REGIONAL MARKET ASSESSMENT AND PRELIMINARY FEASIBILITY REPORT

BANKS LAKE PUMPED STORAGE PROJECT
FERC NO. P-14329

Prepared for:

Columbia Basin Hydropower

"Generation from Irrigation"

Ephrata, Washington

Prepared by:

Kleinschmidt

Gresham, Oregon
www.KleinschmidtGroup.com

Reed Consulting
Highlands Ranch, Colorado

May 2015
First Revision October 2015
Second Revision August 2016

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GLOSSARY OF TERMS

A/S	Ancillary Services
BAA	Balancing Authority Area
BOR	Bureau of Reclamation
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CBHP	Columbia Basin Hydropower
CCCT	Combined Cycle Combustion Turbine
CCED	Centrally Cleared Energy Dispatch
CT	Combustion Turbine
DOE	Department of Energy
EIM	Energy Imbalance Market
EPAct	Energy Policy Act of 2005
ESA	Endangered Species Act
FAS	Interconnection Facilities Study
FCRPS	Federal Columbia River Power System
FDR	Franklin D. Roosevelt
FERC	Federal Energy Regulatory Commission
FES	Interconnection Feasibility Study
GI	Generator Interconnection
HC	Hourly Coordination
IRP	Integrated Resource Plan
ISIS	Interconnection System Impact Study
kV	Kilovolt
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
LLI	Line or Load Interconnection
LOLP	Loss of Load Probability
MC	Market Assessment and Coordination Committee
MW	Megawatt
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NWE	Northwestern Energy
NWPCC	Northwest Power & Conservation Council
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
PAC	PacifiCorp
P/G	Pump/Generators
PGE	Portland General Electric
PNCA	Pacific Northwest Coordination Agreement
PNW	Pacific Northwest
PNUCC	Pacific Northwest Utilities Conference Committee
PPA	Power Purchase Agreements
Project	Banks Lake Pumped Storage Project

PSCo	Public Service Company of Colorado
PSE	Puget Sound Energy
PUD	Public Utility District
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
RPS	Renewable Portfolio Standards
RRSD	Regulation Reserve Sharing Group
SCED	Security Coordinated Economic Dispatch
TSR	Transmission Service Request
USFWS	United States Fish and Wildlife Service
WDFW	Washington Department of Fish & Wildlife
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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EXECUTIVE SUMMARY

Columbia Basin Hydropower (CBHP, formerly known as the Grand Coulee Project Hydroelectric Authority) has two alternatives for pumped storage development under a preliminary permit from the Federal Energy Regulatory Commission (FERC) (Project No. 14329). Alternative No. 1 would use Banks Lake as the upper reservoir and Lake Roosevelt as the lower reservoir; Alternative No. 2 would use Banks Lake as the lower reservoir and involve construction of a new upper reservoir. Both Lake Roosevelt and Banks Lake are components of the Columbia Basin Project, and are currently connected by a feeder canal that provides water for twelve pumps operated by the Bureau of Reclamation (BOR) at the John W. Keys III Pump Generating Plant (Keys Plant). This report focuses on preliminary analysis of Alternative No.1, known as the Banks Lake Pumped Storage Project (Project).

CBHP retained Kleinschmidt Associates (Kleinschmidt) to perform a pre-feasibility analysis of potential power and load balancing benefits and to identify course level cost estimates for the potential development of the Project. In turn, Kleinschmidt retained Lands Energy Consulting, Muchlinski Consulting, and Reed Consulting to determine the future power value and ancillary benefits through an energy market analysis.

In summary, the Project has the potential to serve multiple regional needs within the next 10 to 50 years in the areas of power generation, load balancing, and other ancillary services. In evaluating preliminary capital construction costs, the Project is projected to cost approximately $1.25 billion (assuming an installed capacity of 500 MW) due to expansive tunneling, relatively low head, transmission inter-tie, and equipment costs. However, there is great potential for this Project to help address regional generation and load balancing demands needed to offset factors such as wind integration, retirement of coal-fired plants and carbon-emitting resources, meeting renewable energy demands in the Northwest and California, and improving irrigation/water management objectives within the Columbia Basin Irrigation Project. While the projected $1.25 billion cost is subject to several contingencies, this estimate provided enough level of precision at this stage of the Project pre-feasibility effort to perform a preliminary cost/benefit analysis as discussed below. In addition, the Project is scalable up to an installed capacity of 1,000 MW. In this configuration, the overall Project costs are estimated to be approximately $2.5 billion.

The results of a preliminary cost/benefit analysis that was performed using the cost and power revenue figures discussed in further detail in the body of this Report indicate that the Project has a positive Net Present Value (NPV) in both of the scenarios that were evaluated. The NPV for the 500 MW Project across the 40-year (2025 to 2064) study period ranged from a low of approximately $1,259 million to a high of $1,590 million. The NPV for the 1,000 MW Project configuration across the 40-year study period ranged from a low of approximately $2,491 million to a high of $3,137 million. While preliminary in nature, these results indicate that the Project may be economically viable assuming that CBHP could secure long-term commitments for the sale of energy, capacity, and ancillary services from the Project.

REPORT UPDATE INFORMATION

On April 28, 2015, the findings of the initial version of this Report were presented to the CBHP Board of Directors. Given the preliminary favorable viability of the Project, the Board of Directors supported the idea to further refine the feasibility of the Project, collaborate with stakeholders, off-takers, and potential investors and to implement a Project awareness campaign. In collaboration with CBHP Management and the Board of Directors, the list of next steps identified in Section 14 of the initial Report were used to develop the planned near term next steps for the Project.

As indicated on the cover page, this Report is the second update to the initial version that was issued in May 2015 as a result of Board of Directors approval to proceed with the Project. The purpose of this second revision is to (1) update several portions of the Report to incorporate recent events and Project-related activities and (2) to present the results of an updated economic analysis for the Project. As CBHP furthers its effort, this Report may continue to be updated from time to time as new information becomes available.

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1.0 INTRODUCTION

CBHP and Kleinschmidt have prepared this Report developed principally by Reed Consulting. This Report provides a pre-feasibility analysis of a proposed 500 to 1,000 megawatt (MW) pumped storage project located in north central Washington near the town of Grand Coulee. On August 22, 2013, CBHP was issued a Preliminary Permit by the Federal Energy Regulatory Commission (FERC) to study the feasibility of the Banks Lake Pumped Storage Project (Project), FERC Project No. P-14329. FERC subsequently granted a two-year extension of the Preliminary Permit for the Project on July 5, 2016. The Project evaluated in this Report is based upon a preliminary site layout as shown in Figure 1 for both the 500 MW and 1,000 MW configurations.

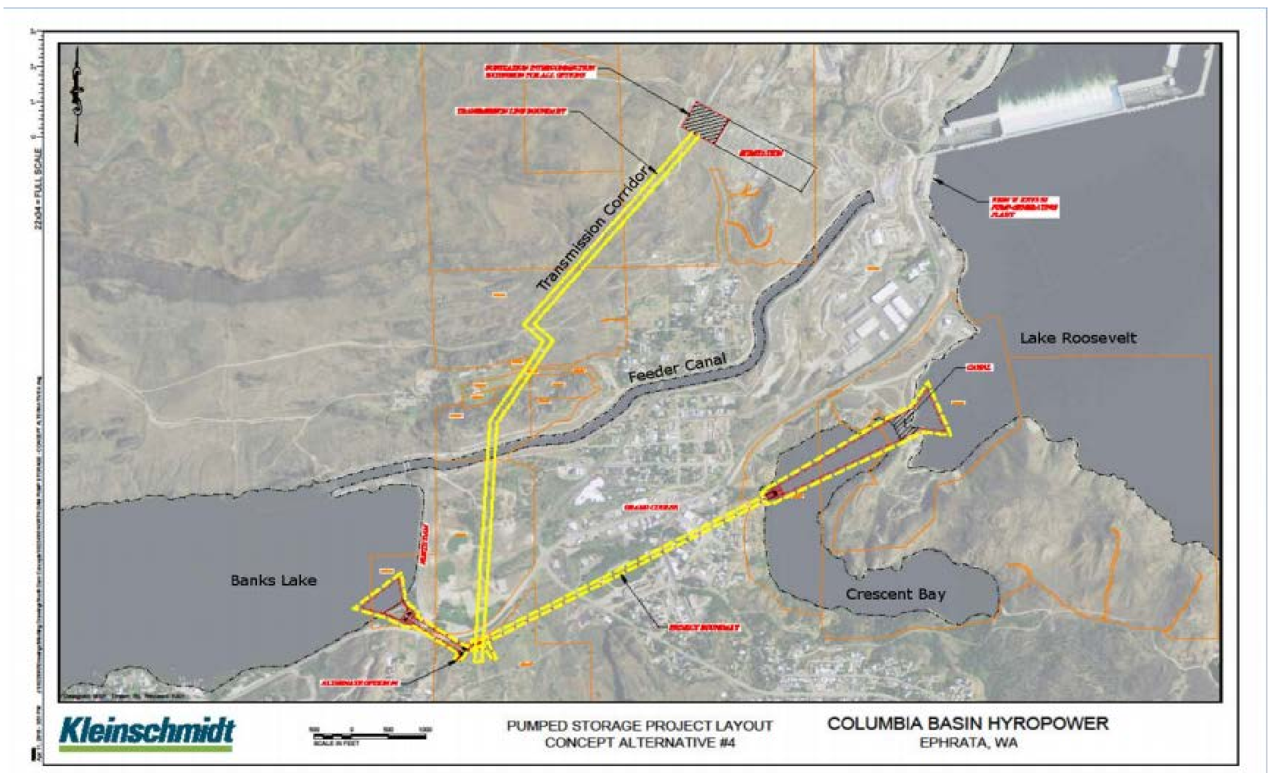

FIGURE 1 PRELIMINARY SITE LAYOUT

The preliminary results described in this Report indicate that the Project should be investigated based on the conservative assumptions and the high-level pre-feasibility analysis presented herein regarding size, estimated costs, and long-term regional energy market conditions. Furthermore, with the Northwest and California's increasing reliance on renewable power sources (e.g., wind and solar) and the pressure to reduce and eliminate carbon producing generation resources, the need for new "clean" sources of energy, capacity, and ancillary services will likely increase in the future. The Project would be well-suited to provide a reliable source of power and ancillary services for the benefit of the Northwest's citizens and businesses.

1.1 NEED FOR THE PROJECT

The Project is located in north central Washington near Grand Coulee Dam within the Western Electricity Coordinating Council (WECC) region. The WECC region comprises a large geographic area that includes the majority of 11 western states and portions of British Columbia and Baja Mexico.

Many areas of WECC, including the Pacific Northwest (PNW), are currently in a moderate "overbuild" status. As a result of this oversupply situation, the pace of new power plant construction in the PNW and WECC has slowed significantly from the mid-late 2000s, with the notable exception of renewable resources such as wind and solar. In spite of the overbuild status, many states within WECC, such as Washington, Oregon, and California, have enacted renewable resource plans whereby load-serving utilities are required to have certain target amounts of renewable resources in their power supply portfolios. In some cases, utilities are being required to acquire additional amounts of renewable resources even though they do not need the additional power to meet near-term forecasted firm loads.

Under these circumstances, conventional generating plants would be used to compensate for the variability and unpredictability of intermittent renewable resources. As having highly flexible conventional generating plants "on standby" to respond to changes in intermittent generation may result in these plants not being available for other purposes (such as serving firm loads), the availability of a balancing facility such as the Project may be of great value to the region and its utilities.

Another impending development that will have a significant impact on the load/resource balance in the PNW is the early retirement (due to environmental reasons) of the Centralia, Boardman, and Colstrip 1 & 2 coal-fired generating plants. Also, it’s clear that the current state Governors and Legislatures of Washington and Oregon are openly interested in moving away from coal by wire generation sources and mitigating future capacity deficiencies by using non-carbon producing renewable resources. Finally, based upon our research, electric utilities in the PNW will likely remain in a moderate to slight overbuild condition until approximately 2020 to 2022. At that point, several regional utilities including Avista and Puget Sound Energy (PSE) are forecasting that they will need to acquire new generating capacity to serve firm loads. An in-service date of approximately 2025 for the Project aligns well with the current projected need for new generating capacity in the PNW.

2.0 PROJECT OVERVIEW

The Project is located in north central Washington as shown on Figure 2, between Banks Lake and Lake Roosevelt reservoirs. A proposed layout for the Project is shown in Figure 1. Based on the Preliminary Permit issued by FERC, the Project could generate up to 1,000 MW of power during periods of peak demand by dropping water over an average of 300 feet in elevation through two tunnels that would connect the two large reservoirs. A powerhouse would be constructed on either Crescent Bay (Figure 1 – Site Layout) or Lake Roosevelt and would contain up to four 250 MW adjustable speed pump-generating units that would generate power when power demand is greatest, and pump water up to the Banks Lake reservoir during off-peak periods when power rates are lowest. The Banks Lake reservoir is located adjacent to the town of Grand Coulee, Washington. The lower reservoir, Lake Roosevelt, is located behind Grand Coulee Dam, immediately east of Banks Lake. Crescent Bay is a small body of water that is located adjacent to the west shore of Lake Roosevelt, slightly upstream from Grand Coulee Dam.

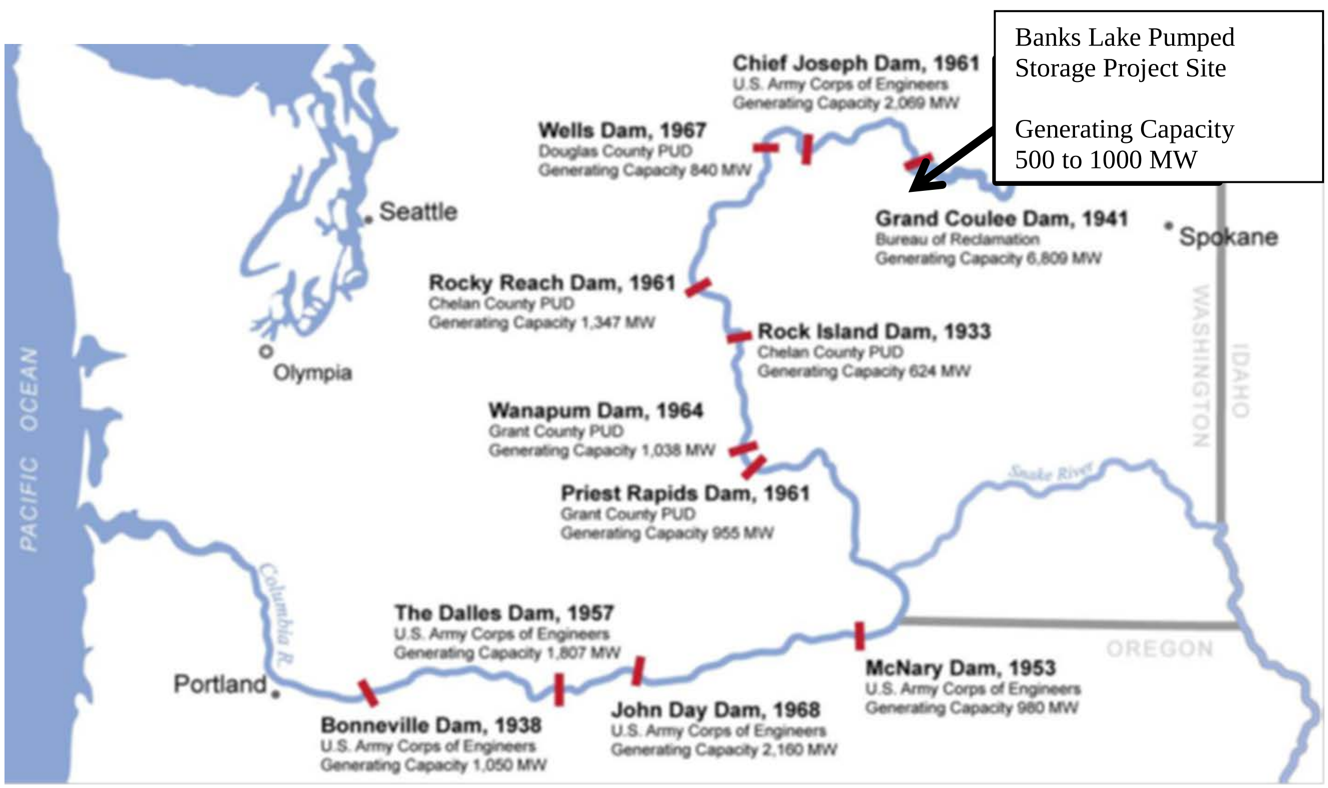

FIGURE 2 PROJECT LOCATION IN NORTH CENTRAL WASHINGTON

Both the Project's upper and lower reservoirs have very large storage capabilities relative to other proposed PNW pumped storage facilities:

Banks Lake active storage = 715,000 acre-feet
Lake Roosevelt active storage = 5,200,000 acre-feet

The Project would utilize adjustable-speed pump/generators (P/G) which would allow the plant's pumping load to be varied in real-time (in addition to being able to vary generation output in real-time).

Although the Project's FERC preliminary permit specifies an installed generating capacity of 1,000 MW, there is flexibility to design and construct a smaller project. Based on the initial interest expressed by potential off-takers, project design optimization, identified operational constraints at Banks Lake, and environmental considerations, CBHP is focusing on the development of the 500 MW configuration alternative (although the Project could feasibly range in size from 250 MW to 1,000 MW). Annual generation from the Project would vary depending on the final adopted operating plan, the specific needs of the purchasers/off-takers and regional power market conditions. Based on currently forecasted market conditions and a Project maximum capacity of 500 MW, it is estimated that the Project's annual generation in its first year of operation (2025) would be approximately 769,600 megawatt hours (Mwh). Under the maximum 1,000 MW configuration, the Project's annual 2025 generation would be approximately 1,430,000 Mwh.

3.0 OVERVIEW OF HYDROELECTRIC PUMPED STORAGE PROJECTS

Hydroelectric pumped storage is a mature technology and has been in use by the electric utility industry in the United States for many decades. Pumped storage plants utilize two reservoirs that are in close proximity but that have a significant elevation differential. During periods of low power use/low power prices, water is pumped from the lower reservoir into the upper reservoir. Then, during periods of high power usage/high market prices, water is released from the upper reservoir into the lower reservoir through the same reversible pump/generator units. Since the efficiency of the plant in both pumping and generation modes is less than 100%, a pumped storage plant is a net consumer of energy.

Many pumped storage plants developed in the United States were originally constructed for the primary purpose of providing firm capacity to the grid in order to help reliably serve peak power loads. This was especially the case for many thermal based utilities that had limited options to develop peaking facilities, especially during the periods of time when the use of natural gas as a power plant fuel was severely restricted by U.S. Government policies. Pumped storage plants are also capable of being operated for energy shifting purposes which allows the plant operator to potentially realize additional revenues by arbitraging differences in wholesale power prices between low-priced and high-priced periods.

The addition of greater levels of intermittent generating plants (such as wind and solar) to the bulk power system has created a need by many Balancing Authority Area (BAA) operators to provide large amounts of short-term balancing energy and capacity in order to manage the variable output of wind and solar plants while maintaining the reliability of the bulk power system. With FERC's recently acquired (2005) ability to levy civil penalties of up to $1,000,000/day for the violation of established reliability criteria, it is more imperative than ever that BAAs and other transmission system operators have sufficient supplies of flexible generating capacity available in order to maintain the stability and reliability of the bulk power system. To this end, the potential development of new pumped storage plants is increasingly being driven by the need for BAAs and electric utilities to acquire additional sources of operating flexibility and ancillary services.

3.1 PUMPED STORAGE OPERATIONS IN THE PACIFIC NORTHWEST

The majority of the existing pumped storage plants in the United States are located in areas outside of the PNW and the WECC region. Of the 40 pumped storage plants currently in operation in the U.S., only 14 of the plants are located within the WECC region and only one plant is located in the Northwest.

The only existing Northwest hydro pumped storage plant is the John W. Keys III plant (Keys Plant), which is located near Grand Coulee Dam and is operated by the BOR. The Keys Plant was originally constructed for the sole purpose of lifting water from Lake Roosevelt into Banks Lake in order to supply irrigation flows to the central Columbia River Basin in Washington State. However, in the early 1980s, the Keys Plant was expanded to include six new reversible pump/generators that allowed the plant to generate up to approximately 314 MW.

While the Keys Plant's generating capabilities were used sparingly at first, over the last 20 years the plant has been more actively utilized by the Bonneville Power Administration (BPA) to help manage various needs on the Federal Columbia River Power System (FCRPS). In particular, the addition of significant amounts of new intermittent wind plant capacity in the BPA BAA has led BPA to utilize the Keys Plant to help manage the real-time variability of these wind plants, especially during high flow events when the flexibility of the FCRPS is severely constrained.

In the last 5 to 10 years, several new pumped storage plants (in addition to the Banks Lake Project) have been proposed in the Northwest region including the following four plants that are currently under various phases of investigation and development:

- JD Pool – Potential – 1,200 MW
- Swan Lake – Potential – 400 MW
- Gordon Butte – Potential – 400 MW
- Coffin Butte – Potential – 250 MW

In addition to the above noted plants, multiple other potential pumped storage sites have been investigated in the past by various utilities and developers including BPA and Chelan Public Utility District (PUD).

4.0 POWER MARKET ASSESSMENT FOR THE PACIFIC NORTHWEST REGION

4.1 CURRENT STATUS OF THE WHOLESALE POWER MARKETS

Currently, the wholesale power markets in the Pacific Northwest (PNW) region are in a condition of moderate oversupply. This condition is the result of a large amount of new generating capacity - much of it constructed by merchant developers - that was added to the PNW resource base in the early 2000s. In addition, the economic slowdown of 2008 caused many PNW utilities to revise their load forecasts significantly lower than was previously forecast, which in turn acted to create a larger overall regional capacity surplus relative to the amount needed to reliably meet firm load obligations.

In addition to the above factors, the emergence of fracking technology in several of the natural gas and oil producing regions of the U.S. in the last five years has acted to significantly reduce the cost of natural gas as compared to previous forecasts. This in turn has acted to depress the wholesale market value of energy in the PNW regional markets since natural gas-fired Combined Cycle Combustion Turbine (CCCT) units are typically the marginal units on the system. The combination of a significant surplus of generating capacity needed to serve firm PNW loads and historically inexpensive natural gas has acted in tandem to depress wholesale energy prices and to discourage the development of new generating resources in the PNW region. This situation has also led to the condition whereby the market price of capacity in the PNW region is very low, even approaching zero in some cases.

While the PNW currently has very active spot markets and forward markets for wholesale energy products, the PNW does not have an established market for capacity products. So while projected future values for wholesale energy can be obtained from various sources (including quotes from sellers/brokers and natural-gas price based fundamental analysis), obtaining future projected values for capacity is by comparison very challenging. The value of capacity also tends to be driven by the reliability requirements of the region’s load serving utilities, which can vary from entity to entity.

The addition of a significant amount of intermittent generation (primarily wind plants) on the PNW grid over the last 5 years has created an increased need for system balancing energy and capacity. In order to manage the variation and unpredictability of wind plant generation, generators that can be re-dispatched on very short notice must be available to respond to these variations to ensure that the bulk power grid is reliably managed pursuant to the criteria established by the North American Electric Reliability Corporation (NERC) and WECC.

The increasing need for flexible generating capacity to manage variations in intermittent plant output has added significant new operational requirements for many PNW BAA operators, most notably BPA. Due to operational constraints on its hydro system, BPA has been forced to limit the amount of real-time regulation capacity that they can make available for the purpose of providing intra-hour/real-time balancing energy and capacity for generators that operate within its BAA. Other PNW BAA operators that have large amounts of intermittent generation within their BAAs (such as PSE) are increasingly being required to utilize gas-fired CCCTs and Combustion Turbines (CTs) for the purpose of providing real-time balancing energy and capacity.

4.2 NEAR-TERM WHOLESALE POWER MARKET ASSESSMENT

Given the current levels of load growth and conservation being forecasted by regional utilities, the PNW region would appear to have sufficient generating capacity to reliably serve firm energy and peak loads until approximately 2020 to 2022. Given the current projection of continued low natural gas prices, the value of wholesale energy in the PNW is also expected to remain relatively low through this timeframe (and potentially even longer).

The market value of capacity in the PNW is also expected to remain relatively low up until the point when one or more PNW utilities are required to add new generating resources in order to reliably meet their firm peak load obligations. This situation is not expected to occur until approximately 2020 to 2022 based upon a review of the Integrated Resource Plans (IRPs) of multiple PNW utilities and recent regional load/resource studies conducted by the Northwest Power & Conservation Council (NWPCC), Pacific Northwest Utilities Conference Committee (PNUCC), and BPA.

Although the pace of construction for new wind plants has slowed down considerably in the PNW over the last 2 to 3 years, the ability of PNW BAA operators to provide the required amounts of real-time balancing energy and capacity is still presenting significant challenges. In addition, California (and to a lesser extent the Desert Southwest and Idaho Power) is in the process of adding large amounts of new solar generation, most of which is solar photovoltaic (PV) technology that also requires large amounts of real-time balancing energy and capacity to be provided from conventional dispatchable plants. In addition, in October 2015, the California Legislature approved a plan to increase its renewable energy target to 50% by 2030. The California Independent System Operator's (CAISO) need for additional real-time operational flexibility will therefore likely "spill over" and create a higher demand for such services in the PNW as well. Also, in March 2016, the Oregon Legislature approved a plan to increase the renewable energy target for investor-owned utilities to 50% by 2040. This action will likely increase the need in the PNW for new sources of system flexibility, A/S, and energy storage services.

4.3 LONG-TERM MARKET ASSESSMENT

There are several events that are currently projected to occur around 2020 to 2022 that have the potential to create a significant shift in the PNW wholesale power markets. As was previously mentioned, at least one PNW utility, PSE, is forecasted to need new generating capacity in order to reliably serve 2021 firm peak loads. In 2020, both the Boardman coal-fired plant (585 MW) and Centralia Unit #1 (730 MW) are expected to be shut down due to environmental constraints with Centralia Unit #2 (730 MW) also expected to be shut down in 2025. In addition, PSE and Talen Energy recently announced the early retirement of Colstrip Units 1 & 2 in 2022. The shut-down of these two coal-fired units will result in the loss of an additional 307 MW of firm generating capacity for the PNW region.

A recent study conducted by the NWPCC in October 2014 indicated that the PNW region could face a capacity shortfall of up to 2,700 MW in 2021 unless new generating resources are constructed. The most recent version of the NWPCC's 2021 regional adequacy assessment released in August 2016 lowered the 2021 regional capacity shortfall amount to 1,000 MW. This change was primarily due to lower utility load forecasts. However, the projected 2022 regional capacity shortfall amount, which includes the impact of the early retirement of Colstrip Units 1 & 2, rises to 1,400 MW. While Portland General Electric (PGE) has announced plans to replace its majority share of the Boardman plant with new gas-fired generation, no entity to date has announced plans to replace the generating capacity to be lost by the early shutdown of Centralia Units 1 & 2 in 2020 and 2025 (which are owned by TransAlta) or Colstrip Units 1 & 2 (which are jointly-owned by PSE and Talen Energy).

In addition, there has also been some discussion in the PNW region regarding the potential early shutdown of Colstrip Units 3 & 4 although at present, no definite plans have been announced. It is also possible that some western states could enact restrictions on the construction of new gas-fired power plants, as has been mentioned by Washington State's present Governor.

Given the above referenced situation in the 2020 to 2022 timeframe, the probability is increasing that some amount of new generating capacity will be needed in order for the region's load-serving utilities to be able to reliably meet their firm winter peak load obligations. At the point in time when new generating capacity is required to be added to the system for reliability purposes, the market value of capacity would be expected to rise to the cost of constructing a new incremental gas-fired CCCT or CT. It should be noted that one or more PNW utilities could be required to add new generating capacity for reliability purposes *even if the wholesale value of energy in the marketplace remains relatively low*.

If California is successful in achieving its current renewable energy targets of 33% by 2020 and 50% by 2030, the real-time balancing energy and capacity demands on the CAISO's system could exceed its internal capabilities, thereby requiring external sources of such balancing services. Combined with the addition of new renewable resources in the PNW region to meet Oregon's 50% by 2040 renewable energy target (which may include a significant amount of solar PV generation), the PNW will also likely face challenges with regard to meeting real-time grid reliability management requirements. In addition, it is also possible that Washington State may increase its RPS targets above the currently-in-effect 15% by 2020 requirement.

4.4 POTENTIAL WECC/PNW ENERGY IMBALANCE MARKET FORMATION

Over the last several years, multiple entities have been discussing the possibility of developing and implementing some type of Energy Imbalance Market (EIM) in the PNW. The primary focus of these discussions is to create a more liquid short-term/real-time market for wholesale energy, capacity, and ancillary services products. The need for such within-the-hour products has increased significantly in recent years in the PNW, due largely to the addition of several thousand megawatts of new wind plants in the region.

The formation of one or more EIMs in the PNW would likely be beneficial for the Project in that the EIM would create a more liquid marketplace for the sale of the energy/capacity/ancillary service products that the Project is capable of producing. There appears to be a growing expectation among many PNW wholesale market participants that *some kind* of EIM will ultimately be implemented in the PNW region; however the exact characteristics of such an EIM and the specific BAA operators that will participate in such a market remain somewhat vague at present. The following sub-section describes the current status of EIM formation in the PNW region and the potential impacts on the Project.

4.4.1 NWPP EIM/SCED

The Northwest Power Pool (NWPP) has been coordinating discussions over the past several years among multiple stakeholders regarding the potential formation of an EIM that would cover a significant portion of the PNW region, under a program called the Market Assessment and Coordination Committee (MC) Initiative. In early 2015, the NWPP MC group adopted the moniker of Security Coordinated Economic Dispatch ("SCED") rather than "EIM" to describe the proposed NWPP within-the-hour wholesale market.

Under Phase 3 of the MC Initiative (which was completed in early 2015), 19 PNW utilities and other interested participants drafted a set of market design principles for the formation and operation of the NWPP SCED. On March 25, 2015, the NWPP MC group announced that it had agreed to launch Phase 4 of the SCED market development. As discussions continued throughout 2015 regarding the formation of the SCED, the NWPP MC group decided to modify and generally pare down the original SCED concept into two main components (1) a Centrally Cleared Energy Dispatch (CCED) market, and (2) a Regulation Reserve Sharing Group (RRSG). On September 4, 2015, the NWPP MC group submitted a petition requesting that FERC issue a Declaratory Order accepting the overall CCED market design.

Under the proposed NWPP CCED market design, the CCED market would initially be an automated 15-Minute displacement energy market designed to complement and expand upon wholesale power and transmission scheduling mechanisms that are already in place in the PNW. A formal CCED operating entity would “clear” voluntary bids and offers from market participants. These bids and offers would then be used to inform regional generation dispatch decisions. A centralized CCED market “centroid” would also be created that would allow market participants to schedule power deliveries and receipts directly with the CCED (i.e., with the CCED acting as either a source or a sink for schedule tagging purposes). The NWPP CCED would not change any of the bilateral market trading mechanisms that are currently in place in the PNW region, nor would the CCED shift any NERC/WECC system reliability requirements between the participants.

In January 2016, the NWPP MC Executive Committee voted to suspend its efforts to establish the CCED market and on January 29, 2016 the group filed with FERC to withdraw its petition for a declaratory order. The Executive Committee’s decision was driven largely by (1) a lack of consensus among the NWPP MC Group and other stakeholders regarding several key features of the proposed CCED market design, and (2) growing momentum among several of the Group’s members to join the CAISO’s Energy Imbalance Market (EIM).

Should the NWPP MC Executive Committee decide in the future to re-initiate the formation of the CCED market (or some other similar market design) in the PNW the Project would be well suited to participate in such a market on many levels. First, the Project would be capable of providing a variable within-the-hour energy output in both generating and pumping modes across a wide megawatt range. Second, although the initially proposed CCED market did not include a capacity market, the Project could still provide capacity and ancillary services to CCED market participants in the “regular” hour-ahead and 15-Minute bilateral markets so that such entities can meet the CCED’s resource sufficiency standard. Therefore, it is expected that the establishment of the NWPP CCED (or, alternatively, some other similar within-the-hour market) would create more opportunities for the Project to monetize the hour-ahead/within-the-hour flexibility that the Project is capable of providing.

4.4.2 CAISO EIM

The CAISO has been operating a short-term energy imbalance market for several years within its balancing authority area. The CAISO EIM is designed to allow market participants to purchase and sell short-term energy, capacity, and ancillary service products. Beginning on November 1, 2014, the PacifiCorp East and West BAAs were incorporated into the CAISO's EIM. This addition allowed PacifiCorp (PAC) and the merchant generators located within its two BAAs to participant in the CAISO's EIM, subject to certain transmission limitations between the three BAAs. Subsequently, NV Energy, which is an affiliate of PAC, began operations in the CAISO EIM on November 1, 2015.

Immediately upon the startup of the combined CAISO/PAC EIM on November 1, 2014, several pricing "anomalies" arose in the PacifiCorp East BAA which caused the CAISO to temporarily suspend several portions of the EIM's FERC tariff pending further investigations into the cause (and solutions) to the pricing anomalies. Several participants in the CAISO/PAC EIM also expressed concerns regarding some of the market's design features, especially with regard to generation market power issues. In response to these events, FERC instituted an investigation into the cause of the pricing anomalies and, in an order issued on November 19, 2015, required that PacifiCorp and NV Energy be subject to certain bid caps when selling imbalance energy into the CAISO EIM.

PSE and Arizona Public Service (APS) are both preparing to commence operations in the CAISO EIM on or about October 1, 2016 (pending FERC approval). With the addition of these two new EIM entities, the EIM geographic "footprint" will be expanded to cover six BAAs. In addition, both PGE and Idaho Power have announced their intentions to join the CAISO EIM in 2017.

The Project would likely benefit from participation in the CAISO EIM; in particular the Project would be able to sell short-term capacity and ancillary service products directly into the EIM market. However, for the Project to participate in the EIM, BPA would either need to be a member as well, or alternately provide the transmission services required for the Project to participate in the CAISO EIM (which it has agreed to do in PSE's case)

4.4.3 OTHER EIM ALTERNATIVES

While the CAISO EIM currently appears to be the frontrunner for the establishment of an EIM in the PNW, regional entities could choose to explore other alternatives as well. For example, in late 2014 Public Service Company of Colorado (PSCo) announced the formation of a “mini EIM” in their BAA that will implement within-the-hour least cost dispatch across multiple generation and loads that are located within the PSCo BAA market. A key feature of the proposed PSCo EIM is that there would be no transmission charges between the market participants for within-the-hour EIM transactions.

An important consideration for the Project regarding the establishment of an alternate EIM in the PNW is whether or not BPA was a participant in the EIM. Since the Project would interconnect directly with the BPA transmission system, BPA being a member of an EIM would allow the Project to participate as well, potentially with reduced or zero transmission costs.

4.5 MANAGEMENT OF VARIABLE INTERMITTENT RESOURCES

Most states located in the WECC region have adopted some form of Renewable Portfolio Standards (RPS) to foster the development of renewable generating resources such as wind and solar. Pursuant to these state mandated programs, many PNW electric utilities have already acquired significant amounts of renewable resources, primarily wind plants. In addition, some of the state RPS programs (such as Washington State’s RPS) incorporate “step-up” renewable generation targets that require the affected utilities to acquire larger percentage amounts of renewable resources through time.

Although the pace of development of renewable resources in the PNW has slowed in the last several years, it is still expected that more than insignificant amounts of new renewable resources will be built in the PNW region and California in the next 10 to 20 years. In particular, Oregon’s new 50% by 2040 RPS for investor-owned utilities will likely spur a new round of significant renewable resource development in the PNW. Although many utilities in the PNW may not need to add additional renewable generation to meet state-mandated RPS requirements until around 2022 to 2023, there is a heightened interest by many utility customers in the West in installing distributed solar PV generating technology.

Recent drops in the prices of solar PV panels, combined with generous federal and in some cases state financial incentives, are leading many commercial and residential customers in the PNW and Western regions to consider the installation of solar PV equipment at their facilities and homes. It is currently forecasted that California could install up to 12,000 MW of distributed solar PV generation by 2020. Also, Idaho Power is in the process of acquiring (through multiple PURPA contracts) the output of approximately 420 MW of utility-scale solar PV plants that are currently under construction in southern Idaho; this generation is expected to be on-line in mid to late 2016.

One important feature of wind and solar generating technologies is that the generation output of these plants is both highly variable and difficult to predict. These operational characteristics are considerably different from conventional generating plants (such as hydro, natural gas, coal, or nuclear) where the desired generation amount from each plant can be controlled to a very high degree. In fact, conventional generating plants must be used to compensate for the variability and unpredictability of intermittent resources. In the case of distributed renewable generation (which is typically located "behind the meter"), variations in generation output will be reflected through increased volatility in the net load being served by the local electric utility.

Since the output of a wind plant or solar plant can change at any time, and in some cases very abruptly, the conventional generating plants that are compensating for these variations must be a very flexible resource that can quickly ramp up or ramp down their generation output. Furthermore, having highly flexible conventional generating plants "on standby" to respond to changes in intermittent generation may result in these plants not being available for other purposes (such as serving firm loads).

As more and more intermittent generating resources have been added in the WECC region, the need for flexible conventional generation to offset the variability of the wind and solar plants has increased significantly. Up until the last couple years, the existing hydro system in the PNW and the fleet of conventional generating plants within the broader WECC region was generally able to supply the needed amounts of system flexibility. However, some utilities within WECC that have added large amounts of intermittent generation have already exhausted their available supplies of system flexibility. For instance, in 2013 Xcel Energy announced that it planned to construct a new gas-fired power plant in Colorado for the express purpose of providing the additional operational flexibility needed for it to manage the large amount of wind generation on its system. In addition, BPA has already been forced to limit the amount of real-time generation flexibility that it provides to the wind plants located on its power system in the PNW.

There are currently several different power products in the PNW and WECC markets that can be used to provide the flexibility required to manage the variable output of intermittent resources. Several of these products are collectively referred to as "ancillary services" (A/S). In particular, the provision of "regulation" or "regulation capacity" service refers to a generator changing its output level on an instantaneous, real-time basis to exactly offset other variations on the power system (which includes generation variations at wind and solar plants). Another common A/S product is known as "energy imbalance;" this service accounts for the difference in an intermittent plant's overall actual generation across an hourly (or alternatively 15-minute) scheduling interval versus its forecasted generation across that same period.

Several different types of conventional generating plants have the capability to provide A/S to the bulk power system. Hydroelectric plants (including pumped storage plants) are especially well-suited to provide flexible services to the bulk power system due to their wide operating ranges and very fast startup times and ramping rates. However, as the PNW hydroelectric system has become more highly constrained, utility operators such as PSE are increasingly being forced to utilize gas-fired CTs or CCCT plants in order to manage system flexibility needs. Many of these existing thermal plants were never designed to operate in the fashion that they are increasingly being called upon to do, which in turn is creating maintenance and reliability issues. Also, utilizing CTs that were originally constructed to help meet utility peak loads to manage the variable output of renewable resources may mean that these resources will not be fully available for their original purpose.

4.6 The Potential Role of New Hydro Pumped Storage Plants in the PNW

As was previously discussed, the current and near-term status of the PNW wholesale power market is characterized by a combination of: (1) very low (and potentially approaching zero) capacity prices and (2) relatively low energy prices being driven by the expectation of continued historically low natural gas prices. Such conditions, on their own, are not conducive to the development of a large hydro pumped storage plant.

However, the PNW region appears to be headed towards a significant shift in the regional load/resource balance around 2020 to 2022 that may result in the need for new sources of generating capacity in order for the region to reliably meet firm peak load obligations. The region will also likely have additional requirements for sources of flexible generation in order to manage the variable output of intermittent generating plants such as wind and solar PV while maintaining compliance with established NERC/WECC reliability criteria.

Given the long lead time needed for the development of large-scale hydro pumped storage plants, estimated to be approximately ten years, a commitment to construct such a plant in the PNW would mean that the plant would come on-line around 2025, which is squarely within the time period when the region will likely need new sources of firm capacity, ancillary services, and flexibility. Also, the planned addition of a hydro pumped storage plant would not be directly impacted by potential future restrictions on the use of fossil fuels for power production that may be enacted on the federal, state, or local level.

In addition, the Project would be especially well-suited to provide A/S and grid flexibility to the PNW power system. FERC defines A/S as "Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include: load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services."

The wide operating range of the P/G units, combined with large upper and lower storage reservoirs would allow the Project to provide a variety of A/S, potentially on a simultaneous basis, to multiple customers and off-takers. Also, if the Project were equipped with adjustable-speed P/G units (as proposed), the plant could provide some A/S (such as regulation) in *both* pumping and generating modes. It should be noted that the existing Keys P/G Plant does not have this capability; therefore when BPA is dispatching the Keys Plant in pumping mode, it must also utilize other hydro plants on its system (operating in tandem with the Keys Plant) in order to supply the full range of flexibility services that it requires. There are obvious efficiencies to BPA and other utility operators in having the capability to source a full range of needed A/S from a single generating plant.

5.0 POWER PRICE FORECASTS

Three different sets of power price forecasts were developed for use in the Project pre-feasibility studies. Specifically, long-term (40-year) forecasts were derived for: (1) energy, (2) capacity, and (3) ancillary services. The following sub-sections describe how each set of forecasts was developed.

5.1 ENERGY PRICE FORECASTS

The base monthly-level energy price forecasts utilized for the pumped storage plant studies were the 2025 and 2026 Mid-Columbia monthly forecasts developed by the Kleinschmidt Team for use in the CBHP small hydro plant pre-feasibility evaluation. Monthly-level Mid-Columbia energy price forecasts were then derived for the period 2027 to 2064 using the 2026 forecasts and applying a 2.0% per year escalation factor. The full set of forecasted Mid-Columbia energy prices used in the pumped storage plant analysis is included in Appendix A.

It should be noted that utilizing monthly (or even weekly) *average* prices in the evaluation of the energy shifting/arbitrage potential of a pumped storage plant will almost always *underestimate* the revenue potential for the plant. This is due to the fact that within any given monthly period, hourly wholesale energy prices usually vary to a considerable degree. For instance, if in a given month the average off-peak energy price is $30.00/Mwh and the average on-peak price is $35.00/Mwh, a monthly-level energy shifting/arbitrage analysis would conclude that the plant would not pump or generate at all in this month since the monthly average off-peak/on-peak price differential is not large enough to overcome the cycle losses (assuming an 81% cycle efficiency). However, on any given day within this month, the off-peak/on-peak price differential could easily be high enough to justify energy shifting operations on that particular day. Since pumped storage plants are, by nature, very flexible resources, they are capable of earning revenues from the variations in (and volatility of) short-term energy prices.

In order to capture the full potential for the Project to earn revenues from energy shifting/arbitrage operations, several sets of daily-level prices were first derived from the base monthly-level long-term energy price forecasts. The 2025/2026 monthly off-peak and on-peak energy price forecasts were converted into daily-level off-peak/on-peak/super-peak forecasts through the application of several randomizing factors that simulate the day-to-day variations in the PNW wholesale energy market, including the impacts of Sundays and NERC holidays. The super-peak period was assumed to occur 6 hours per day every Monday through Saturday, excluding holidays.

A total of 12 different randomized hourly price sets were then created for each year in order to access the value of energy shifting operations at the pumped storage plant under different price set scenarios. In order to simplify the modeling process, the prices across each of the off-peak/on-peak/super-peak periods of each day were uniform values (i.e., all hourly off-peak prices were the same and all hourly on-peak prices were the same, etc.). The monthly average prices in each of the 12 randomized price sets were kept at the same values (within a small tolerance band). These 12 sets of randomized daily energy prices were then used as inputs into the Project operational model to produce 12 sets of pumped storage energy shifting operations and associated costs and revenues, as is described in Section 7.1.

5.2 CAPACITY PRICE FORECASTS

In the WECC region (outside of the CAISO's system), there currently is not an established market for capacity products. While the Western Systems Power Pool (WSPP) agreement allows for the purchase and sale of capacity between the members of the agreement (and such transactions do take place from time to time), these bilateral capacity transactions are established directly between the buyer and seller. However, unlike bilateral wholesale energy sales that take place in the PNW, there is currently no established publically available capacity price index. It is therefore difficult for market participants to identify the prices at which capacity transactions are actually taking place. Similarly, there is currently no established forward market for capacity products in the PNW, which also makes it difficult to derive long-term capacity price forecast for the PNW region.

Due to the lack of market-based information on the value of capacity in the PNW wholesale power markets, many market participants utilize the installation cost of new gas-fired CT or CCCT generating plants as a proxy for the long-term value of capacity in the PNW. However, if the PNW wholesale market has (or is forecasted to have) a capacity surplus, the market value of capacity is likely to be lower, possibly much lower, than the installation cost of a new CT or CCCT plant. This is the condition that the PNW region has been in since the mid-2000s following the construction of approximately 3,500 MW of new gas-fired generation that was added in the wake of the 2000 to 2001 western power crisis. However, recent studies conducted by the NWPCC, PNUCC, and BPA indicate that the PNW region is likely to become capacity deficient in the winter months around 2020 to 2022 unless new sources of firm capacity are added to the bulk power system. At the point in time when load-serving utilities are required to add new dispatchable resources to their systems in order to meet Loss of Load Probability (LOLP) or other peak load planning requirements, the value of capacity in the PNW markets should approximately equal the fixed installation and operations costs of these new resources.

Several PNW investor-owned utilities are forecasting that they will need to acquire new capacity resources in the next 10- to 15-year period in order to meet their peak load planning requirements. For instance, in its 2015 IRP PSE's resource plan indicates that it will need to acquire a new 277 MW CT in 2021, followed by another 126 MW CT in 2025 and a 577 MW CCCT in 2026. PGE and PacifiCorp also appear to have large winter capacity needs during this same timeframe.

The current and forecasted conditions in the PNW region, which include forecasts of relatively low-priced natural gas, favor the development of simple cycle CTs over CCCTs as the preferred solution for utilities to meet their currently forecasted capacity needs. The long-term value of capacity for load-serving utilities is therefore tied to the forecasted costs of building or acquiring new gas-fired CT plants. Furthermore, in order to reduce fixed costs, some PNW utilities do not plan on purchasing all firm natural gas pipeline capacity for these new peaking units; rather, they plan to utilize a mix of firm and interruptible gas transportation services combined with oil backup fuel capability.

In their respective 2013 IRPs, PSE and Avista provided some details regarding the generic CT plants that they plan to add to their systems in order to meet their future capacity needs. It is possible to derive an estimated value of capacity in $/Kw-mo from the data provided by PSE. The estimated capacity cost of installing new gas-fired CTs (assuming all interruptible natural gas pipeline capacity combined with on-site backup oil supplies) and new gas-fired CCCTs (assuming 100% firm gas pipeline service) act as reasonable bookends for the value of capacity in the PNW wholesale power markets. Referenced to 2025 prices, this results in a capacity price forecast ranging from $9.43/Kw-mo in the low case to $10.55/Kw-mo in the high case. The 2025 low case and high case annual capacity price forecasts were escalated at a 2% annual rate in order to produce price forecasts across the 2025 to 2064 study period. The full set of annual capacity price forecasts used in the pumped storage plant evaluation is included in Appendix B.

5.3 ANCILLARY SERVICES PRICE FORECASTS

Determining the value of A/S in the PNW power markets suffers from the same type of issues regarding the determination of the value of capacity: the lack of a centralized A/S market, and the lack of an established publically available index for A/S products results in an illiquid and non-transparent market as compared to the bilateral PNW energy markets. While some market-based A/S price data are available from the CAISO market, it is unclear whether those prices would be representative of the prices for A/S products in the PNW wholesale markets, especially given the large amount of hydro generation that is present in the PNW region.

Further complicating the picture is that while several of the Open Access Transmission Tariff (OATT) defined A/S products can be supplied on a simultaneous basis with other energy and/or capacity products from a single resource, some cannot. For instance, while the Project could simultaneously provide firm capacity for load and downward regulation/load following A/S, it could not simultaneously provide firm capacity and operating reserves if the plant were operating at its maximum generation level.

This situation leads to the two-fold challenge of (1) determining a value for each A/S product and (2) determining how much of each A/S product could be provided in conjunction with the plant's provision of capacity and energy to the grid. This is an especially challenging issue for pumped storage plants given their operational flexibility to produce multiple power products to the grid. Determining the optimal greatest value solution is a very complex process. However, it is also important to avoid double-counting the capacity and A/S value of pumped storage plants by making the assumption that all energy, capacity, and A/S products could be provided on a simultaneous basis.

One method of valuing A/S is similar to valuing firm capacity: to utilize the installation cost of a new CT or CCCT plant that is assumed to be dedicated to providing A/S products. There is a precedent in the PNW region that illustrates this concept: Northwestern Energy (NWE) recently constructed the David Gates gas-fired CT plant for the express purpose of providing A/S to the NWE transmission grid. NWE's cost of providing A/S to its transmission customers is tied to the fixed and variable costs of operating the David Gates plant. Since 100% of the capabilities of the plant are dedicated to meeting NWE's A/S requirements, there is no "double counting" of value.

For the purposes of valuing the A/S that the Project could provide, the pre-feasibility evaluation used the same values of capacity as determined in Section 5.2 with an adjustment applied (described in Section 7.4) to avoid the double counting of value issue.

6.0 PROJECT DESCRIPTION AND PROBABLE COST

Several conceptual site layouts were considered during this pre-feasibility study for the Project; however the Project Team is currently focusing on two potential alternatives. The first Project site layout incorporates a powerhouse with one or two power tunnels from Banks Lake and two to four low pressure tunnels to Crescent Bay. The second Project site layout is similar to the first alternative except that the powerhouse would be located on Lake Roosevelt. No dedicated geotechnical investigations were conducted at this stage of the study; therefore, general rock properties and tunneling effort were estimated from publically available sources. Generating equipment costs were estimated based on extrapolations from previous budgetary information for similar proposed projects. Site specific topography, transmission routing, and assumed fish protection requirements were each considered when developing the opinion of probable cost. Using the information summarized above, the probable Project cost of the 500 MW configuration, under either of the two site layouts described, is approximately $1.25 billion. The probable cost of the 1,000 MW configuration, under either layout, is approximately $2.5 billion.

The following summarizes the key proposed features and characteristics of the Project:

- The Project would be located at the North Dam of Banks Lake in north central Washington State near Grand Coulee Dam.
- The Project would be a separate project from the Bureau of Reclamation's existing Keys Plant.
- Generating Capacity: 500 MW, scalable up to 1,000 MW.
- Turbine Type: Two to four 250 MW adjustable speed pump-generating units.
- Maximum turbine design flow: 25,000 cubic feet per second (cfs) for the 500 MW configuration; 50,000 cfs for the 1,000 MW configuration.
- Powerhouse: Site Layout No. 1 - Located on the west side of Crescent Bay. Site Layout No. 2 – Located on the west side of Lake Roosevelt just upstream of Grand Coulee Dam and near the BOR's existing Keys Plant
- Estimated average annual generation: 769,600 Mwh for the 500 MW configuration; 1,430,000 Mwh for the 1,000 MW configuration.
- Upper Intake/Reservoir: Site Layout No. 1 - Banks Lake. Site Layout No. 2 – Banks Lake.
- Lower Intake/Reservoir: Site Layout No. 1 – Crescent Bay. Site Layout No. 2 – Lake Roosevelt.

- Main Tunnels: Site Layout No. 1 – One or two 35-foot-diameter tunnels approximately 7,000 feet in length. Site Layout No. 2 - One or two 35-foot-diameter tunnels approximately 9,000 feet in length.
- Branch (unit) Tunnels: Two to four 25-foot-diameter tunnels approximately 900 feet in length.
- Transmission Interconnection: Grand Coulee Dam 230 kilovolt (kV) or 500 kV switchyards.

7.0 OPERATION OF THE PROJECT AND REVENUE FORECASTS

As has been previously mentioned, pumped storage plants are very flexible resources that are capable of providing multiple power products and services. In evaluating potential sources of revenue for the Project, four separate categories of products and services were analyzed in this report. These four product categories are:

- Energy Shifting/Price Arbitrage
- Firm Capacity
- Ancillary Services (A/S)
- Grand Coulee Supplemental Flow Benefits

Each of these four product categories and the results of the pre-feasibility revenue studies are discussed in detail in the following sub-sections.

7.1 ENERGY SHIFTING/ARBITRAGE STUDIES

In order to evaluate how the Project might be operated for the purpose of conducting energy shifting/arbitrage activities, a set of Excel-based models were created to simulate the operation of the Project under varying energy market conditions. These models generally fall into two categories (1) a random pricing model, and (2) an operational model. Each of these models is described in more detail below.

The potential energy shifting/arbitrage value of the Project is a function of the forecasted market value of wholesale energy in the PNW regional markets. In particular, the Project's ability to earn energy shifting revenues is directly related to short-term *differentials* in the market value of energy both on a daily and on a weekly basis. If the Project is being operated to produce the maximum amount of energy shifting revenues, the Project will pump during the periods of lowest energy prices and will generate during the periods of highest energy prices if the price differential between the pump/generation periods is large enough to off-set the overall pump/generation cycle loss.

The overall pump/generation cycle efficiency for the Project was assumed to be 81.0%; therefore, in order for a pump/generation cycle to create positive revenue, the following condition needs to be met:

$$\text{Generation Period Price (\$/Mwh)} > \text{Pump Period Price (\$/Mwh)}/0.81$$

For example, if the pump period price is $30.00/Mwh, the minimum price needed during a generation period in order for the cycle to result in positive revenues for the Project is (30.0/0.81) =$37.04/Mwh. If the generation period price in this example were $40.00/Mwh and if the Project generated 1,000 Mwh, the overall pump/generation cycle would result in revenues of $2,960 (=1,000 * [40.00 – 37.04]).

7.1.1 PROJECT OPERATIONAL MODEL

In order to derive the costs and revenues associated with energy shifting/arbitrage operations at the Project, an Excel-based model was developed to simulate the operation of the Project on an hourly basis across an annual period. Inputs to the model included the base operational parameters of the Project (as previously described), user defined constraints for the minimum and maximum elevations at Banks Lake, Grand Coulee reservoir annual draft/refill operations, and 12 randomized sets of hourly-level Mid-Columbia energy prices. Outputs from the model include hourly pump and generation levels at the Project (in MW), Banks Lake surface elevation, and hourly pumping costs and generation revenues (in dollars).

The Project operational model was designed to operate on a weekly pump/generation cycle with the surface elevation of Banks Lake both beginning the week (at 0100 hours on Monday) and ending the week (at 2400 hours on Sunday) at the same user defined surface elevation. Within the Monday to Sunday week, the Project would be free to pump and generate for energy shifting/arbitrage purposes as long as the Banks Lake surface elevation did not violate either the defined minimum or maximum elevation. The model also ensures that water rights and related deliveries to the various Irrigation Districts are maintained as they were prior to the commercial operation of the Project. In practice, the operation of the Project would not have any effect on the water supply necessary to meet current or prospective (e.g., Odessa Subarea) irrigation needs.

The model was also designed to create a semi-optimal pump/generation schedule for each week. The model first computes the optimal pump/generation schedule for each Monday to Sunday week based upon the off-peak/on-peak/super-peak energy price pattern for that upcoming week. The only constraint placed upon this first step is that the Banks Lake surface elevation must begin and end the week at the same elevation target. In the second step, the model makes adjustments to the hourly pump and generation schedules to avoid violating either a minimum elevation or a maximum elevation constraint. This second step makes adjustments on a forward looking basis only (through the balance of the current week).

It is recognized that the above described "perfect foresight" of Mid-Columbia wholesale energy market price for an upcoming week is not possible in actual power system operations. However, this methodology was chosen to help establish the initial "best case" range of energy shifting/arbitrage revenues for the Project. Also, it should be noted that the second step of the operational modeling process – pump/generation schedule adjustments due to Banks Lake elevation constraints – *is not* an optimized solution. This second modeling step, therefore, acts to reduce the overall level of energy shifting/arbitrage net revenues to a more realistically achievable level.

In order to speed up the modeling process, the Project operational model was run using 12 randomized energy price sets for every five years of the 40-year study period beginning in 2025 and ending in 2064. The model produced 12 sets of net energy shifting revenues in each of these 9 base years and the average, minimum, and maximum net revenues were then saved. Net energy shifting revenues for the years between each of the base years were then derived via a linear interpolation process.

The Project energy arbitrage studies assumed that five feet of water in Banks Lake could be utilized for pump/generation operations during all months of the year. In most months, this would result in the surface elevation of Banks Lake varying between elevations 1565 and 1570 feet (full). During the month of August; however, Banks Lake is drawn down to elevation 1565 feet to provide additional flows downstream of Grand Coulee Dam for fisheries protection. Additional analysis will need to be conducted to determine the impacts of this annual drawdown of Banks Lake on the proposed operation of the Project.

7.1.2 OPERATIONAL MODEL ENHANCEMENTS

CBHP has been in discussions with BPA and the BOR regarding a series of enhancements that might potentially be made to the Project's operational model in order to more fully incorporate operational constraints and/or operating policies that are (or may be in the future) in place at Lake Roosevelt and Banks Lake. It is envisioned that the enhanced model would have the capability of evaluating multiple Project operating modes under varying sets of constraints, short-term streamflow conditions, and wholesale power market prices. The Parties are currently evaluating several different modeling tools and expect to commence enhanced operational modeling of the Project in late 2016.

7.2 RESULTS OF THE ENERGY SHIFTING/ARBITRAGE STUDIES

For the 500 MW configuration, the annual net revenues from energy arbitrage operations for the Project in its first year of operation (2025) are forecasted to range between \$8.29 million in the low case and \$10.99 million in the high case. In the last year of the study (2064) revenues are forecasted to be \$18.15 million in the low case and \$25.01 million in the high case. The NPV of the annual energy revenues across the 40-year study period is \$225.67 million in the low case and \$305.91 million in the high case, assuming a 4.0% annual discount factor. An annual summary of the energy shifting revenues is included in Appendix C.

For the 1,000 MW configuration, the annual net revenues from energy arbitrage operations for the Project in its first year of operation (2025) are forecasted to range between \$15.83 million in the low case and \$20.24 million in the high case. In the last year of the study (2064) revenues are forecasted to be \$34.35 million in the low case and \$45.68 million in the high case. The NPV of the annual energy revenues across the 40-year study period is $423.58 million in the low case and $569.44 million in the high case, assuming a 4.0% annual discount factor. An annual summary of the energy shifting revenues is included in Appendix C.

7.3 RESULTS OF THE FIRM CAPACITY STUDIES

The low case and high case forecasted capacity prices discussed in Section 5.2 were applied to the 500 MW installed capacity of the Project in order to derive annual capacity revenues for the Project. Annual capacity revenues in the Project's first year of operation (2025) are forecasted to range between $56.58 million in the low case and $63.30 million in the high case. In the last year of the study (2064) capacity revenues are forecasted to be $122.40 million in the low case and $137.04 million in the high case. The NPV of the capacity revenues across the 40 year study period is $1,527.53 million in the low case and $1,709.50 million in the high case, assuming a 4.0% annual discount factor. An annual summary of capacity revenues is included in Appendix C.

For the 1,000 MW configuration, annual capacity revenues in the Project's first year of operation (2025) are forecasted to range between $113.16 million in the low case and $126.60 million in the high case. In the last year of the study (2064) capacity revenues are forecasted to be $244.80 million in the low case and $274.08 million in the high case. The NPV of the capacity revenues across the 40-year study period is $3,055.05 million in the low case and $3,419.00 million in the high case, assuming a 4.0% annual discount factor. An annual summary of capacity revenues is included in Appendix C.

7.4 RESULTS OF THE ANCILLARY SERVICES STUDIES

In order to avoid the "double counting of value issue" that was described in Section 5.3, the $/Kw-mo capacity value for A/S was applied to a 150 MW capacity amount as opposed to the full 500 MW installed capacity of the Project. In effect, using a de-rated Project capacity for the A/S value determination recognizes that some, but not all, A/S products can be supplied by the Project in tandem with energy and capacity services.

The low case and high case forecasted capacity prices discussed in Section 5.2 were applied to the 150 MW de-rated capacity figure in order to derive annual A/S revenues for the Project. Annual A/S revenues in the Project's first year of operation (2025) are forecasted to range between $16.97 million in the low case and $18.99 million in the high case. In the last year of the study (2064) A/S revenues are forecasted to be $36.72 million in the low case and $41.11 million in the high case. The NPV of the A/S revenues across the 40-year study period is $458.26 million in the low case and $512.85 million in the high case, assuming a 4.0% annual discount factor. An annual summary of A/S revenues is included in Appendix C.

For the 1,000 MW configuration, annual A/S revenues in the Project's first year of operation (2025) are forecasted to range between $33.95 million in the low case and $37.98 million in the high case. In the last year of the study (2064) A/S revenues are forecasted to be $73.44 million in the low case and $82.22 million in the high case. The NPV of the A/S revenues across the 40-year study period is $916.52 million in the low case and $1,025.70 million in the high case, assuming a 4.0% annual discount factor. An annual summary of A/S revenues is included in Appendix C.

7.5 RESULTS OF THE GRAND COULEE SUPPLEMENTAL FLOW STUDIES

Quantifying the incremental value that might be created by drafting Banks Lake to provide additional flows downstream from Grand Coulee Dam is a very complex task; this is especially due to the fact that the incremental value created through this operation is created off-site of the Project. Quantifying this benefit therefore entails modeling the entire PNW hydro system since the operation of Grand Coulee Dam and all 10 of the downstream federal and non-federal dams are operated on a holistic basis. This is especially true in a regional long-term load-resource planning context where the operation of the PNW hydro system is intertwined with the operation of the region's non-hydro projects in order to meet the energy and capacity needs of the region. Section 11.4 of the report provides additional details regarding the Grand Coulee Supplemental Flow concept.

The same range of capacity price forecasts that was previously discussed in Section 5.2 was also utilized in evaluating the capacity/sustained peaking benefits of the Project in providing supplemental flows to Grand Coulee. For example, the Project's ability to release water from

Banks Lake and then have that water released downstream through Grand Coulee Dam (during periods when Grand Coulee is at or near its daily draft limit) would create incremental amounts of sustained peaking capability at these existing hydro plants. This incremental sustained hydro peaking capability could then be valued at the aforementioned CT and CCCT based capacity prices, with appropriate adjustments.

BPA and the NWPCC both have modeling tools that could be utilized to help value the Banks Lake supplemental flows that might be provided from the Project. In particular, the GENESYS model is used by both of these entities in conducting long-term regional load/resource planning studies. This model already includes the Keys Plant, and it could be expanded to incorporate the Project as well. The NWPCC's GENESYS model output is then used as an input to their regional LOLP model. The results of the LOLP model with and without the Banks Lake supplemental flow operations could then be compared. The result of this comparison would be the incremental capacity/sustained peaking benefit of the supplemental flow operations on a MW basis. One could then apply the capacity value determined in Section 5.2 to this MW amount in order to produce a dollar value.

For the purposes of this pre-feasibility evaluation, it was conservatively estimated that the Banks Lake supplemental flows provided by the Project would result in a 75 MW capacity/sustained peaking benefit on an overall PNW basis and that CBHP could execute agreements with BPA and the Mid-Columbia PUDs that would allow it to retain 50% of this value.

The low case and high case forecasted capacity prices discussed in Section 5.2 were applied to the 75 MW capacity figure in order to derive annual supplemental flow revenues for the Project. Annual supplemental flow revenues in the Project's first year of operation (2025) are forecasted to range between $4.24 million in the low case and $4.75 million in the high case. In the last year of the study (2064) supplemental flow revenues are forecasted to be $9.18 million in the low case and $10.28 million in the high case. The NPV of the supplemental flow revenues across the 40-year study period is $114.56 million in the low case and $128.21 million in the high case, assuming a 4.0% annual discount factor. An annual summary of supplemental flow revenues is included in Appendix C.

For the 1,000 MW configuration, annual supplemental flow revenues in the Project's first year of operation (2025) are forecasted to range between $8.49 million in the low case and $9.50 million in the high case. In the last year of the study (2064) supplemental flow revenues are forecasted to be $18.36 million in the low case and $20.56 million in the high case. The NPV of the supplemental flow revenues across the 40-year study period is $229.13 million in the low case and $256.42 million in the high case, assuming a 4.0% annual discount factor. An annual summary of supplemental flow revenues is included in Appendix C.

7.6 OVERALL POWER REVENUE SUMMARY

The total forecasted revenues for the Project are derived by summing the revenues for energy arbitrage, capacity, A/S, and Grand Coulee supplemental flows. Annual overall power revenues for the 500 MW configuration in the Project's first year of operation (2025) are forecasted to range between $86.09 million in the low case and $98.03 million in the high case. In the last year of the study (2064) total power revenues are forecasted to be $186.45 million in the low case and $213.44 million in the high case. The NPV of overall power revenues across the 40-year study period is $2,326.01 million in the low case and $2,656.47 million in the high case, assuming a 4.0% annual discount factor. An annual summary of overall power revenues is included in Appendix C.

For the 1,000 MW configuration, annual overall power revenues in the Project's first year of operation (2025) are forecasted to range between $171.43 million in the low case and $194.32 million in the high case. In the last year of the study (2064) total power revenues are forecasted to be $370.95 million in the low case and $422.54 million in the high case. The NPV of overall power revenues across the 40-year study period is $4,624.27 million in the low case and $5,270.55 million in the high case, assuming a 4.0% annual discount factor. An annual summary of overall power revenues is included in Appendix C.

8.0 PRELIMINARY COST/BENEFIT ANALYSIS

Using results from the Project Opinion of Probable Cost section and the Overall Power Revenue Summary section, a preliminary cost/benefit analysis was performed in order to assess the potential economic feasibility of the Project. The cost/benefit study also incorporated operations and maintenance costs for the Project based upon the average estimated Operations & Maintenance (O&M) costs of five similarly sized pumped storage facilities that were studied by Chelan PUD and HDR Engineering in 2010.

The 40-year NPV of the Project for the 500 MW configuration under two different revenue scenarios is summarized in Table 1.

TABLE 1 40-YEAR NET PRESENT VALUES (500 MW INSTALLED CAPACITY)

SCENARIO	CONDITIONS	NPV ($M)
1	Low Revenue	+1,259.07
2	High Revenue	+1,589.53

The above preliminary results indicate that the Project is forecasted to have a positive NPV under both scenarios analyzed, assuming (1) 70% of the financing need is at a 1.50% tax free rate from the Department of Energy for the first 30 years, (2) 30% of the financing need is at a 3.00% tax free market rate for the first 30 years, (3) 100% of the financing need is at a 3.00% tax free market rate for the remaining 10 years, and (4) a 4.0% NPV discount rate. An annual summary of the preliminary cost/benefit analysis is included in Appendix D.

The 40-year NPV of the Project for the 1,000 MW configuration under the same two revenue scenarios is summarized in Table 2.

TABLE 2 40-YEAR NET PRESENT VALUES (1,000 MW INSTALLED CAPACITY)

SCENARIO	CONDITIONS	NPV ($M)
1	Low Revenue	+2,491.08
2	High Revenue	+3,137.36

The above preliminary results indicate that the Project is forecasted to have a positive NPV under both scenarios analyzed, assuming (1) 70% of the financing need is at a 1.50% tax free rate from the Department of Energy for the first 30 years, (2) 30% of the financing need is at a 3.00% tax free market rate for the first 30 years, (3) 100% of the financing need is at a 3.00% tax free market rate for the remaining 10 years, and (4) a 4.0% NPV discount rate. An annual summary of the preliminary cost/benefit analysis is included in Appendix D.

9.0 POTENTIAL PURCHASERS OF CAPACITY, ENERGY AND ANCILLARY SERVICES FROM THE PROJECT

Based upon a preliminary review of publically available data and reports (including the 2013 and 2015 Integrated Resource Plans of multiple PNW electric utilities), one-on-one meetings, and discussions with several interested parties, the following entities are thought to have an interest in learning more about the Project and/or potentially being Project off-takers or purchasers:

- Avista
- Puget Sound Energy (PSE)
- Bonneville Power Administration (BPA)
- PacifiCorp (PAC)
- Portland General Electric (PGE)
- Grant County PUD
- Snohomish County PUD
- Powerex
- California Independent System Operator (CAISO)

While other interested parties, stakeholders, utilities, agencies, councils, etc. may have some interest in this Project, the purpose of this list is to document potential Project off-takers and pump back energy suppliers as of the writing of this Report. We anticipate this list will evolve as parties are added or removed from the list. Also, we have endeavored to include the names of other interested parties in other Sections of the Report that may be more representative of their potential participation in the Project.

10.0 PROJECT TRANSMISSION INTERCONNECTION

Transmission interconnection related considerations and issues are addressed in this section. Regulatory matters related to FERC/NERC bulk power system management requirements that may have an impact on the Project are covered later in the Report.

10.1 PROPOSED PROJECT TRANSMISSION INTERCONNECTION POINT(S)

The Project would be located near Grand Coulee Dam in an area that has a number of potential BPA owned interconnecting transmission lines of multiple voltage levels (230 kV and 500 kV). These high-voltage lines provide key transmission links between the Project, off-takers, Pump-Back energy suppliers, markets in the PNW, and possibly markets in California. In addition to providing the transmission system access for Grand Coulee Dam and the John W. Keys Plant, the area transmission system delivers power to BPA load service areas.

BPA provides Transmission Services for reliable open access transmission service for direct service customers, utilities, generators, and power marketers consistent with applicable regulatory requirements. Transmission Services also provides asset management services for the transmission assets of the Federal Columbia River Power System (FCRPS) including transmission system planning, design, construction, and operations and maintenance.

BPA operates and maintains about 75% of the high-voltage transmission network in the Northwest region. BPA's service territory is approximately 300,000 square miles and includes portions of Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. BPA's transmission system includes more than 15,000 circuit miles of transmission lines and over 260 substations. The transmission system serves many sectors of the Northwest including publicly owned and investor owned utilities, independent power producers, and direct service industries

The only non-BPA owned transmission line that is located in the general vicinity of the Project is Avista's 115 kV Stratford – Chelan line. The nearest interconnection point to this line is approximately 27 air miles southwest of the Project. Due to this long interconnection distance and the relatively low transfer capability of 115 kV lines, interconnecting the Project to Avista's transmission system does not appear to be a viable alternative. Therefore, it is assumed that the Project would be interconnected to the BPA system for the purpose of evaluating transmission related issues and costs.

The Project would be located near the Mid-Columbia trading hub that can act as an interchange point for energy transferred to or from the BPA transmission system. The proximity to the Mid-Columbia enhances the access of Project power to off-takers and market participants.

10.2 PROJECT INTERCONNECTION STUDIES

BPA performs a detailed and rigorous Large Generator Interconnection Procedure (LGIP) to study the transmission-related impacts of new generating facilities interconnecting to their transmission system.

The LGIP provides for three increasingly detailed study stages. These studies explore and refine the design and cost estimates for a plan of service that will be defined in detail in a Large Generator Interconnection Agreement (LGIA), following obligatory National Environmental Policy Act (NEPA) review. CBHP would participate in meetings that review each study report, and each subsequent study requires CBHP to confirm the recommended and agreed-upon decisions arising from the previous stage. The three studies are:

- Interconnection Feasibility Study (FES): (45 calendar days) - $10,000
    - Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the new generator interconnection;
    - Preliminary identification of any thermal overload or voltage limit violations resulting from the new interconnection; and
    - Preliminary description and non-binding estimated cost of facilities required to interconnect the Project to the transmission system.
- Interconnection System Impact Study (ISIS): (90 calendar days) - $50,000
    - Identification of any circuit breaker short circuit capability limits exceeded as a result of the new generator interconnection;
    - Identification of any thermal overload or voltage limit violations resulting from the new interconnection;

- Identification of any instability or inadequately damped response to system disturbances resulting from the new interconnection; and
- Description and non-binding, good faith estimated cost of facilities required to interconnect the Project to the transmission system and to address the identified short circuit, instability, and power flow issues.

- Interconnection Facilities Study (FAS): (customer elects a 90-day or 180-day study period) - Up to $100,000
  - Provide a description, estimated cost of and schedule for required facilities to interconnect the Project to the transmission system; and
  - Address the short circuit, instability, and power flow issues identified in the Interconnection System Impact Study.

Each study agreement requires CBHP to provide a deposit for the studies to be performed pursuant to the timelines indicated above. Each study report would be followed by a review meeting, which provides opportunities for the CBHP and BPA teams to meet and discuss all the aspects of the proposed interconnection and to obtain clarity on any outstanding issues.

CBHP is under no obligation to initiate any subsequent study (ISIS or FAS) should the Project be deemed unviable during the initial Feasibility Study phase.

10.3 BPA TRANSMISSION SERVICE

Qualified customers may request transmission service on BPA’s transmission system. This service is requested through Transmission Service Requests (TSR) according to the terms of the BPA OATT (Tariff). TSRs are one of the drivers for system expansion projects.

10.4 BPA GENERATOR INTERCONNECTION SERVICE

Qualified customers may request interconnection to BPA’s system for interconnecting new generation. BPA receives Generator Interconnection (GI) Requests according to Attachment L - Large Generator Interconnection Procedures - of the BPA OATT. The Generator Interconnection projects listed in the BPA Plan include projects over 20 MW (Large Generator Projects) which have an executed Large Generator Interconnection Agreement (LGIA).

10.5 BPA LINE AND LOAD INTERCONNECTION SERVICE

Qualified customers may request new points of interconnection on BPA's transmission system. These Line or Load Interconnections (LLI) are typically for new load service or to allow the Customer to shift the delivery of service to different points on their system. This service is requested according to Attachment J - Procedures for Addressing Parallel Flows - of the BPA OATT. Like the generator interconnection projects, only larger projects which have an executed interconnection agreement are included in the BPA Plan.

11.0 PROJECT CONTRACTS AND AGREEMENTS

The development and ongoing operation of the Project will require that a number of different long-term contracts and agreements be negotiated and executed between CBHP and multiple other parties. This section describes (1) the types of agreements that will need to be put in place for the successful development of the Project (Sections 11.1 through 11.3) and (2) optional agreements that may provide incremental benefits to the Project (Sections 11.4 and 11.5).

11.1 LONG-TERM PURCHASE POWER AGREEMENTS

Long-term Power Purchase Agreements (PPA) (potentially up to 40 to 50 years in duration) would need to be negotiated and executed between CBHP and the entity (or entities) that is (are) participating in the Project (which are referred to in this report as "purchasers" or "off-takers"). These long-term commitments by one or more purchasers would constitute the backing required for the Project to obtain financing for the construction and operation of the Project. These long-term PPAs could be structured in several different ways depending upon the needs and preferences of the specific off-taker. Three general categories of potential PPA structures are (1) a "slice of the project" agreement whereby one or more off-takers receive the rights to a percentage share of all of the operational attributes of the Project in exchange for paying a corresponding share of the capital/operating costs, (2) a "tolling" type agreement whereby the off-takers bear all power market-related price risk and the Project bears most (or all) of the operational-related risks, or (3) an agreement whereby the Project bears some level of power market-related risk (through its obligation to provide pump-back energy) and also bears most (or all) of the operational risk.

The first PPA alternative is similar to the model used for the development and operation of the five Mid-Columbia hydro plants constructed and owned by Douglas PUD, Chelan PUD, and Grant PUD. In exchange for paying a percentage portion of the debt service and ongoing O&M costs, the purchasers are entitled to a proportional share of the operational capabilities of the projects including inflow, unit capacities, unit flexibility (such as ramping and regulation up/down capability), and water pondage. The main difference for the Project is that inflow rights would be replaced with pumping obligations; therefore the off-taker(s) would be responsible for providing (and paying for) the power needed for pumping their “share” of water. Under this PPA model CBHP (or its designee) would itself have a share in the Project which it could operate (within its percentage share rights) in order to generate incremental wholesale power market derived revenues for the benefit of its members. CBHP would therefore bear some level of wholesale market price risk under this agreement model.

The second alternative is similar to the first alternative and is patterned after the agreement model typically used in the natural gas industry for gas storage services. Under alternative 2, CBHP itself would not retain a share of the Project’s operational capabilities for its own benefit, but rather it would “lease” 100% of the Project’s power storage capability and associated generation services to one or more third parties. Under this alternative, CBHP would receive a single monthly fixed payment from the off-taker(s) which would be sufficient to cover the Project’s debt payments, operations and maintenance costs, all other ongoing Project costs, and a return on investment. In exchange for the fixed monthly payment, the Project would generate and pump at the direction of the off-taker(s), pursuant to the terms and conditions specified in the PPAs. Under this alternative, the off-taker(s) would bear all power market related risks, including the obligation to obtain and provide pump-back energy to the Project. CBHP would bear certain operational risks, i.e., that the Project could actually provide the amounts of energy, capacity, and ancillary services requested by the off-taker(s) pursuant to the terms of the PPAs, and that it could actually accept pump-back energy (as delivered by the off-taker[s]).

Under the third PPA alternative, CBHP would retain operational control of 100% of the Project and sell energy, capacity, and ancillary services to the off-taker(s) at pre-defined fixed and/or variable prices. CBHP would be responsible for obtaining (and paying for) the pump-back energy required to fulfill its obligations under the PPAs. Under this alternative, the specified payments from the off-taker(s) would need to be sufficient to cover CBHP’s fixed and variable costs of owning and operating the Project (including the costs of CBHP purchasing pump-back energy). Depending upon the exact terms and conditions in the PPAs, the Project would likely bear some level of wholesale power market-related price risk; for instance, its actual costs of acquiring pump-back energy might be higher than the amount that was included in the agreed upon payment(s) from the off-taker(s). The Project would also have the obligation to locate and purchase pump-back energy at the times and in the amounts as determined by the off-taker(s), which could result in volumetric-related risks to the Project. Conversely, CBHP would have the opportunity to optimize the overall long-term and short-term operation of the Project for its own benefit, which could result in additional net revenues to CBHP above and beyond those incorporated into the long-term PPAs.

11.2 TRANSMISSION INTERCONNECTION AGREEMENT

As was previous discussed, the Project would most likely be interconnected to BPA transmission facilities and would therefore be located within the BPA BAA. This would require that CBHP negotiate and execute an LGIA with BPA. Given the complexities of hydroelectric pump/generator plants, especially the fact that power flows both into (pumping mode) and out of (generation mode) the Project, the BPA LGIA could contain non-standard provisions that would need to be agreed to between the parties. Also, as a BAA operator that is required to meet multiple NERC/WECC grid reliability criteria, BPA would likely have the ability to instruct that CBHP operate (or not operate) the Project in certain fashions for grid reliability purposes that may not be in CBHP's best interests (and/or may conflict with the provisions of CBHP's PPAs with the Project's off-taker(s). It is therefore imperative that the terms and conditions of the negotiated interconnection agreement with BPA be consistent with the terms and conditions established by CBHP and its off-taker(s) under the long-term PPAs.

11.3 BPA/BOR OPERATIONAL COORDINATION AGREEMENTS

Since the Project would utilize two existing multi-use reservoirs and would be located in close proximity to the existing Keys Plant, CBHP would likely need to enter into one or more operational coordination agreements with BPA, the BOR, and possibly other stakeholders as well.

In particular, the BOR has multiple pre-existing commitments to make irrigation water deliveries out of Banks Lake; the Project would therefore need to be operated in such a fashion as to not negatively impact the BOR's ability to make scheduled irrigation water deliveries. It is noted, however, that the larger pumping capability and the higher efficiency of the Project (as compared to the capabilities of the BOR's existing Keys Plant) could actually create a benefit to the BOR by providing more flexibility in how it moves water from Lake Roosevelt into Banks Lake. The

Project might also provide back-up pumping services to the BOR during periods of time when P/G units at the Keys Plant are out of service for either scheduled or forced outages. CBHP and the BOR would need to define and agree to several key parameters for the operation of the Project including allowable minimum/maximum water levels in Banks Lake and associated ramp rates.

While Banks Lake is primarily utilized for irrigation and recreational uses, Lake Roosevelt is utilized for power generation, flood control, irrigation (via pumping into Banks Lake), flow augmentation for endangered species, and recreation. Often times these multiple desired uses of Lake Roosevelt are in conflict with each other. This situation has resulted in a network of different agreements among multiple regional stakeholders that, on a holistic basis, governs the water storage levels in Lake Roosevelt and the operation of Grand Coulee Dam. Although operations at the Project would result in only *short-term* (i.e., daily or weekly) changes in the water level in Lake Roosevelt (via a shifting of water between Lake Roosevelt and Banks Lake), new incremental withdrawals and injection of water from or into Lake Roosevelt would likely require both (1) modifications to existing operational agreements between the BOR, BPA and other entities and (2) the execution of new operating agreements between CBHP and other regional stakeholders.

11.4 GRAND COULEE SUPPLEMENTAL FLOW OPERATIONS

The Project would have a unique operating characteristic that other proposed PNW pumped storage plants do not possess: the ability to provide supplemental flows into the main stem of the Columbia River for the purpose of increasing generating capability at existing off-site hydro plants. In particular, during periods of time when Grand Coulee Dam's discharges are operationally limited to 1.3 feet per day from Lake Roosevelt, conditions that tend to occur in the winter season during high regional load events, water could be drafted out of Banks Lake (through the Project's generating units) thereby increasing net inflows into Lake Roosevelt and allowing BPA to pass the additional water through Grand Coulee Dam. Not only does this additional inflow increase available generation at Grand Coulee, associated discharges out of Grand Coulee would produce increased generation at the ten federally and non-federally owned dams located downstream of Grand Coulee.

Assuming that hydro plants downstream of Grand Coulee Dam are not in a spill condition due to lack of available turbine capability, each 10,000 cfs of water released out of Banks Lake and passed through Grand Coulee could produce approximately 800 MW of incremental generation (with some time delays due to river flow time). Not only would these supplemental flows increase overall PNW hydro energy production, the extra inflows would increase the sustained peaking capability of the PNW hydro system as well. The PNW is becoming more peak capacity constrained, and this condition is forecasted to begin occurring with more frequency, especially in the winter months. An increase in the sustained peaking capacity of the existing PNW hydro system could reduce (or negate) the need for regional utilities to construct new thermal peaking plants that may only be required to meet peak loads for a few hours or days per year.

This additional energy and sustained capacity produced at the main-stem Columbia River hydro plants would be *in addition to* the energy, capacity, and ancillary services that could be produced on-site at the Project. Therefore, coordinating the operation of the Project with BPA’s and the Mid-Columbia PUD’s operation of the main-stem plants could potentially add significant amounts of new energy and sustained peaking capability to the PNW region at a relatively low cost.

In order for CBHP to harvest the benefit of this supplemental flow capability, operating agreements would need to be negotiated and put in place with BPA and the Mid-Columbia PUDs. Such agreements might be modeled on the provisional draft provisions of the Pacific Northwest Coordination Agreement (PNCA) with the potential addition of a financial payment mechanism.

11.5 MID-COLUMBIA HOURLY COORDINATION

There may be a potential for the Project to be incorporated into the Mid-Columbia Hourly Coordination Agreement. Adding the relatively large water storage capability of Banks Lake and the flexible operation of the Project’s P/G units might add diversity to the pool of seven hydro plants that are currently included in Hourly Coordination (HC); thereby, increasing operational flexibility for the current HC participants. Given that Banks Lake is located off-stream of the main-stem Columbia River, special conditions and/or provisions may need to be negotiated and implemented in order for the Project to be incorporated into HC. For instance, CBHP might receive financial payments from the other HC participants in exchange for allowing the HC program to control certain operational parameters at the Project.

12.0 REGULATORY ISSUES AND IMPACTS

The power industry in the United States is subject to a high degree of regulatory oversight on many levels. With regard to the development of the Project, two areas of particular interest are (1) environmental regulation regarding the Project's licensing, permitting, construction, and operation and (2) power system operations and bulk power system reliability criteria. The two sub-sections that follow briefly summarize the impacts of these two areas on the Project.

12.1 LICENSING AND ENVIRONMENTAL CONSIDERATIONS

In its Preliminary license application to FERC, CBHP proposed two alternatives for its pumped storage project: Alternative No. 1 would use Banks Lake as the upper reservoir and Lake Roosevelt as the lower reservoir; Alternative No. 2 would use Banks Lake as the lower reservoir and involve construction of a new upper reservoir. CBHP is currently focusing on the development of Alternative No. 1. Both Lake Roosevelt and Banks Lake are components of the Columbia Basin Project and these two bodies of water are currently connected by a feeder canal that provides water for twelve pumps operated by BOR at the John W. Keys III Plant (Keys Plant).

On August 22, 2013, FERC issued the preliminary permit (P-14329). The United States Fish and Wildlife Service (USFWS) submitted comments on the preliminary permit application on April 17, 2013. The USFWS participates in Endangered Species Act (ESA) section 7 consultation and provides conservation planning assistance through its role as managers of fish and wildlife in the Columbia Basin Irrigation Project. The USFWS recommended that the permit for this Project contain the following conditions:

1. The applicant should prepare and submit with its license application a detailed analysis of the water rights associated with the license and Project, and consider how the proposed Project would affect other water rights in the Columbia River Basin.
2. The construction, operation, and maintenance of the powerhouse should be compatible with the primary functions of the Columbia Basin Irrigation Project, which provides water for irrigation, fish and wildlife, flood control, and recreation.

3. Insure that additional water will not be diverted or over-allocated for purposes other than Project-related functions, to retain the existing adequate flows in the basin.
4. Consult with the USFWS, National Marine Fisheries Service (NMFS), Washington Department of Fish and Wildlife (WDFW), and the Tribes (e.g., Colville, Yakama) for guidance in conducting Project investigations to preserve and protect the fish and wildlife resources in the Project area and to explore alternatives that minimize damage to these resources.
5. Engineer facilities within water withdrawal, conveyance and impoundment structures that provide opportunity to identify and collect entrained fish during maintenance and operations, so that entrained fish can be documented and/or released unharmed. Also document and report fish entrainment by species, age, size, and life stage. In this way, Project effects to fish can be more fully understood and documented.
6. Provide adequate fish screens that meet National Oceanic and Atmospheric Administration (NOAA) and WDFW compliance standards in all facilities that have the potential to entrain or kill fish, while moving water within facilities.
7. If reservoirs (storage and re-regulation) are created, design them to include wetland and riparian habitats for native fish and wildlife, if doing so would not inundate existing shrub-steppe habitat. The USFWS could assist the BOR in identifying suitable sites, as well as provide a list of native plants for this purpose.
8. The applicant shall arrange for and fund studies necessary to determine the impact of Project construction and operation on fish and wildlife resources, including threatened and endangered species and their habitat, and to develop appropriate measures to protect, mitigate, and if possible, enhance these resources. That means the applicant shall:
    - Determine the methods for discharging flows from the generating facilities and returning them to the river without causing fish stranding, restricting the movement and abundance of any fish species (i.e., bull trout), or degrading water quality.
    - Determine if water retention time is adversely affecting the zooplankton standing crop and the effects on the Banks Lake and Lake Roosevelt fishery resulting from the implementation of the Project.
    - Determine the effects of Project reservoir operations on the food base of Lake Roosevelt.
    - Explain the effects of the Project on fish resources, in particular to spring spawning fish.
    - Conduct studies of juvenile fish bypass systems at appropriate hydropower facilities to prevent mortality resulting from the downstream passage of migrants through turbines at the proposed Project.
    - Investigate alternative transmission-line routes with emphasis on reducing possible impacts to raptors, particularly bald eagles and other birds such as the sage-grouse.

- Conduct sufficient inventories, evaluations, and/or compile existing information to estimate the number of big game and upland games species that would be lost through the construction of the powerhouse, penstock, pipeline, roads, and transmission line corridors.

On May 9, 2013, BOR filed comments with FERC debating their interpretation of Section 2406 of the Energy Policy Act of 1992. In summary, BOR disagrees that FERC has unilateral authority to allow for the development of power sites on federal projects. BOR asks to enter into the Memorandum of Understanding (MOU) process developed in 1992 to address jurisdictional issues. CBHP will need to work with FERC and BOR to address licensing and jurisdictional issues should the Project advance towards design, licensing, permitting, construction, and operation.

12.2 CURRENT AND POTENTIAL FUTURE ENVIRONMENTAL REGULATION

Existing and/or newly enacted environmental restrictions placed on power plant development by various regulatory bodies could have a significant impact on the viability of the Project. For example, legislation currently on the books in Washington State (1) effectively prohibits the construction of any new coal-fired power plants in the state and (2) restricts the ability of utilities serving load within the state from purchasing the output of existing coal plants located in other states. In addition, there has been some discussion in Washington State regarding potential new restrictions on the construction of new gas-fired plants within the state and the use of oil as a backup fuel to natural gas at CCCT and CT plants.

Plans have already been announced by PGE and TransAlta for the shutdowns of the Boardman and Centralia coal-fired plants. In particular, the early shutdown of Centralia Unit #1 in 2020 and Centralia Unit #2 in 2025 will create an additional need for new sources of firm energy and capacity in order for the region to continue to reliably meet its energy and peak load obligations.

Also in the mix is that pending and/or future environmental regulations may force the early retirement of one or more of the existing Colstrip units.

Environmental-based restrictions on the development of new coal-fired plants and possibly gas-fired plants would significantly improve the attractiveness of the Project, since there are few remaining generating technologies that could provide significant amounts of firm capacity and A/S to the PNW bulk power system.

One key advantage of the Project from an environmental perspective is that the Project would not require the construction of any new dams or reservoirs. Given that the construction of such facilities usually entails a great deal of environmental permitting processes, having two such facilities already in place is a great benefit. The Project would, however, need to be operated in a manner that is consistent with the environmental constraints already in place at Lake Roosevelt and Banks Lake or, alternately, existing constraints may need to be modified through established regulatory processes.

12.3 POWER SYSTEM OPERATIONS AND GRID RELIABILITY CRITERIA

As a publically owned entity, CBHP's sales of energy, capacity, and A/S in the PNW regional markets are not subject to the jurisdiction of FERC with regard to rates. However, following the passage of the Energy Policy Act of 2005 (EPAct), FERC gained significant new regulatory powers with regard to (1) overseeing many aspects of bulk power grid operations and (2) developing and enforcing system reliability criteria.

Since 2005, operators of generating plants (as well as transmission system operators and BAA operators) have been subject to an ever growing list of mandatory reliability criteria. The "self-policing" system for reliability compliance that was in place prior to 2005 has been largely replaced by a much more tightly monitored NERC/WECC compliance program. The EPAct also granted FERC the authority to issue civil penalties in an amount up to $1,000,000 per day, per violation, of the established reliability criteria. It is important to note that with regard to system reliability related penalties, FERC has the ability under EPAct to access these fines against *both* jurisdictional and non-jurisdictional entities.

CBHP is currently registered as a generator owner (GO) and generator operator (GOP) and is subject to some of the GO/GOP reliability criteria due to its operation of its existing smaller hydro projects; however if CBHP were the operator of record for the Project, they would be subject to a *much higher* reliability compliance burden. In addition, the risks to CBHP, in the form of potential civil penalties and/or other FERC enforcement actions, would also be much greater.

In addition to the requirements as a GO/GOP, CBHP *could also* be required by NERC/FERC to register as a Transmission Owner (TO) and/or a Transmission Operator (TOP).

In Order 785, released in September 2013, FERC clarified that in some cases, facilities that interconnect generating plants to the bulk power system (i.e., transmission lines, transformers, etc.) could be considered critical elements to the overall reliability of the system. In this situation, the operators of such interconnecting facilities would be considered to be TOPs and would be subject to the TOP category of reliability criteria regarding the operation and maintenance of the plant’s interconnection equipment. FERC did not establish any “bright line” standard with regard to how it would make this determination other than to state that it will consider the specific facts on a case-by-case basis.

Even though the interconnection link(s) to the BPA transmission system (whether it be by overhead lines or by underground conduits) would likely be very short, it is more probable than not that FERC would find these facilities to be vital to the reliable operation of the bulk power system, since they would interconnect a very large (500 to 1,000 MW) pump/generation plant. Therefore, CBHP should be prepared to register with NERC as a TO/TOP, and be prepared to be subject to both the GO/GOP and the TO/TOP classes of NERC reliability standards regarding the operation of the Project.

13.0 LOANS, CREDITS, AND GRANTS

This section provides an overview of the results discovered in researching loans, credits and grants that might be available to help fund or improve the economics of the Project. The following summarizes the pre-feasibility findings for loans, credits and grants:

- There are no apparent Grants available for Pumped Storage Projects at this time, but if the Project proceeds beyond this pre-feasibility phase, addition research is warranted.
- Due to the size (500 to 1000 MW) and technology (hydro) of the Project, it is not eligible for Production Tax and Investment Tax Credits. Projects based on wind and solar technologies have enjoyed these Credits for a number of years.
- The Department of Energy (DOE) has a loan program for which the Project may be eligible. The following are the Financial Terms of the program:
    - $4 Billion In Remaining Loan Authority
    - **LOAN GUARANTEE:** A loan guarantee can support debt from a commercial lender or the U.S. Treasury.
    - **LOAN TENOR:** Long-term financing is available based on the useful life of the asset – up to 30 years.
    - **INTEREST RATES:** Interest rates set based on equivalent U.S. Treasury rate plus a credit-based spread (~0.5 to 1.5%).
    - **EQUITY:** The DOE program can only guarantee up to 80% of the total project cost. Most projects have at least 35% equity.
    - **CO-LENDING:** Co-lending with commercial lenders is encouraged but not required.
- DOE Loan Programs Office (LPO) – Eligibility
    - **INNOVATIVE TECHNOLOGY:** Eligible projects must utilize new or significantly improved technology or systems.
    - **GREENHOUSE GAS BENEFITS:** Eligible projects must reduce, avoid, or sequester greenhouse gases.
    - **LOCATED IN THE U.S.:** Eligible projects must be located in the United States but may be foreign-owned.
    - **REASONABLE PROSPECT OF REPAYMENT:** Eligible projects must have a reasonable prospect of repayment.

14.0 RECOMMENDED NEXT STEPS

As noted above, further analysis of the Project is recommended to determine whether a feasible Project exists and warrants taking the future steps to licensing, design, and construction. However, before those future steps are considered, some near-term next steps and action items need to be completed. The initial version of this Report offered a set of recommended action items to the CBHP Management and Board of Directors based on the analysis of the power market in terms of the perspective value of capacity, energy, and A/S, as well as the potential value the Project can bring to the region as a large dispatchable, carbon-free and environmentally friendly generation source. The CBHP Board of Directors approved a proposed set of near-term next steps and action items in their April 28, 2015, meeting, and authorized CBHP Management to draft a Task Order covering the identified items.

14.1 DESCRIPTION OF NEAR TERM NEXT STEPS

During the spring and summer of 2015, CBHP Management, working in conjunction with Kleinschmidt and Reed Consulting, developed an updated set of proposed near-term next steps and action items based upon the list contained in Section 14.1 of the initial (May 2015) version of this Report. A Task Order defining the recommended near-term next steps to further refine the feasibility of the Project, collaborate with stakeholders, off-takers, and potential investors, and to implement a Project awareness campaign, was approved by the CBHP Board of Directors on June 23, 2015. This Task Order specified that the next phase of Project related work be completed by December 31, 2015. The CBHP Board of Directors subsequently elected to extend the time period for the completion of several Project-related activities through January 31, 2017. It is currently anticipated that the CBHP Board of Directors will consider whether or not to actively continue pre-development work on the Project beyond January 31, 2017 at some point during Q1, 2017.

The key Project activities and action items targeted for completion by January 31, 2017, (or at a later date as may be extended by the CBHP Board of Directors) are as follows:

- Implement the plan to create an industry, public, and political awareness campaign for the Project that communicates its value for meeting long term regional power needs in an environmentally friendly way.
- Research the availability of state or federal grants to help fund study work, stakeholder, off-taker, and investor interactions and the Project awareness campaign.
- Continue to meet with BOR and BPA to establish a level of support and address any identified issues. Begin work to develop MOUs among the parties as appropriate.
- Hold informational meetings about the Project with key electric industry officers and executives within the region.
- Meet with Washington State officials, agencies, the Governor's staff, Tribes, and senate and congressional representatives regarding the Project.
- Meet with the public and stakeholders regarding the Project.
- Meet with federal officials, agencies, and U.S. senate and congressional representatives regarding the Project.
- Implement the marketing plan for the Project in order to effectively present the Project to potential investors and/or off-takers. Develop marketing and general informational materials about the Project.
- Contact potential investors and set up meetings/conference calls to present the Project and to respond to questions. Conduct additional analysis and research as needed, to provide feedback to potential investors. Provide information and assistance to investor staff as needed, to allow investors to utilize their own in-house modeling tools.
- Contact potential off-takers and Pump-Back energy suppliers in order to provide updated information regarding the Project (including preliminary cost estimates). Gather additional information regarding potential off-taker and Pump-Back energy supplier interest in the Project, and how the off-takers would propose to operate the Project (or a portion of the Project) in order to analyze alternate Project sizes and to provide information for use in the transmission Interconnection Feasibility Study ("FES") to be performed by BPA. Assemble any additional information regarding the load/resource status within the PNW that supports the interactions with potential off-takers or Pump-Back energy suppliers.
- Develop the set of information/data required for the performance of the FES for the Project. Based upon information gathered from potential Project off-takers and industry stakeholders regarding the optimal Project size, execute BPA's Large Generator Interconnection Procedure (LGIP) Request forms and complete the FES Agreement with BPA. Work with BPA on the FES and report to CBHP Management and Board of Directors the results of the Study. *Note: Completion of this action item may be deferred beyond December 31, 2015.*
- Determine if potential off-takers and Pump-Back energy suppliers are interested in entering into Letters of Intent for long-term Power Purchase Agreements (PPA) with the Project. Begin preliminary PPA negotiations as appropriate.

- Update the long-term power cost and revenue estimates (that were incorporated in the initial version of this Report) for use in maintaining the Project's financial analysis.
- Collaborate with BPA and the BOR to jointly develop analytical modeling tools and the associated modeling datasets/assumptions needed to perform enhanced operational modeling of the Project.
- Perform additional analysis to determine the range of optimal Project sizes and associated costs based upon interest expressed by potential off-takers, different operating modes for the Project, potential impacts of operational constraints at Banks Lake and/or Lake Roosevelt, the results of the FES (if completed prior to December 31, 2016), refined Project capital and O&M costs, and other relevant factors.
- Conduct further detailed Project financial modeling based on more comprehensive estimates for Project construction and initial investment costs; off-peak and on-peak energy prices; operating, maintenance, and life-cycle renewal costs, as well as debt and equity terms and conditions.
- Prepare the data/information required to submit bids in response to Requests for Proposals (RFP) for new generation that potential off-takers might issue. Perform follow-up actions in the RFP processes as required.
- Monitor power market and transmission market regulatory and/or reliability related policies and procedures that could have an impact on the Project (including FERC regulatory requirements and NERC/WECC system reliability criteria).
- Perform other Project related tasks as needed to support the study work, stakeholder, off-taker, and investor interactions, and Project awareness campaign.

APPENDIX A

MONTHLY AVERAGE MID-COLUMBIA ENERGY PRICE FORECASTS

APPENDIX A

CBHP - Banks Lake Pumped Storage Project
Monthly Average Mid-Columbia Energy Price Forecasts
2025 - 2064

Escalation Factor Beyond 2026	1.020

Year Num	Year	Month	Off-Peak ($/Mwh)	On-Peak ($/Mwh)
1	2025	Jan	51.37	55.26
1	2025	Feb	49.29	53.40
1	2025	Mar	40.63	46.22
1	2025	Apr	26.30	43.71
1	2025	May	20.27	37.05
1	2025	Jun	20.44	29.80
1	2025	Jul	24.14	50.20
1	2025	Aug	39.86	57.30
1	2025	Sep	45.00	54.08
1	2025	Oct	51.27	54.36
1	2025	Nov	48.74	53.25
1	2025	Dec	55.79	60.71
2	2026	Jan	52.50	56.48
2	2026	Feb	50.36	54.56
2	2026	Mar	41.51	47.22
2	2026	Apr	26.89	44.69
2	2026	May	20.73	37.87
2	2026	Jun	20.89	30.46
2	2026	Jul	24.67	51.31
2	2026	Aug	40.73	58.55
2	2026	Sep	45.97	55.25
2	2026	Oct	52.37	55.53
2	2026	Nov	49.92	54.53
2	2026	Dec	57.30	62.35
3	2027	Jan	53.55	57.61
3	2027	Feb	51.37	55.65
3	2027	Mar	42.34	48.16
3	2027	Apr	27.43	45.58
3	2027	May	21.14	38.63
3	2027	Jun	21.31	31.07
3	2027	Jul	25.16	52.34
3	2027	Aug	41.54	59.72
3	2027	Sep	46.89	56.36
3	2027	Oct	53.42	56.64
3	2027	Nov	50.92	55.62
3	2027	Dec	58.45	63.60
4	2028	Jan	54.62	58.76
4	2028	Feb	52.39	56.76
4	2028	Mar	43.19	49.13
4	2028	Apr	27.98	46.50
4	2028	May	21.57	39.40
4	2028	Jun	21.73	31.69

4	2028	Jul	25.67	53.38
4	2028	Aug	42.38	60.92
4	2028	Sep	47.83	57.48
4	2028	Oct	54.49	57.77
4	2028	Nov	51.94	56.73
4	2028	Dec	59.61	64.87
5	2029	Jan	55.71	59.94
5	2029	Feb	53.44	57.90
5	2029	Mar	44.05	50.11
5	2029	Apr	28.54	47.43
5	2029	May	22.00	40.19
5	2029	Jun	22.17	32.32
5	2029	Jul	26.18	54.45
5	2029	Aug	43.22	62.13
5	2029	Sep	48.78	58.63
5	2029	Oct	55.58	58.93
5	2029	Nov	52.98	57.87
5	2029	Dec	60.81	66.17
6	2030	Jan	56.83	61.14
6	2030	Feb	54.51	59.06
6	2030	Mar	44.93	51.11
6	2030	Apr	29.11	48.37
6	2030	May	22.44	40.99
6	2030	Jun	22.61	32.97
6	2030	Jul	26.70	55.54
6	2030	Aug	44.09	63.38
6	2030	Sep	49.76	59.80
6	2030	Oct	56.69	60.11
6	2030	Nov	54.04	59.03
6	2030	Dec	62.02	67.49
7	2031	Jan	57.96	62.36
7	2031	Feb	55.60	60.24
7	2031	Mar	45.83	52.13
7	2031	Apr	29.69	49.34
7	2031	May	22.89	41.81
7	2031	Jun	23.06	33.63
7	2031	Jul	27.24	56.65
7	2031	Aug	44.97	64.64
7	2031	Sep	50.75	61.00
7	2031	Oct	57.82	61.31
7	2031	Nov	55.12	60.21
7	2031	Dec	63.26	68.84
8	2032	Jan	59.12	63.61
8	2032	Feb	56.71	61.44
8	2032	Mar	46.75	53.18
8	2032	Apr	30.28	50.33
8	2032	May	23.35	42.65
8	2032	Jun	23.53	34.30
8	2032	Jul	27.78	57.78
8	2032	Aug	45.87	65.94
8	2032	Sep	51.77	62.22
8	2032	Oct	58.98	62.54
8	2032	Nov	56.22	61.41
8	2032	Dec	64.53	70.22
9	2033	Jan	60.31	64.88

9	2033	Feb	57.85	62.67
9	2033	Mar	47.68	54.24
9	2033	Apr	30.89	51.33
9	2033	May	23.81	43.50
9	2033	Jun	24.00	34.99
9	2033	Jul	28.34	58.94
9	2033	Aug	46.79	67.26
9	2033	Sep	52.81	63.46
9	2033	Oct	60.16	63.79
9	2033	Nov	57.34	62.64
9	2033	Dec	65.82	71.62
10	2034	Jan	61.51	66.18
10	2034	Feb	59.00	63.93
10	2034	Mar	48.64	55.33
10	2034	Apr	31.51	52.36
10	2034	May	24.29	44.37
10	2034	Jun	24.48	35.69
10	2034	Jul	28.90	60.12
10	2034	Aug	47.72	68.60
10	2034	Sep	53.86	64.73
10	2034	Oct	61.36	65.06
10	2034	Nov	58.49	63.89
10	2034	Dec	67.14	73.05
11	2035	Jan	62.74	67.50
11	2035	Feb	60.18	65.20
11	2035	Mar	49.61	56.43
11	2035	Apr	32.14	53.41
11	2035	May	24.77	45.26
11	2035	Jun	24.97	36.40
11	2035	Jul	29.48	61.32
11	2035	Aug	48.68	69.97
11	2035	Sep	54.94	66.03
11	2035	Oct	62.59	66.36
11	2035	Nov	59.66	65.17
11	2035	Dec	68.48	74.51
12	2036	Jan	64.00	68.85
12	2036	Feb	61.39	66.51
12	2036	Mar	50.60	57.56
12	2036	Apr	32.78	54.48
12	2036	May	25.27	46.16
12	2036	Jun	25.46	37.13
12	2036	Jul	30.07	62.55
12	2036	Aug	49.65	71.37
12	2036	Sep	56.04	67.35
12	2036	Oct	63.84	67.69
12	2036	Nov	60.85	66.47
12	2036	Dec	69.85	76.00
13	2037	Jan	65.28	70.23
13	2037	Feb	62.62	67.84
13	2037	Mar	51.61	58.71
13	2037	Apr	33.43	55.57
13	2037	May	25.78	47.09
13	2037	Jun	25.97	37.87
13	2037	Jul	30.67	63.80
13	2037	Aug	50.64	72.80

13	2037	Sep	57.16	68.70
13	2037	Oct	65.12	69.04
13	2037	Nov	62.07	67.80
13	2037	Dec	71.25	77.52
14	2038	Jan	66.58	71.63
14	2038	Feb	63.87	69.20
14	2038	Mar	52.64	59.89
14	2038	Apr	34.10	56.68
14	2038	May	26.29	48.03
14	2038	Jun	26.49	38.63
14	2038	Jul	31.29	65.07
14	2038	Aug	51.66	74.26
14	2038	Sep	58.30	70.07
14	2038	Oct	66.42	70.43
14	2038	Nov	63.31	69.16
14	2038	Dec	72.67	79.07
15	2039	Jan	67.91	73.06
15	2039	Feb	65.15	70.58
15	2039	Mar	53.70	61.08
15	2039	Apr	34.79	57.81
15	2039	May	26.82	48.99
15	2039	Jun	27.02	39.40
15	2039	Jul	31.91	66.37
15	2039	Aug	52.69	75.74
15	2039	Sep	59.47	71.47
15	2039	Oct	67.75	71.83
15	2039	Nov	64.58	70.54
15	2039	Dec	74.12	80.66
16	2040	Jan	69.27	74.52
16	2040	Feb	66.45	71.99
16	2040	Mar	54.77	62.31
16	2040	Apr	35.48	58.97
16	2040	May	27.35	49.97
16	2040	Jun	27.56	40.19
16	2040	Jul	32.55	67.70
16	2040	Aug	53.74	77.26
16	2040	Sep	60.66	72.90
16	2040	Oct	69.10	73.27
16	2040	Nov	65.87	71.95
16	2040	Dec	75.61	82.27
17	2041	Jan	70.66	76.01
17	2041	Feb	67.78	73.43
17	2041	Mar	55.87	63.55
17	2041	Apr	36.19	60.15
17	2041	May	27.90	50.97
17	2041	Jun	28.12	41.00
17	2041	Jul	33.20	69.06
17	2041	Aug	54.82	78.80
17	2041	Sep	61.87	74.36
17	2041	Oct	70.48	74.74
17	2041	Nov	67.19	73.39
17	2041	Dec	77.12	83.91
18	2042	Jan	72.07	77.53
18	2042	Feb	69.13	74.90
18	2042	Mar	56.98	64.82

18	2042	Apr	36.91	61.35
18	2042	May	28.46	51.99
18	2042	Jun	28.68	41.82
18	2042	Jul	33.87	70.44
18	2042	Aug	55.91	80.38
18	2042	Sep	63.11	75.85
18	2042	Oct	71.89	76.23
18	2042	Nov	68.53	74.86
18	2042	Dec	78.66	85.59
19	2043	Jan	73.51	79.09
19	2043	Feb	70.52	76.40
19	2043	Mar	58.12	66.12
19	2043	Apr	37.65	62.58
19	2043	May	29.03	53.03
19	2043	Jun	29.25	42.65
19	2043	Jul	34.54	71.85
19	2043	Aug	57.03	81.98
19	2043	Sep	64.37	77.36
19	2043	Oct	73.33	77.76
19	2043	Nov	69.90	76.36
19	2043	Dec	80.23	87.31
20	2044	Jan	74.98	80.67
20	2044	Feb	71.93	77.93
20	2044	Mar	59.29	67.44
20	2044	Apr	38.41	63.83
20	2044	May	29.61	54.09
20	2044	Jun	29.84	43.50
20	2044	Jul	35.23	73.28
20	2044	Aug	58.17	83.62
20	2044	Sep	65.66	78.91
20	2044	Oct	74.80	79.31
20	2044	Nov	71.30	77.88
20	2044	Dec	81.84	89.05
21	2045	Jan	76.48	82.28
21	2045	Feb	73.37	79.48
21	2045	Mar	60.47	68.79
21	2045	Apr	39.17	65.10
21	2045	May	30.20	55.17
21	2045	Jun	30.43	44.37
21	2045	Jul	35.94	74.75
21	2045	Aug	59.34	85.30
21	2045	Sep	66.97	80.49
21	2045	Oct	76.29	80.90
21	2045	Nov	72.72	79.44
21	2045	Dec	83.48	90.83
22	2046	Jan	78.01	83.93
22	2046	Feb	74.83	81.07
22	2046	Mar	61.68	70.17
22	2046	Apr	39.96	66.41
22	2046	May	30.80	56.27
22	2046	Jun	31.04	45.26
22	2046	Jul	36.66	76.24
22	2046	Aug	60.52	87.00
22	2046	Sep	68.31	82.10
22	2046	Oct	77.82	82.51

22	2046	Nov	74.18	81.03
22	2046	Dec	85.14	92.65
23	2047	Jan	79.57	85.60
23	2047	Feb	76.33	82.69
23	2047	Mar	62.92	71.57
23	2047	Apr	40.76	67.74
23	2047	May	31.42	57.40
23	2047	Jun	31.66	46.17
23	2047	Jul	37.39	77.77
23	2047	Aug	61.73	88.74
23	2047	Sep	69.68	83.74
23	2047	Oct	79.38	84.16
23	2047	Nov	75.66	82.65
23	2047	Dec	86.85	94.50
24	2048	Jan	81.16	87.32
24	2048	Feb	77.86	84.35
24	2048	Mar	64.17	73.00
24	2048	Apr	41.57	69.09
24	2048	May	32.05	58.55
24	2048	Jun	32.30	47.09
24	2048	Jul	38.14	79.32
24	2048	Aug	62.97	90.52
24	2048	Sep	71.07	85.42
24	2048	Oct	80.96	85.85
24	2048	Nov	77.18	84.30
24	2048	Dec	88.58	96.39
25	2049	Jan	82.79	89.06
25	2049	Feb	79.41	86.04
25	2049	Mar	65.46	74.46
25	2049	Apr	42.40	70.47
25	2049	May	32.69	59.72
25	2049	Jun	32.94	48.03
25	2049	Jul	38.90	80.91
25	2049	Aug	64.23	92.33
25	2049	Sep	72.49	87.12
25	2049	Oct	82.58	87.57
25	2049	Nov	78.72	85.99
25	2049	Dec	90.36	98.32
26	2050	Jan	84.44	90.84
26	2050	Feb	81.00	87.76
26	2050	Mar	66.77	75.95
26	2050	Apr	43.25	71.88
26	2050	May	33.34	60.91
26	2050	Jun	33.60	48.99
26	2050	Jul	39.68	82.53
26	2050	Aug	65.51	94.17
26	2050	Sep	73.94	88.87
26	2050	Oct	84.23	89.32
26	2050	Nov	80.29	87.71
26	2050	Dec	92.16	100.29
27	2051	Jan	86.13	92.66
27	2051	Feb	82.62	89.51
27	2051	Mar	68.10	77.47
27	2051	Apr	44.12	73.32
27	2051	May	34.01	62.13

27	2051	Jun	34.27	49.97
27	2051	Jul	40.47	84.18
27	2051	Aug	66.82	96.06
27	2051	Sep	75.42	90.64
27	2051	Oct	85.92	91.10
27	2051	Nov	81.90	89.46
27	2051	Dec	94.01	102.29
28	2052	Jan	87.85	94.51
28	2052	Feb	84.27	91.30
28	2052	Mar	69.46	79.02
28	2052	Apr	45.00	74.79
28	2052	May	34.69	63.37
28	2052	Jun	34.96	50.97
28	2052	Jul	41.28	85.86
28	2052	Aug	68.16	97.98
28	2052	Sep	76.93	92.46
28	2052	Oct	87.64	92.92
28	2052	Nov	83.54	91.25
28	2052	Dec	95.89	104.34
29	2053	Jan	89.61	96.40
29	2053	Feb	85.96	93.13
29	2053	Mar	70.85	80.60
29	2053	Apr	45.90	76.28
29	2053	May	35.38	64.64
29	2053	Jun	35.66	51.99
29	2053	Jul	42.11	87.58
29	2053	Aug	69.52	99.94
29	2053	Sep	78.47	94.31
29	2053	Oct	89.39	94.78
29	2053	Nov	85.21	93.08
29	2053	Dec	97.80	106.42
30	2054	Jan	91.40	98.33
30	2054	Feb	87.68	94.99
30	2054	Mar	72.27	82.21
30	2054	Apr	46.82	77.81
30	2054	May	36.09	65.93
30	2054	Jun	36.37	53.03
30	2054	Jul	42.95	89.33
30	2054	Aug	70.91	101.94
30	2054	Sep	80.03	96.19
30	2054	Oct	91.18	96.68
30	2054	Nov	86.91	94.94
30	2054	Dec	99.76	108.55
31	2055	Jan	93.23	100.30
31	2055	Feb	89.43	96.89
31	2055	Mar	73.72	83.86
31	2055	Apr	47.75	79.36
31	2055	May	36.81	67.25
31	2055	Jun	37.10	54.09
31	2055	Jul	43.81	91.12
31	2055	Aug	72.33	103.98
31	2055	Sep	81.64	98.12
31	2055	Oct	93.00	98.61
31	2055	Nov	88.65	96.84
31	2055	Dec	101.76	110.72

32	2056	Jan	95.10	102.31
32	2056	Feb	91.22	98.83
32	2056	Mar	75.19	85.53
32	2056	Apr	48.71	80.95
32	2056	May	37.55	68.60
32	2056	Jun	37.84	55.17
32	2056	Jul	44.69	92.94
32	2056	Aug	73.78	106.06
32	2056	Sep	83.27	100.08
32	2056	Oct	94.86	100.58
32	2056	Nov	90.42	98.77
32	2056	Dec	103.79	112.94
33	2057	Jan	97.00	104.35
33	2057	Feb	93.04	100.80
33	2057	Mar	76.69	87.24
33	2057	Apr	49.68	82.57
33	2057	May	38.30	69.97
33	2057	Jun	38.60	56.28
33	2057	Jul	45.58	94.80
33	2057	Aug	75.25	108.18
33	2057	Sep	84.93	102.08
33	2057	Oct	96.76	102.60
33	2057	Nov	92.23	100.75
33	2057	Dec	105.87	115.20
34	2058	Jan	98.94	106.44
34	2058	Feb	94.91	102.82
34	2058	Mar	78.23	88.99
34	2058	Apr	50.68	84.22
34	2058	May	39.07	71.37
34	2058	Jun	39.37	57.40
34	2058	Jul	46.49	96.70
34	2058	Aug	76.76	110.34
34	2058	Sep	86.63	104.12
34	2058	Oct	98.69	104.65
34	2058	Nov	94.08	102.76
34	2058	Dec	107.98	117.50
35	2059	Jan	100.92	108.57
35	2059	Feb	96.80	104.88
35	2059	Mar	79.79	90.77
35	2059	Apr	51.69	85.90
35	2059	May	39.85	72.79
35	2059	Jun	40.16	58.55
35	2059	Jul	47.42	98.63
35	2059	Aug	78.29	112.55
35	2059	Sep	88.36	106.20
35	2059	Oct	100.67	106.74
35	2059	Nov	95.96	104.82
35	2059	Dec	110.14	119.85
36	2060	Jan	102.94	110.74
36	2060	Feb	98.74	106.97
36	2060	Mar	81.39	92.58
36	2060	Apr	52.72	87.62
36	2060	May	40.64	74.25
36	2060	Jun	40.96	59.72
36	2060	Jul	48.37	100.60

36	2060	Aug	79.86	114.80
36	2060	Sep	90.13	108.33
36	2060	Oct	102.68	108.88
36	2060	Nov	97.88	106.92
36	2060	Dec	112.35	122.25
37	2061	Jan	104.99	112.95
37	2061	Feb	100.71	109.11
37	2061	Mar	83.02	94.43
37	2061	Apr	53.78	89.38
37	2061	May	41.46	75.74
37	2061	Jun	41.78	60.92
37	2061	Jul	49.34	102.61
37	2061	Aug	81.46	117.09
37	2061	Sep	91.93	110.49
37	2061	Oct	104.73	111.05
37	2061	Nov	99.83	109.05
37	2061	Dec	114.59	124.69
38	2062	Jan	107.09	115.21
38	2062	Feb	102.73	111.30
38	2062	Mar	84.68	96.32
38	2062	Apr	54.85	91.16
38	2062	May	42.29	77.25
38	2062	Jun	42.61	62.13
38	2062	Jul	50.32	104.67
38	2062	Aug	83.08	119.44
38	2062	Sep	93.77	112.70
38	2062	Oct	106.83	113.27
38	2062	Nov	101.83	111.24
38	2062	Dec	116.89	127.19
39	2063	Jan	109.24	117.52
39	2063	Feb	104.78	113.52
39	2063	Mar	86.37	98.25
39	2063	Apr	55.95	92.99
39	2063	May	43.13	78.80
39	2063	Jun	43.47	63.38
39	2063	Jul	51.33	106.76
39	2063	Aug	84.75	121.82
39	2063	Sep	95.65	114.96
39	2063	Oct	108.97	115.54
39	2063	Nov	103.87	113.46
39	2063	Dec	119.22	129.73
40	2064	Jan	111.42	119.87
40	2064	Feb	106.88	115.79
40	2064	Mar	88.10	100.21
40	2064	Apr	57.07	94.85
40	2064	May	44.00	80.37
40	2064	Jun	44.33	64.65
40	2064	Jul	52.36	108.90
40	2064	Aug	86.44	124.26
40	2064	Sep	97.56	117.26
40	2064	Oct	111.14	117.85
40	2064	Nov	105.95	115.73
40	2064	Dec	121.61	132.33

APPENDIX B

CAPACITY PRICE FORECASTS

APPENDIX B

CBHP - Banks Lake Pumped Storage Project
Capacity Price Forecasts
2025 - 2064

Base Values (2010)		**7.01**	**7.84**

Year Num	Year	Capacity Value-Low ($/Kw-mo)	Capacity Value-High ($/Kw-mo)
1	2025	9.43	10.55
2	2026	9.62	10.76
3	2027	9.81	10.98
4	2028	10.01	11.20
5	2029	10.21	11.42
6	2030	10.41	11.65
7	2031	10.62	11.88
8	2032	10.83	12.12
9	2033	11.05	12.36
10	2034	11.27	12.61
11	2035	11.50	12.86
12	2036	11.73	13.12
13	2037	11.96	13.38
14	2038	12.20	13.65
15	2039	12.44	13.92
16	2040	12.69	14.20
17	2041	12.94	14.48
18	2042	13.20	14.77
19	2043	13.46	15.07
20	2044	13.73	15.37
21	2045	14.00	15.68
22	2046	14.28	15.99
23	2047	14.57	16.31
24	2048	14.86	16.64
25	2049	15.16	16.97
26	2050	15.46	17.31
27	2051	15.77	17.66
28	2052	16.09	18.01
29	2053	16.41	18.37
30	2054	16.74	18.74
31	2055	17.07	19.11
32	2056	17.41	19.49
33	2057	17.76	19.88
34	2058	18.12	20.28
35	2059	18.48	20.69
36	2060	18.85	21.10
37	2061	19.23	21.52
38	2062	19.61	21.95
39	2063	20.00	22.39
40	2064	20.40	22.84

APPENDIX C

FORECASTED POWER REVENUES

APPENDIX C

CBHP - Banks Lake Pumped Storage Project
Forecasted Power Revenues - 500 MW Installed Capacity (Revised August, 2016)
2025 - 2064

Input Assumptions

Installed Capacity (MW)	500
NPV Discount Rate (%)	4.00

Year Num	Year	Capacity for Load Value Low Forecast ($M)	Capacity for Load Value High Forecast ($M)	Capacity for A/S Value Low Forecast ($M)	Capacity for A/S Value High Forecast ($M)	Capacity for GC Supp Flows Low Forecast ($M)	Capacity for GC Supp Flows High Forecast ($M)	Energy Arbitrage Margin Low Forecast ($M)	Energy Arbitrage Margin High Forecast ($M)	Total Power Revenues Low Forecast ($M)	Total Power Revenues High Forecast ($M)
Net Present Value ($M)		**1,527.53**	**1,709.50**	**458.26**	**512.85**	**114.56**	**128.21**	**225.67**	**305.91**	**2,326.01**	**2,656.47**
1	2025	56.58	63.30	16.97	18.99	4.24	4.75	8.29	10.99	86.09	98.03
2	2026	57.72	64.56	17.32	19.37	4.33	4.84	8.48	11.30	87.84	100.07
3	2027	58.86	65.88	17.66	19.76	4.41	4.94	8.67	11.62	89.60	102.20
4	2028	60.06	67.20	18.02	20.16	4.50	5.04	8.85	11.93	91.44	104.33
5	2029	61.26	68.52	18.38	20.56	4.59	5.14	9.04	12.24	93.27	106.46
6	2030	62.46	69.90	18.74	20.97	4.68	5.24	9.23	12.56	95.11	108.67
7	2031	63.72	71.28	19.12	21.38	4.78	5.35	9.37	12.87	96.98	110.88
8	2032	64.98	72.72	19.49	21.82	4.87	5.45	9.51	13.18	98.85	113.17
9	2033	66.30	74.16	19.89	22.25	4.97	5.56	9.64	13.49	100.81	115.46
10	2034	67.62	75.66	20.29	22.70	5.07	5.67	9.78	13.80	102.76	117.84
11	2035	69.00	77.16	20.70	23.15	5.18	5.79	9.92	14.11	104.80	120.21
12	2036	70.38	78.72	21.11	23.62	5.28	5.90	10.19	14.31	106.97	122.55
13	2037	71.76	80.28	21.53	24.08	5.38	6.02	10.47	14.50	109.14	124.89
14	2038	73.20	81.90	21.96	24.57	5.49	6.14	10.74	14.69	111.39	127.31
15	2039	74.64	83.52	22.39	25.06	5.60	6.26	11.01	14.89	113.64	129.73
16	2040	76.14	85.20	22.84	25.56	5.71	6.39	11.29	15.08	115.98	132.23
17	2041	77.64	86.88	23.29	26.06	5.82	6.52	11.54	15.36	118.30	134.82
18	2042	79.20	88.62	23.76	26.59	5.94	6.65	11.80	15.64	120.70	137.49
19	2043	80.76	90.42	24.23	27.13	6.06	6.78	12.06	15.92	123.10	140.24
20	2044	82.38	92.22	24.71	27.67	6.18	6.92	12.31	16.19	125.59	143.00
21	2045	84.00	94.08	25.20	28.22	6.30	7.06	12.57	16.47	128.07	145.83
22	2046	85.68	95.94	25.70	28.78	6.43	7.20	12.77	16.86	130.58	148.78
23	2047	87.42	97.86	26.23	29.36	6.56	7.34	12.98	17.26	133.18	151.81
24	2048	89.16	99.84	26.75	29.95	6.69	7.49	13.18	17.65	135.78	154.93
25	2049	90.96	101.82	27.29	30.55	6.82	7.64	13.39	18.04	138.46	158.04
26	2050	92.76	103.86	27.83	31.16	6.96	7.79	13.59	18.43	141.14	161.24
27	2051	94.62	105.96	28.39	31.79	7.10	7.95	13.91	18.89	144.01	164.58
28	2052	96.54	108.06	28.96	32.42	7.24	8.10	14.22	19.34	146.96	167.93
29	2053	98.46	110.22	29.54	33.07	7.38	8.27	14.53	19.80	149.91	171.35
30	2054	100.44	112.44	30.13	33.73	7.53	8.43	14.85	20.26	152.95	174.86
31	2055	102.42	114.66	30.73	34.40	7.68	8.60	15.16	20.71	155.99	178.37
32	2056	104.46	116.94	31.34	35.08	7.83	8.77	15.57	21.18	159.20	181.98
33	2057	106.56	119.28	31.97	35.78	7.99	8.95	15.99	21.66	162.51	185.67
34	2058	108.72	121.68	32.62	36.50	8.15	9.13	16.40	22.13	165.89	189.44
35	2059	110.88	124.14	33.26	37.24	8.32	9.31	16.81	22.60	169.27	193.29
36	2060	113.10	126.60	33.93	37.98	8.48	9.50	17.23	23.07	172.74	197.15
37	2061	115.38	129.12	34.61	38.74	8.65	9.68	17.46	23.56	176.11	201.10
38	2062	117.66	131.70	35.30	39.51	8.82	9.88	17.69	24.04	179.47	205.13
39	2063	120.00	134.34	36.00	40.30	9.00	10.08	17.92	24.53	182.92	209.25
40	2064	122.40	137.04	36.72	41.11	9.18	10.28	18.15	25.01	186.45	213.44

APPENDIX C

CBHP - Banks Lake Pumped Storage Project
Forecasted Power Revenues - 1,000 MW Installed Capacity (Revised August, 2016)
2025 - 2064

Input Assumptions

Installed Capacity (MW)	1,000
NPV Discount Rate (%)	4.00

Year Num	Year	Capacity for Load Value Low Forecast ($M)	Capacity for Load Value High Forecast ($M)	Capacity for A/S Value Low Forecast ($M)	Capacity for A/S Value High Forecast ($M)	Capacity for GC Supp Flows Low Forecast ($M)	Capacity for GC Supp Flows High Forecast ($M)	Energy Arbitrage Margin Low Forecast ($M)	Energy Arbitrage Margin High Forecast ($M)	Total Power Revenues Low Forecast ($M)	Total Power Revenues High Forecast ($M)
Net Present Value ($M)		**3,055.05**	**3,419.00**	**916.52**	**1,025.70**	**229.13**	**256.42**	**423.58**	**569.44**	**4,624.27**	**5,270.55**
1	2025	113.16	126.60	33.95	37.98	8.49	9.50	15.83	20.24	171.43	194.32
2	2026	115.44	129.12	34.63	38.74	8.66	9.68	16.20	20.92	174.93	198.46
3	2027	117.72	131.76	35.32	39.53	8.83	9.88	16.58	21.59	178.45	202.76
4	2028	120.12	134.40	36.04	40.32	9.01	10.08	16.95	22.26	182.12	207.06
5	2029	122.52	137.04	36.76	41.11	9.19	10.28	17.32	22.93	185.79	211.36
6	2030	124.92	139.80	37.48	41.94	9.37	10.49	17.69	23.61	189.46	215.84
7	2031	127.44	142.56	38.23	42.77	9.56	10.69	17.85	24.14	193.08	220.16
8	2032	129.96	145.44	38.99	43.63	9.75	10.91	18.00	24.68	196.70	224.66
9	2033	132.60	148.32	39.78	44.50	9.95	11.12	18.16	25.21	200.49	229.15
10	2034	135.24	151.32	40.57	45.40	10.14	11.35	18.32	25.75	204.28	233.82
11	2035	138.00	154.32	41.40	46.30	10.35	11.57	18.47	26.28	208.22	238.47
12	2036	140.76	157.44	42.23	47.23	10.56	11.81	18.98	26.64	212.53	243.12
13	2037	143.52	160.56	43.06	48.17	10.76	12.04	19.49	27.00	216.83	247.77
14	2038	146.40	163.80	43.92	49.14	10.98	12.29	20.00	27.36	221.30	252.59
15	2039	149.28	167.04	44.78	50.11	11.20	12.53	20.51	27.72	225.77	257.40
16	2040	152.28	170.40	45.68	51.12	11.42	12.78	21.02	28.08	230.41	262.38
17	2041	155.28	173.76	46.58	52.13	11.65	13.03	21.49	28.60	235.00	267.52
18	2042	158.40	177.24	47.52	53.17	11.88	13.29	21.97	29.12	239.77	272.83
19	2043	161.52	180.84	48.46	54.25	12.11	13.56	22.45	29.64	244.54	278.30
20	2044	164.76	184.44	49.43	55.33	12.36	13.83	22.93	30.16	249.48	283.77
21	2045	168.00	188.16	50.40	56.45	12.60	14.11	23.41	30.68	254.41	289.40
22	2046	171.36	191.88	51.41	57.56	12.85	14.39	23.79	31.41	259.41	295.25
23	2047	174.84	195.72	52.45	58.72	13.11	14.68	24.17	32.14	264.58	301.26
24	2048	178.32	199.68	53.50	59.90	13.37	14.98	24.55	32.87	269.74	307.43
25	2049	181.92	203.64	54.58	61.09	13.64	15.27	24.93	33.59	275.07	313.60
26	2050	185.52	207.72	55.66	62.32	13.91	15.58	25.31	34.32	280.40	319.94
27	2051	189.24	211.92	56.77	63.58	14.19	15.89	25.91	35.20	286.12	326.59
28	2052	193.08	216.12	57.92	64.84	14.48	16.21	26.51	36.07	292.00	333.24
29	2053	196.92	220.44	59.08	66.13	14.77	16.53	27.11	36.94	297.88	340.05
30	2054	200.88	224.88	60.26	67.46	15.07	16.87	27.70	37.81	303.91	347.02
31	2055	204.84	229.32	61.45	68.80	15.36	17.20	28.30	38.68	309.96	354.00
32	2056	208.92	233.88	62.68	70.16	15.67	17.54	29.03	39.51	316.30	361.10
33	2057	213.12	238.56	63.94	71.57	15.98	17.89	29.77	40.33	322.81	368.35
34	2058	217.44	243.36	65.23	73.01	16.31	18.25	30.50	41.16	329.48	375.78
35	2059	221.76	248.28	66.53	74.48	16.63	18.62	31.23	41.98	336.15	383.37
36	2060	226.20	253.20	67.86	75.96	16.97	18.99	31.96	42.81	342.99	390.96
37	2061	230.76	258.24	69.23	77.47	17.31	19.37	32.56	43.53	349.86	398.61
38	2062	235.32	263.40	70.60	79.02	17.65	19.76	33.16	44.24	356.73	406.42
39	2063	240.00	268.68	72.00	80.60	18.00	20.15	33.76	44.96	363.76	414.40
40	2064	244.80	274.08	73.44	82.22	18.36	20.56	34.35	45.68	370.95	422.54

APPENDIX D

PRELIMINARY COST/BENEFIT ANALYSIS

APPENDIX D

CBHP - Banks Lake Pumped Storage Project

Preliminary Cost/Benefit Analysis - 500 MW Installed Capacity (Revised August, 2016) 2025 - 2064

Input Assumptions

Installed Capacity (MW)	500
NPV Discount Rate (%)	4.00
2025 Annual Generation (Mwh)	769,575

Year Num	Year	Total Power Revenues Low Forecast ($M)	Total Power Revenues High Forecast ($M)	Total Project Costs ($M)	Scenario 1 Low Revenues ($)	Scenario 2 High Revenues ($)
Net Present Value ($M)		**2,326.01**	**2,656.47**	**(1,066.94)**	**1,259.07**	**1,589.53**
1	2025	86.09	98.03	(49.65)	36.44	48.38
2	2026	87.84	100.07	(49.76)	38.08	50.31
3	2027	89.60	102.20	(49.88)	39.72	52.33
4	2028	91.44	104.33	(49.99)	41.44	54.34
5	2029	93.27	106.46	(50.11)	43.16	56.34
6	2030	95.11	108.67	(50.24)	44.88	58.43
7	2031	96.98	110.88	(50.36)	46.62	60.52
8	2032	98.85	113.17	(50.49)	48.36	62.68
9	2033	100.81	115.46	(50.62)	50.19	64.84
10	2034	102.76	117.84	(50.75)	52.01	67.08
11	2035	104.80	120.21	(50.89)	53.91	69.32
12	2036	106.97	122.55	(51.03)	55.94	71.52
13	2037	109.14	124.89	(51.17)	57.97	73.72
14	2038	111.39	127.31	(51.31)	60.08	75.99
15	2039	113.64	129.73	(51.46)	62.18	78.27
16	2040	115.98	132.23	(51.61)	64.37	80.62
17	2041	118.30	134.82	(51.76)	66.53	83.05
18	2042	120.70	137.49	(51.92)	68.78	85.57
19	2043	123.10	140.24	(71.30)	51.80	68.94
20	2044	125.59	143.00	(71.85)	53.74	71.15
21	2045	128.07	145.83	(52.41)	75.66	93.43
22	2046	130.58	148.78	(52.57)	78.01	96.21
23	2047	133.18	151.81	(52.75)	80.44	99.07
24	2048	135.78	154.93	(52.92)	82.86	102.01
25	2049	138.46	158.04	(53.10)	85.36	104.94
26	2050	141.14	161.24	(53.28)	87.85	107.96
27	2051	144.01	164.58	(53.47)	90.54	111.11
28	2052	146.96	167.93	(53.66)	93.30	114.27
29	2053	149.91	171.35	(53.85)	96.06	117.50
30	2054	152.95	174.86	(54.05)	98.90	120.81
31	2055	155.99	178.37	(64.36)	91.62	114.01
32	2056	159.20	181.98	(64.57)	94.64	117.41
33	2057	162.51	185.67	(64.78)	97.73	120.89
34	2058	165.89	189.44	(64.99)	100.90	124.45
35	2059	169.27	193.29	(65.21)	104.06	128.08
36	2060	172.74	197.15	(65.43)	107.31	131.72
37	2061	176.11	201.10	(65.66)	110.45	135.44
38	2062	179.47	205.13	(65.89)	113.58	139.24
39	2063	182.92	209.25	(66.13)	116.79	143.12
40	2064	186.45	213.44	(66.37)	120.09	147.07

APPENDIX D

CBHP - Banks Lake Pumped Storage Project

Preliminary Cost/Benefit Analysis - 1,000 MW Installed Capacity (Revised August, 2016) 2025 - 2064

Input Assumptions

Installed Capacity (MW)	1,000
NPV Discount Rate (%)	4.00
2025 Annual Generation (Mwh)	1,430,153

Year Num	Year	Total Power Revenues Low Forecast ($M)	Total Power Revenues High Forecast ($M)	Total Project Costs ($M)	Scenario 1 Low Revenues ($M)	Scenario 2 High Revenues ($M)
Net Present Value ($M)		**4,624.27**	**5,270.55**	**(2,133.20)**	**2,491.08**	**3,137.36**
1	2025	171.43	194.32	(99.29)	72.13	95.02
2	2026	174.93	198.46	(99.52)	75.41	98.94
3	2027	178.45	202.76	(99.75)	78.69	103.01
4	2028	182.12	207.06	(99.99)	82.13	107.07
5	2029	185.79	211.36	(100.23)	85.56	111.13
6	2030	189.46	215.84	(100.48)	88.98	115.36
7	2031	193.08	220.16	(100.73)	92.35	119.43
8	2032	196.70	224.66	(100.98)	95.71	123.68
9	2033	200.49	229.15	(101.24)	99.24	127.91
10	2034	204.28	233.82	(101.51)	102.77	132.31
11	2035	208.22	238.47	(101.78)	106.44	136.69
12	2036	212.53	243.12	(102.06)	110.47	141.06
13	2037	216.83	247.77	(102.34)	114.49	145.43
14	2038	221.30	252.59	(102.63)	118.67	149.96
15	2039	225.77	257.40	(102.92)	122.85	154.48
16	2040	230.41	262.38	(103.22)	127.18	159.16
17	2041	235.00	267.52	(103.53)	131.47	163.99
18	2042	239.77	272.83	(103.84)	135.93	168.99
19	2043	244.54	278.30	(123.38)	121.16	154.92
20	2044	249.48	283.77	(124.09)	125.39	159.68
21	2045	254.41	289.40	(124.81)	129.60	164.59
22	2046	259.41	295.25	(125.55)	133.86	169.70
23	2047	264.58	301.26	(105.49)	159.08	195.76
24	2048	269.74	307.43	(105.84)	163.90	201.59
25	2049	275.07	313.60	(106.20)	168.87	207.39
26	2050	280.40	319.94	(106.57)	173.83	213.37
27	2051	286.12	326.59	(106.94)	179.17	219.65
28	2052	292.00	333.24	(107.32)	184.67	225.91
29	2053	297.88	340.05	(107.71)	190.17	232.34
30	2054	303.91	347.02	(108.10)	195.81	238.92
31	2055	309.96	354.00	(128.72)	181.23	225.27
32	2056	316.30	361.10	(129.14)	187.16	231.96
33	2057	322.81	368.35	(129.56)	193.25	238.79
34	2058	329.48	375.78	(129.98)	199.50	245.80
35	2059	336.15	383.37	(130.42)	205.73	252.94
36	2060	342.99	390.96	(130.87)	212.12	260.09
37	2061	349.86	398.61	(131.32)	218.54	267.29
38	2062	356.73	406.42	(131.78)	224.94	274.63
39	2063	363.76	414.40	(132.26)	231.50	282.14
40	2064	370.95	422.54	(132.74)	238.21	289.80

APPENDIX D

CBHP - Banks Lake Pumped Storage Project

Project Cost Summary - 500 MW Installed Capacity (Revised August, 2016) 2025 - 2064

Year Num	Year	Debt Service Payment ($M)	Fixed + Variable O&M ($/Mwh)	Fixed + Variable O&M ($M)	A & G Expenses ($/Mwh)	A & G Expenses ($M)	Capital Replacement Expenses ($M)	Total Expenses ($M)
Net Present Value ($M)		**(895.55)**		**(113.57)**		**(39.75)**	**(18.07)**	**(1,066.94)**
1	2025	(43.97)	5.88	(4.21)	2.06	(1.47)	0	(49.65)
2	2026	(43.97)	6.00	(4.29)	2.10	(1.50)	0	(49.76)
3	2027	(43.97)	6.12	(4.38)	2.14	(1.53)	0	(49.88)
4	2028	(43.97)	6.24	(4.46)	2.18	(1.56)	0	(49.99)
5	2029	(43.97)	6.37	(4.55)	2.23	(1.59)	0	(50.11)
6	2030	(43.97)	6.49	(4.64)	2.27	(1.63)	0	(50.24)
7	2031	(43.97)	6.62	(4.74)	2.32	(1.66)	0	(50.36)
8	2032	(43.97)	6.76	(4.83)	2.36	(1.69)	0	(50.49)
9	2033	(43.97)	6.89	(4.93)	2.41	(1.72)	0	(50.62)
10	2034	(43.97)	7.03	(5.03)	2.46	(1.76)	0	(50.75)
11	2035	(43.97)	7.17	(5.13)	2.51	(1.79)	0	(50.89)
12	2036	(43.97)	7.31	(5.23)	2.56	(1.83)	0	(51.03)
13	2037	(43.97)	7.46	(5.33)	2.61	(1.87)	0	(51.17)
14	2038	(43.97)	7.61	(5.44)	2.66	(1.90)	0	(51.31)
15	2039	(43.97)	7.76	(5.55)	2.72	(1.94)	0	(51.46)
16	2040	(43.97)	7.92	(5.66)	2.77	(1.98)	0	(51.61)
17	2041	(43.97)	8.07	(5.77)	2.83	(2.02)	0	(51.76)
18	2042	(43.97)	8.24	(5.89)	2.88	(2.06)	0	(51.92)
19	2043	(43.97)	8.40	(6.01)	2.94	(2.10)	(19.22)	(71.30)
20	2044	(43.97)	8.57	(6.13)	3.00	(2.14)	(19.61)	(71.85)
21	2045	(43.97)	8.74	(6.25)	3.06	(2.19)	0.00	(52.41)
22	2046	(43.97)	8.91	(6.37)	3.12	(2.23)	0.00	(52.57)
23	2047	(43.97)	9.09	(6.50)	3.18	(2.28)	0	(52.75)
24	2048	(43.97)	9.27	(6.63)	3.25	(2.32)	0	(52.92)
25	2049	(43.97)	9.46	(6.76)	3.31	(2.37)	0	(53.10)
26	2050	(43.97)	9.65	(6.90)	3.38	(2.41)	0	(53.28)
27	2051	(43.97)	9.84	(7.04)	3.44	(2.46)	0	(53.47)
28	2052	(43.97)	10.04	(7.18)	3.51	(2.51)	0	(53.66)
29	2053	(43.97)	10.24	(7.32)	3.58	(2.56)	0	(53.85)
30	2054	(43.97)	10.44	(7.47)	3.66	(2.61)	0	(54.05)
31	2055	(54.08)	10.65	(7.62)	3.73	(2.67)	0	(64.36)
32	2056	(54.08)	10.87	(7.77)	3.80	(2.72)	0	(64.57)
33	2057	(54.08)	11.08	(7.93)	3.88	(2.77)	0	(64.78)
34	2058	(54.08)	11.31	(8.08)	3.96	(2.83)	0	(64.99)
35	2059	(54.08)	11.53	(8.25)	4.04	(2.89)	0	(65.21)
36	2060	(54.08)	11.76	(8.41)	4.12	(2.94)	0	(65.43)
37	2061	(54.08)	12.00	(8.58)	4.20	(3.00)	0	(65.66)
38	2062	(54.08)	12.24	(8.75)	4.28	(3.06)	0	(65.89)
39	2063	(54.08)	12.48	(8.93)	4.37	(3.12)	0	(66.13)
40	2064	(54.08)	12.73	(9.10)	4.46	(3.19)	0	(66.37)

APPENDIX D

CBHP - Banks Lake Pumped Storage Project
Project Cost Summary - 1,000 MW Installed Capacity (Revised August, 2016) 2025 - 2064

Net Present Value ($M)		(1,791.10)		(227.14)		(79.50)	(35.46)	(2,133.20)
Year Num	Year	Debt Service Payment ($M)	Fixed + Variable O&M ($/Mwh)	Fixed + Variable O&M ($M)	A & G Expenses ($/Mwh)	A & G Expenses ($M)	Capital Replacement Expenses ($M)	Total Expenses ($M)
1	2025	(87.94)	5.88	(8.41)	2.06	(2.94)	0	(99.29)
2	2026	(87.94)	6.00	(8.58)	2.10	(3.00)	0	(99.52)
3	2027	(87.94)	6.12	(8.75)	2.14	(3.06)	0	(99.75)
4	2028	(87.94)	6.24	(8.93)	2.18	(3.12)	0	(99.99)
5	2029	(87.94)	6.37	(9.10)	2.23	(3.19)	0	(100.23)
6	2030	(87.94)	6.49	(9.29)	2.27	(3.25)	0	(100.48)
7	2031	(87.94)	6.62	(9.47)	2.32	(3.32)	0	(100.73)
8	2032	(87.94)	6.76	(9.66)	2.36	(3.38)	0	(100.98)
9	2033	(87.94)	6.89	(9.86)	2.41	(3.45)	0	(101.24)
10	2034	(87.94)	7.03	(10.05)	2.46	(3.52)	0	(101.51)
11	2035	(87.94)	7.17	(10.25)	2.51	(3.59)	0	(101.78)
12	2036	(87.94)	7.31	(10.46)	2.56	(3.66)	0	(102.06)
13	2037	(87.94)	7.46	(10.67)	2.61	(3.73)	0	(102.34)
14	2038	(87.94)	7.61	(10.88)	2.66	(3.81)	0	(102.63)
15	2039	(87.94)	7.76	(11.10)	2.72	(3.88)	0	(102.92)
16	2040	(87.94)	7.92	(11.32)	2.77	(3.96)	0	(103.22)
17	2041	(87.94)	8.07	(11.55)	2.83	(4.04)	0	(103.53)
18	2042	(87.94)	8.24	(11.78)	2.88	(4.12)	0	(103.84)
19	2043	(87.94)	8.40	(12.01)	2.94	(4.20)	(19.22)	(123.38)
20	2044	(87.94)	8.57	(12.25)	3.00	(4.29)	(19.61)	(124.09)
21	2045	(87.94)	8.74	(12.50)	3.06	(4.37)	(20.00)	(124.81)
22	2046	(87.94)	8.91	(12.75)	3.12	(4.46)	(20.40)	(125.55)
23	2047	(87.94)	9.09	(13.00)	3.18	(4.55)	0	(105.49)
24	2048	(87.94)	9.27	(13.26)	3.25	(4.64)	0	(105.84)
25	2049	(87.94)	9.46	(13.53)	3.31	(4.74)	0	(106.20)
26	2050	(87.94)	9.65	(13.80)	3.38	(4.83)	0	(106.57)
27	2051	(87.94)	9.84	(14.08)	3.44	(4.93)	0	(106.94)
28	2052	(87.94)	10.04	(14.36)	3.51	(5.03)	0	(107.32)
29	2053	(87.94)	10.24	(14.64)	3.58	(5.13)	0	(107.71)
30	2054	(87.94)	10.44	(14.94)	3.66	(5.23)	0	(108.10)
31	2055	(108.16)	10.65	(15.24)	3.73	(5.33)	0	(128.72)
32	2056	(108.16)	10.87	(15.54)	3.80	(5.44)	0	(129.14)
33	2057	(108.16)	11.08	(15.85)	3.88	(5.55)	0	(129.56)
34	2058	(108.16)	11.31	(16.17)	3.96	(5.66)	0	(129.98)
35	2059	(108.16)	11.53	(16.49)	4.04	(5.77)	0	(130.42)
36	2060	(108.16)	11.76	(16.82)	4.12	(5.89)	0	(130.87)
37	2061	(108.16)	12.00	(17.16)	4.20	(6.01)	0	(131.32)
38	2062	(108.16)	12.24	(17.50)	4.28	(6.13)	0	(131.78)
39	2063	(108.16)	12.48	(17.85)	4.37	(6.25)	0	(132.26)
40	2064	(108.16)	12.73	(18.21)	4.46	(6.37)	0	(132.74)

APPENDIX D

CBHP - Banks Lake Pumped Storage Project

Generic Costs and Assumptions for the Cost/Benefit Analysis (Revised August, 2016)

	500 MW Installed Capacity	1,000 MW Installed Capacity
Tax Free (Market) Financing Rate (%)	3.00	3.00
Tax Free (Market) Financing Percentage	30.00	30.00
Financing Period (years)	40	40
Tax Free (DOE) Financing Rate (%)	1.50	1.50
Tax Free (DOE) Financing Percentage	70.00	70.00
Financing Period (years)	30	30
Annual Plant Cost Escalation Factor (%)	2.00	2.00
NPV Discount Rate (%)	4.00	4.00
Project Capital Cost - ($/KW)	2,500	2,500
Project Capital Cost - ($M)	1,250	2,500
2010 Project Fixed + Variable O&M Costs ($/Mwh)	4.37	4.37
2010 Project A & G as a Percent of O & M (%)	35	35
2010 Project Capital Replacement Costs ($M)	10.00	10.00
Year 1 (2025) Annual Project Generation (Mwh)	769,575	1,430,153

Note:

1) Capital replacement costs are forecasted to occur in Project Years 19 and 20 only for the 500 MW alternative and in Project Years 19, 20, 21 and 22 only for the 1,000 MW alternative.