



U.S. Hydropower Market Report

January 2021

On the front cover: Red Rock Hydroelectric Project, Marion County, IA (image courtesy of Missouri River Energy Services). This project, which adds hydropower generation capability to a non-powered dam owned by the U.S. Army Corps of Engineers, will have a capacity of 36.4 MW and generate enough electricity to meet the demand of approximately 18,000 households. The Federal Energy Regulatory Commission issued the Western Minnesota Municipal Power Agency a license to develop the project in April 2011, construction started in the third quarter of 2014 and was completed in the summer of 2020. Commercial operation is scheduled for the spring of 2021.

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U.S. Hydropower Market Report (January, 2021)

Highlights

In 2019, hydropower capacity (80.25 GW) accounted for 6.7% of installed electricity generation capacity in the United States and its generation (274 TWh) represented 6.6% of all electricity generated and 38% of electricity from renewables produced in the United States.

Hydropower in the United States is used extensively for power system flexibility and resilience.

- » In many parts of the country, hydropower provides more frequency regulation and reserves than its share of installed capacity.
- » In nearly every balancing area assessed, hydropower was more extensively utilized for hourly ramping flexibility than any other resource.
- » Hydropower represents less than 6.7% of U.S. electricity generation capacity but provides approximately 40% of black start resources.

U.S. hydropower capacity continues to grow through upgrades to existing plants and other types of innovative new projects.

- » Hydropower capacity has increased by a net of 431 MW since 2017, with total net growth of 1,688 MW from 2010 to 2019, mostly through capacity increases at existing facilities, new hydropower in conduits and canals, and by powering non-powered dams (NPDs).
- » At the end of 2019, an additional 1,490 MW, from 217 projects, were in the U.S. development pipeline, 93% of proposed capacity from powering NPDs and expanding existing facilities.

Pumped Storage Hydropower (PSH) contributes 93% of grid storage in the United States and it is growing nearly as fast as all other storage technologies combined.

- » Forty-three PSH plants with a total power capacity of 21.9 GW and estimated energy storage capacity of 553 GWh accounted for 93% of utility-scale storage power capacity (GW) and more than 99% of electrical energy storage (GWh) in 2019.
- » Almost as much PSH capacity was added from 2010 to 2019 (1,333 MW), mostly from upgrades to existing plants, as the combined installed capacity of all other forms of energy storage in the United States (1,675 MW).

PSH continues to be the preferred least cost technology option for 4–16 hours duration storage.

- » Energy storage cost for 4–16 hours duration is even lower for compressed air energy storage (CAES), but there are only two CAES projects installed worldwide (built in 1978 and 1991) versus more than 150 PSH projects.

Fifty-two gigawatts of new PSH is in the project development pipeline in the United States and over 50 GW is currently under construction around the world.

- » Sixty-seven new PSH projects with a total proposed capacity of 52.48 GW were in various stages of evaluation or development across 21 states.
- » The number of PSH projects in the U.S. development pipeline increased by 31% in 2019. The Federal Energy Regulatory Commission (FERC) issued 14 preliminary permits for PSH in 2019 (and an additional 17 preliminary permit applications were pending at the end of the year).
- » Global installed PSH capacity at the end of 2019 was 158 GW, but another 53GW of capacity (across 50 projects) were under construction globally at the end of 2019, and an additional 226 GW of PSH were at earlier stages of the development process.

The U.S. market for hydropower turbine installation remains competitive and robust and import/export trade balance for hydraulic turbines is near zero.

- » Five companies (American Hydro, Andritz, GE Renewable Energy, Voith, and Toshiba) manufactured all the turbines installed in the United States with capacities greater than 30 MW in the past decade, and more than a dozen companies served the demand for smaller turbines. American Hydro, Voith, and Andritz have manufacturing facilities in the United States.
- » In the past five years, the three top countries from which the United States imported turbines and turbine parts were China, Canada, and Brazil—the countries with the three largest hydropower fleets in the world. Canada and Mexico were the two top countries to which the United States exports turbines and turbine parts; they accounted for 51% of exports in 2015–2019.

FERC relicensing activity is set to more than double in the coming decade.

- » In the past decade, FERC issued 80 relicenses for 6.9 GW of hydropower capacity and 6.7 GW of PSH capacity (17% and 37% of FERC-licensed capacity, respectively). From 2020 to 2029, 281 facilities will be up for relicensing. That equates to 4.7 GW of hydropower capacity and 9.1 GW of PSH capacity (12% and 50% of FERC-licensed capacity, respectively).

Regulatory policy continues to evolve with several significant changes in recent years.

- » In October 2017, FERC announced a revised policy on license terms (for both original licenses and relicenses) in which the default term became 40 years.
- » The American Water Infrastructure Act of 2018 (AWIA) directed FERC to introduce an expedited licensing process—2 years from license application to final decision—for qualifying NPDs and closed-loop PSH projects.





U.S. Hydropower Market Report — In Brief

Introduction

**Chapter 1 — Looking Back:
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U.S. Hydropower and PSH Fleet**

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U.S. Hydropower Market Report – In Brief

Published: January 2021

Introduction

This is the third complete edition of the U.S. Hydropower Market Report (the first two were the 2014 and 2017 Hydropower Market Report published in 2015 and 2018, respectively);^{1,2} In intervening years between publishing the full report, updated data are also summarized and released, and can be found at the Oak Ridge National Lab (ORNL) [HydroSource](https://hydrosource.ornl.gov/) website.³ This report combines data from public and commercial sources as well as research findings from other Department of Energy (DOE) R&D projects in order to provide a comprehensive picture of developments in the U.S. hydropower and PSH fleet and industry trends. Prior to the first Market Report being published, there was a noted lack of publicly available and easily accessible information about hydropower in the United States and other important trends affecting this important sector of the energy industry. New and valuable types of information are constantly being developed in the course of DOE research activities and, in a rapidly evolving energy industry, it is important that these data be made available in a predictable and consistent manner for use by all different types of stakeholders and decision-makers.

The report highlights developments in 2017–2019 (the years for which new data has become available since the publication of the 2017 Hydropower Market Report), and contextualizes this information compared to evolving high-level trends over the past 10–20 years. Apart from presenting trends over time, the report discusses differences in those trends by region, plant size, owner type, or other attributes. This “In Brief” section highlights some of the key points of interest, including charts and visuals, from the seven chapters in the report.

A summary of the new content in each of the report chapters is shown in Table ES-1. This edition also updates the information about U.S. and global hydropower and PSH development pipeline, hydropower prices, and performance metrics for the period since the publication of the 2017 Hydropower Market Report. For discussion of the flexibility services and contributions to grid reliability provided by U.S. hydropower and PSH, the report also summarizes findings from research conducted under the Department of Energy’s [HydroWIRES](https://www.energy.gov/eere/water/hydrowires-initiative) initiative.⁴

Table ES-1. Summary of updated and new content by chapter

Chapter	New content
1	<ul style="list-style-type: none">• Relicensing hydropower and PSH activity in the United States
3	<ul style="list-style-type: none">• International comparison of hydropower permitting processes• International comparison of hydropower incentives
4	<ul style="list-style-type: none">• Detailed revenue data (energy, capacity, ancillary services) for selected U.S. PSH plants
5	<ul style="list-style-type: none">• Hourly ramping for U.S. hydropower and PSH fleet (and natural gas) by balancing authority• Participation of U.S. hydropower and PSH in ISO/RTO ancillary services markets
7	<ul style="list-style-type: none">• List of new FERC regulatory policies influencing hydropower• List of U.S. jurisdictions with clean energy mandates and energy storage mandates/targets

1 <https://www.energy.gov/eere/water/downloads/2014-hydropower-market-report>

2 [https://www.energy.gov/sites/prod/files/2018/04/f51/Hydropower Market Report.pdf](https://www.energy.gov/sites/prod/files/2018/04/f51/Hydropower%20Market%20Report.pdf)

3 <https://hydrosource.ornl.gov/>

4 <https://www.energy.gov/eere/water/hydrowires-initiative>

Chapter 1 – Looking Back: An Overview of Changes Across the U.S. Hydropower and PSH Fleet

AT THE END OF 2019, 80.25 GW OF GENERATING CAPACITY WERE OPERATIONAL IN 2,270 HYDROPOWER PLANTS IN THE UNITED STATES^{5,6} — In 2019, the U.S. hydropower fleet generated 274 TWh of electricity, close to the average annual generation during the past decade (277 TWh); an additional 36 TWh (roughly 12% of hydropower used in the United States) were imported from Canada. **Hydropower accounted for 6.6% of all electricity generated and 38% of electricity from renewables produced in the United States in 2019.**⁷ Additionally, 43 PSH plants with a total power capacity of 21.9 GW and estimated energy storage capacity of 553 GWh accounted for 93% of utility-scale storage power capacity (GW) and more than 99% of electrical energy storage (GWh).⁸ For comparison, all other utility-scale energy storage projects deployed by the end of 2019—including batteries, flywheels, solar thermal with energy storage, and natural gas with compressed air energy storage—had a combined power capacity of 1.6 GW and energy storage capacity of 1.75 GWh (see Figure ES-1).

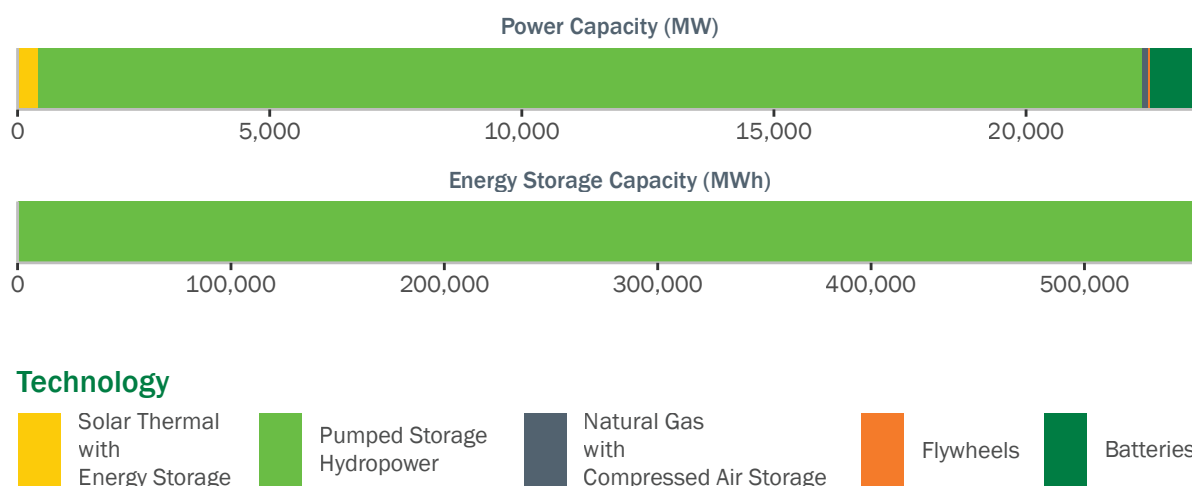


Figure ES-1. U.S. Utility-scale electrical energy storage capacity by technology type (2019)

Source: EIA Form 860 Early Release (2019)

HYDROPOWER IN THE UNITED STATES CONTINUES TO GROW – HYDROPOWER CAPACITY INCREASED BY 431 MW SINCE THE PUBLICATION OF THE LAST HYDROPOWER MARKET REPORT (2017–2019), AND A TOTAL OF 1,688 MW FROM 2010 TO 2019.⁹ Net increases took place in every region. Figure ES-2 shows that the net increase in the past decade was primarily from capacity additions to the existing fleet (1,704 MW), but 562 MW came from new developments, which mostly added hydropower generation to NPDs and conduits.

- » Capacity added from new projects or upgrades to the existing fleet from 2010 to 2019 (2,225 MW) outweighed capacity reductions due to plant retirements or downrates (538 MW).¹⁰

5 A plant is defined as a facility containing one or multiple powerhouses located at the same site and using the same pool of water. A hydropower project may include one or more plants.

6 Throughout the document, unless otherwise noted, “hydropower” does not include PSH. PSH is discussed separately throughout the report.

7 In 2019, wind generation surpassed hydropower as the largest renewable electricity generation source in the United States for the first time, producing 300 TWh as opposed to the 274 TWh produced by hydropower (<http://www.eia.gov/todayinenergy/detail.cfm?id=42955>).

8 See Appendix for details on the data sources and approach used to estimate energy storage capacity.

9 The last year of capacity data in the 2017 Hydropower Market Report was 2016.

10 Plant downrates are downward adjustments to the reported capacity of existing turbine-generator units or retirement of some of the units in a plant while the rest continue operating.

» In 2017–2019, there were 40 capacity additions (583.1 MW) and 26 downrates (-215.8 MW) to the existing fleet. Moreover, two new stream-reach developments (NSD) projects were completed and hydropower generation capability was added to 15 conduits and four NPDs. The combined capacity of all the new projects is 115 MW.

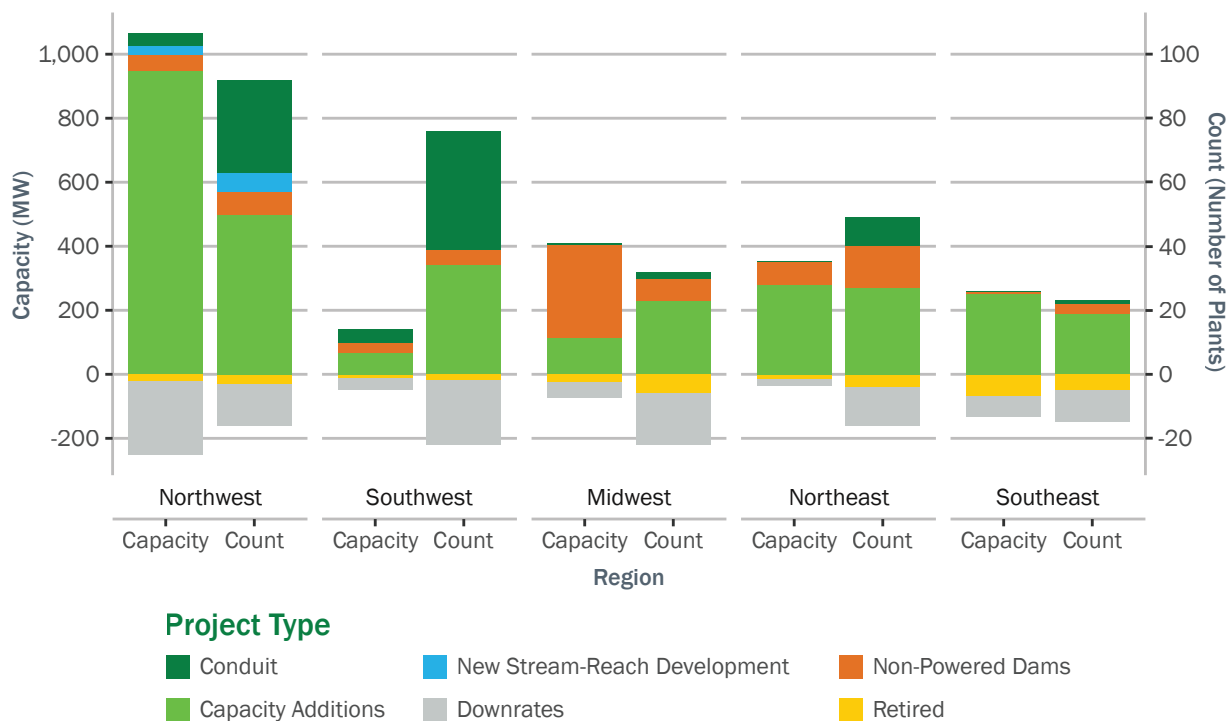


Figure ES-2. Hydropower capacity changes by region and type (2010–2019)

Sources: EIA Form 860 (2010-2018), EIA Form 860 Early Release (2019), Existing Hydropower Assets dataset¹¹, FERC eLibrary

Note: Changes in installed PSH capacity are not included in Figure ES-2.. Each instance of a capacity increase or decrease reported in EIA Form 860 is counted separately. Some plants reported multiple capacity changes during this period. Figure ES-2 shows which states are included in each region. See Glossary for project type definitions.

PSH ADDED SIGNIFICANT CAPACITY IN THE PAST DECADE — Net PSH capacity increased by 1,333 MW from 2010 to 2019. Except for the Olivenhain-Hodges facility in California (42 MW), the remaining increase came from upgrades to six existing PSH plants: Castaic in California, Northfield Mountain in Massachusetts, Muddy Run in Pennsylvania, and Bad Creek, Fairfield, and Jocassee in South Carolina. The most recent increase—228 MW reported in 2018—results from upgrading the four units of the Northfield Mountain facility.

AT LEAST \$8 BILLION INVESTED IN REFURBISHMENTS AND UPGRADES (R&U) IN THE PAST DECADE — Since 2010, at least \$7.8 billion have been invested in R&U of the U.S. hydropower and PSH fleet. Almost \$2 billion correspond to projects initiated in 2017–2019. The most common items in the scope of tracked R&U projects are replacement or refurbishment of turbine runners and generator rewinds. The fraction of total R&U investment dedicated to the PSH fleet in 2010–2019 (24%) is slightly higher than the fraction of capacity that PSH represents in the combined U.S. hydropower and PSH fleet (20%). Average R&U investment per installed kilowatt in 2010–2019 was similar for hydropower owned by federal agencies vs. other owners.

11 <https://hydrosourc.eornl.gov/market-info-and-data/existing-hydropower-assets>

FERC RELICENSING ACTIVITY SET TO MORE THAN DOUBLE IN THE COMING DECADE — In the past decade, FERC issued 80 relicenses that extended the authorization to operate an additional 30 to 50 years to projects accounting for 17% (6.9 GW) of FERC-licensed hydropower capacity and 37% (6.7 GW) of FERC-licensed PSH capacity. In the decade of the 2020s, 281 licenses that currently authorize 12% (4.7 GW) of installed FERC-licensed hydropower capacity and 50% (9.1 GW) of FERC-licensed PSH are set to expire. Figure ES-3 shows their regional and size distribution. The number of hydropower plants with licenses expiring in the Northeast region (169) is greater than in the other four regions combined. For 99 of those 169, this would be their first relicensing process as they started operating in 1980 or later. Since the average capacity of Northeast plants to be relicensed is small (5.5 MW), they only account for 21% of hydropower capacity whose licenses expire between 2020 and 2029. Additionally, one of the six PSH plants that will need a rlicense during this decade is also in the Northeast (Bear Swamp in Massachusetts). Of the remaining five, four are in the Southeast (Bath County in Virginia, Rocky Mountain in Georgia, and Fairfield and Bad Creek in South Carolina) and the other one is Helms in California.

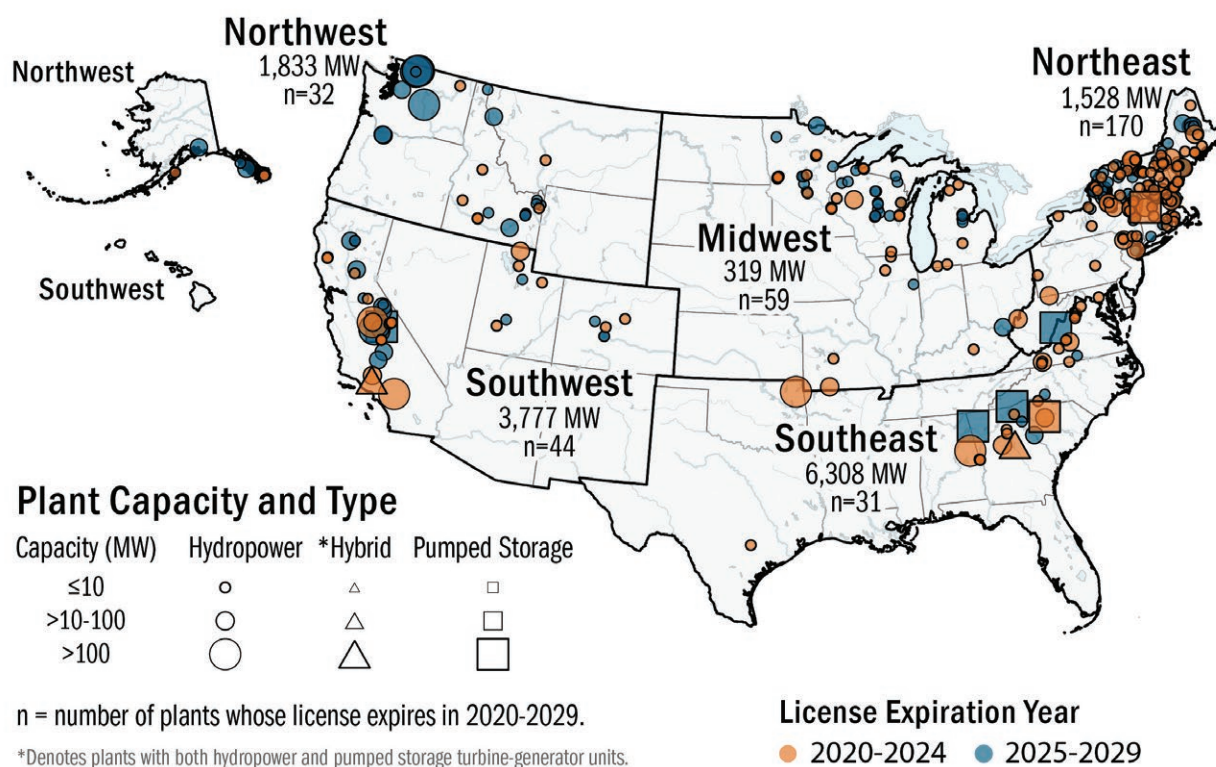


Figure ES-3. Hydropower and PSH plants with licenses expiring in 2020–2029

Sources: Existing Hydropower Assets dataset

Between 2010 and 2019, FERC received 41 license surrender applications of constructed projects. The median capacity of these projects is 0.5 MW and only 5 have capacity greater than 10 MW. License surrenders are most often motivated by economic reasons ranging from the cost of repairs needed to continue operation to the cost and risk of an upcoming relicensing process.

RELICENSES AFFECT THE OPERATIONAL FLEXIBILITY OF THE U.S. HYDROPOWER FLEET

A relicense extends the authorization to operate a hydropower project, subject to compliance with a set of terms and conditions agreed among the licensee and project stakeholders and approved by FERC. Complying with the relicense terms and conditions may require changes in operations that affect the operational flexibility of the projects. Three of the 80 hydropower relicenses issued from 2010 to 2019, with a combined relicensed capacity of 83.5 MW, required run-of-river operation (either seasonally or all year) for projects that had previously been operated more flexibly (in peaking mode).¹² For two of them (Claytor in Virginia and Waterbury in Vermont), the change in mode of operation was a mandatory condition to obtain a water quality certification from the relevant state agencies. In the third project (Scotland in Connecticut), it was the licensee who proposed to switch to run-of-river operation.¹³ Other relicenses issued in the past decade included terms or conditions that restrict operational flexibility to some extent (e.g., new or tighter ramping rate restrictions, increased minimum flows). However, for some projects, the changes agreed in a relicense result in additional flexibility. For instance, the relicense for the Yards Creek PSH project issued in 2013 approved the project's owner proposal to raise the operating level of the upper reservoir to increase daily generation capacity and enhance operational flexibility.

MORE THAN HALF OF THE RELICENSES REQUIRED SOME CONSTRUCTION — Most often, the construction was related to the addition/improvement of recreational facilities (e.g., boat launches, parking areas, trails) or environmental measures (e.g., installation of fish passage structures, replacement of turbines to improve their environmental performance). For six of the 44 projects that required construction, all with relicenses issued before 2015, construction involved turbine upgrades or installation of new turbines to increase power generating capacity.

12 Peaking hydropower plants store and release water for hydroelectric generation at targeted times; their reservoirs may experience large fluctuations in elevation. Run-of-river hydropower minimizes the fluctuation of the reservoir surface elevation and deviation from natural flow regimes.

13 In that project, the licensee combined the switch to run-of-river operations with installation of an additional turbine resulting in a net increase in estimated annual electricity generation.

Chapter 2 – Looking Forward: Future U.S. Hydropower and PSH Development Pipeline

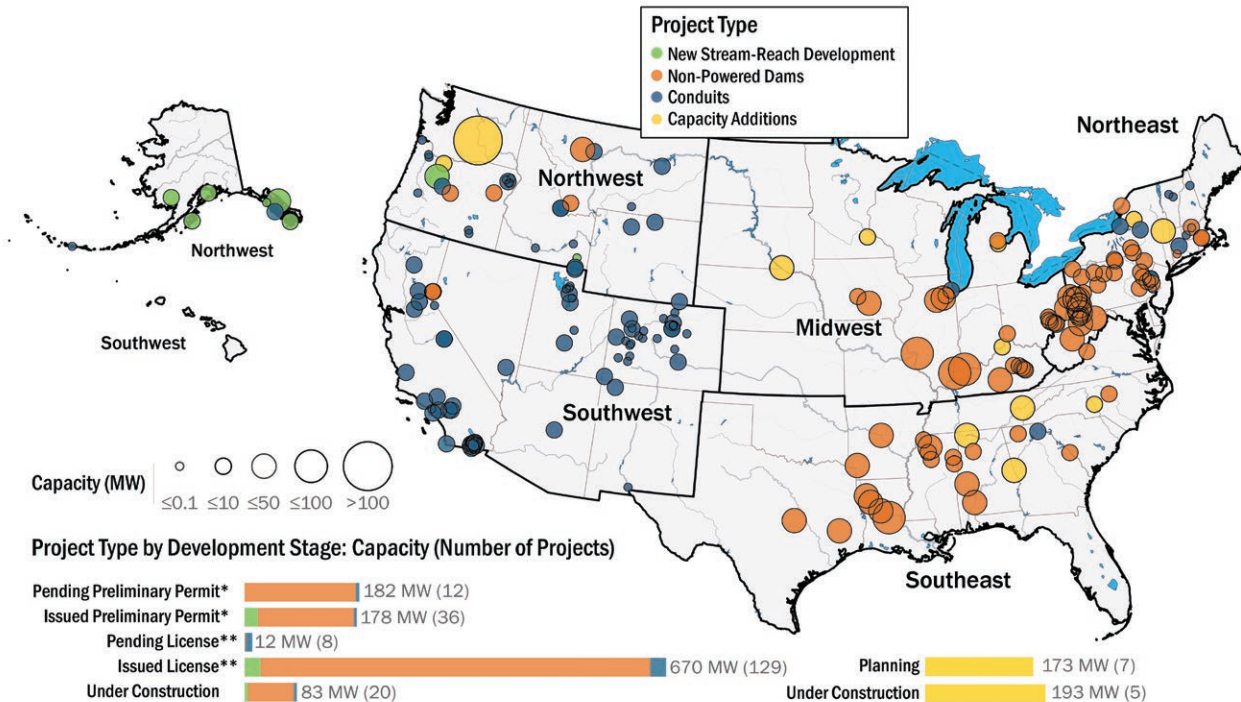


Figure ES-4. Hydropower project development pipeline by project type, region, size, and development stage (as of December 31, 2019)

Sources: FERC eLibrary, U.S. Bureau of Reclamation (Reclamation) LOPP database, Industrial Info Resources (IIR), web searches

*Projects in the Pending Preliminary Permit and Issued Preliminary Permit stages have high attrition rates. *Pending Preliminary Permit* includes projects pending a preliminary lease in the Reclamation Lease of Power Privilege (LOPP) process and projects pending issuance of a preliminary permit. *Issued Preliminary Permit* includes projects that have received a preliminary lease in the LOPP process, projects that have obtained a FERC preliminary permit, and projects with an expired preliminary permit but that have submitted a Notice of Intent to file a license or a draft license application.

***Pending License* includes projects that have applied for an original FERC license or a FERC exemption or have requested to be considered a “qualifying conduit” hydropower facility by FERC. *Issued License* includes projects that have been issued an original FERC license or FERC exemption, have been approved by FERC for “qualifying conduit” hydropower status, or that have received a final lease contract under the LOPP process.

NEARLY 1.5 GW OF HYDROPOWER IN THE U.S. DEVELOPMENT PIPELINE — At the end of 2019, 217 hydropower projects with a total proposed capacity of 1.49 GW were in the U.S. development pipeline. Figure ES-4 displays the location of proposed hydropower projects and information about their types, sizes, and stage of development. Half of the projects would add hydropower to existing conduit infrastructure; this set of projects only represent 3% of the proposed capacity. More than two-thirds (69%) of proposed capacity would come from retrofitting NPDs and another 25% from capacity additions at existing facilities. All 8 NSD projects in the pipeline are in the Northwest region; six of them are in Alaska. Proposed hydropower projects are distributed across 34 states. Pennsylvania, Kentucky, and Louisiana are the three states with more than 100 MW of new hydropower capacity in the development pipeline and most of that capacity is in NPD projects.

AT THE END OF 2019, 129 HYDROPOWER PROJECTS (670 MW) HAD AN ISSUED FEDERAL AUTHORIZATION BUT HAD NOT STARTED CONSTRUCTION — More than half of the projects in the pre-construction stage have spent three or more years in it. Key activities that are typically completed during that development stage include: obtaining additional non-FERC permitting, completing technical design, and securing property rights, financing, and power purchase agreements (PPAs).

NUMBER OF PSH PROJECTS IN THE DEVELOPMENT PIPELINE INCREASED BY 31% IN 2019 – Sixty-seven new PSH projects with a total proposed capacity of 52.48 GW were in various stages of evaluation or development at the end 2019 (see Figure ES-5). Moreover, three projects to increase capacity at existing PSH projects were ongoing; they will add 119 MW of power generating capability. Twenty-one states have at least one new PSH project planned. Pennsylvania, Arizona, and California are the top three states by number of PSH projects under consideration with 11, 10, and seven projects, respectively.¹⁴

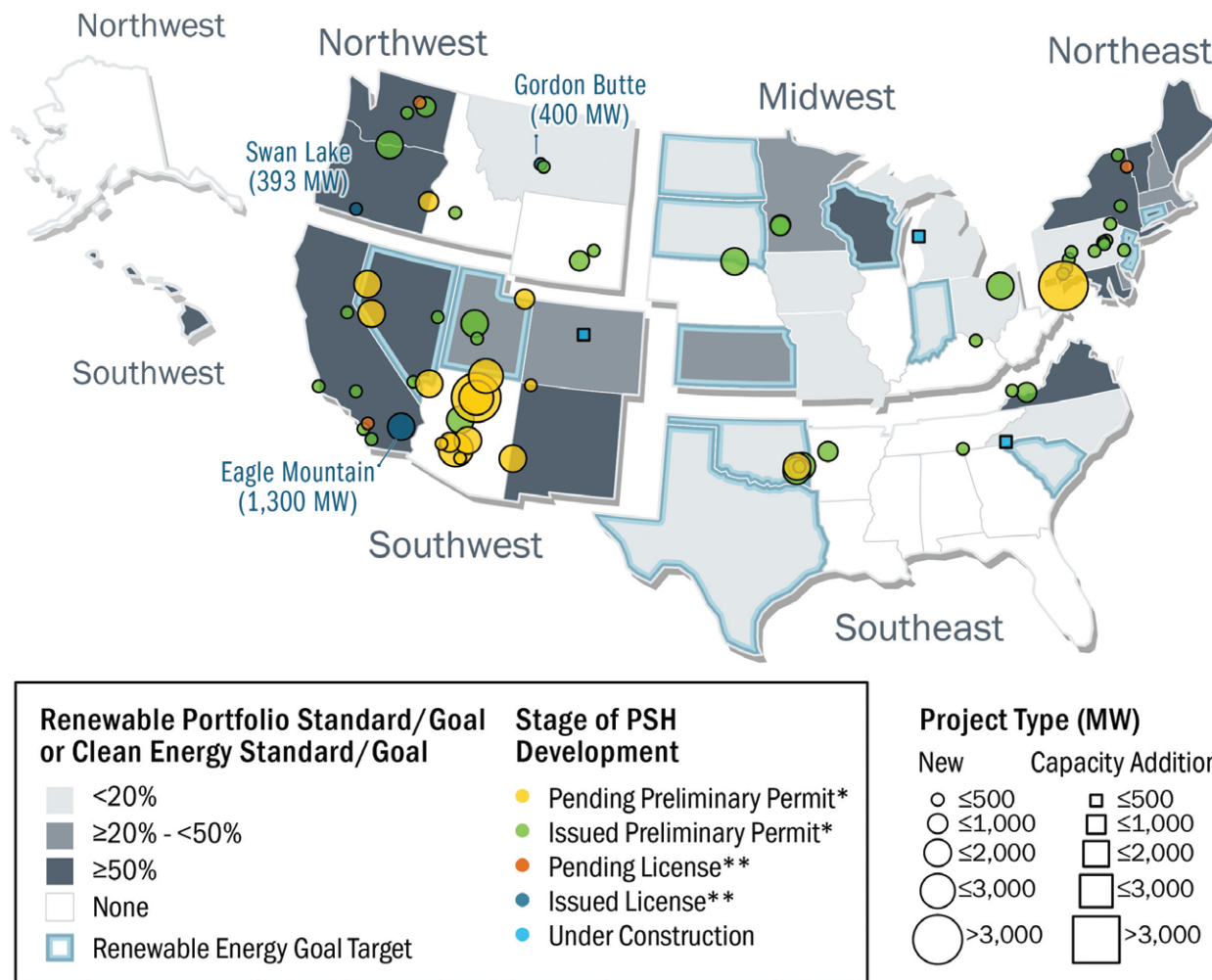


Figure ES-5. PSH project development pipeline by region and status in relation to state-level renewable energy targets (as of December 31, 2019)

Sources: FERC eLibrary, DSIRE, Internet searches

Note: See Figure ES-4 notes for details about which projects are included in each stage. For states that have both a renewable portfolio standard (RPS) or voluntary renewables goal and a Clean Energy Standard (or voluntary goal), the map shows the maximum percentage to be attained across the two.

¹⁴ The same private developer has proposed nine of the PSH projects in Pennsylvania and three of the Arizona projects.

U.S. PSH PROJECTS WITH FERC LICENSES

At the end of 2019, three PSH facilities had issued licenses: Eagle Mountain in California, Gordon Butte in Montana, and Swan Lake in Oregon. FERC licensed Swan Lake in April 2019 with a capacity of 393 MW. Since then, the developers of this closed-loop project obtained right-of-use authorization from Reclamation to construct the transmission line, which would pass through public land parcels in its planned route.

Gordon Butte, licensed in 2016, requested a second time extension to start construction in July 2020; its new construction start deadline is December 2022. This PSH project has a planned capacity of 400 MW and an off-stream closed-loop design in which the two man-made reservoirs will be connected by an underground penstock ending in an underground powerhouse. The project developers announced they secured equity investment for the project from a Danish investor in July 2019 but, as of July 2020, negotiations for a PPA are still ongoing.

Finally, license issuance for Eagle Mountain took place in 2014. It has a proposed capacity of 1,300 MW, and it is a closed-loop project using abandoned mine pits as upper and lower reservoirs. The project developer requested a construction start extension after two years from license issuance and has secured additional time extensions due to the passage of the AWIA in November 2018. Obtaining access to the public lands within the project boundary has been a key issue delaying construction. In March 2020, the project developer signed the right-of-way grant with the Bureau of Land Management after extensive negotiation. Additionally, the developer has completed geotechnical studies needed to inform the final engineering designs for the project.

FERC issued 14 preliminary permits for PSH in 2019 (and an additional 17 preliminary permit applications were pending at the end of the year). Some of these projects revisited locations that had previously been studied for PSH such as the Camp Pendleton and Vandenberg Air Force Base projects in California. These two projects propose to use the Pacific Ocean as their lower reservoir and to include both PSH units and a desalination facility. Other proposed PSH projects are in states that have rarely been considered for this type of storage facility such as the Freestone project in Georgia. Seven of the PSH projects with preliminary permits proposed capacities of less than 100 MW, which is much smaller than the median PSH size in the project pipeline (480 MW). All these smaller projects envisioned closed-loop configurations and four of them would use abandoned mine sites for one of their reservoirs.

Figure ES-6 summarizes PSH development activity in the United States in the past five years. Except for 2015, more developers submitted preliminary permit applications each year than developers surrendered their permit or license. As a result, the number of projects in the development pipeline has been steadily increasing. Additionally, five developers submitted license applications in 2015–2019 and FERC issued two licenses during that period.

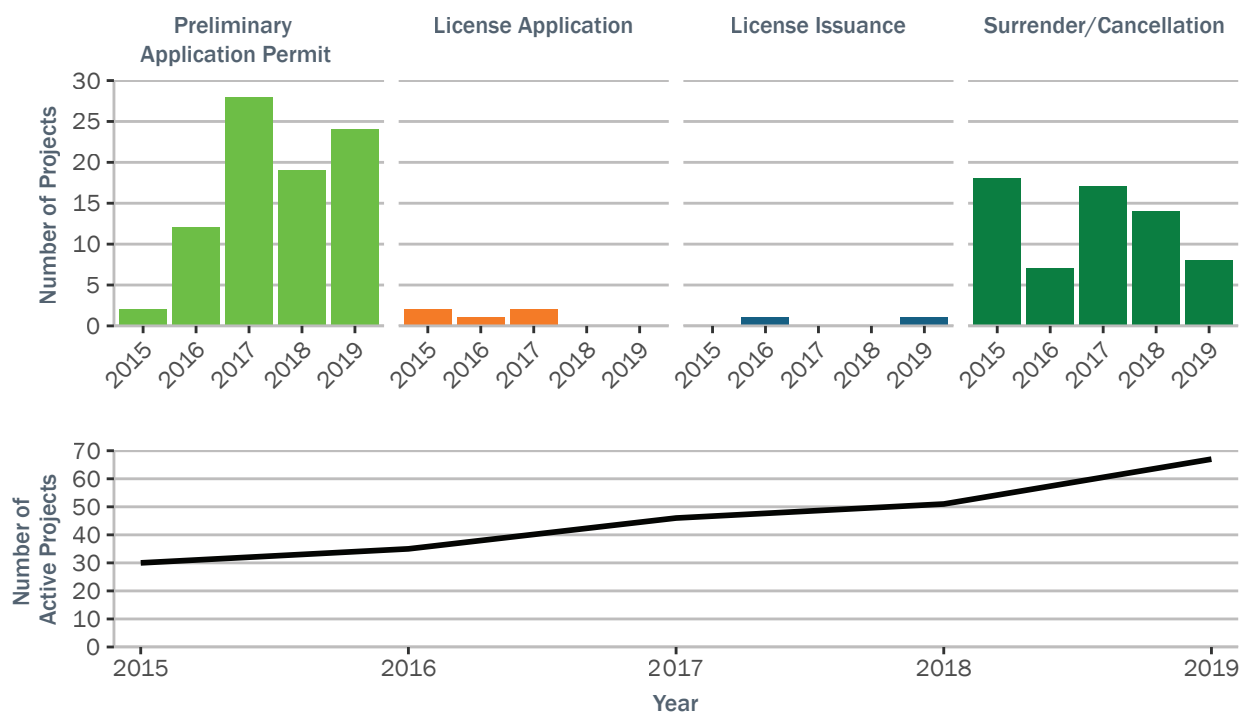


Figure ES-6. U.S. PSH Project Development Activity (2015–2019)

Source: FERC eLibrary

Chapter 3 – U.S. Hydropower in the Global Context

GLOBAL HYDROPOWER CAPACITY REACHED 1,150 GW AT THE END OF 2019 — Eighty-four countries have more than 1 GW of installed hydropower capacity and the top six fleets (China, Brazil, European Union, Canada, United States, and Russia) account for two thirds of installed capacity. The U.S. fleet represents 7% of global hydropower capacity. Hydropower is the largest global renewable by installed capacity, with 46% of global renewable generation capacity.

GLOBAL HYDROPOWER CAPACITY INCREASED BY 58 GW IN 2017–2019 — 57% of the new capacity was added in China and Brazil. Hydropower additions represented 12% of global renewable generation capacity installations during that period; the shares of solar and wind were 55% and 29%, respectively.

THE GLOBAL HYDROPOWER DEVELOPMENT PIPELINE INCLUDED 4,545 PROJECTS WITH A TOTAL CAPACITY OF 414 GW BY THE END OF 2019 — Two hundred and twenty-three hydropower projects and 19 PSH projects reached construction stage in 2017–2019. In total, at the end of 2019, there were 117 GW of hydropower being constructed in 616 projects across 66 countries. An additional 297 GW of hydropower were in different phases of scoping, permitting, and development. Figure ES-7 shows the regional distribution of the global hydropower pipeline as well as the shares of projects in early vs. late stages of development. All the countries in the top 20 for new planned hydropower capacity are in Asia, Africa, or South America. China has the most hydropower capacity (93 GW) in the pipeline.

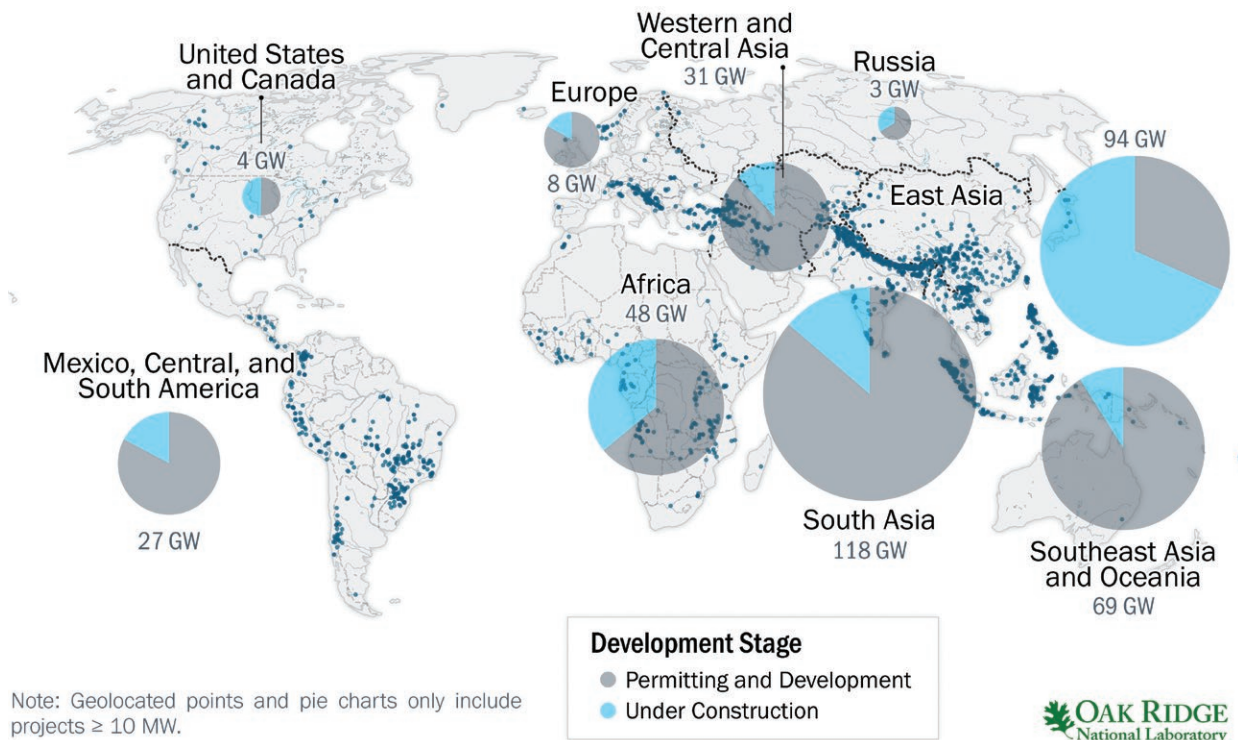


Figure ES-7. Map of hydropower project development pipeline by region and development stage

Source: IIR, FERC

Note: Each point represents an individual project. The “under construction” category includes projects that have completed the permitting process and secured financing but have not yet broken ground.

GLOBAL INSTALLED PSH CAPACITY WAS 158 GW AT THE END OF 2019 — The top six PSH fleets (European Union, China, Japan, United States, India, and South Korea) represented 86% of worldwide capacity; only 35 countries have any PSH capacity in operation. The U.S. fleet represents 14% of global PSH capacity.

GLOBAL PSH DEPLOYMENT SLOWED IN 2018–2019, BUT PROJECTS IN PLANNING AND CONSTRUCTION STAGES WOULD MORE THAN DOUBLE GLOBAL CAPACITY

— From 2010 to 2017, global PSH grew by an average of 3.3 GW per year. In contrast, only 2 GW of PSH capacity was added in 2018–2019. Figure ES-8 provides more detail about the temporal and regional distribution of new PSH plants starting operation during the past decade. Of the 20 plants shown, 13 are in the East Asia region (11 in China, one in South Korea, and one in Japan), four in European countries (Austria, Norway, Switzerland), and one each in North America (Olivenhain-Hodges in the United States), Africa (South Africa), and Western and Central Asia (Israel).

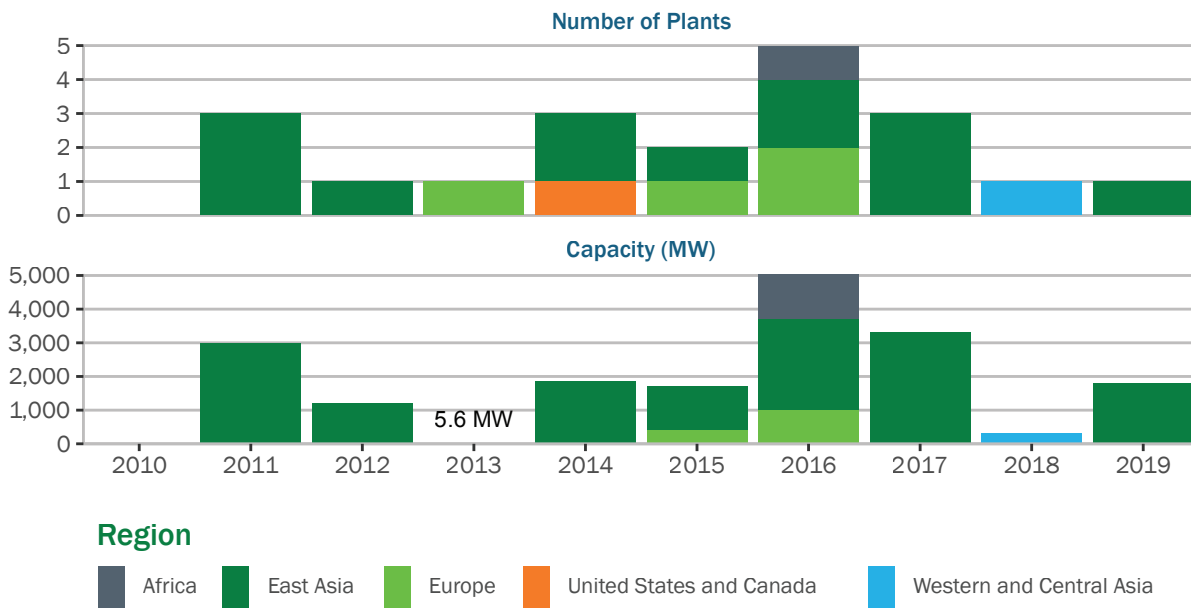


Figure ES-8. New PSH installations in 2010–2019 by world region

Source: IIR

Note: This plot does not include PSH capacity increases resulting from upgrades to existing units.

AT THE END OF 2019, THE GLOBAL DEVELOPMENT PIPELINE INCLUDED 284 PSH PROJECTS WITH A TOTAL CAPACITY OF 226 GW.

Figure ES-9 summarizes the regional distribution of the global PSH pipeline. Thirteen countries were constructing 50 PSH projects with total capacity of 53 GW at the end of 2019. An additional 226 GW of PSH were at earlier stages of the development process. China leads the PSH pipeline ranking with 102 GW of PSH projects; the United States and eight European countries are also within the top 20 countries with the largest PSH pipelines.

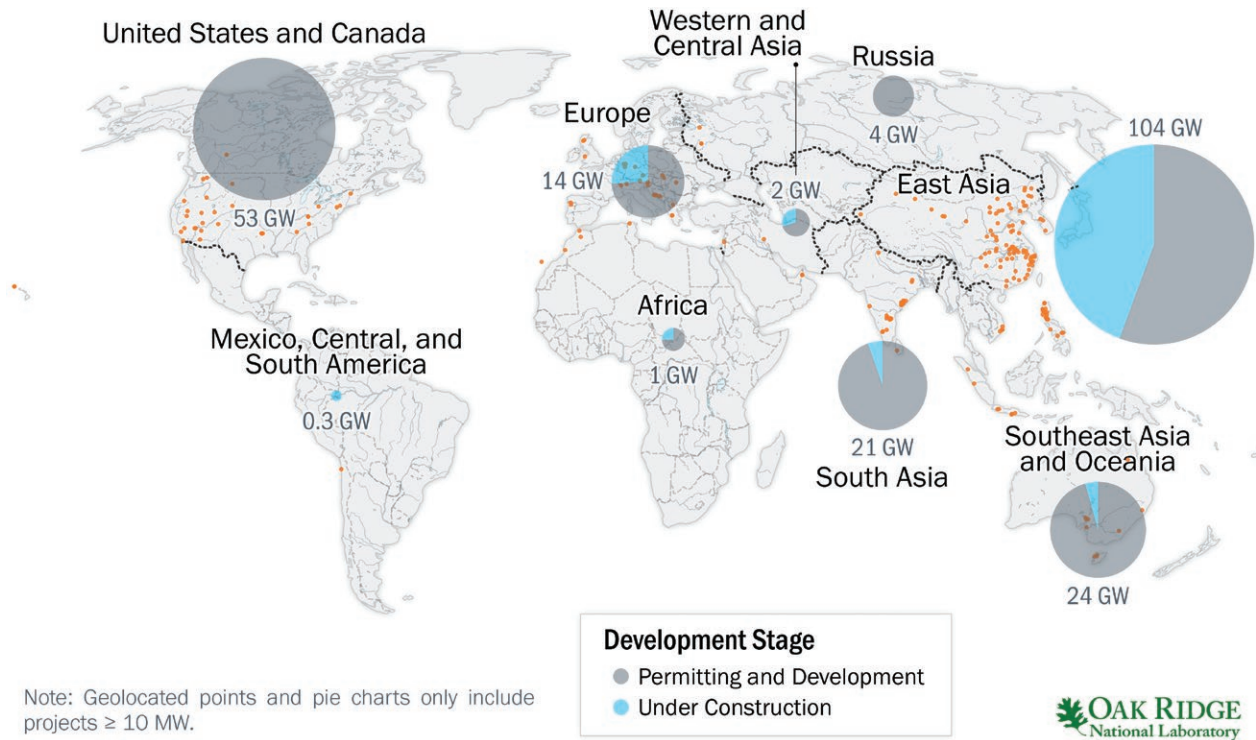


Figure ES-9. Map of PSH project development pipeline by region and development stage

Source: IIR, FERC

Note: Each point represents an individual project. The “under construction” category includes projects that have completed the permitting process and secured financing but have not yet broken ground.

EAST ASIA LEADS GLOBAL INVESTMENTS IN NEW HYDROPOWER AND PSH PLANTS; NORTH AMERICA LEADS GLOBAL INVESTMENTS IN R&U — North America (United States and Canada) is the region with the oldest fleet, in terms of capacity-weighted average age, and is the region that spends the most on R&U projects worldwide.¹⁵ At the end of 2019, North America’s R&U investment (planned and ongoing) totaled \$11.6 billion, distributed across plants that make up 36% of the region’s installed hydropower capacity and 19% of its PSH capacity.

Figure ES-10 shows the distribution of planned and ongoing capital expenditures between development of new plants, plant expansion projects, and R&U projects in each region for hydropower and PSH. More than 90% of global expenditures are directed toward development of new plants. Tracked capital investment in plant expansions and R&U at the end of 2019 totaled \$73 billion, distributed approximately evenly between the two expenditure types. Asian regions concentrate 73% of global hydropower expenditure and 69% of global PSH expenditure. North America and Russia are the only two regions with larger tracked expenditures for PSH than hydropower. In a dollar per installed kilowatt basis, North America R&U expenditure in PSH more than doubles that in other regions.

¹⁵ Age is calculated relative to the initial plant in-service date. It does not account for the fact that individual units within a plant might have been replaced or extensively rehabilitated since that initial date.

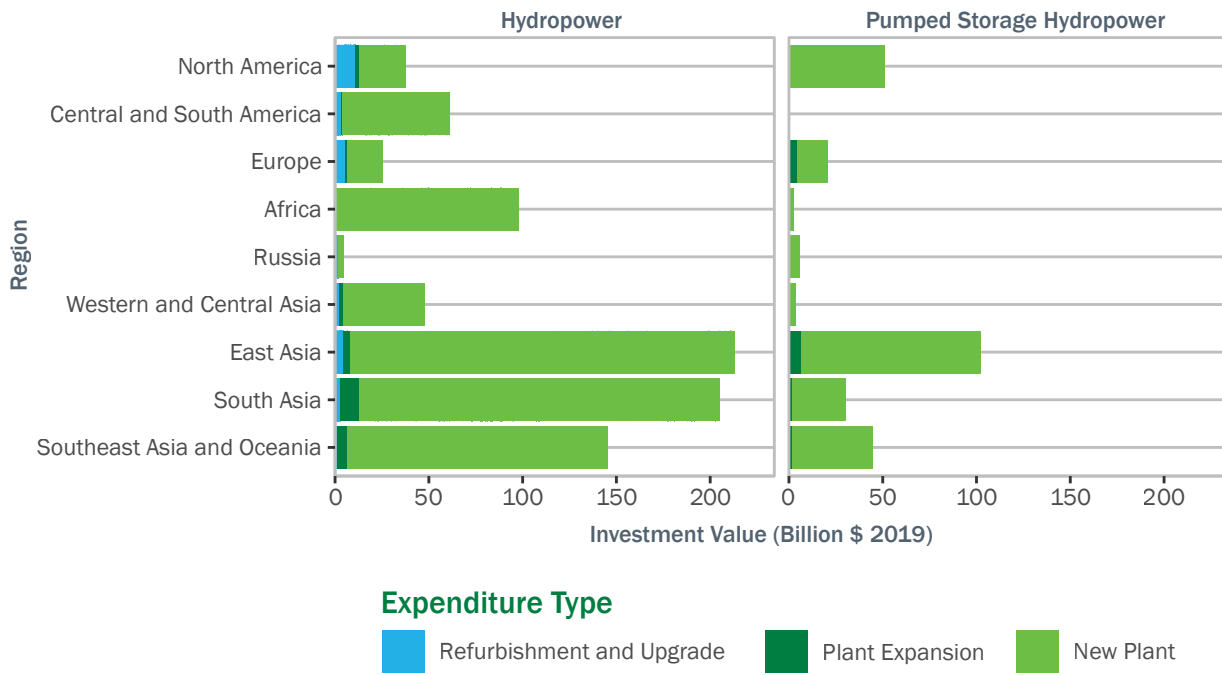


Figure ES-10. Expenditures on hydropower and PSH (new projects, R&U, and plant expansions) by world region

Source: IIR

Note: See glossary for expenditure type definitions

Chapter 4 – U.S. Hydropower Price Trends

U.S. FEDERAL POWER MARKETING ADMINISTRATIONS (PMAS) INCREASE PARTICIPATION IN OTHER ORGANIZED ELECTRICITY MARKETS

— To better adapt to the ongoing changes in market structure, generation mix, and the transmission system, several PMAs—the federal agencies responsible for marketing the electricity generated by government-owned hydropower projects—have considered the option of becoming participants in one of the competitive wholesale electricity markets coordinated by an independent system operator/regional transmission organization (ISO/RTO) market, the California ISO (CAISO)—administered Western Energy Imbalance Market, or the proposed Southwest Power Pool (SPP)—administered Western Energy Imbalance Service market.

- » In October 2015, the Western Area Power Administration’s (WAPA) Upper Great Plains–East Region joined the SPP.
- » In September 2019, WAPA’s Colorado River Storage Project, Rocky Mountains Region, and Upper Great Plains–West Region announced plans to join the SPP Energy Imbalance Service market in February 2021.
- » In September 2019, WAPA’s Sierra Nevada Region announced plans to join the CAISO Western Energy Imbalance Market in April 2021.
- » In December 2019, Bonneville Power Administration (BPA) signed an implementation agreement to start the process of joining the Western Energy Imbalance Market with April 2022 as the planned membership start date.

On average, federal hydropower prices remain competitive with regional wholesale prices. Hydrologic conditions are the key variable that affects the average hydropower prices received by PMAs. The price of the peaking power (i.e., power generated at the times of higher electricity demand) marketed by two of the PMAs—Southwestern Power Administration (SWPA) and Southeastern Power Administration (SEPA)—has been higher in recent years than wholesale electricity prices in their respective regions.

THE MEDIAN HYDROPOWER PPA PRICE IN 2018 WAS \$48.47/MWH — the Median PPA Price Across All

Electricity Generation Technologies Was \$47.61/MWh. In 2015–2018, median hydropower prices were higher than the regional wholesale spot prices in the Northwest and Southeast. Those two regions account for 64% of installed hydropower capacity and have little or no geographic overlap with ISO/RTO markets. In the rest of the country, the median hydropower price has followed the wholesale spot price closely since 2008.

Utilities continue to be the off-takers in most hydropower PPAs but, in recent years, other entities (e.g., universities) are also entering into purchase agreements with hydropower facilities that can help them meet sustainability goals. The only corporate hydropower purchase deal that has been publicly disclosed to date is a five-year power supply agreement between Microsoft and Chelan County Public Utility District announced in 2019. In contrast, corporate and industrial buyers accounted for 22% of U.S. solar and wind procurements in 2018.

Chapter 5 – U.S. Hydropower Cost and Performance Metrics

AFTER TWO YEARS OF HIGH DOMESTIC HYDROPOWER PRODUCTION (~300 TWH) IN 2017–2018, PRODUCTION RETURNED TO A LEVEL CLOSE TO THE 2003–2018 AVERAGE IN 2019 (274 TWH). Canadian imports contributed an additional 35–45 TWh of hydroelectricity per year.

CANADIAN IMPORTS ARE EXPECTED TO CONTINUE INCREASING IN THE 2020S – The projected increase is driven by U.S. state-level renewable standards and clean energy goals, new Canadian hydropower capacity, and new Canada–United States transmission capacity. Canadian hydropower producers have recently signed multiple new PPAs with off-takers in the United States.

SMALL HYDROPOWER PLANTS HAVE THE HIGHEST O&M COSTS — In 2018, the average O&M cost was \$6/kW for very large plants (>500 MW), \$20/kW for large plants (100–500 MW), \$42/kW for medium plants (10–100 MW), and \$122/kW for small plants.

TREND IN RISING O&M COSTS FOR SMALL HYDROPOWER PLANTS CONTINUES – Small plants are the only size category for which O&M costs grew faster than inflation in 2016–2018.

Figure ES-11 shows the trends in O&M costs segmented by plant size and year of operation for the 296 U.S. hydropower plants and 10 PSH plants (all in the large or very large categories) with continuous FERC Form 1 records in 2009–2018. The right panel of Figure ES-11 shows that average O&M costs are highest for the older plants and lowest for those starting operation after 1960. However, since (for this set of plants) average age increases as size increases, further statistical analysis is needed to disentangle the effect of age from the effect of size on O&M costs.

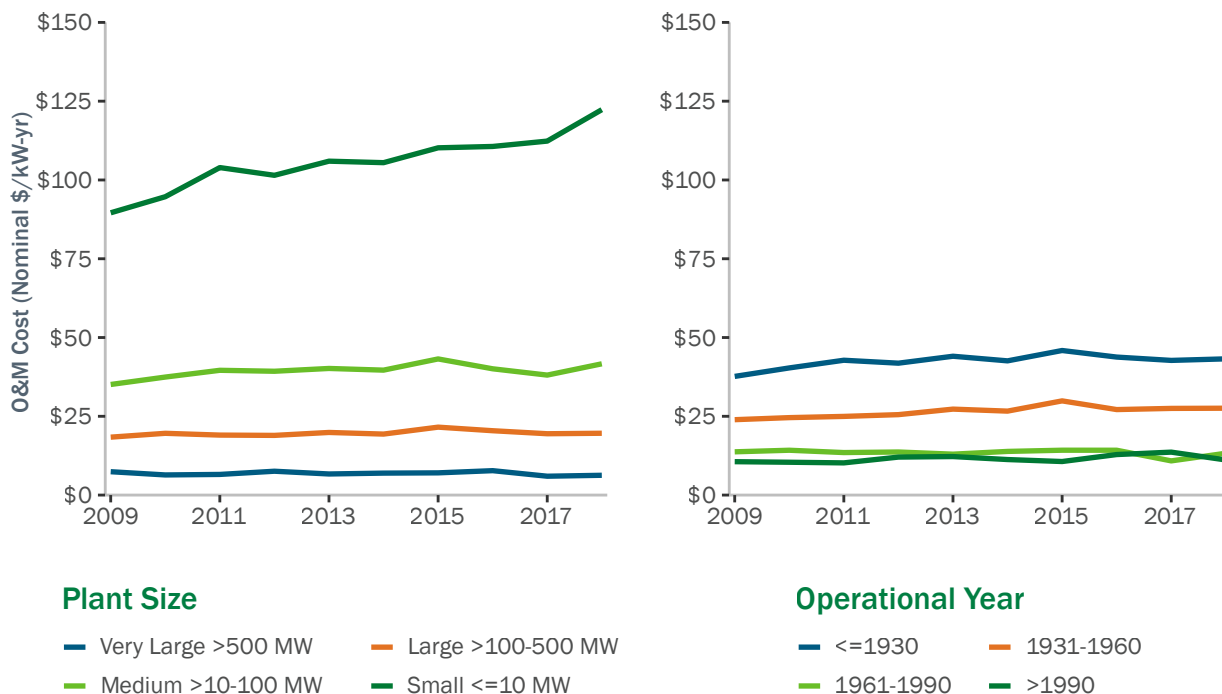


Figure ES-11. Trend in operations and maintenance costs for hydropower projects by size class

Source: FERC Form 1, Bureau of Labor Statistics

Note: Number of plants by size category: 7 (Very Large), 42 (Large), 124 (Medium), 133 (Small). Number of plants by operational year interval: 178 (< 1930), 73 (1931–1960), 50 (1961–1990), 5 (>1990). This set of plants account for 16% and 35% of installed U.S. hydropower and PSH capacity, respectively. O&M cost elements reported in FERC Form 1 are defined as “operating expenses” in FERC’s Uniform System of Accounts. They include labor, materials, and overhead associated with the operation, supervision, engineering and maintenance of the electric plant and associated structures as well as rents from leased property.

Average operations and maintenance (O&M) costs for the federal hydropower and PSH fleet are similar to those of the nonfederal fleet. For the U.S. Army Corps of Engineers (USACE)-owned fleet, the average O&M funding in Fiscal Year (FY)2018–FY2020 was \$471 million (\$21.50/kW-year). The median size of USACE-owned plants is 100 MW.¹⁶ As for the U.S. Bureau of Reclamation-owned fleet, the median capacity of their hydropower plants is 38 MW and the hydropower O&M expenses detailed in its budget justification documents averaged \$469 million (\$31.85/kW-year) in FY2018–FY2020.¹⁷ In comparison, the average O&M costs for medium and large non-federal facilities (i.e., those in the same size categories as the median federal plants) in 2018 were \$42/MW and \$20/MW, respectively.

MEDIAN U.S. HYDROPOWER CAPACITY FACTOR FROM 2005 TO 2018 HAS RANGED BETWEEN 35% AND 45% LARGELY DEPENDING ON HYDROLOGICAL CONDITIONS — On average, the median capacity factor was 39% during this period. Hydrological and market conditions as well as plant-level variables (mode of operation, outage schedule, multipurpose constraints) explain variability across plants and years. Figure ES-12 displays the median, 10th, and 90th percentiles of the capacity factor distribution along with the capacity-weighted average runoff for 2005–2018.

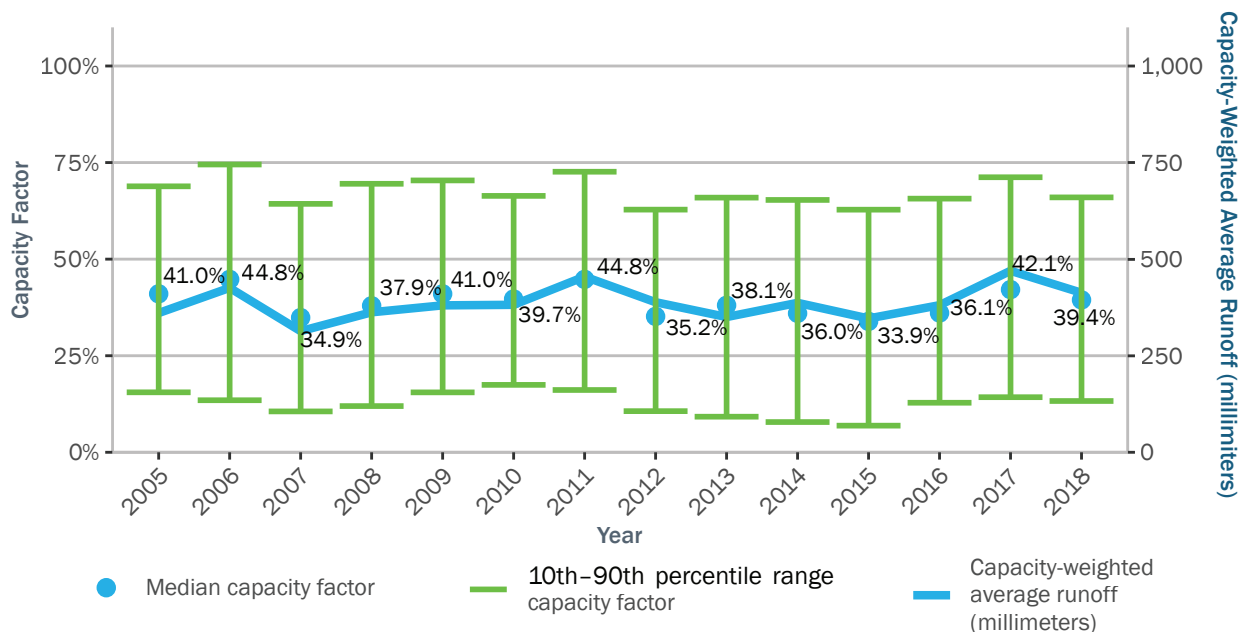


Figure ES-12. Plant-level distribution of capacity factors by year (nationwide fleet) and capacity-weighted average runoff

Source: EIA Form 923, EIA Form 860, USGS WaterWatch.

Note: Capacity factor data include hydropower plants in the 50 U.S. states. HUC2 region runoff data excludes Alaska and Hawaii. HUC2 region weights for the capacity-weighted average runoff calculation are based on installed hydropower capacity in each region.

THE FLEXIBILITY OF HYDROPOWER AND PSH ASSETS IS BEING UTILIZED EXTENSIVELY ACROSS THE UNITED STATES. One-hour ramps (i.e., hourly changes in energy output) in 36 balancing authorities show large average ramps and wide ramp ranges for the hydropower fleets (including PSH). Thus, hydropower and PSH play an important role toward resolving supply-demand imbalances at the hourly frequency.

The average and range of one-hour ramps performed by the hydropower and PSH fleet vary widely across BAs. The percentage of the hydropower fleet operating in peaking mode, the extent of operational constraints due to non-power purposes (e.g., flood control, irrigation, recreation) of the dams, and the generation fuel mix in the BA help explain some of the variability.

16 USACE Pressbooks: <https://cdm16021.contentdm.oclc.org/digital/collection/p16021coll6/id/42>

17 Bureau of Reclamation Budget Justifications: <https://www.usbr.gov/budget/>

Figure ES-13 displays the mean and 10th to 90th percentile range of the distribution of one-hour ramps performed by the hydropower (including PSH) and natural gas fleets by BA in 2019.¹⁸ BAs are ordered left to right from largest to smallest hydropower and PSH capacity. For each fleet, to facilitate comparison, the ramp distribution is shown as percentage of its installed capacity.

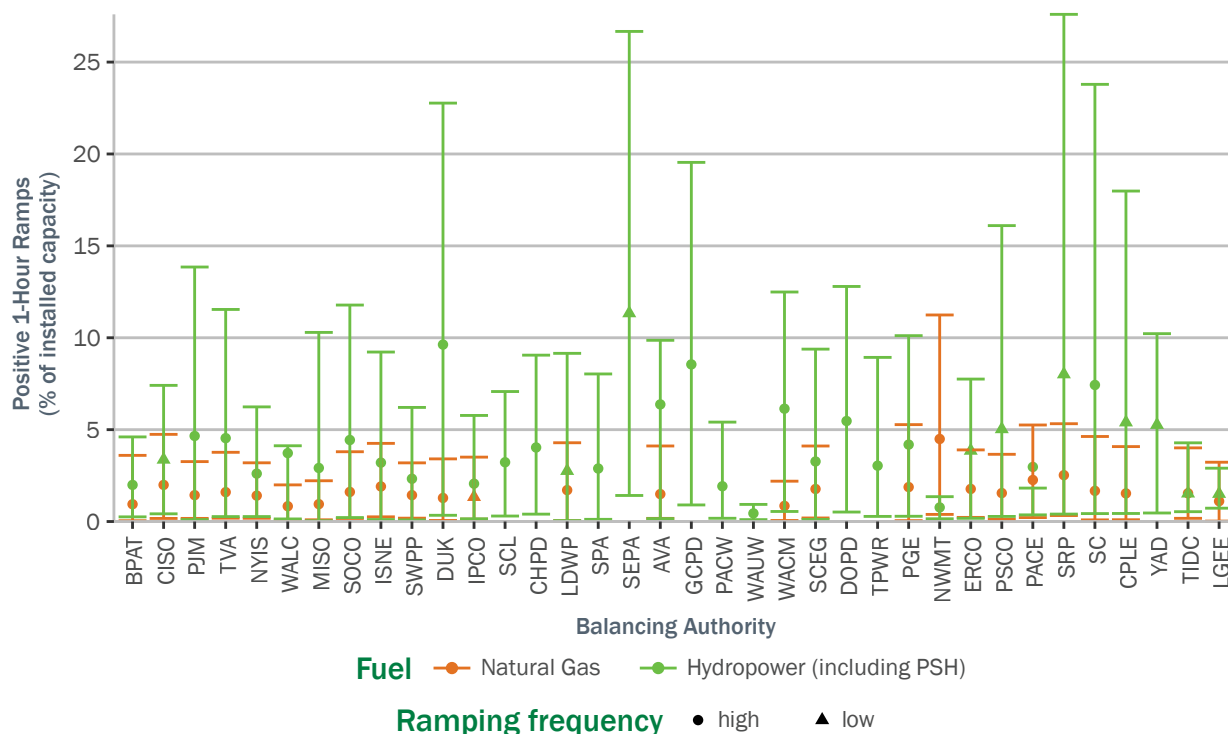


Figure ES-13. One-hour ramps per installed megawatt for hydropower (including PSH) and natural gas by balancing authority (BA) in 2019

Source: EIA Form 930

Notes: BA acronym definitions are provided in the Appendix. Only positive ramps are shown. The distribution of negative ramps mirrors that of positive ramps almost exactly. CISO (CAISO) data are missing for October-December. Balancing authorities with less than 100 MW of hydropower and PSH capacity or with reported generation values greater than what would be feasible given the installed capacity are excluded. High-frequency ramping means that the fleet changed generation level from one hour to the next in at least 75% of hours in the year (both positive and negative changes were counted for this classification).

IN MULTIPLE ISOs, THE SHARES OF FREQUENCY REGULATION AND RESERVES PROVIDED BY HYDROPOWER ARE MUCH HIGHER THAN HYDROPOWER'S SHARE OF INSTALLED CAPACITY

For instance, in the Pennsylvania–Jersey–Maryland (PJM) Interconnection, hydropower supplied a larger percentage of regulation, non-synchronized reserve, and day-ahead scheduling reserve in 2014–2019 than the percentage of installed capacity it represents in that ISO/RTO.¹⁹ However, Figure ES-14 shows that the share of reserves contributed by hydropower has decreased sharply in recent years.

18 The requirement for BAs to report hourly generation mix data to EIA became effective in July 2018. Therefore, 2019 is the first full calendar year for which this dataset was available.

19 In 2018, hydropower and PSH contributed 7.5% of cleared Tier 2 synchronized primary reserve. In 2019, run of river hydropower and PSH provided 6.8% and 5.4% of Tier 1 and Tier 2 synchronized primary reserve. Hydropower and PSH percentages for those products were not specified in earlier editions of the PJM State of the Market Report.

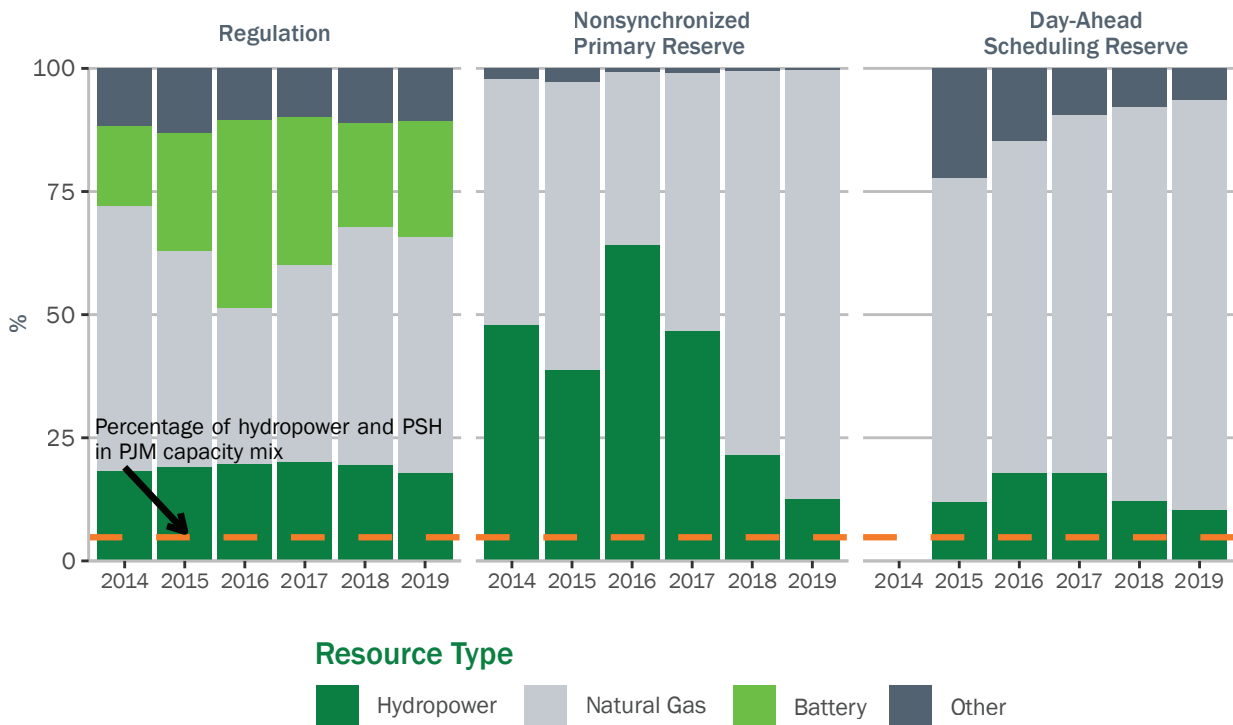


Figure ES-14. PJM ancillary service provision by hydropower and other resource types (2014–2019)

Source: PJM State of the Market Report (2014, 2015, 2016, 2017, 2018, 2019). https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml

Note: Natural gas includes the contribution from combustion turbines and combined cycles; however, it should be noted that a small portion of the fuel used by (dual-fired) combustion turbines is diesel.

HYDROPOWER REPRESENTS LESS THAN 10% OF U.S. ELECTRICITY GENERATION CAPACITY BUT IT PROVIDES APPROXIMATELY 40% OF BLACK START RESOURCES. More than 70% of U.S. hydropower capacity can perform a cold unit start within 10 minutes and less than 5% need more than 1 hour for a cold start.

Chapter 6 – Trends in U.S. Hydropower Supply Chain

THE U.S. HYDRAULIC TURBINE MARKET REMAINS DIVERSE AND ROBUST — Almost 12 GW of hydropower and PSH turbine capacity has been installed in the United States since 2010. Seventy-nine percent of the 291 turbine installations went toward R&U of existing hydropower facilities and represented 96% of the turbine capacity installed. Fourteen (5%) of installations are PSH turbines that account for 33% of installed capacity in the past 10 years. In 2017–2019, at least 67 turbine units were installed in the United States (roughly 3 GW of combined capacity).²⁰

Five companies (American Hydro, Andritz, GE Renewable Energy, Voith, and Toshiba) manufactured the 92 turbines with capacities greater than 30 MW installed in the United States in the past decade, and more than a dozen companies served the demand for smaller turbines. American Hydro, Voith, and Andritz have manufacturing facilities in the United States.

The distribution of turbine types is significantly different for installations at new plants vs. unit replacements. For unit replacements, 62% of the units were Francis, and they represented 60% of capacity. For new projects, 72% (316 MW) of installed turbine capacity since 2010 has been Kaplan units, the preferred turbine type for low-head NPD developments.

Figure ES-15 shows the distribution of turbine installations—both new units and turbine R&U whose scope includes turbine runner replacements—among the three main types of hydraulic turbines: Francis, Kaplan, and Pelton disaggregated by turbine manufacturer. More than 99% of the turbine capacity in the “Other/Unknown” category since 2010 corresponds to seven PSH pump turbine units.

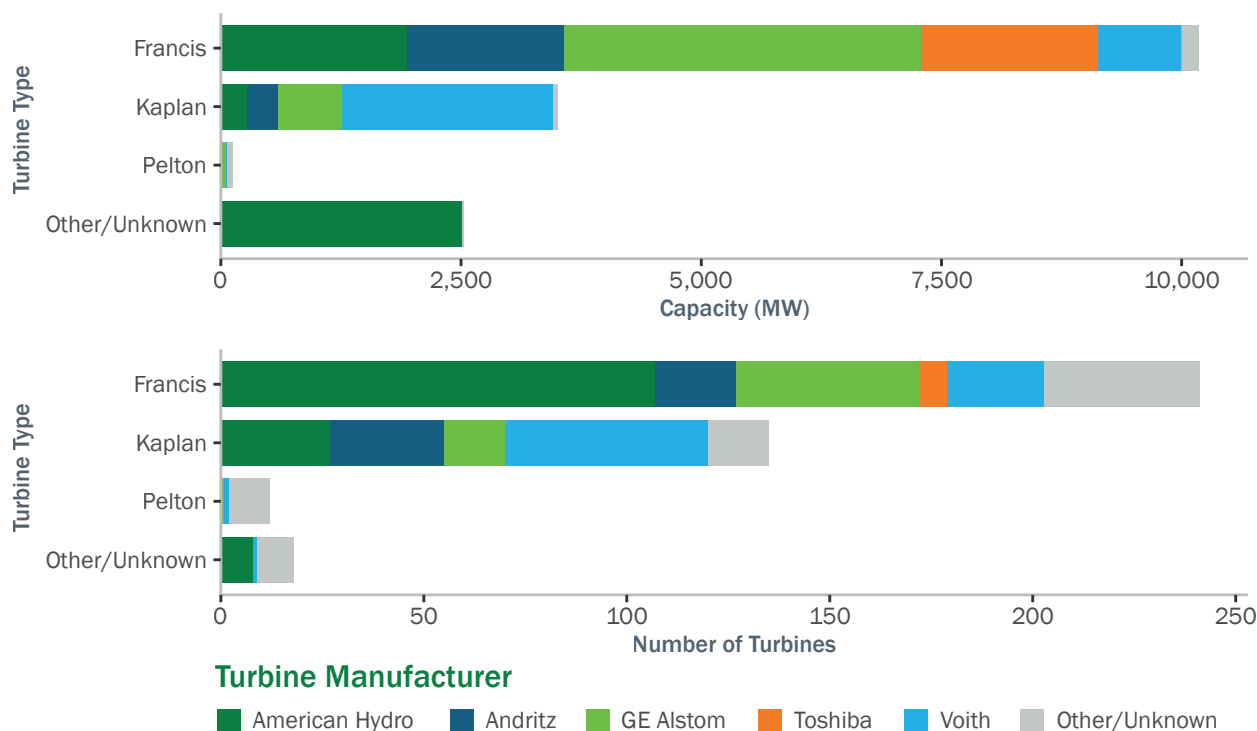


Figure ES-15. Installed hydropower turbines in the United States by type and manufacturer (2007-2019)

Source: IIR, Existing Hydropower Assets dataset, personal communication with Debbie Mursch (GE Renewable Energy), personal communication with Gerry Russell (American Hydro).

Note: The plot covers new turbines and turbine R&U whose scope includes turbine runner replacement.

²⁰ Data on turbine replacements come from IIR. The IIR dataset primarily tracks turbine R&U at medium and large plants owned by federal agencies, utilities, and wholesale power marketers.

FOR 2015–2019, THE U.S. HYDRAULIC TURBINE TRADE BALANCE WAS CLOSE TO ZERO – The values of turbine/turbine parts imports and turbine/turbine parts exports during that period were \$279 million and \$263 million, respectively. The three top countries from which the United States imported turbines and turbine parts in the past five years were China, Canada, and Brazil—the countries with the three largest hydropower fleets in the world. Canada and Mexico were the two top countries to which the United States exported turbines and turbine parts; they accounted for 51% of exports in 2015–2019. Figure ES-16 displays the U.S. hydraulic turbine (and turbine parts) trade flows from 1996 to 2019 and zooms into the composition of trade flows in the past five years.

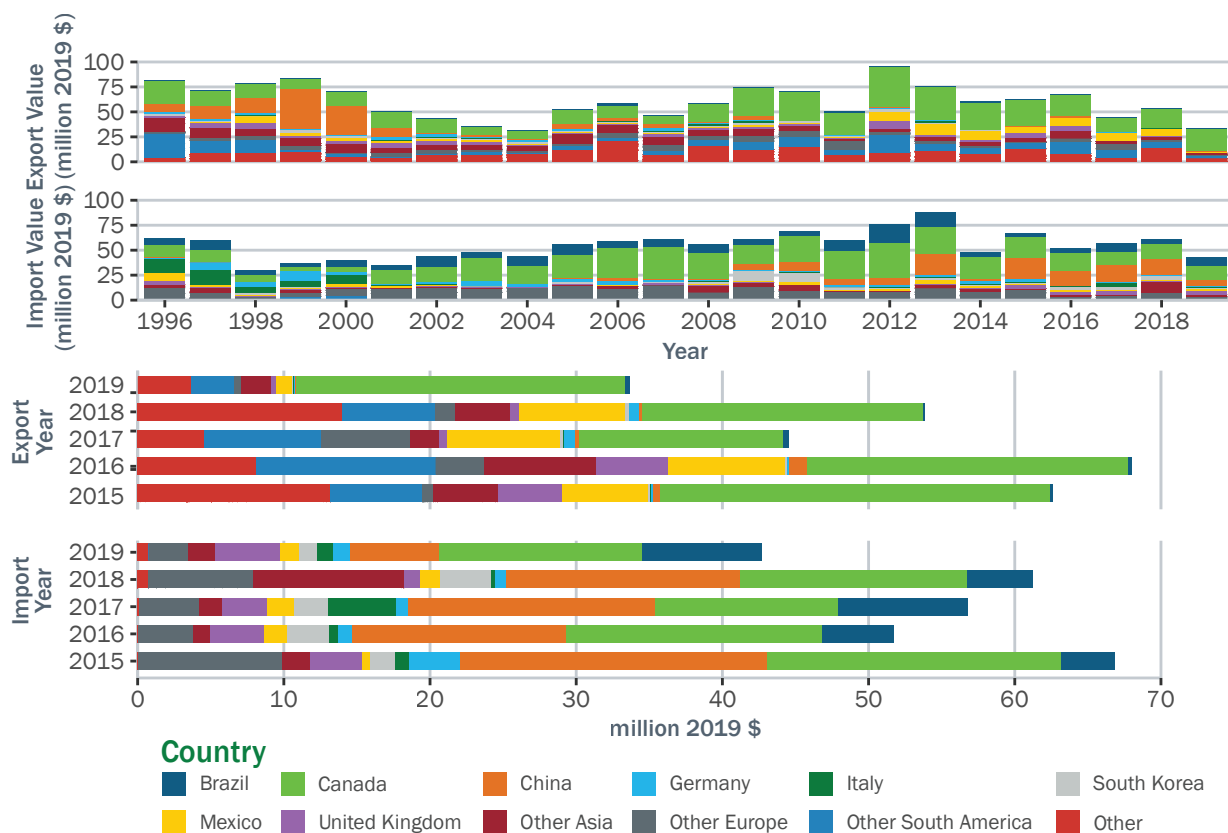


Figure ES-16. U.S. hydropower turbine/turbine parts import and export values by country

Source: U.S. International Trade Commission

Note: The 2019 data are preliminary and could be subject to revision by USITC

Chapter 7 – Overview of New Policies Influencing the U.S. Hydropower Market

In October 2017, FERC announced a revised policy on license terms (for both original licenses and relicenses) in which the default term became 40 years. Nevertheless, FERC can still issue longer or shorter licenses if needed to coordinate license terms for projects within the same river basin or supported by a settlement agreement. Moreover, a longer license term can be granted if the relicense requires extensive new measures or the licensee already voluntarily implemented significant measures during the prior license term.

The American Water Infrastructure Act of 2018 (AWIA) directed FERC to introduce an expedited licensing process—2 years from license application to final decision—for qualifying NPDs and closed-loop PSH projects. AWIA also introduced amendments to the qualifying conduit authorization pathway and allows FERC to extend preliminary permits and construction start timelines for longer periods. Additionally, AWIA directs FERC, in determining the term of a relicense, to give the same weight to project-related investments made over the term of the existing license—if those investments have not been expressly considered by FERC as contributing to the length of the existing license term—and investments to be made under the new license.

States are committing to increasingly ambitious renewable or clean energy mandates and energy storage targets that could help increase investment in new hydropower and PSH.

- » Since 2018, at least nine states have increased their renewable energy targets, and eight states (i.e., California, Hawaii, Maine, New Mexico, New York, Rhode Island, Virginia, Washington), as well as Washington D.C. and Puerto Rico, have set a 100% renewable or clean energy mandate. Hydropower is limited in its eligibility to meet RPS targets in most states, but it typically counts toward clean energy mandates (Stori, 2020).
- » Seven states have adopted energy storage targets, and many others are considering introducing them. For the seven states which have adopted energy storage targets, Table ES-2 shows target capacity, target year, and the supporting policy document. PSH is typically eligible to meet those targets but, given target sizes and years, will not be a practicable technology option in some of the states.

Table ES-2. State Energy Storage Mandates/Targets (as of March 2020)

State	Target	Target Year	Target Type	Policy Document
California*	1,325 MW	2020	Mandate	D. 13-10-040
Oregon	5 MWh (for each utility serving more than 25,000 customers)	2020	Mandate	HB 2193
New Jersey	2,000 MW	2030	Target	Assembly No. 3723
New York	1,500 MW (aspirational goal of which 350 MW are mandated)	2025	Mandate	PSC CASE 18-E-0130
Massachusetts	1,000 MWh	2025	Target	H4857
Nevada	1,000 MW	2030	Target	Docket No. 17-07014
Virginia	3,100 MW	2035	Target	SB 851

*: PSH facilities with capacity greater than 50 MW are not eligible.

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Acronyms and Nomenclature

AWIA	American Water Infrastructure Act of 2018	O&M	operations and maintenance
BA	balancing authority	PJM	Pennsylvania–Jersey–Maryland Interconnection
BPA	Bonneville Power Administration	PMA	power marketing administration
CAISO	California Independent System Operator	PPA	power purchase agreement
DOE	Department of Energy	PSH	pumped storage hydropower
EIA	US Energy Information Administration	PURPA	Public Utility Regulatory Policies Act
FERC	Federal Energy Regulatory Commission	QF	qualifying facility
FY	Fiscal Year	R&U	refurbishments and upgrades
GADS	Generating Availability Data System	Reclamation	U.S. Bureau of Reclamation
HUC	hydrologic unit code	RPS	renewable portfolio standard
IIR	Industrial Info Resources	RTO	regional transmission organization
ISO	independent system operator	SPP	Southwest Power Pool
ISO-NE	ISO New England	SEPA	Southeastern Power Administration
LOPP	Lease of power privilege	SWPA	Southwestern Power Administration
NERC	North American Electricity Reliability Corporation	WECC	Western Electricity Coordinating Council
NOPR	Notice of Proposed Rulemaking	WAPA	Western Area Power Administration
NPD	non-powered dam		
NSD	new stream-reach development		

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Introduction



Introduction

This is the third complete edition of the U.S. Hydropower Market Report (the first two were the [2014](#) and [2017](#) Hydropower Market Report published in 2015 and 2018, respectively);^{1,2} In intervening years between publishing the full report, updated data are also summarized and released, and can be found at the Oak Ridge National Lab (ORNL) [HydroSource](#) website.³ This report combines data from public and commercial sources as well as research findings from other Department of Energy (DOE) R&D projects in order to provide a comprehensive picture of developments in the U.S. hydropower and PSH fleet and industry trends. Prior to the first Market Report being published, there was a noted lack of publicly available and easily accessible information about hydropower in the United States and other important trends affecting this important sector of the energy industry. New and valuable types of information are constantly being developed in the course of DOE research activities and, in a rapidly evolving energy industry, it is important that these data be made available in a predictable and consistent manner for use by all different types of stakeholders and decision-makers.

The report highlights developments in 2017–2019 (the years for which new data has become available since the publication of the 2017 Hydropower Market Report), and contextualizes this information compared to evolving high-level trends over the past 10–20 years. Apart from presenting trends over time, the report discusses differences in those trends by region, plant size, owner type, or other attributes. This “In Brief” section highlights some of the key points of interest, including charts and visuals, from the seven chapters in the report.

A summary of the new content in each of the report chapters is shown in Table ES-1. This edition also updates the information about U.S. and global hydropower and PSH development pipeline, hydropower prices, and performance metrics for the period since the publication of the 2017 Hydropower Market Report. For discussion of the flexibility services and contributions to grid reliability provided by U.S. hydropower and PSH, the report also summarizes findings from research conducted under the Department of Energy’s [HydroWIRES](#) initiative.⁴

Table ES-1. Summary of updated and new content by chapter

Chapter	New content
1	<ul style="list-style-type: none">• Relicensing hydropower and PSH activity in the United States
3	<ul style="list-style-type: none">• International comparison of hydropower permitting processes• International comparison of hydropower incentives
4	<ul style="list-style-type: none">• Detailed revenue data (energy, capacity, ancillary services) for selected U.S. PSH plants
5	<ul style="list-style-type: none">• Hourly ramping for U.S. hydropower and PSH fleet (and natural gas) by balancing authority• Participation of U.S. hydropower and PSH in ISO/RTO ancillary services markets
7	<ul style="list-style-type: none">• List of new FERC regulatory policies influencing hydropower• List of U.S. jurisdictions with clean energy mandates and energy storage mandates/targets

1 <https://www.energy.gov/eere/water/downloads/2014-hydropower-market-report>

2 [https://www.energy.gov/sites/prod/files/2018/04/f51/Hydropower Market Report.pdf](https://www.energy.gov/sites/prod/files/2018/04/f51/Hydropower%20Market%20Report.pdf)

3 <https://hydrosorce.ornl.gov/>

4 <https://www.energy.gov/eere/water/hydrowires-initiative>



Chapter 1

Looking Back: An Overview of Changes Across the U.S. Hydropower and PSH Fleet

- 1.1 New Project Development and Capacity Changes (2010–2019)**
 - 1.2 Ownership Changes (2010–2019)**
 - 1.3 Investment in Refurbishments and Upgrades (2010–2019)**
 - 1.4 Relicensing Trends (2010–2019)**
- 

1. Looking Back: An Overview of Changes Across the U.S. Hydropower and PSH Fleet

At the end of 2019, 2,270 hydropower plants were operational in the United States with a total generating capacity of 80.25 GW.¹ In 2019, this hydropower fleet produced 6.6% of all electricity and 38% of electricity from renewables in the United States.² Additionally, 43 PSH plants with a total generation capacity of 21.9 GW provided 94% of utility-scale electrical energy storage capacity. Table 1 shows the top 20 states by installed capacity and hydropower’s share in the electricity generation mix.

This chapter presents an overview of the U.S. hydropower fleet and summarizes key developments over the past few years since the publication of the last full U.S. Hydropower Market Report, and broadly over the past decade. It contains information on capacity additions to existing hydropower plants and new developments, as well as retirements. Trends in R&U investment in the existing fleet are also discussed. Additionally, the chapter presents data on license transfers (i.e., changes in ownership), issued relicenses, and license surrenders.

Table 1. Top 20 States by Installed Hydropower Capacity and Hydropower Percentages of In-State Generation

Hydropower Capacity (MW)		Hydropower Percentage of In-State Generation (%)		Pumped Storage Hydropower Capacity (MW)	
Cumulative (end of 2019)		Average (2017–2019)		Cumulative (end of 2019)	
Washington	21,191	Washington	67.59	California	3,758
California	10,107	Idaho	59.15	Virginia	3,109
Oregon	8,448	Vermont	57.62	South Carolina	2,657
New York	4,727	Oregon	54.58	Michigan	1,979
Alabama	3,109	South Dakota	47.43	Massachusetts	1,768
Idaho	2,733	Montana	37.93	Tennessee	1,714
Arizona	2,722	Maine	29.93	Georgia	1,635
Montana	2,710	Alaska	24.66	Pennsylvania	1,541
Tennessee	2,504	New York	22.72	New York	1,240
Georgia	2,178	California	17.86	Missouri	600
North Carolina	1,904	Tennessee	11.89	Colorado	508
South Dakota	1,650	New Hampshire	7.63	New Jersey	453
South Carolina	1,366	Alabama	7.31	Washington	314
Arkansas	1,321	North Dakota	6.88	Oklahoma	259
Kentucky	1,098	Arizona	6.02	Arizona	194
Nevada	1,057	Maryland	5.93	North Carolina	95
Pennsylvania	870	Kentucky	5.8	Connecticut	31
Virginia	831	Nevada	5.03	Arkansas	28
Oklahoma	819	Arkansas	4.56	<i>Rest of United States</i>	0
Maine	724	North Carolina	4.2		
<i>Rest of United States</i>	8,180	<i>Rest of United States</i>	1.39		

Sources: Existing Hydropower Assets dataset, EIA Form 923

Note: in-state generation percentages do not include hydropower-based electricity imports from Canada.

1 A plant is defined as a facility containing one or multiple powerhouses located at the same site and using the same pool of water. A hydropower project may include one or more plants.
 2 In 2019, wind generation surpassed hydropower as the largest renewable electricity generation source in the United States for the first time, producing 300 TWh as opposed to the 274 TWh produced by hydropower, according to EIA (<https://www.eia.gov/todayinenergy/detail.php?id=42955#>).

Half of all U.S. hydropower capacity is concentrated in three states on the Pacific coast: Washington, Oregon, and California. For Washington and Oregon, hydropower accounts for more than 50% of the electricity generated in those states; for California, hydropower represents a more modest share of generation (18%). In 2017–2019, hydropower represented more than 20% of electricity generated in nine states, mostly in the Northwest and Northeast. For the 30 states not included in Table 1, hydropower represents a small portion of electricity generation on average.

Delaware and Mississippi are the only states that have no hydropower at all. In contrast, less than half of the states have any PSH facility, and two thirds of installed PSH capacity are in the Northeast and Southeast regions. Nonetheless, California is the state with the highest number of PSH facilities and highest PSH capacity.

The estimated energy storage capacity of the U.S. PSH fleet is 553 GWh.³ That would be the electricity volume generated by passing through the turbines all the water in the PSH upper reservoirs that it’s allocated for power generation. For comparison, 553 GWh would be the volume produced by the U.S. hydropower fleet at a capacity factor of 38.9% (the average U.S. hydropower median capacity factor in 2005–2018) for approximately 18 hours. Depending on the generating capacity of each PSH plant and the volume of water in its upper reservoir that can be used for electricity generation, the number of hours to pass that water through the turbines varies widely across plants. For instance, storage duration is four hours for Cabin Creek (Colorado) and more than 100 hours for Helms (California).

For context, Figure 1 shows PSH generating capacity (21.9 GW) and energy storage capacity (553 GWh) alongside all other utility-scale energy storage projects operational in the United States by the end of 2019. All those other projects—including batteries, flywheels, solar thermal with energy storage, and natural gas with compressed air energy storage—had a combined capacity of 1.6 GW and energy storage capacity of 1.75 GWh.

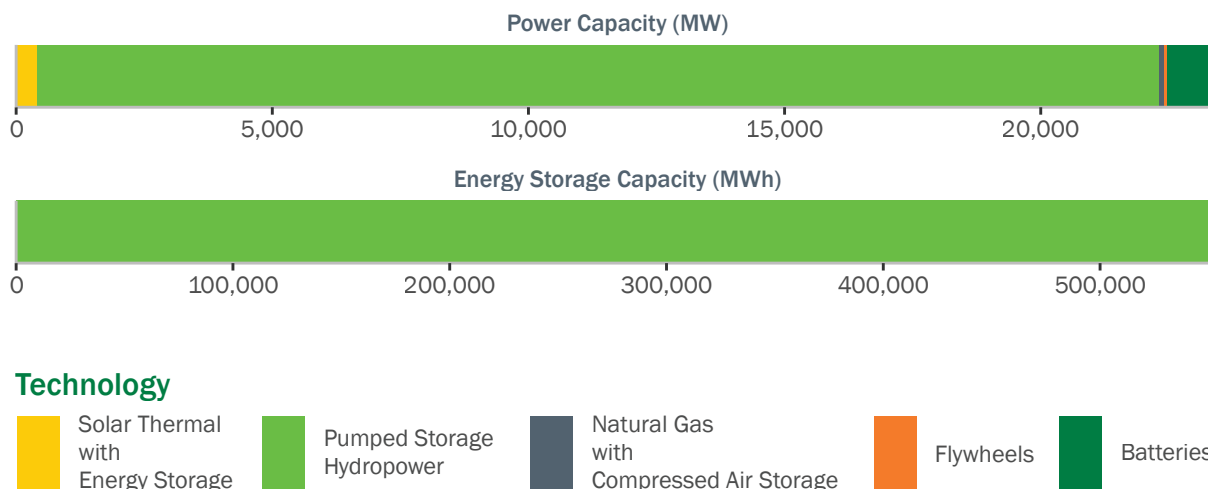


Figure 1. U.S. Utility-scale electrical energy storage capacity by technology type (2019)

Source: EIA Form 860 Early Release (2019)

3 See Appendix for details on the data sources and approach used to estimate energy storage capacity.

1.1 New Project Development and Capacity Changes (2010–2019)

Hydropower capacity in the United States (excluding PSH) increased by 1,688 MW from 2010 to 2019. The net increase was primarily from capacity additions to the existing fleet, but 562 MW came from 119 new plants, which mostly added hydropower generation to NPDs and conduits.

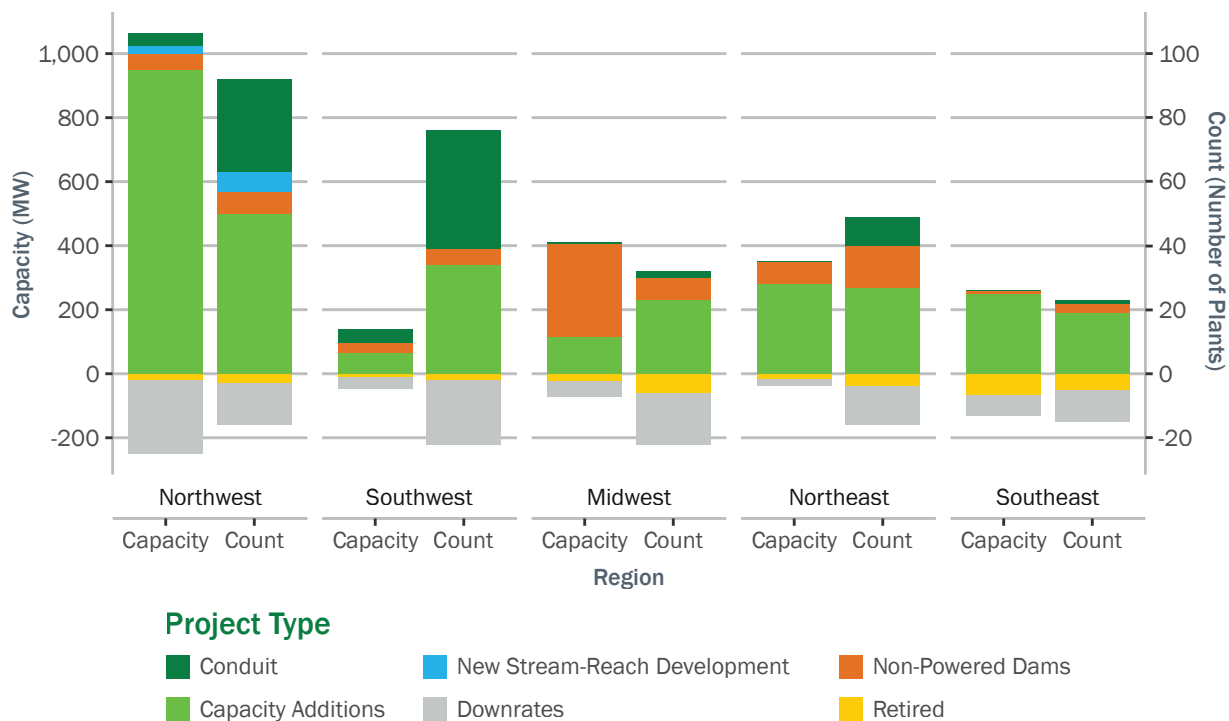


Figure 2. Hydropower capacity changes by region and type (2010–2019)

Sources: EIA Form 860 (2010-2018), EIA Form 860 Early Release (2019), Existing Hydropower Assets dataset, FERC eLibrary

Note: Each instance of a capacity increase or decrease reported in EIA Form 860 is counted separately. Some plants reported multiple capacity changes during this period. Figure ES-3 contains information on which states are included in each region. See Glossary for project type definitions.

From 2010 to 2019, capacity added from new projects or upgrades to the existing fleet (2,225 MW) outweighed capacity reductions due to plant retirements or unit downrates (538 MW).⁴ Therefore, installed hydropower capacity in the United States experienced a net increase of 1,688 MW during that period. Net increases took place in every region.

Changes in PSH capacity are not included in Figure 2. Installed PSH capacity increased from 20.5 GW in 2010 to 21.9 GW in 2019. Except for the Olivenhain-Hodges facility in San Diego (42 MW), the rest of the increase came from upgrades to the existing fleet. Six plants upgraded their nameplate capacity during this period: Castaic in California, Northfield Mountain in Massachusetts, Muddy Run in Pennsylvania, and Bad Creek, Fairfield, and Jocassee in South Carolina. The most recent increase, reported in 2018, resulted from upgrading the four units of the Northfield Mountain facility (Massachusetts). The capacity of each of the new units was 24% higher than before the upgrade for a total capacity increase of 228 MW.

Capacity additions resulting from upgrades to existing plants added up to 1,664 MW during the past decade. The regional distribution of the Capacity Additions bar segments in Figure 2 differs significantly from the regional shares of installed capacity. The greatest divergence is for the Southwest region, which accounts for 19% of installed capacity but only 4% of the megawatts in the Capacity Additions category. On the other hand, the Northwest contains 45% of installed capacity and 57% of capacity additions in the past decade. Over half (52%) of the Capacity Additions took place at privately owned hydropower plants. The federal fleet (hydropower plants owned by the US Army Corps of Engineers, Reclamation, or the Tennessee Valley Authority) accounted for almost 50% of installed hydropower capacity but 20% of Capacity Additions from 2010 to 2019.

⁴ Some of the downrates are temporary because they correspond to units taken out of service for rehabilitation or upgrade. Downrates also include plants in which individual units are kept out of service because the investment required to keep them operational is deemed too expensive.

Nonfederal public owners (publicly owned utilities, state agencies, municipalities, and cooperatives) added the remaining 28% of new capacity to their plants.

The Northwest and Southwest display the highest number of new projects (42 each), which are mostly small conduit installations. Eight of the 78 conduit installations in the past decade repowered conduits that had been inactive for several years. For the other three regions, new development in the past 10 years has strongly concentrated on the addition of hydropower generation to NPDs. Of the 35 NPD projects shown in Figure 2, six were repowerings of dams that had produced hydropower in the past but had been retired for several years. Finally, all six NSDs have taken place in the Northwest.

In 2017–2019, 40 capacity additions (583.1 MW) and 26 downrates (–215.8 MW) were incorporated into the existing fleet. Moreover, two NSD projects were completed, and hydropower generation capability was added to 15 conduits and four NPDs. The combined capacity of all the new projects was 114.7 MW, 83% of which corresponded to the four largest projects: Smithland NPD in Kentucky (75.9 MW), Pueblo Dam NPD in Colorado (7 MW), and the two NSDs in Washington—Calligan Creek and Hancock Creek (6 MW each). Finally, six plants retired, reducing the installed capacity by 51 MW. Rocky Creek (South Carolina, 28 MW) is the largest of the 32 retirements in Figure 2.

The following textboxes describe in more detail some of the new projects that became operational in the past three years or are in the late stages of construction.

CALLIGAN CREEK

The Calligan Creek hydropower plant started operation in 2018 in King County (Washington). The developer of this NSD, PUD No.1 of Snohomish County, submitted a license application in August 2013, and the Federal Energy Regulatory Commission (FERC) issued the original license in June 2015. Construction started by the end of that year and was completed in February 2018. The hydropower plant is a run-of-river facility with a 6-MW Pelton turbine and an estimated capacity factor of 39%. Construction involved building a 45-ft wide, 8-ft tall weir for the water not diverted through the turbine to flow over; a fish ladder; a 1.2-mile penstock; a powerhouse; and 2.5 miles of transmission line to interconnect with the grid.



Calligan Creek Powerhouse (image courtesy of Snohomish PUD)

JAMES W. BRODERICK PLANT AT PUEBLO DAM

In 2011, the Southeastern Colorado Water Conservancy District submitted a proposal to develop hydropower at Pueblo Dam in response to a call for applications by the U.S. Bureau of Reclamation (Reclamation). Reclamation selected the proposal, and both parties engaged in the lease of power privilege (LOPP) permitting process, which is necessary for nonfederal hydropower development at Reclamation-owned dams authorized for federal power development. Reclamation granted the LOPP in April 2017.⁵ Construction started in September of the same year. The Southeastern Colorado Water Conservancy District signed 30-year PPAs with the City of Fountain and Colorado Spring Utilities. The total cost of the project was \$20.2 million, 85% of which came from a low-interest loan by the Colorado Water Conservation Board.⁶ The powerhouse contains three turbines and two generators with a total capacity of 7.01 MW. The facility started operation in May 2019.



Pueblo Dam turbine-generator units (image courtesy of Kevin Meador, Southeastern Colorado Water Conservancy District)

FULTON HYDROPOWER PROJECT

The Fulton hydropower project is in Custer County (Idaho). It has a Pelton-Twin Jet turbine with a nameplate capacity of 0.406 MW. The developer applied to FERC for qualifying conduit determination in December 2014. FERC issued the qualifying conduit determination in February 2015 after a 45-day comment period in which no objections were raised by the public. The project required pressurizing a pipeline owned by the developer and previously used for irrigation and water storage. Construction started in April 2016 but was held up for two years until the Bureau of Land Management issued a right-of-way authorization. After resuming construction in April 2018, the project was completed in July 2019.



Fulton Hydropower Project turbine-generator unit (image courtesy of Gordon Fulton)

5 Reclamation introduced a simplified LOPP process in 2012. The permitting process has been much shorter for projects using the new process (Curtis et al., 2018)

6 <https://www.chiefain.com/news/20190604/new-hydroelectric-plant-at-pueblo-dam>

RED ROCK HYDROELECTRIC PROJECT

The Red Rock project in Marion County (Iowa) adds 36 MW of hydropower generation capability to the U.S. Army Corps of Engineers–owned Red Rock dam. FERC issued the license for this project to the Western Minnesota Municipal Power Agency in 2011. Additionally, the developer had to obtain Section 408 authorization from the U.S. Army Corps of Engineers. Missouri River Energy Services, acting on behalf of the licensee, manages the construction and operation of the facility. Construction started in 2014 and was completed in the summer of 2020—later than originally expected as flooding conditions in the spring of 2019 forced crews to interrupt penstock construction. The powerhouse will contain two turbine-generator units with Kaplan turbines.⁷ Commercial operation is scheduled to commence in the spring of 2021.



Red Rock Hydroelectric Project powerhouse overview during construction (image courtesy of Missouri River Energy Services)

⁷ <https://www.hydroreview.com/2019/07/16/powering-red-rock-dam/#gref>

1.2 Ownership Changes (2010–2019)

FERC has approved 287 license and exemption transfers since 2010 which resulted in ownership changes for more than 300 hydropower plants and three PSH plants. After a period (2012–2017) in which 30 or more plants were being transferred each year, the number of plant transfers was much lower in 2018–2019. Ninety-five percent of transfers in 2010–2019 were between privately owned entities.

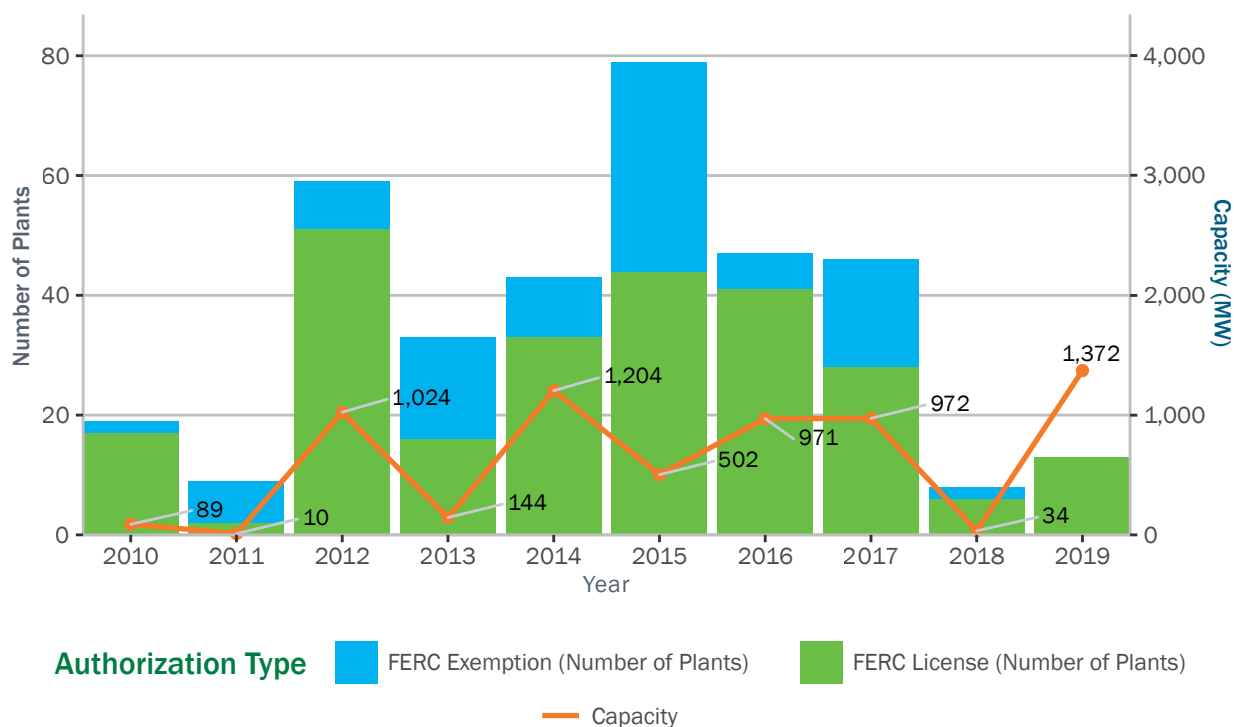


Figure 3. Hydropower and PSH ownership transfers by year and authorization type

Sources: FERC eLibrary, Existing Hydropower Assets dataset

Since 2010, 287 FERC licenses and exemptions have been transferred, resulting in ownership changes for 356 plants. The total capacity transferred from 2010 to 2019 is 6.3 GW. Sixty-eight percent of the transfers corresponded to hydropower and PSH plants in the Northeast. Transfers from one privately owned entity to another represented 95% of the total showing that U.S. fleet percentages owned by public vs. private entities have not changed significantly as a result of these transactions.

Figure 3 shows that the number of license and exemption transfers in 2018–2019 (eight each year) has been much lower than in previous years. The set of plants transferred in the past two years includes 1 very large (>500 MW), 6 medium (10–100 MW), and 14 small (≤10 MW) plants. Both transferor and transferee were private entities (utilities or non-utilities) in all but one of these transfers. Half of the license transfers in 2019—including Northfield Mountain PSH, which accounts for 85% of transferred capacity that year—were from FirstLight Hydro to other affiliates within the same company.

In 2018, the Public Service Company of New Hampshire (operating as Eversource Energy) transferred five licenses to an affiliate of the private equity firm Hull Street Energy. These transfers and the related plant sales are part of the divestiture of assets required by the New Hampshire Public Utilities Commission as part of the deregulation process of the electricity market in that state. Another instance of transfer from an investor-owned utility to a private non-utility is Cushaw (Virginia, 7.5 MW) in 2019. The Virginia Electric and Power Company sold this project because the capital expenditures required to upgrade the facility were more expensive than selling the project and purchasing replacement power. The utility might continue purchasing the electricity generated by Cushaw under its new ownership.

1.3 Investment in Refurbishments and Upgrades (2010–2019)

Since 2010, at least \$7.8 billion have been invested in R&U to the U.S. hydropower and PSH fleets. In 2017–2019, R&U investments have included dozens of projects in the federal fleet and a few large projects in the PSH fleet.

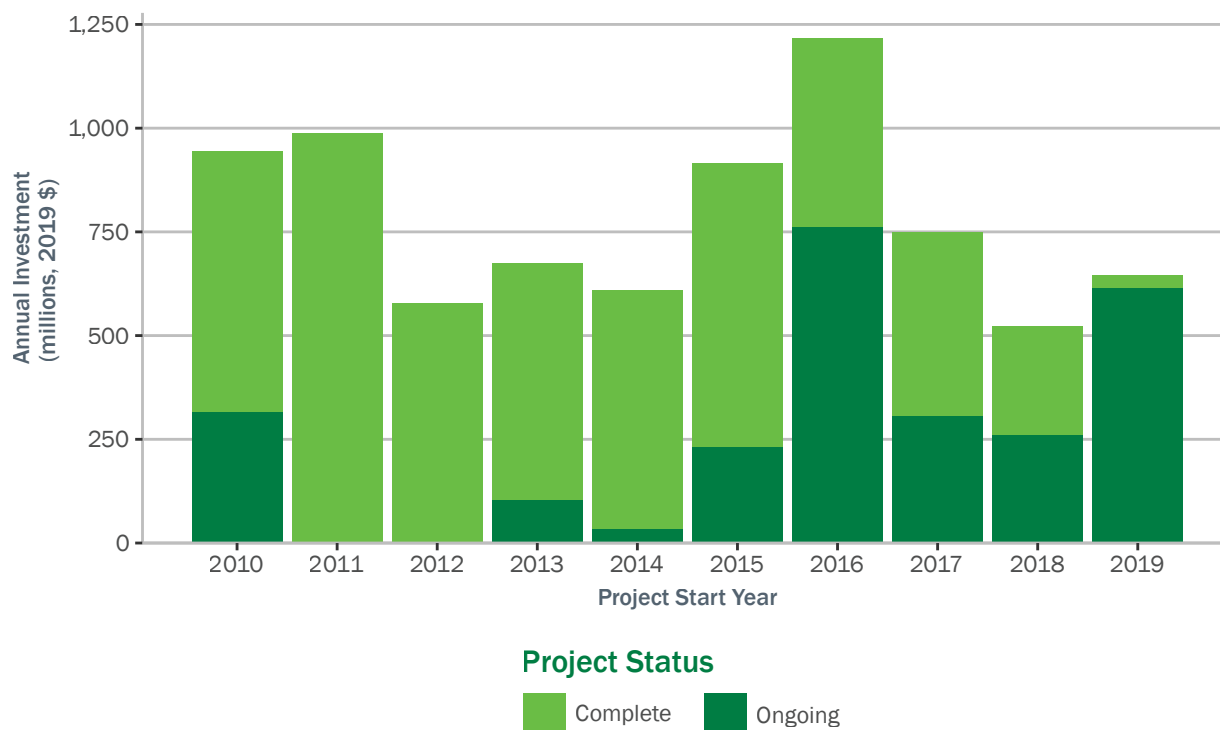


Figure 4. Expenditures on rehabilitations and upgrades of the existing hydropower and PSH fleet (as of December 31, 2019)

Source: IIR.

Note: The full value of each project is assigned to the project start year. Total R&U investment for one hydropower plant can be broken up into several projects over a long time period. See glossary for definitions of refurbishment vs. upgrade.

At the end of 2019, 49 R&U projects were underway with a total investment value of \$2.6 billion. An additional \$5.2 billion have been invested in R&U projects completed since 2010. The most common items in the set of 339 R&U projects included in Figure 4 are replacement or refurbishment of turbine runners (104 projects), generator rewinds (91 projects), installation of digital governors (34 projects), replacement or refurbishment of floodgates (28 projects), and replacement or upgrade of the transformer (16 projects). Many projects combine several of these items within their scope.

The fraction of total R&U investment dedicated to the PSH fleet during this period (24%) was slightly higher than the fraction of capacity that PSH represents in the combined hydropower and PSH fleet (20%). For the Southwest, Northeast, and Southeast regions, the fraction of national hydropower R&U investment is very close to their shares of installed hydropower (including PSH) capacity. The Northwest contains 35% of installed capacity and accounted for 28% of R&U investment during this period. However, the fraction of R&U investment in Midwest plants (18%) is more than double its fraction of capacity (8%). The relatively large fraction of R&U investment in the Midwest is driven by one large project: the upgrade of the Ludington PSH plant (1,979 MW).

The distribution of R&U hydropower investments initiated between 2010 and 2019 across owner types mimics closely the distribution of installed capacity. Privately-owned plants represent 27% of installed capacity and accounted for 26% of R&U investment. On average, nonfederal public owners spent the most per kilowatt in R&U during the past decade as they own 24% of installed capacity and were responsible for 27% of the R&U investment during that period. The federal fleet accounted for 47% of the R&U investment in hydropower (excluding PSH) and 49% of installed capacity. Out of the 122 R&U projects with a start date in 2017–2019, 71% were for the federal fleet, but they represented only 30% of the investment initiated in those three years.

R&U investment initiated in the past three years has been below the \$784 million annual average for 2010-2019. Noteworthy among the projects initiated in 2019 is New York Power Authority's R&U of the Robert Moses Niagara plant (2.4 GW). This initiative will involve an estimated investment of \$1.1 billion over a 15-year period.⁸ Refurbishment of the plant's penstock and head gate, included within the set of 2019 projects in Figure 4, constitute the first phase of this long-term R&U initiative.

1.4 Relicensing Trends (2010–2019)

In the past decade, FERC issued 80 relicenses that extended the authorization to operate an additional 30 to 50 years to projects accounting for 17% (6.9 GW) of FERC-licensed hydropower capacity and 37% (6.7 GW) of FERC-licensed PSH capacity. In the decade of the 2020s, 281 licenses that currently authorize 12% (4.7 GW) of installed FERC-licensed hydropower capacity and 50% (9.1 GW) of FERC-licensed PSH are set to expire.

Relicensing is an important milestone in the lifecycle of a hydropower plant. Each hydropower license lasts for 30 to 50 years. When a license term expires, the project licensee must seek a new license, called relicensing. Relicensing is a multi-year process that requires consulting with all relevant stakeholders and conducting studies to evaluate the environmental impacts of the project. Compliance with the terms and conditions set by FERC in a relicense can require the project owner to make significant investments or change operations, as both the regulations and the science for measuring and mitigating impacts have changed since the project sought an original license. Given the time, expenditure, and risks involved, as the time for relicensing approaches, project owners re-evaluate whether continuing to own and operate the project makes financial sense. The alternatives to relicensing are to either transfer the license to a new entity or surrender it.

8 <https://www.hydroreview.com/2019/08/01/ny-governor-announces-1-1-billion-project-to-extend-life-of-niagara-power-project/#gref>

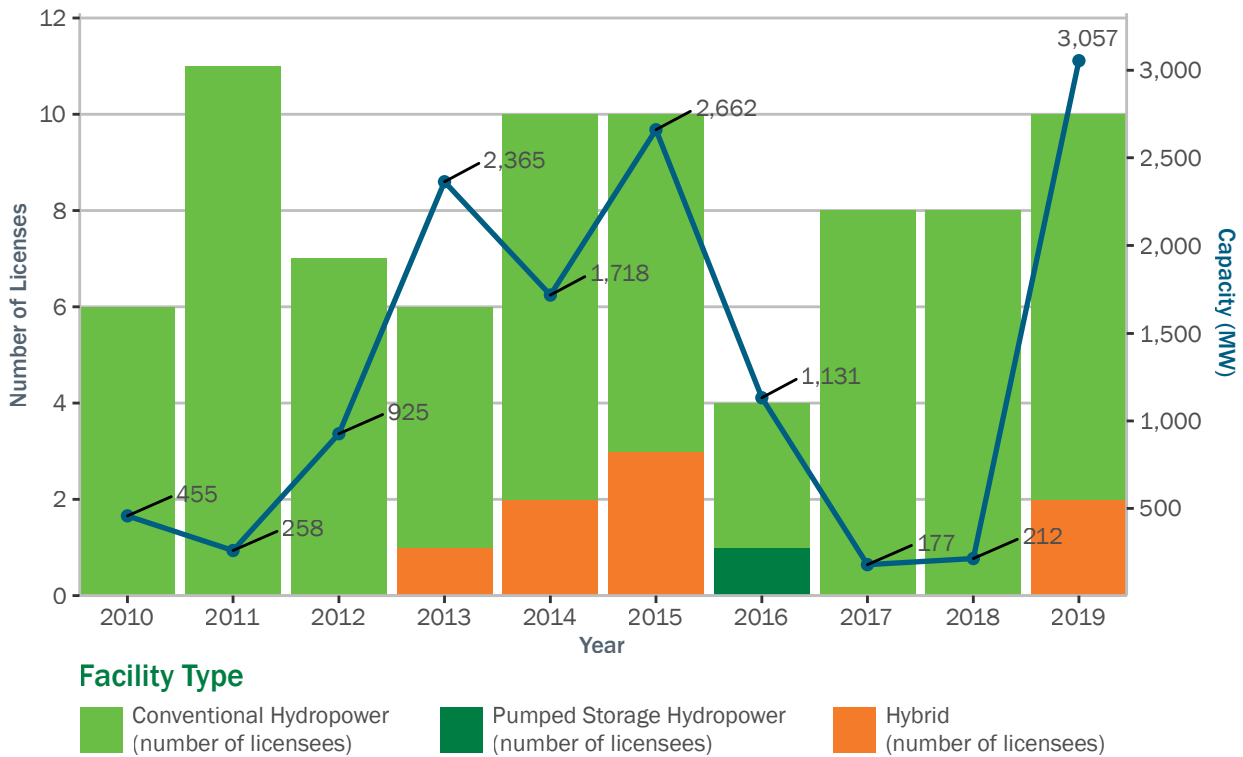


Figure 5. Issued hydropower and PSH relicenses by year and facility type

Source: FERC eLibrary

From 2010 to 2019, FERC issued 80 relicenses that extended the authorization to operate 71 hydropower projects, eight PSH projects, and one project containing both hydropower and PSH units. The total capacity relicensed from 2010 to 2019 (13.6 GW) represents 17% (6.9 GW) of installed FERC-licensed hydropower capacity and 37% (6.7 GW) of PSH FERC-licensed capacity. Figure 5 summarizes the number of relicenses and capacity relicensed by year and facility type. On average, FERC issued eight relicenses per year.

For relicenses issued in 2010–2017, 48% had 30-year terms, 35% had 40-year terms, and the remaining 16% had 50-year terms. In October 2017, FERC announced a revised policy on license terms (for both original licenses and relicenses) in which the default term became 40 years (See Chapter 7 for details). Out of the 18 relicenses issued in 2018–2019, 16 had license terms in the 40 to 49-year range and the other two were issued for 50 years.

More than half (55%) of the relicenses required some construction, usually for environmental measures or to add or improve recreational facilities. Relicense terms and conditions may also require changes in operations that restrict or, more rarely, enhance flexibility.

As part of the terms and conditions of a relicense, 44 of the relicensed projects (55%) required some construction. Most often, the construction was related to the addition/improvement of recreational facilities (e.g., boat launches, parking areas, trails) or environmental measures (e.g., installation of fish passage structures, replacement of turbines to improve their environmental performance). For six of the 44 projects, all with relicenses issued before 2015, construction involved turbine upgrades or installation of new turbines to increase power generating capacity. The additional authorized capacity across these six projects amounted to 90 MW. This capacity is only a small fraction (7%) of the capacity added by FERC-licensed projects in the same period (see Figure 2 discussion), which indicates most of the additions were authorized through capacity license amendments.

For most projects with relicenses issued from 2010 to 2019, the operation mode of the facility—typically peaking or run-of-river—remained unchanged after relicensing.⁹ Three of the 80 hydropower relicenses issued from 2010 to 2019, with a combined relicensed capacity of 83.5 MW, required run-of-river operation (either seasonally or all year) for projects that had previously been operated more flexibly (in peaking mode). For two of them (Claytor in Virginia and Waterbury in Vermont), the change in mode of operation was a mandatory condition to obtain a water quality certification from the relevant state agencies. In the third project (Scotland in Connecticut), it was the licensee who proposed to switch to run-of-river operation.¹⁰ Other relicenses issued in the past decade included terms or conditions that restrict operational flexibility to some extent (e.g., new or tighter ramping rate restrictions, increased minimum flows). However, for some projects, the changes agreed in a relicense result in additional flexibility. For instance, the relicense for the Yards Creek PSH project issued in 2013 approved the project’s owner proposal to raise the operating level of the upper reservoir to increase daily generation capacity and enhance operational flexibility.

In the decade of the 2020s, 281 licenses that currently authorize 12% (4.7 GW) of installed FERC-licensed hydropower capacity and 50% (9.1 GW) of FERC-licensed PSH capacity are set to expire and will require a relicense to continue operating. This number is significantly higher than the total number of licenses (168), including both original licenses and relicenses, issued by FERC in 2010–2019. Therefore, it highlights the expected increase in work for FERC licensing offices in the 2020s. On the licensee side, there are eight hydropower owners—a mixture of investor-owned utilities and private non-utilities—each holding five or more licenses that expire during the 2020s for whom relicensing activity will also be particularly intense.

Figure 6 displays their regional and size distribution. Some licenses authorize operation for multiple plants. The number of hydropower, PSH, and hybrid plants depicted in Figure 6 are 328, six, and two, respectively. The number of hydropower plants with licenses expiring in the Northeast region (169) is greater than in the other four regions combined. For 99 of those 169, this would be their first relicensing process as they started operating in 1980 or later. Since the average capacity of Northeast plants to be relicensed is small (5.5 MW), they only account for 21% of hydropower capacity whose licenses expire between 2020 and 2029. Additionally, one of the six PSH plants that will need a relicense during this decade is also in the Northeast (Bear Swamp in Massachusetts). Of the remaining five, four are in the Southeast (Bath County in Virginia, Rocky Mountain in Georgia, and Fairfield and Bad Creek in South Carolina) and the other one is Helms in California. At least 35 of the hydropower plants (536 MW) and five of the PSH plants (6.7 GW) to be relicensed have operated in peaking mode under their current license.¹¹

9 Peaking hydropower plants store and release water for hydroelectric generation at targeted times; their reservoirs may experience large fluctuations in elevation. Run-of-river hydropower minimizes the fluctuation of the reservoir surface elevation and deviation from natural flow regimes.

10 In that project, the licensee combines the switch to run-of-river operations with installation of an additional turbine resulting in a net increase in estimated annual electricity generation.

11 Mode of operation information, obtained from the Existing Hydropower Assets dataset, was not available for 90 of the 337 plants whose licenses expire in the 2020s.

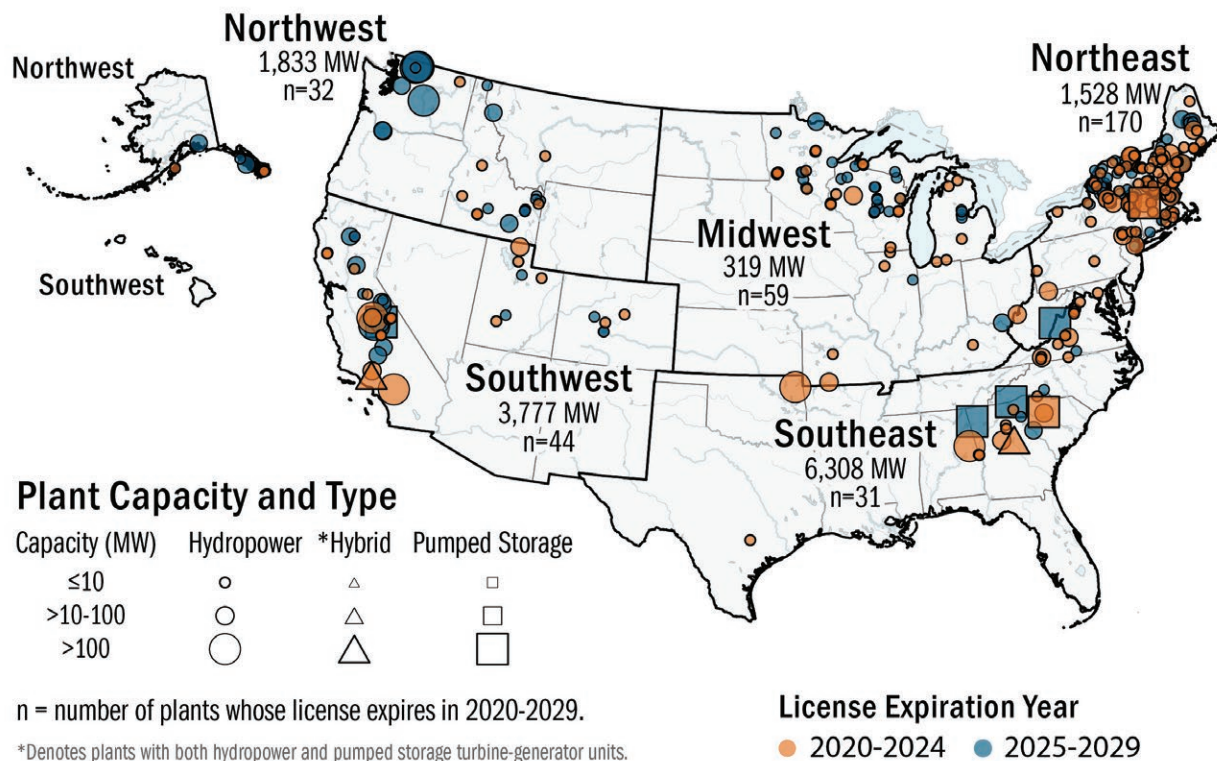


Figure 6. Hydropower and PSH plants with licenses expiring in 2020–2029

Source: Existing Hydropower Assets dataset

Plant owners must submit their relicensing application at least two years before the current license expires. Out of the 36 licenses with expiration dates in 2020 or 2021 (i.e., licenses included in Figure 6 for which a relicensing application should have been submitted by the end of 2019), 29 had submitted a relicensing application by the end of 2019, three applied for an extension of the term of their existing license, three submitted license surrender applications, and one was terminated by FERC as a result of its implicit surrender by the licensee.

At the end of 2019, 73 licenses were in the process of being renewed. Less than half of them correspond to relicensing applications submitted in the past two years. For most of the rest, the old license had expired before a new one has been issued. Plant owners that have not yet received a relicensing by the time the current license expires are automatically granted annual license extensions by FERC.

Between 2010 and 2019, FERC received 41 license surrender applications of constructed projects. The median capacity of these projects is 0.5 MW and only five have a capacity greater than 10 MW. License surrenders are typically motivated by economic reasons – whether it is the costs of the relicensing process, the costs to implement the terms and conditions of a relicense, or the costs to make extensive repairs, licensees consider the expected costs and revenues from continued project operations versus surrender. Aquatic ecosystem restoration efforts agreed by project stakeholders are the motivation for four of the license surrenders.

Forty-one project owners submitted applications to surrender a license (or an exemption from licensing) to FERC from 2010 to 2019.¹² The combined capacity authorized under these licenses was 281 MW. The median capacity of the projects is 0.5 MW and only five of them have capacity greater than 10 MW.¹³ The number of surrender applications submitted each year ranged from one to eight without any observable time trend in submissions during the period considered. The region with the most surrender applications is the Northeast (20), which is the region with the largest number of small plants (552). The number of license surrender applications was evenly split between public and private project owners.

FERC issued an order of license surrender for 26 of the 41 (with a total capacity of 82 MW). The median time elapsed between surrender application and surrender issuance was 0.65 years. In one instance (1.5 MW), obtaining a license surrender was a necessary step in converting all or part of the project's components from license to exemption and the surrender did not result in plant retirement. In the rest of the cases, the surrender application includes a plan for decommissioning the facility which can entail leaving some project features in place for other uses or removing all project features and restoring the site.

For four of the 41 surrender applications, the licensee withdrew the surrender application after finding a buyer that will continue operating and maintaining the project upon approval of a license transfer. The remaining 11 applications are being processed and their outcome is not yet final. Within this subset of pending surrenders is the license with the largest authorized capacity, Lower Klamath Project (169.6 MW).¹⁴ Out of the eleven pending applications, three were submitted more than three years prior showing that negotiating the terms of the surrender can be a lengthy process.

FERC requires licensees to include the reason for surrendering the license as part of the surrender application. Thirty-three of the 41 applications in the past decade cite economic reasons as the main cause for surrender. This subset includes projects where regular O&M has become too expensive relative to the value of the power generated and others that have fallen into disrepair and for which the needed investments to restart operation are deemed too large relative to the expected revenue. In five of these 33 applications, the cost and risk of an upcoming or ongoing relicensing process is also listed as one of the economic-based reasons for surrender and, in another instance, the decision to surrender results from relicensing terms and conditions negotiated in a new license that are too expensive to implement.

Among the eight surrender applications not motivated by economic reasons, three mention legal reasons or constraints to future operation connected to decisions about infrastructure or water supply taken by government agencies. Another one accepted a request by the local water agency to use the impoundment for municipal water supply. For the remaining four projects, the decision to surrender a license and decommission the project is part of an aquatic ecosystem restoration effort agreed upon by project stakeholders. These usually entail partial or complete dam removal and stream restoration.

12 This number does not include the surrender of original licenses for new projects that never became operational.

13 Lower Klamath in Oregon and California (169.6 MW), Eagle and Phenix in Georgia (27.7 MW), Morris Shepard in Texas (22.5 MW), Borel in California (12 MW), and Jackson Bluff in Florida (12 MW).

14 On September 23, 2016, PacifiCorp and the Klamath River Renewal Corporation filed a joint application to transfer ownership of the project from the former to the latter. On that same day, Klamath River Renewal Corporation—a nonprofit organization formed to oversee decommission of four dams on the Klamath River—filed the license surrender application for the project.

Chapter 2

Looking Forward: Future U.S. Hydropower and PSH Development Pipeline

2.1. U.S. Hydropower Development Pipeline

2.2 U.S. PSH Development Pipeline



2. Looking Forward: Future U.S. Hydropower and PSH Development Pipeline

This chapter presents a snapshot of the U.S. hydropower and PSH development pipeline as of the end of 2019. It describes the following pipeline attributes: regional distribution, project types, project sizes, developer types, and distribution of projects among different stages of the development process.

2.1. U.S. Hydropower Development Pipeline

At the end of 2019, there were 217 hydropower projects with a total proposed capacity of 1.49 GW in the U.S. development pipeline.

The U.S. hydropower development pipeline includes 88 NPD projects (additions of hydropower generation capability to existing dams previously used for other purposes), 109 conduit projects (additions of hydropower generation capability to conduits previously used for other purposes), 8 NSD projects (hydropower installations at previously undeveloped sites and waterways), and 12 capacity additions at plants that are already operational. The NPD and capacity additions combined account for 93% of proposed capacity. Figure 7 displays the location of proposed hydropower projects and information about their types, sizes, and stage of development. It includes both new projects and planned capacity additions to the existing fleet.

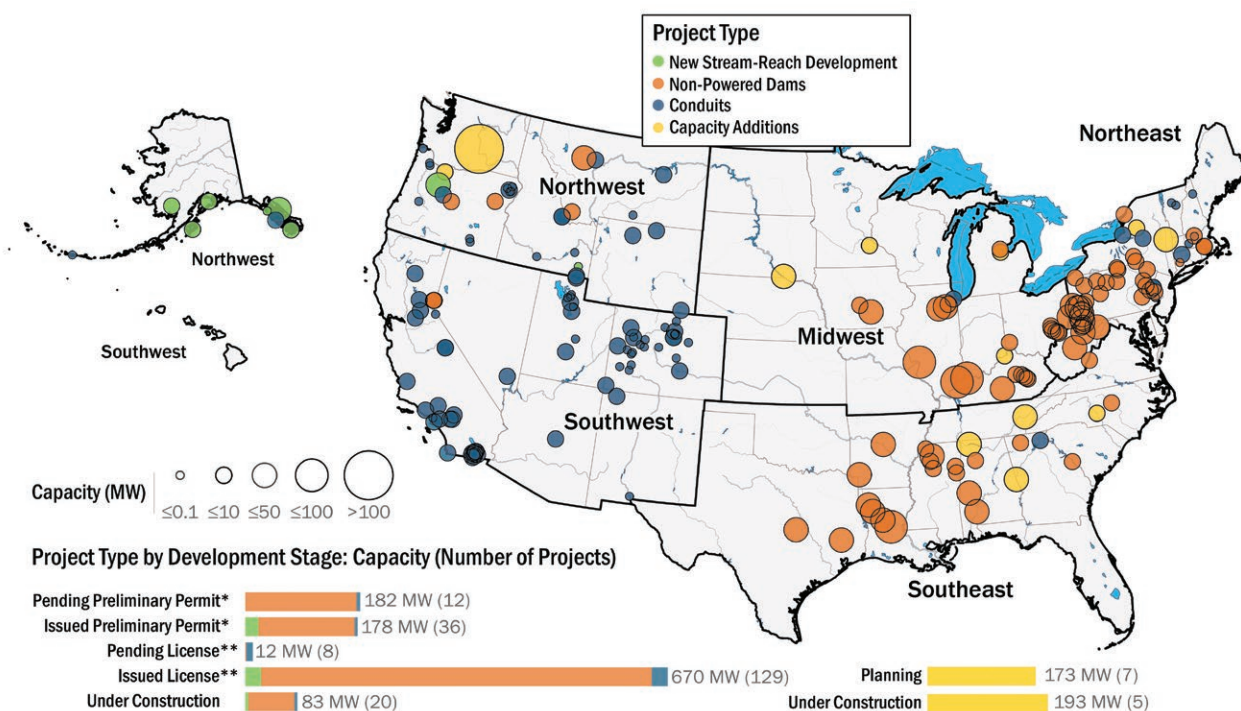


Figure 7. Hydropower project development pipeline by project type, region, size, and development stage (as of December 31, 2019)

Sources: FERC eLibrary, Reclamation LOPP database, IIR, Internet searches

Note: See Glossary for project type definitions

*Projects in the *Pending Preliminary Permit* and *Issued Preliminary Permit* stages have high attrition rates. *Pending Preliminary Permit* includes projects pending a preliminary lease in the Reclamation LOPP process and projects pending issuance of a preliminary permit. *Issued Preliminary Permit* includes projects that have received a preliminary lease in the LOPP process, projects that have obtained a FERC preliminary permit, and projects with an expired preliminary permit but that have submitted a Notice of Intent to file a license or a draft license application.

***Pending License* includes projects that have applied for an original FERC license or a FERC exemption or have requested to be considered a “qualifying conduit” hydropower facility by FERC. *Issued License* includes projects that have been issued an original FERC license or FERC exemption, been approved by FERC for the qualifying conduit hydropower status, or received a final lease contract under the LOPP process.

New proposed hydropower projects (i.e., excluding capacity additions) are distributed across 34 states. Pennsylvania, Kentucky, and Louisiana were the only states with more than 100 MW of new hydropower capacity in the pipeline, with their proposed capacity mostly concentrated in NPD projects.

Except for NSD projects, which were only being pursued in the Northwest, every region had at least one project of each type. However, the mix of project types varies markedly across regions. The Northwest and Southwest contained 87% of U.S. conduit projects, partly because these are the regions with the most irrigation and water supply conduit mileage in the United States. However, 92% of NPD projects were in the other three regions (Northeast, Midwest, and Southeast), where most of the NPD resource potential lies. Proposed NPD capacity in those regions nears 1 GW.

Out of the eight NSD projects in the pipeline, six were in Alaska which accounted for 78% of proposed NSD capacity. The Grant Lake project (5 MW, Alaska) is the only one that proposed building a new impoundment dam. For the rest, proposed project facilities included weirs—structures whose main purpose is diverting flow to a canal or penstock ending at the powerhouse rather than storing water.

NPDs in the Northeast had the largest increases in the number of projects from 2018 to 2019 (from 26 at the end of 2018 to 35 at the end of 2019). Except for some new small conduits, new projects under construction remained unchanged from the previous year (82 MW at the end of 2018 and 83 MW at the end of 2019). Four NPDs (Red Rock in Iowa, Lake Livingston in Texas, Marseilles Lock and Dam in Illinois, and Ravenna in Kentucky) and one NSD project (Reynolds Creek in Alaska) accounted for almost 95% of capacity in new projects under construction at the end of 2019.

Figure 7 also includes capacity additions to the existing fleet.¹⁵ At the end of 2019, at least 12 plants had planned or had ongoing construction to add 366 MW to the existing fleet. Six of the capacity addition projects applied to privately owned plants, two to public nonfederal plants, and the rest to the federal fleet. The Midwest and Southeast regions had the largest number of capacity addition projects (four each) and the Southwest was the only region with no capacity addition projects. For some of the small plants, the ongoing expansion represented a doubling or more of capacity. In larger plants, the ongoing projects would increase capacity by 10%–20%. Among these larger plants, the ones with capacity expansions greater than 15% are federal.¹⁶

At the end of 2019, 129 projects (59% of projects in the development pipeline) had an issued authorization but had not yet started construction. More projects are in the “issued authorization” phase than in any other phase of the development process, and more than half of the projects in that stage have spent three or more years in it.

At the end of 2019, 77% of conduits (84), 47% of NPD projects (41), and 50% of NSD projects (4) had an issued authorization (license, exemption, or qualifying conduit status) but had not yet started construction. The hydropower projects in this development stage had a combined capacity of 670 MW. The median year of issuance of the authorization was 2016. Therefore, more than half of the projects in the “issued authorization” stage have spent more than three years in it. In 2019, 17 projects entered the “issued authorization” stage after one of three FERC actions: issuance of a license (4), issuance of an exemption (1), or determination of qualifying conduit status (12). Four qualifying conduits moved to the “under construction” stage. The large number of projects in the “issued authorization” stage relative to what was under construction suggests that many developers face challenges and delays to meet some of the milestones required before construction starts.

15 The number of capacity additions refers to the number of hydropower plants with planned or ongoing R&U projects resulting in capacity increases. One hydropower plant might be counted in both the “planning” and “under construction” stages if it has projects in the two stages.

16 For nonfederal plants licensed by FERC, increasing the hydraulic capacity of a project by 15% or more and by more than 2 MW requires a capacity license amendment, which requires a potentially lengthy three-stage consultation process (Levine et al., 2017).

For project developers that obtained a FERC license from 2007 to 2018, Uriá-Martínez et al. (2020) computed timelines from license issuance to construction start as well as attrition rates. Out of the 91 developers that received a license during that period, more than half were conducting preconstruction activities by mid-2018. Among the 29 projects under construction or operational, 58% started construction within the two-year timeframe required in the FERC license; all of them were small (≤ 10 MW). For projects in the preconstruction stage, the key challenges reported by developers related to additional non-FERC permitting, technical design, increases in construction cost estimates, and securing property rights, financing, and PPAs. Seven of the 91 licensed projects analyzed surrendered their license. These developers cited a lack of economic viability—manifested by an increased cost estimate or the inability to obtain financing or a PPA—as the reason for abandoning the project.

Private non-utilities propose most NPD projects and non-federal public entities are the most frequent developers for conduit projects. The median capacity and capacity range of hydropower projects is 0.17 MW [0.0003 MW–5 MW] for conduits, 4.8 MW [0.076 MW–93 MW] for NPDs, and 5 MW [0.035 MW–19.8 MW] for NSDs.

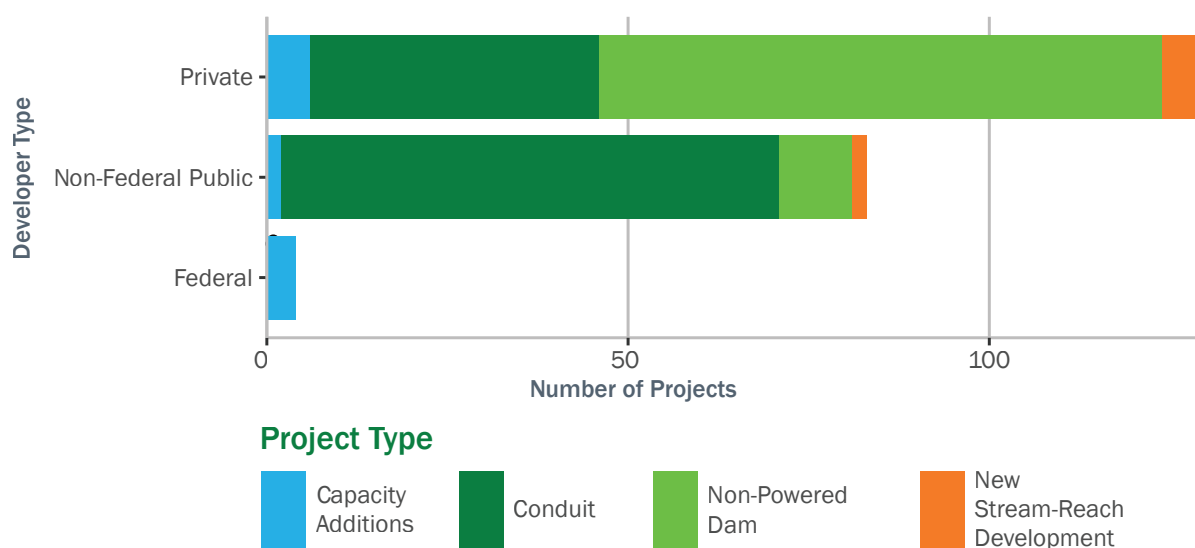


Figure 8. Hydropower project development pipeline by project type and developer type (as of December 31, 2019)

Sources: FERC eLibrary, Reclamation LOPP database, IIR, Internet searches

Private developers and owners pursued 60% of projects and 72% of capacity in the pipeline (see Figure 8). For NPD, private developers represented 89% of the projects. For the subset of projects in advanced pipeline stages (with issued authorization or under construction), private developers accounted for 52% of the projects and 71% of capacity.

Most private developers are not utilities and would eventually have to negotiate a PPA, transfer the project to a utility, or participate directly in an independent system operator/regional transmission organization (ISO/RTO) to market their electricity. Any of those options constitutes an added complexity to project development relative to a utility (investor-owned or public) which can recover the cost of the project in its customers' rates. Investor-owned electric utilities engage in capacity additions at existing facilities, but they are pursuing no new hydropower projects.

Nonfederal public developers include cooperatives, publicly owned utilities, and political subdivisions (e.g., municipalities, irrigation and water districts). Political subdivisions are the most active public hydropower developers and concentrate much of their activity on adding hydropower generation equipment to conduit infrastructure they own or operate.

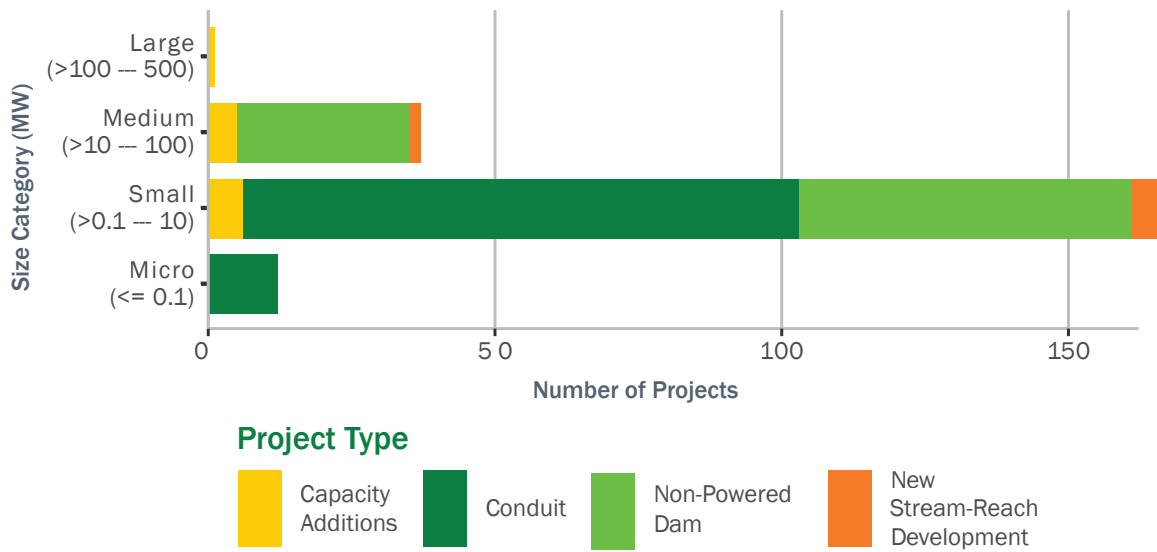


Figure 9. Hydropower project development pipeline by project type and size (as of December 31, 2019)

Sources: FERC eLibrary, Reclamation LOPP database, IIR, Internet searches

Eighty-two percent of the projects in the pipeline proposed capacities of less than 10 MW (see Figure 9). The largest new hydropower project in the pipeline was the Melvin Price NPD in Missouri (93 MW), and 30 NPD projects were within the medium size category (10 MW – 100 MW). The median capacity of NPD projects was 4.8 MW. As for NSD, all 8 projects had less than 20 MW of capacity.

All conduit projects proposed installing turbine-generator units with capacity ≤ 5 MW. Out of the 109 conduit projects in the pipeline, only 11 proposed capacities >1 MW. Seventy-nine percent of conduit projects applied for “qualified conduit” status from FERC. The rest were distributed between the FERC conduit exemption process or the LOPP process if they fell under the jurisdiction of Reclamation. The 5 MW maximum proposed capacity for conduit projects was not motivated by a regulatory threshold. Size limits to be eligible for the FERC conduit exemption process or, since the passage of the AWIA, to qualify for conduit status are much higher (40 MW).

2.2 U.S. PSH Development Pipeline

At the end of 2019, there were 67 PSH projects in the development pipeline distributed across 21 states. Three of these projects had FERC authorization; all three are in the western half of the United States. Additionally, three existing PSH plants were undergoing capacity upgrades.

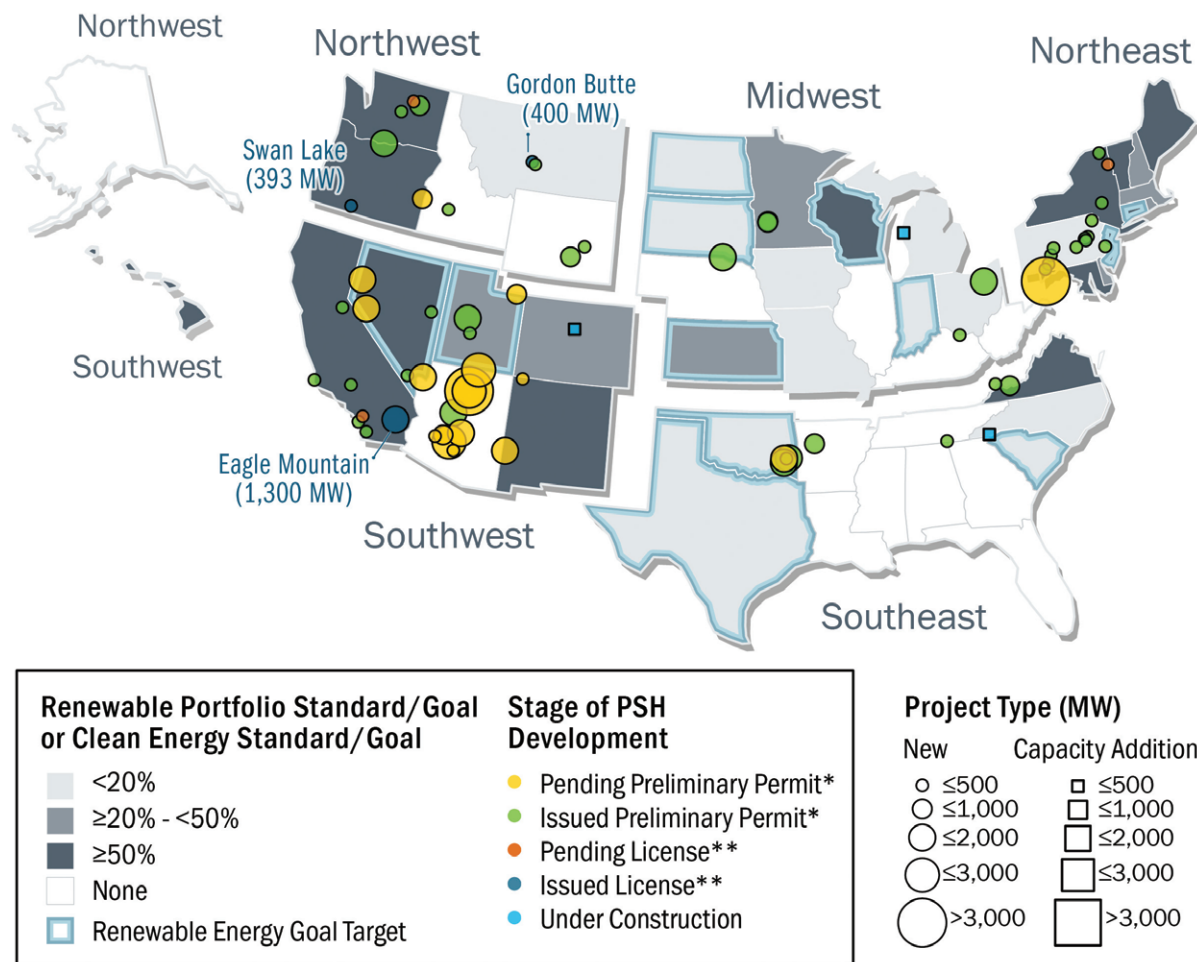


Figure 10. PSH project development pipeline by region and status in relation to state-level renewable energy targets (as of December 31, 2019)

Sources: FERC eLibrary, DSIRE, Internet searches

Note: See Figure 7 notes for details about which projects are included in each stage. For states that have both an RPS or voluntary renewables goal and a Clean Energy Standard (or voluntary goal), the map shows the maximum percentage to be attained across the two. The years by which the mandate/goal must be attained vary from state to state.

Figure 10 displays the location of PSH projects in the U.S. development pipeline at the end of 2019 as well as a summary of renewable energy targets or goals in each state. The renewable targets shown result from either RPS or clean energy standards. Eighty per cent of proposed PSH facilities are in a state with a renewable energy target or goal greater than 50% or adjacent to one of those states. The large expected penetrations of variable renewables in those states will, in turn, create demand for energy storage making them attractive locations for PSH developers. In addition, California, Nevada, New York, New Jersey,

and Virginia all have adopted energy storage targets of at least 1,000 MW (see Chapter 7 for additional details). PSH is eligible to meet those targets although, in the case of California, there is a size limit (50 MW).

Figure 10 contains both proposed new PSH projects and existing PSH projects whose capacity is being upgraded. At the end of 2019, there were 67 new projects and 3 capacity upgrades (Cabin Creek in Colorado, Ludington in Michigan, and Bad Creek in South Carolina). The combined additional capacity expected from the ongoing upgrades to those three facilities is 286 MW.¹⁷

The 67 new PSH projects in the development pipeline at the end of 2019 were distributed across 21 states (see Figure 10). Pennsylvania, Arizona, and California concentrated 42% of all sites considered. The PSH development pipeline contained 35 closed-loop and 32 open-loop projects. The closed-loop projects would operate off-stream, without a continuous connection to a naturally flowing water feature. Therefore, they typically have lower (i.e., more localized and of shorter duration) environmental impacts than open-loop projects (Saulsbury, 2020). Closed-loop projects can request to use (along with qualifying NPDs) the expedited two-year licensing process introduced by FERC in 2019 as required by AWIA.

Proposed new PSH projects have a very wide size range (from 5 MW to 4,000 MW). Among the new PSH projects entering the pipeline in 2019, the three in Navajo nation lands (Utah and Arizona) stood out by their size; each of them has a proposed capacity of more than 2,000 MW. Nonetheless, the largest new PSH proposal was for the Ulysses project in West Virginia (4,000 MW). These four very large projects had pending preliminary permit applications at the end of 2019. On the other hand, seven of the PSH projects with active preliminary permits proposed capacities of less than 100 MW, which is much smaller than the median PSH size in the project pipeline (480 MW). All these small projects envisioned closed-loop facilities and four of them considered using abandoned mine sites for one of their reservoirs. Another example of a closed-loop PSH project using an abandoned mine site and with a much greater proposed capacity is the New Summit PSH project in Ohio (1,500 MW).

FERC issued 14 preliminary permits for PSH in 2019. Some of these projects revisited locations that had previously been studied for PSH such as the Camp Pendleton and Vandenberg Air Force Base projects in California. These two California projects proposed to use the Pacific Ocean as their lower reservoir and to include both PSH units and a desalination facility. Others proposed PSH in states that have rarely been considered for this type of storage facility in the past decade such as the Freestone project in Georgia.

No new license applications were submitted for PSH projects in 2019, but the licensing process is ongoing for three projects: Mineville in New York (240 MW), Lake Elsinore in California (500 MW), and Pearl Hill in Washington (5 MW). For Mineville, FERC plans to issue the final Environmental Impact Statement in 2020. For Pearl Hill, FERC published the final Environmental Assessment in October 2019 with a finding of no significant adverse effects to the human environment. Moreover, the state of Washington provided a Section 401 water quality certification in November 2019. The license application for Lake Elsinore was submitted in 2017, but it was not accepted by FERC until July 2019 after the developer addressed additional information requests required by FERC in the application.

Two PSH projects dropped from the pipeline in the past two years after submitting license applications. FERC dismissed the license application for the Parker Knoll project in Utah in 2018 after the developer failed to submit documentation of the status of its Section 401 water quality certification (WQC) request to Utah's Department of Environmental Quality. The project developers for the Hurricane Cliffs project, a 335 MW facility proposed as part of the Lake Powell Pipeline project in Arizona, decided to no longer pursue a hydropower license and only continue with the water supply pipeline portion of the project.

At the end of 2019, three PSH facilities had issued licenses: Eagle Mountain in California, Gordon Butte in Montana, and Swan Lake in Oregon. FERC licensed Swan Lake in April 2019 with a capacity of 393 MW. Since then, the developers of this closed-loop project obtained right-of-use authorization from Reclamation to construct the transmission line, which would pass through public land parcels in its planned route.

¹⁷ The capacity tracked here corresponds to the PSH units with planned or ongoing upgrades at the end of 2019. PSH plant upgrades are typically conducted in stages, with one unit being upgraded at a time.

Gordon Butte, licensed in 2016, requested a second time extension to start construction in July 2020; its new construction start deadline is December 2022. This PSH project has a planned capacity of 400 MW and an off-stream closed-loop design in which the two man-made reservoirs will be connected by an underground penstock ending in an underground powerhouse. The project developers announced they secured equity investment for the project from a Danish investor in July 2019 but, as of July 2020, negotiations for a PPA are still ongoing.

Finally, license issuance for Eagle Mountain took place in 2014. It has a proposed capacity of 1,300 MW, and it is a closed-loop project using abandoned mine pits as upper and lower reservoirs. The project developer requested a construction start extension after two years from license issuance and has secured additional time extensions due to the passage of AWIA in November 2018. Obtaining access to the public lands within the project boundary has been a key issue delaying construction. In March 2020, the project developer signed the right-of-way grant with the Bureau of Land Management after extensive negotiation. Additionally, the developer has completed geotechnical studies needed to inform the final engineering designs for the project.

Since the number of PSH projects that entered the development pipeline in 2019 was larger than the number of projects exiting it, the number of active PSH projects at the end of 2019 was 31% greater than one year earlier. Figure 11 summarizes PSH development activity in the United States in the past five years. Except for 2015, more developers submitted preliminary permit applications each year than developers surrendered their permit or license. As a result, the number of projects in the development pipeline has been steadily increasing. Both in 2017 and 2019, most of the new applications were submitted as project portfolios by single developers. Additionally, five developers submitted license applications in 2015–2019 and FERC issued two licenses during that period.

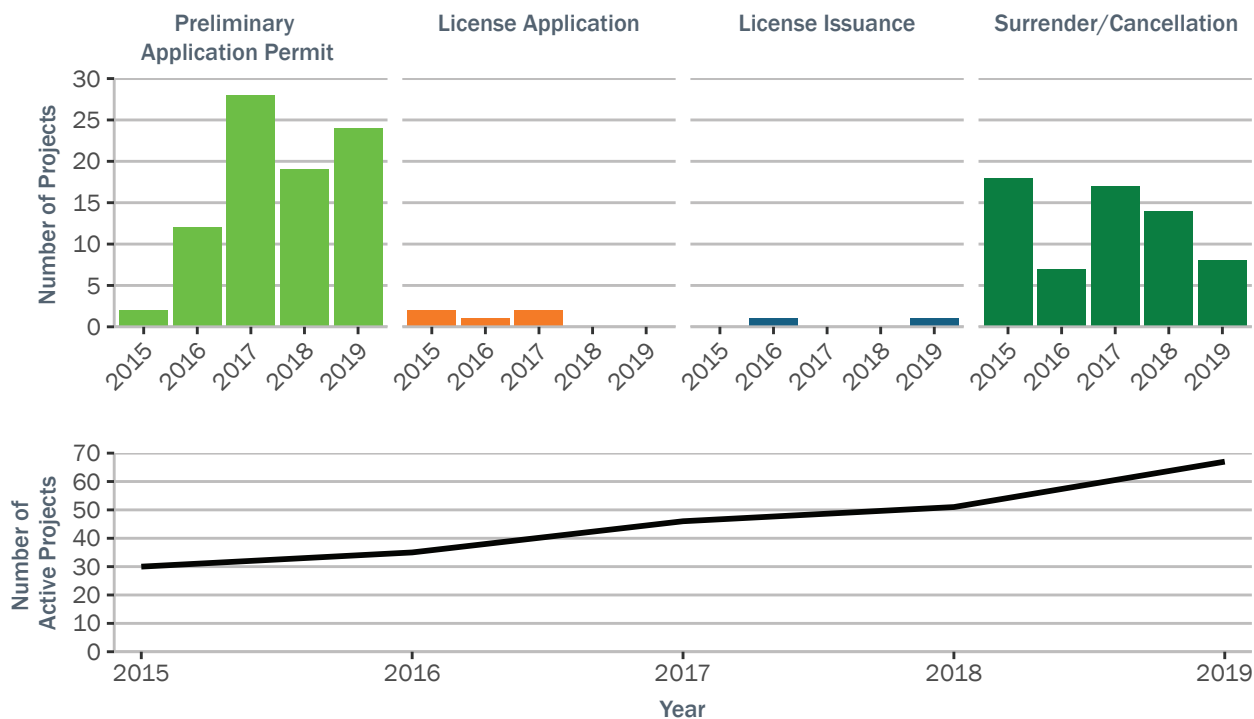


Figure 11. U.S. PSH Project Development Activity (2015–2019)

Sources: FERC eLibrary

The image is a composite. The left side shows an aerial view of a large concrete dam with a spillway. A red lattice boom crane is positioned on top of the dam. The water is turbulent as it flows through the spillway. The right side of the image is a solid green vertical bar that contains the chapter title and table of contents.

Chapter 3

U.S. Hydropower and PSH in the Global Context

3.1 Description of the Existing Fleets

3.2 International Trends in Hydropower and PSH Development

3.2.1 Development Pipeline by Region

3.2.2 Global Hydropower and PSH Investment

3.2.3 Global Comparison of Hydropower
Permitting Process

3.2.4 International Comparison of Hydropower
Incentives

3. U.S. Hydropower and PSH in the Global Context

This chapter describes the existing global hydropower and PSH fleets and summarizes international trends in hydropower development as well as R&U to the existing fleets. This chapter serves to place in an international context the trends discussed in Chapter 1 and Chapter 2 regarding new development and R&U for the United States. For topics covered in the previous edition of the Hydropower Market Report, this chapter updates key values and highlights changes since that report was published. Additionally, some metrics (particularly in Section 3.2.2) that had been previously reported for hydropower and PSH combined are now reported separately for each project type. Finally, Section 3.2.3 and Section 3.2.4 are entirely new content. They compare hydropower permitting and incentives across regions internationally, which demonstrate some drivers of different levels of hydropower investment across regions.

3.1 Description of the Existing Fleets

The U.S. fleet represents 7% of global hydropower capacity and 14% of global PSH capacity. On average, U.S.-installed capacity grew at 0.2% per year for hydropower and 0.7% for PSH in the past decade. In contrast, China’s hydropower and PSH fleets grew at 6% and 7% annual average growth rates, respectively, in 2010–2019 and China had the largest installed capacities at the end of 2019.

Global hydropower and PSH capacity increased by 57.7 GW and 3.9 GW, respectively, in 2017–2019. With these additions, resulting from a combination of new projects and upgrades to existing facilities, global installed capacity stood at 1,150 GW for hydropower and 158 GW for PSH at the end of 2019 (IHA, 2020). Eighty-four countries have more than 1 GW of installed hydropower capacity, but only 35 countries have any PSH capacity.

The combined fleets of China, the European Union, Brazil, United States, Canada, and Russia accounted for two thirds of global hydropower capacity. Figure 12 shows the renewable generation capacity mix in 2019 and the net capacity additions in 2017–2019 in those six countries/regions and for the world.

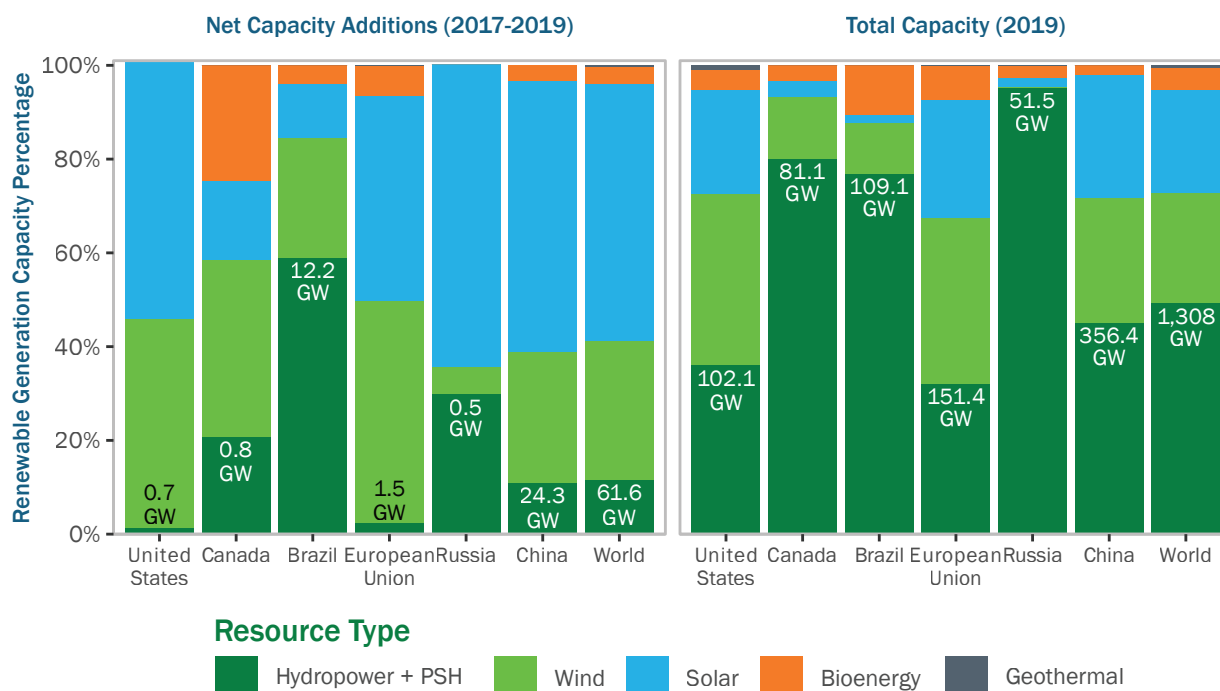


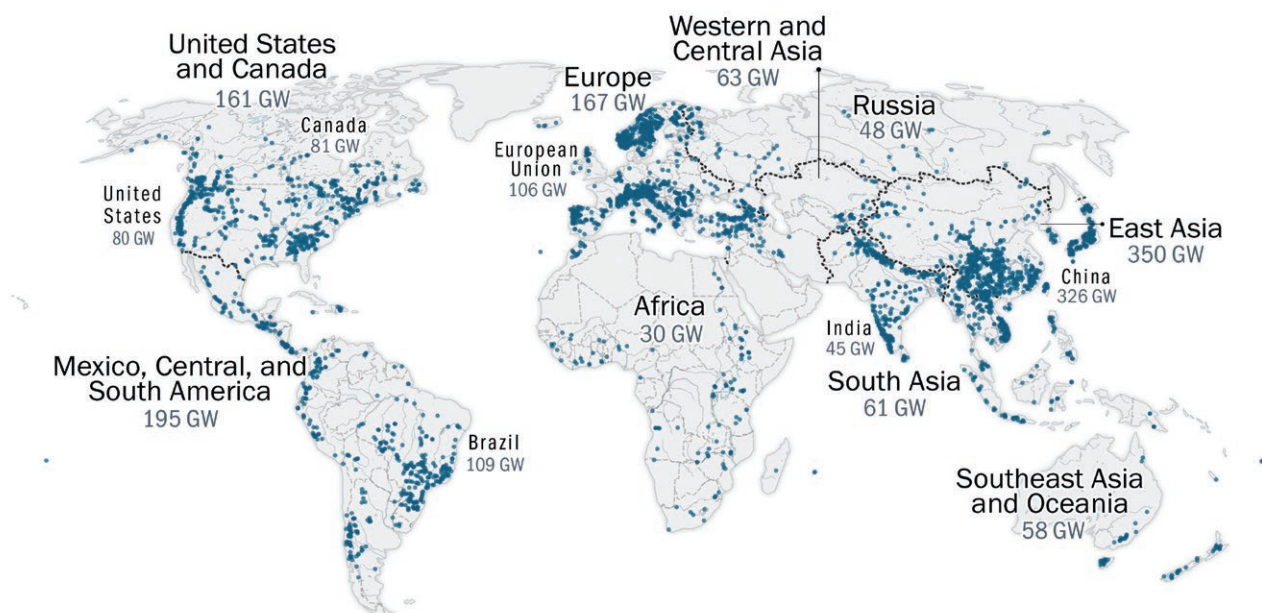
Figure 12. Renewable generation capacity mix in the countries/regions with the largest hydropower fleets

Source: Hydropower (United States): Existing Hydropower Assets dataset, EIA; Other resource types and other countries/regions: IRENA Renewable Capacity Statistics.

Note: European Union includes EU27 countries. Labels refer to hydropower capacity.

In 2019, hydropower was the largest renewable by installed capacity globally as well as in China, Russia, Brazil, and Canada. For the United States and the European Union, wind is the only renewable with larger capacity installed than hydropower. For Russia, Canada, and Brazil, hydropower represents more than 75% of their renewable generation capacity. As for the 529 GW of global renewable capacity installations in 2017–2019, solar accounted for 55%, wind for 29%, and hydropower for 12%. Brazil was the only country of the ones shown in Figure 12 where hydropower was the largest renewable for new capacity added in the past three years.

Figure 13 and Figure 14 show which areas within each world region have the largest concentration of hydropower and PSH facilities. China has the largest hydropower fleet in the world, with an installed capacity of 326 GW in 2019. On average, it added 14 GW of hydropower capacity every year since 2010. The hydropower capacity commissioned in China between 2010 and 2014 is greater than the capacity of the entire U.S. hydropower fleet. China’s hydropower buildout decelerated in recent years; its capacity additions were less than 10 GW per year in 2017–2019. In 2019, Brazil surpassed the hydropower capacity of the European Union and became the second largest hydropower fleet in the world after completing the Belo Monte complex (11.2 GW). In regions with mature hydropower fleets (i.e., United States, Canada, European Union, and Russia), capacity grew less than 1% per year on average during 2010–2019.

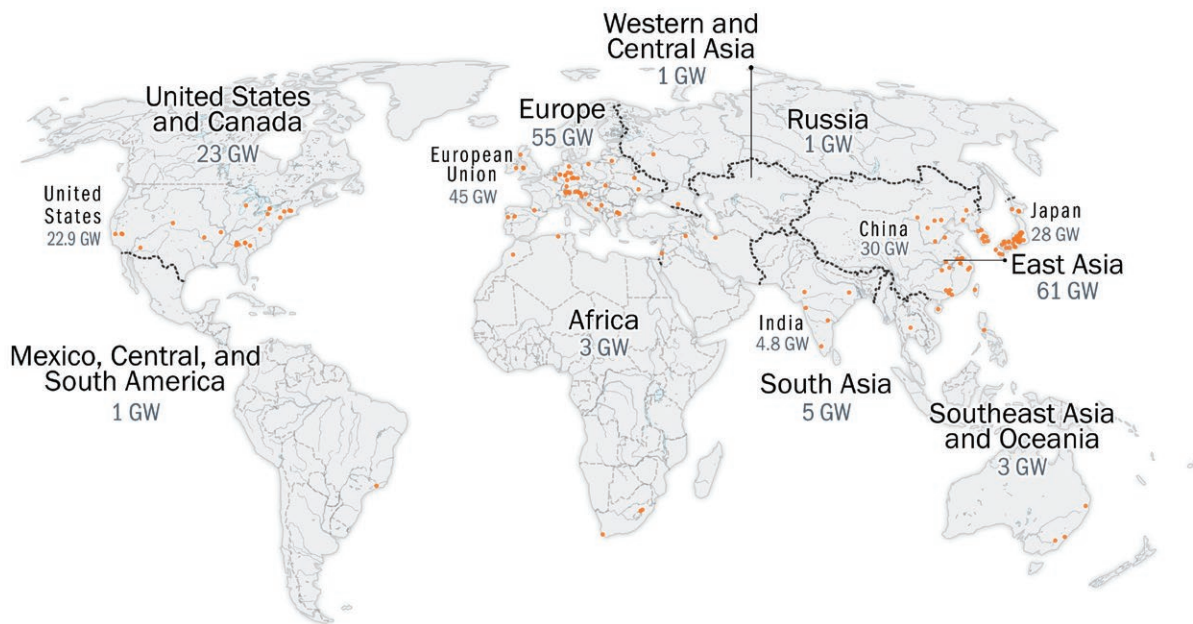


Note: Geolocated points only include plants with a capacity ≥ 10 MW but capacity labels include plants of all sizes.



Figure 13. Map of operational hydropower plants by world region

Source: IIR, International Hydropower Association



Note: Geolocated points only include plants with a capacity ≥ 10 MW but capacity labels include plants of all sizes.



Figure 14. Map of operational PSH plants by world region

Source: IIR, International Hydropower Association

The capacities shown in this figure are net summer capacity. In contrast, for the U.S. fleet, the capacity number stated in Chapter 1 was nameplate capacity.

Figure 14 displays the capacity of the top six PSH fleets (i.e., European Union, Japan, United States, China, India, and South Korea), which represented 86% of the global capacity, as well as the capacities in all world regions. The combined PSH fleet of all European Union countries is the largest in the world, accounting for 30% of global PSH capacity. However, the European PSH fleet grew by less than 1% per year during 2010–2019. In contrast, China’s PSH fleet grew 7% per year on average and became the second largest (largest by individual country) in 2017. This strong growth is motivated by the Chinese government’s objective of reaching 40 GW of PSH capacity by 2020 to help integrate increasing volumes of wind and solar capacity. However, with a temporary pause in government support for new PSH investment announced in November 2019, it is unlikely for that milestone to be reached (IHA, 2020).

Figure 15 provides more detail about the temporal and regional distribution of new PSH plants starting operation during the past decade. Of the 20 plants shown, 13 are in the *East Asia* region (10 in China, one in South Korea, and one in Japan), four in European countries (Austria, Norway, Switzerland), and one each in *United States and Canada* (Olivenhain-Hodges in the United States), *Africa* (South Africa), and *Western and Central Asia* (Israel). The year with the higher number of new PSH plants coming online was 2016 with 5 new PSH plants in three different world regions and a combined new capacity of 5 GW. Except for 2010 and 2016, between one and three new plants started operation each year of the past decade. Twelve of the 20 plants shown in Figure 15 have capacities of 1,000 MW or larger. The three smallest have capacities below 100 MW.

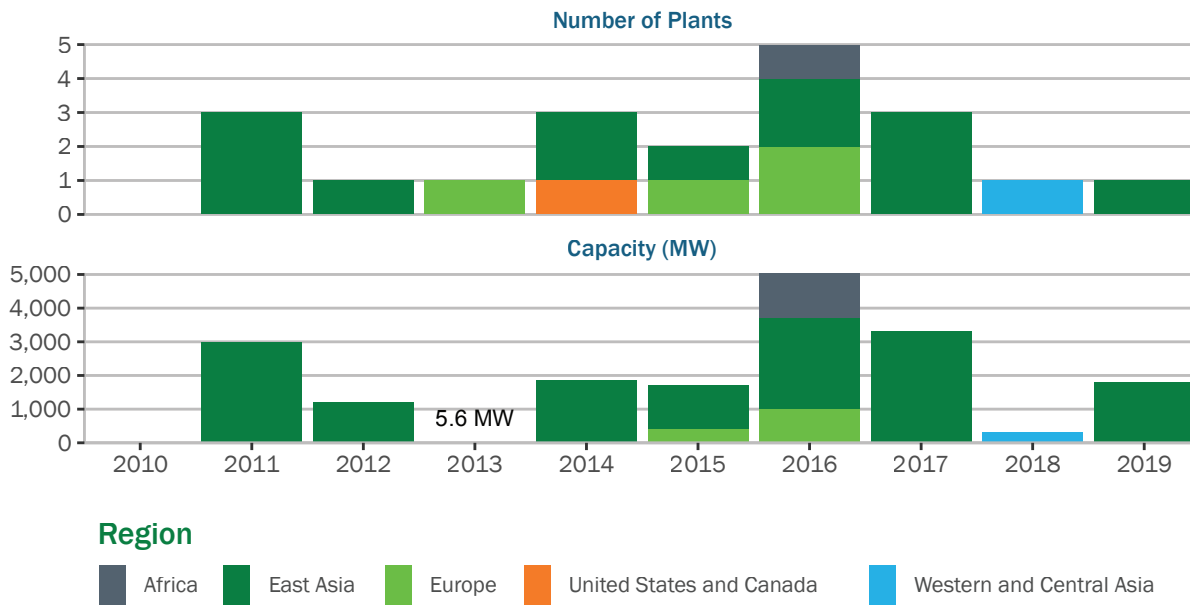


Figure 15. New PSH installations in 2010–2019 by world region

Source: IIR

Note: This plot does not include PSH capacity increases resulting from upgrades to existing units.

3.2 International Trends in Hydropower and PSH Development

3.2.1 Development Pipeline by Region

The global development pipeline by the end of 2019 includes 4,545 hydropower projects and 284 PSH projects with total capacities of 414 GW and 226 GW, respectively. Asia accounted for 75% of the combined potential development for hydropower and PSH. The United States has the largest PSH project pipeline outside of Asia, but most of the proposed capacity comes from projects at the feasibility study stage. Projects in this early stage have a very high attrition rate. (See Table 2 below for specific details by country)

Two hundred and twenty-three hydropower projects and 19 PSH projects reached construction stage in 2017–2019. In total, at the end of 2019, 117 GW of hydropower were being constructed in 616 projects across 66 countries and 13 countries were constructing 50 PSH projects with total capacity of 53 GW. China accounted for 55% and 87% of hydropower and PSH capacity under construction (64 GW and 46GW, respectively). Another 16 countries were building more than 1 GW of combined hydropower and PSH capacity. Additionally, there were 297 GW of hydropower and 173 GW of PSH in different phases of scoping, permitting, and development.

Overall, one third of the global capacity in the development pipeline is for PSH projects. Figure 16 shows the distribution of the project development pipeline across world regions for projects with an installed capacity greater or equal than 10 MW.

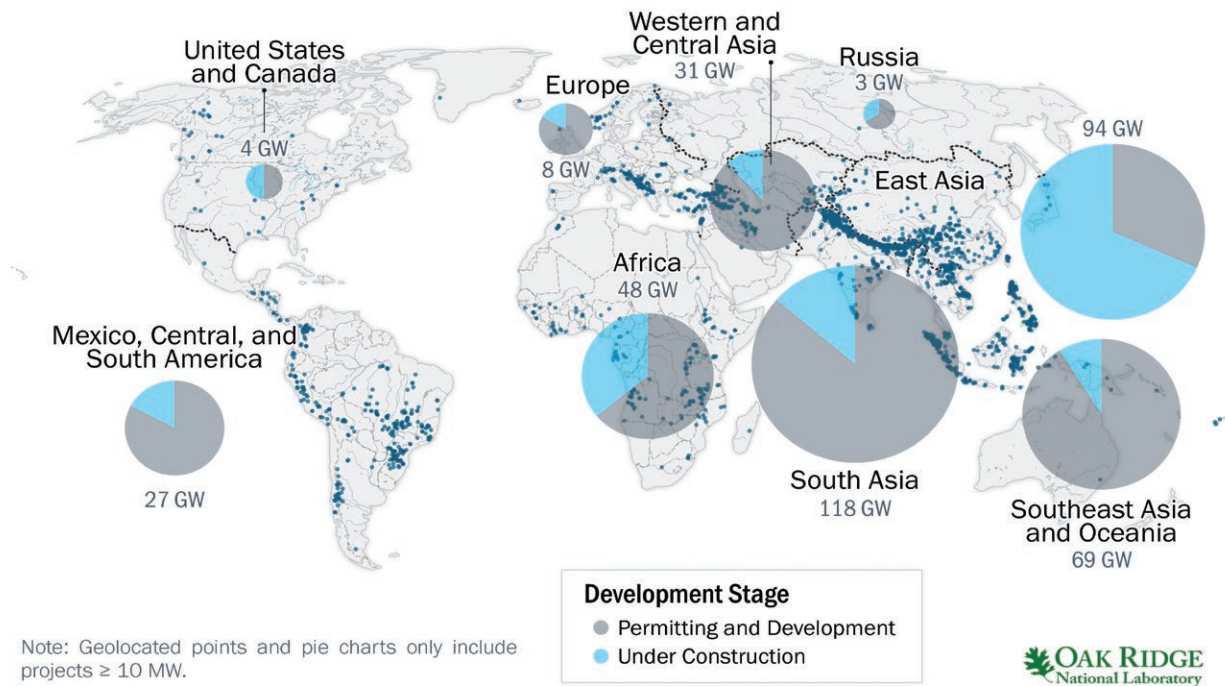


Figure 16. Map of hydropower project development pipeline by region and development stage

Source: IIR

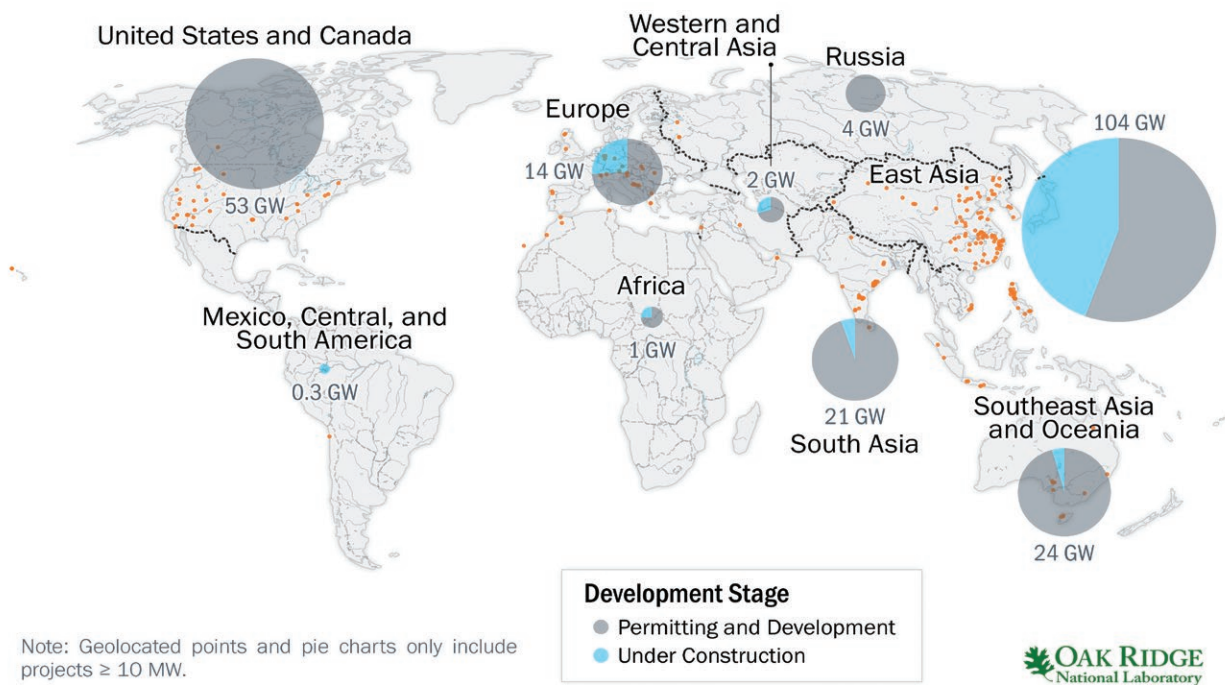


Figure 17. Map of PSH project development pipeline by region and development stage

Source: IIR

Note: The “under construction” category includes projects that have completed the permitting process and secured financing but have not yet broken ground.

Figure 16 and Figure 17 display the relative sizes of the hydropower and PSH project development pipeline in each region and how they are distributed between projects “under construction” vs. earlier stages of “permitting and development”.

South Asia has the largest hydropower development pipeline (118 GW). However, *East Asia* has the most hydropower capacity “under construction” and it is the only region where more than 50% of all capacity in the development pipeline is in advanced stages of development. *United States and Canada* has the second smallest hydropower pipeline by capacity (4 GW) of which 50% is “under construction”. *South Asia* and *Southeast Asia and Oceania* have by far the largest number of projects—more than 600 each—but their average capacity is significantly lower than for the projects in *East Asia*.

East Asia has the largest PSH development pipeline (104 GW). PSH capacity “under construction” in that region (46.13 GW) is far greater than capacity “under construction” in all other regions combined (6.95 GW). Only two regions—*East Asia* and *Europe*—have more than two PSH projects in the “under construction” stage. *United States and Canada* has the second largest PSH pipeline (53 GW) of which all but 75 MW is in the United States. As discussed in Section 2.1, three U.S. projects with a combined capacity of 2.1 GW have obtained FERC authorization but have not met all the milestones to be classified as “under construction” in the international dataset. Sixty-one of the 67 PSH projects in the U.S. development pipeline are at a very early stage of the development process in which feasibility studies are being conducted. At this early stage, project attrition rates are very high.

RECENT ASSESSMENTS IDENTIFY VAST GLOBAL PSH ENERGY STORAGE POTENTIAL

PSH accounts for approximately 95% of installed global energy storage capacity in 2020 (IHA, 2020) and its energy storage cost (in dollars per kilowatt-hour) is lower than in most other commercially available energy storage technologies (see Section 5.1.2). Recent global PSH resource assessments show that there are hundreds of thousands of technically feasible sites for new PSH projects to support future grid scenarios with higher penetrations of variable renewables.

Researchers from the Australian National University developed geographic information system algorithms to catalog potential closed-loop PSH sites around the world. In 2019, they published a global atlas of the 616,000 locations identified in their analysis, with a combined energy storage capacity of approximately 23 million GWh.¹⁸ The sites are further disaggregated into five categories depending on their estimated cost. Although only a small portion of the identified sites would ultimately be viable once more detailed geological and environmental studies are conducted, the authors estimate that developing as few as 1% of the identified energy storage capacity would be enough to fulfill the storage requirements of a global grid with 100% renewables.

Hunt et al. (2020) use geographic, topographic, and hydrological data to search for suitable sites for seasonal PSH projects where upper reservoirs are built in proximity to major rivers to provide both water and energy storage. Combining a detailed siting assessment methodology and a cost model, they select as most promising 1,092 locations with estimated cost of storage below 50 \$/MWh. They are highly concentrated in mountainous regions and cost estimates are based on a power generating capacity of 1 GW. Relative to conventional hydropower dams that also provide energy and water storage services, the authors argue that seasonal PSH would have a lower land footprint to achieve the same energy storage volume because the upper reservoirs could fluctuate their elevation further than in-stream reservoirs do. The value of seasonal PSH projects would be highest in regions with substantial seasonal and interannual flow variability, which they could help smooth, and where the periods of high demand for water storage capacity do not coincide with the periods of highest electricity demand.

18 <http://re100.eng.anu.edu.au/global/>

Table 2 ranks hydropower and PSH development pipelines by country, including projects in early and advanced development stages.

Table 2. Top 20 Countries by Proposed Hydropower and PSH Capacity in the Development Pipeline

Country	Hydropower Proposed (MW)	Country	Pumped Storage Hydropower (MW)
China	92,937	China	102,080
India	41,995	United States	52,476
Nepal	30,361	India	20,425
Pakistan	28,860	Philippines	10,270
Myanmar	25,782	Australia	5,555
Indonesia	24,227	Indonesia	5,280
Bhutan	19,244	Russia	4,360
Ethiopia	12,419	Vietnam	2,700
Brazil	10,234	United Kingdom	2,050
Turkey	8,534	Austria	2,005
Lebanon	8,100	South Korea	1,850
Iran	7,997	Bosnia-Herzegovina	1,767
Laos	7,796	Germany	1,417
Philippines	6,640	Switzerland	1,020
Argentina	5,722	Romania	1,008
Tanzania	4,541	Iran	1,000
Angola	4,418	Morocco	950
Peru	4,137	Portugal	880
Nigeria	3,762	Greece	680
Zimbabwe	3,653	United Arab Emirates	650

Sources: IIR, FERC, Reclamation

China has the most capacity in the pipeline for both hydropower and PSH and is pursuing similar amounts for both capacity types. Only five countries are part of the top 20 for both hydropower and PSH: China, India, Indonesia, Iran, and the Philippines. The United States is not part of the hydropower top 20 but it has the second largest PSH pipeline. All the countries in the top 20 for new planned hydropower capacity are in Asia, Africa, or South America. On the other hand, eight of the countries in the top 20 for PSH are in Europe.

3.2.2 Global Hydropower and PSH Investment

Global hydropower and PSH investment (planned and under construction) amounted to \$1.1 trillion at the end of 2019. PSH projects account for 24% of the total. More than 90% of global expenditures are directed toward development of new hydropower and PSH plants. The rest is evenly distributed between plant expansion and R&U projects.

The estimated investment in projects that reached construction stage in 2017–2019 is \$53 billion for hydropower and \$20 billion for PSH. If all hydropower and PSH investment projects in the global pipeline at the end of 2019 are completed, they represent an estimated expenditure of \$1.1 trillion. This total includes investment in new plants as well as plant expansions (addition of new turbine-generator units to existing plants) and R&U of existing units. It also includes both projects already under construction and those in the planning and permitting stages. Figure 18 shows the distribution of capital expenditures between development of new plants, plant expansion projects and R&U projects in each region for hydropower and PSH.

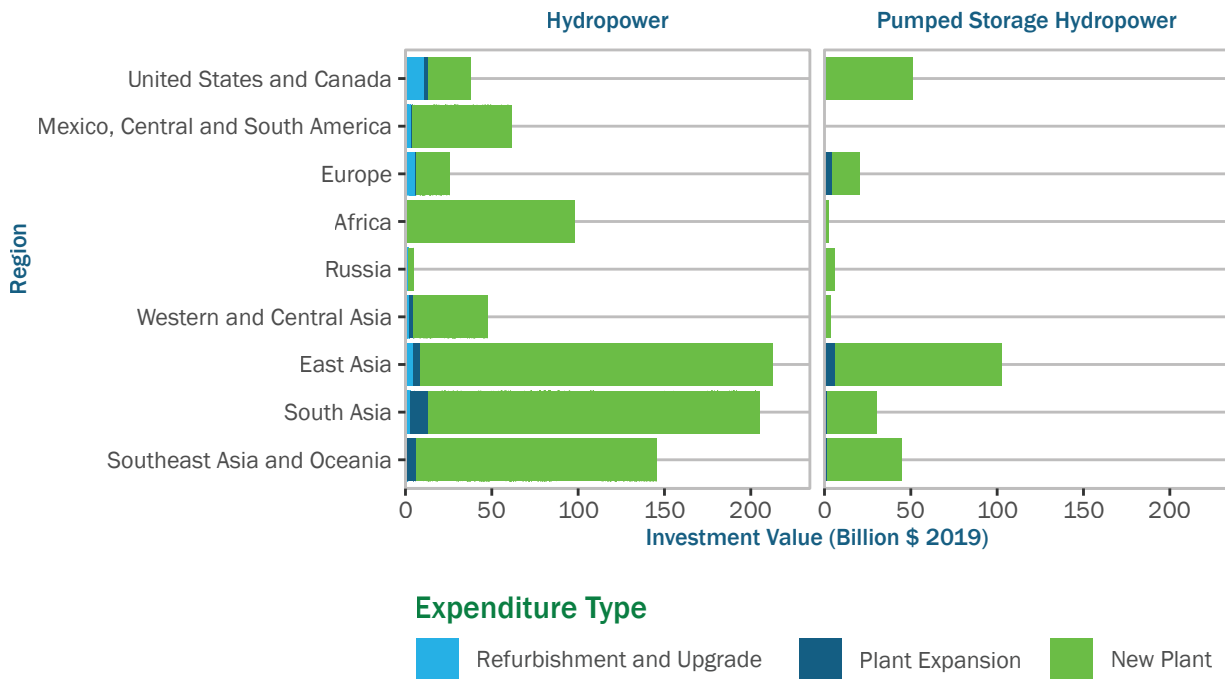


Figure 18. Expenditures on hydropower and PSH (new projects, R&U, and plant expansions) by world region

Source: IIR

Note: See regional boundaries in Figure 13 and Figure 14. See expenditure type definitions in the Glossary

Asian regions concentrate 73% of global hydropower expenditure and 69% of global PSH expenditure. *United States and Canada* accounts for 4% of global hydropower expenditure and at least 20% of PSH expenditures.¹⁹ *United States and Canada and Russia* are the only two regions with larger tracked expenditures for PSH than hydropower.

More than 90% of global expenditures are directed toward development of new plants. Tracked capital investment in plant expansions and R&U at the end of 2019 totaled \$73 billion, distributed approximately evenly between the two expenditure types. For hydropower, Asian regions lead global investment in plant expansions and *United States and Canada* leads in R&U investment. For PSH, except *United States and Canada*, all regions that invest to increase capacity in existing sites do so mostly through plant expansions.

The remainder of this chapter analyzes in more detail the R&U portion of the capital expenditure pipeline. Figure 19 translates the total R&U expenditures presented in Figure 18 into average expenditure per installed kilowatt of hydropower and PSH in each region. It also differentiates the fraction of expenditures in “permitting and development” vs. “under construction” stages. Figure 20 provides a complementary view of the intensity of R&U expenditures across regions by showing expenditures per refurbished/upgraded kilowatt.

United States and Canada have the oldest hydropower and PSH fleets and it spends the most per installed kilowatt on R&U projects worldwide.

19 Project investment value comes from IIR which only tracks 35 of the 67 PSH plant in the U.S. development pipeline at the end of 2019.

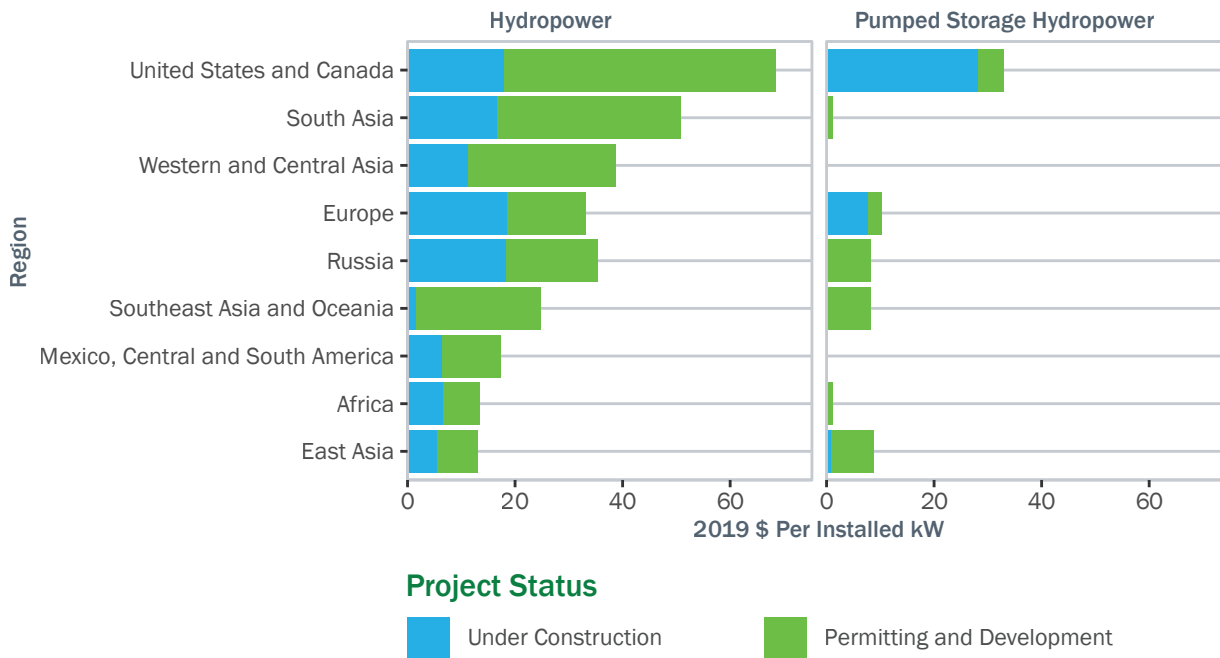


Figure 19. Expenditures on hydropower and PSH refurbishments and upgrades per kilowatt installed by world region and project status

Source: IIR, EIA International Energy Statistics

Note: The “under construction” category includes projects that have completed the permitting process and secured financing but have not yet broken ground. See regional boundaries in Figure 13 and Figure 14.

When the total R&U expenditure figures from Figure 18 are converted into average dollars per installed kilowatt, Figure 19 shows that *United States and Canada* again leads the ranking for both hydropower and PSH. For hydropower, almost 75% of expenditures in *United States and Canada* correspond to projects in the early “permitting and development” stages.²⁰ Of the 201 tracked projects in *United States and Canada* in the permitting and development phase, 71% are in the United States. Of the plants being refurbished, 86% are publicly owned, mostly by the federal government in the United States or one of the provincial governments in Canada. When focusing on projects “under construction” four regions—*United States and Canada*, *South Asia*, *Europe*, and *Russia*—have remarkably similar expenditure levels, all approximately \$18/kW. Together, these four regions account for approximately 40% of global installed hydropower capacity. They are also the four regions with the oldest (capacity-weighted) fleets (see Figure 20).²¹

As of the end of 2019, 875 hydropower plants have ongoing or planned R&U activities. The average expenditure per project is \$36 million but there are several projects with expenditures near or over \$1 billion (Mactaquac in Canada, Rogun in Tajikistan, Robert Moses Niagara in the United States).

For PSH, R&U expenditure per installed kilowatt is more than double in United States and Canada than in any other world region. R&U expenditure per installed kilowatt is significantly lower for PSH than for hydropower in every region. The PSH capital expenditures displayed in Figure 19 are distributed among 49 PSH plants around the world which add up to 19% of global installed PSH capacity.

20 The average expected construction start date for R&U hydropower projects in the permitting and development phase is ranges from 2020 and 2023 across world regions, and only 3% of tracked projects have expected start dates later than 2025.

21 Capacity-weighted fleet age is computed as the average plant age where the age of each plant is weighted by its capacity. If most large plants in a region were built first, the capacity-weighted age of its fleet will be greater than its raw average age.

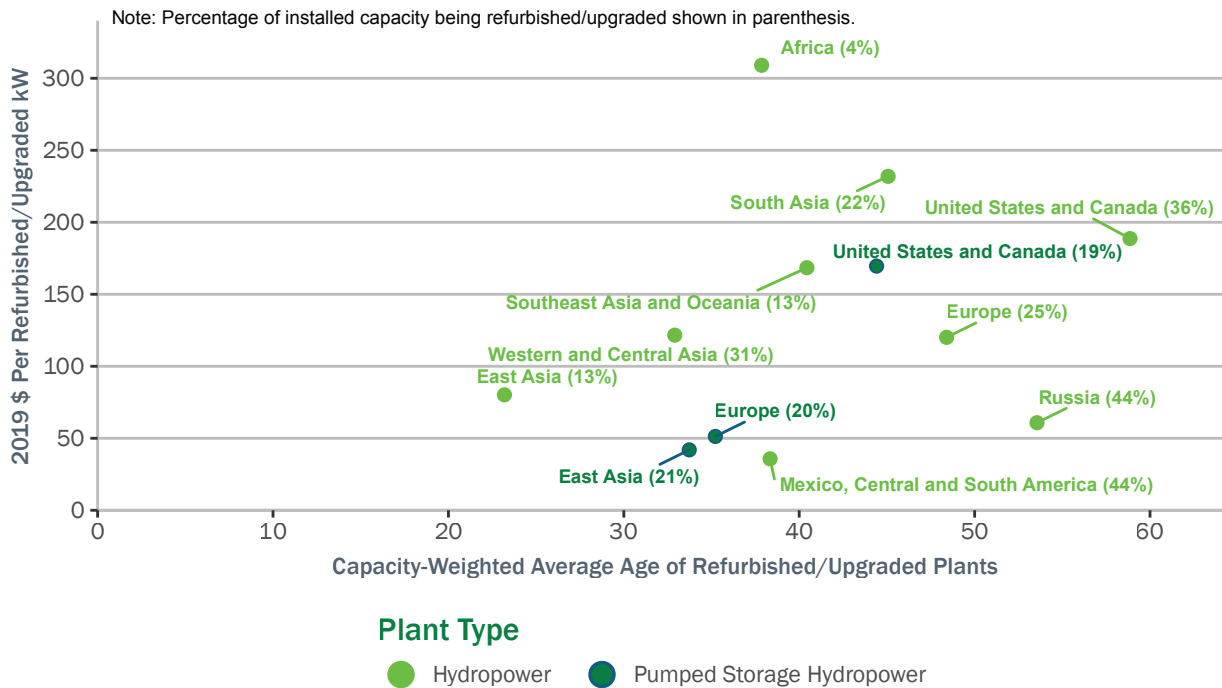


Figure 20. Expenditures on hydropower and PSH refurbishments and upgrades per kilowatt refurbished/upgraded and fleet age

Source: IIR, EIA International Energy Statistics.

Note: See regional boundaries in Figure 13 and Figure 14. For PSH, only regions with more than one project are included.

Generally, regions with older fleets spend more in each kilowatt being refurbished or upgraded. With the exception of *Africa*, all regions in which the average expenditure in R&U projects is greater than \$150/kW are directing that expenditure to fleets with a capacity-weighted average age of 40 years or older. However, not every region with a fleet 40 years or older is spending at that level; *Europe* and *Russia* are both spending significantly less. Within *United States and Canada*, the average expenditure per kilowatt refurbished at hydropower plants is 18% lower in the United States—which has the oldest capacity-weighted fleet—than in Canada. The age of the fleet relative to its initial commercial operation date is not the only driver for R&U decisions. How much R&U investment a plant requires today also depends on how much maintenance received throughout its operational life, on its mode of operation, and the metrics (e.g., availability, environmental performance) being targeted. Moreover, the funding mechanisms available to finance R&U capital expenditures vary by country and owner type and may also affect the volume and timing of investment. Further exploration of R&U investment patterns taking account a richer set of drivers is ongoing and needed.

In all three regions with data points for both hydropower and PSH, the investment per kilowatt refurbished or upgraded is higher for hydropower. The difference is likely related to PSH plants having a lower average age than hydropower and also to their scale. The median capacity of hydropower projects being refurbished or upgraded is 132 MW in *United States and Canada*, 70 MW in *Europe*, and 25 MW in *East Asia*. In contrast, for PSH, the median capacities are 314 MW, 360 MW, and 628 MW, respectively. Just as it happens for new hydropower construction (see Section 5.1.1), the relative R&U numbers for hydropower and PSH in Figure 20 are also likely indicative of economies of scale. It should also be noted that R&U investments are sometimes concentrated into some of the units within a hydropower plant in which case the values in Figure 20, where expenditures are divided by plant capacity, underestimate the investment per kilowatt actually refurbished or upgraded.²² Figure 20 also shows the percentage of installed capacity that is being refurbished or upgraded. *Africa* is engaging in several intensive R&U projects, but the subset of plants being refurbished or upgraded is very small (4%). On the other hand,

22 Capacity data for individual turbine-generator units was not available in this global dataset.

the expenditure per kilowatt refurbished is very low in *Mexico, Central and South America*, but it covers close to half of its installed capacity. In *United States and Canada*, the percentages of installed capacity with ongoing or planned R&U projects are 36% for hydropower and 19% for PSH.

3.2.3 Global Comparison of Hydropower Permitting Process

Multiyear hydropower permitting processes that require coordination from multiple agencies at various levels of government are standard in regions across the world. The permitting timeline is typically longer for larger projects.

In every world region, the public domain status of waterways and the multiple uses connected to water reservoirs result in administrative complexity in hydropower permitting. The hydropower authorization process typically requires coordination from multiple agencies at various levels of government: national, regional, and/or local. The need for coordination, along with extensive study requirements and stakeholder consultations, result in multiyear hydropower authorization processes.

Figure 21 summarizes information about the length of the permitting process for countries in different world regions. In some cases, the data correspond to a specific project; in others, it draws from descriptions of average permitting timelines across all projects or for small vs. large projects. The authorization process complexity and its duration (Figure 21) increase with project size.²³ For instance, the average permitting timeline for small hydropower projects in Canada is 3.3 years, but large projects such as Keeyask and Muskrat Falls took 5–6 years to complete their authorization process. Similarly, small hydropower projects in Norway (<10 MW) take 1–2 years to be authorized vs. a minimum of 4 years for larger projects. Reported average process durations for the United Kingdom and Germany range from 1–3 years and, in both cases, recent development is almost exclusively for small projects. On the high end of the spectrum, the ranges reported for Portugal (3–11 years), Spain (6–10 years), and Sweden (2–7 years) are very wide and reveal a large degree of uncertainty and associated cost for developers (Glachant, 2014). For the United States, FERC (2017) reports a median time of 3.34 years from notice of intent to submit a license application to license issuance based on the timelines for the 83 original licenses (i.e., licenses for new projects) issued from 2003 to 2016. The distribution of original license timelines spans a wide range around that median value.

23 For example, simplified versions of an environmental impact assessment are sufficient for projects below certain thresholds in many countries (e.g., 100 kW in Italy, 500 kW in Turkey, 10 MW in Brazil) (United Nations Industrial Development Organization, 2016).

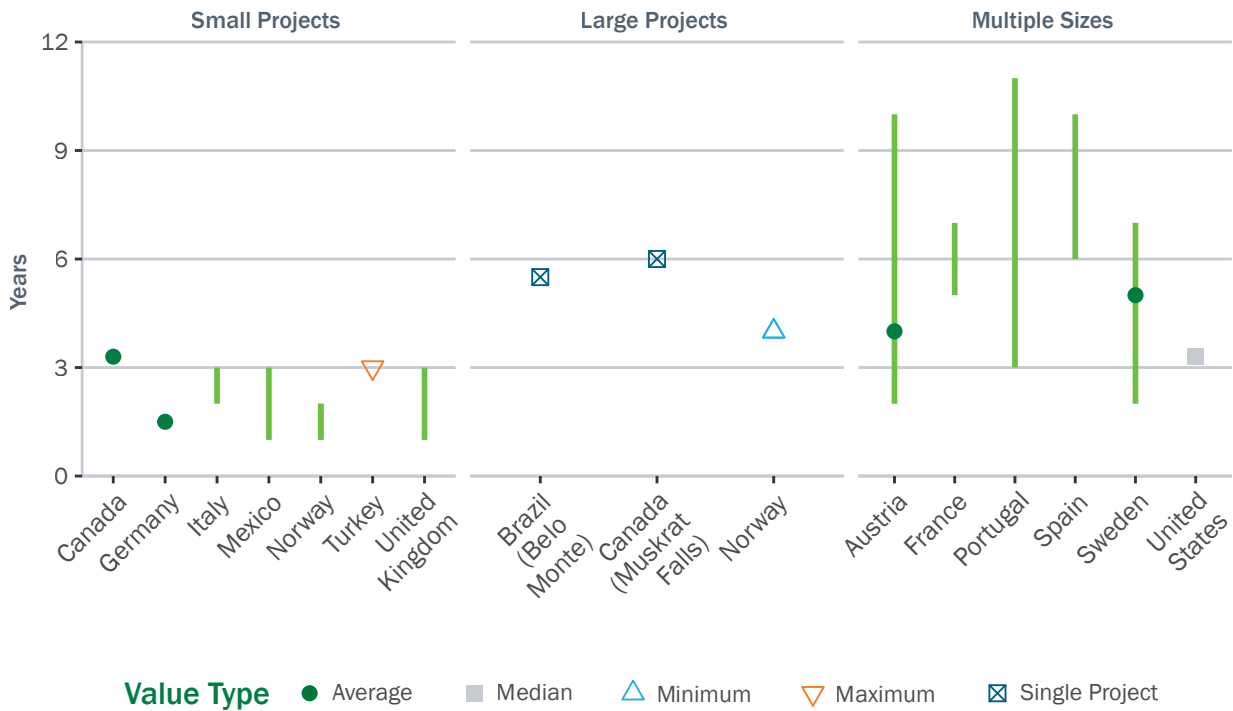


Figure 21. Duration of the hydropower authorization process in selected countries and projects

Sources: European Small Hydropower Association (2012): Austria, France, Germany, Italy, Portugal, Spain, Sweden, United Kingdom; United Nations Industrial Development Organization (2016): Mexico; FERC (2017): United States; International Energy Agency (2017): Canada; personal communication with Oystein Grundt: Norway; Internet searches: Belo Monte, Muskrat Falls, Turkey

Note: Belo Monte and Muskrat Falls are two specific large projects in Brazil and Canada, respectively. All other values in the plot summarize durations across recent projects in a country. The points provide permitting duration summary statistics: average, median, maximum, or minimum. The lines depict typical duration ranges.

European Small Hydropower Association (2012) and World Bank (2008) conclude that predictability and transparency are desirable attributes in a modern hydropower authorization process. Among the recommendations highlighted in those studies to improve existing processes are the designation of a “one-stop shop” (i.e., a lead agency that coordinates among all the other agencies with jurisdiction over the process), administrative deadlines for key milestones along the process, and standardization of required forms, particularly for small hydropower projects. Some of these recommendations would be easier to implement in countries with a more centralized authorization process. In the United States, FERC is the license-granting authority for all projects regardless of size; however, other agencies have mandatory conditioning authorities within the FERC process.²⁴ Brazil, Japan, South Africa, and Turkey are other examples for which the granting authority is highly centralized at the national level. In other countries, regional or local authorities have the lead role in the authorization process for all projects (e.g., Canada, Germany, India, Sweden) or for projects below a size threshold (e.g., Spain, France, Norway) (Glachant, 2014). Within the European Union, the hydropower authorization regime is set at the national level but is subject to supranational public procurement rules and environmental directives.

There are some differences in the obligations of hydropower project owners in countries with different project authorization models (i.e. licenses versus concessions). Authorization duration and renewal processes vary substantially across countries.

24 As an exception, projects under the Reclamation jurisdiction need a Lease of Power Privilege instead of a FERC license.

Depending on the country, hydropower authorization results in the issuance of an authorization/license or a concession to use public water resources and construct and operate a hydropower facility.²⁵ In exchange for the concession or license, the facility owner pays royalties or fees. In the United States, FERC charges multiple fees. Every owner of a FERC-licensed hydropower facility pays annual fees (as a function of installed capacity and electricity volume generated) to repay the cost of administering the regulatory hydropower program. Hydropower owners whose facilities are located on federal land, use a government dam, or benefit from the flow regulation provided by an upstream storage reservoir (headwater benefits) pay additional fees. States can apply additional fees due to their authority in water resource management. Washington, Oregon, California, and New York all apply additional fees to hydropower owners (Pineau et al. 2017).

In countries with a concession authorization model, the government initiates the process by issuing a call for tender, and private companies bid for the concession. In return for the right to develop and operate the facility, the concessionaire pays back a royalty to the public agency. The royalty is most often set as a function of electricity generation but might, alternatively, be a function of installed capacity (e.g., some Chinese provinces), the unit of water used (e.g., California), or sale revenue (e.g., Brazil) (Pineau et al. 2017). In India, the royalty is typically the free delivery of a percentage of the power generated by the plant to the state in which it is located.

The duration of the license or concession also varies significantly across countries and by owner type. For government-owned projects—including the federal fleet in the United States and much of the hydropower installed in China, India, Russia, Norway, Canada, and Australia—there is no time limit to the authorization, but the government can make revisions to the terms of operation. For privately-owned hydropower, long authorizations enhance the investment return opportunities for the project owner but provide limited flexibility for the regulator to request modifications of hydropower operations in response to changes in environmental or other conditions. In the United States, most of the nonfederal fleet holds a FERC license. Since October 2017, the default duration for new FERC licenses is 40 years; before that, they ranged from 30 years to 50 years (see Section 1.4 for more details).²⁶ Durations in the 30–50 year range are consistent with authorization duration in many other countries. In Norway, the authorization is indefinite for municipalities and counties, but the leases to private companies are no more than 15 years. Several countries have shortened the length of their licenses or concessions in recent years (e.g., United Kingdom from unlimited to 12–24 years, France from 80 to 40 years).

At the time of concession renewal, the government has multiple options: renegotiate authorization with the existing owner, open the concession to bidding by other operators, or assume ownership of the project. In Indonesia, all-new hydropower projects with more than 10 MW of installed capacity must follow a build-own-operate-transfer (BOOT) model in which the project is transferred back to the state at the end of a 30-year concession.²⁷ In the European Union, much of the hydropower built in the 1940s and 1950s had very long concessions (75–80 years), and the European Commission requires the governments of their member countries to implement a competitive bidding process at the time of renewal.

25 The concession model of authorization is typical in countries with civil law systems (e.g., France, Spain, Portugal, the Netherlands and their former colonies, and much of East Asia). Common law countries (e.g., United Kingdom and most of its former colonies, including the United States) tend to use a licensing system for hydropower authorization.

26 In the United States, it is typical for FERC to include reopen provisions in licenses, but they are rarely exercised.

27 <https://www.slideshare.net/AbdurrahmanArum/indonesia-renewables-investment-guide-series-hydro>

3.2.4 International Comparison of Hydropower Incentives

A combination of feed-in tariffs, tax incentives, and renewable energy tradable credits support small hydropower development in many jurisdictions around the world. In recent years, due to their high cost, feed-in tariffs have often been replaced with premium tariffs or other procurement mechanisms such as renewable energy auctions. In many countries (but not the United States), new large projects like PSH are often owned or financially supported by the government, or receive loans from multilateral financing institutions. These financial mechanisms drive different levels of hydropower investment across regions.

Table 3 summarizes government support for new hydropower installations in countries with large hydropower fleets and/or project development pipelines. The main categories of hydropower support are feed-in tariffs, premium tariffs, tradable renewable energy certificates, tax incentives, and grants. Incentives are tailored toward the types of hydropower pursued by each country and are most concentrated on the small hydropower segment whose definition also varies widely across countries.

Table 3. Summary of National (or Regional) Incentives for New Hydropower Installations in Selected Countries (as of December 31, 2019)

Country	Hydropower Incentives Category
Australia	Feed-in tariff (≤ 100 kW, Victoria)
Austria	Feed-in tariff (≤ 2 MW), grants
Brazil	Grants, tax breaks, concession fee exemption (< 30 MW)
China	National level: hydro capacity target, tax incentives; province level: Feed-in tariff
France	Feed-in tariff (≤ 500 kW), premium tariff (< 1 MW)
Germany	Feed-in tariff (≤ 100 kW), premium tariff
United Kingdom	Feed-in tariff (≤ 5 MW), contract for difference (> 5 MW)
India	National level: hydro capacity target; province level: Feed-in tariff, grants, royalty exemption
Indonesia	Feed-in tariff (≤ 10 MW)
Italy	Premium tariff, tax incentives
Japan	Feed-in tariff (≤ 30 MW)
Mexico	Clean energy certificates, tax incentives
Norway	Certificate trading system, tax incentives (≤ 5 MW)
Portugal	Guaranteed payment (bidding discount with respect to a reference tariff)
Russia	Long-term (15-year) capacity contracts allocated through a tender process (5–25 MW)
South Africa	Long-term (20-year) capacity contracts allocated through auction (≤ 40 MW)
Spain	Premium tariff
Sweden	Certificate trading system
Switzerland	Feed-in tariff (≤ 10 MW), grants
Turkey	Feed-in tariff, licensing fee exemption, hydro capacity target
United States	Federal: Public Utility Regulatory Policies Act, 10-year incentive payment (eligible NPDs and conduits); Renewable Electricity Production Tax Credit (1.2 c/kWh for 10 years); Rural Energy for America Program (grants and loan guarantees; ≤ 30 MW for projects developed by agricultural producers and small businesses in eligible rural areas) State-level: renewable energy certificates, tax incentives, Feed-in tariff (e.g., Vermont)

Source: <https://www.iea.org/policies>: Australia, Canada, China, Indonesia, Mexico, Russia, United States; <http://www.res-legal.eu/search-by-country>: Austria, France, Germany, United Kingdom, Italy, Norway, Portugal, Spain, Sweden, Switzerland, Turkey; United Nations Industrial Development Organization (2016): China; web searches: Brazil, India, Japan, South Africa, United States.

Note: These mechanisms are available for application by eligible plants as of the end of 2019. Hydropower plants in operation might be receiving other incentives from other programs that have now expired for new applicants. Net metering programs are not included in the table but are available in many countries.

In the United States, the “must purchase” obligation from the Public Utility Regulatory Policies Act (PURPA) has guaranteed an off-taker for new small hydropower projects since 1978. The guaranteed price is the avoided cost rate, which is set at the utility level.²⁸ Over time, the methodologies for determining the avoided cost rate and the size of eligible plants have changed in ways that reduced the overall level of support for small hydropower (see Chapter 7). The other primary federal incentive is the hydroelectric production incentive program outlined in Section 242 of the Energy Policy Act of 2005. Contingent on congressional appropriation of funds each year, it offers a 10-year incentive payment for projects adding hydropower to NPDs or conduits. Additionally, 30 states and the District of Columbia have RPSs, and a few states also have clean energy standards. For hydropower plants eligible for compliance with these standards, the resulting renewable energy certificates generate an income stream in addition to the sale of energy and capacity. RPS eligibility requirements for hydropower vary by state (see Chapter 7 for details).

Feed-in tariffs have been a popular instrument for promoting small hydropower globally, and many projects constructed in the past two decades benefit from them. Feed-in tariff levels are technology-specific and designed to ensure the profitability of the renewable energy facility.²⁹ Figure 22 shows feed-in tariff rates—typically, ranges depending on size and other project attributes—and duration of the support payment in selected countries and regions.

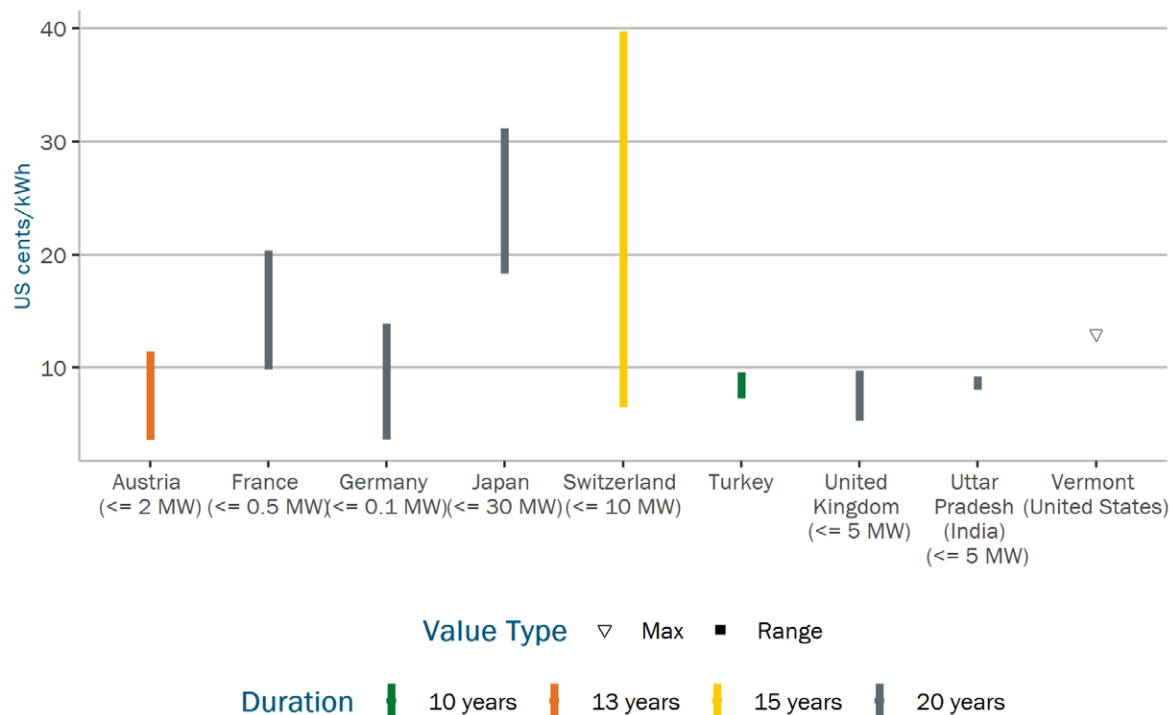


Figure 22. Hydropower feed-in tariff values and duration of feed-in tariff support in selected countries/regions

Sources: <http://www.res-legal.eu/search-by-country>: Austria, France, Germany, United Kingdom, Switzerland, Turkey; <https://vermontstandardoffer.com/standard-offer/technologies/hydro/>: Vermont; web searches: Japan, India, Vermont

Notes: All the tariffs were in force in 2019. The values were transformed from their original currency to U.S. dollars using the 2019 average exchange rate.

²⁸ The avoided cost methodology is set at the state level and the resulting avoided cost rates vary by utility.

²⁹ In contrast, PURPA rates represent the avoided cost to the purchasing utility. Hempling et al. (2010) examine the pathways available to states to implement feed-in tariffs within the constraints of the PURPA of 1978 and the Federal Power Act of 1935.

All the feed-in tariffs included in Figure 22 focus on small hydropower; the size limits for eligibility vary depending on the definition of the small hydropower in each jurisdiction. The value for Vermont is the maximum rate that can be bid in its annual standard offer request for proposals. Although the Vermont program does not specify a size limit, it does restrict eligibility as new hydropower to hydropower built at NPDs and facilities repowered after more than 10 years out of service. In all other cases, a range of rates is offered depending on project capacity (Austria, Germany, United Kingdom, Switzerland, Japan), project head (France, Switzerland), season (France), local content (Turkey), or commissioning date (India). Generally, the higher end of the tariff range is for the smallest projects since they typically have higher capital costs per installed kilowatt. Given the combination of tariff amount, duration, and size limit, Japan and Switzerland offer the strongest incentives of the group presented in Figure 22.

The cost of feed-in tariffs has become very large in some countries since the rates offered were much higher than market prices. For this reason, in recent years, there has been a trend toward replacing feed-in tariffs with renewable energy auctions or other mechanisms (e.g., contract for differences in the United Kingdom; premium tariffs in France, Germany, and Spain; renewable energy auctions in Ontario). In the European Union, the transition toward auctions has also been driven by the requirement issued by the European Commission in 2014 to progressively introduce more competition. However, even in countries that have transitioned to using renewable energy auctions (e.g., Germany, Japan), feed-in tariffs remain for hydropower installations below certain capacity thresholds for which there is not enough competition (unlike solar and wind) to make auctions a workable mechanism.

Renewable energy auctions have mostly focused on procuring wind and solar power, but there have also been some hydropower participation and awards. In 2017 and 2018, IRENA (2019a) tracked results from auctions in 50 countries that awarded contracts for 97.5 GW of renewable energy. Hydropower represented less than 1% of that total volume (700 MW of small hydropower in auctions held in South and East Asia, the Pacific, and the Americas). Solar photovoltaic power accounted for 55% and wind power accounted for 32% of the total. An additional 668 MW of small hydropower resulted from auctions in the Americas in 2016, mostly in Brazil (IRENA, 2017). In its first four rounds, the South African renewable energy auction for small projects procured 19 MW of hydropower out of 6,328 MW procurements (Eberhard and Naude 2016). In the United States, the Renewable Auction Mechanism in California is an example of a renewable energy auction, but most states and utilities have favored competitive solicitations over auctions for procuring the renewables needed to meet their RPS objectives.³⁰

Although most countries have renewable electricity goals, it is less common for them to have targets for specific technologies. China, Turkey, and India are salient examples of countries with hydropower installation targets. Capacity goals translate into a monetary incentive for hydropower owners if facilities that meet the standard receive tradable certificates. Tradable certificates are a feature of many of the RPSs in the United States. Norway and Sweden created a market for green certificates in 2012. Mexico started issuing clean energy certificates for its internal market in 2016.

As shown in Table 3 and Figure 22, feed-in tariffs and premium tariffs tend to target small hydropower. National governments often fund or actively support the financing and development of the largest, most expensive projects. Out of 49 PSH projects under construction globally at the end of 2019 (with a median capacity of 1,200 MW), the 34 projects in China are mostly being developed by subsidiaries of the State Grid Corporation. PSH plants in China are currently compensated through either a capacity-only tariff or a two-part tariff with capacity and energy components (Zhang et al., 2018). Projects in India, Dubai, and Morocco are being constructed by consortia of international companies but will be owned by their respective governments. Other projects developed by private or nonfederal, public entities often have backing from the government or receive part of

30 The main difference between competitive solicitations and auctions is that the former evaluates qualifying proposals based on price and nonprice criteria, whereas auctions select qualifying bids based on price alone (Kreyck et al. 2010).

their funding in the form of loans provided by multilateral financing institutions that have green infrastructure programs. For instance, the Espejo de Tarapacá PSH in Chile received \$60 million from the Green Climate Fund, and the Tamega PSH in Portugal received a \$672 million loan from the European Investment Bank. In Israel, a private company is developing the Star PSH project (344 MW) under a design-build-operate-own license from the government-owned electric utility which will also be the off-taker for the energy generated by the project.³¹

Europe is the region with the most PSH projects being developed by investor-owned utilities or privately-owned energy companies. These PSH projects are important contributors toward achieving ambitious changes to the energy mix. Switzerland, whose target is to become carbon neutral by 2050 while phasing out nuclear energy, has two PSH plants under construction. Greece also has two PSH plants under construction and has pledged to phase out coal by 2028.

31 <https://www.hutchisonwater.com/projects/star-pumped-storage/>

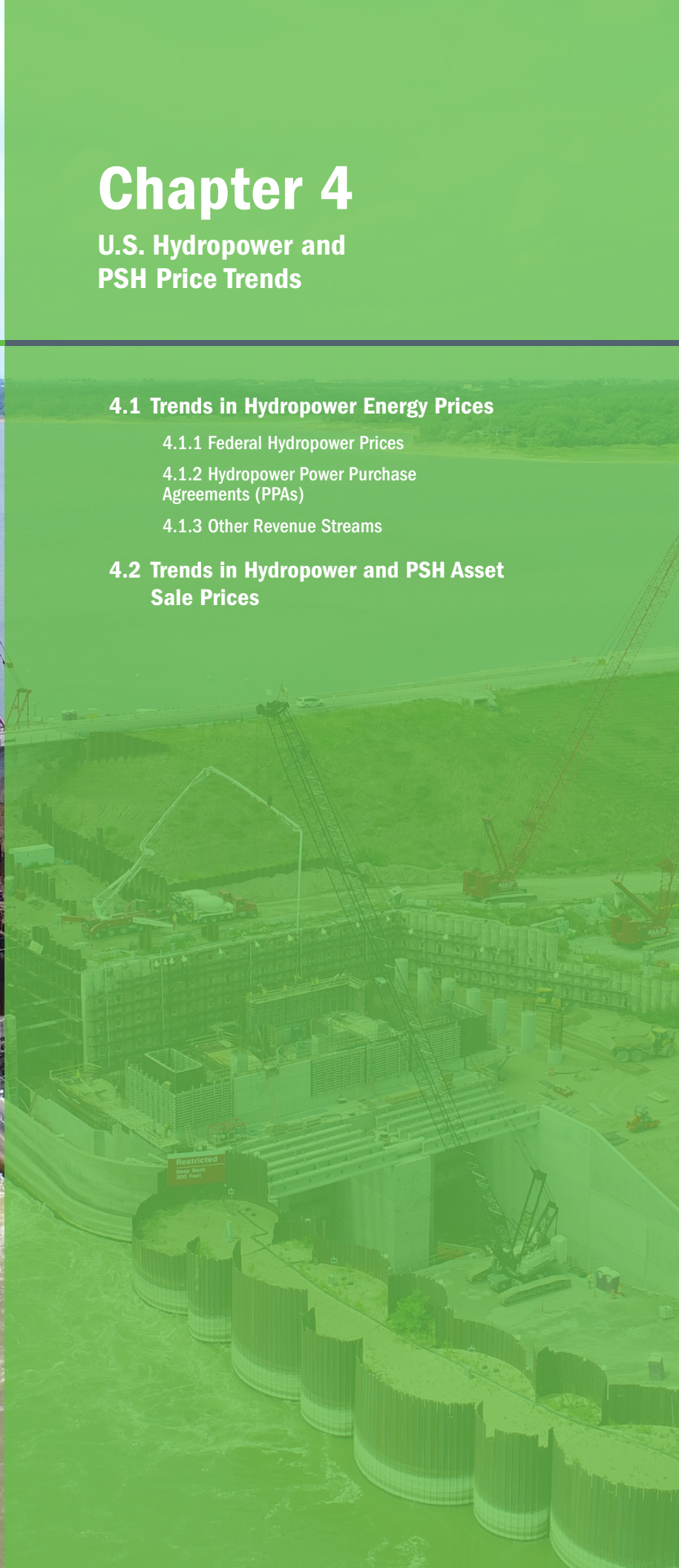
Chapter 4

U.S. Hydropower and PSH Price Trends

4.1 Trends in Hydropower Energy Prices

- 4.1.1 Federal Hydropower Prices
- 4.1.2 Hydropower Power Purchase Agreements (PPAs)
- 4.1.3 Other Revenue Streams

4.2 Trends in Hydropower and PSH Asset Sale Prices



4. U.S. Hydropower and PSH Price Trends

This chapter provides an analysis of trends in hydropower energy prices—both for the federal and nonfederal segments of the fleet—and hydropower asset sale prices. It also presents data on revenue composition, including energy and ancillary services, for a subset of PSH plants in the United States.

4.1 Trends in Hydropower Energy Prices

The price of hydropower varies significantly by region, energy market structure, and ownership type among other factors. Federal hydropower is sold by PMAs at cost-based rates; nonfederal hydropower, depending on geography and ownership type, is sold through long-term contracts—with a variety of pricing methods—or transactions in organized wholesale markets.

The revenue received by hydropower owners for the energy they sell varies significantly depending on region, electric market structure, and ownership type. Energy generated by the federal hydropower fleet, approximately 50% of installed capacity, is sold by PMAs at cost-based rates. Electricity generated by the rest of the fleet is sold through long-term PPAs (the most typical arrangement for plants owned by private non-utilities), other bilateral contract agreements, or at spot prices in an ISO/RTO market or wholesale trading hub. Thus, building a comprehensive view of the value hydropower receives for the energy it produces requires combining data from multiple sources.

Moreover, the rates and prices received by different hydropower plants might not be exactly comparable. The rates paid by federal hydropower customers, typically public utilities, sometimes include ancillary services, such as frequency regulation and reserves. The prices paid in PPAs may or may not include a capacity component; and, in states with RPSs, the value of environmental attributes is typically also included in the price. At a trading hub or ISO/RTO, the locational market price reflects the price of the marginal unit dispatched in each period, as well as transmission congestion. Given these differences, it is more informative to present revenue trends separately for different segments of the U.S. hydropower fleet.

4.1.1 Federal Hydropower Prices

On average, federal hydropower prices remain competitive with regional wholesale prices. Hydrologic conditions are the key variable that affects the average prices paid by federal hydropower customers. The price of the peaking power marketed by Southwestern Power Administration (SWPA) and Southeastern Power Administration (SEPA) has been higher in recent years than the wholesale electricity prices in their respective regions.

The PMAs—Bonneville Power Administration (BPA), Western Area Power Administration (WAPA), Southwestern Power Administration (SWPA), and Southeastern Power Administration (SEPA)—are federal agencies within the U.S. Department of Energy created to market federal hydropower.³² PMAs allocate the capacity and energy of the federal fleet to preference customers, primarily municipalities and cooperatives, that have entered into long-term contracts with a PMA. There are substantial differences in the products sold across PMAs, which include a mix of power types (e.g., peaking power, as-available energy) driven by hydrology and mode of operation of their respective fleets. For example, BPA fully meets the load requirements for many of its customers. Meanwhile, customer allocations in SWPA and SEPA guarantee only 3–4 hours of peaking power per day (although additional supplemental energy is offered when hydrologic conditions are favorable) and WAPA sells as-available energy from some of its projects rather than offering a guaranteed allocation.

32 The Tennessee Valley Authority is also a federal hydropower owner, but it became self-financing in 1959 and functions like a vertically integrated utility that sells energy to its customers directly, rather than through a PMA.

Each year, the PMAs determine their cost-based energy rates. To do this, they first calculate their revenue requirements to 1) meet their Treasury payment obligations and 2) operate and maintain the hydropower fleet. Deviations from forecasted water availability can lead to energy deficits or surpluses compared with the contracted customer allocations. When there is a deficit, to fulfill their contracts if required, the PMAs purchase replacement power through bilateral transactions with utilities or through an organized wholesale market. When there is a surplus, they offer it to their customers or sell it to third parties in the market. Thus, even though the base energy rates are fixed for a whole year, in dry years, PMA customers still face price risk, either directly or indirectly.³³ On the other hand, in wet years, supplemental energy might essentially bring down the average price paid by preference customers for their federal hydropower supply. Thus, hydrologic conditions ultimately affect the average prices paid by federal hydropower customers. Figure 23 compares the average revenue per megawatt-hour obtained by PMAs for hydropower to wholesale electricity prices in the same regions from 2006 to 2018.

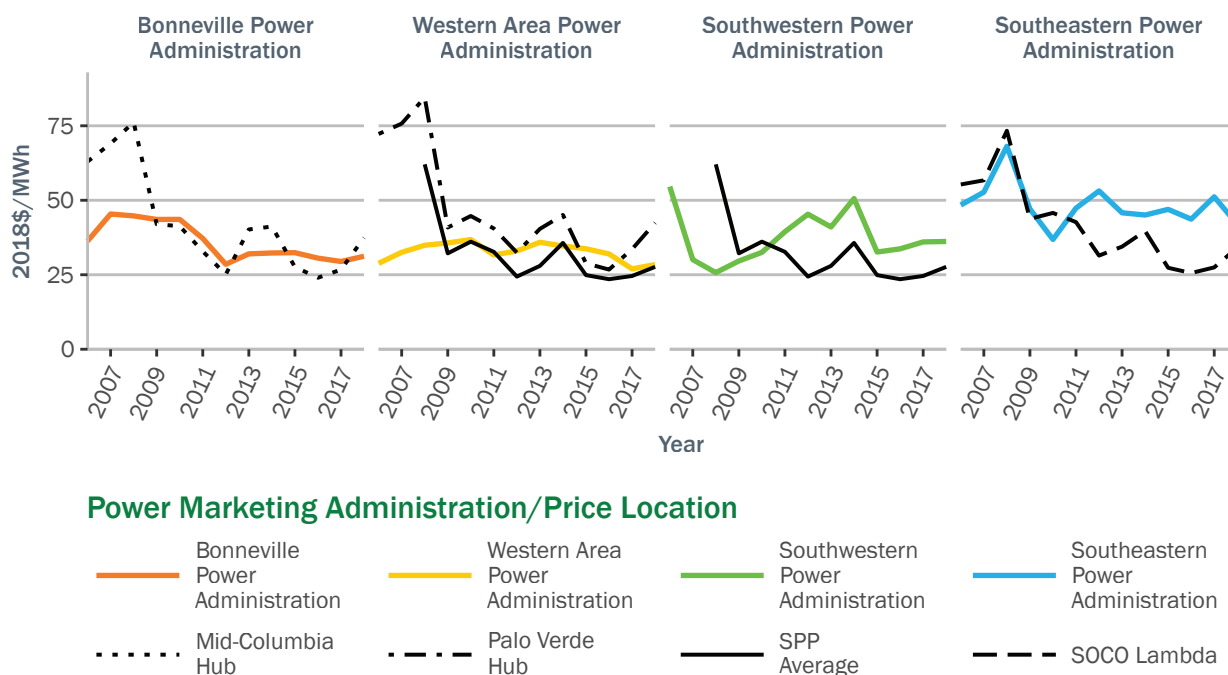


Figure 23. Average federal hydropower revenue vs. average wholesale electricity prices

Sources: EIA Form 861 (for federal hydropower prices), EIA Wholesale Electricity and Natural Gas Market Data (Mid-Columbia and Palo Verde hubs), SPP State of the Market reports (Southwestern Power Pool Average), FERC Form 714 (SOCO Lambda).

Notes: PMA average revenues are calculated as the ratio of total revenues from retail sales and sale for resale over the volumes sold. Mid-Columbia and Palo Verde hub are daily volume-weighted average prices across all wholesale transactions at those hubs. The SPP average price is the day-ahead price of energy (since the start of the Integrated Marketplace in 2014, it also includes the cost of operating reserves and uplift payments). SOCO Lambda represents the average cost of operating the marginal unit in each hour of the year in the Southern Company BA.

33 In some cases, customers can opt out of the replacement power and find alternative ways to cover the deficit from their federal allocations.

In 2016–2018, the average wholesale price was \$30.41/MWh for BPA, \$29.12/MWh for WAPA, \$35.30/MWh for SWPA, and \$45.58/MWh for SEPA. For both BPA and WAPA, the hydropower price was lowest in 2017, a year with above average runoff. Typically, the average federal hydropower prices in the two eastern PMAs (SWPA and SEPA) are higher than in the other two largely because of the lower capacity factor of their fleets which are operated as peaking plants. For instance, in 2018, the average capacity factor was 41% for BPA, 37% for WAPA, 33% for SWPA, and 28% for SEPA.

The wholesale prices shown in Figure 23 represent prices being paid to other nonfederal electricity producers in the same region. The Mid-Columbia hub offers a relevant comparison with BPA's hydropower prices because it corresponds to the same geographical area, and the generation mix is dominated by hydropower through the whole Pacific Northwest region. The hydropower fleet marketed by WAPA extends from the Upper Great Plains of North Dakota to the Arizona–Nevada border as well as the Central Valley of California and contains multiple marketing regions with markedly different hydrology. For that reason, two wholesale prices are included for comparison in that panel: WAPA's northernmost marketing region (Upper Great Plains) became an SPP market participant in 2015, and the Palo Verde hub is not far from the largest projects in WAPA's Desert Southwest region and is a trading point for the California market. Some of the public utilities that have contract allocations with SWPA are also SPP customers (because federal hydropower in SWPA covers only a small fraction of overall load for those customers), making SPP also a relevant comparison for the prices of that PMA. Finally, SEPA's footprint has limited overlap with ISOs/RTOs or liquid wholesale trading hubs. The marginal cost of operation in Southern Company's BA was selected as representative of the value of electricity in that region. The four wholesale price series in Figure 23 differ in levels, because of differences in energy mix and other characteristics of each regional market, but their trajectory from 2006 to 2018 is remarkably similar. That similarity indicates that annual average prices are largely explained by national-level macroeconomic indicators. The availability of abundant, low-cost natural gas after 2008 is one of the key drivers for the generally low wholesale electricity price levels in Figure 23. In the Pacific Northwest and the SPP territory, large growth in installed wind capacity has also contributed to the low prices.

The cost-based average prices paid for federal hydropower typically vary less year to year than the wholesale market price trajectories. For the two eastern PMAs (SWPA and SEPA), the average rate has been higher than the wholesale prices every year since 2011. On average, revenue per megawatt-hour for BPA and WAPA has remained comparable to the wholesale prices in the region in recent years. The increase in Mid-Columbia and Palo Verde prices in 2017 and 2018, driven by natural gas price and pipeline transmission outages and, in 2018, lower than average hydroelectric output, has not been tracked by the federal hydropower price.³⁴ SEPA and SWPA experience more interannual revenue variability than the other PMAs. For SWPA, where inflow depends on rainfall (rather than snowpack) and whose storage capacity is small, the variability in annual generation is larger than for other PMAs. In contrast, despite a severe drought in 2012–2015, average prices remained remarkably stable in BPA and WAPA.

34 <https://www.ferc.gov/market-assessments/reports-analyses/st-mkt-ovr/2018-A-3-report.pdf>

To better adapt to the ongoing changes in market structure, generation mix, and the transmission system, several PMA marketing regions have considered the option of becoming participants in an ISO/RTO market, the CAISO-administered Western Energy Imbalance Market, or the proposed SPP-administered Western Energy Imbalance Service market.

Several shifts have happened to lead to federal PMAs pursuing participation in ISO/RTO or imbalance markets. For federal hydropower prices to remain stable, PMAs need to have access to liquid markets for purchasing replacement power and selling surplus power. As more nonfederal BAs join an ISO/RTO or an imbalance market, fewer trading partners are left to engage in the bilateral contracts that underpinned much energy trading by PMAs until recently (particularly in the West). For the PMAs and their customers, this decrease in the number of counterparties could potentially create the risk of higher/more volatile replacement power costs in dry years and fewer opportunities to sell surplus power in wet years. Additionally, the substitution of renewable energy for fossil fuels in the generation mix leads to higher net load variability and changes in the transmission paths through which electricity is routed. All these changes are becoming more difficult to manage for the PMA BA areas. For these reasons, some of them have explored the option of joining an ISO/RTO or an energy imbalance market.

- » In October 2015, WAPA's Upper Great Plains - East Region joined the SPP.
- » In September 2019, WAPA's Colorado River Storage Project, Rocky Mountain Region, and Upper Great Plains - West Region announced plans to join the SPP EIS in February 2021.
- » In September 2019, WAPA's Sierra Nevada Region announced plans to join the CAISO Energy Imbalance Market in April 2021.
- » In December 2019, BPA signed an implementation agreement to start the process of joining the Western Energy Imbalance Market with April 2022 as planned membership start date.

In each case, the PMAs conducted cost-benefit analyses of their status quo as independent BAs vs. multiple membership alternatives.³⁵ The analyses generally concluded that access to the larger, more diverse generation portfolios in ISOs/RTOs or imbalance markets offers opportunities for modest improvements in net cost (or revenue) from energy trading, lower transmission congestion costs, enhanced reliability, and—in the case of an ISO/RTO—more efficient transmission planning. For BPA, an important motivation for joining the CAISO Energy Imbalance Market is to enhance the value of the flexibility provided by the Federal Columbia River Power System by using it in the sub-hourly dispatch process of the CAISO Energy Imbalance Market to help balance the fluctuations in variable renewables in California.³⁶

4.1.2 Hydropower Power Purchase Agreements (PPAs)

The median hydropower PPA price has followed a similar trend to wholesale electricity prices in recent years, except in regions with little or no geographic overlap with ISO/RTO markets (Northwest and Southeast), where the median hydropower price has remained higher than the wholesale electricity price.

PPAs are the usual instruments by which non-utility hydropower owners sell energy and other attributes from their projects. The off-taker has typically been a utility, but other entities are playing a growing role in recent years (see textbox).

35 Energy imbalance markets are essentially real-time (5-minute dispatch intervals) energy markets. Resource offers into the energy imbalance market are voluntary and the BA retains most its autonomy over transmission and reserves planning. In contrast, joining an ISO/RTO gives the BA access to more markets (day-ahead and real time energy market and ancillary services markets) but also requires joint transmission planning and resource adequacy planning which reduces the BA's autonomy.

36 Additionally, BPA is working with CAISO on developing a flexible capacity product that would create an incentive for the PMA to reserve transmission capacity to provide ramping at the hours required by California's net load patterns, instead of structuring sales in 16-hour blocks (Florescu and Pead 2018).

CORPORATE (AND OTHER NON-UTILITY) PPAS FOR U.S. HYDROPOWER

International Renewable Energy Agency (2018) estimates that more than half of the 465 TWh of renewable electricity used by corporations worldwide comes from hydropower which is largely driven by the historical co-location of energy-intensive industries (e.g., aluminum, steel, mining) in areas with abundant, cheap hydropower in the United States and elsewhere. On the other hand, hydropower has not played a large role in the current trend of corporate PPA deals in the United States. In 2018, corporate and industrial buyers accounted for 22% of U.S. solar and wind procurement contracts.³⁷ The only corporate hydropower purchase deal that has been publicly disclosed is a 5-year power supply agreement between Microsoft and Chelan County Public Utility District announced in 2019. In this agreement, Microsoft purchases 50 MW of the hydropower from the utility district, and the power sale revenues will be invested in the hydropower fleet and the expansion of broadband coverage in rural Chelan county.³⁸ Another example of a corporate hydropower deal that does not involve a PPA is the purchase of the 45-Mile Hydroelectric Project (3 MW, Oregon) by Apple in 2014 to power a nearby data center.³⁹

The low participation of hydropower in corporate renewable procurement can be attributed to multiple factors. First, corporate buyers often want to claim “additionality” in their renewable energy purchases, meaning that the procurement caused the plant to come online, and this requirement focused purchases on newly installed capacity. The relative amounts of new capacity for wind (70 GW), utility-scale solar (30 GW), and hydropower (2 GW) in the United States in 2008–2018 thus help explain the observed mix of technologies in corporate renewable PPAs. Second, corporate PPA deals are very price-driven, and the price of solar and wind PPAs has been lower than prices for hydropower partly because of the 30% tax incentive available to those other renewables but not to hydropower in recent years. Third, corporate buyers favor projects that can be brought online quickly, and those online date requirements are not well aligned with the completion timeline of many hydropower projects. Fourth, some potential buyers express uneasiness about the environmental impact of hydropower; low-impact hydropower development approaches like NPD projects are not widely familiar to corporate energy buyers (Renewable Energy Buyers Alliance, 2019).

Despite these influences, there will be opportunities for more hydropower plants to engage with corporate procurement. As more companies commit to achieving higher percentages of renewable energy in their operations or along their supply chain, companies will need to turn to more dispatchable renewable energy like hydropower and biomass, or electricity from energy storage systems, including PSH. Seeking third-party low-impact certification can be a useful tool for hydropower project owners to allay environmental impact concerns of corporate buyers.

Even if corporations have not been active in seeking hydropower PPAs, other non-utility off-takers are purchasing energy from new hydropower projects in the United States. The higher education sector provides multiple examples, including the 10-year PPA between Penn State University and Mahoning Creek Hydro (6 MW, Pennsylvania) and a PPA between the University of Pittsburgh and the Allegheny Lock and Dam 2 (17 MW, Pennsylvania). Other examples of universities selecting hydropower to meet a portion of their electricity demands are Berea’s College investment in the Ravenna hydropower project (2.6 MW, Kentucky) and University of Notre Dame’s ongoing construction of a 2.5 MW hydroelectric facility in South Bend, Indiana, after the city transferred to the university a FERC exemption it held but had not acted upon since 1984.⁴⁰ For smaller hydropower projects (<1 MW), institutions in the education and health sectors are also entering net metering or group net metering agreements to claim credits from generation at local hydropower facilities, particularly in the Northeast.^{41, 42}

37 <https://www.woodmac.com/news/editorial/us-renewables-technology-giants-top-of-the-list-in-a-bumper-year-for-corporate-procurement/>

38 <https://news.microsoft.com/2019/04/12/microsoft-expands-clean-energy-connectivity-investments-in-washington-state-with-chelan-public-utility-district/>

39 <https://www.hydroreview.com/2014/04/15/apple-acquires-45-mile-small-hydropower-project/#gref>

40 <https://www.usdams.org/our-news/notre-dame-to-build-hydroelectric-station/>

41 <https://www.berkshireeagle.com/stories/second-scully-hydroelectric-plant-restoration-to-power-up-in-spring,164144>

42 <https://www.unh.edu/unhtoday/2016/08/artisanal-energy>

Major electric utilities are required by FERC to report power purchase volumes and expenditures—from long-term and short-term purchase agreements—as part of Form 1.⁴³ For hydropower PPAs, the FERC Form 1 dataset includes hundreds of agreements between utilities and private owners of small plants (PURPA contracts in many cases), as well as agreements between regional utilities exchanging much larger volumes from an entire hydropower fleet. From 2006 to 2018, the authors identified 4,891 hydropower energy purchases from 689 buyer-seller pairs (proxy for number of PPAs) on FERC Form 1. All purchasing entities filing FERC Form 1 are electric utilities. Sellers selected for the analysis of hydropower PPAs either own a single hydropower plant or a fleet of plants that are 100% hydropower.^{44,45} The purchased hydroelectricity volumes identified added up to 35 TWh in 2006 and declined steadily to 14 TWh by 2018 mostly as a result of the expiration of some large PPAs. On average, the hydropower sales identified on FERC Form 1 represented 8% of total U.S. hydropower generation.

Figure 24 compares the trend in median and generation-weighted average prices for hydropower PPAs with the full Form 1 purchased power dataset, which includes data for all electricity generation technologies.

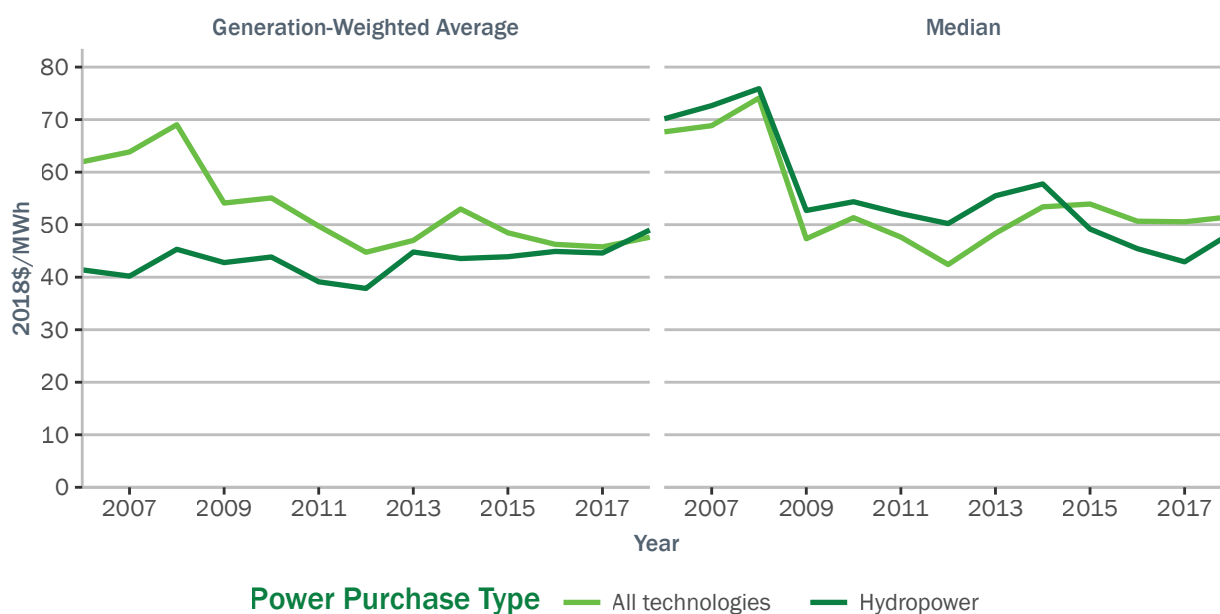


Figure 24. Median and generation-weighted average FERC Form 1 purchased power prices for hydropower vs. all technologies

Source: FERC Form 1

Note: Divergence in the numbers for 2006–2016 relative to the same plot from the 2017 Hydropower Market Report is due to the inclusion of additional transaction categories.

Figure 24 shows that the generation-weighted average price for hydropower has been in the \$40–\$50/MWh range, more stable than for the aggregate of all technologies during this period. The generation-weighted average price was lower for hydropower than for the aggregate for most of the 2006–2018 period. The median hydropower price has followed the same trend as the rest of PPA sales, but its level was higher until 2015.

The substantial difference between median and generation-weighted average for hydropower in the first half of the period means that some of the largest power purchases in those initial years took place at prices much lower than the median price. These included PPAs with Manitoba Hydro and Hydro-Québec and transactions between some utilities in the West.

43 Form 1 is a comprehensive financial and operating report submitted for electric rate regulation and financial audits.

44 Based on EIA Form 860 data, there are 346 generation owners in the United States whose generation capacity is 100% hydropower. This set includes limited liability companies, municipalities, and irrigation districts, as well as several public utility districts in the Northwest.

45 Federal hydropower owners were excluded from the analysis.

Overall, the shape of the median purchased power price trends in Figure 24 is similar to those of wholesale electricity spot prices. Figure 25 compares wholesale electricity spot prices to the median, 10th, and 90th percentiles of hydropower purchase prices by region.

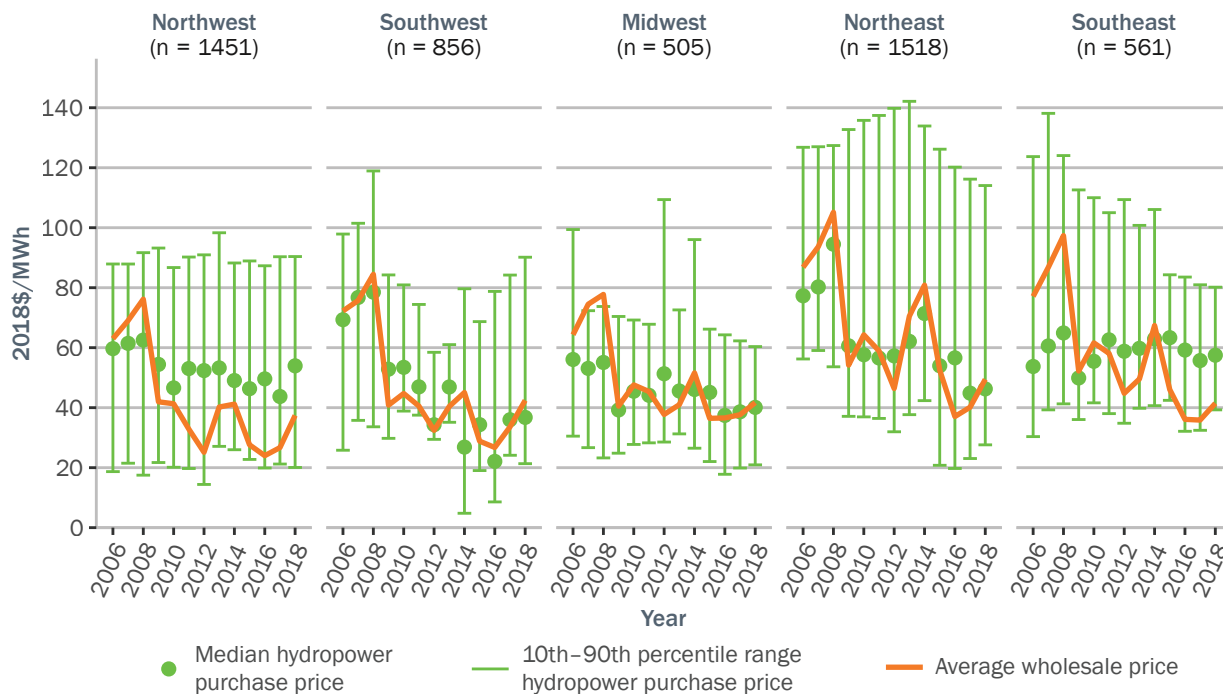


Figure 25. Hydropower price by region and report year from power sales reported on FERC Form 1

Sources: FERC Form 1, EIA Wholesale Electricity and Natural Gas Market Data

Note: Points correspond to the median hydropower purchase price based on FERC Form 1 data, and the range represents the 10th to 90th percentile FERC Form 1 hydropower purchase price range. Trend lines display the average wholesale price at selected electricity trading hubs in each region (Mid-Columbia Hub for the Northwest, Palo Verde Hub for the Southwest, Indianapolis Hub for the Midwest, Massachusetts Hub for the Northeast, and PJM Interconnection West Hub for the Southeast). The figure displays only the energy component of prices; the capacity component—which only exists for 25% of transactions—is not shown. Divergence in the numbers for 2006–2016 relative to the same plot from the 2017 Hydropower Market Report is due to the inclusion of additional categories of transactions on FERC Form 1.

The number of hydropower purchases captured by the FERC Form 1 dataset is highest for the Northwest (the region with the largest installed hydropower capacity) and the Northeast (the region with the greatest number of hydropower plants). For most of the period shown in Figure 25, the Northeast and Southeast had the highest median hydropower price.

In 2015–2018, median hydropower prices were higher than the regional wholesale spot prices in the Northwest and Southeast regions which account for 64% of installed hydropower capacity. In the rest, the median hydropower price has followed the wholesale spot price closely since 2008. The geographical footprint of the Northeast and Midwest regions overlaps ISOs/RTOs (ISO-New England [ISO-NE], New York ISO, and PJM for the Northeast; Midcontinent ISO and SPP for the Midwest), and many utilities in those regions calculate the avoided cost for PURPA PPA rates by indexing energy rates to the locational marginal prices from one of the ISOs. In contrast, in the Northwest, there are no organized wholesale markets, and PURPA PPA rates have more often been based on the cost of obtaining energy from a combustion turbine or combined cycle gas turbine (Yeazel 2018). The Southwest and Southeast regions are intermediate cases; only parts of their territory overlap with an ISO/RTO.

The 10th – 90th percentile price interval spans a wide range in most regions and years. For the Northwest, that interval is approximately symmetric and remained very stable throughout the period analyzed. For the Northeast and Southeast, the 90th percentile of the price distribution has been greater than \$100/MWh for most of the period, but it shows a clear declining trend (as older PPAs signed at higher prices expire).

The hydropower prices in Figure 25 do not include the value of renewable energy certificates. Those certificates provide additional revenue per megawatt-hour for hydropower owners whose plants are an eligible resource to comply with RPS requirements. Stori (2020) details hydropower eligibility criteria in each of the 29 states (plus Washington D.C.) with an RPS as of 2020. Renewable energy certificate prices were as high as \$60/MWh for a subset of RPS-eligible resources in Massachusetts and Rhode Island in 2013–2014. By 2018, renewable energy certificate prices were approximately \$20/MWh in New England and close to zero in other jurisdictions like Illinois and Washington D.C. (Barbose, 2019)

The variability in prices being paid for hydropower across regions and years is partly explained by differences in contract length, type of service (firm/non-firm), and contract vintage.

To provide insight into the price ranges observed in Figure 25, Figure 26 and Figure 27 show the trends and regional differences in volume-weighted prices across agreement terms (long-term vs. short-term) and types (firm vs. non-firm), respectively. In contrast to Figure 25 where only the energy component of prices is shown, Figure 26 and Figure 27 combine both energy and capacity components of price. Approximately 25% of transactions include a capacity component. The fraction of transactions with a capacity component is highest in the Southwest (62%) and lowest in the Northeast (9%). When included, the capacity component accounts for 25% of total revenue per megawatt-hour, on average.

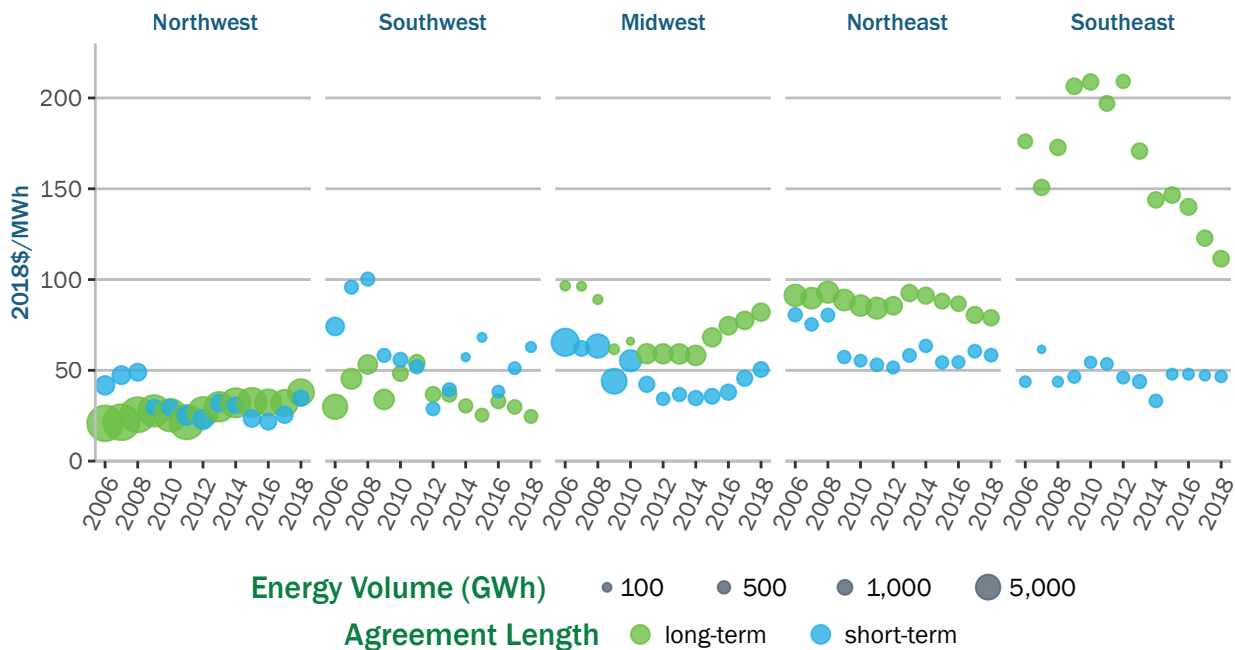


Figure 26. Volume-weighted hydropower price by region, year, and contract length

Source: FERC Form 1

Note: Long-term purchases correspond to contracts with lengths of five or more years.

The mix of sales and their ranking by price differs significantly across regions. The Northwest has the largest fraction of long-term purchase transactions (69%) and purchases the largest volume of hydropower through long-term contracts. The volume-weighted price has been similar for long-term and short-term transactions since 2008. In the Southwest, the average price of long-term transactions (65% of total transactions) has been more stable, but generally lower, than the average price of short-term transactions.

The Midwest has the lowest fraction of long-term transactions (39%). Average prices follow a similar trajectory in that region regardless of length but were higher for long-term than short-term contracts, particularly in the 2006–2008 and 2015–2018 subperiods. The large volumes of short-term sales in the Midwest in the first few years mostly corresponded to a PPA between Northern States Power Company and Manitoba Hydro, which became a long-term contract after 2010.

In the Northeast and Southeast, the volumes and volume-weighted prices of long-term transactions are higher than for short-term transactions. The difference is most acute in the Southeast. The very high average price for long-term transactions is driven by one contract: the 42-year PPA between Entergy Louisiana and the Sydney Murray Hydroelectric Station. The latter is a large plant (192 MW) that started operation in 1990. It has an average capacity factor of 55%, which results in large volumes being exchanged at prices that were determined several decades ago and are very different from prevailing market prices.

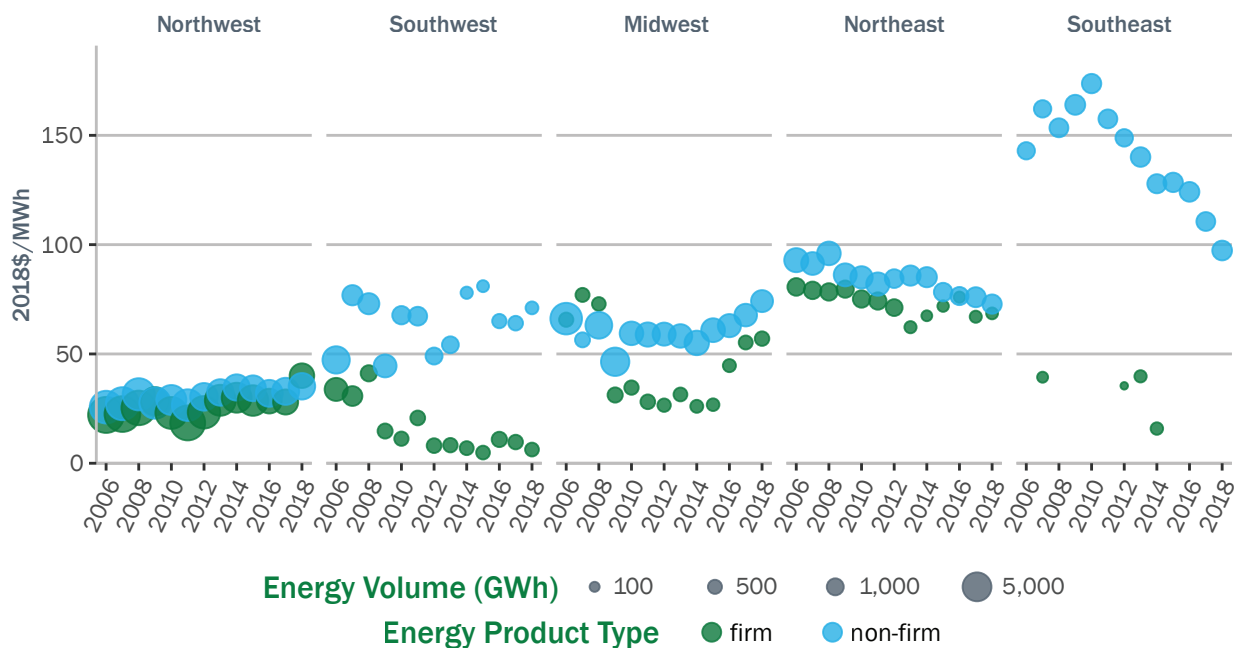


Figure 27. Volume-weighted hydropower price by region, year, and energy product type

Source: FERC Form 1

Note: Firm service means that “service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.”

Figure 27 shows the relative volumes and prices of hydropower purchase agreements for firm vs. non-firm service across regions and over time. On average, the energy price paid for firm hydropower is lower than for non-firm service. This ranking is consistent across all regions, but the magnitude of the difference is not. In the Northwest and Northeast regions, the average prices of firm and non-firm hydropower are closer than in other regions.

In general, hydropower facilities with firm service PPAs have higher capacity factors. Therefore, the difference in revenue per megawatt is smaller than the difference in revenue per megawatt-hour of energy provided. The average price of firm hydropower purchase agreements is lowest in the two Western regions. These low prices are driven by purchase agreements to exchange large volumes of power between regional utilities. The dataset for these regions also contains PURPA PPAs in which the sellers are non-utility owners of small plants but, given the small sizes of those plants, they have little influence on the regional volume-weighted average price.

The average price for hydropower PPAs in 2006–2018 was higher for smaller plants and for plants with lower capacity factors; all instances of prices greater than \$100/MWh are for plants that started operation before 2001.

Figure 26 and Figure 27 show that PPA length and service type partly explain the wide observed hydropower price ranges. The vintages of the PPAs (i.e., the year in which they were negotiated), whether they receive PURPA rates, and how those rates are calculated are also factors worth exploring to understand the price variability. For a subset of the selling entities on FERC Form 1

purchased power data, it was possible to link the seller to a specific power plant. The year of operation of the plant can be used as a proxy for PPA vintage, and the plant size and owner type help determine whether the plant is certified as a qualifying facility (QF).

QFs have the right to sell their energy to public utilities at avoided cost rates. By mandating utilities to purchase energy produced by QFs, PURPA created a market for small renewables. For hydropower, PURPA and a U.S. Department of Energy Small Hydropower Program that invested in research and development and provided loans were important drivers for the construction of more than 300 new hydropower plants of less than 80 MW capacity in the 1980s. PURPA’s mandatory purchase obligation initially applied to every QF (renewable energy plants of up to 80 MW and co-generation facilities), but the decision regarding the avoided cost rate methodology was made at the state level.⁴⁶ Then, the Energy Policy Act of 2005 effectively limited the mandatory purchase obligation to renewable QFs below 20 MW for utilities in service areas where the QFs could have access to the competitive markets created by ISOs/RTOs. Thus, avoided cost rates paid to QFs can vary significantly depending on state and size. Yeazel (2018) summarizes the avoided cost methodologies used in each state as of 2018. They range from fixed rates based on the cost of a gas turbine to rates indexed to the locational marginal prices of an ISO/RTO. In 2019, FERC and Congress proposed further modifications to the PURPA avoided cost rate allowed methodologies and the mandatory purchase obligation (see Chapter 7 for details).

Based on EIA data, 301 hydropower plants greater than 1 MW were certified as QFs under PURPA as of 2018, with a total capacity of 1.63 GW.⁴⁷ Figure 28 shows the average prices received by 113 of them in 2006–2018, depending on year of operation, plant size, and PURPA eligibility.

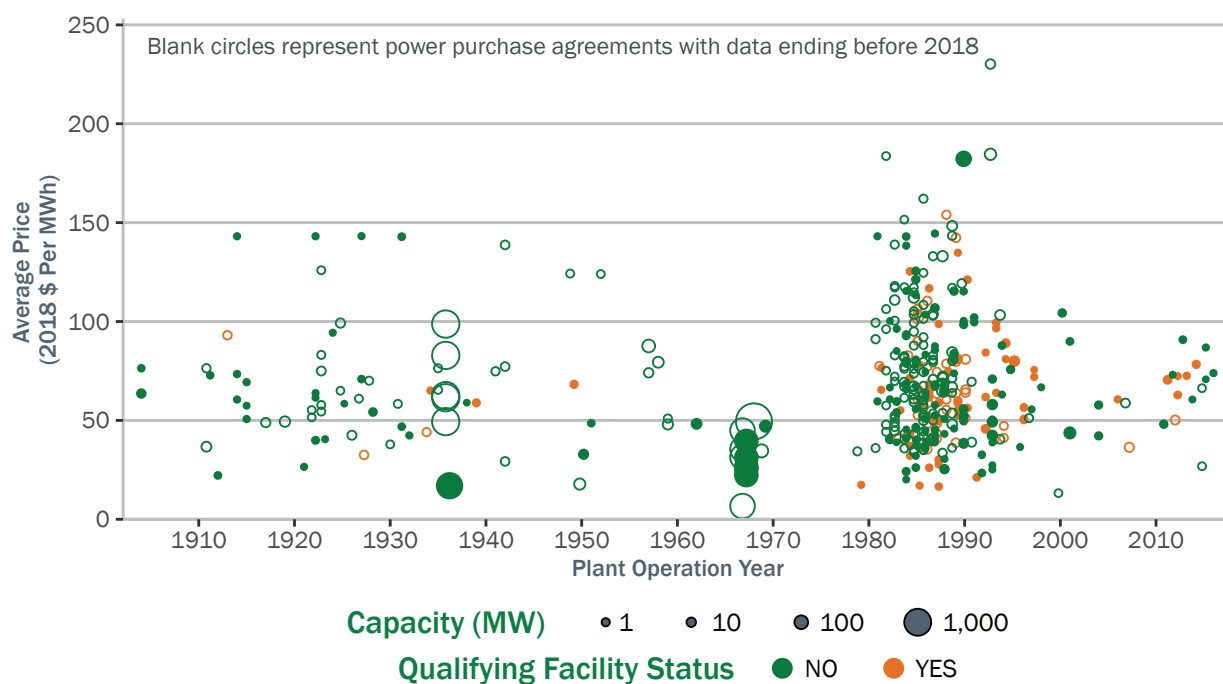


Figure 28. Average hydropower price by plant operation year, capacity, and qualifying facility status

Sources: FERC Form 1, Existing Hydropower Assets dataset, EIA Form 860

Note: Each dot represents a contract for a specific buyer-seller pair. Only sellers that can be traced to an individual power plant are included, and there can be multiple agreements corresponding to the same plant. Information on qualifying status comes from EIA Form 860, which includes information only for plants ≥ 1 MW. Plants smaller than 1 MW that began operating after 1978 are also likely to be QFs under PURPA.

46 Avoided cost is the cost the utility would have to pay for energy, capacity, or both if the QF was not constructed.

47 Many hydropower plants smaller than 1 MW are also QFs but do not file the EIA Form (Form 860) that compiles that information.

Figure 28 shows the PURPA-driven concentration of small plants with PPAs starting operation in the 1980s and early 1990s.⁴⁸ The median average price of electricity is similar regardless of whether they had QF status as of 2018: \$61.7/MWh vs. \$64.9/MWh, respectively. Smaller plants, up to 10 MW of capacity, received higher prices (\$63.93/MWh) than the larger ones (\$58.00/MWh). Of the plants represented in Figure 28, 30% have average capacity factors greater than 50%. The median average price for this subset is \$53.93/MWh vs. \$63.98/MWh for the rest of the subset. The negative relationship between PPA prices and plant capacity factor is observed for other technologies as well because the levelized cost of energy that PPA revenue should cover is lower in plants with higher capacity factors (Wiser and Bolinger 2019).

No plants starting operation after 2001 signed PPAs yielding average prices greater than \$100/MWh in 2006–2018. Additionally, 42% of all contracts with average prices greater than \$100/MWh expired before 2018. New hydropower plants becoming operational since the mid-2000s in states with RPSs typically generated renewable energy certificates, which are an additional attribute that can be bundled with energy and/or capacity in a PPA. Except for three plants in Idaho, new plants that have begun operating since 2005 and have PPA data in the FERC Form 1 dataset are in states with RPS.

4.1.3 Other Revenue Streams

Detailed transaction data for a set of U.S. PSH plants in 2014–2018 shows that energy sales were the largest revenue stream; however, in a few instances, a combination of capacity payments and ancillary service revenues accounted for more than half of annual revenue.

Besides providing energy and capacity, the hydropower fleet contributes to a variety of grid services ranging from frequency regulation and voltage control to reserves and black start. Those PSH facilities whose main design purpose was to arbitrage the differential between peak and off-peak energy prices and provide grid services tend to be highly flexible.⁴⁹ To explore the magnitude of ancillary service revenue for PSH facilities, the authors analyzed the detailed data on transactions and revenue in FERC Electric Quarterly Reports for a sample of PSH plants. Figure 29 shows their revenue composition differentiating between energy, capacity (if data were available), and ancillary services components. Figure 30 zooms into the ancillary service portion of revenue. Revenues from all services are presented here in \$/kW to show their relative magnitudes and changes in revenue composition over time. However, in practice, not all services are remunerated in a \$/kW basis.

48 Older plants with capacity less than 80 MW and owned by private non-utilities could also certify themselves as QFs after PURPA came into law in 1978 and a few did.

49 Much of the U.S. PSH fleet fits this description, but there are also PSH plants with limited flexibility due to environmental or multipurpose constraints.

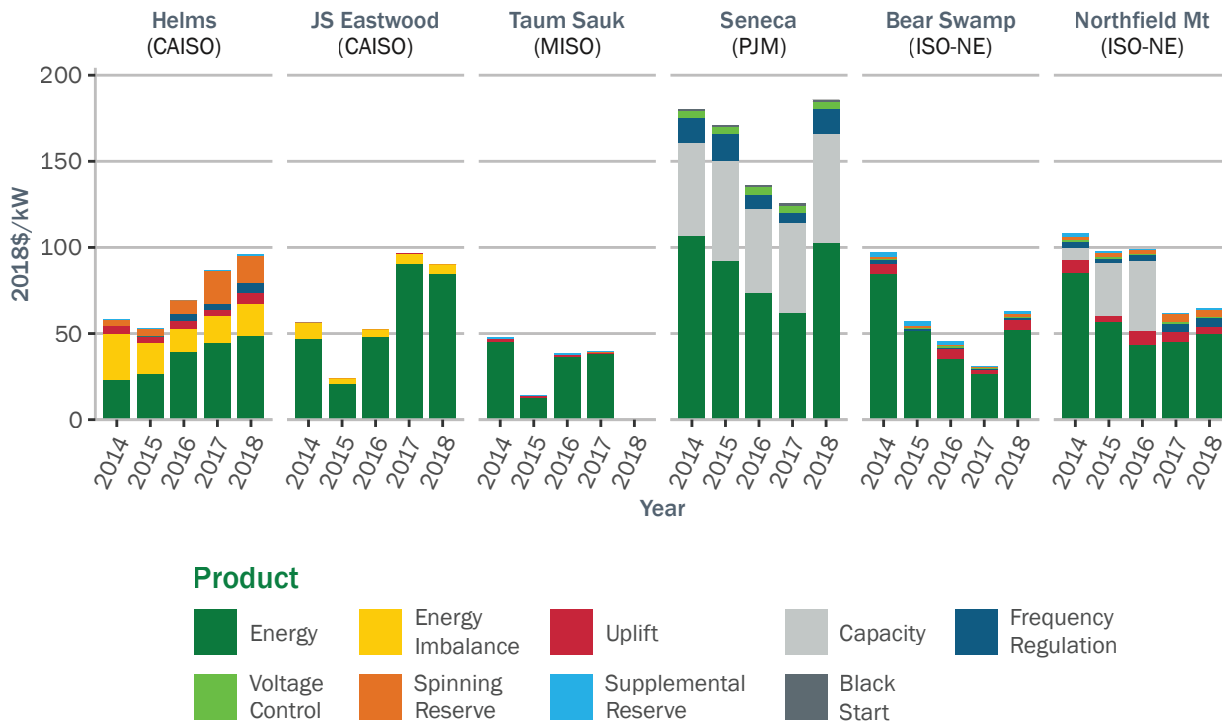


Figure 29. Annual revenue streams for selected PSH plants (energy + capacity + ancillary services)

Source: FERC Electric Quarterly Reports

Note: The plot shows gross revenue (i.e., the cost of pumping is not netted out). Taum Sauk data for 2018 are excluded because they were available only for the first quarter of the year. The plot only includes transactions that could be matched to an individual PSH plant. In most cases, matching of the transactions to the PSH plants is based on transmission node. For Seneca, data are reported at the company level (Seneca Generation LLC), but the PSH plant is the only plant listed in EIA Form 860 for that owner. Except for Seneca, revenues from black start are usually settled at the company level and could not be included in the plot. Capacity revenue for Northfield Mountain is not available in the Electric Quarterly Report dataset after 2016; however, based on ISO-NE's forward capacity auction results, both Bear Swamp and Northfield Mountain have received capacity payments in 2014–2017.

In 2014–2018, the energy component of revenue was typically the largest for all plants depicted in Figure 29. However, a combination of capacity payments and ancillary services revenue accounted for more than half of annual revenue for Northfield Mountain in 2016, and Seneca in 2017. The trend in energy revenue is different for the California PSH plants compared with the rest. The lower energy revenue observed for the CAISO PSH plants in 2014 and 2015 was due to the extreme drought conditions experienced in California during that period. The drought had more impact on JS Eastwood because its upper reservoir depends on natural flow (rather than only receiving water pumped from the lower reservoir). The energy imbalance market in CAISO is a real-time energy market that, since November 2014, allows participation from outside balancing authorities. Since the energy revenue from PSH plants in other ISO/RTOs results from transactions in their day-ahead and real time markets, they can be compared with the sum of energy and energy imbalance revenue for the CAISO plants. For Taum Sauk, the pronounced dip observed in 2015 is largely explained by a summer outage of both of its units for plant repairs. For Seneca, Northfield Mountain, and Bear Swamp, the trend in energy prices matches that observed for wholesale prices in the Northeast in Figure 25.

Uplift credits are out-of-market payments that cover shortfalls between a resource's offer to the ISO/RTO and the revenue earned through market clearing prices.⁵⁰ Uplift payments were approximately \$5/kW every year for Helms and \$1/kW for Taum Sauk; in contrast, they vary significantly across years for the ISO-NE plants. In PJM, the only uplift credit received by Seneca during 2014–2018 was \$0.01/kW in 2015.

50 <https://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf>. Different ISO/RTOs have different mechanisms to pay/charge uplift. In 2018, FERC issued Order 844 to address the transparency and efficiency of uplift payments.

Seneca had the highest total revenue every year, helped by capacity payments and the higher electricity prices in PJM relative to other markets. For Seneca, capacity payments ranged between \$49/kW in 2016 and \$63/kW in 2018. Therefore, they represented 30%–40% of total revenue for that facility in 2014–2018. Capacity revenue for Northfield Mountain accounted for 31% of total revenue in 2015 and 41% in 2016. Capacity revenue for Northfield Mountain is not available in the Electric Quarterly Report dataset after 2016; however, based on ISO-NE’s forward capacity auction results, both Bear Swamp and Northfield Mountain have received capacity payments in 2014–2017.⁵¹

Instead of a centralized capacity market like those in MISO, ISO-NE, NYISO, and PJM, the California Public Utilities Commission manages a resource adequacy program that sets capacity requirements for the load-serving entities in CAISO. Those requirements can be met by self-supply or through bilateral contracts. One hundred percent of Helms and J.S. Eastwood capacity is eligible to meet the capacity requirements of the utilities that own them (Pacific Gas & Electric and Southern California Edison, respectively). Plant-level information from bilateral capacity contracts is not public, but the average annual value of capacity traded in resource adequacy bilateral contracts can be taken as an approximation for the capacity value of Helms and J.S. Eastwood. Those averages were \$42/KW in 2014, \$35/kW in 2015, \$33/kW in 2016, \$25/kW in 2017, and \$32/kW in 2018.⁵²

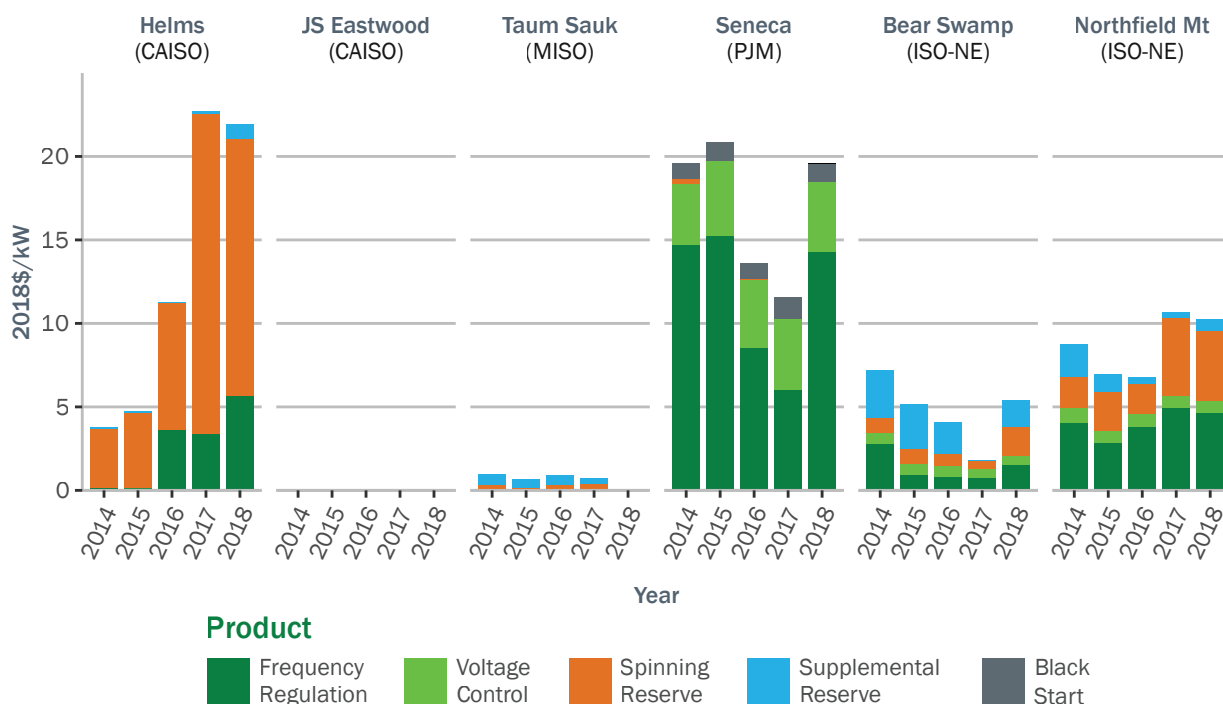


Figure 30. Annual revenue streams for selected PSH plants (ancillary services)

Source: FERC Electric Quarterly Reports

Note: Taum Sauk data for 2018 are excluded because they were available only for the first quarter of the year. The plot only includes transactions that could be matched to an individual PSH plant. In most cases, matching of the transactions to the PSH plants is based on transmission node. For Seneca, data are reported at the company level (Seneca Generation LLC), but the PSH plant is the only plant listed in EIA Form 860 for that owner. Except for Seneca, revenues from black start are usually settled at the company level and could not be included in the plot.

51 <https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fca-results>. In Forward Capacity Auctions Obligations spreadsheet, the name for the Bear Swamp PSH units is J. Cockwell.

52 Based on “Capacity Prices by Compliance Year” tables in annual Resource Adequacy Reports (<https://www.cpuc.ca.gov/ra/>). All values converted to 2018 dollars.

Figure 30 zooms into the ancillary services components of total revenue. The percentage of total revenue from provision of ancillary services (frequency regulation, voltage control, spinning or supplemental reserve, black start) ranged between 0.1% (J.S. Eastwood, 2014) and 26% (Helms, 2017) across the plants and periods considered.

The mix of ancillary services provided differs across plants. For Helms, most of the ancillary service revenue comes from provision of spinning reserve. Seneca gets the bulk of its ancillary service revenue from participation in frequency regulation and voltage control service. Seneca is also the only plant in this sample receiving revenue from black start services (~\$1/kW per year). The ISO-NE plants provide the most diversified mix of services but all in small quantities, leading to small revenues.

4.2 Trends in Hydropower and PSH Asset Sale Prices

Most U.S. hydropower plant transactions in the past 15 years have been between private buyers and sellers. Yet, the largest transactions in 2018 and 2019 were the purchases of 85 U.S. hydropower plants (611 MW) by a publicly owned Canadian company.

To evaluate asset sale price trends, transaction prices for U.S. hydropower plants reported in the news media or in Securities and Exchange Commission documents were evaluated. Based on those sources, the authors assembled a dataset of 71 sale prices accounting for 4.7 GW of transferred hydropower capacity. The total value of the sales in this sample is \$7.4 billion (in 2019 dollars). Figure 31 displays the price per kilowatt for each of the transactions along with information about region and capacity exchanged.



Figure 31. U.S. hydropower plant sale prices by year, capacity, and region

Source: Internet searches and Securities and Exchange Commission filings.

Note: For transactions in which multiple plants were sold but only the total price was reported, the price shown is the average across all capacity sold.

The average sale price for a hydropower plant was \$1,161/kW, and prices ranged between \$42/kW and \$3,400/kW. The Northeast region had the greatest number of transactions during this period, followed by the Southeast. Out of the ten transactions in which more than 100 MW of capacity were purchased, only two involved a single plant. The largest transaction by capacity was the purchase of a fraction of the Bath County pumped storage plant in 2017 by a subsidiary of LS Power Equity Partners. The largest transaction by number of plants is the purchase of Eagle Creek Renewable Energy's fleet (76 plants with a total capacity of 226 MW) by Ontario Power Generation in 2018 at an average price of \$1,342/kW. The Canadian company, an experienced hydropower operator with 66 plants (7.5 GW) in its fleet in Ontario, issued \$500 million in green bonds to finance the purchase. In 2019, Ontario Power Generation announced the purchase of Cube Hydro, another large U.S. private operator that owned 19 hydropower plants with a total capacity of 385 MW at the time of the purchase. The average price paid in this second purchase was \$2,195/kW. The two fleets purchased by Ontario Power Generation in the United States will be combined as a wholly-owned subsidiary of the parent company and operated under the Eagle Creek name.

Most transactions in the dataset involved private companies as both buyers and sellers, but there were also six transactions in which privately-owned capacity was purchased by a public entity and one case each of public-to-private and public-to-public transactions. The motivations for these hydropower transactions vary widely. For instance, the sale of the Holtwood and Wallenpaupack plants in Pennsylvania in 2016 was required by FERC as part of the merger of PPL Corporation and Riverstone Holdings to limit the generation share of Talen Energy, a newly formed company, in parts of the PJM. In Michigan, a public agency purchased three small hydropower plants from their private owner with the main purpose of guaranteeing consistent elevations in the reservoirs associated with each of the dams. In 2019, Duke Energy Carolinas sold five small hydropower plants in 2019 because of their increasingly costly O&M. The buyer is Northbrook Energy, an independent power producer specializing in hydropower asset management.



Chapter 5

U.S. Hydropower and PSH Cost and Performance Metrics

5.1 Capital Costs

5.1.1 Hydropower

5.1.2 Pumped Storage Hydropower

5.2 Operations and Maintenance Costs

5.3 Energy Generation

5.3.1 Hydropower Generation and Canadian Imports

5.3.2 Pumped Storage Hydropower

5.4 Capacity Factors

5.5 Availability Factors

5.6 Hydropower Operation Flexibility

5.6.1 Ramping (hourly frequency)

5.6.2 Unit Starts

5.6.3 Contribution to Provision of Ancillary Services

5. U.S. Hydropower and PSH Cost and Performance Metrics

This chapter reports a wide array of metrics regarding hydropower cost and performance. It provides updates on databases of U.S. hydropower construction and O&M costs. Then, it turns to a discussion of hydropower and PSH generation trends and capacity factors at the national and regional levels. The discussion of hydropower generation trends explores the role of hydrologic conditions in more detail than previous editions of the report. Next, the chapter summarizes trends in U.S. hydropower and PSH availability factor by unit size, region, and season. The rest of the chapter presents metrics that help characterize the contribution of U.S. hydropower to grid reliability: ramping, unit starts, and participation in ancillary services markets.

5.1 Capital Costs

5.1.1 Hydropower

Approximately \$3 billion have been invested in new hydropower plant construction since 2005. Average capital costs were in the \$4,000/kW–\$5,000/kW range for the various project types, but there was large variability around those values.

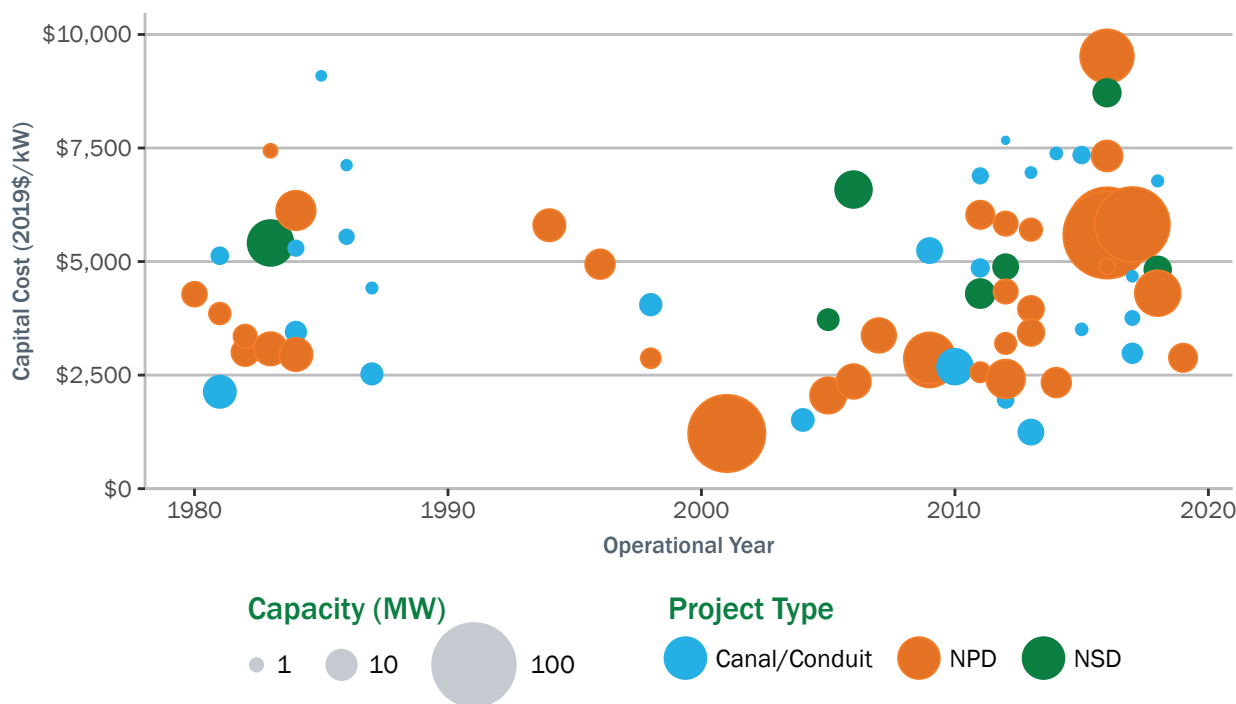


Figure 32. Cost of new hydropower development since 1980

Sources: O'Connor et al. (2015), IIR, internet searches

Note: The U.S. Bureau of Reclamation Construction Cost Trends composite trend index was used to adjust for inflation cost data from different years.

Figure 32 shows capital costs ranges for a subset of U.S. hydropower projects constructed since 1980, differentiated by project type.⁵³ Cost ranged, with a few exceptions, between \$2,500/kW and \$7,500/kW throughout the entire period. The 70 data points in Figure 32, with a combined capacity of 789 MW, represent only 8% of hydropower plants (15% of installed capacity) built in the United States from 1980 to 2004. In terms of median capacity (3 MW), the sample is representative of the facilities constructed during that period. For 2005–2019, the 46 available data points represent 38% of new plants and 86% of capacity installed during that period and add up to an investment of \$2.9 billion.

⁵³ To the extent possible, the data were quality controlled to use cost estimates with similar scope. Generally, these costs are inclusive of all project construction works and equipment purchases including the cost of electrical interconnection. They do not include the cost of the licensing and permitting process or financing-related charges.

The average cost across the entire dataset is \$4,236/kW for NPDs, \$4,774/kW for facilities built in canals or conduits, and \$5,320/kW for NSDs. Capacity-weighted averages are very close to the raw means for NPDs (\$4,515/kW) and NSDs (\$5,558/kW) but significantly lower for canal/conduit projects (\$3,213/kW). This divergence indicates that canal/conduit projects display stronger economies of scale than the other project types.

Capacity and hydraulic head—the change in elevation between water intake and water discharge points—are the two main variables used in hydropower cost estimation models. For the period shown in Figure 32, hydropower development in the United States has predominantly involved small facilities—no greater than 10 MW. Ninety-one percent of hydropower plants built since 1980 have had capacities below that threshold. For the period since 2005, small plants account for 97% of all new hydropower projects in the United States. The small average size of new U.S. projects helps explain the higher average capital cost per kilowatt relative to global averages. IRENA (2019b) reports a global capacity-weighted average hydropower cost below \$2,000/kW in 2010–2018, but that figure is heavily weighted towards the large projects being built in Asia.

Hydropower turbine technology development is now focused on low-head sites because they account for much of the remaining untapped sites in countries with mature hydropower fleets like the United States. For a given flow volume, the equipment and civil works needed to get to a target plant capacity are larger in a low-head site leading to higher costs per kilowatt. Although there is no universally agreed threshold to define low-head projects, 20 meters (66 feet) is often used. Close to one third of the projects in Figure 32 would be categorized as low head based on that threshold. Those low-head projects account for 55% of capacity because they are, on average, three times larger than the other two-thirds of the project sample. The average capital cost for low-head projects was \$5,059/kW, 15% higher than for medium and large head projects.

5.1.2 Pumped Storage Hydropower

For energy storage applications requiring short cycles and extremely rapid responses, battery systems are projected to become cost-competitive relative to PSH by 2025; PSH is expected to remain the least expensive option (along with compressed air energy storage) for energy arbitrage and other applications with long charge/discharge cycles through 2025.

PSH provided 93% of the bulk electrical power storage capacity in the United States in 2018. Because no new PSH has started operation in the United States since 1995, no recent cost figures are available.⁵⁴ Instead, estimates on the cost of new PSH are based on international experience and engineering models.

Future PSH deployment decisions also need to factor in the cost progress of batteries and other storage technologies. Mongird et al. (2019) conducted a comprehensive review of the capital cost of energy storage technologies in 2018 and their projected cost by 2025. The most relevant metric of comparison depends on the application of the proposed storage unit. For applications requiring long charging/discharging cycles such as seasonal storage, the metric of reference is the energy-specific cost (\$/kWh); for shorter storage cycles such as those required for frequency regulation, power-specific cost (\$/kW) is appropriate. Figure 33 and Figure 34 summarize power-specific and energy-specific capital cost estimates and ranges for PSH and other electrical energy storage technologies.

54 The Olivenhain-Hodges project in southern California contains two PSH units that started operation in 2014, but its main purpose is water storage and supply rather than provision of electrical energy storage.

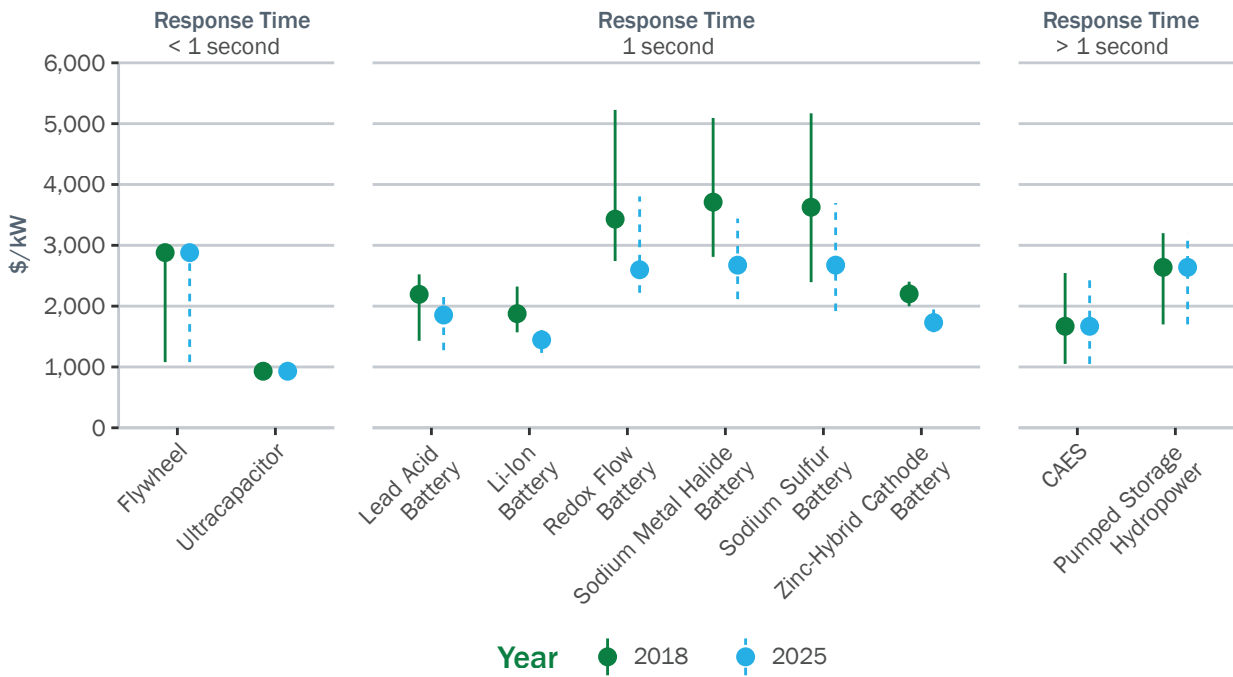


Figure 33. Power-specific capital cost of PSH and other electrical energy storage technologies (2018 and 2025)

Source: Mongird et al. (2019)

Note: Ranges based on literature review and interviews with vendors. The point estimate was selected giving additional weight to values reported for systems with performance parameters close to selected baseline values.

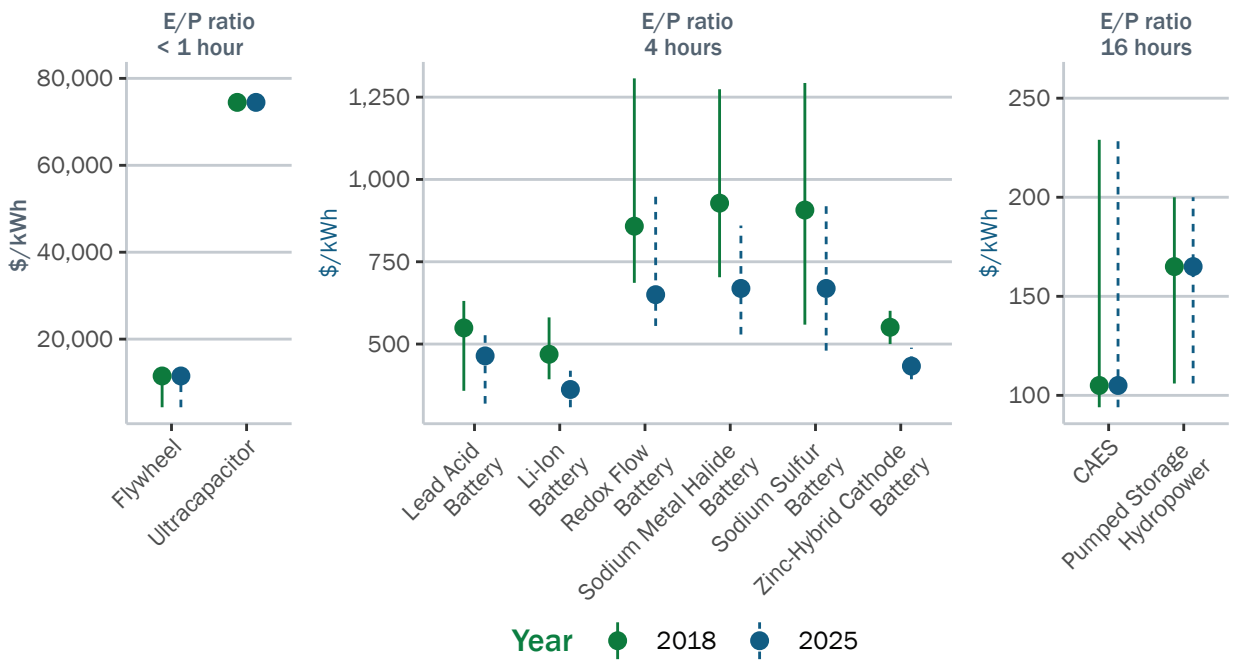


Figure 34. Energy-specific capital cost of PSH and other electrical energy storage technologies (2018 and 2025)

Source: Mongird et al. (2019)

Note: E/P ratio is energy to power ratio and it indicates how long it takes to take the storage unit from a full charge to empty. Ranges based on literature review and interviews with vendors. The point estimate was selected given additional weight to values reported for systems with performance parameters close to the baseline E/P ratio.

Because of the maturity of the technology and their long development timeline, PSH facilities coming online by 2025 have no capital cost reduction projected. However, ongoing DOE-funded R&D is targeted at reducing longer-term PSH costs.^{55,56} Factoring in the projected cost reductions in battery storage related to performance metric improvements and economies of scale, all other technologies could compete with PSH in power-specific cost by 2025.⁵⁷ Beyond cost, the slower response time and large minimum capacity of PSH relative to batteries, flywheels, and ultracapacitors limit its suitability in behind-the-meter applications. Some innovative PSH technologies whose research is being supported by DOE, like Ground-Level Integrated Diverse Energy Storage (GLIDES) are smaller and could be sited in buildings and tap into the market for behind-the-meter applications (Chen et al., 2019). Other innovative PSH technologies being researched include a geo-mechanical pumped storage system that stores energy by pumping water into existing rock fissures at high pressures (Quidnet Energy) and a submersible pump-turbine/motor-generator that is installed in a single vertical borehole without extensive underground excavation (Obermeyer Hydro).^{58,59} PSH stands out for its very low energy-specific capital cost (\$106–\$200 \$/kWh for a reference unit with a 16-hour discharge duration), making it an attractive option for energy arbitrage and other long-duration energy-intensive applications. Figure 34 shows that energy storage cost for 4–16 hours duration cycles is even lower for compressed air energy storage (CAES), but there are only two CAES projects installed worldwide (built in 1978 and 1991) versus more than 150 PSH projects. Therefore, PSH is a more mature technology.

Schmidt et al. (2019) proposed the levelized cost of storage as “the total lifetime cost of the investment in an electricity storage technology divided by its cumulative delivered electricity” and projected the probability of nine storage technologies being the cheapest technology in 12 different applications from 2015 to 2050. In 2015, the probability of PSH being the cheapest was high for energy arbitrage, secondary response, tertiary response, peaker replacement, black start, transmission and distribution investment deferral, and congestion management. By 2025, mainly because of the drastic projected cost reduction from lithium-ion batteries, the probability for PSH to be the cheapest drops to around 50% or lower, except for energy arbitrage and transmission and distribution investment deferral. Beuse et al. (2019) asserted that when learning spillovers from electric vehicles is considered, the cost of lithium-ion batteries will drop even faster. Besides the competition among energy storage technologies, opportunities also exist for batteries and PSH to work together in hybrid systems. For instance, Pérez-Díaz et al. (2019) suggested that installing a battery at a PSH plant could be a promising alternative to a PSH unit upgrade to enhance system frequency control capabilities.

55 <https://www.energy.gov/eere/water/articles/energy-department-awards-98-million-next-generation-hydropower-technologies>

56 <https://www.energy.gov/eere/articles/funding-selections-announced-innovative-design-concepts-standard-modular-hydropower>

57 Mongird et al. (2019) also include combustion turbines in the comparison since they can also provide many of the grid services relevant to storage technologies. Combustion turbines offer the second cheapest power-specific capital cost even in 2025.

58 <https://www.energy.gov/eere/water/articles/new-approach-pumped-storage-hydropower>

59 <https://www.energy.gov/eere/water/project-profile-cost-effective-small-scale-pumped-storage-configuration>

5.2 Operations and Maintenance Costs

In the past two years, O&M costs grew fastest for small plants (≤ 10 MW), which already have by far the highest cost per kilowatt installed per year.

Because it has no fuel purchase costs, hydropower has minimal variable costs of operation, and O&M costs are typically expressed as annual fixed cost (\$/kW-year).

Figure 35 shows the trend in O&M costs segmented by plant size and plant age for the approximately 296 U.S. hydropower plants and 10 PSH plants (all in the Large or Very Large categories) with continuous FERC Form 1 records for 2009–2018.

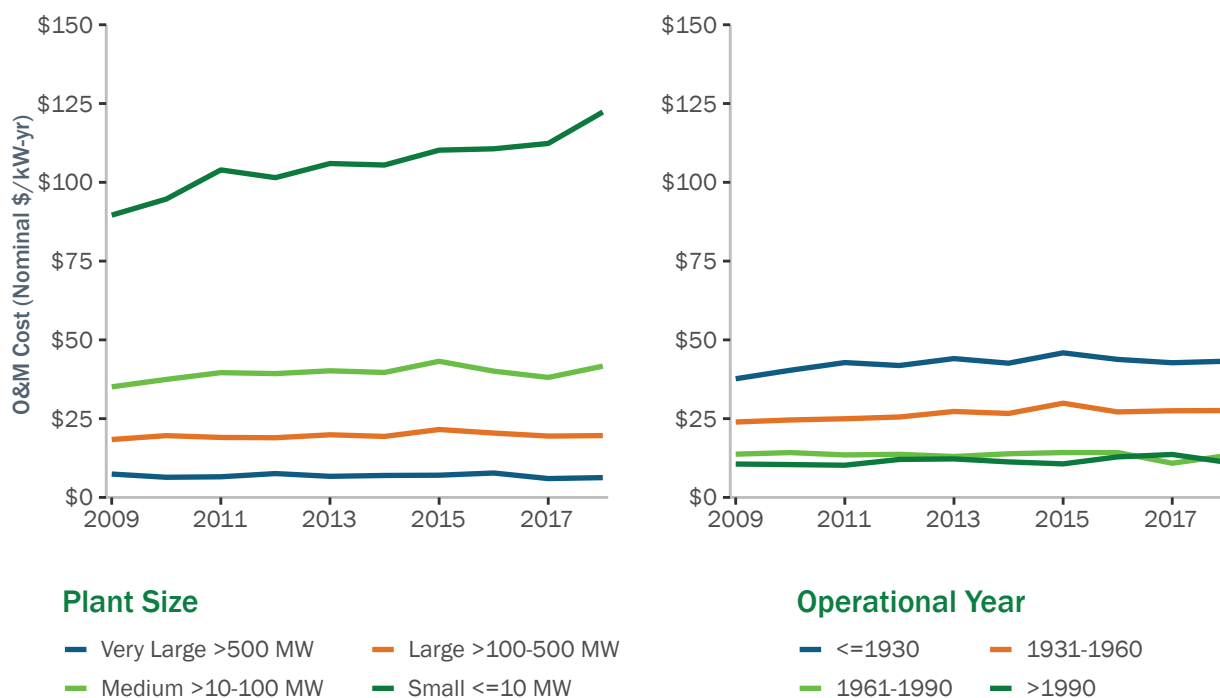


Figure 35. Trend in operations and maintenance costs for hydropower and PSH projects by size class and age

Sources: FERC Form 1, Bureau of Labor Statistics

Note: Number of plants by size category: 7 (Very Large), 42 (Large), 124 (Medium), 133 (Small). Number of plants by operational year interval: 178 (< 1930), 73 (1931–1960), 50 (1961–1990), 5 (>1990). O&M cost elements reported in FERC Form 1 are defined as “operating expenses” in FERC’s Uniform System of Accounts. They include labor, materials, and overhead associated with operation, supervision, engineering and maintenance of the electric plant and associated structures, and rents from leased property.

The capacity-weighted average O&M cost across all sizes was \$27/kW-year in 2018. The plants included in Figure 35 account for 16% and 35% of installed U.S. hydropower and PSH capacity, respectively. Six of the seven plants in the very large category are PSH plants. The most important determinant of O&M costs is plant capacity (O’Connor et al., 2015). Figure 35 shows that because of strong economies of scale, average O&M cost per kilowatt-year was six times larger for small plants (<10 MW) than large plants (100–500 MW). The 2018 average O&M cost was \$6/kW for very large plants (>500 MW), \$20/kW for large plants (100–500 MW), \$42/kW for medium plants (10–100 MW), and \$122/kW for small plants (≤ 10 MW). However, these relatively high historical costs for smaller hydropower systems also present an opportunity for significant cost reductions. The Department of Energy is currently engaged in a multi-year research effort to investigate opportunities to standardize, modularize, and increase the ecological compatibility for smaller hydropower systems, all with the long-term aim of dramatically reducing costs.

In its capacity expansion model, EIA assumes a cost of \$41.63/kW-year for a 100-MW new hydropower plant. In comparison, EIA's fixed O&M cost assumption by EIA for onshore wind, solar photovoltaic, and combined-cycle natural gas plants are \$26.22/kW-year, \$15.19/kW-year, and \$14.04/kW-year, respectively.⁶⁰

Hydropower O&M costs in the United States generally grew faster than the consumer price index for all categories in most years of 2009–2018, except for the very large plant segment. From 2016 to 2018, the consumer price index increased by 4.6% and the small plant segment was the only one for which O&M costs increased faster (10.5%).

Variability was also great across individual plants in each category. In 2018, the 10th to 90th percentile cost ranges reported in FERC Form 1 were \$5–\$10/kW-year for the very large plants, \$8–\$36/kW-year for large plants, \$19–\$99/kW-year for medium plants, and \$41–\$310/kW-year for small plants. Plant age and degree of automation are among the factors driving the differences within each size category.

The right panel of Figure 35 shows the relationship between O&M cost and operational year for the same set of plants used to explore the cost vs. size relationship. Plants commissioned before 1930 had the highest average O&M cost (\$43/kW) in 2018 followed by those that started operations between 1931 and 1960 (\$28/kW). For the other two intervals, the 2018 average O&M costs were very significantly lower: \$13/kW for plants commissioned from 1961 to 1990 and \$11/kW for plants that are 30 years old or less.

For the set of plants included in Figure 35, the average age of plants decreases as size increases. Therefore, it is difficult to disentangle the effect of age from the effect of size on O&M costs in this sample. Average age is 39 years for the subset of very large plants and 92 years for the small plants. In contrast, when considering the entire U.S. hydropower and PSH fleet, average age ranges from 69 years for medium-sized plants to 56 years for small plants. This difference calls into question whether the ranking of O&M costs by operational year interval would also hold for the entire fleet.

Average O&M costs for the federal fleet are similar to those of the nonfederal fleet

FERC Form 1 is required for investor-owned utilities and some public utilities. The two agencies that own more than 90% of federal hydropower (U.S. Army Corps of Engineers and Bureau of Reclamation) do not file FERC Form 1, but information on planned O&M expenses for the hydropower function within their projects, which are typically multipurpose, is presented in their budget documents. For both agencies, the hydropower O&M budget includes congressional appropriations and, for the plants whose power is marketed by Boneville, financing provided by the PMA.

For the U.S. Army Corps of Engineers–owned fleet, the average O&M funding in Fiscal Year (FY) 2018–FY 2020 was \$471 million (\$21.50/kW-year).⁶¹ These budget numbers incorporate the congressionally allocated percentage of costs that hydropower is required to share for project features and assets that benefit all authorized purposes of the project. These allocated percentages may vary greatly across projects. Also included in these numbers may be varying amounts of small capital expenditures for purchasing or repairing assets with a definable service life. Reclamation's hydropower O&M expenses for the FY2018–FY2020 period averaged \$469 million (\$31.85/kW-year).⁶²

The generating capacity of U.S. Army Corps of Engineers–owned hydropower plants ranges from 8 MW (Robert D. Willis, Texas) to 2,456 MW (Chief Joseph, Washington) and their median capacity is 100 MW. As for the 53 plants owned by Reclamation, they range in capacity from 0.35 MW (Lewiston, California) to 6,809 MW (Grand Coulee, Washington) and their median capacity is 38 MW. Thus, the inverse relationship between O&M costs and plant size previously discussed for the nonfederal fleet also holds when considering average O&M expenses and median plant sizes for these two federal agencies. The average federal O&M costs per kilowatt-year are within the range of those shown in Figure 35 for medium (10 MW–100 MW) and large (100 MW–500 MW) nonfederal plants.

60 https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

61 USACE Pressbooks: <https://cdm16021.contentdm.oclc.org/digital/collection/p16021coll6/id/42>

62 Bureau of Reclamation Budget Justifications: <https://www.usbr.gov/budget/>

5.3 Energy Generation

5.3.1 Hydropower Generation and Canadian Imports

After two years of high domestic hydropower production (~300 TWh) in 2017–2018, production returned to a level close to the 2003–2018 average in 2019 (274 TWh). Canadian imports contributed an additional 35–45 TWh of hydroelectricity and are expected to continue increasing in the 2020s driven by state-level renewable standards, new Canadian hydropower capacity, and new Canada-U.S. transmission capacity.

Figure 36 displays regional trends in hydropower generation from 2003 to 2019. The average domestic U.S. hydropower generation during that period was 273,000 GWh per year, approximately 50% of which the Northwest region represents. The range around that average volume was bounded by 247,000 GWh in 2007 and 319,000 GWh in 2011. The only other year in 2003–2019 in which hydropower generation surpassed the 300,000 GWh mark was 2017.

The Southwest region displayed the greatest coefficient of variation in its annual hydroelectric output (23%). Its 2011 peak was 128% greater than the 2015 volume (2015 was the last year of a four-year drought period affecting most of the region). In contrast, the Northwest and Northeast had the most stable generation output during 2003–2019.

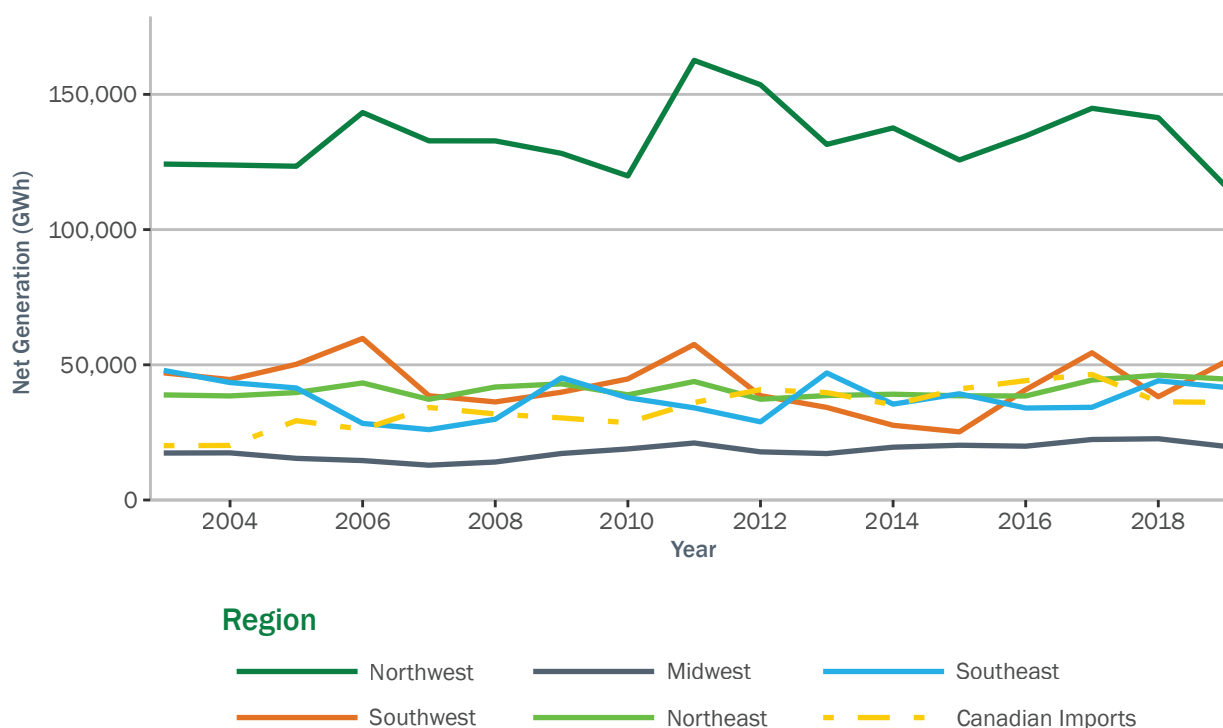


Figure 36. Annual hydropower generation by region (2003–2019)

Sources: EIA Form 923 (2003–2018), Canada Energy Regulator, EIA Electric Power Monthly (2019).

Note: Canadian imports only include imports from Hydro-Québec, Manitoba Hydro, and BC Hydro. Generation series for U.S. regions are only in-state generation and do not include imports.

Figure 36 also includes Canadian electricity imports from the top three Canadian electricity exporters into the United States: Hydro-Québec, Manitoba Hydro, and BC Hydro.⁶³ Imports from these three companies enter the New England, New York, Midwest, and Pacific Northwest electricity systems, respectively. On average, the exports from these companies accounted for 63% of all electricity imports from Canada in the years analyzed. Because the generation mix for each of these province-owned companies is more than 90% hydropower, these imports can be generally classified as hydropower. However, hydropower is also a fraction of the rest of electricity imports, making the hydropower import volumes in Figure 36 a conservative estimate of total U.S. hydropower imports from Canada. Electricity imports from those three companies increased from 20,106 GWh in 2003 to a maximum of 46,437 GWh in 2017. In 2018–2019, a drop to ~36 TWh occurred. For Canadian electricity imported by New York, New York ISO cites higher prices in Canada as well as congestion and outages in transmission links as reasons for reduced Canadian imports in 2018.⁶⁴

The increasing trend in Canadian imports is expected to continue in the 2020s because Canadian hydropower companies have recently signed multiple PPAs with off-takers in the United States. Manitoba Hydro signed agreements with Minnesota Power (250 MW of capacity for 2020–2035) and Northern States Power (125 MW for 2021–2025). These new export flows will be largely sustained by the production from the Keeyask project (695 MW) and the Great Northern Transmission Line, whose completion dates are 2021 and June 2020, respectively. At its projected capacity factor of 78%, 375 MW of capacity from Keeyask could deliver up to 2,500 GWh of additional hydropower per year for the Midwest markets. In the Northeast, Hydro-Québec and Central Maine Power Company signed a 20-year agreement in June 2018 with Massachusetts electricity distribution companies to deliver 9,450 GWh/year (energy plus environmental attributes). The generation and transmission assets linked to these agreements are the Romaine complex (1,550 MW) and the New England Clean Energy Connect. The Romaine complex is under construction, but the transmission line faced strong opposition from environmental groups and has not yet obtained all the necessary permits. It reached an important milestone in May 2020 with the latest of the state-level approvals, by the Maine Department of Environmental Protection. It now requires approvals from the U.S. Army Corps of Engineers and ISO New England as well as a Presidential Permit.

Dimanchev et al. (2020) argue that expanding transmission interconnections between the U.S. Northeast and Quebec can help significantly reduce the cost of achieving a zero-carbon electricity system in that region, without needing to build additional hydropower reservoirs. These savings would be best achieved through two-way flows between Quebec and the Northeast. Hydropower reservoirs in Quebec would be used as a complement to other renewables in the United States—storing water during periods of excess supply of solar and wind energy and drawn down for electricity generation when production from those other renewables is low—rather than as a baseload source of energy.

Overall, as of 2020, the United States is a net importer of electricity from Canada. However, in the Pacific Northwest, the electricity trade balance has the opposite sign. On average, electricity exports from the United States to BC Hydro were 8.8 TWh/year in 2010–2019.⁶⁵ Part of those exports are driven by provisions in the Columbia River Treaty. Signed in 1964 by the United States and Canada to develop water resources infrastructure delivering flood control and hydropower benefits to the Pacific Northwest region, both countries had the option to terminate the Treaty (with 10-year notice) starting in 2014. Instead, they started negotiations for its modernization and extension in May 2018.

63 Most exports for BC Hydro are made through a subsidiary (Powerex Corporation)

64 2018 State of the Market Report for the New York ISO Markets

65 <https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpst/2020/01-01lctrcyxpmtprt-eng.html>

Treaty modernization discussions center around post-2024 flood control provisions, U.S. compensation to Canada for downstream power benefits, and ecosystem function improvements (Stern, 2019).⁶⁶ During the first 60 years of the Treaty, flood control provisions assured the United States a certain volume of annual water storage capacity at the three Canadian reservoirs built under the Treaty. Unless otherwise agreed before then, flood control provisions would switch to a “called-upon” regime in 2024 whereby the United States would request Canada to modify operations for flood control purposes during periods of flood risk. The streamflow volume triggering U.S. requests for flood control operations by Canada as well as the method to determine compensation to Canada for the costs incurred by those operations are among the details being discussed.⁶⁷ As for downstream power benefits, the original Treaty stipulated that the United States would pay Canada half of their value. The United States argues that the methodology set in the 1960s to calculate this “Canadian entitlement” leads to overestimation of the power benefits and should be revised in a modernized post-2024 Treaty.⁶⁸ In contrast, Canada asserts that the compensation it receives through the entitlement does not account for the full extent of Treaty benefits to the United States and Treaty impacts to British Columbia.

The contemporaneous correlation between annual hydropower generation and the percentage of territory under drought conditions varies widely across hydrologic unit code (HUC)-2 regions depending on drought intensity and duration, reservoir storage capacity, and competing water uses.

Figure 38 explores the effect of hydrologic conditions on hydropower generation volumes at the HUC water resource region level shown in Figure 37. HUC-2 regions contain the drainage area of a major river or the combined drainage areas of a series of rivers.⁶⁹

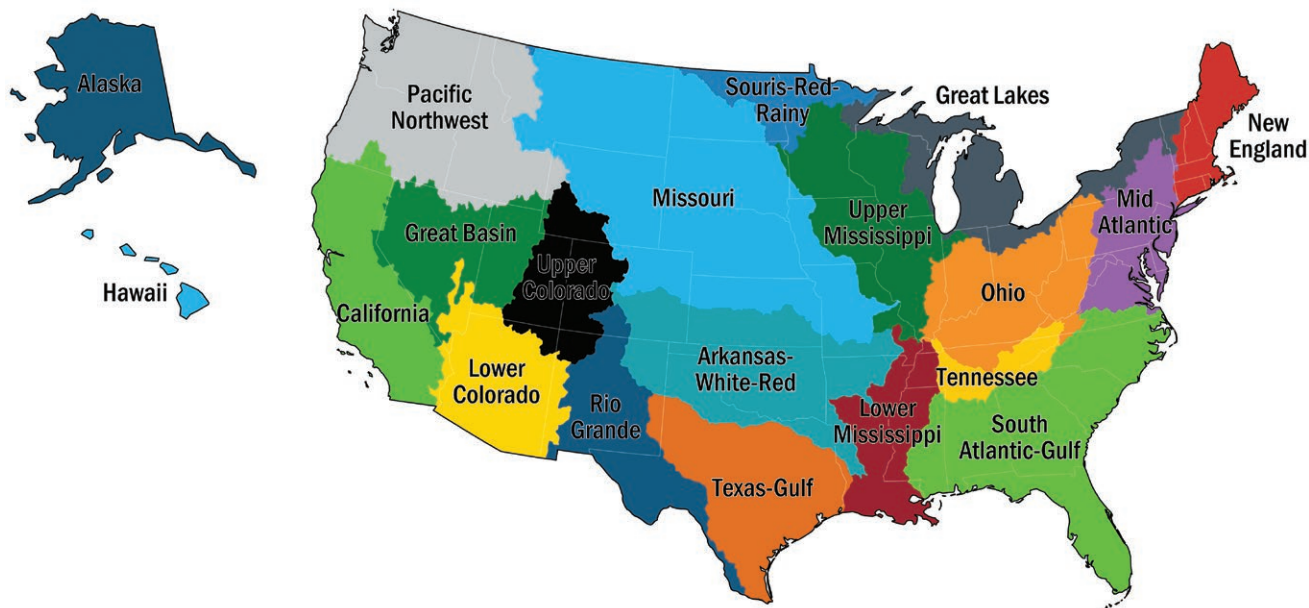


Figure 37. HUC-2 water resource regions

66 Downstream power benefits are the additional U.S. hydropower production made possible by the flow regulation provided by Canadian dams built as a result of the Treaty (https://thebasin.ourtrust.org/wp-content/uploads/downloads/2018-07_Trust_CRTDownstreamPowerBenefits_Web.pdf).

67 The United States paid \$64.4 million to Canada for the first 60 years of assured flood control operations.

68 British Columbia sold the first 30 years (1973-2003) of its power benefits entitlement to U.S. utilities to help pay for construction of the dams. Since 2003, BPA delivers the power benefits as electric capacity and energy.

69 The HUC-2 classification comprises 21 regions, but region 21 (Caribbean) is not included in this analysis.



Figure 38. Annual deviations from average generation vs. percentage of area under drought conditions (by HUC-2 region; 2003–2018)

Sources: EIA Form 923, U.S. Drought Monitor

Notes: D1 is moderate drought, D2 is severe drought, D3 is extreme drought, and D4 is exceptional drought. Classification is based on ranges for five metrics (Palmer Drought Severity Index, Climate Prediction Center Soil Moisture, USGS Weekly Streamflow, Standardized Precipitation Index, and Objective Drought Indicator Blends) and supplemented with winter snowfall measures in the West and expert best judgment as described by the U.S. Drought Monitor (<https://droughtmonitor.unl.edu/About/AbouttheData/DroughtClassification.aspx>).

The numbers shown in each of the panels are the correlation coefficients between the two series. Asterisks indicate the correlation coefficient is statistically significant at a 5% confidence level.

In the buildout process of the U.S. hydropower fleet, the sites with the highest long-term average runoff were developed first. As a cumulative result of those siting decisions, the National Hydropower Map shows a clear concentration of installed capacity in regions like the Pacific Northwest, the Northeast, or the Tennessee Valley.⁷⁰ However, the amount of runoff available to a hydropower plant can fluctuate significantly from year to year relative to its long-term average. Figure 38 displays the relationship between annual hydropower generation and average percentage of area classified in one of the four drought categories—from moderate to exceptional drought conditions—defined by the U.S. Drought Monitor (see figure notes for more details about drought classifications).

Adding up or averaging the percentage of area in drought conditions indicates that HUC-2 regions in the Southwest were the overall most affected by drought during 2003–2018. On average, the Rio Grande, upper Colorado, California, Great Basin, and lower Colorado regions had 40% of their area affected by drought during this period. During 2012–2016, 86% of the area in the California HUC-2 region experienced at least moderate drought, and 40% fell under the extreme or exceptional drought categories. On the other end of the spectrum, Alaska, Ohio, Mid Atlantic, Great Lakes, and New England had less than 10% of their area under drought conditions in 2003–2018. At the aggregate national level for 2003–2018, 2012 had the most widespread drought conditions (43% of areas under D1–D4 drought categories), and 2017 had the least widespread drought conditions (12% of areas under D1–D4 drought categories).

The correlation coefficient between hydropower generation and the percentage of area under drought conditions was negative in all but two regions. For Alaska and the lower Colorado regions, the correlation coefficient was positive but statistically insignificant. The strength of the contemporaneous linkage between the extent of dry conditions and hydropower output varied widely across regions. Seven regions had correlation coefficients of 80% or higher (in absolute value); other eight exhibited a correlation statistically not different from zero. The differences are partly due to drought intensity and duration and the precise area affected relative to the location of hydropower plants. Additionally, the lag and strength of hydropower generation response to water deficits depended on system characteristics such as the available amount of reservoir storage and the location of hydropower relative to the sinks for higher-priority consumptive uses. For instance, generation remained close to average in the lower Colorado region despite multiple years in which over 80% of its area fell into the D1–D4 drought classifications. Almost 80% of generation capacity in that region corresponds to Hoover Dam, which has a very large storage reservoir capable of buffering the effects of multiyear droughts. In the West and the Southeast, increased irrigation demand during periods of drought can result in even less water becoming available for electricity generation.

70 <https://dx.doi.org/10.21951/1454737>

EFFECTS OF EXTREME HYDROLOGICAL CONDITIONS ON HYDROPOWER

Given drought's unpredictability and its dependence not only on atmospheric variables but also on soil moisture and land surface conditions, the relationship between drought and climate change is complex and a subject of ongoing investigation by climate scientists. At the global scale, Bindoff et al. (2017) concluded that "there is low confidence in attributing changes in drought over global land areas since the mid-20th century to human influence owing to observational uncertainties and difficulties in distinguishing decadal-scale variability in drought from long-term trends."⁷¹ For the recent California drought, multiple studies agree that precipitation levels fell within the range of natural variability but the higher temperatures experienced are likely a result of climate change and exacerbated the effects of the drought (Folger, 2017).

To project climate-driven changes in hydropower generation, climate models must be properly downscaled and combined with hydrological models because detailed hydrologic processes must be represented at finer spatial units. Kao et al. (2016) downscaled 10 Coupled Model Intercomparison Project 5 Global Climate Models under Representative Concentration Pathway 8.5 emission scenario to watershed-scale hydrologic variables and generated projections of hydropower generation for 132 federal hydropower plants in the United States. The climate models agreed regarding projected temperature increases (2°F in the short term and 3.5°F in the mid-term, on average) and slight increase, albeit within a wider range of multi-model uncertainty, in precipitation. As for hydropower generation, Kao et al. found decreases in the near term (2011-2030) for BPA's fleet and a multi-model median close to the historical baseline for other federal plants in the West and South. In the mid-term (2031-2050), the annual hydropower generation is projected to increase across the board, but it comes with a shift from summer and fall to winter and spring due to the effects of earlier snowmelt.⁷² The study also projected an increased probability of extreme runoff periods leading to flood and droughts.

Both types of extreme runoff events create challenges for hydropower operations. Drought leads to reduced electricity output (although the time elapsed between onset of drought and reduced hydropower production varies by region and plant). In contrast, heavy precipitation can bring record hydropower production levels, but it limits operation flexibility because flood control objectives become the top priority. Because flood control is one of the originally mandated purposes of many hydropower reservoirs, hydropower operations have historically been better prepared to manage flood than drought. However, in recent years, hydropower plants are increasingly adopting drought management protocols (e.g., 2007 guidelines for the operation of Lake Powell and Lake Mead during droughts and the 2015 Sustainable Water Management Plan in the Southeastern Apalachicola-Chattahoochee-Flint basin). Beyond changes in operational rules, which require complex agreements involving multiple jurisdictions and end uses, other strategies to increase resilience and optimize operations under climate extremes include capital investments (e.g., installation of wide-head turbines in Hoover Dam to increase the range of surface reservoir levels over which turbines can access the water) and storage capacity expansions as discussed by Madani and Lund (2010) for high-elevation hydropower dams in California.

5.3.2 Pumped Storage Hydropower

In 2017, gross PSH generation reached 22,867 GWh, the highest value since 2011. Both 2011 and 2017 were wet years. In 2018-2019, gross PSH generation was ~21,000 GWh. Regional distribution of PSH output has remained stable since 2003 with the Southeast accounting for approximately half of national PSH generation.

The average gross generation from the PSH fleet in 2003-2019 was 23,023 GWh, and the range extends from 19,189 GWh in 2013 to 27,019 GWh in 2003. The years of maximum and minimum PSH gross generation over this period differed from those for hydropower because the link between PSH use and hydrology is weaker. Instead, PSH use was more driven by market signals than by hydrology. Nonetheless, since all the existing PSH facilities in the United States are open-loop (i.e.,

71 However, some confidence exists in that anthropogenic forcing has contributed to intensification of heavy precipitation.

72 The reservoir model used to generate hydropower projections using precipitation and unregulated runoff as inputs assumes no changes in installed hydropower capacity or mode of operation over the period of analysis.

continuously connected to a naturally flowing water feature), water availability for filling up the upper PSH reservoir is affected to some degree by hydrologic conditions.

On the aggregate level, PSH gross generation decreased for most of 2003–2019 with a slight recovery in 2016–2018. Gross generation level in 2019 (20,740 GWh) was the lowest since 2015. Figure 39 displays regional PSH generation trends during this period.

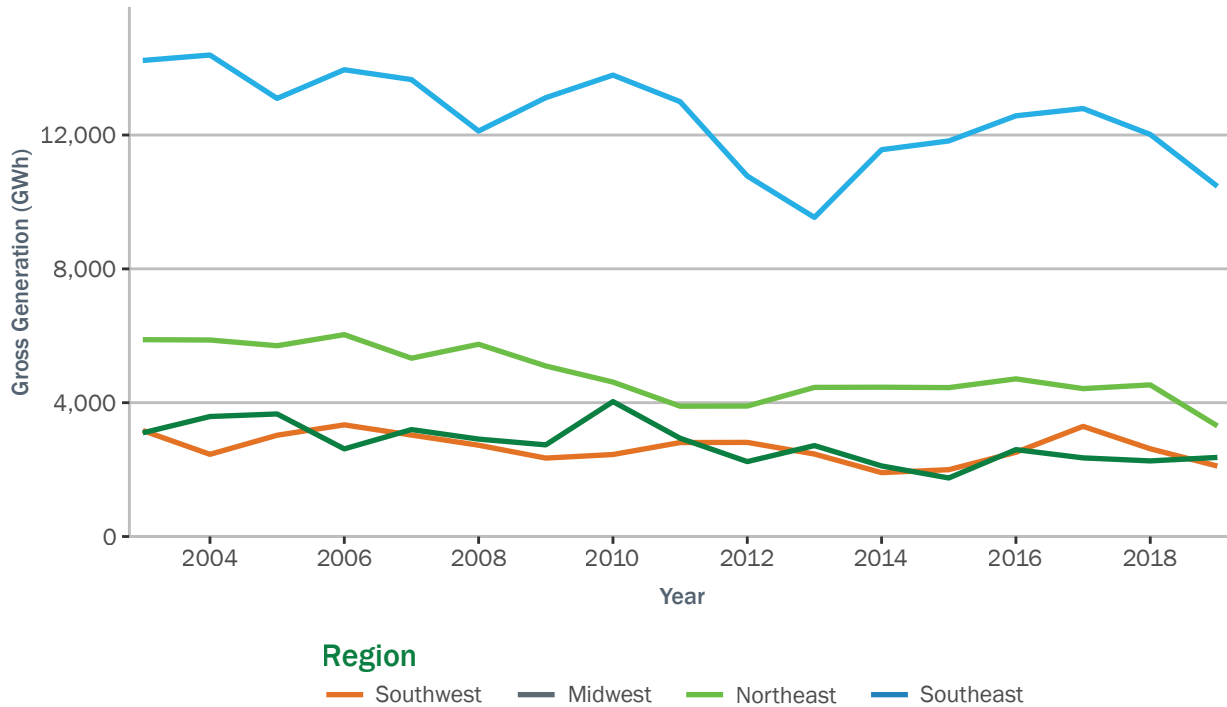


Figure 39. Annual gross PSH generation by region (2003–2019)

Source: EIA Form 923 (2003–2018), EIA Form 923 Early Release (2019)

Note: The Northwest region was excluded because it has a very small PSH capacity.

Despite the Southwest having 70% more PSH capacity than the Midwest, both their PSH fleets produced similar electricity volumes. Thus, on average, PSH plants in the Southwest operated at lower capacity factors. In the Midwest, since 2011, PSH generation comes from only two plants: Ludington and Taum Sauk.⁷³ Both had units out of service for repairs or upgrades in 2015, which contributed to the dip in Midwest PSH generation that year.

In the Southwest, the effect of the mid-2010s drought was not as pronounced regionwide for PSH as for hydropower. However, the specific configuration of each plant affected the performance of the facilities during the drought period. For instance, J S Eastwood’s upper reservoir receives considerable natural inflow from a river rather than just filling with water pumped from a lower reservoir. Its capacity factor—adjusted for roundtrip efficiency—decreased from 26% in 2012–2013 to 8% in 2014 and down to 0% in 2015. Generation at Helms also experienced decreases in production during the mid-2010s drought, but not as severe as at J S Eastwood. After drought conditions subsided, both facilities returned to levels of generation closer to the pre-drought average in 2016–2017 but have declined again in the past two years.

For PSH facilities in the Northeast, aggregate generation declined slightly in 2019 after remaining stable in 2013–2018. The decrease in 2019 was observable for all facilities in the region, suggesting it relates market conditions rather than outages. The Northeast region includes three facilities operating in ISO-NE (Bear Swamp, Northfield Mountain, and Rocky River), two in New York ISO (Blenheim Gilboa and Lewiston Niagara), and three in PJM (Yards Creek, Seneca, and Muddy Run). All of them experienced a sharp drop in generation in 2008–2010. However, total generation for the facilities operating in the ISO-NE

⁷³ Taum Sauk restarted operations on April 2010 after rebuilding its reservoir that had failed in 2005.

market has gone back to levels similar to those in 2008. The facilities in New York ISO have been generating at levels close to 2009 until now. For PJM PSH, the decline in generation lasted the longest (2008–2012) and has only partially reversed. This different evolution likely relates to different price trends and other market conditions in those ISOs/RTOs.

The Southeast region has the most PSH capacity and accounts for an average of over 50% of U.S. PSH generation every year. After a pronounced decrease in 2012–2014, it has returned to more than 12,000 GW of gross PSH generation per year since 2015. The sharp decrease in generation in 2013 seen in Figure 39 is partly explained by a forced outage of the second largest facility in the region (Tennessee Valley Authority’s Raccoon Mountain) and by wet, cool summer conditions in which PSH peaking generation was needed less often than usual.

5.4 Capacity Factors

On average, the median nationwide capacity factor from 2005 to 2018 has been 39%. Hydrological and market conditions, as well as plant-level variables (mode of operation, outage schedule, multipurpose constraints), explain variability across plants and years.

Capacity factor is the ratio between actual generation and maximum possible generation if the unit or plant works at full capacity without interruption.

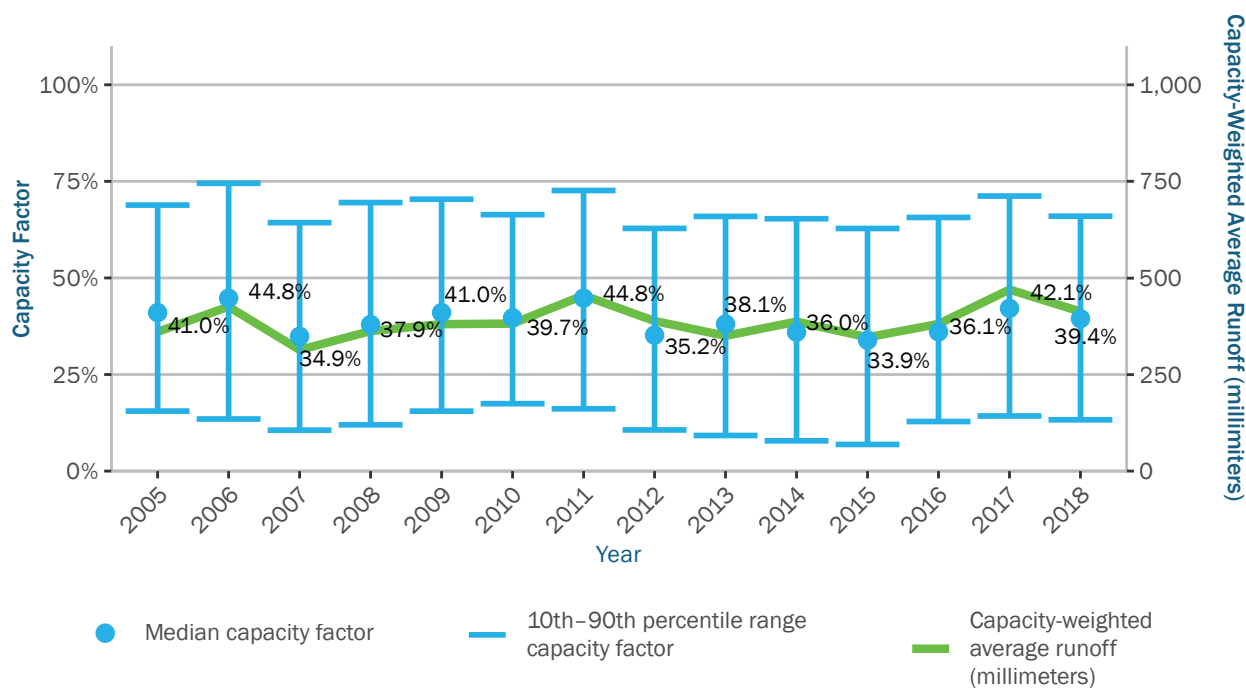


Figure 40. Plant-level distribution of hydropower capacity factors by year (nationwide fleet; 2005–2018)

Sources: EIA Form 923, EIA Form 860, USGS WaterWatch

Note: Capacity factor data include hydropower plants in the 50 U.S. states. HUC2 region runoff data excludes Alaska and Hawaii. HUC2 region weights for capacity-weighted average runoff calculation are based on installed hydropower capacity in each region.

Figure 40 shows the evolution of plant-level capacity factors from 2005 to 2018. For each year, the figure displays information on the median, 10th, and 90th percentiles of the capacity factor distribution along with the capacity-weighted average runoff. On average, the median capacity factor from 2005 to 2018 was 39%. The minimum capacity factor during this period was 33.9% in 2015 and the maximum was 44.8% in 2006 and 2011. The extremes in capacity factor are linked to hydrological conditions in the Northwest and Southwest regions. 2015 was the fourth year of a period in which drought conditions progressively covered the Western half of the United States. In contrast, the area percentages experiencing drought conditions in the Pacific Northwest and California HUC-2 regions—which contain 55% of installed hydropower capacity in the United States—were 3% in 2006 and 0% in 2011.

Figure 40 also shows that every year had a very wide range of plant capacity factors reflecting planned or unplanned outages, hydrological and market conditions, and mode of operation (run-of-river vs. peaking). After four years of progressively lower values for the 10th percentile of the capacity factor distribution, it has been 13% or higher in 2016–2018. To explore the influence of selected plant and market attributes on capacity factor, Figure 41 summarizes average capacity factor trends by region, mode of operation, owner type, and the type of BA (ISO/RTO vs. traditionally regulated markets).

A significant difference exists between the average capacity factors of the northern half of the country (43% Northwest, 44% Midwest, and 45% Northeast) and the southern half (32% Southwest, 27% Southeast). Resource quality (average runoff) can explain some of the difference. The combination of prevalent operation mode, ownership type, and market structure in each region is also relevant.

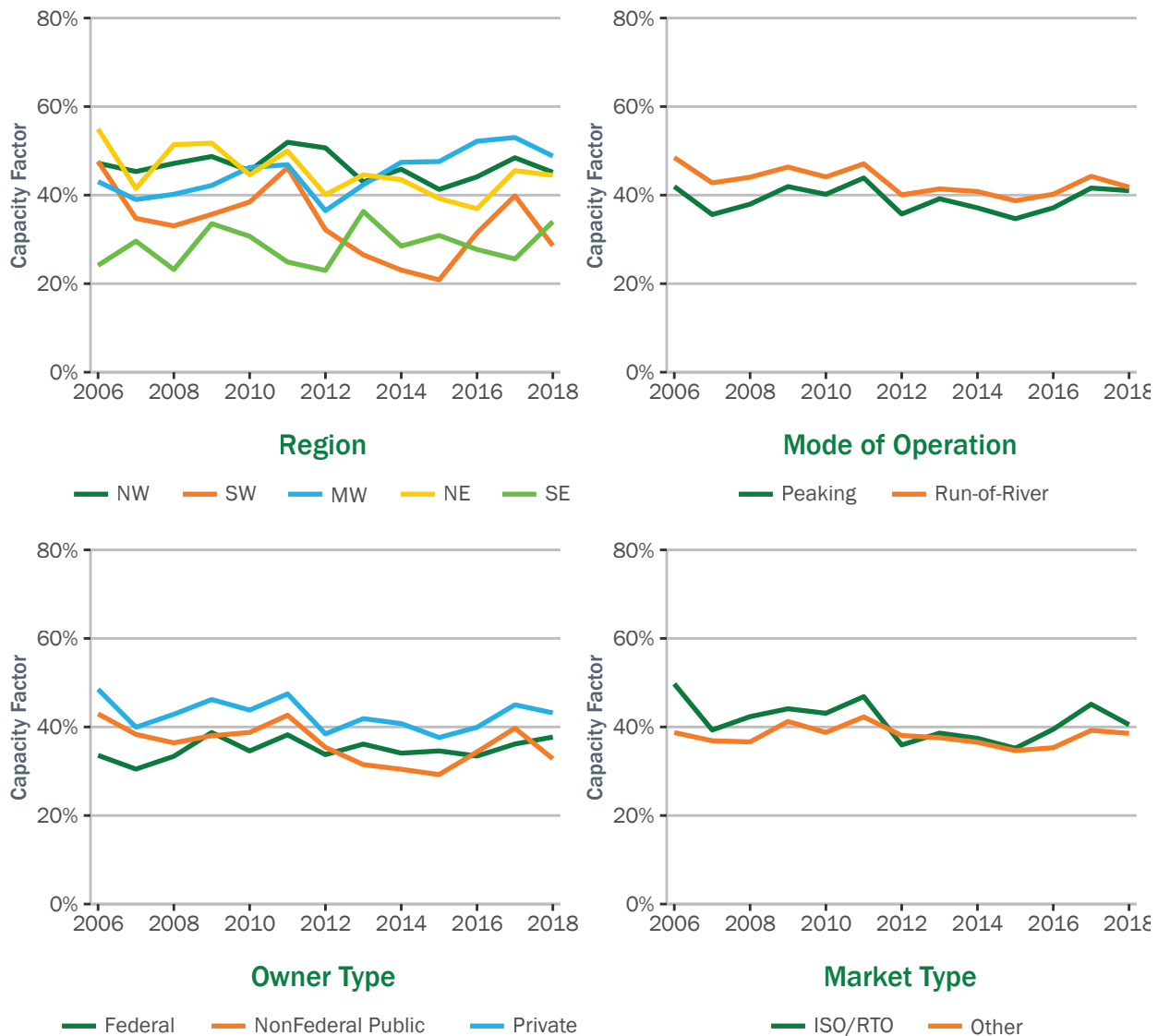


Figure 41. Annual average hydropower capacity factor by region, mode of operation, owner type, and market type (2006–2018)

Sources: EIA Form 923, EIA Form 860, Existing Hydropower Assets dataset

Note: The average number of plants for each fleet segment are 272 (Northwest), 345 (Southwest), 197 (Midwest), 363 (Northeast), 230 (Southeast), 317 (Peaking), 618 (Run-of-River), 158 (Federal), 384 (Nonfederal Public), 848 (Private), 793 (ISO/RTO), and 614 (Other).

Out of all considerations, region made the most difference for average capacity factor. The average capacity factor in 2006–2018 was 46% for the Northwest region, 45% for the Northeast and Midwest, 34% for the Southwest, and 29% for the Southeast. Plants in the Northwest had an average capacity factor greater than 40% every year of the period analyzed. The Northwest also displayed the lowest variability in average capacity factor over this period. Depending on the year, the fleet segment with the highest capacity factor was in the Northwest, Midwest, or Northeast regions. Beyond year-to-year variability, average capacity factor in the Northeast region displayed a downward trend over 2006–2018, whereas average capacity factor in the Midwest trended upward. The hydropower fleet in the Southeast region typically displayed the lowest capacity factor except for in 2013–2015, when the Southwest region experienced a sharp decrease in average capacity factor due to drought conditions.

The two operation mode categories shown in Figure 41 display the same general trend. The average capacity factor for the run-of-river segment of the fleet was always greater than for the peaking segment (43% average over the entire period for peaking and 39% for run-of-river), but the difference shrank from 6.5 percentage points in 2006–2008 to 2 percentage points in 2016–2018. The two operation mode categories shown in Figure 41 are the two aggregate categories summarizing a more detailed classification with seven modes developed by McManamay et al. (2016).⁷⁴ If the sample was restricted to only include plants that operate strictly as run-of-river or peaking, the capacity factor differences between the two groups widened (average capacity factors of 38% for peaking plants and 45% for run-of-river plants; the difference in capacity factors between the two groups shrank from 10 percentage points in 2006–2008 to 5 percentage points in 2016–2018).

Privately owned plants operated at a higher average capacity factor than federal- or nonfederal-owned plants in every year shown in Figure 41. The average capacity factor in 2006–2018 was 43% for the segment of the fleet with private owners (investor-owned utilities, private non-utilities, industrial, wholesale power marketers), 36% for those with nonfederal public owners (public utility districts, state agencies, political subdivisions, cooperatives), and 35% for the federal fleet. Within the privately owned segment of the fleet, the subset owned by wholesale power marketers had an average capacity factor of 50%, which is almost 10 percentage points higher than the average for plants owned by private non-utilities and investor-owned utilities. The multipurpose nature of federal dams in which hydropower tends to be a lower priority use relative to flood control, irrigation, or navigation partly explains the lower capacity factors for that segment of the fleet. Based on data from the National Inventory of Dams database, the median ranking of the hydropower production purpose in plants connected to federally owned dams is second; for the rest of the fleet, the hydropower purpose typically ranks first. For the federal segment of the fleet, Section 1.3. showed that 2008–2019 R&U capital expenditures per installed megawatt have been lower for federal than nonfederal plants, which can also affect availability and capacity factors.

In general, average capacity factor was higher for hydropower plants operating in ISO/RTO market regions (41% average capacity factor) than in the rest of the country (38% average capacity factor). This difference relates to the discussion of capacity factor differences across owner types. As of 2018, 69% of privately owned hydropower plants in the sample operated in ISO/RTO markets. However, 89% of the federal fleet is located outside organized wholesale markets. Nevertheless, the average capacity factor for privately-owned plants did not change significantly across market types (43.5% for the subset located in ISO/RTO market regions and 42.4% for the rest). Therefore, owner type appears to be a stronger influence than market type on capacity factor. The drought conditions in CAISO heavily influenced the convergence of the ISO/RTO versus Other capacity factor series in 2012–2015. If the CAISO plants are removed from the sample, the two series still display the same average capacity factor in 2012 (37%) but, from 2013 to 2015, the average capacity factor in ISO/RTO markets is approximately 5 percentage points greater than in the rest of the country.

⁷⁴ The aggregate Peaking category includes Peaking, Intermediate Peaking, and Reregulating facilities. The aggregate Run-of-River category includes strictly Run-of-River plants, Run-of-River/Upstream Peaking, and Run-of-River/Peaking facilities in which the mode of operation changes by season.

A capacity-weighted variant of Figure 41 shows three notable differences. First, in the regional panel, the capacity factor for the Northeast is significantly higher when capacity weights are applied—56% on average over the 2008–2019 period vs. 45% without capacity weights. Second, in the panel segmenting capacity factor by mode of operation, the capacity factor for run-of-river plants is higher—45% on average over the 2008–2019 period vs. 43% without capacity weights. Third, applying capacity weights results in the nonfederal public fleet having the highest average capacity factor among all owner type groupings—47% on average over the 2008–2019 period vs. 36% without capacity weights. Therefore, within each of those three groupings (Northeast, run-of-river, nonfederal public), some of the largest plants had higher-than-average capacity factors. For instance, the Robert Moses (912 MW) and Robert Moses Niagara (2,429 MW) power plants are the largest in the Northeast region and among the largest in the nonfederal public grouping and reported capacity factors of 87% and 68% during this period, respectively.

5.5 Availability Factors

In 2016–2018, availability factors remained stable for small (< 10 MW) and large units (> 100 MW) but continued decreasing for medium-sized units (10–100 MW).

As shown in Section 5.4, the average capacity factor for the U.S. hydropower fleet ranged between 35% and 45% in the past 15 years and some plants exhibited annual capacity factors lower than 20% and greater than 75% during that same period. The availability factor—the percentage of hours in a year in which a hydropower unit is available to provide generation and grid services—provides additional important information to evaluate performance. For instance, a low capacity factor (e.g., 20%) can mean different things if the availability factor is close to 20% vs. 100%. In the first case, the unit produced energy every hour in which it was possible to do so (capacity factor constrained by availability). In the second case, the unit might have provided services other than generation or simply been idle because of peaking duties, market conditions, or competing purposes.

Part of the hydropower fleet has a mandatory requirement to report information on availability factor and number of hours spent in different operational statuses to the North American Electricity Reliability Corporation (NERC). NERC makes these data public through the pc-GAR software but in a form that does not allow linking the data to unit names or other identifying attributes. Figure 42 shows data on availability and hourly breakdown of operational status segmented by unit sizes.

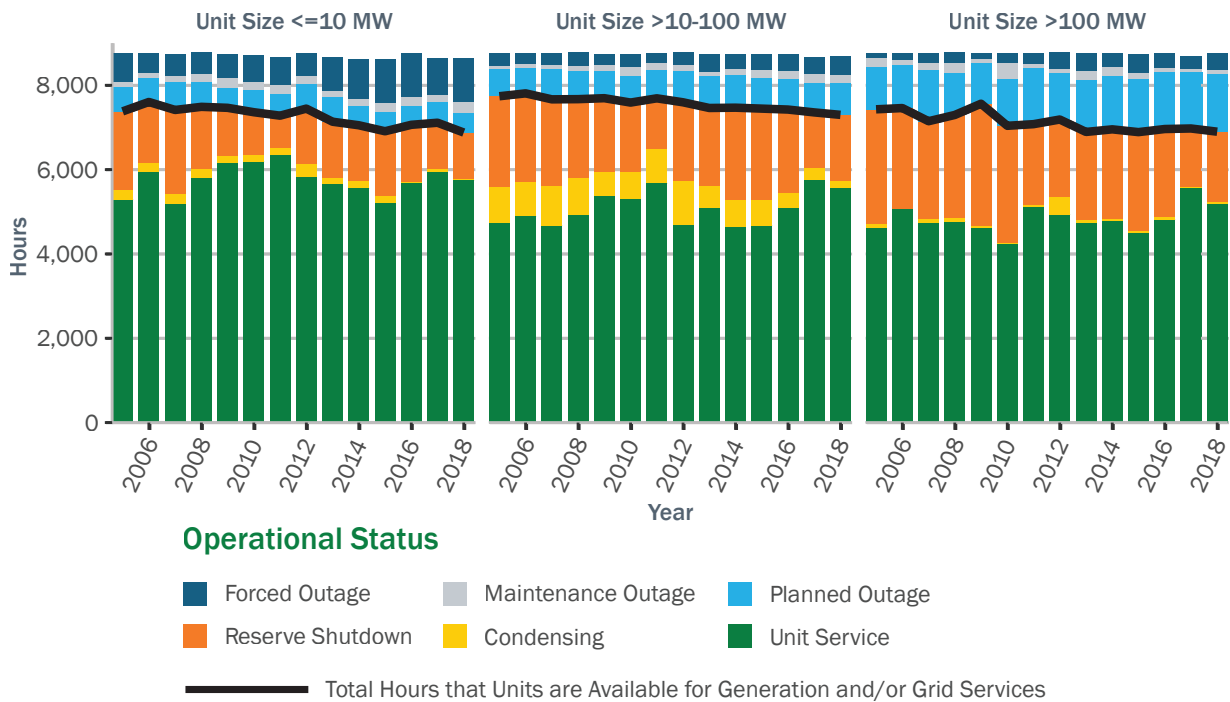


Figure 42. Average hydropower operational status (hourly breakdown by unit size classes of units reporting to NERC Generating Availability Data System [GADS]; 2005–2018)

Source: NERC GADS

Note: Operation and outage state definitions from the NERC Glossary of Terms: Forced Outage (unplanned component failure or other conditions that require the unit to be removed from service immediately, within six hours or before the next weekend), Maintenance Outage (unit removed from service to perform work on specific components that can be deferred beyond the end of the next weekend but not until the next planned outage), Planned Outage (unit removed from service to perform work on specific components that is scheduled well in advance and has a predetermined start date and duration), Reserve Shutdown (a state in which the unit was available for service but not electrically connected to the transmission system for economic reasons), Pumping Hours (hours the turbine-generator operated as a pump/motor), Condensing (units operated in synchronous mode), and Unit Service Hours (number of hours synchronized to the grid).

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The percentage of U.S. hydropower fleet coverage for each unit size shown in the panel titles varied slightly from year to year. On average, 16% of U.S. hydropower units ≤ 10 MW, 67% of U.S. hydropower units $>10\text{--}100$ MW, and 76% of U.S. hydropower units >100 MW reported data to NERC GADS in 2005–2018.

In 2016–2018, the average number of available hours remained stable for large units, continued a slowly decreasing trend for medium units, and showed the most variability for small units. Average availability factors in those years were 79%, 84%, and 80% for large, medium, and small units, respectively.

Jumps in average number of unit service hours in 2006, 2011, and 2017 correlate to the favorable hydrologic conditions in the Western regions in those years. For medium and large units, an uptick occurred in the percentage of available hours in which the units are synchronized to the grid in 2016–2018 relative to previous years. Relatedly, the combined number of hours spent in Reserve Shutdown or Condensing status decreased.

Within the average fraction of hours in which units were unavailable (16%–21% depending on unit size classes), the tradeoff between planned and forced outage hours discussed in the 2017 Hydropower Market Report continues to be visible. Figure 43 zooms into the evolution of the number of hours spent in each of the three outage types—forced, planned, and maintenance—in

2009–2018 by each of the hydropower unit size classes. Large units had the longest planned outage and the shortest forced outage periods, and the opposite is true for small units. For small and medium units, the average number of planned outage hours has remained stable during the past decade. However, average planned outage hours have increased by 41% for large units, from 982 in 2009 to 1,382 in 2018. All unit sizes display increases in average forced outages over the period considered in Figure 43; for medium and large units, the trend is slight but average forced outage hours have almost doubled for small units.

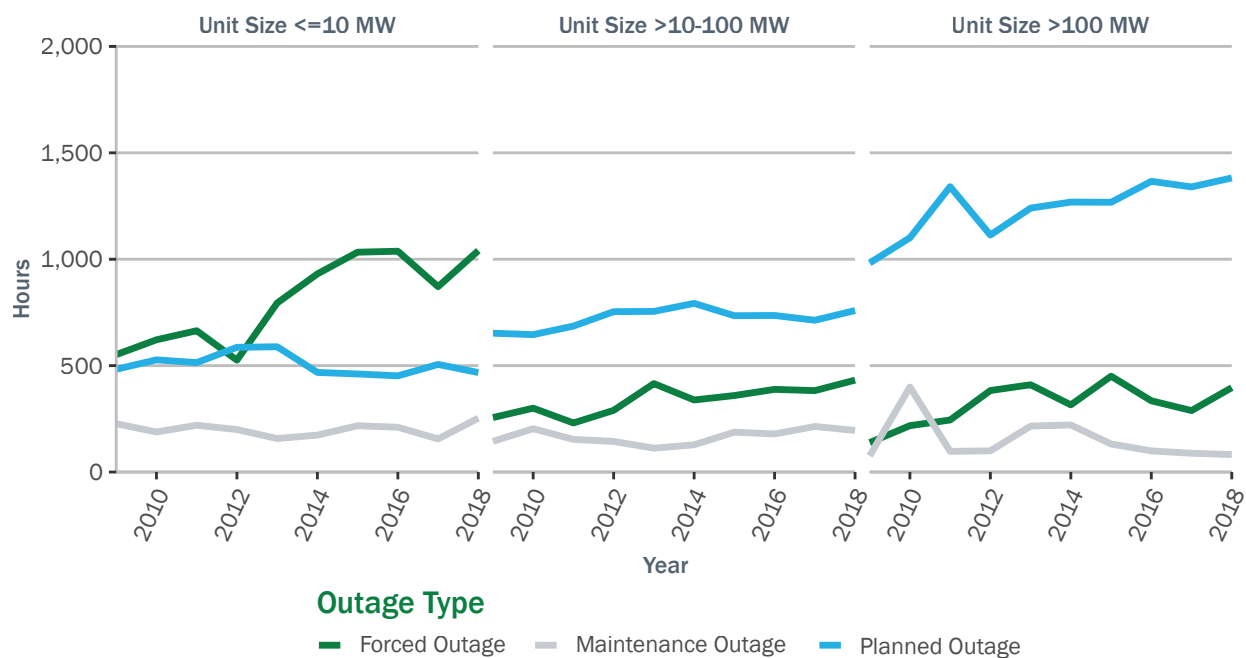


Figure 43. Average hydropower outage hours by outage type and unit size classes of units reporting to NERC Generating Availability Data System [GADS]; 2009–2018)

For large units, the top three causes for forced outages in 2005–2018—ranked by average annual generation lost per unit—were 1) generator stator windings, bushings, and terminals, 2) generator rotor, 3) main transformer. In contrast, for small units, the top three causes during the same period were not related to plant components but to external events: 1) lack of water, 2) flood, 3) transmission system problems. The top three causes for forced outages among medium-sized units include plant component issues and external events: 1) main transformer, 2) generator stator windings, bushings, and terminals, 3) lack of water. Among the top 25 causes for forced outages, 18–20 are related to turbine or generator components for all unit sizes. For large units, 13 of the top 25 causes are related to generator components and seven to turbine components. In contrast, only five of the top 25 causes for forced outages among small units in the sample are generator-related and turbine components account for 13 of the 25.⁷⁵

The Western Electricity Coordinating Council (WECC) exhibited the lowest availability factor most years in 2005–2018 for both hydropower and PSH out of all NERC regions; however, its hydropower units were synchronized to the grid for more hours on average than other regional fleets with higher availability factors.

Figure 44 provides a complementary view of the trends in availability and operational status in which the NERC pc-GAR dataset is segmented by NERC regional groupings (see NERC regions in Figure 45) instead of unit sizes.

⁷⁵ Water supply and discharge components (e.g., intake tunnel, headgates, shutoff valves, penstock, tailrace) are classified as turbine components.

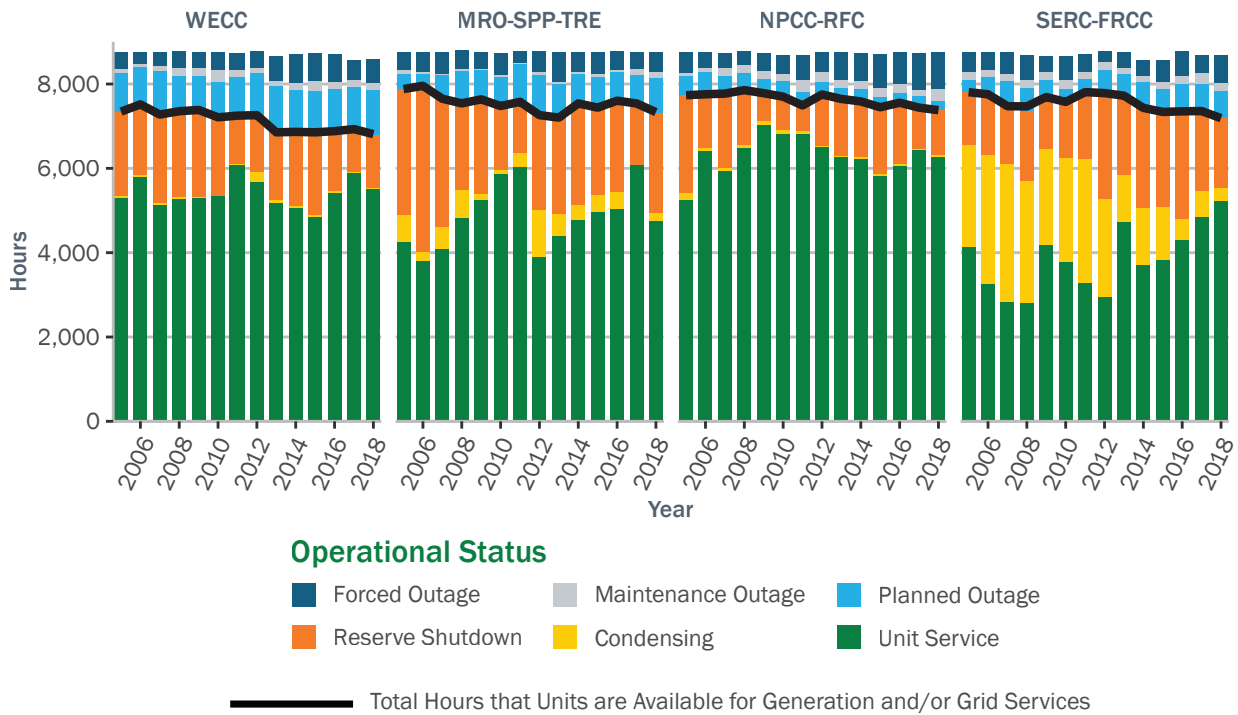


Figure 44. Average hydropower operational status (hourly breakdown by regional groupings of units reporting to NERC GADS; 2005–2018)

Source: NERC GADS

Note: Operation and outage state definitions are provided in the note for Figure 42. The NERC region classification comprises 8 regions: Western Electricity Coordinating Council (WECC), Midwest Reliability Organization (MRO), Southwest Power Pool (SPP), Texas Regional Entity (TRE), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), Southeastern Electric Reliability Council (SERC), and Florida Reliability Coordinating Council (FRCC). Data are presented for groupings of multiple regions because pc-GAR does not allow extracting data for most single regions.

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The percentage of U.S. hydropower fleet coverage for each NERC regional grouping varied slightly from year to year. On average, 49% of U.S. hydropower units >1 MW in WECC, 33% of U.S. hydropower units >1 MW in MRO_SPP_ERCOT, 31% of U.S. hydropower units >1 MW in NPCC_RFC, and 44% of U.S. hydropower units >1 MW in SERC_FRCC reported data to NERC GADS in 2005–2018.

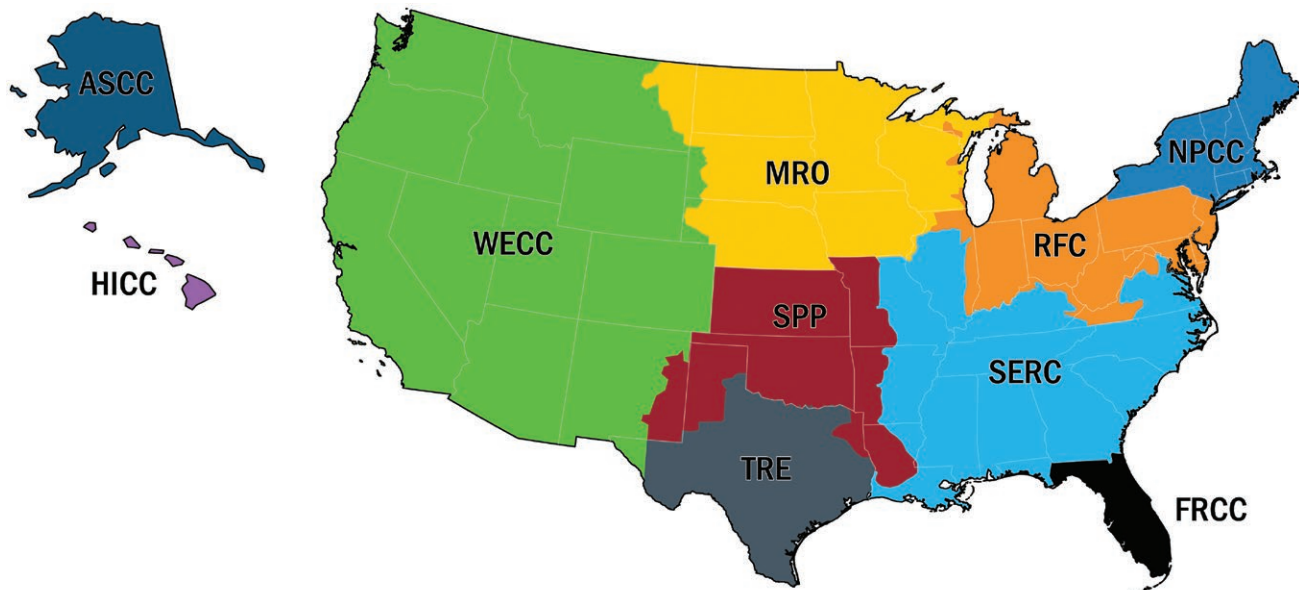


Figure 45. NERC regions

Any sharp changes shown in Figure 44 around 2012–2013 should be interpreted with caution because the population of units with mandatory NERC reporting requirements changed in that year (see Appendix for annual pc-GAR dataset sizes). NERC reporting became mandatory for units >50 MW in 2012 and for units >20 MW in 2013. Therefore, the average size of units reported in each region was lower after 2012.

The decreasing trend in the availability factor was common to all regions, but significant differences appeared in the average availability factor. Among the sample of plants that reported to NERC, WECC had the lowest average availability factor every year from 2005 to 2018. However, the average number of unit service hours for the WECC sample was higher than for SERC-FRCC every year and higher than MRO-SPP-ERCOT every year except 2010, 2015, and 2017.

Condensing hours were heavily concentrated in the SERC-FRCC region grouping. The decrease observed after 2012 coincided with the start of mandatory reporting for units with capacities lower than 20 MW. Condensing hours were not evenly distributed among all units in that regional grouping. For instance, in 2012, 352 units were reporting in SERC-FRCC, 106 of which spent 0 hours in Condensing status; the median unit was in Condensing status for 1,230 hours, and units in the highest quartile of the distribution classified its operational status as Condensing more than half of the hours in that year.⁷⁶ While in Condensing status, units might be providing voltage support and reactive power and might be compensated for those services. Because of the large average of condensing hours, SERC-FRCC had the lowest average number of unit service hours every year except 2018, when MRO-SPP-ERCOT became the regional grouping with the lowest average unit service hours. The only other regional grouping with non-negligible levels of condensing activity was MRO-SPP-ERCOT.

WECC had the highest average number of planned outage hours and NPCC-RFC had the lowest. Without information on the size distribution of units in the two regions, determining whether this result was driven by size or regional differences is difficult.

⁷⁶ The large average number of condensing hours in the Southeast is partly explained because some utilities in that region never put their hydropower units in cold shut down status. Instead, they always keep them rotating. When the units are rotating and not producing electricity but just spinning air (i.e., acting as motors instead of as generators), the units are in Condensing status.

Figure 46 summarizes available unit hours and an hourly breakdown of operational status for PSH units by NERC grouping.

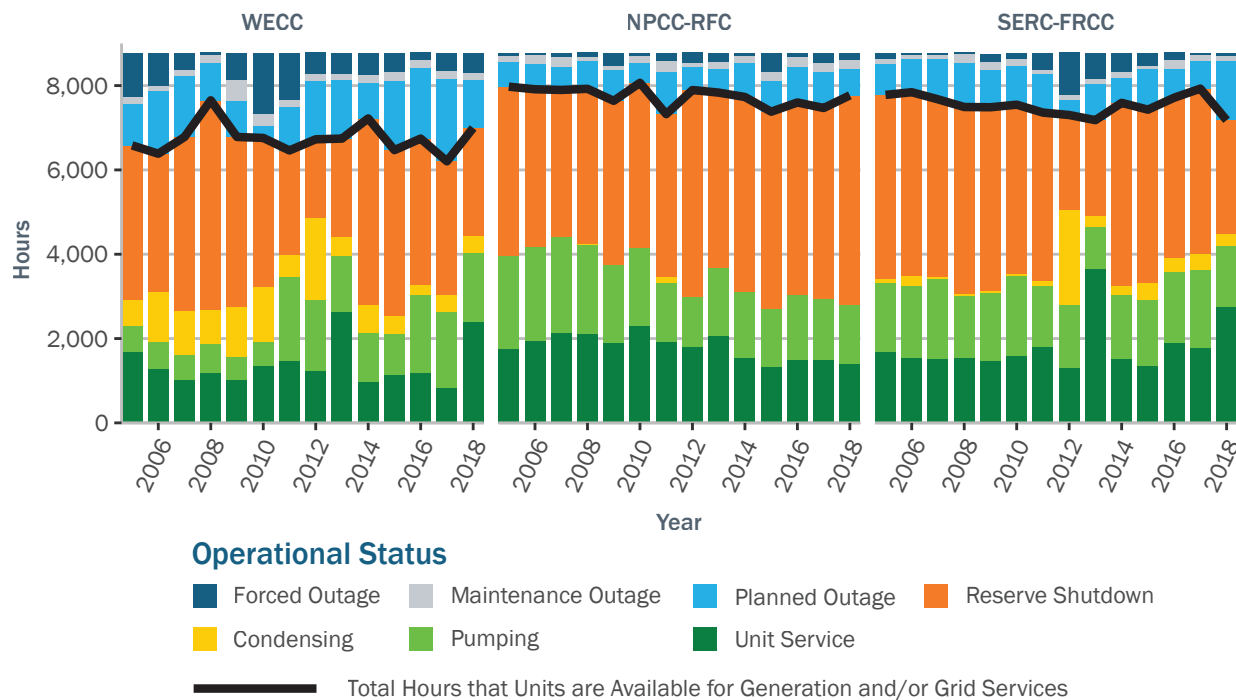


Figure 46. Average PSH operational status (hourly breakdown by regional groupings of units reporting to NERC GADS; 2005–2018)

Source: NERC GADS

Note: Operation and outage state definitions are provided in the note for Figure 42.

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The percentage of U.S. PSH fleet coverage in NERC GADS varied slightly from year to year. On average, 72% of U.S. PSH units in NPCC-RFC, 53% of U.S. PSH units in SERC_FRCC, and 56% of U.S. PSH units in WECC reported data to NERC GADS in 2005–2018. The number of reporting units in MRO-SPP-ERCOT was too low to extract data from the pc-GAR software.

Figure 46 shows substantial differences in PSH availability and operational status between WECC and the other regions. The differences between WECC and the other regions are partially explained because the PSH fleet in the West includes multiple facilities owned by state or federal agencies that have water supply and irrigation as higher-ranked purposes than generation of electricity or provision of grid services. Some of these PSH facilities (e.g., Waddell in Arizona) only generate during the summer months, resulting in low average annual capacity and availability factors. On average, the availability factor for PSH units in the WECC region only was greater than 80% in 2008 and 2014. For NPCC-RFC and SERC-FRCC, the average availability factors in 2005–2018 were 88% and 86%, respectively. WECC PSH units also had the lowest number of unit service hours in most years. The average number of unit service hours has trended downward in recent years in the NPCC-RFC region; however, the average number of unit service hours in SERC-FRCC in 2016–2018 was greater than in the rest of the period (except for in 2013).⁷⁷ The tradeoff between planned and forced outage hours discussed for hydropower units does not

⁷⁷ The number of hours generating at full capacity can be significantly lower than unit service hours (hours synchronized to the grid). For instance, the spike in unit service hours in SERC-FRCC in 2013 coincided with the year of lowest PSH generation in the Southeast. In 2013, 16 PSH units were in this regional grouping synchronized to the grid for more than 5,000 hours. The following year, no PSH unit in the region was synchronized for more than 4,100 hours. However, PSH generation in the Southeast was significantly higher in 2014 than in 2013 (see Figure 38).

seem to be present for PSH units segmented by region. For instance, units in NPCC-RFC tended to have both lower planned and forced outage hours than WECC. The average number of condensing hours has been very low—and exactly zero since 2015—for NPCC-RFC PSH units. For WECC, the average number of condensing hours has been much higher than in other regions but has trended downward since 2015.

FURTHER ANALYSIS OF HYDROPOWER OPERATIONAL STATUS AND AVAILABILITY TRENDS IS NEEDED

The NERC GADS data presented in this section provide a useful high-level breakdown of the operational status of hydropower and PSH units. With a timespan of more than a decade and national coverage, this dataset reveals regional patterns and time trends, but it leaves open questions about their drivers. First, why are average planned outage hours significantly greater in WECC than in the rest of the country for both hydropower and PSH units? Second, which services are hydropower and PSH units providing and which revenue are they receiving during the hours spent in Reserve Shutdown status (20% of hours in a year on average for hydropower units and more than 40% for PSH units)? For PSH, the data presented in Section 4.1.3 shows that the supplemental reserves that can be provided while in Reserve Shutdown status represent a miniscule fraction of total revenue. Are there other revenue streams adequately valuing available hydropower capacity that is not synchronized to the grid? Third, what drives the different behavior around the use of hydropower for voltage support (i.e., number of hours in Condensing status) in different regions? Fourth, how much do market design details matter relative to plant characteristics, or ownership type for the observed patterns of operation? Ongoing research under the DOE's [HydroWIRES](#) initiative which includes detailed case studies as well as the development of valuation methodologies and optimization models can provide insight to some of these questions. Among the key research thrusts of HydroWIRES are investigating the constraints (mechanical, hydrological, institutional) shaping the use of hydropower and PSH capabilities and seeking to align their use with the evolving needs of the grid.⁷⁸

Availability factors exhibit more seasonal variation for PSH than for hydropower. Runoff patterns largely determine hydropower seasonality; in contrast, PSH operations depend less on hydrologic cycles and are managed to ensure availability during summer and winter peak load periods.

Figure 47 provides seasonal details for the availability factor trend data presented in Figure 43 and Figure 46. The differences in seasonal availability factors between hydropower and PSH units displayed in are partly explained by a stronger dependence of hydropower plants on hydrologic conditions vs. the fuller ability of PSH owners to schedule planned outages around periods of lowest demand and electricity prices.

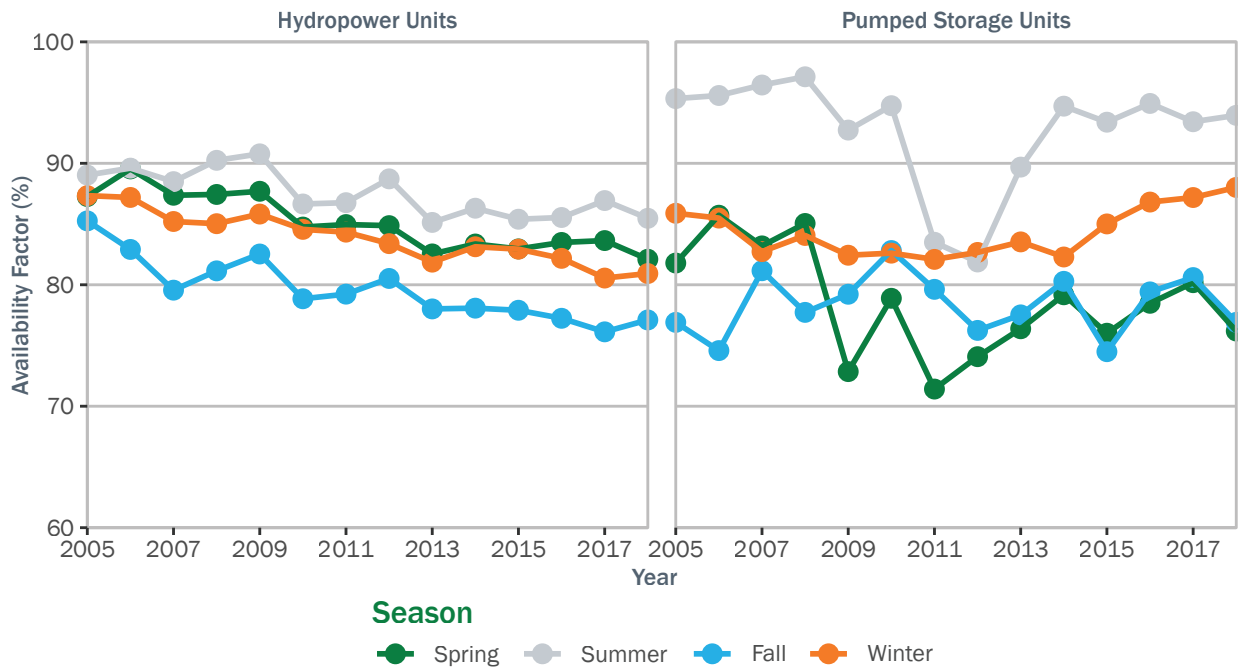


Figure 47. Capacity-weighted hydropower and PSH unit availability factor by season (for units reporting to NERC GADS; 2005–2018)

Source: NERC GADS

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The percentage of U.S. hydropower fleet coverage for the unit types shown in the panel titles varied slightly from year to year. On average, 28% of U.S. hydropower units and 55% of U.S. PSH units reported data to NERC GADS in 2005–2018.

For hydropower units, availability is highest in summer (greater than 85% every year), slightly lower in spring, and lowest in fall. Average fall availability has fallen below 80% every year since 2012. Depending on the region, streamflows are highest in late spring (in regions with snowmelt-dominated hydrology) or winter, and hydropower units are ideally available at those times. Fall is not the peak flow season in any region, making it the preferred season for planned outages for many hydropower owners. For some hydropower plants, the months of the year when planned outages must take place are specified in the FERC license.

For PSH units, availability is most valuable in summer and outages are planned outside of that season. Therefore, outside of 2011–2013 when some large units were unavailable for the full period, the average summer availability factor has been approximately 95%. Winter availability has increased notably since 2013. Spring and fall—the shoulder periods in terms of electricity demand—are targeted for planned outages and result in the lowest average availability factors for the sample of PSH units reporting to NERC.

5.6 Hydropower Operation Flexibility

Power system flexibility is the ability to effectively cope with variations in the supply or demand of electricity (International Energy Agency, 2019). Mismatches between supply and demand take place at multiple frequencies, from seasonal to millisecond, and the solutions to address them also vary by time scale and grid characteristics. Variable renewable energy penetration level is an important factor in assessing the demand for flexibility in an electric BA. The International Energy Agency (2019) describes six phases in variable renewable energy penetration and their implications for flexibility demand. Hydropower is one of the most versatile technologies, able to contribute to short-duration grid reliability needs (e.g., frequency regulation service) and provide seasonal storage. However, the degree of flexibility varies widely across hydropower facilities depending on their configuration, number of turbine units, and external constraints motivated by the need to provide other non-energy services. The increasing utilization of hydropower to provide flexibility can also induce accelerated equipment degradation (EPRI, 2017).

The information presented in this section focuses on three metrics—ramping, ancillary services provision, and unit starts—indicative of the contribution of the U.S. hydropower fleet to maintaining electric supply-demand balance and ultimately ensuring the reliability of the electric grid. The assembled datasets aim to reflect overall U.S. fleet trends. Detailed case studies recently published as part of the U.S. Department of Energy’s HydroWires Initiative are also cited as further reference.

5.6.1 Ramping (hourly frequency)

The average and range of one-hour ramps of electricity production performed by the hydropower fleet (including PSH) vary widely across BAs. In 34 out of 36 BAs analyzed, hourly ramps were larger (and their ranges wider) for hydropower than for natural gas.

Ramping rates, the maximum change in output per unit of time, are one of the attributes typically used to compare the operational flexibility of power plants. Similarly, the ramps performed in actual operation by different plant types are a metric to assess their relative contribution to maintain power supply and demand in balance. Depending on the time frequency at which ramps are measured, they provide information about contributions to resolve different types of imbalances. For instance, ramps measured over seconds or minutes would be informative as to output changes in response to high-frequency fluctuations in wind and solar output. In contrast, hourly ramps are better suited to understand how the mix of generation plants in a power system adjust to changes in electricity load (i.e., demand) patterns throughout the day. The most versatile dataset for an analysis of ramping behavior would be one containing unit-level information at a high frequency. However, those data are not publicly available. The public dataset used in this section (EIA Form 930) contains fleet-level data for each technology type and BA at an hourly frequency. Ramps are compared for hydropower and natural gas because those are typically the two most flexible plant types. Balancing authorities are the most relevant spatial units for analyzing ramps because they are the units within which supply and demand must be balanced at all times. It is important to note that the results presented for hourly ramps do not necessarily translate to ramping at higher frequencies. Moreover, aggregation at the fleet level means that it is not possible to ascertain if most individual units within the fleet adjust their output similarly or most of the ramp is just performed by the few, most flexible units.

One-hour ramps (i.e., hourly changes in output), as a percentage of installed capacity, for hydropower and natural gas generation fleets were computed from hourly generation mix data reported by BAs to EIA. Hydropower generation data included net generation by PSH. Therefore, negative net generation instances occurred at the fleet level in BAs with a significant fraction of PSH capacity in their fleets (e.g., DUK: Duke; SRP: Salt River Project). On average across all BAs, the hydropower fleet (including PSH) changed generation level from one hour to the next in 84% of hours; for natural gas, the average was 93%. The observations with no change were excluded from the ramp distribution summary. Figure 48 displays the mean and 10th to 90th percentile range of the distribution of one-hour ramps performed by the hydropower and the natural gas fleet by BA in 2019.⁷⁹ BAs are ordered left to right from largest (Bonneville Power Administration [BPAT]) to smallest (Louisville Gas and Electric Company and Kentucky Utilities Company [LGEE]) hydropower plus PSH capacity. The list of BA names associated with the codes in the plot is included in the Appendix.

⁷⁹ The requirement for BAs to report hourly generation mix data to EIA became effective in July 2018. Therefore, 2019 is the first full calendar year for which this dataset was available.

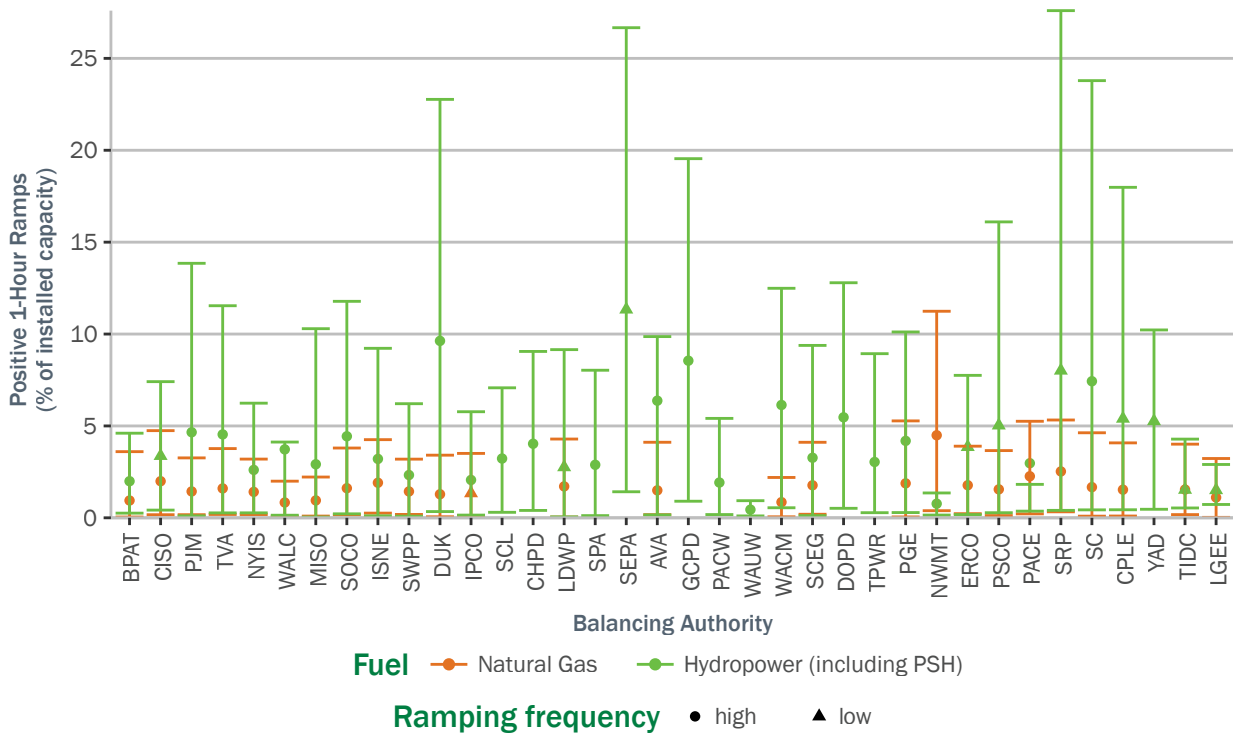


Figure 48. One-hour ramps per installed megawatt for hydropower (including PSH) and natural gas by balancing authority in 2019

Source: EIA Form 930

Note: BA acronym definitions are provided in the Appendix. Only positive ramps are shown. The distribution of negative ramps mirrors that of positive ramps almost exactly. CISO (CAISO) data are missing for October–December. BAs with less than 100 MW of hydropower and PSH capacity or with generation values greater than what would be feasible given the installed capacity are excluded. High-frequency ramping means that the fleet changed generation level from one hour to the next in at least 75% of hours in the year (both positive and negative changes were counted for this classification).

With the exceptions of NorthWestern Corporation [NWMT] and TIDC Turlock Irrigation District [TIDC], the average onehour ramp as a percentage of installed capacity was greater for hydropower (including PSH) than for natural gas. This result is consistent with the finding for previous years in ISO/RTO regions discussed in the 2017 Hydropower Market Report. The range between the 10th and 90th percentiles was also wider for hydropower than for natural gas in most BAs. An important limitation of this dataset is its short history. One year of data is insufficient to fully characterize the ramping ability of the various fleets because climate and hydrologic conditions matter (as do prolonged outages of large facilities). However, it does convey the idea of a large range of ramping behaviors across BAs and the very robust result of large average ramps and wider ranges, at the hourly frequency, for hydropower (including PSH).

Out of the 11 BAs with average hourly hydropower ramps greater than 5% of installed capacity, five are in the Southeast, four in the Northwest, and two in the Southwest. None of them are ISOs/RTOs. Two of them (Southeastern Power Administration [SEPA], and Western Area Power Administration Rocky Mountain Region [WACM]) are managed by PMAs and mostly contain federal hydropower. The group of BAs with average hydropower ramps greater than 5% of their installed hydropower capacity includes both BAs in which a large fraction of hydropower capacity is PSH (e.g., Duke Energy Carolinas [DUK], Public Service Company of Colorado [PSCO]) and others that have no PSH at all (e.g., PUD No. 1 of Douglas County [DOPD], South Carolina Public Service Authority [SC]).

Figure 48 also summarizes differences in ramping frequency. Some of the BAs with large average ramps (Southeastern Power Administration [SEPA], Salt River Project [SRP], Duke Progress Energy East [CPLE], Public Service Company of Colorado [PSCO], Alcoa Power Generating, Inc. – Yadkin Division [YAD]) had relatively low ramping frequencies with no hourly change in aggregate fleet generation for 25% or more hours in the year. Several of the BAs with the lowest ramping frequencies

(Salt River Project [SRP], Turlock Irrigation District [TIDC]) corresponded to systems in which the hydropower dams store water to serve irrigation demands and hydropower might only be produced during the irrigation season.

Variable renewable penetration does not help explain cross-sectional variability in average one-hour ramps across the BAs.

Variable renewable energy (solar and wind) penetration is another BA attribute that is useful to investigate in relation to ramping.⁸⁰ Figure 49 shows that cross-sectional variation in average hourly ramping is not strongly correlated with variable renewable energy penetration. Only 1 of the 11 BAs in which the hourly average ramp for hydropower was greater than 5% has high renewable penetration (Public Service Company of Colorado [PSCO]), and many of them are in BAs with almost zero penetration of solar and wind energy. The results are the same if the width of the 10th to 90th percentile is in the y-axis instead. The correlation between penetration of renewables and ramping will more likely appear by tracking the evolution of ramping distribution over time in one BA as renewable penetration increases than by comparing across BAs at one point in time.

With the hourly data available, it is not possible to compute the sub-hourly ramps that account for a large portion of the overall generation adjustments in response to the output fluctuations of variable renewables.⁸¹ Flexibility products offered in ISO/RTO markets are typically at the sub-hourly level, and the mileage as a performance metric for regulation is usually measured at several-second intervals. Still, some of the changes in hydropower operation patterns that result from high solar penetrations do play out at hourly frequencies: flexible generation must ramp down for several hours in the early morning as solar output increases and ramp up for several hours in the late afternoon as the sun sets.

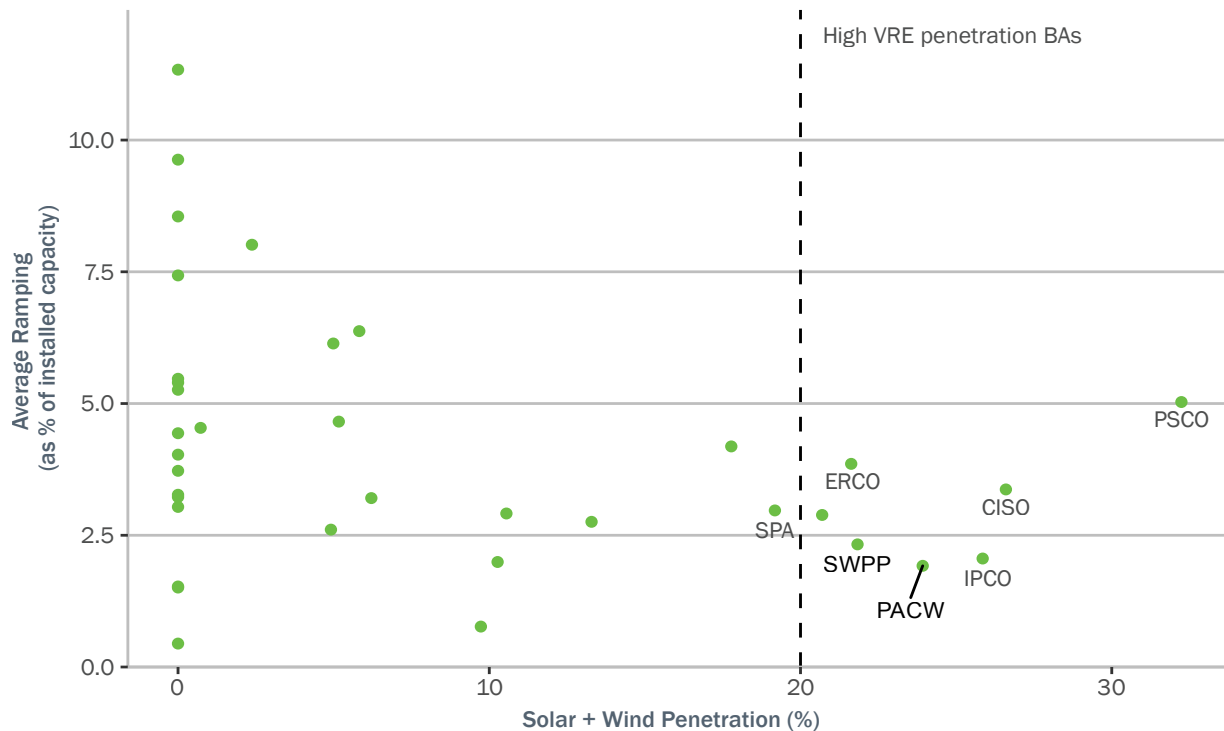


Figure 49. Average positive hydropower (including PSH) one-hour ramps per installed megawatt in 2019 vs. solar and wind penetration by balancing authority

Sources: EIA Form 930, EIA Form 860

Note: BA acronym definitions are provided in the Appendix. CISO (CAISO) data are missing for October–December. BAs with less than 100 MW of hydropower capacity or with generation values greater than what would be feasible given the installed capacity are excluded.

80 Penetration is measured as the percentage of total installed capacity rather than percentage of generation.

81 The BPA [BPAT] BA does provide public 5-minute data and is a useful example because hydropower operations in that BA must sometimes adjust to changes in wind generation. The annual hydropower mileage in that BA—the result of adding up all the ramps in absolute value—based on 5-min data was 69% higher, on average, than mileage based on hourly data.

Fleet attributes can help explain the variation in average hourly ramping across BAs. Figure 50 shows the positive trend underlying the relationship between ramping and the percentage of hydropower fleet classified as peaking in each BA. Most BAs with average one-hour hydropower ramps greater than 5% have 75% or more peaking capacity and are either in the WECC or SERC NERC regions. Nonetheless, several BAs are shown in which the ramping averages fall far from the trendline. The overall availability of flexible generation in the BA and the number of constraints associated with non-power purposes of the dams are also important drivers of hydropower ramping activity. For instance, Southern Carolina Service Authority [SC] displays large average one-hour ramps despite not having peaking capacity. Out of the BAs included in Figure 50, SC is the one with the highest fraction of coal generation capacity, which is not flexible. Thus, the ability to ramp hydropower in that system is particularly valuable and is used as much as possible. In Duke Energy Carolinas [DUK], 44 out of 47 hydropower plants representing more than 99% of capacity have hydropower as their primary purpose, making them less constrained to ramp at the times of more value for the electric grid than many other BAs with similar fractions of peaking capacity. For instance, in the Tennessee Valley Authority [TVA] BA area, only 53% of hydropower capacity is in plants with dams for which hydropower is the primary purpose. The number and type of environmental constraints are other potential sources of ramping restrictions to consider.

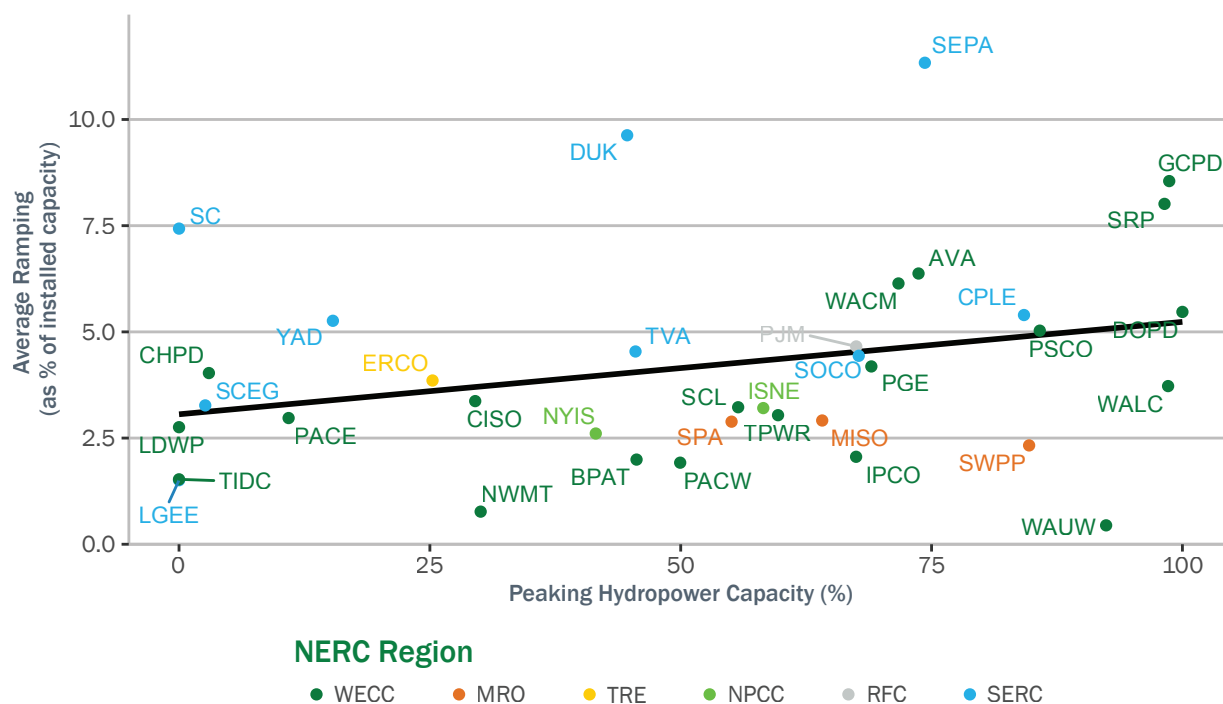


Figure 50. Average positive hydropower (including PSH) one-hour ramps per installed megawatt in 2019 vs. peaking fraction of hydropower fleet in each balancing authority

Sources: EIA Form 930, Existing Hydropower Assets dataset

Note: BA acronym definitions are provided in the Appendix. CISO (CAISO) data are missing for October–December. BAs with less than 100 MW of hydropower capacity or with generation values greater than what would be feasible given the installed capacity are excluded. Peaking fraction is calculated based on the mode of operation categories using the classification in McManamay et al. (2016). Mode of operation information is available for 78% of installed capacity. Thus, the peaking fraction should be interpreted as a low bound.

5.6.2 Unit Starts

The median number of starts is consistent with one or more cycles per day only for the PSH fleet. In contrast, small units typically start 8 to 12 times per year. The median number of starts for large and medium hydropower units display a decreasing trend.

Hydropower units can perform startups quicker and less expensively than most other generation technologies (except combustion turbines). This ability makes them an attractive option to act as peaking units to fill short gaps in the supply-demand balance. The annual number of unit starts is an informative metric for assessing where in the baseload-to-peaking spectrum different segments of the U.S. hydropower fleet are located. Figure 51 presents data on the median and 10th to 90th percentile range of the distribution of unit starts for hydropower units of various sizes, as well as pumped storage units from 2005 to 2018.

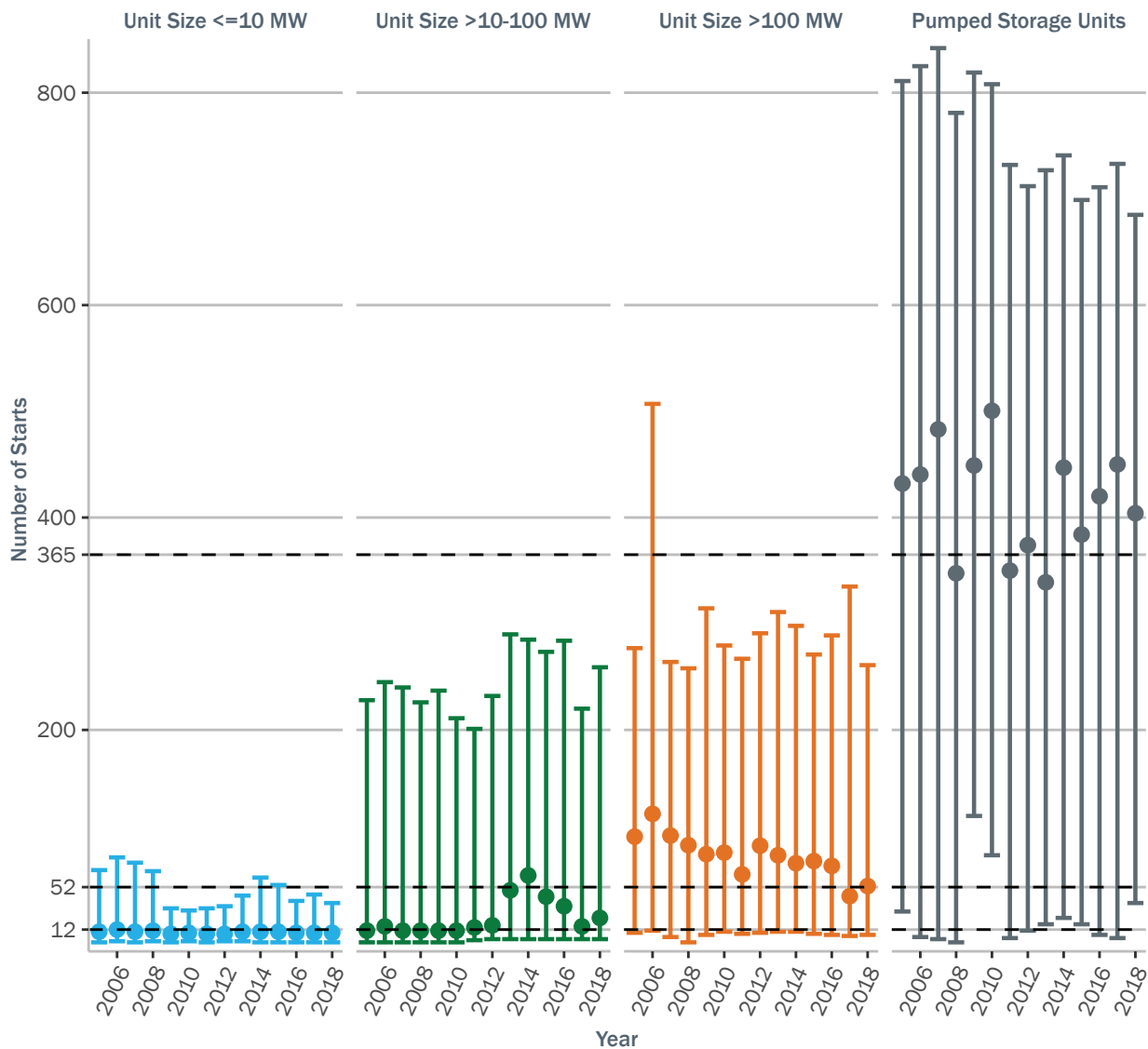


Figure 51. Hydropower and PSH unit start distributions by year, unit type, and unit size (2005–2018)

Source: NERC GADS

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The percentage of U.S. hydropower fleet coverage in NERC GADS for the unit types shown in the panel titles varied slightly from year to year. On average, 16% of U.S. hydropower units ≤ 10 MW, 67% of U.S. hydropower units >10 –100 MW, 76% of U.S. hydropower units >100 MW, and 55% of PSH units reported data to NERC GADS in 2005–2018.

Figure 51 shows a sharp difference in the median and range of unit starts performed by PSH units vs. the rest of the fleet. PSH units operated most clearly as peaking units; even the hydropower units in the 90th percentile of unit starts started fewer times than the median PSH unit. The median number of starts for units <10 MW remained stable within the range of 8 to 12 per year, indicating that they operated as baseload units with, at most, one start per week on average. The median number of starts for medium-sized units was also approximately 12 (i.e., once per month on average) until 2012. From 2013 to 2016, the median number of starts for medium-sized units was substantially higher, reaching 63 (i.e., more than once per week on average) in 2014. In 2017 and 2018, it returned closer to pre-2013 levels. For large units, the median number of starts steadily trended downward, from 100 in 2003 to 53 in 2018. The decrease in the number of starts in 2017 and 2018 for medium and large units is consistent with the increase in unit service hours for these types of units shown in Figure 42. As for PSH units, they typically start and stop more than once a day, and the number of starts for the 90th percentile of the distribution trended downward considerably over the period of analysis.

5.6.3 Contribution to Provision of Ancillary Services

With increasing variable renewable energy penetration, maintaining the reliability and resilience of the grid, which is underpinned by various ancillary services and dispatchable generation capacity, is increasingly challenging. As a flexible, renewable resource, hydropower could play a vital role in a deep-decarbonized grid in terms of ancillary services and capacity adequacy.

Based on its operational experience, PJM (2017) finds that hydropower offers the most complete set of reliability attributes for flexibility and essential reliability services including frequency response, voltage control, ramping, and black start capability. More than 70% of U.S. hydropower capacity can perform a cold unit start within 10 minutes and less than 5% need more than 1 hour for a cold start (EIA, 2020). On average, these speeds are faster for hydropower than for most other technologies. Such fast and usually isolated startup capability makes hydropower competitive in providing a black start. Gracia et al. (2019) point out that hydropower represents less than 10% of U.S. electricity generation capacity but provides approximately 40% of black start resources.

Although hydropower has an outstanding technical capability to provide most ancillary services, it also faces many constraints (see textbox). More than 60% of U.S. hydropower facilities connected to dams have multiple authorized purposes, including flood control, irrigation, water supply, recreation, fish, and navigation, and providing electricity is often not the highest priority. Besides the limits from multiple purposes, water availability also has a critical impact on hydropower operational flexibility.

MULTIPURPOSE CONSTRAINTS TO HYDROPOWER OPERATIONAL FLEXIBILITY

Protection of fish and wildlife is an important priority shaping hydropower operations in many parts of the United States. In the lower Snake and lower Columbia dams that are part of the Federal Columbia River Power System, water spilling to help the downstream passage of juvenile fish has been implemented in the spring and summer seasons (April through August) since the 1980s (Fish Passage Center, 2016). Multiple factors are considered in selecting the flow levels spilled for fish passage. Water diverted for spilling means reduced power generation and flexibility. Additionally, water spill volume is capped to limit total dissolved gases in the dam tailrace, which otherwise affect fish health.

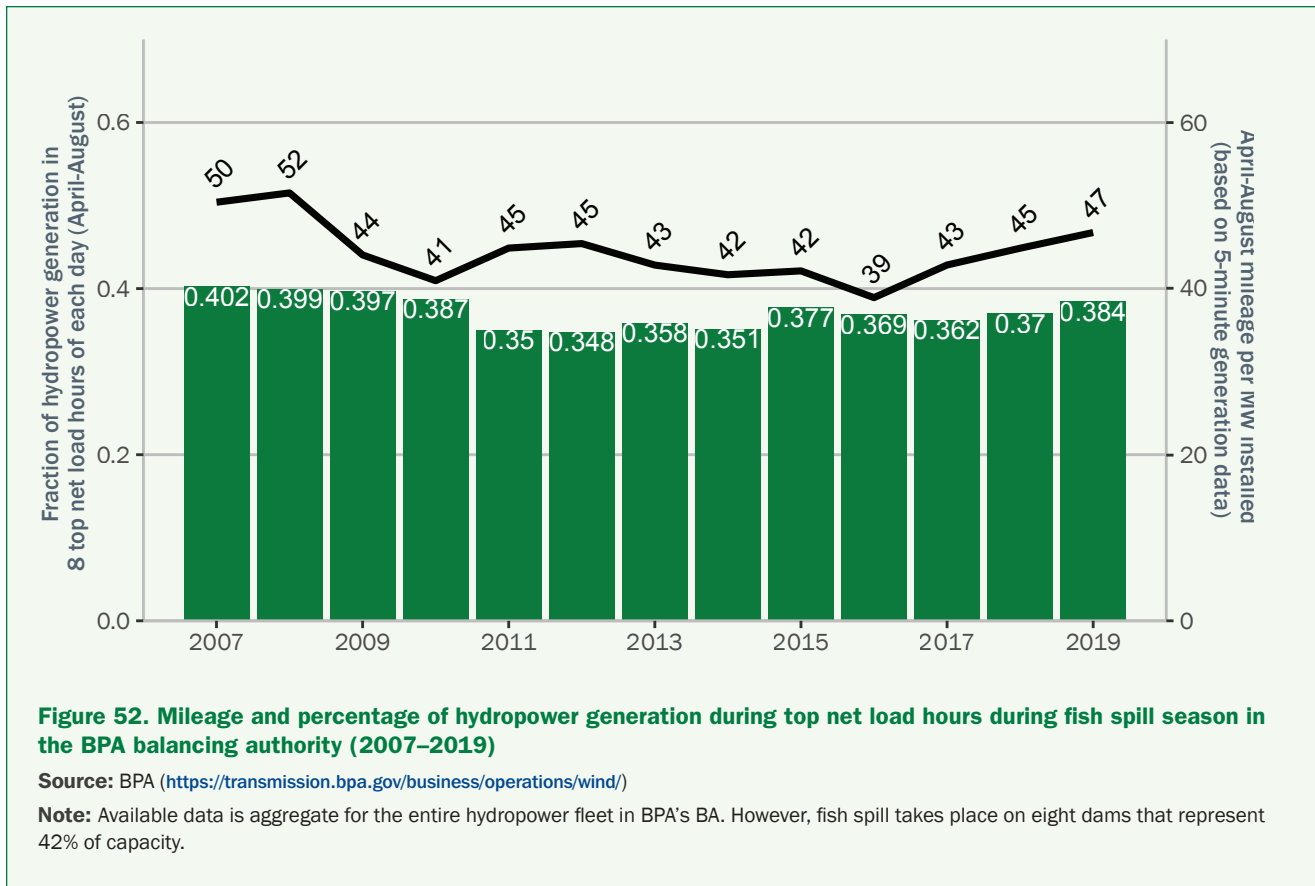
In an example of stakeholder collaboration that enables improved operational flexibility for hydropower while meeting environmental objectives, federal and state agencies, along with tribal nations in the Pacific Northwest (BPA, the states of Oregon and Washington, the Nez Pierce Tribe, the U.S. Army Corps of Engineers, and Reclamation), signed a collaborative agreement in December 2018 to modify spring fish passage spill operations for 2019–2021. The agreement introduces some flexibility on the times of day when the spill takes place. In 2018, court-mandated spring spill for fish passage was required 24 hours/day at the maximum level that would not exceed waivers (at 120%) allowing spill beyond the state total dissolved gases limits. Under the new agreement, spill volumes are set to match the waivers allowing spill beyond the state total dissolved gases limit (up to 120%) for 16 hours/day and lower for the remaining 8 hours. BPA will try to time the reduced spill hours to coincide with those when hydropower generation is most valuable.

Figure 52 displays the evolution of two metrics related to hydropower operation flexibility during the spill season from 2007 to 2019, the first year of implementation of the flexible spill agreement. The figure shows that the fraction of hydropower generation taking place during the eight highest net load hours of each day during the spill season (April to August) in BPA's BA was higher in 2019 than in any of the previous eight years.⁸² Additionally, the spill season mileage (based on 5-min generation data) performed on average by each installed megawatt of hydropower in that BA reached its highest level since 2008.⁸³ These two metrics suggest that the flexible spill agreement slightly increased hydropower operational flexibility in its first year of implementation. Results from fish survival studies under the new spill regime were not publicly available at the time of writing this report.

Continues

82 Net load is calculated as total load minus wind generation. It should be noted that the BPA BA exports significant volumes of electricity to California. Therefore, BPA also takes into consideration the load profile in that region for shaping its hydropower production.

83 Mileage is a measure of the total "work" performed by electricity generation assets (here, the hydropower fleet in BPA's BA), calculated as the sum of all the upward and downward adjustments (in absolute value) done at a given frequency (here, five minute intervals) over a given period (here, the spill season). The total is then divided by generation capacity to obtain the mileage per installed megawatt.



In ISO-NE, at least two thirds of hydropower capacity receive uplift revenue and provide reserves and voltage control.

Market data from ISOs/RTOs help document hydropower’s versatility in the provision of grid services. Figure 53 shows how much ISO-NE hydropower capacity provided a variety of grid services in 2008–2017. Most of the sampled capacity received uplift payments (“make whole” payments to compensate generators for costs not reflected in the market-clearing price), which partly reflects hydropower’s ability to quickly change its operation in response to instructions from the system operator. Spinning and supplemental reserves were also provided by a large fraction of the sampled capacity. Regulation was provided by the smallest subset of the sampled fleet. Provision of spinning reserve by hydropower units trended upward in recent years, which could be a result of increasing penetration of solar and wind in ISO-NE. A black start was provided by only a small fraction of the fleet, and that fraction decreased significantly after 2013, mainly because of a revision of NERC standards.

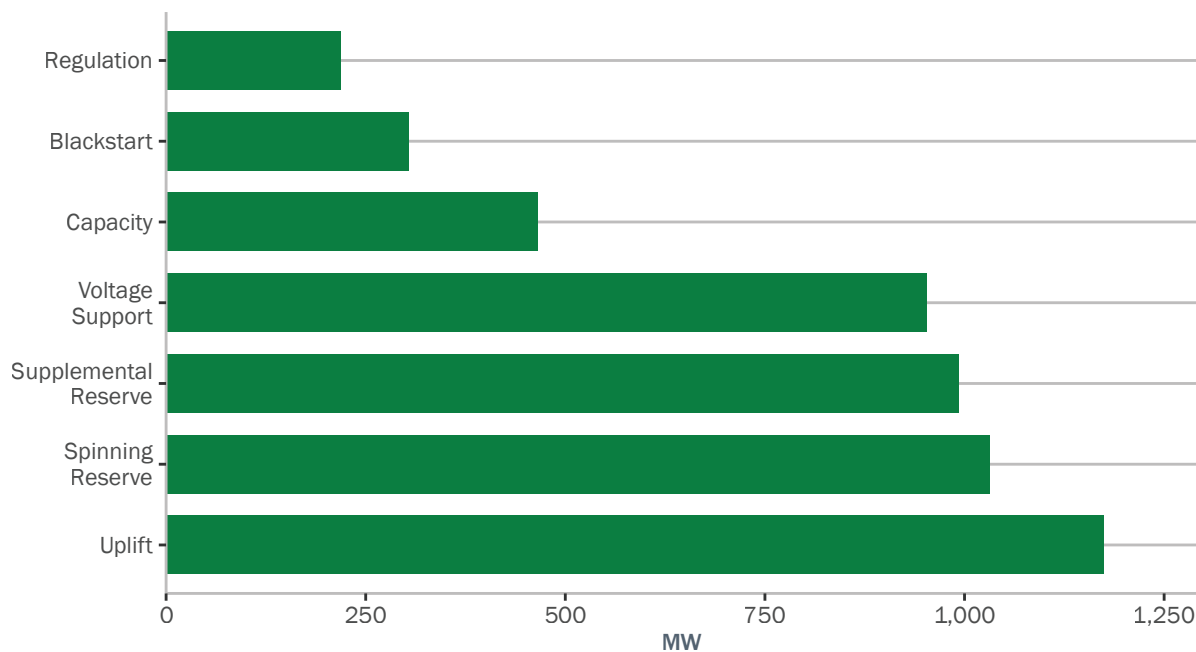


Figure 53. Relative sizes of ISO-NE hydropower fleet providing selected grid services (2008–2017)

Source: FERC Electric Quarterly Report

Note: Total capacity analyzed was 1,386 MW (approximately 75% of hydropower capacity, excluding PSH, in ISO-NE)

In PJM and CAISO, the shares of frequency regulation and some reserve products provided by hydropower are much higher than the share of installed capacity.

In its annual State of the Market Report, PJM provides technology-specific information about ancillary service provision. Regulation and reserve products in that market are important sources of flexibility to maintain grid reliability. As shown in Figure 54, regulation is mainly provided by natural gas and batteries with their shares fluctuating in recent years because of changes in regulation signal and related market design. Hydropower’s share is relatively stable (15%–20%) and much higher than its share of installed capacity in that market (<5%).

Hydropower also contributes to the supply of most of PJM’s reserve products. Primary reserve must be able to convert into energy within 10 minutes and it is supplied by a mixture of synchronized (i.e., online) units (Tier 1 and Tier 2) and non-synchronized (i.e., offline) units. Secondary reserve must be available within 30 minutes. Hydropower provides Tier 2 synchronized primary reserve, non-synchronized primary reserve, and day-ahead scheduling (secondary) reserve.⁸⁴ For both non-synchronized reserve and day-ahead scheduling reserve, hydropower supplied a larger percentage of the product in 2014–2019 than the percentage of installed capacity it represents in the PJM region.⁸⁵ However, Figure 54 shows that the hydropower share for these two types of reserves has decreased sharply in recent years.

⁸⁴ From 2013 to 2018, hydropower units were excluded from Tier 1 primary reserve provision. Tier 1 synchronized reserve resources are online units that follow economic dispatch and are only partially loaded. They must be able to increase output within 10 minutes following PJM dispatcher request to an event.

⁸⁵ In 2018, hydropower and PSH contributed 7.5% of cleared Tier 2 synchronized primary reserve. In 2019, run of river hydropower and PSH provided 6.8% and 5.4% of Tier 1 and Tier 2 synchronized primary reserve. Hydropower and PSH percentages for those products were not specified in earlier editions of the PJM State of the Market Report.

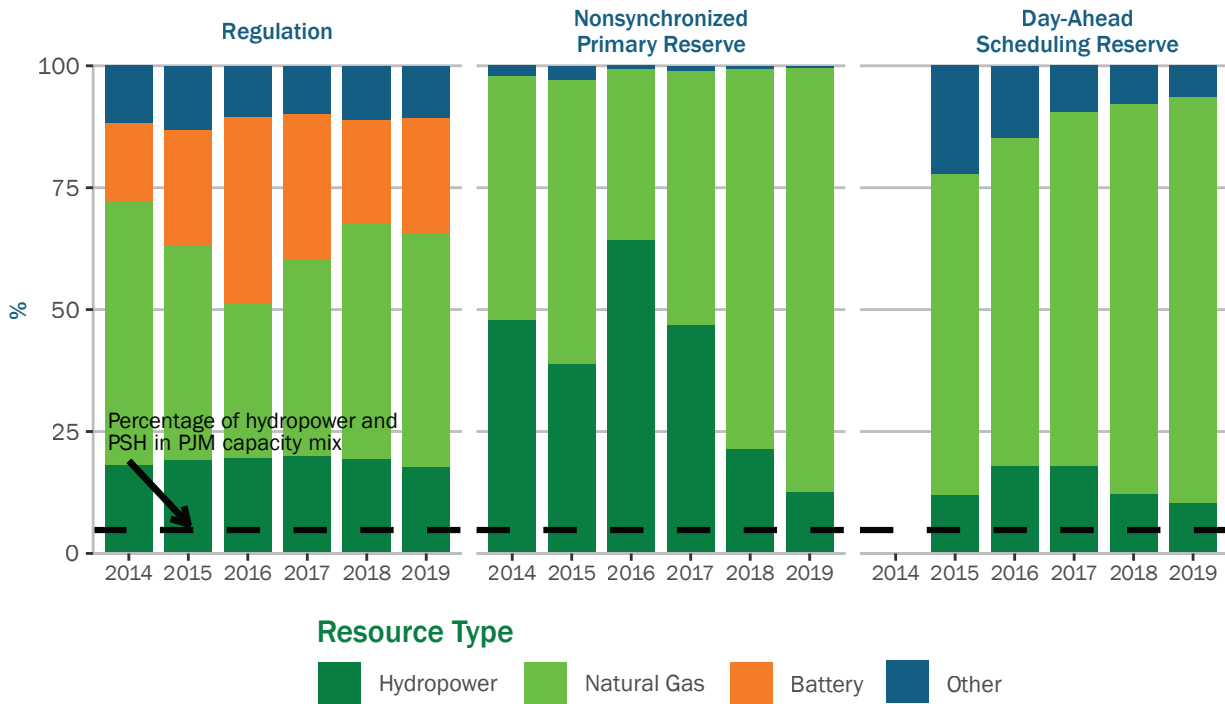


Figure 54. PJM ancillary service provision by hydropower and other resource types (2014–2019)

Source: PJM State of the Market Report (2014, 2015, 2016, 2017, 2018, 2019). https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml

Note: Natural gas includes the contribution from combustion turbines and combined cycles; however, it should be noted that a small portion of the fuel used by (dual-fired) combustion turbines is diesel.

CAISO is a leading market in decarbonization and solar development. Trends in the provision of ancillary services from hydropower in that market could be a leading indicator of the operation of hydropower in the future grid in other regions. For instance, Shan et al. (2020) show that the small hydropower fleet in CAISO has provided flexibility to facilitate solar development. Figure 55 summarizes the market share of hydropower in the provision of four ancillary services in the CAISO market—regulation up, regulation down, spinning reserve, and non-spinning reserve—for 2014–2019.⁸⁶ As seen in Figure 38, much of California was under drought conditions in 2014–2015 (and part of 2016) which resulted in low hydropower generation in those years. The low hydropower generation volumes in 2014 and 2015 accounted for the low provision of regulation down service. However, regulation up and spinning reserve were not affected by drought conditions. Except for regulation down in 2015, hydropower (including PSH) provided more than its share of capacity in regulation and spinning reserve. For spinning reserve, hydropower offered more than 50% in three out of the four years examined. Natural gas and imports have been the other main resource types providing ancillary services in CAISO. Additionally, batteries are serving increasingly larger fractions of the regulation requirements of the California market.

⁸⁶ Spinning reserve is standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy within 10 minutes when dispatched. Non-spinning reserve is capacity that can be synchronized to the grid and ramped to a specified load within 10 minutes.

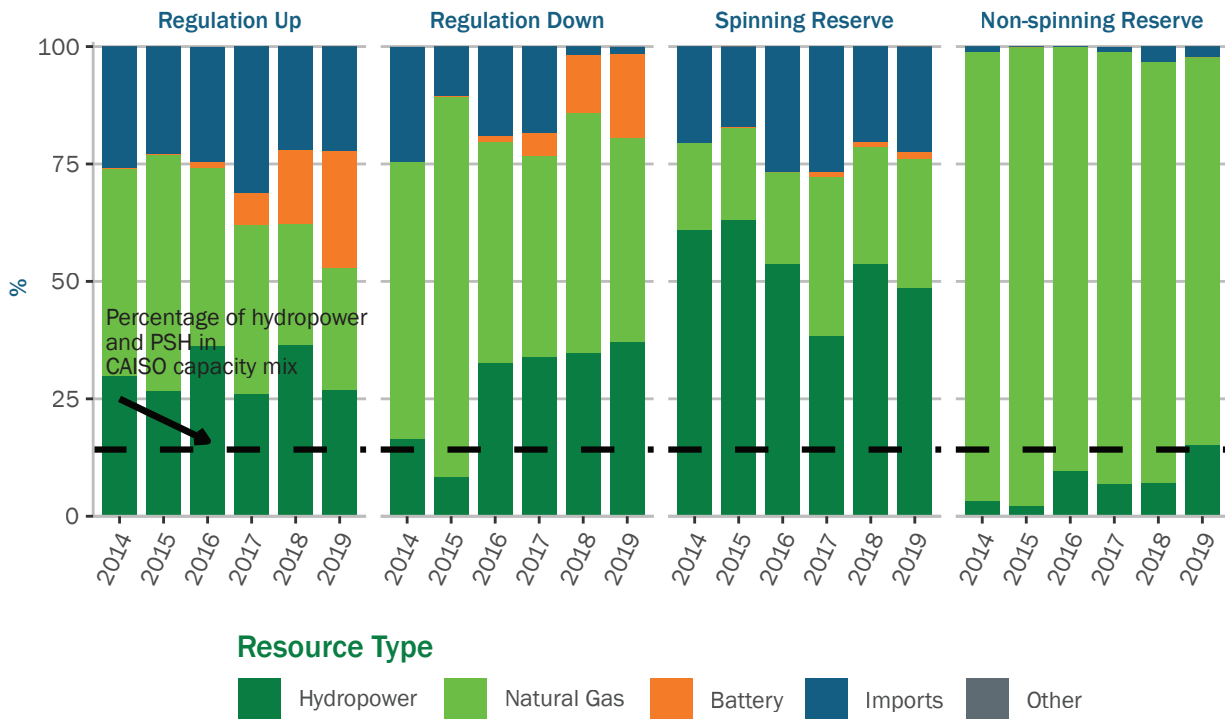


Figure 55. CAISO ancillary service provision by hydropower and other resource types (2014–2019)

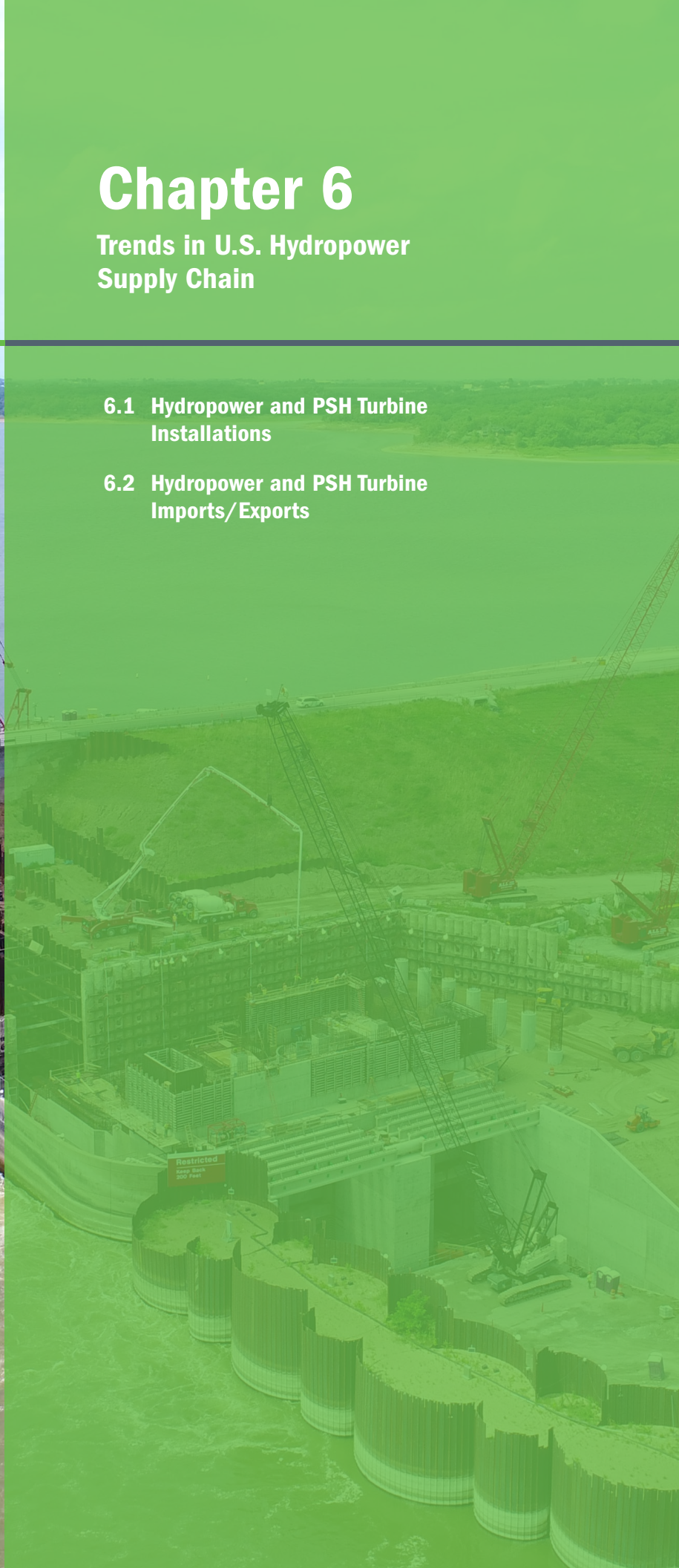
Source: CAISO Annual Report on Market Issues and Performance (2016, 2017, 2018, 2019) <http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx>

Chapter 6

Trends in U.S. Hydropower Supply Chain

6.1 Hydropower and PSH Turbine Installations

6.2 Hydropower and PSH Turbine Imports/Exports



6. Trends in U.S. Hydropower Supply Chain

Based on survey data, Keyser and Tegen (2019) report that the hydropower industry employed 66,500 workers in 2018. More than half of the employees (53%) worked in the manufacturing and utilities sector. At least one third of survey participants in each of six sectors across the hydropower industry—construction, manufacturing, trade and transportation, professional and business services, utilities, other service sectors—reported experiencing difficulty when hiring new employees. Because approximately one quarter of the U.S. hydropower workforce will reach retirement age in the next decade, hydropower-focused training programs and knowledge transfer systems are crucial. However, transferring skills is not only occurring across generations but also across sectors. The set of resources and skills needed to operate and maintain the existing fleet and build new facilities is evolving. Examples of innovation in the hydropower industry include the materials and techniques used to manufacture hydropower plant components and new plant operation and maintenance (O&M) paradigms that rely on automation and advanced data analytics.

For instance, new composite materials and coatings are being tested in turbine runner manufacturing, and several research institutions and companies are using additive manufacturing to produce standardized and modular turbine-generator units to decrease the cost of developing low-head sites. Other turbine designs bring construction costs down by limiting the need for submerged civil works.

Regarding digitalization, as shown in Section 1.3, many plant owners have been investing in digital governors and control upgrades. Digital governors allow for the precise control of flow and operations required to meet increasingly stringent flow-related license requirements and provide grid services. To control O&M costs, there has also been a trend toward automation and substitution of remote control from centralized dispatch rooms for on-site operators. Additionally, all major turbine original equipment manufacturers offer Industrial Internet of Things platforms with sensors collecting real-time, continuous data on temperature, vibration, pressure, or even sound anomalies and machine learning software that turns the data into insights to inform O&M decisions.⁸⁷

This section focuses on one component of the supply chain: turbine manufacturing. It discusses trends in domestic turbine installations with details on the market shares of different manufacturers and turbine types. It also presents trends in the imports and exports of turbines and turbine parts.

6.1 Hydropower and PSH Turbine Installations

Almost 12 GW of hydropower turbine capacity has been installed in the United States since 2010. Seventy-nine percent of the 291 turbine installations went toward R&U of existing hydropower facilities and represented 96% of the turbine capacity installed. Five companies manufactured 92 turbines with capacities greater than 30 MW, and more than a dozen companies served the demand for smaller turbines.

In 2017–2019, at least 67 turbine units were installed in the United States (roughly 3 GW of combined capacity).⁸⁸ Only 97.3 MW of the 2017–2019 installations took place at newly constructed facilities. Over the past five years (2015–2019), Consumers Energy, an investor-owned utility, was responsible for 41% of the replaced turbine capacity in the United States as a result of the extensive upgrade of the Ludington PSH facility. With one unit replaced every year during the past five years, the total capacity of the new Ludington units is 1.8 GW. The upgrades to Ludington's PSH units will have a total cost of \$800 million and extend the life of the facility for another 40 years.⁸⁹

87 <https://www.powermag.com/iiot-and-the-future-of-hydropower/>

88 Data on turbine replacements come from IIR. The IIR dataset primarily tracks turbine R&U at medium and large plants owned by federal agencies, utilities, and wholesale power marketers.

89 <https://energynews.us/2018/09/24/midwest/michigan-utilities-upgrade-pumped-storage-plant-ahead-of-renewable-push/>

Figure 56 shows 16,334 MW of hydropower turbine installations in the United States from 2007 to 2019 disaggregated by turbine manufacturer. For turbine R&U projects to be included here as a turbine installation, they must involve replacement of the turbine runners.⁹⁰

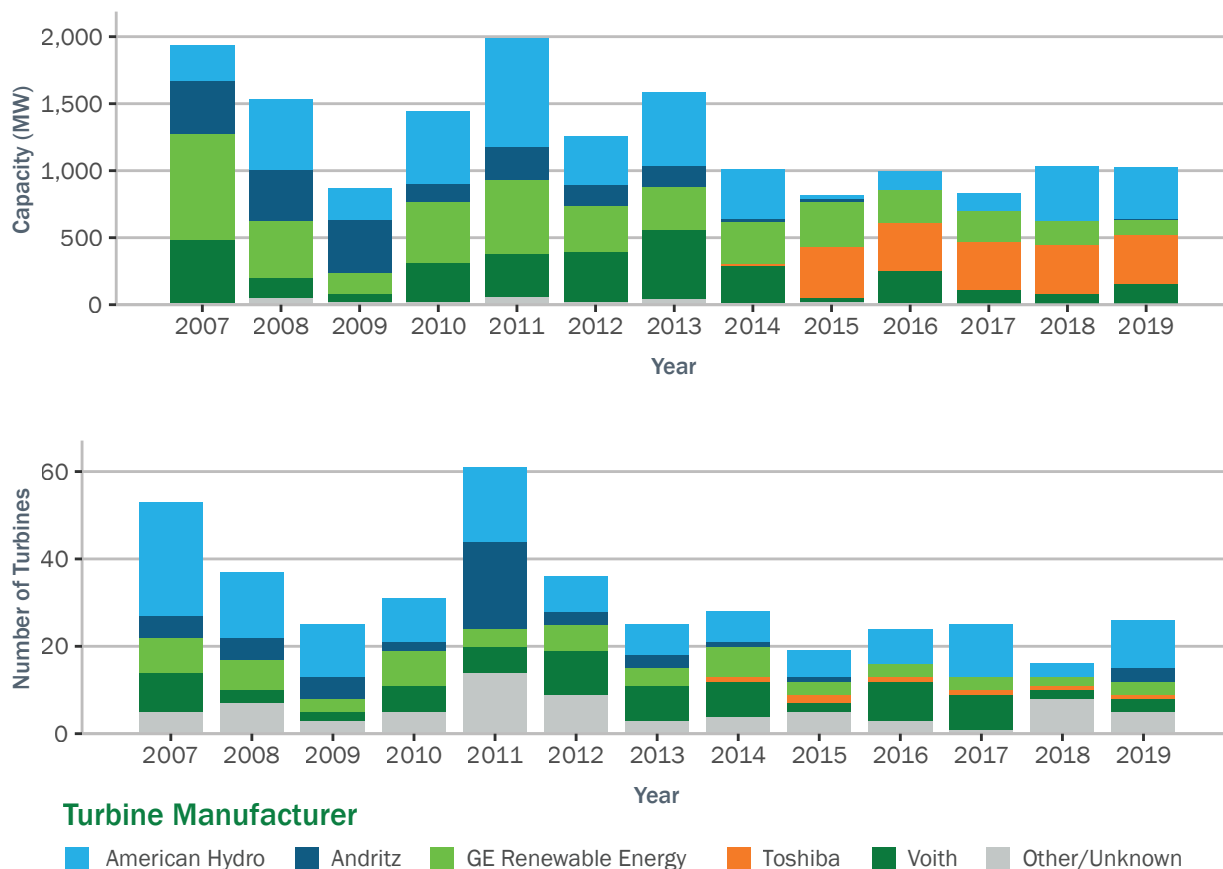


Figure 56. Annual installations of hydropower and PSH turbines in the United States by manufacturer

Source: IIR, Existing Hydropower Assets dataset, personal communication with Debbie Mursch (GE Renewable Energy), personal communication with Gerry Russell (American Hydro).

Note: The manufacturers in the plot are the major industry participants resulting from multiple merger and acquisition operations during 2007–2019. The plot covers new turbines and turbine R&U whose scope includes turbine runner replacement.

The number of turbine installations ranges from 19 in 2015 to 61 in 2011. Fourteen (5%) are PSH turbines and account for 33% of installed capacity. Sixty-two (21%) of the turbine units installed in the past 10 years were for newly constructed facilities, and the remaining were unit additions, replacements, or upgrades at existing plants. The average capacity of new plant turbine installations since 2010 was 7 MW with a median size of 1 MW. For turbine installations at existing facilities, the average and median turbine capacities were 50 MW and 16 MW, respectively.

Within the category of turbine R&U, the federal fleet accounts for 17% (73) of units and 27% of capacity in 2010–2019, but only 18% of those turbine upgrades occurred in the last three years of the decade. The remainder of the turbine R&U activity was distributed between the public, nonfederal fleet (24% of units) and privately-owned plants (59% of units).

90 Even though they do not cover the exact same period, Figure 2 and Figure 56 are complementary. The former shows capacity additions resulting from construction of new projects or R&U of existing turbines; the latter shows the nameplate capacity of new turbines and turbines undergoing extensive R&U that involves runner replacement. Most of the capacity shown in Figure 56 is being replaced rather than added.

American Hydro, Andritz, GE Renewable Energy, Voith, and Toshiba supplied 80% of the units installed in the United States since 2010, and they accounted for 98.2% of installed capacity. The median capacity of turbines installed by these companies in the United States during this period is 21.5 MW. American Hydro manufactured 31% of the turbine units installed during 2010–2019, and these units accounted for 31% of installed capacity. Voith, GE Renewable Energy, and Andritz had the next largest market shares by number of units (21% Voith, 15% GE Renewable Energy, and 11% Andritz). The average capacity per unit installed was significantly greater for GE Renewable Energy’s units (72 MW) than for the rest of manufacturers, except Toshiba. Toshiba held a very small market share by number of units (2%), but those seven units represented 15% of installed capacity due to the large size of Ludington’s units (362 MW each).

Three of the five major turbine manufacturers shown in Figure 56, have manufacturing facilities in the United States: Voith in York, Pennsylvania; American Hydro in York, Pennsylvania; Andritz in Spokane, Washington. GE Renewable Energy is the only one headquartered in the United States, but GE Renewable Energy’s manufacturing of hydropower turbines for the North American market is located in Sorel-Tracy, Canada. Finally, both of Toshiba’s hydraulic turbine manufacturing facilities are in Asia, one in China and the other in Japan.

The median capacity of the 57 turbines in the “Other/Unknown” project manufacturer category installed in the past decade is 3.6 MW. Fourteen different companies manufactured the 39 units within the “Other/Unknown” category for which information was available. This large number of companies reflects the stronger competition that exists in the small turbine industry segment. Some of these manufacturers are U.S. companies (e.g., Canyon Hydro, Cornell, SOAR, Kiser), and the others are headquartered in Canada, Europe, or Asia.

Figure 57 shows the distribution of turbine installations among the three main types of hydraulic turbines: Francis, Kaplan, and Pelton. Francis is the most common turbine type (56% of units installed in 2010–2019), and every major turbine manufacturer installed Francis units for the U.S. hydropower fleet during this period. American Hydro and GE Renewable Energy were the two companies that manufactured the largest number of Francis units for the U.S. market during this period; American Hydro manufactured 67 units and GE Renewable Energy manufactured 31 units. Fifteen of the 32 installed turbines with capacities greater than 100 MW were Francis units. Kaplan was the second most common type of turbine installed in recent years (35% of units installed in 2010–2019). Voith has captured the largest market share (42%) for this turbine type, followed by Andritz (24%). Pelton units are typically used in high-head settings, and only 11 have been installed since 2010 with a total capacity of 109 MW. More than 99% of the turbine capacity in the “Other/Unknown” category corresponds to seven PSH pump turbine units.⁹¹

91 For the remaining 7 PSH units, turbine type is categorized as Francis.

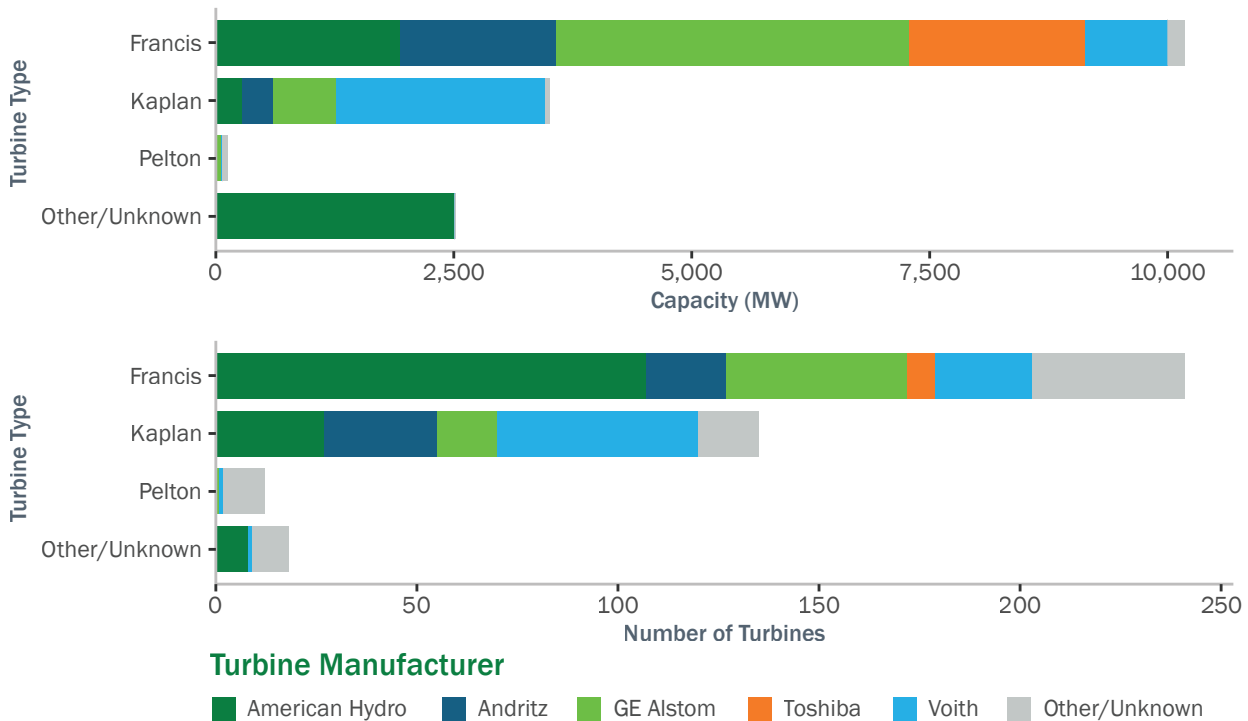


Figure 57. Installed hydropower and PSH turbines in the United States by type and manufacturer (2007-2019)

Source: IIR, Existing Hydropower Assets dataset, personal communication with Debbie Mursch (GE Renewable Energy), personal communication with Gerry Russell (American Hydro).

Note: The plot covers new turbines and turbine R&U whose scope includes turbine runner replacement.

The distribution of turbine types installed in the past decade is significantly different for installations at new plants vs. unit replacements. For unit replacements, 62% of the units were Francis, and they represented 60 % of capacity. Kaplan units also accounted for a substantial share of unit replacements (32%). For new projects, the most common turbine type is Kaplan. Since 2010, 316 MW or 72% of installed turbine capacity at new plants have been Kaplan units. By capacity, the predominant type of new project is the addition of hydropower equipment to low-head (up to 20 m), NPDs, and Kaplan is typically the preferred turbine type for low-head sites. Francis turbines account for 96 MW and 32% of new plant installations since 2010. For Pelton units, six of the 11 installations in the past decade were small units in new projects in the Northwest region.

Apart from the increases in efficiency and availability that result from upgrading to state-of-the-art turbines, project owners also pursue improvements in operational flexibility and environmental performance in their turbine replacement decisions. An example of increased flexibility is the ability of the new units in Ludington PSH to run in pumping mode for a wider range of elevations of its upper reservoir. As for examples of improvements in environmental performance:

- » the new turbines for the High Rock hydropower plant in North Carolina and Center Hill hydropower plant in Tennessee have aeration capabilities that help address water quality issues related to dissolved oxygen content,
- » the new turbine runners at Chelan PUD's Rock Island in Washington feature four blades instead of six, one type of design change to reduce the probability of fish strike,
- » Voith used the Pacific Northwest National Laboratory's Biological Performance Assessment Tool to assess geometries and shapes to incorporate fish-friendly design points into the new turbines at USACE's Ice Harbor in Washington. In 2019, studies with live fish and the Sensor Fish confirmed the fixed blade turbine in unit 2 at Ice Harbor significantly reduced risk to fish from pressure changes and blade strike injuries by overall improvements in hydraulic conditions, relative to the baseline conditions measured at the dam before the turbine replacement.⁹²

6.2 Hydropower and PSH Turbine Imports/Exports

For 2015–2019, the U.S. hydraulic turbine trade balance was very close to zero (\$279 million imports and \$263 million exports). In the past five years, the top three countries from which the United States imported turbines and turbine parts were China, Canada, and Brazil—the countries with the three largest hydropower fleets in the world. Canada and Mexico were the two top countries to which the United States exports turbines and turbine parts; they accounted for 51% of exports in 2015–2019.

Turbines are the only piece of equipment for which the current Harmonized Tariff Schedule of the United States trade classification is granular enough to identify trade flows in the hydropower industry.⁹³ Some turbine-generator sets (“water-to-wire” packages) used in small hydropower plants, as well as other products such as certain pump-turbines, are not included in Figure 58 because the Harmonized Tariff Schedule does not have a hydropower-specific statistical reporting number for turbine-generator sets.

92 The Sensor Fish is a small autonomous device whose sensors measure the conditions, such as acceleration, pressure, and rotational velocity, experienced by fish as they pass through a dam.

93 Hydraulic turbine trade data were queried through the Interactive Tariff and Trade Data Web (<https://dataweb.usitc.gov>) maintained by the U.S. International Trade Commission, which compiles import and export statistics from the U.S. Department of Commerce, as well as tariff information. The values presented in Figure 58 are “Customs Value,” which exclude any shipping or duty costs. They include the values from Harmonized Tariff Schedule subheadings 8410.11 (hydraulic turbines with capacity less than or equal to 1 MW), 8410.12 (hydraulic turbines with capacity greater than 1 MW but less than or equal to 10 MW), 8410.13 (hydraulic turbines with capacity greater than 10 MW), and 8410.90 (hydraulic turbine parts and regulators) for “U.S. General Imports” and “U.S. Total Exports.”

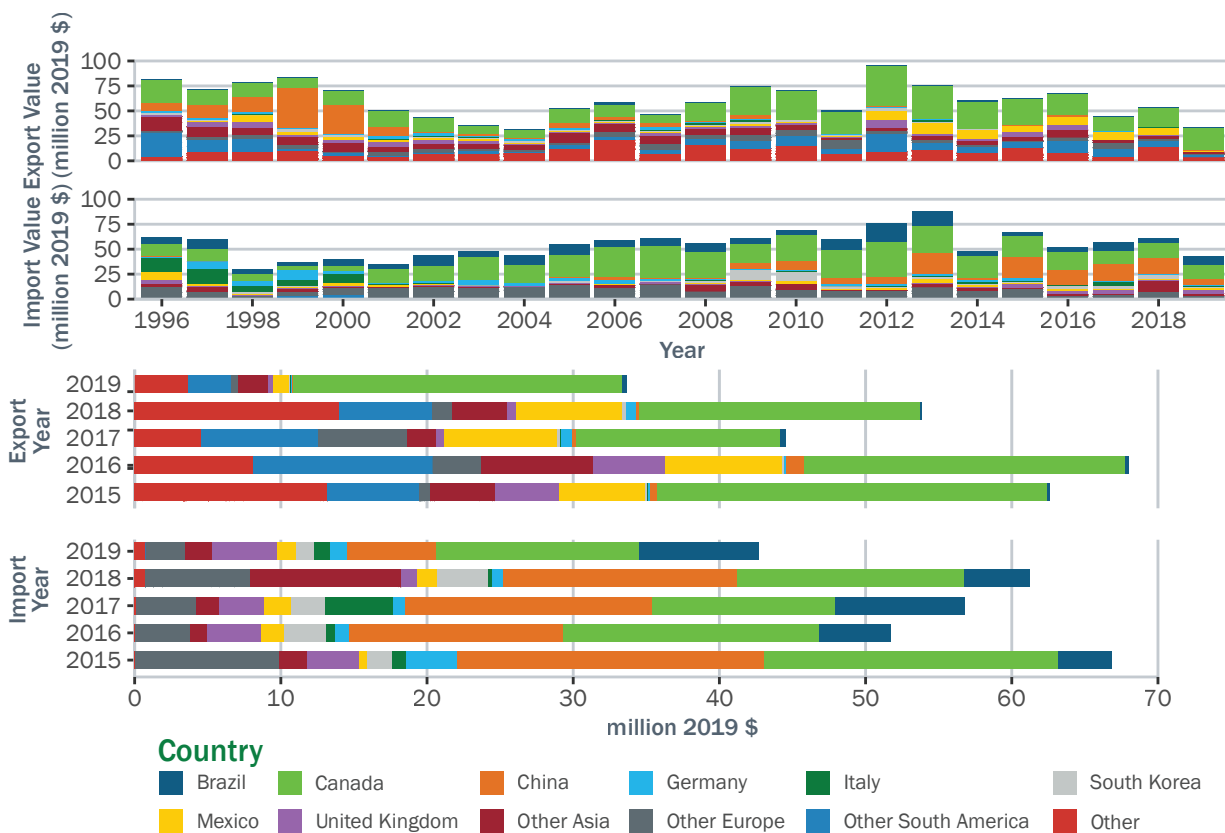


Figure 58. U.S. hydropower and PSH turbine/turbine parts import and export values by country

Source: U.S. International Trade Commission

Note: The 2019 data are preliminary and could be subject to revision by the U.S. Department of Commerce.

Figure 58 shows that trade flows in 2018 were close to the average values of the past two decades, but imports and exports of hydraulic turbines and parts experienced a strong decline in 2019. The value of exports in 2019 (\$33.7 million) is the second lowest in the past 24 years, after 2004. As for turbine imports, their value in 2019 (\$42.6 million) was the lowest since 2001.

Canada was the largest trade partner for imports and exports in 2019. Two thirds of U.S. turbine exports in 2019 went to Canada, and one third of all U.S. imports came from Canada. On the other hand, exports to Mexico, which had averaged more than \$5 million per year since 2012, dwindled to just \$1 million in 2019. The decline in turbine exports to Mexico in 2019 is not representative of the broader trade relationship between the two countries. In 2019, U.S. Census data show that the total value of trade between the United States and Mexico increased and, for the first time, Mexico was the top trading partner to the United States.

The value of imports from China in 2019 was less than half the value in any of the previous four years. This drop might be partly due to the 25% ad valorem tariff imposed by the United States in June 2018 to a list of products imported from China that included the Harmonized Tariff Schedule product codes in Figure 58. Separately, the 25% tariff applied to foreign steel in March 2018 also increased the cost of most turbines manufactured in the United States to the extent they use imported steel as their raw material.⁹⁴

⁹⁴ The initial steel tariff announced in March 2018 excluded imports from Canada and Mexico. The tariff was extended to those two countries in June of the same year and lifted after negotiations in May 2019.

For turbines and turbine parts, the trade balance for the United States over the period covered in Figure 58 is positive (\$144 million). However, the largest positive balances occurred in the earliest years of the period. In 2015–2019, the trade balance was very close to zero (\$279 million imports and \$263 million exports). The top destinations for hydraulic turbines exported from the United States in the past five years have been Canada and Mexico; they accounted for 51% of U.S. turbine exports. The three top countries from which the United States imported turbines and turbine parts in the past five years were China, Canada, and Brazil.⁹⁵ China, Brazil, and Canada also have the three largest hydropower fleets in the world. The overlap between major exporters of hydropower turbines to the United States and largest hydropower fleets shows that, in the hydropower industry, manufacturing facilities tend to be sited in countries with large volumes of installed capacity. For large turbines especially, the logistics of shipping are complex and expensive, which incentivizes companies to locate their manufacturing plants close to the largest markets for their products.

⁹⁵ The only variation to this top three during that period occurred in 2018 when the third largest import value originated in “Other Asia,” driven by imports from Japan.

Chapter 7

Overview of New Policies Influencing
the U.S. Hydropower Market



7. Overview of New Policies Influencing the U.S. Hydropower Market

This chapter discusses policy changes that occurred in the past three years (2017–2019) that modified the permitting processes for hydropower or / and the incentives available for developers seeking to build new hydropower or PSH. FERC’s revised policy on license terms, the American Water Infrastructure Act (AWIA) of 2018, and the U.S. Environmental Protection Agency’s proposed new rules on the Section 401 water quality certification process aim to improve the efficiency of the federal hydropower authorization process. FERC’s proposal to modernize PURPA might affect the ability of new small hydropower projects to secure PPAs. Finally, states are committing to increasingly ambitious renewable or clean energy mandates and energy storage targets that could help spur investment in new hydropower and PSH.

In October 2017, FERC announced a revised policy on license terms (for both original licenses and relicenses) in which the default term became 40 years.

Until then, FERC’s decisions on relicense term depended primarily on the amount of investment required in the relicense for redevelopment, new construction, new capacity, or environmental mitigation or enhancement. Relicense duration was 30 years for cases in which minimal investment was required, 40 years if the required investment was moderate, and 50 years if the required investment was extensive.

The aim of the new default term policy is to provide more certainty to process participants, reduce administrative costs as a result of the lower average relicensing frequency, and offer licensees more time for recouping the costs of any investments they make in the project. Under the new policy, FERC can still issue longer or shorter licenses if needed to coordinate license terms for projects within the same river basin or supported by a settlement agreement. Moreover, a longer license term can be granted if the relicense requires extensive new measures or the licensee already voluntarily implemented significant measures during the prior license term.

AWIA directed FERC to introduce an expedited licensing process—2 years from license application to final decision—for qualifying NPDs and closed-loop PSH projects. AWIA also introduced amendments to the qualifying conduit authorization pathway and allows FERC to extend preliminary permits and construction start timelines for longer periods.

AWIA has introduced innovations spanning various stages of the federal hydropower authorization process and several project types. For project developers conducting feasibility studies, AWIA extends the duration of their option to start the licensing process by increasing the term of preliminary permits from three to four years.⁹⁶ Additionally, if the developer requests a preliminary permit extension, then FERC can grant an additional four years; before AWIA, a permit extension was only for two years.⁹⁷ For licensees in the preconstruction stage, AWIA grants FERC the authority to extend the construction start timeline for up to eight years. Before AWIA, FERC could only grant a two-year extension over the default two-year period set in the license terms.⁹⁸

For the qualifying conduit determination process—introduced by the Hydropower Regulatory Efficiency Act of 2013, which led to the addition of hydropower to dozens of nonfederal conduits—AWIA shortens the maximum wait period from the developer’s notice of intent submission to FERC’s final decision on whether the facility development can proceed from 60 to 45 days. It also increases the capacity limit of eligible qualifying conduits from 5 to 40 MW.

96 Holding a preliminary permit for a site gives developers the exclusive right to submit a FERC license application to develop it.

97 From enactment of AWIA in October 2018 until May 2020, four PSH project developers requested successive preliminary permits with three or four-year terms taking advantage of the changes in preliminary permit timeline authorized by AWIA. FERC issued the extensions for the term requested by the developer in each case. Additionally, upon requests from the permit holders, FERC issued an amendment to a two-year preliminary permit extension and reinstated an expired preliminary permit on the basis of the extended timelines authorized by AWIA.

98 From October 2018 to May 2020, 12 licensees requested extensions to the construction start deadline that benefit from the extended timeline authorized by AWIA.

AWIA also built upon FERC's 2017 policy statement on establishing license terms for hydroelectric projects. The law directs FERC, when issuing a new license under section 15 of the Federal Power Act, to take into consideration, among other things, project-related investments to be made by the licensee under a new license, as well as project-related investments made by a licensee over the term of the existing license (as long as they were not expressly considered as contributing to the length of the license term). To ensure that all of the licensee's project-related investments are treated equally when considering the license term length, AWIA requires FERC to give "equal weight" to these pre-relicensing and post-relicensing project-related investments. In addition, when requested by a licensee, FERC must make a determination within 60 days regarding whether proposed early investments meet the statutory definition.⁹⁹

AWIA also directed FERC to introduce an expedited licensing process for NPDs and closed-loop PSH projects. Only projects with low environmental impact can qualify for this process. NPDs must not alter the dam's preexisting storage, release, or flow operations, and closed-loop PSH must neither affect endangered species nor cause significant change to preexisting surface or groundwater flow. Under the expedited licensing process, which developers can request to use since July 2019, FERC must issue a final licensing decision no later than two years from license application submission. From July 2019 to the end of March 2020, only one license application eligible for the new process was submitted to FERC, and the developer did not request to use the expedited process.

In 2019 as part of AWIA's mandate, FERC published two reports with information that supports the development of federal NPDs and closed-loop PSH: a list of the 230 federal NPDs with the best development potential and a technical guidance document for developing closed-loop PSH at one of the hundreds of thousands of abandoned mines in the United States.^{100,101}

The stated aim of the rule update regarding scope and timeline for the Section 401 water quality certification process published by the Environmental Protection Agency in June 2020 is to increase transparency and efficiency in this portion of the FERC licensing process.

In August 2019, the Environmental Protection Agency published a Notice of Proposed Rulemaking (NOPR) that updates and clarifies several provisions of Section 401 of the Clean Water Act, the legislation that requires FERC hydropower license applicants to request a water quality certification (WQC) from the relevant certifying authority (i.e., a state or tribal agency). NOPR aims to eliminate ambiguities regarding the scope of Section 401 review, conditions that can be included in a WQC, and the amount of time available for a certifying authority to act on a WQC request. This NOPR received extensive comments from all sector involved in the WQC process and the Environmental Protection Agency finalized the rule on June 1, 2020.

The NOPR limits the scope of Section 401 to ensure that discharge from a federally licensed project to navigable waters complies with federal and state water quality requirements.¹⁰² It also offers a detailed description of the necessary content of a valid WQC request and the criteria to determine the beginning and end dates for the certifying authority to act on the request. The Environmental Protection Agency states that the reasonable time period for action by the certifying authority should be set by the federal agency in charge of licensing the project and can be no longer than one year. For hydropower licensing, FERC has considered the reasonable time period to be the full year. To improve process efficiency, the Environmental Protection Agency encourages the early coordination of information needs among FERC, the state agency, and the project applicant. Within the reasonable time period, the certifying authority can take four actions: 1) issue a WQC with a finding of compliance, 2) issue a WQC with conditions for compliance, 3) deny the WQC, or 4) waive the certification requirement. NOPR explicitly forbids the certifying authority to ask applicants to withdraw and resubmit a WQC request to reset the start of the review period.

99 The AWIA definition of project-related investments include investments that resulted in redevelopment, new construction, new capacity, efficiency, modernization, rehabilitation or replacement of major equipment, safety improvements, or environmental, recreation, or other protection, mitigation, or enhancement measures conducted over the term of the existing license.

100 <https://www.ferc.gov/industries/hydropower/gen-info/guidelines/10-17-19-notice.pdf>

101 <https://www.ferc.gov/industries/hydropower/gen-info/guidelines/hydro-development-guide.pdf>

102 Examples of conditions included in past WQCs that would not fit into this scope definition are constructing trails, providing fishing access, and paying the certifying authority for environmental improvements or enhancements unrelated to the project being certified.

Recent modifications to PURPA implementation could reduce the number of hydropower projects eligible to receive avoided cost rates from utilities and increase energy price risk for hydropower developers and owners entering new PURPA contracts.

As of 2019, under PURPA, utilities were mandated to purchase the output from hydropower projects under 20 MW in ISO/RTO regions (under 80 MW elsewhere) at avoided cost rates.¹⁰³ There was already significant variation in the approaches used to compute avoided cost rates in each state. In recent years, utilities increasingly argued that offering a long-term guaranteed rate to new renewables had become too expensive and risky for them. On the other hand, renewable energy developers caution that a lack of guaranteed rates would make projects riskier and project financing more difficult to obtain.

In July 2020, FERC issued Order 872 to update PURPA regulations.¹⁰⁴ First, the new regulation gives states additional flexibility in how they compute avoided cost rates by allowing them to index the energy rates in PURPA contracts to the locational marginal prices of ISO/RTO areas, wholesale prices in liquid trading hubs, or natural gas prices. Any of these approaches would result in variable energy rates that increase revenue risk for the developer relative to the fixed, long-term rates they have received previously. On the other hand, capacity rates would remain fixed, which is important for projects to obtain the long-term financing needed to construct new projects. However, avoided cost rates might not include a capacity component if the utility can show that it does not need additional capacity to meet its forecasted load. Competitive solicitations (e.g., requests for proposals) would also be allowable methods for setting energy and capacity rates under the new rules.

Second, Order 872 reduces the capacity limit for which utilities in ISO/RTO areas can argue that a new renewable facility has nondiscriminatory access to a competitive market from 20 to 5 MW. Qualified facilities above 5 MW can rebut the presumption that they have nondiscriminatory access. In comments on the NOPR that preceded this order, hydropower stakeholders asked for the 20 MW limit to be maintained for hydropower as is done for cogeneration plants, but this request was not approved in the final rule. Commenters argued that PURPA is comparatively a more important incentive for hydropower than other renewables because of differences in eligibility for federal tax credits and meeting RPS targets.¹⁰⁵ They also argued that hydropower developers or owners—particularly in conduit and NPD projects—might not have the necessary in-depth knowledge of energy markets necessary for the direct participation in ISO/RTO markets because their primary business has been irrigation, flood control, or other purposes the dam or conduit is meant to fulfill.¹⁰⁶

Third, the “one-mile” rule has also been modified by Order 872. Until now, the capacity of renewables using the same energy source, developed by the same entity, and located within 1 mile of each other was added up as a single facility for determining their eligibility as qualifying facilities under PURPA. The new rule establishes a rebuttable presumption that facilities located within 1–10 miles of each other that are owned by the same developer or use the same funding arrangement are separate facilities for the purpose of PURPA eligibility. This new rebuttable presumption might come into play in the negotiation of PURPA contracts for hydropower projects in which various small facilities owned by affiliates of the same parent company might surpass the size limit if they are considered a single project for PURPA purposes.

103 In ISO/RTO regions, utilities could avoid the mandatory purchase requirement if they could successfully argue that the small hydropower developer had non-discriminatory access to the sell electricity directly in the wholesale market.

104 A bill proposing similar thrusts of PURPA reform has been introduced in the House of Representatives (H.R. 1502 PURPA Modernization Act of 2019).

105 The federal production tax credit rate for qualifying hydropower projects has been half of the rate for wind and geothermal. Hydropower eligibility for the production tax credit or investment tax credit ended in 2017, but other renewables continued being eligible for those incentives past that date. However, the Tax Extender and Disaster Relief Act of 2019, passed into law in December 2019, extended hydropower eligibility through the end of 2020, with 2018 and 2019 included retroactively.

106 Comments of the National Hydropower Association, IdaHydro, New England Hydropower Company, and New England Small Hydro Coalition in response to the FERC NOPR.

Since 2018, at least nine states have increased their renewable energy targets, and seven states have set a 100% renewable or clean energy mandate. Hydropower is limited in its eligibility to meet RPS targets in most states, but it typically counts toward clean energy mandates.

Thirty states and Washington D.C. have RPSs as of the end of 2019. For 13 states, the RPS targets extend to 2030 or later with renewables requirements ranging from 35% (Massachusetts) to 100% (Hawaii) of retail electricity sales. Most RPSs contain eligibility restrictions for hydropower based on project capacity, project type, owner type, or in-service date. Stori (2020) presents a detailed account of hydropower RPS eligibility limits.

Caps on project capacity or project type aim to limit environmental impact. For instance, several RPSs restrict eligibility to run-of-river hydropower and exclude hydropower projects that require new impoundments. Capacity expansion, efficiency improvement, and other upgrades to existing hydropower plants are also eligible for RPS in some states if they do not entail significant construction and environmental impacts. However, capacity and project type are not necessarily accurate descriptors of the environmental impact. For that reason, other states require explicit environmental criteria to be met in order for a hydropower project to be eligible. Four states (i.e., Massachusetts, New Jersey, Oregon, Pennsylvania) require a hydropower facility to be certified by the Low Impact Hydropower Institute or meet similar environmental standards as one of the components for RPS eligibility.

Since the beginning of 2018, at least nine states (plus Washington, D.C.) have increased their RPS targets, and Virginia changed its previously voluntary goal to an RPS mandate in March 2020.¹⁰⁷ There have also been some changes in hydropower eligibility criteria. In 2017, Ohio House Bill 49 clarified that small hydropower facilities less than 6 MW were an eligible resource. In 2018, Connecticut Senate Bill 9 made run-of-river hydropower facilities licensed after January 1, 2018 an eligible Class 1 energy source. In 2019, Nevada Senate Bill 358 expanded the definition of renewable energy to include hydropower facilities larger than 30 MW that began operation before 1997 and whose energy is being purchased by a utility in the state through long-term contracts (with duration of 10 or more years) that were already in place when the bill was enacted into law.

In addition to RPS targets, seven states (i.e., California, Hawaii, Virginia, Maine, New Mexico, New York, Washington), as well as Washington D.C. and Puerto Rico, have set a 100% renewable or clean energy mandate, and five states (i.e., Connecticut, Colorado, Nevada, New Jersey, Wisconsin) have set 100% clean energy goals for no later than 2050. Massachusetts (Bill H.2836), Illinois (SB 2132), Maryland (HR 330), and Minnesota (HF 2208) are discussing legislation to set similar targets. Hydropower is typically eligible to meet clean energy targets.

¹⁰⁷ U.S. Renewables Portfolio Standards 2019 Annual Status Update, Lawrence Berkeley National Laboratory: https://eta-publications.lbl.gov/sites/default/files/rps_annual_status_update-2019_edition.pdf

Table 4 lists the target type and year for the 13 states (plus Washington D.C. and Puerto Rico) with a 100% clean or renewable energy mandate or goal as of March 2020. Figure 10 in Section 2.2 shows the most ambitious objective (RPS or clean energy mandate/target) in each state.

Table 4. U.S. Jurisdictions with 100% Renewable or Clean Energy Mandates or Goals

State	Target Year	Target Type	Policy Document
Rhode Island	2030	Renewable Energy Mandate	EO 20-01
Washington D.C.	2032	Renewable Energy Mandate	B22-0904
New York	2040	Clean Energy Mandate	S 6599
California	2045	Clean Energy Mandate	SB 100
Hawaii	2045	Renewable Energy Mandate	HB 623
New Mexico	2045	Clean Energy Mandate	SB 489
Washington	2045	Clean Energy Mandate	SB 5116
Maine	2050	Clean Energy Mandate	LD 1494
Puerto Rico	2050	Renewable Energy Mandate	PS 1121
Virginia	2050	Clean Energy Mandate	HB 1526
Connecticut	2040	Clean Energy Goal	EO 3
Colorado	2050	Clean Energy Goal	SB 19-236
New Jersey	2050	Clean Energy Goal	EO 28
Nevada	2050	Clean Energy Goal	SB 358
Wisconsin	2050	Clean Energy Goal	EO 38

Source: 2019 University of California, Los Angeles report *Progress Toward 100% Clean Energy in Cities and States*. <https://innovation.luskin.ucla.edu/wp-content/uploads/2019/11/100-Clean-Energy-Progress-Report-UCLA-2.pdf>.

Note: For states in which the mandate is set through legislation, only one of the two bills (House or Senate) is cited in the table.

Seven states have adopted energy storage targets, and many others are considering introducing them. PSH is typically eligible to meet those targets but, given target sizes and years, may be practically excluded (due to how storage targets are structured) in some states.

As the need for energy storage to maintain grid reliability with increasing penetration of variable renewables becomes more pressing, policy support for energy storage has increased, leading states to set mandates or targets for storage separate from their RPSs.¹⁰⁸ As early as 2013, the California Public Utilities Commission adopted a target of 1,325 MW of energy storage by 2020, and PSH under 50 MW was eligible to achieve it (D.13-10-040). By March 2020, seven states had adopted energy storage targets, and several others (i.e., Colorado, Illinois, Indiana, Minnesota, Missouri, New Mexico, Ohio, Vermont) are considering them.¹⁰⁹ To date, the approved targets typically do not exclude PSH, but some of the target levels (e.g., Oregon, Massachusetts) are very small compared with typical PSH projects capacity, suggesting a greater focus on short-term storage from batteries and other new storage technologies. Separate from the energy storage target, Massachusetts has also introduced a Clean Peak Energy Standard that compels electricity retailers to purchase a certain amount of clean peak energy certificates each year, leading to more peaking energy from clean resources. Energy storage systems, including PSH plants, are eligible as clean peak resources if they store and discharge clean energy most of the time.

108 PSH is explicitly eligible in 6 RPSs (although typically only to the extent that the energy used for pumping water to the upper reservoir is renewable) and explicitly excluded from seven RPSs (Stori, 2020)

109 In Virginia, the energy storage mandate is part of its broader Virginia Clean Economy Act, which also includes a 100% clean energy mandate.

Table 5 shows the seven states which have adopted energy storage targets, including target capacity, target year, and the supporting policy document. PSH is eligible to meet these targets, but with some limitations. The California target only allows PSH facilities with installed capacity no greater than 50 MW. In other states, the target year is too early, or the target size is too small, to make PSH a practicable option for compliance.

Table 5. Energy Storage Mandates/Targets as of March 2020

State	Target	Target Year	Target Type	Policy Document
California*	1,325 MW	2020	Mandate	D. 13-10-040
Oregon	5 MWh (for each utility serving more than 25,000 customers)	2020	Mandate	HB 2193
New Jersey	2,000 MW	2030	Target	Assembly No. 3723
New York	1,500 MW (aspirational goal of which 350 MW are mandated)	2025	Mandate	PSC CASE 18-E-0130
Massachusetts	1,000 MWh	2025	Target	H4857
Nevada	1,000 MW	2030	Target	Docket No. 17-07014
Virginia	3,100 MW	2035	Target	SB 851

*: PSH facilities with capacity greater than 50 MW are not eligible.

Some legislation and other state-level initiatives focus on PSH. Virginia enacted HB 1760 in 2017, which encourages PSH development in its coalfield region by authorizing utilities to obtain a rate adjustment clause for cost recovery if the PSH facility uses renewable energy for all or part of its pumping needs. Virginia also passed HB 2747 in 2019 to establish the Southwest Virginia Energy Research and Development Authority. One of the new authority's tasks is to support PSH development in Southwest Virginia. By the end of 2019, there were two PSH projects in the region for which FERC issued preliminary permits: Tazewell PSH (870 MW) in Tazewell County and Big Rock PSH (20 MW) in Buchanan County. Although not mandatory, Oregon filed a Senate Resolution (S.C.R.1) in 2019 to encourage regulators and utilities to develop closed-loop PSH projects. Oregon has two PSH projects in development. Swan Lake, which already has a FERC license, has a closed-loop configuration. The Owyhee PSH project, which is in the preliminary permit stage, is open loop. In March 2020, the California Public Utilities Commission approved a reference system portfolio as guidance for load-serving entities in developing their integrated resource plans. The approved portfolio calls for 973 MW of PSH or other long-duration storage, along with more than 8 GW of battery storage, by 2026. Because of the long development timeline for PSH, the two projects most likely to meet this long-duration storage goal (if load-serving entities in the state decided to pursue it) are Eagle Mountain PSH, which was licensed by FERC in 2014, and the Lake Elsinore PSH project, which has a pending license application with FERC. There are five other PSH projects in California at earlier stages of development.

Chapter 8

External Reviewer Recommendations Regarding Future Reports



8. External Reviewer Recommendations Regarding Future Reports

As in previous editions of the Hydropower Market Report, this document has benefitted from significant review and input from a diverse set of external reviewers. Not only have reviewers provided comments that improved the report, but they also posed questions that can inform the direction of future analyses.

Topics identified by external stakeholders for potential future analyses include:

- » Collecting and summarizing information on hydropower R&D trends to understand in more detail the main thrusts of innovation in plant equipment and what goals (e.g., cost reduction, environmental performance improvement) they are targeting.
- » Analysis of hydropower and PSH unit outage causes and their evolution over time for different fleet segments.
- » Assembling data to document changes in hydropower operation patterns (at the BA level) in response to increases in variable renewable penetration and changes in market design.
- » Developing a metric to summarize annual hydrologic conditions at national and regional levels to help interpret national average capacity factor trends.
- » Deeper examination of drivers and scope of U.S. hydropower and PSH R&U capital expenditure projects to determine the percentage of the expenditures directed towards capacity and/or energy increases vs. other objectives such as reduced O&M costs, life extension, civil infrastructure remediation, and environmental remediation.

Resources



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Glossary

Capacity addition – This category, as shown in Figure 2 and Figure ES-2, includes additions of new turbine-generator units to existing hydropower projects as well as upgrades to existing turbine-generator units that result in an increase in unit nameplate capacity

Conduit – Hydropower project where hydropower generation capability is added to an existing conduit (“any tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity” 18 CFR 4.30)

Plant downrate – Downward adjustment to the reported (to EIA Form 860) nameplate capacity of existing turbine-generator units or situations where a plant owner decides to retire some of its turbine-generator units but continues to operate the rest

New stream-reach development – Hydropower project where hydropower generation capability is added to previously undeveloped sites and waterways

Non-powered dam – Hydropower project where hydropower generation capability is added to an existing dam used solely for other purposes (e.g., flood control, navigation)

Plant refurbishment – Projects that involve modifications in turbine-generator units or other elements of a hydropower plant to extend the life of the facility and improve its performance but do not result in increased generating capacity or increased energy output.

Plant retirement – A plant retires when its owner decides to stop operating all of its turbine-generator units. Depending on the cause of the retirement (e.g., accident, safety concerns, economic reasons), the retirement might be temporary or permanent

Unit upgrade – A hydropower unit is upgraded when some or all of its components are modified in a way that results in increased generating capacity and/or increased energy output through improved efficiency.

Plant expansion – Addition of new turbine-generator units (in existing or new powerhouse) at existing hydropower project.

Appendix

Data Sources



Appendix: Data Sources

PSH Energy Storage Capacity

For each PSH plant, energy storage capacity is computed as the product of its generation capacity (MW) and its storage duration (i.e., the number of hours it takes to empty the maximum volume of water in its upper reservoir allocated to hydropower). Generation capacity information comes from ORNL's Existing Hydropower Assets dataset. For storage duration:

- » The Department of Energy Office of Electricity's Global Energy Storage Database contains information on storage duration for 17 U.S. PSH plants that account for 73.2% of installed capacity. In most cases, the database authors obtained this information directly from PSH plant managers.¹¹⁰
- » For other four U.S. PSH plants (15.4% of installed PSH capacity), storage duration data comes from MWH (2009).
- » For other 17 plants (10.5% of installed PSH capacity), an estimate of storage duration was constructed using the following formula:
 - Available water volume is based on either:
 - a. power pool (reservoir storage space for hydropower purpose)
 - b. conservation pool (reservoir storage space for all project purposes other than flood control)
 - c. surface of flood control pool or, preferably, conservation pool multiplied times reservoir elevation range during normal operation

Note: b) and c) could overestimate the reservoir storage available for hydropower purpose
- » For the remaining five plants (0.9% of installed PSH capacity), not enough information was available to estimate water volume; the conservative assumption of 4 hours of storage duration—the minimum storage duration for any other 38 plants—was made for them.

NERC Generating Availability Data System

The sample size for the NERC GADS dataset is not constant over time. Until 2011, hydropower plant owners were reporting to NERC on a voluntary basis. Reporting became mandatory for units greater than 50 MW in 2012 and for units greater than 20 MW in 2013. Figure A1 and Figure A2 show the percentage of installed units reporting to NERC each year for the various unit size and regional groupings discussed in Section 5.5 and Section 5.6.

¹¹⁰ <https://www.sandia.gov/ess-ssl/global-energy-storage-database/>

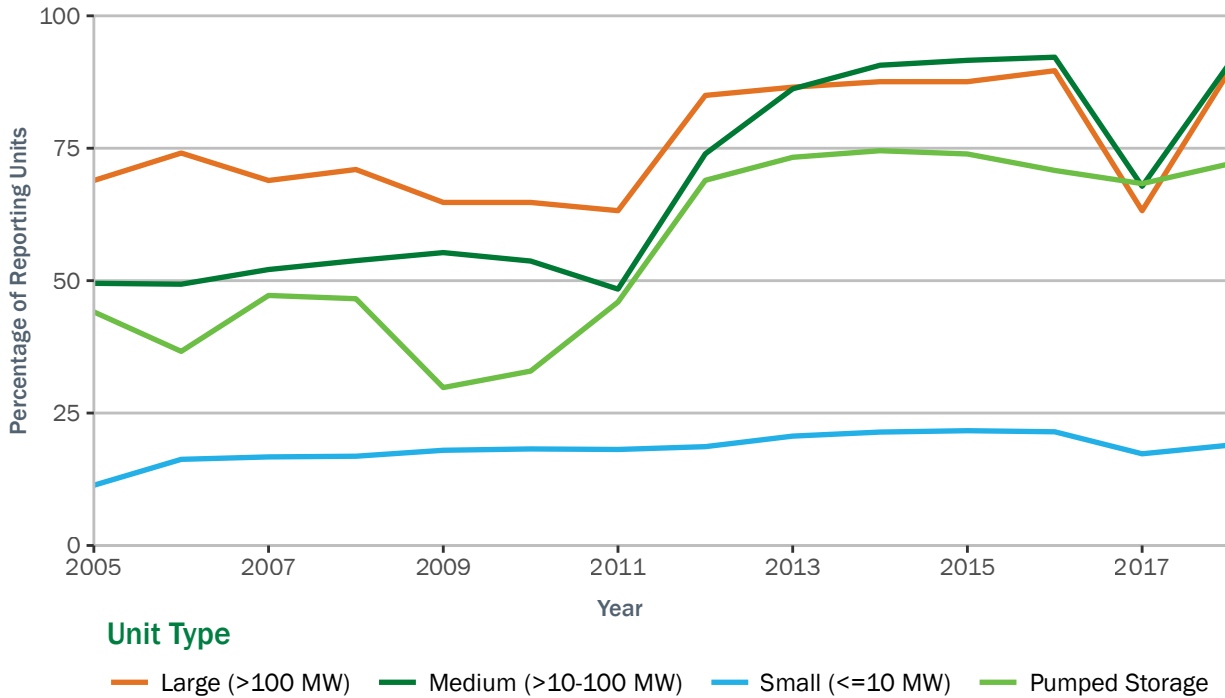


Figure A1. Percentage of units reporting to NERC GADS by type and size

Source: NERC GADS, Existing Hydropower Assets dataset

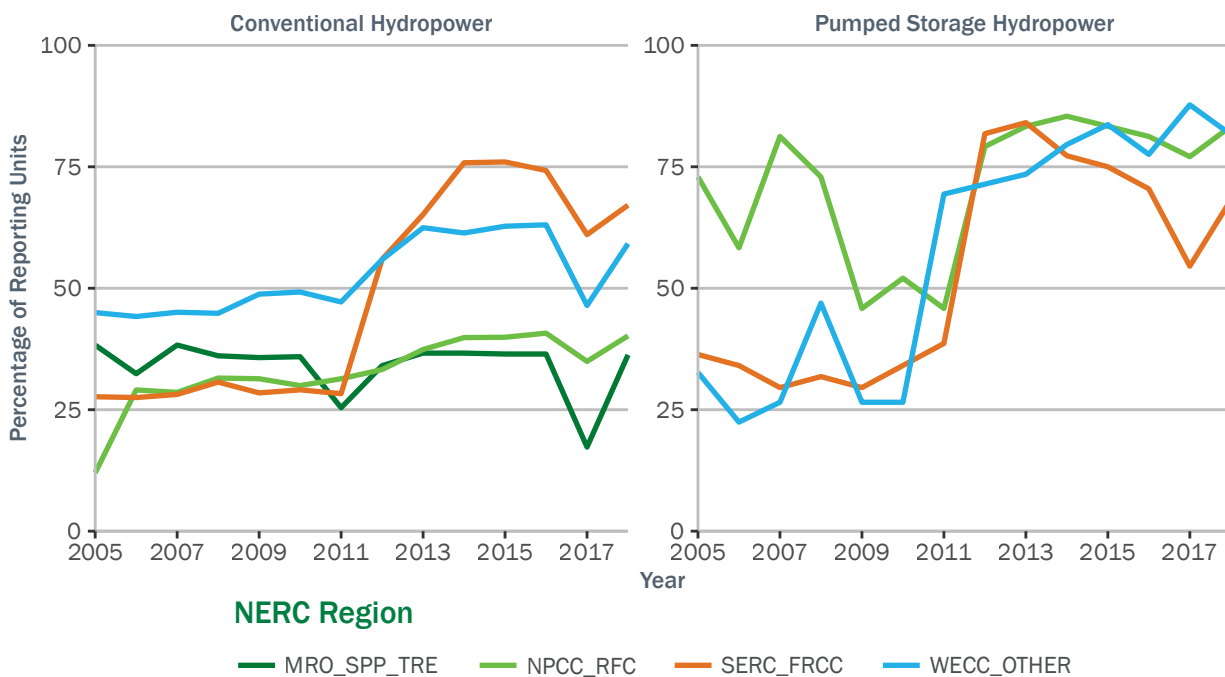


Figure A2. Percentage of units reporting to NERC GADS by type and regional grouping

Source: NERC GADS, Existing Hydropower Assets dataset.

The pc-GAR software used to query NERC GADS data is meant to keep plant names anonymous. Queries are only allowed for

groups of plants large enough to preserve anonymity. For each query, which units are included can be seen but individual plants cannot be associated to specific unit-level results. A significant amount of reverse engineering the data would be required to identify the subset of units that have reported continuously since 2005. Because the figures presented in Chapter 5 are not based on a constant sample of units, the changes in sample composition over time is important for interpreting the trends observed in availability factors, hourly breakdown of operational status, and number of unit starts.

Even though pc-GAR provides an option to segment output by unit type that is meant to distinguish between hydropower units vs. PSH units, a considerable fraction of reporting units do not self-report themselves in either category. Therefore, an alternative strategy was used to segment results by unit type. Units reporting zero pumping hours in a year are classified as hydropower units, and units with one or more hours of pumping are classified as PSH units. This segmenting criterion leads to misclassification of PSH units that had zero pumping hours in a year because of being out of service. However, the number of misclassified units is small enough that it should not affect the results for the large hydropower sample.

Balancing Authorities

Table A1. Selected Electricity Balancing Authorities

BA Acronym	BA Name	NERC Region
BPAT	Bonneville Power Administration Transmission	WECC
CISO	California Independent System Operator	WECC
PJM	PJM Interconnection, LLC	RFC
TVA	Tennessee Valley Authority	SERC
NYIS	New York Independent System Operator	NPCC
WALC	Western Area Power Administration – Desert Southwest Region	WECC
MISO	Midcontinent Independent System Operator, Inc.	MRO
SOCO	Southern Company Services, Inc. – Trans	SERC
ISNE	ISO New England	NPCC
SWPP	Southwest Power Pool	MRO
DUK	Duke Energy Carolinas	SERC
IPCO	Idaho Power Company	WECC
SCL	Seattle City Light	WECC
CHPD	Public Utility District No. 1 of Chelan County	WECC
LDWP	Los Angeles Department of Water and Power	WECC
SPA	Southwestern Power Administration	MRO
SEPA	Southeastern Power Administration	SERC
AVA	Avista Corporation	WECC
GCPD	Public Utility District No. 2 of Grant County, Washington	WECC
PACW	PacifiCorp West	WECC
WAUW	Western Area Power Administration – Upper Great Plains West	WECC
WACM	Western Area Power Administration – Rocky Mountain Region	WECC
SCEG	South Carolina Electric & Gas Company	SERC
DOPD	Public Utility District No. 1 of Douglas County	WECC
TPWR	City of Tacoma, Department of Public Utilities, Light Division	WECC
PGE	Portland General Electric Company	WECC
NWMT	NorthWestern Corporation	WECC
ERCO	Electric Reliability Council of Texas, Inc.	TRE
PSCO	Public Service Company of Colorado	WECC
PACE	PacifiCorp East	WECC
SRP	Salt River Project Agricultural Improvement and Power District	WECC
SC	South Carolina Public Service Authority	SERC
CPLE	Duke Energy Progress East	SERC
YAD	Alcoa Power Generating, Inc. – Yadkin Division	SERC
TIDC	Turlock Irrigation District	WECC
LGEE	Louisville Gas and Electric Company and Kentucky Utilities Company	SERC

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Front Cover Image

Red Rock Hydroelectric Project, Marion County, IA
(image courtesy of Missouri River Energy Services)

