A Review of Technology Innovations for Pumped Storage Hydropower

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HydroWIRES

In April 2019, WPTO launched the HydroWIRES Initiative[1] to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. While increasing deployment of variable renewables such as wind and solar have enabled low-cost, clean energy in many U.S. regions, it has also created a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy but also a source of large-scale flexibility and a force multiplier for other renewable power generation sources. Realizing this potential requires innovation in several areas: understanding value drivers for hydropower under evolving system conditions, describing flexible capabilities and associated tradeoffs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

HydroWIRES is distinguished in its close engagement with the DOE national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the

[1] Hydropower and Water Innovation for a Resilient Electricity System ("HydroWIRES")

HydroWIRES portfolio as well as broader DOE and national laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES Initiative are designed to benefit hydropower owners and operators, independent system operators, regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

More information about HydroWIRES is available at https://energy.gov/hydrowires.

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Executive Summary

Key Takeaways

- Although pumped storage hydropower (PSH) has been around for many years, the technology is still evolving. At present, many new PSH concepts and technologies are being proposed or actively researched. This study performs a landscape analysis to establish the current state of PSH technology and identify promising new concepts and innovations.
- The focus of this study is the review of 12 innovative PSH technologies using a set of predefined evaluation criteria. Because the innovative PSH technologies are at different technology readiness levels (TRLs), this study did not attempt to rank or directly compare innovative technologies to each other. Rather, the goal was to provide an independent review of various proposed PSH technologies and discuss their innovations to assess whether they have the potential to reduce the cost and time required for the construction of new PSH projects in the United States.
- Based on the review performed in this study, several promising innovative PSH technologies have been identified: submersible pump-turbines and motor-generators, geomechanical PSH, open-pit mine PSH, and hybrid PSH technologies.
- This study also discusses potential methods for adding PSH capabilities to certain types of existing hydropower plants and briefly describes several other innovative PSH technologies for which there was not sufficient information available to conduct detailed evaluation.
- Finally, this study also presents innovative construction methods, including new excavation techniques and modular dam construction methods, that could potentially reduce the cost and time required for the construction of new PSH projects.

ES.1 Background and Objectives

Energy storage is essential in enabling the economic and reliable operation of power systems with high penetration of variable renewable energy (VRE) resources. Currently, about 22 GW, or 93%, of all utility-scale energy storage capacity in the United States is provided by PSH. To achieve power system decarbonization goals, a significant amount of new energy storage capacity will need to be added to support the grid as the expected very high penetration of VRE resources progresses. In addition to short-duration energy storage technologies, such as batteries and flywheels, there will be a need for large amounts of long-duration energy storage (LDES) that will provide power system resiliency in case of prolonged extreme weather events and other disturbances. PSH is a commercially available and proven technology that can reliably meet the needs for both short- and long-duration storage. In addition to large amounts of flexible generating capacity, which can be used to balance energy supply and demand and provide a variety of grid services, PSH also provides large amounts of energy storage to store surplus VRE generation and provide energy generation when needed by the system.

Despite these favorable technology characteristics, not many new PSH plants have been constructed in the United States in the last few decades. The developers of new PSH projects face significant challenges, including high capital investments, long construction periods, revenue uncertainties, long permitting and licensing processes, lack of mechanisms to provide revenues for PSH services and contributions to the system, and others. To address these challenges, the U.S. Department of Energy's (DOE's) Water Power Technologies Office (WPTO) has been making investments in PSH technology research and development, focused on new PSH designs and technologies that can meet cost-reduction goals and competitive timelines to commissioning, as well as on developing methodologies to assess the value and role of PSH plants in power systems and the many services that they can provide. Following on this research, WPTO commissioned this PSH portfolio evaluation study to establish the current state of PSH technology, identify trends in technology development, and highlight technology gaps that have yet to be addressed.

This study performs a landscape analysis to establish the current state of PSH technology and identify promising new concepts and innovations. The analysis is not vendor-specific, and should benefit the entire hydropower industry, as well as electric utilities that own and/or operate PSH plants and other developers of new PSH projects. First, a retrospective review of WPTO-funded PSH research and industry-funded PSH technology innovations was conducted to establish the current state-of-the-art of PSH technology. Next, the study investigated a suite of proposed new PSH concepts and technology innovations that may potentially reduce the cost and time to commission new PSH projects. The study focused less on specific technology components and more on overall PSH configurations. It assessed the proposed new PSH concepts and technology innovations to identify the most promising future PSH technologies and configurations that may lead to new PSH deployment, as well as to identify concepts that are not on a realistic path to a deployable technology. The study also included an assessment of innovative excavation and construction methods being employed by the civil infrastructure industry that may have potential to reduce the cost and shorten the time to construct new PSH projects.

ES.2 Evaluation of Innovative PSH Technologies

This study evaluates innovative PSH technologies to provide an objective third-party assessment of their key features, capabilities, and technoeconomic parameters, based on the information available to the project team. The objective of the assessment performed in this study was not to compare innovative PSH technologies to each other, nor to rank them in any particular way with regard to their perceived value, preference, commercialization, or market potential. Rather, the objective was to assess their potential advantages and disadvantages relative to today's conventional PSH plants and whether they may reduce the cost, time, and risk for project development; provide new desirable operational characteristics; or be better suited to provide certain grid services than existing conventional PSH plants.

The following 12 innovative PSH technologies were evaluated in this study:

- Small PSH with reservoirs of corrugated steel and floating membranes;
- PSH using submersible pump-turbines and motor-generators;

- Geomechanical PSH;
- Hybrid PSH and wind plant;
- Integrated PSH and desalination plant;
- Underground PSH using tunnel-boring machines for storage excavation;
- Underground mine PSH;
- Open-pit mine PSH;
- Hybrid modular closed-loop scalable PSH;
- Pressurized vessel PSH;
- Thermal underground PSH; and
- High-density fluid PSH.

This is not an exhaustive list of proposed innovative PSH technologies; other PSH concepts, designs, and ideas are currently being pursued in the United States and other countries. Some of these concepts involve adding PSH capabilities to existing hydropower plants, new hybrid configurations for PSH, and improved excavation techniques, and they are qualitatively reviewed in this report.

To make this assessment of the 12 innovative PSH technologies as objective as possible, we established a set of evaluation criteria, provided in Table ES-1. Additional important factors influence the total cost and construction duration of PSH project development, notably pre-construction regulatory and engineering factors; however, this assessment is not meant to address those issues. During the course of this study, the developers of innovative PSH technologies had an opportunity to review and comment on the summary tables of our preliminary assessments of their technologies and provide input and feedback.

In addition to the above 12 innovative PSH concepts that were assessed using the evaluation criteria presented in Table ES-1, this study also addressed and described other innovative methods and technologies that could potentially reduce the cost and time required to construct new PSH projects. These include new excavation methods using tunnel-boring machines, road-header machines, and oscillating-disc machines, as well as new dam construction methods using modular prefabricated components that can be manufactured offsite and delivered to the project site for assembly.

ES.3 Key Findings of the Study

Although PSH technology has been around for many years, it is still evolving as it integrates innovative concepts being deployed across the infrastructure spectrum. This is a rich innovation space, and many new PSH concepts and technologies are being proposed or actively researched. These include both modifications and improvements of current technologies, as well as some concepts that are very different from traditional PSH plants. These proposed PSH technologies can support various aspects of power grid operations, from bulk power generation and transmission to distribution systems. Of course, there are also tradeoffs, and no technology is optimal in every respect. Which PSH technology is best suited for a certain application or role in the power system depends on various factors, including the PSH unit or plant size, energy storage capacity and duration, operating characteristics, plant location, and others.

Table ES-1 Evaluation Criteria

Criteria	Evaluation Parameters and Considerations	Metrics
Estimated Project Cost	Estimated investment cost or total capital expenditures to develop PSH project	$/kW
Estimated Levelized Cost of Storage (LCOS)	Estimated LCOS over the lifetime of the project	$/MWh
Construction Time	Potential to reduce project construction time compared to current PSH technologies	Years
Project Development Risk	Potential to either increase or reduce project development risks (e.g., by applying either new innovative concepts or applying proven construction methods and technologies used in other industries)	Qualitative
Scalability and Applicability	Whether the PSH design is scalable to allow for a range of capacities (e.g., modular design) and a variety of use cases	Estimated minimum and maximum capacity range (MW)
Operational Flexibility	PSH technology potential to provide flexible operation (i.e., wide operating range, fast ramp rates, quick mode change times)	Estimated operating range
Potential Market Size	Estimated market potential for PSH technology in the United States	MW of capacity or number of installations
Environmental Impacts	Discussion of potential impacts of PSH technology on the environment, including potential public acceptance issues	Qualitative
Physical Siting Limitations	Geographical or topological limitations that may limit the siting opportunities	Qualitative
TRL	Estimated TRL of PSH technology	TRLs 1–9

Based on the review performed in this study, we found that some of the proposed innovative PSH concepts and technologies have the potential to significantly reduce the cost, time, and risk for the development of new PSH projects. We think that three proposed PSH technologies have the greatest potential to progress toward deployment in the United States: (1) submersible pump-turbines and motor-generators, (2) geomechanical PSH, and (3) using open-pit mines to develop new PSH plants. Other innovative PSH technologies also feature excellent innovations and present good value propositions that make them suitable for many storage applications. For example, hybrid PSH/desalination plants may be suitable for development in coastal areas that need fresh potable water. Other hybrid PSH projects that support variable wind and solar generation may be excellent solutions for greater integration of VRE resources into the power grid.

Table ES-2 shows some of the key parameters describing the 12 reviewed innovative PSH technologies, including their estimated unit/plant size, LCOS values, and TRLs. Note that the proposed innovative PSH technologies are at different stages of TRL development and should not be compared directly to each other. Many of them are at early TRL stages and will eventually need demonstration projects to confirm the effectiveness of the technology advancements, and potentially pilot projects to further refine the technology and develop accurate, scalable estimates for construction costs and schedules. Demonstration and pilot projects in the field would significantly help PSH technology developers advance their concepts toward higher TRLs and ultimately to commercialization.

Because the reviewed technologies are at different TRLs, the estimated LCOS values should not be used for ranking technologies, because their cost estimates and other parameters may change as they are further refined through the development process and progress toward commercialization.

Table ES-2 Key Characteristics of Innovative PSH Concepts and Technologies

Technology	Estimated Unit/Plant Size (MW)	Estimated LCOS ($/MWh)	Estimated TRL
Small PSH with reservoirs of corrugated steel and floating membranes	Unit: 0.5–5 Plant: 1–10	246–338	Estimated overall TRL is 4–5. Higher TRL estimate of 6–7 for a project design that uses steel tanks for both reservoirs.
PSH using submersible pump-turbines and motor-generators	Unit: 1–100 Plant: 10–200	156–174	Estimated TRL is 3 for pump-turbine geometry, TRL 9 for submersible motor-generator. Estimated overall TRL is 4–5.
Geomechanical PSH	Unit: 4–40 Plant: 16–320	127–158	Estimated TRL is 5.
Hybrid PSH and wind plant	Unit: 2–4 Plant: 8–32	151–208	Estimated TRL is 7–8.
Integrated PSH and desalination plant	Unit: 50–150 Plant: 100–500	174–230	Estimated TRL is 7.
Underground PSH using tunnel-boring machines for storage excavation	Unit: 100–300 Plant: 500–1,000	210–230	Estimated TRL is 6.
Underground mine PSH	Unit: 10–50 Plant: 20–100	162–201	Estimated TRL is 6.
Open-pit mine PSH	Unit: 100–300 Plant: 100–2,000	193	Estimated TRL is 8–9.
Hybrid modular closed-loop scalable PSH	Unit: 0.1–1 Plant: 1–10	221–369	Estimated TRL is 3.
Pressurized vessel PSH	Unit: 0.1–100 Plant: 1–300	143–827	Estimated TRL is 5.
Thermal underground PSH	Unit: 100–300 Plant: 300–1,000	213–258	Estimated TRL is 4–5.
High-density fluid PSH	Unit: 1–20 Plant: 5–50	127–173	Estimated TRL is 4.

In addition to new PSH concepts and configurations, several proposed advances in excavation and PSH construction methods have the potential to reduce cost and shorten the time required for the construction of new PSH plants. These new methods could improve the economic and financial viability of PSH projects and make them an attractive energy storage solution for the fast-evolving power grid.

Regarding environmental concerns, closed-loop PSH projects and pump-back retrofits may be good ways to add significant quantities of energy storage with minimal environmental impacts. These projects would not require the construction of new dams on rivers and waterways, which reduces the environmental impacts of both the dam and changes to the downstream flow regime.

In summary, although there are currently many different energy storage options available, PSH is still the one with generally the lowest LCOS value and able to provide long-duration storage, which will be essential for integrating high levels of variable wind and solar generation and achieving power grid decarbonization goals. With a variety of advanced existing and promising innovative PSH technologies ready for deployment as closed-loop power systems, PSH can serve as the backbone that supports the transition to carbon-free electricity generation and to the power grid that will provide clean electricity for transportation, manufacturing, and other sectors of the economy.

Acronyms and Abbreviations

A-LEAF	Argonne's Low-carbon Electricity Analysis Framework (computer model)
Argonne	Argonne National Laboratory
AWIA	American Water Infrastructure Act of 2018
BCR	benefit-to-cost ratio
CAPEX	capital expenditure
CFD	computational fluid dynamics
CFSM	converter-fed synchronous machine
CODM	continuous excavation process using oscillating-disc machine
CRHM	continuous excavation process using road-header machine
D&B	drill and blast (excavation method)
DER	distributed energy resource
DFIM	doubly fed induction machine
DOE	U.S. Department of Energy
ESGC	energy storage grand challenge
FAST	Furthering Advancements to Shorten Time (DOE prize competition)
FDE	French Dam Enterprises
FERC	Federal Energy Regulatory Commission
FOA	funding opportunity announcement
GE	General Electric
GHG	greenhouse gas
GLIDES	Ground-Level Integrated Diverse Energy Storage
GW	gigawatt
GWh	gigawatt-hour
HDPE	high-density polyethylene
IFPSH	International Forum on Pumped Storage Hydropower
ICOLD	International Commission on Large Dams
IHA	International Hydropower Association
IPHROCES	Integrated Pump Hydro Reverse Osmosis Clean Energy System
IPP	independent power producer

IRP	integrated resource planning
IRR	internal rate of return
ISO	independent system operator
IUPUI	Indiana University—Purdue University Indianapolis
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LCA	life-cycle analysis
LCOS	levelized cost of storage
LDES	long-duration energy storage
Li	lithium
LLC	Limited Liability Company
MCDA	multi-criteria decision analysis
MPa	megapascal
MW	megawatt
MWe	megawatt electrical
MWh	megawatt-hour
MWth	megawatt thermal
NHA	National Hydropower Association
NOTA	notice of opportunity for technical assistance
NPV	net present value
NREL	National Renewable Energy Laboratory
ODM	oscillating-disc machine
O&M	operations and maintenance
ORNL	Oak Ridge National Laboratory
OPEX	operating expenditure
PNNL	Pacific Northwest National Laboratory
PPA	power purchase agreement
PSH	pumped storage hydropower
PV	photovoltaic

R&D	research and development
ReEDS	Regional Energy Deployment System (computer model)
RHM	roadheader machine
ROI	return on investment
RTE	round-trip efficiency
RTO	regional transmission organization
SENA	Shell Energy North America
StEnSea	Storing Energy at Sea (pumped storage concept)
SwRI	Southwest Research Institute
TBM	tunnel-boring machine
TIC	total investment cost
TRL	technology readiness level
TUPH	thermal underground pumped storage hydropower
UCS	uniaxial compressive strength
VRE	variable renewable energy
WACC	weighted average cost of capital
WPTO	Water Power Technologies Office

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1.0 Introduction

As the power system undergoes rapid changes, pumped storage hydropower (PSH) is an important energy storage technology that has significant capabilities to support high penetrations of variable renewable energy (VRE) resources. In addition to providing highly flexible dispatchable generating capacity, which can balance supply and demand and provide a variety of grid services, PSH can also store large amounts of surplus energy produced by VRE, and provide energy generation when necessary to meet net load demands.[1] This becomes even more critical because many of the current system balancing attributes will be lost as the large rotating machinery in the domestic thermal fleet is retired in favor of smaller, non-dispatchable renewable resources.

According to the 2021 *U.S. Hydropower Market Report*,[2] there are currently 43 PSH plants in the United States. They have a total installed power capacity of 21.9 GW and about 553 GWh of energy storage. This represents about 93% of all utility-scale energy storage capacity and about 99% of all energy storage in the United States. Since 2010, about 1,300 MW of new PSH capacity has been added in the United States, mostly as upgrades and repowering of existing PSH plants. Only one new PSH project was commissioned during this time (Lake Hodges, 40 MW, in 2012).

Over the last 20–25 years, the developers of new PSH projects have been facing and still face significant challenges, including those associated with the magnitude of project costs; the length of time from initial project investment until the project starts generating revenue; permitting challenges and construction risks; competition from other storage technologies; and lack of mechanisms to provide revenues for some PSH services and contributions to the system. To address these challenges, the U.S. Department of Energy's (DOE's) Water Power Technologies Office (WPTO) has made several investments in technology research and development (R&D), focused mostly on new PSH designs and technologies that can meet cost-reduction goals and competitive timelines to commissioning. The WPTO-funded research also focuses on developing methodologies for assessing the value and role of PSH plants in the power systems and the many services they provide. This work resulted in the development of a PSH Valuation Guidebook (Koritarov et al., 2021) which provides the PSH developers and other stakeholders with a valuation methodology and detailed step-by-step process for valuing existing or new PSH projects. WPTO also commissioned this PSH portfolio evaluation study to establish the current state of PSH technology, evaluate impacts achieved through WPTO investments, identify trends in technology development, and highlight technology gaps that have yet to be addressed.

This study analyzes the existing PSH landscape to establish the current state of PSH technology and identify promising new concepts and innovations. The analysis is not vendor-specific, and we hope this work will benefit the entire hydropower industry, as well as the electric utilities that own and operate PSH plants and other developers of new PSH projects.

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[1] Net load is the difference between the total system load and the load supplied by VRE.
[2] See https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf.

First, a retrospective review of WPTO-funded PSH research and industry-funded PSH technology innovations was conducted to establish the current state of the art of PSH technology. Next, we investigated proposed new PSH concepts as well as technological innovations that may potentially reduce the cost and time to commission new PSH projects. This study focused less on specific technology components and more on overall PSH configurations. The study also investigated innovative ways to reduce time, cost, and risk associated with commissioning new PSH projects, as explored in the WPTO's FAST[3] Commissioning for Pumped Storage Hydropower prize competition.

Our study assessed the proposed new PSH concepts and technology innovations to identify the most promising future PSH technologies and configurations that may lead to new PSH deployment, as well as to identify dead-end concepts that are not on a realistic path to becoming a deployable technology. The study also included an assessment of innovative new excavation and construction methods that may have a potential to reduce the cost and shorten the time required for the construction of new PSH projects.

To evaluate the proposed PSH innovations and technologies, the authors mostly relied on information provided by technology developers in publicly available literature, company websites, presentations at industry conferences and workshops, and other publicly available sources. The purpose of this study was not to critically review, verify, or validate developers' cost estimates and other technology parameters, but to provide a landscape analysis of the latest trends in PSH innovations and discuss potential advantages and disadvantages of proposed new PSH concepts and technologies.

[3] FAST stands for "Furthering Advancements to Shorten Time."

2.0 Overview of PSH Technology

2.1 Brief History of PSH

The precursors of modern PSH plants first appeared in Europe in late 19th century. In 1882, a mechanical water storage plant was built in Zurich, Switzerland (DOE, 2016). This plant used a reciprocating pump powered by the wind to store water in an upper reservoir. The plant did not have a generator to produce electricity; instead, the water from the upper reservoir was released to drive a waterwheel that powered belt-driven machines (Donalek, 2020). The first pumped storage plant was built in Zurich in 1891 on the Limmat river, followed by a second installation in 1894 at Lake Maggiore, and a third one in 1899 at the Aare River (Brun et al. 2020). Another early example was the pumped water storage plant built in Luino, Italy, in 1894. It used a 50-kW centrifugal pump to drive a spinning mill (Donalek, 2020).

In 1908, a PSH plant was built for test purposes (two hydraulic machines and two electrical machines) in Heidenheim, Germany. This was followed in 1909 by the construction of the first large PSH plant near Schaffhausen, Switzerland, which had a capacity of 1.5 MW and used a separate pump and turbine (Donalek, 2020). In the United States, the first PSH plant was the Rocky River project, which was commissioned in 1929 in Connecticut (DOE, 2016). In the original design, the Rocky River PSH used two pumps, rated at 8,100 horsepower each, to pump the water from the Housatonic River up to Lake Candlewood. A single generator rated at 24 MW was used to generate electricity (Donalek, 2020).

The need for energy storage was recognized very early during the development of electric power systems. Most early power systems at the beginning of 20th century operated as small, isolated systems, supplying their local electricity demand. It was rather challenging to balance their load and generation at all times, especially with the limited technology for system monitoring and control that was then available to system operators. Conventional hydropower stations with large reservoirs and PSH were the only utility-scale energy storage technologies available at that time.

Isolated power systems started interconnecting with each other, and regional interconnections in were developed in the early to mid-20th century. As this occurred, interconnected power systems could rely on each other to balance their loads and generation and the need for energy storage decreased. Power exchanges among interconnected systems reduced the amount of reserve capacity (e.g., spinning reserve) that each system individually needed to maintain. They also significantly increased the operational reliability of regional interconnections.

A big wave of utility-scale energy storage development occurred in the second half of the 20th century, following the development of large coal and nuclear generating units. The key driver for the construction of large PSH plants was the need to provide additional load for to operate coal and nuclear units during the night, and to serve as a reserve in case large coal and nuclear generating units experienced forced outages. Therefore, the operation of PSH plants at that time was typically characterized by a diurnal cycle, where the PSH plants generated electricity during the daily peak period and consumed electricity for pumping at night.

At present, the key driver for the deployment of energy storage technologies is the rapid penetration of wind and solar technologies for electricity generation, complicated by the loss of grid-stabilizing system inertia as large thermal resources are retired. Smaller amounts of these VRE resources have been integrated into the power system using the flexibility of existing conventional generating units and transmission systems. However, it is now understood that large amounts of energy storage capacity will be needed to integrate high penetrations of wind and solar generation.

Many utilities or power systems have been increasingly developing large amounts of wind and solar generation, but not all have strong interconnections with large regional power systems (e.g., Ireland, Spain, Portugal), so they have started to build new PSH plants to balance the variability of these renewable resources. Currently, the largest amount of new PSH capacity is being built in China; this country is also characterized by the largest wind and solar generation capacity in the world. Another driving factor for PSH plants in China is the revenue system, which is a combination of a fixed annual capacity-based payment and generation-based tariff intended for cost recovery (IFPSH, 2021).

2.1.1 Overview of PSH Technology and Its Benefits for the Grid

PSH is an energy storage technology that utilizes the elevation difference between two water reservoirs to store energy (Figure 2-1). Energy is stored as potential energy of water in the upper reservoir. To store energy, the water is pumped from lower to upper reservoir, typically at times when electricity prices are low (e.g., due to low net electricity demand, or when there is surplus electricity generation). To generate electricity, the water is released from upper reservoir and its potential energy is converted to kinetic energy that runs a turbine, which turns the generator that produces electricity.

Electricity is typically generated in this way during times of high demand or high electricity prices, when the system needs more power. This type of operation is referred to as the energy or price arbitrage. Typical round-trip efficiency (RTE; cycle efficiency) of new PSH plants is currently around 80%, which means that price arbitrage is economical if the electricity price when generating is at least 25% higher than the electricity price used for pumping. In addition to load shifting, PSH provides a variety of grid services, including inertial response, frequency regulation, operating and contingency reserves, voltage support, black start, and others.

Most existing PSH plants use reversible pumps/turbines, which are typically Francis-type turbines designed for both generating and pumping. The Tennessee Valley Authority constructed the first reversible pump/turbine (59.5 MW, Hiwassee Unit 2) in North Carolina in 1956 (DOE, 2016). Before that, PSH plants employed a pump and motor on one shaft, and a turbine and generator on another shaft not connected to the first. Separate pumps and turbines are still used for some PSH configurations, such as in ternary, quaternary, and pump-back PSH plants that have a separate pumping station. A pump-back PSH plant can utilize natural inflows into the upper reservoir to produce electricity as a conventional hydropower plant, but can also pump the water back into the upper reservoir for additional storage as a PSH plant.

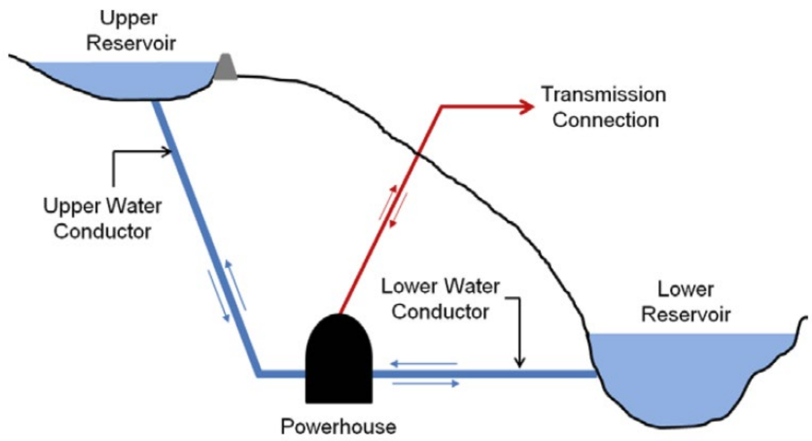

Figure 2-1 Typical Configuration of a PSH Plant (Source: Koritarov et al., 2014)

PSH plants that are continuously connected to naturally flowing river or other water body are called open-loop PSH plants. In contrast, the upper and lower reservoirs of closed-loop PSH plants are typically manmade and are not continuously connected to naturally flowing bodies of water. The power output of a PSH generator depends mainly on the hydraulic head and flow. While the head can vary within the designed limits, depending on the water levels in the upper and lower reservoirs, the flow through the turbine is typically used to regulate the power output.

PSH is a very flexible energy storage technology, with quick startup times and fast ramp rates. While most existing PSH plants were envisioned for one daily pumping and generating operation cycle, over the past decade they have been performing multiple pumping/generating cycles per day as they are called upon to integrate increasing amounts of variable renewable resources (e.g., wind and solar). This creates some challenges with system hydraulics, degradation of equipment, and in some cases environmental impacts. New advances in PSH technologies are currently being integrated that allow for multiple cycles per day without these impacts. Such advances have already been included in projects commissioned in Europe, China, Japan, and other parts of the world. In addition, advanced PSH technologies (i.e., adjustable speed and ternary PSH units) are being developed to provide even more flexibility to power systems and support higher penetration of variable renewables. For example, while conventional fixed speed PSH units can provide frequency regulation in the generating mode of operation only, advanced PSH technologies can regulate frequency in both generating and pumping modes of operation. In addition, advanced PSH technologies provide flexible dispatchable capacity in the pumping mode of operation as well—an important feature that can compensate for the variability of demand and VRE resources.

The size of PSH generating units can vary widely from very small (about 1 MW) to very large (hundreds of megawatts). Because multiple generating units can be housed in a single powerhouse, some PSH plants may have a total capacity of several thousand megawatts. The largest PSH plant in the world is the Bath County Pumped Storage Station, constructed in 1985 in the state of Virginia in the United States, with a total installed capacity of 3,003 MW. For grid-scale applications it is often desirable to have high power output and large energy storage, so most PSH plants that were constructed in the past were large, with a plant capacity of several hundred megawatts. Projects of large size also benefited from economies of scale, making them more cost-effective per unit of capacity. At present, due to the increasing penetration of distributed energy resources (DERs), there is also an interest for smaller PSH plants. Significant research has been carried out in recent years to support the development of small modular PSH plants, as a way of reducing the project costs by standardizing components and using off-the-shelf equipment (Hadjerioua et al., 2014; Witt et al., 2015).

Compared to the other grid-scale energy storage technologies, PSH has several advantages: the capability to store large amounts of energy for long periods of time; the ability to provide large quantities of flexible, dispatchable generating capacity; a very long economic lifetime (50 years or more); and A long cycle life without significant degradation of performance. Typically, PSH infrastructure is designed for 80 or more years of operation, if properly maintained. The power units (pump-turbines and motor-generators) may last 30–40 years and can be replaced after this time while using the same civil infrastructure (e.g., reservoir and waterways).

PSH is a proven energy storage technology that can provide very low cost energy storage,[4] as well as a variety of grid services, such as the inertial response that is increasingly important for the stability of power systems with large penetration of variable renewables. In addition, PSH is currently the only commercially available grid-scale technologies that can provide long-duration energy storage (LDES).[5] LDES is very important in power systems with large penetration of variable renewables, for both storing excess generation and providing dispatchable capacity during extreme weather events, such as extended periods of low wind and/or solar generation.

2.1.2 Current Status of PSH Capacity Development

According to the 2021 Hydropower Status Report (IHA, 2021), published by the International Hydropower Association (IHA), the total PSH capacity in the world in 2020 was about 160 GW (Table 2-1). Most PSH capacity is in Asia (e.g., China and Japan), followed by Europe and North America. New PSH capacity is being developed very quickly, with most new construction taking place in Asia—especially China and India—and in Europe. For example, about 30 GW of new PSH capacity was under construction in China[6] in 2019. Figure 2-2 illustrates global PSH development activities in 2019 (DOE, 2021), with over 220 GW of new PSH capacity under construction or undergoing permitting and licensing.

In the United States, the 2021 U.S. Hydropower Market Report (DOE, 2021) lists 43 PSH plants in operation with a total installed capacity of 21.9 GW (DOE, 2021) and 553 GWh of energy storage. The newest PSH plant in the United States was commissioned in 2012 (Lake Hodges, 40 MW) in California. Because of favorable geography, which allowed for a significant elevation difference between the lower and upper reservoirs, most existing PSH plants in the United States were constructed in mountainous areas near the east and west coasts. However, several PSH projects were also constructed in the Midwest, including a large 1,876-MW Ludington project in Michigan, which uses Lake Michigan as its lower reservoir. The 2021 U.S.

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[4] Mongird et al. (2019) estimated total PSH project costs at $165/kWh.
[5] While no single definition has been adopted yet, LDES is typically defined as 8 or more hours of storage.
[6] See https://www.reuters.com/article/us-china-renewables-state-grid-idUSKCN1P30PD.

Hydropower Market Report (DOE, 2021) states that, in 2019, PSH accounted for about 93% of all utility-scale energy storage power capacity in the United States and about 99% of all energy storage capability (Figure 2-3).

Table 2-1 Global PSH Capacity by Region

Region	PSH Capacity (MW)
Africa	3,377
East Asia and Pacific	69,454
South and Central Asia	7,751
Europe	54,876
North and Central America	23,032
South America	1,004
World	**159,494**

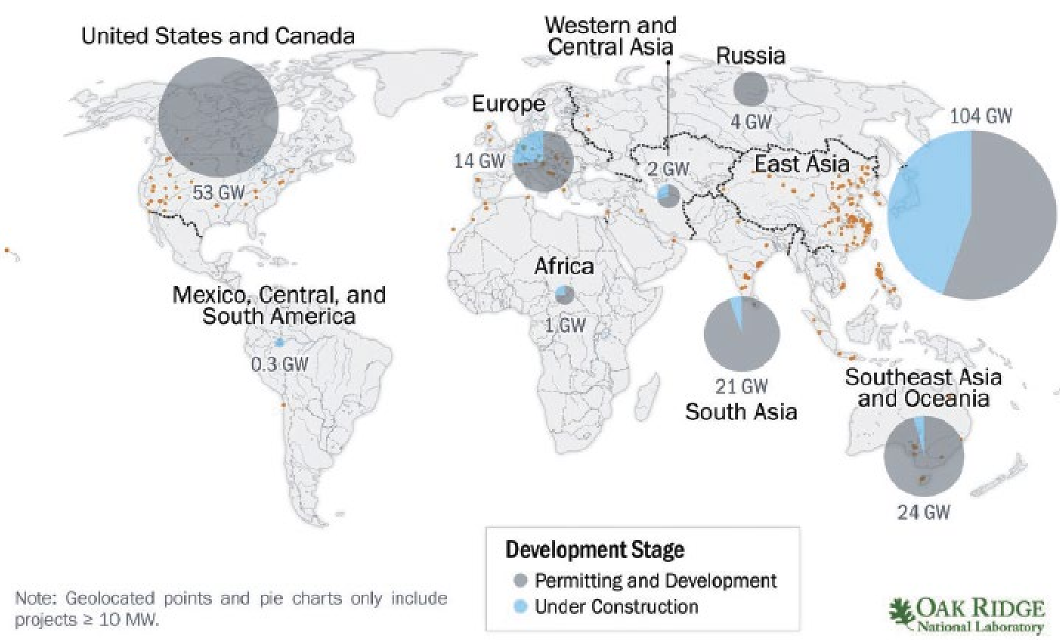

Figure 2-2 Global PSH Development Activities in 2019 (Source: DOE, 2021)

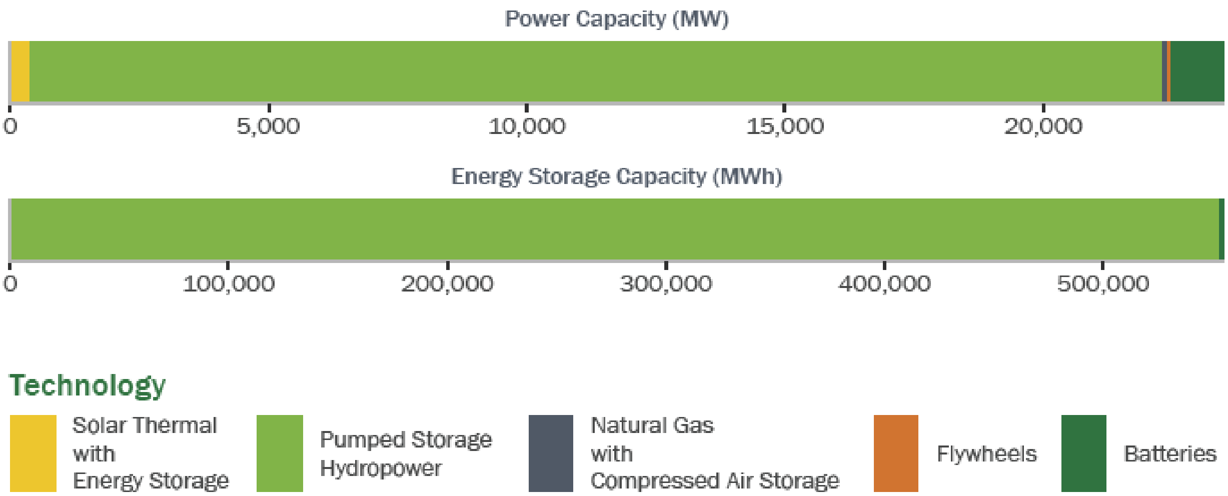

Figure 2-3 Capacity and Energy Storage Capability of Utility-Scale Energy Storage Technologies in the United States in 2019 (Source: DOE, 2021)

Most of the PSH projects in the United States were developed from the 1960s through the 1990s, primarily by electric power utilities (i.e., investor-owned utilities, public utilities, and customer cooperatives). Federal agencies, such as the Bureau of Reclamation and U.S. Army Corps of Engineers, also own several PSH projects. In recent years in the United States, many private developers and independent power producers (IPPs) have become interested in developing new PSH projects. Currently, it is mostly private developers, rather than electric utilities and federal agencies, that are planning the construction of new PSH projects in the United States.

2.2 Current State of PSH Technology

2.2.1 Fixed-Speed PSH Technology

Most existing PSH plants in the world use traditional fixed-speed (or single-speed) technology. They employ a synchronous machine as motor-generator, which operates in sync[7] with the grid frequency. This is also the case with most other generating technologies, as they typically employ synchronous machines to generate electricity. While other technologies use synchronous machines only as generators, PSH plants use them as both motors and generators. The synchronous machine is used as a motor when the PSH unit operates in the pumping mode, consuming the electricity from the grid to pump the water into the upper reservoir. The same synchronous machine is used as a generator when the water is released from the upper reservoir, reversing the direction of rotation, to generate electricity for the grid.

[7] This is always true in steady-state conditions, which means most of the time (e.g., in normal operation). However, in transient conditions (i.e., during outages of other generating units, or other contingency events), there might be a difference in the frequency of the synchronous machine and the frequency of the grid, until the grid frequency is restored to nominal value. These events are rare and of short duration, so it is appropriate to say that fixed-speed PSH plants operate in sync with the grid frequency.

Existing fixed-speed PSH units in the generating mode of operation technically can operate between approximately 30% and 100% of their rated power output. However, most existing fixed-speed PSH units typically do not operate below 60% of their rated power output to avoid "rough zone[8]" operation, which accelerates turbine wear and tear. When operating in the rough zone, typically between 40% and 60% of rated power, the hydropower turbine may experience vibrations and increased cavitation (material pitting) due to reduced water flow. Therefore, prolonged operation in the rough zone may accelerate wear and tear on the turbine and other equipment, so PSH operators try to avoid extended operation in the rough zone. Because most PSH plants contain several units within the same powerhouse, in most cases it is relatively easy to avoid rough zones by distributing the load to different units or by shutting down one unit. In addition, equipment manufacturers are now able to design turbines that have an extended operating range from 0% to 100%, with little to no rough zone. This technology is being used in retrofits of the existing PSH fleet and in new PSH installations. This new generation of fixed-speed PSH turbines gives operators excellent operational flexibility.

A fixed-speed PSH unit with a reversible pump-turbine can vary its power output in generating mode; however, in pumping mode at a given head it always consumes the same amount of power from the grid. Regarding grid services, fixed-speed PSH units can provide regulation and spinning reserve services in the generating mode of operation. On the other hand, because they cannot vary their pumping power, they cannot provide regulation service in pumping mode. Spinning reserve service can still be provided in pumping mode by turning the pumping off completely (shutting the unit down), which is equivalent to adding the same amount of generating capacity to the power system. However, this can only be performed in steps that correspond to individual unit sizes in the PSH plant.

2.2.2 Adjustable Speed PSH Technology

Adjustable-speed PSH technology, also called variable speed in some areas of the world, was developed in Japan in early 1990s and first applied at the Yagisawa PSH plant[9] using power converters with semiconductor technology. The key driver for this was the need for increased flexibility in the power system at night. Because electricity demand is low during the night, mostly baseload generation remains in operation during the night to meet the electricity demand. PSH plants are highly desirable in this situation, because they can provide additional nighttime load for baseload units through pumping, thus allowing more must-run baseload capacity to continue operating overnight. PSH plants can also provide more flexibility to the grid by following the system load while generating, thus allowing for a steady operating regime for baseload generating units. Because adjustable-speed PSH units can vary the power they consume from the grid for pumping, they can also provide regulation service in the pumping mode of operation. The adjustable-speed units also have a variety of other operational and performance characteristics that make them very desirable for power systems with a large share of baseload generation or, at the other end of the spectrum, for power systems with a high penetration of

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[8] Rough zone: 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). For more information, see: https://www.hydroreview.com/world-regions/standardizing-parameters-for-managing-rough-load-zones-and-no-run-zones/#gref.

[9] Yagisawa unit 2 was converted from fixed speed to adjustable speed by Toshiba Corporation.

variable renewables. For this reason, a number of adjustable speed PSH plants were constructed in Japan, as well as in several European countries and a few other countries around the world. In the United States, there are no adjustable-speed PSH plants in operation. However, developers of many proposed new PSH plants are considering this technology to participate in ancillary services markets in addition to the energy and capacity markets.

At present, there are two main types of adjustable-speed PSH technology. One uses a doubly fed induction machine (DFIM) with a frequency converter that controls the rotational speed of the machine (Koritarov et al., 2013a). As the frequency converter is used to adjust the rotational speed of DFIM in a relatively narrow range (approximately ±7%) around the nominal speed, the capacity of the converter does not need to match the full rated power of the DFIM unit. Typically, the frequency converter is sized to just a fraction of the full power of the DFIM unit.

The other type of adjustable speed PSH technology is a converter-fed synchronous machine (CFSM). This technology employs a synchronous machine as motor-generator, which is controlled using a "full-size" frequency converter, the size of which matches the capacity of the generating unit. Until recently, because of the cost of power electronics, CFSM technology was only considered economically viable for smaller PSH units (e.g., less than 100 MW). With the advancement of technology and decreasing cost of power electronics, CFSM is now available and potentially economical even for larger PSH units (Aubert et al., 2014). The full-size frequency converter CFSM units employ allows for a wider range of power factor and speed adjustments than DFIM technology, which uses smaller converters. Figure 2-4 illustrates configurations of fixed-speed and two adjustable-speed PSH technologies.

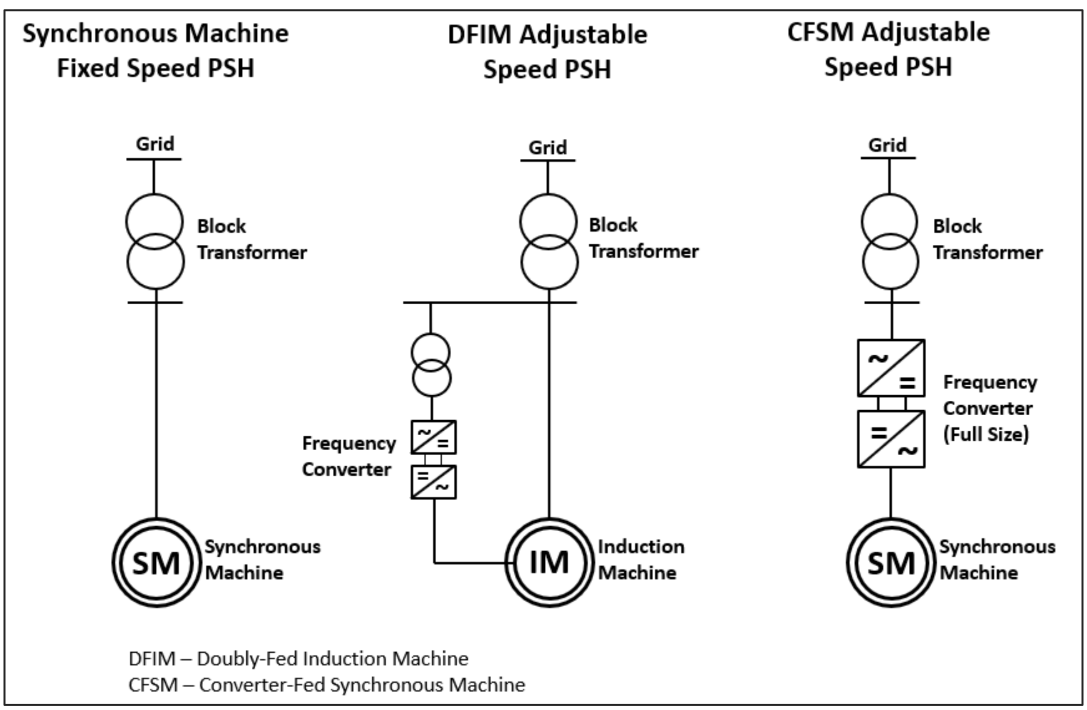

Figure 2-4 Single-line Diagrams of Fixed- and Adjustable-Speed PSH Technologies (Source: Koritarov et al., 2015)

Fixed-speed PSH technology is very flexible in the generating mode, and the latest generation of advanced fixed-speed PSH plants has been improved to have faster responses (i.e., fast ramp rates, short mode change times) and wider operating ranges (lower minimum load, wider operating head range). However, adjustable-speed PSH technology still has several operational advantages. Compared to fixed-speed units, the main advantages of adjustable speed units include:

- Ability to provide regulation service in the pumping mode of operation by varying the power consumed for pumping. Adjustable-speed PSH units can typically operate in the range of 70–100% of their rated pumping capacity.

- Slightly higher operating efficiency in the generating mode of operation, especially at partial load operation. This is because the rotating speed of the adjustable-speed machine can be optimized for a given head and flow rate through the turbine.

- Narrower (if any) rough zone than that of the fixed speed technology, again because the rotor speed can be adjusted for the given flow rate.

- Lower technical minimum load, as low as 20–30% of the rated capacity, which provides for a wider operating range than that of fixed-speed units.

- Because adjustable-speed units operate at optimal or close to optimal speeds, even at partial loads, they experience less wear and tear. This means they have a longer expected lifetime than fixed-speed units.

- Adjustable-speed units can provide more flexible voltage support for the power system, because they have electronically decoupled control of active and reactive power through a frequency converter.

- Compared to fixed-speed units, adjustable-speed units have better dynamic response characteristics in case of grid disturbances. This contributes to improved power system stability and fewer frequency drops due to sudden generator or transmission outages.

On the other hand, adjustable-speed units have slightly higher capital investment costs than fixed-speed units of the same size, because they require additional power electronics and other equipment.

At present, there are more than 20 adjustable-speed PSH units in operation, mostly in Japan and Europe. Some of these include fixed-speed units that have been converted to adjustable-speed technology. In those cases, the additional expenses for conversion were deemed to be justified by the economic benefits and operational flexibility the adjustable-speed technology provides. However, not every fixed-speed PSH unit is a good candidate to be converted to adjustable-speed technology. Certain technical and space conditions have to be met in order for them to be good candidates. For instance, space should be available in the powerhouse to accommodate additional equipment. One key condition is that the powerhouse ceiling should be high enough to allow for the additional height of adjustable-speed units (Henry et al., 2013).

2.2.3 Ternary PSH Technology

Ternary technology employs three components, a motor-generator, a separate turbine, and a separate pump. This was a typical PSH configuration before the invention of the reversible pump-turbine. However, modern ternary technology is typically designed with so-called "hydraulic short circuit" capabilities, which provides for excellent operational flexibility. Pump and turbine can be mechanically disconnected by a clutch; however, when connected, they both operate at the same time and rotate in the same direction. This kind of operation is referred to as "hydraulic short circuit," "hydraulic bypass," or "mixed mode" operation.

The three components—motor-generator, pump, and turbine—can have several different configurations in a ternary PSH plant (Koritarov et al., 2013b). Figure 2-5 illustrates two ternary plant configurations, both with hydraulic short-circuit capability. One has a motor-generator located on the top, above the turbine and the pump; the other has a motor-generator located between the turbine and the pump. A horizontal configuration of the ternary unit is also possible.

The key advantage of this technology is that the power of the ternary unit can vary in an almost continuous range from -100% to 100% of its rated power. This is achieved by controlling the flow through the turbine and the amount of power used to run the pump. In generating mode, ternary units normally operate as fixed-speed PSH units (with the pump disconnected). In pumping mode, they can operate in hydraulic short-circuit mode, with the turbine and pump coupled by the clutch. In this mode, power is supplied to the pump by a combination of power from the turbine and from the grid. By regulating the flow through the turbine, the plant operator can control how much power is taken from the grid to run the pump. In this manner, the ternary unit can vary the pumping power that it receives from the grid and thus provide regulation service through the full range of its pumping mode. When operating in the short-circuit mode, the loss of efficiency is the price paid for precise power regulation provided to the grid.

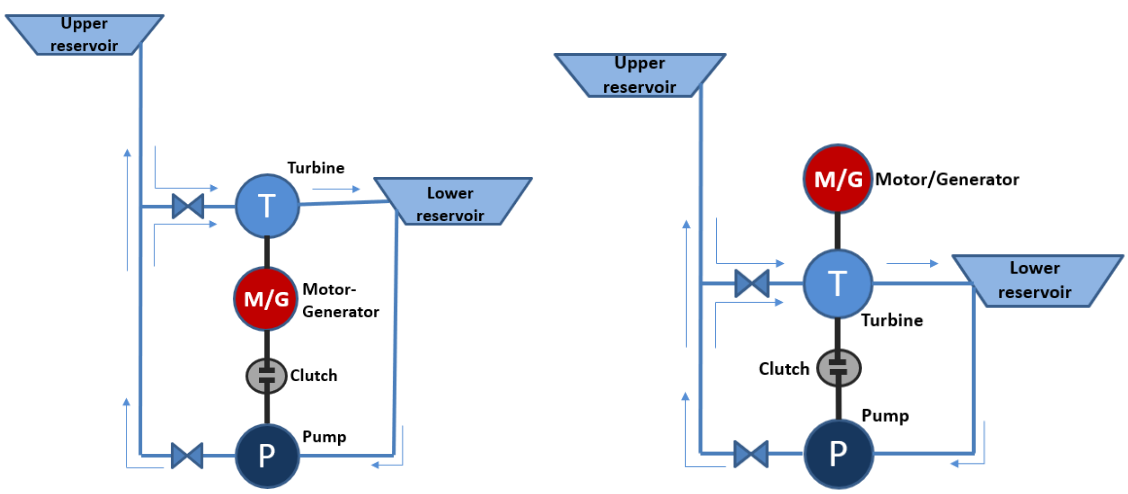

Figure 2-5 Two Configurations of Ternary PSH Technologies with Hydraulic Bypass (Source: Koritarov et al., 2013b)

When operating in hydraulic short-circuit mode, the ability to operate the pump and turbine simultaneously provides added flexibility to the operation of ternary PSH units. Because the pump and turbine are both on the same shaft and rotate in the same direction, the ternary unit does not need to stop and change its direction of rotation when it changes from pumping to generating, and vice versa. Ternary units typically employ Pelton turbines, but Francis or other turbine types could be used, depending on the hydraulic characteristics of the site.

Table 2-2 compares key technical and operational characteristics of fixed-speed, adjustable-speed, and ternary PSH technologies (DOE, 2016). Note that the actual performance and operating characteristics of individual PSH plants may differ, depending on the project design and site-specific conditions.

Because of the additional equipment (separate pump and turbine, the hydraulic clutch) and hydraulic short-circuit design, ternary PSH units cost more than adjustable-speed technology. However, ternary units may provide more operational flexibility, especially in the pumping mode of operation.

Several ternary PSH plants with hydraulic short-circuit capabilities have been constructed in Europe. Typical examples of ternary PSH plants are Kops II[10] (450 MW) in Austria and Hongrin-Leman[11] (240 MW) in Switzerland.

Table 2-2 Typical Operating Capabilities of PSH Technologies

Capability	Fixed-Speed PSH	DFIM Adjustable-Speed PSH	Ternary PSH with Hydraulic Bypass and Pelton Turbine
Generation Mode			
Power output (% of rated capacity)	30–100%	20–100%	0–100%
Standstill to generating mode (seconds)	70	75–85	65
Generating to pumping mode (seconds)	240–420	240–415	25
Frequency regulation	Yes	Yes	Yes
Spinning reserve	Yes	Yes	Yes
Ramping/load following	Yes	Yes	Yes
Reactive power/voltage support	Yes	Yes	Yes
Generator dropping	Yes	Yes	Yes
Pumping Mode			
Power consumption (% of rated capacity)	100%	60–100% (75–125%)[a]	0–100%
Standstill to pumping mode (seconds)	160–340	160–230	80
Pumping to generating mode (seconds)	90–190	90–190	25
Frequency regulation	No	Yes	Yes
Spinning reserve	No	Yes	Yes
Ramping/load following	No	Yes	Yes
Reactive power/voltage support	Yes	Yes	Yes
Load shedding (pump dropping)	Yes	Yes	Yes

[a] If a PSH unit is converted from fixed to adjustable speed and the same pump-turbine runner is used, its power consumption may range from 75% to 125% of the former fixed-speed power consumption (100%).

[10] See https://www.waterpowermagazine.com/features/featurea-second-option-kops-ii-pumped-storage-plant/.

[11] See https://www.andritz.com/hydro-en/hydronews/hn32/hongrin-lemans-switzerland.

2.2.4 Quaternary PSH Technology

Quaternary technology is similar to ternary, except that in addition to a separate pump and turbine, quaternary units also have separate motors and generators. Since there are four separate components in this configuration, this PSH plant design is called quaternary. Unlike ternary technology, which has a single shaft for the pump, turbine, and motor-generator, quaternary technology employs a power converter, motor, and pump on one shaft and a turbine and generator on another. Therefore, each quaternary unit has two shafts (essentially a separate pump and generator set), which is a distinct design among PSH technologies. Like ternary technology, quaternary technology can also be designed for hydraulic short-circuit operation. This provides almost full operational flexibility from -100% to +100% of generating unit's rated power, except for a small band between the minimum turbine loads in the generating and pumping modes of operation. In hydraulic short-circuit operation, a quaternary unit can operate both the turbine and the pump at the same time. In pumping mode, the power taken from the grid can be regulated by controlling the flow through the turbine, and by controlling the power supplied to the motor through converter.

Because it includes additional equipment and has a larger powerhouse footprint, the quaternary design requires somewhat higher initial capital expenditures (CAPEX), but it provides great operational flexibility in both generating and pumping modes. Figure 2-6 is a schematic of the quaternary PSH design.

In the United States, quaternary technology has been considered for several proposed new PSH projects, mainly in areas with high wind and solar power generation. If constructed, these PSH plants would provide system operators with large dispatchable capacity and additional operational flexibility to compensate for the variability of wind and solar power generation.

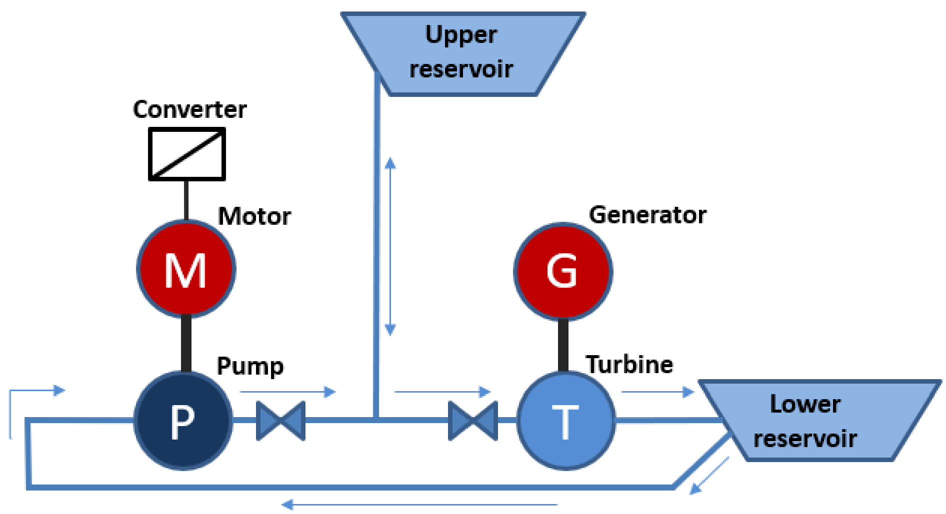

Figure 2-6 Illustration of Quaternary PSH Design with Hydraulic Short Circuit

2.2.5 Small, Modular PSH Technologies

At present, a significant amount of research is devoted to developing small, modular PSH technologies, which are often focused on reducing civil infrastructure components rather than the pumping/generating equipment features described above. The key idea is to minimize costs by using standardized off-the-shelf equipment and components, which would allow small, modular PSH installations to be designed and constructed in very short time periods. Small, modular PSH plants are typically considered to be less than 10 MW, but they could be larger if the site allows for multiple units. Most projects are envisioned to be closed-loop design. Although small, modular PSH plants are characterized by their size, their technologies and plant configurations can vary widely, depending on the location and site characteristics.

2.3 Key Challenges and Barriers for the Development of PSH Projects

Despite all the benefits provided by PSH, very few new PSH plants were constructed in the United States in the last couple of decades. Here we briefly describe some of the key challenges and barriers faced by the developers of new PSH projects.

2.3.1 Revenue Uncertainties

Many areas in the United States and around the world are now operating as fully restructured competitive electricity markets. In the United States there are seven electricity markets that are operated by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs).[12] The market rules for energy and capacity price formation, as well as for grid services, vary from market to market. Most wholesale electricity markets have both energy and capacity markets, while some have only energy markets. Not having a capacity market—or having a poorly designed capacity market—is an obstacle for PSH developers, because capacity payments are a very important revenue stream for repaying the investment costs. PSH developers also face uncertainty related to future electricity market prices under conditions of large deployments of VRE generation, which have near zero marginal cost of operation. This may translate into uncertain revenues from energy/price arbitrage.

The rules related to provisions and remunerations for grid services also vary from market to market. The key obstacle here is that PSH plants provide many grid services that are currently not remunerated in organized electricity markets. These are mostly system-wide services such as inertial response, reduced curtailments of VRE generation, reduced cycling and ramping of other units in the system, improved power system stability, increased reliability and resilience of grid operations, and reduced transmission congestion and transmission deferral benefits. The *PSH Valuation Guidebook* (Koritarov et al., 2021) provides detailed descriptions of the various benefits that PSH plants provide to the system and how to evaluate them.

To avoid or reduce revenue uncertainties, many IPP developers would prefer to establish long-term power purchase agreements (PPAs) with local utilities for at least a part of their PSH

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[12] See https://www.ferc.gov/electric/power-sales-and-markets/rtos-and-isos.

capacity. These bilateral PPA contracts would allow for some steady revenue streams, while the remaining PSH capacity could be offered to the market. However, utilities are often reluctant to enter into long-term PPAs because they face many uncertainties as well. These uncertainties are mainly caused by changes of the plant mix on the bulk power side. There are also significant changes on the demand side, where the emergence of DERs and behind-the-meter technologies (e.g., rooftop solar) are changing the behavior of demand as many consumers also become producers of electricity (i.e., prosumers).

Considering all these changes, even vertically integrated utilities that are still traditionally regulated are reluctant to invest in large PSH projects. Utilities are traditionally very risk-averse business entities, and it may be difficult to justify a very large investment in a rapidly evolving and uncertain business environment.

2.3.2 Large Capital Investments

Most PSH projects tend to be large undertakings, with capacity ranging from several hundreds to over a thousand megawatts. This requires a large capital investment for project construction and sometime coordination of multiple owners/offtakers. The large initial CAPEX increases project development risks, prolongs the investment payback period, and makes it more difficult to close financing. Many PSH developers (including utilities and IPPs), as well as financial lending organizations, are risk averse and prefer projects with smaller investment requirements and shorter payback periods. This is one reason why DOE/WPTO issued a prize competition for innovative PSH technologies that could reduce the cost, time, and risk of developing new PSH projects (Hadjerioua et al., 2020). Because energy storage cost reduction is recognized as one of key challenges, DOE recently issued the Long Duration Storage Shot[13] initiative, with the goal to reduce the cost of LDES by 90% by 2030.

2.3.3 Inadequate PSH Representation in Power System Modeling Tools

Most power system modeling tools do not represent PSH plants with sufficient detail and accuracy to capture the full range of benefits these plants provide to the grid. This is true for both operation planning, using production costs models, and for the long-term integrated resource planning (IRP), using capacity expansion and IRP models.

There are several shortcomings in the treatment of PSH plants in production cost models. Typically, production cost simulations are performed using hourly time steps, which does not allow the analyst to capture the intra-hourly variability and the role of storage in balancing the system within the hour. Even if the production cost model is capable of simulating shorter time periods within the hour, the models often use simplified representations of PSH plants that do not fully capture their operational capabilities, or their modeling is based on old PSH technology that does not represent advanced new technologies (IFPSH, 2021).

The treatment of PSH plants in IRP models is even more limited, and many utilities do not even consider PSH candidates when performing IRP planning. In cases when PSH plants are considered as potential candidates for system expansion, their representation is often inaccurate

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[13]See https://www.energy.gov/sites/default/files/2021-07/Storage%20shot%20fact%20sheet_071321_%20final.pdf.

or inadequate to properly capture the benefits they provide to the system in the long term. Because of the significant computational burden, most long-term capacity expansion models use a limited number of sample time segments instead of performing chronological hourly simulations. Using time segments does not allow for proper simulation of energy storage technologies, especially the ones with longer duration storage. In addition, most IRP models do not have the capability to optimize PSH operations over multiple days or weeks, and therefore do not capture the benefits of long-duration storage in overcoming extreme weather events or prolonged drought periods. Finally, some IRP models to not differentiate between storage technologies enough to capture the life-cycle differences between 50-plus-year PSH assets and much shorter duration technologies. The result is an inaccurate representation of the levelized cost of PSH compared to batteries or similar shorter life-cycle storage assets.

2.3.4 Long Permitting and Licensing Process

Large non-federal hydropower infrastructure projects are subject to long permitting and Federal Energy Regulatory Commission (FERC) licensing processes, which in case of PSH development may take several years to complete. In the United States, the permitting and licensing of a new PSH project may take 3–5 years (IFPSH, 2021), significantly longer than most other energy storage technologies. This long schedule increases project costs and development risks.

To reduce the time required to license closed-loop PSH projects, because they have lower environmental impacts, the American Water Infrastructure Act of 2018 (AWIA) directed FERC to introduce an expedited licensing process of 2 years after license submittal for these projects (DOE, 2021). As mandated by AWIA, FERC in 2019 published guidance[14] for expedited 2-year licensing of closed-loop PSH projects at abandoned mine sites.

Note that, although the expedited 2-year licensing process is favorable to closed-loop projects, no PSH project in the United States has so far used this process to obtain a FERC license (NHA, 2021).

2.3.5 Environmental Issues

In the past, many PSH projects in the United States faced public opposition because they were designed and constructed as open-loop projects, which involved building a dam on a river or lake and thus impacting aquatic and other ecosystems. The AWIA and FERC guidance recognize that closed-loop PSH projects may have lower environmental impacts and thus can move faster through the permitting and licensing process. In contrast to open-loop PSH projects, closed-loop projects typically use manmade reservoirs, do not involve building a dam on a river, and do not have a continuous connection to natural water bodies or waterways. The manmade reservoirs of closed-loop projects, either newly constructed or constructed by repurposing abandoned mines or other brownfield sites, are normally devoid of fish and aquatic life. Therefore they have minimal impacts on the biological ecosystem. Many environmental organizations recognize this and are now more receptive to construction of new closed-loop PSH projects.

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[14]See https://cms.ferc.gov/sites/default/files/industries/hydropower/gen-info/guidelines/hydro-development-guide.pdf.

2.3.6 Other Challenges

PSH developers also face many other challenges. For example, in the United States, PSH projects are excluded from state renewable portfolio standard mandates. So far no tax incentives are provided for PSH projects at either the state or the federal level, in contrast to some other technologies. Some state policies specifically exclude PSH from policies, while others place an artificial capacity cap (in megawatts) that discriminates against PSH projects. This may change with new state or federal energy policies, including the adoption of the Infrastructure Investment and Jobs Act of 2021[15], which has certain provisions that may eventually provide some financial incentives for PSH projects.

Existing regulatory structures do not account for many grid services PSH plants provide, thus leading to their undervaluation. Some recent studies (Balducci et al., 2021) included the value of grid resilience in their assessments. However, although the electric power grid faces increasing outages, extreme weather events, wildfires, and other prolonged grid disturbances for which the LDES provided by PSH plants would be very valuable, very few studies have attempted to model the grid resiliency services PSH provides.

Another challenge that is unique to PSH among energy storage technologies is that while energy storage resources can support generation, transmission, and distribution functions, PSH is regulated as generator-type resource; therefore the value of storage assets for transmission and distribution systems are not fully utilized. This is another example of how economic or planning models misrepresent the true value of a PSH asset.

Because of these and other challenges mentioned above, it is difficult to develop a robust business model for large energy storage project that provides enough certainty for some investors (i.e., reasonable payback period and return on investment [ROI]). More certainty in dealing with various challenges and policies would help PSH developers reduce the risk of their investment by creating certainty in the process. Several hydropower organizations recently provided recommendations on how to overcome some of the challenges PSH developers face. The National Hydropower Association (NHA) published their recommendations in the *2021 Pumped Storage Report* (NHA, 2021). The International Forum on Pumped Storage Hydropower (IFPSH), led by the International Hydropower Association (IHA), has established the Policy and Markets Frameworks working group to analyze the challenges to developing PSH projects in different regions around the world. Their findings and recommendations were recently published in the IFPSH (2021) report. Key barriers and challenges identified by the working group included planning and modeling, financial and revenue uncertainties, ownership models and asset status (i.e., generation/transmission), and licensing and permitting issues.

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3.0 Assessment of Proposed New and Innovative PSH Technologies and Configurations

In addition to the existing PSH technologies and configurations presented in Section 2, there are many innovative PSH concepts and technologies that are currently being pursued by the industry, PSH developers, and energy storage researchers. While this study could not cover every proposed new PSH concept or technology, we have selected a set of twelve PSH technologies that are covering different types and sizes of PSH projects and may be able to satisfy various energy storage needs, from large bulk power system applications to small, distributed energy storage.

3.1 Evaluation Criteria

To enable an objective evaluation of innovative PSH technologies, we established a set of evaluation criteria that address some key project development and operational characteristics that are important for PSH plants. Note that the objective of this study was not to directly compare different PSH technologies, nor to rank them according to their perceived values or the benefits that they may be able to provide to the power system. The set of evaluation criteria was developed so that each technology can be assessed objectively, addressing the same set of parameters, features, and capabilities, and using the same metrics. It is well understood that it is not possible to directly compare technologies that are at different technology readiness levels (TRLs). In addition to their different stages of development, the proposed innovative PSH technologies that are reviewed in this study are different sizes and employ different designs that are not directly comparable to each other. Obviously, different technologies may have different roles in the power system; some innovative designs may be well suited to provide certain services, while others may be better at providing other services. Again, this study does not intend to compare innovative PSH technologies to each other, nor to rank them according to their perceived value, because different technologies may serve different needs.

To evaluate the proposed PSH innovations and technologies, we mostly relied on data and information that was provided by technology developers in publicly available literature, company websites, presentations at industry conferences and workshops, and other publicly available sources. The purpose of this study was not to verify or validate developers' estimates or claims related to technology costs, efficiency, and other technoeconomic parameters, but to provide a landscape analysis of the latest trends in PSH innovations and discuss potential advantages and disadvantages of proposed new PSH concepts and technologies.

The evaluation criteria that were used in this study to review and assess the main characteristics and features of proposed new PSH technology concepts and configurations are summarized in Table 3-1.

Table 3-1: Evaluation Criteria

Criteria	Evaluation Parameters and Considerations	Metrics
Estimated Project Cost	Estimated investment cost or total CAPEX to develop PSH project	$/kW
Estimated Levelized Cost of Storage (LCOS)	Estimated LCOS over the lifetime of the project	$/MWh
Construction Time	Potential to reduce project construction time compared to current PSH technologies	Years
Project Development Risk	Potential to either increase or reduce project development risks (e.g., by applying either new innovative concepts or proven construction methods and technologies used in other industries)	Qualitative
Scalability and Applicability	Whether the PSH design is scalable to allow for a range of capacities (e.g., modular design) and a variety of use cases	Estimated minimum and maximum capacity range (MW)
Operational Flexibility	PSH technology potential to provide flexible operation (i.e., wide operating range, fast ramp rates, quick mode change times)	Estimated operating range
Potential Market Size	Estimated market potential for PSH technology	MW of capacity or number of installations
Environmental Impacts	Discussion of potential impacts of PSH technology on the environment, including potential public acceptance issues	Qualitative
Physical Siting Limitations	Geographical or topological limitations that may limit the siting opportunities	Qualitative
TRL	Estimated TRL of PSH technology	TRLs 1–9

The above criteria are not listed in any particular order. Depending on the reader's perspective, different capabilities may have different value or importance. For example, some PSH developers may value the scalability and applicability of the design more than operational flexibility, while others may have the opposite view. Typically, when innovative new PSH technologies are reviewed, the key considerations are whether the technology has the potential to reduce the cost, time, and risk for project development. This is not to say that other factors are unimportant; the TRLs, environmental impacts, potential market size, and other factors should also be considered.

The following sections provide more details on these evaluation criteria and how they are used in this study.

3.1.1 Estimated Project Cost

The key consideration here is to estimate the potential for cost reduction compared to current PSH technologies. A recent grid energy storage cost and performance assessment study (Mongird et al., 2020), which was developed for DOE's Energy Storage Grand Challenge (ESGC), was used as one reference point for cost comparison. This study[16] estimated the total

[16] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

PSH project costs at $2,623/kW for a generic 100-MW PSH plant with 10 hours of storage, and $2,202/kW for a generic 1,000-MW PSH plant with 10 hours of storage. The larger PSH plant has lower specific cost per kilowatt due to economy of scale.

Because the authors of the ESGC report considered PSH to be a mature technology, no learning curves were applied for potential cost reductions in the future. However, some of the innovative PSH technologies that are reviewed in this study are at relatively early TRLs and may benefit from technology learning curves, because a first-of-a-kind project is typically more expensive than subsequent projects.

Finally, because most of the innovative PSH technologies reviewed in this study are at early TRLs and do not have detailed engineering studies for the development of specific projects, the cost estimates are somewhat uncertain. In some cases we considered a potential range of values.

3.1.2 Estimated LCOS

For each PSH technology, we calculated estimated LCOS values to assess how the proposed innovative technology compares to generic conventional PSH plants in terms of cost of storage. The methodology used in this study for LCOS calculations is presented in Appendix 6.1. Like the above reference values for total PSH project costs, the reference LCOS values were based on the ESGC cost and performance report (Mongird et al., 2020). Because the ESGC study did not provide LCOS values, we calculated estimated LCOS values for generic conventional PSH technologies using the cost and performance data and parameters provided in the ESGC report. Note that the authors of the ESGC report (Mongird et al., 2020) assumed a low 40-year estimate for PSH lifetime. Hydropower industry typically assumes a 50- or 60-year PSH lifetime; this better corresponds to reality, as most PSH projects that have been built around the world are still in operation, some for more than 80 years.

To calculate the estimated LCOS value for the proposed innovative PSH technologies, we used a more realistic 60-year lifetime for most technologies, but included the estimated additional cost of minor and major overhauls during the project lifetime. For the generic PSH technologies from the ESGC report we calculated reference LCOS values using a 40-year lifetime to remain consistent with the technology assumptions that were used in that study (Mongird et al., 2020). Next, we calculated LCOS values for generic PSH technologies using the 60-year lifetime and applying the same overhaul and operations and maintenance (O&M) assumptions that were used for the innovative PSH technologies. We then compared these results with the LCOS values that were obtained for generic PSH technologies using the assumptions from the ESGC study. The LCOS results were very similar; differences for four generic PSH technologies ranged from -0.8% to 2.7%. This confirmed that despite the shorter 40-year lifetime assumed in the ESGC study, the LCOS values calculated for the generic PSH technologies could be used as reference values for comparison with calculated LCOS values of the proposed innovative PSH concepts and technologies.

To estimate how innovative PSH technologies compare to current state-of-the-art battery technologies, we also calculated estimated LCOS for Li-ion batteries, again using the data from the ESGC report. We calculated estimated LCOS values for three Li-ion battery plants (1 MW, 10 MW, and 100 MW, all with 4 hours of storage). For this purpose, we used the lithium iron phosphate battery technology as representative Li-ion battery technology. The LCOS values obtained for the reference PSH and Li-ion technologies using the data from the ESGC study are presented in Table 3-2 and illustrated in Figure 3-1.

Table 3-2 LCOS Values Calculated for Reference PSH and Battery Technologies[a]

Technoeconomic Parameters	PSH 100 MW, 4 h	PSH 100 MW, 10 h	PSH 1,000 MW, 4 h	PSH 1,000 MW, 10 h	Li-ion 1 MW, 4 h	Li-ion 10 MW, 4 h	Li-ion 100 MW, 4 h
Plant generating capacity (MW)	100	100	1,000	1,000	1	10	100
RTE (%)	80	80	80	80	86	86	86
Plant lifetime (Years)	40	40	40	40	10	10	10
Total Investment Cost (TIC) ($/kW)	2,046	2,623	1,717	2,202	1,793	1,643	1,541
LCOS Total ($/MWh)	**209**	**135**	**180**	**121**	**254**	**238**	**227**

[a] Data source: PNNL (2020).

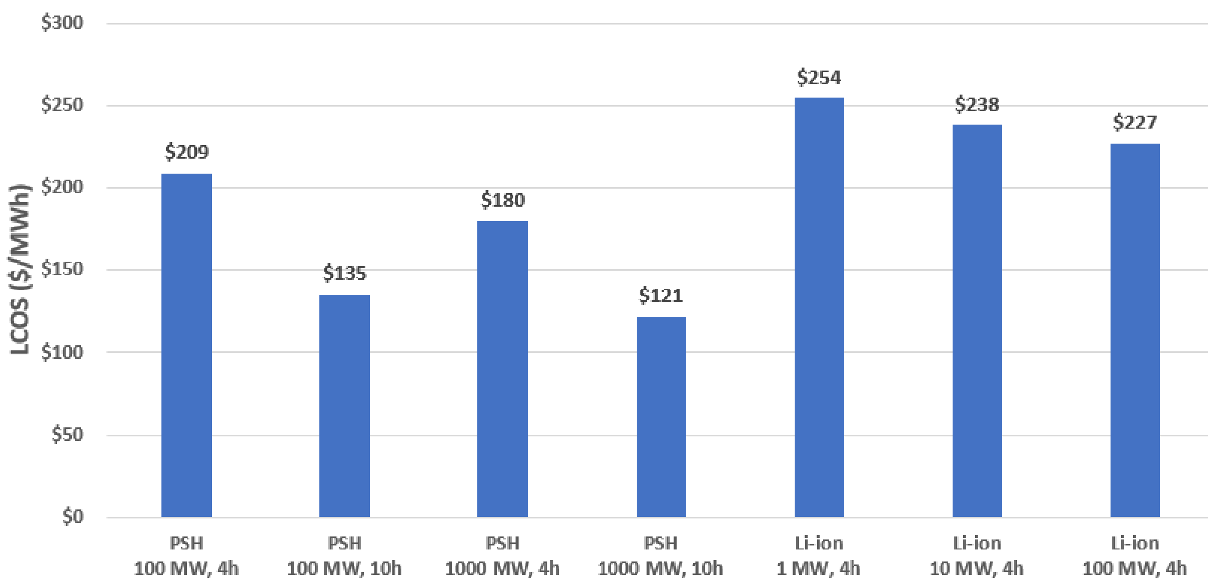

Figure 3-1 LCOS Values for Reference PSH and Battery Technologies

3.1.3 Construction Time

Construction times were considered for new innovative PSH technologies to evaluate how they compare to the conventional PSH technologies. Note that construction times for conventional PSH projects can vary widely, depending on the location, size of the plant, site characteristics, plant design, and other factors.

Typically, the construction of a large-scale PSH plant can be completed in about 4–7 years, with less time typically required for smaller-scale PSH. This construction period does not include the licensing and permitting, pre-feasibility and feasibility studies, engineering design studies, and other project development activities, which can increase the total project development time to 7–10 years or longer.

Because these project development activities depend on numerous factors, many of which are not directly related to the PSH technology, our evaluations focused on the actual construction period and tried to assess how quickly the project could be constructed from start to finish.

3.1.4 Project Development Risk

The project development risk criterion evaluates risks of new innovative PSH technologies from the point of view of complexity of their technical design and construction processes. For example, some key factors for this evaluation included whether a technology applies proven construction methods and technologies, employs simple project designs and plant configurations, uses commercially available hydraulic and electromechanical equipment, and others.

The reasoning here is that the project development risk increases if the project requires a lot of unique or first-of-a-kind technologies for its development, including the increased risk surrounding regulatory acceptance of a new technology. The longer project construction time can also contribute to increased project development risk, which is covered by the previous criterion.

3.1.5 Scalability and Applicability

The scalability and applicability attributes were grouped together. Scalability was used in two ways:

- To assess whether the innovative PSH technology can be developed for a range of plant or unit capacities, from very small (e.g., few megawatts) to very large (e.g., hundreds of megawatts), and
- Whether the technology allows for modular design and construction, so that the plant size can be increased by adding additional modules.

The applicability attribute considered the versatility of the innovative PSH technology by assessing the types of services or use cases to which the technology could be applied.

3.1.6 Operational Flexibility

The operational flexibility criterion included evaluating the PSH technology potential to provide flexible operation (i.e., wide operating range, fast ramp rates, quick mode change times). Operational flexibility is becoming increasingly important in power systems with high penetration of variable renewables, such as wind and photovoltaic (PV) solar, as the grid operators need flexible dispatchable resources to balance their variability.

3.1.7 Potential Market Size

The purpose of the potential market size parameter was to estimate the potential market size for innovative PSH technologies in the United States, primarily in terms of number of potential projects that could be expected to be developed in the next 20–30 years. This was largely based on our view of the potential market share that an innovative PSH technology may be able to achieve, in other words, whether a technology can be expected to result in only few projects built at several locations, or whether it would be suitable for wide deployment at many different locations. This estimate also considered that the innovative PSH technology would compete against other energy storage technologies, including conventional PSH plants and other innovative PSH technologies that may come along in the near future.

The estimates provided in this study indicate our view of maximum number of projects, or total installed capacity in megawatts of all projects, that could be expected in the United States based on the market factors mentioned above, and not on the maximum resource potential or total number of plants that could be theoretically constructed. Because market conditions and needs for storage may vary widely in other regions of the world, we limited our assessments of potential market size only to the United States. Obviously, global market size could be significantly larger than that of the United States.

3.1.8 Environmental Impacts

Estimated impacts of PSH technology on the environment are a key factor determining the feasibility of the technology for real world applications and development. For example, closed-loop PSH projects have fewer environmental impacts than open-loop PSH projects. Therefore, they may be easier to license and gain public acceptance for their construction, because they are typically considered to be more environment-friendly projects. It is important to note that new open-loop PSH projects will typically have less environmental impacts compared to the existing fleet of PSH plants, but it is generally agreed that closed-loop PSH will always have lower environmental impacts due to avoidance of dams on navigable waters.

3.1.9 Physical Siting Limitations

The physical siting limitations parameter was used to assess whether geographical or topological requirements may limit the siting opportunities of certain innovative PSH technologies. For example, PSH technologies that require high hydraulic head (i.e., the elevation difference between the upper and lower reservoirs), may have fewer geographic sites available than those that can operate at lower head.

3.1.10 TRL

The purpose of the TRL parameter was to indicate an estimated TRL for innovative PSH technologies. While some of the proposed technologies were estimated to be at early TRL stages, others were more mature and closer to commercialization stage.

The objective of estimating the TRL was to provide an indication to the reader of where the technology is in its development process, not to indicate the perceived value of the technology. For example, a technology with higher TRL value is closer to commercial maturity, but that does not necessarily mean that it has greater value than other PSH technologies with lower TRLs. Some technologies with lower TRL values may be based on technological breakthroughs that will eventually provide greater value than some of the more mature technologies. The definitions for different TRLs that were used in this study are provided in Appendix 6.3.

3.2 Assessment of Potential New PSH Technologies

The evaluation of innovative PSH technologies presented in this section provides an objective third-party assessment of their key features, capabilities, and technoeconomic parameters based on the information that was available to the project team. Because many of the evaluated innovative technologies are in relatively early stages of TRL development, there was limited information available on their technoeconomic characteristics and parameters. In most cases, we used the data provided by the technology developers as the starting point, but in some cases we also added our own estimates or likely ranges of expected values. This approach using estimates, although imperfect, is common and practically inevitable when dealing with new technologies that are still under development.

To make this assessment as objective as possible, we established a set of evaluation criteria, described in Section 3.1, which were used to address key features and capabilities of various innovative PSH technologies. We also used these evaluation criteria to comment on the potential advantages or disadvantages of innovative PSH technologies, in comparison to conventional PSH plants. Note that the developers of the innovative PSH technologies had an opportunity to review and comment on the summary tables of our assessments of their technologies. These tables are provided in this report at the end of each section for each technology that was evaluated.

Again, the objective of the assessment performed in this study was not to compare innovative PSH technologies to each other, nor to rank them in any particular way with regard to their perceived value, preference, commercialization, or market potential. Rather, the objective of this study was to assess their potential advantages or disadvantages relative to today's conventional PSH plants and whether they may provide improvements in reducing the cost, time, and risk for project development, or bring some new desirable operational characteristics, or be better suited to provide certain grid services than the existing conventional PSH plants.

Finally, this study provides a landscape analysis; the inclusion of any innovative PSH technologies or concepts in this study does not mean endorsement of these technologies or concepts by the U.S. government, the DOE, or Argonne National Laboratory. All views and opinions expressed in this study are those of the authors, based on the information that was available to them during the study. The innovative PSH technologies that are evaluated in this study are not presented in any particular order, and most definitely not in the order of their perceived value or merit. The following subsections provide brief technology descriptions and summarize our assessments of 12 innovative PSH technologies that were evaluated in this study. Note that this is not an exhaustive list of innovative PSH technologies, as there are also other PSH concepts, designs, and ideas that are currently being researched in the United States and other countries. Some of these concepts and ideas are briefly described in Section 4.

3.2.1 Small PSH with Reservoirs of Corrugated Steel and Floating Membranes

3.2.1.1 *Technology Description*

This concept was originally proposed by Shell Energy North America (SENA) for the DOE's HydroNEXT[17] funding opportunity announcement (FOA). For the purpose of this FOA, SENA proposed a small modular PSH technology that can use reservoirs made of corrugated steel or floating membranes. In principle, this technology could be designed and configured as either an open- or a closed-loop PSH system. One requirement of the HydroNEXT FOA was to demonstrate the concept feasibility for closed-loop PSH systems, so SENA proposed a concept that uses corrugated steel for the upper reservoir and a floating membrane reservoir (floating in a larger body of water, e.g., a lake) for the lower reservoir. The water in this closed-loop PSH system, which was referred to by SENA as a "hydro battery," would circulate between the upper and lower reservoirs and would not mix with the water in the lake in which the lower floating membrane reservoir is situated, except for occasional small amounts of water additions to make up for losses and evaporation.

In this study, we evaluated the closed-loop configuration of this PSH technology, consisting of upper reservoir made of corrugated steel and lower floating membrane reservoir. This was the configuration that was proposed by SENA for the HydroNEXT FOA. Figure 3-2 illustrates this configuration.

The key innovative aspect of this technology is the proposed use of corrugated steel reservoirs, which theoretically could be used for both upper and lower reservoirs. Another innovation is the use of floating membrane reservoirs, which could be used if a closed-loop PSH system is desired when using a larger body of water that is already present at the plant location.

SENA's idea to use corrugated steel reservoirs is based on their proven experience in the oil and gas industry, and leverages their knowledge of construction methods and materials for large oil and gas reservoirs. In their proposed hydro battery example, SENA envisioned a corrugated steel reservoir about 300 feet in diameter and around 20 feet tall. The reservoir would feature about 2 inches of insulation around the perimeter and an insulated floating roof to protect against change in water temperature, as well as against the intrusions of debris and wildlife. The lower reservoir was proposed as floating membrane reservoir in an existing body of water. The floating reservoir could consist of multiple cells that are tied to floating high-density polyethylene (HDPE) pipe floats around the perimeter and between the cells.

In their proposed hydro battery example (Hydro Battery Pearl Hill), SENA envisioned a closed-loop PSH system with 5 MW of generating capacity, 9 MW of pumping capacity, and 30 MWh—or 6 hours—of energy storage (FERC, 2019). The Pearl Hill design envisioned a single 5-MW twin-jet Pelton turbine and five separate pumps with a total capacity of 9 MW. A 3-foot-diameter steel penstock would convey the water between the upper and lower reservoirs.

[17] HydroNEXT FOA (DE-FOA-0001455) was issued by WPTO in 2016 with the objective to fund research in innovative technologies that may advance non-powered dam and PSH development.

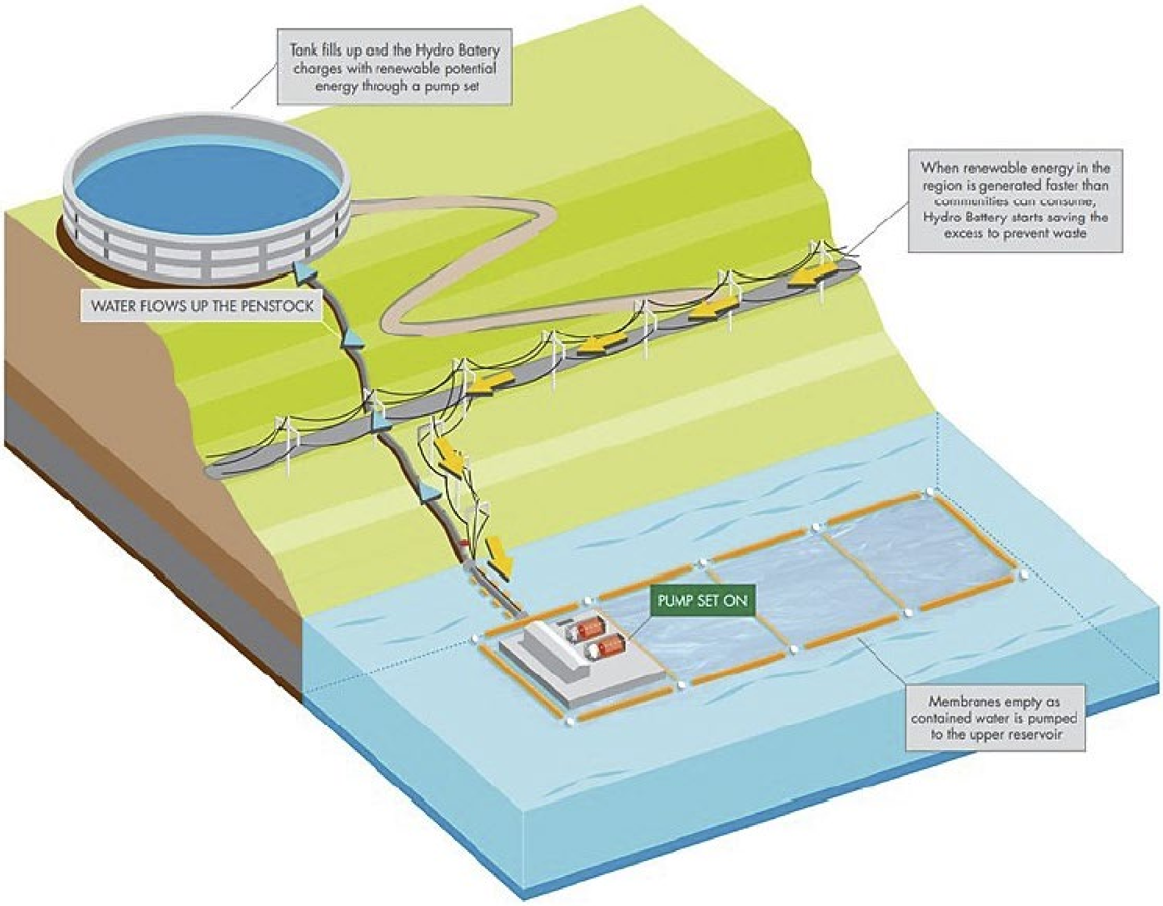

Figure 3-2 SENA Hydro Battery Rendering (Source: Balducci et al., 2018)

For the HydroNEXT project, the SENA team was supported by PNNL and ORNL. PNNL was tasked with performing the market assessment and estimating the potential project revenues and ROI in different electricity markets in the United States, while ORNL helped with the design and cost estimates for the floating membrane reservoir. Note that SENA has discontinued research on this PSH concept due to potential site conflicts identified during the licensing process after the HydroNEXT project. At present, SENA is not trying to use it for the development of PSH plants. Nevertheless, some facets of the proposed concept still have merit because it is based on existing technology applications in other industries. Therefore, it was included in this study as one of the potential innovative PSH technologies because it still gets some attention in the industry and research circles. For example, researchers at ORNL are still developing improved designs for floating membrane reservoirs.

Some key advantages of this technology include its modularity and scalability; the design relies heavily on the use of standard off-the-shelf equipment and materials. Different plant configurations can be designed by combining different types and sizes of reservoirs. Adjusting configurations of pumps and turbines enables a more flexible selection of plant capacity and storage duration. The relatively small plant size also allows for easier project siting, because many geographical locations are suitable for a project of this size. Hybrid project opportunities are also possible, by co-locating a small PSH project with wind and solar plants.

3.2.1.2 *Technology Evaluation*

Here we discuss the key characteristics of this technology, including its potential advantages and disadvantages by using the evaluation criteria described in Section 3.1.

Estimated Project Cost: Most of the data used to assess the estimated costs of this technology come from PNNL's 2018 market analysis report (Balducci et al. 2018), which provided project cost estimates for a first-of-a-kind 5-MW plant, as well as for the mature systems. The cost of the first-of-a-kind plant was estimated at $4,460/kW, or $743/kWh, while the cost of mature systems is expected to decrease to $2,940/kW, or $490/kWh.

We can compare these costs to the estimated PSH project costs presented in the ESGC cost and performance report (Mongird et al., 2020). The ESGC report provides estimates for four PSH plant configurations (100 MW and 1,000 MW, with 4-hr and 10-hr storage), as shown in Table 3-2. Because of the small size of the proposed innovative technology, we can compare its costs with the 100-MW, 10-hr storage PSH configuration from the ESGC report.

While the cost of the first-of-a-kind system is relatively high, the cost of mature system at $2,940/kW is still somewhat higher than that of reference PSH systems from the ESGC study ($2,632/kW for the 100-MW PSH system with 10-hr storage, and $2,046/kW for a 100-MW PSH system with 4-hr storage). This is probably because of the economy of scale, as the use of the standard pumps, turbines, and other equipment may not completely outweigh the impact of small project size on the specific $/kW project costs. Nevertheless, these cost estimates were developed at an early stage of technology development and should be considered preliminary.

Estimated LCOS: The methodology that was used in this study to calculate LCOS is described in Appendix 6.1. To address the uncertainty regarding the estimated project costs, LCOS analysis was performed for two values, one corresponding to the first-of-a-kind (high CAPEX), and the other corresponding to mature systems (low CAPEX). The results of LCOS calculations are presented in Table 3-3.

Table 3-3 LCOS for Small PSH Using Corrugated Steel and Floating Membrane Reservoir

Technical Data	Base (Low CAPEX)	Base (High CAPEX)
Plant generating capacity (MW)	5	5
RTE (%)	75	75
Average capacity factor (%)	20	20
Average annual generation (MWh)	8,760	8,760
Plant lifetime (years)	30	30
Major plant overhaul period (years)	15	15
Number of overhauls	1	1
Economic & Financial Data		
Investment cost ($/kW)	2940	4,460
Weighted average cost of capital (WACC) (%)	8	8
TIC ($)	14,700,000	22,300,000

Table 3-3 (cont.)

Technical Data	Base (Low CAPEX)	Base (High CAPEX)
Major overhaul cost (10% of TIC)	1,470,000	2,230,000
Annual O&M cost ($) (1.5% of TIC)	220,500	334,500
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	584,000	584,000
LCOS analysis period (years)	30	30
LCOS by Component		
Investment cost ($/MWh)	$149.06	$226.12
Replacement cost ($/MWh)	$4.70	$7.13
O&M cost ($/MWh)	$25.17	$38.18
Charging cost ($/MWh)	$66.67	$66.67
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$245.60**	**$338.10**

Table 3-4 shows how these estimated LCOS values compare to those calculated for the reference PSH and Li-ion battery technologies from the ESGC study (Mongird et al., 2020). The obtained LCOS values are higher than those calculated for the reference 100-MW PSH systems, especially for the PSH system with 10 hours of storage. The estimated LCOS values of mature hydro battery system and reference 100-MW PSH system with 4 hours of storage are closer, $245.60/MWh and $208.63/MWh, respectively. Some of this difference possibly could be attributed to the economy of scale, because 5 MW is a much smaller installation than the 100-MW reference PSH system.

Table 3-4 Comparison of LCOS Values for Small PSH Using Corrugated Steel and Floating Membrane Reservoirs and Reference PSH and Battery Technologies

Technoeconomic Parameters	SENA (low CAPEX)	SENA (high CAPEX)	PSH 100 MW, 4 h	PSH 100 MW, 10 h	Li-ion 1 MW, 4 h	Li-ion 10 MW, 4 h	Li-ion 100 MW, 4 h
Plant generating capacity (MW)	5	5	100	100	1	10	100
RTE (%)	75	75	80	80	86	86	86
Plant lifetime (Years)	30	30	40	40	10	10	10
TIC ($/kW)	2,940	4,460	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**246**	**338**	**209**	**135**	**254**	**238**	**227**

Because of its small size, the proposed innovative PSH system would more likely compete against battery installations of similar size, rather than against 100-MW PSH projects. Comparing it to the estimated LCOS values obtained for reference Li-ion batteries, it seems that the mature (low CAPEX) innovative PSH system proposed by SENA would be competitive against similarly sized Li-ion batteries.

Construction time: The construction time for this technology is estimated at 2–3 years. This is faster than the construction of conventional PSH projects, mainly because less civil work would be required for the construction of reservoirs. The reservoirs can be constructed from prefabricated modular components that can be transported to the project site by truck. This is true for both the corrugated steel and the floating membrane reservoirs. Similarly, the powerhouse for this technology can also be prefabricated and assembled onsite.

Project development risk: Project development risk is estimated to be about the same as for a conventional PSH of the same size. The benefits of using modular and prefabricated components are somewhat offset by the uncertainties related to the application of corrugated steel for the upper reservoir and floating membrane for the lower reservoir. Other than that, the plant configuration and equipment is nearly identical to that in a conventional PSH plant of this size. Project development risk is also reduced by the shorter construction time.

Scalability and applicability: This technology is highly modular and scalable. Plant sizes are estimated at 1–10 MW, with the average plant size about 5 MW. The upward scalability is limited by the size of the upper reservoir that can be supported by corrugated steel, as well as the size of the floating membrane-type lower reservoir. Theoretically, plant size can be increased by constructing multiple upper and lower reservoirs. Due to its relatively small size, this technology would likely serve to support the electricity generation from wind and solar plants, as well as energy storage in distribution systems and isolated island systems.

Operational flexibility: This technology should support flexible operation in both generating and pumping mode, because the proposed configuration envisions multiple pumps for each generating unit. This would provide an estimated 30–100% operating range in generating mode, and several pumping levels, depending on how many pumps are used at a time to pump the water from lower to upper reservoir.

This kind of flexibility would be valuable in compensating for the variability of wind and solar generation in hybrid plant applications, or for providing certain grid services for system applications. For example, the plant would be able to provide frequency regulation if connected to an automatic generation control system at the utility control center.

Potential market size: Because of its small size and relatively low-head needs, this technology can be easily sited at many locations in the United States. While there is no shortage of potential locations that have favorable geographical characteristics and could support the siting of this technology, the actual number of installations would be limited by economic factors and competition from other technologies.

Assuming that the economics of the mature technology will be competitive with other energy storage solutions, mainly batteries, a maximum of several hundred installations of the proposed small PSH technology may be expected in the United States, under the most favorable scenario. For an average plant size of 5 MW, that would amount to about 1–2 GW of total capacity. The relatively high capital cost may be a limiting factor for market potential.

Environmental impacts: Estimated impacts of this PSH technology on the environment are expected to be smaller than those of conventional PSH plants of similar size, mainly because less civil work would be required for plant construction. The closed-loop design has smaller impacts on the environment, and the small project size requires only a small footprint.

Physical siting limitations: The technology requires a difference in elevation between the upper and lower reservoirs and proximity to a water body for the lower reservoir. It is estimated that many thousands of geographical locations in the United States would have the required minimum characteristics to support this technology. Due to its small plant size, the technology could possibly be located close to urban population centers as well.

TRL: At present, the estimated overall TRL for this technology is 4–5. The technology is in an early stage of development. While proof of concept has been established, no lab testing or field demonstration projects were conducted. The steel tanks for the upper reservoir have been used in the oil and gas industry, but the floating membrane lower reservoir is at very early conceptual design. A higher TRL between 6 and 7 would be appropriate for a project design that uses steel tanks for both upper and lower reservoirs.

3.2.1.3 *Evaluation Summary*

Table 3-5 summarizes the findings of our evaluation. Overall, we find the potential use of corrugated steel reservoirs an interesting proposition. They could be potentially a cost-effective and time-saving solution for the construction of small modular PSH projects, but the project cost must be competitive with other energy storage solutions available on the market, mainly batteries. To achieve competitiveness, the cost of reservoirs must be reduced by using prefabricated standardized modular components that are easy to transport by truck and assemble at the project site.

Table 3-5 Evaluation Summary for Small PSH Using Corrugated Steel and Floating Membrane Reservoirs

Evaluation Criteria	Small PSH Using Corrugated Steel and Floating Membrane Reservoirs
Estimated Project Cost	\$4,460/kW or \$743/kWh for first-of-a-kind 5-MW plant \$2,940/kW or \$490/kWh for mature systems
Estimated LCOS	\$246 to \$338 per MWh
Construction Time	Estimated 2–3 years
Project Development Risk	Average: The benefits of using the modular and prefabricated components are offset by the uncertainties related to the application of corrugated steel and/or flexible membrane reservoirs
Scalability and Applicability	Highly modular and scalable: Plant size estimated at 1–10 MW, average size 5 MW
Operational Flexibility	Above average: Estimated 30–100% operating range in generating mode and several pumping levels, depending how many pumps are installed
Potential Market Size in the United States	Hundreds of potential installations, totaling about 1–2 GW of capacity (assuming 5 MW average plant size)
Environmental Impacts	Low: Closed-loop project design, small project size requires small footprint.
Physical Siting Limitations	Low: Requires height differential and proximity to a water source; many thousand locations would be suitable for this technology
TRL	Estimated overall TRL 4–5: Proof of concept has been established, but no lab testing or field demonstration projects were developed. A higher TRL estimate of 6–7 would be appropriate for a project design that uses steel tanks for both upper and lower reservoirs

3.2.1.4 *References*

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3.2.2 PSH Using Submersible Pump-Turbines and Motor-Generators

3.2.2.1 *Technology Description*

Obermeyer Hydro, Inc., is developing PSH technology using submersible pump-turbines and motor-generators in the United States. While conventional PSH plants typically use reversible pump-turbines that are submerged below water level and non-submerged motor-generators above them in the powerhouse, this technology proposes that both pump-turbine and motor-generator can be submerged in a vertical shaft (or "well"), thus avoiding the need for the construction of powerhouse. Obermeyer estimates that the diameter of the well would be approximately 2–3 m (Obermeyer et al. 2019). Figure 3-3 is a cross-section of a power plant using this technology.

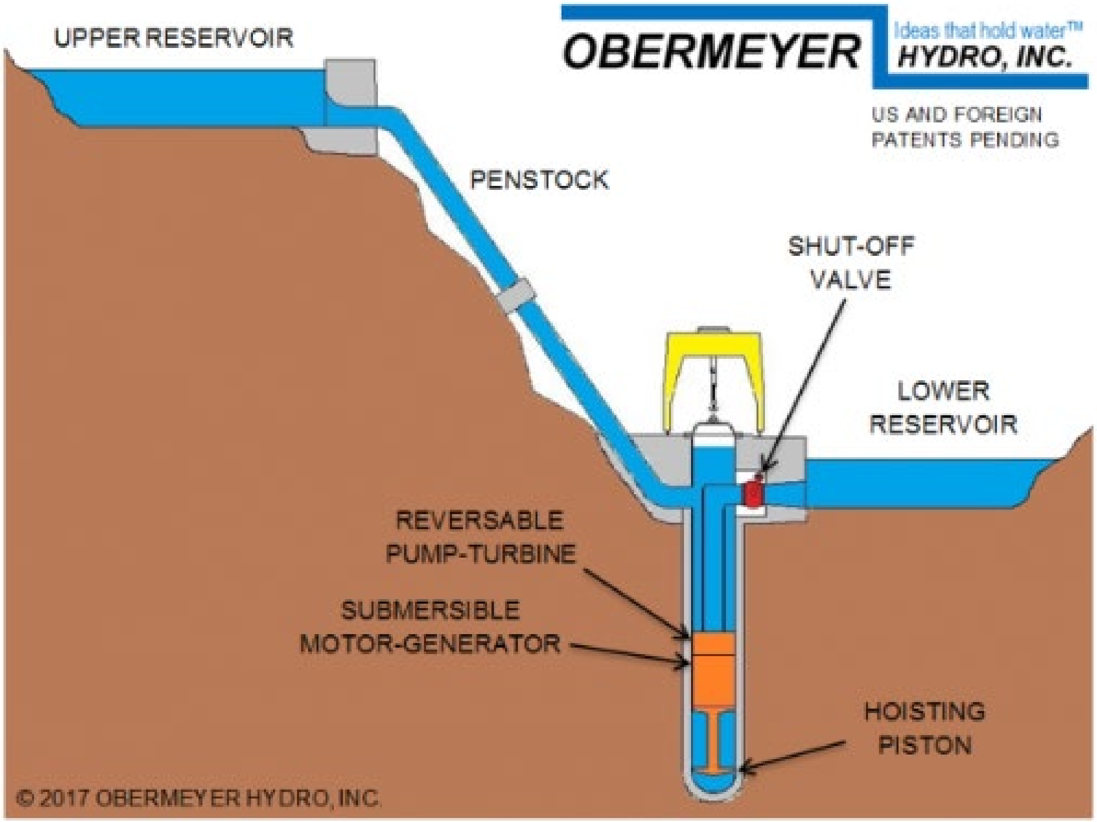

Figure 3-3 Cross-Section of PSH Plant Using Submerged Pump Turbine and Motor Generator (Source: Obermeyer Hydro)

For this technology to work, Obermeyer is developing a special type of pump-turbine with a flow inverter, which redirects the flow of water by 180 degrees because the water enters and exits the well from above in both the generating and pumping modes of operation.

Figure 3-4 provides a more detailed cross-section of the well with pump-turbine and motor generator that is available on Obermeyer Hydro website.[18] The motor-generator is located at the bottom of the well, with the pump-turbine and flow inverter located above it. They are all fully submerged in water.

The developers of this technology propose to use commercially available submersible motor-generators, so the key innovation here is the reversible pump-turbine with flow inverter. While the turbine runner is similar to Francis-type turbines, a flow inverter is needed to redirect the water flow so that the water that enters the well also exits the well. In the generating mode of operation, the water from the upper reservoir flows through the penstock to the turbine, then the flow inverter redirects it to go up the well into the lower reservoir. In the pumping mode of

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[18] See http://www.obermeyerhydro.com/pumpedstorage?language=en.

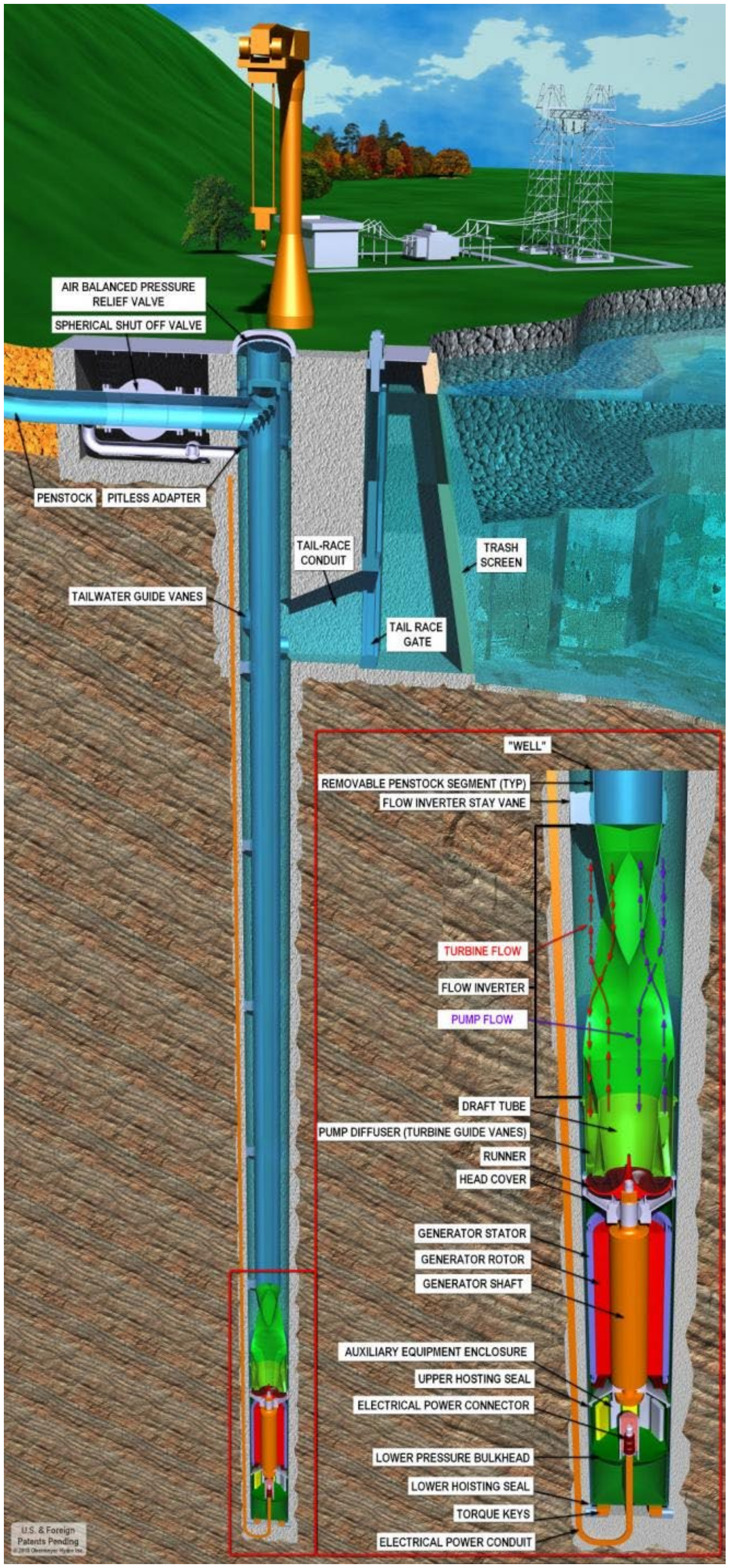

Figure 3-4 Cross-Section of a Well with Submerged Pump Turbine and Motor Generator (Source: Obermeyer Hydro)

operation, the water flows down from the lower reservoir into the well and then is pushed up by the pump and redirected by the flow inverter to go up the penstock into the upper reservoir. Obermeyer Hydro claims that the efficiency of their reversible pump-turbine is over 94% in generating mode and 95% in pumping mode. The overall RTE is estimated to be between 78.4% and 81.6% (Obermeyer et al., 2019).

The technology developer claims that unit sizes can range from less than 1 MW to about 100 MW, and that this type of pump-turbine can be applied for hydraulic heads from 40 to 600 m. This allows a wide range of potential applications of this technology, from relatively small PSH plants to very large ones that may include several large units.

This technology has the potential to reduce the costs and time for construction of new PSH plants because it eliminates the need for an underground powerhouse. Instead, it requires straight vertical wells to be constructed to house the pump-turbine and motor-generator for each generating unit. The machines can be lowered into the well or raised up for inspection and maintenance by using auxiliary water pressure acting on a hoisting piston below each machine.

Because of the small footprint and minimal civil works required for the construction of wells to house generating units, this technology may also be applicable for the development of pumped storage capabilities at existing hydropower plants, as well as for applications at non-power dams.

Obermeyer Hydro is currently developing a prototype unit to confirm the simulation results obtained for the operation and efficiency of reversible pump-turbine with flow inverter.

3.2.2.2 *Technology Evaluation*

Here we discuss the key characteristics of this technology, including its potential advantages and disadvantages using the evaluation criteria described in Section 3.1.

Estimated project costs: The developers estimate total project costs of $1,680/kW for a 74-MW PSH plant (Obermeyer et al., 2019). The PSH plant is assumed to have 7 hours of energy storage, with a total of 518 MWh of electricity generation from a single charge. The estimate also included a proposed rock quarry for the upper reservoir and existing earthen dam for the lower reservoir, connected with a 12-foot-diameter penstock that is 5,000 feet long. The diameter of the turbine well for this configuration is 8.5 feet. Because for this particular site the cost estimate assumed a quarry for the upper reservoir and the use of an existing lower reservoir, we think that a somewhat higher cost estimate, around $2,000/kW, would likely be a more realistic value in most cases, where additional civil works for reservoir construction are needed.

These cost estimates rate favorably compared to the cost estimates for reference 100-MW PSH plants presented in the ESGC report (Mongird et al., 2020). The ESGC study estimates total project costs of $2,632/kW for the 100-MW PSH system with 10-hr storage, and $2,046/kW for a 100-MW PSH system with 4-hr storage.

Estimated LCOS: We calculated the estimated LCOS value for this 74-MW PSH plant configuration using the methodology and assumptions detailed in Appendix 6.1. The results of LCOS calculations for this technology are presented in Table 3-6.

Table 3-7 shows how the estimated LCOS values of $156.38/MWh and $174.26/MWh compare to those calculated for the reference PSH and Li-ion battery technologies from the ESGC study (Mongird et al., 2020). The obtained LCOS values are higher than the 135.22/MWh obtained for the reference 100-MW PSH systems with 10 hours of storage, but significantly lower than the $208.63/MWh obtained for the system with 4 hours of storage. Compared to Li-ion batteries, the estimated LCOS values for this innovative PSH technology are much lower than those obtained for the Li-ion battery plants, including the one sized at 100 MW.

Table 3-6 Estimated LCOS for Submersible Pump-Turbine and Motor-Generator PSH

Technical Data	Low CAPEX	High CAPEX
Plant generating capacity (MW)	74	74
RTE (%)	80	80
Average capacity factor (%)	20	20
Average annual generation (MWh)	129,648	129,648
Plant lifetime (years)	60	60
Major plant overhaul period (years)	20	20
Number of overhauls	2	2
Economic & Financial Data		
Investment cost ($/kW)	1,680	2,000
WACC (%)	8	8
TIC ($)	124,320,000	148,000,000
Major overhaul cost (10% of TIC)	12,432,000	14,800,000
Annual O&M cost ($) (1.5% of TIC)	1,864,800	2,220,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	8,103,000	8,103,000
LCOS analysis period (Years)	60	60
LCOS by Component		
Investment cost ($/MWh)	$77.48	$92.24
Replacement cost ($/MWh)	$2.02	$2.40
O&M cost ($/MWh)	$14.38	$17.12
Charging cost ($/MWh)	$62.50	$62.50
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$156.38**	**$174.26**

Construction time: The project construction time, not including licensing and permitting, is estimated to be about 3–4 years. Compared to conventional PSH plants, most of the time savings are achieved because there is no need to construct an underground powerhouse. The vertical wells that will house generating units are easier to construct and require less civil work than excavating an underground powerhouse. Typically, each well will house a single generating unit. The diameter of the well will vary depending on the size of the unit, with the largest units requiring a well diameter of approximately 10 feet (3 m). Because the generating units can be lifted up from the well for inspection and maintenance, there is no need for access tunnels or ventilation shafts; this also reduces the complexity of plant design, construction time, and costs.

Table 3-7 Comparison of LCOS Values for Submersible Pump-Turbine and Motor-Generator PSH Technology and Reference PSH and Battery Technologies

Technoeconomic Parameters	Submersible P-T and M-G	PSH 100 MW, 4 h	PSH 100 MW, 10 h	Li-ion 1 MW, 4 h	Li-ion 10 MW, 4 h	Li-ion 100 MW, 4 h
Plant generating capacity (MW)	74	100	100	1	10	100
RTE (%)	80	80	80	86	86	86
Plant lifetime (years)	60	40	40	10	10	10
TIC ($/kW)	1,680	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**156**	**209**	**135**	**254**	**238**	**227**

Project development risk: This technology has the potential to reduce overall project development risk because it requires less civil works and excavation to construct the vertical shafts to house the pump-turbines and motor-generators, compared to a traditional underground powerhouse. In addition, because the shafts are relatively narrow, geotechnical characterization of underground rock formations could potentially be achieved with a single borehole at the location of the vertical shaft, which reduces the cost of geological testing and geological risks.

Scalability and applicability: Unit sizes can range from less than 1 MW up to 100 MW, which provides excellent scalability for specific site situations; normally, a single PSH plant would have several generating units. In addition, the plant can be designed for staged development. Additional units would be added in phases, with minimal additional civil works required. Typical plant size is estimated to be 10–200 MW, with an average plant size around 75 MW.

This technology could be suitable for a variety of applications, including large grid-scale PSH plants co-located with the wind and solar plants, and small PSH plants for distribution systems. Because it does not need an underground powerhouse, this technology may be a cost-effective solution for small PSH projects, which can be prohibitively expensive if significant civil works are required for their construction.

Operational flexibility: The technology developer envisions the use of adjustable-speed generating units, which would provide excellent operational range as well as the full range of grid services, including the capability to provide frequency regulation during pumping. Use of adjustable-speed motor-generators should allow for an operating range of 20–100% in generation mode and 70–100% in pump mode.

Potential market size: There are theoretically thousands of geographical locations in the United States that would be suitable for this technology, but we estimate that the potential maximum number of installations would be in the low hundreds. Assuming an average plant size of 75 MW, the maximum total capacity of all projects of this type can be expected in the range of 5 to 10 GW.

Environmental impacts: The environmental impacts are slightly lower than for the conventional PSH plants of the same size because this type of plant requires less civil works and excavation. This technology can be configured as either an open- or a closed-loop PSH plant.

Physical siting limitations: Like conventional PSH plants, this technology requires an elevation difference between the upper and lower reservoirs. However, because of its smaller plant size, it is suitable for applications close to load centers, variable renewables, and transmission facilities. The relatively small footprint of the pump-turbine makes it suitable for use at existing hydropower sites and to add pumped storage capabilities to non-powered dams.

TRL: A TRL of 3 is estimated for the reversible pump-turbine geometry with flow inverter. Extensive computational fluid dynamics (CFD) simulations have shown that the pump-turbine operation is highly efficient in both generating and pumping mode. TRL 9 is estimated for the submersible motor-generator, because they are commercially available in multi-megawatt sizes. Overall TRL for this technology is estimated to be 4–5.

3.2.2.3 *Evaluation Summary*

Table 3-8 summarizes our evaluation findings. This seems to be a very promising technology: it has potential to reduce the costs, time, and risks associated with the construction of PSH plants. The scalability of plant sizes, from very small to medium projects, supports a variety of potential sites and applications. While the CFD simulations show that reversible pump-turbines with flow inverter are very efficient, it is important to develop prototypes and perform lab and field testing. If these estimates are confirmed, this technology may be a good choice for the construction of small to medium PSH plants, as well as for adding pumped storage capabilities to existing hydropower plants and non-powered dams.

Table 3-8 Evaluation Summary for Submersible Pump-Turbine and Motor-Generator PSH Technology

Evaluation Criteria	Submersible Pump-Turbine and Motor-Generator PSH Technology
Estimated Project Cost	Obermeyer Hydro, Inc., estimates capital costs of $1,680 per kW for a 74-MW PSH plant using an existing lower reservoir
Estimated LCOS	$156 to $174 per MWh
Construction Time	Estimated 3–4 years: Time to construct the vertical shaft for the pump-turbine is measured in months compared to years for an underground powerhouse
Project Development Risk	Slightly lower: Less excavation required for construction of vertical shafts to house submersible pump-turbines and motor-generators, compared to the traditional underground powerhouse
Scalability and Applicability	Unit sizes can range from less than 1 MW to about 100 MW; typical plant size estimated at 10–200 MW, average plant size 75 MW
Operational Flexibility	Use of an adjustable-speed motor-generator should allow for an operating range of 20–100% in generation mode and 70–100% in pump mode
Potential Market Size in the United States	Hundreds of potential installations, totaling about 5–10 GW of capacity (assuming 75 MW average plant size)
Environmental Impacts	Somewhat lower than the conventional PSH plant due to less excavation
Physical Siting Limitations	Requires elevation difference between upper and lower reservoirs. The small footprint of the pump-turbine makes it suitable for use at existing hydropower sites.
TRL	• TRL 3 for pump-turbine geometry: Extensive CFD analysis by multiple parties shows high efficiency • TRL 9 for submersible motor-generator: Submersible motors are commercially available in multi-MW sizes • Estimated overall TRL 4–5

3.2.2.4 *References*

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3.2.3 Geomechanical PSH

3.2.3.1 *Technology Description*

The geomechanical PSH technology is an innovative energy storage concept that is currently being developed by Quidnet Energy, Inc. (Quidnet). The main idea is to pump water down into the ground, between rock layers where the water would be kept under pressure. The natural elasticity of certain rock formations will act like a spring and keep the water under pressure, until the valve is opened and the water is released through a hydroelectric turbine to generate electricity.

Compared to the typical configuration of conventional PSH plants, in which the water is pumped up to an upper reservoir and then released down to a lower reservoir, the geomechanical PSH technology has the opposite reservoir placement. In this PSH concept, water is pumped down into rock formations and small caverns that would correspond to the upper reservoir of conventional PSH plants. Then the pressurized water is released up through the turbine and goes to an open reservoir at atmospheric pressure at ground level, which would correspond to the lower reservoir of a conventional PSH plant. Figure 3-5, taken from the Quidnet's website.[19] illustrates the geomechanical PSH technology and describes how it works.

The idea of using the natural elasticity of some rock formations to pressurize the water to store energy underground leverages the experience from the oil and gas extraction industry, where water would be repeatedly injected underground to push out oil and gas reserves to the surface. Pressurizing water within underground rock formations has already been established as possible way to store energy, and the key remaining research goal for Quidnet is to develop an efficient high-pressure "injector-generator" design that would be suitable for this type of application. For this research, Quidnet has been successful in obtaining some DOE funding through competitive FOA process.

Regarding the potential locations for this technology in the United States, Quidnet claims that this technology can be applied to any site where underground rock formations with the desired elasticity exist. Technology developers claim that rock formations suitable for geomechanical PSH are quite common and can be found in most parts of the United States. Because the water is

[19] See https://www.quidnetenergy.com/solution/#technologySection.

pumped underground and the other reservoir is an open-air surface reservoir at the ground level, this technology does not need hilly terrain to provide an elevation difference between the reservoirs. Therefore, it can be located anywhere where the right geological rock formations exist.

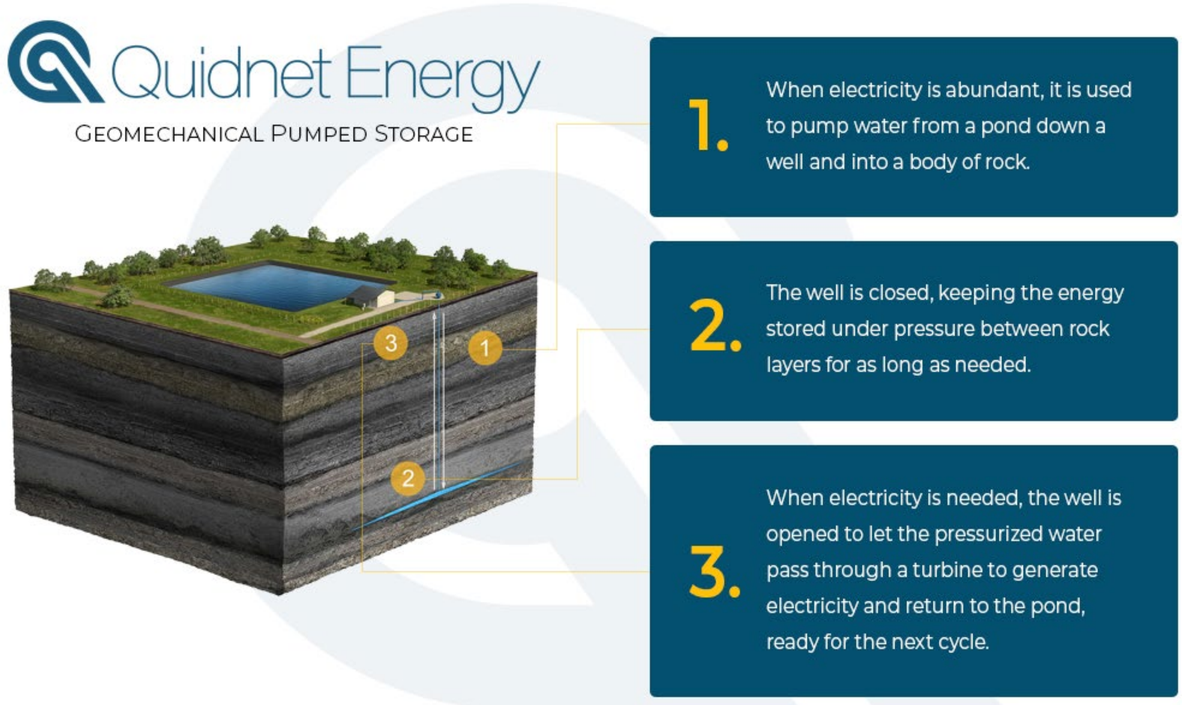

Figure 3-5 Geomechanical PSH Technology (Source: Quidnet)

In principle, geomechanical PSH technology would operate as a closed-loop PSH plant. It is highly scalable and modular because each surface reservoir may be able to serve multiple generating units. Unit sizes may vary from about 1 to 10 MW, with energy storage duration of 10 hours or longer. The construction of geomechanical PSH can also be performed in stages, with new units added by drilling additional wells. Quidnet envisions that generating units would be constructed in groups of four, and multiple groups could be combined to provide a PSH plant of larger size.

The construction process is likely to be quick, with standardized unit sizes using off-the-shelf equipment. There is no need for an underground powerhouse, and the drilling of relatively narrow wells would likely be fast, leveraging some of the experience and technologies from the oil and gas extraction industry.

3.2.3.2 *Technology Evaluation*

Estimated project cost: Quidnet estimates the TICs at $1,000–$1,500/kW of installed capacity for early systems. This would translate to about $100–$150/kWh for a 10-hour storage duration. The costs of mature systems are expected to decrease to less than $1,000/kW of capacity, or less than $100/kWh of energy storage. Quidnet also considers longer duration energy storage (e.g., 20–30 hours), which would be achievable with marginally higher costs per kilowatt and provide substantially lower costs per kilowatt-hour.

Estimated LCOS: Using the estimated range for project costs provided by Quidnet, we calculated LCOS for capital cost estimates of $1,000/kW (low CAPEX for mature systems), and $1,500/kW (high CAPEX for early systems). Table 3-9 shows the LCOS calculations and the obtained values of $127.53/MWh and $157.96/MWh for low and high CAPEX estimates, respectively.

Table 3-9 LCOS for Geomechanical PSH Technology

Technical Data	**Base (low inv. cost estimate)**	**Base (high inv. cost estimate)**
Plant generating capacity (MW)	40	40
RTE (%)	75	75
Average capacity factor (%)	20	20
Average annual generation (MWh)	70,080	70,080
Plant lifetime (years)	30	30
Major plant overhaul period (years)	15	15
Number of overhauls	1	1
Economic & Financial Data		
Investment cost ($/kW)	1,000	1,500
WACC (%)	8	8
TIC ($)	40,000,000	60,000,000
Major overhaul cost (10% of TIC)	4,000,000	6,000,000
Annual O&M cost ($) (1.5% of TIC)	600,000	900,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	4,672,000	4,672,000
LCOS analysis period (years)	30	30
LCOS by Component		
Investment cost ($/MWh)	$50.70	$76.05
Replacement cost ($/MWh)	$1.60	$2.40
O&M cost ($/MWh)	$8.56	$12.84
Charging cost ($/MWh)	$66.67	$66.67
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$127.53**	**$157.96**

Table 3-10 shows that these LCOS values compare favorably to the values obtained for the reference PSH technologies from the ESGC study (Mongird et al., 2020). They are also significantly lower than those obtained for reference Li-ion systems. This is an important finding because the estimated lifetime of geomechanical PSH technology is several times longer than that of Li-ion batteries. To calculate LCOS, we used a conservative 30-year estimated lifetime for geomechanical PSH, mainly because this is a new technology and we do not have data on the long-term elasticity degradation characteristics of rock formations and how many cycles they can provide before their elasticity degrades significantly. Note that Quidnet expects a longer

40+ year lifetime for geomechanical PSH plants. If that is the case, the LCOS values for this technology would be even lower.

Table 3-10 Comparison of LCOS Values for Geomechanical PSH and Reference PSH and Battery Technologies

Technoeconomic Parameters	Geomech. PSH (low CAPEX)	Geomech. PSH (high CAPEX)	PSH 100 MW, 4 h	PSH 100 MW, 10 h	Li-ion 1 MW, 4 h	Li-ion 10 MW, 4 h	Li-ion 100 MW, 4 h
Plant generating capacity (MW)	40	40	100	100	1	10	100
RTE (%)	75	75	80	80	86	86	86
Plant lifetime (years)	30	30	40	40	10	10	10
TIC ($/kW)	1,000	1,500	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**128**	**158**	**209**	**135**	**254**	**238**	**227**

Construction time: The time required to construct a geomechanical PSH plant is estimated to be 1.5 to 2 years. This estimate is for the actual facility construction and does not include time for licensing and permitting process, feasibility and engineering studies, and other project development activities.

Project development risk: As with other innovative technologies, there are certain inherent risks in developing this new technology and how it will operate in real-world conditions. In this case two key issues that may affect the feasibility of geomechanical PSH technology: (1) the efficiency and cost-effectiveness of the high-pressure injector-generator, and (2) the long-term elasticity characteristics and potential degradation of rock formations that are subject to repeated cycling over the years. Quidnet is currently addressing the first issue by developing a specialized injector-generator for this use. For the second issue, Quidnet has field tested rock formations. Very little degradation of elasticity was observed.

Note that these are technology development risks, not project development risks. Once the technology has been perfected and is ready for commercialization, it can be reasonably expected that project development risks will be much lower than for the conventional PSH plants of similar size. This is because geomechanical PSH plants can be constructed quickly; would require minimal civil works; may use an existing pond as surface reservoir, thus eliminating the need for dam or reservoir construction; do not need an underground powerhouse because the generating units can be housed at the ground level; and have minimal excavation requirements because they just need several relatively narrow vertical wells to be drilled down to the rock formation. This is a very simple plant design that—except for injector-generators, which are a new technology—relies on standard equipment and technologies and proven construction methods.

Scalability and applicability: As mentioned above, this technology is highly scalable and modular, with individual units ranging from about 1 to 10 MW, and each site supporting multiple units. Quidnet envisions that generating units will be built in groups (clusters) of four units and multiple clusters can be combined to create a PSH plant of larger size. For example, four 40-MW clusters, each consisting of four 10-MW units, would provide a total plant size of 160 MW.

In addition to the flexible sizing and modular construction of geomechanical PSH plants, their applicability for different locations and uses are enhanced by two characteristics: (1) The siting of these plants does not depend on the geographical areas with elevation difference, but rather on the availability of suitable underground rock formations. It seems that these rock formations are abundant in the United States, so the plants could be constructed in most areas, including the Midwest plains. This would provide proximity to wind resources and help integration of wind energy into the grid. (2) Geomechanical PSH plants can provide energy storage of varying duration, which enhances their usefulness for different applications. With minimal cost increase, the technology can be designed to provide energy storage with duration of 20 to 30 hours or longer, thus providing a low-cost LDES.

Operational flexibility: This is a new technology and it is difficult to estimate the operating ranges and efficiency curves for individual generating units. However, the modularity of the design and the ability to start and stop individual units should provide very flexible operation.

Potential market size: Because the rock formations with desirable geological characteristics are apparently abundant in many parts of the United States, there are theoretically thousands of sites that could support this technology. However, considering that geomechanical PSH plants will be competing in a market with other technologies, such as Li-ion and flow batteries, we estimate that maximum number of potential project installations will likely be in the hundreds, not thousands.

Assuming an average plant size of 40 MW, the maximum total capacity of this type of storage can be expected to be between 5 and 10 GW. Note that Quidnet estimates total resource potential for this technology in the United States at over 500 GW.

Environmental impacts: Compared to conventional PSH plants, the geomechanical PSH technology has lower environmental impacts, because it is a closed-loop system that needs only one relatively small reservoir, which is at ground level. Brownfield oil and gas fields can also be used. The civil works for the construction of plant are also small, because there is no need for an underground powerhouse, water conveyance systems, access tunnels, and other structures. The project footprint is practically equal to the size of the surface reservoir.

Physical siting limitations: The key siting requirement is the presence of appropriate subsurface rock geology. Quidnet claims that geology with appropriate geomechanical characteristics is ubiquitous in the United States.

TRL: For this technology we estimate a TRL of 5, because it mostly relies on technologies that have been applied and tested in oil and gas industry, and field testing has been performed to analyze the geomechanical characteristics of rock formations under repeated cycling. The remaining uncertainty lies in the development of a high-pressure injector-generator and its durability and performance characteristics. Once it is developed, a pilot plant should be constructed to demonstrate the technology in an operational environment.

3.2.3.3 *Evaluation Summary*

We think that the geomechanical PSH technology is a very promising energy storage technology, assuming a high-pressure injector-generator is successfully developed, and that the natural elasticity of underground rock formations can be retained for many years over thousands of cycles with little or no degradation. If those conditions are satisfied, we can envision numerous applications of this technology at sites that are normally not favorable for conventional PSH plants.

Because of favorable characteristics such as low project cost, fast construction, minimal environmental impacts, scalability and modular design, and long lifetime, this technology may successfully compete with other energy storage solutions, such as batteries and flow batteries. In addition, the ability to provide energy storage for 20 or 30 hours or longer would allow geomechanical PSH plants to serve as LDES technology and help the integration of large amounts of wind and solar generation, thus supporting the decarbonization of electric power systems. The key findings of the evaluation of this technology are summarized in Table 3-11.

Table 3-11 Evaluation Summary for Geomechanical PSH Technology

Evaluation Criteria	Geomechanical PSH Technology
Estimated Project Cost	Estimated at \$1,000–\$1,500 per kW (\$100–150/kWh) of installed capacity for early systems, less than \$1,000 (\$100/kWh) per kW for mature systems at 10 hours.
Estimated LCOS	\$127–\$158 per MWh
Construction Time	Estimated 1.5–2 years
Project Development Risk	Potential to lower project development risk: less civil works (no underground powerhouse), smaller plant footprint, no excavation for underground reservoir
Scalability and Applicability	Plant size estimated at 16–320 MW, based on multiples of unit sizes (4–40 MW per unit)
Operational Flexibility	Because it is modular, the plant should be able to provide very flexible operation by engaging multiple units
Potential Market Size in the United States	Hundreds of potential installations, totaling about 5–10 GW of capacity (assuming 40 MW average plant size); Quidnet estimates that total resource potential in the United States would exceed 500 GW, assuming 10-hour energy storage
Environmental Impacts	Minimal: Uses an underground reservoir, and the surface reservoir is relatively small; brownfield oil and gas fields can also be used
Physical Siting Limitations	Site must have appropriate subsurface rock geology; Quidnet claims that geology with appropriate geomechanical characteristics is ubiquitous in the United States
TRL	Estimated TRL is 5

3.2.3.4 *References*

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3.2.4 Hybrid PSH and Wind Plant

3.2.4.1 *Technology Description*

While there are many ways to design a hybrid wind and PSH plant, here we will highlight one interesting design that was proposed by the Max Boegl Wind AG (Max Boegl) company in Germany. On their website,[20] Max Boegl presents a "water battery" concept *Naturstromspeicher* (Naturspeicher GmbH, 2016), which is an innovative design that includes the construction of small concrete reservoirs around the foundations of wind turbines located on a hill. The combination of these small reservoirs then serves as a multi-part upper reservoir, and they are connected via water conduits with a lower reservoir at the bottom of the hill.

Max Boegl developed a pilot of this technology in Gaildorf, Germany. The pilot project includes four wind turbines with towers made of concrete and water reservoirs around their bases, which are also made of concrete. Max Boegl specializes in constructing concrete structures; both the wind towers and the water reservoirs can be built either from prefabricated elements that are transported to the project site or using mobile fabrication facilities at the project site.

Figure 3-6, taken from the Max Boegl website,[21] illustrates the Gaildorf pilot plant. Figure 3-7 illustrates the water reservoir being constructed around the base of one of the wind towers. The actual photograph of the completed pilot project is shown in Figure 3-8.

The four wind turbines at the Gaildorf pilot project have an installed capacity of 3.4 MW each, for a total of 13.6 MW. The installed capacity of the PSH plant is 16 MW. This is a closed-loop PSH system where the upper reservoirs at the bases of wind turbines are connected to each other and then to the lower reservoir using an underground penstock. The hydraulic head between upper and lower reservoirs is 200 m, or about 656 feet.

Some advantages of this technology include lower investment costs due to the standardization of construction and prefabrication of components, short construction period, long PSH plant lifetime (Max Boegl estimates about 50 years), and possible hybrid operations with other renewable resources (e.g., solar) in addition to wind.

[20] See https://www.mbrenewables.com/en/.
[21] See https://www.mbrenewables.com/en/pilot-project/.

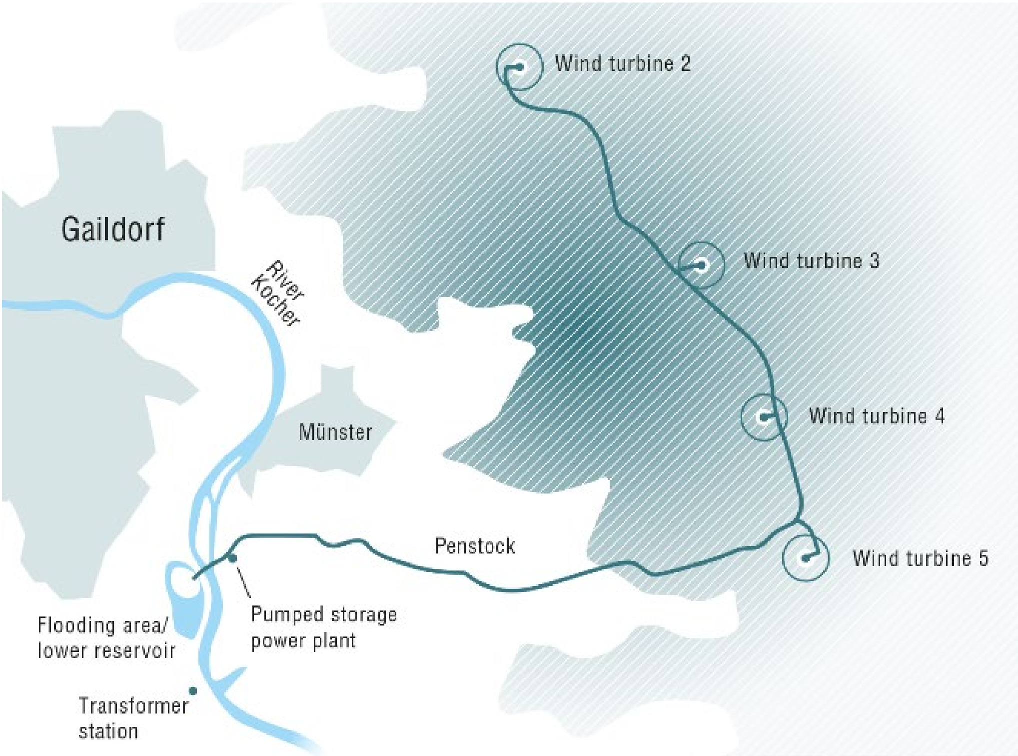

Figure 3-6 Gaildorf Pilot Project (Source: Max Boegl website, https://www.mbrenewables.com/en/pilot-project/)

Figure 3-7 Water Reservoir around the Foundation of Wind Tower (Source: Max Boegl website, https://www.mbrenewables.com/en/pilot-project/)

Figure 3-8 Photograph of Gaildorf Pilot Project (Source: Max Boegl website, https://www.mbrenewables.com/en/pilot-project/)

3.2.4.2 *Technology Evaluation*

Estimated project costs: Max Boegl has not provided the project costs for the Gaildorf pilot project, except to note that the project has been partially supported by German government with a grant of 7.5 million euros. Max Boegl also does not provide any estimates for typical investment costs for this technology. This may be because the costs are site-specific, and because it is difficult to separate the costs of the PSH plant from the costs of an overall project that includes a wind farm as well.

For our evaluation of innovative PSH technologies, it is important to separate the costs of the PSH plant from the costs for the wind farm. We estimate that the capital costs for the PSH component would likely be lower than for a conventional PSH plant of the same size. This considers the standardized and modular construction of upper reservoirs around the foundations of wind turbine towers, the relatively short length of the penstock, and the fact that the powerhouse for relatively small PSH units does not need to be constructed underground. For our evaluation, we assume that capital cost for the PSH component of the project falls in a range from $1,500/kW to $2,500/kW. This is a relatively wide range that should account for a variety of potential installations and site-specific situations.

LCOS calculations: Using the estimated project costs and other technical parameters available for this technology, we calculated LCOS values for two endpoints of the estimated project cost range. An LCOS value of $151.32/MWh was obtained for capital costs of $1,500/kW, while a higher LCOS value of $207.75/MWh was obtained for the assumed capital cost of $2,500/kW. Table 3-12 shows LCOS calculations performed for this technology.

Table 3-13 shows a comparison of LCOS values obtained for the PSH component of the hybrid PSH and wind plant with those of reference PSH and battery technologies featured in the ESGC report (Mongird et al., 2020). The LCOS values obtained for this technology are in a similar range to those for reference PSH technologies and are lower than those obtained for Li-ion batteries.

Construction time: The construction time for this technology is estimated to be 2–3 years, because less civil work is required to construct the upper reservoir and assembly of prefabricated modular elements at the project site would be rapid.

Project development risk: Except for the construction of the upper reservoirs at the foundations of the wind turbines, the project uses standard PSH construction practices and equipment. The overall project development risk could potentially be lower because it would use modular prefabricated structures for the wind turbine towers and the integrated water reservoirs at their foundations.

Scalability and applicability: The proposed technology is easily scalable and can be constructed in various plant sizes (e.g., 16, 24, or 32 MW, with a total energy storage from 70 to 150 MWh). The plant size can be customized for a particular location depending on the number and capacity of wind turbines used. For this technology to be cost effective, it is preferrable to have a small number of larger wind turbines, rather than a large wind farm with dozens or hundreds of wind turbines.

Operational flexibility: This technology needs to be flexible in order to compensate for the variability of wind energy generation. The PSH capacity does not need to fully compensate for wind generation variability (it can also rely on the grid for that), but it should be able to maximize the storage and minimize the curtailments of wind generation. Therefore, the use of adjustable-speed motor/generator units would be preferred over fixed-speed units. If adjustable-speed units are used, they should allow for an operating range of 30– 100% in generation mode and 70–100% in pumping mode.

Potential market size: There are many geographical locations that could be suitable for this technology, but its market size will also be affected by competing technologies like batteries and flow batteries. We estimate the maximum market potential for this technology in the United States would be less than 100 potential installations, with a total capacity between 1 and 2 GW, assuming an average plant size of 24 MW.

Environmental impacts: The environmental impacts of these PSH plants are expected to be smaller than for conventional closed-loop PSH projects, because the reservoirs at the base of wind turbines would be small. The wind turbines at the Gaildorf pilot project are very tall, with a hub height of about 155 m.

Table 3-12 LCOS Calculations for PSH Component of Hybrid PSH and Wind Plant

Technical Data	Base (Low CAPEX estimate)	Base (High CAPEX estimate)
Plant generating capacity (MW)	16	16
RTE (%)	75	75
Average capacity factor (%)	20	20
Average annual generation (MWh)	28,032	28,032
Plant lifetime (years)	50	50
Major plant overhaul period (years)	20	20
Number of overhauls	2	2
Economic & Financial Data		
Investment cost ($/kW)	1,500	2,500
WACC (%)	8	8
TIC ($)	24,000,000	40,000,000
Major overhaul cost (10% of TIC)	2,400,000	4,000,000
Annual O&M cost ($) (1.5% of TIC)	360,000	600,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	1,868,800	1,868,800
LCOS analysis period (years)	50	50
LCOS by Component		
Investment cost ($/MWh)	$69.99	$116.64
Replacement cost ($/MWh)	$1.82	$3.04
O&M cost ($/MWh)	$12.84	$21.40
Charging cost ($/MWh)	$66.67	$66.67
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$151.32**	**$207.75**

Table 3-13 Comparison of LCOS Values for PSH Component of Hybrid PSH and Wind Plant with Reference PSH and Battery Technologies

Technoeconomic Parameters	Hybrid PSH (low CAPEX)	Hybrid PSH (high CAPEX)	PSH 100 MW, 4 h	PSH 100 MW, 10 h	Li-ion 1 MW, 4 h	Li-ion 10 MW, 4 h	Li-ion 100 MW, 4 h
Plant generating capacity (MW)	16	16	100	100	1	10	100
RTE (%)	75	75	80	80	86	86	86
Plant lifetime (years)	50	50	40	40	10	10	10
TIC ($/kW)	1,500	2,500	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**151**	**208**	**209**	**135**	**254**	**238**	**227**

Physical siting limitations: This technology requires sites with good wind energy potential and an elevation difference between 150 and 350 m for the PSH plant. Note that, because the small reservoirs around the bases of wind turbines are connected to act as a single upper reservoir, the wind tower bases must all be at the same elevation. This may be a limiting factor that reduces the number of viable sites for this technology. It also may limit the number of wind turbines that can be built at a particular project site.

TRL: For this technology we estimate a high TRL of 7 to 8, because the pilot plant has already been constructed and the technology and the system has been incorporated in commercial design. This technology was developed, tested, and supported by a large wind construction company and is ready for full commercialization.

3.2.4.3 *Evaluation Summary*

The summary of evaluation findings for the hybrid PSH and wind technology developed by Max Boegl is presented in Table 3-14. This technology provides an interesting option for hybrid PSH and wind plants that has potential to reduce the cost, time, and risk for PSH project development. The key innovation is an upper PSH reservoir consisting of multiple small reservoirs built around the foundations of wind turbine towers. Max Boegl has developed a technology that uses prefabricated modular elements made of concrete for fast construction of both water reservoirs and wind turbine towers.

Table 3-14 Evaluation Summary for Hybrid PSH and Wind Plant Technology

Evaluation Criteria	Hybrid PSH and Wind Plant Technology
Estimated Project Cost	Capital cost for PSH needs to be separated from the cost for the wind farm; no cost data available at present
Estimated LCOS	$151 to $208 per MWh
Construction Time	Estimated 2–3 years
Project Development Risk	Potential to decrease project development risk due to application of modular prefabricated structures for wind turbines and integrated water reservoirs at their foundations
Scalability and Applicability	Plant size of 16, 24, or 32 MW, with a total energy storage of 70–150 MWh.
Operational Flexibility	Use of adjustable-speed generating units should allow for operating range of 20–100% in generation mode and 70–100% in pump mode
Potential Market Size in the United States	Less than 100 potential installations in the United States, totaling about 1–2 GW of capacity (assuming an average plant size of 24 MW)
Environmental Impacts	Expected to be lower than for conventional closed-loop PSH projects, because of the small size of reservoirs at the base of wind turbines
Physical Siting Limitations	Requires sites with good wind energy potential and height differential of 150–350 m for PSH plant; the wind turbine bases must be at the same elevation, which reduces the number of viable sites
TRL	Estimated TRL 7–8

3.2.4.4 *References*

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3.2.5 Integrated PSH and Desalination Plant

3.2.5.1 *Technology Description*

An example of a technology that combines PSH and a water desalination plant is the IPHROCES (Integrated Pump Hydro Reverse Osmosis Clean Energy System) technology being developed by Oceanus Power & Water, LLC (Oceanus).

IPHROCES combines a seawater PSH plant with a reverse-osmosis desalination plant to provide an integrated energy storage and fresh-water supply system. By combining the PSH plant and desalination plant, the hybrid facility may achieve synergistic benefits that would not be available if each plant were operating separately. The addition of a desalination process to the PSH plant brings an additional value stream and revenue from providing large amounts of fresh, potable water. The desalination plant also benefits from synergy with the PSH plant, which provides the energy needed for desalination, thus making desalination more cost-effective.

Figure 3-9 is a rendering of an integrated PSH and desalination plant, and Figure 3-10 is a schematic diagram of IPHROCES technology. The seawater is pumped from the ocean to the upper reservoir using the energy from the grid or from the co-located renewable generation sources. When electricity generation is needed, the water from the upper reservoir is released through the turbine to turn the generator and produce electricity, just as in any conventional PSH plant. The desalination process uses the water from the upper reservoir, which goes through pretreatment and through reverse-osmosis desalination to produce fresh, potable water for consumers. The key benefit from synergy with the PSH plant is that the desalination plant does not need to consume energy to pump the water through the reverse-osmosis process, because it can use the gravity-based water flow from the upper reservoir. The desalination process is in principle independent of PSH operations and can be conducted at any time by simply releasing the water from the upper reservoir through a separate conveyance system that connects the upper reservoir and the desalination plant. The energy potential of the hydraulic water pressure (created by the elevation difference between the upper reservoir and the reverse osmosis plant) is captured by the energy-recovery unit. The processed brine is then mixed with the water discharged from the PSH turbine and diluted brine is discharged into the ocean.

Oceanus is currently developing an IPHROCES project in Chile, South America (REGlobal, 2021).

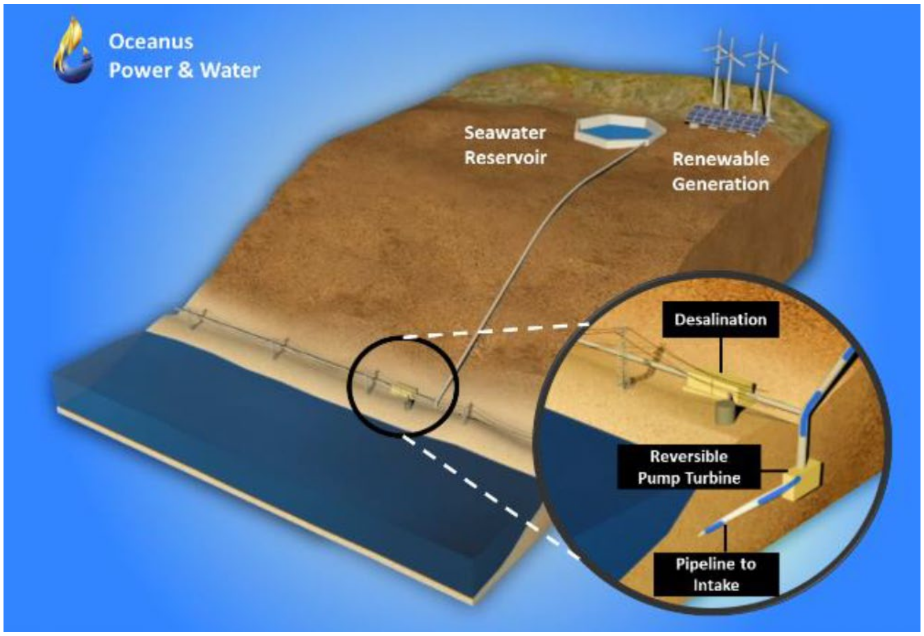

Figure 3-9 Combined PSH and Desalination Plant (Source: Oceanus Power & Water)

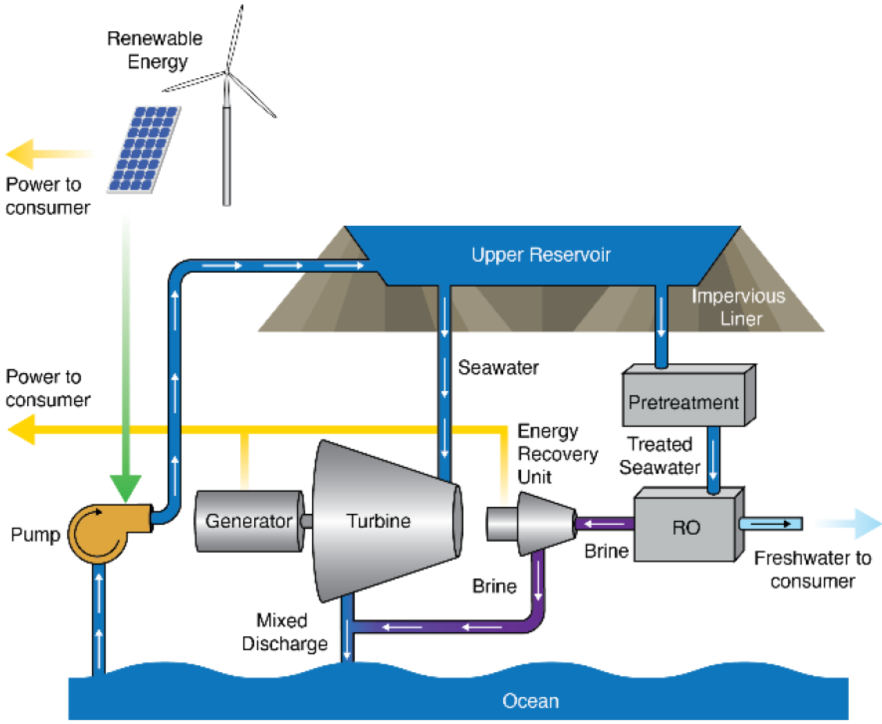

Figure 3-10 IPHROCES Technology (Source: Oceanus Power & Water)

3.2.5.2 *Technology Evaluation*

Estimated project costs: No cost information is available at present. We estimate that the total project costs, including the desalination plant, would be 10–30% higher than for a conventional PSH plant of the same size. In addition to the desalination plant, this cost increase would include additional costs related to the use of seawater in the PSH plant (e.g., corrosion protection of equipment and materials). For this study, we assumed that the likely project costs will range between $2,000/kW and $3,000/kW of PSH capacity.

Estimated LCOS: Using the estimated project costs and technoeconomic parameters for this technology, we calculated LCOS values for two endpoints of the estimated project cost range. The LCOS results were $174.26/MWh for the assumed low CAPEX value of $2,000/kW, and $230.14/MWh for the assumed higher CAPEX estimate of $3,000/kW. Table 3-15 shows LCOS calculations performed for this technology.

Table 3-15 LCOS Calculations for Integrated PSH and Desalination Plant

Technical Data	Low CAPEX Estimate	High CAPEX Estimate
Plant generating capacity (MW)	300	300
RTE (%)	80	80
Average capacity factor (%)	20	20
Average annual generation (MWh)	525,600	525,600
Plant lifetime (years)	60	60
Major plant overhaul period (years)	20	20
Number of overhauls	2	2
Economic & Financial Data		
Investment cost ($/kW)	2,000	3,000
WACC (%)	8	8
TIC ($)	600,000,000	900,000,000
Major overhaul cost (10% of TIC)	60,000,000	90,000,000
Annual O&M cost ($) (1.5% of TIC)	9,000,000	13,500,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	32,850,000	32,850,000
LCOS analysis period (years)	60	60
LCOS by Component ($/MWh)		
Investment cost ($/MWh)	$92.24	$138.35
Replacement cost ($/MWh)	$2.40	$3.61
O&M cost ($/MWh)	$17.12	$25.68
Charging cost ($/MWh)	$62.50	$62.50
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$174.26**	**$230.14**

Table 3-16 compares LCOS values obtained for the integrated PSH and desalination plant with those for reference PSH and battery technologies from the ESGC report (Mongird et al., 2020). As expected, the LCOS values obtained for this technology are somewhat higher than those for reference PSH technologies. The LCOS values for reference battery technologies are not shown, because this technology is not expected to compete with battery technologies.

Table 3-16 LCOS Values for Integrated PSH and Desalination Plant and Reference PSH Technologies

Technoeconomic Parameters	PSH + Desalination (low CAPEX)	PSH + Desalination (high CAPEX)	PSH 1,000 MW, 4 h	PSH 1,000 MW, 10 h
Plant generating capacity (MW)	300	300	1,000	1,000
RTE (%)	80	80	80	80
Plant lifetime (years)	60	60	40	40
TIC ($/kW)	2,000	3,000	1,717	2,202
LCOS Total ($/MWh)	**174**	**230**	**180**	**121**

Construction time: The average construction time for this technology is estimated to last 4–5 years, but this may depend on the size and location of the project, as well as on other site-specific conditions. This construction time does not include licensing, permitting, feasibility and engineering studies, and other project development activities. Oceanus estimates construction time to be 3–5 years.

Project development risk: Compared to the conventional PSH project, this technology has a potential to increase project development risk due to possible corrosion issues from using seawater for PSH operations. The project configuration is also more complex because of the additional desalination plant, equipment, and separate water conveyance system for its supply.

Scalability and applicability: This technology would typically require a larger plant size, most likely between 100 and 500 MW of PSH capacity. Sizes larger than 500 MW may also be possible, if there is sufficient demand for energy storage and especially for fresh water supply. These larger projects may benefit from economies of scale. This technology may be applicable in many coastal areas that experience long-term shortages of fresh water.

Operational flexibility: The flexibility of this PSH plant would be similar to that of a conventional PSH plant of the same size. If adjustable-speed generating units are used, they would allow for a 30–100% operating range in generation mode, and 70–100% in pumping mode. The PSH power plant would be able to provide all grid services that conventional PSH plants provide.

Potential market size: The demand for fresh water will be the primary driver for the construction of integrated PSH and desalination plants. We estimate that no more than a few dozen of these plants could potentially be constructed in the United States, mostly on the West Coast. Assuming an average plant size of 300 MW, this would amount to about 3–5 GW of total capacity.

Environmental impacts: The environmental impacts of this technology are likely to be about the same as for conventional open-loop PSH plants of the same size, and potentially greater than for land-based closed-loop projects. Only the upper reservoir needs to be constructed, since the ocean serves as lower reservoir; however, this is an open-loop PSH system and care must be taken to protect aquatic life and the environment. The desalination plant returns the salt brine to the sea, but the salinity effects can be diffused by the operation of PSH plant as the brine mixes with the water discharged from the PSH turbine.

Physical siting limitations: Ideally, this technology needs to be located along the coast with an elevation differential of about 400 m, less than 4 km from the sea. There are many geographical locations that satisfy these requirements. However, potential project developers may face a challenge in finding a suitable site that is available at relatively low cost, because the cost of land in coastal areas are typically higher than inland.

TRL: For this technology we estimate a TRL of 7, because it relies on proven PSH and desalination technologies, and combines them into an integrated system. The key uncertainty here is the use of seawater for a PSH plant, because of the potential corrosion issues. A pilot project is currently being developed in South America.

3.2.5.3 *Evaluation Summary*

Table 3-17 summarizes the findings of our evaluation for the integrated PSH and desalination technology. This technology combines energy storage and freshwater production, both of which are expected to be in high demand in coming years. The integration of PSH and a desalination plant allows for a lower cost freshwater production, which provides an additional revenue stream to project developers, in addition to the energy storage, capacity, and grid services that the PSH plant can provide. This technology may be a good solution for coastal areas that are experiencing shortages of freshwater. The combined PSH and desalination plant can support high levels of clean renewable electricity generation, while producing large amounts of fresh water using green renewable energy from wind and solar PV plants.

Table 3-17 Evaluation Summary for Integrated PSH and Desalination Technology

Evaluation Criteria	Integrated PSH and Desalination Plant
Estimated Project Cost	No cost data available at present; it is estimated that the total project cost would be 10–30% higher than a conventional PSH of the same size
Estimated LCOS	$174 to $230 per MWh
Construction Time	Estimated 4–5 years
Project Development Risk	Potential to increase project risk due to possible corrosion issues from using seawater for PSH plant operations; this technology is also more complex than conventional PSH because it requires additional equipment for desalination
Scalability and Applicability	Plant size estimated at 100–500+ MW, with an average size of 300 MW
Operational Flexibility	Use of an adjustable-speed motor/generator should allow an operating range of 30–100% in generation mode and 70–100% in pump mode
Potential Market Size in the United States	Dozens of potential installations in the United States, especially on the West Coast, totaling about 3–5 GW of capacity (assuming an average plant size of 300 MW)

Table 3-17 (cont.)

Evaluation Criteria	Integrated PSH and Desalination Plant
Environmental Impacts	PSH environmental impacts are about the same as for conventional open-loop PSH plants, and potentially greater than for the land-based closed-loop PSH projects. While only the construction of upper reservoir is required, since the ocean serves as lower reservoir, this is an open-loop PSH system and care must be taken to protect aquatic life and the environment.
Physical Siting Limitations	Needs a coastal location with a significant height differential relatively close to the sea; the cost of land may be a limiting factor
TRL	Estimated TRL is 7

3.2.5.4 *References*

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3.2.6 Underground PSH Using TBMs for Storage Excavation

3.2.6.1 *Technology Description*

Different concepts of underground PSH plants have been around for years, but here we focus on the idea proposed by Nelson Energy, LLC. This concept proposes using TBMs to excavate a lower reservoir in solid rock, such as granite. The TBMs will be used to first excavate an access tunnel to a depth of about 2,500 feet, where the lower reservoir and powerhouse will be located. This depth was chosen to maximize the head for which a single-stage reversible pump-turbine can be used. The lower reservoir is then excavated as spiral of underground tunnels until the desired volume is reached to provide the desired amount of storage. The crushed rock excavated from the underground bedrock is brought up to the surface through the access tunnel and used to construct a rockfill embankment to form the upper reservoir at ground level. A nearby river, lake, or other water source can be used for the initial filling of upper reservoir. In this way, a closed-loop PSH system can be developed. Figure 3-11 illustrates such a system, as envisioned by Nelson Energy (IFPSH, 2021).

Since this concept involves a significant amount of excavation and civil works, larger plant sizes of at least 500 MW are preferred, because this type of construction may not be economical for small PSH plants. Therefore, it is desirable to locate the powerhouse and lower reservoir at a significant depth, to maximize the hydraulic head and power output of the plant. Nelson Energy plans to use this concept for their Granite Falls project in Minnesota. Granite Falls will have an installed capacity of 666 MW, a storage duration of 12 hours, and a lower reservoir located at a depth of 2,500 feet.

This PSH concept and design may be suitable for areas like the Midwestern plains in the United States that do not have the topography to support conventional PSH but may have underground rock formations suitable for TBM excavation.

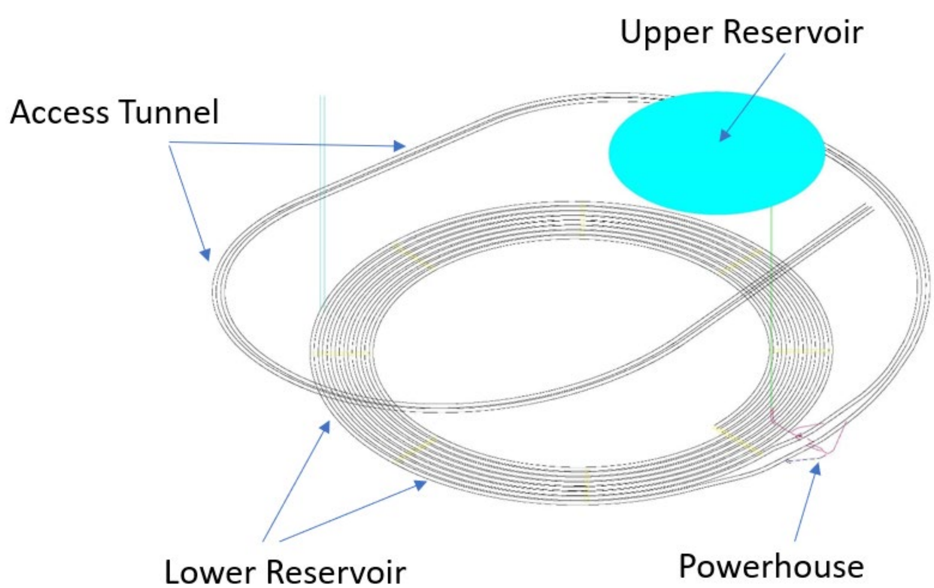

Figure 3-11 Design Concept of Underground PSH (Source: Nelson Energy)

3.2.6.2 *Technology Evaluation*

Estimated project costs: Nelson Energy estimates the total project costs for their Granite Falls project will be $2,640/kW (IFPSH, 2021).

Estimated LCOS: We calculated an estimated LCOS for the project of $2,640/kW, as well as a more conservative value of $3,000/kW. The rationale for including a higher CAPEX value was to account for unforeseen difficulties that may be encountered in the first developments of this type of underground PSH technology.

The LCOS values obtained for this technology were $210.03/MWh for Nelson Energy's estimate of capital costs, and $230.14/MWh for the conservative high CAPEX estimate. The LCOS calculations performed for this technology are presented in Table 3-18.

Table 3-19 compares LCOS values obtained for the underground PSH technology and those of reference PSH technologies from the ESGC report (Mongird et al., 2020). The obtained LCOS values for underground PSH are higher than those for reference PSH technologies, especially for the example with 10 hours of storage.

Table 3-18 LCOS Calculations for Underground PSH Using TBM

Technical Data	Base CAPEX Estimate	High CAPEX Estimate
Plant generating capacity (MW)	666	666
RTE (%)	80	80
Average capacity factor (%)	20	20
Average annual generation (MWh)	1,166,832	1,166,832
Plant lifetime (years)	60	60
Major plant overhaul period (years)	20	20
Number of overhauls	2	2
Economic & Financial Data		
Investment cost ($/kW)	2,640	3,000
WACC (%)	8	8
TIC ($)	1,758,240,000	1,998,000,000
Major overhaul cost (10% of TIC)	175,824,000	199,800,000
Annual O&M cost ($) (1.5% of TIC)	26,373,600	29,970,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	72,927,000	72,927,000
LCOS analysis period (years)	60	60
LCOS by Component		
Investment Cost ($/MWh)	$121.75	$138.35
Replacement Cost ($/MWh)	$3.17	$3.61
O&M Cost ($/MWh)	$22.60	$25.68
Charging Cost ($/MWh)	$62.50	$62.50
End-of-Life Cost or Value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$210.03**	**$230.14**

Construction time: Nelson Energy estimates that it will take 4.5 years to construct the Granite Falls project. Considering the amount of civil works and excavation required by this technology, we think that the average construction time for the projects of this type would be 5 to 6 years.

Project development risk: Because of the significant amount of underground excavation required for this technology, there is a potential for increased project development risk due to possible geological issues encountered during the TBM excavation. Some of these issues (e.g., unexpected cracks or porous layers) may also later affect the operation of the PSH plant.

Table 3-19 Comparison of LCOS Values for Underground PSH and Reference PSH Technologies

Technoeconomic Parameters	Hybrid PSH (low CAPEX)	Hybrid PSH (high CAPEX)	PSH 1,000 MW, 4 h	PSH 1,000 MW, 10 h
Plant generating capacity (MW)	666	666	1,000	1,000
RTE (%)	80	80	80	80
Plant lifetime (years)	60	60	40	40
TIC ($/kW)	2,640	3,000	1,717	2,202
LCOS Total ($/MWh)	**210**	**230**	**180**	**121**

Scalability and applicability: The project capacity is scalable, but the economics are better for larger plant sizes and greater energy storage. Plants are estimated to have 500–1,000+ MW of capacity. This technology is applicable for areas that do not have topography to support the conventional PSH design with the required elevation difference above ground. Once constructed, the project would operate as a closed-loop PSH and be able to provide all the same services as a conventional PSH plant.

Operational flexibility: Assuming that these types of underground PSH plants are most likely to be developed in the Midwest, which has significant wind resources, it would be recommended to use adjustable-speed generating units for additional flexibility in the pumping mode of operation. Use of an adjustable-speed motor-generator would allow a 30–100% operating range in generation mode, and 70–100% operating range in pumping mode.

Potential market size: Although there are more than a few locations in the United States, mostly in the upper Midwest, that could be suitable for this underground PSH using TBM for reservoir excavation, we do not foresee a huge number of these projects being built. We estimate a maximum of about a dozen projects potentially being built in the United States, with the total capacity between 5–15 GW, assuming an average plant size of 750 MW.

Environmental impacts: Environmental impacts are smaller than for conventional PSH plants because the lower reservoir is underground, and the upper reservoir can be constructed using the material excavated from the underground reservoir. Except for the initial filling and occasional make-up water for losses and evaporation, the underground PSH plant would operate as a closed-loop PSH plant.

Physical siting limitations: The key requirement is to have an adequate geological rock formation suitable for a watertight lower reservoir. In principle, this technology could be applied at any location where suitable geology exists, but the prime candidates would be the plains and other areas without the topography to support conventional PSH plants.

TRL: For this technology we estimate a TRL of 6. While the technology uses the same electromechanical equipment as conventional PSH plants, and TBM technology has been demonstrated in other applications, the proposed plant configuration and the use of TBM to excavate spiral reservoirs to depths of 2,500 feet have not yet been demonstrated in real- world pilot projects.

3.2.6.3 *Evaluation Summary*

Table 3-20 summarizes the findings of our evaluation for underground PSH technology that uses TBM to excavate lower reservoirs. This technology may provide a solution for large amounts of energy storage in areas that do not have the topography to support conventional PSH plants. Note that this technology requires significant civil works, but these mostly consist of underground excavations, so the environmental impacts are small. Once constructed, the PSH plant would operate as a closed-loop project, with minimal environmental impacts on its surroundings.

Table 3-20 Evaluation Summary for Underground PSH Using TBM for Storage Excavation

Evaluation Criteria	Underground PSH Using TBM for Storage Excavation
Estimated Project Cost	Nelson Energy estimates the total costs for their Granite Falls project to be $2,640/kW
Estimated LCOS	$210 to $230 per MWh
Construction Time	Estimated 5–6 years; Nelson Energy estimates 4.5 years of construction time for a 666-MW project
Project Development Risk	Potential to increase project risk due to possible geological issues found during TBM excavation; some of these geological issues (e.g., unexpected cracks or porous layers) may also later affect the operation of the PSH plant
Scalability and Applicability	The project size is scalable, but the economics are better for larger plants and energy storage; plant size estimated at 500–1,000+ MW
Operational Flexibility	Use of an adjustable-speed motor-generator should allow an operating range of 20–100% in generation mode and 70–100% in pump mode
Potential Market Size in the United States	Dozens of potential installations in the United States, where adequate geological rock formations are available, totaling about 5–15 GW of capacity (assuming an average plant size of 750 MW)
Environmental Impacts	Lower than for conventional PSH plants: Closed-loop operation, lower reservoir is underground, and the upper reservoir can be constructed using the materials excavated from the underground reservoir
Physical Siting Limitations	The key requirement is to have an adequate geological rock formation suitable for a watertight lower reservoir
TRL	Estimated TRL is 6

3.2.6.4 *References*

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3.2.7 Underground Mine PSH

3.2.7.1 *Technology Description*

The concept of using existing underground mines for the lower reservoirs of PSH plants has been considered for decades, but no actual projects have been constructed yet. As penetration of variable renewables into the power system increase and needs for energy storage to balance them increase, there is renewed interest in using abandoned underground mines to construct PSH plants (Madlener and Specht, 2020). At present, conceptual designs and feasibility studies are being carried out for several potential projects around the world, including at Aland and Pyhasalmi mines in Finland, Martelange slate mine in Belgium (Kitsikoudis et al., 2020), and abandoned coal mines in Germany (Prosper-Haniel in Bottrop, Porta Westfalica or Hartz mine) and Australia (Centennial Fassifern coal mine). In the United States, ORNL performed a study in 2015 on the feasibility of using abandoned coal mines for small modular PSH plants (Witt et al., 2015). Carbon Solutions, LLC, in collaboration with Indiana University—Purdue University Indianapolis (IUPUI) are investigating potential use of this technology in the state of Indiana.[22]

Several factors are often used to make the case for the potential use of abandoned mines to develop PSH plants. One is the topography: for example, in Indiana the land is mostly flat and there are no opportunities to construct conventional PSH plants. In addition, there are the economic reasons: using an existing underground mine as lower reservoir is thought to reduce the overall project costs. Environmental reasons are also considered: developing a closed-loop PSH project on a brownfield site would allow its re-use and revitalization, which may be much more acceptable to surrounding communities than greenfield development.

The underground mine PSH concept envisions using the tunnels and galleries of an existing abandoned mine as a lower reservoir and constructing or using an existing surface reservoir to serve as an upper reservoir for the PSH plant. An underground powerhouse needs to be constructed to contain the electromechanical equipment. A penstock between the upper reservoir and the powerhouse also needs to be constructed, as well as access shafts and tunnels, ventilation shafts, a surge tank, and other features necessary for PSH operation. It is also highly likely that some existing mine tunnels and galleries will need to be structurally reinforced to ensure their stability during rapid changes of water level during PSH operations. Finally, there may be a need to excavate additional underground tunnels to increase the volume of the lower reservoir. Figure 3-12 is a conceptual layout of an underground powerhouse in a coal mine (Witt et al., 2015).

[22] See https://netl.doe.gov/sites/default/files/netl-file/21AES_Ellett.pdf.

Obviously, even though an existing mine is being used for the lower reservoir, civil works are still involved to make it operational. The geology of the mine is very important, and geological strength is a key factor that determines whether or not a certain mine can be used.

Water quality is another issue that should be considered. Depending on the type of mine (coal, iron, copper, lead and zinc, etc.), underground water can be contaminated with various substances and may also present a corrosion risk to hydraulic equipment. This may reduce the life of equipment, necessitate more frequent maintenance, and increase the O&M costs.

3.2.7.1 *Technology Evaluation*

Estimated project costs: Witt et al. (2015) estimated the project costs would be between $1,768/kW and $2,406/kW. The IFPSH report (2021) provides estimated project costs from several studies, including one from Germany that estimates project costs to range from 1,200 to 2,400 EUR/kW (Stenzel et al., 2012), and from Spain, which shows an average project cost of 1,675 EUR/kW, based on the full use of existing underground mine structure and without excavation of new tunnels and galleries for the underground reservoir (Menendez et al., 2020).

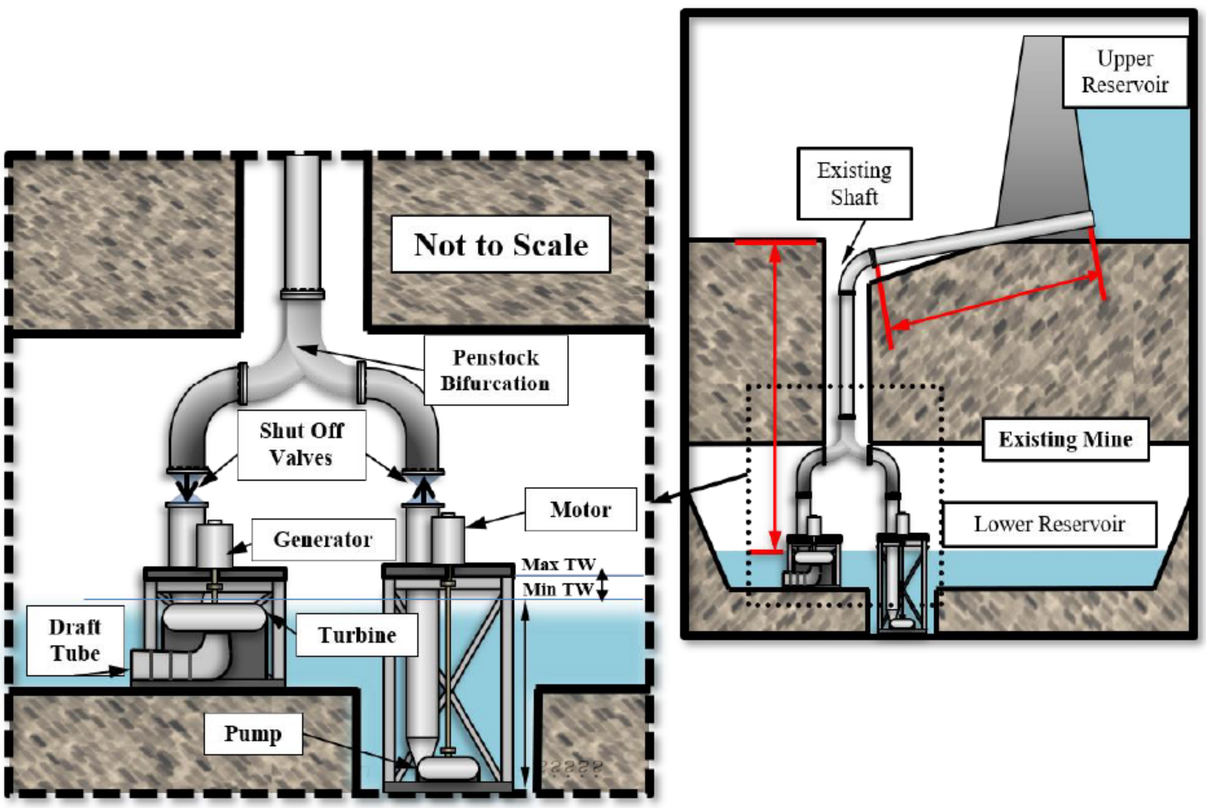

Figure 3-12 Conceptual Configuration of a Closed-loop PSH Plant in an Underground Coal Mine (Source: Hadjerioua et al., 2020)

Estimated LCOS: To calculate the LCOS of underground mine PSH in this study, we used a range of estimated project costs from $1,700/kW to $2,400/kW, which corresponds approximately to the range of estimated costs provided in the ORNL study (Witt et al., 2015).

This is also within the cost range estimated by Stenzel et al. (2012) for projects in Germany, and the estimate from Spain (Menendez et al. 2020) is approximately the midpoint of our range. The LCOS values obtained for the two endpoints of the range are shown in Table 3-21.

Witt et al. (2015) assumed the average RTE for this technology would be 75%, which is the value we used for the LCOS calculations. The obtained LCOS values of $161.66/MWh (low CAPEX), and $200.78/MWh (high CAPEX), are within the range of LCOS values obtained for reference PSH technologies from the ESGC study (Mongird et al., 2020). Because smaller underground mine PSH projects may be competing against some battery projects, Table 3-22 compares LCOS values obtained for reference Li-ion batteries as well.

Table 3-21 LCOS for Underground Mine PSH Technology

Technical Data	UM-PSH (low CAPEX)	UM-PSH (high CAPEX)
Plant generating capacity (MW)	50	50
RTE (%)	75	75
Average capacity factor (%)	20	20
Average annual generation (MWh)	87,600	87,600
Plant lifetime (years)	60	60
Major plant overhaul period (years)	20	20
Number of overhauls	2	2
Economic & Financial Data		
Investment cost ($/kW)	1,700	2,400
WACC (%)	8	8
TIC ($)	85,000,000	120,000,000
Major overhaul cost (10% of TIC)	8,500,000	12,000,000
Annual O&M cost ($) (1.5% of TIC)	1,275,000	1,800,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	5,840,000	5,840,000
LCOS analysis period (years)	60	60
LCOS by Component ($/MWh)		
Investment cost ($/MWh)	$78.40	$110.68
Replacement cost ($/MWh)	$2.04	$2.88
O&M cost ($/MWh)	$14.55	$20.55
Charging cost ($/MWh)	$66.67	$66.67
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$161.66**	**$200.78**

Construction time: We estimate the average construction time for this technology would be 3–5 years. The construction time is very site-specific and will vary depending on the layout and condition of the existing mine, such as whether additional tunnels and galleries need to be excavated to increase the storage volume, how much the existing tunnels need to be reinforced, the type and size of the upper reservoir, and other factors. Note that some developers of this technology (e.g., Mine Storage International AB) estimate the construction time would be 2–4 years (Johansson, 2021).

Table 3-22 LCOS Values for Underground Mine PSH and Reference PSH and Battery Technologies

Technoeconomic Parameters	UM-PSH (low CAPEX)	UM-PSH (high CAPEX)	PSH 100 MW, 4 h	PSH 100 MW, 10 h	Li-ion 1 MW, 4 h	Li-ion 10 MW, 4 h	Li-ion 100 MW, 4 h
Plant generating capacity (MW)	50	50	100	100	1	10	100
RTE (%)	75	75	80	80	86	86	86
Plant lifetime (years)	60	60	40	40	10	10	10
TIC ($/kW)	1,700	2,400	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**162**	**201**	**209**	**135**	**254**	**238**	**227**

Project development risk: The geology of existing mines is typically very well known. However, there are still some risks related to potential cracks developing during PSH operation, which may either cause water loss or allow additional underground water to enter the lower reservoir system. Neither of these options are good for a closed-loop PSH system, because mixing with the surrounding underground water should be avoided. Water losses would also require additional water to be added from some water source; in the opposite case, the plant would need to pump out surplus water entering the system, either of which would increase the cost of operations. Depending on the type of mine, potential water quality issues may affect the operation of the PSH plant by causing corrosion and premature aging of the equipment, and increasing O&M costs. It is also highly likely that some existing mine structures will need to be reinforced to ensure they remain stable during PSH operations.

Scalability and applicability: We expect that this technology will likely be most suitable for small to medium PSH projects, ranging from about 20 to 100 MW. The project size is site-specific and is determined by the size of the lower reservoir and the elevation differential. Projects larger than 100 MW may also be possible, if the mine is deep and the geological strength of the tunnels and surrounding rock formations can support higher water pressure.

Operational flexibility: The operational flexibility of an underground mine PSH is expected to be similar to that of conventional PSH plants. Either fixed-speed or adjustable-speed generating units can be applied. Adjustable-speed units should support an operating range of 20–100% in generation mode, and 70–100% in pumping mode.

Potential market size: There are thousands of abandoned underground mines in the United States, but not all of them are suitable for conversion to PSH plants. As with other PSH technologies evaluated in this study, the maximum potential market size will depend on the overall demand for energy storage, and the competitiveness of evaluated technology against other energy storage technologies—both existing and emerging new ones. For the underground mine PSH technology, we estimate that the maximum potential number of projects will likely be a few dozen, not hundreds. Assuming an average plant size of 50 MW, the maximum total capacity of all projects of this type in the United States would likely be 0.5–2 GW.

Environmental impacts: Environmental impacts are smaller than for the greenfield PSH developments because the lower reservoir is underground and the upper can be constructed on an existing brownfield site.

Physical siting limitations: This technology requires an available underground mine with stable geological characteristics. There are likely hundreds of abandoned underground mines in the United States that could be suitable for conversion to PSH plants.

TRL: We estimate a TRL of 6 for this technology because it relies on the same principles and electromechanical equipment as conventional PSH plants. However, the concept has not been demonstrated and tested by developing a pilot project in a real-world environment.

3.2.7.2 *Evaluation Summary*

Table 3-23 summarizes the findings of our evaluation for this technology. While the idea to use underground mines for PSH plants has been considered for decades, no such plants have been constructed yet. The concept is technically feasible, as it would use nearly the same overall principle and electromechanical equipment as conventional PSH plants, except that in this case the lower reservoir and powerhouse would be deep underground.

This technology also has several other positive characteristics. It naturally lends itself to be a closed-loop system with just one reservoir above ground, thus reducing the plant footprint, the amount of civil works, and environmental impacts. Rather than using a greenfield site for project development, this technology would use a brownfield site, which is likely to be improved by the construction of the upper reservoir and the restoration of surrounding areas. Despite these and other potential advantages, this technology has not gained traction so far, mostly because of the uncertainties related to the new concept and its operation over the long term. A pilot project would provide much-needed experience and information on the plant O&M requirements and associated costs, and would help developers understand potential impacts of PSH operations on the stability of underground tunnels and surrounding rock formations.

Table 3-23 Evaluation Summary for Underground Mine PSH Technology

Evaluation Criteria	Underground Mine PSH
Estimated Project Cost	Project costs are very site-specific and can vary widely; the ORNL study on modular PSH provides cost estimates between $1,768/kW and $2,406/kW
Estimated LCOS	$162–$201 per MWh
Construction Time	Estimated 3–5 years; Mine Storage International AB estimates a plant construction period of 2–4 years
Project Development Risk	Potential to increase the project risk because of possible geological issues during excavations, the conditions of underground mine shafts and tunnels, and water quality issues
Scalability and Applicability	Typical plant size is estimated to be 20–100 MW
Operational Flexibility	Use of an adjustable-speed motor-generator should allow for an operating range of 20–100% in generation mode and 70–100% in pump mode
Potential Market Size in the United States	Dozens of potential installations in the United States, with a total capacity of 0.5–2 GW, assuming an average plant size of 50 MW

Table 3-23 (cont.)

Evaluation Criteria	Underground Mine PSH
Environmental Impacts	Lower than for the greenfield PSH developments: Lower reservoir is underground and the upper can be constructed on an existing brownfield site
Physical Siting Limitations	Technology requires an available underground mine with stable geological characteristics
TRL	Estimated TRL is 6

3.2.7.3 *References*

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3.2.8 Open-Pit Mine PSH

3.2.8.1 *Technology Description*

This concept is similar to the one described in the previous section, but instead of using underground mines, it proposes to use the infrastructure of decommissioned open-pit mines for the development of PSH projects. This is not a new idea, and one PSH project of this type has already been constructed – the 1,728-MW Dinorwig[23] PSH plant in the United Kingdom, which was commissioned in 1984. Dinorwig is a closed-loop PSH project that utilizes an abandoned slate quarry as lower reservoir. In Australia, construction has been approved for the 250-MW Kidston[24] PSH project, which will be located on the site of a decommissioned open-pit gold mine (IFPSH, 2021). Two existing pits of the gold mine, which are at different elevations, will be converted into the upper and lower reservoirs of a closed-loop PSH project. In the United States, the 1,300-MW Eagle Mountain[25] PSH project is planned on the site of a decommissioned iron ore mine. Two open mine pits will serve as upper and lower reservoirs of the proposed closed-loop PSH project.

The potential key benefits of using decommissioned open-pit mines to develop PSH projects include cost and time savings, because less civil works would be needed to construct the reservoirs. In addition, the water conveyance hydraulics are significantly better than other underground alternatives. Significant civil works are still necessary, because the reservoirs may need to be shaped and their slopes graded to ensure slope stability. In some cases, the reservoirs may also need to be lined to prevent water losses or erosion. A powerhouse also needs to be constructed, typically underground, as well as tunnels and penstocks between the upper and lower reservoirs. Still, the overall project costs are likely to be lower than those for greenfield PSH construction, although it is very site-specific because every site is different. Additional cost savings may be possible if the existing infrastructure that was serving the mine operations before its closure (e.g., access roads, electricity and water supply) still exists and could be used to support the construction of the PSH project.

All of this could contribute to lower costs and faster construction for an open-pit mine PSH project, compared to a conventional PSH project of similar size. By reducing the cost and time to construct the project, the developer also reduces some of the project development risks. However, some factors may contribute to increased project risk due to uncertainties related to the structural rigidness of open-pit mine walls, potential cracks and leaks, and water quality issues.

One additional benefit of converting decommissioned open-pit mines into PSH projects is that brownfield sites are being reused and repurposed. This brings certain environmental benefits, as

[23] See https://www.fhc.co.uk/en/power-stations/dinorwig-power-station/.
[24] See https://www.genexpower.com.au/250mw-kidston-pumped-storage-hydro-project.html.
[25] See http://www.eaglecrestenergy.com/project-description.html.

the brownfield site will be improved after the construction of the PSH project: the site will be converted into a non-polluting energy storage facility.

3.2.8.2 *Technology Evaluation*

Estimated project costs: Project costs are very site-specific and can vary widely. The IFPSH (2021) report cites publicly available estimates for three proposed South Australian open-pit mine PSH projects, which range from $750/kW to $1,600/kW. However, the authors also express some skepticism about these cost estimates, especially the lower range. Note that Kidston PSH was not included in these estimates.

In the United States, the license application for the Eagle Mountain project predicts total project costs, in 2008 dollars, of $1.325 billion (FERC, 2008). For a 1,300-MW project, this translates to about $1,020/kW in 2008 dollars (about $1,280/kW in 2021 dollars).

Since Genex Power has recently secured funding (Genex Power, 2021) and is about to start constructing the Kidston PSH project, we decided to use Kidston as an illustrative example for the open-pit mine PSH project. Genex Power, in their financial close brochure (Genex Power, 2021) provides the most recent technical and cost information for the project. Kidston is being developed as a 250-MW project with 1,500 MWh of energy storage, or about 6 hours of storage. Genex Power estimated total project costs, including transmission connection, would be AU$775.5 million, or about US$584 million.[26] This translates to about US$2,335 per kW of installed capacity.

Estimated LCOS: Using the $2,335/kW cost estimate from Genex Power, the resulting LCOS is $192.98/MWh. This calculation is presented in Table 3-24.

Table 3-25 shows how the estimated LCOS value of $192.98/MWh compares to the values calculated for the reference PSH technologies from the ESGC study (Mongird et al., 2020). The obtained LCOS value falls between the LCOS values obtained for reference 100-MW PSH projects with 4 hours and 10 hours of storage, but is higher than LCOS of larger 1,000-MW PSH projects. We did not include the LCOS comparison with Li-ion batteries, because this PSH technology is not likely to compete with batteries.

Construction time: The construction time for open-pit mine PSH projects is estimated to be about 3–5 years, which is slightly shorter than for the conventional PSH projects of similar size.

Project development risk: While the somewhat shorter project construction period slightly decreases project development risks, some factors could potentially increase project risks, such as uncertainties related to structural rigidness of open-pit mine walls, potential cracks and leaks due to rapid reservoir fluctuations, and water quality issues.

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[26] Exchange rate: 1 Australian dollar = 0.75274 U.S. dollar (https://www1.oanda.com/currency/converter/).

Table 3-24 Estimated LCOS for Open-Pit Mine PSH

Technical Data	Kidston (250 MW)
Plant generating capacity (MW)	250
RTE (%)	80
Average capacity factor (%)	20
Average annual generation (MWh)	43,800
Plant lifetime (years)	60
Major plant overhaul period (years)	20
Number of overhauls	2
Economic & Financial Data	
Investment cost ($/kW)	2,335
WACC (%)	8
TIC ($)	583,750,000
Major overhaul cost (10% of TIC)	58,375,000
Annual O&M cost ($) (1.5% of TIC)	8,756,250
Average charging electricity price ($/MWh)	50
Annual charging cost ($)	27,375,000
LCOS analysis period (years)	60
LCOS by Component	
Investment cost ($/MWh)	$107.68
Replacement cost ($/MWh)	$2.81
O&M cost ($/MWh)	$19.99
Charging cost ($/MWh)	$62.50
End-of-life cost or value ($/MWh)	$0.00
LCOS Total ($/MWh)	**$192.98**

Table 3-25 Comparison of LCOS Values for Open-Pit Mine PSH and Reference PSH Technologies

Technoeconomic Parameters	Open-Pit Mine PSH	PSH 100 MW, 4 h	PSH 100 MW, 10 h	PSH 1,000 MW, 4 h	PSH 1,000 MW, 10 h
Plant generating capacity (MW)	250	100	100	1,000	1,000
RTE (%)	80	80	80	80	80
Plant lifetime (years)	60	40	40	40	40
TIC ($/kW)	2,335	2,046	2,623	1,717	2,202
LCOS Total ($/MWh)	**193**	**209**	**135**	**180**	**121**

Scalability and applicability: Depending on the site characteristics, plant sizes can range from about 100 MW to over 2,000 MW. Once constructed, these projects can provide all the same services as conventional PSH plants

Operational flexibility: As with conventional PSH plants, the operational flexibility will depend on the plant design (e.g., number and configuration of generating units and penstocks) and the type of PSH technology that is used. A closed-loop PSH plant can be designed for high operational flexibility, such as the Dinorwig PSH, which is still the fastest ramping PSH plant in the world (0 to 1,320 MW in 12 seconds).[27] Note that Dinorwig uses fixed-speed generating units, but the water conduits were specially designed for high operational flexibility and ramping that is several times faster than other existing PSH plants. We estimate that most open-pit mine PSH plants will use adjustable-speed generating units, which will provide an operating range of 20–100% in generating mode, and 70–100% in pumping mode.

Potential market size: We estimate that dozens of open-pit mine PSH plants could potentially be constructed in the United States. Assuming an average plant size of 500 MW, this translates into a potential installed capacity between 5 and 15 GW.

Environmental impacts: This technology is expected to have smaller environmental impacts than conventional PSH plants because it will use existing mines for one or both reservoirs. In addition, the PSH plant is typically expected to operate as closed-loop system. Note that, because these projects are located on brownfield sites, there may be some risk of groundwater contamination.

Physical siting limitations: Availability of an open-pit mine and elevation differential between the upper and lower reservoirs are the key requirements for this technology.

TRL: Because an open-pit mine PSH uses the same technology as conventional PSH plants, and there is already one project in existence, we estimate the TRL to be between 8 and 9.

3.2.8.3 *Evaluation Summary*

Table 3-26 summarizes evaluation findings for open-pit mine PSH technology. As mentioned above, this technology may benefit from potential reductions in cost and time for project development. The shorter construction time reduces risk, while the uncertainties related to the use of open mine pits as reservoirs, stability of reservoir walls, water quality and other issues may increase project development risks. The technology is expected to have low environmental impacts because the projects will mostly be developed as closed-loop PSH plants. Utilization and rehabilitation of brownfields is an additional benefit that this technology provides.

Table 3-26 Evaluation Summary for Open-Pit Mine PSH Technology

Evaluation Criteria	Open-Pit Mine PSH
Estimated Project Cost	In their 2021 financial close report, Genex Power, the developer of the 250-MW Kidston project, estimates total project cost at US$2,335/kW
Estimated LCOS	193/MWh
Construction Time	Estimated 3–5 years
Project Development Risk	Average: A shorter project construction period slightly decreases project development risks, while uncertainties related to structural rigidness of open-pit mine walls, potential cracks and leaks, and water quality issues may increase risk
Scalability and Applicability	Plant size from can vary from under 100 MW to over 2,000 MW

[27] See https://www.electricmountain.co.uk/Dinorwig-Power-Station.

Table 3-26 (cont.)

Evaluation Criteria	Open-Pit Mine PSH
Operational Flexibility	Use of an adjustable-speed motor-generator should allow an operating range of 20–100% in generation mode and 70–100% in pump mode
Potential Market Size in the United States	Dozens of potential installations in the United States, totaling 5–15 GW, assuming an average plant size of 500 MW
Environmental Impacts	Lower environmental impacts than for a conventional PSH plant because it will use existing open mines for one or both reservoirs; the PSH plant also is typically expected to operate as a closed-loop system
Physical Siting Limitations	Availability of an open-pit mine and elevation differential.
TRL	Estimated TRL 8–9

3.2.8.4 *References*

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IFPSH (International Forum on Pumped Storage Hydropower). 2021. *Innovative Pumped Storage Hydropower Configurations and Uses*. Capabilities, Costs & Innovation Working Group, September. Available at: https://www.hydropower.org/publications/innovative-pumped-storage-hydropower-configurations-and-uses. Accessed October 24, 2021.

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3.2.9 Hybrid Modular Closed-Loop Scalable PSH

3.2.9.1 *Technology Description*

The key underlying idea of this PSH concept is to use very large polymeric bags as reservoirs for mini or micro PSH plants. This is a relatively recent idea, appearing in the last decade or so. Various researchers around the world (e.g., Denmark, Ireland, United States) have explored the possibilities of using large bladder-type reservoirs for small PSH plants. For example, Aarhus University[28] researchers in Denmark considered using a large pillow-shaped bag made of polymeric geomembrane material to serve as the upper reservoir for a small PSH plant, while an existing water body would serve as the lower reservoir. They also considered covering the bag

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[28]See https://stateofgreen.com/en/partners/aarhus-university/news/water-balloon-tech/.

with a thick layer of soil (up to 25 m) to increase the pressure on the water inside the bag, thus adding "virtual hydraulic head" and increasing the power rating of the PSH plant.

Other ideas included a closed-loop underwater system that would consist of two large polymeric bags at different depths under the sea. One bag would be anchored deep under the sea and serve as high-pressure reservoir, while the other would be a low-pressure reservoir floating close to the sea surface. The difference in the hydrostatic pressure between the two bags could be used to store energy and produce power when the water from the high-pressure bag is released up to the floating surface bag.

For our evaluation, we will use as a representative example of bladder-type technology the concept proposed by Liberty University professors Thomas Eldredge and Hector Medina, as featured in the IFPSH report (2021). They proposed a hybrid modular closed-loop scalable PSH system (h-mcs-PSH) consisting of multiple bladder-type tanks that are located at different elevations to serve as upper and lower reservoirs of the PSH plant, as illustrated in Figure 3-13.

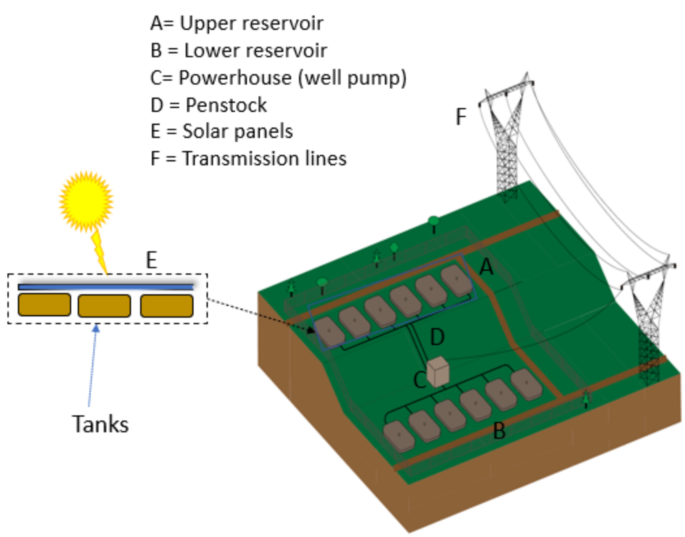

Figure 3-13 Hybrid Modular Closed-Loop Scalable PSH Technology (Source: T. Eldredge and H. Medina from Liberty University)

The concept is modular and the amount of energy storage depends on the number of bladder tanks used and elevation difference between the upper and lower reservoir locations. The tanks are connected to each other using an HDPE piping system, which can also be used for the penstock between the upper and lower reservoirs. The size of the PSH plant may range from 0.1 to 10 MW. For this small PSH size, there is no need to use an underground powerhouse. Instead, the developers plan to use the vertical shaft submersible pump-turbine technology that is being developed by Obermeyer Hydro, Inc. Please refer to Section 3.2.2 of this report for more details on this technology.

The bladder-type tanks are made of a flexible polymeric-type geomembrane material and will be laid on the ground at atmospheric pressure. The ground surface will need some preparation, to make it flat and avoid sharp rocks and other material that may damage the tanks over time. A layer of fine sand or plastic lining material underneath the tanks may also be needed in some cases. Since the polymeric bags will be exposed to sunlight, temperature changes, and other weather conditions, they may also need to be covered with a protective material—or at least painted to reduce the exposure to ultraviolet radiation and thus slow the aging and degradation of the polymeric membrane material. To avoid exposure to ultraviolet radiation and protect against premature degradation of polymeric tanks, the developers have proposed a hybrid concept with solar panels installed above the bladder tanks. The developers estimate the lifetime of this PSH concept to be 20+ years.

Potential advantages of this PSH concept include its modular structure, with plant sizes expected to vary between 1 and 10 MW; use of standard off-the-shelf equipment and components; minimal civil works needed for project construction; and small environmental impacts of the closed-loop project. Additional benefits may be provided by integrating the PSH plant with a solar PV farm, which would extend the lifetime of bladder tanks and provide electricity for pumping needs. Because of its relatively small size and footprint, this technology would be suitable for many geographical locations, including collocations with solar and wind farms, as well as potential locations closer to urban population centers.

A potential disadvantage of this technology is the relatively high specific project cost per kilowatt of installed capacity, because the small project size does not provide economy of scale benefits like some larger PSH projects. This technology is mostly expected to operate with a relatively low hydraulic head, which does not provide for a high density of energy storage. In addition, the estimated maximum plant size of 10 MW may be too small for grid-scale applications or even hybrid applications with larger solar and wind farms. However, it could be suitable for microgrids, some isolated communities, and island grids. There are also uncertainties related to the long-term durability of polymeric bladder tanks in real-world operations, as well as potential regulatory issues since this is a new technology and there is not much prior experience or established operating practices.

3.2.9.2 *Technology Evaluation*

Estimated project costs: The technology developers estimated project costs with and without renewable solar component. Figure 3-14. show the estimates for specific project costs for the PSH plant only, for plant sizes of 3, 5, and 10 MW. The specific project costs decrease with the size of the plant, from $4,342/kW for a 3-MW installation, to $3,270/kW for a 5-MW installation, and finally to $2,235/kW for a 10-MW installation.

The specific project costs per kilowatt of capacity increase for a hybrid PSH project with a solar PV component. Figure 3-15 provides the estimates of specific project costs with and without PV solar component for project sizes from 0.1 to 10 MW. The specific capital cost of a very small 0.1-MW project is extremely high, but the costs quickly decrease as the project size increases.

Figure 3-14 Estimated Capital Costs for H-mcs-PSH Plant without Solar Component (Source: T. Eldredge and H. Medina from Liberty University)

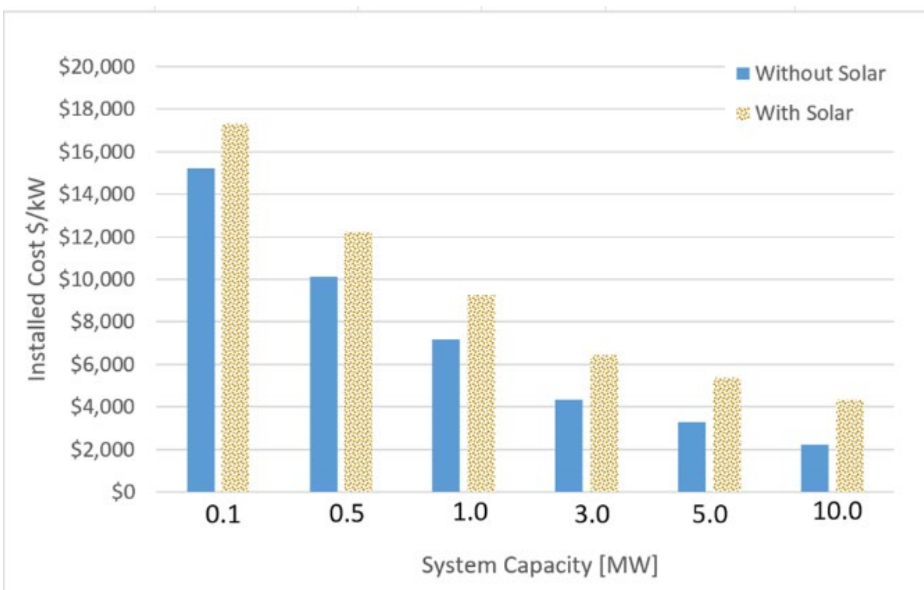

Figure 3-15 Estimated Capital Costs for H-mcs-PSH plant with and without Solar Component (Source: T. Eldredge and H. Medina from Liberty University)

Estimated LCOS: For the evaluation in this study, we are interested in the project costs of the PSH plant only, so we used the cost estimates without the solar component. For LCOS analysis we used two plant sizes, 3 and 10 MW, that bookend the expected range of project sizes for most applications of this technology.

The RTE was estimated by technology developers to be 74.3% for the 3-MW plant size, and 75.9% for the 10-MW plant size. Table 3-27 provides details of LCOS calculations performed for this technology assuming a plant life of 20 years with one major overhaul after 10 years. Similar to the other PSH technologies evaluated in this study, minor overhauls and repairs that are done annually or every few years are included into the estimated O&M costs.

Table 3-27 LCOS Calculations for Modular Closed-Loop Scalable PSH Technology

Technical Data	PSH (3 MW) w/o Solar	PSH (10 MW) w/o Solar
Plant generating capacity (MW)	3	10
RTE (%)	74.3	75.9
Average capacity factor (%)	20	20
Average annual generation (MWh)	5,256	17,520
Plant lifetime (years)	20	20
Major plant overhaul period (years)	10	10
Number of overhauls	1	1
Economic & Financial Data		
Investment cost ($/kW)	4,342	2,235
WACC (%)	8	8
TIC ($)	13,026,000	22,350,000
Major overhaul cost (10% of TIC)	1,302,600	2,235,000
Annual O&M cost ($) (1.5% of TIC)	195,390	335,250
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	353,701	1,154,150
LCOS analysis period (years)	20	20
LCOS by Component		
Investment cost ($/MWh)	$252.42	$129.93
Replacement cost ($/MWh)	$11.69	$6.02
O&M cost ($/MWh)	$37.17	$19.14
Charging cost ($/MWh)	$67.29	$65.88
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$368.58**	**$220.96**

The obtained LCOS values of $368.58/MWh for a 3-MW PSH plant and $220.96/MWh for a 10-MW PSH plant are higher than those obtained for reference PSH technologies from the ESGC study (Mongird et al., 2020). However, this small PSH technology is more likely to compete with battery technologies rather than with larger grid-scale PSH plants. As shown in Table 3-28, the LCOS value obtained for the 10-MW plant is competitive with the Li-ion battery technologies.

Table 3-28 LCOS Values for H-mcs-PSH and Reference PSH and Battery Technologies

Technoeconomic Parameters	Bladder PSH (3 MW)	Bladder PSH (10 MW)	PSH 100 MW, 4 h	PSH 100 MW, 10 h	Li-ion 1 MW, 4 h	Li-ion 10 MW, 4 h	Li-ion 100 MW, 4 h
Plant generating capacity (MW)	3	10	100	100	1	10	100
RTE (%)	74.3	75.9	80	80	86	86	86
Plant lifetime (Years)	20	20	40	40	10	10	10
TIC ($/kW)	4,342	2,235	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**369**	**221**	**209**	**135**	**254**	**238**	**227**

Construction time: Considering the small size of the project and minimal civil works required for its development, the construction time is estimated to be up to 2 years.

Project development risks: On one hand, project development risks are smaller because of short construction time, minimal civil works required, and use of standard equipment and components. On the other hand, this is a new technology that faces numerous uncertainties, mainly related to the use of polymeric tanks, their durability, and operation performance.

Scalability and applicability: This technology is modular and highly scalable, but the plant sizes are small, 10 MW or less. It is more likely that PSH plants of this type would be connected to a distribution system network, rather than to a high-voltage transmission network. While mostly expected to serve as distributed storage resources, these PSH plants may also be used for grid applications, especially in hybrid configurations if collocated with grid-scale wind and solar plants.

Operational flexibility: Developers of this technology at Liberty University envision using Obermeyer adjustable speed PSH units, which should allow an operating range of 20–100% in generating mode, and 70–100% in the pumping mode. The modular configuration of the PSH plant allows additional operational flexibility through selective use of bladder tanks during operation to improve water flows and efficiency at different power output levels.

Potential market size: Many geographical locations in the United States could be suitable for this technology because of its small footprint, low environmental impacts, and minimal water requirements for the closed-loop system.

However, because of its relatively high capital cost and small plant size, this technology will be competing against battery technologies for most applications. While competitive at present, this technology will have to reduce the cost of mature systems significantly to remain competitive with battery technologies in the future.

For the modular bladder-type PSH technology, we estimate the maximum potential number of projects in the United States would be about 100. Assuming an average plant size of 5–10 MW, this translates to a maximum total capacity of about 500–1,000 MW.

Environmental impacts: The environmental impacts are minimal due to the technology's small size and footprint, and the minimal civil works required for plant construction. The closed-loop PSH system will also have minimal environmental impacts during operation.

Physical siting limitations: Ideally, the project would use two relatively flat ground surfaces that are close to each other but at different elevations for the modular bladder-type upper and lower reservoirs. A source of water for initial filling of reservoirs is also required.

Many thousands of geographic locations would be suitable for this technology in the United States. Due to its closed-loop design and small plant size, the water requirements are minimal, and this technology could be implemented even in places without nearby water bodies, by using available groundwater for initial fill up of tanks and occasional make-up water additions. Because the water tanks are fully enclosed, water losses are expected to be minimal.

TRL: The estimated TRL is 3. This technology would benefit from a pilot plant to help developers improve the design and configuration of PSH plant, as well as determine the capital costs, construction time, maintenance requirements, and costs during operation.

3.2.9.3 *Evaluation Summary*

Table 3-29 summarizes our evaluation findings for modular, scalable, closed-loop PSH technology that uses multiple bladder-type tanks to store water in upper and lower reservoirs. The key advantages of this technology include its short construction time, with minimal civil works and environmental impacts. The technology does not need dams or an underground powerhouse to be constructed, so civil works are needed only to prepare terrain for the bladder tanks, penstock, and a vertical shaft that would house a submerged pump-turbine.

The technology's modular design allows for construction in stages and use of standard prefabricated components and equipment. it is also suitable for use as distributed energy storage and for hybrid applications, when co-located with wind and solar plants, thus supporting carbon-free electricity generation.

On the other hand, this technology also has several weaknesses, including a relatively high specific capital cost because the small plant size does not benefit from the economy of scale like large PSH plants. There are also uncertainties related to the durability of polymeric tanks, and regulatory requirements regarding their use for PSH applications are uncertain.

This PSH technology will be competing against battery technologies, which may be faster to construct and easier to operate than a PSH plant. Since the cost of battery technologies, such as Li-ion, is expected to continue decreasing, the capital cost of mature systems of this PSH technology should decrease significantly in order to remain competitive against battery technologies.

Table 3-29 Evaluation Summary for Hybrid Modular Closed-Loop Scalable PSH Technology

Evaluation Criteria	Hybrid Modular Closed-Loop Scalable PSH
Estimated Project Cost	Liberty University estimates capital costs for a 3-MW system at $4,342/kW ($5,162 with solar component), and a 10-MW system at $2,235/kW ($2,692 with solar component)
Estimated LCOS	$221 to $369 per MWh
Construction Time	Estimated up to 2 years
Project Development Risk	Project development requires less excavation; however, key uncertainties are in operation and related to the durability of bladder-type reservoirs
Scalability and Applicability	Modular and highly scalable: Plant sizes are small, 10 MW or less, and more likely to be connected to the distribution network; grid-scale applications are also possible, especially as hybrid projects co-located with wind and solar plants
Operational Flexibility	Liberty University plans to use Obermeyer AS-PSH units, which should allow an operating range of 20–100% in generation mode and 70–100% in pump mode
Potential Market Size in the United States	Estimated maximum potential installations in the United States are about 100, with a total capacity of 0.5–1 GW (assuming an average plant size of 5–10 MW)
Environmental Impacts	Minimal due to use of bladder-type reservoirs and closed-loop systems. Plant construction requires minimal civil works.
Physical Siting Limitations	Ideally, the project would use two relatively flat ground surfaces that are close to each other but at significant elevation difference. A source of water for initial filling of reservoirs is also required.
TRL	Estimated TRL 3

3.2.9.4 *References*

Hadjerioua, B., T.V. Eldredge, H. Medina, and S. DeNeal. 2019a. "Design and Modeling of a Prototype Floating Membrane Reservoir System Application for Pumped Storage Hydropower," ASCE EWRI Congress, Pittsburgh, PA, May 2019.

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3.2.10 Pressurized Vessel PSH

3.2.10.1 *Technology Description*

Researchers from ORNL in the United States proposed a new concept to store energy by using water to pressurize air in a vessel. The concept is called ground-level integrated diverse energy storage (GLIDES), and it uses water as a liquid piston to pressurize air in a high-pressure reservoir (Kassaee et al., 2019; Chen et al., 2019). The energy is stored when the water is pumped into the vessel to pressurize the air, while energy is generated when the water is released from the vessel and pushed by the compressed air to turn the turbine and generate electricity. Figure 3-16 illustrates the pumping and generating cycles for GLIDES.

ORNL has considered different types of vessels that could be used as high-pressure reservoirs for GLIDES technology. These included steel tanks, carbon fiber tanks, pipe segments, abandoned pipelines, and underground caverns.

A small lab-scale prototype using four steel vessels was developed to provide a proof of concept. It used a separate motor to pump the water into the reservoirs and a small Pelton turbine to turn the generator when the water is released under pressure to generate electricity. The energy storage capacity of this prototype was 3 kWh.

Next, an improved prototype was developed using a single vessel made of carbon fiber, reversible pump-turbine and motor-generator, as well as a spray cooling/heating system. The smaller size of carbon fiber vessel allowed for energy storage of 1 kWh. These two prototype devices are illustrated in Figure 3-17.

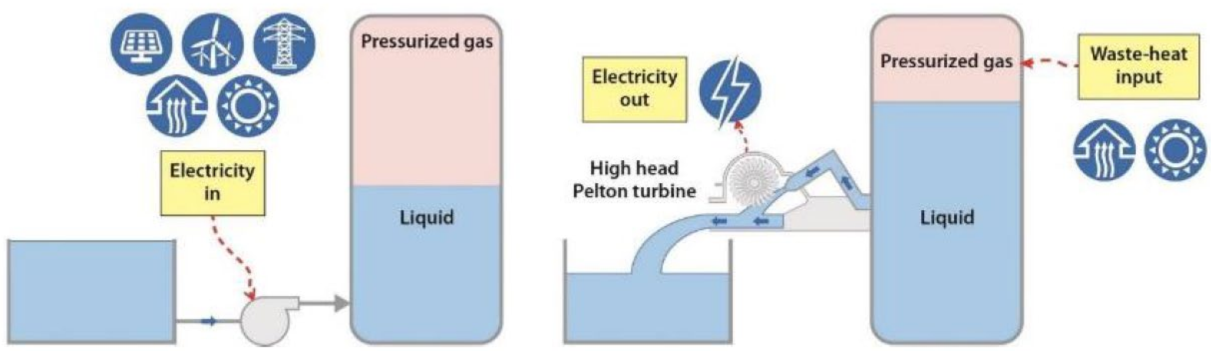
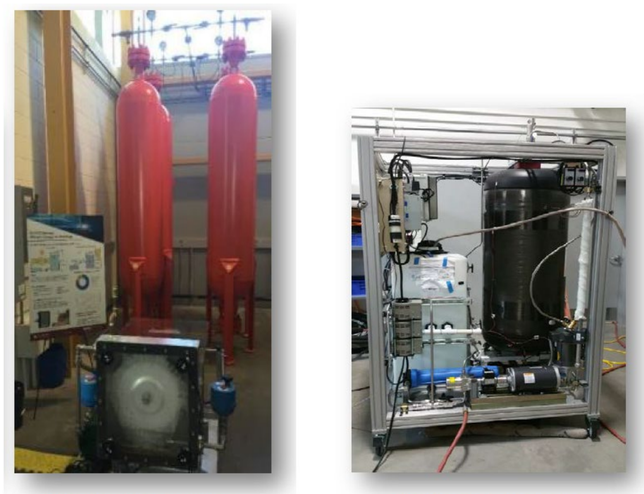


Figure 3-16 GLIDES Pumping and Generating Cycles (Source: Abu-Heiba, 2019)

Having confirmed the technical feasibility of the GLIDES concept through lab-scale prototypes, ORNL researchers developed a model to calculate the capital cost of a GLIDES system using different types of vessels, including steel vessels, carbon-fiber vessels, and high-pressure pipe segments. The cost model showed that carbon-fiber vessels and pipe segments reduce the overall cost of the system; they are manufactured semi-automatically and fully automatically, in contrast to steel vessels, which are mostly manufactured and welded manually (Kassaee et al., 2019). Of the three options analyzed, the high-pressure pipe segments were least expensive and provided the lowest estimated cost of storage. To further reduce system costs, ORNL researchers explored other storage options, such as underground storage, including depleted oil and gas underground reservoirs, aquifers, and salt caverns (Kassaee et al., 2019; Abu-Heiba et al., 2019). Using underground reservoirs has significant potential to reduce the overall project costs, as well as to provide a large energy storage and power output suitable for grid-scale applications.



GLIDES 1st generation
Steel Vessels
3 kWh

GLIDES 2nd generation
Carbon Fiber Vessel
1 kWh

Figure 3-17 GLIDES Proof-of-Concept Prototypes (Source: Abu-Heiba, 2019)

The key advantages of the GLIDES technology include its modularity and scalability, from very small systems using different types of vessels to large-scale installations using underground reservoirs; high efficiency of operation, with the ability to use waste heat that is generated during the discharging process; no need for elevation difference; and no geographical restrictions with regard to plant siting, as the above-ground pressure vessels can be located anywhere. Some siting limitations exist for the use of underground reservoirs; however, in the United States there are many underground caverns, aquifers, and depleted oil/gas reservoirs that could be available and suitable for GLIDES application.

3.2.10.2 *Technology Evaluation*

Estimated project costs: Kassaee et al. (2019) provide the results of their cost model for GLIDES systems using different types of pressure vessels. The total cost of a 100-kW and 2-hour system using a steel vessel was estimated at $1.2 million, which translates to about $12,000/kW. The cost for a GLIDES system of the same size (100 kW, 2 hours) using carbon-fiber vessels was estimated at $650,000, which translates to about $6,500/kW. Similarly, the cost for a GLIDES of the same size that uses pipe segments as storage vessels was estimated at $225,000, which translates to $2,250/kW of installed capacity. Finally, ORNL estimated that the cost for a 10-MW, 4-hour storage system using an underground cavern would be $1,280/kW.

Estimated LCOS: Using the cost estimates and technoeconomic parameters from ORNL papers and reports, we performed LCOS analyses for the above four GLIDES configurations. Table 3-30 shows LCOS results obtained for GLIDES configurations using steel vessels, carbon-fiber vessels, pipe segments, and underground reservoirs.

Table 3-30 LCOS Results Obtained for GLIDES Technology Configurations

Technical Data	Steel Vessel (100 kW, 2 h)	Carbon Fiber (100 kW, 2 h)	Pipe Segment (100 kW, 2 h)	Underground Cavern (10 MW, 4 h)
Plant generating capacity (MW)	0.1	0.1	0.1	10
RTE (%)	83	74	76	70
Average capacity factor (%)	20	20	20	20
Average annual generation (MWh)	175.2	175.2	175.2	17520
Plant lifetime (years)	30	30	30	60
Major plant overhaul period (years)	15	15	15	20
Number of overhauls	1	1	1	2
Economic & Financial Data				
Investment cost ($/kW)	12,000	6,500	2,250	1,280
WACC (%)	8	8	8	8
TIC ($)	1,200,000	650,000	225,000	12,800,000
Major overhaul cost (10% of TIC)	120,000	65,000	22,500	1,280,000
Annual O&M cost ($) (1.5% of TIC)	18,000	9,750	3,375	192,000
Average charging electricity price ($/MWh)	80	80	80	50
Annual charging cost ($)	16,886	18,940	18,442	1,251,428
LCOS analysis period (years)	30	30	30	60
LCOS Calculation				
Investment cost (CAPEX) ($)	1,200,000	650,000	225,000	12,800,000
Replacement cost (CAPEX-R) ($)	37,829	20,491	7,093	333,541
O&M cost ($)	202,640	109,763	37,995	2,376,298
Charging cost ($)	190,107	213,229	207,617	15,488,371
End-of-life cost or value ($)	0	0	0	0
Electricity discharged (MWh)	1,972	1,972	1,972	216,837
LCOS by Component				
Investment cost ($/MWh)	$608.41	$329.55	$114.08	$59.03
Replacement cost ($/MWh)	$19.18	$10.39	$3.60	$1.54
O&M cost ($/MWh)	$102.74	$55.65	$19.26	$10.96
Charging cost ($/MWh)	$96.39	$108.11	$105.26	$71.43
End-of-life cost or value ($/MWh)	$0.00	$0.00	$0.00	$0.00
LCOS Total ($/MWh)	**$826.71**	**$503.70**	**$242.20**	**$142.96**

Table 3-31 compares the LCOS results obtained for GLIDES technologies with those for reference PSH and battery technologies from the ESGC study (Mongird et al., 2020). Mainly due to the cost of vessels, the GLIDES configurations using steel and carbon-fiber vessels are expensive compared to both PSH and battery technologies. The GLIDES technology using high-pressure pipe segments is currently competitive with battery technologies in terms of LCOS results. However, to achieve 100 kW and 2 hours of storage, the GLIDES system needs approximately 32 pipe segments of 30 m each, which would require much larger land area than that required for a 100-kW battery. GLIDES technology using an underground cavern can provide more cost-effective energy storage because its larger plant size benefits from the economy of scale and in terms of LCOS value is competitive with both conventional PSH plants and battery technologies.

Table 3-31 LCOS Values for GLIDES and Reference PSH and Battery Technologies

GLIDES	Steel Vessel (0.1 MW, 2 h)	Carbon Fiber (0.1 MW, 2 h)	Pipe Segment (0.1 MW, 2 h)	Undergr. Cavern (10 MW, 4 h)	PSH (100 MW, 4 h)	PSH (100 MW, 10 h)	Li-ion (1 MW, 4 h)	Li-ion (10 MW, 4 h)	Li-ion (100 MW, 4 h)
Plant generating capacity (MW)	0.1	0.1	0.1	10	100	100	1	10	100
RTE (%)	83	74	76	70	80	80	86	86	86
Plant lifetime (years)	30	30	30	60	40	40	10	10	10
TIC ($/kW)	12,000	6,500	2,250	1,280	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**827**	**504**	**242**	**143**	**209**	**135**	**254**	**238**	**227**

Construction time: The construction time for GLIDES technology depends on the type of pressure vessels used. We estimate the construction times would last between 1 and 2 years, with shorter construction times for steel and carbon-fiber vessels, and longer construction times for use of underground caverns.

Project development risk: Project risks are different for projects using pressure vessels at ground level and those using underground reservoirs. For surface installations, civil works are reduced significantly because the system uses piping rather than tunnels. In addition, standard prefabricated components can be used on a large scale. For underground reservoirs, there is a small geological risk related to the strength and airtightness of the cavern structure under high pressure during repeated charging and discharging cycles.

Scalability and applicability: GLIDES technology is very scalable, and plant sizes may vary from less than 1 MW to about 300 MW. While small surface installations may serve as distributed storage resources, the larger projects using underground caverns are suitable for grid-scale applications.

Operational flexibility: Operational flexibility is expected to be similar to conventional fixed-speed PSH plants.

Potential market size: While there are no limits for potential sites for ground-level GLIDES technology, the market potential is estimated to be low because of the high cost of pressure vessels. There are thousands of potential sites with underground reservoirs, but the total market size in the United States is estimated to include dozens of projects, with a total capacity between 0.5 and 2.5 GW, assuming an average plant size of 50 MW.

Environmental impacts: Environmental impacts of GLIDES technologies are much smaller than for the conventional PSH plants, because they require less civil works for plant construction.

Physical siting limitations: Ground-level pressure vessels can be located almost anywhere in the United States. There are also thousands of potentially usable underground reservoirs located in many parts of the United States.

TRL: The estimated TRL for GLIDES technology is 5.

3.2.10.3 *Evaluation Summary*

Table 3-32 summarizes our evaluation findings for the GLIDES technology. While the configurations using ground-level pressure vessels made of steel, carbon fiber, or high-pressure pipe segments may have limited applicability, mainly because of the high cost of pressure vessels, GLIDES installations using underground caverns may be competitive with other energy storage technologies for grid-scale applications.

Table 3-32 Evaluation Summary for Pressurized Vessel PSH Technology

Evaluation Criteria	GLIDES Technology
Estimated Project Cost	The cost of the system varies widely depending on the type of pressure vessel being used. ORNL investigated pressure vessels made of steel, carbon fiber, and high-pressure pipe segments. ORNL is also looking into potential use of underground reservoirs (aquifers, salt caverns, and depleted oil/gas reservoirs).
Estimated LCOS	$143 to $827 per MWh
Construction Time	Estimated 1–2 years, depending on the type of vessel being used
Project Development Risk	Project risks vary depending on the type of vessel being used. For surface systems, civil works are reduced significantly, and prefabricated components can be used on a large scale. For underground reservoirs, there is a small geological risk related to the strength and airtightness of the cavern structure.
Operational Flexibility	Average: Operational flexibility is expected to be similar to that of conventional fixed-speed PSH plants
Scalability and Applicability	Modular and scalable: Plant size can vary from 1 to 300 MW. Small surface installations may serve as distributed storage resources, while larger projects using underground caverns are suitable for grid-scale applications.
Potential Market Size in the United States	Market potential for surface installation is estimated to be low because of the high cost of pressure vessels. There are thousands of potential sites with underground reservoirs, but the total market size in the United States is estimated to be dozens of projects, with a total capacity between 0.5 and 2.5 GW, assuming an average plant size of 50 MW
Environmental Impacts	Environmental impacts are lower than for conventional PSH plants because less civil works would be needed
Physical Siting Limitations	Ground-level pressure vessels can be located almost anywhere in the United States; there are also thousands of potentially usable underground reservoirs located in many parts of the United States
TRL	Estimated TRL is 5

3.2.10.4 *References*

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3.2.11 Thermal Underground PSH

3.2.11.1 *Technology Description*

The thermal underground PSH (TUPH) concept was proposed by Professors Georg Pikl, Wolfgang Richter, and Gerald Zenz of Graz University of Technology in Austria (Pikl et al., 2017, 2019). This is an interesting concept that envisions a closed-loop underground PSH system that uses hot water for PSH operations. Both the upper and lower reservoirs of the PSH plant are built underground, so that geothermal energy can be used to heat the water in the reservoirs up to 95°C. The heat energy of the water can be used to provide heating and cooling functions for the local community. For this purpose, heat exchangers would be placed in the upper and lower reservoirs of the PSH plant and connected to the district heat network. An illustration of the TUPH concept is shown in Figure 3-18.

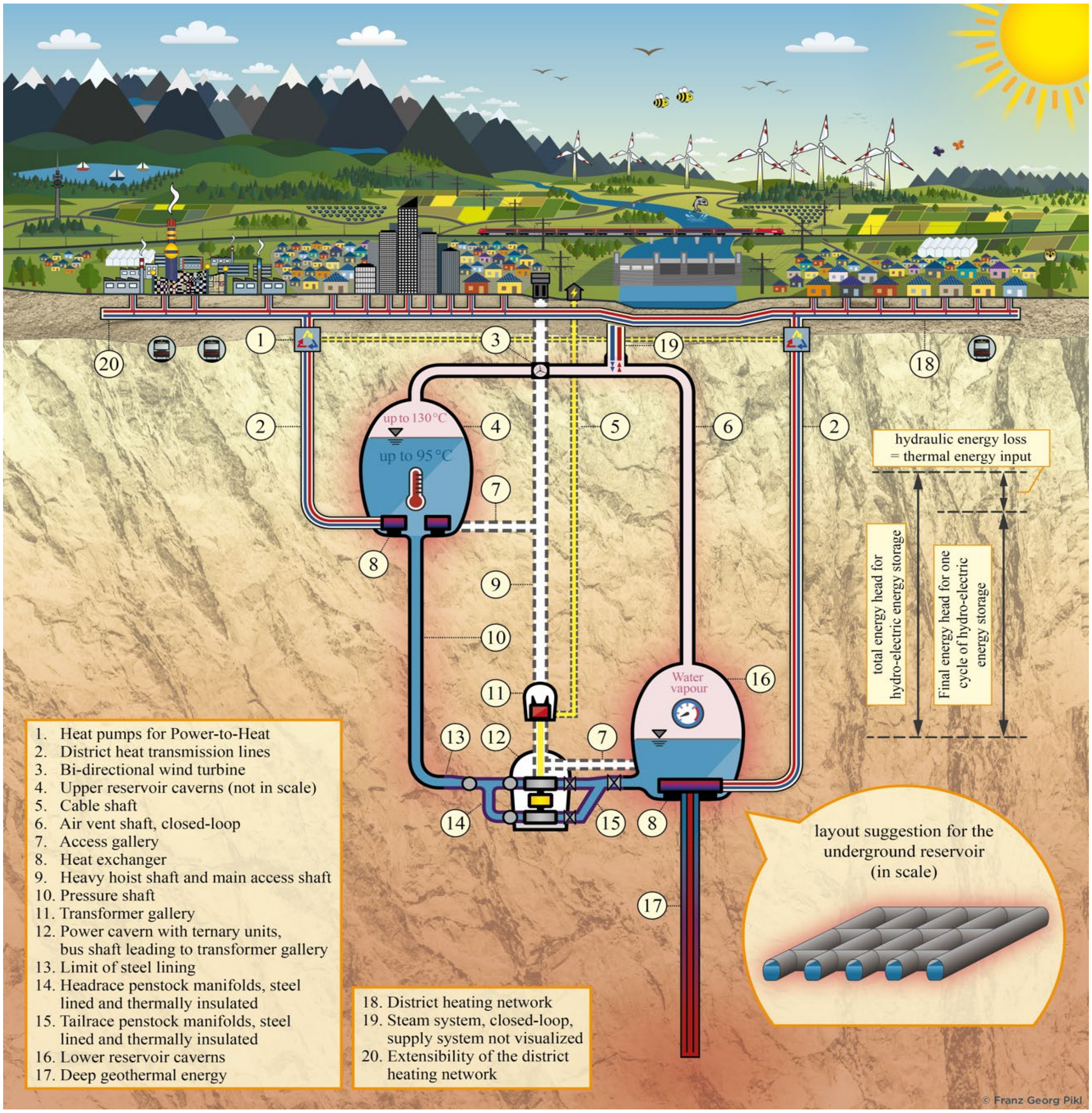

Figure 3-18 Schematic of Thermal Underground PSH System (Source: Franz Georg Pikl, Graz University of Technology)

There are several key innovations envisioned for the TUPH concept. It combines energy storage for electricity generation with heat storage that can be used to provide heating and cooling. The PSH component of the TUPH system operates on the same basic principles as regular PSH plants, except that it uses hot water for its operations. To maintain water temperature and minimize heat losses, both the upper and lower reservoirs are built underground.

For PSH operations, the technology developers propose to use ternary generating units because they provide high operational flexibility. This flexibility is important for the integration of nearby variable renewable generation sources, such as wind and solar, thus potentially allowing for completely carbon-free renewable operations of the system.

In addition to clean electricity, the developers also aim to provide clean energy for heating and cooling. Depending on the season, the heat storage contained in the upper and lower reservoirs can be used to provide or supplement the heating and cooling services to the local community. The developers call it a 3-in-1 energy storage, because in addition to generating electricity, it can also supply heating and cooling services. This multipurpose operation also increases the overall energy efficiency of the TUPH system.

To fulfill all three purposes, this concept needs to be constructed near communities with district heating networks or large industrial facilities with significant heat demand. Locating the project near urban or industrial areas should be feasible, because everything is built underground and there are minimal environmental impacts affecting the above ground landscape—except during the excavations, when there are some aboveground operations. As shown in Figure 3-18 (Pikl et al., 2021), the developers even envision an underground transformer substation that will connect the PSH generators to the electrical grid. Similarly, the heat exchangers are connected to the district heating network through underground heat conduits. The excavation of two underground reservoirs, powerhouse, shafts and other conveyance systems will produce a large amount of rock that needs to be either sold as construction material or deposited somewhere. Even if deposited, the authors point out that weathering[29] of crushed rock will serve as natural carbon capture and storage mechanism, thus providing an additional benefit.

Because both reservoirs are built underground, this technology does not require topography with an elevation differential; however, it does require certain geology and stable rock formations to enable long life and operations of the system. Because of the significant excavations and civil works necessary for the construction of this technology, we estimate that projects of larger size (e.g., 300–1,000 MW) would be more likely, because they would benefit from the economy of scale. Note that, despite the large plant size, these projects could be easily sited near urban environments or in industrial areas. Once constructed, the system will have only a few small objects/buildings above ground, with most of the structures deep underground.

3.2.11.2 *Technology Evaluation*

Estimated project costs: Technology developers at Graz University of Technology estimate that project costs for TUPH technology would total about $1,200/kW to $1,900/kW, based on case studies for both electric and thermal capacity (Pikl et al., 2021). For our study, they provided a cost estimate for a sample TUPH system with 500 MW of electric plus 385 MW of thermal capacity (Pikl F.G., 2021). They estimated that the cost of the overall system would be $1.35 billion, which translates to about $1,525 per kW of total capacity (electric + thermal), or about $2,700 per kW of electric capacity of PSH plant.

[29]See https://www.nature.com/articles/d41586-020-01965-7.

Estimated LCOS: Because for our evaluation analysis we are interested only in the PSH component, we calculated LCOS for the thermal underground using the cost estimate of $2,700/kW of electric capacity. Considering that the project construction involves a significant number of excavations and underground civil works, we also performed a sensitivity study and calculated LCOS for a high-CAPEX estimate of $3,500/kW. The results of LCOS calculations are presented in Table 3-33.

The obtained LCOS values of $213.38/MWh and $258.08/MWh are higher than those obtained for reference PSH technologies from the ESGC study (Mongird et al., 2020), especially when compared to a 1,000-MW PSH with 10 hours of storage. However, our LCOS calculation includes only the value of PSH for electricity generation, and not the value of heat storage for heating and cooling services. Because of the large size, the thermal underground PSH technology is not expected to compete against Li-ion batteries, so we omitted those from Table 3-34.

Table 3-33 LCOS Values for TUPH Technology

Technical Data	TUPH (low CAPEX)	TUPH (high CAPEX)
Plant generating capacity (MW)	500	500
RTE (%)	80	80
Average capacity factor (%)	20	20
Average annual generation (MWh)	876,000	876,000
Plant lifetime (years)	60	60
Major plant overhaul period (years)	20	20
Number of overhauls	2	2
Economic & Financial Data		
Investment cost ($/kW)	2,700	3,500
WACC (%)	8	8
TIC ($)	1,350,000,000	1,750,000,000
Major overhaul cost (10% of TIC)	135,000,000	175,000,000
Annual O&M cost ($) (1.5% of TIC)	20,250,000	26,250,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	54,750,000	54,750,000
LCOS analysis period (years)	60	60
LCOS by Component		
Investment cost ($/MWh)	$124.52	$161.41
Replacement cost ($/MWh)	$3.24	$4.21
O&M cost ($/MWh)	$23.12	$29.97
Charging cost ($/MWh)	$62.50	$62.50
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$213.38**	**$258.08**

Table 3-34 LCOS Values for TUPH and Reference PSH and Battery Technologies

Technoeconomic Parameters	TUPH (low CAPEX)	TUPH (high CAPEX)	PSH (1,000 MW, 4 h)	PSH (1,000 MW, 10 h)
Plant generating capacity (MW)	500	500	1,000	1,000
RTE (%)	80	80	80	80
Plant lifetime (years)	60	60	40	40
TIC ($/kW)	2,700	3,500	1,717	2,202
LCOS Total ($/MWh)	**213**	**258**	**180**	**121**

Construction time: Technology developers estimate a construction time of 4–7 years, depending on the plant size. For the sample TUPH plant (500 MWe + 385 MWth), they estimated a construction time of 5.5 years. Considering the significant number of underground excavations required for these types of projects, we estimate that an average construction period of 6–8 years would be more likely.

Project development risk: The project risks are higher than for conventional PSH plants because a significant amount of excavation is required for both lower and upper reservoirs, as they are both completely underground. However, the reservoir volumes are significantly smaller because high hydraulic heads (>600 m) are realized for a very compact plant design. Additional complexity to the overall project design is added by the integrated thermal energy storage system and the use of hot water for PSH operations.

Scalability and applicability: The design is scalable for larger plant sizes (i.e., greater than 300 MW) and the capacity can be chosen to match the demand for electricity and heat. Typical electrical capacity range is between 300 and 1,000 MW, while the thermal capacity depends on the regional/urban demand needs (peak load supply, seasonal storage, etc.).

Operational flexibility: This technology provides a sector-coupling design for multipurpose use of electricity and thermal energy that allows high energy system flexibility and connects different energy markets. Technology developers plan on using ternary units for the PSH plant, which would provide excellent operational flexibility in both generation and pumping mode. Integrated heat pumps are used to recover heat via efficient power-to-heat conversion. Additional flexibility is achieved by combining the energy flows of electricity, heating, and cooling.

Potential market size: The technology application depends on having a large demand for heat, which may be a limiting factor for its applications in the United States, where district heating networks are not as common as in Europe. Potential applications could include urbanized or industrial areas with suitable geology and existing heating networks.

Environmental Impacts: Environmental impacts are minimal because the entire facility, including the powerhouse, both reservoirs, and the thermal equipment with the district heating network, are completely underground. The technology relies on resource-saving use of water as a natural and available 2-in-1 energy carrier. The closed-loop underground system should not impact natural waters.

Physical siting limitations: In theory, this technology can be located at any site with the appropriate geology. However, its application depends on having a large demand for heat and/or cooling nearby, such as centralized district heating and cooling systems in urban areas, or a large industrial heat demand.

TRL: The combination of underground PSH and cavern thermal energy storage is new and needs some technical adaptions and solutions for some specific challenges, but it is technically feasible concept. The estimated overall TRL is 4–5.

3.2.11.3 *Evaluation Summary*

Table 3-35 summarizes our evaluation findings for thermal underground PSH technology. This is an innovative and versatile PSH concept (Pikl, 2018) that provides both electricity and heat storage, is highly flexible in operation, and has low environmental impacts. Since both reservoirs are located underground, it does not need to be sited at geographical locations with an elevation differential; however, it does need be connected to a large heat demand, such as a district heating network. This may be an obstacle for wider application of this technology in the United States. In addition, this technology requires significant underground excavations, which increase the cost and time for the construction of the PSH plant, which may not be viewed favorably by potential investors.

Table 3-35 Evaluation Summary for Thermal Underground PSH Technology

Evaluation Criteria	Thermal Underground PSH
Estimated Project Cost	Graz University of Technology estimates total project costs based on case studies would be about $1,200–1,900/kW and $5–18/kWh. Values are for the sum of electrical and thermal capacities. The costs per kilowatt is almost double if based only on megawatts of electrical capacity.
Estimated LCOS	$213 to $258 per MWh
Construction Time	Estimated 6–8 years, depending on plant size
Project Development Risk	Higher than for the conventional PSH plants because a significant amount of excavation is required for underground reservoirs. Added complexities are the integrated thermal energy storage system and the use of hot water for PSH operations.
Scalability and Applicability	The design is scalable for larger plant sizes (i.e., >300 MW). Capacity can be chosen to match the demand for both electricity and heat. Typical electrical capacity range is 300–1,000 MW, while the thermal capacity depends on the regional/urban demand needs.
Operational Flexibility	This technology provides a sector-coupling design for multipurpose use of electricity and thermal energy that allows high energy system flexibility and connects different energy markets
Potential Market Size in the United States	The technology application depends on having a large demand for heat; potential applications may include urbanized or industrial areas with suitable geology and existing heating networks
Environmental Impacts	Minimal because the entire facility is completely underground; the closed-loop system should not impact natural waters
Physical Siting Limitations	Potential sites require adequate geology and a large demand for heat and/or cooling nearby, such as centralized district heating and cooling networks, or a large industrial heat demand
TRL	Estimated TRL is 4–5

3.2.11.4 *References*

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3.2.12 High-density Fluid PSH

3.2.12.1 *Technology Description*

This innovative concept is similar to traditional PSH technologies, except that instead of water, it uses a high-density fluid for PSH operations. A representative example of this technology is being developed by RheEnergise, Ltd.,[30] a startup company based in the United Kingdom and Canada.

Because it uses a high-density fluid instead of water for PSH operations, this technology can only operate as closed-loop PSH system. The main reason is that high-density fluid is used is to obtain more power from a smaller PSH project, thus achieving cost savings. Compared to a traditional PSH plant that uses water as working fluid, the high-density fluid PSH should be able to achieve the same power output for a lower hydraulic head and turbine flow. The footprint of the high-density fluid PSH plant is also smaller, because smaller of upper and lower reservoirs may contain the same energy storage as those of a traditional PSH plant that uses water (Crosher, 2021).

For their high-density hydro technology, RheEnergise proposes to use their proprietary R-19 fluid. RheEnergise has been developing this fluid since 2017 and laboratory tests were performed to determine its characteristics and usability for PSH applications. RheEnergise claims that R-19

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[30] See https://www.rheenergise.com/.

is an inert and environmentally benign fluid that is characterized by low viscosity and a specific gravity of 2.5, which means it is 2.5 times denser than water.

In addition to the smaller project size and reduced hydraulic head, the high-density fluid PSH technology also benefits from smaller penstocks and other conduits, as well as smaller reversible pump-turbines. Lower hydraulic head means that many geographic locations could be suitable for this technology, with elevation differentials as low as 75 m. The prospective PSH site also does not need to be near a source of water to fill the reservoirs, because they are filled with the high-density fluid instead of water.

Technology developers claim that the use of high-density fluid will not require special pump-turbine design, and that standard PSH reversible pump-turbines designed to operate in water could be used. While the technology developers claim that the high-density fluid has relatively low viscosity, our understanding is that its viscosity is still higher than that of water, which could potentially lead to increased abrasion, cavitation, and accelerated wear and tear of hydraulic equipment. This may also increase O&M costs compared to traditional PSH plants. Furthermore, this technology will require an additional fluid management system, which increases project costs.

The high-density fluid, such as R-19, must be manufactured and is, naturally, more expensive than water. Therefore, high-density PSH technology is more suitable for smaller PSH sizes, with power outputs ranging from about 5 to 50 MW, and energy storage duration from 2 to 10 hours. The reduced head and size of reservoirs, because of the use of high-density fluid instead of water, means that the overall footprint and size of the PSH project will be smaller than that of a traditional PSH plant with the same power output.

The smaller reservoir volume allows some other cost-savings, such as using large storage tanks instead of constructing traditional PSH reservoirs. For example, large storage tanks are used in the oil and gas industry to store various liquid petrochemical products and similar tanks could be used for high-density fluid PSH as well.

3.2.12.2 *Technology Evaluation*

Estimated project costs: RheEnergise estimates that the project cost would be $1,189/kW for a sample 20-MW high-density fluid PSH plant (Bertenyi, 2021). They estimate that using R-19 fluid, which is 2.5 times denser than water, will translate into 2.5 times decreased volumetric flowrate compared to the traditional closed-loop PSH plant. Cost savings will also be achieved due to reduced reservoir size, reduced penstock and valve diameters, and reduced powerhouse dimensions. They expect that standard reversible pump-turbine and hydraulic equipment can be used as in traditional PSH plants.

Overall, for mature high-density fluid PSH systems RheEnergise estimates that costs will be 1.5–2 times lower compared to equivalent closed-loop PSH plants using water as the working fluid.

Estimated LCOS: Table 3-36 presents LCOS calculations performed for the high-density fluid PSH technology. In addition to the $1,189/kW project cost estimate provided by RheEnergise (Bertenyi, 2021), we also ran a sensitivity study using a higher CAPEX estimate of $2,000/kW.

Table 3-36 LCOS Results for High-Density Fluid PSH Technology

Technical Data	RheEnergise CAPEX Estimate	High CAPEX Estimate
Plant generating capacity (MW)	20	20
RTE (%)	82	82
Average capacity factor (%)	20	20
Average annual generation (MWh)	35,040	35,040
Plant lifetime (years)	60	60
Major plant overhaul period (years)	20	20
Number of overhauls	2	2
Economic & Financial Data		
Investment cost ($/kW)	1,189	2,000
WACC (%)	8	8
TIC ($)	23,780,000	40,000,000
Major overhaul cost (10% of TIC)	2,378,000	4,000,000
Annual O&M cost ($) (1.5% of TIC)	356,700	600,000
Average charging electricity price ($/MWh)	50	50
Annual charging cost ($)	2,136,585	2,136,585
LCOS analysis period (years)	60	60
LCOS by Component		
Investment cost ($/MWh)	$54.83	$92.24
Replacement cost ($/MWh)	$1.43	$2.40
O&M cost ($/MWh)	$10.18	$17.12
Charging cost ($/MWh)	$60.98	$60.98
End-of-life cost or value ($/MWh)	$0.00	$0.00
LCOS Total ($/MWh)	**$127.42**	**$172.74**

The obtained LCOS values of $127.42/MWh and $172.74/MWh, respectively, seem to be competitive with the reference PSH technologies from the ESGC report (Mongird et al., 2020). As shown in Table 3-37, this technology is also competitive with Li-ion batteries.

Construction time: Because of the reduced scale of the project, use of prefabricated storage tanks, standardized pump-turbines and generators, and reduced civil works, technology developers estimate a construction time of 12 to 18 months. While this may be the case with mature systems and experience gained after many project installations, we estimate that a construction time of 2–2.5 years is more likely, at least for the first several installations.

Table 3-37 LCOS Values for High-Density Fluid PSH and Reference PSH and Battery Technologies

Technoeconomic Parameters	HDF PSH (low CAPEX)	HDF PSH (high CAPEX)	PSH (100 MW, 4 h)	PSH (100 MW, 10 h)	Li-ion 1 MW, 4 h)	Li-ion (10 MW, 4 h)	Li-ion (100 MW, 4 h)
Plant generating capacity (MW)	20	20	100	100	1	10	100
RTE (%)	82	82	80	80	86	86	86
Plant lifetime (years)	60	60	40	40	10	10	10
TIC ($/kW)	1,189	2,000	2,046	2,623	1,793	1,643	1,541
LCOS Total ($/MWh)	**127**	**173**	**209**	**135**	**254**	**238**	**227**

Project development risk: While the construction of high-density fluid PSH will use nearly the same construction methods and equipment as traditional PSH plants, we estimate that the project development risks are slightly higher due to the use of R-19 fluid and the specialized fluid management system. This offsets some of the reduced risks from the project's relatively smaller size and footprint compared to a conventional PSH plant of similar capacity. Additional uncertainty can be expected during project operation, related to the potential impacts of high-density fluid on pump-turbines and hydraulic equipment.

Lab tests or a demonstration project would help provide more information about whether the high-density fluid PSH plant will experience more abrasion, cavitation, and wear and tear than conventional PSH plants using water. Accelerated wear and tear may require increased O&M and overhaul costs over the long term.

Scalability and applicability: Due to the use of high-density fluid, this concept is likely to be applied for smaller PSH projects, from about 5 to 50 MW. Within this range, the size of the plant is highly scalable and can be adjusted to match the power system needs. The concept is also modular, as additional tanks and generating units can be added to increase the project size.

This technology can provide the same services as conventional PSH plants, with an additional benefit that it has more available geographical locations (due to the smaller hydraulic head and reservoirs) and it does not need to be located near a water source.

Operational flexibility: Operational flexibility will depend on the type of pump-turbine and motor-generator used. Because the plant uses heavier R-19 fluid instead of water, the ramp rates are expected to be better than for conventional PSH plants, with a similar overall operational flexibility. The ramp rates are expected to be slightly better due to increased energy density and reduced delta volumetric flowrate requirements. The operating ranges in the generating and pumping modes of operation should be about the same as in PSH plants using water.

Potential market size: This technology has the potential to use PSH sites with lower head, thus increasing the number of viable PSH sites. Sites with little or no water could also be used because the high-density fluid is used instead of water.

On the other hand, there is a potential reluctance to adopt R-19, or another fluid, for PSH applications in the United States. We estimate the potential market size for this technology will be dozens of projects, with a total capacity of 0.5–2 GW, assuming an average plant capacity of 40 MW.

Environmental impacts: Environmental impacts of this technology are expected to be lower than for conventional large-scale PSH plants because it has a smaller plant footprint and reservoirs. The reservoir tanks can be at ground level or partially buried.

The use of R-19 fluid in a closed-loop system should not impact water courses, fish passage, or aquatic life. Technology developers claim that R-19 is environmentally benign, inert, non-reactive, and natural. In the event of spillage, no remedial action is required, although it would be a good policy to contain the fluid and allow it to evaporate.

Physical siting limitations: Regarding the potential siting locations, this technology has an advantage over the conventional PSH plants because it can use sites with lower hydraulic head and does not need a source of water for reservoirs.

TRL: The technology developers have performed limited prototype capability validation in a laboratory environment. The estimated TRL is 4.

3.2.12.3 *Evaluation Summary*

Table 3-38 summarizes the findings of our evaluation for this technology. It is an interesting idea to use a high-density fluid that is much heavier than water but with a relatively low viscosity for closed-loop PSH operations. The obvious benefits are the reduced plant size and footprint compared to conventional PSH plants of the same megawatt capacity. The construction costs and time can also be reduced by using storage tanks instead of traditional PSH reservoirs, thus reducing the amount of civil works required for plant construction. Additional cost savings can be achieved by using smaller pump-turbines and penstocks compared to PSH plants that use water.

However, some of these savings are offset by the cost of high-density fluid. The key to economic viability for this technology is whether large amounts of high-density fluid can be produced and transported to the project site at relatively low cost. The environmental characteristics of the high-density fluid are also very important to gain public acceptance and, ultimately, to obtain the construction permit. Since this technology does not use water, an FERC license may not be required.

Table 3-38 Evaluation Summary for High-Density Fluid PSH Technology

Evaluation Criteria	High-Density Fluid PSH
Estimated Project Cost	Technology developers estimate total project costs of $1,189/kW for a mature 20-MW system, or about 1.5–2 times lower cost than for an equivalent PSH plant using water.
Estimated LCOS	$127 to $173 per MWh
Construction Time	Estimated to be 2–2.5 years; RheEnergise estimates a 12- to 18-month construction period for mature systems
Project Development Risk	Estimated to be slightly higher than for a conventional PSH, due to use of R-19 fluid and the need for specialized fluid management equipment; lab tests or a demonstration project are needed to determine potential impacts of high-density fluid on wear and tear, maintenance needs, and lifetime of PSH plant
Scalability and Applicability	Estimated plant size 5–50 MW
Operational Flexibility	Depends on the type of pump-turbine and motor-generator technology; heavier fluid could boost ramp rates, while overall flexibility remains the same
Potential Market Size in the United States	Estimated to dozens of projects, with a total capacity of 0.5–2 GW, assuming an average plant capacity of 40 MW; dense fluid makes low head sites promising, but developers may be skeptical of an alternative fluid
Environmental Impacts	Expected to be somewhat lower than for conventional large-scale PSH plants due to its smaller plant footprint and use of tank reservoirs; technology developers claim that R-19 is environmentally benign, inert, non-reactive, and natural
Physical Siting Limitations	This technology can use sites with lower hydraulic head and does not need water for reservoirs
TRL	Estimated TRL of 4. Limited capability prototype validation in laboratory environment as of May 2021

3.2.12.4 *References*

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4.0 Other Innovative PSH Concepts and Technologies

In addition to the innovative PSH technologies reviewed in Section 3, there are also other innovative concepts and ideas for the development of new PSH plants. In this section we will describe how some existing hydropower plants may be converted to PSH plants without the construction of new dams or reservoirs, how PSH plants can be built as hybrid projects with VRE resources, and a few other innovative PSH concepts and ideas. These technologies were not reviewed using the evaluation criteria because they are either very site-specific (e.g., adding PSH capabilities to existing hydropower plants) or there are many potential technology variations (e.g., hybrid PSH and VRE configurations), or there was not much information available to conduct a more detailed review.

4.1 Converting Existing Hydropower Plants to PSH

The most common method of adding PSH capability to an existing hydropower plant is to construct an upper reservoir and use the existing hydropower reservoir as the lower reservoir, where a new PSH powerhouse would be located. This would require the construction of an upper reservoir.

However, in some cases a PSH capability can be added to an existing hydropower plant without constructing new dams or reservoirs. For example, some existing hydropower plants can be converted to pump-back PSH plants either by replacing their turbines with reversible pump-turbines, or by adding separate pumps that would serve to pump the water from downstream back to the upstream reservoir. The advantage of these two conversion methods is that they only require new hydraulic and electromechanical equipment to be installed, and do not require a new dam to be constructed to convert an existing hydropower plant into a PSH plant.

Obviously, not all existing hydropower plants can be converted into PSH plants. Prime candidates for conversion would include pondage hydropower plants characterized by medium to high hydraulic head and storage capacity for at least several hours of full generation. Low-head run-of-river and hydropower plants with little storage capacity are not good candidates for this conversion.

The first conversion method, installing reversible pump-turbines, is typically considered for storage hydropower plants with medium- to high-head that are using Francis-type turbines. It should be noted that replacing an existing turbine with a reversible pump-turbine requires certain space and powerhouse design conditions to be met for this conversion to be technically and economically feasible. Many existing hydropower plants may not be suitable for this conversion because of the space and powerhouse design constraints.

The second conversion method, adding separate pumps and water conduits, is typically a more feasible solution. It is the primary choice for storage hydropower plants with very high head (e.g., those using Pelton-type turbines), but can also be applied for medium- to high-head plants that are using Francis-type turbines as well.

4.1.1 Replacing Existing Turbine with Reversible Pump-Turbine

Pondage hydropower plants that are due for major overhaul could be considered for a potential conversion to pump-back PSH plants. After many years of operation, the turbines may need to be replaced and other electromechanical equipment, such as generators, may need to be rewound or replaced as well. This may be a good time to consider installing reversible pump-turbines and other equipment needed to develop PSH capabilities. However, certain conditions must exist to make this conversion feasible. For example, a regulating reservoir downstream or some other suitable reservoir should exist to allow the water to be pumped back into the upper reservoir. In addition, a fundamental challenge is obtaining the required submergence of the pump-turbine to avoid cavitation. It is rare that a conventional turbine setting is deep enough to allow a simple replacement with a reversible pump-turbine.

In addition to fitting a pump-turbine, some modifications to water conveyance systems may be needed since they were originally designed for generating mode only, not for pumping. For example, the power rating of reversible pump-turbines may need to be greater than that of the original turbines, in order to have sufficient pressure head to pump water back into the upstream reservoir. If the space is limited, then additional booster pumps can be installed in the draft tube to add pumping power to the reversible pump-turbine, thus avoiding the need to increase the runner dimensions.

Depending on the configuration of the hydropower plants and number of units and penstocks, it may be possible to convert one or more generating units to PSH operation, while the remainder may still operate as conventional hydropower units. This may allow for phased conversion process.

Note that pump-back PSH is not a new concept and some existing open-loop PSH plants have been designed to operate as pump-back PSH plants. For example, the Richard B. Russell[1] plant on the Savannah River between South Carolina and Georgia has a total of eight 75-MW units, of which four are conventional hydroelectric turbines, and four are reversible pump-turbines that can pump the water back into the upper reservoir.

4.1.2 Adding Separate Pumps and Water Conduits

The other method to convert an existing hydropower plant to a pump-back PSH is to add separate pumps that will pump the water from the downstream reservoir back to the upstream reservoir. Typically, this method does not require any changes to the configuration of the existing hydropower plant, as the pumps can be housed in a separate pumping station and have their own water conveyance system. The pumping station can be at a convenient location downstream of the existing hydropower plant and house the pumps that will pump the water back into the upstream reservoir using water conduits that can be either on the surface or underground, or a combination of the two.

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[1] See https://www.sas.usace.army.mil/About/Divisions-and-Offices/Operations-Division/Richard-B-Russell-Dam-and-Lake/Hydropower/.

The number and installed capacity of pumps do not need to match the number and capacity of generating units in the hydropower plant. They can be optimized for the desired type of PSH operation (e.g., how frequently it needs to cycle during the day or during the week). In addition, the natural water inflows into the upper reservoir should be taken into account when sizing the pumping equipment, so the total capacity of the pumps can be lower than the capacity of generating units.

On the other hand, the pumping capacity could also be higher than the generating capacity of existing hydroelectric units, to allow for fast filling of the upper reservoir in case multiple daily charging and discharging cycles are needed. Since pump-back PSH plants are open-loop PSH plants, very fast filling of upper reservoir, if associated with rapid water level changes, may pose environmental concerns and issues that need to be addressed. These should be considered early in the project design phase when determining the optimal pumping capacity.

In the United States, the Los Angeles Department of Water and Power (LADWP) recently proposed[2] adding PSH capabilities to the Hoover Dam by constructing a separate pumping station and water conveyance system. In 2018, LADWP proposed a project[3] to install a pumping station about 20 miles downstream from the Hoover Dam to pump the water back up to Lake Mead, which was created by the development of Hoover Dam on the Colorado River.

In summary, there are several key benefits of converting conventional hydropower plants to pump-back PSH plants. The conversion adds additional energy storage, thus increasing the total energy generation from the project, but not on a net basis when pumping energy is included. It also allows for better use of plant capacity, because more of its capacity will be available for dispatch during the day.

More energy is available because the upstream reservoir does not depend only on natural inflows but can also be refilled with water that previously passed through the turbines to generate electricity and has been pumped back from downstream to the upstream reservoir. While the size of the upstream reservoir and the natural water inflows remain the same, the hydropower plant can generate more electricity because the water is processed multiple times. This provides additional storage capabilities and greater operational flexibility as the pump-back PSH plant can also be used to store surplus VRE generation.

Another significant advantage of converting suitable hydropower plants into pump-back PSH plants is that the conversion does not require the construction of new dams or reservoirs and the cost of conversion is significantly lower than constructing a completely new PSH plant.

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[2]See https://www.utilitydive.com/news/los-angeles-considers-3b-pumped-storage-project-at-hoover-dam/528699/.

[3]See https://www.nytimes.com/interactive/2018/07/24/business/energy-environment/hoover-dam-renewable-energy.html?mtrref=undefined&gwh=7509419BC3E3197CD4E8737870D08061&gwt=pay&assetType=PAYWALL.

4.2 Hybrid PSH Configurations

In recent years, an increasing number of wind and especially solar PV plants have been developed as hybrid projects that include some energy storage, typically batteries. The storage component of the plant helps firm up the VRE generation, thus increasing the plant's firm capacity output, which translates into higher capacity credit or equivalent load carrying capability. The energy storage also helps store surplus VRE generation and shift it from low-demand hours to hours when the energy is more valuable, thus reducing curtailments. The financial benefits of firming up VRE generation are increased capacity payments, while storing and shifting VRE generation results in increased energy revenues. With more firm capacity and energy available, the hybrid power plant may also be able to provide more ancillary services, resulting in additional revenues.

For power systems approaching high VRE penetration levels, energy storage will be increasingly important, especially LDES. LDES increases grid resiliency and allows it to survive extreme weather events and other prolonged power system disturbances (hurricanes, polar vortex events, wildfires, etc.). PSH is currently the only proven, commercially available LDES technology and may play a key role in providing LDES capabilities to the grid in the future. In light of current power system decarbonization efforts and objectives, a significant amount of LDES may need to be deployed in the United States in the next 10 to 15 years.

In many cases, large utility-scale wind and solar plants can be designed as hybrid projects that include small PSH plants instead of batteries, or in addition to batteries and other energy storage technologies. Small modular PSH plants, including some of the innovative technologies that were reviewed in Section 3, could be good candidates for this type of hybrid project.

While large PSH plants of several hundred megawatts are generally expected to remain primarily system storage facilities, they can still incorporate some co-located VRE generation, thus adding some hybrid characteristics. For example, a wind or solar PV plant can be co-located with a nearby PSH plant. Floating solar PV panels can also be installed to cover PSH reservoirs, thus providing some electricity for pumping, while reducing water evaporation losses.

A hybrid PSH system is currently being developed in Hawaii by the Kauai Island Utility Cooperative and the AES Corporation. The West Kauai Energy Project[4] will combine a small PSH plant (20 MW) with a solar PV array (35 MW), battery storage (35 MW, 70 MWh), and a small conventional hydropower plant (4 MW). A series of three reservoirs will be used for water supply and control. The upper reservoir will supply the 4-MW hydropower plant. It will discharge to the middle reservoir, which will supply the PSH plant located at the lower reservoir. The PSH plant will pump from the lower to the middle reservoir using solar generation and batteries during the day, and this water will be later released through the turbines to generate electricity during the evening and night. The PSH plant is designed to have 12 hours of energy storage, and thus would be able to generate during prolonged periods without sunlight.[5] Batteries

[4] See https://www.utilitydive.com/news/kauai-electric-aes-pursue-nations-first-solar-powered-pumped-hydro-projec/593199/.

[5] See https://www.powerengineeringint.com/renewables/kauai-island-coop-and-aes-to-develop-solar-pumped-hydro-in-hawaii/.

will supplement solar to provide steady power for the pumps and additional energy to cover evening and morning peaks. The hybrid system will be able to satisfy about 25% of Kauai's energy needs. The Kauai Island Utility Cooperative is currently in the process of obtaining regulatory approvals for this project, with the actual construction expected to begin in 2022.[6] Once constructed, the West Kauai Energy Project will bring Kauai's energy resource mix to over 80% renewables.[7]

4.3 Other Potential PSH Concepts

The 12 innovative PSH technologies reviewed in Section 3 are not an exhaustive list; many other potential PSH concepts and ideas have been explored or proposed by various researchers over time. Most of these have remained in an early conceptual stage, or just as an idea, so there is not much information available for a detailed review. Here we briefly describe a few of the better-known concepts that have gained attention in recent years.

4.3.1 Deep-Sea PSH

This innovative PSH concept has been proposed by researchers at Fraunhofer Institute for Energy Economics and Energy System Technology (Fraunhofer IEE) in Germany. The concept "Storing Energy at Sea (StEnSea)" envisions placing a number of large spheres on the seabed deep under the sea (Puchta et al., 2017). The spheres would be hollow, made of concrete, with a diameter of about 30 m, and submersed at a depth of about 600 to 800 m. Each sphere represents a mini PSH plant.

Instead of using two water reservoirs at different elevations, this concept uses the static pressure of water surrounding the sphere at the bottom of the deep sea, which is equivalent to an upper reservoir. The sphere is hollow, allowing seawater to flow into it, which is equivalent to a lower reservoir. When the high-pressure seawater is allowed to flow into the sphere it turns the turbine and generator, thus producing electricity. The pumping mode of operation occurs when the water is pumped out of the sphere, against the pressure of the surrounding deep seawater environment. The pump-turbine and motor-generator are in the central cylinder inside the sphere. An additional feed pump is needed to prime the main pump-turbine with water to avoid cavitation. Figure 4-1 illustrates a cross section of the sphere.

The developers of this concept estimate that each full-scale sphere would have a capacity of about 5 MW and about 3 to 4 hours of energy storage. This assumes that the submersed sphere is placed on the seabed at a depth of 750 m and has a diameter of 30 m. The concept allows for modular construction, as each sphere is a separate unit; the size of the project can be easily increased by adding more spheres. The developers envision storage farms with 5 to 140 units (Puchta et al., 2017).

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[6] See https://www.civilbeat.org/2021/01/kauai-is-moving-forward-on-one-of-the-nations-most-advanced-energy-projects/.

[7] See https://www.energy-storage.news/hawaiis-kauai-island-will-get-beyond-80-renewables-thanks-to-solar-plus-pumped-hydro-plant/.

The RTE is estimated at 73%. Once in operation, the units can be easily maintained by just lifting the pump-turbine-generator unit from the central cylinder, as the concrete sphere can remain on the seabed. Therefore, all unit maintenance and repair can be performed on a ship or land.

A pilot demonstration project using a 1:10 scale sphere was performed in Lake Constance in 2016. The pilot project successfully demonstrated the feasibility of this concept by using a concrete sphere with a diameter of 3 m, placed at the depth of 100 m.[8]

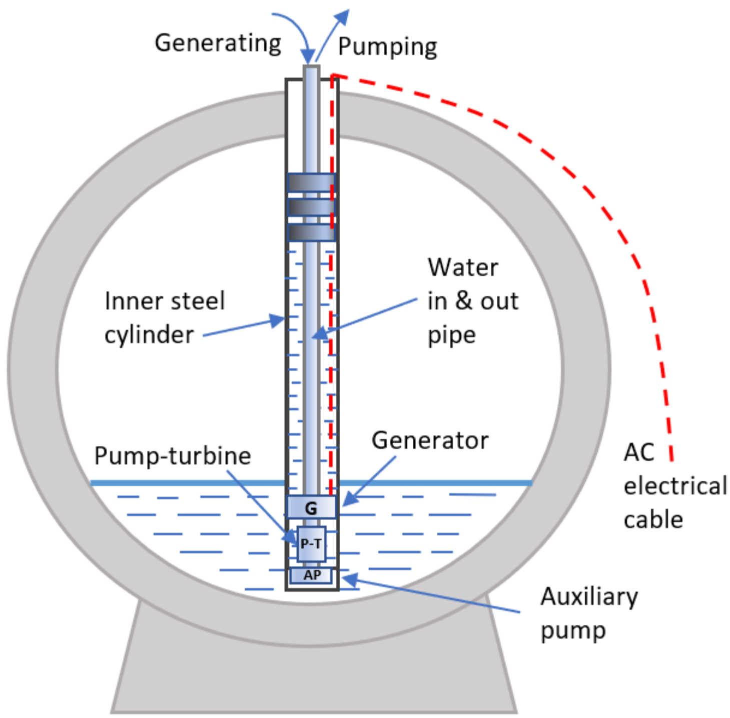

Figure 4-1 Cross Section of the Submersed Sphere

4.3.2 Energy Island PSH

This concept envisions an offshore PSH plant developed as a small manmade island with an interior lake that would serve as lower PSH reservoir. The energy island would be surrounded by a number of wind turbines and solar PV resources that provide energy to pump the water out of the interior lake into the surrounding sea. This would create an elevation differential as the level of the interior lake would be lower than the level of the surrounding sea, thus creating a hydraulic head for the operation of the PSH plant. In the case of energy island, the surrounding sea represents the upper reservoir, while the interior lake represents the lower reservoir. To generate electricity, the water from the surrounding sea is let into the interior lake and passes through the turbines, which turn generators that generate electricity. The island is connected to

[8]See https://en.wikipedia.org/wiki/Stored_Energy_at_Sea.(Accessed November 27, 2021)

the transmission network on the coast via an underwater cable. The concept of the energy island is illustrated in Figure 4-2.

The energy island is not a new idea, as it has been around for many years, at least since 2007.[9] The Dutch engineering firm Lievense, in collaboration with the then KEMA (now DNV), proposed an energy island about 25 km off the Dutch coast. The size of the island was envisioned to be about 6 by 10 km, with dozens of wind turbines on a ring dike. Assuming a maximum elevation difference between the interior lake and the surrounding sea is 40 m,

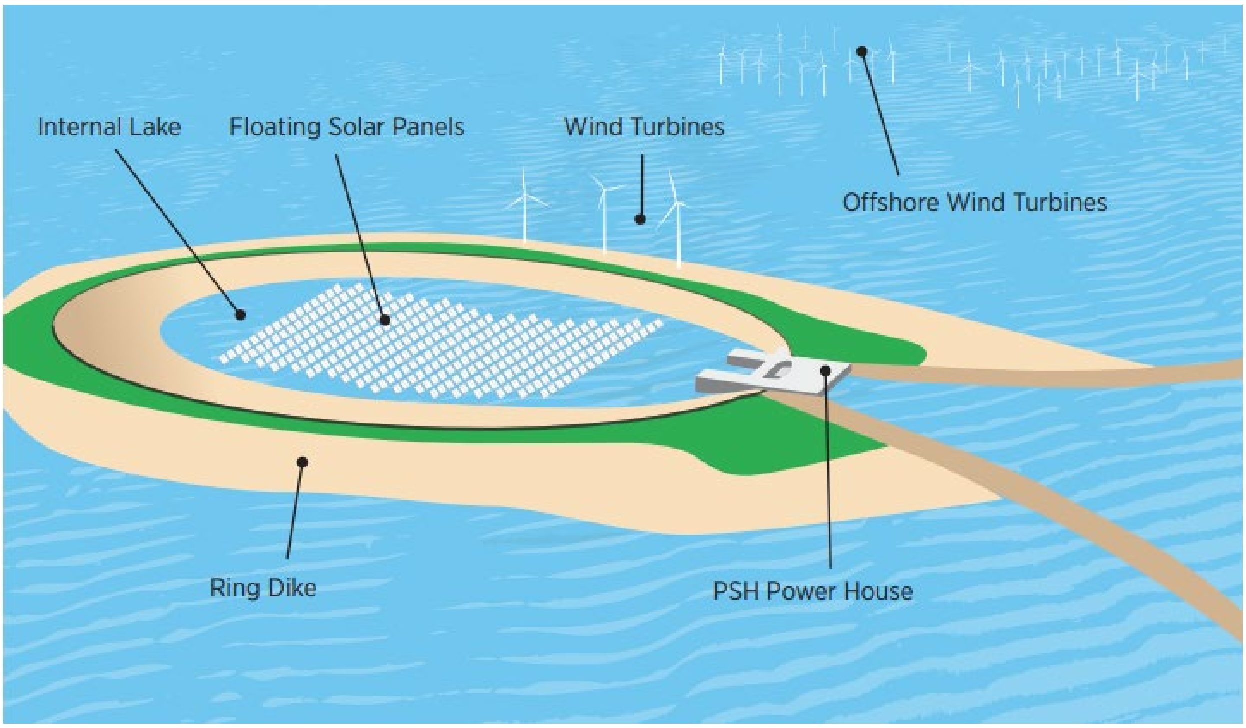

Figure 4-2 Energy Island PSH Concept (Source: DOE, 2016)

Lievense and KEMA estimated that the size of the interior lake would be sufficient to provide 1,500 MW of capacity for 12 hours. They also estimated the total cost of the project would be about 2.5 billion euros, or about $3 billion (in 2007 dollars). We can imagine that, despite the relatively high cost, this type of energy storage project might be of interest to the Netherlands, Belgium, and other countries that do not have favorable topography for PSH plants.

Denmark is currently considering somewhat different energy island solution: whether to build a 10-GW energy island in the North Sea, about 50 mi west of the Danish coast.[10] The energy island will be about the size 18 football fields and will use wind and solar PV energy to generate electricity. In contrast to the energy island described above, this island will not use PSH as a storage technology. Instead, electricity generated by wind and solar PV resources will be used to

[9]See https://tweakers.net/reviews/7696/6/veelbelovende-technologie-voor-de-emissieloze-economie-stuwmeren.html.
[10]See https://www.bbc.com/news/world-europe-55931873.

perform water electrolysis and store energy as hydrogen. The overall cost of the project is estimated at $34 billion.[11]

A smaller 2-GW energy island project is planned on the Bornholm Island in the Baltic Sea.

4.3.3 Hydraulic PSH

Several companies, including Gravity Power,[12] have proposed a PSH concept that uses the weight of a large concrete piston to create water pressure that can be used to generate electricity. The piston, made of layers of concrete, is located in a deep round vertical shaft with a diameter of about 6 to 15 m, or larger. Multiple units featuring several shafts are also possible. The vertical shaft can be very deep, up to 2,000 m.

During the pumping cycle, water is injected underneath the piston, lifting the piston up in the shaft. Flexible seal rings prevent water leakage between the piston and the shaft sides, keeping the piston up and maintaining the pressure on the water under the piston. To generate electricity, the piston is allowed to sink and force the water into a penstock and to the turbine that turns the generator. The power output depends on how fast the piston is allowed to sink, while the energy storage duration depends on the depth of the shaft. Theoretically, this type of PSH plant would be able to generate a large power output of up to 150 MW per shaft. Figure 4-3 provides an illustration of this PSH concept.

Some advantages of this concept are that it is a closed-loop underground PSH system that does not need a surface reservoir and would have minimal environmental impacts during operation. However, the concept also faces many challenges, both financial and technological, that seriously undermine its feasibility.

Technological challenges include constructing a very large vertical shaft with such precision that an enormous concrete piston may glide up and down with very little friction. Next, constructing a concrete piston of such a large diameter and weight is another potential technological challenge. One critical technology challenge is to design seal rings around the piston that would be flexible enough to slide up and down with the piston, but strong enough to maintain tight seal that would keep the piston up. It is also not clear what the expected lifetime of the seal rings would be in real-world operations and how they would be maintained—and eventually replaced—if they fail during PSH operations.

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[11] See https://www.youtube.com/watch?v=2GC3VcB0gLY.
[12] See https://www.gravitypower.net/.

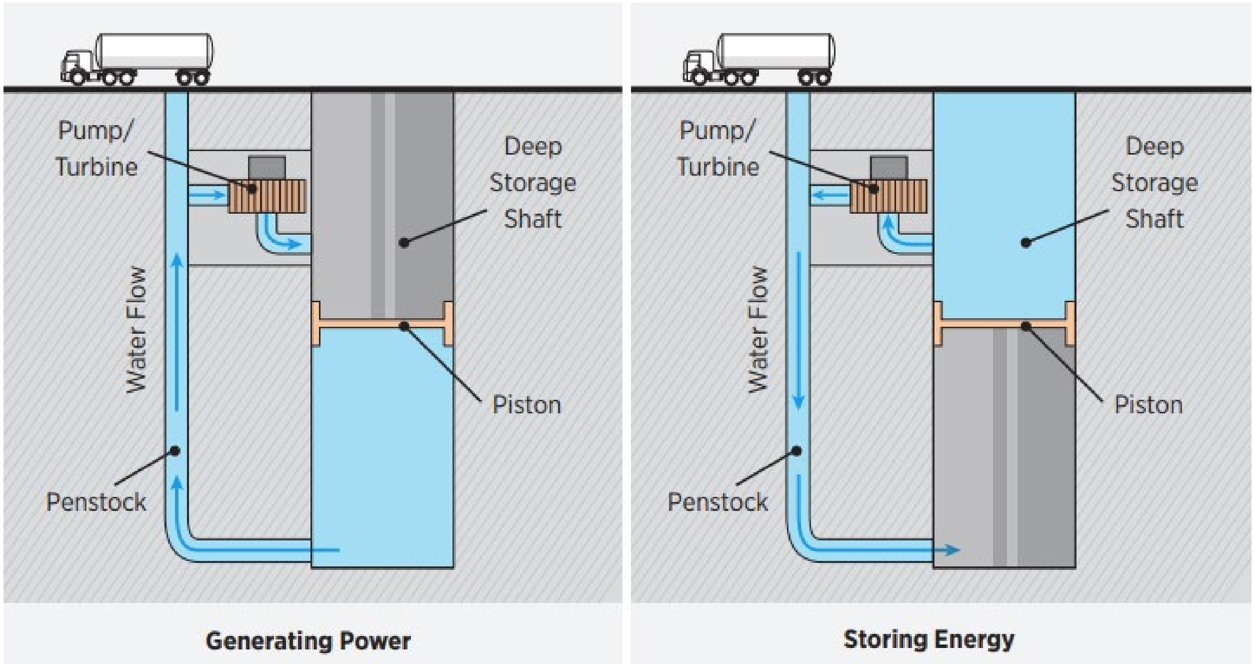

Figure 4-3 Hydraulic PSH Concept (Source: DOE, 2016)

Other uncertainties include the rock geology, which needs to withstand frequent pressure changes during PSH operations, as well as the potential vulnerability of this concept to earthquakes or even small tectonic movements that may cause changes in the geometry of the deep vertical shaft. The key financial challenge is obviously the uncertainty related to the cost of this system. This uncertainty relates to both the project development cost and the O&M costs during PSH operations.

A similar concept, but using a much larger piston, was proposed by Heindl Energy.[13] Their hydraulic gravitational energy storage concept envisions piston sizes with diameters from 150 to 250 m, with an energy storage capacity from 1 to 8 GWh, respectively. This concept faces similar types of technological challenges to those described above, but in this case they may be even more challenging because of the much larger piston size.

4.3.4 Aquifer PSH

Underground aquifers could potentially be used as lower reservoirs of PSH plants, with a surface reservoir serving as the upper reservoir. In western United States, especially in California, many irrigation wells use aquifers to irrigate crops. The aquifer PSH concept envisions using existing irrigation wells and converting them into hydro energy storage systems that would serve the needs of a farm or local community. The aquifer PSH facilities could also be used to support microgrid operations during power system outages or demand-response events.

[13] See https://heindl-energy.com/.

The principle of aquifer PSH operation is similar to that of conventional PSH plants. Onsite renewable wind and solar generation or off-peak grid electricity can be used to pump water from the well to the surface reservoir, where it would be stored for later use. To generate electricity, the water would be released back to aquifer and the pump-motor in the well would be used as generator to generate electricity. Because they are so small, usually less than 1 MW, aquifer PSH units may use a "pump as turbine" to generate electricity, instead of using the reversible pump-turbines that are typically applied at larger PSH plants. More information on the use of pumps as turbines for micro-PSH plants is provided by Williams (1996) and Morabito and Hendrick (2019). A 150-kW aquifer PSH demonstration project was recently completed in Echo, Oregon.

While aquifer PSH plants may have small capacities, their energy storage can be quite large, allowing them to generate electricity for up to 100 hours or more. This long-duration storage is important because it maintains a reliable electricity supply for farm operations during extreme weather events or other grid disturbances.

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5.0 Innovations in PSH Excavation and Construction Methods

The cost of civil works represents a significant portion of the overall PSH project cost. Therefore, any technology or construction method that could reduce the cost of civil works is of great interest to PSH developers. In this section we describe some new excavation technologies and dam construction methods that may help reduce the cost of civil works for the development of new PSH projects.

5.1 New Excavation Methods

One potential way to reduce the cost and time for the construction of new PSH plants is to apply new technologies and methods for excavation of water conveyance systems, such as headrace tunnels and penstocks. This would also include using non-hydropower industry design and construction concepts and adapting them for PSH projects. The well-known L/H ratio, which is the ratio between the water conveyance length (L) and plant hydraulic head (H), is a key factor influencing the cost of civil works, so any savings in underground excavation costs will have a positive impact on the overall cost of the PSH project.

Traditionally, most underground excavation works were carried out using the “drill and blast” (D&B) method. In recent years, the use of TBMs and/or combinations of D&B and TBM has become more frequent. For example, a TBM was used to construct Linthal PSH in Switzerland.[14] Three TBMs will also be used to excavate 27 km of tunnels for the Snowy 2.0 PSH plant in Australia.[15,16] PSH developers are also now starting to consider other excavation technologies, such as RHMs and oscillating-disc machines (ODMs) that, so far, have not been used much for the construction of PSH plants.

The choice of excavation method and the appropriate technology is very site-specific and depends on many factors. The key factors are the length and design of water conveyance systems (e.g., length and diameters of tunnels and penstocks) and factors related to site geology, which describe the rock types and conditions that may be encountered during excavation. The site geology is determined by a geotechnical analysis that looks at rock types and hardness, soil types and structure of geological layers at various depths, the presence of groundwater, and many other factors.

The metric for rock hardness is called uniaxial compressive strength (UCS) and the unit is the megapascal (MPa). Based on their UCS, rocks can be characterized from very weak to very strong, as shown in Table 5-1. The UCS hardness of common rock types are shown in Table 5-2 (adapted from Attewell and Farmer, 1976).

[14]See https://www.herrenknecht.com/en/newsroom/pressreleasedetail/40-degrees-uphill/.
[15]See https://www.geplus.co.uk/news/tbm-delivery-in-the-snowies-for-australian-hydro-scheme-04-11-2020/.
[16]See https://www.waterpowermagazine.com/news/newsfirst-tbm-commissioned-for-snowy-20-8613416.

In preparation for tunnel excavation, detailed geotechnical studies need to be performed to identify the geological layers and types of rock formations that the tunnel will go through. This results in detailed geologic mapping of the proposed tunnels, which helps PSH developers choose the appropriate excavation methods and equipment for the specific site. Detailed geologic mapping will also minimize surprises that may be encountered during the excavation process. In the following sections we briefly describe some excavation technologies, provide information on their applicability for different site situations, and comment on their key advantages and disadvantages.

Table 5-1 Typical Scale for Rock Hardness

Strength Range (MPa)	Strength Classification
5–20	Very weak
20–40	Weak
40–80	Medium
80–160	Strong
160–300	Very strong

Table 5-2 Classification of Rock Hardness

Strength Range (MPa)	Typical Rock Types
5–100	Shale
20–170	Sandstone
30–250	Limestone
30–250	Dolomite
50–200	Gneiss
100–200	Slate
100–250	Marble
100–250	Granite
100–300	Basalt
150–300	Quartzite

5.1.1 TBMs

TBMs have been used for decades, mostly to construct tunnels for roads and railways, and for urban tunneling projects such as underground metro tunnels and urban water conduits. The continuous technological advancements for these types of projects are directly applicable for use in hydropower and PSH applications. Tunnel diameters can vary from about 1 to 17.6 m.[17] Figure 5-1 is an illustration of a typical TBM. TBMs are the preferred technology for urban tunneling projects, because they create less vibration and stress on the surrounding rock formations than D&B methods.

[17] See https://en.wikipedia.org/wiki/Tunnel_boring_machine. (Accessed December 12, 2021)

Figure 5-1 TBM Cutter Head (Photo credit: Shutterstock)

A TBM is a large cylindrical machine consisting of a rotating cutting wheel, main bearing, a thrust system, and trailing support mechanisms. The rotating cutting wheel, or cutter head, has many cutting discs made of tungsten carbide that create compressive stress fractures in the rock, causing it to crumble and chip away from the tunnel face. TBMs can be used for both soft and hard rock conditions. In soft rock, shielded TBMs are used to protect the machine from rocks that could crumble from the tunnel roof and sides. In hard rock, open-type TBMs can be used if the geology is good and there are no fractured or fragmented rocks.

Note that TBMs can only move forward and cannot move backward. The forward movement of open-type TBMs is typically achieved using hydraulic grippers that press on the sides of the excavated tunnel walls and push the machine forward. Shielded TBMs use various methods for their movement. A common one is to use thrust cylinders to advance forward by pushing against concrete segments behind the machine. The excavated rock material is moved through the TBM to the back of the machine using an Archimedes screw.

TBMs create cylindrical tunnels with a very smooth surface. When boring through poor-quality rock formations, the tunnels need to be quickly supported by concrete segments behind the machine to make sure that the tunnel roof and walls will hold. In high-quality rock, the tunnel roof and walls do not need to be secured immediately, and can be supported by rock bolts, ring beams, steel rings, and wire mesh before being lined with concrete or steel.

TBMs are normally custom-ordered and built for each project, depending on the tunnel size, rock conditions, and other factors. For larger TBMs, it may take a year or more to build the machine for the specific project. Once built, TBMs are delivered to the project site and assembled there.

Once assembled, TBMs are very fast tunnel-excavating machines that are suitable for long tunnels. Their rock cutting speed is called penetration rate and can vary from 2 m per hour, when boring in poor rock condition, to about 6 m per hour in good rock conditions (Barton, 2012). The rock conditions are referred to as Q-values and mostly relate to unexpected events, such as rock faults, extreme water, combinations of faulting and water, squeezing rock conditions, and other issues that may be encountered during the tunneling process, rather than to rock hardness.

After each boring cycle, the TBM is locked in place using hydraulic and mechanical brakes, and the side grippers are released and moved forward into a new position to provide hydraulic push for the next boring cycle. The actual advance rate is therefore slower than the penetration rate, as it accounts for time when the TBM is not actively boring. TBM advance rates range from about 100 m per week in poor rock conditions to over 200 m per week in good rock conditions (Barton, 2012). Note that TBM advance rates decrease with tunnel length and over time. For example, the average weekly advance rate during the first month of excavation is normally greater than the average weekly advance rate after a year of tunnel boring.

While TBMs have been used in the past to excavate the headrace and tailrace tunnels for hydroelectric and PSH projects, they have not yet been used to excavate underground PSH reservoirs. Nelson Energy proposed this innovation for their concept of an underground PSH plant that is described in Section 3.2.6.

Their concept envisions the use of two TBMs to tunnel from the surface to about 2,500 feet below ground, where the powerhouse, transformer cavern, and spiral-shaped lower reservoir will be excavated. The lower reservoir will actually look like a double spiral because two TBMs will be used in parallel for its excavation. The two spirals will be connected to each other at many points with side passages to allow for quick removal of excavated rock material, without the need to go through the entire length of the spiral. The site geology features high-strength impermeable granite that is ideal for excavating the large caverns needed for the powerhouse and associated chambers to house valves and power transformers. Due to this favorable granite geology, most of the reservoir and other excavated tunnels will not need any structural support, except for the pressure shafts and draft tubes, which will be lined with concrete, and penstocks, which will be steel-lined.

For this particular application, the TBMs will tunnel down from the surface to a depth of 2,500 feet by creating an oval-shaped access ramp that is over 7 km long and has a downward gradient of 12.5%. While TBMs are typically used for excavations of straight horizontal tunnels, they can also steer and excavate under an angle. For example, a TBM was used to excavate the headrace tunnel for the Linthal PSH plant in Switzerland at an uphill angle of 40 degrees.[18]

To speed up the excavation process, Nelson Energy also envisions using, in addition to conveyer systems, narrow-bodied trucks to haul the rock debris from TBMs up to the surface. The tunnel diameter will be large enough for two trucks to pass each other, which would allow fast removal and transportation of rock materials. This excavated material will be used to construct the surface reservoir. In their application to DOE's FAST PSH prize competition, Nelson Energy claimed that the use of TBMs would reduce the cost of underground PSH to a level that is comparable with conventional PSH plants.

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[18]See https://www.herrenknecht.com/en/newsroom/pressreleasedetail/40-degrees-uphill/.

This is an innovative concept because TBMs have not yet been used to excavate underground PSH reservoirs; however, they have been used in the development of traditional hydropower and water supply reservoirs. Obviously, a key challenge for this concept will be the very long tunnels required for the excavation of the access ramp and spiral-shaped lower reservoirs. In addition, Barton (2012) lists some other challenges that may be encountered when using TBMs for tunnel excavations. The key ones are fault-zone challenges, which may cause delays due to fractured or fragmented rock conditions. Other challenges include extreme water presence, or combinations of faulting and water, and squeezing rock conditions. Some of these challenges can cause significant delays for the excavation process. Note that because the TBM cannot move backward, it blocks access to the tunnel face for optional D&B excavation through the fault zone. In extreme cases when the TBM gets stuck, the D&B method needs to be used to excavate the tunnel from the other end, or to create a bypass and approach the TBM face from the other side. Barton (2012) provides several examples when the choice of TBM has been incorrect for the geological conditions and the TBM had to be abandoned.

This emphasizes the need for detailed geotechnical research in order to choose the correct excavation method, and the right type of TBM for the project (e.g., single- or double-shielded, or open-type TBM). The order, delivery, and assembly of the TBM usually takes 1–1.5 years, which needs to be considered as part of the project development time. Because of this lead time, other methods such as D&B may be more appropriate for short tunnels. Although D&B advance rates are slower than those of TBMs, D&B requires little lead time and it may be possible to complete the overall excavation process for short tunnels in less time than if TBMs are used. Of course, for longer tunnels, the higher advance rate of TBMs will make up for the lead time and the overall excavation time will be shorter than if the D&B method was used.

5.1.2 RHMs and ODMs

As described above, using TBMs for tunnel excavation requires a long lead time and may not always be the best technology choice, especially for short tunnels. While the D&B method has been traditionally used to excavate short tunnels, an alternative tunneling technology has recently been proposed. The use of RHMs and ODMs has the potential to speed up the tunnel excavation process, thus reducing the cost and time to develop a PSH project, while avoiding some of the excavation risks associated with the use of TBMs.

A mobile RHM is a self-propelled mining or tunneling machine that consists of a telescopic boom-mounted cutting head, a loading apron and conveyor, and a crawler travelling track that moves the entire machine back and forth. One illustration of an RHM is shown in Figure 5-2. The cutting head may have different shapes, but typically looks like a rotating drum with tungsten carbide bit picks that chip the rock into smaller pieces (Figure 5-3). The cutting head is mounted on a telescopic boom that can move left and right, as well as up and down, which allows for excavation of various profiles. The roadheaders were first used in coal mining operations for "room and pillar" excavations, but later their use expanded to tunneling and other types of excavation. RHMs are most applicable for excavations through soft rock with a hardness up to 100 MPa, but some can be designed to cut through harder rock, especially in tunneling

Figure 5-2 RHM (Photo credit: Shutterstock)

Figure 5-3 Cutting Head of RHM (Photo credit: Shutterstock)

applications.[19] RHMs come in different sizes (e.g., from 18 to 135 tons) and can excavate tunnel widths from about 4 to 8.5 m.

The tunnel excavation speed, in meters per week, depends on the rock hardness, and the cutting rates can decrease significantly for excavations through harder rock. Advance rates of more than

[19] Roadheaders Tunneling for Most Rock Formations | Sandvik — Sandvik Mining and Rock Technology. Available at https://www.rocktechnology.sandvik/en/products/mechanical-cutting-equipment/roadheaders-for-tunneling/.

100 m per week are possible for a rock hardness of 40 MPa. For harder rocks (90 MPa), advance rates may decrease to about 50 m per week. The advance rates are also proportional to the tunnel face area being excavated. Small RHMs will not be able to advance quickly when excavating tunnels with large profiles. For the best results, the excavation machine should be properly sized for a given tunnel profile.

ODMs are similar to RHMs, except that instead of the drum-shaped cutting head, ODMs have cutting heads with one or more oscillating discs. ODMs use undercutting technology and are applicable for cutting through hard rock of up to 240 MPa. The undercutting technology allows the ODM to use 60% less power than a TBM to cut through the same rock type (Ramezanzadeh and Hood, 2010). This is because the TBM cutting discs are perpendicular to the rock face and cut by exerting significant direct pressure on the rock. In contrast, the cutting discs of the ODM are parallel to the rock face and cut when the telescopic arm moves from side to side. The rotating discs get underneath the rock face, causing it to fracture and crumble.

Both RHMs and ODMs are electro-hydraulically powered machines that do not emit any fumes. They are track-driven and, in contrast to TBMs, have greater maneuverability and can move both forward and backward. The reverse speed is slow, typically about 1 mile per hour. Their ability to excavate the desired profile with little vibration and stress on the surrounding rock formations makes them suitable for excavations in urban areas as well.

Currently, RHMs and ODMs are mostly used for batch excavation processes, which are typically applied for room-and-pillar type excavations. For tunnel excavations, the batch process is less efficient, because after each 6 m of advance, the tunnel roof and sides need to be secured. For this, the RHM or ODM will have to drive back to an alcove that was dug out previously on the side of the tunnel, to let the roof bolter vehicle pass and secure the roof. Then, the roof bolter drives back to a different alcove to allow a shotcrete machine to pass and secure the roof and sides of the newly excavated tunnel section. Once this process has been completed, the shotcrete machine goes back and the RHM or ODM is brought to the tunnel face to continue excavation.

Kinetic Power, LLC, in its application to DOE's FAST PSH Prize[20] competition project, estimated that the tunnel batch process would take about 6.3 hours for each 6-m excavation cycle. They also noticed that the average length of tunnels for existing PSH plants in the United States is increasing. In 1980, it was about 1,500 m, while the average tunnel length for proposed new PSH projects is now over 3,000 m. Therefore, accelerating the tunnel excavation process has potential to decrease the cost and time for the development of new PSH projects.

Kinetic Power proposed that instead of the batch RHM and ODM process, a continuous tunnel excavation process should be developed. While continuous miners[21] exist for room and pillar mining operations, there is currently no such machine for tunnel excavations. For tunnel boring, this machine would need to integrate a RHM or ODM with a roof bolter machine and a shotcrete machine, to avoid the need to back up to an alcove in order to have the tunnel roof and walls secured. The continuous excavation machine will also need a fleet of narrow-bodied trucks to

[20] See https://americanmadechallenges.org/fast/.

[21] See Continuous Miners For Cutting Coal & Soft Materials | Sandvik — Sandvik Mining and Rock Technology. Available at https://www.rocktechnology.sandvik/en/products/mechanical-cutting-equipment/continuous-miners/.

remove the excavated rock material from the tunnel. Kinetic Power estimated that the conversion from batch RHM to continuous RHM (CRHM) operation has a potential to increase excavation speed by 42%. The conversion from batch ODM to continuous ODM (CODM) operation has even greater potential, up to a 137% increase over the batch ODM excavation speed.

Figure 5-4 illustrates applicable tunnel excavation processes for different rock hardness conditions. Kinetic Power estimates that CRHM would be applicable for rock hardnesses of up to 100 MPa, the CODM would be applicable between 100 and 240 MPa, and D&B will have to be used for very hard rock conditions above 240 MPa. Note that most rock types are within the CRHM and CODM hardness capability.

Kinetic Power also estimated the tunnel completion times in soft rock (40 MPa) for different excavation technologies, including D&B, TBM, CRHM, and CODM. The results of their analysis are shown in Figure 5-5. For the assumed 5-m tunnel diameter, CODM technology would provide the fastest completion times, except for very short tunnel lengths up to 0.5 km, where the D&B method would be faster. This is mainly because the D&B process can start very quickly, after just a few weeks of preparation, while the CODM requires about 3 months for equipment delivery and assembly before the excavation process can start. The lead time for TBM is even longer, and Kinetic Power estimated a lead time of 1 year for TBM.

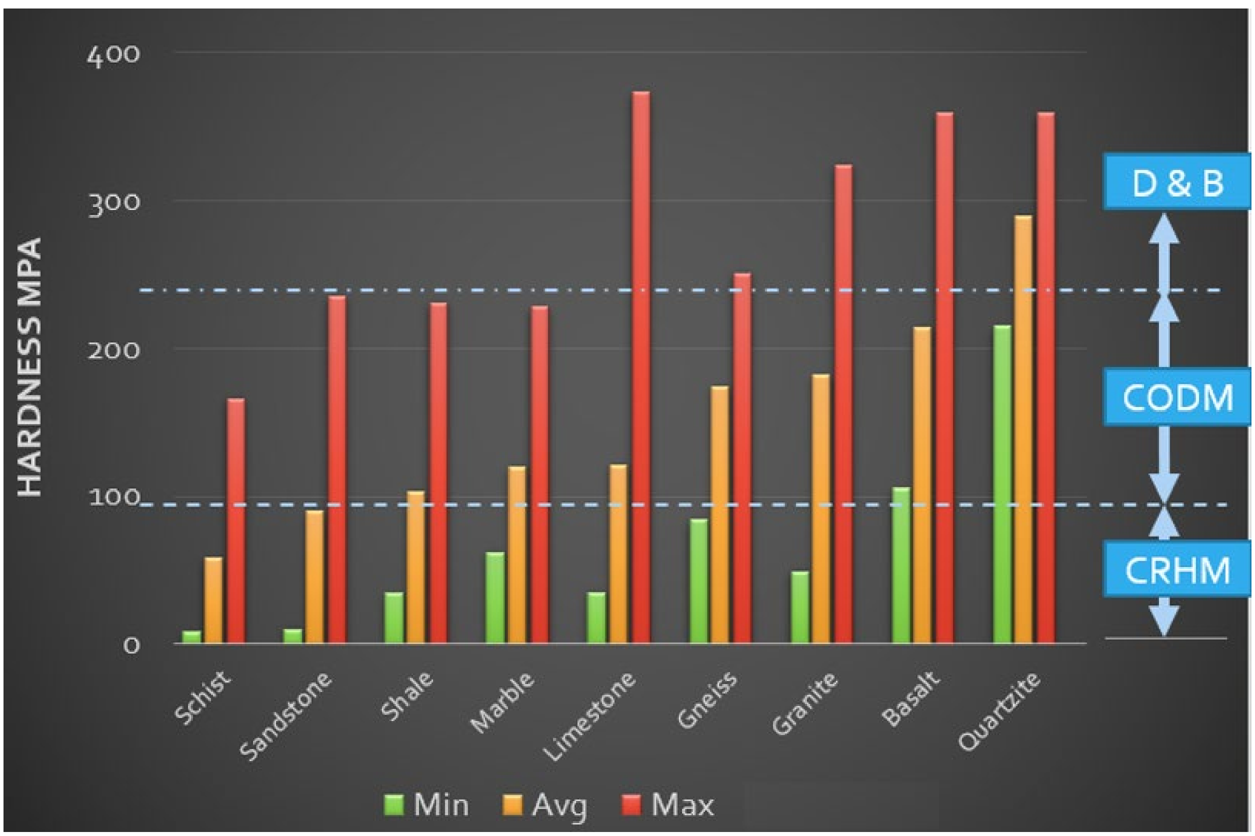

Figure 5-4 Applicable Excavation Process for Rock Hardness (Source: Kinetic Power, LLC)

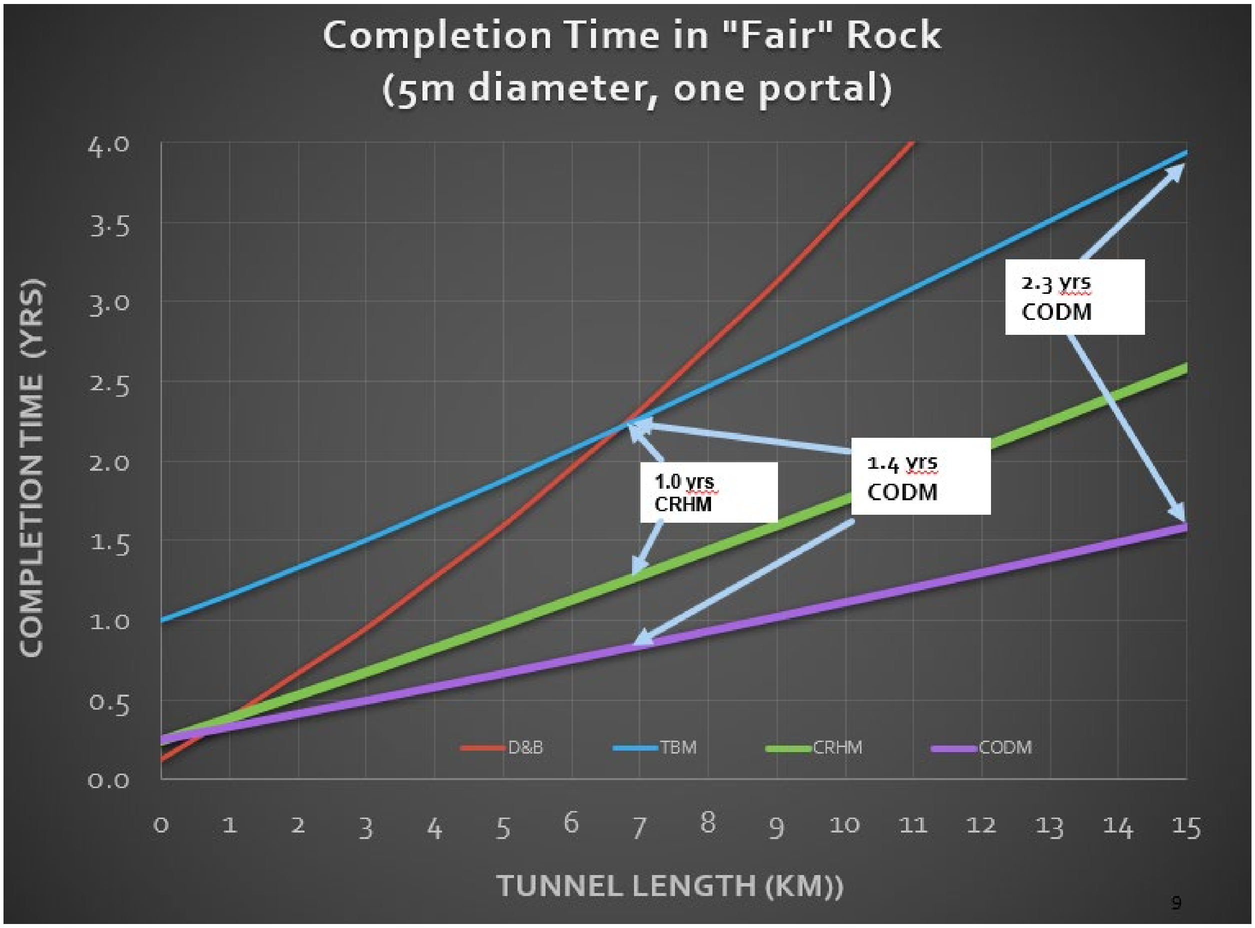

Figure 5-5 Tunnel Completion Times for Different Excavation Methods as Function of Tunnel Length (Source: Kinetic Power, LLC)

For the assumed tunnel length of 15 km, this example shows that it would take 1.6 years to excavate it using the CODM technology, while it would take 3.9 years for TBM technology. This translates into 60% time savings if CODM technology is applied instead of TBM. Similarly, for a tunnel length of 7 km, CODM is again the fastest excavation method and would complete the tunnel in 0.8 years, while CRHM and TBM would complete it in 1.4 and 2.2 years, respectively. Note that the D&B method is faster than TBM for tunnel lengths of up to about 7 km. This is because D&B method has almost a full year head start before the TBM excavation process starts.

In summary, the key benefits of using RHM and ODM include their versatility and applicability to different rock hardness, as well as their adaptability to unforeseen conditions and situations. They can be transported to the project site by truck and deployed in 2–3 months, cost less than TBMs, and have higher residual value after the excavation has been completed. Kinetic Power estimates that the most significant benefit of using CODM technology is its potential to reduce the cost of tunnel excavation by 50% and to shorten the excavation time by 50%.

5.2 New Dam Construction Methods

In addition to new excavation methods, some innovative dam construction methods have also been proposed in recent years for the development of new PSH projects. Here, we will highlight two ideas related to the proposed modular dam construction and steel dam construction. Both methods could be used for traditional types of dams on rivers and waterways, but are especially suitable for constructing the low-height ring dams that PSH plants typically use.

5.2.1 Modular Dam Construction

This innovative idea has the potential to reduce cost and shorten the time required for the construction of new dams or PSH reservoirs. It would use prefabricated modular dam components that were manufactured off-site and then transported for assembly and integration at the project site. This modular type of construction would mostly be applicable to low head dams, both impoundment dams as well as circular or oval-shaped “turkey nest” dams for PSH reservoirs. The method could be used both to construct of new dams and to retrofit or rehabilitate existing dams.

The key advantages of the modular precast dam construction method are the potential time and cost savings over traditional dam construction methods. French Dam Enterprises (FDE),[22] a leading proponent of modular precast dam construction in the United States, estimates that substituting a cast-in-place dam construction with a precast manufacturing and onsite installation has the potential to reduce the time required for dam construction by a factor of 4. The precast concrete modules are manufactured offsite and delivered onsite just in time for installation, which can be performed using standard construction equipment. Standardized offsite manufacturing allows for the highest level of consistency and product quality. The modular design can be adapted to any type of dam, depending on the specific site and project needs. The precast dam components can be manufactured in any shape and size to fit the civil structure needs. The modular construction reduces the size of civil works operations on the project site, which also minimizes impacts on the environment. Finally, the modular dam structure can be easily dismantled and removed in case of decommissioning.

FDE envisions that most dams could be constructed using standardized modular blocks shaped like hollow cubes. The cube size and wall thickness can be optimized to reduce the material needs and system weight, while providing the required structural strength for a particular application. Each module consists of four vertical walls and a floor, and the entire module is cast as a single piece. The modules are delivered to the project site and stacked on top of each other, so that the floor of one becomes the ceiling of the one beneath it. As illustrated in Figure 5-6, the bottom layer of modules is secured to the underlying bedrock using anchors or rock bolts. The anchoring holes for the bottom layer of modules—as well as the holes on the side walls for securing the modules to each other—have already been included in the cast design, so there is no need for drilling at the project site. The modules are secured to each other using steel bolts. On the outside, the modules are designed with a double groove on the sides to ensure watertight connections between the modules. A water sealant material can be installed into the grooves to

[22] See https://fdepower.com/hydropower/french-dam/.

ensure that there are no leaks or water seepage between the modules. The top level of modules will be covered with a slab to enclose the system.

DOE/WPTO has funded FTE under the HydroNEXT[23] FOA to demonstrate the feasibility of their modular dam concept in the field. FDE, with their project partners Oldcastle Precast and GEI Consultants, successfully tested a 24-ft-long and 16-ft-high prototype dam, which was composed of six precast concrete blocks—each weighing 27,000 lb.[24] Figure 5-7 illustrates the prototype dam constructed for this project. For this prototype, FDE designed precast modules measuring 8 ft on each side. Once the modules were delivered to the demonstration site, the construction crew assembled them in less than 3.5 hours.

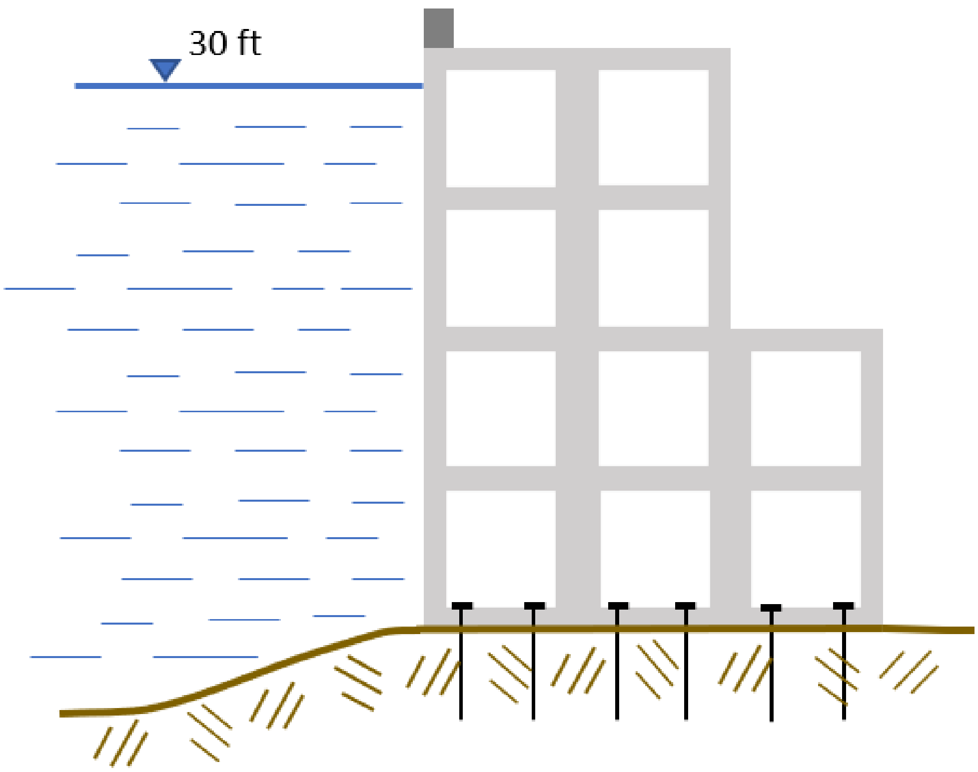

Figure 5-6 Cross-section of a Modular Dam for 30-ft Reservoir

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[23] See https://www.energy.gov/eere/water/downloads/hydronext-fact-sheet.

[24] See https://www.energy.gov/eere/success-stories/articles/eere-success-story-innovative-french-dam-cuts-cost-and-construction.

Figure 5-7 Precast Modular Dam Prototype (Source: DOE)

FDE also performed a comparison analysis of potential cost and time savings between the precast modular dam approach and the traditional cast-in-place dam construction. The Allendale Dam in Rhode Island was used for this comparison analysis. The Allendale Dam was originally built in 1865, but was completely reconstructed in 2002, so the cost data and other relevant information were available for this analysis. For this comparison, the Allendale Dam was redesigned using the FDE modular dam technology. Instead of the original cast-in-place dam, the redesign included a precast French impoundment dam, consisting of two rows of 13 precast concrete units (8 ft wide, 8 ft long, and 7.2 ft tall) for a total dam width of 104.5 ft. The bottom units would be anchored to the riverbed using 20-ft rock bolts. Dam stability analysis was also performed to make sure that the modular dam would be stable for normal operating conditions, for a 100-year flood, and for extreme loading, such as normal operation with earthquake. The modular redesign also included a granite capstone on top of the dam, to match the original Allendale Dam design.

The results of this comparison showed that the modular precast dam would reduce the overall project timeline by 31% (Drown, 2017). The cost savings for dam construction were comparatively smaller, approximately $13,000, or about 4%. These cost savings included only direct costs for dam construction and did not include indirect savings due to the shorter construction schedule. Note that the cost savings in this particular case are not very large because Allendale Dam is a relatively small dam (10-ft head) and a fairly simple structure to cast, so there was not much room for cost savings. However, at larger dam heights, the modular precast dam is expected to provide more significant cost savings over a comparable cast-in-place concrete dam.

An interesting follow up analysis would be to compare the cost and time needed to construct a 20- to 50-ft-high modular ring-shaped embankment dam versus traditional earth dam, roller-compacted concrete, or rockfill dam. Since most closed-loop PSH plants will have at least one reservoir of this type, this application may be much more important than traditional impoundment dams.

5.2.2 Steel Dam Construction

Another promising dam construction method was proposed by Southwest Research Institute (SwRI).[25] For the PSH FAST Prize competition, SwRI proposed a steel dam concept, which could potentially reduce the cost and time required to construct PSH reservoirs. This is also a modular dam construction method, which uses standardized prefabricated steel frames that are manufactured offsite and then transported by truck or by other means to the project site for assembly. As with the precast concrete modular dams discussed in Section 5.2.1, the steel dams could be used both for the impoundment of reservoirs and for embankment ring-shaped dams. The latter would be of great interest for closed-loop PSH applications.

Steel dams, consisting of curved steel plates and a steel buttress structure, are not a totally new concept. In the United States three steel dams were constructed more than 100 years ago, two of which (Ashfork-Bainbridge in Arizona, and Redridge in Michigan) are still standing (Reynolds, 1989). This confirms that the longevity of steel dams could be similar to that of concrete and other types of dams. With modern high-strength corrosion-resistant steel and more durable and effective weather-resistant coatings, steel dams deserve to be revisited and considered again as a potential option for reservoir development.

In their forthcoming final report to DOE for the FAST PSH Prize competition (Wittmeyer et al., forthcoming), the developers of steel dam technology at SwRI list several potential benefits of steel dams, including reduced cost of construction, shorter construction times, more accurate estimates of dam construction cost, and improved physical access to the dam's critical structural components for inspections, maintenance, and repair. In addition, the cost estimates for steel dams could be more accurate than for other dam types because most structural components would be manufactured offsite under well-controlled factory conditions.

For their modular steel dam approach, SwRI developed a design for a standard steel frame that would serve as structural support for the dam. To make it suitable for truck transportation to project site, each frame consists of four segments or modules: A, B, C, and D (Figure 5-8)[26]. These frames are then installed at the project site, approximately 8 ft apart from each other, to construct the dam. The frames are positioned, braced, and installed on concrete foundations that are anchored to the underlying bedrock using rock bolts.

Figure 5-9 illustrates the steel dam construction process, with assembly advancing from left to right. The completed frame sections are then covered with three rows of surface plates. Figure 5-10 is an artist's rendering of a completed steel dam.

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[25] Southwest Research Institute. Available at https://www.swri.org/.

[26] Figures 5-8, 5-9, and 5-10 are reprinted with permission from Southwest Research Institute®, Copyright 2019.

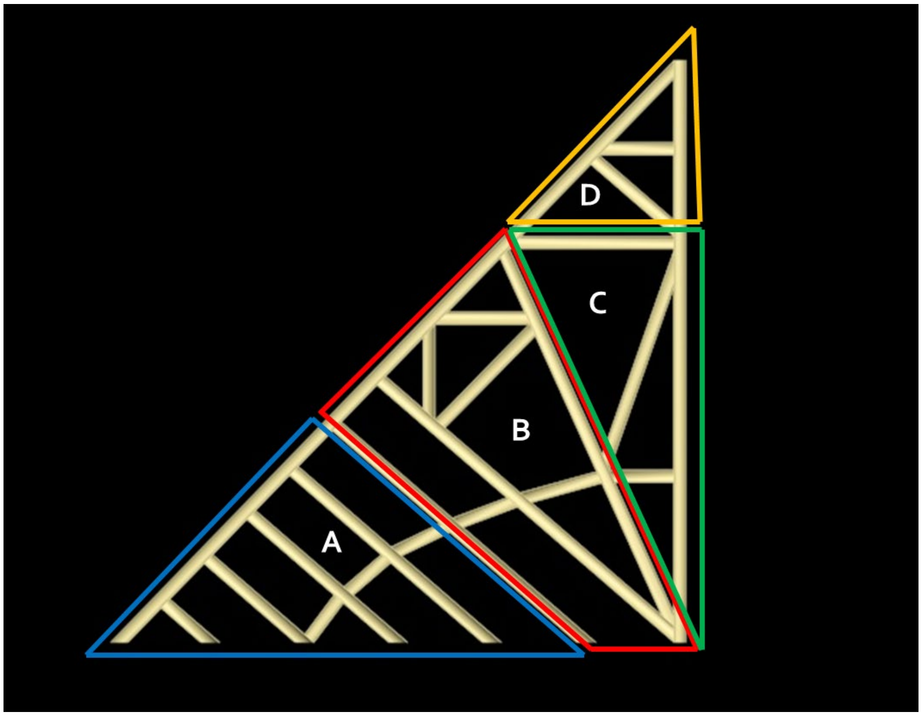

Figure 5-8 Steel Frame Design Consisting of Four Segments: A, B, C, and D (Source: SwRI)

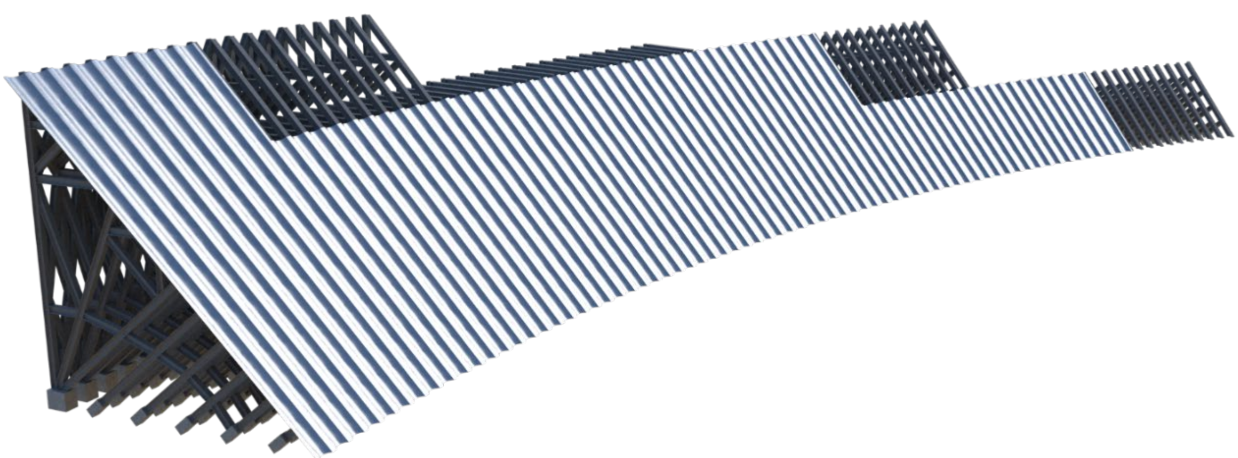

Figure 5-9 Modular Assembly of a Steel Dam (Source: SwRI)

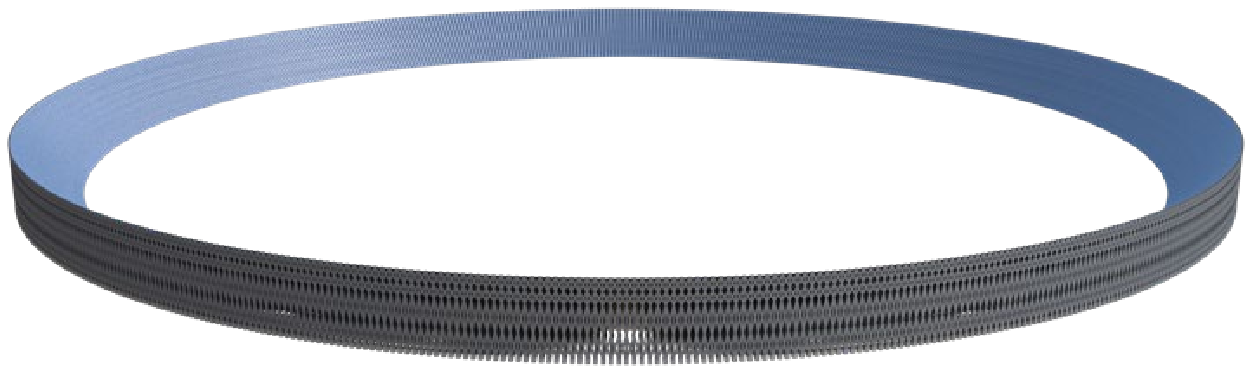

Figure 5-10 Completed Circular Steel Dam (Source: SwRI)

Steel dam frames can be custom designed for various dam heights and crest lengths. SwRI has analyzed dam heights from 10 to 150 ft, but dams higher than 150 ft should also be possible. Depending on the terrain, steel dams can also be designed to form different shapes, which makes them ideally suited for the construction of PSH reservoirs (i.e., to match the shape of the mountaintop). Some civil works are needed to flatten the terrain and prepare the foundation for the dam, but compared to the traditional embankment dams, the civil works are much smaller. In addition, reservoir lining may need to be installed to minimize leaks and seepage, but that would also be required for traditional construction of embankment reservoirs. The plates covering the face of the frame are designed to be cylindrically curved and can be made of thicker steel for the lower part of the dam and thinner steel for the upper part of the dam. Each plate will span and be welded between two structural frame members.

The developers of steel dam technology at SwRI estimate that the cost of a large steel dam (100 ft high and 7,000 ft long) could be as little as 25% of an equivalent dam constructed of roller-compacted concrete, or about 70% of an equivalent rockfill embankment dam (Wittmeyer et al., forthcoming). They also estimate the steel dam construction time would be approximately half of that for equivalent traditional embankment dams. We understand that these estimates are based on detailed cost analysis but would suggest that these analytical estimates should be confirmed by a pilot project in the field. It is important to note that the use of steel dams would need to be independently evaluated for regulatory approvals, including by FERC's Dam Safety Division, as well as state dam authorities.

5.2.3 References

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6.0 Appendices

6.1 Levelized Cost of Storage (LCOS)

LCOS is defined as the total cost of ownership over the investment period, divided by the delivered energy (Pawel, 2014). Schmidt et al. (2019) use the same definition but express it a slightly different way: “[LCOS] can be described as the total lifetime cost of the investment in an electricity storage technology divided by its cumulative delivered electricity.” Defined in this way, LCOS is analogous to the levelized cost of electricity that is commonly calculated for generating technologies (Schmidt et al., 2019).

The total lifetime cost of an energy storage project is calculated as a sum of several cost components, including the investment cost (CAPEX), additional investments over the project lifetime (replacement cost or CAPEX-R), O&M costs, cost of energy consumed for charging (in case of PSH, for pumping), and end-of-life cost or value (decommissioning cost minus the residual value of equipment and materials). Except for the initial investment cost, all other cost items occur over time and are discounted to present value using discount rate *r*.

To calculate LCOS, the total lifetime costs of the storage project are divided by the cumulative delivered energy from the storage. This cumulative energy value is calculated as the sum of annual discharged electricity over the project lifetime. Because these energy deliveries occur over the lifetime of the project, they are discounted using the discount rate *r*, which is the same as the one used for discounting of costs.

Therefore, the LCOS equation can be calculated using equation (1). This LCOS equation is expressed in a similar way as in Schmidt et al. (2019):

$$LCOS = \frac{CAPEX + \sum_1^N \frac{Replacement\ Cost}{(1+r)^t} + \sum_1^N \frac{O\&M\ Cost}{(1+r)^t} + \sum_1^N \frac{Charging\ Cost}{(1+r)^t} + \frac{End{-}of{-}life\ Cost}{(1+r)^{N+1}}}{\sum_1^N \frac{E_{discharged}}{(1+r)^t}} \tag{1}$$

Where:

LCOS	=	Levelized cost of storage ($/MWh)
CAPEX	=	Project capital investment costs ($)
Replacement Cost	=	Additional capital investment costs over the project lifetime ($)
O&M Cost	=	Annual O&M costs ($)
Charging Cost	=	Annual cost of electricity used for charging ($)
End-of-life Cost	=	Decommissioning cost minus recovery value at the end of project lifetime ($)

$E_{discharged}$	=	Annual discharged electricity (MWh)
N	=	Project lifetime (years)

One difference between equation (1) and the equation in Schmidt et al. (2019) is that for PSH plants we have separated the operating expenses into two parts: (1) replacement costs (CAPEX-R), and (2) O&M costs. This was done in a similar way as in Smallbone et al. (2017), who have separate replacement cost and O&M cost components. The main reason for this is to account for the capital investments needed for major overhauls of PSH plants. These major overhauls are typically performed about 30 years after the project commissioning and may include rewinding the generators and refurbishing or replacing the turbines. There are also minor overhauls, which are typically performed every 5 years, and are less expensive than major overhauls. For the LCOS analysis performed in this study, we included the cost of minor overhauls in the O&M costs.

6.1.1 Key Assumptions for LCOS Calculations in This Study

Technoeconomic parameters for each innovative PSH technology were specified based on the information that was available to the project team. These include data on plant generating capacity, capital investment costs, RTE, and plant lifetime. Best estimates were made if certain data items were not available. For example, because of the uncertainties in capital investment costs, we often performed LCOS calculations for a range of potential capital costs.

The annual electricity output was calculated assuming a capacity factor of 20%. This is an average capacity factor for PSH plants in the United States. Note that for energy storage technologies, capacity factor accounts only for discharging time, and not for charging time. To account for both charging and discharging, the utilization factor can be calculated by taking into account the capacity factor and the RTE. Therefore, a 20% capacity factor and 80% RTE translate to a 45% utilization factor of PSH capacity.

The cost of major overhaul was assumed to be 10% of the project original capital investment cost. Normally, a more accurate approach would be to estimate the overhaul costs as percentage of the cost of electromechanical equipment. However, because most of the considered innovative PSH concepts and technologies are in very early stage of development, itemized cost estimates were not available. Therefore, 10% of the total project investment cost was adopted as a reasonable approximation for the cost of a major overhaul. It was also assumed that at least one major overhaul will be performed over the plant lifetime. Since these major overhauls occur many years after the project is commissioned, they are heavily discounted and typically comprise only a small fraction of the LCOS value.

The annual O&M costs were estimated to be 1.5% of the original capital investment cost. Note that for the analysis performed in this study, the costs of minor overhauls were included into the O&M costs.

The WACC was assumed to be 8% for all innovative PSH technologies considered in this study. The WACC also served as a proxy for discount rate r that was used for cost discounting.

Similarly, the cost of electricity for pumping was assumed to be $50/MWh for all innovative PSH technologies. We assumed that all PSH technologies would pay wholesale electricity price, except for three very small GLIDES installations (100 kW each); we assumed that these would pay retail price for electricity. Wholesale electricity prices were assumed for the larger 10-MW GLIDES concept.

In this study, end-of-life cost or value was assumed to be zero for all innovative PSH technologies, as well as for the reference PSH and battery technologies. This is a very common assumption in LCOS calculations (Schmidt et al., 2019).

6.1.2 References

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6.2 Summary of LCOS Results

Figure 6-1 illustrates LCOS results obtained for innovative PSH concepts and technologies that were evaluated in this study.

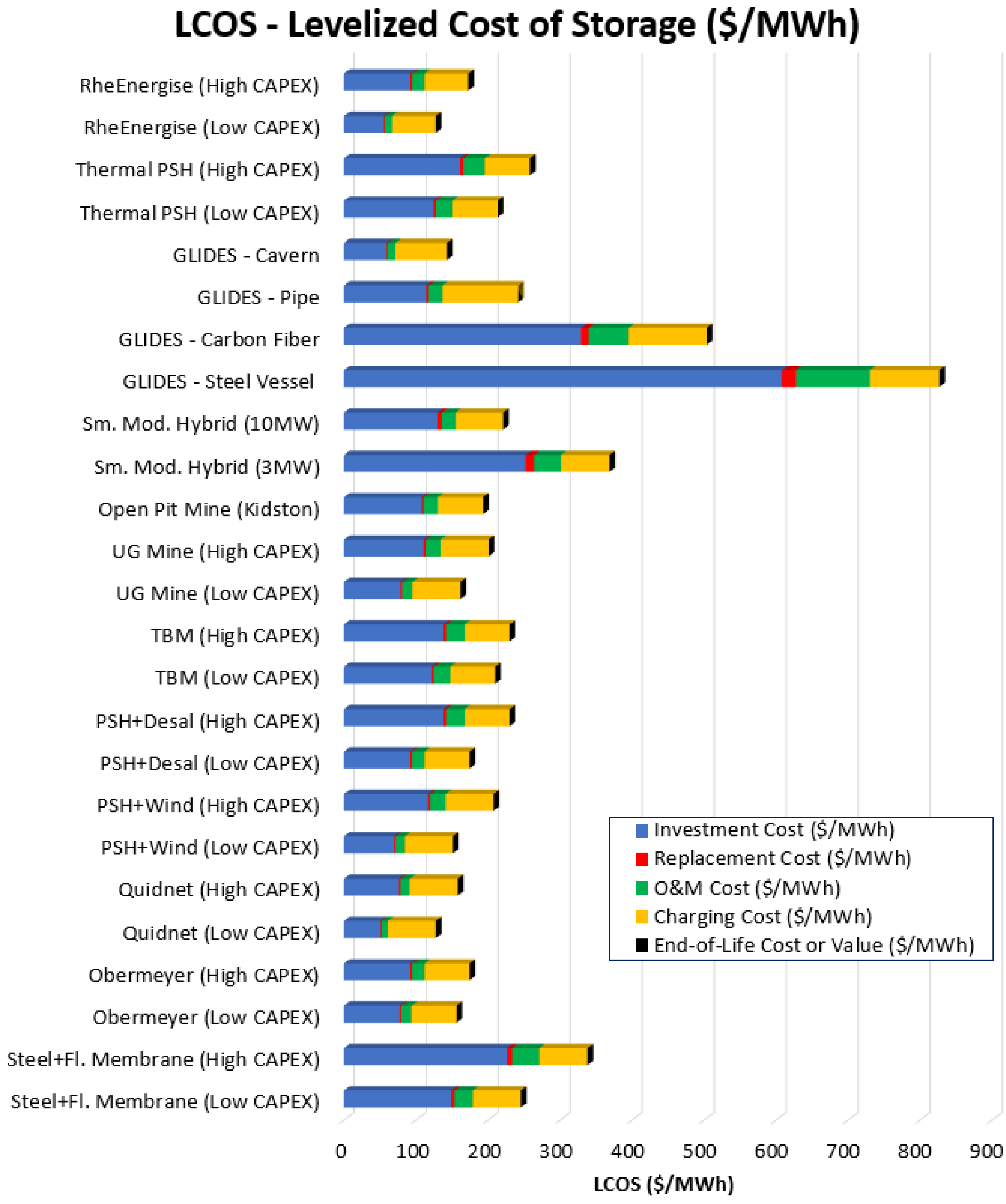

Figure 6-1 Summary of LCOS Results for Innovative PSH Concepts and Technologies

6.3 TRL Definitions

TRLs identify the readiness levels of the technology that is progressing from the initial idea or concept toward full commercialization. The following TRL definitions were used in this study:

- **TRL 1, Basic Research**—Basic principles observed and reported: Scientific problem or phenomenon identified. Essential characteristics and behaviors of systems and architectures are identified using mathematical formulations or algorithms. The observation of basic scientific principles or phenomena has been validated through peer-reviewed research. Technology is ready to transition from scientific research to applied research.

- **TRL 2, Applied Research**—Technology concept and/or application formulated: Applied research activity. Theory and scientific principles are focused on specific application areas to define the concept. Characteristics of the application are described. Analytical tools are developed for simulation or analysis of the application.

- **TRL 3, Critical Function or Proof of Concept Established**—Analytical and experimental critical function and/or characteristic proof of concept: Proof of concept validation has been achieved at this level. Experimental R&D are initiated with analytical and laboratory studies. System/integrated process requirements for the overall system application are well known. Demonstration of technical feasibility using immature prototype implementations are exercised with representative interface inputs to include electrical, mechanical, or controlling elements to validate predictions.

- **TRL 4, Lab Testing/Validation of Alpha Prototype Component/Process**—Component and/or process validation in laboratory environment, Alpha prototype (component): Standalone prototyping implementation and testing in laboratory environment demonstrates the concept. Integration and testing of component. technology elements are sufficient to validate feasibility.

- **TRL 5, Laboratory Testing of Integrated/Semi-Integrated System**—Component and/or process validation in relevant environment, Beta prototype (component): Thorough prototype testing of the component/process in relevant environment to the end user is performed. Basic technology elements are integrated with reasonably realistic supporting elements based on available technologies. Prototyping implementations conform to the target environment and interfaces.

- **TRL 6, Prototype System Verified**—System/process model or prototype demonstration in a relevant environment, Beta prototype (system): Prototyping implementations are partially integrated with existing systems. Engineering feasibility fully demonstrated in actual or high-fidelity system applications in an environment relevant to the end user.

- **TRL 7, Integrated Pilot System Demonstrated**—System/process prototype demonstration in an operational environment, Integrated pilot (system): System prototyping demonstration in operational environment. System is at or near full scale (pilot or engineering scale) of the operational system, with most functions available for demonstration and test. The system, component, or process is integrated with collateral and ancillary systems in a near production quality prototype.

- **TRL 8. System Incorporated in Commercial Design**—Actual system/process completed and qualified through test and demonstration, Pre-commercial demonstration: End of system development. Full-scale system is fully integrated into operational environment with fully operational hardware and software systems. All functionality is tested in simulated and operational scenarios with demonstrated achievement of end-user specifications. Technology is ready to move from development to commercialization.

- **TRL 9, System Proven and Ready for Full Commercial Deployment**—Actual system proven through successful operations in operating environment, and ready for full commercial deployment.

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