Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest

Final Report

prepared for:

U.S. Army Corps of Engineers
Northwest Division
Hydroelectric Design Center

prepared by:

MWH

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August 20, 2009

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Attn: Mr. Dan Davis

Subject: Report on Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest

Ref: Solicitation No. W9127N-07-R-0018, MWH Americas, Inc. - Task 12

Dear Dan,

Enclosed is our final report discussing various aspects of pumped storage hydro development and integration with wind energy in the Pacific Northwest. This work was performed under Task 12 of our IDIQ contract for Hydroelectric Power and Pumping Plant Engineering and Design Services.

We enjoyed working with the Corps on this interesting assignment and hope this document provides useful background information to support your ongoing discussions with BPA and DOE regarding policy development and potential future pumped storage research activities.

Although preparing this report presented several challenges to us including the very short amount (approximately 4 weeks) of time available for us to complete the work, the need for multiple authors working in parallel, and the collaborative nature of the final editing process, we believe the report fully addresses all of the important topics included in the work scope. Primary authors of the report include Peter Donalek, Patrick Hartel, Bruno Trouille, Kathleen King, Manoj Bhattarai, Ron Krohn, Kirby Gilbert, Howard Lee, and John Haapala.

We enjoyed our collaboration with the USACE and BPA on this study and look forward to additional opportunities to be of service.

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BUILDING A BETTER WORLD

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EXECUTIVE SUMMARY

The difficulties of wind integration lie in the variability of wind, making wind energy a difficult resource to dispatch. The challenge is to find a way to make energy created by wind resources available on demand. BPA has already experienced large ramping events of several hundred megawatts of unscheduled changes in wind output occurring within an hour. As the percentage of wind penetration grows, the risk of having a major system failure event from an unpredicted change of the wind energy level increases. Pumped storage offers the ability to store energy produced from wind or other renewable resources when it is difficult to utilize these resources on the power grid or integrate them into the power system, and to release the energy at a time when it is needed, most often during peak electrical demand, at a higher value.

The burden of integrating wind power into the Pacific Northwest power grid has been imposed on existing hydroelectric facilities that were not designed for that purpose and already have many operating constraints (maintenance of flow rates, temperature controls, limits in dissolved gas concentration, etc.). This burden is likely to increase maintenance costs and failure rates of the equipment. The wind integration service needs from the existing hydroelectric system will soon exceed system limits due to the combined operational restrictions on the hydroelectric facilities.

Properly designed pumped storage (PS) facility (or facilities), if integrated into the Pacific Northwest (PNW), can assist with integration of intermittent wind energy resources into regional dispatch. A projected 6,000 MW wind generating capacity by the year 2013, representing 60% of BPA's present peak load in the BPA control area, is under consideration. By comparison, a portfolio of 15% to 20% of wind resources within the grid has been anticipated as the practical limit by a number of recent technical papers on the subject. It is therefore evident that new transmission interconnections and energy storage facilities will be required.

PS sites require two water reservoirs with different elevations so that energy can be stored in the upper reservoir and released when needed to generate electricity. When the elevation difference between the reservoirs is large, more energy can be stored using smaller reservoirs, smaller water conveyance conduits, and smaller physical equipment sizes, usually resulting in lower investment costs. A dedicated off-stream PS project will not have operational restrictions imposed such as those that occur on the Columbia River and hence can freely start, stop, reverse, and fluctuate as needed by the power system.

By investing in the newest technology available, adjustable speed or ternary units, the PS project can not only supply load following, but can become one of the fastest response stations on the power system. It can offer frequency regulation whether pumping or generating, and can allow pumping at less than full load, thereby increasing the flexibility to integrate the PS project specifically with wind energy resources. The big improvement with the new technology is that frequency regulation and load following are also possible in pumping mode. A conventional PS project cannot provide frequency regulation or load following in pumping mode. This is a quantum change in favor of the new technology.

The present transmission congestion and overload could be reduced by having a PS project located near the wind energy source. Storing wind energy, even a portion during critical times, could allow that same power to flow at a time when the congestion is reduced and/or the power is needed on other parts of the system. Studies for capacity and storage sizing and location of PS projects should determine what percentage of the wind energy needs to be reinforced by PS.

To maintain overall dynamic performance and stability of the transmission system, BPA has used Special Protection Schemes (SPS) to deal with system disturbance events. These include shedding of large industrial loads. A PS project could reduce the frequency of these events that can have significant financial consequences to the owner/operator of the industrial loads.

The operation of a PS project requires understanding that the near continuous cycle duty on the equipment at varying loads will shorten the life of the equipment. More frequent maintenance outages for major rehabilitations are required than for base loaded equipment. Some of this is caused by thermal cycling, and some of this is caused by operation under less than ideal conditions with resulting increased fatigue loading. The use of adjustable speed generation can eliminate some of the fatigue in turbine components and some of the stress imposed by starting and stopping, because of reduced vibrations and smoother operation. Otherwise, operation and maintenance practices are similar to those in conventional hydroelectric projects.

Use of PS provides a cycle efficiency of 70% to 80% that must be overcome by rate structures if dispatch of a PS project is to be financially viable. At some point in time, it will be necessary to consider the financial viability as well as the funding mechanisms, since no entity will be interested in operating a facility that does not earn enough revenues. To make this work, especially in the environment of wind energy where rates are already high, additional revenues from ancillary benefits for the facility will be needed, besides the arbitrage gains between rates when buying and selling power.

While pumped storage may or may not be the optimum solution, it is certainly one solution that offers maximum flexibility to resolve the problem of wind integration. If a decision is made to move forward with a PS project, the usual choice would be to bundle as many features as possible into the resource so as to be able to collect revenues for as many features as possible. Valuation of design features is a necessary prelude to selecting the features to be provided in a new facility.

There are a number of potential PS sites that were identified in the Pacific Northwest during the past 30 years. Some are now in the FERC licensing process. It is recommended that these previous studies be reviewed and updated to prioritize and rank the best projects. Unfortunately, permitting, designing, procuring equipment and constructing a PS project is a long term process requiring at least 6 to 7 years and 10 to 12 years to completing construction is more likely. Much of the time is in the up-front licensing and permitting process that is required, but it also takes significant time to build systems of tunnels, reservoirs and a power plant. A large scale PS project has never been accomplished by private developers in the United States, only by Government or major utilities with significant financial resources. New innovative ways such as Public Private Partnerships and fast-track permitting and licensing, as well as tendering and financing should be explored.

Because of the timeline for new projects, short term measures will be required. Notably, one pumped storage site already exists in the PNW at the USBR Grand Coulee P/G project (aka Banks Lake) with an installed capacity of 314 MW. Although not ideal from a transmission congestion perspective, an enhanced utilization of this site may be able to be part of the short term plan. Although more distant, there are several PS projects in central California, and it may be possible to use them in the short-term to assist with wind integration in the PNW. However it is expected that system operators in that area are already considering similar plans to use these projects for their own area wind integration needs.

Further short term planning is required, starting with listing what the most immediate needs and specific opportunities are. One possibility might be to deploy the adjustable speed technology for use on a few hydro generators at selected existing dams. This would allow immediate high speed response of generation without grossly affecting the flow regime of the river systems, within limits. The technology could be deployed at these selected existing dams within a few years time instead of a decade. By spreading the deployment over several sites, it may be able to house the increased equipment sizes without having to completely replace entire powerhouses.

Responses to the initial list of questions from the scope of work are presented in Section 6 of this report.

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TABLE OF CONTENTS

List of Figures

List of Tables

List of Appendices

List of Exhibits

SELECTED DEFINITIONS

Ancillary Services – Technical within-hour power and transmission services necessary for reliable power delivery other than simple megawatt-hours. Includes spinning and non-spinning generation reserves, VAR support, within-hour load following and regulation, generation imbalance and others. Some ancillary services are charged in power rates, others in transmission rates, and others are provided without specific charge. Ancillary services are purchased by BPA Transmission from BPA Power (FCRPS resources) to support transmission reliability.

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

Balancing Reserves – A portion of the operating system that is held ready to maintain load resource balance at all times. This includes load following, regulating reserves, generation imbalance (scheduling error), and the variability of intermittent resources (upreg or INC and downreg or DEC).

Black Start Capability – Black start is the recovery procedure after a total or partial shutdown of the transmission system that causes an extensive loss of supplies. Plants with black start capability can be started individually by themselves and be gradually reconnected to each other to restore interconnected system operation.

Capacity – The greatest amount of power a generator or system of generators can supply at its peak output. Capacity is measured in kilowatts (kW), megawatts (MW) or gigawatts (GW), where one GW is equal to 1,000 MW.

Cavitation – During pumping, cavitation refers to cavities or air and gas bubbles that are formed at low pressure (negative gage pressure) on the suction side of the pump.

Corona – Ionization of air surrounding electrical conductors due to high electric field intensity**.**

DEC (decremental) – Downward-regulating, load-following reserves; a backing-off of a system's generation as wind or other generation picks up or as area load drops off.

Direct-Service Industries (DSIs) – Industrial customers, primarily aluminum smelters, that buy power directly from BPA at relatively high voltages.

Energy – Where used specifically, an amount of electricity consumed over time, which may include periods of higher and lower consumption within that time frame. Energy is measured in kilowatt-hours (kWh), megawatt-hours (MWh) and also gigawatt-hours (GWh).

Energy Storage – Accumulation of energy during periods of excess energy availability for later use during periods of lower energy availability or higher system loads. Methods of energy storage include pumping water to the upper reservoir in a pumped storage system or charging of large scale batteries.

FCRPS – Federal Columbia River Power System. The transmission system constructed and operated by BPA and the 31 hydroelectric dams on the Columbia River and tributaries constructed and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation in the Northwest. Each entity is separately managed and financed, but the facilities are operated as an integrated power system.

Firm Power – Firm power is electric power (capacity and energy) that BPA will make continuously available under contracts executed pursuant to section 5 of the Northwest Power Act.

Frequency Regulation – In the USA, electricity is transmitted from a power plant to an end user at a frequency of 60 Hz. Electrical equipment designed to operate at 60 Hz may not operate efficiently or even safely at frequencies other than the intended frequency. Frequency of a system can vary with an imbalance between loads and generation. The power system frequency declines when loads exceed generation and increases when generation exceeds loads. Maintaining the balance between loads and generation provides frequency regulation.

HLH – Heavy Load Hours. Typically (but not universally) the 16 daily hours between 6 AM and 10 PM, Monday through Saturday not including holidays. Synonymous with high load hours.

Intermittent Resources - An electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints. Intermittent resources include wind power that cannot increase or produce generation at the command of their operators, but are only available at Nature’s discretion. Synonymous with non-dispatchable generation.

LLH – Light-Load Hours. The remaining hours of the week that are not defined as heavy load hours. Synonymous with low load hours.

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

Load Following – Balancing of loads and resources over a several minute response time, typically 10 to 60 minutes. Northwest system operators must have access to sufficient load following reserves to meet the incremental variability and uncertainty created by wind.

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

NWPCC – Northwest Power and Conservation Council: An eight-member council, established by the Pacific Northwest Electric Power Planning and Conservation Act. It is comprised of two voting members from the four Northwestern states: Washington, Oregon, Idaho, and Montana. Helps guide BPA and the region with planning for conservation and generation resources and for protection, mitigation, and enhancement of fish and wildlife in the Columbia River Basin.

Peak Load – The highest amount of electricity demand in a specific area, either for a moment, an hour, a set of hours, or another specified period. To maintain reliability, peak loads must always be less than generation capacity available to the specified area.

Power Factor – The ratio of power actually being used in an electricity circuit measured in kW, to the power that is apparently being drawn from the power source, measured in kilovolt-amperes (kVA). It is the cosine of the angle between the real power and apparent power vectors.

Pumped Storage Project Cycle Efficiency – long-term energy generated divided by the long-term pumping energy input.

Pumped Storage Project Roundtrip Efficiency – energy generated by evacuating the upper reservoir while operating at maximum output divided by the energy required to completely refill the upper reservoir, with all units operating simultaneously and continuously during the generation and pumping modes.

Reactive Power (VARS) – A component of apparent power that does not produce any real power (watts). Reactive power is measured in units called volt-amps-reactive or VARS. An imbalance in VARS causes voltage to rise or drop across the power system.

Reserves (Operating Reserves) – In a power system, reserves provide the necessary capability in excess of that required to carry the normal total load. Electric power needed to serve customers in the event of generation or transmission system outages, adverse streamflows, delays in completion of new resources, or other factors which may restrict generating capability or increase loads. Normally provided from additional resources acquired for that purpose, or from contractual rights to interrupt, curtail, or otherwise withdraw portions of the electric power supplied to customers.

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

Regulation – Balancing of loads and resources over a several second response time. Northwest system operators must have access to sufficient regulation and reserves to meet the incremental variability and uncertainty created by wind.

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

Shaping – Taking energy (or streamflows) from a generation source as it is produced, and providing, in return, energy (or water) in the amount(s) over time as requested by a customer or as required. Shaping can be accomplished with pumped storage by storing energy from intermittent resources during LLH for use during HLH or by storing energy for later use when output from intermittent plus must-run resources exceeds the load.

Speed Droop – A governor function that changes the governor reference speed as power output changes in response to system loads.

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

Ternary Type Pumped Storage System –A type of pumped storage system that consists of a hydraulic bypass or "short circuit" with a single synchronous machine coupled to both a separate turbine and a separate pump by a torque converter or clutch.

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

Variable Generation – An electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints. Hydropower is variable beyond the storage capabilities of reservoirs. Wind and solar output vary with wind and sun, respectively.

VAR (Volt-Ampere Reactive) – A unit to measure reactive power in an AC electric power system.

Voltage support – As with frequency, voltages must be kept within design tolerances. Transmission system voltage control involves balancing the supply and demand of reactive power.

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1 INTRODUCTION TO PUMPED STORAGE TECHNOLOGY

1.1 Overview of Pumped Storage

A succinct definition of pumped storage (PS) is: A hydroelectric plant that generates electric energy to meet peak load (demand) using water that was previously pumped into an upper storage reservoir during off-peak periods. The basic definition will be expanded and developed into a broader understanding of the underlying technical and economic principles associated with the pumped storage concept.

The original concept behind the development of PS plants was the conversion of relatively low cost, off-peak base-load energy generated in thermal or nuclear plants into high value, on-peak power. In today's world of electricity markets, one can refer to this as a "time shift of energy" accomplished by an electricity storage technology.

Today, many new large-scale PS projects are under construction throughout the world. These modern projects are being justified under a new set of technical and economic criteria as compared to the criteria that were previously used to justify the construction of pumped storage plants in North America. Many PS projects in North America were constructed in the 1960's and 1970's and were built in conjunction with large base-load nuclear plants. Today, the introduction of intermittent renewable generation such as wind and solar has added a new degree of uncertainty to the dispatch of interconnected power systems. PS projects have the capability to play a significant role in the integration of intermittent renewable sources into power system operation. PS technology has advanced since its original introduction and now includes the reversible pump-turbine, static frequency converter motor starting equipment, improved generator insulation systems, mechanical bearings and high-speed automatic controls. In Japan and Germany, new PS projects have been constructed using adjustable speed machines. Ternary PS projects are also being constructed, consisting of a hydraulic bypass or "short circuit" with a single synchronous machine coupled to both a separate turbine and a separate pump by a torque converter or clutch. The new technology adds yet another degree of new operating capabilities, flexibility of operation, and improved efficiency. Adjustable speed or ternary technology is further discussed in later chapters of this paper.

PS projects use a variety of configurations to accomplish the objective of electric energy storage. Along the way there have been several significant milestones that have reduced first costs, simplified pump starting, improved efficiency and improved provision of ancillary system support services.

The introduction of regional electricity markets has also allowed PS projects to be compensated for energy generation as well as for the supply of ancillary system support services and dynamic benefits.

As shown in Figure 1-1, a typical PS project consists of two interconnected reservoirs (lakes), tunnels that convey water from one reservoir to another (water conductors), turbine shutoff valves, hydro machinery (a pump-turbine, a motor-generator, transformers), a transmission switchyard, and a transmission connection. The product of the total volume of water and the differential height between reservoirs is proportional to the amount of stored electricity. Thus, storing 1,000 MWh (deliverable) in a system with an elevation change of 1,000 feet requires a water volume of about 1,120 acre-feet.

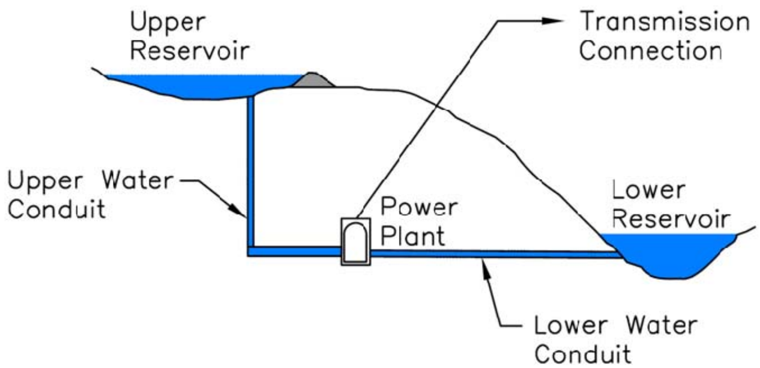

Figure 1-1 Typical PS Arrangement

Traditionally, during periods of low power demand, typically overnight, inexpensive electricity produced by base load power plants was used to pump water from the lower to the upper reservoir. This water was released during peak power demand periods, delivering more valuable electricity to the grid.

As with all electricity storage systems, PS is not 100% efficient. Its overall cycle efficiency depends on a variety of factors, but generally ranges between 70% and 80%. The largest loss is about 8% in the pump/turbine in both the pumping and generation modes. In order to be an economic component of the power system, the electricity price differential between pumping and generating modes would have to cover the cost of the electricity used in pumping, O&M costs, and the capital investment cost recovery. Other system benefits produced by the project also need to be recognized.

In addition to the basic energy arbitrage, traditional PS plants also provide critical system “ancillary” benefits while in generating mode, including: frequency regulation, load following, spinning reserve and reactive power for voltage control. In the Pacific Northwest, pumped storage would provide reliable energy to compliment highly intermittent wind energy. In addition to the expected variability of wind energy, an additional component of uncertainty in the scheduling of generating resources to meet loads results from forecast errors in wind energy generation due to forecast errors in the timing and magnitude of weather systems. Pumped storage energy could fill-in (generate energy or consume excess wind energy by pumping) for the forecast errors of wind energy output.

Pumped storage projects that use conventional hydro units, with a pumped-storage cycle superimposed on the normal hydro generation operation, form a class of projects known as “on-stream integral pumped storage” or “pump-back” projects. “Pump-back” projects use two reservoirs located in tandem on the same river. They are operated as a conventional hydro plant part of the time, but when water flows are low, or when peak demand is high, the project can be operated in the pumped storage mode. Since these projects involve normal river flow, they are subject to various mandated water flows, navigation and environmental constraints. Such constraints are often onerous and hence, the “pump-back” concept is usually not the preferred configuration for energy storage projects.

“Seasonal pumped-storage” is another type of pumped storage operation often found on large river and canal systems where there is a need to accommodate annual and multi-year water storage cycles. In this application, water can be stored on a long-term cycle that takes advantage of annual or seasonal water cycles. Often in these applications, operation of the pumped storage units in the generation mode is on a time cycle that does not coincide with the daily load cycle of the electric system. Nonetheless, such applications are often economical and produce sufficient revenues to justify the added cost of the pumped storage facility.

The most commonly used configuration for PS, as an electricity storage facility, consists of a dedicated storage reservoir (usually an upper reservoir), water tunnels and conductors, a power house with electrical substation and transmission connection, and a lower reservoir that is often part of a naturally occurring stream, river, lake or hydro plant reservoir.

Until recently all PS projects used fresh or sweet water as opposed to salt or sea water. There is one project in Japan that uses saltwater, with the ocean being the lower reservoir. It has shown that a saltwater design is possible, but that there are unique technical issues that need to be addressed. Many of the technical issues have to do with corrosion and materials for seals.

There are a variety of ways that the PS can be implemented within specific geologic and hydrologic constraints. Many early PS projects used existing, conventional hydro facilities to provide the necessary upper reservoir for water storage. Modern pumped storage installations are on a larger scale, with most installations having multiple units of 100 MW or greater. These require considerable civil construction. With proper site selection, the lower reservoir can be an existing water feature such as a river, lake or existing hydro reservoir and it is only necessary to build an upper reservoir. Figure 1-2 shows a recent 1,060 MW installation at Goldisthal, Germany. Two of the four units are of the adjustable speed type. Originally the project was designed with four single-speed units, but two units were changed to adjustable speed after the technology became available in mid 1990’s.

Additional potential issues with a saltwater pumped storage project in general would include preventing permeation of saltwater into the ground at the upper reservoir, adhesion of marine organisms in the water conduits to the pump-turbine, and impacts on marine organisms near the outlet. In the PNW, a coastal

PS project would also be quite remote from the location of most wind power projects and there are relatively few existing major transmission lines to coastal areas.

Figure 1-2 Aerial Photo of the Goldisthal Project Site

The upper reservoir, in the pure pumped storage configuration, is dedicated to the operation of the PS project. The dedicated aspect means that there are fewer water-use constraints on the operation of the plant. Similarly the lower reservoir is designed to hold the volume of water stored in the upper reservoir and to minimize impacts of water use regulations and constraints on project operations.

Components of the PS project system are organized to optimize both the operational and the initial construction costs. Figure 1-1 shows an underground powerhouse connected by a lower water conductor to the lower reservoir and by an upper water conductor to the upper reservoir. Other designs use either a surface powerhouse with an open lower channel or incorporate the powerhouse into the outlet works at the edge of the lower reservoir. This results in a very long upper water conductor, but no lower water conductor. The surface powerhouse design may not be the more cost effective solution, but it may reduce “first costs” or be required if it is not possible to construct an underground powerhouse for geotechnical reasons. The reason for underground powerhouses is usually to reduce friction losses in long upper water conductors that can cause significant generation losses.

In some applications it is necessary to include a “surge tank” in either or both of the upper or lower water conductors. Surge tanks are required for long water conduits in cases where water–hammer and pressure surges are high due to the need to maintain reasonable turbine wicket gate operating times. Projects with wicket gates times that are too slow will not have the dynamic performance characteristics required to provide the desirable range of ancillary services or the corresponding revenues from the use of those ancillary benefits. Such plants, having slow response rates, cannot provide full frequency regulation, load following or fast response spinning reserve.

PS projects are particularly cost effective at sites having high heads (large differences in elevation between the upper and lower reservoir). Having higher head requires less volume of water to store the same quantity of energy, resulting in smaller reservoir sizes, reduced civil works and generating equipment sizes, smaller pump-turbine and motor-generator size and hence lower investment costs.

During off-peak hours, such as the early morning hours, low cost electricity produced by conventional base-load power plants (coal and nuclear), conventional hydropower, and/or intermittent renewables (wind and solar) can be used to pump water from the lower to the higher reservoir. PS projects also provide an opportunity to store energy from surplus intermittent renewable resources. This results in energy that can be dispatched at a later time when it is needed, or when its value is greater.

PS projects are uniquely suited to supply energy and capacity when demand for electricity is high. They also can supply reserve capacity to complement the output of large fossil-fueled, nuclear steam-electric plants, conventional hydro plants that are run-of-river or that have highly constrained operations, and intermittent renewable generation resources. Start-up of a pumped storage unit is almost immediate, thus serving peak demand for power better than fossil-fueled plants that require significantly more start-up time.

PS projects offer significant flexibility to supplement other electricity supplies such as intermittent renewables. Combined use of PS projects with other types of electric generation, in an optimized market driven dispatch, offers the prospect of significant cost savings through more efficient utilization of base-load generating plants and displacement of expensive, low efficiency, oil and natural gas fired peaking units. It also reduces cycling and shut downs of thermal or hydro units during the off-peak hours.

Turnaround between pumping and generating modes can be accomplished reasonably fast, as discussed in Section 2.6. Most units with pump-turbine runners have the ability to generate down to 50%, and some units down to 30% load load without damage to the equipment.

On a conventional unit, pumping occurs at a fixed speed and almost fixed wicket gate opening. The power input is nearly constant at the input rating of the pump and the discharge varies with the pumping head. An adjustable speed pumping unit can operate over a larger head range and pumping power input range than a single speed unit, which permits these units to be used for frequency regulation and VAR control during the pumping cycle.

When adjustable speed or ternary technology is used, the pump-generating units become among the fastest responding equipment on the power grid system, with the ability to respond to variations in wind power and maintain system frequency.

The overall cycle efficiency of PS is improved, the ability of the equipment to pump at reduced power input is added, and the ability to load follow and regulate frequency while in pumping mode is added.

As of the writing of this report, there are no operating pumped storage plants in the U.S. with adjustable speed machines. However, there are several projects in planning that may use adjustable speed machines. These are: Lake Elsinor, Iowa Hill in California, Hawaii and Phantom Canyon in Colorado. Appendix B presents a list of projects with adjustable speed machines that are in operation in Europe and Japan. The first one, Yagisawa No. 2, was commissioned in 1990 in Japan.

1.2 Summary of Operating PS Projects in the U.S. and Worldwide

Worldwide, PS is the most widespread electric energy storage system in use on bulk power, high voltage electric power networks. PS is a mature technology with a proven track record and is represented by many large and small projects ranging from tens of MW to over two thousand MW.

A significant and growing portion of the hydroelectric generation capacity worldwide is devoted to PS projects that are designed not only to provide power during peak loads but also frequency control, load following and provision of spinning reserve.

As of 2008, there were 344 developed PS projects worldwide, with a total generating capacity of 126 gigawatts (GW). In the U.S. there are 40 PS plants located in 18 states, owned by 23 entities. The total installed capacity in the U.S. is 23 GW. Figure 1-3 shows the amount of PS by country. Figure 1-4 shows the amount of PS construction worldwide by year since 1940.

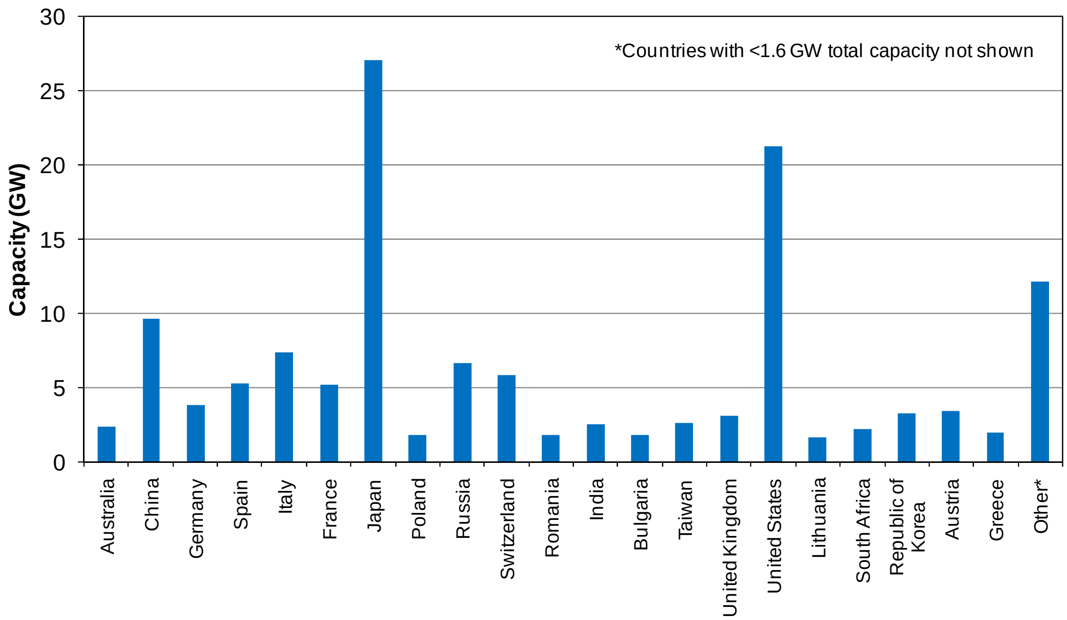

Figure 1-3 Pumped Storage Capacity by Country

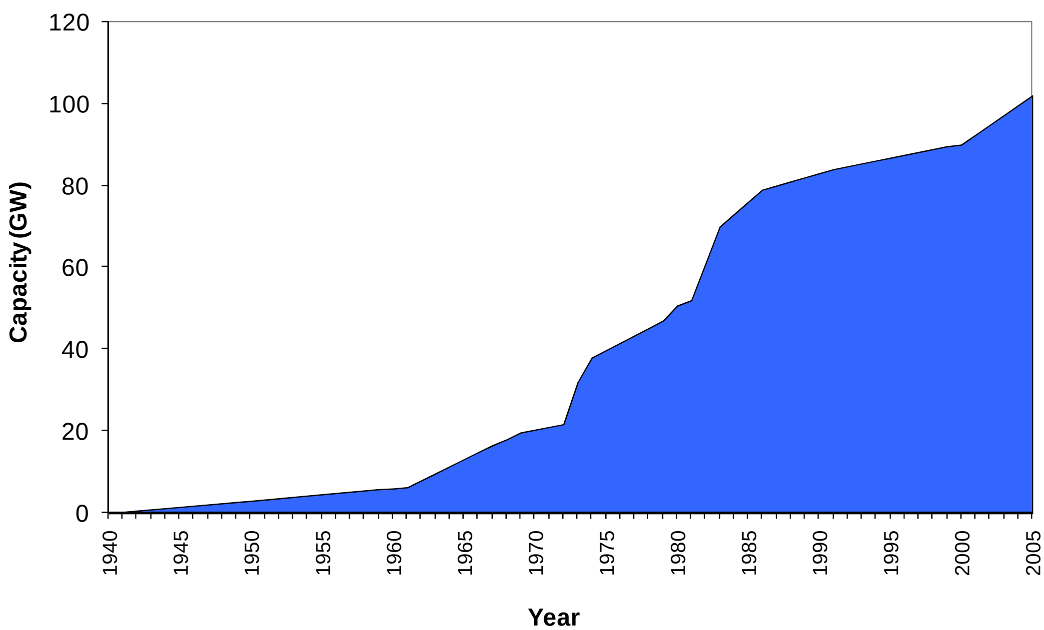

Figure 1-4 Pumped Storage Capacity Worldwide by Year 2005

Since 1996, there has been almost no pumped storage construction activity in the U.S. At present there is only one pumped storage project under construction in the U.S., which is the Olivenhain Hodges project, owned by the San Diego County Water Authority. The project has two reversible pump/turbine units each rated at 23 MVA. The project is part of the San Diego County Emergency Water Storage system and is scheduled to go on line in 2010.

A compendium of pumped storage projects prepared by the American Society of Civil Engineers in 1993 provides data and information about pumped storage projects in the U.S. Figure 1-5 is a map showing the location of the 36 pumped storage plants in service in the U.S. at that time.

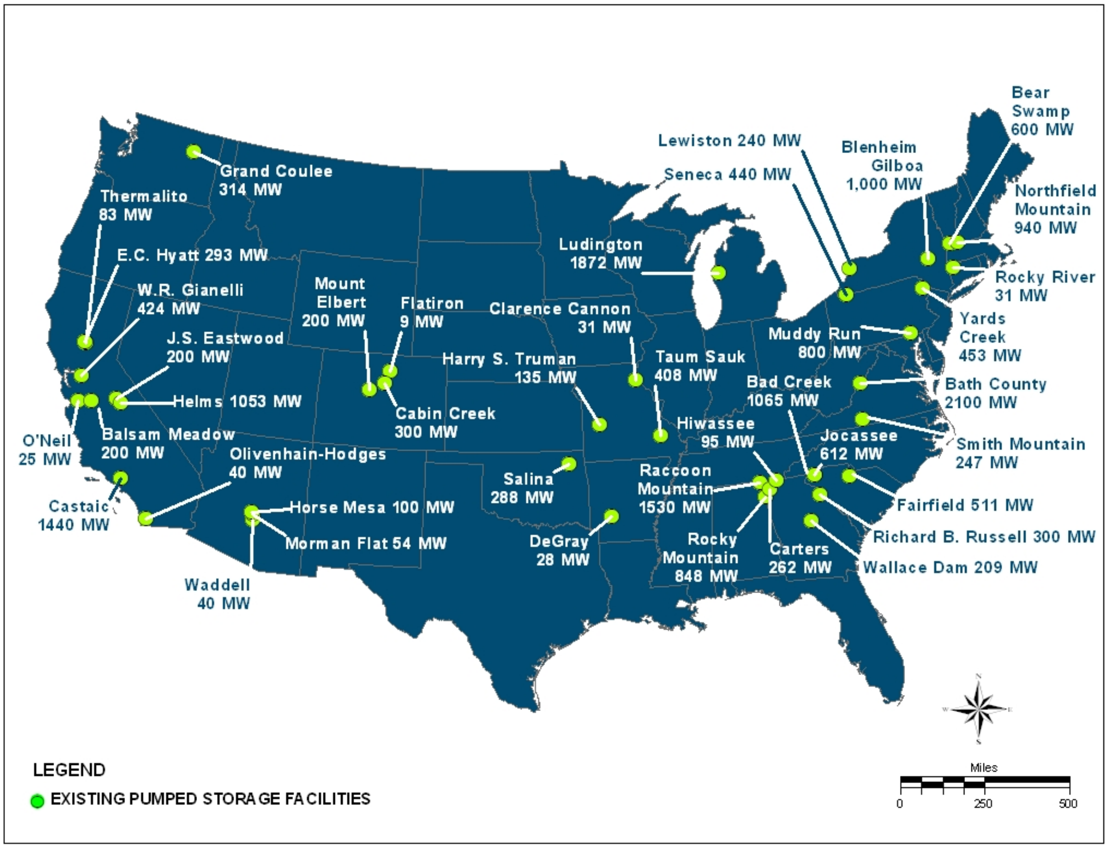

Figure 1-5 Existing Pumped Storage Plants in the U.S. as of 1995

There is a renewed interest worldwide in pumped storage. This interest is largely driven by the need to integrate intermittent renewable capacity sources into the economic system dispatch and to improve the stability of the electric power grids. The need for energy storage as a system integrator of intermittent renewable capacity was made clear in February 2008. On the evening of February 26, 2008 the bulk power grid in West Texas lost 1,200 MW of wind power over period of 20 to 30 minutes (Reuters, 2008). The power loss was the result of a sudden drop in wind velocity due to the arrival of a cold front. The 1,500 MW of output from wind powered generators that were operating at near ideal conditions with a steady wind suddenly dropped to 300 MW. After available spinning reserves were used, the control center exercised its option to interrupt large loads, start combustion turbines and re-dispatch generators. System dispatchers narrowly avoided a major system blackout. If there had been a pumped storage plant in the area it could have been used to provide capacity during the critical period.

The uptick in interest in PS can be seen via the number of projects that are in the various steps of the FERC licensing process. It shoud be noted that a federal development license is required from FERC for all non-federal hydro projects, including pumped storage hydro. The categories are (with approximate times to complete): Preliminary permit pending (6 months); Preliminary permit issued (3 years – concurrent with NOI/PAD license application preparation); License Implementation and Final Design (2 years) and Construction 2-5 years). Table 1-1 shows the PS projects pending license as of June 2009. There are three projects in California and one project in Missouri. The total proposed capacity is 2,608 MW.

Table 1-1 Pending FERC Licenses for Pumped Storage (June 2009)

Project Name	Owner	Capacity (MW)	Comment
Upper American River/Iowa Hill, CA	Sacramento Municipal Utility District (SMUD)	400	Final application submitted
Taum Sauk, MO	AMEREN	408	Amended license
Lake Elsinor, CA (LEAPS)	Elsinor Valley Municipal Water District	500	Final application submitted
Eagle Mt. CA	Eagle Crest Energy Company	1300	Draft application submitted

Table 1-2 shows the PS projects for which FERC Preliminary Permits have been issued. The total proposed capacity is 25,282 MW.

Table 1-2 FERC Preliminary Permits Issued (June 2009)

Project Name	Permittee	State	Capacity (MW)
RED MOUNTAIN BAR PUMPED STORAGE	MODESTO IRRIGATION DISTRICT (CA)	CA	880
SAN VICENTE PUMPED STORAGE	SAN DIEGO COUNTY WATER AUTH (CA)	CA	570
KINGS RIVER PUMPED STORAGE	PACIFIC GAS AND ELECTRIC CO (C	CA	380
MOKELUMNE PUMPED STORAGE	PACIFIC GAS AND ELECTRIC CO (C	CA	380
MULQUEENY RANCH PUMPED STORAGE	BPUS GENERATION DEVELOPMENT LLC	CA	280
LAKE ROOSEVELT PUMPED STORAGE	BPUS GENERATION DEVELOPMENT LLC	WA	1,310
DUFFEY LAKES PUMPED STORAGE	BPUS GENERATION DEVELOPMENT LLC	WA	1,150
JD POOL PUMPED STORAGE	PUD NO 1 OF KLICKITAT COUNTY, WA	WA	1,129
UMTANUM RIDGE PUMPED STORAGE	BPUS GENERATION DEVELOPMENT LLC	WA	1,100
BANKS LAKE PUMPED STORAGE	BPUS GENERATION DEVELOPMENT LLC	WA	1,040
LAKE POWELL PIPELINE	UTAH BOARD OF WATER RESOURCES	WA	443
SENTINEL MOUNTAIN	UNITED POWER CORPORATION	WA	2,000
PARKER KNOLL PUMPED STORAGE	PARKER KNOLL HYDRO, LLC	UT	1,330
LONG CANYON PUMPED STORAGE	UTAH INDEPENDENT POWER	UT	800
BULL CANYON PUMPED STORAGE	UTAH INDEPENDENT POWER	UT	800
CEDAR CREEK PUMPED STORAGE	CEDAR CREEK HYDRO, LLC.	TX	662
BRYANT MOUNTAIN PUMPED STORAGE	UNITED POWER CORPORATION	OR	1,175
SWAN LAKE NORTH PUMPED STORAGE	SWAN LAKE NORTH HYDRO, LLC	OR	1,144
SUMMER LAKE PUMPED STORAGE	NT HYDRO	OR	256
ABERT RIM PUMPED STORAGE	NT HYDRO	OR	134
MINEVILLE PUMPED STORAGE	MORIAH HYDRO CORP	NY	189
OGDENSBURG PUMPED STORAGE	RIVERBANK OGDENSBURG, LLC	NY	100
DIVISION CANYON PUMPED STORAGE	DIVISION CANYON HYDRO, LLC	NV	500
THOUSAND SPRINGS PUMPED STORAGE	THOUSAND SPRINGS HYDRO, LLC	NV	470
BLUE DIAMOND PUMPED STORAGE	NEVADA HYDRO COMPANY, INC.	NV	450
HOPPIE CANYON PUMPED STORAGE	HOPPIE CANYON HYDRO, LLC	NV	380
LOOMIS CREEK PUMPED STORAGE	LOOMIS CREEK HYDRO, LLC	NV	370
YEGUA MESA PUMPED STORAGE	YEGUA MESA HYDRO, LLC	NM	1,100
SPARTA PUMPED STORAGE	RIVERBANK SPARTA, LLC	NJ	1,000
RIVERBANK WISCASSET ENERGY PS	RIVERBANK WISCASSET ENERGY CENTER, LLC	ME	1,000
LITTLE POTLATCH CREEK PUMPED STORAGE	BPUS GENERATION DEVELOPMENT LLC	ID	1,340
CORRAL CREEK SOUTH PUMPED STORAGE	CORRAL CREEK SOUTH HYDRO, LLC	ID	1,100
PHANTOM CANON PUMPED STORAGE	H20 PROVIDERS, INC.	CO	220
NORTH EDEN PUMPED STORAGE	NORTH EDEN HYDRO, LLC	ID	100
34 Sites Total	Total MW Permitted		25,282

Table 1-3 shows the PS projects for which FERC Preliminary Permits are pending. The total proposed capacity is 4,132 MW.

Table 1-3 FERC Preliminary Permits Pending (June 2009)

Project Name	Permittee	State	Capacity (MW)
Lorella	BPUS Generation Development or Intertie Storage LLC	OR	1,000
Champion Ridge	Champion Ridge Hydro	WY	700
Ford Canyon	Arizona Independent Power	AZ	800
River Mountain	Nevada Hydro	AR	600
Square Butte	Square Butte Hydro	MT	1,032
5 Sites	Total MW		4,132

Figure 1-6 shows the location of the pumped storage plants currently in FERC process that have yet to receive a FERC license. Except for a few projects in the northeast and one in Arizona, there are all proposed in the western or southern part of the U.S.

Figure 1-6 PS Projects in FERC Queue (June 2009)

Notwithstanding the fact that there is currently a lot of interest in pumped storage, the onerous FERC regulatory process in place makes project development very difficult and time consuming. Due to the large scale of these types of projects and the need for large amount of debt and equity investments in the order of $1 to $2 billion, financing may also pose an insurmountable hurdle to private project developers.

2 TECHNICAL ASPECTS OF PUMPED STORAGE

2.1 History of Pumped Storage Technologies

The first hydro plants with pumped storage capability were built in Switzerland. The first known pumped-storage development was in Zurich, Switzerland, and operated as a hydro-mechanical storage plant until 1891. The first documented use of pumped-storage for electricity generation was at the Ruppoldingen plant in Switzerland on the Aare River in 1904 (Hartey & Scott, 1993). In 1929, the Rocky River pumped storage plant, the first such plant in North America, was constructed on the Housatonic River in the US state of Connecticut (ASME, 1980).

The pumps and turbines in these early plants were installed as individual units. These plants did not use reversible pump-turbines that are now standard in pumped storage plants. In some cases the plants had physically separate motor driven pumps and separate turbine driven generators. Other plants used a tandem type unit consisting of a generator-motor and separate pump and turbine mounted on a common shaft.

Many of the early plants used motor-pump and turbine-generators on horizontal shafts and required large machine halls. The use of large reversible vertical shaft machines is now the preferred configuration.

These early pumped storage plants, with individual pumps and turbines, had high overall cycle efficiencies because pumps and turbines could be designed for maximum efficiency at the single synchronous speed of the generator/motor. However, the electrical-mechanical equipment costs for these plants, as a percentage of the total plant cost, was high due to the separate pump-motor and turbine – generator installations.

The modern pumped storage era in the U.S. began in the mid 1960's and included Taum Sauk, Yards Creek, Muddy Run and Cabin Creek. These stations were intended primarily utilize relatively inexpensive surplus off-peak energy for pumping and return blocks of peaking power. Once in use some of these plants were operated to take advantage of their capability to provide frequency regulation, load following and spinning reserve.

Table 2-1 presents a time line of pumped storage hydro technology advances. The table lists several major technological milestones in the development of modern pump storage. Among these are the development of large capacity reversible pump/turbines, use of solid-state soft start, and the development of adjustable speed machines.

Table 2-1 PS Technology Time Line

1849	James B. Francis. Developed inward flow reaction turbine
1873	First application of movable wicket gates
1880's	Swiss develop pump back and pump storage schemes
1910's	Pump storage plants constructed in Germany
	Vertical shaft Francis turbines manufactured
1929	Rocky River PS Project on the Housatonic River - first PS in US
	Development of wicket gates in conjunction with Francis pump – turbine
1956	TVA Hiwassee Unit 2 is a true reversible pump-turbine. Proves that a single runner can perform as a pump and turbine.
1960's	Develop adjustable frequency motor starting system – over comes the problem of pump motor starting
1980's	US Bureau of Reclamation experiment with adjustable speed machine
1990's	Japanese manufacturers develop adjustable speed machines
1985	World's largest PS project: Bath County VA; six unit 2,100 MW
1996	First 395 MVA adjustable speed machine at Ohkawachi PS project, Japan, enters commercial operation
1998	Chaira, Bulgaria; two units 864 MW; highest-head (2,400 feet), single-stage pump/turbines
1990's	Development of electricity markets. PS receives full compensation for ancillary services
1999	Yanbaru – Okinawa, Japan; One unit rated 30MW, first pumped storage plant to operate with sea water
2003	Goldisthal, Germany; four units (two single speed, two adjustable speed), 345 MVA each.
Late 2000's	Several adjustable speed projects (Avce, Nant de Drance, Linth-Limmern, Kozjak) are being built or planned in Europe

2.1.1 Reversible Pump-Turbine Development

Until the 1950's there was slow progress in the development of the pumped storage. It was well known that a synchronous electric machine could operate either as a motor or a generator. That is, a synchronous machine could be made to rotate in the motor (pump) direction or the generator (turbine) direction simply by reversing two of the three electrical phases. However it was not so simple to design a single pump-turbine impeller that could perform efficiently at a single common synchronous speed.

Although it was known that a Francis type pump impeller could function as a pump or turbine, some designers theorized at the time, that there was a theoretical limit, on the order of 25 MW, to the maximum rating of a reversible pump-turbine. The theoretical limit was to be tested at the Hiwassee dam.

Pumped storage plants had been in use for electric energy storage in Europe prior to the installation of Unit 2 at TVA's Hiwassee plant. European plants either used completely separate motor-driven pumps and turbine-generators, or they used a pump, a turbine and a generator/motor all on a single shaft. In the European installations, the cost of equipment was high because two separate units were required, which also increased the cost of the civil works.

The TVA Hiwassee dam and power plant (ASME, 1981) are located on the Hiwassee River near Murphy, North Carolina. The dam and power plant were constructed between 1936 and 1940 as a flood control and hydro generating plant. The plant was designed for two 57.6 MW hydro generating units driven by Francis turbines. The first unit went into operation in 1940.

Studies were made in the late 1940's for the installation of a second generating unit. At the time TVA was faced with a capacity short fall in the months of January and March. It was recognized that the reservoir for the downstream hydro plant (Appalachia) could be used as a lower reservoir for a pumped storage operation at Hiwassee. The studies showed that the second unit at Hiawassee could be a reversible pump-turbine and that it could be used to provide peak capacity during peak load periods. The reversible pump-turbine, rated at 59.5 MW, was subsequently designed and constructed and placed into service in May 1956.

Hiwassee Unit 2 was the first reversible pump-turbine installed for the purpose of storing electrical energy in a hydroelectric plant. An earlier pump-turbine was installed at the Flatiron Power and Pumping Plant n Colorado in 1954, but it was used primarily for irrigation water rather than electric energy storage.

The unique achievement of the Hiwassee Unit 2 installation is that it is the first unit to use a single pump/turbine mechanically connected to a generator/motor. The Hiwassee Unit 2 installation proved that a single pump/turbine could be used efficiently. This was a technological breakthrough and resulted in reduced total cost of equipment because a single component could be used in two modes of operation.

In 1956, TVA and Allis Chalmers Corporation showed that it was possible to construct a true reversible pump/turbine driven by a generator/motor on a single shaft. This technological breakthrough established the precedent for use of reversible pump-turbines in virtually all pumped storage plants since. Since the breakthrough at Hiwassee reversible pump-turbines have become the standard and have supplanted the use of separate pumps and turbines.

The design of a reversible pump-turbine, operating at a single speed, represents a compromise between efficient pumping operation and efficient turbine operation. As a result, the head range over which a reversible single – speed unit can operate, with reasonable efficiency both as a pump and a turbine, is limited. Since high cycle efficiency is desired, this forces the design of a single-speed pump-turbine into a relatively narrow head range. Another limitation of the single speed reversible pump/turbine is that it can only provide frequency regulation in the generation mode.

2.1.2 Adjustable Speed Development

The precursor of adjustable speed technology was the development of a two-speed synchronous motor-generator. Then in the early eighties, high capacity power electronics and thyristors allowed for the design of medium voltage adjustable speed machines. The early developments of adjustable speed drives to hydropower were in Japan in the late eighties, using predominantly the cyclo converter technology (Fayolle & Lafon, 2008).

One of the first experiments with adjustable speed machines applied to hydro plants was conducted by the US Bureau of Reclamation (Gish, 1981). The study was reported in the May 1981 IEEE Transactions on Power Apparatus and system and was authored by W. Gish, J. Schurz, B. Milano and F. Schleif. The first adjustable speed PS machines were however constructed in Japan, during the late 1980's and into the mid 1990's.

Adjustable speed capability is accomplished with three-phase low-frequency alternating current excitation on the rotor. The excitation system injects a slip frequency current into the rotor. The first adjustable speed machines, in commercial operation, used the cycloconverter technology with thyristors or Gate Turn Off (GTO) thyristors to provide the three phase alternating current field excitation required on the rotor.

The latest technological evolution came with the introduction of multi-level voltage source inverter (VSI) excitation and Pulse Width Modulation (PWM) techniques. An advantage of the VSI excitation is that it uses a two winding transformer on the input, as compared to the use of three-winding transformer with the Cycloconverter.

To develop these new techniques, different manufacturers have developed excitation systems with several different semiconductor devices. Basically there are those who use the thyristor technology with the more recent Insulated Gate Commutated Thyristor (IGCT), or Insulated Gate Bipolar transistor (IGBT) and those who favor transistor technology with the more recent Injection Enhanced Gate Transistor (IEGT). There are three plants under construction in Japan that are using the latest excitation systems.

At the Goldisthal PS project in Germany the adjustable speed machines can be regulated from 40 MW up to 265 MW, while the synchronous machines can only be regulated from 100 MW to 265 MW (Beyer 2007). The ability to operate at the lower MW level results in a savings in water to be used for later generation.

The Kansai Electric Company of Japan reports that the adjustable speed machines at their Ohkawachi PS plant are used to maintain frequency and other system characteristics. Kansai compared the effectiveness of the PS AGC (a.k.a. AFC) with that of a combustion turbine. The combustion turbine was loaded to 160 MW and maintained frequency at 60 Hz with a reliability of 96.8 percent. The adjustable speed machine met the target with a reliability of 99.9 percent. These results show that the adjustable speed machines' response to an AGC command is faster than that of the combustion turbine (Kita & all 1994). In addition fast response time enables these machines to react quickly to the power disturbances occurring in the grid.

The ability of an adjustable speed PS unit to change rotor speed through the rotor current and frequency allows active power stored in rotating inertia to be supplied or absorbed by the motor/generator, and stabilizes instantaneous changes of system frequency and power level. This feature is common to all hydro plants; however an adjustable speed machine has the advantage that it can rapidly change output through the electronic controls. Thus an adjustable speed PS unit offers the potential to modulate power fluctuations from a wind farm. It should be noted however that the kinetic energy in the rotor would not provide enough energy for very large power system disturbances or swings.

2.2 Load Following, Frequency Regulation, Spinning Reserve and Voltage Regulation

The original concept for pumped storage was mostly to consume electricity at night by pumping water from a lower reservoir to an upper reservoir and to produce electricity during the daily peaking hours, when water was returned from the upper to the lower reservoir. Generally from the 1960s to 1980s, PS projects were intended to support large base-load nuclear or coal-fired development, absorbing excess electricity generated during off-peak hours and delivering stored energy during on-peak hours. These early projects already provided considerable regulation by integrating full operation of large nuclear or coal plants into existing power systems, further optimizing the operation of cycling units during the night loads, and reducing costly thermal peaking generation.

Over the years and with deregulation of the electricity market and creation of spot markets, the use of pumped storage projects has greatly expanded to cover a range of ancillary benefits: load following, frequency control, spinning reserve, and voltage regulation. These technical aspects and benefits are described in the following paragraphs.

2.2.1 Load Following

Like conventional hydropower projects, PS projects, in the generation mode, can quickly follow load demand whether the demand is increasing or decreasing. PS projects have a ramp rate capability in the range of 10-30% of maximum capacity per minute. In a large power system such as the PNW, the morning and evening load swings are typically in the order several thousand MW. This requires a number of units to be started up and shut down daily to follow the load. The practice of daily shutdowns of cycling units carries additional operation and maintenance costs from wear and tear. PS projects can reduce the number of start ups and shutdowns and/or increase the time for other units to start up or shut down.

In the pumping mode, conventional PS projects are constrained and cannot adjust their pumping load requirements. Typically it is operated at no load or full load. A variable speed PS project does not have this limitation and can be adjusted over a load range of 50 to 60% of rated pumping power. This would help to better integrate wind generation.

2.2.2 Frequency Regulation

In any power system, controlling frequency is needed to balance electricity supply and demand. Speed governors on most generating units are used to constantly monitor frequency and regulate the unit's power output to help balance demand and supply and maintain a constant frequency. However power output does not change instantaneously. The rate at which a generator's output can increase or decrease depends on the type of generator. Typically, large nuclear or coal units are slow to change outputs while hydro and PS units are very responsive.

In a conventional PS single speed machine, the governor is used to control unit speed and frequency by way of the wicket gates (adjustable guide vanes that surround the turbine and control the area available for water to enter the turbine). The wicket gates can open and close in approximately 10 seconds or less.

Adjustable speed machines can provide frequency control in both generating and pumping modes. There are two control components. One is the turbine governor controlling the wicket gate position of the turbine and the other is the inverter controlling the rotor currents of the generator/motor. With these two control elements in turbine mode, two quantities can be controlled more or less independently. The control strategy for the pump mode is similar. More details are provided in Appendix A.

With an adjustable speed machine the response rate is faster than that of a conventional unit under speed governor control. In a presentation by Alstom for the Goldisthal project, the total time of a step response was estimated at 150 milliseconds, for change in power from zero to rated capacity by way of the cycloconverter and associated controls.

A pumped storage plant with adjustable speed generator/motors can use the rotating inertia of the machine and modulate instantaneous (short time) power fluctuations. However, for longer time fluctuations in the adjustable speed machine, a frequency governor (which controls rotor speed by way of excitation frequency and rotor current) is provided, in addition to a speed governor to control the wicket gates. Because rotor speed can be controlled by the cycloconverter exciter, the machine can change speed and modulate power output.

The kinetic energy stored in the rotor (rotating inertia) can be utilized in the event of load variations or short circuits by changing the rotor speed. Since the rotor speed can be changed by varying the frequency of the rotor currents (and not only by changing the turbine flow), response time is faster than for a conventional synchronous power generator.

DOE's Energy Storage Section has recently announced a $200 million dollar program that includes funding for projects that provide fast response for frequency regulation (Gyuk, 2009). The performance requirement for frequency regulation ancillary services is: "Fast response multi megawatt system that can achieve full power in 4 seconds or less, up or down. Zero CO2 emissions from operations. Energy storage capacity sufficient to perform frequency regulation as defined by the applicable tariff, 15 minutes as charge to discharge. Minimum round trip efficiency of 75%."

2.2.3 Spinning Reserve

Spinning reserve is another ancillary service that is extremely important to any power system. Spinning reserve is the spare generation capacity (or dispensable load) which can respond rapidly to a sudden loss of generating unit or imported power (EPRI 1989).

There are inherent costs associated for providing spinning reserve to a power system. The benefits, however, may be difficult to quantify. PS projects, in the standby mode, may or may not be classified as spinning reserve, hence it may or may not be given proper spinning reserve credit by the utility. PS projects are sometimes operated below maximum output in order to be able to provide spinning reserve in the generation mode.

There are two parts to potential spinning reserve capability of PS projects: (i) spinning reserve in generation mode, when a PS project is generating at less than its full capacity, and (ii) spinning reserve in pumping mode, associated with the ability of PS units pumping loads to be discontinued instantaneously. Generally, spinning reserve in pumping mode for a PS project may not be of much financial value because spinning reserve may be plentiful in the system during off-peak hours.

An adjustable speed machine provides further economic benefits as it has a wider operation zone in the generation mode and provides spinning reserve capability in pumping mode.

2.2.4 Voltage Control

As for frequency, voltages must be kept within design tolerances. Regulating voltage involves balancing supply and demand of power, although in this case, it involves balancing reactive power, measured as VARs (Volt-Ampere Reactive power), rather than real power. An imbalance in the supply and demand of VARs causes voltage to rise or drop across the power system.

In both pumping and generation modes, voltage control is performed through the voltage regulator which is part of the excitation system. The machine voltage is adjusted by changing the field current via the excitation system.

Both conventional and adjustable speed PS projects can provide voltage control. The power factor over which a pumped storage unit can operate is a design choice. The range of choices for power factor (lagging) is from a low of 85% up to 95%. Once the lower limit of power factor is selected a curve showing the operating range is prepared. Figure 2-1 shows an example of a generator/motor reactive capability curve for round rotor machines. Salient pole machines tend to have much more liberal limits in the under-excited region than shown on this curve.

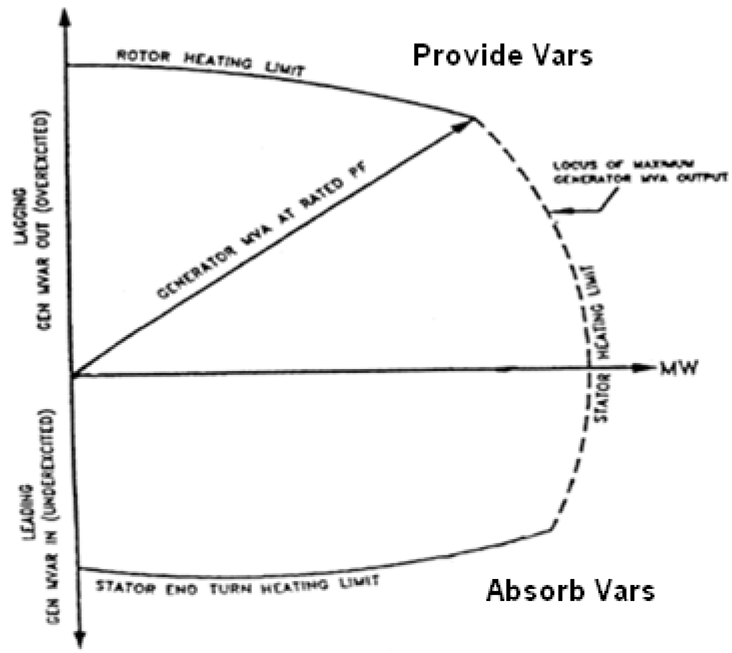

Figure 2-1 Typical Generator Reactive Capability Curve

The selection of the lower limit of power factor is based on the need for reactive power within close proximity of the power plant. If there is a need for reactive power in the vicinity of the plant then a lower power factor is selected. If there is minimal need for reactive power in the vicinity of the plant then a power factor of 95% is selected. Operation in the leading power factor is not always recommended because of concern over transient instability. That concern is however system specific; many of the BPA controlled hydro units operate for extensive periods of time in the under-excited region per request from the Technical Operations section in BPA. Studies have not shown that to be of a concern for many of the main stem Columbia hydro plants.

2.3 Design Criteria for Head, Flow Rates and Reservoir Size

An attractive PS project is one that develops its head with relatively short water conductors between the upper and lower reservoirs. Typically the length of the water conductors range from 4 to 12 times the head. Table 2-2 summarizes key design characteristics of existing projects.

Table 2-2 Existing US Pumped Storage Projects Characteristics

Project	Initial Operation	Installed Capacity (MW)	Hours of Storage	Energy Storage (MWh)	Average Gross Head (Feet)	Water Conductor Length (Feet)	Length to Head Ratio L/H	No. of Existing Res./Lakes
Taum Sauk	1963	350	7.7	2,700	809	7,003	8.7	0
Yards Creek	1965	330	8.7	2,894	723	3,700	5.1	0
Muddy Run	1967	855	14.3	12,200	386	1,290	3.3	1
Cabin Creek	1967	280	5.8	1,635	1,159	4,340	3.7	0
Seneca	1969	380	11.2	3,920	736	2,520	3.4	1
Northfield	1972	1,000	10.1	10,100	772	6,790	8.8	1
Blenheim Gilboa	1973	1,030	11.6	12,000	1,099	4,355	4.0	0
Ludington	1973	1,888	9.0	15,000	337	1,252	3.7	1
Jocassee	1973	628	93.5	58,757	310	1,700	5.5	1
Bear Swamp	1974	540	5.6	3,019	725	2,000	2.8	0
Raccoon Mountain	1978	1,370	24.0	33,000	968	3,650	3.8	1
Fairfield	1978	512	8.1	4,096	163	2,120	13.0	0
Helms	1984	1,200	118.0	14,200	1,645	20,519	12.5	2
Bath County	1985	2,100	11.3	23,700	1,180	9,446	8.0	0

2.3.1 Head

Pumped storage projects have been constructed with heads ranging from about 100 feet to 2500 feet. Most of the projects at the lower end of this range are either multi-purpose projects, pump-back projects, or projects that use an existing lake. The minimum practical head for an off-stream pumped storage project is generally around 300 feet, with higher heads being preferred. Some projects have been built with heads exceeding 3000 feet. These projects involve the use of separate pumps and turbines, or multiple-stage pump/turbines. Studies have also been undertaken to develop PS projects with underground lower reservoirs sited 4000 to 5000 feet below the surface.

2.3.2 Flow Rate

The capacity of a project is a function of the head and the flow rate passed through the powerplant. For a PS project with a given head and reservoir storage volumes, flow rate is determined to achieve a desired cycling time. Higher flow rate lowers the cycling time. Higher flow rate requires larger size of the generating and pumping units, and waterways diameter. Benefit-cost optimization is generally carried out to optimize the design flow rate, and hence the plant capacity. Design flow rate is also constrained by the head loss associated with particular waterways diameter. For a flow required by the power plant capacity, economic diameter of waterways is optimized by balancing the loss of energy benefits due to higher head losses associated with smaller diameters versus waterways construction costs associated with larger diameters.

2.3.3 Reservoir Size

The size of the upper and lower reservoirs are dependent on available head, plant capacity, plant operation, and site characteristics including the cost of land acquisition. Good physical and geological site conditions are vital to create both reservoirs. The upper reservoir is typically created by building a dam across an existing stream, or a ring-dike on a plateau. The lower reservoir is created by building a dam across a small stream, or by using an existing quarry, an underground mine, or a natural lake or reservoir. One PS project in Japan uses the ocean as the lower reservoir.

Both upper and lower reservoirs have usually enough storage to provide generation at full capacity for about 6 to 8 hours. The selection of the reservoir size is dependent upon the site characteristics, the electrical system characteristics and needs, and the amount of non-dispatchable renewable energy to be integrated into the power system. The governing factor is generally the electrical system into which the pumped storage project will operate. Some pumped storage projects have more than 20 hours of operating storage, and some may have as little as 4 hours of operating storage. Those with larger quantities of operating storage were probably planned with the intent of using the weekend for storing energy (weekly cycle). Those with limited storage were probably planned for either primarily reserve operation or daily cycle operation.

For reference, a project where each reservoir has an operating storage volume of 10,000 acre-feet and where the head differential between the reservoirs averages 1,000 feet has an energy content of about 8,800 MWh, based on a generating efficiency of 86.7%. This energy content can support an installed capacity of 880 MW with an energy storage equivalent to 10 hours of operation.

Providing additional energy storage generally becomes increasingly more costly for increasing quantities of energy storage. One can use simulation, production costing models or generation expansion planning models to estimate the reduction in system operating costs for increasing levels of energy storage. Typically the savings will diminish as the storage is increased. By comparing the (1) cost vs. storage and (2) benefit or system operational cost savings vs.

storage, one should find a point where the incremental costs and benefits are equal; this would be the preferred size of the energy storage.

2.4 Pumped Storage Project Efficiencies

Operational efficiency of a pumped storage plant is measured in terms of cycle efficiency. Multiple terms and methods are used to represent the cycle efficiency of a PS project. The term "cycle efficiency", as defined in the ASCE hydropower planning and design guide, is the ratio of the generating output of the pumped storage plant to the generating input, including pump turbine, generator motor and hydraulic losses. Dividing the recorded energy output (from generation) by the recorded energy input (for pumping) would provide cycle efficiency.

A review of the historical data for seventeen different large PS projects in operation in the United States showed that the overall cycle efficiencies ranged from a low of 60% to a high of 80%. Figure 2-2 shows the plant cycle efficiency for nineteen plants commissioned between 1963 and 1995. These cycle efficiencies are representative of optimum operating conditions and related to equipment. They do not include hydraulic losses. It is interesting to note that the overall efficiency has increased over time. Indeed modern equipment has become very efficient.

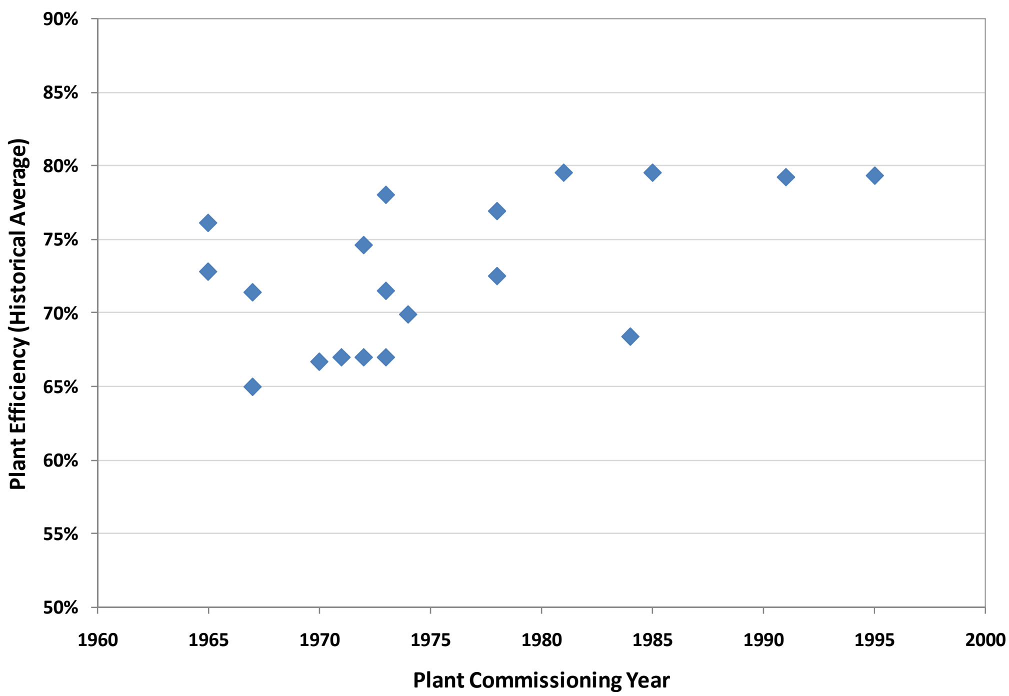

Figure 2-2 US Pumped Storage Plant Efficiency

For planning purposes, an overall cycle efficiency value on the order of 75% is frequently used, including hydraulic losses. It may be possible to achieve 80% or more in a controlled test of evacuating and refilling the reservoir within a short time, with the facility operated at optimized output (sometimes this has been called a test to determine "round trip" efficiency). Also, in the historical vertically integrated utility, an owner had much more control over system operation. However, in actual operation in today's markets, plants often must be operated off best efficiency for overall system economy and market reasons, and the best theoretical cycle efficiency is sometimes not attained.

While it is the combined efficiency that determines the overall economic efficiency of a pumped storage project, the efficiency of each component and subcomponent can be evaluated and measured individually. Table 2-3 gives the typical ranges of efficiency values associated with the water conductors, turbine/pump, generator/motor, and transformer for the generating and pump cycles, and operation of typical conventional single-speed PS projects.

Table 2-3 Composition of Pumped Storage Hydro Plant Cycle Efficiency

	Component	Indicative Value, %
Pump cycle	Water Conductors	98.0 - 98.6
	Pump	90.0 – 92.0
	Motor	97.8 – 98.3
	Transformer	99.0 – 99.6
	Overall	*85.4 – 88.8*
Generating cycle	Water Conductors	98.6 – 98.0
	Turbine	75.0 – 91.0
	Generator	97.8 – 98.3
	Transformer	99.0 – 99.6
	Overall	*71.6 – 86.4*
Operational	Losses & Leakage	98.0 – 99.8

As an example, Figure 2-3 and Figure 2-4 show representative turbine efficiency curves over a range of head and power output for both single and adjustable speed units.

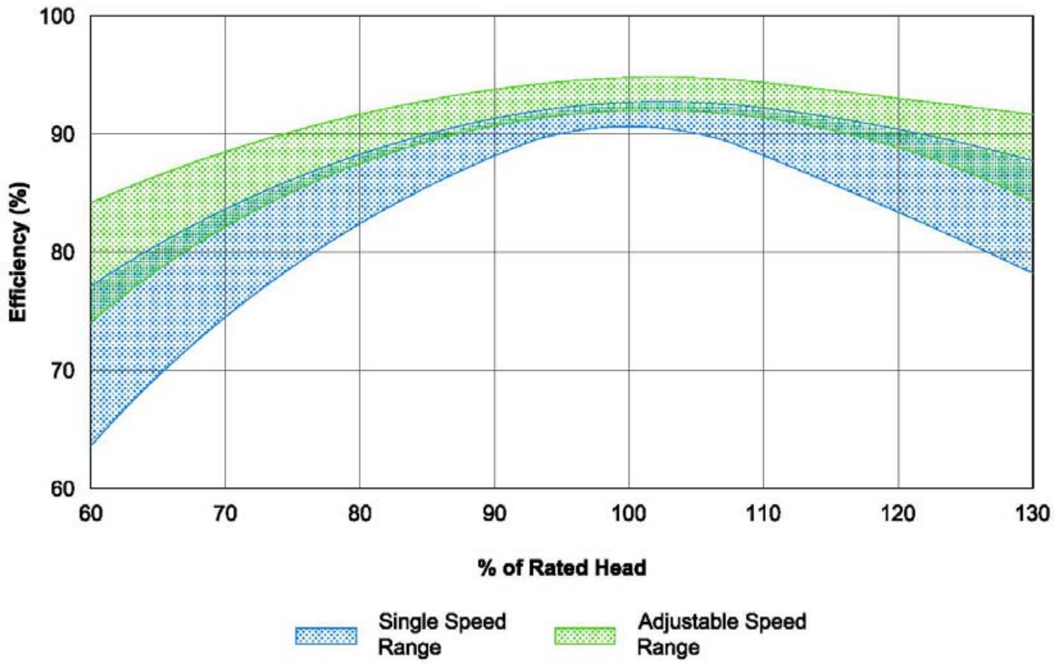

Figure 2-3 Turbine Efficiency Versus Rated Head

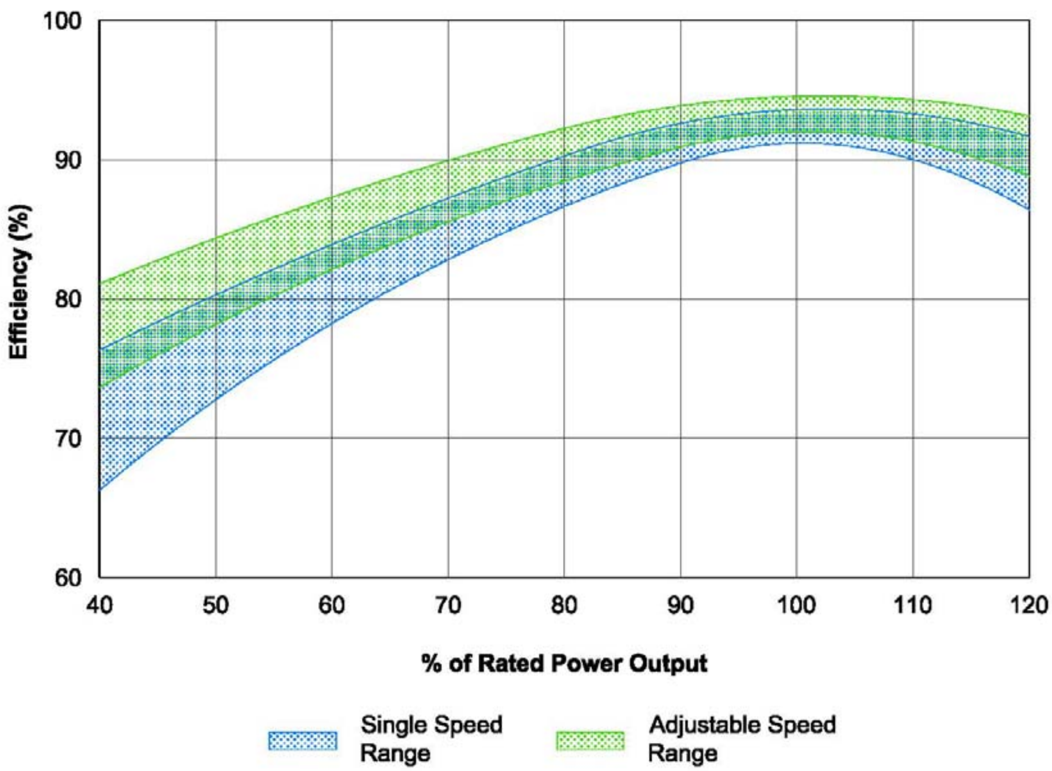

Figure 2-4 Turbine Efficiency Versus Rated Power Output

Efficiencies through the water conductor are highly site specific. Design of a complex system of waterways could improve the efficiency associated with the water conveyance. While the motor-generator and transformer tend to have a pretty flat efficiency curve, efficiency of a pump-turbine varies significantly with the net head and/or water flow. Peak turbine efficiency on a pump-turbine is almost always at a head that is above the operating range, because of the necessary compromise between pump requirements and turbine requirements.

Adjustable-speed operation can provide a noticeable efficiency improvement at low output. For turbine operation the benefits from adjustable speed operation are associated with reduced speed, because a speed reduction will move the operation closer to the condition of highest turbine efficiency. The optimum speed is determined by the net head which varies with the power output.

2.5 Pumped Storage Project Losses

2.5.1 Reservoir evaporation

Evaporative losses depend on the size and location of reservoirs. Shallow reservoirs, located in tropical climates and with a large surface to storage ratio, are much more impacted by evaporative losses than reservoirs in temperate climates. Similarly, a large shallow reservoir will evaporate faster than a small and deep reservoir. Evaporation is greatest in conditions of dry heat and wind. Pan evaporation rates and pan coefficients for a particular site can help estimate evaporative losses from the reservoir. If evaporative losses (or other sources of lost water volume) are significant, supplemental water supply may be required to refill some of the reservoir volume.

2.5.2 Leakage losses

Depending in the geological conditions, a liner may be required in one or both reservoirs to prevent leakage. Seepage through the reservoir liner could occur, although the lining systems may include a leak detection system and seepage collection system designed to capture most seepage through the lining, if it occurs. The effluent from this system would be pumped back to the reservoir, and therefore would not be lost. A main source of leakage is cracks that develop in concrete-lined sections of the waterways.

2.5.3 Transmission Losses

Electric power transmission losses are a function of transmission line length, voltage and conductor size and type.

During the planning phase of a PS project, applicable transmission system planning criteria would be taken into account as part of the transmission planning process. These criteria are established by the WECC, and PNW under NERC review. This planning process would also take into account several transmission interconnection options. The selection of a point of connection for a given PS site could involve a study of whether the point of connection should be a nearby substation or if it should be connected to an existing transmission line.

In the case of a connection to a nearby substation, it would be necessary to determine if there is adequate space in the substation to accommodate the line termination equipment. Another consideration, when connecting to an existing substation, is the issue of access to the substation and avoidance of crossings of existing lines that are terminated in the substation.

In the case of a connection to an existing line, there are options of a ‘Tee Tap” or a loop-in-loop out connection. If a PS plant is to be connected by a long transmission line, then transmission losses can be minimized through an optimum conductor study effort.

When transmission studies are being prepared for several transmission connection options, it will be possible to evaluate the impact of the new PS plant on total system losses. The load flow studies would determine the magnitude of capacity real and reactive power losses under peak and minimum generating and pumping conditions. Based on the demand loss and system load factor, a loss factor would be determined and used to convert the demand loss into an energy loss value. With this process it would be possible to evaluate alternative transmission connection options from the point of view of impact on system losses. In addition to real and reactive power losses it will also be necessary to account for corona losses associated with extra high voltage transmission facilities.

A PS plant that is located at or near an area with voltage and reactive supply issues in the power system grid can provide reactive power control to reduce high reactive power flows and therefore reduce transmission losses. If it is located in an area with potential for voltage instability, the PS plant may also be a positive factor in reducing the risk of voltage instability.

System impact studies will be necessary and will include transient stability studies. These studies will determine the adequacy of the new and upgraded transmission circuits as well as confirm the reliability and dynamic performance of the PS project as part of the interconnected system.

2.6 Response Time of Pumped Storage

Operation of reversible pump-turbine units in the generation (turbine) mode is similar to that of a conventional hydro generator operation. The output of a hydro generator can be adjusted by changing wicket gate opening. Changing wicket gate opening changes the amount of water passing through the turbine. This capability allows the units to be used for automatic generation control, to help regulate frequency and load, when they are in the generation mode.

However operation of a single speed pump-turbine unit in a regulating mode as a generator results in a loss in efficiency. Because efficiency is reduced many single-speed pumped storage plants are commonly operated block-loaded and operated at or near their point of best efficiency.

In the pump mode, the unit operates at the gate openings that allow the most efficient operation for a given head.

Typical turn around and starting times for reversible pump-turbine units are:

- From pumping to full-load generation 2 to 20 minutes

- From generation to pumping 5 to 40 minutes
- From shut down to full load generation 1 to 5 minutes
- From shut down to pumping 3 to 30 minutes

With adjustable speed machines, it is possible to reduce some of these times because synchronization can occur at a lower speed. The control systems can match the rotor electrical speed and the system frequency within seconds. Synchronization can thus occur more rapidly and well before a machine reaches full speed. Further, when the adjustable speed machine is in the pumping mode, speed does not need to be brought to or even near its nominal speed for synchronization. A potential reduction in time of 5 to 15% can usually be achieved.

With a PS system that consists of a single synchronous machine coupled to both a turbine and a pump with a hydraulic bypass or "short circuit", faster turn-around times can be obtained, when going from one mode to the other as no rotation direction reversal is needed.

2.7 Optimum Site Characteristics and Environmental Considerations

2.7.1 Closed System versus River as Lower Reservoir

Recently, a number of pumped storage projects have been proposed that incorporate a “closed loop” system, where both the upper and lower reservoirs are located “off-stream”. It is common for the upper reservoir to be constructed as a basin, where material is excavated from the interior of the basin, and an enclosing perimeter dike is placed to form the reservoir. Examples include Rocky Mountain, Raccoon Mountain, Seneca, Ludington and others. However, in these cases, the lower reservoir is either an existing body of water (Lake Michigan, in the case of Ludington) or a stream (Allegheny River in the Case of Seneca). There may be cases where it is desirable or economic to construct the lower reservoir off stream. This type of development may be considered due to environmental reasons or due to site conditions.

If both reservoirs are off-stream, there will be a need to provide a source of filling water. Proponents have suggested pumping from surface and groundwater sources. Either may be feasible, depending upon the supply availability and local water rights situation. When considering use of groundwater resources, a pumping test to determine the sustainable yield would be required. This can be quite costly and time consuming. One program reviewed by MWH (but never implemented) would have required a test of about six months in duration and a cost of about $500,000. Pumping water from underground sources to balance water losses from evaporation and leakages would require energy and therefore reduce the overall cycle efficiency of the PS project.

Another possibility for filling a closed loop system is to use treated wastewater. Case-by-case study would be required to examine particular water quality considerations, but wastewater treated and used for such purposes as lawn and ornamental irrigation or for dust control could probably be used as the supply for a pumped storage project.

Also when considering off-stream storage reservoirs, there will be a long term need for make up water to replace water lost to evaporation, and also to periodically replace some water for controlling dissolved solid buildup.

At least one developer has in the past proposed reservoirs with floating covers to limit evaporation and the need to furnish makeup water. Two technical problems make the covered reservoir solution difficult. First, the water surface level of a pumped storage reservoir can fluctuate over a wide range, and the concept is untested. Providing a guarantee for the performance of a floating cover would be difficult. Second, solar radiation, in conjunction with the restricted evaporation and its associated cooling effects, would cause the temperature of the stored water to reach high levels. In one MWH study, it was estimated that reservoir water temperatures could reach nearly 150°F without supplemental cooling. The performance of the various systems in a pumped storage project have not been designed or tested for such operation. Technically, it is probably possible to deal with such issues, but realistically, it is preferable to avoid these issues if possible.

In general, it is probably more expensive to develop a closed loop system than a conventional river basin lower reservoir. However, the overall cost of reservoir storage is often a rather small percentage of the total pumped storage hydro cost. If choosing a closed loop system reduces permitting time by improving public acceptance or reducing the impact on existing fisheries, then the added costs may be justified.

2.7.2 Effects on Columbia River Fishery

It is unlikely that development of a new PS facility in the Columbia River basin would be able to free up water for other uses such as fish enhancement since a pumped storage operation would likely not lead to a change in system operations that are prescribed through a complex set of constraints including those designed to protect fisheries. These constraints include meeting spill and flow augmentation requirements, maintaining reservoir levels to protect fisheries in Lake Roosevelt in fall and winter and maintaining flow levels at Vernita Bar in winter and spring.

NOAA Fisheries has listed 13 anadromous fish runs in the Columbia River basin for Endangered Species Act protection. The U.S. Fish and Wildlife Service (USFWS) has listed other non-anadromous fish in Columbia River and its tributaries including bull trout and Kootenai River white sturgeon. NOAA Fisheries Service and USFWS is required by the ESA to assess whether federal actions will jeopardize the continued existence of listed species. It does this through a process of consultation with the Corps, Reclamation, and BPA regarding operation and/or changes to the FCRPS. Consultation typically results in NOAA's issuing a biological opinion (often called a BiOp or BO).

Development of a pumped storage system that could affect future operations of the FCRPS would require consultation with NOAA Fisheries Service and U.S. Fish and Wildlife Service regarding species protected under the Endangered Species Act.

The level of effect on the fishery resources would be highly dependent upon the location and interconnectedness of any proposed pumped storage hydro facilities. Developing a closed loop system would greatly reduce the chance of riverine fisheries being adversely affected. Developing a more traditional pumped storage project using the river or its tributaries for a lower reservoir would require considerable evaluation to help identify potential effects to any listed species or other aquatic species of concern and to help design and operate such a project to protect such species. Possible issues would include effects of reservoir fluctuations on fisheries and protecting fisheries from possible entrainment in the intake facilities of the pumped storage plant. Issues related to fish entrainment into the intake structures and turbines would need to be addressed. Developing an open pumped storage facility using the Columbia River or its tributaries above Chief Joseph dam would limit the concern to non-anadromous fish, however the potential for intake screening would likely still be a consideration depending on the resources in the lower reservoir/river area.

2.7.3 Water Quality Considerations

Hydropower and other storage developments on the Columbia River mainstem create an active storage capacity of more than 46-million acre feet. This volume represents about one third of the mean annual flow of the Columbia River as measured at the Dalles Dam. Reservoirs can provide water that can be used to increase river flows, which in turn can reduce water temperature and increase dissolved oxygen, both considered a problem in the Columbia River mainstem. Increased flows can also reduce inputs of sediments, pesticides, and fertilizers associated with agricultural practices.

In situations where water is diverted and transported out of the mainstem, there could be a net reduction in river flows at times that have the potential to increase stream temperatures. In 2005 the Columbia River mainstem from below Bonneville Dam to the Canadian border was listed on the federal Clean Water Act Section 303(d) list that is used by the Environmental Protection Agency (EPA) to identify surface waters that the state has determined to be out of compliance with water quality standards. The Columbia River was found to be out of compliance at times for temperature, dissolved oxygen, fecal coliform and other toxins in various reaches. The Colville and Spokane Tribes also have water quality standards, similar to Washington State. In past years the total dissolved gas levels in the Columbia River were high, however in more recent times spills from Columbia River dams have been modified to reduce the total dissolved gas levels.

Developing a PS project would require analysis and modeling of likely water quality changes. In an open system PS project, there could be temperature increases to waters of the lower reservoir by cycling the water through the upper reservoir system if exposed to solar radiation and ambient temperatures and wind. In a closed system, the effects to the mainstem river would be limited to non-existent, but the water used in the closed system could have its own water quality problems over time as temperature increases and evaporation concentrates pollutants over time. A water treatment system and program would likely be needed to address water quality considerations of both the initial fill waters, the periodic make up water, and water used in daily operations along with any periodic discharges from the project reservoirs. Ground water could also be affected, both positively and/or possibly adversely; however the lining of reservoirs could reduce leakage and mitigate adverse effects.

It should be noted that indirectly, if the system benefits of operation of PS project helped reduce or conserve other energy resource extraction that had consumptive uses of water in the Columbia River basin, then offsetting those uses with operation of the PS project could result to some increase in the water availability for other beneficial uses.

2.7.4 Cultural Resources Considerations

Cultural resources are protected at the state and federal level. Effects of a pumped storage system in the Columbia River Basin could affect cultural resources such as historic properties, archaeological, and Native American resources include tribal reserved water rights and traditional cultural use areas or places. Most federal permits or funding requirements necessitate compliance with Section 106 of the National Historic Preservation Act (36 CFR 800). Section 106 requires that the effects of an undertaking on historic properties within the project's Area of Potential Effects (APE) must be considered. Other federal laws that may apply at the project level include the Native American Graves Protection and Repatriation Act, which regulates the inadvertent discovery of Native American remains on Federal or Tribal lands and Archaeological Resources Protection Act, which regulates excavation of sites on Federal lands. The American Indian Religious Freedom Act affirms the right of Native Americans to access their sacred places. All of these laws could likely be applicable to the siting, development and operation of a pumped storage project in the Columbia Basin.

Tribal water rights for out-of-stream uses are generally set in terms of priority in the western water rights doctrine by the date the reservation was established. The priority date for water rights for fish and instream flows may also have to be considered in a pumped development scheme that uses Columbia River Basin waters depending on the location of such development. Additionally, different Native American groups continue to have access to their "usual and accustomed places" for a variety of traditional uses, including in areas outside of present-day reservations. In the Columbia River Basin this includes access to traditional fishing areas along the river and its tributaries, and hunting and gathering in shrub-steppe habitat. Cultural resources studies and government to government consultation efforts would be required to evaluate the effects of a particular pumped storage system on such potential resources.

The Columbia River Basin Tribal Groups and Reservations to consider in the early planning of pumped storage projects include:

- Confederated Tribes and Bands of the Yakama Nation (Washington)

- Spokane Tribe of Indians (Washington)
- Shoshone-Paiute Tribes of Duck Valley Reservation (Nevada)
- Shoshone-Bannock Tribes of the Fort Hall Reservation (Idaho)
- Nez Perce Tribe (Idaho)
- Kootenai Tribe (Idaho)
- Kalispel Tribe of Indians (Washington)
- Confederated Tribes of the Colville Reservation (Washington)
- Confederated Salish and Kootenai Tribes of the Flathead Reservation (Montana)
- Confederated Tribes of the Umatilla Indian Reservation (Oregon)
- Confederated Tribes of the Warm Springs Indian Reservation (Oregon)
- Coeur d'Alene Tribe (Idaho)
- Burns Paiute (Oregon)

2.7.5 Impacts to Recreation

Because of the extent and frequency of cycling of waters in a PS system, one or both reservoirs experience large fluctuations in water levels which can make them unsuitable for recreation. In an open system where the lower reservoir is a larger reservoir, the effect can be minimal (i.e. John Day or McNary Reservoir) because the amount of water cycled through the system is small when compared to the size of the reservoir. Most pumped storage systems developed under FERC licensing have developed nearby recreation opportunities to offset any perceived or real losses to recreation resulting from the development and operation of a PS project. Many PS projects can offer non-water based recreation opportunities that can be provided by designing the project around community needs depending on where a facility is sited. Most closed system sites are generally not in locations of high recreation uses, although aesthetic considerations will arise in the planning that can also be mitigated through proper design considerations.

3 OPERATIONAL ASPECTS OF PUMPED STORAGE

3.1 Pumped Storage Operation in a Power System

The traditional mode of operation for a PS plant is to pump sometime after 10 PM through midnight and into the early morning hours, during the period when low cost pumping energy is available from base load units, and to generate during day time peak periods when energy values are highest. Since the electrical demand is usually less during the weekend, there is more low-cost pumping energy available. In a weekly cycle the upper reservoir is full on Monday morning and nearly empty on Friday evening. The units generate during the week as part of the weekly dispatch. During the weekend, the units pump to completely refill the upper reservoir.

Figure 3-1 is an example of a weekly operating cycle for a conventional PS plant. The pumped storage operation is used to supply the power for peaks of the system load. It is to be noted that Figure 3-1 is generic in nature and does not illustrate the sharp changes in system load as pumps are started and stopped.

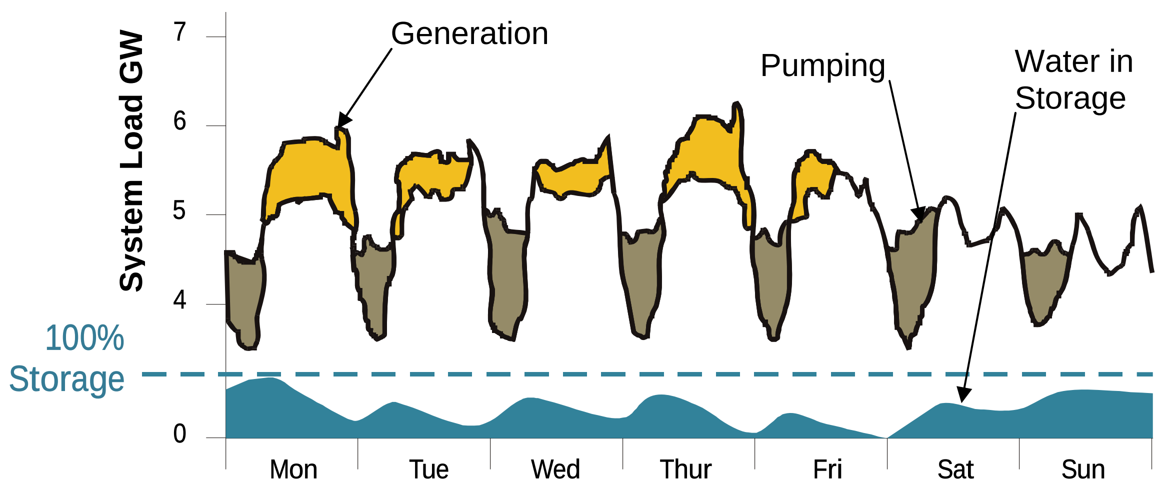

Figure 3-1 Representative Weekly Pumped Storage Operating Cycle

The advent of FERC Rule 888, and subsequent related rules for Open Access Transmission and power marketing, has resulted in new operating requirements that impact PS operation. The energy arbitrage function can remain as the basic economic driver for plant revenue. However it is now possible for a PS plant to receive revenue for the class of services identified as ancillary services. These services were previously bundled into the overall plant operating costs and it was not possible to obtain revenue directly for these services. In the deregulated system these services are now sources of revenue. The basic ancillary services that impact directly on daily PS operation and are recognized by FERC rules include: energy balancing (aka frequency regulation), load following, and spinning reserve. Voltage support is often included in the list but it is not yet one that is providing revenue in most markets.

In addition to the changes associated with the deregulated market there is the added issue of integration of intermittent renewable resources such as wind and solar. As noted in Section 5 the issue of wind integration into the PNW is a critical one. With the resolution of this issue as a work in progress, it should be possible to use existing PS and hydro units in PNW as a system resource for wind integration.

Pumped storage can be of great advantage in the shorter time frame, within the hour, minute, or even real-time to assist in the wind integration task. First is the ability of pumped storage to store energy when surplus energy is being produced by wind powered generators. But the storage of surplus renewable energy at any time of day, if it cannot be absorbed by the grid, could result in a change to the basic daily pump-generate cycle. In this case it would be necessary to change units from generation to pump during the day time hours so that surplus energy from wind powered generators could be stored.

One of the bigger advantages to the adjustable speed systems may lie in the real time or hours/minutes periods of power system operation. As the variability of the output of wind generation is not confined to off-peak or on-peak hours, a solution to "absorb" or "smooth out" that variability is needed at all times of the day. Modern pumped storage systems can provide this "smoothing" in several ways. In off-peak periods, where the pumped storage system may be in pumping mode, the level of pumping on-line could be higher than 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 plant is generally in generating mode, the actual output of the pump generators could be adjusted such that the wind plus the pump generation output is smoother within the minute or hour to minimize load change impacts on other units in the area.

There are examples of this type of operation in Europe. The Vianden PS plant in Luxembourg, for example, makes multiple mode changes from generation to pumping throughout the day.

Second is the need for fast response on a short term basis. In this regard there is a need for a PS unit to provide fast response for frequency regulation, load following and spinning reserve, and these capabilities are indeed available from PS plants.

3.2 Operating Characteristics of Pumped Storage

The operation of reversible pump/turbine units in a pumped storage plant provides the basic operating characteristics. The operating characteristics are determined by the hydraulic limits of the pump/turbines that are established within the limits of head, flow, cavitation, and turbulence. There are also limitations imposed by the wicket gates as well as considerations about efficiency and power.

Until the introduction of adjustable speed machines the speed was a constant, and imposed limitations on the range of operation in generating and pumps modes. The following is a discussion of single speed units and adjustable speed units.

3.2.1 Single Speed Units

In the generation mode, a conventional synchronous speed unit can typically operate over a range of heads from about 65% to about 125% of the rated net head, where the rated net head is the head that generally corresponds to the head at which full power is achieved. The best efficiency point is always above the maximum operating head because of the necessary compromise between pumping and generating. As the upper and lower reservoirs fluctuate during the course of a generating cycle, the head will be progressively reduced, and the amount of water to produce a given amount of power output will increase in response to this reduction in head and the associated reduction in the operating efficiency.

Similarly, a conventional synchronous speed unit can typically operate over a range of flows down to about 50% of the rated discharge, where the rated discharge is the discharge that produces the power to match the generator rating at the rated head. Normally the unit would be designed so it produces the rated power output when the wicket gates are near or at 100% open. If the unit has been sized according to this rule, then the discharge would need to be curtailed to produce rated generator power at heads greater than the rated head.

Often there is a “rough operating zone” between about 35 to 50% of the rated discharge where excessive vibration may occur. Often a unit may be operated at very low power output, below 35% of the rated discharge, without problems. The rough operating zone is caused by the action of the part load vortex that is a normally occurring phenomenon in a fixed blade Francis pump-turbine runner. The vortex “rope” rotates at about 1/3 of the synchronous speed.

The part load vortex typically diminishes in intensity and eventually disappears at decreasing wicket gate openings below the rough operating zone. In some cases, the pump-turbine can be operated continuously in the generating mode at gate openings below the rough operating zone, without vibration or cavitation. This operation can be beneficial as it can be marketed as “on-line spinning reserve”. Sometimes the rough operating zone is not very bad or it can be masked by the use of smoothing air – but it is always there.

A conventional synchronous speed pump-turbine, in pumping mode, has a fixed relationship of power input requirement vs net head. In the normal range, there is a single value of power input for any given value of net head, with essentially no flexibility in terms of operating with less or more power. There is some limited capability for adjusting the power by adjusting the wicket gate opening but the reduction in efficiency is so great that this option is used only in special circumstances. For practical purposes, therefore, the pump is almost always operated at best-efficiency wicket gate opening. The instantaneous head differential between the upper and lower reservoirs, combined with the number of units operating on a given water conduit, will then control the amount of power required to operate the unit. The discharge rate is determined by the head, the power input, and the efficiency of the pump-turbine for the prevailing conditions. An important exception to this general trend is the pumping instability condition which, on a fixed speed pump, must be arranged to take place above the maximum operating head. This condition becomes an important constraint with adjustable-speed operation, as discussed elsewhere in this report.

The pump turbine design must provide for trouble-free operation over the range from minimum head (which occurs at the beginning of the pumping cycle) to maximum head at the end of the pumping cycle). A curious characteristic of a synchronous speed pump is that power requirement to run the pump at a fixed speed generally decreases as the head increases. Therefore, during the course of a pumping cycle, maximum pump power input for a particular unit occurs at the beginning of the pumping cycle, and decreases as the water is transferred to the upper reservoir. Similarly, the pumped flow rate decreases at a much greater rate as the head increases, because power is a function of head, flow and efficiency.

In unusual circumstances, a pump-turbine may experience instability near the end of the pumping cycle as the head approaches the maximum. Typically, in siting studies, one factor is to consider the ratio of the maximum head to the minimum head to avoid the need to consider large variations in pumping head in the design of the pump-turbine.

3.2.2 Adjustable Speed Units

In the generation mode, the capabilities of an adjustable speed unit are quite similar to a single speed unit, except that the operating efficiency can be optimized by adjusting the speed for the prevailing head and desired power output. For example, with adjustable speed it would be possible to operate at the point of maximum turbine efficiency, which is normally at a head that is above the normal operating range for a fixed-speed pump-turbine. It may also be possible to avoid the issues of operating in the so called “rough operating zone” that would exist for the synchronous speed unit. For example, in Yagisawa plant a reduction in rough operation was reported (Tanaka 1991).

In the pumping mode, the differences are much more significant. As stated above, the fixed-speed operation is along the fixed relationship of discharge vs. head, and wicket gates are normally positioned to provide the least throttling effect (reduce the losses) at the prevailing head and speed. Throttling with the wicket gates in pumping mode is undesirable because it produces vibrations and it also increases the losses. As can be expected and as confirmed by experience, adjustable speed machines can be effectively used to extend the single pump operating curve to a broad range of pumping operation, and provide positive control over the discharge and the required input power.

With adjustable speed hydro the limits of the pumping range are normally defined by cavitation (low head, high speed operation), motor-generator output (medium to high head, high speed operation), turbulence or reverse flow (high head, low speed operation), and range of operating speed. Although these limits seem to be very restrictive, in reality the improvement in operating range is extremely impressive, especially when considering the possibilities of how the extended range can be used to avoid cavitation and reduce input power at low heads, adjust pumping power, avoid reverse flow at high head operation, and provide frequency control in the pumping mode.

Figure 3-2 and Figure 3-3 show the operating ranges for an adjustable speed machine. These figures show that the operating range in the generation mode is increased from what it would be if the machine were a conventional single speed unit. In the pumping mode, the figure shows the operating range that is possible. As explained above a conventional single-speed unit in pumping mode can only operate along a single line whereas an adjustable speed unit can operate within a range. The graphs are for the adjustable speed pumped storage machines at the Ohkawachi plant in Japan (EPRI 1995).

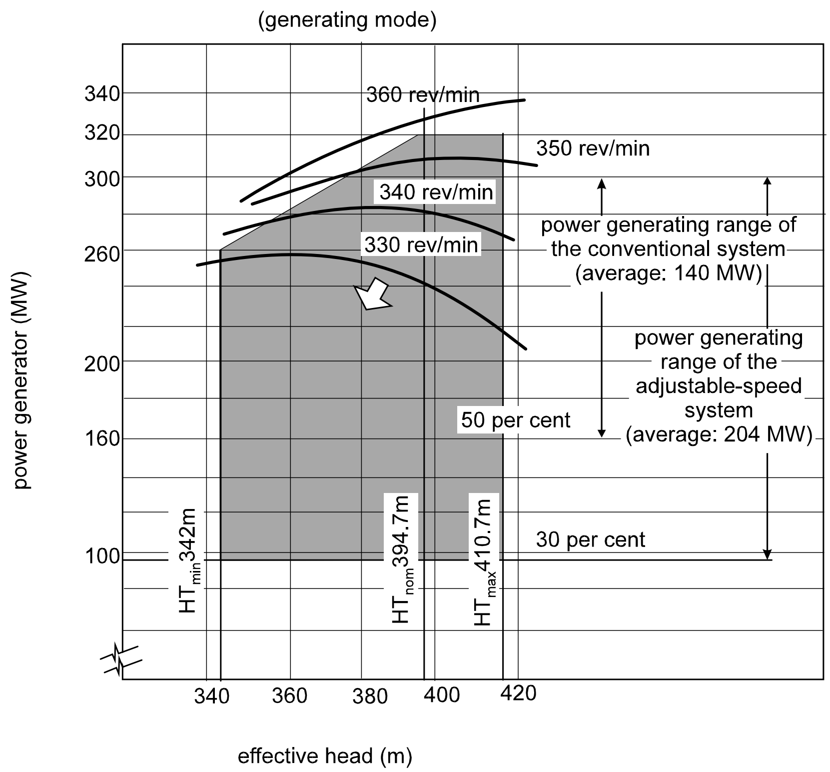

Figure 3-2 Single Speed PS vs Adjustable Speed PS Generating Range

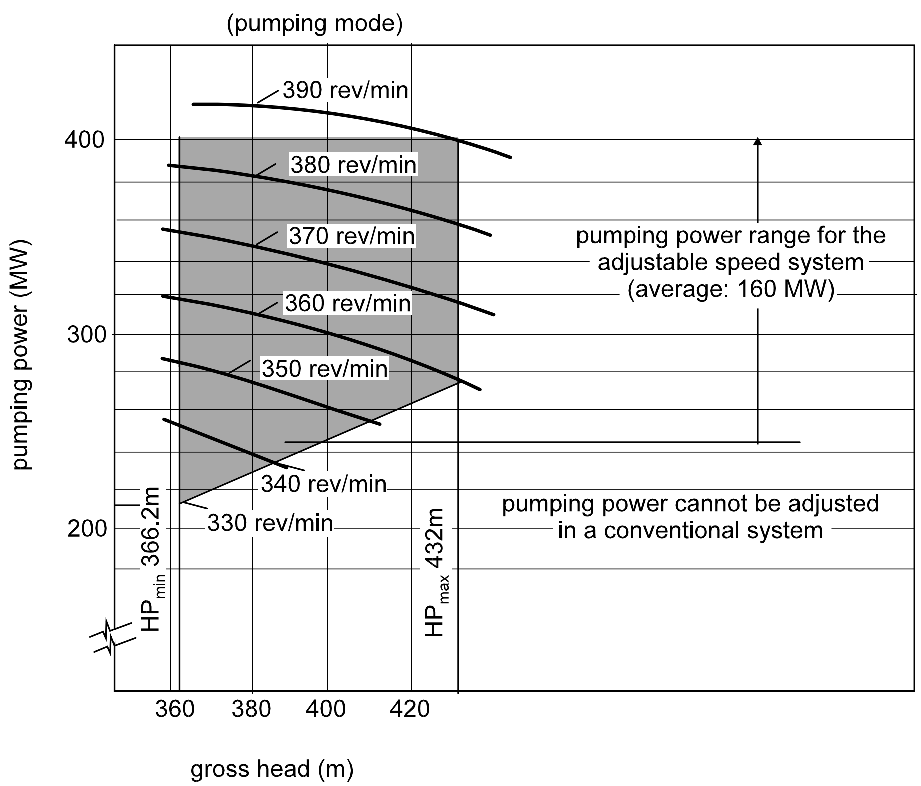

Figure 3-3 Single Speed PS vs Adjustable Speed PS Pumping Range

3.3 Storage and Shaping

Reservoir size and elevation difference are significant characteristics in relation to storage and shaping capabilities. The economic sizes of upper reservoirs will determine the amount of water that can be transferred without an interim discharge or recharge. The volumes of those reservoirs, together with the available head difference will determine the total amount of electric energy that could be stored or released without an interim discharge or recharge. The generating / pumping capabilities will determine the power that can be absorbed or returned at any instant.

A PS plant with two or more units can be used to provide different services. A plant with multiple units can be used to provide both storage and shaping as well as regulation and load following. Flexibility can be accomplished by assigning one unit to shaping and load following and another to regulation. This operating flexibility can be expanded if one or two units are of the adjustable speed type.

As long as there is water in the upper reservoir, a pumped storage unit has the best sustained response to a load change or a change in power output from intermittent resources.

3.4 Ancillary Services

There are several basic components that need to be considered from an operational point of view. These include: upper and lower reservoir size, hydraulic head, penstock length and diameter, above ground or underground plant, transmission interconnection and pump/turbine and generator motor capabilities.

Figure 3-4 shows the relative time ranges in which the various power system control functions occur and the expected response time of single speed and adjustable speed machines. Surges and power swings are power system events and are shown to provide a time reference within which the machine responses occur.

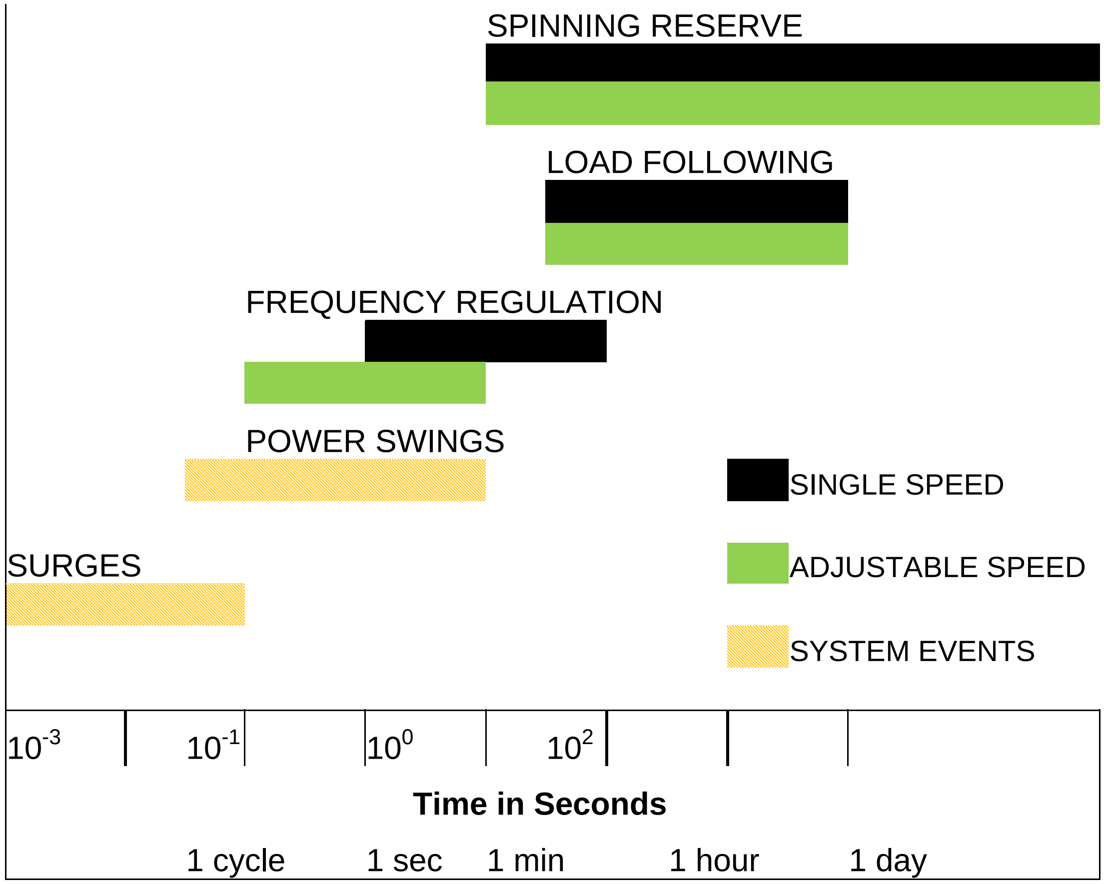

Figure 3-4 Power System Control Functions

3.4.1 Spinning Reserve

With a PS plant, spinning reserve can be provided in both pumping and generating modes. In generating mode the units can be operated at less than rated capacity so that there is capacity available to provide spinning reserve. In the pumping mode spinning reserve is available by reducing pumping load.

In the case of a single speed unit the amount of spinning reserve in pumping mode at any given time is equal to the pumping power input of a unit at the then existing head. For single speed pumps the amount of spinning reserve is equal to the full pump rating of the machine because a single-speed pump must operate at the power input associated with the given head. If the pump is to be used for spinning reserve, it must be disconnected when the reserve is required. In this case the pump is an interruptible load.

With an adjustable speed machine it is possible to have spinning reserve in both pumping and generation modes. With adjustable speed the range of operation in generation and pumping modes allows spinning reserve amounts to be selected and controlled at any value within the operating range of the units. The limit is up to maximum acceptable motor input power and down to some designated margin from the instability condition at any given head.

3.4.2 Load Following and Frequency Regulation

The goal of frequency regulation and load following is to balance load and generation, and keep the frequency constant. Balance between load and generation is achieved by changing output and is part of the automatic generation control (AGC) function.

Frequency regulation is accomplished by injecting or withdrawing real power from the grid, in response to small changes in frequency. When frequency is greater than 60 Hz there is more generation than load and when frequency is less than 60 Hz there is less generation than load. The speed governor on a turbine is used to control the power output of an individual generating unit. It allows that unit to contribute to overall system frequency control.

Load following is accomplished by changing generator output either increasing or decreasing. Load following is at a greater (slower) time scale than frequency regulation so load following is done by units with slower response times. In the case of fossil fueled generators, load following involves unit commitment decisions and takes into account heat rates, start up and shut down costs as well as maintenance considerations. For hydro plants load following also involves unit commitment decisions but instead of fuel costs the decisions involve water availability.

Frequency regulation and load following characteristics of a PS plant are determined by the response rate of the pump/turbine and generator/motor. The response time of a conventional single speed PS unit is determined by machine inertia, speed governor, gate opening and closing time and water column time constant. Water column time constant is a function of penstock length and diameter. Plants with short penstocks or high heads are generally more responsive than plants with long water conductors or low heads. It should be noted that a conventional single-speed pumped storage unit can only provide regulation and load following service in the generation mode. As noted in other sections, a single speed PS unit cannot provide regulation or load following service in pumping mode.

With the advent of adjustable speed PS machines, it is possible to provide regulation and load following in both pumping and generation modes. In addition to the added regulation and load following capability in pumping mode, an adjustable speed machine can provide faster response than any other machine on the system. The frequency can be increased by, in effect, causing the generator to slow down while the cyclo converter drives the frequency in the other direction.

As shown in Figure 3-4 the relative time ranges in which the various power system control functions occur. Since the adjustable speed PS machine has the fastest response rate of generators on the system it is suggested that it would be used as the preferred machine for frequency regulation. Load following function would be assigned to conventional hydro, combustion turbines and other generators with appropriate response capabilities.

If frequency regulation is assigned to the adjustable speed PS project then there should be a cost savings to the system. The cost savings would be in the form of reduced consumption of imported oil and natural gas that would otherwise be used by combustion turbines and steam units for frequency regulation services. A similar savings would also accrue if conventional hydro were used.

3.4.3 Response Time

The introduction of intermittent renewable generation (wind and solar) has resulted in the need for more short-term response generation for system regulation service. The unpredictable output from intermittent resources requires that regulation units be able to provide fast response at all times of the day. Pumped storage with adjustable speed machines can provide the fast response that is required in both pumping and generating modes.

The ramp rate is the maximum rate at which a unit's output power can change, expressed in percent of rated capacity per second. The maximum ramp rate (OTA, 1989) for a conventional PS facility with single speed synchronous machines under AGC control can be in the range of:

- Small units (10 to 59 MW) 1 to 6% per second
- 60 MW and above 4 to 6% per second

The 4% and 6% limits are typical limits and there can be units with ramp rates that are outside of the limits given. There can be larger machines with ramp rates greater than 6%. Figure 3-5 illustrates different types of responses to a load increase on the system.

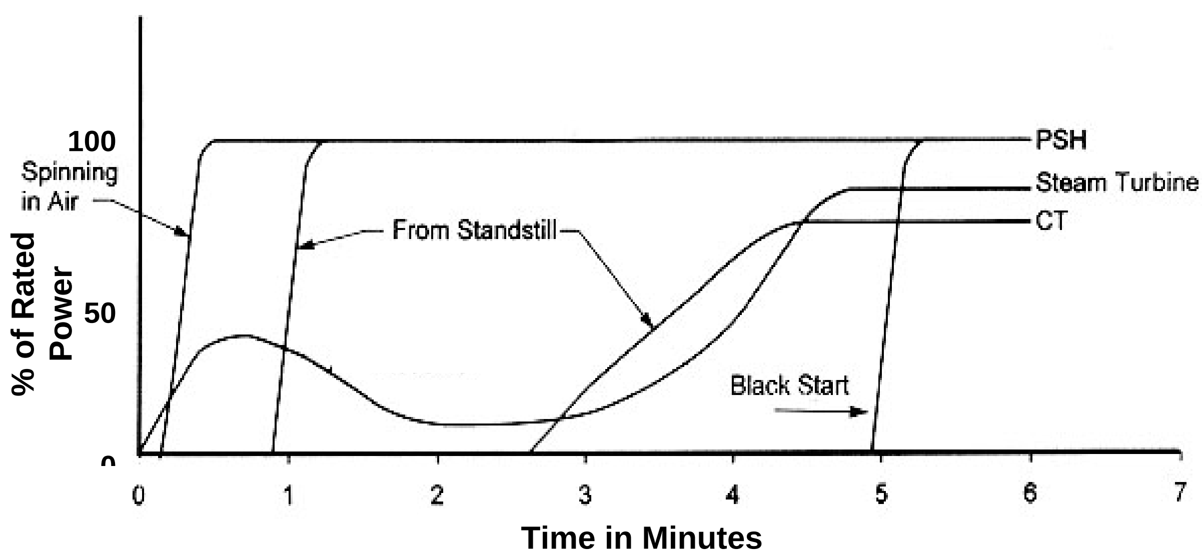

Figure 3-5 Comparison of PS, Steam Turbine and CT Response Time (Fisher 1994)

Figure 3-5 shows a PS unit in the generation mode going from the synchronized spinning in-air mode to full output in less than one minute. This is a simplified illustration because the full load condition can be achieved faster but there will be an initial power input surge as the water is flushed out of the runner. The figure also shows that once at its maximum the unit can sustain the maximum output for an extended period. Again, this is a simplified illustration because a sustained drawdown of the upper reservoir will eventually reach a point where the output is limited by the available head.

Ramp rates for combustion turbines are on the order of 55% per minute (OTA, 1989). Steam Units (all fuels) are often between 2% and 8% per minute, depending on the size of the units. For example, combustion turbines can react more quickly than steam units and some hydros.

The droop setting on a governor is used to allocate response to system load changes to designated generating units according to their response characteristics. Generally, droop is set at 5% on large interconnected systems. The droop is set higher for boiler equipped power plants so they are less susceptible to frequency changes. Hydroelectric generators and PS units, combustion turbines and diesel generators can be set at 3% so they take most variations of load. All units in Western Electricity Coordinating Council (WECC) control area are set to 5% (BPA 2009).

In addition to the added capability in the regulation and load following functions an adjustable speed machine can provide faster response than any other machine on the system. This faster response capability is due to the fact that with an adjustable speed machine the change in output is accomplished by electronic means via the excitation system. The fast exciter allows the unit to speed up or slow down in milli seconds and inject or absorb energy stored in the spinning inertia of the unit.

An example of the faster response time is reported by the owners of the Ohkawachi PS plant in Japan. In tests of the machines' performance in meeting a sudden need to increase or decrease power input during pumping operation, a command was given to increase power load from 246 to 400 MW in 20 seconds. (154 MW/20 sec = 7.7 MW/sec) With the increase in the required value, the wicket gate opened, and rotation speed increased, to achieve the desired operating condition (Kita, E., Ohno, Y., Kuwabara T., & Bando, A, 1994).

3.4.4 System Dynamic Performance

Pumped storage has historically been categorized as a generation asset. However in the modern North American power system, with its emphasis on generation being separated from transmission, there is an opportunity to add pumped storage as a transmission asset as well (IEEE, 2007). Recent experience with the Dinorwig PS project in U.K and the Vianden PS project in Luxembourg are two examples of how a pumped storage plant can be used to provide system wide transmission services in a deregulated environment.

When pumped storage is viewed as a transmission asset, then its capabilities to provide shaping, frequency regulation, load following and spinning reserves takes on added relevance. Under the present system of Regional Transmission

Organizations (RTO) and Independent System Operators (ISO), together with new legislation that puts an emphasis on power system reliability and operation, pumped storage can play a unique role.

For example, BPA uses Special Protection Schemes (SPS) to provide system dynamic performance and reliability during underfrequency and undervoltage events to avoid cascading outages. These schemes include shedding of large industrial loads that can be disconnected, when necessary, to deal with system disturbance events. The use of SPS has technical and financial consequences to the owner/operator of the industrial load. Such actions could be reduced with a PS plant as part of the transmission grid system, and would provide a quantifiable benefit in the form of an avoided cost for an interruption of service.

SPS are also a concern because they rely on the operation of the industrial plant at the time when a system disturbance occurs. If this service could be provided by a PS plant that was part of the overall transmission control system, then there would be greater confidence that such events would be successfully dealt with.

The ability to control power flows and contingency events in this bulk power system requires state of the art controls and techniques. Although the use of SPS has been used extensively, it may be reaching the limits of their capabilities with more and more wind power coming on line. In recent years, several studies and plans for the adoption of new control techniques based on GPS-synchronized phasor measurements techniques have been undertaken. Phasor measurement based systems (IEEE, 2005) are a basic component in the Wide Angle Measurement System (WAMS) and Wide Area stability and voltage Control System (WACS).

The WACS system employs strategically placed sensors that react to arbitrary power system disturbances, and trigger discontinuous action such as generation tripping or capacitor switching. The WACS platform could also be used for control of generators, such as adjustable speed or ternary PS units. The time in which system wide contingency events occur is in the time range of a few electrical cycles (one 60 Hz electrical cycle is 16.7 milli-seconds) to several seconds. In this time it is necessary to identify that a contingency event has occurred, communicate the information, and implement corrective action (CIGRE, 2007). With the new PS technology, it is possible to exchange energy between the rotating mass of the machine and the transmission system. The excitation system of an adjustable speed machine directly controls the torque angle of the doubly fed machine. This allows the machine to respond to a change in speed in milli-seconds. It should be possible for a pump storage machine to provide system damping during transient disturbances. Most of the existing transmission limitations are thermal and voltage stability in nature but that could change to transient stability as the transmission system is stressed more in the future.

If another PS plant was part of the PNW system and if it had sufficient capacity, it could be used to inject or absorb power to the grid and provide a stabilizing service during system disturbances. Such a response has been observed in Japan at the Ohkawachi plant (Kuwabara, 1996). The referenced paper describes the system damping capability of a 400 MW adjustable speed machine in the Ohkawachi Pumped Storage Plant on the Kansai Electric System in Japan. In the paper, the authors note that unit number four was in operation when the Hanshin earthquake occurred on the morning of January 17, 1995, and they report that the machine absorbed power disturbances in random spikes.

3.4.5 Black Start Capability

Black start capability is recognized as an ancillary service within the deregulated power system markets. Black start service is the component of total system restoration requirement, under control of the system dispatcher. Black start requires a plant that can provide sustainable power quickly to the power system at rated voltage and frequency from a source that has been isolated and lacks an offsite source of electrical power.

Black start capability of some power plants is essential to facilitate recovery restoration following a system blackout, and is thus a critical requirement for most utilities. Hydro plants provide a robust source of power for line energizing, black starting thermal plants and a source of voltage regulation and load following to help restore the transmission grid following a blackout. A PS plant with conventional or adjustable speed units can provide black start service. Because of its tight control of reactive power and frequency, an adjustable speed machine may have advantages over a conventional synchronous machine.

To provide black start service, a PS plant uses its generators and water stored in the upper reservoir. A source of dc excitation is needed to initiate build-up of motor/generator stator voltage which, in turn, can be used by the cycloconverter to develop rotor voltage. This can be provided by a battery, or a diesel generator.

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4 PUMPED STORAGE PROJECT ECONOMIC CONSIDERATIONS

The objective of this chapter is to provide an overview of aspects related to the economic evaluation of pumped storage hydropower to facilitate the development of a large block of wind generation in the Pacific Northwest Region. The objective of an economic evaluation is to demonstrate that a particular long-term generation and transmission plan, which may or may not include pumped storage, results in the lowest long-term cost of supply, given a minimum level of reliability, and given other constraints, such as a minimum quantity of power and energy supplied by renewables.

Economic analysis includes the consideration of capital and operational costs for various technologies that may be included in a future generation mix. Although there is limited publically available historical cost information available on pumped storage hydropower, characterizing the probable costs is relatively easy in comparison with characterizing the benefits. Costs can be characterized by examining historical information (although the available information is limited) or developing physical layouts and estimating budgetary costs.

The much more difficult task is the actual quantification of benefits, which can only be established through detailed operational modeling. The second section of this chapter summarizes the ancillary services capabilities of pumped storage (which are more fully described in previous sections) and attributes that make it a suitable technology for facilitating the integration of wind into an electrical supply system grid.

The objective in an economic study is to determine which course of action is the low cost plan for delivering power and energy given the specified development and operational constraints. The means is not necessarily a direct comparison of two different project types, because different solutions to wind integration have differing operational characteristics that are not directly comparable. Detailed production simulation modeling is required. The framework for operational modeling to quantify benefits is described in the third section of this chapter.

4.1 Project Costs

This section provides a general discussion on (1) capital costs and (2) operational costs.

4.1.1 Capital Costs

Pumped storage project development costs are difficult to characterize in terms of “typical costs” for the following reasons:

1. Pumped storage site conditions - physical, geological and environmental - weigh heavily in the determination of project costs.

2. Only the owners of pumped storage facilities are in a position to truly compile all project costs, which occur over a number of years, in escalating currency. In the US, regulated utilities report capital cost information to the FERC. However, not all owners may treat costs or

allocate costs in a similar manner, so reports on actual costs may not be comparable. For example, a transmission interconnection, potentially a relatively large cost item, might be treated as a project cost by one owner and a transmission improvement cost by another owner.

3. There are relatively few pumped storage projects existing in North America from which valid statistical analysis to support a typical cost characterization can be made.

The development cost of a pumped storage facility includes many “soft costs” which are not direct construction and equipment procurement costs. The cost of construction and equipment procurement is only a portion of the total project cost. In a typical pumped storage project, there are substantial costs for preliminary and environmental investigations, design engineering, land procurement, financing and interest costs, legal costs, independent engineering and review costs, owner’s allocated administrative and management costs, construction management costs, and O&M startup costs. Given that a typical pumped storage project has a long development period (10 years or more from initial concept to start-up), costs are escalating, and estimates and budgets must consider this factor. Allocation of risk and the owner of contingency funds affects the budget. Lastly, changing environmental planning constraints and changing market conditions create costs not specifically identified in project budgets. Therefore, adequate contingencies are important components in a project budget. The key point here is that when a project cost is cited, it is critically important to note what is being included or excluded. A full, all-in project cost with all escalation, contingency allowances, engineering and financing costs may be double the construction and equipment procurement bid price.

The following describes two cost studies carried out in an attempt at characterizing capital costs. In the first study (Section 4.1.1.1), historical data was compiled and analyzed with the objective of establishing cost trends as a function of some key characteristics.

In the second study (Section 4.1.1.2), cost data for projects that have been studied recently was tabulated and analyzed to determine if any trends or “rule of thumb” could be identified.

4.1.1.1 Historical Capital Cost Information

There are 36 licensed i.e. non-federal and operating pumped storage projects in the US. Of this group, 14 are considered to be relevant to the current study of pumped storage costs. The other 22 projects excluded and not considered in the study are pump-back schemes, or are part of larger water supply projects, and the reported costs are not considered as good indicators of conventional pumped storage development costs. This could be further investigated and refined if given more time to perform the analysis.

The 14 projects selected for use in the analysis are listed in Table 4-1.

Historical cost data used for this study was acquired from the "Compendium of Pumped Storage" and FERC Form 1 reports. Historical costs have been adjusted to present day (year 2009) price levels incorporating the following assumptions:

1. It is assumed that the reported costs are actual expenditures for relevant hydropower plant expenditures as defined by the Uniform Cost Accounting System outlined in 18CFR Part 101. It appears that data represents expenditures over the construction period (and beyond), and thus incorporate an escalating price level base.

2. The "Compendium of Pumped Storage" provides a price level year and a construction cost per kW for each project. The construction cost is assumed to be properly escalated to the price level year.

3. The Bureau of Labor Statistics Consumer Price Index (BLS CPI) for general hydropower work was used to escalate reported costs from the price level year to 2009 price levels.

The resulting present day costs are indicated in Table 4-1.

Table 4-1 Key Capital Cost Parameters for Selected Projects

Project	Initial Operation Year	Rated Capacity (MW)	L:H Ratio	Total Cost adjusted to 2009 $	Specific Cost adjusted to 2009 $/kW
Bad Creek	1991	1065	8.85	$1,760,445,000	$1,653
Bath County	1988	2100	8.20	$2,643,543,000	$1,259
Bear Swamp	1974	600	2.65	$619,200,000	$1,032
Blenheim-Gilboa	1973	1000	3.58	$794,170,000	$794
Cabin Creek	1967	300	3.87	$215,775,000	$719
Fairfield	1978	512	7.02	$752,906,240	$1,471
Helms	1981	1206	13.02	$2,113,273,800	$1,752
Jocasse	1973	610	5.26	$533,213,200	$874
Ludington	1973	1979	4.20	$1,793,171,900	$906
Muddy Run	1967	800	3.49	$493,200,000	$617
Northfield Mountain	1972	1080	8.45	$870,696,000	$806
Raccoon Mountain	1981	1530	3.90	$1,008,790,200	$659
Rocky Mountain	1990	760	4.79	$986,221,600	$1,298
Yards Creek	1965	360	5.03	$233,496,000	$649

There is some uncertainty about what is included or not included in the reported costs. For example, it is not known if costs such as engineering, administration, interest or other “soft costs” have been treated as project capital expenditures or reported in some other account. Since these expenses can be significant, any conclusions about project costs or specific costs ($/kW) based on the historical data should be applied with caution.

In the following sections, analyses to identify cost trends are described.

The L:H ratio is a simple ratio used to measure the initial viability of a pumped storage project in siting level studies. L is the length of the waterway from the intake structure to the tailrace outlet and H is the net rated head available for energy production. Waterways tend to be a sizeable portion of the cost of a project; minimizing the length while maintaining a sizeable head difference between reservoirs is very important in having a viable project. Generally speaking, potential projects having an L:H ratio under 10 show promise as a pumped storage project. Lower ratios will have a lower cost in $/kW terms, as shown in Figure 4-1.

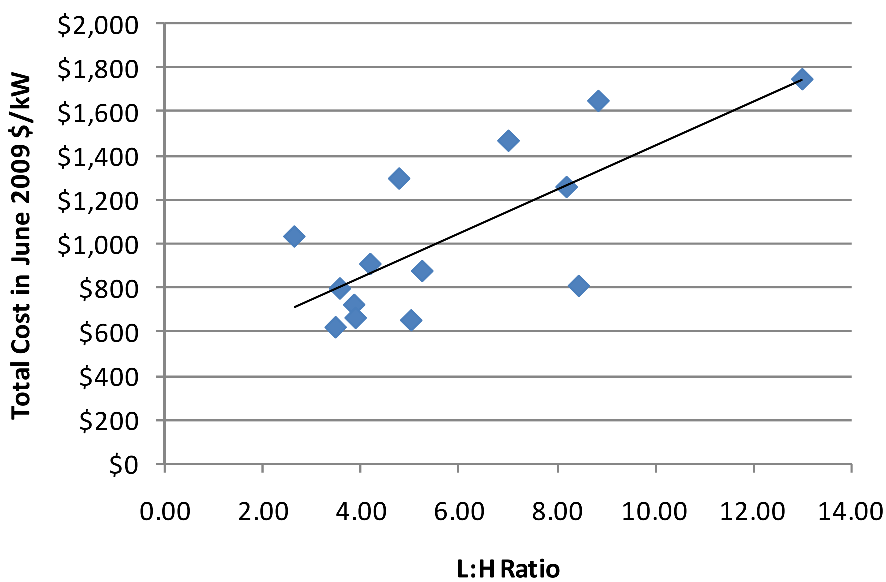

Figure 4-1Historical Capital Cost (2009 $/kW) vs. L:H Ratio

As the rated capacity increases, there is an expectation of a corresponding decrease in costs per kW. However, this trend is not evident for the sample projects, as shown in Figure 4-2. Each pumped storage project has unique costs that are independent of the size of the project, such as environmental investigations, land procurement, design engineering, and construction costs.

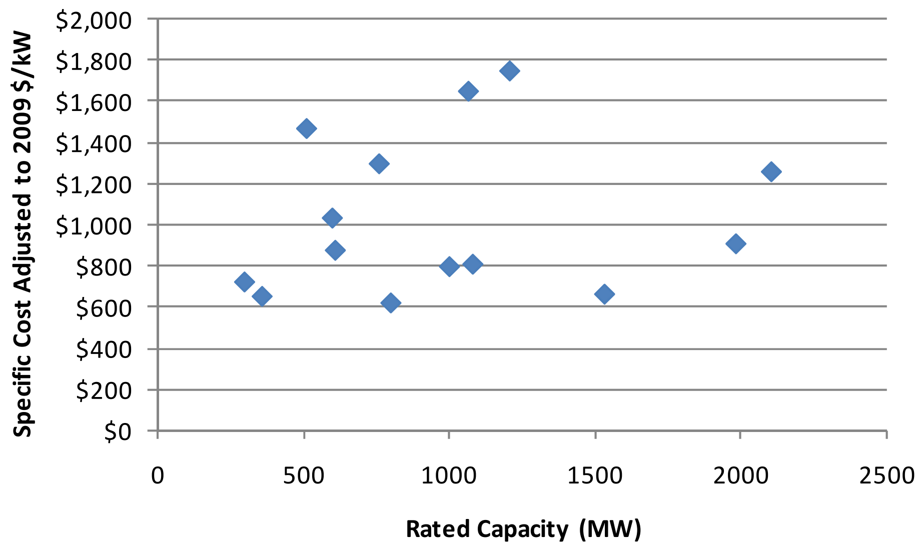

Figure 4-2 Historical Capital Cost (2009 $/kW) vs. Rated Capacity (MW)

Figure 4-3 shows the specific project costs, in 2009 dollars per kW, of the 14 sample projects, and the year that construction was completed. Project costs, expressed in constant dollar terms per kW of generating capacity appear to be trending upward. Reasons for this could be related to the regulatory environment or siting factors. Pumped storage facilities built in the 1960s did not face the same regulatory environment as more recently developed projects. Once can also speculate that as most favorable sites are developed, remaining sites with less favorable characteristics are more expensive to develop.

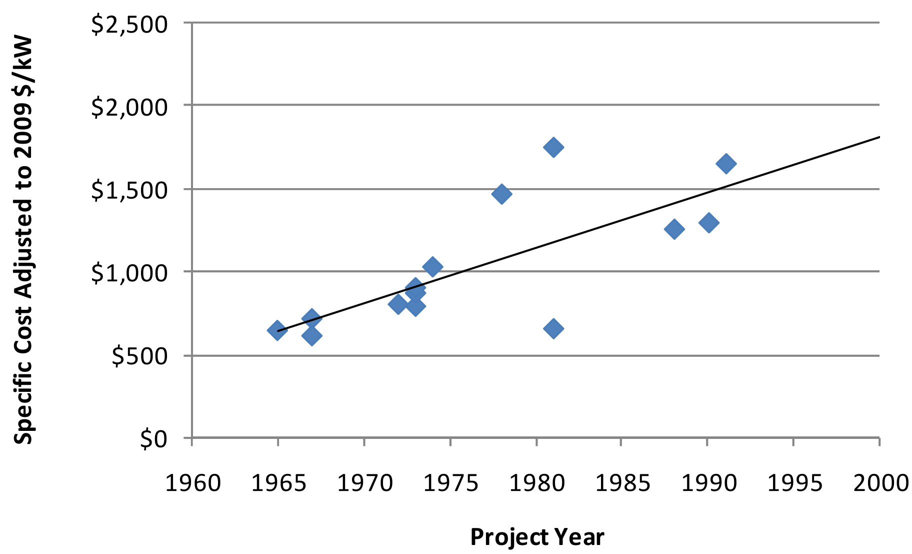

Figure 4-3 Historical Capital Cost (2009 $/kW) vs. Project Year

In conclusion, there are relatively few pumped storage projects in the U.S. from which a typical cost characterization can be made. Additionally, there are numerous costs that are site-specific and contribute significantly to the total cost of a pumped storage project.

4.1.1.2 Observed Cost Trends for Projects Currently Under Study

MWH has recently performed a number of siting and preliminary assessment level cost studies for several clients interested in pumped storage hydropower development.

Figure 4-3 provides an indication of the current costs being estimated for pumped storage hydropower development with approximate upper and lower cost values, which will depend upon site-specific conditions. The cost data indicated by the graph are intended to represent 2009 price level “overnight” cost for construction and equipment procurement, excluding escalation to the midpoint of the construction period, and without any allowances for third party engineering and legal costs, owner’s administration, land, transmission, or financial costs (interest or other fees).

In addition to the above, the data used in the analysis has been developed with the following in mind:

1. Bidding for construction and equipment procurement in a neutral bidding environment where prevailing economic and market factors are not affecting pricing. Thus the market would not be favoring high pricing due to supply constraints or low pricing due to underutilized production facilities.

2. A normal design, bid, build project delivery system, where risk is equitably shared; i.e. no risk premiums for onerous contract conditions or turnkey project delivery.

The trend line on this graph is the result of considering approximately 60 preliminary level estimates for pumped storage hydropower projects prepared within the last 3 years.

The specific results of individual cost studies are confidential, specific to individual conditions, and cannot be explicitly discussed or disclosed. The conclusion, based on inspection of the chart, is that the expected specific construction and equipment procurement cost for a 1000 MW pumped storage project is slightly under 2000 $/kW. The specific cost is close to 4000 $/kW for small projects on the order of 30 MW.

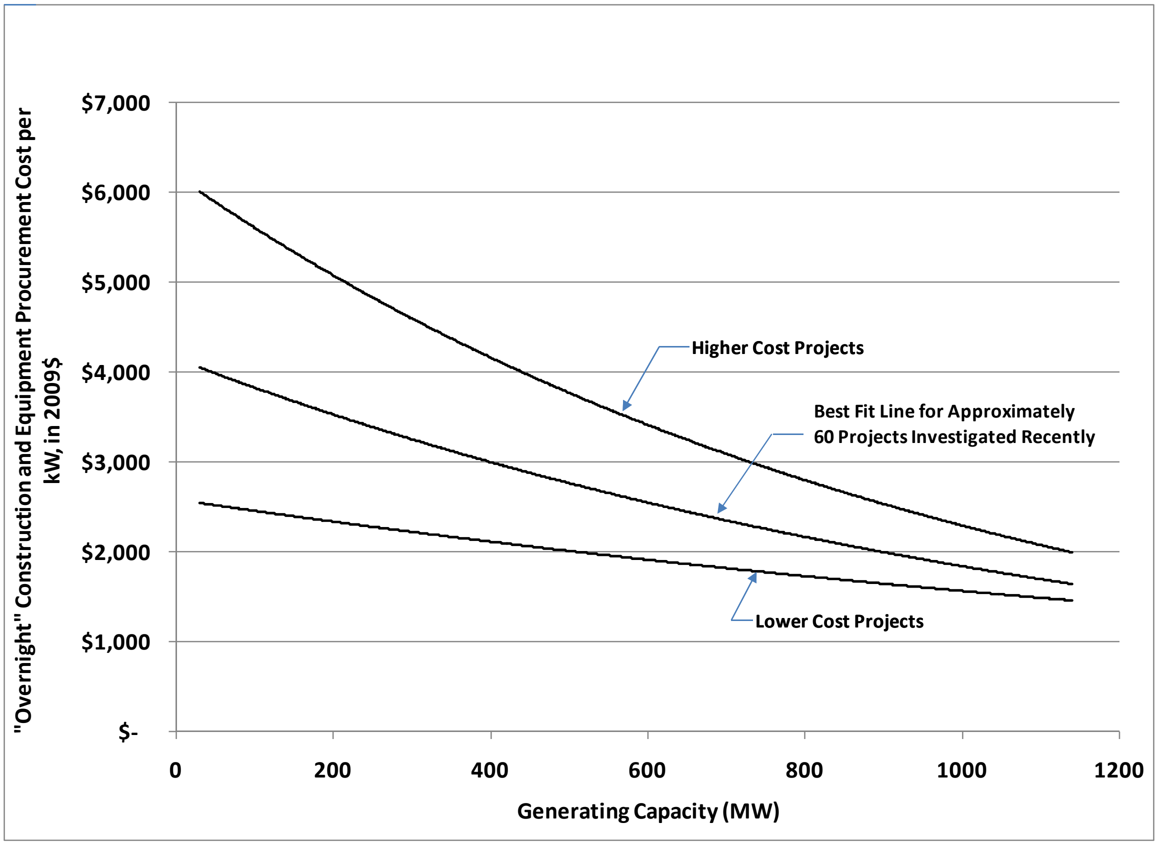

Figure 4-4 Indicative Overnight Construction Cost for Greenfield Pumped Storage Projects in 2009 $

4.1.1.3 Incremental Cost of Adding Adjustable Speed Capability

The additional cost of incorporating adjustable speed capability is mainly related to the costs associated with the generator motor, excitation system, cooling system for the thyristors, and the civil structures to accommodate the space for larger and additional cubicles and equipment. The size and cost of the excitation system is related to the selected speed range above and below the nominal synchronous speed.

Pricing information received from equipment vendors provided to MWH in response to various inquires over the past few years has suggested a wide range of variability and uncertainty in added cost. Incremental costs for adjustable speed capability have ranged from about 50% to 125% of the conventional fixed speed generator-motor price. The wide range could be a result of differences in logistics for rotor assembly and balancing and speed range. Also significant is that there has been a shift from the application of cycloconverter technology to the lower cost self commutated type converter technology with Injection Enhanced Gate Transistors excitation systems.

The increase in cost of civil structures to accommodate larger equipment is nominal, probably resulting in a civil structural cost increase of up to about 5% of the powerhouse cost. (added civil costs for a deeper setting because of the speed range)

In terms of the overall project cost, an incremental cost of 50 to 125% on the generator (assumed at approximately 10% of the total project cost) and 10 to 15% increase in the cost of powerhouse civil works (assumed at 20% of the total project cost) results in an incremental project cost of approximately 7% to 15%.

4.1.1.4 Potential for Cost Variability

The actual cost of any project developed could vary substantially from the above stated typical costs due to a variety of factors. A detailed feasibility or conceptual design study, including subsurface exploration and environmental study would be required to conclusively estimate total development costs. However, even after detailed studies, a variety of unknowns can have a significant impact on the actual construction cost as the project development proceeds, and actual costs could still be quite different than those estimated as a result of detailed study.

4.1.2 Key Driving Factors in Construction Cost

Projects with better geological and environmental characteristics, lower L:H ratios and higher head tend to have lower construction costs. Key driving factors affecting the construction cost of a project are discussed in the following paragraphs.

4.1.2.1 Reservoirs

The main factor that affects the cost of reservoirs is the volume of water to be stored. Larger storage volumes will obviously be more expensive, but larger storage volumes tend to exhibit lower unit cost per acre-foot (AF) of storage. Storage costs typically range from $2000/AF to $20,000/AF.

The volume of water that must be accommodated includes primarily the water that is available for cycling in carrying out the intended energy storage and redelivery function of the pumped storage project. Additionally, there is a nominal space in each reservoir that is considered unusable or dead. This may exist to provide space for sediment inflow, submergence on the intake structures, or conservation storage, or the minimum level may be set based on limiting the reservoir drawdown range. Storage space may also be provided for accommodating flood inflows or accidental over pumping.

The configuration and design of the dams and dikes affects the overall cost. Either or both of the reservoirs may be configured as “off-stream” reservoir, generally constructed as a basin by excavation from within the reservoir area and using the excavated material to form an enclosing dike. This type of construction tends to result in higher costs per unit of storage, but the cost penalty is dependent upon the amount of material involved in the construction of the dams. Depending upon foundation conditions, the basin type reservoir will generally require a reservoir liner, or at least foundation treatment to prevent or minimize leakage.

If either of the reservoirs is developed by damming a stream or a drainage feature, the choice of dam type is made to minimize the construction costs within the site constraints, which are mainly related geological conditions and available construction materials. In a situation where there is an abundant rockfill and sufficient clay, the choice might be to opt for a clay-core rockfill dam. In the absence of impervious material, one may choose a concrete dam, if foundation conditions are suitable. If weak foundation conditions exist, then the preference might be for a concrete-faced rockfill dam. These aspects are generally not known until site reconnaissance can be carried out for a specific site or area, and the selection of a dam type requires a comparative study of the reasonable options to address cost, environmental impact, scheduling, construction material use and functionality.

Reservoirs generally comprise only 10 to 15% of the construction and equipment procurement budget. While it is important to develop an efficient and safe storage concept, the potential for greater cost savings lies in other areas of the pumped storage project.

4.1.2.2 Waterways

Often the waterway cost is a major component of the construction cost of a facility. The main factor affecting the waterway cost is the size of the proposed facility and the “length to head ratio”. The length refers to the “screen to screen” waterway length, and the head refers to the vertical distance between the upper and lower reservoirs. Often the L:H ratio is used as a screening criterion in comparing sites. Projects with lower L:H ratios tend to have lower costs and greater (better) cycling efficiencies.

In general, the economic upper limit on the L:H ratio seems to be about 10. Larger L:H ratios may be observed for some projects, but these projects may have other overriding purposes. For example, the Helms Project in California has exceptionally long waterways, but it is a seasonal water storage project.

The L:H ratio is also an indicator of the need with respect to surge chamber(s), shaft(s) or tank(s). Depending upon the vertical profile of the waterway, it may or may not be possible to incorporate surge features. The response time and regulating stability characteristics of a project generally degrades as the L:H ratio increases.

The vertical profile of the waterways and the diameter of the various components of the waterway system affect the cost. The waterway profile may include surface or buried sections, but for high pressure and large diameter segments, a waterway constructed within a hard rock tunnel (if an available option) is normally the lower cost option. Site topographic and geological characteristics control the configuration of the waterway, both in terms of horizontal and vertical alignment.

The generating capacity of the facility and the prevailing head both heavily influence waterway cost. The number and size of the waterway is determined as a function of flow and various hydraulic parameters. Given the same output specification, a high head will have smaller waterway flow cross section than a low-head project. Given the same head, higher capacity projects will obviously have greater waterway flow cross section than lower capacity projects.

The design of the waterways is an important aspect in the performance of the facility. The characteristics of the waterway in the constructed project controls the head loss and the also affects the responsiveness of the plant, and the plant's ability to deliver ancillary services.

4.1.2.3 Powerhouse

A pumped storage facility may have an "underground" or a "surface" type powerhouse. An underground powerhouse is generally meant to include one or more underground excavated caverns with access via an access tunnel or access shaft (e.g. TVA's Raccoon Mountain facility in Tennessee). A surface powerhouse is generally sited in an open excavation near the lower reservoir (e.g. Bath County in Virginia). A third type of powerhouse design is a "pit" type powerhouse, where the pumping and generating unit is situated at the bottom of a pit, generally located adjacent to the lower reservoir (e.g. Olivenhain Hodges, under construction in California).

Generally various options are examined in a feasibility-level layout study to develop the best waterway and powerhouse combination that achieves the various objectives of minimizing cost and risk, while also minimizing the construction duration. Assuming suitable geological conditions, the conventional solution for a high head project is an underground powerhouse, mainly for the reason to minimize expensive high pressure, and sometimes problematic, waterways. The underground powerhouse also permits the selection of a lower-cost, higher-speed unit, without incurring a significant cost penalty for the required deeper submergence. Conversely, surface powerhouses tend to be the preferred option for low head projects. A silo powerhouse provides an arrangement that permits a deep unit setting, allowing the selection of a faster unit operating speed (lower in cost), without large surface excavations generally required for a conventional surface powerhouse design.

Once a particular site is chosen based on a screening study of multiple candidates, progressively more detailed studies, in conjunction with subsurface exploration, proceed to define the combined waterway and powerhouse arrangement. Generally this involves examination of various arrangements, narrowing down to a particular preferred arrangement and then defining the overall dimensions of the major features, followed by more detailed design of the components. It is a progressive study that requires some time and interactions with various disciplines to arrive at the best layout in terms of cost minimization and understanding and managing risks.

4.1.3 Range of O&M Costs for a Pumped Storage Facility

O&M costs, like capital costs, are highly project specific, and also depend on the owner's philosophy with respect to maintenance. Major factors in the operations and maintenance budgets are:

1. Age of facility – initial years of a project operation life tend to have slightly higher costs as the staff is becoming familiar with the facility and the efficiency of the O&M organization increases. Later in the project life, O&M costs tend to increase at the needs for equipment replacement become a factor.

2. Remote vs. attended operation – remote operation would tend to reduce costs.

3. Operation mode of the plant – primarily use for energy storage vs. primary use in providing ancillary benefits, where providing ancillary benefits tends to result in cycling and exercising the equipment more frequently, resulting in greater wear and tear.

4. The operational philosophy of the owner – some owners tend to spend more on O&M, while other owners may tend to defer maintenance to minimize O&M expenditures (run it until something fails).

5. Extent and type of equipment included in the O&M budget.

The following analysis provides an assessment of typical O&M budgets from two perspectives. First, historical costs derived from FERC reporting requirements are summarized and described. Second, some industry rule-of-thumb values are described, with a concluding section on the recommended range to consider for budgeting in economic studies.

4.1.3.1 Historical O&M Cost Information

Regulated utilities with licensed projects are required to submit cost data to FERC on an annual basis, and data is available through 2008. Unregulated licensees are not currently required to submit information, but were required to submit cost data to the Energy Information Administration up until 2003. The most recent three years of data was acquired for both classes (e.g. 2006 to 2008 or 2001 to 2003).

For the 14 projects selected as representative, O&M cost data as acquired from FERC and the EIA were tabulated (most recent three years available), and the average statistics are presented in Table 4-2. Note that some information was not available.

Table 4-2 Historical O&M Cost for Selected Projects

Project	3-Year Average O&M Cost Adjusted to 2009 $/MWh	3-Year Average Number of Employees
Bad Creek	3.41	8
Bath County	2.43	58
Bear Swamp	NR	NR
Blenheim-Gilboa	22.23	145
Cabin Creek	15.42	13
Fairfield	4.11	28
Helms	19.44	6
Jocasse	5.07	8
Ludington	5.55	41
Muddy Run	NR	NR
Northfield Mountain	NR	NR
Raccoon Mountain	19.86	36
Rocky Mountain	6.64	NR
Yards Creek	5.28	9

Notes:
(1) Projects listed above are the same projects listed in Table 4-1
(2) NR – Not reported or not available

(3) Explanation of the large disparity in reported costs and number of employees would require further investigation. Possible explanations are methods of assigning costs and employee responsibility or on-going major maintenance programs

O&M cost data does not include energy for pumping. The average O&M cost is about $9.95 per MWh.

4.1.3.2 Indicative O&M Cost Parameters

A rule of thumb for very high level budgeting purposes would be about $5 per MWh of energy produced (although the above analysis suggests a higher average; $5 per MWh is used as it is suspected that the tabulated values include some major maintenance). However, the actual unit cost may be higher for smaller plants and greater for smaller plants. Table 4-3 provides an indication of the estimated O&M costs for a range of plant sizes, incorporating some assumptions about the variability of the unit price of O&M per MWh as a function of generating capacity.

Another rule of thumb is that hydro project O&M cost is on the order of 1% of the construction and equipment procurement cost.

Table 4-4 provides an indication of the O&M cost, with some assumptions about typical pumped storage specific costs, if this rule is applied.

Another view is derived from the ”Pumped Storage Planning and Evaluation Guide” (6-28). Table 4-5 contains estimates of annual O&M budgets, based on historical 1980s data for a small group of projects, with estimates indicated in Table 4-5 escalated to present day levels using the BLS CPI.

Table 4-6 summarizes the anticipated range of costs that might be expected for a pumped storage hydropower facility derived from the above three estimates.

These figures are only intended to be an approximation of the anticipated cost. A feasibility study for a pumped-storage project would typically identify O&M costs by developing a staffing plan with associated salary and overhead costs, along with an estimate of costs for materials, supplies, replacements, insurance, other third party costs, etc. In developing a plan and applying annual budget projections in a financial analysis, it must be recognized that annual costs may change over the life of the project due to changing conditions or operating modes. One possible condition to be considered is where a plant is designed for remote operation, but in the first year or two, the plant is operated as a staffed facility for testing and training purposes.

Table 4-3 O&M Budget Estimated by $/MWh of Average Annual Production

Capacity (MW)	Assumed O&M Cost $ Per MWh	Annual Budget (in million 2009 $) by Capacity Factor of			
		10%	15%	20%	25%
50	7	0.3	0.5	0.6	0.8
100	6.75	0.6	0.9	1.2	1.5
250	6	1.3	2.0	2.6	3.3
500	5	2.2	3.3	4.4	5.5
750	4	2.6	3.9	5.3	6.6
1000	3	2.6	3.9	5.3	6.6

Table 4-4 O&M Budget Estimated by Percentage of Construction Cost

Capacity (MW)	Assumed Specific $ Per kW Installed	Estimated Annual O&M Cost (million 2009 $)
50	3000	1.5
100	2940	2.9
250	2750	6.9
500	2500	12.5
750	2250	16.9
1000	2000	20.0

Table 4-5 O&M Budget Estimated by EPRI Empirical Formula

Capacity (MW)	Annual Budget (in million 2009 $) by Capacity Factor of			
	10%	15%	20%	25%
50	0.8	0.9	1.0	1.1
100	1.3	1.4	1.6	1.7
250	2.3	2.6	2.9	3.1
500	3.6	4.1	4.5	4.9
750	4.7	5.3	5.9	6.3
1000	5.6	6.4	7.1	7.6

Table 4-6 O&M Budget Ranges for Pumped Storage Hydropower Projects

Capacity (MW)	Likely Range in million 2009 $		
50	0.3	to	1.5
100	0.6	to	2.9
250	1.3	to	6.9
500	2.2	to	12.5
750	2.6	to	16.9
1000	2.6	to	20.0

4.1.4 Operational Factors Affecting O&M Costs

The following factors may have some influence on the actual O&M costs. However, it is difficult to pinpoint the exact cost implication of such factors. In the long-run, the following described conditions may require either increased maintenance or shorter times between major replacements.

1. Thermal cycling of the units causes increased degradation of generator insulation systems. More frequent generator rewinds are usually required.

2. For single speed units, operation near rough zones causes cavitation of the turbine runner that must be repaired.

3. For single speed units, the definition of spinning reserve varies across the country. In some places, spinning reserve requires that the unit be producing positive megawatts (not synchronous condensing). To operate at a small percentage of rated load is usually a very rough zone on a single speed turbine, unless specifically designed for the purpose. Rough operation causes excess vibration that can result in adverse consequences for the equipment, both generator and turbine.

4. Starting a pumped storage unit in pumping mode normally is done by bringing the unit to speed with the runner in air rather than submerged to

reduce starting loses. Once the unit is synchronized, the air bubble is released until the pressure behind the gates reaches a maximum. This results in stresses on the wicket gate moving parts that a normal hydro turbine sees very rarely, but in this case occurs at every pump start cycle. The result is more frequent rebuilding of bushings in the wicket gates is required.

5. Stopping a pumped storage unit can be done in two ways. 1) Close the wicket gates completely and trip the generator circuit breaker at minimum current. 2) Close the wicket gates and trip the generator circuit breaker before the wicket gates reach the fully closed position. Under condition 1) the generator circuit breaker sees minimum wear, but the wicket gates see stresses even greater than during the pump prime cycle and results in increased wear of bushings and wicket gates. Under condition 2) part of the wear is taken in the generator circuit breaker and part of the stress is taken in wicket gate assemblies. Air blast circuit breakers may require rebuilding on 2 to 3 year intervals while SF_6-type breakers may require rebuilding on 5 to 8 year intervals. The wicket gate and bushing stresses are reduced to approximately the pump priming pressure, increasing the probable maintenance interval from 5 to 6 years up to 8 to 10 years. The turbine repairs require much longer to make, must be made in situ, and require an outage to disassemble the machine to the required level so the work can be performed. The generator circuit breaker can be replaced with a spare in a few days time, and the repairs completed with the unit back in service.

6. With large capacity units comes the tendency to want to increase the operating voltage to limit the stator current and losses through the connecting components. Units operating in excess of 20 kV have a tendency to have problems with corona in the windings. Corona can shorten the life of the windings requiring more frequent service.

7. The pump starting of single speed units is today performed using static frequency converters or SFC, one in the plant for up to 4 units, two in the plant for more than 4 units (this break point is not fixed, just usual practice). Eventually, duty cycles will require some extended maintenance on the SFC. It is still customary to have either a 2nd SFC or a back to back starting method (using another unit to supply the starting power). The back-to-back method leaves one unit unable to operate as a pump if it is the only starting means available.

8. Costs associated with pumped storage project maintenance are higher than normal because normally, the asset is extremely valuable and clients wish to have the revenue stream from the asset. Hence, allowed maintenance time is reduced by using multiple shifts wherever possible,

and absorbing this cost rather than to have the asset in a non-revenue mode.

9. Adjustable speed units can help reduce the wear and maintenance in the following ways:

    a. Rough zones and associated cavitation damage can be avoided completely through selection of the operating speed.
    b. Startup and shutdown forces on the wicket gate assemblies can be greatly reduced through changing the runner speed during these cycles.
    c. For similar reasons, the wear on the generator circuit breaker can be greatly reduced.
    d. Each adjustable speed unit essentially has its own SFC in the form of a cyclo-converter, so a separate SFC is not required.
    e. Conversely, the cyclo-converter on each unit is fairly complex, although moving parts are minimal.

The above listed considerations will probably not make the difference between choosing a pumped storage project for wind integration over some other technology. However, the considerations are important for consideration once a decision is made to proceed with a pumped storage hydro, after a site is selected, and once the selected site is into a preliminary design phase. During the preliminary design is where the issues listed above are considered in making decisions about the characteristics of the equipment.

4.2 Project Benefits

4.2.1 Capacity and Energy

In the early stage of planning for a particular pumped storage project, regardless of location, the two basic questions are: How should the project be sized in terms of capacity (and a related question is how many units?) and the second question is what reservoir storage should be provided?

The amount of capacity to be provided by the pumped storage project, if used for wind integration, would need to be analyzed in view of diversity of generation resources connected to the transmission system. The actual capacity needed to firm up wind generation would probably be somewhat less than the capacity of the wind resource.

Energy storage would be determined on the basis of operation through periods of curtailed wind output (pumped storage energy is being delivered to the system), and in addition, through periods of high output and at times when not all wind generation can be absorbed by the system (the pumped storage facility is being charged). In addition, it may be economic to charge the pumped storage project using low cost system generation resources when available (e.g. must run units).

To analyze and determine the economically efficient parameters for capacity and energy, one needs to perform operational studies (production simulation type studies) to determine the value (i.e. reduced system operational costs) of considering increasing capacity and energy storage ratings. Increasing value of incremental investments in either capacity or storage can be compared with incremental costs to determine the economically efficient generating capacity and energy storage ratings.

4.2.2 Ancillary Services

A pumped storage facility can provide a number of ancillary services, depending upon the design of the facility and the equipment installed. From a financial viewpoint, compensation for ancillary services could substantially contribute to the project’s financial viability. From an economic viewpoint, the ancillary services and system flexibility offered by pumped storage can substantially reduce the overall operation and maintenance cost of the interconnected electrical system.

The following is a discussion of the revenue producing ancillary services. A framework for economic analysis from a system operations viewpoint is described in the next section.

The largest component of ancillary services benefits and potential revenue result from spinning reserve, frequency regulation and load following capabilities of the pumped storage project. Other revenue producing services include stabilization service and black start service.

Spinning reserve can be provided in both modes by a single speed machine, although the reserve in the pumping mode is limited to discrete blocks of load defined by the pump motor input. In an adjustable speed machine, there is more flexibility in providing small increments of spinning reserve by adjusting the pump mode operation to suit the spinning reserve need.

A conventional pumped storage plant with single speed machines can only provide frequency regulation and load following in the generation mode. With adjustable speed, it is possible to provide frequency regulation in both the pumping and generating modes. In an open market a pumped storage project could earn revenue from the sale of frequency regulation and load following capability as an ancillary service (although if the facility does not have adjustable speed units, this benefit would only be available when the units are operating in the generation mode). If analyzed from a supply cost minimization perspective (an economic viewpoint), this translates to lower operational costs for the operating thermal units, or it could result in a completely different dispatch with a lower operational cost.

In some markets, operators may have contractual obligations or agreements to be compensated for supplying “system resources” such as operating in a mode to primarily provide system stabilization. A hydropower project can provide system stabilization services because the rotating inertia of the unit and the water column are generally robust and provide a stabilizing effect during short system disturbances. A single speed pumped storage project could provide such service in the generating mode; an adjustable speed machine can provide services in both modes. In addition, high-speed controls used for an adjustable speed machine make it possible to program the machine to inject or absorb power and damp out transient power swings during system events (Donalek, 1998). There may be conditions under which a pumped storage unit could be operated as a synchronous condenser for reactive power and voltage regulation. This mode of operation would be another system resource.

Some facilities may qualify for “black start” capability service. To qualify as a black start service provider, the facility must have the capability to energize a portion of a system that has shut down or “blacked out” using a source of generation that has been isolated and lacks an off-site source of electrical power. Ordinarily a pumped storage project would be capable of providing black start service.

4.3 Framework for Economic Analysis

Although it is possible, depending upon the ownership and market structure, for an owner of a pumped storage plant to obtain revenue and compensation for energy arbitrage and ancillary services, adopting a market valuation basis to analyze the economics of pumped storage and its ability to provide a means for economic wind integration may not be the best approach for initial justification studies. A market valuation approach to project justification would be appropriate for a private developer who would be trading and operating within an open market and who would be more concerned with financial feasibility and justification.

The question to be addressed is how can pumped storage be used in the regional electrical system to firm up wind generation, or the more basic question is – how is the overall regional cost of supply minimized while supporting the desired wind development targets?

The means to analyze this question involves adopting two specific types of models: (1) an extended term dynamic simulation of the generators and the transmission grid to evaluate the responsiveness of a pumped storage hydro and to verify that the pumped storage hydro can provide such services under various adverse conditions (rapid wind drop off situations) created by the introduction of wind, and (2) a detailed production simulation to demonstrate the total cost of operating the electrical system with the pumped hydro is lower in cost than operating the system with some other technology to provide the ancillary services required to support wind integration.

In simplistic terms, the procedure would incorporate the following steps:

1. Establish a baseline forecast of loads and generating resources adopting the target wind generation penetration, and the required thermal system to provide service at the desired minimum level of reliability. This would be fully supported by integrated transmission and generation system modeling to (1) demonstrate that constraints, in terms of reliability, transmission line loads are satisfied and (2) to quantify the future capital cost and operational costs.

2. Establish an alternative forecast of generating and transmission resources that includes pumped storage hydro, and perform similar modeling that would address the same points in terms of operational constraints and operational costs.

3. Evaluating the differences between the two scenarios to determine the lowest cost means to meet future demands.

One very significant factor is that because of the operational flexibility offered by a PS project, it is possible that the future generation mix would be different if pumped storage was adopted rather than a thermal alternative. Because of reliability and flexibility, it may be possible that the existence of a PS project would reduce reserve margin requirements, both in terms of long term generation resource needs, and in terms of day-to-day unit commitment. Reducing the reserve margin would reduce future capital expenditures and annual operating expenses

Much work needs to be done in the industry to develop more sophisticated analytical tools to understand the dynamic behavior of adjustable speed or ternary PS projects. At the present time, there are two significant modeling deficiencies. First, there are no detailed dynamic models of adjustable speed generator motors that would permit an extended term dynamic simulation of the transmission system to evaluate system response to rapid wind output changes. Second, the available production simulation models do not provide the needed definition in terms of small time steps to understand how the overall dispatch of units in a system would be affected if pumped storage is implemented.

An additional deficiency of the existing production simulation models is that some ancillary services functions of pumped storage with adjustable speed or ternary units may not be adequately modeled. Smaller step intervals (5 or 10 minutes) would be required to perform the analysis. Previous sections of this report describe the capabilities of pumped storage. A summary of the ancillary services discussed in this report, and observations on how such services should be included in production simulation modeling for operations study are summarized in Table 4-7**.**

Table 4-7 Tabulation of Ancillary Services Capabilities and Benefits

Ancillary Service or Potential Benefits	Description of Single Speed Unit Ancillary Services Capability	Description of Adjustable Speed Unit Ancillary Services Capability	Applicability of Ancillary Services to Wind Integration in PNW Region	Preliminary Method to Quantify Benefits
Frequency Regulation (FR) (Generation mode)	Can be used to provide frequency regulation in the generation mode.	Same.	It is anticipated that this benefit could apply. Detailed study would be required.	A detailed operations simulation (hourly and with smaller incremental steps) analysis of the PNW region power system would be required to quantify the benefits.
Frequency Regulation (FR) (Pumping mode)	Cannot be used to provide FR in the pumping mode	Can be used to provide FR in the pumping mode.	Same as above.	Same as above.
Spinning Reserve (SR) (Generation mode)	Can be used to provide SR in the generation mode when unit is not operating at capacity. The range of operation for spinning reserve is up to 40% of capacity.	Can be used to provide SR in generating mode. The operating range is greater and up to 60% of capacity.	Same as above.	Same as above.

Ancillary Service or Potential Benefits	**Description of Single Speed Unit Ancillary Services Capability**	**Description of Adjustable Speed Unit Ancillary Services Capability**	**Applicability of Ancillary Services to Wind Integration in PNW Region**	**Preliminary Method to Quantify Benefits**
Spinning Reserve (SR) (Pumping mode)	In pumping mode, can be shut down thereby providing 100% of its capacity for SR.	Can be operated in a range of 40% to 100% of its capacity, and therefore can provide more flexible SR.	Same as above.	Same as above.
Load Following (LF) (Generation mode) b	Can be used to provide LF in the generation mode over the range of 60% to 100% of capacity.	Can be used to provide LF in the generation mode over the range of 40% to 100% of capacity.	Same as above.	Same as above.
Load Following (LF) (Pumping mode)	Cannot be used to provide LF in the pumping mode	Can be used to provide LF in the pumping mode over the range of 40% to 100% of capacity.	Same as above.	Same as above.

Ancillary Service or Potential Benefits	Description of Single Speed Unit Ancillary Services Capability	Description of Adjustable Speed Unit Ancillary Services Capability	Applicability of Ancillary Services to Wind Integration in PNW Region	Preliminary Method to Quantify Benefits
Synchronous Condenser Mode	Can be used to provide synchronous condenser voltage support in both generating and pumping directions with the unit operating at synchronous speed.	Same, but in addition, can be used to provide synchronous condenser service at lower speed, thus reducing friction and windage losses.	The plant location would determine if this benefit can be realized. The project would need to be located close to where reactive power regulation is needed.	The incremental benefits would be very small since it is only related to a decrease in friction and windage losses in the adjustable speed units.
Reserve and Coverage of Forced Outage of Other Units (Generation mode)	When not in operation, unit can be used to cover a forced outage by starting from stopped mode to sustained full output at a rate of 4 to 6% capacity per second for 60 MW and above units, 1 to 6% capacity per second for smaller units.	Same		No incremental benefits.

Ancillary Service or Potential Benefits	**Description of Single Speed Unit Ancillary Services Capability**	**Description of Adjustable Speed Unit Ancillary Services Capability**	**Applicability of Ancillary Services to Wind Integration in PNW Region**	**Preliminary Method to Quantify Benefits**
Reserve and Coverage of Forced Outage of Other Units (Pumping mode)	Can be used to assist by shedding 100% of the pump load, but a load rejection power transient will occur.	Can be used to assist because its loading can be rapidly changed without causing power transients and the unit can remain synchronized.	Applicable.	An adjustable speed unit would help, keeping thermal units operating at more optimum efficiencies (less fluctuation and power transients on thermal units). A detailed operations simulation model would be required to quantify benefits.
Voltage Control (Generation and Pumping modes)	Can be used to perform the voltage regulation function	Same		No incremental benefits.

Ancillary Service or Potential Benefits	Description of Single Speed Unit Ancillary Services Capability	Description of Adjustable Speed Unit Ancillary Services Capability	Applicability of Ancillary Services to Wind Integration in PNW Region	Preliminary Method to Quantify Benefits
Unit Commitment (Generation mode)	Generation output can be adjusted to provide assistance in transitioning from the low load hours to the peak load hours as part of a unit commitment strategy. Typical range of operation is 60% to 100% capacity.	Same, but an adjustable speed unit can be used to provide UC in the generation mode over an additional range from 40% to 60% of maximum output. Thus, typical range of operation is 40% to 100% capacity.	Applicable.	A detailed operations simulation model would be required to quantify benefits.
Unit Commitment (Pumping mode)	Not available – pumping power input is not adjustable.	The pumping load is adjustable, so pumping can be done during shoulder periods, thereby assisting with unit commitment flexibility.	Applicable.	A detailed operations simulation model would be required to quantify benefits.

Ancillary Service or Potential Benefits	**Description of Single Speed Unit Ancillary Services Capability**	**Description of Adjustable Speed Unit Ancillary Services Capability**	**Applicability of Ancillary Services to Wind Integration in PNW Region**	**Preliminary Method to Quantify Benefits**
Reduce Thermal Plant Cycling	Rapid load changes can be made only in the generation mode to allow slower or gradual adjustments to thermal unit output, or to allow continued operation at a fixed output.	Rapid load changes can be made in both the pumping and generating modes to allow slower or gradual adjustments to thermal unit output, or to allow continued operation at a fixed output.	Applicable.	A detailed operations simulation model would be required to quantify benefits.
Transmission Loss Reduction	In generation mode transmission line loading can be adjusted by changes in generator output. No assistance in the pumping mode	In generation and pumping modes, loading can be adjusted to manage transmission line loads.	Dependent upon the physical location of the project.	A detailed operations simulation model would be required to quantify benefits.
Reduction of wear and tear.		Less vibration and less wear and tear on the unit bearings.	Yes	Reduced maintenance costs.

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5 APPLICATION OF PUMPED STORAGE TO THE PACIFIC NORTHWEST

5.1 Overview of the PNW Generating and Transmission System

The Bonneville Power Administration (BPA) markets wholesale electrical power from 31 Federal hydro projects in the Columbia River Basin, one non-federal nuclear plant and several other small non-federal power plants, which include output from several renewable power plants under power purchase contracts with BPA, primarily cogeneration and wind turbines. BPA does not own generating resources. The Federal dams are operated by the U.S. Army Corps of Engineers (USACE) and the United States Bureau of Reclamation (USBR). Table 5-1 presents the capacity and operator of the 31 dams in the Federal Columbia River System. In addition to the Federal Columbia River hydroelectric projects, non-federal hydroelectric projects on the Columbia including Rock Island, Rocky Reach, Wanapum, Priest Rapids, and Wells add a total of about 5,300 MW of installed capacity. The locations of major dams in the Columbia River basin are shown on Figure 5-1.

The BPA load obligations are comprised of BPA's sales to Pacific Northwest (PNW) Federal Agency, public agency and cooperative, USBR, Investor Owned Utilities (IOU), and Direct Service Industry (DSI) customers as well as other firm contractual obligations to deliver power. BPA sells Federal power at wholesale and has no retail customers.

About one-third of the electric power used in the Northwest comes from BPA via its power market activities. BPA also operates and maintains about three-fourths of the high voltage transmission in its service territory. A map of the BPA service area and transmission lines is shown on Figure 5-2. BPA's service territory includes Washington, Oregon, Idaho, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming. BPA also operates the Northwest portion of large interregional transmission lines (called interties) that can transmit power to and from the region as necessary. A summary of the operating voltage and circuit miles of the BPA transmission system are presented in Table 5-2. A more detailed map of the BPA transmission system is provided on Exhibit 1. The juxtaposition of BPA transmission lines with major Columbia River systems dams is shown on Exhibit 2.

Table 5-1 Federal Columbia River Hydroelectric Projects

Reach	Plant Name	River	State	In-service Date	Capacity (MW)	Operating Agency
Lower Columbia	Bonneville	Columbia	OR/WA	1938	1,104	USACE
	The Dalles	Columbia	OR/WA	1957	2,080	USACE
	John Day	Columbia	OR/WA	1971	2,480	USACE
	McNary	Columbia	OR/WA	1952	1,120	USACE
	Chandler	Yakima	WA	1956	12	USBR
	Roza	Yakima	WA	1958	13	USBR
Upper Columbia	Chief Joseph	Columbia	WA	1958	2,614	USACE
	Grand Coulee	Columbia	WA	1942	6,809	USBR
	Albeni Falls	Pend Oreille	ID	1955	49	USACE
	Libby	Kootenai	MT	1975	605	USACE
	Hungry Horse	Flathead	MT	1953	428	USBR
Lower Snake	Ice Harbor	Snake	WA	1962	693	USACE
	Lower Monumental	Snake	WA	1969	930	USACE
	Little Goose	Snake	WA	1970	930	USACE
	Lower Granite	Snake	WA	1975	930	USACE
	Dworshak	Clearwater	ID	1973	465	USACE
Upper Snake	Black Canyon	Payette	ID	1925	10	USBR
	Boise River Diversion	Boise	ID	1912	2	USBR
	Anderson Ranch	Boise	ID	1950	40	USBR
	Minidoka	Snake	ID	1909	28	USBR
	Palisades	Snake	ID	1958	177	USBR
Willamette & Snake	Big Cliff	Santiam	OR	1953	21	USACE
	Detroit	Santiam	OR	1953	115	USACE
	Foster	Santiam	OR	1967	23	USACE
	Green Peter	Santiam	OR	1967	92	USACE
	Cougar	McKenzie	OR	1963	28	USACE
	Dexter	Willamette	OR	1954	17	USACE
	Lookout Point	Willamette	OR	1953	138	USACE
	Hills Creek	Willamette	OR	1962	34	USACE
	Lost Creek	Rogue	OR	1977	56	USACE
	Green Springs	Emigrant Cr.	OR	1960	17	USBR
Total Corps of Engineers Columbia River System Hydroelectric Capacity = 14,524 MW						
Total Bureau of Reclamation Columbia River System Hydroelectric Capacity = 7,536 MW						
Total Federal Columbia River System Hydroelectric Capacity = 22,060 MW						

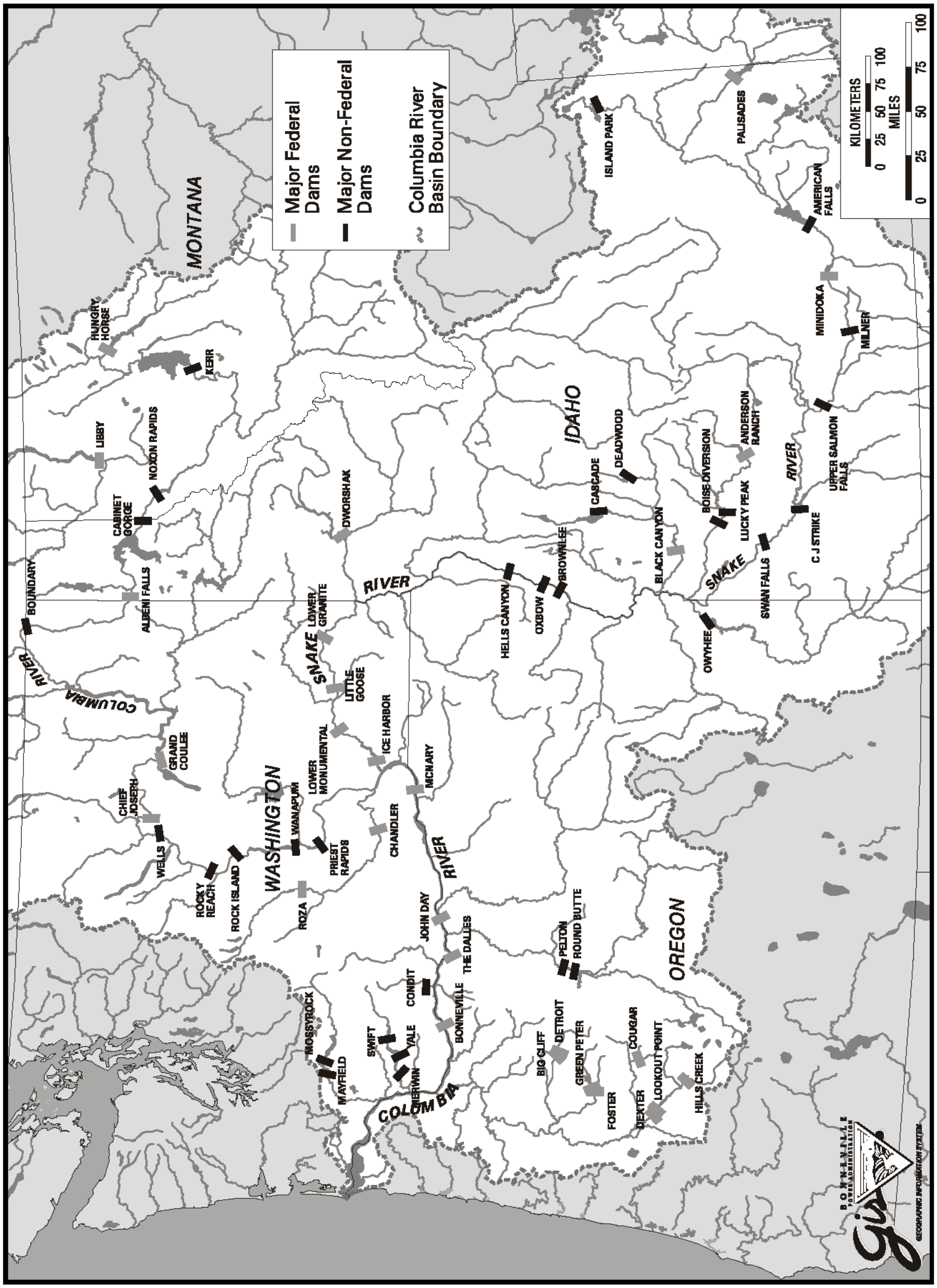

Figure 5-1 Dams in the Columbia River Basin

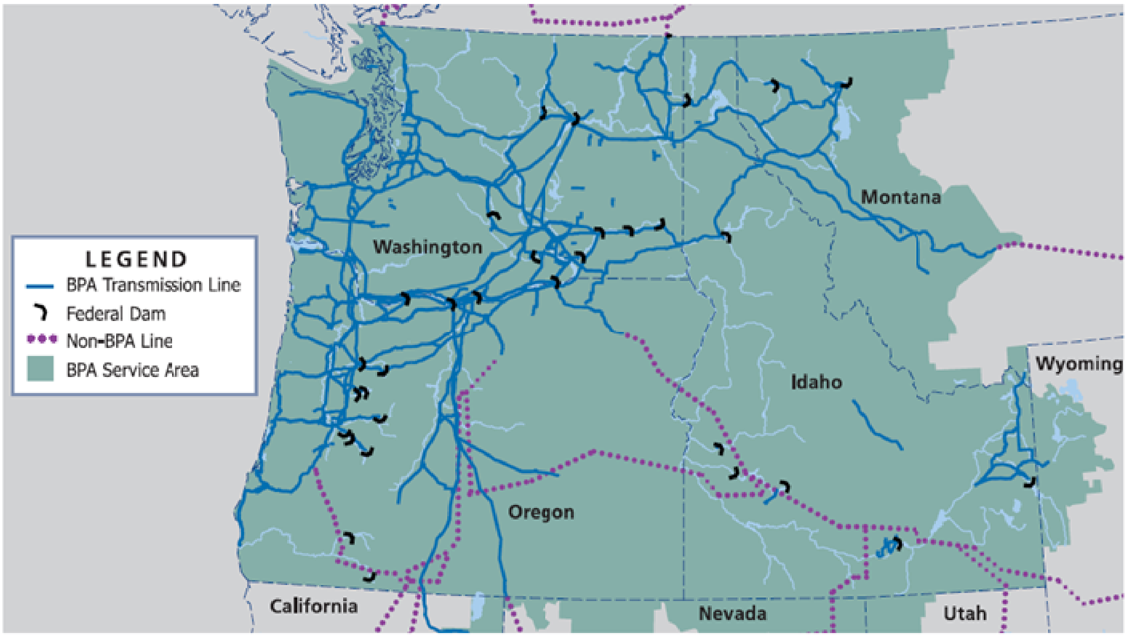

Figure 5-2 BPA Service Area and Transmission Lines

Table 5-2 BPA Transmission Summary

Operating Voltage (kV)	Circuit Length (miles)
1,000	264
500	4,734
345	570
287	227
230	5,348
161	119
138	50
115	3,557
< 115	367
Total	15,236

The PNW has a total installed generating capacity of about 57,000 MW and an average generating capability of about 34,000 MW (Northwest Power and Conservation Council 2009). The resource distribution of installed capacity and average generating capability are shown on Figure 5-3 and Figure 4-4. Data in this section was based on publicly available documents and Web sites and may need to be updated with the latest information available to BPA.

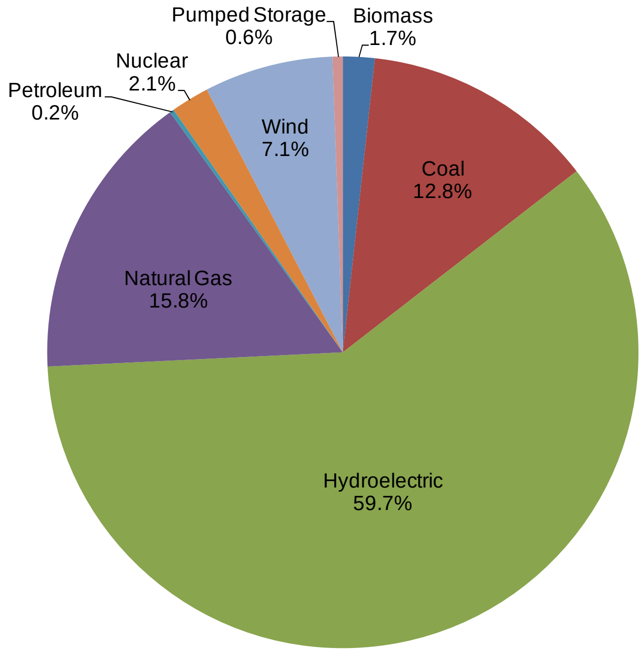

Figure 5-3 Pacific Northwest Installed Capacity

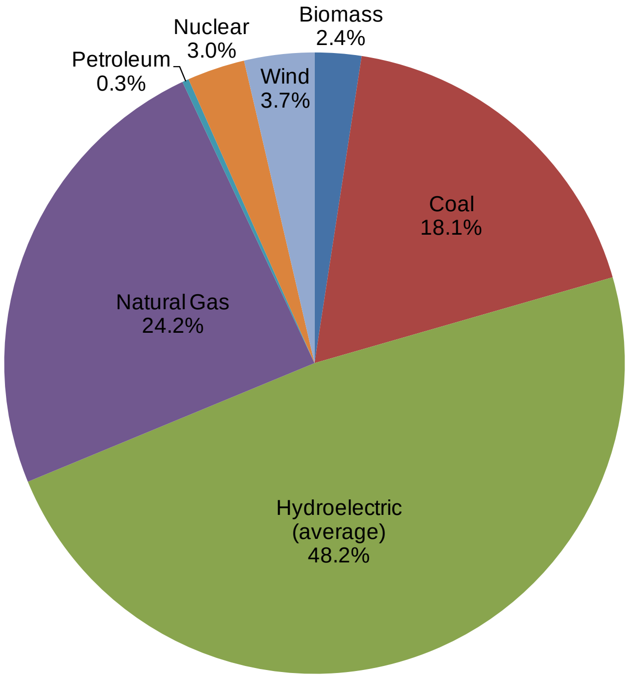

Figure 5-4 Pacific Northwest Average Generating Capability

The amount of installed wind power capacity currently (July 2009) connected to the BPA transmission system is about 2,100 MW. Figure 5-5 shows how the installed wind capacity connected to the BPA system is projected to increase rapidly to 6,250 installed MW by 2013 (BPA 2009). The vast amounts of wind power lined up to interconnect to BPA's transmission grid are overwhelming the existing federal hydropower system's ability to provide sufficient integration services (BPA 2008). Integration services maintain the constant balance of loads and resources to assure system reliability second-by-second, minute-by-minute and hour-by-hour. Although variable wind power requires large amounts of balancing services, BPA strongly supports wind and other renewable resources. A description of wind power development in Pacific Northwest and a description of the system operating issues required to accomplish wind integration are provided in The Northwest Wind Integration Action Plan (NWPCC 2007).

The fundamental value of wind power to a utility portfolio lies in its ability to displace fossil fuel consumption, limit exposure to volatile fossil fuel prices, and hedge against possible greenhouse gas control costs. At present, the principle alternative to existing hydro generation for providing system flexibility for wind integration is natural gas-fired generation (NWPCC 2007). Although it is more of a long-term solution, pumped storage offers a clean renewable energy alternative for wind energy integration in a carbon dioxide emission restricted future.

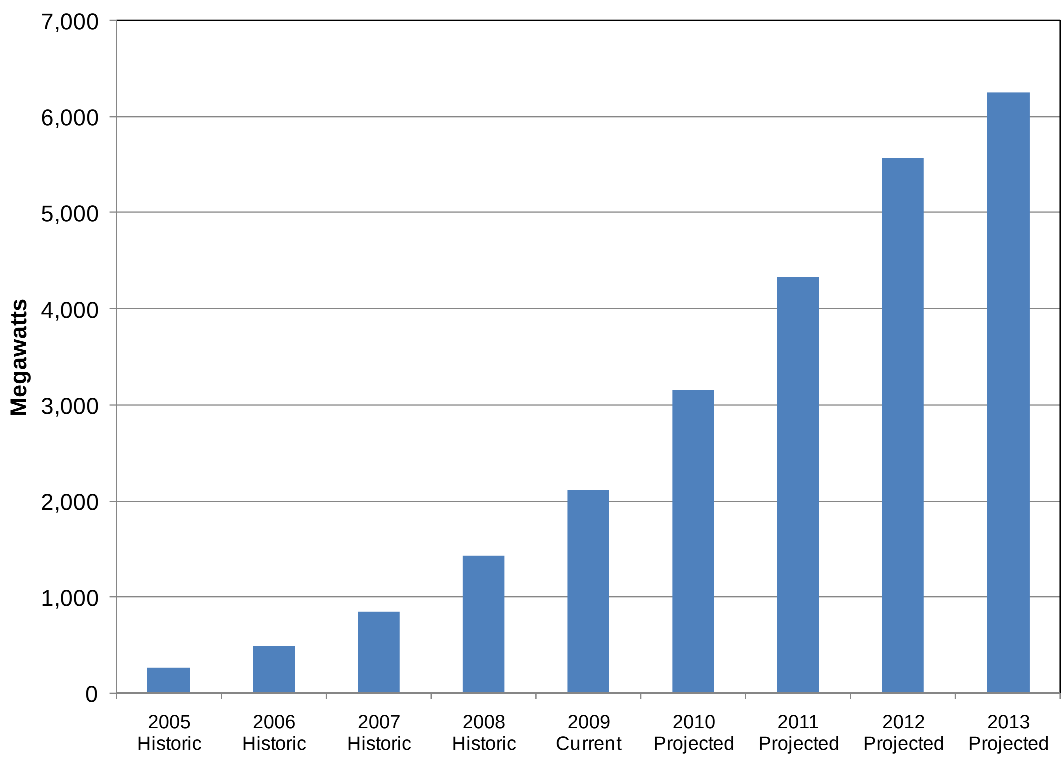

Figure 5-5 Pacific Northwest Wind Power installed Capacity

Figure 5-6 displays the highly variable nature of wind power generation in relation to the BPA load over a recent period of unusually hot weather days. It is noted that during this period of days, wind generation peaked at a maximum of 36.5% of the load.

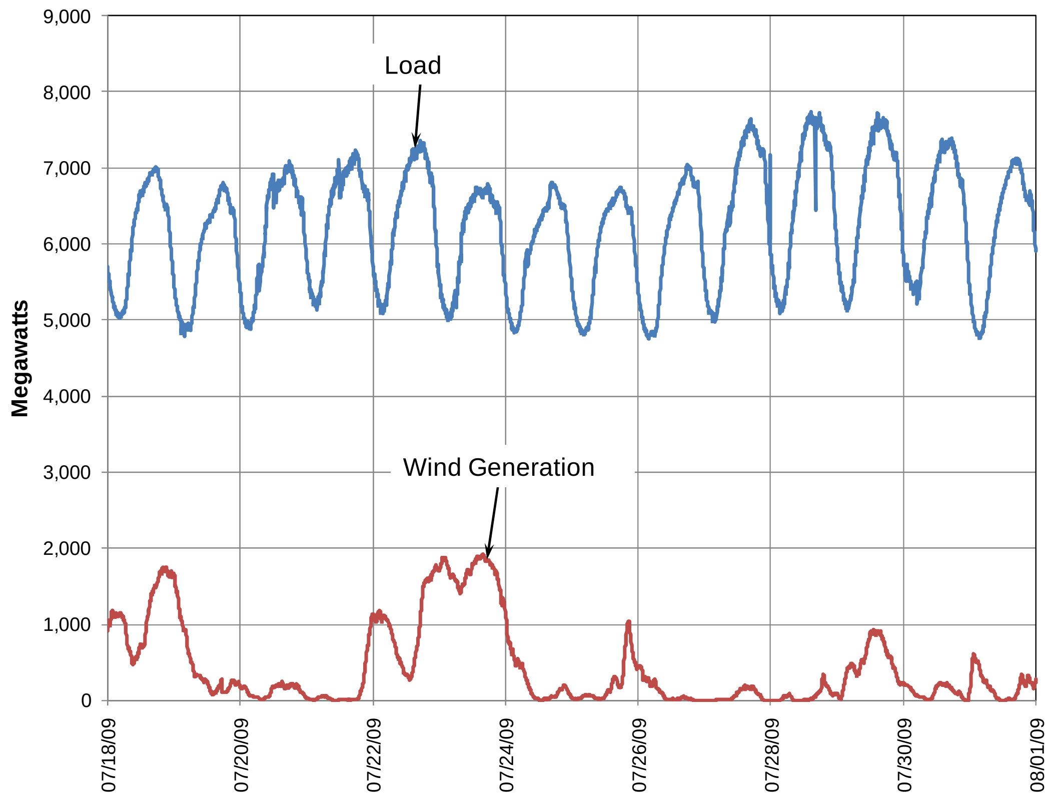

Figure 5-6 Example Hot Weather Load and Wind Generation Variability

Recent experience has indicated that wind power tends to be reduced when weather systems prevail that cause both unusually hot and unusually cold weather in the Pacific Northwest. Figure 5-7 displays load and wind generation data during a recent period of unusually cold weather, which is the condition that typically results in the highest loads in the Pacific Northwest. At the peak load of 10,760 MW, wind power supplied only 100 MW, or 0.9% of the peak load. Recent experience has also shown that wind power can be reduced to essentially zero output for a period of almost two consecutive weeks, as shown on Figure 5-8. Pumped storage can provide reliable large-scale energy storage to generate on-demand when wind power has been becalmed.

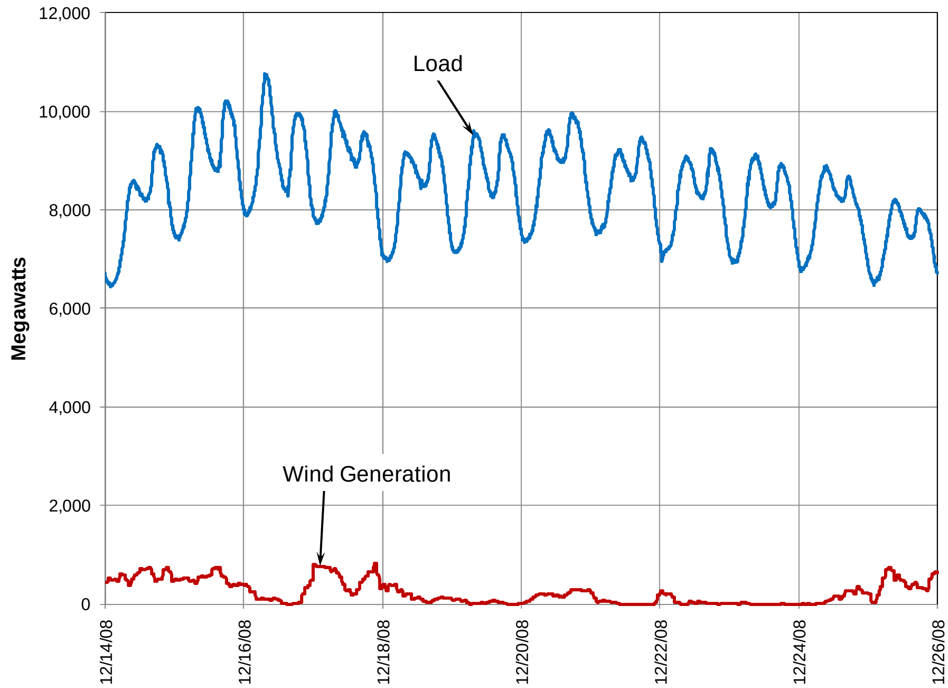

Figure 5-7 Example Cold Weather Load and Wind Generation Variability

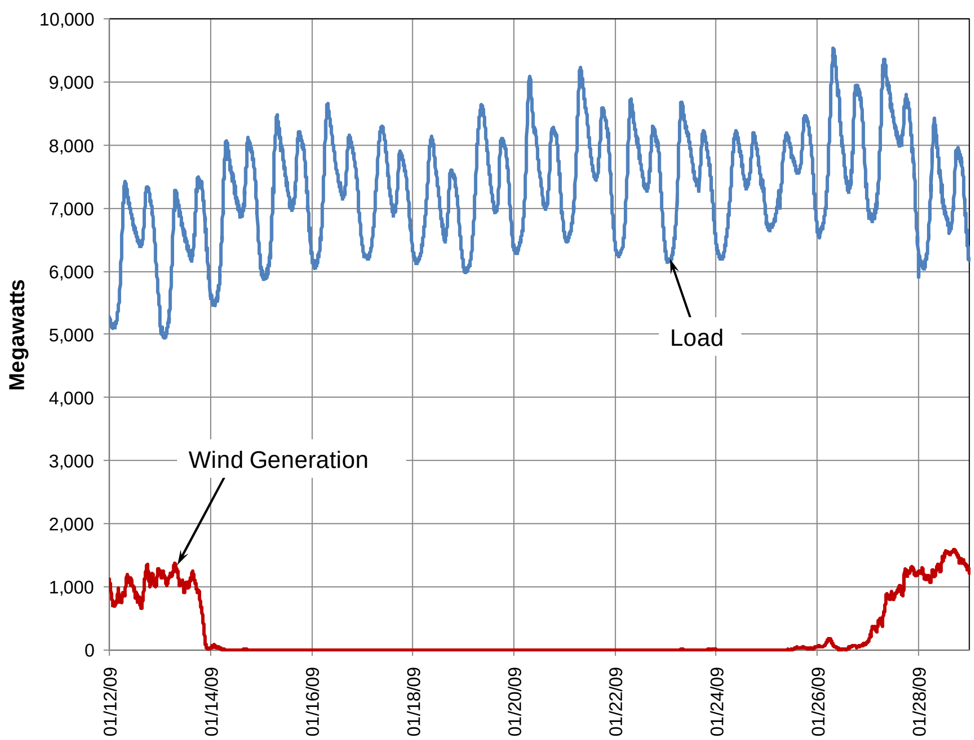

Figure 5-8 Example Very Low Wind Generation Period

Figure 5-9 shows load and wind generation in the BPA Balancing Authority Area for a two day time period when large wind power ramping events occurred. Table 5-3 provides statistics on the maximum ramping events for various time periods over the two day period in both wind power megawatts and as a percentage of the installed wind power capacity.

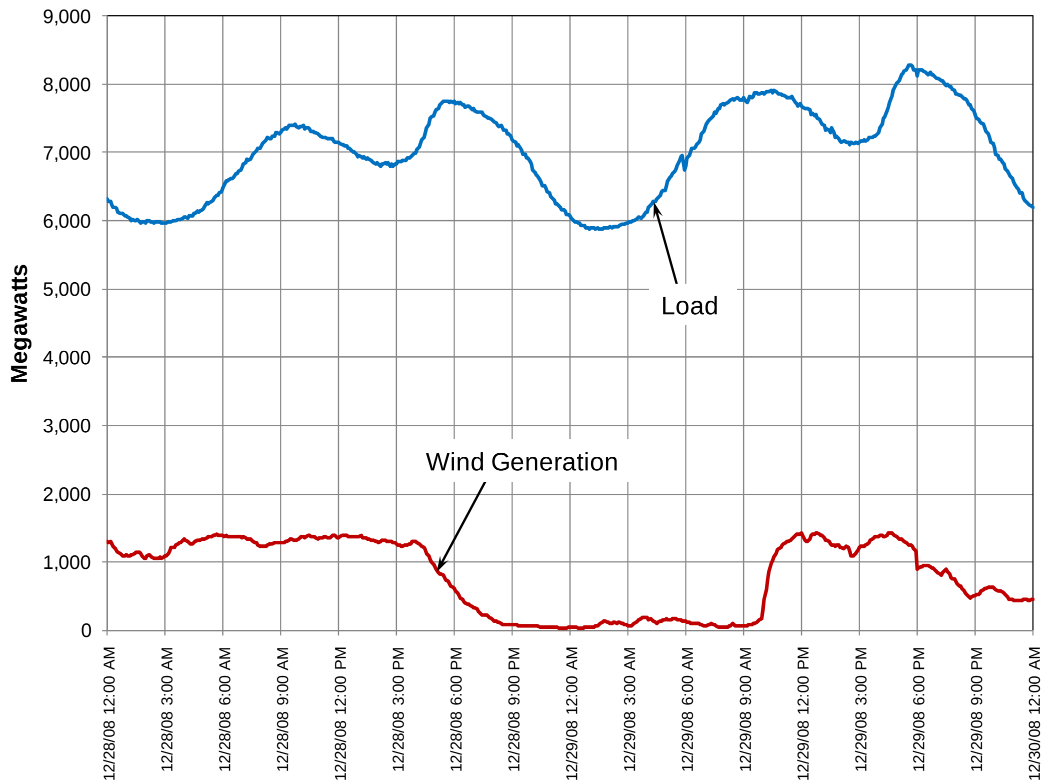

Figure 5-9 Example Wind Power Large Ramping Events

Table 5-3 Wind Power Ramping December 28-29, 2008

Wind Ramping Parameter (Total installed wind capacity is 1,592 MW)	Time Period of Up or Down Ramp		
	5 minutes	30 minutes	60 minutes
Maximum Up Ramp (MW)	179	818	1068
Up Ramp as a % of Wind Capacity	11.2%	51.4%	67.1%
Maximum Down Ramp (MW)	-258	-358	-452
Down Ramp as a % of Wind Capacity	-16.2%	-22.5%	-28.4%

As shown on Figure 5-10 (Source: BPA Web site), a large fraction of the wind power in the Northwest is either located or planned to be located in the heart of BPA's transmission grid. Wind power in BPA's balancing area has grown from 25 MW 10 years ago to 2,100 MW today. The wind power installed capacity will soon equal or exceed 30 percent of the current peak load of about 10,500 MW in BPA's balancing authority area. BPA's balancing authority area is shown on

Figure 5-11 (Source: Balancing act: BPA grid responds to huge influx of wind power, BPA November 2008). This would be one of the highest, if not the highest, proportion of wind power to load in any power system in the USA (BPA 2008). By 2013, BPA could have to constantly balance loads and generation for 6,000 MW of wind capacity in a balancing area where loads today average about 6,000 MW. BPA recognizes the need to address the particular generation imbalance problems that are related to wind power generation.

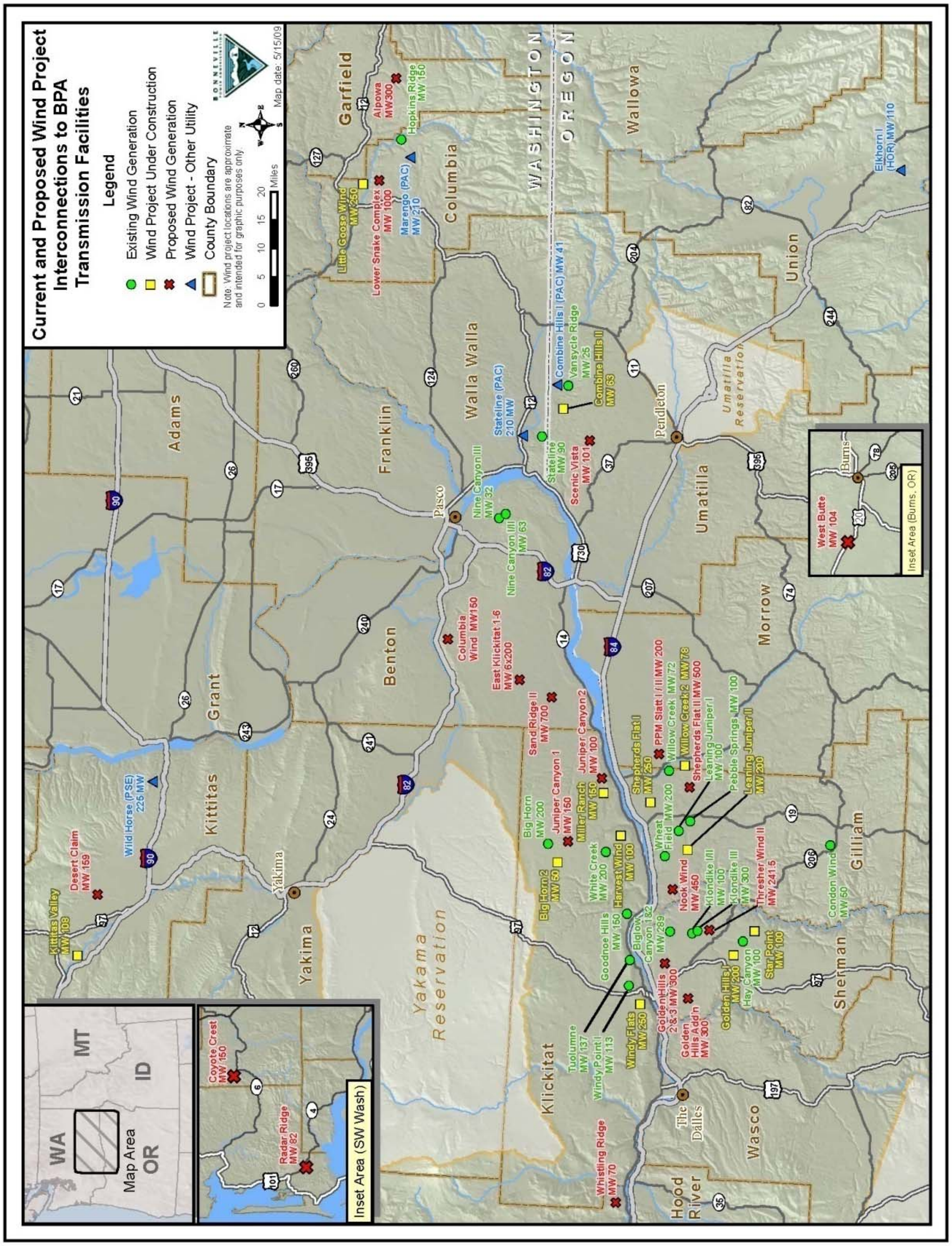

Figure 5-10 Current and Proposed Wind Project Interconnections to BPA Transmission Facilities

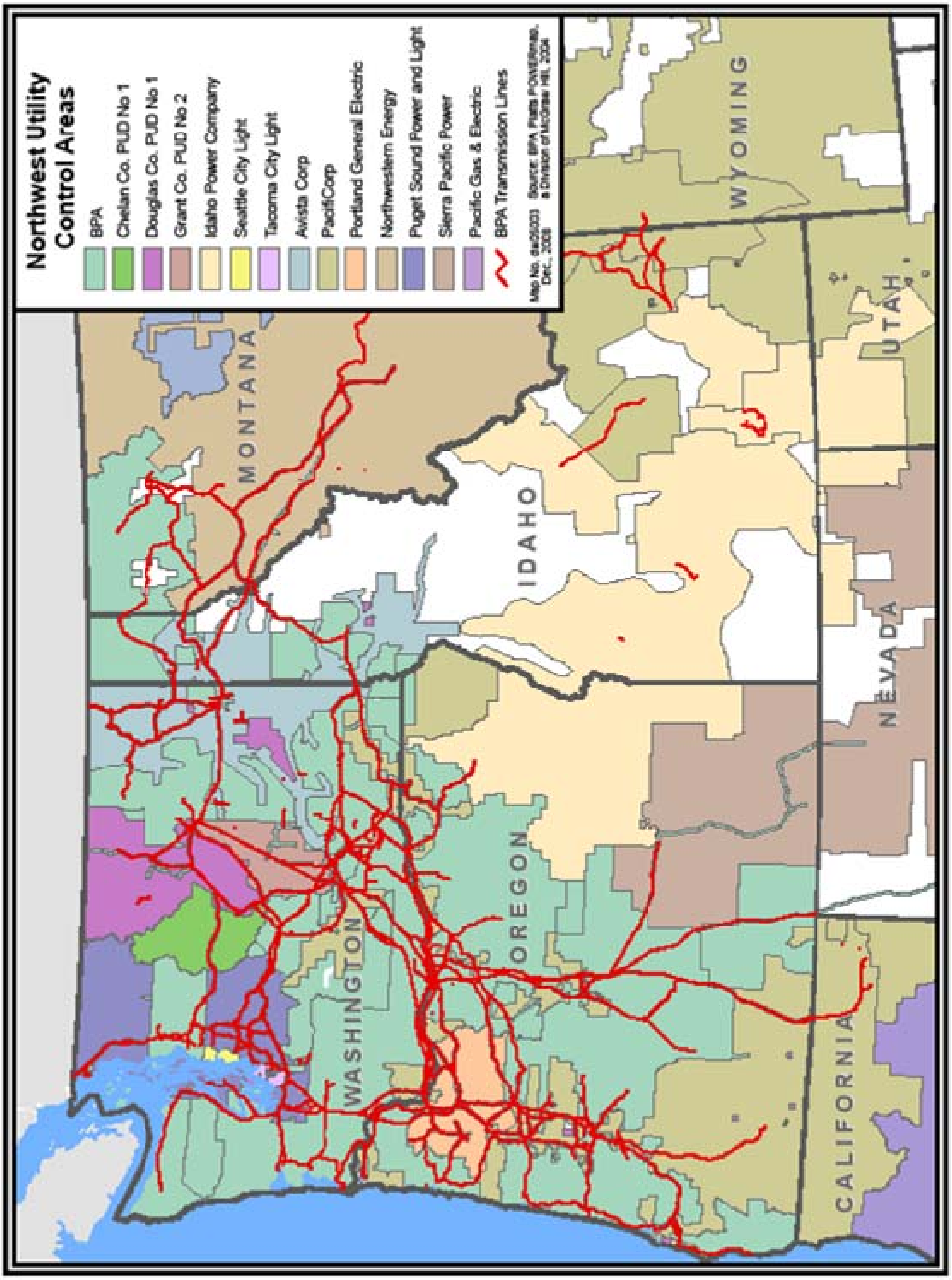

Figure 5-11 BPA's Control Area

5.2 PS Functions in an Integrated PNW System

The Grand Coulee pump-generating plant is one of four powerhouses at Grand Coulee dam and entered commercial operation in October 1973. The lower reservoir to the pumped storage part of the plant is the Franklin D. Roosevelt Lake that is formed by Grand Coulee Dam. The upper reservoir for the pumped storage plant is Banks Lake, which is formed by two embankments. A feeder canal connects Banks Lake to the powerhouse head works. The storage capacity of the upper reservoir is 11,115 MWh.

The Grand Coulee pump-generating plant has six 200 rpm vertical Francis pump/turbines. Four are rated 70,000 hp (52.2 MW) pumping and two are rated at 67,000 hp (49.9 MW) pumping. All units are rated at 67,500 hp (49.9 MW) generating.

There may be an opportunity to use the Grand Coulee pumped storage plant as part of the wind integration program. Since the civil and hydraulic infrastructure is in place for operation as a pumped storage plant, the cost to upgrade these pump/turbine units for fast response could be cost effective. Although not ideal from a transmission congestion perspective, an enhanced utilization of this site may be able to be part of the short-term plan.

Since the existing units are used primarily as pumps and are driven by single speed machines, they cannot contribute to the frequency regulation and load following. However, if they were converted to adjustable speed, then they could contribute frequency regulation service in the pumping mode. In this way they could become a system dispatch tool with regard to wind integration. Additional benefits from conversion to adjustable speed include increased efficiency and reduced vibration.

There may be other opportunities to introduce pumped storage into the Pacific Northwest system portfolio in the form of self-contained off-stream and pump-back plants. It may be possible to convert some existing conventional hydro units to adjustable speed operation and use the fast response capability as part of a wind integration plan.

5.2.1 Energy Storage

PS is able to provide energy storage as bounded by the civil design limits of a particular PS project. The primary civil design limits are typically the size of the upper and lower reservoirs and restrictions bounding the flow. The second most important aspect of civil design limits is the water conductors that determine the volume of water that can be passed without excessive friction losses in either direction. The third primary civil design limit is the construction of the powerhouse to house the main pumping and generating equipment. A final consideration is the availability of an adequate transmission connection.

While all things are possible, each site will have technical and economic limits that define the boundaries for each particular site. In the civil world, technical limits are usually hydraulic flow related, or geotechnical relating to the geology at site. More often, the technical capability is bounded by staying within the limits of the cost that must be overcome to make the project viable. As mentioned in the overview, higher head sites are more economic because, (1) the volume of water required to achieve a given capacity is minimized, (2) the size of the water conductors required to deliver a fixed capacity are smaller, and (3) the dimensions of the equipment for the powerhouse are physically smaller because the operating speed can be increased. The PNW contains numerous high head sites along the Columbia River Gorge that may be possible to develop.

5.2.2 Energy Shaping

A given wind powered generating project that is interconnected to the PNW control area schedules and delivers energy into the system on an hourly basis. A procedure has been used so that at the end of each day, the power market operator averages the scheduled (and delivered) peak and off-peak generation from the wind powered generation project. This amount of power is then redelivered a week later in flat peak and off-peak blocks. With pumped storage or pump-back schemes, it could be possible to accomplish this function on a daily basis. The time delay (one week or daily) allows the end-use customer to plan its system for redelivery volumes and takes the hour-to-hour uncertainty out of the wind generation.

There is a possibility that operation of some existing hydro plants could be modified or converted to provide pumped storage services. One possibility would be existing run-of-river plants. Normal operation is for a run-of-river plant to produce energy as water flow is available, without use of reservoir storage. However, if the lower reservoir were modified to provide some storage, then the water in storage could be pumped back up to the upper reservoir during times when there is low flow in the river. In this way a block of water could be used on a daily basis to generate during peak demand periods and pumped back to the upper reservoir during the night.

When designing a PS project, it is customary to try to define the operating limits of the machinery to match the load requirement it must serve. Maximum capacity is part of the limit. Minimum operating load capability of a unit is a second defining quality. For single speed units, the minimum operating MW limit is usually defined by cavitation limits and/or rough operating zones on the turbine. Reversible pump-turbines generally operate very roughly below 50% load in generator mode and for single speed equipment, the pumping mode is only at rated load.

5.2.3 Frequency Regulation and Load Following

Another system area where pumped storage can assist is in the area of frequency regulation and load following. As more wind power is connected to the grid, there is a corresponding need for additional capacity to provide frequency regulation and load following that can maintain the balance between generation and load.

The ideal for energy balance is when load equals power generated. This condition is a goal that is never achieved; since load is constantly changing, the generation controls are constantly adjusting generator output to bring the system back into balance. When power generated is less than the load, the frequency drops under 60 Hz. When power generated is greater than the load, the frequency rises over 60 Hz. Generators with fast response capability are assigned the role of frequency regulation and are used to control the power level so that frequency variation is within a narrow band. North American Electric Reliability Corporation (NERC) has established standards and procedures to set speed governor droop-settings to control system frequency.

Until the introduction of wind and solar powered generation, the frequency control problem was assigned to fast acting hydro, pumped storage, fast acting combustion turbines and some steam plants. These units were able to respond to the load increase and decrease during the daily load cycle. Although the load was unpredictable, on a short term basis, the load pick up and drop off in terms of MW/minute or MW/second was within the capability of regulating plants.

However with increased amounts of wind generation on the system there is a greater degree of uncertainty. The daily load cycle was reasonably predictable as a daily trend but with uncertain variable output from wind powered generation there is a need for added regulation and reserve capacity. Increased wind penetration creates a need for greater regulation capacity and faster regulation ramping capability.

5.3 Benefits of Pumped Storage in an Integrated PNW System.

The benefits of pumped storage in the PNW system include the conventional system operating benefits as well as the ability to assist with the integration of intermittent renewables such as wind and solar. The conventional benefits include power and energy arbitrage, frequency regulation, load following, spinning reserve and reactive power for voltage regulation.

The wind integration functions that pumped storage can provide are based on the ability of pumped storage units to respond quickly to changes in power output and frequency resulting from variations in output from wind powered generators. Since pumped storage units can be designed to have fast response times they can be play a significant role with regard to wind integration.

Pumped storage plants can play a significant role in system restoration if they are designed for black start. In the event of a blackout, a plant with black start capability is self-contained and can start by itself.

The possibility to upgrade or convert existing hydro generators in the PNW to pure pumped storage or to pump-back operation should not be overlooked. The adjustable speed technology can be applied to conventional hydro generators as well as to pumped storage.

Another consideration would be the relationship between the capacity of a pumped storage plant and the installed capacity of a wind powered generation facility. One could envision an analytical effort to establish the magnitude of wind powered generation and the capacity of pumped storage plant that was dedicated to modulating the power and frequency fluctuations from the wind powered generators.

To illustrate the benefits of pumped storage in the PNW system, one historical week (June 3-9, 2009) of system demand and wind generation data was simulated. Figure 5-12 shows the basic customer load demand and wind generation data.

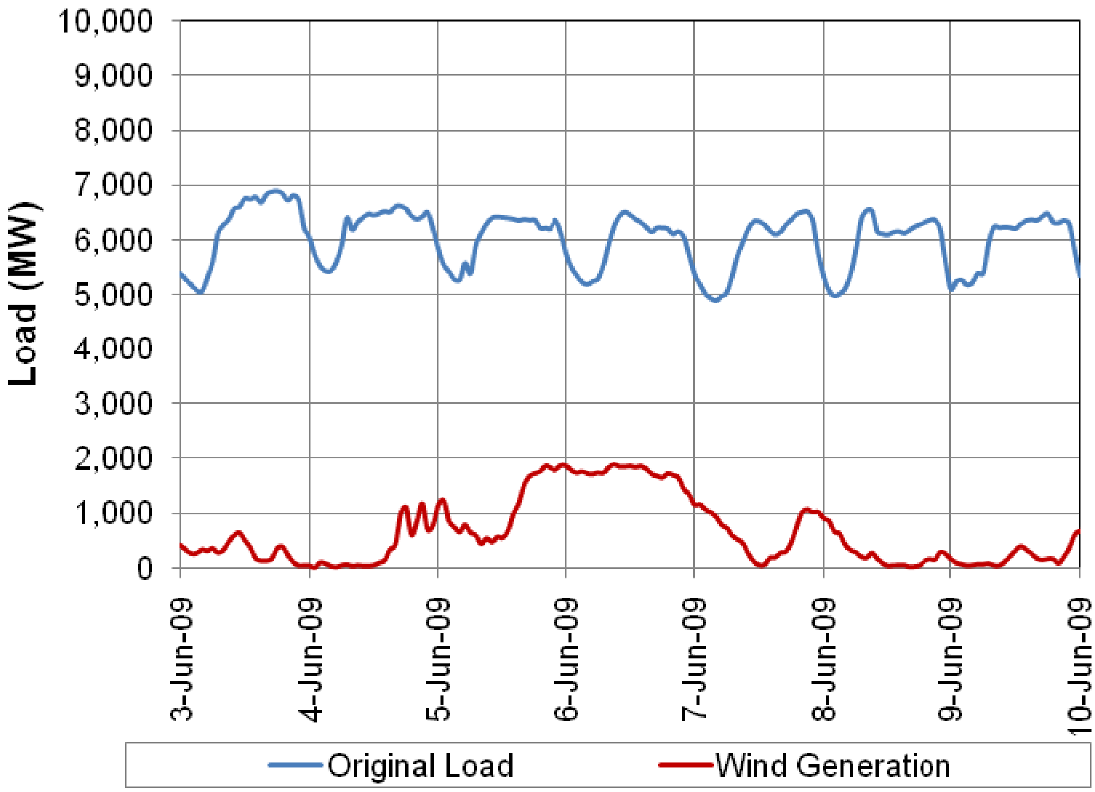

Figure 5-12 PNW System Load and Wind Generation for a Typical Week

As shown above, the typical daily demand fluctuations vary between approximately 5,000 MW during the off-peak or night hours and 7,000 MW during the peak hours, a difference of 2,000 MW. Figure 5-13 shows the same customer load demand minus the wind energy generation data. Without any storage capacity, the existing hydro system and other non-wind generation units would need to meet the load below the “with wind generation” curve. As shown on Figure 5-13, the resulting maximum difference between the minimum and maximum loads after deducting wind is now 3,200 MW (June 6-7), as compared to 2,000 MW without wind generation. It is not unusual that wind will greatly increase load demand fluctuations to be met by other hydro and thermal units of the system.

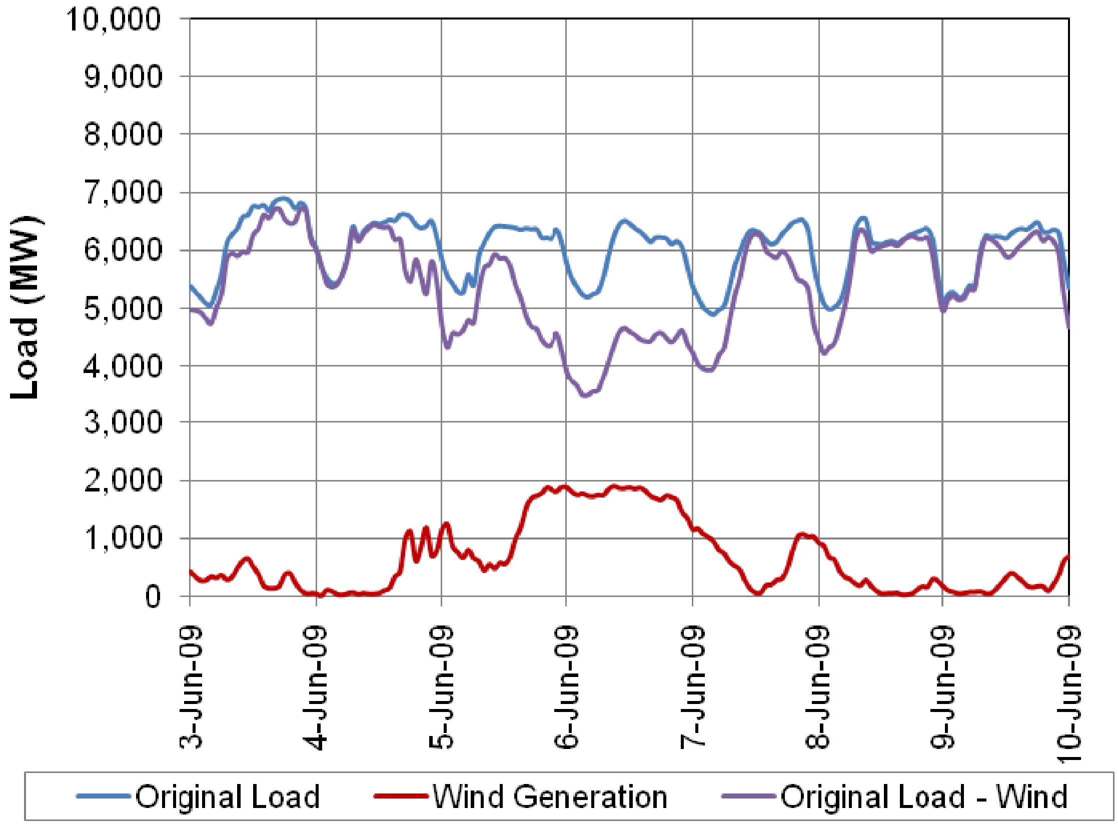

Figure 5-13 PNW System Load minus Wind Generation or "with Wind Generation" Load Curve

Introduction of more pumped storage into the PNW system would help alleviate the challenges associated with integrating wind power. First, the daily fluctuation of load on existing hydro and thermal resources could be considerably smoothened. As an example, Figure 5-14 shows preliminary results obtained with 1600-MW of pumped storage having a 10-hour hour storage (16,000 MWh) capacity.

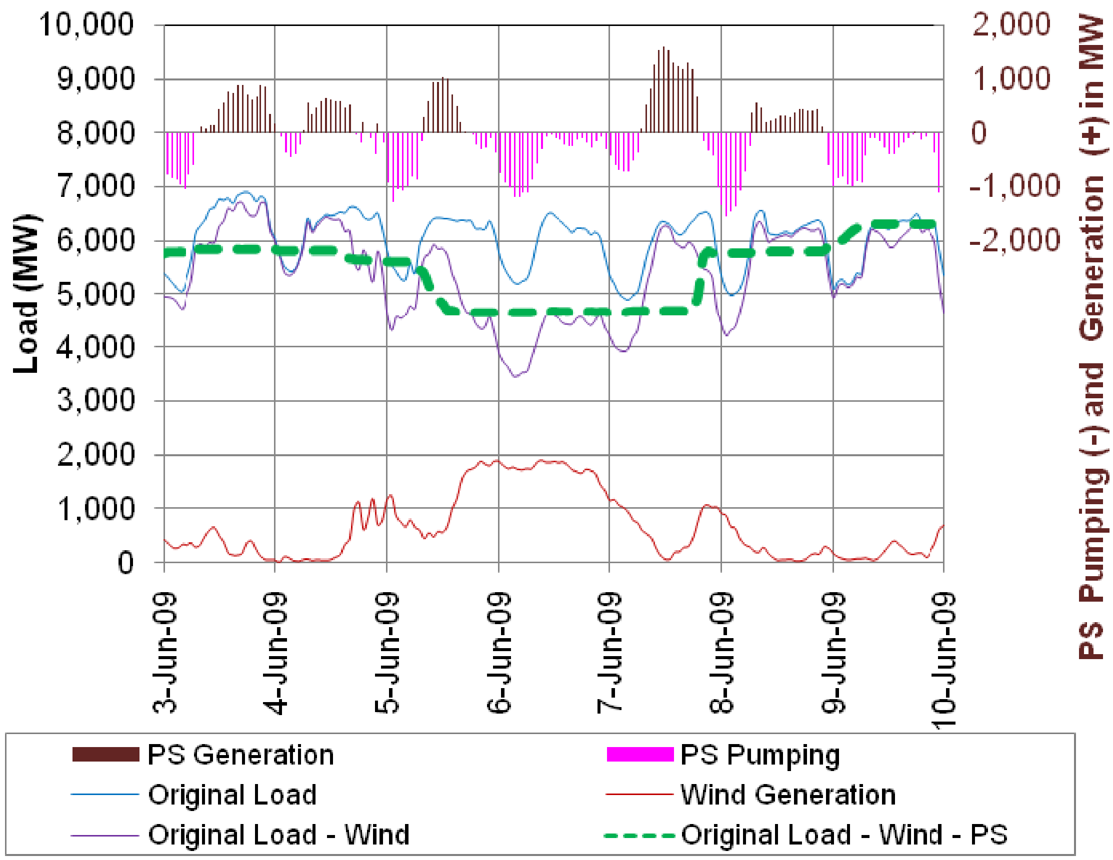

Figure 5-14 PNW Load on Existing Hydro and Thermal Resources after Deducting Wind and Smoothing with Pumped Storage

The above results (dashed line) for pumped storage operation show a considerable flattening of the demand curve to be served by other existing hydro and thermal units. This exercise was done using a very simple spreadsheet model without the sophistication of a detailed hourly production costing model. It does however illustrate the “smoothing” capability of pumped storage. The late evening hours of June 4 are of particular interest. As wind generation varies nearly on an hourly basis, pumped storage provides a solution to "absorb" or "smooth out" these hourly variations. The resulting hourly PS pumping and generation patterns are shown in the upper portion of the graph.

Figure 5-15 shows the operation of pumped storage for the same historical week. The PS hourly pumping and generation are shown along with the changes in reservoir storage capacity. For this exercise, it was assumed that the upper reservoir would start with a capacity of 12,000 MWh, at the beginning of the week. At the end of the week, the reservoir has regained its initial capacity of 12,000 MWh. There is a weekly balance between pumping and generation, taking into account the overall PS cycle efficiency. Looking at the minimum and maximum level of storage over the entire week, it can be seen that a total storage of 16,000 MWh would be necessary to provide the operational benefits described above. It can also be clearly observed that PS changes from pumping to generation mode not only to satisfy the daily cycle of LLH to HLH, but also to absorb the hourly variability of wind output, on a real time basis.

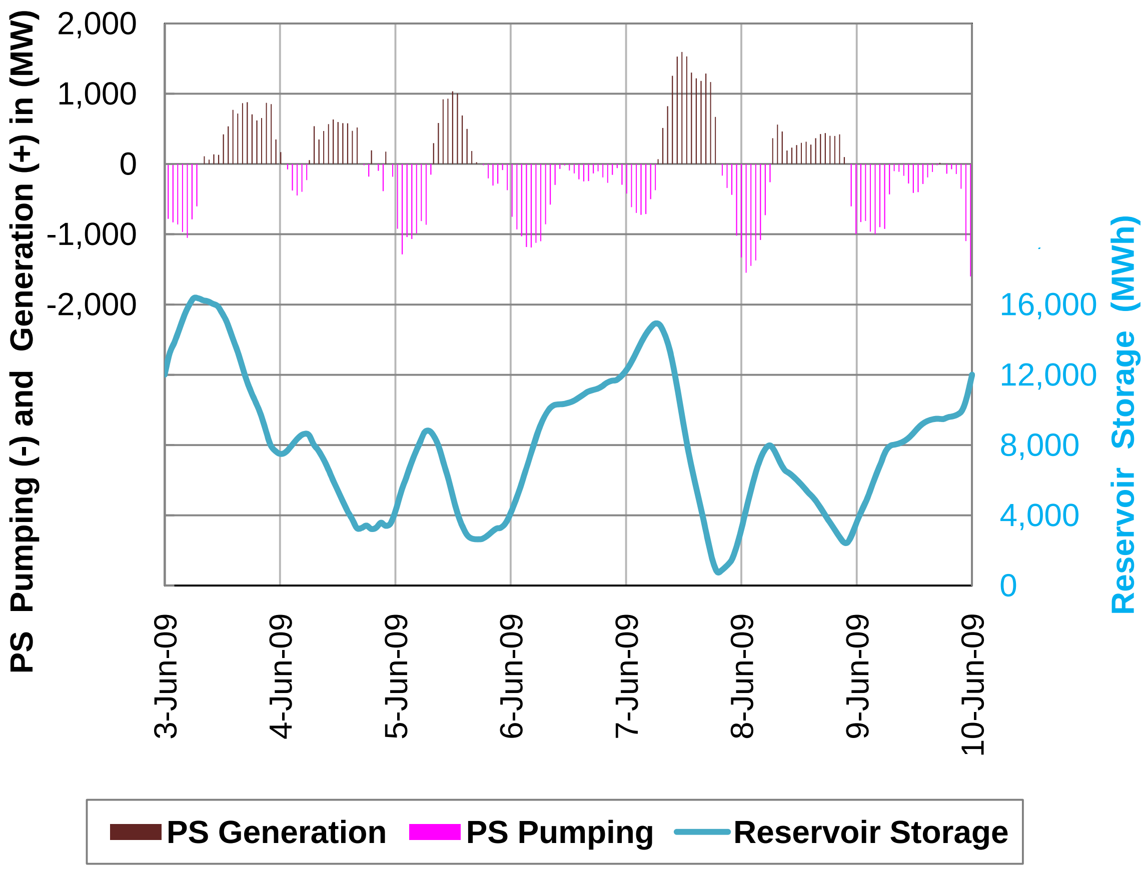

Figure 5-15 Example of PS Pumping and Generation and Reservoir Storage Variation Pattern

5.3.1 Pumped Storage Integration Effects

When a single speed pumped storage unit is in the generation mode it can change its output level and participate in ramping operations. A single speed pumped storage unit in pumping mode cannot change its power level so it cannot play a role in the ramping operation. A pumped storage plant with adjustable speed machines, however, can participate in ramping operations in both pumping and generation modes.

Since pumped storage is site specific and the transmission grid is inflexible with regard to routing of transmission lines, there may be little that can be done to directly configure pumped storage with regard to transmission. However, there may be a relationship between the areas where good wind resources exist and pumped storage plant sites.

Just as developers, of wind powered generation, use wind profile maps to identify locations for wind powered generators, so might developers of pumped storage use the same maps to find good pumped storage plant sites. The idea being that there may be good pumped storage sites in the same areas that are ideal for wind powered generators. If such a serendipitous relationship could be found then it may be possible to connect the output from wind powered generators to the substation at the pumped storage plant. If such a configuration could be achieved, then it may be possible for the pumped storage plant to act as an interface between the wind powered generators and the bulk power system.

5.3.2 Location of Pumped Storage with Regard to Transmission

The best site with regard to transmission is one that provides maximum benefits to the operation of the bulk power transmission system, reduces congestion and requires minimum construction and impact. The selection of a site with regard to the transmission grid has several considerations.

One aspect is the physical size and location of a connection point and another is the location with available transmission voltage, line and substation power capacity, and regard to support to the bulk power system. Other considerations have to do with availability of right of way, constructability, siting, permitting and environmental issues.

Physical considerations include proximity (distance) to a substation of proper voltage, proximity to an existing transmission line with proper voltage and available transmission capacity, need for upgrading of existing lines and substations due to the injection of a significant amount of new capacity and need for multiple transmission circuits for reliability and flexibility to move power to more than one market.

Given that the topology of the transmission grid is driven by the need to transmit power and energy from generators in remote areas to distant load centers, one would expect that it would be best if the pumped storage plants were located in close proximity to the wind powered generators.

There are potential benefits to the bulk power system from the connection of a new pumped storage plant. Some examples are: supply of reactive power to resolve low voltage conditions and potential voltage instability issues, congestion relief, improved stability and dynamic performance, spinning reserve, and black start.

There are other considerations with regard to the broader perspective of transmission system loading and planning. The PNW has experienced some transmission system loading conditions that reinforces the need to have pumped storage close to major wind sites and use pumped storage to minimize regulation impacts on the transmission system.

The location of a pumped storage plant can have a beneficial impact on transmission line congestion. Figure 5-16 shows areas of the PNW transmission system that are of concern from the congestion point of view.

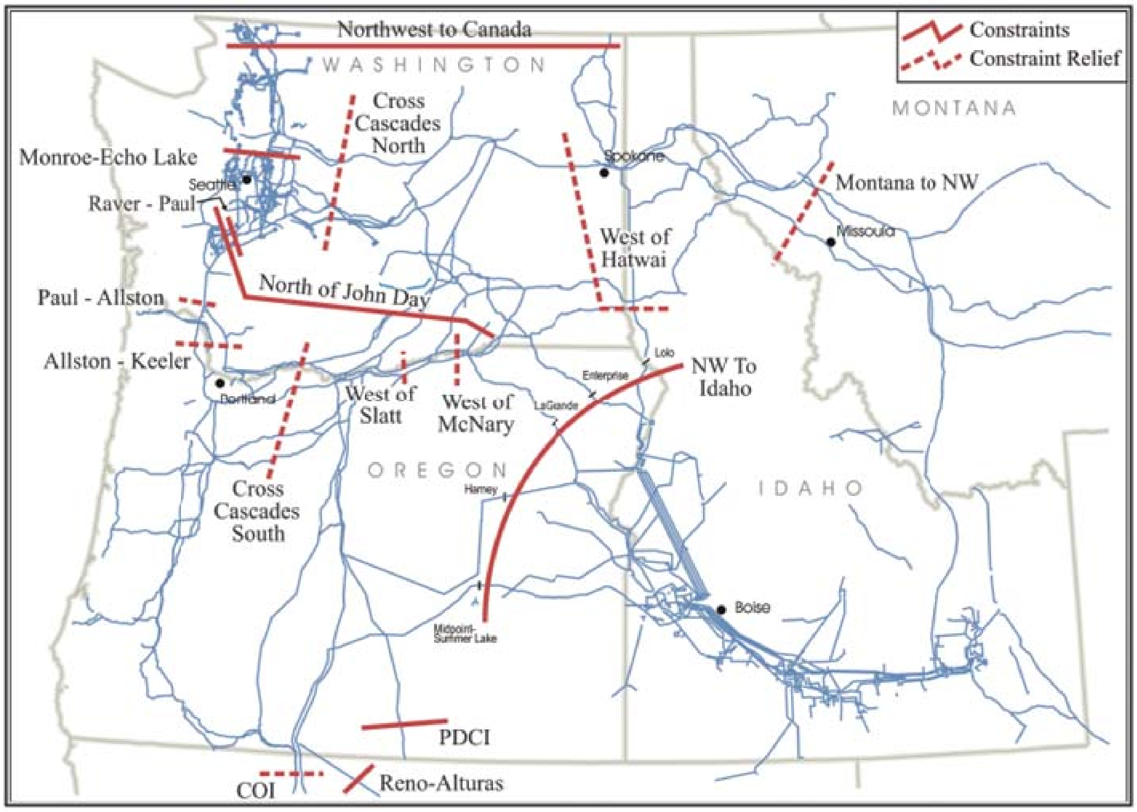

Figure 5-16 Potential Transmission Line Congestion Areas

It was reported by BPA representatives (Mike Viles, 2009) that, during the March-April period in 2009, the North of Hanford transmission path experienced higher loading in the south to north direction than it has in the prior years. The loading conditions appeared to be aggravated by the following conditions:

- Wind generation was higher (South of Hanford)
- Low Upper Columbia generation (Chief Joseph and Grand Coulee hydro generation North of Hanford)
- High northwest exports to Canada (increases South to North power flow on the North of Hanford path)
- Pump generators at Grand Coulee on-line (increases load North of Hanford)

The maximum wind generation on the BPA system has increased from 700 MW during this period in 2007 to 1200 MW in 2008 to 2100 MW in 2009. Similarly, the maximum South to North flow during this period has increased from 3000 MW in 2007 to 3200 MW in 2008 and 3400 MW in 2009. The increase in wind generation appears to be the biggest factor in the higher North of Hanford flows.

A pumped storage plant provides low cost capacity and energy during times of peak demand and in so doing avoids the need to operate fossil fueled generators. Assuming the transmission system can accommodate the capacity from the pumped storage plant the supply of power in generation mode is a system benefit. In the majority of cases a new pumped storage plant does not have a negative impact on the transmission system when the plant is in pumping mode. However there is a need to evaluate the impact of the plant on the grid when it is in pumping mode. There have been cases where pumping mode operation during light load periods involves transmission of a large block of power over a long distance during light load conditions. In a few cases the power transmission for pumping mode has resulted in potential system instability.

Some transmission related issues have to do with increased short circuit levels in substation and necessitating major upgrades, overloading of existing transmission circuits, adverse transient stability and dynamic performance issues and impact on economic system dispatch.

An example of a potentially fortuitous location for a pumped storage plant is at the California – Oregon border near the Captain Jack or Malin substations. If a pumped storage plant were built along the border and connected to the Captain Jack or Malin substations, then it could provide voltage support to the 500 kV transmission lines that connect California to the PNW.

5.4 Overview of Pumped Storage Economics for the Pacific Northwest

The economic viability of a pumped storage hydropower resource addition to an electric system needs to be analyzed in the overall context of the electrical system within which it will be integrated. The main criterion in any generating resource addition is a demonstration that the addition of the resource will result in the lowest overall cost of providing power and energy to the end user at some specified level of reliability. Furthermore, the resource is but one resource of an overall plan of resource additions and retirements that may take place over an extended time horizon. Therefore, the decision viewpoint must be in terms of “resource future plan A” in comparison with “resource future plan B”, and not a comparison of pumped storage hydro versus continued cycling duty on conventional hydro resources.

Often, future supply planning is not strictly a question of minimizing the cost of supply. Numerous constraints must be considered which are deemed overriding considerations. The Columbia River is not operated to maximize generation, but rather to maximize generation subject to a host of constraints. Similarly, the overall PNW generating fleet will not necessarily evolve in a minimum cost manner, but rather in a way that tends to minimize supply cost subject to a myriad of constraints, one of which is growth of renewable supply to meet certain mandated targets.

Notwithstanding the above philosophy, what are the economic factors that could contribute to the selection of a pumped storage project as a component in integrating wind generation as a reliable and dependable component of an overall power supply plan? Some of the factors are listed below:

1. A candidate site must be viable in terms of technical aspects and environmental characteristics, with minimal design or geotechnical risk.A candidate site that has unfavorable geological conditions or some other

other potentially difficult development aspect would be an unfavorable choice for consideration.

2. The location of the facility with respect to transmission and wind generation may be critical, depending upon line loading and transmission constraints. However, transmission system improvements to remove constraints may or may not be a cost attributable to wind integration if transmission congestion mitigation is needed for other reasons.
3. The basic premise in economic justification is that the facility must result in system operational cost savings (in comparison with some other plan) in an amount that is greater than the capital cost plus recurring operational costs. Making this determination is difficult due to the complex nature of the interconnected supply system and operational uncertainties and variability associated with non-dispatchable renewables. In addition, due to the large hydropower generation resource base, traditional on-peak off-peak energy arbitrage would probably not be a significant component to a pumped storage project's economic viability.
4. Sophisticated modeling tools are required to demonstrate how various supply sources may operate, along with associated costs, to meet loads with a specified degree of reliability. Complicating the problem is that the basic variables (e.g. a future wind generation output time series record for study purposes) all have an associated range of uncertainty, so even if one could truly model all of the system interactions, one would probably only be able to state that a particular plan is most efficient under subset of all alternative futures.

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6 SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

The statement of work for this study included a list of 14 questions that must be addressed, 7 questions on technical aspects and 7 questions on operational aspects of pumped storage installations. Sections 6.1 and 6.2, below, provide MWH's responses to the questions in summary form. It is important note that there isn't a "typical" pumped storage plant – every pumped storage plant is different from every other pumped storage plant. Each answer brings together information found throughout the report. Section 6.3 provides a conclusion.

6.1 Technical Aspects of a Pumped Storage Installation

1. *What is the capability of pumped storage for regulation and load following?*

Capabilities that set pumped storage projects apart from other sources of generation include ancillary services – such as frequency regulation, voltage regulation and load following – that are vital for grid stability.

In any power system, controlling frequency is needed to balance electricity supply and demand. When sudden changes in system load occurs, system frequency would destabilize if generated output is not adjusted to match the changed load. The rate at which a generator's output can increase or decrease depends on the type of generator and its driver; typically, large nuclear or coal units are slow to change output while conventional hydropower turbines, pumped storage units, and combustion turbines are very responsive. In a single speed pumped storage machine, the governor is used to control unit speed and frequency by way of the wicket gates (adjustable guide vanes that surround the turbine and control the area available for water to enter the turbine) – but only if that unit is serving an isolated load. In the far more common interconnected system, the wicket gates adjust the power output of that unit, which contributes to the restoration of balance among all of the interconnected generators and their common load. On some plants, the wicket gates can be set to open and close as fast as 10 seconds or less but many other plants are often set for much slower timing for various reasons.

Adjustable speed machines can provide additional benefits as compared to single speed machines. They offer frequency control in both generating and pumping modes. With adjustable speed technology, there are two control components: one is the turbine governor controlling the wicket gate position of the turbine (in generating mode), as noted above; the other is the inverter controlling the rotor current of the generator/motor (in pumping and generating modes). The total time for change in power from zero to rated has been estimated at as low as 150 milliseconds for some existing adjustable speed units.

Similarly, voltages must be kept within design tolerances. An imbalance in the supply and demand of reactive power (VARs) causes voltage to rise or drop across the power system; regulating voltage involves balancing VARs (as opposed to real power). In both pumping and generating modes, voltage control is performed through the voltage regulator, which is part of the excitation system.

Both single and adjustable speed pumped storage can provide voltage regulation. The selection of the lower limit of power factor is based on the need for reactive power within close proximity of the power plant. If there is a need for reactive power in the vicinity of the plant, then a lower power factor is selected. If there is minimal need for reactive power in the vicinity of the plant, then a power factor of 95% is selected. The power factor over which a pumped storage unit can operate is a design choice, ranging from a low of 85% up to 95% for power factor (lagging).

In the generation mode, pumped storage can quickly follow load demand whether the demand is increasing or decreasing (similar to conventional hydropower projects). Pumped storage projects have a ramp rate capability in the range of 10-30% of maximum capacity per minute. During load swings, other generating units on the grid may be started or shut down to follow load. However, because of the comparatively fast ramp rate, pumped storage projects can reduce the number of start-ups and shut-downs for other units in the system (e.g. conventional hydropower units or thermal units), and/or increase the time for other units to start-up or shut-down, thereby reducing wear and tear on units.

In addition, an adjustable speed pumped storage project is capable of following load in the pumping mode by adjusting its input over a load range of 50-60% of rated pumping power. However, single speed pumped storage projects are constrained in pumping mode, and cannot adjust their pumping load requirements (it is typically run at either no load or full load).

From the point of view of frequency regulation, it is necessary for a pumped storage plant to provide these services to the grid in both pump and generation modes. DOE's Energy Storage section has recently announced a $200 million dollar program that includes funding for projects that provide fast response for frequency regulation (Gyuk, 2009).

2. *Are there rules-of-thumb on costs?*

a. *Various design options*

Project-specific design features, such as head and capacity, affect the overall project cost. As head increases (within the limits of a single-stage pump-turbine unit), equipment size (and corresponding equipment cost) decreases. A rule-of-thumb for the cost of design options is extremely site specific, but an approximation of the cost of developing a pumped storage project may be around $2,000 to $3,000 per kW.

b. *Reservoir construction costs*

The main factor that affects the cost of reservoirs is the volume of water to be stored. Larger storage volumes will be more expensive, but larger storage volumes tend to exhibit lower unit cost per acre-feet (AF) of storage. Storage costs could range from $2,000 /AF to $20,000 /AF, depending on site characteristics such as topography and geology.

***3.** What are the key driving factors in cost effectiveness?*

Generally, higher head sites (within the capabilities of a single-stage pump-turbine) and short conduit lengths are more cost effective. Higher head sites can achieve higher installed capacities with smaller sized units and waterways, thereby reducing the equipment and civil construction costs for a given installed capacity. The existing transmission system – more specifically the distance of the nearest transmission interconnection point for a proposed PS, also plays a factor in determining the cost-effectiveness of a site, as it determines the cost of integrating the facility with the system.

A larger margin between the Low Load Hour (LLH) pricing and High Load Hour (HLH) pricing will affect the financial feasibility of the project, and will help define what project cost can be justified given current value of energy and ancillary services. The value of ancillary service must be considered to fully appreciate the value of pumped storage in the region.

***4.** Are there optimal design criteria for head, flow, reservoir size, etc.?*

Optimal design criteria will vary based on the specific project objectives and the site conditions. Power is proportional to head and flow; an ideal site would have (among other things) the highest head available within the pumping capability range for a single stage pump. Lower head projects require more flow to produce the same output, which increases the reservoir volumes, waterway diameters, and the size of the machines (all of which increase cost). It would also have a short horizontal distance between the upper and lower reservoirs.

The L:H ratio is a simple ratio used to measure the initial viability of a pumped storage project in siting level studies. L is the length of the waterway from the intake structure to the tailrace outlet and H is the gross head available for energy production. Waterways tend to be a sizeable portion of the cost of a project; minimizing the length while maintaining a sizeable head difference between reservoirs is very important in having a viable project. Generally speaking, potential projects having an L:H ratio under 10 show promise as a pumped storage project. Lower ratios will have a lower cost in $/kW terms

Reservoir size will be determined by the storage and cycle selected based on project objectives. The reservoir storage is typically equal to a generation equivalent to 6 to 8 hours (for daily cycle pumped storage) at full capacity. The selection of the reservoir size is dependent upon the site characteristics (in terms of constraining the size), and the electrical system characteristics.

Other factors that affect project design include the geotechnical suitability of the site, which is essential for both structural stability and leakage considerations. The environmental and social surroundings are an important factor, and impact the feasibility of development, schedule and cost. Location (to wind power facilities and transmission) impacts the project design and cost; an ideal site would be close to installed wind power and near an area of the transmission system that is not congested.

5. *Can you define the operating bounds or characteristics of pumped storage for various products (storage, shaping, regulation, load following) and can these products be done coincidentally or are there tradeoffs?*

The characteristics of regulation and load following are discussed in the answer to Question 1, above. It should be noted that if regulation and load following capabilities are desired while the project is in pumping mode, an adjustable speed unit would be required.

Storage and shaping characteristics will depend on the desired cycle duration (daily, weekly, etc.), the capacity of non-dispatchable renewable generators that the facility will respond to, and the ancillary services capability desired.

A plant with multiple units can be used to provide both storage and shaping, as well as regulation and load following. This can be accomplished by assigning one unit to shaping and load following and another to regulation. This operating flexibility can be expanded if one or two units are of the adjustable speed type; a conventional pumped storage plant with single speed machines can only provide frequency regulation and load following in the generation mode while an adjustable speed unit can provide frequency regulation in both the pumping and generating modes. The availability of ancillary services is tied to the capability of the machines (installed capacity, operating range, etc) and the volume of the reservoirs.

There are tradeoffs between these products and project cost.

6. *What are the efficiencies of various configurations?*

a. *Storage vs. energy loss*

Reservoir characteristics may affect cycling efficiency. Shallow, wide reservoirs may result in a smaller range of operating heads, allowing operation at or near the best efficiency of the pump turbines, and contribute to a higher cycling efficiency. Projects with a narrow, deep reservoir may exhibit reduced cycling efficiency because of operating over a greater head range. Selection and specification of pump-turbine characteristics for a site with deep reservoirs would need to specifically consider the wide operation range, particularly pump-mode operation at the end of the pumping cycle when the pumping head is greatest.

Design heads for existing pumped storage projects range from 100 feet to 2500 feet. The percent change in head due to moving water from the upper reservoir to the lower reservoir (and vice-versa) is normally small, even in the case of deep, narrow reservoirs. For new project siting, the minimum practical head for an off-stream pumped storage project is generally around 500 feet, with higher heads being preferred – most of the existing projects with less than 500 feet are either multi-purpose projects, pump-back projects, or projects that use and existing lake.

For a closed loop (off-stream) application, the range of head values that the project will operate under may vary from the minimum head condition of full lower reservoir and empty upper reservoir (dead storage remains), to the maximum head condition with empty (with dead storage remaining) lower reservoir and full upper reservoir. However, if either reservoir utilizes a river or other water body (or has local inflow/outflow), the change in head during operation will depend on the characteristics of the water body.

For existing projects, upgrading the units to include modern-design runners can improve unit efficiency, depending on the age and condition of the existing units. A two to ten percent gain – dependent on age and condition – in efficiency compared to existing unit performance is reasonable. If operation of the project has changed since the existing units were brought online (i.e. more ancillary service operation in response to non-dispatchable renewables), new runners may also be designed with current project objectives, increasing the potential to enhance efficiency.

It is known that the adjustable speed operation can provide a noticeable efficiency improvement at low output. For turbine operation, the benefits from adjustable speed operation are associated with reduced speed; a speed reduction will move the operation closer to the condition of highest turbine efficiency. The optimum speed is determined by the net head, which varies with the power output.

b. *Evaporative and leakage losses*

Evaporation and leakage may decrease the efficiency of a pumped storage project because it results in the loss the project's fuel, water. This is especially true in off-stream arrangements. In projects that use a river for the lower reservoir, water loss in the upper reservoir through leakage and/or evaporation still manifests itself as an efficiency loss, increasing the required pumping to maintain upper reservoir levels. However, if the system is not a closed loop, water may be recovered without requiring supplemental water from another source (i.e. additional water would be taken from the lower reservoir/river).

Depending on the geological conditions, a liner may be required in one or both reservoirs to prevent leakage. A main source of leakage is cracks that develop in concrete-lined sections of the waterways. Evaporative losses depend on the size and location of reservoirs. Shallow reservoirs, which a large surface to storage ratio, located in tropical climates are much more impacted by evaporative losses than reservoirs in temperate climates. Evaporation is greatest in conditions of dry heat and wind. If water losses are significant, supplemental water supply may be required to refill some of the reservoir volume. The extent of these losses is very site specific, and can be estimated by looking at pan evaporation rates in similar climates.

7. *What are the Operations and Maintenance costs for a pumped storage facility?*

The operations and maintenance cost are highly dependent upon the design and condition of the facility, the owner's operational philosophy, the manner in which the facility is used, the size, and other factors. Historical O&M costs reported by various owners indicated a range from a low of $2 to nearly $20 per MWh at 2009 price levels. The upper end costs may result from costs associated with maintenance of older projects. A suggested rule of thumb for very high-level budgeting purposes would be about 5 $/MWh of energy produced (at 2009 price levels), and assuming a normal plant factor of about 20%; the O&M cost per MWh may be higher for smaller plants and lower for larger plants.

6.2 Operational Aspects of Pumped Storage Installation

1. *How do you most effectively integrate wind with pumped storage?*

Given that the topology of the transmission grid is driven by the need to transmit power and energy from generators in remote areas to distant load centers, one would expect that it would be best if the pumped storage plants were located in close proximity to the wind powered generators. If this were possible, then the pumped storage plants could act as an interface between the wind-powered generators and the load centers.

Another consideration would be the relationship between the capacity of a pumped storage plant and the installed capacity of a wind-powered generation facility. One could envision an analytical effort to establish the magnitude of wind powered generation and the capacity of pumped storage plant that was dedicated to modulating the power and frequency fluctuations from the wind powered generators.

Adjustable speed units have greater ancillary service capabilities, namely frequency regulation and load following in the pumping mode, which are valuable for integrating intermittent wind. For example, an adjustable speed unit has the advantage of being able to utilize a greater range of input power to pump, allowing the unit to operate under a range of wind conditions. The increased capital cost of adjustable speed units must be weighed against its benefits.

2. *Can you have both storage and shaping vs. regulation and load following or do these functions have to be separate?*

See the response to Question 5, under Technical Aspects.

A plant with multiple units can be used to provide both storage and shaping, as well as regulation and load following. This can be accomplished by assigning one unit to shaping and load following and another to regulation. This operating flexibility can be expanded if one or two units are of the adjustable speed type; a conventional pumped storage plant with single speed machines can only provide frequency regulation and load following in the generation mode while an adjustable speed unit can provide frequency regulation in both the pumping and generating modes. The availability of ancillary services is tied to the capability of the machines (installed capacity, operating range, etc) and the volume of the reservoirs.

3. *Would you design the pumped storage project differently for different purposes (e.g. shaping LLH to HLH, wind integration, or storage and shaping vs. regulation and load following?)*

The design of a pumped storage project will be different depending on the objectives of the project, and intended use.

The size of the reservoir will depend on the cycle; reservoir storage is typically equal to a generation equivalent to 6 to 8 hours at full capacity, although some pumped storage projects have more than 20 hours of operating storage. Those with larger quantities of operating storage were probably planned with the intent of using the weekend for storing energy (weekly cycle). Those with limited storage were probably planned for either primarily reserve operation or daily cycle operation.

The design cycle depends on the system that the pumped storage project is fitting in to, and the intended use. If the primary purpose is to integrate wind by storing excess wind energy, it is expected that the project will be pumping throughout the week, and would not be designed for weekend pumping cycles to refill the upper reservoir. Looking at local wind patterns and durations in conjunction with demands may indicate when ancillary services will be most needed, and when excess power may be available.

In addition to the design cycle’s influence on reservoir storage, it will also be a consideration for selecting a unit. An adjustable speed unit has the advantage of being able to utilize a greater range of input power to pump, allowing the unit to operate under a range of wind conditions. If there will be situations where it will be desired to simultaneously generate and pump, a separate pump (and separate waterways) may be utilized; this would be the case for a dedicated pump to utilize wind generation in isolation of the greater transmission system, which may run during the day while the pumped storage project is providing peaking power. This would have the advantage of responding to wind intermittence outside of the grid, but the disadvantage of decreased cycle efficiency when wind is operating during peak hours (since wind would not be directly connected to the grid, and instead must still be used to power the pump as the pumped storage project generates for peak power). It should be noted that the arrangement of separate pumps and turbines described is conceptual; no existing commercial pumped storage project uses this arrangement.

An alternative design is a ternary arrangement, normally comprising an impulse turbine, a motor-generator, a torque converter and a storage pump connected via a common shaft. A ternary arrangement (using a clutch in place of a torque converter) has been adopted for the recently completed Kops II project in Austria. In a ternary arrangement, the generator-motor rotates in one direction. This arrangement offers many of the advantages of adjustable speed machines and the separate pump and turbine arrangement described above, but the generating mode efficiency will be somewhat lower. The clutch or torque converter component may impose physical limits in capacity rating that are somewhat less than binary arrangement (the conventional reversible pump-turbine and generator-motor).

Light Load Hour (LLH) and Heavy Load Hour (HLH) prices during the week and over the weekend can also help guide when it will be best to refill the reservoir, and how much storage will be used. LLH and HLH price may also be used to determine project cycling (daily cycle or weekly cycle) if the price differential is more during daily peak/off-peak hours, or weekday/weekend hours.

4. What happens with integration by pumped storage at the tails of wind generation (wind ramping up or down)?

A particular problem with wind generation occurs as wind approaches the cut-in speed (minimum speed at which the turbine can operate) or cut-out speed (maximum speed at which the turbine can operate).[1] Wind turbines can only operate when the wind speed is above the cut-in speed, but below the cut-out speed. When wind speeds are outside of this range, the wind turbines cannot operate.

If there is wind generation and wind drops below the cut-in speed or increases above cut-out speed, wind generation from that unit drops to zero. Depending on the geographical distribution of wind turbines/farms, installed wind power capacity, and characteristics wind turbines and the wind itself (among other factors), a change in wind speed can cause a significant drop in generation. Some wind turbines have a maximum power output at the cut-out speed; hence, if the wind speed exceeds cut-out speed, there is potentially significant drop in generation from maximum output to no output for the affected wind unit(s). During a storm – where wind speed might exceed the cut-out speed, for example – wind generation could drop from near maximum capacity to no capacity within minutes or over several hours (again, this depends on the specific project and site conditions). This is somewhat more challenging than a simple load following situation; in this sense, the drop in generation is more analogous to an unplanned outage or tripping of a thermal generation unit, creating a greater need for spinning reserve.

To mitigate such situations, it is necessary to forecast wind output as accurately as possible, and to commit and dispatch available resources in a manner that can deal with the resulting change in wind generation. This would require that fast response units be committed and in spinning reserve mode. The unit commitment and dispatch of committed units may be much different than in a situation without a large block of wind generation. In other systems with significant installed wind capacity, this has been dealt with by increasing the minimum levels of spinning reserve. We are aware of one utility that now maintains spinning reserve at 250% of what was practiced in the pre-wind generation environment.

Pumped storage has a high response capability, and the ability to ramp from speed no-load to full output in a few seconds. If a system has to deal with tens or hundreds of megawatts of generation dropping off with little warning, a pumped storage unit can cover the event, ramping up to full output in seconds, when

[1] Cut-out speed is typically in the range of 20 to 25 meters per second (wind turbines typically reach rated capacity at wind speeds between 12 and 16 meters per second). If wind speed drops back below the cut-out speed, the wind turbines do not immediately resume operation. The restart of wind units after exceeding cut-out speed (known as the hysteresis loop) usually requires a drop in wind speed of 3 to 4 meters per second below cut-out speed. Some manufactures offer wind turbines with output that decrease as wind speed approaches cut-out speed to minimize the challenges cut-out imposes on power systems operations and prevent a sudden drop in output from rated power to zero output. (Ackermann (ed.), Wind Power in Power Systems)

operating in a spinning reserve mode. With a pumped storage project available to operate in a spinning reserve mode, committing and dispatching other highly responsive units for reserves (which are likely to be the Columbia River hydropower plants, with a whole host of constraints of their own) is not necessary, thereby reducing fatigue on other units in the system.

Adjustable speed machines have the additional advantage of changing power input in pumping mode, increasing the ability to respond to changes in wind generation fluctuations and variability (also see the response to Questions 1 and 5, under Technical Aspects). A single speed pumped storage unit can change its output level and participate in ramping operations in generation mode, but cannot change its power level (participate in ramping) while in pumping mode.

Figure 6-1, below, illustrates real data on system load and wind generation during one week (June 3-9), and demonstrates how pumped storage may help to handle wind fluctuations and tails. In this graph, the overall load is shown on the blue line. First, it is noted that some of the wind generation (red) is during LLH, and is curtailed during the HLH. The net result (purple line) of load minus wind is that the peak to valley difference with wind generation integrated is much greater, increasing from about 2,000 MW to 3,200MW. This causes more difficulty in dispatching units. Also, the ramp rate of load growth from the valley to the peak during the early portion of the day seems to be exaggerated with wind, and similarly, the net system load to be met by non-wind generation also must be planned for steeper ramp rates. The result is a much different dispatch, with a definite need for units with characteristics that can address this dispatch requirement. The contribution of pumped storage is shown as the brown (generation) and pink (pumping) bars, corresponding to secondary y-axis, in brown. It can be seen that by incorporating pumped storage, the curve for load to be met by other (non-wind) units is changed from the purple curve to the smooth green dashed-line. The late evening hours of June 4 are of particular interest. As wind generation varies nearly on an hourly basis, pumped storage provides a solution to “absorb” or “smooth out” these hourly variations, in addition to the longer daily flattening of the load to be met by the existing hydro and thermal units.

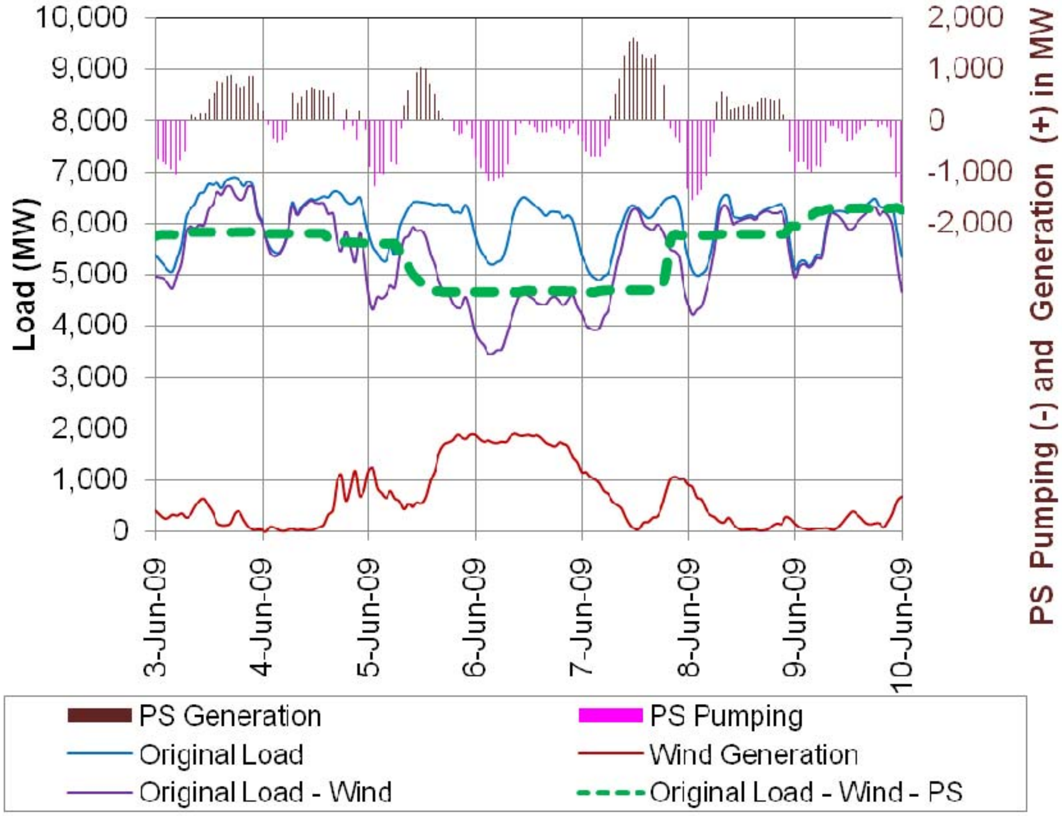

Figure 6-1 Example Pumped Storage Operation with BPA Loads and Wind Power

5. *Can you describe how to configure pumped storage with wind given the PNW power & transmission system portfolio?*

The best site with regard to transmission is one that provides maximum benefits to the operation of the bulk power transmission system, reduces congestion and requires minimum construction and impact. Since pumped storage is site specific and the transmission grid is flexible with regard to routing of transmission lines, there may be little that can be done to directly configure pumped storage with regard to transmission. However there may be a relationship between the areas where good wind resources exist and pumped storage plant sites.

Just as developers of wind powered generation use wind profile maps to identify locations for wind powered generators, so might developers of pumped storage use the same maps to find good pumped storage plant sites. The idea being that there may be good pumped storage sites in the same areas that are ideal for wind powered generators. If such a serendipitous relationship could be found then it may be possible to connect the output from wind powered generators to the substation at the pumped storage plant. If such a configuration could be achieved, then it may be possible for the pumped storage plant to act as an interface between the wind powered generators and the bulk power system.

BPA has experienced some changed transmission system loading conditions on the North of Hanford transmission path. During the March-April 2009 period, the

North of Hanford transmission path experienced higher loading in the South to North direction as compared to what it had been in prior years. The increased loading may be caused by one or more factors including large amounts of new wind powered generation.

If the transmission connection for a pumped storage plant were at a transmission line terminal location where power flows on the North of Hanford path could be influenced by the pumped storage plant, then the operation of the pumped storage plant might be scheduled to counteract the increased power flows.

6. *General economics and site constraints (e.g., cultural and environmental considerations) of pumped storage for wind integration in the PNW.*

    a. *Economics compared to various alternatives.*

As explained below in the answer to the next question – a decision on deciding which site to carry into a full evaluation must consider a whole host of factors in a formal siting study process. The decision process must take into account factors that will lead to a selection of the best choice in terms of the system's needs, considering general economics and site constraints. As part of such a siting process, considerations of site constraints will be a factor, but not the only factor. Naturally if there are overriding fatal flaws for a particular candidate site – for example severe environmental impacts – the candidate site will not be considered. Siting and selection of a preferred site is a balancing of a number of factors. With respect to general economics – the objective would be to minimize the cost of the facility, subject to the minimum performance requirements and desired operational constraints.

With respect to the question of "economics compared to various alternatives" – it is not really valid to consider a comparison of "Project A" vs "Project B". The decision on whether to use pumped storage requires a system analysis approach, where the following question is to be answered: "What overall development plan (whether it is one with pumped storage or without pumped storage) will minimize the cost of the regional electricity supply, while maintaining the expected standard of reliability with the development of the desired renewable generation targets?" The only way to answer this question (and determine if wind integration can be done at the lowest cost with pumped storage) if is to perform detailed modeling of system operational aspects – generally chronological production simulation with appropriate constraints and modeling detail – for alternative future scenarios. A robust least-cost generation expansion plan model study that credits the ancillary benefits of pumped storage, which can generally be harder to quantify, needs to be carried out to compare pumped storage against other various alternatives.

7. *What is the best potential site for pumped storage (i.e. is physical location within the system a critical factor or are geographic characteristics – reservoir size and available head – more important)?*

Determining the best potential site for a pumped storage project requires a structured siting study that considers balanced and documented evaluation of technical (including long-term operational), economic and environmental factors.

Some of the factors to be considered are:

- Ability to operate in a closely linked fashion with wind generation facilities. This implies that there are no transmission constraints in terms of delivering energy to the load center and absorbing energy when needed, to maximize the utilization of the non-dispatchable resource.
- Ability to provide ancillary services, again implying that adequate transmission and control facilities are available. This also implies that the waterway hydraulics and machine controls are properly sized and specified so the plant provides responsive operation.
- Within a geographic area of interest, sites may be identified based on certain topographic, geological and environmental physical site parameters which are “must have” type metrics. For example, for a site to be considered as a potentially viable site, the analysts may use a minimum head of 1000 ft and a maximum waterway length to head ratio of 10.

The basic steps in siting and narrowing the group of candidate sites would include:

1. Development of a statement of the objectives, constraints, the “must-haves” and “wants”. This could also include defining the geographic area of interest for candidate projects.
2. Execution of an investigative process that identifies the possible solutions to achieving the objectives. This may be done by map study, review of existing inventories, harvesting corporate knowledge, and literature review.
3. Screening of the possible solutions to first weed out any solutions that contain fatal flaws or do not meet minimum criteria.
4. Narrowing the field of candidates down to a few manageable candidates – perhaps three – using any one of various decision techniques. One technique is to develop a matrix with various evaluation factors, and use a weighted scoring system to determine which candidates best meet the objectives. The main objectives are typically (1) good performance at (2) reasonable cost with (3) a minimum of environmental issues, and (4) a reasonable or manageable risk profile. Other factors could be location with respect to the existing transmission and wind generation, expandability, or site L:H ratio. There are many factors, but the basic factors are ***cost*** and the ***likelihood that the project can be successfully implemented***. Most all other factors are really a subset of these.
5. Performing sufficient technical studies on a small group of candidates to permit selection of one preferred candidate for carrying forward.

In some cases, there may be "low-hanging fruit", or a solution that is obvious and would not warrant a detailed siting study to make a decision for proceeding. One such candidate, although it may not be in an ideal location with respect to transmission, might be to consider refurbishing the reversible units at Grand Coulee so that they can operate as originally intended, or to perhaps add reversible capability to all units. The reason this is attractive is because the physical infrastructure exists, and it is quite possible that the solution could be implemented in much less time than would be required for developing a greenfield pumped storage project.

6.3 Conclusions

The amount of installed wind power capacity currently connected to the BPA transmission system is about 2,100 MW. Projections show that wind generation will increase rapidly to approximately 6,250 MW by 2013. This vast amount of wind power interconnected to BPA's transmission grid will likely overwhelm the existing federal hydropower system's ability to provide sufficient integration services in the future. Integration services are important in that they maintain the constant balance of loads and resources to assure system reliability second-by-second, minute-by-minute and hour-by-hour. As the percentage of wind generation grows, the risk of having a major system event from an unpredicted change of the wind energy level increases. Therefore, it is evident that new transmission interconnections, improvements to the existing federal hydropower projects and new energy storage facilities will be required in the Pacific Northwest (PNW) over the next decade.

Pumped storage offers the ability to store energy produced from renewable resources when it is difficult to market or integrate them into the power system, and to release it at a time when it is really needed, most often during peak system demand, at higher value. Properly designed pumped storage hydro facilities can assist with integration of intermittent wind energy resources into regional dispatch. By investing in the newest technology available, adjustable speed units, a PS project can supply load following services and can become one of the fastest response stations on the power system. It can offer frequency regulation whether pumping or generating, and can allow pumping at less than full load, thereby increasing the flexibility to integrate the PS project specifically with wind energy resources.

In order to analyze and determine the economic benefits of a PS project, production simulation type operational modeling is needed to determine the value (i.e. reduced system operational costs) of increased capacity, energy and ancillary services.

6.4 Recommendations

As highlighted in this report, significant opportunities exist for federal development of a pumped storage facility in the Pacific Northwest. In fact, without federal leadership, it may be impossible to build these types of badly needed resources due to the sheer size of the undertaking and scale of the projects.

Pumped storage hydro is a proven technology that could be an ideal solution to the looming problems associated with integration of increasing amounts of wind generation in the coming years. A number of ideas for possible future project development or system enhancements are discussed in this report. If there is continued interest in exploring options available to BPA and the FCRPS project operators (i.e. the Corps of Engineers and Bureau of Reclamation) then we suggest consideration of some or all of the following activities to contribute to a regional planning effort. It is recognized that some of these activities may already be underway.

6.4.1 Potential Future Studies

The following items summarize potential future studies to support pumped storage and wind integration in the Pacific Northwest.

- Review existing reports, previous studies, and on-going FERC permitting and licensing on potential PS sites in the Pacific Northwest. Also identify potential new sites based on the criteria discussed in this report. Perform a ranking analysis of all these sites. Ranking criteria should include, but not be limited to the following: project capacity; capital cost; potential development schedule; location relative to ability to import/export power and increase stability and reliability of local and regional grid; environmental issues; regulatory constraints; permitting issues; land acquisition and use issues; etc.

- Perform a comprehensive generation and transmission optimization study taking into account not only the location of potential future wind farms and other renewable projects but also the sites and capacity of potential PS projects. Since it is most likely that the increased level of wind power development will require significant additions of new transmission lines and reinforcements, these studies and investments should be made in parallel and in coordination with the planning for a potential future PS site.

- Further investigate the role and benefits of PS plants and adjustable speed technology by researching the state-of-the-art of the industry in selected countries with similar wind integration issues, particularly in Japan and several European countries.

- Review current operation of the Grand Coulee (Banks Lake) PS project and outline a strategy to further upgrade (e.g. replace generators with adjustable speed equipment) or expand the pumped storage capabilities of this facility (e.g. add a new generating plant with an adjustable speed unit) in order to enhance its operation to provide greater system benefits.

- Continue Corps of Engineers and Bureau of Reclamation support of the BPA Wind Integration Team to implement a comprehensive regional strategy, which includes investigation of potential sites for development of a new 1,000 MW+/- pumped storage project. Elements of the strategy should be developed collaboratively among the interested parties.

- Transmission system studies could be undertaken to quantify the dynamic benefits to the Western North American power system, including the PNW, with a pumped storage plant or plants that have single speed and adjustable speed units.

- Continue to improve knowledge of local and regional wind generation patterns and real-time (week, day, hour) forecasting of wind generation. Collect and analyze historical hourly and 5-minute interval data on existing wind generation as well as expected wind generation patterns at proposed sites to better assess the variability and consistency of regional wind generation over time. Probabilistic planning techniques and approaches should be further developed to better assess wind generation.

- Evaluate the possibility of gaining access to larger pools of generation and demand that may be required to fully integrate large scale development of wind generation in the Pacific Northwest.

- Investigate whether or not some type of Public-Private Partnership (PPP) might be implemented to facilitate study, design, licensing, and building of pumped storage facilities in the Pacific Northwest, on a fast-track basis, especially looking for ways to expedite the NEPA EIS process to gain rapid development approval.

- Assess the appropriate level of system flexibility to deal with system ramping and reserve factors (regulating and contingency) that will be required with future large scale wind and other renewable energy developments. Other factors such as reactive power supply and voltage control, quick start/black start capability, low minimum generating levels, and the ability to more frequently cycle existing units should also be analyzed. Adding/upgrading digital governors on some of the FCRPS hydro units and the capability of PS to offer such services should be fully evaluated and modeled. Most likely, new models (5-minute intervals or less) will need to be developed to fully analyze the impacts and relationships between various factors and assess the reliability of power systems.

- Improve generation and market forecasting techniques for local and regional wind generation to feed into weekly, daily and hourly real-time dispatch.

6.4.2 Possible Next Steps

The following Action Plan is suggested if there is interest in continuing efforts to determine the optimum means of providing additional energy storage and system improvements in the Pacific Northwest to facilitate integration of future wind generation:

1. Define major options available
    a. Banks lakes project modifications
    b. Siting and feasibility studies for a new large-scale regional PS project
    c. Improvements to existing FCRPS hydro plants
2. Establish a Core Team to fast-track each of the above options with BPA, Corps, Reclamation, Consultants, and possibly Equipment Vendors
3. Develop a work plan, schedule and budget for each option
4. Enter into contractual arrangements and teaming agreements
5. Identify planning, licensing, design, and construction funding requirements and secure funding through public and private entities
6. Review legal and congressional authority for project development

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USACE and BPA

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APPENDICES

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APPENDIX A

List of Figures

A ADJUSTABLE SPEED MACHINES IN PUMPED STORAGE PLANTS

The introduction of adjustable machine technology to pumped storage (PS) plants is the latest development in a continuous line of hydro plant technology improvements. This appendix describes the several components that are used to provide the adjustable speed capabilities.

A.1 General Features

A generator-motor for an adjustable speed PS hydro system is operated over a range of speeds. The machine used in adjustable applications is known as a Doubly Fed Induction Machine. A wound rotor with three-phase excitation is used in place of a conventional synchronous single-speed machine with a salient pole rotor.

The rotor of a doubly-fed machine is fundamentally different from that of a salient-pole single-speed synchronous machine. By comparison, the rotor of a doubly-fed machine does not have discrete, removable pole pieces that can be factory assembled, tested, and disassembled -- and then reassembled back onto the rotor hub at the site.

Because the flux must smoothly move along the surface of the rotor of a doubly-fed machine, the rotor must be of laminated construction and be smooth and continuous (i.e. overlapping laminations) around the entire rotor periphery. To achieve a solid rigid rotor, laminations are stacked, compacted and attached to the rotor hub.

Figure A-1[1] is a comparison of a salient pole rotor and the solid rotor of the doubly fed machine

[1] Furuya S, Fujiki S, Hioki T, Yanagisawa T, Ozazaki S, Kobayashi S; "Development and achieved Commercial Operation Experience of the World's First Commissioned Converter-Fed Variable Speed Generator-Motor for a Pumped Storage Power Plant"; CIGRE 1992 Session; paper number 11-104; Figure 10; 30 Aug – 5 Sept 1992.

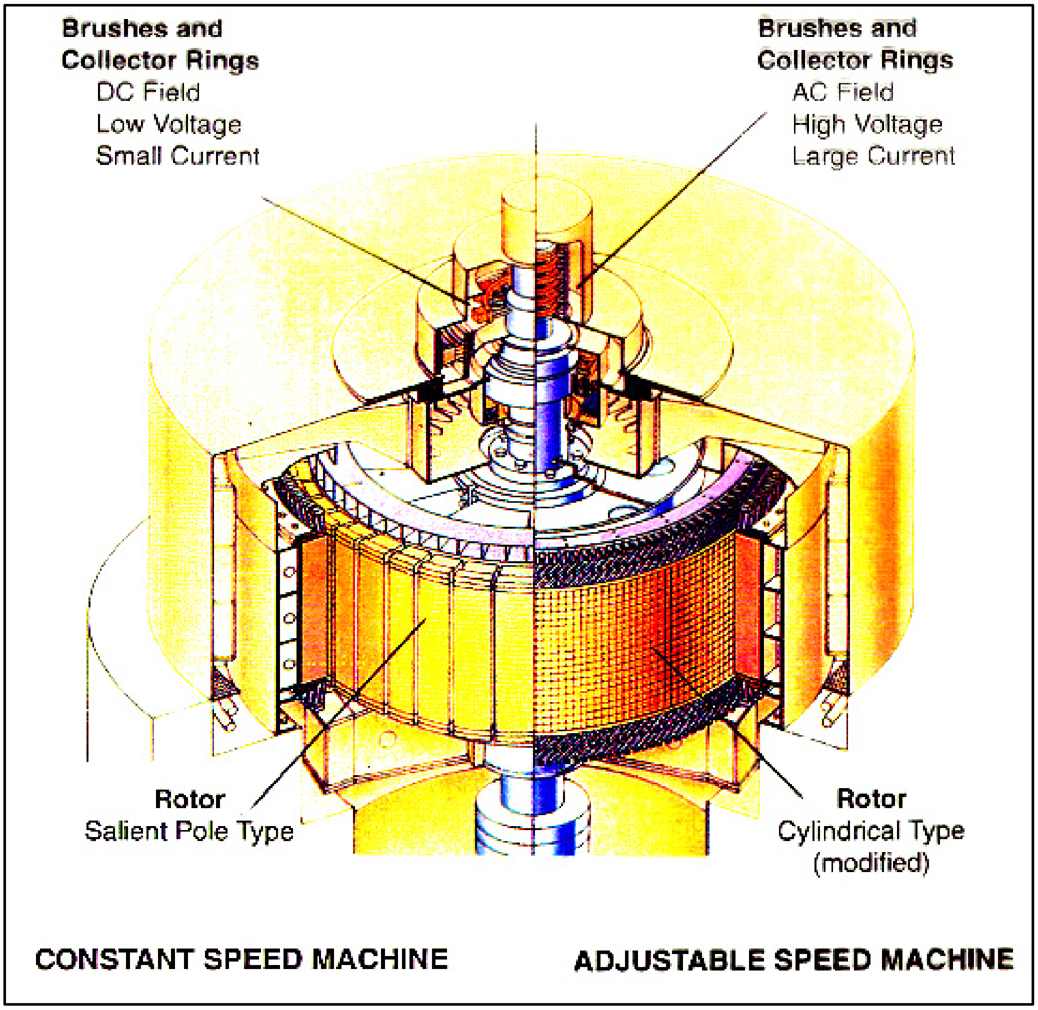

Figure A-1 Machine Comparison

Figure A-2[2] is a picture of a rotor for an adjustable speed machine.

Figure A-2 Doubly Fed Machine Rotor

Pie shaped lamination segments are assembled onto a 'spider' spindle cage. The laminations are similar in shape to those used in the stator -- except for the winding slots located on the edge of the larger, rather than smaller, diameter. The 'spider' spindle cage is essentially only the length of the finished axial length of the winding portion of the finished rotor. The bottom stub shaft for the thrust

[2] Furuya S, Fujiki S, Hioki T, Yanagisawa T, Ozazaki S, Kobayashi S; "Development and achieved Commercial Operation Experience of the World's First Commissioned Converter-Fed Variable Speed Generator-Motor for a Pumped Storage Power Plant"; CIGRE 1992 Session; paper number 11-104; Figure 11;30 Aug – 5 Sept 1992.

bearing and the upper stub shaft for the collector rings are added to the spindle cage in the field.

Figure A-3 shows the various components that make up the rotor of an adjustable speed machine.

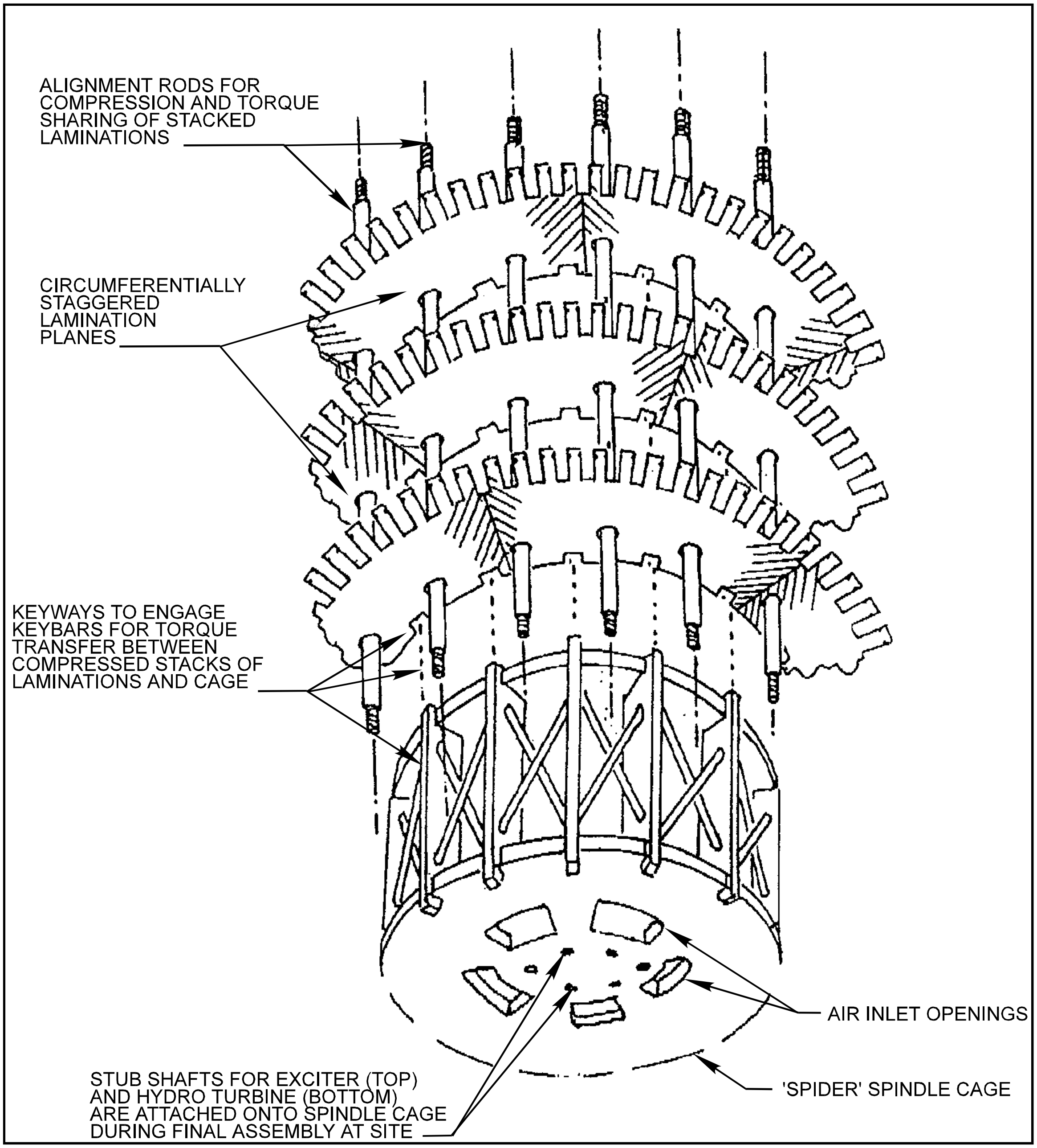

Figure A-3 Adjustable Speed Rotor Assembly

A.2 Type of Excitation Equipment

An alternating current excitation system is adopted to provide a synchronous magnetic field on the rotor. The excitation frequency is adjusted to provide a slip frequency that is equal to the difference between rotor speed and synchronous speed. Therefore the rotor with attached pump/turbine can rotate at a speed that is different from synchronous speed while the stator remains at system frequency.

Excitation equipment for AC excitation can be adopted in two types of frequency converters, Cycloconverter and self commutated type converter. The self-commutated type converter is suggested, because the generator reactive power is reduced as compared to the Cycloconverter type. The frequency converter is connected to an excitation transformer and the transformer is connected to the bulk power transmission grid.

The cycloconverter approach to adjustable frequency converters is relatively efficient, but does not have some advantages available in devices designed around the gate turn-off (GTO) thyristor. A power converter based on the GTO thyristor can be, effectively, self-commutated on both sides. As such, it can move power in either direction and absorb or supply reactive power on either side independently. It thus provides an additional source of reactive power to the system (assisting the generator) rather than placing a variable demand for reactive power on the system and thereby reducing the reactive power that the generator can supply to the system. On the rotor side, the converter supplies any reactive power necessary to regulate rotor voltage.

Recent developments of Insulated-Gate Bipolar Transistors (IGBT) and Pulse Width Modulation (PWM) techniques provide additional operational capabilities and flexibility to the excitation system.

Figure A-4 shows a typical connection arrangement for an adjustable speed PS hydro unit along with a diagram showing the excitation system for a conventional single speed unit.

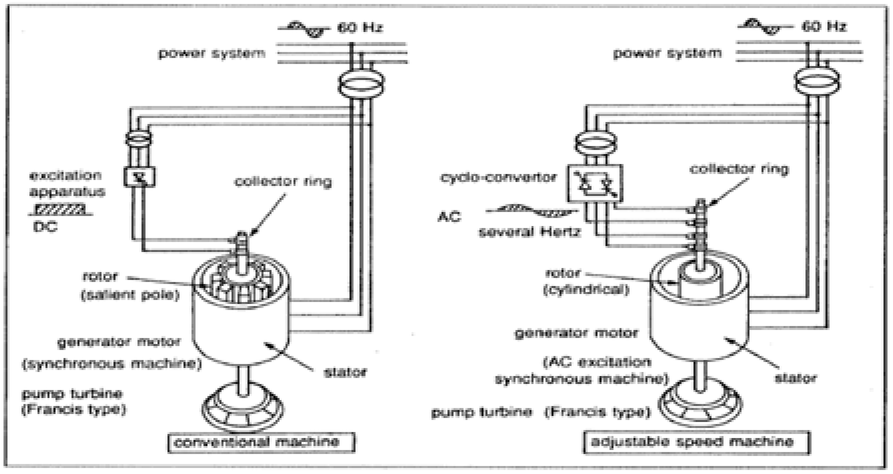

Figure A-4 Comparison of Excitation Systems for Adjustable Speed Pumped Storage Hydro Unit and Conventional Single-Speed Unit[3]

An adjustable speed machine with the solid state starting system can be started in the pumping mode using the excitation system. This means that a plant with adjustable machines does not require a separate static frequency converter system.

A.3 Change of Speed

In a typical synchronous machine, the operating synchronous speed is based on the following equation:

nSync = 60 * f1 / p

where nsync is synchronous speed in rpm, f1 is the grid frequency and p is the number of pole pairs.

In the doubly-fed asynchronous adjustable speed machine, the stator and overall concept of the adjustable speed machine are basically the same as a conventional synchronous speed machine, however the rotor design is very different.

The doubly-fed machine consists of a three-phase stator winding of the same type required by a salient pole synchronous machine. The rotor consists of a cylindrical laminated body made of steel sheets in which a three-phase winding is embedded in slots. The three-phase rotor windings are connected to an external exciter by slip rings mounted on the shaft. The stator winding is energized from the constant frequency bulk power grid, and a synchronous alternating magnetic

[3] Sugimoto; Haraguchi E; Kuwabara T; Hitomi I; Bando A, and Nagura O; "Developments Targeting 400 MW Class Adjustable Speed Pumped Hydro Plant and Commissioning of 18.5 MW Adjustable Speed Hydro Plant"; ASME Fifth International Symposium on Hydro Power Fluid Machinery; FED vol. 68.

field is established. The rotor is excited from an adjustable frequency voltage source.

A rotating magnetic field is established in the rotor when a three-phase excitation current of the frequency f2 is applied to the rotor. The speed of the magnetic field, nE is given as:

nE = 60 * f2 / p

where nE represents the motion of the magnetic field (in rpm) when viewed from the rotor, and f2 is the frequency of the rotor circuit.

When viewed from the stator the mechanical rotational speed of the rotor, nM, is added to the magnetic motion of the rotor, nE. Therefore, the equation for the speed as viewed from the stator can be expressed as:

nS = nE ± nM;

or expressed in terms of f1 and f2,

nS = 60 * (f1 ± f2) / p

where nS is the speed of rotation (in rpm) of the stator as determined by the frequency of the bulk power system. When nE = 0 the rotor and stator are at synchronous speed; when nE >0 or nE <0 we have:

nS = nE + nM and nS = nE - nM

Therefore adjusting the rotor excitation frequency can control the rotational speed of the rotor and pump/turbine. While stator frequency remains constant, kinetic energy may be stored or retrieved from the rotor by adjusting the rotor speed through the excitation frequency. Rapid adjustment in rotor speed makes possible the rapid changes in power levels in pumping and generating modes.

A.4 Speed and Frequency Governors and Control

In the case of a conventional synchronous machine the governor is used to control unit speed and frequency by way of the wicket gates[4] (aka guide vanes). However, in the adjustable speed machine it is necessary to have a frequency governor that controls rotor speed by way of excitation frequency and rotor current as well as a speed governor to control the wicket gates.

Figure A-5[5] shows a control block diagram for an adjustable speed machine. The diagram is divided into common control functions and the specific control functions for generation and pumping modes.

[4] Wicket Gates. Adjustable vanes that surround a hydro turbine and control the area available for water to enter the turbine.

[5] Erlich I; Bachmann U; "Dynamic Behavior of Variable Speed Pump Storage Units in the German Electric Power System"; 15th Triennial World Congress, Barcelona, Spain; 2002.

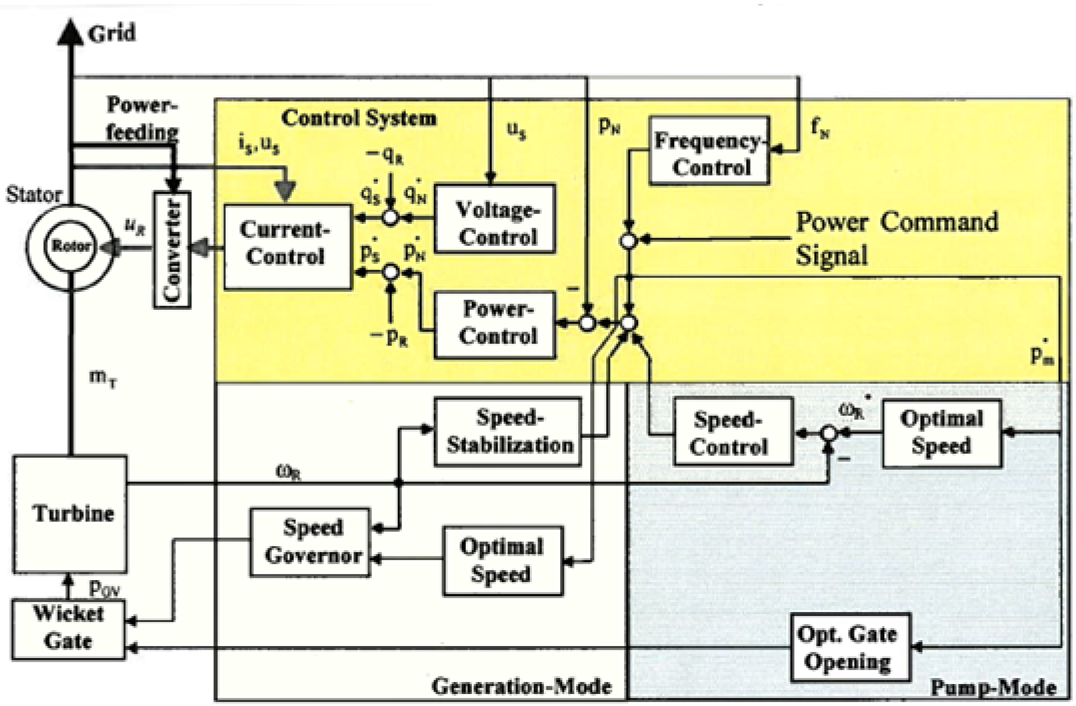

Figure A-5 Control System in generator and pumping mode

In a conventional PS synchronous machine, the governor is used to control unit speed and frequency by way of the wicket gates (adjustable guide vanes that surround the turbine and control the area available for water to enter the turbine). The wicket gates can open and close in approximately 10 seconds or less.

Adjustable speed machines can provide frequency control in both generating and pumping modes. There are two control components. See graph below that shows the control model of the Goldhistal PS project in Germany. One is the turbine governor controlling the wicket gate position of the turbine and the other is the inverter controlling the rotor currents of the generator/motor. With these two control elements in turbine mode, two quantities can be controlled more or less independently. The control strategy for the pumping mode is similar.

A.5 Operating Range in Pumping Mode.

Most modern Single Speed Reversible Pump Turbine units are of the Francis type and are for operation at fixed single-speed. Their operation is along the single Q-H (discharge vs. head) pump curve, and wicket gates are normally positioned to provide the least throttling effect (reduce the losses) at the prevailing head and speed. Throttling with the wicket gates in pumping mode is undesirable because it produces vibrations and it also increases the losses. As can be expected and as confirmed by experience, Adjustable Speed Hydro machines can be effectively used to extend the single pump operating curve to a broad range of pump operation, and provide positive control over the discharge and the required input power.

With Adjustable Speed Hydro the limits of the pumping range are normally defined by cavitation (low head, high speed operation), motor-generator output (medium to high head, high speed operation), turbulence or reverse flow (high head, low speed operation), and range of operating speed. Although these limits seem to be very restrictive, in reality the improvement in operating range is extremely impressive, especially when considering the possibilities of how the extended range can be used to avoid cavitation and reduce input power at low heads, adjust pumping power, avoid reverse flow at high head operation, and provide frequency control in the pumping mode. The following figure shows an example of the operating range in pumping mode.

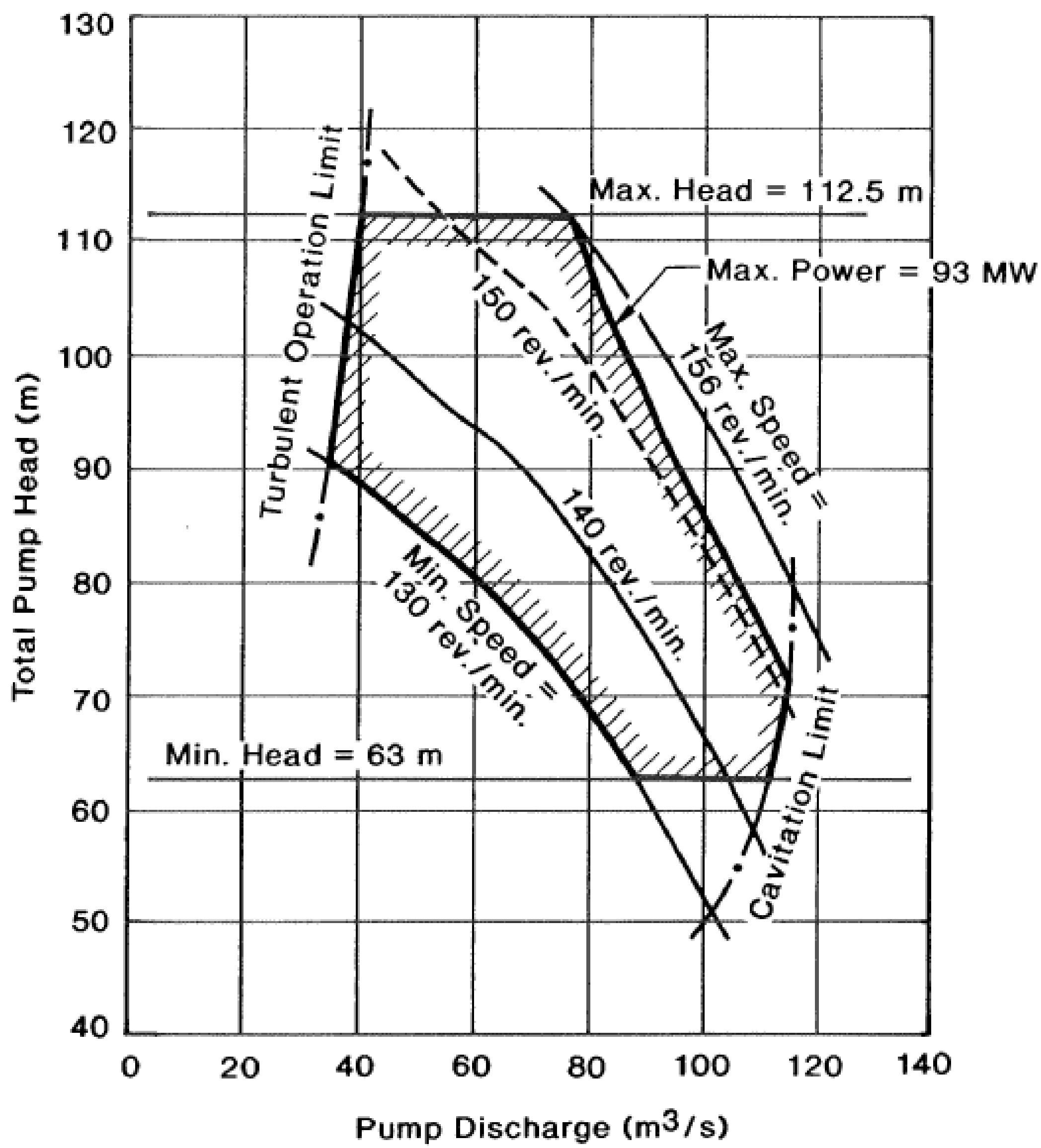

Figure A-6 Operating Range in Pumping Mode

A.6 Speed And Efficiency for Generation and Pumping.

Adjustable Speed machines can operate at optimum efficiency points in both turbine and pump modes while single speed machines may only operate at optimum efficiency in one mode. The ability to operate at peak efficiency in both pumping and generating modes results in improved overall efficiency.

With a single speed machine, the pump - turbine designer is faced with a design dilemma, namely, the water wheel in a PS plant is designed for operation as a pump and a generator. For a given speed, it is not possible to have the maximum efficiency point for the pump and the turbine occuring at the same speed. See following figure for an illustration of the two conditions.

Adjustable speed machines allow mechanical speed to be set at the pump-turbine maximum efficiency point at all times. Hydro plant operators will be able to fine tune turbine efficiency and track variations in head as reservoir levels or available flow changes. In PS plants, adjustable speed machines will allow operators to adjust for optimum efficiency in both the pumping and generating modes.

Where hydraulic conditions can be measured in terms of head and flow, then peak turbine and pump efficiency can be realized for specific hydraulic conditions.

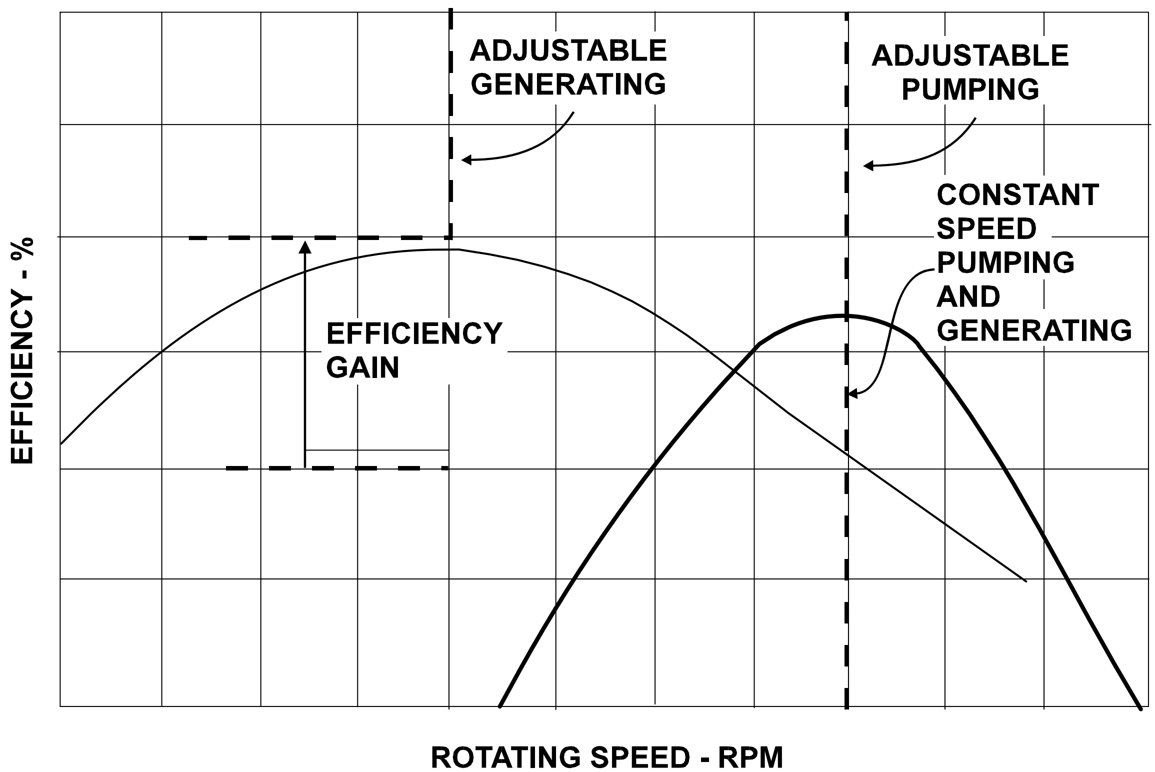

Figure A-7 Typical Efficiency Curves

See following figure for an added illustration. In the upper figure the water wheel can only be designed to achieve maximum efficiency in one of the two modes. If designed for best efficiency as a pump, then efficiency in the generating mode will occur at a different speed. Thus with an adjustable speed machine it is possible to achieve best efficiency in both pumping and generating modes because the speed can be changed; this is illustrated in the lower figure.

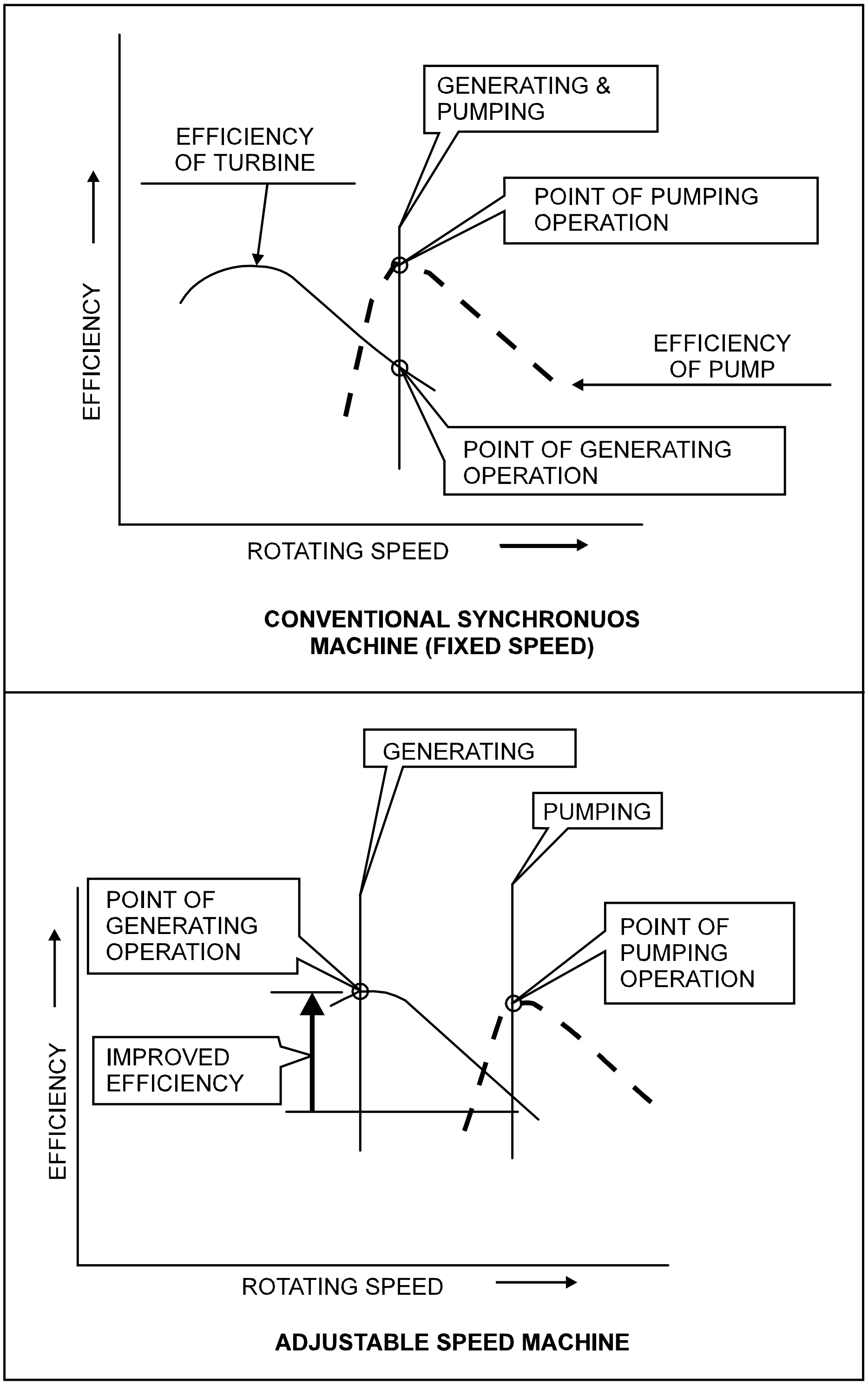

Figure A-8 Typical Pump & Turbine Efficiency Curves

Increased energy production will result with an adjustable speed machine since the water wheel can be at maximum efficiency in both pumping and generating modes. In Japan, the improvement has been estimated at 3 percent per year. This is a conservative estimate, and is based on early reports about adjustable speed units. The following graph shows the increased efficiency with an adjustable speed machine (upper blue line) in comparison to the efficiency of a single speed machines. As can be seen the increased efficiency gain is at the reduced power level. This means that machines that are operated at low capacity for spinning reserve will be more efficient as compared to conventional single-speed machines.

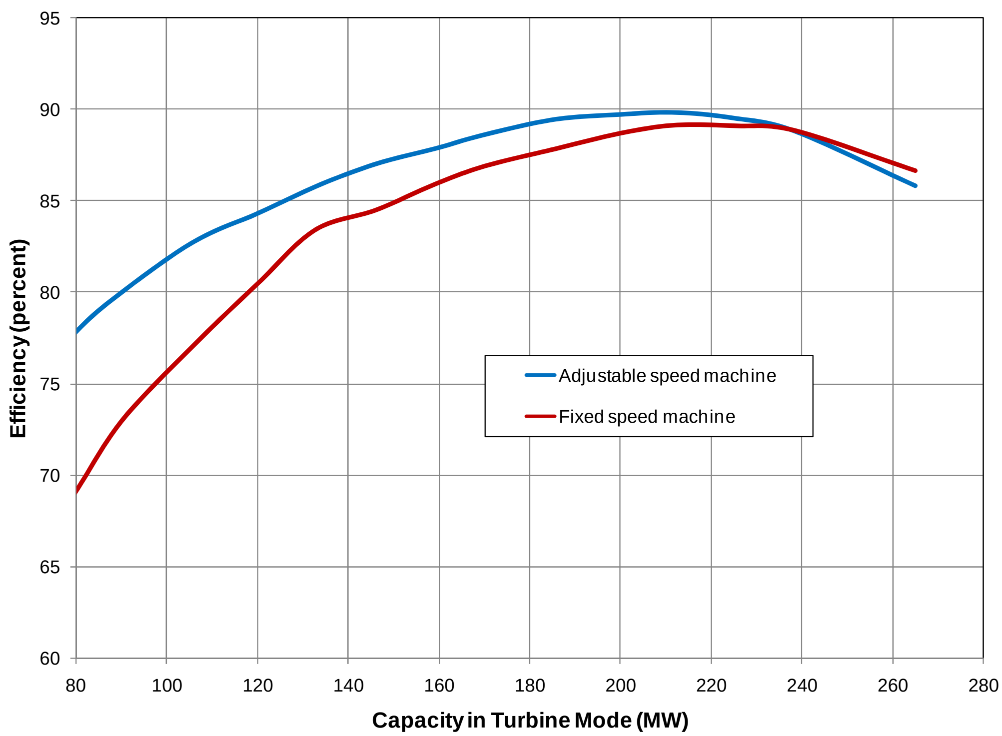

Figure A-9 Comparison of Adjustable Speed Machine to Single Speed Machine

A.7 Adjustable Speed and Existing Pumped Storage Units

PS plants have relatively useful life of 50 to 100 years as compared to conventional fossil fuel generation. Many PS plants are ageing and require rehabilitation and upgrading. These units present an opportunity for upgrading and conversion to adjustable speed operation.

Conventional single-speed PS units can be converted to adjustable speed operation. If the existing machine stator is adequate, then the conversion involves installation of a wound rotor, slip rings and a new excitation system with controls. Thus existing PS projects can realize immediate benefits from adjustable speed technology and play a key role in a market based power system operation. As noted in the experience list, the two Yagisawa machines were conversion projects.

A.8 Pump/Turbine

The pump/turbine commonly used in PS plants is a reversible Francis type with fixed pitch blades. The direction of rotation in the generation mode is opposite of the direction of rotation in the pumping mode. The Francis turbine is a reaction turbine, which means that the working fluid changes pressure as it moves through the turbine and gives up its energy to the turbine. See Figure 5 for a plan view of a Francis pump/turbine.

A spiral case is provided to contain the water flow and distributes the water uniformly around the perimeter of the runner. Stay vanes and guide vanes (also known as Wicket Gates) direct the water tangentially at the correct angle to the runner. The runner blades have a complex surface profile and direct the water so that it exits axially from the center of the runner. As it flows through the runner the water imparts its pressure energy to the runner before leaving the turbine. At the turbine exit, the water flows through a draft tube and into the tailrace.

The radial flow acts on the runner blades, causing the runner to rotate. As the water moves through the runner its spinning radius decreases, further acting on the runner. Imagine swinging a ball on a string around in a circle. If the string is pulled short, the ball spins faster. This property helps inward flow turbines harness water energy.

The Francis turbine is fitted with adjustable guide vanes (also known as Wicket Gates). The adjustable guide vanes (or wicket gates) provide for efficient turbine operation over a range of water flow conditions. The guide vanes regulate the water flow as it enters the runner and are positioned by a speed governing system that matches flow and rotational speed to turbine loading.

The above description is for operation in the turbine/generator mode. A similar description would describe operation in the pumping mode.

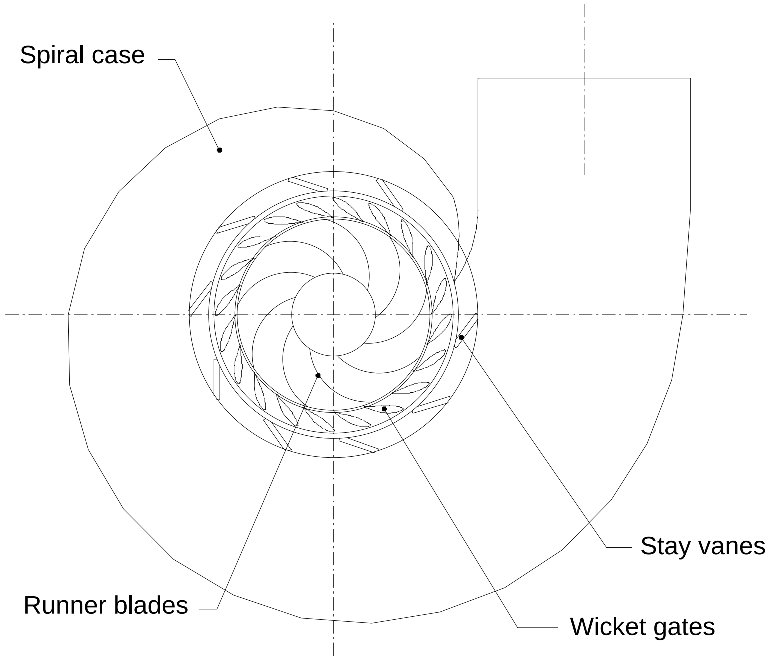

Figure A-10 Pump Turbine

A.9 Range of Speed Change

The range of speed change determines the limits of variation in pumping and generating operating range. Since pump-turbine characteristics vary as the cube of the speed, a speed range of plus/minus five to plus/minus ten percent of synchronous speed provides the pump-turbine designer with sufficient latitude.

A.10 Benefits

The benefits[6] from an adjustable speed machine in a PS hydro plant include:

- Increased overall annual efficiency of 3% or more
- Part load pumping
- Frequency regulation in pump mode
- Reduced vibration and reduced mechanical wear
- Increased pump-turbine life
- Power system stabilization

Increased overall efficiency results from the fact that the pump-turbine can be operated at peak efficiency in both pumping and generation modes. With a conventional single speed machine, the pump-turbine can only achieve its peak efficiency in one of the two modes - not both.

6 EPRI Report TR-105542; Research Project 3577-01;"Application of Adjustable Speed Machines in Conventional and Pumped Storage Hydro Projects"; Final Report Nov. 1995.

Part load pumping means increased operating flexibility and possible lower costs for pumping power. With adjustable speed, it is possible to operate the pumps in the range of 60% to 100% of rated capacity. This means that a unit does not have to wait until a block of power equal to its full pump capacity rating is available before pumping can begin. Thus there are more opportunities to purchase blocks of pumping power.

A conventional PS plant with a single speed machine can only provide frequency regulation in the generation mode. With adjustable speed, it is possible to provide frequency regulation in both the pumping and generating modes. In an open market, this means added revenue from the sale of frequency regulation capability as an ancillary service.

With adjustable speed it is possible to operate the pump-turbine under head and flow conditions that would otherwise not be possible because of vibration conditions. This results in reduced wear and tear on the machine, seals and bearings. Thus the time between maintenance shut-downs and overhauls can be increased. With adjustable speed operation it is possible to avoid operating in cavitation situations; thus pump/ turbine life is extended.

An example of the benefits of adjustable speed can be seen in Japan. It was discovered by the utilities that, during the early morning hours, oil fueled generators were providing frequency regulation. At the same time there were a significant number of PS units operating in the pumping mode. When it was realized that frequency regulation could be provided from adjustable speed machines there was an obvious benefit. Since the price of imported oil is high there was an immediate quantifiable benefit that could be attributed to the adjustable speed machines. The savings in fuel oil provided a base benefit value in the economic analysis and provided an incentive to develop the adjustable speed machines for pumped storage. Today Japanese utilities, with large PS plants, are using their adjustable speed machines in pumping mode to provide frequency regulation.

A.11 Adjustable Versus Variable

In the technical literature one finds the term Variable Speed used interchangeably with Adjustable Speed. We have chosen to use the term Adjustable Speed instead of Variable Speed. This choice was made as part of the EPRI study that was done in 1995. Adjustable carries the notion that there is control and variable implies uncertainty and lack of control.

In the case of a PS plant with an adjustable speed machine, the speed of the machine is not variable, it is adjustable. We purposely select an operating speed that provides desired performance for prevailing head and flow conditions. When head and flow conditions change the speed is adjusted so that the machine operates efficiently under the changed conditions.

An example to illustrate the difference between the two names is: the weather outside is variable while the climate indoors is adjustable. There is nothing we can do to control the outdoor weather in terms of variation of temperature, wind velocity, humidity or precipitation. However we can adjust the indoor temperature, air changes and humidity by operation of a fan, humidifier, furnace or air conditioner. When conditions change with regard to indoor air temperature, humidity etc. we adjust the thermostat so that we are comfortable.

APPENDIX – B

List of Figures

List of Tables

B ADJUSTABLE SPEED PUMPED STORAGE PROJECTS

Energy storage using pumped storage (PS) hydro technology has advanced since pumped storage was first introduced. Development of adjustable speed machine technology and solid-state power electronics applied to PS units provides significant benefits and additional operational capabilities.

B.1 Experience

Since 1990 adjustable speed machines have been in commercial operation in PS plants in Japan. The following table shows the PS projects that are in commercial operation using adjustable speed technology. It should be noted that the two Yagasawa experiences were conversions of single speed machines to adjustable speed.

Table B-1 Adjustable Speed Pumped Storage Projects in Commercial Operation

PLANT NAME	SERVICE DATE	PUMP INPUT RANGE MW	GEN INPUT RANGE MVA	SPEED INPUT RANGE rpm	MANUFACTURER	UTILITY
Yagisawa No. 2	1990	53 to 82	85	130 to 156	Toshiba	TEPCO
Takami No. 2	1993	54 to 140	140	208 to 254	Mitsubishi	HOKKAIDO
Ohkawachi No. 2	1993	331 to 392	395	330 to 390	Hitachi	KANSAI
Shiobara No. 3	1995	200 to 330	360	356 to 394	Toshiba	TEPCO
Ohkawachi No. 4	1995	240 to 400	395	330 to 390	N/A	KANSAI
Yagisawa No. 3	1996	53 to 82	85	130 to 156	Toshiba	TEPCO
Okukuyotu No. 2	1996	230 to340	345	408 to 450	Toshiba	EPDC
Goldisthal	2003	300 to 351.6	265	299.7 to 346.3	VATech	Vattenfall Germany
Goldisthal	2004	300 to 351.6	265	299.7 to 346.3	VATech	Vattenfall Germany
Kazunogawa	2005	N/A	500	500 synch	N/A	TEPCO
Omarugawa No. 3	2005	230 to330	340	576 to 624	Mitsubishi	EPDC

Table B-2 Adjustable Speed Pumped Storage Projects In Design/Construction

PLANT NAME	SERVICE DATE	PUMP	GEN	SPEED	MANUFACTURER	OWNER
		INPUT RANGE				
		MW	MVA	rpm		
Avce	Est. 2009	185	-	-2% to +4%	-	SENG – Soske Elektrarne
Nant de Drance	Est. 2017	628	680	+/- 7%	Alstom	Alpiq
Limmern	Est. 2015	1000	-	+/- 6%	Alstom	Kraftwerke Linth-Limmern AG
Tehri	Est. 2017	1000	295		Voith	THCD Ltd.
Kazunogawa	Est. 2015	1600	1600		Toshiba	Tokyo Electric Power Co.
Kyogoku	Est. 2014		230		Toshiba	Hokkaido Electric Power Co.

B.1.1. Projects in Commercial Operation

B.1.1.1. Goldisthal PSH – Germany.

The Goldisthal PS plant has four pump-turbine generator-motors each with a nominal rating of 265 MW, Two units are equipped with single speed synchronous generator-motors and two with adjustable speed generator-motors.

The units are connected to the upper reservoir by two headrace tunnels, and to the lower reservoir by two tailrace tunnels. Each penstock tunnel is shared by two units, one adjustable speed (asynchronous) and one conventional single speed synchronous.

The main data for the plant is:

- Head range: 280.7 m - 325.0 m (rated: 301.25 m)
- Rated speed: 333.3 rpm (synchronous speed for a 50 Hz system)
- Speed range for the adjustable speed unit: 300-346.6 rpm
- Turbine Mode
- Rated Capacity: 269 MW
- Rated Discharge: 103.3 m^3/s
- Pump Mode
- Rated Capacity: 257 MW
- Rated Discharge: 80 m^3/s

The storage capacity of the upper reservoir is designed to be 12 million cubic meters. The maximum storage capacity is on the order of 8.8 GWh and is sufficient for eight hours of full load operation.

As a part of the operation experience in this plant, commissioned in early 2004, we can mention the smoothness in the operation of the adjustable speed unit compared side by side with the synchronous one, especially in situations like load rejection where the asynchronous (adjustable) speed machine offers a much more favorable behavior.

B.1.1.2. Ohkawachi Pumped Storage Hydro Plant. (Kita, Ohno, Kuwabara, & Bando 18-27) – Japan.

Commissioned in December 1993, the Ohkawachi PS plant is owned and operated by the Kansai Electric Company. The plant has four reversible pump/turbine generator/motors with a nominal generator rating of 320 MW; two machines have adjustable speed capability. The synchronous speed of the machines is 360 rpm. The adjustable speed machines can operate at speeds over the range of 330 rpm to 390 rpm.

The amount of power drawn by the Ohkawachi unit when it is pumping at a certain head can be adjusted from 320 MW to 400 MW by changing the rotation speed in the range between 330 and 390 rpm.

Operators can maximize a unit's generating efficiency at virtually any head or operating condition. The operating constraints are entered into the control system, and the machine regulates rotation speed on a steady basis up to the optimal speed. The adjustment begins within 100 milliseconds or less.

Tests at Ohkawachi show that a command to adjust effective power from 0 to 320 MW can be implemented within 50 seconds. (320 MW/50 sec = 6.4 MW/sec) During the change, the wicket gates of the machine open to increase the volume of available water. However, because the increase in water is insufficient to produce the requested change in power, the shortage is compensated by the energy stored in the rotating inertia (fly-wheel effect) of the machine. Rotation speed decreases temporarily as power increases, then declines again as the volume of water "catches up" with the power demand. The cycle of increasing and decreasing speed continues until the water volume and power demand are in balance.

In tests of the machines' performance in meeting a sudden need to increase or decrease power input during pumping operation, a command was given to increase power load from 256 to 400 MW in 20 seconds. (144 MW/20 sec = 7.2 MW/sec) With the increase in the required value, the wicket gate opened, and rotation speed increased, to achieve an appropriate operation condition (Akagi 980).

Ohkawachi operates as a conventional PS plant and provides frequency regulation, load following and spinning reserve services. However, the adjustable speed machines are used for frequency regulation in the pumping mode. The cost savings in terms of fuel (oil for combustion turbines) was a primary factor in the decision to adopt the adjustable speed machines.

The field windings of the wound-rotor 20-pole machine are excited with three-phase low-frequency ac currents. The excitation current is supplied via slip rings by a 72 MVA three-phase 12-pulse line-commutated cycloconverter. The output terminals of the machine are rated 18 kV and are connected to the 500 kV 60 HZ bulk power transmission grid through a conventional step-up transformer.

The output frequency of the cycloconverter is controlled within +/- 5 Hz, and the line frequency is 60 Hz. The cycloconverter operates in a circulating current-free mode. The machine has a synchronous speed of 360 rpm, with a speed range from –8.3% (330 rpm) to + 8.3% (390 rpm). In the pumping mode, the speed control results in pump operation from 240 MW to 400 MW; a range of 160 MW (40%).

B.1.1.3. Okukuyotu II Pumped Storage Plant

An adjustable speed generator-motor nominally rated 300 MW was commissioned in June 1996 at the Okukuyotu PS plant. The plant is owned and operated by the Electric Power Development Corporation (EPDC) of Japan.

Rotor excitation is provided by a voltage-source Pulse Width Modulation (PWM) rectifier/inverter using Gate Turn Off (GTO) thyristors. The rectifier/inverter is rated 4.5 kV and 3 kA, and is connected between the stator and rotor winding terminals of the machine.

The GTO thyristor-based rectifier/inverter system is rated 40 MVA. Each of four three-phase rectifiers is composed of three single-phase H-bridge voltage source rectifiers. One pair of three-phase rectifiers is connected to one excitation transformer, and the other pair of three-phase rectifiers is connected to the other excitation transformer. Thus the three-phase rectifier system has positive and negative terminals and a neutral terminal on the dc side. Each of the three-phase voltage-source inverters connected in parallel through ac reactors is a three-level voltage-source PWM inverter. This forms the 40 MVA inverter system whose ac terminals are connected to the rotor via three slip rings. The switching frequency of the GTO thyristors is 500 Hz.

B.1.1.4. Hydropower Plant Kops II - Austria

The project is located in the extreme western tip of Austria. It uses existing Kops reservoir as an upper reservoir and existing balancing reservoir Rifa as the lower reservoir and has a nominal head of 800 meters. The underground plant is connected to upper and lower reservoirs by an extensive tunnel system. Commissioning of the three units began in 2008.

The project has three units designed for a of speed 500 rpm. Maximum capacity in turbine operation 3 x 150 MW and pump power 3 x 150 MW.

Each unit consists of a vertical shaft that connects an individual Pelton turbine to a motor/generator a clutch and a pump. When the clutch is open the Pelton turbine drives the generator. When the clutch is closed the motor/generator operates as a motor in pump mode. In pumping mode, the Pelton turbine is used to provide mechanical power that reduces the amount of electrical power needed to drive the pump.

The following description of the project is from a publication found on the internet ("Hydropower Plant Kops II").

> "Storage pumps can only be used if operated with 1005 load. With a surplus of power in the grid the adaptation to the fluctuations have to be compensated by a controllable pump. In order to be able to assure a power control also in pump mode, the principle of the "hydraulic short-circuit" is used in Hydropower Plant Kops II. The difference between the steady take of full load of the pump and the lesser surplus of power in the grid is compensated by the simultaneous operation of the turbines to the necessary extent. Since the turbine is assuring a good control ability in the complete range, a good control ability will also be given in pump mode."

B.1.2. Projects in Design/Construction

B.1.2.1. Hydropower Plant Tehri – India

Tehri will be a 1,000 MW PS plant located in the State of Uttarakhand in Northern India. The project has a unique challenge that has made adjustable speed turbines a necessity. Tehri has the widest head range worldwide for a PS plant. The operational head range is from approximately 130 to 230 meters.

The plant will consist of an underground powerhouse with four 250 MW reversible turbine units. It will be located adjacent to the existing Tehri Dam & Hydropower Plant which has an installed capacity of 1,000 MW and began operation in 2007. Tehri PSP will utilize the existing Tehri Dam reservoir for the upper reservoir which has a live storage capacity of 2,600 million m^3. Tehri reservoir is highly affected by the monsoon season. At the peak of the monsoon season the reservoir reaches a Full Reservoir Level at elevation 830 meters. Between power demand and irrigation requirements the Mean Drawdown Level reaches 740 meters before the next monsoon season. Given the large variations in available head, Tehri PSP will require adjustable speed turbines to maximize efficiency in both pumping and generating modes. Figure B-1 shows a cross section of the project layout.

The unique scenario at the Terhi PSP will require state-of-the-art technology. Adjustable speed technology gives the project a more economically feasible option as compared to other equipment configurations. The PS capability will be a greatly needed addition to the Indian electrical grid for peak demand power and stabilization.

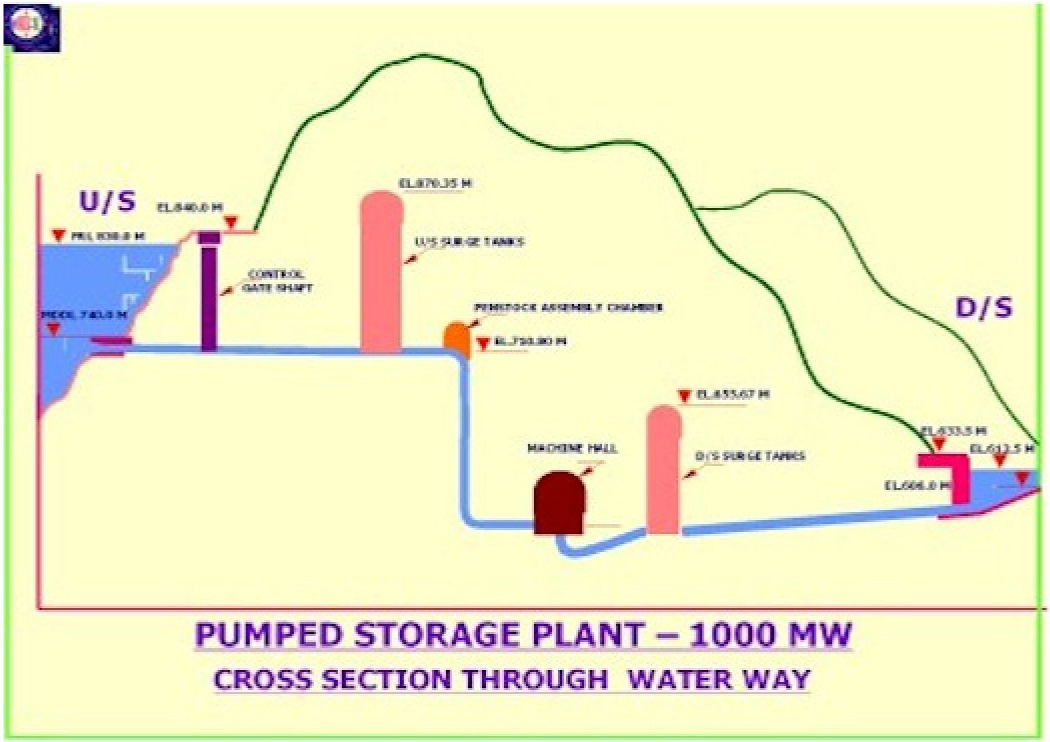

Figure B-1 Tehri Pumped Storage, Source: THDC Ltd.

B.1.2.2. Hydropower Plant Avce – Slovenia

Currently under construction, the Avce PS facility has a planned completion date in the first half of 2009. The upper reservoir is a naturally formed basin located in the north Kanalski Vrh. The reservoir has an effective water volume of 2,170,000 m^3. An already existing basin of the Ajba accumulation provides the lower basin. Maximum head is 521-m and drives a single 185 MW adjustable speed turbine. The nominal rotating speed of the turbine is 600 rpm with the possibility of speed variation from -2 to +4%. Rated discharge of the turbine will be 40 m^3/s in generation mode and 34 m^3/s in pumping mode. The single Francis turbine has a pumping capacity of 180 MW.

On the left shore of the Soca River at the lower basin is the location of the powerhouse. Water from the upper reservoir will travel 2264 meters before reaching the powerhouse shaft. This distance includes an 862-meter-long open air penstock and a 395-meter-long underground horizontal shaft. The powerhouse sits above ground with an 18-meter-wide by 80-meter-deep shaft for the turbine. Figure B-2 shows a cross section of the project layout.

The plant is being developed to compensate for the huge price gaps in electric energy from peak and valley periods. The plant will be utilized to take excess energy off the grid when it is not in demand and provide peak generation when required.

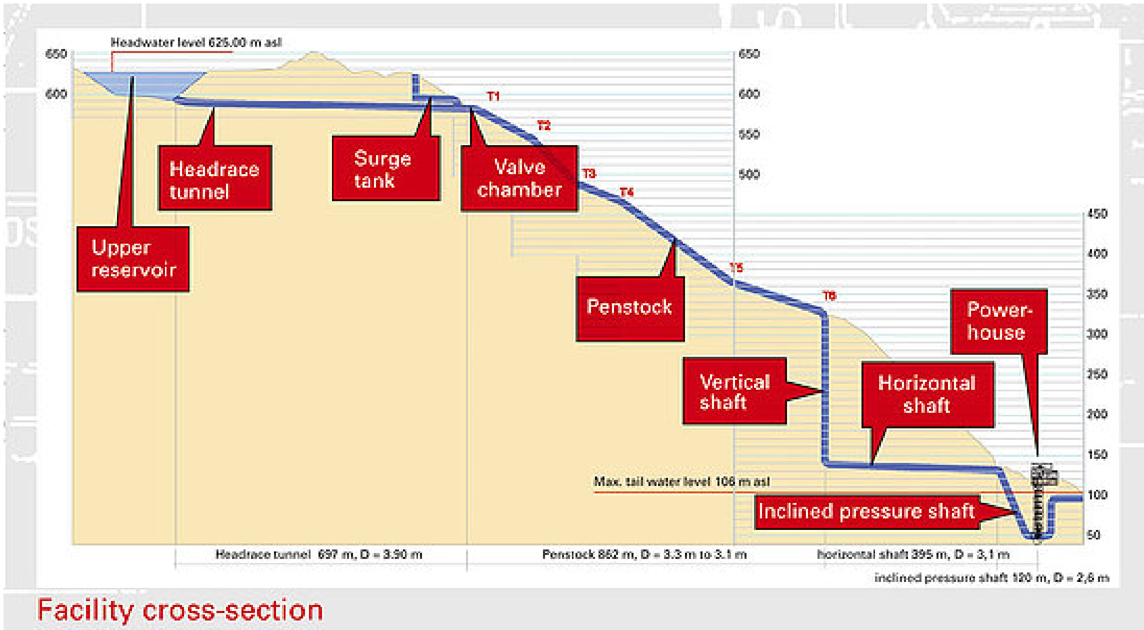

Figure B-2 Avce Pumped Storage, Source: SENG (Soske Elektarne Nova Gorcia)

B.1.2.3. Hydropower Plant Nant de Drance – Switzerland

Located in the Swiss Alps in the Valais community of Finhaut, the Nant de Drance PS facility will integrate state-of-the-art variable-speed pump-turbines. Conventional turbines can only operate on a fixed quantity of energy, while the variable speed turbines can be adjusted in order to regulate the amount of energy they draw down.

The four 157-MW Francis reversible pump turbines are to be supplied by Alstom. They will also be supplying four 170 MVA asynchronous motor-generators. The turbines will run between 428,6 rpm with a speed variation of +/- 7%. The turbines will be housed in an underground powerhouse that will be located 1,800 meters above sea level and require a 5 kilometer long access tunnel. The tunnel will minimize the environmental impact. The head will be provided for by two existing reservoirs, Emosson and Vieux Emosson. The system includes, “two parallel water conveyance systems with 250-meter headrace tunnel, 470-meter vertical shaft, 160-meter steel-lined pressure tunnel with manifold, and tailrace tunnel with manifold.”(hydroworld.com)

A ground breaking ceremony was held on Tuesday June 30, 2009 and planned completion is around 2017. The plant will be utilized to offset the irregular production of energy by renewable sources and provide energy supply security to the Swiss Electricity grid.

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EXHIBITS

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