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2014 Hydropower Market Report

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On the front cover: Smithland Hydropower Project, Livingston County, KY (image courtesy of American Municipal Power). The plant—scheduled for completion in late 2015 or early 2016—will have an estimated rated capacity of 72 MW and an estimated annual production of 379 GWh. It is one of three projects being built by American Municipal Power at non-powered dams along the Ohio River. The photo was taken in November 2014.

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2014 Hydropower Market Report

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Acronyms and Nomenclature

AMP	American Municipal Power
BPA	Bonneville Power Administration
CREB	Clean Renewable Energy Bond
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GW	gigawatt
GWh	gigawatt-hour
HREA	Hydropower Regulatory Efficiency Act
IIR	Industrial Information Resources
ITC	Investment tax credit
kW	kilowatt
LOPP	Lease of power privilege
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NHAAP	National Hydropower Asset Assessment Program
NID	National Inventory of Dams
NPD	Non-powered dam
NSD	New stream-reach development
O&M	Operations and maintenance
PMA	Power marketing administration
PSH	Pumped storage hydropower
PTC	Production tax credit
REC	Renewable energy certificate
Reclamation	U.S. Bureau of Reclamation
RPS	Renewable portfolio standard
TVA	Tennessee Valley Authority
USACE	U.S. Army Corps of Engineers

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Executive Summary

The U.S. hydropower fleet has been providing clean, reliable power for more than a hundred years. However, no systematic documentation exists of the U.S. fleet and the trends influencing it in recent years. This first-ever *Hydropower Market Report* seeks to fill this gap and provide industry and policy makers with a quantitative baseline on the distribution, capabilities, and status of hydropower in the United States.

Overall, the size of the U.S. hydropower fleet has continued to grow over the last decade as owners optimize and upgrade existing assets. Despite some retirements, U.S. hydropower capacity increased by nearly one and a half gigawatts (GW) from 2005 to 2013. For those new projects that have been constructed during that time, only four—out of more than a hundred—were not associated with existing water infrastructure. Instead, the industry has focused on opportunities to develop hydropower on existing pieces of water infrastructure at non-powered dams (NPDs) and conduits. These types of projects, along with dozens of new large-scale pumped storage hydropower (PSH) projects that are being pursued, dominate the current development pipeline and face at least two differences relative to projects completed since 2000. The permitting and licensing process for many smaller hydropower projects has changed in recent years, which could result in less cost and time spent in federal permitting. Also, the extensive bond, tax credit, and grant programs that helped fuel development in recent years are no longer available, and hydropower projects might have to rely on alternative sources of funding and revenue, which could complicate or slow future developments.

Key findings from this report include the following:

Section 1—Description of Existing U.S. Hydropower Fleet

- **The U.S. hydropower fleet contains 2,198 active plants with a total capacity of 79.64 GW** (approximately 7% of all U.S. generating capacity). Half of the installed capacity is located in three states (Washington, California, and Oregon). The Northwest has the largest amount of installed capacity, but the Northeast ranks first in number of facilities. Despite slow recent growth, in 2013 hydropower remained the largest renewable energy source in the United States.
- **Hydropower projects support more than just the power system—most installed hydropower capacity, particularly in large projects, is connected to reservoirs that *also* provide recreation, flood control, irrigation, navigation, and/or water supply.** At least 84% of the fleet (by capacity) provides one or more of these additional benefits, with recreation being the most common. The multipurpose nature of these projects influences their design, operations, and life cycle costs and benefits.
- **Most of the installed capacity is located at large projects built between 1930 and 1970.** On the other hand, the most active decade in number of projects built was the 1980s. But most of those projects were small or medium size and did not represent a large capacity increase compared with previous decades.
- **Federal agencies (U.S. Army Corps of Engineers, Bureau of Reclamation, and the Tennessee Valley Authority) own nearly half of the installed hydropower capacity.** The 176 plants they own

account for 49% of the capacity but only 8% of the plants. Publicly owned utilities, state agencies, and electric cooperatives own an additional 24% of capacity. The remaining quarter—which corresponds to 62% of the plants—belongs to private owners.

Section 2—Trends in Hydropower Development Activity

- **Although the expansion of the U.S. fleet has slowed, growth is still occurring from three different kinds of projects:** (1) unit additions and upgrades at existing facilities; (2) NPD and conduit projects to which hydropower generating equipment is added; and (3) low-impact, new stream-reach developments (NSDs).
- **Installed capacity in the United States experienced a *net* increase of 1.4 GW from 2005 to 2013.** Capacity additions to existing projects accounted for 85% of the increases. The net capacity change was positive in every region but was largest in the Northwest (587 megawatts [MW]). A total of 432 MW were lost to either downrates (61%) or retirements (39%). In a few cases, retirements involved full decommissioning of the plant (including dam removal).
- **Significant capital investment toward modernizing and upgrading the existing fleet is consistently taking place.** Since 2005, the industry has invested at least $6 billion in refurbishments, replacements, and upgrades to hydropower plants. Nonfederal owners have spent more per installed kilowatt than federal owners. Funding mechanisms play an important role in explaining differences in spending within the federal fleet.
- **The length of the development process varies widely across hydropower projects that require a Federal Energy Regulatory Commission (FERC) license depending, among other factors, on size, location, and environmental effects.** For new projects requiring a FERC license that came online in the last decade, postlicensing activities required before the start of construction (e.g., additional permitting, financing, and interconnection and power purchase agreement negotiations) typically took longer than obtaining the license.
- **The number of hydropower projects in the FERC or Lease of Power Privilege development pipeline is 331, amounting to a capacity of 4.37 GW.** Of that capacity, 407 MW are currently under construction, and an additional 315 MW have received authorization by FERC or the Bureau of Reclamation. More than 60% of proposed capacity in the FERC pipeline corresponds to developers holding (or having solicited) preliminary permits—which grant the developer exclusive rights to study and file a license application at a specific site during a three-year period. The attrition rate between the preliminary permit and license application stages has traditionally been high.
- **Regardless of modality (NPD, conduit, or NSD), the median project size in the development pipeline is small (<=10 MW).** NSD is the least common category and is highly concentrated in the Northwest. Of NSD projects, 66% are in a single state: Alaska. NPD projects dominate the pipeline, accounting for 233 projects and 58% of capacity.
- **New NPD and conduit projects will typically have to operate within parameters that do not harm the originally intended function of the dam or conduit.** Consequently, these projects will normally have limited flexibility in their mode of operation but also might have limited additional environmental impact because of their use of existing infrastructure.

Section 3—Hydropower Performance Metrics

- **Generation from the hydropower fleet has averaged 288 terawatt-hours from 2011 to 2013, accounting for 7.1% of U.S. electricity generation during that period**. Even though the total generation changes significantly from year to year based on water availability, its geographical and seasonal distribution is relatively stable.
- **The capacity factor for the entire fleet was 39% in 2013, 40% in 2012, and 46% in 2011.** Capacity factors vary from year to year because of hydrologic conditions, water demands for competing uses, environmental and regulatory restrictions, and factors such as plant outages that affect available capacity.
- **There is also significant plant-to-plant variability in capacity factor**. In 2012, one quarter of active projects had capacity factors below 30% while projects in the top quartile had capacity factors above 55%. The two most common operational modes for facilities in the top quartile were run-of-river and conduit.
- **For a representative set of plants installed before 1970, a long-term decreasing trend in capacity factor is visible.** Likely contributors to this trend include equipment aging—combined with different funding availability for refurbishments and upgrades—operational changes from environmental regulations, climate change, and realignments of the relative priority given to different water uses in multipurpose projects.
- **For the set of turbine-generator units that report performance data to the North American Electric Reliability Corporation during the 2000–2013 period, there is a visible decreasing trend in availability factor.** The trend is most pronounced for smaller (<=10 MW) units and suggests a trade-off between planned and forced outages. However, availability factor changes by season and has been on average 5 to 10 percentage points larger in the summer—when electricity demands are generally the greatest—compared with fall.
- **The operational mode of the hydropower fleet displays a broad spectrum of flexibilities.** For the portion of the fleet for which operational mode information was available, more than 39 GW have operational modes with high flexibility potential. That portion of the fleet will be the most valuable for following the shape of the daily load curves primarily influenced by demand fluctuations and variable renewable generation.

Section 4—Pumped Storage Hydropower

- **PSH plants account for the bulk of utility-scale electrical energy storage in the United States (and worldwide)**. With their ability to provide a wide range of ancillary services, PSH plants play an important role in ensuring grid reliability. In the United States, many new PSH projects are under consideration but—in contrast with other countries—none is currently under construction.
- **PSH plants can consist of only reversible turbine-generator units (*dedicated PSH plants*) or a combination of conventional and reversible turbine-generator units (*hybrid PSH plants*)**. Median size, ownership, and patterns of operation are significantly different for the two kinds of plants.

- **The PSH fleet comprises 42 plants with a capacity of 21.6 GW.** The Southeast has the most PSH capacity (9.06 GW). Three-quarters of the installed capacity is located at *very large* (>500 MW) plants indicating that economies of scale have proved to be very strong for this type of project.
- **The majority of PSH construction took place between 1960 and 1990**. PSH complemented nuclear and thermal base load plants that provided cheap power for pumping and that were not well suited to follow demand peaks. Since 1995, except for a 40-MW plant that went into service on 2011 (Olivenhain Hodges, located in California), all additional PSH capacity has come from modernization and upgrades to the existing fleet.
- **Given current electricity prices in many areas of the United States, analyses have shown that the old model of peak, off-peak energy arbitrage might no longer be sufficient to justify additional PSH development**. A new wave of interest in PSH development has been spurred by (1) regulatory changes in electricity markets, allowing the participation of storage in ancillary service and capacity markets; and (2) policies, mostly at the state level, requiring increased penetration of renewable generation. Due to its flexibility, PSH is capable of providing a range of ancillary services to support the integration of variable renewables into the grid.
- **There are 51 PSH projects in the FERC development pipeline with a capacity of 39 GW.** However, the developers had pursued a license application for only three of these projects as of the end of 2014. The rest have been issued (or are waiting for) preliminary permits to conduct feasibility studies. Most of the projects are pursued by private developers.
- **In 2014, FERC authorized the first original license for PSH in more than 15 years (Eagle Mountain) and a second PSH facility (Iowa Hill) as part of the relicensing of an existing hydropower project—the Upper American River Project in California.** Eagle Mountain and Iowa Hill differ substantially in configuration (closed-loop versus open-loop), size (1,300 versus 400 MW), and ownership (private versus public). They are both in California, an attractive market because of the high wind and solar penetration and a state renewable portfolio standard with a target of 33% by 2020.
- **The key performance metric for PSH is its availability factor.** For units reporting performance data to the North American Electric Reliability Corporation, the availability factor has decreased slightly over the 2000–2014 period. The effect of seasonality is more acute and noticeable than for hydropower plants. On average, availability factors stayed above 90% every summer but fell as low as 75% in some fall and spring seasons.

Section 5—Trends in U.S. Hydropower Supply Chain

- **Since 1996, Voith has led the United States in terms of market share of installed turbine capacity.** Of the 9,455 MW capacity installed identified—either at new facilities or as upgrades/retrofits—from 1996 to 2011, Voith manufactured 5,389 MW, including 2,683 MW for 62 turbine replacements/upgrades at federal facilities. Alstom held the second largest share of the United States market with 1,991 MW.
- **At least 172 companies, spread across 35 states, have manufacturing facilities in the United States to produce one or more of six major hydropower components (turbines, generators,**

transformers, penstocks, gates, and valves). The facilities typically are located close to substantial installed hydropower capacity and/or access to waterways to facilitate shipping of their end products.

- **Turbines are the only hydropower plant component for which trade data—excluding turbine-generator sets—are publicly available.** Most of the U.S. hydraulic turbine trade involves turbine parts.
- **The direction and magnitude of U.S. hydraulic turbine trade with various countries has changed during the last 15 years.** More than 50% of the value of U.S. hydraulic turbine trade during the last three years has corresponded to imports and exports within North America—a significantly larger percentage than in the late 1990s. From 1996 to 2014, China and other Asian countries have gone from net importers of U.S. manufactured turbines to net exporters of turbines—and turbine parts—to the United States.

Section 6—Policy and Market Drivers

- **Broadly supported federal regulatory reforms have altered the permitting and licensing process for some (typically smaller) projects**. Federal legislation passed unanimously in 2013 aims to lower the cost and time necessary for small NPDs and conduits to obtain federal permits. FERC is also investigating the potential for a two-year licensing process for NPDs.
- **Access to incentives has supported nearly all recent capacity additions and new projects.** Although public and private owners have access to different funding and incentive resources, both have been able to leverage incentives provided by the American Reinvestment and Recovery Act to support project development efforts. This substantially benefitted project economics. The1603 grant program supported more than $1.6 billion of hydropower development activity by private owners, and Clean Renewable Energy Bonds and Build America Bonds supported billions more by public power entities. In addition, several states have provided financing for smaller projects.
- **Hydropower is treated very differently across state-level renewable portfolio standards, which have been major drivers of growth in other renewables.** Each of the 29 states that include hydropower as a primary-tier renewable defines hydropower eligibility in a unique way. Common restrictions on eligibility are inconsistent and include project size, type, age, and a variety of implicit and explicit environmental sustainability criteria. The way in which hydropower is classified as “renewable” for purposes of renewable portfolio standard compliance or future carbon policies could weigh heavily on project development prospects.

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Table of Contents

Acronyms and Nomenclature iii
Executive Summary v
List of Figures .... xiii~~xiv~~
List of Tables .... xiv~~xv~~
Introduction 1
1. Description of Existing U.S. Hydropower Fleet 5
1.1 Installed Capacity and Regional Distribution 5
1.2 Size of U.S. Hydropower Plants 7
1.3 Purpose and Other Uses Associated with Hydropower Plants 10
1.4 Ownership of U.S. Hydropower Plants 12
2. Trends in Hydropower Development Activity 15
2.1 Recent Capacity Changes for Hydropower (2005–2013) 17
2.2 Hydropower Project Cost and Investment Data 22
2.3 Hydropower Project Development Pipeline (as of December 2014) 25
3. Hydropower Performance Metrics 33
3.1 Energy Generation 33
3.2 Capacity Factors 35
3.3 Availability Factors 39
3.4 Operational Mode 42
4. Pumped Storage Hydropower 47
4.1 Installed Capacity and Regional Distribution of Pumped Storage 47
4.2 Trends in Pumped Storage Development Activity 50
4.2.1 Recent Capacity Changes for Pumped Storage 50
4.2.2 Pumped Storage Project Development Pipeline 51
4.3 Performance Metrics for Pumped Storage 55
5. Trends in U.S. Hydropower Supply Chain 61
5.1 Domestic Manufacturing 64
5.2 Imports/Exports 67
6. Policy and Market Drivers 71
6.1 Regulatory Changes for Hydropower 71

6.2 Incentives and Funding Available for Hydropower 72
6.3 Hydropower in Renewable and Clean Energy Markets 74
7. Conclusions and Future Work 77
References 79

List of Figures

Figure 1. Hydropower installation timeline and major legislative and institutional milestones 3
Figure 2. Map of the U.S. hydropower fleet 7
Figure 3. Hydropower installation timeline by plant size 9
Figure 4. Distribution of additional purposes on existing hydropower projects with dams 12
Figure 5. U.S. hydropower fleet ownership mix 13
Figure 6. Recent hydropower capacity changes by region and project type (2005–2013) 18
Figure 7. Length of development process for a sample of recently completed projects from 2005 to 2013 20
Figure 8. U.S. hydropower construction cost by project type and project size (1980–2015) 23
Figure 9. Expenditures on rehabilitations, replacements, and refurbishments of existing hydropower fleet 25
Figure 10. Hydropower project development pipeline by region, status, and project type (as of December 31, 2014) 27
Figure 11. Annual hydropower capacity and generation (2002–2013) 34
Figure 12. Monthly hydropower generation by region (2002–2013) 35
Figure 13. Long-run monthly hydropower capacity factor for plants built before 1970 36
Figure 14. Average hydropower operational status (hourly breakdown by unit size classes of units reporting to NERC GADS) 40
Figure 15. U.S. hydropower availability factor (for units reporting to NERC GADS) 42
Figure 16. Distribution of operational modes in U.S. hydropower fleet 44
Figure 17. Map of the U.S. pumped storage hydropower fleet by plant type and size 48
Figure 18. Pumped storage hydropower installation timeline by plant size 49
Figure 19. Distribution of additional purposes on existing pumped storage hydropower plants 50
Figure 20. Pumped storage hydropower project development pipeline by region and status in relation to state-level penetration of variable renewables (as of December 31, 2014) 53
Figure 21. Monthly gross generation by pumped storage hydropower plants by region (2002–2013) 56
Figure 22. Average pumped storage hydropower operational status (hourly breakdown of units reporting to NERC GADS) 58
Figure 23. U.S. pumped storage hydropower unit availability factor (for units reporting to NERC GADS) 59
Figure 24. Installed hydropower turbine in the United States by type and manufacturer (1996–2011) 62
Figure 25. Annual installation of hydropower turbines in the United States by manufacturer 63
Figure 26. History of major hydropower turbine manufacturer acquisitions and mergers 64
Figure 27. U.S. hydropower domestic manufacturing map 66
Figure 28. U.S. hydropower turbine import and export values by country 68

List of Tables

Table 1. Top 20 States by Installed Hydropower Capacity and Hydropower Percentage of In-State Generation.......6
Table 2. Authorizations that Might Be Required from Federal Agencies to Construct New Hydropower Capacity (by Project Size and Type of Site).......17
Table 3. Definitions of Operational Mode for Hydropower Plants.......43
Table 4. Pumped Storage Hydropower Development Pipeline (Broken Down by System Type) 54

Introduction

This report catalogues the characteristics of the existing fleet of hydropower and pumped storage plants in the United States and discusses recent trends in development, performance, and supply chain along with the policy and market context that influences them. Figure 1 sets the stage for the document content by depicting the evolution of installed hydropower and pumped storage capacity alongside significant legislative and institutional milestones.

Section 1 presents comprehensive information for the hydropower fleet regarding location, construction timeline, additional purposes, sizes, and ownership. Section 2 explores in more detail the capacity changes observed from January 2005 through December 2013 and provides a snapshot of the project development pipeline (as of December 2014). [1] Section 3 discusses trends, variability, and, when possible, seasonality and regionality of generation, capacity factor, and availability factor. It also presents information on the spectrum of operational modes present in the fleet. Section 4 covers pumped storage hydropower (PSH), which has unique market and operational characteristics. Section 5 provides information on the supply chain for hydropower and focuses on turbine installations, imports, exports, and the location of domestic manufacturing facilities. Finally, Section 6 provides information on existing policy and market drivers, with emphasis on the incentives and funding mechanisms that have been used by recent projects.

The size and regional groupings used throughout the document are established in Section 1. Plants are classified regionally to maintain consistency with Federal Energy Regulatory Commission (FERC) hydropower regions. This grouping also closely matches existing census regions except for dividing the West into northern and southern regions. Size classification is based on an extensive review of groupings used by various regulatory and industry organizations, as well as equipment manufacturers. Plants are classified as *Micro* (less than or equal to 0.1 megawatts [MW]), *Small* (>0.1 MW–10 MW), *Medium* (>10 MW–100 MW), *Large* (>100 MW–500 MW) or *Very Large* (>500 MW). Different sections include both plant-level and unit-level information, where unit refers to each of the turbine-generator units within a hydropower plant (or "facility," which is synonymous with the term "plant").

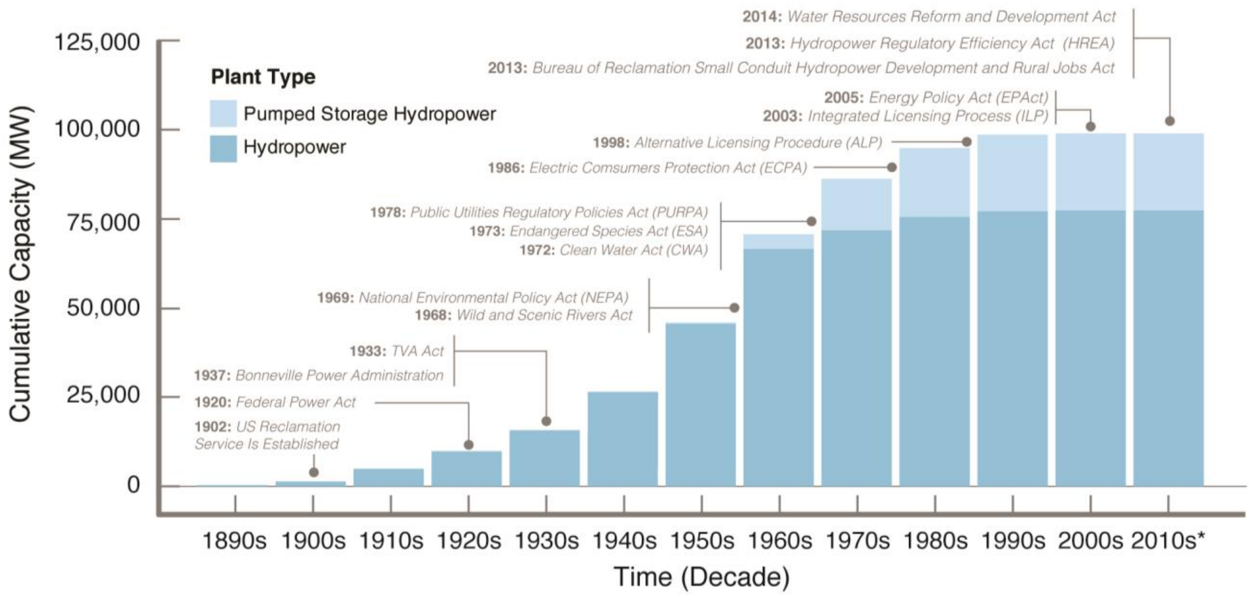
Data availability is more limited for *Micro* plants than for other categories. Consequently, and because *Micro* capacity is less noticeable when displayed in combination with the rest of the fleet, most of the figures and discussion leave out plants within this category. However, since this industry segment is growing, it is discussed in separate inserts at several points in the report. Marine and hydrokinetic technologies (such as tidal, wave, and in-stream kinetic) are not covered in this report.

In compiling this initial *Hydropower Market Report*, a variety of data sources was used. The range of years for which data were available varied across sources. Section 1 draws heavily from Oak Ridge National Laboratory's National Hydropower Asset Assessment Program (NHAAP), a geospatial database of U.S. hydropower that includes information on existing facilities, water resource infrastructure, hydrography, and environmental attributes.[2] NHAAP, in turn, assembles data from a variety of primary

[1]Data on historical capacity changes come from EIA Form 860. At the time of writing, Form 860 data were available only until 2013. Data on the project development pipeline mostly come from FERC and Bureau of Reclamation websites, which contain data for 2014.
[2]http://nhaap.ornl.gov/

sources (FERC, the U.S. Energy Information Administration [EIA], National Inventory of Dams [NID], and Hydropower Asset Management Partnership are the most relevant for this document).[3] Operational mode in Section 3 and turbine installations in Section 5 are also based on NHAAP data. For the other sections, the main data sources accessed, collected, or purchased include EIA Form 860 (2005–2013); EIA Form 923 (2002–2013); FERC summaries of permitting activity (as of December 2014), as well as individual dockets from the FERC eLibrary; U.S. International Trade Commission data for turbine imports and exports (1996–2014); North American Electric Reliability Corporation (NERC) Generator Availability Data System (GADS) for performance metrics (2000–2013); and Industrial Information Resources (IIR) for construction and refurbishment/replacement/upgrade activity and expenditure data (2005–2014).

[3]The Hydropower Asset Management Partnership was started in 2001 with the objective of simplifying and improving the condition assessment processes that enable priority-based asset management practices at hydropower plants. The partnership involves asset management experts from the U.S. Army Corps of Engineers, Bureau of Reclamation, Bonneville Power Administration, and Hydro-Quebec.



*Data for the 2010s only cover 2010-2013.

Source: NHAAP

Figure 1. Hydropower installation timeline and major legislative and institutional milestones

1890s-1920s: Birth of the power industry

- Technological advances and the formation of electric utilities initiate the electrification of the United States.
- More than 300 hydropower plants (most small and medium private developments) are operational by 1920 and hydroelectricity represents about one third of total electricity production by that date.
- Regulatory uncertainty and focus on navigation lane expansion hinder hydropower development on navigable waters.

1920s-mid 1960s: "Big Dam" period

- The Federal Power Act of 1920 creates the Federal Power Commission to grant hydropower licenses on public lands and, eventually, for all utilities engaged in interstate commerce.
- Massive investment in multipurpose water resource projects by federal agencies and hydropower facilities by electric utilities. Hydropower is an important component in the portfolio of post-Depression infrastructure projects aimed at boosting economic recovery. Postwar economic growth necessitates rapid growth in electricity supply.

Mid 1960s-1980s: Targeted growth and a changing regulatory environment

- Small hydropower flourishes in the 1970s and early 1980s as PURPA guarantees avoided cost rates and DOE launches a Small Hydropower Demonstration Program.
- Pumped storage hydropower development accelerates to complement rapid nuclear power expansion.
- Development of other hydropower resources slows with the rebalancing of water management priorities reflected through environmental legislation (National Environmental Policy Act, Endangered Species Act, and the Clean Water Act), culminating with ECPA.

1990s-Current: Low-growth decades, promising future

- The development of new hydropower facilities dramatically wanes in the face of major regulatory reform and electricity market restructuring and uncertainties. However, capacity slowly grows as the existing fleet is modernized.
- Concerns over climate change and increasing deployment of variable renewables revives interest in hydropower and pumped storage as valuable contributors to the grid, sparking major increases in permitting activity.
- Early 21st century regulatory reforms incrementally address the efficiency of the hydropower permitting process through revised FERC licensing and exemption processes and improvements to regulations governing the addition of power to federal dams, canals, and conduits.

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1. Description of Existing U.S. Hydropower Fleet

1.1 Installed Capacity and Regional Distribution

As of December 2013, operational hydropower capacity in the United States was 79.64 gigawatts (GW). That capacity is distributed across 2,198 plants with a wide variety of physical configurations, sizes, owners, and modes of operation.[4] The fleet contains approximately 5,600 turbine-generator units. Hydropower plants are typically classified as either impoundment or diversion plants. Impoundment plants are those that "use a dam to store river water in a reservoir." Diversion plants "channel a portion of the river through a canal or penstock." Diversion plants are also often referred to as run-of-river plants, and, sometimes, they do not use a dam.[5] Half of the installed capacity is located in just three states (Washington, California, and Oregon). Nonetheless, all but two states (Delaware and Mississippi) contain some amount of hydropower capacity. During 2011–2013, hydropower was responsible for 7.1% of all electricity generation in the United States. In three states (Washington, Idaho, and Oregon), hydropower accounted for more than half of the in-state generation. Table 1 displays the top 20 states in terms of installed hydropower capacity and average hydropower percentage of in-state generation.

Figure 2 displays the hydropower fleet by size category along with average runoff data at the subbasin level. The regional distribution of hydropower installations is highly correlated with runoff availability. The runoff information in Figure 2, obtained from the U.S. Geological Survey, corresponds to the 1989–2013 annual average. Runoff is a proxy for resource (water) availability. However, it is a less direct proxy than solar radiation is for solar generation or wind speed is for wind generation. At impoundment hydropower projects that feature large reservoirs, storage capacity makes generation less dependent on year-to-year hydrologic variability. In addition—particularly in some river systems—laws, regulations, and competing water uses significantly dampen the correlation between runoff and generation.[6]

The regions delineated in Figure 2 (Northwest, Southwest, Midwest, Southeast, and Northeast) coincide with FERC hydropower regions. This classification matches closely with the U.S. Census Bureau regions except that the West is separated into northern and southern portions which, from a hydropower potential perspective, are strongly influenced by the Columbia and Colorado River basins hydrologic cycles, respectively. Throughout this document, Alaska is treated as part of the Northwest, while Hawaii is included in the Southwest. The Northwest has the largest amount of installed capacity and contains 19 of the 28 plants with more than 500 MW of nameplate capacity. Meanwhile, the Northeast tops the ranking in number of hydropower plants, although they are predominantly small. Only 6 out of the 607 hydropower plants in the Northeast are above 100 MW. In the Southwest, California contains most of the installed capacity even though the two largest hydropower plants in the region (Hoover and Glen Canyon) are located outside of that state, along the Colorado River, in areas with low average annual runoff. Within the Midwest, the largest plants are along the Missouri and Ohio rivers, while a cluster of smaller plants is concentrated around the Great Lakes. In the Southeast, most hydropower is either east of the Mississippi along the Tennessee and Chattahoochee rivers or west of the Mississippi along the Arkansas

[4]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 might include one or multiple plants.

[5]http://energy.gov/eere/water/types-hydropower-plants

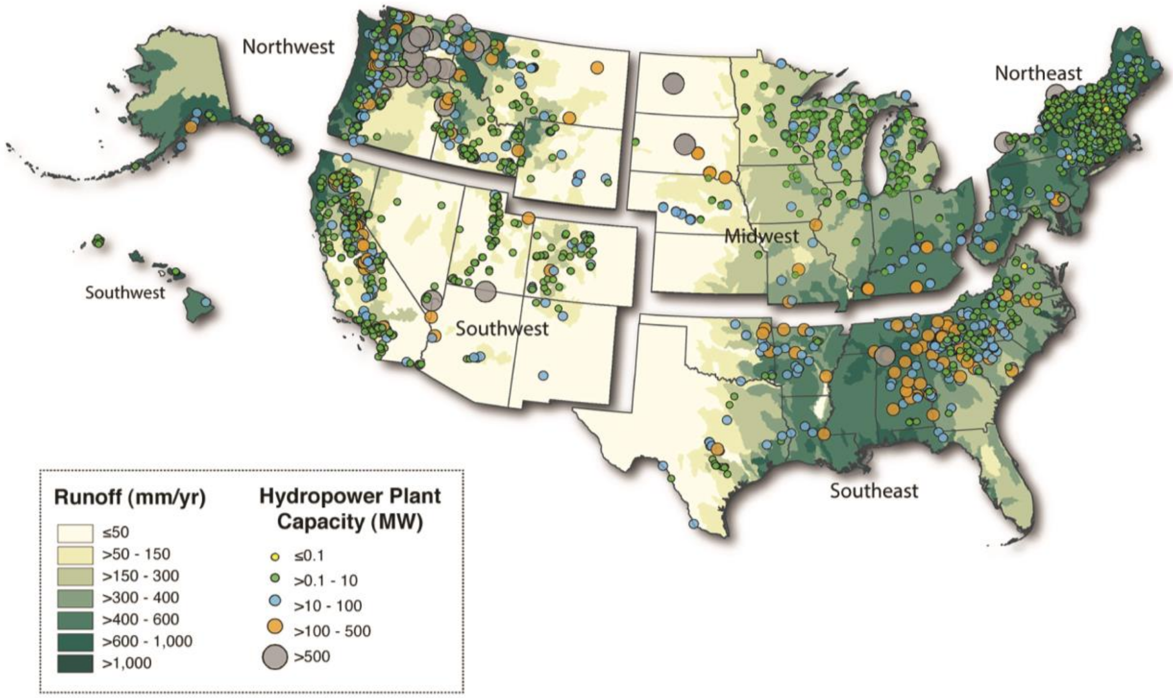
[6]For instance, dam releases at the Colorado River Basin reservoirs are governed by Endangered Species Act compliance, Supreme Court decisions, the 2007 Colorado River Interim Guidelines, and the 1944 U.S./Mexico Water Treaty (Santos 2015).

and Red River basins. The median size of plants in the Southeast is by far the largest (19 MW versus 5.30 MW in the Northwest and less than 5 MW in the other three regions).

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

Hydropower Capacity (MW)	
Cumulative (end of 2014)	
WA	21,303
CA	10,334
OR	8,335
NY	4,673
AL	3,109
MT	2,638
ID	2,568
TN	2,499
GA	2,241
NV	2,096
NC	1,904
AZ	1,679
SD	1,600
SC	1,371
AR	1,321
PA	882
OK	807
KY	805
VA	786
ME	723
Rest of United States	7,963
TOTAL	**79,637**

Hydropower Percentage of In-State Generation (%)	
Average (2011–2013)	
WA	74.89
ID	68.98
OR	63.60
SD	48.32
MT	39.10
ME	25.69
AK	21.45
NY	18.94
VT	18.89
CA	15.49
TN	12.70
NH	7.30
NV	7.05
AZ	6.62
ND	6.48
AL	6.36
MD	5.10
AR	4.20
NC	3.99
NE	3.73
Rest of United States	1.01
TOTAL	**7.06**



Note: This map displays the location and capacity of existing hydropower projects in the United States in relation to runoff distribution by watershed. Runoff was calculated based on the best available data; runoff for the contermi-nous United States is by 8-digit hydrologic unit code (HUC), and runoff for Alaska and Hawaii is by 4-digit HUC.

Source: ORNL NHAAP Existing Hydropower Assets Data Set. U.S. Geological Survey-Watershed Boundary Data Set. 2000 Census-State Boundaries.

Figure 2. Map of the U.S. hydropower fleet

1.2 Size of U.S. Hydropower Plants

One useful way to classify the hydropower fleet is according to plant size, and incentive policies for hydropower often depend on plant size. Plant owners also use size as one of the attributes used to create relevant peer groups against which to benchmark their operation and maintenance (O&M) costs and performance. Throughout this document, five plant size categories will be used: micro, small, medium, large, and very large. This classification results from a review of size groupings used by different countries, international agencies, and hydropower equipment manufacturers (with a particular focus on their being suitable to the U.S. fleet). The most controversial size limit is the one for small hydropower. The upper limit to what is considered small hydropower varies widely by country (e.g., it is 1.5 MW in Sweden versus 50 MW in Canada or China). The threshold used in this report for the U.S. fleet (10 MW) is driven by two factors. First, the FERC exemption size threshold is set at 10 MW. Second, the 10 MW threshold is used by many international agencies: the International Energy Agency, European Small Hydropower Association, United Nations Industrial Development Organization, and the International Center of Small Hydro Power.

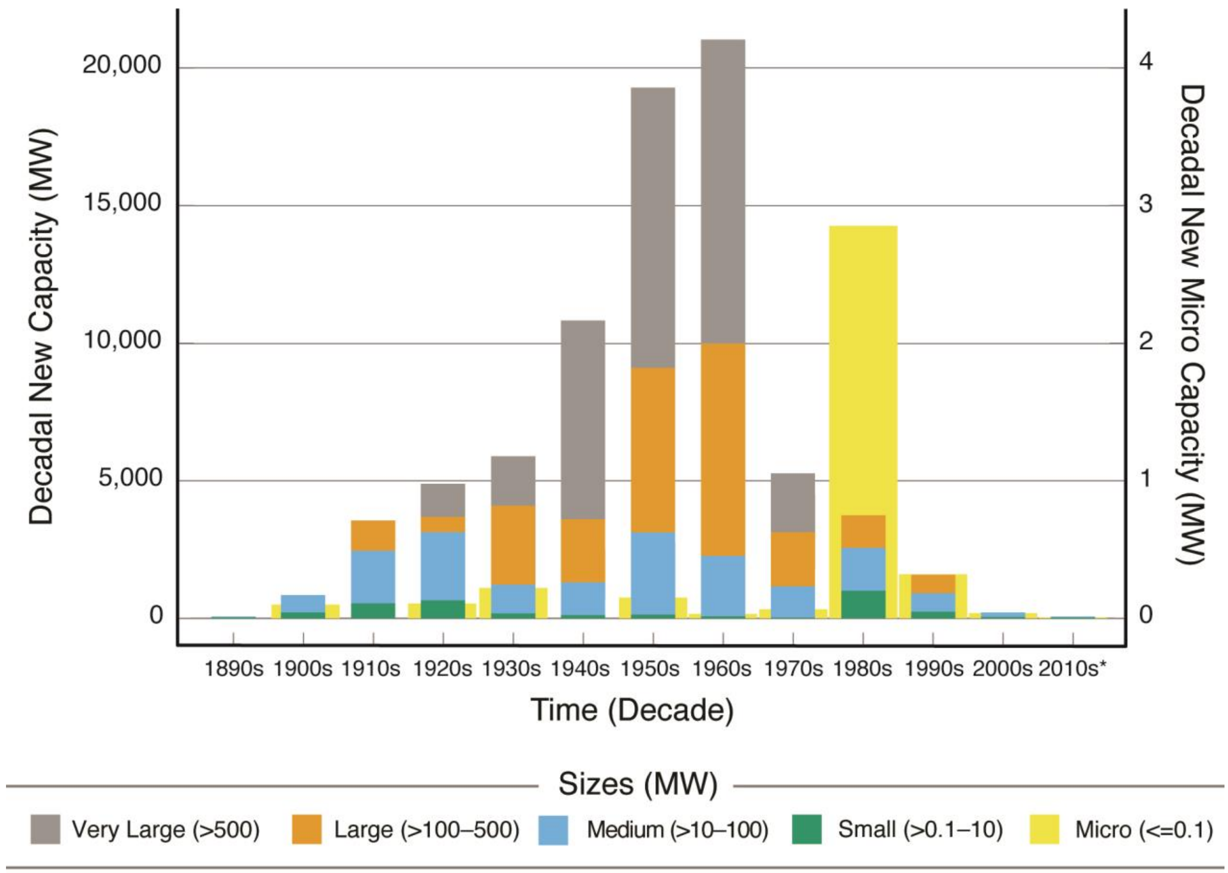
For equipment performance and reliability comparisons, unit sizes and types are more relevant than plant sizes. For information at the unit level, 10 MW and 100 MW thresholds are used. The median size of units in the hydropower fleet is 1.6 MW, and only one-fourth of the units have a nameplate capacity of more than 10 MW. Three of Grand Coulee's hydropower units are 805 MW, the largest in the U.S. fleet.

Figure 3 shows how the total amount of hydropower development and the average size of plants installed in the United States have evolved over time. Since hydropower development began in the 1890s, new installed capacity in each decade was larger than in the previous decade until the 1960s. Over the first three decades of hydropower development, small and medium plants dominated the landscape. The first *very large* plants came in the 1920s (Wilson Dam in Alabama and Conowingo in Maryland). But it was in the 1930s that the era of large dams and large hydropower began. During the next three decades most of the installed capacity came from *very large* plants. That trend came to a halt in the 1970s and resulted in a dramatic drop in new installed capacity during the following decades. This drop reflects changes in the licensing process that were motivated primarily by environmental issues (e.g., enactment of the Endangered Species Act). If economic development was a central thrust of the federal dam building programs of previous decades, legislation in the 1970s and 1980s focused on the noneconomic considerations that had been underplayed until then. Since the 1970s, the new installed capacity in each decade has been smaller than in the previous one.

The trend of ever increasing installed capacities from the 1890s to the 1960s mirrors what happened in the electric industry overall. However, a pronounced slowdown in new total megawatts installed did not take place until the 1980s. Thus, the large drop in new installed hydropower in the 1970s was largely because of hydropower-specific factors (e.g., legislative changes, less attractive available sites). Moreover, the electric industry reversed the slowdown in capacity additions in the 2000s, although hydropower has not managed to mimic that reversal. Despite the 2008–2009 recession, installed electric generation capacity in the 2000s (319 GW) was the largest decadal installation to date. Natural gas and wind accounted for 85% and 10% of that capacity, respectively. Those two technologies have continued to contribute most of the growth in new installed electric generating capacity in the 2010s.

The hydropower capacity timeline shown in Figure 3 hides an important fact. By number of plants installed rather than capacity, the 1980s were the most active years for hydropower. Almost 600 plants (close to 30% of the total number of active plants today) were built during that decade. However, they were mostly small- and medium-sized plants and did not add up to a capacity increase comparable to that of previous decades. Another important caveat to be made about Figure 3 is that it assigns the total *current* installed capacity of each plant to the plant's initial year of operation. Therefore, it does not correctly depict the year of operation for generating units added later to an existing project. It also does not reveal the sequence in which capacity at existing units increased because of upgrades to generator and turbine units. For instance, the Bureau of Reclamation (Reclamation) added almost 2 GW of capacity to its fleet between 1983 and 2010 just through uprates (Reclamation 2010).[7]

[7]Uprates typically involve an increase in rating of more than 15%. This report uses a more general term—upgrades—to refer to turbine-generator unit modifications that result in rated capacity increases, regardless of their magnitude.



*Data for the 2010s only cover 2010-2013.

Source: NHAAP

Figure 3. Hydropower installation timeline by plant size

If the numbers on the x-axis were subtracted from the current year, Figure 3 would indicate the age of each plant (since its original units started operation). Of current installed capacity, 75% is located at hydropower plants that are 50 years or older. However, that does not mean that 75% of the current installed capacity is 50 years or older. The small number of new plants installed since the 1990s is not synonymous with lack of hydraulic turbine installations. Sections 2 and 5 discuss in more detail the ongoing activity spurred by upgrades and modernization of the existing fleet.

MICRO HYDROPOWER

Micro hydropower plants are commonly defined as those with an installed capacity less or equal to 100 kilowatts (kW). Existing micro hydropower has been developed on streams, irrigation canals, and along water pipeline systems. Homeowners and small business owners often choose installations of this size (particularly in the agricultural sector). These owners either consume the power on-site, while entering into a net metering agreement with their electric provider, or sell the power to a utility using a power purchase agreement. There are 141 micro plants that hold FERC licenses or exemptions. If built on private land and not connected to the transmission grid or displacing power from the grid, FERC permitting is not always required for micro plants. However, permits from state or local authorities are typically needed (for instance, for obtaining water rights). There is no centralized database that keeps track of all micro hydropower installations and performance throughout the United States. Because of incomplete coverage, most of the following graphs and metrics in this report do not include micro installations. Instead, information regarding trends in micro hydropower development are discussed separately in sidebars such as this.

1.3 Purpose and Other Uses Associated with Hydropower Plants

One of the attributes that sets hydropower plants apart from most other electricity generation resources is that the energy source they use (water) and some of their physical components (e.g., reservoirs and pipelines) often serve other purposes. Historically, hydropower has been developed in the context of multipurpose water reservoir projects in which power production was not the only, or even the primary, authorized purpose. Reducing the risk of floods, providing irrigation to the arid West, and promoting commerce through improved navigation channels are some of the original missions that drove the development of, mostly publicly owned, water resource projects. In federal hydropower plants, the "project purposes" are defined by law, usually in the legislation that authorized project construction. In many of these facilities, operators refer to electricity production as a by-product of the other project purposes (i.e., the volume and timing of water releases from the reservoirs that will pass through the turbines and be converted into electricity is dictated by flood control, irrigation, fish mitigation needs, or other purposes).

Not only do many facilities serve multiple functions but also hydropower plants are components of larger river systems in which the operation of each plant must take into account constraints in upstream and downstream reservoirs. With multiple uses and river networks, river managers and hydropower plant operators face complex optimization problems. The multiple uses of hydropower assets influence design and operational decisions, as well as the overall life cycle costs and benefits of the project. Although all the functions served by hydropower have an intrinsic value, not all of them can be monetized. Often, the electricity sales revenue from a multipurpose hydropower project is used to repay portions of the total cost of the project that are exclusively associated with other purposes. For instance, in some Reclamation multipurpose water projects, power sales revenue is expected to cover a fraction of the costs associated with the irrigation purpose through what is called irrigation assistance payments (Government Accountability Office 2014).

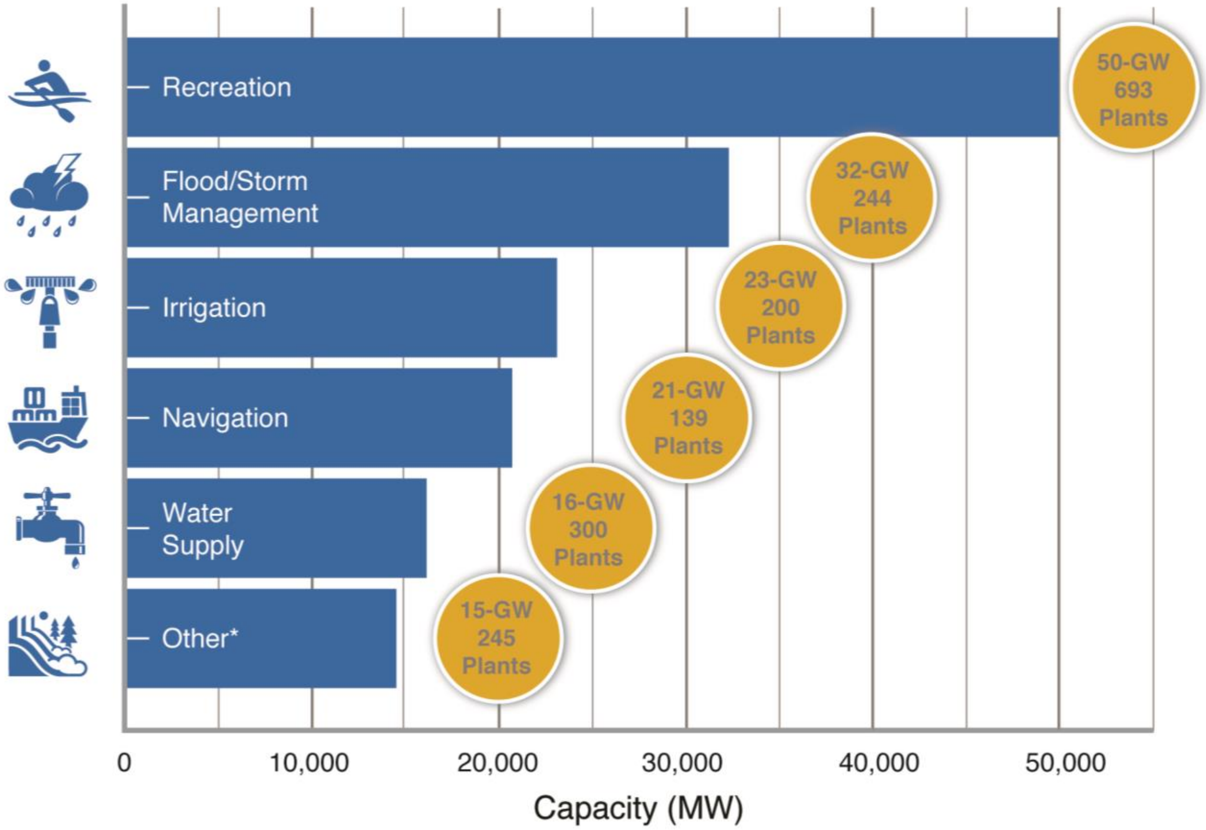
The NID—a congressionally authorized database maintained by the U.S. Army Corps of Engineers (USACE)—contains information about the purposes served by each dam in the United States. By linking dams to power plants, it is possible to draw a comprehensive picture of the extent to which the various purposes are being supported by water reservoir plants that also produce hydropower. Figure 4 summarizes the number and total capacity of hydropower projects that also provide each of the following missions: recreation, flood storm/management, irrigation, navigation, water supply, or “other.”

The purposes included in Figure 4 are not exclusive of each other. One single project can be listed as supporting multiple additional purposes along with hydropower generation. Recreation is the most widespread additional purpose of water reservoirs associated with hydropower plants. Almost 700 plants, accounting for more than 60% of installed capacity, draw water from reservoirs that also accommodate recreational activities. Fewer projects encompass flood control, irrigation, and navigation, but the average size of hydropower plants included in these projects is larger than for recreational purposes. Water supply and the residual *Other* category are represented in many, but usually smaller, projects.

The NID data regarding dam purpose was mapped to 1,702 plants (out of the total 2,198). Only 664 of those plants listed hydropower as their only purpose. The average size of that subset is 18 MW, and more than 75% of them are owned by private entities. However, the largest plant reported by NID as hydropower-only (Robert Moses Niagara in New York, 2.4 GW) is owned by the New York Power Authority, a state-owned corporation. For at least 90 small hydropower plants located at conduits, no dam exists, and, therefore, the NID does not provide information on their additional non-hydropower purposes. Most of those conduit plants likely have either irrigation or water supply as their primary use, so the plant numbers for those two categories are somewhat understated in Figure 4.

To the extent that the multiple uses of water resource infrastructure compete with each other, the ability to optimize one of them (electricity production) is likely restricted. For instance, if hydropower equipment is added to an irrigation system, production of electricity will occur only during the irrigation season. In large multipurpose water reservoirs, the flow volumes that pass through the turbine and generate electricity are partly determined by reservoir elevation rules set for flood control and environmental and recreational purposes.

Given the long life of hydropower plants, the relative value and priority ranking of the various purposes for which they are authorized can change over time in ways that might impact their performance as electricity generation assets. Section 3 provides examples of those impacts. As for planned hydropower capacity, Section 2 discusses how the majority of current plants leverage existing water resource infrastructure (non-powered dams [NPDs] and conduits). Those future hydropower plants will have to be operated within parameters that accommodate the original purpose for which the infrastructure was built.



*The "Other" category primarily includes fish and wildlife ponds, fire protection, stock or small farm ponds, debris control, and tailings (i.e., storage/receipt of waste rock from mining operations).

Source: NHAAP

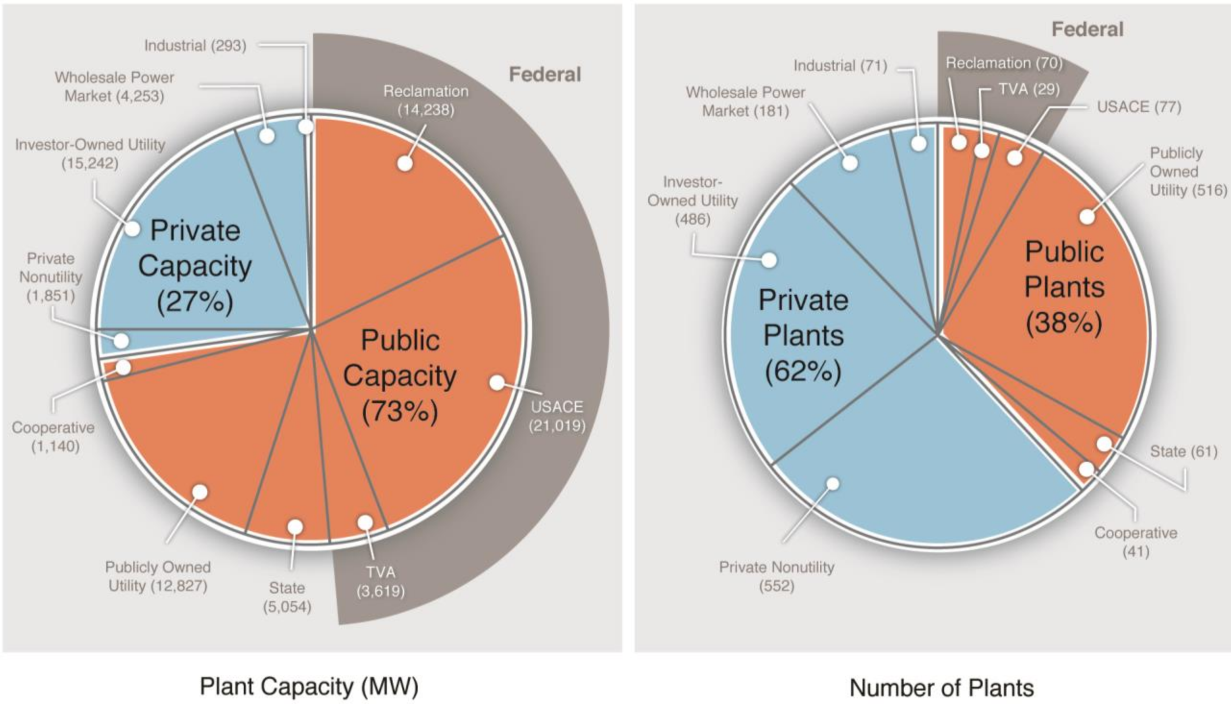
Figure 4. Distribution of additional purposes on existing hydropower plants with dams

1.4 Ownership of U.S. Hydropower Plants

The ownership mix of the U.S. hydropower fleet looks very different when considering capacity vs. number of plants. Figure 5 indicates that the 176 plants owned by federal agencies account for 49% of the capacity but only 8% of the plants. Publicly owned utilities, state agencies, and cooperatives own an additional 24% of total capacity. The remaining quarter of installed capacity belongs to private owners and corresponds to 62% of hydropower plants.

Federally developed hydropower plants are exempt from FERC licensing. In contrast, the vast majority of the nonfederal fleet is under FERC jurisdiction. FERC authorizes construction of hydropower facilities and monitors dam safety. In addition, the terms set on FERC's authorization—either a license or an exemption—outline required environmental measures and the operational mode for the facility. The distribution of operational modes is discussed in Section 3.

For the majority of hydropower plants, the same entity is owner and operator. However, according to data from the EIA, at the end of 2012 there were 101 hydropower plants with joint ownership or where the owner was different from the operator (e.g., plants owned by Reclamation but operated by irrigation districts). In most of those cases, the joint owners or owner and operator are either both public or both private entities.



Source: NHAAP, EIA Form 861, FERC Market-Based Rates Contact List, and web searches

Figure 5. U.S. hydropower fleet ownership mix

Within the federal fleet, only the Tennessee Valley Authority (TVA) actually sells the power from the facilities it owns and operates. In the case of USACE and Reclamation, power marketing administrations (PMAs) are responsible for selling the power produced at these federal multipurpose projects. The four PMAs are Bonneville Power Administration (BPA), Western Area Power Administration, Southwestern Power Administration, and Southeastern Power Administration. Their mission is to sell power from the federal facilities at cost-based rates giving priority to “preference customers” (public power providers) with whom they sign long-term contracts.[8] PMAs use the revenue from power sales to repay the U.S. Treasury for the initial investment made to build the federal hydropower fleet, all reinvestment in those projects, interest on initial investment, and any reinvestment and O&M costs. Repayment includes 100% of the hydropower specific costs and a project-specific allocation of joint-use costs.[9]

For the nonfederal fleet, ownership has not remained static over the decades. In fact, ownership transfers (partial or in full) are quite common. Of nonfederal hydropower plants with a FERC license, 46% were

[8]For Reclamation projects, only power in excess of *project use power* (electrical capacity and energy and associated ancillary service components required to provide the electrical service needed to operate and maintain Reclamation facilities and to provide electric service for project purposes and loads as authorized by Congress) is made available to the PMAs for marketing.
[9]For definitions of joint and specific costs, see Loughlin (1977).

transferred between 1980 and 2003 (Kosnik 2008). Most of those transfers involved small plants and were more common in the West and Northeast. Industrial owners and private utilities were the most likely transferors, and private nonutilities were the most common transferees.

The typical profile for more recent plant transfers has not changed substantially. From 2004 until the end of 2014, FERC approved license transfers for 203 hydropower plants. Most of these were small, privately owned plants changing hands among subsidiaries of the same parent company or from one corporation to another. Of the license transfers, 10 involved a change from private to public ownership. The license transfer of the Conowingo plant from the Susquehanna Power Company and PECO Energy to Exelon in 2008 stands out because Conowingo is one of only three privately owned *very large* plants (533.2 MW) in the U.S. fleet.

The list of FERC license transfers gives only a partial account of changes in ownership. On one hand, small plants holding a FERC exemption rather than a license do not need authorization for changes in ownership. Instead, they simply notify FERC that the transaction has taken place. Moreover, important deals do not always translate into a license transfer. For instance, the purchase of the Safe Harbor project in Pennsylvania by Brookfield Renewable Energy Partners does not appear in a query of FERC's license transfers. The likely reason is that the licensee of the plant has remained Safe Harbor Water Corporation, even if the owners of the corporation itself have changed. This transaction, along with the transfer of 11 power plants from PPL Montana to Northwestern Energy, were the largest hydropower-related financing deals in the United States in 2014, for which a value has been publicly disclosed. These two transactions together amounted to $1.5 billion (Ingram 2015).

2. Trends in Hydropower Development Activity

This section provides context for the extent and types of hydropower development that have been observed over the last decade and that are currently being pursued. Section 2.1 provides a detailed view of capacity changes from 2005 to 2013, which considers not only new projects but also the capacity changes (positive and negative) in already active projects. For a sample of new projects that became operational during that period, details on the length of the development processes and their construction costs are included. Section 2.2 summarizes the status of the current project development timeline and provides details on location, ownership, and type of project.

During the first decade of the 21st century, 32.75 GW of wind capacity and 2.10 GW of photovoltaic solar capacity were added to the U.S. grid. Strong increases in fossil fuel prices for much of the decade, state renewable portfolio standards (RPSs) legislation, attractive tax incentives, and mounting evidence regarding the need to curb greenhouse gas emissions all converged and made a strong case for investment in renewable generation capacity. The same magnitude of growth in new renewable generation technologies did not extend to hydropower; but nonetheless, growth and interest in further development of the U.S. fleet has continued in three different resource segments.

First, given the age of the existing fleet, rehabilitations, replacements, and upgrades need to be performed consistently to maintain existing capacity. While those upgrades are in process, it is often possible to increase the capacity of the turbine-generator units or install additional generating units. Second, adding hydropower to already existing water storage, regulation, and conveyance systems can be an attractive strategy, given that site access and infrastructure already exist and additional environmental impacts are often small. Third, cost-competitive, low-impact opportunities in new stream-reaches can also be pursued. Significant recent advancements have been made in identifying the potential capacity from these various pathways to new development.

Only 3% of dams in the United States have associated hydropower-generating facilities. The two single largest U.S. hydropower owners (USACE and Reclamation) are also the owners of a significant portion of the NPDs and conduits where hydropower could be installed.[10] The Energy Policy Act of 2005 included an initial effort to catalog the remaining potential for hydroelectric development at federal facilities. The Energy Policy Act Section 1834 Study concluded that few economically attractive sites remained (DOI/DOA/DOE 2007). In 2010, the same three agencies that coauthored that study signed a memorandum of understanding by which they committed to promoting hydropower development by nonfederal parties on their water resource infrastructure. Since then, several additional resource assessments have detailed opportunities for new projects associated with federal infrastructure (Reclamation 2011a; Reclamation 2012; USACE 2013).

At the direction of the U.S. Department of Energy, Oak Ridge National Laboratory has recently looked beyond the federal water infrastructure and performed comprehensive national assessments of hydropower potential at NPDs and new stream-reaches. The NPD assessment revealed a potential of 12.1 GW from this type of project in the United States (Hadjerioua et al. 2012). Two-thirds of that potential capacity is concentrated at 100 sites, which are mostly owned by USACE and located on the Ohio,

[10]Conduit means "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).

Mississippi, Alabama, and Arkansas rivers. As for stream-reach developments (NSDs), a resource potential of 65.5 GW—after excluding national parks, wild and scenic rivers, and wilderness areas—was identified in another assessment (Kao et al. 2014). The Oak Ridge National Laboratory assessments do not evaluate the financial viability of the projects they identify. In contrast, the federal owners computed benefit cost ratios at the sites they investigated. The USACE assessment found 2.8 GW of economically feasible capacity, while the 2011 Reclamation assessment concluded that 70 out of the 191 sites considered had attractive enough benefit-cost ratios to be further considered for development. Finally, the Reclamation 2012 site inventory and energy assessment of conduits identified 103.6 MW on 373 canals and conduits and did not evaluate economic feasibility. A comparison of the projects identified as promising in these resource assessments and the FERC development pipeline suggests that information generated by all these studies has been a useful guide for developers in selecting projects for further feasibility studies.

Beyond identifying resource potential, effort is also being applied to making the permitting process more efficient. In the vast majority of cases, hydropower project development requires federal authorization. For most other types of power plants—except nuclear and offshore wind—the majority of the siting and permitting take place at the state and local levels; however, some federal permitting might also be required.[11] Hydropower developers also have to obtain appropriate state and local permits (e.g., water quality certification and construction permits), meaning they have additional layers of authorization relative to other power plant types. As indicated in Table 2, project size and site type matter for the specific federal permitting process a developer will have to follow to build new hydropower.

Most of the alternative pathways for nonfederal hydropower involve some form of FERC authorization (either a license or an exemption). Obtaining a license typically requires more studies and involves more steps than an exemption. Moreover, a license is issued for up to 50 years, while exemptions are granted in perpetuity. The size threshold to qualify for a small hydropower exemption was doubled from 5 to 10 MW as part of the Hydropower Regulatory Efficiency Act (HREA) of 2013 (U.S. Congress 2013b).

Table 2 shows two cases in which neither a FERC license nor an exemption is needed. First, development at Reclamation conduits and non-powered Reclamation dams where hydropower is an authorized purpose requires obtaining a lease of power privilege (LOPP) from Reclamation instead of a FERC authorization. Second, developers of projects to be built on nonfederal conduits that will have a generation capacity less than 5 MW can send FERC a *Notice of Intent to Construct a Qualifying Conduit Facility*. If FERC determines (within a period of 60 days on average) that it qualifies, the project needs no additional federal permitting.

While some projects are exempt from federal permitting, others require authorization from multiple federal agencies. The developers of projects to be located on USACE NPDs need two types of federal authorization: a license or exemption from FERC and a Section 408 permit from USACE. The Section 408 permit certifies that the addition of hydropower to the site will not conflict with the uses for which it was originally intended. One of the current thrusts of effort by FERC, USACE, and Reclamation involves improving coordination to reduce redundancies and shorten total time spent in obtaining all the permits

[11]For instance, permits from the U.S. Department of Interior will be needed for any power plant built on federal, public lands.

required in projects that add hydropower to USACE NPDs. USACE is currently collecting feedback on ways to improve the Section 408 process.[12]

Table 2. Authorizations that Might Be Required from Federal Agencies to Construct New Hydropower Capacity (by Project Size and Type of Site)

<table>
<tr><th></th><th></th><th>Non-Powered USACE Dam</th><th>Non-Powered Reclamation Dam[13]</th><th>Nonfederal, Non-Powered Dam</th><th>Reclamation Conduit</th><th>Nonfederal Conduit</th><th>New Stream-Reach Development</th></tr>
<tr><td rowspan="4">Important size distinctions for federal permitting processes</td><td><=5 MW</td><td rowspan="4">FERC license and Section 408 permit from USACE</td><td rowspan="4">FERC license or Reclamation LOPP</td><td rowspan="2">FERC exemption or FERC license</td><td rowspan="4">Reclamation LOPP</td><td>“Qualifying Conduit” Status Petition</td><td rowspan="2">FERC exemption of FERC license</td></tr>
<tr><td><=10 MW</td><td rowspan="2">FERC conduit exemption</td></tr>
<tr><td><=40 MW</td><td rowspan="2">FERC license</td><td rowspan="2">FERC license</td></tr>
<tr><td>>40 MW</td><td>FERC license</td></tr>
</table>

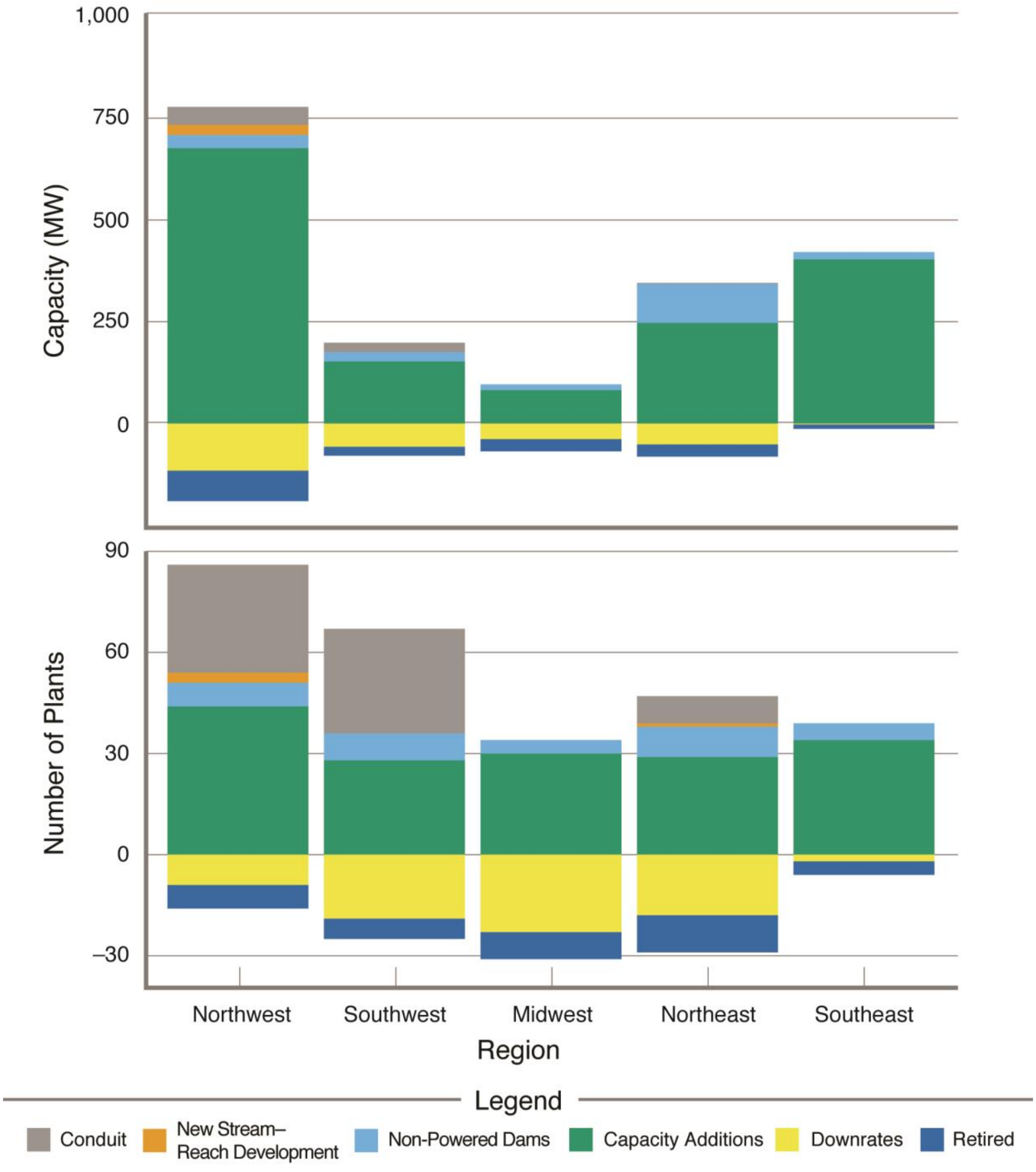
For developers of projects that require a FERC license, there is a choice between three different licensing processes: Traditional, Alternative, or Integrated. The latter was introduced in 2003 and set by FERC as the default process in 2005. In the ILP, “a potential license applicant’s pre-filing consultation and the Commission’s scoping pursuant to the National Environmental Policy Act would be conducted concurrently, rather than sequentially (FERC 2003).” By treating multiple milestones in parallel rather than sequentially, as well as increasing FERC’s participation and feedback to the applicant throughout the process, the ILP pursues improved efficiency and timeliness of the licensing process.

2.1 Recent Capacity Changes for Hydropower (2005–2013)

Figure 3 in Section 1 shows a timeline of installed capacity that assigns all current capacity in a given plant to its initial year of operation. That view of the timeline hides capacity changes that result from upgrades to the existing fleet. Figure 6 accounts for those changes from 2005 through 2013 and considers six different categories of capacity changes. *Capacity Additions* include the addition of new units to existing projects, as well as upgrades to existing units. *Downrates* correspond to downward adjustments to the reported (to EIA Form 860) nameplate capacity of existing units or situations where a plant owner decides to retire some of its units but continues to operate the rest. *Retired* projects include cases in which a plant stops operating because of accidents (e.g., fire), natural disasters (e.g., avalanche), safety concerns associated with aging infrastructure, or economic reasons (e.g., bankruptcy of the owner, increased

[12]http://www.usace.army.mil/Missions/CivilWorks/Section408.aspx
[13]Whether FERC permitting or the LOPP process is used in these cases depends on whether power production is an authorized purpose for that project (LOPP) or not (FERC permitting). http://www.hydro.org/wp-content/uploads/2011/01/Testimony_Miller.pdf

environmental mitigation requirements, or more restrictive operating conditions where it no longer makes financial sense to keep the plant in operation). Some of the retirements involve a full decommissioning of the plant including dam removal. The other three categories correspond to new projects that either add hydropower-generating equipment to NPDs, conduits, or develop projects at new stream-reaches.



Source: EIA Form 860 and NHAAP

Figure 6. Recent hydropower capacity changes by region and project type (2005–2013)

Both nationally and for each region, Figure 6 displays a positive net capacity change from 2005 to 2013. The Northwest experienced the largest net capacity increase (586.75 MW). Meanwhile, for the Southwest and Midwest, the net change was only 111.67 MW and 35.8 MW, respectively. Most of the activity corresponded to the *Capacity Additions* and *Downrates* categories (i.e., capacity changes in the existing fleet).

The average size of the retired plants is 6.53 MW. The Bull Run plant in Oregon was the largest plant retired (20.8 MW) since 2005. More than half of the 36 retirements identified took place in 2012 and 2013.

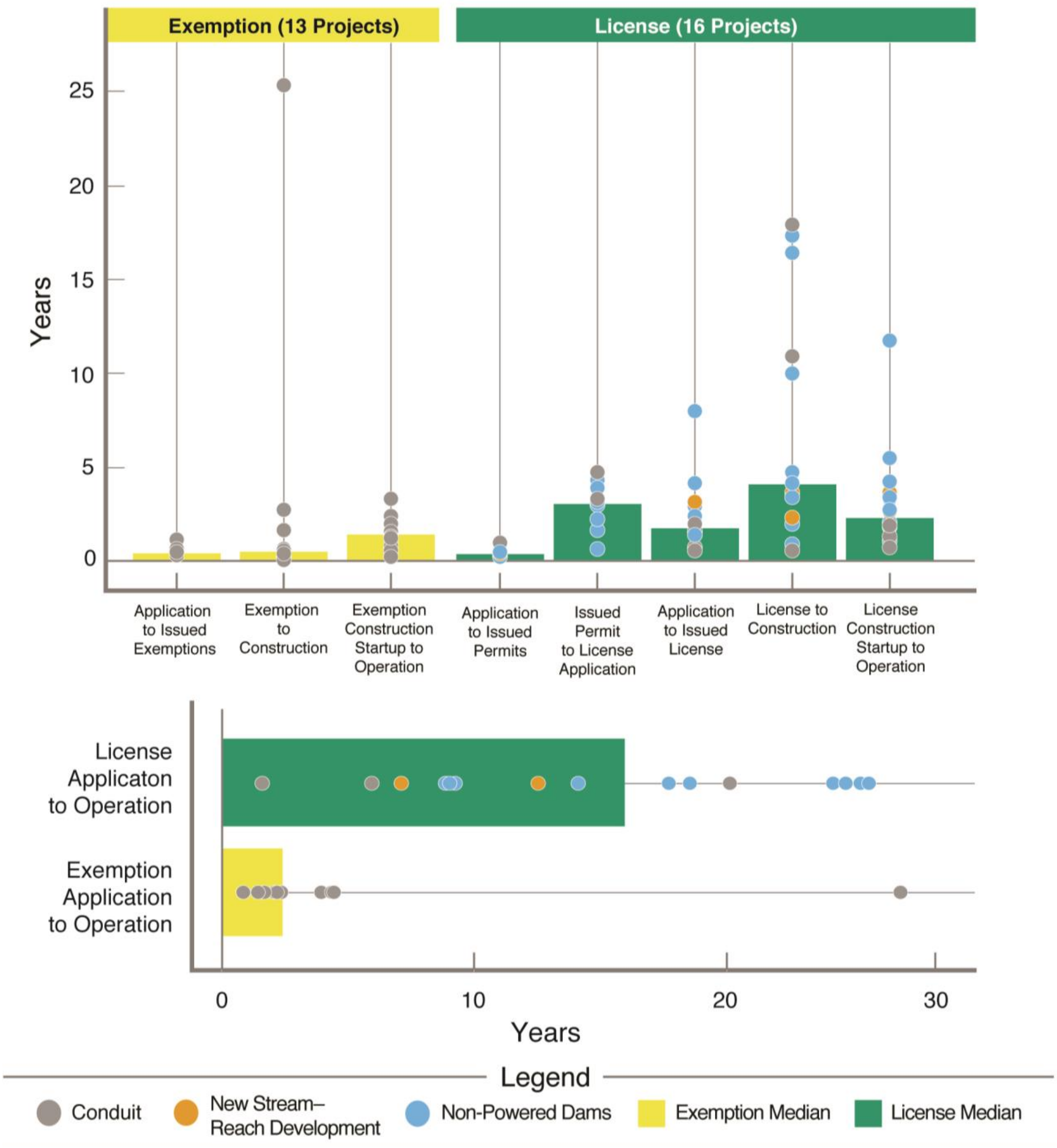
The 1,563 MW of capacity additions to existing projects accounted for 85% of the positive capacity changes. Of the total capacity additions, 370 MW, 24% corresponded to federal projects. On average, 18 plants received capacity additions each year. By far, 2013 was the most active year in that category, with capacity increases in existing plants totaling 485 MW.

Repowerings correspond to plants that have produced hydropower in the past (dating back to 1896 or as recent as 1993) but that have been inactive for several years and then restarted for operation. Several of these types of projects have occurred since 2005, particularly in the last few years. In Figure 6, 11 repowerings are included in the conduit or NPD categories. They add up to 217 MW.

NHAAP lists 156 plants as retired/withdrawals. Depending on the condition of their civil works and electromechanical components, as well as their license status and available market incentives, some of these might offer “low-hanging fruit” opportunities for developers.

Among new projects, the vast majority added electricity-generation capacity to NPDs or existing conduits. All new projects under both categories were small or medium in size. Most conduit projects were located in the western half of the country. NSD projects have been virtually nonexistent. Only one NSD project a year is documented in the EIA Form 860 database from 2008 to 2011. Three of the projects were located in the Northwest (Kasidaya Creek Hydro, Lake Dorothy Hydroelectric Facility, and Youngs Creek Hydroelectric Project) and the most recent one (Alder Brook Mini Hydro Plant) in the Northeast.

For the projects that required FERC licenses or exemptions, their dockets contain most of the information necessary to assemble a timeline of their development process. Figure 7 summarizes such a timeline for 29 projects that came online from 2005 to 2013. Figure 7 does not include all projects but rather a sample for which dates for all steps of the process could be assembled.



Note: The projects with exemptions are Juniper Ridge, Mora Drop, Rancho Penasquitos, Los Vaqueros Pipeline Energy Recovery, Lower South Fork Irrigation, Linden, Sloan, Horizon Ridge, Loring Road, Cortez Micro, Swalley Irrigation, Cascade Generating, and Esquatzel Power. The licensed projects are Arrowrock, Gross, Kasidaya Creek, Lake Dorothy, Tieton Dam, White River Lock and Dam 1, White River Lock and Dam 2, White River Lock and Dam 3, Youngs Creek, Upper Turnbull, Lower Turnbull, Saint Anthony Falls, South Fork Black Bear, Jordan, Culinary Water System, and Mahoning Creek. Of the 16 licensed projects, 6 did not apply for a preliminary permit and therefore only include license application to operation time.

Source: FERC dockets, EIA Form 860, and web searches

Figure 7. Length of development process for a sample of recently completed projects from 2005 to 2013

FERC issued 79 exemptions from 2005 to the end of 2014. Of these, 78% were conduit exemptions. They amounted to 101.84 MW and their median size was 241 kW. The search for development timeline information focused on the 54 exempted projects above 100 kW. Of those, approximately half were operational at the end of 2014 and the other half are still engaged in preconstruction or construction activities.

As for licenses, FERC issued 46 original licenses for hydropower projects from 2005 to 2014. In the last decade, 2014 has been the most prolific year for issued original licenses both in the number of issued licenses (11) and authorized new capacity (140.7 MW). The authorized capacity for the 46 projects licensed since 2005 is 443 MW. Their median size is 4 MW, and the largest is American Municipal Power's (AMP's) Meldahl project (105 MW). Of those 46 licenses, 7 correspond to repowerings, expansions, or existing projects that had not yet applied for a license because they were built before the FERC licensing process was required. Among the remaining 39 licensed projects, 32 are still engaged in preconstruction or construction activities. On the other hand, 12 of the 16 licensed projects in Figure 7 obtained their license before 2005.

For the exemption projects included in Figure 7, the median project took approximately 2.5 years between applying for exemption and reaching commercial operation. The longest stage in the development process was the construction period. Except for one outlier that took more than 20 years from when the exemption was issued to the start of construction, all 13 projects experienced similar timelines.

For the projects that started operating between 2005 and 2013 and that have FERC licenses, except for the first stage in the development process, there is a remarkable spread in the time it took to complete each step. This variability is a reflection of the unique issues that face each hydropower project. The projects with the longest total development periods were NPD and conduit projects rather than the few instances of NSD installations.

The data show that obtaining a license can be a complex and expensive process but can also be relatively quick in some circumstances. Results vary widely based on a number of different factors. The median licensed project included in Figure 7 took the most time from issued license to start of construction (more than four years). The postlicensing activities that delay the progress toward construction include obtaining, if needed, USACE 408 permits, as well as any other required state and local permits, arranging project financing, finalizing the engineering design, securing an interconnection agreement and, if the developer is not a utility, finding a buyer for the power that the project will produce.

Changes in ownership often take place between the license issuance and construction start dates. Some developers specialize in obtaining financing from private equity and strategic investors at the early stages of development and/or on navigating the licensing process. Once they reach that milestone, they transfer the rights to develop the project to another party that will continue with the financing, construction, and marketing agreements. Two recent examples of license transfers are the Mahoning Creek Project and the Red Rock Hydroelectric Project.[14]

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[14]Advanced Hydro Solutions obtained the FERC license for the Mahoning Creek project on March 2011 and sold it to Enduring Hydro, LLC, in July 2012. Enduring Hydro worked through USACE's Section 408 process and ultimately constructed the project. Similarly, Nelson Energy obtained the license to develop the Red Rock Hydroelectric Project in April 2011 but transferred the development rights to Western Minnesota Municipal Power Agency in January 2012.

The median time from construction start to being placed in service for the projects in Figure 7 was 28 months for licensed projects and 17 months for those with an exemption. FERC exemptions and licenses include requirements—although they can be extended within certain limits if requested by the project developer and/or authorized by Congress—regarding the time that can elapse between their issuance and the start of construction and between start of construction and placement in service. While developers of the projects with conduit exemptions, included in Figure 7, typically met the expected schedule, developers of licensed projects often did not and had to obtain extensions. Several licenses and exemptions have also been revoked over the years because of failure to comply with the established timelines.

Figure 7 does not include any project that has been developed under the LOPP process. To date, nine nonfederal hydroelectric projects have come online through a LOPP on Reclamation-owned infrastructure. Seven of them are located in Colorado, one in Utah, and one in Oregon. Projects range in size from 120 kW to 13 MW. Three of these projects (Grand Valley Project, Jackson Gulch Dam, and Lemon Dam) have been operational for decades. The remaining six projects have all been brought online in the past seven years (Reclamation 2015b). To date, all LOPP project owners are public entities. According to the Bureau of Reclamation Small Conduit Hydropower and Rural Jobs Act, Reclamation must offer the first opportunity to develop hydropower at its conduits to the irrigation district or water users association that operates or is served by the conduit. Reclamation also must give preference to public entities over private entities as developers of conduit projects under the LOPP process.

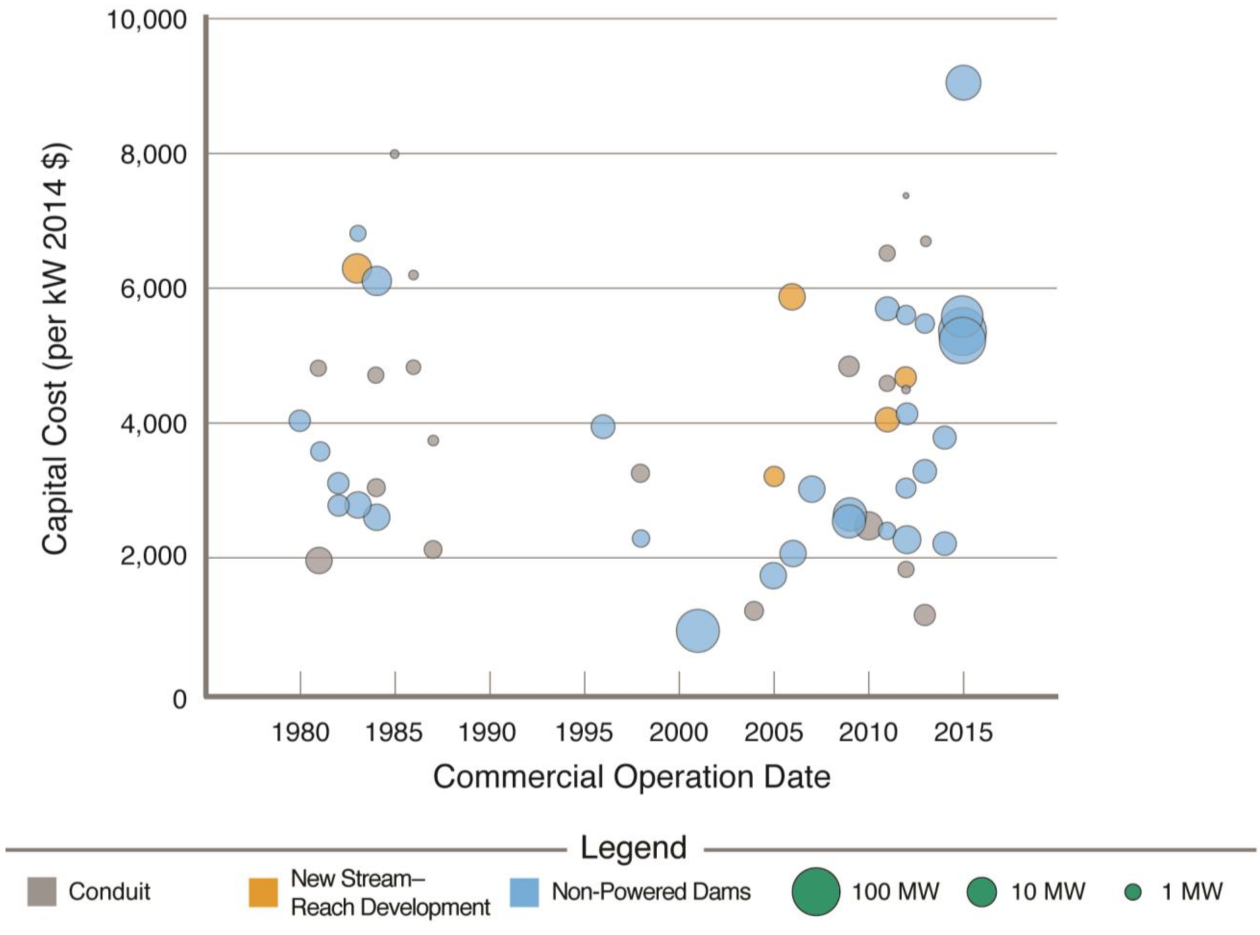
Starting in 2011, Reclamation collaborated with its stakeholders and the hydropower industry to improve the LOPP process. This collaboration culminated in the release of an updated LOPP directive and standard in September 2012, which established a more coherent and transparent lease process. Under the revised directive and standard, the median length of development (from project solicitation to commercial operation) has been 3.77 years, with the LOPP-to-online phase being shorter than the solicitation-to-LOPP phase in all but one case.

2.2 Hydropower Project Cost and Investment Data

While Figure 7 illustrates the length of the development process, Figure 8 tracks the cost of constructing hydropower plants (i.e., the cost of the last step of the development process as described in Figure 7).[15] In order to explore long-term construction cost trends, the dataset used for Figure 8—based on a number of data sources, including a capital project database from IIR, data collected from the U.S. Department of Energy's 1970s–1980s small hydropower program, consultant estimates, and others—captures a subset of NPD, conduit, and NSD projects constructed over the last three decades. For more background on the data sources used in Figure 8, see O'Connor et al. (2015).

Generally, costs have ranged from $2,000 to $6,000 per kilowatt for all three resource classes, with extremes as low as $1,000 and as high as $9,000. The average conduit project cost $4,100 per kilowatt, the average NPD project cost approximately $3,800 per kilowatt, and development along new stream-reaches cost approximately $4,900 per kilowatt.

[15]Estimates exclude the cost of licensing and other project activities such as staff and legal expenses necessary to develop power purchase and interconnection agreements and to obtain financing.



Note: Costs have been escalated to 2014 dollars using annual average values of the Consumer Price Index. Cost "bubble" size is proportional to the square root of capacity; the legend provides visual scale for 1, 10, and 100 MW projects.

Source: Cost data from O'Connor et al. (2015)

Figure 8. U.S. hydropower construction cost by project type and project size (1980-2015)

In all three cases, costs were driven by economies of scale (i.e., lower costs) from higher hydraulic head, while only conduit projects appear to exhibit meaningful economies of scale from higher installed capacity. Studies of hydropower costs focusing on isolated powertrain components—such as turbine runner and generator—have found strong economies of scale based on unit capacities (such as Idaho National Laboratory [Hall 2003] and the Electric Power Research Institute [EPRI 2011]). However, every site presents a unique civil engineering challenge, and as such the economies of scale from increased project size appear to average out for recent NPD and NSD developments, at least for the subset of potential U.S. projects economically competitive enough to reach commercial operation.

Across the time span of collected data, construction costs for hydropower plants have not grown on a real, inflation-adjusted basis. However, this has not necessarily held true at all times during the past three decades as inflation has generally risen faster than major hydropower construction cost indices between the mid-1980s and mid-2000s, only recently converging (that is, hydropower becoming relatively more expensive) following steep commodities price increases in the 2000s and the financial crisis and recession (O'Connor et al. 2015).

Significant capital investment towards modernizing and upgrading the existing fleet is consistently taking place (see Figure 9). According to IIR, approximately $3.6 billion has been spent ("complete") over the last decade to repair, replace, and refurbish U.S. hydropower facilities. The scope of work in these projects is very diverse and includes many other items aside from turbine unit modifications, which could be as small as replacing bearings or as large as rebuilding a dam. The expenditures tracked by IIR include not only the purchase cost of components but also the cost of engineering studies and installation.

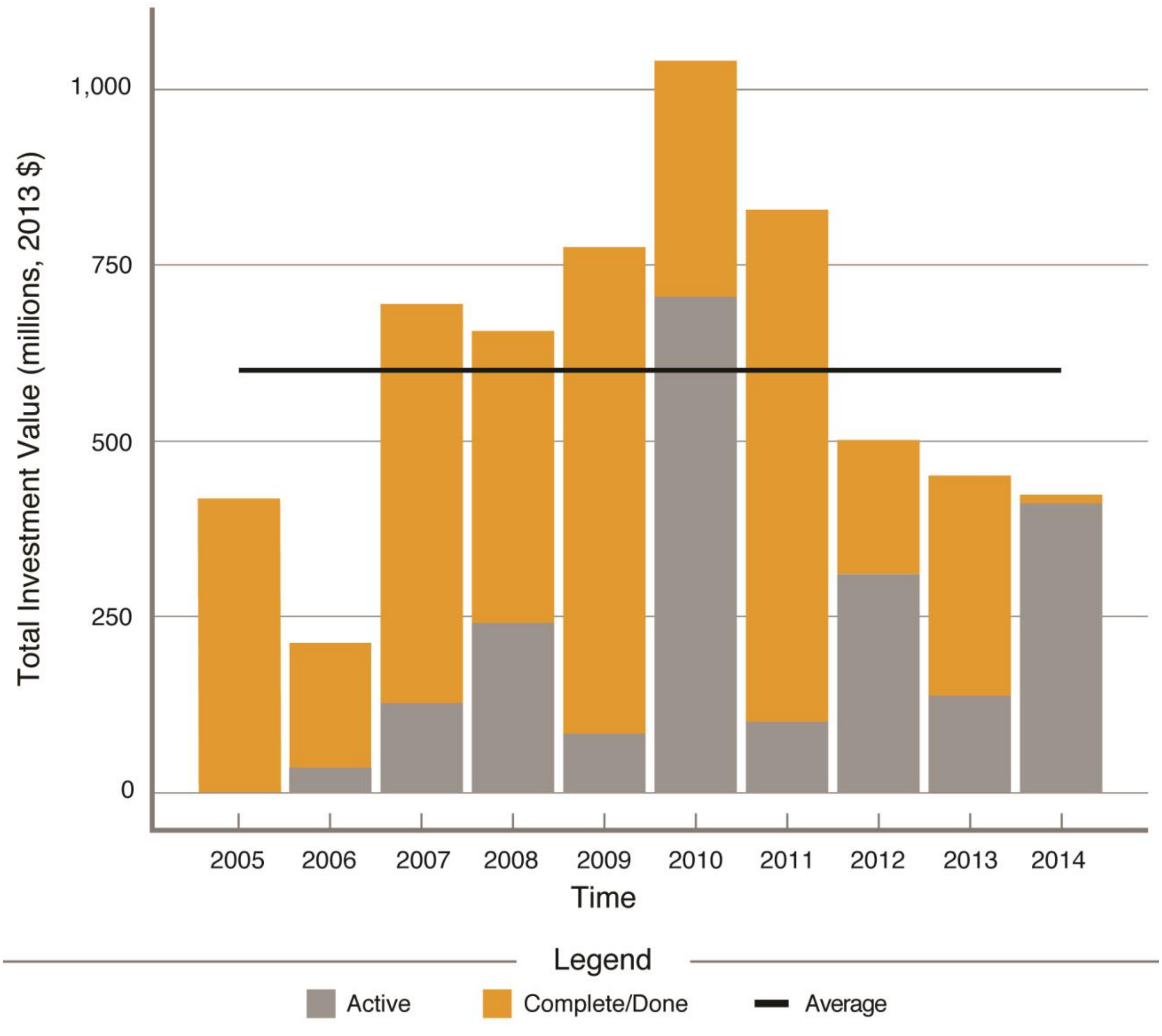
Since 2005, IIR has tracked $6 billion invested in refurbishments, replacements, and upgrades to U.S. hydropower plants. Federal owners were responsible for 26% of this total, even though they own about half of the installed capacity. Thus, nonfederal owners have been spending significantly more per kilowatt installed than federal owners.

The projects completed in 2014 consist of transformer replacements and generator rewinds. Of the 15 projects reported as still active for 2014, 11 include some type of maintenance towards the hydraulic turbine or turbine parts. The estimated investment value of those 15 projects is $339 million.

As shown in Figure 6, most of the recent hydropower capacity additions in the United States have come from unit upgrades or additions to existing projects. Another economic growth channel for the hydropower industry is the construction of new projects. The estimated cost of the 16 new, nonmicro projects identified as being under construction as of December 2014 is $1.96 billion (O'Connor et al. 2015).[16] There are six micro projects that received conduit exemptions from FERC that are also under construction, with an estimated value of $3.97 million.[17] Additionally, there could be up to 23 more micro- or small-conduit projects under construction that received a positive determination using the FERC qualifying conduit pathway. The construction cost of these projects has not been tracked at this time.

[16]The list of projects under construction, from largest to smallest, includes Meldahl (OH), Cannelton (KY), Smithland (KY), Red Rock (IA), Willow Island (WV), Lake Livingston (TX), Blue Lake (AK), Puu Lua (HI), Dorena Lake (OR), Reynolds Creek (AK), Clark Canyon (MT), Whitman Lake (AK), Chester Diversion (ID), Plateau Creek (CO), 45-Mile Conduit (OR), and Conduit 3 (OR).

[17]The six micro projects include Monroe Cold Springs (UT), Oak Springs (OR), SPS of Oregon (OR), Coltsville Flow Control Station (MA), and Veazie Energy Recovery Hydropower Plant (ME).



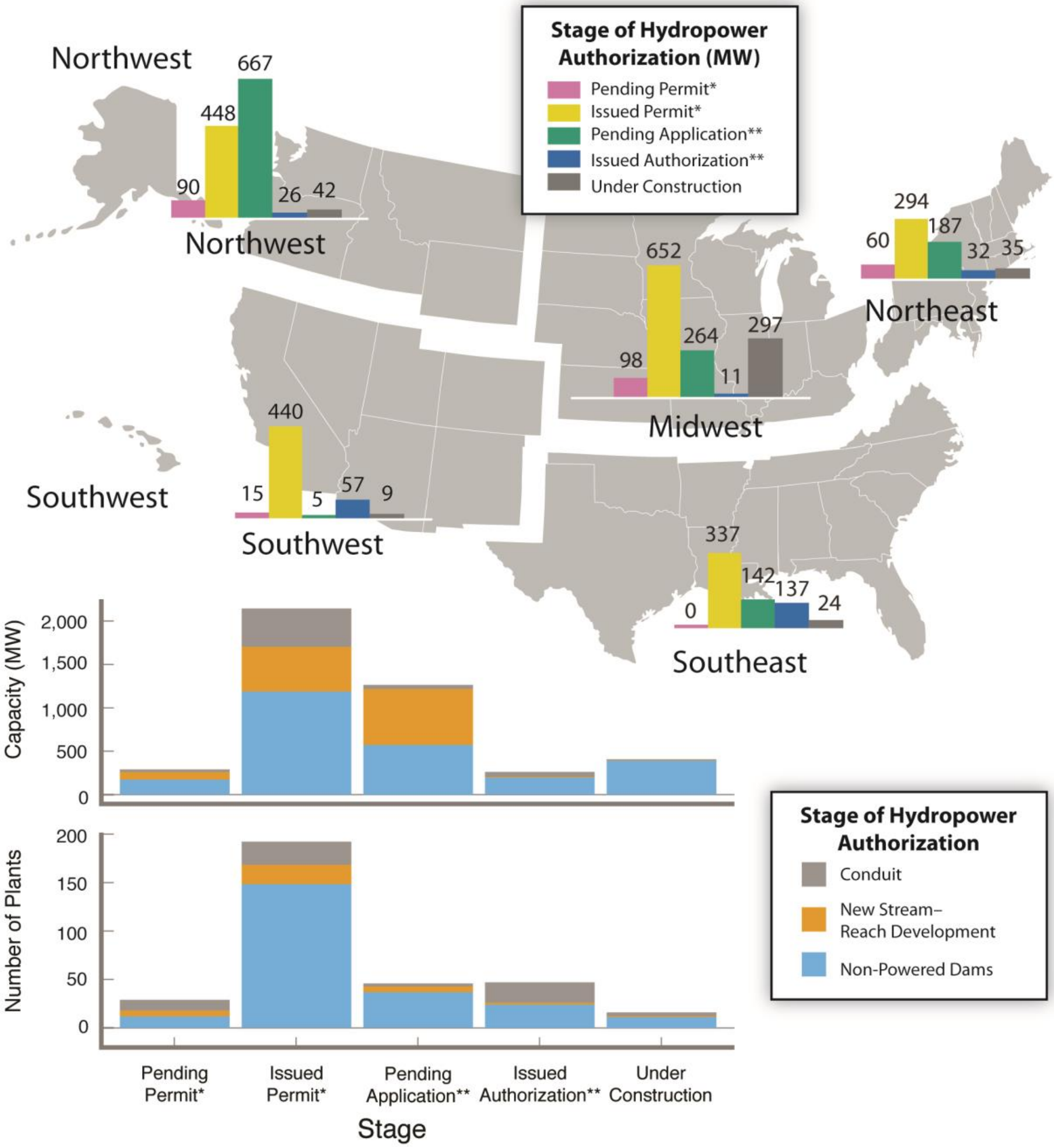
Source: PECWeb Dashboard data from Industrial Info Resources: http://www.industrialinfo.com/

Figure 9. Expenditures on rehabilitations, replacements, and refurbishments of existing hydropower fleet

2.3 Hydropower Project Development Pipeline (as of December 2014)

The previous section described the capacity changes that have materialized over the past decade and reviewed data regarding the length of the development process and the cost of construction for recently completed projects. This section covers projects that are currently in the development pipeline. The focus is on new projects rather than capacity changes to the existing fleet.

Figure 10 provides a snapshot of the new project development pipeline as of December 2014. The map included in Figure 10 conveys information on the regional distribution of the development activity, while the accompanying bar plots classify activity by project type. The information contained in both images includes projects that are at any stage of the FERC license or exemption process—including preliminary permits—as well as conduit projects pursuing LOPP authorization from Reclamation. Micro hydropower projects are excluded in Figure 10. Some of the micro projects have applied for “qualifying conduit” status, an alternative that is discussed in the sidebar on page 29. Thus, the following figures and discussion do not represent the total universe of projects being considered but show the new projects greater than 100 kW that are being actively pursued. To simplify the visualization of the information and convey the idea of how advanced in the permitting process each project is, projects are classified in one of five categories that correspond to specific points within each of the permitting pathways:



*Projects in the *Pending Permit* and *Issued Permit* stages have high attrition rates. *Pending permit* includes projects pending a preliminary lease in the LOPP process and projects pending issuance of a preliminary permit. *Issued permit* includes projects that have received a preliminary lease in the LOPP process and projects that have obtained a FERC preliminary permit.

***Pending Application* includes projects that have applied for an original FERC license or for a small hydropower or conduit exemption. *Issued Authorization* includes projects that have been issued an original FERC license or either of the two FERC exemption types or that have a final lease contract under the LOPP process.

Source: FERC, Reclamation LOPP database, HydroWorld, and web searches

Figure 10. Hydropower project development pipeline by region, status, and project type (as of December 31, 2014)

Simplifying the Permitting Process for Qualifying Conduit Hydropower Projects

With passage of the HREA of 2013, conduit projects smaller than 5 MW with nonfederal owners have a new, simple route to permitting for qualifying conduit facilities that negates the need for FERC authorization and addresses concerns of developers pursuing projects where the cost and complexity of obtaining an exemption was disproportionate in relation to the construction cost of the project itself.[18] *Since August 2013, 51 notices of intent to build this type of project have been filed with FERC. They mostly have come from municipalities and irrigation districts, although some are from private individuals. The median size of the projects was 285 kW, and only five of them were greater than 1 MW. As for their regional distribution, they were overwhelmingly on the western half of the country: 30 in the Southwest, 13 in the Northwest, with the remainder in the Northeast (7) and Midwest (1). As of December 2014, 12 of the notices were rejected, 12 were pending, and the remaining 27 projects have qualified to proceed as qualifying conduits without having to obtain a license or an exemption. All final qualifying conduit determinations were issued by FERC in less than three months after the notice of intent was submitted; that period includes 30 days over which FERC revises the notice to discern if it meets the required criteria and 45 days for any third-party to raise concerns against a positive determination.*

Given their size, it is difficult to track the status of these projects once they are approved. At least 4 of the 27 that have been approved to date are already operational. The fact that these projects are concentrated in western states partly reflects the prevalence of conduit infrastructure (particularly irrigation canals) on that side of the country but also that some states have been particularly proactive in offering incentives for this type of development. For instance, on January 2015, the Colorado Department of Agriculture was awarded a grant for $1.8 million by the U.S. Department of Agriculture to support the development of agricultural hydropower systems in the state, most of which would be eligible for pursuing qualifying conduit status. Additionally, rural businesses and agricultural producers looking to install small hydropower systems anywhere in the United States might be eligible for guaranteed loan financing and grant funding under the U.S. Department of Agriculture Rural Energy for America Program.

Pending permit—includes projects pending a preliminary lease in the LOPP process and projects pending issuance of a preliminary permit. Applying for a preliminary permit is an option rather than a requirement in the licensing process. The preliminary permit reserves the project developer the option to apply for a license at a specific site during a three-year period. During that time, the developer conducts feasibility studies to decide whether to proceed with a full license application.

Issued permit—includes projects that have received a preliminary lease in the LOPP process and projects that have obtained a FERC preliminary permit.

Pending application—includes projects that have applied for an original FERC license or for a small hydropower or conduit exemption.

Issued authorization—includes projects that have been issued an original FERC license or either of the two FERC exemption types or that have a final lease contract under the LOPP process.

Under construction—includes projects from any of the permitting pathways for which a construction start date has been verified (either through the FERC dockets or through web searches).

[18]http://democrats.energycommerce.house.gov/sites/default/files/documents/Testimony-Johnson-EP-HR-4273-Environmental-and-Grid-Reliability-HR-5892-Hydropower-Regulatory-Efficiency-2012-5-9.pdf

As of December 2014, the number of hydropower projects in the FERC or LOPP pipeline is 331, amounting to a capacity of 4.37 GW. The LOPP pipeline includes seven projects (25.1 MW) of which three have already received final authorization, three have obtained a preliminary lease, and one is awaiting the preliminary lease.[19]

The development stage with the most projects and most capacity is *Issued Permit*. For the 407 MW under construction, there is a reasonable guarantee that they will be placed in service. Of the 16 projects identified as being under construction, 72% of the capacity consists of the four lock and dam projects on the Ohio River (Meldahl, Cannelton, Smithland, and Willow Island) being built by AMP. The only other three projects under construction greater than 10 MW are also NPD projects: Blue Lake in Alaska, Lake Livingston in Texas, and Red Rock in Iowa. All projects under construction are either NPD or conduit projects.

For any stage before construction, there is a nontrivial probability that the projects will be abandoned, but the probability decreases with each step of the process. In assembling this snapshot, care was taken to drop from the reported set those projects that let their preliminary permit expire without taking any further action towards a license application, projects that have surrendered a license or exemption after being issued, and projects whose applications were rejected by FERC.

NPD facilities dominate the pipeline, accounting for 233 projects and 58% of capacity. NSD projects are overwhelmingly concentrated in the Northwest (31 projects and 1,125 MW out of 1,259 MW nationwide). In fact, 21 of the 35 NSD projects in the development pipeline are in Alaska. Nearly half (48%) of all NSD capacity being pursued nationwide is embodied in a single project (Susitna in Alaska). Its status in the pipeline is *Pending Application*. At the time of this writing, Susitna's developer (Alaska Energy Authority) has requested that FERC suspend the licensing process for two months because of state cuts on discretionary spending brought about by lower oil revenues. The only other large NSD project in the pipeline is the Mississippi River Chain of Rocks project in Missouri (125 MW). Of the 35 proposed NSD projects, 18 would fall under the category of diversion projects and would not involve significant dam construction. It also means that they would be operated as run-of-river projects.

Within the conduit category, one project (Lake Powell Pipeline) has more capacity (345 MW) than all other 61 combined. The Lake Powell Pipeline project is being pursued by the Utah Board of Water Resources. Its primary purpose is water delivery, but hydropower generating equipment will be included along the conduit to take advantage of the large elevation differential (2,900 feet) between both ends of the pipeline. The planned completion date for this project is 2025.[20]

The distribution of projects by developer type follows a similar pattern as observed in the existing fleet (except that there are no federal projects). Private developers pursued two-thirds of the projects, which account for only 40% of the total capacity in the pipeline. This means that the average size of projects being developed by public entities is larger than for private entities. The financing instruments at the disposal of public entities might be better suited to develop projects above a certain threshold and that have a long payoff period.

[19]Developers for an additional 12 projects (20 MW) have contacted Reclamation to participate in the LOPP process but have not yet made a formal public solicitation. Those 12 projects are not included here.
[20]http://www.water.utah.gov/lakepowellpipeline/Timeline/default.asp

Within the private developers, the most common subcategory is private nonutility. These are mostly limited liability corporations that do not have a customer base to whom they could sell the power from the project and will have to pursue power purchase agreements with public or investor-owned utilities. On the other hand, investor-owned utilities are practically absent from the hydropower development pipeline. Outside of Alaska, no investor-owned utility is currently pursuing new hydropower development. However, those utilities are proposing capacity upgrades as part of project relicensing. Looking through the current list of proposed projects for all electricity generation technologies as reported on EIA Form 860, the lack of development activity by investor-owned utilities is not only a hydropower phenomenon but seems more extreme for hydropower than for other technologies.

Some developers in the private nonutility category obtain preliminary permits on clusters of projects for which they then proceed to determine economic viability. As a result, those developers might hold a large number of preliminary permits at any given time. The cluster approach would appear to diversify risk and reduces the costs of determining the best projects in a particular region since the stakeholders to be engaged will be very similar for all the projects in a given cluster (Lissner 2014).

The median size of projects in the pipeline is 0.42 MW for conduit projects, 4.8 MW for NPD projects, and 6 MW for NSD projects. Therefore, regardless of project modality, the typical project is small. The volume of financing needed for these projects will subsequently be low, but this poses its own problems. Large institutional investors are generally uninterested in smaller investments, and even in cases where small projects are able to secure the interest of large, conventional financing sources (such as commercial banks), their financing costs are higher on a relative basis, as the projects must still go through a rigorous due diligence process, the cost of which is spread across many fewer megawatts relative to their larger counterparts.

Size and developer type are not the only determinants of the attractiveness of a project to investors. Expected performance and flexibility should also determine the value of an installed kilowatt. Most new projects are NPD or conduits where the original purpose of the infrastructure will place constraints on the volume and timing of generation and on the flexibility with which the capacity can be operated. For the most part, new projects will be operated as run-of-river, with limited flexibility. Metrics that summarize the observed performance of the existing fleet are discussed in Section 3.

Discussion and figures presented in this section focus on new projects. Projected capacity changes to the federal fleet can be partially tracked through the planned upgrade schedules published by USACE, Reclamation, and TVA as part of their hydropower modernization initiatives (discussed in Section 3). However, these planned schedules might be delayed or not materialize because of budgetary restrictions. For the nonfederal fleet, capacity changes might be communicated to FERC in one of two ways. If they can be framed as the result of a maintenance project in which a turbine unit is replaced for another with the same specifications (i.e., in-kind replacement) or of generator rewinds, all that is typically needed is to file revised drawings for some of the license exhibits (Kleinschmidt Group 2015). If the change will result in "an increase in the maximum hydraulic capacity of 15% or more, and would result in an increase in the installed capacity of two megawatts or more," it will necessitate a capacity-related license amendment filing (Kleinschmidt Group 2015). The process to obtain authorization for license amendments involves six steps that are similar to those involved in an original license application (FERC 2001). To avoid extra regulatory reviews, project owners often propose capacity amendments in conjunction with a relicensing process.

- As of December 2014, 14 projects propose capacity increases, while five projects propose capacity decreases as part of their relicensing processes. The net capacity increase from those 19 projects is 270 MW.
- Outside of relicense applications, another 13 projects in the FERC pipeline entail capacity increases or unit additions at existing projects, accounting for 312 MW. Of these, 280 MW correspond to a single project. A private developer is proposing to add four units at an existing empty powerhouse bay that is part of USACE’s John Day project in Washington.

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3. Hydropower Performance Metrics

This section delves into observed trends in fleet performance. The first metric considered is generation volume focusing on variability over time and across regions over the last decade. The capacity factors implied by those generation volumes, along with a view of the long-term evolution of capacity factors for a selected subset of plants, are discussed next. An important idea illustrated throughout the section is that hydropower performance is not only about generation volumes. Hydropower generating assets provide many other services to the grid. Even though a data gap exists as to the number of hours or the capacity volumes providing ancillary services, an hourly breakdown of operational status offers some clues. Since hydropower units might be contributing valuable services to the grid even when they do not generate power, the evolution of availability factor becomes a key metric to track. Finally, another key indicator of value is flexibility, which is discussed using data on operational mode and the number of unit starts. Unlike in Sections 1 and 2, which covered the entire fleet, many of the data sources used throughout this section cover only segments of the fleet, which is made clear throughout the discussion.

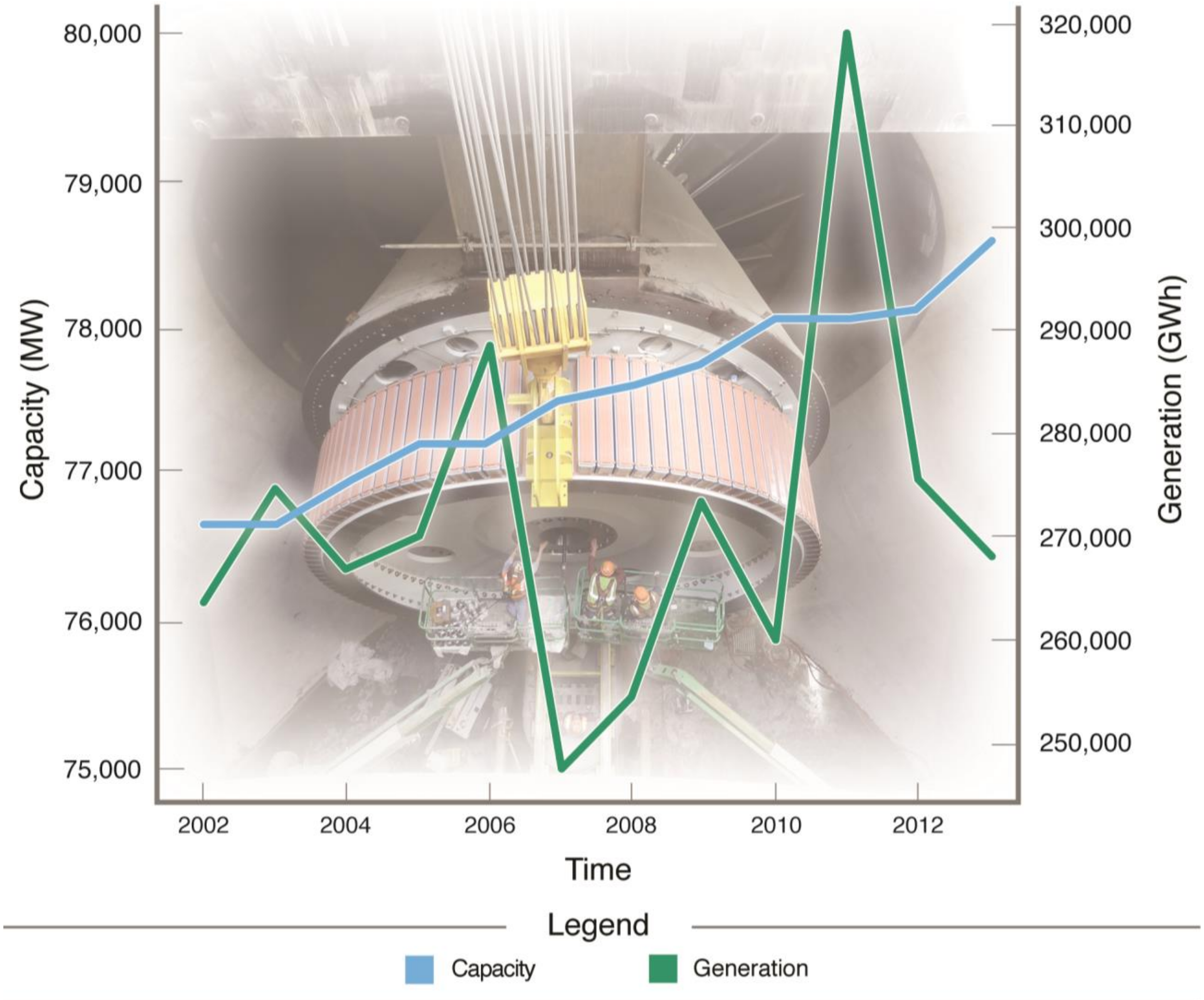
3.1 Energy Generation

Figure 11 displays net generation and installed capacity of the U.S. hydropower fleet from 2002 to 2013. Net generation from the U.S. hydropower fleet averaged 272,350 gigawatt-hour (GWh) from 2002 to 2013. While the average annual increase in installed capacity during that period was 0.23%, the maximum net generation (319,355 GWh in 2011) was 29% greater than the minimum (247,510 GWh in 2007). Variability in hydrologic conditions is the main, though not unique, reason for the strong year-to-year fluctuations.

Even though total generation changes significantly year-to-year, there are relatively stable patterns as to the geographical and seasonal distribution of annual generation. Figure 12 reveals those patterns. The central lines depict the median generation for each month in each region during 2002–2013, while the surrounding bands enclose all but the 10% highest and 10% lowest observations.

The region with the largest fleet (Northwest) generates, by far, the most hydropower, while the region with the least installed capacity (Midwest) produced the least in all the months and years included in Figure 12. On the other hand, even though the Southwest and Southeast have similar installed capacities, the median generation by the Southwest fleet is significantly larger than in the Southeast for most months. And while the Northeast has much less installed capacity than the Southeast (8.3 GW versus 14.8 GW, respectively), its median generation is higher throughout the year.

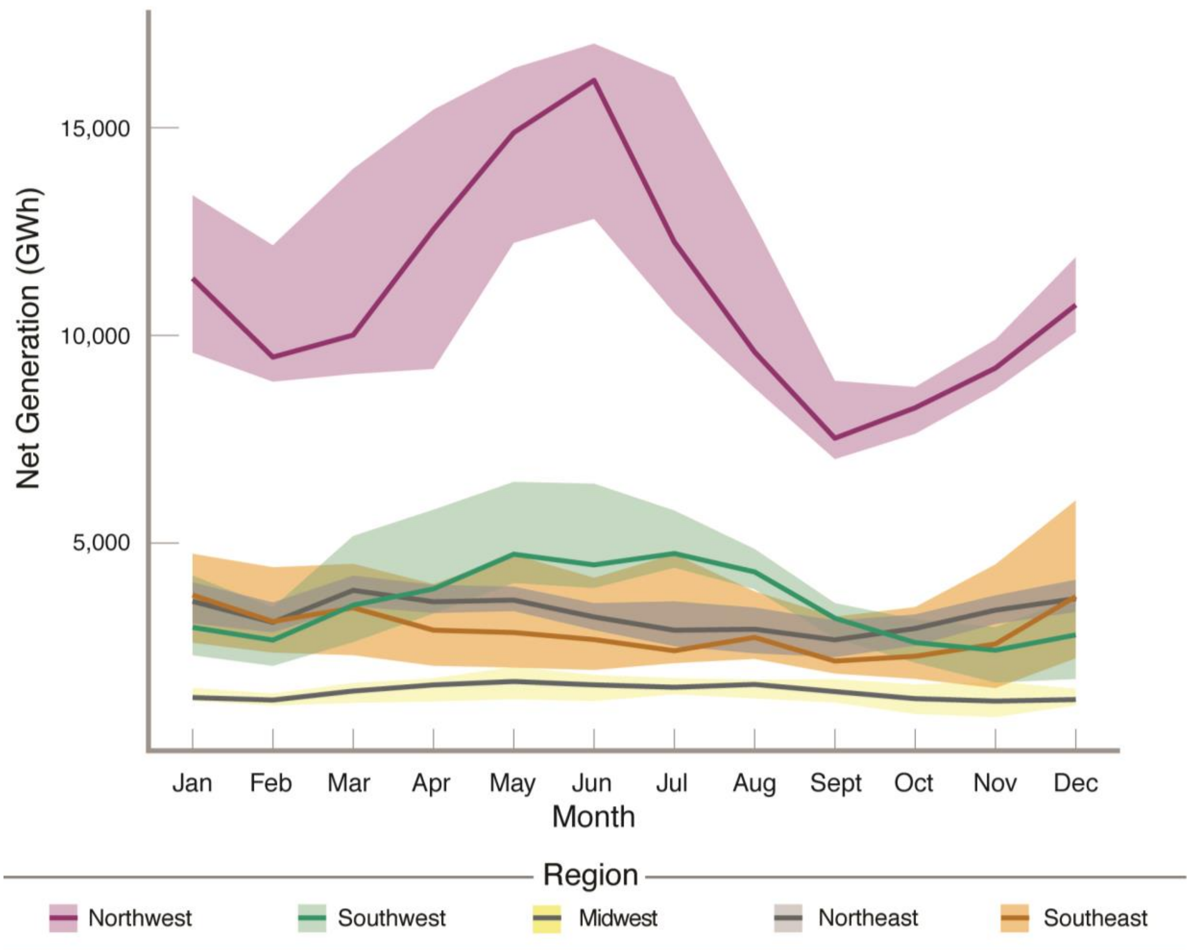
In both the Northwest and Southwest, most of the runoff comes from melting snowpack. Consequently, the peak in generation is observed during late spring in those two regions. By contrast, in the Northeast and Southeast, the generation peak occurs during the winter months, coinciding with the major flood seasons in their main river basins. Finally, for the Midwest, generation tends to be slightly higher in summer than in winter but the seasonality is much less marked than elsewhere.



Note: EIA data cover only a fraction of hydropower plants with nameplate capacity lower than 1 MW. The set of plants included in this figure accounts for approximately 98% of the total hydropower capacity estimated by NHAAP.

Source: EIA Form 860 and EIA Form 923. The background image is provided by American Municipal Power and shows the Meldahl plant.

Figure 11. Annual hydropower capacity and generation (2002–2013)



Note: The central lines depict the median generation level for each month in each region during 2002-2013. The surrounding bands enclose all but the 10% highest and 10% lowest observations.

Source: EIA Form 923

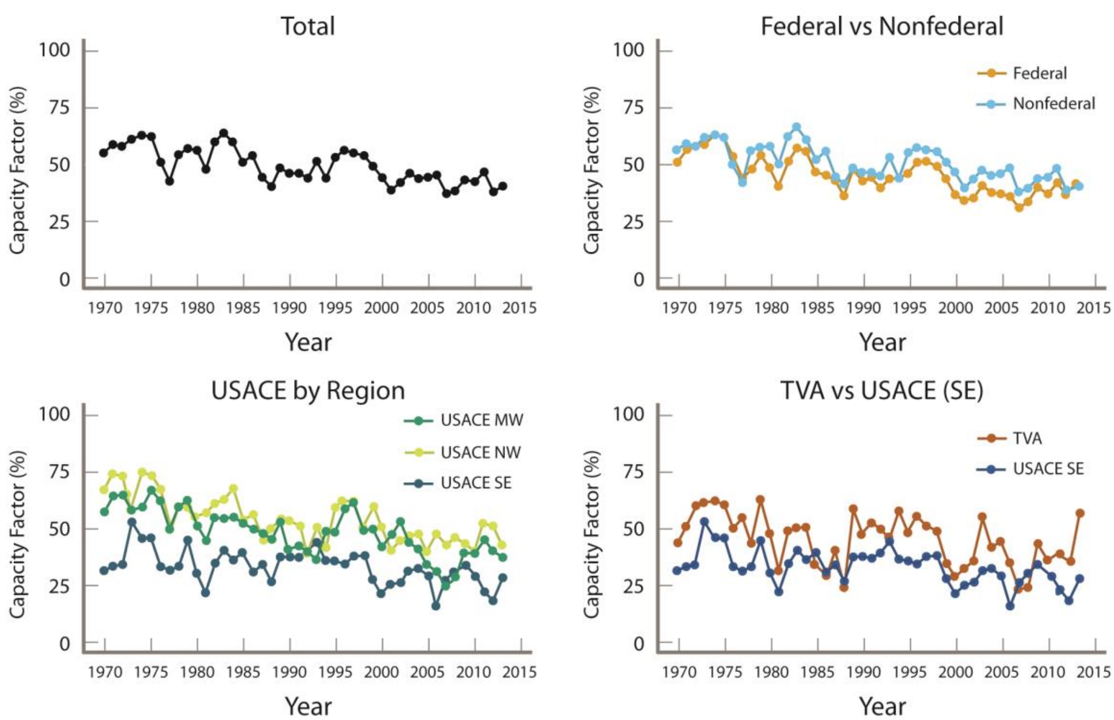
Figure 12. Monthly hydropower generation by region (2002–2013)

The large late spring peak in generation in the Northwest does not correlate well with the electricity demand load profile in their region. Not being able to save the water for later in the summer is, at least partly, a consequence of storage constraints in the system. In other words, the reservoirs in that region are not large enough to hold the volume of water from a typical snowpack melt. The Southwest has more storage capacity relative to its typical annual runoff and can allocate it more evenly through the summer. The smoothing effect of storage would also likely explain the asymmetries on the band around the median during summer. The range of above-median generation volumes is much larger than the range of below-median generation volumes. During wet years, the electric grid welcomes additional generation, but during dry years, it resorts to lowering reservoir elevation levels if needed to avoid reducing generation much beyond the median level.

3.2 Capacity Factors

Because the installed capacity in the United States during the last decade has not changed much, the variability in generation observed in Figure 11 for that period largely translates into variability in capacity factors. The capacity factor of a hydropower plant is the ratio of actual output to potential output over a given period of time where the potential output is computed by multiplying the number of period hours times the nameplate capacity of the plant. For instance, in the last three years, the capacity factor for the entire fleet was 39% in 2013, 40% in 2012, and 46% in 2011, a "wet" year for the dominant Northwest region. Capacity factors vary year to year because of hydrologic conditions, water demands for competing uses (e.g., during a dry year, not only will there be less total water available but also more will be needed for irrigation), environmental and regulatory restrictions, and other factors like plant outages that affect available capacity. Variation is also significant from plant to plant. In 2012, one-quarter of active plants had capacity factors below 28%, while plants in the top quartile had capacity factors above 55%. The two most common operational modes for projects in the top quartile were canal/conduit and run-of-river.

Given that the U.S. hydropower fleet has a long history, it is worth exploring the presence of longer-term trends underlying the year-to-year variation. Figure 13 shows four snapshots of the evolution of capacity factor since 1970. To avoid mixing changes in capacity factor for a stable set of plants with changes in the composition of the fleet, the set of projects in Figure 13 includes only those built before 1970 for which a complete data series was available. The sample includes 532 plants that amount to 73% of current installed capacity. The capacity of this sample grew over the four decades considered here because of unit additions and upgrades. Only for 204 out of the 532 plants did installed capacity remain unchanged throughout the entire period. Only subsets with sufficient coverage were separated out from the "Total" series.



Source: EIA Form 920/921/923

Figure 13. Long-run monthly hydropower capacity factor for plants built before 1970

All four panels in Figure 13 display a decreasing trend over time. The variability range for the "Total" series is smaller than for some of the subsets, particularly the regional ones, a result of the smoothing effect of geographic diversification in the fleet. During the 1970s and early 1980s, capacity factor was routinely more than 50%, while, from then on, it has become increasingly rare to achieve such average level of utilization in any given year. The panels in Figure 13 show that ownership and geographic location have been important for the evolution of capacity factor.

- The "*Federal vs Nonfederal*" panel indicates that both segments of the fleet had very similar capacity factors for most of the 70s, but, particularly since the mid-nineties, the nonfederal plants have maintained a higher capacity factor than the federal fleet.
- The "*USACE by Region*" panel shows that the performance of plants owned by the same federal agency in different regions is markedly different. This is partly because of hydrology but also to other factors like differences in the financing mechanisms used to upgrade the aging fleet in each region (see sidebar on page 39).
- The "*TVA vs USACE (SE)*" panel shows that, within a single region, the capacity factor of plants owned by two different federal agencies has also been markedly different. It would be difficult to justify this difference on the basis of hydrology. For TVA, the 1990s seem to mark the reversal from a previous trend of decreasing capacity factors. The comprehensive modernization program that this federal agency initiated around that time seems to be a plausible explanation for the observed change.

Equipment aging, climate change, operational changes from environmental regulations, and realignments of the relative priority given to different water uses in multipurpose projects are all likely contributors to the long-term trends in capacity factor. In recent years, the role of hydropower (particularly in the Northwest and Southwest) in providing the additional capacity reserves required to integrate variable renewables is also contributing to decreases in capacity factors. It is beyond the scope of this report to disentangle the contributions of all these factors, but their net effect is shown in Figure 13. The most acute, steady decreases in capacity factor took place in the late eighties and late nineties.

Refurbishment and Modernization Strategies for the Federal Fleet

As the median age of federal hydropower plants approaches 50 years, maintaining reliability and performance within a satisfactory range requires a sustained program of refurbishments and/or upgrades. Available funding mechanisms to sustain those programs vary across federal agencies, which influences the levels of nonrecurring O&M expenditures and, as shown in Figure 13, capacity factors.

Since 1959, TVA has funded modernization and upgrades directly from power sales revenues. The objective of its Hydro Modernization Program, initiated in 1992, is improving reliability in all units and increasing capacity whenever financially sensible. As of the end of 2013, 60 units (out of a total of 111) had been modernized, with a capacity gain of 576 MW and an average efficiency gain close to 5%. Modernization of the remaining units is scheduled to take place by 2030 (TVA 2011b).

Using asset management principles, USACE and Reclamation have prioritized the capital investments needed in their fleets. USACE published a 20-year asset management plan where the proposed investment ranges from $1.5 billion to $2.6 billion for three different budget scenarios (USACE 2011). Reclamation identified major rehabilitation and replacement needs for fiscal years 2012–2016 to be $2.6 billion for all their assets, not just hydropower (Reclamation 2015a).

For federal projects whose power is marketed by BPA, the funding situation is similar to that of TVA. Since 1992, BPA can fund project upgrades directly out of power sales revenues. Attempts to expand this funding model to the other three PMAs did not succeed (National Research Council 2013). Instead, those PMAs send their power revenues back to the U.S. Treasury to repay the federal funds that were invested in those projects to date, and it is the asset owners (USACE and Reclamation) who submit budget requests to Congress for future rehabilitation and upgrades. Some recent studies have pointed out that funding levels made available for upgrades might not keep pace with the growing needs of an aging fleet (Sale 2011). For USACE, the expected hydropower appropriations for fiscal years 2011–2015 were approximately $200 million per year, of which only 10% would go towards nonroutine O&M.[21]

Proposed options to offset the need for appropriations to fund capital investment range from alternative financing mechanisms (e.g., Energy Savings Performance Contracts) to an increase in rates for PMA customers or even the sale of federal hydropower assets to private investors (Bracmort 2013; Sale 2011). Until now, the main source of alternative, nonappropriated funds has been PMA customer funding. For Reclamation-owned plants, the legislation that authorizes customers to contribute funds for capital investments and O&M expenditures was passed many decades ago, but only started being used extensively to finance O&M and capital upgrades in the last two decades.[22] *As for USACE-owned plants, Section 212 of the Water Resources Development Act of 2000 allows USACE, PMAs, and their customers to enter agreements in which PMA customers pay upfront for nonroutine O&M projects. Western Area Power Administration, Southwestern Power Administration, and the Southeastern Power Administration have used this framework extensively.*

For nonfederal plants, the decrease in the late eighties correlates to the passing of the Electric Consumers Protection Act, which directs FERC to give non-hydropower values (energy conservation, fish and wildlife protection, recreation, and other aspects of environmental quality) equal consideration with power generation and economic development during the (re)licensing process. The adoption of the Electric Consumers Protection Act materialized in an increased percentage of recommendations made by federal or state resource agencies being accepted by FERC without modifications, from 66% in 1982–

[21]http://www.usace.army.mil/Portals/2/docs/civilworks/5yr_devplan/fy11_5yrplan.pdf

[22]The Sundry Civil Expenses Appropriations Act of 1922 is the contributed funds act for construction, and the Interior Department Appropriations Act of 1928 is the contributed funds act for O&M.

1986 to 77% in 1988–1991 (Government Accountability Office 1992).[23] Even though not licensed by FERC, the federal plants are also required to mitigate fish and wildlife impacts. Mitigation strategies typically involve both capital cost investments and changes to hydropower operations. The latter, which includes increased water spill, reduced peaking, and changes to the seasonal timing of hydropower production affect both the quantity produced and the value per megawatt produced. For instance, for the portion of the federal fleet managed by BPA, foregone revenues associated with operational changes for environmental protection have been more than \$100–\$150 million annually in recent years.[24]

Another contributing factor to the federal versus nonfederal differences is the reallocation of federal reservoir storage capacity from hydropower to other uses. Under the Water Supply Act of 1958, USACE and Reclamation have authority to reallocate (within certain limits) reservoir storage from other authorized project purposes to municipal and industrial use. USACE has used this authority, sometimes also requiring Congressional approval, at 44 of its projects to accommodate the water demands of growing metropolitan areas (Brougher and Carter 2012). In at least half of those, hydropower is an authorized purpose. Though the reallocations have been generally small, in some cases they have had noticeable effects for power customers (e.g., Lake Lanier in Georgia and Lake Texoma in Oklahoma and Texas). The Lake Texoma reallocation meant a 23% reduction in reservoir storage available for hydropower and an estimated lost energy and capacity revenue of \$1.6 million per year (Sale 2011).

As for the effects of climate change, several studies have translated precipitation and temperature projections coming from global climate models into projections of U.S. regional snowpack and runoff volume and timing—standard indicators of water availability for hydropower production (Reclamation 2011b; Kao et al. 2015). These studies provide ranges of possible outcomes. Aware of those ranges and having recently experienced acute drought situations, some hydropower owners have started implementing climate change adaptation strategies. For instance, Reclamation has installed new wide head range turbines at Hoover Dam that allow more efficient operation over a wider range of reservoir levels than the turbines used until now.

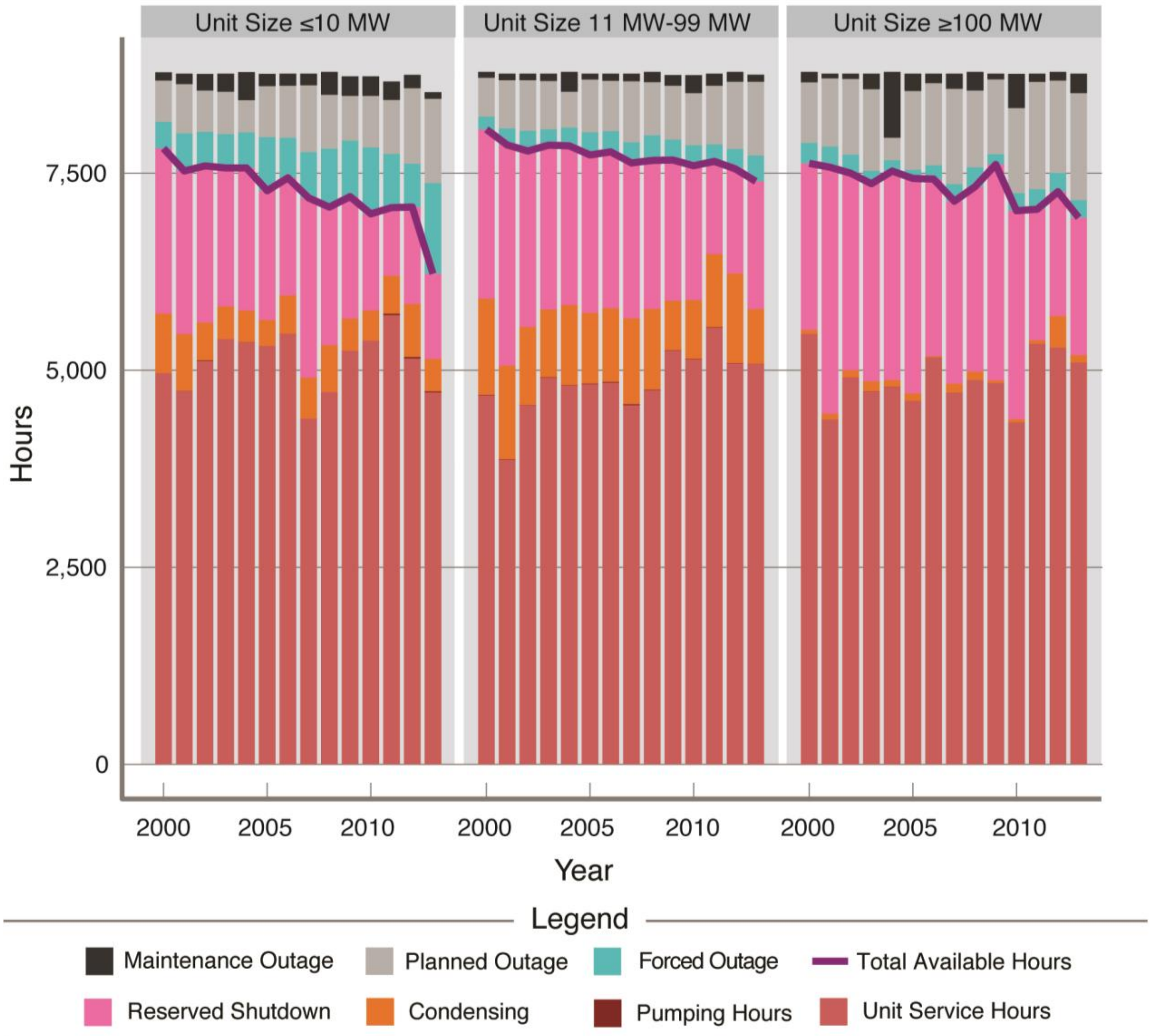
3.3 Availability Factors

The capacity factors discussed in the previous section can be interpreted not only as the ratio of actual generation over potential generation but also as the percentage of hours in a given year in which a plant or unit produced at its maximum, nameplate capacity. While synchronized to the grid, plants are not always producing at their nameplate capacity. However, they might be providing other valuable services to the grid. For that reason, the number of hours in which a plant is synchronized to the grid is also an important performance metric. NERC collects detailed performance information for a subset of hydropower units in GADS. The hourly breakdown of operational status for units reporting to GADS is presented in Figure 14.

Hydropower units were separated into three different groups based on their size. The average number of units reporting to GADS during 2000–2012 was 258 for units below 10 MW, 520 for units between 10 MW and 100 MW, and 126 for units greater than 100 MW. This corresponds to 6%, 42%, and 67% of the total number of installed units, respectively. Therefore, results should be interpreted with caution (especially for units in the smallest size group).

[23] Recommendations by these agencies typically consist of setting minimum flows, requiring installation of fish passage or other structures to mitigate impacts on aquatic populations, reservoir drawdown limitations, and purchase of lands to be managed for fish and wildlife conservation.

[24] http://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2014IPRMeetingMaterials/2014_IPR_FW_Workshop.pdf



Note: Operation and outage state definitions from the NERC Glossary of Terms: *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), *Forced outage* (unplanned component failure or other conditions that requires the unit to be removed from service immediately, within six hours or before the next weekend), *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), *Unit service hours* (number of hours synchronized to the grid).

The number of units reporting to NERC GADS varies from year to year resulting in different levels of coverage. During the 2000-2013 period, coverage ranged from 4% to 7% for units less than or equal to 10 MW, from 35% to 45% for units in the 11 MW-99 MW range, and from 61% to 76% for units greater than or equal to 100 MW.

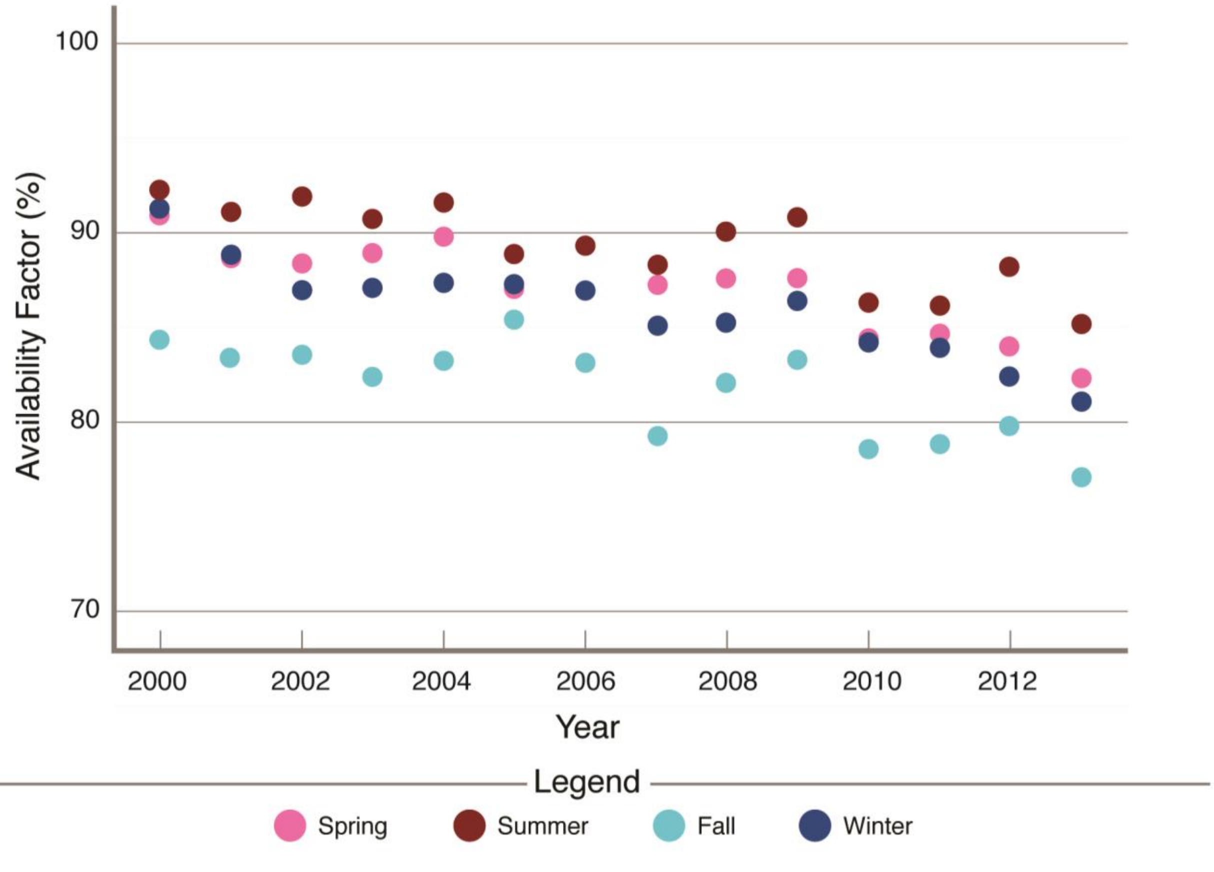
Source: NERC GADS

Figure 14. Average hydropower operational status (hourly breakdown by unit size classes of units reporting to NERC GADS)

Reporting units distribute total period hours in each year (typically 8,760) across seven different categories. Four of them are active states (unit service, pumping, condensing, and reserve shutdown), and the remaining three are outage states (forced outage, planned outage and maintenance outage). The sum of hours spent in the four active states constitutes the total number of available hours (represented as a purple line in Figure 14). On average, the number of unit service hours during 2000–2013 was 5,118; 4,850; and 4,896 for the small, medium, and large units, respectively. These are the hours that matter for a computation of capacity factor, suggesting that smaller units (not to be confused with small plants) had, on average, higher capacity factors. Small- and medium-size units spent, on average, 504 and 953 hours per year, respectively, in condensing state, while large units spent almost no time performing that function. When condensing, a hydropower unit is operated as a motor, spinning freely in air and drawing power from the grid to provide reactive power/voltage support. On the other hand, the largest units spent more time in the reserve shutdown state than the smaller units. All in all, a decreasing trend in availability factor is present for all unit sizes but is particularly strong for units under 10 MW.

Figure 14 suggests the existence of a tradeoff between planned and forced outages. The larger units spend, on average, the most time out of service for planned maintenance and inspections. As a result, they also experience the lowest number of unplanned outage hours. The outcome is reversed for the smaller units, which experienced an increasing trend in unplanned outages during the last 13 years. The unplanned outage of a very large unit is very expensive; therefore, it would make sense to invest more in avoiding it.

By averaging over the whole year, Figure 14 leaves the marked seasonal component in availability factor out of sight. For units reporting to NERC GADS, Figure 15 shows that the availability factor during the summer is 5 to 10 percentage points larger than in the fall. Fall is when planned outages typically take place because that is also the time with the lowest cost of opportunity associated with the outage.



Note: The number of units reporting to NERC GADS varies from year to year resulting in different levels of coverage. During the 2000-2013 period, coverage ranged from 13% to 18%.

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Source: NERC GADS

Figure 15. U.S. hydropower availability factor (for units reporting to NERC GADS)

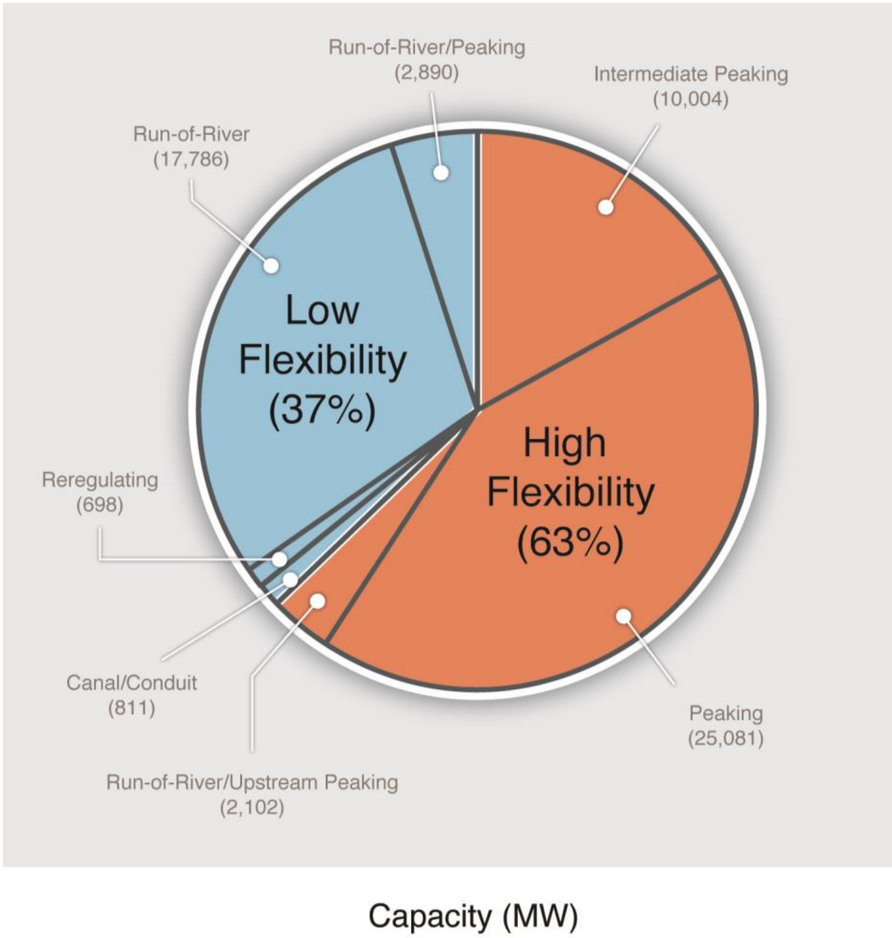
3.4 Operational Mode

Operational mode is partly determined by the physical configuration of the hydropower plant and, for projects with a FERC license, is often one of the terms of the license. It gives an indication as to how closely a given hydropower plant can follow the load profile and/or contribute to accommodating fluctuations in variable renewable generation. The operational mode categories in Table 3 are listed in ascending order in terms of the degree of operational flexibility they allow. For hydropower generation plants located in a canal or conduit, the volume and timing of water flow is dictated by the purpose (typically, irrigation or water supply) for which the conduit was initially built. Therefore, the owner has very little flexibility to decide when or how much to generate. On the other extreme of the flexibility distribution are peaking plants. Some of the intermediate categories (reregulating and run-of-river/upstream peaking) are found on cascading hydropower systems where downstream plants mitigate or replicate the fluctuations from an upstream peaking plant.

Table 3. Definitions of Operational Mode for Hydropower Plants

Mode-of-Operation Class	Description/Purpose
Canal/Conduit	Uses water flow determined by the original purpose of the conveyance structure to generate electricity.
Run-of-River	Discharges from the project tailrace or dam, approximately, the sum of inflows to the project reservoir at any given time. Hydroelectric generation depends on natural incoming flows. Minimizes the fluctuation of the reservoir surface elevation and deviation from natural flow regimes.
Reregulating (Cascading Systems)	Stabilizes flow fluctuations from upstream peaking or storage release facilities and generates electricity. Often used to mitigate impacts to natural flow regimes from peaking reservoirs. Reduces impacts to natural flow regimes from upstream peaking plants.
Run-of-River/Peaking	Operates as run-of-river facility for periods of time or seasons (e.g., during fish spawning) and then operates as a peaking facility the remainder of time.
Intermediate Peaking	Stores limited amounts of water for occasional releases, or moderates the intensity of peaking for hydroelectric generation.
Run-of-River/Upstream Peaking (Cascading Systems)	Operates as run-of-river facility but harnesses the energy from upstream storage releases or peaking operations to generate electricity.
Peaking	Stores and releases water (high-flow releases) for hydroelectric generation. Typically large reservoir fluctuations because of seasonal drawdowns.
Source: McManamay and Bevelheimer (2013).	

For 547 power plants representing 77% of installed hydropower capacity, information on operational mode was assembled from a variety of sources (McManamay and Bevelheimer 2013). Figure 16 depicts the distribution of that subset of the fleet across the various operational modes listed in Table 3. From the portion of the fleet whose operational mode information was tracked, more than 39 GW correspond to operational mode categories with high flexibility potential. The two most frequent categories are peaking and run-of-river, which are present in all regions. Nonetheless, there are an additional 12 GW that essentially take advantage of the peaking flows of an upstream plant to amplify the peaking potential of the system as a whole. Most of the “run-of-river/peaking” capacity is located in the Northeast, while the “intermediate peaking” category is found almost exclusively in the western regions. The median size of plants in the “peaking” category is 30 MW, whereas it is 1 MW for “run-of-river” plants. Because the plants for which no information on operational mode was available were predominantly small, it is likely that the nontracked capacity concentrates on the low-flexibility end of the spectrum.



Note: Operational mode information is not available for the entire fleet. This figure includes 1,206 plants equaling 59,372 MW which is approximately 75% of total active installed capacity as of December 31, 2014.

Source: FERC documents, federal agency reports and contacts, Internet searches

Figure 16. Distribution of operational modes in U.S. hydropower fleet

Even though flexibility is viewed as a valuable attribute from the perspective of the electricity market, run-of-river plants are typically preferred from an environmental standpoint. Over time, mitigation of environmental impacts has become a higher priority in hydropower project design, licensing, and operation. One manifestation of that trend appears during project relicensing. From 1988 to 2000, 13% of the projects (28 out of 223) that went through the relicensing process changed their operational mode from peaking to run-of-river (Jager and Bevelheimer 2007).[25]

The number of starts performed by a turbine-generator unit provides an indication of the degree of flexibility with which it operates. NERC defines actual unit starts as the number of times a turbine-generator unit becomes synchronized to the grid. For the sample of units reporting to NERC GADS, the

[25]The reasons cited for these changes ranged from mitigating impacts to fish populations to water quality certification requirements and aesthetic considerations.

median number of actual unit starts ranged from 11 to 17 per year over the 14-year period that was analyzed. Had those starts taken place at regular intervals, this would be roughly consistent with one to two starts per month. However, the maximum number of starts in any given year ranged from 560 to 1,813 (consistent with multiple starts per day). Therefore, there is a wide range of operational behaviors. It is to be expected that the units with the largest number of actual starts per year would correspond to peaking plants.

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4. Pumped Storage Hydropower

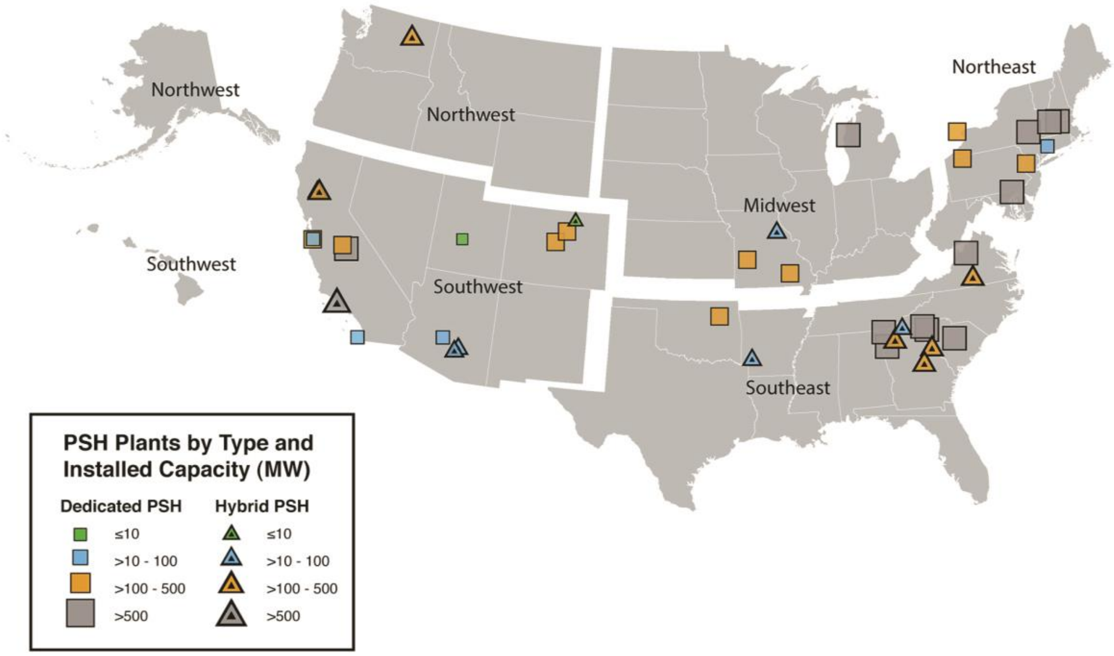
Sections 1–3 describe the existing hydropower fleet and discuss its development and performance trends but leave out PSH projects. PSH projects are classified as storage rather than generation resources and are often described as “giant water batteries.” The existing 21.6 GW of PSH capacity make up the overwhelming majority (97%) of utility-scale electricity storage in the United States.[26] PSH projects have a lower reservoir and an upper reservoir. Water is pumped from the lower to the upper reservoir, typically when electricity is cheap, and then released from the upper reservoir to generate electricity during peak demand. More energy is spent pumping up the water than is generated when releasing it back down. Therefore, PSH plants are net consumers of energy. They tend to generate when the price of electricity is high enough relative to the cost paid for the pumping energy to cover the pumping losses. Beyond taking advantage of the arbitrage opportunities enabled by the peak-to-off-peak price differential of electricity, PSH can provide a long list of other services to the grid. Those services include inertial response, primary frequency control, operating reserves, reduced cycling of thermal generating units, reduced transmission congestion, voltage support, black-start capability, and other portfolio effects (Koratirov et al. 2014). Since both the role of PSH on the grid and its development trends are different from those of the rest of the fleet, it made sense to discuss it separately. This section discusses most of the same material as the previous three but focuses on the PSH portion of the fleet.

4.1 Installed Capacity and Regional Distribution of Pumped Storage

As of December 2014, the PSH fleet comprises 158 units distributed across 42 plants. There are two types of plants: those in which all turbine-generator units are reversible (*dedicated PSH plants*) and those that contain both regular and reversible units (*hybrid PSH plants*). Median size, ownership type, and patterns of operation are different for these two types of plants. The average capacity of dedicated PSH plants is more than three times the average pumped storage capacity of hybrid plants (673 MW versus 146 MW). All but two of the hybrid plants are owned by public (federal and state-level) entities. On the other hand, 71.6% of the capacity in dedicated PSH plants is privately owned. Figure 17 shows the geographical distribution of the existing PSH fleet, distinguishing dedicated and hybrid PSH plants as well as their sizes.

Figure 17 provides a detailed account of the distribution of sizes and locations for PSH plants. There is at least one PSH plant in each region. The Northwest, the region with the most hydropower installed, has the least PSH capacity. The capacity shown in Washington corresponds to the six reversible pump units in the Grand Coulee plant. The Southeast leads the country in terms of installed PSH capacity (9.06 GW). As for sizes, large and very large plants make up most of the installed PSH capacity. The seven PSH plants containing less than 100 MW of installed capacity account for only 1.4% of total PSH installed capacity. Although there is an expectation of strong economies of scale in PSH projects, historical data from the existing fleet do not show a clear inverse relationship between cost per kilowatt installed and plant size (MWH 2009). At present, research is being conducted to determine whether standardized reversible pumps, new penstock materials, and strategies for the reduction of civil works costs might make smaller, modular PSH projects feasible (Hadjerioua et al. 2014).

[26]Based on EIA Form 860 data for 2013. The remainder is made up of battery installations, flywheels, and a compressed air energy storage facility.



Note: This map displays the location and capacity of existing pumped storage hydropower (PSH) plants in the United States by region. Different symbols are used for PSH plants depending on whether all their units are pumped storage units (dedicated PSH) or they contain a mixture of regular and pumped storage units (hybrid PSH). For plants that contain both types of units, only the capacity of the pumped storage units is shown in the map.

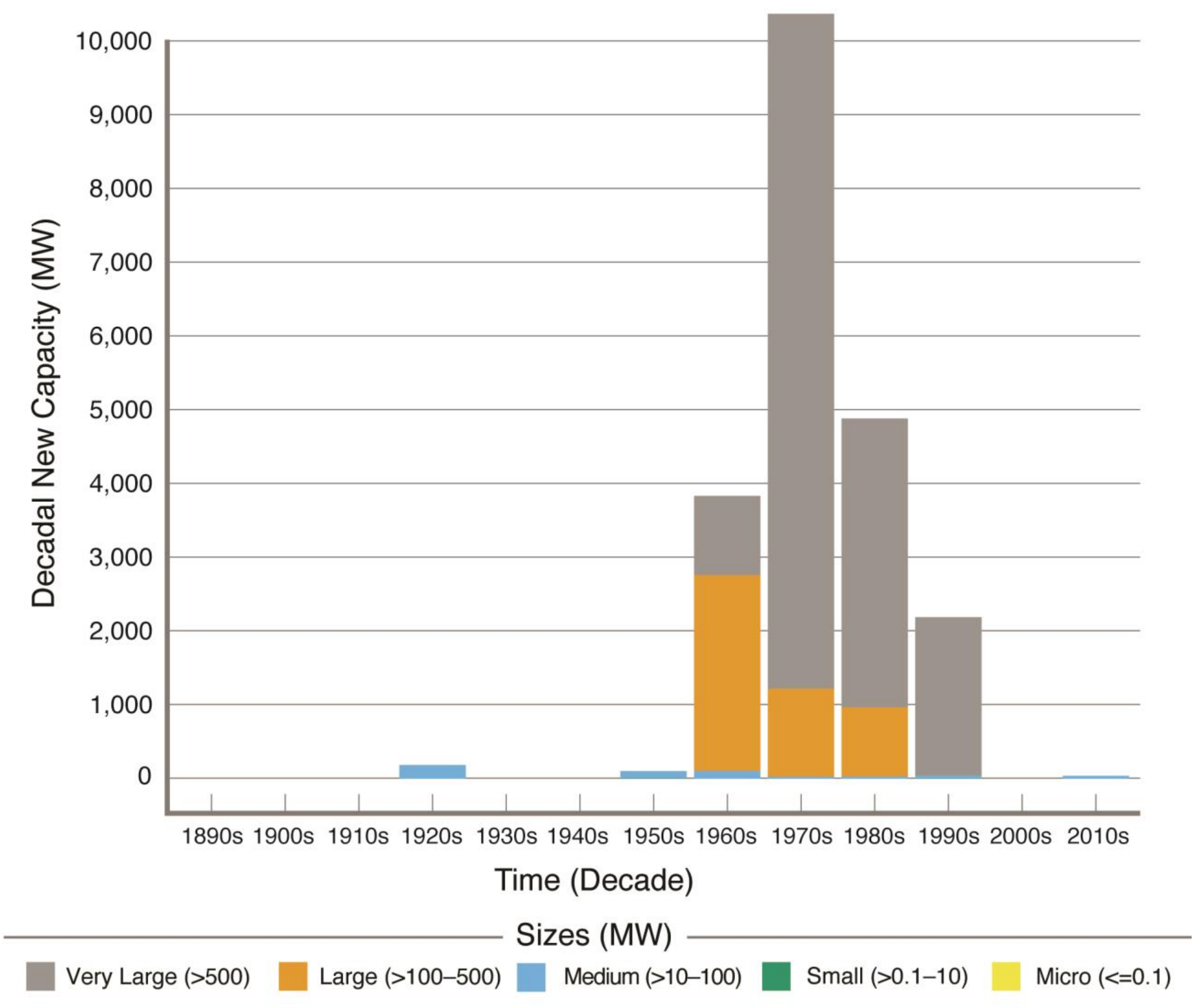
Source: ORNL NHAAP Existing Hydropower Assets Data Set, 2000 Census-State Boundaries.

Figure 17. Map of the U.S. pumped storage hydropower fleet by plant type and size

The first three pumped storage units were built in 1929 in the Rocky River Project (CT). However, the unit TVA installed at the Hiwassee plant in 1956 has special significance because it was the first reversible pump-turbine installed in the United States for the purpose of energy storage. That powertrain option has become standard in PSH projects, but earlier facilities either used separate pumps and turbine-generators, or a pump, a turbine, and a generator all on a single shaft (TVA 1981).

The vast majority of installed capacity was built between 1960 and 1990. Figure 18 shows that the decade when the largest PSH capacity was installed, the 1970s, coincides with the period in which development of hydropower generation resources faded. In contrast, since 2000, only one medium-size plant has been developed. The two pumped storage units at the Olivenhain-Hodges project in Southern California add up to 40 MW and are part of the San Diego County Water Authority's Emergency Storage Project. The main purpose of the project is water storage/supply, while ancillary revenue from the operation of the PSH portion of the project helps to offset ratepayer costs.

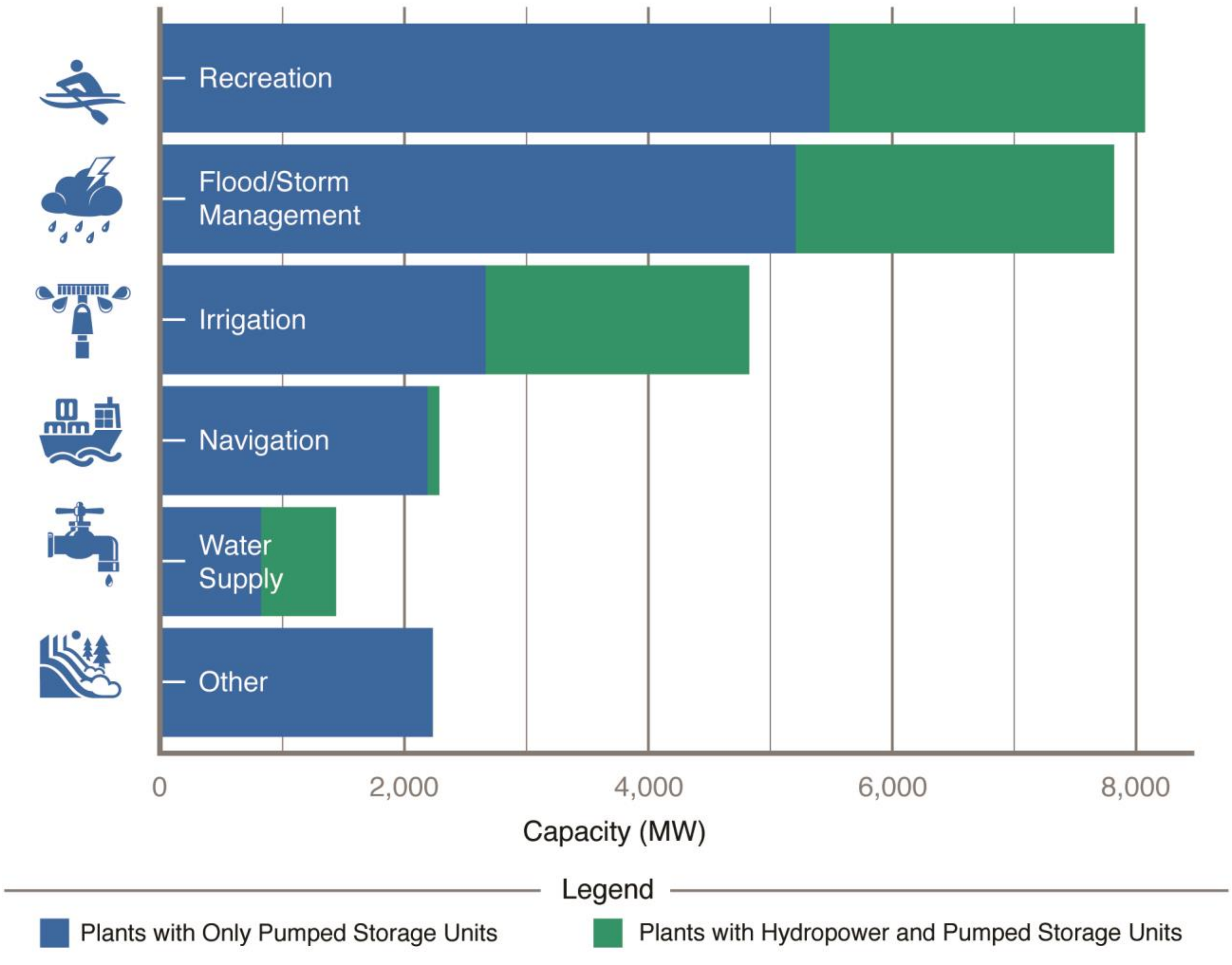
The Olivenhain-Hodges project is a good example for highlighting the multiple purposes associated with PSH plants. The prevalence of multiple purposes, shown in Figure 19, is somewhat lower for the PSH fleet than it was for the 2,198 hydropower generation plants discussed in Sections 1–3. The percentage of installed PSH capacity that provides each of the additional purposes ranges between 5% (water supply) and 38% (flood/storm management). In contrast, for hydropower generation resources, those same fractions ranged from 19% (other) to 62% (recreation).



Note: This figure displays the initial year of operation for each project except in two cases (Hiwassee and Grand Coulee) in which no pumped storage units were installed when they first became operational. In those two cases, the capacity was assigned to the decade in which the pumped storage units were added.

Source: NHAAP

Figure 18. Pumped storage hydropower installation timeline by plant size



Note: The "Other" category primarily includes fish and wildlife ponds, fire protection, stock or small farm ponds, debris control, and tailings (i.e., storage/receipt of waste rock from mining operations).

Source: NHAAP

Figure 19. Distribution of additional purposes on existing pumped storage hydropower plants

4.2 Trends in Pumped Storage Development Activity

4.2.1 Recent Capacity Changes for Pumped Storage

The last large PSH development in the United States was the Rocky Mountain project in 1995. Since then—with the exception of Olivenhain Hodges—all additional PSH capacity has come from modernization and upgrades to the existing fleet. Since 2005, six PSH plants have reported increases in nameplate capacity to EIA. The six plants were Bath County in Virginia, Raccoon Mountain in Tennessee, Muddy Run in Pennsylvania, Castaic in California, and Bad Creek and Jocassee in South

Carolina. Those increases amounted to 1,326 MW and do not include an additional 120 MW at the Blenheim Gilboa project in New York.[27]

At least four other PSH facilities—Northfield Mountain and Bear Swamp in Massachusetts, Lewiston in New York, and Ludington in Michigan—are currently embarked on modernization projects that will result in several hundred megawatts of pumped storage capacity by the end of this decade. In Colorado, the Cabin Creek project obtained a new license in May 2014 that authorizes a capacity upgrade of 36.6 MW. The owner of the project is currently assessing the financial feasibility of the upgrade.[28]

Except for Castaic, all the facilities for which recent capacity additions or significant current upgrades have been identified correspond to the class of dedicated PSH plants focused on producing power and other grid services and on maintaining grid reliability. Precisely because maintaining reliability is a key mission for these facilities, project upgrades are completed sequentially in each unit so that most of the capacity still remains online at any given time.

No PSH unit derates or retirements have taken place over the last decade. However, in some cases, equipment or structural failures lead to forced, total plant outages that lasted several years. For instance, TVA's Raccoon Mountain in Tennessee had to be closed for two years for repairs associated with a cracked rotor. It reopened in April 2014.[29] Taum Sauk in Missouri was out of service from December 2005 until 2010 because of a breach in its upper reservoir dam.[30]

4.2.2 Pumped Storage Project Development Pipeline

Unlike the existing fleet, largely built to complement base load nuclear or thermal plants, one of the central arguments for new development of PSH is that its flexibility makes it ideal for integrating variable renewables. For effectively fulfilling that role, many of the new PSH project proposals feature differences in configuration and equipment relative to the existing facilities. Although all but one—Olivenhain Hodges in California—of the existing PSH plants are open-loop facilities, many of the proposed new PSH developments would be configured as closed-loop facilities. Closed-loop PSH plants are not "continuously connected to a natural flowing water feature" and would typically reduce impacts on fish populations and effects on other resources associated with open-loop PSH development. For that reason, the restrictions to operational mode placed on some open-loop projects to mitigate environmental impacts would not apply to closed-loop facilities. As a result, they would have more flexibility as to the magnitude and frequency of reservoir elevation fluctuations and, in turn, less constraints on the frequency of starts and stops. Moreover, since they do not need to be placed next to a flowing stream, the pool of potential locations for closed-loop projects is larger. They still need a site with enough elevation differential between the upper and lower reservoir and an alternative water source but, after an initial fill of their reservoirs, they only need additional water to compensate evaporation or seepage losses.

Technological innovations in reversible pump-turbine units are another factor that will enable more flexible operations for new PSH projects. For instance, adjustable-speed pump turbines—not yet installed at any of the existing U.S. PSH projects but in service in multiple European and Asian projects—can

[27] http://www.nypa.gov/press/2010/100610a.html
[28] http://www.colorado.gov/cs/Satellite?blobcol=urldata&blobheader=application%2Fpdf&blobkey=id&blobtable=MungoBlobs&blobwhere=1251898265069&ssbinary=true
[29] http://www.timesfreepress.com/news/local/story/2014/jun/02/pumped-storage-plant-finally-ready-for-summer/141950/
[30] http://www.hydroworld.com/articles/2010/07/abb-provides-equipment.html

operate at peak efficiency over a larger portion of their operation range than traditional, single-speed pump turbines. Moreover, adjustable-speed machines are able to provide frequency regulation service while pumping.[31] The flexibility to operate efficiently over a broader range of speeds makes them particularly attractive to providing ancillary services to the grid and helping to integrate variable renewables. On the other hand, these units are also more expensive making it crucial that they operate in markets where their added flexibility will be rewarded.

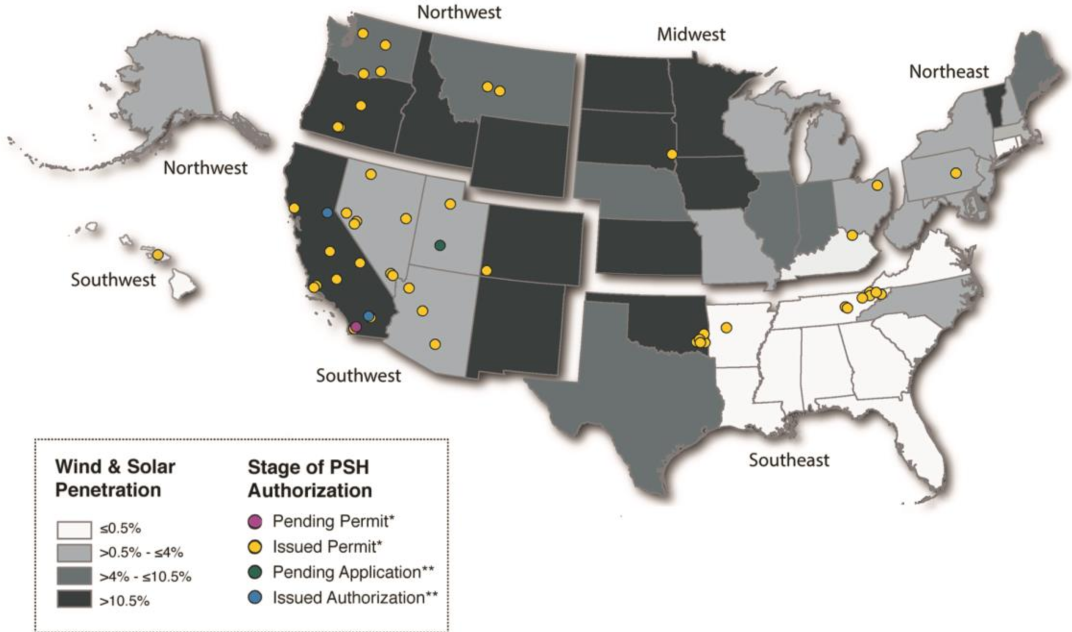
Figure 20 lays out the 51 PSH projects being actively pursued in the FERC pipeline as of December 2014. They add up to 39 GW and all are 150 MW or larger (the average size is 787 MW). In an attempt to explore the degree of correlation between the location of variable renewables and the location of proposed PSH, the map in Figure 20 displays both information sets. The base layer of the map shows the fraction of total installed generating capacity in each state that is wind or solar (as reported in EIA Form 860).

Of the projects, 21 are concentrated in 5 states—Oregon, California, Colorado, South Dakota, and Oklahoma—that are in the top quartile in terms of penetration of variable renewables. Because of the current market structure, revenue from supporting the integration of variable renewable energy resources is not a sufficient market condition to spur PSH development. Texas would appear as a prime spot given that it is the state with the largest installed wind generation capacity, but not a single site in that state is currently included in the FERC pipeline.

The vast majority of the projects are at the earliest phase of the licensing process in which the developer obtains a preliminary permit to conduct initial feasibility studies. For the last seven years, the overall number of PSH preliminary permits has remained relatively stable. One important regulatory change that might help explain the increased interest in PSH development is FERC Order 890. Issued in 2007, it asks independent system operators and regional transmission organizations to modify their market rules so that storage resources can participate in ancillary services and capacity markets. This essentially opened up new revenue streams for PSH facilities, although it does not yet fully recognize the suite of grid reliability services PHS provides. On the downside, a drop in electricity prices and related fuel commodities in 2009, followed by the new norm of abundant and cheap natural gas, dealt a severe blow to the business case for PSH. At the current electricity price, the old model of peak, off-peak energy arbitrage might no longer be sufficient to justify additional PSH development (Kirby 2012). Nonetheless, it would appear that developers continue to find the value of holding a preliminary permit higher than the cost of complying with the relatively minor progress reporting requirements associated with holding it. Upon request by the developer, the initial three-year term of the preliminary permit could be extended for up to two years.[32]

[31]http://energystorage.org/energy-storage/technologies/variable-speed-pumped-hydroelectric-storage

[32]HREA changed provisions regarding the extensions of preliminary permits. According to FERC Order 800, effective in February 2015, FERC can now extend a preliminary permit once for not more than two years without issuing public notice that would allow competing applications to be made. Before HREA, the holder of the preliminary permit had to submit a new application to obtain a successive three-year permit. That point, other developers could submit competing applications for the same site.



Note: This map displays the location and development status of proposed new pumped storage hydropower (PSH) projects in the United States in relation to the fraction of total generating capacity that is either wind or solar in each state. The point locations of PSH projects were derived by computing county centroids. Please note: some points overlap due to county level aggregation.

*Projects on the *Pending Permit* and *Issued Permit* stages have high attrition rates.

*******Pending Application* includes projects that have applied for an original FERC license. *Issued Authorization* includes projects that have been issued an original FERC license.

Source: FERC

Figure 20. Pumped storage hydropower project development pipeline by region and status in relation to state-level penetration of variable renewables (as of December 31, 2014)

Within the context of sustained interest not materializing into firm commitments toward new PSH development, 2014 has been an important year. FERC issued licenses for two PSH facilities.[33] Although, as mentioned in Section 2, having a license is not a guarantee that a project will be built or that construction will start in earnest, it is nonetheless a significant step.[34] Both licensed projects (Eagle Mountain and Iowa Hill) are in California, an attractive market because of the already high penetrations of wind and solar and a state RPS with a target of 33% by 2020. Eagle Mountain (1,300 MW) first applied for a preliminary permit in 2008 and is being pursued by Eagle Crest Energy Company, a private developer. Iowa Hill (400 MW) has been authorized as part of the relicensing process of Sacramento Municipal Utility District's Upper American River Project. These projects also present some differences

[33]The Olivenhain-Hodges Project was developed under a conduit exemption.
[34]Two PSH projects—Blue Diamond South in Nevada and River Mountain in Arkansas—obtained FERC original licenses in the 1990s. Neither of them started construction, and, in both cases, the license ended up being revoked.

in their physical configuration. Iowa Hill would be an open-loop project that uses an existing reservoir connected to a flowing stream as its lower reservoir. In contrast, Eagle Mountain would be a closed-loop project that uses abandoned mine pits as its upper and lower reservoirs. Water for the initial fill of the upper and lower reservoirs and for subsequent replenishments would be supplied by groundwater wells.

Table 4 provides a breakdown of the 51 PSH projects in the development pipeline depending on whether they are closed- or open-loop systems. Two-thirds of all the projects are proposed to operate as closed-loop systems.[35] Among the remaining 18 projects, 5 are a special case of open-loop development in that they would be developed on the coastline and use the ocean as their lower reservoir. No project of this kind is in service in the United States, but one can be found in Japan. Four of the proposed projects would be in California with a fifth in Hawaii.

Table 4. Pumped Storage Hydropower Development Pipeline (Broken Down by System Type)

System Type	Number of Projects
Closed Loop	33
Open Loop	13
Open Loop (Ocean)	5

Only 9 of the 51 projects proposed mention in their FERC documents the use of adjustable-speed pump turbines. Iowa Hill is one of them. Seven of those are located within or close to deregulated market areas in which day-ahead and real-time ancillary service markets exist. Two caveats apply to these pump-turbine type figures. First, given the early stage of most of these project proposals, their equipment choices should be interpreted as very tentative. Second, at the preliminary permit stage, FERC does not require project developers to report whether they plan to install adjustable-speed machines. Anecdotal evidence suggests that the number based on preliminary permit information might actually be an underestimation of the fraction of project developers considering the use of adjustable-speed units, particularly in the West.

About one-third of PSH projects, including both Eagle Mountain and Iowa Hill, propose using sites with an existing reservoir or abandoned mine pits. This type of site is attractive in that it could help reduce construction costs. The lack of recent PSH development—in the United States—and the fact that new proposed projects have some different attributes than the existing ones make it difficult to project what the construction cost of new projects will be.

Only 7 of the 51 projects are being put forward by a public entity. Investor-owned utilities back 2 of the projects, and the remaining 42 are being pursued by private nonutilities. Some of these developers seem

[35]HREA directed FERC to study the feasibility of a two-year licensing process for both NPD projects and closed-loop PSH projects. One closed-loop PSH project developer—Tomlin Infrastructure Group for the Wildflower Pumped Storage Project in Oklahoma—submitted a proposal to participate in the pilot study, but FERC determined that the project did not meet the required criteria to be selected.

to be adopting the cluster approach discussed in Section 2. For instance, one developer has permits to investigate the feasibility of seven projects in Tennessee, and another one holds permits for five projects in Oklahoma. In both of these clusters, the projects are located so close to each other that it seems likely that only one (if any) would proceed to a full license application.

In some ways, it is surprising that private developers who do not own other electricity generation assets would be the ones pursuing PSH projects, and it raises the question of whether they would remain as owner and/or operator if and when the project went into service. Owning a PSH facility as a merchant generator without a portfolio of other generating assets means relying entirely on the energy, ancillary services, and capacity markets to raise revenue. A significant part of the value of a PSH plant resides in the so called "portfolio effects," which allude to the fact that having one of these facilities in a system reduces the total cost of operating it (Koratirov et al. 2014). That value can best be captured by producers who own multiple generating units. Independent system operators are steadily offering new products meant to reward generation and storage units for services that improve the reliability and stability of the grid (i.e., for their "portfolio effects" at the independent system operator/regional transmission organization level), but it is not yet clear that the offering is compelling enough to make the case for many of these proposed projects. Different market rules and price levels for energy, capacity, and ancillary services across markets are an important consideration when planning PSH (Paine et al. 2014).

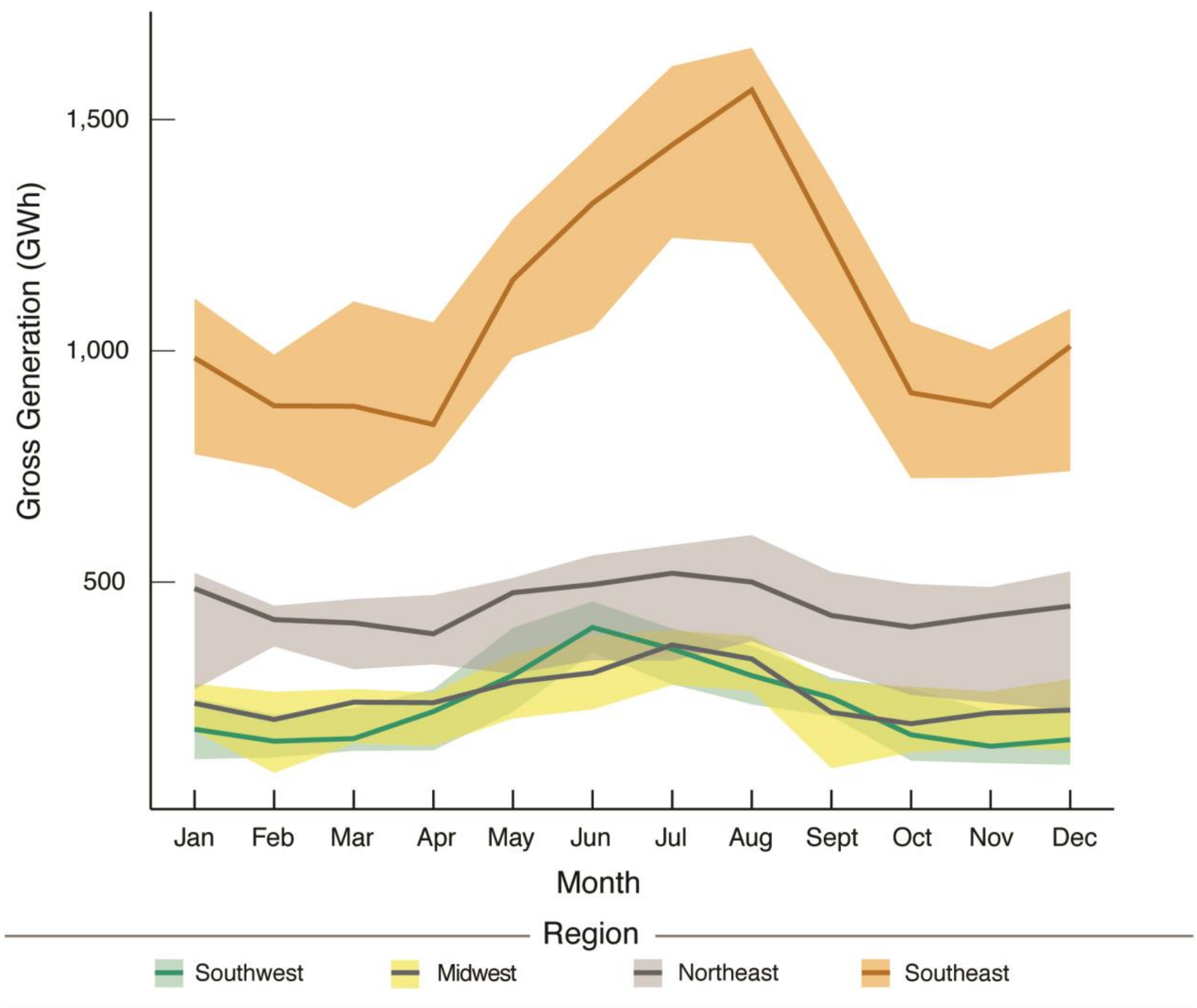
For the typical sizes of PSH installations currently in the FERC pipeline, private developers will have to raise very large amounts of financing (typically over $1 billion) to build a project. This is a very different proposition than getting a loan for a micro or small hydropower project. To secure financing, longer terms than the standard 20-year purchase power agreement would likely be needed for these projects.

Beyond the projects being explored in the FERC pipeline, there are some additional expressions of interest in PSH investment coming from the federal agencies. TVA outlined a possible 850 MW PSH project for the 2020–2024 timeframe in its 2010 Integrated Resource Planning document. It is not yet clear if that option will still be considered in the next round of their Integrated Resource Planning, the results of which are to be published in 2015 (TVA 2011a). Reclamation is also planning to modernize the pumped storage units at Grand Coulee. The current modernization project is meant to address decreased reliability because of aging of the plant. In 2010, BPA hired a consulting company to investigate the feasibility of two options that would increase pumped storage capacity in its system. The first option entailed capacity increases at John W. Keys III (the pumped storage units at Grand Coulee), while the second explored the possibility of a greenfield 1,000 MW PSH development (HDR 2010). Neither of these options has been openly pursued to date.

4.3 Performance Metrics for Pumped Storage

Since PSH units are a net consumer of energy (i.e., net generation is a negative number), it seems more useful to explore PSH trends in *gross* generation. The main purpose of Figure 21 is to show the relative size of gross electrical output from PSH plants in the various regions and the typical seasonal profile in each region. Not surprisingly, most of the generation from PSH projects happens in the Southeast, where the largest PSH plants are located. The second largest volume corresponds to the Northeast. Meanwhile, the Midwest and Southwest have similar averages and ranges. All regions peak in the summer although in varying degrees. For the PSH fleet in the Southeast, the summer peak is very pronounced. In the

Northeast, however, the spring and fall generation levels are followed by almost equally sized peaks for winter and summer. Generation peaks for dedicated PSH plants follow price peaks much closer than most hydropower generation resources can. They are the ultimate peaking units, highly tuned to price signals.



Note: The Northwest region was left out because it has very small pumped storage hydropower gross generation. The solid line is the average gross generation from 2002 to 2013. The shaded band surrounding it corresponds to the 10% and 90% percentiles.

Source: EIA Form 923

Figure 21. Monthly gross generation by pumped storage hydropower plants by region (2002-2013)

The denominator—potential output over a given time—in the capacity factor calculation for PSH facilities needs to take into account the number of hours spent pumping. For a typical roundtrip efficiency of 75% in the existing PSH fleet, the plant will have to spend 1.3 hours pumping for each hour spent generating at nameplate capacity. Thus, the maximum number of hours that a PSH plant could spend generating at full capacity is approximately 3,750 rather than 8,760. Based on that number of hours to compute potential output, the capacity factor of the existing PSH fleet over the last decades has averaged 23%.

PSH pumping operations often result in fish entrainment issues. Combinations of fish protection systems and pumping operation restrictions are used to mitigate those issues when they arise. Environmental restrictions to the frequency and timing of pumping operations are one of the reasons that capacity factors are low at some PSH projects.[36] Most of these restrictions would not be faced by closed-loop PSH projects.

Since the value of PSH derives more from the timing of the grid services and electricity it provides than the volume of the electricity it generates, the key performance attribute to track for these resources is availability factor. Figure 22 illustrates the average operational status hour breakdown for PSH units reporting to NERC GADS.

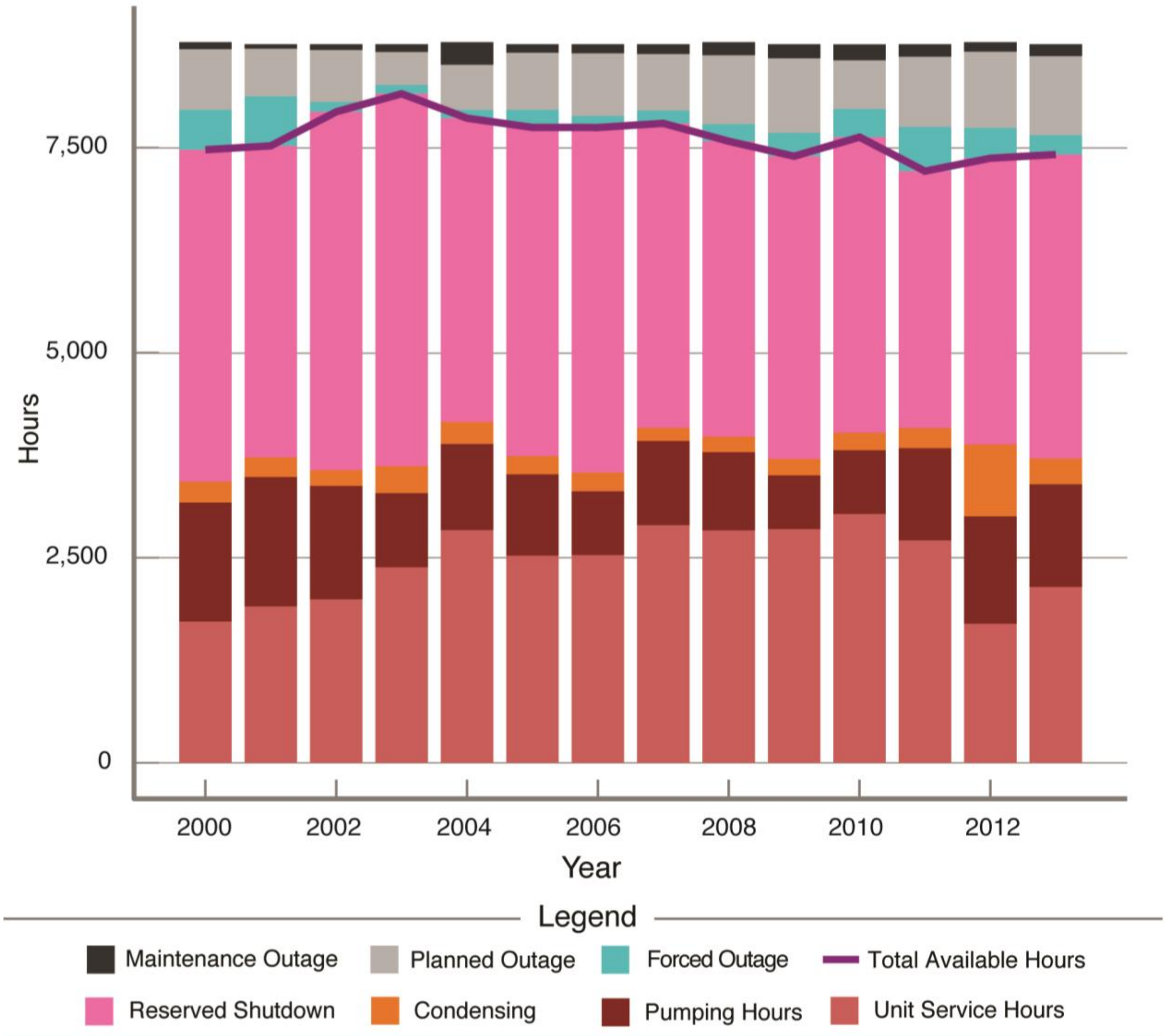
The average number of PSH units reporting to GADS from 2000 to 2012 was 96. This corresponds to 59% of the total number of installed units. Figure 22 reveals "reserve shutdown" as the most frequent operation state for those units. While in that state, its capacity can be providing reserves to the electric grid. The number of unit service hours ranged from 2,000 to 3,000. While synchronized, the unit could be generating, providing frequency regulation or reserves that require rapid response. The number of hours spent on pumping mode provides an indication of the fraction of unit service hours that were spent generating. Based on a roundtrip efficiency value of 75%, the average number of generation hours ranged from 489 in 2009 to 1,183 in 2001. The number of available hours for this PSH unit sample decreased steadily from 2003 to 2011 (except for 2010) but has slightly recovered in the most recent years.

Figure 23 shows availability in the summer to be much higher than in the rest of the year, and the difference is larger than for the hydropower fleet. The lowest availability corresponds to the fall and spring.

Dedicated PSH projects typically contain highly flexible peaking units. The median number of actual unit starts for those reporting to NERC GADS ranged from 84 in 2008 to 408 in 2001. From 2000 to 2013, every year there have been some PSH units with more than 1,000 unit starts.

New PSH plants are expected to have improved performance relative to the existing fleet. On one hand, the roundtrip efficiency of new reversible pump-turbines should be higher than the average roundtrip efficiency of pump-turbines installed decades ago. At recently built PSH projects in Europe, the roundtrip efficiency of pump-turbine units can be as high as 82% (Fisher et al. 2012). On the other hand, if the new PSH plants are closed-loop facilities, they will face less environmental operational restrictions and could achieve higher capacity factors. Additionally, the closed-loop configuration and/or variable speed pump-turbines that many of the proposed new PSH plants would have are flexibility-enhancing attributes that will greatly help providing the ancillary services and renewable integration functions needed in today's electric grid.

[36]http://www.louisberger.com/sites/default/files/pumped-storage-all-final.pdf

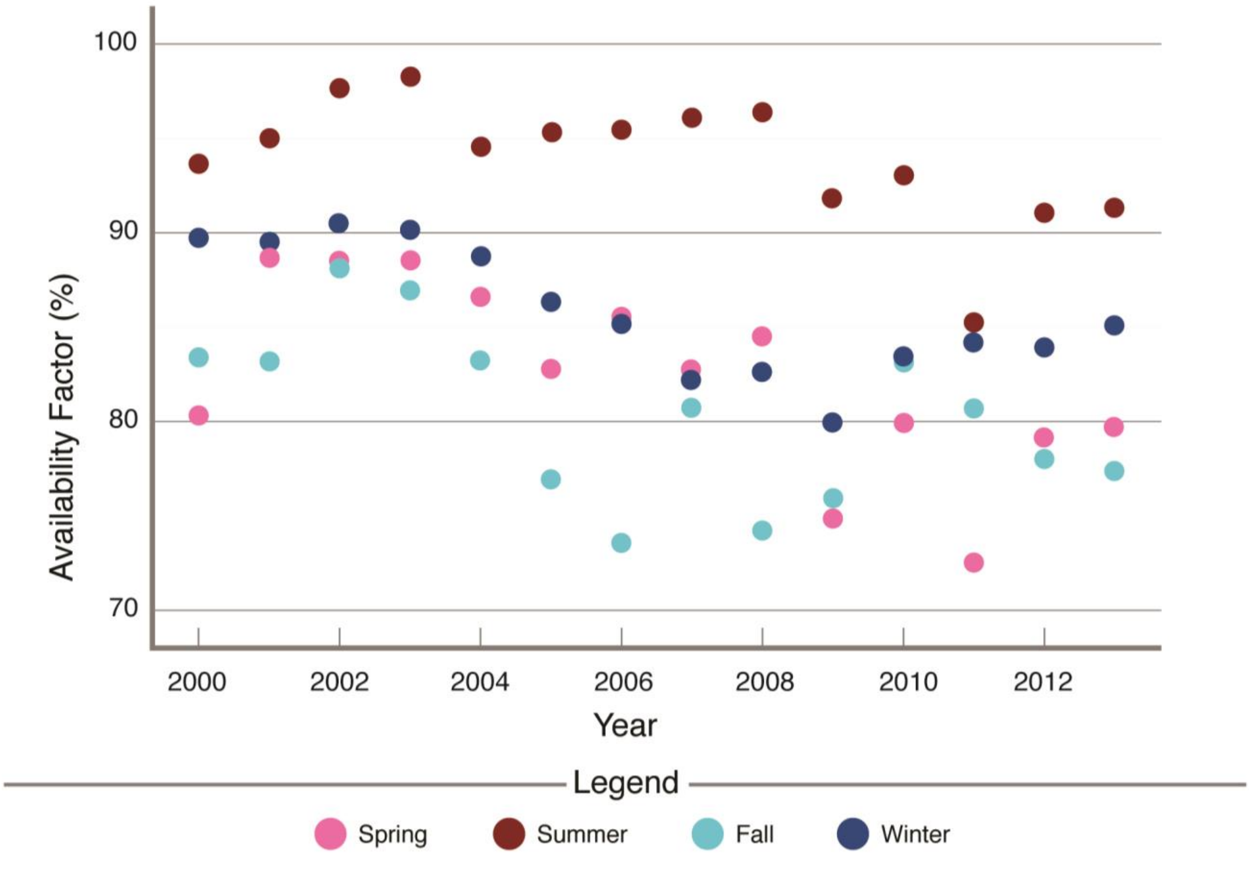


Note: Operation and outage state definitions from the NERC Glossary of Terms: *Maintenance outage* (unit removed from service to perform work on specific components that can be deferred beyond the end of the next weekend but not until the next planned outage), *Planned outage* (unit removed from service to perform work on specific components that is scheduled well in advance and has a predetermined start date and duration), *Forced outage* (unplanned component failure or other conditions that requires the unit to be removed from service immediately, within six hours or before the next weekend), *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), *Unit service hours* (number of hours synchronized to the grid).

The number of units reporting to NERC GADS varies from year to year resulting in different levels of coverage. During the 2000-2013 period, coverage ranged from 37% to 69%.

Source: NERC GADS

Figure 22. Average pumped storage hydropower operational status (hourly breakdown of units reporting to NERC GADS)



Note: The number of units reporting to NERC GADS varies from year to year resulting in different levels of coverage. During the 2000-2013 period, coverage ranged from 50% to 69%.

Source: NERC GADS

Figure 23. U.S. pumped storage hydropower unit availability factor (for units reporting to NERC GADS)

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5. Trends in U.S. Hydropower Supply Chain

The hydropower supply chain is very diverse and includes the providers of all materials, components, and services needed to bring a project from planning to operation and keep it generating for decades. A recent study estimates that the hydropower industry accounts for 55,433 direct jobs in the United States (Muro et al. 2011).[37] Those jobs are distributed among the various elements of the value chain: project development, manufacturing, project deployment and O&M.[38]

This section primarily focuses on the manufacturing element of the value chain. Clean energy manufacturing is a sector of increasing importance both in the United States and worldwide.[39] In the United States, it has been presented as an engine for job creation in a sector of the U.S. economy—manufacturing—that was hit hard by the 2008–2009 recession. In addition, clean energy manufacturing and deployment contributes toward the broader goals of energy security and climate policies. Estimates of domestic content for the various technologies within the clean energy sector are a useful metric to track in order to elucidate the strength and competitiveness of domestic manufacturing in those sectors.

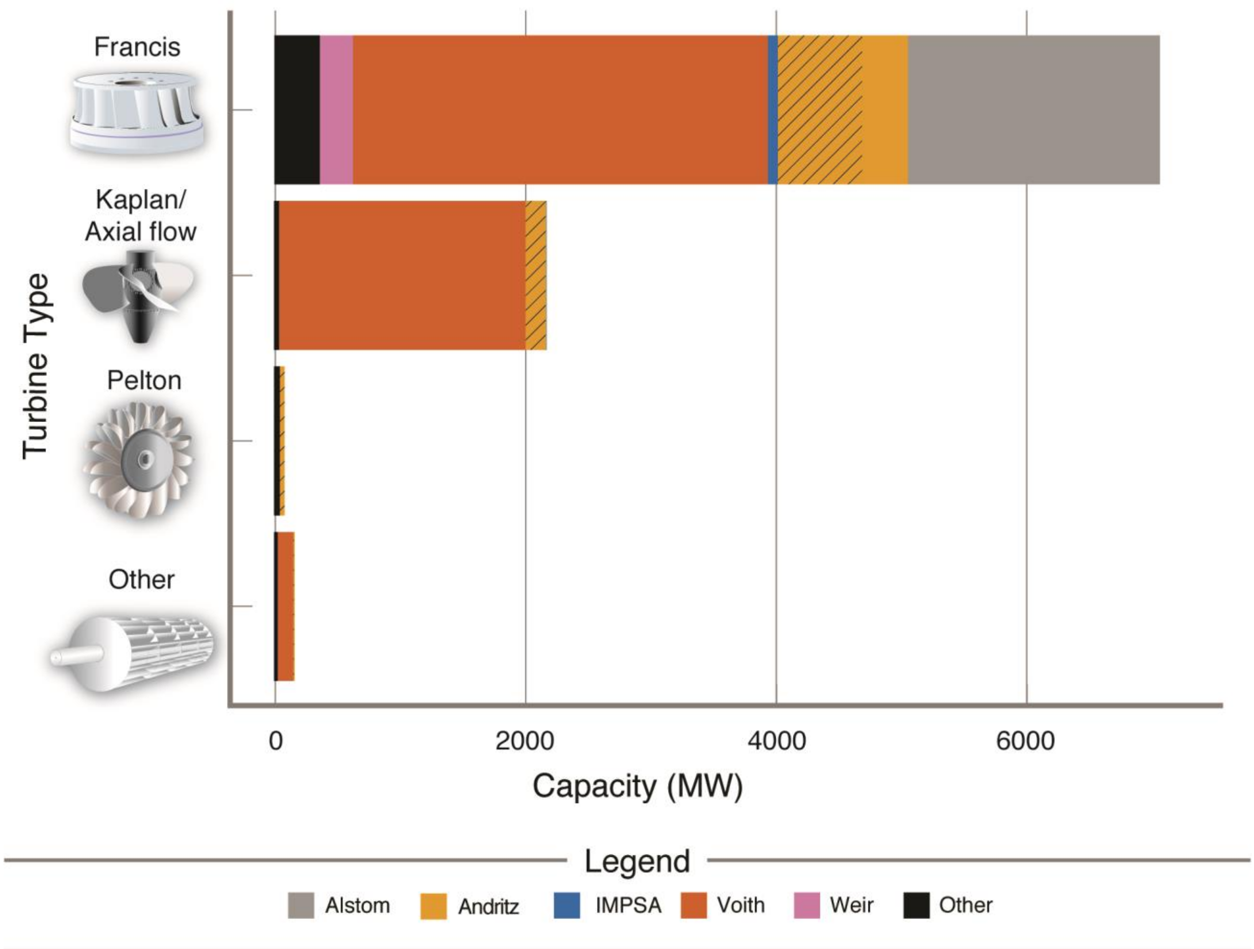
Because of insufficient data availability, this report does not produce estimates of domestic content for the hydropower industry. However, it provides an initial picture of the extent and geographical distribution of domestic manufacturing for six main components that can be found at any hydropower facility: turbines, generators, transformers, gates, valves, and penstocks. For only one of those components—turbines—is there detailed information on the number of installations and trade flows. Consequently, the turbine is the hydropower plant component discussed most extensively in this section.

Turbines and generators perform the key steps of turning flowing water into mechanical energy and then into electricity. The three most common types of hydraulic turbines are Francis, Kaplan (combined here with related Axial Flow designs such as bulb turbines), and Pelton. Turbine selection in each hydropower project depends primarily on available head at the site and, less crucially, on flow rate.[40] The Francis turbine has been the most commonly installed in all decades (except the 1970s), which is a reflection of the large range of flow and head combinations it can accommodate. Pelton turbines are best suited to projects with high head and low flow, while the Kaplan and Axial Flow units are preferred at low head sites.

Figures 24 and 25 summarize available data on turbine installations from 1996 to 2011. The data include turbine installations at new projects, as well as additional units installed at existing projects and major refurbishments of existing units at federal plants. Because of the lack of consistent data over the period of interest, major turbine refurbishments at nonfederal facilities are not included. Therefore, Figures 24 and 25 understate the total number of turbine installations that took place in the United States during 1996–2011.

[37]This study defines a direct job as a job at an establishment that directly produces goods and services with environmental benefits or that produces goods and services that add value to products with an environmental benefit.
[38]http://www.hydro.org/wp-content/uploads/2010/12/NHA_JobsStudy_FinalReport.pdf
[39]DOE's Clean Energy Manufacturing Initiative strategically focuses on boosting this sector in the United States.
[40]http://en.wikipedia.org/wiki/Water_turbine

Of the 9,455 MW of identified turbine capacity installed from 1996 to 2011, 7,035 MW (74%) are Francis turbines followed by Kaplan/Axial Flow with 2,174 MW.[41] Pelton turbines follow with only 83 MW. Only 5 out of 21 Pelton turbines exceed 5 MW, making this category seem small in terms of capacity, but its total number of turbines installed exceeds any other individual turbine type in the "other" category.[42]

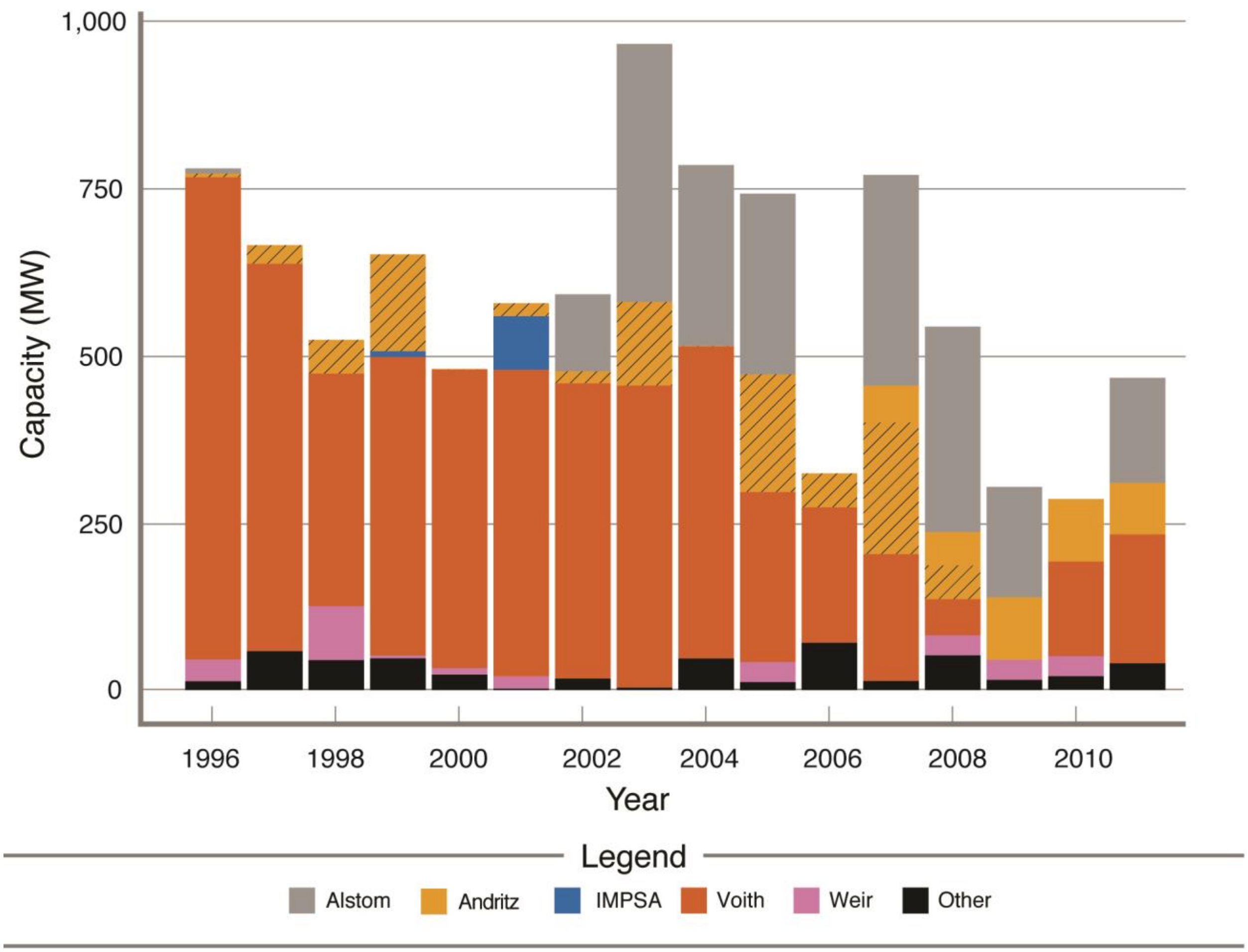


Note: The hashed portions of the bars correspond to turbines installed by companies that were acquired during the 1996-2011 period by the manufacturer Andritz.

Source: NHAAP

Figure 24. Installed hydropower turbines in the United States by type and manufacturer (1996-2011)

[41]Turbine installations at micro hydropower projects are not included in Section 5 figures and analysis because of lack of data.
[42]The "other" category includes the following turbine types: reverse pump (used in PSH facilities), camelback, crossflow, turgo, and diagonal flow.



Note: The hashed portions of the bars correspond to turbines installed by companies that were acquired during the 1996-2011 period by the manufacturer Andritz.

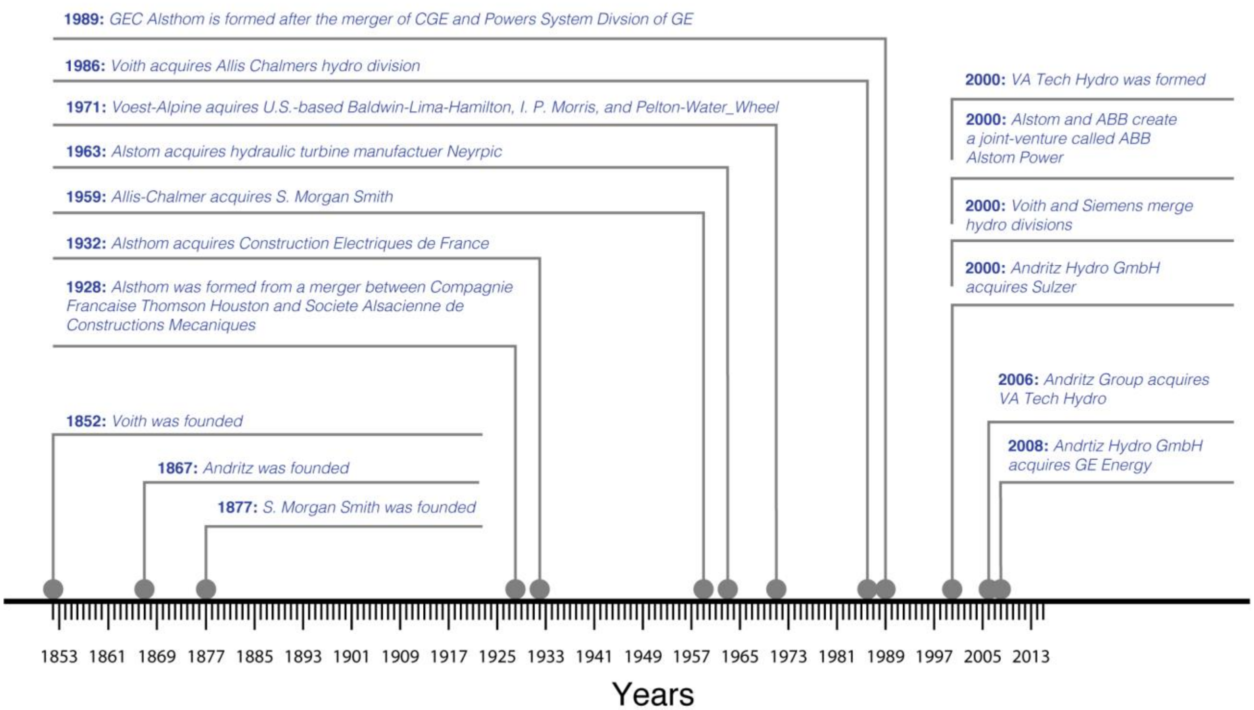
Source: NHAAP

Figure 25. Annual installation of hydropower turbines in the United States by manufacturer

Voith was the manufacturer for 31% of all turbine installations identified, accounting for 57% of the capacity (Figures 24–25). That includes furnishing 2,683 MW or 62 turbines for large federal facilities. In a ranking of turbine capacity, Alstom ranked second with 1,991 MW and 7% of the units, followed by Andritz (1,235 MW, 14% of the units), Weir (264 MW, 5% of the units), and IMPSA (89 MW, 1% of the units). While three companies are responsible for more than 90% of the installations of turbines greater than 10 MW, the number of manufacturers catering to the smaller turbine segment is much more ample.

Recent mergers and acquisitions have contributed to increased consolidation of the turbine manufacturing industry. Figure 26 identifies three major mergers and acquisitions from 2000 to 2008 that are reflected in Figures 24 and 25. In 2000, Sulzer merged with ELIN and VOEST-ALPINE to create VA Tech. VA Tech's hydropower division was then acquired by Andritz in 2006. In 2008, Andritz acquired General Electric Energy's hydro business. Another important and most recent event is the 50:50 joint venture between Alstom and General Electric for nuclear turbine operations, renewable energy activities (including the hydropower business), and grid equipment.[43] This deal is in process of “due diligence” but has not yet been completed or approved by the U.S. Department of Justice or the European Trade Commission.

Over many decades the major turbine manufacturers have transformed into their present state by merging and acquiring companies to become leaders of the industry. Figure 26 illustrates important turbine manufacturing industry milestones beginning in 1852.



Source: Web searches

Figure 26. History of major hydropower turbine manufacturer acquisitions and mergers

5.1 Domestic Manufacturing

Turbine installations for new projects have fluctuated widely from decade to decade both in number and median size. Such fluctuations paired with the long operating life of turbines pose challenges for turbine manufacturers in terms of how much productive capacity to maintain in the United States and how to diversify their operations to adjust to slow and fast hydropower capacity growth periods. The complex logistics of transporting turbines or turbine components are one of the factors determining the location of manufacturing facilities. Shipping bulky or very heavy equipment poses many issues. Since turbines are made mostly of structural steel and can weigh thousands of tons, companies are faced with transportation laws that cause them to quickly weigh out—a truck can only carry so much weight—rather than cube

[43]“GE [General Electric] Set To Expand Its Power Business With Alstom Acquisition—Forbes,” 2015. Accessed January 26. http://www.forbes.com/sites/greatspeculations/2014/06/25/ge-set-to-expand-its-power-business-with-alstom-acquisition/

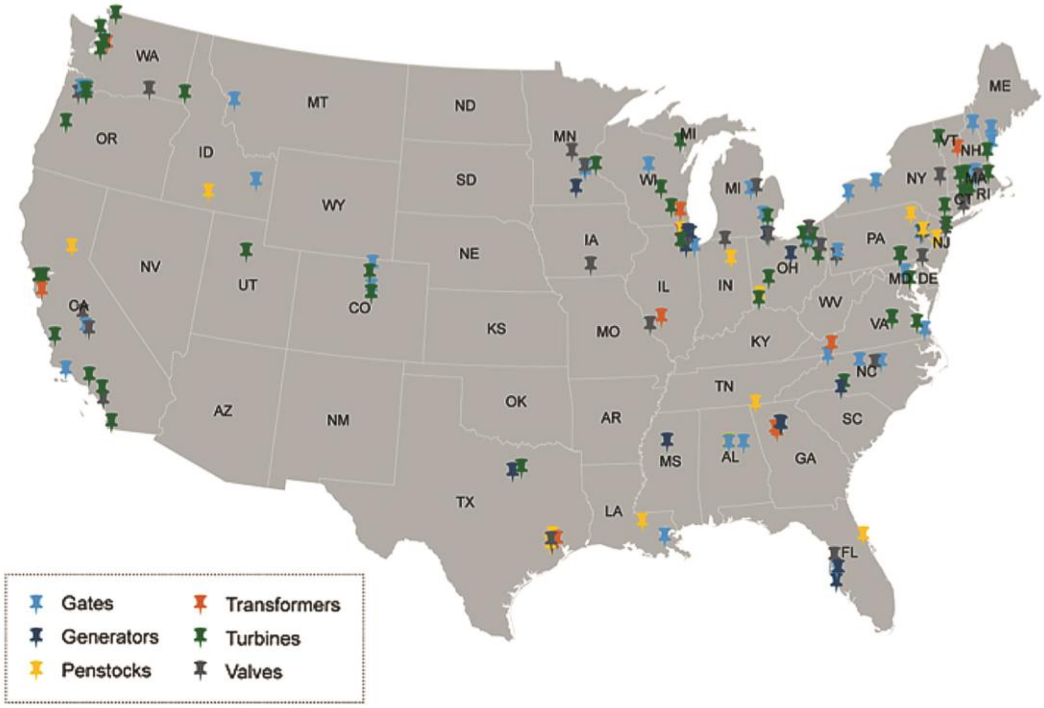
out—filling a truck in terms of space—when shipping by truck. That can mean added costs of multiple truck loads and labor. Also, oversized load driving laws vary across states, which can mean reroutes causing delays and added fuel costs. One way turbine manufacturers have avoided this complex logistic circumstance is transporting by waterways (e.g., barges and tugboats).

Another factor that hydropower component manufacturers might take into account in deciding where to locate their plants to serve the U.S. market is the *Buy American Act* criterion enforced by the Federal Acquisition Regulation. The Federal Acquisition Regulation restricts imports by federal agencies (including USACE and Reclamation) for use in the construction, alteration, or repair of any public work in the United States.[44] Unless "domestic construction material" is unavailable, its use is impractical, or its cost unreasonable, it should be chosen over "foreign construction material."[45] For construction material to qualify as being of domestic origin, the cost of its U.S. components must account for more than half of the total component cost. Also allowed under the Federal Acquisition Regulation are acquisitions whose value is above $7.4 million and covered under applicable trade agreements. In summary, the two largest owners of hydropower capacity in the United States are subject to restrictions regarding the source of their hydropower component purchases. Manufacturers whose products would qualify as being of domestic origin under the Federal Acquisition Regulation might have, all else equal, better prospects to do business with federal hydropower owners.

Figure 27 displays the 172 companies that have been identified to produce at least one of the six electromechanical or civil components selected for this analysis. Seen side by side with Figure 2, the map illustrates how most manufacturers are positioned near substantial hydropower capacity and/or close to waterways to facilitate product shipping. This set of companies includes small and large firms, global and domestic firms, and both publicly traded and privately held firms.

The map in Figure 27 does not offer an all-inclusive list of companies in the United States that provide these types of parts but is meant to represent how suppliers of these components are leveraged geographically to meet the needs of hydropower facilities. For a more extensive list beyond the electromechanical or civil component scope, see the National Hydropower Association Interactive Supply Chain Map.[46]

[44]https://acquisition.gov/far/current/html/Subpart%2025_2.html
[45]Construction material means an article, material, or supply brought to the construction site by a contractor or subcontractor for incorporation into the building or work.
[46]http://www.hydro.org/why-hydro/available/industrysnapshot



Note: This map is not intended to include all hydropower supply chain participants but to provide insight on the location of domestic manufacturers for key hydropower electromechanical and civil equipment components. Those facilities labeled as "Turbines" can include turbines and any combination of generators, transformers, and/or gates. In other cases, the manufacturing facilities can produce any combination of generators, transformers, gates, valves, and/or penstocks.

Source: Technology/Equipment Companies & Products Guide from HydroWorld Buyers Guide: http://buyers-guide.hydroworld.com/c/technologyequipment.html, International Water Power & Dam Construction Contractors by Category: http://www.waterpowermagazine.com/contractors/, and U.S. Hydropower Industry Snapshot data gathered by the National Hydropower Association: http://www.hydro.org/why-hydro/available/industrysnapshot

Figure 27. U.S. hydropower domestic manufacturing map

A recent example of a manufacturing plant positioned to serve a cluster of projects under construction is the Voith facility in Hannibal (OH). The initial momentum to build this facility came from Voith winning a contract to supply all the turbines and generators in the four AMP Ohio River projects. However, resource assessments have identified the Ohio River as one of the regions with the most resource potential for NPD facilities, and several other projects in that region are in earlier stages of the development pipeline.

Voith entered into a five-year lease contract to use an old mill along the Ohio River for manufacturing generator stators and assembling generator distributors shipped from their York (PA) manufacturing facility. The facility employs 56 workers who, at least partly, have been hired and trained locally. One key factor for selection of the Hannibal site was its on-site barge access, crucial to bringing large and heavy components to the project sites. Moreover, to secure the project, the Ohio state government offered a seven-year job creation tax credit and a grant to help modernize the site.

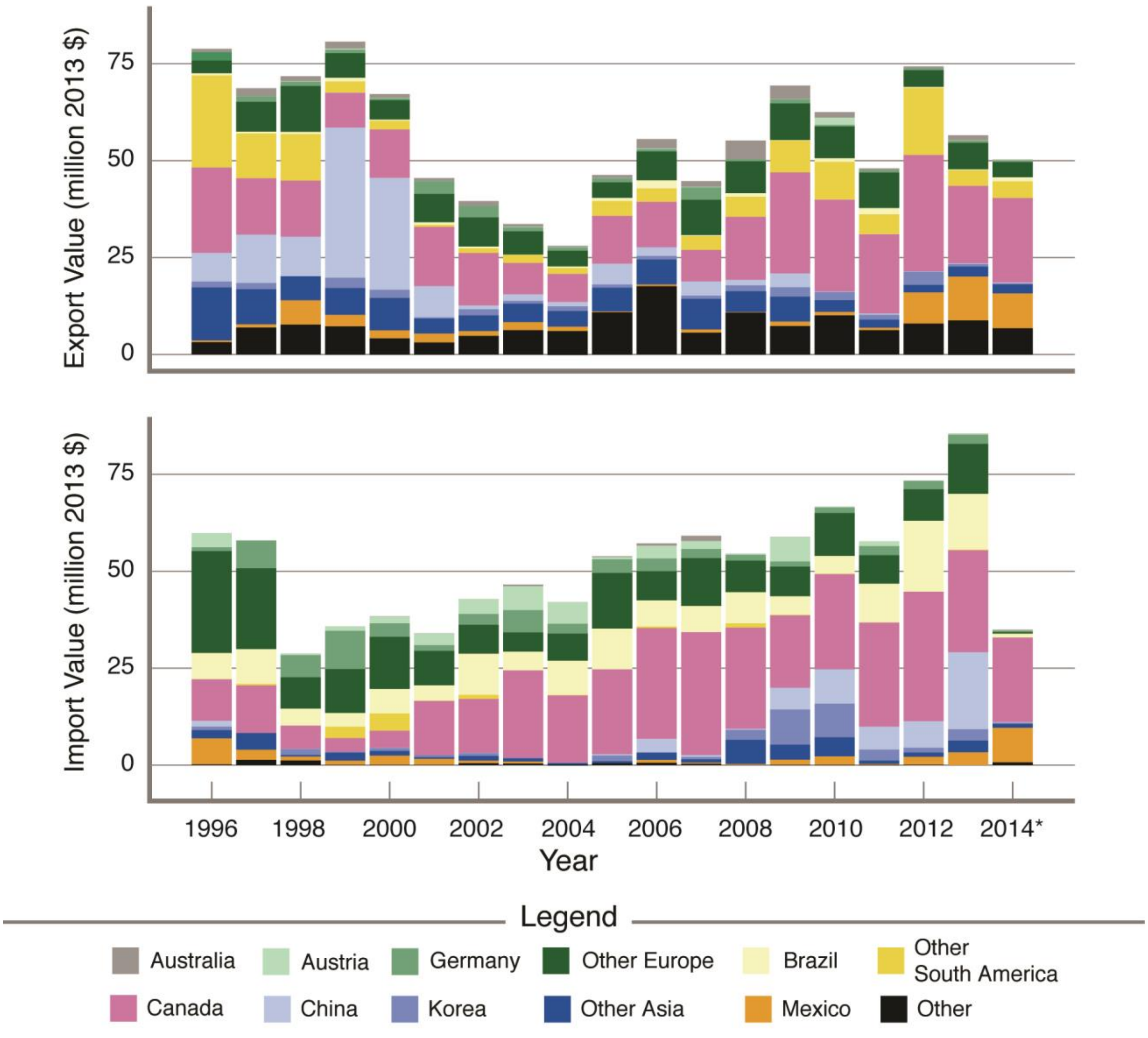
Sources: http://www.monroecountybeacononline.com/Aug_2009/Aug_6_2009_news.htm and http://www.monroecountybeacononline.com/Sept_2009/Sept_24_2009_news.htm

5.2 Imports/Exports

Figure 28 provides estimated import and export dollar value of *tracked* hydraulic turbines and turbine parts by using U.S. Department of Commerce trade codes.[47] The overall trends for imports and exports are influenced by a combination of factors: changes in the location of manufacturing plants, changes in project development trends, and changes in relative price and quality of turbine units and parts from various countries. For micro and small hydropower projects, manufacturers often offer water-to-wire packages. These are essentially standardized turbine-generator sets. Because imports and exports of turbine-generator sets are reported under a broad trade category that does not allow identification of their final use, they are not captured in Figure 28. Therefore, the data presented understate the aggregate value of turbine equipment into and out of the United States.[48] Similarly, for the other five components included in the domestic manufacturing map (generators, transformers, gates, penstocks, and valves), the current U.S. International Trade Commission code breakdown is not granular enough to determine the fractions of the totals traded that are to be used in hydropower facilities.

[47]The hydraulic turbine trade data can be queried through the Interactive Tariff and Trade DataWeb produced by the U.S. International Trade Commission, which compiles import, export, and tariff statistics from the U.S. Department of Commerce. This analysis focuses on "Customs Value," which excludes any shipping or duty costs. The analysis presented in Figure 28 relies on the Harmonized Tariff Schedule (HTS) codes 8410.11, 8410.12, 8410.13, and 8410.90 for "U.S. General Imports" and "U.S. Domestic Exports" for "Current U.S. Trade (1996–2014)." These codes encompass hydraulic turbines with capacity less than or equal to 1 MW, turbines with capacity greater than 1 MW but less than or equal to 10 MW, turbines with capacity greater than 10 MW, and turbine parts and regulators.

[48]Any turbines imported with a generator are classified as generating sets and are included in 8502.39. However, the current breakout of code 8502.39 does not distinguish which generating sets are used for hydroelectric production versus other electricity production technologies. For instance, gas turbines generating sets are also included in 8502.39.



*Note: 2014 data were accessed on January 2015 and do not include revisions to be released later in the year.

Source: USITC Interactive Tariff and Trade Data Web: http://dataweb.usitc.gov

Figure 28. U.S. hydropower turbine import and export values by country

Figure 28 reveals a number of trends within and between exports and imports:

- In the late 1990s to early 2000s, the United States exported heavily to China, but the trend fades by 2010 around the same time that China begins exporting to the Unites States. This pattern is most visible for China but also applies to Korea and the "other Asia" grouping.

- More than 50% of U.S. imports and exports in the last three years are within North America, which could be explained by logistic costs and market demands.
- Most turbine and turbine parts imported from South America come from Brazil where Voith has a manufacturing facility. On the other hand, most turbines and turbine parts exported from North America to South America go to countries other than Brazil.
- The number of countries from which the U.S. imports turbine and turbine parts is smaller than the number of countries to which it exports those same products. The “other” category is practically invisible for imports although it is significant for exports.
- Most of the U.S. hydraulic turbine trade involves parts rather than complete turbines.

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6. Policy and Market Drivers

For nearly two decades, development of new or expanded hydropower capacity has been limited relative to other generation technologies such as wind, solar, and natural gas. This slowdown in development has been the result of twin changes in the hydropower regulatory and electricity market environments in the United States. However, incremental regulatory policy changes and the increasing value placed on renewable electricity are reviving interest in hydropower technologies.

6.1 Regulatory Changes for Hydropower

On the regulatory front, changing environmental sentiments in the country produced landmark pieces of legislation altering the legal framework in which hydropower could be developed and operated, including the Wild and Scenic Rivers Act (1968), the National Environmental Policy Act (1969), the Clean Water Act (1972), and the Endangered Species Act (1973). This legislation changed the way in which the environmental effects of hydropower operations are mitigated. Ultimately, the passage of the Electric Consumers Protection Act in 1986 fundamentally changed the process by which FERC licensed hydropower projects by giving equal consideration to both power and non-power values during the licensing process. For the existing hydropower fleet, this has meant that upon reaching the expiration of a pre-Electric Consumers Protection Act FERC license, projects could be required to implement a new suite of environmental, recreational, and other regulatory mandates, resulting in additional capital investment requirements and potentially lowering generation and flexibility (FERC 2001), accounting for some portion of the downward trajectory in capacity factor seen in Section 3.

The market for power in general also began changing with calls for the restructuring of localized, vertically integrated electric monopolies into formalized competitive markets. The long-term uncertainty associated with changing market structures, the way new capacity and generation resources were procured, and new regulatory processes combined to drastically slow the development of new hydropower resources. Recent reforms of the regulatory process have attempted to address this issue for certain classes of hydropower development deemed to be minimally impactful to the environment. The 2013 HREA increased the capacity of conduit projects eligible for the FERC exemption process to 40 MW and the small hydropower exemption to 10 MW[49]; conduit projects on existing nonfederal infrastructure less than 5 MW were removed entirely from FERC jurisdiction. HREA also directed FERC to study the potential for a two-year licensing process for NPDs and closed-loop PSH. The Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act of 2013 authorized extending the LOPP process to nonfederal development of hydropower on conduit facilities owned by Reclamation the capacity of which would be less than 5 MW (U.S. Congress 2013a). Reclamation was also directed to apply its categorical exemption authority to exclude these small projects from undergoing National Environmental Policy Act review, further speeding the development process.[50]

[49]"Small hydropower" is limited to the powering of nonfederal dams constructed before 2005 and the addition of hydropower-generating capabilities to natural water features (such as waterfalls) that do not require construction of an impoundment structure.
[50]Additionally, the Carl Levin and Howard P. "Buck" McKeon National Defense Authorization Act, signed into law in December 2014, extended the possibility of nonfederal hydropower development using the LOPP process at a subset of Reclamation conduits and dams in which it had been previously prohibited, the 11 projects and 3 units built pursuant to the Water Conservation and Utilization Act.

6.2 Incentives and Funding Available for Hydropower

Where new development of hydropower has occurred, the drivers for this have generally been idiosyncratic combinations of resource, market, and policy realities. Other renewable technologies such as wind and solar have made significant use of federal tax incentives to justify project economics, particularly the production tax credit (PTC) and the investment tax credit (ITC). The hydropower industry, on the other hand, has had a less consistent experience with this form of incentive as hydropower's eligibility for federal tax incentives has evolved significantly through time but has always differed from those incentives available to the wind, solar, and geothermal industries.

The 2005 Energy Policy Act established the eligibility of hydropower for the PTC, however only at a half value (compared to wind and geothermal) rate of $0.011 per kilowatt-hour. Existing facilities and the powering of non-powered dams and other water conveyance infrastructure—including applicable pumped storage projects—were eligible to receive the PTC; new stream-reach development (NSD) projects were, and still remain, ineligible. Between 2005 and 2008, 33 hydropower projects received the PTC for a total of 374 GWh of additional annual generation (FERC 2015). Adjusted for inflation, in aggregate those projects would have received $4.1 million annually in incentive payments for their first 10 years of operation. In 2009, the American Reinvestment and Recovery Act extended eligibility for the ITC to hydropower at the full value of 30% under the same requirements applied for the PTC. Accompanying ITC eligibility was the creation of the 1603 Cash Grant Program, applicable to all ITC-eligible technologies where a renewable energy facility could elect a lump sum cash payment from the U.S. Treasury in lieu of the 30% tax credit.[51] Between 2009 and 2014, an additional 105 projects qualified for PTC/ITC/1603 eligibility, representing an additional 1,300 GWh of additional generation (FERC 2015).[52] During this same time frame, the U.S. Treasury issued 57 cash grant payments totaling more than $500 million (U.S. Treasury 2014), [53] suggesting that when available, the 1603 cash grant is the preferred incentive mechanism of the three mutually exclusive options—certainly in the face of a PTC paying only half value. In general, federal tax credit policy has required frequent uncertain renewals, creating substantial additions of uncertainty for hydropower projects given the long lead times for hydropower project developments identified in Section 2.1. Most recently, federal tax incentive eligibility was retroactively extended to construction started in 2014, but as of January 1, 2015, all three programs had expired.

The Energy Policy Act of 2005 also established a nontax-based incentive in the form of Section 242 production incentive. This incentive applies only to the installation of new generating equipment at existing dams and not efficiency or capacity upgrades. Although the program was authorized in 2005, Congress did not allocate funding for the Section 242 incentive until fiscal year 2014 when $3.6 million was appropriated. Annual payments for a project are limited to $750,000/year, and receipt of the incentive

[51]The 1603 program was created in the face of a shortage of tax equity investors during the 2007–2008 financial crisis and recession. In a typical nonrecourse project financing arrangement, outside tax-equity investors are generally necessary to capture the full value of the PTC and ITC.

[52]A "project" can refer to any specific addition of incremental capacity or generation to an NPD or existing hydropower facility. One single hydropower plant can have multiple projects that qualify for PTC/ITC/1603 eligibility.

[53]It is unclear whether multiple 1603 eligible projects for a single owner are lumped into one cash grant payment. Additionally, there is considerable lead time between the receipt of a PTC (and subsequently ITC and 1603) eligibility order and the actual issuance of the cash grant. Additional payments could be outstanding for projects that have only recently met the December 31, 2014, construction start deadline.

on an annual basis is contingent on continued appropriation of adequate funding by Congress to the U.S. Department of Energy, as opposed to the previous incentives that are administered by the U.S. Treasury. Given the relative magnitude of the Section 242 payments and their reliance on funding through annual appropriations, they are unlikely to fill the void left for private developers by the expiration of the federal tax incentives or lead to substantial new development given future uncertainties about their existence.

Although tax-credit based incentives have been a useful mechanism for spurring additional generation in the private hydropower fleet, 73% of all existing hydropower capacity is owned by public entities, such as the federal government, public utility districts, or municipal utilities. For these entities, the incentive to increase renewable generation and capacity from tax credits does not exist, leaving the PTC and ITC ineffective as mechanisms for facilitating increased generation from the public fleet. However, nonfederal hydropower owners and developers have made substantial use of federal bond subsidies in lieu of their ability to leverage direct tax credits—instead of lowering project costs through tax subsidies. Public owners of hydropower projects have been able to lower effective project costs through federally subsidized financing arrangements.

Clean Renewable Energy Bonds (CREBs) and Qualified Energy Conservation Bonds are two mechanisms by which public entities can fund special-purpose renewable projects at federally subsidized interest rates.[54] Both specialty bond issues were in existence before 2009, but the American Recovery and Reinvestment Act substantially expanded their availability up to $2.2 billion for CREBs and $3.4 billion for Qualified Energy Conservation Bonds. In the case of CREBs, hydropower projects (under eligibility requirements akin to those for the PTC) received 24% of the most recent CREB allocation of $2.2 billion (Kreycik 2010). In addition to renewable energy specialty bonds, the general-use Build America Bonds created by the American Recovery and Reinvestment Act were instrumental in helping public entities finance the development of hydropower. CREBs and Build America Bonds in particular have been used to finance some of the largest new hydropower facilities under development. The most prominent example is the funding of AMP's 208 MW of Ohio River NPD projects; AMP funded more than $1.7 billion of its $2 billion expenditures through the issuance of Build America Bonds and CREBs (Myers 2013). No additional authority under the CREB, Qualified Energy Conservation Bond, or Build America Bonds programs has been authorized by Congress since the American Recovery and Reinvestment Act allocations.

Similarly, while much of the development activity for other renewables has occurred on a nonrecourse project finance basis, the long-lived nature of hydropower projects has created a self-selection effect where new construction projects that ultimately reach commercial operation are necessarily those made economic by access to low-cost financing or preferential incentives. The hydropower-backed revenue bonds issued by public power owners and developers of larger projects, such as the Mid-Columbia Public Utility Districts and NPD-developing municipal consortium Missouri River Energy Services, have been recently rated as high, investment grade (Aa3/AA- or above), allowing these entities to fully finance projects on low-cost debt. While smaller and private owners and developers might lack the favorable credit worthiness of their larger counterparts, they have been able to make extensive use of preferential loan arrangements (from both federal and state entities) and state-level incentives, such as those offered by the U.S. Department of Agriculture and some states such as Colorado, Oregon, Alaska, and others.

[54] These subsidies have been variously available as either redeemable by the issuer (in the form of a cash payment from the U.S. Treasury) or issued as tax credits to the purchaser.

Bond incentives to public entities have also resulted in unique financing arrangements for small private developers. In Lawrence, Kansas, the city issued a series of Industrial Revenue Bonds to provide the financing for an expansion to the Bowersock Mills & Power Company hydropower project. The entire $23.5 million was funded through different tax-advantaged bonds of which $8.7 million was comprised of the municipality's allotment of Qualified Energy Conservation Bonds (Friedman and Fazell 2012). This sale-leaseback measure is similar in concept to the sale-leaseback arrangements made for tax-equity investors to use the ITC.

6.3 Hydropower in Renewable and Clean Energy Markets

Renewable energy certificates (RECs) or other clean or green energy markets have provided some additional incentive for renewable energy development. Prices vary significantly between markets and depend on a variety of factors, including the stringency of legal requirements in "compliance markets" such as state RPSs or the value of sustainable or renewable qualities of renewable power to individual organizations in voluntary markets. The extent to which either compliance or voluntary markets provide value to hydropower is additionally contingent on the eligibility of specific hydropower resources (e.g., NPD and NSD) to participate. Typical eligibility requirements placed on hydropower for participation in the most valuable, primary tiers of REC markets include the following:

- **Capacity limitations**, with 30 MW–50 MW being a range of common upper limits.
- **Hydropower resource and technology limitations** that define or restrict eligibility based on whether the project in question is incremental to an existing facility, power added to an existing NPD or conduit, or is pumped storage.[55] A typical restriction in the most valuable markets is that a facility be constructed on an existing dam or conduit, excluding NSD. Some unique RPS provisions exist with respect to pumped storage, which most often must pump from energy generated by RPS-eligible resources for its generation to qualify. This could prove to be a significant challenge because of the extreme difficulty of tracking the source of an electron as it moves through a transmission system.
- **Age, online dates, or vintage criteria** that typically restrict primary-tier eligibility to projects constructed after the initial enactment of an RPS provision, excluding the existing hydropower resource base.
- **Explicit environmental criteria** not covering other renewable energy generation technologies that outline the operational, environmental, and social qualities of a hydropower project that enable it to be deemed eligible for participation. The most common such standard is the Low Impact Hydropower Institute's certification program, used for RPS eligibility purposes in four compliance markets (PA, MA, OR, and DE). The Low Impact Hydropower Institute does not include age or vintage restrictions (though the organization does not currently certify any NSD projects) but issues only certifications that must be renewed after 5 to 10 years.
- **Asset ownership** is also used to delineate RPS eligibility (albeit less frequently), including restricting hydropower RECs to facilities owned by municipal or cooperative utilities (PA) or legislating special provisions for energy from the federal fleet marketed by the PMAs (OR, NC).

[55] A number of RPS policies explicitly allow for marine and hydrokinetic technologies such as wave, tidal, and in-stream turbines.

Stori (2013) provides a comprehensive review snapshot of hydropower eligibility requirements in U.S compliance markets, and general updates to state RPS policies can be found in the Database of State Incentives for Renewables.[56]

Generally, compliance RPS policy has provided some value to hydropower owners, but the price variation between markets is substantial—prices in the primary tiers range from a low of approximately $1/megawatt-hour (MWh) in Texas, to $15/MWh in the Mid-Atlantic states served by the PJM company, all the way to nearly $60/MWh in northeastern states. The eligibility criteria for hydropower participation also vary significantly; 29 states accept some form of hydropower RECs, but often only those from a small subset of either existing or new resources are eligible. This patchwork of eligibility generally makes hydropower RECs less liquid, and subsequently less valuable, and creates inconsistencies in how the "green" or "sustainable" aspects of hydropower development and operation are actually effectively incorporated and ultimately valued in the REC market. In RPS policies where large or existing hydropower plants are excluded from participation, owners see no additional economic incentive to make their operations more sustainable.

From the distribution of active project capacity under development in Section 2, it appears that REC revenues are not a primary determinant of hydropower project economics at a national scale, but they certainly could be incenting some new developer entry and providing key project revenue.

Although voluntary markets provide less of a monetary incentive for hydropower—voluntary RECs from hydropower and other renewable energy sources have traded at less than $1/MWh in recent years—they employ many of the same eligibility criteria found in compliance markets. As an example, meeting the Green-e standard requires U.S. hydropower projects to meet an age/vintage requirement for which only new facilities (defined on a 15-year rolling window) are eligible. Projects must also meet either the explicit environmental criteria set out by the Low Impact Hydropower Institute or a resource qualification restricting eligibility to power conduits or canals. Overall, hydropower comprised 4% of total retail green power sales in 2013 (Heeter et al. 2014).

[56] http://www.dsireusa.org. The Database of State Incentives for Renewables systematically catalogues all state RPS provisions, but ultimately the most accurate source of information on state-level hydropower eligibility can found in state public utility commission orders and legislation creating and amending RPS policies.

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7. Conclusions and Future Work

Hydropower remains a major contributor to the U.S. power system, accounting for (excluding pumped storage) 7% of installed generation capacity and—on average over the last three years—7.1% of generation. The existing fleet was constructed over the course of an entire century and is very diverse in terms of location, sizes, ownership, and operational modes. The fleet includes high-flexibility PSH and peaking hydropower plants, run-of-river facilities with capacity factors as high as 80%, and projects associated with large reservoirs where electricity generation is viewed as a by-product of other authorized purposes. This report attempts to document that diversity through discussion of a selected set of attributes for the entire fleet.

The past ten years of activity within the hydropower industry stand in contrast to historical development. Major projects were actively constructed until market and legislative changes in the 1970s and 1980s concluded the era of big dams. The 1980s, however, was an active decade in which more than 600—mostly small—projects were constructed in the United States. Since then, new development has slowed down considerably. From 2005 to 2013, 85% of capacity increases originated in turbine-generator unit upgrades and replacements at existing plants. Recent assessments have pointed out that large amounts of potential resources still remain undeveloped, while unanimously approved legislation in 2013 introduced reforms of the hydropower permitting process that could contribute to realizing some of that potential.

The current project development pipeline contains a mixture of non-powered dams, conduit, and new stream-reach development projects. Among more than 300 projects actively involved in the FERC and LOPP project pipelines, less than 20 involve any significant dam construction. It must be noted that the majority of the development pipeline is concentrated at the preliminary stage of the development process, which implies that final determinations have not yet been made about the technical and economic feasibility for most of these projects. Traditionally, the attrition rate at that stage of the authorization process has been high.

Beyond new development, owners have continued to invest—in the order of hundreds of millions of dollars annually—in replacements and upgrades of existing units. Capital investment has not only been made to improve performance metrics but also to mitigate environmental impacts. Mitigation has also resulted in changes in operational mode towards run-of-river operation. As a counteracting effect, other trends like the increased penetration of variable renewables place the most value on those generation and storage resources that can be operated more flexibly.

The expiration of the financial incentive programs that many recent hydropower projects have used poses questions as to the effects on both new project development and which financing mechanisms will be relied upon in the future. Eligibility requirements for hydropower to receive the most valuable, primary-tier RECs vary widely across states, though in general, REC revenues have not been a primary determinant of hydropower project economics. As new clean energy policies continue to develop at the state and federal levels, the set of variables that project developers and investors consider when evaluating hydropower projects will also continue to evolve.

The data collection and analysis performed for this report revealed several information gaps. In some cases, filling those gaps will require engaging industry to improve the availability and quality of data. In addition, reviewers of this report suggested expanding its scope to address other topics of interest. Among the data gaps to fill and scope additions to pursue in future versions of this report, the following items would take priority:

- A more complete analysis of the typical length and attrition rates for each step of hydropower project development process
- Trends on O&M costs and licensing costs
- Trends on price and other terms of power purchase agreements signed by the owners of recently completed hydropower projects
- Expanded coverage of supply chain information to estimate domestic content of hydropower civil and electromechanical equipment, as well as discussions of nonmanufacturing components of the value chain
- Expanded coverage of information regarding turbine upgrades and refurbishments at nonfederal facilities
- Evidence gathering regarding changes in mode of operation resulting from increased penetration of variable renewables in some regions of the country

Another thrust of future work to enhance the usefulness of this report involves placing its content into a broader context. On one hand, it would be informative to compare hydropower development trends in the United States versus other countries. On the other hand, understanding how the metrics presented here (e.g., cost and length of the development process and capacity factor) compare with hydropower and other renewable (or nonrenewable) electricity generation technologies would be valuable for investors, policymakers, and other hydropower industry stakeholders. Future versions of the report are planned to include basic international comparisons of hydropower development trends and, to the extent useful and possible, will present standardized metrics that facilitate comparison with similar publications for other technologies (e.g., the *Wind Technologies Market Report*).

One important message that stems from all the information presented in this report is that, for most metrics, average values will be poor descriptors of the U.S. hydropower fleet and should not be used for comparison with other technologies. Ranges for hydropower costs, capacity factors, and length of the development process are very wide. Therefore, any conclusion regarding the economic feasibility of a specific hydropower project or the value of an existing hydropower plant to the grid must be made using detailed project-level data, with an eye to idiosyncrasies related to site characteristics, market structure, and ownership type. The U.S. hydropower industry is quite diverse and nuanced, and it has been the goal of this Market Report to provide accurate and unbiased information with which to better understand these complexities and other emerging trends.

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Front Cover Image

Smithland hydropower plant, KY

Top Back Image

Meldahl hydropower plant, KY

Bottom Back Image

Cannelton hydropower plant, KY

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