A Component-Level Bottom-Up Cost Model for Pumped Storage Hydropower

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Errata

This report, originally published in September 2023, has been revised in March 2024 to improve and correct calculations of technical specifications and costs for water conductor components so that the model is more closely aligned with the 1990 EPRI *Pumped-Storage Planning and Evaluation Guide* cited throughout the report. We now separately calculate or assume maximum flow velocities for the penstock, draft tube, and other tunnels, and these values inform tunnel diameters, discharge rates, and cost. Tunnel diameter now reflects the number of tunnels for all water conductor components. The cost of each water conductor is now dependent on the length of that specific component, and the method of estimating water conductor length has been updated to better match guidance in the EPRI report. Water conductor costs also now incorporate the number of units or number of tunnels where appropriate. When a surface penstock is chosen, its length is estimated in the same manner as an underground penstock.

In addition, we have revised the default indirect cost factors to better match industry expectations. Along with the changes to water conductor costs, these changes affect the quantitative model output throughout the report, so tables and figures are updated to align with the updated calculations. The updated model validation section now also discusses agreement of direct and indirect costs separately, as direct cost estimates closely agree to our comparison case, where NREL estimated indirect costs are much higher by assumption. The change to the validation results is reflected in the conclusions and executive summary.

There have also been some minor changes for clarity in Section 4.2, and the term “soft cost” is largely replaced by “indirect cost” throughout the report to reflect the material nature of many indirect costs such as EPC costs. The PSH schematic has also been modified to more accurately reflect the distinction between upper low- and high-pressure tunnels.

Acknowledgments

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List of Acronyms

AACE	Association for the Advancement of Cost Engineering
cfs	cubic feet per second
DOE	U.S. Department of Energy
EPC	engineering-procurement-construction
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GW, GWh	gigawatt, gigawatt-hour
kW, kWh	kilowatt, kilowatt-hour
MW, MWh	megawatt, megawatt-hour
NREL	National Renewable Energy Laboratory
PSH	pumped storage hydropower
USD	U.S. dollars

Executive Summary

Pumped storage hydropower (PSH) can meet electricity system needs for energy, capacity, and flexibility, and it can play a key role in integrating high shares of variable renewable generation such as wind and solar. While ongoing license and preliminary permit applications in the United States suggest renewed interest in PSH deployment, there remains high uncertainty in project capital costs due to limited recent deployment and the proprietary nature of many cost estimates. This report documents a component-level, bottom-up cost model for PSH that constitutes the most detailed publicly available tool for screening-level PSH cost estimation. It uses existing literature and original data collection to inform a set of site-level input assumptions that determine the technical characteristics and component costs for a new PSH system, with the default setup being a closed-loop configuration.

The cost model is validated against public data for the proposed Eagle Mountain PSH plant in California. Modeled costs are 26% higher than in the Eagle Mountain Federal Energy Regulatory Commission application, which is within the −50% to +100% uncertainty range of a screening-level cost estimate. Higher costs in the NREL model reflect conservative choices for indirect costs, as the direct construction cost is 15% lower than in the Eagle Mountain application. We demonstrate how the cost model can be used for a parametric sensitivity analysis that shows how total costs are more sensitive to parameters like head and storage duration but less sensitive to parameters like geology type or penstock type. Overall, the cost model is the most detailed PSH cost model available to the public. It is a versatile tool for exploring and estimating PSH costs for hypothetical, proposed, or existing PSH sites, and it can be used to provide insight into overall PSH cost/benefit trade-offs.

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1 Introduction

As wind and solar photovoltaic technologies are increasingly deployed to satisfy electricity demand, energy storage solutions play a critical role to shift the time when variable generation from these technologies can be used. Storage technologies can also provide firm capacity and ancillary services to help maintain grid reliability and stability. A variety of energy storage technologies are being considered for these purposes, but to date, 93% of deployed energy storage capacity in the United States and 94% in the world consists of pumped storage hydropower (PSH) (Uría-Martínez, Johnson, and Shan 2021; Rogner and Troja 2018). PSH is a proven technology for providing energy, capacity, and ancillary services. It was deployed in the United States largely in the 1960s–1980s to shift energy produced by nuclear generating facilities (Johnson, Kao, and Uría-Martínez 2022). However, development has been limited in the United States in recent decades, as high capital costs and long development timelines make it difficult for PSH to compete with other storage technologies like utility-scale lithium-ion batteries. This could change over the long term, however, as long-duration energy storage solutions could become increasingly important. PSH has several advantages such as long asset lifetime and the ability to store large energy quantities at low marginal cost of energy.

Interest in new PSH deployment has resurged in recent years, owing largely to the accelerated deployment of variable generation and the corresponding interest in longer-duration storage solutions. Several projects are in the Federal Energy Regulatory Commission (FERC) licensing and permitting process: As of March 2023, there were 46 gigawatts (GW) in active preliminary permits and another 42 GW with pending preliminary permits (FERC 2023). The increased attention on PSH necessitates a clear understanding of the trade-offs associated with the technology, and one critical downside has been the relatively high upfront project capital cost. Unfortunately, limited recent deployment and a host of site-specific factors create much uncertainty for new PSH project costs, particularly for those in the public domain without access to the proprietary site and cost data necessary to evaluate project potential. The lack of publicly available cost data and cost modeling tools for PSH makes it difficult to understand the competitiveness of specific projects and the systemwide potential and role of PSH in future electric grids.

A publicly available PSH cost model was published in 2019 by Australia National University. (Blakers et al. 2019). This model is useful for understanding relationships between key PSH system characteristics (e.g., dam height, reservoir size) and capital costs but does not include the component-level detail or design choices that are important to estimate site-specific costs. The National Renewable Energy Laboratory (NREL) has thus created a more detailed bottom-up PSH cost model that uses dozens of design choices, system specifications, and industry cost relationships to assess costs with much higher fidelity. This tool, implemented in a publicly available Excel workbook, enables highly customizable PSH cost estimation with itemized direct and indirect (soft) costs. It is built on underlying data and equations that can also be tailored for user needs. It is also set up to automatically adjust cost formulas based on the size class of the PSH system. This report documents the assumptions and methods used to develop the NREL PSH Cost Modeling Tool, including calculations to define plant specifications and component-level costs. It also includes model validation and sample results to demonstrate how the tool may be used.

2 Current Landscape of Pumped Storage Hydropower Systems

PSH is a mature technology that was deployed widely after the Second World War. Current global installed PSH generating capacity is around 160 GW with about 9,000 gigawatt-hours (GWh) of energy storage (Rogner and Troja 2018). The United States has 43 PSH facilities with 22 GW of capacity and 550 GWh of energy, and most other global capacity resides in a small number of countries in Asia (China, Japan, South Korea, and India) and Europe (Italy, Germany, Spain, France, Austria) (Rogner and Troja 2018; Uría-Martínez, Johnson, and Shan 2021; IHA 2022). Globally, there is continued growth of PSH technologies, with more than 50 GW of capacity under construction at the end of 2019 and more than 200 GW at earlier stages of development at that time (Uría-Martínez, Johnson, and Shan 2021). A 2018 International Hydropower Agency report expected an increase in global PSH capacity by 78 GW by 2030, with much of this growth occurring in China (Rogner and Troja 2018). Upgrades to existing PSH plants have added to the U.S. PSH capacity in recent years, but no new facilities larger than 50 megawatts (MW) have been commissioned since Oglethorpe Power's Rocky Mountain pumped storage station was commissioned in 1995. However, there are nearly 100 GW of potential new PSH in the U.S. licensing and permitting process, and this number is growing despite high attrition (Uría-Martínez, Johnson, and Shan 2021; FERC 2023).

There are many possible PSH system configurations, depending largely on economic and site-specific factors. Many design choices relate to the planned unit capacity size, where smaller units might not justify excavation for the powerhouse or penstock. Where most units in service today use less expensive fixed-speed technologies for the pump-turbines and motor-generators, alternative options such as variable-speed and ternary technologies are also being considered due to their enhanced flexibility and ability to supply additional grid balancing and stability services (Rogner and Troja 2018). There are also many options for reservoir construction, from connecting two existing reservoirs, as with the Snowy 2.0 facility in Australia, to building two new reservoirs off a river system for a closed-loop system that will not impact any existing aquatic ecosystem (Snowy Hydro Ltd. 2020; Saulsbury 2020). In the United States, closed-loop systems are favored for their reduced environmental impacts, and more proposals that are furthest along in development, such as Gordon Butte in Montana, are closed-loop systems (Absaroka Energy LLC 2022). Another, Eagle Mountain in California, proposes to use abandoned pit mines as reservoirs to reduce construction costs (CARES 2023). Beyond these basic system configuration choices, there are often other uncertainties involving geology and terrain that affect system design and cost but might not be known before a detailed site-level feasibility investigation. This complexity creates challenges in building a bottom-up cost model and leads to the scope and cost model limitations described in Section 4.4.

3 PSH Components

Figure 1 is a schematic of a PSH system that includes the key components and input assumptions used in the bottom-up cost model described in this report. Each component specified in the figure is a line item in the cost model, with some components labeled with critical dimensions used to determine component costs in the model. Components are not to scale, and proportions and orientation between components are purely representative. Actual system layout will be site-specific and design-dependent.

The upper and lower reservoirs each have a combined dam/spillway component representing the necessary structure to contain water within the upper and lower reservoirs. The dam height is a key input assumption, and reservoirs are characterized by the average maximum depth across the reservoir bottom and the average cross-sectional reservoir area[1] to determine the reservoir water volume.

Water conveyance from the upper and lower reservoirs includes intake/outlet structures at each reservoir. The full water conveyance length is represented here as the low-pressure tunnel, vertical shaft, high-pressure tunnel, penstock tunnel(s), draft tube tunnel(s), and tailrace tunnel. The shape and orientation of these conveyance components will be site-specific, and a user of the cost model can decide how best to allocate conveyance length between them. The schematic shows underground conveyance tunnels, but these could instead be a surface penstock.

The pump-turbine and motor-generator components that convert between water pressure and electrical energy sit between the penstock and draft tube. They are shown as underground in the schematic but could be above ground as well. A surge chamber is also typically included to maintain flow conditions in the pump-turbine and manage pressure extremes during startup and shutdown events.

An access tunnel is shown to enable maintenance of the underground pump-turbine and motor-generator components. The powerplant structure encloses the pump-turbine and motor-generator, which produces power that goes to the switchyard, which provides the interconnection between the step-up transformers at the powerhouse and the long-distance transmission. The transmission lines shown here are assumed to be the new required transmission to interconnect the PSH facility to the existing high-voltage transmission system.

The schematic also shows an access road that would be constructed to access the facility by motor vehicle, a water supply that might be required to fill the new PSH reservoirs, and the land that must be acquired to build the facility.

[1] Reservoir area is called out on the figure but not shown as a measurement because of the 2D figure orientation. The average reservoir area would occur at some depth below the surface and go into the depth dimension not shown in the figure.

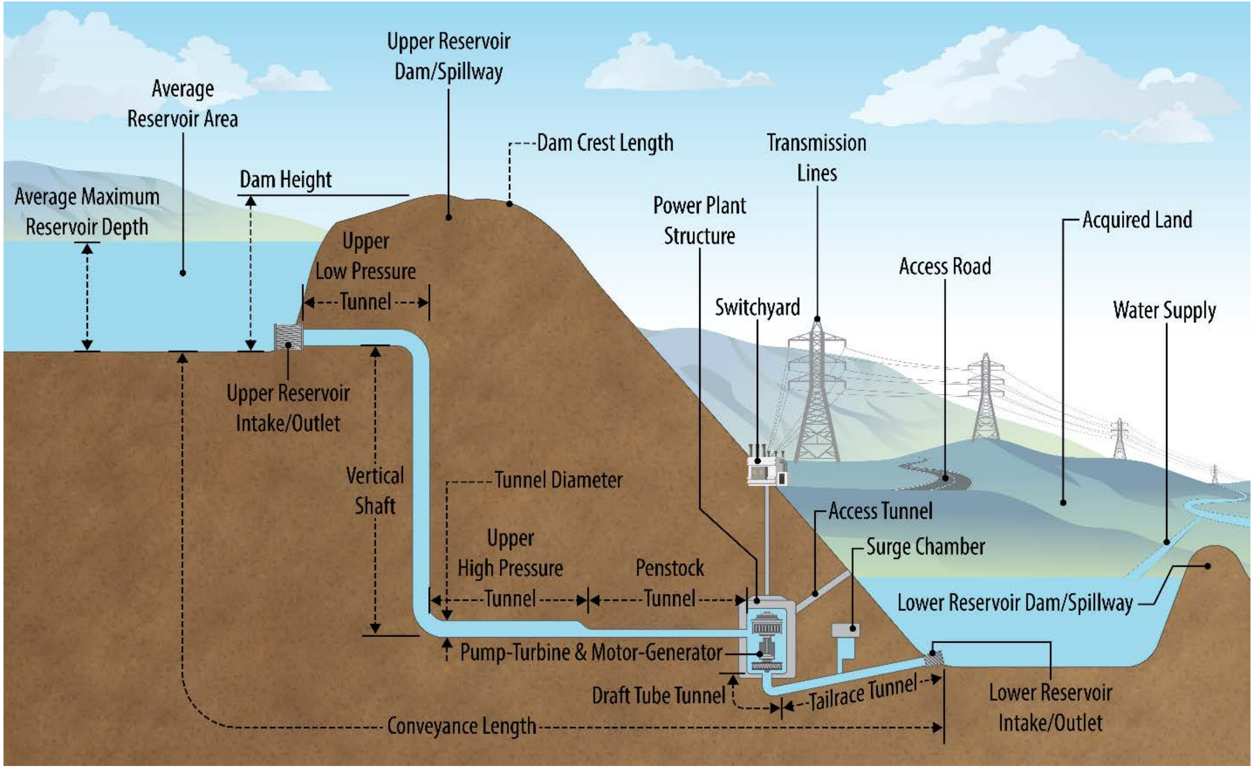

Figure 1. Schematic of a PSH system showing components and input assumptions used in the bottom-up PSH cost model.

Graphic by Besiki Kazaishvili, NREL

4 Capital Cost Modeling Methodology

The bottom-up PSH cost model was developed in consultation with HDR, Inc. and Small Hydro Consulting, LLC. This engagement enabled model validation and thorough review along with access to industry standard data and methods. The two industry partners were selected to provide perspectives across the range of potential PSH project sizing, which enables special provisions in the model for larger versus smaller PSH systems.

Given the interest in closed-loop PSH in the United States, the NREL PSH bottom-up cost model is nominally configured to quantify capital costs for a closed-loop PSH system. From this standard configuration, users can consider alternate reservoir configurations by removing or substituting the relevant cost categories. The model also has a separate cost calculator for units with less than 25 MW capacity, which is the "small PSH" threshold for purposes of this work. It also offers a versatile set of user design choices, such as whether the power station and penstock are underground or on the surface, and whether the reservoir intake/outlets are vertical or horizontal. It also offers several choices related to site-specific geology and construction conditions, such as adverse geological conditions for excavation, poor conditions for tunneling, and challenging terrain for access roads or transmission.

For a given user input set of system configuration sizing assumptions, the PSH system cost is estimated using a bottom-up cost model that calculates different cost components using cost curves derived from existing literature and along with assumptions and data collected from interviews with industry consultants and a stakeholder committee. All cost components are adjusted to account for inflation, regional cost differences, and other market cost adjustments to reflect the installation cost of PSH systems in 2022 U.S. dollars (USD) for a given location in the United States. Thus, all cost data should be entered in the same dollar year to maintain internal consistency, and the first iteration of the cost model as well as this report uses 2022 real USD. The overall cost model approach includes all the key cost categories and components relevant to PSH installation. We assume the total cost estimated for each component includes the cost of materials, equipment rental, and installation labor. The model also includes indirect costs such as sales tax, contingency cost, engineering-procurement-construction (EPC) cost, developer cost, overhead, and profit. As different system specifications could impact structural and electrical equipment requirements, the spreadsheet model is set up flexibly to allow the user to enable or disable applicable individual cost components.

The cost model estimates total direct and indirect construction cost but does not include any policy or financing considerations. Thus, no applicable incentives from the U.S. Inflation Reduction Act or Bipartisan Infrastructure Law[2] are taken into account, nor are any assumptions about how project finance might impact the total installed capital cost. These considerations can be incorporated downstream.

Given the level of uncertainty inherent in PSH design and construction and the parametric, component-level approach taken, this model is considered a screening level (Class 5) to study-feasibility level (Class 4) cost estimation tool, as defined by the Association for the

[2] For more information on how the Inflation Reduction Act can incentivize PSH, see https://www.energy.gov/eere/water/inflation-reduction-act-tax-credit-opportunities-hydropower-and-marine-energy.

Advancement of Cost Engineering (AACE) (AACE 2020). The expected accuracy of such estimates is −50% to +100% for Class 5 and −30% to +50% for Class 4. These uncertainties should be considered both at the component and total cost levels.

4.1 Data Sources

Data underlying the parametric cost functions used in the model come mainly from the Electric Power Research Institute (EPRI) Pumped Storage Planning and Evaluation Guide (EPRI 1990). Interviews with consultants at HDR Inc. and Small Hydro Consulting also contributed to several default assumptions and data. The model is also supplemented by locational construction cost indices data published for different states by a construction cost guide (RSMeans 2022) and land cost data from the Land Values Summary report published by U.S. Department of Agriculture, which incorporates data through 2022 (USDA 2022).

4.2 Plant Specifications and Calculations

This section lists different plant specifications that are calculated using user-specified input data and assumptions. These plant specifications are then used to estimate component and total costs using the calculations described in Section 4.3.

4.2.1 Conveyance Length

The conveyance length is the total length of the water flow path in a PSH facility and is approximated here as the sum of horizontal and vertical distance of all water conductors. Conveyance length is converted from feet to miles for use in cost calculations.

$$Conveyance\ Length\ in\ miles = 0.00019 \times Conveyance\ Length\ in\ feet$$

4.2.2 Reservoir Volume

The volume of a reservoir is calculated in acre feet from the average reservoir area and the average maximum depth of the reservoir.

$$Reservoir\ Volume = Average\ reservoir\ area\ in\ acre \times Average\ maximum\ reservoir\ depth\ in\ feet$$

4.2.3 Dam Volume

The volume of the dam in cubic yards is calculated from a unit dam volume (cubic yards per foot [ft]) and the dam crest length in feet (the length along the span of the dam). The unit dam volume is a function of the dam height as specified in EPRI (1990). These functions assume a zoned embankment dam, and calculations would potentially have to be modified for use with other dam types.

$$Dam\ Volume = Unit\ Dam\ Volume \times c$$

c = crest length

$$Unit\ Dam\ Volume = \{0.09h^2 + 3.9h + 70.7\}$$

h = average dam height

4.2.4 Active Storage

Active storage volume is estimated in acre feet from a user input active storage volume fraction.

$$Active\ Storage = Active\ Storage\ Fraction \times Upper\ Reservoir\ Volume$$

4.2.5 Gross Head

Minimum gross head is calculated in feet from the input nominal (maximum) head and an assumed min/max head ratio that is input by the user. Mean gross head is then the average of the nominal and minimum gross head.

$$Minimum\ Gross\ Head = Nominal\ Head \times Input\,\frac{Hmin}{Hmax}\ ratio$$

$$Mean\ Gross\ Head = \frac{Nominal\ Head + Minimum\ Gross\ Head}{2}$$

4.2.6 Generation Discharge

Mean generation discharge is calculated in cubic feet per second using the ratio of active storage and the specified generation duration along with unit conversion factors (43,560 acre-foot/cubic-foot and 3,600 seconds/hour). Minimum and maximum discharge are calculated from mean discharge because the ratio of min or max discharge to mean discharge is proportional to the square root of the ratio of min or max head to mean head.

$$Mean\ Generation\ Discharge = \frac{Active\ Storage\ in\ acre\ foot \times 43560}{Generation\ Duration\ in\ hours \times 3600}$$

$$Minimum\ Generation\ Discharge = \sqrt{\frac{Minimum\ Gross\ Head}{Mean\ Gross\ Head}} \times Mean\ Generation\ Discharge$$

$$Maximum\ Generation\ Discharge = \sqrt{\frac{Nominal\ Head}{Mean\ Gross\ Head}} \times Mean\ Generation\ Discharge$$

4.2.7 Maximum Tunnel Velocity

Maximum flow velocities are necessary to calculate tunnel diameters and ultimately cost. The maximum velocity of the upper high- and low-pressure tunnels, the vertical shaft, and the tailrace tunnel is a user input but should be based on practical design criteria. The maximum flow velocities of the penstock and draft tube are calculated from equations regressed using data tables in the EPRI report (EPRI 1990). The penstock velocity is taken as a function of the nominal head height, although in practice a larger head might be more accurate to account for potential reservoir level fluctuations. The head borne by the draft tubes is in practice much lower, so the maximum draft tube tunnel velocity is conservatively taken as a function of the nominal head minus the minimum gross head.

$$Maximum\ Penstock\ Velocity = 0.0074 \times Nominal\ Head\ Height\ in\ ft + 16.512$$

$$\begin{aligned}&Maximum\ Draft\ Tube\ Tunnel\ Velocity\\ &\quad = 0.0046 \times (Nominal\ Head\ Height\ in\ ft - Minimum\ Gross\ Head\ in\ ft) + 7.516\end{aligned}$$

4.2.8 Tunnel Diameter

The nominal tunnel diameter to accommodate the necessary water flow for the upper high- and low-pressure tunnels, the vertical shaft, and the tailrace tunnel is first calculated in feet from the maximum discharge and maximum flow velocity, using the formula for the cross-sectional area of the tunnel. If the nominal tunnel diameter is greater than the assumed maximum tunnel diameter, an adjusted tunnel diameter is calculated assuming there are two tunnels. The draft tube tunnel and penstock diameters are calculated using their respective maximum velocities along with the number of draft tubes and penstocks, which is equal to the number of generating units.

$$Tunnel\ Diameter = \sqrt{\frac{4 \times Maximum\ Generation\ Discharge}{Maximum\ Tunnel\ Velocity \times \pi}}$$

$$Adjusted\ Tunnel\ Diameter = \sqrt{\frac{4 \times Maximum\ Generation\ Discharge}{No.of\ Tunnels \times Tunnel\ Velocity \times \pi}}$$

$$Draft\ Tube\ Tunnel\ Diameter = \sqrt{\frac{4 \times Maximum\ Generation\ Discharge}{No.of\ Draft\ Tubes \times Maximum\ Draft\ Tube\ Velocity \times \pi}}$$

$$Penstock\ Diameter = \sqrt{\frac{4 \times Maximum\ Generation\ Discharge}{No.of\ Penstocks \times Maximum\ Penstock\ Velocity \times \pi}}$$

4.2.9 Length-Height Ratio

The conveyance-length-to-head-height ratio is calculated using the mean gross head.

$$Estimated\ \frac{L}{H}\ ratio = \frac{Conveyance\ Length}{Mean\ Gross\ Head}$$

4.2.10 Head Loss

Head loss based on pipe friction is estimated in feet using the empirical head loss equation below (Williams and Hazen 1933). This quantity is calculated for minimum, mean, and maximum generation.

$$Generation\ Headloss = \frac{4.73 \times Generation\ Discharge^{1.85} \times Conveyance\ Length}{Hazel\ Williams\ Constant^{1.85} \times \text{Adjusted Tunnel Diameter}^{4.87}}$$

4.2.11 Net Head

Net head at each generation discharge point (min, mean, max) can then be calculated in feet using head loss values.

$$Net\ Head = Gross\ Head - Head\ Loss$$

4.2.12 Generation Power

Total plant generation capacity in megawatts is calculated based on the conversion efficiency from potential to kinetic energy, with constants in the equation below serving as unit conversion factors. Power output is calculated at minimum, mean, and maximum discharge conditions. Power output at minimum discharge and minimum head would typically be considered the firm capacity available for resource adequacy purposes.

$$Generation\ Power = \frac{Generation\ Discharge \times Net\ Head \times Pump\ Turbine\ Efficiency \times 9.81 \times 10^3}{3.28^4 \times 10^6}$$

4.2.13 Unit Rating

The unit generation capacity is then determined based on the number of units, which is based on a user-specified maximum unit capacity and minimum number of units.

$$Estimated\ Capacity\ of\ Generation\ Unit = \frac{Maximum\ Plant\ Generation\ Capacity}{Number\ of\ Generation\ Units}$$

4.2.14 Pump Discharge

Pump discharge is calculated in cubic feet per second in the same manner as generation discharge, and pump time is a function of this discharge and a pump time factor, which itself is the inverse of the round-trip efficiency of the storage system.

$$Pump\ Discharge = \frac{43560 \times Active\ Storage}{3600 \times Pump\ Time}$$

$$Pump\ Time = Discharge\ Time \times Pump\ Time\ Factor$$

4.2.15 Pump Head Loss

Head loss during pumping is estimated in feet using the same head loss equation as in Section 4.2.9.

$$Pump\ Headloss = \frac{4.73 \times Pump\ Discharge^{1.85} \times Conveyance\ Length}{Hazen\ Williams\ Constant^{1.85} \times Adjusted\ Tunnel\ Diameter^{4.87}}$$

4.2.16 Pump Net Head

Net head that the pump must overcome is calculated in feet by adding gross head to the pump head loss.

$$Net\ Head\ at\ Pump = Mean\ Gross\ Head + Pump\ Head\ Loss$$

4.2.17 Pump Power

Pump power capacity in megawatts is then calculated similar to generation power in Section 4.2.11.

$$Pump\ Power = \frac{Pump\ Discharge \times Net\ Head\ at\ Pump \times Pump\ Turbine\ Efficiency \times 9.81 \times 10^3}{3.28^4 \times 10^6}$$

4.3 Cost Categories and Calculations

The model estimates key PSH plant metrics like discharge rate, head loss, net head, plant capacity, and generation unit capacity with the help of site-specific inputs and technology assumptions under the Inputs and Assumptions section of the model. Overall, the model quantifies each cost component in its intrinsic unit (e.g., feet, kilowatt, miles), and the total cost of each cost component is calculated by multiplying the estimated unit quantity, unit cost, and any applicable multiplication factors for inflation, locational differences, or market effects. Also, all the inputs and unit quantity values are overridable with a user-defined value in the model. Multiplication factors include a locational factor that adjusts for local material and equipment rental costs, an inflation factor that adjusts the dollar year using a consumer price index, and a market adjustment factor that accounts for changes in component-specific markets beyond inflation from the base cost year (e.g., changes to raw material commodity markets and supply chains). Indirect costs are calculated as the product of the total direct construction cost, a specified indirect cost markup factor, and a material-to-equipment factor that specifies the percent of total direct construction costs that might apply to a given indirect cost.

$$Total\ Direct\ Construction\ Cost = \sum_{\text{all components}} (\text{Quantity} \times \text{Unit Cost} \times \text{Locational Factor} \times \text{Inflation Factor} \times \text{Market Adjustment Factor})$$

$$Total\ Indirect\ Cost = \sum_{\text{all components}} (\text{Indirect Cost Markup} \times \text{Material to Equipment Factor (if applicable)} \times \text{Total Direct Construction Cost})$$

$$Total\ Direct\ and\ Indirect\ Cost = Total\ Direct\ Construction\ Cost + Total\ Indirect\ Cost$$

The estimated unit cost of each cost component is either derived from a cost curve or by using data provided by industry stakeholders during interviews. A user can override the estimated quantity and unit cost of any cost component in the model if desired.

Table 1 and Figure 2 demonstrate an example cost curve based on data from the EPRI report (EPRI 1990) for underground power station costs with 80-MW units. The EPRI report includes figures that display smooth parametric curves with no explicitly presented equations or data tables. NREL digitized these curves by extracting a set of points that were tabulated and fit with regressions model to reproduce the EPRI curves and enable subsequent adjustments and cost escalation.

For an underground power station, there are unique tables for unit sizes of 80, 125, 225, and 350 MW in either average or adverse geologic conditions. The applicable table is chosen by taking the "ceiling" of the unit capacity determined in the plant specification calculations (i.e., any unit size between 125 MW and 225 MW will use the 225 MW table). The applicable column in the table is then chosen based on the number of units determined in the plant specification calculations, along with the choice between average and adverse geology. Having selected the appropriate cost curve, the head height is then entered into a regressed parametric cost curve to determine the unit cost. The regression type for each set of component cost curves is chosen to maximize the correlation coefficient of the fit, and in this example a power curve is used to produce a correlation coefficient (R-squared) value of roughly 98%. In some cases, a single regression equation can be used for component costs; in other cases, multiple regression equations are used depending on component size or other characteristics. For components with multiple regression equations, regression coefficients are shown below as lowercase letters a, b, c, etc., and the values for these coefficients can be found in the Excel spreadsheet.

A similar procedure is used for other components to first select the appropriate curve based on the most conservative cost estimate then follow the parametric regression to identify the unit cost. For example, the cost curve for concrete-lined water conductors is chosen based on the tunnel distance and tunneling condition; then, the inside diameter is entered into the regressed equation to identify unit cost.

Table 1. Example Table of Values From an EPRI Cost Curve for Underground Power Station Costs as a Function of Average Head in Both Average and Adverse Geological Conditions, Assuming Each Generating Unit Is 80 MW or Smaller (EPRI 1990)

	Cost per Kilowatt ($/kW) Average Conditions				Cost per Kilowatt ($/kW) Adverse Conditions			
Average Head (ft)	**2 Units**	**3 Units**	**4 Units**	**6 Units**	**2 Units**	**3 Units**	**4 Units**	**6 Units**
350	135	116	104	92	174	145	132	118
500	113	96	86	78	150	124	113.5	102
1,000	91	76	68	60	116	98	86	76.5
1,500	81	69	59.5	54	103	88	77	68.5
2,000	78	63	58	50	98	82	72	62.5
2,250	77	62	57	49	97	81	71	62

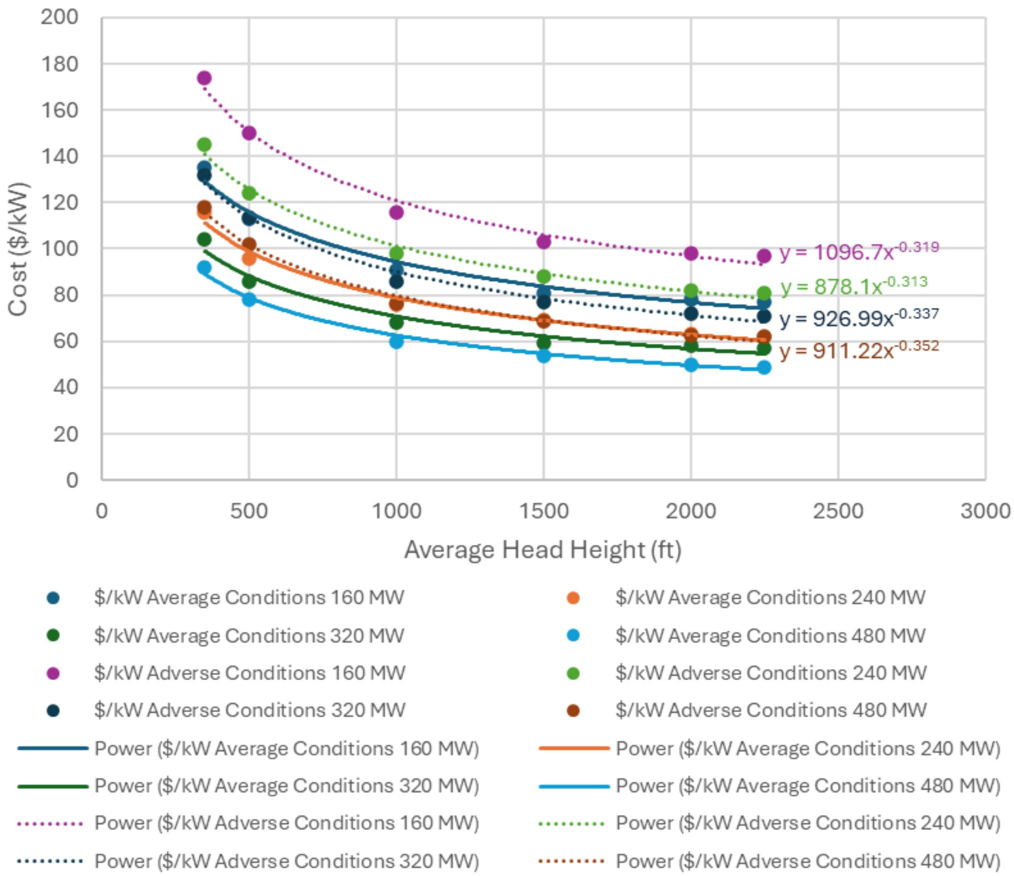

Figure 2. Plot of underground power station cost versus average head height assuming 80-MW units, showing points from the EPRI report along with power regression lines used in the cost model. Example equations on the right are used for adverse conditions.

4.3.1 Land and Land Rights

The total cost of acquiring parcels of land for PSH project development and installation is estimated using the average dollar-per-acre value published for different locations and land types by the U.S. Department of Agriculture (USDA 2022). For this analysis we took the average dollar-per-acre value of irrigated cropland, non-irrigated cropland, farmland, and pastureland. For locations not included in the list of states in the model, a U.S. average dollar-per-acre estimated land value is used.

$$Total\ Cost\ of\ Land\ \&\ Land\ Rights$$
$$= Total\ acreage\ \times\ average \frac{\$}{acre} of\ land\ \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

4.3.2 Power Plant Structure

The structural cost of the power plant includes the cost to build the foundation, substructures, and superstructures for the unit bays, service bays, and erection bays. Different sets of cost curves were derived using the EPRI (1990) report as described in Section 4.3 to estimate unit structural cost based on the average head height, type of power station (underground or surface), and size of generating units. Also, the estimated cost varies between adverse and average site geological conditions.

$$Total\ Cost\ of\ Underground\ Powerplant\ Structure = Maximum\ plant\ capacity\ \times a(H)^b \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

H = head height in feet; a and b vary by geology type, power station type, and generator unit rating

$$Total\ Cost\ of\ Surface\ Powerplant\ Structure = Maximum\ plant\ capacity\ \times \{a(H)^2 \pm bH + c\} \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

H = head height in feet; a, b, and c are regression coefficients unique to this set of equations that vary by geology type, power station type, and generator unit rating

4.3.3 Reservoirs, Dams, and Waterways

The cost to build the embankment dam, reservoir, and spillway is estimated using the unit cost of the embankment dam fill volume. Equations are developed from the EPRI (1990) data extraction and regression procedure described in Section 4.3. Here, we assume a zoned embankment dam, but future work could expand the model to apply to other dam types. The total dam volume in cubic yards is estimated separately for the upper and lower reservoir dams using the average dam height and the dam crest length. The unit cost per cubic yard of dam volume is then a function of the total dam volume, and this unit cost multiplied by the total volume and other factors produces the total reservoir dam and spillway cost. This estimate includes foundation and core trench excavation, fill materials for core, filters, random fill and rockfill, and foundation grouting. The cost equation assumes a smaller spillway, which is typical in PSH projects. For larger spillways, a 20% premium could be added to the base unit cost to build reservoir, dams, and waterways.

$$Total\ Cost\ of\ Reservoir, Dam, and\ Spillway = Total\ Dam\ Volume\ \times\ Unit\ Cost\ \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

$$Unit\ Cost = \frac{7.75v}{v - 0.05}$$

v = dam volume in cubic yards

$$v = Total\ Dam\ Volume/10^6$$

$$Total\ Dam\ Volume = \{0.09H^2 + 3.9H + 70.7\} \times c$$

H = dam height in feet, c = crest length in feet

The total cost of an intake/outlet is calculated using the water conductor diameter and number of tunnels. Cost curves are provided for both horizontal and vertical configurations. The cost for horizontal intake/outlets includes the concrete structure, excavation, backfill, trash racks, emergency gates with hoists, and bulkhead gate for servicing emergency gates. The cost for vertical intake/outlets includes only the concrete structure.

$$Total\ Cost\ of\ Reservoir\ Intake = \{a(d)^2 - bd + c\} \times n \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

d = conductor diameter; n = number of tunnels; a, b, and c are regression coefficients unique to this set of equations that vary by intake/outlet type.

Based on EPRI (1990), surge chambers are estimated to be 30%–40% of the total cost of water conductors. In the model surge chambers are only enabled for estimated L/H ratio values greater than or equal to 7.

$$Total\ Cost\ of\ Surge\ Chamber = x\% \times Total\ Cost\ of\ Concrete\ Lined\ Water\ Conductor$$

4.3.4 Water Conductors

The cost per linear foot of each water conductor component is estimated using the tunnel diameter and length as well as the assumed tunneling conditions. The length used for each component cost is the total length of tunnel required and incorporates the number of tunnels or penstocks, as applicable. Unit cost equations are developed from the EPRI (1990) data extraction and regression procedure described in Section 4.3. Based on the geotechnical characterization of the site, a user can select between average and poor tunneling conditions. Tunnel costs are assumed to include excavation, concrete lining and reinforcing steel, rock support, and lining.

The cost related to vertical shaft excavation, concrete lining with reinforcing steel, shaft support, and consolidation grouting is included under the total cost of vertical shafts. The unit cost of vertical shafts per linear foot is a function of adjusted tunnel diameter in the model and was also derived using the procedure described in Section 4.3. The vertical shaft length is estimated as the mean gross head height. Adjusted tunnel diameter is calculated from the flow conditions at maximum water discharge, where the maximum tunnel velocity is assumed to be 20 feet/second by default, and the maximum tunnel diameter is assumed to be 35 feet by default.

$$\begin{aligned} &Total\ Cost\ of\ Vertical\ Shafts \\ &\quad = (186.57d + 27.14) \times H \times Number\ of\ Tunnels \times \text{Inflation Factor} \times \text{Market Adjustment Factor} \end{aligned}$$

d = adjusted tunnel diameter in feet; *H* = Mean gross head height in feet.

The cost of concrete-encased underground penstock tunnels lined with steel is a function of penstock diameter and only applies to an underground penstock. This equation is developed as described in Section 4.3. Penstock length is estimated to be 25% of the mean gross head as suggested by the EPRI report (EPRI 1990), and the number of penstocks is assumed equal to the number of generating units. This cost is assumed to include tunnel excavation, steel, and concrete lining.

The draft tube tunnel cost is also enabled only for the underground power stations and uses another regressed equation as described in Section 4.3. The draft tube tunnel length is assumed to be 200 feet based on guidance from (EPRI 1990), and the number of draft tubes is also equal to the number of generating units.

$$\begin{aligned} &Total\ Cost\ of\ Penstock\ Tunnels = \\ &\quad = \{a(d)^2 \pm bd + c\} \times Individual\ Penstock\ Tunnel\ Length \times Number\ of\ Units \\ &\quad \times \text{Inflation Factor} \times \text{Market Adjustment Factor} \end{aligned}$$

$$Individual\ Penstock\ Tunnel\ Length = 0.25 \times Mean\ Gross\ Head$$

d = tunnel diameter; *a*, *b*, and *c* are regression coefficients unique to this set of equations that vary by tunneling condition and estimated tunnel length in miles.

$$Total\ Cost\ of\ Draft\ Tube\ Tunnels = a(d)^b \times 200 \times Number\ of\ Units \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

200 feet = individual draft tube tunnel length as per EPRI estimate; *a* and *b* are regression coefficients unique to this set of equations that vary by difference between nominal head height, and minimum gross head height, tunnel diameter;

The cost of upper low- and high-pressure tunnels and tailrace tunnels is a function of the adjusted tunnel diameter with a similar functional form as an underground penstock. The length of each of these components is assumed equal to half the remaining conveyance length after subtracting the mean gross head, penstock length, and draft tube tunnel length. The total length of tunnel material must also account for the number of tunnels.

$$\begin{aligned} &Total\ Cost\ of\ Upper\ Low\ and\ High\ Pressure\ Tunnels\ or\ Total\ Cost\ of\ Tailrace\ Tunnels \\ &\quad = \{a(d)^2 \pm bd + c\} \times Individual\ LHP\ Tunnel\ Length \times Number\ of\ Tunnels \\ &\quad \times \text{Inflation Factor} \times \text{Market Adjustment Factor} \end{aligned}$$

$$\begin{aligned} &Individual\ LHP\ Tunnel\ Length\ or\ Individual\ Tailrace\ Tunnel\ Length \\ &\quad = 0.5(Conveyance\ length - Mean\ Gross\ Head - Individual\ Penstock\ Length \\ &\quad - Individual\ Draft\ Tube\ Tunnel\ Length) \end{aligned}$$

d = tunnel diameter; *a*, *b*, and *c* are regression coefficients unique to this set of equations that vary by tunneling condition and estimated tunnel length in miles; 0.5 = length fraction assuming tailrace and upper low- and high-pressure tunnels each make up 50% of the remaining conveyance length after subtracting other components.

If a surface steel penstock is chosen, its cost includes the supply and erection of the penstock, couplings and girders, concrete supports and anchors, earthwork, and connections to individual generating units. The surface penstock is typically used for smaller PSH systems of capacity less than 100 MW. There is assumed to be one penstock per generating unit.

$$\begin{aligned} &Total\ Cost\ of\ Surface\ Penstock\ Tunnels \\ &\quad = na(d)^b \times Individual\ Penstock\ Tunnel\ Length \times Number\ of\ Units \\ &\quad \times \text{Inflation Factor} \times \text{Market Adjustment Factor} \end{aligned}$$

n = number of generating units; *d* = penstock diameter; *a* and *b* are regression coefficients unique to this set of equations that vary by maximum gross head height and penstock diameter.

4.3.5 Power Station Equipment

As described above, power station equipment costs are determined with the method described in Section 4.3. Depending on the type of power station (underground or surface) the total cost of power station equipment is estimated using head height and power plant capacity to reflect economies of scale. The cost is assumed to include the pumps and turbines; generators and motors; main transformers; main leads; breakers and switches; controls and communication equipment; current-limiting reactors; starting equipment; heating, ventilating, and air conditioning; bridge crane; cooling water supply and drainage; compressed air system; emergency diesel generator; and other balance of plant items. The pump is assumed to be fixed-speed, and future work could incorporate cost adjustments for other pump types.

$$\begin{aligned} &Total\ Cost\ of\ Large\ PSH\ Powerstation\ Equipment \\ &\quad = \{a(H)^2 - bH + c\} \times Plant\ Capacity\ in\ kW \times \text{Inflation Factor} \times \text{Market Adjustment Factor} \end{aligned}$$

h = mean gross head height; *a*, *b*, and *c* are regression coefficients unique to this set of equations that vary by power station type, generator unit rating and number of units.

For smaller PSH systems (<100 MW) we itemize pump/motor and turbine/generator costs. The total cost of pumps/motors for small PSH systems is only a function of mean pump discharge rate calculated based on total active storage volume and pump time. The cost of generator and turbines is a function of plant capacity and varies by head height.

$$Total\ Cost\ of\ Small\ PSH\ Pump/Motors = 0.7799q^{0.7442} \times 1000 \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

q = mean pump discharge in gal/min.

$$Total\ Cost\ of\ Small\ PSH\ Turbines/Generators = am^b \times Plant\ Capacity\ in\ kW \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

m = maximum plant capacity; a and b are regression coefficients unique to this set of equations that vary by head height.

4.3.6 Roads, Railroads, Bridges, and Access

The cost of access roads is estimated by terrain type for either new construction or a rebuild/upgrade. The cost assumes a 24-ft-wide, two-lane unpaved road for new construction and a single-lane unpaved road for rebuilding/upgrading existing roads. Road costs also depend on terrain type classified as flat, mild, or steep grade.[3]

$$Total\ Cost\ of\ Access\ Road = number\ of\ miles \times \$\ per\ mile\ by\ terrain\ type\ and\ road\ condition \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

If any highway realignment is suspected, an additional cost can be enabled in the model that adds x% to the total cost of access roads, with 25% being the default assumption.

$$Total\ Cost\ of\ Highway\ Realignment = x\% \times \% \times Total\ Cost\ of\ Access\ Road$$

Using the access tunnel length in feet, the total cost of the access tunnel is estimated for a 26-ft by 26-ft tunnel section including excavation, concrete pavement, rock bolts, and shotcrete.

$$Total\ Cost\ of\ Access\ Tunnel = 2489.4l^{0.118} \times l \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

l = access tunnel length.

4.3.7 Switchyard

The total cost of the switchyard is a function (derived as in Section 4.3) of the number of generating units and the switchyard voltage. The model assumes a conventional outdoor air-insulated substation.

$$Total\ Cost\ of\ Switchyard = \{a(n)^2 - bn + c\} \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

n = number of generating units; a, b, and c are regression coefficients unique to this set of equations that vary by number of generator units and substation voltage.

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[3] The EPRI 1990 report does not specify a specific percent grade for each of these classifications; thus, this choice is up to user discretion.

4.3.8 Transmission Line

Based on the transmission voltage and plant capacity, the transmission line cost per mile is first estimated using a cost curve derived from EPRI (1990) as demonstrated in Section 4.3. Newer estimates are available, but we maintained the use of the EPRI report for overall consistency with other cost curves. The estimate unit cost is then adjusted for terrain type and transmission circuit type (Andrade and Baldick 2017). Then, the total cost can be calculated using the maximum plant generating capacity and the transmission distance to the interconnection with the high-voltage transmission system. The transmission lines are assumed to be built using steel structures.

$$Total\ Cost\ of\ Transimssion\ Line = \{a(m)^2 - bm + c\} \times r \times t_t \times t_c \times \text{Inflation Factor} \times \text{Market Adjustment Factor}$$

m = maximum plant capacity; r = transmission distance in miles, t_t = transmision terrain type multiplier; t_c = transmision circuit type multiplier; a, b, and c are regression coefficients unique to this set of equations that vary by number of generator units and substation voltage.

4.3.9 Other Costs

The model also includes the option to include a water supply cost based on a user-specified dollar-per-kilowatt cost.

$$\begin{aligned} &Total\ Cost\ of\ Water\ Supply \\ &\qquad = Input\ \$\ per\ kW\ for\ water\ supply \times plant\ capacity\ in\ kW \\ &\qquad \times \text{Inflation Factor} \times \text{Market Adjustment Factor} \end{aligned}$$

4.3.10 Indirect Costs

All indirect costs are a function of a user input percentage value and applicable plant cost. We use an assumed material-to-equipment percentage factor for some of the indirect costs, assuming only the material portion of the total cost is applicable for the indirect cost estimation. While default values are included in the model, assumed indirect cost percentages are highly uncertain and should be subject to scrutiny by the user.

$$Sales\ Tax\ \$ = Sales\ Tax\ \% \times Total\ Direct\ Construction\ Cost \times Material\ to\ Equipment\ Factor$$

$$Contingency\ \$ = Contingency\ \% \times Total\ Direct\ Construction\ Cost$$

$$Mobilization/Demobilization\ \$ = Mobilization/Demobilization\ \% \times Total\ Direct\ Construction\ Cost$$

$$EPC\ Cost\ \$ = EPC\ \% \times Total\ Direct\ Construction\ Cost \times Material\ to\ Equipment\ Factor$$

$$Developer\ Cost\ \$ = Developer\ \% \times Total\ Direct\ Construction\ Cost$$

$$Overhead\ \&\ Profit\ \$ = Overhead\ \&\ Profit\ \% \times Total\ Direct\ Construction\ Cost \times Material\ to\ Equipment\ Factor$$

4.4 Limitations and Areas for Improvement

The representative bottom-up cost model has several limitations that could be addressed with follow-on research and stakeholder engagement.

1. The modeling results may be highly sensitive to atypical PSH project specifications. For instance, the estimated cost of components for a small hydropower storage system of less than 100 MW capacity is highly sensitive to certain input specifications compared to the

cost of larger PSH systems typically in use today (several hundred megawatts to gigawatt-scale) (Uría-Martínez, Johnson, and Shan 2021; Rogner and Troja 2018).

2. The cost model currently assumes certain site configuration choices, such as a fixed-speed pump and embankment dam. Thus, it could be expanded to consider alternative site configurations, specifically those that use different types of dams or different pump-turbine designs such as variable-speed or ternary pumps.
3. While the component-level detail is considered here to constitute a bottom-up approach, there are several cost components that could be further disaggregated, particularly power station equipment and reservoir/dam/waterway costs, which make up relatively large shares of total cost. There could also be a more detailed breakdown of material, equipment rental, and labor costs by component and cost category.
4. The model uses cost data and relationships from a relatively old (1990) technical report, adjusted to a current year using inflation, location, and market adjustment factors. We use the consumer price index along with stakeholder-provided market adjustment factors to reflect the combined effects of inflation and industry-specific changes to hydropower costs. However, these adjustments could have limited accuracy depending on site and market specifics, and the user might want to use alternative adjustment factors.
5. Since the project specifications could also vary drastically by site location and planned capacity, there remains a high level of uncertainty in reported costs. Improvements would be aimed at improving accuracy in cost estimates to potentially go beyond the Class 4 uncertainty range of −30% to +50%.
6. Costs assessed by this model are static in time, so another valuable extension would be to develop component-level and overall cost projections, based on scenarios for future technology development, learning, or other cost factors. Doing so would advance upon similar work last performed for the U.S. Department of Energy's (DOE's) *Hydropower Vision* report (DOE 2016) and create a richer PSH cost dataset for use in the NREL Annual Technology Baseline (NREL 2022) and other data and modeling products.
7. All cost data should be entered in the same dollar year value. The current dollar values in the model are adjusted to 2022 real USD. Market adjustment factors for components and component categories should also be kept current to maintain validity of the model.
8. The cost model is validated against Eagle Mountain Creek cost data, but Eagle Mountain costs are estimates themselves, and developed project costs could be much higher, particularly in the context of market factors that are continually changing. Additional validation from other project cost estimates and developed project costs could be used to improve upon this initial cost model version and make NREL cost model estimates more robust in future versions.
9. While the cost model spreadsheet provides a rich and detailed platform for estimating PSH costs, usability could be improved by converting the cost model into a web-based interactive tool, such as NREL's Detailed Cost Analysis Model (DCAM) capability.[4] This tool could be made available to the public for free and would allow users to change

[4] https://dcam.openei.org/

input values, save new models to their personal account, and conduct more in-depth sensitivity analyses using Monte Carlo engines. These new models could perhaps even be integrated with other platforms such as the PSH resource assessment web application at https://www.nrel.gov/gis/psh-supply-curves.html.

5 Results and Discussion

This section presents cost model results for example system configurations and the sensitivity of total costs to various parameters. The total estimated cost of the system using the bottom-up analysis is also validated by comparing it with the estimated cost from the Eagle Mountain Pumped Storage Project license application (ECEC 2009b; 2009a).[5]

5.1 Representative Input Specifications

Table 2 shows the PSH system design assumptions for a representative large-scale PSH site modeled after the proposed project in California (Eagle Mountain) and a representative small PSH system selected from NREL's PSH resource assessment tool.[6] As these parameters vary depending on the needs of specific projects, we provide sensitivity analysis results in Section 5.3. Table 3 also demonstrates the relationship between head, discharge, and power output, which is important when identifying firm capacity for resource adequacy purposes and for understanding power production potential throughout a discharge cycle.

Table 2. Representative Input Assumptions: Large PSH Parameters Are Aligned With the Proposed Eagle Mountain Project, and Small PSH Parameters Are Representative of a Site in the NREL PSH Resource Assessment

Category	Modeled Value (Large PSH)	Modeled Value (Small PSH)
Nominal Head (ft)	1,560	1,004
Maximum Upper Reservoir Depth (ft)	101[7]	40
Upper Reservoir Area (acres)	191	40
Maximum Lower Reservoir Depth (ft)	120	30
Lower Reservoir Area (acres)	163	35
Conveyance Length (ft)	14,394	11,080
Maximum Upper Dam Height (ft)	120; 60[8]	200
Upper Dam Crest Length (ft)	1,300; 1,100[9]	30
Maximum Lower Dam Height (ft)	0[10]	170
Lower Dam Crest Length (ft)	0	30

[5] More detail and license application documents can be found at https://www.waterboards.ca.gov/waterrights/water_issues/programs/water_quality_cert/eaglemtn_ferc13123.html.
[6] The PSH resource assessment tool and supporting documentation can be found at https://www.nrel.gov/gis/psh-supply-curves.html.
[7] Reservoir depth was adjusted to match the max plant capacity of roughly 1,300 MW.
[8] The upper reservoir requires two embankments. The south embankment (URD-1) will have a height of 120 feet and a crest length of 1,300 feet.
[9] The upper reservoir requires two embankments. The west embankment (URD-2) will have a height of 60 ft and a crest length of 1,100 feet.
[10] The entire active lower reservoir volume can be contained within the pit of the Eagle Mountain mine; therefore, construction of dams will not be necessary to create the lower reservoir.

Category	Modeled Value (Large PSH)	Modeled Value (Small PSH)
Generation Time (hours)[11]	18.5	10
Maximum Plant Capacity (MW)[12]	1,283	116
Mean Plant Capacity (MW)	1,005	91
Minimum (Firm) Plant Capacity (MW)	751	68
Estimated Active Storage (acre-feet)	16,397	1,360
Energy Storage (MWh)	18,593	909
Pump-Turbine Efficiency (%)	88%	88%
Maximum Penstock Velocity (feet per second)	28	24
Maximum Draft Tube Velocity (feet per second)	10	8
Tunneling Condition	Average	NA
Access Tunnel Length (miles)	1.25	NA
Upper Reservoir Intake/Outlet	Vertical	Vertical
Lower Reservoir Intake/Outlet	Horizontal	Horizontal
Power Station Geology	Adverse	Average
Power Station Type	Underground	Surface
Penstock type	Underground	Surface
Transmission Terrain Type	Mountain	Mountain
Transmission Circuit Type	Double	Double
Transmission Distance (miles)	13.5	30
Transmission Voltage (kilovolt [kV])	500	500
Switchyard Voltage (kV)	500	300

[11] The generation time is the total stored energy (MWh) divided by the mean plant capacity (MW). In practice, power will fluctuate between min and max power based on head height throughout the discharge period.
[12] The cost model is designed for total capacity up to 2,100 MW with a recommended max generator unit size of 350 MW. Capacities exceeding 2,100 MW will be extrapolated beyond the equations.

Table 3. Summary of the Relationship Between Head, Discharge, and Generator Power Output at Minimum, Mean, and Maximum Head

Category	Value at Minimum	Value at Mean	Value at Maximum
Large PSH			
Net Head (ft)	1,035	1,258	1,481
Discharge (cubic feet per second [cfs])	9,733	10,725	11,633
Power Output (MW)	751	1,005	1,283
Small PSH			
Net Head (ft)	609	741	874
Discharge (cfs)	1,493	1,646	1,785
Power Output (MW)	68	91	116

Optional costs related to water supply, mobilization and demobilization of labor, and highway realignment are also included in this cost estimate. Also, the following indirect cost assumptions were used to be consistent with prior cost modeling work and discussions with industry stakeholders: mobilization and demobilization 5%, sales tax 6%, contingency 33%, EPC cost 25%, developer cost 3%, overhead and profit 7% for both the large and small PSH system (Ramasamy et al. 2022).

5.2 Cost Model Results and Validation

Table 4 shows the cost breakdown and total installed cost for the representative 1,283-MW large PSH plant and the 116-MW small PSH plant. These raw results are shown as produced by the model, and the number of digits shown is not representative of the true accuracy of the estimate. These values are strictly representative to demonstrate the form of cost model outputs. The values and their relative magnitudes may not be representative of typical systems, particularly those with site characteristics that deviate significantly from those used in this example.

Table 4. Cost Model Output Results for a Large PSH System Aligned With the Proposed Eagle Mountain Project and a Small PSH System From the NREL PSH Resource Assessment

The dollars per kilowatt ($/kW) and dollars per kilowatt-hour ($/kWh) are the total cost divided by the maximum power and energy capacity, respectively

Cost Categories	Large PSH Modeled (2022 USD)	Small PSH Modeled (2022 USD)
Land and Land Rights	$16,264,166	$5,954,843
Powerplant Structure	$156,806,248	$21,802,721
Reservoirs, Dams, and Waterways	$214,493,314	$26,354,164
Water Conductors	$257,753,584	$36,201,749
Power Station Equipment	$541,852,349	$71,507,281
Roads, Railroads, and Bridges	$42,643,064	$2,052,261
Switchyard	$40,250,057	$2,478,511
Transmission Lines	$48,578,635	$110,780,450
Contingency Costs	$435,151,668	$91,453,554
Other Indirect Costs	$606,575,052	$127,480,712
Total Cost $	$2,360,368,138	$496,066,247
$/kW (Max. Power Capacity)	$1,839	$4,268
$/kWh (Max. Energy Capacity)	$99	$427

Figure 3 shows the cost breakdown as the share of total installed cost. In this example, contingency and other indirect costs are the biggest individual cost share due largely to the assumed contingency cost of 33% and the EPC contractor indirect costs of 25% of the direct construction cost. The biggest underlying drivers of total cost for large PSH are the power station equipment cost, water conductor cost, and reservoirs, dams, and waterways construction cost. For small PSH systems, the transmission cost is a much more substantive cost component in relative terms. These results illustrate the possible outcomes of this PSH cost model but might not be representative of typical PSH systems. In practice, each cost component has unique drivers of uncertainty that can influence their ultimate contribution to total project costs.

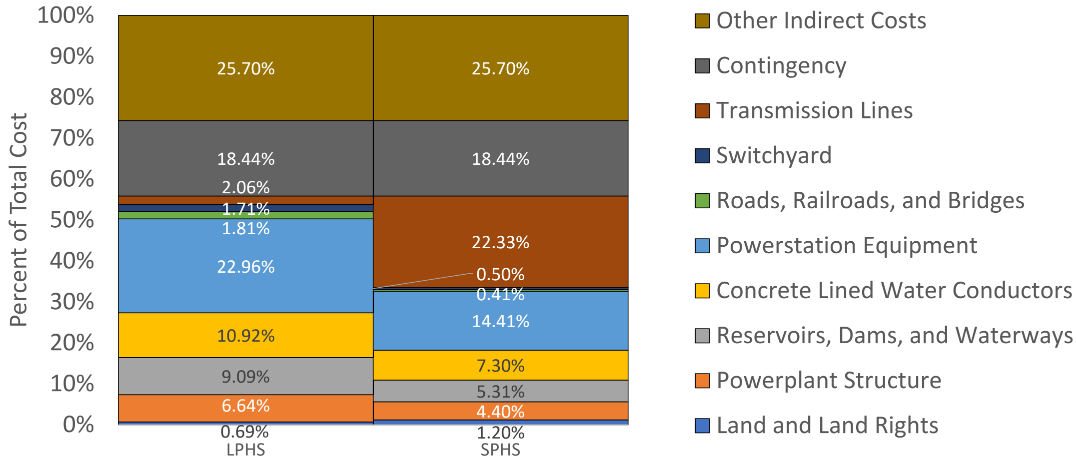

Figure 3. Cost breakdown as a share of total cost for the representative large and small PSH plants

We validated the results by comparing the modeled cost of the proposed Eagle Mountain project to the cost included in the proposed Eagle Mountain project FERC license application (Table 5) (ECEC 2009b; 2009a). Discrepancies for certain cost categories could be the result of site-level details not accommodated by the cost model or inconsistencies in how individual cost components are categorized. For instance, the Eagle Mountain project in the FERC application has a cost category "Waterwheels, Turbines, & Generators" and additional subcategories for power plant and electrical equipment, whereas the NREL cost model has two cost categories for concrete-lined water conductors and pumps, turbines, and generators. Similarly, indirect cost components like contingency, overhead, installer profit, legal fees, interest during construction are not defined and itemized consistently between the cost model and the Eagle Mountain FERC application. Total direct construction costs agree within 15%, but higher assumed indirect costs lead to the total installed cost to be 26% higher with the NREL model than the estimated cost in the FERC application. Because this model is intended to be conservative and considered to be no more accurate than an AACE Class 4 estimate (−30% to +50%) and potentially closer to AACE Class 5 (−50% to +100%), agreement within 26% is considered satisfactory (AACE 2020).

Table 5. Component-Level PSH Cost Comparison Between Eagle Mountain FERC License Application and the NREL Bottom-Up Cost Model

Cost categories are aligned where possible and listed on separate rows where necessary

Eagle Mountain FERC Application (2022 USD)		Eagle Mountain Modeled Cost (2022 USD)	
Direct Construction Cost		**Direct Construction Cost**	
Land and Water Rights	$44,121,370	Land and Land Rights	$16,264,166
Structures and Improvements	$142,041,656	Powerplant Structure	$156,806,248
Reservoirs, Dams, and Waterways	$520,541,568	Reservoirs, Dams, and Waterways	$214,493,314
		Concrete Lined Water Conductors	$257,753,584
		Power Station Equipment	$541,852,349
Waterwheels, Turbines, and Generators	$349,000,246		
Accessory Electrical Equipment	$276,734,658		
Miscellaneous Powerplant Equipment	$62,573,451		
Roads, Rails, and Bridges	$90,786,244	Roads, Railroads, and Bridges	$42,643,064
Substation and Switch Station	$22,880,002	Switchyard	$40,250,057
Transmission Line	$45,124,128	Transmission Lines	$48,578,635
Total Direct Construction Cost	$1,553,803,322	Total Direct Construction Cost	$1,318,641,417
Indirect Costs		**Indirect Costs**	
Engineering, Permitting and CM	$100,997,402	EPC Cost	$329,660,354
Sales Tax	$30,105,301	Sales Tax	$79,118,485
Owners Administration and Legal	$20,198,419		
Interest During Construction	$165,687,256		
		Mobilization/Demobilization	$65,932,071
		Developer Cost	$39,559,243
		Contingency	$435,151,668
		Overhead and Profit	$92,304,899
Total Indirect Costs	$316,988,378	Total Indirect Costs	$1,041,726,720
Total Cost	**$1,870,791,699**	**Total Cost**	**$2,360,368,137**
$/kW (Max. Power Capacity)	**$1,439**	**$/kW (Max. Power Capacity)**	**$1,839**
$/kWh (Max. Energy Capacity)	**$78**	**$/kWh (Max. Energy Capacity)**	**$99**

5.3 Sensitivity Analysis

PSH system specifications are highly site-specific, and the representative system configuration described in this report (Section 5.1) does not capture all the variability among projects in terms of structural design, site requirements, and other factors. To demonstrate the sensitivity of cost results to various assumptions, Figure 4 and Figure 5 show the sensitivity of large and small PSH system total installed cost to different input parameters for representative ranges of those parameters, focusing on physical system characteristics. This representative exercise does not include indirect cost items that can contribute to as-great or greater cost sensitivity, but a user of the cost model can explore indirect cost sensitivity as well.

Among the parameters varied in this exercise, both large and small PSH systems are most sensitive to the nominal head height and the storage duration in hours based on mean power output and total active storage, although the relative importance will depend on unique system specifications. While power output varies with head across the discharge cycle, this quantity is a proxy for the energy stored relative to the capacity of the power station. Both large and small systems are also highly sensitive to conveyance length. While the installed cost of small PSH systems is sensitive to transmission type and transmission miles, the cost of large PSH systems is more impacted by the type of power station. Some configuration options (intake/outlet and penstock type) and the power station structure geology type have a relatively small impact on installed cost with the relationships assumed in the cost model. However, these factors could have larger impacts if site conditions and/or system designs differ substantially from the appropriate conditions for using the underlying cost functions. This sensitivity analysis is specific to the inputs described in this report and cannot be generally extrapolated, but it demonstrates ways that a user can perform a similar sensitivity or parametric analysis with the cost model spreadsheet.

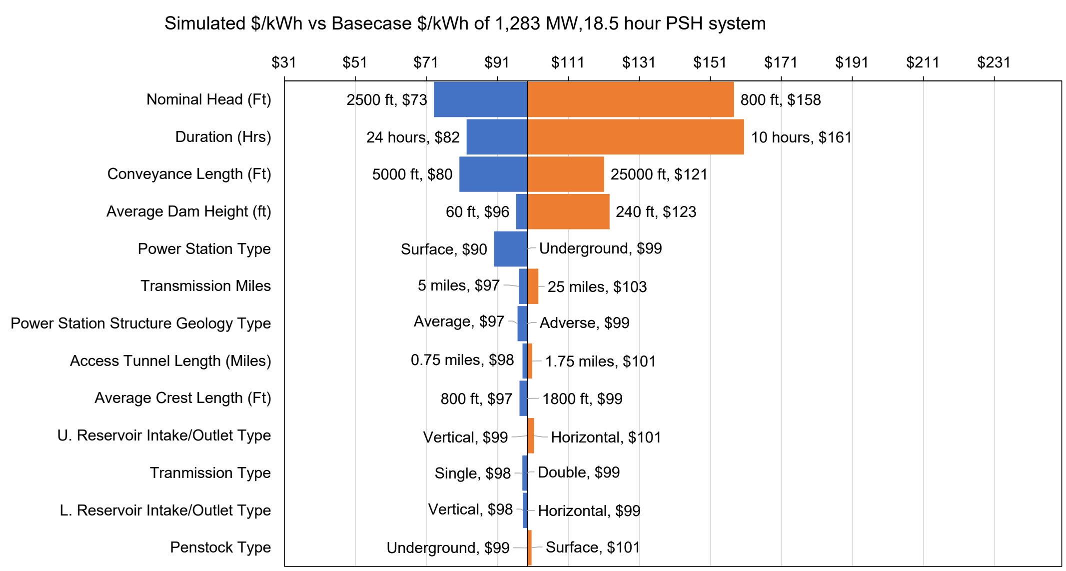

Figure 4. Sensitivity of total installed cost ($/kWh) to various input assumptions for a large PSH system (1,283 MW, 18.5 h). The vertical line is the nominal cost; positive changes (cost increase) are orange, and negative changes (cost reduction) are blue.

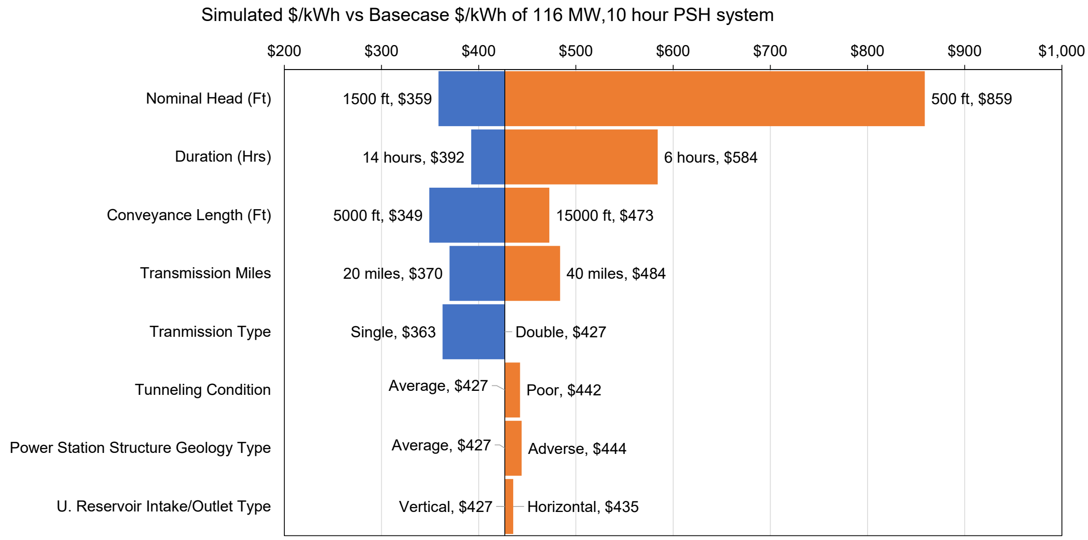

Figure 5. Sensitivity of total installed cost ($/kWh) to various input assumptions for a small PSH system (116 MW, 10 h). The vertical line is the nominal cost; positive changes (cost increase) are orange, and negative changes (cost reduction) are blue.

6 Conclusions

The PSH cost model presented here, to be published initially as an editable spreadsheet, incorporates industry standard procedures and stakeholder input to construct the most detailed PSH cost model available in the public domain. It is highly customizable for a range of PSH system sizes and includes transparent calculations of system specifications and component costs, including hardware, labor, and indirect (soft) costs. The model has been validated against detailed cost data for the Eagle Mountain proposed PSH project in California, with the direct construction costs being 15% lower but the total cost being 26% higher than reported in the FERC license application because of higher assumed indirect costs in the NREL model. This difference is well within the uncertainty bounds of a screening level cost estimate presented here, between −50% and 100%. We use the model to demonstrate the relative importance of input assumptions such as head and storage duration along with how smaller systems are proportionally more impacted by transmission costs. The cost model is a versatile tool for exploring and estimating PSH costs for hypothetical, proposed, or existing PSH sites, and it can be used to provide insight into overall PSH cost/benefit trade-offs.

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