Pumped Storage Hydropower and Conduit Hydropower

Course# ENV101

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Executive Summary

Pumped storage hydropower and conduit hydropower technologies each offer important, but different, ways to enhance the renewable energy portfolios in the United States as part of the suite of tools that can help add flexibility to the power grid; which can also include options such as demand response, use of variable generation forecasting, other types of storage and proactive power grid planning, to name a few.

A pumped storage 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, pumped storage hydropower 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.

Pumped storage units can be incorporated into natural lakes, rivers, or reservoirs, as an open-loop system, or it can be constructed independent of existing natural features, as a closed-loop system, with fewer environmental impacts. All pumped storage plants in the United States today use fixed-speed technology that has a pump/turbine and motor/generator that are operated at a synchronous fixed speed. However, in recent years, interest in adjustable-speed units has increased because of their higher efficiency and their ability to adjust power consumption in the pumping mode.

The additional operational flexibility of adjustable-speed units is becoming increasingly valuable as the penetration of variable renewable generation increases. A recent study demonstrates multiple advantages of adjustable-speed pumped storage hydropower in the Western Interconnection, including increased provision of operating reserves and improved contribution to dynamic stability from pumped storage plants. In a scenario for 2022 with high penetration of renewable energy (34 percent), it was estimated that a combination of eight existing fixed-speed and three new adjustable-speed plants would give a large reduction in renewable energy curtailment (22 percent) and substantial reductions in system operating costs (3.8 percent) and CO_2 emissions (two percent) compared to a case without pumped storage hydropower.

In the United States, there are currently 40 pumped storage plants in operation with a combined capacity of 22 gigawatts (GW), accounting for 95 percent of all energy storage capacity in the power grid. At present, there are about 50 proposed projects that could add more than 40 GW of new storage capacity. There is also interest in upgrading existing fixed-speed units to adjustable-speed technology. It is very difficult to estimate the need for energy storage in the future power grid, but one recent study indicates that more than 100GW of energy storage will be deployed in a future scenario for 2050 with 80 percent renewable energy.

The development of new pumped storage units and adjustable-speed upgrades can be encouraged through streamlined licensing, as proposed by the Hydropower Regulatory Efficiency Act of 2013 (Public Law 113-23) for closed-loop projects, and by ensuring that pumped storage hydropower is compensated for the full range of services provided to the power grid.

Conduit hydropower projects are constructed on existing water-conveyance structures, such as irrigation canals or pressurized pipelines that deliver water to municipalities, industry, or agricultural water users. Although water conveyance infrastructures are not usually designed for energy purposes, new renewable energy can be harvested from them without the need to construct new dams or diversions. The addition of hydropower to existing water conduits, many of which constitute aging infrastructure that is becoming more expensive to maintain, can provide a valuable new revenue source of clean, renewable energy.

The prospects for future development of renewable energy from conduits could be improved with a number of focused actions. These include resource assessment, feasibility analysis tools, improved regulatory efficiency, standardization of electrical interconnection technology and processes, and standardization of technology and development processes to reduce costs of deployment.

II. Introduction

Federal law[2] mandates that the U.S. Secretary of Energy conduct a study on pumped storage hydropower (PSH) and potential hydropower from conduits.[3] This report documents the main results from the study, including recommendations.

The report has the following structure: Section III responds to the Hydropower Regulatory Efficiency Act of 2013 Section 7(a)(1) and provides an overview of the PSH technology, and how it contributes to power grid reliability and adds operational flexibility to aid in the integration of variable renewable resources such as wind and solar power. The advantages of advanced PSH technologies with more flexible operational characteristics are also presented, along with the current status and future outlook for PSH in the United States. Section IV describes the opportunities for new energy development in water conduits, as required in HREA 2013 Section 7(a)(2).

Finally, Section V concludes and provides recommendations for the development of new PSH and hydropower from conduits in the United States.

More detailed discussions of PSH and hydropower from conduits are provided in two supporting technical reports[4,5] prepared for the U.S. Department of Energy by Argonne National Laboratory and Oak Ridge National Laboratory.

III. Pumped Storage Hydropower

This chapter presents an overview of pumped storage hydropower (PSH), which provides the vast majority of large-scale energy storage in the power grid today.

The discussion includes recent developments of PSH technologies with more flexible operational characteristics. The technical capabilities of PSH that can improve the reliability in the electric power grid and help integrate variable renewable generation are also presented. Finally, the current status of and future outlook for PSH in the United States are discussed.

A more detailed discussion on PSH is available in a supporting report prepared by Argonne National Laboratory.[4]

Background and History of PSH

PSH has long been used as a 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. The first unit in North America was the Rocky River PSH plant, constructed in 1929 on the Housatonic River in Connecticut. These early units were relatively basic; each had a motor and pump on one shaft and a separate shaft with a generator and turbine. The Tennessee Valley Authority (TVA) constructed the first reversible pump/turbine (Hiwassee Unit 2) in 1956, which, at 59.5 megawatts (MW), was larger than earlier PSH installations. Developments in technology and materials over the next three decades improved overall efficiency and allowed increasingly larger units to be constructed.[6]

A typical conventional PSH project consists of two interconnected reservoirs, tunnels that convey water from one reservoir to another (water conductors), a powerhouse with a pump/turbine and a motor/generator, and a transmission connection (Figure 1). There are a variety of ways PSH can be implemented within specific geologic and hydrologic constraints. Many PSH projects use natural lakes, large rivers, or reservoirs of existing conventional hydro-facilities as their reservoirs. PSH plants that are continuously connected to a naturally flowing water feature are called "open-loop" projects. Conversely, a "closed-loop" PSH system is constructed independent of a naturally occurring river or lake. An advantage of this approach is that there is minimal aquatic life interaction, which reduces the environmental impacts and concerns.[7]

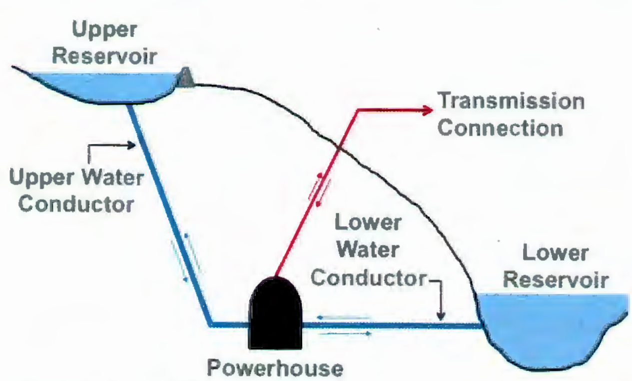


Figure 1. Typical PSH Configuration.

In the United States, there are 40 PSH plants in commercial operation with a total installed capacity of about 22 gigawatts

(GW). This compares to a total installed generating capacity of about 1100GW in the U.S. power grid today. Many of the PSH 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.

The PSH installations vary in size, with the largest one, Bath County Pumped Storage Station in Virginia, having a capacity of 3,000 MW, roughly equal to the size of three nuclear reactors. With an energy storage capacity of 30 gigawatt-hours (GWh), i.e. equal to the average daily electricity consumption of more than one million U.S. households, the Bath County plant can generate at full output for about 10 hours. In contrast, the smallest PSH plants have a capacity of less than 10 MW.

In the traditional mode of operation, PSH plants follow a daily operational cycle. Electricity is used to pump water from the lower reservoir to the upper reservoir during the periods of low electricity demand (e.g., night) or when electricity prices are low. Water stored in the upper reservoir is released during peak demand periods, delivering more valuable electricity to the grid and reducing the need for peak load generation from other power plants. PSH plants can also earn revenue by supplying ancillary services, that is, services that are needed to support and maintain reliable operation of the power grid. The rapid expansion of variable renewable energy (RE), such as wind and solar power sources, can introduce more uncertainty and variability into power grid operation. Hence, increased variability in the net load (i.e., total system load minus renewable generation), along with increased needs for ancillary services, may change the operational regime for PSH plants as well as other generators.

The most common PSH technology is the conventional fixed-speed (FS) plant, where both the pump/turbine and the motor/generator operate at a fixed synchronous speed. A major breakthrough in PSH technology occurred with the introduction of plants with adjustable-speed (AS) capability. An important advantage of AS PSH plants is that they provide a wider operating range, smaller rough zones (i.e., zones of operations that should be avoided due to increased vibration or other concerns), and higher efficiency compared to FS plants (Figure 2). Moreover, AS plants have the flexibility to vary their power consumption in the pumping mode and can therefore provide frequency regulation (i.e., respond to frequency deviations and short-term energy balancing needs in the system) while pumping. FS plants do not have this capability in the pumping mode because their pumps operate at fixed speed. The AS technology also has better capability to provide dynamic response to grid

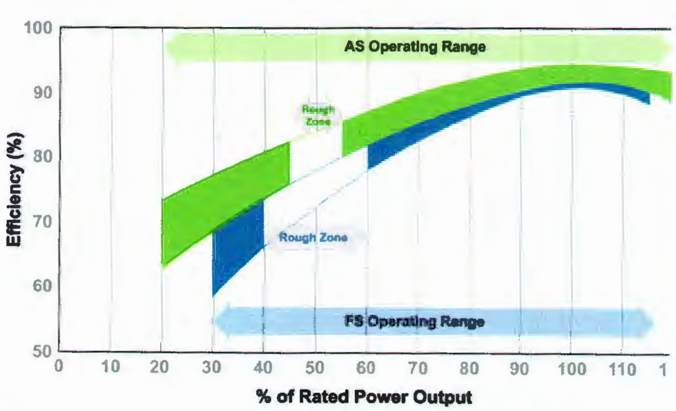


Figure 2. Comparison of Efficiency Curves in Generation Mode for FS (Blue) and AS (Green) PSH Units (adapted from USACE 2009[6]).

disturbances, which contributes to reduced frequency drops in the case of sudden generator or transmission outages, as well as improved stability of the power system. Another advanced technology configuration is the so-called ternary PSH machine. By using a hydraulic bypass, which allows for pumping and generation to occur at the same time, the ternary configuration also allows for more flexible operation than the FS units.

Internationally, more than 20 AS units have been placed in commercial operation since the 1990s, and several more are in design and construction phases. In particular, AS technology is seen as an important solution to grid reliability and renewable energy integration challenges in Japan and Europe. However, to date, no AS or ternary PSH plants have been built in the United States, although several proposed projects are considering the AS technology (e.g., Iowa Hill, Eagle Mountain, and Swan Lake North projects).

Technical Capability of PSH to Provide Grid Reliability and Support Variable Renewable Generation

The electric power grid is a very complex engineering system, where generation must be balanced continuously with loads to maintain power system frequency and stability. In power system operation, a number of different control and operational issues must be addressed, with time frames ranging from microseconds to days (Figure 3).

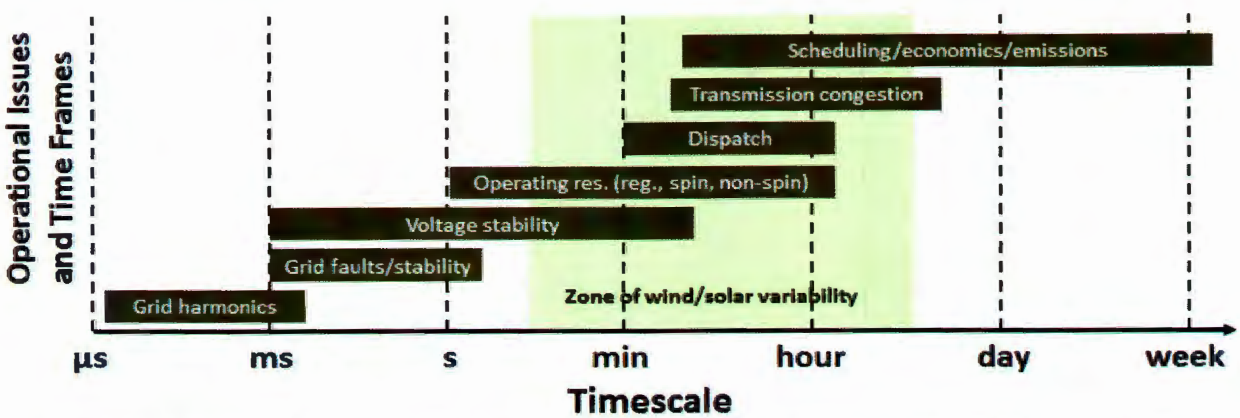


Figure 3. Overview of Issues in Power System Operations and Control (adapted from Fisher et al. 2012[8]).

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. Renewable resources may influence the operational challenges across all timescales, but the impact is typically most prominent in the middle range.

The potential contributions of different PSH technologies toward a spectrum of control, operations, and planning challenges in the power grid are briefly summarized in Table 1.

Table 1. Contributions from PSH to Power System Control, Operations, and Planning. **(adapted from Koritarov et al. 2014[9])**

Power Grid Issues	Description and Contributions from PSH (FS, AS, and ternary technologies)
Inertial response	In the case of a system imbalance event, the inertial response of the rotating mass in generators can arrest the initial grid frequency decay. FS and ternary PSH units provide inertial response directly through their rotating generators, whereas AS PSH units can provide inertial response through power electronic converters.
Governor response	Generating units with a governor can automatically respond to frequency deviations in the grid through governor control actions. This is also known as primary frequency control. Compared to conventional FS PSH units, AS PSH technologies provide faster response to system events and contribute to better control of system frequency.
Dynamic stability	Dynamic stability is the ability of the power system to regain an equilibrium operating condition with synchronism across the system after being subject to a physical disturbance. As AS PSH units employ power electronics, their responses are faster and their controls and capabilities can be designed for improved performance under particular disturbances.
Voltage support	Power system voltages must be controlled within a tight band for all equipment in the grid to ensure proper function. The power electronics of AS PSH units can be designed to mimic voltage support capabilities of conventional FS and ternary PSH units.
Operating reserves	Operating reserves are required to maintain the balance between supply and demand in the grid considering variability in load and generation (frequency regulation) as well as contingencies. PSH can provide all of these services to the grid. AS and ternary PSH have the advantage of being able to also provide frequency regulation during pumping.
Load leveling/ energy arbitrage	Energy arbitrage refers to the operation of energy storage facilities, including PSH, where electricity is generated when demand and/or electricity prices are high, and consumed when demand and/or prices are low. This capability reduces the need for peak load generation with high variable costs, thus decreasing overall operating costs.
Generating capacity	The ability of a power system to meet peak demand is defined by its total available generating capacity. PSH plants contribute toward meeting the peak demand in the power system, thereby reducing the need for capacity from other resources. The high flexibility of PSH operations and the ability to switch between pumping and generation quickly means that a PSH plant can provide up to twice its capacity to meet system ramping needs.
Reduced cycling and ramping of thermal units	The flexibility of PSH capacity creates a flatter net load profile for thermal generating units, which allows them to operate in a steadier mode, thus reducing the need for costly ramping, startups, and shutdowns. This capability is particularly important in systems with high shares of RE, which tends to increase the overall variability in the net load profile.
Reduced transmission congestion	The operational flexibility of PSH plants can be used in the scheduling and dispatch of system resources to influence power flows in the transmission network. Depending on its location, a PSH plant may therefore reduce transmission congestion, improve utilization of transmission assets, and reduce the need for new transmission capacity.
Reduced environmental emissions	Systems with a high share of RE will likely see reductions in greenhouse gas emissions and other pollutants that can be attributed to PSH, because surplus generation from wind and solar resources can be used for pumping purposes instead of being spilled. Moreover, the flexibility of PSH, particularly of AS and ternary units, will help facilitate more RE in the grid, thereby reducing emissions over the long run.
Black-start capability	In the rare case of a widespread blackout in the power grid, system restoration must begin from generating units that have the ability to start themselves: so-called black-start units. FS and ternary PSH units are good candidates for providing black-start service, whereas AS units need an external source of power to start.
Energy security	In a future scenario with greater electrification of transportation, PSH may contribute toward de-carbonization and a lower reliance on imported fossil fuels in the transportation sector. Hence, PSH may contribute toward national energy security goals.

Overall, the value of PSH services and their contributions to the grid depend on many factors. These include the location of the PSH in the system, capacity mix of other generating technologies, renewable energy penetration, shape of consumer electricity demand, and topology and available capacity of the transmission network among other factors.

In a recent study,[9] the benefits of PSH to the power grid were analyzed in detail, with a focus on the advantages of advanced PSH technologies. The superior ability of AS PSH versus FS PSH to provide dynamic stability and maintain system frequency was demonstrated by simulating the response to a sudden outage of a gas turbine (Figure 4). Detailed simulations of the Western Interconnection (WI)[10] projected to 2022 were also conducted to quantify the value of PSH in a large-scale power system. These simulations projected renewable energy penetration levels of 14 percent in the base case (i.e., corresponding to mandated renewable portfolio standards) and 34 percent in a high-wind case.[9] 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 capacity of the PSH plants corresponded to two percent and 3.8 percent of the projected WI peak load in 2022 in the cases with FS PSH only and with FS and AS PSH, respectively.

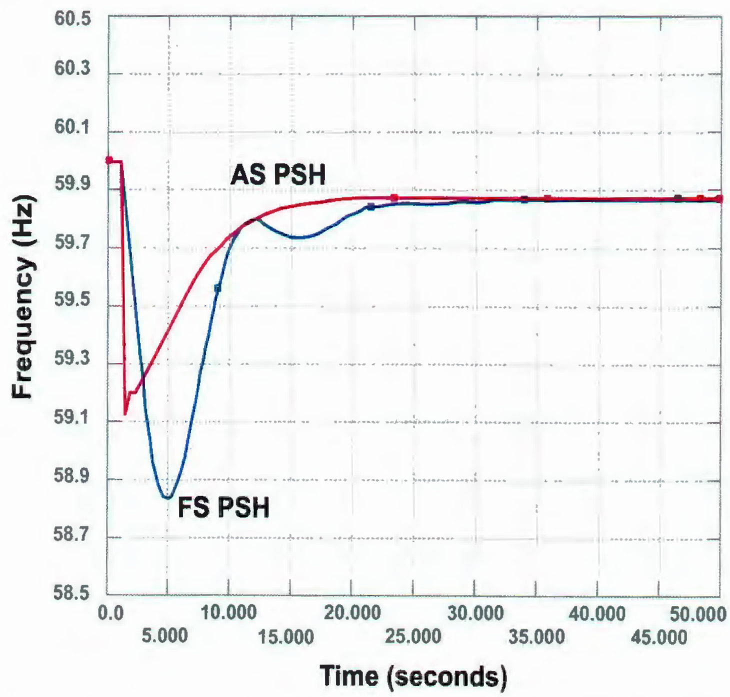


Figure 4. System Frequency with FS and AS PSH after a Gas Turbine Outage (Source: Koritarov et al. 2014[9]).

The results show that the addition of three AS PSH plants gives a substantial increase in the share of the WI operating reserves provided by PSH in 2022, particularly for the regulation down, flexibility down, and non-spinning reserve categories (Figure 5). PSH also increases the utilization of renewable energy by reducing the renewable energy curtailments by 8,482 GWh, or 15 percent, (FS PSH) and 12,675 GWh, or 22 percent (FS&AS PSH), compared to the amount of renewable energy curtailment in the case with no PSH.[9] Moreover, in the high-wind scenario it was found that the total WI annual production cost (fuel and variable operations and maintenance costs) could be reduced by as much as $477 million, or 3.8 percent, while the total CO_2 emissions were reduced by more than two percent, if the eight existing FS and three new AS PSH plants are operating in the system.[11]

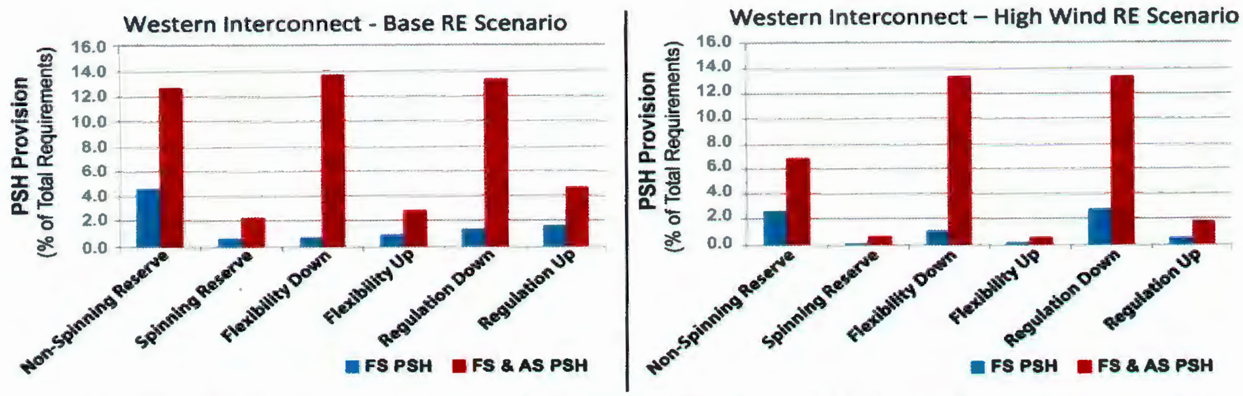


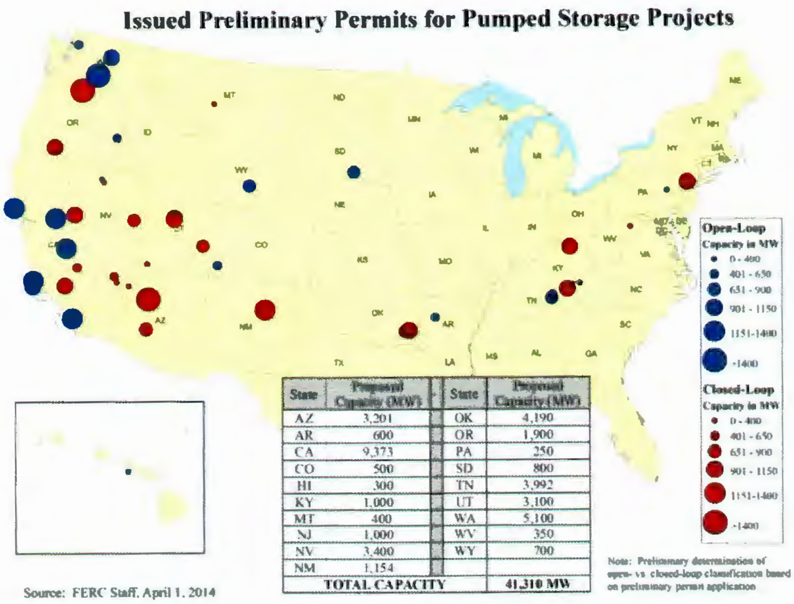
Figure 5. PSH Contributions to WI Operating Reserves in 2022 in Base and High-Wind Renewable Energy (RE) Scenarios (Source: Koritarov et al. 2014[9]).

Opportunities for New PSH Development

Recently, there has been an increasing interest 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 needs for power system flexibility, which could be provided by energy storage. It is very difficult to estimate the need for energy storage in the future power grid, as it depends on the power system capacity mix and a variety of other factors, including the cost of energy storage and the availability and cost of other flexibility solutions. The Renewable Electricity Futures Study found a storage deployment of between 100 and 152 GW across six 80 percent renewable energy scenarios for 2050. Although such estimates are uncertain, they indicate that there is likely to be a substantial need for new storage capacity if a high renewable energy future unfolds. [12]

Preliminary Permits

At present, there are about 50 proposed PSH projects in the United States that are in various stages of planning and licensing. Their total installed capacity amounts to more than 40 GW, and more than half of that capacity involves closed-loop projects. Figure 6 shows proposed PSH projects for which the Federal Energy Regulatory Commission (FERC) has issued preliminary permits. Many of these projects are considering the use of the AS PSH technology, which can be applied in both open- and closed-loop project designs.



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

Figure 6. Preliminary Permits for New PSH in the United States (Source: FERC[13]).

Upgrading Existing PSH Plants with Advanced Technology

There is also interest among PSH owners in upgrading existing FS PSH plants to the advanced AS technology to obtain enhanced operational flexibility from current assets. A number of conditions need to be carefully evaluated to determine whether such a conversion is technically feasible and an economically cost-effective option. Most of the technical requirements for conversion can be summarized into four main groups:[14] civil works, hydraulic design, electrical systems, and mechanical systems, as briefly outlined below.[15]

With regard *to civil works*, one of the key conditions for conversion to AS units is the available ceiling height and floor space of the powerhouse, as it needs to accommodate the additional equipment required for AS motor/generators. This space may be hard to find in existing underground power stations and may require some excavation work, which would increase the cost of the conversion project. Another consideration of owners is the ability of the existing civil structures to withstand the higher loads and stress associated with the operation of AS units.

A conversion to AS should also consider upgrading the plant's *hydraulic design*, including a possible turbine upgrade to maximize the benefits of AS capabilities and optimize pump/turbine performance (Figure 2) for a range of potential speed variations.

With regard to *electrical systems*, at present, most AS PSH plants are designed to use doubly fed induction machines (DFIMs) with a voltage source inverter and power transformer that serve as the rotor excitation system and control the rotor speed. In conversion projects, the existing rotor has to be replaced with a three-phase wound rotor; however, in some cases, the existing stator may be reused. In addition to the motor/generator, other electrical systems may need to be replaced or upgraded.

The *mechanical systems* also need to be checked and potentially upgraded for use with AS technology. Because the DFIM rotor is typically about 30 percent heavier than the comparably sized rotor of FS synchronous machines, the rotor shaft and bearings should be checked to verify that they can withstand additional dynamic loads.

Although there have been a few preliminary evaluations of individual unit conversions,[16,17] a comprehensive nationwide assessment to identify plants that could be converted to AS has not been carried out. It is therefore difficult to estimate how much of the existing PSH capacity could be converted to the AS PSH technology from a technical perspective 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 and financial viability. Both the cost and benefit sides 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.

Goldisthal: The First AS PSH in Europe

Photo Credit: Vattenfall

Goldisthal is a 1,060-MW PSH facility on the Schwarza River in Thuringia, Germany. The facility commenced operation in October 2004. Goldisthal has four 265-MW Francis pump turbines: two with AS motor/generators and two with FS motor/generators. The decision to have a mix of FS and AS units was made as a result of several factors including the demand for controlled pumping, the desire to maintain black-start capability through the FS units, and the perceived new technology risk of AS units. Goldisthal was the first AS PSH in Europe. In generation mode, the two FS units can generate from 100 to 265 MW of power while the AS units can generate from 40 to 265 MW, providing an additional 60 MW of regulation from each unit. In pumping mode, the FS units cannot vary their pumping load, whereas the AS units can operate between 190 MW and 290 MW. Water flows through a 301-m hydraulic head from the upper reservoir, which has 12 million cubic meters of capacity, to the lower reservoir, which has 18.9 million cubic meters of capacity. The project was completed at a total cost of 623 million euros and is owned and operated by Vattenfall Europe.

Costs of New PSH Technologies

Because of the site-specific and custom nature of PSH project development, capital costs are difficult to broadly characterize and estimate. Several factors that influence the costs of a pumped storage project include the following: site-specific geotechnical and topology conditions, permitting processes, size of reservoirs and dams or ring dikes, length of tunnels, surface vs. underground powerhouse, type of electromechanical technology, transmission system interconnection and upgrade costs, and environmental issues requiring mitigation. In addition, development and construction of a PSH plant involves longer timelines as compared to most other types of power plants, which also affects the total cost of construction.

Le Cheylas: Upgrading from FS to AS PSH

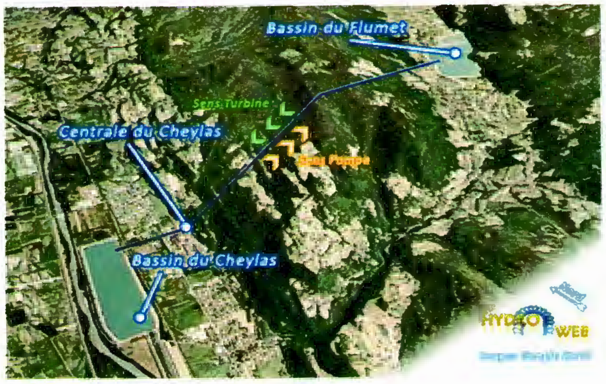


Photo Credit: http://estorage-project.eu

Le Cheylas is a 480-MW AS PSH facility in the French Alps. It commenced operation in 1979 as a FS PSH facility. Currently, one of its two 240-MW units is being upgraded to AS. Once completed, Le Cheylas will provide 70 MW of additional nighttime regulation capability, which will allow the integration of more renewable generation into the power grid. The elevation drop between the upper reservoir, Bassin du Flumet, and the powerhouse is 261 m, and the power plant empties into Bassin du Cheylas. Alstom leads the conversion project and Le Cheylas is owned and operated by Electricite de France (EDF). The upgrade is funded in part by a $21 million grant from the European Commission through its eStorage project (http://estorage-project.eu) to demonstrate advantages of AS PSH and how it contributes to grid integration of renewable energy, and that a significant portion of European PSH can be upgraded to the AS technology.

A recent study[18] presents an analysis of historical costs for 14 representative PSH plants in the northwestern United States. The plants that were evaluated have capacities from 300 MW to 2,100 MW, with an average plant capacity of 900 MW and capital costs ranging from $600/kW to $1,800/kW. The analysis did not reveal a distinct relationship between the plant capacity and capital cost. However, it was found that there has been a tendency for project costs to increase over time.

A study of the costs of new projects was also conducted in the same study.[19] Figure 7 shows estimated cost ranges for greenfield PSH projects. In this case, there is a distinct trend of lower construction costs for larger plants. The expected capital cost of a hypothetical 1,000-MW FS PSH project is on the order of $2,000/kW but could fall in the range of $1,750/kW to $2,500/kW. In another recent study,[20] the Electric Power Research Institute (EPRI) estimated the costs of more than 30 PSH projects with both U.S. and international locations. Although the results show a wide range in the estimated capital costs for the analyzed projects, the majority have a cost between $1,000/kW and $2,000/kW. Other recent studies[21,22] estimate the capital costs of FS PSH in the $1,500–2,700/kW range.

The total capital cost of a new AS PSH project is typically 7–15 percent higher than that of the same project if developed as a FS PSH plant. The main reason for the difference is the additional cost of the electro-mechanical equipment required for AS technology, which is typically about 60–100 percent higher than that of the FS

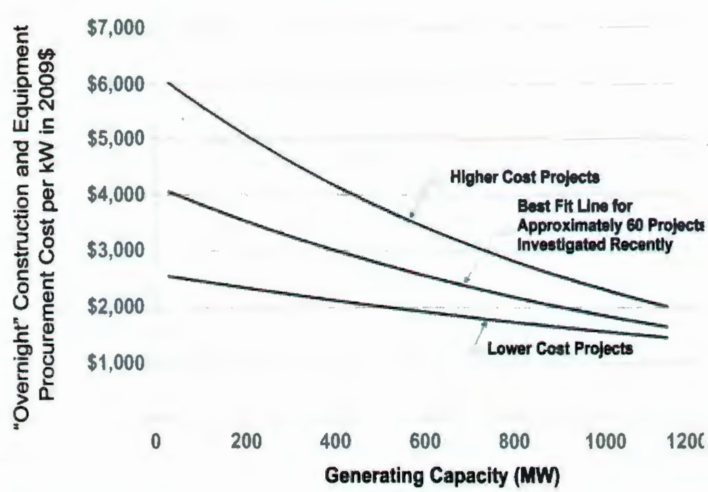


Figure 7. Estimated Construction Costs of New PSH (Source: USACE 2009[6]).

technology. So far, there is very limited experience with ternary PSH with hydraulic bypass. It is estimated that a new ternary PSH plant would have about 30–40 percent higher total capital cost than if the project was developed as FS PSH.

Comparison to Other Energy Storage Technologies

In recent years, there has also been an increasing interest in other energy storage technologies,[23] and substantial research is being conducted in the United States and internationally into the development of grid-scale energy storage.[24] However, PSH provides higher power ratings and longer discharge times than most other technologies. So far, the only exception is compressed-air energy storage (CAES); however, this technology requires very specific geographic conditions and relies in part on fossil fuels for its operations; in fact, there are very few CAES plants in operation today.[25] PSH is a proven technology and it compares favorably in terms of life cycle cost to most other energy storage solutions (Figure 8). In fact, PSH constitutes 95 percent of the installed grid-scale energy storage capacity in the United States[26] and as much as 98 percent of the energy storage capacity at a global scale.[27]

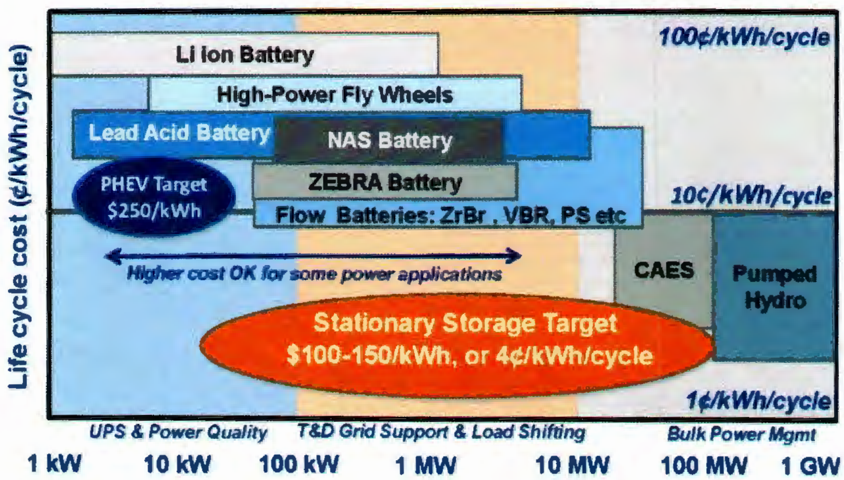


Figure 8. Life cycle costs and power ratings for energy storage technologies (Source: Energy Storage Association).

Barriers and Challenges for PSH Development

There are several barriers and challenges to further development of PSH in the United States. In a recent white paper,[28] the National Hydropower Association (NHA) emphasizes four main challenges for PSH:

(1) Environmental issues associated with PSH siting and limited recognition that closed-loop PSH has small environmental impacts

(2) The regulatory treatment of PSH

(3) Existing market rules and impacts on the 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 report also provides policy recommendations, which cover the licensing process, electricity market rules, and other regulations, to facilitate development of PSH. 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 two years. Other recent reports[29,30] discuss specific electricity market design issues in greater detail, emphasizing the need to introduce revised scheduling practices and corresponding pricing rules in electricity markets that fully capture the flexibility of PSH and other energy storage technologies in grid operations and reward such assets for the full range of services provided to the power grid.

IV. Hydropower from Conduits

This chapter describes the opportunities for new energy development in water conduits, as required in HREA 2013 Section 7(a)(2). A more detailed discussion of these issues, including the case studies called for in Section 7(a)(2)(B), is provided in a supporting technical report that has been prepared for the U.S. Department of Energy (DOE) by Oak Ridge National Laboratory (ORNL).[31]

Defining Conduit Opportunities

HREA 2013[32] defines conduits as, "any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar man-made water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity." Water conduits are existing, man-made infrastructure that has been built for non-power purposes, such as for delivery of water or disposal of wastewater. There are many thousands of miles of previously constructed conduits in the United States, and new, renewable energy can be harvested from them without the need to construct new dams or diversions.[33]

The owners of water conduits include federal and state agencies, municipalities, industrial facilities, farmers, and ranchers. A conduit system, by the aforementioned definition, exists primarily to convey water over an appreciable distance from a storage location to a location of use. It is typically conceived, authorized, designed, constructed, and operated with water delivery as the principal or sole purpose. A facility authorized primarily for hydropower production would not be classified as a conduit system—it would, instead, be sited and designed to maximize hydraulic head and minimize the distance over which the water must be conveyed, so as to maximize energy production and minimize construction, operations, and maintenance costs. Proposed changes to a conduit system configuration or operations that do not sustain expected water deliveries likely would require legislative re-authorization at the municipal, state, or federal level, depending on the original project authorization. Such changes also would likely engender an intense political discussion among stakeholders and decision-makers about the priorities of water use. Such changes may also run afoul of long-established and appropriative water rights. Thus, a common design constraint for a conduit power project is to avoid any undesirable changes to the capability

Figure 9. Representative Open-Channel and Pipeline Sites for Conduit Energy Projects. (Source: Johnson and Britton, 2012[34]).

of the system to sustain water deliveries.

Water is typically conveyed through open canals and ditches, or through pressurized pipes. Pipes can be buried or located aboveground; canals are normally at ground surface level (Figure 9).[34] Movement of water through conduits depends on either gravity or pressure as a driving force. Gravity is the primary force in open canals and ditches. The ability to move water over terrain requires the conveyance infrastructure to follow the topography of the alignment and to likely be raised and lowered in elevation. Larger irrigation schemes—particularly those in the western United States—may serve a multitude of purposes and may move water long distances and require a combination of pipes, canals, and tunnels to move the water from one point to another. Where gravity is insufficient to move water through a conduit, water delivery requires pumping or other energy inputs to move the water within a larger conduit system.

Studies of the energy–water nexus have shown that water supply and conveyance are the most energy intensive parts of the water delivery process.[35] However, water conduits very often have excess energy in them that can be damaging to a water distribution system itself. Examples include (1) high-velocity water flow that causes erosion of canal walls, and (2) pressurized pipelines with high static heads, where pressure is higher than what is needed to push water through the distribution system. In such cases, structures are built into the system to dissipate excess energy before it becomes damaging. Pressure-reducing valves (PRVs) and canal drops are very common examples of energy dissipation devices. These devices are usually located where new energy harvesting and hydroelectric generation can be installed. An engineering assessment is required to determine how much electric energy can be harvested from a specific system without jeopardizing existing water delivery functions.

Pressure-reducing valves as energy opportunities

Photo Credit: National Resources Conservation Service, WY

Pressure-reducing valves (PRVs) are regulators that automatically cut off the flow of a liquid or gas at a certain pressure. Regulators are used to allow high-pressure fluid supply lines or tanks to be reduced to safe and/or usable pressures for various applications. They are used in water distribution and treatment systems and in aqueducts to reduce the buildup of fluid pressure at branching and transfer points. In some cases, small hydro-turbines can be installed into a pipeline either in place of or in parallel with existing PRVs. The nation's existing water infrastructure includes hundreds of thousands of pressure-reduction valves.

Any electric energy that may be harvested from water conduits can offset normal energy utilization. The result is improved energy efficiency within the overall conduit system, which minimizes lost potential water energy. Power generated from a pressurized pipeline project may either be used immediately in the treatment/generation process or returned to the grid. In some cases, this electric energy can be used in the local area through the community distribution system near the conduit infrastructure. In cases where new electricity is used inside a water distribution system, it increases the energy efficiency of that system and can significantly improve the system economics.

The amount of electrical generation possible from water conduits is a function of the hydraulic head at a specific location, and the water discharge, or flow, past that location.[36] Hydraulic head has four components, which vary in magnitude by location:

(1) Velocity head, which is related to the bulk movement of water;

(2) Static (i.e., elevation) head, when there is a drop in water surface elevation;

(3) Pressure head, where there are pressure differentials across a system; and

(4) Resistance head, where there are friction losses within the water system, such as in the walls of pipes or canals.

Other factors are important to factor into estimates of potential generation, such as equipment efficiencies and the percentage of time a project will operate at full or partial capacity (referred to as plant factor or capacity factor). Water flow in conduits is not usually continuous. Any given conduit location will have different components of head, as well as different flow patterns over time, that will affect how much energy is available for harvesting. These site-specific characteristics are accounted for in the energy design of new conduit hydropower projects.[37]

Development of new hydropower projects in conduits must follow all of the same steps as conventional hydropower development, with one additional requirement: the feasibility analysis must also include protection of the existing water distribution purposes of the conduit. The main development steps are as follows, and each must be passed successfully:

- Planning and site selection
- Permitting
- Method of development
- Financing and power purchase agreement
- Interconnection and transmission
- Construction
- Start-up and commissioning
- Operations and maintenance

Available Resource Assessments and Case Studies

There has been relatively little development of hydropower in water conduits in the United States, relative to international development, in part due to low investments in development of the low-head technology needed at these types of sites.[38] To date, there have been no comprehensive national assessments of the undeveloped energy potential from either canal or pipeline sites. There have, however, been several more limited assessments performed at either state or regional levels. Broad resource assessments of pressurized pipeline opportunities are more difficult to perform because of the highly individual nature of each project. A 2013 report by the U.S. Environmental Protection Agency (EPA)[39] on obtaining power from pressurized wastewater treatment systems found that the technology is used more commonly in Europe and Asia than in the United States.

Previous assessments of undeveloped hydropower resources in the United States, such as those by Idaho National Laboratory (INL) in 2006[40] and ORNL in 2014,[41] did not address the conduit opportunities described herein, because those previous assessments focused on natural streams, not man-made conduit infrastructure. Similarly, hydropower assessments at existing, non-powered dams[42] examined dams on natural rivers but omitted man-made canals or water distribution systems.

Some of the more geographically limited assessments of undeveloped conduit resources include the following. These estimates do not include potential hydrokinetic and likely underestimate the conduit resources available due to lack of a consistent methodology and baseline data.

Bureau of Reclamation.[43] A 2012 study by the U.S. Department of Interior's (DOI's) Bureau of Reclamation examined energy development potential on Reclamation-owned facilities in the western United States. Reclamation owns few pressurized pipelines, so its assessment focused almost entirely on known elevation drops in canals. Reclamation found that 191 canals had at least some level of hydropower potential, and 70 of those sites could be considered economically viable for development. This report concluded that there are 104 MW of potential capacity and 365 GWh of potential generation at the 373 Reclamation canals studied, nearly one percent of the total 41,170 GWh generated by Reclamation-owned facilities. The report did not examine non-Federal canals or other types of water distribution systems.

State of California.[44] In 2006, the state of California published a small hydro resource assessment that considered the total hydro potential in "man-made water conveyance conduits," which included canals, irrigation ditches, aqueducts, and pipelines. Because of a lack of comprehensive data on current conduit infrastructure throughout the state, the study was restricted only to conduits owned by water purveyors who had entitlements amounting to 20,000 acre-feet or more. Out of 12 large water

City of Boulder: New energy from a municipal water system

Photo Credit: City of Boulder, CO

The City of Boulder, Colorado, owns and operates a system of eight pressurized pipeline hydroelectric power stations, seven of which were constructed within the last 30 years. The City stores water in high-elevation mountain reservoirs. As water travels from over 9,000 feet down to the City, pressures may be in excess of 800 PSI. Small hydropower plants, using conventional Kaplan and Pelton Wheel turbines, were positioned where a mechanical pressure-reducing valve would traditionally have been used to reduce pressure before water enters the City's municipal delivery system. Annual energy production has been more than 50 GWh. Capital costs for the projects ranged from about $300,000 to $4.43 million. The eight plants together have generated more than $1.96 million/yr in revenue and more than a total of $30 million for the City since their construction.

purveyors examined in the study, eight were found to have the potential for small hydro development in their conduits. When that sample was extrapolated to the whole state, including water districts that were not surveyed, this study estimated a total potential of undeveloped conduit hydro capacity of 255 MW, split evenly between irrigation districts and municipal water systems.

State of Colorado.[45] Conduit opportunities in Colorado have been estimated in two more recent reports. By combining results from Reclamation's conduit report with the results found by ORNL, the Colorado Energy Office estimated that there are around 41 potential sites with undeveloped hydro resources in the state. The total generation of these sites is estimated at 738 GWh/year, nearly 1.5 percent of annual electricity generation of Colorado. The 2013 study performed by the Colorado Department of Agriculture discussed above also contained analysis on the hydropower potential of pressurized irrigation systems.[46] On the basis of geographic information system (GIS) analysis that estimated that seven percent, or 175,000 acres, of Colorado's irrigated farmland is suitable for new, pressurized irrigation development, researchers determined that as much as 30 MW of power could be generated from these systems.

State of Oregon.[47] The Energy Trust of Oregon commissioned a 2010 study in which the organization specifically investigated the hydropower potential of irrigation water providers in the state. Out of an initial list of 108 irrigation water suppliers, 29 were identified as having the potential of developing projects of 0.5 MW or larger, "according to diversion, flow and priority date analysis of existing records." Additional refinement on the likelihood of development was used to narrow this pool to a field of 30 sites owned by 14 water suppliers. Onsite analysis of flow rates, seasonality, head, interconnection potential, equipment requirements, potential conduit size and length, and consistency of reservoir withdrawal was used to better gauge development potential. Potential capacity at these sites ranged from 30 kW to 2.6 MW, and annual generation ranged up to 9,040 GWh, nearly 15 percent of annual electricity generation of Oregon.

State of Massachusetts.[48] The Massachusetts Department of Environmental Protection contracted with Alden Research Laboratory (ARL) in 2013 to assess the pipeline type of conduit projects within their state. ARL produced a series of reports and a screening tool that helps identify pressurized pipeline opportunities in public water supplies (PWSs) and wastewater treatment facilities (i.e., publicly owned treatment works, or POTWs). Infrastructure maintained by municipalities or districts is the primary focus of these reports. Ten projects representing a wide variety of capacities and technologies were chosen as examples, and detailed case study material has been made available by the state in the project's Phase I report. The Phase II report, which focused specifically on applicable technologies for conduit hydropower in water distribution and treatment facilities, identified up to 39.5 GWh of energy potential at 61 PWSs and 3 GWh at 70 POTWs that could be developed, these could amount to 0.15 percent of annual electricity generation for Massachusetts.

Numerous case studies are available to demonstrate the feasibility and success of selected conduit projects. The ORNL technical analysis that supports this report to Congress describes seven of them in detail.[49] Work funded by the Energy Trust of Oregon described the experiences in two irrigation districts in Oregon, and Phase I of the ARL study described ten more pipeline projects in Massachusetts.[50]

A number of site-specific, engineering design tools have been developed to aid in the evaluation of conduit projects. None of these site-specific tools have yet been applied to broader, multisite assessments. Examples of these types of tools include the following:

- ***RETScreen.***[51] RETScreen, a Canadian product, may be used for hydro projects of any size and may be used to predict "the energy production and savings, costs, emission reductions, financial viability and risk for central-grid, isolated-grid and off-grid hydro power projects."
- ***HydroHelp.***[52] HydroHelp is a Microsoft Excel–based tool produced by OEL-HydroSys, a Canadian consulting company, which is designed to assist developers with turbine selection for hydropower projects. The program output identifies applicable turbine types, starting with the least-cost option, and can also suggest alternative turbines depending on the specifications of the proposed powerhouse.
- ***Alden Screening Tool.***[53] As part of its recent work for Massachusetts, ARL developed a screening tool that helps evaluate pressurized pipeline opportunities in water supply and wastewater treatment facilities, with a focus on infrastructure maintained by municipalities or districts. The tool operates in readily available spreadsheet software and can be downloaded for free along with a user manual.

In addition to these assessment tools for engineering and economic feasibility analysis, some new GIS tools are now available to evaluate the environmental sensitivity of potential conduit sites. DOI released a GIS tool in the spring of 2014 designed to help with landscape-scale management of public lands.[54] This tool is the product of a larger five-part strategy that DOI has implemented to mitigate potential damage resulting from development of all types of renewable energy, disseminate information more efficiently to the public, increase resource resilience, ensure that conservation efforts are well-planned and complement one another, and improve processes that provide Federal compensation for mitigation.[55] DOE has also supported development of a GIS database that provides environmental attributes to new hydropower sites.[56]

There are some significant gaps among the tools that are available to conduit developers, especially with respect to accessibility and standardization.[57] Because most conduit opportunities are relatively small in capacity, and therefore involve feasibility analysis with limited budget, it is important for assessment tools to be as easy to use and as cost effective as possible; existing tools fall short of these requirements for small developers.

Available Technologies

With the exception of sites developed for hydrokinetic power, most conduit projects can be developed using existing, off-the-shelf hydropower equipment and other existing technologies that are readily available.[58] The availability of such equipment, however, does not mean that additional research and development is not needed, or that cost reductions or performance improvements cannot be gained. Different types of hydropower turbines exist to provide an optimal match to the head and flow that are available at specific sites. Open-channel canal drops tend to have lower and more stable heads, and relatively lower flows, so fixed or variable-pitch reaction turbines, such as Kaplan, bulb, or propeller turbines, are the best choices there. Impulse turbines, such as Pelton wheels, that are designed for higher heads or pressures that are found in some pipelines, may be better options for pipeline sites that have higher changes in elevation. Available technologies for small hydropower deployment have been reviewed numerous times in recent years, starting with work by EPRI and DOE,[59] then by the states of California[60] and Colorado,[61,62] and the EPA.[63] Most recently, ARL[64] conducted a survey of turbine manufacturers and identified 28 available technologies for use in pipeline conduits that have flows of between 0.8 and 2,000 cubic feet per second (cfs) and heads ranging from 1.5 to more than several hundred feet.

Even though there are numerous hydropower technologies available for application to conduit projects, there is also a serious need for further technology improvements that will enable more cost-competitive conduit development. Engineering economics studies have consistently shown that small hydropower projects in general, and conduit projects in particular, suffer from the fact that cost of development rises rapidly at lower head and capacities, creating a problem for the feasibility of low-head turbines (e.g., Figure 10).[65] There are, however, significant opportunities to push down development costs through aggressive research and development.

The following areas for potential cost reductions in small hydropower projects have been identified by ORNL:[66]

- New manufacturing strategies for less expensive, modular systems and advanced materials applied to turbines and generators
- Improved controls and instrumentation
- Innovative design and construction of powerhouses, dams/spillways, and penstocks
- More efficient engineering and permitting

DOE and others are supporting some development of new turbine technologies that may eventually offer lower costs and higher environmental performance applicable to both conduit projects and other types of small hydropower.[67] The International Energy Agency also operates a Small Hydropower Annex that is a focus point for innovative, new small hydropower technologies and supports an internet-based gateway site for more information.[68] DOE initiated a New Hydropower Innovation Collaborative project that will eventually produce a similar information portal in the United States that will be operational late in 2014.[69]

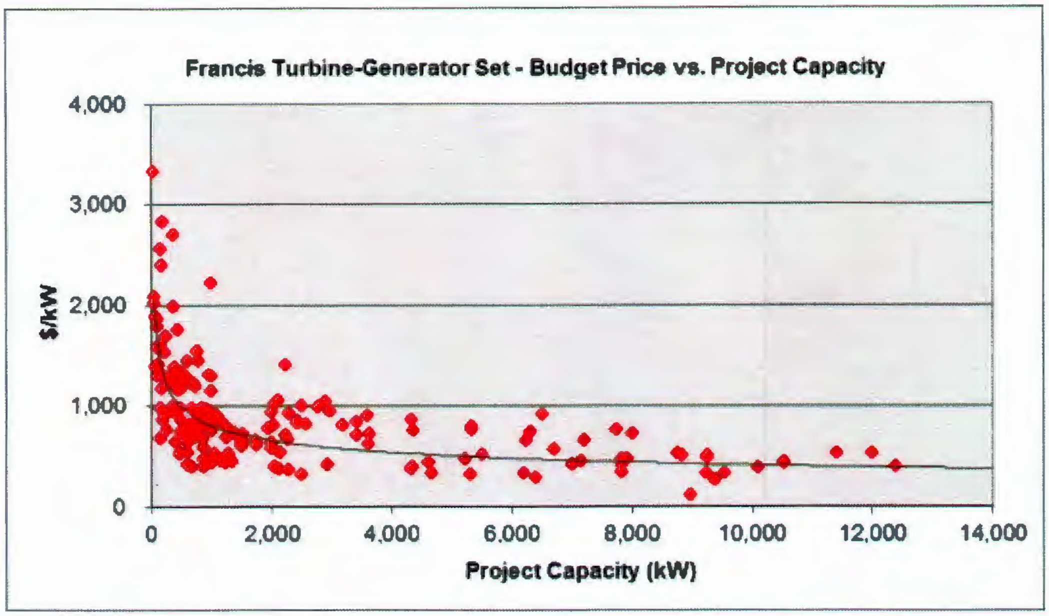


Figure 10. Typical Cost Relationship with Small Hydropower Turbines, Showing a Strong Inverse Relationship between Cost per kW and Capacity. Turbine costs comprise approximately half of project development costs, depending on the site (Source: Zhang et al. 2012[63] [for Francis turbines]).

Barriers and Challenges to Deployment

FERC is the primary regulator of hydropower development in non-federal conduits, although FERC and Reclamation share regulatory control over non-Federal hydropower development in Reclamation owned water conduits.

In response to HREA 2013, FERC has implemented policies that allow more conduit projects to become eligible for a FERC licensing exemption. Only one new FERC-permitted conduit project was placed into service during 2013.[70] According to FERC, "As of December 1, 2014, there have been 46 applications from conduit projects requesting exemption from FERC licensing pursuant to HREA 2013; 26 of these were deemed eligible for exemption, four were rejected, and 16 had not been decided yet."[71] This recent record indicates that few developers are taking advantage of new Federal regulations, and it suggests that perhaps the overall regulatory environment for small conduit projects still involves costs or other risks that are prohibitive.

Developers of small hydropower projects in conduits, typically public entities such as water districts or water utilities, face significant barriers, of which the following are prime examples.

- ***Lack of information regarding appropriate sites.*** Potential conduit development opportunities have not been comprehensive identified across the country, similar to recently completed hydropower resource assessments for existing non-powered dams[68] and new stream-reach development.[69] The Bureau of Reclamation did conduct a 2012 assessment of its conduit infrastructure and various states or other localities have commissioned similar studies, but these types of assessments usually require extremely site-specific information that is largely unavailable nationwide.

Roza Canal: Testing innovative hydrokinetic devices

Photo Credit: Reclamation

Reclamation and DOE have been supporting technology testing and development of canal-based hydrokinetic devices in Reclamation's Roza Canal in the state of Washington since 2011. The canal provides optimal conditions as a test site for no-head, hydrokinetic water power technologies, due to its high velocities and a 10-month flow duration. Hydrovolts, a Seattle based company, received the first License Agreement at this site. Beginning in March 2012, the company conducted a 6-week demonstration of a prototype, "flipwing rotor" turbine there that was designed to produce 5 kW in a flow of 2 m/s and with a nameplate capacity of 18 kW. A second, more recent, demonstration project at Roza Canal has been led by Instream Energy Systems. In August 2013, Instream deployed a hydrokinetic system with a nameplate capacity of 25 kW. The project's rotor and generation equipment was designed by BAE System through a facility use agreement with Instream. Such testing and development is a critically important part of building the knowledge base needed to better understand the potential for new energy developments in conduit projects.

- ***Risk aversion to new technology*.** Owners of possible conduit hydro sites are understandably cautious and risk adverse with respect to the water systems for which they are responsible. There are relatively few existing conduit hydro installations to study as examples to replicate, and most developers have no understanding of or direct experience with available small hydro technologies.[72] The finance community can also be reluctant to invest in new, more cost-effective technologies if they are unproven.

- ***Lack of standardized technology*.** Because relatively few conduit projects have been developed, there are few standard designs. Similar to the situation with other conventional hydropower development, every conduit system is currently custom-engineered, with associated high engineering costs. A custom turbine and engineering configuration will match the conditions at a site and extract an optimal amount of energy from a site, but typically the cost will be higher than a standardized turbine and system design.

- ***Complex permitting.*** Many types of small hydropower projects, including conduit projects that would have minimal impacts (e.g., those within existing pressure reduction vaults), still are required to go through regulatory steps that incur delays and additional costs.[73]

- ***Electrical interconnection.*** Uncertainty in the cost, timing, and technical requirements of the grid interconnection process is especially challenging for small hydro or any other distributed energy resources. Independent system operator processes are typically expensive and time-consuming, with timetables and priorities that are not necessarily consistent with the needs of small hydro developers. To promote interconnection success for small hydro generators, rules are needed that obligate utilities to review applications in a timely manner and to provide detailed cost estimates to interconnection applicants. There also need to be simplified processes for very small generators that are net-metered, and interconnection study and metering requirements that are commensurate with the size of the generator.

- ***Electrical inspection.*** Because few small hydropower projects are installed each year, most electrical inspectors are not familiar with them, and it can be difficult to secure electrical inspection approval. Small hydro facilities are not currently addressed in the existing National Electrical Code. The small hydro industry in the United States is not yet large enough to support mass manufacturing of standardized products that have completed independent certification, such as Underwriters Laboratories product listing. Costs associated with post-manufacture, in-the-field product listing and approval can adversely impact the economic feasibility of small hydro installations.
- ***Financing.*** Small hydropower, including conduit projects, has unique financing challenges, due to factors including lengthy permitting processes and high initial capital costs, variable hydrology, and other project risks. For example, in 2001, FERC estimated that the costs per capacity of licensing for small projects less than one MW were $900/kW, nine times greater than for projects greater than five MW.[74] Despite efforts to improve regulatory processes since then, these types of pressures on small projects still exist. High up-front costs and financial carrying charges are especially difficult for smaller projects. Financing packages in the energy sector tend to be designed for larger projects, with relatively high application and maintenance fees, (i.e., costs that are difficult for small conduit projects to cover). Also, funding is difficult to obtain for initial regulatory costs, because those are not considered an equity contribution to a project's development.
- ***Different tax treatment.*** Hydropower does not receive the same tax treatment as other renewable energy sources, including the Production Tax Credit. For example, hydropower has received one half of the credit that is provided to other renewables.[75]
- ***Technological uncertainty.*** Many of the newer, more innovative and cost-competitive small hydropower technologies that offer a solution to high project costs do not have long operational track records, which can make them questionable investments. Unfortunately, small hydropower technology developers cannot typically afford to fund such applied research, development, and demonstration. More demonstration and testing of advanced technologies are needed to build up a performance record.
- ***State and local policy issues.*** State and local regulatory challenges can be a barrier to small hydro development, including issues associated with water rights as well as state and local environmental requirements. Developers can find themselves in a costly and time-consuming situation of working through the Federal system and then having often to rework through the state and local agencies.

V. Conclusions and Recommendations

Both pumped storage hydropower and conduit hydropower represent clean and renewable energy technologies that can enhance the Nation's energy portfolio. Pumped storage hydropower is a proven, large-scale energy storage solution and the adjustable-speed technology provides additional flexibility for such units. Facilitating the development of new pumped storage units and adjustable-speed upgrades to existing pumped storage units will contribute to grid reliability and facilitate a larger expansion of variable renewable energy in the United States.

New, renewable energy development in water conduits can be a valuable renewable energy asset; however, relatively little of this potential has been developed to date in the United States to assess cost-competitiveness. One barrier to widespread development is the dearth of data and documented outcomes for conduit development, along with guidance and tools for selecting technology and estimating performance and cost-effectiveness.

The recommended actions for improving the prospects for future development of pumped storage hydropower and hydropower in existing conduits are listed below.

Recommendations for New Development of Pumped Storage Projects

Key activities that can help accelerate pumped storage hydropower developments in the United States include the following:

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

Recommendations for New Development of Conduit Projects

There are several actions that could improve the prospects for future development of renewable energy projects in water conduits, including the following:

- Consider the development of feasibility analysis tools appropriate for small developers to estimate the effects of new conduit projects on existing water distribution characteristics (e.g., water pressures throughout a piped distribution system or timing of downstream flows). These tools should be made publicly available and should include the best available economic data;
- Support development of standardized, electrical interconnection rules for small hydropower at facility, distribution, and transmission voltages, along with new, hydropower-specific electrical codes to simplify electrical design, installation, and inspection of new conduit projects (for example, Institute of Electrical and Electronics

Engineers (IEEE) standards or revisions to the National Electric Code.) These can build on successful efforts such as recent legislation in Colorado.[76]

- Continue activities that gather cost and performance data, and best practices from conduit energy development that is underway.