothermal exploration.

6.3.3 Waste heat recovery cogeneration

Cogeneration systems, also known as combined heat and power (CHP), generate electricity (and/or mechanical energy) and thermal energy in a single, integrated system. The thermal energy recovered in a cogeneration system can be used for heating or cooling or in industrial processes such as kiln drying. Because cogeneration captures the

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[12] *See* Federal Interagency Geothermal Activities, Appendix B (January 2010, US Department of Energy).

heat that would otherwise be "lost" in traditional separate generation of electric or mechanical energy, the total efficiency of these integrated systems is much greater than from separate systems.

Cogeneration or CHP is not a specific technology, but an application of technologies to meet end-user needs for heating and/or cooling energy and mechanical and/or electrical power. Recent technology developments have "enabled" new CHP system configurations that make a wider range of applications cost-effective. New generations of turbines, fuel cells, and reciprocating engines are the result of intensive, collaborative research, development, and demonstration by government and industry. Advanced materials and computer-aided design techniques have dramatically increased equipment efficiency and reliability while reducing costs and emissions of pollutants.

The increase in efficiency with cogeneration results in lower fuel consumption and reduced emissions compared with separate generation of heat and power.[13] Power generated from waste heat energy recovery systems is the third priority resource under section 4(e) of the Northwest Power Act.

Cogeneration can be fueled by any number of fuel types, including organic waste (e.g., pulping waste), biomass (by burning or gasification), and/or natural gas. Many systems are equipped to handle multiple fuel types. The portion of electricity generated by a renewable fuel in a cogeneration application is considered renewable electricity and qualifies for Oregon's Renewable Portfolio Standards and has the added benefit of renewable energy certificates.

Benefits of cogeneration include:

- High efficiency
- Base load with high capacity factor
- Reduced emissions or carbon neutral

According to the Council, an inventory of potential opportunities for development in the Northwest needs to be updated and appears promising. The Council reference plant for cost estimates is a modular 5 MW Rankine-cycle generating unit using exhaust gas from the mechanical drive gas turbines of a natural gas compressor station. The Council presents a levelized cost of $63/MWh. Council Plan, pages 6-30 to 6-31.

6.3.4 Biofuels

Biofuels are used to generate power by:

- Burning biomass directly to generate steam from a boiler. The steam is then used to drive a steam-turbine generator. This method is the most widely used.

[13] Combined Heat and Power: Capturing Wasted Energy by R Neal Elliot and Mark Spurr in American Council for an Energy-Efficient Economy (May 1999).

- Replacing a portion of coal with biomass for combustion in a traditional coal-fired plant.
- Gasification of biomass to produce methane as the fuel to fire a gas turbine generator. Examples include landfill gas and wastewater or manure gasification projects.

Bio-residues available to power electrical generation in the Northwest include wood residues, agriculture field residue, pulping (black) liquor, animal manure, and gas generated from landfill and waste water treatment facilities. The technologies for these resource types are mature and in use throughout the region, although advances in gasification and reducing air emissions are continually being tested and brought into production. Recent additions include a 55-megawatt pulp liquor and biomass generating plant at the Simpson paper mill in Tacoma, Washington; a 20-megawatt cogeneration facility fueled primarily from onsite mill woody residue in Eugene, Oregon; and a 1.5-megawatt plant at a wastewater treatment plant in Portland, Oregon.

As shown in Table 6-6, according to the Council there are about 800 average megawatts of bio-fueled energy potentially available for development in Oregon, Washington, Idaho, and Montana. Council Plan, pages 6-19 to 6-22. Levelized costs vary depending on the technology, fuel type, and location of fuel source(s).

Table 6-6 – Bio-fuel energy potential and levelized costs

Plant Type	**Development Potential (aMW)**	**Levelized Cost \$/MWh** **(in 2006 \$s & Start-Up Date of 2015)**
Landfill Gas Energy Recovery	70	\$73
Animal Manure Energy Recovery	50 to 110	\$80 to \$139
Waste Water Treatment Energy Recovery	7 to 14	\$85
Woody Residue Power Plants	665	\$104 to \$125

Many of these projects also provide additional benefits, including carbon-neutral qualification, increased efficiencies, and reduced transmission needs.

6.3.5 Wind

Wind power is the conversion of wind energy into electricity by wind turbines and is the fastest-growing renewable resource in the Pacific Northwest. According to the Council's Sixth Power Plan, the Northwest has exceeded 4,000 megawatts of installed nameplate capacity. BPA announced in September 2010 that wind resources in its transmission grid have exceeded 3,000 megawatts. In addition, some Northwest utilities, including BPA, either purchase power or own wind farms located in Wyoming, which has almost 1,000 megawatts of installed wind power. In the Northwest, according to the Council, 80 percent of the total regional wind generation is located in a 160-mile corridor from The Dalles, Oregon, to Pomeroy, Washington (Council Plan, page 6-28). Five wind resource areas were assessed in the Sixth Power Plan. These are:

- Columbia Basin (eastern Washington and Oregon)
- Southern Idaho
- Central Montana
- Southern Alberta
- Eastern Washington

The annual average capacity factors for each of these regions and used in analysis conducted by the Council are shown in Table 6-7.

Table 6-7 – Annual average capacity factors for wind by region

Wind Resource Area	**Columbia Basin**	**Southern Idaho**	**Central Montana**	**Southern Alberta**	**Eastern Wyoming**
Average annual capacity factor (net plant output)	32%	30%	38%	38%	38%

Capacity factors for variable energy resources such as wind are indicators of how much energy a particular project actually produces in a particular geographical area. Capacity factors are not measures of efficiency of a power plant.

Power production from a wind resource is highly variable, and significant changes in energy at a wind farm occur annually, seasonally, hourly and sub-hourly. The inability to store this energy and the high variability that makes it difficult to forecast output require additional firm capacity and resources for balancing reserves for the control area in which the wind project is located. BPA has analyzed historical wind data and concluded that there can be poor coincidence between peak load and generation of wind resources. Therefore, BPA has adopted 0 percent dependable capacity valued attributable to wind.

Table 6-8 provides the Council's estimates of potential wind development and estimated levelized costs. Council Plan, page 6-30. The cost estimates include cost for transmitting the output or in some cases for building new transmission to the nearest wholesale delivery point. According to the Council (Appendix I page I-53), these forecasted costs also include costs for supplying regulation and sub-hourly load following services for operational integration into the regional grid but do not include longer-term shaping services. The costs of ancillary services for wind power delivery vary significantly by region. The importance of managing this cost component is increasing as high wind penetration rates become a significant factor in transmission system opertaiton and management. For a discussion of BPA balancing reserves for variable generation, see sections 4.2.3 and 4.4.4.

Table 6-8 – Wind energy potential and levelized costs

Resource Location Serving Load Centers	**Potential Capacity** (MW)	**Potential Energy** (aMW)	**Levelized Cost** ($/MWh in 2006 $ with project start date of 2015)
Columbia Basin Serving Westside & Eastside OR/WA	4060	1300	$104
Westside OR/WA Serving Westside OR/WA	340	110	$104
Southern Idaho Serving Local Load	725	215	$109
Montana Serving Local Load	215	80	$89
Montana Imported to OR/WA	2151	814	$128 to $147
Wyoming Imported to OR/WA	1500	570	$154
Alberta, Canada Imported to OR/WA	2000	760	$138

6.3.6 Solar

According to the Council, the inter-mountain basins of Oregon and the Snake River plateau of southern Idaho are the best locations in the Northwest for solar generation installations. Council Plan, page 6.26. Solar power in the region is most useful for serving summer peaking loads.

Utility-scale photovoltaic systems

Utility-scale photovoltaic solar installations convert sunlight directly to electricity. The direct current output is converted to alternating current to allow connection to the grid or local distribution system. This technology produces variable output that is a function of the percentage of cloud cover and daylight available and would require balancing reserves. The Council's reference plant is characterized by (Plan page 6-27):

- Flat-plate non-concentrating crystalline photovoltaic cells
- Single axis trackers
- Capacity factor of 26 percent
- Solar radiation intensities typical of southwestern Idaho and southeastern Oregon

For a project startup date of 2015, the Council estimates a delivered energy cost of $280 per megawatt-hour; costs are expected to decline over time. Federal financial incentives such as the production tax credit and similar state incentives are not included in the levelized cost estimate for a project coming on line in 2015.

Solar thermal

Solar thermal power generation is achieved by concentrating radiation from the sun using lenses or mirrors and a heat exchanger to increase the temperature of synthetic oil. This fuel then powers a turbine or similar mechanical engine to drive a generator.

Solar thermal power generation is optimal where dry, sunny, and clear skies persist. As stated in the Council’s Sixth Power Plan (page 6-28), suitable areas may be found in southern Idaho and southeastern Oregon, but the most suitable locations are in the Southwest U.S. rather than the Northwest. It would require significant transmission investment to bring Southwest power to serve Northwest loads. For example, 600 average megawatts of generation could be available to the region from concentrated solar power plants in Nevada, but facilities to transmit this power are unavailable until post-2015.

The Council’s reference plant for cost estimates includes:

- Dry-cooled parabolic trough technology
- Plant capacity of 100 MW with a capacity factor of 35 percent
- High-temperature heat transfer fluids such as molten salt
- A 2.5 solar multiplier collector field with surplus output thermal storage good for 6 to 8 hours of continuous operation
- Capability to store and re-shape as needed, making resource useful for capacity needs

The Council estimates (page 6-28), with a project start-up date of 2015, a levelized cost of $190 per megawatt-hour for power delivery in Idaho and $230 per megawatt-hour power delivery in Oregon/Washington. A third of this cost is assumed to be transmission and line losses.

6.3.7 Natural gas-fired generation

Natural gas is an easily transported, clean-burning fuel with low CO_2 emissions. Low natural gas prices resulted in booms in installation of combined-cycle natural gas-fired turbines in the 1990s and again during the West Coast power crisis of 2000-2001. Some 9,100 megawatts of natural gas-fired generation are installed in the Northwest. There are three types of natural gas-fired combustion power generation plants: single-cycle, combined-cycle, and reciprocating engines.

Combined-cycle natural gas-fired combustion turbine

A combined-cycle generating turbine consists of one or more natural gas-fired turbine generators provided with exhaust heat recovery steam generators. Use of the exhaust heat to generate additional electricity in a "combined cycle" greatly increases the thermal efficiency of the plant. Contemporary combined-cycle combustion turbines typically have a base load efficiency of 49 percent. Combined-cycle generating turbines have been widely used in bulk power generation since the emergence of efficient and reliable gas-turbine generators in the early 1990s because of factors such as:

- Low capital cost
- Short lead times for development
- Operating flexibility and ability to dispatch
- Low emissions compared to other fossil-fueled combustion technologies

For cost estimates the Council used a reference power plant comprised of a single advanced H-class natural gas turbine generator and one steam turbine generator with a base load capacity of 390 megawatts and an additional 25 megawatts of duct firing. Plant operation would be base loaded during winter and summer and be the marginal resource during high streamflow periods. This results, according to the Council's Sixth Power Plan (page 6-37 to 6-38), in an annual average energy cost of $74 per megawatt-hour, plus an assumed emission cost of $18 per megawatt-hour, resulting in a total delivered cost of $92 per megawatt-hour. The Council provides a range of more-likely cost from $97 per megawatt-hour to $122 per megawatt-hour. These higher cost estimates better reflect the capacity factors (65 percent to 35 percent) within which these types of resources normally operate.

Appendix I of the Sixth Power Plan assumes a resource development limit of 830 megawatts. Any additional development beyond the 830 megawatts may incur future air quality and natural gas supply constraints.

Simple-cycle combustion turbine and reciprocating engine

Simple-cycle combustion turbines (also called single-cycle, gas turbine generators, or single-cycle gas turbines) consist of one or two natural gas-fired combustion turbines driving an electric generator.

Simple-cycle power plants have the following characteristics:

- Compact
- Modular
- Short construction times
- Low to moderate water consumption
- Rapid-response start-up
- Load following capabilities

In the Sixth Power Plan the Council evaluated aeroderivative (aircraft gas-turbine engines adapted to stationary applications), heavy-duty industrial machines (frame), and intercooled natural gas-fueled turbine power plant configurations. The Council also considered reciprocating engine-generators (also known as internal combustion, IC, or gen-sets). Unit sizes for power system applications are typically 1-15 megawatts. Conventional diesel-fueled reciprocating units are used in small, isolated power systems and to provide emergency power and black start capacity at larger plants. According to the Council, the use of internal combustion engines has increased as their efficiency has increased. Growing application includes peaking and load-following services. Reciprocating/IC units can also be modified to run on biogas.

The reference plant capacity and delivered cost assumptions for the different natural gas-fueled types are summarized in Table 6-9. Council Plan, pages 6-33 to 6-38.

Table 6-9 – Plant capacity and delivered costs assumptions for natural gas plants

Natural Gas-Fueled Generation Type	Capacity of "Reference" Plant (MW)	Applications	Levelized Cost Without Emission Cost Assumption ($/MWH in 2006 $ and 2015 plant start-up)	Levelized Cost Including Emission Cost Assumptions ($/MWH in 2006 $ and 2015 plant start-up)
Combined Cycle Combustion Turbines	390 plus 25 of duct firing	Base load, Marginal Resource	$74	$97 to $122
Simple Cycle Combustion:				
A. Frame	85	Peak Load & Replacement Reserves	$113	$142
B. Aeroderivative	2 units x 45	Peak Load & Rapid Response reserves	$106	$130
C. Intercooled (hybrid)	100	Intermediate & Peak Loads, Balancing, Rapid Response & Replacement Reserves	$104	$126
D. Reciprocating Engine	128 MW	Intermediate & Peak Loads	$113	$135

6.4 Market purchases

As discussed in Chapter 4, BPA uses short-term market transactions to balance within-year variations in generation availability and customer loads. BPA also uses short- to mid-term market-based purchases to meet sustained seasonal and annual needs. Historically, BPA has made short- to mid-term market purchases up to five years in duration to provide energy for all or most of the year. A short- 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- to mid-term market purchases can also be attractive to fill diurnal and seasonal needs.

6.5 Energy storage technologies

6.5.1 Pumped storage

Pumped storage generation involves pumping water into a holding reservoir during Light Load Hours when the cost of the electricity is low. The stored water is then used to generate power in Heavy Load Hours when the value of the electricity produced is higher. This practice involves a net energy loss, usually about 20-25 percent. However, where excess energy is available, as it may be during high streamflows or when there is wind power output at night, pumped storage may save as much as 75-80 percent of energy that might otherwise be wasted through hydro power or wind energy spill.

Pumped storage has the ability to provide firm capacity and peak energy. Additionally, it can provide balancing reserves using its variable generation ability and its ability to create load when in pumping mode.

While pumped storage is commercially viable and in use in many regions, it is not widely used in the Northwest because the region has had ample capacity to meet power peaks by using turbine capacity on existing hydro projects. However, there are estimated to be many potential development sites in the region, representing thousands of megawatts of potential availability. Pumped storage costs vary significantly from project to project, and this resource has a long development lead time, up to 10 years. The Council's levelized capacity cost for pumped storage is $352 per kilowatt-year.

6.6 Resources eliminated from further consideration after initial screening

The Resource Program did not evaluate generation resources that the Council did not consider to be commercially available in the Pacific Northwest during the Resource Program planning period. BPA also eliminated from further evaluation resources it believes cannot be commercially developed within the 10-year study period due to permitting and construction lead time. Under these criteria, BPA removed the following resources from consideration in the Resource Program after initial screening.

- Advanced nuclear power. The Sixth Power Plan estimates that this resource would not be available until outside the planning horizon of this Resource Program (2020-2030).
- Conventional nuclear power. It is unlikely a new nuclear project could be sited and constructed in the Northwest within the Resource Program planning horizon.
- Conventional coal plants. Such plants do not comply with Washington's or Oregon's carbon dioxide emission performance standards.
- Advanced coal technologies and CO_2 sequestration technologies. Such technologies are unlikely to be available until the 2020s.
- Integrated gas combined-cycle turbine generation that is fueled through petroleum coke gasification. Such generation has higher CO_2 emissions than coal.

- Marine-generation technologies, such as tidal and wave generation and deep offshore wind power. These emerging technologies are not likely to be commercially available within the Resource Program planning period.
- Enhanced geothermal systems, which fracture existing rock below ground to create new geothermal reservoirs. Such systems are still in the development project stage and are not a stable technology.[14]
- Emerging energy-storage technologies such as compressed air energy storage, flow batteries, super-capacitors, and flywheels. Such technologies are not expected to be commercially available within the 10-year Resource Program horizon.

[14] See, for example, *U.S. and Australia Advanced Geothermal Projects Face Setbacks*, Energy Efficiency and Renewable Energy News (Sept. 9, 2009), http//www.eere.energy.gov

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Chapter 7. Resource Assessment Results

7.1 Introduction

The purpose of this chapter is to present the results of the qualitative assessment of those resources available to meet BPA's forecasted needs. The screening criteria BPA applied when assessing the relative merits of potentially available resources are described in section 5.1 and include Northwest Power Act resource priorities and BPA's strategy to provide benefits to the region. This chapter discusses the relative value of these resources in adequately meeting the range of load and market uncertainties BPA and the region may experience.

7.2 Evaluating resources relative to need

As discussed in Chapter 4, BPA's forecast needs through FY 2019 are categorized as deficits in annual energy, monthly/seasonal Heavy Load Hour energy, and balancing reserves. These needs are determined by evaluating system performance against the reliability and operational metrics described in Chapter 5. Figure 4-3 and Figure 4-4 describe how meeting public power's share of conservation targets in the Council's Sixth Power Plan would be expected to reduce BPA's need for additional power resources. These figures also reflect BPA's intention to continue to utilize short- and mid-term wholesale power market purchases to meet system needs. The resource assessment in this chapter evaluates alternatives for meeting remaining forecast needs, net of achieving conservation targets and reliance on short- and mid-term market purchases. A rough summary of this net forecast need under the Recovery and Modest Growth scenario is as follows: a small annual energy need, a monthly/seasonal Heavy Load Hour need in summer, and potentially substantial balancing resource need. Those resources that passed the Resource Program initial screening are cross-referenced with the reliability metrics, or areas of need, and summarized in Table 7-1 below.

Table 7-1 – Candidate resources by reliability metric

Metric	**Candidate Resources** **for Planning Period (2010 through 2019)**
Annual Energy	• Baseload Resources: o Federal system improvements o Non-federal improvements o New hydropower development o Geothermal o Waste heat recovery cogeneration including combination of natural gas and/or biofueled energy systems o Biofueled energy systems • Variable Energy Resources: o Wind o Solar photovoltaic
Monthly/Seasonal HLH Energy	• Combined cycle with unused capacity or duct-firing capability • Simple cycle combustion turbines o Frame o Aeroderivative o Intercooled o Reciprocating • Pumped Storage • Hydro improvements or new hydro development with storage/load following capabilities.
Balancing Reserves	• Combined-cycle natural gas combustion turbines • Simple-cycle natural gas combustion turbines/engines • Pumped storage • Hydro improvements or new hydro development with storage/load following capabilities

7.3 Data sources

In developing the qualitative resource assessments, BPA relied extensively on the cost analysis performed by the Northwest Power and Conservation Council. BPA augmented the Council's resource availability and operating characteristics information with information from other sources, including the U.S. Department of Energy. In this Resource Program, BPA did not translate the Council's levelized cost data into rate impacts to BPA customers.

7.4 Assessment of resource cost and risk

7.4.1 <u>Levelized cost</u>

The primary purpose of estimating levelized costs is to allow a side-by-side comparison of resources with different capital, fuel, operational, and environmental costs. Estimates of the levelized costs for each resource were calculated by Council staff for each resource type. Levelized cost includes assumptions for the resource lifecycle costs, including fuel, transmission, line losses integration, and ancillary needs. The start-up year of a resource also impacts the estimated levelized cost. The Council's levelized costs are normalized to real 2006 dollars.

For BPA's Resource Program, levelized project costs with a start-up date of 2015 are used for the qualitative assessment. For details regarding the cost estimates and underlying assumptions, please refer to the Council's Sixth Power Plan, Appendix I. The Council's Sixth Power Plan may be found at http://www.nwcouncil.org/energy/powerplan/6/default.htm.

BPA used the Council's levelized cost estimates as a point of reference. However, BPA will conduct a detailed economic analysis of a potential resource acquisition when a specific purchase opportunity is identified. This may include, at a minimum, a full cost-benefit analysis, which could consider various aspects of value not necessarily captured by levelized cost estimates. Examples of value not directly captured include specific siting flexibility; annual cash flows; different financing options; potential positive and negative BPA rate impacts; environmental impacts; operational flexibility, reliability, and potential synergistic use with other resource types; and regional policy implications. Additionally, as discussed in Appendix F, BPA would evaluate specific resource options for potential risk, financial, and environmental impacts under various future scenarios.

Key among the attributes not captured in levelized costs is the value of a resource to provide firm capacity as well as energy. Levelized cost analysis does not alone provide a full apples-to-apples comparison of different resources such as wind generation, which is non-dispatchable and supplies minimal or no firm capacity, to a biofuel plant or combined cycle gas turbine, either of which contributes firm capacity as well as energy. Levelized costs also do not capture the value of a resource to provide firm energy on a planned basis or the difference in the value of energy produced at different times of the day or year. Levelized costs also may not capture the value of some government programs designed to encourage the development of specific resources, since they may change over time.

BPA recognizes that evaluating a resource strictly on a levelized cost basis does not fully capture many of the important and individual aspects a specific resource or a portfolio of resources might provide. However, in this assessment levelized cost is used as a starting point to identify applicable and cost-effective resource types for further consideration.

7.4.2 Resource considerations and annual energy metric

The fixed and variable cost components are critical in deciding the most cost-effective use of a resource. Base load resources often carry high fixed costs and low variable costs, associated mostly with fuel. The low variable costs of these resources provide a low incremental cost of operation. These units typically are operated at a steady level of production output to maximize system mechanical and thermal efficiency and minimize system operating costs.[15] The Columbia Generating Station nuclear power plant is an example of a base load resource.

Base load resources that meet annual energy need are normally those that are operated to take all or part of the minimum load of a system by producing electricity at an essentially constant rate. The minimum utility load served by these resources is present at every hour of the day and is not cyclical. Examples of these load types are certain industrial and hospital loads and commercial/residential refrigerators and freezers.

Historically, these loads are typically served with large-capacity power plants that require a large amount of capital investment and have long lead times for development and construction. Development of these resources can result in additions of capacity that will exceed near-term needs. Examples would include large hydroelectric, nuclear, and coal power plants.

Gas turbine generators and renewable resources that are dispatchable and capable of firm output throughout the year serve an increasing amount of annual energy load. These resources typically are relatively small in nameplate capacity and have shorter lead times for development and construction. This allows incremental increases in base load resource capacity to match annual energy load growth. Gas-fired resources are, however, subject to fuel price volatility and carbon cost risk.

Projects using renewable resources may have lower development costs, though the capital cost per megawatt of nameplate capacity and cost of energy per average megawatt are often higher than those of coal or nuclear plants. Some renewable resources can serve a flat annual energy need and have no fuel costs, which results in a low incremental cost of operation. Examples include geothermal, biofuel, and utility-scale concentrating solar thermal power plants (within obvious diurnal restrictions). Resources using wood residue or other solid biofuels do incur fuel costs but often serve cogeneration loads. Waste heat-fueled cogeneration plants may or may not be base load resources, depending on the operation of the host facility that provides its thermal fuel.

Other resources, such as wind, solar photovoltaic, and wave energy technologies, are not suited to serving constant or sustained load due to the variable nature of their generation. However, they could contribute to reducing BPA's average annual energy need. In many cases, variable energy resources may serve to meet Renewable Portfolio Standards requirements for BPA customers.

7.4.3 Resource considerations and monthly/seasonal Heavy Load Hour metric

Certain resources are suited to cost-effective variable operation to serve high Heavy Load Hour energy needs that BPA and the region may incur during seasonal low streamflow conditions. These resources typically reflect lower fixed costs but higher variable costs than annual energy resources. Even though these generating resources have a higher

[15] Energy glossary, Energy Information Agency, http://www.eia.doe.gov/glossary/glossary_b.htm, retrieved September 2009.

incremental cost of operation, they can be economically dispatched during times of high load because of correspondingly higher electric market prices. They are often cost effective because they have a lower level of fixed costs per megawatt-hour to recover. Limiting operation of these resources to times of high demand provides the most cost-effective use. They can often be built in smaller capacity increments than annual energy resources.

Historically, this kind of resource has been a small-to-moderate-capacity power plant that requires a lower amount of capital investment than a continuously-run resource does and, because it is smaller, has a shorter lead time. These resources are often modular and/or scalable, which allows the addition of only the amount of capacity that will be needed. They can be effectively sited to relieve transmission constraints and can have lower needs for natural gas infrastructure than larger natural gas plants. This reduces the potential for unnecessary rate impacts that can arise from purchasing large capacity resources ahead of actual need. Examples include simple-cycle combustion turbines of frame and aero configurations, reciprocating/internal combustion natural gas engines, and pumped hydro storage. Combined-cycle combustion turbines serving a mostly steady annual load that have unused capacity (or temporarily gain capacity through duct-firing) can also provide firm capacity to meet variable monthly/seasonal energy needs.

This type of resource must be dispatchable and characterized by quick start-up times, with the ability to run partially loaded and to quickly adapt to load changes.

The short lead time and scalable/modular designs of some types of gas-fired generation may reduce development risk and reduce the risk of investing in excess capacity ahead of actual need. Both of these factors imply low rate impact. Further, these resources can be applied to multiple aspects of BPA's forecast needs.

7.4.4 Resource considerations and balancing reserves metric

Balancing reserves provide within-hour voltage and frequency regulation and load following ability, and they compensate for deviations between advance generation schedules and actual output. Non-hydroelectric generation resources used to provide balancing reserves typically have high operating costs. The economic and reliability value of these resources is the ability to maintain stability of the transmission system during times of unstable loads and/or generation.

Resources that provide balancing reserves must be immediately available either from spinning reserves or from quick-start resources. These resources must be able to quickly provide incremental and decremental reserves in response to system changes occurring from second to second and over the course of minutes. The federal hydro system's storage and flexible generation have traditionally provided these services.

The current forecast of BPA's need for balancing reserves is among the most uncertain of BPA's future needs, due to uncertainty of wind power development levels and pending technical solutions and business protocols that may in the next few years mitigate or significantly reduce the forecast need. Since variable generation increases the need for balancing reserves, the large forecast increase in variable energy resources over the next several years in BPA's balancing authority area has resulted in a growing forecast need for balancing reserves. As modeled in the Needs Assessment, the flexibility of the federal hydro system to provide these services might be fully consumed around FY 2014. Further, experiences in the spring of 2010 showed that the FCRPS may already be reaching the limit of the amount of reserves it can supply with the current wind fleet under certain conditions. Efforts by BPA's Wind Integration Team and others throughout the region are focused on additional studies to quantify reserve requirements and the full capability of the FCRPS to integrate wind.

7.5 Cost, emissions, and risk by resource type

A summary of the results of BPA's qualitative resource assessment is provided in Table 7-2. These resources are the candidate resources BPA will consider in the event additional resource acquisition is required over the planning period. At the time of potential acquisition, thorough benefit-cost analysis would be performed on each specific resource proposal. A risk analysis of how that resource increases the overall robustness of BPA's total resource portfolio would be completed prior to entering negotiations for output from any project. More details regarding each candidate resource are presented in the remainder of this chapter.

Table 7-2 – Results of qualitative resource assessment

Candidate Resources for Planning Period (2010 through 2019)	Levelized Cost Estimates ($/MWh in 2006 $ with project start date of 2015)	Carbon/GHG Cost Potential?
Wind power to serve local load	$89 to $109	No
New hydropower development	$66 to $88	No
Waste heat recovery systems	$63	Reduction
Biofueled energy systems	$73 to $139	No
Geothermal	$81	No
Pumped Storage	$352/kW-yr	No
Combined cycle combustion	$74	Yes
Simple cycle combustion	$104 to $113	Yes

Note: MWh means megawatt-hours; GHG means greenhouse gas; kW-yr means kilowatt-year.

7.5.1 <u>Wind</u>

Recognizing that transmission costs become an increasingly large part of the resource cost as wind power is developed farther away from loads, the Council, in its Sixth Power Plan, estimated the cost and potential for additional wind development to meet local needs in the Columbia Basin, Southern Idaho, and Montana. The Council also provided cost estimates for importing wind energy to Northwest load centers from Alberta, Montana, and Wyoming wind resource areas. According to the Council's study, it is unlikely that wind power from Alberta, Montana, and Wyoming would be available to serve Oregon or Washington load prior to 2015 because of transmission constraints.

The Council forecasts about 1,410 average megawatts of Oregon/Washington wind power potential that have not yet been developed. While costs for Montana wind to serve Montana load are the lowest for wind resources, that same wind power imported into Oregon/Washington has a levelized cost that is about 60 percent higher. The difference between Montana wind imported to Oregon/Washington and wind generated in the Columbia basin is also significant, again because of transmission costs and constraints ($147 per megawatt-hour compared to $104 per megawatt-hour). Wind imported into Oregon/Washington from Alberta is also significantly more expensive ($138 per megawatt-hour compared to $104 per megawatt-hour).

Considering these estimates, there is a high likelihood that BPA would first consider acquiring a wind resource from the Oregon/Washington wind pool, since those two states have the largest percentage of load growth that BPA may have to serve and have the largest number of public customers subject to Renewable Portfolio Standards requirements. However, BPA may still consider imported wind power as a potential resource at a future time, since BPA's cost-benefit analysis for any specific resource acquisition will be determined at the time a particular resource purchase is being considered. If relevant, BPA might also evaluate whether wind power located in Montana, Idaho, Wyoming, or Alberta might be cost-effective, including transmission costs, to serve specific loads of BPA's Montana or Idaho customers.

Wind power output depends largely on fuel (wind) availability. It requires within-hour balancing reserves to maintain system reliability during scheduled operation, as discussed in section 4.4.4. The curtailment of wind generation through feathering of the rotor blades can provide some reduction in the amount of needed balancing reserves in times of wind over-generation and low balancing reserves. For example, BPA is implementing operating protocols that limit wind generation to scheduled amounts and curtail wind transmission "e-tags" to actual wind generation when necessary to avoid exhausting reserves. This operating protocol allows BPA to add more wind projects to its grid and to contain reserve costs to wind project owners while it develops alternatives to relying wholly on federal hydropower for reserves. For more on these operating protocols, see http://www.bpa.gov/corporate/WindPower/WIT-DSO.cfm

Wind power contributes energy during some hours in all months, but not as a dispatched resource aligned with need. BPA's primary need for energy is during specific seasonal and Heavy Load Hour periods. These needs would affect BPA's assessment of the suitability of wind to meet its needs during specific time periods. In addition, BPA may see integration costs for "local" wind greater than those average costs used for the Council's levelized cost of (geographically dispersed) "local" wind due to the concentration of wind generation in the BPA balancing authority area.

A wind plant generally has good operating availability when the wind is blowing, since the loss of any one turbine does not significantly reduce output, and maturing wind turbine technology has reduced the frequency of shutdown of wind turbines due to mechanical failure. However, because of its variable nature, wind generation provides no significant contribution to peak load capacity. The Council currently assigns wind power a capacity value of 5 percent of nameplate capacity, while the Needs Assessment assumed 0 percent of nameplate for the dependable capacity.[16] The dependable capacity of wind is influenced by geographic diversity of wind projects. Currently, most wind development in the Oregon/Washington area is occurring east of the Columbia River Gorge in an area that is proving to have essentially a single wind regime.

Generation of wind power produces no greenhouse gas emissions and qualifies to meet regional Renewable Portfolio Standards requirements. To the extent that greenhouse gas-emitting resources are used to provide balancing reserves, however, the carbon-free benefit of wind generation may be reduced, although there is no reduction in renewable energy certificates or production tax credit benefits. There is some cost risk in wind resources in that incentives of renewable energy credits and production tax credits may be scaled back or eliminated in the future as wind becomes well-established as a commercially viable resource.

In summary, wind generation is a non-dispatchable resource that can contribute to meeting annual energy needs but is not able to provide dispatchable, firm monthly/seasonal Heavy Load Hour energy; dependable capacity; or balancing reserves.

7.5.2 New hydropower opportunities

Planned federal hydroelectric improvements are discussed in section 6.3.1 and are assumed within the federal resource capability in the Needs Assessment. Future federal hydropower improvements that might further mitigate BPA's need to acquire additional resources would be evaluated in the context of federal asset management planning and through public review during BPA's Integrated Program Review.

This chapter examines attributes of potential non-federal incremental hydropower. Projects that increase energy output through more efficient use of water offer favorable environmental and economic benefits.

Theoretically, hydropower projects have a high degree of operating flexibility within operating requirements related to, e.g., fish flow operations and bank stability and can be run intermittently and at varying levels without incurring significant additional variable operation and maintenance costs. Facilities with storage capability can provide Heavy Load Hour energy. These characteristics meet the needs presented by BPA's

[16] BPA has analyzed historical wind data and concluded that there can be poor coincidence between peak load and generation of wind resources. Therefore, BPA has adopted 0 percent dependable capacity value attributable to wind.

monthly/seasonal Heavy Load Hour demand. This benefit, coupled with hydropower's emissions-free generation and the fact that incremental increases in hydropower capacity usually qualify to meet Renewable Portfolio Standards requirements, makes cost-effective incremental hydropower an ideal match to meet BPA's known and forecast demand for monthly/seasonal Heavy Load Hour energy.

The region-wide potential development opportunities, costs, and lead times for increasing the energy output of non-federal hydro projects through efficiency improvements or usable added generating capacity have not been identified by the Council or BPA. The cost of acquiring incremental hydropower capacity can vary significantly from project to project, which may restrict the number of cost-effective opportunities available. In Chapter 6 of the Sixth Power Plan, the Council recommended that a "comprehensive assessment of hydropower upgrade potential be conducted," and included this task in its action plan item GEN-11. BPA intends to support this recommendation and has included a similar action item in the Resource Program Action Plan.

7.5.3 Waste heat recovery cogeneration

A cogeneration project associated with a steady waste heat resource can meet or displace annual and monthly/seasonal energy need. Historically, applications of waste heat recovery cogeneration in the Northwest have been primarily with timber and paper industries, where waste heat from combustion is used for both industrial processes and for generating steam to drive a turbine. The feasibility and cost-effectiveness of cogeneration/waste heat resources are project-specific and depend on the configuration of the project and the operation of the host facility. Often, if the plant producing electricity is thermally matched with the industrial plant, the project is a base load resource. However, for planning purposes most waste heat recovery systems are not classified as dispatchable. In the Sixth Power Plan, the Council notes that while there are known cogeneration opportunities that can be developed in the region, there are often economic, fuel, and interconnection challenges for long-term operation. The Council encourages BPA and regional utilities to identify development potential and develop cogeneration/waste heat resources where cost-effective and mutually beneficial to all parties.

7.5.4 Biofuel energy systems

The feasibility and cost-effectiveness of biofuel generation resources are evaluated on a project-specific basis, since there are so many variables that impact the operation and economic feasibility of a project. Overall, according to the Council, there may be limited but significant local opportunities for cost-effective, reliable development of biomass generation in the region. The Council's Sixth Power Plan indicates that the best development potential for biofuel generation resources in the near term is from woody residues. Cost-effective operation of a facility generating power from biomass depends primarily on a local and consistent supply of fuel.

These resources are generally developed in concert with other needs, such as reduction of methane emissions from landfills, and there is no generally accepted quantification of their potential to meet Northwest or BPA resource requirements. Both BPA's and the Council's action plans include the identification and evaluation of opportunities to develop smaller generation projects, including renewable generation such as landfill gas and generation utilizing waste heat/energy recovery.

In May 2010, the U.S. Departments of Energy (DOE) and Agriculture (USDA) jointly announced up to $33 million in funding for research and development of technologies and processes to produce biofuels, bioenergy, and high-value biobased products. According to the press release, DOE and USDA issued the joint funding announcement for several types of projects aimed at increasing the availability of alternative renewable fuels and biobased products. The goal is development of projects to create diverse economically and environmentally sustainable sources of renewable biomass. The expectation is that advanced biofuels produced from these projects could reduce greenhouse gas emissions by a minimum of 50 percent.

Projects are underway to integrate federal and state agencies' goals and policies for healthy management of forest lands and supporting renewable energy sources. Some of the projects in the Northwest make slash available to biofuel generating projects. See the USDA Forest Service report of American Recovery and Reinvestment Act Projects grants at http://groups.ucanr.org/WoodyBiomass/documents/Grant_Information17523.pdf.

7.5.5 Geothermal

Geothermal generation, like most renewable resources, has low variable costs. The newest generation plants, using a binary closed-loop cycle, have little to no greenhouse gas emissions. Geothermal power is not exposed to the risk of fuel cost volatility typically associated with fossil-fueled generation or greenhouse gas emission cost uncertainty.

While BPA has larger seasonal needs than annual energy needs, geothermal generation has attributes that may still make it economically attractive. It is a resource that could help BPA customers meet state Renewable Portfolio Standards requirements. In addition, geothermal generation provides firm capacity and steady generation. Geothermal resources would not require separate balancing reserves to maintain reliability. Unused capacity could provide firm energy for monthly/seasonal energy need, and excess energy could be sold on the market.

Geothermal generation has substantial "dry hole" risk in the development stage, however, and the underground thermal energy sources can vary in quality, affecting the operation, useful life, and/or capability of the geothermal plants. Lead time, high capital cost, and development risks are impediments to the development of this resource. In spite of these risks, geothermal generation deserves consideration as a future resource acquisition. Recently, the federal government has opened Bureau of Land Management lands for exploration and development of geothermal resources. Although many permits have been approved in response to developers' requests, there may be significant lack of transmission access to areas that have been opened for development.

It is currently difficult to tell if BPA will be able to acquire any of the generation that may be developed. This is due, in part, to the risk involved with developing these resources. Entities financing geothermal projects often require the developer to have a signed power purchase agreement for the output of the project before it is built. BPA would likely need to fund pre-construction development to ensure access to a geothermal project's power and achieve the lower levelized costs that are forecast for geothermal development. This would involve assuming some of the development risk.

7.5.6 Pumped hydro storage

Pumped hydro storage shares the same set of attributes that make cost-effective incremental hydroelectric generation economically feasible for meeting monthly/seasonal Heavy Load Hour demand. Pumped storage also has the ability to provide balancing reserves. BPA is currently exploring the potential for pumped storage in the Pacific Northwest and expects to have the initial evaluation completed in 2010. Initial studies indicate that reliability improvements to the Keys Pump-Generator Plant at the Grand Coulee complex (Banks Lake) will be beneficial for providing reserves for integrating variable generation. There is support in the region for the development of pumped storage projects, in part to provide balancing reserves to integrate variable energy resources. According to the Council's Sixth Power Plan, there are pumped storage projects in development in the western part of the region.

Pumped storage does not have flexible siting characteristics. Sites require certain geological conditions, since a sufficient drop in elevation is needed between the reservoir pond and the receiving pond to produce enough energy to drive the turbine generators. There is also development risk with pumped storage, including potentially long lead times for permitting and construction activities. The actual costs of developing a pumped storage project vary significantly depending on project site specifics, making it difficult to frame the economical viability of a pumped storage project.

Pumped storage may provide cost-effective balancing reserves if it can be sited close to where wind resources are concentrated. Depending on the location of a new pumped storage plant, it could provide transmission benefits on the BPA system and could offset some of the environmental costs of using thermal resources for peaking generation and balancing reserves. Additionally, pumped storage could provide capacity for decreasing impacts of the variable generation on the existing hydro system. A pumped storage project could be designed for frequent stops and starts and load following capability, allowing the aging hydro system to operate in a more consistent manner, which could result in reduced maintenance costs on the existing hydro units over the long term and the ability to operate these units more efficiently.

Pumped storage is usually considered a net energy loss; only about 75-80 percent as much energy is produced by releasing water from pumped storage as is consumed to pump the water into storage. Pumped storage has the important ability to shift energy from Light Load Hour to Heavy Load Hour use, however. This provides a significant value when there is an economical differential between Light Load Hour and Heavy Load Hour energy prices. However, there is carbon cost risk to tis resource. As carbon costs increase, normally inexpensive coal-fired genereation will be replaced with more-expensive gas-fired generation to serve firm annual load. This will reduce the spread between Light Load Hour and Heavy Load Hour market prices for electricity and reduce the payback of a pumped storage project.

In summary, pumped storage may provide a unique opportunity for BPA. Pumped storage could potentially return some flexibility to the federal hydro system. Pumped storage pumps that could be turned on quickly could allow BPA to provide decremental balancing reserves. Water could be pumped into storage during Light Load Hours, rather than having to hold federal generation higher during Light Load Hours to ensure generation can be backed off to provide decremental reserves. (See section 4.4.4 for another explanation of decremental reserves.) Water stored through Light Load Hour pumping then could provide generation during Heavy Load Hours.

7.5.7 Combined cycle gas turbine

Consideration of combined cycle gas turbines in the Resource Program is consistent with the Council's Sixth Power Plan. Combined cycle plants have among the lowest levelized cost of the resources evaluated. This is due, in part, to their relatively high efficiency and moderate fixed costs. The cost profile of combined cycle turbines is based on the Council's forecast of expected natural gas prices. The actual cost of power from any natural gas-fired generation is subject to volatility in natural gas prices.

In addition to this fuel price risk, combined cycle plants are also subject to the legislative risk of potential mandatory costs for CO_2 emissions. The potential effect of carbon cost risk is discussed in Chapter 2. In addition, customers have voiced concern over BPA "browning" its no-carbon-emission hydro and nuclear generation with fossil-fuel resources, since this could increase customers' carbon footprint, with potential added costs to the customer. Increasing BPA's carbon footprint could also be a factor for BPA to consider in evaluating any tradeoffs among its public responsibilities for environmental stewardship and low rates. These factors pertain to all fossil-fuel power sources.

Combined cycle natural gas turbines represent a mature and reliable technology capable of operating at high capacity factors and meeting base load and annual energy needs cost effectively. These plants can be acquired in a variety of sizes and can be combined in a modular fashion. Combined-cycle units can be developed most economically (if the project meets all the environmental siting requirements) where sufficient gas pipeline and electrical transmission interconnection capability is available. Additionally, as discussed below, combined cycle plants can also effectively meet BPA's forecast monthly/seasonal and balancing reserves needs.

The Council's levelized costs were derived using a reference plant with a capacity of approximately 400 megawatts. This likely resulted in an economy of scale that would not be applicable to a plant of smaller capacity that might be better aligned with BPA's forecasted needs for long-term acquisitions. Since BPA would not be acquiring large amounts of capacity significantly ahead of actual need, the relatively large size of these plants may limit their usefulness to BPA, though BPA has not yet determined the incremental cost of a smaller capacity unit. Another potential strategy would be to contract for less than the full output of a larger capacity generator, if BPA's operational needs were still met.

The fuel cost of a combined cycle gas turbine is relatively high (compared to other base load and must-run resources in the Pacific Northwest) for constant operation to serve annual energy need. A combined cycle gas turbine is well-suited for intermittent deployment to meet monthly/seasonal Heavy Load Hour demand, although its cost effectiveness may depend on more-frequent operation and the ability to sell excess energy to the market. Combined cycle gas turbines also are capable of providing balancing reserves. Overall, combined cycle gas turbines operate at a higher efficiency than simple cycle combustion turbines and reciprocating internal combustion engine units and have a lower levelized cost.

In summary, combined cycle gas turbines are not optimal resources for an annual energy need that exists in most or all months of the year because of their relatively high fuel cost per megawatt-hour (compared to hydro, nuclear, or coal), fuel price volatility, carbon cost risk exposure, and the need to acquire larger plants to achieve lower costs. However, their use is often the most cost-effective way to provide incremental firm capacity to serve flat annual load, rather than incurring the cost of investing in a large capacity resource. They also can be used to provide monthly/seasonal Heavy Load Hour energy and balancing reserves.

7.5.8 Simple-cycle gas turbine

Simple-cycle gas turbines operate at lower fuel efficiency than combined cycle gas turbines and reciprocating internal combustion engines. On the other hand, simple cycle combustion turbines can run partially loaded with less efficiency loss than combined cycle gas turbines and are quick-response resources. Their operating characteristics are a good match to provide firm capacity and, if used only on an intermittent basis, they can still be a cost-effective source of firm capacity. Aero-derivative versions offer quick start-up capability, so they can be considered as contingency reserves. Like combined cycle gas turbines, they are suited to provide balancing reserves as well as firm capacity to meet monthly/seasonal Heavy Load Hour demand.

Simple cycle gas turbines are available in two configurations—frame units that are typically larger capacity and are installed at a fixed location, and "aero-derivative" models that are lighter, more efficient units, usually in smaller capacity increments. While both configurations provide compact, modular generating plants with rapid-response startup and load-following capability, aero-derivative simple cycle gas turbines provide more operational flexibility. Aero-derivative simple cycle gas turbines can be quickly deployed in a modular fashion to locations that may not have the infrastructure to support a frame simple cycle gas turbine installation. Aero-derivative simple cycle gas turbines are modular, allowing siting near loads, resulting in decreased transmission and energy losses and, depending on the distance from the load, a possible net decrease in greenhouse gas emissions.

As a fossil-fuel resource, simple cycle gas turbines share combined cycle gas turbines' vulnerability to fuel cost volatility, carbon cost risk, and customer, constituent, and BPA environmental considerations. The potential increase in the cost of power due to natural gas and carbon price risks is even more severe for simple cycle gas turbines, due to their lower fuel efficiency.

Reciprocal internal combustion generation can provide peak load capacity to help meet BPA's monthly/seasonal Heavy Load Hour need and balancing reserves. Reciprocal internal combustion generators have a risk profile regarding fuel price volatility and carbon costs similar to that of combined cycle gas turbines and simple cycle gas turbines. The Council's Sixth Power Plan found that reciprocating internal combustion generators have a higher levelized cost than the other simple cycle gas turbines but did not consider benefits of this technology, including high reliability, flexibility, and scalability, in the cost evaluation.

Reciprocating internal combustion generators have excellent flexibility to respond to load and generation fluctuations and provide a strong ability to provide balancing reserves. Reciprocating internal combustion generators run efficiently at partial load, unlike turbine generators. They have quick start-up and black-start capability and need no grid electrical power to start in the event of an outage. Reciprocating internal combustion generators are used in highly modular, scalable configurations, which would minimize the effect of the failure of any single unit.

With their small unit size and no requirement for cooling water, reciprocating internal combustion generators offer flexible siting. These generators also require only low-pressure gas supplies (≈ 75 psig [pound-force per square inch gauge]), allowing the flexibility for siting on lower-pressure gas distribution systems that could not effectively supply the high inlet pressure requirements of simple cycle gas turbines.

7.5.9 Long-term market purchases

Longer-term market purchases (5 years or longer) are a potential resource for serving monthly/seasonal needs. Depending on the terms of the purchase, such a purchase could meet some degree of BPA's forecast monthly/seasonal need. BPA currently forecasts a deficit in 2013 at the P10 level in 11 out of 12 months during the year for energy and 9 out of 12 months for Heavy Load Hour energy.

Long-term market purchases can defer the need to make long-term resource-specific acquisitions that may initially be needed to meet needs only in specific months. Market purchases can also be cost effective relative to longer-term resource acquisitions. Use of these purchases in lieu of long-term resource acquisitions must take into account credit risk. Longer-term market purchases can allow BPA to avoid risks associated with long-term resource acquisitions, such as performance risks and committing to needs that might not materialize.

However, with the changing economic conditions over the past few years, credit risk has become a major factor to be considered in longer-term market purchases. Credit risk has led to reduced liquidity in the longer-term market, making it more difficult to find counter-parties with a strong credit rating. Fewer counter-parties are willing to enter into such non-standard transactions.

Over the last several years, average power market prices have ranged from roughly $30 to $60 per megawatt-hour, significantly below the fully allocated capital and operating cost of most new long-term generating resources. However, the West Coast market can be very volatile, with severe price excursions. To minimize market price risk, BPA will continue to monitor the market for signs of instability or structural change and continually re-evaluate the thresholds established for short- and mid-term market reliance (described in Chapter 4). BPA also continues to evaluate methods for decreasing market risk.

In the current economic environment, it may be effective to utilize market purchases to meet needs up to five years, given the relatively small scope of projected known need and BPA's existing hydro flexibility. BPA can continue to consider prudent use of longer-term market transactions to manage needs in advance of committing to long-term resource-based acquisitions. Structured longer-term market purchases can be an effective source of energy supplies tailored to meet BPA's seasonal needs. In addition, such purchases can provide a low-risk bridge to acquiring output of new resources with potentially longer lead times. To that end, BPA can continue to evaluate the relative financial risks of longer-term market purchases compared to acquisition of output from specific resources.

As described in Chapter 4, BPA has already assumed some short- and mid-term market purchases to meet some of this need. The Needs Assessment assumes that BPA will continue to rely on short- and mid-term market purchases for Heavy Load Hour energy up to 1,000 megawatts in winter and up to 500 megawatts in summer to address seasonal deficits at the P10 level and to manage within-year hydro generation and market price uncertainty. BPA will continue to manage a portfolio of short- and mid-term market purchases consisting of varying amounts, durations, times of day, and seasons.

The current 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. Reliance on these short-term markets will be closely considered in light of the significant uncertainties the agency faces in its future requirements.

7.6 Summary of candidate resources for specific BPA needs

- Wind generation is non-dispatchable and firmed to the hour only by balancing reserve resources. Wind generation can reduce average annual energy needs but provides little or no firm peak capacity or balancing reserves.

- Geothermal, biofuel, certain cogeneration resources, and combined cycle gas turbines can provide firm generation to serve annual energy need and firm Heavy Load Hour monthly/seasonal energy.

- Combined cycle gas turbines and incremental hydropower are the only resources under consideration that, besides being able to serve annual energy need, can provide firm Heavy Load Hour monthly/seasonal energy and balancing reserves. However, combined cycle gas turbines may not be the most cost-effective way to serve small incremental increases in overall annual energy needs.

- Pumped storage has operational ability and characteristics to provide Heavy Load Hour energy and/or balancing reserves and, potentially, to augment hydro resources by storing wind and/or hydro energy, but its cost-effectiveness needs further evaluation. Pumped storage has a long lead time for development, but this does not eliminate it from consideration, because BPA's need for Heavy Load Hour energy, capacity, and balancing reserves may continue to increase.

- Long-term market purchases appear to have the least cost and risk (besides conservation) for meeting forecasted seasonal and Heavy Load Hour deficits.

Chapter 8. Conclusions

The current planning environment is marked by a significant amount of future uncertainty regarding BPA's total system obligations, federal and state policies regulating the electric industry, power markets, fuel costs, rate of economic recovery, and climate change impacts. These uncertainties require BPA to maintain and develop appropriate analytical capabilities and continually re-visit and update planning assumptions and action plans.

The Needs Assessment, Power Market and Load Uncertainties, and other supporting analyses BPA conducted to inform strategies in the Action Plan were structured to frame the range of possible outcomes that could result from the resolution of many of these identified uncertainties. A few of the significant unknowns that could shift the timing and amounts of energy and capacity needs for this Resource Program are provided below.

- There is uncertainty in BPA's future load obligations due to an unknown level of service obligation for customers' above-High Water Mark load in the intermediate and long term and the potential for service to new publicly owned utilities, direct-service industrial customers, and the DOE-Richland plant.
- The need for balancing reserves to support variable energy resources is uncertain due to several factors. The ongoing development of operating techniques and business protocols could significantly reduce the forecast need for balancing reserves, and uncertainty around actual levels of wind resource development also could affect this need.
- Uncertainty is associated with a variety of proposed laws to deal with the issue of climate change. These laws could significantly affect future electricity market prices, the evaluation of fossil fuel resources, and conservation programs.
- Uncertainty remains regarding potential Biological Opinion-mandated changes in FCRPS operation and their effects on hydro generation amount and shape.
- Further uncertainties include the timing and pattern (extent and speed) of economic growth in the Pacific Northwest and how such growth will drive load growth and access to capital.
- Uncertainty remains about the final quantities and distribution of the Council's targeted conservation that will be achieved by public power customers.

In order to account for this possible wide range in future outcomes, BPA developed several scenarios to inform the appropriate actions that BPA can consider and that are in alignment with the evaluation criteria and strategy discussed in section 5.1. A summary of the supporting planning scenarios and assumptions used in formulating actions based on the work from this Resource Program is shown in Table 8-1. The specific details of the Needs Assessment and Market Price Uncertainty analyses can be found in earlier chapters.

Table 8-1 – Resource Program planning scenarios and assumptions

	Planning Scenarios & Assumptions		
	Boom	**Recovery and Modest Growth**	**Prolonged Recession**
BPA Supply Obligations	High	Incremental Increase	Low
Natural Gas	High	Medium	Low
Carbon Penalty	High	Medium	Low
Hydro Variability	1937 water year or P10	1937 water year or P10	1937 water year or P10

For certain other metrics not shown in the table, including resource development in the region, new resource costs, and implementation of emerging technologies, it is reasonable to assume that differences would occur between scenarios. However, BPA did not identify or analyze such potential differences in this Resource Program.

Snapshots of the forecast of deficits and surpluses for the years 2013 and 2019 are shown in Table 8-2 and Table 8-3 by scenario.

Table 8-2 – Forecast of 2013 deficits and surpluses

	Forecast of Potential Deficits/Surplus ***2013***		
	Boom	**Recovery and Modest Growth**	**Prolonged Recession**
Annual Energy (aMW)	-550	-350	0
Winter HLH/All Hours	-900/-1200	-700/-1000	-350/-650
Summer HLH/All Hours	-1200/-1100	-1000/-900	-650/-550
Winter 18 hr Capacity (MW)	1400	1600	1950
Summer 18-hr Capacity (MW)	0	200	550

Table 8-3 – Forecast of 2019 deficits and surpluses

	Forecast of Potential Deficits/Surplus ***2019***		
	Boom	**Recovery and Modest Growth**	**Prolonged Recession**
Annual Energy (aMW)	-950	-400	-300
Winter HLH/All Hours	-1550/-1650	-1000/-1100	-900/-1000
Summer HLH/All Hours	-1550/-1300	-1000/-750	-900/-650
Winter 18 hr Capacity (MW)	500	1050	1150
Summer 18-hr Capacity (MW)	-400	150	250

The large range of possible resource-to-load balances shown in Table 8-2 and Table 8-3 is noteworthy and points to the necessity for flexibility in addressing acquisition needs. It should be noted that the above forecasts of deficits and surpluses reflect embedded conservation but do not reflect additional conservation called for by the Council or short- and mid-term market purchases, the sources of energy BPA will be relying on most for the foreseeable future.

8.1 Conservation and market purchases

According to the Council and as described in Chapter 4 and restated in the figures below, it appears that aggressive implementation of measures to meet public power's share of the conservation targets in the Council's Sixth Power Plan will address a significant portion of BPA's need for annual and seasonal Heavy Load Hour energy through 2013. Continued aggressive conservation efforts also are projected to meet a considerable portion of BPA's projected needs through 2019.

Short- and mid-term market purchases from the wholesale power market further diminish remaining seasonal energy needs to be served by long-term resource acquisitions. BPA expects to continue to rely on short- and mid-term market purchases for up to 500 megawatts of summer power supply and up to 1,000 megawatts of peak winter power supply.

Figure 8-1 shows that BPA would need additional Heavy Load Hour energy in late August in 2013, with or without factoring in conservation to meet the Council's targets and purchasing short- and mid-term power on the wholesale market up to the 1,000-megawatt winter and 500 megawatt summer thresholds. (The cross-hatched blue conservation areas in these graphs show reductions in BPA loads due to conservation achievements to the level of the Council's targets in its Sixth Power Plan.)

Figure 8-1 – 2013 BPA Heavy Load Hour energy need at the 10th percentile

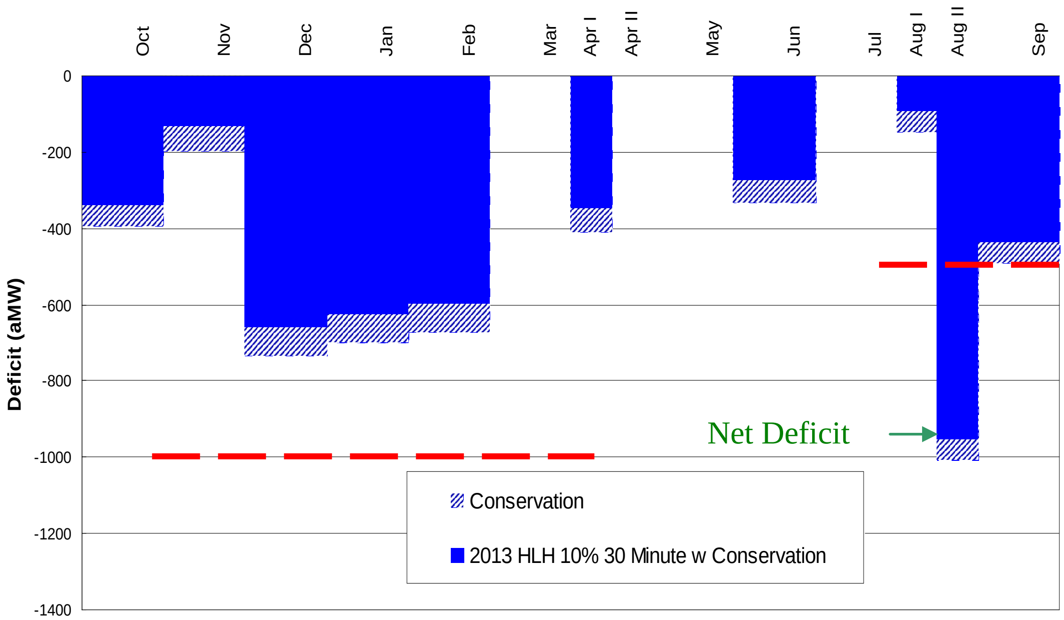

Figure 8-2 shows that, in 2019, under the Recovery and Modest Growth scenario BPA will need additional Heavy Load Hour energy in late August beyond the 500-megawatt threshold amounts for short- and mid-term purchasing, whether or not the Council's conservation targets are met. For the winter, even if only the low estimate of conservation is achieved, BPA should not need to make purchases beyond the short- and mid-term purchases assumed by the 1000-megawatt threshold.

Given that these needs are based on one water year in 10, this scope of need in 2019 suggests that now may be a good time for BPA to explore cost-effective alternatives to traditional energy resources such as new transmission operation techniques, pumped storage, Smart Grid, and demand response programs, along with enhanced transmission coordination among utilities, rather than immediately moving to acquisition of traditional large power sources.

Figure 8-2 – 2019 BPA Heavy Load Hour energy need at the 10th percentile

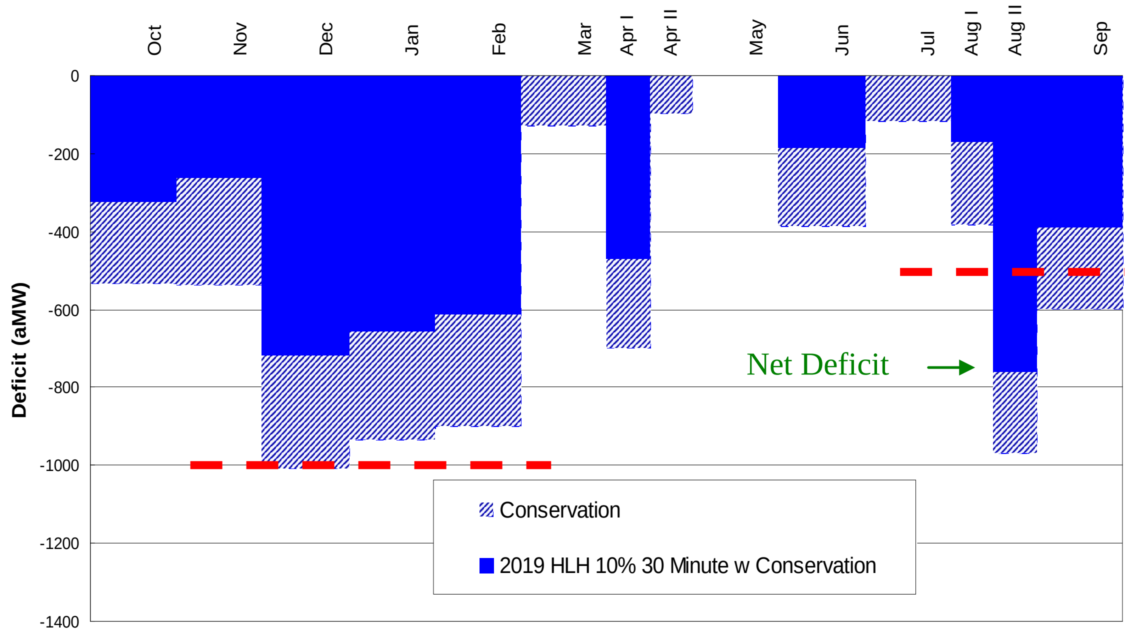

Table 8-4 and Table 8-5 repeat the deficit information of Table 8-2 and Table 8-3, after the additional conservation and short- and mid-term market purchases are applied. The market purchases are made in months when conservation does not eliminate the HLH deficit, and are limited to 1000 MW in winter and 500 MW in late summer.

Table 8-4 – Forecast of 2013 net deficits and surpluses after applying conservation and short- and mid-term market purchases

	*Forecast of Potential **NET** Deficits/Surplus **2013***		
	Boom	**Recovery and Modest Growth**	**Prolonged Recession**
Annual Energy (aMW)	-100	0	150
Winter HLH/All Hours	0/-150	0	0
Summer HLH/All Hours	-150/-50	-450/-350	-100/ 0
Winter 18 hr Capacity (MW)	2450	2650	3000
Summer 18-hr Capacity (MW)	550	750	1100

Table 8-5 – Forecast of 2019 net deficits and surpluses after applying conservation and short- and mid-term market purchases

	Forecast of Potential ***NET*** *Deficits/Surplus* ***2019***		
	Boom	**Recovery and Modest Growth**	**Prolonged Recession**
Annual Energy (aMW)	-400	150	50
Winter HLH/All Hours	-350/-450	0	0
Summer HLH/All Hours	-850/-600	-300/-50	-200/ 0
Winter 18 hr Capacity (MW)	1700	2250	2350
Summer 18-hr Capacity (MW)	300	850	950

8.2 Additional resource options to provide annual energy

Under the less likely but still possible Boom scenario, BPA may have additional energy and capacity needs beyond what the short- and mid-term markets and aggressive conservation can provide. These power obligations could be met by smaller resources that could provide dispatchable annual energy, such as biofuel, geothermal, new small hydro, and cogeneration. BPA could also explore use of waste-heat energy to reduce the load that otherwise would materialize. Additionally, BPA could identify opportunities for incremental improvements in efficiency and generation at non-federal hydro facilities.

8.3 Seasonal and Heavy Load Hour energy

BPA faces all-hour energy deficits at the P10 level in the winter months of 2013. Monthly Heavy Load Hour deficits are around 700 megawatts December-February and exceed 1,000 megawatts for an average of all hours in those three winter months. Additional conservation may reduce these deficits by about 50 megawatts. In the latter half of August, Heavy Load Hour deficits reach 1,000 megawatts. The high-load scenario (Boom scenario) for the Needs Assessment increases the deficit by about 200 megawatts.

For 2019, the deficits for the winter and late summer exceed 1,000 megawatts in late August and near 1,000 megawatts in winter. Additional load that may be placed on BPA by direct-service industrial customers, new public utilities, and DOE-Richland could increase the 2019 deficits by about 550 megawatts, while additional conservation could reduce the deficits by about 200 megawatts.

Deficits in the Light Load Hours generally are larger than those in Heavy Load Hours, resulting in deficits for all hours generally being larger than the Heavy Load Hour deficits. This finding suggests that the deficit is a combination of an energy deficit and a deficit in the ability to shape generation into Heavy Load Hours. The all-hour deficits indicate that BPA should acquire not only Heavy Load Hour energy but also Light Load Hour energy for the winter and summer.

8.4 Capacity

The 120-hour superpeak analysis showed that there is enough flexibility for the model to shift sufficient water into the superpeak hours. Thus, there is no need for BPA to buy any extra energy for the superpeak period beyond the purchases it would need to make for all Heavy Load Hours.

The 18-hour capacity analysis showed no residual need for capacity in winter or summer to meet daily peak power needs during a three-day extreme cold snap or extreme heat spell in August. However, an additional 1,000 megawatts of load uncertainty could cause BPA to become capacity deficit in summer. Additional loads, such as additional direct-service industrial loads, new public utilities, DOE-Richland, or faster load growth, could reduce the capacity margin.

8.5 Balancing reserves

The quantity of balancing reserves needed during the planning period may be greatly affected by the outcome of current regional wind integration efforts and the level of wind power development. BPA's Wind Integration Team is working with regional interests to develop transmission operations and business practices that have significant potential to meet or greatly reduce BPA's needs for balancing reserves, even in the short term. These measures include improved forecasting, sub-hour scheduling, self-supply, and leveraging reserves of other balancing authorities. These measures have been and are being aggressively supported and pursued by the wind community, the Northwest Power and Conservation Council, and BPA.

Whether and to what extent BPA may need to purchase additional resources for balancing reserves is uncertain, because the models used for the Needs Assessment for the Resource Program are not the most definitive methods for assessing reserves. However, the models' FY 2013 results do indicate that the system is reaching its limits. In the study, the system was not consistently able to meet the decremental reserve requirements for wind generation beyond about 2014 with the 7,322-megawatt nameplate wind fleet expected in the BPA balancing authority area by the end of FY 2014. For FY 2019, the study capped reserve requirements at the level projected for the end of FY 2014 because the FCRPS in the hydro models was not able to handle more reserves at the 30-minute reserve level. Low flows in April 2010 and high flows in June 2010 have made it clear that events can stress the hydro system to the brink with the current wind fleet. Additional studies are underway to examine high- and low-flow scenarios with large wind fleets, with a goal of providing a definitive assessment of the ability of the FCRPS to integrate wind.

If long-term acquisitions are needed for balancing reserve purchases, the ideal resources to match these emerging needs are those with high flexibility to increase or decrease output quickly on demand. As described in Chapter 7, the most likely resource choices for this purpose appear to be combined- or simple-cycle combustion turbines/engines or hydropower attained through incremental capacity increases, particularly on FCRPS dams.

Pumped storage is currently undergoing further evaluation and could become part of this eligible resource mix, particularly given additional advantages that might accrue from potential synergies with the resource characteristics of federal hydropower to provide balancing reserves for wind and other variable generation.

8.6 Uncertainties place premium on flexibility attributes

The level and variety of uncertainty BPA faces place a premium on resource flexibility, as noted by the Council in its Sixth Power Plan. Current uncertainties increase the value of smaller, scalable, and quick-deployment resources such as wind, geothermal, and small natural gas-fired turbines. Additionally, resources that can meet multiple aspects of BPA's potential need for annual average energy, monthly/seasonal energy requirements, and balancing reserve requirements are of particular value. Resources with these attributes include combustion turbines and hydropower, either from expansion of current system capability through efficiencies or from new small hydro. Pumped storage also offers the significant flexibilities of being able to shift Light Load Hour generation to Heavy Load Hours and to provide balancing reserves.

Chapter 9. Action Plan

As described in Chapter 4, most of BPA's incremental energy needs for the next several years can be reduced by meeting the conservation targets proposed in the Northwest Power and Conservation Council's Sixth Power Plan and through short- and mid-term market purchases. BPA may also face some additional needs for annual energy and likely will face additional needs for seasonal Heavy Load Hour energy and balancing reserves.

The scope 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 2015 and beyond, climate change legislation, economic recovery, and other unknowns.

This chapter presents actions BPA will undertake to help it prepare to meet a wide range of possible outcomes at lowest economic and environmental cost. This listing also indicates how BPA would propose to respond to actions called for in the Action Plan of the Council's Sixth Power Plan. This Action Plan primarily focuses on addressing outcomes presented by the Recovery and Modest Growth Scenario. However, as discussed throughout this document, there are a number of uncertainties or factors that could drive changes to the actions outlined here, and BPA needs to monitor those uncertainties. These factors are discussed in section 9.8.

9.1 Conservation

<u>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</u>. Continue to collaborate with customers to determine the most-effective approach to structuring BPA's conservation programs and financing under Regional Dialogue contracts that will foster successful attainment of conservation targets, and measure and verify progress toward those targets. Transition to new structure by October 2011 when Regional Dialogue power sales begin.[17]

<u>Participate in and support conservation infrastructure development</u>. The Council included new Model Conservation Standards in its Sixth Power Plan. It also calls for continued market transformation efforts and development of additional conservation measures, including personal computer monitors, commercial outdoor lighting, and distribution system efficiency. BPA will continue to actively support market transformation, adoption of energy-efficient construction, and expansion of the menu of cost-effective conservation and widespread adoption of these measures. This support will be offered through BPA's participation in the Northwest Energy Efficiency Alliance, participation in the Regional Technical Forum and other regional venues, and

[17] The Regional Dialogue Policy directs that BPA conservation costs are allocated in rates to the Tier 1 rate pool. Conservation stretches the resources of the existing Federal Base System and reduces utilities' above-High Water Mark loads.

sponsorship of research and development and pilot projects. In addition, BPA will work collaboratively with the region to implement Northwest Energy Efficiency Taskforce recommendations.

Conduct demand response pilot programs and technology demonstrations. In the Sixth Power Plan, the Council calls on utilities to engage in research pilot programs that explore areas that have not been tried before and development and demonstration programs that are designed to test acquisition strategies and facilitate full-scale deployment. BPA is actively pursuing research pilot programs in the commercial and residential sectors. The results will inform the expansion of these pilots into demonstration programs.

Support improved data acquisition techniques for conservation measure verification to ensure valid long-term measure verification at lowest cost and with least intrusion on the time and privacy of participants in conservation programs.

9.2 Market purchases

Continue to consider the reliance on short- and mid-term market transactions to meet low-probability within-year seasonal needs as an alternative to committing to long-term resource acquisitions. BPA will continue to monitor and evaluate these guidelines in light of evolving wholesale market conditions. Reliance on the short- and mid-term markets will be closely considered in light of the significant uncertainty the agency faces in terms of future requirements.

Continue to consider longer-term market purchases to meet emerging seasonal and annual needs as an alternative to long-term resource acquisitions. BPA will continue to consider prudent use of longer-term market transactions to manage needs in advance of committing to long-term resource-based acquisitions. BPA will continue to evaluate the relative financial risks of longer-term market purchases compared to acquisition of output from specific resources. BPA will explore methods to enhance its ability to provide and obtain credit support for such transactions.

9.3 Variable energy resource integration and acquisition

Preserve and enhance the performance of the hydroelectric generating capability of the FCRPS. Invest in maintenance and capital asset improvements, upgrades, and replacements for the existing federal hydropower resources. Specific actions are conceived and reviewed through the FCRPS Asset Management Strategy, which is vetted publicly through BPA's Integrated Program Review. Specific capital investment decisions are made collaboratively by representatives from all three FCRPS operating agencies and reviewed by BPA's agency-level asset management processes.

Complete existing Wind Integration Team Work Plan projects. These projects will allow BPA to continue to integrate expected wind power into its transmission system and will begin to move BPA and other Northwest balancing authorities toward more flexible power scheduling and joint provision of balancing services.

Develop a formula rate option that can provide a price signal to variable energy resources locating in the BPA balancing authority area. If BPA needs to augment the existing federal system to provide additional balancing reserves, passing the costs of such augmentation directly to the users of balancing services could encourage lower cost alternatives.

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 such as greater use of dynamic scheduling and voluntary markets for the sharing of balancing resources through the Joint Initiative of ColumbiaGrid, WestConnect, and the Northern Tier Transmission Group.

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. Additionally, identify opportunities for incremental improvements in efficiency and generation of non-federal facilities, consistent with item GEN-11 of the Council's Sixth Power Plan Action Plan.

Be prepared to address customer interest in Renewable Portfolio Standards-qualifying resources such as wind, geothermal, and biomass, and stand ready to acquire such resources under the Tier 2 Vintage rate structure where doing so will fill a corresponding BPA resource need.

9.4 Natural gas fired generation

Further evaluate natural gas fired flexible resources. Single-cycle combustion turbines and reciprocating engines perform well economically compared to other generating resource options as sources of flexibility, reserves, and seasonal Heavy Load Hour energy. However, they also produce carbon emissions. Continue to track and evaluate the economic and environmental tradeoffs associated with single-cycle combustion turbine and/or reciprocating engine capabilities to provide balancing reserves, seasonal energy, and, depending on siting, a reduction in transmission requirements.

Continue to track, evaluate, and appropriately pursue combined-cycle natural gas fired generation to supply future reserve requirements, seasonal/monthly energy, and annual energy. Should the high end of BPA's potential load obligations come to pass and BPA finds it requires resources beyond available cost-effective conservation, market purchases, and renewable energy supplies, combined cycle gas turbines would likely be one of BPA's top considerations. Combined-cycle gas turbines provide the lowest cost and lowest emission profile of thermal baseload resources that are now widely available with large enough capacity to meet annual energy needs.

9.5 Sources of flexibility and energy storage

Actively pursue limited pilot programs for augmentation of system flexibility. BPA believes that participation in limited third-party pilot programs for flexibility augmentation will provide valuable operational and economic knowledge to support possible long-term flexibility solutions.

Evaluate flexibility augmentation options. The Council calls for a regional assessment of the relative availability, reliability, and cost effectiveness of resources that can augment the balancing capability of the Northwest power system, including pumped storage, compressed air energy storage, battery, Smart Grid, and demand-side options. BPA concurs with the Council that the Northwest Wind Integration Forum is the appropriate venue for this regional assessment.

Evaluate pumped storage and other energy storage options and pursue cost-effective alternatives. Pumped storage is widely used elsewhere to help accommodate variations in load. Pumped storage, compressed air energy storage, and other storage technologies could prove valuable for firming variable generation and/or providing diurnal reserves and/or Heavy Load Hour energy. BPA is conducting an evaluation of pumped storage potential; the initial evaluation is slated for completion in 2010. Initial studies indicate that reliability improvements to the Keys Pump-Generator Plant at the Grand Coulee complex will be beneficial for providing reserves for integrating variable generation. BPA will explore opportunities to test and evaluate the feasibility and cost-effectiveness of large-scale power storage technologies to increase system flexibility, improve reliability, and provide Heavy Load Hour energy and balancing reserves.

9.6 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. For example:

- Smart Grid. BPA is a participant in the Pacific Northwest Smart Grid Demonstration Project, which includes five project infrastructure technology partners, 11 utilities, and the University of Washington. The Demonstration Project is managed by Battelle Memorial Institute, Pacific Northwest Division. Funded through a 50 percent cost share by the Department of Energy, the project will implement a number of demand response programs through participating utilities.
- Demand response technologies. In addition to the proven Demand Response technologies described in Chapter 6, BPA is leading demand response pilot projects

in the Northwest to test the ability of emerging technologies to automate demand response, provide ancillary services, and facilitate wind integration.

Continue to monitor progress in development of relevant technologies for potential application to future Resource Programs. Monitoring will include Demand Response and Smart Grid technologies, energy storage, and emerging generating resources such as tidal and wave energy, enhanced geothermal, and others.

9.7 Improving methodologies

Continue to further develop tools and analytical methods to enhance BPA's capability to evaluate system needs and resource options. This is the first Resource Program BPA has produced since 1992. The nature of BPA's system needs has evolved considerably and continues to do so, necessitating development of new tools to analyze both the need and the effectiveness of various resources to meet it. BPA will:

- Work with its customers, the Council, and others to improve models and analytical techniques for load forecasting; needs assessment; resource adequacy assessment; comparative resource analysis, including economic analysis; and evaluation of technologies such as storage and demand management needed to integrate variable generation.
- Focus on improving techniques to discern the relative value of non-traditional means of meeting loads, such as demand response programs, Smart Grid technologies, and changes in transmission protocols.
- Continue to work with regional utilities, Northwest states, the Western Energy Renewable Zones initiative, and Western Electricity Coordinating Council to improve techniques for evaluating the relative merit of resources that require construction of new long-distance transmission compared to within-basin alternatives.
- With the Council, reestablish regular periodic assessments of resource availability, cost, and performance to support the Council's Power Plan and BPA's Resource Program.

9.8 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, provided 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
- Natural gas supplies and market trends

- Power market liquidity and trends including increased volatility and frequency of negative prices
- Climate change legislation
- Regional capacity constraints
- Implementation of Renewable Portfolio Standards in the Pacific Northwest and California
- Emergence and cost effectiveness of new technology

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 2015 and beyond, climate change legislation, economic recovery, and many other uncertain future outcomes. This uncertain situation motivates BPA 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 evolve with these changes.

APPENDICES

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APPENDIX A. GLOSSARY

120-hour sustained peaking The term "superpeak" analysis is used in the Needs Assessment for the same metric as the "120-hour sustained peaking capacity" term in the White Book. It is a measure of the system's ability to meet the peaks day after day throughout the month (6 hours/day, 5 days/week, 4 weeks/month 6*5*4=120).

Above-High Water Mark Load A customer's forecast annual Total Retail Load, less Existing Resources, New Large Single Loads, and the customer's Rate Period High Water Mark. The customer may choose to acquire resources to meet Above-High Water Mark Load or purchase power from BPA at a Tier 2 rate to meet it, or a combination.

ALF, Agency Load Forecasting Tool BPA's load forecasting tool that uses historical load, load trends, and temperature information to produce short-, medium-, and long-term load forecasts. This approach is implemented with forecasting software developed by Itron.

Ancillary Services Services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the BPA transmission system in accordance with Good Utility Practice. Ancillary Services include Scheduling, System Control and Dispatch; Reactive Supply and Voltage Control from Generation Sources; Regulation and Frequency Response; Energy Imbalance; Operating Reserve – Spinning; and Operating Reserve – Supplemental. The Needs Assessment refers specifically to ancillary services purchased by BPA Transmission from BPA Power (FCRPS resources) to support transmission reliability.

Auto Vista An analysis module of Columbia Vista Decision Support Software. It simulates hourly operations over multi-year time periods.

Balancing Authority The responsible entity that schedules generation on transmission paths ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area (previously called Control Area), and supports interconnection frequency in real time.

Balancing reserves The sum of load following, generation following, regulation reserves, and generation imbalance. Typically, these are reported as incremental *(inc)* and decremental *(dec)* reserves.

BiOp, Biological Opinion A determination by a responsible Federal agency as to whether the operating plan of a subject Federal agency is adequate to protect affected species listed under the Endangered Species Act. For the Resource Program, the relevant BiOp is the 2008 BiOp on FCRPS operations for Columbia Basin salmon and steelhead.

Block The Block Product is a Core Subscription product that is available to purchasers that have a right to purchase from BPA for their requirements. This product is available in Heavy Load Hour and Light Load Hour quantities per month, with the hourly amount flat for all hours in such periods.

Capacity The greatest amount of power (measured in megawatts) a generator or system of generators can supply at its peak output for a given period. The Needs Assessment analyses FCRPS capacity that can be sustained over 18-hour and 120-hour periods under varying water conditions.

Capacity factor The portion of a generator's nameplate rated output that can be 1) relied upon to be available at need, or 2) average output. (These two definitions can be quite different.) For wind generation, the term "capacity factor" generally refers to the generator's average output.

CCGT, combined cycle gas turbine An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

CGS, **Columbia Generating Station** A nuclear plant owned by Energy Northwest, for which BPA markets all power.

Cogeneration The joint production of electricity and useful thermal or mechanical energy for industrial process, space conditioning or hot water loads.

ColumbiaGrid Regional transmission entity being developed by BPA, Puget Sound Energy, Chelan and Grant Public Utility Districts, and Seattle City Light.

Columbia Vista A hydro scheduling and planning decision support system incorporating marketing objectives and optimization functions. It was developed on the Vista platform as adapted to the Federal Columbia River Power System.

Council Northwest Power and Conservation Council: as defined in the Northwest Power Act, the members appointed to the Pacific Northwest Electric Power and Conservation Planning Council established pursuant to section 839b of the Act.

Critical water The historical sequence of streamflows least able to refill FCRPS reservoirs. Specifically, in the Resource Program, October 1936 to September 1937.

***dec*, decremental** Downward component of balancing reserves; a backing-off of a system's generation as area load drops off or as wind or other generation picks up compared to the forecasts.

Distribution efficiency improvements Efforts to improve reliability, system performance, and power quality. BPA offers several distribution-level efficiency improvement measures, including high-efficiency transformer replacement, load balancing, reconductoring, and voltage optimization.

Dispatchable A resource that can be increased or decreased at will through the actions of a transmission system or power plant operator.

DSIs, direct-service industrial customers Industrial customers, primarily aluminum smelters, that can buy power directly from BPA at relatively high voltages.

***down reg,* Downward regulation** The backing off, or regulation, of a power system's base generation in response to a rising contribution of a non-dispatchable resource, such as wind, as it contributes more energy, or in response to a decreasing demand from load.

DSO 216, Dispatcher Standing Order 216 BPA's Wind Integration Team has developed a set of operating protocols that will allow BPA to continue integrating new wind plants while reliably maintaining the BPA system during extreme wind events. These reliability and operational requirements are formalized in DSO 216.

Dynamic scheduling Control of and responsibility for providing ancillary services within-hour to support a resource that is physically located in a different balancing authority area, through remote electrical controls. BPA is developing greater ability to allow other utilities to dynamically schedule wind resources located in BPA's balancing authority area.

Energy An amount of electricity consumed over time (measured in megawatt-hours or average megawatts).

Federal Base System As defined in the Northwest Power Act, the FBS resource pool consists of the following resources: (1) the FCRPS hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reductions in the capability of the above resource types.

FCRPS, Federal Columbia River Power System The power system comprised of 1) the transmission system constructed and operated by BPA and 2) the hydroelectric dams constructed and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation in the Northwest. Each entity is separately managed and financed, but the facilities are operated as an integrated power system.

Firm Capacity Capacity that BPA will make continuously available under contracts executed pursuant to section 5 of the Northwest Power Act.

Full requirements customers Those public utility customers of BPA who own or control little or no generation capability and who purchase all or almost all of the power required to serve their loads from BPA.

GCL Grand Coulee hydroelectric facility

Graveyard Hours A subset of light load hours; hours ending 01 to 04 (midnight to 4 am)

Henry Hub The major commercial trading point for natural gas deliveries. Henry Hub prices are the general measure of U.S. natural gas market prices.

HLH, Heavy Load Hours Hours ending 07 to 22 (6 am to 10 pm) Monday through Saturday, not including holidays.

HOSS, Hourly Operating and Scheduling Simulator A computer model that simulates the hourly dispatch and short-term marketing of Northwest thermal and hydropower resources for a study period of up to four weeks. It is used to examine, in monthly or semi-monthly periods, the system capacity, marketing, and various environmental constraints that require hourly detail.

HYDSIM or HydSim, Hydrologic Simulator Model A monthly step computer river simulation model that routes water from the headwaters of the Columbia basin through the system of dams, storing in and drafting from reservoirs to meet non-power and power requirements established by the modeler.

HWM, High Water Mark The amount of power a BPA utility customer can purchase from BPA at Tier 1 rates, reflecting costs of the existing federal hydro system, as established in the Regional Dialogue Policy and the Tiered Rate Methodology.

ICE Electricity end-use associated with Information, Communication, and Entertainment appliances and devices.

***inc*, incremental** Upward component of balancing reserves; a picking-up of a system's baseload generation as wind or other renewable generation backs off, or as load increases.

Investor-owned utility A privately owned utility organized under State law as a corporation to provide electric power service and earn a profit for its stockholders. A private utility.

LLH, Light Load Hours Hours ending 23 to 06 (10 pm to 6 am) Monday through Saturday and all hours Sunday and holidays.

Load The total amount of electricity used at any given time or over any given period that a utility is obligated to serve or a balancing authority must balance with generation.

LaRIS, Loads and Resources Information System A BPA Power Services data repository software system for information on loads, resources, and contracts.

Mid-C, Mid-Columbia A major trading point for the competitive wholesale power market in the Northwest. A useful reference point for Northwest wholesale market prices.

NERC, North American Electric Reliability Corporation A council consisting of nine Regional Reliability Councils, encompassing virtually all of the power systems in the U.S. and Canada. Formed by the electric utility industry to promote reliable and adequate supplies of bulk electric power.

Net requirement Amount of federal power that a public utility, cooperative, or investor-owned utility is entitled to purchase from BPA, as defined by sections 5(b) and 9(c) of the Northwest Power Act.

New Resources Firm Power (NR) rate The BPA rate available for the contract purchase of firm power to be used within the Pacific Northwest. Available to investor-owned utilities under Northwest Power Act section 5(b) requirements contracts as specified in the NR rate schedule. Also available to any public body, cooperative or federal agency for service to New Large Single Loads, as defined by the Northwest Power Act.

Nominal dollars Dollars of the value that they held in a specified year, not adjusted for inflation (as opposed to real dollars, which are dollars in values adjusted for inflation).

Non-power operating requirements Constraints on Federal hydro production not related to power production, such as minimum pool elevations to allow barge navigation and irrigation water withdrawals, flood-control requirements, and fish protection requirements.

Obligations, net obligations The sum of BPA's contracted power supply or transmission responsibilities for a given time period. Net obligations are net of any countervailing sources or mandates.

Operating reserves In a power system, the capability in excess of that required to carry the normal total load. Electric power needed to serve customers in the event of generation or transmission system outages, adverse streamflows, delays in completion of new resources, or other factors that may restrict generating capability or increase loads. Normally provided from additional resources acquired for that purpose, or from contractual rights to interrupt, curtail, or otherwise withdraw portions of the electric power supplied to customers. Operating reserves also require the generation system to be able to back down in the event of loss of load or unexpected increases in generation.

Peak load The highest amount of electricity used in a specific area, either for a moment, an hour, a set of hours, or another specified period. To maintain reliability, peak loads must always be less than generation capacity available to the specified area. The Needs Assessment analyzes peak loads in 18-hour and 120-hour "superpeak" increments.

P5 The 5 percent exceedence probability level, having the chance of occurring 1 out of 20 times.

P10 The 10 percent exceedence probability level, having the chance of occurring 1 out of 10 times.

Persistence A concept used to measure scheduling accuracy. Persistence forecasts assume that the future amount will be the same as the current amount. The assumption of scheduling accuracy can make a difference in the amount of reserves BPA needs to provide for wind generation. For the Needs Assessment and Resource Program, the level of required reserves is based on the assumption that wind forecasts will be at least as accurate as if the forecasters used persistence forecasts of actual wind generation 30 minutes before the hour to predict wind generation and to schedule wind generation for the coming hour.

Preference customers Cooperatives or public bodies, such as municipalities and public utility districts, that by law have priority access to buy Federal power from BPA, not already committed by contract, "when the Administrator receives conflicting or competing applications for power that the Administrator is authorized to allocate administratively." *ALCOA v. Central Lincoln PUD et al.*, 467 U.S. 380, at 393 (1984) (citing section 4(b) of the Bonneville Project Act).

Priority Firm Power (PF) rate The BPA rate available for the contract purchase of firm power to be used within the Pacific Northwest. Available to public bodies, cooperatives and federal agencies under Northwest Power Act section 5(b) requirements firm power sales contracts. Also available for purchase of the Slice Product and Residential Exchange Program as specified in the rate schedule.

Reciprocating engine A piston or internal combustion engine fueled by natural gas, gasoline, liquid propane, or diesel.

Redispatch Redirection of a power flow from one transmission path to another by the Dispatcher, normally to maintain system reliability and avoid transmission congestion.

Reserve requirements Amounts and types of reserves a Balancing Authority must maintain in available status to comply with North American Electric Reliability Corporation, Western Electricity Coordinating Council, or other regulatory requirements. Includes contingency reserves (half spinning, half non-spinning), regulating reserves, load following, and generation imbalance.

Reserve sharing Member control areas collectively maintain, allocate and supply operating reserves required for each balancing authority area's use in recovering from contingencies within the group.

Resource Any source of power supply that can be contractually assured.

Resource Adequacy Standard (energy and/or capacity) A standard set by a regulatory or similar body determining how much excess energy supply a utility must have available to ensure it can meet expected energy or capacity loads beyond those presently realized. The Resource Program refers to the Regional Resource Adequacy Standard adopted by the Council.

RSS, Resource Support Services Pursuant to the Tiered Rate Methodology, RSS includes Diurnal Flattening Service, Forced Outage Reserve Service, Transmission Curtailment Management Service, and Secondary Crediting Service. In the future, RSS may include other related services that will be priced in the applicable 7(i) process consistent with the Tiered Rate Methodology.

Secondary Power over and above BPA's firm power obligations to its customers that may be sold in the competitive wholesale power market. BPA's net secondary sales are net of its power purchases in that market to meet its firm obligations.

Shaping Taking energy (or streamflows) from a generation source as it is produced, and providing, in return, energy (or water) in the amount(s) over time as requested by the customer or as required. BPA shapes streamflows to meet spill and flow requirements for fish. BPA's Resource Support Service can shape energy from a customer's power source into flat blocks of power for a customers' base load.

SCGT, simple cycle gas turbine A simple cycle gas turbine generator consists typically of an air compressor and one or more combustion chambers where a liquid or gaseous fuel/compressed air mix is burned and the hot gases are passed to the turbine to drive a generator. A portion of the hot exhaust gases is then used to run the compressor.

Slice The Slice product is a power sale based upon an eligible customer's annual net firm requirements load and is shaped to BPA's generation from the FCRPS through the year. Slice purchasers are entitled to a fixed percentage of the energy generated by the FCRPS. The Slice purchasers' percentage entitlements are set by contract. The Slice product includes both service to net requirements firm load and an advance sale of surplus power.

Spill, spill requirements Spill is water sent through the spillways of a dam rather than through generating turbines, either for fish protection, because there is no market for the power that would be produced, or because streamflows exceed turbine capacity. Spill requirements are amounts and timing of spill to protect fish.

Spinning reserves Generators that are turned on and synchronized with the grid, literally spinning but not connected to load or that are not operating at full capacity, held on stand-by to increase generation at a moment's notice.

Stochastic Involving a random variable, or a study based on probability of occurrence.

Subscription The name given to long-term power sales contracts BPA signed with its customers in 1996, following deregulation of the wholesale power market in the western

United States. These contracts expire in 2012 and will be replaced by Regional Dialogue contracts.

Superpeak Hours A subset of HLH; six peak hours for each weekday, varying by season.

THWM, Transition Period High Water Mark An amount calculated pursuant to section 4.3.2.1 of the Tiered Rate Methodology, to be applied during the TRM transition period, FY 2012-2014.

Tier 1 For purposes of the Resource Program, Tier 1 may be thought of as the amount of power BPA will serve at Tier 1 rates, i.e., up to the High Water Mark.

Tier 1 System Firm Critical Output (T1SFCO) As defined by the Tiered Rate Methodology, the firm critical output of Tier 1 system resources (specified Federal system hydro generation resources, designated non-Federally owned resources, and designated BPA contract purchases) less Tier 1 system obligations (the amount of energy and capacity that BPA forecasts for the designated BPA system obligations over a specific time period).

Tier 2 For purposes of the Resource Program, Tier 2 may be thought of as the amount of power BPA will serve at Tier 2 rates, i.e., above the High Water Mark.

TRM, Tiered Rate Methodology BPA's methodology for setting tiered rates, which will be in effect starting October 1, 2012, including setting each customer's High Water Mark (HWM).

***Up reg,* Upward regulation** Spinning reserves ready to increase generation to compensate for a declining contribution of a non-dispatchable resource such as wind, or an increase in load. This is in addition to the spinning reserves that stand ready to respond to contingency outages.

Variable generation or variable energy resource An electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints. Hydropower is variable beyond the storage capabilities of reservoirs. Wind and solar output vary with wind and sun, respectively. Tidal and wave energy likely will prove variable, within patterns of those resources. Also called non-dispatchable, intermittent.

Waste heat recovery Any conservation system whereby some space heating or water heating is done by actively capturing byproduct heat that would otherwise be ejected into the environment.

Water year, water year strips A water year is one hydrologic cycle corresponding to BPA's fiscal year, October 1 through September 30. In modeling Hydroelectric

Generation and Hydroelectric Generation Variability, BPA used strips of 10 consecutive water years out of the 70 water years used for the analysis.

WECC, Western Electricity Coordinating Council The regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. WECC ensures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members.

Western Interconnection Synchronously-operated interconnected electric transmission systems located in the Western United States; Baja California, Mexico; and Alberta and British Columbia, Canada.

WIT, Wind Integration Team BPA wind study group formed in the WI-09 Rate Case Settlement to study and report on the operational and infrastructure issues associated with integrating large-scale wind resources into the electrical grid.

Within-hour sales or scheduling Power generation is typically scheduled over transmission paths by the hour. Some utilities and balancing authorities, such as the California Independent System Operator, have developed the ability to schedule some generation changes within hours. BPA is developing this capability in concert with other western utilities, particularly to support variable wind generation.

WREZ Western Renewable Energy Zones. The Western Governors' Association and U.S. Department of Energy launched the Western Renewable Energy Zones initiative in May 2008. The WREZ initiative seeks to identify those areas in the West with renewable resources ("renewable energy zones") to expedite the development and delivery of renewable energy to where it is needed. Renewable energy resources are being analyzed within 11 states, two Canadian provinces, and areas in Mexico that are part of the Western Interconnection.

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APPENDIX B. MARKET UNCERTAINTIES

B.1 AURORAxmp® Assumptions

BPA used the AURORAxmp® Electric Market Model[1] to create wholesale electricity price forecasts based on the potential future wholesale electricity market conditions described in Chapter 2. AURORAxmp® is a power market simulation model. The model simulates electricity supply and demand on an hourly basis to provide electricity price forecasts. BPA produced separate price forecasts from AURORAxmp® for each of the scenario tree's five branches. The input assumptions for each branch are fully explained in the Resource Program, Chapter 2. The price forecasts consist of an expected forecast—assuming average hydroelectric generation from the water year samples—and 10 additional forecasts that result from the different hydroelectric generation values. Each price forecast consists of monthly HLH and LLH Mid-C electricity prices from October 2010 through September 2019, the time frame for this analysis. Flat prices represent the average price for all hours. Flat prices were derived by weighting the HLH prices by 57 percent and the LLH prices by 43 percent.

The price forecasts from AURORAxmp® are developed in a two-step process. First, a forecast of generating resource additions and retirements is developed. BPA used the model's long-term resource optimization logic to complete this forecast. The long-term optimization logic selects least-cost generating resources to meet target reserve margins. Once the generating resource forecast is complete, the fixed set of resources is dispatched hourly in a least-cost order to meet demand while maintaining the generating resource's operating constraints. The hourly marginal price is set equal to the variable cost of the most expensive generating resource or load curtailment needed to meet the hourly net load.

Several primary drivers are relevant to the Mid-C electricity price forecasts: the load forecast, the natural gas price forecast, assumptions about hydroelectric generation conditions, the carbon price forecast, and generating resource additions that result from renewable portfolio standard assumptions. The load forecast determines where on the supply curve the marginal price will occur. Natural gas prices will, for most on-peak hours and for most areas, determine the variable cost of the resource on the margin, which sets the marginal market-clearing price. However, the addition of carbon prices alters the price differential between fuels and may lead to changes in the dispatch order. Hydroelectric generation conditions determine the amount of hydroelectric generation that can be used to meet loads. In general, greater amounts of hydroelectric generation will reduce the marginal market-clearing price, because hydroelectric generation is a low variable cost resource. The price forecasts assume that development of generating resources needed to meet renewable portfolio standards will occur. These generating resources are often low variable cost generating resources that will place downward pressure on Mid-C electricity prices, all else equal. The assumptions for the load forecast, natural gas prices, hydroelectric generation conditions, carbon prices, and generating resources are described in detail in the following sections.

[1] AURORAxmp® is owned and licensed by EPIS, Incorporated (EPIS).

B.2 Load Forecast

For the Recovery and Modest Growth scenario, BPA used a load forecast provided by the Northwest Power and Conservation Council. BPA's AURORAxmp® model configuration requires peak demand and energy load forecasts for 16 geographic areas. Using peak demand and energy load forecasts allows BPA to separately control the growth rates for annual peak demand and average annual energy for each area in the analysis. Table B.1 lists the peak demands and annual energy loads, for each of the 16 areas, that BPA used in AURORAxmp® for the Recovery and Modest Growth scenario.

Table B.1 - Forecast Peak Demand and Energy Load for Recovery and Modest Growth Scenario

	Annual Energy Loads (aMW)			Annual Peak Demand (MW)		
Area Name	CY 2010	CY 2020	Growth Rate 2010-2020	CY 2010	CY 2020	Growth Rate 2010-2020
Alberta	8,891	11,390	2.50%	11,212	15,545	3.30%
Arizona	10,769	15,270	3.60%	20,273	29,210	3.70%
British Columbia	7,225	7,659	0.60%	11,117	11,985	0.80%
California North	13,951	15,210	0.90%	25,621	28,603	1.10%
California South	19,101	21,094	1.00%	34,554	39,198	1.30%
Colorado	6,134	7,396	1.90%	9,680	11,603	1.80%
Idaho South	2,593	3,007	1.50%	4,052	4,682	1.50%
Mexico Baja CA North	1,600	2,509	4.60%	2,479	4,076	5.10%
Montana East	893	1,037	1.50%	1,374	1,591	1.50%
Nevada North	1,451	1,544	0.60%	2,148	2,401	1.10%
Nevada South	3,038	3,976	2.70%	7,015	8,668	2.10%
New Mexico	2,713	3,614	2.90%	4,356	6,029	3.30%
PNW Eastside	5,598	6,497	1.50%	8,821	10,001	1.30%
PNW Westside	13,594	15,806	1.50%	21,558	24,340	1.20%
Utah	2,860	3,334	1.50%	4,086	4,938	1.90%
Wyoming	1,950	2,302	1.70%	2,737	3,299	1.90%

B.2.1 Adjustment Method for High and Low Load Forecast

BPA also produced a high load forecast for the Boom scenario and a low load forecast for the Prolonged Recession scenario. To produce these forecasts, BPA evaluated the growth rates for peak demand and energy loads in the four WECC sub-regions: Northwest Power Pool Area, Rocky Mountain Power Area, California/Mexico Power Area, and the Arizona/New Mexico/Southern Nevada Power Area. The data source for the evaluation was the historical peak demand and energy load calendar year data published on page 61 of the WECC 10-Year Coordinated Plan Summary issued in July 2006.

Based on the historical records (1982-2005), BPA calculated the annual compound growth rate over 10-year periods for peak demand and energy loads in the four WECC sub-regions. From these growth rates, BPA calculated the values at the 90^{th} and 10^{th} percentiles. BPA compared the calculated values at the 90^{th} and 10^{th} percentiles to the comparable 10-year growth rate for the

WECC sub-regions from the load forecast used in the Recovery and Modest Growth scenario. To make this comparison, BPA consolidated the 16 AURORAxmp® areas into the four WECC sub-regions using the following assignment:

- Northwest Power Pool Area growth rates for peak demand and energy loads were assigned to the PNW Eastside, British Columbia, Idaho South, Montana East, Utah, Nevada North, Alberta, and PNW Westside areas.
- Rocky Mountain Power Area growth rates for peak demand and energy loads were assigned to the Wyoming and Colorado areas.
- California/Mexico Power Area growth rates for peak demand and energy loads were assigned to the California North, California South, and Mexico Baja areas.
- Arizona/New Mexico/Southern Nevada Power Area growth rates for peak demand and energy loads were assigned to the Nevada South, New Mexico, and Arizona areas.

Where the 90^{th} percentile for the WECC sub-region was greater than the growth rate in the Recovery and Modest Growth scenario, BPA adjusted the area load forecast in the Boom Scenario to equal the higher growth rate. Where the 10^{th} percentile for the WECC sub-region was lower than the growth rate in the Recovery and Modest Growth scenario, BPA adjusted the area load forecast in the Prolonged Recession scenario to equal the lower growth rate. These adjustments created WECC sub-region annual energy load and peak demand forecasts that were equal to the 90^{th} and 10^{th} percentile values calculated from the historical data.

Tables B.7 and B.8 at the end of this appendix display the historical energy load and peak demand data that was evaluated. The tables also contain the calculated growth rates and percentiles that were used to adjust the load forecasts. Tables B.9 and B.10 show the results of the method's application to the Northwest Power Pool load forecasts.

B.3 Natural Gas Prices

BPA developed three natural gas price forecasts based on the three economic scenarios. The gas price forecast assumptions were briefly described in Chapter 2, and the assumptions made for the gas price forecasts are more fully explained below.

B.3.1 Medium Scenario Assumptions

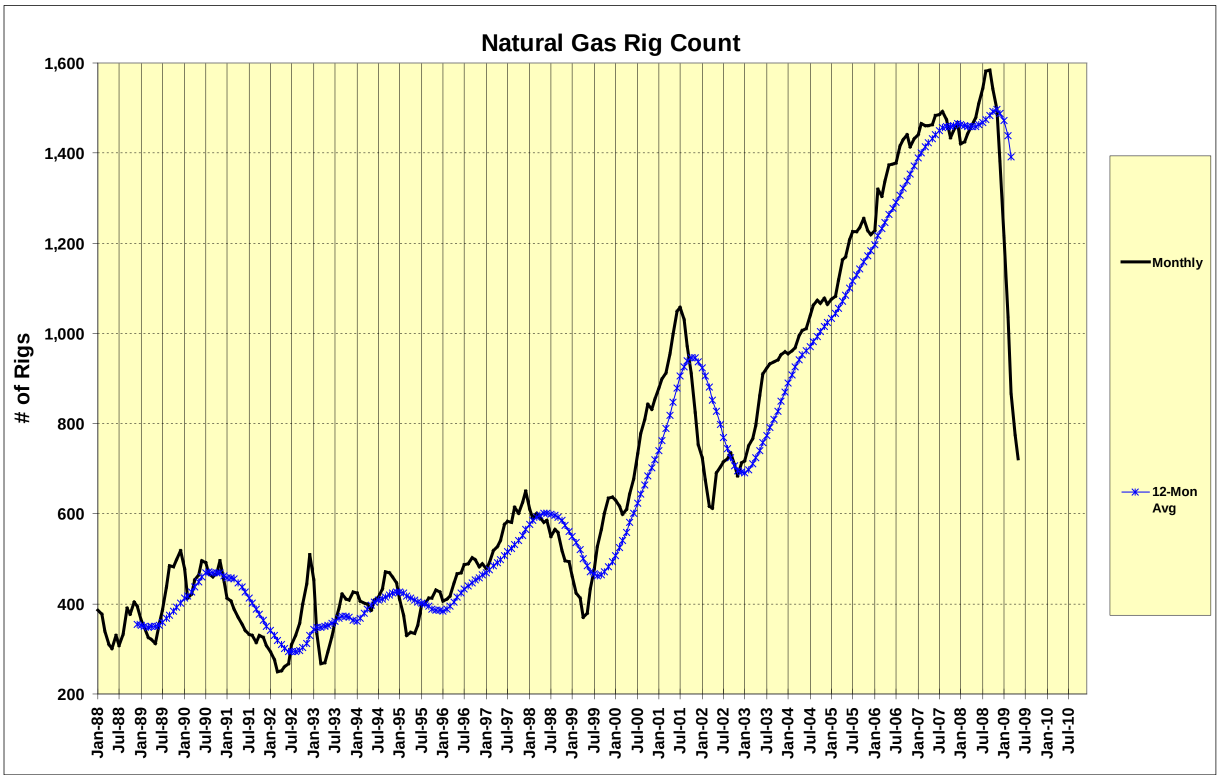
<u>Short-Term</u>
BPA assumed a short-term jump in the natural gas price (2009-2011) for the medium gas price scenario forecast. This jump was driven by the assumption of an economic recovery, which would increase the demand for natural gas in all demand sectors. BPA assumed the economic recovery would increase manufacturing output, power consumption, and consumer incomes. The increases in these variables would increase the natural gas demand from the industrial, power generation, residential, and commercial demand sectors.

The effects of the economic recovery on short-term natural gas prices will be magnified by the cyclical nature of natural gas prices. An economic recession will first lower natural gas demand

and therefore increase natural gas storage inventories. This will lower natural gas prices and lead to a decline in natural gas production. Typically, declines in natural gas production occur with declines in natural gas demand, but the production decline lags the decline in demand. The result is that when the economy and natural gas demand recovers, the recovery will occur during the downturn in natural gas production, and the natural gas price increase is magnified.

The natural gas production decline is evident in the current recession. As a result of the current recession, the number of US natural gas rigs has declined nearly 50 percent from their peak in September 2008. The sharp decline in rig count is seen in Figure B.1.

Figure B.1 - Natural Gas Rig Count



In summary, two factors drove the short term increase in natural gas prices—an economic recovery that increased natural gas demand, and a cyclical lag in natural gas production, which would magnify the short-term price response.

Mid- to Long-Term

In the mid- to long-term, BPA assumed a modest growth in natural gas prices for the medium natural gas price forecast. BPA assumed there would be continued strong demand for natural gas in the power generation sector, but demand from the industrial, residential, and commercial sectors would remain relatively flat. Specific to supply-side fundamentals, BPA assumed that two factors would moderate the price increases that result from power generation demand—a boom in unconventional production and an increase in LNG liquefaction capacity.

Recently, unconventional natural gas production has experienced strong growth. Many natural gas analysts expect the strong growth in unconventional natural gas production to continue for the long term. Unconventional sources include natural gas production from tight sands, shale gas, and coal bed methane. In addition, a large amount of global liquefaction capacity for LNG is expected to become operational from 2010 to 2012. These two factors will increase natural gas supply, and BPA reflected the downward price pressure in the medium natural gas price forecast through a moderate mid- to long-term natural gas price increase.

In summary, BPA assumed that the mid- to long-term natural gas price increase would be moderate, with the upside factor of power generation sector demand growth met by increased global LNG capacity and North American unconventional natural gas production.

B.3.2 Low Scenario Assumption

For the low gas price forecast BPA assumed long-term slow growth in the economy, and the slow economic growth led to less demand for natural gas. Demand from the industrial and power generation sectors would be especially sensitive to economic growth and serve as the primary drivers in economics-induced natural gas demand reduction. The current economic recession has reduced industrial demand growth for natural gas, driving natural gas prices to low levels. The projected slow economic growth in the low scenario would continue this trend.

Prices in the low scenario were also based on downward resistance levels for natural gas. These resistance levels were based on the costs of displacing coal-fired generation and the costs of natural gas production. These costs can vary but are generally assumed to fall in the range of $4.50/MMBtu in nominal terms.

B.3.3 High Scenario Assumption

For the high gas price forecast BPA assumed strong economic growth that led to increased demand across all natural gas demand sectors. The increased natural gas demand was greatest in the industrial and power generation sectors. The increases in natural gas demand put upward pressure on natural gas prices and led to strongly positive growth rates in natural gas prices. In addition to increased demand from strong economic growth, natural gas demand increased, because high CO_2 prices began to make coal power generation uneconomic.

Specific to supply-side fundamentals, BPA assumed that a significant decline in unconventional production reduced natural gas supply and strengthened the price increases that result from power generation demand. Rather than assuming strong natural gas production from unconventional sources, BPA assumed that one or both of the following supply disruptions occurred: unconventional natural gas production experiences high production decline rates or unconventional producers begin to experience access restrictions.

B.3.4 Results

Summaries of the natural gas price forecasts are shown in Figure B.2 and Table B.2.

Figure B.2 - Natural Gas Price Forecasts

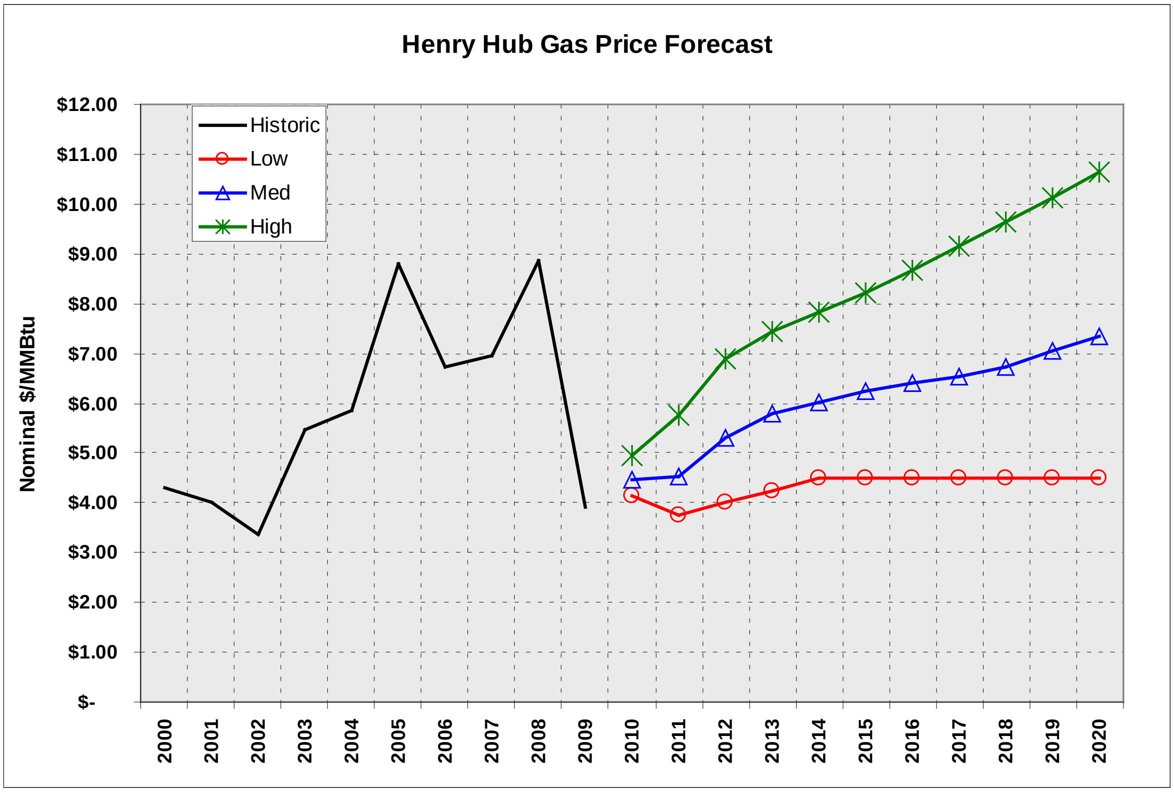


Table B.2 - Natural Gas Price Forecasts

Year	Historic	Forecast Low	Forecast Medium	Forecast High
2000	4.22			
2001	4.07			
2002	3.33			
2003	5.63			
2004	5.85			
2005	8.79			
2006	6.76			
2007	6.95			
2008	8.85			
2009	4.06			
2010		4.13	4.45	4.93
2011		3.74	4.53	5.75
2012		4.00	5.32	6.90
2013		4.25	5.78	7.45
2014		4.50	6.02	7.82
2015		4.50	6.23	8.21
2016		4.50	6.40	8.67
2017		4.50	6.53	9.14
2018		4.50	6.73	9.64
2019		4.50	7.05	10.13
2020		4.50	7.35	10.63

B.4 Treatment of Potential CO_2 Costs in the Resource Program

B.4.1 Overview

The potential for regulations that limit the emissions of greenhouse gases (GHG) is significant in the timeframe being studied by the Resource Program. In 2009, the U.S. House of Representatives has passed a bill (H.R. 2545, the American Clean Energy and Security (ACES) Act) that would have regulated the emission of greenhouse gases in the utility, industry, transportation, and fuel delivery sectors. As of August 2010, the Senate has failed to pass a corollary bill, so it does not appear that a final law will be passed in the immediate future.

There are a variety of methods that can be used by regulators to control GHG emissions, including emission taxes, "command and control" technology requirements, and the method currently favored by U.S. legislators (as reflected in the ACES Bill along with many others proposed in Congress), "Cap and Trade." With cap and trade, regulators/legislators designate a GHG emission cap for each year of a reduction program. That emission target typically shrinks for each year of the program until an acceptable level of emissions is reached. Having identified targeted emissions, the regulating body issues emission permits for each ton of greenhouse gas. Any regulated entity must acquire and submit one of these emission permits for each ton of emission they are responsible for emitting (combusting). There are a variety of ways that the government-issued emission permits can be distributed—the government can auction them or give them out for free. In most cap and trade programs, parties that have emission permits (acquired either from an auction or a free distribution) may sell their permits to others.

In limiting GHG emissions, cap and trade programs create a market and hence a price for GHG emission permits.[2] That emission permit price must be paid whenever fossil-fueled MWh are generated. In other words, a cap and trade program creates a new cost for every MWh of fossil-fueled generation. The greater the carbon emissions of a generating technology, the greater will be the cost of emitting under a cap and trade program. Depending on the design of cap and trade regulation (e.g., the stringency of emission caps, carbon price control mechanisms), carbon prices could be significant enough to affect the relative value of investing in various generating technologies.

In planning for the acquisition of resources one must take this potential new cost of fossil-fueled generation into account, as either a price risk or an expected price. A report titled, *Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans*, stated that most Western utility resource plans incorporate future carbon regulations into their analysis. The report was published by the Ernest Orlando Lawrence Berkeley National Laboratory in March 2008.

In modeling for the Resource Program, BPA took potential carbon costs into account. The goal was to adequately scope the impacts that potential CO_2 prices might have on wholesale electricity prices. The methods used to accomplish this are described briefly below.

[2] The cost of reducing GHG emissions to meet the cap is a direct determinant of the market value of an emission permit.

B.4.2 Method

The AURORAxmp® model is equipped to incorporate CO2 prices into its dispatch and resource acquisition logic. It does so by assigning a CO_2/MWh emission rate to each generator (a figure which is easily derived by identifying a plant's generation technology, fuel source, and the efficiency with which it burns that fuel). Some assumptions must be made about average fuel efficiency for each plant. With a CO_2 emission rate applied to each existing and potential generating facility, the model can apply a marginal CO_2 cost (i.e., a CO_2 emission price per MWh) to each generator when calculating the total costs of operating those generators.

Determining the level of CO_2 prices (usually expressed as $/metric ton) to include in the AURORAxmp® model is a much trickier proposition. This is due to the uncertainties of when (and even if) cap and trade legislation will be passed, how stringent the emission cap will be, what policies (if any) will control CO_2 prices, and how rapidly technology will change in response to CO_2 prices. Fortunately, BPA is able to lean on the extensive work on potential CO_2 prices that two other entities have recently completed. Due to time constraints, BPA has limited itself to testing three different pricing scenarios in its Resource Program modeling: a "high" CO_2 price, a "medium" CO_2 price and, for comparison purposes, no CO_2 price. The high CO_2 price estimate was used in the Resource Program's Boom scenario. All three estimates were used for the Recovery and Modest Growth scenario. No CO_2 price was applied in the Prolonged Recession scenario. It should be noted that BPA's use of a zero CO_2 price is meant to provide reference data so that BPA can see the impacts that CO_2 pricing has on the modeling outcomes.

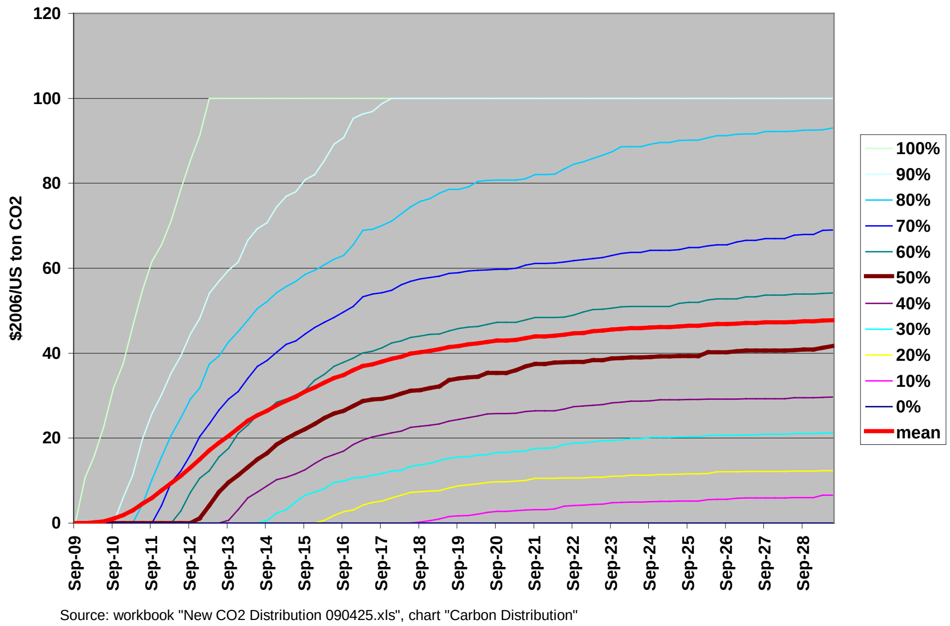
B.4.3 Derivation of BPA's High CO_2 Price Estimate

For its "high" CO_2 price estimate, BPA chose to use price figures derived from the Council's Sixth Power Plan. While the prices derived from the Council work are higher than the baseline estimates of other recent studies, they are not out of the feasible range of CO_2 prices as demonstrated by sensitivity analyses provided in those other studies.

The Council's CO_2 analysis treats CO_2 as a price risk. In other words, Council staff did not guess what the exact provisions and timing of a cap and trade regime would be over the life of their study (2010-2030). Instead, they derived prices as a function of two probability curves, one estimating the cumulative probability of cap and trade legislation passing over the study period, and another estimating the CO_2 price probabilities for each year. Their assumptions were then checked for reasonability against a Council-sponsored study produced by EcoTrust in the spring of 2009. The two probabilities compound in the Council's risk modeling process and result in a "decile chart" showing the probability of a particular CO_2 price being picked by the Council's risk model. These deciles are shown in Figure B.3.

BPA chose to use the Council's "central tendency," or expected, CO_2 prices, which resulted from running their risk model. These prices reflect the mean CO_2 price picked by the risk model in 750 scenario runs. The central tendency price is shown in a heavy red line in Figure B.3.

Figure B.3 - Carbon Penalty Distribution



Source: Council's Sixth Power Plan, Figure 9-9

B.4.4 Derivation of BPA's Medium CO_2 Price

The U.S. DOE Energy Information Administration (EIA) estimated CO_2 prices that might result from the ACES bill. Their study was published in August of 2009 in response to a congressional request for analysis. The EIA work contrasts with Council estimates because it models the effect of a specific regulatory proposal as opposed to the range of possible policy outcomes anticipated by the Council. EIA used their existing macroeconomic models together with EPA-provided models of the cost and supply of greenhouse gas (GHG) offsets[3] to estimate the cost of reaching the ACES emissions targets (17 percent below 2005 emissions in 2020, 80 percent below 2005 emissions in 2050). EIA estimates provide a valuable contrast to the Council's figures, as they reflect potential outcomes associated with a bill that has actually passed out of the House of Representatives.

For the purposes of the Resource Program, BPA used the EIA's "base case" estimate of CO_2 prices. EIA also modeled a variety of sensitivity cases that produced CO_2 price estimates that were both higher and lower than their base case estimates. The sensitivity cases varied in assumptions about the availability/timing of GHG offsets and of certain low-carbon electric generation technologies (such as coal with carbon capture and sequestration and new nuclear construction). EIA's price estimate results are presented in Table B.11 at the end of this

[3] A greenhouse gas offset displaces, avoids, or sequesters greenhouse gas emissions through the implementation of a specific project intended to compensate for emissions occurring at another source. Offsets tend to be emission reduction projects in sectors that are unregulated by a cap and trade program—either domestically (forestry and agriculture) or internationally (where there are no CO_2 emission restrictions).

appendix. A full description of the EIA modeling processes and outcomes can be found at EIA's website.[4]

B.4.5 Resource Program CO_2 Price Data:

Summaries of the CO_2 price forecasts are shown in Figure B.4 and Table B.3. As noted in section 2.2.1 of the Resource Program, Council central tendency CO_2 price estimates and the EIA's estimates of CO_2 prices were pushed out by two years to reflect regulatory delay that was not apparent at the time the Sixth Power Plan analysis was conducted.

Figure B.4 - Future CO_2 Price Projections

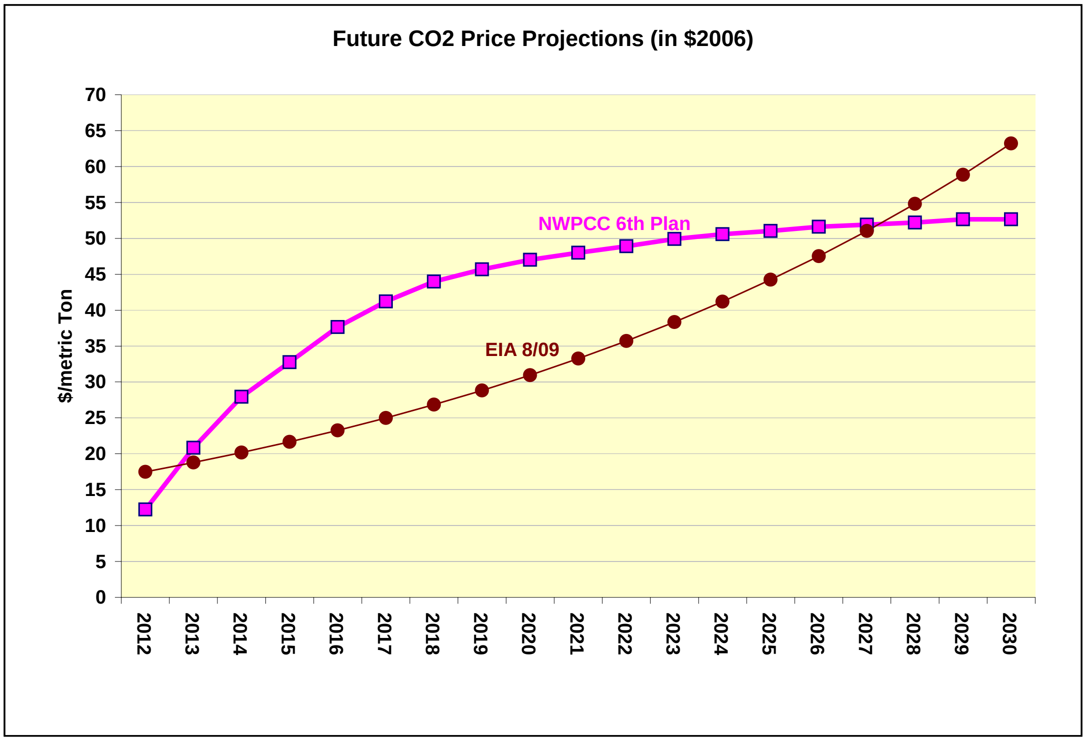


Table B.3 - CO_2 Price Forecasts

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
EIA	17.5	18.8	20.2	21.7	23.3	25.0	26.8	28.8	31.0
NWPCC	12.2	20.8	27.9	32.8	37.7	41.2	44.0	45.7	47.0

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EIA	33.2	35.7	38.3	41.2	44.2	47.5	51.0	54.8	58.9	63.2
NWPCC	48.0	48.9	49.9	50.6	51.0	51.6	51.9	52.2	52.6	52.6

[4] http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html?featureclicked=5&

B.5 Hydroelectric Generation and Hydroelectric Generation Variability

B.5.1 Overview

To account for Pacific Northwest hydroelectric generation in AURORAxmp®, BPA used estimates of monthly regional hydroelectric generation. Monthly energy values for each of the 70 historical Water Years (WY) from fiscal year 2010-2015 were supplied. Energy values for FY 2015 were used as a proxy for FY 2016-2019. The regional hydroelectric generation data are displayed in Tables B.12-B.17 at the end of this appendix.

As stated in Chapter 2, this analysis struck a balance. BPA needed to reduce the substantial amount of computational time required by AURORAxmp®, without ignoring hydroelectric generation variability. To meet both requirements—reduced model run time and recognition of hydroelectric generation variability—BPA elected to sample a subset of the 70 historical Water Years (WY 1929-1998) that ranged from the 5th to the 95th percentile in terms of average 10-year hydroelectric generation produced. The selected water years were chosen based on a completed analysis that focused on Federal hydroelectric generation data. The regional hydroelectric generation values are derived from the regional data for the subset of water years specified by the results from the Federal analysis. The remainder of section B.5 describes the Federal hydroelectric generation analysis.

B.5.2 Federal Hydroelectric Generation Data Description

Monthly and hourly Federal hydroelectric generation data (aMW) for each of the 70 WY were analyzed. These data are produced by the HydSim (monthly data) and HOSS (hourly data) models, based on performing a continuous hydroelectric regulation study in which hydroelectric generation is computed in a sequential manner using historical streamflow patterns from October 1928 through September 1998. These results reflect total Federal hydroelectric generation (i.e., pre-Slice and with hydroelectric independents) based on an assumed 6,220 MW of wind resources located in BPA's control area in 2013. See Chapter 4.

B.5.3 Data Analysis

Annual hydroelectric generation values (aMW) for each of the 70 WY were derived from monthly hydroelectric generation data. These monthly and annual Federal hydro generation data are reported in Table B.18. Statistical values (average, standard deviation, and value at the 5th percentile) for these 70 WY data are also reported at the bottom of these tables.

Seventy 10-year strips of continuous hydro generation were derived, with the initial year of the 10-year strips being each of the 70 WY. Once WY 1998 was reached in the sequence, the subsequent WY began with WY 1929 and proceeded in a sequential manner until 10 years of data were developed (i.e., WY 1998, WY 1929, WY 1930…). This approach was used so that all water years are equally likely to occur during a 10-year period.

The 10-year annual average hydro generation (aMW) data for the 70 WY were sorted from lowest to highest, and a cumulative probability distribution was developed based on each of the 70 WY having the same likelihood of occurrence of 1.43 percent (1/70). This distribution, along with statistical values (average, standard deviation, and value at the 5^{th} percentile) for these 70 WY data, is reported in Table B.19. The statistical values for the 70 WY reported in Tables B.18-B.19 form the bases for comparisons with statistical values (average, standard deviation, and minimum) computed from a subset of the 70 WY to determine whether or not they are statistically similar.

From the cumulative probability distribution of 10-year annual average hydro generation, values representing the 5th, 15th, 25th, 35th, 45th, 55th, 65th, 75th, 85th, and 95th percentiles were identified. These values are reported in Table B.20. Since there are 70 WY, there were two possible 10-year strips that were statistically equal distances from each of the selected percentiles. Accordingly, an additional statistical analysis was performed to decide which of the two 10-year strips to select at each of these percentiles. This analysis was performed by selecting various combinations of 10 WY strips from the two alternatives for each percentile and comparing the statistical values for the whole set of sampled WY to the 70 WY. In this analysis, differences between the minimum values for the sampled WY and values at the 5^{th} percentile for the 70 WY were calculated. This was done to account for how closely the minimum values for the sampled WY approximate the 5^{th} percentile for the 70 WY.

The criterion used to determine the best combination on an average 10-year basis was observing the differences in the statistical values. The criterion used for each year of the 10-year period was to minimize the sum of the differences squared between the annual statistical values for the 70 WY and the annual statistics for each year of the 10-year period. The final selection at each of the percentiles and the statistics associated with these 10 WY are reported at the bottom of Table B.20. As reported in this table, 10-year hydro generation patterns beginning with WY 1929, 1992, 1939, 1941, 1981, 1972, 1957, 1964, 1956, and 1950 were selected.

B.5.4 Results

A statistical comparison of the 10-year and annual hydroelectric generation for the 70 WY and the selected 10 WY is reported in Table B.21. These results indicate that the statistical attributes of the 10 WY are similar to the 70 WY in terms of average, standard deviation, and value at 5^{th} percentile. Given these 10 WY, monthly hydroelectric generation values are extracted from the regional hydroelectric generation forecast provided by BPA's Power Operations and Planning organization.

B.6 Renewable Portfolio Standards

BPA used one RPS requirement for all of the modeled scenarios. The RPS requirement was based on the Council's base case assumptions from their AURORAxmp® input database used in the Sixth Power Plan. BPA accounted for the RPS assumption by increasing generating resource capacity in specific years before the model's long-term resource optimization logic was used to forecast the long-term generating resource additions and retirements. Table B.4 displays the total MW of capacity by generating resource type and area name that was added to

AURORAxmp® through calendar year 2019. For example, in 2019, there is 3,850 MW of new wind in the PNW Eastside area that the long-term resource optimization logic did not select.

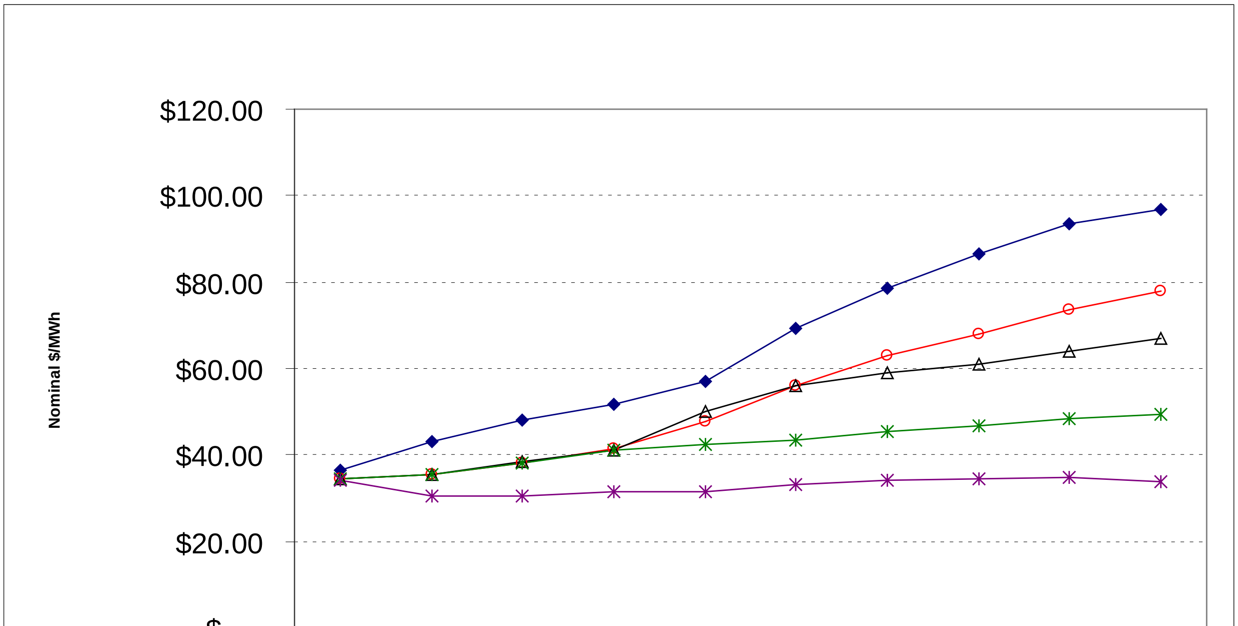
Table B.4 - Total Generating Resource Capacity Additions through 2019 due to RPS Assumptions (MW)

Area Name	Biomass	Geo-thermal	Hydro-electric	Solar Photo-voltaics	Solar Thermal	Wind	Total MW by Area
Arizona	196	0	0	253	331	1,096	1,876
British Columbia	128	9	89	0	0	1,256	1,481
California North	46	110	17	116	140	776	1,205
California South	257	375	16	322	423	2,648	4,042
Colorado	0	0	0	42	411	1,098	1,552
Montana East	0	0	0	0	0	111	111
Nevada North	0	52	0	3	10	9	74
Nevada South	0	196	0	254	585	60	1,095
New Mexico	6	13	0	56	112	785	971
PNW Eastside	123	29	39	83	0	3,850	4,125
PNW Westside	119	0	39	83	0	0	241
Total MW by Resource Type	**875**	**784**	**200**	**1,214**	**2,012**	**11,688**	**16,773**

B.7 Price Results and Observations

BPA produced separate price forecasts from AURORAxmp® for each of the scenario tree's five branches. The price forecasts consist of an expected forecast—assuming average hydroelectric generation from the water year samples—and 10 additional forecasts that result from the different hydroelectric generation values. Each price forecast consists of monthly HLH and LLH Mid-C electricity prices from October 2010 through September 2019. Flat prices represent the average price for all hours. Flat prices were derived by weighting the HLH prices by 57 percent and the LLH prices by 43 percent. Figure B.5 shows the effect that BPA's scenario assumptions have on the Mid-C price forecast. The forecast FY 2019 Mid-C annual prices range from $33.87 to $127.33 in BPA's expected forecasts. Table B.5 displays the effects that hydro variability can have on the expected forecast. Figure B.6 and Table B.6 display the same price forecast values in 2006 dollars.

Figure B.5 - Flat FY Expected Mid-C Price Forecast (Nominal $s)

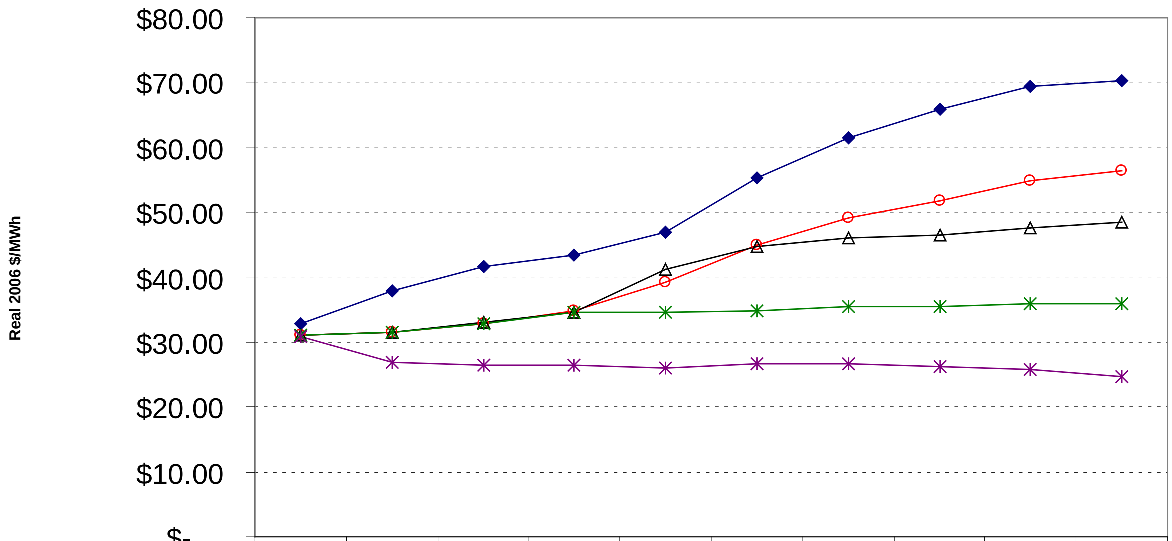


	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Boom	$36.30	$42.99	$48.21	$51.73	$57.10	$69.14	$78.69	$86.55	$93.32	$96.78
Recovery High CO2	$34.36	$35.58	$38.18	$41.37	$47.75	$56.07	$63.00	$68.06	$73.73	$77.88
Recovery Med CO2	$34.36	$35.58	$38.35	$41.13	$50.18	$55.97	$58.90	$61.09	$64.13	$66.93
Recovery Low CO2	$34.36	$35.58	$38.01	$41.25	$42.29	$43.55	$45.36	$46.64	$48.25	$49.48
Prolonged Recession	$34.07	$30.51	$30.66	$31.49	$31.58	$33.29	$34.06	$34.42	$34.76	$33.89

Table B.5 - Nominal $ Fiscal Year Annual Averages for 10 Year Water Strips

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Boom										
Min:	$ 20.33	$ 25.02	$ 29.75	$ 36.76	$ 42.57	$ 48.43	$ 56.57	$ 60.32	$ 66.64	$ 68.01
Expected:	$ 36.30	$ 42.99	$ 48.21	$ 51.73	$ 57.10	$ 69.14	$ 78.69	$ 86.55	$ 93.32	$ 96.78
Max:	$ 52.52	$ 62.11	$ 60.72	$ 68.49	$ 78.15	$ 88.75	$ 98.96	$ 108.49	$ 114.24	$ 120.78
Recovery High CO2										
Min:	$ 25.79	$ 31.44	$ 33.94	$ 35.72	$ 41.35	$ 49.67	$ 55.49	$ 60.03	$ 64.37	$ 65.53
Expected:	$ 34.36	$ 35.58	$ 38.18	$ 41.37	$ 47.75	$ 56.07	$ 63.00	$ 68.06	$ 73.73	$ 77.88
Max:	$ 49.40	$ 40.91	$ 41.95	$ 46.49	$ 52.72	$ 60.18	$ 68.62	$ 72.86	$ 80.17	$ 84.64
Recovery Med CO2										
Min:	$ 25.79	$ 31.44	$ 33.83	$ 35.22	$ 41.84	$ 48.71	$ 51.66	$ 53.24	$ 55.21	$ 56.47
Expected:	$ 34.36	$ 35.58	$ 38.35	$ 41.13	$ 50.18	$ 55.97	$ 58.90	$ 61.09	$ 64.13	$ 66.93
Max:	$ 49.40	$ 40.91	$ 41.89	$ 47.32	$ 55.50	$ 60.01	$ 63.13	$ 65.73	$ 70.17	$ 73.22
Recovery Low CO2										
Min:	$ 25.79	$ 31.44	$ 33.17	$ 34.83	$ 35.52	$ 37.46	$ 40.47	$ 40.71	$ 40.93	$ 41.48
Expected:	$ 34.36	$ 35.58	$ 38.01	$ 41.25	$ 42.29	$ 43.55	$ 45.36	$ 46.64	$ 48.25	$ 49.48
Max:	$ 49.40	$ 40.91	$ 41.66	$ 46.60	$ 46.04	$ 50.61	$ 48.87	$ 51.48	$ 53.67	$ 55.10
Prolonged Recession										
Min:	$ 20.84	$ 18.78	$ 18.58	$ 21.29	$ 21.88	$ 21.79	$ 22.82	$ 22.25	$ 21.74	$ 22.41
Expected:	$ 34.07	$ 30.51	$ 30.66	$ 31.49	$ 31.58	$ 33.29	$ 34.06	$ 34.42	$ 34.76	$ 33.89
Max:	$ 52.43	$ 42.00	$ 40.50	$ 42.97	$ 44.32	$ 43.60	$ 44.92	$ 44.29	$ 45.45	$ 43.13

Figure B.6 - Flat FY Expected Mid-C Price Forecast (2006 $s)



	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Boom	$32.89	$37.99	$41.57	$43.52	$46.86	$55.37	$61.47	$65.97	$69.39	$70.21
Recovery High CO2	$31.13	$31.45	$32.92	$34.80	$39.19	$44.90	$49.21	$51.87	$54.82	$56.49
Recovery Med CO2	$31.13	$31.45	$33.07	$34.60	$41.18	$44.82	$46.01	$46.56	$47.69	$48.55
Recovery Low CO2	$31.13	$31.45	$32.78	$34.70	$34.71	$34.87	$35.44	$35.54	$35.88	$35.89
Prolonged Recession	$30.87	$26.96	$26.43	$26.49	$25.92	$26.66	$26.61	$26.24	$25.85	$24.58

Table B.6 - 2006 $ Fiscal Year Annual Averages for 10 Year Water Strips

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Boom										
Min:	$ 18.42	$ 22.11	$ 25.66	$ 30.92	$ 34.94	$ 38.78	$ 44.19	$ 45.97	$ 49.55	$ 49.34
Expected:	$ 32.89	$ 37.99	$ 41.57	$ 43.52	$ 46.86	$ 55.37	$ 61.47	$ 65.97	$ 69.39	$ 70.21
Max:	$ 47.58	$ 54.89	$ 52.35	$ 57.62	$ 64.15	$ 71.06	$ 77.31	$ 82.68	$ 84.95	$ 87.62
Recovery High CO2										
Min:	$ 23.36	$ 27.79	$ 29.27	$ 30.05	$ 33.94	$ 39.77	$ 43.35	$ 45.75	$ 47.86	$ 47.54
Expected:	$ 31.13	$ 31.45	$ 32.92	$ 34.80	$ 39.19	$ 44.90	$ 49.21	$ 51.87	$ 54.82	$ 56.49
Max:	$ 44.75	$ 36.16	$ 36.17	$ 39.11	$ 43.27	$ 48.19	$ 53.60	$ 55.53	$ 59.61	$ 61.40
Recovery Med CO2										
Min:	$ 23.36	$ 27.79	$ 29.18	$ 29.63	$ 34.34	$ 39.01	$ 40.36	$ 40.57	$ 41.05	$ 40.96
Expected:	$ 31.13	$ 31.45	$ 33.07	$ 34.60	$ 41.18	$ 44.82	$ 46.01	$ 46.56	$ 47.69	$ 48.55
Max:	$ 44.75	$ 36.16	$ 36.12	$ 39.81	$ 45.55	$ 48.05	$ 49.32	$ 50.10	$ 52.18	$ 53.11
Recovery Low CO2										
Min:	$ 23.36	$ 27.79	$ 28.61	$ 29.30	$ 29.15	$ 30.00	$ 31.62	$ 31.02	$ 30.43	$ 30.09
Expected:	$ 31.13	$ 31.45	$ 32.78	$ 34.70	$ 34.71	$ 34.87	$ 35.44	$ 35.54	$ 35.88	$ 35.89
Max:	$ 44.75	$ 36.16	$ 35.92	$ 39.21	$ 37.79	$ 40.52	$ 38.18	$ 39.24	$ 39.90	$ 39.97
Prolonged Recession										
Min:	$ 18.88	$ 16.60	$ 16.02	$ 17.91	$ 17.96	$ 17.45	$ 17.82	$ 16.96	$ 16.16	$ 16.26
Expected:	$ 30.87	$ 26.96	$ 26.43	$ 26.49	$ 25.92	$ 26.66	$ 26.61	$ 26.24	$ 25.85	$ 24.58
Max:	$ 47.50	$ 37.13	$ 34.92	$ 36.15	$ 36.38	$ 34.91	$ 35.09	$ 33.75	$ 33.80	$ 31.29

It is also useful to review the relationship between on-peak (HLH) and off-peak (LLH) prices. The three recovery scenarios provide a price forecast subset that is useful to observe the impact that CO_2 prices have on the monthly price forecasts. Figures B.7 through B.9 display the monthly HLH and LLH price relationships. As the CO_2 price increases, the price difference between HLH and LLH prices decreases.

Figure B.7 - Mid-C Price Forecast from Recovery Scenario – Low CO_2 Price

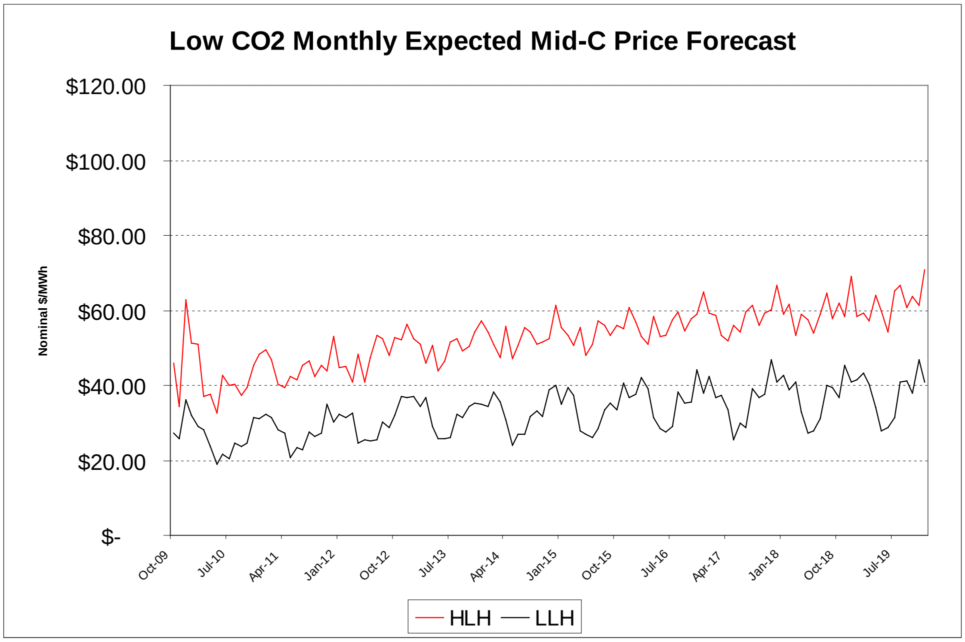


Figure B.8 - Mid-C Price Forecast from Recovery Scenario – Medium CO_2 Price

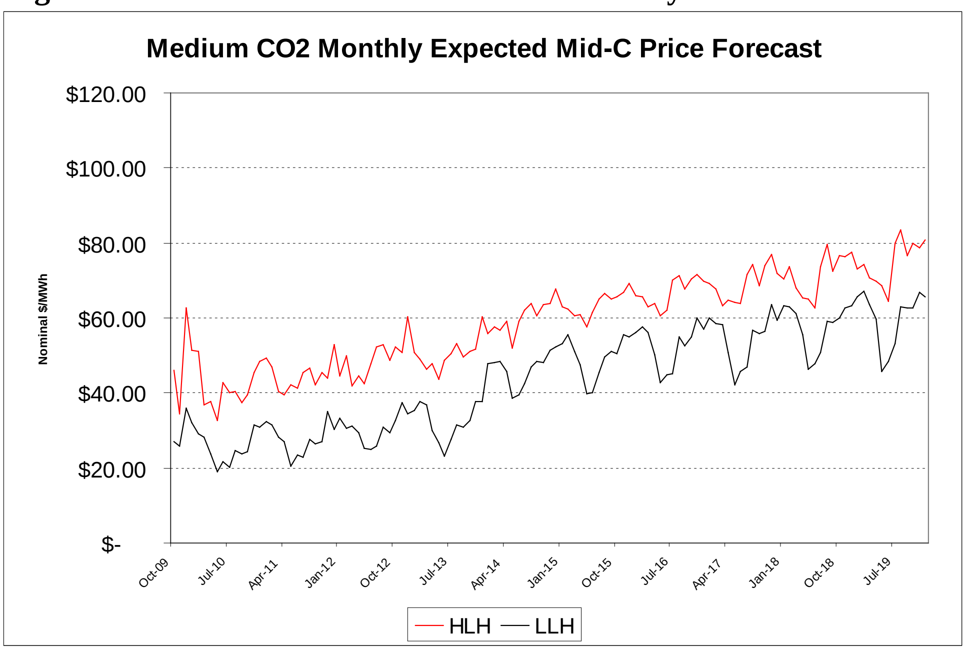
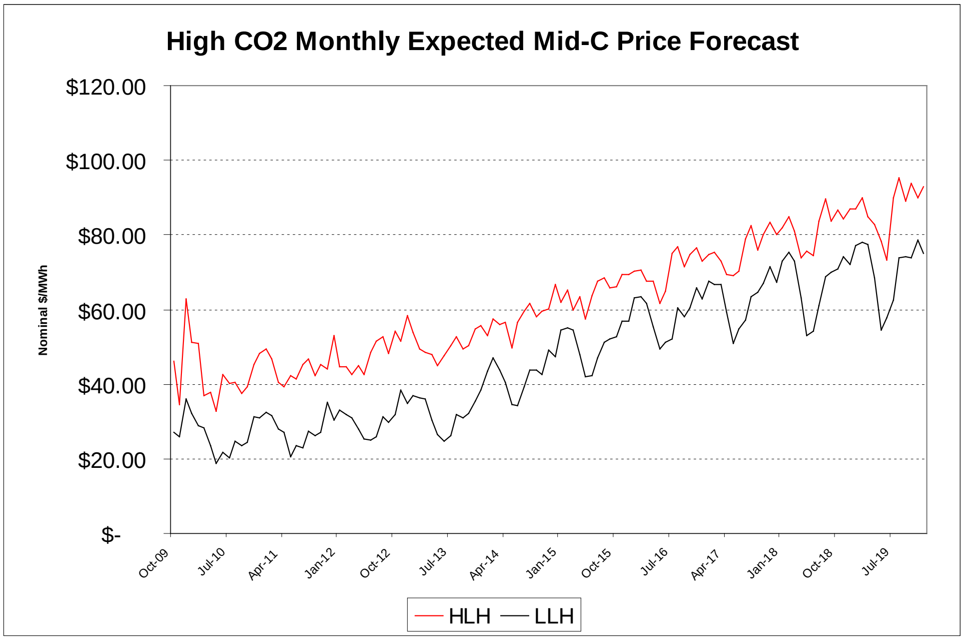


Figure B.9 - Mid-C Price Forecast from Recovery Scenario – High CO_2 Price



From the low to high CO_2 price scenarios within the Recovery scenario, energy produced from coal-fueled generating resources in the PNW was declining. For example, in calendar year 2019 energy produced from coal-fueled generating resources fell from 3,227 aMW (no CO_2 price) to 2,480 aMW (high CO_2 price). Coal power plants were being dispatched for fewer hours, while natural gas-fueled generating resources were dispatched in more on- and off-peak hours. The increased dispatch of natural gas-fueled generating resources in all hours decreased the spread between HLH and LLH prices.

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B.8 Additional Tables and figures

Table B.7 - Historical Energy Loads from WECC 10-Year Coordinated Plan

Historical Energy Load Calendar Year Data (Thousands of GWh)								
Year	**NWPP**	**Ten Year Growth Rate**	**RMPA**	**Ten Year Growth Rate**	**SW**	**Ten Year Growth Rate**	**Cal**	**Ten Year Growth Rate**
1982	234.80		31.28		42.72		188.00	
1983	235.30		31.81		44.08		188.00	
1984	250.90		33.09		46.70		205.20	
1985	257.30		35.40		50.64		209.70	
1986	253.40		34.82		51.46		216.30	
1987	262.40		35.36		63.42		214.60	
1988	280.20		37.03		67.48		223.30	
1989	291.40		38.02		71.25		229.10	
1990	301.10		38.49		74.54		236.70	
1991	305.20		38.44		75.71		230.60	
1992	307.60	2.74%	39.99	2.49%	77.90	6.19%	236.70	2.33%
1993	312.80	2.89%	40.55	2.46%	80.42	6.20%	235.60	2.28%
1994	316.30	2.34%	42.05	2.43%	86.05	6.30%	243.70	1.73%
1995	318.30	2.15%	43.42	2.06%	87.66	5.64%	240.50	1.38%
1996	334.20	2.81%	43.92	2.35%	94.72	6.29%	248.70	1.41%
1997	332.10	2.38%	47.08	2.90%	98.53	4.50%	256.90	1.82%
1998	342.90	2.04%	48.07	2.64%	97.36	3.73%	254.60	1.32%
1999	348.90	1.82%	46.28	1.99%	96.95	3.13%	262.30	1.36%
2000	354.60	1.65%	51.50	2.95%	104.42	3.43%	275.60	1.53%
2001	324.10	0.60%	54.46	3.55%	111.31	3.93%	269.00	1.55%
2002	342.70	1.09%	56.11	3.44%	115.66	4.03%	277.60	1.61%
2003	340.60	0.86%	56.83	3.43%	120.57	4.13%	277.10	1.64%
2004	347.30	0.94%	57.21	3.13%	122.94	3.63%	288.60	1.71%
2005	360.90	1.26%	59.19	3.15%	126.54	3.74%	285.00	1.71%
Percentiles								
90th		2.79%		3.44%		6.26%		2.14%
10th		0.88%		2.15%		3.49%		1.37%

Table B.8 - Historical Peak Demand from WECC 10-Year Coordinated Plan

Historical Peak Demand Calendar Year Data (Thousands of MW)								
Year	**NWPP**	**Ten Year Growth Rate**	**RMPA**	**Ten Year Growth Rate**	**SW**	**Ten Year Growth Rate**	**Cal**	**Ten Year Growth Rate**
1982	43.70		5.41		8.71		35.80	
1983	46.70		5.59		8.90		37.50	
1984	44.80		5.70		9.38		40.90	
1985	45.30		5.74		10.07		42.70	
1986	42.60		5.90		10.35		41.60	
1987	44.50		6.02		12.41		40.80	
1988	45.90		6.10		13.24		44.80	
1989	52.70		6.33		14.47		43.00	
1990	56.10		6.79		14.99		47.80	
1991	51.90		6.49		14.45		44.30	
1992	51.80	1.71%	6.38	1.66%	15.67	6.05%	48.20	3.02%
1993	54.10	1.48%	6.73	1.87%	15.96	6.01%	46.80	2.24%
1994	53.00	1.70%	6.96	2.02%	17.13	6.21%	49.60	1.95%
1995	52.60	1.51%	7.27	2.39%	17.89	5.92%	49.20	1.43%
1996	57.20	2.99%	7.43	2.33%	18.70	6.09%	51.30	2.12%
1997	55.30	2.20%	7.93	2.79%	19.03	4.37%	53.20	2.69%
1998	60.00	2.71%	7.98	2.72%	20.43	4.43%	55.40	2.15%
1999	56.00	0.61%	7.64	1.90%	19.95	3.26%	53.10	2.13%
2000	56.20	0.02%	8.59	2.38%	21.72	3.78%	51.20	0.69%
2001	52.60	0.13%	9.33	3.70%	23.36	4.92%	48.40	0.89%
2002	52.10	0.06%	9.89	4.48%	24.22	4.45%	52.20	0.80%
2003	53.90	-0.04%	10.49	4.54%	25.55	4.82%	53.10	1.27%
2004	58.90	1.06%	10.40	4.10%	25.63	4.11%	55.90	1.20%
2005	60.40	1.39%	11.09	4.31%	27.97	4.57%	57.40	1.55%
Percentiles								
90th		2.56%		4.43%		6.08%		2.55%
10th		0.03%		1.88%		3.88%		0.83%

Table B.9 - Boom Scenario Annual Energy and Peak Demand Forecast (NWPP)

	Annual Energy Loads (aMW)			Annual Peak Demand (MW)		
Area Name	CY 2010	CY 2020	Growth Rate 2010-2020	CY 2010	CY 2020	Growth Rate 2010-2020
Alberta	8,891	12,836	3.70%	11,212	17,025	4.30%
British Columbia	7,225	8,638	1.80%	11,117	13,150	1.70%
Idaho South	2,593	3,381	2.70%	4,052	5,131	2.40%
Montana East	893	1,172	2.70%	1,374	1,752	2.50%
Nevada North	1,451	1,736	1.80%	2,148	2,633	2.10%
PNW Eastside	5,598	7,343	2.80%	8,821	11,006	2.20%
PNW Westside	13,594	17,870	2.80%	21,558	26,790	2.20%
Utah	2,860	3,769	2.80%	4,086	5,415	2.90%
NWPP	**43,105**	**56,745**	**2.79%**	**64,367**	**82,902**	**2.56%**

Table B.10 - Prolonged Recession Annual Energy and Peak Demand Forecast (NWPP)

	Annual Energy Loads (aMW)			Annual Peak Demand (MW)		
Area Name	CY 2010	CY 2020	Growth Rate 2010-2020	CY 2010	CY 2020	Growth Rate 2010-2020
Alberta	8,891	10,664	1.80%	11,212	13,318	1.70%
British Columbia	7,225	7,151	-0.10%	11,117	10,222	-0.80%
Idaho South	2,593	2,803	0.80%	4,052	3,995	-0.10%
Montana East	893	972	0.80%	1,374	1,365	-0.10%
Nevada North	1,451	1,437	-0.10%	2,148	2,048	-0.50%
PNW Eastside	5,598	6,090	0.80%	8,821	8,567	-0.30%
PNW Westside	13,594	14,820	0.90%	21,558	20,850	-0.30%
Utah	2,860	3,126	0.90%	4,086	4,222	0.30%
NWPP	**43,105**	**47,064**	**0.88%**	**64,367**	**64,586**	**0.03%**

Table B.11 - EIA Future CO_2 Price Projections (in $2006/metric ton CO_2)

Year	Base Case	High Offsets	High Cost	No Intl. Offsets	No Intl. Offsets Late CCS & Nuke
2012	**17.5**	11.0	19.5	28.7	51.4
2013	**18.8**	11.8	20.9	30.8	55.2
2014	**20.2**	12.7	22.5	33.1	59.3
2015	**21.7**	13.7	24.2	35.6	63.7
2016	**23.3**	14.7	25.9	38.2	68.4
2017	**25.0**	15.8	27.9	41.0	73.5
2018	**26.8**	16.9	29.9	44.1	78.9
2019	**28.8**	18.2	32.1	47.3	84.8
2020	**31.0**	19.5	34.5	50.8	91.0
2021	**33.2**	21.0	37.1	54.6	97.8
2022	**35.7**	22.5	39.8	58.6	105.0
2023	**38.3**	24.2	42.8	62.9	112.8
2024	**41.2**	26.0	45.9	67.6	121.1
2025	**44.2**	27.9	49.3	72.6	130.1
2026	**47.5**	30.0	53.0	78.0	139.7
2027	**51.0**	32.2	56.9	83.8	150.0
2028	**54.8**	34.6	61.1	90.0	161.1
2029	**58.9**	37.1	65.6	96.6	173.1
2030	**63.2**	39.9	70.5	103.8	185.9

Table B.12 - FY 2010 Regional Hydroelectric Generation Forecast

Regional Hydroelectric Generation Forecast (aMW)															
Year	**Water Year**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr1**	**Apr16**	**May**	**Jun**	**Jul**	**Aug1**	**Aug16**	**Sep**
2010	1929	11,579	13,038	13,568	12,394	12,116	12,016	10,770	13,223	13,503	16,013	13,812	12,172	10,004	10,270
2010	1930	11,175	12,347	13,351	12,731	12,036	11,405	11,007	15,269	12,754	12,992	13,392	10,724	9,969	9,930
2010	1931	10,828	12,795	13,498	12,842	11,904	11,139	11,769	9,680	13,439	12,552	13,433	12,572	10,669	10,751
2010	1932	10,069	11,798	13,163	12,125	11,119	13,156	15,312	20,288	22,305	20,621	15,570	12,285	11,371	10,918
2010	1933	11,344	12,805	15,213	20,301	16,159	12,086	15,350	16,443	20,192	20,780	19,813	16,680	14,015	12,175
2010	1934	13,396	17,235	21,586	21,658	20,863	18,966	19,570	19,631	20,708	18,728	14,938	11,310	10,067	10,509
2010	1935	11,192	12,662	14,280	19,095	19,226	11,494	12,704	15,679	19,465	17,625	17,351	14,716	11,346	10,184
2010	1936	11,033	12,358	13,154	11,349	12,420	11,674	12,460	19,310	20,904	20,464	14,087	12,997	10,766	9,644
2010	1937	11,006	12,737	13,428	12,922	11,266	10,638	9,627	9,953	14,900	14,141	12,782	13,443	11,217	10,435
2010	1938	11,163	13,020	15,025	19,598	14,630	15,548	16,986	20,772	22,964	19,602	16,439	12,152	10,312	11,069
2010	1939	11,448	12,538	13,381	13,309	12,164	13,168	14,020	18,581	21,116	16,257	13,547	11,037	9,650	9,640
2010	1940	11,419	12,881	14,975	12,923	13,336	16,376	16,840	18,303	17,633	17,046	12,107	10,479	9,702	10,312
2010	1941	10,956	12,807	13,601	12,065	12,544	13,797	11,336	12,926	14,007	13,150	13,187	11,945	10,716	11,451
2010	1942	10,353	12,793	15,593	14,893	14,921	11,225	11,898	16,720	17,702	20,530	18,058	14,581	11,982	11,143
2010	1943	11,351	12,611	14,663	17,966	17,686	16,710	20,703	20,772	22,761	20,920	19,132	14,036	11,149	9,526
2010	1944	11,350	12,912	13,704	12,703	12,275	12,109	10,881	13,267	12,483	12,058	11,818	11,824	10,408	11,013
2010	1945	10,073	11,524	12,921	12,565	11,143	11,043	9,590	8,630	18,813	18,450	13,237	12,400	10,386	10,020
2010	1946	10,886	13,717	15,340	17,490	13,862	17,916	18,767	20,654	22,938	20,255	18,288	13,796	11,787	11,203
2010	1947	11,282	13,774	19,633	19,932	19,724	18,958	17,771	18,923	21,279	20,510	18,077	13,190	11,359	10,918
2010	1948	15,924	17,392	16,629	21,648	15,858	15,157	15,552	20,200	22,986	21,152	19,825	16,292	14,283	12,059
2010	1949	12,299	13,405	14,795	13,145	15,573	18,383	18,418	20,561	23,033	20,536	13,312	12,165	9,801	9,567
2010	1950	11,280	13,322	14,817	18,717	19,223	20,385	20,327	20,382	21,787	20,467	20,088	15,136	13,373	11,513
2010	1951	13,977	16,912	21,248	22,109	21,830	20,269	20,347	20,683	22,706	20,241	19,763	15,940	12,225	11,224
2010	1952	14,918	15,328	16,956	21,561	17,073	13,497	19,857	20,805	23,113	21,040	17,094	13,620	11,555	10,270
2010	1953	11,184	12,293	13,506	15,078	19,043	13,987	11,355	16,195	21,801	21,060	20,021	14,290	12,015	11,049
2010	1954	12,267	13,965	16,431	18,723	20,733	15,284	17,567	18,315	22,470	20,358	19,955	18,897	17,657	15,231
2010	1955	12,438	15,449	15,811	14,278	12,887	12,426	12,601	14,508	17,415	20,682	19,854	16,676	13,505	10,998
2010	1956	13,269	16,938	20,390	22,405	21,296	20,230	20,473	20,613	22,814	20,993	20,012	14,655	13,040	11,340
2010	1957	12,832	13,223	16,095	16,185	15,017	17,476	18,038	18,518	23,142	20,855	15,294	12,880	10,362	10,615
2010	1958	11,351	13,068	14,238	15,894	18,913	15,267	16,276	19,752	23,097	20,785	15,096	12,771	11,054	10,372
2010	1959	11,920	14,997	18,528	21,624	20,986	15,824	19,811	18,490	21,945	20,289	17,378	14,901	12,677	15,595
2010	1960	16,999	19,244	19,071	19,497	16,907	16,226	20,250	20,061	20,051	20,344	17,070	13,849	10,766	11,048
2010	1961	11,573	13,485	13,853	18,929	17,139	17,238	19,054	15,776	21,945	20,119	16,013	13,188	12,009	10,128
2010	1962	10,776	13,239	15,351	16,732	16,121	12,585	16,973	20,701	21,190	20,375	14,454	13,223	11,103	10,042
2010	1963	12,856	15,363	18,111	18,344	18,523	11,990	13,991	15,507	19,162	20,881	17,313	14,280	11,801	10,981
2010	1964	11,093	13,481	14,771	15,634	15,792	12,092	14,626	13,571	20,351	21,271	19,874	16,583	12,289	12,728
2010	1965	13,270	14,665	20,238	22,267	21,735	19,634	17,597	20,794	22,876	20,708	17,022	15,410	13,552	11,762
2010	1966	12,477	13,279	14,385	17,829	14,194	11,536	19,992	17,331	19,536	18,656	17,496	14,153	11,624	10,505
2010	1967	11,165	12,808	15,347	21,685	21,246	15,900	15,294	12,885	20,144	21,048	19,834	15,358	12,128	11,175
2010	1968	12,302	13,443	15,051	19,731	18,837	16,349	11,408	13,908	17,446	20,473	19,155	15,182	13,251	14,064
2010	1969	13,859	16,901	17,100	21,936	21,319	16,342	20,437	20,566	23,157	20,710	18,736	12,867	10,784	10,770
2010	1970	12,214	13,495	13,547	14,983	17,871	14,868	14,220	14,750	19,581	21,104	16,019	12,760	10,253	10,036
2010	1971	11,263	13,179	15,065	22,476	21,598	20,433	20,480	20,590	22,897	21,141	20,559	17,235	13,878	11,872
2010	1972	12,728	13,950	15,359	22,559	21,956	20,762	20,582	20,301	22,769	21,173	20,065	18,581	16,025	12,486
2010	1973	12,306	13,456	16,526	16,071	13,129	12,259	9,643	13,467	16,542	14,565	13,763	10,902	9,400	9,949
2010	1974	11,075	12,320	18,317	22,587	21,918	20,643	20,388	20,586	22,598	21,036	20,206	16,553	14,239	11,587
2010	1975	10,965	13,099	14,091	17,906	16,236	16,810	12,576	15,831	22,456	21,141	20,452	13,587	13,226	12,150
2010	1976	14,060	17,247	22,209	22,214	21,474	18,316	20,501	20,529	22,913	20,985	19,891	19,362	19,141	16,865
2010	1977	12,158	13,139	13,642	12,604	12,542	11,775	10,019	11,210	11,575	10,797	11,881	12,329	11,043	10,673
2010	1978	9,117	11,752	16,282	16,208	15,045	14,745	19,534	17,592	21,391	18,716	17,556	13,015	12,041	13,932
2010	1979	12,251	13,287	13,801	13,348	15,344	16,727	13,874	14,466	20,449	15,163	13,123	10,467	9,592	9,776
2010	1980	10,920	12,715	15,045	12,293	14,812	12,338	13,651	19,292	22,952	20,864	14,918	12,275	10,279	10,934
2010	1981	11,256	13,777	19,964	21,455	18,598	15,697	11,783	15,254	18,532	20,555	19,645	16,710	14,648	11,222
2010	1982	11,927	14,069	15,302	19,899	21,861	20,397	19,944	18,766	22,853	20,770	19,451	16,752	13,191	13,559
2010	1983	13,771	14,632	16,537	21,875	17,759	20,565	18,568	19,443	21,581	20,676	20,262	16,867	13,443	12,310
2010	1984	12,168	18,138	15,597	22,552	17,485	20,571	20,468	20,593	19,144	21,125	19,872	14,736	11,588	11,711
2010	1985	12,109	14,966	14,631	16,031	12,600	15,291	18,531	19,577	21,723	17,328	12,676	10,030	9,398	10,565
2010	1986	12,049	15,708	12,896	19,172	19,191	20,560	20,405	19,700	18,393	19,462	15,808	13,063	10,730	10,202
2010	1987	11,060	14,506	14,486	13,062	13,857	13,875	14,735	15,153	17,511	16,885	13,336	10,970	9,462	9,670
2010	1988	10,413	12,225	12,793	11,871	11,701	11,456	11,164	14,499	16,098	11,986	14,065	12,712	10,752	10,114
2010	1989	10,118	12,478	14,289	12,485	13,335	14,666	18,566	20,590	20,539	17,381	13,865	10,418	10,034	10,160
2010	1990	10,927	13,597	17,093	20,554	17,255	14,874	18,729	19,735	19,697	20,207	16,442	13,911	12,534	9,942
2010	1991	10,714	17,247	17,194	21,224	21,029	14,523	17,479	17,006	21,677	19,903	19,625	16,495	13,059	10,644
2010	1992	10,701	12,792	13,075	13,425	12,246	15,643	12,547	13,901	15,040	13,072	12,765	10,013	9,525	9,191
2010	1993	10,493	12,278	13,490	12,530	12,396	12,559	13,282	13,680	19,618	15,060	14,909	12,672	11,575	9,469
2010	1994	10,578	13,176	13,912	12,691	13,665	12,076	11,070	17,666	16,063	14,121	13,562	10,659	9,600	9,461
2010	1995	10,322	12,180	14,428	14,742	18,188	18,255	16,950	14,648	19,491	19,419	16,991	13,279	11,115	10,656
2010	1996	12,692	19,431	22,024	22,294	21,921	20,384	20,391	20,912	22,984	20,758	19,948	16,203	11,995	11,387
2010	1997	12,118	13,710	16,978	22,560	21,978	20,679	20,283	20,613	22,945	21,082	20,304	16,447	13,373	14,128
2010	1998	17,044	15,888	14,996	19,417	17,850	16,104	15,378	15,941	20,002	20,979	17,267	13,674	10,870	10,771

Table B.13 - FY 2011 Regional Hydroelectric Generation Forecast

Regional Hydroelectric Generation Forecast (aMW)															
Year	Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep
2011	1929	11,602	13,062	13,577	12,399	12,122	12,021	10,775	13,231	13,517	16,032	13,833	12,190	10,016	10,280
2011	1930	11,194	12,365	13,360	12,737	12,041	11,410	11,015	15,278	12,772	13,011	13,412	10,741	9,981	9,940
2011	1931	10,850	12,819	13,508	12,848	11,910	11,143	11,774	9,688	13,451	12,568	13,454	12,593	10,687	10,760
2011	1932	10,092	11,821	13,171	12,129	11,124	13,158	15,315	21,036	23,043	21,642	15,592	12,303	11,389	10,933
2011	1933	11,367	12,827	15,223	20,290	16,171	12,090	15,356	16,456	20,218	21,800	20,073	16,703	14,031	12,187
2011	1934	13,420	17,240	22,242	22,810	21,800	18,941	20,885	21,232	20,732	18,704	14,959	11,327	10,079	10,520
2011	1935	11,216	12,684	14,289	19,094	19,192	11,499	12,708	15,688	19,485	17,648	17,377	14,732	11,358	10,197
2011	1936	11,055	12,381	13,163	11,352	12,426	11,678	12,472	19,330	20,929	21,055	14,109	13,018	10,784	9,654
2011	1937	11,024	12,757	13,437	12,928	11,272	10,642	9,630	9,958	14,919	14,158	12,801	13,463	11,230	10,445
2011	1938	11,186	13,043	15,034	19,596	14,637	15,554	17,005	22,175	23,638	19,627	16,462	12,166	10,322	11,080
2011	1939	11,469	12,561	13,389	13,315	12,170	13,176	14,032	18,604	21,147	16,279	13,568	11,055	9,664	9,651
2011	1940	11,442	12,904	14,986	12,928	13,341	16,381	16,848	18,316	17,660	17,071	12,127	10,496	9,714	10,321
2011	1941	10,979	12,831	13,610	12,149	12,456	13,804	11,341	12,938	14,023	13,170	13,208	11,964	10,729	11,461
2011	1942	10,374	12,816	15,602	14,899	14,928	11,231	11,904	16,733	17,726	20,557	18,084	14,602	11,996	11,152
2011	1943	11,370	12,633	14,671	17,972	17,669	16,715	22,012	22,379	22,781	21,947	19,157	14,055	11,161	9,535
2011	1944	11,372	12,935	13,712	12,709	12,283	12,115	10,886	13,279	12,499	12,076	11,838	11,844	10,423	11,026
2011	1945	10,090	11,547	12,930	12,569	11,147	11,047	9,595	8,635	18,833	18,473	13,257	12,419	10,398	10,030
2011	1946	10,905	13,741	15,349	17,496	13,875	17,915	18,772	22,256	23,709	20,281	18,313	13,816	11,800	11,213
2011	1947	11,303	13,797	19,633	19,930	19,710	18,945	17,779	18,939	21,300	21,316	18,104	13,210	11,371	10,928
2011	1948	15,922	17,418	16,640	22,294	14,754	15,163	15,562	20,443	23,746	22,163	20,087	16,314	14,299	12,069
2011	1949	12,322	13,428	14,804	13,150	15,580	18,358	18,434	22,138	23,549	21,041	13,332	12,183	9,812	9,576
2011	1950	11,302	13,344	14,826	18,715	19,198	20,944	20,122	20,378	21,798	21,490	20,261	15,156	13,387	11,523
2011	1951	14,000	16,936	21,238	23,278	22,764	20,705	21,674	22,292	23,313	20,268	20,024	15,964	12,241	11,236
2011	1952	14,930	15,352	16,967	21,558	17,077	13,507	19,816	22,175	23,875	21,701	17,117	13,641	11,570	10,282
2011	1953	11,203	12,315	13,514	15,082	19,029	13,992	11,361	16,210	21,826	22,079	20,281	14,311	12,030	11,059
2011	1954	12,290	13,988	16,441	18,720	20,711	15,290	17,575	18,331	22,560	21,382	20,214	18,923	17,676	15,223
2011	1955	12,461	15,474	15,821	14,283	12,893	12,433	12,606	14,516	17,432	21,704	20,114	16,699	13,520	11,006
2011	1956	13,292	16,963	20,379	23,574	20,569	20,215	20,508	22,230	23,574	22,026	20,272	14,676	13,054	11,349
2011	1957	12,855	13,246	16,104	16,192	15,032	17,483	18,048	18,535	23,902	21,893	15,316	12,900	10,375	10,624
2011	1958	11,373	13,091	14,246	15,901	18,900	15,273	16,286	19,771	23,859	21,797	15,117	12,790	11,067	10,380
2011	1959	11,943	15,020	18,527	22,778	20,923	14,489	19,731	18,403	21,819	21,325	17,403	14,931	12,690	15,585
2011	1960	16,991	19,237	19,072	19,496	16,915	16,233	21,569	20,081	20,079	21,289	17,095	13,868	10,777	11,057
2011	1961	11,596	13,508	13,862	18,928	17,112	17,245	19,064	15,787	21,958	21,134	16,036	13,208	12,023	10,137
2011	1962	10,798	13,263	15,361	16,739	16,128	12,590	16,980	22,300	21,219	21,361	14,475	13,238	11,114	10,051
2011	1963	12,879	15,387	18,111	18,345	18,498	11,996	13,997	15,516	19,186	20,946	17,338	14,301	11,815	10,992
2011	1964	11,116	13,505	14,781	15,640	15,808	12,097	14,629	13,577	20,380	22,285	20,132	16,606	12,303	12,738
2011	1965	13,292	14,690	20,238	23,444	22,670	19,617	17,574	22,396	23,321	21,608	17,048	15,432	13,567	11,772
2011	1966	12,498	13,302	14,394	17,837	14,205	11,540	20,783	17,345	19,566	18,681	17,521	14,176	11,638	10,519
2011	1967	11,188	12,831	15,356	22,713	21,081	14,420	15,088	12,803	20,154	22,054	20,096	15,380	12,143	11,185
2011	1968	12,324	13,466	15,060	19,729	18,813	16,358	11,416	13,923	17,468	21,162	19,183	15,204	13,267	14,066
2011	1969	13,883	16,926	17,111	23,093	20,385	15,833	21,761	22,175	23,916	21,224	18,763	12,887	10,795	10,780
2011	1970	12,237	13,519	13,556	14,987	17,855	14,874	14,229	14,767	19,607	22,113	16,042	12,778	10,265	10,046
2011	1971	11,286	13,202	15,074	23,209	22,526	19,919	19,890	20,951	23,655	22,161	20,817	17,258	13,895	11,884
2011	1972	12,751	13,973	15,369	23,067	22,075	22,331	21,896	20,323	23,528	22,193	20,325	18,607	16,045	12,499
2011	1973	12,329	13,479	16,536	16,077	13,145	12,264	9,647	13,476	16,562	14,585	13,784	10,920	9,414	9,960
2011	1974	11,097	12,341	18,317	23,737	22,835	22,227	21,705	22,199	23,361	22,069	20,465	16,574	14,255	11,597
2011	1975	10,984	13,122	14,100	17,902	16,252	16,816	12,584	15,849	22,474	22,162	20,709	13,607	13,242	12,162
2011	1976	14,083	17,272	22,858	23,379	21,951	16,996	21,188	21,192	23,674	21,897	20,148	19,428	19,164	16,860
2011	1977	12,180	13,162	13,650	12,609	12,549	11,782	10,024	11,220	11,585	10,810	11,902	12,347	11,054	10,684
2011	1978	9,138	11,774	16,278	16,212	15,049	14,749	19,500	17,602	21,398	18,741	17,580	13,033	12,054	13,922
2011	1979	12,275	13,311	13,810	13,353	15,352	16,734	13,884	14,479	20,469	15,181	13,143	10,485	9,606	9,788
2011	1980	10,943	12,739	15,055	12,336	14,774	12,343	13,664	19,314	23,484	20,890	14,940	12,294	10,291	10,943
2011	1981	11,274	13,801	19,966	22,614	16,676	15,705	11,625	15,233	18,524	21,580	19,908	16,735	14,667	11,233
2011	1982	11,950	14,093	15,311	19,898	22,782	21,985	19,380	18,679	23,265	21,772	19,477	16,775	13,205	13,556
2011	1983	13,794	14,656	16,547	21,869	17,744	22,153	18,544	19,466	21,599	20,699	20,521	16,891	13,460	12,323
2011	1984	12,190	18,142	15,606	23,712	16,022	20,762	19,991	20,613	19,169	22,133	19,898	14,758	11,602	11,724
2011	1985	12,131	14,989	14,640	16,042	12,610	15,298	18,499	19,597	21,752	17,349	12,696	10,048	9,410	10,576
2011	1986	12,071	15,733	12,904	19,170	19,149	22,135	21,206	19,723	18,418	19,486	15,831	13,083	10,742	10,211
2011	1987	11,082	14,530	14,495	13,067	13,863	13,882	14,748	15,167	17,528	16,909	13,355	10,987	9,473	9,680
2011	1988	10,429	12,249	12,801	11,875	11,706	11,461	11,168	14,507	16,111	12,002	14,085	12,727	10,763	10,124
2011	1989	10,141	12,501	14,298	12,489	13,341	14,673	18,556	20,798	20,564	17,404	13,885	10,434	10,045	10,169
2011	1990	10,950	13,620	17,104	20,554	17,263	14,880	18,741	21,351	19,722	21,219	16,465	13,930	12,550	9,953
2011	1991	10,736	17,273	17,205	21,727	20,961	13,597	17,444	17,008	21,693	19,926	19,879	16,514	13,072	10,653
2011	1992	10,719	12,809	13,082	13,430	12,251	15,650	12,552	13,909	15,051	13,091	12,784	10,026	9,535	9,199
2011	1993	10,515	12,301	13,499	12,536	12,402	12,563	13,288	13,689	19,640	15,078	14,930	12,692	11,590	9,479
2011	1994	10,594	13,200	13,922	12,696	13,672	12,081	11,074	17,678	16,083	14,141	13,583	10,676	9,612	9,470
2011	1995	10,341	12,202	14,437	14,748	18,165	18,230	16,958	14,656	19,517	19,442	17,014	13,297	11,127	10,666
2011	1996	12,715	19,435	22,663	23,468	22,852	21,959	20,787	22,526	23,564	21,769	20,208	16,227	12,010	11,398
2011	1997	12,141	13,733	16,988	23,726	22,916	22,260	20,376	22,225	23,706	22,105	20,562	16,470	13,388	14,127
2011	1998	17,031	15,913	15,005	19,419	17,855	16,110	15,391	15,960	20,017	21,997	17,293	13,694	10,883	10,782

Table B.14 - FY 2012 Regional Hydroelectric Generation Forecast

Regional Hydroelectric Generation Forecast (aMW)															
Year	Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep
2012	1929	11,630	13,095	13,608	12,604	12,123	11,838	10,758	13,229	13,510	16,043	13,853	12,199	10,019	10,301
2012	1930	11,225	12,401	13,391	12,764	12,053	11,418	11,000	15,280	12,763	13,021	13,432	10,747	9,986	9,961
2012	1931	10,881	12,856	13,543	12,873	11,926	11,150	11,763	9,671	13,447	12,579	13,479	12,608	10,695	10,786
2012	1932	10,119	11,852	13,202	12,149	11,135	13,165	15,308	21,046	23,021	20,890	15,617	12,313	11,398	10,959
2012	1933	11,398	12,856	15,260	20,329	16,199	12,096	15,353	16,461	20,242	21,044	20,786	16,732	14,051	12,213
2012	1934	13,454	17,285	22,567	23,172	22,335	18,959	20,843	20,944	20,758	18,713	14,989	11,334	10,084	10,543
2012	1935	11,246	12,712	14,322	19,131	19,206	11,506	12,697	15,692	19,506	17,669	17,413	14,757	11,366	10,219
2012	1936	11,086	12,416	13,195	11,369	12,444	11,686	12,460	19,342	20,947	20,759	14,134	13,032	10,792	9,674
2012	1937	11,055	12,794	13,470	12,955	11,286	10,647	9,607	9,941	14,919	14,165	12,818	13,477	11,239	10,468
2012	1938	11,216	13,074	15,068	19,631	14,657	15,571	17,008	22,092	23,517	19,656	16,493	12,175	10,327	11,105
2012	1939	11,500	12,595	13,419	13,340	12,183	13,188	14,025	18,616	21,173	16,298	13,589	11,061	9,667	9,670
2012	1940	11,474	12,940	15,025	12,952	13,355	16,401	16,852	18,329	17,675	17,100	12,144	10,502	9,719	10,344
2012	1941	11,009	12,865	13,645	12,473	12,254	13,690	11,329	12,936	14,024	13,180	13,229	11,976	10,737	11,487
2012	1942	10,401	12,850	15,638	14,930	14,951	11,239	11,891	16,739	17,739	20,590	18,121	14,624	12,009	11,176
2012	1943	11,402	12,662	14,701	17,999	17,684	16,734	21,969	22,087	22,801	21,190	19,188	14,072	11,166	9,551
2012	1944	11,401	12,968	13,742	12,734	12,298	12,124	10,870	13,279	12,493	12,080	11,853	11,856	10,429	11,051
2012	1945	10,119	11,579	12,962	12,591	11,155	11,053	9,575	8,613	18,845	18,496	13,274	12,430	10,403	10,051
2012	1946	10,933	13,774	15,385	17,529	13,890	17,939	18,747	21,971	23,631	20,311	18,349	13,835	11,809	11,236
2012	1947	11,331	13,830	19,670	19,965	19,730	18,962	17,783	18,950	21,314	20,799	18,142	13,226	11,378	10,951
2012	1948	15,942	17,462	16,682	22,337	14,772	15,180	15,560	20,460	24,275	21,414	20,716	16,340	14,318	12,095
2012	1949	12,353	13,459	14,839	13,176	15,604	18,373	18,440	21,879	23,524	20,822	13,350	12,191	9,814	9,593
2012	1950	11,331	13,375	14,859	18,745	19,219	20,965	20,098	20,392	21,816	20,740	20,298	15,176	13,400	11,547
2012	1951	14,033	16,977	21,279	23,633	23,299	20,683	21,629	22,001	23,166	20,298	20,755	15,991	12,250	11,258
2012	1952	14,956	15,389	17,008	21,600	17,092	13,519	19,769	22,110	24,325	21,325	17,150	13,659	11,577	10,302
2012	1953	11,232	12,348	13,547	15,108	19,049	14,005	11,345	16,213	21,842	21,328	21,009	14,330	12,038	11,082
2012	1954	12,321	14,022	16,480	18,750	20,726	15,306	17,575	18,338	22,580	20,636	20,929	18,705	17,681	15,238
2012	1955	12,492	15,513	15,861	14,311	12,909	12,445	12,593	14,517	17,444	20,947	20,829	16,726	13,537	11,028
2012	1956	13,324	17,004	20,419	23,930	20,232	20,231	20,484	21,929	23,812	21,263	20,998	14,696	13,066	11,373
2012	1957	12,886	13,277	16,141	16,227	15,052	17,504	18,050	18,546	24,100	21,134	15,343	12,911	10,379	10,646
2012	1958	11,402	13,125	14,278	15,933	18,920	15,292	16,288	19,775	23,997	21,067	15,143	12,801	11,074	10,401
2012	1959	11,973	15,056	18,562	23,134	20,518	14,502	19,711	18,415	21,700	20,574	17,432	14,953	12,702	15,601
2012	1960	17,012	19,276	19,110	19,531	16,941	16,254	21,525	20,100	20,101	20,627	17,128	13,883	10,782	11,081
2012	1961	11,627	13,540	13,896	18,962	17,126	17,268	19,066	15,791	21,977	20,389	16,067	13,224	12,034	10,157
2012	1962	10,825	13,296	15,397	16,775	16,153	12,602	16,979	22,016	21,246	20,663	14,496	13,250	11,122	10,072
2012	1963	12,912	15,425	18,146	18,376	18,516	12,004	13,991	15,519	19,201	20,982	17,371	14,322	11,824	11,016
2012	1964	11,144	13,536	14,817	15,671	15,836	12,106	14,620	13,570	20,401	21,538	20,851	16,635	12,316	12,766
2012	1965	13,329	14,727	20,277	23,799	23,197	18,763	17,495	22,105	23,180	20,990	17,078	15,456	13,584	11,795
2012	1966	12,535	13,336	14,430	17,876	14,226	11,546	20,767	17,353	19,585	18,708	17,557	14,197	11,646	10,540
2012	1967	11,218	12,863	15,393	22,758	21,100	14,433	15,083	12,796	20,176	21,319	20,245	15,407	12,155	11,210
2012	1968	12,355	13,499	15,097	19,764	18,832	16,378	11,401	13,923	17,479	20,759	19,200	15,230	13,283	14,087
2012	1969	13,920	16,968	17,153	23,449	19,997	15,851	21,721	21,884	24,161	20,996	18,803	12,903	10,800	10,802
2012	1970	12,269	13,554	13,589	15,012	17,874	14,891	14,222	14,767	19,624	21,380	16,069	12,789	10,269	10,065
2012	1971	11,315	13,235	15,108	23,251	22,969	19,349	19,874	20,970	24,078	21,405	21,529	17,284	13,915	11,910
2012	1972	12,783	14,005	15,406	23,111	22,091	22,702	21,854	20,337	23,992	21,441	21,040	18,460	16,072	12,524
2012	1973	12,359	13,511	16,575	16,108	13,160	12,275	9,627	13,475	16,572	14,598	13,805	10,925	9,415	9,979
2012	1974	11,126	12,368	18,351	24,091	23,364	22,356	21,659	21,903	23,356	21,308	21,177	16,601	14,276	11,622
2012	1975	11,012	13,155	14,131	17,927	16,276	16,837	12,572	15,853	22,493	21,407	21,423	13,621	13,253	12,187
2012	1976	14,119	17,316	22,954	23,733	21,618	16,994	21,165	21,198	23,789	21,263	20,865	19,050	18,864	16,882
2012	1977	12,212	13,196	13,682	12,635	12,566	11,793	10,005	11,213	11,576	10,814	11,921	12,361	11,064	10,706
2012	1978	9,162	11,802	16,304	16,243	15,067	14,765	19,482	17,610	21,414	18,768	17,611	13,049	12,063	13,933
2012	1979	12,309	13,345	13,842	13,380	15,376	16,756	13,879	14,477	20,489	15,193	13,162	10,491	9,609	9,808
2012	1980	10,974	12,773	15,092	12,656	14,466	12,352	13,656	19,327	23,461	20,922	14,965	12,304	10,296	10,967
2012	1981	11,305	13,836	20,005	22,933	16,011	15,725	11,611	15,235	18,538	20,827	20,141	16,688	14,691	11,257
2012	1982	11,981	14,129	15,348	19,933	23,165	21,458	19,309	18,691	23,186	21,040	19,510	16,804	13,222	13,565
2012	1983	13,830	14,692	16,586	21,909	17,760	22,430	18,238	19,480	21,613	20,719	21,247	16,919	13,475	12,348
2012	1984	12,225	18,188	15,643	23,756	16,041	20,783	19,971	20,622	19,184	21,396	19,938	14,779	11,609	11,748
2012	1985	12,163	15,024	14,675	16,077	12,621	15,319	18,472	19,600	21,774	17,367	12,713	10,049	9,411	10,595
2012	1986	12,102	15,773	12,937	19,200	19,136	22,511	21,177	19,736	18,430	19,511	15,861	13,100	10,748	10,230
2012	1987	11,110	14,564	14,528	13,090	13,880	13,895	14,748	15,170	17,538	16,937	13,377	10,993	9,475	9,699
2012	1988	10,458	12,285	12,830	11,899	11,720	11,468	11,153	14,506	16,118	12,005	14,110	12,741	10,771	10,146
2012	1989	10,169	12,531	14,333	12,510	13,358	14,685	18,530	20,806	20,588	17,426	13,904	10,437	10,048	10,190
2012	1990	10,979	13,653	17,147	20,594	17,292	14,894	18,751	21,056	19,744	20,485	16,493	13,950	12,562	9,973
2012	1991	10,763	17,315	17,249	21,771	20,978	13,609	17,449	17,016	21,710	19,958	20,594	16,467	13,089	10,675
2012	1992	10,748	12,840	13,111	13,457	12,263	15,672	12,542	13,908	15,055	13,104	12,804	10,029	9,539	9,218
2012	1993	10,545	12,335	13,532	12,562	12,418	12,570	13,275	13,683	19,649	15,087	14,953	12,705	11,597	9,496
2012	1994	10,623	13,237	13,958	12,720	13,690	12,088	11,058	17,690	16,091	14,155	13,605	10,682	9,615	9,489
2012	1995	10,371	12,234	14,471	14,776	18,179	18,247	16,961	14,654	19,533	19,466	17,044	13,310	11,134	10,690
2012	1996	12,748	19,473	22,984	23,827	23,370	22,338	20,766	22,227	23,445	21,034	20,925	16,255	12,022	11,421
2012	1997	12,172	13,765	17,018	24,088	23,453	22,638	20,354	21,928	23,643	21,354	21,277	16,497	13,404	14,136
2012	1998	17,054	15,953	15,042	19,450	17,872	16,130	15,390	15,963	20,020	21,249	17,325	13,713	10,888	10,804

Table B.15 - FY 2013 Regional Hydroelectric Generation Forecast

Regional Hydroelectric Generation Forecast (aMW)															
Year	**Water Year**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr1**	**Apr16**	**May**	**Jun**	**Jul**	**Aug1**	**Aug16**	**Sep**
2013	**1929**	11,628	13,081	13,593	13,062	12,093	11,346	10,766	13,241	13,517	16,052	13,865	12,209	10,026	10,309
2013	**1930**	11,224	12,389	13,375	12,760	12,056	11,427	11,008	15,293	12,770	13,032	13,445	10,757	9,994	9,969
2013	**1931**	10,880	12,843	13,528	12,868	11,932	11,159	11,771	9,678	13,456	12,591	13,493	12,621	10,705	10,795
2013	**1932**	10,117	11,839	13,187	12,143	11,139	13,171	15,316	20,936	22,661	22,977	15,631	12,324	11,409	10,968
2013	**1933**	11,397	12,841	15,245	20,310	16,209	12,104	15,365	16,475	19,668	23,129	21,222	16,704	14,066	12,222
2013	**1934**	13,454	17,263	23,295	23,665	22,912	18,907	20,954	20,880	20,269	18,402	15,132	11,344	10,092	10,551
2013	**1935**	11,245	12,696	14,307	19,122	19,196	11,514	12,705	15,707	19,395	17,682	17,431	14,773	11,376	10,227
2013	**1936**	11,084	12,403	13,180	11,361	12,450	11,694	12,468	19,355	20,960	20,929	14,148	13,045	10,801	9,681
2013	**1937**	11,054	12,782	13,454	12,952	11,291	10,656	9,613	9,947	14,928	14,174	12,828	13,490	11,250	10,477
2013	**1938**	11,214	13,060	15,053	19,622	14,663	15,581	17,020	22,041	22,861	19,671	16,508	12,185	10,335	11,114
2013	**1939**	11,498	12,581	13,402	13,336	12,188	13,197	14,034	18,632	20,970	16,312	13,601	11,071	9,675	9,678
2013	**1940**	11,473	12,928	15,011	12,946	13,359	16,411	16,864	18,345	17,689	17,117	12,156	10,512	9,728	10,352
2013	**1941**	11,007	12,852	13,629	12,949	12,229	13,194	11,338	12,948	14,034	13,189	13,242	11,987	10,747	11,496
2013	**1942**	10,398	12,836	15,622	14,926	14,958	11,247	11,898	16,751	17,752	20,607	18,138	14,639	12,020	11,184
2013	**1943**	11,400	12,647	14,684	17,986	17,680	16,722	22,074	22,433	22,282	23,286	19,201	14,084	11,174	9,556
2013	**1944**	11,398	12,954	13,725	13,163	12,272	12,102	10,853	12,557	12,470	12,088	11,863	11,868	10,437	11,060
2013	**1945**	10,116	11,566	12,947	12,585	11,157	11,062	9,581	8,618	18,858	18,509	13,285	12,441	10,412	10,058
2013	**1946**	10,930	13,761	15,370	17,522	13,894	17,896	18,706	22,311	22,957	20,327	18,366	13,849	11,819	11,244
2013	**1947**	11,328	13,815	19,658	19,955	19,728	18,910	17,797	18,966	21,330	21,244	18,145	13,239	11,387	10,959
2013	**1948**	15,944	17,446	16,668	22,318	14,777	15,191	15,572	20,412	23,686	23,512	20,478	16,357	14,332	12,103
2013	**1949**	12,351	13,445	14,824	13,172	15,602	18,319	18,448	21,964	23,492	21,091	13,361	12,201	9,821	9,600
2013	**1950**	11,329	13,361	14,844	18,735	19,217	20,904	20,057	20,408	21,364	22,835	20,314	15,190	13,412	11,555
2013	**1951**	14,032	16,961	21,268	24,116	23,868	19,454	21,742	22,045	22,482	20,313	20,532	16,007	12,260	11,266
2013	**1952**	14,956	15,376	16,995	21,580	17,088	13,529	19,704	22,118	23,580	21,751	17,167	13,673	11,587	10,309
2013	**1953**	11,230	12,335	13,532	15,102	19,047	14,015	11,353	16,226	21,652	23,418	20,928	14,344	12,048	11,090
2013	**1954**	12,319	14,009	16,466	18,740	20,715	15,317	17,586	18,352	21,940	22,727	21,364	18,604	17,646	15,228
2013	**1955**	12,491	15,501	15,848	14,307	12,916	12,456	12,601	14,530	17,457	23,037	21,265	16,742	13,550	11,036
2013	**1956**	13,324	16,987	20,407	24,411	19,289	20,134	20,313	22,270	23,133	23,355	20,995	14,710	13,077	11,381
2013	**1957**	12,885	13,262	16,127	16,224	15,058	17,460	18,032	18,561	23,971	23,234	15,357	12,923	10,387	10,654
2013	**1958**	11,400	13,112	14,261	15,930	18,918	15,304	16,300	19,779	23,853	22,497	15,157	12,813	11,083	10,409
2013	**1959**	11,972	15,043	18,549	23,574	19,373	14,511	19,672	18,386	21,059	22,670	17,446	14,969	12,713	15,591
2013	**1960**	17,015	19,256	19,099	19,521	16,949	16,266	21,635	19,972	19,982	21,342	17,144	13,895	10,790	11,090
2013	**1961**	11,625	13,526	13,881	18,953	17,122	17,250	19,027	15,805	21,374	22,487	16,083	13,237	12,046	10,165
2013	**1962**	10,823	13,282	15,383	16,773	16,160	12,612	16,989	22,352	21,020	21,274	14,509	13,262	11,131	10,080
2013	**1963**	12,911	15,412	18,133	18,365	18,513	12,012	14,000	15,533	19,213	20,999	17,388	14,337	11,835	11,024
2013	**1964**	11,142	13,522	14,803	15,668	15,845	12,115	14,627	13,579	20,385	23,599	21,292	16,652	12,327	12,775
2013	**1965**	13,329	14,715	20,264	24,281	22,965	18,194	17,340	22,443	22,513	21,579	17,092	15,472	13,597	11,803
2013	**1966**	12,533	13,322	14,415	17,865	14,233	11,553	20,730	17,369	19,571	18,725	17,574	14,212	11,656	10,548
2013	**1967**	11,216	12,849	15,378	22,570	21,090	14,443	15,094	12,807	20,185	23,405	20,003	15,424	12,166	11,219
2013	**1968**	12,354	13,485	15,082	19,754	18,828	16,390	11,409	13,936	17,493	21,199	18,958	15,246	13,296	14,080
2013	**1969**	13,920	16,957	17,141	23,933	18,928	15,860	21,794	22,221	23,448	21,275	18,710	12,917	10,809	10,810
2013	**1970**	12,268	13,541	13,573	15,004	17,872	14,901	14,232	14,780	19,637	22,701	16,083	12,800	10,277	10,072
2013	**1971**	11,313	13,221	15,092	23,230	22,920	19,299	19,833	20,916	23,393	23,492	21,970	17,249	13,929	11,919
2013	**1972**	12,781	13,990	15,391	23,091	22,079	22,877	21,960	20,354	23,330	23,516	21,476	18,425	16,089	12,533
2013	**1973**	12,358	13,497	16,560	16,104	13,164	12,284	9,634	13,488	16,585	14,610	13,818	10,935	9,423	9,987
2013	**1974**	11,124	12,351	18,338	24,581	23,948	22,192	21,769	22,244	22,726	23,399	21,610	16,617	14,290	11,630
2013	**1975**	11,009	13,141	14,115	17,914	16,284	16,848	12,580	15,868	21,926	23,496	21,865	13,633	13,263	12,196
2013	**1976**	14,118	17,296	22,943	24,216	20,995	16,969	21,120	21,199	23,094	21,947	21,302	18,949	18,763	16,874
2013	**1977**	12,210	13,182	13,666	13,074	12,536	11,765	9,985	10,439	11,584	10,822	11,933	12,375	11,074	10,715
2013	**1978**	9,158	11,787	16,287	16,239	15,071	14,774	19,445	17,625	21,214	18,782	17,626	13,062	12,073	13,922
2013	**1979**	12,308	13,332	13,827	13,376	15,384	16,758	13,890	14,488	20,504	15,203	13,173	10,500	9,617	9,815
2013	**1980**	10,973	12,760	15,077	13,130	13,940	12,360	13,666	19,343	23,235	20,937	14,978	12,316	10,304	10,975
2013	**1981**	11,303	13,823	19,994	22,582	16,286	15,737	11,620	15,247	18,550	22,920	19,717	16,654	14,707	11,266
2013	**1982**	11,980	14,116	15,333	19,923	23,081	21,356	19,267	18,706	22,508	23,122	19,524	16,821	13,234	13,554
2013	**1983**	13,829	14,678	16,571	21,888	17,755	21,993	18,196	19,497	21,629	20,721	21,327	16,936	13,487	12,356
2013	**1984**	12,222	18,166	15,628	23,728	16,045	20,680	19,932	20,594	19,195	22,718	19,955	14,794	11,617	11,757
2013	**1985**	12,160	15,010	14,660	16,074	13,102	14,896	18,430	19,605	21,790	17,379	12,725	10,057	9,418	10,601
2013	**1986**	12,100	15,761	12,921	19,188	19,103	22,699	21,114	19,751	18,443	19,524	15,876	13,113	10,757	10,237
2013	**1987**	11,107	14,551	14,512	13,391	13,526	13,905	14,760	15,183	17,551	16,912	13,391	11,003	9,482	9,706
2013	**1988**	10,457	12,272	12,823	11,893	11,725	11,476	11,160	14,517	16,122	12,013	14,124	12,753	10,781	10,155
2013	**1989**	10,167	12,517	14,318	12,743	13,086	14,694	18,489	20,812	20,425	17,439	13,917	10,445	10,056	10,197
2013	**1990**	10,977	13,640	17,134	20,569	17,301	14,905	18,766	21,153	19,479	21,590	16,508	13,965	12,573	9,980
2013	**1991**	10,760	17,304	17,237	21,612	20,968	13,618	17,463	17,032	21,333	19,975	21,034	16,433	13,103	10,683
2013	**1992**	10,747	12,826	13,094	13,452	12,452	15,683	12,382	13,898	15,053	13,117	12,817	10,039	9,547	9,225
2013	**1993**	10,544	12,322	13,510	12,557	12,423	12,576	13,281	13,677	19,661	15,096	14,965	12,718	11,606	9,503
2013	**1994**	10,621	13,224	13,944	12,788	13,690	12,092	11,062	17,573	16,103	14,168	13,619	10,691	9,623	9,497
2013	**1995**	10,369	12,220	14,455	14,772	18,174	18,194	16,973	14,667	19,547	19,478	17,059	13,322	11,143	10,698
2013	**1996**	12,748	19,453	23,701	24,309	23,938	22,350	20,612	22,571	22,788	22,500	21,365	16,269	12,034	11,430
2013	**1997**	12,171	13,751	17,004	24,574	24,028	22,351	20,315	22,273	22,986	23,428	21,713	16,513	13,416	14,125
2013	**1998**	17,057	15,941	15,027	19,438	17,870	16,141	15,402	15,977	20,031	23,336	17,341	13,726	10,897	10,812

Table B.16 - FY 2014 Regional Hydroelectric Generation Forecast

Regional Hydroelectric Generation Forecast (aMW)															
Year	Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep
2014	1929	11,637	13,092	13,778	12,886	12,103	11,356	10,773	13,253	13,525	16,059	13,875	12,218	10,033	10,317
2014	1930	11,234	12,401	13,543	12,758	12,055	11,426	11,005	15,023	12,778	13,042	13,455	10,765	10,002	9,977
2014	1931	10,889	12,855	13,539	12,879	11,942	11,168	11,779	9,684	13,465	12,602	13,506	12,632	10,714	10,804
2014	1932	10,126	11,849	13,425	12,136	10,893	13,179	15,322	21,032	22,852	22,285	15,643	12,333	11,418	10,976
2014	1933	11,406	12,850	15,257	20,328	16,222	12,113	15,376	16,490	19,860	22,419	21,732	16,766	14,078	12,231
2014	1934	13,464	17,277	23,789	24,534	23,228	18,848	21,504	21,046	20,485	18,567	15,020	11,352	10,100	10,560
2014	1935	11,255	12,705	14,317	19,140	19,213	11,524	12,713	15,721	19,491	17,694	17,447	14,788	11,385	10,235
2014	1936	11,094	12,414	13,514	11,351	12,087	11,703	12,476	19,368	20,975	21,024	14,161	13,056	10,810	9,688
2014	1937	11,064	12,794	13,569	12,954	11,292	10,656	9,411	9,954	14,938	14,181	12,838	13,501	11,259	10,485
2014	1938	11,224	13,070	15,063	19,638	14,674	15,592	17,031	22,137	23,055	19,685	16,521	12,194	10,342	11,123
2014	1939	11,507	12,592	13,598	13,886	12,148	12,409	14,043	18,647	21,067	16,325	13,612	11,079	9,681	9,685
2014	1940	11,483	12,940	15,024	12,956	13,367	16,422	16,875	18,360	17,703	17,132	12,166	10,520	9,736	10,361
2014	1941	11,016	12,864	13,640	13,589	12,198	12,536	11,346	12,961	14,045	13,198	13,253	11,997	10,755	11,505
2014	1942	10,406	12,847	15,632	14,937	14,969	11,256	11,905	16,764	17,765	20,622	18,154	14,653	12,031	11,192
2014	1943	11,409	12,656	14,693	18,000	17,692	16,733	22,797	22,932	22,486	22,581	19,213	14,095	11,181	9,562
2014	1944	11,407	12,965	14,052	13,591	12,224	12,056	10,816	11,170	12,479	12,095	11,872	11,878	10,445	11,069
2014	1945	10,125	11,576	12,957	12,594	11,164	11,071	9,587	8,623	18,871	18,520	13,294	12,451	10,420	10,065
2014	1946	10,939	13,772	15,381	17,534	13,903	17,908	18,718	22,533	23,149	20,342	18,382	13,861	11,828	11,252
2014	1947	11,335	13,825	19,671	19,971	19,741	18,924	17,809	18,982	21,346	21,339	18,176	13,250	11,395	10,966
2014	1948	15,957	17,460	16,681	22,336	14,786	15,202	15,583	20,495	23,893	22,808	20,574	16,371	14,344	12,112
2014	1949	12,360	13,455	14,835	13,803	14,896	18,332	18,460	22,060	23,516	21,106	13,370	12,209	9,827	9,606
2014	1950	11,338	13,371	14,855	18,750	19,230	20,919	20,070	20,424	21,556	22,131	20,328	15,202	13,422	11,563
2014	1951	14,042	16,973	21,283	24,898	23,672	17,486	21,832	22,091	22,677	20,328	20,635	16,022	12,269	11,274
2014	1952	14,968	15,388	17,007	21,600	17,100	13,540	19,716	22,145	23,789	21,765	17,181	13,685	11,595	10,316
2014	1953	11,239	12,346	13,562	15,090	19,061	14,026	11,360	16,239	21,749	22,715	21,024	14,356	12,057	11,098
2014	1954	12,329	14,020	16,478	18,755	20,731	15,329	17,596	18,366	22,140	22,025	21,867	18,739	17,715	15,241
2014	1955	12,501	15,514	15,861	14,319	12,926	12,467	12,608	14,543	17,471	22,330	21,769	16,756	13,562	11,043
2014	1956	13,334	17,000	20,421	24,635	18,691	20,148	20,327	22,780	23,327	22,647	21,090	14,722	13,086	11,389
2014	1957	12,894	13,272	16,138	16,237	15,068	17,472	18,041	18,576	24,067	22,529	15,370	12,933	10,394	10,661
2014	1958	11,408	13,123	14,271	15,942	18,932	15,316	16,312	19,794	23,949	22,460	15,170	12,822	11,092	10,416
2014	1959	11,982	15,054	18,562	23,646	19,387	14,521	19,687	18,449	21,249	21,974	17,459	14,982	12,723	15,604
2014	1960	17,028	19,271	19,113	19,538	16,961	16,278	22,035	20,069	20,079	21,358	17,159	13,906	10,798	11,098
2014	1961	11,635	13,536	13,892	18,970	17,133	17,263	19,042	15,820	21,582	21,785	16,097	13,249	12,055	10,172
2014	1962	10,832	13,293	15,395	16,787	16,172	12,622	16,997	22,626	21,131	21,369	14,520	13,272	11,140	10,087
2014	1963	12,920	15,424	18,147	18,381	18,525	12,021	14,010	15,546	19,227	21,015	17,402	14,351	11,843	11,033
2014	1964	11,150	13,533	14,815	15,680	15,859	12,126	14,633	13,589	20,435	22,901	21,698	16,667	12,336	12,785
2014	1965	13,341	14,727	20,278	24,767	22,010	18,206	17,351	22,947	22,703	21,594	17,104	15,486	13,608	11,811
2014	1966	12,543	13,333	14,427	17,879	14,245	11,561	20,747	17,384	19,619	18,741	17,591	14,226	11,665	10,556
2014	1967	11,225	12,859	15,390	22,642	21,107	14,454	15,105	12,819	20,209	22,704	20,099	15,440	12,176	11,228
2014	1968	12,363	13,495	15,093	19,770	18,840	16,403	11,417	13,950	17,507	21,231	19,053	15,261	13,307	14,091
2014	1969	13,931	16,970	17,154	24,080	18,810	15,846	21,809	22,473	23,650	21,291	18,806	12,929	10,817	10,818
2014	1970	12,277	13,552	13,584	15,013	17,885	14,913	14,242	14,794	19,651	22,716	16,095	12,810	10,284	10,079
2014	1971	11,322	13,231	15,103	23,247	22,936	19,311	19,845	21,005	23,588	22,782	22,470	17,318	13,941	11,927
2014	1972	12,790	14,000	15,402	23,110	22,094	23,831	22,760	20,371	23,519	22,825	21,980	18,493	16,104	12,542
2014	1973	12,367	13,507	16,572	16,115	13,901	12,249	9,610	13,430	16,423	14,121	13,829	10,943	9,429	9,993
2014	1974	11,133	12,359	18,352	25,452	24,803	22,208	22,221	22,745	22,907	22,694	22,113	16,632	14,303	11,639
2014	1975	11,017	13,152	14,125	17,926	16,295	16,860	12,587	15,882	22,118	22,787	22,361	13,643	13,272	12,204
2014	1976	14,128	17,309	22,959	24,904	19,498	16,960	21,130	21,213	23,291	21,961	21,464	19,084	18,898	16,889
2014	1977	12,219	13,192	13,676	13,928	12,473	11,700	9,937	9,009	11,593	10,830	11,944	12,386	11,084	10,723
2014	1978	9,166	11,796	16,297	16,250	15,080	14,785	19,461	17,641	21,350	18,795	17,639	13,074	12,082	13,934
2014	1979	12,319	13,344	13,837	13,960	14,717	16,771	13,901	14,500	20,519	15,212	13,183	10,508	9,624	9,823
2014	1980	10,983	12,771	15,089	13,980	13,001	12,370	13,675	19,359	23,331	20,951	14,990	12,325	10,312	10,983
2014	1981	11,312	13,834	20,009	22,737	16,066	15,751	11,627	15,260	18,564	22,214	19,878	16,722	14,722	11,275
2014	1982	11,989	14,128	15,344	19,940	23,096	21,371	19,279	18,721	22,701	22,421	19,537	16,837	13,245	13,564
2014	1983	13,839	14,689	16,582	21,904	17,767	22,009	18,208	19,514	21,646	20,732	21,422	16,951	13,498	12,364
2014	1984	12,231	18,180	15,639	23,746	16,054	20,694	19,946	20,610	19,208	22,732	19,971	14,806	11,624	11,765
2014	1985	12,169	15,020	14,671	16,088	13,943	14,129	18,441	19,620	21,807	17,390	12,734	10,063	9,423	10,607
2014	1986	12,109	15,774	12,932	19,310	19,104	22,922	21,157	19,767	18,456	19,339	15,890	13,125	10,765	10,244
2014	1987	11,115	14,561	14,523	14,243	12,531	13,915	14,773	15,196	17,564	16,972	13,402	11,011	9,489	9,713
2014	1988	10,467	12,284	13,436	11,859	11,691	11,495	11,165	14,483	15,660	12,020	14,126	12,753	10,779	10,152
2014	1989	10,175	12,473	14,259	13,595	12,651	14,186	18,501	20,829	20,522	17,451	13,927	10,452	10,062	10,205
2014	1990	10,986	13,650	17,148	20,594	17,315	14,917	18,781	21,325	19,606	21,743	16,522	13,978	12,583	9,987
2014	1991	10,769	17,318	17,251	21,684	20,985	13,629	17,477	17,048	21,533	19,990	21,224	16,501	13,115	10,691
2014	1992	10,756	12,836	13,617	13,422	13,290	14,522	12,193	13,882	15,048	13,129	12,828	10,046	9,555	9,231
2014	1993	10,553	12,333	13,511	12,568	12,433	12,583	13,287	13,666	19,674	15,103	14,976	12,728	11,614	9,509
2014	1994	10,630	13,236	13,956	13,023	13,683	12,087	11,057	17,180	16,116	14,179	13,631	10,699	9,630	9,504
2014	1995	10,379	12,231	14,466	14,783	18,184	18,209	16,985	14,679	19,561	19,488	17,071	13,332	11,151	10,707
2014	1996	12,758	19,468	24,335	25,165	24,790	22,301	20,439	23,078	22,974	22,426	21,531	16,288	12,044	11,438
2014	1997	12,180	13,761	17,016	25,441	24,148	22,241	20,328	22,775	23,173	22,744	22,221	16,527	13,427	14,135
2014	1998	17,071	15,953	15,038	19,452	17,883	16,153	15,413	15,990	20,042	22,640	17,355	13,739	10,904	10,819

Table B.17 - FY 2015 Regional Hydroelectric Generation Forecast

Regional Hydroelectric Generation Forecast (aMW)															
Year	Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep
2015	1929	11,637	13,095	14,072	12,574	12,103	11,356	10,773	13,253	13,526	16,060	13,875	12,218	10,033	10,317
2015	1930	11,233	12,403	13,922	12,725	12,032	11,397	10,978	14,348	12,779	13,042	13,455	10,765	10,002	9,976
2015	1931	10,889	12,858	13,836	12,856	11,917	11,145	11,755	9,171	13,466	12,602	13,506	12,632	10,715	10,804
2015	1932	10,126	11,852	13,428	12,136	10,893	13,179	15,322	21,032	22,853	23,407	15,643	12,333	11,418	10,976
2015	1933	11,405	12,852	15,260	20,329	16,223	12,113	15,376	16,490	19,861	23,850	21,850	16,766	14,079	12,231
2015	1934	13,463	17,280	23,845	24,616	23,228	18,848	21,504	21,046	20,486	18,567	15,020	11,352	10,100	10,559
2015	1935	11,254	12,708	14,320	19,140	19,213	11,524	12,713	15,721	19,493	17,694	17,447	14,788	11,385	10,234
2015	1936	11,093	12,417	13,593	11,347	11,999	11,703	12,476	19,368	20,976	21,025	14,161	13,056	10,810	9,688
2015	1937	11,063	12,797	13,950	12,919	11,261	10,625	8,764	9,954	14,940	14,182	12,838	13,501	11,259	10,484
2015	1938	11,223	13,073	15,066	19,638	14,674	15,592	17,031	22,137	23,056	19,685	16,521	12,194	10,342	11,122
2015	1939	11,507	12,595	13,601	13,967	12,143	12,322	14,043	18,647	21,068	16,325	13,612	11,079	9,681	9,684
2015	1940	11,482	12,943	15,027	12,956	13,367	16,422	16,875	18,360	17,705	17,133	12,166	10,520	9,736	10,360
2015	1941	11,015	12,866	13,643	13,589	12,198	12,536	11,346	12,961	14,046	13,198	13,253	11,997	10,755	11,504
2015	1942	10,405	12,849	15,636	14,937	14,970	11,256	11,905	16,764	17,767	20,623	18,154	14,653	12,031	11,192
2015	1943	11,409	12,659	14,696	18,000	17,692	16,733	22,797	23,281	22,487	24,010	19,213	14,095	11,181	9,561
2015	1944	11,406	12,967	14,090	13,554	12,224	12,056	10,816	11,170	12,480	12,095	11,872	11,878	10,446	11,068
2015	1945	10,124	11,579	12,960	12,594	11,164	11,071	9,587	8,623	18,872	18,520	13,294	12,451	10,420	10,065
2015	1946	10,938	13,775	15,384	17,534	13,903	17,908	18,718	22,533	23,150	20,342	18,382	13,861	11,828	11,252
2015	1947	11,335	13,828	19,675	19,971	19,741	18,924	17,809	18,982	21,347	21,340	18,176	13,250	11,395	10,966
2015	1948	15,956	17,463	16,684	22,336	14,786	15,202	15,583	20,495	23,895	24,225	20,574	16,371	14,344	12,111
2015	1949	12,359	13,458	14,838	13,883	14,801	18,332	18,460	22,060	23,517	21,107	13,370	12,209	9,827	9,605
2015	1950	11,337	13,373	14,858	18,750	19,231	20,919	20,070	20,424	21,557	23,557	20,328	15,202	13,422	11,563
2015	1951	14,041	16,976	21,286	24,898	23,672	17,486	21,832	22,091	22,678	20,328	20,635	16,022	12,269	11,273
2015	1952	14,967	15,391	17,011	21,600	17,100	13,540	19,716	22,145	23,791	21,765	17,181	13,685	11,595	10,316
2015	1953	11,239	12,349	13,565	15,090	19,061	14,026	11,360	16,239	21,750	24,131	21,024	14,356	12,057	11,098
2015	1954	12,328	14,023	16,482	18,755	20,732	15,329	17,596	18,366	22,141	23,289	22,426	18,739	17,716	15,241
2015	1955	12,500	15,516	15,864	14,319	12,926	12,467	12,608	14,543	17,472	23,755	22,323	16,756	13,562	11,043
2015	1956	13,333	17,003	20,425	24,636	18,692	20,148	20,327	23,083	23,328	24,074	21,090	14,722	13,087	11,388
2015	1957	12,894	13,275	16,141	16,238	15,068	17,472	18,041	18,576	24,069	23,956	15,370	12,933	10,394	10,661
2015	1958	11,408	13,126	14,274	15,942	18,932	15,316	16,312	19,794	23,950	22,593	15,170	12,822	11,092	10,416
2015	1959	11,981	15,057	18,566	23,646	19,387	14,521	19,687	18,449	21,250	22,880	17,459	14,982	12,723	15,604
2015	1960	17,027	19,274	19,117	19,538	16,961	16,278	22,035	20,069	20,080	21,358	17,159	13,906	10,798	11,098
2015	1961	11,634	13,539	13,896	18,970	17,133	17,263	19,042	15,820	21,583	23,094	16,097	13,249	12,056	10,172
2015	1962	10,831	13,295	15,398	16,787	16,172	12,622	16,997	22,626	21,132	21,369	14,520	13,272	11,140	10,087
2015	1963	12,920	15,427	18,150	18,381	18,525	12,021	14,010	15,546	19,228	21,015	17,402	14,351	11,844	11,032
2015	1964	11,150	13,536	14,818	15,681	15,859	12,126	14,633	13,589	20,436	24,311	21,698	16,667	12,337	12,784
2015	1965	13,340	14,729	20,281	24,767	22,010	18,206	17,351	23,041	22,705	21,595	17,104	15,486	13,608	11,810
2015	1966	12,542	13,336	14,430	17,879	14,245	11,561	20,747	17,384	19,620	18,741	17,591	14,226	11,665	10,555
2015	1967	11,224	12,862	15,393	22,642	21,108	14,454	15,105	12,819	20,210	24,127	20,099	15,440	12,176	11,227
2015	1968	12,362	13,498	15,097	19,770	18,841	16,403	11,417	13,950	17,508	21,232	19,053	15,261	13,307	14,090
2015	1969	13,930	16,973	17,157	24,081	18,811	15,846	21,809	22,473	23,651	21,291	18,806	12,929	10,817	10,818
2015	1970	12,276	13,555	13,754	14,861	17,852	14,913	14,242	14,794	19,653	22,716	16,095	12,810	10,285	10,078
2015	1971	11,321	13,234	15,106	23,248	22,936	19,311	19,845	21,005	23,589	24,215	23,005	17,318	13,941	11,927
2015	1972	12,789	14,003	15,405	23,110	22,095	23,831	23,152	20,371	23,520	24,236	22,534	18,493	16,104	12,541
2015	1973	12,366	13,510	16,575	16,115	14,017	12,242	9,605	13,418	16,332	14,121	13,829	10,943	9,429	9,993
2015	1974	11,133	12,361	18,355	25,534	24,921	22,208	22,221	22,982	22,908	24,106	22,671	16,632	14,303	11,638
2015	1975	11,016	13,155	14,128	17,927	16,295	16,860	12,587	15,882	22,119	24,220	22,911	13,643	13,272	12,204
2015	1976	14,127	17,312	22,963	24,904	19,498	16,960	21,130	21,213	23,292	21,962	21,464	19,084	18,899	16,888
2015	1977	12,219	13,195	13,679	14,009	12,466	11,692	9,931	8,882	11,594	10,831	11,944	12,386	11,084	10,722
2015	1978	9,542	11,811	15,897	16,250	15,080	14,785	19,461	17,641	21,351	18,795	17,639	13,074	12,083	13,933
2015	1979	12,318	13,346	14,066	14,041	14,331	16,771	13,901	14,500	20,520	15,212	13,183	10,508	9,624	9,822
2015	1980	10,982	12,774	15,092	14,061	12,909	12,370	13,675	19,359	23,332	20,951	14,990	12,325	10,312	10,982
2015	1981	11,312	13,837	20,012	22,737	16,067	15,751	11,627	15,260	18,565	23,638	19,878	16,722	14,722	11,274
2015	1982	11,988	14,131	15,347	19,940	23,096	21,371	19,279	18,721	22,703	23,833	19,537	16,837	13,246	13,564
2015	1983	13,838	14,692	16,585	21,905	17,767	22,009	18,208	19,514	21,647	20,733	21,422	16,951	13,498	12,364
2015	1984	12,230	18,183	15,642	23,746	16,054	20,694	19,946	20,610	19,209	22,732	19,971	14,806	11,625	11,764
2015	1985	12,168	15,023	14,674	16,088	14,059	14,018	18,441	19,620	21,809	17,391	12,734	10,063	9,424	10,607
2015	1986	12,109	15,776	12,935	19,310	19,105	22,922	21,157	19,767	18,457	19,340	15,890	13,125	10,765	10,243
2015	1987	11,114	14,564	14,526	14,324	12,434	13,915	14,773	15,196	17,566	16,972	13,402	11,011	9,489	9,713
2015	1988	10,466	12,287	13,811	11,831	11,663	11,467	11,138	14,441	15,331	12,020	14,126	12,753	10,779	10,152
2015	1989	10,175	12,476	14,262	13,676	12,645	14,100	18,501	20,829	20,523	17,452	13,927	10,452	10,063	10,204
2015	1990	10,985	13,653	17,151	20,594	17,316	14,917	18,781	21,325	19,607	21,744	16,522	13,978	12,583	9,987
2015	1991	10,768	17,320	17,255	21,684	20,986	13,629	17,477	17,048	21,534	19,990	21,224	16,501	13,115	10,690
2015	1992	10,756	12,839	13,996	13,390	13,407	13,980	12,193	13,882	15,049	13,129	12,828	10,046	9,555	9,231
2015	1993	10,553	12,336	13,863	12,537	12,399	12,557	13,263	13,030	19,675	15,103	14,976	12,728	11,614	9,508
2015	1994	10,629	13,239	13,960	13,023	13,683	12,087	11,057	17,180	16,117	14,180	13,631	10,699	9,630	9,504
2015	1995	10,378	12,233	14,470	14,783	18,184	18,209	16,985	14,679	19,563	19,489	17,071	13,332	11,151	10,706
2015	1996	12,757	19,470	24,716	25,246	24,909	22,301	20,439	23,606	22,975	22,539	21,531	16,288	12,044	11,437
2015	1997	12,179	13,764	17,019	25,523	24,036	22,241	20,328	23,166	23,175	24,147	22,287	16,527	13,427	14,135
2015	1998	17,070	15,956	15,041	19,453	17,883	16,153	15,413	15,990	20,043	24,009	17,355	13,739	10,905	10,819

Table B.18 - Federal Hydroelectric Generation for the 70 Water Years

Federal Hydro Generation (aMW) With Hydro Independents for the 70 Water Years Results are Pre-Slice and Based on an Assumed 6220 MW of Wind Generation in BPA's Control Area in 2013												
Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Wtd Avg.
1929	6,234	8,037	7,404	7,334	6,880	6,871	6,266	7,247	8,566	8,131	6,571	6,323	7,156
1930	6,726	8,316	7,412	7,539	7,114	6,951	6,807	7,040	7,118	8,102	6,590	6,364	7,174
1931	6,502	8,052	7,557	7,394	6,973	6,295	5,988	7,556	6,922	8,222	7,199	6,743	7,120
1932	5,953	7,382	7,428	6,757	5,506	7,951	10,785	13,607	13,207	9,064	7,033	6,904	8,477
1933	6,720	6,851	8,962	12,094	9,895	7,016	9,050	11,533	13,760	12,134	9,563	7,280	9,572
1934	7,351	9,817	13,683	14,347	13,566	11,259	12,659	11,984	10,401	9,509	6,350	6,568	10,609
1935	6,493	6,475	8,040	10,866	10,879	7,739	9,018	11,123	9,471	10,246	8,045	6,167	8,706
1936	6,540	8,125	7,337	6,662	6,908	7,136	9,183	12,217	11,570	8,624	7,180	5,983	8,126
1937	6,652	8,366	7,459	7,641	6,660	5,901	5,389	8,507	7,215	7,466	7,443	6,507	7,107
1938	6,610	7,338	8,604	10,688	9,767	9,511	11,246	12,875	11,296	9,705	6,614	6,998	9,267
1939	6,794	7,504	7,330	7,529	6,926	7,938	9,492	12,247	8,680	8,067	6,206	5,930	7,895
1940	6,852	8,312	8,648	7,344	7,475	10,085	10,477	10,654	10,120	7,042	6,047	6,454	8,293
1941	6,586	7,944	8,230	7,802	7,563	7,429	7,122	8,290	7,310	8,001	7,159	7,283	7,562
1942	6,221	7,832	9,193	9,147	8,027	6,817	8,555	10,819	12,381	10,972	8,189	6,409	8,718
1943	6,716	7,337	8,357	10,792	10,987	10,227	12,641	12,929	13,559	10,694	7,541	6,050	9,808
1944	6,416	7,960	7,332	7,456	7,073	7,078	6,558	7,036	6,481	7,395	6,983	6,929	7,059
1945	6,019	8,003	7,501	6,967	6,346	5,459	4,930	11,112	10,337	7,989	6,857	6,137	7,312
1946	6,225	7,963	8,890	9,266	8,725	10,749	11,953	12,654	11,197	10,728	7,782	6,853	9,420
1947	6,526	7,908	11,606	12,189	11,282	11,194	10,415	12,758	12,239	10,860	7,402	6,643	10,084
1948	8,845	10,150	9,888	12,299	10,447	9,328	10,287	13,457	13,689	12,134	9,477	7,139	10,599
1949	6,987	7,642	8,530	8,671	8,125	11,279	11,446	13,284	12,142	7,564	6,320	5,832	8,989
1950	6,547	7,392	8,201	10,934	11,490	12,114	11,330	12,414	12,828	11,323	8,439	6,865	9,981
1951	7,733	9,393	11,891	14,170	13,022	11,519	12,294	12,526	11,211	11,878	8,539	6,622	10,893
1952	8,266	8,760	10,010	12,413	10,275	8,672	12,053	13,190	12,577	10,172	7,638	6,115	10,011
1953	6,613	7,761	7,459	7,969	10,152	9,768	8,058	12,247	13,607	12,520	7,897	6,677	9,222
1954	6,976	8,029	9,423	10,461	12,250	9,233	10,035	12,873	12,567	12,614	10,986	9,277	10,383
1955	7,002	8,815	9,302	8,059	7,273	7,481	7,611	10,391	13,868	12,827	9,506	6,362	9,055
1956	7,215	9,519	11,789	14,192	11,813	11,861	11,834	12,658	13,588	12,095	8,290	6,785	10,969
1957	7,223	7,717	8,795	9,282	8,054	10,657	10,746	13,619	13,548	9,210	6,833	6,532	9,358
1958	6,612	7,670	8,153	9,720	10,039	9,558	10,291	13,670	13,011	9,092	7,092	6,363	9,265
1959	6,911	8,518	10,882	13,497	11,340	10,332	10,555	11,974	12,510	9,778	8,373	9,503	10,340
1960	9,521	11,106	11,124	11,983	9,826	9,397	11,833	11,806	12,465	10,075	7,178	6,756	10,257
1961	6,750	7,544	8,100	11,096	9,689	10,490	10,220	12,666	12,675	9,719	7,716	6,163	9,402
1962	6,238	7,639	8,969	10,046	9,198	7,972	11,208	12,417	12,403	8,358	7,186	6,115	8,973
1963	7,531	8,795	10,637	10,931	9,221	8,061	8,879	11,670	11,530	10,477	8,119	6,692	9,384
1964	6,294	7,669	8,628	8,858	8,495	7,128	8,603	12,120	13,638	12,531	9,069	7,593	9,223
1965	7,672	8,569	11,881	14,375	13,165	11,106	11,115	12,707	12,158	9,996	8,923	6,933	10,707
1966	7,142	7,419	8,711	10,502	8,257	6,587	10,961	11,203	10,488	10,406	7,840	6,200	8,815
1967	6,435	7,189	8,907	12,477	12,566	10,295	7,525	11,638	12,771	11,642	8,499	6,873	9,724
1968	6,882	7,531	8,734	11,349	10,387	10,050	7,084	10,733	11,352	11,331	8,908	8,309	9,388
1969	7,733	9,705	10,085	13,408	12,192	10,817	12,049	12,962	12,088	11,167	7,207	6,421	10,477
1970	7,027	7,711	7,978	8,536	10,053	9,193	8,250	11,357	12,978	9,632	6,800	6,141	8,795
1971	6,556	7,571	8,584	13,235	13,352	11,755	11,434	13,100	13,430	13,120	9,785	7,099	10,739
1972	7,194	7,811	9,031	13,278	12,844	13,492	11,709	13,208	13,054	12,769	10,486	7,299	11,010
1973	6,999	7,738	9,518	9,175	7,348	7,229	6,779	9,923	7,671	8,015	6,113	5,987	7,718
1974	6,478	7,215	10,821	15,060	14,384	13,009	12,366	12,856	13,024	13,040	9,597	6,830	11,211
1975	6,271	7,530	7,849	9,562	9,958	10,336	7,904	12,778	13,416	13,513	8,022	7,298	9,538
1976	7,903	9,851	12,933	13,707	12,898	10,397	12,037	13,029	12,283	12,203	11,165	10,258	11,549
1977	7,027	8,064	7,414	8,052	7,297	7,101	5,259	6,224	5,634	7,342	7,327	6,704	6,957
1978	5,644	6,728	9,649	9,731	9,227	8,652	10,508	12,358	10,736	10,429	7,567	8,399	9,135
1979	7,235	8,206	7,378	8,727	9,063	9,257	7,750	11,680	8,973	7,629	6,082	5,913	8,155
1980	6,548	8,097	8,535	7,478	7,759	7,167	8,856	13,528	12,302	8,856	6,694	6,678	8,543
1981	6,665	8,030	11,365	12,856	10,300	9,307	7,613	10,397	13,826	11,706	9,974	6,682	9,899
1982	6,808	8,233	8,853	11,614	13,105	12,418	11,084	12,950	12,745	11,138	9,510	8,182	10,537
1983	7,917	8,506	9,507	11,464	11,664	12,428	10,690	12,696	11,856	12,536	9,460	7,278	10,500
1984	7,001	10,386	8,991	12,640	10,392	11,990	11,150	12,271	12,818	12,063	7,985	7,153	10,404
1985	6,887	8,496	8,697	9,488	8,320	8,207	10,671	12,902	9,216	7,306	5,724	6,457	8,531
1986	6,888	9,234	7,620	10,972	11,036	12,471	11,812	11,184	12,178	9,668	7,345	6,087	9,695
1987	6,293	8,318	7,970	7,619	7,364	8,247	8,063	10,305	10,204	8,169	6,190	5,767	7,878
1988	6,309	8,004	7,164	7,078	6,764	6,768	7,480	8,305	6,441	8,659	7,173	6,292	7,209
1989	6,046	7,038	8,054	7,032	8,130	8,602	10,545	12,087	9,956	7,785	5,889	6,122	8,103
1990	6,465	7,734	9,828	11,301	10,419	9,096	10,187	11,599	12,347	9,809	8,071	5,982	9,398
1991	6,088	9,578	10,094	12,471	12,068	9,056	9,363	12,424	11,825	12,121	9,328	6,290	10,051
1992	6,352	7,851	7,317	7,920	7,580	7,546	7,592	8,514	7,419	7,720	6,024	5,633	7,288
1993	6,359	7,881	7,612	7,628	6,662	7,160	7,688	11,785	8,552	8,823	7,439	5,911	7,804
1994	6,229	8,393	7,998	7,663	7,557	6,924	8,096	9,701	7,079	8,153	6,141	5,776	7,477
1995	6,225	7,007	8,244	8,519	10,348	10,727	8,246	11,161	12,018	10,392	7,430	6,571	8,900
1996	7,316	11,050	14,316	14,461	13,748	13,066	12,134	13,291	13,164	12,561	8,983	6,703	11,727
1997	6,847	7,729	9,976	14,562	14,238	12,152	12,284	12,665	13,268	12,655	9,226	8,330	11,143
1998	9,558	9,112	8,612	11,076	9,921	9,556	8,318	11,698	13,827	10,252	7,481	6,508	9,660
Average	**6,863**	**8,188**	**9,043**	**10,277**	**9,709**	**9,295**	**9,577**	**11,577**	**11,297**	**10,113**	**7,797**	**6,757**	**9,206**
Std Dev	**729**	**949**	**1,593**	**2,436**	**2,275**	**2,015**	**2,056**	**1,799**	**2,261**	**1,844**	**1,284**	**870**	**1,266**
5th %tile	**6,065**	**7,021**	**7,334**	**7,053**	**6,708**	**6,669**	**6,113**	**7,386**	**6,993**	**7,427**	**6,063**	**5,868**	**7,136**

Table B.19 - Cumulative Probability Distribution of 10-Year Annual Averages

Cumulative Probability Distribution of 10 Year Annual Average Hydro Generation (aMW) for the 70 Water Years Results are Pre-Slice and Based on an Assumed 6220 MW of Wind Generation in BPA's Control Area in 2013			
Yr 1 Water Year	**10-Yr Annual Average**	**Probability**	**Cumulative Probability**
1936	8,115	1.43%	1.43%
1937	8,244	1.43%	2.86%
1935	8,254	1.43%	4.29%
1929	8,331	1.43%	5.71%
1985	8,343	1.43%	7.14%
1998	8,371	1.43%	8.57%
1986	8,380	1.43%	10.00%
1930	8,405	1.43%	11.43%
1931	8,517	1.43%	12.86%
1938	8,542	1.43%	14.29%
1992	8,545	1.43%	15.71%
1932	8,561	1.43%	17.14%
1987	8,583	1.43%	18.57%
1933	8,585	1.43%	20.00%
1934	8,609	1.43%	21.43%
1984	8,636	1.43%	22.86%
1993	8,664	1.43%	24.29%
1939	8,675	1.43%	25.71%
1997	8,774	1.43%	27.14%
1940	8,784	1.43%	28.57%
1991	8,838	1.43%	30.00%
1994	8,841	1.43%	31.43%
1983	8,906	1.43%	32.86%
1988	8,910	1.43%	34.29%
1941	8,953	1.43%	35.71%
1990	9,060	1.43%	37.14%
1980	9,130	1.43%	38.57%
1996	9,134	1.43%	40.00%
1979	9,135	1.43%	41.43%
1995	9,154	1.43%	42.86%
1989	9,155	1.43%	44.29%
1981	9,215	1.43%	45.71%
1982	9,231	1.43%	47.14%
1977	9,236	1.43%	48.57%
1942	9,286	1.43%	50.00%
1973	9,324	1.43%	51.43%
1978	9,328	1.43%	52.86%
1944	9,357	1.43%	54.29%
1972	9,372	1.43%	55.71%
1943	9,416	1.43%	57.14%
1976	9,421	1.43%	58.57%
1971	9,456	1.43%	60.00%
1970	9,481	1.43%	61.43%
1961	9,489	1.43%	62.86%
1975	9,522	1.43%	64.29%
1957	9,573	1.43%	65.71%
1974	9,603	1.43%	67.14%
1958	9,609	1.43%	68.57%
1959	9,621	1.43%	70.00%
1962	9,623	1.43%	71.43%
1955	9,623	1.43%	72.86%
1960	9,635	1.43%	74.29%
1964	9,660	1.43%	75.71%
1945	9,689	1.43%	77.14%
1969	9,713	1.43%	78.57%
1953	9,722	1.43%	80.00%
1968	9,738	1.43%	81.43%
1954	9,739	1.43%	82.86%
1966	9,742	1.43%	84.29%
1956	9,788	1.43%	85.71%
1949	9,813	1.43%	87.14%
1952	9,826	1.43%	88.57%
1963	9,826	1.43%	90.00%
1965	9,858	1.43%	91.43%
1946	9,864	1.43%	92.86%
1948	9,946	1.43%	94.29%
1950	9,948	1.43%	95.71%
1951	9,975	1.43%	97.14%
1967	10,015	1.43%	98.57%
1947	10,019	1.43%	100.00%

Average:	**9,206**
Std Dev:	**539**
5th %tile:	**8,293**

Table B.20 - Selection of 10 Year Hydroelectric Generation at Different Percentiles

Selection of 10 Year Hydro (aMW) Generation Patterns at the 5th, 15th, 25th, 35th, 45th, 55th, 65th, 75th, 85th, and 95th Percentiles
Assessment Based on a Cumulative Probability Distribution of 10 Year Annual Average Hydo Generation for the 70 Water Years

Yr 1 WY	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	10 Yr Avg	CumPrb
1935	8,706	8,126	7,107	9,267	7,895	8,293	7,562	8,718	9,808	7,059	8,254	4.29%
1929	7,156	7,174	7,120	8,477	9,572	10,609	8,706	8,126	7,107	9,267	8,331	5.71%
1938	9,267	7,895	8,293	7,562	8,718	9,808	7,059	7,312	9,420	10,084	8,542	14.29%
1992	7,288	7,804	7,477	8,900	11,727	11,143	9,660	7,156	7,174	7,120	8,545	15.71%
1993	7,804	7,477	8,900	11,727	11,143	9,660	7,156	7,174	7,120	8,477	8,664	24.29%
1939	7,895	8,293	7,562	8,718	9,808	7,059	7,312	9,420	10,084	10,599	8,675	25.71%
1988	7,209	8,103	9,398	10,051	7,288	7,804	7,477	8,900	11,727	11,143	8,910	34.29%
1941	7,562	8,718	9,808	7,059	7,312	9,420	10,084	10,599	8,989	9,981	8,953	35.71%
1989	8,103	9,398	10,051	7,288	7,804	7,477	8,900	11,727	11,143	9,660	9,155	44.29%
1981	9,899	10,537	10,500	10,404	8,531	9,695	7,878	7,209	8,103	9,398	9,215	45.71%
1944	7,059	7,312	9,420	10,084	10,599	8,989	9,981	10,893	10,011	9,222	9,357	54.29%
1972	11,010	7,718	11,211	9,538	11,549	6,957	9,135	8,155	8,543	9,899	9,372	55.71%
1975	9,538	11,549	6,957	9,135	8,155	8,543	9,899	10,537	10,500	10,404	9,522	64.29%
1957	9,358	9,265	10,340	10,257	9,402	8,973	9,384	9,223	10,707	8,815	9,573	65.71%
1960	10,257	9,402	8,973	9,384	9,223	10,707	8,815	9,724	9,388	10,477	9,635	74.29%
1964	9,223	10,707	8,815	9,724	9,388	10,477	8,795	10,739	11,010	7,718	9,660	75.71%
1966	8,815	9,724	9,388	10,477	8,795	10,739	11,010	7,718	11,211	9,538	9,742	84.29%
1956	10,969	9,358	9,265	10,340	10,257	9,402	8,973	9,384	9,223	10,707	9,788	85.71%
1948	10,599	8,989	9,981	10,893	10,011	9,222	10,383	9,055	10,969	9,358	9,946	94.29%
1950	9,981	10,893	10,011	9,222	10,383	9,055	10,969	9,358	9,265	10,340	9,948	95.71%

Yr 1 WY	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Avg Yr 1-10	10 Yr Strips
1929	7,156	7,174	7,120	8,477	9,572	10,609	8,706	8,126	7,107	9,267		8,331
1992	7,288	7,804	7,477	8,900	11,727	11,143	9,660	7,156	7,174	7,120		8,545
1939	7,895	8,293	7,562	8,718	9,808	7,059	7,312	9,420	10,084	10,599		8,675
1941	7,562	8,718	9,808	7,059	7,312	9,420	10,084	10,599	8,989	9,981		8,953
1981	9,899	10,537	10,500	10,404	8,531	9,695	7,878	7,209	8,103	9,398		9,215
1972	11,010	7,718	11,211	9,538	11,549	6,957	9,135	8,155	8,543	9,899		9,372
1957	9,358	9,265	10,340	10,257	9,402	8,973	9,384	9,223	10,707	8,815		9,573
1964	9,223	10,707	8,815	9,724	9,388	10,477	8,795	10,739	11,010	7,718		9,660
1956	10,969	9,358	9,265	10,340	10,257	9,402	8,973	9,384	9,223	10,707		9,788
1950	9,981	10,893	10,011	9,222	10,383	9,055	10,969	9,358	9,265	10,340		9,948
Avg:	9,034	9,047	9,211	9,264	9,793	9,279	9,090	8,937	9,021	9,385	9,206	9,206
Stdev:	1,471	1,334	1,422	1,035	1,312	1,388	1,044	1,253	1,341	1,202	1,280	558
Minimum:	7,156	7,174	7,120	7,059	7,312	6,957	7,312	7,156	7,107	7,120	7,147	8,331

Table B.21 - Statistical Comparison of 70 WY and Selected 10 WY

Statistical Comparison of 10 Year and Annual Hydro Generation (aMW) for the 70 WY and 10 WY		
70 WY Hydro Generation Statistics		
	10-Yr Strips (aMW)	**Annual (aMW)**
Average:	9,206	9,206
Standard Dev:	539	1,266
5th Percentile:	8,293	7,136
10 WY Hydro Generation Statistics		
	10-Yr Strips (aMW)	**Annual (aMW)**
Average:	9,206	9,206
Standard Dev:	558	1,280
Minimum:	8,331	7,147

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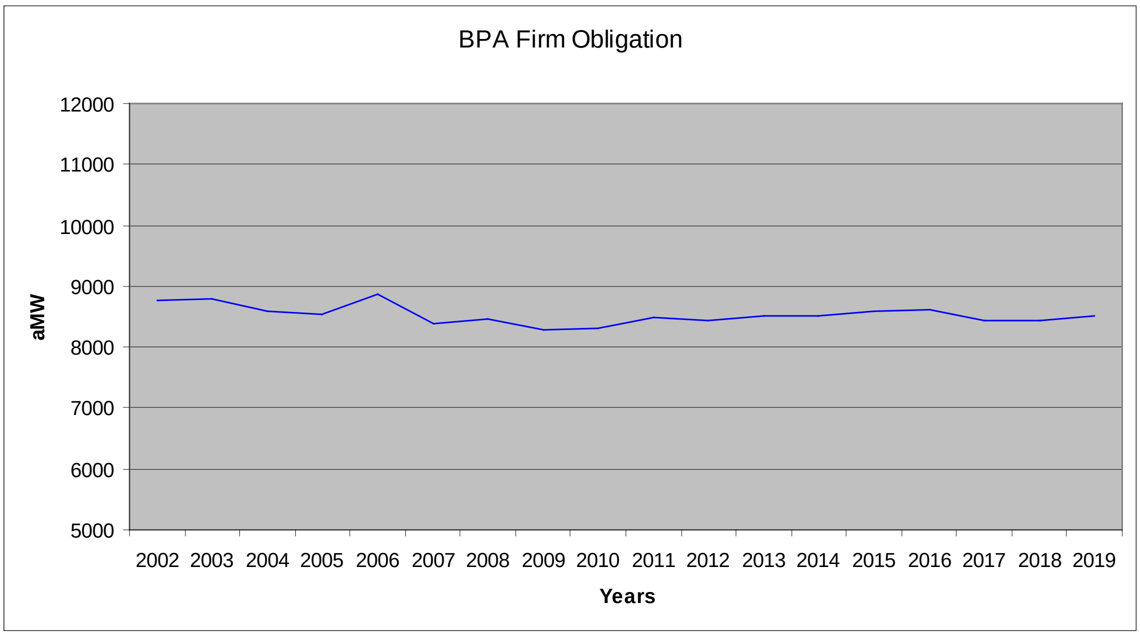
APPENDIX C. Total Supply Obligation Forecast

Summary

The firm obligation for BPA is expected to grow in the future as energy consumption for the retail consumers of BPA customers grows. As noted throughout the Resource Program, however, BPA's forecast does not include the uncertainties of economic recovery or long-term load growth. Figure C.1 shows the net effect of this growth on BPA's firm obligation forecast. The growth rate averages 0.9 percent from 2009 through 2019. The BPA firm obligation forecast forms the basis of the Needs Assessment for the Resource Program.

Figure C.1 - BPA Firm Obligation



C.1 Load Forecasts

For the Resource Program, forecasts of loads and resources are needed to determine BPA's energy obligation determined by contract. The forecasts include projected total retail loads of regional public agencies, BPA's direct-service industrial customers (DSIs), and Federal entities. BPA also produces or reviews forecasts for other entities within the Pacific Northwest Region (PNW), including investor-owned utilities (IOUs) and DSIs. Forecasts for all entities are included in a BPA regional summary load forecast. BPA must quantify its transactions with others in the region to ensure that regional loads are counted only once in the aggregation of loads to a total. These loads are not separated by state boundaries, thus making alignments with state data challenging. However, regional loads are not used for the Needs Assessment—only BPA obligations in the region are used

Currently, due to the diversity of the service territories within the region and the data available from each, a variety of forecasting methods are applied by analysts at BPA to produce the forecasts. The analysts regularly review the performance of their forecasts to make sure that the results are as expected. Such assurance about the components leads to assurance that the total forecast represents the region. The diversity of the region also does not facilitate a single set of assumptions for the forecast modeling. The forecasting staff regularly reviews the national, regional, and state economic activity to ensure that it is accurately reflected in the forecasts used, either explicitly or implicitly.

During development of the long-term forecast used for the Resource Program, the national economy was settling on a course after the recent financial crisis. For this updated forecast, BPA assumes that the economic downturn has bottomed and that dampened conditions will continue into the first quarter of calendar year (CY) 2011. Following that, we expect growth to start recovering, with growth returning and strengthening in the following years. The diversity of the regional economy is further seen when forecasts are designed to incorporate the impacts of the economic changes being experienced. Some areas experience record unemployment levels, while others experience growth based on the industrial sectors in the local area. Some areas receive funds from the Federal stimulus package, thus invigorating growth, and some areas see industries closing facilities permanently.

BPA annually prepares forecasts for several years into the future. This cycle is designed to capture the events that effect long-term changes. These events may include consumer expansions, changes in economic sector activity, or changes in consumer appliance mix and technological changes.

The following discussion details how BPA develops a forecast of regional loads for comparative and completeness purposes and then further defines the forecasts of BPA's obligations within the PNW. These forecasts are produced in the Agency Load Forecasting system (ALF), a forecasting tool created by ITRON, an international firm with expertise in energy forecasting. ALF is a statistical approach that uses time-series-based regressions that reflect a fundamental assumption that historical patterns will continue into the future. It allows the customer load to be influenced by heating and cooling weather conditions and explicitly models new industrial production sites in a customer's service territory.

C.1.1 Public Agencies Total Retail Load Forecasts

The monthly energy load forecasts for public agencies are based on the sum of the utility-specific load forecasts routinely produced by BPA analysts. The utility-specific forecasts of total retail load are produced using least squares regression-based models on historical monthly energy load totals. In general, BPA uses 10 years of historical data, when possible, to create its total retail load forecasts. However, if discrete changes in a customer's historical loads occurred, changes in the length of the historical data streams may be incorporated to reflect the current conditions in the customer forecast. These models may include several independent variables, such as a time trend, heating degree days (HDD), cooling degree days (CDD), and monthly indicator variables. Some models include economic drivers, such as forecasts of employment by county. Other models may be a function of a large industrial entity in a utility's service territory. Historical data may not show a regular linear trend, and the analyst may include indicator variables to account for a shift in trend or magnitude in the time series. Separate models are produced at the total customer level and for several points of delivery within the customer's service territory, if they exist.

Results from the point of delivery models are summarized and compared against the single total customer model. The review of the bottom-up forecast and the total forecast for each customer should produce a confirming growth rate for each customer. The analysts gain additional insight by reviewing and analyzing differences between these models, possibly leading to identifying changing events that indicate where models may be refined to produce a better forecast for each utility.

Heating and cooling degree days are a measure of temperature effects to account for the change in electricity use related to temperature changes. Heating degree days are typically calculated when the temperature is below a base temperature, such as 65 degrees; cooling degree days are calculated when the temperature is above a base temperature. Thus, the models explicitly account for the impact of temperature on a monthly basis and then use normal weather to forecast the future. Not all consumers respond to the typical HDD, so the modelers have the capability to select a base temperature to use for calculating HDDs for each utility independently. The models may also have a separately selected base temperature for calculating CDDs. Weather stations to use in the model are selected based on having sufficient quality and quantity of data and being located within or near each utility's service territory.

The monthly peaks are forecast in a similar fashion as the energy, but historical data used in the models is the customer's coincidental peak (CP). The peak coincident to the BPA generation system peak (GSP) is obtained by applying historical relationships between the CP and the GSP to the forecasted CP.

The energy figures are split into Heavy Load Hour (HLH) and Light Load Hour (LLH) segments using recent historical relationships.

Specific additions to load from known or expected growth may also be planned within a customer's service territory. These are modeled based on estimates obtained from the customer about the additions. Consumers considering a large expansion will review their plans with the utility, and that information is gathered by the forecasting analyst. The analyst models the specific addition based on the projected connected load, starting date, hours of operation, expected load factor, and additional pertinent information. This forecast is then added to the regression-based forecast to include the off-trend expansion. Similarly, forecasts can be reduced when a specific decrease is also identified.

Forecasting analysts will also regularly meet with the customer to gather information about the economic climate in its service territory, changing trends, and specific events.

These items are included in the modeling process when they can be, or included judgmentally after the model results are produced.

C.1.2 Investor-Owned Utilities Total Retail Load Forecast

BPA reviews and assesses forecasts for the regional IOUs' total retail load within the PNW. These forecasts are used in the BPA regional summary but not in the BPA obligations. The IOUs are Avista Corporation, Idaho Power Company, NorthWestern Energy Division of NorthWestern Corporation (formerly Montana Power Company), PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. A clear understanding of the loads, characteristics of the load, areas of subjectivity in the IOU's forecast development, and range of load variability is important in assessing total regional loads and their impact on BPA. In assessing the loads, BPA takes a keen interest in each IOU's resource planning and the forecasts used for this purpose and will use the customer's forecast as a starting point for review and planning.

C.1.3 Direct Service Industry Sales Forecast

BPA reviews energy activity at the several DSIs within the PNW. For load forecasting purposes, these industries are assumed to continue to operate at existing levels regardless of energy supplier. BPA monitors the industries for factors that may alter energy consumption levels.

C.1.4 Hourly Load Forecasts

Forecasts of hourly loads are needed for all types of load forecasts to assess all the needs within the Region. Technology changes, customer preferences, and industrial mixes all result in changing peak growth and relationships between peak and energy. Modeling the changes in the hourly load shape allows for these relationships to be reflected into the future. Because hourly load shapes have not been used at BPA for several years, a new process was developed and incorporated into the ALF tool. Using historical data, hourly shapes are developed for each category of forecast produced and each specific entity in the category. When specific data is not available, regional data created by summing known activity for several utilities or data from a specific nearby utility with similar usage patterns is used to develop the hourly shape. The forecasted hourly shape is then conformed to reflect the changing monthly shape over time for the energy forecast developed using the monthly aggregations of data.

This process allows for a different system level load shape to emerge as individual customers grow differently. This method properly supports what will happen when faster-growing customers with increasing summer loads influence the overall system shape.

C.1.5 Conservation Treatment in the Forecast

BPA's modeling method for Public Agencies, which uses actual metered usage, results in a forecast that includes some level of achieved conservation. The level of metered usage is affected by conservation that was acquired in any single year. The cumulative impact of the single-year impacts slows the energy growth rate, which affects the forecasting models. Additionally, any trend in the achieved conservation impacts the overall trend of the metered usage, further impacting the long-term energy growth rate. This can be seen by looking at the average annual growth rate using the metered data and adjusting the data for the impact of the historical conservation activities. The average annual growth rate for the metered data that includes the impacts of conservation is 1.2 percent from 1999 to 2008. If the achieved conservation is added back in, the annual growth rate of the energy would have been 1.6 percent.

Analysis did find a small trend in the conservation activity in historical information, and we did see a sustained persistence of achievement in conservation activity. Given the commitment by BPA and other customer utilities to continually accomplish the conservation levels they have, we forecasted a continuation of this activity at current levels throughout the forecast horizon. Using data from the last five years we estimate that the forecast has 55-56 aMW of conservation annually from BPA and customer programmatic and alliance activities included in it.

Determining the precise amount of conservation in the forecast is an impossible task. Based on possible measurement methods, the value has a range around the estimated value of nearly 10 aMW. Thus while we have confidence in our estimate there is uncertainty that may have an impact on some final decisions. This is a fundamental uncertainty associated with planning for the future.

C.1.6 Results

Table C.1 shows the resulting forecast for categories of load in the PNW from 2009 through 2019 and historical data for the same categories from 1999 through 2008 in average megawatts. Actual data comes from either metering readings available to BPA or national data sources. BPA, along with others in the region, has increased its focus on the total region, and it has become evident that it is difficult to use consistent data across the region. Data is not available for all entities in a timely fashion. Thus, BPA was required to estimate later years that would typically be considered actual for some entities. BPA recognizes the need and will be taking a more active role in the accounting of regional data to ensure that consistent numbers are being used by all parties, thus making review between entities easier.

Table C.1 – PNW load forecast and historical data

Calendar Year	aMW (at the generator)					
	Total PNW Retail Load	**IOUs**	**DSIs**	**Federal Entities**	**BPA Load Following Entities**	**BPA Non-Load Following Entities**
1999 A	22360	13188	867	130	3115	5060
2000 A	22427	13139	839	130	3200	5119
2001 A	19287	11178	123	126	3016	4844
2002 A	19819	11220	339	125	3250	4883
2003 A	19986	11206	400	127	3355	4899
2004 A	20187	11295	315	127	3417	5033
2005 A	20685	11622	308	126	3510	5119
2006 A	20816	11479	302	126	3668	5240
2007 A	21928	12030	573	124	3810	5391
2008 E	22234	12165	598	127	3925	5419
2009 E	20670	10909	495	131	3854	5285
2010 F	20671	10695	371	135	3859	5374
2011 F	21159	10981	376	137	3932	5532
2012 F	21611	11282	376	139	4032	5582
2013 F	22092	11549	376	140	4097	5729
2014 F	22481	11781	387	155	4162	5796
2015 F	22828	11967	431	158	4224	5867
2016 F	23131	12141	463	159	4284	5903
2017 F	23474	12311	463	209	4340	5951
2018 F	23749	12478	463	210	4411	5987
2019 F	24034	12654	463	212	4476	6029
Average annual growth rate 1998-2008	-0.1%	-0.8%	-4.0%	-0.3%	2.6%	0.9%
Average annual growth rate 2009-2019	1.5%	1.7%	-0.7%	4.9%	1.5%	1.3%

Note:
A after the year means Actual data.
E after the year means includes some Estimated data.
F after the year means Forecast data.

Table C.1 also shows the historical average annual growth rates from 1998 through 2008 for comparative purposes with the forecasted values from 2009 through 2019. As can be seen from Table C.1, loads dropped appreciably from 2000 to 2001. Much of this drop is attributable to the decline of the aluminum industry in the Northwest due to increasing prices and worldwide competition. Additionally, declines are seen in other areas due to the increased prices during the energy crisis of 2000-2001 and the resulting market transformation and economic slowdown. BPA calculates an average annual growth rate of 1.9 percent from 2002 through 2008 for the total region and 1.3 percent for the IOUs' regional load.

Table C.2 shows the year over year percentage load growth or load loss for categories of load in the PNW from 2009 through 2019 and historical data for the same categories from 2000 through 2008.

Table C.2 – Annual percentage change in PNW load forecast and historical data

Calendar Year	Year over Year Percent Change					
	Total PNW Retail Load	IOUs	DSIs	Federal Entities	BPA Load Following Entities	BPA Non-Load Following Entities
2000 A	0.3	-0.4	-3.2	-0.2	2.7	1.2
2001 A	-14.0	-14.9	-85.3	-3.1	-5.8	-5.4
2002 A	2.8	0.4	175.6	-0.8	7.8	0.8
2003 A	0.8	-0.1	17.7	1.6	3.2	0.3
2004 A	1.0	0.8	-21.2	0.0	1.8	2.7
2005 A	2.5	2.9	-2.2	-0.8	2.7	1.7
2006 A	0.6	-1.2	-1.9	-0.0	4.5	2.4
2007 A	5.3	4.8	89.7	-1.6	3.9	2.9
2008 E	1.4	1.1	4.4	2.4	3.0	0.5
2009 E	-7.0	-10.3	-17.2	3.1	-1.8	-2.5
2010 F	0.0	-8.7	-25.0	2.9	1.1	1.7
2011 F	2.4	2.7	1.3	1.7	0.9	2.9
2012 F	2.1	2.7	0.0	1.3	2.5	0.9
2013 F	2.2	2.4	0.0	10.3	1.6	2.6
2014 F	1.8	2.0	2.9	2.3	1.6	1.2
2015 F	1.5	1.6	11.3	0.6	1.5	0.9
2016 F	1.3	1.4	7.6	31.3	1.4	0.6
2017 F	1.5	1.4	0.0	0.5	1.3	1.1
2018 F	1.2	1.4	0.0	0.7	1.6	0.6
2019 F	1.2	1.4	0.0	0.6	1.5	0.7

Note:
A after the year means Actual data.
E after the year means includes some Estimated data.
F after the year means Forecast data.

Because of the recession the U.S. is experiencing at the time of publication of this Resource Program, in 2009 and 2010 the forecasted growth rates will be higher than what could be considered a stable period growth rate. The stable period growth rates are calculated from 2014 through 2019, the period after which BPA expects the rebound from the recession to be ended. The stable period shows a lower growth rate than the overall forecast period. The stable average annual growth rates are lower than or nearly equal to the historical growth rates due to the shifting regional economy and the underlying mixture of energy-intensive industries and changing mixture of appliances and appliance and building efficiency changes over time.

Table C.3 shows annual percentage load growth or load loss for categories of load in the PNW from 2009 through 2019 and historical data for the same categories from 1999 through 2008.

Table C.3 – Average annual growth rate in PNW load forecast and historical data

	Total PNW Retail Load	**IOUs**	**BPA Load Following Entities**	**BPA Non-Load Following Entities**
Historical or stable period average annual growth rate 1999-2008	1.9%	1.3%	2.6%	0.9%
Stable period average annual growth rate 2014- 2019	1.3%	1.4%	1.5%	1.1%

C.2 BPA's Obligation Forecasts

BPA's load forecasts described above are used as the basis for BPA's obligation forecast. For those customers for whom BPA has contracted to follow their load, customer-owned generation and/or contract power purchases are subtracted from their total retail load forecast to produce an obligation forecast. For the customers with Slice/Block and Block contracts, BPA's sales obligations are those designated by contract; for these customers, their total retail load is subtracted and the contractual obligation is added in. For those utilities that have not entered into a contract with BPA to provide energy, none of the load is included in the forecast of BPA obligation.

BPA's obligation forecast is an input to the Needs Assessment, which compares the agency's obligations to its existing resources to determine need for resource additions, if any. For this obligations forecast, BPA made the simplifying assumption that it will serve customers' above-High Water Mark load under the new Regional Dialogue contracts in similar proportions in future years as in the first commitment period, for which customers have already made elections.

C.2.1 Customer Resource Forecasts

Customers have contractually dedicated resources or have entered into contractual arrangements to supply some of their total retail load. Quantities of the energy produced by the resources listed in the contracts were subtracted from the utilities' forecasted total retail load. Hourly output for each resource was determined by using the resource type stated in the contract and the monthly quantity of energy that the resource is contractually obligated to provide. Hourly shapes were applied to the expected monthly delivery based on the metered information for that resource or a resource with similar operating characteristics.

C.2.2 Contractually Designated Obligation Forecasts

To reflect the Regional Dialogue contracts, which will take effect October 1, 2011, the Slice forecast after FY 2011 has been updated to be 27.027 percent of the Slice resource stack, and the list of customers with an effective Slice contract has been updated. The Slice resource stack, used only for the Slice product, is comprised of a set of specific Federal resources and contract purchases, net of a specific set of Federal obligations. The Block energy obligations were also updated to the new contractual levels. Hourly quantities were determined by the type of contract. For the customers with a Block quantity identified in the contract, BPA's obligation is a flat load amount for all hours of the Block period identified in the contract. For customers with a Slice contract, the hourly values are determined by the hourly shape of the BPA system and the customer's contractual percentage of the system load.

BPA offered the Port Townsend Paper Corporation a 17 aMW surplus power sales contract; the current obligation forecast includes this 17 aMW load in the forecast for the DSIs in the PNW for the length of the contract (i.e., until September 2011). As noted in Chapter 4, Service to Alcoa's Intalco smelter at 320 megawatts is included in the analysis for 2013 because BPA has a signed contract for such service, contingent on the outcome of litigation regarding DSI service.

BPA provides Federal power to customers under a variety of contract arrangements not included in the load obligation forecasts described above. These contracts are categorized as power sales, power or energy exchanges, capacity sales or capacity-for-energy exchanges, power payments for services, and power commitments under the Columbia River Treaty. These arrangements are collectively called "Other Contract Obligations," and each can have a different structure. These firm obligations are set by individual contracts and are included in the obligation forecast.

C.2.3 Loss Adjustment

The load forecast is at the level of delivery that BPA provides. For several utility customers, this energy delivery includes the distribution losses within the customer's system to deliver the energy to the final consumers. This forecast was increased to reflect the amount of energy required to be produced, to result in the amount of power forecasted at the customers' meters or across the necessary transmission systems, for use as the final BPA obligation forecast in the Resource Program.

C.2.4 Results

Table C.4 shows the resulting forecast for the obligation placed upon BPA for Power requirements from 2009 through 2019 and historical data for the same categories from 2002 through 2008 in average megawatts. Actual data comes from meter readings available to BPA.

Table C.4 – BPA obligation forecast and historical data

Calendar Year	aMW
2002 A	8755
2003 A	8792
2004 A	8578
2005 A	8535
2006 A	8868
2007 A	8385
2008 A	8464
2009 E	8287
2010 F	8316
2011 F	8479
2012 F	8444
2013 F	8517
2014 F	8512
2015 F	8601
2016 F	8615
2017 F	8440
2018 F	8432
2019 F	8505
Average annual growth rate 2002-2008	-0.6%
Average annual growth rate 2009-2019	0.3%

Note:
A after the year means Actual data.
F after the year means Forecast data.

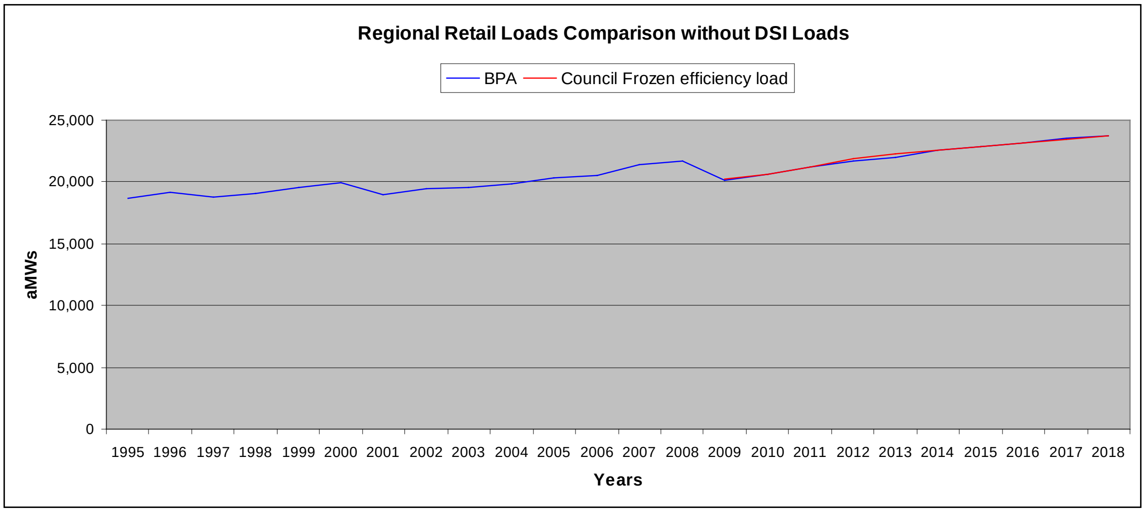
Table C.4 also shows the historical average annual growth rates from 2002 through 2008 for comparative purposes with the forecasted values from 2009 through 2019. As can be seen from the table forecasted growth rates are expected to increase, whereas past growth has decreased. This is due to expected growth in consumer electricity demands in customers' service territories that BPA has a contractual obligation to meet. It is also impacted by the customers' choices of contract type in the future. As customers choose the Load Following contract option or the Slice/Block option it changes the obligation that BPA has had from past trends.

C.3 Comparison with the Council Forecast

BPA's load forecast for the Region for the Resource Program is similar to the most recent load forecast from the Council's Sixth Power Plan. Although there are methodological differences in the formulation of the two forecasts, both yield comparable rates of load growth. A load forecast is fundamentally an estimate of future outcomes, and it is not unreasonable to have two forecasts where the numbers are not exactly the same. Council and BPA staffs have discussed the two forecasts and have an understanding of the differences that occur when the unit of analysis is an end-use sector rather than a customer. There is a need for BPA analysts to further discuss and review the Council forecasts. It has been difficult to match all aspects of the Council's forecasting activities with the Resource Program forecast developed at BPA to ensure that similar products are being compared. Results thus far are similar enough using different methods to provide some assurance that neither method is fundamentally flawed. However, for making regional decisions, such differences need to be further defined and eliminated.

Difficulties of comparison are further increased by the level of forecast development by the Council and BPA. The Council has details at the state level, while BPA does not. As this activity matures, fundamental comparison points must be established. Figure C.2 shows the BPA forecast and the Council's forecast. The graph shows that the two forecasts are very similar. There is some difference of interpretation regarding when the economic return will be completed, but once completed, the forecasts are quite similar. Figure C.2 includes the Council's frozen efficiency forecast and the BPA forecast adjusted to include the future conservation codes and standards used by the Council in preparing its forecast. For the stable period after the recovery from the current recession, the Council's forecast has an average annual growth rate of 1.2 percent, compared to 1.3 percent for the BPA forecast.

Figure C.2 - Comparison of BPA load forecast with Council forecast



BPA has recently acquired the Energy 2020 model and is in the process of making it a completely functional energy forecasting tool. Before implementing the energy forecasting capabilities of Energy 2020 BPA wants to make sure that it easily allows comparability and compatibility with the summary of the numerous individual utilities in the region. After Energy 2020 is reviewed and becomes completely functional it will be a valuable tool in the ensemble of energy forecasting tools BPA has available. Energy 2020 will also allow a more direct comparison with future Council forecasts.

C.4 Risk Factors

The use of historical trend variables in BPA's customer-level models may not fully account for the current economic recession—over the next year, the load forecast could be overly optimistic given normal weather. However, extreme winter or summer weather could contribute to heating and cooling load levels that compensate for some of the current recessionary impacts. Because of the assumption of normal weather, the load forecast is considered to be a 1 in 2 forecast, with a 50 percent level of probability in any given year.

Additionally, with the method used by BPA, there may be changes to the assumption that past trends will continue into the future, and rapid shifts can occur. This risk factor is compensated for by the frequency of updates done to the forecast. Regular updates make sure that as trends unfold, they will be included in the forecasting process. This result is possible even before the trend and its cause are identified. Trends in air conditioning penetration in the Northwest indicate that more consumers are choosing to install air conditioning. Our models currently do not explicitly model this changing trend, creating additional uncertainty about peak growth over time. With enough penetration of air conditioning summer peaks will grow differently from winter peaks, and this change does need to be considered in planning for the future. Model improvements have been underway for months to address this change and will be included in future updates. Other major uncertainties, such as economic cycles or the loss of major industrial sectors, are not covered in the base line forecast described above. The analytic process used by BPA to cover these possibilities is done through scenarios analysis identified in this work.

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APPENDIX D. NEEDS ASSESSMENT

D.1 Summary

The Needs Assessment seeks to match the forecast generation output of Federal system resources with forecast system load, measuring the resulting surpluses and deficits, if any. The studies take advantage of the hydro system flexibility that is routinely available. They do not include extra releases of water from headwater projects (except for permissible additional draft at Grand Coulee Dam (GCL) during heat/cold events), and do include planned and forced outages. These studies provide results by month as well as by time of day (Heavy Load Hours (HLH) and Light Load Hours (LLH)).

The Needs Assessment identified shortfalls in both energy and capacity under certain hydro conditions in 2013 and 2019. Additionally, under certain water conditions, the inventory model was unable to hold the required level of downward regulating/load following reserve margin (*dec* reserve) required to manage the wind resources projected beyond 2014.

The annual energy metric indicates a need to acquire energy to keep the system in balance. Furthermore, deficits against the HLH and superpeak metrics specify that the energy BPA acquires must have a reliable HLH capacity.

The energy and capacity metrics do not specify whether the acquisition needs to be dispatchable. However, the Hydrologic Simulator Model (HYDSIM) and Hourly Operating and Scheduling Simulator (HOSS) model fail to meet the downward regulation *(dec)* reserve requirements above those required in 2014 under certain water conditions. This failure indicates that BPA would need to acquire a dispatchable resource to help provide *dec* reserves unless the reserve requirement changes further.

The Needs Assessment for 2013 demonstrates a need for 350 aMW of annual energy to meet load in 2013. This shortfall is seasonally shaped such that it requires about 700 MW in the winter HLH; 1,000 MW in the late summer HLH; 1,000 aMW winter and late summer energy (not just HLH); and smaller amounts for the rest of the year. See Table D.1. Under average water conditions, there would be surpluses in almost all months and on an annual average basis.

The Needs Assessment for 2019 indicates a need for 400 aMW of annual energy to meet load in 2019. Because several contracts, both purchases and sales, end between 2013 and 2019, there is not a simple increase in the annual deficit attributable to load growth. The shape of the shortfall in 2019 requires about 1,000 MW in the Heavy Load Hours in late summer and winter and smaller amounts for the rest of the year. See Table D.1; note that additional load not yet under contract, such as service to direct-service industrial customers (DSIs) (discussed below), could increase deficits around 200 MW for 2013 and 550 MW for 2019. Under average water conditions, instead of the deficits noted in Table D.1, there would be surpluses in almost all months and on an annual average basis.

Table D.1 – BPA's need to acquire resources

Need Type	2013	2019
Annual Energy Deficit (critical water)	350 a MW	400 aMW
Seasonal/monthly: (10^{th} percentile by month)	Winter: HLH deficits around 700 MW and all-hour energy deficits around 1,000 MW Summer: HLH deficits around 1,000 MW and all-hour deficits at 900 MW in second half of August	Winter: HLH deficits of almost 1,000 MW and all-hour energy deficits around 1,100 MW Summer: HLH deficits just under 1,000 MW and all-hour deficits at 750 MW in second half of August
Superpeak or 120-hour Sustained Peaking (10^{th} percentile by month)	Not as large as HLH deficits	Not as large as HLH deficits
18-hour Capacity (1 in 10 year cold snap or heat spell)	Winter: Surplus (unless load is much bigger from load uncertainty and new load) Summer: Essentially load/resource balance with current load	Winter: Slightly smaller surplus compared to FY 2013 Summer: Similar to FY 2013
Ancillary Services for Reserves[1]	Adequate with 30-minute persistence accuracy wind forecasts (but other analyses suggest possible need before 2014)	System is unable to supply additional reserves beyond those required in 2014; exact need is evolving as region is learning to integrate wind

Additionally, the Needs Assessment found that BPA is not able to meet the full reserve requirements for wind integration under certain water conditions. At the reserve requirement for 30-minute persistence accuracy wind forecast scheduling, the system could supply almost the full reserves for FY 2014. The 30-minute persistence study assumed that reserves are needed for the mid-range forecast of 7,322 MW of wind power expected in BPA's balancing authority by the end of FY 2014. As stated in the Resource Program, there is considerable uncertainty around the rate of wind power development. The need for flexibility would indicate that acquired resources to meet the load in the longer term should include a dispatchable generator with dependable capacity and the ability to load factor to help address the reserve issue unless the reserve requirement on the FCRPS is reduced.

[1] Studies are ongoing to look closer at high and low flow scenarios with larger wind fleets with a goal of providing a definitive assessment of the ability of the FCRPS to integrate wind.

The HYDSIM and HOSS studies presented in the Needs Assessment are not the most rigorous measure of system ability to flexibly deploy water to produce ancillary services—that will be examined through studies using the Columbia Vista model. However, the HYDSIM and HOSS studies did show that the system was not quite able to accommodate all of the *dec* reserves associated with integrating variable wind generation in FY 2014 at the requirements for 30-minute persistence accuracy wind forecasts. Not being able to provide the full reserve requirement implies that the system did not have enough flow to generate minimum turbine flow plus the flow needed for the *dec* reserves on a monthly basis. *Dec* reserves require that the system operate above minimum flows, so that when the *dec* reserves are called upon, the system can reduce generation and still be above minimum flow and generation requirements.

Inc requirements require the system to generate below capacity in order to leave room for the system to increase generation if use of generating reserves is required. The HYDSIM/HOSS studies were able to accommodate the full *inc* requirement in FY 2014. The Needs Assessment did not evaluate the ability of the system to increase *inc* reserves beyond the 2014 level, the point at which the system was no longer able to meet the *dec* reserves.

Low flows in April 2010 and high flows in June 2010 have made it clear that events can stress the hydro system to the brink with the current wind fleet. Studies are ongoing to look more closely at high and low flow scenarios with larger wind fleets with a goal of providing a definitive assessment of the ability of the FCRPS to integrate wind. However, the general results of the HYDSIM and HOSS models are consistent with actual experiences in showing an impending need for reserves or a reduction in the reserve requirement. Both models show increased spill, primarily under wet conditions, and the shifting of generation from HLH to LLH.

D.2 Background

D.2.1 Load Uncertainty

The load forecasts have an intrinsic uncertainty. For expected weather conditions in 2013, the uncertainty is around ±250 MW. For extreme weather conditions, there is the added uncertainty of how the load will react to temperature swings. BPA has seen a wide range of responses to temperature. Therefore, for extreme temperatures, the combination of intrinsic load uncertainty and uncertainty about the temperature effect yields a total uncertainty for extreme-temperature loads of 1000 MW.

In addition to these load-forecasting uncertainties, BPA faces uncertainties in load contracts. In FY 2012, BPA begins a new set of contractual obligations under its Regional Dialogue contracts. All 135 BPA publicly owned utility customers signed these contracts in 2008. The contracts give these customers the choice of purchasing Federal power from the existing Federal Base System (the Federal Columbia River Power System, including the Columbia Generating Station nuclear plant and non-Federal augmentation purchases) in amounts up to their High Water Marks (HWM), roughly comparable to their existing BPA power purchases. Customers may buy this power at Tier 1 rates, which will reflect the costs of the Tier 1 System, made up for the most part of costs of the Federal Base System.

Customers may also choose to purchase additional power from BPA, above their High Water Marks, at Tier 2 rates. Tier 2 rates will reflect the cost of power acquired to meet those requests. The amount of power customers may choose to purchase from BPA at Tier 2 rates is a significant uncertainty in BPA's future supply obligations. Customers may choose to place all, a portion, or none of their above-HWM load on BPA. Those that do not place all above-HWM load on BPA may choose Resource Support Services (RSS) to firm and shape their non-Federal resources. Currently, customers have made their elections for their above-HWM load in FY 2012-FY 2014. These choices lock in portions of the above-HWM load for the duration of the Regional Dialogue contracts, but there remains some flexibility in their allocations for part of the above-HWM load. The forecast for this Needs Assessment assumes that customers will make future elections similar to those of the first election period.

The Needs Assessment does not address the uncertainty in other areas. Specifically, the Needs Assessment does not consider service to additional BPA DSIs beyond the existing contracts, service to new public utilities that would have a right to power from BPA at Tier 1 rates under Regional Dialogue contracts, possible additional load from DOE-Richland, and faster economic growth. While all of these uncertainties may materialize together and to the full extent, some are more likely than others. BPA estimates that the high-load scenario for FY 2013 would add about 200 MW to BPA's load obligation, and in FY 2019 the high load scenario increases load by about 550 MW.

D.2.2 Capacity Issues

Historically, ensuring resource adequacy for the BPA system has focused on energy, because the FCRPS hydro-based power system is energy limited. The recent highest one-hour peak load on the BPA system was near 16,000 MW. Given 22,000 MW of installed hydro capacity plus the 1,120 MW of CGS and access to energy in the commercial power market, even with projected planned and forced outages the FCRPS has been adequate to meet peak load. The primary source of uncertainty has been the volume and timing of streamflows to create energy to meet the load.

Faced with steady load growth, the need for significantly higher levels of operating reserves, and significant changes to the operation of the Federal hydro system, BPA's planning focus has begun to shift from energy to capacity. For instance, in 1994 the Pacific Northwest Utilities Conference Committee (PNUCC) made a first step toward capacity planning when it inventoried the capacity planning practices in the Northwest Region.[2] In that publication, BPA was shown as planning to meet the load created by normal weather conditions during winter months over a 50-hour sustained peak, assuming existing resources with critical streamflow levels. This is in contrast to several

[2] *Capacity Planning: An Inventory;* Pacific Northwest Utilities Conference Committee, January 1994.

other Northwest utilities that judged their capacity sufficiency against a one-hour peak load.

Over the 16 years since the PNUCC study, load has continued to increase, and hydro operations are increasingly constrained by non-power water uses. In particular:

- Regional peak loads are growing relative to energy loads, and summer peak demand is increasing relative to winter.
- Biological Opinion (BiOp) fish operations requirements under the Endangered Species Act to mitigate the impact of operations on listed salmon and steelhead have further degraded the hydro system's annual average capability, limited the use of the FCRPS to meet winter loads, and imposed seasonal reservoir operations and spill requirements that impact system capability.
- Rapid growth of new non-dispatchable resources such as wind interconnecting to the BPA balancing authority area has created significant new operating reserve obligations.
- The hydro system is aging, creating an increased need for extended planned maintenance outages of generating resources.

Fish operations are mandatory obligations. They are treated as firm obligations in the Needs Assessment. BPA plans its hydropower capabilities and operations based on the power available after these obligations are reliably met. The Needs Assessment does not address potential emergency exceptions to fish operations for public health and safety, flood control requirements, water withdrawal rates to avoid stream-bank sloughing, or other firm operational requirements.

The recently executed Regional Dialogue contracts may create new capacity obligations in support of customer resources through Resource Support Services. BPA has committed to provide RSS to customers with Specified Resources dedicated to serve their Total Retail Load. RSS are tailored to each specific resource and provide a financial leveling of the variable generation of a resource. RSS include diurnal flattening services, secondary crediting service, forced outage reserves, and others. BPA's supplying of RSS will not exceed the annual energy requirements needed to serve all above-HWM load. This limitation arises because RSS rely on capacity to shape a customer's non-Federal resources; by definition, RSS do not place more load on BPA than would serving all customers' above-HWM load. Based on customer choices during the first election period, RSS are a very small obligation.

D.3 General Approach

The Needs Assessment examines energy, capacity, and ancillary services. BPA has significant experience, expertise, and models designed to focus on energy assessments. Accomplishing the capacity and ancillary services components required developing new methods and standardizing definitions.

When discussing this task with other parties, BPA found that examining hydro system capacity is more complex than assessing thermal system capacity. Unlike hydro systems, thermal systems typically do not have a single stochastic fuel supply that may randomly limit the system capability to produce power across HLH periods seasonally or hourly. The Federal hydro system has that kind of variability.

In April 2007, BPA established a capacity metric for measuring the capability of FCRPS hydro to meet peak loads. The capacity metric was defined as the average of the inventory on the six highest load hours during weekdays limited by any hour in the period when maximum generation is approached, assuming the maximal amount of generation is shaped into these hours. For long-term studies, BPA has been using this metric with the 6 highest hours over 3 consecutive days of a heat or cold event (18 hours total). Over time, BPA will continue to test and refine the capacity metric so that the FCRPS capability can be appropriately measured.

In addition to the focus on energy and capacity to meet load under various monthly and hourly conditions, there is a fundamental question of whether or not the combined generators of the FCRPS have enough flexibility, given their various physical or mandated operational limitations, to meet all of the system's operating reserve and load demands. The Needs Assessment emphasizes energy and capacity and makes only preliminary inferences about the ability of the FCRPS to supply reserves.

The Needs Assessment examined conditions for FY 2013 and FY 2019. During both of these years, CGS is scheduled for a refueling outage; therefore, they represent years with slightly less energy than other years. This choice was deliberate to ensure covering the needs of these years. Because of the time required to complete a study, coupled with other workload priorities, the Needs Assessment was limited to two study years, one early and one late in the Resource Program study period.

D.3.1 Foundational Assumptions

In designing this assessment, the following assumptions were fundamental:

1. **Reliance on energy supply from the open commercial market.** On one hand, expecting no opportunity to acquire energy on the open market seems too constrained, because that is generally not BPA's experience. On the other hand, counting on the ability to buy energy on any particular hour to meet load, particularly during extreme temperature events, would be like assuming there is free capacity for BPA to access during times of duress. The Needs Assessment examines the total need to acquire energy and capacity, leaving to later steps in the Resource Program the analysis of how much of that need could be filled by long-term acquisitions and how much could be left for shorter-term marketing.
2. **Water conditions assumed in the Needs Assessment.** Agency analyses have ranged from average to critical period water, as well as presenting the

full spectrum of 70 years of water conditions.[3] For energy studies, a set of 70 water years was used to show the range of possible outcomes. The annual energy analysis focused on critical water. The HLH analysis examined the 10th percentile (P10) conditions by month. This percentile is roughly comparable to the 5th percentile (P5) by season (winter, late summer).

The definition of FCRPS hydro system for 18-hour capacity assumes average hydro generation and 10th percentile loads to create a roughly 5th percentile combined event for purposes of capacity adequacy evaluation. Choosing this probability range for a capacity-stressed event seems appropriate, because BPA's firm power contracts, which establish its loads, are predicated on critical water supply, and critical water is approximately 5th to 10th percentile probability water supply as an annual average.

3. **Load conditions.** The Needs Assessment used a variety of loads for various analyses, similar to what was described above for water conditions. The annual energy and HLH assessment used expected loads and dry water conditions. For the 18-hour capacity assessment, the results are dependent more on load than on water conditions (because the system can still shape water reasonably well over a few days). Therefore, the 18-hour capacity assessment used median water conditions paired with the loads one would expect for an extreme weather event, namely for a 1 in 10 year cold spell or heat wave.
4. **Above-High Water Mark Load Placement.** Customers have made their elections for their above-HWM load in FY 2012-FY 2014. These choices lock in portions of the above-HWM load for the duration of the Regional Dialogue contracts, but there remains some flexibility in their allocations for part of the above-HWM load. The forecast for the Needs Assessment assumes that customers will make future elections similar to those of the first election period

D.3.2 Further Assumptions

The inputs for this study were finalized in spring of 2010, roughly in parallel with the inputs for the 2010 White Book and the preliminary T1SFCO study for the BP-12 rate case initial proposal.

D.3.2.1 Loads

Appendix C describes the total supply obligation forecast. Briefly, the total supply obligation forecast for the Needs Assessment updated the Slice forecast after 2011 to include 27.027 percent of the system and changed the list of customers that are participating in Slice after 2011 based on customer decisions in signing Regional Dialogue contracts.

[3] Water years 1929-1998, i.e., August 1928-July 1998.

The load forecast did not include DSI load beyond the current contracts (which may include 320 MW service to Alcoa in 2013), load to potential new public utilities, or potential additional load to DOE-Richland.

The capacity assessment for the Needs Assessment required forecast loads, resources, and obligations on an hourly basis for the years covered by the Resource Program, namely out to 2019. This had never been done before BPA subject-matter experts created the first *hourly* forecast of loads, resources, and obligations for multiple future years using long-term load forecasting techniques for the Preliminary Needs Assessment in 2008-2009.

The capacity studies are weekly studies that measure the capacity inventory over the 6 peak load hours for 3 days (18 hours) using the median hydro generation with loads that are predicted for extreme temperature events. For this purpose, net requirements were increased using temperature adders provided by BPA Load Forecasting and Analysis staff. The Canadian Entitlement delivery was assumed at the maximum contractual limit. The temperature adders were based on a 1 in 10 year occurrence over 3 consecutive days. Even without this added extreme, there is a large uncertainty in the load for any given hour. Working with load data in the past, BPA has seen a 300-500 megawatt change in load when controlling for conditions that typically explain the variability. With the uncertainty of the weather impacts, this range would be greater, on the order of 1000 MW for FY 2013. This uncertainty is very large, and BPA plans to examine this issue further. Meanwhile, it is important to keep in mind that when the 18-hour capacity metric for extreme temperature conditions falls below 1000 MW surplus, it may be prudent to plan more conservatively.

On the generation side, Federal wind generation was reduced to 0 percent of the Federal share of nameplate capacity, based on extensive analysis of historical wind generation during extreme temperature events. The residual hydro load for the winter and summer extreme temperature events served as inputs to HOSS for capacity analyses for February (cold) and the first half of August (August I) (heat) events.

System losses were set at 2.82 percent for normal weather and 3.59 percent for extreme weather.

D.3.2.2 Resources

The FCRPS hydro system was constrained according to the May 2008 BiOp filing, the same as in the WP-10 rate case, with the current (spring 2010) interpretation of BiOp implementation. Under this assumption, spill on the lower Snake River usually ends by mid-August, and this timing was modeled. However, in some years, fish counts by mid-August do not drop below the point at which spill would end, and thus the lower Snake River projects could continue spilling throughout August, resulting in a reduction of about 400 MW of generation during this period.

For FY 2013, this analysis included 300 MW of Heavy Load Hour balancing purchases from November-April and 58 MW of annual purchases that extend through FY 2013.

The hydro project resources include planned runner replacements at Chief Joseph and Grand Coulee Dams.

D.3.2.3 Reserve Requirements

Contingency reserves are based on peak control area generation by month, currently 5 percent hydro and 7 percent thermal, but the Needs Assessment used 3 percent of generation and 3 percent of load, as this standard is currently under consideration for the future. BPA is a member of the Northwest Power Pool (NWPP); BPA's obligation is generally equal to 80 percent of the NWPP's reserve obligation.

Regulation, Load Following, and Generation Imbalance levels were based on a regional wind fleet of 6,120 MW by the end of FY 2013, with 30-minute persistence scheduling accuracy.

- ***Inc* = 1,390 MW** by the end of FY 2013.
- ***Dec* = 1,827 MW** by the end of FY 2013.

For 2019, the reserve requirement was capped at the level for the end of FY 2014 (1,564 MW *inc* and 2,063 MW *dec)*. Wind generation is expected to continue growing beyond 2014 levels, but in the models for the Needs Assessment, the FCRPS cannot produce those additional reserves. Thus BPA will need to acquire reserves, count on non-Federal sources of reserves, and/or promote additional developments that reduce the amount of required reserves. The results section discusses reserves further.

The HOSS model does not include the effect of deployment on water management and slight reduction in efficiency from deploying these reserves.

Table D.2 shows balancing reserve requirements: the projected size of the wind fleet, the associated reserve requirement at 30-minute persistence accuracy forecasts, and the amount of reserves included in the Needs Assessment. It should be noted that the model was not able to accommodate reserves past those identified for 2014 with the 30-minute reserves. Low flows in April 2010 and high flows in June 2010 have made it clear that events can stress the hydro system to the brink with the current wind fleet. Studies are ongoing to examine more closely high and low flow scenarios with larger wind fleets with a goal of providing a definitive assessment of the ability of the FCRPS to integrate wind. Further efforts by the WIT and region should help reduce the reserve requirement as well.

Table D.2 – Balancing reserve requirements

	2013	2019
Wind Fleet Nameplate (MW)	5022 growing to 6122[4]	
Inc (MW) modeled	1230 growing to 1390	1564
Dec (MW) modeled	-1612 growing to -1827	-2063

Input Summary:

The Annual Energy, HLH, and 120-hour Superpeak Assessment:

- Used expected loads.
- Used 70 water years and recent T1SFCO hydroregulation.
- Used stochastic variability in CGS performance and load variability.

The 18-hour Capacity Assessment:

- Used loads expected for a 1 in 10 year heat or cold event.
- Used the median hydro generation year (median based on water and unit availability).
- Allowed Grand Coulee to draft up to 1.9 ft/day in summer (normal draft limit in the model is 1.37 ft/day).
- Did not use extra water from Canadian projects or Dworshak Dam for capacity on a planning basis, even though in an emergency BPA could request more water.
- Modeled BPA's wind generation at 0 percent of nameplate capacity, as a result of extensive analysis of historical wind data.

D.3.3 Analysis Methodology

After the hourly net obligation forecast was assembled (all loads and obligations minus any resources serving that load other than the major Federal hydro projects), the load was input into the HYDSIM model to obtain monthly hydroregulation runs. From there, the analysis moved to an hourly model, HOSS, to perform two sets of runs:

[4] Wind development continues through the year, and thus the reserve requirement increases from the beginning to the end of the year.

1. Annual energy, seasonal or monthly energy and Heavy Load Hour, and superpeak (120-hour sustained peaking) for 70 water years, with a focus on dry years.
2. 18-hour capacity (6 hours/day for 3 days) for extreme temperature events.

The first set of HOSS studies used expected load conditions with 70 water years to analyze the surplus/deficit position with respect to annual energy, seasonal or monthly energy and HLH, and 120-hour superpeak.[5] This study used expected loads and focused on the variability of the hydro energy supply to meet load.

The metric adopted for the Resource Program for the Heavy Load Hours is seasonal surplus/deficit at the 5th percentile (P5). The model produces results for 14 periods—10 complete months plus April and August split into 2 half-months.[6] An in-depth statistical analysis by BPA's Risk group using the results of the Preliminary Needs Assessment showed that the 10th percentile (P10) monthly results were roughly equivalent to the P5 results by season for winter and late summer. If each month were perfectly correlated, one would expect that P10 by month would equate to P10 by season. If the months were not correlated at all, one would expect that P10 by month would equate to a probability of 0.1 percent per season. Not surprisingly, the winter months, December, January, and February, are somewhat correlated, and thus the monthly P10 results correspond to about P5 for the winter season. Similarly, using P10 by month (period) for late summer (August I, August II, and September) yields about a P5 measure for the late summer. P10 for each month is independently and statistically selected from combinations of water supply, generator availability, and some stochastic load fluctuations.

In performing this analysis, the HOSS study incorporated the requirement to carry reserves, both *inc* and *dec* reserves, that require the generation to be able to increase or decrease as load or variable generation fluctuates. Because the reserve requirement increases through the years, there came a point when the model indicated that the system could not supply any more reserves. Thus, these HOSS studies give a rough indication of the need to acquire additional reserves (unless new procedures or technologies reduce the reserve requirement).

The second set of HOSS studies was an assessment of the "18-hour capacity" for roughly 1 in 10 year extreme temperature events. This 18-hour metric is a measure of the system's ability to meet extreme load events not encountered every year. Meeting these events is a critical measure of system reliability. However, if the hydro system is flexed to meet such an extreme temperature event, it would involve borrowing a significant

[5] The term 'superpeak' is used in the Needs Assessment for the same metric as the '120-hour sustained peaking capacity' term used in the BPA White Book up to now. It is a measure of the system's ability to meet the peaks day after day throughout the month. (6 hours/day x 5 days/week x 4 weeks/ month = 120 hours.) The Council's Resource Adequacy Assessment uses the term "sustained peaking" for an 18-hour capacity assessment; therefore, the Needs Assessment uses the term 120-hour superpeak to reduce (if not eliminate) confusion.

[6] For intuitive simplicity, this chapter will use the term "monthly" in referring to the HOSS outputs even though the results include 14 periods, including two half-month periods in each of August and April.

amount of water from other days and weeks. Thus, it is a good measure of reliability under duress, but it does not measure the ability of the system to meet peak events beyond 3 days. Therefore, the 120-hour superpeak and Heavy Load Hour assessments (discussed above) were also performed.

D.3.4 Uncertainties/Risks

A number of assumptions made in these studies embody risks and uncertainties. Two major uncertainties involve customer choices and contract decisions:

- The Needs Assessment assumes that customers will make elections for above-HWM load beyond 2014 similar to their choices for the first election period, for FY 2012-2014.
- BPA may serve load to additional DSIs beyond the current contracts (320 MW in FY 2013), new public utilities, and increased load to DOE-Richland. These options create significant load uncertainty for BPA.

Table D.3 describes a number of contractual options that may increase load service for BPA. In addition, there is uncertainty in the load growth, as discussed in the previous chapter. While all of these uncertainties may materialize together and to the full extent, some are more likely than others. BPA estimates that the high load scenario for FY 2013 adds about 200 MW to BPA's load obligation, and in FY 2019 the high load scenario increases load by about 550 MW. Conversely, load growth may be smaller, and pending the outcome of legal review, BPA may not serve load for Alcoa in 2013. Therefore, the load obligation for BPA may be smaller. Table D.4 presents estimates of load increases and decreases for high and low load scenarios.

Table D.3 – Uncertain BPA loads (MW)*

	2013	**2019**
DSI load	160	480
New publics	38	200
DOE-Richland	5	70
Total contractual load uncertainty	203	750

*Based on BPA's expected load forecast; does not reflect load growth uncertainty

Table D.4 – Uncertain BPA loads including both contractual uncertainty and load growth uncertainty (MW)

	2013	**2019**
Load increase	200	550
Load decrease	-350	-80

Additional uncertainties besides contractual load uncertainties lie more in the realm of forecasting, wind-integration developments, and stochastic conditions:

- If the recession proves to be deeper and/or longer than forecast as of spring 2010, net requirements might be less.
- If additional conservation is achieved at the level specified in the Council's Sixth Power Plan (rather than the historical levels based on the Fifth Power Plan, on which the load forecast is based), then deficits could be smaller.
- Deficits could be bigger if generating capacity is lost. The capacity assessment assumed full CGS generation during the extreme temperature events. The energy assessment "gamed" CGS outages. A prolonged CGS outage is very rare, so it is in the low-probability tail—low probability but high risk.
- If the reserve requirements are reduced significantly, then more water and generation may be available in Heavy Load Hours, reducing the deficit in Heavy Load Hours while increasing deficits in Light Load Hours.
- The load uncertainty for annual energy and HLH seasonal energy is about 250 MW. If the loads are indeed higher, then the deficits could be greater.
- In the capacity analysis, there is some uncertainty in the effect of extreme temperature on the loads. Because of a difference between historical and current load composition (less DSI, more residential/commercial), the level of confidence in the temperature effect on loads is relatively low. The combination of forecast error and the possibility of larger temperature-effects on load yields a 1,000 megawatt load uncertainty. There is an intrinsically large volatility of the effect of temperature on load. The study uses about a 900-MW temperature effect for winter peak and 800-MW for summer. If the extreme-temperature loads are indeed larger by about 1,000 MW, then there could well be a capacity deficit in the summer in both 2013 and 2019.
- Another uncertainty involves fish and other non-power constraints. Changes in operating requirements may reduce the amount of energy the system can produce and/or reduce the flexibility of the system. We modeled the BiOp as filed in May 2008, which includes ending spill on the lower Snake River in early August when fish passage tapers off in most years. If this operation changes, the deficits in the second half of August will be even larger.
- The models have limitations. For example, modeling the full operating characteristics of reserves has not been a big concern in the past, and up to now it has been modeled as reductions in unit availability (for *inc* only). As the need for spinning reserves increases, not every model can capture them completely. This is one of the reasons BPA is using multiple models to mitigate the risks of not capturing the full impact of reserves. However, one must remember that these analyses are treading in uncharted territory and may be missing something.
- Water conditions could turn out to be anywhere over the wide range of possible streamflows. The Heavy Load Hour results, for example, address the 10th percentile of generation conditions, but the tail events with extremely dry years could have deficits that may be 1,000 MW larger.

D.4 Results

D.4.1 Annual Average Energy

The Pacific Northwest has traditionally planned to critical water conditions, and so the Needs Assessment does the same. Table D.5 summarizes the expected deficits in FY 2013 and FY 2019 under critical water conditions.

Table D.5 – Annual Average Energy Deficit (aMW) under critical water conditions

Fiscal Year	2013	2019
Deficit	-350	-400
Low load scenario deficit	0	-300
High load scenario deficit	-550	-950
Surplus in average generation year	1200	1150

Additional load for service to DSIs, new public utilities, DOE-Richland, and higher load growth may increase the deficits by about 200 MW in 2013 and 550 MW in 2019. Termination of service under the Alcoa DSI contract and additional conservation (addressed in Resource Program section 4.7.3) could reduce these deficits by about 350 MW in 2013 and 80 MW in 2019. Additionally, in better water years, BPA is surplus. The last line in Table D.5 shows generation under average conditions (average being a combination of water, load fluctuations, and outages).

D.4.2 Heavy Load Hour Seasonal and Monthly Assessment

As discussed earlier, the region is recognizing that annual energy planning is no longer sufficient by itself for ensuring an adequate power supply for the future. Therefore, the Resource Program adopted additional metrics, with seasonal Heavy Load Hours being the next finer timescale. As discussed earlier, the official metric is seasonal Heavy Load Hours at the 5th percentile (P5), but monthly Heavy Load Hours at the 10th percentile (P10) is a close proxy. Thus, Table D.6 shows deficits for 2013 at the 10th percentile. Results are for HLH, superpeak, all-hour average, and LLH.

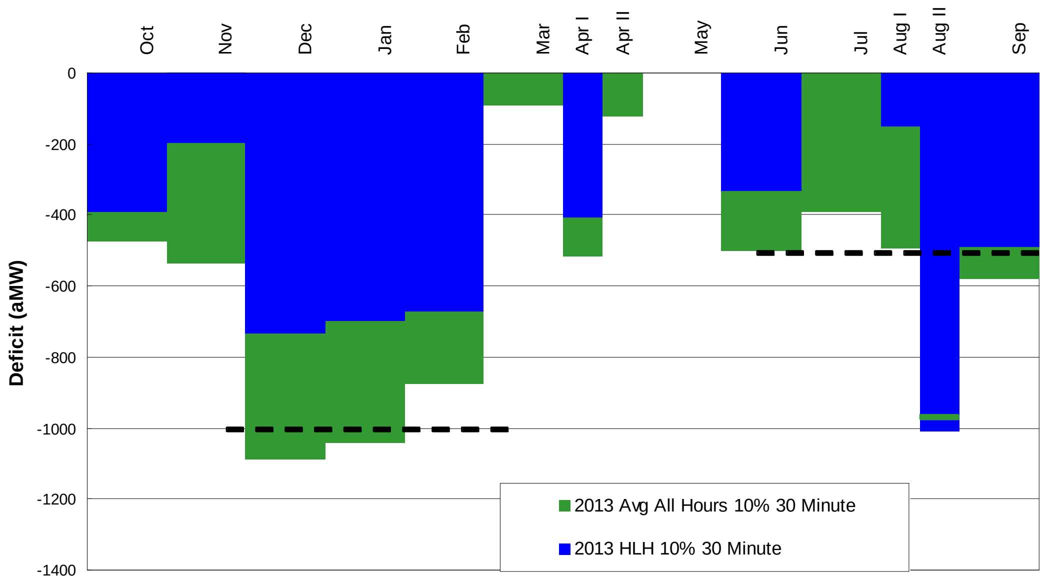
Table D.6 – Modeled monthly or period deficits for 2013 at the 10th percentile

	HLH	Spk	Avg	LLH
October	-400	-150	-450	-600
November	-200	300	-550	-1000
December	-750	-100	-1100	-1550
January	-700	-150	-1050	-1500
February	-650	100	-850	-1150
March	100	1100	-100	-400
April I	-400	-100	-500	-650
April II	50	300	-100	-350
May	1850	2550	1300	450
June	-350	150	-500	-800
July	0	350	-400	-1000
August I	-150	150	-500	-950
August II	-1000	-950	-900	-750
September	-500	-150	-600	-750
Average	-200	300	-450	-800

Figure D.1 below shows the projected deficit for FY 2013 for the Heavy Load Hours and for all-hours (Heavy Load Hours plus Light Load Hours). The graph shows that BPA faces significant deficits in 2013 during winter months under P10 conditions. The large deficits in the winter result largely from high winter demand for electricity. During the summer, demand is not quite as high as in the winter, but the water supply is significantly more limited, particularly in the latter half of August (denoted as August II on the graph). Changes in recent years in the summer operation of storage reservoirs above Grand Coulee Dam have led to significant decreases in available water and generation in August, resulting in the deficits identified in this Needs Assessment.

On Figure D.1, the blue bars represent the deficits for the Heavy Load Hours, and the green bars represent the deficit for all hours of the month. In the second part of August, the all-hour deficit is smaller than the HLH deficit and is shown by the green line at 950 MW. The dashed lines at 1,000 MW (winter) and 500 MW (summer) are the current thresholds for long-term acquisitions.

Figure D.1 - Monthly (period) deficits for 2013 at the 10th percentile



The deficits identified in this Needs Assessment can be met by a combination of long-term purchases of market or specific resource energy, short-term and mid-term purchases, and additional energy available in most non-critical water years. BPA has a threshold of 1,000 MW for Heavy Load Hour winter to trigger long-term purchasing and a 500 MW threshold for purchasing Heavy Load Hour late summer, based on expectations of available market depth for within-year purchasing. The horizontal lines added to Figure D.1 represent these thresholds. Deficits smaller than these winter and summer thresholds (above the line on the graph) will be managed through mid-term and shorter-term market purchases, up to 5 years.

The analysis for 2013 included an expected date for the end of spill on the lower Snake River projects based upon expected operations pursuant to the May 2008 BiOp. However, in some years when fish migration continues later than normal, spill may continue through the end of August, in which case there would be about 400 MW less generation in the second half of August, leading to even higher deficits.

A comparison of the amount of energy deficit for all hours in each month with the Heavy Load Hour deficit by month (Figure D.1 and Table D.6) suggests that the deficit is a combination of an energy deficit and a Heavy Load Hour deficit. The presence of Light Load Hour deficits in any given month indicates that there is not enough water to generate energy during the month. The presence of a large Heavy Load Hour deficit in any given month indicates that there is not sufficient ability to shape the existing water into the Heavy Load Hour period. Thus, there is a need for energy that includes Heavy Load Hour energy at the 10th percentile in most months.

As discussed in section D.3.4, the Needs Assessment considered not only an expected load forecast but also higher and lower load scenarios. Even in the high-load scenario, the winter Heavy Load Hour deficits at the 10th percentile are smaller than the 1000 MW threshold for purchasing.

Figure D.2: The monthly (period) deficits for Heavy Load Hours for FY 2013 at the 10th percentile for low (light blue) and high (dark blue) load scenarios as well as for the expected case (medium blue as in Figure D.1)

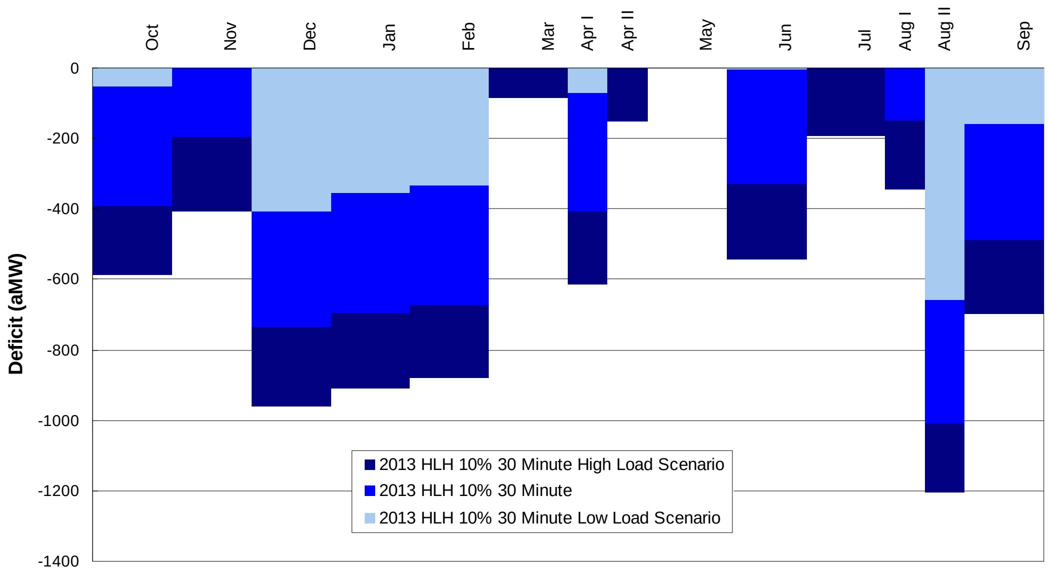


Table D.7 – Modeled monthly or period deficits for 2013 for average generation conditions

	HLH-Avg	Spk - Avg	All-hour Energy-Avg	LLH-Avg
October	400	700	150	-150
November	700	1200	250	-400
December	750	1350	150	-650
January	1600	2200	900	-100
February	1600	2450	1200	650
March	2450	3150	2200	1800
April I	2300	2500	2000	1650
April II	2500	2650	2250	1950
May	3350	3600	3150	2900
June	2650	2900	2500	2350
July	1900	2250	1450	800
August I	1500	1850	1000	300
August II	100	300	-100	-350
September	200	600	0	-350
Average	**1550**	**2000**	**1200**	**700**

The large deficits in 2013 for the 10th percentile low generation conditions disappear when there is more water. Table D.7 shows mostly large surpluses and only limited deficits for average generation conditions. The deficits in Light Load Hours when there is no monthly deficit stem from the fact that the HOSS model shifts as much energy as possible into the Heavy Load Hours and especially into the Superpeak hours.

For FY 2019, the deficits for the winter are significantly larger than in FY 2013 (Figure D.3 and Table D.8). The winter period of the Heavy Load Hour deficit falls within the current limits of 1,000 MW for winter for mid-term and shorter-term purchasing. However, the summer Heavy Load Hours extend beyond the limit of 500 MW for summer. The deficits for all-hours (monthly energy) winter and summer extend beyond these limits and suggest a need for long-term purchasing. Winter Heavy Load Hours could easily exceed the threshold if additional load not included in the Needs Assessment, such as additional DSI service, is placed on BPA. On Figure D.3, the blue bars represent the deficits for the Heavy Load Hours, and the green bars represent the deficit for all hours of the month. The horizontal dashed lines at 1,000 MW in winter and 500 MW in summer are current thresholds for needing long-term acquisitions. Figure D.4 presents the Heavy Load Hour deficits not only for the expected load case, but also for the high and low load scenarios. For average generation conditions, shown in Table D.9, there are no deficits except in some Light Load Hours because the HOSS model shaped as much energy as possible into the Heavy Load Hours.

Figure D.3 - Monthly (period) deficits for FY 2019 at the 10th percentile

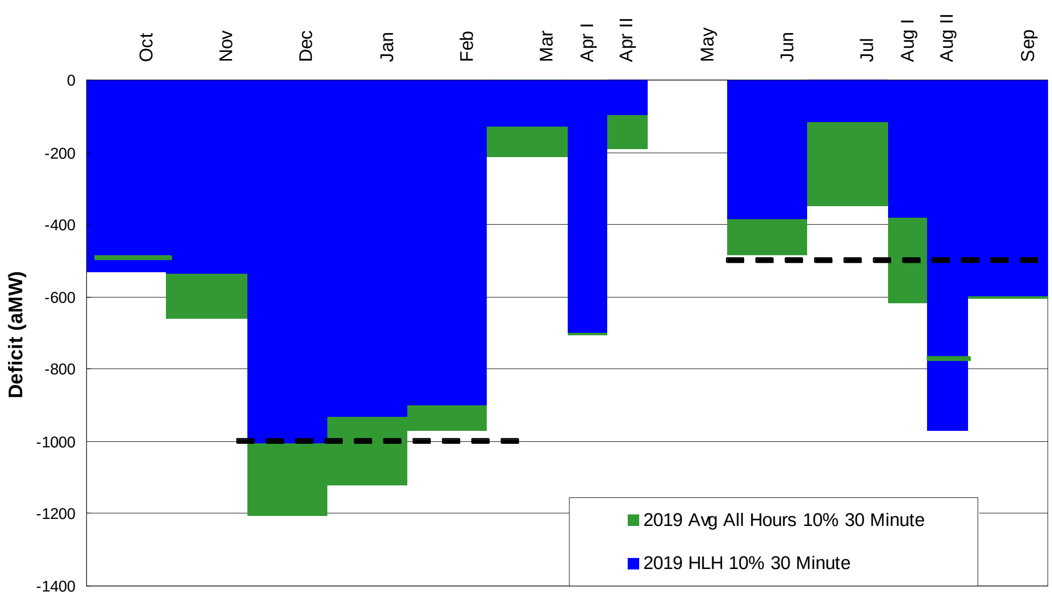


Table D.8 - Modeled monthly or period deficits for 2019 at the 10th percentile

	HLH	Spk	Avg	LLH
October	-550	-350	-500	-450
November	-550	-100	-650	-850
December	-1000	-350	-1200	-1450
January	-950	-450	-1100	-1350
February	-900	-250	-950	-1100
March	-150	800	-200	-350
April I	-700	-450	-700	-750
April II	-100	100	-200	-250
May	1800	2500	1250	550
June	-400	100	-500	-650
July	-100	150	-350	-750
August I	-400	-150	-600	-900
August II	-950	-950	-750	-550
September	-600	-300	-600	-600
Average	-350	100	-500	-700

Figure D.4: The monthly (period) deficits for Heavy Load Hours for FY 2019 at the 10th percentile for low (light blue) and high (dark blue) load scenarios as well as for the expected case (medium blue as in Figure D.3) Note the change in scale on this graph.

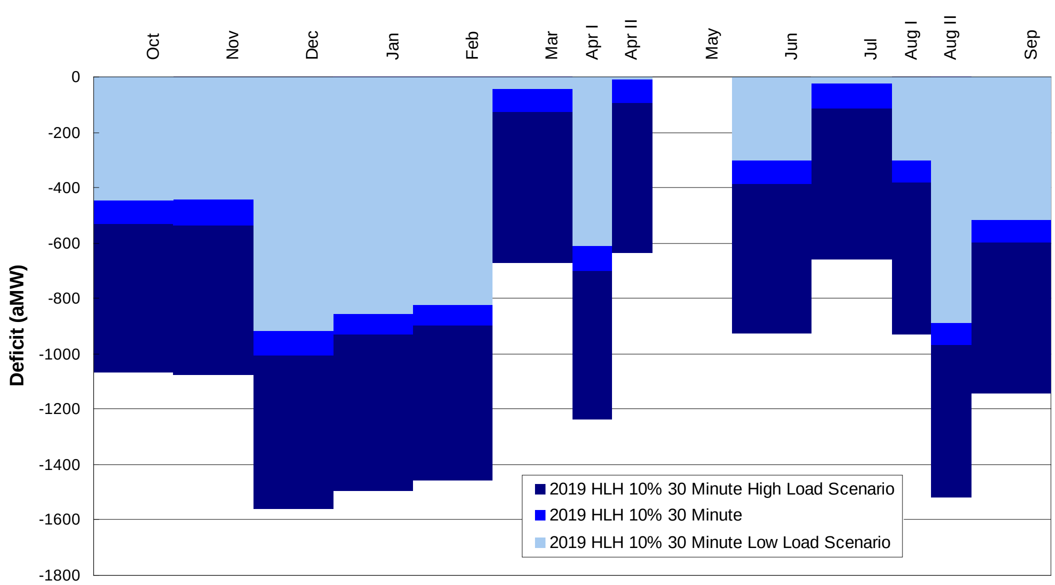


Table D.9 - Modeled monthly or period deficits for 2019 for average generation conditions

	HLH-Avg	Spk - Avg	All Hour Energy-Avg	LLH-Avg
October	300	550	150	0
November	400	850	100	-300
December	450	1100	0	-550
January	1350	1850	750	50
February	1350	2150	1050	650
March	2250	2850	2050	1800
April I	2000	2150	1800	1550
April II	2300	2400	2200	2000
May	3350	3650	3150	2900
June	2650	2900	2550	2450
July	1800	2100	1450	950
August I	1300	1600	900	350
August II	150	350	0	-200
September	150	500	0	-200
Average	**1400**	**1800**	**1150**	**800**

Superpeak Assessment

In addition to the Heavy Load Hour energy, BPA also examined the superpeak hours (same as the "120-hour sustained peaking" used in the White Book). This metric looks at the highest 6 hours of the day, 5 days a week, 4 weeks a month. The modeling study showed that the deficit for these superpeak hours is slightly less than the deficit for the Heavy Load Hours. This result indicates that there is enough flexibility for the model to shift sufficient water into the superpeak hours so that there is no need to buy energy for the superpeak in addition to the purchases that would need to be made for all Heavy Load Hours. The results for the superpeak hours at the 10th percentile ("Spk") are listed in Tables D.6 (2013) and D.7 (2019).

D.4.3 18-hour Capacity

The Heavy Load Hour and annual energy assessments are sufficient to ensure reliability under typical load conditions and under relatively low water conditions. They do not, however, assess the system's reliability during particularly stressful periods when the loads are high. As demand on the hydro system grows and flexibility decreases, capacity becomes more and more a concern. The 18-hour capacity metric for extreme temperature events uses median generation conditions together with loads that would occur during a 1 in 10 year cold snap or heat spell. These events require the system to flex as much capacity as possible to handle the cold spell or heat wave, capacity that would not be sustainable for long periods. The results for winter and summer 2013 and 2019 are summarized in Figures D.5 and D.6 and Table D.10. In the graphs, the blue, bubbled area represents modeled hydro generation to meet load (after subtracting load served by other resources, including the smaller hydro plants that are not treated explicitly in the model). The red, hatched bars above the load indicate surplus capacity, and the red bars below the baseline are purchases made during the graveyard hours that free up water and capacity for the daytime.

Figures D.5 and D.6 show graphs for hydro generation averaged over 3 days of extreme cold or heat, showing generation to meet load (blue bubbles), graveyard purchases (striped bars below baseline), and surplus capacity (striped bars above the load line). The load is the net load after applying thermal generation and other resources not included in the hydro model.

On Table D.10, peak-limited capacity is the turbine-limit for the peak-load hour, which in these cases is not the limiting constraint. Rather, the ability to shape the water (energy) within the day creates the constraint for available capacity.

Figure D.5 - 18-hour capacity for 2013

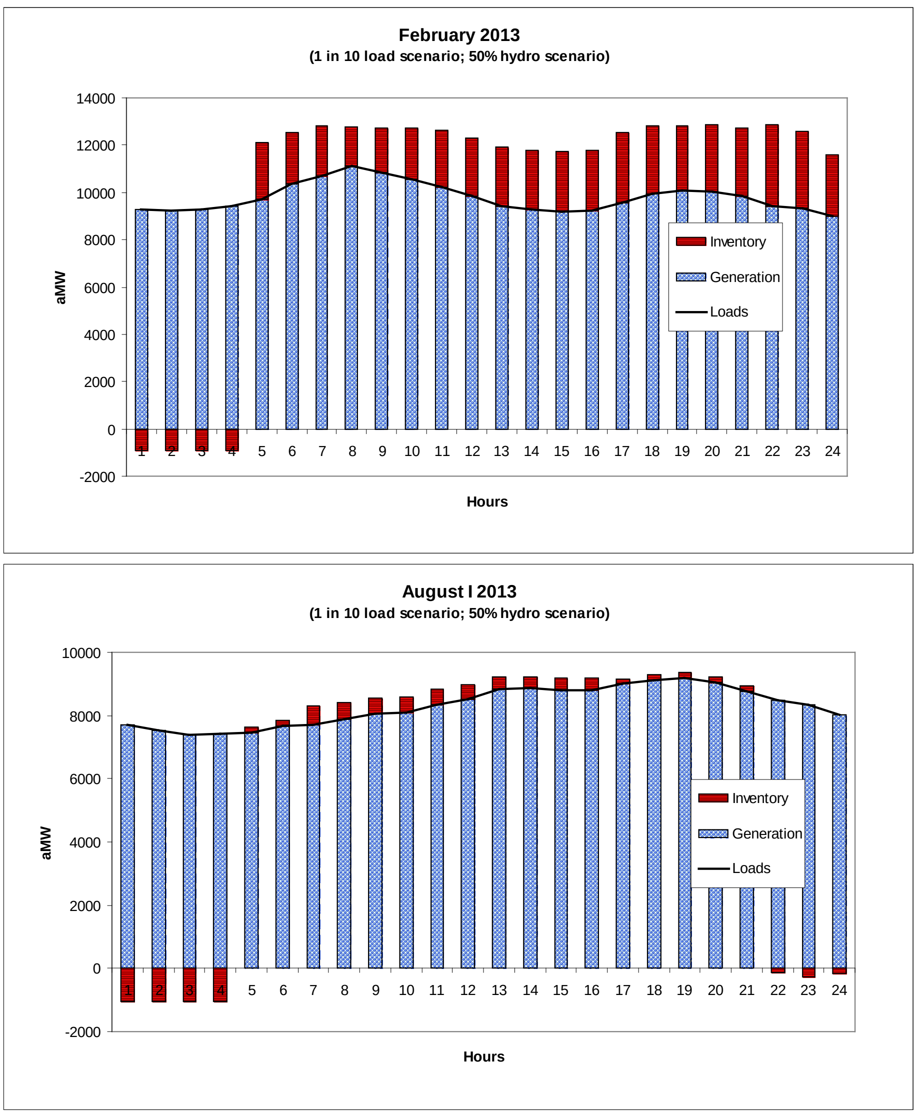
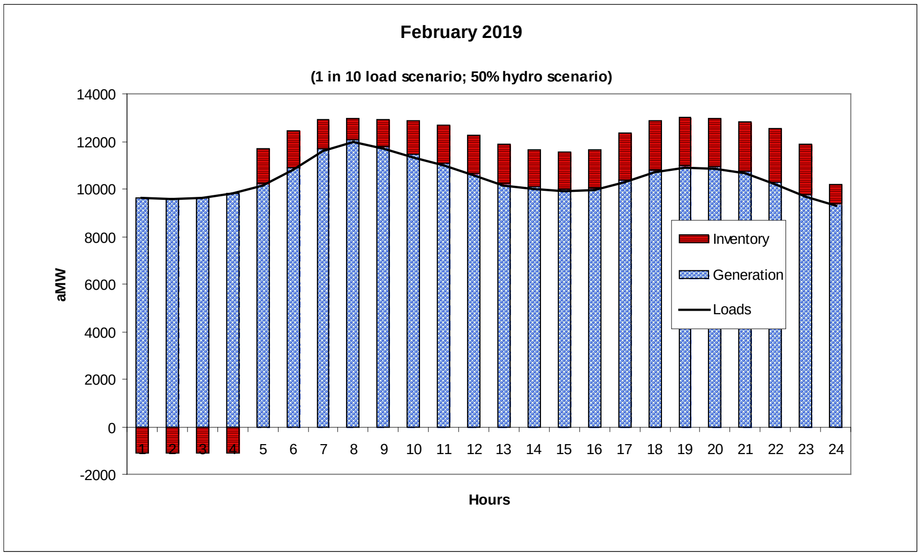


Figure D.6 - 18-hour capacity for 2019



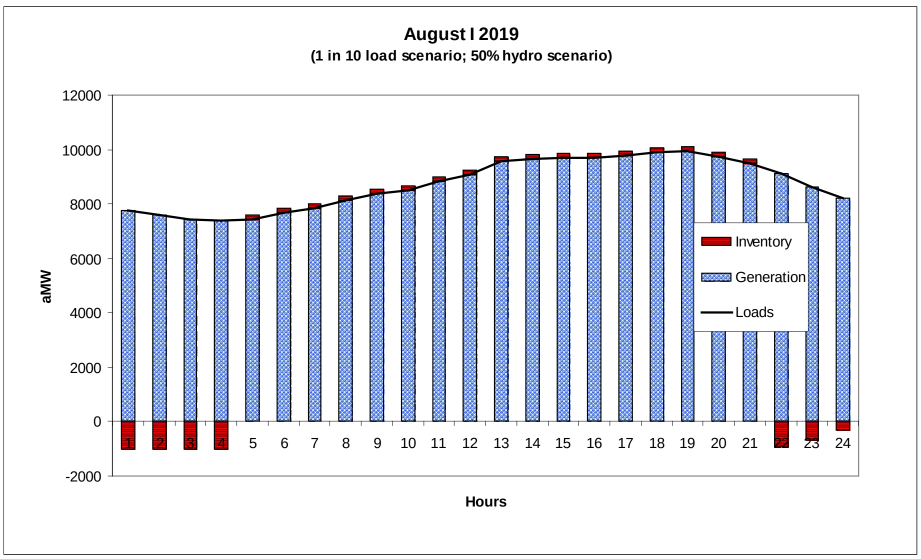


Table D.10 - Summary of 18-hour capacity assessment

	Energy-Limited Capacity	Peak-Limited Capacity	Final Available Capacity
February 2013	1600	4350	1600
August 2013	200	1150	200
February 2019	1050	3550	1050
August 2019	150	750	150

The 18-hour capacity metric covers the 6 highest load hours over 3 consecutive days. The studies are performed with peak loads corresponding to a 1 in 10 year event with average hydro generation. Energy-limited capacity is the amount of capacity available on the 18 highest hours, limited by how much water is available to spread over the day. The peak-limited capacity refers to how much energy could be generated in a single hour (based in large part on turbine limitations) if the water were concentrated in any given hour. Because the peak-limited capacity in the analysis result is so much larger than the energy-limited capacity, there is sufficient turbine flexibility to shape the water (energy) from hour to hour. Thus, in these studies, energy availability becomes the effective limit on the available capacity, and the capacity is not limited to the exact hourly distribution of generation that the model chose. There is some room in the run-of-river projects' forebays to shape energy from one hour to the next within a day.

- In 2013 and 2019, the system has ample 18-hour capacity for a predicted cold spell, with or without 1,000 MW of Light Load Hour purchases.
- This surplus will grow if BPA purchases to meet the winter and late-summer Heavy Load Hour energy deficit as long as the purchased energy has a significant capacity component. Purchases of Light Load Hour energy may help slightly as well.
- The surplus will also grow slightly, particularly in 2019, if conservation increases beyond the level of recent years.
- For a heat-wave, in both 2013 and 2019, the system is essentially in load-resource balance for 18-hour capacity if BPA does not purchase energy with a significant capacity component. Note: when such an extreme weather event occurs, it would reduce the available energy for the rest of the month by about 100 aMW winter or 50 aMW summer.

The combination of forecast error (about 250 MW uncertainty) and the possibility of larger temperature effects (750 MW uncertainty) on load cause an additional 1000 MW load uncertainty. There is intrinsically large volatility of the effect of temperature on load. We use about 900 MW temperature effect for February peak hours (800 MW day-average) and 800 MW for August (500 MW day-average), but peaks could be 1,000 MW higher. If the actual load is indeed higher than in our forecast, we would have a significant capacity deficit in summer heat waves.

The result for summer heat waves, in particular, underscores the earlier conclusion that BPA has a need for Heavy Load Hour energy with dependable capacity. Acquiring this energy would cover the deficit if the loads turn out to be higher by the full 1,000 MW of uncertainty.

This capacity analysis assumed that there would be no release of additional water from Canadian projects and headwater projects in the United States. The only change made to operations was for summer heat waves to increase Grand Coulee's draft limit to 1.9 ft/day from 1.37 ft/day (a dispensation that the Bureau of Reclamation generally grants for such rare but extreme events). While Dworshak Dam's operation can flex during an emergency to gain energy at Dworshak and downstream, BPA does not plan the system to require emergency measures.

These studies were performed using median hydro generation conditions. Separate studies have shown that the 18-hour capacity is not highly dependent on water conditions. This is because the system still has enough flexibility to shape water into the peak hours of the day for a cold snap or a heat wave, even when water is relatively low. (This is not the same scale of flexibility used for wind reserves, where there are only minutes' to a couple of hours' notice of the need to consume the reserves. In a cold snap, weather forecasts typically provide at least a couple of days to set up the system to meet the peaks.)

The water used to meet the demands during the extreme event is taken out of the rest of the month (perhaps also subsequent months, depending on the time of the year or that year's flood control and fish Variable Energy Content Curve constraints). If the energy comes out of the balance of the month, the capacity assessment presented here for February would reduce energy for the rest of February by about 100 aMW. Though this is a significant reduction in terms of the need to buy energy, this 18-hour capacity assessment shows that the system can meet load during the 3-day event when market power purchases are likely to be extremely expensive or unavailable. The energy that must be made up for the balance of the month would presumably be more available outside the 3-day event. Fortunately, this type of cold snap is a rare event, estimated to occur only once every 10 years.

For an August heat-wave, the water needed to meet peak loads for a 3-day event reduces the energy available for the rest of the month by about 50 aMW. Again, the event analyzed here should be rare (once in 10 years), and the key measure of the 18-hour metric is to be capacity-sufficient during the event, when there would be little or no energy or capacity available on the market.

Under adverse hydro generation conditions, the system would have somewhat less energy. However, during an adverse water year, the system is already energy deficit, so BPA would presumably have to buy energy, including Heavy Load Hour energy, and that would assist with capacity to meet the cold snap/heat spell loads.

D.4.4 Ancillary Services to Support Reserves

As mentioned above in the section on methodology, the modeling studies for this Needs Assessment found that the system was not able to model wind reserves beyond the level required for 2014 using 30-minute persistence accuracy forecasts. The challenge with the *dec* reserves manifests itself primarily during Light Load Hours in the drier years. In order for the hydro system to have the flexibility to decrease generation at night (such as when the wind fleet picks up unexpectedly and decremental reserves are called upon), the hydro system must be generating above its minimum level by the amount of the *dec* reserves. However, in drier years, there often is not enough flow in the river to meet each hydro project's minimum flow plus the additional flow requirement for the *dec* reserves.

The HYDSIM/HOSS studies showed that, as the reserve requirements increase, there is a shift in generation from Heavy to Light Load Hours. One reason for this shift is that the higher *dec* reserves require generation above minimum turbine levels in the Light Load Hours (especially during the graveyard, defined as midnight to 4 a.m. or HE01-04). The increased *dec* reserves require generation above the minimum, thus shifting energy out of the Heavy Load Hour period into the Light Load Hour/graveyard period. An increase in *dec* reserves will affect the system primarily in low flow periods.

The HYDSIM/HOSS studies showed that the increased *inc* reserve requirements also contribute to shifting energy out of the Heavy Load Hour period by increasing the amount of spare (unloaded) turbine capacity needed. In high flow periods, the reduced turbine availability will limit the amount of water that can be shaped into the Heavy Load Hour period. This in turn shifts energy into the Light Load Hour period and in very high flow periods can lead to increased spill.

Missing *dec* reserves can create unacceptable reliability issues or violations of non-power system operation requirements. The hydro system would not be able to compensate for wind increases without violating some combination of Total Dissolved Gas spill caps, Area Control Error standards, or other reliability constraints.

As indicated in Table D.2, this Needs Assessment indicates that the FCRPS is approaching the limit of reserves it can supply for wind integration around 2014 using 30-minute wind reserves. However, the HYDSIM and HOSS models are not the most sophisticated approaches to assessing wind integration.

Low flows in April 2010 and high flows in June 2010 have made it clear that events can stress the hydro system to the brink with the current wind fleet. Studies are ongoing to look more closely at high and low flow scenarios with larger wind fleets with a goal of providing a definitive assessment of the ability of the FCRPS to integrate wind.

BPA and the region are actively pursuing opportunities to reduce further the regulating reserve requirement on the FCRPS, such as the following:

- Further improving wind generation scheduling techniques.
- Pursuing opportunities to reduce generation imbalance, such as promoting wind diversity, implementing mid-hour scheduling for wind, and coordinating with other utilities for sharing area control errors (Area Control Error diversity sharing).
- Exploring third-party supply and self-supply of wind integration reserves.

D.5 Regional Standards

D.5.1 Pacific-Northwest (PNW) Resource Adequacy Standard

On April 16, 2008, the Northwest Power and Conservation Council adopted a resource adequacy standard for the regional power supply. The Council's standard is based on recommendations from the Resource Adequacy Forum, which was initiated in 2005 by the Council and BPA to address resource adequacy issues. This standard includes both energy and capacity adequacy metrics. Currently, the minimum thresholds include an annual energy load-resource balance, a 23 percent winter planning reserve margin, and a 24 percent summer planning reserve margin. These thresholds are derived from the Council's probabilistic analyses, in which a regionally adequate resource mix is defined as one with a Loss of Load Probability not greater than 5 percent.

The standard is comprised of a consensus-based methodology for assessing the resource adequacy of the Northwest region; the region is defined by the 1980 Northwest Power Act. The standard provides an implementation plan, which is predicated upon voluntary actions to ensure that the region's electricity supply is sufficient to meet the region's needs now and in the future. The standard's minimum thresholds serve as an early warning should resource development fall dangerously short. It also suggests a higher threshold that encourages greater resource development to offset electricity price volatility. It does not mandate compliance or enforcement. Only high-level guidance has been provided to date, to allow individual utilities to determine whether their resource planning efforts are aligned with the regional standard. Because every utility's circumstances differ, individual utilities must assess their own needs and risk factors and determine their own planning targets in coordination with their public utility commissions or local regulatory bodies. It would be a misapplication of the adequacy standard to infer that utilities should slow their resource acquisition activity simply because the minimum threshold in the adequacy standard is being met. The Pacific Northwest Resource Adequacy Standard can be found at http://www.nwcouncil.org/library/2008/2008-07.pdf.

In 2008, when the region's utilities compared their load and (firm) resources, they showed a substantial need to acquire resources. In contrast, the regional resource adequacy assessment indicated that the region was above the minimum threshold for physical adequacy. While these perspectives appear inconsistent with one another, each is valid. The regional adequacy standard defines a floor or minimum amount of resource development, whereas the utility assessments (and the Council's Power Plan) suggest targets for more optimal amounts of new resource capability in utilities' service territories. There are four main reasons for the difference:

- The regional adequacy standard includes a large amount of market generation that is physically available to the region but is not owned or under contract by any regional utility. Most utilities count only resources they have firm rights to, through ownership or contract.

- Most utilities use critical water (one of the driest years on record) to forecast hydroelectric generating capacity. The regional adequacy standard uses a less stringent measure to define the minimum threshold for adequacy.
- Many utilities do not count the full availability of particular resources because of high operating costs, lack of firm fuel contracts, or other reasons. The regional standard is based on the assumption that during emergencies, many of these resources would be available.
- Many utilities are concerned about the risk of high costs during periods when the power supply is tight, and therefore take a more conservative, risk-managed approach in defining their need to acquire new resources.

D.5.2 Alignment of BPA Resource Program with Council's Regional Resource Adequacy Standard for Energy

Guidance on how to align utility resource planning efforts with the Council's Resource Adequacy Standard has thus far been limited to a presentation made by Council staff at the June 27, 2007, Resource Adequacy Forum's Steering Committee Meeting. The presentation itemized non-firm hydro and uncontracted market resources that the regional Loss of Load Probability analysis counts as being available to the region. The Steering Committee agreed with the suggestion that each utility limit its reliance on these common resources to the following:

- Utility share of in-Region market = Region's uncontracted merchant generation * utility load share.
- Utility share of out-of-Region market = assumption regarding winter market availability of resources from California * utility load share.
- Utility share of non-firm hydro = total non-firm hydro available to Region under a 5 percent Loss of Load Probability study * hydro utility's percentage of regional hydro resources.

The Federal system's share of these common regional resources is estimated to be around 1,500 aMW. The Needs Assessment demonstrates that the Federal system's reliance on these resources is significantly less than this amount.

The Council has not issued detailed guidance for utilities to use as an economic standard, but rather refers to its Sixth Power Plan as a measure of prudent planning thresholds for economic reliability.[7]

D.5.3 WECC's Power Supply Assessment

The Western Electricity Coordination Council issues an annual Power Supply Assessment, which is WECC's resource adequacy document. The key metric is the peak

[7] See, e.g., pages 14-5 to 14-6 of the Council's Sixth Power Plan.

hour reserve margin in summer and winter. The 2009 Power Supply Assessment[8] uses a building block approach to calculate the reserve margins, developed from an evaluation of a number of uncertainties facing load-serving entities. The building block approach has four elements: contingency reserves, regulating reserves, reserves for additional forced outages, and reserves for 1 in 10 year weather events. Separate building block values were developed for each balancing authority and then aggregated by sub-regions for the analysis. For the Northwest, the summer margin is 18.6 percent, and the winter margin is 20.0 percent. For BPA, the sum of the four building blocks is well above these margins.

D.6 Conclusions and Recommendation

As stated previously, BPA's ability to serve load depends significantly on customer elections regarding their above-HWM load. Further, new DSI service, new public utilities served by BPA, and new Federal load placed on BPA all could change the outlook. Therefore, the results of this Needs Assessment will need to be re-evaluated as these factors evolve.

The Needs Assessment identified deficits on an annual average basis for projected load for both 2013 and 2019. The deficit could be met in large part by purchases made to fill seasonal Heavy Load Hour and seasonal energy needs. Also, these deficits would mostly disappear and convert to surpluses under average water conditions.

For the winter, in FY 2013 the projected deficits for Heavy Load Hours at the 10^{th} percentile by month are below 1000 MW. Therefore, it may be possible to fill this need using short- and mid-term (up to 5-year) market purchases. The same holds true in FY 2019 if BPA is not asked to serve new loads. However, the monthly deficits for all hours (Heavy Load Hours and Light Load Hours) are beyond the 1000 MW threshold and may suggest long-term purchasing.

In late summer, particularly in the second half of August, the Needs Assessment identified significant needs for Heavy Load Hours at the 10^{th} percentile. The deficits are well in excess of 500 MW, the current amount BPA may serve through short- and mid-term (up to 5-year) market purchases. Therefore, there is a need to acquire energy for late summer through longer-term acquisitions for both 2013 and 2019.

The assessment of the system's ability to meet load during an extreme-temperature event as measured by the 18-hour capacity metric indicates that BPA has surplus capacity in winter. The ability of the system to peak during a 3-day event, however, comes at the expense of energy during the rest of the month. Thus, the Heavy Load Hour purchases identified above are still necessary. In summer, the system is projected to meet peak-event loads, but there is no buffer to meet additional load (new load or simply higher load

[8] See Power Supply Assessment at http://www.wecc.biz/committees/StandingCommittees/PCC/LRS/Shared%20Documents/Forms/AllItems.aspx Power Supply Assessment

from load uncertainty). Purchases made to fill monthly energy and Heavy Load Hour needs should ameliorate this situation.

The hydro models used for the Needs Assessment identified a need for additional reserves beyond 2014 using 30-minute persistence wind forecasting accuracy. A reduction in the reserve requirement may allow BPA to provide sufficient reserves for some time beyond 2014. However, as noted previously, BPA is currently examining reserves in more detail, particularly in light of recent incidences when the hydro system was stressed with the current wind fleet. Sooner or later, there will be a need for new sources of reserves, whether through BPA acquisitions, self-supply, third-party supply, or more mechanisms to reduce the reserve requirement for any given penetration of wind generation.

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APPENDIX E. RESOURCE DESCRIPTIONS

E.1 Introduction

Appendix E includes three sections. The first section after this introduction contains information on conservation. The second section contains information on demand side management. The third section contains information on generating resources.

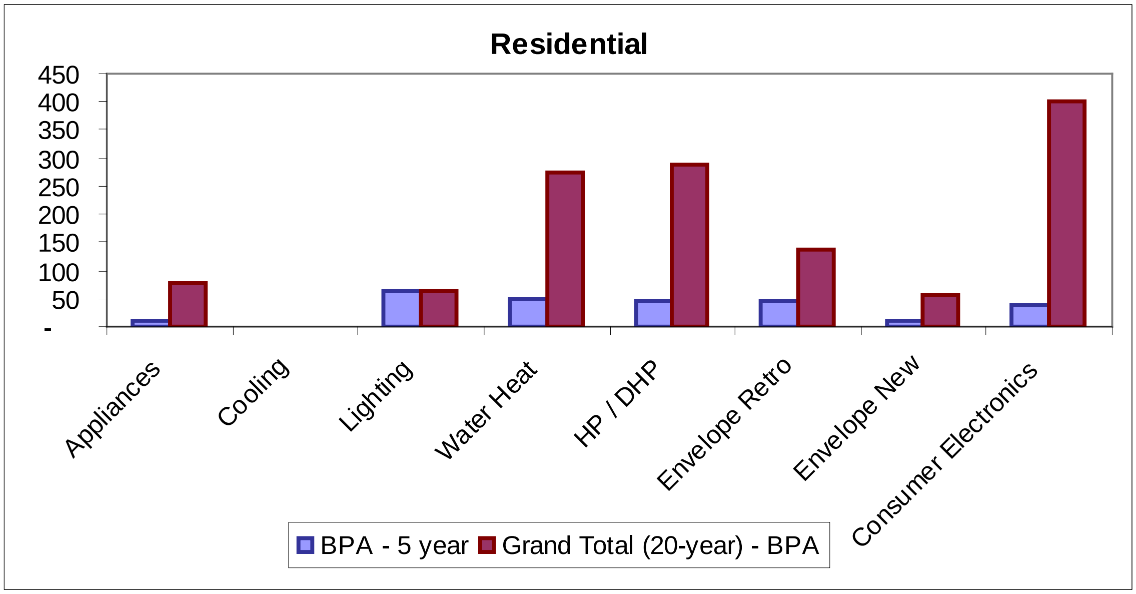
E.2 Conservation

Conservation is specified in the Council's Sixth Power Plan as the least-cost and least-risk resource. For the Sixth Power Plan, Council staff developed supply curves of potential conservation savings for the region. These supply curves are built of thousands of individual conservation measures, with the expected savings, number of units available in the region, and total resource cost (TRC) of each measure or practice. The TRC includes the first cost of the equipment or practice, any ongoing operations and maintenance costs, any non-energy benefits that accrue based on the measure, and transmission and distribution benefits of conservation. The measures and practices are defined by type (retrofit or lost opportunity) and by sector—residential, commercial, industrial, agriculture, and distribution efficiency improvements. Each measure or practice has a defined ramp rate to move from current market penetration to the 85 percent achievable potential. For inclusion in the Council's portfolio model, these data are summarized by year, type, and TRC. The Council's portfolio model, using these data and an assumed rate of "maximum annual" that can be achieved in the region, chooses the quantity of conservation in the portfolio and the hedge value of conservation. The result is the regional target for conservation and the avoided cost of conservation implied by the model.

BPA, in partnership with public power, is committed to acquiring the public power share of the conservation targets in the Council's Sixth Power Plan, as described in section 6.1.

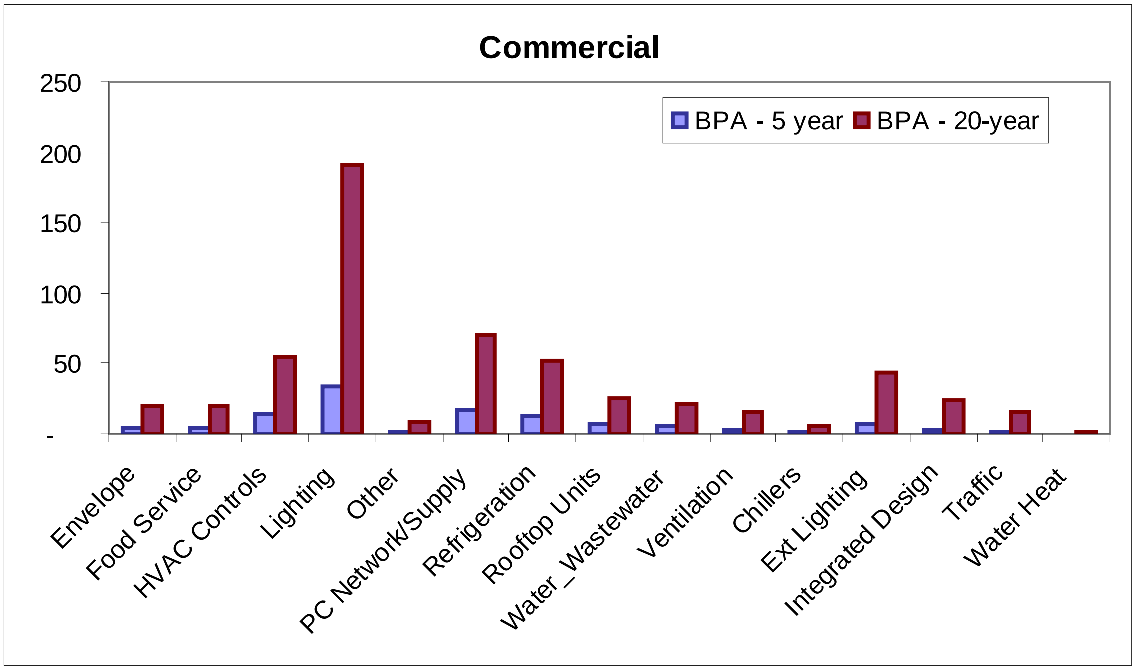
Within each sector, the savings are distributed among various end-uses, measures, and practices. To be consistent with the Council's Plan, the following charts are shown for the 5- and 20-year timeframes for illustrative purposes. The residential sector accounts for approximately one-half of the conservation potential in the region. In the residential sector, as shown in Figure E.1, the largest areas of savings are in consumer electronics (primarily TVs), heat pumps and ductless heat pumps, and heat pump hot water heaters. In the 2010-2014 timeframe, the targets are also focused on specialty lighting and weatherization (envelope retrofitting).

Figure E.1 - Potential Residential Conservation



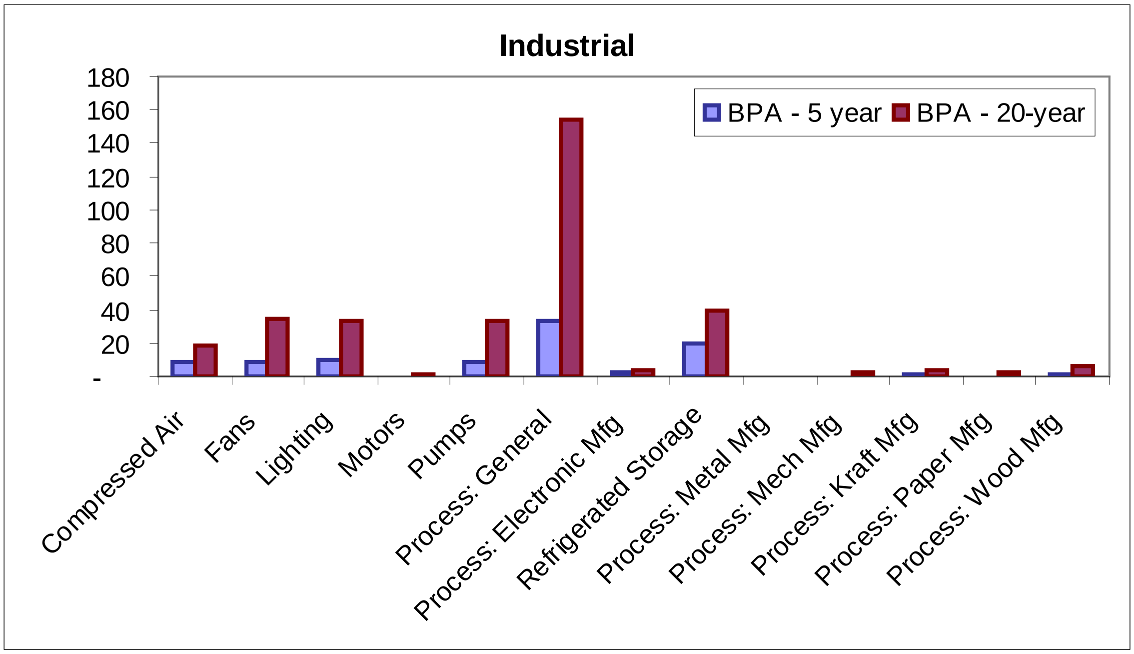
In the commercial sector, the savings are much more diffuse across measures and practices. In the 20-year time-frame, as shown in Figure E.2, the largest share of savings is from lighting, followed by HVAC controls and computing controls. Additionally, exterior lighting and grocery refrigeration have large shares of the commercial potential.

Figure E.2 - Potential Commercial Conservation



In the industrial sector, as shown in Figure E.3, the largest share of potential is in “process: general,” which includes many general process efficiency improvements, as well as energy management optimization. Additionally, there are large savings in lighting, fans, compressed air, refrigerated storage and pumps.

Figure E.3 - Potential Commercial Conservation



The agriculture sector has a relatively small amount of potential (42 aMW in 20 years, 21 aMW in 5 years), which is primarily focused on irrigation hardware. Distribution efficiency improvements account for 28 aMW in the next five years and 162 aMW over 20 years.

E.3 Demand Response

In 2008, BPA Power staff developed 5 Capacity Constraint Scenarios to identify how and when BPA needs demand response (DR). The Energy Efficiency group contracted with the Brattle Group and Global Energy Partners for assessment of potential and strategic recommendations. Table E.1 outlines the capacity constraint scenarios utilized in the study.

Table E.1 - BPA Capacity Constraint Scenarios

Table 1: BPA Capacity Constraint Scenarios

	Scenario 1 Summer Heat Wave	Scenario 2 Winter Cold Spell	Scenario 3 Increased Reliance on Wind	Scenario 4 Large Unit Outage	Scenario 5 Difficulty Managing System
Season	Summer	Winter	Any	Any	Shoulder
Continuous Event Days	Three Days	Three Days	Year-Round	Two-Days	One Day
Timing	Afternoon(2-9pm)	Morning (6am-9am) Evening (5pm-9pm)	Intermittent	All Day	All Day
Frequency	Once per day; 3 events per summer	Twice per day; 0-1 events per winter	Many deviations from expected output per day	Constant throughout day	Constant throughout day
Foresight	2 to 5 Days	1 to 2 days	less than 1 hour	less than 1 hour	1 day
Trigger	Reliability/Price	Reliability/Price	Reliability	Reliability/Price	Reliability/Price
Relevant Region	Pacific Northwest	Pacific Northwest	Pacific Northwest	BPA Control Area	BPA Control Area
Size of Peak Impact	1,000 to 2,000 MW	1,000 to 2,000 MW	1,000 to 4,000 MW	1,100 MW	1,000 MW

Using this information and research of national demand response programs, the study developed profiles of program options, which included targeted customer segment, controlled end-uses, eligibility requirements, likely incentive levels, notification time, and technology requirements. The following list outlines the key demand response programs analyzed.

Residential and small commercial direct load control: Utility remotely shuts down or cycles a customer's electrical equipment on short notice.

Emergency demand response: Large customer reduces load during events triggered by either reliability or high market prices. Participation is voluntary. Targets medium and large commercial and industrial loads.

Capacity market: Participants commit to provide pre-specified load reductions when system contingencies occur. Participation in specific events is mandatory once a participant commits to the program. Targets medium and large commercial and industrial loads.

Ancillary services: End-use customers bid curtailments into the market as operating reserves. Accepted bids are paid market price for committing to be on standby. Targets large commercial and industrial loads.

Irrigation: Irrigation direct load control is a program under which utility dispatchers can interrupt irrigation pumping during summer peak days.

The study then mapped DR Options to Capacity Constraint Scenarios and estimated the costs and potential for peak reductions. Peak demand reduction potentials were based on:

- Seasonal and hourly load profiles, by sector and end-use
- End-use equipment saturation
- Size of eligible market segment

- Estimates of utility participation rates and event participation rates
- Control technology availability

Additionally, program costs were estimated based on:

- Internal staff costs
- Program development costs
- Customer recruitment and marketing
- Equipment, capital and installation costs
- Annual O&M
- Incentives

The results of the program options analysis were compared to the capacity scenarios and the Council's demand response inputs to develop supply curves for inclusion in the Resource Program. The BPA study developed 10-year ramp rates for program deployment that were extrapolated to the Council's levels to be consistent with BPA's regional share of the 2029 potential. The costs developed in the BPA study were utilized for the Resource Program. Table E.2 shows the summer and winter demand reductions for 2013 and 2019.

Table E.2 - Summer and Winter Demand Reductions

	2013 MW		**2019 MW**		**Levelized Costs ($/kW-year)[1]**
	Summer	**Winter**	**Summer**	**Winter**	**Average**
Residential direct load control	24	21	54	49	$100
Small Commercial direct load control	3	3	9	8	$100
Emergency demand response	6	5	21	19	$120
Capacity market demand response	9	8	30	28	$150
Ancillary services demand response	1	0	2	2	$400
Irrigation	5	0	21	0	$80

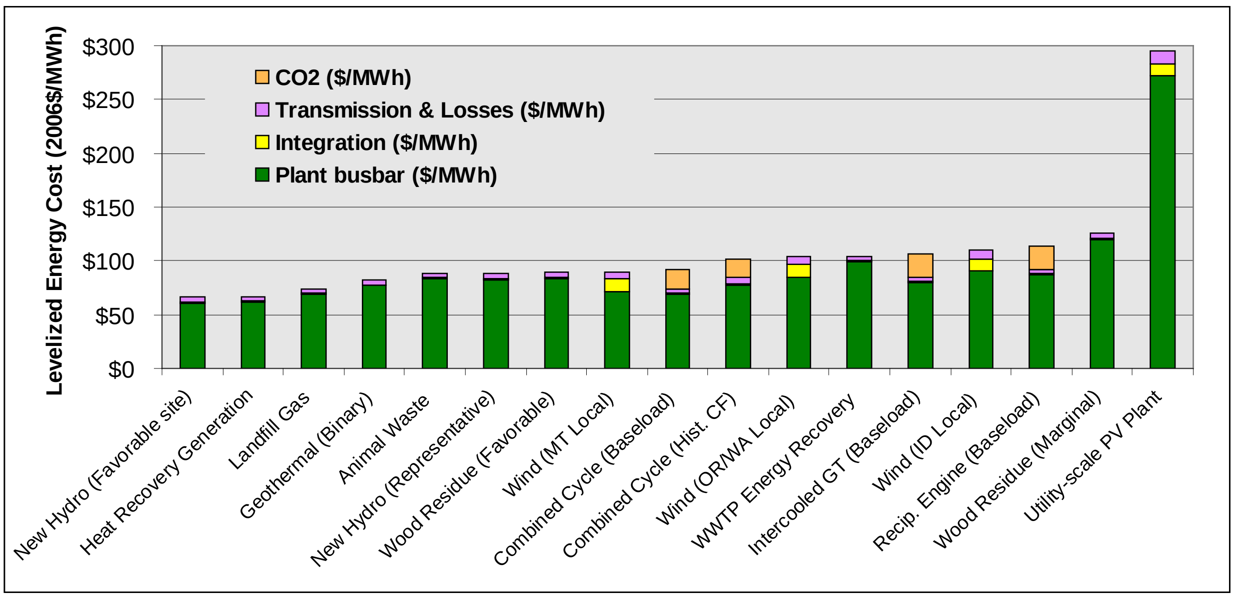
[1] All the costs on the table are based on the Global Energy Partners study "Assessment of DR Options for BPA" dated 26 January 2009; Table 7.10 "Levelized Costs for Reliability-based DR Options in 2016," page 29.

E.4 Resource Information

For its Resource Program, BPA relied extensively on the Council's Sixth Power Plan for information about the various types of resources. This information mostly came from Chapter 6 and Appendix I of the Sixth Power Plan. The full Sixth Power Plan can be found at the following link: http://www.nwcouncil.org/energy/powerplan/6/default.htm

Since BPA has a fairly thorough discussion about resources in Chapter 6 and Chapter 7 of this document and much more information is available from the Council, the purpose of this section of this appendix is to highlight some key resource information from the Council, as shown in the following tables and figures.

Figure E-4: Levelized Lifecycle Electricity Cost for Generating Options Available in the Near Term (2010-14)[2]



Source: Council's Sixth Power Plan, Figure 6-1A

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[2] Assumptions: 2015 service, investor-owned utility financing, medium fuel price forecast, wholesale delivery point. CO_2 allowance costs at the mean values of the portfolio analysis. Incentives excluded, except accelerated depreciation. Actual project costs may differ because of site-specific conditions and different financing and timing.

Table E.3 - Summary of Generating Resources and Energy Storage Technologies

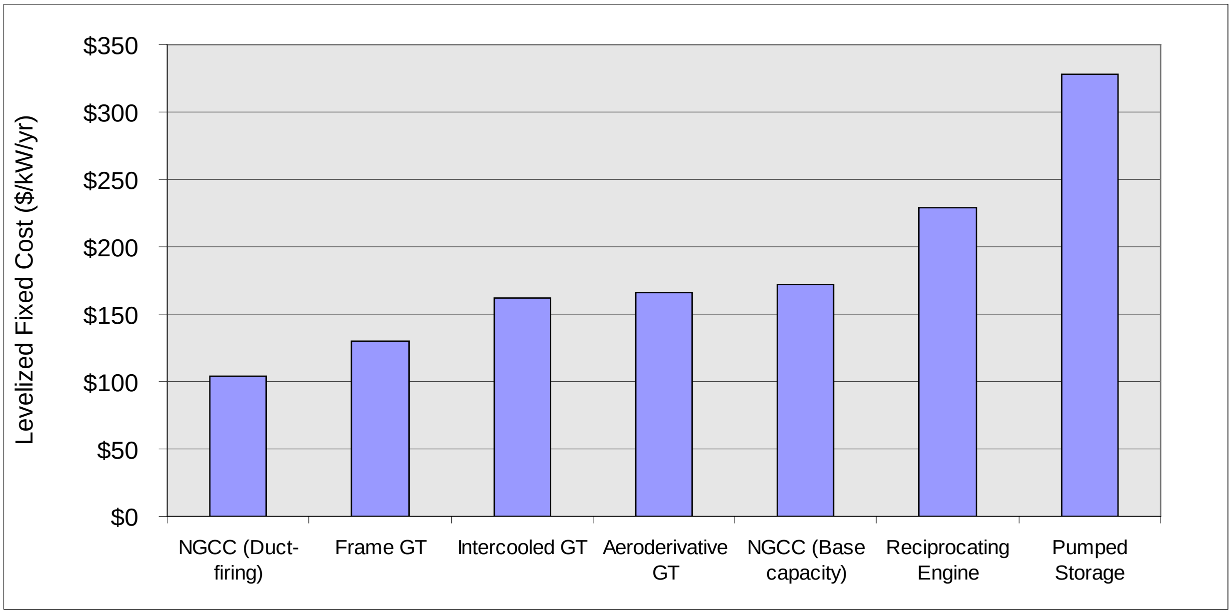
Resource	Leading Technology	Services	Estimated Undeveloped Potential	Earliest Service	Capacity Cost ($/kW-yr)6	Energy Cost ($/MWh)5	Key Issues
Renewable Resources							
Hydropower	New projects	Firm capacity Energy	Low hundreds of MWa?	2016	--	$60 and up	Siting constraints Development cost & lead time
	Upgrades to existing projects	Firm capacity Energy Balancing	Low hundreds of MWa?	Project-specific	Project-specific	Project-specific	
Wastewater treatment gas	Reciprocating engines	Firm capacity Energy	7 - 14 MWa	2012	--	$104	Cost (smaller treatment plants)
Landfill gas	Reciprocating engine	Firm capacity Energy	70 MWa	2012	--	$73	Competing uses of biogas
Animal manure	Reciprocating engine	Firm capacity Energy	50 - 110 MWa	2012	--	$80 - $140	Cost Competing uses of biogas
Woody residues	Steam-electric	Firm capacity Energy Cogeneration	665 MWa	2014	--	$88 - $125	Cost CHP revenue Reliable fuel supply
Geothermal	Binary hydrothermal	Firm capacity Energy	370 MWa	2017	--	$81	Investment risk (Exploration & well field confirmation)
	Enhanced geothermal	Firm capacity Energy	Thousands of MWa?	Uncertain	--	Not available	Immature technology
Tidal current	Water current turbines	Energy	Low hundreds of MWa?	Uncertain	--	Not available	Immature technology Environmental impacts Competing uses of sites
Wave	Various buoy & overtopping devices	Energy	Low thousands of MWa?	Uncertain	--	Not available	Immature technology Competing uses of seaspace
Offshore Wind	Floating WTG	Energy	Thousands of MWa?	Uncertain	--	Not available	Immature technology Competing uses of seaspace
Solar	Utility-scale Photovoltaic arrays	Energy	Abundant	2013	--	$280	Cost Poor load/resource coincidence Availability and cost of balancing services
Solar (Nevada)	Parabolic trough	Firm capacity Energy	600 MWa/500kV circuit	2015	--	OR/WA $230 ID $190	Cost Lack of suitable PNW resource Availability and cost of transmission
Wind (Local)	Wind turbine generators	Energy	OR/WA - 1410 MWa ID - 215 MWa MT - 80 MWa	2013	--	OR/WA $103 ID $109 MT $89	Availability and cost of balancing services

Resource	Leading Technology	Services	Estimated Undeveloped Potential	Earliest Service	Capacity Cost ($/kW-yr)[6]	Energy Cost ($/MWh)[5]	Key Issues
Wind (Alberta)		Energy	760 MWa/+/-500kV DC Ckt	2015	--	OR/WA $140	Availability and cost of balancing services Availability and cost of transmission
Wind (Montana)		Energy	570 MWa/new 500kV Ckt Via CTS Upgrade	2015	--	ID $116 OR/WA $150 OR/WA $130	Availability and cost of balancing services Availability and cost of transmission
Wind (Wyoming)		Energy	570 MWa/500kV Ckt	2015	--	ID $121 OR/WA $150	Availability and cost of balancing services Availability and cost of transmission
Waste Heat							
Waste heat	Bottoming Rankine cycle	Energy	Tens to low hundreds of MW?	2014	--	$63	Suitable host facilities Host facility viability
Fossil Fuels							
Coal	Steam-electric	Firm capacity Energy	Abundant	No CSS 2017 CSS Uncertain	--	No CSS OR/WA $108 (2020) CSS MT > OR/WA via CTS repower $140 (2025)	GHG policy Immature CO_2 separation technology Lack of commercial CO_2 sequestration facility
	Gasification combined-cycle	Firm capacity Energy Balancing Polygeneration	Abundant	No CSS 2017 CSS Uncertain	--	No CSS OR/WA - $118 (2020) CSS MT > OR/WA via CTS repower $140 (2025)	Investment risk Reliability GHG policy Lack of commercial CO_2 sequestration facility
Petroleum coke	Gasification combined-cycle	Firm capacity Energy Balancing	Abundant	No CSS 2017	--	No CSS WA/OR - $120	Investment risk Reliability GHG policy
		Polygeneration		CSS Uncertain		(2020) CSS MT > OR/WA via CTS repower $140 (2025)	Lack of commercial CO_2 sequestration facility
Natural gas	Combined-cycle gas turbine	Firm capacity Energy Balancing Cogeneration	Abundant	2014	Baseload increment $166 Duct-firing increment $113	Baseload $87 Duct-firing increment $117[7]	Gas price volatility & uncertainty
	Aeroderivative gas turbine	Firm capacity (fast-start) Balancing Cogeneration	Abundant	2012	$164	$130	Gas price volatility & uncertainty

Resource	Leading Technology	Services	Estimated Undeveloped Potential	Earliest Service	Capacity Cost ($/kW-yr)[6]	Energy Cost ($/MWh)[5]	Key Issues
	Frame gas turbine	Firm capacity Balancing Cogeneration	Abundant	2012	$134	$140	Gas price volatility & uncertainty
	Hybrid intercooled gas turbine	Firm capacity (fast-start) Balancing Cogeneration	Abundant	2012	$164	$125	Gas price volatility & uncertainty
	Reciprocating engine	Firm capacity (fast-start) Energy Balancing Cogeneration	Abundant	2012	$172	$135	Gas price volatility & uncertainty
Nuclear Fission							
Nuclear	Advanced light water reactor	Firm capacity Energy	Abundant	2023	--	$108 (2025)	Public acceptance Cost escalation Construction delays Regulatory risk "Single shaft" reliability risk
	Small modular reactor	Firm capacity Energy Cogeneration	Abundant	Uncertain	--	Not available	Immature technology
Energy Storage							
Electricity	Compressed air energy storage	Firm capacity Balancing Diurnal shaping	Uncertain	Not evaluated	Uncertain & site-specific	--	Confirming suitable geology Monetizing system benefits
	Flow batteries	Firm capacity Balancing Diurnal shaping	No inherent limits	Uncertain	Uncertain	--	Immature technology Monetizing system benefits
	Pumped storage hydro	Firm capacity Balancing Diurnal shaping	Thousands of MW	2016	$324	--	Project development Monetizing system benefits
	Sodium-sulfur batteries	Firm capacity Balancing Diurnal shaping	No inherent limits		Uncertain	--	Early commercial technology Monetizing system benefits

Source: Council's Sixth Power Plan, Table 6-1

Figure E.5 - Fixed cost of commercially available firm capacity options with a 2015 service start date



Source: Council's Sixth Power Plan, Figure 6-2

Table E.4 - Key Planning Assumptions for Reference Power Plants

Reference Plant	Plant Size (MW)	Heat Rate (HHV Btu/kWh)	Capacity Factor/ Availability	Total Plant Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Integration Cost	Trans Cost ($/kW/yr)	Trans Losses	Plant Dev / Construction (mos)	Earliest Service	Developable Potential (MWa)
Animal manure energy recovery	0.85	10,250	75%	$5000	$45	$15	--	$17	1.9%	12/12	2012	50 - 110
Landfill gas energy recovery	2 x 1.6/unit	10,060	85%	$2350	$26	$19	--	$17	1.9%	18/15	2012	70
Waste water energy recovery	0.85	10,250	85%	$5000	$40	$30	--	$17	1.9%	18/15	2012	7 - 14
Woody residue - Greenfield, no CHP	25	15,500	80%	$4000	$180	$3.70	--	$17	1.9%	24/24	2014	665
Woody residue - Brownfield, CHP	25	19,300	80%	$3000	$194	$0.73	--	$17	1.9%	24/24	2014	Not separately estimated
Geothermal - binary	3x13/unit	28,500	90%	$4800	$175	$4.50	--	$17	1.9%	36/36	2017	375
Hydropower - new	10	--	50%	$3000	$90	Incl in fixed	--	$17	1.9%	48/24	2016	100's
Solar - CSP (NV > ID)	100	--	36%	$4700	$60	$1.00	--	$102	4.0%	24/24	2015	530/500kV ckt
Solar - CSP (NV > OR/WA)	100	--	36%	$4700	$60	$1.00	--	$189	6.5%	24/24	2015	530/500kV ckt
Solar - Tracking PV	20	--	S. ID - 26% MT - 25% OR - 25% E. WA - 24%	$9000	$36	Incl in fixed	$7.98	$17	1.9%	12/24	2013	Ltd by integration capability
Solar - Tracking PV (NV)	20	--	30%	$9000	$36	Incl in fixed	$7.98	$96	4.0%	12/24	2015	435/500kV ckt
Wind (ID Local)	100	--	30%	$2100	$40	$2.00	$7.98	$17	1.9%	18/15	2013	215
Wind (MT Local)	100	--	38%	$2100	$40	$2.00	$7.98	$17	1.9%	18/15	2013	80
Wind (OR/WA Local)	100	--	32%	$2100	$40	$2.00	$7.98	$17	1.9%	18/15	2013	1410
Wind (AB > OR/WA)	100	--	38%	$2100	$40	$2.00	$7.98	$179	4.3%	18/15	2015	570/500kV ckt
Wind (MT > ID)	100	--	38%	$2100	$40	$2.00	$7.98	$104	4.2%	18/15	2015	570/500kV ckt
Wind (MT > OR/WA)	100	--	38%	$2100	$40	$2.00	$7.98	$198	6.4%	18/15	2015	570/500kV ckt
Wind (MT > OR/WA via CTS)	100	--	38%	$2100	$40	$2.00	$7.98	$120	10%	18/15	2015	244/500kV ckt
Wind (WY > ID)	100	--	38%	$2100	$40	$2.00	$7.98	$120	4.5%	18/15	2015	570/500kV ckt
Wind (WY > OR/WA)	100	--	38%	$2100	$40	$2.00	$7.98	$219	7.0%	18/15	2015	570/500kV ckt
Waste heat recovery	5	38,000	80%	$3500	Incl in var.	$8.00	--	$17	1.9%	24/24	2014	10's - 100's
Coal - Supercritical steam	450	9000	85%	$3500	$60	$2.75	--	$17	1.9%	36/48	2017	--

Reference Plant	Plant Size (MW)	Heat Rate (HHV Btu/kWh)	Capacity Factor/ Availability	Total Plant Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Integration Cost	Trans Cost ($/kW/yr)	Trans Losses	Plant Dev / Construction (mos)	Earliest Service	Developable Potential (MWa)
Coal - Ultra-Supercritical steam	450	8010	85%	$3570	$60	$2.75	--	$17	1.9%	36/48	2017	--
Coal - USC steam w/90% CSS	450	10,170	85%	$5495	$128	$5.85	--	$17	1.9%	36/48	2023	--
Coal - IGCC	623	8680	80%	$3600	$45	$6.30	--	$17	1.9%	36/48	2017	--
Coal - IGCC w/88% CSS	518	10760	80%	$4800	$60	$8.50	--	$17	1.9%	36/48	2023	--
NG - Frame gas turbine	85	11960	91%	$610	$11	$1.00	--	$17	1.9%	18/15	2012	--
NG - Aero gas turbine	2 x 47/unit	9370	91%	$1050	$13	$4.00	--	$17	1.9%	18/15	2012	--
NG - Intercooled gas turbine	99	8870	91%	$1130	$8	$5.00	--	$17	1.9%	18/15	2012	--
NG - Reciprocating engine plant	12 x 8.3/unit	8850	93%	$1150	$13	$10.00	--	$17	1.9%	18/15	2012	--
NG - Combined-cycle	Baseload - 390 Peak incr - 25	Baseload - 6930 Pk incr - 9500	89%	$1120	$14	$1.70	--	$17	1.9%	24/30	2014	--
Nuclear	1117	10,400	90%	$5500	$90	$1.00	--	$17	1.9%	48/72	2023	--

Source: Table 6-3, Council's Sixth Power Plan

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APPENDIX F. DRAFT METHODOLOGY FOR RESOURCE COST ASSESSMENT

F.1 Overview

For the Resource Program, BPA used AURORAxmp® to model the effects that a range of future market scenarios may have on wholesale electricity prices. BPA did not take the next step of analyzing for the Resource Program the results of power purchases from different resource types for a given need under the same range of future market scenarios.

To quantify the benefits, costs, and risks associated with power purchases from resources to meet a specified need, BPA will need to employ a more complete modeling method. At this time, BPA has not selected the method or model(s) that will be used for the more sophisticated analysis.

One method to evaluate the cost of a power purchase from a resource is to calculate the present value costs of a resource given certain plant characteristics and assumptions about fuel costs. In the course of preparing the Resource Program, BPA began to explore this method using a spreadsheet model. The spreadsheet model is not intended to replace the more sophisticated analysis and has some of the same limitations that levelized cost calculations have (see Chapter 7), but it may prove to be a flexible tool in initially assessing the costs of power purchases when different power needs are being met.

The spreadsheet model is structured to use reference plant characteristics as inputs to calculate the present value costs of purchasing power from a resource to meet an annual or seasonal energy need. The spreadsheet model calculates the present value costs of compensating a plant owner for the resource's capital cost, fixed operation and maintenance cost, fuel costs, costs from CO_2 emissions, and variable operation and maintenance cost, excluding start-up costs. In the seasonal analysis, the spreadsheet can calculate the present value revenues from marketing power that may be greater than the seasonal need. The spreadsheet model does not quantify other revenue streams that could apply (e.g., production tax credits or revenue from renewable energy certificates). The formulas for the different cost categories are presented below. The formulas are written with the assumption that cost inputs are initially valued in real terms (2006$), and the generating resource's online date is 2012. When a resource's costs are quantified, the costs are calculated as total monthly costs.

F.2 Fixed Costs: Plant & Financing Costs

Let i be the index for the month, C be the overnight plant cost in 2006 real dollars, k be the annual inflation rate, p be the discount rate representing the combined debt and after tax return rates, M_i be the monthly payment for month i, and L be the economic life of the plant. The monthly payment is given by:

$$M_i = \frac{C \times (1+k)^{2012-2006}}{\sum_{j=1}^{L\times 12} \left[\frac{1}{\left(1+\frac{p}{12}\right)} \right]^j}$$

Note: this result follows from rearranging the equation

$$NPV\left(\sum M_i\right) = C \times (1+k)^{2012-2006}$$

To illustrate this calculation, consider a combined-cycle gas turbine plant. Using data from the Council's draft Sixth Power Plan as an example, gives an overnight cost of $945 per kW in 2006 real dollars for a plant built in 2012. The reference plant from Chapter 6 of the draft Sixth Power Plan has a baseload capacity of 390 megawatts. Using this plant as guidance, the overnight cost would be $945 × 1000 × 390 = $368,550,000 in 2006 real dollars. Using an inflation rate of 2.5 percent, we would inflate this amount to 2012 nominal dollars by multiplying by (1 + .025) for each year or multiplying by $1.025^6 = 1.1597$. This gives the nominal overnight cost of $368,550,000 * 1.025^6 = $427,405,009. To account for servicing debt and cost of capital, we assume a discount rate of 12 percent. The economic life given by the Council is 30 years, so we divide the total figure by:

$$\sum_{j=1}^{12\times 30} \left(\frac{1}{1+.012/12} \right)^j = \sum_{j=1}^{360} \left(\frac{1}{1.01} \right)^j = \frac{1-(1/1.01)^{360}}{1-(1/1.01)} = 98.19$$

This gives a monthly payment of $427,405,009 / 98.19 = $4,352,814

F.3 Fixed Costs: Fixed O&M Costs

Let i be the index for the month, P_i be the monthly fixed O&M costs, g be the 2006 real dollars per kW-year spent on fixed O&M, Z be the plant size in MW, k be the annual inflation rate, and y_i be the year from month i. The monthly fixed O&M costs are given by

$$P_i = \left[(Z \times g \times 1{,}000) / 12 \right] \times (1+k)^{(y_i - 2006)}$$

Continuing with the combined-cycle gas turbine plant, the Council gives the fixed O&M as $14 per kW per year. Thus, for the first month $I = 1$, the monthly cost in nominal dollars is

$$\left[390 \times 14 \times 1{,}000 / 12 \right] \times (1+.025)^6 = \$527{,}660.5$$

F.4 Variable Cost: Variable O&M Costs

Let i be the index for the month, V_i be the monthly variable O&M costs, b be the variable O&M cost in 2006 real dollars per MWh, Z be the plant size in MW, t be the capacity factor, d_i be the number of days in month i, k be the annual inflation rate, and y_i be the year from month i. The monthly variable O&M costs are given by

$$V_i = (Z \times t \times b) \times 24 \times d_i \times (1+k)^{y_i - 2006}$$

For the combined-cycle gas turbine plant, the variable O&M is given as $1.70 (2006$) per MWh. The capacity factor is given as .9. Thus, the monthly cost in nominal dollars is

$$390 \times .9 \times 1.7 \times 24 \times 31 \times (1+.025)^6 = \$514{,}839.9$$

F.5 Variable Cost: Anticipated CO_2 Cost Natural Gas

Let i be the index for the month, F_i be the CO_2 cost for month i, M_i be the nominal dollars per MTon of CO_2 emitted for month i, Z be the plant size in MW, t be the capacity factor, d_i be the number of days in month i, and h be the heat rate for the plant in Btu per kWh. The monthly anticipated CO_2 cost is

$$F_i = \left[{(h \times 1000 \times Z \times t)} \big/ {1000000} \right] \times \left(117 \big/ 2204.6 \right) \times 24 \times d_i \times m_i$$

Note: the 117 is lbs per MMBtu; the 2204.6 converts lbs per MMBtu into metric tons.

To calculate the anticipated CO_2 cost for natural gas, we need to use a forecast of the CO_2 cost for 2012. The Council's forecast gives a CO_2 cost of $12.20 (2006$) per metric ton of CO_2. The heat rate for the example plant is 7110 Btu per kWh for baseload. Thus, the anticipated CO_2 cost would be

$$\left[7110 \times 1{,}000 \times 390 \times .9 \big/ 1{,}000{,}000 \right] \times \left(117 \big/ 2204.6 \right) \times 24 \times 31 \times 12.20 = \$1{,}202{,}169$$

F.6 Variable Cost: Fuel Cost

Let i be the index for the month, U_i be the fuel cost for month i, Z be the plant size in MW, t be the capacity factor, h be the heat rate for the plant in Btu per kWh, s_i be the price of fuel per MMBtu (natural gas or woody residue) in nominal dollars for month i, and d_i be the number of days in month i. The monthly fuel cost is given by

$$U_i = [(s_i \times h \times 1000)/1000000] \times Z \times t \times 24 \times d_i$$

To calculate the fuel cost for the example plant we need a natural gas price forecast. The high gas price forecast for January 2012, in the draft Resource Program, was $10.43 per MMBtu in nominal dollars. Thus the fuel cost would be:

$$\left[(10.43 \times 7110 \times 1{,}000) / 1{,}000{,}000\right] \times 390 \times .9 \times 24 \times 31 = \$19{,}365{,}734$$

F.7 Conclusion

BPA needs to explore possible methods and models to further its ability to perform quantitative resource analysis. The methodology described above is one possible method to initially assess the costs of power purchases from a resource when different power needs are being met. However, as stated above and in more detail in Chapter 7, this type of approach has limitations. BPA will further explore this method and may present results based on the method in future Resource Programs.

APPENDIX G. STATE RENEWABLE PORTFOLIO STANDARD REQUIREMENTS

G.1. Preface

As explained in Chapter 2 and Appendix B, for modeling purposes BPA relied on Renewable Portfolio Standards (RPS) assumptions consistent with the Council's Sixth Power Plan. Table G.1 summarizes the RPS.

Table G.1 RPS Summary 09/04/09

	Montana	Oregon	Washington
Legislative Basis	Senate Bill 415; codified as Title 69, Section 3, Part 20 MCA	2007 Senate Bill 838; codified as ORS 469A.005 to 469A.310	Initiative 937
Required Utilities	Any electric utility regulated by the Public Utility Commission and competitive electric suppliers Cooperatives are exempt but those with >5,000 meters or more must implement RPS considering effects on rates, reliability & finances	Utilities with retail sales >3% of all retail sales in Oregon are in large standard. No requirement for smaller utilities until 2025. However, small utilities must offer a green pricing program after 1/01/2008. Utilities must meet large standard if they purchase coal (unspecified purchases by BPA are OK). Note: no minimum term set for coal purchases.	Utilities serving > 25, 000 customers in Washington

	Montana	Oregon	Washington
Requirements	Utility required to purchase renewables unless competitive bid shows total cost plus ancillaries is greater than or equal to cost of another power source over equivalent contract term; utility must purchase RECs with or without associated electricity except both RECs and electricity must be purchased from community renewable energy projects 2008-2009 5% of retail sales from renewables 2010-2014 10% of retail sales from renewables 50 MW of which from <5MW CREs; HB 207: Changes the definition of CRE project to be 25 MW or less HB 208: Sets 1/1/2012 as first compliance year for CRE projects instead of 2010 2015 – 15% of retail sales from renewables 75 MW of which is from <5MW projects HB 343 added dispatchability and seasonability of renewable energy sources as factors utilities may consider in complying with the RPS. Also allows utilities to own CRE’s up to 25 MW.	2011-2014 5% of retail sales from renewables 2015-2019 15% of retail sales from renewables 2020-2024 20% of retail sales from renewables 2025 25% of retail sales from renewables Utilities with 1.5% retail sales must have 5% of total sales from renewables as of 2025 Utilities with 1.5-3.0% retail sales must have 10% of total sales from renewables as of 2025. If a small utility grows into the large standard, it must meet interim targets that are set based on date it reaches large standard.	2012-2015 3% of retail sales from renewables 2016-2019 9% of retail sales from renewables 2020 – 15% of retail sales from renewables Potential Amendment: RPS may be revised to apply to load growth only. E.g. 100% of load growth met with renewables (conservation could be used to avoid RPS).

	Montana	Oregon	Washington
Eligible Renewables	Energized after 1/01/05 Located in Montana or delivered to Montana ***Wind*** ***Solar*** ***Geothermal*** ***Hydro*** (15 MW or less installed at existing dams or irrigation systems) ***Landfill or farm-based methane gas*** ***Wastewater treatment gas*** ***Biomass*** (excludes treated wood only) ***Hydrogen*** from renewable sources Renewable energy fraction from multiple fuel process that may also involve fossil fuels Compressed air produced from any other listed eligible renewable energy source, stored, and later released through a generator to produce power.	Energized after 1/01/1995, Located in WECC other than Canada ***Wind*** ***Solar PV and solar thermal*** ***Wave, Ocean, Tidal*** ***Geothermal*** ***Biomass*** (including black liquor but not MSW, or treated wood) ***Landfill gas or biogas*** ***Hydro*** located outside council protected areas, federal wild and scenic areas and Oregon scenic water ways. ***Efficiency upgrades to existing hydro facilities***. For FBS, only Oregon's proportionate share of upgrades counts toward standard. ***Old hydro*** if Certified Low Impact after 1/01/95 (capped at 50MW) ***EPP*** "Any electricity that the Bonneville Power Administration has designated as environmentally preferred power, or has given a similar designation for electricity generated from a renewable resource, may be used to comply with a renewable portfolio standard." ***Hydrogen*** from renewable sources.	Energized after 3/31/99 Located in Pacific NW or delivered real-time to the state. ***Wind*** ***Solar*** ***Geothermal*** ***Landfill gas*** ***Wave, Ocean, Tidal*** ***Gas from sewage treatment*** ***Biodiesel*** ***Biomass*** (excludes MSW, old-growth timber, black liquor & treated wood) ***Incremental Hydro*** owned by qualifying utility & not increasing impoundment – excludes FBS, IPP and PURPA projects**.** NOTE: Potential amendments may: • strike real-time delivery requirements and broaden location from PNW to WECC, • include <30MW hydro, • include biomass energized prior to 3/31/99, • include FBS incremental hydro, and • list black liquor as a qualifying biomass.

	Montana	Oregon	Washington
Bonus points	None	1) No limit on unbundled RECs if they are from Oregon projects, QF projects or net metered projects. 2) Solar carve out for IOUs. Total IOU solar nameplate capacity in the state must be 20 mw by 2020. For solar projects larger than 500 kw and built before 2016, IOUs get 2:1 RECs toward RPS standard up to 20 MW capacity cap.	1) Dbl points for <5MW projects 2) 1.2 points for projects energized after 2005 where the developer uses approved apprenticeship programs.
Special REC provisions	2-year rollover rights if purchase exceeds need.	1) All RECs must be certified by WREGIS unless net metered 2) RECs can be banked from 1/01/08, but must be used on a first in, first out basis. 3) RECs acquired prior to 3/31 of any year can be used for the proceeding year. 4) Bundled RECs can come from anywhere in US. 5) Unbundled RECs generated outside Oregon can only be used to satisfy 20% of the large renewable standard. COUs in large standard can use 50 percent RECs until 2020. (Net metered projects exempt from this.) 6) BPA's EPP (or replacement) qualifies (regardless of energization date or location).	RECs produced during the compliance year, proceeding year or subsequent year all satisfy current year requirements. *Note: There is interest in clarifying this limited banking language.*

	Montana	Oregon	Washington
Compliance Exceptions or Alternatives	1) Utility cannot acquire RECs. 2) Generation or interconnection jeopardizes reliability. 3) Utility is restructured under Title 69 chapter 8 and competitive bids show alternative supply would cost less over equivalent term (renewables cost includes ancillary services. 4) Incremental cost of renewable acquisition exceeds 15% of the cost of any other generating resource.	1) Do not have to acquire power in excess of load; 2) Do not have to supplant BPA or Mid C-purchases. 3) Cost cap: Incremental costs exceed 4% of annual rev req. compared to cost of a conventional resource with the same terms of delivery. 4) Alternative compliance payments acceptable means of complying (established by commission for IOUs and COU boards for COUs. COUs can invest ACP in energy efficiency projects)	1) Incremental RPS costs exceed 4% of rev req. compared to cost of conventional purchase with the same terms of delivery. 2) load growth over 3 years is zero 3) force majeure or regulatory actions adversely affecting source generation.
Penalty	$10/MWh	No financial penalty, but OPUC has enforcement authority for IOUs. COUs are not subject to penalties.	$50/MWh
BPA Customers Impacted	Flathead, Ravalli, Vigilante, Glacier, Missoula, Lincoln	EWEB is in large standard All other utilities must offer renewables to retail customers and cannot invest in new coal resources or purchase power from coal facilities without triggering large standard.	Clark, Seattle, Snohomish, Cowlitz, Tacoma, Benton PUD, Grays Harbor, Lewis, Inland, Mason 3, Clallam, Peninsula

	Montana	Oregon	Washington
Loose-ends		Bill does not set a term limit for coal purchases. Bill contains a loophole for market purchases attached to RECs to qualify as bundled RECs. *(No material difference between bundled and unbundled because bill does not require RECs and generation to be from the same resource.)* ODOE currently trying to define (by administrative rule) qualifying hydro efficiencies.	Only state auditor has the authority to determine which hydro efficiencies qualify. No definition of 'delivered real-time'.
Projects which meet both WA and OR RPS (excluding Montana)	**Without amendments**: Energized after 03/31/1999 Located in the Pacific NW or located in WECC delivered real-time to Washington. Wind, geothermal, solar, tidal, wave, efficiency upgrades to hydro owned by WA-LSE, biogas, some biomass. **With amendments:** No delivery requirements to Washington. Other parameters still apply/limit *except*: biomass now includes black liquor and biomass energization date relaxed to 1/01/1995. Include <30MW LIHI-endorsed hydro owned by WA LSE (no restriction on energization date)		

APPENDIX H. COMMENT SUMMARY

As noted in Chapter 1, BPA received comments on the draft Resource Program from Pacific Northwest Utilities Conference Committee (PNUCC), PNGC Power, Tacoma Power, Northwest Requirements Utilities (NRU), Seattle City Light, Public Power Council (PPC), and Demand Energy Networks. BPA appreciates these efforts to help BPA develop the Resource Program. Comments are addressed throughout the Resource Program and its appendices through reorganization and clarification of text and additional information presented.

H.1 Background and Context

Several comments (PNUCC, PNGC, NRU, Seattle) commended BPA for the comprehensive content and thorough analysis contained in the draft Resource Program. Commenters stated that they were pleased that the draft Resource Program was developed and showed results consistent with the Northwest Power and Conservation Council's draft Sixth Power Plan.

Several commenters (PNUCC, NRU, PNGC, PPC) stated their appreciation for BPA's collaboration with them and other stakeholders when developing the draft Resource Program. Comments stated that BPA should update the Resource Program on a regular basis and develop processes for evaluating resources so that customers are provided timely information for decisionmaking and their input is considered.

One comment (PPC) stated that the draft Resource Program was unclear when BPA would do a project-specific Environmental Impact Statement (EIS) and when it would rely on the 1995 Business Plan EIS and 2007 Supplement Analysis. The commenter stated that it expects that it would be appropriate for BPA to do a project-specific EIS before a major acquisition, rather than basing such an action on the Business Plan EIS.

One commenter (PNGC) stated concern that too many entities and agencies are chasing the same opportunities. PNGC does not view BPA as the clearinghouse for this knowledge. This comment stated that BPA should acquire resources only as specifically requested by a customer or group of customers. The assessment and identification process must be transparent and open to all. BPA should clarify in the final Resource Program that BPA does not own resources but may acquire output (e.g., of pumped storage and natural gas-fired resources). PNGC encourages pursuing such opportunities but competitively and with foreknowledge of BPA's customers.

One comment (NRU) stated that the Resource Program should outline a transparent process for acquiring resources, with substantial customer input. BPA should identify the purpose(s) of each potential resource acquisition. BPA should develop a long-term risk management policy for resource development. BPA and customers need to work out a protocol for accommodating customers' resource acquisition preferences.

One comment (PPC) stated that the Resource Program needs to acknowledge that the Tier 2 resource acquisition process will be driven by customer choice, not determined solely by BPA. BPA and customers need to work out a protocol for accommodating customers' resource acquisition preferences, in synch with timing of load placement notices, including how Vintage Renewable commitment and acquisition will work.

H.2 Market Uncertainties

One comment (NRU) stated that BPA should update its carbon assumptions in the scenario tree to include all three CO_2 price assumptions in each economic scenario. Another comment (Tacoma) stated that BPA should use more realistic forecasts of CO_2 costs than those in the Council's draft Sixth Power Plan, which are too high and are far above projections made for the Waxman-Markey bill.
One comment (Tacoma) stated that BPA should carefully review and reconsider long-term gas forecasts in light of the current economic downturn and technological advancements that have lowered natural gas prices. The assumption taken directly from the Council's draft Sixth Power Plan overstates the future price of natural gas and electricity.

H.3 BPA Total Supply Obligation Forecast

One comment (NRU) stated that the most significant single uncertainty in the draft Resource Program is the potential for BPA service to the region's two remaining aluminum smelters, Alcoa and Columbia Falls Aluminum Company (CFAC). BPA should remove this uncertainty by assuming that any service to Alcoa and CFAC would be accompanied by a resource or market purchase tied directly to that load, with costs and risks borne by that load, not BPA's other customers. One comment (PPC) stated that offering service to DSIs on concessionary terms will exacerbate BPA's problems with market exposure.

One comment (PNGC) stated that the final Resource Program should clearly identify a mechanism for utilities to account for conservation against their Above-HWM load.

H.4 Needs Assessment

Two comments (PNGC, NRU) stated that BPA should update its planning criteria to reflect customers' elections for Above-HWM service—the result will be that very little annual energy augmentation will be needed. One comment (NRU) also suggested that the Resource Program should use updated load forecasts.

One comment (NRU) stated that BPA should update the Resource Program for 30-minute persistence for the wind fleet.

One comment (PPC) stated that the assumption that 500 aMW of power is available for purchase in late summer is problematic, because it coincides with peak loads in California and the Southwest.

One comment (PPC) stated that the Resource Program needs to reflect planned additions to the FCRPS such as CGS output increase of 30 aMW and planned hydro upgrades.

One commenter (PNGC) stated that BPA should continue efforts to increase its technical and modeling capabilities to further understand the capabilities of the FBS before further committing to wind integration. PNGC stated that it is deeply concerned about the ability of the FBS and the region to respond to its commitment of reserves. Current models do not study the system in the time increments necessary to produce defendable answers. Studies need to address ramping capabilities, transmission congestion, and updated remedial action schemes to ensure reliable second-to-second system management. PNGC stated that BPA should investigate the "disconnect" between the monthly energy quantities in BPA's 70-year studies for July-September and corresponding generation realized. PNGC stated that BPA should confirm and verify the modeling components and software being used for its power planning and resource programs, including inputs such as streamflows and H/K tables and plant loss factors. The Resource Program should establish and publish a metric that will judge resource models on a weather (precipitation)-normalized basis.

H.5 Resource Evaluation

One commenter (PNGC) stated that BPA should continue the work of understanding the capacity and flexibility of the system. FBS flexibilities may not be sufficient to meet the ever-increasing needs of competing stakeholders. BPA has done a good job of wringing more capability from the existing system but may be providing too much deference to the mandate of integrating variable generation into the FBS. BPA should continue to work with those wishing to add variable generation and should develop more rigorous analyses showing impact to the system. This commenter stated that BPA is not under FERC jurisdiction and is not required to provide ancillary services.

H.6 Resource Descriptions

One comment (PNGC) stated that the final Resource Program should better describe expected conservation amounts in annual values. The draft mixes the Council's five-year planning period and BPA's different planning period, and the use of cumulative conservation totals makes it difficult to follow the values.

One comment (PNUCC) stated that the final Resource Program should expand on the uncertainty and risks associated with acquiring conservation. Include estimates of the likely uncertainties facing the region with conservation measures and program design challenges for acquiring the savings BPA and the Council envision. Work with the Council to help the region quantify these risks and identify potential actions to be taken in the event the targeted amounts of savings are not achievable. One comment (NRU) stated that BPA should run sensitivity analyses of whether BPA's customers will fully achieve BPA's share of the Council's conservation target in the assumed timeframe, and what impact failure may have on BPA's load-resource balance.

One comment (NRU) stated that utilities will need assistance from BPA to make acquisition of all cost-effective conservation a reality. One comment (PNGC) stated that the Council's targets are achievable if BPA and consumer-owned utilities have a collaborative working relationship that allows utilities numerous degrees of freedom to capture energy savings in their service areas.

One comment (Demand Energy Networks) stated that peak demand conservation, the most valuable form of conservation, should be included in the definition of conservation and in the Resource Program. Distributed electricity storage should be included in the definition of methods of conservation and as a means of demand response.

One comment (Demand Energy Networks) stated that the draft Resource Plan includes only pumped storage; distributed electricity storage, specifically battery storage, should be included as accepted methods of providing energy storage. Distributed electricity storage, using current battery technology, is available and currently installed at BPA utility customer sites.

H.7 Resource Assessment

One commenter (Tacoma) stated that the 5 percent capacity value the Northwest Power and Conservation Council ascribed to wind is suspect given the studies that found an inverse correlation between wind speed and load patterns during periods of sustained peak load such as hot spells and cold snaps. BPA should include planned improvements in the final Resource Program, including planned upgrades, hydropower improvements, and capital equipment replacements at NW Federal dams.

One commenter (Seattle) stated that it believes BPA has a responsibility to acquire new resources to meet the demands of new services rather than planning to rely on the flexibility of the existing FCRPS. The comment stated that the approach in the draft Resource Program is fundamentally wrong when it states that, because the flexibility of the FCRPS will be reduced as new uses are added, BPA will have to acquire new resources to replace that flexibility. Instead, the flexibility of the FCRPS should be reserved to BPA's preference customers, to meet current fish and wildlife goals, and for use in extraordinary situations. New power uses should be fully funded by new power users and should not be allowed to displace preference uses.

One commenter (PPC) stated that BPA needs to ensure that the public and regional decisionmakers are aware of the consequences of further restrictions on the FCRPS. BPA needs to carefully delineate the amount of FCRPS capacity required to serve its requirements loads in each year and separately describe the amount of capacity it expects wind generation to use in each year for balancing capacity. One significant weakness in the draft Resource Program is that BPA used the same level of reserves in 2019 as in 2013, which obscures BPA's expectations of what it will do with regard to capacity uses post 2013. The Resource Program needs to explain what BPA is planning to do regarding wind integration. BPA also needs to carefully delineate what further restrictions in hydro capability will do to BPA's ability to meet the balancing capacity needs of requirements load and to integrate wind.

One comment (PPC) stated that BPA's support of the further development of analytical models is an important part of understanding how much capacity BPA has available and what demands there are on BPA's capacity.

H.8 Market purchases and risk

One commenter (PNGC) agrees that short-term purchases could be prudent but is concerned about volumes and strategies. BPA should establish and make available to paying customers BPA's Risk Management Policies and Procedures to ensure customers that BPA's risks are vetted and addressed (the customers bear BPA's risks).

One commenter (NRU) supports BPA's decision to rely on market purchases but asks BPA to reassess this reliance on a regular basis in light of the volatile prices in the power market. BPA should develop a long-term risk management policy for resource development. With customer input, BPA needs to carefully evaluate when and how it will procure longer-term resources rather than rely solely on short-term market purchases.

One commenter (PPC) stated that BPA should carefully consider to what extent it is going to rely on market purchases, and the risks attendant on relying on the market. One thing that is not considered in the draft Resource Program is the likely actions of others in the market. If a number of major market participants plan on market purchases to meet needs, that is going to increase the risks of going short. BPA needs to consider publicly available information regarding the plans of other participants in evaluating the extent of its dependence on market purchases.

H.9 Action Plan

One commenter (Tacoma) offered qualified support for draft Resource Program action plan item 9.2.1, Renewable Resource Integration. The commenter stated that it supports collaborative efforts of joint initiative parties as long as each of participating balancing authorities benefits and opposes any result where one balancing authority receives an unfair share of benefits or is asked to bear an unequal portion of the burden.

One comment (Demand Energy Networks) stated that the Resource Program should include distributed electricity storage as an accepted method of conservation. Explore and assess coupling small-scale renewable resources with distributed electricity storage. Evaluate and consider utilizing distributed electricity storage as part of market purchase strategies, including short- and long-term purchases and in-year seasonal needs. Include distributed electricity storage in the evaluation of flexibility augmentation options. Include distributed electricity storage in efforts 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.

One comment (PNUCC) stated that the Resource Program should be expanded to include an economic analysis of the alternatives for meeting the projected capacity and flexibility needs.

One comment (Tacoma) stated that the key uncertainty is the extent to which additional resources will be needed to balance variable wind generation. The commenter stated that it is not prudent to assume that efforts will obviate the need for new generation resources. The commenter strongly recommends that the Resource Program include a scenario that assumes new natural gas resources are needed to integrate a significant share of the new wind resources, and in that scenario assess the cost and CO_2 emissions.

One commenter (NRU) encourages BPA to further evaluate enhancements to increase generation efficiency and capacity at hydro facilities, and also pumped storage.

One commenter (NRU) states that the Resource Program should address potential impacts to customers and the BPA BAA given the increased renewable portfolio requirements in California and the expected increase in amount of intermittent generation integration into BPA's BAA. The potential need for carbon-emitting resources for balancing reserves to integrate wind needs careful thought in collaboration with customers. Costs of resources acquired to integrate intermittent resources should be borne by those using integration services.

H.10 Comments addressing Council assumptions

Two commenters (Tacoma, NRU) stated their concern with the assumptions taken directly from Council's draft Sixth Plan of 1,100 aMW of conservation rather than the 1,000 supported by utility and BPA staff in the Cost Recovery Adjustment Clause (CRAC) process. The lower end of the Council's conservation assumption (1,100 aMW) is not supported by robust analysis; 1,000 is more realistic. One comment (NRU) stated that BPA should revise the statement regarding 42% to say: the public power share of regional load is 42%, based on the Council's data, and BPA currently uses this percent to set its conservation target but is reviewing the appropriateness of using the 42% for future policy decisions. One comment (PPC) stated that the Council's regional conservation targets are overly ambitious. BPA and the Council need to develop a method for determining public power's share of the Council's targets that is based on a more sophisticated look at the conservation potential within public power's service territories rather than based on load. One comment (Tacoma) advocated using a "ground up" approach to estimate public power's share of the region's future conservation potential.

One comment (Tacoma) stated that the assumption taken directly from the Council's draft Sixth Power Plan overstates the amount of renewable resources that will be developed in response to state Renewable Portfolio Standards (RPS).

One comment (Tacoma) stated that the cost of integrating wind will vary across regional balancing authorities more than the $88-108/MW assumed by the Council's draft Sixth Power Plan.

One commenter (Tacoma) stated its concerns about the assumptions taken directly from the Council's draft Sixth Power Plan, including that the draft Plan understates the cost of resources needed for wind integration and capacity and present rate impacts in a way that disguises the actual increase in electric bills that customers are likely to experience.

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