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Pumped Storage Hydropower: Benefits for Grid Reliability and Integration of Variable Renewable Energy

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Acronyms

AS	adjustable speed
AWG	Advisory Working Group
BPA	Bonneville Power Administration
CAES	compressed-air energy storage
DA	day ahead
DFIM	doubly fed induction machine
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
ED	economic dispatch
EdF	Électricité de France
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FS	fixed speed
HREA	Hydropower Regulatory Efficiency Act
IGBT	insulated-gate bipolar transistor
IGCT	insulated-gate commutated thyristor
ISO	independent system operator
KEPCO	Kansai Electric Power Company
LMP	locational marginal price
NHA	National Hydropower Association
NREL	National Renewal Energy Laboratory
PSH	pumped storage hydropower
RE	renewable energy
RT	real time
RTO	regional transmission organization
SMUD	Sacramento Municipal Utility District
TEPCO	Tokyo Electric Power Company
TVA	Tennessee Valley Authority

UC	unit commitment
USACE	U.S. Army Corps of Engineers
WI	Western Interconnection

Executive Summary

Pumped storage hydropower (PSH) technologies have long provided a form of valuable energy storage for electric power systems around the world. A PSH unit typically pumps water to an upper reservoir when loads and electricity prices are low, and subsequently releases the water back to a lower reservoir through a turbine when loads are high and electricity is more expensive. Moreover, PSH is a flexible resource that contributes to balance supply and demand in the power grid and helps integrate variable renewable energy sources like wind and solar. These units can be incorporated into natural lakes, rivers, or reservoirs—so-called "open-loop" systems—or PSH reservoirs can be constructed to be independent of existing natural water flows—so-called "closed-loop" systems. Three main types of PSH technologies can be implemented. The most common is a fixed speed (FS) unit with pump/turbine and motor/generator that operate at a fixed synchronous speed. In recent years, adjustable speed (AS) units have become more popular due to their increased efficiency and ability to adjust their power consumption when in the pumping mode. This flexibility enables AS units to provide load-following and regulation services (i.e., respond to frequency deviations and short-term energy balancing needs in the system), which are becoming increasingly valuable as the penetration of variable renewable generation technologies, such as wind and solar, increases. Globally, more than 20 AS units have entered commercial operation since 1990. The third type of PSH technology is ternary units that can use a hydraulic bypass to provide more flexible operation, especially in the pumping mode, although this configuration is less common than AS. In the United States, 40 PSH plants are currently in operation, all of which utilize FS technology. The PSH plants provide 22 GW of total installed capacity. This accounts for 95% of all energy storage capacity in the United States.

In general, PSH units are characterized by several key performance metrics, including their net head, flow rate, waterway length, and reservoir size. The head is the vertical distance between the upper and lower reservoirs, typically between 100 and 2500 ft. The combination of the head and the flow rate of a PSH unit determines its capacity, and the flow rate is typically optimized to achieve a desired cycling time. The length of the waterway connecting the upper and lower reservoirs is a major contributing factor to the total cost of the project. Therefore, successful PSH projects tend to have relatively short waterways, and accordingly, projects typically target a waterway length to head ratio of less than ten. Reservoir size is dependent on various other characteristics of the project, as well as numerous geographical and geological considerations. The marginal benefit of a larger reservoir typically decreases with the reservoir size, and the reservoir size is typically chosen at the point where marginal cost equals marginal benefit.

Interest has arisen in upgrading a number of FS PSH units in the United States to advance AS technology to further enhance operational flexibility. This interest has been driven, in part, by the increased penetration of variable energy resources, such as wind and solar, that must be counterbalanced by flexible resources. Compared with FS units, AS units can adjust their power consumption in pumping mode and are also more efficient, have wider operating ranges and narrower rough zones in generation mode (i.e., zones of operations that should be avoided due to increased vibration or other concerns). Such conversion projects are subject to several technical and economic considerations. First, turbine and rotor upgrades are usually considered to optimize performance and maximize the benefits of AS operation. Second, AS operation is usually

provided by a doubly-fed induction machine (DFIM). Mechanically, AS units require more physical floor space and a greater powerhouse ceiling height (to allow for higher rotor lift clearance) than FS units, and such space is not always readily available in existing underground power stations. In addition, DFIM rotors are up to 30% heavier than a synchronous machine rotor, and engineers must ensure that the existing civil structures can withstand the greater stresses associated with operation of AS units. Third, new AS plants are estimated to cost 7%–15% more than a comparable FS plant. Much of this cost is associated with the 60%–100% cost premium of an AS motor/generator over a conventional FS counterpart. For conversion projects, estimating how many existing PSH units are technically or economically viable for upgrades to AS is difficult without detailed analyses of individual project sites.

Capital cost requirements for new PSH plants are site-specific and can vary widely. Factors influencing the cost of PSH projects include site topology conditions, type of technology, environmental issues, permitting costs, and the ownership structure. Typically, PSH projects also have long development and construction timelines because of the complex regulatory environment, which adds to the project costs. A recent study of the historical costs of 14 existing PSH plants in the United States did not reveal a significant relationship between project size and capital cost per kilowatt capacity (USACE 2009). However, the study did anticipate that capital cost per kilowatt will decrease with increasing capacity for new projects. An upward trend in capital cost per kilowatt was also identified over time for new projects developed between 1965 and 2000, likely due to the increased regulatory requirements established over that period. This study estimates that a hypothetical 1,000 MW new PSH project would likely cost between $1,750 and $2,500 per kilowatt. Similar cost ranges are found in other studies. Overall, PSH is a cost-effective storage solution compared to most other storage technologies. Also, PSH is the only current large-scale energy storage solution, providing 95% of all energy storage in the United States and 98% of the global energy storage capacity.

A number of barriers and challenges have long inhibited the development of new PSH units. These include environmental issues with the siting of new PSH units, the current regulatory environment, and the absence of markets that fully capture the value of PSH. A number of solutions have been proposed to help overcome these barriers: streamlining the licensing process for low-impact PSH units; developing markets that value the fast-response ancillary services provided by PSH units, such as regulating reserves, governor response, and voltage control; and allowing day-ahead and real-time markets to schedule PSH units in a flexible manner based on longer time horizons. Despite these barriers to new PSH development, new FS and AS units are currently being considered. At present, there are a total of about 50 proposed PSH projects in the United States, which amount to over 40 GW of total new PSH capacity. The development of new and upgraded AS units can further be encouraged through updated market designs that better capture the benefits provided by the increased flexibility of these units.

As variable energy resources, such as solar and wind generation, become more prevalent, a corresponding increase in demand will arise for a wide range of ancillary services to balance supply and demand in real time. These services take place over time scales from fractions of seconds (voltage stability and primary frequency control) to seconds (regulation) to minutes (spinning and non-spinning reserves). Due to their high level of operational flexibility, PSH units are able to provide many of these ancillary services to support grid operations. For example,

Koritarov et al. (2014) report that PSH, particularly AS units, may provide a significant portion of the ancillary services in the Western Interconnection, despite accounting for only 3% of total capacity. While both FS and AS units can provide regulation and spinning reserves in an economic manner when generating below their full load, AS units offer the added benefit of providing regulation service while in the pumping mode. Under most existing regulated and restructured markets in the United States, PSH units are able to earn revenues for only a small subset of the many services they provide to support grid operation and promote system reliability. Therefore, establishing more comprehensive market structures that recognize the unique role of PSH and provide compensation for these services would help promote future development of new PSH resources.

We conclude that providing further support for the development of new PSH units and AS upgrades to existing PSH units will contribute to grid reliability and will facilitate a larger expansion of variable renewable energy, thereby reducing power system emissions in the United States. Further developments of PSH can be encouraged through streamlined licensing, as proposed by HREA of 2013 for closed-loop projects. Moreover, key activities that can help accelerate PSH developments in the United States include (1) the development of tools to allow owners/operators of pumped storage hydropower plants to evaluate the feasibility of conversion from fixed-speed to adjustable-speed technologies; and (2) investigate market mechanisms that would accurately compensate pumped storage hydropower for the full range of valuable services provided to the power grid.

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1 Introduction

The Hydropower Regulatory Efficiency Act (HREA) of 2013 states that the U.S. Department of Energy (DOE) shall conduct a study and prepare a report to Congress on "Pumped Storage and Potential Hydropower from Conduits." The objective of our technical report is to provide supporting material to the report to Congress and more details on the pumped storage hydropower (PSH) technology and its role in providing reliability and integrating variable renewable energy sources into the power grid.

In developing this report, we relied heavily on a recent DOE-funded project entitled "Modeling and Analysis of Value of Advanced PSH in the United States." The main purpose of the project was to develop detailed simulation models of advanced PSH technologies and to analyze their technical capability to provide various grid services and to assess the value of these services under different market structures and for different levels of variable renewable generation resources integrated within the power system. The project was led by Argonne National Laboratory with support from Siemens PTI, Inc.; Energy Exemplar, LLC; MWH Americas, Inc.; and the National Renewable Energy Laboratory (NREL). Throughout the study, the project team received guidance from an Advisory Working Group (AWG) consisting of 35 experts from a diverse group of organizations, including industry, research, and regulatory institutions. The results of the project are documented in a comprehensive report (Koritarov et al. 2014).

Our technical report builds on information in Koritarov et al. (2014) and other relevant literature, with the objective of providing a description of the PSH technology and its contributions to power grid operations. The report has the following structure. Chapter 2 gives a brief background to PSH and the historical development of the technology. Chapter 3 discusses the potential for development of new PSH in the United States. Chapter 4 describes the technical capabilities of PSH and its role in providing grid reliability and supporting the integration of variable renewable generation. Finally, Chapter 5 concludes by summarizing the main findings and provides recommendations for how further developments of PSH in the United States can be accelerated.

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2 Background and History of Pumped Storage Hydro

Pumped storage hydro has long been used as an important component of electric power systems. One of the earliest known applications of PSH technology was in Zurich, Switzerland, in 1882, where a pump and turbine operated with a small reservoir as a hydro-mechanical storage system for nearly a decade. Beginning in the early 1900s, several small hydroelectric PSH plants were constructed in Europe, mostly in Germany. The first large-scale PSH development in North America was the Rocky River PSH plant, completed in 1928 on the Housatonic River in Connecticut. Rocky River used a Francis turbine and two separate pumps. The plant had a capacity of 24 MW in generation mode (ASME 1980).

These early units were relatively basic as they had a motor and pump on one shaft and a separate shaft with a generator and turbine. Subsequent developments through the middle of the 20th century used a configuration composed of a single vertical shaft with a motor/generator at the top, a pump in the middle, and a turbine at the bottom. In other applications, separate pump-motor and turbine-generators were used. Both the pump and the turbine in these cases were usually of the Francis type. Wicket gates, eventually under hydraulic control, were developed and used to regulate the power output in the generation mode.

It was realized early on that a Francis turbine could also operate as a pump, but it was not used for both purposes until the Tennessee Valley Authority (TVA) and Allis Chalmers constructed the Hiwassee Unit 2 in 1956. This unit was a true reversible pump/turbine and, at 59.5 MW, was larger than earlier installations. Early pumped storage applications were limited by pump starting requirements. Pump/motor starting was done with pony motors or back-to-back configurations until the advent of solid-state starting devices. Technology and materials developments over the next three decades improved overall efficiency, reduced pump-starting issues, and allowed increasingly larger units to be constructed.

2.1 Technology Overview

A typical conventional PSH project consists of two interconnected reservoirs (lakes), tunnels that convey water from one reservoir to another (waterways), turbine shutoff valves, hydro machinery (a pump/turbine, a motor/generator, and transformers), a transmission switchyard, and a transmission connection, as illustrated in Figure 1.

The PSH technology can be implemented in various ways within specific geologic and hydrologic constraints. Many early PSH projects used existing conventional hydro facilities to provide the necessary lower reservoir for water storage. These installations form a class of projects known as “on-stream integral pumped storage” or “pump-back pumped storage.” The latter uses two reservoirs located in tandem on the same river. They can operate as a conventional hydro plant, but when water flows are low, or when peak demand is high, they can be operated in the pumped storage mode.

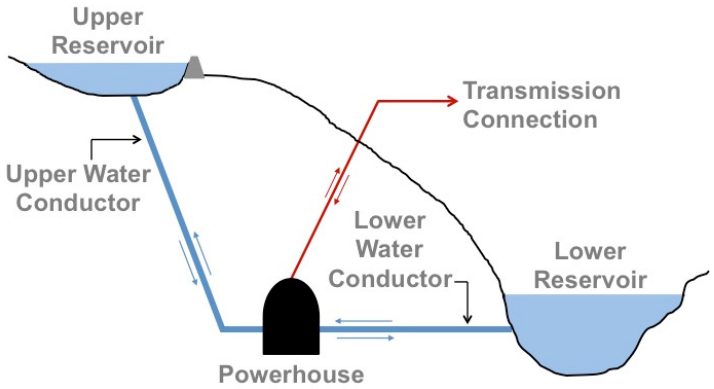
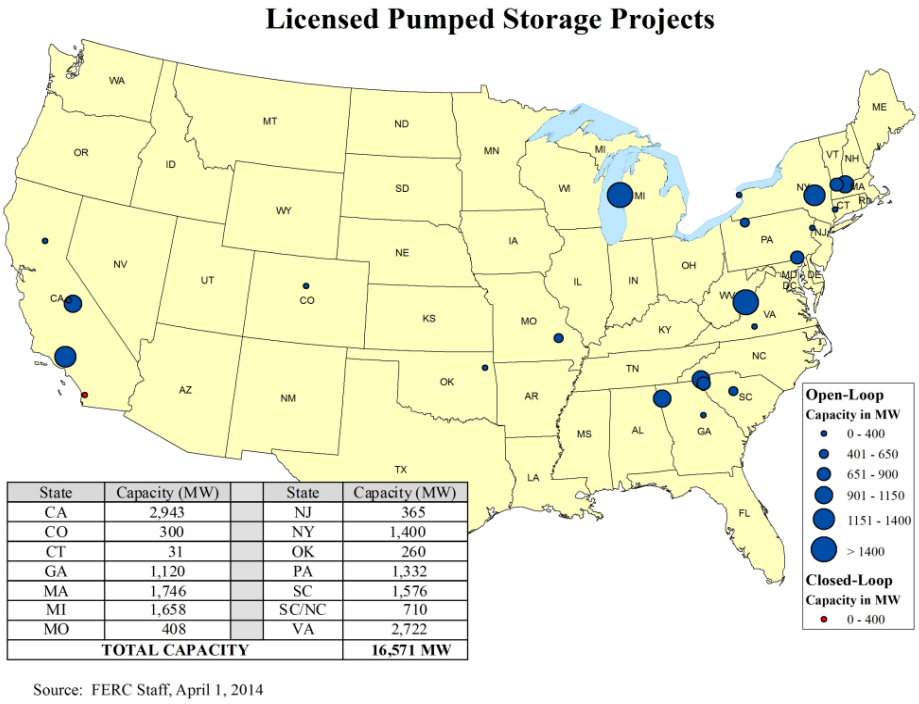


Figure 1 Typical Pumped Storage Configuration (Source: Koritarov et al. 2014)

It is also possible to construct PSH projects that are independent of a naturally occurring river or lake. Plants of this type are often referred to as "closed-loop" PSH systems. In this type of plant, the upper and lower reservoirs are located "off stream." An advantage of this approach is that there is minimal aquatic life interaction, which reduces the environmental impacts and concerns (Yang and Jackson 2011). The closed-loop design thus minimizes or avoids the permitting and environmental review process. The development of a closed-loop system requires that a water source be identified to provide the initial charge and additional water to replace losses from evaporation and leakage.

Recent PSH projects are typically large-scale installations having multiple units rated at 100 MW or greater. These require considerable civil construction, often with the need to build an upper reservoir and dams linked to an existing water feature for a lower reservoir. In the United States, 40 PSH plants are in commercial operation, all of them using traditional fixed speed (FS) technology. Many of these plants were constructed in the 1960s to 1980s to complement the operation of large, base load nuclear and coal power plants by increasing loads at night and providing peaking power during the day, while also serving as backup capacity in case of outages. Figure 2 provides an overview of current licensed PSH plants in the United States.



State	Capacity (MW)		State	Capacity (MW)
CA	2,943		NJ	365
CO	300		NY	1,400
CT	31		OK	260
GA	1,120		PA	1,332
MA	1,746		SC	1,576
MI	1,658		SC/NC	710
MO	408		VA	2,722
TOTAL CAPACITY				**16,571 MW**

Source: FERC Staff, April 1, 2014

Figure 2 PSH Projects in the United States (Source: FERC)

2.2 Advancements in Technology

A major breakthrough in PSH technology was the introduction of the doubly-fed induction machine (DFIM) motor/generator with adjustable speed (AS) capability. The main advantages of AS plants are that they provide more flexibility in operations, as well as a higher efficiency. In particular, the ability of AS plants to adjust power consumption while pumping enables provision of dispatch flexibility and regulation (i.e., respond to frequency deviations and short-term energy balancing needs in the system) in the pumping mode. The first application of the AS technology was a pilot project in a conventional hydro plant. In 1987 Hitachi installed a 22 MVA AS generator at the Narude hydro plant of Kansai Electric Power Company (KEPCO). The installation included a three-phase rotor, cycloconverter, power electronics controller, and protective relaying. The unit was initially operated in the generation mode to demonstrate the feasibility of AS technology applied to hydro generation. The Narude pilot project was a pioneering accomplishment and led to the development of large AS PSH units. Internationally, more than 20 AS units have entered commercial operation since the 1990s, and several more are under design and construction. In particular, AS technology is seen as an important solution to grid reliability and renewable energy integration challenges in Japan and Europe. Many of the proposed new PSH projects in the United States are also considering AS technology, including the Iowa Hill plant which is being developed by SMUD, with funding support for design studies by DOE's Water Power Program. Existing installations use the asynchronous DFIM machines. It is also possible to convert FS synchronous machines to AS operation. Ternary PSH represents another configuration with FS synchronous power conversion. In recent years, a more flexible variation of the ternary PSH configuration with a hydraulic bypass has been developed. The hydraulic bypass allows for pumping and generation to occur at the same time, resulting in more

flexible operation than the FS including the ability to provide regulation in the pumping mode. The technical characteristics of the FS, AS, and ternary PSH units are discussed in more detail in Chapter 4.

In the traditional mode of operation, PSH follows a daily operational cycle. Electricity is used to pump water from the lower to the upper reservoir during low loads at night. Water stored in the upper reservoir is released during peak demand periods, delivering valuable electricity to the grid and reducing the need for peak load generation from other power plants. Because the deregulation of the bulk power electric system created separate products and prices for ancillary services, i.e., certain services required to maintain reliability in the power system, it is now possible to earn revenue for supplying such ancillary services. The rapid expansion of renewable energy (e.g., wind and solar) will likely increase the ancillary service requirements. The need for additional ancillary services has led some developers to consider new PSH projects that are focused on providing them. In this context, the enhanced flexibility of advanced PSH technologies such as AS and ternary units is particularly relevant. However, no such plants have been built to date in the United States.

For a more detailed presentation of the history of PSH, see USACE (2009) and Koritarov et al. (2014).

3 Opportunities for New PSH Development

In this chapter we first discuss general design issues for PSH plants, before pointing out the main advantages of the AS PSH technology. Then, we look at the potential for new PSH plants in the United States, as well as the possibility of upgrading existing plants to more advanced AS technologies. We also review the costs of different PSH technologies and compare them with other energy storage technologies. We conclude with a brief discussion of current barriers and challenges for further development of new PSH in the United States, and present case studies of recent international projects. The discussion below is based, in part, on Koritarov et al. (2014).

3.1 Design of New PSH Projects

The design of a PSH plant often begins with a site that is in a desirable location and has favorable geotechnical and seismic conditions with an adequate water source, upper and lower reservoir possibilities, and reasonable head[1] conditions. For the purpose of this discussion, reasonable geotechnical and seismic conditions are assumed to exist, and the focus is on technical characteristics and facilities that contribute to a successful PSH plant.

3.1.1 Head

Pumped storage projects have been constructed with heads ranging from about 100 ft to 2,500 ft. Most projects at the lower end of this range have either multiple purposes, involve water pump-back, or use an existing lake or reservoir. The minimum practical head for an off-stream PSH project is generally around 300 ft, with higher heads being preferred. Some projects have been constructed with heads exceeding 3,000 ft. These higher head projects involve the use of separate pumps and turbines or multi-stage pump/turbines. Studies have also been undertaken to develop PSH projects with underground lower reservoirs sited 4,000 to 5,000 ft below the surface.

3.1.2 Flow Rate

The capacity of a PSH project, P, is a function of the hydraulic head and flow rate, that is, $P = \eta \cdot \rho \cdot q \cdot g \cdot h$, where η is turbine efficiency, ρ is water density (kg/m^3), q is flow rate (m^3/s), g is gravity acceleration (9.81 m/s^2), and h is the hydraulic head (m). For a project with a given head and reservoir storage volume, the flow rate is determined to achieve a desired cycling time. A higher flow rate lowers the cycling time and also requires larger generating units, pumping units, and waterways. Cost-benefit optimization is generally carried out to optimize the design flow rate and, hence, the plant capacity. The design flow rate is constrained by the head loss associated with a particular waterway diameter. For a given flow rate dictated by the power plant capacity, the waterway diameter is optimized by balancing the higher head losses associated with smaller diameters and the increased construction costs associated with larger diameters.

[1] "Head" refers to the vertical distance between the upper and lower reservoirs.

3.1.3 Waterways

Figure 3 shows the major components that make up the waterways in a typical PSH plant. Note that not all PSH plants have surge tanks, and that the potential need for surge tanks is determined by using hydraulic transient analysis as part of the project design.

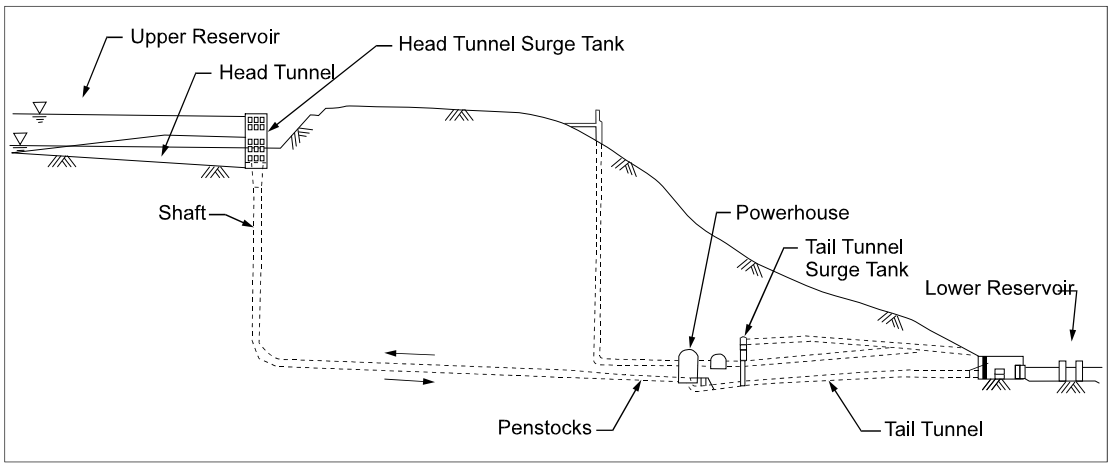


Figure 3 Cross Section of PSH Plant Showing Water Ways (Figure from Koritarov et al. 2014, Original Source: EPRI 1995)

Successful PSH projects have a relatively short waterway between the upper and lower reservoirs. Waterways constitute a major component of the total plant construction cost. The main factor affecting the waterway cost is the overall size of the proposed facility and the "length-to-head ratio" (L:H) of the waterway. Waterway length refers to the distance from the head tunnel intake to the outlet into the lower reservoir. The L:H is often used as a screening criterion when comparing alternative project configurations. Minimizing the length, while maintaining a sizeable head between the upper and lower reservoirs, is an important component of project optimization. Lowering the L:H tends to lower costs and increase cycling efficiency.

In general, the economic upper limit of the L:H is about ten. Some projects may have higher L:H, but they also may have other overriding factors that make them feasible. For example, the Helms project in California has exceptionally long waterways, but it is also a seasonal water storage project, where the benefits of large storage outweigh the cost of longer waterways.

The L:H is also a possible indicator of the need for a surge chamber(s), shaft(s), or tank(s). A surge chamber, shaft, or tank may be required on a long waterway as a means to reduce hydraulic pressure rise during transient events such as load rejection. The L:H is also an indicator of response time and regulating capability, which generally decrease as the L:H increases.

Site topographic and geological characteristics control the configuration of the waterway, both in terms of horizontal and vertical alignment. The waterway profile may include surface or buried sections. Use of high-pressure and large-diameter segments constructed as tunnels in hard rock

(if available) is normally the lower cost option. The alternatives to tunnels in rock include steel or concrete water pipes.

Waterway costs are influenced by total generating capacity and prevailing head. The number of required waterways and their respective sizes are determined as a function of flow and other hydraulic parameters. Given the same output specification (MW), a high-head project will have a smaller waterway cross section than a low-head project. Given the same head, high-capacity projects will have greater waterway flow cross section than low-capacity projects.

The design of the waterways is an important aspect in the performance of the project. The characteristics of the waterway determine head loss and also influence unit responsiveness in terms of ramp rate and ability to provide other ancillary services.

3.1.4 Reservoir Size

The sizes of the upper and lower reservoirs depend on available head, plant capacity, plant operation, and site characteristics. Site characteristics include land acquisition cost as well as physical and geotechnical conditions. Good physical and geological site conditions are vital to selection and design of the upper and lower reservoir. Upper reservoirs are typically created by building a dam across a three-sided depression, a ring-dike on a plateau, or a dam across a stream or other water feature.

A lower reservoir can be a natural lake or an existing hydro project reservoir, or one can be created by building a dam across a small stream. It is also possible to use an existing quarry, an underground mine, or even the ocean (as is the case for the Yanbaru Seawater Pumped Storage Plant on Okinawa in Japan).

The selection of the reservoir size depends on site characteristics and the needs of the electric power system. Some PSH projects have more than 20 hours of operating storage, and some have as little as four hours of operating storage. Those with larger operating storage were typically planned with the objective of using the weekend to store water as part of a weekly operating regime. Most PSH projects with limited storage were planned for operation on a daily cycle or to provide short-time operating reserves. With current changes in the generation mix, the amount of variable renewable energy sources is another determining factor in reservoir sizing, since it may change the operating pattern of the PSH plants.

Production cost models, operational simulations, and generation expansion modeling tools are used to study and estimate the reduction in system operating costs associated with increasing levels of energy storage. Typically, the marginal savings will diminish as energy storage increases. The comparisons to be made include: cost vs. storage capacity, and benefit (or system operational cost savings) vs. storage capacity. The optimal storage capacity is at the point where incremental costs and benefits are equal.

3.1.5 Pump/Turbine and Motor/Generator

Modern multi-unit PSH plants use reversible Francis turbines with wicket gates and a speed governor. Design and selection of the pump/turbine take into account a multitude of factors, such as operating head, setting in relation to upper and lower reservoir levels, specific speed, synchronous speed, water-column time constant, draft tube surging, and other factors. In the case of advanced PSH plants with AS capability, the range of speed variation needs to be determined. The selection of synchronous speed as well as the range of speed adjustment is an important factor in overall performance, operating cost, and revenue.

The AS machines use a DFIM, which has a three-phase wound rotor that is built up with laminated steel sheets, whereas a synchronous FS machine has salient poles mounted on a spider-shaped support structure. The design of stators for the AS machines is similar to that for conventional synchronous FS motor/generators. However, the design and manufacturing of rotors for AS machines present several challenges for manufacturers. Some of these include circulation of cooling air, balance, attachment of rotor coil overhang, testing, transportation, installation, and commissioning.

3.1.6 Other Design Issues

Other design considerations have to be taken into account when planning a new PSH project. Design issues for the three main types of PSH technologies discussed in this report are summarized in Table 1.

Table 1 PSH Plant Design Issues (Source: Koritarov et al. 2014)

Benefits	Conventional with FS Synchronous Motor/Generators	AS with DFIM Motor/Generators	Ternary with Hydraulic Bypass and FS Synchronous Motor/Generators
Bearing life	Base	Same as base but with reduced vibration	Base
Maintenance cost	Base	Increased	Base
Vibrations	Base	Reduced	Base
Time between major overhaul	Base	May be extended due to reduced vibration	Base
Pump/turbine setting	Base	Deeper	N/A
Crane capacity	Base	Greater	Base
Floor space	Base	Greater	Base
Water-cooled electronics	Static Frequency Converter	Yes	Not required
Pump mode starting	Static Frequency Converter	Rotor electronics	N/A

Table 1 (Cont.)

Benefits	Conventional with FS Synchronous Motor/Generators	AS with DFIM Motor/Generators	Ternary with Hydraulic Bypass and FS Synchronous Motor/Generators
Power house height	Base	Higher	Base
Rotor overvoltage protection	No	Rotor circuit	No
Hydraulic churning	In back-to-back mode on a common penstock	In back-to-back mode on a common penstock	Yes

3.2 Advantages of AS PSH

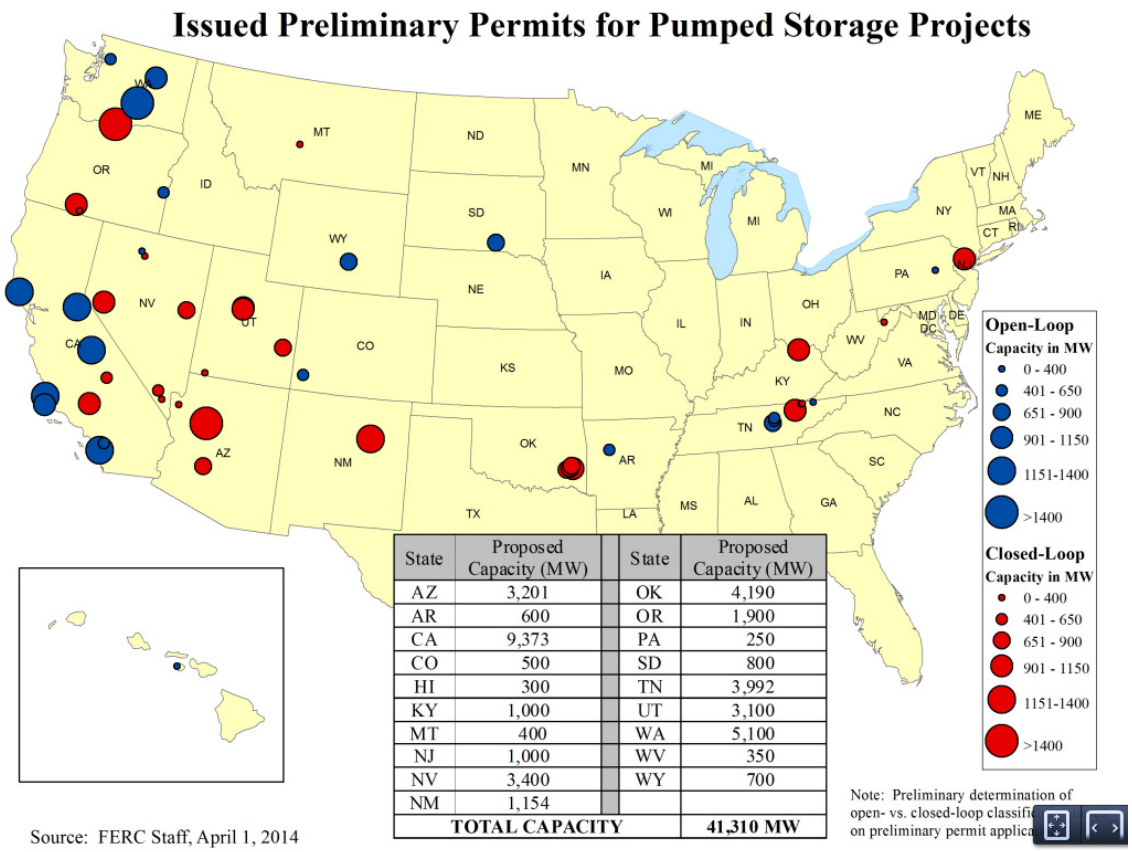
Although the conventional FS PSH technology is among the most flexible technologies for power generation, the AS PSH technology provides even more flexibility. Koritarov et al. (2014) summarize some of the additional capabilities provided by AS PSH technologies as compared to conventional FS plants:

- More flexible and efficient operation and smaller rough zones (i.e., zones of operations that should be avoided due to increased vibration or other concerns) in the generation mode;
- Lower minimum unit power output (could be 30% or lower);
- Increased efficiency of the turbine at partial loads by operating at optimal speed, also contributing to longer lifetime;
- Operation at no load without significant reduction in the lifetime of the turbine;
- Ability to adjust power consumption in the pumping mode (e.g., speed variations of 10% typically allow the pumping load to vary from 70% to 100% of full pumping capacity);
- Frequency regulation capabilities available in the pumping mode of operation;
- More flexible voltage support due to electronically decoupled control of active and reactive power;
- Improved dynamic behavior and stability of power system in the case of grid disturbances and reduced frequency drops in the case of generator outages;
- Better compensation of variability of renewable energy sources:
  - More flexible and quicker response in generating (turbine) mode,
  - Variable power in pumping mode to counterbalance variability of wind, and
  - Excellent source of frequency regulation during off-peak hours.

The technical characteristics of the different PSH technologies, including the advantages of the advanced AS and ternary units, are discussed in more detail in Chapter 4.

3.3 Potential for New PSH Projects in the United States

Recently, interest has grown in developing new PSH plants in the United States. This interest is triggered, in part, by the recognition that the rapid expansion of renewable energy in the electricity grid gives rise to increasing need for power system flexibility, which could be provided by energy storage. At present, about 50 proposed PSH projects are in various stages of planning and licensing in the United States. Their total installed capacity amounts to more than 40 GW, where more than half of that capacity involves closed-loop projects. Figure 4 shows proposed PSH projects for which the Federal Energy Regulatory Commission (FERC) has issued preliminary permits. Several of these projects (e.g., Eagle Mountain) are considering the use of AS PSH technology, which can be applied in open- and closed-loop designs. Barriers and challenges for the development of PSH in the United States are discussed in Section 3.7.



State	Proposed Capacity (MW)	State	Proposed Capacity (MW)
AZ	3,201	OK	4,190
AR	600	OR	1,900
CA	9,373	PA	250
CO	500	SD	800
HI	300	TN	3,992
KY	1,000	UT	3,100
MT	400	WA	5,100
NJ	1,000	WV	350
NV	3,400	WY	700
NM	1,154		
TOTAL CAPACITY			41,310 MW

Note: Preliminary determination of open- vs. closed-loop classifi on preliminary permit applica

Figure 4 Preliminary Permits for PSH in the United States (Source: FERC)

3.4 Upgrading Existing PSH Plants with Advanced Technology

Interest has also grown in upgrading existing conventional FS PSH plants in the United States to advanced AS technology. One of the key driving factors for such upgrades is the rapid expansion of variable renewable generation, which tends to increase the need for flexibility from other generating units in the power grid to counterbalance the increased uncertainty and variability in the system. Typically, a larger share of variable generation in the system requires greater amounts of operating reserves to be maintained during normal operation, including regulating reserve as well as other reserve products with longer response times. The regulating reserve serves to balance the system load with the total power output of all generating units and to maintain system frequency within a narrow band around 60 Hz. As the market penetration of wind power increases in many areas in the United States, it has become more difficult and costly to provide regulation service during the off-peak periods, especially during the night. At that time, wind power generation tends to be high, but the system load is low and has little flexibility because mostly base-load "must run" generating units are in operation. The capability of the AS PSH plants to provide regulation service in the pumping mode, especially the regulation down service, greatly increases the flexibility of system operation and may, therefore, enable integration of a larger share of variable renewable resources.

Another reason for converting an existing FS PSH plant to AS technology is the resultant increase in overall plant efficiency, especially in the generation mode. This increase occurs because the rotating speed can be adjusted optimally for a given head and rate of water flow through the turbine. Typically, the total cycle efficiency of the PSH plant can be increased by one to two percent by upgrading to AS technology. Because the AS turbines are operating at optimal speed, even at partial loads, they also have increased lifetime expectancy compared to FS turbines. Moreover, AS turbines driven by the DFIM can even operate at no load without significantly reducing the lifetime of the turbine due to decreased vibrations.

Because the rotating machine speed can be adjusted to given conditions, the minimum power output of a AS PSH unit is typically lower than that of a comparably sized FS PSH unit; this difference could be as low as 20%-30% of the unit's total installed capacity. In addition, the rough zones[2] for AS PSH units are narrower, which allows for a wider range of available unit power output during operation.

An additional benefit of advanced AS technologies is the electronically decoupled control of active and reactive power, which provides more flexible voltage support for the system. Compared to FS PSH units, AS PSH technologies have better capability to provide dynamic response to grid disturbances, which contributes to reduced frequency drops in case of sudden generator or transmission outages and improved stability of the power system.

The capabilities of FS and AS PSH plants are discussed in more detail in Chapter 4 of this report.

[2] A "rough zone" is a part of the range between minimum and maximum output that should be avoided due to deteriorating impacts on plant equipment, e.g., due to vibration.

3.4.1 Requirements for Conversion from Fixed to Adjustable Speed

Not every FS PSH plant is a good candidate for conversion to AS technology. A number of conditions need to be carefully evaluated to determine if conversion is technically feasible and economically cost-effective. Most technical requirements for conversion fall into four main groups: civil works and hydraulic, electrical, and mechanical systems.

Civil Works

One of the key conditions for conversion to AS units is the available ceiling height of the powerhouse, as it needs to accommodate the increased vertical space requirements of AS units. Because the rotor of the DFIM AS unit will have a three-phase commutator (slip rings) typically mounted on the shaft above it, the crane lift needs a higher clearance than that for the rotor of the FS unit. In addition, the crane needs adequate capacity to lift a heavier rotor made with stacked laminations. The available ceiling height is of critical importance in underground power stations. Theoretically, additional excavations could be performed to provide additional space in the powerhouse, but that would significantly increase the cost of the conversion project.

The civil works requirements also include the available floor space needed to accommodate the additional electrical systems for the DFIM rotor, including the voltage source inverter and power transformer. These serve as a rotor excitation system and control the rotor speed. Alstom Hydro estimates that a unit with a pumping capacity of 30 MW requires 1,615 square feet of floor space to accommodate the voltage source inverter and transformer, which are two of the largest pieces of additional electrical equipment required for DFIM units (Henry et al. 2013). This space may be hard to find in existing underground power stations and may require some excavation, which would increase the cost of the conversion project.

Another consideration is the ability of the existing civil structures to withstand higher loads and stresses associated with the operation of AS units. As the civil works requirements in the powerhouse may not be cost-effective, the size of AS units may need to be limited to what the existing concrete structures can safely support in static and dynamic operation conditions.

Hydraulic Systems

Any conversion to an AS unit should consider a turbine upgrade that maximizes the AS capabilities and optimizes turbine performance for a range of potential speed variations (typically +/-10% around the synchronous speed). The reversible turbine design also needs to be optimized for AS pumping. Typically, speed variations of 10% allow for the pumping load to vary from 70% to 100% of full pumping capacity.

As the hydraulic systems of existing FS PSH plants were designed for FS operation, the conversion to AS units should address the impact of AS operation on hydraulic transients associated with the range of speed variations for both the generating and pumping modes of operation. This analysis should include a determination of what impacts penstocks and

waterways will have, how the newly installed hydraulic components will operate within the existing waterways, and how cavitation can be minimized for a range of turbine speeds.

An additional benefit of the upgraded hydraulic design is the improved efficiency of operation, especially in the generation mode, where the efficiency may increase by several percentage points over the FS unit.

Electrical Systems

There are two main approaches to providing AS operation for a PSH plant:

1. Using a synchronous generator with a full-power frequency converter.
2. Using a DFIM with a reduced-power frequency converter in the rotor circuit.

The first option requires the synchronous motor/generator to be connected with a full-power frequency converter for unit speed adjustments. The converter connects to the stator, and its power should match the full power of the motor/generator. Given that the cost of the full-power converter unit can be prohibitive for larger unit sizes, this option is typically considered for units that are smaller than 100 MW.

The second option requires replacing the existing salient pole rotor of the FS motor/generator with a three-phase wound rotor and the addition of a frequency converter that is connected to the rotor via a three-phase commutator. The rotational speed of the rotor is controlled by the frequency converter so that the combination of actual rotor speed plus the frequency shift provided by the frequency converter matches the speed of the rotating magnetic field in the stator, which is always at synchronous speed. As the frequency converter feeds the rotor and supplies power only for the speed differential, it does not need to be sized to match the full power of the motor/generator. Rather, its power is typically just a small fraction of the full machine power, which makes it suitable and cost-effective for applications with large unit sizes of several hundred megawatts. A smaller frequency converter will also have smaller power losses, which are typically about 3% of a converter's power, which is an additional benefit. In the 1990s, cycloconverters were typically used as frequency converters, but now voltage source inverters using IGBTs (insulated-gate bipolar transistors) or IGCTs (integrated-gate commutated thyristors) are preferred options as they allow for a faster response, have a smaller size, do not need a supply of reactive power, and do not produce sub-harmonics that could generate sub-synchronous resonances.

At present, most AS PSH plants are designed to use DFIM technology and voltage source inverters. The same technology is also preferred for conversion of existing FS to AS units as well.

In conversion projects, the existing rotor has to be replaced with a three-phase wound one, but the existing stator may be re-used. The stator winding needs to be compatible with the rotor winding and must also allow increased power to pass through the rotor for speed regulation. If

this is not the case, the stator will also need to be replaced. This will increase the total cost of the conversion project and reduce its benefit/cost ratio.

The frequency converter is connected to the rotor through large slip rings that need to be enclosed so that air cooling and filtration systems can be provided. An air filtration and vacuuming system is also needed to maximize the lifetime of the brushes and capture the carbon particles and dust, thus preventing the premature failure of rotor insulation.

In addition to the motor/generator, other electrical systems have to be replaced or re-engineered. While some equipment can be re-used, others will need to be replaced. Henry et al. (2013) provide a detailed list of new electrical equipment required for a conversion project. On the DFIM rotor side, required new equipment includes the following:

- Heavy-duty power tapping device on the medium voltage side of the unit's power transformer,
- Current-limiting reactors to prevent short circuits,
- Medium-voltage breaker,
- Harmonic filters,
- Voltage-source inverter and transformer,
- Segregated-phase bus ducts from voltage source inverter to rotor ring cubicle,
- Cubicle for rotor over-current and over-voltage protection, and
- Non-conventional current transformers and voltage transformers for rotor current and voltage measurement at very low frequency.

On the stator side, additional equipment that needs to be installed includes:

- Isolated phase bus ducts (part of which may be re-used from the existing synchronous unit),
- Starting/braking short circuit breaker used for the DFIM launching in motor mode and for the regenerative breaking sequence,
- Generator circuit breaker (depending upon its condition and rating, a new breaker might be considered), and
- Phase reversal disconnectors (may be re-used or replaced depending on their condition, ageing, and rating).

Some of the new equipment will require additional floor space for its installation within the powerhouse. That requirement may be a significant challenge in underground powerhouses; therefore, expansion may be required to accommodate additional equipment.

In addition to the above, the power transformer for the PSH unit has to be checked and possibly replaced, depending on the rating of the new motor/generator and/or special requirements due to harmonics produced by the DFIM and voltage source inverter.

Mechanical Systems

As a DFIM rotor is typically about 30% heavier than a comparably sized salient pole rotor used with synchronous machines, the rotor shaft should be checked and verified to ensure that it can withstand additional dynamic loads.

In addition, the thrust bearing will be impacted by the new hydraulic design and by the increased weight of the DFIM rotor, so it too needs to be checked for higher operating loads. The parameters that need to be taken into account in the shaft line calculation include a possible increase in the bearing span, an increase in rotor weight, modification of runaway speed, and variation in operating speed. The critical parameter for shaft line safety is its bending natural frequency. Modification to mitigate potential problems with shaft vibrations may affect the entire machine layout.

Additional mechanical system issues that need to be addressed are related to the design of slip-ring filtration system and the water-cooling system.

3.4.2 Potential for Conversion Projects

Although a few individual unit conversions have been preliminarily evaluated (DOI 2008, BPA 2010), a comprehensive nationwide assessment has not been performed yet to identify plants that could be converted to AS. It is, therefore, difficult to estimate how much of the existing PSH capacity would be technically possible to convert to AS PSH technology and what the associated costs would be. In principle, a cost/benefit analysis would need to be performed for each specific project to determine its economic viability. In addition, a financial analysis should be performed to determine key financial parameters and the financial viability of the conversion project. Both the cost side and the benefit side of the equation are very much site-specific and need to be assessed individually for each potential conversion project. Moreover, the long permitting and construction stages must be factored into such assessments, adding uncertainty to the estimated costs and benefits.

One of the key motivations for conversion to AS PSH technology is the ability to provide regulation service in the pumping mode of operation. If, for illustration purposes, we assume that about half of the existing 22,000 MW of FS PSH plants in the United States can be converted to AS technology, this condition would provide about 3,300 MW of regulating reserve during off-peak hours, assuming that 30% of the AS PSH capacity can be used for regulation in the

pumping mode. This amount of regulating reserve would enable larger integration of variable renewable generation into the power system and reduce the costs of power system operation by decreasing the need for thermal generating units to provide regulation service.

Internationally, there have been several conversion projects of existing FS PSH plants to AS technology. In Japan, Unit 2 at the Yagisawa PSH plant was converted from FS to AS in 1990. In Europe, Électricité de France (EdF) is currently performing a conversion of the existing Le Cheylas PSH plant to AS technology, as further discussed in Section 3.8.3.

3.5 Cost of PSH Technologies

3.5.1 Capital Costs

Because of the overall scope and site-specific nature of PSH project development, capital costs are difficult to characterize and estimate. Factors that influence the costs of a PSH project include: site-specific geotechnical and topology conditions, size of reservoirs and dams or ring dikes, length of tunnels, use of surface vs. underground powerhouse, type of electromechanical technology, type of transmission system interconnection and upgrade costs, environmental issues, permitting process, regulatory environment, business plan, and ownership structure.

In addition, a PSH plant has a longer development and construction period than most other types of power generation plants, often as long as ten years or more. During the pre-construction period, many activities are undertaken in the form of preliminary engineering, permitting, and environmental, regulatory, and other non-engineering items.

Given the large scale and long construction times of PSH projects, there is always some uncertainty about what is included or excluded in reported capital costs. For example, it is often not known whether costs from engineering, administration, financing fees and interest, or other "soft costs" are reported as project capital costs, or if they are reported in some other way. Because these costs can be significant, any conclusions about project costs and guidelines, such as cost per kilowatt installed, that are based on historic data need to be considered with care.

A study of historical costs for 14 representative PSH plants in the United States was conducted by MWH (USACE 2009). Historical cost data from FERC Form 1 reports and a compendium of PSH plants were used to evaluate the cost per kilowatt of each plant, and costs were adjusted to 2009 levels using Bureau of Labor Statistics data. The plants that were evaluated have power capacities from 300 MW to 2,100 MW, with an average plant capacity of 900 MW. The number of units per plant ranged from two to eight; five of the 14 plants have four units. The study did not reveal a distinct relationship between the plant capacity and capital cost. However, the project costs plotted against the in-service years for the 14 sample projects do follow an upward trend, as shown in Figure 5. This trend may be related to the regulatory environment or site-specific factors. It is also possible that the first projects developed are the most favorable, and that the later sites have less favorable characteristics and were, therefore, more expensive to develop. A study of the costs of new projects was also conducted. Figure 6 shows estimated cost

ranges for greenfield pumped storage projects. The variation reflects site-specific (and other) items with large cost variability. Inspection of the curves shows that an expected construction and equipment procurement cost of a hypothetical 1,000 MW pumped storage project is on the order of $2,000/kW but could fall in the range of $1,750/kW to $2,500/kW.

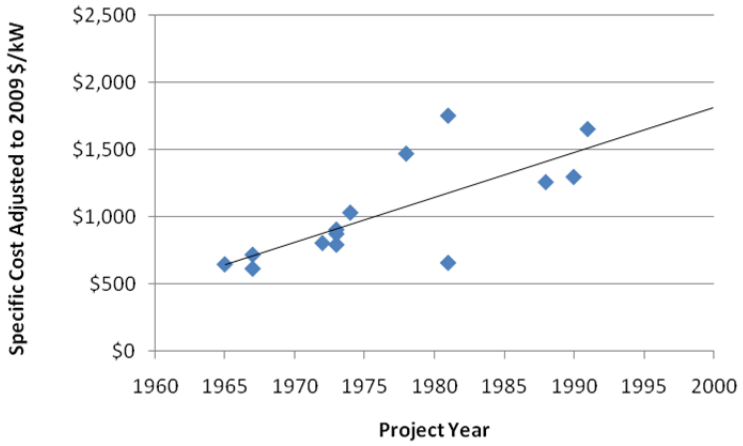


Figure 5 Historic Capital Cost (2009 $/kW) vs. Project Year (Figure from Koritarov et al. 2014, Original Source: USACE 2009)

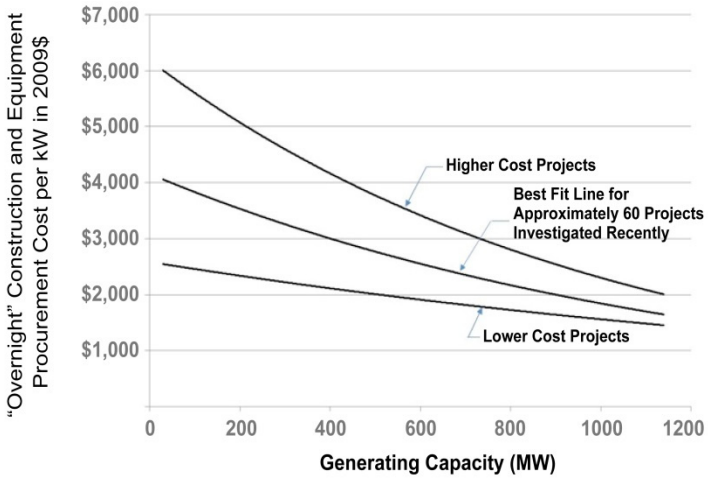


Figure 6 Indicative Overnight Construction Cost for New Pumped Storage Projects (Figure from Koritarov et al. 2014, Original Source: USACE 2009)

The Electric Power Research Institute (EPRI) conducted a study of the costs of existing and proposed PSH projects, comprising more than 30 projects in the United States and internationally (EPRI 2011). The results show a wide spread in the estimated capital costs for the analyzed projects, but most of them have a cost between $1,000/kW and $2,000/kW. Similar to Figure 6, capital costs show a downward trend for increasing installed capacity (Figure 7) and no significant relationship with the head distance (Figure 8).

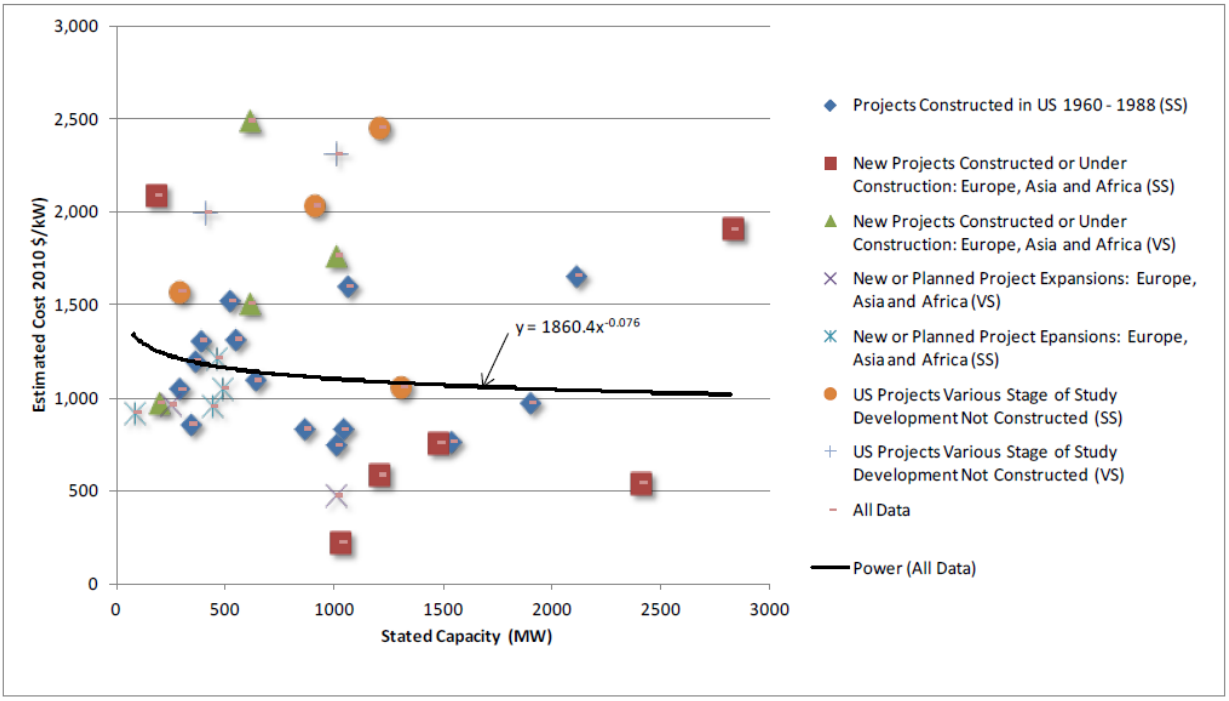


Figure 7 Estimated Capacity Costs for Existing and Proposed PSH Projects as a Function of Capacity (Source: EPRI 2011)

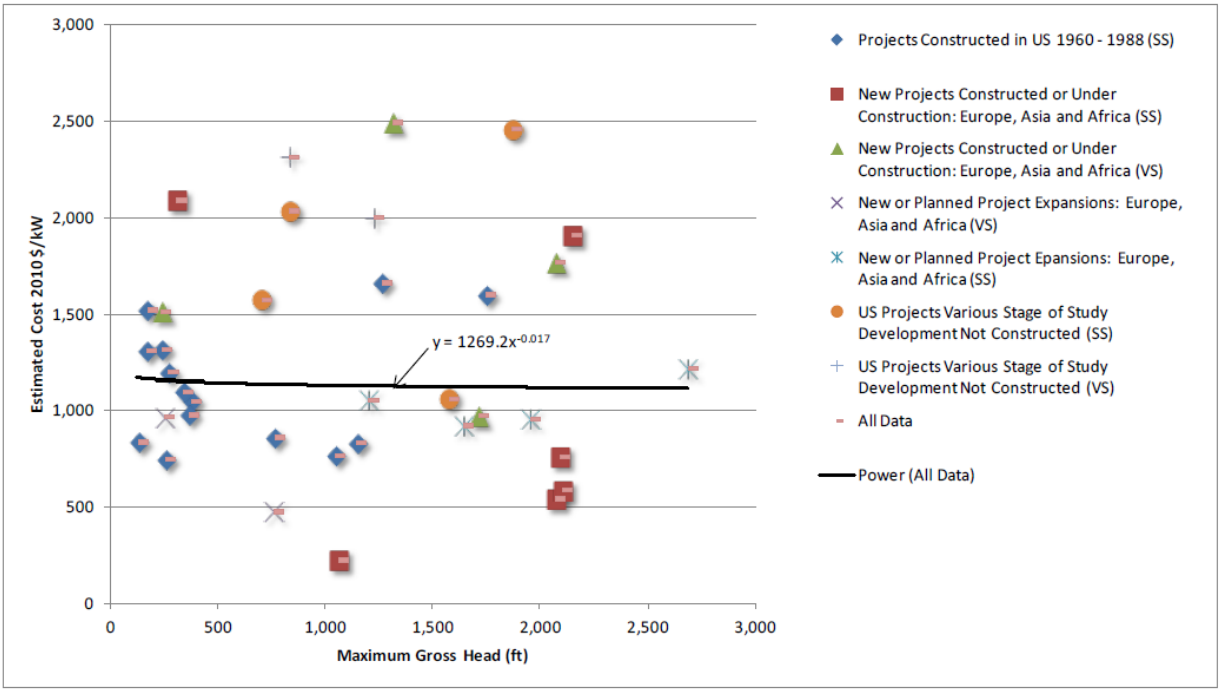


Figure 8 Estimated Capacity Costs for Existing and Proposed PSH Projects as a Function of Head Distance (Source: EPRI 2011)

Other assessments of capital costs can be found in Akhil et al. (2013), who report capital cost estimates for a new PSH project in the $1850-2500/kW range. A recent study on energy storage (Viswanathan et al. 2013) estimates capital costs from available literature and concludes that FS units are likely to cost between $1500/kW and $2500/kW, whereas AS units are in the $1,800–$3,200/kW range. Cost estimates for PSH mainly focus on capital expenses, since costs for operations and maintanace are small in comparison.

3.5.2 Additional Costs for Advanced Technologies

The incremental cost for incorporating AS capability is mainly related to equipment and civil costs. Equipment costs include the motor/generator rotor and stator, rotor excitation system, cooling system for the solid-state devices in the rotor excitation system, rotor-circuit overvoltage protection system, and smoothing reactors. The civil structural costs are for the necessary space to accommodate electrical equipment. The selection of the speed range affects the civil works in the form of additional excavation and civil structural costs associated with the deeper setting of the pump/turbine. Another cost factor is the need for an overhead crane with adequate capacity to lift a rotor made with stacked laminations. The speed range also affects the cost for the rotor excitation AC/DC/AC converter. Greater speed range requires a converter with increased MVA rating.

In terms of overall PSH project cost, an incremental project cost increase in the range of 7% to 15% might be expected if the project is developed as AS rather than FS PSH. Estimates from electrical equipment manufacturers suggest that, compared to an equivalent FS unit, the electromechanical equipment of AS units has about 60% to 100% higher cost. The manufacturing cost of the laminated rotor includes additional effort to test the weight distribution of the assembled rotor for proper balance. Other factors contributing to the increased cost of electromechanical equipment of AS units are the additional power electronics and excitation systems needed to control the DFIM generator.

There is limited experience with ternary PSH plants and units having hydraulic bypass. The cost of a ternary unit with hydraulic bypass is greater than a ternary unit without it. Added costs are associated with civil works, water conductors, and valves to create the hydraulic bypass.

Power conversion equipment is similar to a conventional FS pumped storage with some major differences. Instead of a single reversible pump/turbine, the ternary plant has a separate pump and turbine with a hydraulic torque converter (clutch). Major power conversion equipment that is used for a ternary unit with hydraulic bypass includes the synchronous FS motor/generator, separate pump and turbine, clutch (hydraulic torque converter), and valves. With regard to costs, some hydro industry experts estimate that a new ternary PSH plant would have about 30%–40% higher total capital cost than if the project had been developed as FS PSH.

3.5.3 Economics and Costs of Conversion Projects

The economics of converting an existing FS PSH plant to AS technology are very much project specific as they heavily depend on the plant design and equipment configuration of the existing PSH facility. A detailed study of required modifications to civil structures, the hydraulic profile, electrical systems, and mechanical systems should be conducted to derive a detailed cost estimate for the conversion project. As discussed in previous sections, if significant civil works are required, the conversion project may not be cost-effective.

The potential benefits of the conversion project are also site-specific. The location of the PSH plant in the power system may impact its operation and the value of services that it provides to the power system. For example, a PSH plant located closer to an area with large variable renewable generation (i.e., wind and solar) may be more beneficial than a similar plant at some other location. Similarly, the location of a PSH project in a restructured electricity market may impact its energy and ancillary service revenues, as market clearing prices may vary from zone to zone.

3.6 PSH Compared to Other Energy Storage Technologies

In recent years, interest has grown in other energy storage technologies, and substantial research is being conducted in the United States and internationally into the development of grid-scale energy storage (DOE 2013). Akhil et al. (2013) provide an overview of current storage technologies, including batteries, flywheels, and compressed-air energy storage (CAES). As evidenced by Figure 9, PSH provides higher power ratings and longer discharge times than most other energy storage technologies, with the exception of CAES. However, CAES requires specific geographic conditions and relies, in part, on fossil fuels for its operations, and few CAES plants are in operation today. In contrast, PSH is a proven technology that also compares favorably in terms of cost to most other energy storage solutions (Figure 10). In fact, PSH constitutes 95% of the installed grid-scale energy storage capacity in the United States (DOE 2013) and as much as 98% of the energy storage capacity at a global scale (Patel 2014).

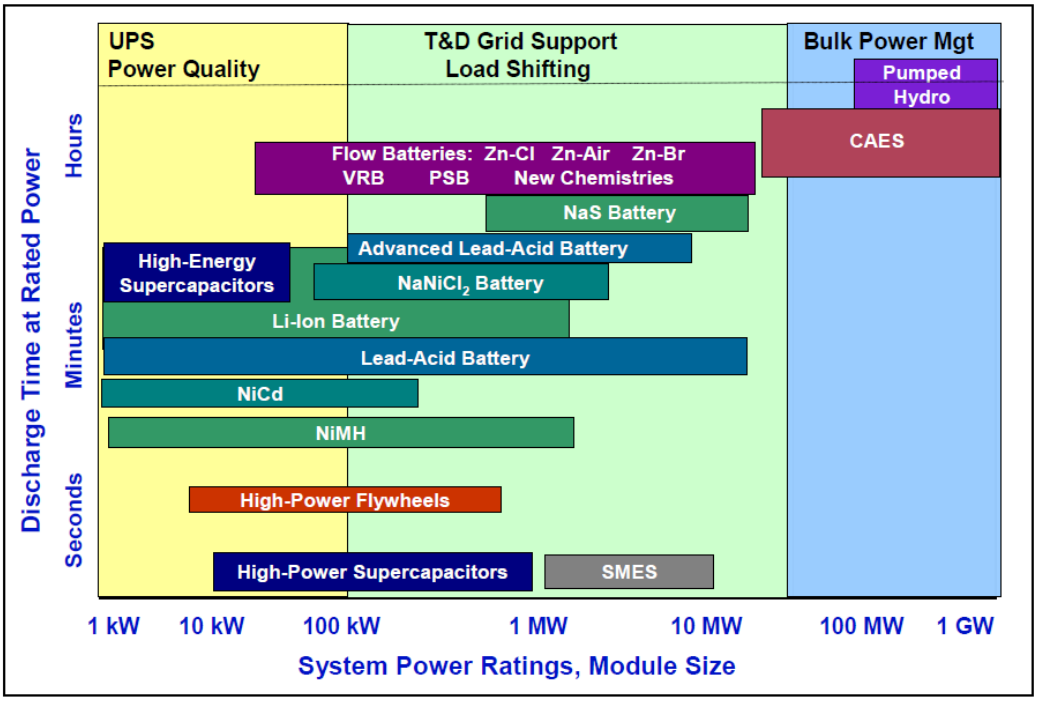


Figure 9 Power Rating vs. Discharge Time for Energy Storage Technologies (Source: Akhil et al. 2013)

3.7 Barriers and Challenges

This section gives a brief overview of barriers and challenges for PSH development that are identified in the literature. Whereas some of the obstacles to development are specific to PSH, others are more general and also apply to other energy technologies.

In a recent white paper, the National Hydropower Association (NHA) discusses challenges and opportunities for development of new PSH. Four main challenges are listed (NHA 2012): (1) environmental issues associated with PSH siting and limited recognition that closed-loop PSH has small environmental impacts, (2) regulatory treatment of PSH, (3) existing market rules and impact on energy storage value, and (4) debate on whether storage is a generation or transmission asset, or if it should be considered a new asset class. The NHA goes on to provide key policy recommendations to facilitate the development of PSH in the United States (NHA 2012):

- Create market products that allow flexible resources to provide services that help meet electric grid requirements, including fast responding systems that provide critical capacity during key periods of energy need.

- Level the policy playing field for PSH with other storage technologies to encourage the development and deployment of all energy storage technologies.

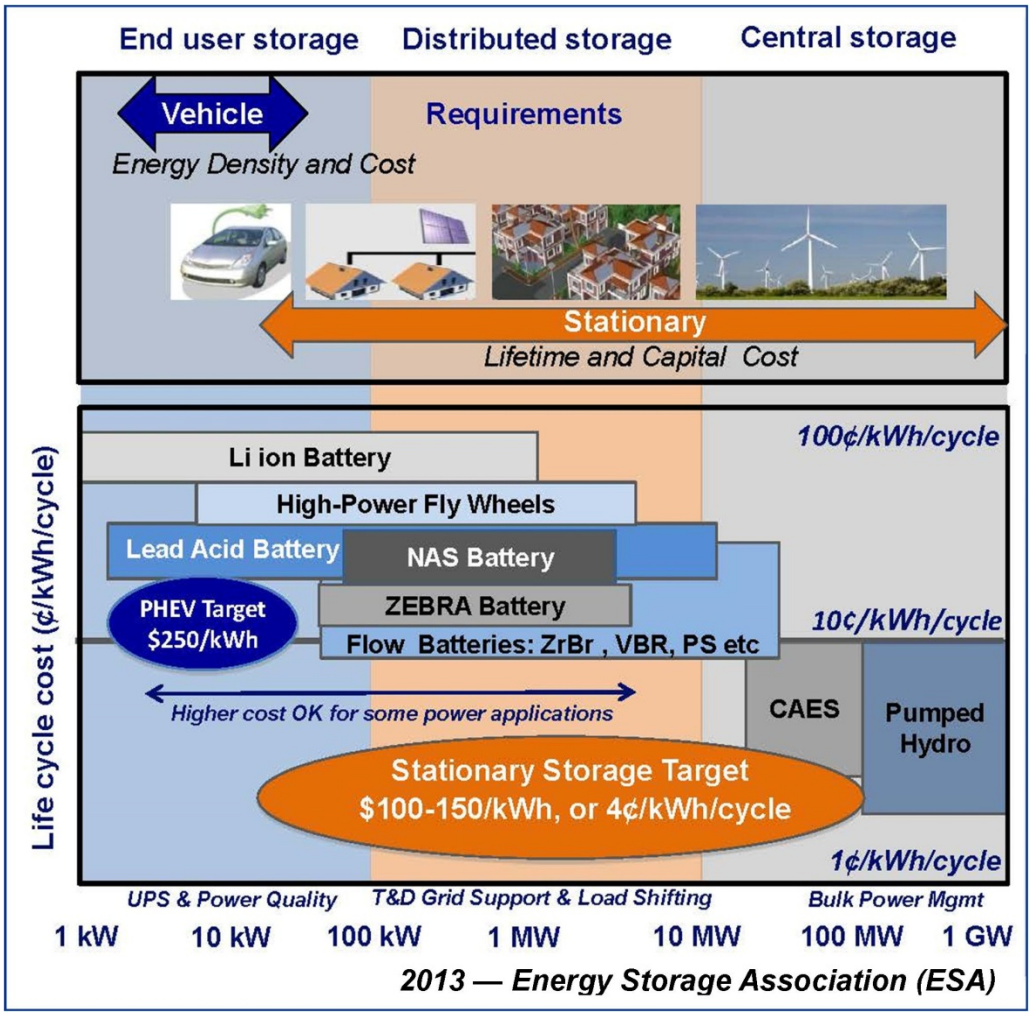


Figure 10 Life Cycle Cost for Different Energy Storage Technologies (Source: Energy Storage Association)

- Recognize the regional differences within the U.S. generation portfolio and the unique roles that energy storage technologies play in different regions.
- Recognize the energy security role PSH plays in the domestic electric grid.
- Establish an alternative, streamlined licensing process for low-impact PSH, such as off-channel or closed-loop projects.
- Improve integration of Federal and state agencies into the early-stage licensing processes for PSH.
- Facilitate an energy market structure where transmission providers benefit from long-term agreements with energy-storage facility developers.

A major concern for PSH project developers has been the long licensing process. This is addressed in HREA 2013, which mandates FERC to investigate the feasibility of issuing licenses to closed-loop PSH projects within 2 years.

The treatment of PSH in current electricity markets in the United States is discussed in more detail in Koritarov et al. (2014), which highlights several market design issues with relevance to PSH as summarized in Table 2.

Table 2 Electricity Market Design Issues Related to PSH (Source: Koritarov et al. 2014)

Issue	Description and Current State
Full optimization in day-ahead markets	Allowing the day-ahead market to schedule the mode of PSH based on minimizing costs over the full time horizon. Currently, PJM is the only market that does this.
Full optimization in real-time markets	Allowing the real-time market to schedule the mode of PSH based on minimizing costs and information that has been updated since the day-ahead market. Currently, no market performs this action in the real-time commitment models.
Lost opportunity costs based on multiple hours for ancillary-service clearing prices	Since the value of PSH depends greatly on its optimal operation over longer time periods (typically at least a day), the lost opportunity costs of its water resources are highly complex. Pricing mechanisms should account for situations where providing ancillary services in one hour results in a lost opportunity to provide energy in another.
Make-whole payments for PSH operation	If PSH units are fully optimized in the market by the independent system operator (ISO), the owner/operators should be given guarantees that if they follow schedules that are given by the ISO, they will not incur operational losses, similar to the rules that apply to conventional generators. This should apply if PSH plants end up paying more during pumping operation than is gained during generating operation.
Settlements based on sub-hourly time intervals	If financial settlements are based on sub-hourly prices, the PSH plant will have opportunities to use its fast response to meet real-time pricing swings that can greatly benefit the system. With settlements based on hourly prices, PSH and other resources have little incentive to respond to sub-hourly prices, only to follow the average hourly price. Few ISOs settle sub-hourly, while all calculate sub-hourly prices as part of the real-time dispatch.
Pay for performance for regulating reserves	PSH can improve system reliability by providing regulating reserves that respond faster than those provided by many other technologies. PSH could therefore earn additional revenue if reserve payments were based on quality of performance. All of the ISOs have modified rules in response to FERC Order 755 and are beginning to implement design modifications related to a pay-for-performance market.

Table 2 (Cont.)

Issue	Description and Current State
Market and pricing for primary frequency response	Primary frequency response is a service that is not necessarily incentivized in current electricity markets. It could be an additional revenue stream for PSH, especially given that AS PSH units are particularly suited to provide primary frequency response.
Market and pricing for flexibility reserves	Different types of flexibility reserves are being proposed in the Midwest and California ISOs and are also discussed more broadly throughout the industry to address the operational challenges from renewable energy. Such new services can bring additional revenues to PSH plants, especially AS PSH, which can provide reserves during both the generation and pumping modes.
Market and pricing for voltage control	There are currently no markets for voltage control in the United States, only cost recovery mechanisms. A pricing mechanism for voltage control could bring additional revenues to PSH.
Capital cost compensation	Financing long-lived resources with high capital costs and low operating costs is difficult without a firm long-term commitment, regardless of how worthwhile a project is for rate payers. Existing capacity markets, where they exist, cover only a portion of capital costs and only offer annual commitments at most. Treating PSH as a regulated, rate-based, transmission-like regulated resource under system operator control might be beneficial by providing more certainty to PSH investors.

Along similar lines, a recent EPRI study (2013) discusses four ways to increase the value of hydropower and PSH plants in electricity markets:

- Settle energy markets sub-hourly, increasing conventional and PSH energy arbitrage opportunities with load-leveling benefits based on grid demand.
- Have the ISO or regional transmission organization (RTO) schedule hydro to co-optimize energy and ancillary services within a balancing authority.
- Treat PSH as a new storage asset class capturing the full value of services and improving the economics in areas with resource constraints.
- Credit hydro for its very fast regulation response in situations where resource adequacy is a power-system reliability issue.

More general challenges for energy storage technologies are also frequently discussed in the literature. These challenges apply to PSH as well as the suite of other energy storage technologies being considered for grid applications. For instance, in a recent report, Ecofys (2014) argue that utilities and regulators desiring to compare the economics of energy storage with traditional generators face some special challenges:

- Storage acts as both generation and load.
- Generation is limited by the available energy in storage.
- Value proposition can span across generation, transmission, and distribution systems ("value stacking").
- Many technologies have undergone limited commercialization.
- Value proposition includes sub-hourly benefits that may not be captured with standard power system models or methods.
- Standardization and interoperability of communications and controls with existing utility control and communications systems are lacking.

Finally, in a recent study by DOE (2013) four main barriers for energy storage technologies are listed: (1) cost-competitive energy storage systems, (2) validated performance and safety, (3) equitable regulatory environment, and (4) industry acceptance.

3.8 Case Studies

Internationally, several AS PSH plants have been developed since the first installation in 1987. Table 3 and Table 4 summarize the AS PSH units that are in commercial operation and various stages of design and construction, respectively. Most of the developments so far have been in Japan. Japanese and European manufacturers that have supplied pump/turbines, motor/generators, rotor excitation, and control systems for AS PSH plants include Toshiba, Hitachi, Mitsubishi, Andritz, Alstom, Converteam/GE, ABB, and Voith. Below, we present a brief overview of three PSH plants with advanced technologies.

Table 3 Existing AS PSH Units (Source: Koritarov et al. 2014)

Plant Name	Country	Utility Name	Service Date	Pump (MW)	Generator (MVA)	Speed Range (rpm)	Synchronous Speed (rpm)	Frequency (Hz)	Speed Range (%)	AFC Type
Narude, No. 2[a]	Japan	Kansai EPCo	1987	18.5	22	190-210	200	60	+/- 5	Cyclo – C
Yagisawa, No. 2[b]	Japan	TEPCO	1990	53-82	85	130-156	150	50	+ 4/- 13	Cyclo – C
Takami, No.2	Japan	Hokkaido EPCo	1993	44-140	103	200-254	230.8	50	+/- 10	GTO inv
Okawachi, No.2	Japan	Kansai EPCo	1993	331-392	395	330-390	360	60	+/- 8	Cyclo – C
Okawachi, No.4	Japan	Kansai EPCo	1995	240-400	395	330-390	360	60	+/- 8	Cyclo – C
Shiobara, No. 3[c]	Japan	Kansai EPCo	1995	200-330	360	356-394	375	50	+/- 8	Cyclo – C
Okukiyotsu No. 2 PH	Japan	EPDC	1996	212-340	345	407-450	428.6	50	+/- 5	GTO inv
Yanbaru No. 1[d]	Japan/ Okinawa	EPDC	1999	1.5-31.5	31.5	423-477	450	60	+/- 6	GTO inv
Goldistahl, No. 1	Germany	VEAG	2002	170-300	351	300-346.6	333	50	+ 4/- 10	Cyclo – C
Goldistahl, No. 4	Germany	VEAG	2002	170-300	351	300-346.6	333	50	+ 4/- 10	Cyclo – C
Omarugawa, No. 4	Japan	Kyushu EPCo	2007	310	340	576-624	600	60	+/- 4	Cyclo – C
Omarugawa, No. 3	Japan	Kyushu EPCo	2008	330	345	576-624	600	60	+/- 4	GCT inv
Omarugawa, No. 1	Japan	Kyushu EPCo	2010	330	350	576-624	600	60	+/- 4	GCT inv
Omarugawa, No. 2	Japan	Kyushu EPCo	2011	330	345	576-624	600	60	+/- 4	Cyclo – C
Avce, No. 1	Slovenia	SENG	2012	125-180	195	576-636	600	50	+ 6/- 4	GCT inv

[a] Pilot project to test excitation and controls for adjustable speed doubly fed machine
[b] Conversion from single speed to adjustable speed
[c] Formerly named Sabigawa
[d] Seawater pilot project

TEPCO = Tokyo Electric Power Company
GTO inv = Gate Turn-off Thyristor inverter
PH = Powerhouse
EPDC = Electric Power Development Company (Japan)
VEAG = Vattenfall Europe Generation (Germany)
GCT inv = Gate Commutated Thyristor inverter
SENG = Soske Elektrarne Nova Gorica (Slovenia)

Table 4 AS PSH Units in Various Stages of Construction and Installation (Source: Koritarov et al. 2014)

Plant Name	Country	Utility Name	Service date	Pump (MW)	Generator (MVA)	Speed Range (rpm)	Synchronous Speed (rpm)	Frequency (Hz)	Speed Range %	AFC Type
Kazunogawa, no.3	Japan	TEPCO	2014	460	475	475-525	500	50	+/- 5	GTO inv
Kazunogawa, no.3	Japan	TEPCO	2015	460	475	475-525	500	50	+/- 5	GTO inv
Kyogoku, no.1	Japan	Hokkaido EPCo	2015	230	230	475-525	500	50	+/- 5	IEGT inv
Limmern	Europe	Axpo/Glarus	2015	250	280	470-530	500	50	+/- 6	IGBT VSI
Venda Nova/Frades	Portugal	EDP	2015		445		375	50		
Nant-de-Drance	Switzerland	Alpiq/SBB	2016	154.7	170	399-459	428.6	50	+/- 7	IGBT VSI
Tehri	India	THDC	2015	250	259	214-250	230.8	50	+/- 8.3	TBD

TEPCO = Tokyo Electric Power Company
GTO inv = Gate Turn-off Thyristor inverter
IEGT inv = Injection Enhanced Gate Transistor inverter
IGBT VSI = Insulated Gate Bipolar Transistor Voltage Source Inverters
EDP = Energias de Portugal
TBD = To be determined

3.8.1 Japan: An Early Adopter of AS PSH

Japanese utilities were the first to develop AS PSH on a large scale, and today the majority of existing AS units are located in Japan. Development of these units began in the late 1980s and continued through the 1990s, the motivation being the increased need for frequency regulation as more nuclear generation units were brought online and government regulation led to reduced reliance on imported fossil fuels (EPRI 1995). The first AS PSH project in Japan, and in the world, was a 22 MW pilot installation by the Kansai Electric Power Company (KEPCO) at the existing Narude hydroelectric facility. This new unit commenced operation in 1987 and utilized a motor/generator with a cylindrical rotor and a three-phase wounded rotor. Recognizing their increasing need for frequency regulation and based on the success of the Narude pilot project, KEPCO proceeded with development of two full-scale AS units at Okawachi, a new facility where two other FS units were also developed. Kansai Electric Power determined that upgrading existing FS units to AS technology was not economic due to the significant costs of expanding underground powerhouses in existing facilities. The AS units at Okawachi each have a capacity of 395 MW in the pumping mode and 320 MW in the generation mode and are capable of operating at +/- 8% of synchronous speed (360 rpm). They can each provide up to 102 MW of frequency regulation in the generation mode and 80 MW in the pumping mode. These units were developed almost entirely for their ability to provide frequency regulation and the unit sizing was largely based on the corresponding economics and demand for this service. The first AS unit at Okawachi commenced operation in 1993 and the second in 1995. Tokyo Electric Power Company (TEPCO) also recognized the increasing demand for frequency regulation and similarly began development of AS PSH resources in the 1990s. Their first installation was a unit at the Yagisawa plant in 1990. The AS unit has a capacity of 87.4 MW in the pumping mode and 77 MW in the generation mode and can operate at +4% to -13% of synchronous speed (150 rpm). The unit provides frequency regulation over the range of 53 MW to 82 MW when operating in the pumping mode. Tokyo Electric Power developed their second AS unit at Shiobara in 1996, which has a capacity of 309 MW in the pumping mode and 360 MW in the generation mode and can be operated at +/- 8% of synchronous speed (375 rpm).

3.8.2 Goldisthal (Germany): The First AS PSH in Europe

Goldisthal (Figure 11) is an AS pumped storage facility on the Schwarza River in Thuringia, Germany, that has approximately 1,060 MW of pumping and generating capacity. The facility commenced operation in October 2004 after a prolonged development period. Plans for the project were initially generated in the early 1980s, but they were put on hold for economic reasons. The approval process for the project was revitalized in the early 1990s, construction commenced in 1997, and the facility began operations seven years later (Beyer 2007).

Goldisthal has four 265-MW Francis pump turbines, two of which have AS asynchronous motor/generators and two of which have synchronous motor/generators. The choice of synchronous and asynchronous units was based on several factors, including the demand for controlled pumping at the time of construction, the desire to maintain black-start capability through the synchronous units, and the perceived risk of asynchronous units. At the time asynchronous pumping units were relatively unproven and not used anywhere in the world; in

fact, Goldisthal was the first such large-scale implementation of this technology in Europe. The AS units can be started more quickly and are 10% more efficient than the fixed output units when operating at partial load, and they also operate over a wider head and flow range. In the generation mode, the two synchronous units can generate from 100 to 265 MW of power while the asynchronous units can generate from 40 to 265 MW. The lower minimum operating level saves water during periods of low demand and allows each unit to provide an additional 60 MW of regulation. In the pumping mode, the synchronous units are not controllable, while the asynchronous units can operate between 190 MW and 290 MW, offering 100 MW of control power per unit. The AS units have lower maintenance costs due to the smaller starting and brake load operations; however, they are subject to more frequent and lengthier inspections. The storage capacity of the upper reservoir in the system is 12 million cubic meters, while that of the lower reservoir is 18.9 million cubic meters. The reservoirs are connected by two 6.2-meter head race tunnels and two 8.2-meter tail race tunnels that cover a 301-meter hydraulic head. The project was completed at a total cost of 623 million euros, with most equipment provided by Voith Hydro.

Figure 11 Goldisthal AS PSH plant in Germany (Photo Credit: Vattenfall)

3.8.3 Le Cheylas (France): Upgrading from FS to AS PSH

Le Cheylas is a 480-MW PSH facility in the French Alps that commenced operation in 1979 as an FS PSH facility (Figure 12). The elevation drop between the upper reservoir, Bassin du Flumet, and the powerhouse is 261 meters, and the power plant empties into Bassin du Cheylas. Currently, one of its two 240-MW units is being upgraded to AS. Once completed, Le Cheylas will provide 70 MW of additional night-time regulation capability, which will allow the integration of more renewable generation into the power grid. The upgrade will also improve operational efficiency of the unit, increasing the generation output by 45 GWh per year. The current unit will be taken offline in 2016 to implement the upgrade, and operation of the new unit is planned to commence in 2017. The main technical issues faced by the conversion include space optimization for new equipment in the existing powerhouse and a 25% increase in rotor

weight that will intensify mechanical loads on the system. Mechanically, the runner and wicket gates will be exchanged while the existing draft tube, staying ring, and spiral casing will remain in place for economic reasons (Lefebvre et al. 2014).

Alstom leads the conversion project at Le Cheylas, and the facility is owned and operated by EdF. The upgrade is funded in part by a $21 million grant from the European Commission through its eStorage project (http://estorage-project.eu/), a collaborative effort between Alstrom, EdF, the transmission system operator Elia, two consultancies (DNV Kema and Algoe), and the Imperial College of London. The upgrade at Le Cheylas will demonstrate a proof of concept for AS PSH upgrades in Europe, and the lessons learned from this project may enable similar upgrades of over 75% of European PSH capacity, with the goal of eventually providing up 10 GW of low-cost regulation capacity with low environmental impact.

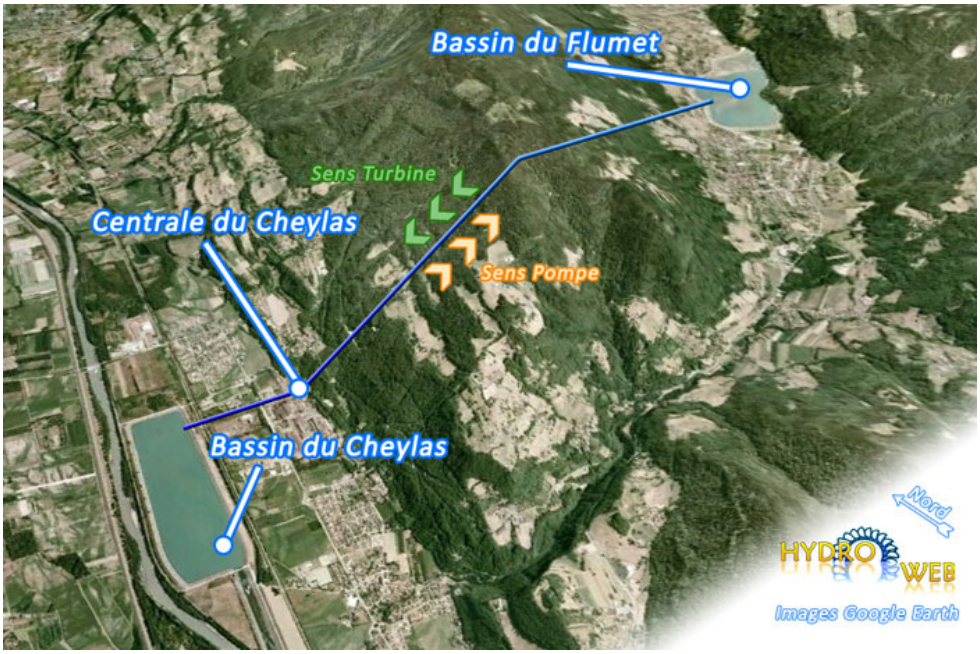


Figure 12 Le Cheylas PSH plant in France (Photo Credit: http://estorage-project.eu/)

3.8.4 Kopswerk II (Austria): Ternary PSH

Kopswerk II is a ternary pumped storage facility on the Ill River in Vorarlberg, Austria, that has 525 MW of generation capacity and 450 MW of pumping capacity. This project was a major addition to the Austrian hydroelectric system, increasing hydropower capacity by 42% and pumping capacity by 85% at the time it commenced operations in May 2009. It adjoins Kopswerk I, a conventional 247 MW hydroelectric facility. Kopswerk II consists of three units, each one containing a 150-MW storage pump and 175-MW Pelton turbine and a starting converter. This facility differs from AS PSH facilities in that it maintains a pumping mechanism separate from the generating turbine, and does not use reversible pump/turbines. A hydraulic bypass allows both the pump and the turbine to operate simultaneously, allowing shorter

response times and increased operational flexibility. The units have a response time of less than 20 seconds, operate at a speed of 500 rpm, and can accommodate up to 60 load changes each day. The system can also utilize a hydraulic short circuit to provide regulation at 100% of capacity in either direction (generation or pumping). The facility was constructed over a four year period at a total cost of 400 million euros ($568 million) and is operated by Vorarlberger Illwerke AG. Voith Hydro supplied the major equipment for this project while Kuenz provided design and equipment for the draft tube gate. Water flows through a head of 818 meters from Kops Lake to the Rifa reservoir, or vice versa, at a maximum flow rate of 160 cubic meters per second in either direction. Kopswerk II was the first major pumped storage investment in Austria after market liberalization in the early 2000s (HydroWorld 2009).

4 Capability of PSH to Provide Grid Reliability and Support Renewable Generation

4.1 Grid Operations, Electricity Markets, and Impacts of Renewable Energy

The electric power grid is a very complex engineering system, where generation must be balanced continuously with loads to maintain frequency and stability. A number of different control and operational problems must be addressed towards this end in time frames ranging from microseconds to days (Figure 13). In the very short term, grid harmonics and stability are addressed through system control and automated response actions. In the middle time frame, regulation and dispatch actions are employed to maintain system frequency and balance supply and demand. At longer timescales, the challenge is to schedule sufficient resources to handle variability and uncertainty in the load and supply resources in a cost-effective manner. Increasing amounts of renewable energy add to the existing uncertainty and variability in the system, and the impacts are typically most significant in the middle range of the operational time frame, as indicated in Figure 13. PSH can contribute towards meeting all the control and operational challenges in Figure 13 and this is discussed in more detail in Section 4.2, where we also point out potential impacts of renewable energy on the system-balancing challenges.

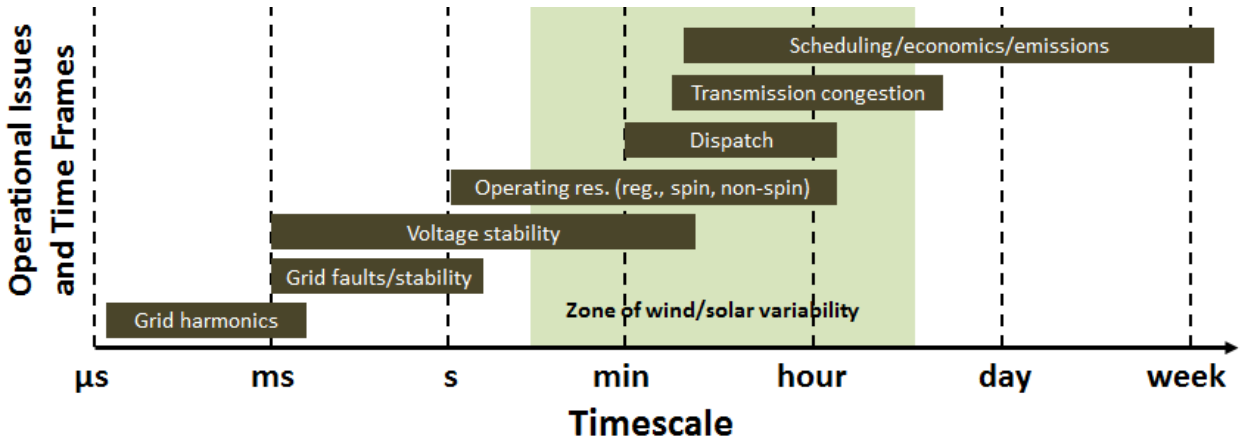


Figure 13 Overview of Issues in Power System Operations and Control (adapted from Fisher et al. 2012)

At a high level, the main objective for power system operators is to ensure that demand for electricity is met and to maintain system reliability in a cost-efficient manner. This is the case regardless of whether it is a traditional regulated utility system or a restructured electricity market. However, approaches towards achieving this goal differ. In regulated utilities the focus is on minimizing total cost, as dictated by rules enforced by regulatory agencies (e.g., FERC or state utility commissions). In contrast, regions with restructured electricity markets focus on unbundling different parts of the system (generation, transmission, and distribution) and creating competitive markets for individual products where such is possible (e.g., energy, operating

reserves). Today, two-thirds of electricity consumers in the United States are served by electricity markets with multiple competing market participants and an ISO or RTO in charge of operating the system (Figure 14). The main steps in the daily operation of ISO/RTO markets are illustrated in Figure 15. At the day-ahead (DA) stage, the ISO/RTO takes bids from consumers and offers from generators and clears the market in a process that includes security-constrained unit commitment (UC) and economic dispatch (ED). The process considers the projected needs for both energy and operating reserves for the next day, and calculates market prices for both products through so-called co-optimization. Energy prices are calculated for each individual node in the transmission network (i.e., locational marginal prices or LMPs), whereas zonal prices are typically used for operating reserves. The resulting schedules and prices are communicated to the market participants. After the DA market, the ISO/RTO will take actions as needed to commit additional resources if unexpected events unfold such as higher loads or lower generation from renewable resources than originally forecasted. This is called the "reliability unit commitment." Finally, the real-time (RT) market balances the system with RT prices and dispatch schedules for energy and reserves calculated every five minutes in current ISO/RTO markets. Generators are paid the DA prices for the DA schedule, whereas any deviations are settled at the RT prices. Certain incentive and penalty schemes are also in place to ensure that market participants offer their resources to the DA and RT markets and follow their dispatch instructions. Other markets may also exist in addition to the energy and operating reserve markets. For instance, financial transmission rights offer the possibility of hedging against congestion in the transmission grid and corresponding differences in LMPs at various locations. Some ISO/RTOs also have capacity markets that provide an additional revenue stream to generators or demand resources to ensure capacity adequacy in the long run.

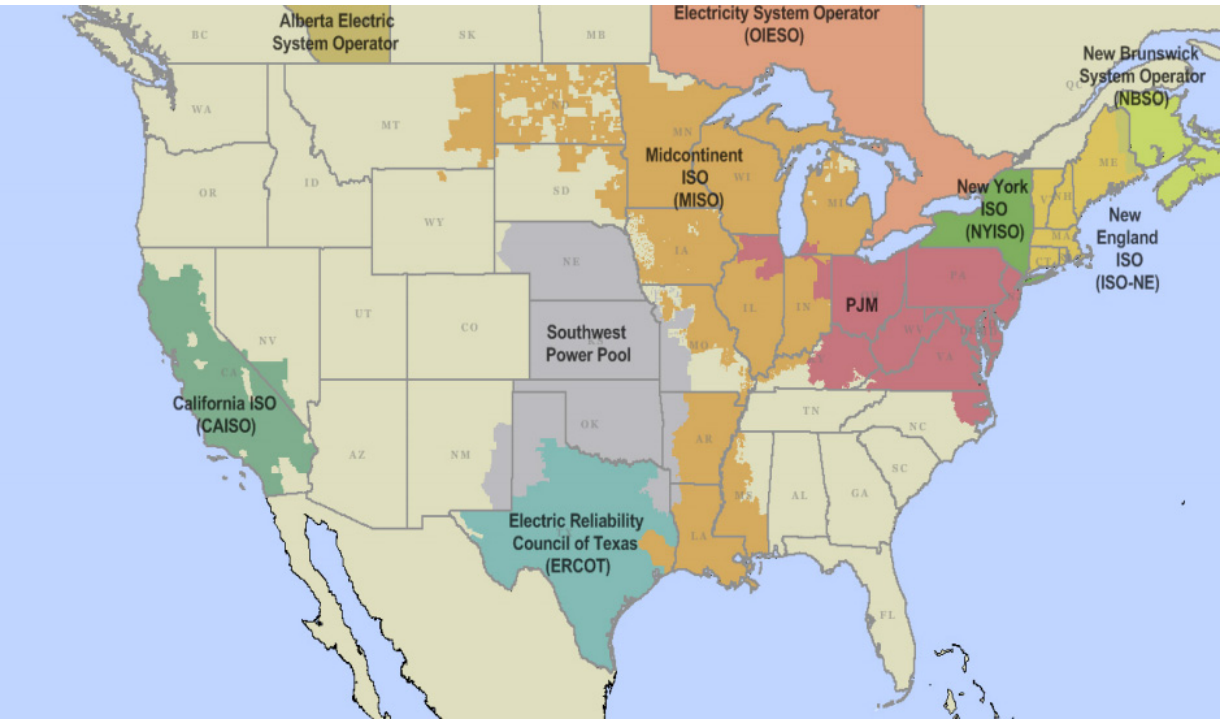


Figure 14 Regions in North America with Electricity Markets Operated by ISOs or RTOs (Source: FERC).

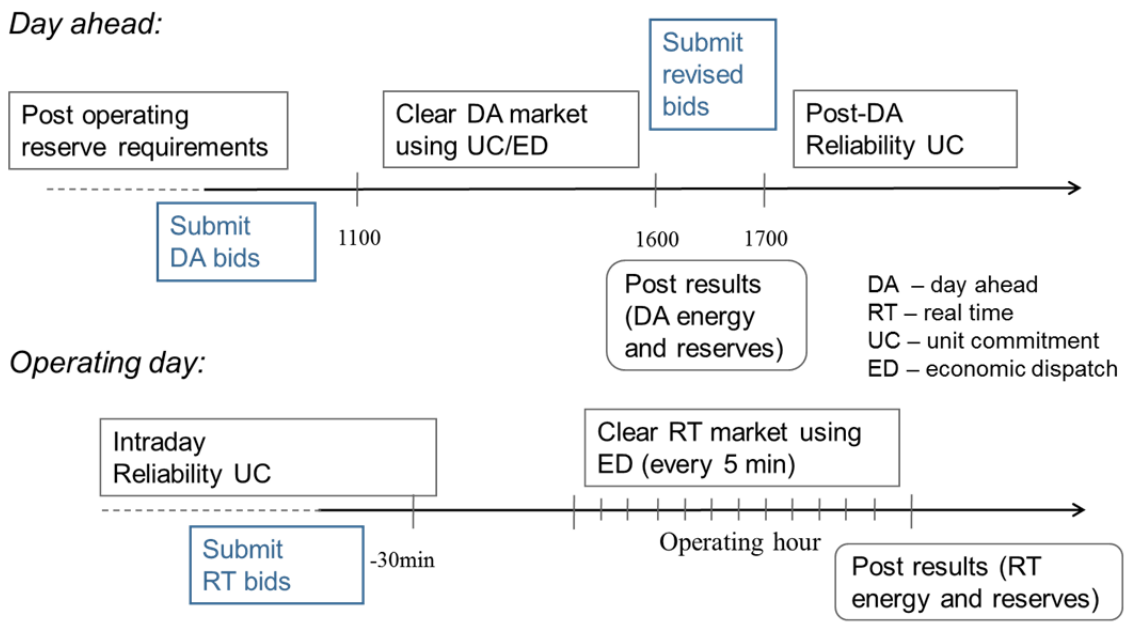


Figure 15 Main Stages in Electricity Market Operations with Day-Ahead (DA) and Real-Time (RT) Markets for Energy and Operating Reserves (Timeline from MISO)

The basic economics of power system operations are the same in regulated and restructured areas. The lowest cost generators are scheduled to reliably serve the expected load and then operated to meet the actual load based on security-constrained UC and ED. In regulated areas, generator marginal costs are used, while in restructured market areas, generator bid prices are used as inputs to the optimization process. In well run markets, without the presence of market power, the bid-based offers should be close to marginal costs. Although PSH serves the same basic functionalities towards balancing the grid in regulated systems and competitive markets, the compensation schemes vary. In regulated systems, the focus is on minimizing the total cost of operating the system. Hence, PSH is evaluated based on its contribution towards reducing system costs. In contrast, in restructured electricity markets, PSH and other market participants are compensated mainly through the market prices for energy and reserves. Hence, the combined revenues from energy arbitrage and provision of ancillary services along with contributions from any other incentive schemes (e.g., capacity markets) must be sufficient to cover the cost of building and operating the plants. Electricity markets make pricing and compensation for certain products and services more transparent, which should be an advantage for investors in PSH and other technologies. However, not all contributions of PSH to grid operations and reliability are priced in current electricity markets. Moreover, a large PSH plant (or other storage facility) is likely to impact energy prices and reduce the potential for energy arbitrage that it was initially targeting. Hence, incentive schemes and resulting PSH expansions are likely to differ in regulated and restructured systems. The challenges faced by PSH under current regulatory structures are discussed in more detail in Section 3.7.

The rapid increase in renewable generation significantly impacts how power systems and electricity markets are operated. In particular, the variability and forecast uncertainty in wind and solar resources create new challenges for system operators and market participants. To some extent, this can be addressed by the use of forecasting at the various stages of electricity market operations (Botterud et al. 2010). However, although the accuracy of wind and solar forecasting has improved rapidly in recent years, significant forecasting error remains due to the complex nature of these renewable resources. One consequence is the need for additional operating reserves to balance the system. Traditionally, operating reserves are defined as "That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection" (NERC 2014). The most common operating reserve products traditionally scheduled and priced in U.S. electricity markets include regulating reserves as well as spinning and non-spinning contingency reserves (Figure 16). The impacts of renewable energy on the needs for operating reserves are discussed by Ela et al. (2011), who provide a wider definition of operating reserves, which includes categories such as following and ramping reserves that are currently not directly scheduled and priced in most U.S. electricity markets (Figure 17).[3] In general, the increased forecast uncertainty and variability from renewable resources will likely lead to higher reserve requirements to accommodate expected and unexpected outputs from those resources. In turn, this situation is likely to lead to higher prices for such services, thereby creating an increased opportunity for PSH. As discussed later in this chapter, the ability of PSH to provide operating reserves depends on the technical capabilities of the plant. Conventional FS pumped storage plants typically cannot provide regulation or spinning reserves while pumping, and usually also not when idle. However, AS PSH plants can provide both regulation and spinning reserves while in the pumping mode and also when idling in the condensing mode (i.e., when the turbine is spinning in air without water flow) with the turbine spinning in air. In the generation mode, both FS and AS technologies can provide regulation and spinning reserves when generating below full capacity. All PSH plants can provide non-spinning reserve when idle as long as they are able to startup within 10 to 30 minutes, depending on the ancillary service requirements of the specific region.

Renewable energy also affects the electricity markets beyond its forecasting errors and the corresponding increased need for operating reserves. For instance, wind and solar power have essentially zero marginal cost, which could lead to lower energy prices on average. Moreover, increased price volatility is likely to follow from the high variability in these resources. These price impacts may potentially lead to revenue insufficiency and inadequate investment signals for PSH as well as other technologies operating in the power grid, unless the incentives within current or proposed new market structures provide enough incentives for operations and investments. For an in-depth discussion on the general impacts of renewable energy on electricity market design, see Ela et al. (2014). The treatment of PSH in electricity markets is discussed in more detail in Koritarov et al. (2014).

[3] However, CAISO and MISO have recently both introduced flexible reserve products to address unexpected ramping events, similar to the "ramping reserve" in Figure 17.

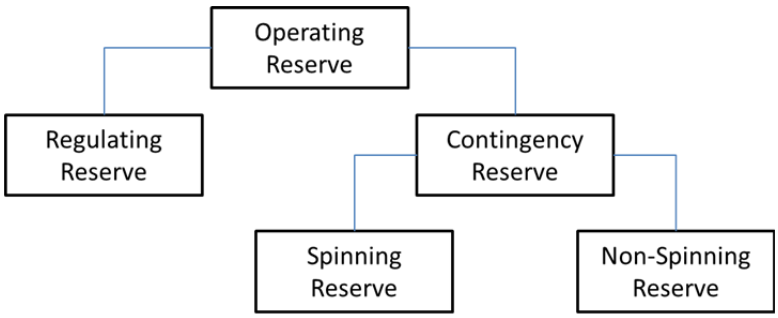


Figure 16 Operating Reserve Products Typically Traded in Current U.S. Electricity Markets

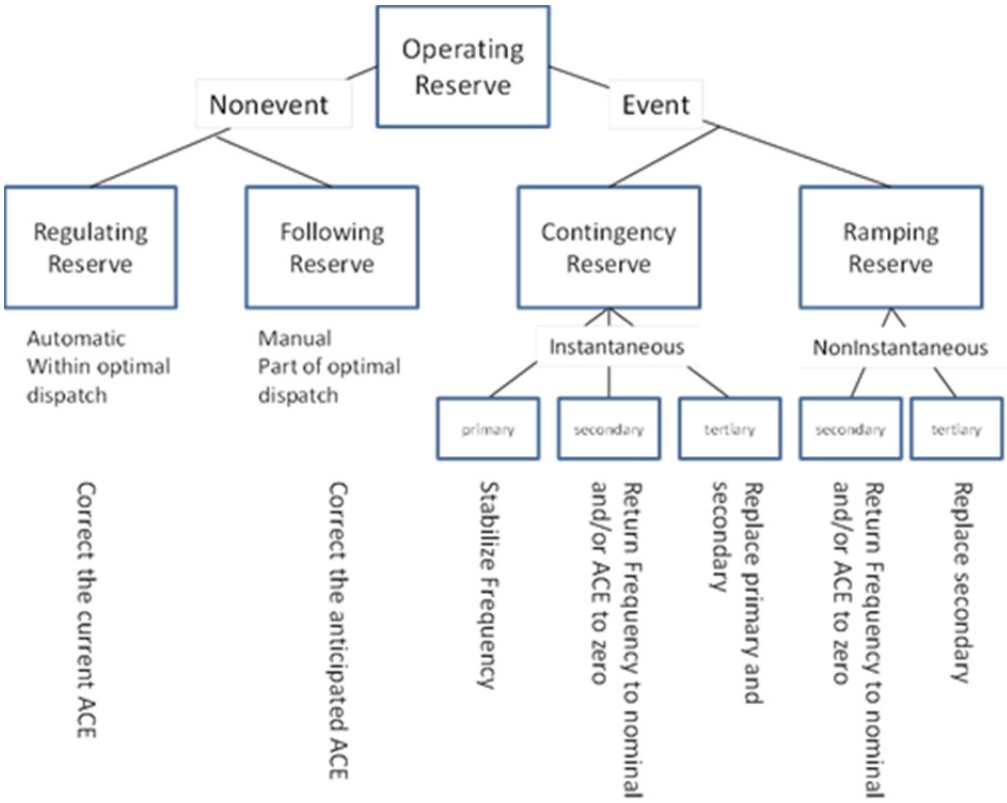


Figure 17 Overview of Operating Reserves and Their Contribution to Balancing the System (Source: Ela et al. 2011, reprinted with permission by the National Renewable Energy Laboratory, from NREL publication: http://www.nrel.gov/docs/fy11osti/51978.pdf)

4.2 Services and Contributions of PSH to the Power System

Pumped storage hydropower plants are versatile facilities that provide many benefits to the power system. This section gives an assessment of PSH benefits to the power grid and discusses how such plants can contribute to grid reliability and more efficient integration of renewable energy.

4.2.1 Overview of Main PSH Contributions

Table 5 lists key PSH services and contributions to the power grid. As is the case with any energy storage technology, PSH plants are net consumers of energy as their electricity generation is smaller than the electricity consumed for pumping. Despite that net energy loss, PSH plants are still valuable, as they can shift large quantities of energy for later use, based on the daily load pattern and price differentials between the peak and off-peak hours. Moreover, PSH plants provide a variety of additional services necessary for power system operation. Table 5 also summarizes how different PSH technologies can contribute towards different needs in the power grid and, when applicable, identifies how a large-scale expansion of renewable energy (RE) is likely to change the need for those services in the system. A more detailed discussion of the contributions of PSH towards the different challenges of power system operations is provided in Koritarov et al. (2014).

Table 5 Overview of PSH Services to the Power Grid

Characteristic	PSH Contribution
Inertial response	This response is provided by the rotating mass in generators, which arrests the initial grid frequency decay following a system imbalance event. Most wind and solar technologies do not provide inertial response, and the need for such services from other generators is, therefore, likely to increase with higher RE penetrations. FS and ternary PSH units provide inertial response directly through their rotating generators. AS PSH units can provide inertial response through power electronic converters.
Governor response, primary frequency control	Response to frequency deviations in the grid occurs through governor control actions. Conventional generators (e.g., steam turbines, gas turbines, and hydro plants) all have operating governors. There is a concern of lower availability of governor response because more generators are operating at maximum output, and RE penetration is increasing. The capability of AS and ternary PSH to supply frequency control in both pumping and generation modes is superior to that of FS PSH units, which can supply primary frequency regulation only when generating.

Table 5 (Cont.)

Characteristic	PSH Contribution
Dynamic stability	Stability of the power system is achieved by its generators regaining an equilibrium operating condition with synchronism across the system after being subjected to a physical disturbance. Stability is system dependent, as it is influenced by the synchronous machines and their controls. FS and ternary PSH units employ conventional generators and have similar characteristics with respect to stability as conventional generators. AS PSH units employ power electronics; thus, their controls and capabilities can be designed for improved performance under particular disturbances.
Voltage support	The power system voltages must be controlled to within a tight band for all equipment and devices in the grid to function properly. Voltage control is usually a local issue. System voltages are controlled by supply of reactive power from generators or other system devices, such as capacitor banks, synchronous condensers, and power electronic devices (e.g., static VAR compensators). FS and ternary PSH units employ conventional generators and have similar voltage support capabilities to conventional generators of the same size. AS PSH units employ power electronics, which can be designed to provide voltage support beyond the capabilities of conventional generators of the same size.
Load leveling/energy arbitrage	Energy arbitrage refers to the operation of energy storage facilities, including PSH, by generating electricity when demand and/or electricity prices are high, and consuming electricity when demand and/or prices are low. From a system's perspective, this load leveling is advantageous since it reduces the need for peak load generation and capacity from other resources. RE tends to create more variability in both load and prices. All PSH plants can earn revenues from the differences between peak and off-peak prices.
Generating capacity	The capacity of PSH plants contributes to meeting the peak demand in the power system, thereby reducing the need for capacity from other resources. Capacity contributions from PSH may, therefore, reduce total system costs. Moreover, the high flexibility of PSH operations and the ability to quickly switch between pumping and generation mean that, in many situations, a PSH plant can provide twice its capacity to meet system ramping needs. System ramping needs tend to be increased by the expansion of RE. All PSH plants can provide generation capacity and also participate in capacity markets, which represent an additional source of revenue for such resources.

Table 5 (Cont.)

Characteristic	PSH Contribution
Environmental emissions	The impact of PSH on power system emissions depends on what type of generation is being used during pumping and displaced during generation. Hence, systems with a traditional thermal mix using coal-fired plants for base load and gas-fired plants for peak load are not likely to see emissions benefits, although PSH may lead to fewer emissions due to cycling and startups. In contrast, systems with a high share of RE will likely see emission reductions due to PSH, since surplus generation from wind and solar can be used for pumping purposes instead of being wasted. Moreover, the flexibility of PSH, particularly AS and ternary units, will help facilitate more RE in the grid, thereby reducing emissions in the long run.
Cycling and ramping of thermal units	The flexibility of PSH capacity, its fast ramping characteristics and load-leveling operation, creates a flatter net load profile for thermal generating units. This allows these units to operate in a steadier mode, thus reducing the need for ramping and frequent startups and shutdowns. Ramping and startups incur significant costs due to operation at reduced efficiencies, burning of additional startup fuels, and increased wear and tear. This capability is particularly important in systems with high shares of RE, which tend to increase the overall variability in the net load profile for thermal plants.
Transmission congestion	The added flexibility from PSH to the overall scheduling and dispatch of system resources will influence the power flows in the transmission network. Depending on its location, a PSH plant may reduce transmission congestion and improve utilization of transmission assets. In turn, strategically located PSH plants may reduce the need for investments in new transmission capacity.
Black-start capability	In the rare case of a widespread blackout in the power grid, system restoration must begin from generating units with the ability to start themselves. These units, called “black-start” units, are then used as the kernels to begin the restoration process, starting by picking up transmission connected to this unit and emanating outward towards the critical system load. FS and ternary PSH units are good candidates to provide black-start service. This capability is more of a challenge for AS units, as they employ power electronics which require an external source of power that would likely not be available under black-start conditions.
Energy security	In a future scenario with greater electrification of transportation, PSH may contribute towards de-carbonization and reduce reliance on imported fossil fuels in the transportation sector. Hence, PSH may also contribute towards national energy security goals.

The value of PSH services and contributions to the grid depends on many factors, including their location in the system, the capacity mix of other generating technologies, the level of RE penetration within the system, the consumer electricity demand, the topology and available capacity of the transmission network, and other factors. For example, two identical PSH plants in different locations may be of very different value for the power system. This is true for both regulated utilities and restructured market environments. A PSH plant located in a "load pocket" will have much higher value than the one located in an area with large supply of flexible generating capacity and a strong transmission network. Hence, the valuation of PSH projects is site-specific and depends heavily on the conditions within a particular utility system or electricity market.

In existing U.S. electricity markets, PSH plants earn revenues for only a handful of the services that they provide to the system. In most markets, PSH and other market participants can receive revenues from energy, ancillary services (regulation, spinning, and non-spinning reserves), and capacity markets. The provision of black-start capability is typically arranged through a long-term contract. Most existing markets have no established mechanisms to provide revenues for other services and contributions of PSH to the power grid. In contrast to competitive electricity markets, the traditional regulated utilities do not have established revenue streams for specific PSH services. The system operator typically optimizes the operation of PSH plants to minimize total production costs. Therefore, in both traditional and restructured market environments, most PSH services are not explicitly monetized. Since PSH plants typically provide multiple services at the same time, it is difficult to distinguish the specific value of certain services and contributions, such as inertial response, voltage support, transmission deferral, and energy security.

4.2.2 Quantification of PSH Benefits for RE Integration and System Reliability

In the recent study of PSH in grid operations (Koritarov et al. 2014), extensive simulations were carried out with the aim of quantifying the benefits of PSH in power system operations. Production cost simulations[4] were conducted for the Western Interconnection (WI)[5] in two future scenarios with different renewable energy penetrations. The renewable energy penetration was projected to 14% of demand in the base case (i.e., corresponding to mandated renewable portfolio standards) and 34% in a high-wind case. The benefits of PSH were assessed by simulating the WI with no PSH, with eight existing FS PSH plants, or with three additional AS PSH plants assumed to be in operation by 2022. The total capacity of the PSH plants corresponded to 2.0% and 3.8% of the projected WI peak load in 2022 in the cases with FS PSH only and with FS and AS PSH, respectively. Figure 18 shows the contribution of PSH to meeting

[4] The PLEXOS model from Energy Exemplar (http://www.energyexemplar.com/) was used for production cost simulations. A detailed description of the simulation approach, data, and results is provided in Koritarov et al. (2014).

[5] The Western Interconnection is one of the major power grids in North America covering the western United States, the Canadian provinces of British Columbia and Alberta, and a small part of northern Mexico. The model representation of the WI was based on The Western Electricity Coordinating Council's (WECC's) Transmission Expansion Planning Policy Committee (TEPPC) 2022 Common Case database, which is frequently used in renewable energy integration studies.

different types of operating reserves in the Base Renewable Energy and High Wind Renewable Energy scenarios. The figure shows that PSH plants provide a significant amount of operating reserves to the interconnection. In particular, when both FS and AS PSH plants operate in the system, PSH provides more than 10% of the total requirements for several of the considered reserve categories (regulation down, flexibility down, and non-spinning). In California, the simulated PSH contributions to operating reserve needs are even higher. The study also estimated the potential for energy arbitrage revenues in California and found that those revenues increased substantially in the case with more renewable energy (Figure 19). Moreover, simulation results for total production costs (i.e., fuel and variable operations and maintenance costs) showed significant savings for three geographical regions (WI, California, and Sacramento Municipal Utility District [SMUD]), particularly in the case with both FS and AS units where the WI savings amounted to as much as $477 million or 3.8% (Table 6). The simulation results also showed that the operation of PSH plants in the system allows for a significant reduction of variable energy resource curtailments in WI under both the Base and High Wind Scenarios (Table 7 and Table 8). The superior ability of AS PSH to provide dynamic stability and maintain system frequency was also demonstrated in the same study through dynamic simulations of power system stability (Figure 20). Overall, these results demonstrate substantial benefits of PSH for grid reliability and integration of renewable energy. Moreover, the results demonstrate the additional benefits provided by PSH with the AS technology. More detailed results of the estimated benefits of PSH in power system operations are documented in Koritarov et al. (2014). Other studies (e.g., EPRI 2013) have also demonstrated potential benefits of PSH to grid operations.

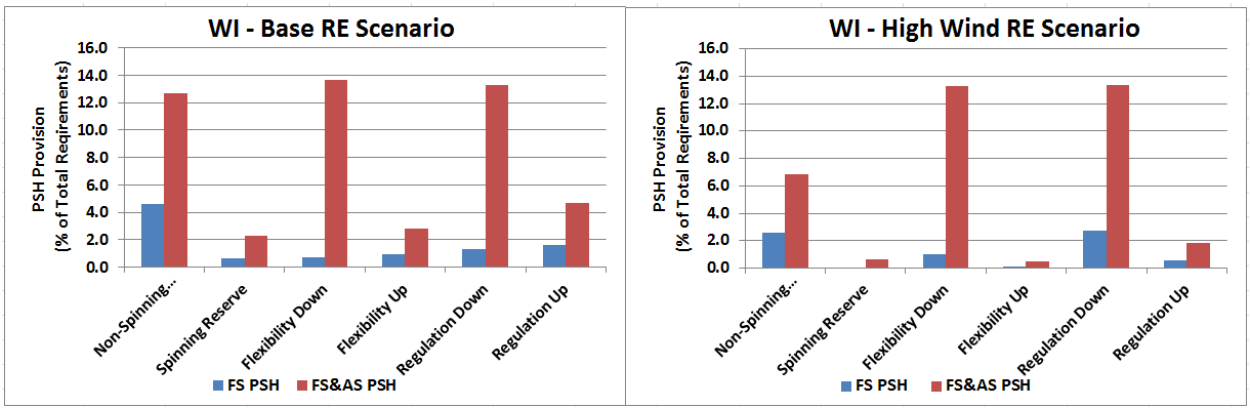


Figure 18 PSH Contributions to WI Operating Reserves in 2022 (Source: Koritarov et al. 2014)

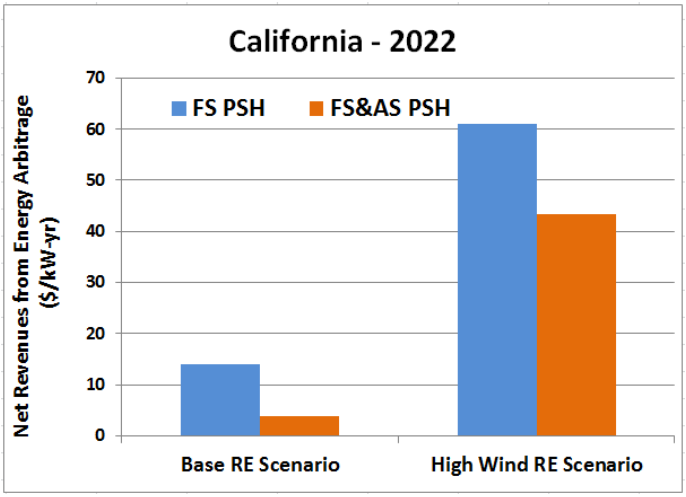


Figure 19 Net Revenues from Energy Arbitrage per kW of PSH Capacity (Source: Koritarov et al. 2014)

Table 6 Production Cost Savings (%) in 2022 due to PSH Capacity (Source: Koritarov et al. 2014)

Production Cost Savings due to PSH Capacity (%)	Western Interconnection		California		SMUD	
	Base Renewable Scenario	High Wind Renewable Scenario	Base Renewable Scenario	High Wind Renewable Scenario	Base Renewable Scenario	High Wind Renewable Scenario
With FS PSH	1.14	1.96	2.18	4.52	-	-
With FS & AS PSH	2.11	3.77	3.36	9.12	8.62	16.45

Table 7 Comparison of WI Renewable Curtailment in the Base RE Scenario (Source: Koritarov et al. 2014)

	Curtailed Energy	Renewable Curtailment Reduction	
Case	GWh	GWh	%
No PSH	1,921	-	0%
With FS PSH	1,356	565	29%
With FS&AS PSH	964	958	50%

Table 8 Comparison of WI Renewable Curtailment in the High Wind RE Scenario (Source: Koritarov et al. 2014)

	Curtailed Energy	Renewable Curtailment Reduction	
Case	GWh	GWh	%
No PSH	56,885	-	0%
With FS PSH	48,403	8,482	15%
With FS&AS PSH	44,211	12,675	22%

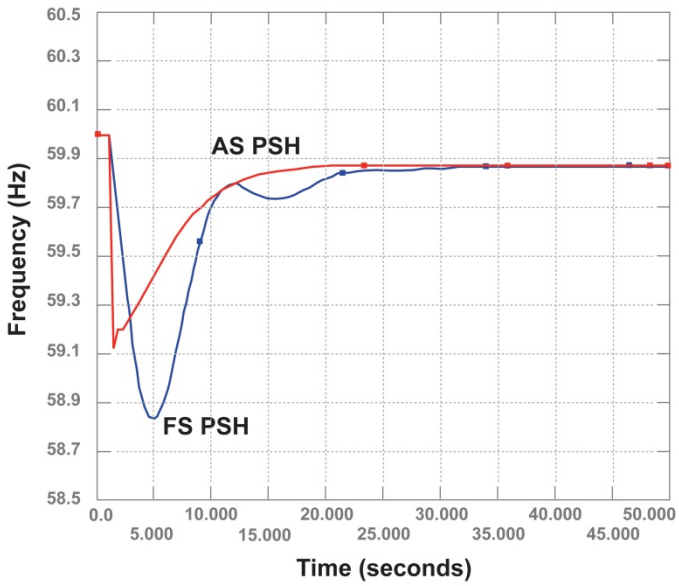


Figure 20 System Frequency with the FS and AS PSH Units in Response to the Outage of a Gas Turbine (Source: Koritarov et al. 2014)

4.3 Technical Capability of Conventional and Advanced PSH Technologies

This section discusses in more detail the technical characteristics of PSH technologies, including FS, AS, and ternary configurations.

4.3.1 Fixed Speed Conventional PSH Units

With a conventional FS unit, pumping occurs at a fixed synchronous speed. Therefore, in the pumping mode, the unit cannot provide regulating service to the system. The power input is nearly constant at the input rating of the pump, and the discharge varies with the pumping head. In the generation mode, the reversible pump/turbine is used to drive the FS synchronous generator and deliver electric energy and regulation to the system.

4.3.2 Adjustable Speed PSH Units

Compared with an FS unit, an AS unit has a greater generating range and a wider range of pumping power input, and it provides frequency regulation and VAR control during the pumping cycle. Adjustable speed operation is possible due to the application of a DFIM. The frequencies of the DFIM's rotor voltage and current are adjusted to control rotor speed.

The AS capability makes it possible to change rotor and pump/turbine mechanical speed by using high-speed electronic systems. By optimizing the two variables (speed and power), an AS

unit can be dispatched at optimum efficiency over a large head range. Because the rotor excitation system uses robust high-capacity solid-state devices and high-speed computer controls, energy stored in the rotating mass of the rotor can be rapidly interchanged with the grid to provide the fast response that is needed for frequency regulation.

Compared with an FS unit, an AS motor/generator PSH unit has a larger range of operation in the generation mode. Moreover, AS units have a reduced rough zone, improved efficiency, and the ability to operate at lower power levels, as shown in Figure 21.

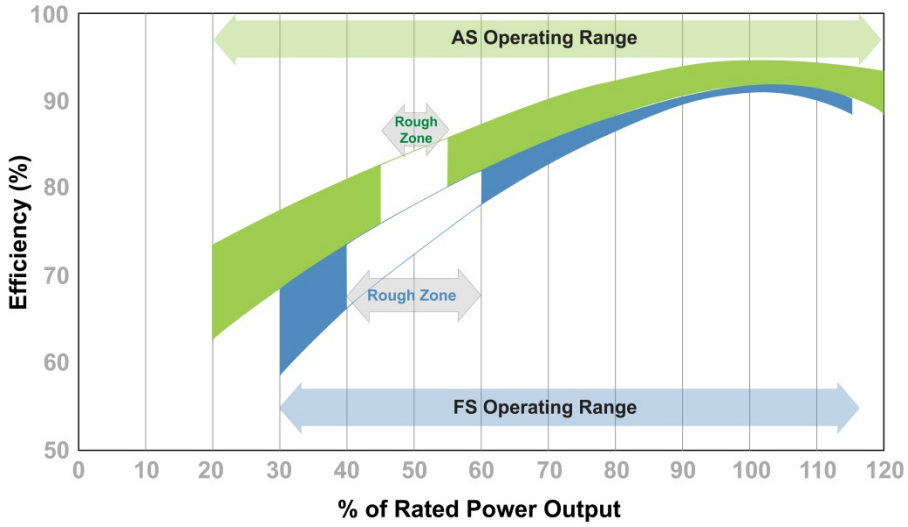


Figure 21 Generation Efficiency Curves for FS (Blue) and AS (Green) PSH Units (Figure from Koritarov et al. 2014, adapted from USACE 2009)

4.3.3 Ternary PSH Units with Hydraulic Bypass

Ternary PSH units use a separate synchronous motor and generator, turbine, and pump on a single shaft and are operated in a single rotational direction. Because the direction of rotation of a ternary unit is the same in the pumping and generation modes, the time to change from one mode to another is faster than with a reversible pump/turbine unit. Ternary units can have turbines that are either impulse (Pelton) or Francis type and can have multiple stages. Ternary units can also have a hydraulic torque converter coupling connecting the pump to the shaft system. The clutch allows the pump to be quickly connected and disconnected.

Traditionally, these units have operational capabilities similar to FS reversible pump/turbine PSH units with synchronous motor/generators. In this context, the standard ternary unit can only provide frequency regulation and load following in the generation mode. Because the pump and turbine are separate, each can be designed for best efficiency at the same synchronous speed.

A recent refinement of the ternary configuration allows for regulation in the pumping mode. This added capability is achieved with the introduction of a hydraulic bypass, also known as

"hydraulic short circuit" or "mixed mode." The hydraulic bypass allows the total output of the plant to be controlled by diverting a portion of the pump output back into the flow of water to the turbine. A ternary unit with hydraulic bypass can accomplish regulation using water flow and mechanical valves, while regulation with an AS unit is accomplished via rotor current electronics.

The most recent ternary plant with a hydraulic bypass is the Kopswerk II plant in Austria. This plant is located in the Alps and is installed in a large-scale water storage system with multiple reservoirs and tunnels. Kopswerk II has three units, each rated at 150 MW. When the hydraulic bypass is activated, the turbine utilizes some of the water from the pump to generate power and offset the power used by the pump. This arrangement allows the unit to provide a wide range of adjustable power absorption to the grid when it is operating in the pumping mode. Figure 22 shows the ternary plant configuration of the Kops II plant.

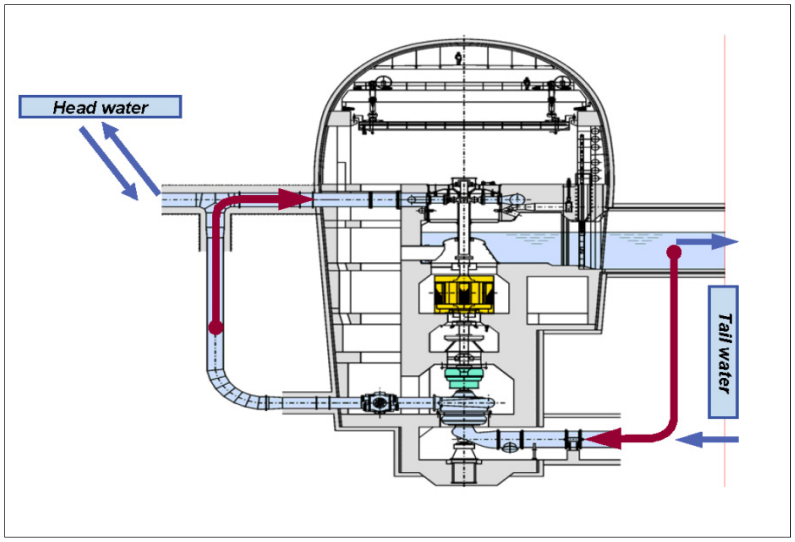


Figure 22 Ternary PSH Plant Configuration (Figure from Koritarov et al. 2014; Original Source: Spitzer and Penninger 2008)

When the transmission system requires regulation service, the plant is operated in the hydraulic bypass mode, with the clutch engaged so that both the pump and turbine are operating. The net plant load as seen by the transmission system is the power being drawn by the pump motor minus the power being produced by the generator.

4.3.4 Comparison of Capabilities for Different PSH Technologies

The tables and figures below summarize the capabilities for the FS, AS, and ternary PSH technologies outlined above in more detail. Primary and secondary benefits of the three configurations are listed in Table 9 and Table 10. Operating mode transition times are shown in Figure 23. Ternary units are the ones with the fastest transition times for most mode changes, whereas AS (variable speed) and conventional FS have longer transition times. The overall cycle

or "round-trip" efficiency tends to be in the 70-80% range for most PSH plants. Table 11 breaks down the cycle efficiency into different components for an FS plant. For a given FS PSH unit, the maximum efficiency point for the pump and the turbine cannot occur at the same speed. In this case, the reversible, FS unit can only be designed to achieve maximum efficiency in one of the two modes. If designed for best efficiency as a pump, which is the common design of FS units, then the best efficiency point in the generation mode will occur at a different speed and will not be achieved. In contrast, AS units can operate at maximum efficiency in both the pumping and generation modes (Figure 24). This leads to improved overall cycle efficiency for AS units.

Table 9 Primary Benefits of Pumped Storage Hydro Technologies (Source: Koritarov et al. 2014)

System or Plant Capability	Conventional with FS Synchronous Motor/Generators	AS with DFIM Motor/Generators	Ternary Type with Hydraulic Bypass and FS Synchronous Motor/Generators – Based on Kops II
Energy arbitrage	Yes	Yes	Yes
Minimum unit capacity rating (MW)	25	31.5	25
Maximum unit capacity rating (MW)	400 +	400 +	400 +
Generation Mode			*Pelton turbines are used at Kops II*
Spinning reserve	Yes	Yes	Yes
Efficiency	Less than the pumping mode	Changes with speed	Per turbine design
Range of operation (% of rated capacity)	30% to 110%	20% to 120%	30% to 110%
Pumping Mode			Francis pump
Spinning reserve	No	Yes	Yes
Efficiency	Per pump design	Changes with speed	Per pump design
Range of operation %	Only pump at full capacity	75% to 125%	100%

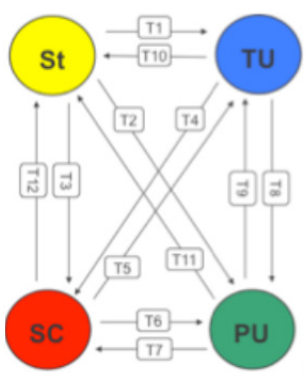
Table 10 Secondary Benefits of Pumped Storage Hydro Technologies (Source: Koritarov et al. 2014)

System or Plant Capability	Conventional with FS Synchronous Motor/Generators	AS with DFIM Motor/Generators	Ternary Type with Hydraulic Bypass and FS Synchronous Motor/Generators – Based on Kops II
Synchronize at less than system frequency?	No	Yes	No
Mode change time	Base Case	Faster[a]	Fastest
Change direction of rotation for mode change	Yes	Yes	No
Hydraulic churning during mode change?	Yes	Yes	No

Table 10 (Cont.)

System or Plant Capability	Conventional with FS Synchronous Motor/Generators	AS with DFIM Motor/Generators	Ternary Type with Hydraulic Bypass and FS Synchronous Motor/Generators – Based on Kops II
Generation Mode			
Regulate frequency	Yes	Yes	Yes
Load following	Yes	Yes	Yes
Ramp rate	Yes	Yes	Yes
Flywheel effect	No	Yes	No
Reactive power	Yes	Yes	Yes
Generator dropping	Yes	Yes	Yes
Pumping Mode			
Shoulder pumping	No	Yes	No
Regulate frequency	No	Yes	Yes
Load following	No	Yes	Yes
Ramp rate	No	Yes – fast	Yes
Reactive power	Yes	Yes	Yes
Load shedding	Yes, 100%	Yes, partial to 100%	Yes, 100%
Flywheel effect	No	Yes	No
Hydraulic churning	No	No	Continuous in hydraulic bypass mode

[a] Note that PSH units with AS capability can provide regulation service in both pumping and generation modes, and therefore, fast mode change capability is not necessary for regulation.



T	Pump Turbine Mode change			time [seconds] A	B	C	D	E
1	Standstill	→	TU-Mode	90	75	90	90	65
2	Standstill	→	PU-Mode	340	160	230	85	80
5	SC-Mode	→	TU-Mode	70	20	60	40	20
6	SC-Mode	→	PU-Mode	70	50	70	30	25
8	TU-Mode	→	PU-Mode	420	240	470	45	25
9	PU-Mode	→	TU-Mode	190	90	280	60	25

Reversible PT
A – advanced conventional (2012)
B – extra fast response conventional
C – VarSpeed, DFIM

Ternary set
D – with hydraulic torque converter + hydr. short circuit, horiz, with Francis Turbine
E – same as E but vertical with Pelton Turbine

Figure 23 Operating Mode Transition Times (Figure from Koritarov et al. 2014; Original Source: Fisher et al. 2012)

Table 11 Cycle Efficiency of FS PSH Plant Components (Source: Koritarov et al. 2014)

Component		Indicative Value %
Pump Cycle	Water conductor	98.0–98.6
	Pump	90.0–92.0
	Motor	97.8–98.3
	Transformer	99.0–99.6
	Overall pump cycle	85.4–88.8
Generation Cycle	Water conductors	96.8–98.0
	Turbine	76.4–91.0
	Generator	97.8–98.3
	Transformer	99.0–99.6
	Overall generation cycle	71.6–87.3
Hydraulic Losses and Leakage		98.0–99.8
Operational – both Modes		60.0–77.4

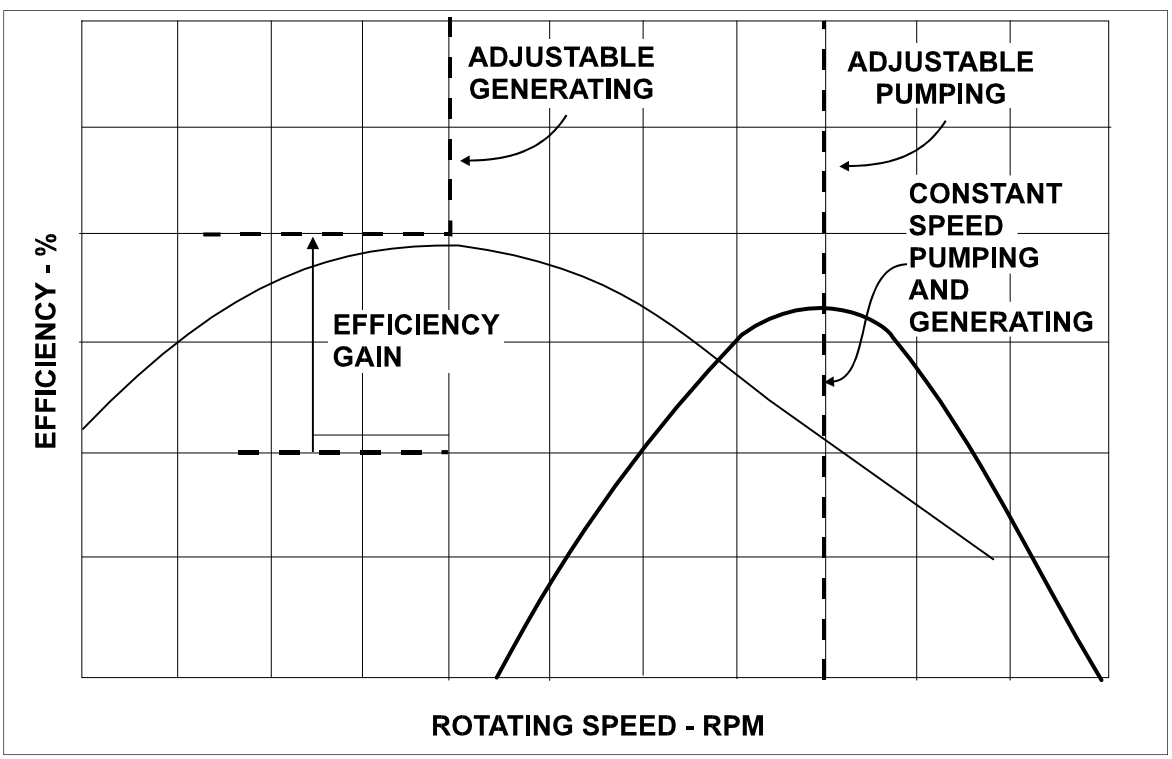


Figure 24 Efficiency Gain from AS Operation (Figure from Koritarov et al. 2014; Original Source: USACE 2009)

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5 Conclusion

The rapid expansion of variable renewable energy resources such as wind and solar provides clean energy, but also increases the need for flexibility in the power grid to address more uncertainty and variability in supply resources, provide increased ancillary service needs, and maintain power-system reliability in a cost-efficient manner. Currently, this flexibility is largely provided by natural gas plants, conventional hydropower and PSH, and other generators that are able to quickly adjust their output and follow variations in the net system load. However, interest is growing in the potential for advanced PSH technologies to provide system flexibility and ancillary services. Conventional FS PSH units typically operate on a daily cycle and are unable to provide frequency regulation and dispatch flexibility when operating in the pumping mode due to the fixed speed and power consumption. Conversely, AS PSH units are able to vary their power consumption while operating in the pumping mode and are, therefore, well suited to provide these valuable services.

PSH is a proven, cost-effective solution to large-scale energy storage. There are currently 40 such plants in operation in the United States, which provide 22 GW of total capacity. Globally, more than 20 AS units have been developed since the 1990s, but there are currently no operational AS units in the United States. The development of new PSH units in the United States has been inhibited by a number of factors, including environmental concerns over the siting of new facilities, the lengthy licensing process for new PSH units, and a lack of markets to properly monetize all the services that PSH can provide to the power grid. Despite the presence of these barriers, about 50 PSH projects have been proposed in the United States, totaling over 40 GW of new capacity. These projects are in various stages of planning, licensing, and development and many are considering the use of AS technology. There is also interest in upgrading some of the existing FS units to the more flexible AS technology.

Providing further support for the development of new PSH units and AS upgrades to existing PSH units will contribute to grid reliability, facilitate a larger expansion of variable renewable energy, and thereby reduce U.S. power system emissions. Further developments of PSH can be encouraged through streamlined licensing, as proposed by HREA of 2013 for closed-loop projects. Moreover, key activities that can help accelerate PSH developments in the United States include the following:

- Developing tools to allow owners and operators of pumped storage hydropower plants to evaluate the feasibility of conversion from fixed-speed to adjustable-speed technologies; and

- Investigating market mechanisms that would accurately compensate pumped storage hydropower for the full range of valuable services provided to the power grid.

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