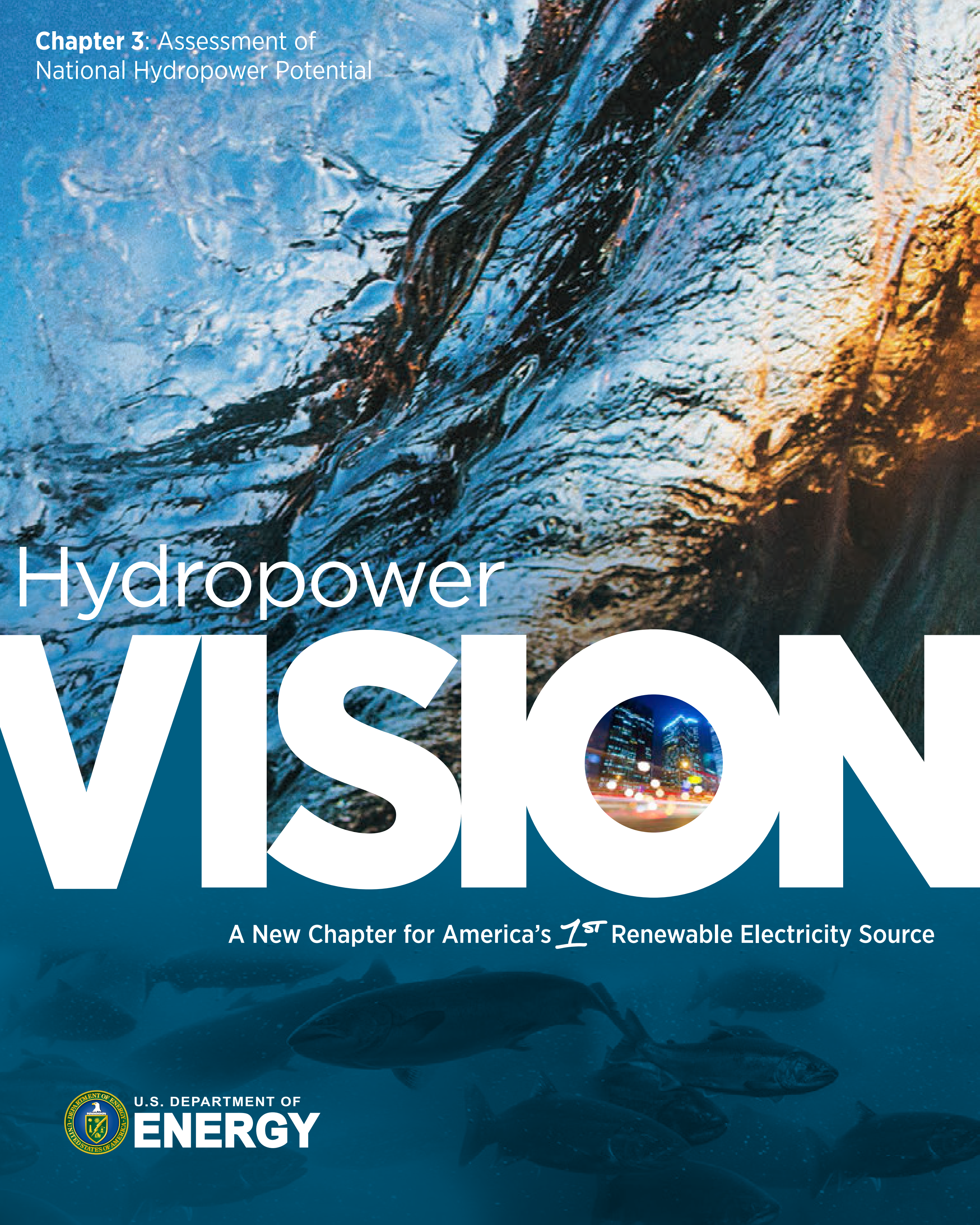
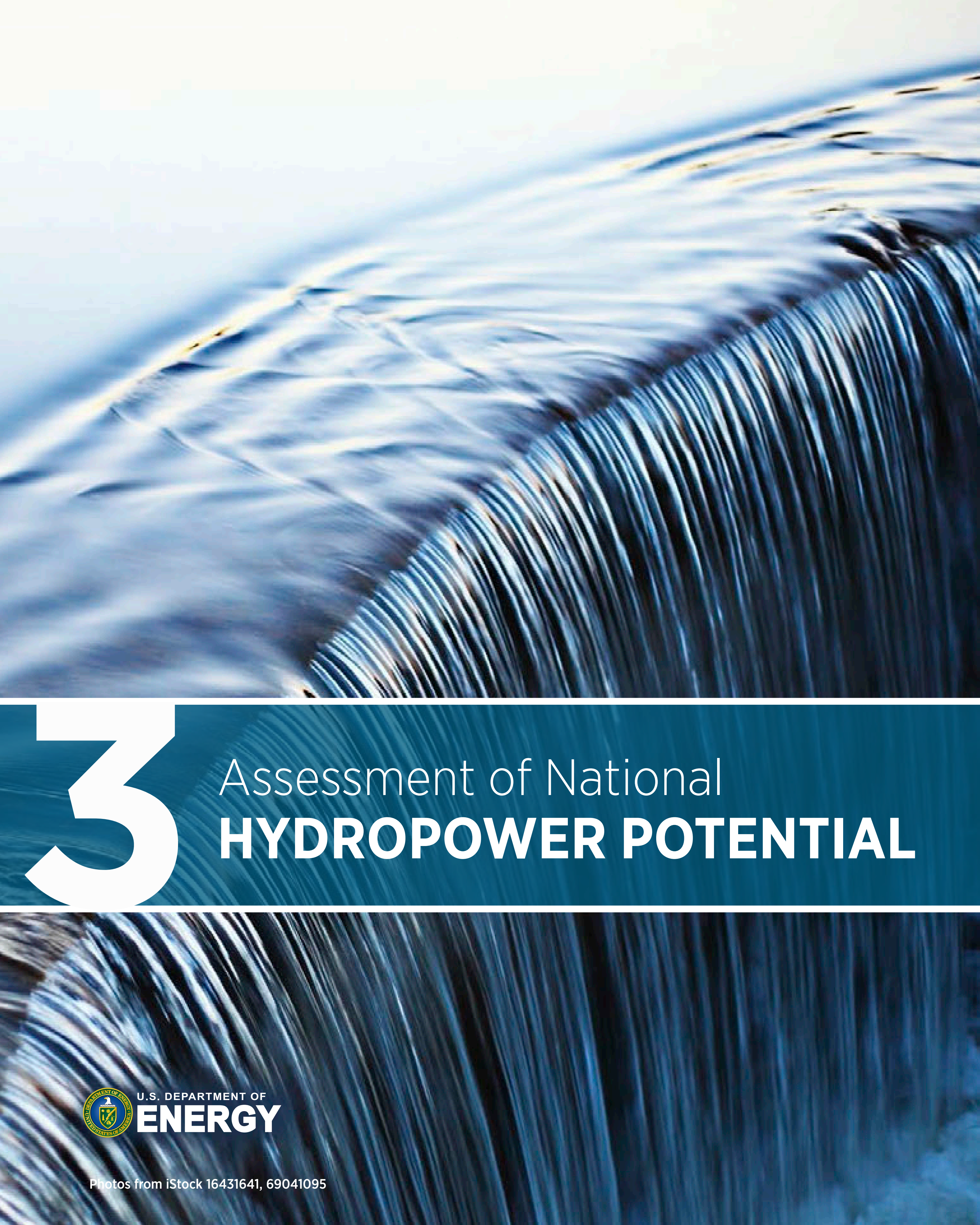
Chapter 3: Assessment of National Hydropower Potential



Hydropower VISION

A New Chapter for America's 1st Renewable Electricity Source

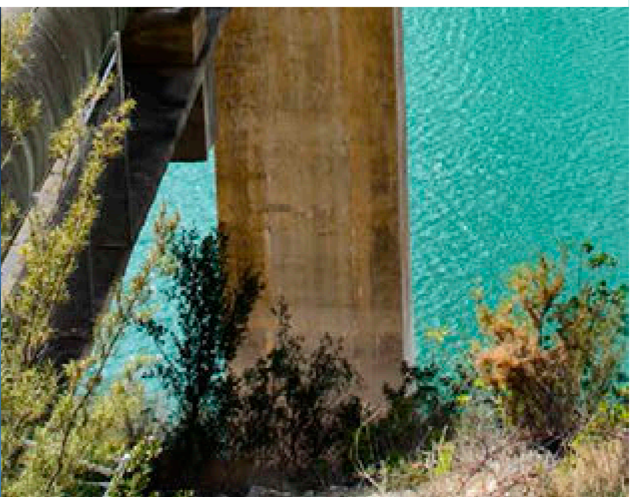
U.S. DEPARTMENT OF ENERGY



3 Assessment of National HYDROPOWER POTENTIAL

U.S. DEPARTMENT OF ENERGY

Photos from iStock 16431641, 69041095

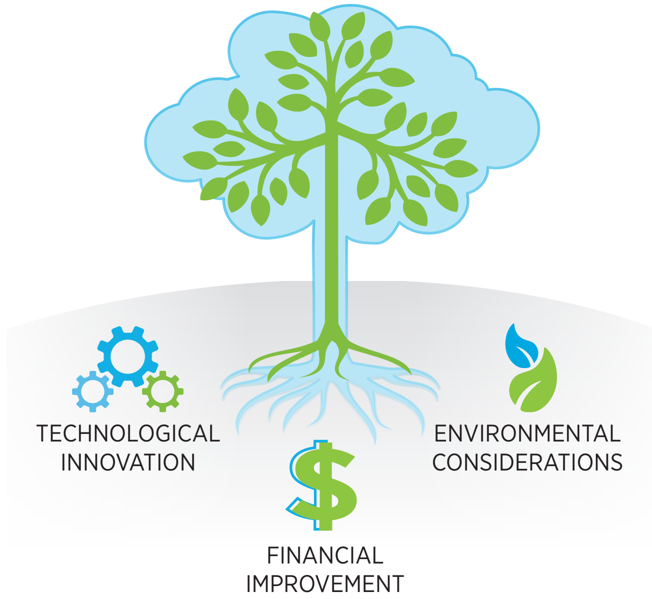


Overview

The *Hydropower Vision* report utilized economic modeling of the electric sector to explore an array of possible futures for the hydropower industry. This summary provides an overview of the methods applied and highlights key conclusions that may be drawn from the extensive body of analysis presented in full in Chapter 3. These results are intended to provide new insights into the opportunities and challenges for hydropower and to quantify certain costs and benefits of the industry.

The analysis contained here considers potential contributions over time to the electric sector of both the existing hydropower fleet and new hydropower deployment resulting from: upgrades at existing plants, powering of non-powered dams (NPD), pumped storage hydropower (PSH), and new stream-reach development (NSD).

KEY ELEMENTS FOR GROWTH



The analysis indicates that three key variables in combination have the greatest influence on potential growth scenarios.

Scenarios and modeling results presented here are not intended as DOE forecasts or projections. Growth potential is tied to a complex set of variables, and changes in these variables over long periods of time are difficult to predict. Modeling results serve primarily as a basis for identifying key factors and drivers that are likely to influence the role and scale of hydropower within the nation's energy mix in the coming decades. This analysis enabled improved understanding of the U.S. hydropower industry, which, in turn, informs the *Hydropower Vision.*

Modeling Tools

The primary computational tool used to assess potential growth trajectories and evaluate resulting cost and benefit impacts was the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) model. ReEDS is an electric sector capacity expansion model that simulates the cost of constructing and operating generation and transmission capacity to meet electricity demand and other power system requirements on a competitive economic basis over discrete study periods. For this report, the focus study periods were from 2017 through 2030 and 2050. Results from ReEDS include estimated electricity generation, geographic distribution of new electricity infrastructure additions, transmission requirements, and capacity additions of power generation technologies built and operated during the study period. These outputs enable calculation of some key impacts including the first quantification of greenhouse gas (GHG) emissions reductions from U.S. hydropower.

The development of the *Hydropower Vision* entailed a number of modeling enhancements that allow the work presented here to be among the most sophisticated and comprehensive multi-decadal national-scale assessments of U.S. hydropower to date. However, it is important to acknowledge certain limitations of the modeling when considering the outcomes. Geographic information system screening of resource potential is used to evaluate environmental considerations rather than site-specific assessment of environment sustainability, and climate change uncertainties are evaluated only through variations in the potential magnitude and timing of water availability. In addition, the ReEDs model is limited to the continental United States; consequently, the resource potential of Alaska and Hawaii is not evaluated quantitatively in the report (they are, however, discussed qualitatively). Similarly, insufficient data exist to effectively model the potential of existing water conveyances, such as canals and conduits. Though some impacts do extend beyond the electric sector, ReEDS models only the electric sector and does not directly include interactions with other sectors, including those associated with non-power-related land and water use. Analysis evaluating the effects of alternate government policy options for hydropower is also outside the scope of the *Hydropower Vision*.

Modeling Approach

The full *Hydropower Vision* analysis involved more than 50 modeled scenarios (Figure O3-1). Each scenario examined the effects of a key variable or combination of variables that influence the deployment of hydropower facilities in electricity market competition with other generation sources. This exploratory analysis established the relative influences of a wide range of variables on the hydropower industry. From this full suite of scenarios, nine were selected as providing insights particularly relevant within the context of the *Hydropower Vision* pillars of optimization, growth, and sustainability. These nine scenarios are described in detail throughout Chapter 3. From among these nine scenarios, four scenarios became the ultimate focus of the hydropower industry development and impacts analysis presented in this chapter summary. Reference cases for comparing alternative hydropower deployment scenarios are provided by (1) a *Business-as-Usual* scenario, which assumes a continuation of existing market and technology development trends, and (2) a baseline scenario under which no new unannounced hydropower is built (after 2016).

Assessing Growth Potential

The nine selected scenarios and their primary differentiating elements are summarized in Table O3-1, and the four focus scenarios are highlighted within the table. Table O3-2 summarizes assumptions that are constant across all scenarios, including *Business-as-Usual*. Table O3-3 summarizes the resource estimates and modeled resource potential used in the analysis. Notably, modeled resource potential represents a conservative interpretation of the total hydropower technical potential, as it is intended to focus modeling efforts on the most competitive resource sites. Specific differences among resource estimates are described in detail in Section 3.2.2.

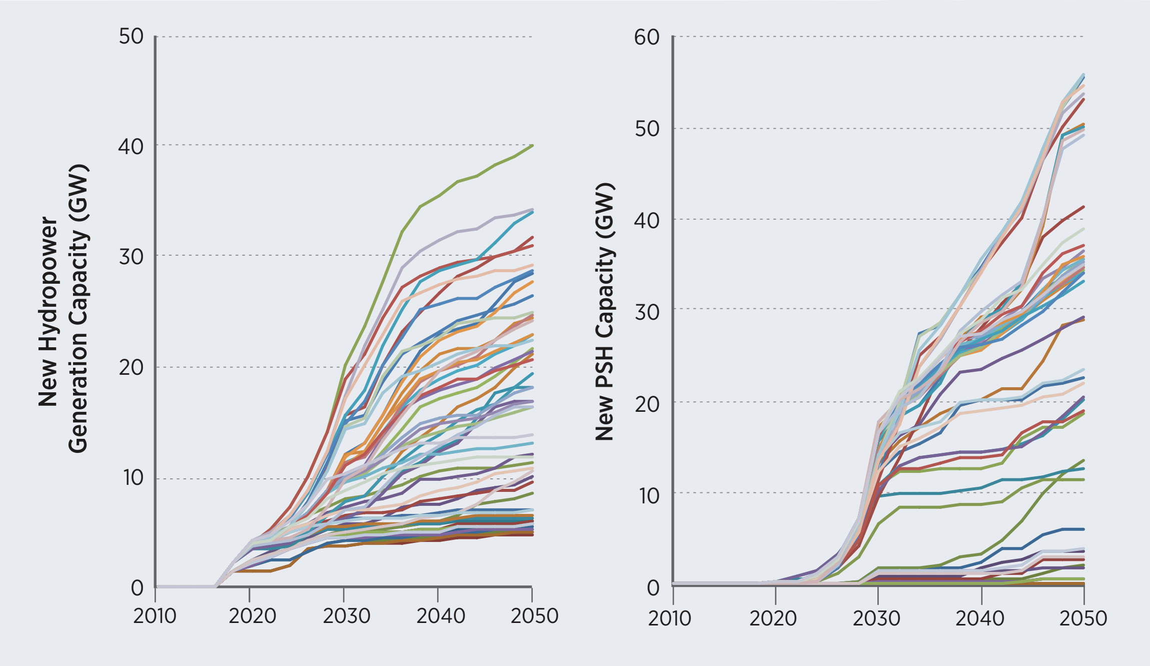


Figure O3-1. More than 50 potential scenarios of new hydropower capacity (GW) growth between 2017 and 2050 were analyzed using the Regional Energy Deployment System model to assess the influence of a wide range of variables on growth curves

Table O3-1. Nine Selected *Hydropower Vision* Analysis Scenarios

	Scenario	Key Variables Assessed
1	*Business-as-Usual*	Reference model conditions and cost reduction trajectories; legally protected lands are excluded
2	*Advanced Technology*	Reduced hydropower costs resulting from innovation
3	*Low Cost Finance*	Reduced hydropower costs due to improved financial terms reflecting lower risks and long asset life
4	*Advanced Technology, Low Cost Finance, Combined Environmental Considerations*	Combination of variables in scenarios #2 and #3, plus seven environmental considerations
5	*Advanced Technology, Low Cost Finance*	Combination of variables in scenarios #2 and #3, with no environmental considerations
6	*Advanced Technology, Low Cost Finance, Critical Habitat*	Combination of variables in scenarios #2 and #3, plus one environmental consideration
7	*Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost*	Scenario #6, plus low costs of variable generation technologies (i.e., wind and solar)
8	*Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost*	Scenario #6, plus high cost of fossil fuels
9	*Advanced Technology, Low Cost Finance, High Fossil Fuel Cost*	Scenario #8, with no environmental considerations

Within the model, environmental considerations directly impact only NSD resource sites. The incremental effect on species and habitats at existing facilities, NPDs, and for PSH facilities is expected to be relatively limited.

Table O3-2. Constants across Modeled Scenarios

Input Type	Input Description
Electricity demand	AEO[a] 2015 Reference Case (average annual electricity demand growth rate of 0.7%)
Fossil technology and nuclear power	AEO 2015 Reference Case
Non-hydro/wind/solar photovoltaics renewable power costs	NREL Annual Technology Baseline 2015 Mid-Case Projections
Policy	As legislated and effective on December 31, 2015.
Transmission expansion	Pre-2020 expansion limited to planned lines; post-2020, economic expansion, based on transmission line costs from Eastern Interconnection Planning Collaborative

Note: Despite the Supreme Court stay of the Clean Power Plan (CPP), the CPP is treated as law in all scenarios and is thus assumed active. The CPP is modeled using mass-based goals for all states with national trading of allowances available. Though states can ultimately choose rate- or mass-based compliance and will not necessarily trade with all other states, a nationally traded mass-based compliance mechanism is viewed as a reasonable reference case for the purpose of exploring hydropower deployment under a range of electricity system scenarios.

a. "AEO" refers to the U.S. Energy Information Administration's Annual Energy Outlook (e.g., EIA [18])

Table O3-3. Resource Estimates and Modeled Resource Potential

Resource Category	Technical Resource Potential (gigawatts [GW])	Modeled Resource Potential (GW)[d]
Upgrades and Optimization of Existing Hydropower Plants	8–10% increase in generation	6.9
Powering of Non-Powered Dams[a]	12	5
Powering Existing Canals and Conduits[b]	2	n/a
New Stream-Reach Development[c]	65.5	30.7
New Pumped Storage Hydropower	>1,000	109

Note: Potential in Alaska and Hawaii is not included due to lack of contemporary high-resolution resource assessments.

a. In the development of the modeled potential for NPD, existing technical potential estimates were modified to include the removal of some existing dams (slated for removal) and the addition of some projects omitted from the 2012 resource assessment. Technical potential estimates of generation and capacity were also revised to be consistent with improved methodologies from the 2014 NSD assessment that better replicate the sizing and economics of real-world projects.

b. Canals and conduits are discussed qualitatively in the report as there have been no nationwide resource assessments for them.

c. Existing technical potential estimates for NSD were modified for reaches in a handful of Western basins that were discovered to have relied on an earlier version of the site sizing methodology.

d. The modeled resource potential is the portion of the technical resource potential made available to the model. Economic assumptions and corrections have been applied to reduce the technical resource potential to the modeled resource potential.

The analysis scenarios that demonstrated the most influence on the market potential of hydropower relative to *Business-as-Usual* generally focused on three key factors or variables: 1) technology innovation to reduce cost; 2) improved financing and lending conditions grounded in hydropower's relatively low-risk hardware and long-lived facility life; and 3) the individual or combined influence of an array of relevant environmental considerations, beyond the exclusion of legally protected lands.[1] Other scenarios explored impacts from broader electric sector trends such as low and high variable generation (VG) cost, and low and high fossil fuel costs, with particular interest in conditions with high fossil fuel costs or low VG costs. Potential impacts to hydropower from climate change were partially captured by modeling changes in the magnitude and timing of hydropower water availability, which directly influences energy availability in the model.

Deployment of New Hydropower Generation

Across the nine selected scenarios, post-2016 deployment of hydropower generation (upgrades, NPD, and NSD) is 5–31 gigawatts (GW) in 2050 (Figure O3-2, left panel). This full range demonstrates how *Advanced Technology* and *Low Cost Finance* assumptions promote additional hydropower generation growth, but their combined effect is greater than their individual effect. The right panel of Figure O3-2 more clearly highlights the individual influences of technology and finance cost reduction. *Advanced Technology* assumptions alone have little effect—an additional 0.8 GW by 2050 as compared to 5.2 GW under *Business-as-Usual*—while *Low Cost Finance* assumptions alone provide only a modest increase—an additional 1.8 GW by 2050 as compared to *Business-as-Usual* deployment. Combining these factors, along with several alternative electricity market conditions and hydropower environmental considerations, produces the full range of results shown in the left panel of Figure O3-2.

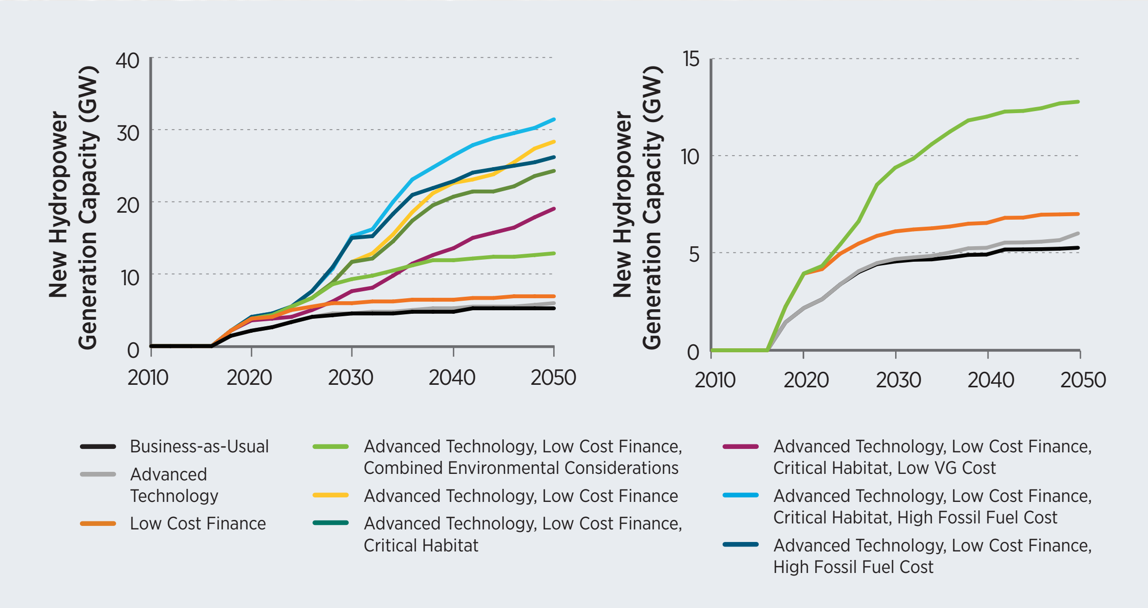


Figure O3-2. ReEDS modeled deployment of new hydropower generation capacity (GW) in 2017–2050 for the nine selected scenarios (left panel) and the four scenarios highlighted in this overview (right panel) [each panel uses a unique y-axis]

1. Within the model, environmental considerations directly impact only NSD resource sites. The incremental effect on species and habitats at existing facilities, NPDs, and for PSH facilities is expected to be relatively limited.

The *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario is highlighted in the right panel of Figure O3-2 to emphasize the importance of incorporating environmental considerations into sustainable hydropower development, particularly NSD. This scenario is the subject of additional emphasis within this chapter overview. In the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario, an additional 7.6 GW is deployed relative to *Business-as-Usual,* for a total of 12.8 GW of new hydropower generation capacity by 2050. Nearly 75% of this amount is deployed by 2030 (see Table O3-4).

Figure O3-3 and Table O3-4 offer long-term snapshots of differences between the *Business-as-Usual* and *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenarios. The *Business-as-Usual* scenario achieves the majority of its 2050 growth (99%) from upgrading and optimizing existing hydropower plant capacity. This 5.2 GW of upgrades deployed under *Business-as-Usual* conditions is 76% of the total 6.9 GW of modeled upgrade capacity potential. The *Advanced Technology, Low Cost Finance and Combined Environmental Considerations* scenario deploys an additional 1.1 GW of upgrades, 4.8 GW powering of NPDs, and 1.7 GW of NSD.

The largest remaining potential for additional hydropower generation capacity beyond the *Advanced Technology, Low Cost Finance* and *Combined Environmental Considerations* scenario is through consideration of further development of new projects on undeveloped stream-reaches. Text Box O3-1 discusses how innovation and transformative technologies might help make this resource available.

Pumped Storage Hydropower Deployment

The left panel of Figure O3-4 illustrates PSH deployment across the nine selected scenarios, with a range of 500 megawatts (MW) to 55 GW in 2050, while the right panel of Figure O3-4 shows PSH deployment for the four focus scenarios of the

Table O3-4. Summary of Modeling Results for the *Business-as-Usual* and *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* Scenarios in 2030 and 2050

Resource Category	*Business-as-Usual* Scenario (GW)		*Advanced Technology, Low Cost Finance, Combined Environmental Consideration* Scenario *(GW)*	
	2030	2050	2030	2050
Total New Hydropower Generation Capacity	4.57	5.28	9.40	12.79
Upgrades and Optimization of Existing Hydropower Plants	4.53	5.23	5.62	6.27
Powering of Non-Powered Dams (NPD)	0.04	0.04	3.56	4.83
Low-impact New Stream-Reach Development (NSD)	0.00	0.00	0.22	1.69
New Pumped Storage Hydropower (PSH) Capacity	0.17	0.48	16.25	35.52
Total New Hydropower Capacity	4.74	5.76	25.64	48.31

Note: The *Business-as-Usual* scenario reflects economic outcomes under reference conditions and assumes no changes in policy or underlying electric sector fundamentals. Moreover, modeling on a national scale requires non-trivial generalizations and averaging of project level details that may limit the ability of the model to perceive niche megawatt-scale opportunities where they exist. For example, NPDs that might be powered under conditions similar to the *Hydropower Vision* low cost finance terms, which are available to some projects today, or under alternative project specific financing or policy terms (e.g., a corporate power procurement designed to meet specific third-party needs that may not be limited to lowest cost).

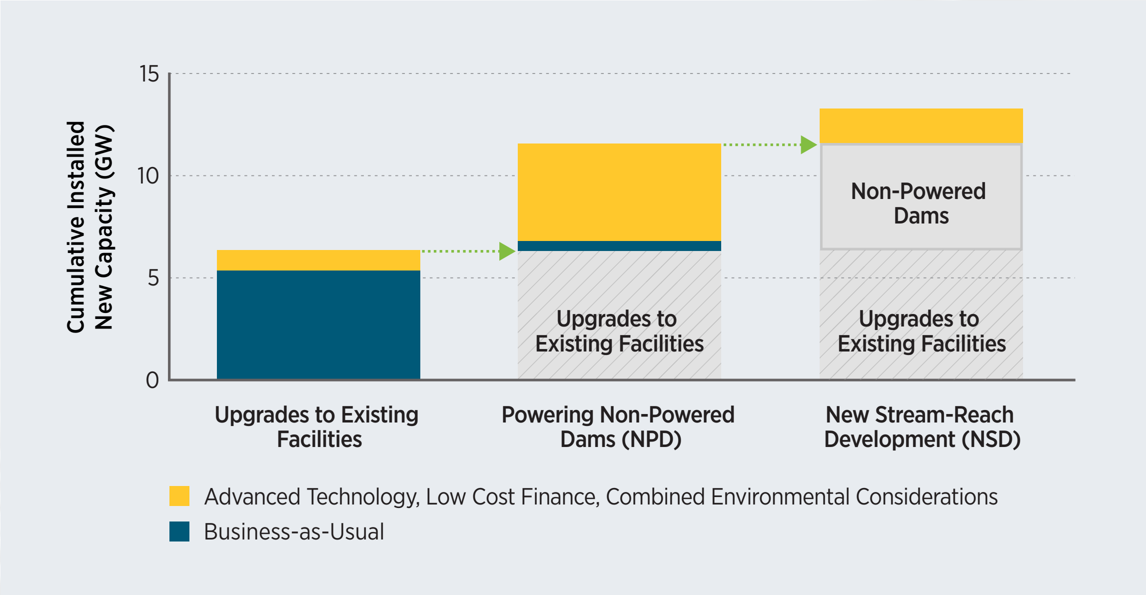
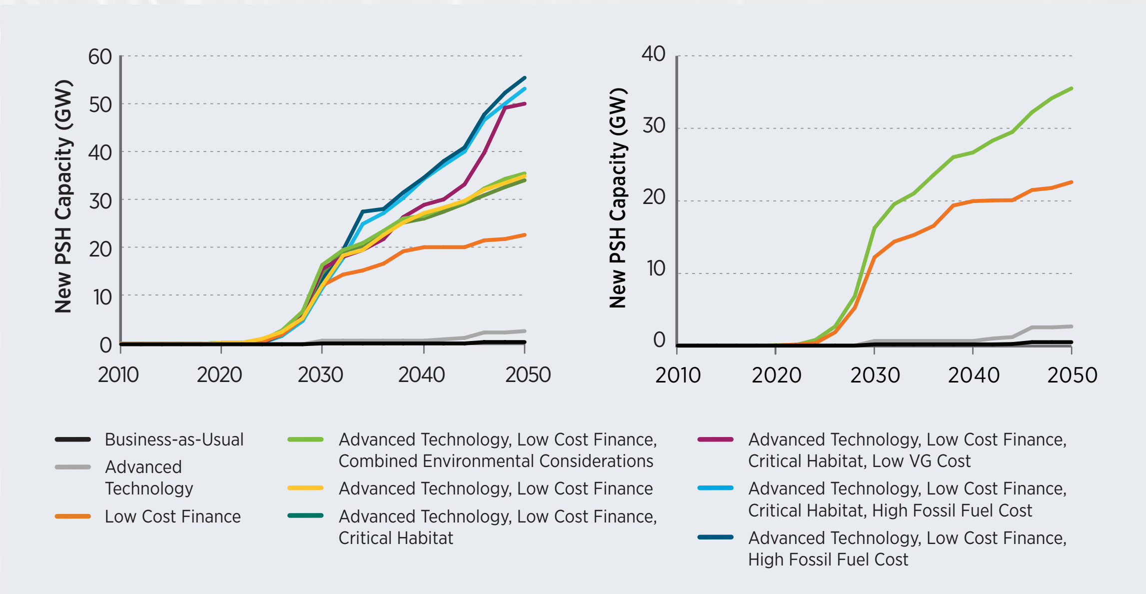


Figure O3-3. ReEDS modeled cumulative 2050 deployment of both existing and new hydropower generation capacity by resource category (GW)



Note: Although PSH is deployed regionally, modeling does not evaluate or designate specific PSH locations within a balancing area and environmental considerations by scenario are not applied to the PSH resource supply (environmental considerations are only applied to NSD resource). Notwithstanding these modeling nuances, PSH development will require location-specific compliance with applicable regulations, including environmental considerations.

Figure O3-4. ReEDS modeled deployment of new pumped storage hydropower capacity, selected scenarios, 2010–2050 (GW)

Hydropower Vision. For new PSH capacity, *Advanced Technology* assumptions alone have a modest effect on deployment (2.6 GW by 2050) as compared to *Business-as-Usual* (0.5 GW in 2050), while *Low Cost Finance* assumptions alone provide a comparably significant increase in deployment (22.6 GW by 2050). Under the focus scenario combining *Advanced Technology* and *Low Cost Finance* assumptions, 35.5 GW of new PSH capacity deployment occurs by 2050, with approximately half of this (53%) occurring by 2030 (see Table O3-4). In this scenario, PSH provides more operating reserves (52%) than any other technology by 2050, when high VG penetration could result in acute grid integration challenges (during the Spring night when electricity load is lowest) (see Figure O3-4).

As shown in the left panel of Figure O3-4, PSH deployment is strongly influenced by fossil fuel and VG costs, as *High Fossil Fuel Costs* and *Low VG Costs* create an electricity system that more highly values the use of energy storage to provide grid flexibility. This result stems largely from higher penetration of VG in the grid. Figure O3-5 plots new PSH capacity in 2030 and 2050 versus the percent of demand met by VG in those years under the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario assumptions. Though the exact relationship between PSH and VG depends on many electricity system characteristics, there is a clear positive correlation between VG energy and PSH capacity in the modeled scenarios.

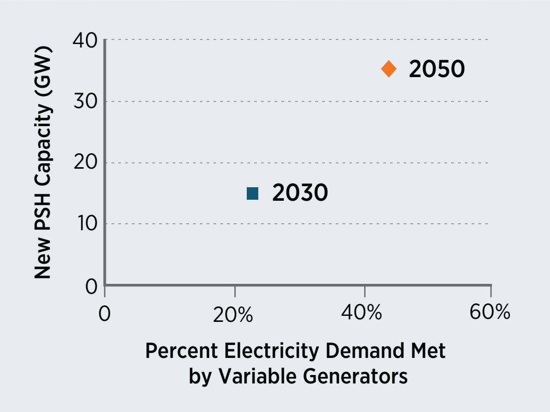


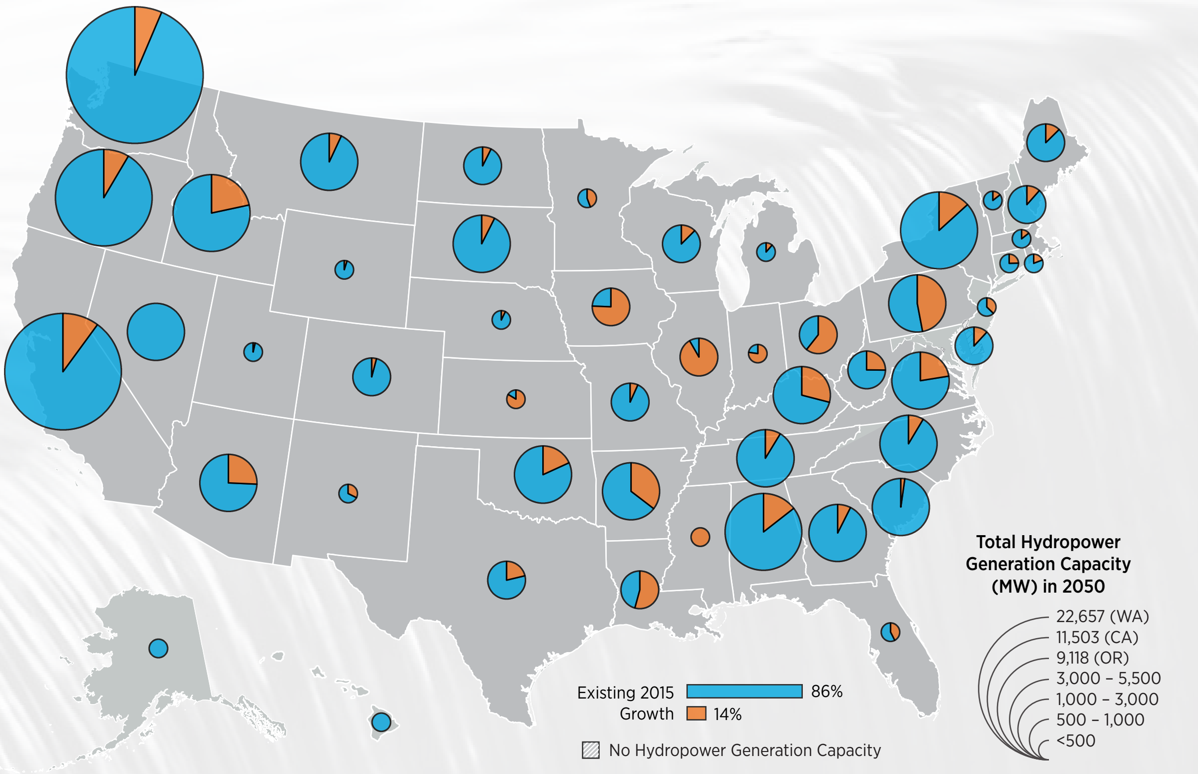
Figure O3-5. The relationship between new pumped storage hydropower growth and generation from variable generators under *Advanced Technology, Low Cost Finance, and Combined Environmental Considerations* assumptions

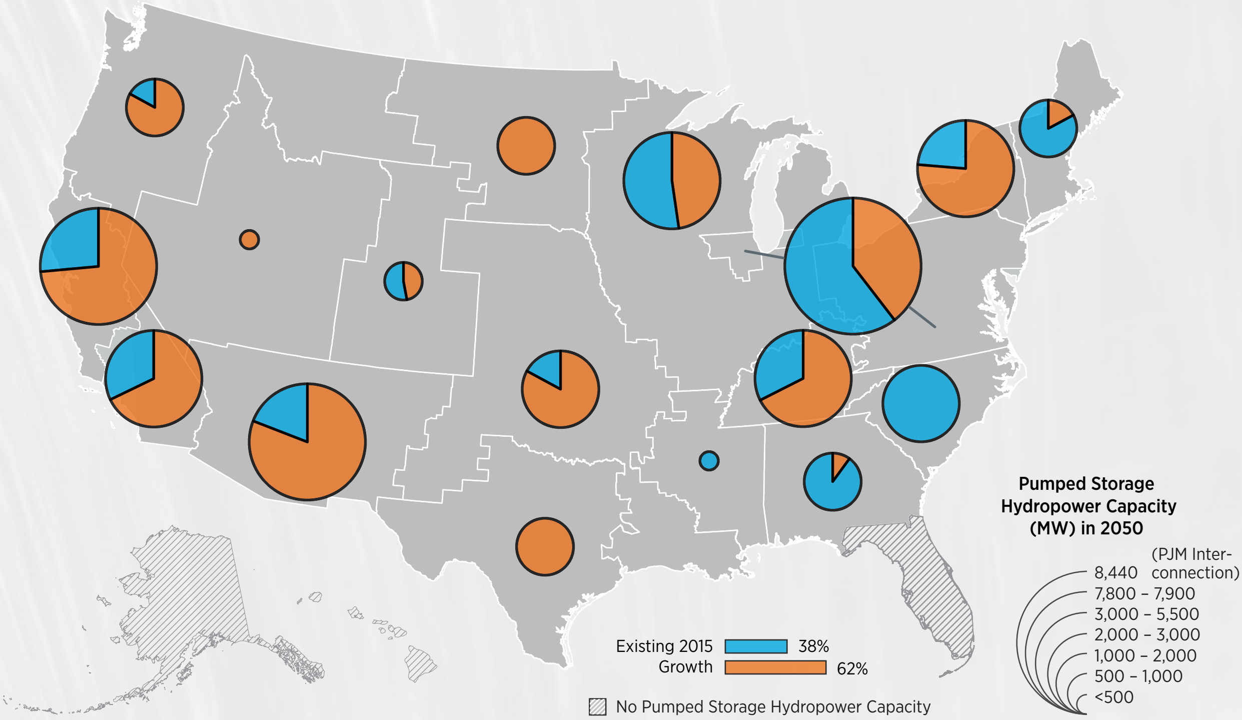
Combined Hydropower Capacity Results

Notable observations from the analysis of growth potential include:

- U.S. hydropower could grow from 101 GW of combined generating and storage capacity at the end of 2015 to nearly 150 GW by 2050, with growth distributed broadly throughout the nation.
- Technology research, development, and deployment to reduce levelized cost of energy, plus improved lending terms, are essential to achieve growth beyond *Business-as-Usual*.
- In the near term (before 2030), hydropower generation growth is likely to be driven primarily through optimizing and upgrading the existing fleet, and powering NPDs.
- In the mid- to long term (from 2030–2050), additional growth may come through sustainable deployment of NPDs and NSD.
- PSH growth can increase in both the 2030 and 2050 periods, while complementing renewable energy (VG) growth by providing flexibility and other important grid services.

Geographically, hydropower generation and pumped storage capacity growth as observed is distributed across the nation. Figure O3-6 highlights the specific geographical growth characteristics of the *Advanced Technology, Low Cost Finance, Combined Environmental Consideration* scenario.





Note: ReEDS modeling applies to the continental United States only, so potential growth in Alaska and Hawaii is not captured.

Figure O3-6. Hydropower generation capacity (MW, top) and pumped storage hydropower capacity (MW, bottom) in 2050, illustrating growth from 2017 under the modeled scenario *Advanced Technology, Low Cost Finance, Combined Environmental Exclusions*

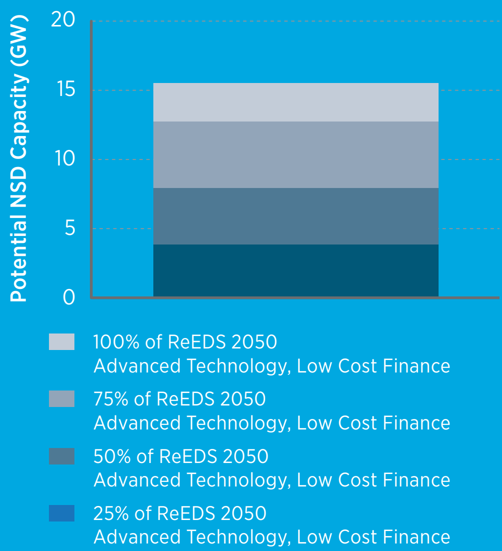
Text Box O3-1.

Evaluating New Stream-Reach Development Potential

Beyond the hydropower generation deployed in the four focus scenarios, and specifically in the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario, the largest remaining potential for additional hydropower generation capacity is in NSD. However, cost and environmental considerations create challenges for development of this resource. New—even transformative—hydropower technologies and project designs capable of avoiding or minimizing adverse environmental and social impacts are generally understood to be essential for calculable growth of NSD.

Alternative scenarios presented in Chapter 3 demonstrate NSD growth opportunities if innovative approaches to the challenges presented by NSD deployment were to become widely available. A 2014 DOE resource assessment [14] found more than 60 GW of NSD technical potential across the United States. After applying additional economic assumptions, a modeled resource potential of 30.7 GW is made available to ReEDS. If innovation were to successfully address the cost and environmental considerations to make all 30.7 GW available for deployment (e.g., the *Advanced Technology, Low Cost Finance* scenario), the resulting economic opportunity estimated under reference electricity market assumptions is 15.5 GW of additional economic NSD growth above the 1.7 GW achieved under similar economic conditions with *Combined Environmental Considerations*. Using this opportunity as an upper bound, the figure below conveys conceptually that the greater the effectiveness of innovation, the more NSD that is potentially accessible to the nation. The table then details estimates of the deployment and economic impacts at various NSD deployment levels, with the gross jobs values being an average between job estimates corresponding to low and high domestic content.

Range of potential future NSD deployment beyond modeled results



New Stream-Reach Development Deployment Outcomes with *Advanced Technology* and *Low Cost Finance* Assumptions

Fraction of Additional New Stream-Reach Development Deployment	Cumulative New Stream-Reach Development Deployment (GW)	2017–2050 Present Value of Hydropower Economic Investment[a] ($ billion)	Gross Jobs[b]
25%	2.8	4	15,000
50%	7.6	11	41,000
75%	11.7	19	63,000
100%	15.5	32	83,000

a. Capital investment and annual operating expenses

b. Gross jobs are calculated from the average of a range from job estimates related to low to high domestic content for the total 15.5 GW deployment.

Selected Costs, Benefits, and Impacts of Hydropower

In addition to examining the key factors influencing a broad range of potential futures for U.S. hydropower, Chapter 3 quantifies a subset of the costs and benefits associated with future hydropower deployment and operations through 2050. To estimate the impacts of new hydropower capacity (hydropower generation and PSH), many metrics are compared between a given scenario and its corresponding baseline scenario in which hydropower electricity market conditions remain the same and no new unannounced (as of 2016) hydropower is built through 2050. Impacts for the existing fleet were estimated by comparing the quantified costs and benefits of existing hydropower capacity to those that would result if this capacity were to be replaced by the regional composite mix of other cost-competitive generation sources in future (model) years under a baseline scenario with reference electricity market assumptions.

Focusing on the existing hydropower fleet and new deployment as modeled under the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario, identified *Hydropower Vision* economic and social benefits. These benefits include $209 billion savings from avoided global damages from GHG emissions; $58 billion savings in avoided mortality, morbidity, and economic damages from cumulative reduction in emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_X), and fine particulate matter ($PM_{2.5}$); and 30 trillion gallons of avoided water withdrawals from 2017 to 2050. Additionally, more than 195,000 jobs are supported in 2050 (see Figure O3-7).

This scenario reflects the impact of key variables affecting deployment—technology, markets, and sustainability. It also presents a credible outcome of combined actions by government, industry, and public stakeholders to successfully reduce technology cost through research and development and more efficient regulatory process; monetize the long asset life of hydropower in project financing; and address the co-objective of environmental preservation. These objectives, among others, are discussed in the *Hydropower Vision* roadmap.

Impacts specific to the existing fleet and new deployment under the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario are provided in more detail below. Additional impact metrics and results associated with the balance of the nine selected scenarios are described within Chapter 3 and demonstrate a broader range of possible hydropower industry impacts.

Benefits—Existing and New Capacity, 2017–2050[a,b,c]

	Economic Investment	Greenhouse Gases	Air Pollution	Water	Jobs
Existing Fleet and New Capacity Additions Combined (149.5 GW)	$148 billion in cumulative economic investment[d] $110 billion for hydropower generation and $38 billion for PSH	Cumulative GHG emissions reduced by 5,600,000,000 metric tons CO_2-equivalent, saving $209 billion in avoided global damages	$58 billion savings in avoided mortality, morbidity, and economic damages from cumulative reduction in emissions of SO_2, NO_X, and $PM_{2.5}$ 6,700–16,200 premature deaths avoided	Cumulative 30 trillion gallons of water withdrawals avoided for the electric power sector	Over 195,000 hydropower-related gross jobs spread across the nation in 2050

Figure O3-7. Selected benefits and impacts from the existing hydropower fleet and from new deployment, 2017–2050

a. Cumulative benefits are reported on a Net Present Value basis ($2015) for the period of 2017 through 2050.

b. Estimates reported reflect central values within a range of estimates as compared to the *baseline scenario* with no new hydropower.

c. Existing fleet includes new projects and plant retirements announced as of the end of 2015; new development reflects the modeled scenario titled *Advanced Technology, Low Cost Finance, and Combined Environmental Considerations.*

d. Capital investment and annual operating expenses, 2017–2050.

Impacts: Existing Fleet

Cumulative impacts from avoided power-sector GHG and air pollutions emissions from 2017 to 2050 from the existing hydropower fleet total $184.5 billion in savings from avoided global damages from GHG emissions, and $58 billion in savings from avoided mortality, morbidity, and economic damages from cumulative reduction in emissions of SO_2, NO_X, and $PM_{2.5}$ (Figure O3-8). The existing hydropower fleet also avoids approximately 1,450 billion gallons of water withdrawals per year compared to the energy sources that would otherwise be deployed; and 100 billion gallons of water consumption savings per year as of 2016. These savings represent a 4.1% and 7.3% reduction in national water withdrawal and consumption, respectively. Long-term jobs supported by the existing fleet exceed 120,000 in 2050.

Impacts: New Capacity Additions

Relying on the mid-range *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario, the cumulative impacts from avoided power-sector GHG emissions from new hydropower capacity additions from 2017 to 2050 total nearly $25 billion in savings from avoided global damages (Figure O3-9 and Table O3-5). In addition, cumulative capital investment is estimated at more than $71 billion. These new investments are estimated to support approximately 76,000 new full-time equivalent jobs.

Impacts: Combined Existing Fleet and New Capacity Deployment

The overall impacts to human health from reduced air pollution were estimated through 2050 and comprise 294,000 metric tons of fine particulate matter (PM), 2,760,000 metric tons of nitrogen oxides (NO_X), and 1,418,000 metric tons of sulfur dioxide (SO_2). These reductions could result in avoidance of 6,700–16,200 premature deaths (see Note "d" in Table O3-5 for additional detail regarding interactions between air pollution impacts of the existing fleet and new hydropower capacity). Cumulative capital and operating expenditures from 2017–2050 are approximately $110 billion for hydropower generation and $38 billion for PSH. Cumulative avoided GHG emissions from the combined capacity of existing and new hydropower were calculated to be 5.6 billion metric tons of carbon dioxide from 2017–2050, corresponding to $209 billion in avoided global damage (Table O3-5, Figure O3-7).

Benefits—Existing Capacity, 2017–2050[a,b,c]

	$ Economic Investment	GHG Greenhouse Gases	Air Pollution Air Pollution	H_2O Water	Jobs
Existing Fleet (101.2 GW)	$77 billion in cumulative economic investment[d]	Cumulative GHG emissions reduced by 4,900,000,000 metric tons CO_2-equivalent, $184.5 billion savings	$58 Billion savings in avoided mortality, morbidity, and economic damages from cumulative reduction in emissions of SO_2, NO_X, and $PM_{2.5}$	Cumulative 30 trillion gallons of water withdrawals avoided for the electric power sector	120,500 hydropower-related gross jobs spread across the nation in 2050

Figure O3-8. Selected benefits and impacts from the existing hydropower fleet and from new deployment, 2017–2050

a. Cumulative benefits are reported on a Net Present Value basis ($2015) for the period of 2017 through 2050.

b. Estimates reported central values within a range of estimates as compared to the *baseline scenario* with no new hydropower.

c. Existing fleet includes new projects and plant retirements announced as of the end of 2015.

d. Capital investment and annual operating expenses, 2017–2050.

Benefits—New Capacity, 2017–2050[a,b,c]

	Economic Investment	Greenhouse Gases	Air Pollution	Water	Jobs
New Capacity Additions (48.3 GW)	$71 billion in cumulative economic investment[d]	Cumulative GHG emissions reduced by 700,000,000 metric tons CO_2- equivalent, $24.5 Billion savings	n/a[e]	n/a[f]	76,000 hydropower-related gross jobs spread across the nation in 2050

Figure O3-9. Selected benefits and impacts from new hydropower capacity additions under the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario, 2017–2050

a. Cumulative benefits are reported on a Net Present Value basis ($2015) for the period of 2017 through 2050.

b. Estimates reported reflect central values within a range of estimates as compared to the *baseline scenario* with no new hydropower.

c. Existing fleet includes new projects and plant retirements announced as of the end of 2015; new development reflects the modeled scenario titled *Advanced Technology, Low Cost Finance, and Combined Environmental Considerations*.

d. Capital investment and annual operating expenses, 2017-2050.

e. In the model, once the Clean Power Plan carbon cap is realized, the addition of new hydropower can displace marginal natural gas generation, thereby allowing for additional coal generation—and associated criteria pollutant emissions which reduced the calculated value of avoided air pollution emissions for new hydropower deployment by $6.2 billion over the 2017-2050 time period. However, this result reflects the model's use of AEO 2015 Reference Case natural gas prices, which are higher than those in the more recent AEO 2016 Reference Case. AEO 2016 data were unavailable for inclusion in the *Hydropower Vision* analysis, but lower natural gas prices could allow new hydropower to displace more coal relative to natural gas. Due to the sensitivity of this result to recently updated natural gas price projections, the $6.2 billion reduction in value is not reflected in the total value of avoided SO_2, NO_X, and $PM_{2.5}$ in the *Advanced Technology, Low Cost Finance, and Combined Environmental Considerations* scenario.

f. Cumulative 2017-2050 water use impacts from new hydropower capacity in the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario include a 0.1% increase in water withdrawals (0.8 trillion gallons). Given the magnitude of these impacts relative to those from the existing fleet and model precision limitations generally, these results are not reflected in the avoided water use impacts reported here.

Table O3-5. Cumulative Impacts of Hydropower under the *Advanced Technology, Low Cost Finance,* and *Combined Environmental Considerations* Scenario, 2017–2050[1]

Resource Category	Capacity, 2050 (GW)	Avoided GHG Emissions ($B)	Avoided Emissions of SO_2, NO_X, and $PM_{2.5}$ ($B)[b]	Avoided Water Use (trillion gallons)[c]	Annual Jobs Supported, 2050
Existing Hydropower	101.2	184.6	57.8	30.1 withdrawals, 2.2 consumption	120,500
New Hydropower	48.3	24.5	n/a[d]	n/a[e]	76,000
Total	149.5	209	57.8	30.1 withdrawals, 2.2 consumption	196,500

a. As compared to the baseline scenario, under which no new unannounced (as of 2016) hydropower is built.

b. Savings in avoided mortality, morbidity, and economic damages.

c. Water withdrawal is water that is removed from the ground or diverted from a water source for use, but then returned to that source, Water consumption is water that is removed from the immediate water environment altogether, e.g., through evaporation or use for production and crops.

d. The Clean Power Plan (CPP)—which is estimated to provide substantial air quality benefits [65]—limits total carbon emissions but does not directly limit SO_2, NO_X, and $PM_{2.5}$ emissions. In the model, once the CPP carbon cap is realized, the addition of new hydropower can displace marginal natural gas generation, thereby allowing for additional coal generation—and associated criteria pollutant emissions, which reduced the calculated value of avoided air pollution emissions for new hydropower deployment by $6.2 billion and avoided water withdrawals by 0.8 trillion gallons over the 2017–2050 time period. However, this result reflects the model's use of AEO 2015 Reference Case natural gas prices, which are higher than those in the more recent AEO 2016 Reference Case. AEO 2016 data were unavailable for inclusion in the *Hydropower Vision* analysis, but lower natural gas prices could allow new hydropower to displace more coal relative to natural gas. Due to the sensitivity of this result to recently updated natural gas price projections, the $6.2 billion reduction in value is not reflected in the total value of avoided SO_2, NO_X, and $PM_{2.5v}$.

e. Cumulative 2017–2050 water use impacts from new hydropower capacity in the *Advanced Technology, Low-Cost Finance,* and *Combined Environmental Considerations* scenario include a 0.1% increase in water withdrawals (0.8 trillion gallons) and a 0.0% change in water consumption (0.00 trillion gallons). Given the magnitude of these impacts relative to those from the existing fleet and model precision limitations generally, these results are also not reflected in the avoided water use impacts reported here; they are, however, summarized in the main body of Chapter 3.

Key Modeling Findings

Along with the highlights already noted, several general conclusions may be drawn from the full analysis presented in Chapter 3:

- Across the breadth of potential scenarios, growth of hydropower capacity could also add billions of dollars in societal value in the form of avoided GHG and air pollution emissions, avoided water consumption, and avoided water withdrawals.
- Although opportunities for new hydropower capacity and generation are less than implied by gross resource assessments, they do imply continuation and incremental growth of a robust multi-billion dollar industry under all scenarios, including *Business-as-Usual.*
- Continued investment in the hydropower industry is expected to be significant, as indicated by the $4.2 billion per year investment estimate under *Business-as-Usual*; and $9.9 billion per year under the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenario.
- Comprehensive sustainability and cost reduction advances through innovation will play a major role in determining what levels of NSD are ultimately realized.
- Modeled ranges yield dramatically different results based on assumptions, indicating that actions defined in the *Hydropower Vision* roadmap (chapter 4) as well as external factors such as climate change (Text Box O3-2) can influence outcomes.
- Due to its large installed capacity and long capital lifetime, the existing fleet will continue to contribute a substantial majority of the societal benefits of hydropower as a whole.

Text Box O3-2.

Hydropower in an Uncertain Climate Future

Climate change creates uncertainty for hydropower generation, with potential impacts that include increasing temperatures and evaporative losses that result in reductions in available water resources and changes in operations; changes in precipitation and decreasing snowpack that result in changes in seasonal availability of resources and changes in operations; and increased intensity and frequency of flooding that results in greater risk of physical damage and changes in operations.

The impact of water availability on future hydropower deployment was explored by modeling low (*Dry*) and high (*Wet*) hydropower water availability futures for each of the nine selected scenarios. Most upgrades are economically attractive even with reduced water availability, which leads to less than a 5% change in deployment under *Business-as-Usual* conditions. NPDs are also similarly unaffected by changing water availability under *Advanced Technology, Low Cost Finance* assumptions, which support construction of a large fraction of the NPD resource even when water availability is reduced. In contrast, the range of NSD deployment variation across *Wet* and *Dry* conditions is 42–74% of the reference NSD deployment for scenarios in which NSD is economically feasible.

Hydropower energy production varies across alternate water availability scenarios, both for existing and new resources. From the reference long-term average output of 270 terawatt-hours (TWh), variation in existing fleet generation in climate scenario spans 260–290 TWh in 2030, and 250–310 TWh in 2050. For new hydropower generation, energy production across the full range of *Wet* and *Dry* variants for the nine selected scenarios spans 13–120 TWh in 2030 and 6–260 TWh in 2050.*

* The low end of the range declines because *Business-as-Usual* in *Dry* conditions does not build enough new capacity to replace reduced generation due to declining water availability for previously built hydropower.

3.0 Introduction

Hydropower has played a pivotal role in the U.S. electricity generation sector for more than a century, and the technology has the potential to remain an important source of energy in the nation's electricity future. Chapter 3 of the *Hydropower Vision* applies detailed electric sector modeling and impacts assessment to explore an array of possible futures for the hydropower industry and to better understand a subset of the quantifiable impacts associated with multiple scenarios. Within the analysis conducted, no scenario or set of scenarios is intended as a hydropower industry forecast. Rather, the work detailed in this chapter is intended to provide new quantitative insights and understanding regarding future opportunities, costs, and benefits associated with the existing hydropower fleet and potential new hydropower deployment. The results detailed in this chapter are meant to inform a variety of stakeholders and decision makers of the future potential and value of hydropower technology in the nation's electricity future.

This chapter details analysis considering an array of future scenarios for hydropower development, including those that maintain existing levels of industry activity (*Business-as-Usual*), as well as several more ambitious scenarios, described in Section 3.3. It then examines a subset of potential impacts, opportunities, and benefits that might be realized from the existing fleet and new hydropower facilities under these scenarios. Based on these data, new insights on the growth potential of hydropower technologies and a detailed understanding of potential drivers and influences on future growth are identified. In addition, this chapter examines the development potential within specific hydropower market segments, and the drivers and effects relevant to future growth within those market segments. The chapter also explores critical uncertainties in hydropower development—specifically, how future growth may intersect with a changing climate and environmental and social considerations that are important to all power generation technologies but sometimes have unique implications for hydropower.

Analysis work presented in this chapter relies primarily on the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) capacity expansion model ([1], [2]) with supplemental analysis methods applied to model outputs when analyzing impacts. In addition, Chapter 3 and its related appendices serve as documentation for a synthesis of recent cost and resource assessments conducted by Oak Ridge National Laboratory, characterizing the nation's hydropower resource potential and applying it for the first time in the *Hydropower Vision*.

Section 3.1 describes the electric sector expansion model and the approach used for this analysis, which includes acknowledging the general challenges and limitations in modeling hydropower at a national level. This section includes particular focus on hydropower modeling assumptions.

Section 3.2 provides an overview of the hydropower resources modeled in ReEDS and describes how the modeled resource differs from other forms of resource estimates, such as physical or technical resource potential.

Section 3.3 provides a high-level overview of the economic assumptions that characterize hydropower opportunities, and briefly documents the input assumptions used to describe the existing and future electric sector, including generation technology resource, cost, and performance; electricity demand; fuel prices; and retirements. Additional details are included in Appendices B, C, and D. Section 3.4 also lays out the full range of scenarios and model input parameters that are varied in order to create the range of outcomes. This section also defines the selected scenarios for which the impact metrics are calculated.

Section 3.4 presents and explores the range of future hydropower deployment captured by nine selected scenarios, identified for their ability to reflect both priorities in the hydropower stakeholder community (e.g., technology cost reduction, environmental considerations) as well as the potential for uncertainty in the broader electric sector (e.g., high fossil fuel prices). This section explores how the specific market and resource conditions embodied in these scenarios inform the possibilities for future hydropower growth by varying technology cost reduction, long-term asset valuation, among other assumptions. One focus specific to new stream-reach development (NSD) is the extent to which development potential intersects with selected environmental and social considerations.

The results from these scenarios can inform the need for innovative technology and planning solutions to improve sustainability outcomes. Section 3.4 also explores the manner in which changes in water availability resulting from climate change could impact future contributions of hydropower to the grid.

Section 3.5 details a subset of quantifiable impacts for future hydropower deployment as well as benefits associated with continued operation of the existing fleet capabilities through 2050. Impacts discussed include electric sector economics, greenhouse gas (GHG) emissions, air quality, water usage, and workforce. In summary, the analytic framework presented in Chapter 3 is intended to provide insight into a range of possible outcomes for U.S. hydropower and to demonstrate potential impacts associated with scenarios that result in continued operation of the existing hydropower fleet as well as new growth in the hydropower industry. These data and insights are intended to provide information for a variety of stakeholders and decision makers with respect to the potential future for hydropower as a source of clean and renewable energy for the nation.

3.1 Analytical Approach: Overview

Evaluating potential drivers of growth and quantifying a range of future costs and benefits associated with the hydropower industry requires multiple methods and datasets. Within the quantitative analysis detailed in this chapter, existing resource data and characterizations are used in a detailed electric sector modeling framework, with other methods derived from the literature to quantify potential benefits (e.g., avoided GHG damages) and impacts (e.g., hydropower-derived employment). Analytical methods are applied to both the existing hydropower fleet and varying levels of new hydropower deployment in the form of upgrades, NSD, powering of non-powered dams (NPD), and pumped storage hydropower (PSH). The basic modeling and analysis approaches applied to the existing fleet and to new hydropower potential are described in this section.

3.1.1 Existing Fleet

With nearly 100 gigawatts (GW) of combined hydropower generation and PSH capacity—10% of all U.S. generating capacity—the existing fleet has a tremendous national impact on the power system. The methodology and assumptions used to characterize the impacts of the existing fleet were a core consideration throughout the *Hydropower Vision* effort. The focus included whether to calculate the historical versus "as-of" or future value of the existing fleet, as well as methodological concerns focused on if and how a particular impact might be assessed. In order to analyze the existing fleet, this analysis ultimately considers the benefits of the existing fleet as of 2015 and through the future study period. Estimates of historical benefits, costs, and environmental impacts were deemed to be outside the scope of the *Hydropower Vision*.

Existing fleet benefits (e.g., GHG emissions) through 2050 are calculated as a function of the other electricity generators in the grid, on a regional basis. Analysis of the existing fleet uses the average characteristics of the rest of the regional electric system in a given year to characterize the value of existing hydropower in that same region and year. In effect, the assumption is that, if the existing hydropower fleet were not available, it would be replaced by the average characteristics of the rest of the electric sector in that region. Estimates for the present are based on the average electric sector characteristics of 2015, while average electric characteristics of the future are estimated in ReEDS.

3.1.2 Potential New Deployment

For new hydropower potential—including that from upgrading the existing fleet, NPD, NSD, and PSH—the NREL ReEDS model is used to capture the complex dynamics of the power grid and simulate how those might evolve under different scenarios. In this modeled context, the future scenarios of hydropower industry growth can be explored, with modeled representations of hydropower resources competing against other generation technologies (and other hydropower technologies) to see how the grid may evolve most economically. The specific costs and benefits of hydropower can be isolated by comparing scenarios of growth (such as what might happen if technology costs can be decreased) to control scenarios ("baselines") with no hydropower growth. The differences between these two sets of scenarios then highlight how new hydropower affects the selected cost and benefit metrics analyzed.

Although the *Hydropower Vision* analyzed more than 50 total scenarios, impact metrics detailed within the main report body are calculated for a subset of nine selected modeling scenarios chosen to capture key hydropower industry priorities (e.g., aggressive cost reduction, financial valuation of the long-term asset life of hydropower, environmental considerations) as well as key electric sector uncertainties (e.g., high fossil fuel prices and low variable generation [wind and solar] technology costs). Metrics of interest include: primarily costs measured in terms of changes in electricity rates and cumulative system expenditures; benefits derived from changes in power sector GHG emissions, air pollution, water consumption, and water withdrawals; and other impacts measured in terms of contribution to electricity capacity and generation, workforce and economic development, changes in electric sector sensitivity to fossil fuel price volatility, and reductions in consumer expenditures on natural gas.

Ecological, environmental, and other positive and negative externalities associated with hydropower were not quantified; in this sense, the impacts analysis is not comprehensive of all potential costs and benefits of new hydropower deployment. However, environmental considerations for hydropower growth, particularly NSD, are examined for several modeled scenarios.

3.1.3 Regional Energy Deployment System (ReEDS)

As noted in Section 3.0, the NREL's ReEDS[2] electric sector capacity expansion model is the primary analytic tool used to quantify the impacts studied in the *Hydropower Vision* analysis. ReEDS simulates the construction and operation of electricity generation and transmission capacity while meeting electricity demand and other system requirements through 2050 for each of 134 supply-demand balancing area (BA) regions. The model uses a system-wide[3] least-cost optimization to estimate the type, location, and timing of fossil, nuclear, renewable, and storage resource deployment; the necessary transmission infrastructure expansion; and the generator dispatch and fuel needed to satisfy regional demand requirements and maintain grid reliability. It includes a sophisticated representation of variable generation renewable resources and the flexible systems necessary for their integration, including natural gas and energy storage systems such as PSH. ReEDS also incorporates technology, resource, and policy constraints, including state renewable portfolio standard policies, enacted tax credits, and the the U.S. Environmental Protection Agency's Clean Power Plan (CPP).[4] The model considers only the continental United States and performs the least-cost optimization sequentially in 2-year solve periods.[5] Additional details of the ReEDS model formulation are contained in the ReEDS documentation [1] and more recent publications containing ReEDS analysis, particularly the *NREL 2015 Standard Scenarios Annual Report* [2] and the U.S. Department of Energy's (DOE's) *Wind Vision* report [3].

2. *http://www.nrel.gov/analysis/reeds/description.html*
3. The ReEDS model optimizes the electric sector of the continental United States as a system, in contrast to optimizing around impacts to individual market actors or specific regions.
4. Model results do reflect the December 2015 renewable energy tax credit extension.
5. Alaska, Hawaii, and Puerto Rico are not currently included in ReEDS due to model limitations. Potential hydropower capacity from canals and conduits are also not currently included in ReEDS. ReEDS assumes exogenous estimates of net energy transfers from Canada to the United States [4] but ignores the limited interactions with Mexico.

For the *Hydropower Vision*, ReEDS is used to generate a set of future U.S. electric sector scenarios from which the impacts of a growing hydropower of a future hydropower industry can be assessed. As noted above, ReEDS scenarios are not forecasts or projections; rather, they aim to provide a consistent framework for understanding the effects of potential future conditions.

The primary outputs of the ReEDS model include the location, capacity, and generation of all power generation technologies built and operated during the study period along with the transmission infrastructure expansion necessary to support this new generation. Capital costs, fixed operating costs, variable operating costs, fuel usage and costs, and other associated costs are reported, along with transmission capital and operating costs. Cost metrics—such as present value system cost and an approximation of electricity prices (neither of which incorporate environmental externalities) can be derived from this raw cost information. Capacity expansion and generation results are then used to inform impacts assessments (e.g., GHG emissions, other environmental and health benefits, thermal cooling water use, energy diversity and risk, and workforce and economic development). The hydropower deployment results are further analyzed to more thoroughly assess their physical attributes, regional distribution, and potential intersection with environmental considerations.

3.1.4 Challenges and Limitations

The development of the *Hydropower Vision* entailed a number of improvements to how hydropower is modeled in ReEDS, making the representation of U.S. hydropower for this study among the most sophisticated and complete to date for models of its class. Some modeling limitations and challenges, however, persist. These are briefly discussed in this section to provide context and acknowledge the many important issues about which continued work may provide enhanced resolution and better intelligence in future analyses.

Hydropower Technology Representation. A core difficulty in modeling hydropower is attempting to capture the unique, site-specific dynamics that drive technology choice and project economics in the real world. In modeling hydropower potential, attributes are often approximated from resource and cost assessment efforts that necessarily rely on limited data and assumptions based on averages across site-specific features. The *Hydropower Vision* analysis uses the most current U.S. resource assessment and cost data available as of 2015, but these data can still only provide generalized, uncertain estimates that are more accurate at an aggregate scale than for individual projects. The results presented in this chapter should be interpreted as capturing large-scale trends and identifying regions and areas with economically competitive hydropower potential, not necessarily implying that a specific dam will be powered at a specific cost, or that an individual stream-reach is ideal for development.

Future improvements are believed to be most valuable for characterizing the full potential of upgrading and expanding the existing fleet, as well as predicting and estimating the cost of environmental mitigation measures for all types of hydropower.

Modeling Sustainability. Issues of sustainability are of paramount importance to the development and operation of hydropower projects, but are difficult to translate into robust modeling assumptions. In practice, decisions related to hydropower are ultimately made through processes that rely on input from a variety of stakeholders with an equally diverse set of economic, social, and environmental objectives. Modeling realities limit the investigation of these multiple objectives to the economic optimization performed by the ReEDS model, and the *Hydropower Vision* analysis can only begin to explore these issues through scenario analyses that observe how economics intersect with other considerations. Because of this, the *Hydropower Vision* analysis does not claim that sustainability has been approximated in the modeling process, only that the bounds of some considerations have been explored.

A key conclusion from this effort is that better data and new modeling techniques would be particularly valuable to incorporate sustainability concerns into models themselves. Some data advances were made during the *Hydropower Vision*, including the creation of national data layers of stream connectivity and the predicted habitat of migratory fish species. However, further improvement is necessary in the development of science-based environmental metrics and approaches that can consider hydropower development in the context of multiple objectives beyond economics.

Modeling Climate Change. Climate change has the potential to significantly alter many aspects of the power system and its relationships with other systems such as water supply. Modeling these complex interdependencies is difficult, but previous work with ReEDS has examined climate impacts such as temperature effects on load and the thermal fleet operation and expansion [5]. The analysis presented here also explores isolated potential impacts of climate change on hydropower through the modeling of changes in runoff and the resulting magnitude and timing of water availability for hydropower generation. However, fully resolving climate change in a modeled context must link together the joint impacts on energy and water systems, such as operational impacts to thermal generators, changes to electricity demand, and the availability and timing of water for hydropower generation. Such a comprehensive climate scenario is outside the scope of the *Hydropower Vision*, so climate change is discussed in this report with respect to its direct and isolated effects on the hydropower industry only.

The issue of a changing climate also highlights the modeling challenges in sustainability and the technology representation for hydropower discussed previously, as changes to water quality and temperature could influence project design and operations to minimize or mitigate environmental and economic impacts. Beyond these considerations, adaptation to climate may also intersect with hydropower development in ways the *Hydropower Vision* analysis does not model, such as adding power generating capabilities to new water resource infrastructure constructed to accommodate future changes in the timing and availability of water.

Costs and Benefits. The cost and benefit metrics included in the *Hydropower Vision* analysis are only a subset of those that are typically of interest to hydropower's many stakeholders. In addition, the direct cost metrics in the ReEDS model do not include environmental or health externalities that are not directly incorporated into existing electricity cost structures. Some of these externalities (such as electric sector GHG emissions) are evaluated separately using the outputs of the ReEDS scenarios as described in Section 3.5. Many additional hydropower-specific considerations, such as impacts on water quality or species populations require complex site-specific modeling techniques and strategies to resolve and therefore cannot be addressed at the national-scale of the modeling analysis considered here. As described in Section 3.4, this analysis includes some sensitivity scenarios that attempt to explore the intersection of hydropower deployment and other, non-economic considerations. The assumptions embedded in these scenarios are not intended to serve as proxies for sustainability concerns. Rather, they are simply a first step towards identifying and understanding the effects of other water uses that new hydropower deployment must complement.

It is also not feasible to quantify in an electric sector model many of the potential benefits associated with hydropower development, including recreation opportunities and water supply capabilities. Instead, the analysis calculates those metrics where data and methods are adequate for scientifically credible evaluations. For a more thorough accounting of the cost and benefits of hydropower development, future research must address these additional quantification challenges.

Additional Potential Outside of the Modeling Scope. The modeling scenarios described in this chapter of the *Hydropower Vision* are not intended to be interpreted as representative of the full range of outcomes possible for the hydropower industry. Instead, they constitute a useful—albeit imperfect—modeling tool to explore the major opportunities, challenges, and drivers of a 21st century hydropower industry. To that end, there are certain segments of the power sector that cannot be modeled in the existing ReEDS model. As such, these topics are discussed qualitatively throughout the report.

The largest model constraint is that the scope of the ReEDS model prevents the explicit modeling of Alaska and Hawaii. Hydropower is a potentially important resource in these states; their unique hydropower resources and power markets are discussed in Chapter 2 of the *Hydropower Vision*.

Also absent from ReEDS is the generation potential from conduits and canals, for which consistent site-specific data are not available on a basis that allows for integration into a national electric sector model. Distributed owner and state-level assessments do exist; for example, the resource potential for canals owned by the U.S. Bureau of Reclamation (Reclamation) is about 104 megawatts (MW) [6]. Beyond this quantity, states such as California, Massachusetts, Oregon, and Colorado have all done partial assessments of canal and conduit potential, but there have been no nationwide resource assessments that could be modeled consistently in ReEDS [7] (Sale et al. 2014).

An additional market segment that is only partially modeled is Canadian hydropower and the extent to which it interacts with U.S. markets. As of 2015, the ReEDS model uses a static forecast from Canada's National Energy Board of new hydropower development and anticipated exports of energy to the United States [8]. Changing policy and market conditions in the United States could result in subsequent changes to how Canadian hydropower competes in cross-border markets.

Broader Power System Considerations in the ReEDS Model. ReEDS is a system-wide least-cost optimization model. As such, it does not consider revenue impacts for individual project developers, utilities, or other industry participants, and does not resolve some other factors that may influence power system economics. These factors include:

- Constraints associated with the supply chain and manufacturing sector, which are not included. All technologies are assumed to be available up to their technical resource potential.[6]
- Technology cost reductions from manufacturing economies of scale and "learning by doing" are not calculated in the model internally; these market behaviors are defined as inputs that do not depend on the capacity deployed by the model.
- With the exception of future natural gas fuel costs, foresight is not considered explicitly in ReEDS (i.e., the model makes investment decisions based on the conditions it observes at a given point in time, without considering how those conditions may change further into the future).
- ReEDS is deterministic and has limited considerations for risk and uncertainty, so it cannot study inter-annual variability in hydropower energy availability. As such, the model is restricted to projections of average system behavior.
- As an electric-sector-only model, ReEDS does not directly include fuel infrastructure, land competition challenges associated with fossil fuel extraction and delivery, or water competition challenges with agricultural or other use.[7] As is the case for all models, these challenges in combination mean that ReEDS represents a simpler power system than exists in reality. The advances made in the *Hydropower Vision* ensure a thorough examination of many key issues surrounding the hydropower industry. These include competition with other technologies; regional distribution of new deployment; influence of economic drivers, such as cost reductions and fuel prices; and initial explorations of the potential influence of climate change, as well as the intersection of possible hydropower development with other priority water uses.

6. ReEDS does, however, include a growth penalty on capital costs for rapid technology deployment. For hydropower, capital costs will be greater than their base defined amounts if annual capacity additions are to exceed 1.44 times the additions in the previous year.

7. The model does include a static resource supply of water availability for new thermal cooling water requirements by new capacity, and this resource supply implies relative water availability between the electric sector and other sectors.

3.2 Hydropower Resource Potential

Understanding and characterizing the potential opportunity for hydropower in the future begins with a base level of knowledge of the existing fleet and the types and quantities of new resource development potential. Details and data presented in this section are intended to provide this initial foundation and to assist in understanding new power generation and storage opportunities presented by hydropower technologies. This section will also define the hydropower resource representation in ReEDS and help to inform interpretations of ReEDS scenario results in Section 3.4.

3.2.1 Defining Resource Potential

The opportunities for developing new hydropower resources are varied and have been studied at multiple levels of detail. To understand how differences in these studies ultimately influence hydropower modeling in ReEDS, it is useful to understand a few basic distinctions between different types of energy potential estimates:

- **Physical Potential** is the amount of power or energy recoverable for a given resource. For solar, this quantity might be regional or global insulation; for hydropower, it consists of the average physical energy moving through a river system (i.e., flow multiplied by elevation change).
- **Technical Potential** is the "achievable energy generation of a particular technology given system performance, topographic limitations, environmental, and land-use constraints" [9]. In practice, this quantity reflects energy generation and power output based on the limits of current commercial technologies.
- **Modeled Potential** in the context of the *Hydropower Vision* analysis is the subset of technical potential made available to the ReEDS model. Practical and economic reasons discussed later in this section motivate removal of some hydropower technical potential for ReEDS modeling to better characterize hydropower deployment opportunities within the modeling framework.
- **Market Potential** is the amount of a technology competitively deployed under specific market conditions. The use of the ReEDS model to simulate deployment outcomes produces a range of estimates for market potential.

Most existing hydropower resource estimates assess technical potential, although variations in the assumptions underlying these estimates can produce large differences in the results.

3.2.2 Challenges in Modeling of New Hydropower Resources

Analysis presented in Chapter 3 draws from the best available technical resource potential assessments and assumptions in order to construct a modeled representation of hydropower resources that are useful for exploring market potential in ReEDS. This modeled resource builds upon the methodologies and data from these technical resource estimates with some minor updates and revised assumptions. In its existing construction, the modeled resource is intended to be a conservative interpretation of hydropower's technical potential, meaning that the modeled potential in ReEDS is lower for all hydropower resource categories than the technical potential described subsequently and in Chapter 2 of the *Hydropower Vision*. The differences between technical and modeled potential are described here.

Increased Modeling Resolution to Identify Economically Competitive Hydropower. Existing technical potential estimates of NPD and NSD are built from site-specific resource estimates at more than 53,000 existing dams [13] and nearly 230,000 stream-reaches [14], respectively. However, the ReEDS model requires hydropower resources to be aggregated to its 134 BAs. To facilitate this aggregation, the modeled NPD resource only includes projects greater than 500 kilowatts (kW), and the modeled NSD resource only includes projects greater than 1 megawatts (MW). This simplification allows a more accurate identification of economic resources for application within the competitive framework in ReEDS. This is because smaller facilities are by construction the most expensive resources in the hydropower supply curve and, as such, are uneconomical to deploy in the model under most conditions.

These project size thresholds effectively remove 0.5 GW of NPD and many of the 53,000 existing dams, as well as over 20 GW of NSD and approximately 220,000 reaches, from the technical potential estimates to arrive at the modeled resource. The final NPD modeled resource contains 5 GW from 671 dams, while the final modeled NSD resource contains 30.7 GW from nearly 8,000 reaches. So while hundreds of thousands of potential projects have been removed, thousands of the most economic projects remain. The intent is not to dismiss the potential from responsible hydropower projects below these size thresholds, but instead to allow the ReEDS model to more easily identify economically competitive hydropower capacity. While these reductions can be significant, no *Hydropower Vision* modeling scenario deploys 100% of either NPD or NSD resource, so removing this resource improves modeled resolution for lower-cost hydropower without eliminating opportunities that would otherwise deploy in ReEDS.

Lack of Site-Specific Data. Estimates of NPD and NSD resource have benefited from rigorous DOE-sponsored resource assessments [13, 14]. Other resources though, including PSH, canals and conduits, and the potential for upgrading and expanding the existing fleet lack similarly comprehensive and site-specific resource estimates that could be used in ReEDS. The *Hydropower Vision* analysis includes approaches for estimating PSH and upgrade potential in order to illustrate the impacts of key levers. More technical potential (than is modeled) may exist in both cases, but any additional potential has not been sufficiently quantified to date. The limited data available on canal and conduit resource potential prohibits an explicit modeling representation. These projects are still considered to be an important component of future growth in the hydropower industry, however, and many of the modeling conclusions drawn from NPD and NSD can be instructive for maximizing the use of the nation's existing water supply infrastructure.

3.2.3 Model Representation: Existing Hydropower Fleet

The ReEDS model uses net summer capacity (versus full rated capacity) in order to better characterize electric sector resource adequacy requirements, so the modeled hydropower generation capacity of 76 GW and PSH capacity of 22 GW is slightly lower than referenced in Chapter 2 of the *Hydropower Vision*. Notwithstanding this technicality, the total amount of generation from existing hydropower is consistent with that described in Section 2.1. With the exception of announced upgrades, expansion opportunities, and 200 MW of announced plant retirements (through 2018), there are no changes to the existing fleet represented in ReEDS into the future.

While ReEDS maintains a largely static representation of the existing fleet, in practice many future uncertainties may alter the contributions it makes to nation's power grid. In particular, as projects undergo relicensing, they may be subject to new operating conditions that could affect future generation and capacity levels. In addition, some existing facilities may face conditions including minimum flow requirements and ramp rate restrictions that might further impact the future contributions of the existing hydropower fleet. While these possibilities are not reflected in the model, they are important to the discussion of the *Hydropower Vision* for the existing fleet.

3.2.4 Model Resource: Existing Fleet Upgrade Potential

The potential to upgrade or expand the existing hydropower fleet is the most difficult of the hydropower resources to quantify, as there are many different types of opportunities at existing facility sites. Individual units can be upgraded via the refurbishment or replacement of turbines and generators, while modifications to the water conveyance system could increase generation efficiency, and modified impoundment structures could be raised to increase plant hydraulic head. The capacity at existing plants could also be expanded through the addition of new generators in existing or new powerhouses. Optimized dispatch of units at a plant, and the coordination of plants within a system, can also increase

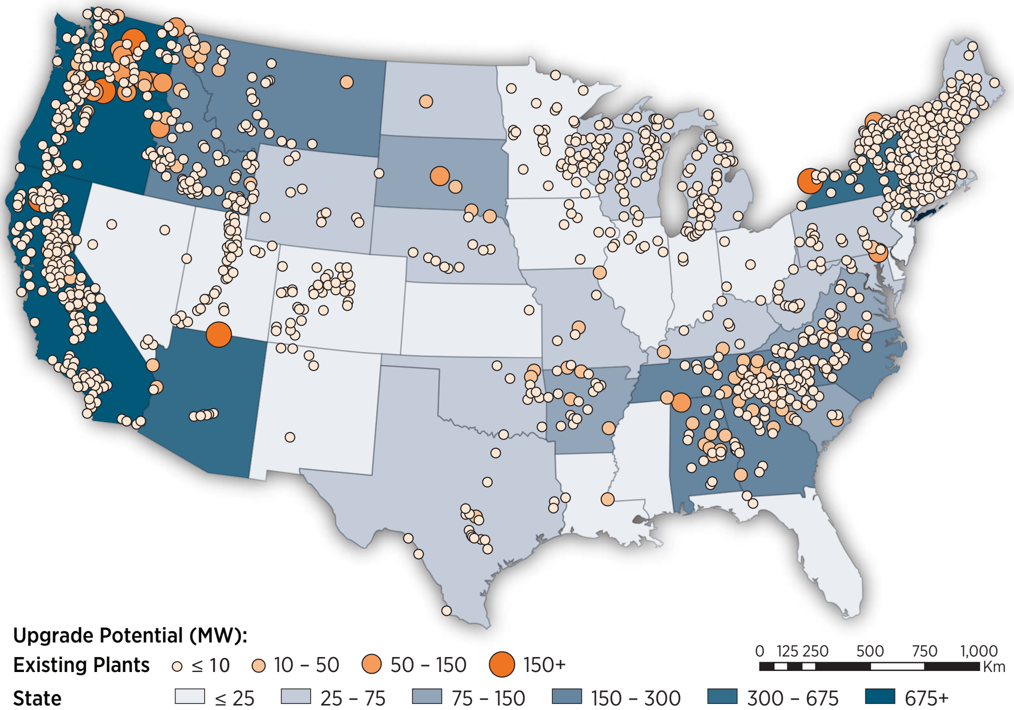


Figure 3-1. Modeled upgrade potential at the state- and plant-level

generation from the same amount of water without any physical modification to a plant. No efforts have fully documented the potential to optimize the existing 100 GW of hydropower assets in the United States. Limited case studies have shown that in-plant upgrade opportunities may increase generation on average by 8–10% [10, 11]. The National Academy of Sciences believes that untapped generation increases from upgrades and rehabilitation at U.S. Army Corps of Engineers (Corps) facilities could be at least 20% [12]. This latter estimate suggests that upgrade potential may be much higher than suggested by case studies completed as of 2015.

Given ReEDS model limitations, upgrade and expansion potential is modeled generically as a capacity increase with the equivalent capacity factor of the existing facility. In total, upgrade resource potential at 1,799 plants comprises 6,856 MW of potential (Figure 3-1), resulting in the potential opportunity to grow the existing fleet by about 9%. Additional details about the upgrade resource assessment employed in this analysis can be found in Appendix B.

3.2.5 Model Resource: Powering Non-Powered Dams

The powering of existing dams that previously lacked generation capabilities, or NPD, represents another way to expand hydropower production while making use of existing waterway infrastructure. Contemporary high-resolution resource assessments covering the continental United States have found technical potential for 12 GW of new capacity on NPDs [13]). Limited NPD potential exists in Alaska and Hawaii; however, no studies have been done to systematically quantify the opportunity.

The NPD resource included in the ReEDS analysis is a refinement of the 12 GW of technical potential described by Hadjerioua et. al [13]. In addition to minor corrections that were made to adjust resource potential for dams slated for removal or with powerhouses under construction, the modeled resource

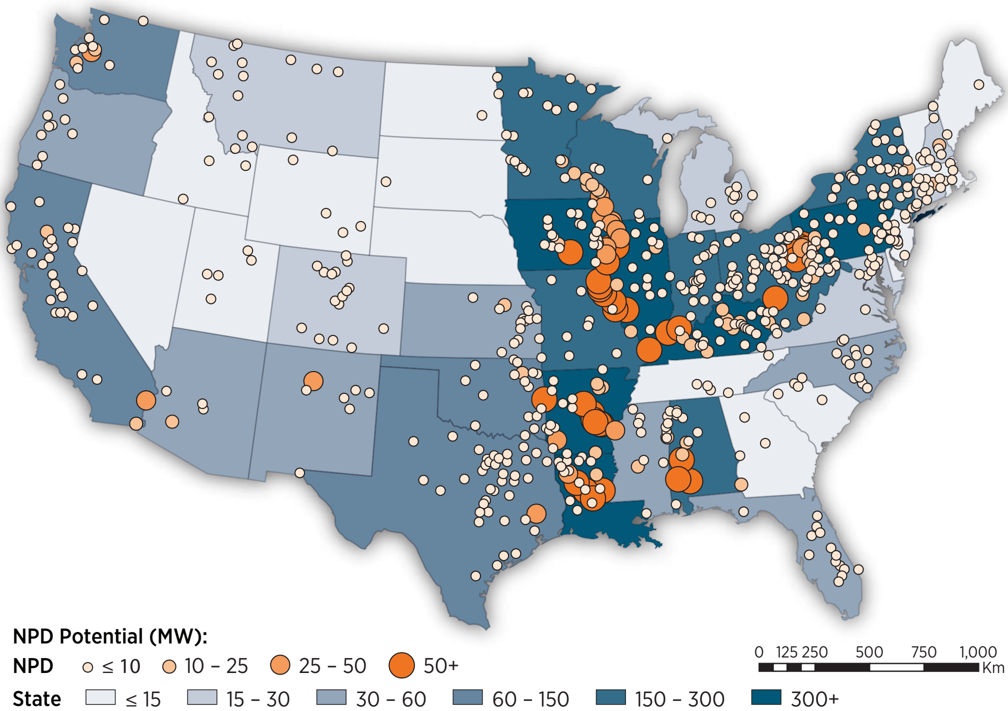


Figure 3-2. State- and project-level distribution of modeled non-powered dams potential

entails a significant change in the assumptions used to estimate individual NPD potential. Specifically, the power and generation potential of the NPD resource has been revised to be consistent with the methodological advances made between the publication of the original resource assessment in 2012 [13], and an NSD resource assessment completed in 2014 [14]. Applying the economic sizing methodology developed for NSD by Kao et. al [14] more accurately reflects the size of modern real-world NPD projects, improves the modeled economics[8] of the NPD projects to make them more competitive in ReEDS, and allows for full comparability between the NSD and NPD resource estimates. This change, however, reduces resource potential by more than 50%, down to 5.6 GW.

Additionally, a minimum facility size of 500 kW reduces the total modeled NPD potential to 5 GW at 671 facilities (down from more than 50,000), with an energy potential of 29 terrawatt-hours (TWh) per year. These filters on NPD resource do not reflect a belief in absolute limitations in NPD deployment; rather, they are targeted towards identifying the most economic resources for application within the competitive framework in ReEDS. Even in scenarios with the largest growth in NPDs, dozens of small projects with challenging economics remain unutilized within the modeled 5 GW.

The resulting resource is mapped in Figure 3-2.[9] NPD resource is located primarily along major rivers across the Midwest and South, at sites that are often lock-and-dam infrastructure. Appendix B includes additional discussion of NPD resource estimates.

8. In the revised NPD resource, project capacities decline. These lower capacities, however, improve overall economics through increases in capacity factor that more accurately reflect common run-of-river-style developments.

9. NPD resource includes 393 MW across 20 NPD projects are either already under construction as of 2015, or that have been approved and are in the near-term pipeline for development. These projects are assumed to be deployed in every *Hydropower Vision* scenario. These include: B. Everett Jordan Hydro Project (NC), Bowersock Mills (KS), Cannelton, Dorena Lake (IN), Lower St. Anthony Falls Hydroelectric Project (MN), Meldahl (OH), Red Rock (IA), Robert V Trout Hydropower Plant (CO), Smithland (KY), Turnbull Drop (MT), and Willow Island (WV).

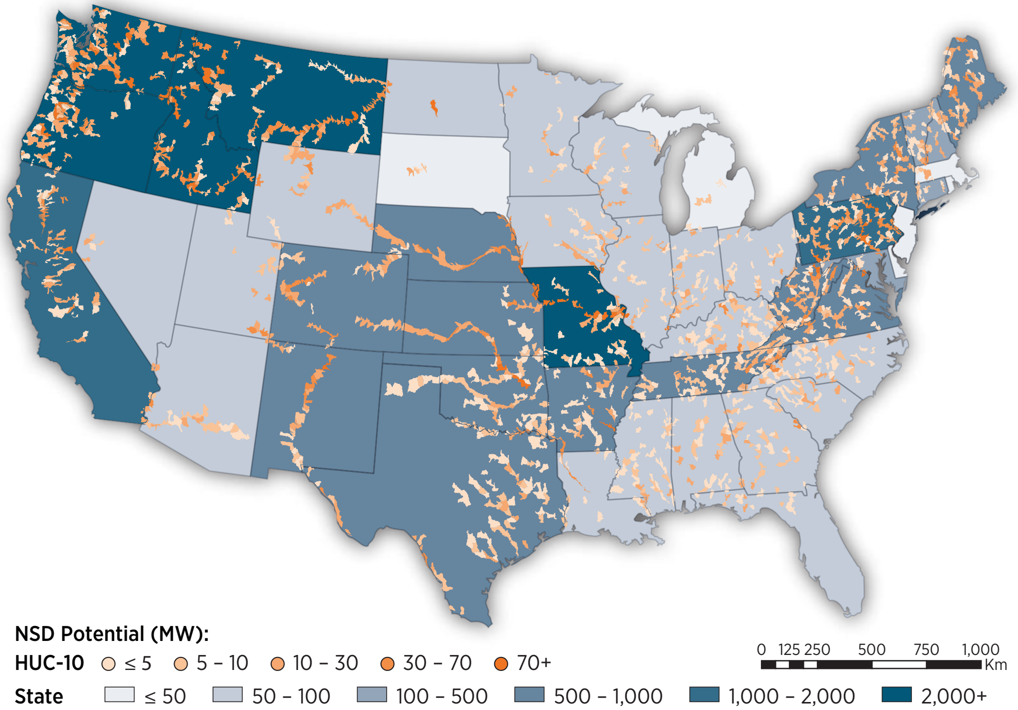


Figure 3-3. Distribution of new stream-reach development resource potential at the state and watershed level

3.2.6 Model Resource: New Stream-Reach Development

The largest source of potential new hydropower capacity comes from the development of new projects on undeveloped stream-reaches; however, NSD is also the most costly and potentially environmentally challenging class of hydropower potential due to the need for new impoundment structure construction. A 2014 DOE resource assessment [13] identified 66 GW of NSD potential and forms the basis of the resource estimates used in the modeling work detailed here. NSD resource estimates are framed by the need to minimize disruption to ecosystems. As such, the assumption is that impoundment area is minimized and NSD would generally operate as "run-of-river" with limited water storage capacity so they do not disrupt natural flows. As a result, NSD is presumed less flexible than much of the existing hydropower fleet. Data limitations prevented the extension of these systematic assessment efforts beyond the continental United States to Alaska and Hawaii. However, Kao et al. [14] consolidated existing NSD project inventories to generate a lower bound technical potential estimate of 4.7 GW in Alaska and 145 MW in Hawaii.

For modeling in ReEDS, base resource estimates are adjusted to reflect corrections to the original resource assessment (noted previously) and to limit the modeling of NSD to those projects with a power potential of 1 MW or more. The latter helps the ReEDS model more accurately identify economically competitive NSD potential by reducing the number of reaches under model consideration to those with the lowest development costs and representing high resolution for those resources. The resulting modeled NSD resource has 30.7 GW capacity and 176 TWh of energy production potential at less than 8,000 sites. While this number is lower than the original estimate of 66 GW at more than 200,000 reaches, it is important to note that there are no *Hydropower Vision* scenarios that approach the full deployment of all 30.7 GW of modeled NSD resource. Many of the projects that are not deployed—and those that are not modeled—are small projects with high costs that are not competitive under the scenarios explored in this analysis.

The NSD potential is mapped in Figure 3-3 at the watershed level, due to the uncertainties inherent in estimating NSD resource. See Appendix B for more detail on NSD resource assumptions.

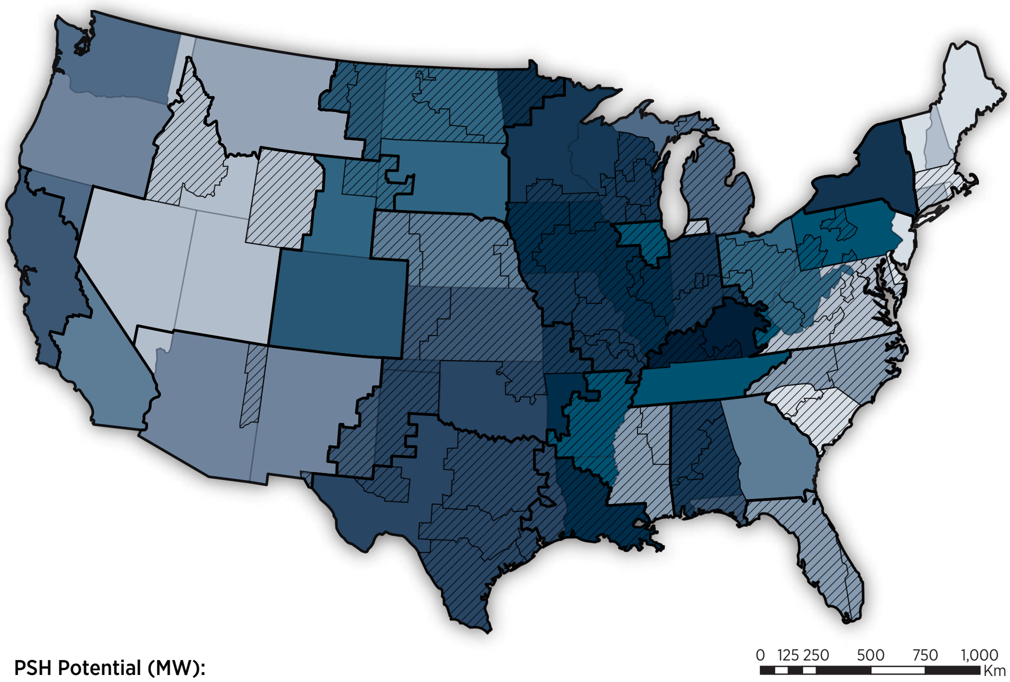


Figure 3-4. North American Electric Reliability Corporation regional-level pumped storage hydropower resource potential

3.2.7 Model Resource: Pumped Storage Hydropower

No national resource assessment exists for PSH, and the variety of possible plant configurations and designs makes it difficult to characterize PSH resources. “Open-loop” systems can be installed at existing dams or new reservoirs along existing waterways, while “closed-loop” configurations disconnect both reservoirs from natural waterbodies. Closed-loop configurations are possible in any location with sufficient elevation change, making PSH construction theoretically possible in most geographic regions. In this context, historical studies of PSH have found potential in excess of 1,000 GW based on physical geography [15]. The potential for new closed-loop concepts using existing “brownfield” sites, such as abandoned mines, has not been quantified.

This modeling analysis uses historical proposed development as a lower bound for resource availability by examining all PSH projects proposed to the Federal Energy Regulatory Commission (FERC) since 1980.

This exercise produces 108.7 GW of PSH potential across 166 sites. This approach reflects only a subset of potential PSH projects, however, as some hydropower owners and developers either do not need FERC authorization to pursue projects (Corps, Reclamation, Tennessee Valley Authority), or have potential PSH projects defined but have not yet sought to secure development rights via the regulatory process.

To avoid overly constraining PSH potential in regions without previously proposed projects, every ReEDS balancing area is also allowed to deploy one “artificial” 750 MW closed-loop PSH project, adding another 100 GW to the total resource base. This example size was selected because 750 MW is an approximate average of the capacity of PSH projects proposed in the decade leading up to the *Hydropower Vision*. Figure 3-4 illustrates the distribution of the resource derived from FERC permit applications. Given the uncertainty in the PSH resource, the available supply and deployment results are shown in aggregate, based on

Table 3-1. Hydropower Resource Potential Capacity and Energy Statistics

	Upgrade	NPD	NSD	PSH[a]
Total Capacity (MW)	6,856	5,047	30,669	108,742
Potential Project Sites	1,799	671	7,977	166
Average Capacity (MW)	3.9	7.6	3.8	655
Median Capacity (MW)	0.4	1.6	1.9	600
Minimum Capacity (MW)	0.00006	0.5	1.0	5.0
Maximum Capacity (MW)	394	192	357	2,000
Energy Production Potential (TWh)	27	28	176	n/a

Note: Announced projects scheduled to come online by 2018 are not included in these statistics.
a. PSH data detailed here are derived from resource potential reflected in FERC preliminary permit applications.

sub-regions defined by the North American Electric Reliability Corporation. Balancing areas with only artificial resource available are shaded with diagonal lines. Appendix B contains additional information on PSH resources.

3.2.8 Model Resource Potential Summary

Table 3-1 summarizes key characteristics of hydropower resources modeled in ReEDS.

3.3 Hydropower Modeling Economics and Scenarios

The hydropower resource data described in the previous section are crucial to quantifying the range of hydropower market potential in the *Hydropower Vision* analysis. In addition to the resource data, however, market potential analysis requires characterization of existing and future hydropower costs. Potential climate change impacts on water availability and environmental siting considerations must also be considered. The subsequent sections describe how each of these facets is addressed in this modeling analysis.

3.3.1 Hydropower Costs and Cost Projections

Each of the hydropower resources identified in the *Hydropower Vision* has individualized cost dynamics that influence economic competitiveness. In general, the cost of developing and operating a hydropower project is highly site-specific, but the *Hydropower Vision* analysis uses a generalized cost estimation methodology for greater consistency and clarity. Appendix B includes a full accounting of the methods used to derive and assign cost to hydropower resource potential, and Table 3-2 summarizes the results of current cost estimates. All costs are reported in 2015 currency (2015$).

Upgrades are often the lowest-cost hydropower resource, but some small projects such as those with installed capacities of only a few hundred kilowatts are estimated to be costly. NPD typically has intermediate costs, while NSD is the most expensive hydropower generation resource on average. PSH capacity costs span a narrower range due to strong economies of scale with capacity. Artificial PSH resource is

Table 3-2. Summary of Modeled Hydropower Initial Capital Cost

Resource	Minimum Cost ($/kW)	Average Cost ($/kW)	Maximum Cost ($/kW)
Upgrades	800	1,500	20,000
Non-Powered Dams	2,750	5,800 (low head) 4,200 (high head)	9,000
New Stream-reach Development	5,200	7,000 (low head) 6,000 (high head)	15,600
Pumped Storage Hydropower	1,750	2,700	4,500

Note: the threshold for low- vs. high-head NPD and NSD is 30 feet.

costed conservatively at $3,500/kW. Figure 3-5 illustrates the full range of existing capital costs across hydropower resources modeled in Chapter 3. Fixed operations and maintenance (O&M) costs also exhibit economies of scale. The smallest NPD resource costs $180/kW per year, while larger plants, including the nation's largest hydropower plant, Grand Coulee, costs $4.2/kW per year.

The *Hydropower Vision* employed literature review and expert stakeholder input to develop three potential future cost trajectories to understand how these initial cost assumptions might evolve across the study period for NSD, high- and low-head NPD, and PSH. The costs of operating, maintaining, and upgrading the existing fleet are constant in all three scenarios. Table 3-3 summarizes the characteristics of each cost trajectory.

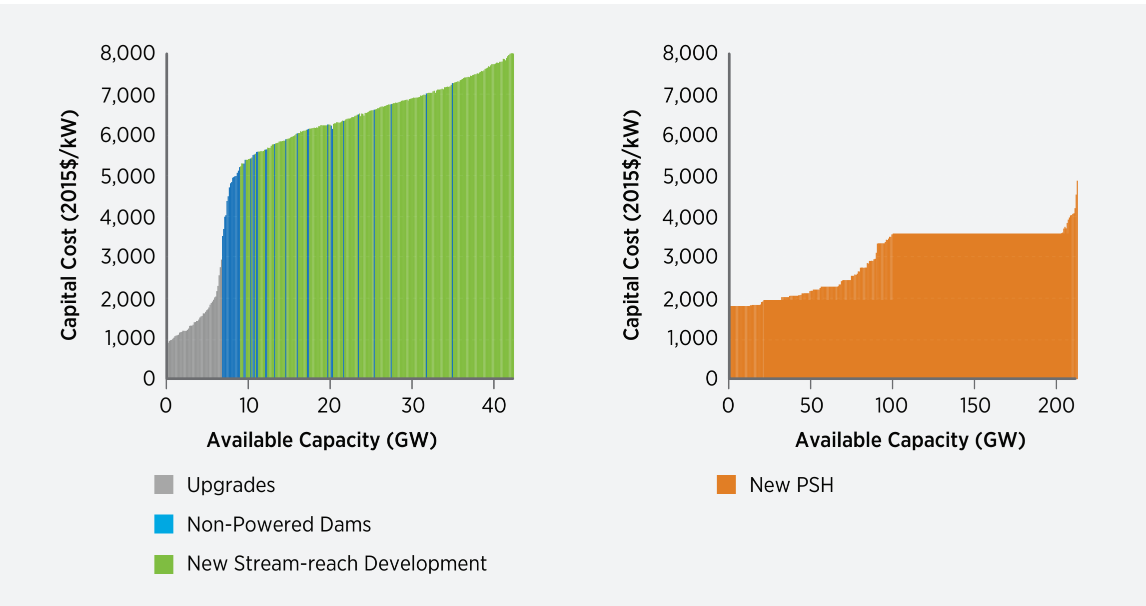


Figure 3-5. Capital cost of hydropower resources (y-axis truncated above $8,000/kW)

Table 3-3. *Hydropower Vision* Analysis Cost Reduction Scenarios (Change From Initial Costs)

Capital Cost	*Business-as-Usual* (relative to 2015)		*Evolutionary Technology* (relative to 2015)		*Advanced Technology* (relative to 2015)	
	2035	2050	2035	2050	2035	2050
NSD	5%	9%	15%	18%	30%	35%
Low-Head NPD			15%	18%	30%	35%
High-Head NPD			10%	13%	25%	33%
PSH			7%	11%	12%	15%
Upgrades	None		None		None	
Fixed O&M Cost						
NPD and NSD	None		25%	28%	50%	54%
Other Types			None		None	

- The *Business-as-Usual* cost conditions assume a low, learning-based capital cost reduction consistent with the EIA Annual Energy Outlook for NPD, NSD, and PSH. All O&M costs and capital costs for all other hydropower types remain constant under central assumptions.
- The *Evolutionary Technology* assumptions envision a world in which NSD and NPD development is increasingly standardized, while automation and dissemination of best practices reduce the O&M costs for these new projects. PSH capital costs also experience modest cost reductions based on continued process, contracting, design, and technological improvements within the conventional hydropower and dam construction industries.
- The *Advanced Technology* assumptions are based on major technology advances in NPD and NSD from modularity and advanced manufacturing. These advances further drive down capital costs for these hydropower resources. NPD and NSD O&M costs are significantly reduced through modularity and design for reduced O&M, in conjunction with smart, data-driven monitoring and maintenance planning. PSH achieves slightly greater cost reductions with *Advanced Technology* assumptions than under *Evolutionary Technology* by using new technologies (e.g., penstock materials) and leveraging advancements in other, non-hydropower construction industries including oil and gas.

3.3.2 Financing Treatment

ReEDS standard financing assumptions include an 8% nominal discount rate and 20-year valuation, implying a 20-year economic life. Typically, these assumptions are applied to all technologies. It is common for hydropower projects, however, to have a feasible lifetime of 30, 50, or even 100 years. To accommodate the difference in hydropower asset life relative to wind, solar, or natural gas plants, an alternative asset valuation treatment is defined for hydropower and denoted as *Low Cost Finance*.

Low Cost Finance represents an investment environment where the long physical life and stable revenue stream of hydropower is more highly valued during project financing and decision making than is historically typical in the industry. Thorough examination of alternative financing conditions resulted in these input conditions being defined as an effective 40% reduction in the cost of capital. This reduction reflects real-world financing conditions seen when developers and investors, both in the private and public sectors (e.g., municipal or utility districts), value the long life of hydropower assets. Whereas alternate cost trajectories phase in through time and vary across hydropower types, the *Low Cost Finance* assumption is applied immediately to all ReEDS solve years and hydropower technologies. Appendix B details the conditions surrounding the improved asset valuation assumptions.

3.3.3 Scenarios of Water Availability in a Changing Climate

Future water availability trends driven by climate change have the potential to alter the economic attractiveness of hydropower projects by changing the nature of the "fuel" needed by hydropower plants. Total annual water availability could change due to overall changes to hydro-meteorological variables, and the temporal distribution of water availability within a year could change. A prime example of this is earlier snowmelt from higher temperatures leading to earlier reservoir filling [16, 17].

The *Hydropower Vision* analysis examines two alternative water availability futures—one in which the United States on average becomes dryer (that is, less runoff) through 2050, and one in which it becomes wetter. Figure 3-6 illustrates, in terms of runoff, the magnitude and regional nature of changes in annual and summer water availability under *Wet* and *Dry* conditions scenarios. Other seasonal changes are detailed in Appendix B along with further description of scenario development. At a national scale, *Wet* conditions exhibit an 11% increase in runoff in 2030 and a 22% increase in 2050. The *Dry* conditions scenario envisions an average reduction in water availability of 4% in 2030 and 8% in 2050. However, regional and seasonal variations are apparent and can influence the characteristics of hydropower deployment examined within the *Hydropower Vision* analysis.

These scenarios do not resolve the complex relationship within the existing storage fleet between water storage capabilities, competing uses, and generation capability. Addressing these important interdependencies to model the seasonal and annual impacts of climate change on the existing fleet would require additional research.

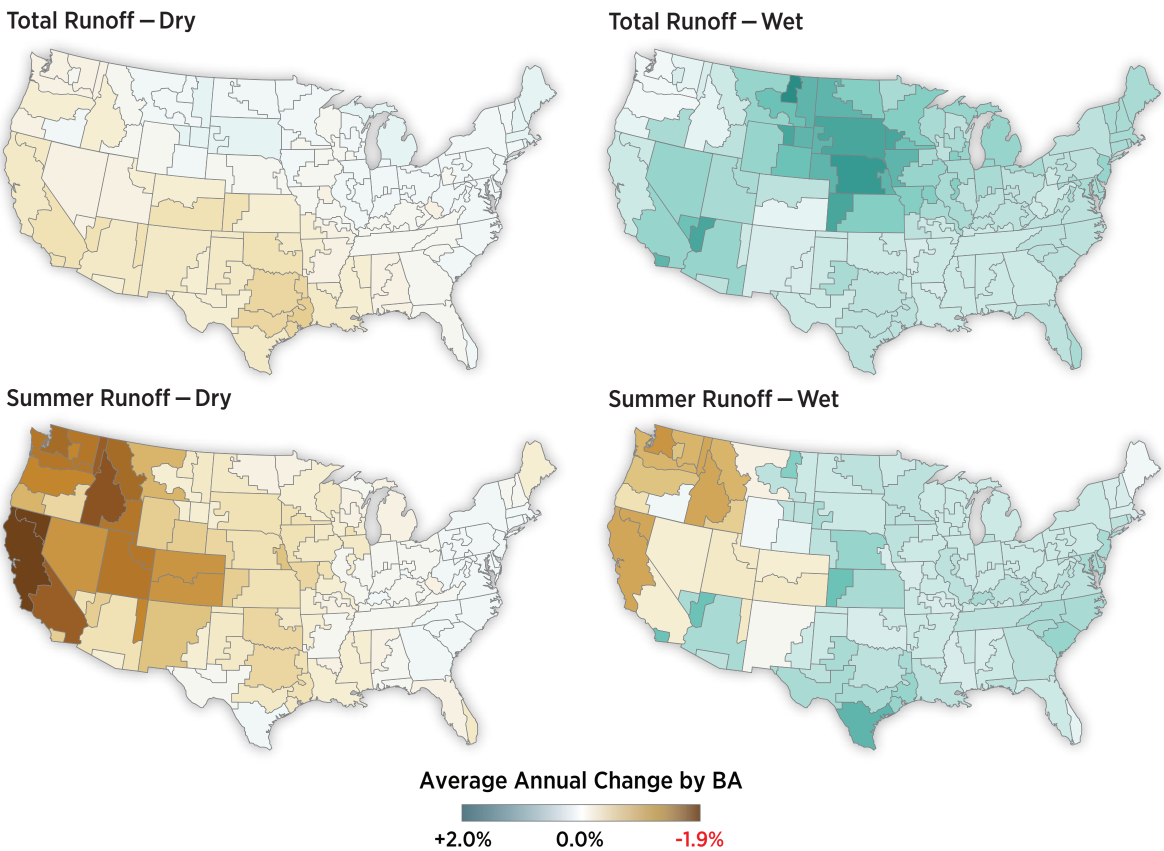


Figure 3-6. Average annual and summer seasonal change in total runoff

3.3.4 Hydropower Environmental Considerations

The ReEDS model identifies economically favorable hydropower development under multiple constraints and assumptions; however, the framework does not directly include hydropower environmental considerations, which can be particularly influential for NSD resources. To examine the influence of environmental attributes on NSD development and provide better context for the future of the hydropower industry, the modeling analysis in the *Hydropower Vision* employs a series of sensitivity scenarios. These scenarios explore how NSD deployment intersects with other existing priority uses of the nation's water resources, such as providing habitat for valued species.

In these scenarios, hydropower technologies must compete against all other electric sector technologies but deployment of NSD that overlaps a specific consideration or combination of considerations is avoided. The intent of these scenarios is not to assert that hydropower development in these areas is not possible. Instead, these scenarios help illustrate that achieving NSD growth must include accommodating and complementing the many other values of rivers. They also demonstrate the opportunity for addressing environmental considerations through innovation, when deployment results are compared to scenarios that do not explicitly avoid regions overlapping environmental considerations.

The following environmental considerations are implemented as sensitivity scenarios in the *Hydropower Vision* analysis. Datasets used in the environmental considerations analysis and the details of their geospatial implementation are described more thoroughly in Appendix B. Two example maps of environmental attributes are shown in Figure 3-7.

1. **Critical Habitat**: NSD is avoided in ecologically sensitive areas, as defined by their designation as critical habitat. The data for this consideration were provided by the U.S. Fish and Wildlife Service and are also inclusive of species managed by other U.S. agencies.
2. **Ocean Connectivity**: NSD is avoided at locations that would disturb existing river connectivity to the ocean. Connectivity in this context is extended to reaches on which data for artificial downstream passage exist, either through explicit passage technology or implicitly through navigation locks. This layer was developed uniquely for the *Hydropower Vision* analysis.
3. **Migratory Fish Habitat**: NSD is avoided on reaches in which potamodromous and diadromous fish species are likely to be present, based on ocean connectivity and/or reach characteristics such as length and average annual flow rates. This layer was developed uniquely for the Hydropower Vision analysis.
4. **Species of Concern**: NSD is avoided on reaches where aquatic species (fish, mussels, and crayfish) of concern are known to exist. This includes those listed under the Endangered Species Act (endangered, threatened, a candidate for listing, proposed for listing, or of concern), or as "near threatened," "vulnerable," "endangered," or "critically endangered" according to the International Union for Conservation of Nature. This layer was developed uniquely for the *Hydropower Vision* analysis.
5. **Protected Lands**: Areas with formal protections designated as Status 1 or 2 under the U.S. Geological Survey's Gap Analysis Program[10] are avoided for development. Gap Analysis Program 1 and 2 designations cover a variety of areas, ranging from state or local parks to formal conservation areas managed explicitly for species preservation.
6. **National Rivers Inventory**: Development is avoided on potentially high-value river systems, as approximated by placement on the National Rivers Inventory. Note that hydropower potential located along designated Wild and Scenic Rivers is already excluded in the base *Hydropower Vision* supply curves because of statutory limitations.

10. The Gap Analysis Program is an effort to catalogue and spatially document lands afforded formal protection designations by federal, state, local, and private owners.

7. **Low Disturbance Rivers**: NSD is avoided on stream-reaches that are minimally altered from their natural state as approximated by categorization of low or very low levels of disturbance, as measured by the National Fish Habitat Action Plan.
8. **Combined Considerations**: Three scenarios explore the combined influence of multiple environmental considerations (as detailed in 1–7). *Combined Species Concerns* includes items 1–4, *Combined Sensitive Lands* includes items 5–7, and *Combined Environmental Considerations* includes all seven considerations. *Combined Environmental Considerations* particularly illustrates that accommodating the wide variety of use values of reaches with NSD potential is essential for realizing growth.

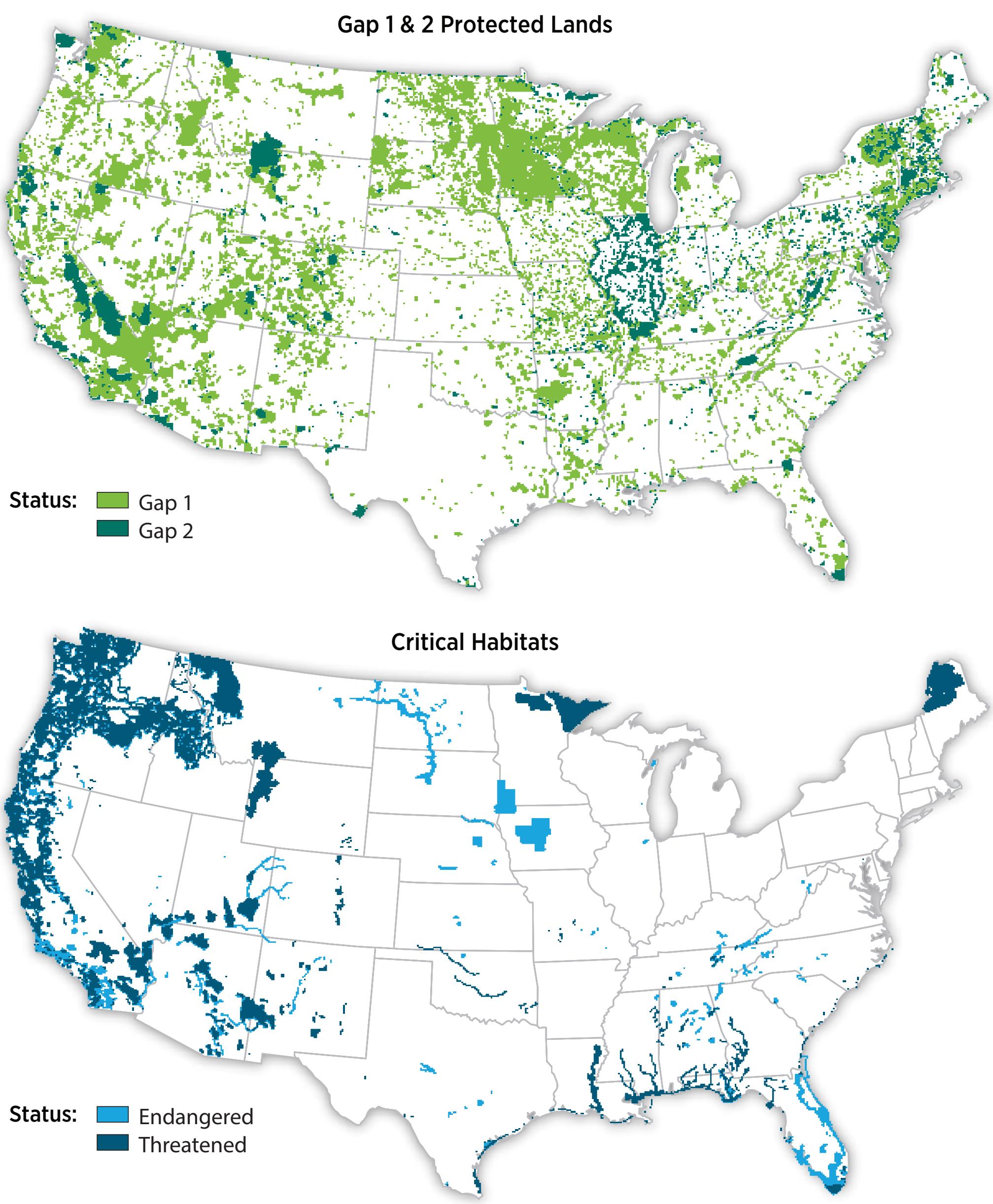


Figure 3-7. Spatial distribution of two selected environmental considerations

3.3.5 *Hydropower Vision* Analysis Scenario Framework

The assumptions described previously and in Appendix D are used in varying combinations within the *Hydropower Vision* analysis to develop a suite of modeling scenarios that documents the range of market opportunities for hydropower deployment and the resulting impacts. As a reference for subsequent sections, Tables 3-4 and 3-5 summarize assumptions that are constant across all scenarios and those that are varied across scenarios. The *Hydropower Vision* analysis is intended to demonstrate a wide range of hydropower futures and how these futures could be affected by key factors of relevance to the hydropower industry. Alternative policy options for hydropower or other technologies are not included in the scenario analysis. While energy policy is important to the future of hydropower and the electric sector as a whole, policy analysis is outside the scope of the *Hydropower Vision*.

Table 3-4. Constants across Modeled Scenarios

Input Type	Input Description
Electricity demand	AEO 2015 Reference Case (average annual electricity demand growth rate of 0.7%)
Fossil technology and nuclear power	AEO 2015 Reference Case
Non-hydro/wind/solar photovoltaics renewable power costs	NREL Annual Technology Baseline 2015 Mid-Case Projections
Policy	As legislated and effective on December 31, 2015.[a]
Transmission expansion	Pre-2020 expansion limited to planned lines; post-2020, economic expansion, based on transmission line costs from Eastern Interconnection Planning Collaborative

Note: Appendix D describes the non-hydropower technology and other assumptions noted here in additional detail. "AEO" refers to the U.S. Energy Information Administration's Annual Energy Outlook (i.e., EIA [18])

a. Despite the Supreme Court stay of the Clean Power Plan (CPP), the CPP is treated as law in all scenarios and is thus assumed active. The CPP is modeled using mass-based goals for all states with national trading of allowances available. Though states can ultimately choose rate- or mass-based compliance and will not necessarily trade with all other states, a nationally traded mass-based compliance mechanism is viewed as a reasonable reference case for the purpose of exploring hydropower deployment under a range of electricity system scenarios. Scenarios and implications resulting from excluding the CPP are discussed in Appendix F.

Table 3-5. Summary of Sensitivity Scenario Data Variations

Sensitivity Scenario Variation	Description	Input Data Changes
High and Low Fossil Fuel Cost	These scenarios examine the sensitivity of results to changes in fossil fuel costs.	Fossil fuel costs: High Cost uses AEO 2015 High Coal Cost Case and AEO 2014 Low Oil and Gas Resource Case; Low Cost uses AEO 2015 Low Coal Cost Case and AEO 2015 High Oil and Gas Resource Case (see Appendix D, for further detail)
High and Low Variable Generator Cost	These scenarios examine the sensitivity of results to changes in variable generator (wind and solar photovoltaics (PV)) costs.	Wind/Solar costs: NREL ATB[a] High/Low-Case Projections for wind. Utility PV reaching the DOE 62.5% reduction scenario in 2020 and remaining constant thereafter (high cost) or reaching the DOE 75% reduction scenario by 2020 and remaining constant thereafter (low cost). Distributed rooftop PV following the DOE 50% reduction scenario (high cost) or following the 62.5% reduction scenario to 2020 then the 75% reduction scenario by 2030 (see Appendix D, for further detail)
Evolutionary and Advanced Technology	These scenarios examine the sensitivity of results to changes in hydropower costs.	Hydropower costs/financing: Reference financing, with AEO Mid/Low Cost Reduction Pathways
Low Cost Finance	These scenarios examine the sensitivity of results to changes in hydropower asset valuation.	Hydropower costs/financing: Reference costs, with long-term asset valuation providing an approximate 40% reduction in the cost of capital
Dry and Wet scenarios of Water Availability	These scenarios examine the sensitivity of results to changes in water availability for hydropower.[b]	Hydropower resource: Hydropower water availability adjusted over time, based on prevailing wet/dry conditions
Environmental Attribute Scenarios: 1. Critical Habitat 2. Ocean Connectivity 3. Migratory Fish Habitat 4. Species of Concern 5. Protected Lands 6. National Rivers Inventory 7. Low Disturbance Rivers 8. Combined Sensitive Lands (5–7) 9. Combined Species Concerns (1–4) 10. Combined Environmental Consideration (all) (1-7)	These scenarios examine the sensitivity of results to hydropower NSD resource avoidance in areas with certain environmental attributes. Resource avoidance highlights opportunities for environmental mitigation activities.	Hydropower resource: Portions of resource excluded based on the indicated environmental attributes

Note: For the purposes of electric sector modeling described in this chapter, variable generators are defined as wind and solar photovoltaic generators, based on their variable resource characteristics. While solar thermal technology without thermal storage is also included in the ReEDS model as variable generation, economically built CSP in ReEDS uses thermal storage that allows dispatchability. The primary purpose of the High and Low Variable Generator Cost scenarios is examining the relationship between hydropower and variable generation, so costs of CSP systems with storage are not varied in these scenarios.

a. National Renewable Energy Laboratory's Annual Technology Baseline

b. Water quality is another possible concern. The ReEDS model is not designed to incorporate water quality metrics, which are better analyzed using tools with more spatial and temporal resolution and the ability to model individual power plants and waterways. Though water quality is not explicitly included in the ReEDS model analysis, the range of deployment scenarios is expected to encompass most of the influence water quality concerns might have on long-term hydropower deployment.

3.4 Hydropower Market Potential

More than 50 scenarios were simulated for the *Hydropower Vision* by varying the parameters in Table 3-5 (see Appendix F for results from all scenarios). A full list of those parameters is available in Appendix E. This large suite of scenarios is used to identify the key drivers of future hydropower market potential that are the focus of this chapter. Examining this broad suite of scenarios revealed the following themes.

- Maintaining the existing fleet allows it to provide continued electricity system benefits under a wide range of electric sector futures. All scenarios reflect the optimization pillar of the *Hydropower Vision* with continued operation of all hydropower facilities that are not scheduled to retire, allowing the existing fleet to continue providing energy and maintaining system reliability under a range of fossil fuel or variable generation (VG) cost assumptions.
- Improving hydropower economics is central to the growth pillar of the *Hydropower Vision*. A set of scenarios examines the deployment response to changes in hydropower costs and value. The *Advanced Technology* and *Low Cost Finance* settings are applied individually and in combination to demonstrate the effect of improved economics on the potential for hydropower growth.
- An important factor in the future of the U.S. hydropower industry is environmental sustainability, and any future with hydropower growth must consider the environmental impacts of that growth. Twelve scenarios embed an avoidance of NSD resource potential that overlaps with certain environmental considerations, while incentivizing hydropower deployment with *Advanced Technology* and *Low Cost Finance* assumptions to demonstrate the opportunities from mitigating environmental impacts of new hydropower (environmental attributes are described in Section 3.3 and Table 3-5). Any difference in hydropower deployment between these environmental considerations scenarios and the *Advanced Technology, Low Cost Finance* scenario represents an opportunity to address the relevant environmental considerations through investment in innovation. Upgrades to the existing hydropower generation fleet and new NPD growth are negligibly affected by these scenarios, but PSH deployment can be indirectly affected by reduced NSD growth that corresponds to additional fossil or renewable technology deployment.
- Non-hydropower technology costs are important to the *Hydropower Vision* because they influence the relative competitiveness between hydropower and other technologies in the electricity market. To better understand the relationship between hydropower, fossil fuel, and renewable generation technologies, the *High* and *Low* variants on *Fossil Fuel* and *VG Cost* are applied to several hydropower cost and value combinations. This set of scenarios allows a thorough discussion of potential impacts under a wide range of deployment and electricity market scenarios. Collectively, these scenarios demonstrate a more comprehensive range of hydropower market opportunities than can be described with hydropower-only scenario parameters.

Climate uncertainty and the inter-annual variability of hydropower generation create the need to include sensitivity analysis on hydropower water availability. Defining and studying a comprehensive climate scenario is outside the scope of the *Hydropower Vision*, and ReEDS is unable to provide a stochastic treatment of inter-annual variability. As such, these sensitivity scenarios are limited to representing an average increase or decrease in regional and seasonal hydropower water availability over time. Climate-influenced water availability is examined by combining the *Wet* and *Dry* water availability scenarios with several other combinations of scenario parameters. These scenarios demonstrate the importance of long-term water availability on hydropower industry growth and operation.

From the full suite of scenarios, nine are chosen that collectively support the *Hydropower Vision* pillars of optimization, growth, and sustainability. These nine selected scenarios, listed below, demonstrate the importance to the U.S. hydropower industry of maintaining the existing fleet, reducing technology cost, valuing the long asset life of hydropower facilities, and considering local environmental attributes. Scenarios that avoid NSD resource with certain environmental attributes reveal the opportunities provided by investment in environmental impact mitigation. Scenarios incorporating high fossil fuel costs or low VG costs show the effect of non-hydropower technology costs on hydropower competitiveness in the U.S. electric sector. *Wet* and *Dry* water availability scenario variants are modeled for all nine selected scenarios to show how expected future water availability can influence hydropower deployment. While not inclusive of all possible hydropower industry outcomes, these scenarios provide a wide range of possible pathways for the hydropower industry across many alternative notions of the future U.S. hydropower industry and the electricity market as a whole.

1. **Business-as-Usual:** This scenario uses all reference input parameters to the ReEDS model.
2. **Advanced Technology:** This scenario shows the effect of technology cost reduction on hydropower deployment.
3. **Low Cost Finance:** This scenario shows the effect of long-term asset valuation on hydropower deployment.
4. **Advanced Technology, Low Cost Finance:** This scenario explores the combined impact of technology cost reduction and long-term valuation on hydropower deployment when environmental impacts are assumed to be fully mitigated throughout the NSD resource base and thus are not avoided.
5. **Advanced Technology, Low Cost Finance, Combined Environmental Considerations:** This scenario explores a future with improved hydropower economics where difficulty mitigating environmental impacts leads to avoiding NSD resource overlapping with any of the environmental attributes discussed in Section 3.4.[11]
6. **Advanced Technology, Low Cost Finance, Critical Habitat:** This scenario represents a future with improved hydropower economics and intermediate avoidance of NSD resource with environmental considerations. The *Critical Habitat* attribute is part of this and other scenarios because when combined with *Advanced Technology* and *Low Cost Finance* assumptions, it achieves intermediate NSD deployment levels across the full range of scenarios examined, not because of a perceived importance of critical habitats over other environmental attributes.
7. **Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost:** This scenario explores the influence of a power system that has access to low cost variable renewable power with improved hydropower economics and intermediate avoidance of NSD with environmental considerations. Low-cost VG can compete with hydropower generation (upgrades, NPD, and NSD) while complementing PSH growth.
8. **Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost:** This scenario explores the influence of high fossil fuel costs with improved hydropower economics and intermediate avoidance of NSD with environmental considerations. High fossil fuel costs improve competitiveness of hydropower generation (upgrades, NPD, and NSD) and VG, the latter of which can promote PSH growth.
9. **Advanced Technology, Low Cost Finance, High Fossil Fuel Cost:** This scenario explores an upper bound of hydropower deployment with improved hydropower economics while not avoiding NSD with environmental attributes when high future fossil fuel costs make fossil energy increasingly uncompetitive relative to hydropower and other non-fossil resources.

For some result metrics, four scenarios are chosen from the set of nine as representative low, intermediate, and high hydropower deployment scenarios. This selection primarily serves to improve the conciseness of results presentation while preserving the range of deployment outcomes. *Business-as-Usual* is used as the **low deployment scenario**, *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* is the **high deployment scenario**, and the **two intermediate scenarios** are *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* and *Advanced Technology, Low Cost Finance, Critical Habitat*.

11. As a reminder, the *Combined Environmental Considerations* scenarios avoids NSD resource overlapping with the following: *Critical Habitat, Ocean Connectivity, Migratory Fish Habitat, Species of Concern, Protected Lands, National Rivers Inventory*, and *Low Disturbance Rivers*.

Ultimately, the opportunity for new hydropower as embodied in this suite of scenarios depends on the characteristics of both the hydropower industry and the electricity sector as a whole, at the time of this report and into the future. The remainder of Section 3.4 details the nine selected pathways for hydropower deployment and the national-scale implications of hydropower's role in the U.S. electric sector, before exploring these scenarios more deeply for each hydropower market segment and investigating climate uncertainty. Section 3.5 describes the implications of these scenarios on the rest of the electric sector and examines a subset of the costs and benefits associated with selected scenarios, including electricity system costs, greenhouse gas emissions reductions, air pollution and human health benefits, thermal cooling water usage reduction, and impacts on workforce and economic development.

3.4.1 Potential for Growth: National Capacity and Energy in Selected Analysis Scenarios

This section explores the range of national hydropower capacity and energy deployment over the study period[12] for the nine selected scenarios. Across these scenarios, combined new post-2016 deployment[13] of upgrades, NPD, and NSD falls within ranges of 5–15 GW in 2030 and 5–31 GW in 2050, while new PSH ranges from 0–16 GW in 2030 and 0–55 GW in 2050. Hydropower generation energy production from this new post-2016 capacity (excluding net energy use by PSH) ranges from 17–76 TWh in 2030 and 21–170 TWh in 2050; when added to existing hydropower generation, total generation is 290–350 TWh in 2030 and 290–440 TWh in 2050. The rest of this section describes where each of the nine scenarios fits within those ranges and explores national expansion trends for each hydropower category.

National Capacity Additions

As mentioned in the introduction to this section, capacity growth by 2050 across the nine selected scenarios ranges from 5–31 GW in total for upgrades, NPD, and NSD and from 0–55 GW for PSH. This spectrum of future growth is illustrated in two figures:

- Figure 3-8 plots the cumulative new deployment of hydropower capacity from the combined deployment of upgrades, NPD, and NSD, and that from PSH.
- Figure 3-9 plots the cumulative new deployment of hydropower capacity from upgrades, NPD, and NSD individually.

Many *Hydropower Vision* analysis scenario results are illustrated in this section for the full modeled period of 2017–2050; however, discussion is often focused on the magnitude of hydropower deployment in 2030 and 2050 as representative mid- and long-term milestone years.

***Business-as-Usual* Scenario:** The *Business-as-Usual* scenario provides a valuable reference point for discussing the nine selected scenarios. The *Business-as-Usual* scenario reflects conditions representative of the existing electricity market (e.g. future electricity demand and fossil fuel cost), along with reference or central cost and performance projections for all electricity technologies as modeled in ReEDS. *Business-as-Usual* assumptions motivate the deployment of 5.3 GW new hydropower generation; however, all economically deployed hydropower generation comes from using 76% of modeled upgrade resource potential. Just 500 MW PSH is built in this scenario. Throughout this section and the remainder of Chapter 3, the *Business-As-Usual* scenario is contrasted with numerous scenarios where the *Business-as-Usual* conditions are altered individually or in combination, and their implications for growth in the hydropower industry and the broader evolution of the electric power sector are explored.

12. While the *Hydropower Vision* study period is 2017–2050, the ReEDS model solves from 2010–2050, so many results are presented that include the historical years 2010–2017. Scenario variables only influence the solution in the 2017–2050 time period.

13. Unless otherwise stated, all cumulative quantities are reported in text as post-2016 numbers, though figures might show deployment beginning in 2010. Deployment from 2010–2016 consists of known projects rather than modeled economic growth.

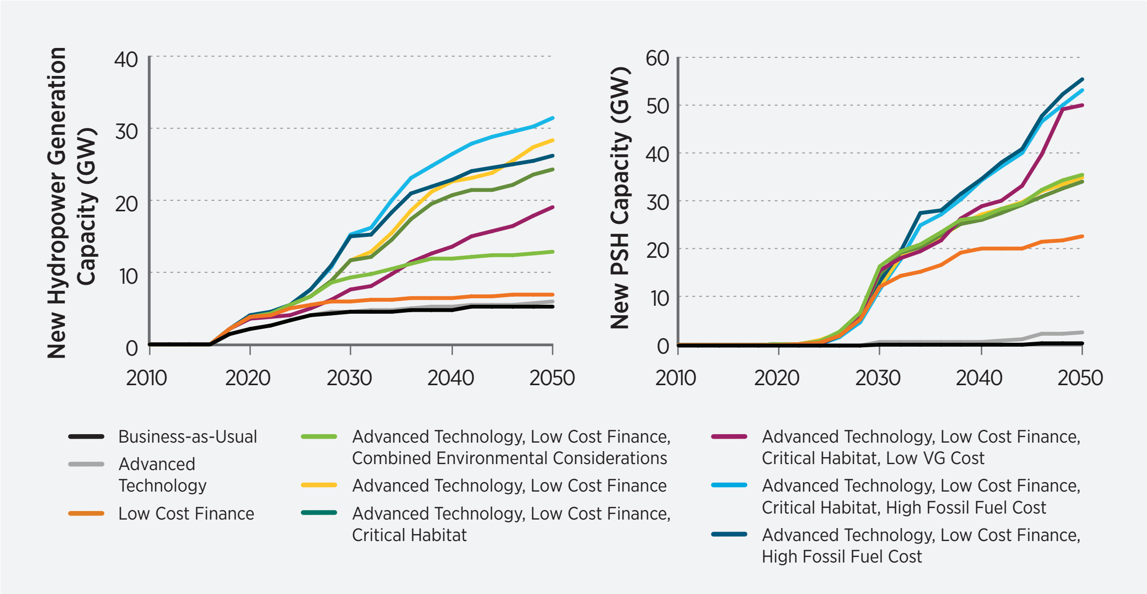


Figure 3-8. Capacity growth of hydropower generation and pumped storage hydropower in select deployment scenarios (each panel uses a unique y-axis)

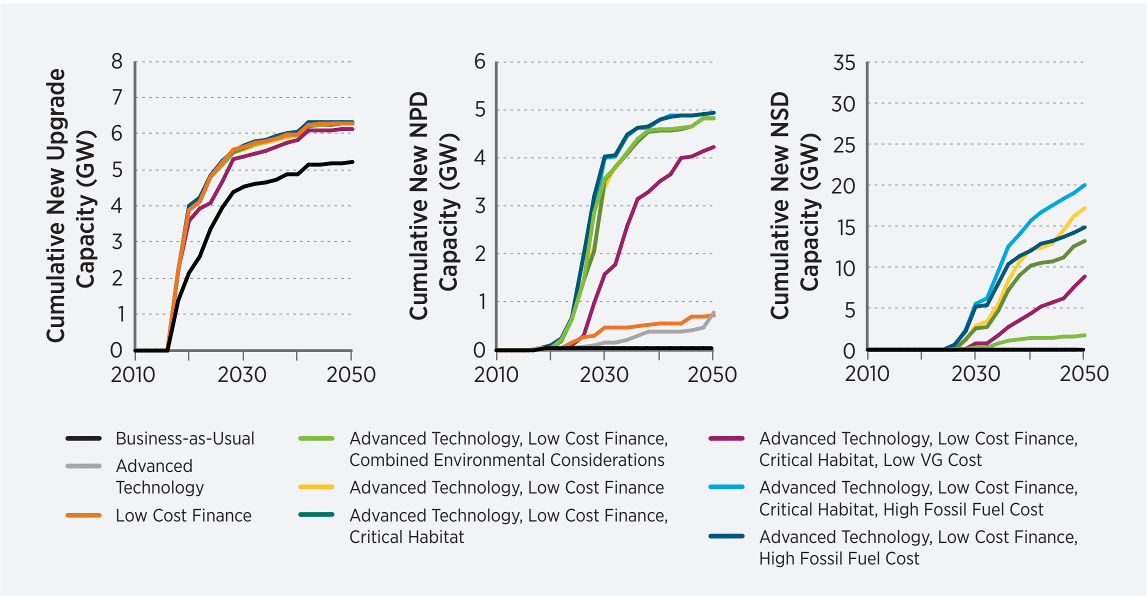


Figure 3-9. Capacity growth of upgrades, NPD, and NSD in select deployment scenarios (each panel uses a unique y-axis)

Hydropower Cost and Financing: Limited growth in the *Business-as-Usual* scenario suggests that existing economic conditions result in relatively little hydropower growth outside of upgrades to the existing fleet, but lower technology costs and long-term asset valuation could create an economic climate suitable for growth in NPD and NSD. The cost reduction pathways for NPD, NSD, and PSH assumed in the *Advanced Technology* scenario do not stimulate substantial hydropower generation growth beyond these upgrades, with only 800 MW of NPD and no NSD deployed through 2050. New PSH deployment, however, increases to 2.6 GW. Long-term asset valuation, which is assumed applicable to all hydropower types, could provide stronger motivation to deploy additional hydropower resources, as financing terms reflecting the long-lived, stable revenue streams of hydropower projects allow a considerable near-term and persistent reduction in the cost of capital. The 40% reduction in capital costs assumed in the *Low Cost Finance* scenario incentivizes an additional 1.1 GW of upgrades such that 82% of available upgrades are completed by 2030 and 91% by 2050. Long-term asset valuation has an even larger impact on PSH deployment, with 12 GW installed through 2030 and 23 GW through 2050. For PSH, intermediate deployment levels could be possible even with long-term asset valuation terms and conditions that have relatively lower impact on the cost of capital than is represented by the *Low Cost Finance* scenario.

Coupling *Advanced Technology* with *Low Cost Finance* conditions allows for a large incremental change in growth relative to *Business-as-Usual*. Most available NPD resource becomes economical under these conditions, with 63% utilization in 2030 (3.4 GW) and 89% utilization in 2050 (4.8 GW). A large portion of the NSD resource base is also deployed, reaching 17.2 GW and 56% utilization in 2050. New PSH capacity nears 35 GW in this scenario.

Environmental Considerations: *Advanced Technology* and *Low Cost Finance* are the major growth drivers in the scenarios considered here. Equally important for the future of hydropower growth, however, are sustainable development and environmental impact mitigation, particularly for NSD.[14] The *Advanced Technology, Low Cost Finance* scenario does not explicitly avoid any hydropower resource with identified environmental considerations. Thus, that scenario represents a deployment future that assumes successful environmental impact mitigation across the modeled NSD resource. To test model sensitivity to varying degrees of success in environmental impact mitigation, *Advanced Technology* and *Low Cost Finance* assumptions are combined with NSD resource avoidance for environmental considerations; the *Critical Habitat* attribute is used as an intermediate scenario; and *Combined Environmental Considerations* attributes represents a bounding case in which a substantial fraction of NSD resource is avoided due to environmental considerations.[15]

Relative to the case with all NSD resource available (*Advanced Technology, Low Cost Finance*), avoiding environmentally sensitive NSD resource necessarily lowers overall hydropower deployment with a direct reduction in NSD growth. Upgrades and NPD are largely unaffected by changes to NSD resource. Avoiding critical habitat areas reduces NSD deployment by only 200 MW through 2030, but deployment is 4 GW lower through 2050, as most NSD deployment occurs later in the study period after less expensive upgrades and NPDs are built. Avoiding resource overlapping with all environmental attributes, however, nearly eliminates NSD growth, with only 200 MW through 2030 and 1.7 GW through 2050. Under a given set of economic conditions, environmental considerations are a strong determinant of what NSD resource ultimately can be deployed. Additional discussion of how environmental considerations influence the regional distribution of hydropower resources and the characteristics of deployed facilities is included in Section 3.4.2.

PSH growth is not directly affected by environmental considerations, as little overlap in resource potential is assumed and changes are minor across environmental consideration scenarios. There are slight increases in PSH deployment with all environmentally-based NSD resource avoidance restrictions, because NSD capacity is displaced partly by VG resources that in turn support additional PSH installation. However, this effect is small, with only 700 MW more PSH in 2050 relative to the unconstrained case with all NSD resource available. This effect is not observed when only critical habitats are avoided.

14. Upgrades and NPDs would be deployed at sites with previously existing structures. NSD requires new infrastructure development and hence has the potential for greater environmental impact.

15. See Section 3.3 for a full list and description of all environmental attributes considered.

Fossil and VG Costs: The competitiveness of hydropower resources also depends on non-hydropower technology costs, with fossil fuel and VG costs expected to play a major role in the future evolution of the electric grid. From the large suite of fossil fuel and VG cost sensitivity scenarios, three are chosen to demonstrate a broader range of hydropower deployment pathways with *Advanced Technology, Low Cost Finance* assumptions. Two of these scenarios include *Critical Habitat* avoidance to reflect intermediate success addressing environmental impacts, with *High Fossil Fuel Cost* representing a scenario that improves competitiveness of both hydropower generation and PSH, and *Low VG Cost* representing a scenario that supports PSH growth but reduces hydropower generation competitiveness with VG. A scenario with no NSD avoidance for environmental attributes and *High Fossil Fuel Costs* pairs improved hydropower economics with assumed successful mitigation of environmental impacts across all NSD resource. This scenario thus embodies a modeled upper bound of hydropower deployment.

Hydropower resources compete differently in the electric sector for providing electricity services and thus respond differently to changes in fossil fuel or VG costs. While the flexible portion of the existing fleet and its potential upgrades can provide grid flexibility through reserve provision and load following, new NPD and NSD is assumed to be relatively inflexible owing to run-of-river operations. These resources are built primarily to supply low-cost energy to the grid. PSH, on the other hand, is built largely to supply grid flexibility through reserves, curtailment reduction, and shifting energy production from inflexible baseload and VG resource from times of low to high demand. Therefore, NPD and NSD (and, to a lesser extent, upgrades) compete most directly with energy-focused resources, such as combined cycle gas turbines, wind, and solar photovoltaics (PV). PSH competes most directly with flexible combined cycle gas and gas combustion turbine resources, while complementing wind and PV growth.

Relative to the *Advanced Technology, Low Cost Finance, Critical Habitat* scenario, including *Low VG Costs* reduces hydropower generation capacity 5 GW in 2050 by making VG more attractive, but additional VG supports 16 GW more PSH. More expensive hydropower generation resources are disproportionally affected; 2050 upgrades fall by only 150 MW while NPD is 600 MW lower and NSD is 4.3 GW lower. Exchanging *Low VG Costs* for *High Fossil Fuel Costs* promotes primarily NSD and PSH, with 1.7 GW more NSD in 2050 and 21 GW more PSH. *High Fossil Fuel Costs* do not encourage much additional upgrade or NPD deployment because all but extremely high-cost resources are utilized without the additional incentives provided by *High Fossil Fuel Costs*. The upper bound scenario combining *Advanced Technology, Low Cost Finance*, and *High Fossil Fuel Costs* with all NSD resource available achieves 15 GW new hydropower generation in 2030 and 31 GW in 2050; the 2050 quantity consists of 6.3 GW upgrades, 4.9 GW NPD, and 20 GW NSD. New PSH is 11 GW in 2030 and 53 GW in 2050 for the same scenario. This slightly lower quantity versus the equivalent scenario including the *Critical Habitat* consideration is because additional hydropower generation displaces VG, indirectly suppressing PSH growth. Alternate market conditions for upgrades, NPD, and NSD have unique effects for each resource class. These are explored in more depth, including impacts on regional distribution and technical characteristics, in Section 3.3.

While the lower bound on PSH growth is 500 MW under *Business-as-Usual* conditions, the upper-bound of new PSH is 16 GW in 2030 and 55 GW in 2050. PSH plays a different role in the power system. Its ability to provide reserves and dependable capacity either does not compete as directly with alternative technologies in the same way NPD and NSD do (such as with gas technologies), or it instead is potentially complementary (such as for VG). This role changes the relative economics of PSH and makes its deployment more sensitive to hydropower cost and value drivers than other hydropower technologies, resulting in a wider range of potential deployment pathways than the other hydropower resources. Deployment is also strongly influenced by fossil fuel and VG costs, with *High Fossil Fuel Costs* and *Low VG Costs* creating an electricity system that more highly values the use of energy storage to provide grid flexibility.

To add context to these total growth levels, Figures 3-10 through 3-13 plot historical and modeled new annual growth of the hydropower resources for representative low, intermediate, and high hydropower deployment scenarios that sufficiently characterize the range of hydropower deployment across the nine

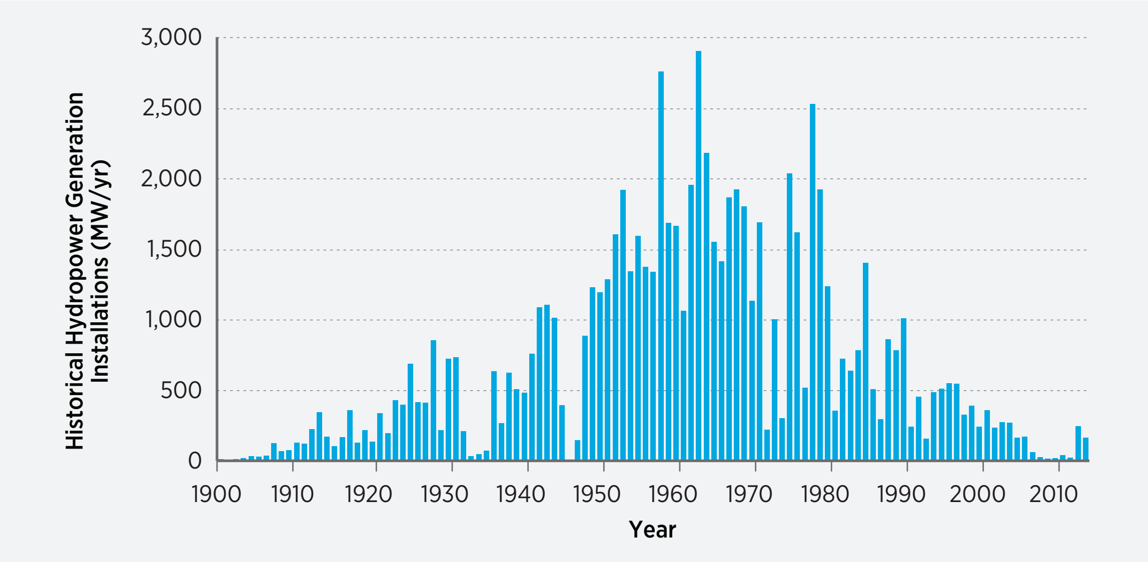


Figure 3-10. Historical hydropower generation capacity installations through 2010

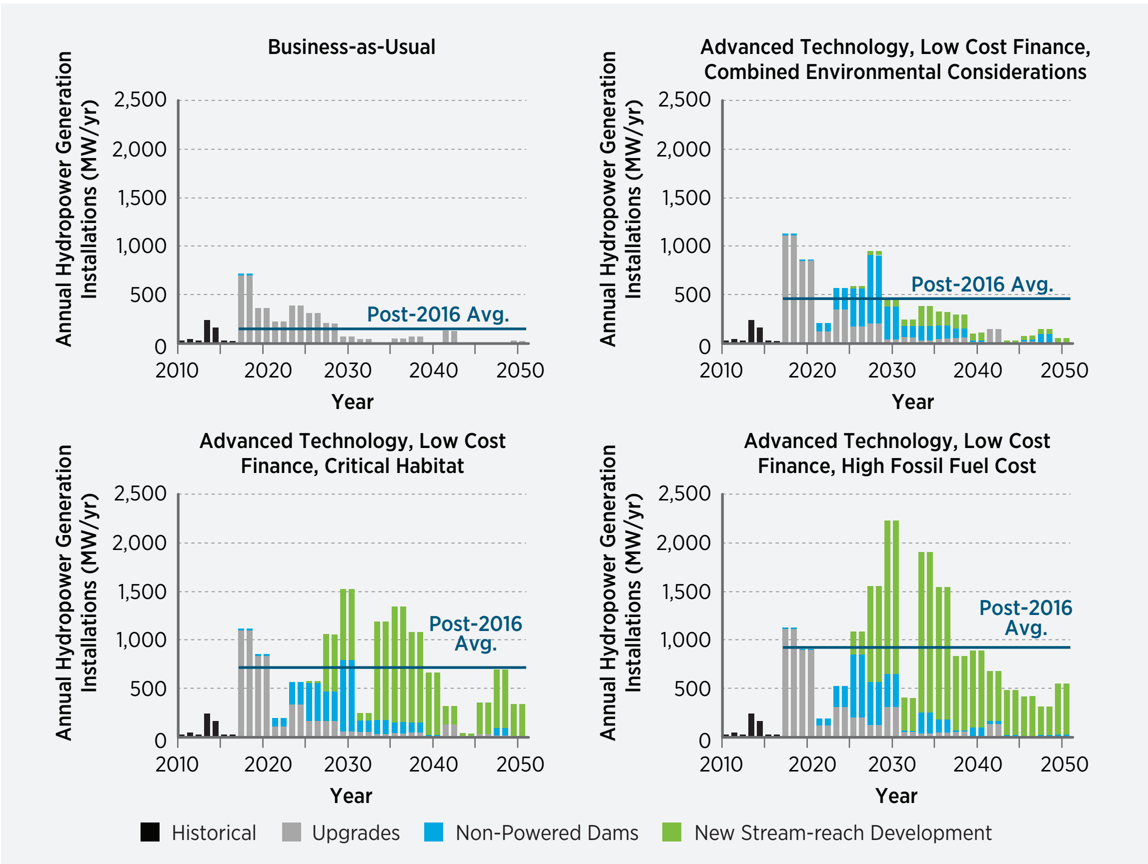


Figure 3-11. Post-2010 capacity growth from upgrades, non-powered dams, and new stream-reach development in representative low, intermediate, and high deployment scenarios

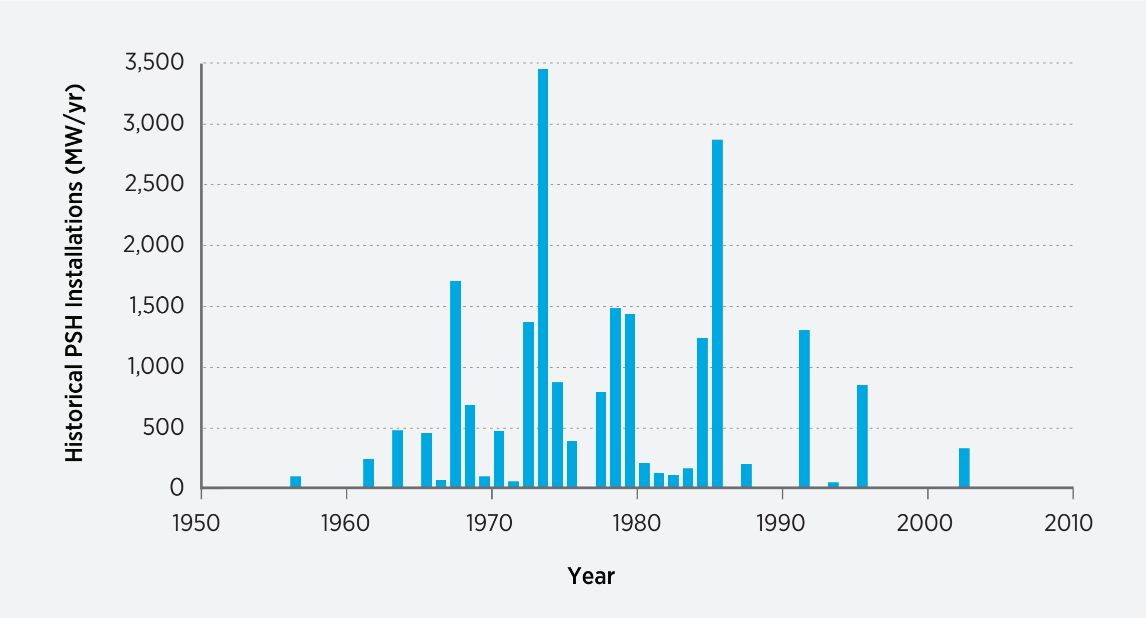


Figure 3-12. Historical pumped storage hydropower capacity installations through 2010

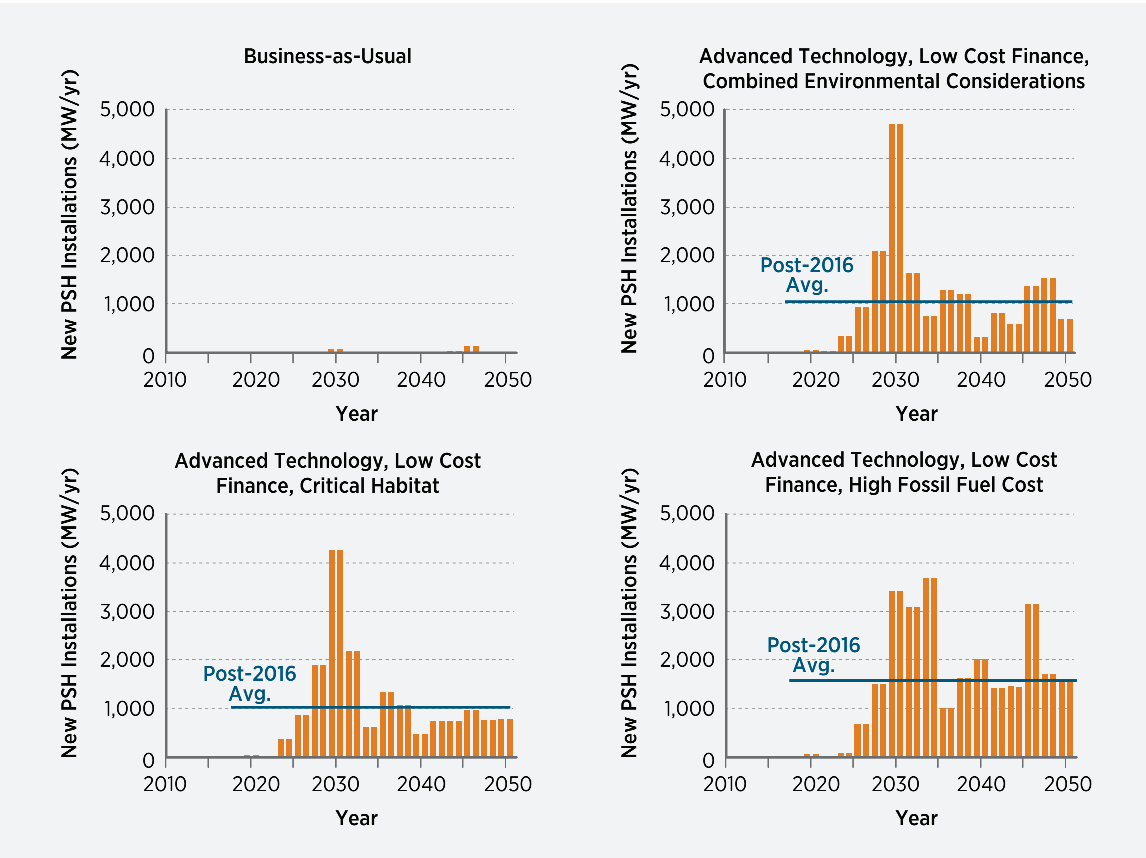


Figure 3-13. Post-2010 pumped storage hydropower capacity growth in representative low, intermediate, and high deployment scenarios

selected scenarios. Results for these four scenarios are often shown exclusively within the chapter to improve clarity and conciseness, and results for other scenarios appear in Appendix F. Figures 3-10 and 3-11 of hydropower generation installations demonstrate the near-term focus on existing fleet upgrades along with mid-term growth of NPD and long-term growth of NSD in scenarios supporting investment in these hydropower types.

Historical installations help put the new deployment results in perspective. In these scenarios, an initial focus on upgrades and NPD supports the optimization pillar of the *Hydropower Vision*, while the growth pillar is potentially reflected in long-term NSD installations. While annual growth is sometimes sporadic and approaches the historical maximum in the highest deployment scenarios, practical realities of the industry that are not modeled in ReEDS could buffer annual variability in hydropower construction.

The post-2016 average annual hydropower growth for each scenario is plotted for reference, and real-world construction would likely fall somewhere between a uniform average growth and the variable growth produced by the model.

The equivalent figures for PSH demonstrate rapid growth through 2030 when *Advanced Technology* and *Low Cost Finance* are assumed. While growth rates sometimes exceed historically observed annual PSH construction in high deployment scenarios, average installation rates are on par with historical values.

Contributions to National Energy Supply

The range of combined upgrade, NPD, and NSD deployment across sensitivity scenarios produces a corresponding range in energy production,[16] and differences between scenarios in Figure 3-14 (left panel) reflect the capacity differences in Figure 3-8 (left panel). As a lower bound, the *Business-as-Usual* scenario yields only an 8% generation increase from 2016 levels to 2050, but the full range of selected scenarios

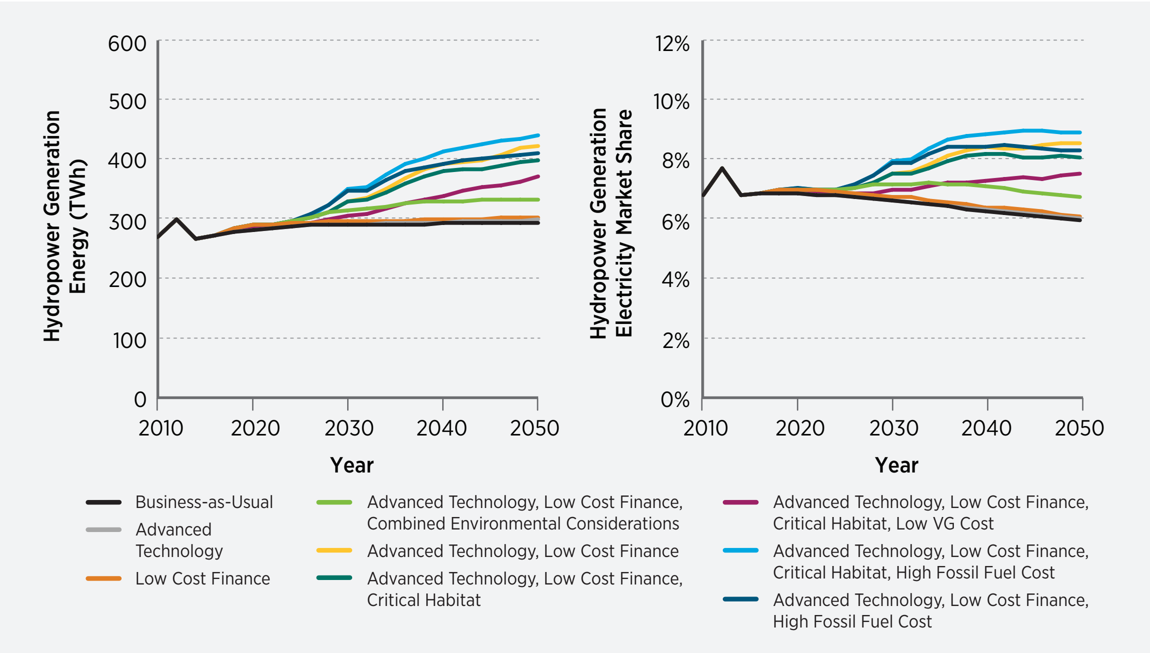


Figure 3-14. Electricity generation and share of national electricity consumption from the existing hydropower fleet and growth in upgrades, non-powered dams, and new stream-reach development (excludes net generation from pumped storage hydropower)

16. PSH is technically a net consumer of electricity, with round-trip efficiencies of up to 85% (modeled round-trip efficiency is 80%). As it serves a fundamentally different role in the power system, its consumption and production of energy are ***not*** included in the generation totals described throughout the *Hydropower Vision* document.

results in 290–350 TWh in 2030 and 290–440 TWh in 2050, which constitutes 6–28% and 8–61% increases, respectively. Higher generation scenarios align with high-capacity hydropower generation scenarios. Energy production is strongly influenced by expected future water availability, which is a strong function of climate change expectations. These interactions are discussed in Section 3.4.3.

In terms of market share (Figure 3-14), outcomes vary widely across scenarios. In scenarios with limited new hydropower capacity, the share of generation provided by hydropower declines, falling as low as 5.9% in 2050 in *Business-as-Usual* as generation remains flat while load growth continues. High-deployment scenarios, however, reach up to 7.9% share in 2030 and 8.9% share in 2050, with the best-case being the upper bound *Advanced Technology*, *Low Cost Finance*, *High Fossil Fuel Cost* scenario. Maintaining the existing fleet is essential to retaining hydropower's energy contribution to the electricity system, but new growth is necessary to grow its relative share of generation.

All scenarios with significant NPD or NSD deployment experience a greater relative increase in energy than capacity because NPD and NSD resources are expected to have higher capacity factors than much of the existing fleet. These projects are modeled as being developed and operated on a run-of-river basis, resulting in relatively higher capacity factors (but less flexibility) than the existing hydropower fleet, which operates with considerable water storage.

Figures 3-15 and 3-16 illustrate category-specific hydropower generation growth for representative low, intermediate, and high deployment scenarios. Figure 3-15 includes existing fleet generation for the *Advanced Technology, Low Cost Finance, Critical Habitat* scenario, and known new hydropower built between 2010 and 2016. Figure 3-16 shows new hydropower generation for post-2016 deployment only. Maintaining the existing fleet is important to the overall hydropower contribution to electricity generation, as it contributes the large majority of total hydropower energy through 2050 in all scenarios. Trends in energy growth by hydropower category follow those of capacity growth, with energy growth accelerating slightly in the mid- to long-term because NPD and NSD resource has higher capacity factors than the existing units where upgrades are applied. Across selected scenarios, new upgrades provide 17–21 TWh in 2030 and 20–24 TWh in 2050, new NPD provides 0–22 TWh in 2030 and 0–27 TWh in 2050, and new NSD provides 0–32 TWh in 2030 and 0–116 TWh in 2050.

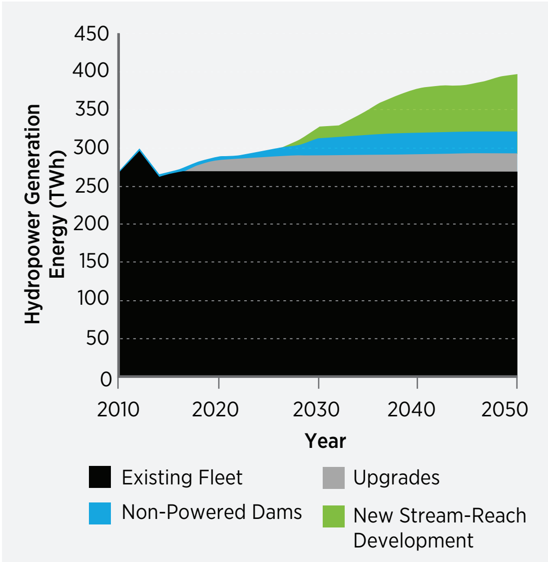


Figure 3-15. Total electricity generation from hydropower (excluding pumped storage hydropower) in the *Advanced Technology, Low Cost Finance, Critical Habitat* scenario (existing fleet generation in 2010–2014 adjusted to match historical data)

Pumped Storage Hydropower and Variable Generation

The relationship between PSH and VG is explored further in Figure 3-17, which plots new PSH capacity in 2030 and 2050 versus the percent of demand met by VG in those years for the subset of the nine selected scenarios that includes *Advanced Technology, Low Cost Finance* assumptions. These results show a positive correlation between VG generation and PSH capacity, with higher-VG scenarios (*High Fossil Fuel Costs* and *Low VG Costs*) reaching 50% or more demand met by VG in 2050 and 50 GW or more PSH. PSH deployment is much lower when VG generation is lower in earlier years, or under reference VG and fossil cost conditions.

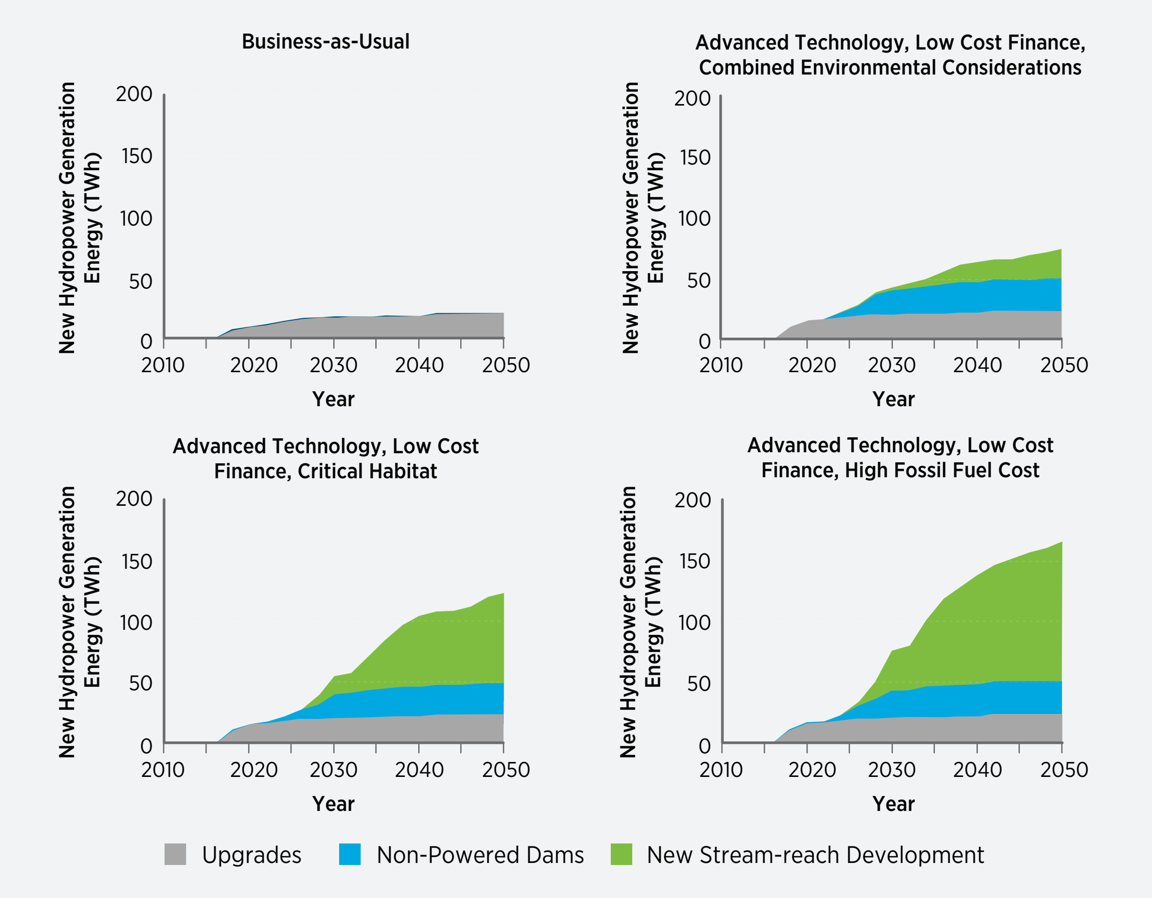
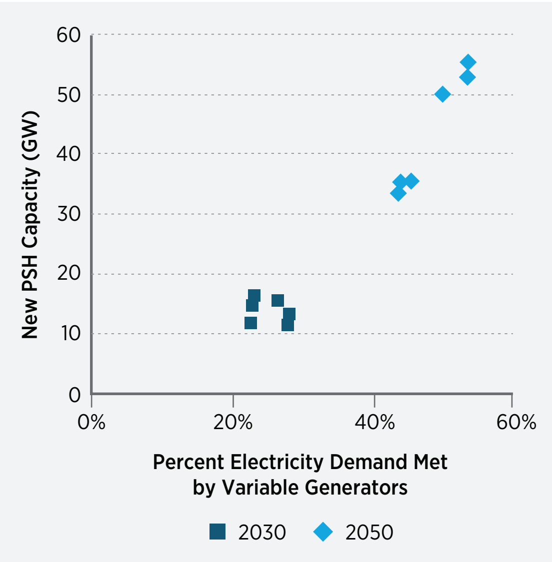


Figure 3-16. Electricity generation from new hydropower in representative low, intermediate, and high deployment scenarios (generation from the existing fleet and net energy use by pumped storage hydropower is not shown)



The exact relationship between PSH and VG, however, is dependent on the state of the electricity system, and the data shown here do not necessarily imply a specific functional relationship between the two quantities. For instance, higher assumed PSH costs could reduce PSH growth for a given VG generation, or other storage technologies (e.g. batteries, compressed air energy storage) could displace PSH if lower costs were assumed for those technologies. The complementary relationship between PSH and VG is supported by model results, but the details of this relationship must be borne out by the future realities of the electricity system.

Figure 3-17. The relationship between new pumped storage hydropower growth and generation from variable generators for fuel and cost sensitivities under *Advanced Technology* and *Low Cost Finance* conditions

3.4.2 Growth Considerations within Market Segments

Each of the nine scenarios presented in the *Hydropower Vision* analysis produces a different modeled outcome for each of the resource classes represented in ReEDS—Upgrades, NPD, NSD, and PSH. As mentioned previously, the intention of these scenarios is not to *predict* future outcomes for the hydropower industry. Instead, they serve a useful analytical purpose in demonstrating the relative sensitivity of each resource to key scenario levers such as technology cost, financing, the cost of variable generation technologies and fossil fuels, and the importance of environmental considerations. This investigative approach supports the development of the *Hydropower Vision's* roadmap by highlighting and quantifying the importance of specific key issues. To that end, this section documents key observations from the nine scenarios for each of the hydropower resource classes, addressing key components of site attributes and regionality. Discussion on the impact of climate change is in Section 3.4.3.

Market Potential for Upgrades

As modeled, the capability to upgrade and expand the existing fleet is generally the most cost-effective and economically attractive of the hydropower resource options. Because of this cost effectiveness, upgrades are the first generation resource to deploy and are used extensively in most scenarios, forming the foundation of growth in the modeled scenarios. Of the 6.9 GW of potential, deployment in 2050 ranges from 5.2 GW under *Business-as-Usual* to approximately 6.3 GW in most scenarios incorporating *Low Cost Finance* assumptions and favorable market conditions. Unfavorable market conditions for hydropower generation resources, such as increasing competition from renewables under *Low VG Cost* assumptions, only slightly reduces deployment levels to 6.1 GW. Figure 3-18 illustrates the levels of use of upgrades in 2030 and 2050 across the selected modeled scenarios.

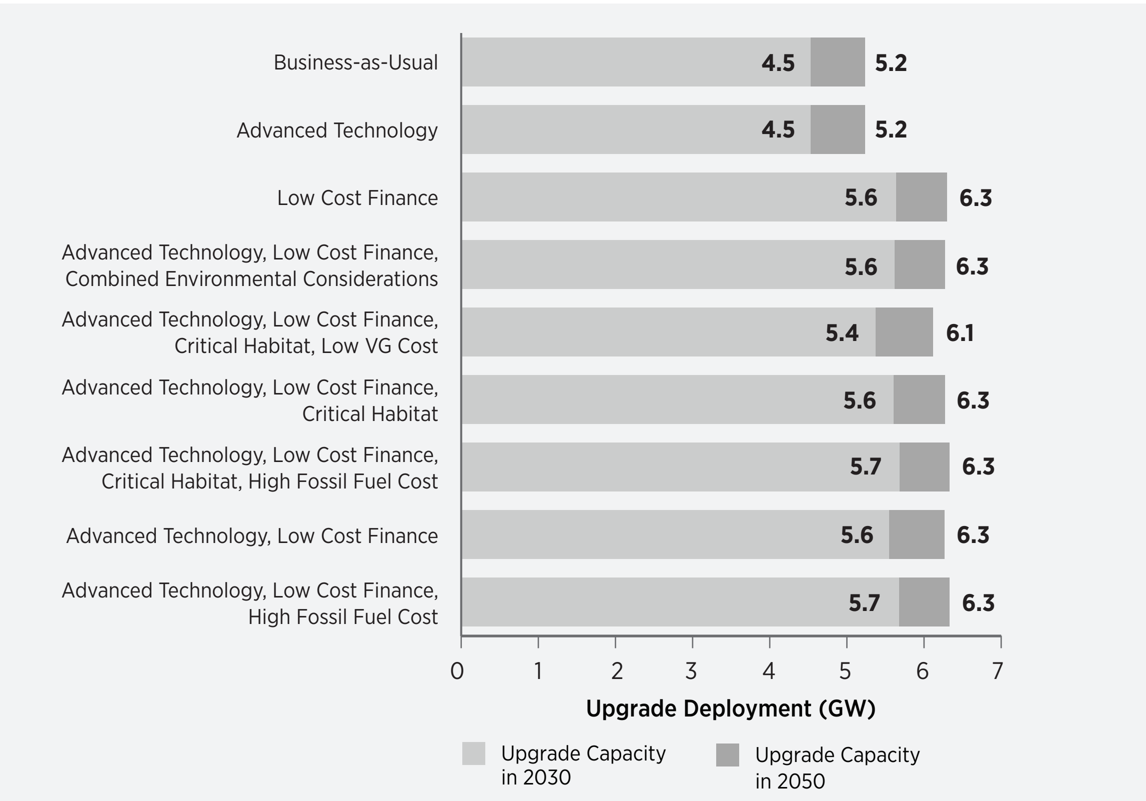


Figure 3-18. Deployment of upgrades in 2030 and 2050 in selected modeling scenarios

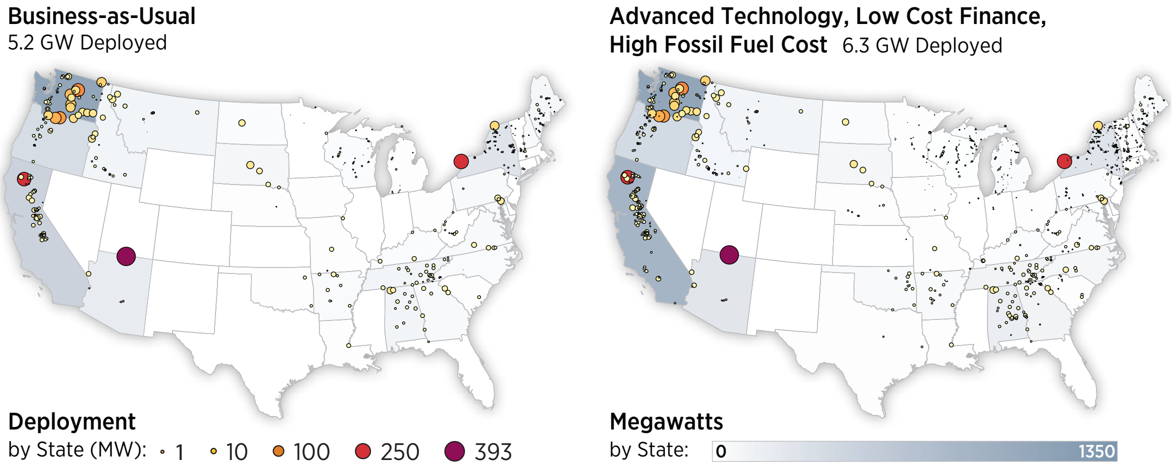


Figure 3-19. Regional deployment of upgrades for representative low and high deployment

The difference between the relatively low 5.2 GW scenarios and the higher 6.3 GW upgrades scenarios are overwhelmingly a function of the *Low Cost Finance* assumption, which improves the economics of otherwise marginal upgrade opportunities. Only the largest projects that benefit from the economies of scale inherent in hydropower development deploy in the 5.2 GW scenarios, with that level of deployment coming from upgrading 426 projects. The additional 1.1 GW seen in the higher deployment scenarios requires upgrading over 500 additional projects. Figure 3-19 illustrates the regional differences in these deployment levels using *Business-as-Usual* and *Advanced Technology*, *Low Cost Finance*, *High Fossil Fuel Cost* as representative high and low outcomes. An additional 500 small upgrade projects are spread across the United States, but produce noticeable increases in upgrade capacity in California and the Northeast.

The near-full utilization of potential upgrade capacity in *Low Cost Finance* scenarios does not mean all plants are considered economic to upgrade or expand. Generally, between 900 and 1,100 facilities are upgraded in these scenarios; however, an additional 600 to 800 projects with upgrade potential totaling approximately 500 MW are not. Owing to the economies of scale in the cost of constructing, operating, and maintaining hydropower projects, these small remaining projects are considered too expensive to be upgraded cost effectively. The challenging economics facing these facilities are apparent in the fact that no scenario achieves any meaningfully higher upgrade deployment. The highest—*Advanced Technology, Low Cost Finance, High Fossil Fuel Cost*—only deploys an additional 30 MW relative to the *Low Cost Finance* scenario.

Market Potential for NPDs

After upgrades, NPDs are generally the next most economically competitive hydropower generation resource. Where a significant portion of the upgrade resource is competitive under *Business-as-Usual* conditions, the broad powering of non-powered dams requires meaningful cost reduction—either through access to financing mechanisms that value hydropower's long lifetime (*Low Cost Finance*) or through technology, development processes, and O&M cost reductions (*Advanced Technology*). Figure 3-20 illustrates the levels of NPD deployment across different market and hydropower economics assumptions.

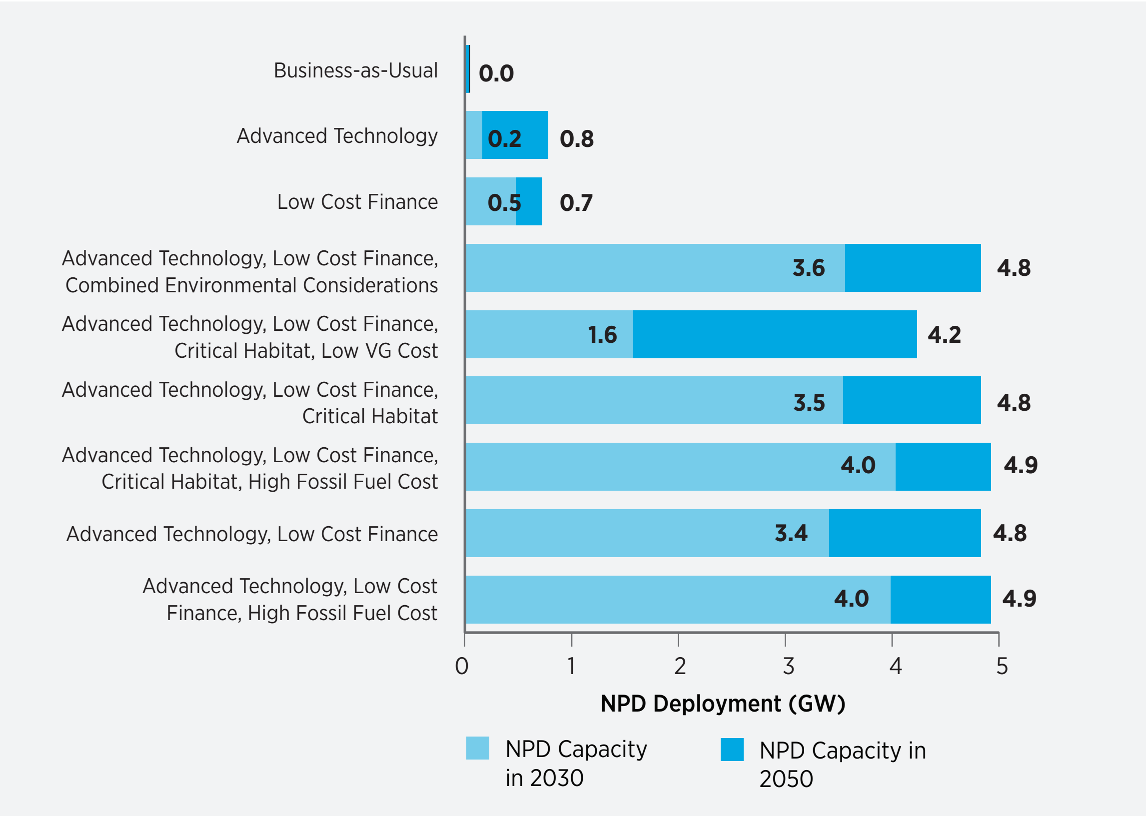


Figure 3-20. 2030 and 2050 deployment of NPD in selected modeling scenarios

No new previously unannounced NPD capacity is deployed economically under *Business-as-Usual* market and economic conditions. With individual advances in technology cost reduction or long-term valuation, 2050 deployment is between 700-800 MW with some minor variation in timing between scenarios.[17] When both *Low Cost Finance* and *Advanced Technology* advances are realized, deployment of NPD is more significant, ranging between 4.2 and 4.9 GW and resulting in the powering of between 450 and 600 existing dams of the 671 modeled. Both R&D and valuation solutions are essential to realizing the broad utilization of the nation's low-head NPD resources. In the scenarios with high deployment of NPD in excess of 4 GW, the median NPD project has a design head of only 40 ft. Without more favorable economic parameters such as in the scenarios where *Advanced Technology* or *Low Cost Finance* are used individually, only higher-head, lower-cost projects are deployed, and the median project head increases to above 90 ft. While canal and conduit projects are not modeled in ReEDS, the results from NPD suggest that similar approaches to cost reduction and valuations could be beneficial to these resource types.

The economically competitive NPDs are generally distributed consistent with the location of the remaining NPD resource potential; deployment is concentrated largely in the Midwest and the South at large existing dams along the Mississippi and its major tributaries. Figure 3-21 shows the regional distribution of these dams.

17. There are also minor changes in the geography of deployment. Where the *Low Cost Finance* scenarios reduce the cost of all NPD projects, the *Advanced Technology* scenario differentially reduces the cost of low-head versus high-head development (30% versus 25%, respectively, by 2050) and also reduces O&M cost, further changing the relative economics of different NPD projects.

Across all scenarios, a majority of the deployed capacity from NPDs is at Corps facilities that lack power infrastructure; these facilities are typically flood control or navigation structures such as locks and dams. In the scenarios combining *Advanced Technology* and *Low Cost Finance,* 75% of the deployed NPD capacity is on Corps infrastructure; at lower levels of deployment, this share rises to between 80–90%.

Market Potential for NSD

Of the hydropower generation options, NSD shows the highest growth potential—but it also carries the greatest uncertainty. Many modeling scenarios show no growth for NSD, including the *Business-as-Usual* scenario. Scenarios that do see growth have a wide variation in outcomes between 1.7 GW and 20.1 GW of cumulative deployment in 2050, with variations in growth driven by the evolution of market factors and the potential intersection or incompatibility of NSD development with environmental considerations. Figure 3-22 documents the range of NSD deployment in the selected scenarios.

On the basis of economics alone, realizing NSD deployment requires effort by industry and stakeholders to drive down costs and better value the long life of hydropower assets—and these steps must be done in combination for NSD to deploy at all. Neither *Low Cost Finance* nor *Low-Hydropower Cost* conditions can independently motivate deployment of NSD, but in combination they provide an economic competitiveness threshold that could support GW of deployment. As is this case for NPD, cost reductions must come in part from innovation targeted at low-head development—the median NSD project deployed in the selected modeled scenarios has a design head of between 30 and 40 feet.

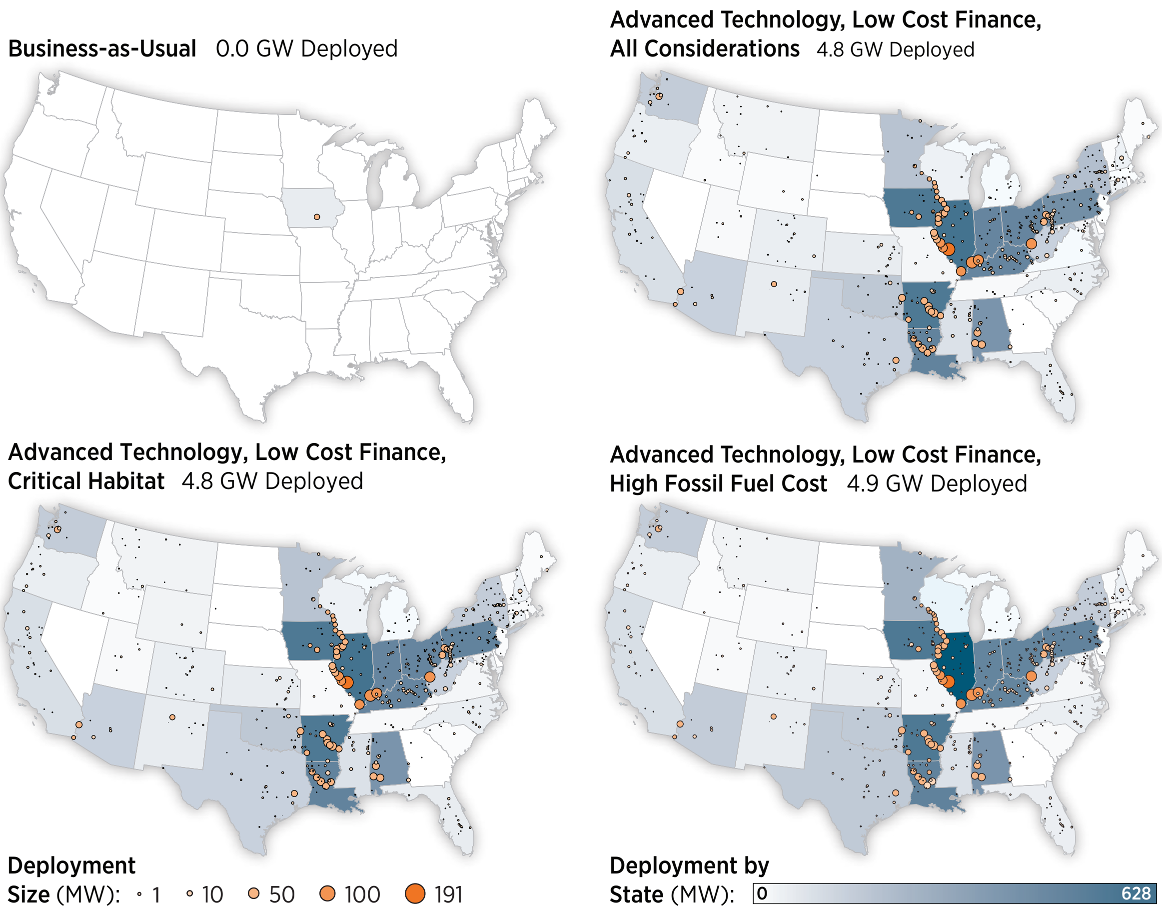


Figure 3-21. Regional deployment of NPD across a range of selected modeling scenarios

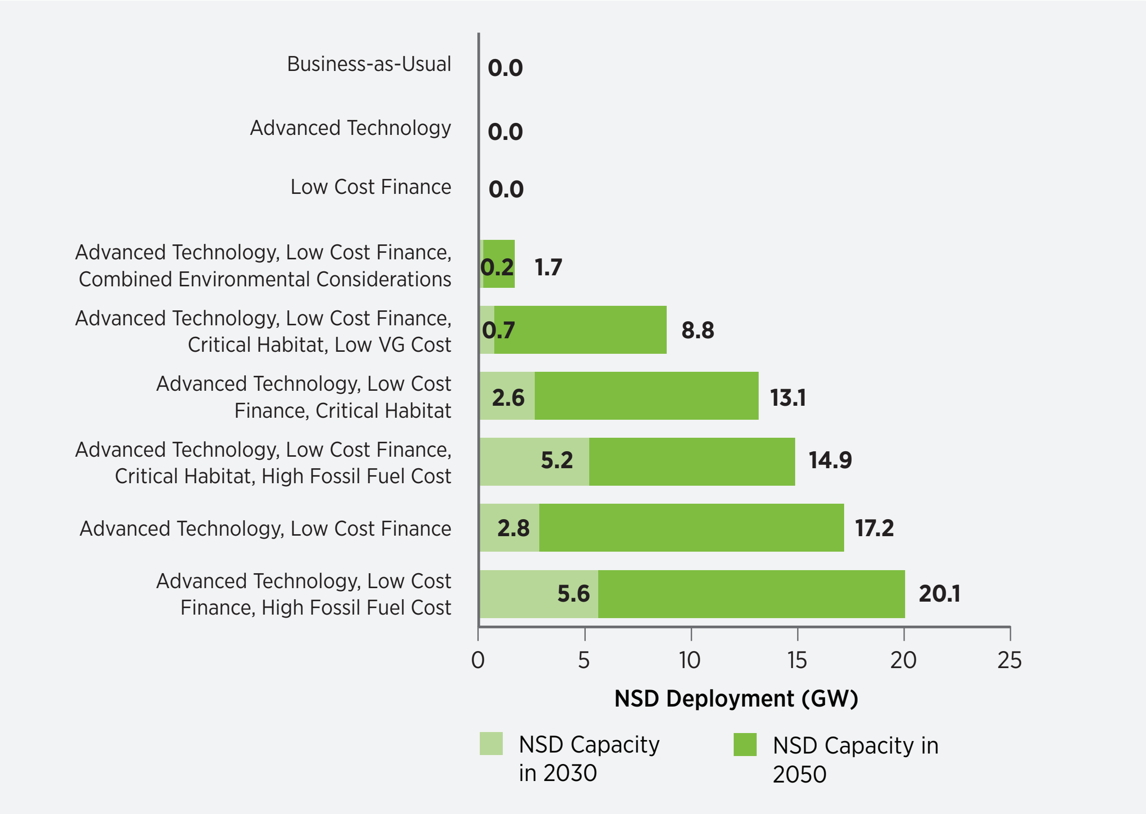


Figure 3-22. 2030 and 2050 deployment of NSD in selected modeling scenarios

The environmental considerations described in Section 3.3 are not proxies for sustainability singularly or in combination. They do, however, demonstrate the fundamental need for NSD development to accommodate, if not support and improve, the other values and uses of the nation's rivers. When NSD development is avoided in areas overlapping only one consideration—*Critical Habitat*—economic deployment is reduced by 2.3 GW relative to outcomes from the combination of *Advanced Technology* and *Low Cost Finance* (14.9 GW versus 17.2 GW). When development is avoided in areas intersecting any of the eight considerations modeled in the scenario with *Combined Environmental Exclusions*, only 1.7 GW of growth in NSD occurs.

Figure 3-23 provides two examples illustrating how environmental considerations scenarios can alter the regional deployment of NSD by mapping 2050 NSD deployment for representative low, mid, and high deployment scenarios.

In the scenario most favorable on economic merits alone—*Advanced Technology, Low Cost Finance*, *and High Fossil Fuel Cost*—NSD is competitively deployed in all but two states (Nevada and Delaware) in the continental United States, with particularly concentrated development in Oregon, Washington, Idaho, Montana, Missouri, and Pennsylvania. However, the uncertainties introduced by the example *Critical Habitat* consideration are readily visible, showing that development may not be possible in the Pacific Northwest if NSD cannot satisfy environmental and social objectives alongside the economic objectives optimized by the

ReEDS model. This result is even more apparent in the bounding case of the *Combined Environmental Considerations* scenario, which shows that meaningful deployment of NSD at the national scale may prove to be prohibitively challenging. The need for a sustainable development paradigm is evident, and steps towards this goal, both in terms of technology innovation and sustainability perspective, are documented in the *Hydropower Vision* roadmap (Chapter 4).

The range of NSD's potential contribution to the future power system also highlights the variation in potential logistical and infrastructure needs to support these scales of development. At the low end of deployment (1.7 GW under *Combined Environmental Considerations*), 375 new NSD projects would be required by 2050—along with the associated regulatory, construction, and manufacturing needs. At the high end of the NSD deployment spectrum (20.1 GW for the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario), these needs rise to a total of 3,608 projects. This range of project counts indicates that for significant NSD deployment, major advances are necessary to sustainably—from both environmental and logistical perspectives—deploy numerous small projects, as the average size of NSD across scenarios ranges from 4–8 MW.

Market Potential for PSH

Unlike hydropower generation resources, the advent of closed-loop development opportunities ensures that the potential supply of pumped storage projects does not face the same resource availability constraints as upgrades, NPD, and NSD. Instead, the deployment of PSH is contingent on its ability to cost-effectively meet the needs of the evolving power system represented in ReEDS. Subsequently, dependent on market and value drivers, the range of overall

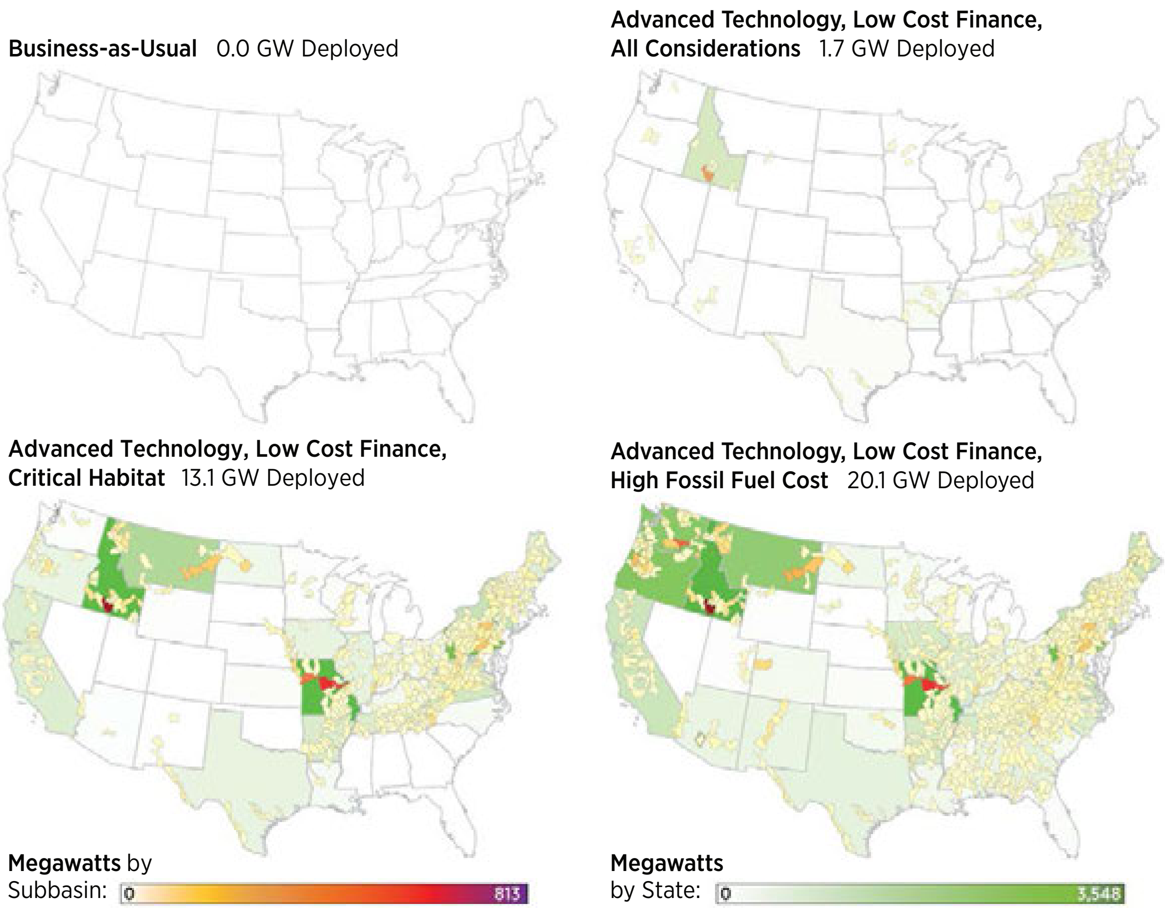


Figure 3-23. Regional deployment of NSD for representative low, mid, and high deployment scenarios

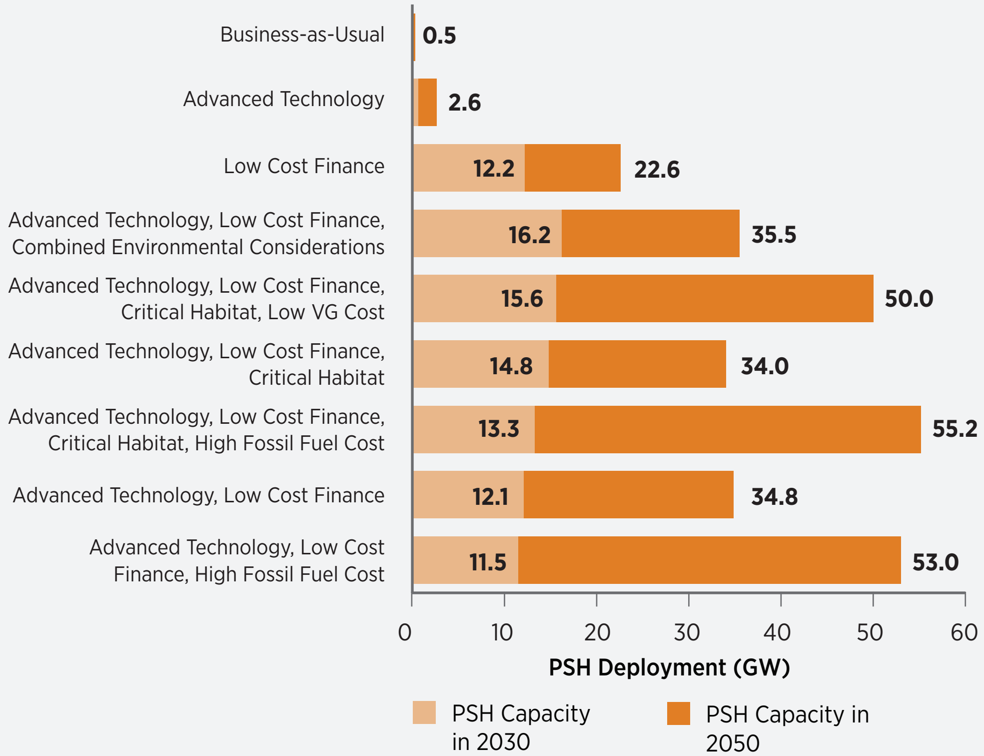


Figure 3-24. 2030 and 2050 deployment of PSH in selected modeling scenarios

2050 PSH deployment spans from a few hundred MW under *Business-as-Usual* conditions to more than 50 GW when cost, value, and market conditions align favorably. Levels of PSH deployment in 2030 and 2050 across scenarios are illustrated in Figure 3-24.

While the modest cost reductions for PSH in the *Advanced Technology* scenario support incrementally higher levels of deployment (2.5 GW), the real catalyst for use of PSH is application of the *Low Cost Finance* perspective that independently motivates the deployment of 22.6 GW of new PSH capacity. These conditions together produce somewhat higher deployment outcomes, between 34 and 36 GW. The highest levels of PSH deployment—50 GW and higher—are seen when combining improvements in cost and valuation with market conditions more favorable to storage technologies, namely *Low VG Costs* and *High Fossil Fuel Costs*. The increase in VG deployment in these scenarios relative to *Business-as-Usual* motivates the development of economically competitive PSH. Higher fossil fuel prices, however, favorably influence the economics of PSH in an additional way, as the natural gas-based combined cycle (CC) and combustion turbine (CT) capacities that would have otherwise balanced VG become relatively more expensive. Figure 3-25 shows the regional implications of the range of PSH deployment possible in the *Hydropower Vision* analysis.

When applying the *Low Cost Finance* perspective to PSH, significant deployment is seen throughout the country, with particularly high demand in California, the Southwest, Midwest, and Mid-Atlantic regions. When adding the modest cost reductions from the *Advanced Technology* conditions, additional deployment is seen in most regions, but PSH gains a particular economic edge in backing solar generators in the Southwest. Adding *High Fossil Fuel Cost* further increases deployment, most notably in the Mid-Atlantic/New York and Pacific Northwest regions.

As the utility-scale PSH projects available to the ReEDS model have large capacities relative to modeled hydropower generation projects, the number of new PSH projects necessary to reach the levels of modeled levels of deployment is much lower than that for upgrades, NPD, and NSD. The average capacity of a PSH plant varies by scenario from 700–1,000 MW, with the exception of the *Business-as-Usual* scenario that deploys a just one 300-MW plant. Thus, there is an approximately linear relationship between total capacity deployment and the number of required projects, with three projects in *Advanced Technology*, 22 in *Low Cost Finance,* and more than 70 when *High Fossil Fuel Cost* is introduced.

3.4.3 Hydropower in an Uncertain Climate Future

As discussed previously, climate change potentially creates significant uncertainty about water availability for hydropower generation, and this uncertainty can affect the long-term outlook of the hydropower industry. Water availability affects the energy production potential of hydropower resources, which in turn influences their economic attractiveness in the electric sector. To understand how this uncertainty in water availability could influence levels of growth, the bounding *Wet* and *Dry* conditions documented in Section 3.3 were applied to all nine selected scenarios. It is important to reiterate that these scenarios change only the availability of water for hydropower generation; they do not combine these adjustments with other potential impacts from a changing climate, such as the availability of water for thermal power

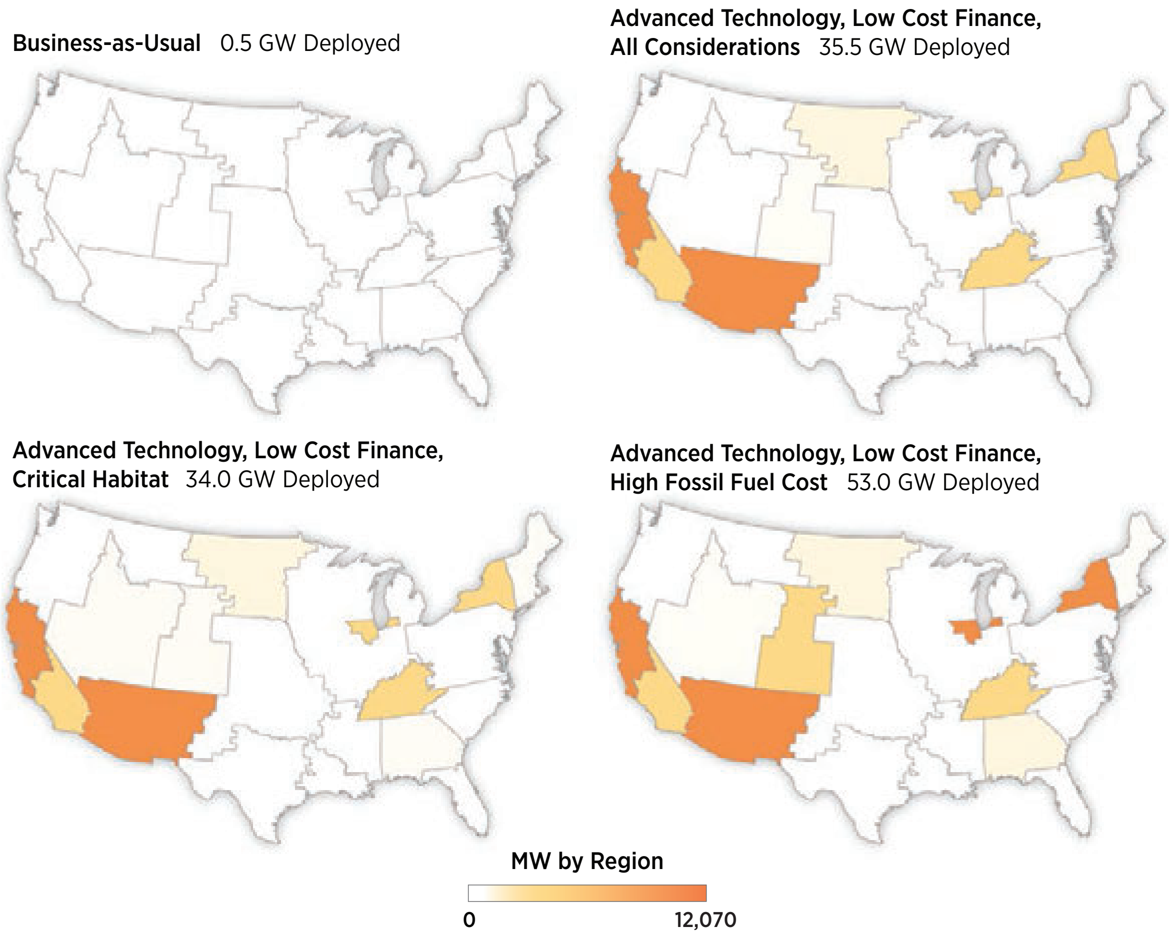


Figure 3-25. Regional deployment of PSH across a range of selected modeling scenarios

plant cooling or the influence of temperature on electricity demand. These scenarios also do not represent the influence of climate change on water quality (e.g. temperature), as doing so requires a detailed hydrology representation not included in the ReEDS electric sector modeling framework.

Even with this limited focus, the modeled scenarios can demonstrate a range of national impacts of water availability on hydropower deployment potential. Figure 3-26 plots the range of 2030 and 2050 new hydropower generation capacity deployed across the *Wet* and *Dry* variants of each of the nine selected scenarios, while also plotting the reference deployment value when water availability is unchanged throughout the study period. Most upgrades are economically attractive even with reduced water availability, so deployment under *Business-as-Usual* conditions changes no more than 5% with changing water availability (4.4–4.7 GW vs. 4.6 GW reference). Non-powered dams are also similarly unaffected by changing water availability when combined *Advanced Technology* and *Low Cost Finance* assumptions are sufficient to support construction of a large fraction of NPD resource even under reduced water availability.

In the scenarios implementing *Advanced Technology* and *Low Cost Finance* assumptions individually, the range of 2050 NPD deployment between *Wet* and *Dry* variants is up to 1.6 GW because water availability is

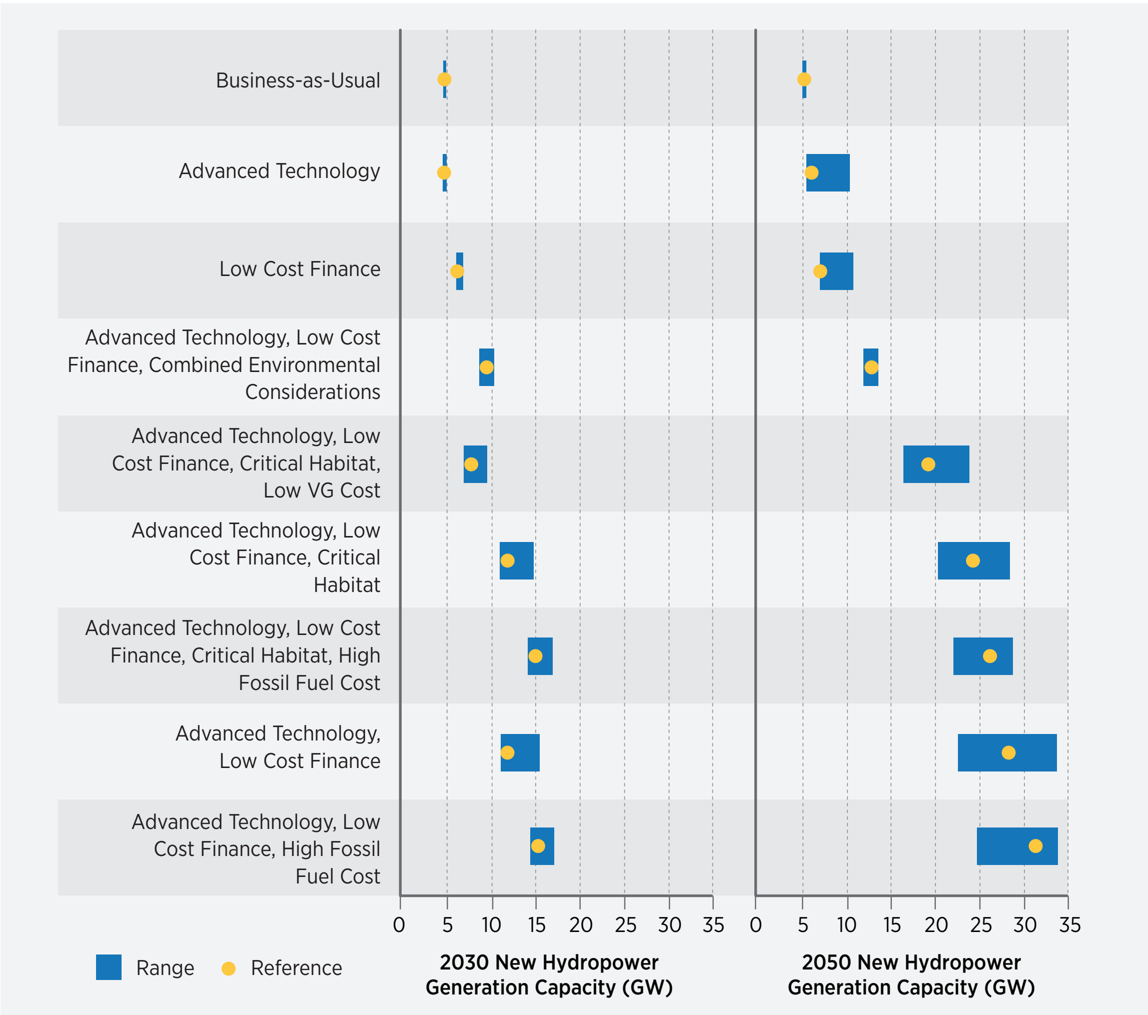


Figure 3-26. Range of new hydropower generation capacity in 2030 and 2050 across the *Wet* and *Dry* water availability scenario variants of the selected scenarios

important to NPD when these resources are marginal. That is, small changes in expected energy production can be enough to determine whether or not the capacity is economical in comparison with other available technologies. Most of the deployment spread across water availability variants, however, is attributed to changes in NSD deployment. For the top five deployment scenarios, the range of 2050 NSD growth varies from 6.3–10.5 GW, which accounts for most of the 6.7–11.2 GW deployment ranges shown in Figure 3-26. There is less variation with *Combined Environmental Considerations* because so little NSD resource is available. The range of NSD deployment variation across *Wet* and *Dry* conditions is 42–74% of the reference NSD deployment for scenarios when NSD is built.

Figure 3-27 plots the range of energy production from new hydropower generation built through 2030 and 2050 when water availability is varied. Energy from the existing hydropower generation fleet is not shown in the figure but is also influenced by assumed water availability. From the reference long-term average output of 270 TWh, existing fleet generation in climate scenario variants spans 260–290 TWh in 2030 and 250–310 TWh in 2050. Note that the modeled long-term trends do not assume any interannual variability, so actual generation could exceed these bounds. For new hydropower generation, energy production across the full range of *Wet* and *Dry* variants for the nine selected scenarios

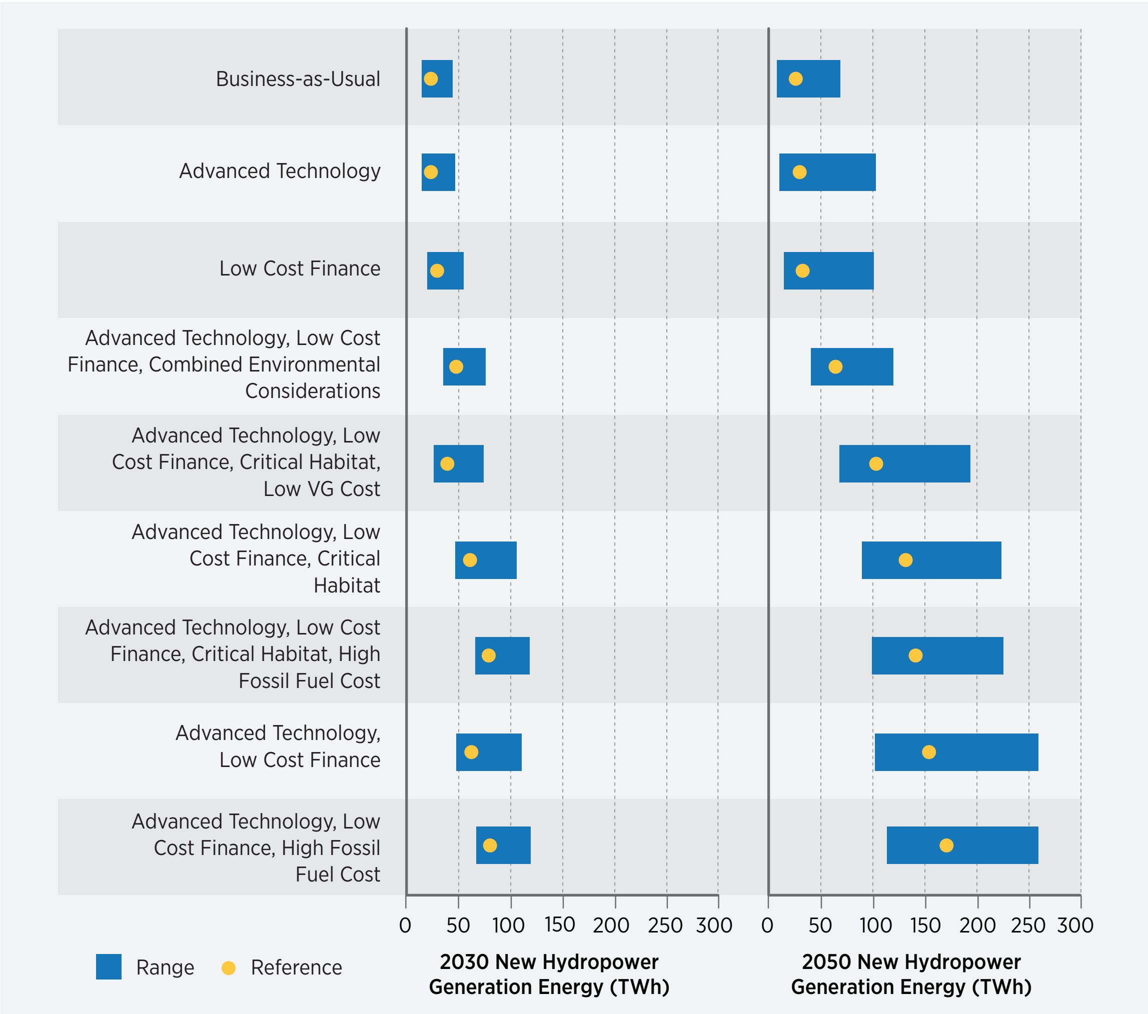


Figure 3-27. Range of new hydropower generation energy in 2030 and 2050 across the *Wet* and *Dry* water availability scenario variants of the selected scenarios

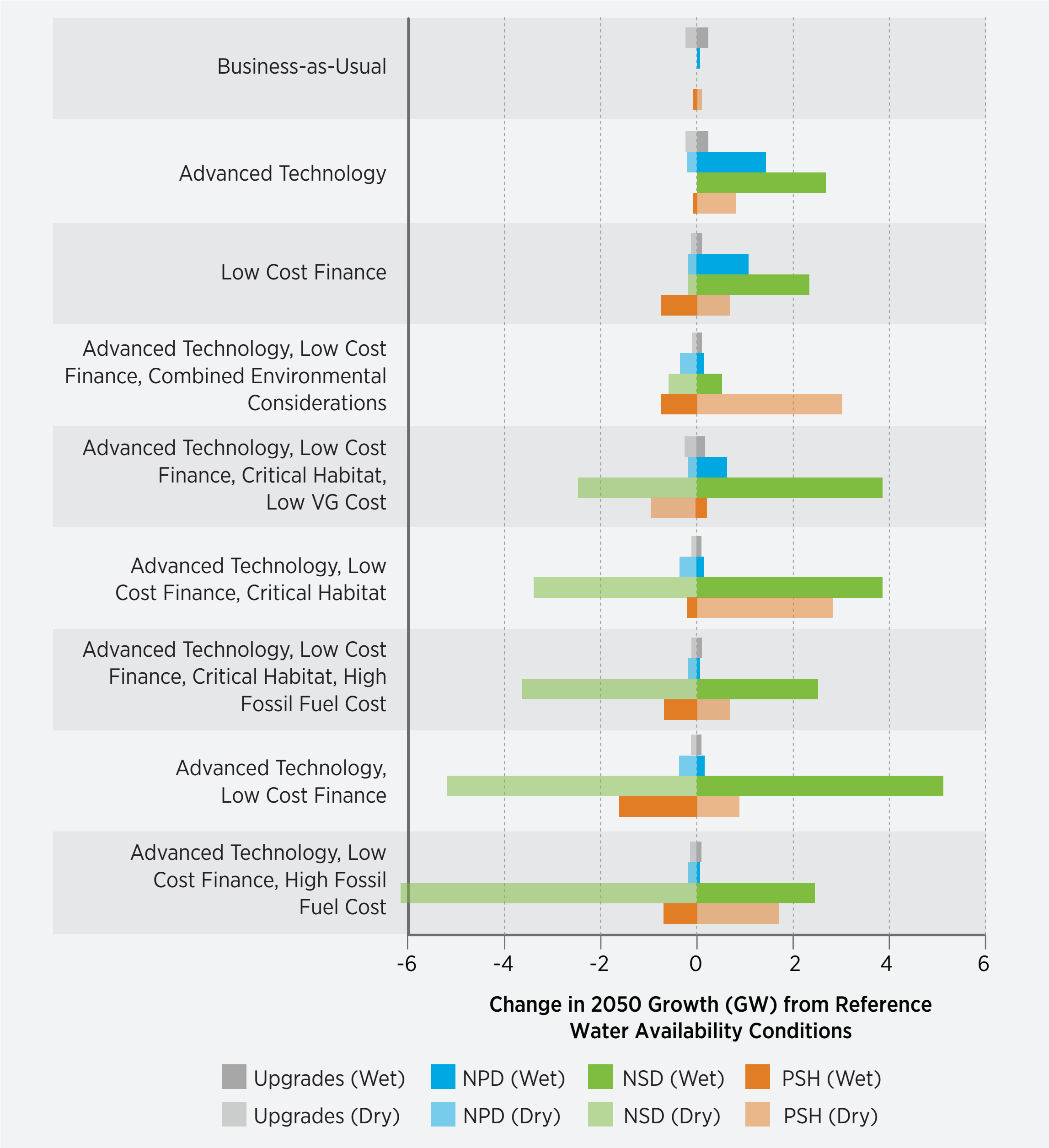


Figure 3-28. Influence of *Wet* and *Dry* water availability conditions on 2050 hydropower deployment in selected scenarios

spans 13–120 TWh in 2030 and 6–260 TWh in 2050. The low end of the range declines because *Business-as-Usual* in *Dry* conditions does not result in building of enough new capacity to replace reduced generation from previously built hydropower due to declining water availability.

Water availability plays a key role in determining the economic attractiveness of hydropower resources, particularly higher-cost NSD resources that are more economical if greater energy production is expected. Low water availability scenarios also highlight the importance of maintaining and upgrading existing infrastructure so that hydropower can maintain its contribution to the U.S. electric sector.

Figure 3-28 examines the impacts of water availability on each scenario by illustrating the impacts of *Wet* and *Dry* conditions on the 2050 growth of each hydropower resource category. Most of the differences in growth between scenarios are the product of changes to NSD deployment. Both NPD and upgrades experience higher deployment when more water is available and lower deployment when less water is available. These changes are within 1 GW except for the *Advanced Technology Scenario* and the *Low Cost Finance Scenario*, where a large fraction of the NPD resource is highly competitive with other technologies. The directional change in PSH deployment is typically opposite of those seen in the hydropower generation resources. This outcome is largely the result of regional market outcomes, particularly in the West.

Seasonal as well as annual changes to hydropower generation resources, particularly when reducing energy availability, can allow VG technologies to outcompete NSD (and some NPD) due to reduced capacity factors annually and across key seasons such as summer. Increased VG capacity can improve the value of PSH, resulting in greater deployment. Additionally, lower water availability results in a reduced capability for the existing fleet to meet reserve and balancing needs, again potentially improving the value of PSH.[18] While PSH variation is on the order of variation in other hydropower types, the relative change in PSH deployment is less than 10% for all water availability scenarios except *Business-as-Usual* and *Advanced Technology*, which deploy less than 3 GW of PSH under reference

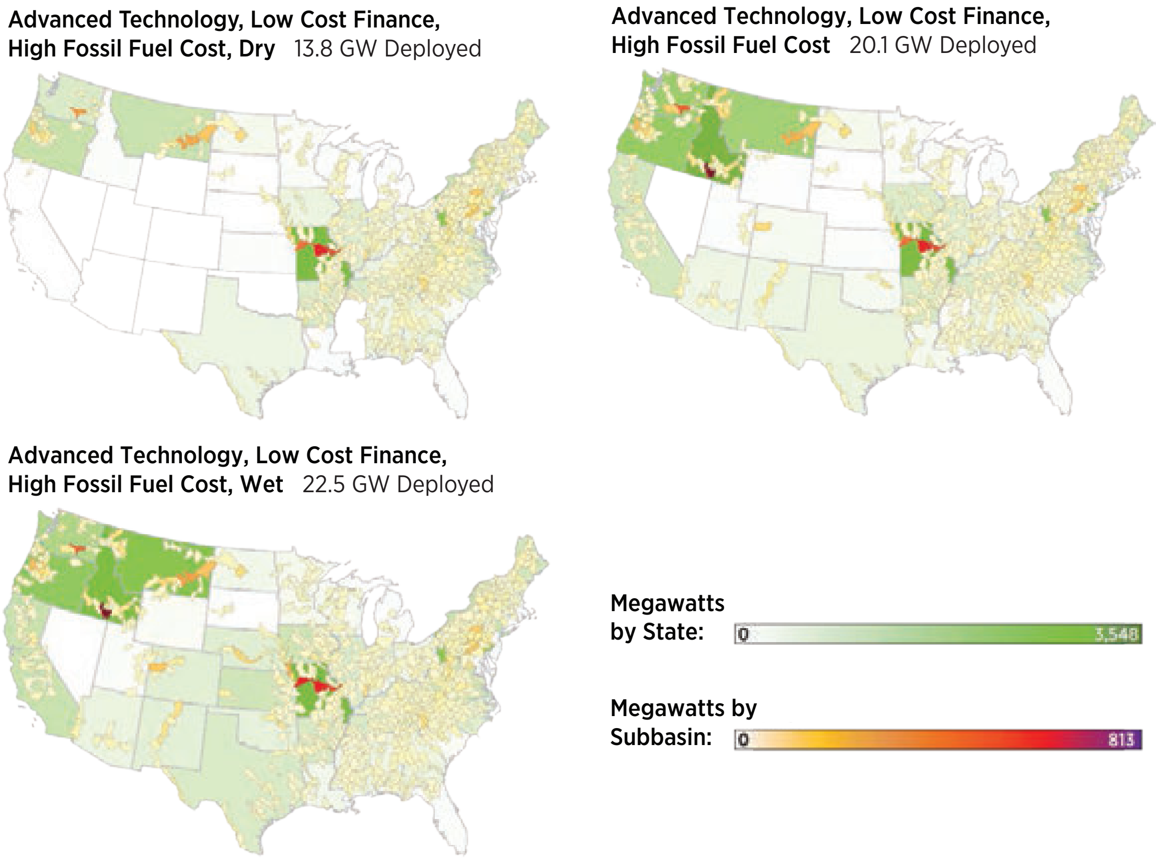


Figure 3-29. Influence of *Wet* and *Dry* water availability conditions on 2050 NSD deployment in the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario

18. It should be noted that the simplified water availability scenarios used here may not account for key economic and social impacts associated with climate change that may influence hydropower growth. In particular, water rights for hydropower resources are not explicitly modeled. This may suggest that PSH could face practical difficulties in securing water rights for development, as even closed-loop systems must perform an initial fill and then replenish water lost to evaporation and seepage.

water availability. On a relative basis, NSD opportunities are more affected by changing water availability than other hydropower types.

To examine the importance of regional differences in water availability, Figure 3-29 shows the change in NSD deployment across the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario and its *Wet* and *Dry* sensitivities. As the upper bound of NSD deployment, this scenario demonstrates the full possible range of effects from changes in water availability.

The impact of reduced water availability is illustrated in the lower deployment of NSD in western states in the *Dry* scenario. Deployment in the Eastern United States remains largely unchanged, but significantly less capacity is added in Idaho, Oregon, Washington, eastern Montana, and California. While the reductions in average annual water availability in California are modest, the modeled loss of runoff for Northern and Central California can exceed 70% during the summer months. Losing this much generation capability during what are often the most valuable times to produce power fundamentally harms the economic competitiveness of NSD in these and other areas, despite the cost (*Advanced Technology*) and value (*Low Cost Finance*) advances.

Results from the *Wet* scenario show a general increase in NSD deployment nationwide. However, some areas, such as Idaho and Western Montana, see a decrease in deployment despite increasing average annual water availability. The change in summer runoff alters the value proposition for the run-of-river NSD resource. By 2050, change in summer runoff for this area falls within a range of reductions of 25–40% despite an increase in the annual average.

3.5 Selected Costs, Benefits and Impacts of Hydropower Growth Scenarios

This section quantifies the costs and benefits associated with future hydropower deployment, as well as benefits associated with continued operation of the existing fleet through 2050. Future electricity rates and system costs; GHG and other pollution; and impacts on health, water for thermal cooling, and workforce are estimated for the nine selected scenarios. To estimate the impacts of new hydropower capacity (hydropower generation and PSH), a number of result metrics are compared between a given scenario and a corresponding baseline scenario in which hydropower electricity market conditions remain the same, and no new unannounced (as of the end of 2015) hydropower is built through 2050.[19]

The baseline scenario construct allows for quantification of impacts from all future hydropower deployment by quantifying the capacity and generation from other technologies that is offset by new hydropower, along with the corresponding implications within and outside the electric sector. It is important for a baseline to have consistent non-hydropower electricity market conditions with the scenario being compared, which means there are three baseline scenarios: a *High Fossil Fuel Cost Baseline* for the two scenarios with *High Fossil Fuel Costs*, a *Low VG Cost Baseline* for the scenario with *Low VG Costs*, and a *Central Baseline* for all other scenarios in which only hydropower parameters are varied. Impacts for the existing fleet are estimated by comparing the quantified costs and benefits of existing hydropower capacity to those that would result if this capacity were to be replaced by the composite mix of other generation sources in future (model) years under a baseline scenario with reference electricity market assumptions (e.g., the *Central Baseline*).

Results are often presented as a range from low to high, each corresponding to different methodological assumptions. These assumptions may include discount rates, different models used to calculate impacts, and assumptions about the growth of industries in the United States that support hydropower. Results ranges are also presented as a function of the nine modeled scenarios, which vary in future hydro

19. Announced post-2016 hydropower totals 40 MW of planned powering of non-powered dams, which has a negligible effect on the impacts assessed for the *Hydropower Vision* analysis.

power deployment (see Section 3.4). In many cases, the former methodological ranges are larger than the latter ranges of impacts across the four hydropower deployment scenarios analyzed.

The impacts discussion begins by examining the electric sector capacity and generation mix over time, which includes consideration of which technologies are displaced by incremental hydropower growth and a focused discussion of the role of PSH in providing operating reserves. Economic impacts within the electric sector are discussed next, with the key metrics being changes in national average electricity price, the present value of post-2016 electric system costs, and expenditures within the hydropower industry. Fossil fuel displacement then allows a discussion of energy diversity and risk. Changes in GHG and air pollution emissions are discussed, and these impacts are translated into an economic benefit using a range of social cost metrics in the literature. The thermal cooling water use reduction with displaced generation is then quantified. Finally, economic development impacts of hydropower deployment scenarios are discussed in the context of jobs and workforce needs.

Section 3.5 is organized as follows to characterize the listed impacts:

3.5.1 Impacts on the electric sector

3.5.2 National average electricity prices

3.5.3 Present value of electricity system costs

3.5.4 Hydropower industry expenditures

3.5.5 Energy diversity and risk reduction

3.5.6 Greenhouse gas emissions

3.5.7 Air pollution and human health

3.5.8 Thermal cooling water use

3.5.9 Workforce and economic development

While the array of impacts detailed this section is extensive, it is by no means exhaustive. In particular, detailed site- and basin-specific environmental impacts of new hydropower deployment are not discussed, as such an assessment requires a level of detail that is outside the scope of the *Hydropower Vision*. Instead, this report uses scenarios with different environmental considerations to examine the high-level implications of local environmental characteristics and opportunities to address them. Lack of a broadly accepted methodology also prevents inclusion of biogenic emissions in the GHG discussion or water losses due to reservoir evaporation and leakage in the water use discussion. In addition, methodological limitations prevent quantification of indirect economic impacts from changes in water use or non-hydropower industry workforce changes.

3.5.1 Impacts on the Electric Sector

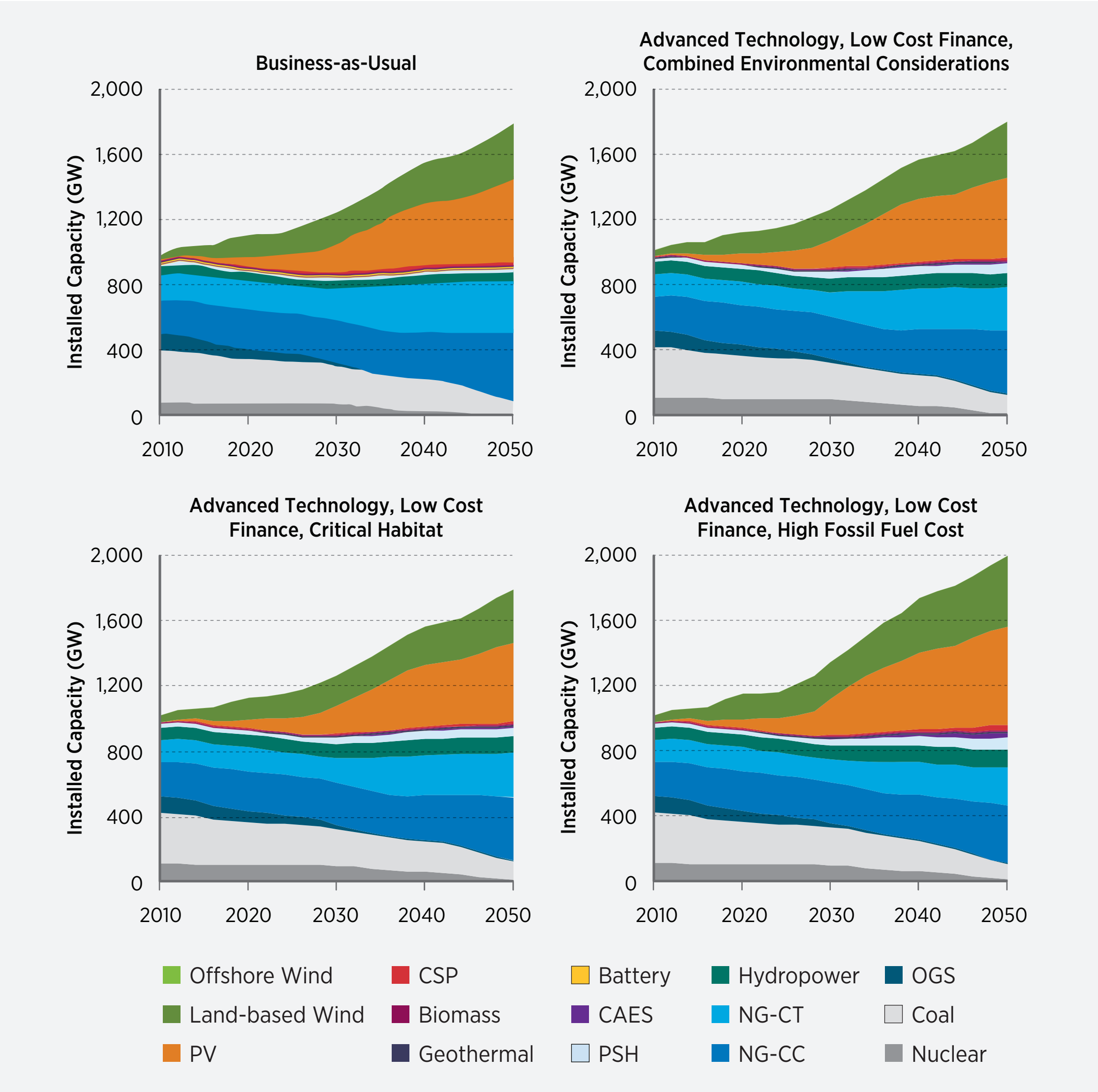
The U.S. electricity sector generated 4,093 TWh in 2014. This electricity comprised 39% coal, 27% natural gas, and 19% nuclear generation. Hydropower generation provided the most electricity of any renewable generation type at 6.3% in a lower-than-typical hydropower year, followed by 4.4% from wind, and 2.4% from other renewable generation including solar, geothermal, and biomass. The 6.3% of U.S. electricity produced by hydropower generation equated to about 260 TWh from the existing fleet [62]. Existing PSH consumed roughly 6 TWh of electricity in 2014 due to pumping efficiency losses, but PSH generation provided necessary flexibility services and reserves in the regions where it is available. The 102 GW of total existing hydropower constitutes 9.4% of the approximately 1,060 GW of total installed U.S. capacity at year-end 2014 [63].

Using these generation statistics as a reference point, this section describes the evolution of the U.S. electricity generation and capacity mix in the selected scenarios, focusing in some cases on the representative low, intermediate, and high scenarios for hydropower deployment. The scenarios examine several possible electric sector futures driven by fuel and technology costs, hydropower economics, and success with mitigating hydropower environmental impacts. These scenarios facilitate discussion of many variables important to the *Hydropower Vision,* but do not constitute a full range of possible outcomes. In addition, uncertainty exists in all electric sector results and increases as results extend further into the future. Factors that can influence electric sector outcomes include electricity load growth and distribution, plant retirement decisions, and future policy developments. While important, full consideration of all these issues is outside the scope of the *Hydropower Vision*.

Evolution of the Electric Sector

It is important to understand the *Hydropower Vision* in the context of broader U.S. electricity system development, because many factors outside the hydropower industry can shape the future of U.S. hydropower. Fossil fuel and VG costs are two such variables discussed within this report; while other factors influence the electric sector, these two help examine a broader range of possible impacts.

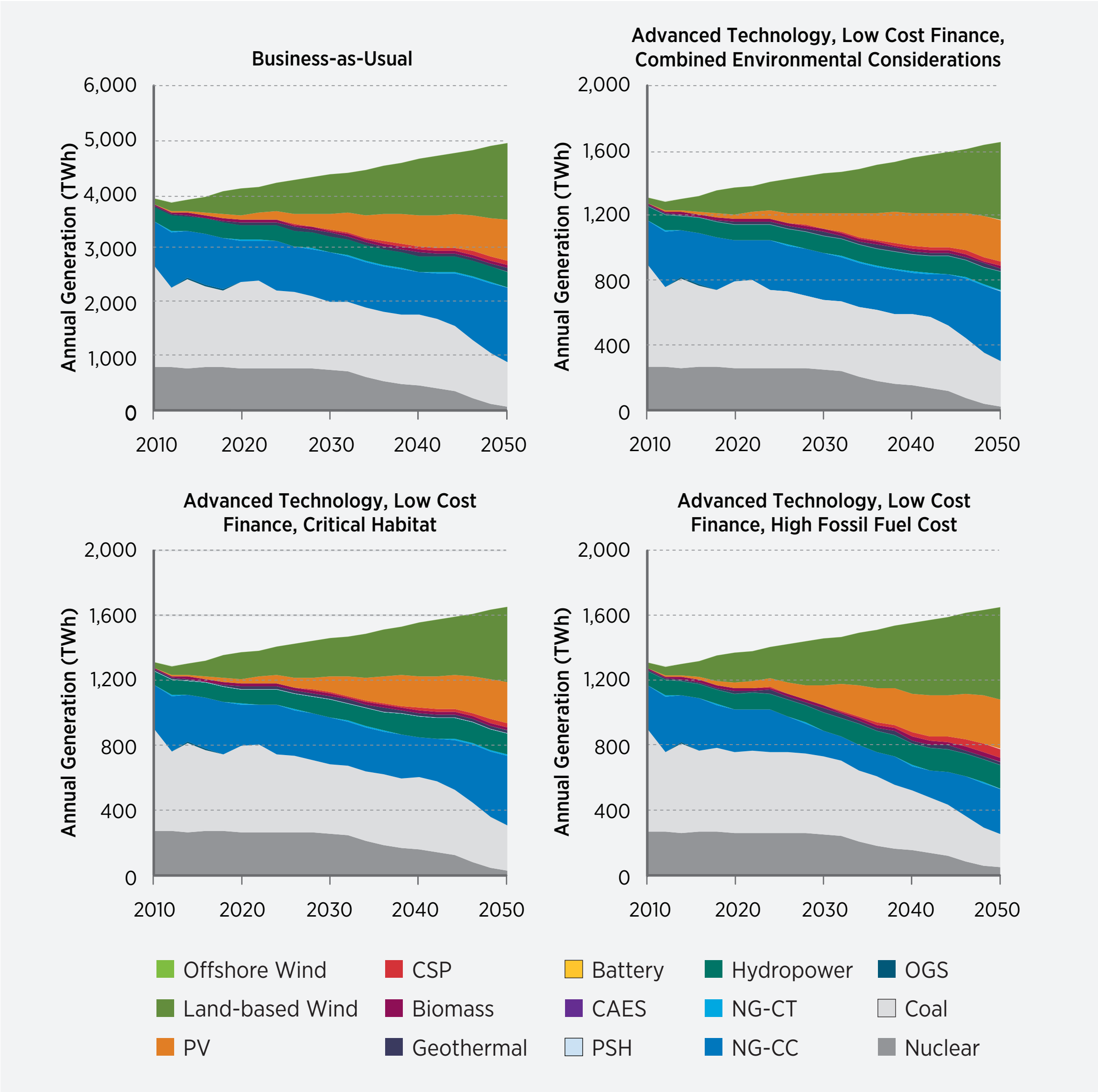
The national capacity and energy mix over time demonstrates overarching long-term trends in electric sector scenarios; these results are shown for the representative low, intermediate, and high deployment scenarios in Figures 3-30 and 3-31. Through 2030, total electricity sector capacity growth is modest, with most changes resulting from replacement of retiring fossil-fueled capacity with new renewable capacity. In the *Business-as-Usual* scenario, total hydropower generation capacity grows by 5 GW



Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

Figure 3-30. Installed capacity by technology type and year in representative low, intermediate, and high deployment scenarios through 2030, while new PSH grows by 200 MW. At the same time, wind capacity grows by 110 GW and PV by 140 GW, and natural gas-based capacity grows by 45 GW to meet both reserve and electricity load requirements. Coal-based capacity declines by 50 GW and nuclear capacity is relatively stagnant (declining by 9 GW), as these technologies are not chosen over renewables or natural gas-based facilities after existing units retire. Near-term policy drivers such as renewable energy tax credits and the CPP help motivate success of renewables over fossil fuels and nuclear in this time period.

From 2030 to 2050, ReEDS predicts a rapid increase in capacity needs as fossil fuel and nuclear plants retire, electricity load increases, and economics favor VG with lower capacity value than the conventional resources being retired. For *Business-as-Usual* in 2050, wind capacity reaches 330 GW, while PV capacity reaches



Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

Figure 3-31. Annual generation by technology type and year in representative low, intermediate, and high deployment scenarios

490 GW; combined, these resources supply 44% of electricity load. The grid flexibility needs required by new VG are provided by natural gas-based resources, primarily combustion turbines in the 2030s and combined-cycle units in the 2040s. Natural gas combustion turbines comprise a large portion of capacity but never supply more than 0.5% of electricity consumption in a year, as this capacity is used almost exclusively for peaking generation and reserves.

Scenarios that exclusively vary hydropower assumptions have a qualitatively similar national electricity mix as *Business-as-Usual* despite up to 31 GW of new hydropower generation and 55 GW new PSH. Differences are described in greater detail in subsequent sections of this chapter. Though the hydropower industry is substantially changed in many of these scenarios, particularly those including *Advanced Technology* and *Low Cost Finance* assumptions, the incremental change in hydropower remains small relative to the total electricity system size. As such, the national electric sector evolution remains largely the same.

In contrast, *High Fossil Fuel Costs* in the high hydropower deployment scenario example (*Advanced Technology, Low Cost Finance, High Fossil Fuel Cost*) drive the system towards greater use of renewable electricity and reduced use of natural gas. In 2050, wind capacity nears 440 GW, and PV capacity exceeds 600 GW. Together, those two generation sources supply 53% of electricity load, while the share of natural gas-based electricity falls to 17% from 28% in *Business-as-Usual.* Because variable generation has lower capacity value than the fully dispatchable resources it replaces, this scenario requires 210 GW more total capacity to meet planning and operating reserve requirements. Energy storage capacity also increases with VG penetration, reaching 105 GW of storage capacity in 2050.

The only other of the nine selected scenarios having a capacity expansion noticeably different from *Business-as-Usual* is the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* scenario. This scenario deploys less VG than when fossil fuel costs are high—but still more than *Business-as-Usual*—with 430 GW wind and 420 GW PV in 2050, which collectively supply 50% of 2050 electricity load. Assumed cost reduction trajectories are proportionally more favorable towards wind than PV, resulting in less PV capacity than *Business-as-Usual*. Natural gas-based generation supplies 22% of load, while storage capacity grows to 88 GW to provide grid flexibility.

Technology Displacement Due to Hydropower Construction

Electric sector evolution is overall similar between *Business-as-Usual* and scenarios adjusting hydropower-specific parameters. Still, constant electricity load across all scenarios means that any additional electricity produced by hydropower resources must displace other technologies, and this generation displacement drives many of the impacts discussed in subsequent sections. Notably, such displacement is not unique to, or caused by hydropower and is germane to any technology that experiences growth in the context of total load remaining relatively constant. Regional differences in incremental hydropower deployment can also shift the regional distribution of VG and fossil fuel electricity, potentially resulting in high interannual variability in national displacement trends.

Figure 3-32 shows the difference in non-hydropower generation types between the representative low, mid, and high hydropower deployment scenarios and a baseline with no new hydropower. Positive numbers represent higher generation in the baseline scenario relative to the scenario allowing hydropower deployment.

Through the mid-2030s, hydropower displaces a mix of non-hydropower renewable energy (VG), as well as coal and natural gas. Past 2030, as VG growth accelerates and natural gas-based capacity and coal-fired units retire, hydropower displaces more natural gas and non-hydropower VG. *Business-as-Usual* builds 5 GW of new hydropower generation. These are primarily near-term upgrades, which tend to displace some natural gas and shift some electricity supply toward non-hydropower RE in early years and toward coal in later years, when remaining coal-based resources are used for flexible generation. When *Advanced Technology* and *Low Cost Finance* improve hydropower economic competitiveness, incremental hydropower resources displace a mix of natural gas and non-hydropower renewable energy. Relative displacement of natural gas is higher in scenarios with lower overall hydropower deployment (e.g., *Advanced Technology, Low Cost*

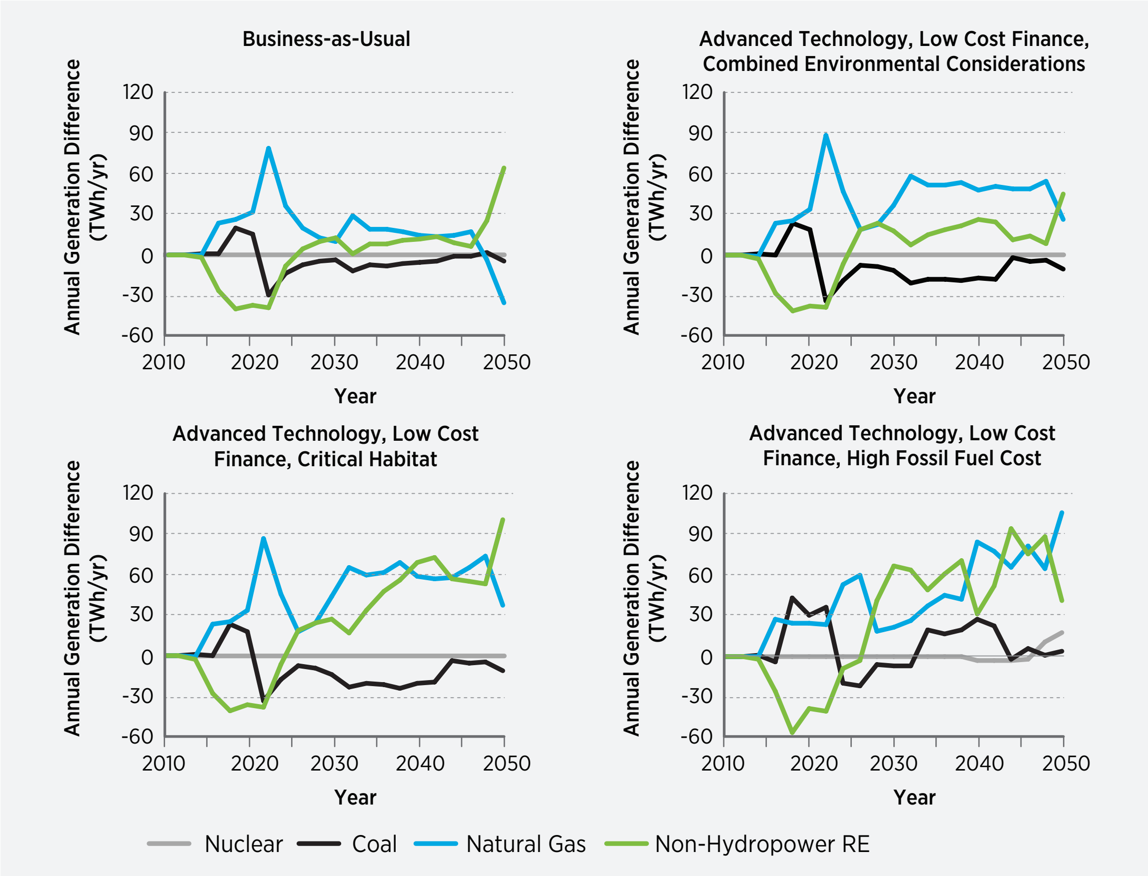
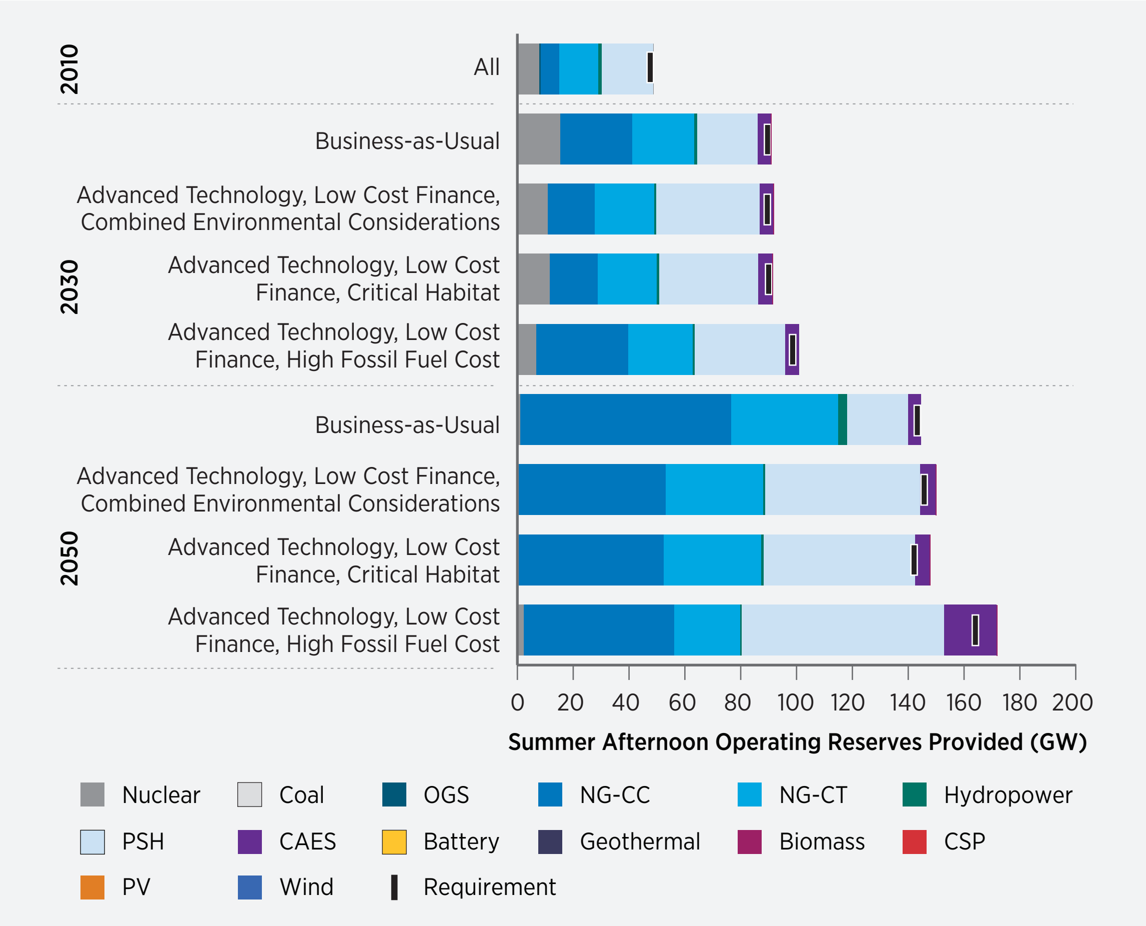


Figure 3-32. Difference in technology-specific generation between the baseline scenario and representative low, intermediate, and high deployment scenarios

Finance, Combined Environmental Considerations), with scenarios achieving higher levels of hydropower growth demonstrating non-hydropower RE displacement of a similar order as natural gas displacement.

Changes in coal-based generation vary, but many years have higher coal generation because new hydropower does not provide as much system flexibility as does the combination of natural gas and VG it replaces, particularly when new hydropower comprises inflexible NPD and NSD resource. These results demonstrate that under more favorable hydropower conditions, the technology could compete effectively with wind, PV, and natural gas-based resources. Nonetheless, the scale of this displaced generation—on the order of 0–100 TWh—represents a relatively small fraction of the electric sector as a whole (i.e., 2050 load is projected at more than 4,900 TWh).

Capacity displacement follows similar trends. For mid and high hydropower deployment scenarios, a greater share of natural gas-based ***capacity*** is displaced as compared to natural gas-based ***generation,*** because PSH displaces gas-based combustion turbines for reserve provision (and neither PSH nor combustion turbines contribute significantly to energy production). This effect is not observed with *Business-as-Usual,* because little new PSH is built. Across the representative low, mid, and high hydropower deployment scenarios, differences in 2050 capacity are in the range of 0–3 GW for coal, 1–54 GW for natural gas, and 5–42 GW for non-hydropower renewable energy.



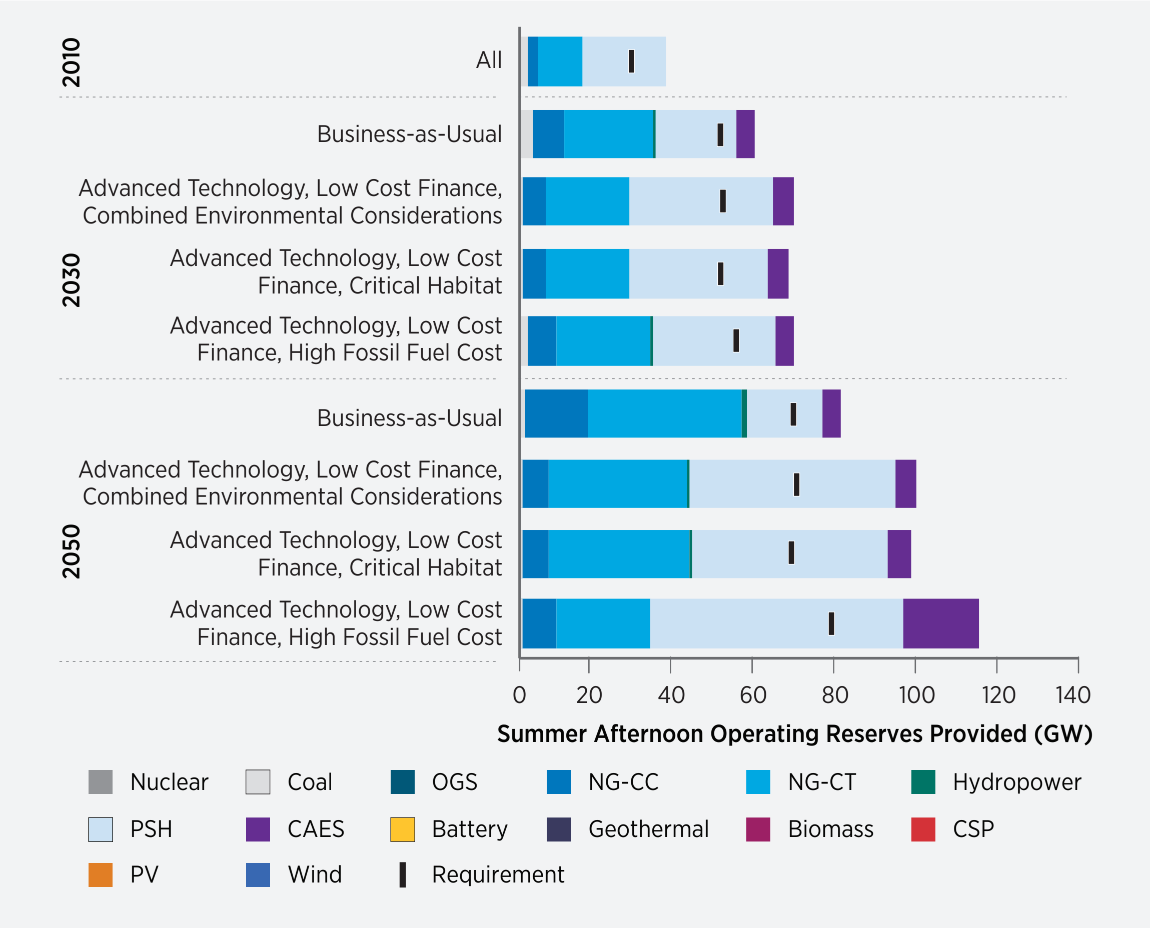
Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

Figure 3-33. Comparison of summer afternoon operating reserves provision between representative low, intermediate, and high deployment scenarios

Pumped Storage Hydropower Role in Providing Electricity Reserves

Section 3.4.1 discussed the relationship between PSH and VG generation, demonstrating that scenarios with higher VG generation support greater PSH deployment. One reason PSH can complement VG is its ability to provide reserve capacity. Load growth and VG growth increase operating reserve needs in the ReEDS model, as VG installation induces additional operating reserve requirements in the model. VG also has limited ability to provide planning reserves.

Figures 3-33 and 3-34 compare operating reserve provision by technology in 2010, 2030, and 2050 for the representative low, mid, and high deployment selected scenarios in the summer afternoon (Figure 3-33) and spring night (Figure 3-34). Summer afternoon is when national electricity load is the highest, so most generating capacity provides energy and little is left available for reserves. Spring night is when national electricity load is the lowest, so this time period reveals the preferred resources for reserves when there is a large amount of available capacity. In both time periods, operating reserves are provided primarily by NG-CC (natural gas combined cycle), NG-CT (natural gas-fired combustion turbines), and PSH, with some coal contribution in the short- to mid-term and some CAES in the mid- to long-term. Oversupply of reserves can occur if capacity can be made available for reserves at negligible cost. In



Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

Figure 3-34. Comparison of spring night operating reserves provision between representative low, intermediate, and high deployment scenarios

Business-as-Usual, nearly all PSH capacity is committed to providing operating reserves in all years, and very little PSH is supplying energy. The cost of being available for reserves is negligible, so PSH is an attractive technology for operating reserves. When substantial new PSH capacity is constructed in scenarios with *Advanced Technology* and *Low Cost Finance* assumptions, its contribution to operating reserves grows in kind, displacing natural gas-based capacity. In these scenarios, PSH provides more operating reserves[20] than any other technology by 2050.

3.5.2 National Average Retail Electricity Price

Electricity prices are the most tangible and visible metric by which consumers experience the changing economics of the power system. As described in Section 3.1, the ReEDS model estimates a cost-of-service electricity price over time in each scenario. While ReEDS does not have sufficient resolution for this price to directly represent individual or regional consumer electricity prices, comparing national aggregate electricity prices provides an understanding of the incremental impact of a given scenario on electricity prices.

20. In addition to operating reserves, ReEDS also requires a certain level of planning reserves in the power system. Given its inherent flexibility, PSH can provide its full capacity towards planning reserves, supporting the deployment of variable wind and solar energy technologies that provide only a fraction of total capacity towards planning reserves.

Figure 3-35 plots the incremental change in ReEDS electricity price of the selected scenarios compared to a baseline scenario with no new hydropower. Allowing economic hydropower construction allows for slightly lower electricity prices in most years across all scenarios. Scenarios with *Advanced Technology* and *Low Cost Finance* assumptions tend to see greater improvements in the long-term due to increased deployment of economic hydropower. All changes to electricity price, however, are relatively small and of a similar order of magnitude because incremental new hydropower is a relatively small portion of the system. Electricity price reductions are typically on the order of 0.1¢/kilowatt-hour (kWh) or less, which corresponds to a 1% change or less. Across a wide range of future possible hydropower deployment scenarios, electricity prices are not likely to be strongly affected.

3.5.3 Present Value of Total System Cost

The total present value of expenditures within the modeled power system is a single-value economic metric for all capital and operating costs across the entire ReEDS study period. Total system costs are calculated for all scenarios. Changes in total system costs, as a function of changes in scenario inputs, are subsequently used to demonstrate the economic impact of changing the power system conditions.

Business-as-Usual has a total system cost of $3,960 billion (which represents a savings relative to the baseline). More than half of this cost comes from natural gas, coal, and nuclear fuel. The biggest drivers of system cost across the scenario sensitivities are fossil fuel and VG costs, as these variables alter the costs of the predominant technology types. Selected scenarios with *High Fossil Fuel Costs* have total system costs of $4,030 billion, while the *Advanced Technology, Low Cost Finance, Low VG Cost* scenario reduces costs to

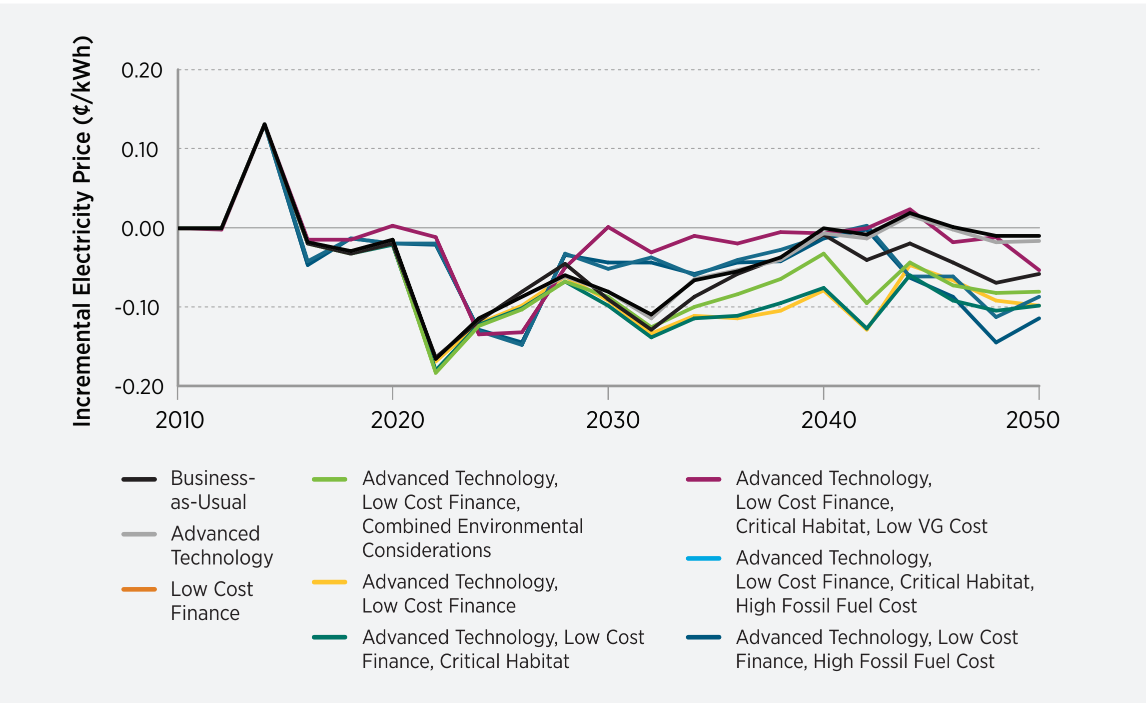


Figure 3-35. Incremental average electricity prices in selected scenarios relative to their corresponding baseline scenarios

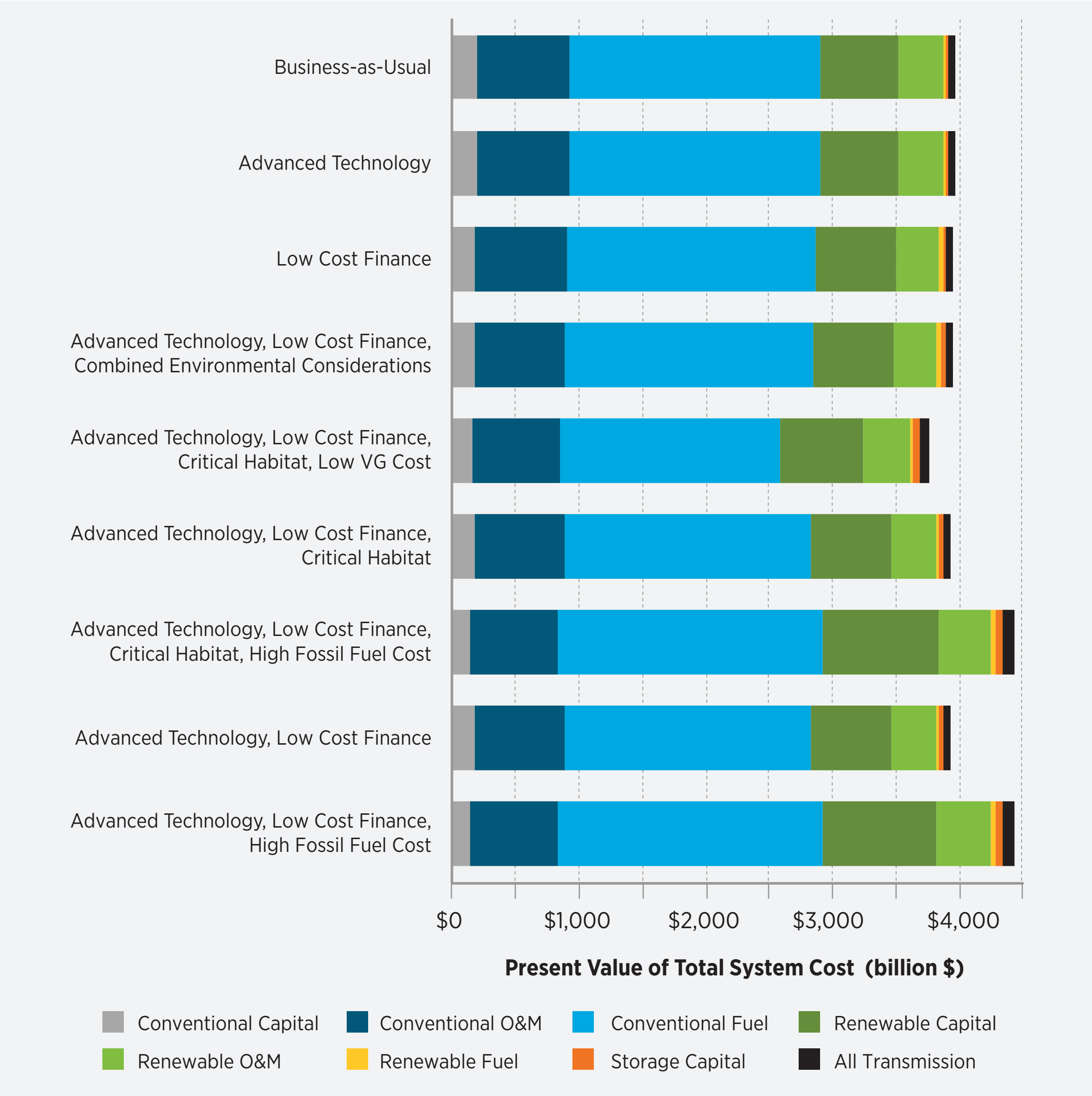


Figure 3-36. Present value of total system cost for the selected scenarios

$3,760 billion. Scenarios varying these cost assumptions in the opposite direction (not shown) change system costs by a similar magnitude in the opposite direction.

Relative to these major power system cost drivers, hydropower economics and resource variables have a less noticeable impact on system costs as a whole (Figure 3-36). System costs for scenarios varying hydropower economics and resource are $0–$26 billion less than *Business-as-Usual*, which corresponds to less than a 1% change for the scenario assuming *Advanced Technology, Low Cost Finance*, and no NSD resource avoidance.

While the effects of hydropower-specific variables are less than the changes caused by fossil fuel and wind/solar costs, the relative power system cost and savings of the selected scenarios can still be evaluated. To illustrate this comparison, Figure 3-37 plots the incremental present value of system savings for the selected scenarios relative to the baseline.

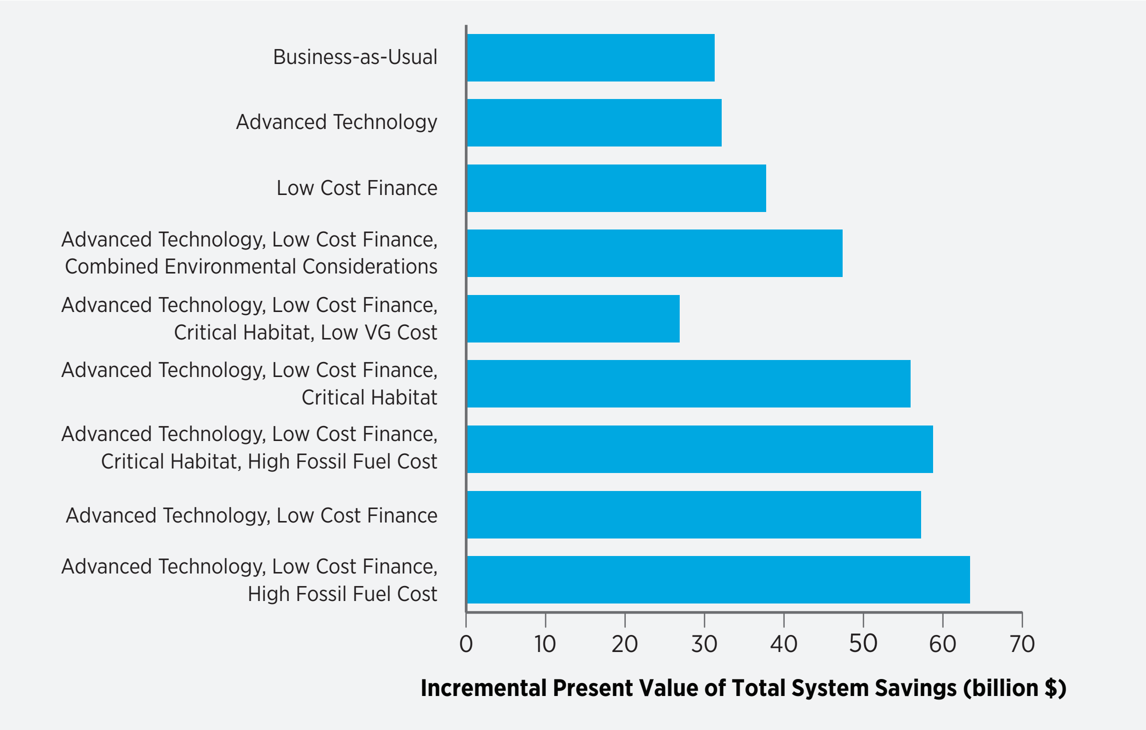


Figure 3-37. Incremental system costs of selected scenarios, relative to their corresponding baseline scenarios

The range of savings across selected scenarios is $27 billion to $63 billion, corresponding to 0.7–1.4% of total system costs. Absent any improvements to hydropower technology costs or financing, *Business-as-Usual* produces $31 billion in savings, primarily by allowing economic hydropower generation upgrades that produce low-cost electricity. While an additional $6 billion is spent on renewables due to direct and indirect expenditures from hydropower growth, $36 billion is saved in fossil and nuclear fuel and capital costs. The bulk of the latter is in fossil fuel savings.[21]

For other scenarios, savings are largely proportional to hydropower deployment, which follows from the hydropower economics and resource assumptions in these scenarios. The scenario with highest deployment, *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost,* achieves $63 billion in savings. Renewable and storage costs increase by $75 billion, but these added costs are more than offset by fossil and nuclear cost savings of $134 billion. Though the relative costs and savings from each cost category vary across scenarios, savings are consistently achieved primarily through reduced fossil and nuclear costs, with the largest contributor being fossil fuel costs.

The notable exception to the relationship between savings and hydropower deployment is the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* scenario. With *Low VG Costs*, lower baseline natural gas usage and prices lead to a smaller incremental benefit from displacing natural gas-based generation with hydropower. Though *Low VG Costs* lead to an overall lower-cost system than *Business-as-Usual*, this system with high renewable generation and low fossil fuel generation reduces the opportunity for hydropower to displace fossil fuel generation and cost.

Though substantial in magnitude for the hydropower industry, incremental cost savings on the order of 1% remain relatively small in the context of total system costs. While the *Hydropower Vision* analysis scenarios reduce electric sector costs under a wide range of system conditions, the absolute change is much smaller than the stronger market drivers such as fossil fuel or VG costs.

21. The remaining balance is storage capital, storage operations and maintenance, and transmission costs.

3.5.4 Hydropower Capital and Operating Expenditures

Capital and operating costs for hydropower are shown for representative low, mid, and high deployment scenarios in Figure 3-38. Capital costs follow largely from trends in capacity deployment, while operating costs grow over time as new capacity comes online. Before 2018, expenses in all scenarios are primarily operating costs of the existing fleet and capital costs attributed to announced hydropower projects that come online through 2018. After 2018, costs in the *Business-as-Usual* scenario are primarily attributed to continued operation of the existing fleet, with the only notable difference being pre-2030 capital costs for upgrades. Other scenarios deploy NPD and NSD resource, so capital costs for hydropower generation are much higher than *Business-as-Usual* in many years. The temporary reduction in new capacity in the early 2030s can be attributed to the stagnating stringency of the CPP, which temporarily reduces incentives for low-carbon electricity before demand growth motivates additional low-carbon capacity growth. The highest-cost time periods are those when

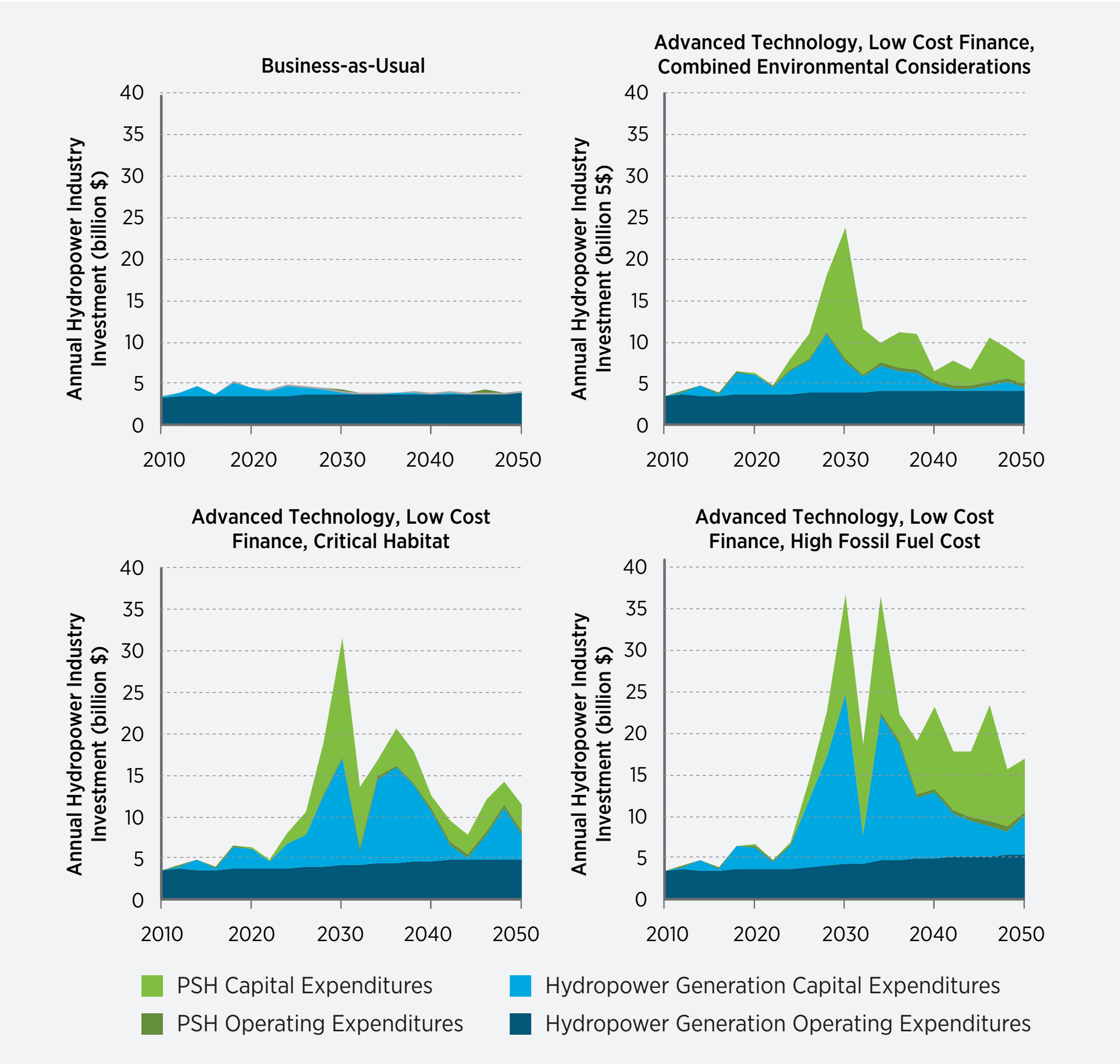


Figure 3-38. Hydropower industry investments by market segment in *Advanced Technology, Low Cost Finance, Critical Habitat* scenario and representative low, mid, and high deployment scenarios

large quantities of both NSD and PSH are deployed. While NSD deployment tends to fall in the later years, PSH deployment remains strong in scenarios supporting high deployment.

Annual variance in industry costs is likely higher than what would be observed in practice due to supply chain constraints, financing behavior, and construction schedules. The average post-2016 expenditures are $4.2 billion/year in *Business-as-Usual*; $9.9 billion/year in *Advanced Technology, Low Cost Finance, Combined Environmental Considerations*; $13.0 billion/year in *Advanced Technology, Low Cost Finance, Critical Habitat*; and $18.2 billion/year in *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost*. For a given scenario, annual industry costs would likely be somewhere between this average and the range of values observed in model years.

3.5.5 Energy Diversity and Risk Reduction

Electric sector resource planning must account for unique risk profiles for different sources of electricity. For instance, capital-intensive technologies are subject to construction material prices, while fossil fuel-based technologies are subject to risks in fuel supply and price. Additional risks result from environmental impacts and the potential for social or political barriers to cost-effective construction and operation of electricity systems. Hydropower is exposed to risk in capital prices (and interest rates), environmental impacts, and variability in long-term and year-to-year water availability. Once built, however, hydropower becomes a low-cost electricity source with high predictability on the daily to weekly time scales that are important for balancing electricity supply and demand.

The impact of the selected scenarios on system cost uncertainty and risk can be examined in the context of the ReEDS model by comparing how hydropower growth reduces the range of potential system costs when other market variables are uncertain. With reference hydropower assumptions, the present value of system costs can range widely depending on the trajectory of fossil fuel and VG prices; high fossil fuel costs ***increase*** power system costs 14%, while low costs ***reduce*** this cost by 15%. Variation in VG costs with reference hydropower assumptions ***increases*** power system cost by up to 10%, or ***reduces*** it by 5%. Hydropower deployment under *Advanced Technology, Low Cost Finance* scenario conditions reduces these uncertain ranges by less than 1% in each case, as new hydropower deployment makes up a small fraction of the system as a whole.

New hydropower also reduces fossil fuel use, which can affect the supply-demand equilibrium for fossil fuels and, as such, potentially reduce fossil fuel prices. Figure 3-39 plots the difference in coal and natural gas usage between the nine selected scenarios and a no new hydropower baseline. Positive values indicate higher fuel use or cost than the baseline, while negative values indicate lower fuel use or cost than the baseline. Modeled coal use throughout the study period varies from 15–16 quadrillion British thermal units (Btu) in 2016 to 6–9 quadrillion Btu in 2050, while natural gas use is 7 quadrillion Btu in 2016 and 6–10 quadrillion Btu in 2050. As such, the differences shown in these figures are on the order of 10% or less of the total. For scenarios varying only hydropower assumptions, coal usage is slightly higher in many years to replace flexible generation capabilities lost when hydropower displaces flexible natural gas-based capacity. Across these scenarios, coal usage ranges from a 1.8 quadrillion Btu reduction to a 4.3 quadrillion Btu increase. With *High Fossil Fuel Costs* or *Low VG Costs*, however, new hydropower generation more persistently results in reduced coal usage, with a 2017–2050 reduction of 3.1–5.6 quadrillion Btu. Consistent with the generation displacement results shown in Figure 3-32, natural gas usage is lower for scenarios when improved hydropower economics lead to substantial new deployment.

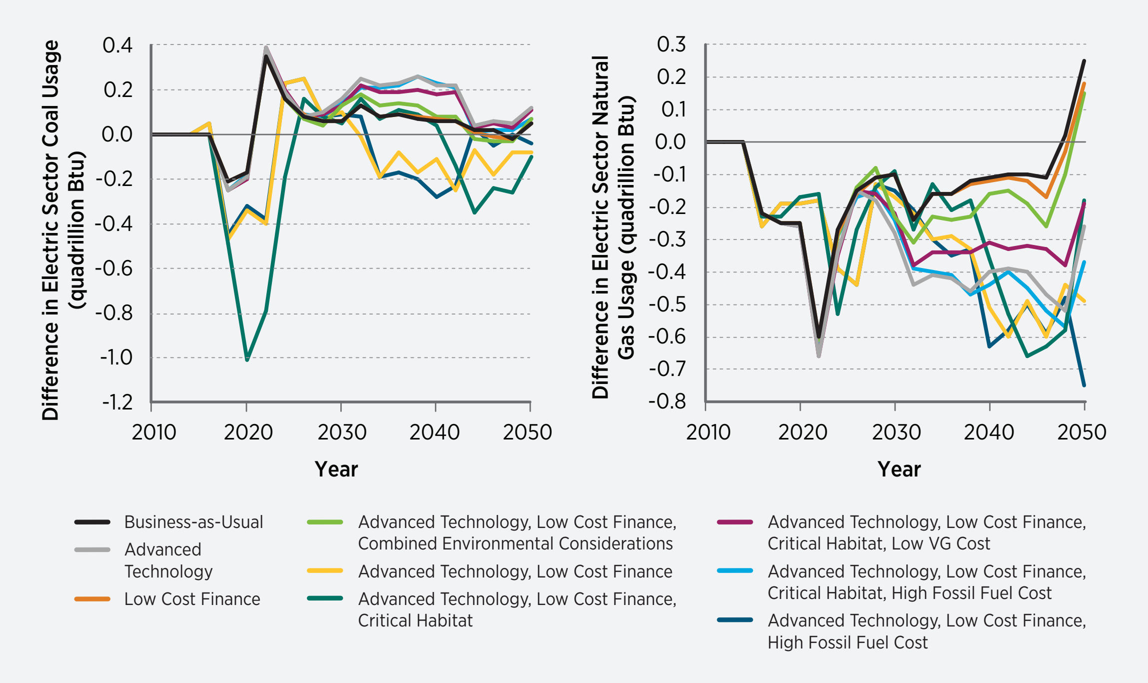


Figure 3-39. Differences in electric sector fossil fuel usage in selected hydropower generation and pumped storage hydropower deployment scenarios relative to a no new hydropower baseline (differences taken as scenario value minus baseline value)

ReEDS does not contain a full fossil fuel supply sector model, but it does incorporate natural gas supply curves to represent price elasticity to natural gas demand in the electric sector.[22] This framework produces modeled natural gas prices, which are then used to produce Figure 3-40 plotting differences in national average natural gas prices between each scenario and a no new hydropower baseline. Trends follow those in natural gas usage, with lower gas usage corresponding to lower prices for a given set of electricity market conditions[23]. Gas prices vary from approximately $5/MMBtu (one million British Thermal Units) in 2018 to $9/MMBtu in 2050 for scenarios with reference fossil fuel costs and reach $11.5/MMBtu with *High Fossil Fuel Costs*, making price differences in Figure 3-40 within 3% of the baseline in all years and scenarios. Though this change is small, the absolute impact can be more noticeable given the large volumes of natural gas used. For instance, if the ReEDS gas price reductions were applied to AEO 2015 Reference Case projections of non-electric sector natural gas usage, the result is a net present value range across scenarios (from 2017 to 2050 discounted at 3% real) of $11 billion to $31 billion in natural gas cost savings to consumers outside of the electric power sector [19].[24]

22. Coal prices are exogenously specified in ReEDS as described in Section 3.1 and Appendix D.

23. For example, scenarios with *High Fossil Fuel Costs*, while having higher absolute natural gas prices, are compared to a *High Fossil Fuel Cost* baseline, so the price changes are of the same order as other scenarios.

24. This consumer savings constitutes primarily a transfer from producers (including owners and investors) to consumers, and, as such, it does not necessarily represent an economy-wide increase in disposable income. In addition, this calculation does not take into account any possible increase in natural gas demand due to reduced prices. A detailed economic analysis that fully accounts for fuel supply and demand equilibrium is outside the scope of this report, but the calculations herein demonstrate that the *Hydropower Vision* could allow fossil fuel cost savings both within and outside the electric sector, particularly to consumers.

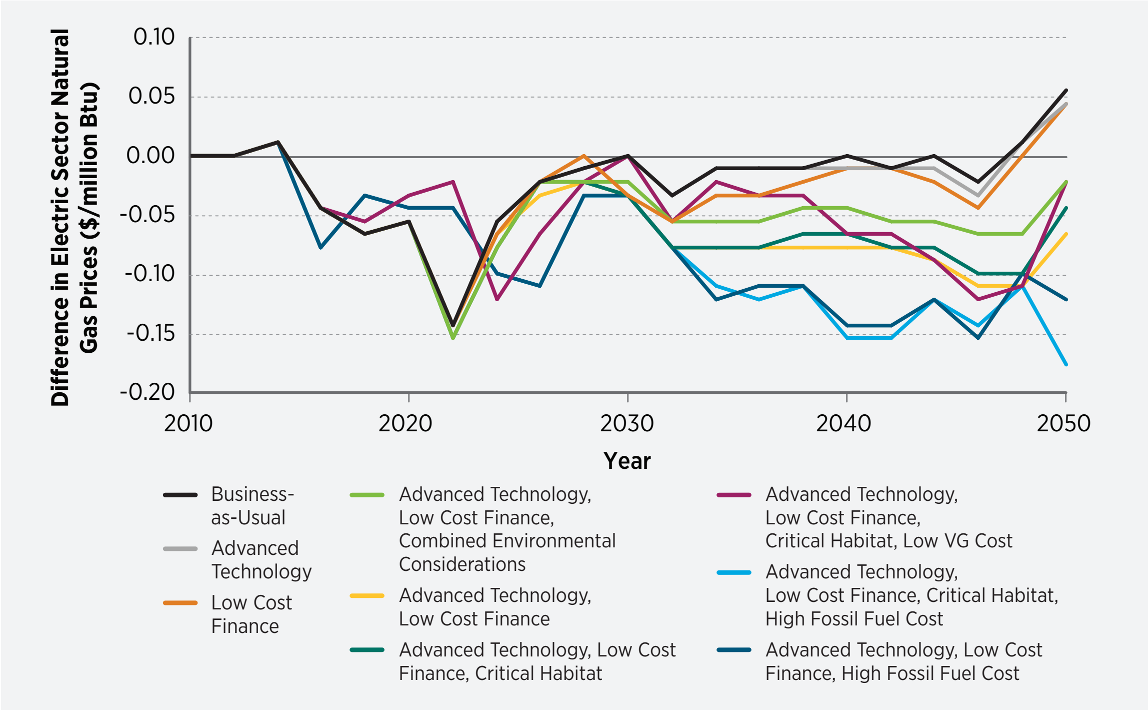


Figure 3-40. Differences in electric sector natural gas prices in selected hydropower generation and pumped storage hydropower deployment scenarios relative to a no new hydropower baseline (differences taken as scenario value minus baseline value)

3.5.6 Greenhouse Gas Emissions Reductions

The majority of scientists agree that significant changes will occur to the Earth's climate on both multi-decadal and multi-century scales as a result of past and future anthropogenic GHG emissions [16]. Renewable energy (including hydropower) could be deployed to reduce projected GHG emissions, which, in turn, could help to decrease the likelihood and potential severity of future climate-related damages [20, 21].

This section discusses estimates of the potential GHG reductions resulting from new hydropower growth within the nine selected scenarios explored in detail within the *Hydropower Vision* analysis. All scenarios are considered relative to a baseline scenario with no new hydropower construction. The impact of potential GHG emissions avoided by retaining the existing hydropower fleet is also assessed by assuming that, if existing hydropower were not available, it would be replaced by the average generation mix in the remainder of the fleet, in a given region, in a given ReEDS solve year (see also Section 3.1). GHG impacts are estimated on a life cycle basis and are based on a review of peer-reviewed publications and knowledge as of 2016 of GHG emissions from hydropower and other electricity generation technologies.[25] The economic value of the GHG reductions associated with

25. A life cycle-based assessment considers upstream emissions, ongoing combustion and non-combustion emissions, and downstream emissions. Upstream and downstream emissions include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, on-site construction, project decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the equipment and other site material. For more information on the life cycle emissions (and associated uncertainties) for a range of renewable and non-renewable electricity generating technologies, see Appendix G, which includes results from an extensive database of published life cycle assessments on electricity generation technologies available through the National Renewable Energy Laboratory's Life Cycle Assessment Harmonization project: *www.nrel.gov/harmonization*. Direct combustion-related emissions for ReEDS scenarios are calculated but not reported quantitatively in this section of the *Hydropower Vision*.

reduced carbon dioxide emissions are then estimated based on a range of independently developed social cost of carbon (SCC) estimates, in terms of present value dollars [22, 23].[26]

The *Hydropower Vision* acknowledges that there are important scientific questions surrounding the potential for GHG emissions from bacterial processes in waters and soils (hereafter "biogenic GHG emissions") of any freshwater systems, including impoundment systems such as hydropower reservoirs. However, given the state of scientific understanding and discourse, the *Hydropower Vision* does not attempt to address hydropower-related biogenic GHG emissions given persistent, large uncertainties. Instead, an introduction to biogenic GHG emissions and a review of the literature focused in this field are described in Text Box 3-1. This limitation is acknowledged as a source of uncertainty generally in the estimation of life cycle GHG emissions as a function of hydropower deployment.

In addition to GHG emissions, this chapter also considers another related metric—energy return on investment (or EROI)—that is often used to compare energy technologies on a life cycle basis, and one in which hydropower electricity performs well in comparison to other electricity generation sources. The literature on the EROI of different electricity generation technologies, including hydropower, is also summarized (Text Box 3-2).

Hydropower Electricity and Reduced Greenhouse Gas Emissions

Maintaining the existing fleet and achieving the hydropower deployment levels of the nine selected scenarios explored here will generally reduce fossil energy use, leading to reduced fossil fuel-based GHG emissions in the electric sector. At a sub-national level, existing fleet contributions to avoided combustion emissions are concentrated in the Pacific Northwest and in New York. Similarly, combustion GHG emissions avoided with new hydropower are concentrated in portions of Arkansas and New York, as well as parts of the Southeast, Midwest, and West Coast.

On a life cycle basis, GHG emissions from hydropower electricity generation are lower than fossil fuels and similar to other renewable technologies (see Appendix G). As a result, the nine scenarios evaluated for the *Hydropower Vision* result in life cycle GHG emission reductions larger in absolute terms than combustion-only carbon dioxide (CO_2e) reductions. Figure 3-41 and Table 3-6 show the life cycle emissions reductions associated with the selected scenarios through time, relative to a baseline scenario.

Initially, the existing hydropower fleet avoids annual emissions of around 0.25 gigatonnes (GT) of carbon dioxide equivalent (CO_2e)/year near 2016. This value gradually declines to near zero by 2050 as carbon intensity of the remaining non-hydropower generation mix declines. Cumulative avoided GHG emissions by the existing fleet from 2017–2050 are estimated at 4.9 GT CO_2e. Annual emissions reductions from new hydropower deployment scenarios vary from 0—0.10 GT CO_2e/year between 2017–2050. Cumulative GHG emission reductions (2017–2050) from new hydropower deployment range from 0.2–1.3 GT CO_2e, with increased hydropower deployment and high fossil fuel prices contributing to outcomes with greater GHG reductions.

While estimates in Figure 3-41 and Table 3-6 suggest potential for hydropower electricity in reducing GHG emissions, there are two key factors that introduce some uncertainty in these results and may affect the actual emissions savings from hydropower growth. First, as discussed in Text Box 3-1, all freshwater systems have potential for biogenic GHG emissions. Second, GHG reductions in the electric sector may induce secondary impacts throughout the economy, including economy-wide rebound[27] and spillover[28] effects. Moreover, the model used for the *Hydropower Vision* analysis focuses on the electric sector, and the analysis is intentionally policy-agnostic.

26. The SCC methods applied here are consistent not only with those used by U.S. regulatory agencies [24], but also with those used in the academic literature [25, 26, 27, 28, 29].

27. The rebound effect is a reduction in expected gains from the use of new technologies due to several potential economic reactions. Increased use of the new technology lowers the costs of alternatives that can be substituted, decreased new technology costs allow increased household consumption of other goods and services, and new technologies allow for the new technological possibilities that build on the new technology

28. Spillover effects are a specific instance in which the use of a new technology within a defined geographic area leads to rebound effects specifically outside that geographic area.

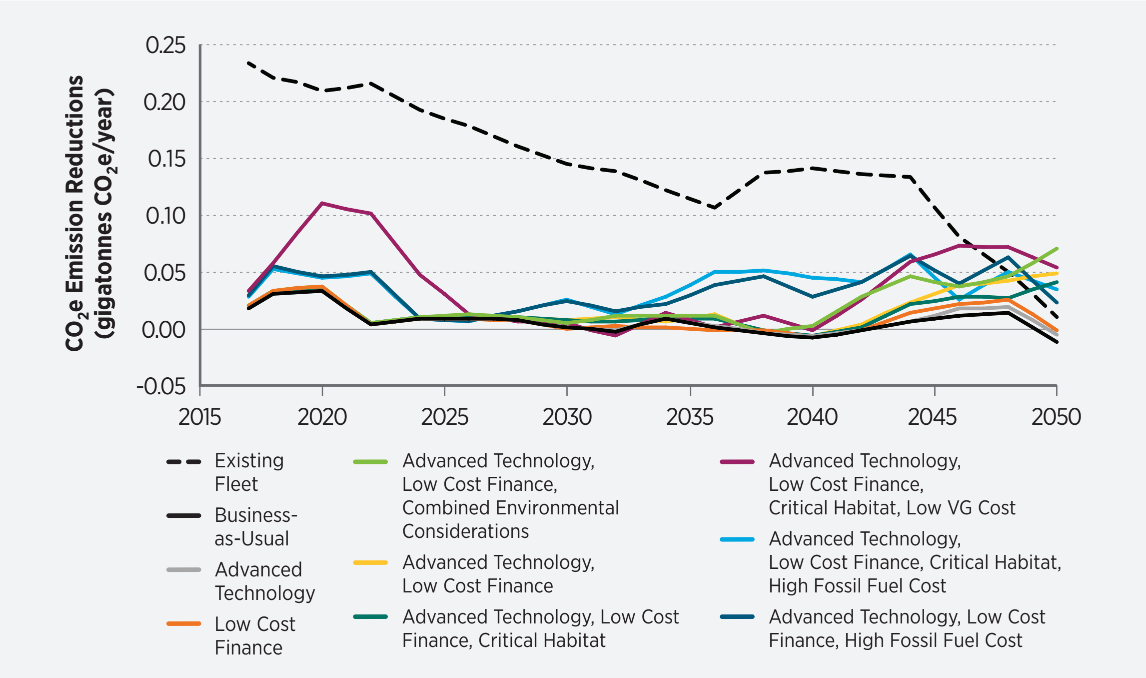


Figure 3-41. Annual life cycle greenhouse gas emissions avoided by the existing fleet and emission reductions of the selected scenarios

Table 3-6. Total Cumulative Life Cycle Emissions Reductions

Scenario	2017–2030		2017–2050	
	Reduction (GT CO_2e)	Percent Change	Reduction (GT CO_2e)	Percent Change
Existing Fleet	2.7	(8.9%)	4.9	(7.2%)
Business-as-Usual	0.2	(0.6%)	0.2	(0.3%)
Advanced Technology	0.2	(0.6%)	0.3	(0.4%)
Low Cost Finance	0.2	(0.7%)	0.3	(0.5%)
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	0.2	(0.8%)	0.7	(1.1%)
Advanced Technology, Low Cost Finance, Critical Habitat	0.2	(0.8%)	0.5	(0.7%)
Advanced Technology, Low Cost Finance	0.2	(0.8%)	0.5	(0.8%)
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	0.4	(1.4%)	1.2	(1.9%)
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	0.4	(1.3%)	1.2	(2.0%)
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	0.7	(2.4%)	1.3	(2.0%)

Literature has shown that spillover and rebound effects can impact GHG savings, as can the specific policy mechanisms used to support renewable energy deployment [21]. Depending on how policies are deployed,[29] the significance of rebound and spillover effects, and the potential for biogenic emissions, actual GHG reductions estimated may either be higher or lower than the results presented here.

Economic Benefits of Hydropower in Limiting Climate Change Damages

The economic benefits of hydropower energy resulting from its ability to limit damages from climate change can be estimated through the use of the SCC. The SCC reflects, among other things, monetary damages resulting from the future impacts of climate change on agricultural productivity, human health, property damages, and ecosystem services [81]. The methodology for estimating the benefits from reduced GHG emissions involves multiplying the emissions reduction (on a life cycle, CO_2e basis) in any given year by the SCC for that year, and then discounting those yearly benefits to the present.[30] Because of the significant role that the existing hydropower fleet plays in carbon abatement, benefits are calculated for new hydropower under the nine selected scenarios as well as for the existing fleet.

Estimating the magnitude and timing of climate change impacts, damages, and associated costs is challenging, especially given the many uncertainties involved [20, 23, 44, 47, 48, 49, 50, 81]. Models of climate response to GHG emissions and damage functions associated with that response are imperfect. Even when looking to events over the several decades leading up to 2014, such as the upward trend in damage costs associated with extreme environmental events [51], caution is necessary to separate causation from correlation [52]. In addition, because the majority of effects will be felt decades and even centuries in the future, the choice of discount rate becomes a key concern when estimating the present value of future damages. The choice of discount rate can greatly influence the relative benefits and timing of alternative strategies to reduce carbon emissions [53, 54].

In part as a result of these challenges, a number of widely ranging estimates of the SCC are available [21, 49, 55]. Key uncertainties about the SCC result from: (1) difficulties in estimating future damages associated with different climate-related causes, as well as uncertainties about the likelihood, timing, and potential impact of (nonlinear) tipping points; (2) the high sensitivity of the SCC to assumptions about growth in world population, gross domestic product, and greenhouse gas emissions; and (3) large differences in the present value of estimated damages depending upon choice of discount rate [49, 56, 57].

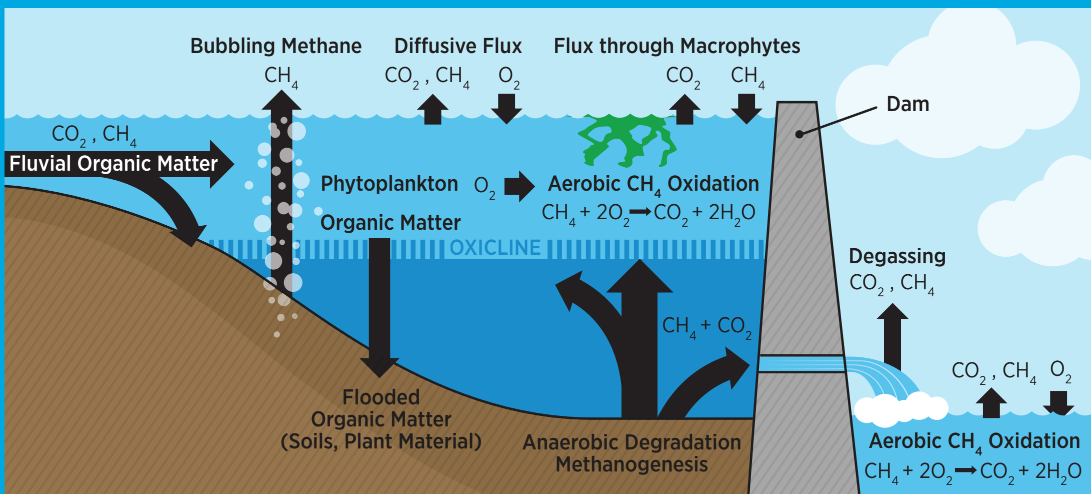
Though these uncertainties have led to some suggestions of possible improvements to SCC estimates [54, 58, 59, 60] and to questions about the use of these estimates [57], U.S. government regulatory bodies regularly use SCC estimates when formulating policy [24, 59]. Under Executive Order 12866, U.S. agencies are required, to the extent permitted by law, to assess monetary costs and benefits—even though these are considered difficult to quantify—during regulatory proceedings. To that effect, in 2010, the U.S. Interagency Working Group (IWG) on the SCC[31] used three integrated assessment models to estimate the SCC under four scenarios [22]. The IWG SCC reflects *global* damages from GHGs, and IWG recommends use of global damages. That approach is followed in the *Hydropower Vision* analysis, recognizing that lower values are obtained if only damages within the United States are considered.[32] In 2013, the IWG updated its estimates based on improvements in the integrated assessment models, which led to an increase in SCC values [23]. These numbers were revised again in 2015 [61]. IWG SCC estimates have been widely used in regulatory impact analyses in the United States, including in numerous proposed or final rules from the U.S. Environmental Protection Agency (EPA), DOE, and others [24].

29. In particular, there is general agreement that GHG savings will be greater and/or achieved at lower cost when met, at least in part, through economy-wide carbon pricing, and lower when met solely through sector-specific financial incentives for low-carbon technologies [21, 30, 31, 32, 33, 34, 35, 36, 37]
30. The discount rate varies for any individual calculation to be consistent with that assumed in the SCC estimate.
31. U.S. agencies actively involved in the process included the EPA and the Departments of Agriculture, Commerce, Energy, Transportation, and Treasury. The process was convened by the Council of Economic Advisors and the Office of Management and Budget, with active participation from the Council of Environmental Quality, National Economic Council, Office of Energy and Climate Change, and Office of Science and Technology Policy.
32. The IWG notes that a range of values from 7–23% should be used to adjust the global SCC to calculate domestic effects, but also cautions that these values are approximate, provisional, and highly speculative [22].

Text Box 3-1.

Freshwater biogenic greenhouse gas emissions

All freshwater systems, whether natural or manmade,[a] emit biogenic GHG emissions as a result of bacterial processes in waters and soils (see figure). Carbon in organic matter, either submerged under water or in the water column, is decomposed by bacteria to produce CO_2 and methane (CH_4); the produced CH_4 can then be oxidized by bacteria to CO_2. Nitrogen in organic matter forms nitrous oxide (N_2O) through bacterial denitrification. There are generally three pathways for emission of GHGs oxidization. GHG emissions related to decommissioning of a dam arise from the disturbance of sediments collected over the life of the structure that exposes accumulated carbon. N_2O emissions have not been well studied but may be important for systems with large inundation areas or in tropical areas [38]. The potential for biogenic GHG emissions from new water retaining structures and for hydropower-generating and non-powered dams is a complex issue and the subject of continuing scientific research.



Carbon dioxide and methane pathways in a freshwater reservoir.

Note: The light tan represents soils present prior to constructing the reservoir. The above processes illustrate gross GHG emissions. Many of these pathways would have been active without the reservoir, but the reservoir could increase and accelerate these pathways.

Source: Intergovernmental Panel on Climate Change

from hydropower systems to the atmosphere: diffusive flux,[b] degassing,[c] and bubbling [38].[d] All freshwater systems also bury some carbon in the sediments, where eventual exposure of these accumulated carbons to the atmosphere also can lead to the formation of biogenic GHG emissions [39, 40].

Any water retaining structure has the potential to lead to biogenic GHG emissions. Biogenic CO_2 and CH_4 emissions occur during two phases in the life cycle. GHG emissions related to the on-going operation of the water retaining structure arise from bacterial decomposition of inundated carbon and from CH_4

Existing literature suggests that ***gross*** GHGs emitted from reservoirs[e] are non-zero and variable [39]. Research suggests that newly impounded tropical reservoirs may emit significant amounts of methane with low to negligible emissions in cold and temperate climates, respectively [38]. Uncertainties still remain in the measurement methods and the scope of measurement needs to account for gross emissions [41].

Estimating ***net*** emissions from new reservoirs—the emissions that arise owing to the retaining structure and not what would have been emitted if the structure were not in place—is more challenging [42]. Inundation areas are collection points for material flowing downstream, including organic matter from terrestrial ecosystems and anthropogenic sources such as agricultural run-off and domestic sewage.

Estimating ***net*** GHG emissions requires knowing the local context such as emissions from natural and anthropogenic sources before and after building the water retaining structure. An assessment of ***net*** emissions involves: a) an estimation of natural emissions from the terrestrial ecosystem, wetlands, rivers, and lakes that were located in the area before impoundment; and b) an estimation of the effect of carbon inflow from the terrestrial ecosystem from natural and anthropogenic activities on ***net*** emissions before and after building the structure. Such quantification is a major topic of new research.

Uncertainty is leading to a lack of scientific consensus on methods for estimating ***net*** emissions from freshwater reservoirs [38]. Few existing studies assess ***net*** emissions from on-going or decommissioning activities [38], and uncertainty and the lack of study preclude the consideration of ***net*** emissions in *Hydropower Vision* analysis.

Despite these uncertainties, any new U.S. water retaining structure located mostly in cold or temperate climates are likely to be low emitters of ***net*** GHG relative to fossil fuels [38, 42]. New deployments of low-impact hydropower on undeveloped streams that do not lead to large inundation areas are also likely to have low biogenic GHG emission impacts. Powering of existing NPDs is unlikely to lead to changes in biogenic GHG emissions, since the dam has already been built [43].

The United Nations Educational, Scientific and Cultural Organization and the International Hydropower Association are among those working to standardize measurement techniques and tools for assessing ***net*** biogenic GHG emissions from reservoirs, including those used for hydropower. Those two organizations published the *GHG Measurement Guidelines for Freshwater Reservoirs* in 2010 [43] to enable standardized measurements and calculations worldwide. Subsequently, they aim to develop a database of emissions estimates for a representative set of hydropower systems worldwide. The final outcome of the project will be validated predictive modeling tools to assess the emissions status of unmonitored reservoirs as well as new reservoir sites.

a. Natural systems include rivers, lakes, and wetlands, while manmade systems include reservoirs and canals.
b. Transfer of GHG emissions from surface water to the atmosphere, both upstream and downstream of the water retaining structure.
c. Transfer of GHG emissions from any water retaining structure's outlet water to the atmosphere
d. Methane emissions resulting from carbonation, evaporation or fermentation from a water body
e. These studies are of existing hydropower facilities, which are multi-purpose. Therefore, not all GHG emission can be attributed solely to hydropower.

Text Box 3-2.

Net energy requirements for different electricity generation technologies

A large body of literature has sought to estimate, on a life cycle basis, the amount of energy required to manufacture and operate energy conversion technologies or fuels (i.e., "input" energy). This concept helps inform decision makers on the degree to which various energy technologies provide a "net" increase in energy supply and is often expressed as ***Energy Return on Investment (EROI)***.

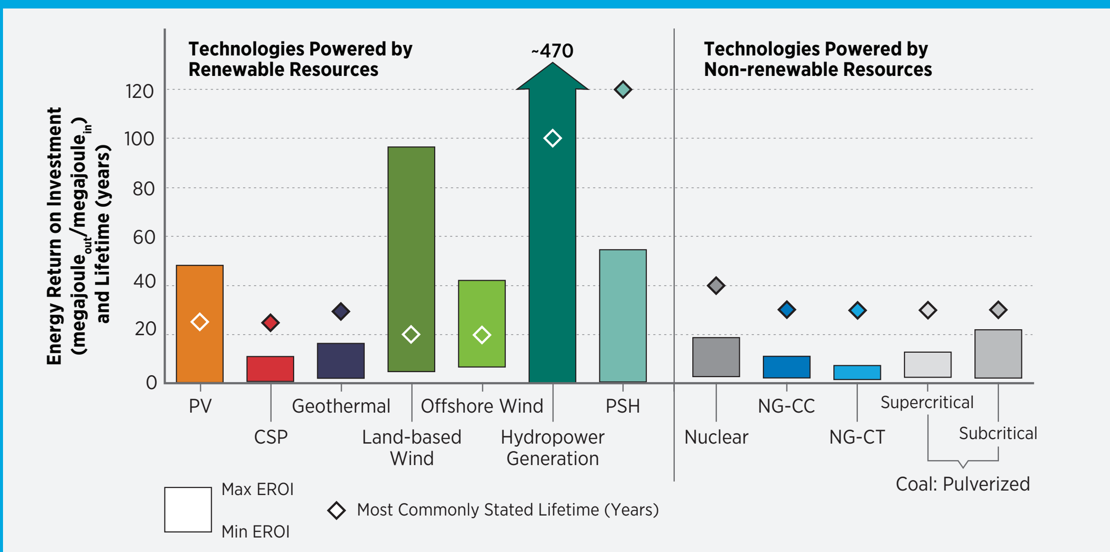
EROI expresses the lifetime amount of energy returned from a system per unit of energy invested (or embodied) in its construction, operation, and decommissioning. EROI indicates the sustainability of an energy system in terms of energy inputs.

This text box summarizes published estimates of this metric for hydropower technologies, in comparison to estimates for other electric generation technologies as presented in a recent report from the Intergovernmental Panel on Climate Change [44] and updated in Mai et al. [45]. Thirteen references reporting more than 30 EROI estimates for hydropower were reviewed using the same literature screening approach as was used for discussing life cycle GHG emissions (see Appendix G). Ranges in EROI estimates reflect current technology as well as future projections in the literature.

The figure below presents a summary of the review. These results are reported from studies that exhibit considerable methodological variability. The literature remains diverse, unconsolidated, and there has been only some analysis of the key issues that can influence results [46]. Variability in the results for hydropower, for example, may in part be due to difference in the assumed system lifetime, capacity factor; and technology evaluated (e.g., size of the dam). Pumped storage hydropower has received little study, but EROI was expected to be highly variable due net electricity generation being highly variable. This variability is related to pumped storage hydropower being used primarily as to store energy rather than as a net energy producer.

Notwithstanding these caveats, the results suggest that EROI is generally higher for renewable technologies (owing to technological advances) while being lower for conventional fossil fuel technologies (owing to resource depletion). In many cases, reservoir-based hydropower has been found to have an EROI higher than many other electricity sources. High hydropower EROI is likely linked to longer lifetimes.

Review of energy return on investment of electricity generating technologies



Note: NGCC = Natural gas combined cycle; NGCT = Natural gas combustion turbine; EROI = energy return on investment; IGCC = integrated gasification combined cycle; PSH = pumped storage hydropower.

Note: The range shown in the figure represents minimum and maximum values from the literature review. Counts of the number of literature estimates of EROI are not available as they were not reported in Edenhofer et al. [21].

Source: Non-wind and hydropower estimates from Kumar et al. [44] and updated with wind estimates from NREL [45]; hydropower estimates based on literature review detailed in Appendix G.

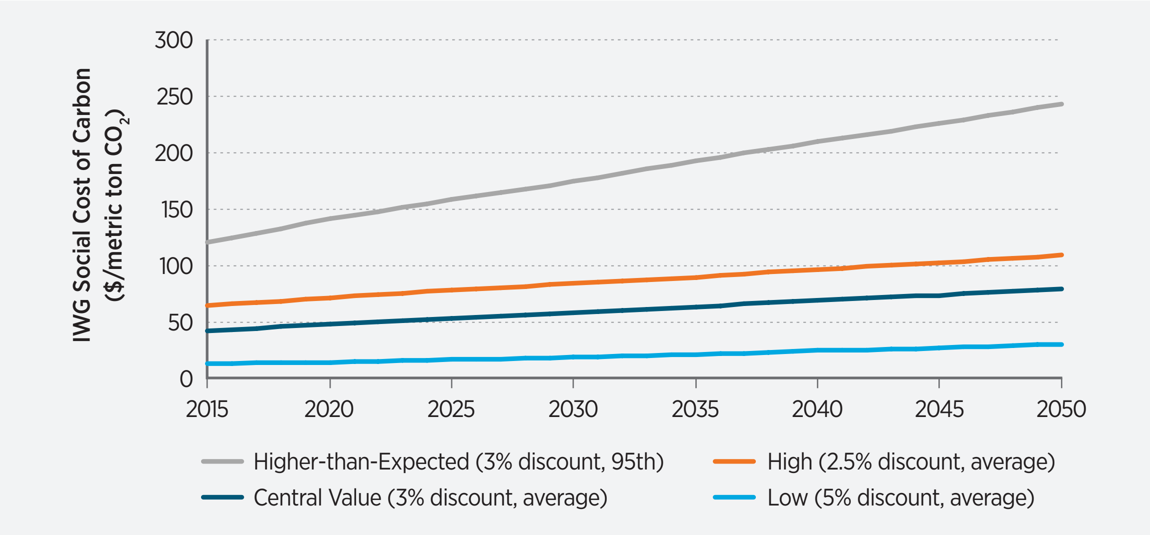


Figure 3-42. Interagency Working Group social cost of carbon estimates

To reflect the inherent uncertainties, the IWG [23] has published four SCC trajectories. Figure 3-42 illustrates these four trajectories from 2010 to 2050. Three of the four trajectories are based on the expected value of the SCC (estimated by averaging the results of the three IWG models), assuming discount rates of 2.5%, 3%, and 5% respectively.[33] A fourth trajectory represents a 95th percentile of the SCC estimates across all three models at the central 3% social discount rate. This 95th percentile case is intended to reflect a much less likely outcome, but one with a much higher than expected impact.[34]

As an alternative to valuing GHG reductions based on the SCC, those reductions are also valued based on the possible cost of complying with legal requirements to reduce GHG emissions.[35] Some U.S. states and regions have already enacted carbon reduction policies; the U.S. Congress has considered such policies in the past; and the EPA has established regulations that will limit emissions from existing and new power plants through the CPP [65, 66].[36] Especially when binding cap-and-trade programs are used to limit GHG emissions, as envisioned in part by the CPP, the climate change benefits of hydropower energy may best be valued based on cost of complying with legal requirements to reduce carbon emissions [26, 28]. In this case, the GHG co-benefits of hydropower come in the form of hydropower helping to meet the carbon reduction target, thereby offsetting some of the "marginal" costs of complying with the policy.

GHG reductions are valued in *Hydropower Vision* analysis based on two sets of estimates for this compliance cost. The first is EPA estimates of the average national cost of complying with the CPP under both mass-based and rate-based application [65][37]. Those estimates are provided by EPA for 2020, 2025, and 2030. The *Hydropower Vision* analysis interpolates between these years to estimate costs in intervening periods, and it presumes that the 2030 cost remains

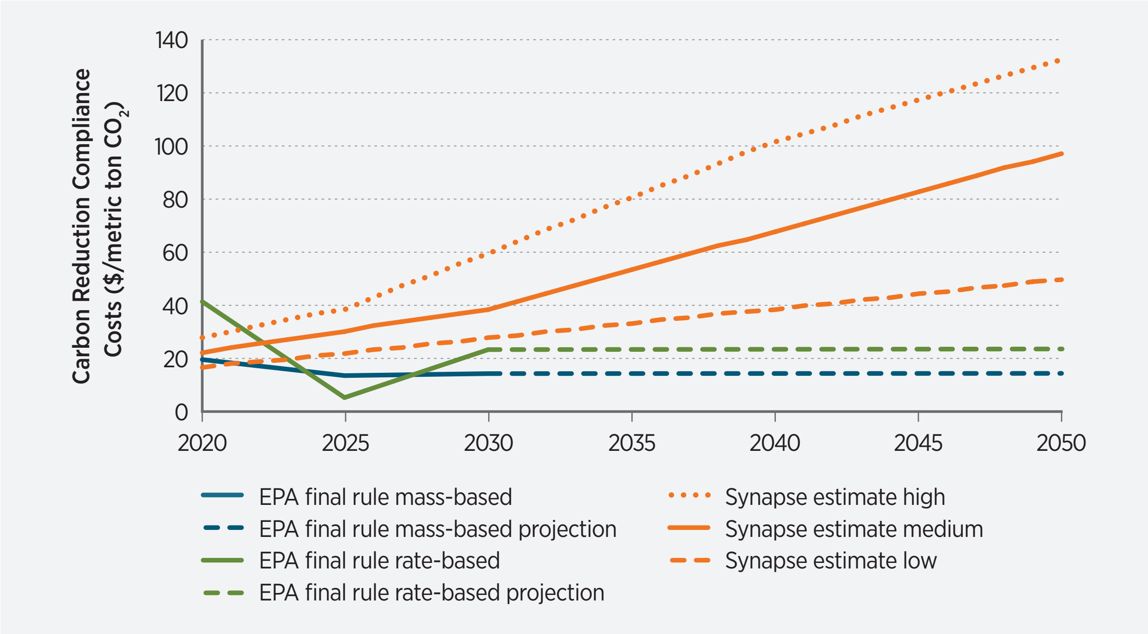
33. The use of this range of discount rates reflects uncertainty among experts about the appropriate social discount rate [22, 55].

34. Each of the integrated assessment models estimates the SCC in any given year by modeling the impact of GHG emissions in that year on climate damages over a multi-century horizon (discounted back to that year). The SCC increases over time because, as IWG explains, "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change" [22].

35. The approach used here and the discussion of incorporating compliance costs (including Figure 3-43) closely follows that used in the recent *On the Path to SunShot* study about the benefits of achieving the DOE's SunShot goals [64].

36.. As a result of the attention to carbon reduction, many utilities already regularly consider the possibility of future policies to reduce GHGs in resource planning, and thereby treat renewable energy sources as options for reducing the possible future costs of climate mitigation [66, 67, 68].

37. Rate-based refers to CO_2 emissions per megawatt-hour, while mass-based refers to the total tons emitted.



Source: Wiser et al 2016 [64]

Figure 3-43. Estimated social cost of carbon for compliance based on U.S. Environmental Protection Agency estimates and Synapse estimates

constant through 2050. The analysis also uses Synapse Energy Economics [66] estimates of carbon costs under "low," "medium," and "high" trajectories. These estimates consider and assume the possibility of more stringent long-term carbon reduction goals than envisioned by the CPP, and, as such, entail higher costs than those from EPA [65]. Figure 3-43 summarizes both sets of resulting carbon compliance costs.

Using the four IWG SCC estimates and the five compliance scenarios, Figure 3-44 shows the present value of the estimated global benefits of life cycle GHG reductions from 2017 to 2050 from the existing fleet (assuming no rebound or spillover effects). For the IWG central value case, discounted present value benefits are estimated to be $185 billion. Across the three expected-value cases, benefits range from $46 billion (for the 5% discount rate case) to $286 billion (for the 2.5% discount rate case). The fourth case, which accounts for the limited possibility of more extreme global climate damages, results in a benefit estimate of $555 billion.[38] The values for the compliance cases are lower on average and show less variation.

There are notable uncertainties in the benefits associated with existing hydropower (and the different hydropower growth scenarios that follow) that extend beyond alternative estimates of the SCC. This includes uncertainties in the evolution of the electricity system and the corresponding influence on hydropower's ability to reduce GHG emissions. This uncertainty exists for a variety of reasons, including the impact of uncertainty in future fossil prices, the timing and nature of carbon or other regulation, accuracy in assumed financing terms, and assumptions embedded in the ReEDS capacity expansion model. In part for these reasons, the balance of this section focuses on the IWG SCC valuation methods across the full range of the nine selected model scenarios.

Figure 3-45 shows, for the four IWG cases, the present value of the estimated global benefits of life cycle GHG reductions from 2017 to 2050 for the nine selected scenarios explored in depth in the *Hydropower Vision* analysis, compared to their respective

38. Annual benefits reflecting the discounted future benefits of yearly avoided emissions are as follows: (1) low: $2.86 billion (2020), $2.6 billion (2030), $0.31 billion (2050); (2) central: $10.0 billion (2020), $8,26 billion (2030), $0.8 billion (2050); (3) high: $14.8 billion (2020), $12.1 billion (2030), $1.1 billion (2050); (4) higher-than-expected: $29.4 billion (2020), $25.1 billion (2030), $2.43 billion (2050) [2015$].

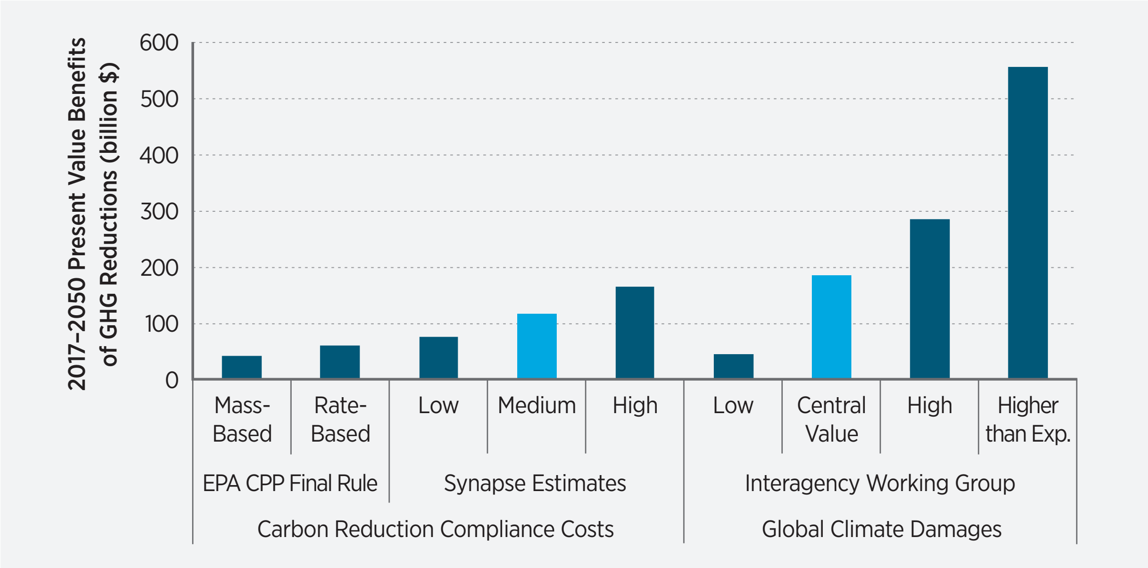


Figure 3-44. Estimated benefits of the existing fleet based on estimated avoided climate change damages and estimated avoided compliance costs

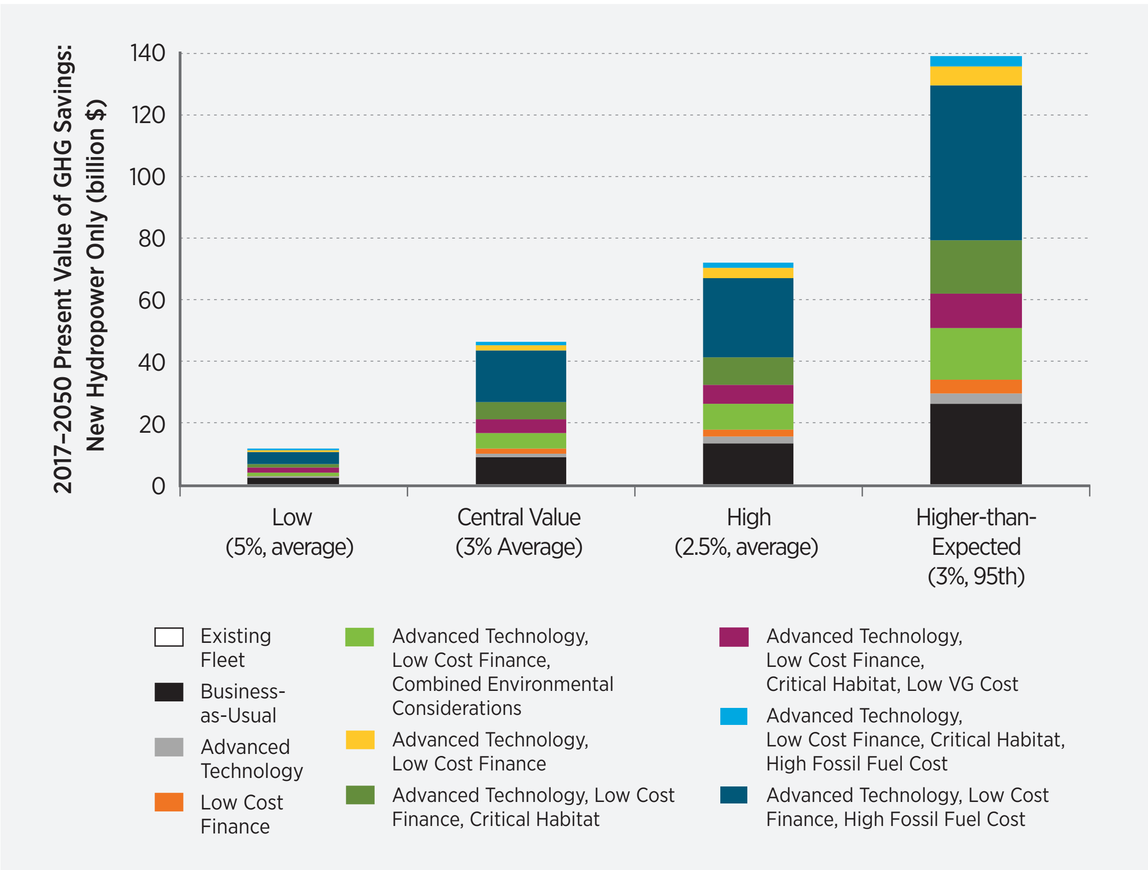


Figure 3-45. Estimated benefits of the nine selected scenarios due to avoided climate change damages

baseline scenario. Figure 3-46 shows the same information, but includes the present value of social benefits of the existing fleet.[39] The present values of the benefits associated with the existing hydropower fleet are larger than those anticipated for new hydropower under any of the new hydropower scenarios explored, as the existing fleet produces the majority of hydropower energy across all scenarios.

The present value of the estimated global benefits of life cycle GHG reductions from 2017 to 2050 from new hydropower growth in the nine selected scenarios varies substantially. For the IWG central value case, discounted present value benefits are estimated to be in the range from $8.8 billion for *Business-as-Usual* to $46.4 billion for *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* scenario. Under the IWG central value case assumptions, new hydropower deployment increases the total present value of GHG benefits by 5% to 25% over that achieved from existing hydropower alone.

Across the three expected-value cases, benefits range from $2.3 billion to $11.2 billion for the 5% discount rate case and from $13.5 billion to $72.0 billion for the 2.5% discount rate case. The fourth case, which accounts for the limited possibility of more extreme global climate damages, results in a benefit estimate ranging from $26.1 billion to $139 billion.[40]

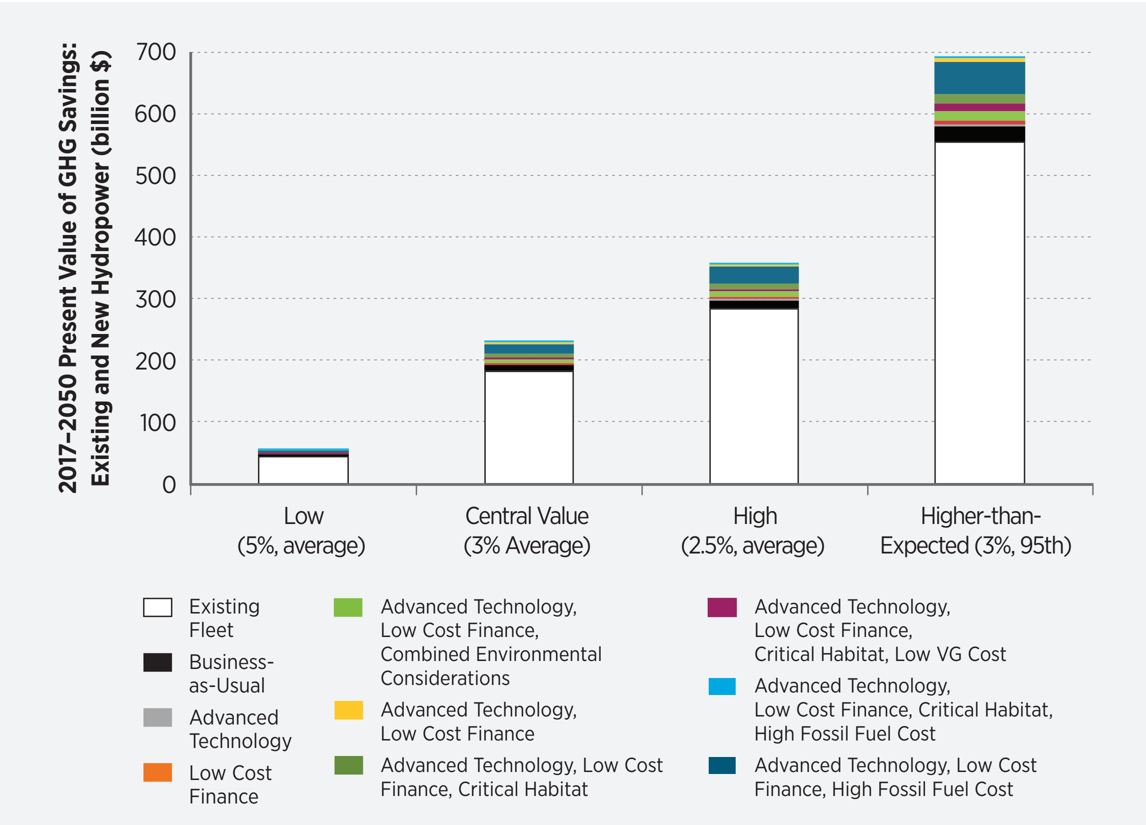


Figure 3-46. Estimated benefits of the nine selected scenarios and the existing fleet due to avoided climate change damages

39. Compliance cases are not included, as the similarity and differences of compliance to IWG cases are shown in Figure 3-44 (including the similarity of the median Synapse case to the central IWG case).

40. As suggested by the IWG, domestic benefits might be 7–23% of these global estimates [22]

3.5.7 Air Pollution Emissions, Human Health, and Environmental Benefits

Combusting fuels to generate electricity produces air pollutants that harm human health and cause environmental damage [69]. Epidemiological studies have shown a causal association between increased mortality (and morbidity) and exposure to air pollution (for examples of the association with mortality, see Dockery et al. 1993 [70]; Krewski et al. 2009 [71]; Lepeule et al. 2012 [72]). Lim et al. [73] estimate more than 3 million premature deaths globally, each year, are attributable to outdoor particulate air pollution.

In the United States, a number of studies have evaluated the potential air quality and public health benefits of reducing combustion-based electricity generation. For example, Driscoll et al. [74] found that policies aimed at reducing power-sector CO_2 emissions would also reduce fine particulate matter ($PM_{2.5}$) and ozone, preventing as many as 3,500 premature mortalities in 2020. Siler-Evans et al. [26] value the health and environmental benefits of displaced conventional generation from new solar and wind power at 1¢/kWh to 10¢/kWh, with the range largely reflecting locational differences. The EPA has estimated that its CPP would provide \$14 billion to \$34 billion of monetized health co-benefits in 2030, based mostly on reductions in premature mortality [65].

Though all energy sources have environmental impacts, most renewable and non-combustion based electricity sources—including hydropower—have no direct air pollution emissions and low life cycle air pollution emissions [44, 75]. Therefore, the existing and new hydropower generation resource estimated by ReEDS has the potential to reduce air pollution emissions into the future.

To evaluate the air quality benefits of existing hydropower and new hydropower deployment in the nine modeled scenarios, the changes in emissions of SO_2, NO_x, and $PM_{2.5}$ from 2017 to 2050 due to hydropower electricity generation are estimated. Based on the emission changes, the public health and environmental impacts are quantified in the form of mortality and morbidity outcomes, as well as in monetary terms. Given uncertainty in pollutant transport, transformation, and exposure as well as uncertainty in the human response to ambient $PM_{2.5}$ and ozone, multiple established methods are used to quantify the health and environmental outcomes and monetary benefits of the emissions changes. The overall approach used to calculate the benefits of new capacity under the capacity expansion scenarios is similar to that used in DOE's *Wind Vision* report [3], and is broadly consistent with methods used in Cullen [28], Driscoll et al. [74], EPA [65], Fann et al. [76], Johnson et al. [25], Novan [77], NRC [69], McCubbin and Sovacool [27], and Siler-Evans et al. [26]. In addition to calculating the benefits of new capacity, a modified approach is used to calculate the benefits of maintaining the existing fleet. The two approaches are described below.

The emission benefits of new capacity under each future scenario is found as the difference between ReEDS-estimated, power-sector combustion-related SO_2 and NO_x emissions in each of the nine selected scenarios relative to a baseline scenario with no new hydropower growth. Power-sector $PM_{2.5}$ emission benefits are calculated similarly, except they are a function of ReEDS generation by power plant type and location.[41] Incorporated in these estimates are assumptions about power sector regulations that apply to emissions of SO_2, NO_X, and/or $PM_{2.5}$, such as the Mercury Air Toxics Rule (MATS) and the Cross-State Air Pollution Rule (CSAPR).[42] Of particular importance to this analysis, EPA's CPP has been incorporated into ReEDS. The CPP limits CO_2 emissions but does not directly address emissions of criteria pollutants.

41. $PM_{2.5}$ emission estimates are developed for both scenarios as a function of the product of ReEDS generation outputs (MWh, by generation type and vintage) and average emission rates (grams/MWh, by generation type). Average $PM_{2.5}$ emissions rates (reported by Argonne National Laboratory [78, 79]) are differentiated by generation type (coal, gas, or oil) and U.S. state. Additionally, $PM_{2.5}$ emission factors are adjusted over time to comply with scheduled $PM_{2.5}$ MATS limits for existing plants (for more details see Appendix L of the Wind Vision report [3]).

42. Although CSAPR is represented in ReEDS, it is essentially non-binding due to the SO_2 reductions required for MATS and due to the long-term substitution of natural gas and other generation sources for coal power generation. Although MATS and CSAPR are both under some legal uncertainty, it is assumed that MATS or something like MATS will remain as an active regulation (supporting this assumption, to a significant degree, the effect of MATS has already been seen, though actual and announced coal plant retirements).

The emissions benefits of the existing fleet are calculated solely for a baseline "no new hydropower" scenario. Specifically, the average non-hydropower emission rate (in grams per megawatt-hour (MWh)-non-hydropower) for SO_2, NO_X, and $PM_{2.5}$ is calculated for each year (2017–2050) over three large regions defined by EPA [65]. Following this step, the electricity generated by hydropower within each region and for each year is multiplied by the corresponding non-hydropower emission rate, providing a total emission benefit.[43]

Based on these emission changes, two different peer-reviewed approaches are used to calculate a range of health and environmental benefits (including reduced morbidity and mortality outcomes and total monetary value). Each approach accounts for pollutant transport and chemical transformation as well as population exposure and response: (1) the Air Pollution Emission Experiments and Policy analysis model (AP2, formerly APEEP; created by and described in Muller et al. [80]), and (2) EPA's benefit-per-ton methodology developed for the Clean Power Plan [65].[44] The EPA CPP approach includes two estimates of the health impacts in order to span the uncertainty in the underlying epidemiological studies.[45] The two outputs from the EPA CPP approach are identified as 'EPA Low' and 'EPA High.' The 'low' and 'high' classifications correspond to differences only between the underlying health impact functions employed by EPA, and EPA notes they do not favor either of its estimates over the other. The simple average of all three benefit estimates is used as the "central" value. One important assumption across all methods used is the monetary value of preventing a premature mortality (or the Value of Statistical Life). Consistent with the broader literature, all use a Value of Statistical Life of approximately $6 million dollars in year 2000.[46]

Several additional aspects of the methodology, and possible related limitations, warrant noting:

- The focus is on a subset of air emissions impacts: SO_2, NO_x, and $PM_{2.5}$. Non-quantified impacts include heavy metal releases, radiological releases, waste products, and land use impacts associated with power and upstream fuel production, as well as noise, aesthetics, and others. Only emissions from power plant operations are considered, ignoring the smaller upstream and downstream life-cycle impacts.
- The air emissions impact estimates are inherently uncertain, in part due to the impact of uncertain policy and market factors on those reductions.
- The methodology presumes that the MATS is maintained or replaced with a similar regulation such that SO_2 and NO_x cap-and-trade programs, such as CSAPR, are essentially non-binding over time. Otherwise, the benefits of the new capacity in the

43. The benefits of the existing fleet were also calculated with the AP2 model, following a similar methodology. In this case, the emissions in the baseline without the existing fleet needed to be calculated for each of the 134 ReEDS regions to match the resolution of the AP2 model. The percentage emission increase for each of the pollutants, across the three EPA regions and for each year, was applied to each of the corresponding ReEDS regions. In this way, the total emission changes found at the EPA region were simply distributed to each smaller ReEDS region and weighted by the baseline level of emissions.

44. Benefits calculated by AP2 and EPA CPP differ in a number of respects. For example, the AP2 model accounts for not only mortality and morbidity, but also air pollution-induced decreases to timber and agriculture yields, visibility reductions, accelerated materials degradation, and reductions in recreation services; while benefits calculated with the EPA CPP benefit-per-ton approach include only mortality and morbidity. Both the EPA CPP benefit-per-ton approach and the AP2 model include the benefits from primary and secondary particulate reductions and from ozone reductions; however, the exact pollutants considered in terms of primary particulate exposure varies.

45. EPA Low is based on research summarized in Krewski et al. [71] and Bell et al. [82], whereas EPA High is based on research presented in Lepeule et al. [72] and Levy et al. [83]. Both sets of epidemiological research have different strengths and weaknesses, and EPA indicates that it does not favor one result over the other.

46. The AP2 model contains monetized benefit-per-ton estimates based on emissions in the year 2008, so damages from AP2 are scaled over time based on Census population projections [85] and per capita income growth projections used by AEO [85], using an elasticity of the value of statistical life to income growth consistent with NRC [69]. EPA benefit-per-ton (BPT) values are developed for each year, within each of three regions, by linearly extrapolating EPA's provided BPT values. In this manner, there is implicit representation of the population and income growth assumptions incorporated in the EPA's analysis. The 2017–2025 BPT values are based on the linear trend established by EPA's 2020 and 2025 BPT values. The 2026–2050 BPT values are based on the linear trend established by EPA's 2025 and 2030 BPT values. The same process is used for EPA's health incidence-per-ton (mortality and morbidity outcomes) estimates.

future scenarios should arguably be calculated based on allowance prices to reflect savings in the cost of complying with the cap [26].[47]

- Estimates of the health and environmental benefits associated with emissions reductions are inherently uncertain. Some, but not all, of those uncertainties are reflected by calculating benefits using two approaches (AP2, EPA) leading to three different estimates (AP2, EPA Low and High).

Air Pollution Reduction Benefits from New Hydropower Capacity

New hydropower deployment provided cumulative air quality benefits in scenarios combining *Advanced Technology, Low Cost Finance* with the following assumptions: 1) *High Fossil Fuel Cost*; 2) *Critical Habitat, High Fossil Fuel Cost*; and 3) *Critical Habitat, Low VG Cost*. In the *Low VG Cost* scenario, the additional hydropower generation allowed for greater new non-hydropower renewable generation, primarily wind. Under these conditions, combined new hydropower and new non-hydropower renewables led to reduced total criteria pollutant emissions and associated public health burdens. In the *High Fossil Fuel Cost* scenarios, the additional hydropower offsets both coal and natural gas, providing air quality benefits. In contrast, new hydropower in the remaining scenarios reduced natural gas generation but facilitated additional coal generation along with non-hydropower renewables. On balance, this increased total criteria pollutant emissions, causing a slight increase to air quality burdens.

Representation of EPA's CPP influences the sign and magnitude of the air quality impacts. The CPP limits total carbon emissions, but does not directly limit SO_2, NO_x, and $PM_{2.5}$ emissions. As the combustion emissions of CO_2 associated with coal generation are larger than that of natural gas generation (on a per-MWh basis), the implementation of the CPP within ReEDS limits generation from coal in both the baseline and new hydropower scenarios. However, in the new hydropower scenarios, the new deployment of combustion-free hydropower allows for the ratio of coal to natural gas generation to increase without increasing total CO_2 emissions. In fact, relative to the baseline scenarios, the new hydropower scenarios (with the exception of the *High Fossil Fuel Cost* and *Low VG Cost* scenarios) show higher absolute coal generation along with lower absolute natural gas generation.

This analysis does not suggest the CPP causes any air quality damages; in fact, the CPP is estimated to provide substantial air quality benefits [65]. However, after those CPP benefits are realized, the addition of new hydropower can allow for additional coal generation in the specific scenarios analyzed here.

Figure 3-47 shows emission impacts from 2017–2050. The figure illustrates that, as the CPP becomes more restrictive closer to 2030, all the selected scenarios have increased emissions of SO_2, NO_x and $PM_{2.5}$ compared to their baselines. The *High Fossil Fuel Cost* scenarios show reduced emissions again soon after 2030, and the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* scenario shows reduced emissions by roughly 2040. Table 3-7 shows cumulative emission changes (new hydropower deployment, relative to the respective baseline scenario) for 2017–2025. The largest reductions were seen for *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* scenario, with SO_2, NO_x, and $PM_{2.5}$ reduced by 460,000; 801,000; and 71,000 metric tons or 1.5%, 2.2%, and 1.3%, respectively, over 2017–2050. The largest increases to emissions were found in the *Advanced Technology, Low Cost Finance, Critical Habitat* scenario. In that scenario in 2017–2050, SO_2, NO_x, and $PM_{2.5}$ emissions increased by 226,000; 160,000; and 41,000 metric tons or 0.7%, 0.5%, and 0.1%, respectively.

47. This is because under strictly binding caps, renewable electricity does not reduce emissions per se, but it instead alleviates the need to reduce emissions elsewhere in order to achieve the cap. In this instance, the benefits of hydropower electricity derive not from reduced health and environmental damages but instead from reducing the cost of complying with the air-pollution regulations. As mentioned above, ReEDS simulations indicate CSAPR SO_2 and NO_x caps are largely non-binding over time, due to the presumed existence of MATS. This result also follows historical experience, as the largest regional SO_2 and NO_x cap-and-trade program (EPA's Clean Air Interstate Rule) was non-binding in 2013 [86, 87]. Therefore, estimates are not calculated for the benefits of new capacity in the *Hydropower Vision* from the perspective of reducing pollution regulation compliance costs. Nonetheless, this alternative valuation approach is mentioned because it is possible that future cap-and-trade regulations applied either nationally or regionally could impact the size and nature of the benefits from the scenarios analyzed here. It is also possible that our emissions treatment may not incorporate some more-localized ***existing*** binding cap-and-trade programs; however, the geographic extent of these programs is limited, so this limitation will not substantially bias the results.

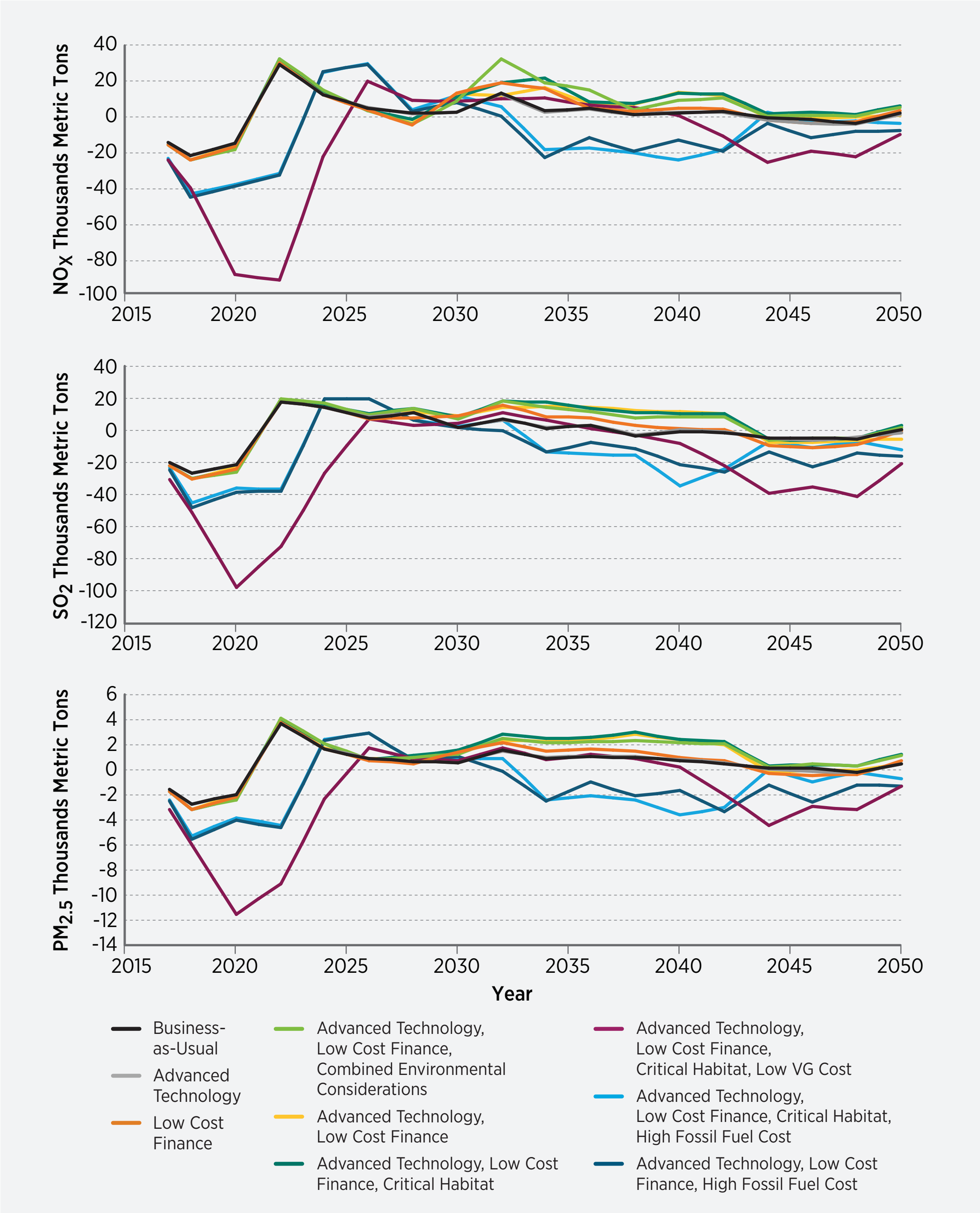


Figure 3-47. Power sector SO_2, NO_x, and $PM_{2.5}$ emissions impacts of new hydropower capacity

Table 3-7. Cumulative Power Sector SO_2, NO_x, and $PM_{2.5}$ Emissions Impacts of New Hydropower Capacity

	SO_2 (metric tons)	Percent Change	NO_X (metric tons)	Percent Change	$PM_{2.5}$ (metric tons)	Percent Change
Business-as-Usual	81,000	0.2%	-10,000	0.0%	16,000	0.3%
Advanced Technology	69,000	0.2%	-10,000	0.0%	16,000	0.3%
Low Cost Finance	124,000	0.4%	17,000	0.0%	20,000	0.4%
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	222,000	0.7%	129,000	0.4%	36,000	0.7%
Advanced Technology, Low Cost Finance, Critical Habitat	226,000	0.7%	160,000	0.5%	41,000	0.8%
Advanced Technology, Low Cost Finance	171,000	0.5%	128,000	0.4%	34,000	0.6%
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	-506,000	-1.5%	-761,000	-2.2%	-70,000	-1.3%
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	-323,000	-1.0%	-436,000	-1.3%	-48,000	-0.9%
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	-274,000	-0.9%	-396,000	-1.2%	-43,000	-0.8%

To summarize the emission impacts, the *Hydropower Vision* analysis scenarios only provide cumulative air quality benefits under conditions that favor additional, non-hydropower, renewable energy deployment, or in scenarios with higher fossil fuel prices. Criteria pollutants are found to increase in the remainder of the new hydropower deployment scenarios. These patterns are a result of the inclusion of the CPP within the modeling framework.

These emission changes would lead to changes in air quality and health outcomes across the continental United States. Specifically, the cumulative, discounted present value of the U.S. health and environmental impacts range from a ***penalty*** of $6.4 billion to a ***benefit*** of $26.5 billion across the central estimates of the nine scenarios (in 2015$). Figures 3-48 and 3-49 and Table 3-8 show the range of total health and environmental impacts values across all the scenarios. The central estimates[48] of premature mortality incidences ranges from an ***increase*** of 1,600 to a ***decrease*** of 5,400.

While these results indicate a range of potential air quality impacts from new deployment of hydropower, there is no attempt to pick a 'most likely' scenario or create an overall average impact estimate. As such, the conclusion must be a qualified statement: Given the constraints of the CPP, air quality impacts from new deployment of hydropower are positive only under conditions that either favor additional non-hydropower renewable deployment or that discourage additional fossil fuel generation, including additional coal generation.

48. The central estimate of mortality incidences is the simple average mortality estimate between EPA Low and EPA High (as mortality incidences were not available for AP2).

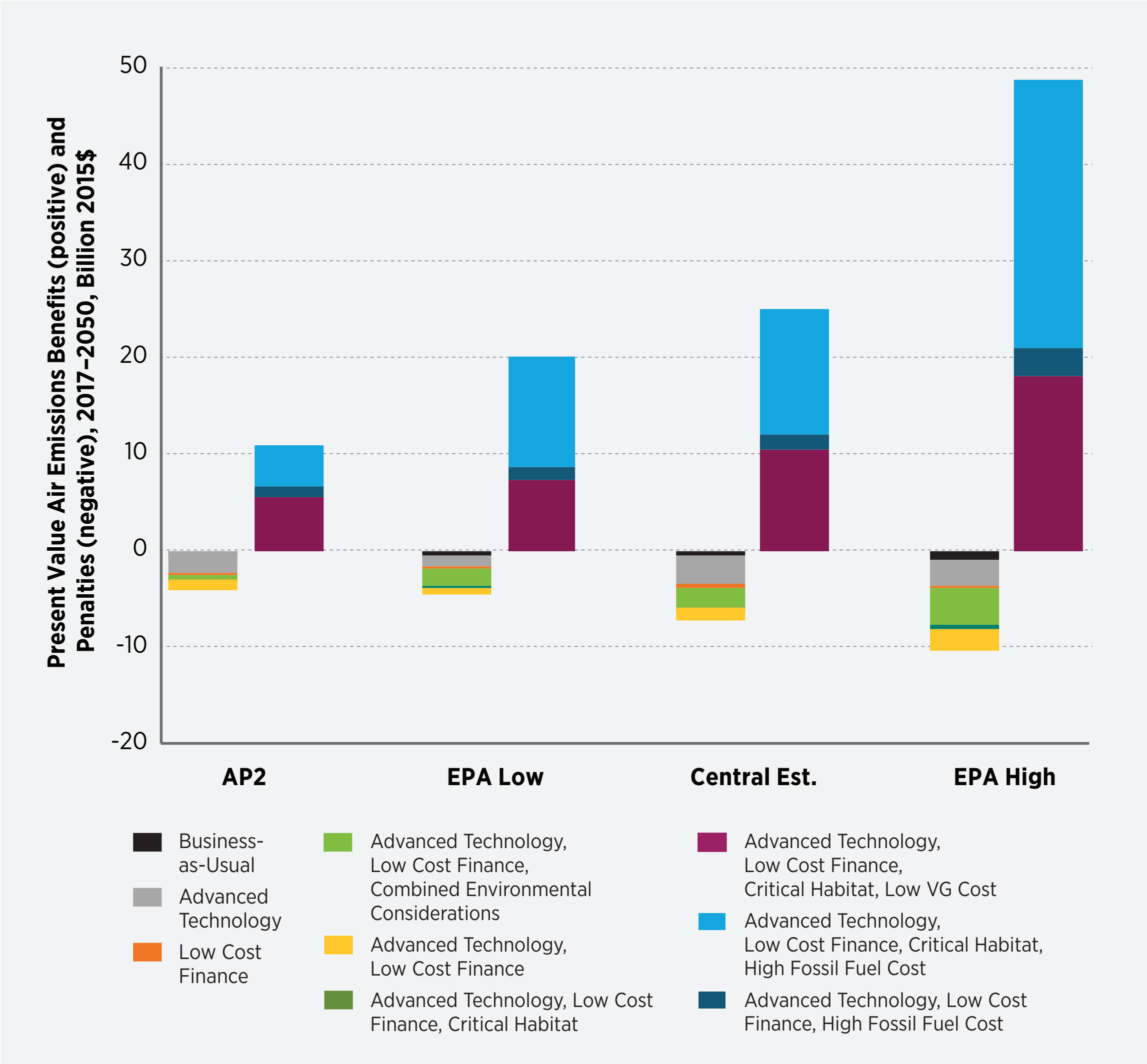


Figure 3-48. Estimated value of SO_2, NO_X, and $PM_{2.5}$ impacts of new capacity with benefits and penalties stacked separately

Air Pollution Reduction Benefits from Existing Hydropower Capacity

The air quality impacts of the existing hydropower fleet are calculated as a function of the average regional emission rates of non-hydropower generation within the baseline scenario. The existing fleet is found to reduce emissions of SO_2, NO_x, and $PM_{2.5}$ by 1.6, 2.8, and 0.3 million metric tons (or 5%, 9%, and 6%), respectively, over 2017–2050. These emission reductions lead to improved air quality and health outcomes across the continental United States. Specifically, total U.S. health and environmental benefits from the existing fleet fall in the range of \$39 billion–\$94 billion on a discounted, present-value basis, depending on the method used to quantify those benefits (see Figure 3-50).

Reduction of SO_2 and the subsequent reduction of particulate sulfate concentrations account for a majority of the monetized benefits. For example, the reduction of SO_2 emissions accounted for 55%, 69%, and 64% of the AP2, EPA Low, and EPA High benefits. The benefits of reduced tropospheric ozone (due to reduced NO_x emissions) account for 8% and 15% of the EPA Low and High benefit estimates, respectively.[49]

49. An estimate of ozone benefits, separate from the total benefits and corresponding to the AP2 valuation, was not available within the model.

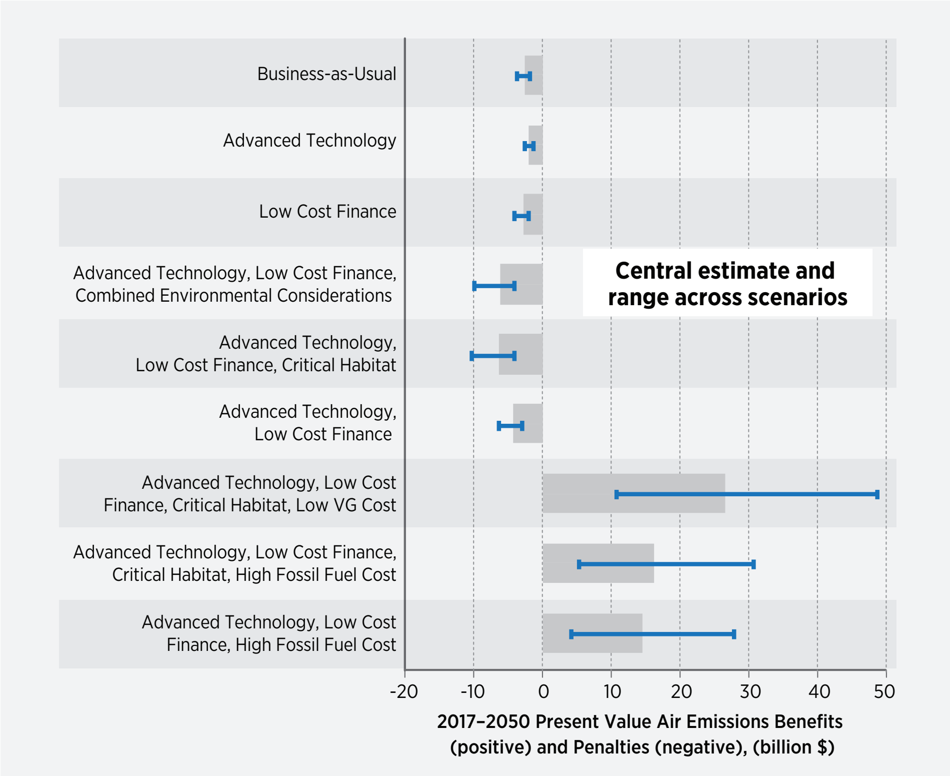


Figure 3-49. Estimated central value and range of SO_2, NO_X, and $PM_{2.5}$ impacts of new capacity

Table 3-8. Estimated cumulative, 2017–2050, discounted value of SO_2, NO_X, and $PM_{2.5}$ impacts of new capacity (million 2015$)

	AP2	EPA Low	Central Estimate	EPA High
Business-as-Usual	-2,300	-1,800	-2,600	-3,700
Advanced Technology	-2,200	-1,300	-2,100	-2,600
Low Cost Finance	-2,600	-2,000	-2,900	-4,000
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	-4,000	-4,600	-6,200	-10,000
Advanced Technology, Low Cost Finance, Critical Habitat	-4,100	-4,700	-6,400	-10,400
Advanced Technology, Low Cost Finance	-3,600	-2,900	-4,200	-6,300
Advanced Technology, Low Cost Finance, Critical Habitat,Low VG Cost	10,800	20,000	26,500	48,700
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	5,300	12,800	16,300	30,800
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	4,100	11,500	14,500	27,900

The data suggest that exposure to particulates (directly or indirectly from emissions of SO_2, NO_x and $PM_{2.5}$) is the primary driver of health outcomes.

Most of the health benefits come from avoided premature mortality, again associated primarily with reduced chronic exposure to ambient $PM_{2.5}$ (which derive largely from the transformation of SO_2 to sulfate and NO_x to nitrate particles). Based on the EPA approach, the existing fleet is found to prevent 6,700 to 16,200 premature mortalities in total from 2017 to 2050. It is also estimated that the existing fleet would reduce numerous forms of morbidity outcomes (see Table 3-9), including 8,500 hospital admissions for respiratory and cardiovascular symptoms, 0.7 million lost work days, and 0.9 million missed school days.

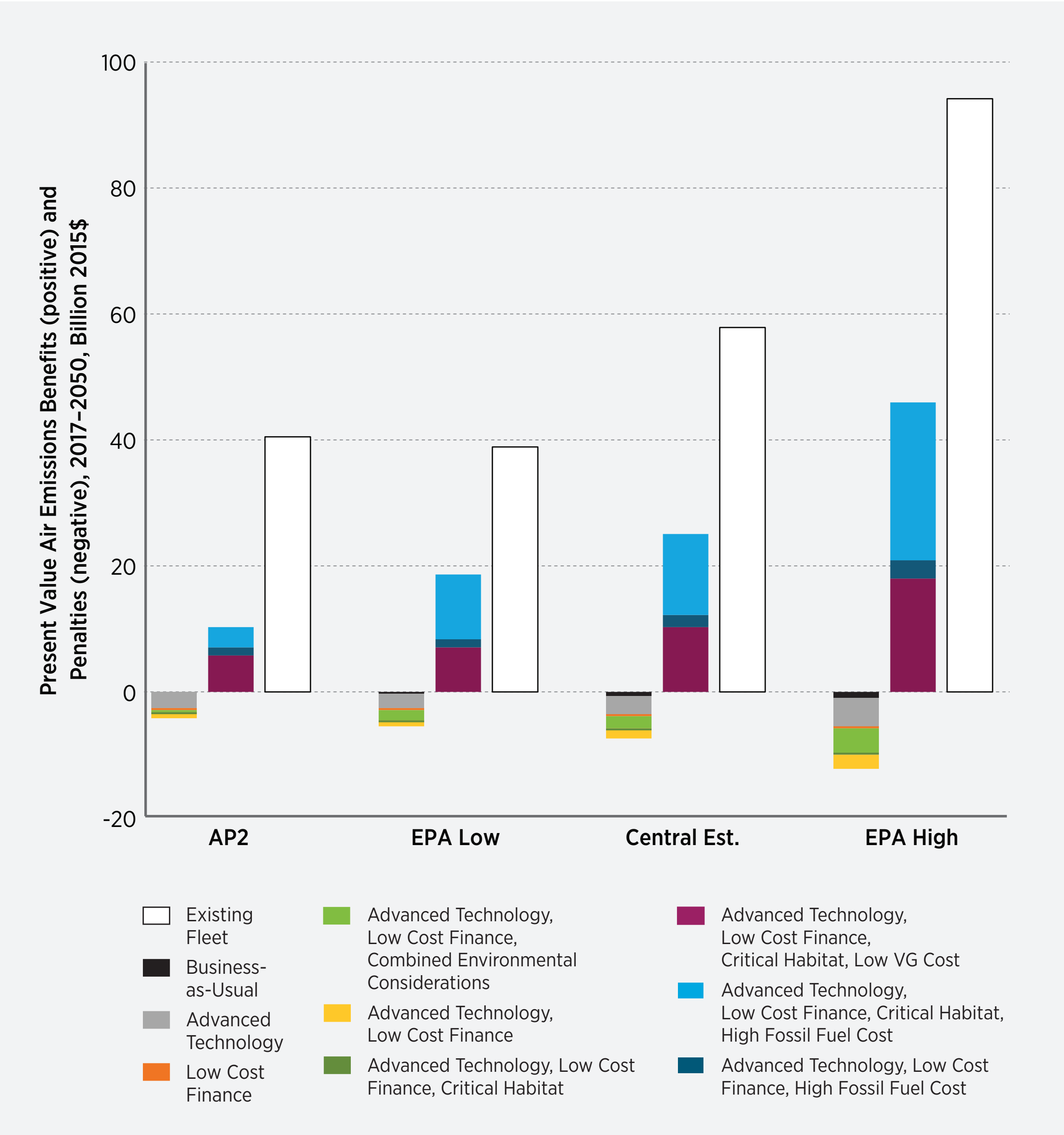


Figure 3-50. Estimated value of SO_2, NO_x, and $PM_{2.5}$ impacts of new capacity with benefits and penalties stacked separately and with the existing fleet benefits for comparison

Table 3-9: Emissions Reductions, Monetized Benefits, and Mortality and Morbidity Benefits over 2017–2050 for the Existing Fleet

Impacts	SO_2	NO_x	$PM_{2.5}$	Total
Emissions Reductions (millions metric tons)				
Existing Fleet impacts	1.64	2.76	0.33	—
Existing Fleet Total Monetized Benefits (Present Value)				
EPA Low benefits (Billions 2015$)	27	7	5	39
EPA High benefits (Billions 2015$)	60	22	12	94
AP2 benefits (Billions 2015$)	22	12	6	40
Existing Fleet EPA Total Mortality Reductions				
EPA Low mortality reductions (count)	4,700	1,100	900	6,700
EPA High mortality reductions (count)	10,600	3,500	2,100	16,200
Existing Fleet EPA Morbidity Reductions from Primary and Secondary PM2.5 Impacts				
Emergency department visits for asthma (all ages)	1,500	200	300	2,000
Acute bronchitis (age 8–12)	6,700	1,100	1,300	9,100
Lower respiratory symptoms (age 7–14)	85,100	13,800	17,200	116,100
Upper respiratory symptoms (asthmatics age 9–11)	127,800	20,000	24,600	172,400
Minor restricted-activity days (age 18–65)	3,247,200	484,900	625,000	4,357,100
Lost work days (age 18–65)	538,700	81,200	104,600	724,500
Asthma exacerbation (age 6–18)	295,900	49,400	58,500	403,800
Hospital Admissions-Respiratory (all ages)	1,400	200	300	1,900
Hospital Admissions-Cardiovascular (age > 18)	1,700	200	300	2,200
Non-fatal Heart Attacks	5,300	700	1,000	7,000
Non-fatal Heart Attacks (Pooled estimates—4 studies)	600	100	100	800
Existing Fleet EPA Morbidity Reductions from NOx — Ozone Impacts				
Hospital Admissions, Respiratory (ages > 65)	—	2,900	—	2,900
Hospital Admissions, Respiratory (ages < 2)	—	1,500	—	1,500
Emergency Room Visits, Respiratory (all ages)	—	1,300	—	1,300
Acute Respiratory Symptoms (ages 18–65)	—	2,723,700	—	2,723,700
School Loss Days	—	943,900	—	943,900

Notes: All values accumulated from 2017–2050. All monetized benefits are discounted at 3%; however, the mortality and morbidity values are simply accumulated over the time period. EPA and AP2 $ benefits include mortality and morbidity estimates from primary and secondary $PM_{2.5}$ effects from SO_2, NO_X, and direct $PM_{2.5}$ emissions and ozone benefits from reduced NO_X emissions during the ozone season (May–September). AP2 benefits also include environmental effects such loss of visibility and crop damage. Both AP2 and EPA benefit estimates are dominated by mortality benefits.

3.5.8 Power-Sector Water Usage Reduction

The electric sector beyond hydropower relies on readily available supplies of water for reliable operations. Most water requirements in the energy sector are for thermal power plant cooling, but all life cycle stages of energy production require water. Although energy supply can also affect water resources through changes in water quality and temperature, water use is typically categorized into two metrics: withdrawal and consumption. Withdrawals are defined as the amount of water removed or diverted from a water source for use, while consumption is the amount of water evaporated, transpired, incorporated into products or crops, or otherwise removed from the immediate water environment [88]. The U.S. power sector is the largest withdrawer of water in the nation, at 38% of total withdrawals [89]. Its share of consumption is much lower, around 3% nationally, but can be regionally important [90].

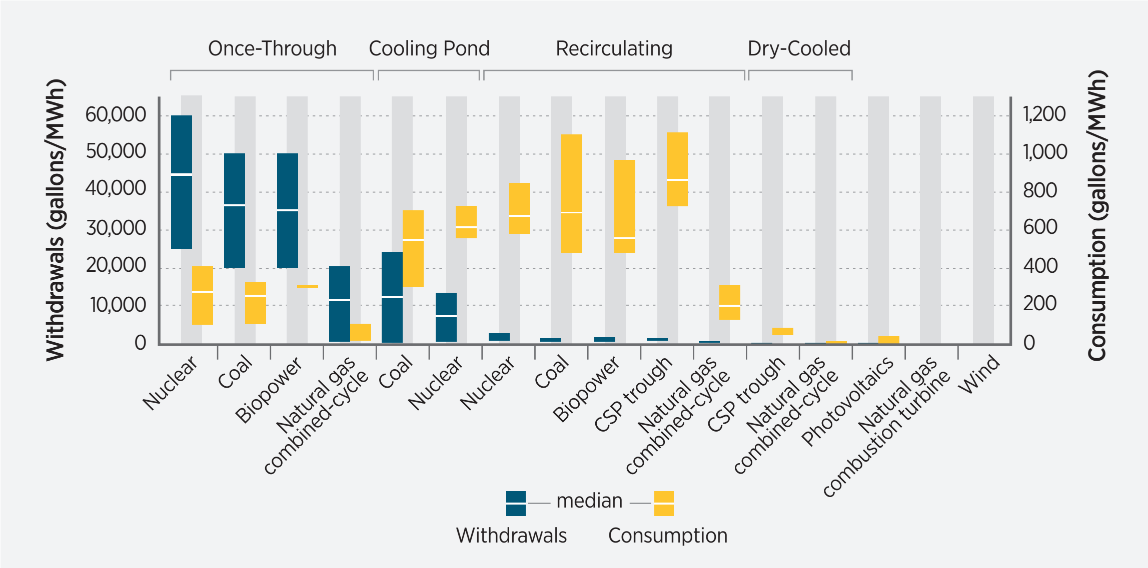
Prior studies have evaluated the impact of a range of U.S. electric sector futures on water demands [2, 91, 92, 93, 94, 95, 96, 97]. Many renewable energy technologies have low operational (see Macknick et al. [98] and *Methodology* discussion in the next section) and life cycle (see Meldrum et al. [99]) water use compared to fossil and nuclear technologies. As a result, prior work generally found that future scenarios designed to meet carbon reduction goals also result in water savings, particularly when renewable-based pathways are envisioned [94, 100]. No studies to date have evaluated the potential changes in water use that could result from scenarios of high hydropower deployment.

Hydropower technologies are unique in that water is not diverted away from a water body in the same way it is for other uses; water is used for hydropower operations and generally remains in, or is returned to, the water body. However, characterizing withdrawal metrics is not uniform across all forms of hydropower and at the national scale. Consumption metrics, which could be measured by evaporation and loss from reservoirs, also have challenges associated with the geometric and geographic diversity of reservoirs; temporal variations in water levels and evaporation rates; and inter-year variations in operational releases and water levels that can affect evaporation rates. Withdrawal and consumption metrics are also complicated by the multiple uses of reservoirs (e.g., water supply, recreation, flood control) and the different methods of allocating evaporation to electricity production or other uses [101, 102, 103]. Given that this modeling analysis, along with many others, does not project any new large hydropower reservoirs to be built or to be retired, this impact analysis does not consider withdrawal or consumption from existing reservoirs that contain hydropower technologies. This modeling analysis focuses on run-of-river hydropower technologies as well as upgrades to existing facilities or powering non-powered dams, which entail little to no increase in water consumption above current levels.

Notwithstanding the uncertainties noted previously, new hydropower deployment is expected to reduce thermal cooling water use in some areas, potentially providing economic and environmental benefits. Some states have already proposed measures to reduce the water intensity of the electricity produced in their states, and EPA has invoked the Clean Water Act to propose various measures to limit the impacts of thermal power plant cooling on aquatic habitats [104]. To the extent that new hydropower deployment considered in this analysis can reduce power-sector water demands, it might also reduce the cost of meeting future policies intended to manage water use. The rest of this section details calculations of the water withdrawal and consumption impacts of the nine selected scenarios explored in greater depth within the *Hydropower Vision* analysis, both nationally and regionally. The economic benefits of water-use reductions are described qualitatively due to limitations in monetary quantification.

Methodology

ReEDS was used to compute power-sector water withdrawal and consumption in each scenario and its corresponding baseline scenario with no new unannounced hydropower construction. ReEDS incorporates the cost, performance, and water use characteristics of different generation technology and cooling system combinations, and the model considers water availability as a limiting condition for new power plant construction [105]. Cooling systems for thermal power plants implemented in ReEDS fall into four categories:



Source: Averyt et al. [110]

Figure 3-51. Operational water withdrawal and consumption requirements by generation technology and cooling system

once-through, pond, recirculating, and dry cooling.[50] Consistent with prior studies and proposed EPA regulations, this analysis does not allow new power plants in ReEDS to employ once-through cooling technologies [94, 96]. The basic approach used here has been applied in multiple studies evaluating the national and regional water impacts of the U.S. electricity sector [3, 94, 100, 105, 106].

Water withdrawal and consumption impacts of the existing hydropower fleet are calculated as a function of the baseline scenarios. Avoided water withdrawal and consumption are calculated utilizing regional average water use rates (gallons per MWh of electricity generated) for non-hydropower generation. The electricity generated by hydropower within each region and for each year is multiplied by the regional water withdrawal and consumption rate to provide water impact results.

The *Hydropower Vision* analysis focuses exclusively on operational water-use requirements. These requirements can vary depending on fuel type, power plant type, and cooling system, and many renewable energy technologies have relatively low operational water withdrawal and consumption intensities (Figure 3-51). Thermal power plants using once-through cooling withdraw more water for every MWh of electricity generated than do plants using recirculating cooling systems. For water consumption, however, once-through cooling has lower demands than recirculating systems. Dry cooling can be used to reduce both water withdrawal and consumption for thermal plants, but at a cost and efficiency penalty [107]. Non-thermal renewable energy technologies (such as PV, wind, and the hydropower technologies considered in this analysis) do not require water for cooling and, thus, have low operational water-use intensities. These water requirements for non-thermal technologies are, however, included in the calculations. Several additional aspects of the methodology, and possible related limitations, deserve note:

- This analysis does not estimate full life cycle water uses, including upstream processes such as construction, manufacturing, and fuel supply. Including these requirements would likely increase the water savings from many scenarios, but associating upstream water uses to specific geographic regions is challenging. Moreover, prior work has

50. Cooling systems for the existing fleet are assigned to ReEDS balancing area generating capacity based on an analysis of individual electric-generating units aggregated at the ReEDS balancing-authority level, as described elsewhere [108, 109].

demonstrated that thermoelectric water withdrawals and consumption during plant operations are orders of magnitude greater than the demands from other life cycle stages [99].

- Power-sector water use will be impacted by various possible changes in the electric sector, such as coal plant retirements, new combined-cycle natural gas plant construction, and increased use of dry cooling. These changes may be driven in part by future, uncertain water policies, and they could affect the estimated water savings under the scenarios analyzed.
- Although water resource impacts are described regionally at the state level, there can be considerable variation in water resource availability and impacts within a given state; evaluating water impacts on a smaller watershed level could partially address this limitation.
- The benefits of water-use reductions are not quantified in monetary terms owing to challenges associated with quantifying the value of water resource services [3].

Results

Both the existing hydropower fleet and new hydropower deployment reduce national power-sector water withdrawal and consumption, when compared with historical use and across selected scenarios.

The existing hydropower fleet contributed to approximately 1,450 billion gallons of water withdrawal savings per year and 100 billion gallons of water consumption savings per year as of 2016, representing a 4.1% and 7.3% reduction in water withdrawals and consumption, respectively. Over time, water withdrawal and consumption savings decline as water-intensive energy technologies (e.g., coal, nuclear) and cooling systems (e.g., once-through cooling), are replaced by lower water intensity natural gas and renewable energy technologies. In 2050, the existing hydropower fleet contributes to a 2.9% reduction in water withdrawals (200 billion gallons) and a 4.6% reduction in water consumption (40 billion gallons) due to the existing fleet. Cumulative water savings for 2017–2050 total 30.1 trillion gallons of withdrawals and 2.2 trillion gallons of consumption.

Regionally, the existing fleet provides different benefits depending on the water intensity of the non-hydropower fleet. In the arid West, where many existing hydropower projects are concentrated, water withdrawal and consumption rates of the non-hydropower fleet tend to be lower than in the East. Figure 3-52 shows national water withdrawal and consumption savings associated with the existing hydropower fleet.

Figure 3-53 shows the decline in annual power-sector water withdrawals for all scenarios considered. On a national level, withdrawals decline substantially over time under all scenarios, largely owing to the retirement and reduced operations of once-through-cooled thermal facilities and the assumed replacement of those plants with newer, less water-intensive generation and cooling technologies. In all scenarios, once-through-cooled plants are largely replaced by new thermal plants using recirculating cooling and a combination of renewable energy technologies. Although national-level withdrawal estimates are relatively similar across scenarios with reference electricity market conditions within each set of baseline scenarios (no more than 1% difference across scenarios for all years), withdrawal estimates have greater variation across scenarios with different market conditions. The *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* scenario has greater penetrations of wind and solar PV technologies than the *Business-as-Usual* scenario, and the low water intensity of wind and PV have the effect of reducing national level water withdrawals in 2050 by 9.6% (~680 billion gallons) from *Business-as-Usual* (680 billion gallons represents the annual water usage of approximately 4.8 million U.S. households). This effect is amplified in scenarios with *High Fossil Fuel Cost*, where increases in fossil fuel costs lead to a sharper reduction in fossil fuel generation, also resulting in greater penetrations of non-thermal electricity technologies. Withdrawal estimates in the *High Fossil Fuel* scenarios in 2050 are approximately 33% (2.3 trillion gallons) lower than those in *Business-as-Usual*.

Across the nine selected scenarios, 2050 water withdrawal impacts relative to their respective baseline range from a 0.5% increase (in the *Low Cost Finance* scenario) to a 4% decrease (in the two *High Fossil Fuel Cost* scenarios). Table 3-10 and Figure 3-54 highlight the range of results for all scenarios as they relate to their corresponding baseline. Cumulative withdrawal reductions for 2017–2050 range from a 0.1% increase for several scenarios, to a 1.2% decrease in the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* scenario.

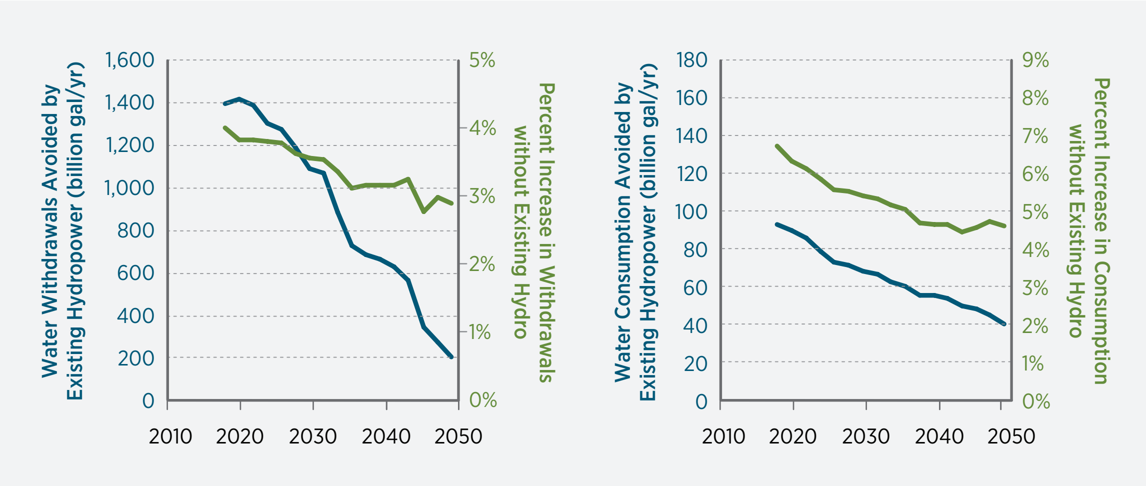


Figure 3-52. Water withdrawal savings (left) and water consumption savings (right) of the existing fleet

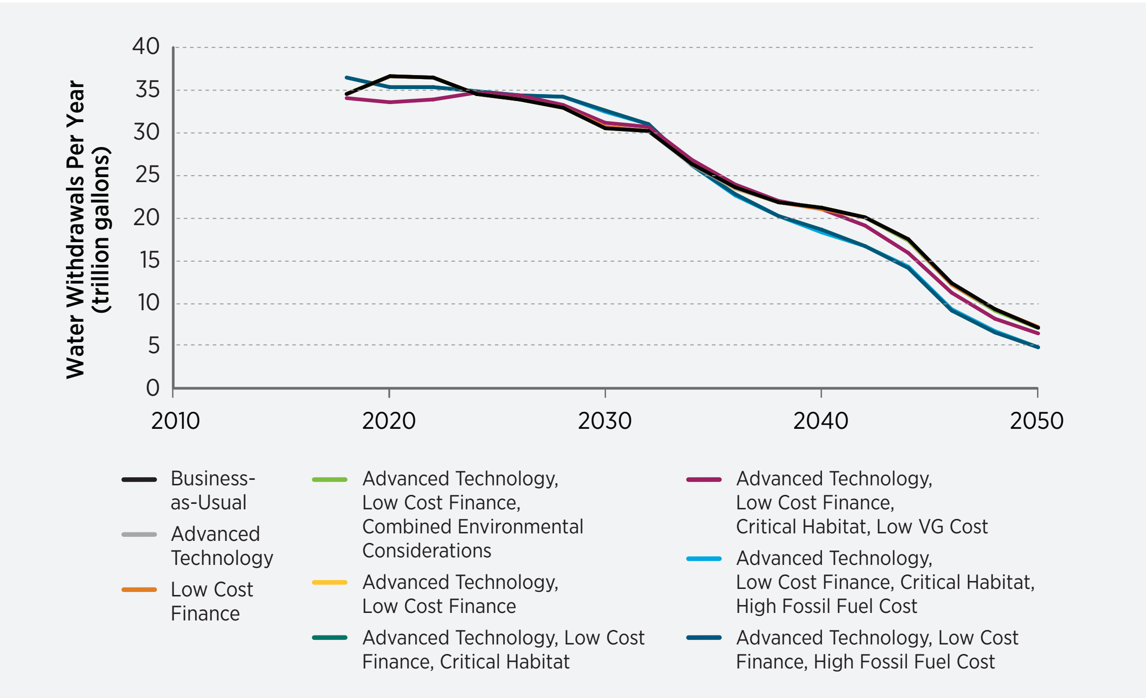


Figure 3-53. Power-sector water withdrawal impacts of selected scenarios

Table 3-10. Water Withdrawal in 2050 under Multiple Scenarios Relative to the Baseline

	2050 Withdrawal (trillion gallons)	Reduction in 2050 Withdrawal from baseline		Reduction in 2017–2050 Withdrawal from baseline	
		(trillion gallons)	(%)	(trillion gallons)	(%)
Business-as-Usual	7.02	-0.03	-0.4%	-1.1	-0.1%
Advanced Technology	7.01	-0.02	-0.3%	-0.5	-0.1%
Advanced Technology, Low Cost Finance	6.97	0.02	0.3%	-0.4	-0.1%
Advanced Technology, Low Cost Finance, Critical Habitat	6.99	0.00	0.0%	-0.7	-0.1%
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	4.71	0.20	4.0%	7.7	0.9%
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	6.35	0.22	3.3%	10.2	1.2%
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	6.99	0.00	0.1%	-0.8	-0.1%
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	4.71	0.20	4.0%	7.2	0.9%
Low Cost Finance	7.03	-0.03	-0.5%	-0.4	0.0%

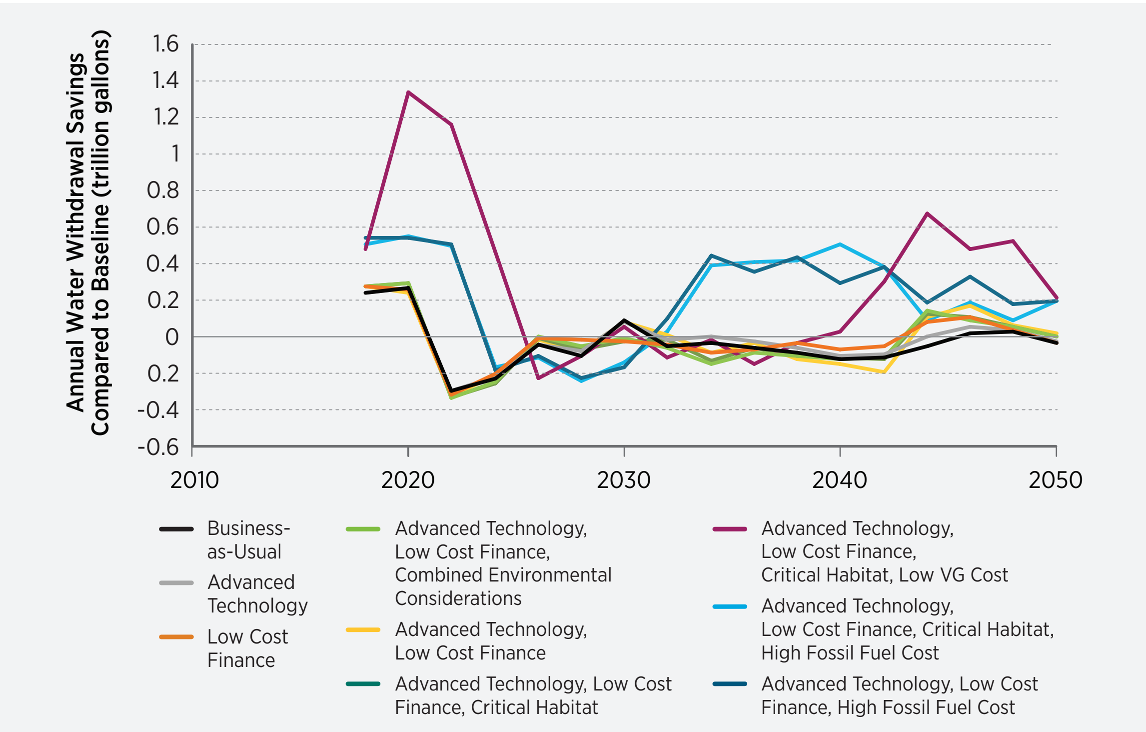


Figure 3-54. Annual water withdrawal savings under selected scenarios

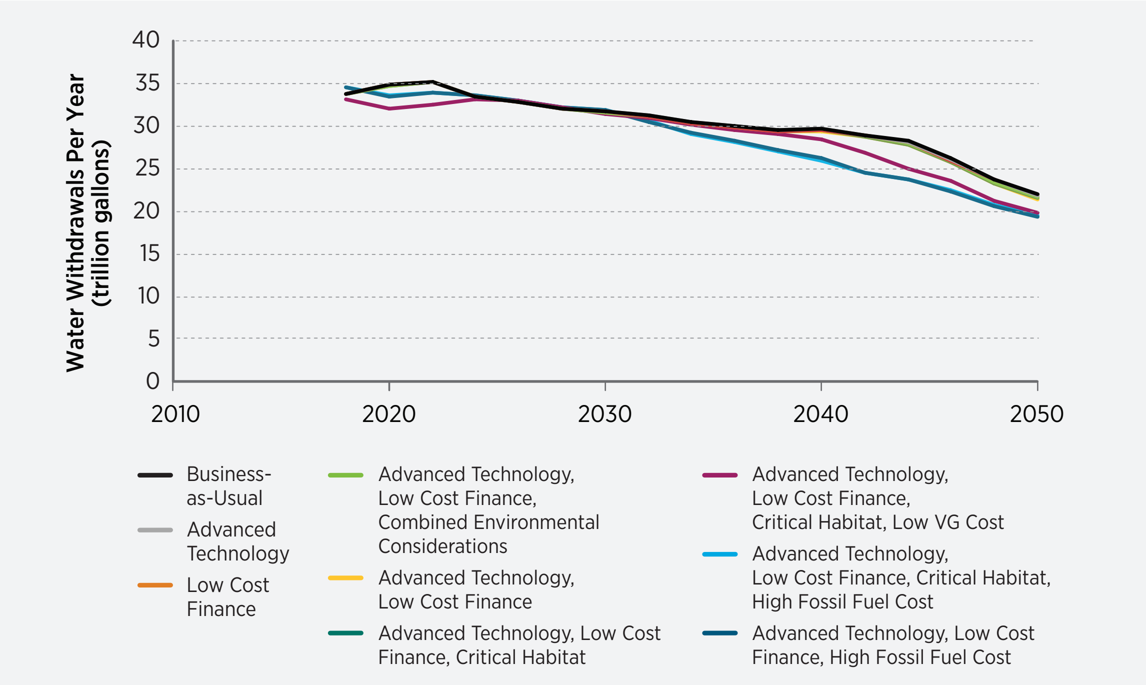


Figure 3-55. Power-sector water consumption impacts of selected scenarios

Figure 3-55 shows the change in annual power-sector water consumption for the selected scenarios. National power-sector water consumption declines over time in all scenarios, but to a lesser extent than water withdrawals. Similar to withdrawals, there is little variability in national water consumption across scenarios using reference fossil fuel and VG costs (no more than 3% difference across scenarios and years). The scenario with *Low VG Cost* leads to national reductions in consumption in 2050 of 9.7% (85 billion gallons), relative to *Business-as-Usual*. Under scenarios with *High Fossil Fuel Cost*, national reductions in consumption in 2050 are 11–12% (~100 billion gallons). As with withdrawals, these changes can be attributed to the amount of low-water-intensity renewable generation sources that are deployed, as compared with high-water-intensity thermal technologies. Consumption differences are smaller than withdrawal differences due to the transition from once-through-cooled to recirculating-cooled thermal technologies, with the latter having a higher water consumption rate.

There is greater variation in impacts on national water consumption than there is for withdrawal. Across selected scenarios, water consumption impacts range from a 2.3% increase (in *Business-as-Usual*) to a 7.6% decrease (in the *Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost* scenario) in 2050 compared to the baseline scenarios. Cumulative 2017–2050 consumption impacts range from a 0.4% increase (in the *Business-as-Usual* and *Advanced Technology* scenarios) to a 2.6% decrease in scenarios with *High Fossil Fuel Cost*. Table 3-11 and Figure 3-56 highlight the water consumption impacts for all selected scenarios. Consumption reductions in 2050 are seen only for the *High Fossil Fuel Cost* scenarios and the *Advanced Technology, Low Cost Finance* scenario, when compared with the baseline. The *Advanced Technology, Low Cost Finance, Critical Habitat* scenario and the scenario with *Low VG Cost* achieve consumption reductions over the 2017–2050 time frame.

Water withdrawal impacts under all scenarios are not uniform throughout the continental United States, and considerable regional differences can mask relatively small national-level differences. Figure 3-57 shows state water withdrawal differences in 2050 for representative low, mid, and high hydropower deployment scenarios, compared with the baseline. In the *Business-as-Usual* scenario, only 18 states show withdrawal savings compared with the baseline, yet for the *Advanced Technology, Low Cost Finance, High*

Table 3-11. Water Consumption in 2050 Compared across Multiple Scenarios and Relative to the Baseline

	2050 Withdrawal (trillion gallons)	Reduction in 2050 Withdrawal from baseline		Reduction in 2017–2050 Withdrawal from baseline	
		(trillion gallons)	(%)	(trillion gallons)	(%)
Business-as-Usual	0.88	-0.02	-2.3%	-0.17	-0.4%
Advanced Technology	0.87	-0.02	-1.9%	-0.15	-0.4%
Advanced Technology, Low Cost Finance	0.86	0.00	0.3%	0.06	0.2%
Advanced Technology, Low Cost Finance, Critical Habitat	0.86	0.00	-0.5%	0.05	0.1%
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	0.77	0.06	7.6%	1.04	2.6%
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	0.79	-0.01	-0.7%	0.40	1.0%
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	0.87	-0.01	-1.0%	0.00	0.0%
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	0.78	0.06	7.1%	1.05	2.6%
Low Cost Finance	0.88	-0.02	-2.2%	-0.08	-0.2%

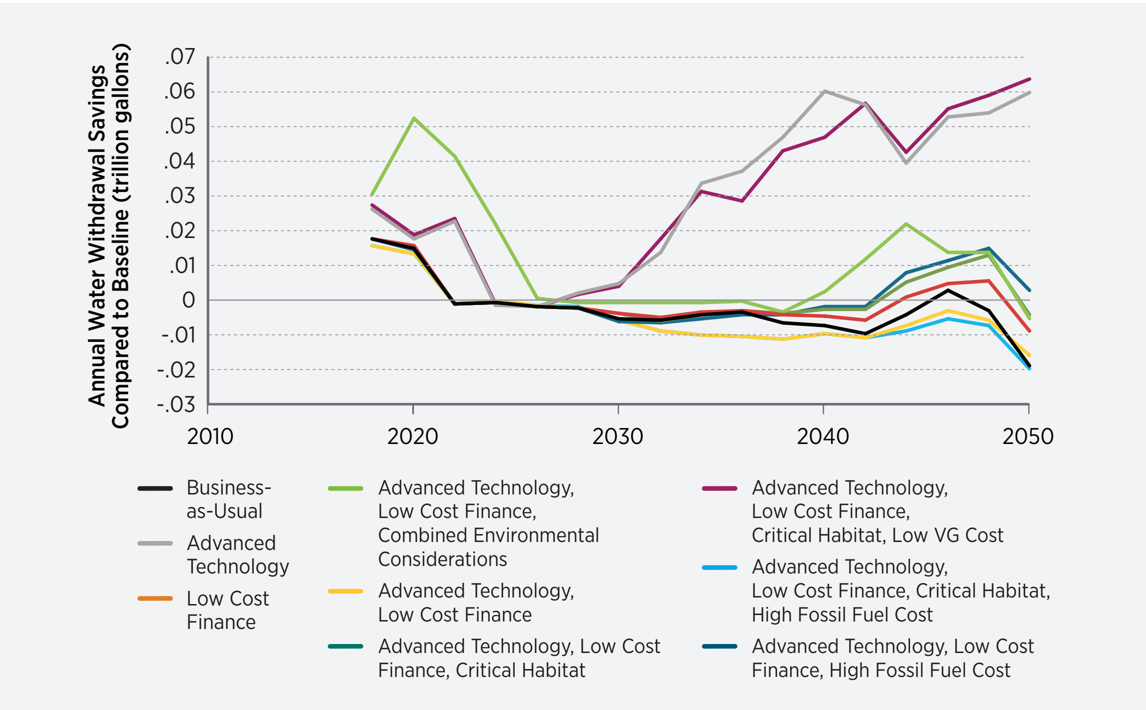


Figure 3-56. Annual water consumption under selected scenarios

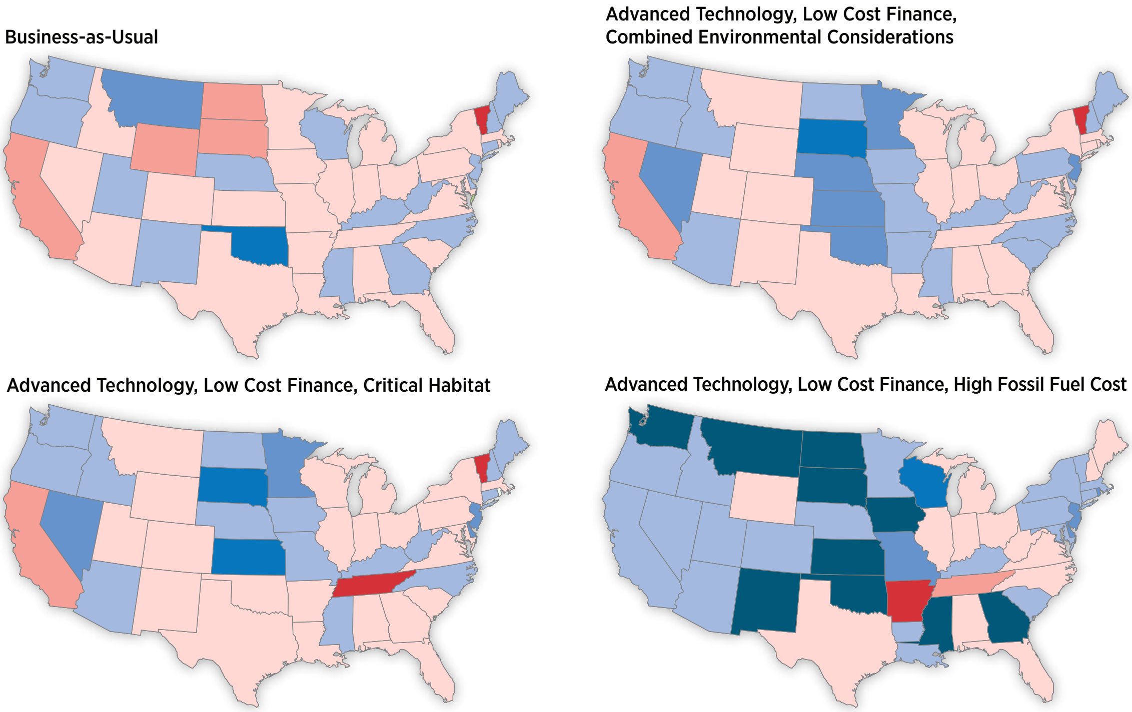
Fossil Fuel Cost scenario, there are 33 states with withdrawal savings. This is largely a reflection of where new hydropower capacity is deployed, where other renewable energy technologies are deployed, and where the most water-intensive thermal plants are offset. Certain states, such as Mississippi, Nebraska, and New Jersey, show withdrawal savings across all scenarios. Other states, such as Illinois, Tennessee, and Texas, show withdrawal increases across all scenarios. Most states, however, including California, show either withdrawal increases or decreases depending on the scenario considered and the regional deployment of technologies. The largest changes in magnitude for water withdrawals are concentrated in the areas with high levels of once-through cooling (e.g., Midwest, Southeast, Texas).

Water consumption impacts under all scenarios are also diverse throughout the continental United States, showing substantial regional differences that are not apparent in national level results. Figure 3-58 shows state water consumption differences in 2050 for representative low, mid, and high deployment scenarios compared with the baseline. In the *Business-as-Usual* scenario, only 17 states show consumption savings compared with the baseline; yet for the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario, 39 states show consumption savings. Regionally, more states show water consumption savings for all scenarios than for withdrawal savings, and fewer states show consumption increases for all scenarios than withdrawal increases. Notably, many water-stressed states (e.g., Texas, California, and other parts of the arid West), show larger water consumption savings than withdrawal savings. The largest increases in consumption tend to be located in the Southeast, whereas the largest reductions in consumption tend to be located in the arid West.

The ability of new hydropower to reduce power-sector water withdrawals and consumption in certain regions offers economic and environmental benefits, especially in regions where water is scarce. By reducing power-sector water use, hydropower technologies considered in this analysis can reduce the vulnerability of electricity supply to the availability or temperature of water, potentially avoiding power-sector reliability events and/or the effects of reduced thermal plant efficiencies—concerns that might otherwise grow as the climate changes [111]. Additionally, increased non-consumptive hydropower deployment can free up water for other productive purposes (e.g., agricultural, industrial, or municipal use) or to strengthen local ecosystems (e.g., benefiting wildlife owing to greater water availability and lack of temperature change). Reducing the quantities of fossil fuels used can help alleviate other power-sector impacts on water resource quality and quantity that occur during upstream fuel production [110].

Quantifying in monetary terms the societal value of these water-use reductions is difficult, however, as no standardized methodology exists in the literature. One potential approach is to consider hydropower deployment as avoiding the *possible* need to otherwise employ thermal power plants with lower water use, or to site power plants where water is available and less costly. ReEDS already includes the cost and performance characteristics of different cooling technologies in its optimization, as well as the availability and cost of water supply; these costs and considerations are embedded in the results presented earlier. If water becomes scarcer in the future and/or if water policy becomes stricter, however, additional costs might be incurred. In such an instance, a possible upper limit of the incremental cost of water-use reductions associated with conventional thermal generation can be estimated by comparing the cost of traditional wet cooling with the cost of dry cooling. Dry cooling adds capital expense to thermal plants and reduces plant efficiencies. The total cost increase of dry cooling for coal generation has been estimated at 0.32–0.64¢/kWh [112]. For natural gas combined cycle plants, Maulbetsch and DiFilippo [113] estimate an "effective cost" of saved water at $3.80–$6.80 per 1,000 gallons, corresponding to approximately 0.06–0.17¢/kWh [3]. These estimated incremental costs for dry cooling are relatively small, and they likely set an upper limit on the water-related cost savings of hydropower or any other power technology intended, in part, to reduce water withdrawal and consumption.[51]

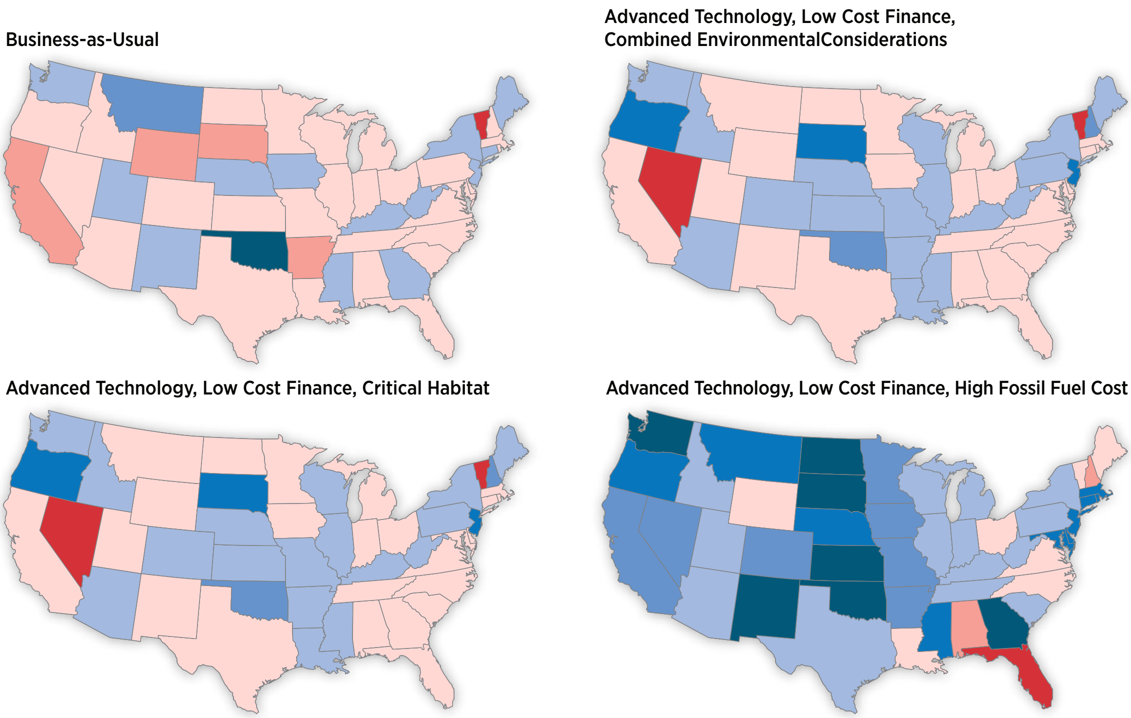
51. The actual benefits, in terms of cost savings, would be lower than these figures for a few reasons. First, many regions of the country are not facing water scarcity, so the economic benefits of reduced water use are geographically limited. Second, to the extent that hydropower offsets more electricity supply (kilowatt-hours) than electricity capacity (kilowatts), it may not be able to offset the full capital and operating cost of less water-intensive cooling technologies. Third, few plants to date have been required or chosen to implement dry cooling; alternative, lower-cost means of obtaining and/or reducing water have predominated, including simply locating plants where water is available. Alternative water resources, such as municipal wastewater or shallow brackish groundwater, could also be more cost-effective than dry cooling in some regions [114]. These lower-cost methods of reducing water use are likely to dominate for the foreseeable future.



Annual Withdrawal Savings in 2050 (% Change from Baseline)

< -20% | -20% – -10% | -10% – 0% | 0% – 10% | 10% – 20% | 20% – 30% | > 30%

Figure 3-57. Water withdrawals savings in 2050 for representative low, mid, and high deployment scenarios



Annual Consumption Savings in 2050 (% Compared with Comparable Baseline)

< -20% | -20% – -10% | -10% – 0% | 0% – 10% | 10% – 20% | 20% – 30% | > 30%

Figure 3-58. Water consumption savings in 2050 in representative low, mid, and high deployment scenarios

3.5.9 Workforce and Economic Development Impacts

Many studies have been conducted that seek to quantify potential jobs and economic activity supported by the construction and operation of energy facilities [3, 121, 122, 123, 124, 125, 126, 127, 128, 129, 130]. This section continues and builds on these efforts by quantifying future gross jobs[52], earnings, gross domestic product (GDP), and economic output supported by the hydropower industry.

Jobs estimates include employment resulting from servicing and maintaining the existing fleet as well as potential additional employment resulting from new hydropower plant development, construction, and operation. Replacement needs within the current workforce through 2030 are also estimated. Economic activity is similarly quantified based on: (1) new investment in maintenance of the existing hydropower fleet, and (2) new investment in facility upgrades, powering of non-powered dams and new hydropower facilities (hydropower generation and PSH).

Methodology

The National Renewable Energy Laboratory's Hydropower Jobs and Economic Development Impacts, or JEDI, model is used to estimate job impacts from the construction and operation of facilities in the modeled scenarios. Appendix H contains a more detailed description of JEDI, including detail on how the model works and its limitations. To better illustrate the trends through time, economic impacts for any given year are reported as a 4-year moving average. Estimates are inclusive of new investments in both hydropower generation and PSH.

The number of U.S. jobs, especially those supported throughout the supply chain, depends on the portion of expenditures made by developers and operators that accrue to companies within the United States. Proportions are estimated from two proprietary sources. First, public- and private-sector contributors to this study contacted manufacturers and other companies within the hydropower supply chain to acquire information about where those respondents operate and the factors that influence location decisions. Second, Oak Ridge National Laboratory surveyed hydropower operators in 2013 about where components are sourced. These two sources of information provide a range of potential local expenditures. Based on these data, a low domestic content and a high domestic content result was estimated for each modeled hydropower scenario. Domestic content proportions are shown in Tables 3-12 and 3-13. While this range of potential results helps to illustrate the uncertainty inherent in these estimates, it is not intended to show the lowest and highest possible impact. It is also not intended to assert a potential probability or likelihood associated with either of these scenarios.

The proportions of domestic content are assumed to be constant throughout the period of analysis. This simplifying assumption is applied due to substantial uncertainty regarding factors that could lead to increases or decreases in local content. Such factors include changes in technology, international trade, economic development incentives, hydropower development outside of the United States, and the preferences of producers and developers.

Workforce replacement estimates come from a demographic cohort-component model. Cohort-component models are often used to project changes in populations in which age, sex,[53] and factors that influence entry and exit from the population are reasonably known. The U.S. Census Bureau, for example, uses a cohort-component model in its population projections. Entry and exit from the population are determined by estimating births, deaths, and in- and out-migration [116]. The cohort-component model used in this study splits the workforce into groups, or cohorts, characterized by occupation, age, and sex. Each cohort is aged over time, and members are removed based on estimates of mortality and retirement. The analysis assumes that workers who are removed need to be replaced; i.e., as workers age, they are more likely to retire or potentially pass away.

52. The difference between gross and net impacts is discussed more thoroughly in Appendix H. The gross impacts estimated in this study solely consider impacts supported by expenditures made by hydropower operators and developers. They do not consider a full range of impacts such as utility rate changes, changes in land values, taxes, or displaced economic activity.

53. Demographers use the term "sex" to refer to biological differences between males and females, which differs from the meaning of "gender." In this case, "sex" is more accurate. For more information, see the U.S. Census Bureau's "About Age and Sex" [115].

Table 3-12. Domestic Content of Construction Expenditures

	Low	High
Land Purchases	100%	100%
Preparation, Prefabricated Structures, Site Access	60%	100%
Turbines and Generators	20%	80%
Balance of Plant	30%	80%
Transformers, Switchyard, and Interconnection	0%	0%
Installation Labor	80%	100%
Mitigation	80%	95%
Licensing, Permitting, Interconnection	80%	100%
Engineering and Other Professional Services	15%	50%
Insurance and Other Development Costs	75%	100%

Table 3-13. Domestic Content of Operations and Maintenance Expenditures

	Low	High
Onsite operations labor	100%	100%
Supplies, tools, vehicles	40%	80%
Replacement parts	25%	80%
Regulatory compliance	80%	95%

Retirements are estimated based on changes in labor force participation over time. Labor force participation can be seen decreasing as older workers age, reflecting both a smaller absolute size of the older population due to mortality and workers choosing to retire.[54] Retirement in this report refers to workers who exit the labor force by ceasing to work or actively seek employment. Retirement estimates by year, age, and sex are derived from Bureau of Labor Statistics projections [116]. These projections contain existing and forecasted labor force participation rates by age and sex through 2022. It is assumed that annual average changes in labor force participation by age and sex beyond 2022 continue on the same linear trajectory as the Bureau of Labor Statistics forecasts between 2012 and 2022.

54. This definition of retirement does not describe financial arrangements such as pensions or social security. For example, a worker who formally retires to begin collecting a pension and then returns to work as a contractor does not exit the labor force. Despite technically retiring from a specific employer, this worker would not be considered a retiree because she or he remains in the labor force

Table 3-14. Jobs (Full-time Equivalents) in 2030 and 2050 Supported by New Hydropower Deployment Scenario with Low and High Domestic Content

	2030		2050	
	Low Domestic Content	High Domestic Content	Low Domestic Content	High Domestic Content
Business as Usual	137,800	140,600	137,600	139,000
Advanced Technology	132,600	135,200	137,200	140,300
Low Cost Finance	173,500	197,100	144,800	149,200
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	203,600	238,900	219,700	251,100
Advanced Technology, Low Cost Finance, Critical Habitat	214,700	260,500	190,000	208,000
Advanced Technology, Low Cost Finance	252,700	297,200	270,300	290,400
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Critical Habitat	271,800	325,000	274,300	300,500
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	214,100	250,800	191,500	202,300
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	329,700	410,000	317,500	352,500

Mortality estimates in this analysis are from the Centers for Disease Control and Prevention's Wide-ranging Online Data for Epidemiologic Research database. These are present-day mortality rates by age and sex, not forecasts. This analysis assumes no change in mortality rates into the future.

Results

Total hydropower-derived employment estimates have been calculated as function of all future investments in hydropower facilities (on-site, supply chain, induced jobs) under conditions with varying levels of new hydropower deployment. More specifically, total hydropower-derived estimates have been made for each of the nine scenarios identified and described in Section 3.4 and under both the low and high domestic content assumptions noted in Tables 3-12 and 3-13.

Total hydropower investment employment estimates for 2030 and 2050 are shown in Table 3-14. Under *Business-as-Usual* conditions, the existing labor force grows to approximately 137,800 to 140,600 jobs (full-time equivalents) in 2030 and holds essentially steady at that level through 2050. The scenario with the largest hydropower capacity expansion—*Advanced Technology, Low Cost Finance, High Fossil Fuel Cost*—consistently supports the highest number of jobs, with impacts in 2030 and 2050 ranging from a low of 317,500 (2050 low domestic content) to a high of 410,000 (2030 high domestic content).

Earnings, gross domestic product, and economic output (total economic activity) are also associated with operation and expansion of hydropower facilities. Table 3-15 highlights these results across representative low, mid, and high hydropower deployment scenarios for 2030. Table 3-16 highlights these results across the same four scenarios for 2050. Relative to the baseline, new hydropower deployment supports 76,000 new jobs (averaged across low and high domestic content estimates) in the *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* Scenario. Estimates of jobs supported by the existing fleet change over time, with 119,600–119,700 jobs supported in 2030 and 120,300–120,700 jobs supported in 2050 (ranges are across low and high domestic content).

Table 3-15. Jobs, Earnings, Output, and Gross Domestic Product Impacts of Representative Low, Mid, and High Deployment Scenarios in 2030, Showing Low and High Domestic Content (dollars in $2015 millions)

2030		Domestic Content	Onsite	Supply Chain	Induced	Total
Business as Usual	Jobs	Low	25,000	60,200	52,700	137,800
		High	25,600	61,400	53,700	140,600
	Earnings	Low	$31,370	$75,540	$66,130	$172,910
		High	$32,130	$77,040	$67,380	$176,420
	Output	Low	$2,350	$4,110	$3,290	$9,740
		High	$2,400	$4,280	$3,330	$10,010
	GDP	Low	$2,410	$15,370	$9,990	$27,750
		High	$2,490	$15,800	$10,100	$28,390
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	Jobs	Low	49,500	81,300	83,400	214,100
		High	60,900	93,400	96,400	250,700
	Earnings	Low	$4,430	$5,490	$5,110	$15,020
		High	$5,370	$6,500	$5,840	$17,700
	Output	Low	$5,500	$20,810	$15,530	$41,840
		High	$7,190	$23,990	$17,740	$48,910
	GDP	Low	$4,580	$13,210	$9,100	$26,880
		High	$5,630	$14,700	$10,400	$30,710
Advanced Technology, Low Cost Finance, Critical Habitat	Jobs	Low	56,400	74,500	83,900	214,600
		High	70,900	89,400	100,200	260,400
	Earnings	Low	$5,030	$5,490	$5,190	$15,690
		High	$6,240	$6,660	$6,100	$18,990
	Output	Low	$6,350	$17,910	$15,770	$40,020
		High	$8,500	$22,070	$18,530	$49,090
	GDP	Low	$5,210	$10,730	$9,240	$25,180
		High	$6,570	$12,760	$10,860	$30,180
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	Jobs	Low	84,300	122,000	123,500	329,700
		High	111,200	146,700	152,100	409,900
	Earnings	Low	$7,500	$7,990	$7,410	$22,880
		High	$9,800	$9,930	$9,030	$28,750
	Output	Low	$9,710	$31,650	$22,510	$63,850
		High	$13,650	$37,840	$27,440	$78,920
	GDP	Low	$7,830	$20,100	$13,190	$41,110
		High	$10,410	$23,190	$16,080	$49,670

Table 3-16. Jobs, Earnings, Output, and GDP Impacts of Representative Low, Mid, and High Deployment Scenarios in 2050, Showing Both Low and High Local Content (dollars in $2015 millions)

2050		Domestic Content	Onsite	Supply Chain	Induced	Total
Business as Usual	Jobs	Low	24,200	60,500	53,000	137,600
		High	24,200	61,200	53,500	138,900
	Earnings	Low	$2,280	$4,130	$3,310	$9,700
		High	$2,280	$4,270	$3,320	$9,860
	Output	Low	$2,280	$15,450	$10,060	$27,790
		High	$2,300	$15,780	$10,080	$28,150
	GDP	Low	$2,280	$10,060	$5,900	$18,220
		High	$2,290	$10,070	$5,910	$18,250
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	Jobs	Low	31,600	78,900	81,000	191,400
		High	34,400	83,000	84,900	202,200
	Earnings	Low	$2,910	$5,250	$5,040	$13,190
		High	$3,140	$5,650	$5,240	$14,030
	Output	Low	$3,170	$20,510	$15,300	$38,980
		High	$3,590	$21,640	$15,920	$41,140
	GDP	Low	$2,950	$13,380	$8,970	$25,280
		High	$3,200	$13,820	$9,330	$26,340
Advanced Technology, Low Cost Finance, Critical Habitat	Jobs	Low	37,900	68,400	83,900	190,000
		High	42,900	74,900	90,300	207,900
	Earnings	Low	$3,500	$5,100	$5,300	$13,900
		High	$3,900	$5,600	$5,700	$15,200
	Output	Low	$3,900	$16,600	$16,100	$36,500
		High	$4,600	$18,600	$17,200	$40,300
	GDP	Low	$3,600	$10,200	$9,500	$23,100
		High	$4,000	$11,200	$10,100	$25,200
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	Jobs	Low	51,700	137,800	128,200	317,500
		High	62,400	149,600	140,600	352,400
	Earnings	Low	$4,670	$8,820	$7,780	$21,260
		High	$5,570	$9,790	$8,480	$23,830
	Output	Low	$5,530	$36,510	$23,640	$65,670
		High	$7,080	$39,520	$25,750	$72,350
	GDP	Low	$4,780	$24,020	$13,850	$42,650
		High	$5,780	$25,500	$15,100	$46,360

In 2030, total contributions to output could be as high as $78.9 billion and contributions to GDP could be as high as $49.7 billion. In 2050, total contributions to output could be as high as $72.4 billion and contributions to GDP could be as high as $46.4 billion.

Communities will often be most interested in local impacts. To illustrate the potential geographic distribution of on-site jobs, Figure 3-59 details on-site jobs by state for representative low, mid, and high hydropower deployment scenarios: *Business-as-Usual*; *Advanced Technology; Low Cost Finance; All Environmental Considerations*; *Advanced Technology, Low Cost Finance, Critical Habitats Consideration*; and *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost*. Data presented in Figure 3-59 assume that all onsite jobs occur within the states where facilities are built and operated. Supply chain and induced employment impacts are not estimated on a state or regional basis, as they may be procured from local or non-local suppliers.

As shown in Section 2.8, the hydropower industry supported approximately 118,000 total full-time equivalent jobs from O&M investments related to the existing fleet (based on estimated 2013 annual expenditures). Approximately 23,200 of these are identified as direct onsite hydropower industry jobs. These jobs and associated impacts are expected to continue throughout the duration of the modeled hydropower scenarios and are included in the total hydropower-related employment estimates shown in Figure 3-59. However, some portion of existing fleet workers will need to be replaced as the workforce ages.

The occupational distribution of the share of existing hydropower-supported jobs that are direct onsite jobs (approximately 20%) is summarized in Table 3-17. Figure 3-60 subsequently shows the age distribution of all U.S. workers, as well as the workers in the hydropower industry jobs categories in Table 3-17.

Note that many hydropower workers are older than 36 years, especially those in managerial or supervisory occupations, and the greatest concentration is in the 46- to 55-year-old cohort. These occupations will thus be the most affected by retirements in the next 10–20 years.

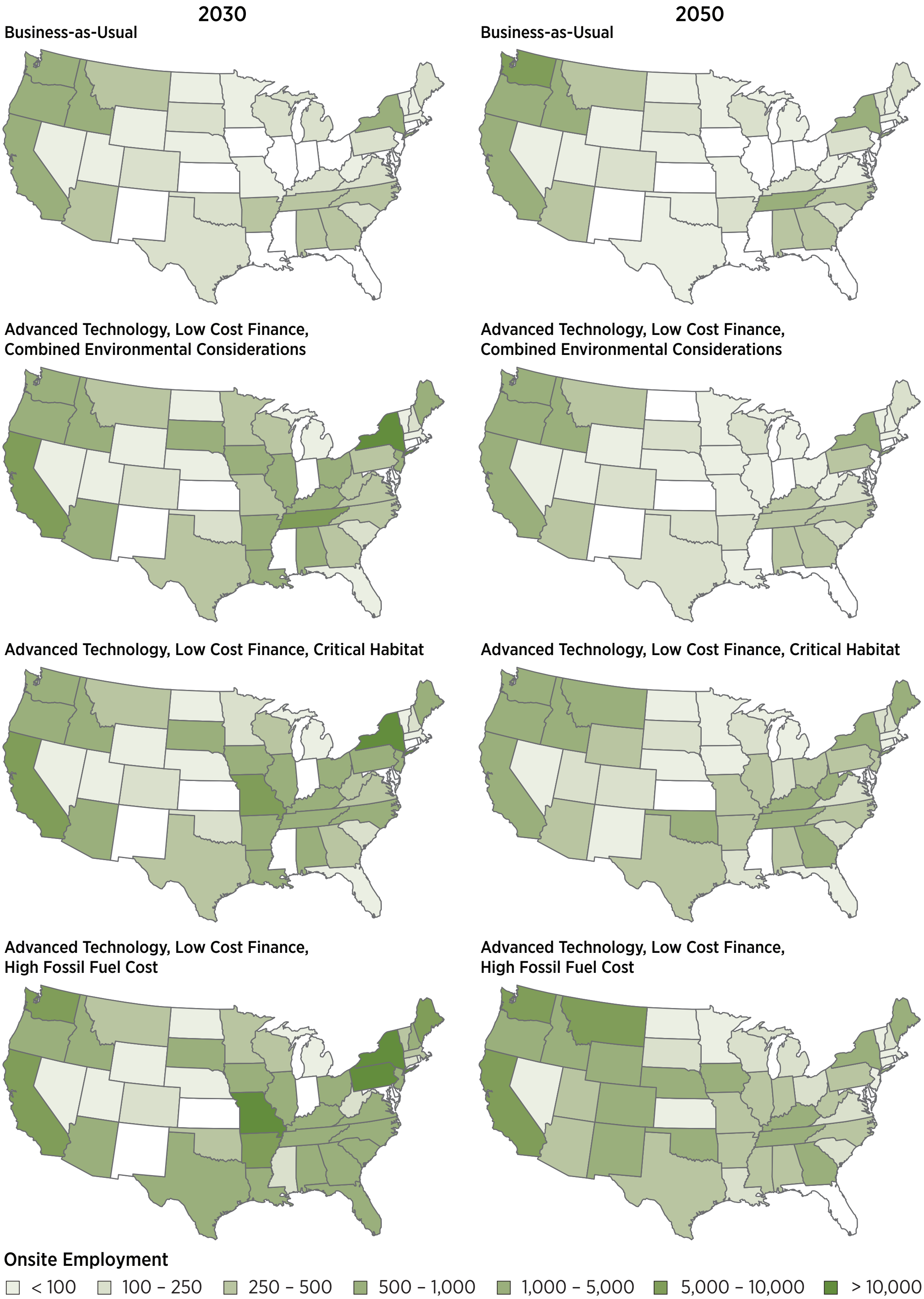


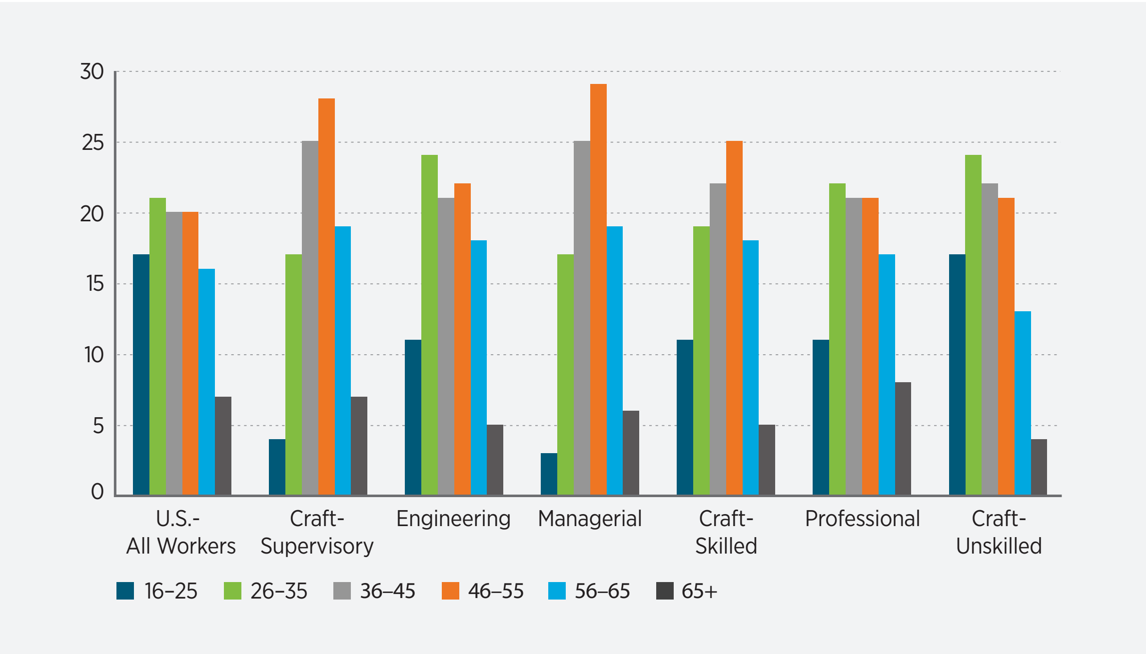
Figure 3-59. Onsite employment (full-time equivalents) by state under representative low, mid, and high deployment scenarios

Table 3-17. Distribution of 2013 Onsite Hydropower Operations and Maintenance Workers by Occupation[a]

Occupation Category	Sample Jobs	Employment (2013)
Craft workers, unskilled	Construction laborers, helpers	1,500
Craft workers, skilled	Heavy equipment operators, mechanics	6,200
Supervisory craft workers	Managers of electricians, mechanics	1,500
Managers	Program manager, operations manager	1,100
Engineering	Civil, electrical, environmental	2,800
Administration	Accountant, clerical workers	3,000
Professional	Biologists, hydrologists, regulatory, compliance support workers	7,100

a. Appendix I-Workforce contains further detail about specific occupations included in each category.

Source: DOE [118]



Source: DOE [118]

Figure 3-60. Age and occupational distribution of the existing hydropower workforce

Table 3-18. Cumulative Projected Workforce Replacement Needs by Occupation

	2025	2030
Craft—Supervisory	460	650
Engineering	800	1,110
Managerial	340	480
Craft—Skilled	1,650	2,320
Professional	2,070	2,800
Craft—Unskilled	330	480
Administration	750	1,040
Total	**6,400**	**8,880**

Source: DOE [118]

Based on these data, Table 3-18 summarizes projected retirements and subsequent replacement needs for the onsite workers through 2030. On a cumulative basis, the most significant workforce replacement needs are for skilled craft laborers and professional occupations, each representing approximately 2,500 jobs. Cumulative total jobs replacements through 2030 are estimated at approximately 8,880 on-site O&M-related jobs. Although managerial and supervisory staff tend to be older, absolute replacement totals for these staff suggest that this not necessarily problematic. These individuals also may start out in other fields and eventually become supervisors or managers, further reducing workforce concerns for this group.

Meeting both the replacement and incremental employment needs of the hydropower workforce may present challenges, especially if existing operators must compete with new operators for talented workers. Many positions require advanced educational backgrounds in science, technology, engineering, and mathematics fields, while others require post-secondary vocational training or trade certification. Workers may be hesitant to relocate to remote rural locations that offer limited employment alternatives if workers choose to leave their jobs [119, 120]. At same time, both the overall magnitude of potential workforce needs and the timing of incremental demand suggest that securing the requisite labor for the hydropower industry will be manageable.

In summary, the existing hydropower fleet provides a substantial workforce foundation to replenish and build from over time. Total employment supported by the existing fleet is estimated at approximately 118,000. Approximately 38% of these jobs are expect to require replacement by 2030. Opportunities for new hydropower deployment (hydropower generation and PSH) present further demand to expand the hydropower workforce. Under *Business-as-Usual* conditions, the hydropower-supported workforce could expand by 17–19% by 2030 and remain largely at that level through 2050. Under the largest new hydropower growth considered in modeling analysis, the hydropower workforce could grow 180–250% by 2030 before declining slightly and stabilizing at levels that are approximately 170–200% larger than the current workforce. Under the largest new hydropower growth scenario considered in modeling analysis, total annual contributions to GDP could approach levels of $40 billion–$50 billion per year by 2030 and remain at that level through 2050.

Chapter 3 References

[1] Short, W.; Sullivan, P.; Mai, T.; Mowers, M.; , C.; Blair, N.; Heimiller, D.; Martinez, A. Regional Energy Deployment System (ReEDS). 2011.NREL Report No. TP-6A20-46534. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 15, 2016. *http://www.nrel.gov/analysis/reeds/documentation.html*.

[2] Sullivan, P.; Cole, W.; Blair, N.; Lantz, E.; Krishnan, V.; Mai, T.; Mulcahy, D.; Porro, G.2015 Standard Scenarios Annual Report: U.S. Electric Sector Scenario Exploration. 2015. NREL Report No. TP-6A20-64072. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 15, 2016. *http://www.nrel.gov/docs/fy15osti/64072.pdf*.

[3] U.S. Department of Energy 2015. Wind Vision: A New Era for Wind Power in the United States. DOE/GO-102015-4557. Washington, D.C.: U.S. Department of Energy. Accessed June 16, 2016. *http://www.energy.gov/eere/wind/maps/wind-vision*.

[4] National Energy Board (NEB). 2013. Canada's Energy Future 2013–Energy Supply and Demand Projections to 2035–An Energy Market Assessment. Cat. No. NE2-12/2013E-PDF. Calgary, Alberta, Canada: National Energy Board, 2013; Accessed June 15, 2016. *https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/index-eng.html.*

[5] McFarland, J., Zhou, Y., Clarke, L., Schultz, P., Sullivan, P., Colman, J., Patel, P., Eom, J., Kim, S., Kyle, G.P., Jaglom, W., Venkatesh, B., Haydel, J., Miller, R., Creason, J., and Perkins, B. 2015. Climate change impacts on electricity demand and supply in the United States: a multi-model comparison. Climatic Change. Accessed July 6, 2016. *https://cfpub.epa.gov/si/si_public_record_report.cfm?dirEntryId=252232*.

[6] U.S. Bureau of Reclamation. March 2012. Site Inventory and Hydropower Energy Assessment of Reclamation Owned Conduits: Supplement to the "Hydropower Resource Assessment at Existing Reclamation Facilities Report." Accessed May 24, 2016. *http://www.usbr.gov/power/CanalReport/*.

[7] Sale, M.J., N.A. Bishop, Jr., S.L. Reiser, K. Johnson, A.C. Bailey, A. Frank, and B.T. Smith. 2014. Opportunities for Energy Development in Water Conduits: A Report Prepared in Response to Section 7 of the Hydropower Regulatory Efficiency Act of 2013. ORNL/TM-2014/272. Prepared for the U.S. Department of Energy by the ORNL Water Power Technologies Team. September.

[8] "Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040," Government of Canada, National Energy Board. © January 2016. Accessed June 24, 2016. *https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html*

[9] Lopez, A., B. Roberts, D. Heimiller, N. Blair, and G. Porro. 2012. *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis.* NREL/ TP-6A20-51946. Golden, CO: National Renewable Energy Laboratory. Accessed June 25, 2016. *http://primo-pmtna01.hosted.exlibrisgroup.com/Pubs:PUBS:NREL_HORIZON83030*.

[10] Montgomery, Watson, Harza (MWH), 2009. Hydropower Modernization Initiative, Phase I, Needs and Opportunities Evaluation and Ranking. Report prepared for the U.S. Army Corps of Engineers Northwest Division Hydroelectric Design Center, Contract No. W9127N-08-D-0003, Task Order 0013.

[11] Zhang, Q.; Smith, B. T. 2015. Final Report: Demonstration Assessments of the Hydropower Advancement Project. Oak Ridge, TN: Oak Ridge National Laboratory. Accessed June 28, 2016. *http://hydropower.ornl.gov/research/hydropower/*.

[12] National Research Council (NRC), 2012. *Corps of Engineers Water Resources Infrastructure: Deterioration, Investment, or Divestment?* The National Academies Press, Washington, DC. Accessed June 28, 2016. *http://www.nap.edu/catalog/13508/corps-of-engineers-water-resources-infrastructure-deterioration-investment-or-divestment*.

[13] Hadjerioua, B.; Wei, Y.; Kao, S.C. An Assessment of Energy Potential at Non-Powered Dams in the United States. GPO DOE/EE-0711. Washington, DC, 2012.

[14] Kao, S-C., R.A. McManamay, K.M. Stewart, N.M. Samu, B. Hadjerioua, S.T. DeNeale, D. Yeasmin, M. Fayzul, K. Pasha, A.A. Oubeidillah, and B.T. Smith. 2014. New Stream-Reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. GPO DOE/EE-1063. U.S. Department of Energy Wind and Water Power Program, Washington, DC. Accessed April 26, 2016. *http://nhaap.ornl.gov/nsd.*

[15] US. Army Corps of Engineers. 1981. National Hydroelectric Power Resources Study Vol X: An Assessment of Hydroelectric Pumped Storage. U.S. Army Corps of Engineers Institute for Water Resources.

[16] IPCC (Intergovernmental Panel on Climate Change) 2014. Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp. Accessed June 14, 2016. *http://www.ipcc.ch/report/ar5/syr/*.

[17] Ashfaq, M., S. Ghosh, S.-C. Kao, L.C. Bowling, P. Mote, D. Touma, S.A. Rauscher, and N.S. Diffenbaugh, "Near-Term Acceleration Of Hydroclimatic Change In The Western U.S.," Journal Of Geophysical Research: Atmospheres 118 (19) (2013): 10,676-10,693. Accessed July 6, 2016. *http://dx.doi.org/10.1002/jgrd.50816*.

[18] U.S. Energy Information Administration (EIA). 2015. Annual Energy Outlook 2015. DOE/EIA-0383(2015). U.S. Energy Information Administration, Washington, D.C. (US). Accessed June 15, 2016: *http://www.eia.gov/forecasts/aeo/*.

[19] U.S. Energy Information Administration (EIA). (2015c). *Annual Energy Outlook 2015.* Accessed June 16, 2016. *http://www.eia.gov/oiaf/aeo/tablebrowser/.*

[20] Field, C.B.; Barros, V.R.; Dokken, D.J.; Mach, K.J.; Mastrandrea, M.D.; Bilir, T.E.; Chatterjee, M.; Ebi, K.L.; Estrada, Y.O.; Genova, R.C.; Girma, B.; Kissel, E.S.; Levy, A.N.; MacCracken, S.; Mastrandrea, P.R.; White, L.L., eds. *Climate Change 2014: Impacts, Adaptation, and Vulnerability: Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge, UK, and New York: Cambridge University Press, 2014. Accessed June 16, 2016. *http://ipcc-wg2.gov/AR5/*.

[21] Edenhofer, O.; Pichs-Madruga, R.; Sokona, Y.; Farahani, E.; Kadner, S.; Seyboth, K.; Adler, A.; Baum, I.; Brunner, S.; Eickemeier, P.; Kriemann, B.; Savolainen, J.; Schlömer, S.; von Stechow, C.; Zwickel, T.; Minx, J.C., eds. *Climate Change 2014: Mitigation of Climate Change: Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge, UK, and New York: Cambridge University Press, 2014b. Accessed June 15, 2016. *http://mitigation2014.org/*.

[22] Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. 2010. Interagency Working Group on Social Cost of Carbon. Washington, DC (US). Accessed June 16, 2016. *http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf*

[23] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. November 2013 revision. 2013. 78 FR 70586. Interagency Working Group on Social Cost of Carbon. Washington, DC: (US). Accessed June 16, 2016. *https://federalregister.gov/a/2013-28242*.

[24] Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates. 2014. GAO-14-663. U.S. Government Accountability Office, Washington, DC (US). Accessed June 16, 2016. *http://www.gao.gov/products/GAO-14-663*.

[25] Johnson, L.T., S. Yeh, and C. Hope, "The Social Cost Of Carbon: Implications For Modernizing Our Electricity System". Journal Of Environmental Studies And Sciences 3 (4) (2013): 369-375. doi:10.1007/s13412-013-0149-5. Accessed June 14, 2016. *http://www.researchgate.net/publication/263492370_The_social_cost_of_carbon_implications_for_modernizing_our_electricity_system.*

[26] Siler-Evans, K., I. L. Azevedo, M. G. Morgan, and J. Apt. 2013. "Regional Variations In The Health, Environmental, And Climate Benefits Of Wind And Solar Generation". Proceedings Of The National Academy Of Sciences 110 (29): 11768-11773. doi:10.1073/pnas.1221978110. Accessed June 16, 2016. *http://www.ncbi.nlm.nih.gov/pubmed/23798431*.

[27] McCubbin, D. and B.K. Sovacool. 2013. "Quantifying the Health and Environmental Benefits of Wind Power to Natural Gas." Energy Policy 53 (February): 429–41. Accessed June 23, 2016. *http://dx.doi.org/10.1016/j.enpol.2012.11.004*.

[28] Cullen, J., "Measuring The Environmental Benefits Of Wind-Generated Electricity". American Economic Journal: Economic Policy 5 (4) (2013): 107-133. doi:10.1257/pol.5.4.107. Accessed June 14, 2016. *https://www.aeaweb.org/articles.php?doi=10.1257/pol.5.4.107*.

[29] Kaffine, D., McBee, B. and Lieskovsky, J. 2012. Emissions Savings from Wind Power Generation: Evidence from Texas, California and the Upper Midwest. Working Paper 2012-03. Colorado School of Mines, Golden, CO (US). Accessed June 16, 2016. *http://econpapers.repec.org/paper/mnswpaper/wp201203.htm*.

[30] Fell, H. and J. Linn. 2013. "Renewable Electricity Policies, Heterogeneity, And Cost Effectiveness". Journal Of Environmental Economics And Management 66 (3): 688-707. doi:10.1016/j.jeem.2013.03.004. Accessed June 14, 2016. *https://www.researchgate.net/publication/259095992_Renewable_electricity_policies_heterogeneity_and_cost_effectiveness*.

[31] Fischer, C. and R.G. Newell, "Environmental And Technology Policies For Climate Mitigation". Journal Of Environmental Economics And Management 55 (2) (2008): 142-162. doi:10.1016/j.jeem.2007.11.001. Accessed June 14, 2016. *http://www.sciencedirect.com/science/article/pii/S0095069607001064*.

[32] Edenhofer, O., L. Hirth, B. Knopf, M. Pahle, S. Schlömer, E. Schmid and F. Ueckerdt, "On the Economics of Renewable Energy Sources." Energy Economics (40) (2013); pp. S12–S23. DOI: 10.1016/j.eneco.2013.09.015. Accessed June 14, 2016. *http://www.researchgate.net/publication/259097121_On_the_economics_of_renewable_energy_sources*.

[33] Kalkuhl, M., O. Edenhofer, and K. Lessmann. "Renewable Energy Subsidies: Second-Best Policy Or Fatal Aberration For Mitigation?". September 2013. Resource and Energy Economics, Volume 35, Issue 3: 217–234. doi:10.2139/ssrn.1873197. Accessed July 6, 2016. *http://www.sciencedirect.com/science/article/pii/S0928765513000043*.

[34] McKibbin, W.J., A.C. Morris, and P.J. Wilcoxen, "Pricing Carbon In The U.S.: A Model-Based Analysis Of Power-Sector-Only Approaches". Resource And Energy Economics 36 (1) (2014): 130-150. doi:10.1016/j.reseneeco.2013.11.007. Accessed June 14, 2016. *https://www.infona.pl/resource/bwmeta1.element.elsevier-4f146c3d-43e3-3440-bacd-79d64acfc198*.

[35] Borenstein, S. "The Private and Public Economics of Renewable Electricity Generation." Journal of Economic Perspectives (26:1), 2012; pp. 67–92. Accessed June 14, 2016. *http://www.nber.org/papers/w17695*.

[36] Rausch, S.; Karplus, V.J. "Markets versus Regulation: The Efficiency and Distributional Impacts of U.S. Climate Policy Proposals." The Energy Journal, Special Issue (35:1), 2014. Accessed June 14, 2016. *http://www.iaee.org/en/publications/ejarticle.aspx?id=2595*.

[37] Tuladhar, S.D.; Mankowski, S.; Bernstein, P. "Interaction Effects of Market-Based and Command-and-Control Policies." The Energy Journal, Special Issue (35:1), 2014. Accessed June 14, 2016. *http://www.iaee.org/en/publications/ejarticle.aspx?id=2588*.

[38] Kumar, A., T. Schei, A. Ahenkorah, R. Caceres Rodriguez, J.-M. Devernay, M. Freitas, D. Hall, Å. Killingtveit, Z. Liu. "Hydropower." In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation. O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow (eds), Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2011. Accessed June 16, 2016. *http://www.ipcc.ch/report/srren/*.

[39] Hertwich, E.G. 2013. "Addressing Biogenic Greenhouse Gas Emissions from Hydropower in LCA." Environmental Science and Technology, 2013(47), 9604–9611. Accessed April 1, 2016. *http://pubs.acs.org/doi/abs/10.1021/es401820p*.

[40] Cole, J. J., Y. T. Prairie, N. F. Caraco, W. H. McDowell, L. J. Tranvik, R. G. Striegl, and C. M. Duarte et al, "Plumbing The Global Carbon Cycle: Integrating Inland Waters Into The Terrestrial Carbon Budget". Ecosystems 10 (1) (2007): 172-185. doi:10.1007/s10021-006-9013-8. Accessed July 6, 2016. *http://dx.doi.org/10.1007/s10021-006-9013-8*.

[41] Beaulieu, J.J.; Smolenski,R.L.; Nietch, C.T.; Townsend-Small,A.; Elovitz, M.S. 2014. "High Methane Emissions from a Midlatitude Reservoir Draining an Agricultural Watershed." Environmental Science and Technology, 2014(48), 11100–11108. Accessed April 1, 2016. *http://pubs.acs.org/doi/pdf/10.1021/es501871g*.
[42] Teodoru et al. 2012. "The net carbon footprint of a newly created boreal hydroelectric reservoir." American Geophysical Union, 26(GB2016), 1-14. Accessed April 1, 2016. *http://onlinelibrary.wiley.com/doi/10.1029/2011GB004187/abstract*.

[43] United Nations Educational, Scientific and Cultural Organization / International Hydropower Association. 2010. GHG Measurement Guidelines for Freshwater Reservoirs. Accessed June 14, 2016. *http://www.hydropower.org/sites/default/files/publications-docs/GHG%20Measurement%20Guidelines%20for%20Freshwater%20Reservoirs.pdf*.

[44] Kumar, A., T. Schei, A. Ahenkorah, R. Caceres Rodriguez, J.-M. Devernay, M. Freitas, D. Hall, Å. Killingtveit, Z. Liu, 2011. Hydropower. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation [O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[45] Mai, T.; Wiser, R.; Sandor. D.; Brinkman, G.; Heath, G.; Denholm, P.; Hostick, D.; Darghouth, N.; Schlosser, A.; Strzepek, K. Exploration of High-Penetration Renewable Electricity Futures. June 2012. Vol. 1 of Renewable Electricity Futures Study. NREL REPORT NO. TP-6A20-52409-1. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 15, 2016. *http://www1.eere.energy.gov/library/viewdetails.aspx?productid=5846*.

[46] Lenzen, M. 2008. Life cycle energy and greenhouse gas emissions of nuclear energy: A review. Energy Conversion and Management 49, 2178-2199. Original publication 2006. Accessed July 6, 2016. *http://www.isa.org.usyd.edu.au/publications/documents/ISA_Nuclear_Report.pdf*.

[47] Parry, M.L.; Canziani, O.F.; Palutikof, J.P.; van der Linden, P.J.; Hanson, C.E., eds. *Climate Change 2007: Impacts, Adaptation and Vulnerability: Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge, UK: Cambridge University Press, 2007. Accessed June 15, 2016. *http://www.ipcc.ch/publications_and_data/publications_ipcc_fourth_assessment_report_wg2_report_impacts_adaptation_and_vulnerability.htm*.

[48] Melillo, J.M., T.C. Richmond, and G.W. Yohe. 2014. *Climate Change Impacts in the United States: The Third National Climate Assessment*. Washington, DC: U.S. Global Change Research Program. Accessed June 16, 2016. *http://www.globalchange.gov/browse/reports/climate-change-impacts-united-states-third-national-climate-assessment-0*.

[49] Metz, B.; Davidson, O.R.; Bosch, P.R.; Dave, R.; Meyer, L.A., eds. *Climate Change 2007: Mitigation of Climate Change: Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge, UK, and New York: Cambridge University Press, 2007. Accessed June 16, 2016. *https://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml*.

[50] Weitzman, M.L. "GHG Targets as Insurance Against Catastrophic Climate Damages." *Journal of Public Economic Theory* (14:2), 2012; pp. 221–244. Accessed June 16, 2016: *http://onlinelibrary.wiley.com/doi/10.1111/jpet.2012.14.issue-2/issuetoc*.

[51] MunichRE 2014. *2013 Natural Catastrophe Year in Review.* (2014). Munich, Germany: Webinar. Accessed Feb. 22, 2015 (recording no longer available).

[52] Sander, J.; Eichner, J.F.; Faust, E.; Steuer, M. 2013. "Rising Variability in Thunderstorm-Related U.S. Losses as a Reflection of Changes in Large-Scale Thunderstorm Forcing." *Weather, Climate, and Society* (5:4), 2013; pp. 317–331. Accessed June 16, 2016. *http://journals.ametsoc.org/doi/abs/10.1175/WCAS-D-12-00023.1*.

[53] Weitzman, M.L. "A Review of the *Stern Review on the Economics of Climate Change*." *Journal of Economic Literature* (45), September 2007; pp. 703–724. Accessed June 16, 2016. *https://www.aeaweb.org/articles.php?doi=10.1257/jel.45.3.703*.

[54] Johnson, L.T.; Hope, C. "The Social Cost of Carbon in U.S. Regulatory Impact Analyses: An Introduction and Critique." *Journal of Environmental Studies and Sciences* (2:3), 2012; pp. 205–221. Accessed June 16, 2016. *http://link.springer.com/article/10.1007%2Fs13412-012-0087-7#page-1*.

[55] Tol, R.S.J. "The Social Cost of Carbon." *Annual Review of Resource Economics* (3), October 2011; pp. 419–443. Accessed June 16, 2016. *http://www.annualreviews.org/doi/abs/10.1146/annurev-resource-083110-120028*.

[56] Kopp, R.E.; Golub, A.; Keohane, N.O.; Onda, C. 2012. "The Influence of the Specification of Climate Change Damages on the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal* (6:2012–13), 2012. Accessed June 16, 2016. *http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2056944*.

[57] Pindyck, R.S. "Climate Change Policy: What Do the Models Tell Us?" *Journal of Economic Literature* (51:3), 2013; pp. 860–872. Accessed June 23, 2016. *http://dx.doi.org/10.3386/w19244*.

[58] Arrow, K.; Cropper, M.; Gollier, C.; Groom, B.; Heal, G.; Newell, R.; Nordhaus, W.; et al. 2013. "Determining Benefits and Costs for Future Generations." *Science* (341:6144), 2013; pp. 349–350. Accessed June 16, 2016. *http://comments.sciencemag.org/content/10.1126/science.1235665*.

[59] Kopp, R.E.; Mignone, B.K. 2012. "The U.S. Government's Social Cost of Carbon Estimates After Their First Two Years: Pathways for Improvement." *Economics: The Open-Access, Open-Assessment E-Journal* (6:2012–15), 2012; pp. 1–41. Accessed June 16, 2016. *http://www.economics-ejournal.org/economics/journalarticles/2012-15*.

[60] Ackerman, F.; Stanton, E.A. "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal* (6:2012-10), 2012; pp. 1–25. Accessed June 16, 2016. *http://www.economics-ejournal.org/economics/journalarticles/2012-10.*

[61] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. July 2015 revision. Interagency Working Group on Social Cost of Carbon. Washington, DC: (US). Accessed July 6, 2016. *https://www3.epa.gov/climatechange/EPAactivities/economics/scc.html*.

[62] U.S. Energy Information Administration (EIA). (2015a). *Electricity Data Browser*. Accessed June 16, 2016. *http://www.eia.gov/electricity/data/browser/.*

[63] U.S. Energy Information Administration (EIA). (2015b). *Electric Power Monthly with Data for December 2014*. February 2015 Issue. Accessed June 16, 2016. *http://www.eia.gov/electricity/monthly/current_year/february2015.pdf.*

[64] Wiser, R., Mai, T., Millstein, D., Macknick, J., Carpenter, A., Cohen, S., Cole, W., Frew, B., and Heath, G. 2016. On the Path to SunShot: The Environmental and Public Health Benefits of Achieving High Penetrations of Solar Energy in the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-65628. Accessed July 6, 2016. *http://primo-pmtna01.hosted.exlibrisgroup.com/Pubs:PUBS:NREL_HORIZON102095*.

[65] EPA (Environmental Protection Agency). 2015. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Washington, D.C.: Environmental Protection Agency. Accessed July 6, 2016. *https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating*.

[66] Luckow, P., E. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher and R. Wilson. 2015. 2015 Carbon Dioxide Price Forecast. Cambridge, MA: Synapse Energy Economics, Inc. Accessed June 16, 2016. *http://www.synapse-energy.com/sites/default/files/2015%20Carbon%20Dioxide%20Price%20Report.pdf*.

[67] Barbose, G., R. Wiser, A. Phadke, and C. Goldman. 2008. "Managing Carbon Regulatory Risk In Utility Resource Planning: Current Practices In The Western United States". Energy Policy 36 (9): 3300-3311. doi:10.1016/j.enpol.2008.04.023. Accessed June 16, 2016. *http://eetd.lbl.gov/publications/managing-carbon-regulatory-risk-in-utility-resource-planning-current-practices-in-the-w.*

[68] Bokenkamp, K., H. LaFlash, V. Singh, and D.B. Wang, "Hedging Carbon Risk: Protecting Customers And Shareholders From The Financial Risk Associated With Carbon Dioxide Emissions". The Electricity Journal 18 (6) (2005): 11-24. doi:10.1016/j.tej.2005.05.007. Accessed July 6, 2016. *http://dx.doi.org/10.1016/j.tej.2005.05.007*.

[69] NRC (National Research Council). 2010. Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Research Council of the National Academies. Washington, DC: National Academies Press. Accessed June 23, 2016. *http://www.nap.edu/catalog/12794/hidden-costs-of-energy-unpriced-consequences-of-energy-production-and*.

[70] Dockery D. W., Pope C. A., Xu X., Spengler J. D., Ware J. H., Fay M. E., Ferris B. G., and F. E. Speizer. 1993. "An association between air pollution and mortality in six U.S. cities." N. Engl. J. Med. 329, 1753–1759. Accessed June 16, 2016. *http://www.nejm.org/doi/full/10.1056/NEJM199312093292401#t=article*.

[71] Krewski D., Jerrett M., Burnett R. T., Ma R., Hughes E., Shi Y., Turner M. C., Pope C. A., Thurston G., Calle E. E., Thun M. J., Beckerman B., DeLuca P., Finkelstein N., Ito K., Moore D. K., Newbold K. B., Ramsay T., Ross Z., Shin H., and B. Tempalski. 2009. "Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality." Research report 140, Boston, MA, June, 2009. Accessed June 16, 2016. *http://pubs.healtheffects.org/view.php?id=315*.

[72] Lepeule J., Laden F., Dockery D., and J. Schwartz. 2012. "Chronic exposure to fine particles and mortality: An extended follow-up of the Harvard Six Cities Study from 1974 to 2009." Environ. Health Perspect. 120, 965−970. Accessed June 16, 2016. *http://ehp.niehs.nih.gov/1104660/*.

[73] Lim S. et al. 2012. "A comparative risk assessment of burden of disease and injury attributable to 67 risk factors and risk factor clusters in 21 regions, 1990−2010: A systematic analysis for the Global Burden of Disease Study." Lancet. 380, 2224−2260. Accessed June 16, 2016. *http://www.thelancet.com/journals/lancet/article/PIIS0140-6736(12)61766-8/abstract*.

[74] Driscoll C. T., Buonocore J. J., Levy J. I., Lambert K. F., Burtraw D., Reid S. B., Fakhraei H. and J. Schwartz. 2015. "US power plant carbon standards and clean air and health co-benefits." Nature Climate Change. DOI: 10.1038/NCLIMATE2598. Accessed June 16, 2016. *http://www.nature.com/nclimate/journal/v5/n6/full/nclimate2598.html*.

[75] Turconi R., Boldrin A. , and T. Astrup. 2013. "Life Cycle Assessment (LCA) of Electricity Generation Technologies: Overview, Comparability and Limitations." Renewable and Sustainable Energy Reviews 28, 555–565. doi: 10.1016/j.rser.2013.08.013. Accessed June 16, 2016. *http://orbit.dtu.dk/en/publications/life-cycle-assessment-lca-of-electricity-generation-technologies-overview-comparability-and-limitations(d8c747fb-3774-4f4b-ac09-588f1226d935).html*.

[76] Fann N., Baker K. R., and C. M. Fulcher. 2012. "Characterizing the PM2.5-Related Health Benefits of Emission Reductions for 17 Industrial, Area and Mobile Emission Sectors Across the U.S." Environment International. (49) 141–151. Accessed June 23, 2016. *http://dx.doi.org/10.1016/j.envint.2012.08.017*.

[77] Novan, Kevin. 2015. "Valuing the Wind: Renewable Energy Policies and Air Pollution Avoided." American Economic Journal: Economic Policy, 7(3): 291-326. Accessed July 6, 2016. *http://dx.doi.org/10.1257/pol.20130268*

[78] Cai H., Wang M., Elgowainy A., and J. Han. 2012. Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units. ANL/ESD/12-2. Lemont, IL: Argonne National Laboratory. Accessed June 16, 2016. *http://www.osti.gov/scitech/biblio/1045758*.

[79] Cai H., Wang M., Elgowainy A., and J. Han. 2013. Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010. Lemont, IL: Argonne National Laboratory. Accessed July 7, 2016. *https://greet.es.anl.gov/publication-electricity-13*.

[80] Muller N. Z., Mendelsohn R., and W. Nordhaus. 2011. "Environmental Accounting for Pollution in the United States Economy." American Economic Review. (101:5). 1649–1675. DOI: 10.1257/aer.101.5.1649. Accessed June 16, 2016. *https://www.aeaweb.org/articles?id=10.1257/aer.101.5.1649*.

[81] Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Washington, DC: Interagency Working Group on Social Cost of Carbon, February 2010. Accessed July 7, 2016. *https://www3.epa.gov/otaq/climate/regulations/scc-tsd.pdf*.

[82] Bell M. L., McDermott A., Zeger S. L., Samet J. M., and F. Dominici. 2004. "Ozone and Short-Term Mortality in 95 US Urban Communities, 1987–2000." Journal of the American Medical Association. (292:19) 2372–2378. Accessed June 16, 2016. *http://www.ncbi.nlm.nih.gov/pubmed/15547165*.

[83] Levy, J.I., Chemerynski, S.M., Sarnat, J.A. 2005. "Ozone Exposure and Mortality: An Empiric Bayes Metaregression Analysis." Epidemiology. (16:4) 458–468. Accessed June 16, 2016. *http://www.ncbi.nlm.nih.gov/pubmed/15951663*.

[84] U.S. Census Bureau. 2012. 2012 National Population Projections Summary Tables, Table 1. Projections of the Population and Components of Change for the United States: 2015 to 2060. Washington, DC: U.S. Census Bureau Population Division. h Accessed June 16, 2016: *https://www.census.gov/population/projections/data/national/2012/summarytables.html*.

[85] AEO (Annual Energy Outlook). 2014. Annual Energy Outlook with Projections to 2040. DOE/EIA-0383(2014). Washington, DC: U.S. Department of Energy, Energy Information Administration, April 2014a; 269 pp. Accessed June 16, 2016. *http://www.eia.gov/forecasts/aeo/*.

[86] U.S. Environmental Protection Agency. 2013. Progress Report: SO2 and NOX Emissions, Compliance, and Market Analyses. Washington, DC: U.S. Environmental Protection Agency.

[87] Schmalensee R. and R. N. Stavins. 2013. "The SO2 Allowance Trading System: The Ironic History of a Grand Policy Experiment." Journal of Economic Perspectives. (27:1) 103–122. Accessed June 16, 2016. *https://www.aeaweb.org/articles.php?doi=10.1257/jep.27.1.103*.

[88] Kenny, J.F., N.L. Barber, S.S. Hutson, K.S. Linsey, J.K. Lovelace, and M.A. Maupin. 2009. *Estimated Use of Water in the United States in 2005.* No. CIR–1344. Reston, VA: U.S. Geological Survey. Accessed June 16, 2016. *http://pubs.usgs.gov/circ/1344/*.

[89] Maupin, M.A., J.F. Kenny, S.S. Hutson, J.K. Lovelace, N.L. Barber, and K.S. Linsey. 2014. *Estimated Use of Water in the United States in 2010*. U.S. Geological Survey Circular 1405. Washington, DC: U.S. Geological Survey. Accessed June 16, 2016. *http://pubs.usgs.gov/circ/1405/*.

[90] Solley, W.B., R.R. Pierce, and H.A. Perlman. 1998. *Estimated Use of Water in the United States in 1995*. U.S. Geological Survey Circular 1200. Reston, VA: U.S. Geological Survey. Accessed June 16, 2016. *https://pubs.er.usgs.gov/publication/cir1200*.

[91] Arent, D., J. Pless, T. Mai, R. Wiser, M. Hand, S. Baldwin, G. Heath, J. Macknick, M. Bazilian, A. Schlosser, and P. Denholm. 2014. "Implications of High Renewable Electricity Penetration in the US for Water Use, Greenhouse Gas Emissions, Land-Use, and Materials Supply." *Applied Energy* 123: 368–77. Accessed June 16, 2016. *http://www.sciencedirect.com/science/article/pii/S0306261913010210*.

[92] Chandel, M.K., L.F. Pratson, and R.B. Jackson. 2011. "The Potential Impacts of Climate-Change Policy on Freshwater Use in Thermoelectric Power Generation." *Energy Policy* 39: 6234–42. Accessed June 16, 2016. *http://www.sciencedirect.com/science/article/pii/S0301421511005465*.

[93] Clemmer, S., J. Rogers, S. Sattler, J. Macknick, and T. Mai. 2013. "Modeling Low-Carbon US Electricity Futures to Explore Impacts on National and Regional Water Use." *Environmental Research Letters* 8 (015004).

[94] Macknick, J., S. Sattler, K. Averyt, S. Clemmer, and J. Rogers. 2012b. "The Water Implications of Generating Electricity: Water Use across the United States Based on Different Electricity Pathways through 2050." *Environmental Research Letters* 7(4): 045803. Accessed June 16, 2016. *http://iopscience.iop.org/article/10.1088/1748-9326/7/4/045803/meta*.

[95] Roy, S.B., L. Chen, E.H. Girvetz, E.P. Maurer, W.B. Mills, and T.M. Grieb. 2012. "Projecting Water Withdrawal and Supply for Future Decades in the U.S. under Climate Change Scenarios." *Environmental Science and Technology* 46: 2545–56. Accessed June 16, 2016. *http://pubs.acs.org/doi/abs/10.1021/es2030774*.

[96] Tidwell, V.C., L.A. Malczynski, P.H. Kobos, G.T. Klise, and E. Shuster. 2013. "Potential Impacts of Electric Power Production Utilizing Natural Gas, Renewables and Carbon Capture and Sequestration on U.S. Freshwater Resources." *Environmental Science and Technology* 47: 8940–47. DOI: 10.1021/es3052284. Accessed June 16, 2016: *http://pubs.acs.org/doi/abs/10.1021/es3052284*.

[97] van Vliet, M.T.H., J.R. Yearsley, F. Ludwig, S. Vogele, D.P. Lettenmaier, and P. Kabat. 2012. "Vulnerability of US and European Electricity Supply to Climate Change." *Nature Climate Change* 2: 676–81. Accessed June 16, 2016. *http://dx.doi.org/10.1038/nclimate1546*.

[98] Macknick, J., R. Newmark, G. Heath, and K.C. Hallett. 2012a. "Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies: A Review of Existing Literature." *Environmental Research Letters* 7(4): 045802. Accessed June 16, 2016. *http://iopscience.iop.org/article/10.1088/1748-9326/7/4/045802/meta*.

[99] Meldrum, J., S. Nettles-Anderson, G. Heath, and J. Macknick. 2013. "Life Cycle Water Use for Electricity Generation: A Review and Harmonization of Literature Estimates." *Environmental Research Letters* 8: 015031. Accessed June 16, 2016. *http://iopscience.iop.org/article/10.1088/1748-9326/8/1/015031/meta*.

[100] Clemmer, S., J. Rogers, S. Sattler, J. Macknick, and T. Mai, "Modeling Low-Carbon US Electricity Futures To Explore Impacts On National And Regional Water Use". Environ. Res. Lett. 8 (1) (2013): 015004. doi:10.1088/1748-9326/8/1/015004. Accessed June 14, 2016. *http://dx.doi.org/10.1088/1748-9326/8/1/015004*.

[101] Gleick, P. 1992. Environmental consequences of hydroelectric development: the role of facility size and type. *Energy* 17 735–747. Accessed June 16, 2016. *http://www.sciencedirect.com/science/article/pii/036054429290116H*.

[102] Torcellini, P., Long, N., and Judkoff, R. 2003. *Consumptive Water Use for U.S. Power Production* (Golden, CO: National Renewable Energy Laboratory). NREL/TP-550-33905. Accessed June 16, 2016. *http://www.nrel.gov/docs/fy04osti/33905.pdf*.

[103] Pasqualetti, M. J., Kelley, S. 2008. *The Water Costs of Electricity in Arizona.* Arizona Department of Water Resources. Accessed June 16, 2016. *http://www.azwater.gov/AzDWR/StatewidePlanning/Conservation2/Documents/documents/TheWaterCostsofElectricityinArizona.pdf.*

[104] U.S. Environmental Protection Agency. 2011. *Environmental and Economic Benefits Analysis for Proposed Section 316(b) Existing Facilities Rule.* EPA 821-R-11-002. Washington, DC: U.S. Environmental Protection Agency. Accessed June 16, 2016. *http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P100B6F8.TXT*.

[105] Macknick, J., Cohen, S., Tidwell, V., Newmark, R., Martinez, A., and Sullivan, S. 2015. *Water Constraints in an Electric Sector Capacity Expansion Model.* NREL/TP-6A20-64270. Golden, CO: National Renewable Energy Laboratory. Accessed June 16, 2016. *http://www.nrel.gov/docs/fy15osti/64270.pdf*.

[106] Rogers, J., Averyt, K., Clemmer, S., Davis, M., Flores-Lopez, F., Kenney, D., Macknick, J., Madden, N., Meldrum, J., Sattler, S., Spanger-Siegfried, E., and Yates, D. 2013. *Water-Smart Power: Strengthening the U.S. Electricity System in a Warming World*. Cambridge, MA: Union of Concerned Scientists. Accessed June 16, 2016. *http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-smart-power.html#.V2Ks-PkrLIU*.

[107] EPA (U.S. Environmental Protection Agency). 2009. *Cooling Water Intake Structures— CWA 316(b), Phase II—Large Existing Electric Generating Plants*. Washington, DC: U.S. Environmental Protection Agency. Accessed July 7, 2016. *http://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201310&RIN=2040-AE95*.

[108] Averyt, K., J. Macknick, J. Rogers, N. Madden, J. Fisher, J. Meldrum, and R. Newmark. 2013. "Water Use for Electricity in the United States: An Analysis of Reported and Calculated Water Use Information for 2008." *Environmental Research Letters* 8 (015001). Accessed June 23, 2016. *http://dx.doi.org/10.1088/1748-9326/8/1/015001*.

[109] UCS (Union of Concerned Scientists). 2012. *UCS EW3 Energy-Water Database. V.1.3.* Cambridge, MA: Union of Concerned Scientists. Accessed June 16, 2016. *http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/ucs-power-plant-database.html#.V2KwbPkrLIU.*

[110] Averyt, K., J. Fisher, A. Huber-Lee, A. Lewis, J. Macknick, N. Madden, J. Rogers, and S. Tellinghuisen. 2011. *Freshwater Use by U.S. Power Plants: Electricity's Thirst for a Precious Resource*. Cambridge, MA: Union of Concerned Scientists. Accessed June 16, 2016. *http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/freshwater-use-by-us-power-plants.html#.V2KjovkrLIU*.

[111] DOE (U.S. Department of Energy). 2013. *U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather.* DOE/PI-0013. Washington, DC: U.S. Department of Energy. Accessed June 16, 2016. *http://www.energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf*.

[112] Zhai, H., and E.S. Rubin. 2010. "Performance and Cost of Wet and Dry Cooling Systems for Pulverized Coal Power Plants with and Without Carbon Capture and Storage." *Energy Policy* 38(10): 5653–60. Accessed June 16, 2016. *http://www.sciencedirect.com/science/article/pii/S0301421510003848*.

[113] Maulbetsch, J.S., and M.N. DiFilippo. 2006. *Cost and Value of Water Use at Combined-Cycle Power Plants.* CEC-500-2006-034. Sacramento, CA: California Energy Commission. Accessed June 23, 2016. *http://www.energy.ca.gov/2006publications/CEC-500-2006-034/*.

[114] Tidwell, V.C., J. Macknick, K. Zemlick, J. Sanchez, and T. Woldeyesus. 2014. "Transitioning to Zero Freshwater Withdrawal in the U.S. for Thermoelectric Generation." *Applied Energy* 131: 508–16. Accessed June 16, 2016. *http://www.sciencedirect.com/science/article/pii/S0306261913009215*.

[115] U.S. Census Bureau. 2013. About Age and Sex. U.S. Census Bureau, Washington, D.C. (US). Accessed July 7, 2016. *http://www.census.gov/population/age/about/*.

[116] U.S. Census Bureau. 2013. Population Estimates and Projections Methodology. U.S. Census Bureau, Washington, D.C. (US). Accessed June 16, 2016. *https://www.census.gov/population/international/data/idb/estandproj.php*

[117] "Employment Projections." U.S. Bureau of Labor Statistics. Accessed July 7, 2016. *http://www.bls.gov/emp/*.

[118] U.S. Department of Energy. Prepared by Navigant Consulting, Inc. , and the National Renewable Energy Laboratory. DOE/EE-1400. Forthcoming (2016). "United States Hydropower Workforce Assessment and Future Scenarios".

[119] Florida, R., C. Mellander, and K. Stolarick, "Inside the Black Box Of Regional Development—Human Capital, The Creative Class And Tolerance". Journal of Economic Geography 8 (5) (2008): 615-649. Accessed July 8, 2016. *http://dx.doi.org/10.1093/jeg/lbn023*.

[120] Waltert, F.; Schläpfer, F. 2007. The role of landscape amenities in regional development: a survey of migration, regional economic and hedonic pricing studies. Working Paper No. 0710. University of Zürich, Socioeconomic Institute, Zürich, Switzerland. Accessed June 16, 2016. *http://www.zora.uzh.ch/52380/1/wp0710.pdf*.

[121] Böhringer, C., N.J. Rivers, T.F. Rutherford, and R. Wigle. 2012. "Green Jobs and Renewable Electricity Policies: Employment Impacts Of Ontario's Feed-In Tariff". The B.E. Journal of Economic Analysis & Policy 12 (1) (2012). Accessed July 11, 2016. *http://dx.doi.org/10.1515/1935-1682.3217*.

[122] Breitschopf, B., C. Nathani, and G. Resch. 2011. Review of Approaches for Employment Impact Assessment of Renewable Energy Deployment. International Energy Agency Renewable Energy Technology Deployment (IEA-RETD). Paris, France. Accessed June 15, 2016. *http://iea-retd.org/wp-content/uploads/2011/11/EMPLOY-task-1.pdf*.

[123] Brown, J.P., J. Pender, R. Wiser, E. Lantz, and B. Hoen. 2012. "Ex Post Analysis Of Economic Impacts From Wind Power Development In U.S. Counties". Energy Economics 34 (6): 1743-1754. Accessed July 11, 2016. *http://dx.doi.org//10.1016/j.eneco.2012.07.010*.

[124] Chien, T. and J.L. Hu, "Renewable Energy: An Efficient Mechanism To Improve GDP". Energy Policy 36 (8) (2008): 3045-3052. Accessed July 11, 2016. *http://dx.doi.org//10.1016/j.enpol.2008.04.012*.

[125] Frondel, M., N. Ritter, C.M. Schmidt, and C. Vance, "Economic Impacts From The Promotion Of Renewable Energy Technologies: The German Experience". Energy Policy 38 (8) (2010): 4048-4056. Accessed July 11, 2016. *http://dx.doi.org/10.1016/j.enpol.2010.03.029*.

[126] Haerer, D., and L. Pratson. 2015. "Employment trends in the U.S. Electricity Sector, 2008-2012," Nicholas School of the Environment, Duke University, Durham, NC (US). Accessed June 15, 2016. *http://www.sciencedirect.com/science/article/pii/S0301421515001123*.

[127] Hillebrand, B., H.G. Buttermann, J.M. Behringer, and M. Bleuel, "The Expansion Of Renewable Energies And Employment Effects In Germany". Energy Policy 34 (18) (2006): 3484-3494. Accessed July 12, 2016. *http://dx.doi.org/10.1016/j.enpol.2005.06.017*.

[128] Marques, A.C. and J.A. Fuinhas, "Is Renewable Energy Effective In Promoting Growth?". Energy Policy 46 (2012).: 434-442. Accessed July 12, 2016. *http://dx.doi.org/10.1016/j.enpol.2012.04.006*.

[129] Meyer, I.; Sommer, M.W. 2014. Employment Effects of Renewable Energy Supply, A Meta Analysis, Policy Paper no 12. THEME SSH.2011.1.2-1. Austrian Institute of Economic Research (WWW For Europe), Vienna, Arsenal. Accessed June 16, 2016. *http://www.wifo.ac.at/jart/prj3/wifo/resources/person_dokument/person_dokument.jart?publikationsid=47225&mime_type=application/pdf*.

[130] Wei, M., S. Patadia, and D.M. Kammen, "Putting Renewables And Energy Efficiency To Work: How Many Jobs Can The Clean Energy Industry Generate In The US?". Energy Policy 38 (2) (2010): 919-931. doi:10.1016/j.enpol.2009.10.044.

A New Chapter for America's 1st Renewable Electricity Source

This first-of-its-kind analysis builds on the historical importance of hydropower and establishes a roadmap to usher in a new era of growth in sustainable domestic hydropower.

U.S. DEPARTMENT OF ENERGY

DOE/GO-102016-4869 • July 2016

Cover photos from iStock 55486650, 83494953, 28045480, 1946803