The Role of Hydropower Flexibility in Integrating Renewables in a Low-Carbon Grid

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About HydroWIRES

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

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

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

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1 Abstract

The firm capacity associated with dispatchable hydropower's flexibility is estimated to be more than 24 GW. To replace this capability with its storage equivalent would require the buildout of over 24 GW of 10-hour storage—that's more than all the existing long-duration storage available in the United States today.

Power system flexibility makes the deployment of variable renewable energy (VRE) easier and more cost-effective to integrate into an existing grid. Dispatchable hydropower's flexibility can help with this process, but its particular benefits to the power system have been difficult to quantify. In this work, we investigate the issue by taking a high-level yet quantitative look at the value that hydropower flexibility offers in terms of services that are helpful in integrating variable renewable energy, with a focus on firm capacity and operating reserves. We found that the flexibility associated with dispatchable hydropower's ability to respond to load offers approximately 24 gigawatts (GW) of firm capacity. This 24 GW is in addition to both the 18 GW that would still be available if dispatchable hydropower were operated as run-of-river (i.e., dispatchable hydropower's flexibility accounts for 58% of the firm capacity it provides) and the 13 GW of firm capacity provided by run-of-river. Also of note is that the contributions of firm capacity provided by hydropower's flexibility vary markedly by region, ranging from 31% in the New York Independent System Operator (NYISO) region to 85% in the PJM region. Finally, in addition to the firm capacity benefits, we found that hydropower's flexibility offers low-carbon operating reserves that can support approximately 140 GW of VRE, which is almost 10% of the VRE estimated to be necessary to achieve the administration's goal of a net-zero carbon grid by 2035.[1]

2 Introduction

In companion work we explored the relationships among pumped storage hydropower, variable generation, fossil-fired generation, and emissions in a low-carbon grid (Stark, Dhulipala, and Brinkman 2023). Here, we take a similar approach and investigate the contribution of dispatchable hydropower to integrating VRE in low-carbon grids.

In this study, we explored the role of hydropower flexibility in VRE integration. Our focus was on the flexibility associated with dispatchable hydropower facilities located in the contiguous United States that have at least 10 hours of storage, i.e., plants that have capacity values[2] similar to those of fossil-fired generation facilities. For our modeling framework, we used the National Renewable Energy Laboratory's (NREL's) "Mid-Case/95% Carbon Reduction by 2035" standard scenario (Cole et al. 2021) as our foundation (known going forward as the Mid-Case/Low-Carbon scenario). This zonal model is representative of the buildout of a near-zero carbon policy grid in an otherwise "business-as-usual" policy and economic environment.[3] We

[1] For the VRE buildout projections of what would be necessary to achieve a near-net-zero goal, please see the "Mid-Case/95% Carbon Reduction by 2035" standard scenario results (Cole et al. 2021).

[2] In simple terms, capacity value is the contribution available to reliably meet demand during times of grid stress.

[3] The Mid-Case/Low-Carbon scenario relies on reference fuel costs, demand growth, and constraints. Policies, excluding the overarching 95% reduction in carbon policy overlay, are those that are in effect as of June 2021. Midrange technology costs and innovation are assumed.

chose this scenario because it aligns well with the administration's goal of a net-zero-carbon grid by 2035 (U.S. Department of State and U.S. Executive Office of the President 2021). Note that this work is intended to be a first look at how the grid, including the integration of VRE, might be affected if hydropower's flexibility were restricted and no new assets were built to replace the lost energy and firm capacity. Think of this work as an opening discussion concerning the value of hydropower flexibility to grid operations and VRE integration.

3 Methodology

PLEXOS, a production cost model (PCM) simulation engine developed by Energy Exemplar, was used to run two Cambium[4] 2021-based PCMs, where each model represented the grid operations in 134 model balancing areas shown in Figure 1. We chose the Cambium platform because it provides a straightforward method of doing comparative studies of the operational differences between standard scenario buildouts (e.g., how does the operation of a low-carbon

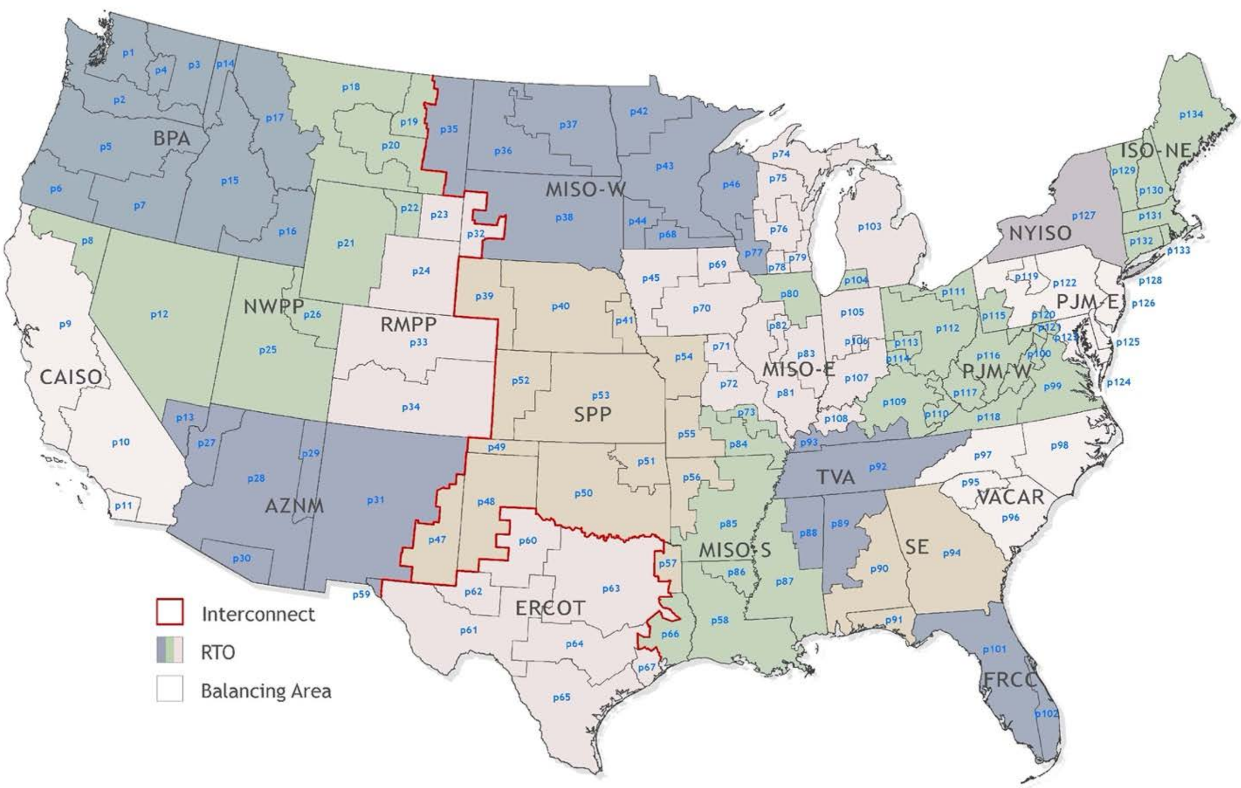

Figure 1. Graphical representation of the zonal production cost model and how the model balancing areas were aggregated

grid compare with that of a more conventional grid?). For our "Baseline," we used the Mid-Case/Low-Carbon model as is. It includes 46 GW of dispatchable (flexible) hydropower and 34 GW of non-dispatchable (run-of-river) hydropower. Our second scenario, referred to as the "NoFlex" scenario, is identical to the Baseline scenario except that the power output of each dispatchable hydropower plant is fixed to the plant's average monthly value. We used the

[4] The Cambium models are autogenerated representations of Standard Scenario results. Additional information can be found at: https://www.nrel.gov/analysis/cambium.html.

differences between the Baseline and NoFlex results to investigate the role of hydropower flexibility in avoiding carbon and reducing production costs. These scenarios consider typical hydrological conditions; this is not a detailed, region-specific resource adequacy analysis. We used dispatch during peak demand hours as a proxy for firm capacity in our calculations. Additional information about the Baseline scenario can be found in the Appendix.

We investigated three different aspects of hydropower flexibility in terms of its ability to help integrate VRE: direct, indirect, and economic. We started the investigation with an exploration of how flexible hydropower helps meet low-carbon goals and avoid fossil fuel emissions by providing both renewable power and high-quality, low-carbon firm capacity. Next, we examined hydropower's supporting role in supplying operating reserves—a key enabler of VRE integration. Finally, we examined how the flexibility of the hydropower fleet helps keep operating costs and energy prices low.

For the purposes of reporting, we divided the Southeast and the non-CAISO West into subregions because hydropower can vary significantly within these regions, and we did not want impacts to be lost through the reporting of averages. Also, all projections reported are for the 2035 operational year (i.e., for the year in which the 95% carbon reduction goal will be met).

Finally, as mentioned earlier, the focus of this paper is on the role of hydropower flexibility in VRE integration. To simplify the language, when we refer to hydropower's capabilities, we are referring to the capabilities that are provided by the flexible (dispatchable) aspects of hydropower unless specifically mentioned otherwise. Other aspects of hydropower also provide value, but the primary scope of this work is investigating the value of hydropower flexibility.

3.1 Variable Generation and Storage Needed to Match Hydropower's Flexibility and Firm Capacity

Dispatchable hydropower can be used to directly avoid fossil fuel generation and its associated carbon emissions. To estimate how the flexibility of dispatchable hydropower contributes to these benefits, we compared the results of the Baseline and NoFlex scenarios, investigating how energy delivery, curtailment, and firm capacity differed between the two runs.

We found that limiting hydropower's flexibility leads to an additional 17 terawatt-hours (TWh) of renewables curtailment (wind, solar, and hydro), all of which can be attributed to the loss of hydropower flexibility. This amount equates to the loss of 11% of the available hydropower energy (see Figure 2). In the NoFlex model, the energy that would have otherwise been delivered by flexible hydropower was replaced by gas-fired generation. Replacing the lost generation with a zero-carbon source would require the addition of approximately 7 GW of new VRE.[5]

[5] The amount of VRE required to replace the lost hydropower was estimated by multiplying the amount of hydropower curtailed by a ratio of the average hydropower capacity factor and blended VRE capacity factor for each region of the model.

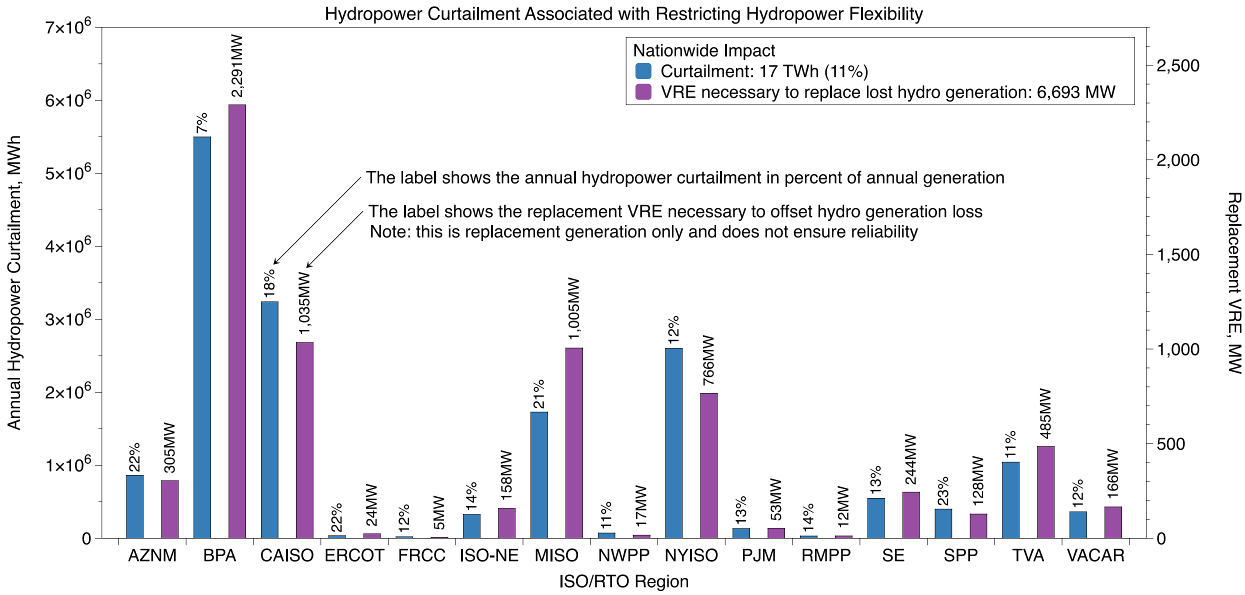

Figure 2. Annual hydropower curtailment and avoided VRE buildout

To better understand the amount of firm capacity that hydropower's flexibility supplies each region, we examined the amount of capacity that hydropower provides during each region's highest net load period of the year. We did this for both the Baseline and NoFlex scenarios and used the difference between the amount of capacity provided as an estimate of the amount of capacity that can be attributed to flexibility.

Figure 3 shows the results on a regional basis where the firm capacity provided by hydropower flexibility ranges from 31% of dispatchable hydropower's firm capacity in NYISO to more than 85% in PJM. These findings are consistent with the particularly strong load-following behavior identified in the *2017 Hydropower Market Report* (Uría-Martínez et al. 2018) for PJM, where summer peak hours have hydropower generation levels 10 times higher than off-peak.

On a national level, hydropower was found to provide 55 GW of firm capacity, 24 GW of which can be credited to its flexibility, 13 GW to run-of-river hydropower, and the balance (18 GW) to dispatchable hydropower that only provides baseload power. The 24 GW figure is particularly significant in that it is more than three-fourths of the total installed capacity of storage today, including batteries and pumped hydropower storage.[6]

[6] As of March 2023, the U.S. Energy Information Administration estimates approximately 31.5 GW of installed utility-scale storage (nameplate capacity) in the United States with durations ranging from 2 to more than 10 hours (U.S. Energy Information Administration 2023). The 2-hour storage offers limited capacity value, whereas the 10-hour or longer-duration storage offers near nameplate, even in high renewable systems (Stark et al., 2023).

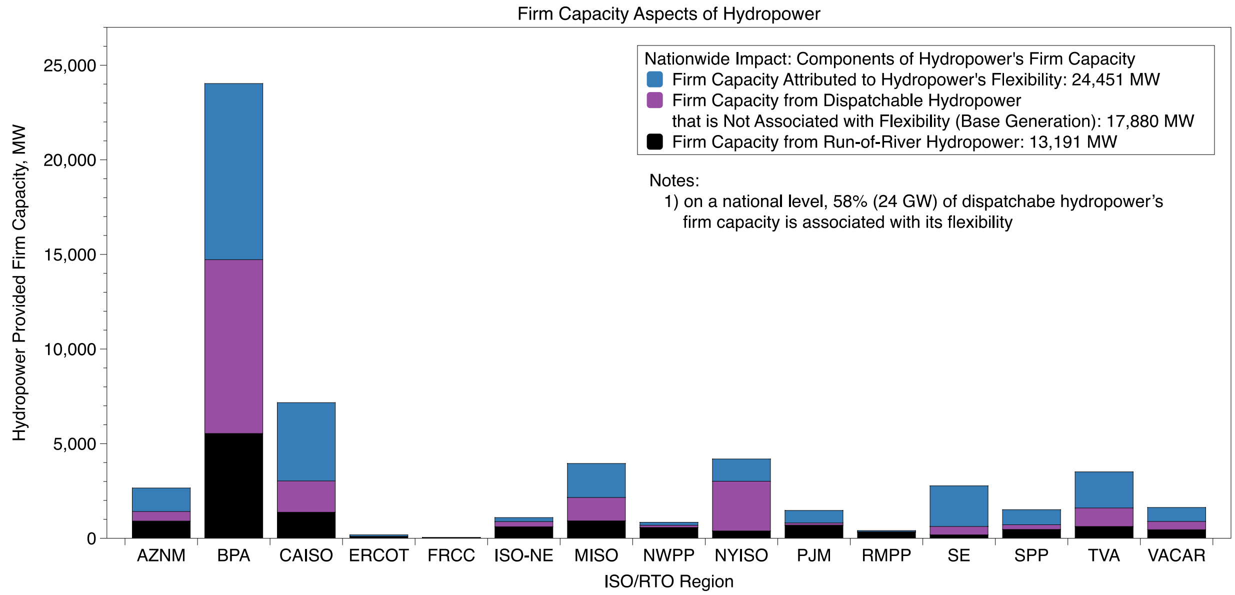

Figure 3. Firm capacity provided by hydropower

Finally, to get a first-order estimate as to what it would cost to replace flexible aspects of hydropower, we considered how much VRE and storage would be required to replace both the energy and firm capacity that hydropower flexibility provides. Assuming a 15% utilization rate and 80% round-trip efficiency for storage, and 0.15 and 0.4 for the marginal VRE capacity value and capacity factor, respectively, we calculated that a mix of 11 GW of VRE and 23 GW of 10-hour storage would be necessary. For this generation and storage mix, the overnight construction cost is estimated to be $67 billion ($11 billion for the VRE and $56 billion for storage[7]). Note that these numbers do not include costs related to replacing the services provided by the non-flexible aspects of hydropower; the carbon-related costs and other impacts of building new storage and VRE; or any operating cost differences, including those inherent with the energy losses associated with non-hydropower storage.

3.2 The Role of Hydropower Flexibility in Supplying Operating Reserves for VRE Integration

To close out the discussion regarding hydropower's capabilities in helping to integrate variable renewable energy, we included a short section that provides an analysis of the importance of the low-carbon operating reserves in this role. The methodology presented, although simple, is an approach that is commonly used by stakeholders today and is included for completeness.

Table 1 shows the values that we used in our operating reserve estimates. These values were first developed as a part of the Western Wind and Solar Integration Study, Phase II (Lew et al. 2013), but they are still in use today.

[7] This calculation assumes that the hydropower is being replaced by blended VRE and like-capability storage—in this case, 10-hour storage. The VRE was sized such that it will cover the energy previously provided by hydropower as well as losses associated with storage. The storage is sized to provide the displaced firm capacity. The underlying cost estimates are $1,000 per kilowatt (kW) for the VRE and $2,500/kW for the storage. Both values are near-term estimates derived from NREL's 2022 Annual Technology Baseline (NREL 2022).

Table 1. Operating Reserve Requirements Used in This Study (Sergi and Cole 2021)

Reserve Type	Wind	Photovoltaics (PV)
Regulation	0.5% of generation	0.3% of capacity
Spinning	–	–
Flexibility (net load following)	10% of generation	4% of capacity
Combined	**10.5% of generation**	**4.3% of capacity**

By using the values from the table combined with the average capacity factors of wind generation for each region, we were able to estimate the capacity of wind supported per megawatt of operating reserve. For solar PV, we used the value in the table directly (1 MW of flex reserves is needed to support 25 MW of PV, i.e., 1/0.04). For our calculations, we assumed that 12.5% of the dispatchable hydropower capacity was provisioned as operating reserves, a value consistent with CAISO's *2021 Annual Report on Market Issues & Performance* (Hildebrandt et al. 2022).

Figure 4 shows how much VRE dispatchable hydropower can help integrate into each region (e.g., in CAISO, estimates are that hydropower could supply operating reserves capable of helping to integrate 17 GW of VRE, which is 25% of the region's projected VRE in this scenario).[8]

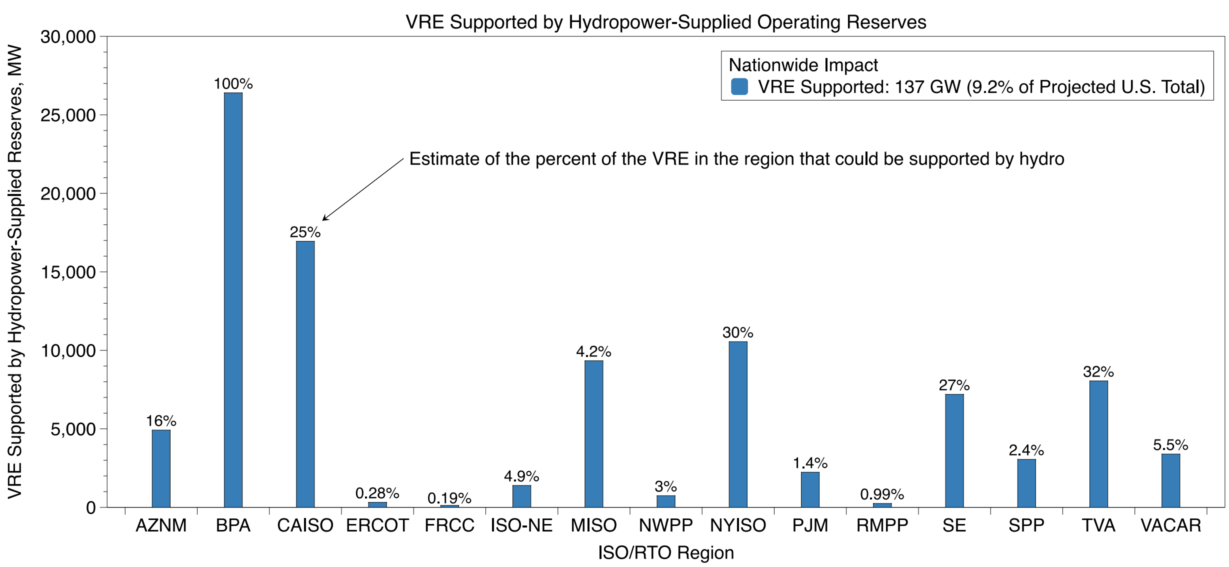

Figure 4. Estimated VRE supported via hydropower-supplied operating reserves

[8] See NREL's "Mid-Case/95% Carbon Reduction by 2035" standard scenario capacity expansion modeling results (Cole et al. 2021). These results served as the foundation from the Cambium model discussed in Section 2.

4 Impact on System Operating Costs, Energy Prices, and Hydropower Revenue

The work discussed in Section 3 focused on the technical aspects of hydropower's direct (energy and firm capacity) and indirect (operating reserves) capabilities in integrating renewable energy into a low-carbon grid. This section differs in that it begins the discussion of the economic value of hydropower's flexibility to its owner-operators and consumers. We say "begin" because the operating costs, wholesale energy prices, and revenue streams are more affected by our simplifying assumptions and methodology than our firm capacity and operating reserves calculations. Consequently, the work in this section can be thought of as an upper bound to how operating costs and consumer prices might change.[9] Additional work is in progress that will examine how the buildout of the system would be impacted should hydropower flexibility be phased out or the fleet retired (Cohen forthcoming).

For this work, we used the now-familiar approach where we compared the differences between the Baseline and NoFlex scenario results to provide insight as to how the loss of flexibility would affect revenues and consumer prices.

As shown in Figure 5, operating costs increased in all regions of the country. Increases ranged from 1% in several of the low hydropower regions to more than 88% in the RMPP area.[10] The low impact in the regions that were affected least is intuitive—less hydropower, less impact. However, the effect on the RMPP prices was less intuitive and required additional inspection. Upon closer examination, it was determined that the energy losses associated with fixing the output of hydropower in the Western Interconnection were primarily being replaced by gas-fired generation in the RMPP region because of lower gas prices in that region relative to other regions.[11] Nationwide, the increase in operating costs was $1.2 billion per year (4.7%).

The trend for wholesale energy prices was similar, with impacts varying by region. Several areas were projected to experience only small impacts (1% or less), but others such as AZNM, BPA, CAISO, NWPP, and RMPP—i.e., the Western Interconnection—saw energy price increases exceeding 40%. On a national basis, the cost-to-load (what wholesale customers paid for energy in the model) was projected to rise by $19 billion per year (13%). These increases are not surprising in that natural-gas-fired generation was used in the NoFlex scenario to cover for the lost generation. While rerunning the capacity expansion model would likely reduce operating costs, it would also lead to increased buildout costs because serviceable assets are being retired early and replaced by new construction, which will incur both cost and carbon impacts. Future research could provide insights into what the new construction ramifications would be and provide a better understanding of the trade-offs.

In addition to the cost-related impacts to the system and consumers, we also investigated the economic value that hydropower flexibility provides to its owner-operators. Specifically, we

[9] By not replacing the services lost with services from new assets, prices for these services have the potential to be more affected than otherwise. That is why we suggest treating this economic analysis as an upper bound. Also note that ancillary service costs were purposefully excluded from this analysis because the zonal models used in this work do not have the fidelity necessary to project meaningful ancillary price impacts.
[10] RMPP consists of Colorado, eastern Wyoming, and a small part of South Dakota, as shown in Figure 1.
[11] As a reminder, we are investigating a scenario of 95% carbon reduction by 2035. Some gas generation remains.

examined how the loss of flexibility would affect revenue in terms of both energy sales and capacity payments. The same two scenarios, Baseline and NoFlex, were used, and a price of $85/kW-yr was assumed for firm capacity.[12] For energy-sales-related revenues, these results are subject to the same caveats as above (these projections can be thought of as a bounding limit). However, for capacity-related revenues, these results are indicative of how owner-operators could be impacted (capacity revenues are independent of issues related to energy scarcity).

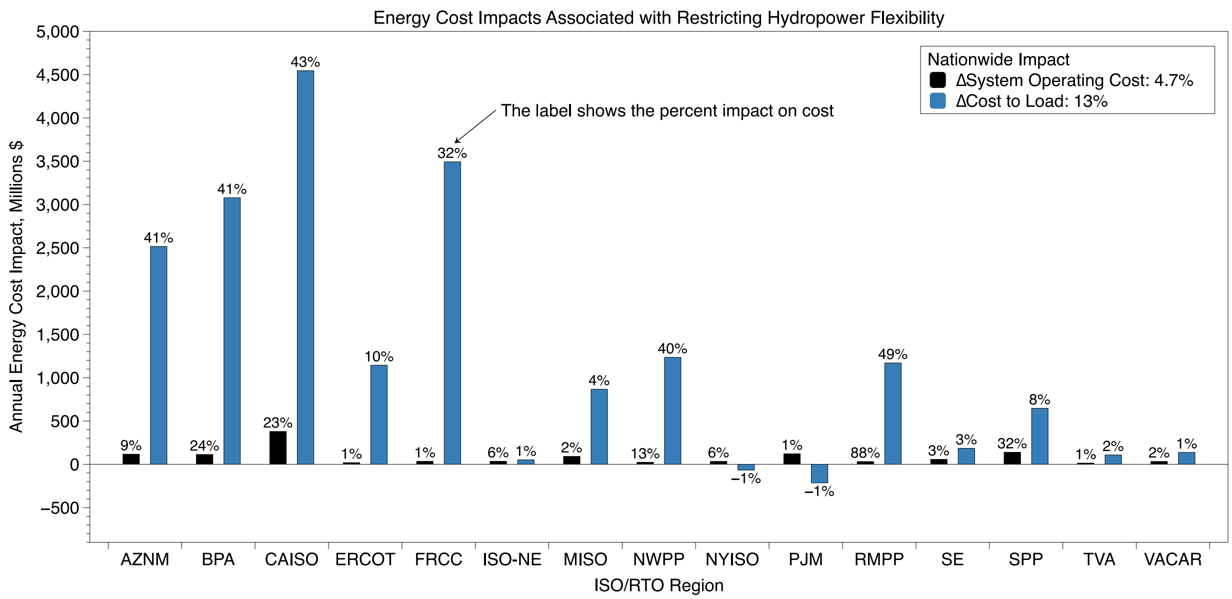

Figure 5. Avoided costs associated with hydropower flexibility

Figure 6 shows that the impact on the projected revenues from energy sales varied regionally, ranging from a 40% loss in ERCOT to a 34% increase for owner-operators in BPA. Overall, payments for hydropower-supplied energy across the nation rose by $568 million per year (9.9%), with these numbers being skewed by large revenue increases in BPA ($922 million) and CAISO ($118 million), which are regions where hydropower has market power, so withholding flexibility can increase prices and therefore revenue. This result differs markedly for capacity sales projections where revenues of hydropower owner-operators were down across all regions, ranging from an 85% loss in PJM to a 31% loss in NYISO. Part of this effect is due to the use of a fixed capacity price in our analysis when the capacity price would likely rise. However, the price increase would have to more than double to offset the losses given that the average ability to deliver capacity declined by 58%.

Nationwide, the loss in capacity payments in this scenario is projected to be $2.1 billion per year (54% loss), almost 4 times the projected energy revenue gains should hydropower flexibility be limited. In terms of combined revenue for hydropower owner-operators, the loss from capacity payments outweighed the gain from higher energy prices, and nationwide losses were $1.5

[12] We chose a value that we felt was a conservative representation of prices in low-carbon systems. For reference, prices have gone as high as $73/kW-yr in CAISO (2008) and $86/kW-yr (2022) in MISO auctions and are expected to continue to rise (Howland 2022). NREL's 2021 Standard Scenarios projects that capacity prices are likely to exceed $150/kW-yr for low-carbon grids (Cole et al. 2021).

billion per year (16%) with only owner-operators in the BPA and FRCC regions projected to benefit.

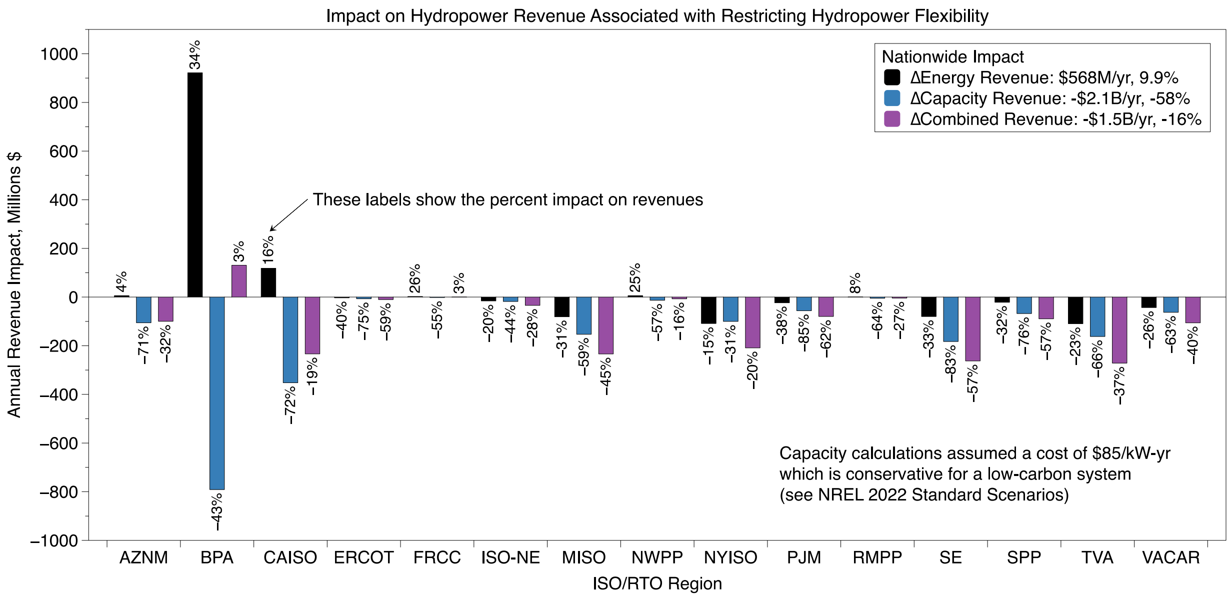

Figure 6. Revenue impacts related to restricting hydropower flexibility

5 Concluding Discussion

We conducted a detailed study that investigated the role of hydropower flexibility in the integration of variable renewable energy into a low-carbon grid (95% carbon reduction by 2035). The key findings of the study are:

- Flexible hydropower provides more firm capacity than run-of-river hydropower because it can deliver more of its energy during peak hours. If this flexibility were eliminated and the lost firm capacity was to be replaced by 10-hour storage, more than 24 GW of storage would have to be built—that is similar to the amount of firm capacity offered by all the existing long duration storage in the United States today.
- The amount of firm capacity provided by dispatchable hydropower's flexibility varies significantly by region, ranging from 31% in NYISO to 85% in PJM. Nationwide, dispatchable hydropower's flexibility provides 58% of its firm capacity. To replace the flexibility-provided firm capacity with non-hydropower yet low-carbon means (a mix of VRE and storage) was estimated to cost almost $67 billion ($11 billion for the VRE and $56 billion for storage).
- Although dispatchable hydropower is projected to supply only 3% of the nation's energy by 2035 (the decline is due to projected load growth), it can supply the operating reserves for the integration of 137 GW of VRE—almost 10% of the VRE necessary for the nation to achieve the administration's low-carbon grid goals.

For these calculations, we used dispatch during peak demand hours as a proxy for firm capacity based on a single hydrology for each balancing area in the study.

We also started the discussion of the role of hydropower flexibility in operating costs, cost-to-consumers, and revenue impacts on owner-operators. This is not a comprehensive analysis; we only investigated a single scenario—one where hydropower's flexibility was restricted, yet no new assets were built to replace the lost energy or firm capacity. These scenario results should be thought of as an upper limit as to how operating costs, cost-to-consumers, and energy sales-related revenues could be impacted. As mentioned, additional work is in progress to better quantify potential economic impacts.

- In the case presented, average operating costs increased by 5% and wholesale prices by 13%. Note that projections throughout the Western Interconnection were substantially higher (wholesale energy price increases exceeded 40%).
- Revenue outcomes related to the effects of loss of flexibility were mixed:
    - Energy sales impacts ranged from a 40% loss in ERCOT to a 34% increase for owner-operators in BPA. Nationwide, energy sales revenues grew by $568 million per year (9.9%). However, it should be noted that this number is skewed by large revenue increases for BPA ($922 million) and CAISO ($118 million) where hydropower holds significant market power (i.e., restricting flexibility will drive prices higher). Many regions showed substantial revenue declines.
    - Capacity payments would decline in all regions and nationwide by $2.2 billion per year, a 58% loss, and almost 4 times the estimated energy sales revenue gains. Actual losses could be higher given that conservative values ($85/kW-yr) were used in these calculations (prices as high as $150/kW-yr have been seen in model projections).
    - Combined revenue losses (energy sales plus capacity payments) would exceed $1.5 billion per year (a 16% decline) with only owner-operators in the BPA and FRCC regions projected to benefit financially should hydropower's flexibility be limited.

In closing, our work shows that dispatchable hydropower's flexibility supports clean energy goals in three important ways: directly by providing clean energy and firm capacity, indirectly by supplying clean, low-carbon operating reserves that help make the integration of variable renewable energy possible, and economically by helping to keep system operating costs and consumer costs low.

Our expectation is that these findings will help stakeholders better understand the role of dispatchable hydropower in the integration of variable generation and the avoidance of fossil fuel generation and how hydropower helps manage system operating costs and wholesale energy prices as many parts of the country strive to meet reduced-carbon goals.

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Appendix

This section is provided for readers who would like to better understand how the results in the main text were obtained.

Mid-Case/Low-Carbon Scenario (the "Baseline" Scenario)

In NREL's *2021 Standard Scenarios Report* (Cole et al. 2021), the team investigated a scenario/carbon policy combination that closely approximates the Biden administration's plan for net-zero carbon by 2035. The scenario, known as the Mid-Case/Low-Carbon scenario, represents expected grid buildout under business-as-usual technology costs, fuel costs, demand growth, and resource constraints. When combined with a 95% reduction in carbon by 2035 policy implementation, it provided an ideal opportunity to investigate how the implementation of a near-zero carbon policy in an otherwise "business-as-usual" scenario would affect grid buildout.

Specifically, the 2021 Mid-Case/Low-Carbon results provide biannual projections of grid buildout (and generator retirement) by technology type for 134 model balancing authorities and 356 renewable energy resource areas along with supporting metrics such as installed capacity, capacity factor,[13] and capacity value[14]—all values that are useful for estimating hydropower's role in a low-carbon system.

Dispatchable hydropower was modeled as it is typically done for large-scale production cost modeling studies: plants were treated independently subject to monthly hydropower limits sourced from the U.S. Energy Information Administration, maximum capacity limits, maximum ramp rates, and minimum generation values.

Additional information about our modeling techniques, assumptions used in the models, data sources, and general information about the Standard Scenarios and Cambium, the modeling framework used in this work, can be found in Cole et al, 2021, and the Standard Scenarios and Cambium websites.[15]

Mid-Case/Low-Carbon Scenario with Hydropower Flexibility Removed (the "NoFlex" Scenario)

As mentioned in the main body of this report, the NoFlex scenario is identical to the Baseline scenario except that the generation at each hydropower plant was fixed at an average monthly value (the monthly hydropower limit divided by the number of hours in the month).

[13] Capacity factor is the unitless ratio of actual electrical energy output over a given period (usually 1 year) to the theoretical maximum electrical energy output over that period.

[14] Capacity value (also known as capacity credit or CC) is the fraction of the installed capacity of a power plant that can be relied upon at a given time (typically during system stress). It is a unitless value that is frequently expressed as a percentage of the nameplate capacity.

[15] Please see https://www.nrel.gov/analysis/standard-scenarios.html and https://www.nrel.gov/analysis/cambium.html.