HydroWIRES
U.S. DEPARTMENT OF ENERGY

Hydropower Value Study: Current Status and Future Opportunities

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HydroWIRES

In April 2019, WPTO launched the HydroWIRES Initiative[6] to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving US electricity system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

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

HydroWIRES is distinguished in its close engagement with the DOE National Laboratories. Five National Laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio as well as broader DOE and National Laboratory efforts such as the Grid Modernization Initiative.

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

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

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

Acronyms and Abbreviations

AGC	Automatic Generation Control
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EFC	Effective Flexible Capacity
EIM	Energy Imbalance Market
EQR	Electric Quarterly Report
FERC	Federal Energy Regulatory Commission
FRA	Flexibility Resource Adequacy
GCD	Glen Canyon Dam
GW	Gigawatt(s)
HVS	Hydropower Value Study
HydroWIRES	Hydropower and Water Innovation for a Resilient Electricity System
ISO-NE	Independent System Operator – New England
LAP	Loveland Area Projects
LMP	Locational Marginal Price
LTEMP	Long-Term Experimental and Management Plan
M&I	Municipal and Industrial
MISO	Midcontinent Independent System Operator
MW	Megawatt(s)
Mid-C	Mid-Columbia Trading Hub
NERC	North American Electric Reliability Corporation
PFR	Primary Frequency Response
PG&E	Pacific Gas & Electric Co.
PPA	Power Purchase Agreement
PSH	Pumped Storage Hydropower
PUD	Public Utility District
RA	Resource Adequacy
ROD	Record of Decision
RM	Reserve Margin
RPS	Renewable Portfolio Standard
SFR	Secondary Frequency Regulation
US	United States
VRE	Variable Renewable Energy
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WPTO	Water Power Technologies Office

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1.0 Introduction

To reveal the current landscape and prospective role and influence of hydropower operations on the nation's electric grid, the U.S. Department of Energy's (DOE's) Water Power Technologies Office (WPTO) commissioned the Hydropower Value Study (HVS). The primary purpose of the study was to gain a comprehensive understanding of current hydropower operations and resulting value across the country.

Hydropower and pumped storage hydropower (PSH) compose a significant fraction of renewable generation and electrical storage in the United States, respectively. The US has approximately 101 GW of nameplate hydropower capacity, including 80 GW of conventional hydropower and 21 GW of pumped storage.[7] Hydroelectric generation in the US represented 41% of all renewable energy generation and 6.8% of the total generation in the US in 2018.[2] At least 40% of the hydropower capacity is composed of PSH and "peaking" hydropower plants, which can store water to produce electricity at times of greatest need and value, and at least 18% is composed of run-of-river plants, which can only produce electricity at the time water is flowing.[8] Pumped storage hydropower represents 95% of grid-scale energy storage in the US. Total hydropower capacity appears to be growing due to retrofits,[9] though annual generation values from hydropower resources appear to be flat for at least the last 20 years.[10] Proportionately, hydropower resources are decreasing in dominance. In 2019, annual wind generation surpassed annual hydroelectric generation.[11] Battery storage growth domestically is growing rapidly, while only one pumped storage facility has been built in the last 15 years.[12]

Yet these static annual generation and total capacity values for hydropower resources do not reflect the dynamic contributions of this sector to electric grid reliability, economic efficiency, and resilience. The economic and financial context for hydropower resources has undergone significant changes in recent years due to changing power grid conditions, such as low natural gas prices and low load growth leading to reduction in energy prices. The rapid growth of renewable energy resources has led to displacement of some baseload-scheduled energy generators while putting a greater emphasis on ancillary services. Further changes are on the horizon—technical, technological, sociopolitical, market structures—that can substantially change the operational requirements of the power grid. The varying degrees to which these changes eventually manifest will affect the value drivers for hydropower resources differently. Evaluating the changing value landscape for hydropower resources and understanding the ability of different resources to provide power system services will enable prudent decisions regarding changes in operating paradigms and capital investments.

The new operating paradigms are creating opportunities well suited for hydropower installations to provide valued power system services. The flexibility of hydropower plants is already being used in many

[7] US DOE. (2016). "Hydro Vision: A New Chapter for America's 1st Renewable Electricity Source." *Department of Energy Wind and Water Power Technologies Office.*

[8] ORNL, ORNL's HydroSource, 2018 https://hydrosource.ornl.gov/

[9] Hydropower Market Report, 2018 update. https://www.energy.gov/sites/prod/files/2019/05/f62/2018-updates-hydropower-market-report.pdf

[10] HMR 2017. "US hydropower capacity has increased by 2,030 MW from 2006 to 2016 bringing installed capacity to 79.99 GW across 2,241 separate plants. Of this net increase, 70% (1,435 MW) resulted from refurbishments and upgrades (R&U) to the existing fleet."

[11] "Annual wind generation totaled 300 million megawatt-hours (MWh) in 2019, exceeding hydroelectric generation by 26 million MWh." US Energy Information Administration. "Wind has surpassed hydro as most-used renewable electricity generation source in US" February 2020. https://www.eia.gov/todayinenergy/detail.php?id=42955

[12] HMR 2017, referencing Lake Hodges, 40 MW, in southern California.

regions of the country to provide services needed to integrate renewables and maintain the reliability of grid operations. The opportunities, however, may also present additional costs, such as accelerated machine wear and tear due to frequent cycling and start-stop operations. This implies that asset management and reinvestment programs need to consider the changing operational paradigms in order to ensure prudent long-term investments. These changing conditions also require new research into technology innovation, data development, analytical tools, and operational strategies to preserve and enable important hydropower capabilities and contributions into the future.

The HVS focused on two primary objectives:

1. **Review of the Current Hydropower Operations Landscape**

   The value of a resource can be discerned from the composition of the portfolio of services (energy, capacity, and ancillary services) it provides, and the relative value of each of those services. This task illustrated the recent trends in provision of grid services by hydropower resources based on a comprehensive, data-driven analysis of hydropower operations in various markets across the country. These trends shed some light on the impacts of further changes on the horizon relative to hydropower operations and value. The work also identified and estimated the value of grid services provided by hydropower that are not currently monetized, such as inertia.

2. **Hydropower Capabilities and Operations in Future Grid States**

   The ability of hydropower resources to provide value to the power system will require a comprehensive understanding of the resources' technical and technological capabilities, costs, and constraints. Hydropower's capabilities to provide valued grid services, and the factors influencing how these capabilities vary unit-to-unit and plant-to-plant, are qualitatively and quantitatively different. This task was designed to analyze the capabilities and constraints that affect a hydropower facility's ability to provide various grid services, both now and in future.

The HVS team comprises experts in the fields of economics, statistics, data analytics, power market design and analysis, hydrology and hydraulics, plant-level controls and operations, as well as power systems engineers. The project was led by Pacific Northwest National Laboratory (PNNL), with support from the Argonne (ANL), Idaho (INL), Oak Ridge (ORNL), and National Renewable Energy (NREL) national laboratories. In collaboration with industry, the HVS looked at the two objectives for hydropower across varying geographic regions of the US, including the California Independent System Operator (CAISO), Mid-Continent Independent System Operator (MISO), Independent System Operator New England (ISO-NE), Western Electricity Coordinating Council (WECC), and the Chelan Public Utility District (PUD). The study included robust review by industry and other external experts.

The key findings across the HVS are summarized below.

Finding 1: Hydropower operations are changing in many parts of the country because of changing grid conditions. The changes, however, differ regionally based on the prevailing value drivers, such as changing arbitrage patterns due to increasing penetration of solar resources. In some regions, these changes manifest as new market opportunities, such as the western Energy Imbalance Market (EIM), which is designed to better incorporate the penetration of variable renewable energy (VRE). However, in some parts of the country, like the Pacific Northwest, hydropower resources continue to operate primarily in load-following mode. Even with these changing conditions, the capacity factor for conventional hydropower resources across the US has remained relatively consistent through the years, between 35 and 45%.

Finding 2: Hydropower generators are important contributors to grid reliability. Even in a changing power system, hydropower continues to be a significant contributor to system reliability through inertial and primary frequency responses, reactive power support, and black-start capabilities.[13] Approximately 40% of units maintained and tested for providing black start in the US are hydropower turbines, even though hydropower makes up only approximately 10% of overall US generating capacity.[1] In addition, in CAISO, hydropower resources have been observed to contribute up to 25% of the total Regulation Reserve (up and down) requirements, as well as up to 60% of the total Spinning Reserve requirements even though hydropower constitutes approximately 15% of installed capacity. Not all generators currently have these capabilities; the ability of inverter-based resources is currently being evaluated in laboratory and field demonstrations, and other traditional generators that supply these services may retire from service in the future, which may increase the demand for certain reliability services from hydropower.

Finding 3: There is wide variation in hydropower plant conditions and capabilities to provide grid services. Hydropower's contributions to the grid are multifaceted, in that hydropower may serve several roles in a generating stack. At least 40% of hydropower resources, by capacity, comprises pumped storage and "peaking" hydropower plants that can store water to produce electricity at times of greatest need and value, and at least 18% comprises run-of-river plants, which may have some operational flexibility but typically cannot impound and store additional water beyond inflows.[14] Even within a given resource class, i.e., peaking or run-of-river, the ability to provide grid services depends on the site-specific electro-mechanical (physical) attributes, which are in turn governed by the hydrological and geological conditions. For a given plant, these capabilities will vary naturally over seasons and over water years (wet/average/dry). In addition, institutional factors such as existing contracts and Federal Energy Regulatory Commission (FERC) licenses determine a resource's ability to provide grid services. In many cases, non-power services such as flood control or environmental flows govern the ability of a hydropower plant to supply energy. The value of these services is not always accounted for in the overall value of hydropower. Additionally, the value of these non-power services is locational, based on stakeholder perspectives and the valuation methodologies that are employed.

Finding 4: Traditional economics for hydropower plants may not provide stable revenue into the future. Conventional value streams, such as energy and ancillary services prices, are exhibiting declining trends in some parts of the country, and these changes have affected hydropower resources adversely. This trend is evident in conventional hydropower plants in the Northeast, as well as in pumped storage hydropower plants in the Midwest. Energy generation remains the primary source of revenue for many hydropower plants, and while most hydropower is technically capable of providing ancillary services, this provision often includes opportunity costs associated with reduced capacity.

Finding 5: New market mechanisms are emerging that could compensate hydropower flexibility. While not all services that hydropower provides are currently monetized, new markets for grid services are emerging that can offer alternative revenue streams. Evolving flexibility requirements have led some ISOs, such as CAISO, to define new flexibility resource adequacy (FRA) capacity constructs, and hydropower is already helping meet some of these requirements. New market mechanisms are emerging for inertia and primary frequency response, and hydropower resources are already being compensated. For example, CAISO recently signed contracts with the Bonneville Power Administration (BPA) and Chelan Public Utilities District for explicit compensation for inertial and primary frequency response provided by hydropower resources.

Highlights from these findings are captured in Section 2: Results. Recommendations for future research to support the HydroWIRES research roadmap are provided in Section 3: Path Forward.

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[13] ORNL. (2019). "Hydropower Plants as Blackstart Resources." ORNL/SPR-2018/1077. https://www.energy.gov/sites/prod/files/2019/05/f62/Hydro-Black-Start_May2019.pdf
[14] ORNL, ORNL's HydroSource, 2018 https://hydrosource.ornl.gov/

2.0 Results

2.1 Hydropower operations are changing in some parts of the country because of changing grid conditions

The changes, however, differ regionally based on the prevailing value drivers, such as changing arbitrage patterns due to the increasing penetration of solar resources. In some regions, these changes manifest as new market opportunities, such as the western EIM, which is designed to better incorporate the penetration of VRE. However, in other parts of the country, like the Pacific Northwest, hydropower resources continue to operate primarily in load-following mode. Even with these changing conditions, the capacity factor for conventional hydropower resources across the US has remained relatively consistent through the years, between 35 and 45%.

2.1.1 The increasing penetration of VRE resources has negatively influenced energy prices

The maximum amount of load served by renewables in CAISO during certain times of the year can be as high as 70% (Figure 2-1). Because VRE resources are inherently variable, the market operators procure reserve capacity to ensure supply-demand balance. The procurement of regulation and spinning reserve capacity can sometimes lead to over-supply of generation, and hence, negative energy prices. Figure 2-2 shows that the occurrence of negative prices in CAISO has increased substantially over the years.[15]

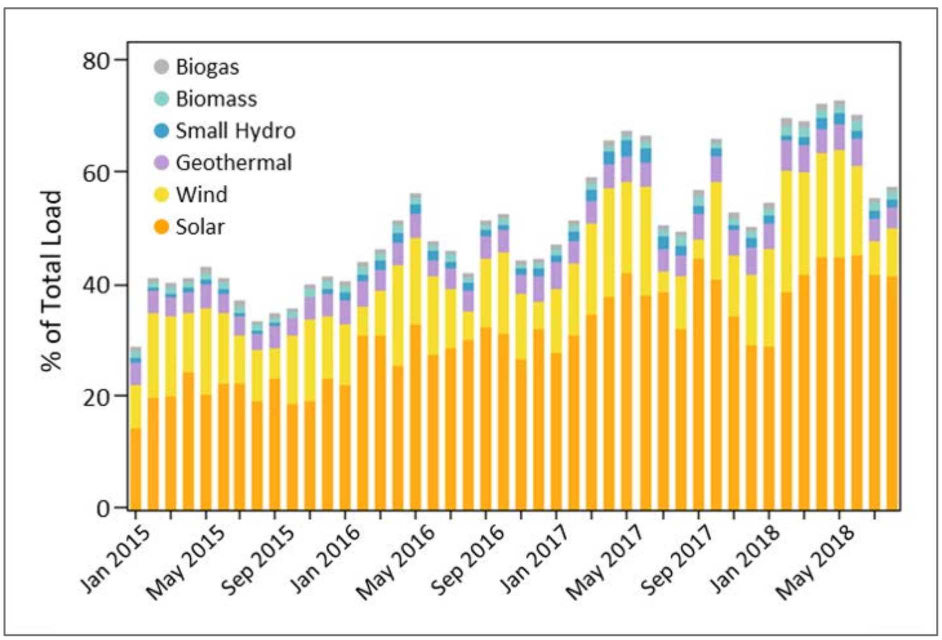

Figure 2-1. The maximum amount of load served by renewables in CAISO. (Data source: CAISO)

[15] Similar trends have been observed in other ISO/Regional Transmission Organization regions as well, NREL - 2018 Renewable Energy Grid Integration Data Book

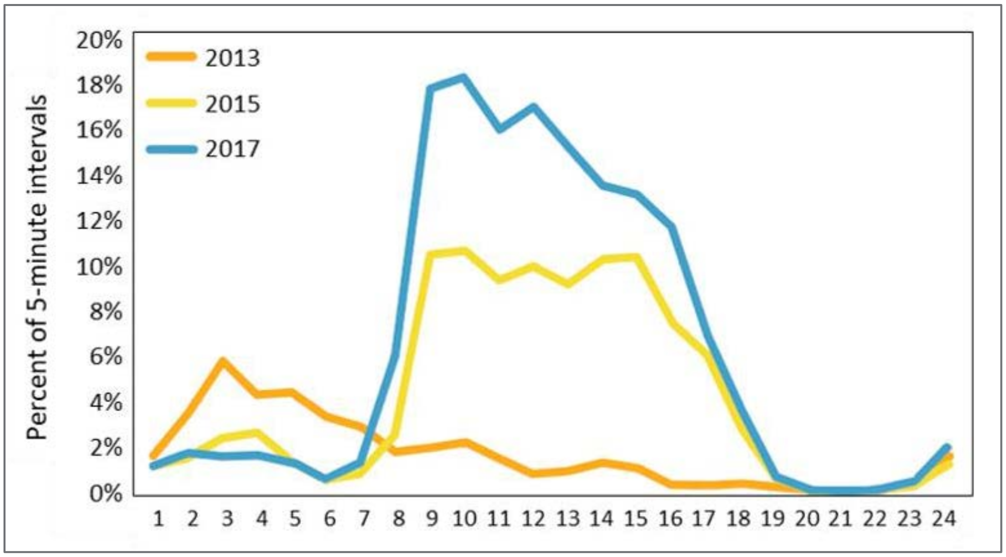

Figure 2-2. Percentage of negative price 5-minute intervals in 2013, 2015, and 2017 in the CAISO during the hours of a day. (Data source: CAISO)

2.1.2 Pumping patterns of pumped storage hydropower have changed in some parts of the country to optimize opportunities to pump during low and generate at high energy price times across the day

PSH plants have conventionally operated in day-night arbitrage patterns, i.e., resources typically pump during nighttime hours in concurrence with low energy prices (due to low load levels) and generate during evening peak-load hours in concurrence with high energy prices. Figure 2-3 below shows that the PSH units in MISO continue to pump during the nighttime hours.

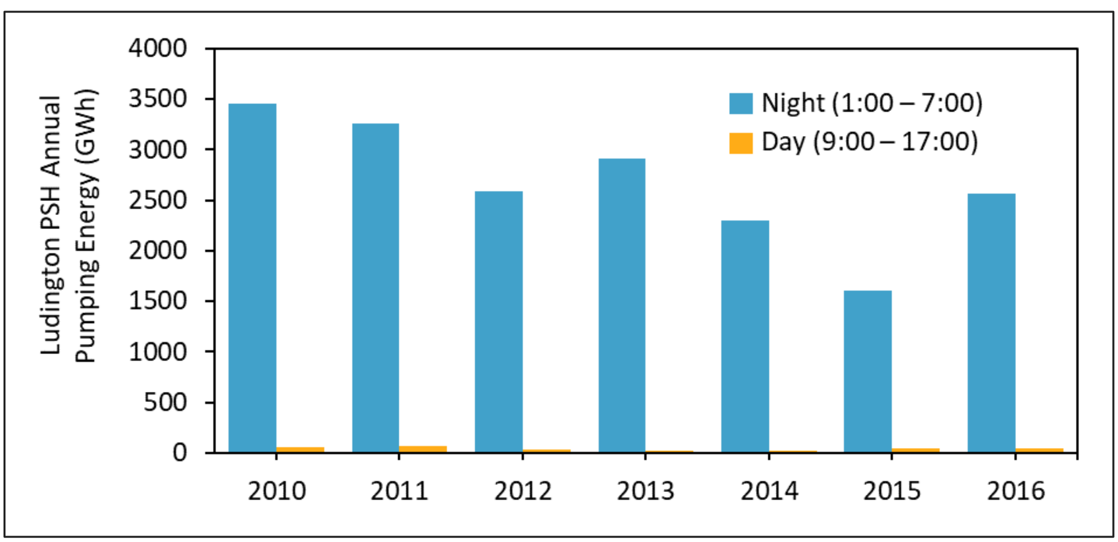

Figure 2-3. Pumping operations of PSH plants in MISO over the years. (Data source: MISO)

The increasing occurrences of negative price hours during day times in CAISO have changed the arbitrage pattern for the region's PSH resources. The change in operations of PSH resources is exemplified by changes in the pumping schedule (Figure 2-4) of the Helms PSH plant, owned by the Pacific Gas & Electric Co. (PG&E).

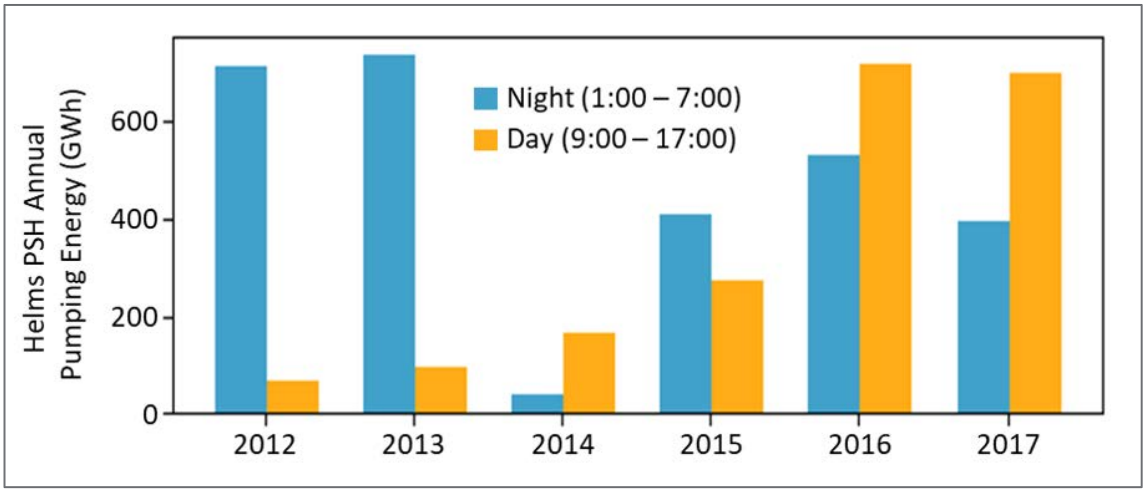

Figure 2-4. The changes in annual pumping schedules of the Helms PSH plant in CAISO. (Data source: PG&E)

Unlike CAISO, the operations of PSH resources in MISO are not driven by the total VRE generation in the system.[16] Figure 2-5 shows that the total amount of generation and pumping at the MISO PSH plants from 2015–2017 remains relatively same at different percentiles of wind generation. The finding is further supported by the fact that locational marginal prices (LMPs) at PSH locations are not affected by wind generation in MISO (Figure 2-5). This implies that the underlying value driver for PSH operations at this particular location within MISO—arbitrage price spread between peak and off-peak prices—is not affected by wind generation, unlike CAISO where the price formation and spread have indeed been affected by increasing VRE capacity. Instead, the PSH pumping and generation schedules in MISO are still driven by total system load, which is also positively correlated with the system prices (Figure 2-6 to Figure 2-8).

[16] It has been observed that wind power is consistently under-scheduled in the day-ahead markets, relative to actual production levels. In recent years, the amount of wind power under-scheduled has been observed to be as high as 1000 MW/h (Potomac Economics, "2018 State of the Market Report for the MISO Electricity Markets," June 2019).

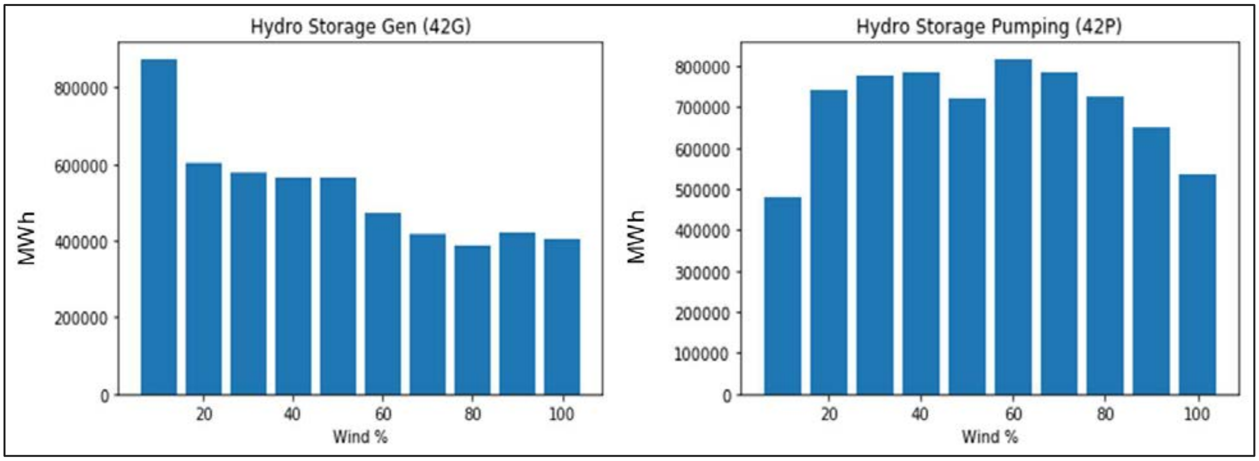

Figure 2-5. PSH generation and pumping relative to wind generation. (Data source: MISO)

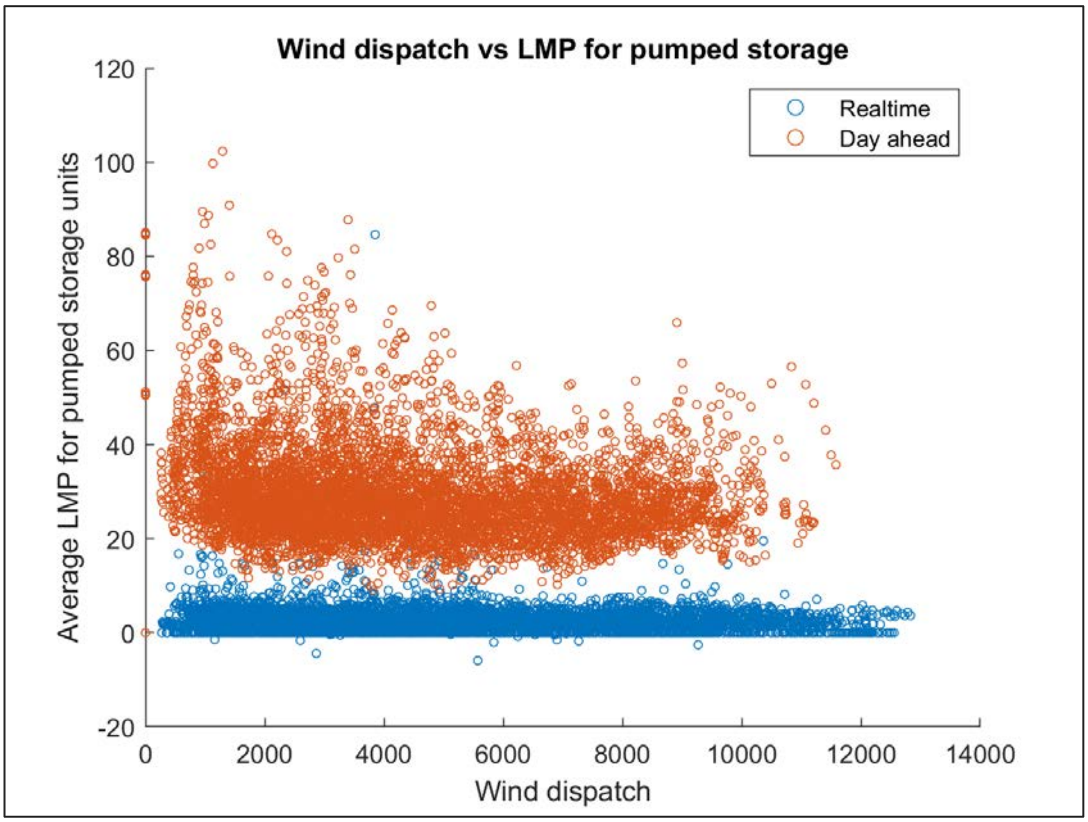

Figure 2-6. Wind generation does not affect LMPs at the PSH locations in MISO. (Data source: MISO)

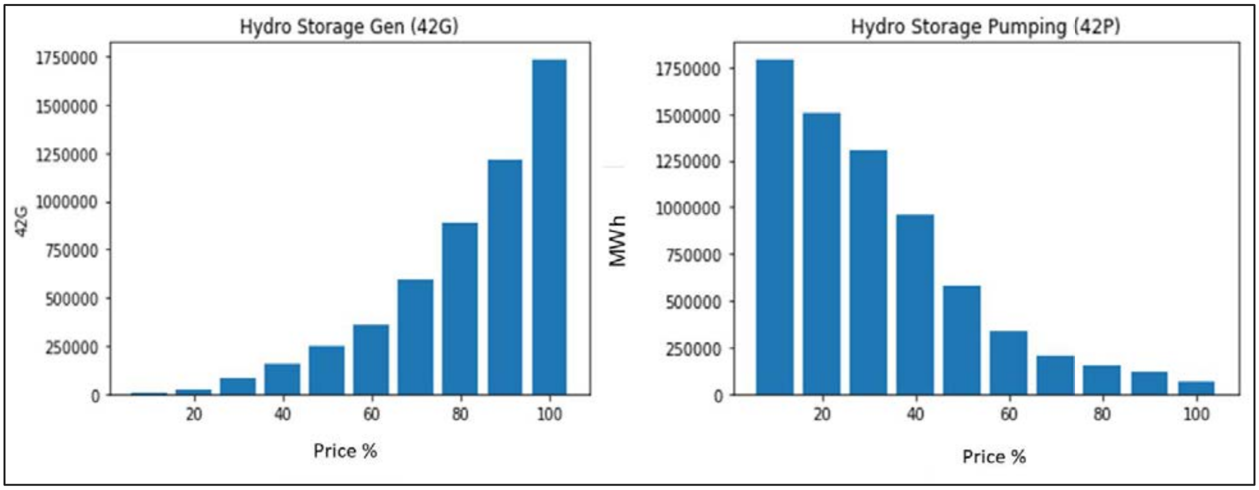

Figure 2-7. PSH generation and pumping relative to system prices (LMPs). (Data source: MISO)

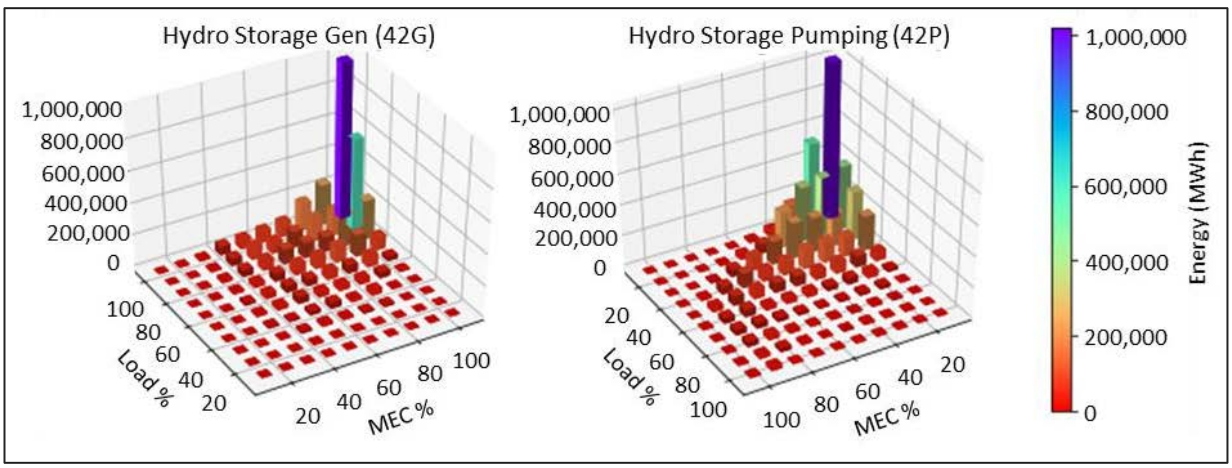

Figure 2-8. Comparison of PSH operations in pumping vs. generation modes in MISO (2015–2017). Marginal Energy Charge (MEC) is the energy component of the LMP. (Data source: MISO)

2.1.3 In other parts of the country, notably in the Pacific Northwest, resources continue to operate predominantly in load-following (gross load) mode

Resources that have limited storage capabilities, or those not operating in organized power markets, such as the Pacific Northwest (Figure 2-9) continue operating in the gross load-following mode as they were designed to operate. When the same time period is superimposed with a time series of prices from an EIM pricing node, it is observed that there is no correlation with hydropower generation.[17] This pattern of operations is most prominently seen in the utilities and balancing authorities, such as BPA, that have yet to join the EIM.

[17] Plant designs and operations, and utility contracts for hydropower facilities were conventionally designed for load-following purposes because markets did not exist at the time. However, many utilities in the WECC have now joined the EIM, which has led to changes in operations due to (1) exposure to prices, and (2) centralized dispatch by CAISO (Croft, Chad, 2019. Industry Changes Affecting Operations. Hydrovision International, Portland, OR).

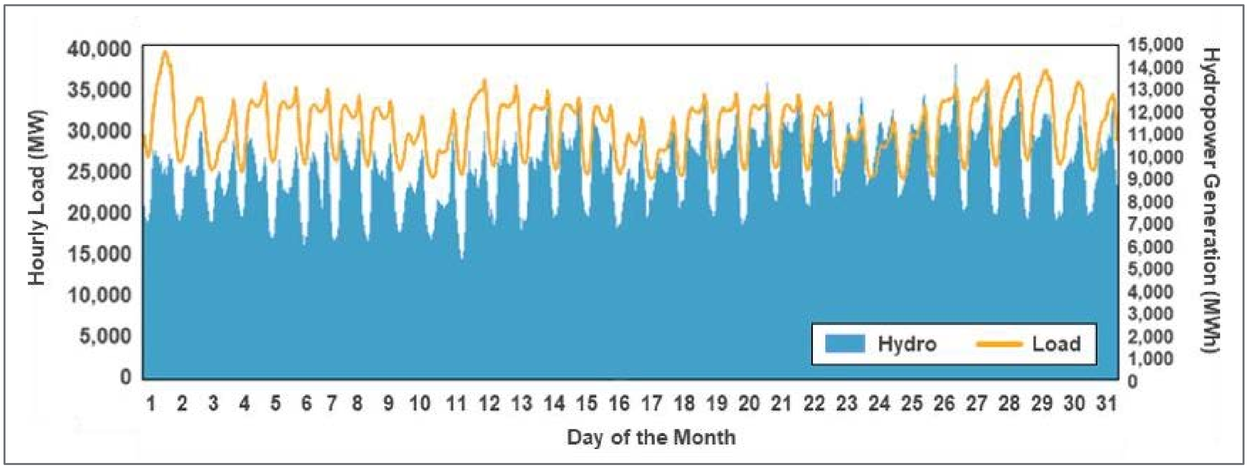

Figure 2-9. Typical pattern of hydropower operations in the Pacific Northwest compared to gross load in March 2016. Hydropower is continuing to operate in gross load-following patterns as designed. (Data source: EIA)

2.1.4 Even with these changing conditions, the capacity factor for hydropower resources in the US has stayed relatively constant through the years, between 35 and 45%

Figure 2-10 shows that the capacity factors of conventional hydropower resources have ranged between 35 and 45%, while accounting for annual water availability, and scheduled and unscheduled plant outages. However, resources in some parts of the country, such as ISO-NE (Figure 2-11) have been observed to operate at lower capacity factors over the years. The exact reasons for the decrease in capacity factors of resources in the ISO-NE region are not well understood.

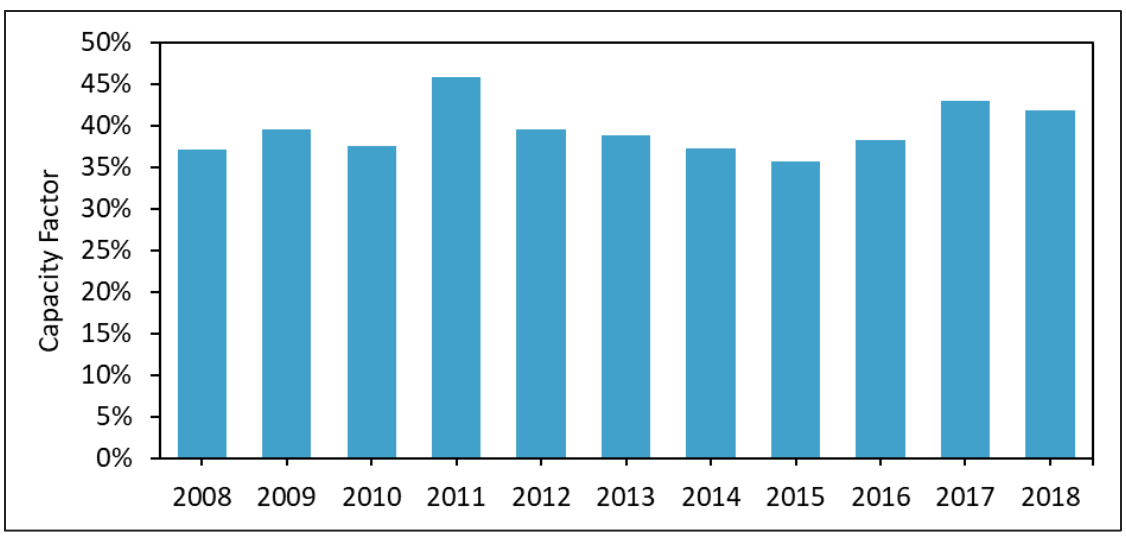

Figure 2-10. Capacity factor of conventional hydropower resources in the US. (Data source: EIA)

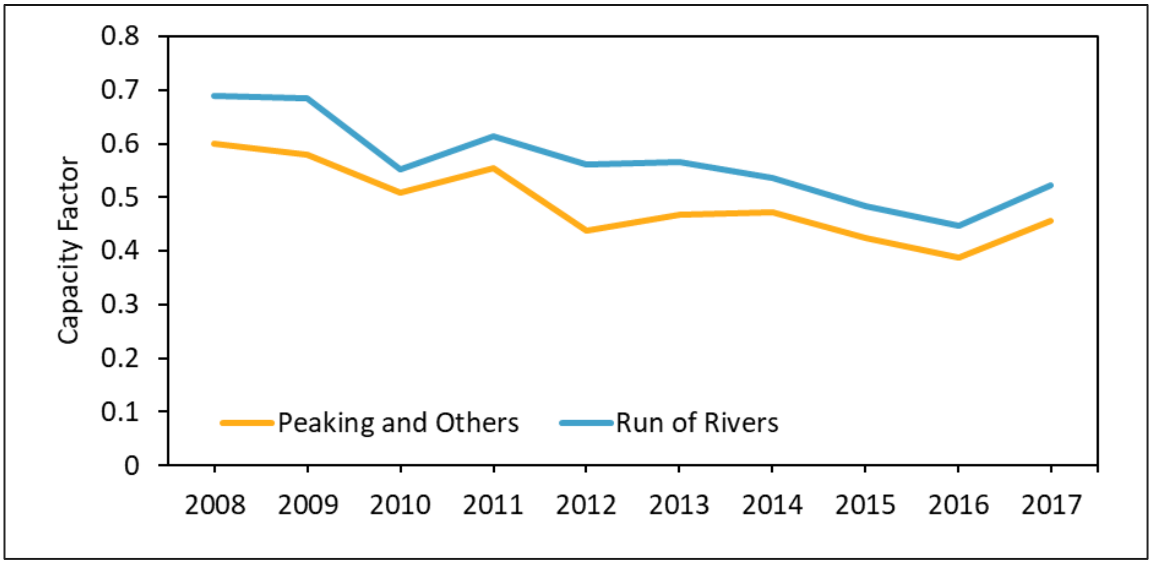

Figure 2-11. Capacity factors of conventional hydro resources in ISO-NE. (Data source: FERC Electric Quarterly Report [EQR])

Although there have been changes in the operational patterns of hydropower resources due to evolving grid conditions, hydropower resources continue to be large contributors to grid reliability. The next section presents the volumes and types of grid reliability services hydropower provides.

2.2 Hydropower generators are important contributors to grid reliability

Even in a changing power system, hydropower continues to be a significant contributor to system reliability through inertial and primary frequency responses, reactive power support, and black-start capabilities.[18] Approximately 40% of units maintained and tested for providing black start in the US are hydropower turbines, even though hydropower makes up only approximately 10% of overall US generating capacity.[1] Not all generators have these capabilities currently; the ability of inverter-based resources is currently being evaluated in laboratory and field demonstrations, and other traditional generators that supply these services may retire from service in the future, which may increase the demand for certain reliability services.

2.2.1 Hydropower capacity contributes, and will most likely continue to contribute, to resource adequacy (RA) requirements at a higher percentage versus capacity compared to other resources to ensure reliable operations of the grid

Resource adequacy standards ensure that utilities carry enough capacity with adequate reserve margins (RMs) to ensure reliable operations of the power system. In the US power grid's western interconnection there is currently deemed to be enough firm capacity resources to reliably meet peak loads in the four

[18] ORNL. (2019). "Hydropower Plants as Blackstart Resources." ORNL/SPR-2018/1077. https://www.energy.gov/sites/prod/files/2019/05/f62/Hydro-Black-Start_May2019.pdf

North American Electric Reliability Corporation (NERC)[19] subregions (Figure 2-12). As shown in Figure 2-13, capacity RMs computed by each individual WECC region of NERC are well above the reference RM that NERC deems to be enough from a reliability perspective in two of the four subregions though the year 2028. It is not until the end of this period that the Rocky Mountain Reserve Group and the Southwest Reserve Sharing Group subregions dip slightly below the reference RM. As a result, the bilaterally contracted values of RA capacity in the WECC remain extremely low.

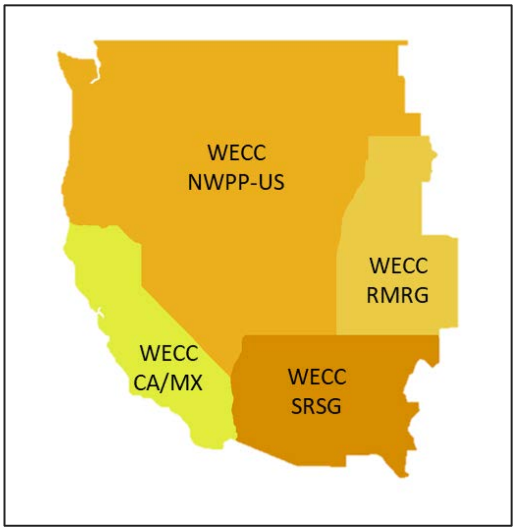

Figure 2-12. NERC subregions in the Western Interconnection.

A study of 2016 bilateral contracts for RA capacity in California showed that the weighted average price for all capacity was $3.10/kW-month, although the individual contracts ranged from 0.5/kW-month to $35/kW-month.[20] However, the recent legislatively mandated requirements to achieve a 100% carbon-free energy mix by 2045 in California and Washington will require those states' utilities to switch from fossil-fuel-based energy resources completely. The impact of these legislatively mandated requirements on the RMs and the associated RA needs are not fully understood. Hydropower capacity will most likely continue to provide the essential reliability services in such future grid scenarios.

[19] NERC Reliability Assessments, 2019 https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[20] California Public Utilities Commission (CPUC). The 2016 Resource Adequacy Report. June 2017. www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942

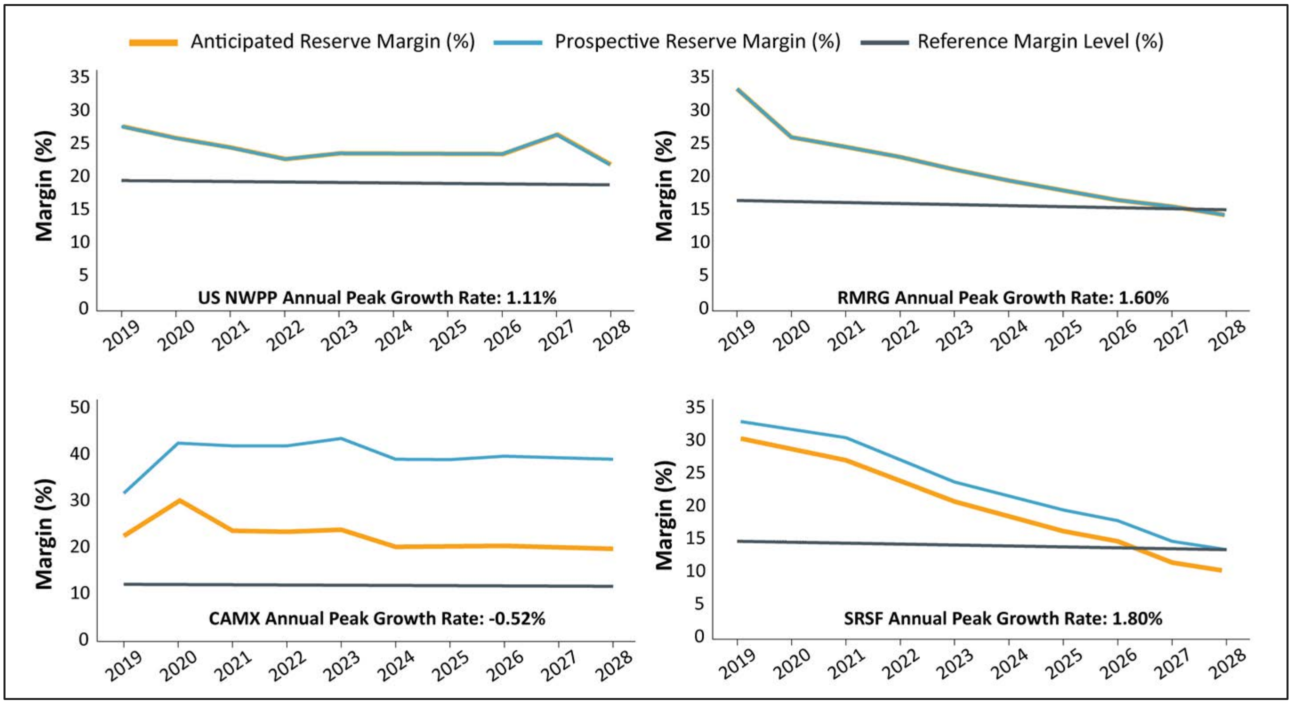

Figure 2-13. Capacity RMs between 2019 and 2008 in the four NERC subregions.

2.2.2 Hydropower resources provide operating reserves, such as spinning reserves and total Regulation Reserve requirements (up to 60% and 25%, respectively, despite being approximately 10% of generation in CAISO) that ensure the stability and reliability of grid operations

Conventional hydropower resources contribute, on average, approximately 15–25% of MISO's hourly spinning reserve requirements (Figure 2-14). The contribution can be as high as 35% during some hours of the year. It should be noted that the resources providing spinning reserves also contribute to a system's online inertia and primary frequency response ability.

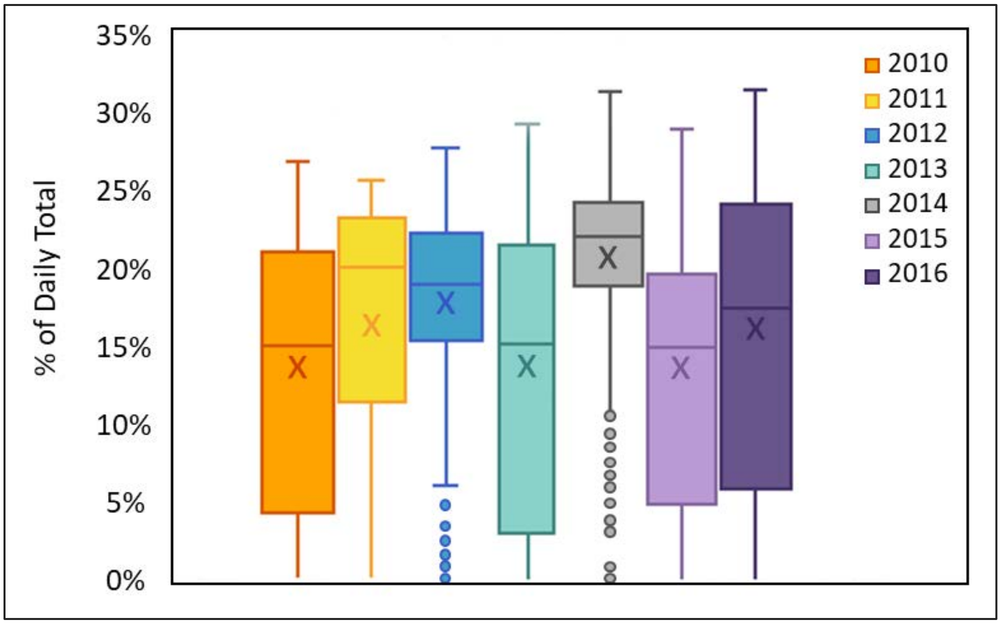

Figure 2-14. Percentage of spinning reserve provided by conventional hydropower resources in MISO. Hydropower's total capacity ranges from 3–5% of total the installed generation capacity. (Data source: MISO)

In CAISO, hydropower resources have been observed to contribute up to 25% of the total Regulation Reserve (up and down) requirements, as well as up to 60% of the total Spinning Reserve requirements (Figure 2-15).

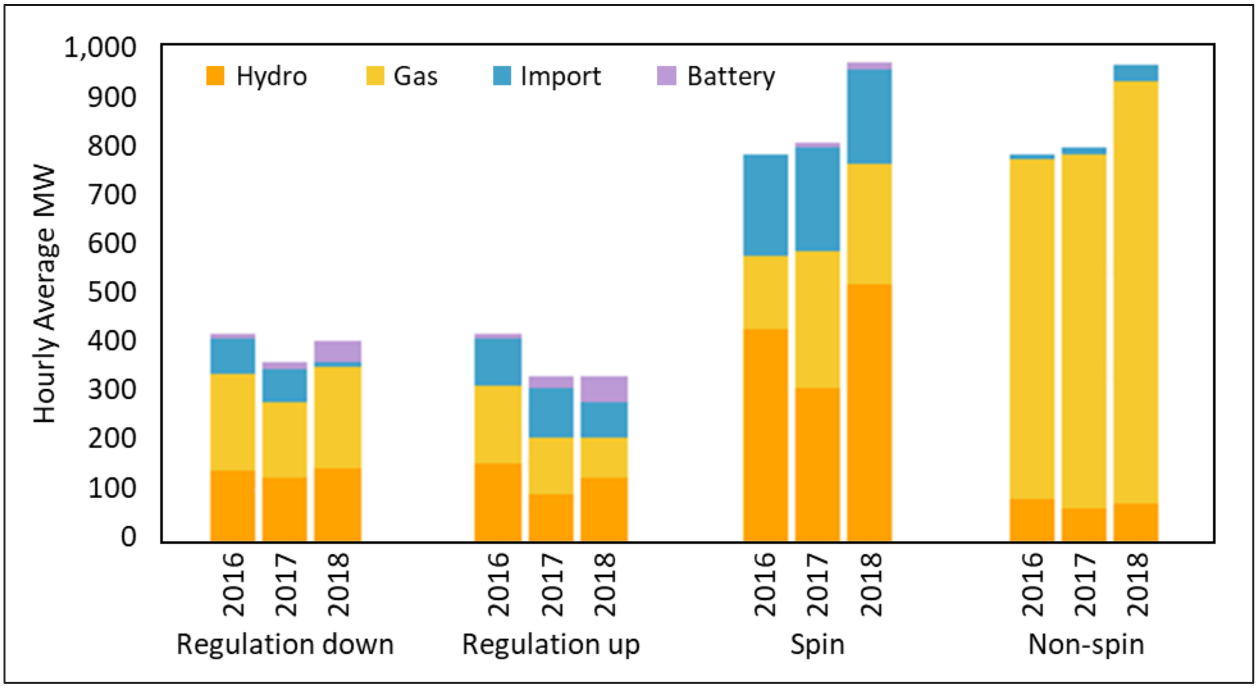

Figure 2-15. Contribution of hydropower resources for essential reliability services in CAISO.[21] Hydropower's total capacity ranges from 10–15% of total capacity in CAISO. (Data source: CAISO)

2.2.3 Hydropower resources provide essential reliability services, such as inertial and primary frequency response

However, the amount of inertial response provided by a hydropower plant depends on the number of units that are online and operating synchronously with the rest of the grid. The number of units operating at a given time, in turn, depends on the prevailing hydrological conditions—dry vs. average vs. wet year. Figure 2-16 shows that Chelan PUD's peak inertia contribution is consistent from year to year, but the amount of time it provides that peak contribution varies considerably based on water conditions. The peak inertia contribution corresponds to the portion of the year when water flow peaks in the Columbia River because of snowmelt and correspondingly when all units are online. During the example dry year, Rocky Reach is at peak inertia contribution from about May through July, and Rock Island is only at peak inertia contribution for about a week. Comparatively, during the example wet year, Rocky Reach is at peak inertia contribution from about May through September, and Rock Island still is only at peak inertia contribution for about a week.

[21] Source: CAISO State of the Market Report, 2018

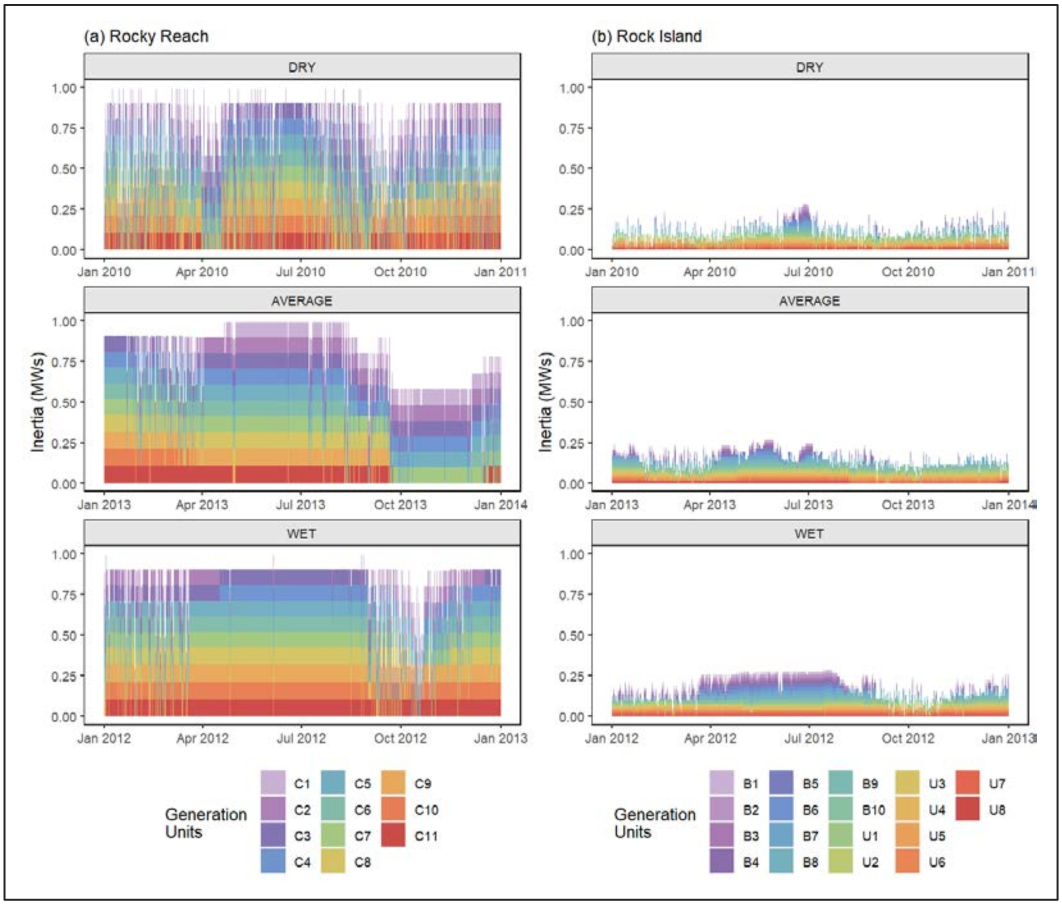

Figure 2-16. Hourly average inertia (MWs) contributed by all generating units for (a) Rocky Reach and (b) Rock Island run-of-river projects across dry, average, and wet years. Inertia response capabilities depend on water availability throughout the year, and the most generation during summer of wet years.

As these examples demonstrate, a hydropower resource's ability to provide reliability services can be bounded by various environmental, hydraulic, electro-mechanical, and contractual constraints. The next section further explores these constraints and the relationships between them.

2.3 There is a wide variation in hydropower plant conditions and capabilities to provide grid services

Hydropower's contributions to the grid are multifaceted, in that hydropower may serve several roles in a generating stack. At least 40% of hydropower resources, by capacity, comprises pumped storage and "peaking" hydropower plants, that can store water to produce electricity at times of greatest need and value, and at least 18% of hydropower resources comprises run-of-river plants, which may have some operational flexibility but typically cannot impound and store additional water beyond inflows.[22] Even within a given resource class, i.e., peaking or run-of-river, the ability to provide grid services depends on the site-specific electro-mechanical (physical) attributes, which are in turn governed by the hydrological and geological conditions. For a given plant, these capabilities will vary naturally over seasons and over

[22] ORNL, ORNL's HydroSource, 2018 https://hydrosource.ornl.gov/

water years (wet/average/dry). In addition, institutional factors such as existing contracts and FERC licenses determine a resource's ability to provide grid services. In many cases, non-power services such as flood control or environmental flows govern the ability of a hydropower plant to supply energy. The value of these services is not always accounted for in the overall value of hydropower. Additionally, the value of these non-power services is locational, based on stakeholder perspectives and the valuation methodologies that are employed.

2.3.1 Hydropower resources' ability to provide grid services depends on the electro-mechanical (physical) attributes, which are in turn governed by the hydrological and geological conditions at a location.

In this study, the team developed a framework to understand the relationship between various attributes of hydropower resources and their abilities to provide various grid services (Table 2-1).

Table 2-1. Hydropower capabilities that enable or assist in provision of services and products.

	Services/ Attributes	Large Inertial Constant	Reactive Power Control	Synch. Cond. Mode	Flexible Power Dispatch	Fast Cold Start-up	Fast Ramp Rate	Isolated Unit Start-up
Must Provide	Inertial support	✓✓✓		✓✓✓				
	PFR						✓	
Chosen to Provide	Voltage control		✓✓✓	✓✓✓				
	SFR (AGC)						✓✓✓	
	Spinning reserves				✓✓✓		✓✓✓	
	Non-spinning reserve				✓✓✓	✓✓✓	✓✓✓	
	Black start				✓✓	✓✓✓		✓✓✓

✓✓✓ well-understood relationship; ✓✓ possible relationship; ✓ relationship exists, but is not well understood.

The attributes of the hydropower resources, and hence, the capability to provide grid services are often based on site-specific design criteria, governed by hydrological and geological conditions, environmental regulations, and multi-use benefits of water at the location. The design criterion for most resources, historically, has been to maximize energy generation around the maximum efficiency points. However, as the operational paradigms change and hydropower resources are increasingly needed to provide essential support services, this framework can be used to evaluate the flexibility of existing resources, as well as the retrofits needed to ensure that the resources are able to provide those services (Table 2-2). The costs of making the necessary adjustments, or the additional wear and tear associated with flexible operations, need to be weighed against the benefits of providing the needed grid services.

Table 2-2. Constraints on hydropower capabilities from multipurpose benefits.

		Constraints Involved				
		Water Use Priorities	**Min Pool Elevation**	**Max Pool Elevation**	**Min Flow**	**Flow Max Ramp Rate**
Multipurpose Benefits	M&I water supply	✓✓✓	✓✓✓			
	Irrigation	✓✓✓	✓✓✓		✓	
	Reservoir recreation	✓✓✓	✓✓✓	✓✓✓		
	Stream reach recreation					✓✓✓
	Seasonal flood control		✓✓✓	✓✓✓		
	Navigation		✓✓✓	✓✓✓	✓✓✓	✓✓✓
	Fish and wildlife				✓✓✓	✓✓✓
Capabilities Restricted	Large inertial constant					
	Reactive power control					
	Synchronous condensing mode					
	Fast cold start-up	✓✓✓				
	Flexible power dispatch	✓✓✓	✓✓✓	✓✓✓	✓✓	✓✓
	Fast ramp rate					✓✓✓
	Isolated Unit start-up					✓✓✓

✓✓✓ well-understood relationship; ✓✓ relationship exists, but is not well understood; ✓possible relationship.

2.3.2 Environmental operating criteria can constrain the flexibility of hydropower operations

For example, there were fewer environmental restrictions at Glen Canyon Dam (GCD) prior to 1991. Table 2-3 shows that power plant water releases could range from 1,000 cfs to 31,500 cfs, with no limit regarding the daily fluctuations or ramp rates.[23] Such flexibility caused significant environmental damage, such as the disappearance of native fishes mainly due to changes in downstream water temperatures. From August 1991 to January 1997, temporary restrictions called "Interim Flow Restrictions" were put in place before the release of a final environmental impact statement. Since 1997, the water release range has been reduced to a range from 5,000 to 25,000 cfs, and daily fluctuations and ramp rates have been limited. More recently, in January 2017, a new Record of Decision (ROD) mandating the preferred alternative prescribed by the Long-Term Experimental and Management Plan (LTEMP) has been adopted and was first implemented in October 2017.[24]

[23] Bureau of Reclamation, "Record of Decision, Operation of Glen Canyon Dam, Final Environmental Impact Statement, Appendix G," October 1996.

[24] U.S. Department of the Interior, Record of Decision for the GCD LTEMP Final Environmental Impact Statement, 2016. http://ltempeis.anl.gov/documents/docs/LTEMP_ROD.pdf

Table 2-3. Evolution of GCD operating constraints.

Operational Constraint	Historical Flows (before 1991)	1996 ROD Flows (from 1997 to 2017)	2016 ROD Flows (after 2017)
Minimum flows (cfs)	3,000 (summer) 1,000 (rest of year)	8,000 (7 a.m. - 7 p.m.) 5,000 (at night)	8,000 (7 a.m. - 7 p.m.) 5,000 (at night)
Maximum non-experimental flows (cfs)[(a)]	31,500	25,000	25,000
Daily fluctuations (cfs/24 h)	28,500 (summer) 30,500 (rest of year)	5,000, 6,000, or 8,000 depending on release volume	Equal to 10 X monthly water release (in thousands of acre-feet) during June-August, and equal to 9 X monthly water release the rest of the year, but never exceeding 8,000 cfs
Ramp rate (cfs/h)	Unrestricted	4,000 up 1,500 down	4,000 up 2,500 down

(a) Except during experimental releases.

Because water flow rate and power are closely related, power capability at GCD has been also significantly reduced (Figure 2-17). Before the environmental restrictions, during the week from July 19 to July 25, 1987, GCD was able to produce a peak of power of 1,164 MW, that is, 90% of the rated capacity of this period. After the 1996 ROD, during the same week of the year 2015, this peak generation dropped to 746 MW, that is, only 56% of its current nameplate capacity.

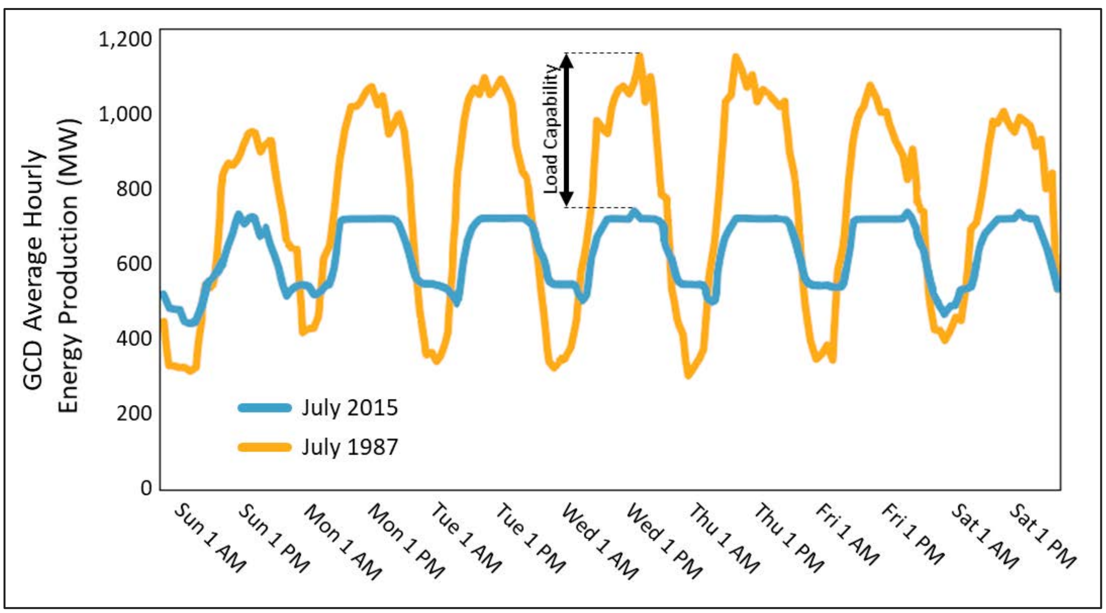

Figure 2-17. Hourly energy production at the GCD powerplant during a July week in 1987 and 2015. Flexibility was restrained with the implementation of new environmental restrictions.

2.3.3 The seasonal variations in water availability from year to year and the prevailing water management practices, due to environmental and other requirements, can imply a great variation in the provision of energy and other essential reliability services by hydropower resources.

In the case of the Chelan PUD, the flexibility of operations is significantly hampered during early summer (i.e., April through July) high flow conditions when energy generation is maximized in order to minimize water spillage. This practice helps avoid increasing the levels of dissolved oxygen. This behavior was also evident even during a relatively dry summer even though the intra-day generation patterns differed markedly during the early summer months between dry and wet weather years. Conversely, dry winter and early spring conditions create the opportunity for increased flexibility and significant reserves (Figure 2-18). Increased water availability during the months of spring run-off and summer results in a flatter daily generation profile with increased overall generation, and lower reserve. As operated, plants showed reduced variability, and flexibility, in hourly generation during spring and early summer—April to July—and high flow conditions in general.

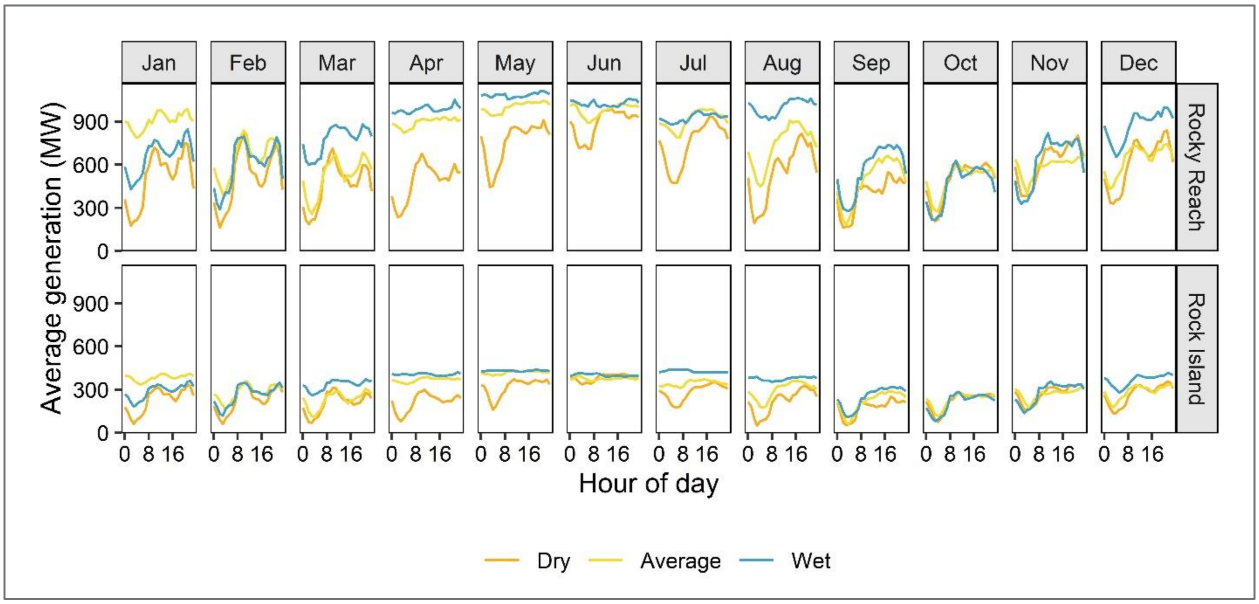

Figure 2-18. Comparison of average hourly generation during dry, average, and wet years at Rocky Reach and Rock Island Dams. During spring and early summer months of wet years at both Rocky Reach and Rock Island, the flexibility of operations is restricted due to high flow conditions. (Data source: Chelan PUD)

These complex constraints on hydropower operations, together with changes in market and power system conditions, can have significant impacts on revenues earned by hydropower. The next section presents some of the observed revenue trends in different parts of the country.

2.4 Traditional economics for hydropower plants may not provide stable revenue into the future

Conventional value streams, such as energy and ancillary services prices, are exhibiting declining trends in some parts of the country, and these changes have affected hydropower resources adversely. This trend is evident in conventional hydropower plants in the Northeast, as well as in pumped storage hydropower plants in the Midwest. Energy generation remains the primary source of revenue for many hydropower plants, and while most hydropower is technically capable of providing ancillary services, this provision often includes opportunity costs associated with reduced capacity.

2.4.1 The average annual wholesale electricity prices across various parts of the country have declined substantially since 2008.

Figure 2-19 shows the average of annual wholesale prices across selected pricing hubs in the US ISO/RTO regions. The data[25] show a sharp drop in prices after 2008, and a relatively small spike in 2014. Oft-noted causes for these price patterns include the steep reduction in natural gas prices,[26] and increasing penetration of VRE resources. Analysis of historical natural gas and wholesale electricity prices shows a strong positive correlation between the two data sets in every US ISO/RTO region.

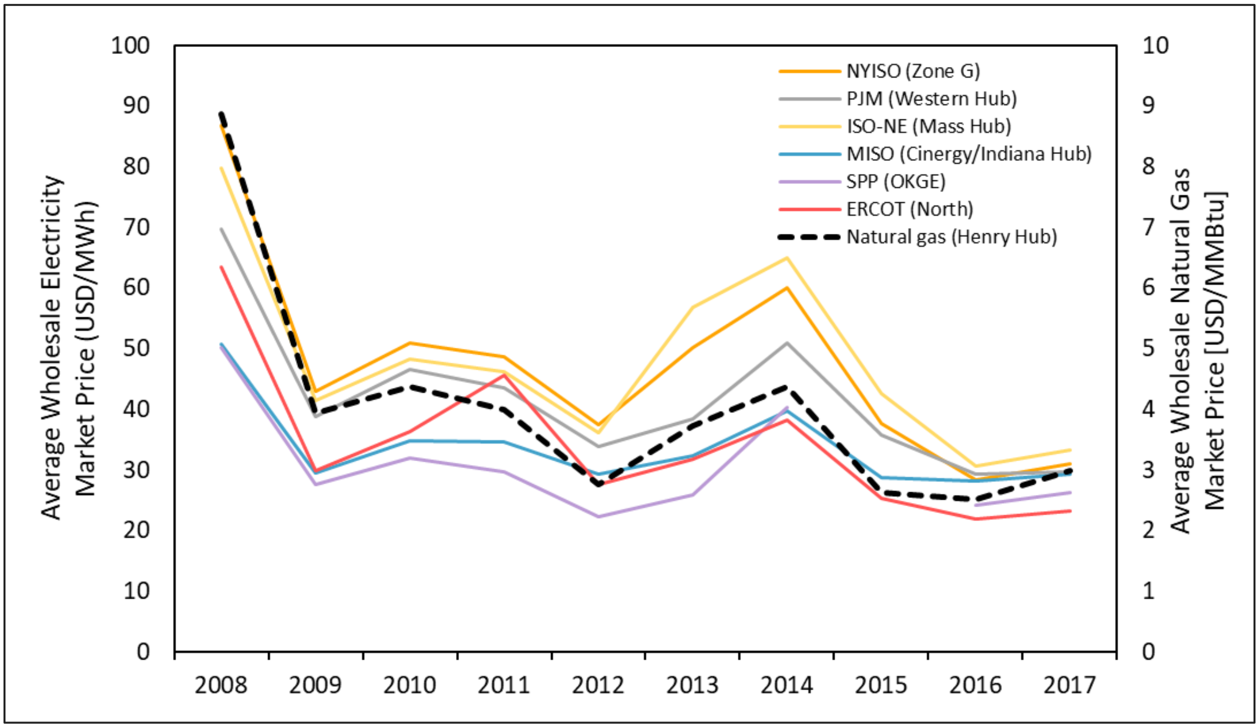

Figure 2-19. Average annual energy prices at select price hubs in US ISO/RTO markets. Wholesale electricity prices are highly correlated with natural gas prices.

The positive correlation between energy and natural gas prices is also observed in areas that have no restructured power markets, such as in the Pacific Northwest. Figure 2-20 shows a strong positive correlation between gas prices at the Citygate trading hub and the wholesale energy prices at the Mid-C

[25] Data were obtained from Wiser et al. 2019, downloaded using ABB's Velocity Suite.

[26] DOE's "Staff Report to the Secretary on Electricity Markets and Reliability," 2017 noted that "Shale gas development has significantly expanded the availability of natural gas and lowered its cost across the United States and the world. Before the widespread use of horizontal drilling techniques in the past decade, US natural gas prices averaged more than $7 per million British thermal unit (MMBtu) between 2003 and 2008, and approached $14/MMBtu in several short periods (including in 2005 after Hurricanes Katrina and Rita reduced production and delivery from Gulf of Mexico sources). Hydraulic fracturing practices spread and made previously inaccessible gas sources economic, causing natural gas prices to fall, averaging less than $3.20/MMBtu between 2012 and 2016."

trading hub. In contrast, hydropower generation in the region has been observed to have an inverse relationship with wholesale energy prices at the Mid-C trading hub. Figure 2-21 shows a moderate negative correlation between monthly hydropower generation and average monthly wholesale prices in the Pacific Northwest region.[27]

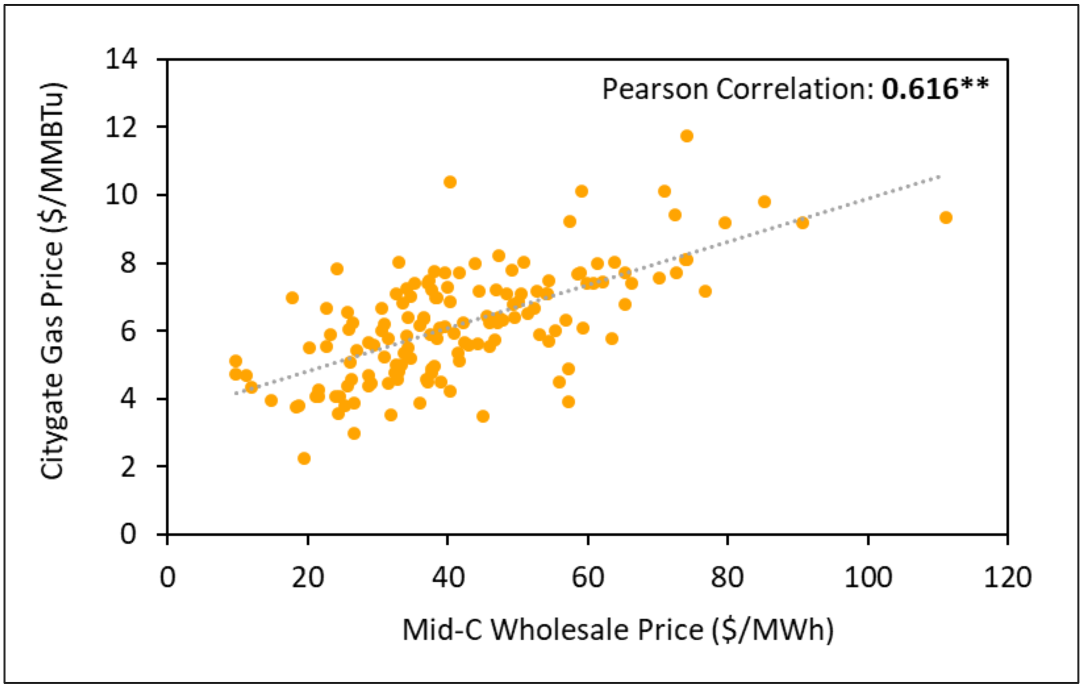

Figure 2-20. The Citygate natural gas price is positively correlated with the Mid-C wholesale price. (Data source: EIA)

[27] Hydropower is the dominant source of electrical energy supply in the region, which impacts the supply from other resources along with the region's energy prices. The relationship between hydropower and wholesale market prices in other parts of the country will depend on the amount of hydropower generation and the mix of other generation resources in the region.

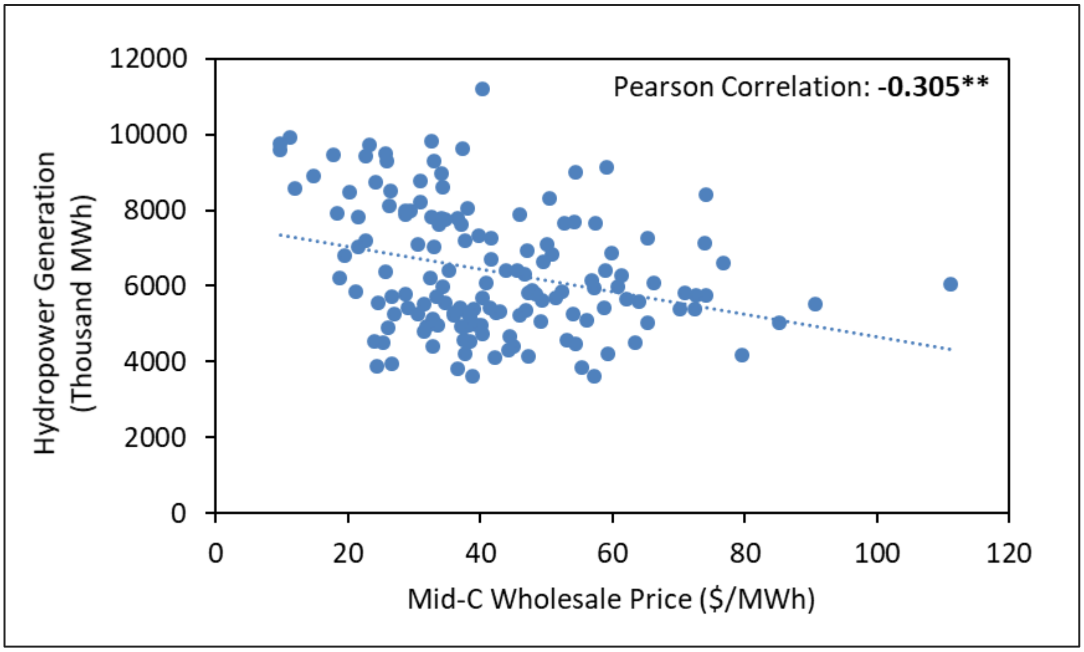

Figure 2-21. Hydropower generation is negatively correlated with Mid-C wholesale price. (Data source: EIA)

2.4.2 Changing market prices have negatively impacted estimated revenues of hydropower resources in the Northeastern states (ISO-NE)

The changes in market prices can affect the revenues directly, such as for market-based merchant generators, or through the influence on long-term bilateral transaction prices. Figure 2-22 shows that ISO-NE's average energy prices have been decreasing over the past 10 years, except for a sharp spike in 2014, which coincided with a sharp spike in natural gas prices. As a result, the total revenues[28] realized by hydropower plants are estimated to have also decreased over the years (Figure 2-22). The capacity factors for run-of-river resources tend to be higher than peaking resources because peaking resources typically operate only during periods of peak load to take advantage of higher prices. The difference in operating strategies is also reflected in the total revenue (normalized by total plant capacity in MW), observed for the two sets of plants. The revenue, as measured in capacity terms ($/kW), is observed to be greater for run-of-river plants due to their higher capacity factors.

[28] The revenues numbers are estimates, based on locational marginal prices (LMPs) and market clearing prices (MCPs) for energy and ancillary services, respectively. It should be noted though that the actual revenues are likely to differ because the terms of power purchase agreements (PPAs) are likely to differ from market-based prices.

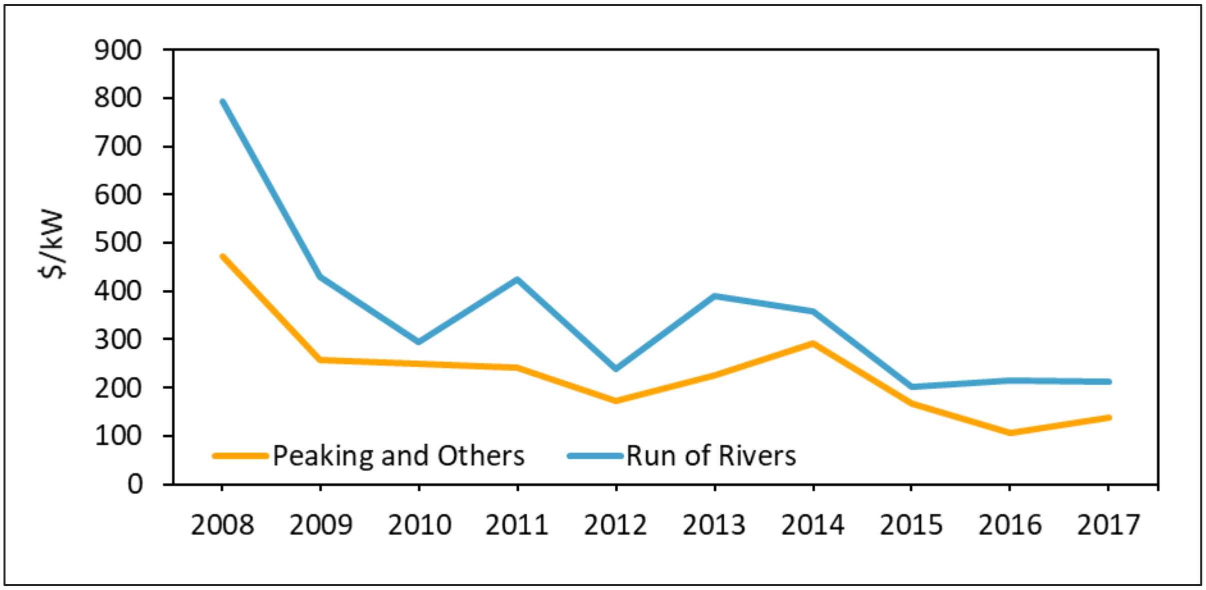

Figure 2-22. The revenue of peaking and run-of-river plants in ISO-NE has been decreasing since 2008. (Data source: FERC EQR)

2.4.3 Changing market prices have also negatively impacted estimated revenues of PSH resources in MISO

Figure 2-23 shows the operational patterns of PSH resources in MISO. A temporary decrease in generation (and pumping) was observed from 2015, which was potentially due to the upgrade project under way at the Ludington PSH facility[29] at the time.

[29] https://www.renewableenergyworld.com/2018/09/25/michigan-utilities-upgrade-pumped-storage-plant-ahead-of-renewable-push/#gref

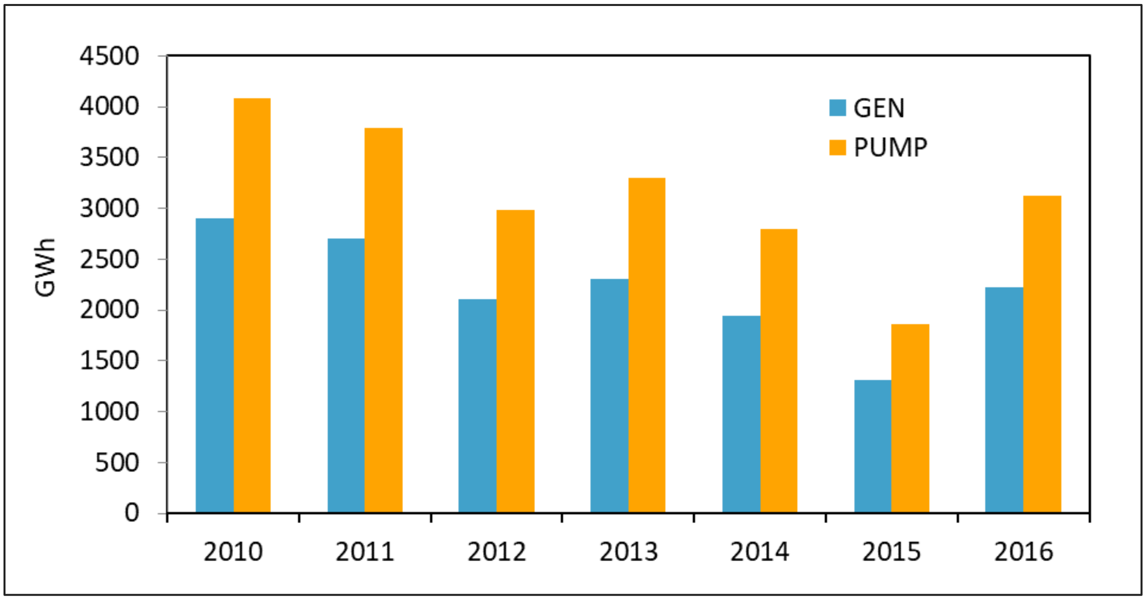

Figure 2-23. Annual generation vs. pumping load for PSH resources in MISO. Total generation and pumping have decreased since 2010. (Data source: MISO)

The decrease in generation was accompanied by a decrease in price spread between peak and off-peak energy prices.

Figure 2-24, which is the primary source of arbitrage value for PSH resources. Hence, the coupling of these two factors was observed to have resulted in decreased net revenues for PSH resources (Figure 2-25). The estimated revenues in MISO witnessed a small increase in 2014 because of the increase in prices driven by the increase in natural gas prices. The net revenues, measured by the difference between revenue from generation and cost of pumping, have decreased in absolute magnitude, but continue to be approximately 10% of the total revenues, except for in 2013. It should be noted here that the reasons for the decrease in generation and pumping load from 2010 to 2015 are not well understood. However, the decrease in price spread between peak and off-peak prices would still have resulted in decreased net revenue even if the generation and pumping patterns had remained unchanged over the years. It is also worth noting that these observations are specific to PSH resources in MISO, and as such, should not be generalized to resources in other parts of the country.

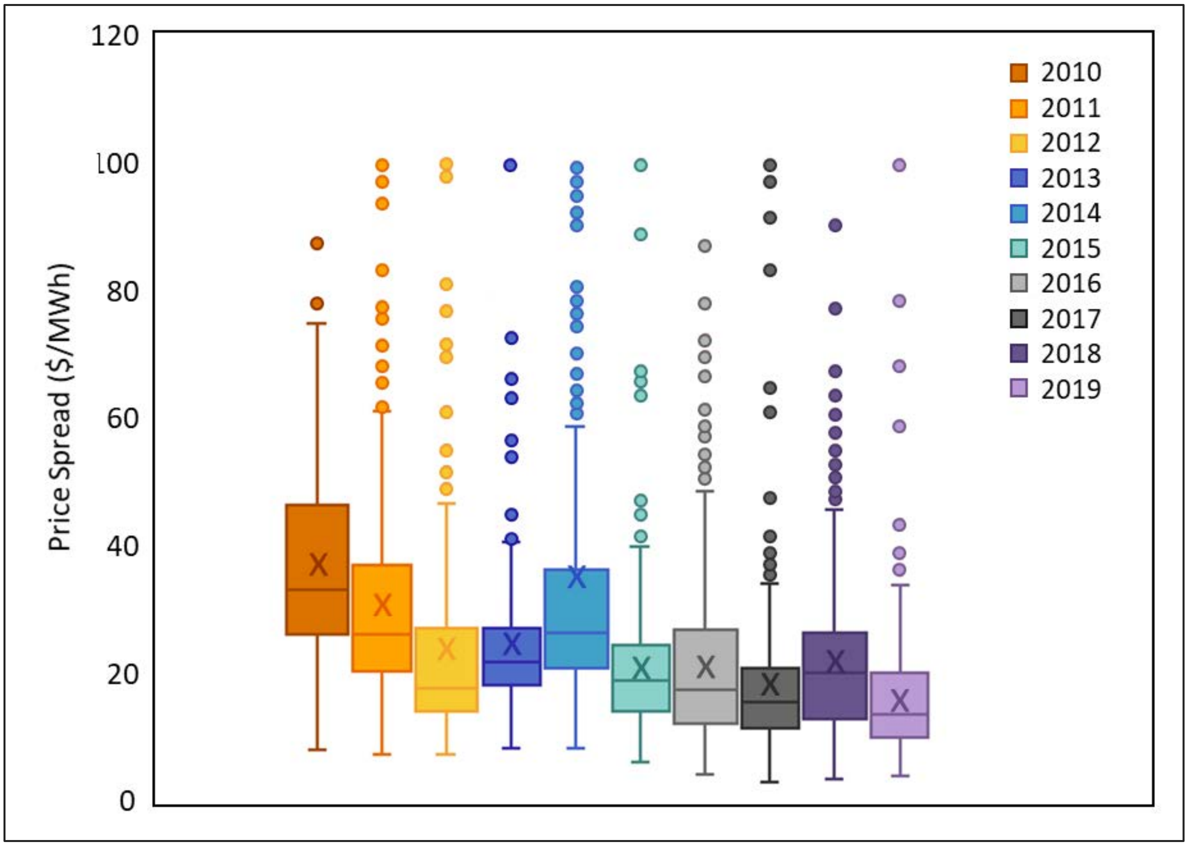

Figure 2-24. The LMP spread between peak and off-peak hours in MISO shows a decreasing arbitrage spread.

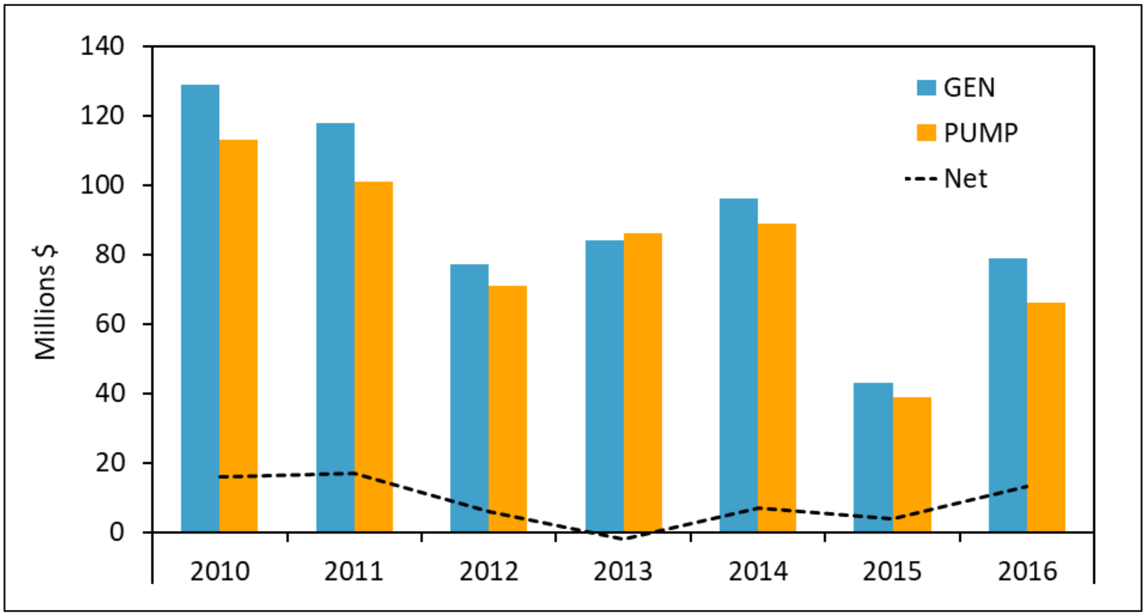

Figure 2-25. Comparison of annual revenue and pumping costs for PSH units in MISO. Net revenue has decreased since 2010 but increased slightly in 2016. (Data source: MISO)

2.4.4 The major revenue source in most markets is still energy generation, followed by long-term capacity payments and ancillary services, including uplift, which contributes to only a small part of the total revenue

In ISO-NE, the revenues from energy production have accounted for 49%–73% of the total revenues across all ISO-NE utilities from 2013 to 2017.[30] Despite lower revenues, hydropower plants in ISO-NE participate in the market of almost all the services. Figure 2-26 shows that the total system cost of serving energy, which includes the cost of ancillary services. These system costs can be viewed as proxies for the revenues earned by participating resources, including hydropower.

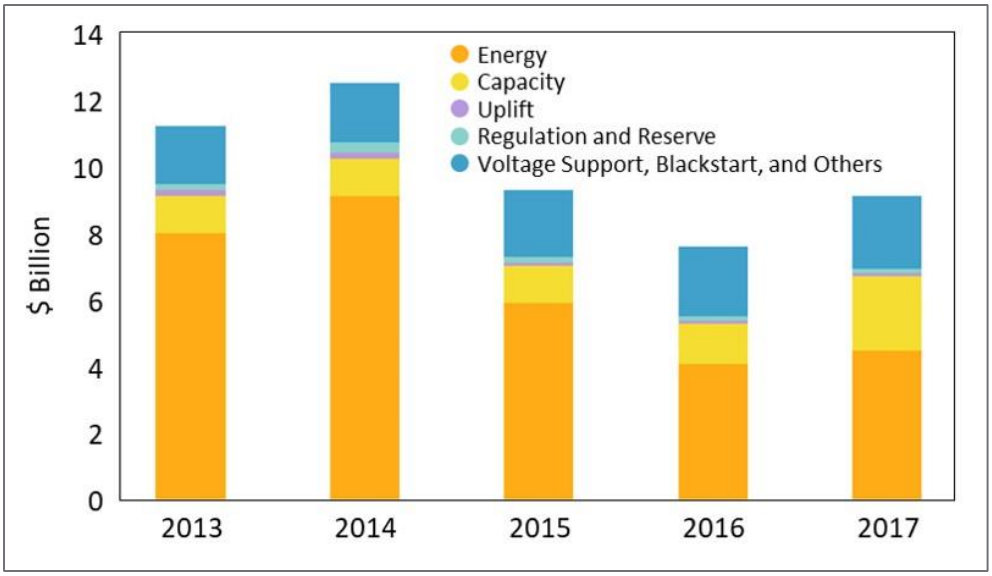

Figure 2-26. Total cost of serving load in ISO-NE from 2013 to 2017. Energy is still the bulk of costs but is decreasing. This can indicate an opportunity cost in providing other services over energy. (Data source: FERC EQR)

In CAISO, the costs of energy generation (which roughly equates to the total revenue for generating resources) have constituted over 50% of the total system operating costs over the years (Figure 2-27). Like ISO-NE, the share of other grid services remains a much smaller fraction (<5%) of the total cost of serving load. Given the total size of ancillary services, any shift from energy generation presents an opportunity cost to resources that must be weighed against the additional cost of providing those services; these costs can include the wear and tear on resources due to providing certain grid services, such as frequency regulation.

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[30] ISO New England, *2017 Annual Markets Report*, May 2018; https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf

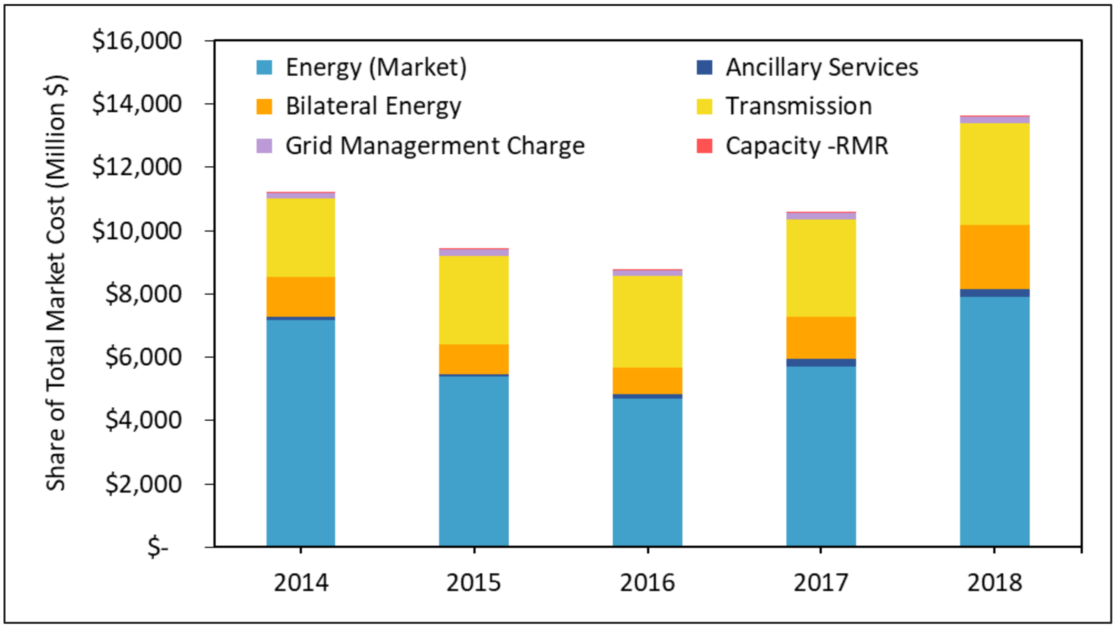

Figure 2-27. The total cost of serving load in CAISO from 2014 to 2018. Energy is still the bulk of costs. This can indicate an opportunity cost in providing other services over energy. (Data source: CAISO[31])

Similarly, energy production continues to be the major source of revenue in MISO. This is because the size of ancillary services markets is much smaller than energy; for instance, the total requirement for regulation reserves in MISO is 0.5% of peak load. Table 2-4 presents estimates of revenues for hydropower resources in MISO from 2015 to 2017.

Table 2-4. Comparison of estimated revenue from regulation vs. energy service in MISO (2015–2017).

		Average Daily Supply	**Estimate of Total Revenue ($M)**
Regulation	Pumped Hydro	255 MW	$2.4
	Conventional	241 MW	$1.6
Energy	Pumped Hydro	4,573 MWh	$129[32]
	Conventional	20,086 MWh	$345

2.4.5 While most hydropower is technically capable of providing ancillary services, there is often an opportunity cost due to the small size and value of the ancillary service market

The total market size for ancillary services tends to be a very small fraction (<1–2%) of the market size for energy.[33] In addition, energy prices are generally higher than the prices for ancillary service, and

[31] Source: CAISO State of the Market Report, 2018

[32] This estimate does not include the cost of pumping water, which should be subtracted from the total revenue.

hence, there are opportunity costs associated with the capacity that is carved out of the plant's maximum operating capability to support these services.

In an analysis of the financial and economic implications of a proposed Rocky Mountain Transmission Group joint-tariff market, the Western Area Power Administration (WAPA) and ANL estimated the lost-opportunity costs associated with the WAPA Loveland Area Projects (LAP) Office carrying operating and contingency reserves at LAP hydropower resources in the WAPA, Colorado-Missouri Region balancing authority area[34] (Figure 2-28).

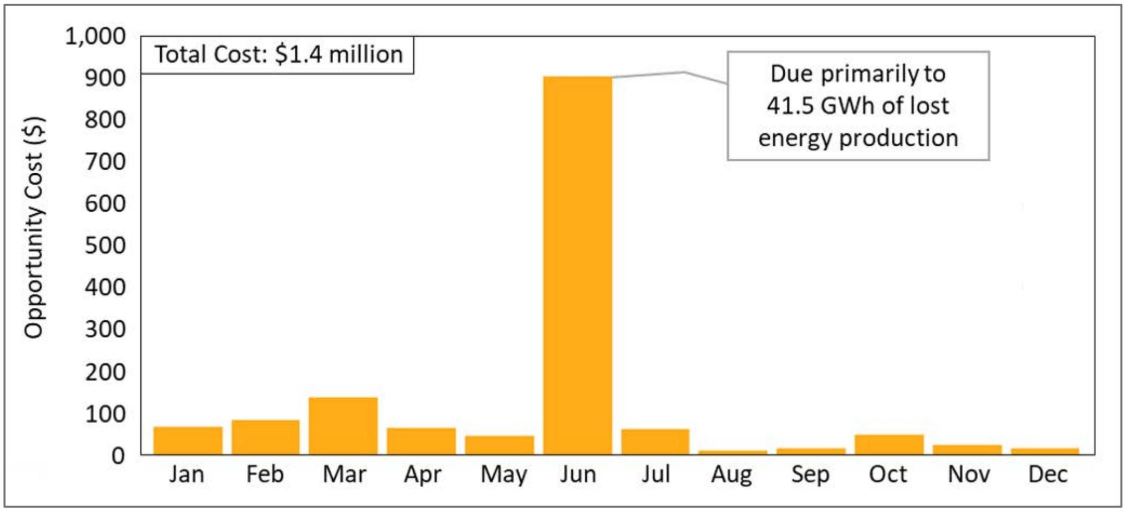

Figure 2-28. Opportunity costs associated with carrying operating and contingency reserves at LAP hydropower resources in the Western Area Power Administration, Colorado-Missouri Region balancing authority area of the Rocky Mountain Transmission Group joint-tariff market, for simulation year 2024.

Note that about 63% of the annual lost-opportunity costs are projected to occur in the month of June. During this month, water releases are generally at a high point, and the powerplant is either fully or nearly fully used much of the time (Figure 2-29). Using all the available water to produce energy leaves little capacity to provide ancillary services. Hence, generation schedules must be dialed back by releasing some water through the plant's bypass tubes in order to have adequate generating capacity to provide regulation-up services and, if needed, to deploy spinning reserves.

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[33] Denholm, et al., 2019. An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind. NREL https://www.nrel.gov/docs/fy19osti/72578.pdf

[34] WAPA, Mountain West Joint Tariff and Regional Transmission Organization Market Study, 2017. https://www.wapa.gov/About/keytopics/Documents/LAP-CRSP_Production-Cost-Study.pdf

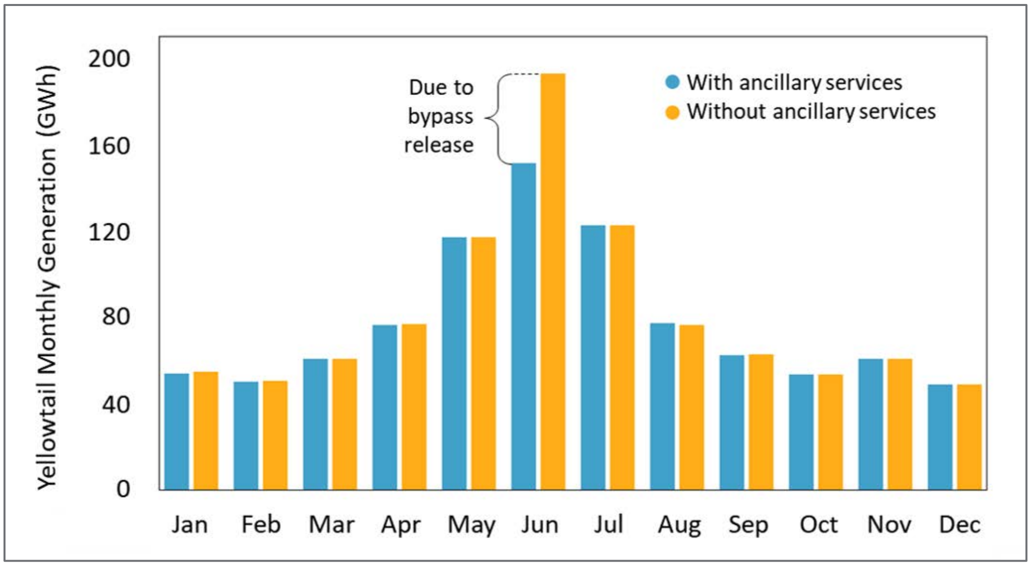

Figure 2-29. Monthly projected generation for Yellowtail hydropower facility during a sample year.

The results from this analysis demonstrate that revenue from provision of ancillary services is expected to be much lower than from generation of energy. Hence, the opportunity cost can be quite substantial based on the existing pricing and compensation paradigms. Flexibility services, in the future, will need to be compensated commensurate to value so that there is enough offset for the lost revenue opportunity from generation of energy alone. The next section presents potential future market mechanisms that are emerging to better compensate hydropower resources for the services they provide.

2.5 Emerging new market mechanisms could compensate hydropower flexibility

While not all services that hydropower provides are currently monetized, new markets for grid services are emerging that can offer alternative revenue streams. Evolving flexibility requirements have led some ISOs, such as the CAISO, to define new FRA capacity constructs, and hydropower is already helping meet some of these requirements. New market mechanisms are emerging for inertia and primary frequency response, and hydropower resources are already being compensated. For example, CAISO recently signed contracts with the BPA and Chelan PUD for explicit compensation for inertial and primary frequency response provided by hydropower resources.

2.5.1 Not all grid services are currently compensated

Apart from the monetized energy and ancillary services, hydropower continues to provide other essential grid services, such as inertial and primary frequency response, as shown in Section 2.2. Hydropower provides these services by the virtue of being online for the purposes of generating electricity and providing the reserves needed for balancing supply and demand, even during normal system operations.[35]

[35] In a study conducted by American Governor Company, The Impact of Hydroelectric Power and Other Forms of Generation on Grid Frequency Stability for the WECC Region, the authors estimate that for the WECC grid as a whole in 2008, hydropower generation contributed between 25% and 90% of the Primary Frequency Control response in the first 10 seconds after an under-frequency event, before intervention from Automatic Generation Control.

However, there is not always an explicit compensation[36] for providing these services, other than through compensation for generating energy or for providing spinning reserves. In addition, hydropower turbines operate at much wider frequency ride-through bands because of their lower rotational speeds compared to steam turbine speeds. This can imply a greater tolerance to frequency deviations,[37] which implies that a unit may not trip off during system events, such as large generation outages. This characteristic of hydropower can be extremely useful to the grid while dealing with situations leading to cascading outages.[38]

2.5.2 Changing grid conditions are likely to put a premium on fast-acting and flexible resources such as hydropower

Figure 2-30 presents the generation profiles of different renewable resources in CAISO on March 18, 2019. The solar generation ramps up from 0 MW to 10,000 MW in a span of two hours (07:00 to 09:00). The solar output then ramps down by an equivalent amount during the evening hours (17:00 to 19:00). These extreme ramping events impose great stress on the system, requiring conventional generation resources, including hydropower, to respond quickly.

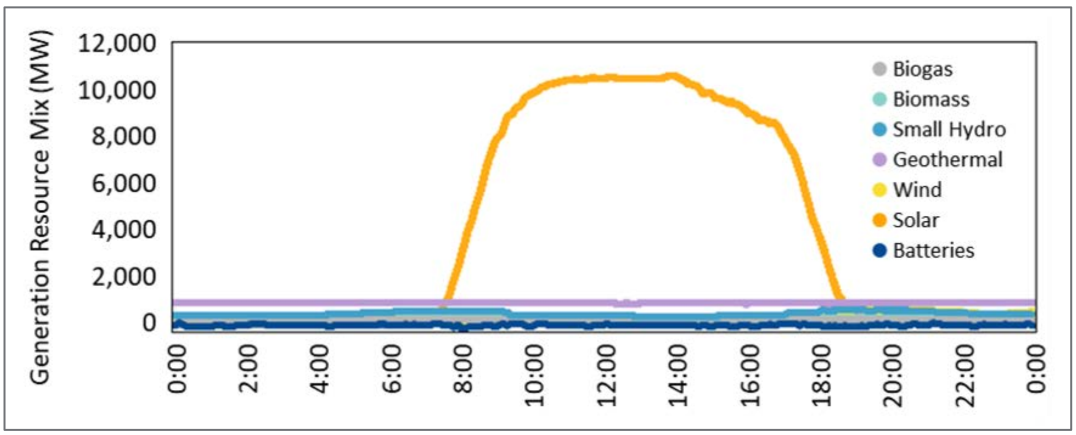

Figure 2-30. The generation mix (MW) on March 18, 2019 in CAISO. (Data source: CAISO)

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36 In 2016, CAISO contracted with two entities for primary frequency response: Seattle City Light (SCL) and the Bonneville Power Administration (BPA). The SCL contract transfers 15 MW/0.1 Hz of frequency regulation to SCL at a contract price of $1.22 million or $81/kW-yr (CAISO 2016a). The BPA contract transfers 50 MW/0.1 Hz of frequency regulation to BPA at a contract price of $2.22 million or $44.40 / kW-yr (CAISO 2016b). More recently, CAISO has also signed a contract for provision of the service with Chelan PUD. All three are primarily hydroelectric utilities.

37 ANSI/IEEE C.37.106-1987, "IEEE Guide for Abnormal Frequency Protection for Power Generating Plants," ANSI, New York City states the following: "The abnormal frequency limitations for hydraulic turbine generators are much less stringent than that for STGs and CTGs. Generally, hydraulic turbine generators are designed to withstand more severe over-speeds than steam and combustion turbines, in some cases up to 100% overspeed (200% speed). Bucket designs on hydro units are therefore more rugged than the tapered blade designs found on other turbines. While manufacturers should be consulted for their specific recommendations, the abnormal frequency capability for continuous operation of a hydro unit is generally outside of the range from 57–63 Hz."

38 During the 2003 blackout in the Eastern Interconnect, an islanded system was formed in the eastern New York area due to the Niagara power plants' ability to ride through a wider frequency band. "[During the blackout,] one relatively large island remained in operation serving about 5,700 MW of demand, mostly in western New York, anchored by the Niagara and St. Lawrence hydro plants. This island formed the basis for restoration in both New York and Ontario."

2.5.3 The evolving flexibility requirements have led some ISOs, such as the CAISO to define new *flexibility resource adequacy* capacity constructs, and hydropower is already helping meet some of these requirements

The different FRA capacity definitions are designed to meet flexible capacity with different attributes, such as the ability to provide ramping services at different times of the day, or for different durations of time (Table 2-5).

Table 2-5. Flexible resource adequacy constructs in CAISO.

	Category 1 – Base Ramping	Category 2 – Peak Ramping	Category 3 – Super Peak Ramping
Economic Bid – Must offer Obligation	05:00 – 22:00	5-hour block (determined seasonally)	5-hour block (determined seasonally)
Maximum quantity of capacity allowed	Set monthly based on largest secondary net load ramp	Set based on the difference between 100% of the requirement and category 1	Maximum of 5% per month of the total requirement per month
Daily start-up capability	Minimum of two starts per day or the number of starts allowed by operational limits as determined by min up and down time	At least one start per day	At least one start per day
Examples of types of resources	Conventional gas-fired resources, wind, hydro, storage with long discharge capabilities	Use-limited conventional gas-fired generation, solar, conventional gas-fired peaking resources	Short discharge battery resource providing regulation and demand response resources

Hydropower in the region is already helping meet some of the FRA capacity obligations (Figure 2-31). However, the terms of these financial contracts are not yet available.

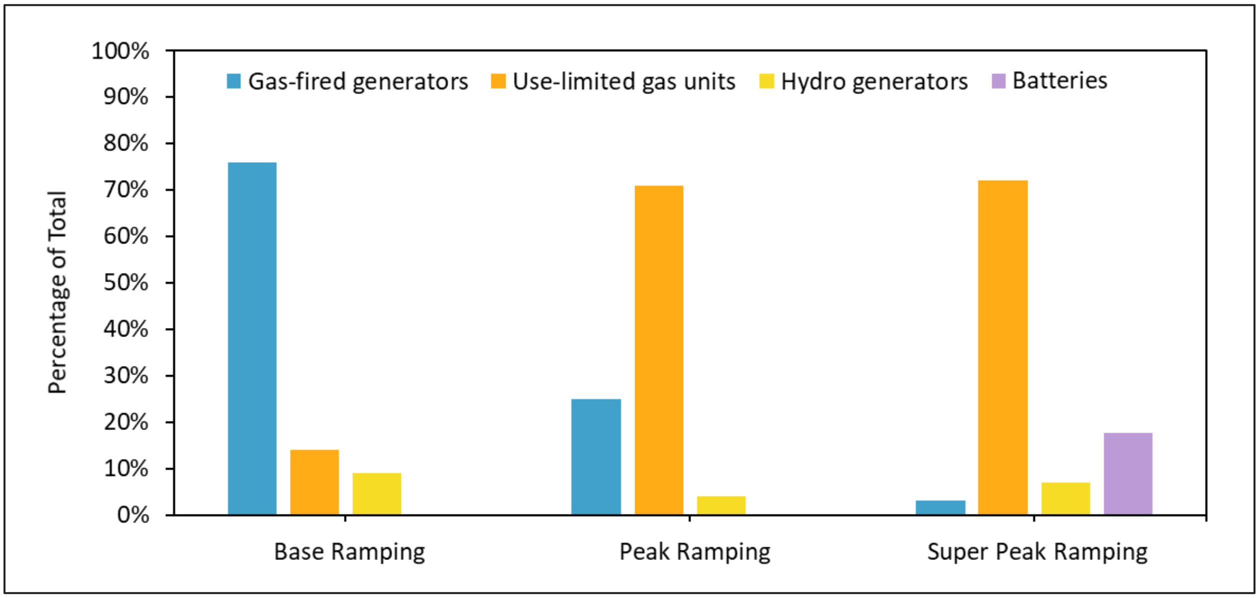

Figure 2-31. FRA capacity provided by different resources in CAISO. (Data source: CAISO)

These examples offer insight into market products and other compensation mechanisms for hydropower that may become more widespread in the future, particularly as other regions gain increasing shares of variable renewables. Despite the challenges associated with changing market conditions and plant-level complexity, opportunities may exist for hydropower to adopt new, more valuable roles that serve the rapidly changing power system.

3.0 Path Forward

Since the inception of this project, DOE's WPTO has unveiled the HydroWIRES Initiative,[39] which is designed to understand, enable, and improve hydropower and PSH's contributions to reliability, resilience, and integration in a rapidly evolving electricity system. The results of this study identified additional research questions and directions that can inform future efforts under the HydroWIRES Initiative.

- **Fully understand the evolving future value streams.**
  - The differences between cost, price, value, and compensation need to be better understood. The value and amounts of grid services, including energy generation will change with changing resource mixes. Present market-based *price* formation (LMPs in energy market auctions) is primarily based on fuel *cost*, which is gradually declining due to a combination of increasing renewables and low natural gas prices. As a result, the *compensation* to resources (power purchase agreement [PPA] prices) has been declining as well because of competition with solar/wind PPAs.[40] However, the *value* from consuming electricity to end-customers remains largely unchanged. The need to differentiate, evaluate, and quantify each of these elements is particularly true for hydropower resources that provide services other than just electrical energy—flood control, irrigation, recreation, and so forth. The true value of hydropower, and hence, the compensation should fully account for all the societal services enabled by these resources.
  - The costs of retrofits or additional wear and tear associated with flexible operations—increased cycling and start-stop operations—need to be weighed against the benefit of providing these services. The nature and value of grid services are changing. There has already been a considerable move away from the provision of energy to other essential grid services by conventional resources, including hydropower. Hydropower resources have the flexibility to provide these services but were not conventionally designed to do so. The effects on hydropower plants of operating outside of original design specifications has a cost, which must be instantiated into the economic calculations of operating decisions.
  - Empirical analyses need to be performed to assess changes in the lost-opportunity costs associated with provision of ancillary services. As resources shift from provision of energy to ancillary services, the compensation mechanisms, either through PPAs or market-based prices, will also need to be adjusted to account for lost-opportunity and direct costs. Empirical analyses will need to be supplemented with simulation-based analyses to assess the optimal operating patterns and tradeoffs between the provision of energy and ancillary services, based on different future pricing and compensation scenarios.
  - Regulatory, policy, and market design scenarios need to be analyzed individually, or in conjunction with each other to understand the changing value proposition for hydropower. Capacity requirements, and the associated resource adequacy constructs, are beginning to be re-defined in places such as California. Alternative market designs are being proposed in places such as PJM, which will radically change price formation and the associated compensation mechanisms for all resources. In addition, many states are switching from a certain percentage renewable portfolio standard (RPS) to 100% carbon-free goals. Each of these changes will affect hydropower differently, although the changes may be overlapping, as is the case in California.

[39] Hydropower and Water Innovation for a Resilient Electricity System (HydroWIRES). More information available at https://energy.gov/hydrowires.
[40] Wiser et al. 2017

- **Gain deeper insights into hydropower's constraints and capabilities.**
  - The combined effects of hydrological, electro-mechanical, and institutional factors on the flexibility of hydropower plants and fleets need to be synthesized. Each factor is well understood individually, but not often in relation with the others. In particular, the impact of institutional factors, such as FERC licenses or the prevalence of long-term PPAs can profoundly limit the flexibility of hydropower resources, but these factors may not consider the implications for preserving flexible capabilities.
  - The relationship between hydropower characteristics and the electric system's ability to respond to challenges in future grid states needs to be studied. Grid reliability and resilience under future conditions will depend on the exact system composition, including the penetration of inverter-based renewable energy resources. Hydropower will continue to provide essential reliability grid services, such as inertia and primary frequency response, but the overall system performance will depend on combined responses with inverter-based resources that do not inherently provide inertial response. Such studies will be instrumental in understanding hydropower's evolving role in providing the essential reliability services. These studies will also inform the desired performance characteristics of inverter-based resources.
  - Hydropower's ability to respond during extreme events, such as cold snaps, heat waves, and natural/man-made events, depend on the specific hydrologic conditions present. For instance, hydropower's ability to provide grid services during drought conditions can be severely limited. System reliability and resilience studies for future grid conditions will need to model extreme events associated with water availability compounded by extreme events associated with increasing penetrations of renewable energy resources. Multiple ongoing efforts are looking at the impact of these events individually, but not in conjunction with each other. The modeling and analysis capabilities need to be developed to analyze compound events that may be different from the ones grid operators are currently accustomed to analyzing.
  - Long-term water availability issues can affect the operational capacity of hydropower resources, potentially affecting the capacity credit assigned to a specific resource. Hence, long-term planning studies will need to factor in the impact of extreme weather events on resource availability in the long term, which will have a system-wide impact on resource adequacy.
- **Evaluate the necessary changes in operations and planning paradigms.**
  - Because of the dynamics and complexity of hydropower resources, enhancements to operational models and practices are needed to optimize hydropower performance.
  - Project- and watershed-scale dynamics should be represented in power system models to analyze hydropower flexibility and support dispatch decisions. The current representation of hydropower flexibility in power system models tends, however, to be static and set for an average year.
  - Water availability and regulation influence the distribution of operational capacity across ancillary services. The provision of grid services is a decision often optimized over the entire portfolio of a utility, and hence, the dynamics of coordination between plants at the utility level, rather than at the individual project level, needs to be well understood. A thorough evaluation would require analysis at the utility scale rather than project by project, likely using a river routing-reservoir model.
  - Joint optimization across reservoir routing models and unit commitment models is difficult. In addition, the knowledge base and skill set of river operators and marketing teams are very different, and often are far separated in many utility organizations. Methods to succinctly and effectively pass information and constraints between the two on a frequent basis should be investigated.

- **Identify insights into the needed technology innovations.**
  - There is growing evidence of plants operating "off-label," or outside of original design specifications, which reduces unit efficiency and introduces additional stress on the machines. An extensive effort needs to be exerted to collect evidence from all sources, including other conventional resources such as natural gas plants, to assess the changes in their operational paradigms under evolving grid conditions. The impact of operating differently from the original design specifications on machine stress needs to be studied extensively. Thorough analysis of the impact of flexible operating conditions on the operational life of turbines is scarce and typically requires investigation from a multi-physics perspective. The modeling of dynamic load conditions resulting from flexible hydro operations requires a depth and breadth of expertise in a combination of computational fluids dynamics, structural design, and power systems modeling. Such studies will provide insights into future design specifications as well as the expected failure rates of existing machines.
  - The hybrid coupling of traditional and PSH with other resources, such as battery storage and floating solar, should be explored. These resources can add flexibility, improve accuracy and speed in response to dispatch signals, alleviate regulatory and other constraints, and mitigate wear and tear impacts on hydropower turbines.

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