Hydroelectric Pumped Storage for Enabling Variable Energy Resources within the Federal Columbia River Power System

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Executive Summary

Bonneville Power Administration's (BPA) ability to operate its balancing authority safely, reliably, and economically while complying with the Federal Columbia River Power System's (FCRPS) mandated non-power obligations is being challenged. The adoption of Renewable Portfolio Standards (RPS) in most states within Bonneville Power Administration's (BPA) power system is driving the development and interconnection of the greatest penetration of variable wind generation in North America, and possibly the largest percentage in the world. Since 1998, BPA has seen wind power develop from an installed capacity of 25 MW to 2,780 MW as of January 2010. With the growing installation of wind generators in the region, BPA expects an estimated capacity of 6,000 MW to be interconnected within BPA's balancing authority by the end of 2013, and an even greater amount of capacity is possible by the end of the decade.

BPA faces a major challenge of balancing increasingly higher levels of variable generation. Absent the application of new tools to integrate variable resources, the expected increases of variable generation will be beyond the existing Federal Columbia River Power System's (FCRPS) capability to balance real-time energy demand with supply and remain compliant with federally mandated non-power obligations, such as flood control, fish protection under the Endangered Species Act (ESA), and meeting grid standards set by the Western Electricity Coordinating Council (WECC) and North American Electric Reliability Corporation (NERC).

As the variable generation output and its relative percentage to load grows, there is increasing risk of having a major electrical-system instability event or a significant fishery event due to spilling of excess Columbia River flows. It is evident that expanded transmission interconnections, continued modernization of the existing FCRPS hydropower plants, and new energy storage facilities will be required in BPA's balancing authority over the next decade. BPA is presently investigating whether pumped storage can be effective in integrating a large amount of variable energy resources and enable greater penetration of new renewable energy resources within the BPA service territory.

BPA's high level of wind penetration is comparable to the electrical grid in Denmark, a benchmark for successfully integrating high levels of wind penetration in Europe. On average, west Denmark's system requires hourly reserves approximately equal to those in BPA's system, on a grid one third the

size of BPA's. Denmark's experience shows that introducing greater variable supply into the generation mix can very likely lead to a greater demand for system reserves. Norway and Sweden, with their predominately hydropower-supplied grids and strong interconnections with Denmark, are generally able to accommodate Denmark's power surges during periods of high wind and can send energy back to Denmark during low-wind periods. Denmark's experience with system operations and interconnection power flows makes it clear that BPA must begin to explore energy storage options, additional flexible generation options, and expanded interconnections with British Columbia or California, as progressively higher levels of variable generation resources are integrated into their system.

Hydroelectric generation, and specifically hydroelectric pumped storage, is uniquely positioned to facilitate the integration of variable generation resources. Hydropower is a sustainable resource that can balance intermittent generation by providing relatively large capacity energy storage and reserves. Hydropower is already the preferred technology providing system reserves throughout the world's transmission systems. While there are many potential solutions to absorb excess energy and maintain a balanced energy system, pumped storage in particular is a proven, successful technology. Hydroelectric pumped storage provides valuable benefits in addition to energy storage, including hydrologic storage, electrical load balancing, frequency control, and incremental and decremental power reserves. It has historically been used to provide reserve capability to balance system load and allow large, thermal generating sources to operate at optimum conditions. As variable generation resources are added, pumped storage is increasingly being recognized worldwide as the preferred means to integrate these resources.

The current forecast of BPA's need for balancing reserves is among the most uncertain of BPA's future needs, due to uncertainty of wind power development levels and pending technical solutions and business protocols that may in the next few years mitigate or significantly reduce the forecast need. Since variable generation increases the need for balancing reserves, the large forecast increase in variable renewable resources over the next several years in BPA's balancing authority area has resulted in a growing forecast need for balancing reserves. As modeled in the BPA's Needs Assessment, the flexibility of the FCRPS may be at some risk to balance growing wind generation by 2013 to 2020. However, efforts by BPA's Wind Integration Team and others throughout the region are aimed at further quantifying reserve requirements, and developing new tools and capabilities with the intent to extend the ability of the FCRPS to integrate variable generation.

BPA uses a modeling tool called Columbia Vista (CV) to model and optimize water use through the FCRPS. The CV model is the best available tool BPA has to evaluate the benefits of adding pumped storage to the FCRPS; however, there are limitations to CV's capability and the results of this analysis should be considered with some caution. HDR/DTA considers the modeling effort to be very preliminary and BPA is working to develop tools that more accurately assess wind reserve impacts on the FCRPS. The initial CV model results indicate that benefits can be realized from operational modifications to John W. Keys III Pumping Plant and Banks Lake, primarily due to the following factors:

- Keys Pumping Plant has the potential as a pumped storage project to reduce the costs associated with additional wind integration because of its ability to absorb reserve requirements that would otherwise be placed on the conventional hydropower fleet.
- Assuming the modernization and upgrades enable all of the pumps and pump generators to be able to be dispatched, the plant could provide from several hundred megawatts up to as much as 900 MW of operating flexibility, depending on a variety of potential operating limits that could be placed on the units.

At BPA's Treasury borrowing rate of 6.75 percent, and a capital cost of about $270 million, the Keys Pumping Plant would have a first-year annual revenue requirement of about $29 million for capital recovery, O&M, periodic overhauls, and reserve deployment costs. The estimated marginal wind balancing reserve cost is about $8.00/kW/month. At a weighted cost of capital of 12.00 percent – BPA's internal rate of return for power investments – the estimated marginal reserve cost is about $12.90/kW/month. All costs are expressed in 2010 dollars.

Preliminary studies indicate a 1,000-MW pumped storage project (Project X) would be capable of providing additional balancing reserves. Integrating higher levels of wind with a new pumped storage project will have a higher cost. At a capital cost of about $2 billion and at a third-party tax exempt financing rate of 5.25 percent, Project X has a first-year revenue requirement of $199 million for an estimated marginal wind balancing reserve cost of about $19.50/kW/month. If Project X is built and financed by a third party seeking a return on equity, first-year revenue requirements are estimated to be significantly higher, about $338 million. The resulting marginal wind balancing cost is about $33.10/kW/month. Again, all costs are in 2010 dollars.

Variable energy resources and hydropower are complementary technologies that can bring substantial benefits to BPA and the Pacific Northwest. To make the most of variable energy resources, they need to be interconnected with flexible generation resources to keep the transmission system in balance and operating reliably. More specifically, for BPA and the FCRPS, shifting system reserve requirements to a modernized and upgraded Keys Pumping Plant, and ultimately to a new, large-scale pumped storage station is potentially a cost-effective solution and will provide BPA with increased wind integration capability and improved operational flexibility. New, large-scale pumped storage projects with robust design features to respond almost instantaneously to grid demands should be on the planning horizon. Pumped storage is the world's leading technology for providing flexible grid-scale capabilities to supply the extensive reserves projected to be required due to wind development in the future within BPA's system

Short-term, medium-term and long-term options are presented, consisting of the modernization and upgrade of the Keys Pumping Plant and a new greenfield Project X. It is imperative that an equipment life extension program be undertaken at the Keys Pumping Plant to allow it to immediately provide system reserves on an hourly basis, and improve reliability and availability. In parallel to the balance-of-plant modernization effort, studies should be initiated to investigate the upgrading of the Keys Pumping Plant's pump-generator Units 7 through 12. These studies, and subsequent vendor evaluation, pump-turbine runner modeling, fabrication and installation can then allow a modernized and upgraded Keys Pumping Plant to support the incremental system reserves needed in the BPA system at a cost comparable to the existing FCRPS. Long-term reserve needs, as indicated by the CV model, can be met with the construction of a 1,000-MW pumped storage project. For this project to be realized, siting studies need to commence as the initial steps of the development process.

The following next steps are recommended:

Develop tools to more accurately assess the capabilities of pumped storage to enable the integration of higher levels of variable generation in the FCRPS.

Pursue equipment modernization and upgrades at the Keys Pumping Plant and Banks Lake, as follows:

1. Establish a source of funding for the next phase of this work by establishing a sub-agreement between BPA and Reclamation to provide capital funding for continued work.
2. Determine if a NEPA study will be required. Determine schedule and costs.
3. Coordinate with Irrigation District/stakeholders on potential upgrades and proposed operational changes at the Keys Pumping Plant.
4. Further develop schedule and costs for reliability improvements and equipment upgrades.
    a. Perform a detailed study of the modernization of the balance-of-plant systems as currently identified in the strategy and incorporate in the overall plan.
    b. Perform a detailed study of the upgrade of the Keys Pumping Plant pump-generator Units 7 through 12, utilizing the existing station and unit geometry, to modern single-speed units.
    c. Perform transmission power flow studies and explore decoupling the pump start sequence for Pumps 1 through 6 from the Grand Coulee Left Powerhouse Units G1-G3.
5. Investigate the existing operational constraints at Keys Pumping Plant to utilize the Banks Lake reservoir including:
    a. Establish a firm commitment for water availability and verify the operating range at Banks Lake that is available for the proposed pumped storage/wind integration operation.
    b. Perform feeder canal and hydraulic conveyance system studies.
    c. Baseline current condition and performance of equipment.
6. Perform a transmission system impact study to identify potential Transmission system reinforcements needed to optimize the use of Keys Pumping Plant for wind integration.

Continue evaluation of greenfield Project X pumped storage project, as follows:

1. Identify physical characteristics for Project X.
    a. Conduct screening studies to identify multiple Project X sites.
    b. Further refine the results from preceding steps to determine the most viable pumped storage site.
2. Develop a strategy to determine how a pumped storage project can be financed and who the stakeholders are that would fund such a project.
3. Decide on a path forward for a project-development approach (federal, non-federal, or consortium) to advance a pumped storage project.
    a. Lay out schedules and refine cost estimates.

Pursue collaborative evaluation of pumped storage in the Pacific Northwest, as follows:

1. Identify stakeholders and interested parties.
2. Layout and execute an inclusive communication plan.

1.0 Introduction

Bonneville Power Administration's (BPA) ability to operate its balancing authority safely, reliably, and economically while complying with the Federal Columbia River Power System's (FCRPS) mandated non-power obligations is being challenged. The adoption of Renewable Portfolio Standards (RPSs) in seven of the nine states within its system is driving the development and interconnection of the greatest penetration of variable wind generation in North America, and possibly the largest percentage in the world. Since 1998, BPA has seen wind power develop from 25 MW to an installed capacity of 2,780 MW as of January 2010. An estimated total installed capacity of 6,000 MW of wind generation is expected to be interconnected within BPA's balancing authority by the end of 2013, and an even greater amount of capacity is possible by the end of the decade. BPA faces a daily challenge of integrating increasing levels of new variable energy resources, changing historical paradigms for managing system reserves, and balancing non-power priorities for the Columbia River.

The FCRPS, which has brought electrical power to the Pacific Northwest at among the lowest power prices in the U.S., seeks to balance the power needs of the system with regional expectations for fishery management, irrigation, water supply, flood control and navigation demands. The introduction of variable generation can generally be managed and integrated into an established system when the penetration levels are less than 10 percent (VTT, 2007; NWPCC, 2007; and NERC 2009). Energy experts understand that the nation's electrical grid system has always had to manage this variability in the need for energy. Transmission system operators also can effectively manage the related variability in energy supply via traditional methods, if it is a relatively small percentage of the overall generation. However, with projections indicating wind-penetration levels exceeding 50 percent, BPA is facing uncharted territory, as no other transmission system in the world has this percentage of the balancing authority related to variable energy. The ratio of wind generation to load served in a balancing authority is important because dispatchers must maintain a constant balance between load and generation in their balancing authority. Most of the wind power based in BPA's balancing authority is wheeled to Portland General Electric, Puget Sound Energy, and other utilities. Dispatchers must constantly and simultaneously serve native load, meet system constraints for fish and other non-power hydro purposes, accommodate all exports, and keep the system in balance. As the proportion of exported wind power to native load rises, this multidimensional challenge becomes more complex.

To address this unique challenge, BPA is aggressively pursuing many policies and projects that will enable the proposed build-out of variable generation resources on the transmission system and is working collaboratively with the wind power community, utility customers, the U.S. Bureau of Reclamation (Reclamation), U.S. Army Corps of Engineers (USACE), Mid-Columbia Public Utility Districts (MCPUD), and the Northwest Power and Conservation Council (NWPCC) in developing a "Wind Integration Action Plan." BPA has taken many steps thus far to integrate variable energy resources, including providing conditional firm services, setting up an Area Control Error (ACE) diversity interchange, improving Automatic Generation Control (AGC) throughout the FCRPS, and instituting new approaches to reserves and operating protocols.

Since 2005, BPA has utilized the Columbia Vista (CV) model as a supplement to existing models and tools used for the short- and mid-term planning of FCRPS operations. In its current form, CV is used to provide a short-term forecast of energy inventory for power marketing and to provide scenarios which test any flexibility that may exist in the FCRPS over a two to three week period. For mid-term planning, CV is used along with existing models to assess the impacts of streamflow and operational uncertainty over a period of a few months. In addition, CV is used by real-time hydro schedulers in simulation mode to assist with real-time planning of the FCRPS.

With existing variable generation levels in BPA's balancing authority already greater than 20 percent, and expected penetration beyond 50 percent of BPA's total energy-supply portfolio, BPA is faced with a daunting task of balancing in real-time energy demand with supply, and also remain compliant with WECC and NERC grid standards and with federally mandated Columbia River fishery operation constraints pursuant to the Endangered Species Act. The predicted levels of variable generation penetration are beyond the capabilities of the existing FCRPS. Robust transmission interconnections and flexible energy options—particularly energy storage in the form of pumped storage—are proven solutions to this increasing challenge of maintaining a balanced energy system.

2.0 Enabling Variable Energy Resources

2.1 Variable Energy Resources

Variable energy resources provide a sustainable source of energy that uses no fossil fuel and produces zero carbon emissions. One of the constraints of variable generation is that the energy available is non-dispatchable; it tends to vary and is somewhat unpredictable. The power-system load is also variable; power-system reserves are required to match changes in generation and demand on a real-time basis. Variable generation cannot be dispatched specifically when energy is needed to meet load demand. Wind and utility industries have been able to address many of the variability issues through improvements in wind forecasting, diversification of wind turbine sites, improvements in wind turbine technology, and the creation of larger power-system control areas. At low wind penetration levels, wind output typically can be managed in the regulation time-frame by calling upon existing system reserves, curtailing output and/or diversifying the locations of wind farms over a broad geographic area.

As more variable energy is added to the power system, additional reserves are required. Flexible and dispatchable generators, such as hydro, are required to provide system capacity and balancing reserves to balance load in the hour-to-hour and sub-hour time-frame. In addition to system reserves, every balancing authority has the need for energy storage to balance excess generation at night and shift its use to peak demand hours during the day. Conventional hydropower projects do this by shutting down units and storing energy in the form of water, and it is the most common form of energy storage in the world. As variable energy output and the ratio of wind generation to load grows, historical system responses will need to be modified to take advantage of the wind energy benefits to the regional grid and to assure system reliability.

2.2 Integrating Wind in BPA's Balancing Authority

BPA markets wholesale electrical power primarily from the FCRPS in a balancing authority with a peak load of approximately 11,000 MW. The main stem Columbia River hydropower projects (with the exception of the John Day, McNary, Chief Joseph and Grand Coulee projects) are generally considered run-of-river (ROR) with minimal storage available and limited peaking power and load-balancing capability. These ROR projects generally operate within 1 percent of the turbines' best efficiency points during the April through October fish-passage season, as this has been determined to be the best method of passing out-migrating salmon downstream through the units, as well as the most efficient use of the available flow for energy production. However, this also limits the use of the ROR projects for minute-by-minute regulation service, and the operating scheme is not flexible enough to provide the hour-to-hour scheduling true-up for the balancing area when high levels of variable generation are added. This hourly true-up is a result of the need to balance the wind forecast with actual generation, similar to the response of non-wind assets to the schedule of service provided by all generators.

A recent BPA study shows that as the amount of wind capacity on its system increases, there is a substantial increase in the need for additional supplemental reserves. Figure 1 shows BPA's balancing reserves for wind and load. Decrementing capacity (blue line) is required to absorb excess power due in part to the installed wind capacity (purple line). Incrementing capacity (yellow line) is also needed to provide power, typically within a one hour period. If adequate reserves are not readily available to match new variable renewable resources being installed, then power supply and demand imbalances could occur. For example, an event of rapidly ramping wind generation could require a short term reduction in traditional hydroelectric generation, possibly resulting in Columbia River spill over dams and increased total dissolved gas (TDG). The estimated levels of incrementing and decrementing reserves as wind generation increases are also shown in Figure 1.

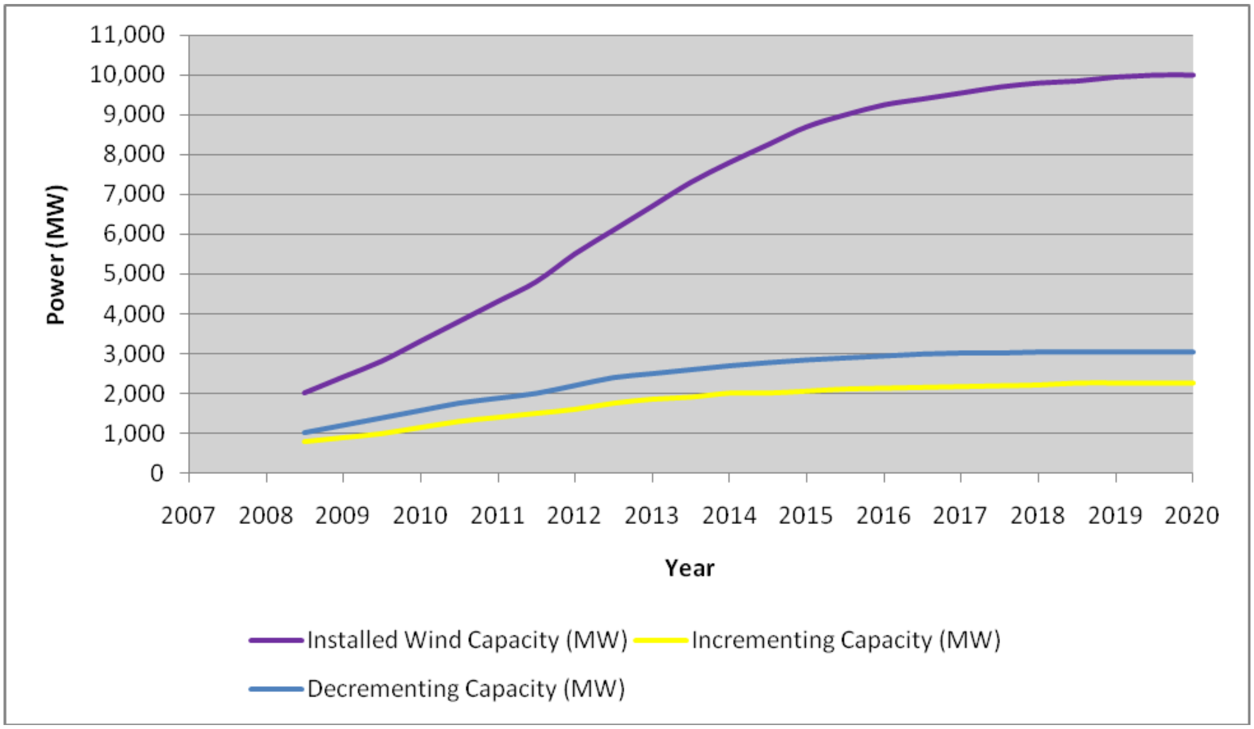


Figure 1. Estimated Supplemental Reserves Required as Wind Generation Increases

BPA's wind integration team has forecasted future wind projects to be connected to the FCRPS grid based on the existing queue and recent trends. According to this forecast, wind plant installation in the Pacific Northwest is estimated to increase dramatically by the end of the decade; corresponding wind reserve requirements for this region are estimated to triple during this time period. The current forecast of BPA's need for balancing reserves is among the most uncertain of BPA's future needs, due to uncertainty of wind power development levels and pending technical solutions and business protocols that may in the next few years mitigate or significantly reduce the forecast need. Since variable generation increases the need for balancing reserves, the large forecast increase in variable renewable resources over the next several years in BPA's balancing authority area has resulted in a growing forecast need for balancing reserves. As modeled in the BPA's Needs Assessment, the flexibility of the FCRPS may be at some risk to balance growing wind generation by 2013 to 2020. However, efforts by BPA's Wind Integration Team and others throughout the region are aimed at further quantifying reserve requirements, and developing new tools and capabilities with the intent to extend the ability of the FCRPS to integrate variable generation.

Hydroelectric generation, and specifically hydroelectric pumped storage, is uniquely positioned to facilitate the integration of wind energy. Hydropower is a renewable resource that can balance wind generation by providing relatively large capacity energy storage and reserves. Hydropower is already the preferred technology providing system reserves throughout the world's transmission systems, and unlike gas turbines it produces virtually zero carbon emissions and has zero fuel cost. However, as noted earlier, the FCRPS has limited operational flexibility due to mandated non-power obligations which minimize its ability to respond to changing transmission system conditions. Additionally, there are physical and electrical constraints to transmitting the vast amount of available energy from Grand Coulee Dam and other projects in eastern Washington, Idaho, and Montana to the load centers in Seattle, Washington and Portland, Oregon. This complex mix of balancing growing demand and growing supply is BPA's challenge now and for the future.

2.3 Wind Integration in Denmark

Denmark, which has the greatest levels of wind penetration in the European Union, is generally regarded in Europe as the model for successful integration of high levels of wind generation. A comparison of the actual system operations and interconnection power flows for the Danish power system can provide guidance for integration of high levels of variable generation in BPA's balancing area.

In 1990, Denmark had six large, centralized generating plants, all of them designed as combined heat and power for West Denmark's largest towns (Figure 2). Five of these plants were coal-fired power stations and the sixth burned natural gas.

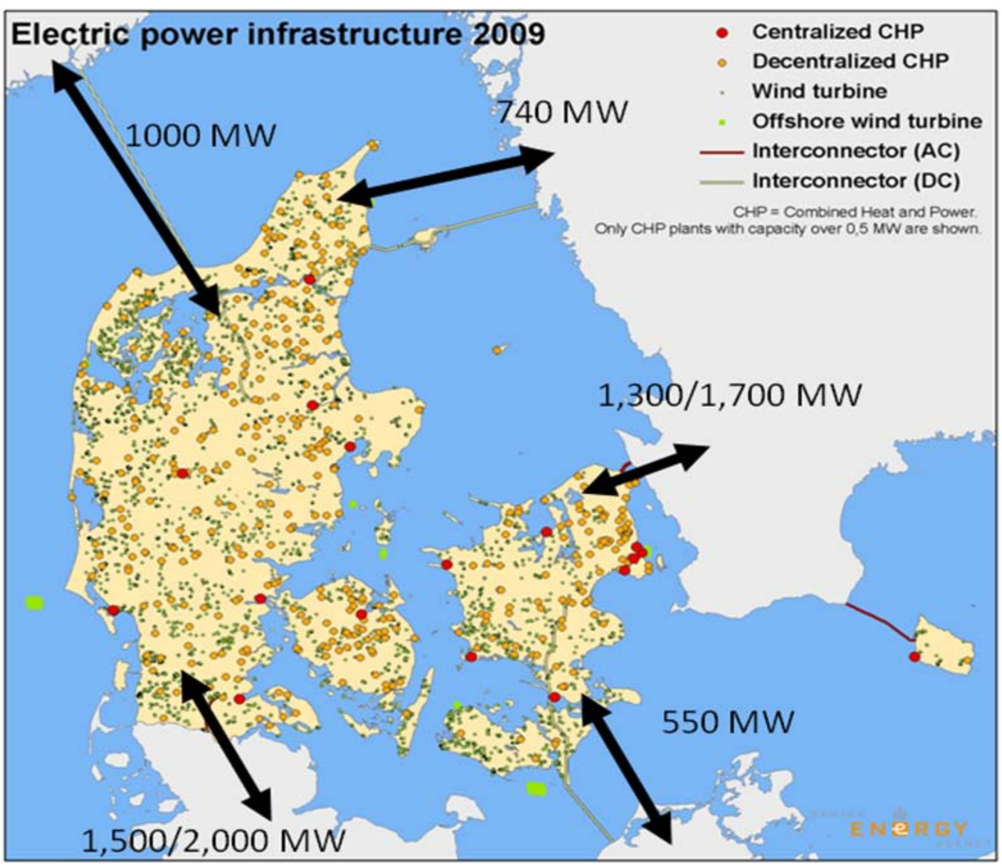


Figure 2. Danish Interconnections

During the past 15 years there has also been an intensive construction program to upgrade the district heating plants in most Danish towns and villages to combined heat and power. The total capacity of these de-centralized power units in 2004 was 1,450 MW. The units also supply heat to the district heating system and are therefore must-run cogeneration plants. There was a significant building program during the 1990s for wind power in Denmark, totaling 2,374 MW at the end of 2003. Although more wind power overall has been installed in the U.S. and Germany, the "wind intensity" of West Denmark is still unmatched. It is equivalent to 0.88 kilowatts (kW) of installed capacity per person in West Denmark compared to 0.18 kW per person in Germany and 0.22 kW per person within the BPA service area (with projections of at least 0.51 kW per person beyond 2013).

As shown in Figure 3, West Denmark makes full use of its interconnections for balancing wind power as there is a strong and direct correlation between wind output and net power outflows. However, the interconnections were built primarily to link hydropower in Norway and Sweden to Germany, and without their prior existence it is possible that it may not have been viable for West Denmark to build wind capacity on the scale it has. This ability has much to do with the extent to which both Sweden and Norway rely on hydropower—which supplies 50 percent and nearly 100 percent of their respective generating needs from flexible hydropower units (Mason, 2005; Sharman 2005; VTT, 2007; White, 2004; and CEPOS, 2009). The strong electrical interconnections between Denmark, Norway, and Sweden, and the access they provide to the flexible hydroelectric power in Norway and Sweden, are the foundation of Denmark's ability to absorb the wind penetration it has. Sweden's and Norway's conventional hydropower output can be adjusted very rapidly as the highly variable wind generation flows through the interconnections.

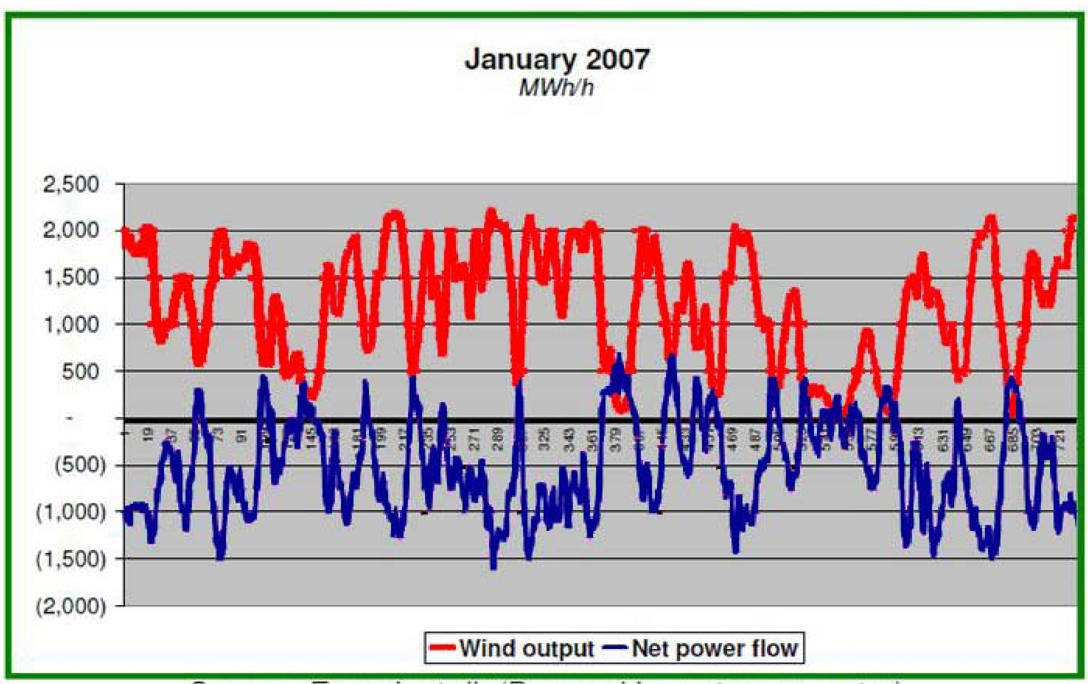


Figure 3. Western Denmark, Wind Output and Net Electricity Flows During High Wind Period
(Source: CEPOS – the Danish Center for Political Studies)

Figure 3 demonstrates the power flows across the Danish interconnections during a high-wind period, and it shows the direct relationship between the high-output wind energy and exported power to Norway and Sweden. The red line shows wind generation and the blue line indicates power flows across the interconnections (negative numbers indicate energy exports from West Denmark). Figure 4 demonstrates the power flows across the Danish interconnections during a low wind period and shows the direct relationship between the low output wind energy and imported power from Norway and Sweden.

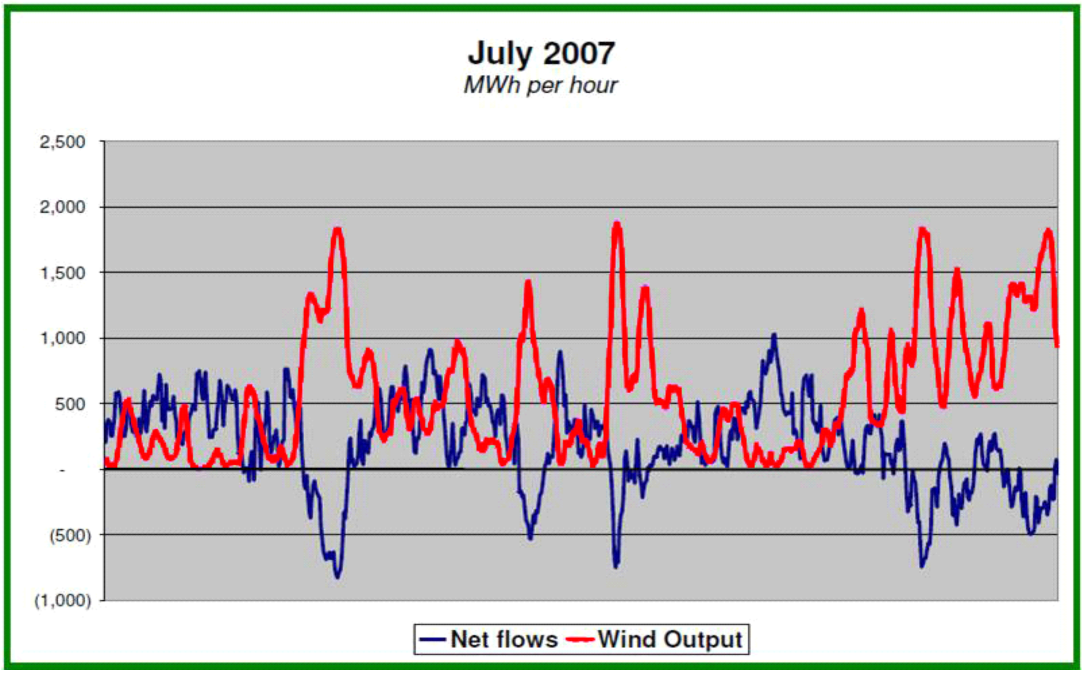


Figure 4. Western Denmark, Wind Output and Net Electricity Flows During Low Wind Period in MWh/hr (July 2007; Source: CEPOS – the Danish Center for Political Studies)

Denmark and BPA have comparable wind penetration levels and similar must-run power stations that limit the flexibility of their respective generation systems. It is apparent that the Danish power system works because it is strongly interconnected to the hydropower supplied grids of Norway and Sweden who are generally able to accommodate power surges during high-wind periods and can send energy back to Denmark during low-wind seasons.

Relatedly, Norway's exposure to extended drought periods is mitigated by wind energy imported from Denmark, and this blend of energy technologies is a global example of the mutual benefits of wind/hydropower integration. As a member of NORDPOOL (the Nordic Transmission System Operator), Denmark is not a balancing authority and can therefore import/export its reserves as needed from Norway or Sweden. It is critical to note that BPA has less operational flexibility as a balancing authority, must meet NERC and WECC system requirements, and provide its own system reserves on a real-time basis. Denmark's experience and the parallels seen in the Pacific Northwest make it clear that BPA must aggressively pursue the long term planning of energy storage options, additional flexible generation options, and perhaps expanded interconnection, to successfully balance both today's wind generation capacity and the increases planned in wind generation through the end of the decade.

3.0 Energy Storage Options

Energy storage technology permeates our society, manifesting in products ranging from small button batteries to large-scale pumped storage projects. Energy storage for utility-scale applications has historically utilized pumped storage hydro and the large reservoirs associated with conventional hydropower stations. In recent years, utilities have also considered and implemented several pilot projects utilizing various battery technologies and flywheels, but they have only limited MW and MWh capacities. One U.S. utility has adopted a distributed method deploying battery and inverter systems with distribution-pad-mounted transformers to provide grid power during transient conditions and continuity of service to customers during local short term outages. When installed over a large service area, the totality of these distributed battery systems could provide reserves to the regional grid for limited durations. Within the electric utility industry, there is uncertainty regarding which energy storage system can provide the optimal benefit. Distributed energy storage typically addresses small power supply fluctuations for short durations of a few MW for minutes to a few hours. On the other hand, night and day wind patterns or seasonal energy fluctuations necessitate large scale load-balancing, and bulk energy storage can provide this load balancing on a given grid.

Relatively small amounts of variable energy can be absorbed into most grids and managed in the same manner as load volatility is currently managed. On a grid such as BPA's, volatility is absorbed first by the inertia of all the generating units, through second-to-second changes by one or more isochronously governed generators and their speed droop governed turbines. Minute-to-minute changes are absorbed by Automatic Generation Control (AGC) systems that dispatch adjustments to governor set-points on many units. Hour-to-hour changes are handled by dispatching base load set-points to many units and plants.

Large concentrations of variable energy can cause large swings in the total power generation in short periods of time. Wind energy development in the Pacific Northwest has to date been geographically concentrated in the Columbia River Gorge and has very limited diversity. Wind projects located along the Columbia River in BPA's balancing authority tend to respond to a similar wind pattern, which means their output tends to peak roughly together. In the Pacific Northwest, these swings pose significant operating challenges that require thoughtful management. The wind generation must be complemented by a flexible base power source that can be easily controlled ("dispatched") by system operators and AGC systems, or the base system must be combined with energy storage that can be quickly utilized.

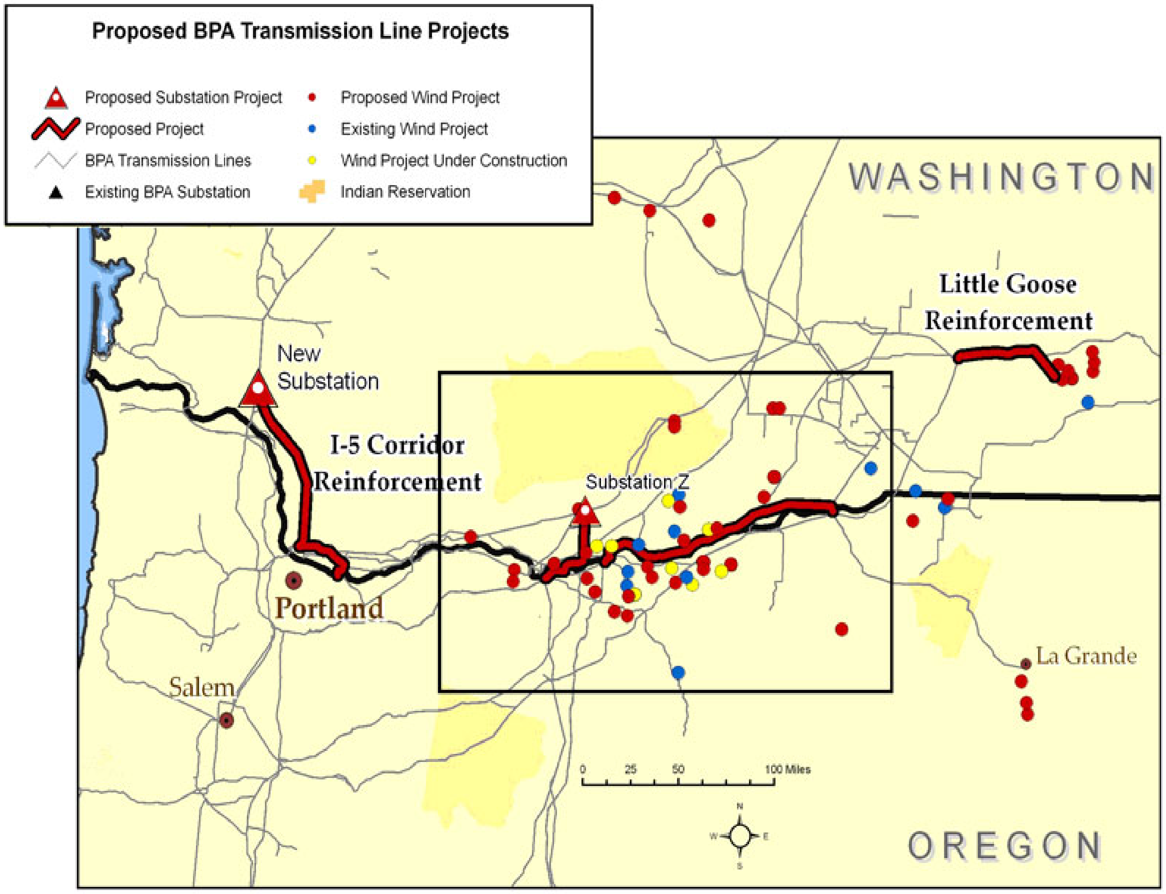


Figure 5. Current and Proposed Wind Project Interconnections

3.1 Summary of Current Bulk Energy Storage Technology

A review of available bulk energy storage technologies was performed for comparative purposes in this study. The results are provided in Appendix B, and include the following storage systems:

- Compressed air energy storage (CAES)
- Batteries
- Electrochemical capacitors
- Flywheels
- Superconducting magnetic storage (SMES)
- Thermal storage
- Hydrogen storage
- Pumped hydroelectric storage

Many of these technologies, such as flywheels, have been proven at the distributed energy scale, and there is significant ongoing research to further develop these technologies and scale them up into bulk energy storage applications. This research is expected to continue for the foreseeable future, but presently, system planners are left with uncertainty as to which technologies will be viable for bulk energy storage application, particularly for the immediate and future need for variable energy integration.

For reference, Figures 6 and 7 illustrate the current capability of energy storage technologies. Figure 6 is derived from the more popularly seen Figure 7 and utilizes the same data, though plotted on a linear scale versus a log-log scale to better reflect the real-time MW and MWh capability of the different technologies. This also allows truer comparison of technologies with smaller capacities and discharge times to larger, longer duration energy storage systems.

At present, only two bulk energy storage technologies with the capability to meet BPA's large reserve needs have been deployed in the United States: compressed air energy storage (CAES) and pumped hydroelectric storage.

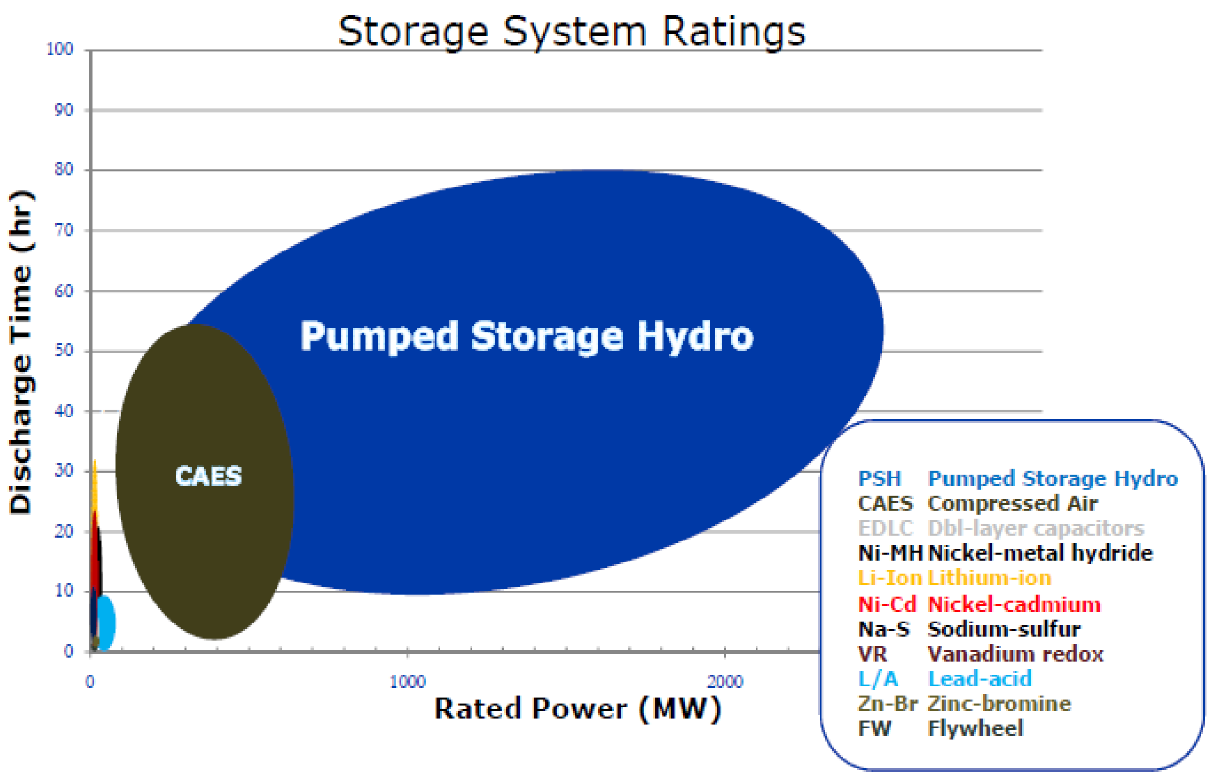


Figure 6. Current Energy Storage Technology Capabilities in Real Time (Source: HDR|DTA)

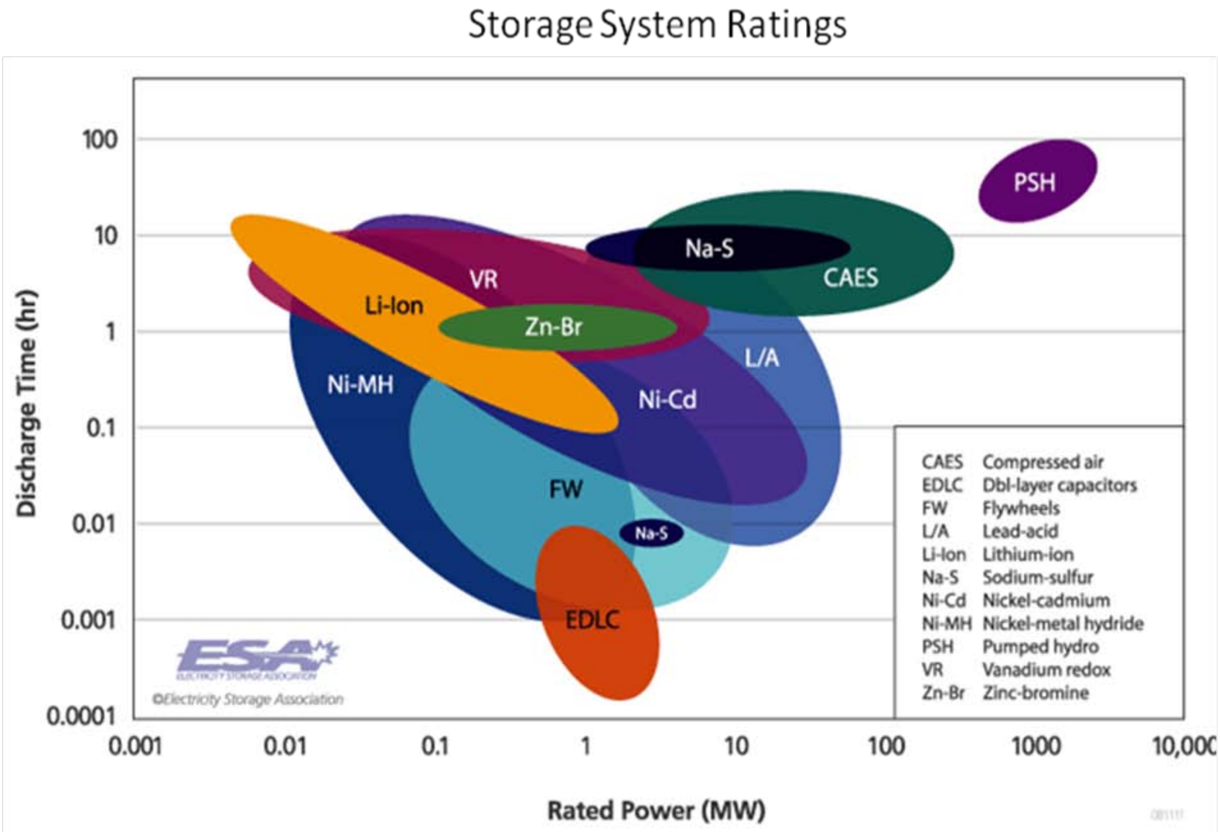


Figure 7. Current Energy Storage Technology Capabilities (Log-Log Scale) (Source: Electricity Storage Association)

Figure 8 illustrates the installed capacity of various energy storage technologies worldwide, and shows that pumped storage makes up the vast majority of this storage. In the U.S., forty pumped storage facilities have been built with a total of over 20,000 MW of capacity. By comparison, there is only one existing CAES facility in the U.S., with a capacity of 110 MW. Bulk battery storage has not been heavily used in the U.S., except on a distributed scale. Sodium-sulfur (Na-S) batteries have been used in Japan with the largest installation supplying approximately 34 MW of capacity for 6-7 hours of storage; this technology is gaining popularity in the U.S. Sixteen MW of lithium-ion (Li-ion) batteries have also recently been installed in Chili, and a 2-MW pilot project has been executed in the U.S. CAES systems, batteries, super capacitors, flywheels, and pumped storage were compared in a number of reports by Sandia National Laboratories (Sandia), Pacific Northwest National Laboratories (PNNL), and by the California Independent System Operator (CAISO). The findings of these reports are summarized in the following section.

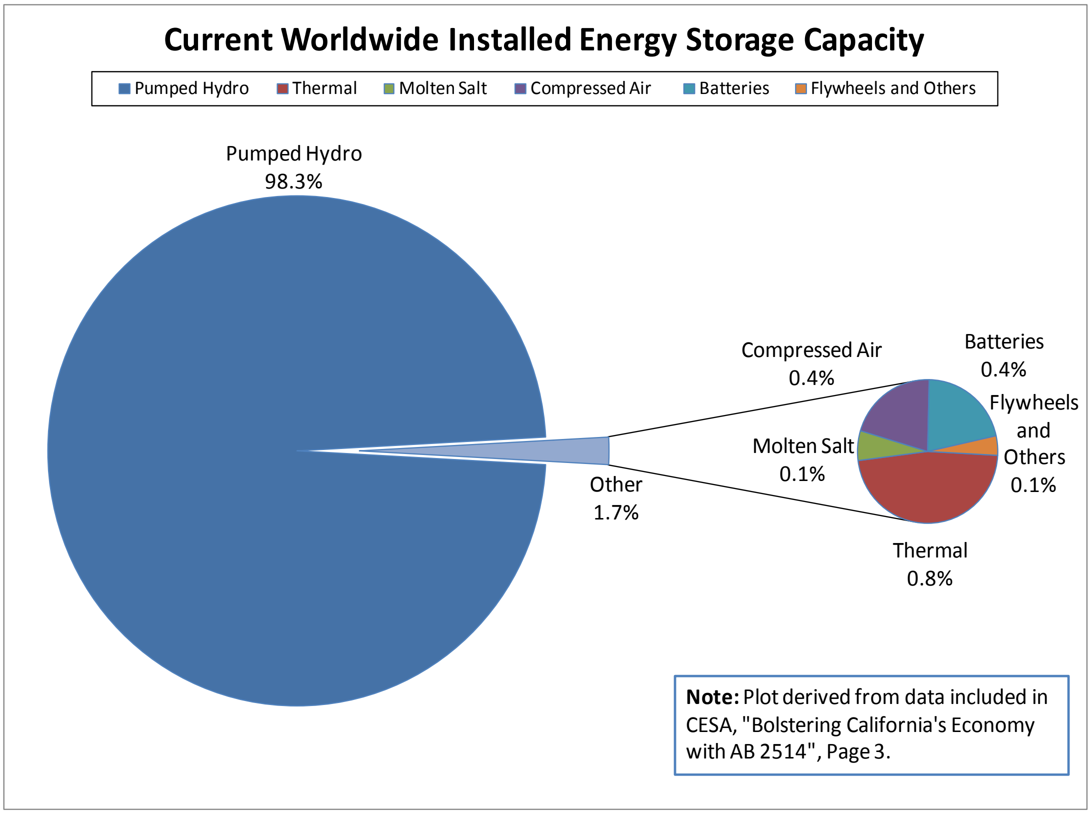


Figure 8. Current Worldwide Installed Energy Storage Facility Capacity (Source: CESA)

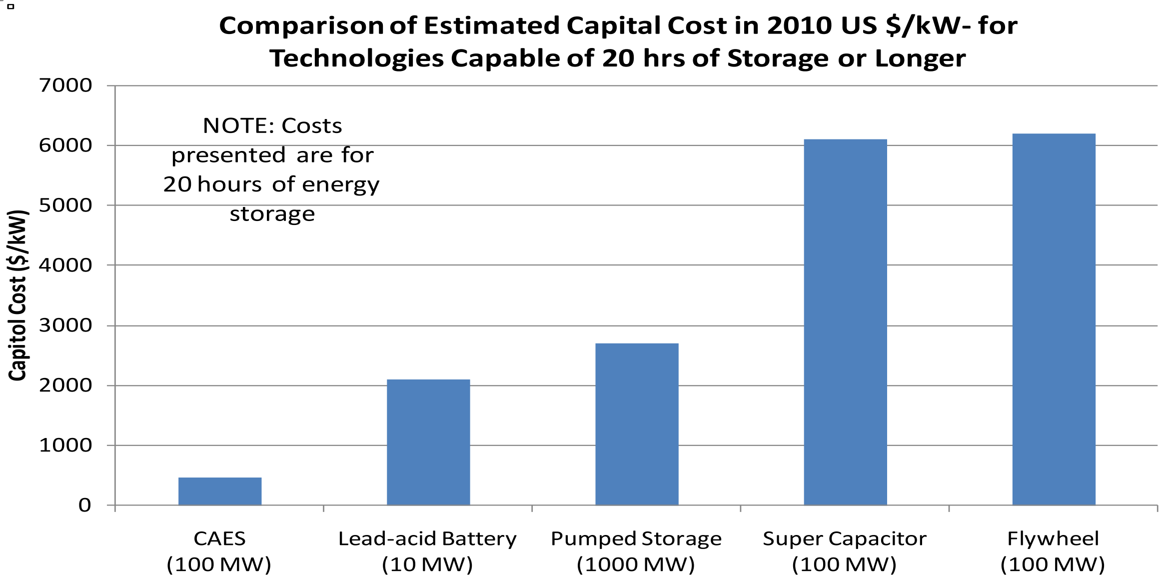
3.2 Comparison of Pumped Storage and Other Technologies for Bulk Energy Storage

There are a number of challenges associated with comparing the different types of energy storage technology. While a conscientious effort was made to discuss the technologies in terms of similarly sized capacities and durations, this comparison is somewhat difficult as the maximum hours of available storage and maximum capacity vary widely from 1 or 2 MW for a lithium-ion battery to over 1,000 MW for a pumped storage project. As noted earlier, many of these storage systems are still undergoing significant product development, and the maximum storage, capacity, lifetime, capital costs, and lifecycle costs of these technologies have yet to be determined. Also for pumped storage and CAES, site specific conditions can significantly impact the cost and spatial needs for any given project. These challenges emphasize the idea that a combination of many different storage technologies may be needed.

A variety of complementing technologies will be required to fully address the effects of variable renewable energy, including bulk storage, distributed storage, and improvements to the interconnecting transmission system, and can extend the argument to bulk storage itself. Due to variable demand and variable generation, it is expected that BPA will need to use multiple technologies and large storage capacity to meet its needs.

3.2.1 Cost Comparison

A project's operating and capital costs are significant factors when determining the appropriate choice of energy storage technology for a given grid. Sandia and PNNL have each performed extensive research on these costs. For example, Figure 9 below was created using data from PNNL's report, "Wide-Area Energy Storage and Management System to Balance Intermittent Resources in the Bonneville Power Administration and California ISO Control Areas" by Y. Makarov, published in June 2008. The chart indicates the cost per kWh of five storage technologies that have available durations of at least 20 hours. It is important to note, however, that the cost per kWh is presented for a project of a given capacity, and these capacities vary by as much as a factor of 100. If a project of a different capacity is chosen, the cost per kWh may not remain constant, and additional study may be required. The capital cost associated with pumped-storage projects was developed by HDR|DTA. While it indicates that pumped storage has a higher capital cost than both lead acid batteries and CAES, the available capacity of a pumped storage project is significantly higher than any of the other technologies presented. CAES was estimated by PNNL to have the lowest initial capital cost, and flywheels and super capacitors were expected to have the highest capital costs per kW.



Note: Pumped Hydro and Pumped Hydro (Var Speed: O&M and Financed Capitol Cost are estimated by HDR|DTA. All other options are derived from data from Makarov, Y. et al. "Wide-Area Energy Storage and Management System to Balance Intermittent Resources in the Bonneville Power Administration and California ISO Control Areas." Table 3.2 .Pacific Northwest National Laboratory, June 2008.

Figure 9. Capital Cost Comparison (Source: PNNL and HDR/DTA)

Capital cost is one initial indicator of project economics, but long-term annual costs may provide a more comprehensive representation of financial feasibility. Figure 10 compares annual costs per kWh of various technologies, including single and variable speed pumped storage (note that HDR|DTA has escalated the costs from 2003 U.S. dollars to 2010 U.S. dollars based on estimated inflation). The costs in the Sandia report are based upon 8 hours of storage and include financed capital cost, fuel cost, electricity cost, operation and maintenance cost, and battery replacement cost. For the pumped storage costs, HDR|DTA has estimated operation and maintenance and financed capital for conservancy and consistency. The costs for variable speed pumped storage were estimated to be 20 percent higher than those of single speed projects.

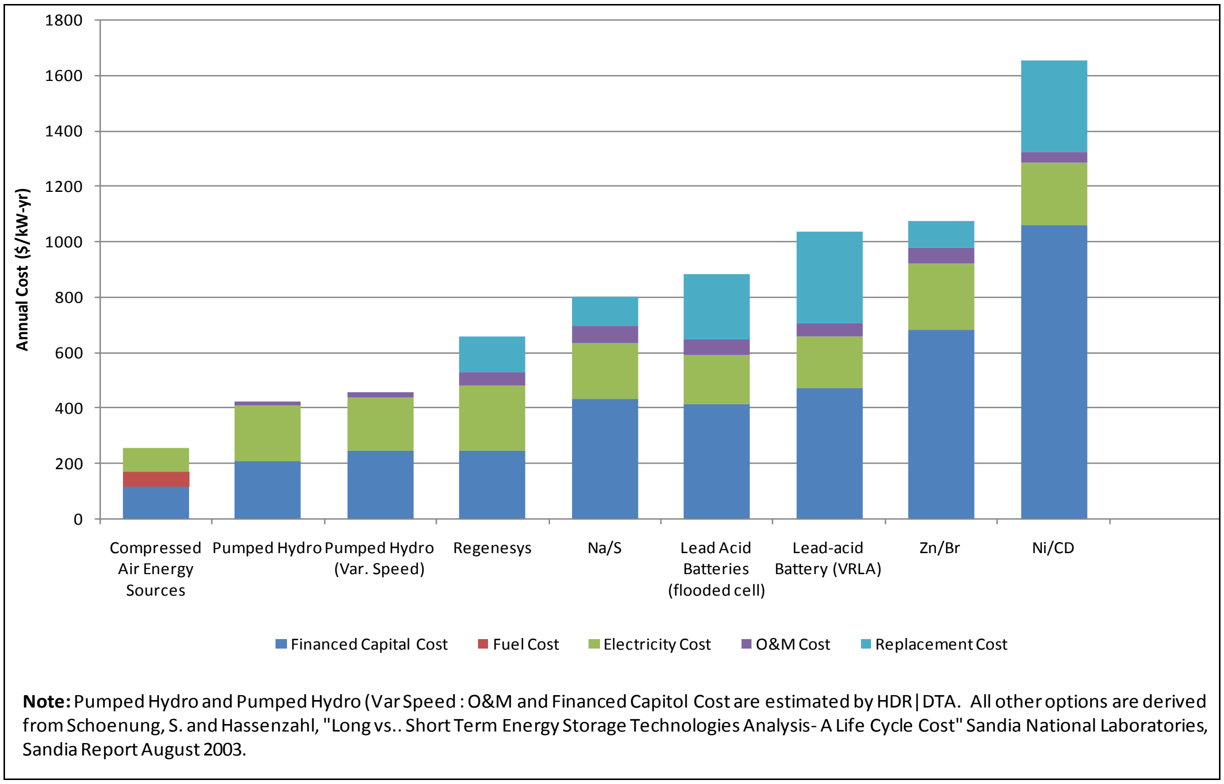


Figure 10. Comparison of Annual Operating Costs of Various Bulk Energy Storage Technologies (8-hour discharge) (Source: Sandia and HDR/DTA)

Sandia's work appears to be consistent with that performed by PNNL, although HDR|DTA did not readily find Sandia discussions of flywheels and super capacitors on a bulk energy scale. CAES has the lowest operating costs, followed by pumped storage (as estimated by HDR|DTA). Lead acid batteries are estimated to have a higher annual cost when compared with pumped storage, and other more novel battery technologies exhibit high annual costs. Many of the battery types can be considered to be developing technologies; and because of this, the costs may be somewhat inflated. Manufacturers may be able to control costs better in the future. It is also important to note that each battery type requires different and typically significant provisions for replacement and disposal. By comparison, most of a pumped storage project's features, including the dam, powerhouse and pump-generator equipment, will be serviceable for many decades, where one-hundred-year lives for similar conventional hydroelectric projects are not uncommon. According to the CAISO study, CAES is also a developing technology, and research and development efforts will be required to solidify operating parameters. CAISO indicated that research is ongoing to determine if abandoned natural gas or oil wells can be converted to compressed air storage systems. Installation of a CAES facility requires specific geographic features for storage which may not be available in all areas.

3.2.2 Space Requirement Comparison

Space requirements for comparably sized (capacity and storage) pumped storage and battery projects can be considerable. For the purposes of this discussion, the space requirements for sodium sulfur batteries (Na-S) and Li-ion batteries are considered, because the energy storage industry anticipates that these are the most likely near-term candidates for bulk battery storage technologies. This statement is based on the Na-S installations in Japan and indications from PNNL and CAISO, and the Li-ion pilot projects discussed in the previous section. Due to the limited application of CAES and flywheels, they have not been considered in this footprint comparison.

Table 1 below indicates the surface space requirements for comparable 20,000 MWh facilities: a 1,000-MW, 20-hour pumped storage plant (including upper and lower reservoirs), a Li-ion battery field, and a Na-S battery field. The space required for a pumped storage facility is somewhat less in acreage than a Na-S battery field, and far less than that of a Li-ion field, when including the area of the reservoirs. The artist's rendering in Figure 11 illustrates the number and size of the Li-ion batteries necessary to store 20,000 MWh of energy. The resulting 1,100 acres would equivalent to approximately 833 football fields. For scale, a typical pumped storage powerhouse is indicated in the foreground.

Table 1. Space Required for 20,000 MWh of Energy Storage

Project Type	Approximate Footprint (Acres)
Sodium Sulfur Batteries	270
Li-ion Battery Field	1,100
Pumped Storage Reservoirs	220

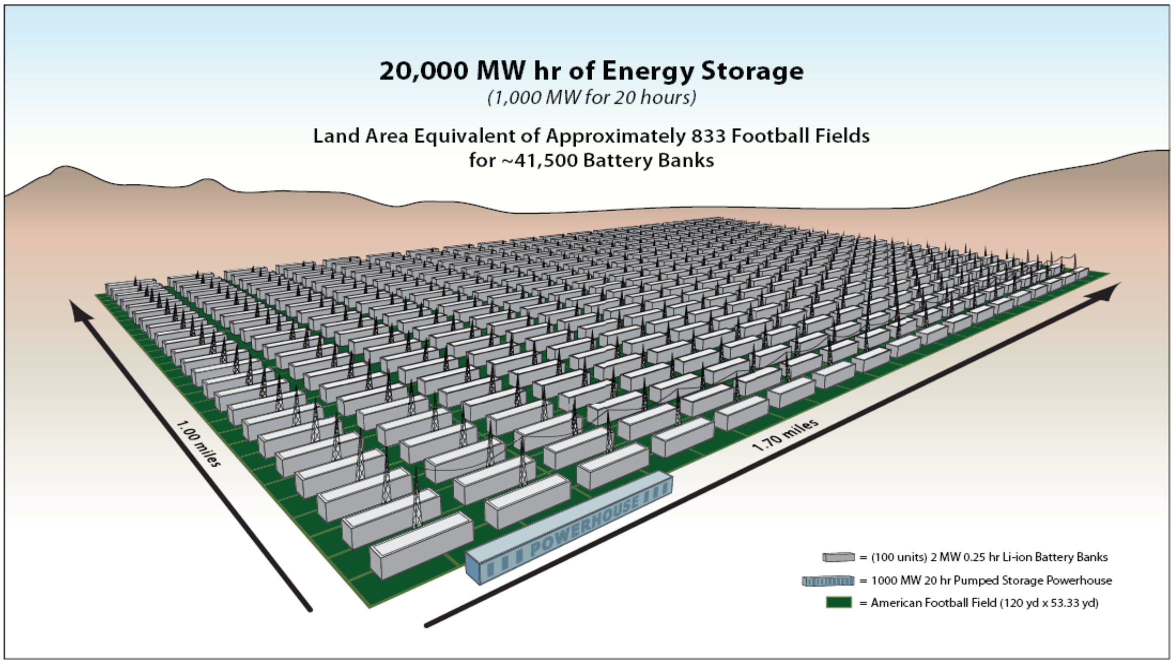


Figure 11. Li-ion Battery Field and a Hydroelectric P/S Plant for 20,000 MWh of Storage (Source: HDR|DTA)

3.2.3 Comparison Summary: Pumped Storage is the Only Proven Bulk Energy Storage Technology

Many balancing authorities are seeking solutions for energy storage on the order of 1,000 MW for 20 hours, or 20,000 MWh. As discussed, there are presently two technologies most applicable for bulk energy storage: pumped storage and CAES, with pumped storage being the most mature and presently having the largest installed capacity in the U.S. and in the world. While there is much debate about the least-cost grid-scale storage technology, pumped storage currently represents an attractive option in terms of space required, total life cycle costs, and proven MW and MWh capacity. Battery, flywheel, and CAES systems have been successfully employed with lower capacities and shorter durations, which make them well suited to short-term storage for general grid stabilization and power quality needs on the order of minutes to a few hours. Ultimately these technologies may be suitable for bulk energy storage, but these applications appear to require more research and development.

HDR|DTA agrees with the statement by CAISO that a number of technologies would be required to smooth variable renewable energy resources, including bulk storage, distributed storage and transmission system improvements. For long-term planning purposes, a new pumped storage project is recommended as one major component in developing a plan to enable greater penetration of variable energy resources and adding grid-scale system reserves.

4.0 Hydroelectric Pumped Storage – Enabling Variable Energy Resources

4.1 Pumped Storage 101

Pumped storage hydroelectric facilities store energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation (Figure 12). During periods of high electricity demand, power is generated by releasing the stored water through turbines in the same manner as a conventional hydro station. Excess energy, usually at lower cost during the night and on weekends, is used to recharge the reservoir by pumping the water back to the upper reservoir. Reversible pump-turbine/generator-motor assemblies can act as both pumps and turbines. Pumped storage stations are unlike traditional hydro stations in that they are actually a net consumer of electricity, due to hydraulic and electrical losses incurred in the cycle of pumping from a lower reservoir to the upper reservoir and then generating from the upper back to the lower. However, these plants can be very beneficial in terms of balancing load within the overall system, and can be economical due to peak to off-peak price differentials, and have the potential to provide ancillary grid services.

Pumped storage hydroelectric projects have been providing valuable storage capacity and transmission grid ancillary benefits in the U.S. and Europe since the 1920s. Today, the 40 pumped storage projects operating in the U.S. (Figure 13) provide more than 20 GW, or nearly 2 percent, of the capacity for our nation's energy supply system (Energy Information Admin, 2007). Pumped storage and conventional hydroelectric plants combined account for 77 percent of our nation's renewable energy capacity, with pumped storage alone accounting for approximately 16 percent of U.S. renewable storage capacity (Energy Information Admin., 2007).

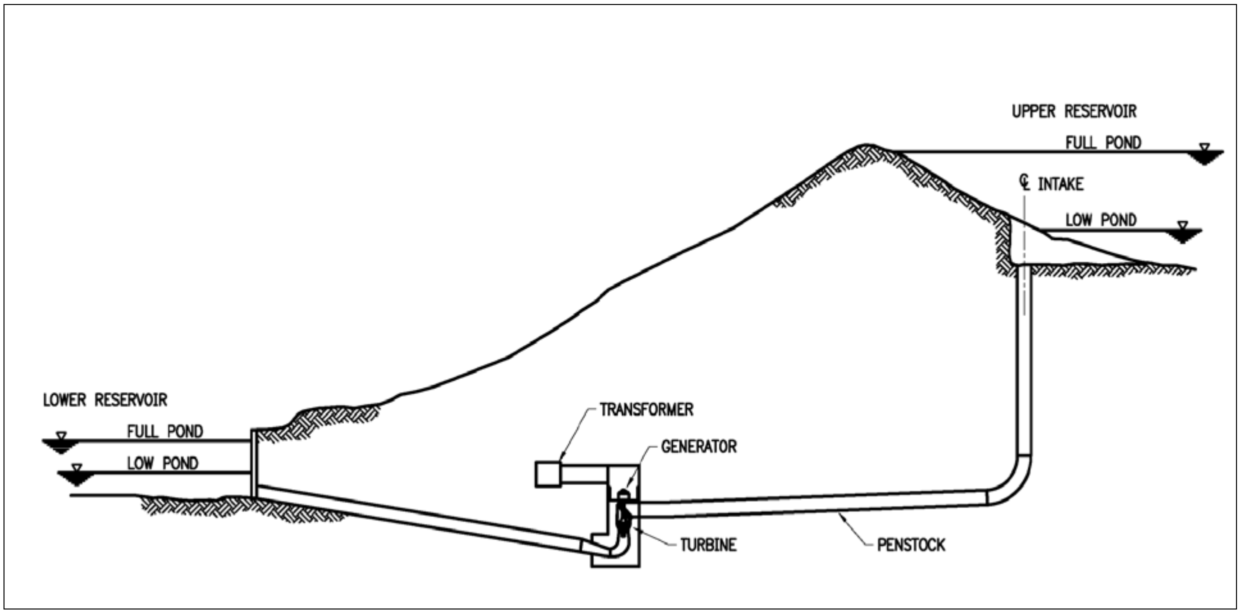


Figure 12. Typical Pumped Storage Plant/System

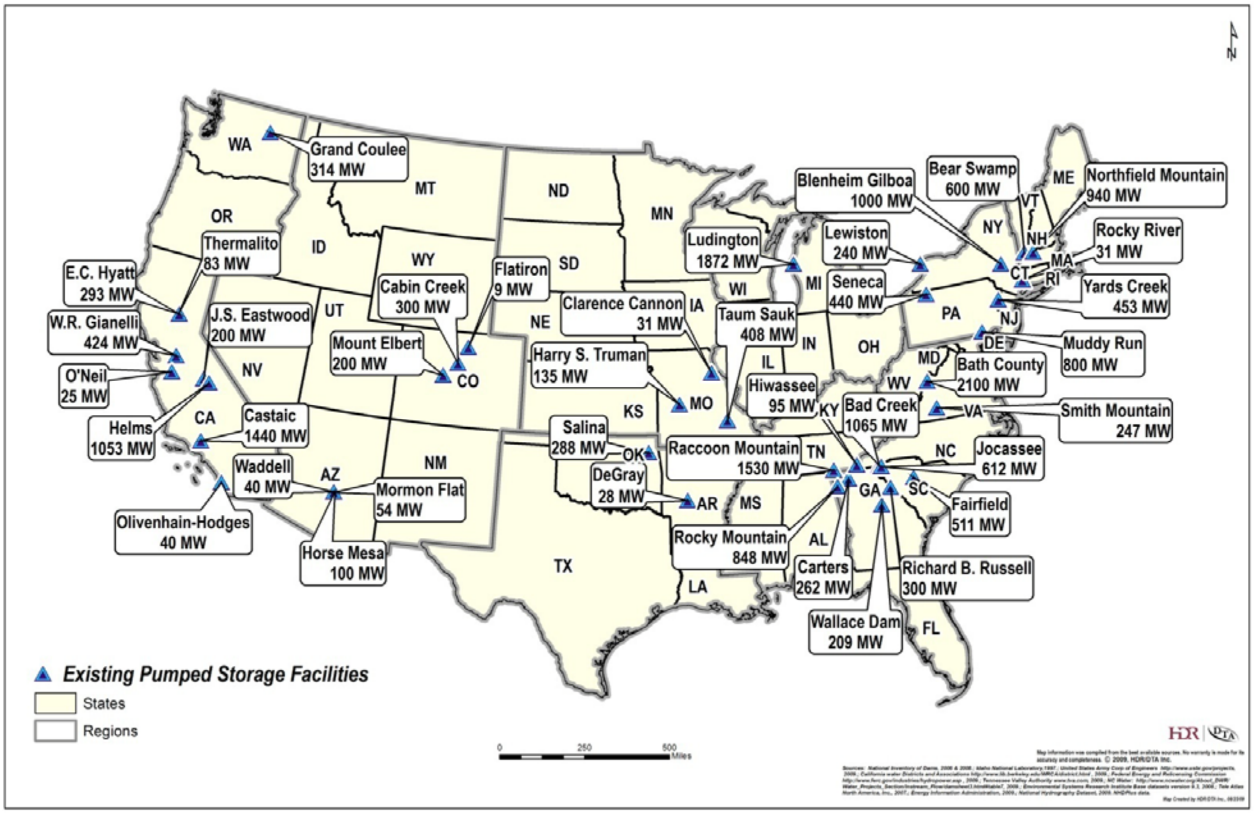


Figure 13. Existing Pumped Storage Projects in the United States

The contributions of pumped storage hydro to our nation's transmission grid are considerable, including providing stability services, energy-balancing, and storage capacity. Pumped storage stations also provide ancillary electrical grid services such as network frequency control and reserves. This is due to the ability of pumped storage plants, like other hydroelectric plants, to respond to load changes within seconds. Pumped storage historically has been used to balance load on a system and allow large, thermal generating sources to operate at peak efficiencies. Pumped storage is the largest-capacity and one of the most cost-effective forms of grid-scale energy storage currently available.

Pumped storage hydro plants can provide load balancing and historically have done so by pumping during night time hours and on weekends, and then generating during periods of higher demand. A pumped storage project would typically be designed to have 8 to 20 hours of hydraulic reservoir storage for operation at full generating capacity. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value.

Pumped storage projects also provide ancillary benefits such as firming capacity and reserves (both incremental and decremental), reactive power, black start capability, and spinning reserve. In the generating mode, the turbine-generators can respond to frequency deviations just as conventional hydro generators can, thus adding to the stability of the grid. In both turbine and pump modes, generator-motor excitation can be varied to contribute to reactive power load and stabilize voltage. When neither generating nor pumping, the machines can be also be operated in synchronous condenser mode, or can be operated to provide "spinning reserve", providing the ability to quickly pick up load or balance excess generation. Grid-scale pumped storage can provide this type of load-balancing benefit for time spans ranging from seconds to hours with the digitally controlled turbine governors and large water reservoirs for bulk energy storage.

The traditional mode of operation for a pumped storage plant is to begin pumping in the evening after the peak load hours of the day, and continue pumping through midnight and into the early morning hours when low-cost pumping energy is available from base load units, and then change modes to generate power during daytime peak periods when energy values are highest. The pump-turbines are gradually taken off line in the morning hours as load ramps up, and then are usually put on line as generators. The rest of the generating system (and the transmission system operator) sees a balanced and easily followed load curve. This daily cycle is routinely followed during the work week. On weekends, when the electrical demand is usually less, there is more low cost pumping energy available and the units typically operate in the pump mode or are off, depending on system load conditions. In a weekly cycle, the upper reservoir is full at the beginning of the work week, at its lowest point at the end of the work week, and returns to full upper reservoir conditions during the weekend's pumping operations.

Pumped storage can be of great advantage in the shorter balancing authority time frames, within the hour, minute, or even real-time, to provide incremental and decremental reserves. One advantage is the ability of pumped storage to store energy when surplus energy is being produced by wind-powered generators at night. A synchronous-speed (i.e., single-speed) pump-turbine in pumping mode has a fixed relationship of power input requirement to net head; therefore, the power input to the pump-turbine cannot change while it is on line. Existing pumped storage projects therefore utilize "blocks" of excess energy off the grid for pumping operations. With the advent of variable speed technology pumped storage units, load balancing in the pump mode can be a very significant grid benefit by providing critical decremental reserves, thus smoothing the supply curve. In off-peak periods where the pumped storage station may be in pumping mode, the level of pumping could vary based upon the expected output in wind energy. The pumps could adjust their input power to smooth out the wind output by reducing pump load as wind drops off and increasing pump load when wind output picks up in real time. In the on-peak hours when the pumped storage station is generally in generating mode, the actual output of the pump-turbines could be adjusted such that the wind plus the pump-turbine output is smoother within the minute or hour to minimize load change impacts on other units in the area. In the generation mode, the capabilities of both single and variable speed machines are identical to conventional hydropower units. By varying the wicket gate position to be between 60 to 100 percent, the units can provide incremental and decremental reserves via load-balancing at partial load and provide Automatic Generation Control (AGC) services.

The Next Generation of Pumped Storage Projects

With the advent of Renewable Portfolio Standards in many states, there has been renewed interest in new pumped storage projects in the United States (Figure 14). Until recently in the U.S., grid system requirements did not dictate the need for, and the subsequent increased incremental expense of, variable speed technology; therefore, none of the existing pumped storage projects in the U.S. are variable speed. However, because variable speed technology is well suited to integration of variable renewable generation, many of the proposed new pumped storage projects are considering variable speed machines. For example, there are three significant pumped storage projects in the development phase in California: Sacramento Municipal Utility District's (SMUD) 400-MW Iowa Hill Project; Eagle Crest Energy's 1,400-MW Eagle Mountain Project; and Turlock Irrigation District's 900-MW Red Mountain Bar Project. The owners/developers of these projects are considering variable speed technology almost exclusively due to the growing need for decrementing reserves at night and enabling greater penetration of variable energy resources.

Variable speed units have been commissioned in Japan and Germany and have demonstrated that they are effective at extending the pump operating curve to a broad range of pumping operation and can follow high wind ramping rates.

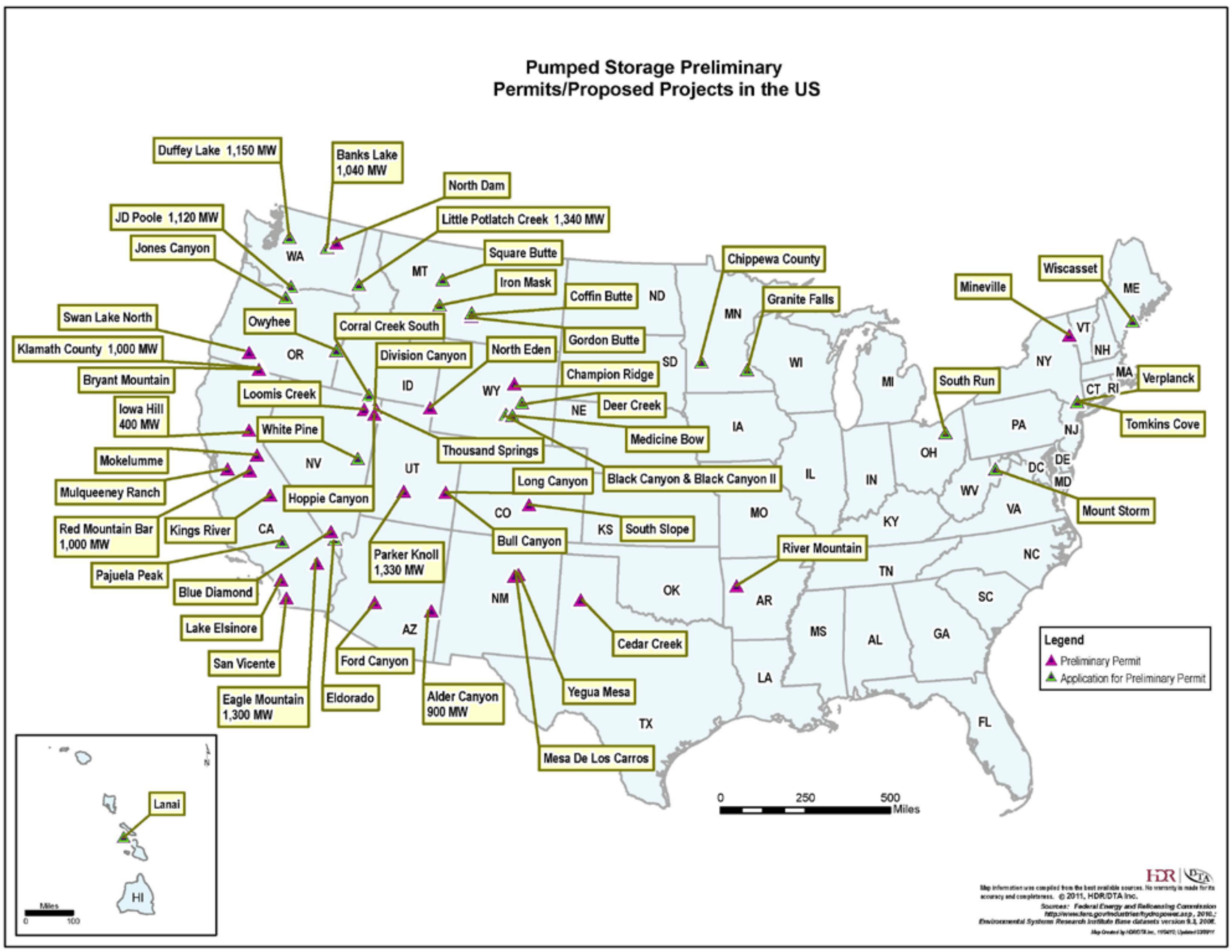


Figure 14. Pumped Storage Preliminary Permits/Proposed Projects in the U.S. (as of September 2010).

Portugal is another example of where double digit levels of variable energy resources within a hydropower-oriented grid are driving the development of new pumped storage projects. As of 2008, the Portuguese electrical grid had a 15,000-MW capacity, a peak demand of 9,100 MW, over 5,000 MW of hydropower, and 2,624 MW of wind. With a goal of approximately 8,000 MW of wind projected to come on line, Iberdrola currently has three pumped storage projects under construction utilizing variable speed technology on the Iberian Peninsula totaling approximately 3,500 MW (Hydro Review Worldwide, July 2009).

It is apparent from these examples that large, grid-scale pumped storage is one of many options available to integrate equally significant levels of variable generation. With the introduction of double-digit levels of variable energy resources onto the BPA grid, the opportunities for pumped storage to play a key role are significant.

4.2 Pumped Storage and BPA

One potential solution to maintaining a balanced energy system for BPA is to have a large bulk energy storage project dedicated to providing system balancing reserves and other ancillary services to manage this new grid dynamic. Pumped storage hydro has the capability to provide these benefits, including energy storage, electrical load balancing, frequency control and incremental and decremental reserves. If built on a large enough scale, multipurpose pumped storage projects can also provide significant water storage benefits within the watershed.

Pumped storage has significant potential in the Pacific Northwest, due to the mountainous terrain lending itself to the economic construction of two closely coupled reservoirs. A diverse pumped storage strategy is proposed to specifically meet the reserve requirements of the BPA balancing authority and includes enhancing the capacity of existing pumped storage to the development of new pumped storage projects in and near BPA's service territory. In the next section, the Keys Pumping Plant at Grand Coulee is studied to determine the potential for increasing its pumped storage capability, in both capacity and operation, and to allow for a more aggressive pumped storage operation to meet BPA's short- to medium-term needs. To meet the long-term increased reserve requirements, one or more new pumped storage projects, referred to as Project 'X1' and 'X2', would be developed in the Northwest near major BPA transmission nodes. A summary of these projects is discussed in Table 2.

Table 2. The Range of Storage and Capacity Considered

Project	Storage (Acre-ft)	Storage (MWh)*	Capacity (Pump/Generator MW)
Existing Keys Pumping Plant (incremental change in storage)	100,000	24,000	-600/+300
Existing Keys Pumping Plant (low drawdown incremental storage)	500,000	120,000	-600/+300
New Pumped Storage Project X1	15,000	20,000	~1,000
New Pumped Storage Project X2	1,550,000+	350,000+	1,136+

*Assumes 100 percent of stored water available for energy storage.

4.3 John W. Keys III Pump Generating Plant

As an existing facility, the Keys Pumping Plant is considered a relatively straightforward and an almost immediately available first step towards providing BPA with additional energy storage and system reserve capability necessary to meet the needs of the present and growing variable energy generation. Improved plant operational flexibility, efficiency, availability and expanded capacity are the some of the benefits of potential enhancements to the existing Keys Pumping Plant.

Banks Lake, a man-made water-supply reservoir filled with water pumped from Lake Roosevelt, was created by building two rock-faced earthfill dams at the north and south ends of the Ice Age channel of the Columbia River, now known as the Grand Coulee. This 27-mile long reservoir, with an active storage capacity of 715,000 acre-feet, feeds Columbia River irrigation water into the Main Canal and ultimately to the Columbia Basin Project. In addition it discharges flow into Lake Roosevelt when the pump-generating units at Keys Pumping Plant are operating in the generating mode. Six pumping units, each rated at 65,000 horsepower, were initially installed in 1951 to lift water from Lake Roosevelt to the 1.6-mile-long feeder canal for delivery into Banks Lake. In the early 1960s, with the Northwest facing power shortages, investigations showed the potential the site offered for pumped storage to support peak power demand needs. Therefore plans were for the next six units (7-12) to be reversible pump-turbines yielding a total generating capacity of the Keys Pumping Plant pump-generating units of 314,000 kW. Units 7 and 8, commissioned in 1973, are each rated at 67,500 horsepower in the pump mode and 50,000 kW in the generating mode; Units 9-12, installed in 1983-1984, are each rated at 70,000 horsepower in the pump mode and 53,500 kW in the generating mode. The total pump load capacity of all 12 units is 614 MW (805,000 horsepower) and the generating capacity is 314 MW.

The Keys Pumping Plant serves multiple purposes including primarily the delivery of irrigation water to the Columbia Basin Project, and is an excellent example of how regional bulk energy storage and seasonal water supply objectives can be simultaneously met. However, these competing obligations have historically limited the reserves that would otherwise be available to support grid needs, as the need to provide full irrigation supply to the Columbia Basin Project takes precedence. In 2009, Reclamation completed a first-phase study titled "Special Report, Study of Pump Storage Capability and Potential Enhancement for Wind Power Integration, [at the] John W. Keys III Pump Generating Plant, Columbia Basin Project" (Reclamation's Keys Study Report). This study indicated that the Keys Pumping Plant is currently limited in its ability to support reserve capacity and dynamic needs of the grid, and that increased Keys Pumping Plant pumped storage capability will require pump-turbine and balance-of-plant system modernizations and potential upgrades. However, the study also indicated that a number of changes to the facility could be implemented to improve reliability and flexibility of pumped storage operations and reduce the manual intervention currently required to switch from pump to generation modes, thereby adding grid services support in the near term.

Improvements to increase reliability, flexibility and capacity that have been routinely implemented by the pumped storage industry are currently being considered by BPA and Reclamation at Keys Pumping Plant, which could include the following:

1. Replacing outdated electrical and mechanical equipment to improve unit reliability and unit response times.
2. Improving capacity by upgrading and/or redesigning the existing pump and pump-generator units.

According to Reclamation's Keys Study Report, there is minimal daily change in the Banks Lake elevation resulting from Keys Pumping Plant pumped storage operations. Typically, it takes days of pumping to change Banks Lake's water surface elevation 2 feet. Pumping normally occurs during nights and weekends and generation occurs during peak periods, thereby moderating water fluctuation at Banks Lake. Banks Lake is typically operated at near full pool of 1,568 feet about 80 percent of the time, which is sufficient for full pumped storage operations (Reclamation, 2009).

By Congressional authorization, Reclamation is obligated to deliver water to irrigate the Columbia Basin Project. This delivery is measured at Mile 0.2 of the Main Canal at Dry Falls Dam. Diversion for the current developed portion of the Project is certified for 2.9 million acre-feet and has a typical water delivery schedule as shown in Figure 15. Keys Pumping Plant irrigation operation begins around March 15 and extends to as late as October 30 of each year, with weather variations slightly impacting the start and end time dates. The Keys Pumping Plant's pump/generating operation has been typically driven by the volume required to meet irrigation demands and has flexibility to operate within the top 5 feet of the full pool elevation in Banks Lake. On average to meet the peak irrigation water demands it requires at least five pumps to operate for a period of time each day, with occasionally more than five pumps required at any given moment. During periods where one or more pumping units are out of service for repair or maintenance, it requires more continuous pumping to occur potentially during high system load demand periods.

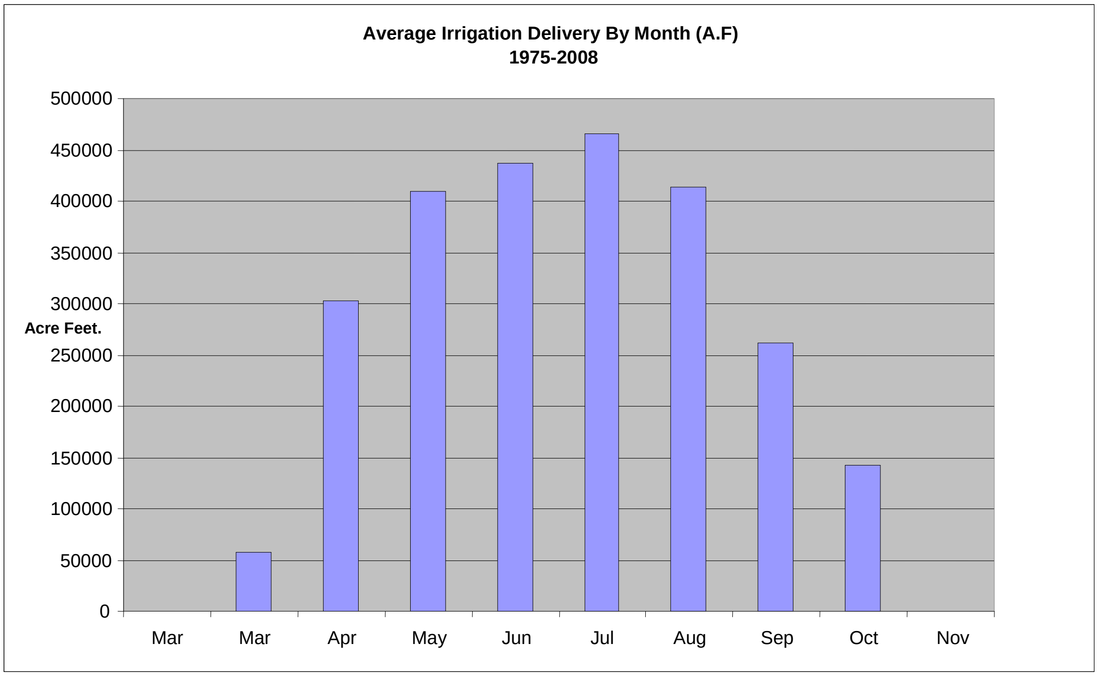


Figure 15: Banks Lake Irrigation Delivery – WY 1975 – WY 2008

The largest operational limitations on the Keys Pumping Plant appear not at the Keys Pumping Plant itself but in the operational flow constraints associated with the Keys Feeder Canal and Banks Lake elevation operating limits and guidelines (related to recreation expectations and warm water resident fish populations). These operational guidelines appear to limit operational flexibility and ability to dispatch the Keys Pumping Plant as a traditional pumped storage scheme. Additional limits on pumping include limits to pumping in the increased head ranges created by the flood control drafts at Lake Roosevelt and the start sequences that tie the pumps to the operation of Grand Coulee Units G1–G3.

It is worth noting that there can be a significant amount of forecast error regarding the irrigation withdrawal which provides some uncertainty on capacity available for energy storage from month to month. BPA staff reportedly set up their dispatch plan based upon a daily forecast of irrigation discharge at the Main Canal outlet, which can vary considerably from actual water demands. Therefore water storage is kept in reserve to account for this, thus limiting overall energy storage capacity within Banks Lake. In addition, BPA has a difficult time planning the operation at the Keys Pumping Plant because the reservoir often doesn't respond to changes the way BPA expects based on system modeling, and there is no long-term forecast of irrigation needs beyond the daily forecast.

The Keys Pumping Plant operations, constraints and options are discussed further in the next section of this report. From a technical perspective, it appears that the Keys Pumping Plant has the flexibility to support additional pumped storage operations at Banks Lake, provided that current water management and allocation guidelines are revisited and reviewed.

4.3.1 Keys Pumping Plant Facility Assessment

Introduction

A due-diligence-level condition assessment and review of potential improvements have been performed for the existing Keys Pumping Plant. The assessment and review resulted in a base case for plant rehabilitation and modernization, along with options for enhancement of capacity and/or operational flexibility. The Keys Pumping Plant study is based in part on Reclamation's Keys Study Report of 2009, along with information gathered during a facility inspection, a review of plant drawings and operating procedures, and interviews with Grand Coulee operating personnel.

Facility Description

Grand Coulee Dam is the largest dam on the Columbia River and is part of the FCRPS. It is operated and maintained by Reclamation and dispatched by BPA. The Keys Pumping Plant facility is part of the overall Grand Coulee project, withdrawing water from Lake Roosevelt by pumping water uphill to a feeder canal that flows into Banks Lake. The Keys Pumping Plant uses Banks Lake, an off-stream storage impoundment, and Lake Roosevelt, the reservoir created behind Grand Coulee Dam, in a pumped storage application with multiple purposes of providing irrigation water and bulk energy storage. Based upon a review of the historical utilization data, the Keys Pumping Plant has not been fully utilized for load balancing and reserves in the past.

The six pumps and six pump-generators at Keys Pumping Plant pump water to, or draw water from, the concrete-lined 1.6-mile feeder canal linking head works of the Keys Pumping Plant to Banks Lake. The table below summarizes the unit ratings at the Keys Pumping Plant.

Table 3. Keys Pumping Plant Unit Detail Characteristics

Keys Pumping Plant Data	Pump 1	Pump 2	Pump 3	Pump 4	Pumps 5 & 6	Pump-Generators 7 & 8	Pump-Generators 9-12
Generator/Motor OEM	GE	GE	Westinghouse	Westinghouse	Westinghouse	Westinghouse	Hitachi
G/M Stator Rewind	Alstom	GE	Alstom	Siemens	N/A	N/A	N/A
MVA	51.5	51.5	50	50	50	51.3/50.0	53.2/53.5
kV	13.6	13.6	13.6	13.6	13.6	13.2/13.8	13.8/13.8
PF	0.95	0.95	1	1	1	1.0/1.0	1.0/1.0
Year Rewound	1991	1999	2010	2002	N/A	N/A	N/A
Pump & P/T OEM	Sulzer Escher Wyss	Sulzer Escher Wyss	Pelton Water Wheel Co.	Pelton Water Wheel Co.	Pelton Water Wheel Co.	Nohab	Toshiba
Pump Impeller Replacement OEM	American Hydro	American Hydro	American Hydro	American Hydro	Not Replaced	Not Replaced	Not Replaced
Horsepower (HP)	65,000	65,000	65,000	65,000	65,000	67,500	70,000
RPM	200	200	200	200	200	200	200
Head (ft)	330	330	310	310	310	292	292-340
Pump Flow (cfs)	1,360	1,360	1,350	1350	1350	1,860	1,372-1,813
Turbine Flow (cfs)	N/A	N/A	N/A	N/A	N/A	2,200	2,380
Year Upgraded	1990	1996	2010	2002	1952 (original units)	1973 (original units)	1983/1984 (original units)

Summary of Plant Condition

In general, the Keys Pumping Plant is well maintained. However, some of the unit and balance-of-plant equipment is worn or becoming obsolete. Over the years several of the pumps have been refurbished by in-kind replacement of the pump impellers, some of the motor stators have been rewound, and minor enhancements have been made to the controls and protection systems. The pump-generators have not yet undergone similar refurbishment and still have the original pump-turbines and generator-motors, governors, and static exciters. Since the plant has not been called on for significant load balancing or meeting reserves, repairs and upgrades may not have been addressed with urgency, leading to some extended unit outages in the past few years. The plant satisfactorily meets the irrigation water pumping needs with a considerable margin of capacity. A summary of the preliminary condition assessment is provided as follows:

- **Pumps 1 through 4**

  Pumps 1 through 4 have recently undergone in-kind impeller and motor refurbishment, with the unit ratings remaining as originally designed. The pumps are singled-speed fixed-geometry units. The excitation systems use individual motor-generator (MG) sets to provide the required DC power, and reportedly have been somewhat of a maintenance issue, requiring frequent attention. The MG sets are original and can be maintained with current maintenance practices.

The pump circuit breakers were recently replaced (within the last six years) with new disconnect switches, removing individual pump switching capability. The pumps are electrically connected to the Left Powerhouse generating units through a typical indoor and outdoor isophase bus. The bus has been problematic from a maintenance point of view requiring constant attention to identifying hot spots and potential leaks. The bus experiences extreme ambient conditions from winter to summer, and is exposed to heavy thermal cycling. It was reported that there has not yet been major failure, likely due to diligent maintenance practices.

- **Pumps 5 and 6**

  Pumps 5 and 6 are generally configured in the same way as Pumps 1 through 4. The main differences are that the impellers and motors have not undergone similar in-kind refurbishment. In all other respects, these units are maintained and operated in a similar fashion. The controls and ancillary systems are in similar condition.

- **Pump-Generators 7 and 8**

  Pump-generators 7 and 8, commissioned in 1973, were the first reversible pump-generators installed at the plant. The horsepower ratings of these units are slightly larger than the original pumps and they were the first units to also provide generation capacity. Their control and protection systems are original, but are undergoing a refurbishment plan similar to the pumps.

  Wicket gate controls for these units employ individual hydraulic actuators, one for each gate, and have been considered a maintenance and reliability issue. This is an unusual design for pump-turbines and is rarely, if ever, used in modern designs.

  The circuit breakers for these units are GE air-blast breakers and are original installation. The breakers are kept in operation by an extensive ongoing maintenance plan, based on the number of operations. The units pose some reliability issues when operated more frequently, thus requiring more maintenance and associated outages.

- **Pump-Generators 9 through 12**

  Pump-generators 9 through 12 were installed a decade after Pump-generators 7 and 8, and have higher horsepower and motor ratings. Their gate control uses a conventional hydraulic servo-motor with mechanical governor and hydraulic power unit. Those governor controllers are now almost thirty years old and will be difficult to maintain into the future.

  The control and protection schemes are original and are also undergoing a refurbishment plan similar to that of the pumps. The circuit breakers for these units are GE air-blast breakers and are original installation. The breakers are kept in operation by an extensive ongoing maintenance practice based on the number of operations. The units may pose some reliability issues when operated more frequently, thus requiring more outages to facilitate maintenance.

- **Pump-Generators 7 through 12 Common Systems**
  To start Pump-generators 7 through 12 as generators, initial excitation power is taken from station service power, rectified, and applied to the field for a short time (referred to as field flashing) to produce excitation current and build up generator voltage. The excitation system is nearly forty years old and will be a problem going forward to maintain without some modernization.

- **Generator Step-Up (GSU) Transformer**
  Two GSU transformers provide step-up or step-down voltage for the pump-generator operation. Three pump-generators are connected and operated on each transformer. One transformer is of original installation and the second was replaced with a new unit.

  The original design included a gas-insulated (GIS) bus to connect the 230-kV GSU windings to the overhead transmission connection to the 230-kV switchyard. The bus is equipped with internal disconnect switches for maintenance and clearance purposes. The bus is a maintenance issue and continues to leak SF6 gas. Therefore when the one transformer was replaced, it was not connected to the GIS bus.

Feeder Canal and Water Conveyance System

The 1.6 mile concrete-lined trapezoidal feeder canal from the Keys Pumping Plant to the outlet into Banks Lake includes three major inline structures along the length of the canal: a submerged, duck-billed long-crested overflow weir near the Banks Lake end of the canal, the Highway 174 bridge crossing the canal approximately midway between the Keys Pumping Plant and the outlet into Banks Lake; and a check structure with five 24-foot-wide radial gates. Presently, the maximum flow in the Feeder Canal in the direction from the Keys Pumping Plant to Banks Lake with all twelve pump-motors (Ps 1-6 and P/Gs 7-12) operating is approximately 23,000 cfs. The maximum flow in the Feeder Canal in the direction from Banks Lake to the Keys Pumping Plant with all six turbine-generators (P/Gs 7-12) operating is approximately 14,000 cfs.

The submerged overflow control weir within the feeder canal near Banks Lake (at Canal Sta. 89+22) presents interesting questions requiring further study to provide definitive answers. The possible removal of this weir with the intent of reducing flow obstruction and turbulence at expanded flows and thereby allowing unrestricted pump-generator unit operations was reviewed. Preliminary analysis indicates that when the water levels in Banks Lake are below 1,567 this weir reduces the slope of the hydraulic grade line during pumping flows in order to hold velocities in the feeder canal at or below approximately 10 fps. The initial HEC-RAS modeling evaluated flow in the canal for both with and without the control weir in a number of modeling scenarios. Within the range of anticipated reservoir pool and flow levels, the hydraulic modeling performed to date indicates that the head loss across the weir is on the order of 1/2 foot or less. Depending on the operational scenario selected, the weir may or may not be a significant restriction that requires further attention.

For pump-generator unit generation mode operations, this initial analysis confirms the current operating guidelines that all six pump-generator units can operate in an unrestricted mode with Banks Lake above 1,567 feet. When Banks Lake water levels are below 1,567 feet it does not appear possible to maintain adequate submergence at the intake to avoid vortices at the penstock inlet when all six of the pump-generators are generating. Reclamation has historically addressed these submergence conditions in part by running fewer units as Banks Lake elevation decreases. Based on the HEC-RAS analysis and other information provided by Reclamation, some hydraulic issues may exist when the Banks Lake water levels fall below 1,567 feet and could require limited changes in either operation or canal/intake configuration. Note also, at a Banks Lake water surface elevation of 1,563 feet, the flow velocity in the canal while operating all six units in generation mode is approximately 15 fps near the powerhouse end of the feeder canal. This relatively high open channel velocity results from the hydraulic grade line in the canal (driving flow from the lake to the plant) converging with the floor of the canal and creating a reduced cross sectional area. In addition, during a load rejection at the plant, the sudden stopping of the flow would generate a bore wave in the canal that could travel from the siphon intake along the canal towards the radial gate structure, reaching a peak elevation, and then dissipating into Banks Lake. The height of the bore wave is a function of the water depth in the canal and the velocity of the flow. Preliminary estimates based on Banks Lake at pool elevation 1,567 feet indicate that upon a full six unit load rejection the bore wave height could reach an elevation of approximately 1,574 feet. For freeboard, the top elevation of the canal wall is 1,578 feet, according to USBR Drawing 222-D-24179. It should be noted that for the present purpose of this study, the original design hydraulics of the feeder canal are not yet fully understood and additional research (including 2-D or 3-D modeling with field calibration testing) would be warranted prior to making definitive conclusions of the various upgrade options considered in this report.

4.3.2 Keys Pumping Plant as Both an Initial Step and Long-Term Support

The utilization rate of the Keys Pumping Plant in a traditional pumped storage application has varied significantly over the years, with slightly more utilization in recent years than in past years. The facility as currently configured could be immediately dispatched more aggressively in a pumped storage application with certain operational adjustments. The counter implications to this are additional wear on units and controls that are already in need of refurbishment. Also, there appears to be potential for increased generation and pumping capacity that could be achieved in a five to ten year timeframe.

HDR's initial assessment of potential operational adjustments that could be implemented relatively quickly are:

- Improved irrigation commitment forecast to allow improved scheduling of the pump and P/G units.

- Utilize more of the existing operational flexibility within the constraints of Banks Lake elevations and feeder canal hydraulics.
- Conduct field testing to confirm the operational constraints related to P/G operations and Banks Lake reservoir levels.
- Add resources to physically verify the operation of the phase reversal switch when changing modes of operation and to support more frequent usage of the P/G's.
- Consideration should be given to the replacement of the phase reversing switches to eliminate the reliability and operational issues associated with the existing equipment.
- Add resources to improve maintenance activities for the P/G's to increase their reliability.
- Assure that the penstocks for the P/G units are kept full after unit shutdown to allow quicker unit starts.

To provide a basis for evaluating the costs and benefits of the different scenarios of the Keys Pumping Plant configuration and operations, the following incremental steps of modernization and upgrade of the plant were developed.

Base Case and Upgrade Options

A base case and four upgrade options were evaluated to provide a basis for evaluating costs of the different options. The base case and options evaluated include an assortment of work necessary to reflect station operations of the CV modeling scenarios considered in Section 5.

- **Keys Pumping Plant Base Case: Modernize Balance-of-Plant (as configured)**
  If the Keys Pumping Plant were fully utilized for providing BPA system balancing and reserves, the existing pumping, generating and balance-of-plant equipment would be subjected to more frequent starts and stops, and many more hours of annual operation. To perform that duty reliably, modernization and potentially upgrade of the plant equipment would be necessary.

  The base case refurbishment and modernization plan consists of the necessary equipment upgrades and replacements required to maintain the originally designed operating reliability and flexibility.

  The program of work summarized below, the minimum effort to maintain reliability and provide life extension, could be carried out over a 5- to 10-year period, and be scheduled so as to keep the plant's availability high during critical periods of the irrigation season. Reclamation is already well along with upgrades to the pumps and rewinds of the pump motors. Modernization of the unit auxiliary equipment would generally require only short outages on individual units or pairs of units. An upgrade of the Left Powerhouse's Units G1 to G3 is also currently in progress. This option maintains the current balance-of-plant (BOP) and unit configuration, with no significant operating procedural changes, and includes the following work:

  - Phase reversal switches and unit circuit breakers, Pump-generators 7 through 12

- Excitation replacement Pump 1 through Pump 6
- Governors, Pump-generators 7 through 12, including upgrade of the wicket gate control components of Units 7 and 8 to reduce maintenance and improve availability
- Unit controls and protection, Pump 1 through Pump 6 and Pump-generator 7 through Pump-generator 12
- Pump motor disconnect switches, Pump 1 through Pump 6 replacement (either with circuit breakers or soft starters)
- Refurbish isophase bus between the Left Powerhouse and the Keys Pumping Plant
- Refurbish the Left Powerhouse's turbine-generator Units G1 through G3
- Refurbish outlet works and siphon components
- Install main transform disconnect switches
- Replace one main step-up transformer KP10B
- Condition monitor and maintain Pumps 5-6 motors and Pump-generator 7-12 generator-motors
- Upgrade CO2 system for generator protection
- Refurbish station electrical service

No significant civil works are expected for this Base Case.

- **Keys Pumping Plant Option 1: Decouple Pumps 1-6 from Left Powerhouse**

  Pumps 1 through 6 are electrically connected in pairs to individual generators in the Grand Coulee Left Powerhouse, and must be started and run in pairs in conjunction with the operation of turbine-generator Units G1 through G3. When any of the Left Powerhouse's turbine-generators Units G1 through G3 are out of service, both associated pumps must also be out of service. Pump operational flexibility is limited with no independent pump start or stop capability. In this option, it is proposed that the pumps be decoupled from the Left Powerhouse and allowed to operate independently, which would require the following BOP changes:

  - Install new circuit breakers on Pumps 1 through 6
  - Install two new 230-13.8 kV step-down transformers
  - Install one new 230-kV circuit from the Keys Pumping Plant to the 230-kV switchyard
  - Modify isophase bus and reconnect the pumps to the new transformer
  - Remove isophase bus between the Keys Pumping Plant and the Left Powerhouse.

  Minor civil and structural works for Base Case and Option 1 pump decoupling would be required to ensure the transformers and power line equipment are on sound foundations, have proper oil containment, and that the powerhouse structure is adequate for the added transformers and associated equipment.

- **Keys Pumping Plant Option 2: Single Speed Upgrade of Pump-Generators 7 through 12**
  This option includes modifications which would be necessary for the plant to perform as analyzed in CV modeling; increasing P/G generating capacity by approximately 20 percent and operating Banks Lake down to elevation 1,567 feet.

  Upgrade of the existing Pump-generator Units 9 through 12 by approximately 20 percent is expected to be feasible, based on industry experience with similar vintage pump-turbines. It may be difficult to increase the capacity of Units 7 and 8 by 20 percent since they were designed with more constrained water passages. This option assumes the generating capacity of the Keys Pumping Plant could be increased from 300 MW to approximately 360 MW, and the pumping capacity from 600 MW to 660 MW.

  Another potential upgrade of the P/G units, although not likely compatible with an increase in capacity, is an increase to the operating range of the P/G units. Units 7 and 8 deadhead at an FDR elevation of 1,263 ft; Units 9-12 deadhead at 1,240 ft; the pump units are operational to 1,208 ft. There may be potential to design and implement modifications to the pump-turbines and water passages that would allow operations at a lower FDR elevation than the existing units.

  The powerhouse work for P/G upgrades would include the following:

  - Perform stair-step analysis of Pump-generators 7 through 12 to determine which components are re-usable and which must be replaced.
  - Investigate upgrade potential – increased capacity and/or expanded operating range.
  - Complete the refurbishment and replacement of Pump-generators 7 through 12 with new single speed pump-generators (including new or upgraded generator-motors, new pump-turbine runners and the replacement or upgrade of other turbine components.)
  - A higher rating would likely require replacement of transformer KP10B in the Base Case above with a higher-rated transformer. The existing transformer KP10A is newer and may be upgraded with additional cooling or also replaced with a higher-rated unit.

  The capacity upgrade option (assuming the intent to operate all six P/G units at once) would affect the feeder canal and intake works, as the maximum generating flow would be increased from approximately 14,000 cfs, the current design limit, to 16,800 cfs. HEC/RAS modeling was performed on the feeder canal and conveyance system to gauge the impact of increasing flows to 16,800 cfs. The modeling results indicated that at Banks Lake elevation 1,567 feet the surface elevation at the intakes would be approximately 1,563 feet, with water depth near Sta 3+12 at 14 feet and flow velocity of 13 feet per second. Figure 16 below provides a pictorial of the water elevation at the intake and expected submergence for the various flows. Another capacity upgrade operational scenario would be to operate five P/Gs within the existing canal and conveyance system flow constraints, and keep the sixth unit available as a spare. Operating the units in this way would eliminate the need for modifications to the feeder canal and intake works.

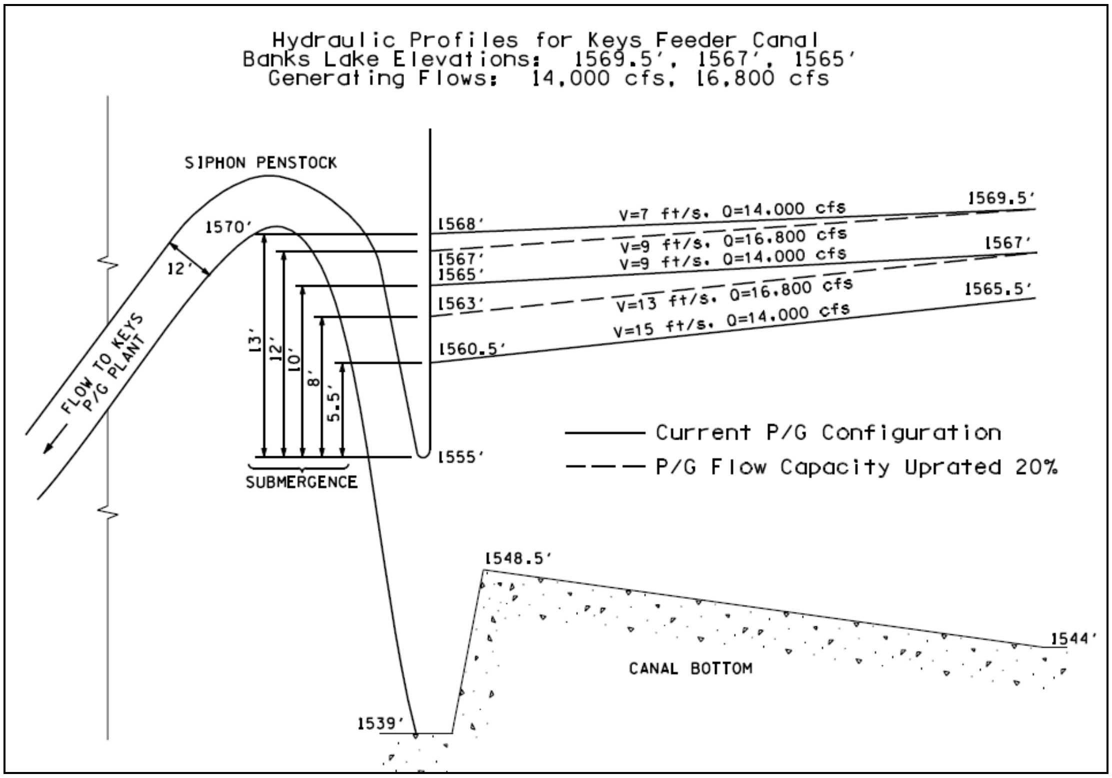


Figure 16. Canal Head Loss and Intake Velocity

Preliminary load rejection calculations for these flow conditions and pool elevation indicate a bore wave could be created during a full load rejection of all six pump-generator units, potentially reaching an overall elevation of 1,574 feet (about 4 feet below the top of the canal embankment). With Banks Lake operating at higher pool elevations, smaller bore waves would be expected and added to the pool elevation.

Due to non-linear effects of such large wave generation the simple classical calculation performed here may not be accurate enough to use in selecting an upgrade option. More thorough analysis and field testing of the current system to validate the calculations and model would be necessary to predict more accurately the head loss, intake vortices, and wave generation with more confidence.

- **Keys Pumping Plant Option 3: Partial Variable Speed Pump 5 and Pump 6 Conversion to Pump-Generators with Option 2**

  This option includes a wider operating range for Banks Lake with drawdown to as low as 1,550 feet in elevation. At the Keys Pumping Plant, Option 3 would be an incremental upgrade over Option 2, and include conversion of two pumps, such as Pumps 5 and 6, to variable speed pump-generator units in addition to the pump-generator upgrades describe above.

  Conversion of two pump units to variable speed reversible pump-turbines combined with upgrade of the existing six pump-turbines would extend the range of pumping power from the current minimum of 50 MW to a minimum of 40 MW and from a nominal maximum of 600 MW to a maximum of 680 MW. Through most of that range the pumping power would be nearly linearly variable; that is, only small step changes of approximately 10 MW would need to occur when changing load conditions, by reducing the load on the variable speed units when another fixed speed unit is brought on line.

Conversion of two pump motors to variable speed reversible pump-generators would require the following plant modifications, in addition to the changes listed above for refurbishment and modernization in the base case and Option 2:

- Replace the motors and impellors of Pumps 5 and 6 with variable speed wound-rotor generator-motor pump-turbines (converting to pump-generator units)
- Install power conversion equipment for variable speed machine operation (converted Pump-generators 5 and 6)
- Install Pump-generator 5 and 6 turbine inlet shutoff valves or replace the head covers with head covers containing cylinder gates.

Option 3 would further increase the maximum generating flow that would be passed through the feeder canal. Two of the existing pumps would be converted to variable speed pump-generators, along with upgrading the existing pump-generator units, increasing the maximum generating flow to approximately 22,400 cfs.

To pass any of the generation flows through the feeder canal when the water surface elevation in Banks Lake is below elevation 1,563 feet will require reconstruction of the feeder canal with significant widening and deepening, and lowering of the penstock intakes by approximately 20 feet. The range of alternatives being considered includes the ability to generate with a water surface elevation in Banks Lake at 1,550 feet and flows in the feeder canal of approximately 22,400 cfs. The increased range of Banks Lake elevations associated with this option would likely require NEPA studies.

Reconstruction of the feeder canal to allow operation in this scenario would require excavating and moving significant amounts of rock and presents construction issues that will need to be carefully considered and analyzed in subsequent planning and/or design efforts.

Note: Due to the complex technical issues associated with unit conversion and the significant feeder canal modifications, this "Keys Pumping Plant Option 3" was not modeled in the following Section 5, Columbia Vista Modeling, to minimize CV model runs.

- **Keys Pumping Plant Option 4: Complete Plant Upgrade to Variable Speed Pump-Turbines**

This option represents the theoretical upper-boundary condition within the existing footprint of the Keys Pumping Plant and may not be viable either technically (due to space constraints) or economically, as was noted during the joint BPA/Reclamation/HDR meeting in Denver, held in March 2010. It is described here solely to provide the context of the theoretical maximum capacity of the Keys Pumping Plant. The conversion of Pumps 1 through 6 to reversible variable speed pump-turbines would either require a significant reduction in capacity to convert them to true variable speed pump-generators, or the machines would have to operate as fixed-geometry units without the variable pumping or generation capability. Such a conversion of the pumps would require complete replacement and is considered a major effort and a high-risk task, and is not considered a practical option given the potential benefits. On the other hand, though still significant, a variable speed conversion of the existing Pump-generators 7 through 12 would be an easier task. At present, there is one known industry conversion of a pump-generator machine to a variable speed pump-generator – on a unit much larger than those at the Keys Pumping Plant.

The incremental energy benefit of a conversion to twelve variable speed machines is considered small. The costs of such a conversion, however, are significant, requiring significant space for the electronic variable speed controls at very high costs. A more practical approach may be the conversion of just a few existing pump-generator units to variable speed units, providing a single speed and variable speed mix for load balancing.

Option 4 would increase the maximum operating flow to approximately 33,600 cfs, in both pumping and generating modes. Reconstruction of the feeder canal to allow operating flows necessary in this scenario would require extensive excavating and moving significant amounts of rock, presenting construction issues that will need to be carefully considered in subsequent planning and/or design efforts.

Note: Due to the complex technical issues associated with unit conversion and the significant feeder canal modifications, this "Keys Pumping Plant Option 4" was <u>not</u> modeled in the following Section 5, Columbia Vista Modeling, to minimize CV model runs.

Keys Pumping Plant Cost Summary

The Keys Pumping Plant Base Case Modernization and upgrade alternatives presented have been evaluated from a high-level perspective, with engineering cost opinions prepared and presented in Table 4 below, with more detail provided in Appendix C.

Table 4 presents the options evaluated with an estimated implementation time in years and an incremental cost range (over Base Case) associated with the option identified.

Table 4. Conceptual Level Summary of Keys Pumping Plant Costs and Schedule

	Description	Implementation Schedule	Cost Ranges
Short/Medium/Long Term – Keys Pumping Plant	Operational procedures	2 to 5 years	$50-100 thousand
	Base Case - Refurbishment and Modernization (No canal modifications included)	7 to 9 years	$45-75 million
	Weir Removal*	3 to 5 years	$1-2 million
	Option 1: Decouple Pumps from Left PH (Incremental over Base Case)	7 to 9 years	$25-35 million
	Option 2: Single Speed Upgrade of Pump-Generators 7-12 (Incremental over Base Case with no canal modifications)	8 to 10 years	$80-$120 million
	Option 3: Partial Variable Speed Conversion ([Pumps 5 & 6), Single Speed Upgrade (Pump-Generators 7-12) (Incremental over Base Case with canal modifications)	9 to 11 years	$1.0-1.5 billion
	Option 4: Complete Unit Conversion and Canal Rebuild (Incremental over Base Case with canal modifications)	10 to 15 years	$1.5-2.0 billion

*Potential removal of weir requires further investigation to determine need, benefits, and impact.

In order to operate all six pump-generators at the various Banks Lake surface elevations below pool elevation of 1,567 feet, changes to the feeder canal and headworks will be required. When evaluating the Keys Pumping Plant upgrade options, the costs of the powerhouse equipment changes, as well as the civil related costs based on the elevation operations, must be considered. When reviewing potential civil modifications, not only must the minimum operation pool level for Banks Lake be considered, but consideration must also be given to the anticipated flow for both pumping and generation modes. Further calibration, more detailed analysis and multi-dimensional hydraulic modeling will be required to resolve the actual existing and upgrade flow capacity of the feeder canal.

4.4 Project 'X' Study

4.4.1 Introduction

As background, a brief commentary on the status of pumped storage development activity is offered. After a long period of relative inactivity, there has been a flurry of recent pumped storage-related permitting activity carried out by private sponsors in the Pacific Northwest. As can be seen in Figure 14 (as shown in Section 4.1), there have been a significant number of preliminary permits filed with the Federal Energy Regulatory Commission (FERC) in recent years, many of which are well suited and sized to address the energy storage requirements described elsewhere in this document. As a caveat, there are undoubtedly other possible sites and concepts for Northwest pumped storage projects not identified or focused upon in this limited snapshot.

Next, it will be useful to more closely examine representative, previously studied projects within the range of 1,000 to 1,200 MW for purposes of contrasting the characteristics of two extremes in pumped storage project size and attributes. These projects could conceivably be constructed within the next 8 to 15 years. Projects for this comparison are referred to as Project X1 and Project X2.

Project X1 was configured as a closed loop, close coupled system meaning that upper and lower reservoirs are connected by a relatively short water conveyance system and the dams are not on a main-stem river. A short conveyance scheme helps to reduce the high costs of underground construction. Reservoir features for Project X1 were also limited in size to reduce capital costs and to provide a "daily peaking" type facility.

In contrast, Project X2 was conceived as a major Columbia River Basin water storage project that would be able to accommodate pumped storage with a two- to three-week duration energy storage capacity, capable of dealing with low-wind anomalies prevalent in the BPA region. This project could better address longer-duration demand fluctuations but comes with a much higher capital cost given the investment required to construct an embankment dam and overall project of this magnitude. As conceived, the project would have more than 1.5 million acre-feet of active storage, two times larger than Banks Lake storage.

Key characteristics of these two projects are highlighted in Table 5.

Table 5. Representative Pumped Storage Project Examples

Project Feature/Characteristic	Project X1**	Project X2***
Upper Reservoir	New off-channel reservoir	New off-channel reservoir
Storage Volume (ac-ft)	15,000	1,550,000+
Active Surface Area (acre)	282	11,750
Dam Height (ft.)	150	780
Max. Water Surface Elev. (msl)	2,436	2,159
Lower Reservoir	New off-channel reservoir	Existing Columbia River reservoir
Active Storage Volume (ac. ft.)	15,000	1,550,000+
Surface Area (acres)	209	80,000
Max. Water Surface Elev. (msl)	624	1,290
Approx. Net Head (ft.)	1,700	870
Conveyance Length (ft.)	4,800	10,560
Plant Capacity (MW)	1,050	1,136+
Units Sizes/Number	250/4	282/4
Est. Annual Generation (GWh)*	1,560	1,760
Est. Annual Pumping (GWh)*	1,950	2,200
Transmission Line Length (mi.)	5.0	7.5
Est. Capital Cost (Million $, 2010)	2,733	2,500
Cost per Installed MW (Million $)	2.603	2,200

*Based on an assumed weekday 6-hour generation cycle.

**Project X1 Source: HDR|DTA.

***Project X2 source: "Columbia River Mainstem Storage Options, Washington, Off-Channel Storage Assessment Pre-Appraisal Report" 2005 by MWH for the U.S. Department of the Interior Bureau of Reclamation Pacific Northwest Region and Washington State Department of Ecology and updated to 2010 dollar values by HDR|DTA. Note that only the pumped storage related components are included here; other water supply cost components are excluded. See the 2007 final "Appraisal Evaluation of Columbia River Mainstem Off-Channel Storage Options" published by Reclamation for those complete costs.

Additional details for the proposed Project X1 are follows:

- This project is in close proximity to an existing FCRPS dam and existing high voltage substation and transmission facilities.
- This project can be categorized as a closed loop system with off-channel storage features.
- Project features were sized to accommodate a maximum 20-hour run duration suited to address daily peak demand fluctuations.

- Source water for this project would be extracted from the Columbia River under an established water right for initial project filling, by means of a permitted pump and intake facility. Additional make-up water required to offset seepage and evaporation losses would also be extracted from the Columbia River on an as-needed basis.
- On a unit cost-per-MW basis, this can be considered an attractive project comparable to many Northwest sites but with the added benefit of being in very close proximity to an existing, high voltage transmission corridor.

Similarly, with respect to Project X2, the following characteristics warrant mentioning:

- As conceived, this project entails a lake tap as the means to withdraw water from the lower reservoir which would be constructed without fish screen provisions.
- With a height of 780 feet, the proposed upper reservoir and dam would be an exceptionally large water storage facility, suited to long term, seasonal storage and much longer duration capacity and energy production.
- On the basis of unit cost per MW of capacity, this would be considered an attractive pumped storage project relative to other Northwest sites since it utilizes an existing lower reservoir and does have potential for multi-use nonpower benefits. It also should be noted that the final project configuration for a seasonal water supply project was substantial and increased the overall cost significantly (ref. the 2007 final appraisal report noted below).

With respect to the estimated capital costs for these projects, HDR has relied upon its extensive in-house pumped storage data base and basic methodology for estimating facility sizes and capital costs derived from a 1990 EPRI Pumped Storage Planning and Evaluation Guide (EPRI GS-6669, Project 1745-30) and public documents ("Appraisal Evaluation of Columbia River Mainstem Off-Channel Storage Options", 2007 U.S. Department of the Interior Bureau of Reclamation Pacific Northwest Region and Washington State Department of Ecology). Given the limited extent of new pumped storage project construction over the past 20 years, EPRI guidelines are considered to be a practical initial approach to estimating project costs where limited engineering effort has been expended. In addition to this guideline HDR|DTA has added engineering project estimating experience and treatment of escalation and contingency factors supplemented by current quotes and unit pricing for major equipment and basic construction materials. Varied contingencies were applied to the major cost categories of indirect costs (permitting, engineering, construction management, etc.), electro-mechanical equipment, and civil works to reflect the perceived uncertainties, risks, and commodity pricing volatility seen throughout world markets and the energy industry today. Contingency values may be considered extreme at this point and could reasonably be reduced through subsequent stages of advanced study and engineering refinement.

Several important conclusions can be drawn from this information. First, it is important to match project feature sizes to anticipated demand and duty cycles over both near and long term horizons. Next, expanded feature sizes, and particularly storage reservoirs, provide additional operating flexibility and capability to address extreme weather, climatic or emergency events.

5.0 Columbia Vista™ Modeling of Wind and Pumped Storage

BPA and HDR staffs were combined into a Joint Modeling Team (JMT) to model various pumped storage options to demonstrate the benefit of pumped storage for wind power integration in the BPA distribution area. The Columbia Vista (CV) model[1] is the tool used to evaluate the impact of pumped storage on meeting reserve requirements. The model was run under each scenario selected for this analysis utilizing a high (10 percent exceedance), median (also referred to as "normal", 50 percent exceedance) and low (90 percent exceedance) water year. This allows comparison between different hydrologic conditions using the same physical and operational constraints, and identifies critical periods of system reliability and seasonal reserve requirements for each type of water year.

Since 2005, BPA has utilized the CV model as a supplement to existing models and tools used for the short- and mid-term planning of FCRPS operations. In its current form, CV is used to provide a short-term forecast of inventory for power marketing and to provide scenarios which test any flexibility that may exist in the FCRPS over a two to three week period. For mid-term planning, CV is used along with existing models to assess the impacts of streamflow and operational uncertainty over a period of a few months. In addition, CV is used by real-time hydro schedulers in simulation mode to assist with real-time planning by the FCRPS.

It is important to note that although CV is the best available tool BPA has to perform this modeling work, the results of this analysis should be considered with some caution, because the CV model is not able to effectively model the impacts of the wind reserves on hydro systems operations. HDR/DTA considers this effort to be very preliminary and BPA is working to develop tools that more accurately assess wind reserves impacts on the FCRPS.

The CV model's short-term (ST) and long-term (LT) modules in auto mode using two- to six-hour time-steps were run to calculate a generation pattern integrating the Keys Pumping Plant and Banks Lake with the rest of the FCRPS. The ST module has an existing model node for Banks Lake and the Keys Pumping Plant that was used for constraint tuning and testing of how CV model logic implements operating constraints directly related to pumped storage operations. Areas of specific interest include:

- Interaction/scheduling results of pumping/generating and irrigation withdrawal requirements at Keys Pumping Plant and Banks Lake;
- Sensitivity of power pricing and market depth to conventional hydro and pumped storage dispatch; and
- Ability of pumped storage to absorb reserve requirements that would otherwise be held on the conventional hydro fleet.

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[1] The Vista DSS model software is a product of Hatch, Ltd. Vista DSS has been configured and the input data populated by Bonneville Power Administration staff to create Columbia Vista to represent the Power Operations of the FCRPS.

For the purposes of evaluating pumped storage for wind integration, CV water and generation balance modeling has focused on a "Big 10 plus Banks Lake" configuration, which simplifies modeling to the largest 10 dams on the Columbia River basin within the FCRPS (Grand Coulee and Chief Joseph Dams on the upper Columbia River, Lower Granite, Little Goose, Lower Monumental, and Ice Harbor Dams on the Snake River, and McNary, John Day, The Dalles, and Bonneville Dams on the lower Columbia River). The Banks Lake project was also included in the model immediately above Grand Coulee with appropriate links into Lake Roosevelt. The remaining generating resources in BPA's system are represented as "External Resources" to maintain a reasonably accurate balance of loads and resources in the model.

To absorb the variability of wind generation, the hydro system is being called upon to increase or decrease its generation instantly to offset the moment to moment fluctuations in wind power as well as make up for forecast/schedule errors. BPA's transmission group has estimated the amount of balancing reserves that are needed to maintain system reliability while adding the current levels of wind resources to the system and has projected the requirements of the future. The approximate reserve requirements associated with current and projected wind penetration levels are shown in Table 6. The balancing reserve requirements shown in the table below include the reserves needed for system load following and well as the wind variability.

Table 6. Projected Reserve Requirements for the BPA Balancing Authority – Existing and Future Wind Capacities

Calendar Year of Projection	Wind Generation Capability (MW)	Spinning Contingency Reserve (MW)	Non-Spinning Contingency Reserve (MW)	Regulation Down (MW)	Regulation Up (MW)
April 2010 (Current)	2,800	300	300	1,046	835
2013	6,200	300	300	1,847	1,404

The CV model does not explicitly model wind penetration; rather, it models the revenue impacts of increasing reserve requirements associated with the growth of wind generation in the BPA balancing authority. In order to develop a more accurate understanding of how large amounts of balancing reserves effect unit dispatch and the FCRPS's ability to meet hydraulic objectives, BPA is investigating new methodologies and enhancements to existing models. BPA is also examining case studies of actual wind and hydraulic conditions that have stressed the flexibility of the FCRPS. BPA will apply tools and knowledge acquired from these efforts to inform the development of any pumped storage project.

5.1 Scenario Modeling

Initial CV modeling focused on the potential benefits of modifying the existing Banks Lake development and the Keys Pumping Plant, by simulating present FCRPS operational constraints to the extent possible and running CV model scenarios to determine the benefits of various operating regimes. The CV model is being used to determine the benefits of including Keys Pumping Plant in the

FCRPS to meet operational and marketing objectives, and system reserve requirements. At the Keys Pumping Plant, upgraded pump and pump-turbine units, increases in efficiency, separated and automated pump startup, and BOP improvements can be modeled and have the potential to add value. Additionally, the Keys Pumping Plant and significantly expanded storage at Banks Lake were used as a proxy in the CV model for a new pumped storage project that would be dedicated to providing system reserves.

A set of modeling scenarios has been developed for the purpose of evaluating the resulting net revenue of the alternatives considered within this study.

CV Model Case 1: Existing Conditions (Equivalent to No Changes to Keys Pumping Plant)

***Assumptions**:* Existing operational and physical conditions for the FCRPS including Banks Lake and the Keys Pumping Plant. This case assumed that Banks Lake/Keys Pumping Plant is not dispatchable for reserves.

CV Model Case 2: Allow Modernized Keys Pumping Plant to Attempt to Meet Reserves (Equivalent to Keys Pumping Plant Base Case plus Option 1)

***Assumptions**:* No change to the physical conditions for the FCRPS, but assumes that the existing units (pumps and pump-generators) at the Keys Pumping Plant undergo general refurbishments and balance-of-plant upgrades required to allow regular and repeated dispatch of the Keys Pumping Plant units to meet reserves.

- Resulting Keys Pumping Plant motor capability: 600 MW (12 pumps @ 50 MW)
- Resulting Keys Pumping Plant generator capability: 300 MW (6 units @ 50 MW)

CV Model Case 3: Allow Upgraded Keys Pumping Plant to Attempt to Meet Reserves (Equivalent to Keys Pumping Plant Base Case plus Option 1 and Option 2 conditions with upgrades to Pump-generator Units 7 through 12 at Keys Pumping Plant, upgrading them to 60-MW single speed pump-turbines)

Assumptions: Carries reserve dispatching assumptions from Scenario 2; assumes that all Keys Pumping Plant units can be operated in parallel, 12 units in pumping mode and 6 units in generating mode (assumes no hydraulic restrictions in Feeder Canal).

- Resulting Keys Pumping Plant motor capability: 660 MW (6 pumps @ 50 MW, 6 pumps @ 60 MW)
- Resulting Keys Pumping Plant generator capability: 360 MW (6 generators @ 60 MW)

These three scenarios were modeled under the range of wind fleet capability and water-year types. Due to the run-time associated with the CV model under a sub-daily time-step, a limited amount of sensitivity runs were performed for this phase of study.

5.2 Operational Considerations and Revenue Impacts

Environmental concerns for fish, sensitive riparian reaches, recreation, and navigation constraints tend to smooth out the diurnal variation of flows (and subsequently power production), occasionally requiring BPA to purchase power in the higher-priced peak hours to meet load, and setting a relatively high minimum flow in the river as compared to the most economical operation of the hydropower resource. Holding downward reserves means that the FCRPS must have enough generation capacity operating at any time such that some of the generation could be backed off to make room for unscheduled wind generation. This further increases the minimum operating levels at the more flexible storage facilities, making less water available for power generation during peak use hours and limiting the overall flexibility and economic value of the hydropower resource.

In addition, during spring and early summer the stream flows of the Columbia River Basin reach their annual peak. In these peak flow conditions, it is fairly common that all available hydro units are operating at their full available capacity during the daylight hours (coinciding with peak electricity use) and often into the off-peak hours. This operating approach is necessary just to move water downstream without violating spill limits related to dissolved gas levels. The added upward reserve requirement effectively reduces the "full capacity" level of the system - limiting generation and increasing spill.

The same forces also reduce the economic potential of the FCRPS for marketing surplus power. Opportunities to time surplus energy into the higher priced on-peak hours are limited by the reserve requirements forcing generation into the lower priced light load hours to assure adequate downward reserves and limiting the ability to generate during on-peak hours to assure upward reserves. Accordingly, measuring the change in the modeled power market results is the simplest way to quantify the cost of integrating wind or, conversely, the value of pumped storage. The impacts of modifying hydro operations to temper the variability of wind generally include a reduction of efficiency in operations resulting in further overall reductions in hydro generation and less opportunity to leverage the on- and off-peak market price differential with surplus power.

Much of the FCRPS is a "must-run" hydropower system due to limitations on upstream storage and spill flows as a proportion of overall releases. As such, changes in operations due to both an increase in reserves carried and the variability of the hydro operations themselves (as reserves are utilized over the course of a day) may lead to additional challenges in meeting regulatory constraints on the Columbia River. The mandated spill requirements of the 2008 Biological Opinion also becomes more difficult to meet as the wind penetration increases. The spill requirements were modeled in these studies but the impacts have not been quantified here. All other things being held equal, the growing reserve requirement of the increasing wind capacity reduces the market potential of the FCRPS.

The CV model economic results are completely dependent on the market price assumptions as well as the market depth. In these studies the market depth was assumed to be large enough that system load could always be served and any surplus power could be sold in the market place. These assumptions allow the analysis to focus on the value of the Keys upgrades. Additional price and market sensitivity studies may be needed to complete the analysis.

The purpose of this study was to assess the economics of the various Keys Pumping Plant options using the CV model. In all cases providing water for irrigation at historical levels is given priority over providing system reserves.

The following table summarizes CV modeling results, showing the change in annual net revenue in a normal water year, measured relative to CV Model Case 1 and a 2800 MW wind fleet.

Table 7. Annual Revenue difference (in $ million) Relative to CV Model Case 1 and 2800 MW Wind Fleet, Normal Water

	CV Model Case 1	CV Model Case 2	CV Model Case 3
2800 MW Wind Fleet	0	3.9	11.2
6200 MW Wind Fleet	(14.3)	(14.0)	(1.8)

Looking first at CV Model Case 1, the decrease of $14.3 million net revenue shown in the above table is the result of the loss of flexibility due to the increased reserve requirement associated with the 6200 MW wind fleet. The additional balancing reserves limit the peaking capability of the FCRPS as well as raising the minimum generating levels at some plants. This impact forces some energy generation out of the higher priced on-peak hours into the lower priced off-peak hours causing a corresponding loss of revenue. Allowing the Keys Plant to provide some operating reserves (CV Model Case 2) provides some increase in revenue, indicating an increase in efficiency and overall flexibility on the conventional hydro system. Again, the impact of the reserves required to manage the 6200 MW causes a drop in net revenue due to loss of flexibility. In CV Model Case 3 the capacity of the six pump-generators at the Keys Pumping Plant is increased by 10 MW each – a direct increase in the flexibility of the overall hydro fleet. The increased capacity leads to an increase in the net revenue of $8.3 million over the general refurbishments of CV Model Case 2. This improved flexibility carries through to the 6200 MW wind fleet study offsetting much of the negative impact of the additional reserves shown in CV Model Case 1. Because the net revenue calculations shown are so sensitive to the price assumptions Table 8 is provided to show the quantity of energy that is moving in each of the study runs.

Table 8. FCRPS Generation by Load Period – All CV Modeled Scenarios

Wind Fleet Level and Water Year Type	CV Model Case	Heavy Load Hour Generation (aMW)	Light Load Hour Generation (aMW)
2,800 MW Wind Fleet Normal Water Year	CV Model Case 1 (Existing FCRPS)	9,282	5,683
	CV Model Case 2 (Allow Modernized Keys to Meet Reserves)	9,283	5,687
	CV Model Case 3 (Upgraded Keys P/G 7-12)	9,307	5,670
	Change in Average Generation (Case 3 vs. Case 1)	+25	-13
	Change in Average Generation (Case 3 vs. Case 2)	+24	-17
6,200 MW Wind Fleet Normal Water Year	CV Model Case 1 (Existing FCRPS)	8,981	5,986
	CV Model Case 2 (Allow Modernized Keys to Meet Reserves)	8,983	5,985
	CV Model Case 3 (Upgraded Keys P/G 7-12)	9,012	5,979
	Change in Average Generation (Case 3 vs. Case 1)	+31	-7
	Change in Average Generation (Case 3 vs. Case 2)	+29	-6
6,200 MW Wind Fleet Wet Water Year	CV Model Case 2 (Allow Modernized Keys to Meet Reserves)	10,532	7,906
	CV Model Case 3 (Upgraded Keys P/G 7-12)	10,612	7,896
	Change in Average Generation (Case 3 vs. Case 2)	+80	-10
6,200 MW Wind Fleet Dry Water Year	CV Model Case 2 (Allow Modernized Keys to Meet Reserves)	7,451	4,669
	CV Model Case 3 (Upgraded Keys P/G 7-12)	7,460	4,668
	Change in Average Generation (Case 3 vs. Case 2)	+9	-1

CV Model Cases 2 and 3 both show that, properly modernized and upgraded, the Keys Pumping Plant enhances the capability of the FCRPS to integrate wind, without adversely impacting the ability to provide irrigation water.

Figure 17 depicts the average annual diurnal shape of the Keys Pumping Plant operation with and without the upgraded pump-generator units. The figure demonstrates that the modeled operation of the existing Keys Pumping Plant compares very similarly to historical trends. The upgraded facility allows an operation that shifts more pumping to off-peak hours and less in on-peak hours. It is worthwhile to note that temporal arbitrage at Banks Lake/Keys Pumping Plant is not seen as a major source of revenue within the CV model. This can likely be explained by the relatively small heavy-load/light-load price ratio observed in the Northwest electricity market (due in large part to the flexibility of the existing hydropower resource). It is plausible that as wind penetration increases and the flexibility of the FCRPS operations diminishes, these price ratios could increase. This phenomenon would add to the revenue potential of refurbishment and/or upgrades to Keys Pumping Plant.

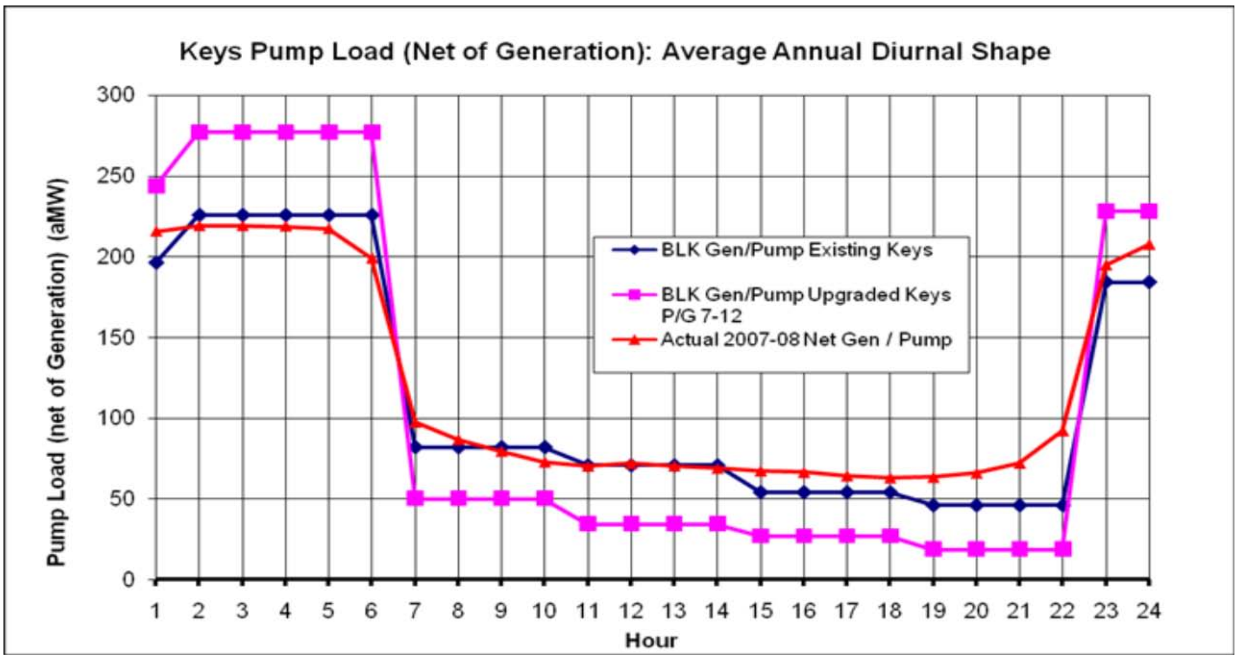

Figure 17. Keys Pumping Plant Powerhouse Average Diurnal Operating Pattern under 6,200 MW Wind Cases.

5.3 CV Modeling Conclusion

Initial FCRPS power operations modeling with Columbia Vista (CV) indicates that benefits for wind integration can be realized from operational modifications at the Keys Pumping Plant in conjunction with its storage reservoir at Banks Lake.

The CV model results demonstrate that:

- Keys Pumping Plant has the potential as a pumped storage project to reduce the costs associated with additional wind integration because of its ability to absorb reserve requirements that would otherwise be placed on the conventional hydropower fleet.
- Assuming the modernization and upgrades enable all of the pumps and pump generators to be able to be dispatched, the plant could provide from several hundred megawatts up to as much

as 900 MW of operating flexibility (the range of maximum pumping load to maximum generation capability, with 90% unit availability) depending on a variety of potential operating limits that could be placed on the units. The ability of the Keys Pumping Plant to provide operating flexibility for wind integration is dependent on its operating status, unit availability and the allocation of pumping resources to meet irrigation commitments. It is important to note that irrigation commitments and Banks Lake elevations can be factored into daily and seasonal operations schedule to optimize unit operations and maximize the potential reserve availability.

- There may be opportunities for incremental amounts of temporal arbitrage at Keys Pumping Plant under the existing Banks Lake operating restrictions if the heavy load/light load price ratios increase.
- Additional studies will be required to provide additional information based on more streamflow conditions and various price forecasts.

6.0 Energy Storage Plans, Costs, and Schedules

This section describes planning, estimated costs, and schedules necessary to implement the pumped storage options developed in Section 4 of this report. Those options include upgrading the Keys Pumping Plant and the potential development of one or more Project "X" pumped storage facilities. Implementation could range from a few years to ten to fifteen years required to study, permit, and construct one or more new large scale pumped storage projects. As increasing levels of variable renewable generation is installed in their balancing area, BPA has an increasing need for additional system reserves, which will grow significantly as more wind capacity is connected to the system. The need for variable energy integration support is grouped into three time-frame categories as follows:

6.1 Short-Term Options (implementation in less than five years)

- Operational changes to the Keys Pumping Plant to improve pump generation utilization factor.
- Minor facility refurbishment to improve unit reliability and availability, and realize early benefits of base-case implementation.
- Further study of the Feeder Canal hydraulics and the submerged overflow weir to improve flow capacity in the short term.

6.2 Medium-Term Options (implementation in five to ten years)

- Full implementation of the Keys Pumping Plant base case refurbishment and modernization.
- Decoupling pumps from the Left Powerhouse (Keys Pumping Plant Option 1).
- Pump-generator Units 7-12 single speed upgrades (Keys Pumping Plant Option 2).

6.3 Long-Term Options (implementation in more than 10 years)

- Partial conversion of Pumps 5 and 6 to variable speed (Keys Pumping Plant Option 3)
- Feeder Canal capacity increase by lowering and expanding canal
- Project X1 or X2

More detailed presentations of costs and schedules for various options associated with the Keys Pumping Plant upgrade can be found in HDR's report provided in Appendix C. Cost ranges for Project X1 and X2 are provided based on a high-level conceptual view and require further study to better define the facility, facility location, and potential costs.

Table 9 provides a summary option cost range and estimated years to implement or construct for the Keys Pumping Plant upgrade options and for Project "X". Full implementation of the Keys Pumping Plant base case refurbishment and modernization is considered a short- to medium-term support alternative, with incremental short-term benefits realized as the modernization process moves forward.

Table 9. Conceptual-Level Summary of Energy Storage Option Costs and Schedules

	Description	Implementation Schedule	Cost Range Incremental	Cost Range Cumulative
Short/Medium Term – Keys Pumping Plant	Operational procedures	2 to 5 years	$50-100 thousand	$50-100 thousand
	Base Case - refurbishment and modernization	7 to 9 years	$45-75 million	$45-75 million
	Option 1: Decouple pumps from left PH	7 to 9 years	$25-$35 million	$70-110 million
	Option 2: Single Speed Upgrade of P/G 7-12	8 to 10 years	$80-$120 million	$150-$230 million
	Option 3: Partial Variable Speed Conversion (P 5 & 6), Single-Speed Upgrade (P/G 7-12)	9 to 11 years	$1.0-1.5 billion	$1.2 - $1.7 billion
	Option 4: Complete unit conversion	10 to 15 years	$1.5-2.0 billion	$1.7-$2.3 billion
Long Term – Project X	Feasibility Studies – leading to development	3 to 5 years	$3 million	-
	FERC/Agency Licensing	4 to 7 years	$5-10 million	-
	Project Development X1	5 to 10 years	$2-3 billion	-
	Project Development X2	5 to 10 years	$2-3 billion*	-

*Pumped storage related component costs only.

Figures 18 through 20 depict estimated schedules for the Keys Pumping Plant Base Case, Options 1 and 2 Upgrades, and developing a new Project X. What is not represented in these figures are the immediate benefits of making operational changes to the Keys Pumping Plant and the incremental benefits that occur during implementation of the Base Case steps.

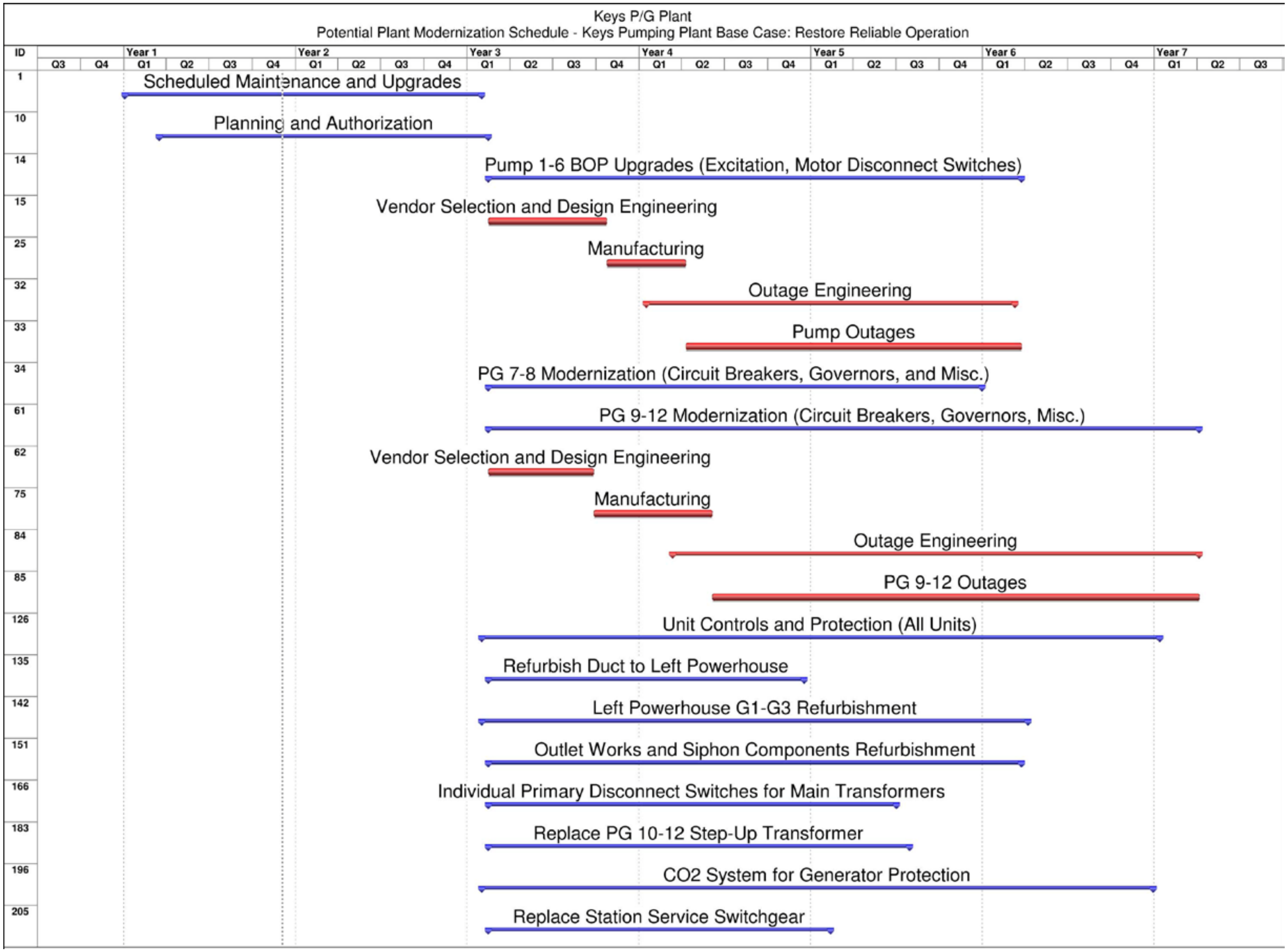

Figure 18. Keys Pumping Plant Base Case Refurbish and Modernization Schedule (Source: HDR|DTA)

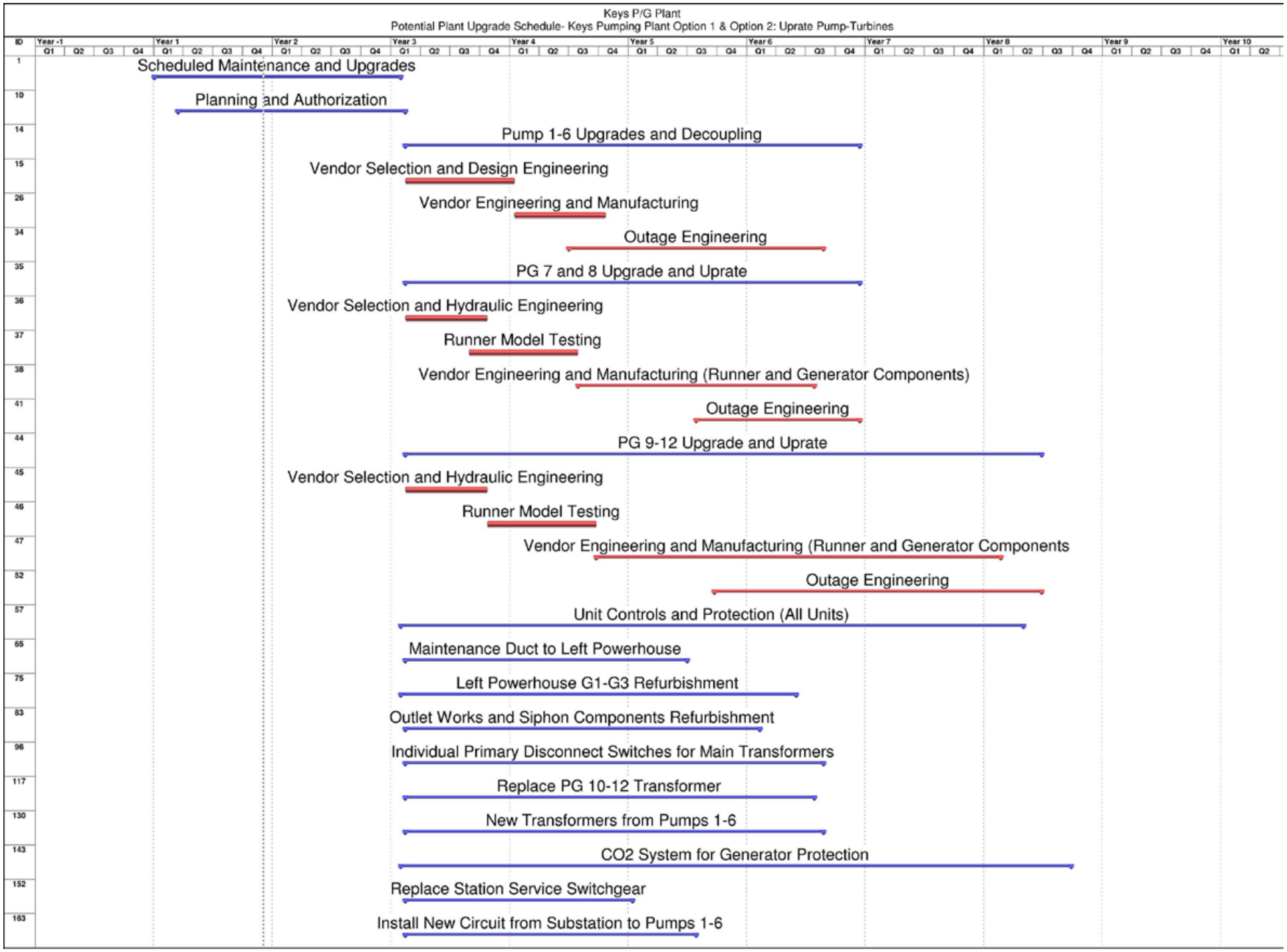

Figure 19. Keys Pumping Plant Option 1 and Option 2 Upgrade Schedule (Source: HDR|DTA)

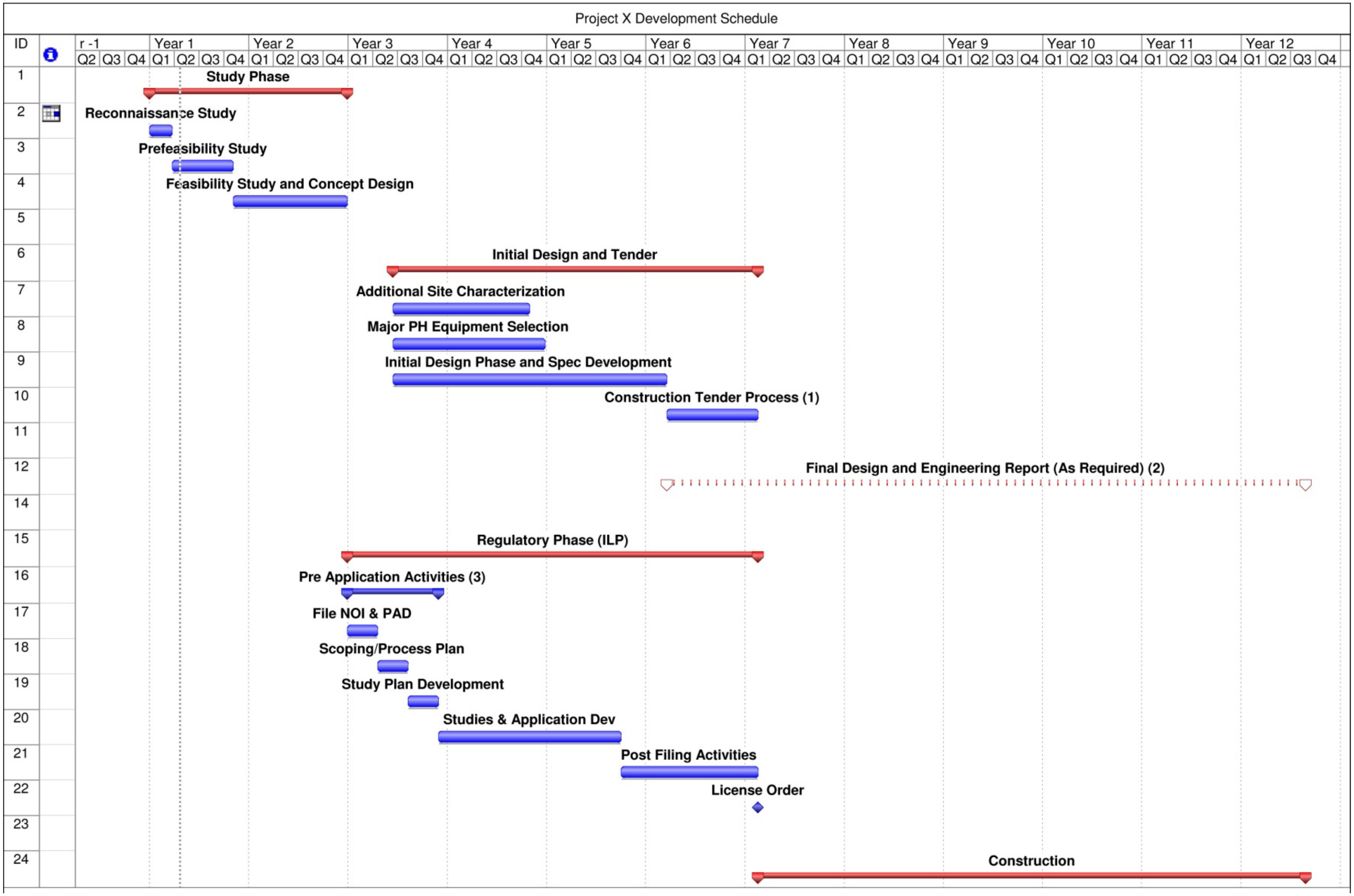

Figure 20. Project X Development Schedule (Source: HDR|DTA)

7.0 Risk Analysis for Adding System Reserves

Identifying, analyzing, and reducing risk, while maximizing benefits will be critical to successfully enabling greater penetration of variable energy into the BPA system. Such a process has been successfully applied to other large projects, including pumped storage refurbishment and several planned new pumped storage facilities. A qualitative risk and benefit analysis is being performed for the various options included in the short-, medium-, and long-term plans, including the following:

- Technical feasibility
- Project reliability
- System support (meeting operational needs)
- Cost assumptions and estimate ranges
- Implementation schedule ranges

7.1 Environmental Risk

Reclamation is the federal agency that oversees the Columbia Basin Project including operations of Grand Coulee, Banks Lake and related features. As a federal agency, Reclamation is required to comply with the National Environmental Policy Act (NEPA).

Reclamation is currently in the process of updating its agency-wide implementation guidance (i.e., NEPA Handbook). A portion of the handbook is expected to outline Reclamation actions that constitute a Categorical Exclusion (i.e., no range of alternatives/detailed documentation) as well as what agency actions constitute the process and preparation of an Environmental Impact Statement.

The current Department of Interior 516 DM14 (NEPA) states that the following Reclamation actions would be considered Categorical Exclusions:

> 14.5 C (3). Minor construction activities associated with authorized projects which correct unsatisfactory environmental conditions or which merely augment or supplement, or are enclosed within existing facilities.
> 14.5 D (1). Maintenance, rehabilitation, and replacement of existing facilities within may involve a minor change in size, location and/or operations.

Conversely, the same manual outlines Reclamation actions that would necessitate an EIS:

> 14.4 A (4). Proposed modifications to existing projects or proposed changes in the programmed operation of an existing project that may cause a significant new impact.

Ultimately, Reclamation will determine whether the potential upgrade options described meet any Categorical Exclusion, or necessitate preparation of an environmental assessment or impact statement. It should be noted that Reclamation did prepare an EIS in 2004 to evaluate the drawdown of water to support fish flows downstream of Grand Coulee in response to the 2000 Federal Columbia River Power System Biological Opinion, issued by the National Marine Fisheries Service.

The EIS evaluated the following two alternatives:

1. **No Action Alternative** (i.e., current operations): Water surface elevation ranges from 1,570 feet (approx. normal pool) to 1,565 feet between August 1 and September 22.
2. **Action Alternative**: Water surface ranges from 1,570 feet to 1,560 feet between August 1 and September 22.

In both alternatives, it appears that Reclamation would still have discretion to manage the lake level to other elevations for authorized purposes. In addition, according to the EIS, Banks Lake is authorized to operate between the full pool water surface elevation of 1,570 feet and a minimal water surface elevation of 1,545 feet at any time of the year.

The EIS summary of the environmental consequences of drawing down Banks Lake elevation to 1,560 feet is indicated in the following table.

Table 10. Summary of Environmental Consequences of Banks Elevation Alternatives

Affected Resource	No Action (i.e., Current Operations)	Action Alternative (i.e., Drawdown to 1,560 feet)
Fish, Vegetation, and Wildlife	Abundance and distribution continue to fluctuate with seasonal water levels, but overall stable.	Distribution and abundance impacted by more severe water level fluctuations.
T&E Species	Abundance and distribution continue to be limited by available habitat.	Fish prey may be more available to bald eagles. Although incrementally small, the 6 percent contribution adds to the total cumulative benefits of flow augmentation for salmon.
Recreation	7 of 12 boat launches are exposed and rendered unusable during the late recreation season (elevation 1,565).	10 of 12 boat launches are exposed and rendered unusable at elevation 1,562. Impacts to communities and businesses adjacent to the reservoir may be greater until users become accustomed to the greater fluctuation of the water surface. No launches on the southern half of Banks Lake would be usable. Steamboat Rock State Park (approx. 600,000 visitors annually) would not have a usable launch at elevation 1,562.
Historic Resources	Same as historically. Eighty-two historical properties appear to be affected from erosion.	Surveys would be conducted in the drawdown zone between elevations 1,570 and 1,560.
Traditional Cultural Properties	Same as historically. Nine TCPs would be affected; three are believed to be eligible to National Register.	It is probable that more TCPs lie in drawdown area below elevation 1,565 feet.
Surface Water Quality	Temperature and stratification will continue to change with changes in water elevation and meteorological conditions.	Mixing may shift 1 or 2 weeks earlier in the fall due to greater mixing and heating of the lake surface.
Visual Quality	Approximately 1,300 acres of an unvegetated bathtub ring between elevations 1,565 and 1,570 feet.	Approximately 2,500 acres of an unvegetated bathtub ring between elevations 1,570 and 1,560 feet.
Social Values	For some, as operation of Banks Lake will not change, values will not be affected. For others who value increased water for endangered salmon runs, their values will not be upheld.	The values of those who desire increased water for endangered salmon runs will be upheld. The values of those desiring higher lake levels would not be upheld.
Public Health	Lake drawdowns in late summer likely have negative impacts to mosquito production, resulting in lesser likelihood of mosquito borne disease, such as West Nile Virus.	In the drawdown area, little or no shallow ponding areas were evident for mosquito use. Therefore, little likelihood of additional risk of mosquito-borne disease, such as the West Nile Virus.

(Reference: Banks Lake Drawdown: Final Environmental Impact Statement, Department of Interior, May 2004.)

Past operational experiences have led to operating protocols being developed that require one hour of time to pass after cessation of pumping operations before the initiation of generation operations. The reasoning behind this is also being investigated by Reclamation. Initial thoughts are that this may be attributable to the favorable feeding conditions created by the influx of Columbia River water causing an unusually high concentration of fish at the outlet of the canal, shock from sudden temperature changes, or other factors created by rapid changes in the flow and water quality.

It is HDR|DTA's understanding that Reclamation may already be conducting the needed review to determine the species and life stages of interest and associated behavioral responses, and will also be meeting with the state and federal resource agencies to determine agency requirements. BPA and Reclamation may consider a separate study to identify fish species of interest and associated life stages that are present in the Banks Lake and specifically within the feeder canal. This study could also discuss level and type of protection, if needed, that the resource agencies may require for pumped storage changes in operation.

Ultimately it is up to Reclamation to decide how to implement NEPA for the proposed action (i.e., modify operations for pumped storage).

7.2 Technical Risk

Project risk assessment has become a discipline of its own, involving the complex and sometimes controversial process of evaluating the hazards of various technologies, engineering designs, construction methods, cost estimating based on historical information to predict future costs, and developing appropriate controls to manage risk to an acceptable level. Questions arise on how to quantify risk and who is the arbiter on what levels of risk are acceptable. For the context of this review, a qualitative discussion of risk for various areas identified above is presented, with an overall scale of risk (low, medium, and high) assigned based on previous experience performing similar engineering and construction activities.

Within the Keys Pumping Plant Summary Assessment (Appendix C) report is a discussion of the qualitative technical risks associated with the various options presented. A summary of that discussion is provided in Table 11, Qualitative Risk Level Assessment for Alternatives. In general, the work for the Base Case and Option 1 can be considered low risk options with regard to each criterion judged. This work would be common industry practice with many vendors available to perform this type of design and installation, allowing a competitive process to minimize cost and schedule risks.

Table 11. Qualitative Risk Level Assessment for Alternatives

		Cost Estimating	Schedule	Reliability	System	Feasibility
Keys Pumping Plant Upgrades	Base Case – Refurbishment and Modernization	Low Risk	Low Risk	Low Risk	Low Risk	Low Risk
	Option 1: Decoupling Pumps from Left Powerhouse	Low Risk	Low Risk	Low Risk	Low Risk	Low Risk
	Option 2: Single Speed Upgrade of Pump-Generators 7-12	Medium Risk	Medium Risk	Low Risk	Low Risk	Low Risk
	Option 3: Partial Variable Pump-Generator Conversion and Pump-Generator Upgrade	High Risk	High Risk	Low Risk	Medium Risk	Low Risk
	Option 4: Complete Variable Speed Pump-Generator Conversion	High Risk	High Risk	Medium Risk	Medium Risk	Medium Risk
	Feeder Capacity Increase	Medium Risk	Medium Risk	Medium Risk	Medium Risk	Medium Risk
Project X	Feasibility Study					
	Developing Project X1	Medium	Medium	Medium	Medium	Medium
	Developing Project X2	Medium	Medium	Medium	Medium	High*

*Project X2 is rated at higher feasibility risk due to utilizing an existing Columbia River reservoir as the lower reservoir for the proposed pumped storage project.

With regard to converting the existing Keys Pumping Plant pumps or pump-generators to variable speed pump-generators, this is a unique and technically challenging process. Though much of the technology that would be used in this conversion process is mature, and can be found in new variable speed machines, there has been little activity in converting existing units to variable speed units, with the only example being a much larger unit than those that exist at the Keys Pumping Plant. Due to the relative R&D nature and associated risk of variable speed pump generators, this option is not recommended at this time.

With regard to a new Project X development, the lengthy regulatory and environmental permitting process would involve potential schedule risk since there are so many stakeholders engaged in the process. However, the geotechnical risk associated with the water-conveyance tunnels and underground powerhouse represent the single biggest unknown for the project. This risk would be mitigated via a well-planned subsurface investigation program during the feasibility-study stage of the project. The uncertainty of any single project being brought to full development would be considered high without further study, but this risk and development uncertainty could be reduced. To reduce the overall risk of a Project X development, initially pursuing and studying multiple project sites for potential development is recommended, while only fully developing those few sites, or the one site, which ultimately would meet the needs of BPA. Once the necessary permitting and environmental reviews for any site were completed, development risk would be considered medium to low, given the industry experience with development of hydroelectric facilities.

8.0 Economic Analysis

Summary

As of January 2010, the FCRPS hydro system is providing balancing reserves to integrate approximately 2,800 MW of wind capacity. As the FCRPS reaches its limit to provide additional balancing reserves, integration services will, by necessity, have to be provided by other sources. This section looks at the cost of providing the next increments of wind integration services from two pumped storage alternatives: refurbishment of the Keys Pumping Plant and a new Project X.

BPA's annual cost of providing wind balancing reserves for 3,053 MW of installed wind capacity is $47,409,887, as referenced in the *2010 BPA Rate Case Wholesale Rate Final Proposal, Generation Inputs Study* dated July 2009. The corresponding Wind Balancing Service Rate charged to all installed wind capacity is $1.29/kW/month. For this wind capacity, BPA supplies 585 MW of balancing reserves at a cost of $6.75/kW/month. The cost of providing balancing reserves for the next increment of wind capacity into BPA's balancing area by refurbishing the Keys Pumping Plant is estimated to be similar to the current cost of providing balancing reserves for wind with the existing hydro system. Balancing reserve costs provided by a new Project X would be much higher.

Refurbishing the Keys Pumping Plant with six 60-MW single-speed units is estimated to cost approximately $270 million (inclusive of required life extension work for the station balance-of-plant systems). First-year revenue requirements for capital recovery, operations and maintenance, and energy losses associated with deployment for wind balancing reserves are estimated at $29 million, or about $8.00/kW/month in 2010 dollars.

A new, publicly financed 1,000 MW Project X plant is estimated to cost $2 billion, with a first-year revenue requirement of $199 million, or about $19.50/kW/month, both in 2010 dollars. Incremental transmission costs to accommodate pumped storage are not estimated in this study, although such costs are not expected to significantly increase the cost of providing wind balance reserves from a refurbished Keys Pumping Plant. Transmission costs for a new Project X could be much higher and would depend on location and other factors.

While there is some potential for incremental benefit from energy arbitrage, that benefit is forecasted to be only about one percent of total revenue requirements.

8.1 Introduction

BPA currently integrates wind with the existing hydro system. As noted in BPA's 2009 Draft Resource Program, the system is at or near its capacity to provide wind balancing reserves; therefore other resources will soon be needed to integrate higher levels of wind penetration. The primary purpose of this analysis is to determine the cost (in terms of revenue requirements) of providing incremental system reserves with pumped storage to enable greater penetration and integration of variable renewables, primarily wind.

For this analysis, two pumped storage project options are evaluated: Refurbishment of the Keys Pumping Plant, which is near end-of-life, and the construction of Project X, a new 1,000 MW pumped storage project. Each project would be dedicated to supplementing wind balancing reserves provided by the existing hydro system and could possibly provide additional benefit in the form of time-of-day energy arbitrage.

The two project alternatives are evaluated against several financing assumptions. For the Keys Pumping Plant, it is assumed BPA would finance refurbishment at its Treasury borrowing rate of 6.75 percent. A case is also run assuming financing at BPA's internal rate of return threshold of 12.00 percent in order to establish a proxy for the "benefit" that would be needed to compare the Keys Pumping Plant with other power investment alternatives considered by BPA. For the Project X alternative, two financing assumptions are considered. The first assumes third party tax exempt financing at 5.25 percent. The second assumes third party taxable financing with a debt/equity ratio of 60/40, 7.00 percent debt rate, and 14.00 percent equity rate.

In addition to the costs to build and maintain pumped storage, energy losses are incurred when pumped storage reserves are called upon. Pumped storage deployment costs are estimated using analysis similar to that for BPA's 2010 Rate Case "Generation Inputs Study."

Incremental transmission costs attributable to pumped storage options are not estimated in this study. Because the Keys Pumping Plant already exists with 300 MW of generating capability, increasing generation to 360 MW is not expected to require significant upgrades to the transmission system in order to accommodate the increase in capacity. Consequently, the cost of providing wind balancing reserves with the Keys Pumping Plant is not expected to be much higher than those shown here if the costs of transmission system improvements are included. A new Project X could require significant transmission system upgrades or additions so associated reserve costs could be much higher.

A preliminary analysis of energy arbitrage opportunities and possible offsets to these revenue requirements is also investigated.

This analysis does not compare the cost of providing incremental wind balancing reserves from pumped storage to that from other technologies.

8.2 Alternatives Considered

Two project alternatives and four financing scenarios are considered in this analysis. All scenarios assume 2 years of planning and 5 years of construction, similar to the schedule for Option 2 in Table 4 of Section 4.3. Alternatives considered are:

1. Modernize and upgrade the Keys Pumping Plant (Six single speed 60 MW units) = 360 MW capacity
    a. Modernization and upgrades contracted for and managed by Reclamation and financed by BPA at its Treasury borrowing rate of 6.75 percent.

   b. Modernization and upgrades contracted for and managed by Reclamation and financed at BPA's internal rate of return threshold of 12.00 percent. This is not a real financing alternative, but is included here to estimate a "benefit" threshold that would be needed to compare a modernized and upgraded Keys Pumping Plant with other power investment alternatives considered by BPA.
2. Project X (Four single speed 250 MW units) = 1,000 MW capacity
   a. Construction contracted for by a tax exempt third party (e.g., a Public Utility District or PUD partner) where BPA would back the debt. The assumed debt rate is 5.25 percent.
   b. Construction contracted for by a taxable third party (e.g., an Independent Power Producer) with a debt/equity ratio of 60/40, 7.00 percent debt rate and 14.00 percent equity rate. This, too, would be backed by BPA.

8.3 Approach

The estimated revenue requirements derived in this study are those necessary for BPA to recover costs associated with providing wind balancing reserves from the identified pumped storage alternatives for higher levels of wind penetration.

Annual costs to recover capital investment, operations, and maintenance requirements are estimated using *Microfin*, a model developed by BPA and further enhanced by the Northwest Power and Conservation Council. *Microfin* takes a set of plant characteristics, operating parameters, financial assumptions, and tax treatments and develops annual revenue requirements to include in a rate base.
In addition to capital recovery, operations, and maintenance costs, pumped storage would incur costs for resource deployment when operated for reserves. These deployment costs represent the value of lost energy associated with pumping and generating cycles when providing decremental and incremental balancing reserves. Deployment costs derived in this study are based on incremental levels of wind penetration and the resulting deployment of incremental and decremental energy from BPA's *2010 BPA Rate Case Wholesale Power Rate Final Proposal, Generation Inputs Study* valued at BPA's 2010 Rate Case long-term forward price forecast, as provided by BPA.

The costs derived from *Microfin* runs plus the costs for reserve deployment comprise the revenue requirement for providing wind balancing reserves from pumped storage. (Revenue requirements associated with incremental transmission system costs for pumped storage are not estimated in this study.) This revenue requirement is then used to estimate a marginal wind balancing reserve cost for higher increments of wind penetration.

An analysis is also done to estimate the potential for energy arbitrage benefit when the price spread between heavy load and light load periods is high enough to warrant incurring energy losses from the pump/generation cycle.

8.4 Costs

8.4.1 Capital Cost

The cost of construction was developed by HDR|DTA using its cost models, market information, and information from comparable projects.

For this analysis, HDR/DTA derived costs for two projects:

1. Keys Pumping Plant modernization and upgrade: 360 MW of pump/generating capacity.

   Keys Pumping Plant modernization and upgrades would involve modernizing balance-of-plant systems and replacing six original 50 MW pump-turbines with six new single speed 60 MW pump-turbines. The estimated median capital cost of the new units, including the modernizing balance-of-plant systems and other life extension scope of work, is approximately $270 million, or $750 per installed kilowatt.

2. Project X: 1,000 MW Greenfield site

   Project X would include a closed loop system with reservoir capacity to support a 20-hour generation run time as previously described in Section 4.4 of this report. The project would consist of four single-speed 250 MW pump turbines with relatively short water passage tunnels and small upper and lower reservoirs. The estimated median capital cost for this project is approximately $2 billion, or $2,000 per installed kilowatt.

8.4.2 Normalized O&M Costs

Normalized O&M costs were estimated using data from comparable pumped storage projects. Normalized O&M costs included in the revenue requirement calculation are comprised of costs for annual operation and maintenance, bi-annual inspection of each unit, and turbine overhaul and generator rewind of each unit every 20 years.

The normalized O&M cost for the Keys Pumping Plant is estimated at $6.6 million per year, or $18.45 per installed kW per year. For Project X, the normalized O&M cost is estimated at $11.2 million per year, or $11.20 per installed kW per year. Normalized O&M costs are assumed to increase at a 1.7 percent rate of inflation.

In addition to normalized O&M costs, Project X, when contracted for by a taxable third party, would be subject to federal and state income taxes. These income taxes are added to the normalized O&M costs in "Other Fixed Costs" results summarized in Section 8.5.

8.4.3 Capital and O&M Cost Summary

Table 12 summarizes the median estimates of capital and O&M related costs associated with the two pumped storage alternatives:

Table 12. Keys Pumping Plant and Project X Capital and O&M Costs (2010 Dollars)

	Plant Size (MW)	# Units	Capital Cost ($000)	Capital Cost ($/kW)	Annual O&M ($000)	Bi-Annual Inspection ($000/station)	20-Year Overhaul & Rewind ($000/station)	Annual Normalized O&M ($/kW)
Keys Pumping Plant - Single Speed	360	6	270,000	750	4,860	270	3,240	18.45
Project X - Single Speed	1,000	4	2,000,000	2,000	9,000	500	6,000	11.20

8.4.4 Deployment Costs

Deployment costs are a function of efficiency losses incurred when operating pumped storage for wind balancing reserves. Average losses for the pumping cycle are estimated at 11.4 percent for both the Keys Pumping Plant and Project X. Average losses for the generating cycle are estimated at 10.6 percent for both plants. Additional losses for regulation services are also incurred when operating units away from peak efficiency points, but are excluded in this proof of concept study for simplification reasons.

Analyses similar to the 2010 Generation Inputs Study were used to estimate the amount of deployment energy attributable to pumped storage. In that study, the incremental reserve requirement from 3,000 MW to 4,000 MW of wind penetration was calculated to be about 310 MW for both incremental and decremental reserves, about the amount that could be provided by the modernized and upgraded Keys Pumping Plant at an average plant availability of 85 percent. The corresponding amount of heavy load hour and light load hour incremental and decremental deployment energy for calling on that reserve amount was also identified in the rate case study.

For this analysis, deployment energy was assumed to be either generated by the Keys Pumping Plant to provide incremental reserve energy or pumped by the Keys Pumping Plant to provide decremental reserve energy. Energy losses incurred by the reserve deployment were calculated at the loss rates identified above, then valued at BPA's long-term energy price forecast to derive deployment costs for the Keys Pumping Plant. These deployment costs were added to other costs identified in Section 8.4 to derive an estimated total revenue requirement and marginal wind balancing reserve cost for the next increment of wind penetration.

The results of the deployment analysis for the Keys Pumping Plant were then scaled up for Project X at a ratio based on plant capacity.

8.5 Cost Analysis Results

Table 13 shows a summary of estimated first-year revenue requirements and marginal wind balancing reserve costs for the two proposed pumped storage alternatives.

Table 13. Estimated First-Year Revenue Requirement and Marginal Wind Balancing Reserve Cost (2010 Dollars)

	Keys Pumping Plant - BPA Treasury Rate of 6.75%	Keys Pumping Plant - BPA Risk Adjusted Rate of 12%	Project X - Third-Party Tax Exempt 5.25%	Project X - Third-Party Taxable 60/40 D/E @ 7.0%/14.0%
First-year Revenue Requirement ($millions)	29.2	47.2	198.7	337.5
Capital Recovery	20.8	38.8	182.4	295.6
Other Fixed Costs	6.6	6.6	11.2	36.9
Balancing Reserve Deployment	1.8	1.8	5.1	5.1
First-year $/kW/month	7.96	12.86	19.48	33.09
Capital Recovery	5.66	10.56	17.88	28.98
Other Fixed Costs	1.81	1.81	1.10	3.62
Balancing Reserve Deployment	0.50	0.50	0.50	0.50

Notes:

- D/E = debt/equity ratio
- Federal Income Tax
  - Federal Income Tax Rate: 34 percent
  - Federal Investment Tax Credit: 0 percent
  - Fraction of ITC Deducted From Tax Basis: 50 percent
  - MACRS Recovery Period: 20
- State Taxes
  - State Income Tax Rate: 3.7%
  - State Investment Credit: 0%
- Property Tax: 1.4%
- Municipal Bond Term: 50 years
- Financial Life: 50 years
- Debt Financing Fees: 2% (of debt placed)
- Inflation Rate: 1.7%
- Other Fixed Costs include normalized O&M and, in the Project X taxable financing scenario, income taxes.

Figure 21 shows a graphical representation of the estimated marginal wind balancing reserve cost for the four scenarios considered.

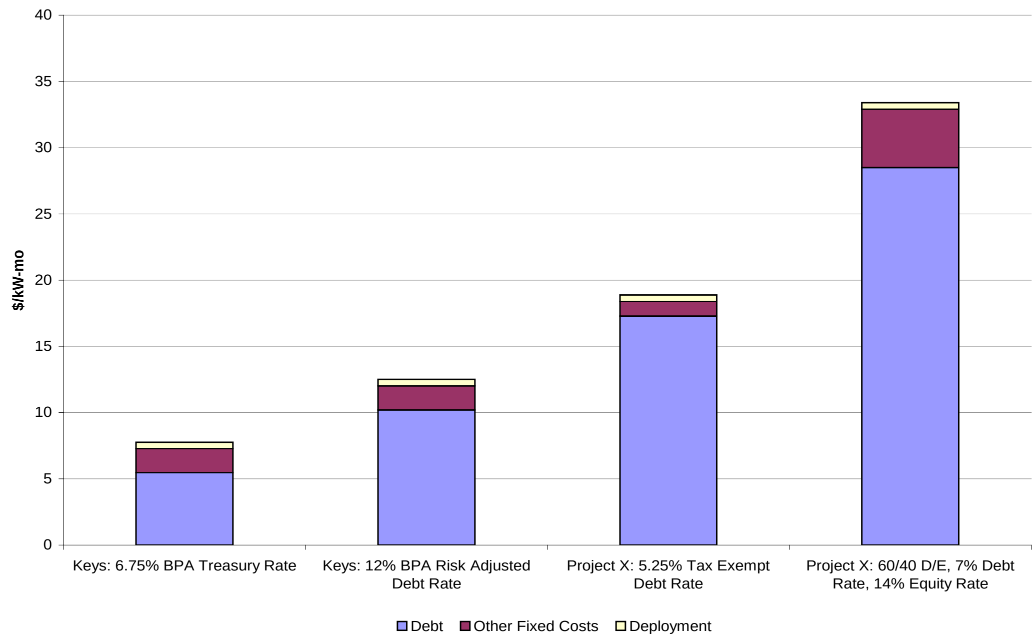

Figure 21. Estimated Wind Balancing Reserve Cost for Pumped Storage Alternatives (2010 Dollars)

Figure 22 compares the current wind balancing reserve cost of $6.75/kW/month to an estimated cost for the Keys Pumping Plant with BPA Treasury financing at 6.75 percent and Project X assuming financing at a tax exempt rate of 5.25 percent. The figure shows that the marginal cost of integrating the next increment of wind with the Keys Pumping Plant would be somewhat higher than the cost incurred by the FCRPS hydro system. The marginal cost would be much higher if based on Project X.

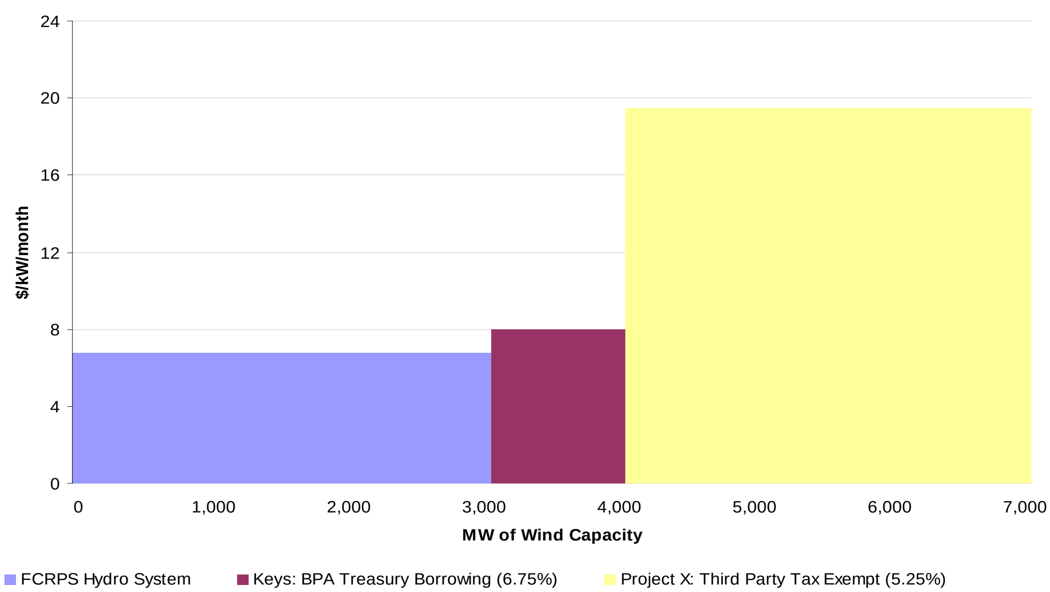

Figure 22. Estimated Marginal Wind Balancing Reserve Cost for Additional Increments of Wind Penetration (2010 Dollars)

8.6 Peak/Off-Peak Arbitrage Value

BPA's 2010 Rate Case long-term price forecast was used to estimate the potential for additional value from energy arbitrage. A pump generation cycle efficiency was calculated for an arbitrage operation using the efficiency losses shown in Section 8.4.4. The average efficiency is estimated to be 78.9 percent for a pump/generation cycle at the Keys Pumping Plant. The same cycle efficiency was assumed for Project X, although it is expected that Project X would have somewhat higher efficiency. Next, a HLH/LLH price ratio was calculated for each month in the long-term price forecast. For those months when the price ratio exceeds 1/(cycle efficiency), an opportunity exists for a net financial gain from energy arbitrage. For those months where a net gain was positive, it was assumed that generation during HLH was possible for eight hours per day, six days per week, an optimistic assumption used to estimate a high side potential for arbitrage value.

The long-term forecast includes energy prices for 2009 through 2028. This entire period was used for estimating arbitrage value even though the commercial operation date for the pumped storage alternatives would be much later than 2009. The purpose of this arbitrage analysis is to estimate the potential for arbitrage net benefit inherent in BPA's long-term price forecast, so using energy prices for dates prior to the commercial operation date, while technically incorrect, is still useful for estimating this value. Estimated month by month arbitrage net gain in dollars per megawatt-hour of generation from a pump-generator is shown in Figure 23.

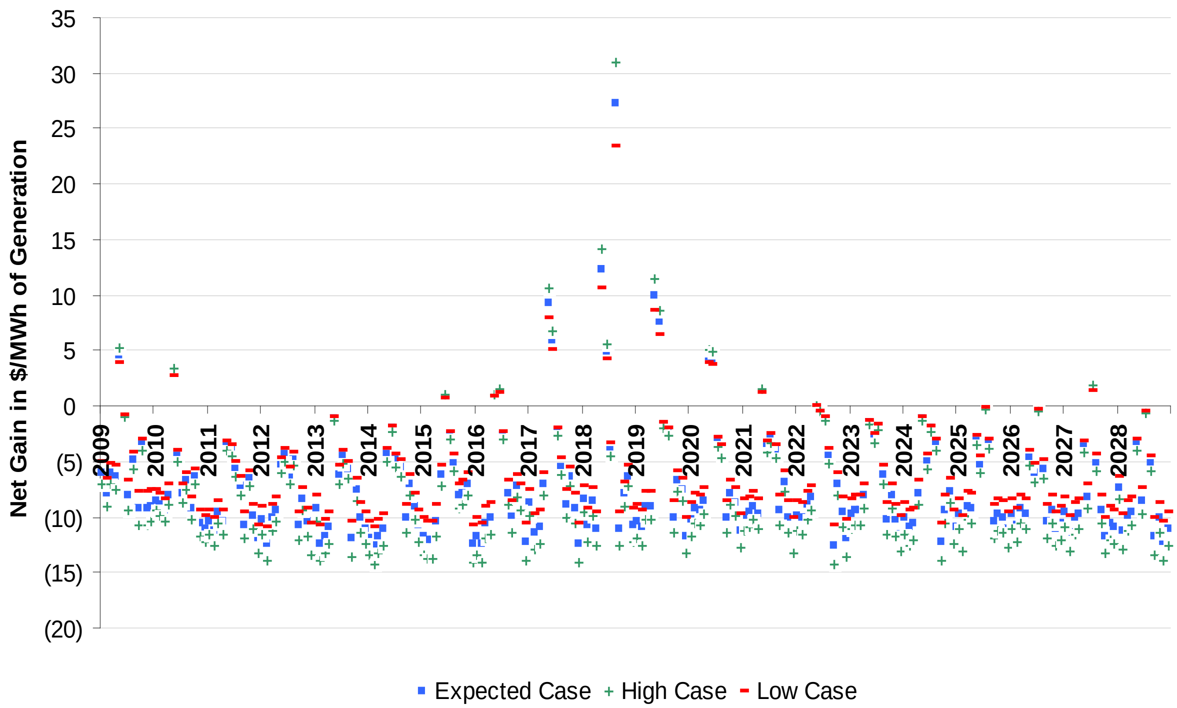

Figure 23. Potential Energy Arbitrage Net Gain after Efficiency Losses (2010 Dollars)

In the majority of months, the net gain in dollars per MW-hour of generation from an arbitrage cycle would be negative. In a few instances, the net gain could exceed $10 per MW-hour. In all, less than 10 percent of the months are estimated to be economically beneficial for energy arbitrage.

Figure 24 shows the cumulative net gain for pumped storage if it is operated for energy arbitrage only when it is economically beneficial. The cumulative net gain would be less than $20,000 per available MW (2010 dollars) over a 20-year period, or about $1,000 per available MW per year. For the Keys Pumping Plant, at 360 MW of capacity and 85 percent availability, this is equivalent to about $300,000 per year in 2010 dollars, only about one percent of the annual revenue requirement. For Project X, the potential is about $850,000 per year, or one half of one percent of the revenue requirement. This analysis suggests that energy arbitrage benefits are unlikely to reduce the cost of providing wind balancing reserves from pumped storage.

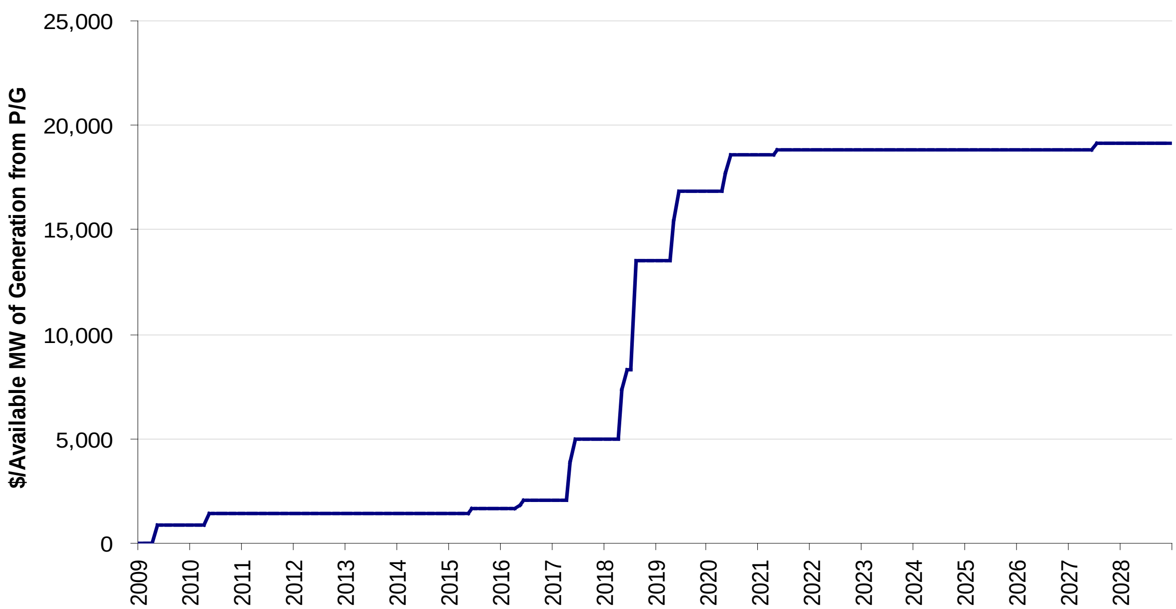

Figure 24. Estimated Cumulative Net Gain from Energy Arbitrage (2010 Dollars)

8.7 Economic Analysis Conclusions

The existing hydro system is now at or near full capacity to provide balancing reserves for current levels of wind generation interconnected to the BPA balancing area. Additional wind balancing reserves will need to come from other sources, possibly pumped storage.

This analysis looks at the cost of providing wind balancing reserves for the next increments of wind into BPA's system with two pumped storage alternatives: a modernized and upgraded Keys Pumping Plant at Grand Coulee, and a hypothetical 1,000 MW Project X located somewhere in the Pacific Northwest. The cost of providing balancing reserves for the next increment of wind with the Keys Pumping Plant is not expected to be significantly higher than the current cost of $6.75/kW/month using the existing flexibility of the hydro system. The cost of providing wind balancing reserves from Project X would be significantly higher.

At BPA's Treasury borrowing rate of 6.75 percent, the Keys Pumping Plant would have a first-year annual revenue requirement of about $29 million for capital recovery, O&M, periodic overhauls, and reserve deployment costs. The estimated marginal wind balancing reserve cost is about $8.00/kW/month. At a weighted cost of capital of 12.00 percent – BPA's internal rate of return for power investments – the estimated marginal wind balancing reserve cost is about $12.90/kW/month. All costs are expressed in 2010 dollars.

Providing balancing reserves for higher levels of wind with Project X will have a higher cost. Project X has a first-year revenue requirement of $199 million at a third-party tax exempt financing rate of 5.25 percent, for an estimated marginal wind balancing reserve cost of about $19.50/kW/month. If Project X is built and financed by a third party seeking a return on equity, first-year revenue requirements are estimated to be significantly higher, about $338 million. The resulting marginal wind balancing cost is about $33.10/kW/month. Again, all costs are in 2010 dollars.

Incremental transmission costs to accommodate pumped storage are not estimated in this study; although such costs are not expected to significantly increase the cost of providing wind balance reserves from a modernized and upgraded Keys Pumping Plant. Transmission costs for a new Project X could be much higher and would depend on location and other factors.

Arbitrage of the peak/off-peak price differential has some potential to lower the cost of providing wind balancing reserves with pumped storage, although at BPA's 2010 Rate Case long-term price forecast, the contribution would be insignificant, about one percent of total revenue requirements.

9.0 Energy Storage Conclusions

Bonneville Power Administration's (BPA) ability to operate its balancing authority safely, reliably, and economically while complying with the Federal Columbia River Power System's (FCRPS) mandated non-power obligations is being challenged. The adoption of Renewable Portfolio Standards (RPS) in most states within BPA's power system is driving the development and interconnection of the greatest penetration of variable wind generation in North America, and possibly the largest percentage in the world. Since 1998, BPA has seen wind power develop from 25 MW to an installed capacity of approximately 2,800 MW as of January 2010. As wind generators continue to be installed in the region, an estimated capacity of 6,000 MW of variable wind energy is expected to be interconnected within BPA's balancing authority by the end of 2013; and an even greater amount of capacity is possible by the end of the decade. BPA faces a major challenge of needing to provide additional system balancing reserves. It is anticipated that the expected incremental system reserve needs will be beyond the FCRPS's existing capability. Additional resources will be required to balance real-time energy demand with supply and still remain compliant with federally mandated non-power obligations (e.g., flood control and fish species protection under the Endangered Species Act) and to meet grid standards set by the Western Electricity Coordinating Council and North American Electric

Reliability Corporation. As the resulting wind energy output and percentage of variable generation versus load grows, system responses will need to be modified in the future to take advantage of the wind energy benefits to the regional grid and to assure system reliability.

BPA's high level of wind penetration is comparable to the electrical grid in Denmark, a benchmark for wind integration in Europe. On average, the West Denmark system's hourly reserves are approximately equal to those in BPA's system, on a grid one third the size of BPA's. Denmark's experience shows that introducing greater variable supply into the generation mix can very likely lead to a greater demand for system reserves. Norway and Sweden, with their predominately hydropower-supplied grids and strong interconnections with Denmark, are generally able to accommodate power surges during periods of high wind and can send energy back to Denmark during low wind periods. Relatedly, Norway's exposure to extended drought periods is also mitigated by wind energy imported from Denmark, so that this blend of energy technologies provides a global example of the mutual benefits of wind power and hydropower integration. Based on Denmark's experience, it is clear that BPA must begin to explore a variety of future system options, including energy conservation, demand response, energy storage, additional flexible generation, and expanded interconnections with British Columbia and/or California, as increasingly higher levels of variable energy resources are integrated into the FCRPS.

Hydropower, and specifically the technology of hydroelectric pumped storage, is a proven technology capable of facilitating the integration of wind energy. Hydropower is a renewable resource that can enable wind generation by providing relatively large capacity energy storage and reserves, and wind energy can mitigate a large hydropower system's exposure to extended droughts. Hydropower is already the preferred technology providing system reserves throughout the world's transmission systems. Hydroelectric pumped storage also provides numerous other valuable benefits besides energy storage, including hydrologic storage, electrical load balancing, frequency control, and incremental and decremental power reserves. It has historically been used to provide reserve capability to balance load on a system and allow large, thermal generating sources to operate at optimum conditions. With the advent of variable speed pump-turbine technology, load balancing in the pump mode can provide significant additional benefits to the grid, including decrementing reserves, minimizing potential spill violations and providing smoother operations.

The current forecast of BPA's need for balancing reserves is among the most uncertain of BPA's future needs, due to uncertainty of wind power development levels and pending technical solutions and business protocols that may in the next few years mitigate or significantly reduce the forecast need. Since variable generation increases the need for balancing reserves, the large forecast increase in variable renewable resources over the next several years in BPA's balancing authority area has resulted in a growing forecast need for balancing reserves. As modeled in the BPA's Needs Assessment, the flexibility of the FCRPS may be at some risk to balance growing wind generation by 2013 to 2020. However, efforts by BPA's Wind Integration Team and others throughout the region are aimed at further quantifying reserve requirements, and developing new tools and capabilities with the intent to extend the ability of the FCRPS to integrate variable generation.

Initial FCRPS power-operations modeling with CV indicates that benefits for wind integration can be realized from operational modifications at the Keys Pumping Plant in conjunction with its storage reservoir at Banks Lake. The CV model is the best available tool BPA has to evaluate the benefits of adding pumped storage to the FCRPS; however, there are limitations to CV's capability and the results of this analysis should be considered with some caution. HDR/DTA considers the modeling effort to be very preliminary and BPA is working to develop tools that more accurately assess wind reserve impacts on the FCRPS.

Although more extensive modeling needs to be done, initial CV modeling indicates that Keys Pumping Plant could provide from several hundred megawatts up to as much as 900 MW of operating flexibility, assuming the modernization and upgrades enable all of the pumps and pump generators to be able to be dispatched and depending on a variety of potential operating limits that could be placed on the units.

Longer-term, new, large pumped storage projects can provide the extensive reserves needed to balance growing wind generation. In fact, several potential hydroelectric pumped storage closed-loop sites in the order of 1,000 MW have been identified within BPA's service territory and could be developed to meet this need. Alternatively, other traditional sites (such as Banks Lake) provide an opportunity to manage water resources in much the same manner as energy resources, including additional spill reduction and load shaping.

Preliminary economic analysis suggests that the cost of integrating the next increment of wind (beyond the approximate 2800 MW interconnected in January 2010) into BPA's system by modernizing and upgrading the Keys Pumping Plant will be somewhat more than the current cost of integrating wind with the existing hydro system. BPA's annual cost of providing wind balancing reserves for 3,053 MW of installed wind capacity is $47,409,887, as referenced in the 2010 BPA Rate Case Wholesale Rate Final Proposal, Generation Inputs Study dated July 2009. The corresponding Wind Balancing Service Rate charged to all installed wind capacity is $1.29/kW/month. For this wind capacity, BPA supplies 585 MW of balancing reserves at a cost of $6.75/kW/month.

At BPA's Treasury borrowing rate of 6.75 percent, and a capital cost of about $270 million, the Keys Pumping Plant would have a first-year annual revenue requirement of about $29 million for capital recovery, O&M, periodic overhauls, and reserve deployment costs. The estimated marginal wind balancing reserve cost is about $8.00/kW/month. At a weighted cost of capital of 12.00 percent – BPA's internal rate of return for power investments – the estimated marginal reserve cost is about $12.90/kW/month. All costs are expressed in 2010 dollars.

Integrating higher levels of wind with Project X will have a higher cost. At a capital cost of about $2 billion and at a third-party tax exempt financing rate of 5.25 percent, Project X has a first-year revenue requirement of $199 million for an estimated marginal wind balancing reserve cost of about $19.50/kW/month. If Project X is built and financed by a third party seeking a return on equity, first-year revenue requirements are estimated to be significantly higher, about $338 million. The resulting marginal wind balancing cost is about $33.10/kW/month. Again, all costs are in 2010 dollars.

Wind energy and hydropower are complementary technologies that can bring substantial benefits to BPA and the Pacific Northwest. It is clear that variable energy resources need to be interconnected with flexible generation resources to keep the transmission system in balance and operating reliably. For BPA and the FCRPS, shifting system reserve requirements to a modernized and upgraded Keys Pumping Plant, and ultimately to a new, large pumped storage project is potentially a cost-effective solution and will provide BPA with increased pumped storage/wind integration capability and improved operational flexibility. New, large scale pumped storage projects with robust design features to respond almost instantaneously to grid demands should be on the planning horizon. Pumped storage is the world's leading technology for providing flexible grid-scale capabilities to supply the extensive reserves projected to be required in the future within the BPA system.

10.0 Pumped Storage Recommendations and Suggested Next Steps

Short-term, medium-term and long-term options have been presented, consisting of the modernization and upgrade of the Keys Pumping Plant and a new greenfield Project X. It is imperative that an equipment life extension program be undertaken at the Keys Pumping Plant to allow it to immediately provide system reserves on an hourly basis, and improve reliability and availability. In parallel to the balance-of-plant modernization effort, studies should be initiated to investigate the upgrading of the Keys Pumping Plant's Pump-generator Units 7 through 12. These studies, and subsequent vendor evaluation, pump-turbine modeling, fabrication and installation can then allow a modernized and upgraded Keys Pumping Plant to provide the incremental system reserves when predicted to be needed in the BPA system at a cost comparable to the existing FCRPS. Long-term reserve needs, as indicated by the CV model, can be met with the construction of a 1,000-MW pumped storage project. For this project to be realized, siting studies need to commence as the initial steps of the development process. The following next steps are recommended:

Model Development

Develop tools to more accurately assess the capabilities of pumped storage to enable the integration of higher levels of variable generation in the FCRPS.

Keys Pumping Plant and Banks Lake

Pursue equipment modernization and upgrades, as follows:

1. Establish a source of funding for the next phase of this work by establishing a sub-agreement between BPA and Reclamation to provide capital funding for continued work.
2. Determine if a NEPA study will be required. Determine schedule and costs.
3. Coordinate with Irrigation District/stakeholders on potential modernization and upgrades and proposed operational changes at the Keys Pumping Plant.
4. Further develop schedule and costs for reliability improvements and equipment upgrades.
    a. Perform a detailed study of the modernization of the balance-of-plant systems as currently identified in the strategy and incorporate in the overall plan.

   b. Perform a detailed study of the upgrade of the Keys Pumping Plant Pump-generator Units 7 through 12, utilizing the existing station and unit geometry, to modern single speed units.
   c. Perform transmission power flow studies and explore decoupling the pump start sequence for Pumps 1 through 6 from the Grand Coulee Left Powerhouse G1-G3 turbines.
5. Investigate the existing operational constraints at Keys Pumping Plant to utilize the Banks Lake reservoir including:
   a. Establishing a firm commitment for water availability and verifying the operating range at Banks Lake that is available for the proposed pumped storage/wind integration operation.
   b. Perform feeder canal and hydraulic conveyance system studies.
   c. Baseline current condition and performance of equipment
6. Perform a Transmission system impact study to identify potential Transmission system reinforcements needed to optimize the use of Keys Pumping Plant for wind integration.

Project X

Continue evaluation of a greenfield Project X pumped storage project, as follows:

1. Identify physical characteristics for Project X.
   a. Conduct screening studies to identify multiple Project X sites.
   b. Further refine the results from preceding steps to determine the most viable pumped storage site.
2. Develop a strategy to determine how a pumped storage project can be financed and who the stakeholders are that would fund such a project.
3. Decide on a path forward for a project-development approach (federal, non-federal, or consortium) to advance a pumped storage project.
   a. Lay out schedules and refine cost estimates.

Regional/National Communication

Pursue collaborative evaluation of a greenfield Project X pumped storage project, as follows:

1. Identify stakeholders and interested parties.
2. Layout and execute an inclusive communication plan.

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APPENDICES

APPENDIX A

APPENDIX B

APPENDIX C