Docket No. RP24-___
Statement P
Exhibit No. T-0065
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Independent Statistics and Analysis
U.S. Energy Information Administration

Annual Energy Outlook

AEO2023

Administrator's Foreword

After a 23-year hiatus, I am reintroducing the Administrator's Foreword as part of the *Annual Energy Outlook* (AEO). The Foreword affords me an opportunity to provide context and outline future directions for one of our flagship products.

The U.S. energy system is rapidly changing. In recent years, technology innovation has accelerated the deployment of renewable energy, expanded markets for electric vehicles, and established record-high levels of petroleum and natural gas production. Heightened geopolitical risks have also influenced the energy system. And this year, recent federal legislation authorizes historic levels of investment in clean energy technology.

Ideally, we would model these dynamics to produce precise numerical forecasts that demonstrate how energy prices, technology deployment, and emissions will shift over time. Unfortunately, such precise forecasts are not possible. The 30-year decision landscape we model is too complex and uncertain. Thus, our objective must be to identify robust insights rather than precise numbers—think ranges and trends, not predictions and point estimates.

The AEO includes a series of projections—which we refer to as *cases*—each with different input assumptions that represent alternative views of how uncertainty may be resolved in the future. The Reference case represents our best guess under nominal conditions, which presumes no new policy or laws over the modeled time horizon. It's best to think of the Reference case as the experimental control: a baseline against which we can judge the other cases. Although the Reference case serves as an important benchmark, judgments about energy futures should never be based on a single projection. The AEO side cases represent plausible variations in key input assumptions that tend to drive the largest changes in projected outputs from the Reference case. This year's AEO narrative focuses on the full set of modeled cases in order to derive insights about our collective energy future.

Among the uncertainties we must confront, the timing, structure, and targets associated with yet-to-be-developed policy are the most uncertain. We only consider current laws and regulations across all modeled cases in this AEO. For some readers, this approach may be unsatisfying because policy rarely remains static for long periods. But this AEO should be considered part of an iterative policymaking process rather than apart from it; it gives decision-makers an opportunity to peer into a future without new policy. If the projected outcomes are undesirable from their viewpoint, they can effect change.

Changes to This Year's Edition

This year's edition of the *Annual Energy Outlook* includes three enhancements that improve the characterization of future uncertainty and provide more technical details on the model results.

Combination cases

Although the AEO core side cases address key uncertainties, each case represents a one-factor change to the Reference case. But, real energy markets often surprise us in more ways than one, particularly over the decades-long timeframes modeled in the AEO. In this year's edition, we include cases that combine assumptions from our macroeconomic and zero-carbon technology cost cases. These new cases reflect a combination of demand-side changes (macroeconomic growth affecting energy demand) and supply-side changes (renewables costs affecting generating capacity deployment) to expand the range of projections in the *Annual Energy Outlook*.

Visualizing uncertainty

Running a set of cases is not enough: how we present and discuss them within the report affects the insights that our readers draw from the analysis. Although the Reference case is an important benchmark, each case represents a possible alternative. So, in each of the figures in this report, you will see shaded areas that represent the range of results obtained across the modeled cases. Uncertainty can be characterized in many other ways beyond the analysis of multiple cases. One way, presented in the discussion section, uses deviations between realized and projected values drawn from previous AEO editions to derive a cone of uncertainty for future energy-related CO_2 emissions. Looking ahead, you should expect to see more innovation in how we treat uncertainty.

Technical notes

The narrative tends to focus on model-based results. We recognize that some readers want a deeper technical explanation around key issues. Although we describe our modeling approach elsewhere, how the model formulation and input assumptions influence the results is not always clear. To better explain key results, we included a series of technical notes in the narrative that focus on heat pump deployment, cost projections for renewables, electric vehicle deployment, and crude oil trade.

Future Work

At EIA, we are also pursuing broader changes to our long-term modeling efforts. I would like to highlight three such efforts.

Open-source code

One of our priorities at EIA is to make our data and model-based analysis as transparent and accessible as possible. We are working to make the National Energy Modeling System (NEMS) publicly available in GitHub under a permissive, open-source license, and we hope to complete this effort later this year. Making our models open source allows users to examine, reuse, and redistribute our code under clear legal guidelines. Giving you this kind of access is important to the learning and discovery process associated with energy modeling.

Expanded scenario range

Building on the combination cases in this year's AEO, we are expanding our capability to model a wider range of future scenarios using NEMS. In particular, decision makers need objective and rigorous assessments of net zero emissions pathways to inform ongoing policy discussions. We are working to incorporate novel fuel and technology pathways into NEMS and to appropriately treat uncertainty around technologies with limited commercial deployment.

A next-generation, open-source modeling framework

Although regularly updated, we have been using NEMS to produce the AEO since 1994—a span of nearly three decades that has born witness to significant changes in the real energy system, energy modeling methods, and software development practices. Moving forward, we need a flexible, next-generation modeling framework that can rapidly assess the cost, emissions, reliability, security, and community-level impacts associated with a number of contemporary energy issues. Some of these issues include pathways to a net-zero energy system, supply chain risks, rapid technology innovation, and shifting trade patterns. This modeling system will also be open source to promote transparency and encourage innovation within the modeling community. We've begun discussing this new framework, and I look forward to sharing our progress throughout my tenure as EIA Administrator.

In Closing

I'd like to thank our long-term modelers for their willingness to take on new directions and their tremendous effort to produce this year's AEO. I am very excited by the future work outlined above, and I feel privileged to help lead such a talented team of energy modelers.

Executive Summary

Our *Annual Energy Outlook* 2023 (AEO2023) explores long-term energy trends in the United States. Since last year's AEO, much has changed, most notably the passage of the Inflation Reduction Act (IRA), Public Law 117–169, which altered the policy landscape we use to develop our projections.

Energy-related CO_2 emissions fall across all AEO2023 cases because of increased electrification, higher equipment efficiencies, and more zero-carbon electricity generation.

We project that U.S. energy-related CO_2 emissions drop 25% to 38% below the 2005 level by 2030. For reference, the United States' *nationally determined contribution* (NDC), submitted as part of the Paris Agreement, calls for a target of 50% to 52% of net greenhouse gas emissions below the 2005 level by 2030.[1] We only consider energy-related CO_2 emissions, which does not cover the full NDC scope. Total energy-related CO_2 emissions in 2050 declined by 17% in this year's Reference case compared with last year's. Some of the primary factors that contributed to the change in our base case include the IRA, updates to technology costs and performance across the energy system, and changes in the macroeconomic outlook. All AEO2023 cases assume current laws and regulations, and compared with last year's AEO, there is a significant shift toward lower future emissions. The IRA represents a complex piece of legislation, and we could not model all provisions given model structure and uncertainty over select implementation details. The appendix includes a detailed accounting of IRA provisions and how we addressed them. To further explore possible emissions reductions, we also derive a cone of uncertainty based on an empirical analysis of our past projections and find that the energy-related CO_2 emissions reduction can be as high as 38% below 2005 levels in 2030.

Overall, our lower projected U.S. energy-related CO_2 emissions is driven by increased electrification, equipment efficiency, and renewable technologies for electricity generation. However, emissions reductions are limited by longer-term growth in U.S. transportation and industrial activity. As a result, these projected emissions reductions are most sensitive to our assumptions regarding economic growth and the cost of zero-carbon generation technology.

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[1] The *nationally determined contribution* (NDC) is a formal submission to the United Nations Framework Convention on Climate Change. The United States submitted, "To achieve an economy-wide target of reducing its net greenhouse gas emissions by 50-52 percent below 2005 levels in 2030."

In AEO2023, we see stable growth in U.S. electric power demand through 2050 in all cases we considered because of increasing electrification and ongoing economic growth. The combination of declining capital costs and government subsidies, including IRA initiatives, drive rising renewable technologies for electricity generation, such as solar and wind. Once built and when the resource is available, wind and solar are the least cost resources to operate to meet electricity demand because they have zero fuel costs. Over time, the combined investment and operating cost advantage increases the share of zero-carbon electricity generation. As a result, in AEO2023, we see renewable generating capacity growing in all regions of the United States in all cases. Across all cases, compared with 2022, solar generating capacity grows by about 325% to 1019% by 2050, and wind generating capacity grows by about 138% to 235%. We see growth in installed battery capacity in all cases to support this growth in renewables. Across the span of AEO cases, relative to 2022, natural gas generating capacity ranges from an increase of between 20% to 87% through 2050.

> Renewable generating capacity grows in all regions of the United States in all AEO2023 cases, supported by growth in installed battery capacity.

> Technological advancements and electrification drive projected decreases in demand-side energy intensity.

Not only is the U.S. electric power sector's composition changing, but we see increased electrification in the end-use sectors. We project more heat pumps and electric vehicles, as well as electric arc furnaces increasingly deployed in the iron and steel industry. In the residential and commercial sectors, higher equipment efficiencies and stricter building codes extend ongoing declines in energy intensity. Despite the growth in adopting heat pumps, natural gas-fired heating equipment, including furnaces and boilers, continue to account for the largest share of energy consumption for space heating in U.S. residential and commercial buildings across all cases through 2050. In the transportation sector, light-duty vehicle energy demand declines through 2045 as more electric vehicles are deployed and stricter Corporate Average Fuel Economy (CAFE) standards largely offset the continued growth in travel demand. The energy demand then increases as rising travel overcomes increasing efficiency. Across all cases, light-duty vehicle energy demand decreases by 3% to 28% in 2050 relative to 2022.

High international demand leads to continued growth in U.S. production, and combined with relatively little growth in domestic consumption, allows the United States to remain a net exporter of petroleum products and natural gas through 2050 in all AEO2023 cases.

Despite no significant change in domestic petroleum and other liquids consumption through 2040 across most AEO2023 cases, we expect U.S. production to remain historically high as exports of finished products grow in response to growing international demand. Despite the shift toward renewable sources and batteries in electricity generation, domestic natural gas consumption remains relatively stable—ending recent growth in most cases. Natural gas production, however, in some cases continues to grow in response to international demand for liquefied natural gas, supported by associated natural gas produced along with crude oil. Given the combination of relatively little growth in domestic consumption and continued growth in production, we project that the United States will remain a net exporter of petroleum products and natural gas through 2050 in all AEO2023 cases.

Total Energy-Related Carbon Dioxide Emission Projection Range for 16 Scenarios in EIA's 2023 Annual Energy Outlook
(West South Central, East South Central, South Atlantic, and Middle Atlantic Regions)

Scenario Name	Scen. #	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Reference case	1	2,449	2,397	2,378	2,286	2,185	2,082	2,027	1,991	1,976
High Economic Growth	2	2,449	2,432	2,424	2,363	2,263	2,184	2,141	2,120	2,120
Low Economic Growth	3	2,450	2,376	2,351	2,246	2,128	1,991	1,938	1,886	1,863
High Oil Price	4	2,450	2,412	2,383	2,260	2,136	2,018	1,961	1,932	1,930
Low Oil Price	5	2,451	2,400	2,383	2,329	2,242	2,108	2,037	1,995	1,973
High Oil and Gas Supply	6	2,449	2,407	2,367	2,294	2,215	2,136	2,076	2,055	2,026
Low Oil and Gas Supply	7	2,451	2,404	2,368	2,284	2,224	2,154	2,074	2,023	1,921
High Zero-Carbon Technology Cost	8	2,449	2,405	2,386	2,324	2,295	2,243	2,222	2,194	2,169
Low Zero-Carbon Technology Cost	9	2,450	2,405	2,388	2,299	2,182	2,057	2,000	1,963	1,914
High Macro and High Zero-Carbon Technology Cost	10	2,450	2,429	2,422	2,386	2,364	2,331	2,300	2,296	2,286
High Macro and Low Zero-Carbon Technology Cost	11	2,447	2,431	2,423	2,360	2,254	2,146	2,068	2,057	2,013
Low Macro and High Zero-Carbon Technology Cost	12	2,450	2,374	2,350	2,278	2,215	2,152	2,109	2,072	2,041
Low Macro and Low Zero-Carbon Technology Cost	13	2,450	2,373	2,351	2,254	2,118	1,980	1,898	1,850	1,780
No Inflation Reduction Act	14	2,455	2,393	2,379	2,329	2,299	2,274	2,264	2,248	2,214
High Uptake of Inflation Reduction Act	15	2,451	2,393	2,378	2,281	2,184	2,058	1,990	1,952	1,925
Low Uptake of Inflation Reduction Act	16	2,456	2,390	2,375	2,316	2,289	2,264	2,246	2,236	2,199

Total Energy-Related Carbon Dioxide Emission Projection Range for 16 Scenarios in EIA's 2023 Annual Energy Outlook
(West South Central, East South Central, South Atlantic, and Middle Atlantic Regions)

Scen. #	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
1	1,957	1,945	1,931	1,911	1,901	1,887	1,891	1,899	1,897	1,896	1,898	1,901	1,904
2	2,115	2,106	2,108	2,063	2,033	2,020	2,018	2,019	2,030	2,031	2,037	2,026	2,025
3	1,834	1,821	1,829	1,772	1,735	1,723	1,733	1,729	1,726	1,732	1,722	1,709	1,694
4	1,943	1,958	1,962	1,927	1,911	1,893	1,873	1,855	1,836	1,820	1,808	1,793	1,789
5	1,974	1,979	1,973	1,964	1,954	1,952	1,952	1,957	1,955	1,963	1,962	1,970	1,989
6	2,036	2,036	2,023	1,994	1,989	1,980	1,996	2,008	2,012	2,017	2,022	2,022	2,031
7	1,878	1,860	1,859	1,839	1,821	1,802	1,793	1,794	1,790	1,786	1,795	1,795	1,794
8	2,145	2,126	2,133	2,115	2,095	2,092	2,096	2,097	2,101	2,102	2,113	2,119	2,125
9	1,868	1,843	1,818	1,758	1,733	1,722	1,726	1,755	1,737	1,729	1,716	1,696	1,681
10	2,281	2,279	2,280	2,253	2,229	2,210	2,201	2,212	2,221	2,231	2,244	2,255	2,269
11	1,991	1,973	1,961	1,902	1,858	1,842	1,844	1,861	1,863	1,857	1,845	1,818	1,819
12	2,019	1,996	2,003	1,971	1,943	1,932	1,941	1,940	1,942	1,941	1,940	1,940	1,941
13	1,734	1,702	1,671	1,634	1,620	1,607	1,594	1,617	1,592	1,614	1,593	1,578	1,545
14	2,183	2,146	2,130	2,123	2,113	2,100	2,101	2,103	2,103	2,097	2,101	2,117	2,116
15	1,900	1,886	1,877	1,847	1,828	1,825	1,821	1,840	1,820	1,826	1,821	1,823	1,831
16	2,170	2,161	2,139	2,117	2,095	2,089	2,085	2,076	2,071	2,064	2,070	2,073	2,078

Total Energy-Related Carbon Dioxide Emission Projection Range for 16 Scenarios in EIA's 2023 Annual Energy Outlook
(West South Central, East South Central, South Atlantic, and Middle Atlantic Regions)

Scen. #	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
1	1,887	1,890	1,887	1,882	1,883	1,891	1,898
2	2,022	2,028	2,031	2,038	2,037	2,041	2,047
3	1,682	1,681	1,678	1,679	1,682	1,683	1,695
4	1,776	1,768	1,765	1,770	1,777	1,783	1,788
5	2,005	2,012	2,022	2,032	2,042	2,058	2,072
6	2,037	2,037	2,037	2,046	2,036	2,030	2,039
7	1,793	1,785	1,775	1,760	1,757	1,776	1,789
8	2,130	2,141	2,144	2,149	2,154	2,165	2,174
9	1,673	1,657	1,660	1,643	1,625	1,581	1,559
10	2,277	2,291	2,298	2,310	2,326	2,333	2,347
11	1,791	1,778	1,785	1,756	1,730	1,732	1,737
12	1,942	1,941	1,946	1,955	1,960	1,968	1,972
13	1,520	1,501	1,492	1,480	1,476	1,468	1,467
14	2,118	2,113	2,117	2,117	2,103	2,115	2,123
15	1,834	1,839	1,838	1,842	1,833	1,832	1,829
16	2,081	2,086	2,098	2,095	2,097	2,097	2,099

BERKELEY LAB
LAWRENCE BERKELEY NATIONAL LABORATORY

Queued Up: 2024 Edition

Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023

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Lawrence Berkeley National Laboratory

April 2024

This work was funded by the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The views and opinions of the authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

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INTERCONNECTION INNOVATION e-XCHANGE
U.S. DEPARTMENT OF ENERGY

Contents

- High-Level Findings
- Data Sources, Background, and Regulatory Activity
- Active Queue Requests
  - Active queue volume & time trends
  - Regional trends
  - Expected online year and current study status
  - Hybrid projects in the queues
- Operational and Withdrawn Requests
  - Volume of operational and withdrawn projects
  - Completion + withdrawn rates and trends
- Duration Trends – Time in Queues
- Conclusions & Possible Solutions

What are interconnection queues?

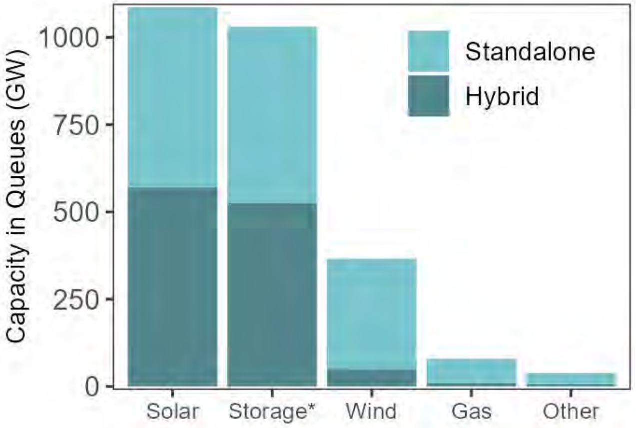
Utilities and regional grid operators (a.k.a., ISOs or RTOs) require projects seeking to connect to the grid to undergo a series of studies before they can be built. This process establishes what new grid system upgrades may be needed before a project can connect to the system and then estimates and assigns the costs of that equipment. The lists of projects that have applied to connect to the grid and initiated this study process are known as “interconnection queues”.

Visit https://emp.lbl.gov/queues to access related resources including the complete dataset used for this analysis and interactive data visualization tools

High-Level Findings

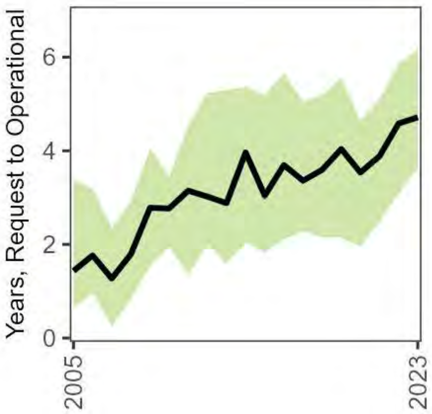
Developer interest in solar, storage, and wind is strong

- Nearly 12,000 projects representing 1,570 gigawatts (GW) of generator capacity and 1,030 GW of storage actively seeking interconnection
- Solar, storage, and wind make up 95% of active queue capacity
- >94% (~1,480 GW) of proposed generation is zero-carbon



Completion rates are generally low; wait times are increasing

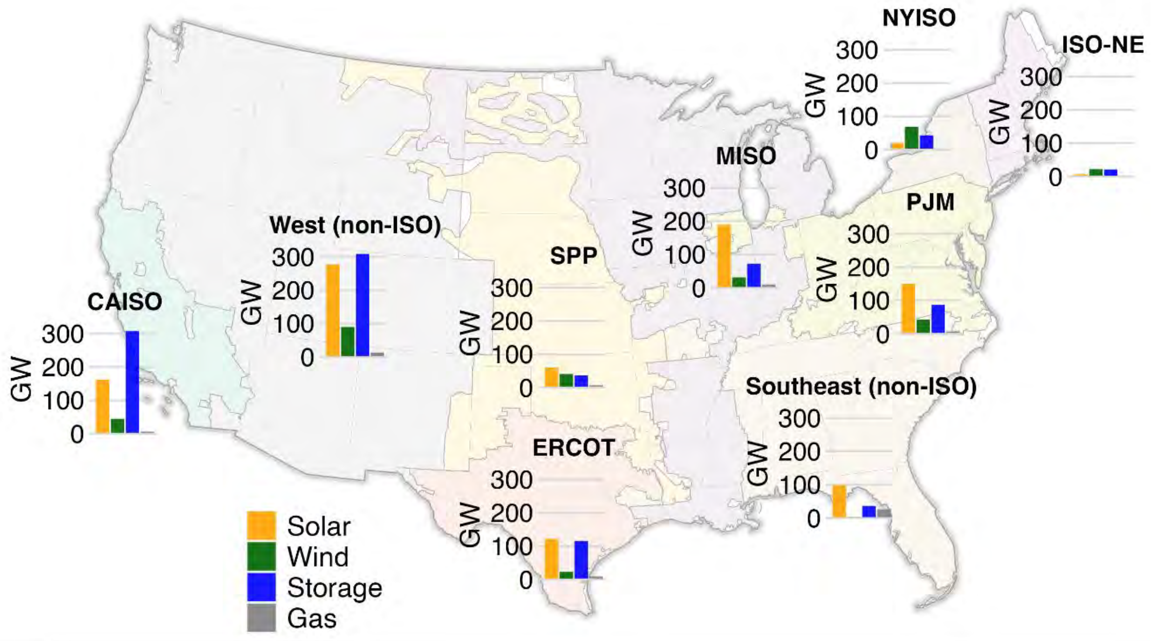
- Only ~19% of projects (14% of capacity) requesting interconnection from 2000-2018 reached commercial operations by the end of 2023



- Completion rates are even lower for solar (14%) and battery (11%) projects
- The average time projects spent in queues before being built has increased markedly. The typical project built in 2023 took nearly 5 years from the interconnection request to commercial operations[1], compared to 3 years in 2015 and <2 years in 2008.

Proposed capacity is widely distributed across the U.S.

- Substantial proposed solar capacity exists in most regions of the U.S.; >1 terawatt (TW) of solar active in queues
- >1 TW of storage is also active in the queues, primarily in the West and CAISO, but also in ERCOT, MISO, and PJM
- >360 GW of wind capacity in the queues, most in the non-ISO West, NYISO (offshore), PJM, and SPP.
- Only 79 GW of gas capacity active in the queues, less than 8% of active solar capacity



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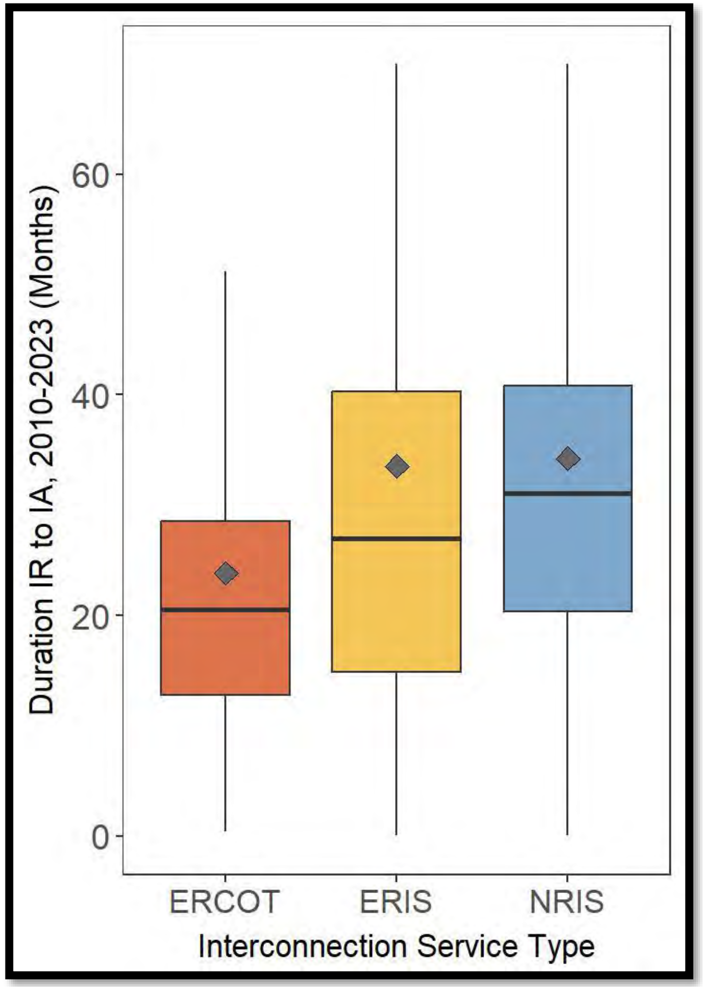
1. *In-service date was only available for 61% of all operational projects*

Important Analytical Additions in the 2024 Edition of “Queued Up”

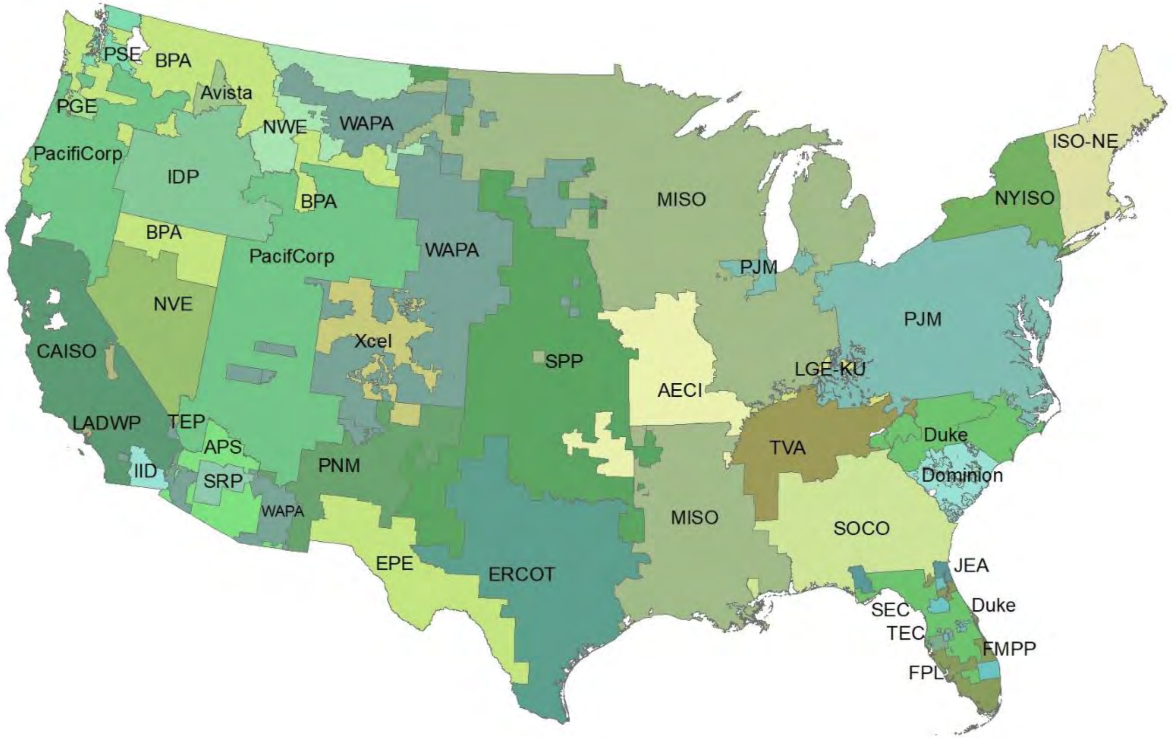
- **Regulatory activities**
  - Summary of key activities at the federal and balancing area level (slide 7)
  - Analysis of post-IRA interconnection request volume (slide 13 + appendix)
- **ERIS and NRIS applications**
  - Capacity of ERIS and NRIS projects within the queue (slide 20)
  - Timeline from interconnection request to signed IA by service type (slide 38)
- **Completion rates**
  - Capacity of executed IAs by region and relative to retirements / load growth (slide 22)
  - Detailed analysis of the study phase at which queue withdrawals occur (slide 30)
  - Comparison of operational projects from queue data with EIA-860 (slide 26)
- **More detailed breakdown of ‘other’ project categories**
  - Detail on Nuclear, Hydro, and Geothermal projects in the queue (see Slide 18)
  - Breakout of non-battery storage within the Queues (slide 19)
- **Miscellaneous items**
  - Implied peak load contribution of projects in Queue (slide 14)
  - DOE Transmission Interconnection Roadmap for possible solutions (slide 46)



Notes: (1) See slide 38 for full explanation of chart. (2) y-axis measures time from submitting an interconnection request to receiving an interconnection agreement. (2) ERIS is energy-resource interconnection service, NRIS is network-resource interconnection service

Data Sources

- Data collected from interconnection queues for 7 ISOs / RTOs and 44 non-ISO balancing areas (including utilities and Power Marketing Administrations), which collectively represent >95% of currently installed U.S. electric generating capacity
  - Includes projects that connect to the bulk-power system, not distribution-connected or behind-the-meter[1]
  - Includes projects in queues through the end of 2023
  - Substantial data cleaning, standardization, and QA/QC conducted by Berkeley Lab analyst team
  - The full sample includes:
    - 4,155 “operational” projects (~470.4 GW)
    - 11,841 “active” projects (~2,598 GW)
    - 325 “suspended” projects (~54.9 GW)
    - 18,372 “withdrawn” projects (~3,097 GW)



Coverage area of entities for which data was collected
Data source: Homeland Infrastructure Foundation-Level Data (HIFLD)
Note that service areas can overlap
No data collected for Hawaii or Alaska

A full list of included balancing areas can be found in the Appendix

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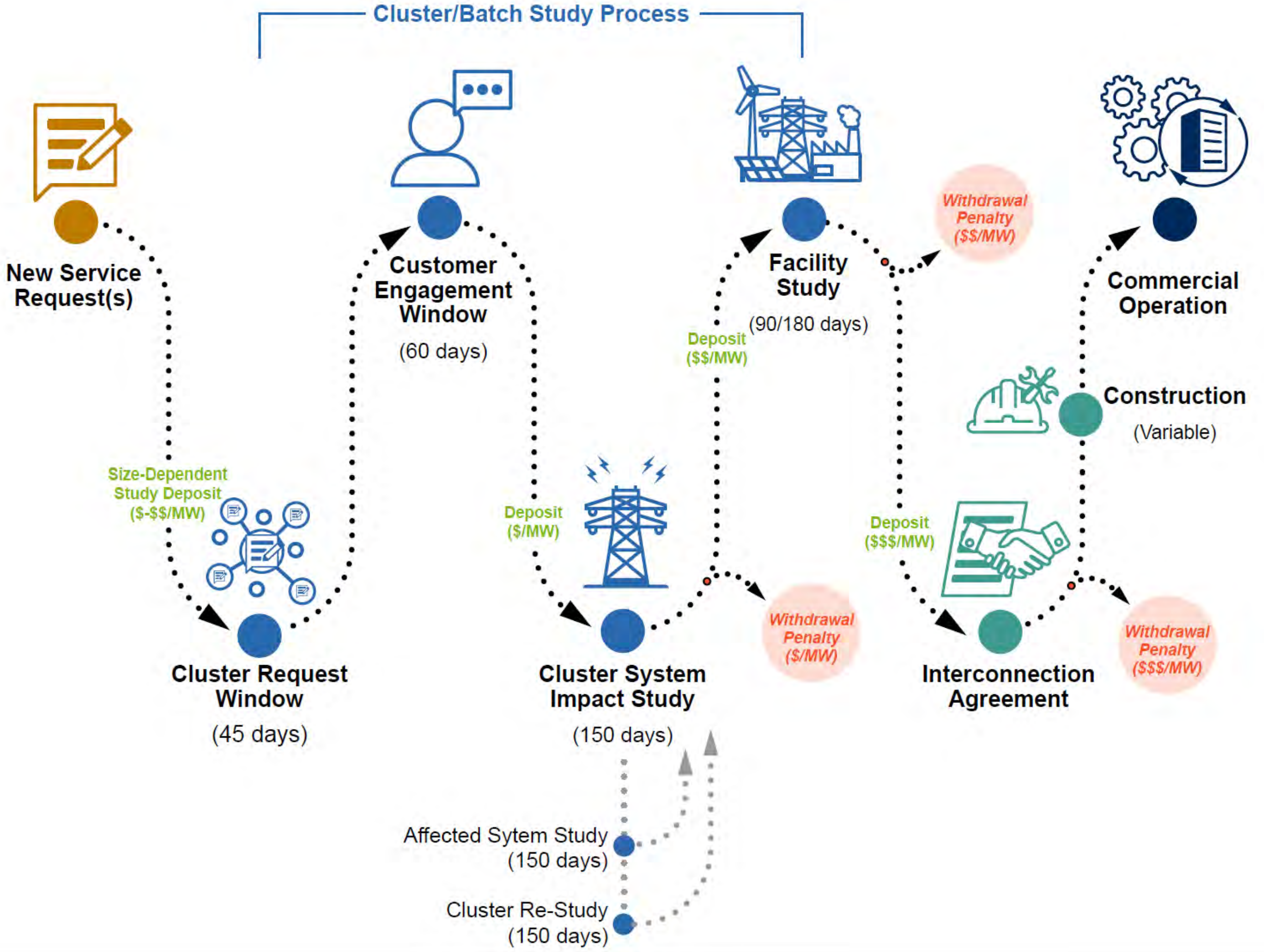
[1] *There are different processes for transmission- and distribution-system interconnection. This report only covers transmission interconnection.*

Typical Interconnection Study Process and Timeline

- A project developer initiates a new ***interconnection request (IR)*** and thereby enters the ***queue***
- A series of ***interconnection studies*** establish what new transmission equipment or upgrades may be needed and assigns the costs of that equipment
- The studies culminate in an ***interconnection agreement (IA)***: a contract between the ISO or utility and the generation owner that stipulates operational terms and cost responsibilities
- Most proposed projects are ***withdrawn,*** which may occur at any point in the process
- After executing an IA, many projects are built and reach ***commercial operation***



Note: These steps are in accordance with Federal Energy Regulatory Commission (FERC) pro-forma interconnection procedures as outlined in FERC Order 2023. Some ISOs already use a cluster-study approach. The data presented in this report pre-date Order No. 2023 implementation.

FERC Order 2023 overhauled the interconnection process, and many RTOs have pending and proposed interconnection process updates and reforms.

Interconnection Reforms in FERC Order 2023

- ***Cluster studies***; ***first ready, first served***; higher ***deposits & readiness*** criteria for developers
- ***Timeline, process, and reporting*** requirements for transmission providers; ***Financial penalties*** for delays
- Visual representation ***(heatmaps) of available transmission capacity***
- Improved and standardized process for ***affected system studies***
- Improved procedures and ***flexibility for storage and hybrid resources***
- Consideration of ***alternative transmission technologies (GETs)***

Major ISO/RTO Reforms & Updates

MISO

- Increased milestone payments, adopted an automatic withdrawal penalty, and expanded site control requirements for interconnection facilities (*approved by FERC, January 2024*)
- Proposed a cap on total queue size (*rejected by FERC, January 2024*)
- Did not accept any new requests in 2023 due to pending reforms

CAISO (*Interconnection Process Enhancements initiative proposed March 6, 2023*)

- Prioritize requests where transmission system has available existing or planned capacity and limit requests in a study area based on planed transmission capacity
- Require power purchase agreements to proceed to Phase II studies
- Proposed to delay Cluster 16 request application window from April 2024 (new date TBD) due to queue volume and pending reforms

PJM

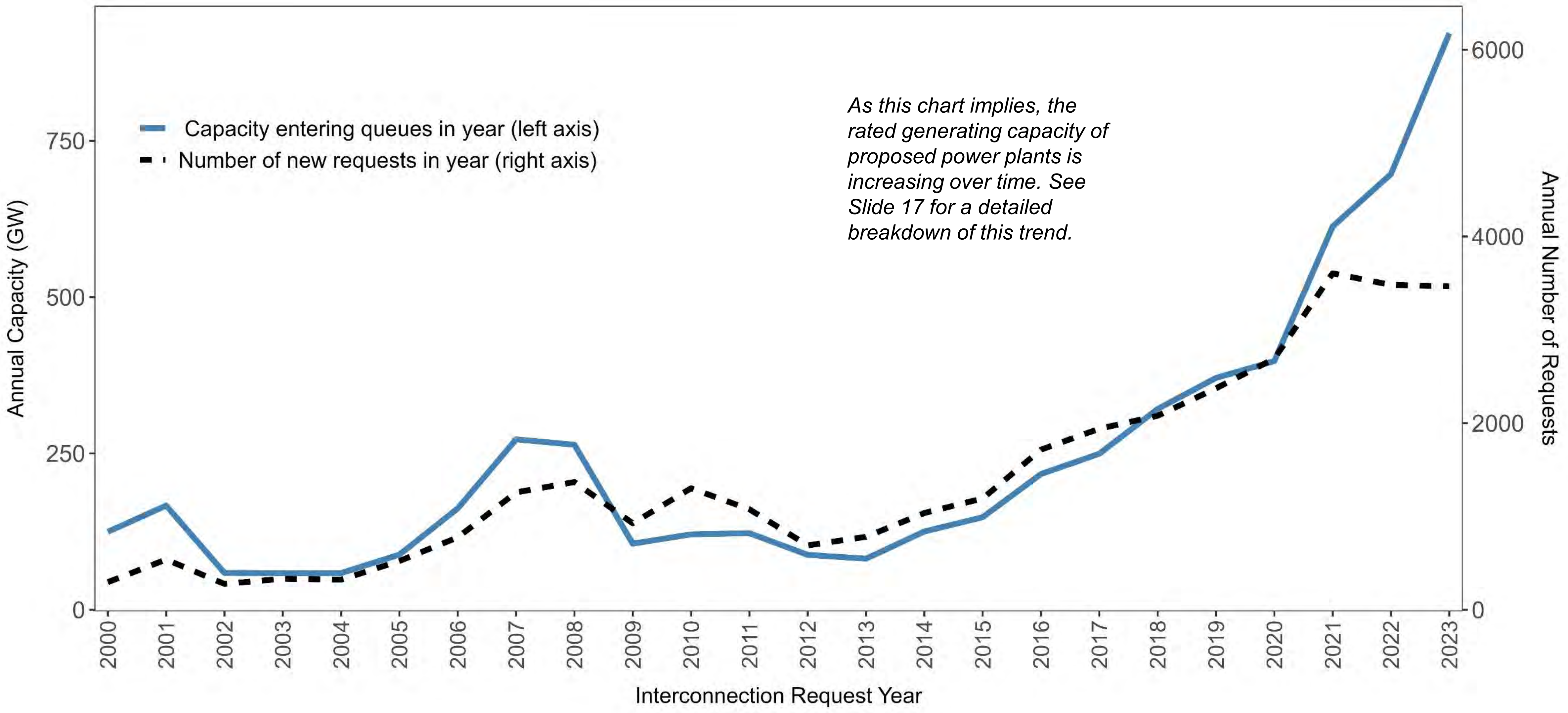
- Implemented transition from serial first-come, first-served queue process to a first-ready, first-served clustered cycle approach, grouping projects into three-phase cluster cycles for studying and allocating interconnection costs (*approved by FERC, November 2022*).
- Will not review new requests until early 2026 as it processes backlog

ERCOT

- Texas HB 1500 proposed an interconnection cost cap, will be an important PUC rulemaking to follow in the future

FERC Order 2023 - RM22-14-000. https://www.ferc.gov/media/e-1-order-2023-rm22-14-000

Annual interconnection requests have surged since 2013 (both in terms of number and capacity); over 900 GW added in 2023 alone



As this chart implies, the rated generating capacity of proposed power plants is increasing over time. See Slide 17 for a detailed breakdown of this trend.

*Notes: (1) This total annual volume includes projects with a queue status of "active", "suspended", "withdrawn", or "operational".
(2) All values – especially for earlier years – should be considered approximate.*

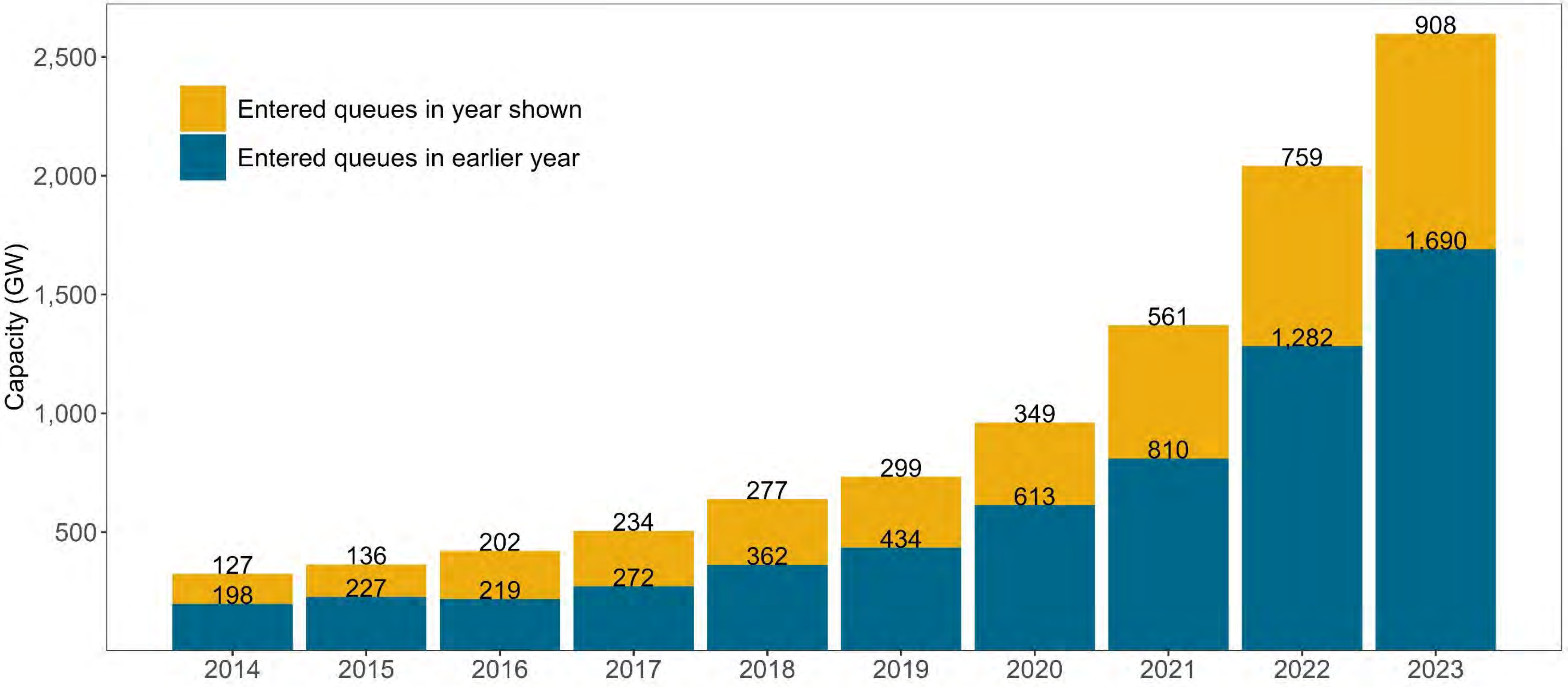
Active Projects in Interconnection Queues: Volume, Regional Trends, Study Phase, and Hybrids

Includes data from all 7 ISO/RTOs and 44 non-ISO balancing areas, totaling 11,841 proposed projects

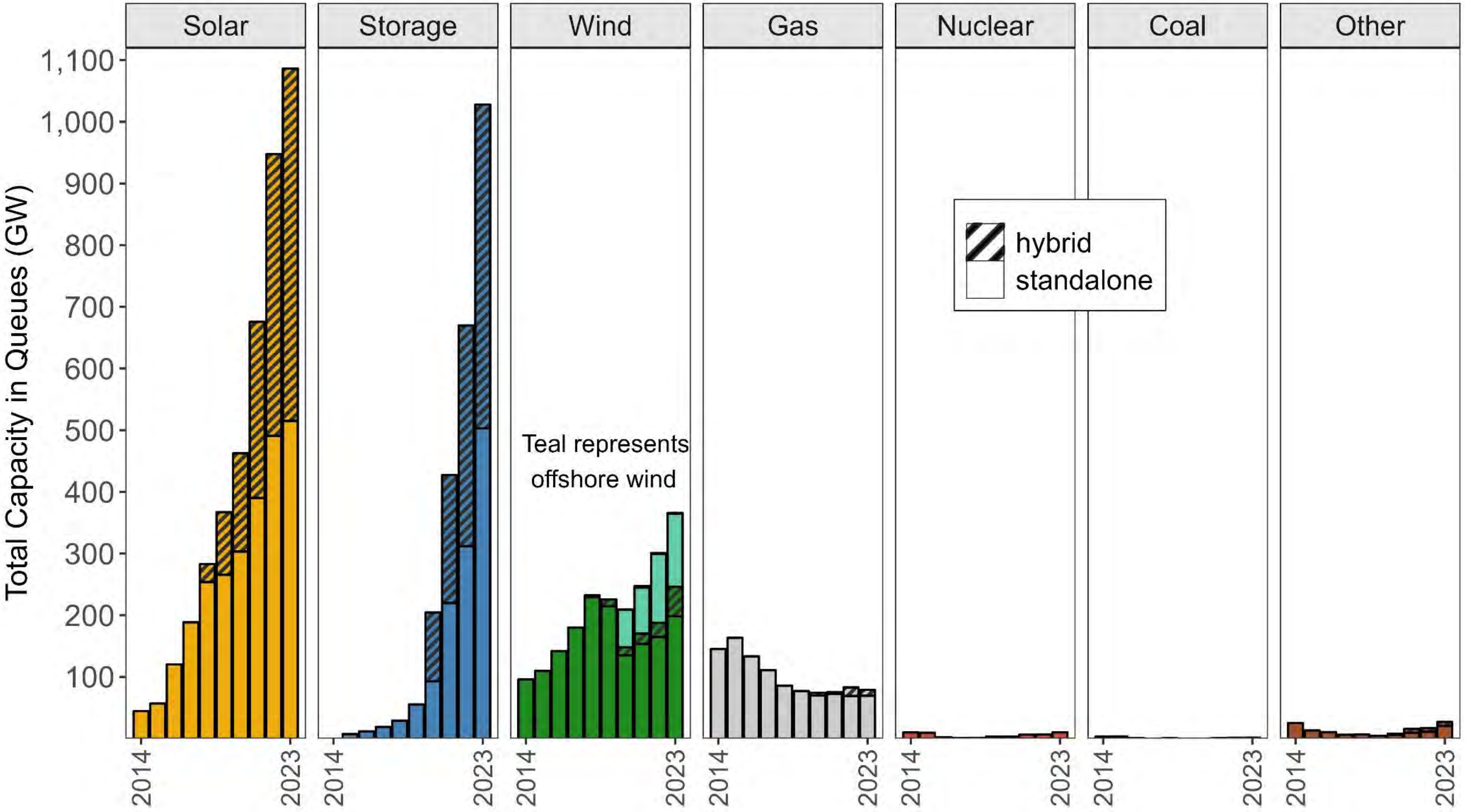
Region	*n* (active)	Capacity (GW)
CAISO	995	523.3
ERCOT	1,090	269.2
ISO-NE	405	51.2
MISO	1,669	311.5
NYISO	492	131.6
PJM	3,309	286.7
SPP	703	144.9
Southeast (non-ISO)	1,134	173.3
West (non-ISO)	2,044	706.5

Notes: (1) Active capacity (GW) shown includes some estimates for hybrid storage capacity in cases where it was missing. (2) Data were sought from 7 ISOs and 44 non-ISO BAs (full list available in appendix). (3) CAISO includes Cluster 15

Total (cumulative) active capacity in queues is now nearly 2,600 GW (2.6 TW); New (annual) capacity entering the queues has increased every year since 2014



Solar (1,086 GW) , Storage (1,028 GW), and Wind (366 GW) make up 95% of active capacity in queues, with 3% (79 GW) from Gas. Most solar and storage capacity is in hybrid plants

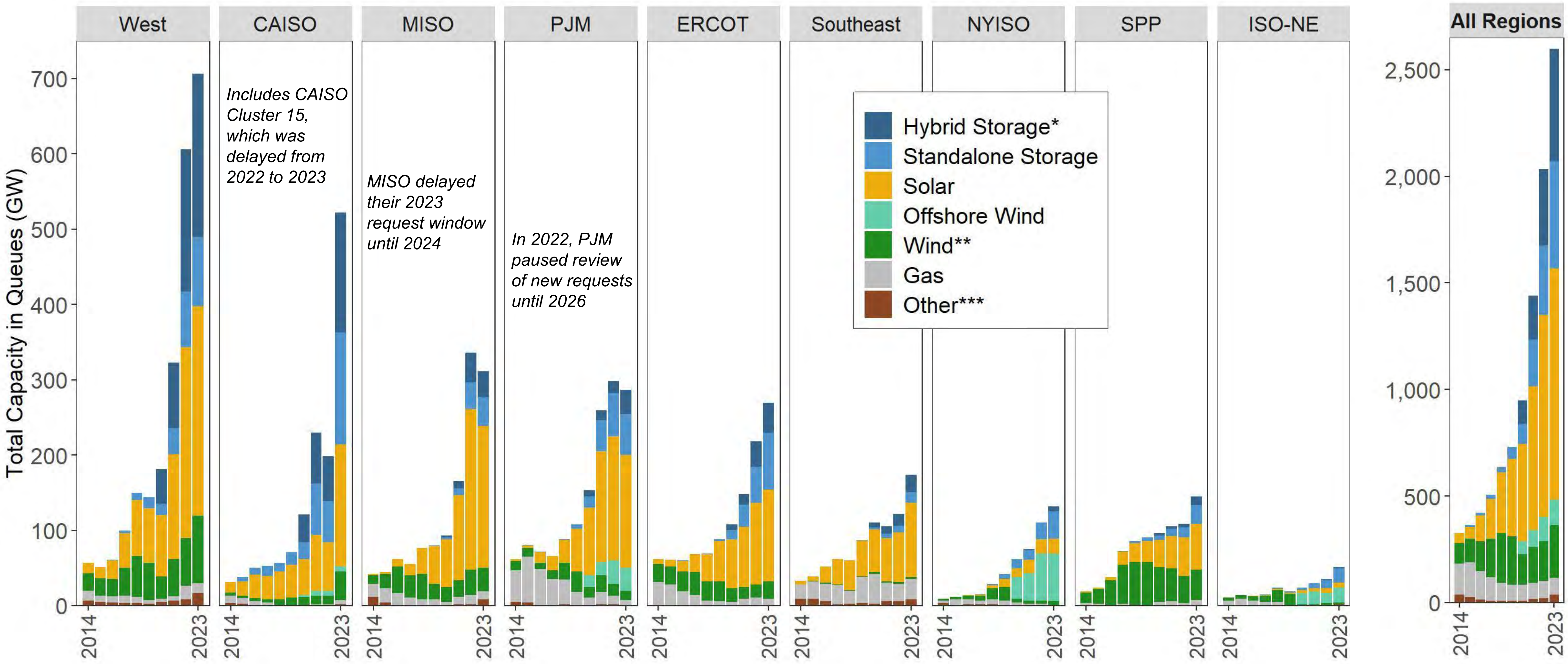


- “**Wind**” includes both onshore and offshore.
- “**Other**” includes
    - Hydropower
    - Geothermal
    - Biomass/biofuel
    - Landfill gas
    - Solar thermal
    - Oil/diesel
- “**Storage**” is primarily (99%) battery, but also includes pumped storage hydro, compressed air, gravity rail, and hydrogen.

See https://emp.lbl.gov/queues to access an interactive data visualization tool.

Notes: (1) Hybrid storage capacity is estimated for some projects using storage:generator ratios from projects that provide separate capacity data, and that value is only included starting in 2020. Storage duration is not provided in interconnection queue data. (2) Wind capacity includes onshore and offshore for all years, but offshore is only broken out starting in 2020. (3) Hybrid generation capacity is included in all applicable generator categories. (4) Not all of this capacity will be built.

Active queue capacity is highest in the West (706 GW), followed by CAISO (523 GW). Several regions have delayed accepting or processing new requests due to backlogs



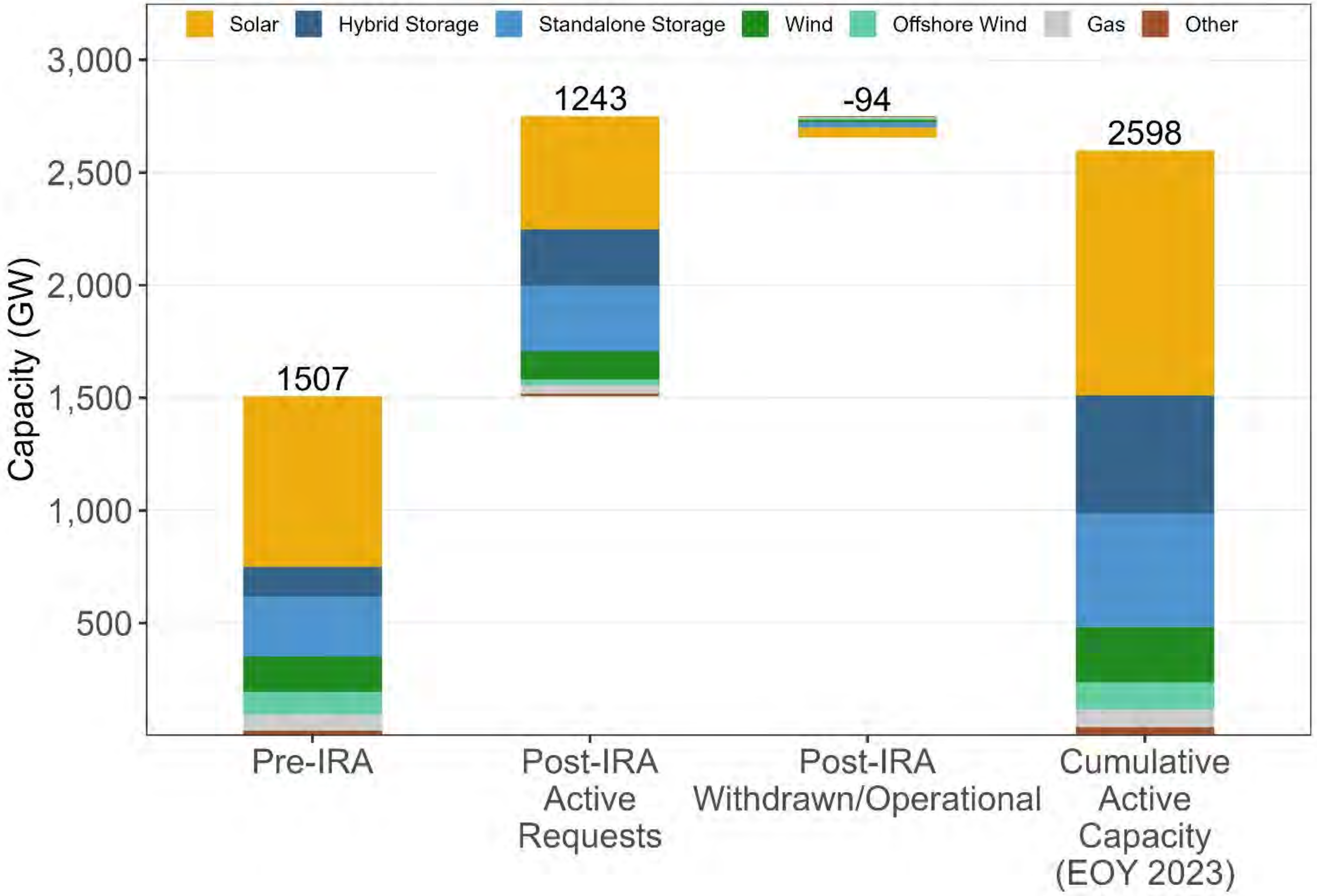
Includes CAISO Cluster 15, which was delayed from 2022 to 2023

MISO delayed their 2023 request window until 2024

In 2022, PJM paused review of new requests until 2026

*Notes: (1) *Hybrid storage capacity is estimated for some projects using storage:generator ratios from projects that provide separate capacity data, and that value is only included starting in 2020. Storage duration is not provided in interconnection queue data. (2) **Wind capacity includes onshore and offshore for all years, but offshore is only broken out starting in 2020. (3) ***Other in this chart includes Coal, Nuclear, Hydro, Geothermal, and Other / Unknown. (4) Not all of this capacity will be built.*

Over 1,200 GW (including >500 GW of solar, >540 GW storage, and 125 GW wind) has requested interconnection since the passage of the IRA



The IRA included a range of tax credits and other provisions anticipated to supercharge clean energy development. These include, for example:

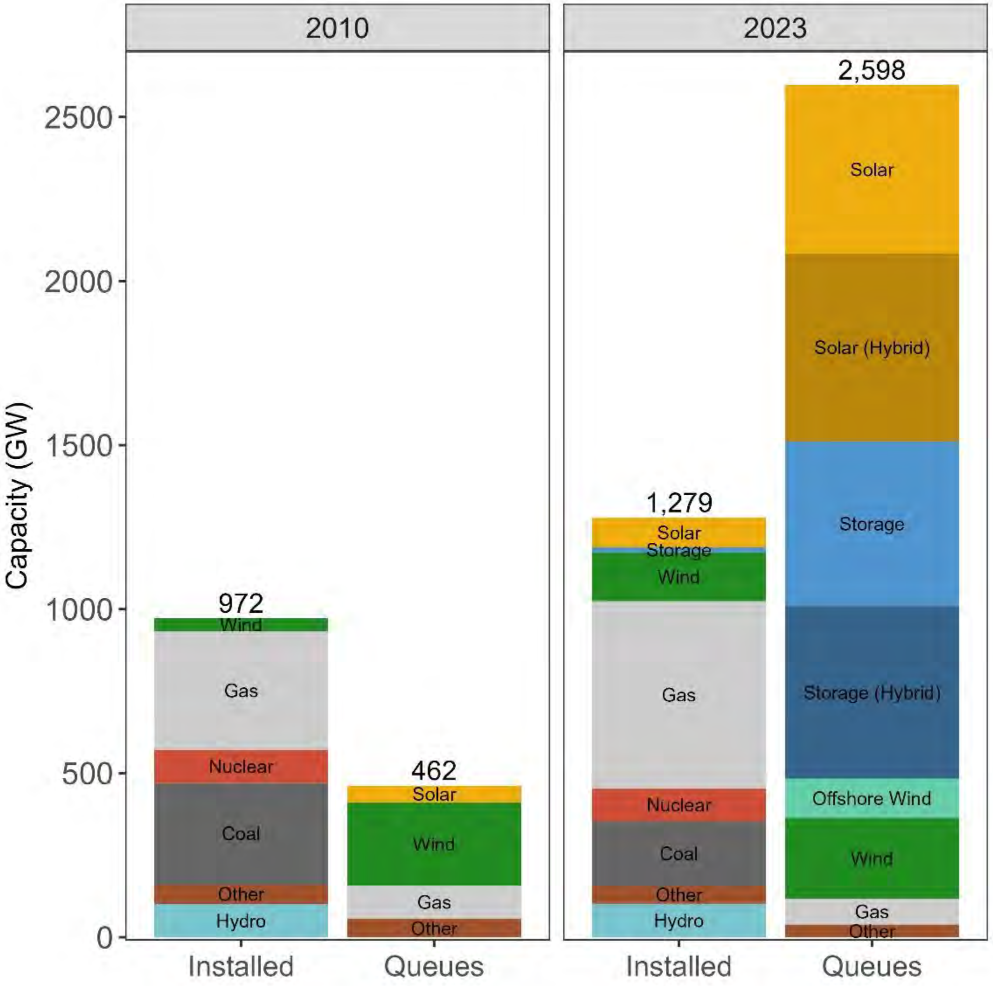
- Extension of existing credits, including technology-neutral Production Tax Credits (PTCs) and Investment Tax Credits (ITCs)
- Emissions-based phase-out, no earlier than 2032
- Standalone storage eligible for ITC; new nuclear as of 2025
- Choice between PTC and ITC: whichever is most valuable
- Bonuses for energy community and domestic content
- USDA grants for rural coops to transition to clean electricity

Although not all of the post-IRA interconnection requests can be attributable to the IRA, these provisions increased developer interest in clean energy and the queues are one indicator of this.

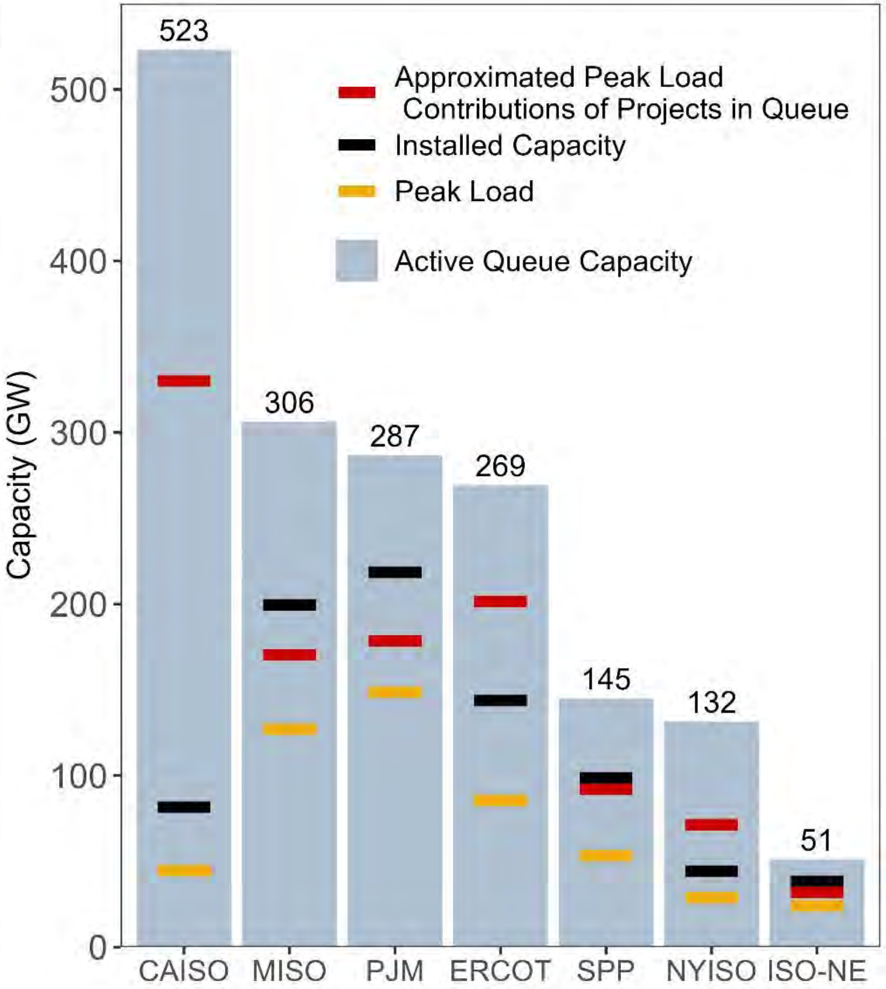
Notes: (1) Pre-IRA includes the cumulative active capacity in the queues as of July 2022. (2) Post-IRA requests include all requests submitted since August 2022. (3) Withdrawn / Operational includes any projects that withdrew or came online since August 2022.

Active capacity in queues (~2,600 GW) is twice the installed capacity of U.S. power plant fleet (~1,280 GW); greater than peak load and installed capacity in all ISOs

Entire U.S. Installed Capacity vs. Active Queues



RTO Installed Capacity & Peak Load vs. Active Queues



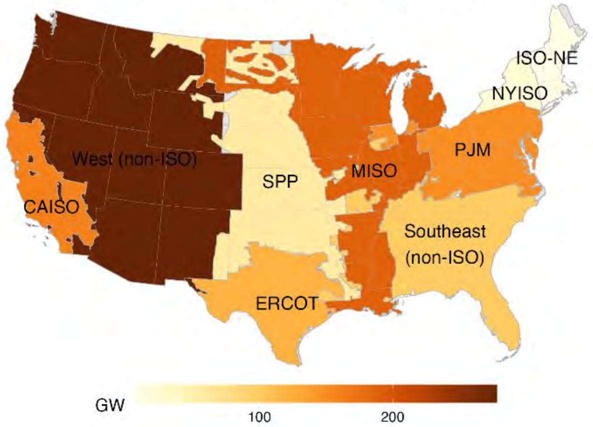
Comparisons of queue capacity to installed capacity or peak load should also consider generators' contributions to resource adequacy, for example their "effective load carrying capability" (ELCC). As variable resources, solar and wind contribute a smaller percentage of their nameplate capacity to resource adequacy and peak load compared to dispatchable generation like natural gas. The red lines in the chart are a simplified estimate of the peak load contribution of projects in the queue.

Decarbonizing the electric sector requires higher levels of *installed* solar and wind capacity to achieve the same resource adequacy contributions. High levels of storage can offset this need to some degree. Electrification of buildings and transport will also result in load growth.

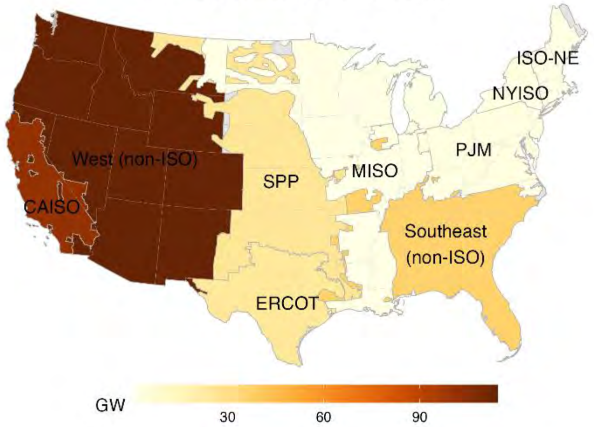
Notes: (1) Hybrid storage in queues is estimated for some projects. (2) Total and RTO installed capacity from EIA-860, December 2023. (3) Peak load data from RTO websites. (4) Peak load contributions by region relies on NERC 2023 reliability assessments for standalone solar, onshore wind, and hydro. Storage, gas, coal, and nuclear are approximated with a peak load contribution of 100%, even though in practice their contributions will be smaller. Offshore wind contributions are based on recent reliability studies.

Proposed solar is widespread, with less in SPP and Northeast; Most wind in the West, SPP, and offshore; Proposed storage in all regions but highest in the West and CAISO; Gas is primarily in the Southeast

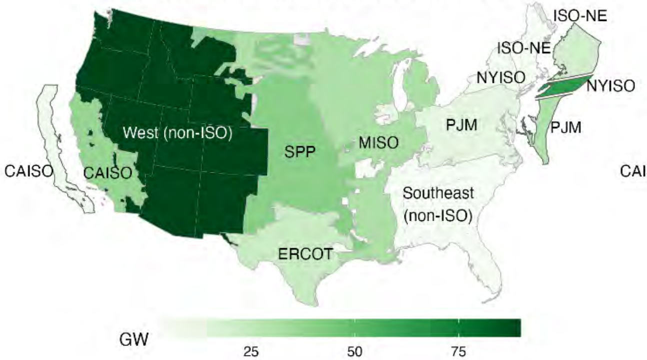
Total Solar Capacity in Interconnection Queues at the end of 2023



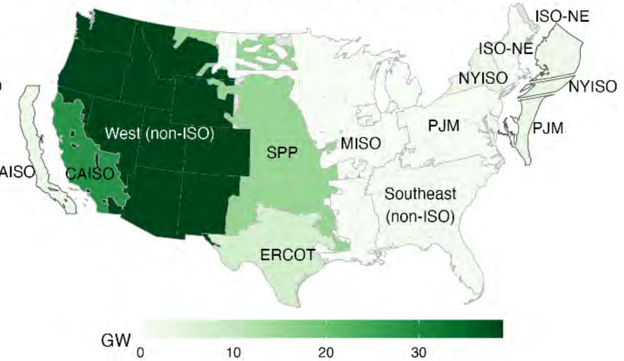
New Solar Capacity Added to Interconnection Queues in 2023



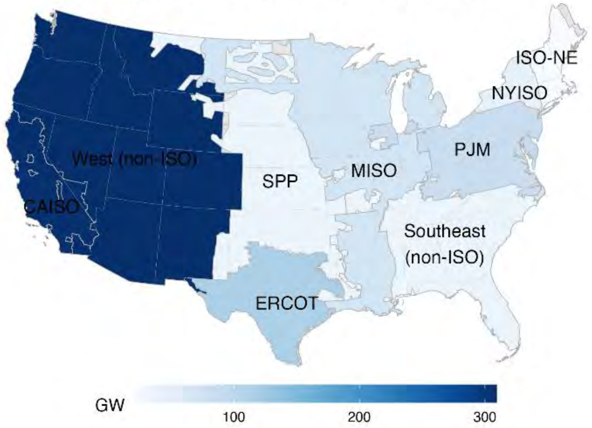
Total Wind Capacity in Interconnection Queues at the end of 2023



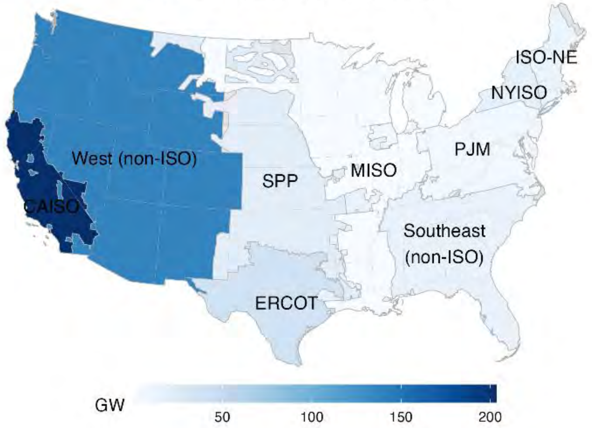
New Wind Capacity Added to Interconnection Queues in 2023



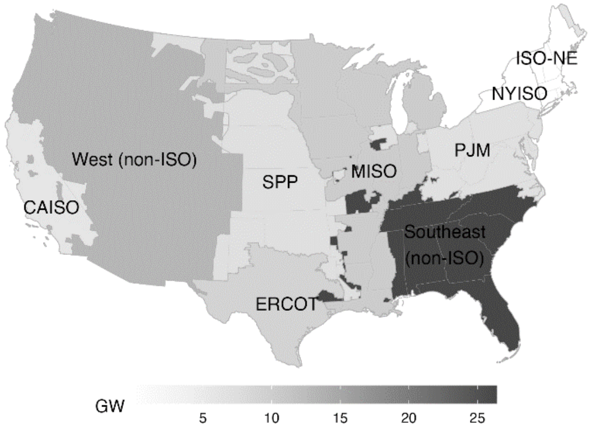
Total Storage Capacity in Interconnection Queues at the end of 2023



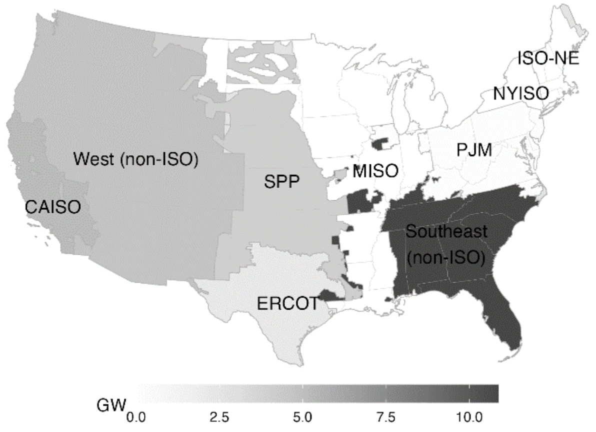
New Storage Capacity Added to Interconnection Queues in 2023



Total Gas Capacity in Interconnection Queues at the end of 2023

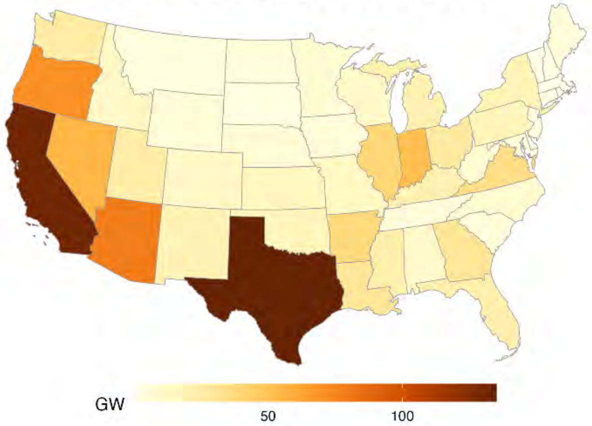


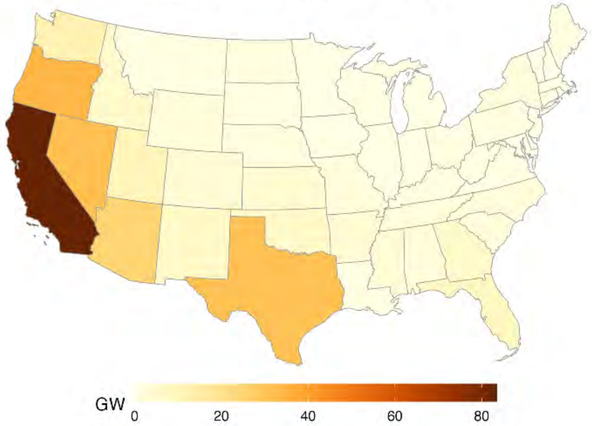
New Gas Capacity Added to Interconnection Queues in 2023

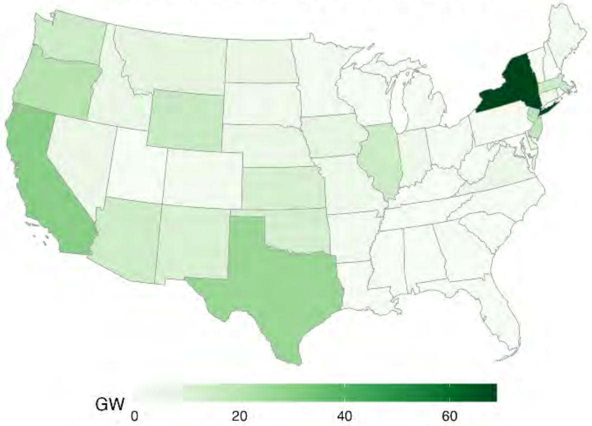


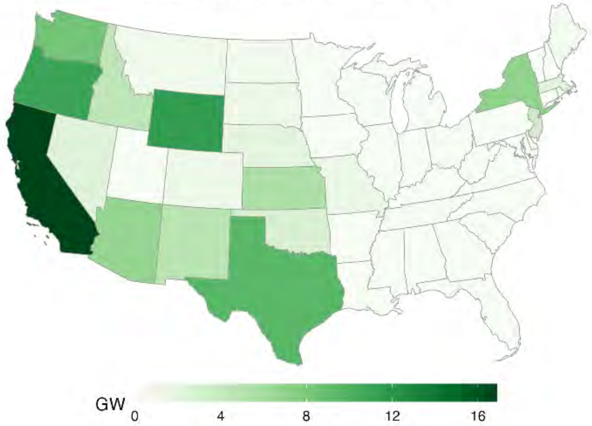
Note: Proposed and ongoing reforms in MISO and PJM resulted in few (or no) new requests in those regions in 2023 (see slide 7)

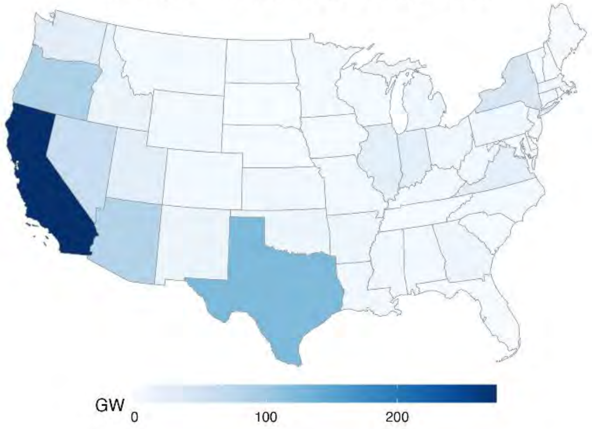
CA and TX dominate solar requests; Wind is in the West, Plains, and East Coast (offshore); Storage is highest in CA, TX, OR, AZ; Most gas in TX and Southeast, with new requests in CA

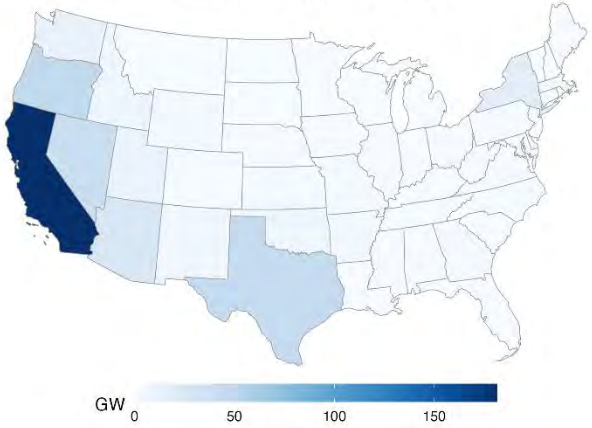

Total Solar Capacity in Interconnection Queues at the end of 2023

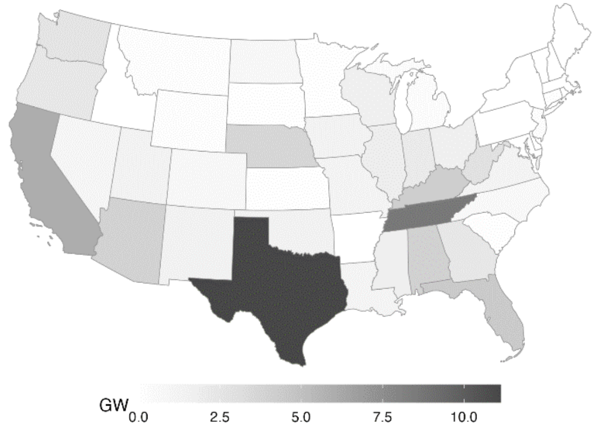

New Solar Capacity Added to Interconnection Queues in 2023

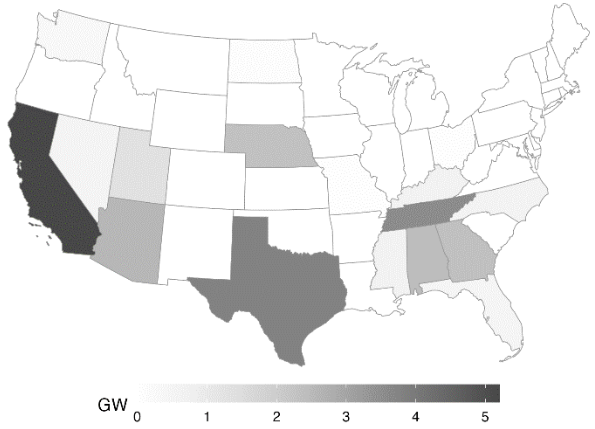

Total Wind Capacity in Interconnection Queues at the end of 2023


New Wind Capacity Added to Interconnection Queues in 2023

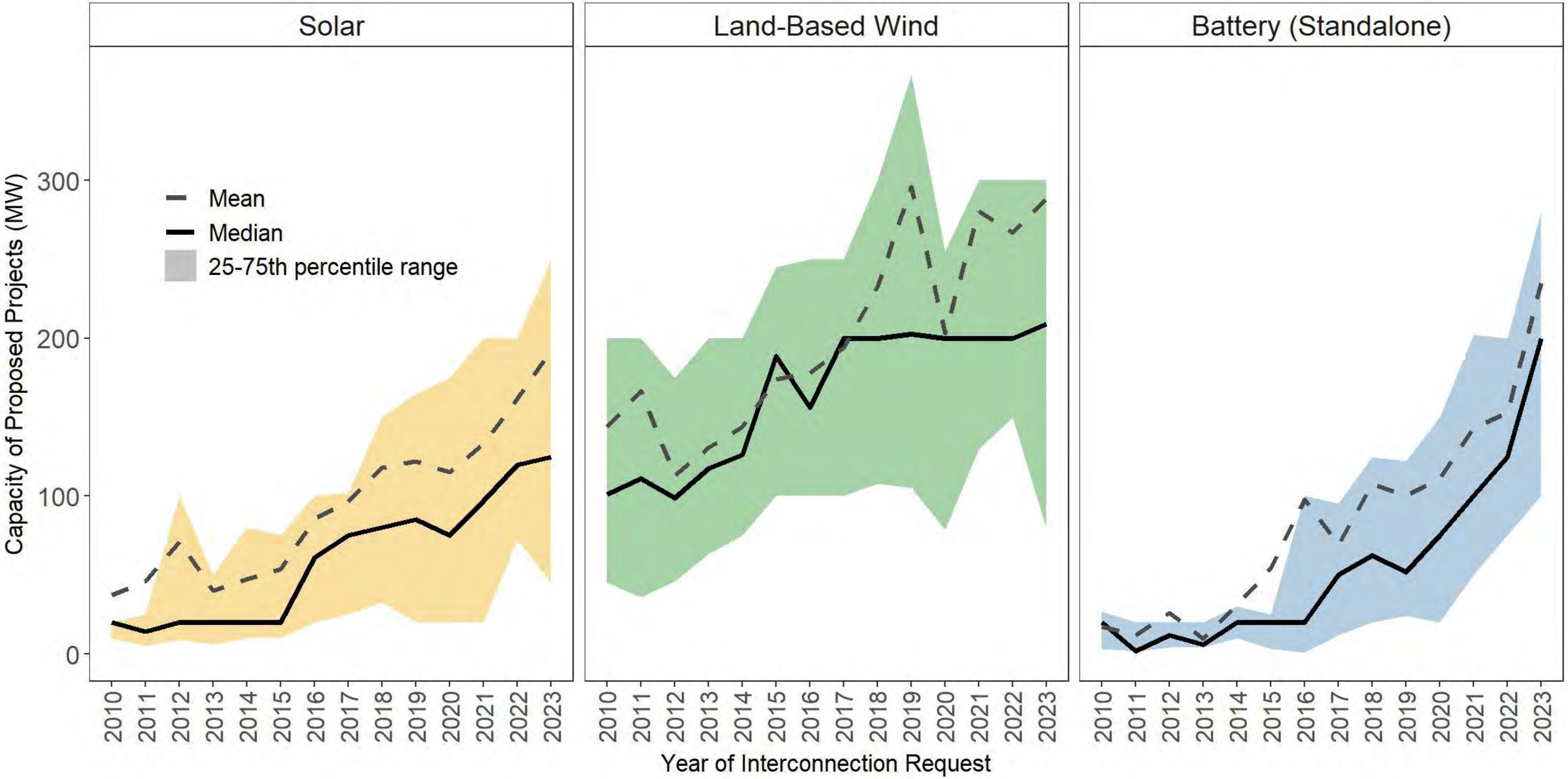

Total Storage Capacity in Interconnection Queues at the end of 2023


New Storage Capacity Added to Interconnection Queues in 2023

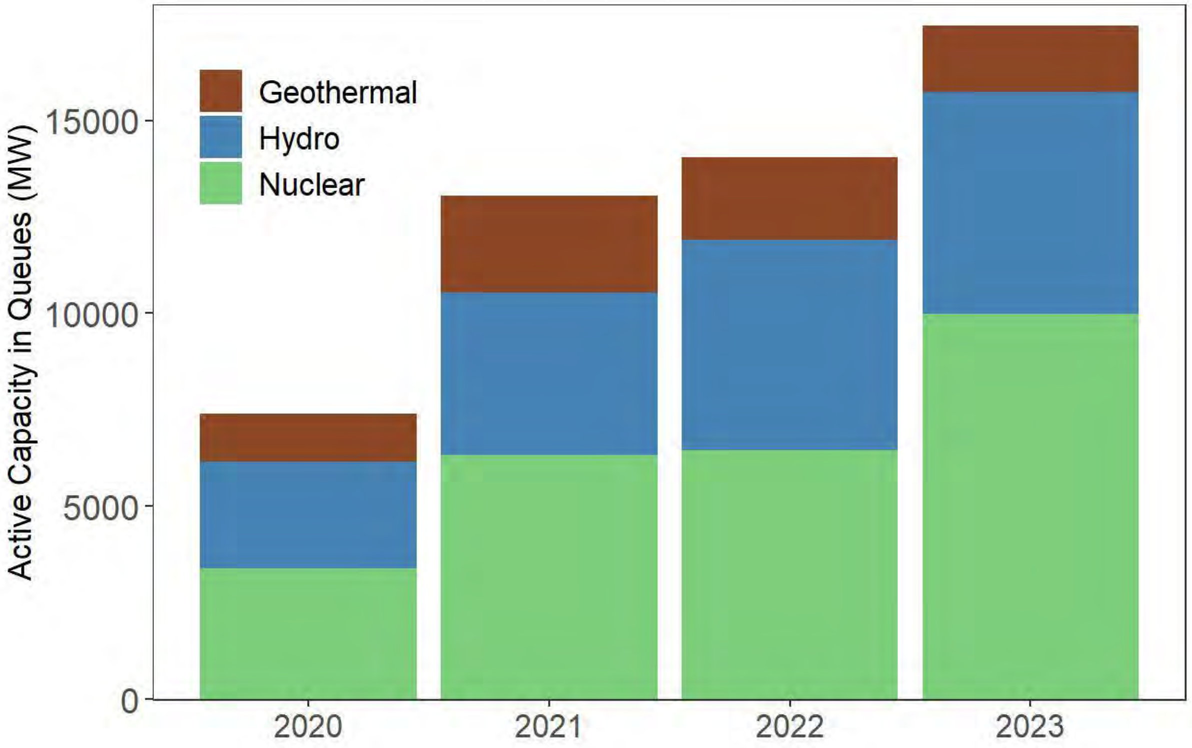

Total Gas Capacity in Interconnection Queues at the end of 2023


New Gas Capacity Added to Interconnection Queues in 2023

The mean Solar plant requesting grid connection in 2023 was 193 MW, >250% larger than in 2015; proposed Wind (+66%) and Battery (+330%) plants have also grown since 2015



Although Nuclear, Hydro, and Geothermal make up less than <1% of the active capacity in queues, this still represents >15 GW of capacity, indicating important development interest

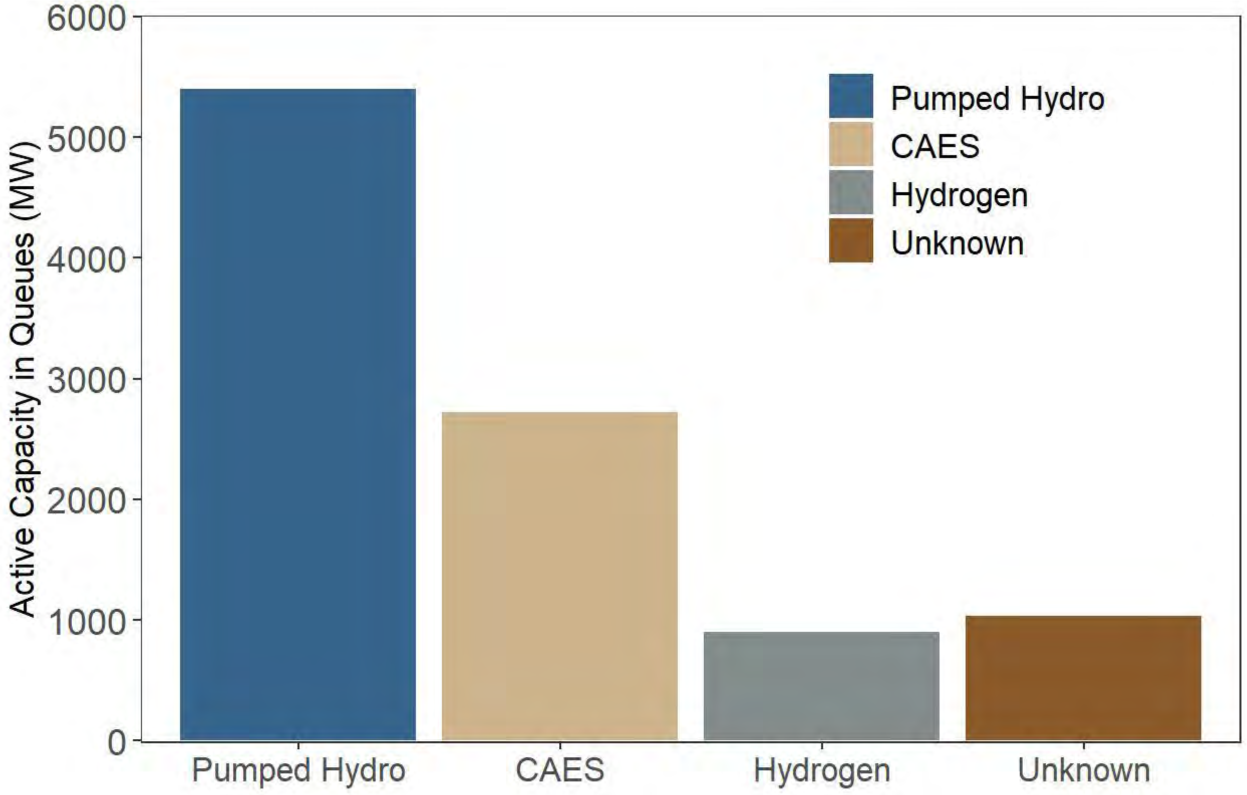


	Active Capacity in Queues (MW)		
Region	Hydro	Nuclear	Geothermal
CAISO	74		
ISO-NE	35		
MISO	201		
PJM	363		
Southeast (non-ISO)	693	5,441	
West (non-ISO)	4,380	4,552	1,711

Active Nuclear capacity seeking grid connection increased to 10 GW in 2023 (up from ~6.5 GW in 2022), while Hydropower capacity held steady at ~5.7 GW. Geothermal capacity contracted slightly to 1.7 GW (from 2.1 in 2022).

Hydropower plants are proposed in several regions, but the majority of capacity is in the non-ISO West. Proposed Nuclear is only in the non-ISO Southeast and West, and Geothermal is only found in the West.

Batteries make up ~99% of storage capacity in the queues, but there are 10 GW of active requests for Pumped Hydro, Hydrogen, and Compressed Air Energy Storage (CAES)

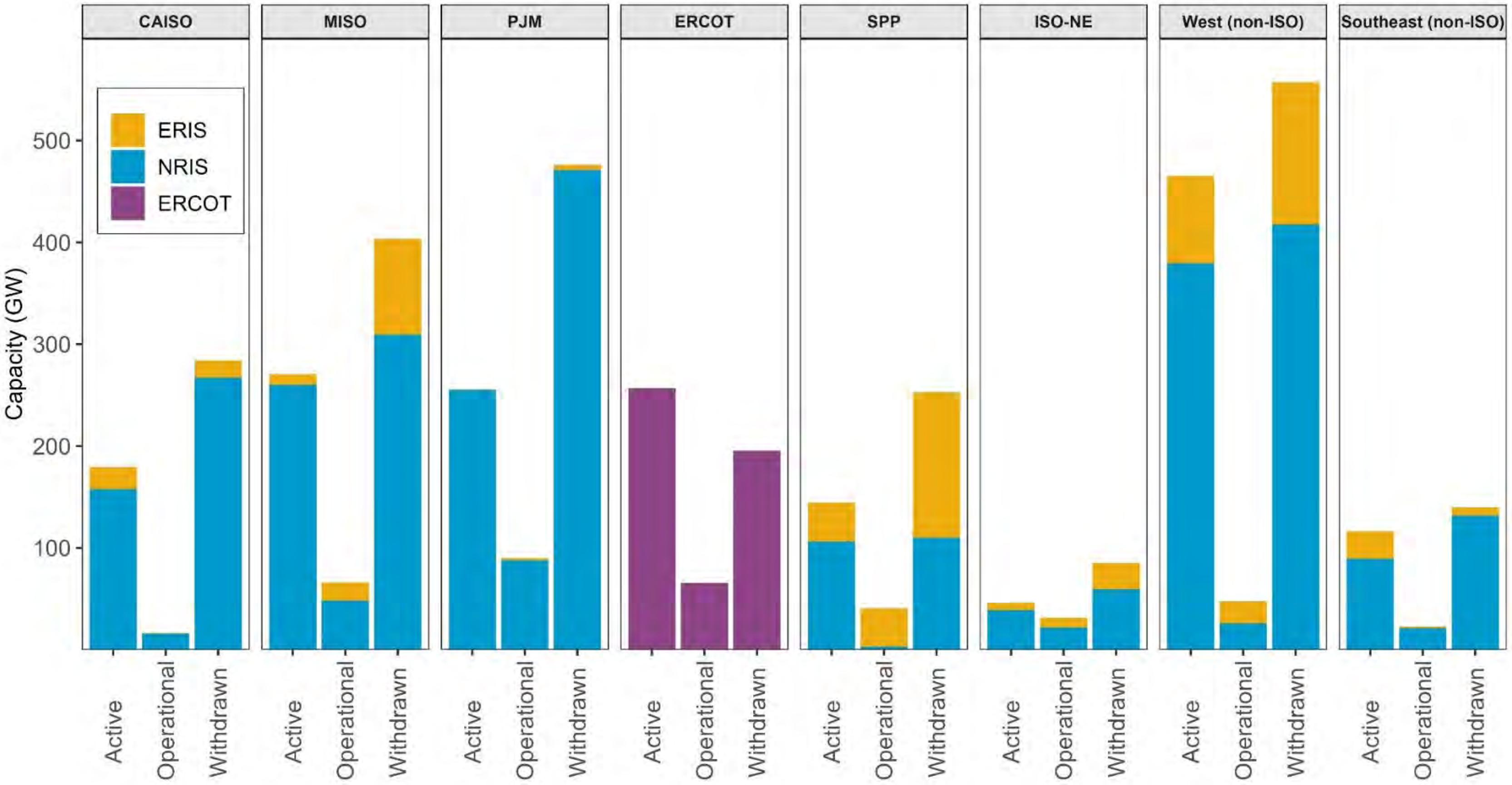


	Active Capacity in Queues (MW)			
Region	Pumped Storage	CAES	Unknown	Hydrogen
CAISO	2,402		1,036	
West (non-ISO)	3,000	2,720		902

All active requests for non-battery storage projects are in CAISO and the non-ISO West.

74%* of all active capacity requested Network Resource Interconnection Service (NRIS). Energy Resource Interconnection Service (ERIS) is less common. ERCOT's approach is similar to ERIS

*Outside of ERCOT, **87%** of active capacity requested to be studied for NRIS.



Network Resource Interconnection Service (NRIS) allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System and be deliverable during congested grid conditions, such that the generator can be designated as a capacity resource and contribute to resource adequacy requirements.

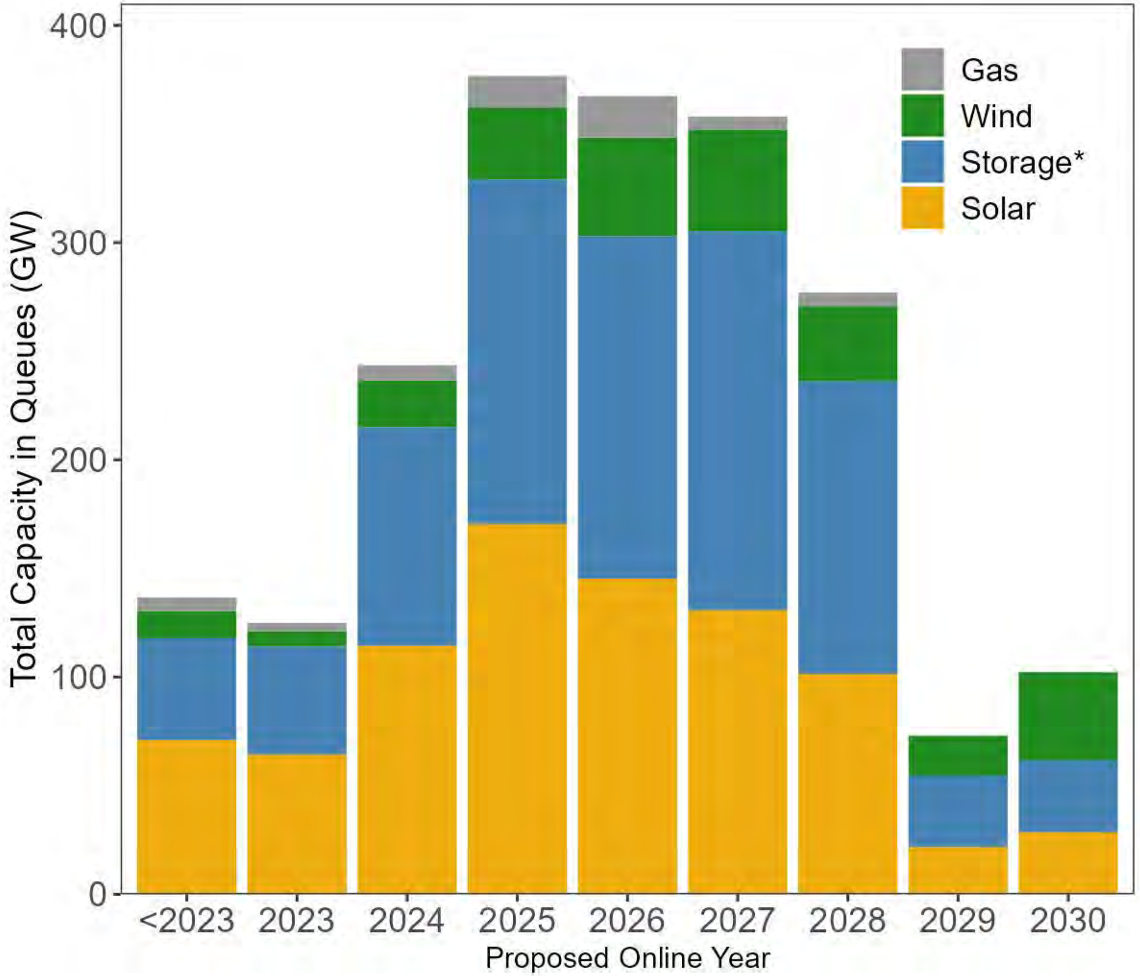
Energy Resource Interconnection Service (ERIS) allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an "as available" basis.

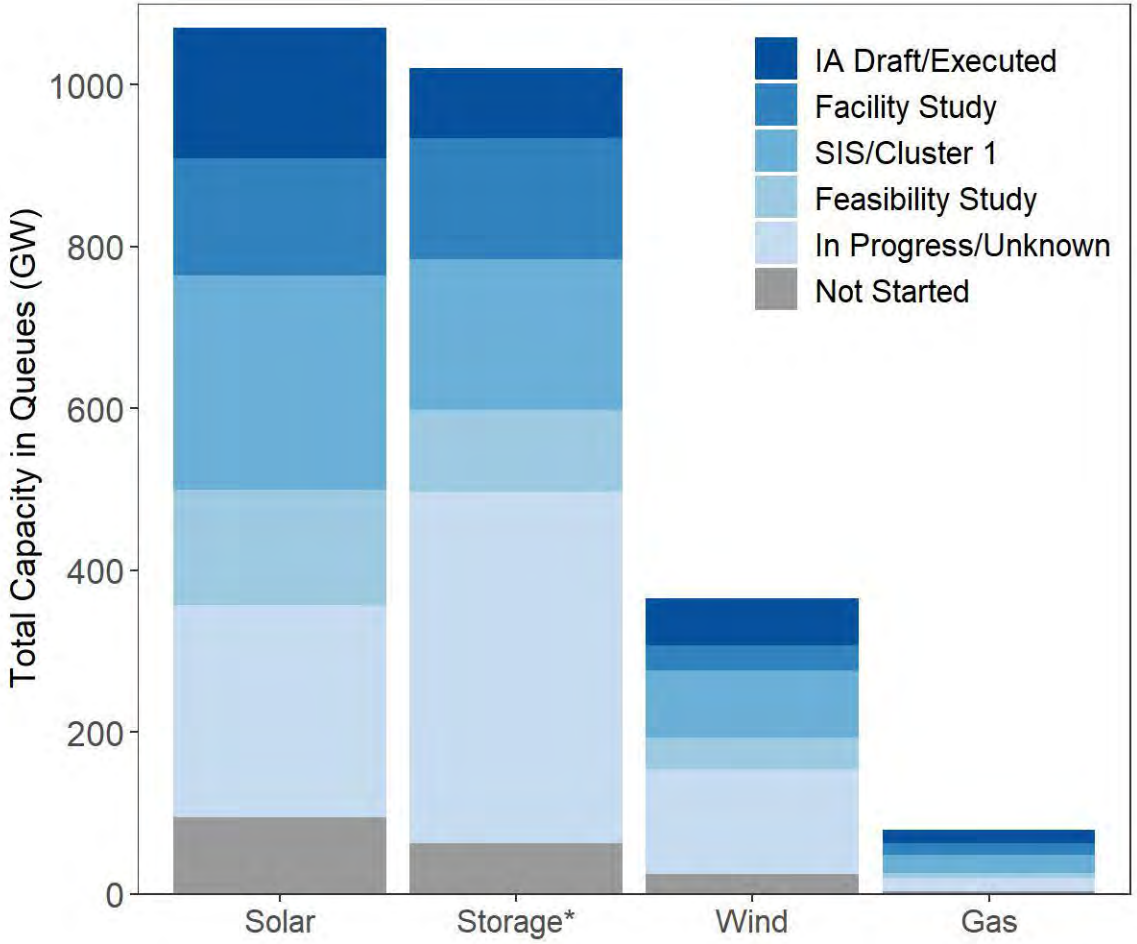
	% of Active Capacity	
region	**ERIS**	**NRIS**
CAISO	12%	88%
MISO	4%	96%
PJM	0%	100%
SPP	26%	74%
ISO-NE	16%	84%
West	18%	82%
Southeast	23%	77%

Notes: (1) NRIS and ERIS were developed under FERC Order 2003, and apply to FERC-jurisdictional transmission providers. (2) ERCOT is not FERC jurisdictional, but uses a "connect and manage" interconnection service that is more similar to ERIS. (3) Data available for 27,693 requests from 6 ISOs and 2 non-ISO balancing areas.

49% (1,271 GW) of total capacity in queues has proposed online date by end of 2026; 12% (311 GW) already has an executed interconnection agreement (IA)

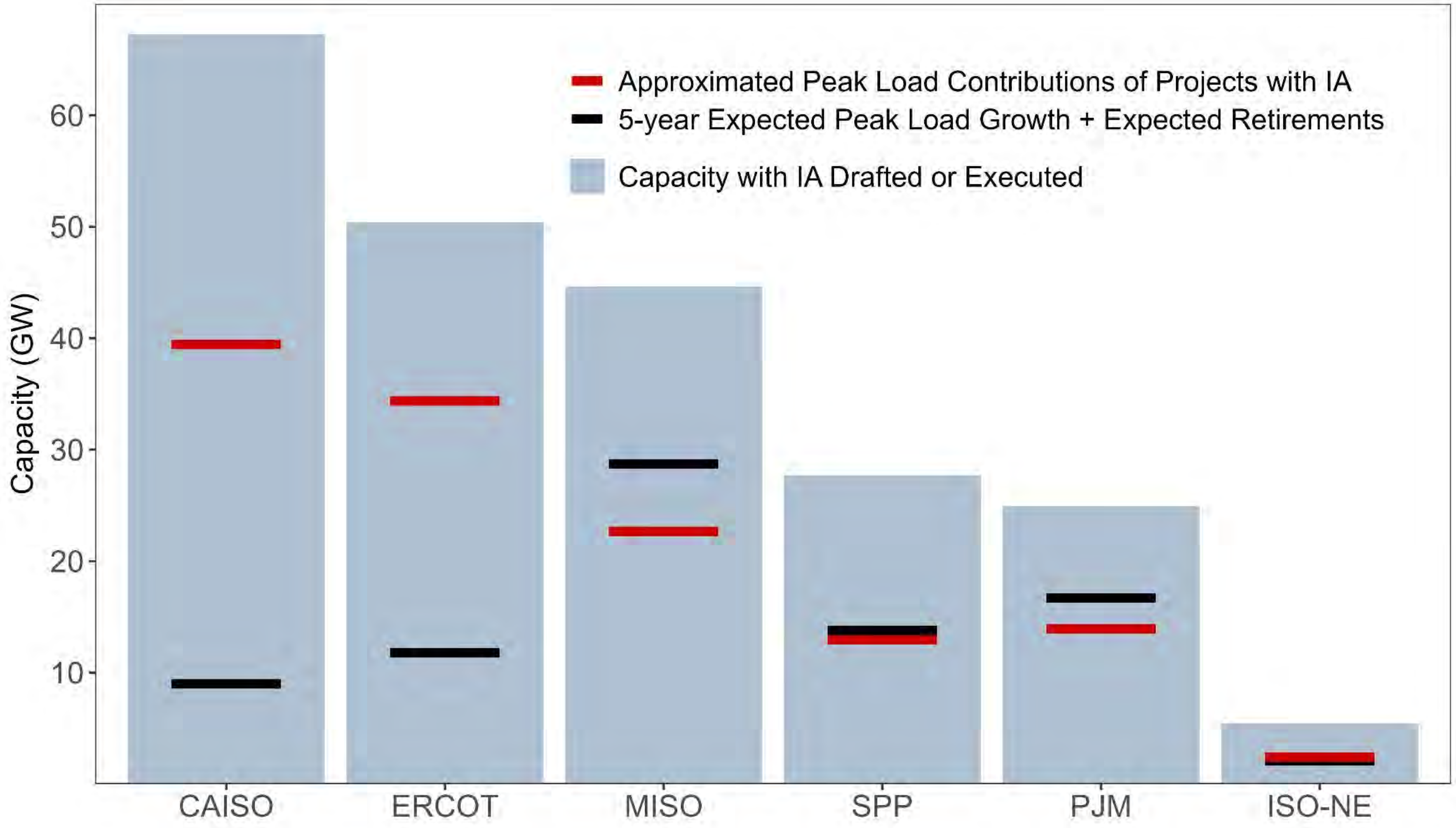
52% of solar (566 GW) is proposed to come online by the end of 2026, compared to 50% of storage (514 GW) and only 33% of wind (120 GW). 14% of solar capacity has an IA, compared to 15% of wind and just 10% of storage.





*Notes: (1) *Hybrid storage capacity is estimated for some projects. (2) Proposed online dates are included in the developer's original interconnection request, and may differ from actual online date. (3) Not all of this capacity will be built. (4) Study status categories are simplified and correspond to the process pre-FERC Order No. 2023 reforms.*

CAISO currently has the most capacity with draft or executed IAs (67 GW). In PJM, just ~25 GW have signed IAs, though it's the largest U.S. RTO.

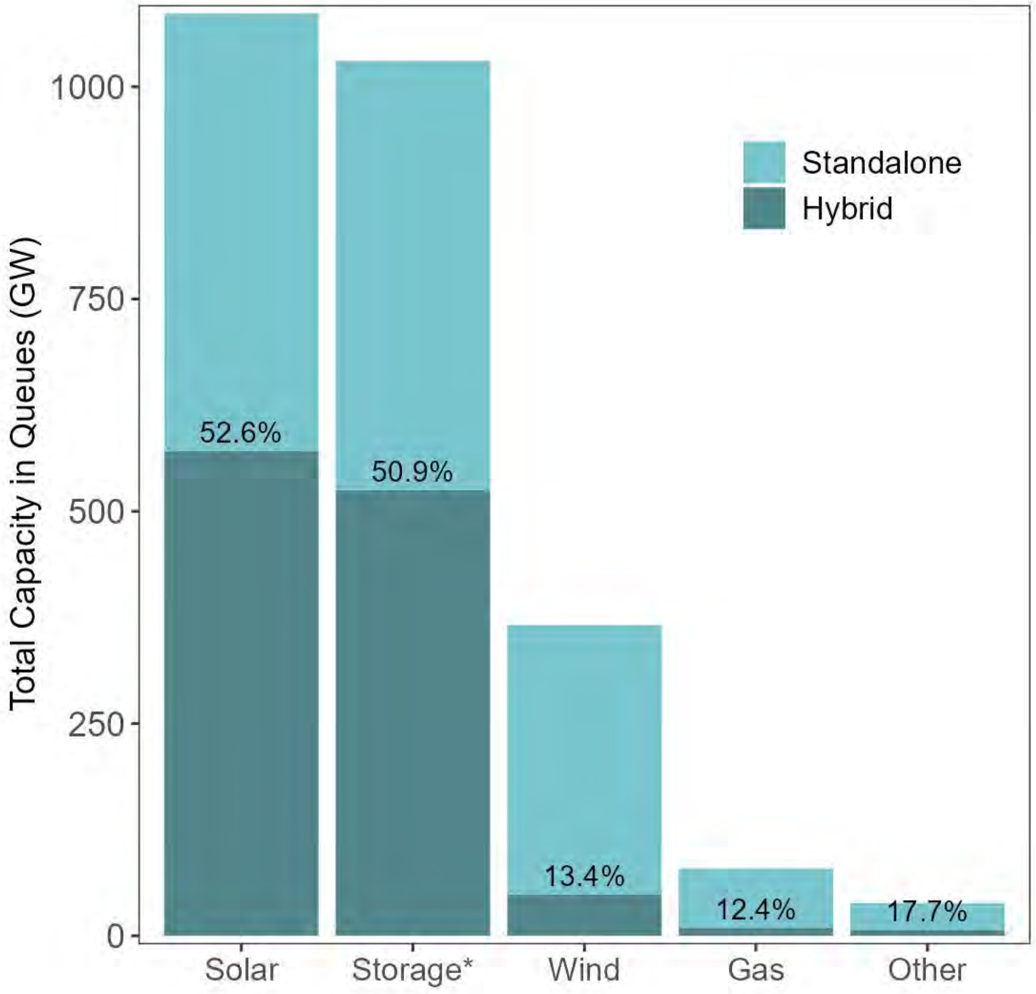


While total capacity of generators and storage active in interconnection queues provides an indication of longer-term developer interest in grid expansion, it provides less insight into shorter-term resource adequacy concerns related to power plant retirements and/or load growth that is being driven by transport electrification, manufacturing growth, and data centers. Signed interconnection agreements provide a better understanding of the nearer-term pipeline of project development (see graph).

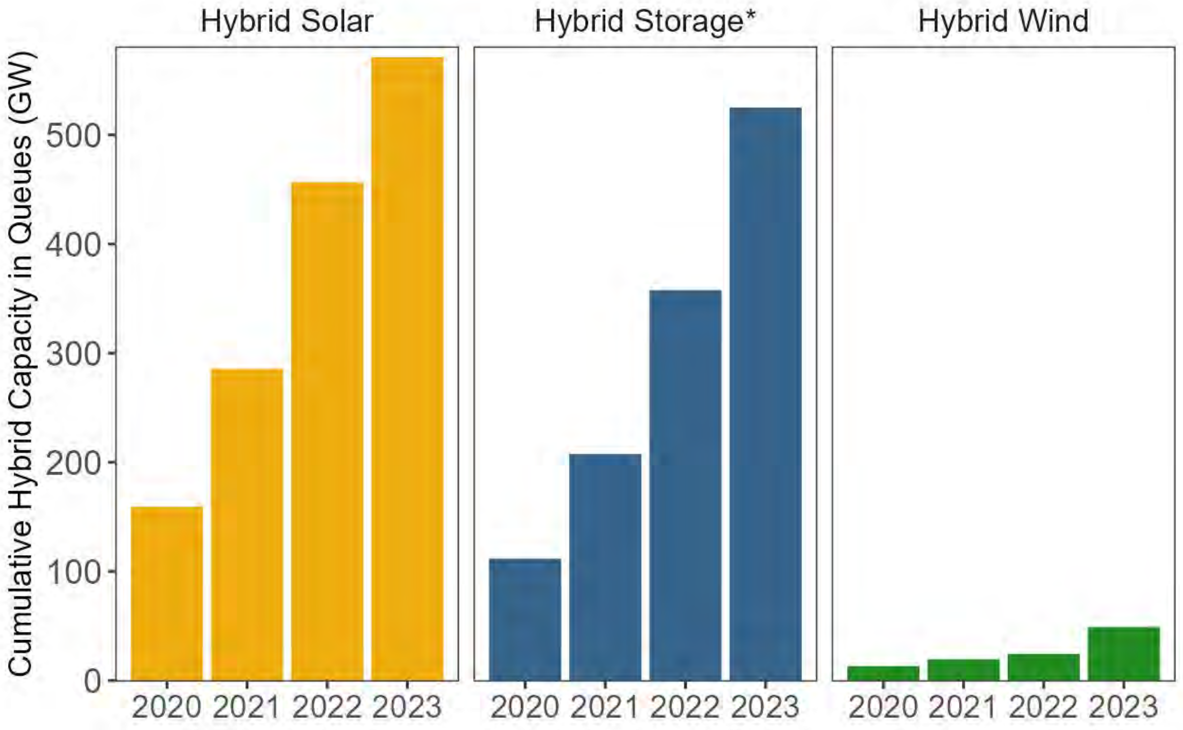
Predicting future power plant retirements and load growth is difficult. The graph indicates varying levels of difference between expected load growth and retirements when compared to the quantity of interconnection requests with a signed interconnection agreement.

Notes: (1) IA capacity bars include capacity in the queues that has either a draft or fully executed interconnection agreement. (2) 5-year peak load growth and expected retirements from NERC's 2023 electricity supply and demand database. (3) Peak load contributions by region relies on NERC 2023 reliability assessments for standalone solar, onshore wind, and hydro. Storage, gas, coal, and nuclear are approximated with a peak load contribution of 100%, even though in practice their contributions will be smaller. Offshore wind contributions are based on recent reliability studies.

Capacity in hybrid plants is increasing: Hybrids comprise 53% of active solar capacity (571 GW), 51% of storage (525 GW), and 13% of wind (49 GW)



Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data



- **Solar Hybrids** include: Solar+Storage (548 GW), Solar+Wind (0.2 GW), Solar+Wind+Storage (12 GW)
- **Wind Hybrids** include: Wind+Storage (35 GW), Wind+Solar (0.2 GW), Wind+Solar+Storage (13 GW)
- **Storage Hybrids** may be paired with any generator type; most are paired with solar
- **Gas Hybrids** include: Gas+Solar+Storage (10 GW) [not shown above]

Notes: (1) Some hybrids shown may represent storage capacity added to existing generation; only the net increase in capacity is shown; (2) Capacity for hybrid plants (e.g., Wind+Solar+Storage) is captured in each generator category (i.e., the solar component shows up in hybrid solar, storage in hybrid storage), presuming the capacity is known for each type.

Hybrids comprise a sizable fraction of all proposed solar plants in multiple regions; wind hybrids are less common overall but still a large proportion in CAISO + West

Region	% of Proposed Capacity Hybridizing in Each Region			
	Solar	**Wind**	**Gas**	**Storage***
CAISO	98%	34%	88%	52%
ERCOT	49%	7%	4%	34%
ISO-NE	30%	0%	10%	8%
MISO	20%	6%	0%	48%
NYISO	24%	4%	16%	16%
PJM	24%	1%	0%	37%
SPP	22%	2%	3%	32%
Southeast (non-ISO)	34%	0%	0%	63%
West (non-ISO)	81%	30%	29%	72%
TOTAL	**53%**	**13%**	**12%**	**51%**

- **Solar** hybridization relative to total amount of solar in each queue is highest in CAISO (98%) and non-ISO West (81%), and is above 20% in all regions
- **Wind** hybridization relative to total amount of wind in each queue is highest in CAISO (34%), the non-ISO West (30%), and is less than 10% in all other regions

Operational & Withdrawn Projects: Volume and Completion Rates

Operational project data were available from all 7 ISO/RTOs and 31 non-ISO balancing areas, totaling 4,155 projects.

Region	*n* (Operational)	Capacity (GW)
CAISO	198	26.6
ERCOT	358	65.6
ISO-NE	255	34.7
MISO	459	66.7
NYISO	100	11.2
PJM	1,163	91.0
SPP	271	40.8
Southeast (non-ISO)	361	76.7
West (non-ISO)	990	57.2

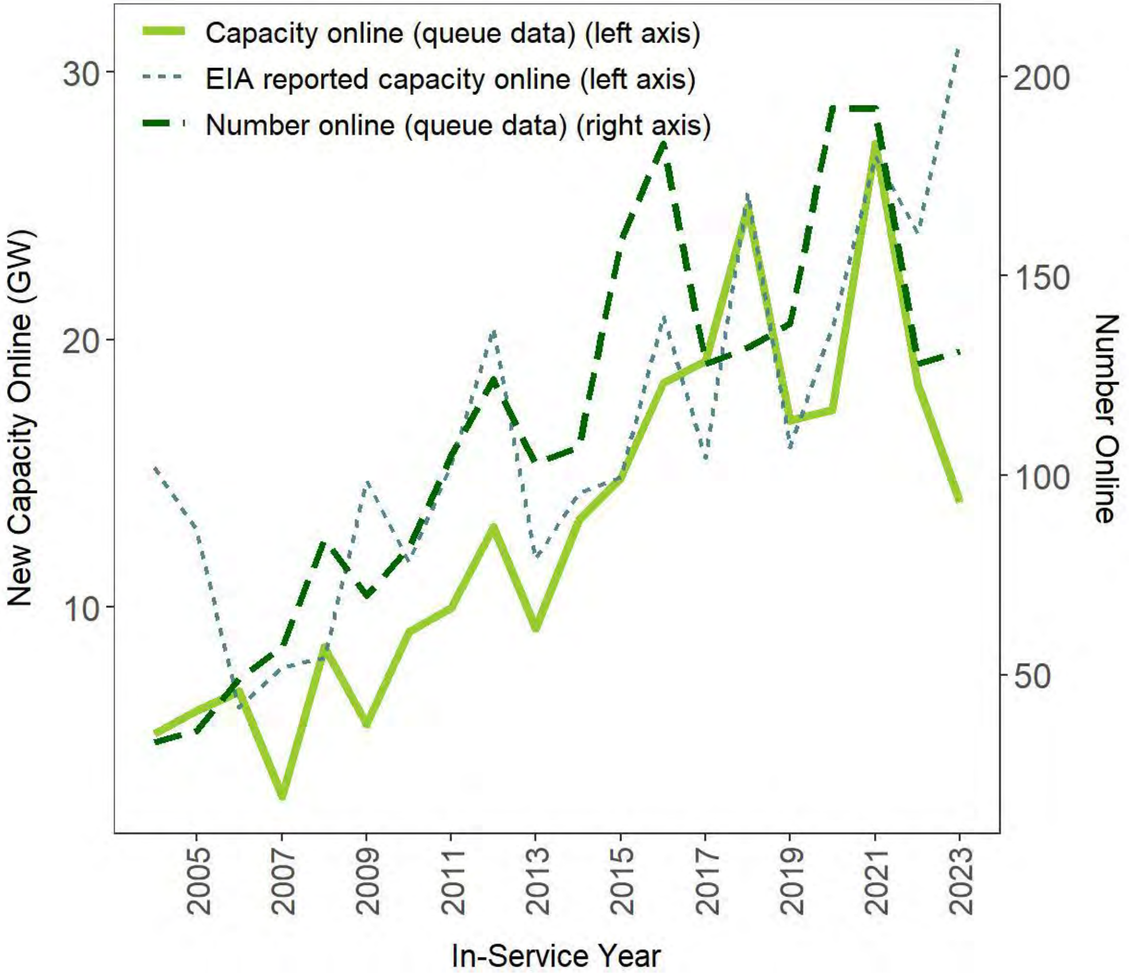
Withdrawn project data were available from all 7 ISO/RTOs and 37 non-ISO utilities, totaling 18,372 requests.

Region	*n* (Withdrawn)	Capacity (GW)
CAISO	1,630	401.0
ERCOT	803	195.6
ISO-NE	605	90.8
MISO	2,113	408.6
NYISO	843	135.7
PJM	4,588	476.4
SPP	1,419	280.8
Southeast (non-ISO)	2,001	450.1
West (non-ISO)	4,370	657.9

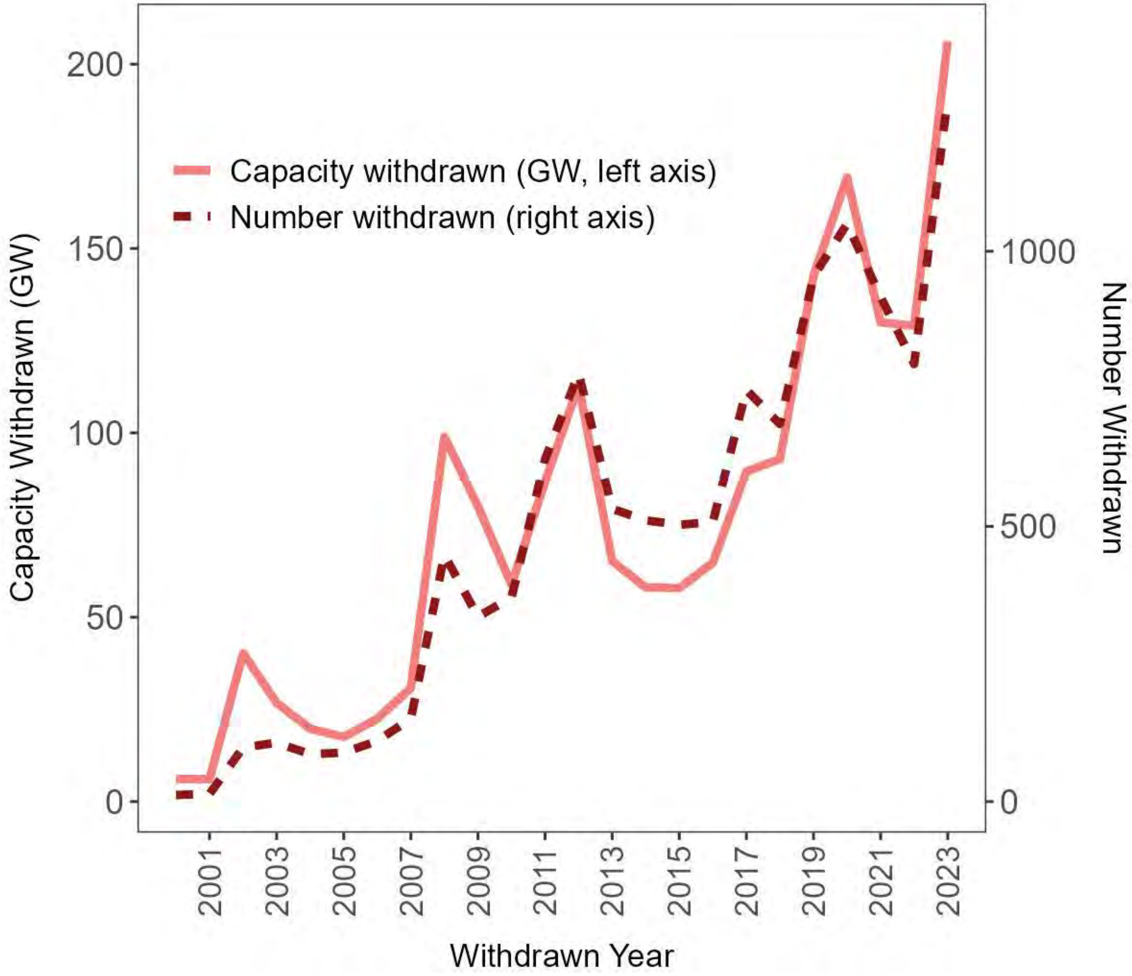
*Notes: (1) The number of operational and withdrawn projects with available data may be fewer than the total number of operational or withdrawn projects for each entity. (2) Data were sought from 7 ISOs and 44 non-ISO BAs; operational and withdrawn project data may be delayed or unavailable. (3) Capacity (GW) shown in these tables does **not** include estimates for missing hybrid storage capacity.*

Volume (number and capacity) of operational and withdrawn projects is trending upward; more than 1,250 requests (>200 GW) were withdrawn in 2023

Operational Projects

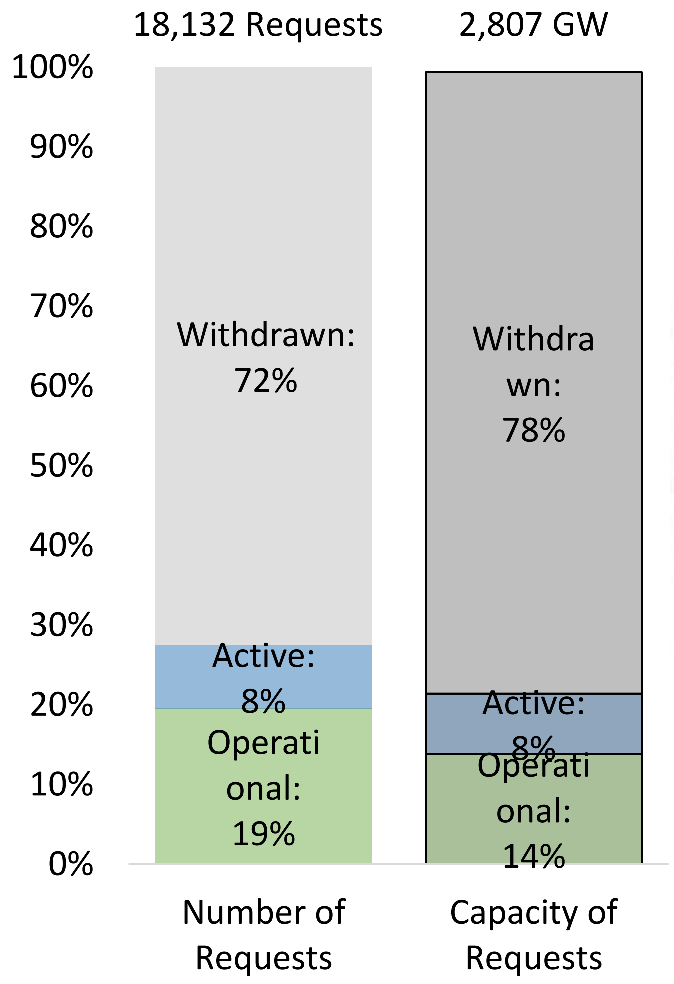


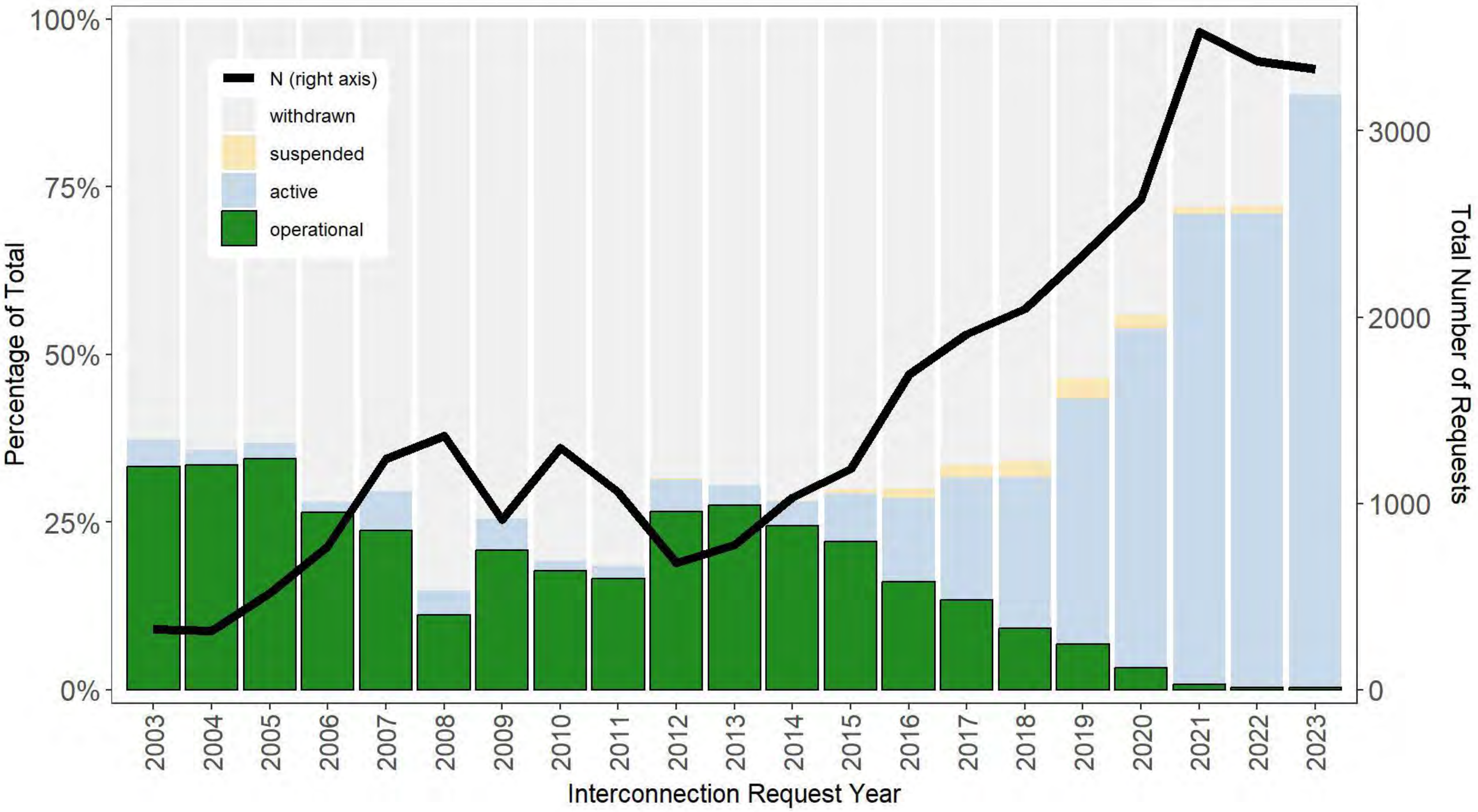
Withdrawn Projects



Note: (1) In-service year only available for 61% of the "operational" project sample; withdrawn year only available for 64% of the "withdrawn" project sample. These figures therefore only include a subset of total data. (2) The discrepancy between queue capacity and EIA capacity in recent years (2022-2023) is attributable to lags in online/operational status reporting in the queue data.

The majority (>70%) of interconnection requests are withdrawn. Just 19% of requests (14% of capacity) submitted from 2000-2018 had been built as of the end of 2023

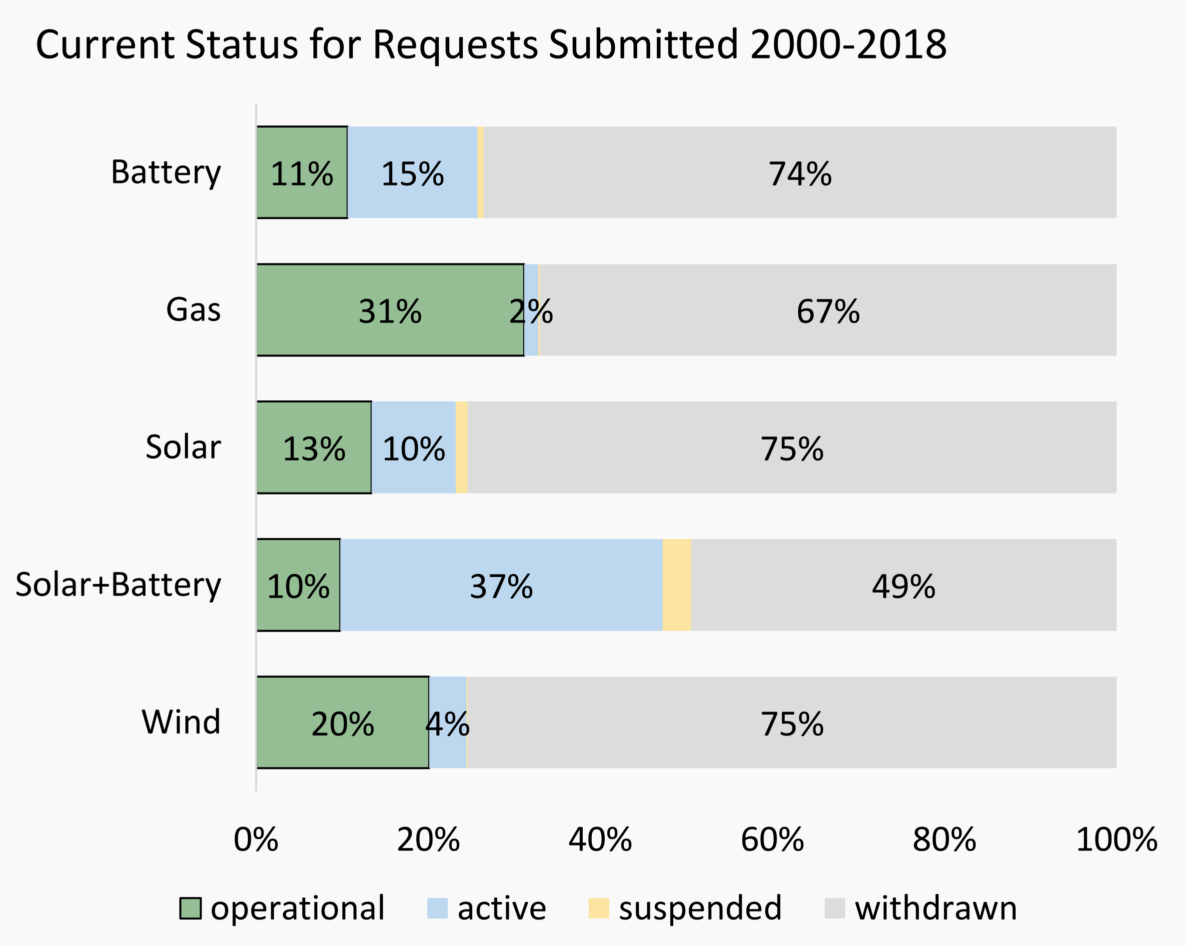




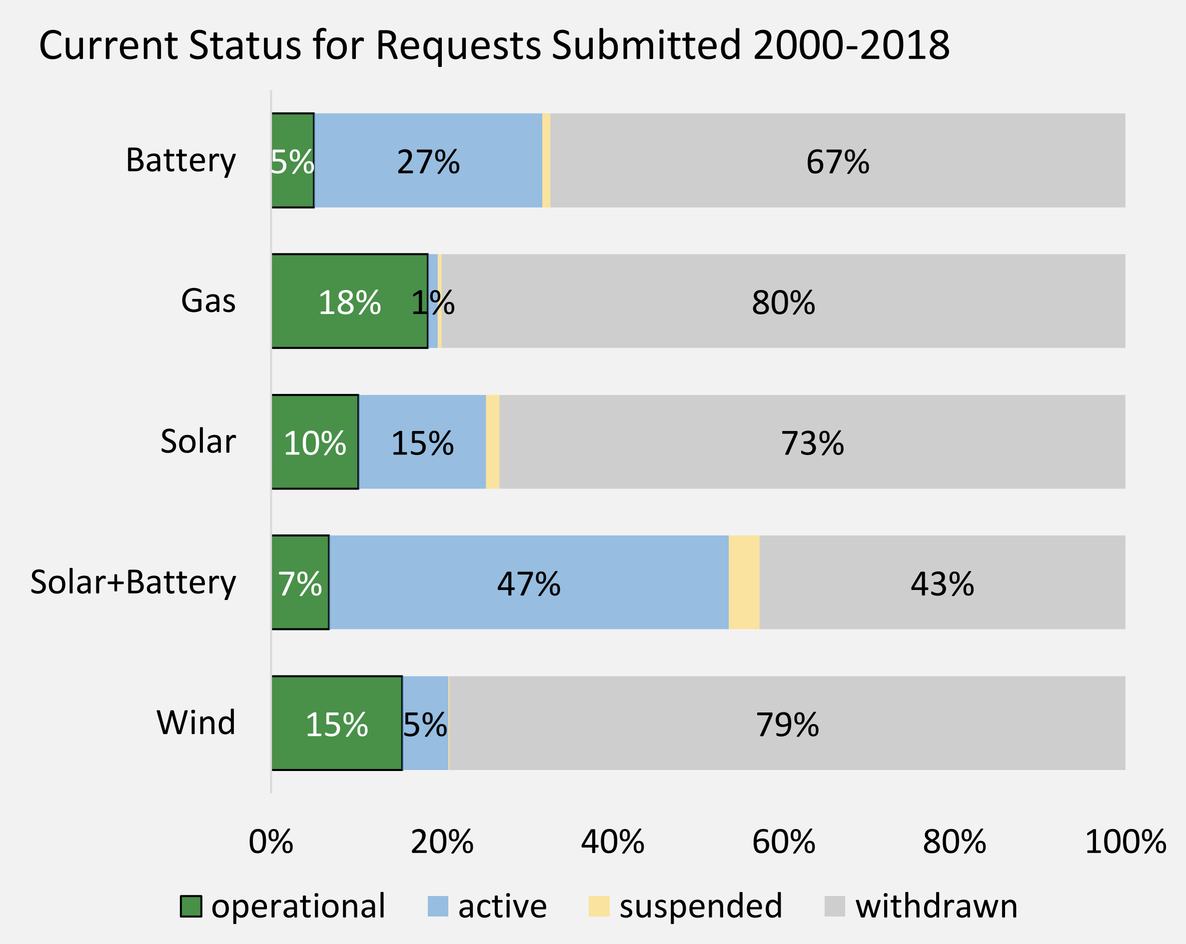
Notes: (1) Final outcome for projects entering the queues in recent years may not yet be determined; some take 5 or more years from request to COD. (2) Status shown represents a snapshot of all available data as of the end of 2023. (3) Completion rate shown in chart on right is calculated by ***number*** *of projects, not capacity. (4) Limited to data from 7 ISO/RTOs and 30 non-ISO balancing areas which provide comprehensive status information.*

There is considerable variation in completion rates across generator types; Solar (13%) and Battery (11%) have lower historical average than Gas (31%) or Wind (20%)

By Number of Requests

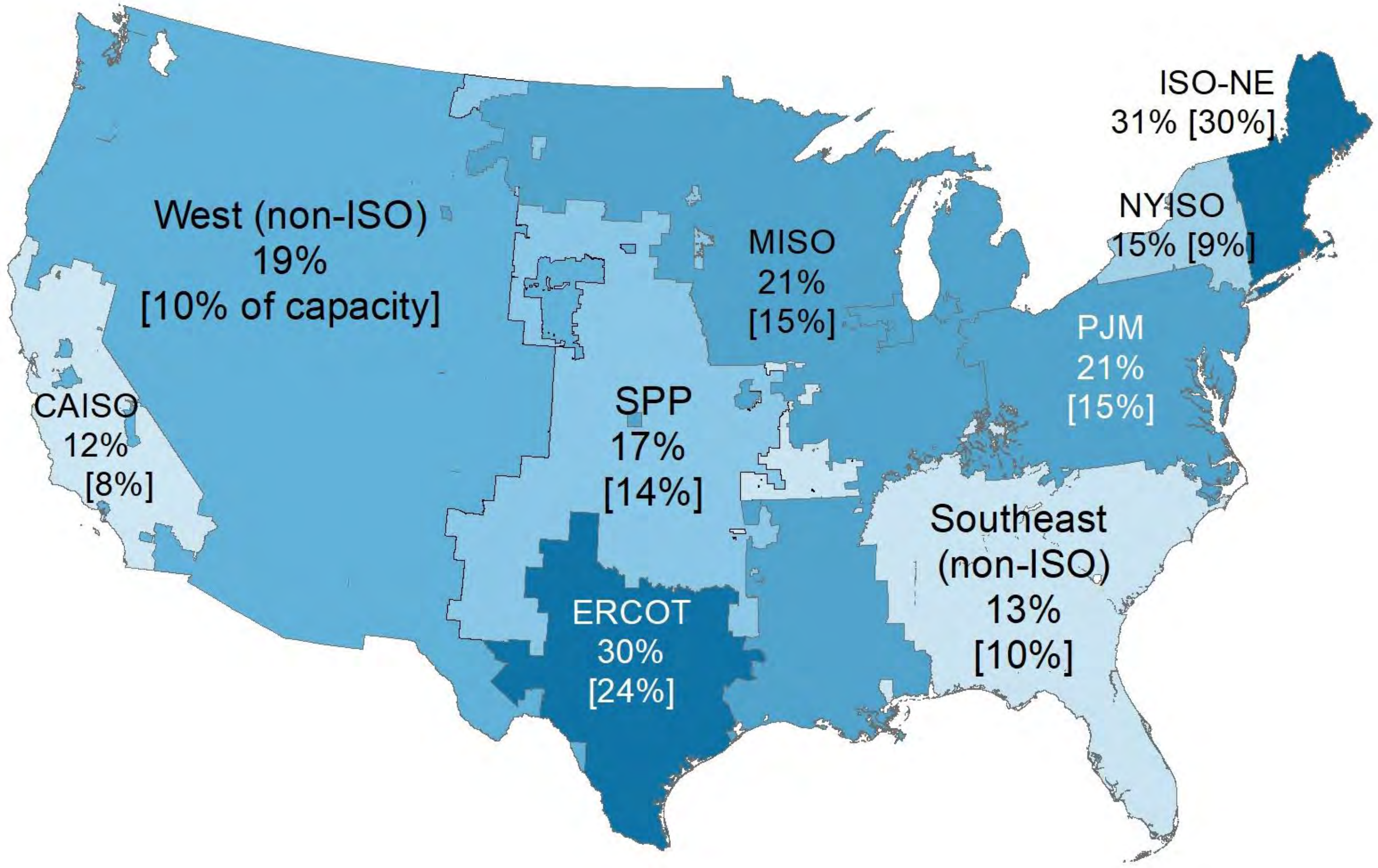


By Capacity of Requests



Note: (1) Calculated as number of projects operational as of EOY 2023 divided by the total number of requests per year. (2) Includes data from 7 ISOs and 30 non-ISO BAs which provide comprehensive status information. (3) See appendix for time-series data

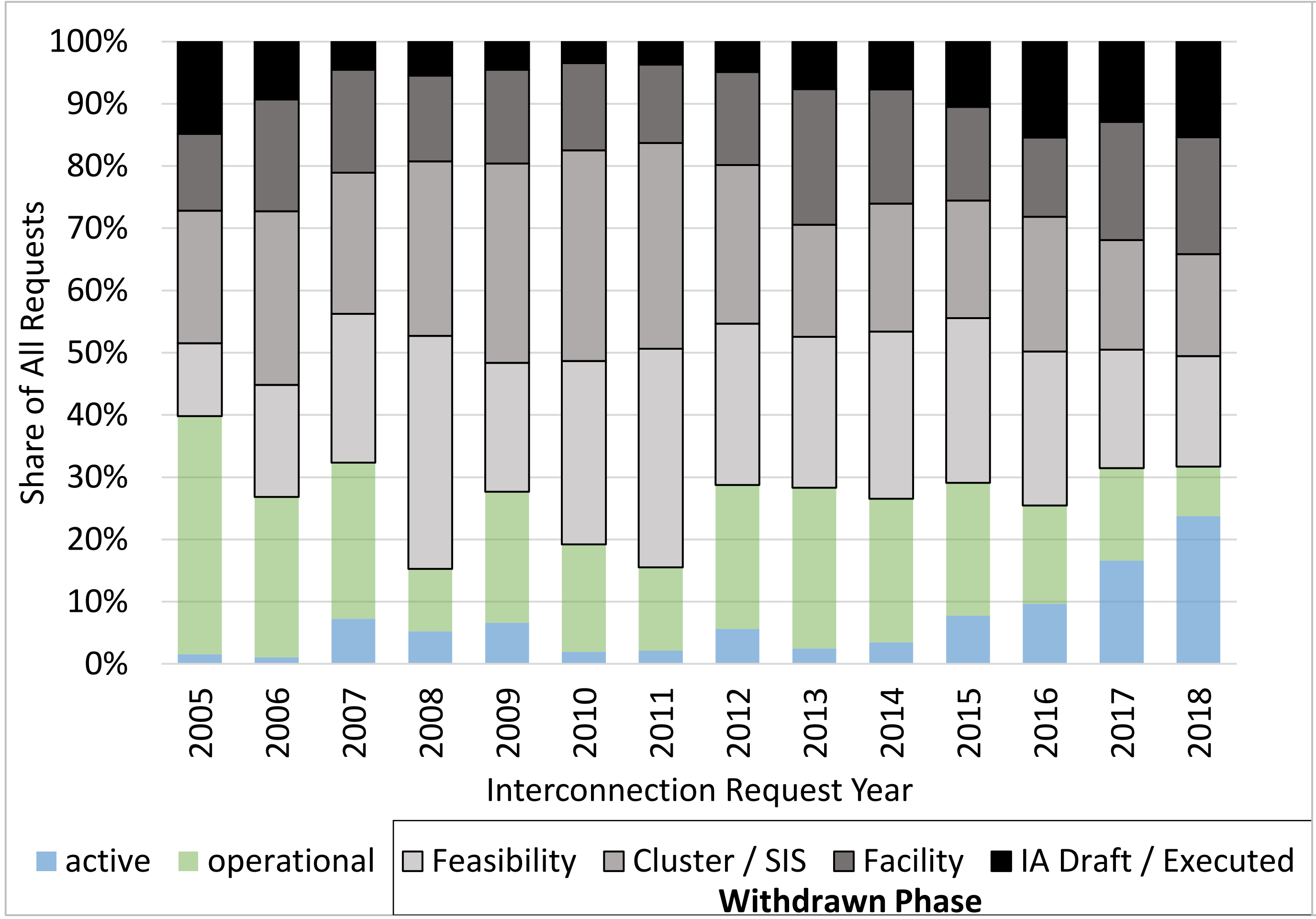
The share of projects requesting interconnection from 2000-2018 that have reached COD is relatively low across regions: Only ISO-NE and ERCOT exceed 30% completion

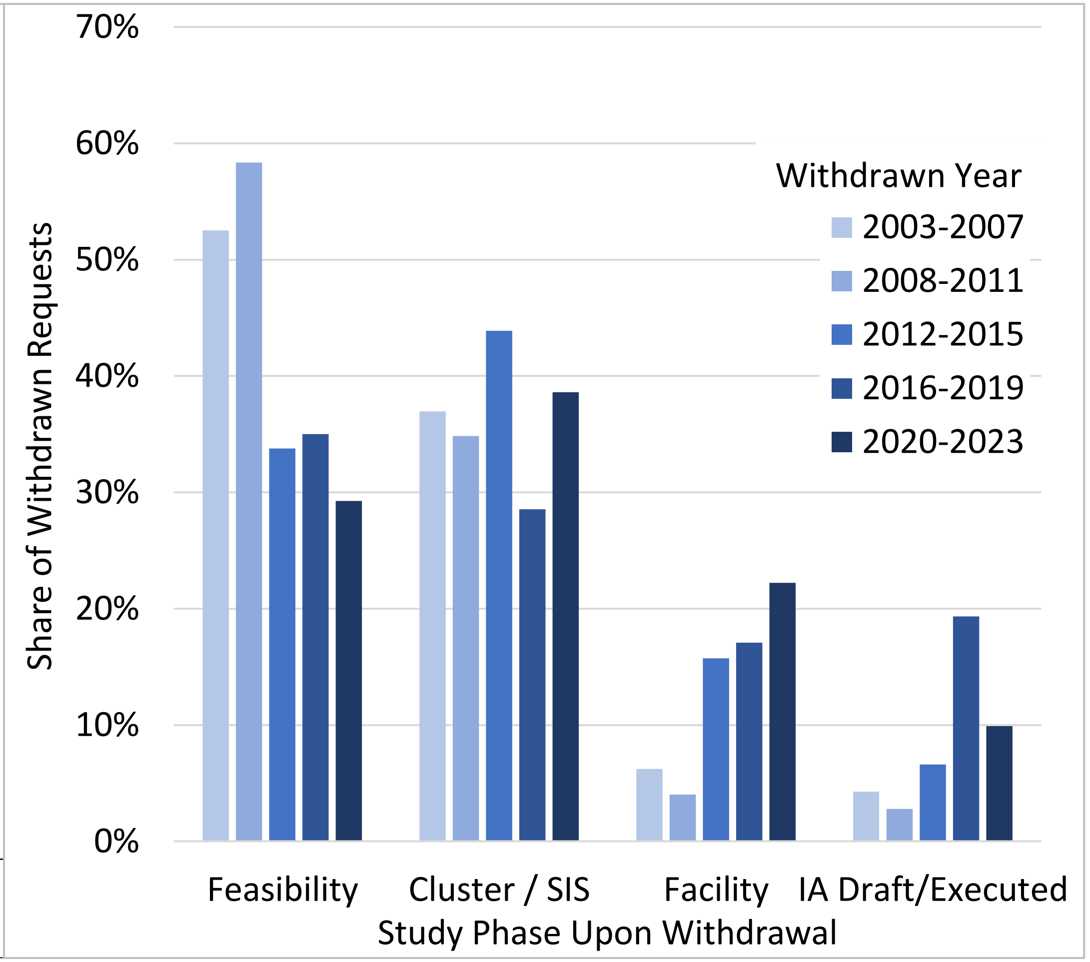


- ☐ Capacity-weighted completion rates are even lower; shown in brackets [%]
  - ◘ ISO-NE and ERCOT are the only regions with >20% of capacity reaching commercial operation date (COD)
- ☐ For interconnection requests from 2000-2018, ISO-NE (31%) and ERCOT (30%) had the highest project completion percentages, with CAISO (12%) and the Southeast (13%) lower on average
- ☐ These rates are variable by year, and trends may be shifting as queue volumes and reforms evolve
- ☐ The difference between regions, temporal trends, and the implications of these low rates on electric-sector decarbonization, are important areas for future research

Notes: (1) Capacity-weighted completion rates are shown in brackets [ ]. (2) Percentages only include projects requesting interconnection from 2000-2018. (3) Includes data from 7 ISOs and 30 non-ISO balancing areas which provide comprehensive status information. (4) See appendix for time-series data.

Most withdrawals occur in earlier study phases (e.g., Feasibility or System Impact Study), but later-stage withdrawals (Facility or IA phase) may be increasing





Late-stage withdrawals can be more costly for developers (sunk costs, deposits) and can trigger re-studies for other projects in the queue, increasing delays.

Note: Only includes data for entities that provide study phase for withdrawn projects and comprehensive status information (4 ISOs and 10 non-ISO balancing areas).

Duration Trends: How Long Do Projects Spend In the Queues?

Withdrawn Projects:

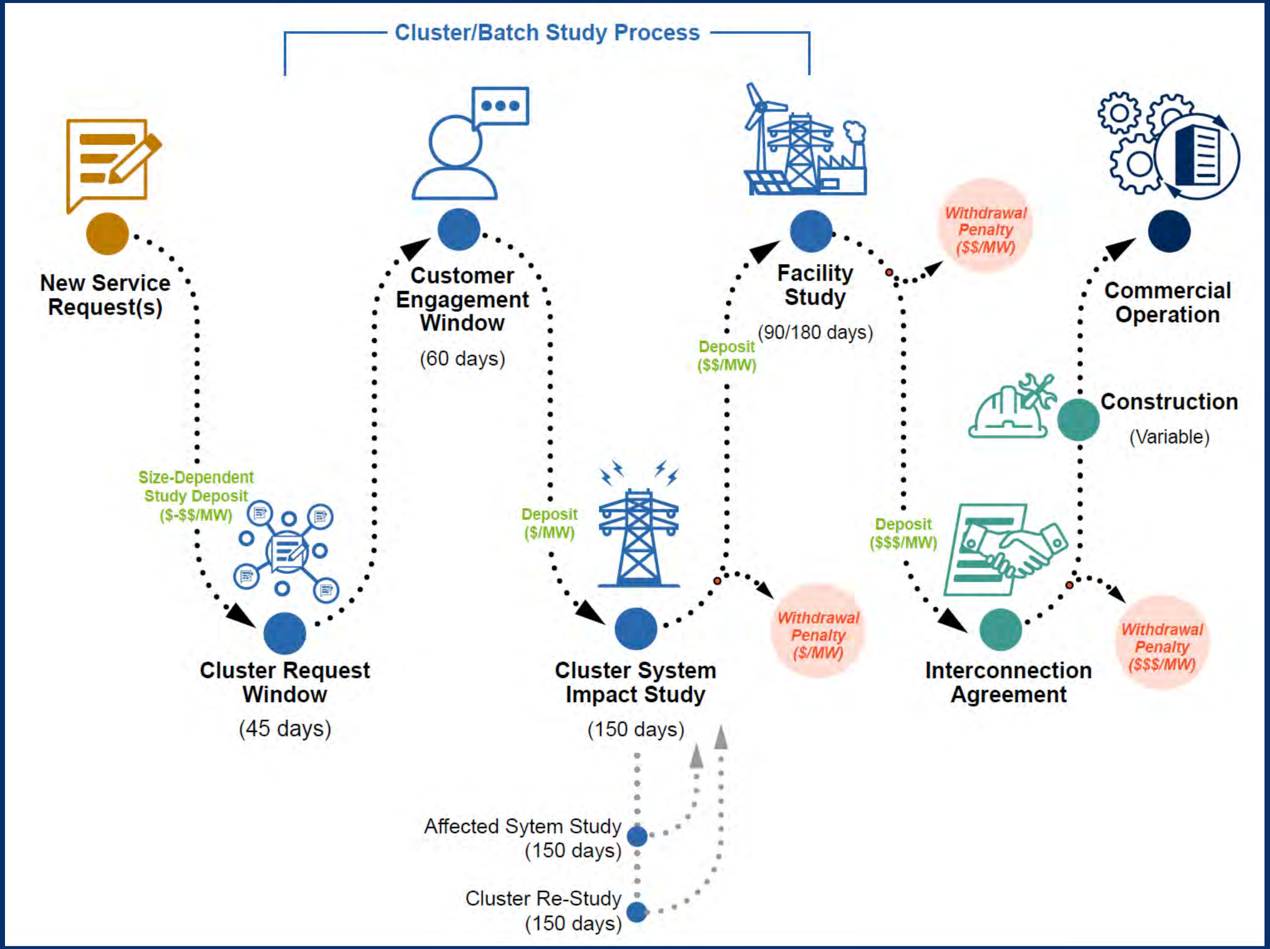
- Duration from Interconnection Request (IR) to Withdrawn Date
  - By region and generator type

All Projects:

- Duration from IR to Interconnection Agreement (IA)
  - By region, generator type, size, and service type

Operational Projects:

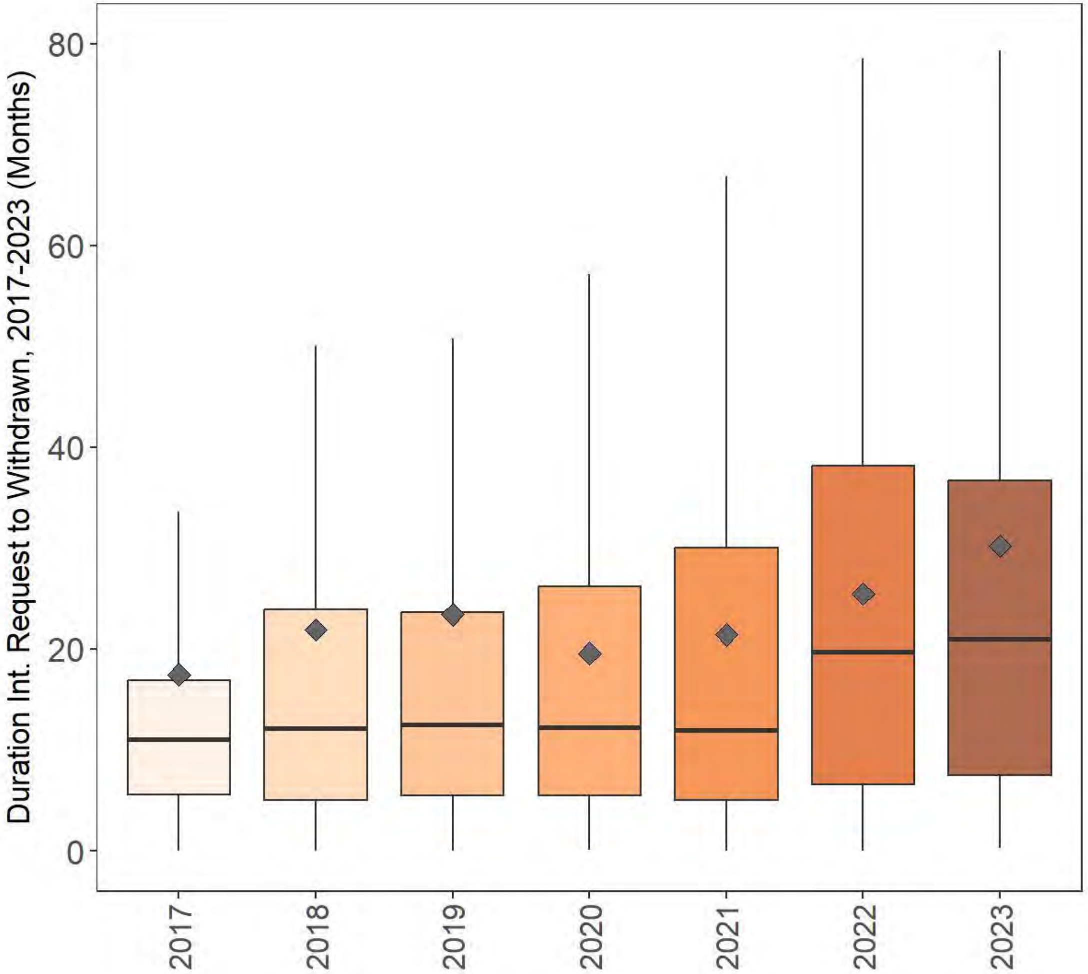
- Duration from IA to COD
  - By region and generator type
- Duration from IR to Commercial Operations Date (COD)
  - By region, generator type, and size



Note: The interconnection process diagram (right) reflects the pro-forma process under FERC Order No. 2023. While some ISOs already follow this cluster-study approach, the data presented in this report pre-date Order No. 2023 implementation.

The average duration from interconnection request to withdrawal date has edged upward in recent years

Duration Analyzed: *Interconnection Request (IR)* → *Withdrawn Date* → *Commercial Operations (COD)*

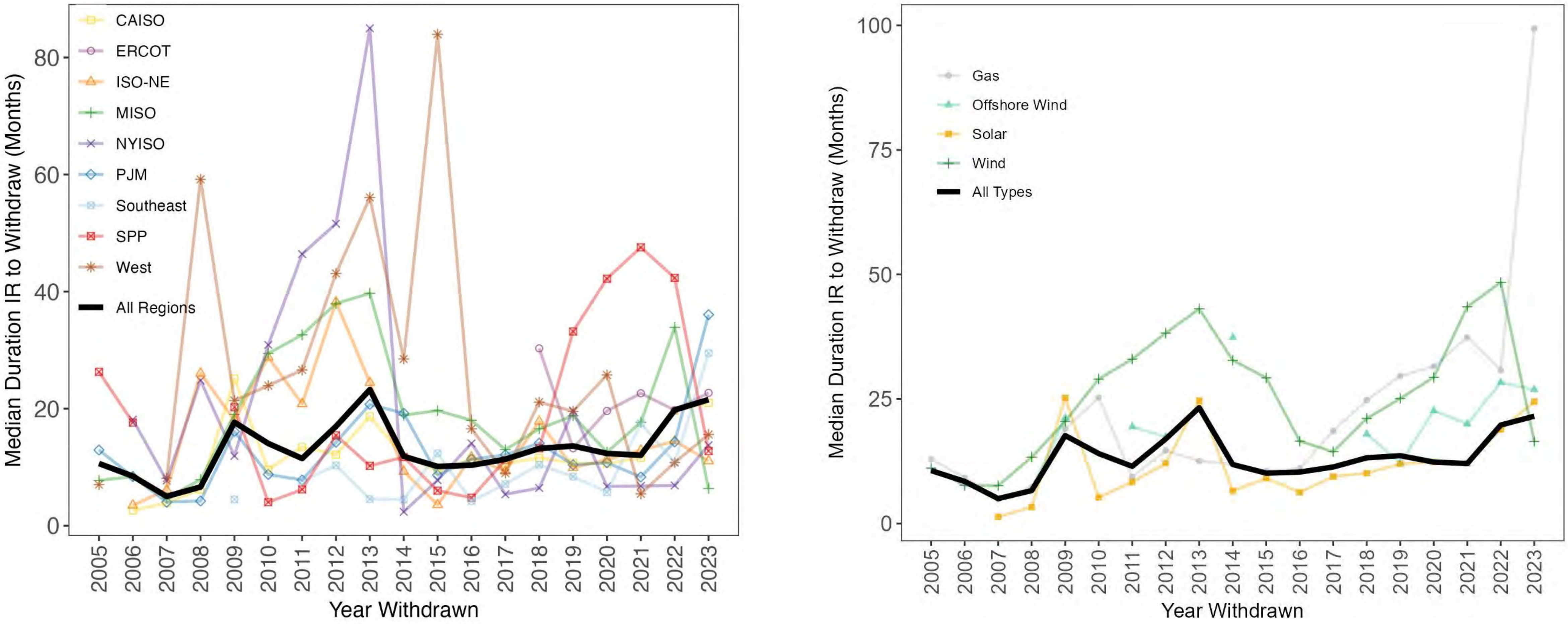


- ☐ This trend implies that some recently-withdrawn projects have waited longer in the queues before making the determination to withdraw
- ☐ This corroborates the findings on cumulative withdrawal rates and late-stage withdrawals illustrated on Slide 30
- ☐ Later stage withdrawals can be costly for developers and can disrupt assumptions built into other projects' interconnection studies, necessitating re-studies in some cases and lengthening study durations

***Note on Boxplots**: Many of the following slides utilize box and whisker plots. The boxes represent the interquartile range (IQR), with the central horizontal line being the median. Gray diamonds are the mean. Whiskers (vertical lines) are 1.5 times the IQR. Outliers are not shown.*

Duration to withdrawal is trending up in several regions, and across technologies. A number of old Gas requests were withdrawn in Southern Co., NYISO, and PJM in 2023

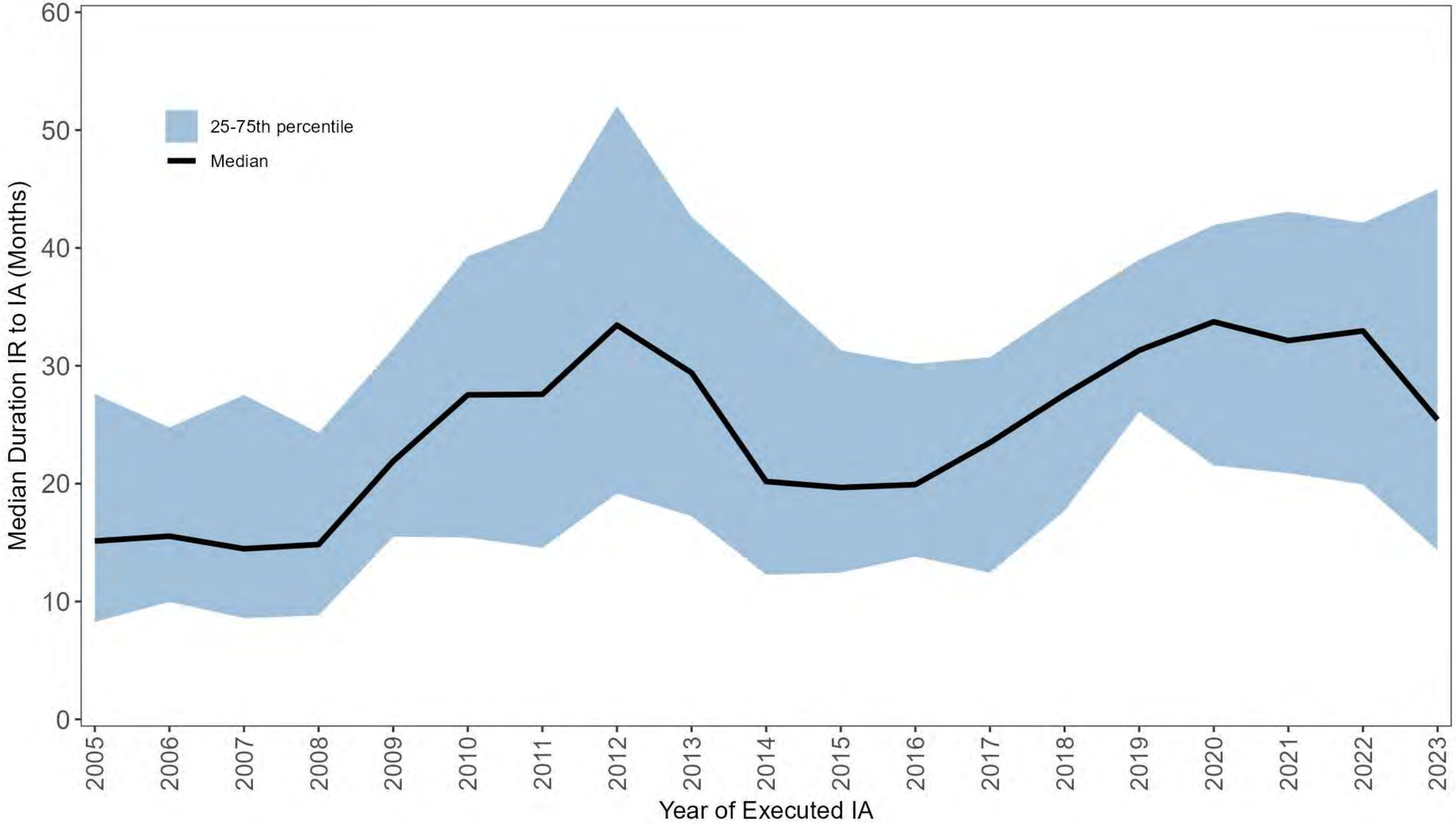
Duration Analyzed: *Interconnection Request (IR)* → *Withdrawn Date* → *Commercial Operations (COD)*



Notes: (1) Withdrawn date was available for 11,680 projects from 7 ISOs and 8 non-ISO balancing areas. (2) Duration is calculated as the number of months from the queue entry date to the date the project was withdrawn from queues.

Duration from interconnection request to interconnection agreement had increased recently, but moderated slightly in 2023 (note: 2023 data sample is dominated by ERCOT and West[1])

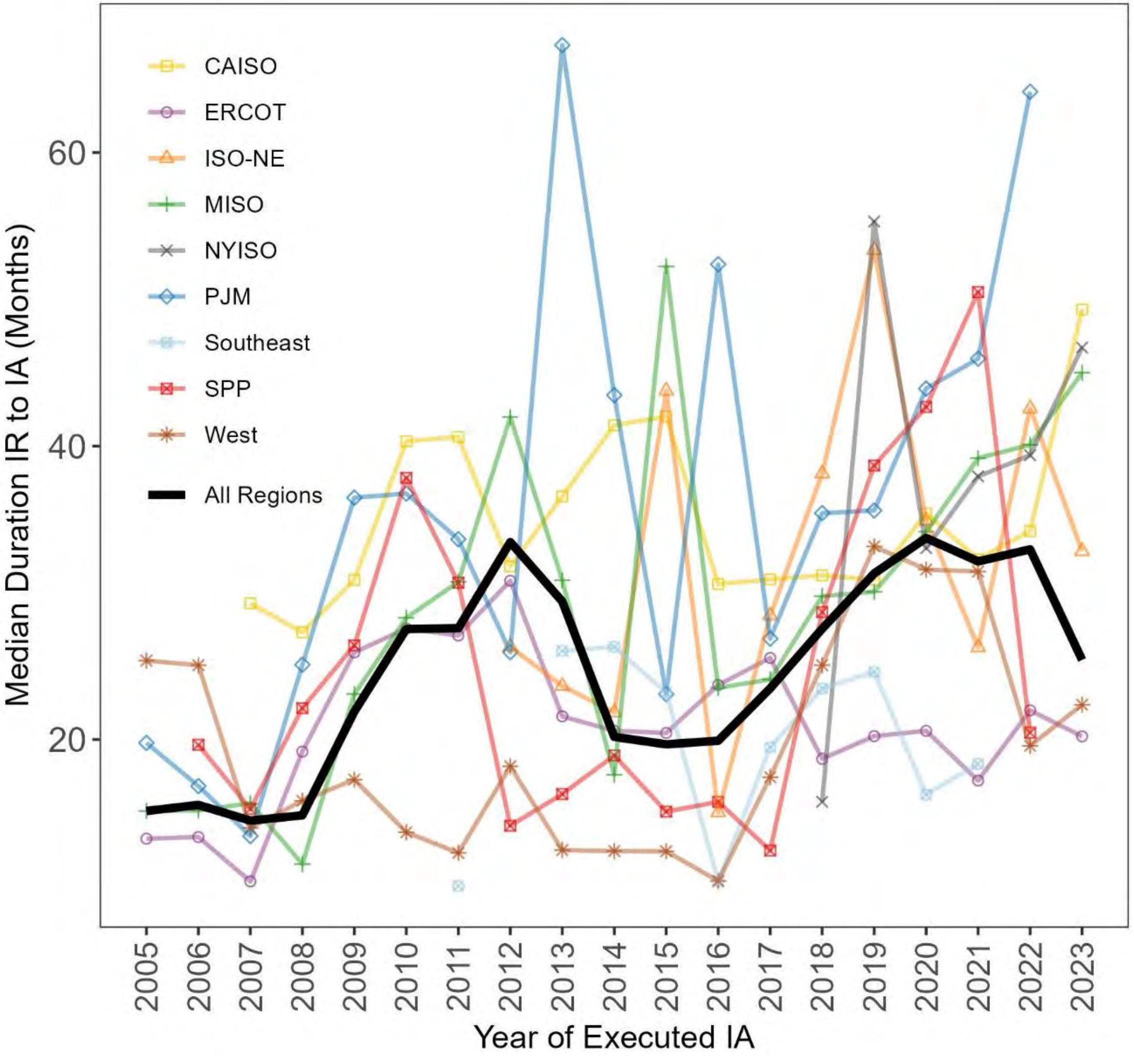
Duration Analyzed: | *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*

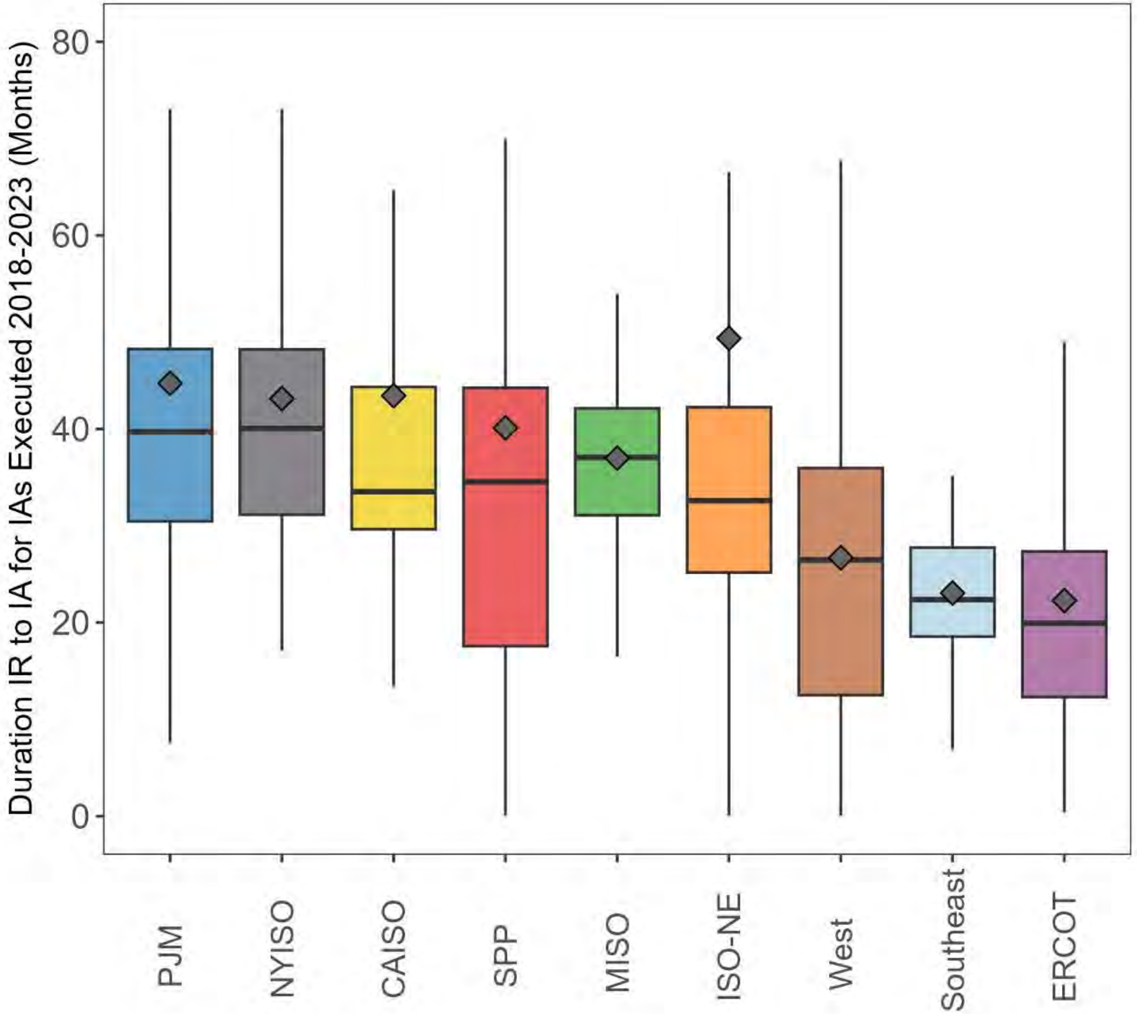


Notes: (1) The majority of the 2023 data sample for this analysis came from ERCOT (39%) and the West (23%), which typically have relatively shorter durations (see next slide); there were no 2023 IAs in PJM. (2) Sample includes 3,864 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (3) Not all data used in this analysis are publicly available.

IR to IA duration is typically longest in PJM (but no IAs were completed in PJM in 2023); ERCOT and the non-ISO regions (Southeast and West) have fastest processing times

Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*

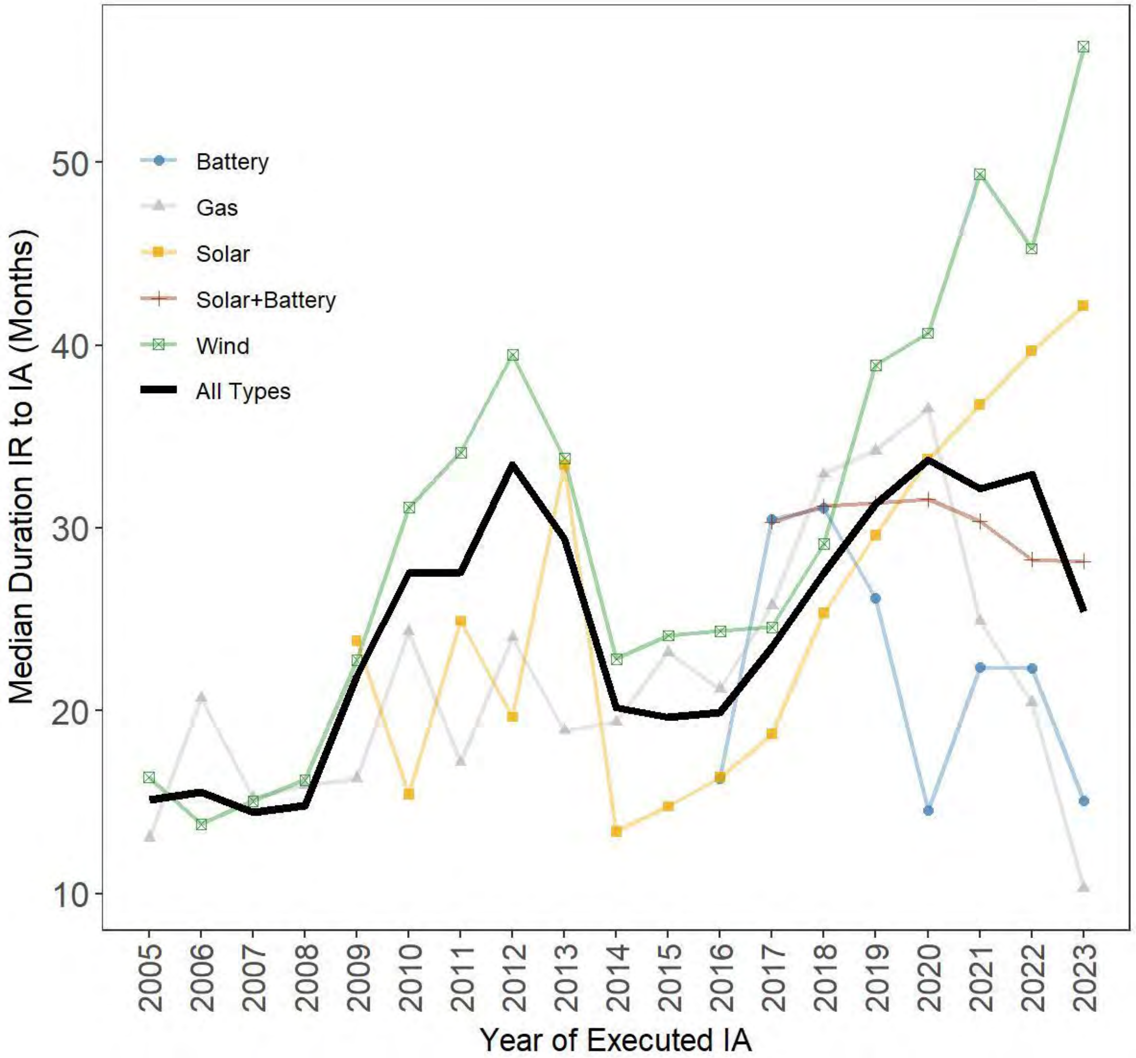


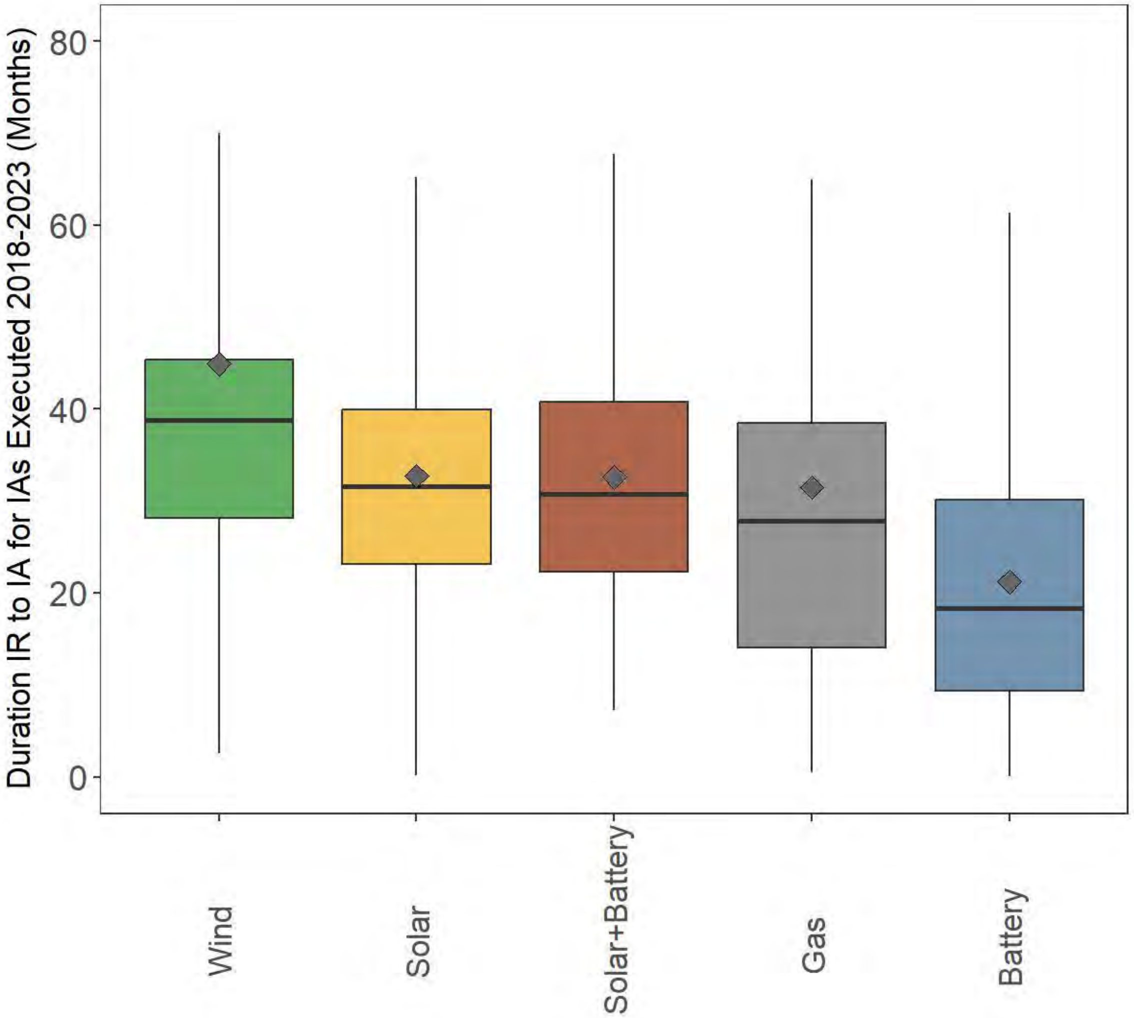


Notes: (1) Sample includes 3,864 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (2) Not all data used in this analysis are publicly available.

Wind projects typically face longer interconnection study timelines; recent battery and gas projects have been processed much more quickly

Duration Analyzed: Interconnection Request (IR) → Interconnection Agreement (IA) → Commercial Operations (COD)

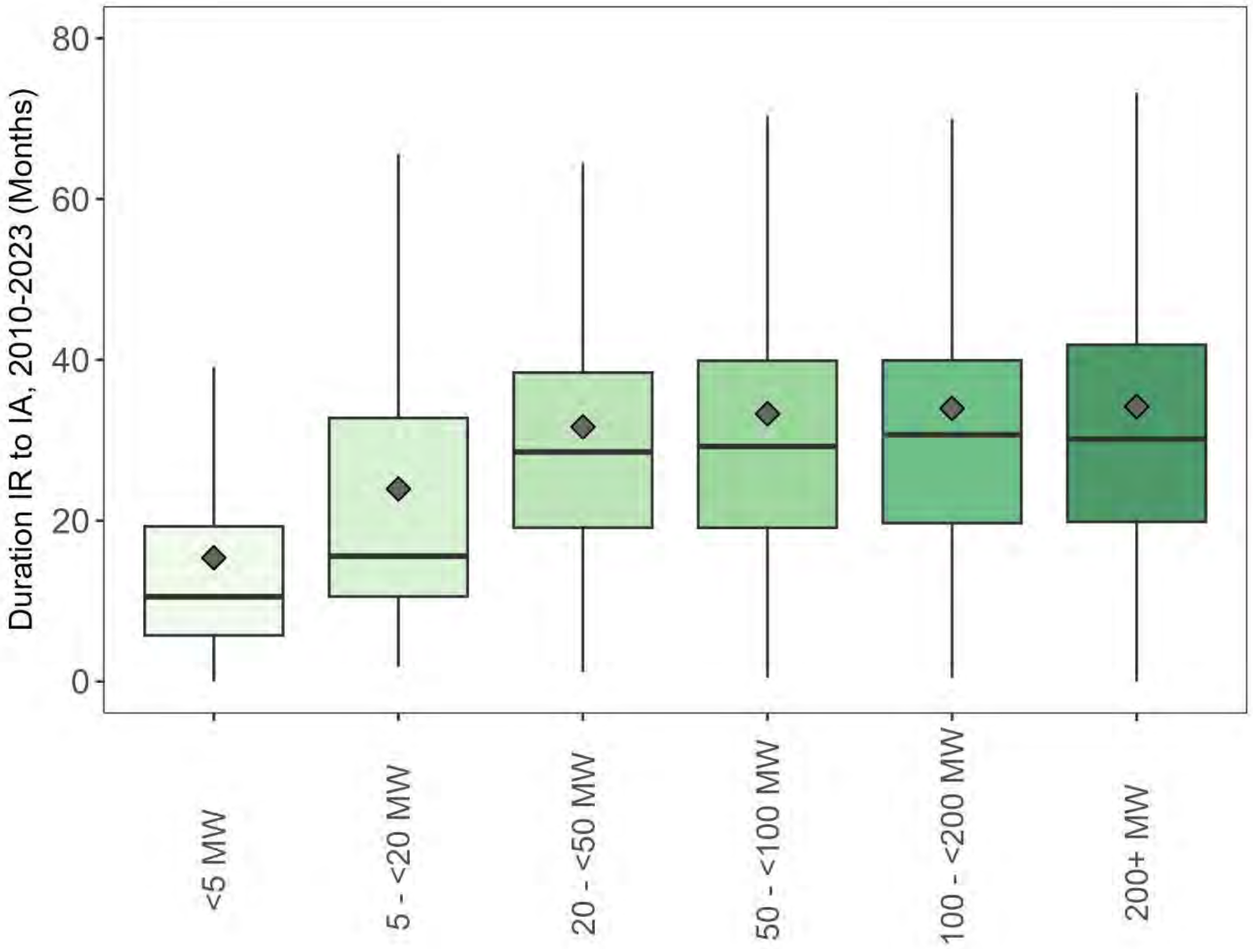




Notes: (1) Sample includes 3,864 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (2) Not all data used in this analysis are publicly available.

There is a clear step change in IR to IA duration between “small” (<20 MW) and “large” (>20 MW) generator interconnection procedures

Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*

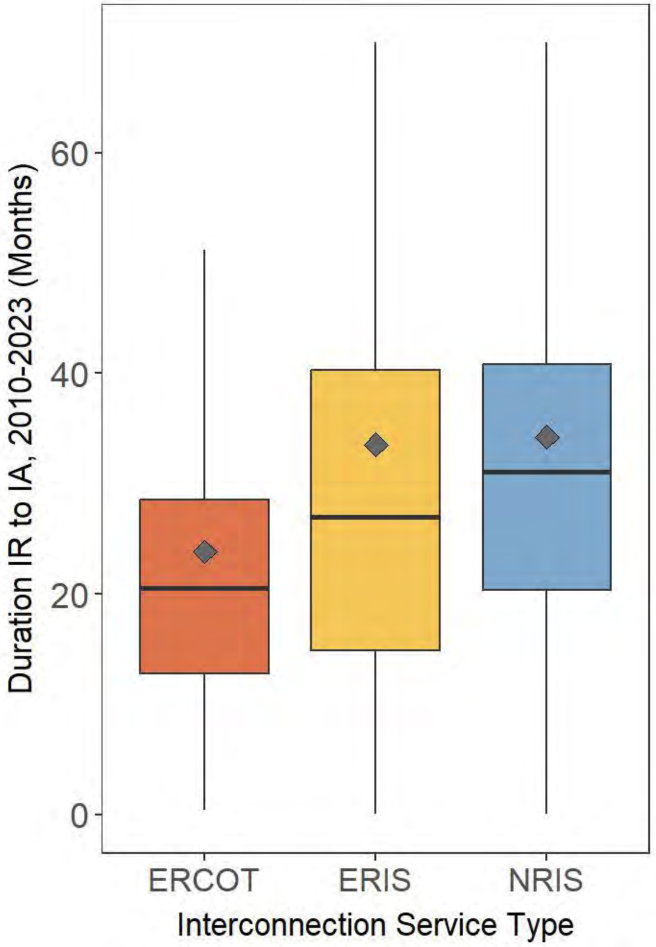


- On average, projects with rated capacity <20 MW complete studies and execute interconnection agreements much faster than larger projects
  - Median is 11 months for projects <5 MW
  - 18 months for projects 5 - <20 MW
- The median duration for projects 20 MW or larger hovers around 30 months across the four larger project groups analyzed
- 20 MW is the threshold between the FERC “large” and “small” generator interconnection procedures (LGIP / SGIP)
  - The median LGIP duration is twice the median SGIP duration for projects in our sample

Notes: (1) Sample includes 3,864 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (2) Not all data used in this analysis are publicly available.

Energy Resource Interconnection Service (ERIS) requests are not significantly faster to process than Network Resource Interconnection Service (NRIS) requests, though ERCOT requests are

Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*



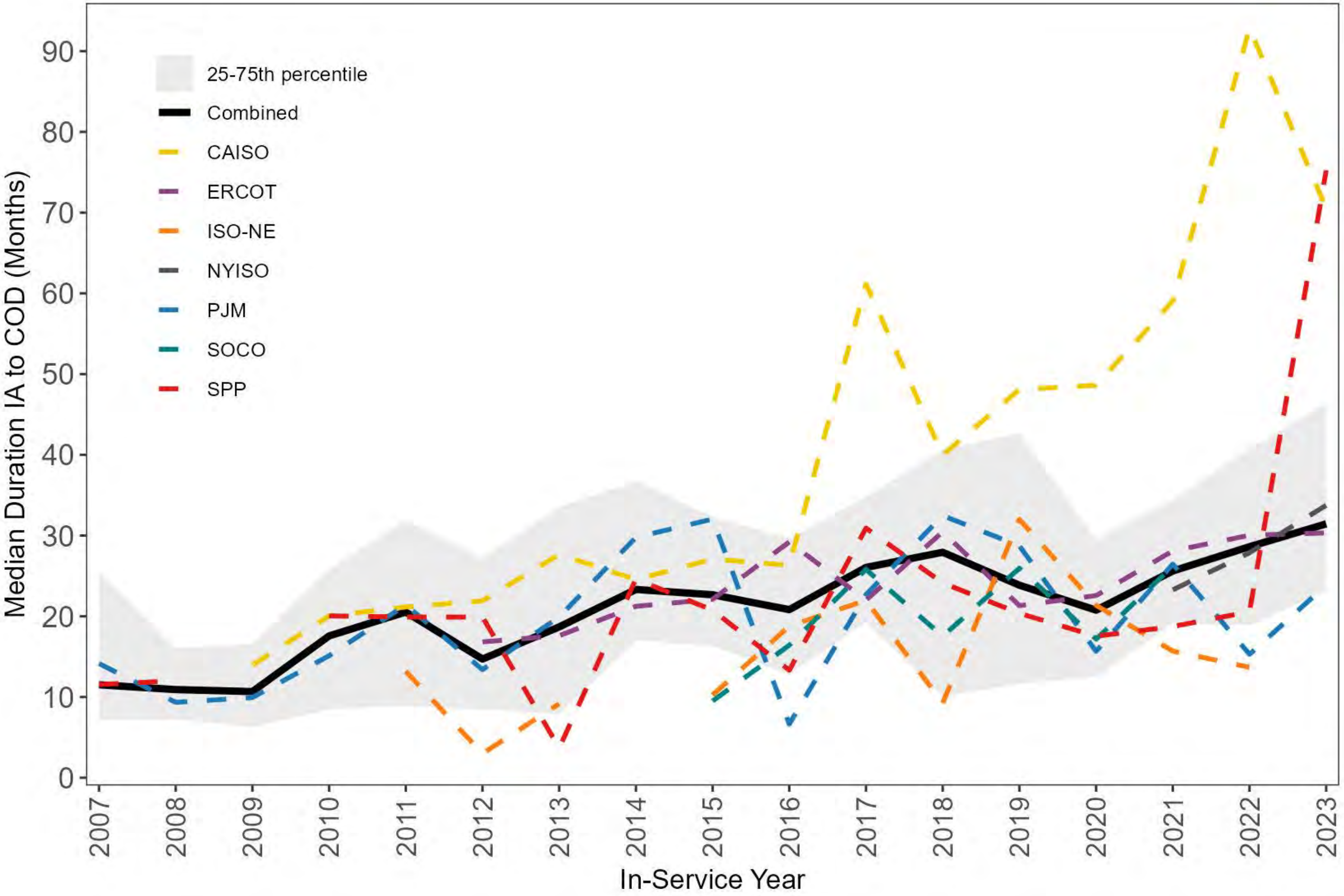
The mean IR-IA duration for ERIS requests submitted since 2010 (33.5 months) is not significantly shorter than that for NRIS requests (~34.2 months) ($p = 0.27$).

ERCOT – which is not FERC jurisdictional – utilizes a ‘connect and manage’ approach, which is similar to ERIS. But ERCOT requests are processed faster on average (~23.8 months) than ERIS requests in other regions since 2010 ($p < 0.001$).

Notes: (1) Sample includes 3,536 projects from 6 ISO/RTOs and 4 non-ISO balancing areas with executed interconnection agreements since 2005 that also provided service type information (2,894 since 2010). (2) Not all data used in this analysis are publicly available.

Typical duration from IA to commercial operations date (COD) has increased modestly; in some regions (e.g., CAISO and SPP), recent projects are facing substantial delays after securing an IA

Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*

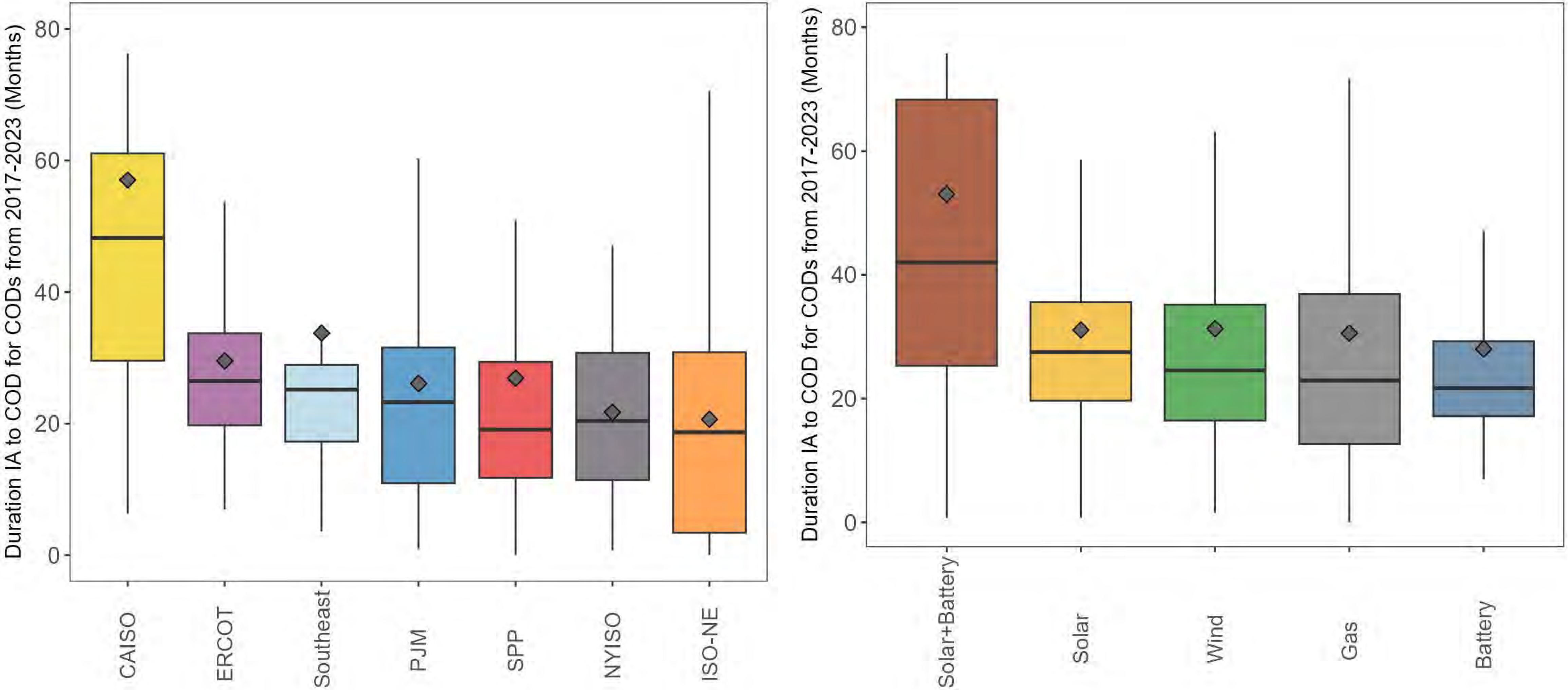


- Limited data were available to analyze typical durations from interconnection agreement to commercial operations
- Considering 861 projects across 6 entities, the typical IA to COD duration has increased modestly since 2007.
  - From ~17 months for projects built from 2007-2015 to ~25 months for projects built from 2016-2023.
- But, that duration has increased dramatically for CAISO projects in the last 5 years.
  - The typical solar project built in CAISO since 2018 took over 4 years to reach commercial operations *after securing an interconnection agreement*; those built in 2022 averaged over 6 years.

Notes: (1) Data were only available for 861 projects across 5 ISO/RTOs and one utility (Southern Company), out of 4,155 total "operational" projects in the full dataset. (2) Not all data used in this analysis are publicly available.

Moving from an executed IA to COD tends to take substantially longer in CAISO compared to other regions; standalone battery projects are quickest to complete this phase

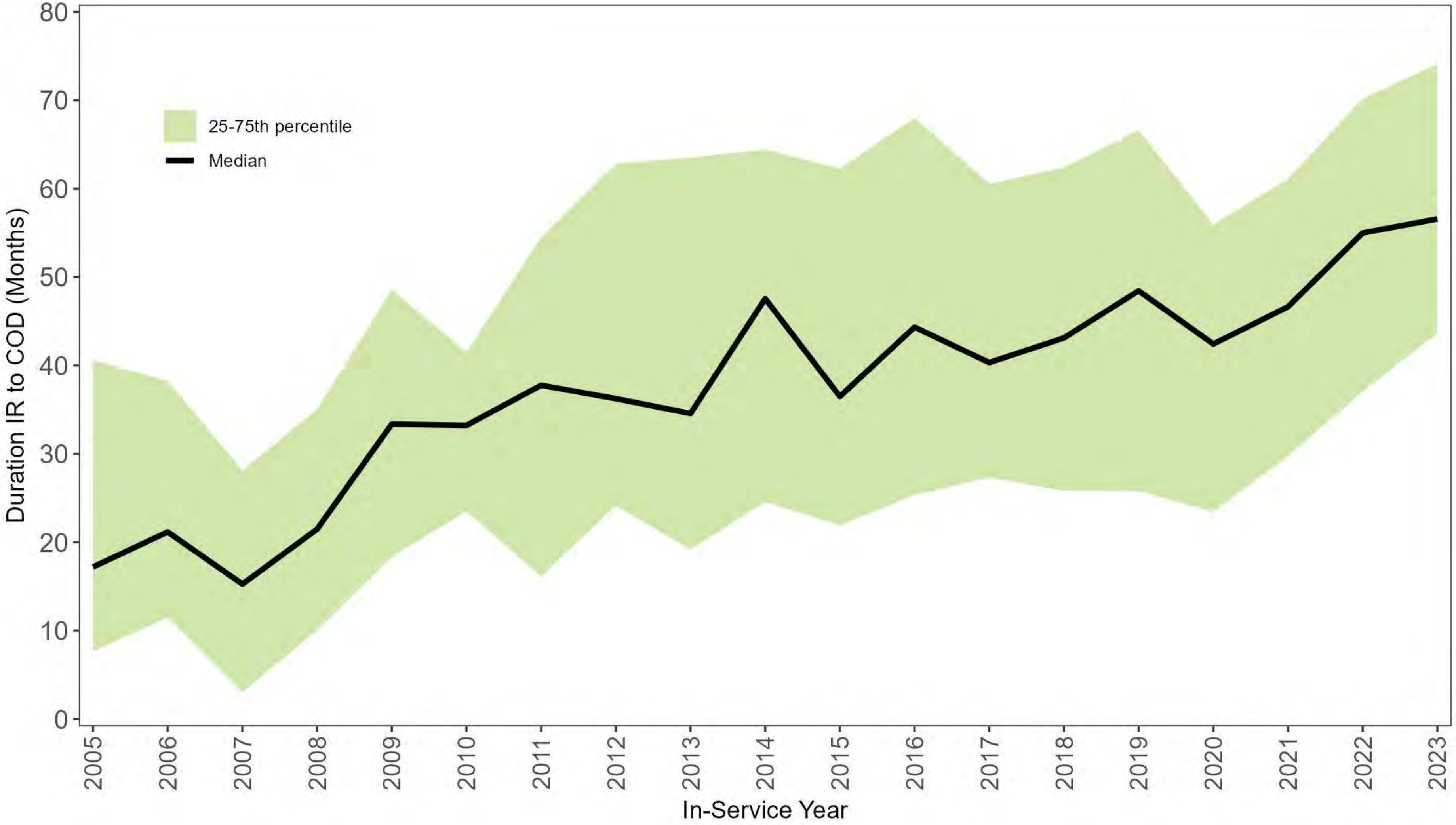
Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*



Notes: (1) Data were only available for 836 projects across 5 ISO/RTOs and one utility (Southern Company), out of 4,155 total "operational" projects in the full dataset. (2) Not all data used in this analysis are publicly available.

The median duration from interconnection request (IR) to commercial operations date (COD) continues to rise, approaching 5 years for projects completed in 2022-2023

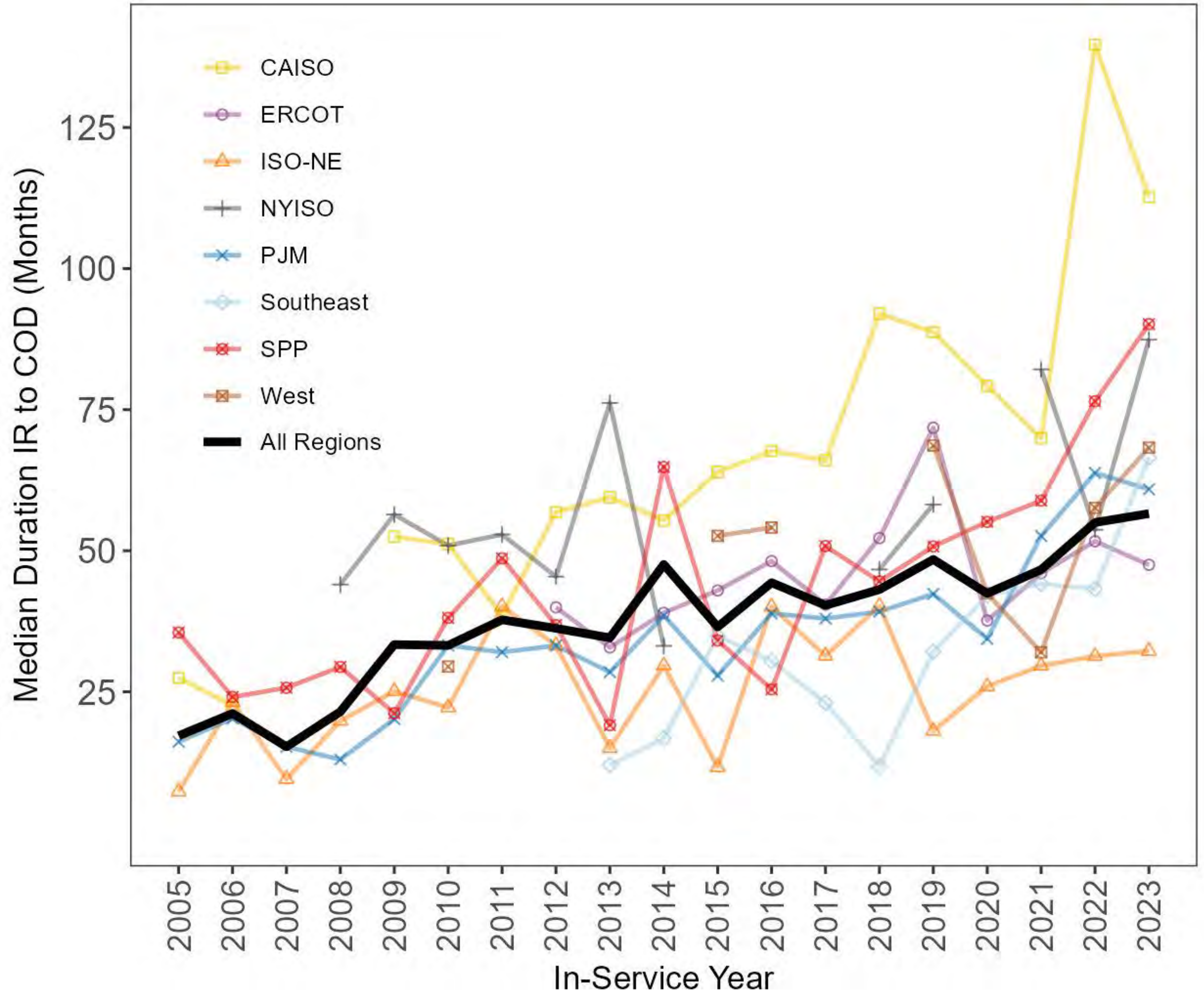
Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*

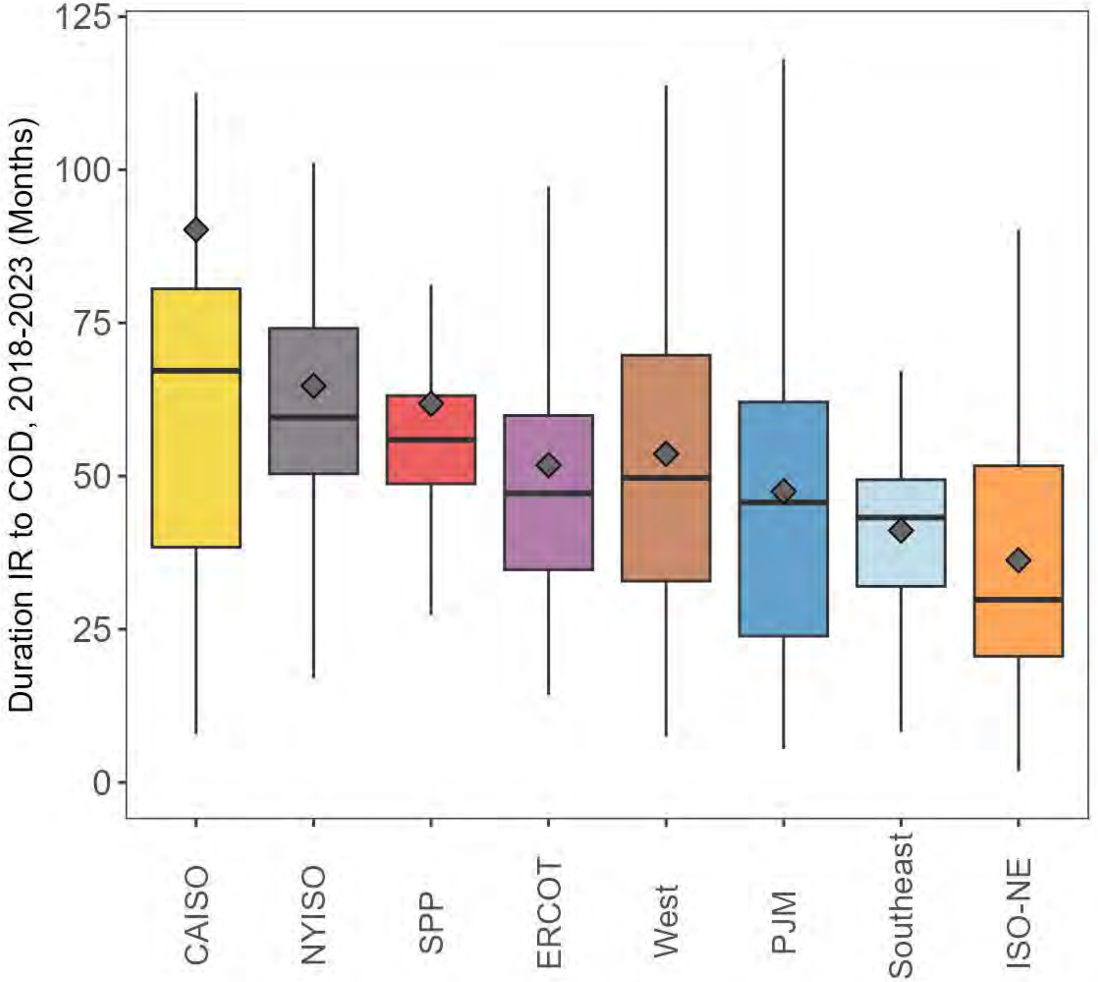


Notes: (1) In-service date was only available for 6 ISOs (CAISO, ERCOT, ISO-NE, NYISO, PJM, SPP) and 8 non-ISO BAs (Duke, FPL, LADWP, PSCo, SOCO, SEC, SRP, TSGT) representing 61% of all operational projects. (2) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

The request to operational timeline has been increasing in all regions; duration tends to be longest in CAISO, NYISO, and SPP and shortest in ISO-NE

Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*

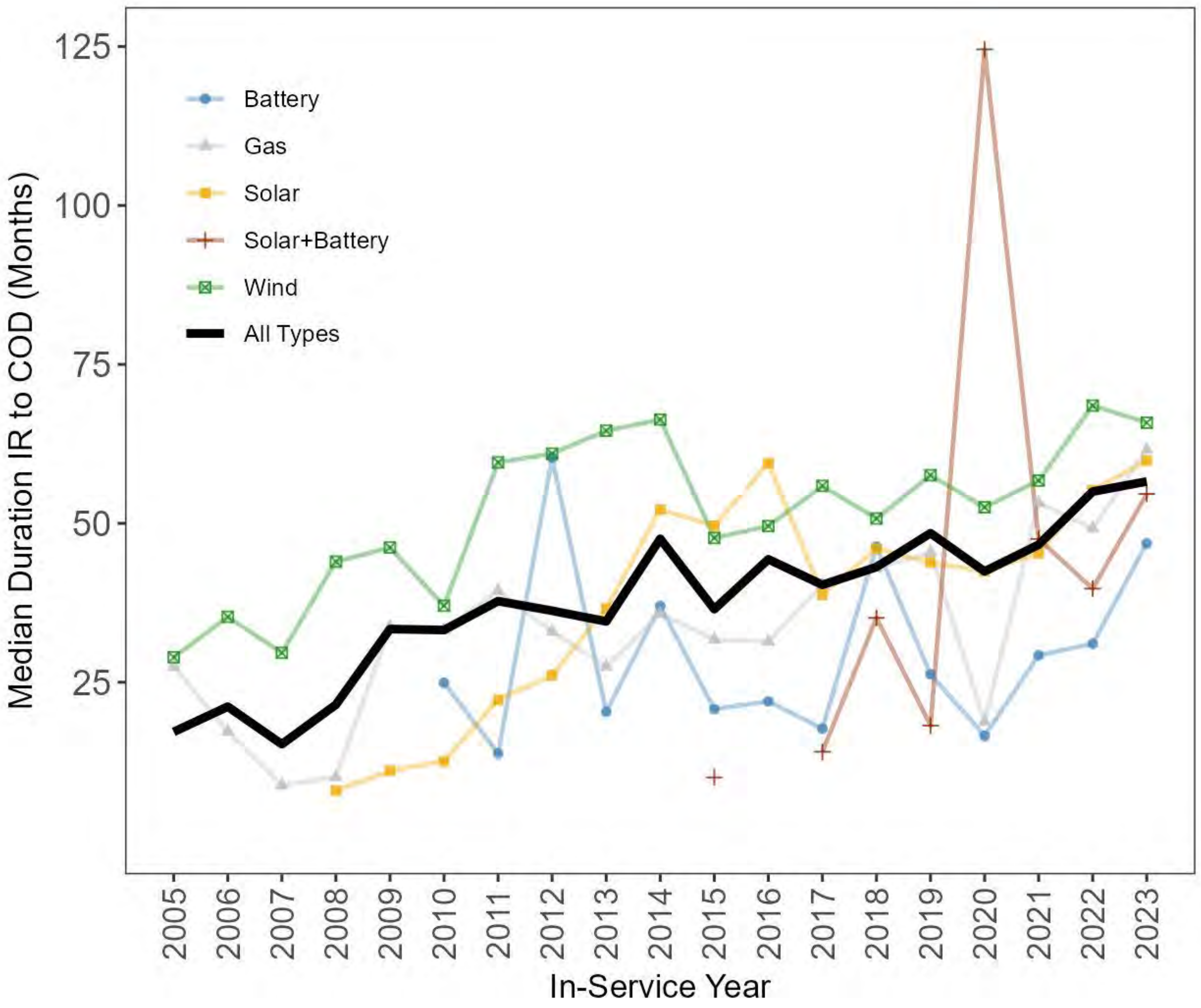


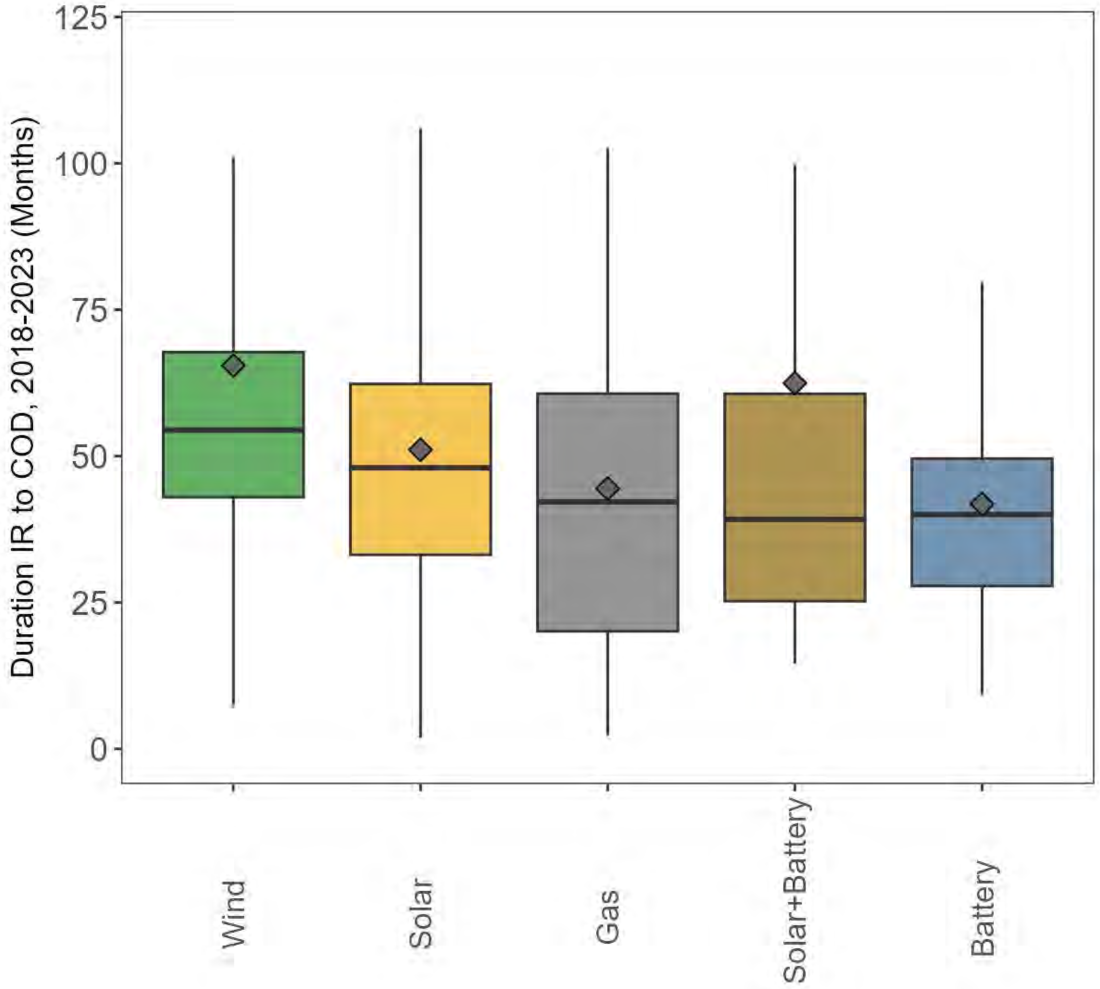


Notes: (1) In-service date was only available for 6 ISOs and 8 non-ISO BAs representing 61% of all operational projects; .(2) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

Wind projects typically take longer than other types to go from request date to commercial operations, with standalone battery projects moving fastest

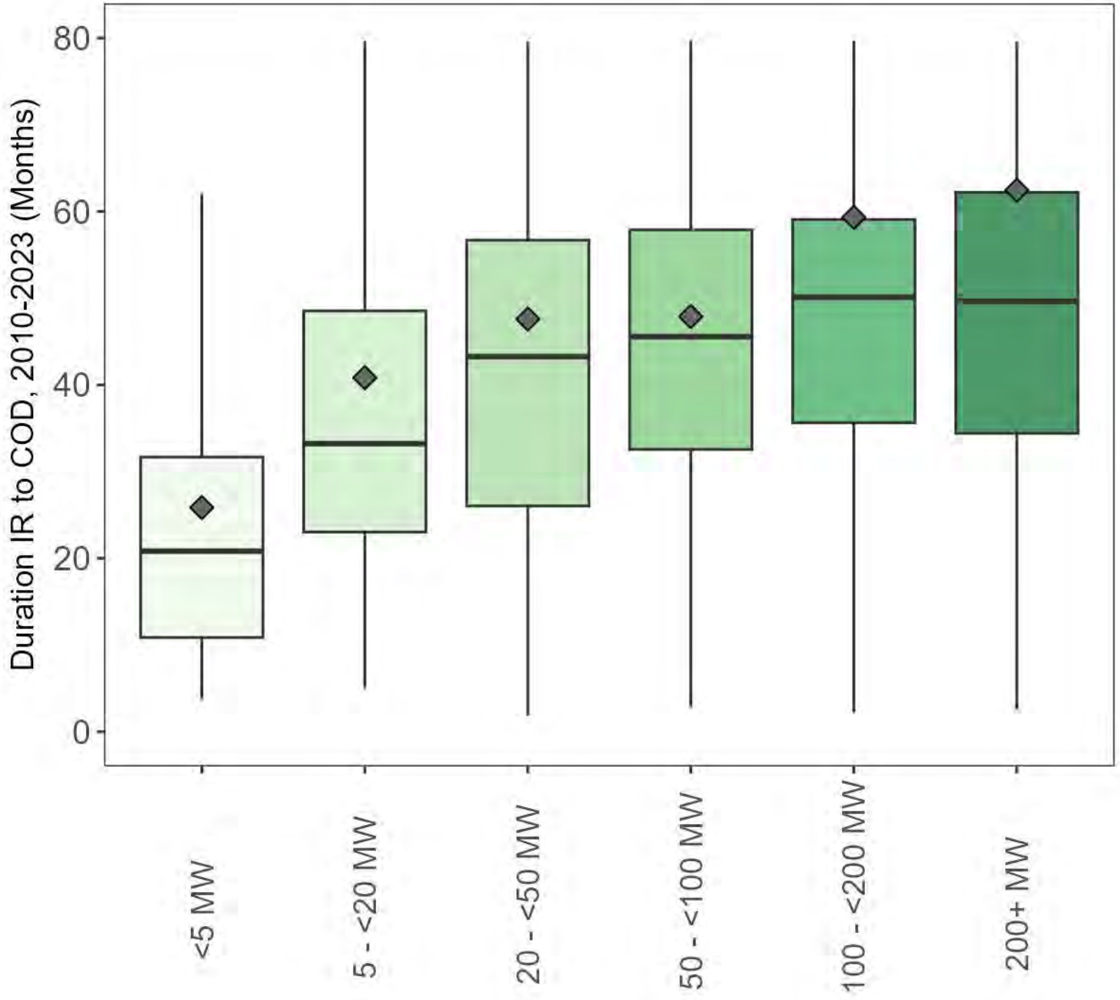
Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*





Notes: (1) In-service date was only available for 6 ISOs and 8 non-ISO BAs representing 61% of all operational projects; .(2) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

Larger projects have longer development timelines: The average IR to COD duration increases monotonically by project size (MW)



- □ For the smallest projects in our sample (<5 MW), the median project came online less than 2 years (20 months) after the interconnection request
- □ The median 5-20 MW project, meanwhile, takes nearly 3 years (33 months) from IR to COD
- □ Larger projects spend even more time in the interconnection and development process, with the median 100-200 MW project taking >4 years and the median 200+ MW project taking over 4.5 years (55 months) from IR to COD

Notes: (1) Box-plot includes projects reaching commercial operations from 2010-2023. (2) Includes data from 6 ISOs and 8 non-ISO BAs representing 61% of all operational projects (3) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

As of the end of 2023, there were nearly 12,000 projects actively seeking grid interconnection across the U.S., representing 1,570 GW of generation and approximately 1,030 GW of storage.

- Solar (1,086 GW), storage (1,028 GW), and wind (366 GW) account for ~95% of all active capacity seeking transmission connection.
  - Over half of solar and storage capacity in the queues are from hybrid projects; Roughly 1/3 of wind capacity is for offshore projects
  - Over 1,200 GW of generation and storage projects submitted interconnection requests *after* the passage of the IRA.
- The combined capacity of just solar and wind now active in the queues (>1,400 GW) exceeds the total installed U.S. power plant fleet capacity, and is greater than the estimated 1,100 GW needed to approach a zero-carbon electricity target[2].
- Capacity in queues is widespread across U.S. but some states dominate: Texas has 13% of solar, 14% of gas, 12% of storage, and 7% of wind; New York has 19% of wind (mostly offshore); California has 27% of storage, 12% of solar, and 8% of wind.
- Hybrids now comprise a large – and increasing – share of proposed projects, particularly in CAISO and the West. 571 GW of solar hybrids (primarily solar+battery) and 49 GW of wind hybrids are in the queues.
- Roughly half (1,271 GW) of the active capacity in the queues is proposed to come online before 2026, and 12% (311 GW) already has an executed interconnection agreement (IA).
- The time projects spend in queues before reaching COD is increasing. For the regions with available data[3], the median duration from IR to COD has doubled from <2 years for projects built in 2000-2007 to over 4 years for those built in 2018-2023.
  - The full interconnection process timeline (from IR to IA) has also increased, though moderated somewhat in 2023
  - Larger projects have longer development timelines; interconnection study duration increases notably for projects >20 MW.
- Ultimately, much of this proposed capacity will not be built. Historically only ~19% of projects (and only 14% of capacity) requesting interconnection from 2000-2018 have reached commercial operations. As well, late-stage withdrawals may be on the rise.
- FERC Order 2023 is an important step toward addressing interconnection backlogs and bottlenecks. Additional operational and technical solutions like those outlined in i2X can further improve efficiency, reliability, and help meet decarbonization goals

Notes: (1) Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data. (2) See https://gridlab.org/2035-report/ (3) Data for this analysis were available for six ISO/RTOs and eight non-ISO balancing areas.

DOE’s Transmission Interconnection Roadmap identifies 35 solutions to mitigate queue backlogs, focus on four interconnection goals

Goal #1: Increase Data Access and Transparency

- Highlight improvements that ***go beyond*** FERC Order 845 and 2023 to improve decision making
- Facilitate screening, optimal siting, and ***automation***
- Enhance equitable outcomes by ***enabling benchmarking, tracking, and auditing*** of processes and reform performance

Goal #2: Improve Process and Timeline

- Backlogs and delays result of ***rapid growth in requests*** and ineffective management
- Balance tradeoff between ***quantity of projects and maintaining competition***
- Provide ***interconnection opportunities*** for all

Key focus areas
- Queue Management
- Affected System Studies
- Inclusive and fair process
- Workforce Development

Goal #3: Promote Economic Efficiency

- Acknowledge that ***interconnection and transmission planning*** are closely related
- Focus on both ***allocative efficiency*** (‘who pays’) and ***productive efficiency*** (‘minimizing costs’)

Key focus areas
- Cost Allocation
- Planning Coordination
- Interconnection Studies

Goal #4: Maintain a Reliable, Resilient, and Secure Grid

- In recent years, there has been ***a series of disturbance events*** leading to IBR disconnection
- Foundation to manage ***high penetration rates of IBRs*** and minimize disturbances

Key focus areas
- Interconnection Models and Tools
- Interconnection Standards

Final Roadmap coming soon. Full report provides detail of key solutions as well as identifying key target metrics that can be used to monitor the status of ongoing interconnection process reform. See https://www.energy.gov/eere/i2x for more information.

BERKELEY LAB

ENERGY MARKETS & POLICY

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Joseph Rand (jrand@lbl.gov)

More Information:

- Visit https://emp.lbl.gov/queues to download the data used for this analysis and access an interactive data visualization tool
- Visit https://emp.lbl.gov/interconnection_costs for related research on interconnection costs

Acknowledgements:

This work was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, in particular the Solar Energy Technologies Office and the Wind Energy Technologies, in part via the Interconnection Innovation eXchange (i2X). We thank Michele Boyd, Ammar Qusaibaty, Dexter Hendricks, Cynthia Bothwell, Jian Fu, Patrick Gilman, Gage Reber, and Paul Spitsen for supporting this project.

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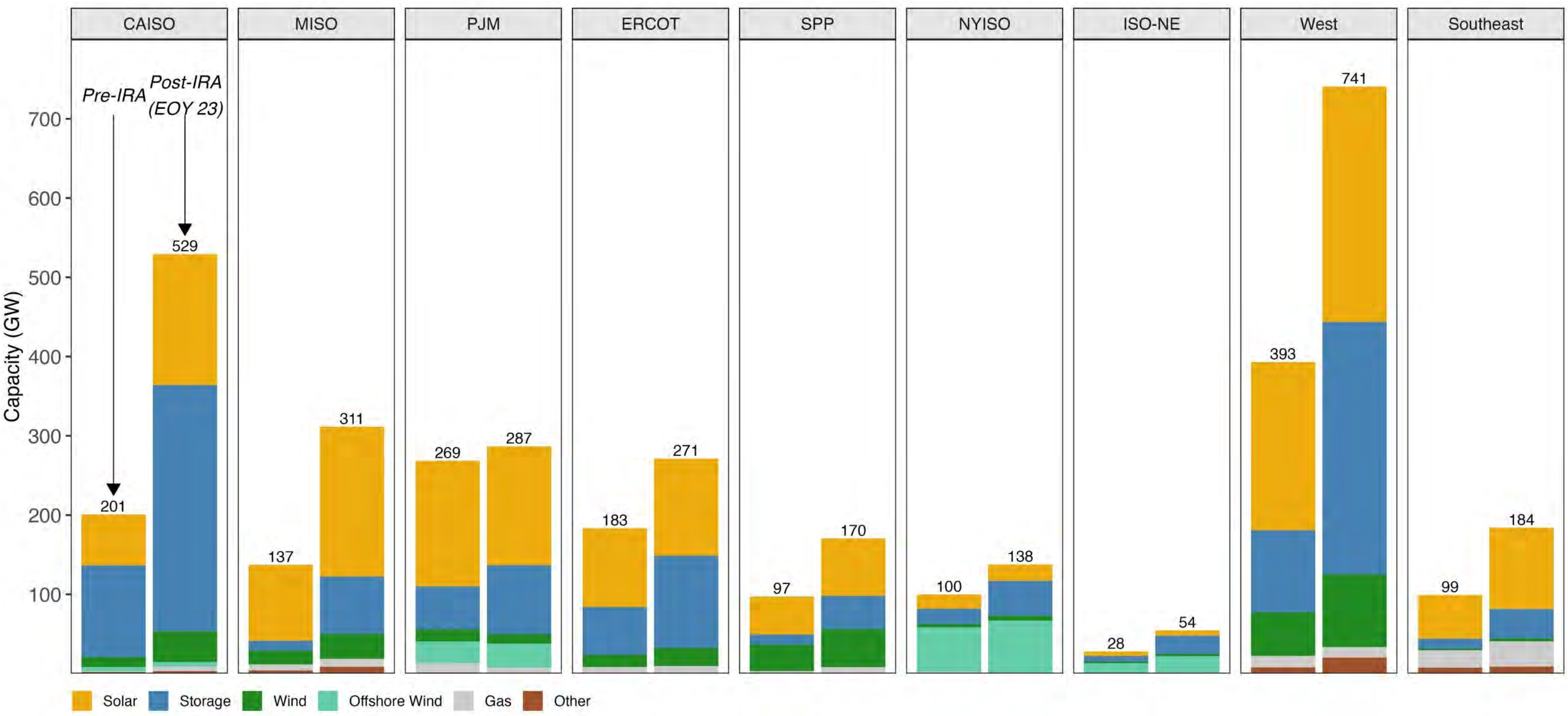
Appendix

Balancing Areas Included In Data:

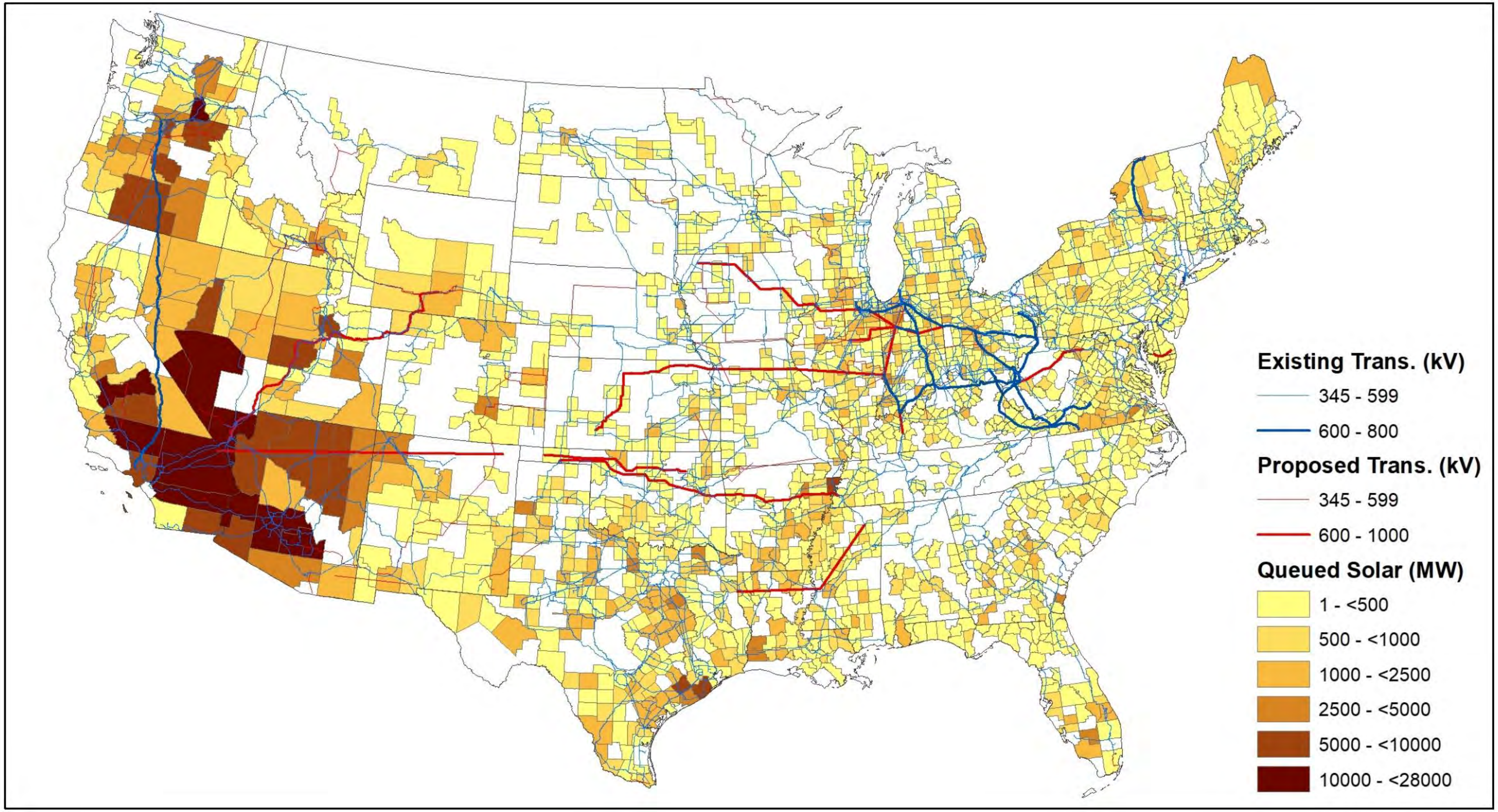
ISO/RTOs	Southeast (non-ISO)	
CAISO	Associated Electric Coop.	Georgia Transmission Corp.
ERCOT	Dominion	Jacksonville Electric Authority
ISO-NE	Duke Carolinas	LG&E & KU Energy
MISO	Duke Florida	Santee Cooper
NYISO	Duke Progress	Seminole Electric Coop.
PJM	Duke/Progress	Southern Company
SPP	Florida Municipal Power Pool	Tampa Electric Co.
	Florida Power & Light	Tennessee Valley Authority

West (non-ISO)		
Arizona Public Service	Imperial Irrigation District	Public Service Co. of CO
Avista	L.A. Dept. Water & Power	Public Service Co. of NM
Black Hills Colorado	Navajo-Crystal	Puget Sound Energy
Bonneville Power Admin.	NorthWestern	Salt River Projects (4 entities)
Cheyenne Light Fuel & Power	NV Energy	Tri-State G&T
El Paso Electric	PacifiCorp	Tucson Electric Power
Grant PUD	Platte River Power Authority	WAPA (4 regions)
Idaho Power	Portland General Electric	

Clean energy has ballooned in many regions' queues after the passage of the Inflation Reduction Act (IRA), which likely spurred additional development interest

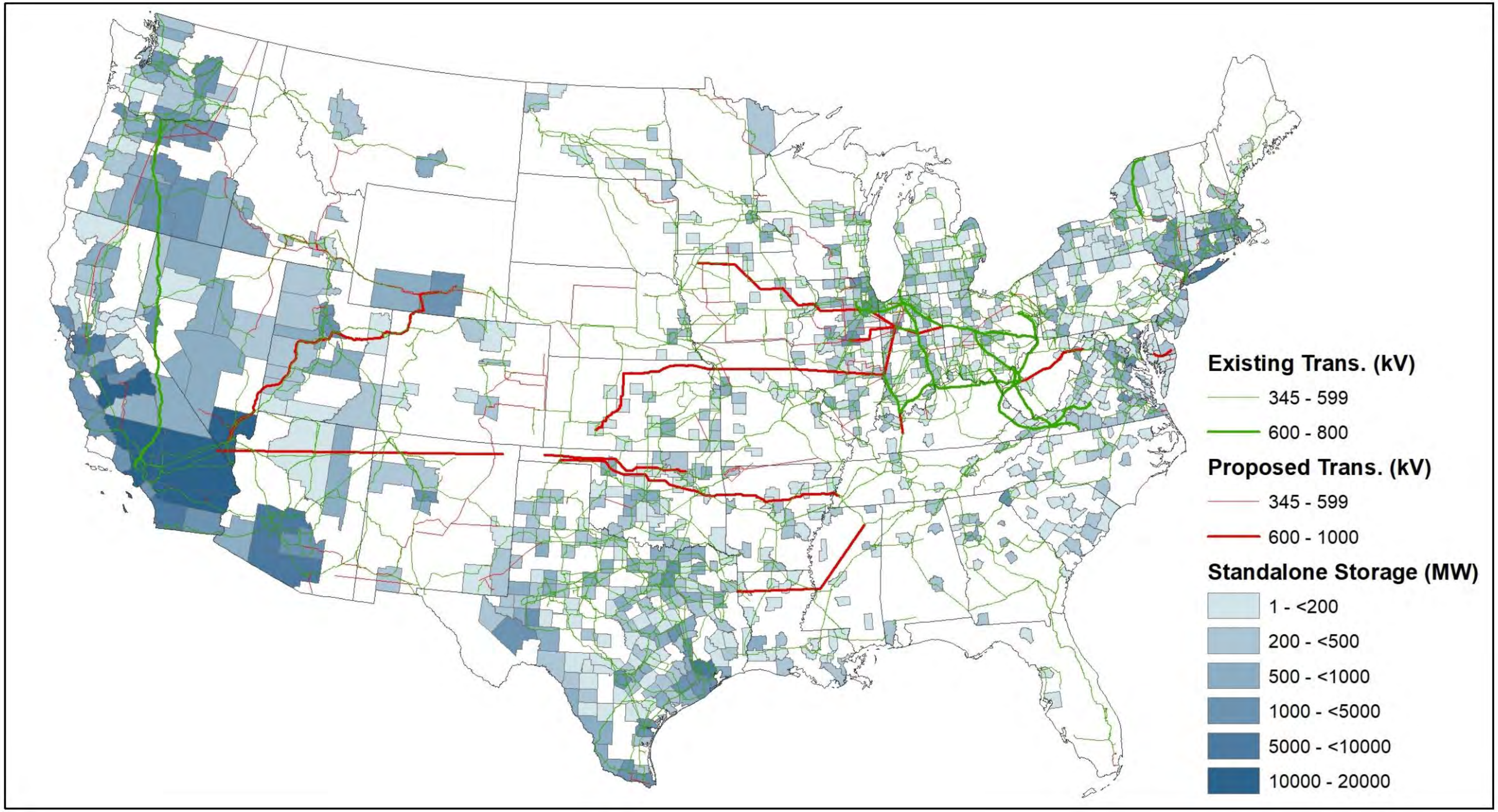


Active solar capacity in queues: by county



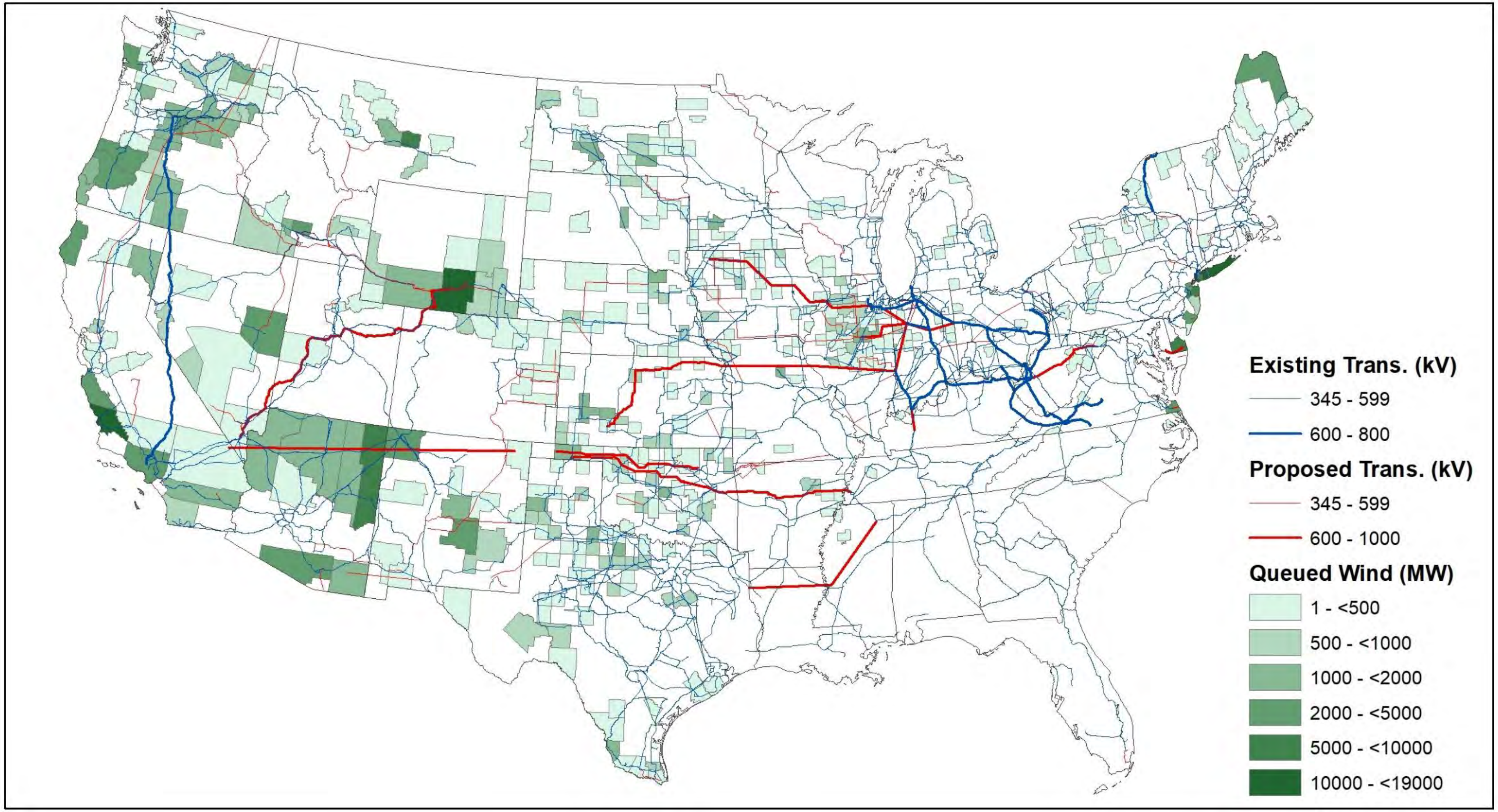
Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 2.7% of active solar requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

Active standalone[1] storage capacity in queues: by county



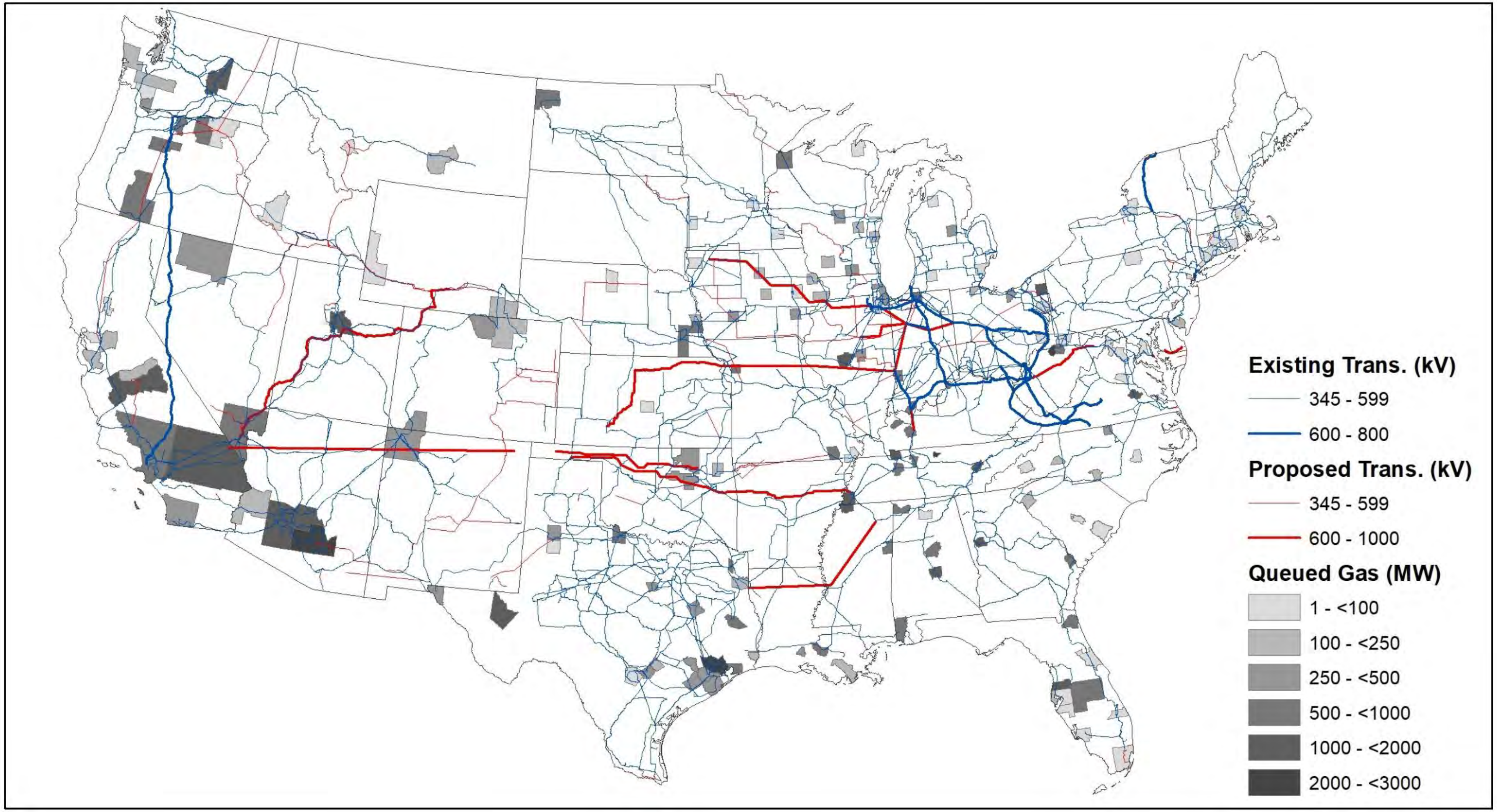
Notes: (1) Excludes hybrid storage capacity, which could not be estimated at the county-level. (2) Includes "active" interconnection requests only. (3) County was missing or could not be determined for 2% of active standalone storage requests. (4) Transmission line data from Hitachi Velocity Suite. (5) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

Active wind capacity in queues: by county



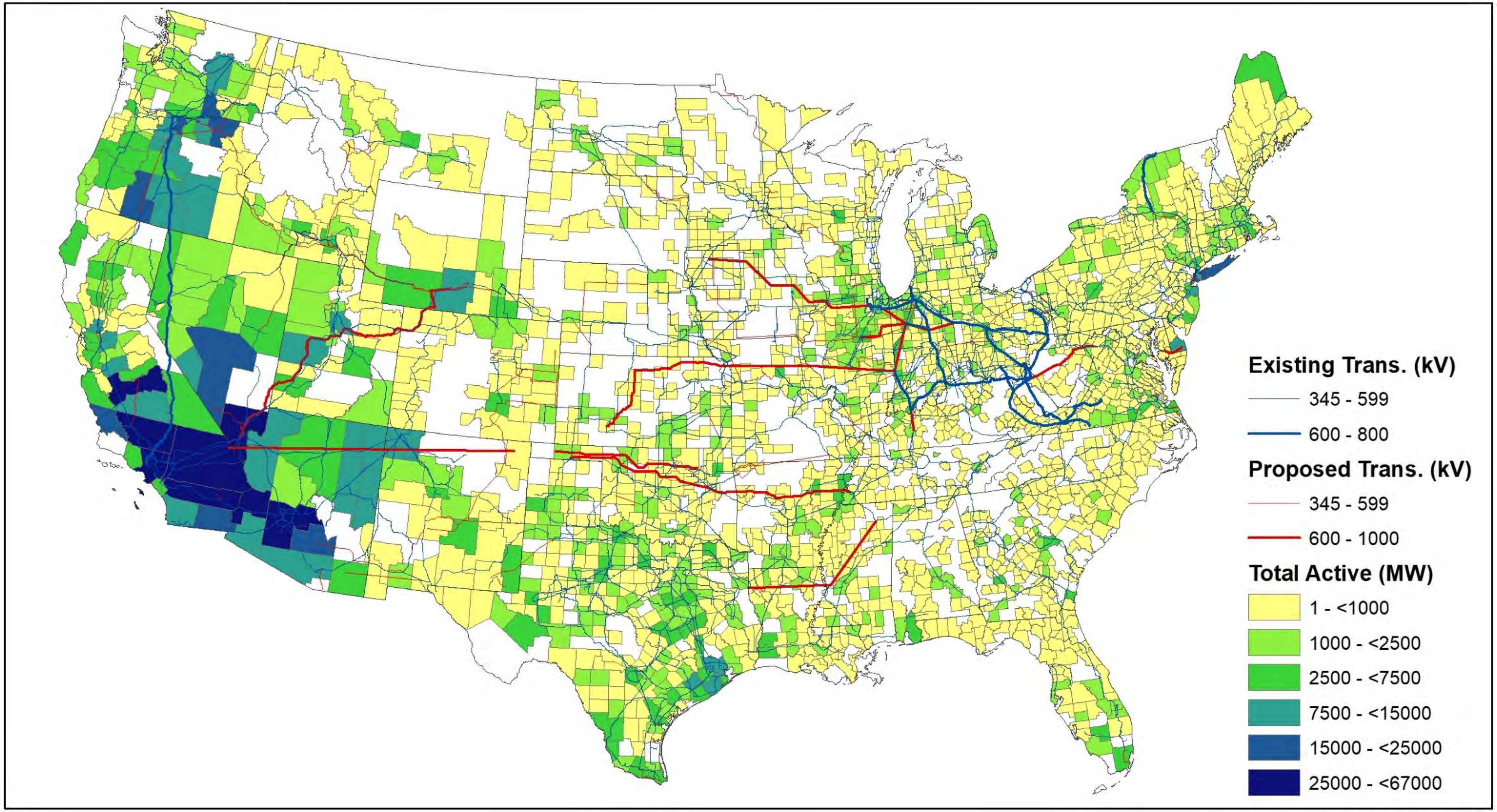
Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 2.8% of land-based wind requests, and 16.1% of offshore wind requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

Active gas capacity in queues: by county



Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 7.3% of active gas requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

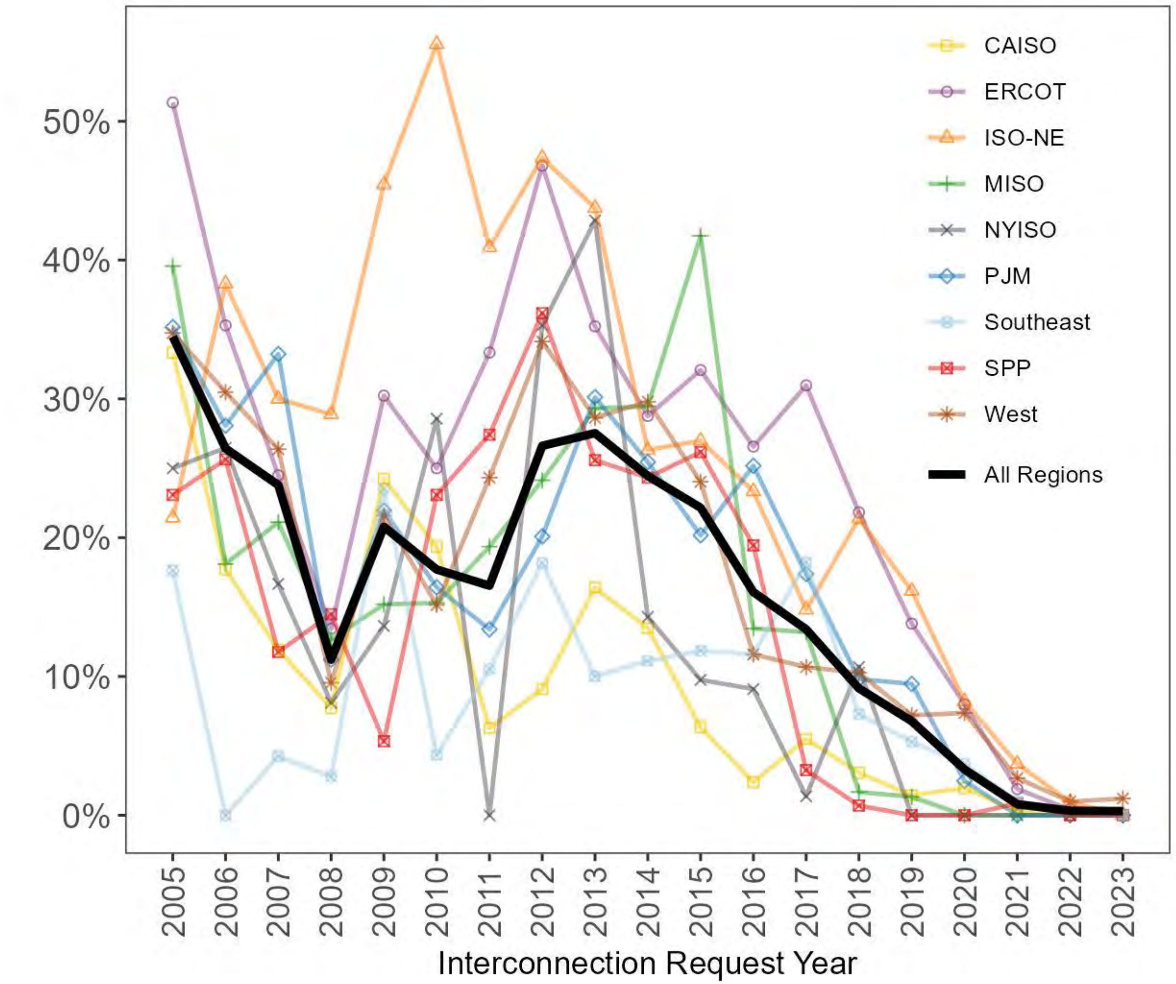
Total active capacity in queues: by county



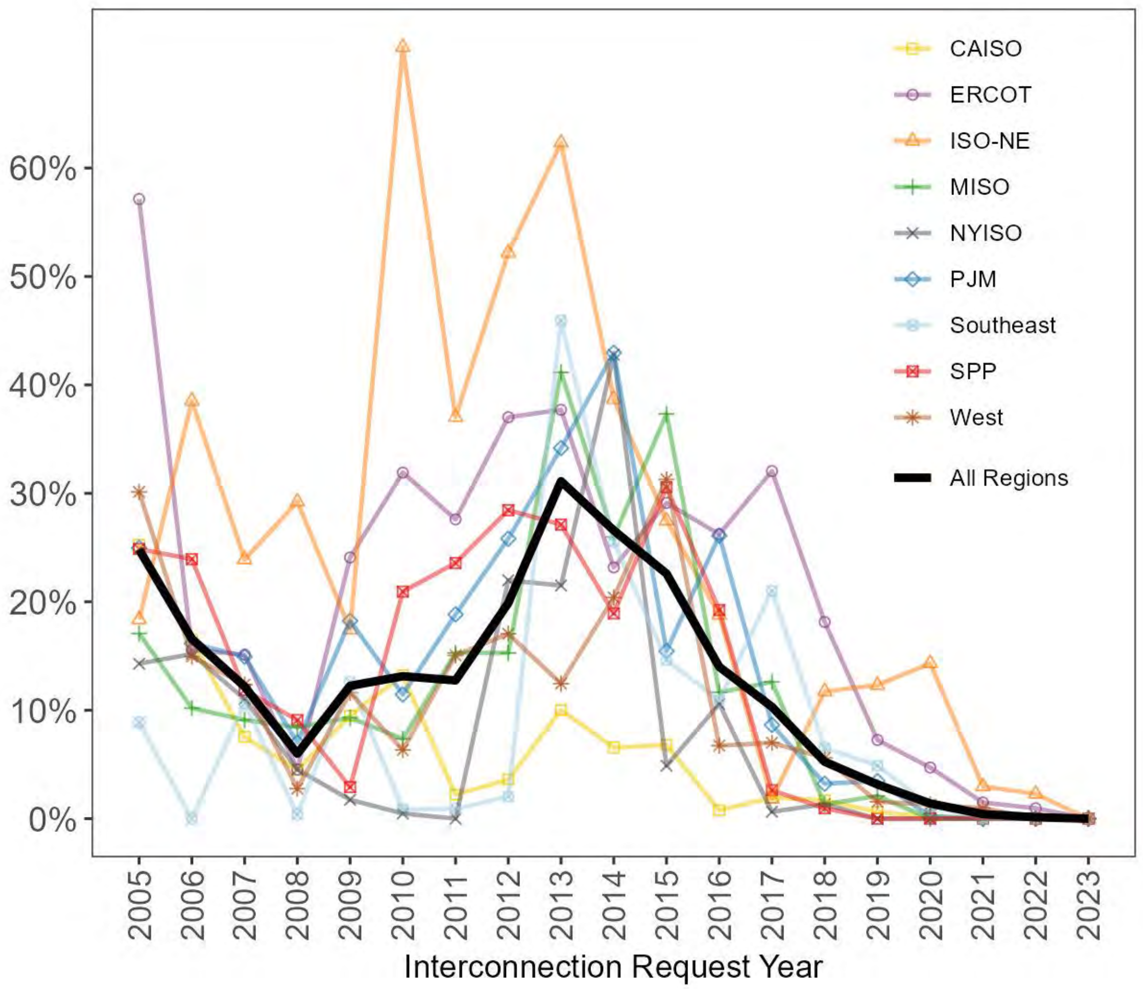
Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 6% of all active requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

ISO-NE and ERCOT have consistently had higher completion rates than other regions; CAISO has been consistently lower

By Number of Requests



By Capacity of Requests



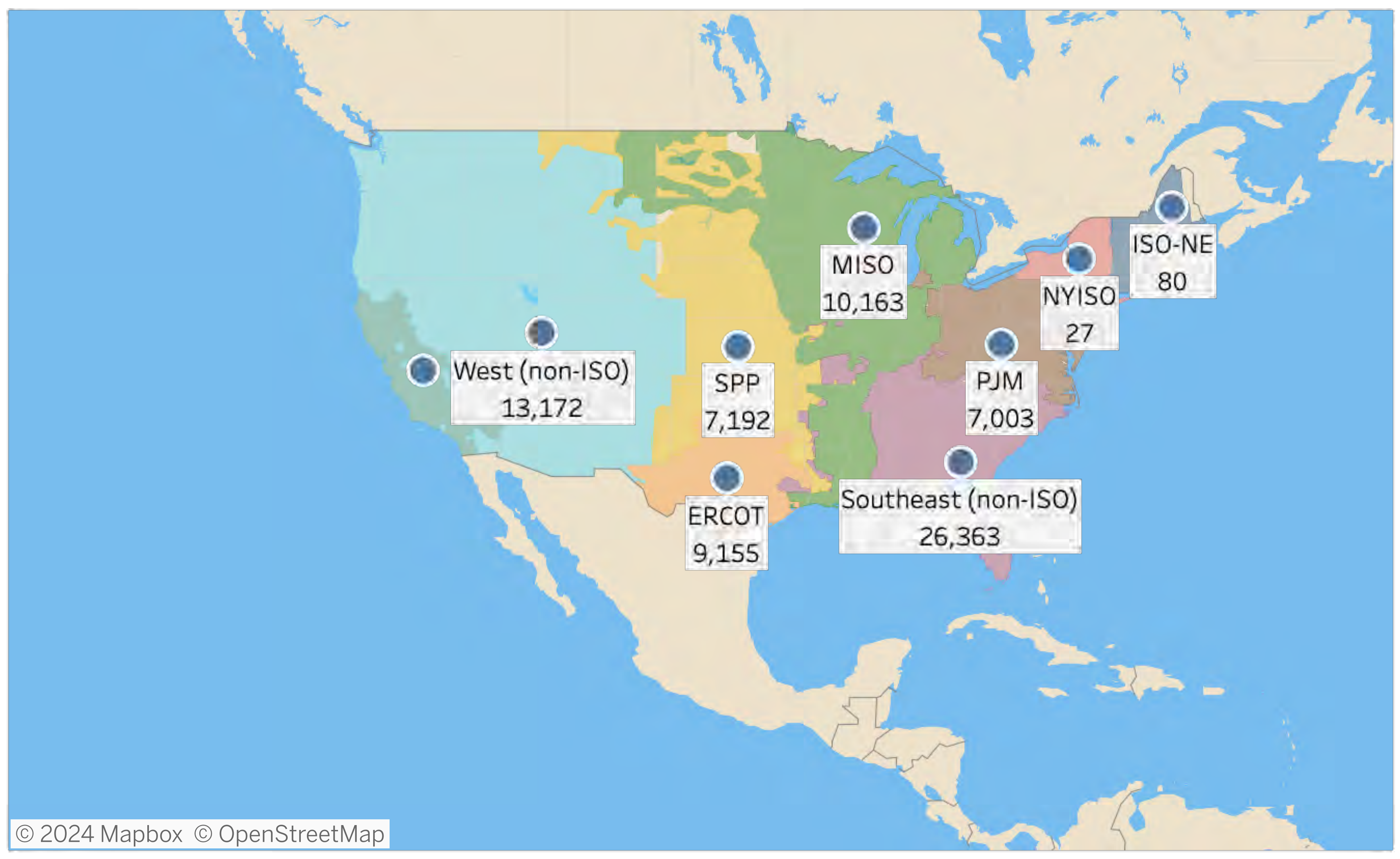
Note: (1) Completion rate shown here is calculated by number of projects online by end of 2023, not capacity-weighted. (2) Calculated as number of projects operational as of EOY 2023 divided by the total number of requests per year. (3) Includes data from 7 ISOs and 30 non-ISO BAs.

Maps of Projects by Region, State, and County

US Interconnection Queues by Region, State, and County

Regional | State | County

MW in Regional Queues: **Cumulative / Gas**



Select the Resources
○ (All)
● Gas
○ Offshore Wind
○ Onshore Wind
○ Other
○ Solar
○ Storage

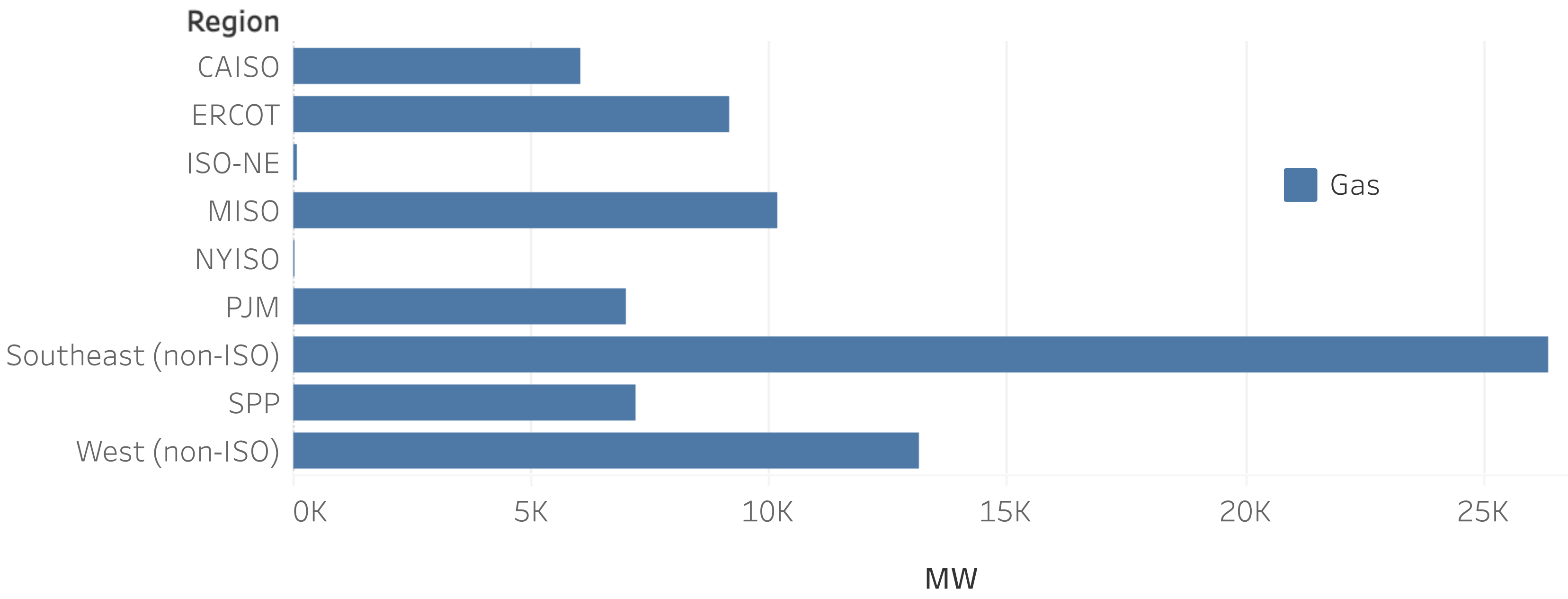
Select the Status
○ Added in 2023
● Cumulative

Total MW in this data set
79,213

Region-level data notes:

- This data set is thought to be the most complete, at 2.6 TW.
- Includes capacity in standalone and hybrid configurations.
- Hybrid storage capacity is estimated for some projects - therefore total "Storage" capacity is approximate.
- Reforms in CAISO and PJM paused or slowed new interconnection requests in 2022. MISO paused in 2023.

Regional queues by resource -- **Cumulative / Gas**



For more research on interconnection queues visit emp.lbl.gov/queues.

Map of ISO and non-ISO regions courtesy of Hitachi Energy Velocity Suite.

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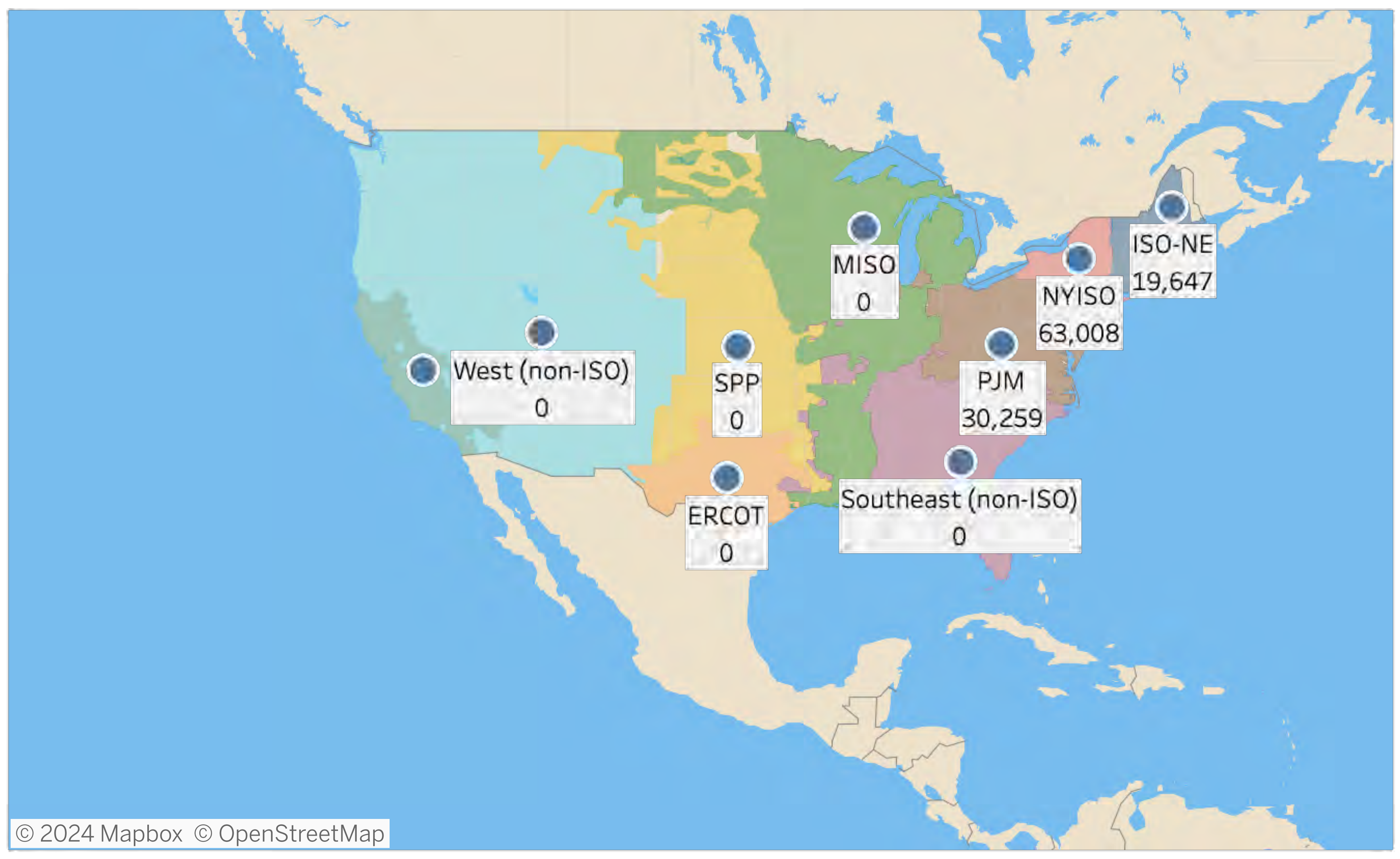
Maps of Projects by Region, State, and County

US Interconnection Queues by Region, State, and County

Regional | State | County

MW in Regional Queues: **Cumulative / Offshore Wind**



Select the Resources
○ (All)
○ Gas
● Offshore Wind
○ Onshore Wind
○ Other
○ Solar
○ Storage

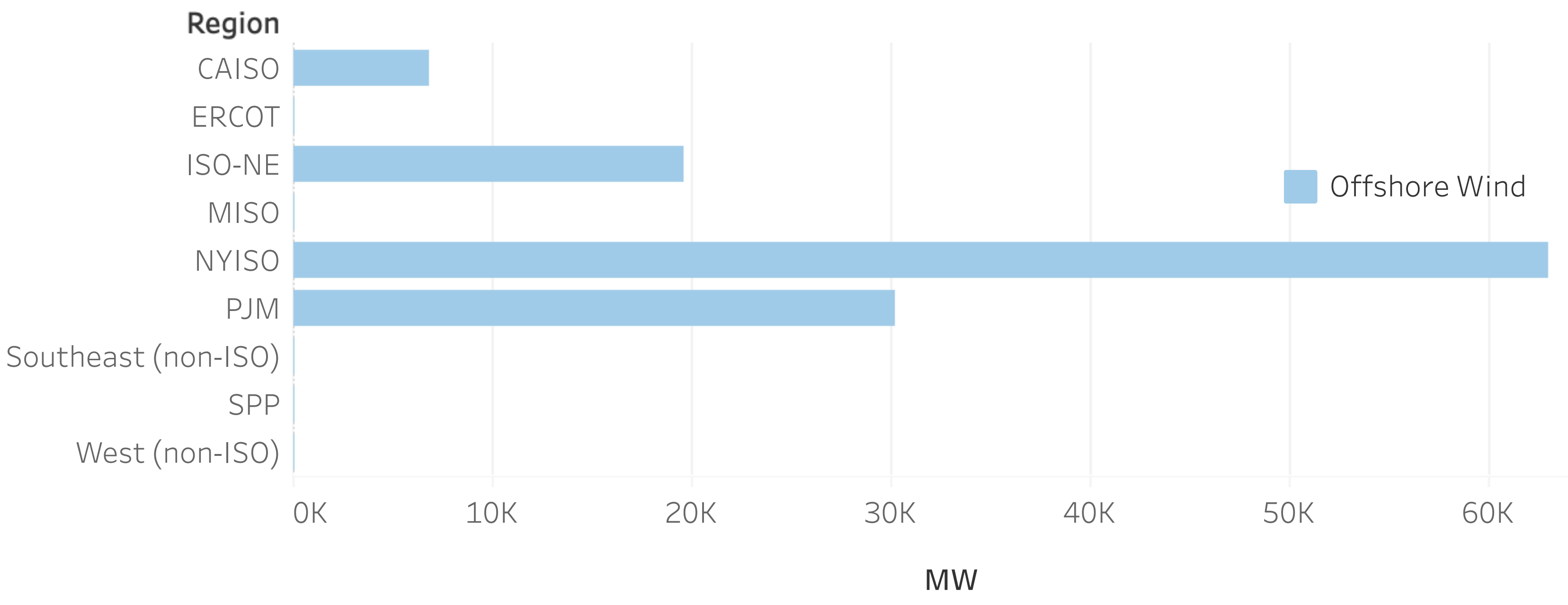
Select the Status
○ Added in 2023
● Cumulative

Total MW in this data set
119,801

Region-level data notes:

- This data set is thought to be the most complete, at 2.6 TW.
- Includes capacity in standalone and hybrid configurations.
- Hybrid storage capacity is estimated for some projects - therefore total "Storage" capacity is approximate.
- Reforms in CAISO and PJM paused or slowed new interconnection requests in 2022. MISO paused in 2023.

Regional queues by resource -- **Cumulative / Offshore Wind**



For more research on interconnection queues visit emp.lbl.gov/queues.

Map of ISO and non-ISO regions courtesy of Hitachi Energy Velocity Suite.

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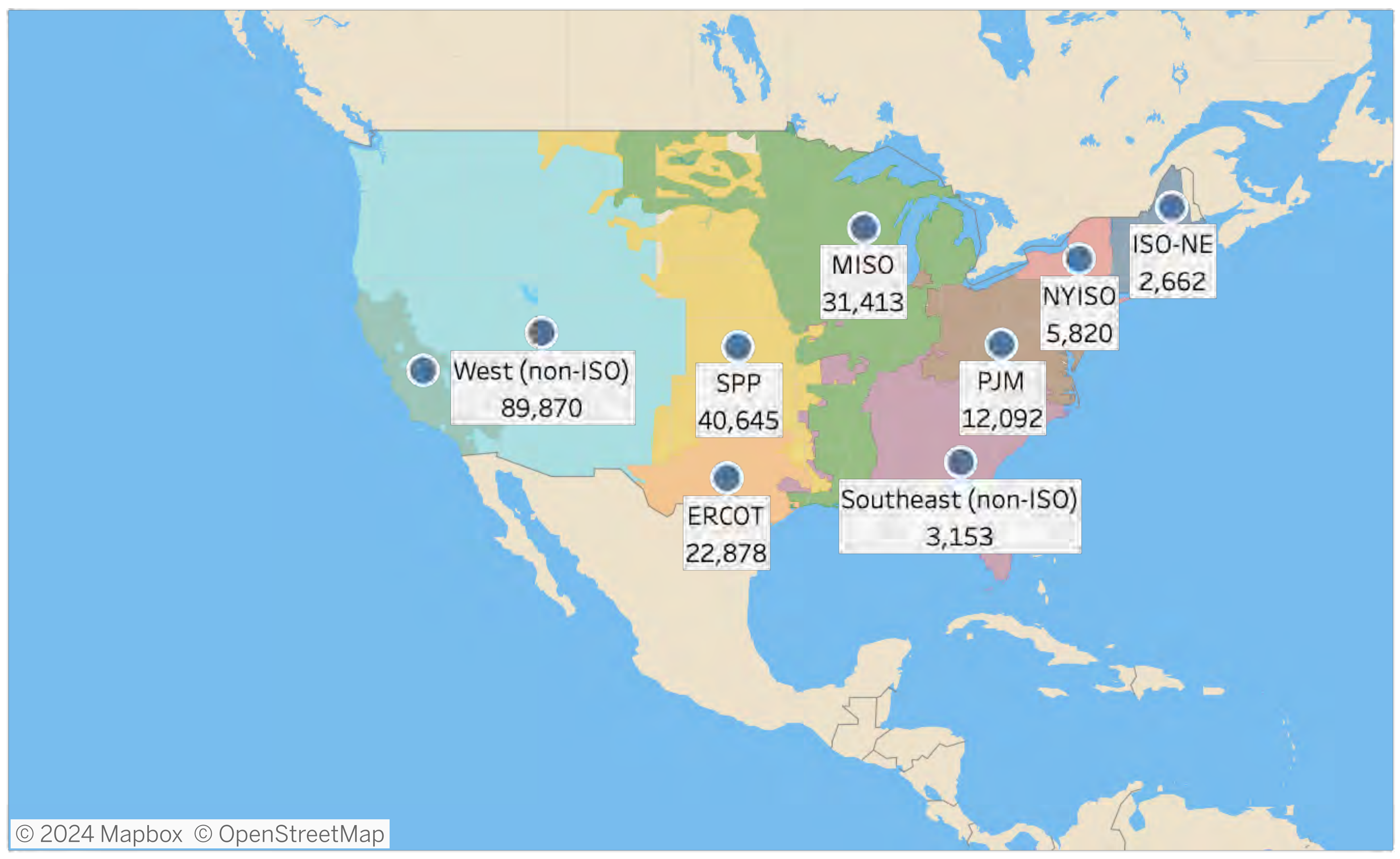
Maps of Projects by Region, State, and County

US Interconnection Queues by Region, State, and County

Regional | State | County

MW in Regional Queues: **Cumulative / Onshore Wind**



Select the Resources
○ (All)
○ Gas
○ Offshore Wind
● Onshore Wind
○ Other
○ Solar
○ Storage

Select the Status
○ Added in 2023
● Cumulative

Total MW in this data set
246,150

Region-level data notes:

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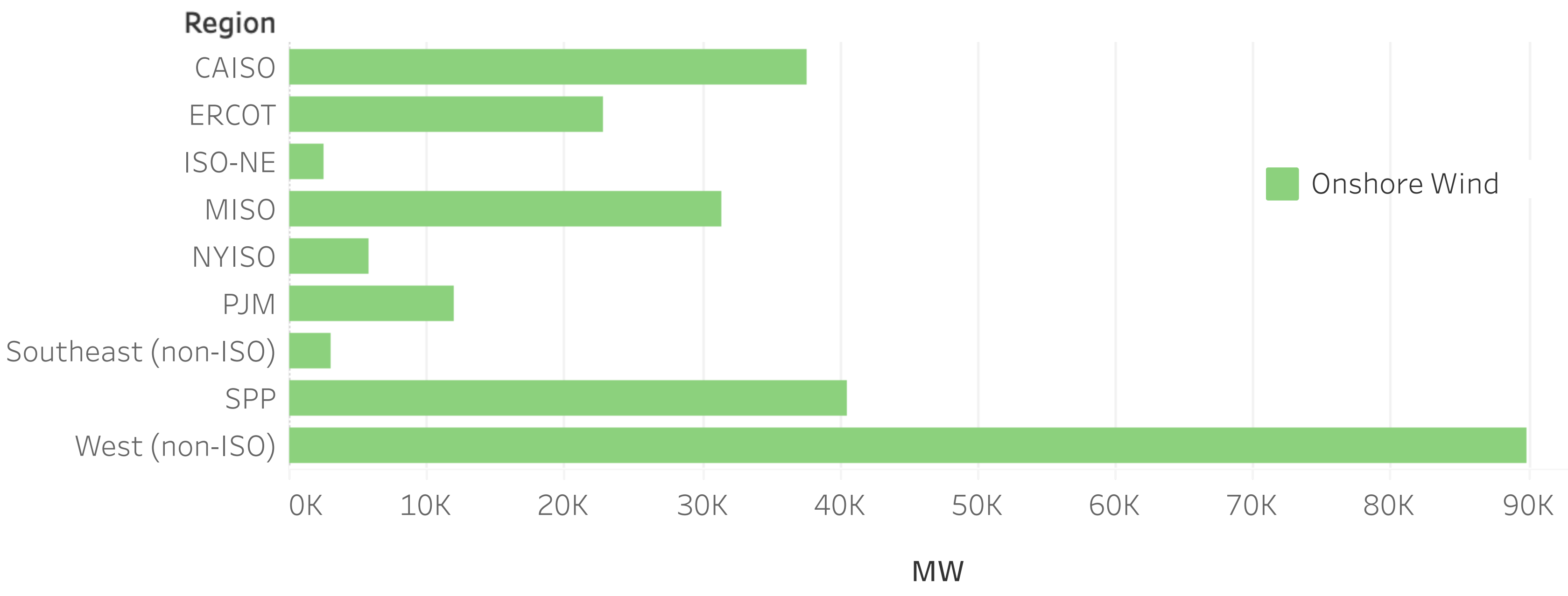
- Includes capacity in standalone and hybrid configurations.

- Hybrid storage capacity is estimated for some projects - therefore total "Storage" capacity is approximate.

- Reforms in CAISO and PJM paused or slowed new interconnection requests in 2022. MISO paused in 2023.

Regional queues by resource -- **Cumulative / Onshore Wind**



For more research on interconnection queues visit emp.lbl.gov/queues.

Map of ISO and non-ISO regions courtesy of Hitachi Energy Velocity Suite.

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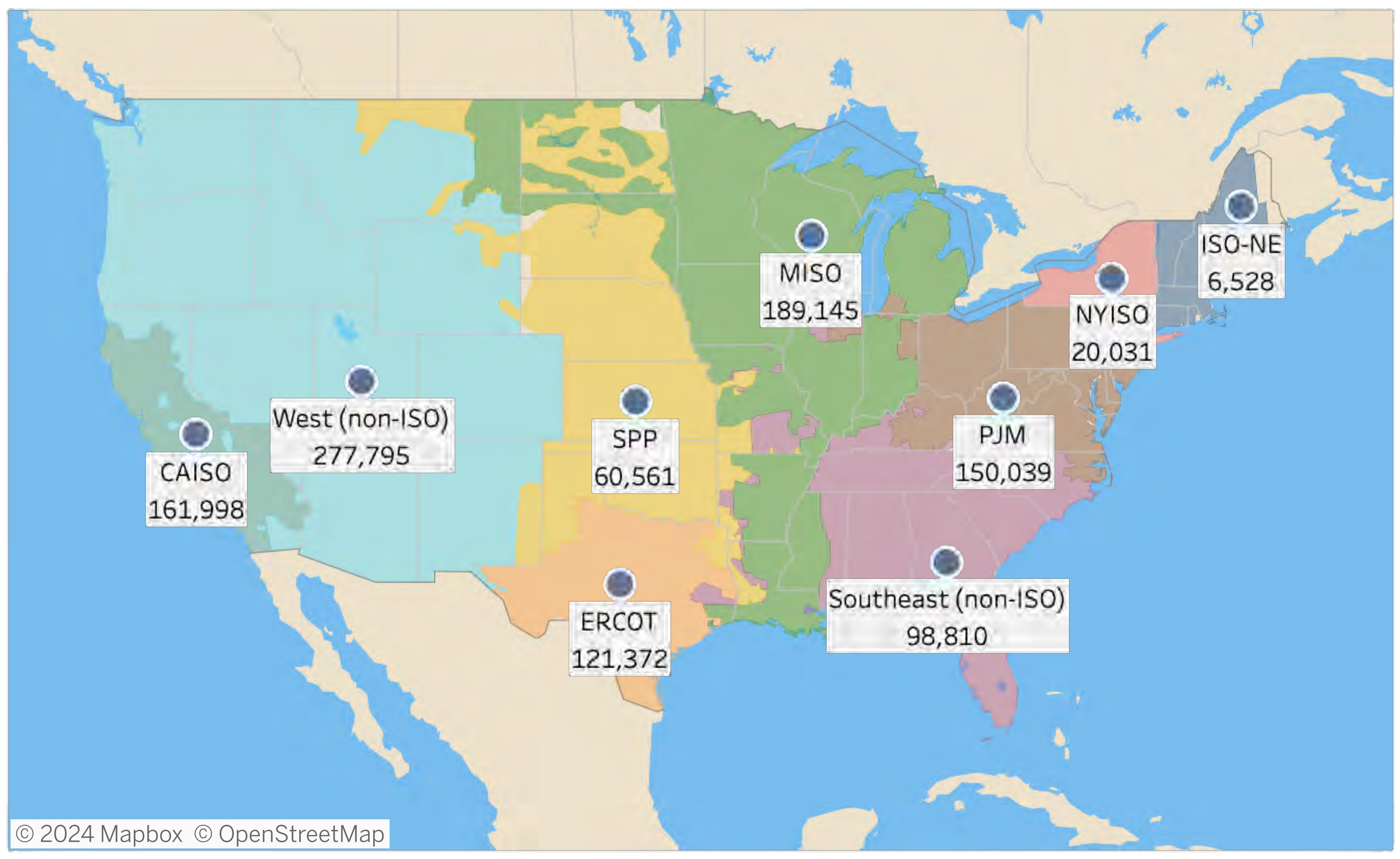
Maps of Projects by Region, State, and County

US Interconnection Queues by Region, State, and County

Regional | State | County

MW in Regional Queues: **Cumulative / Solar**



Select the Resources
○ (All)
○ Gas
○ Offshore Wind
○ Onshore Wind
○ Other
● Solar
○ Storage

Select the Status
○ Added in 2023
● Cumulative

Total MW in this data set
1,086,279

Region-level data notes:

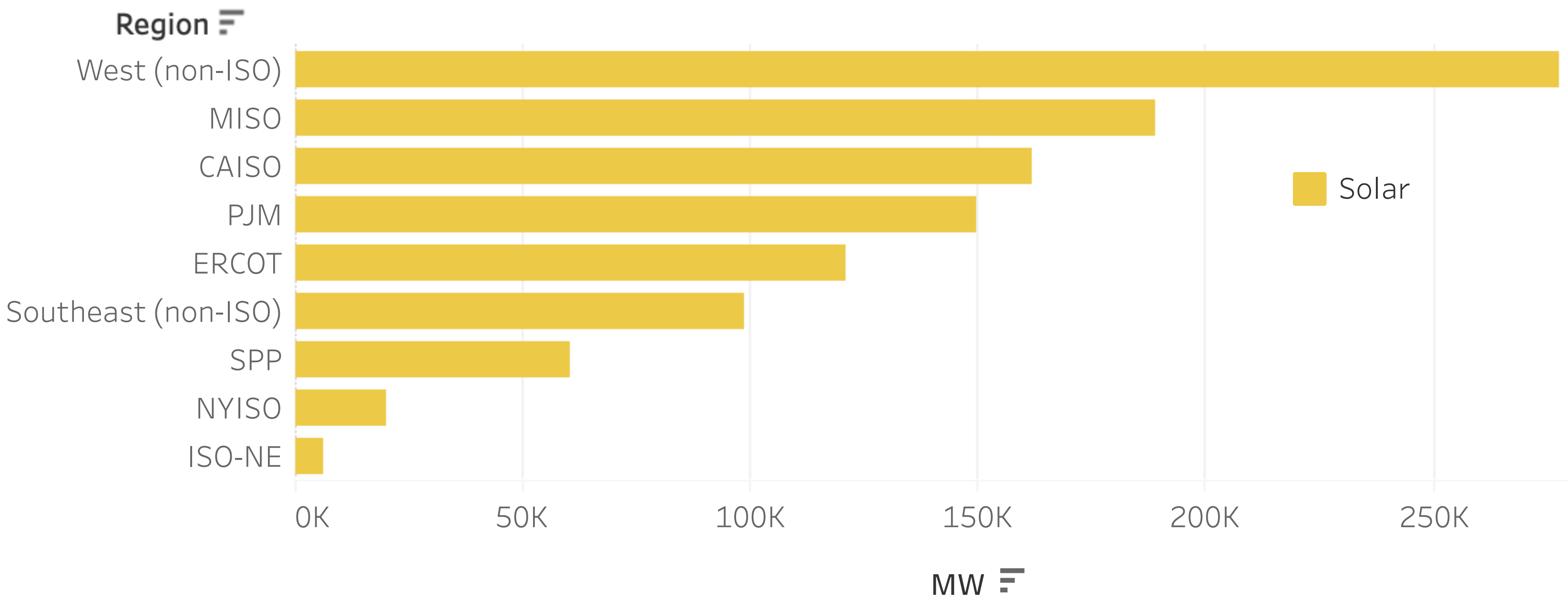
• This data set is thought to be the most complete, at 2.6 TW.

• Includes capacity in standalone and hybrid configurations.

• Hybrid storage capacity is estimated for some projects - therefore total "Storage" capacity is approximate.

• Reforms in CAISO and PJM paused or slowed new interconnection requests in 2022. MISO paused in 2023.

Regional queues by resource -- **Cumulative / Solar**



For more research on interconnection queues visit emp.lbl.gov/queues.

Map of ISO and non-ISO regions courtesy of Hitachi Energy Velocity Suite.

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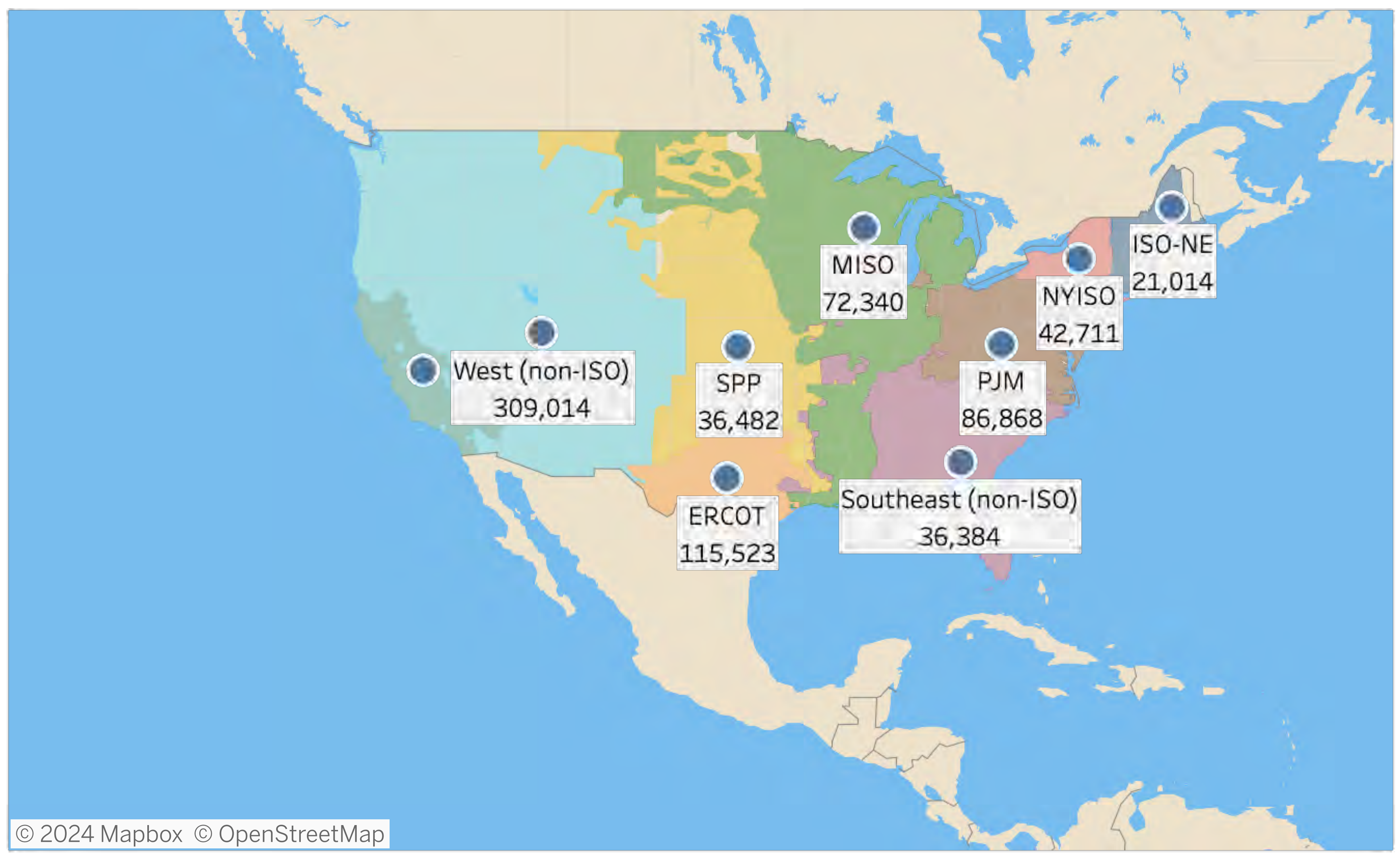
Maps of Projects by Region, State, and County

US Interconnection Queues by Region, State, and County

Regional | State | County

MW in Regional Queues: **Cumulative / Storage**



Select the Resources

○ (All)
○ Gas
○ Offshore Wind
○ Onshore Wind
○ Other
○ Solar
● Storage

Select the Status

○ Added in 2023
● Cumulative

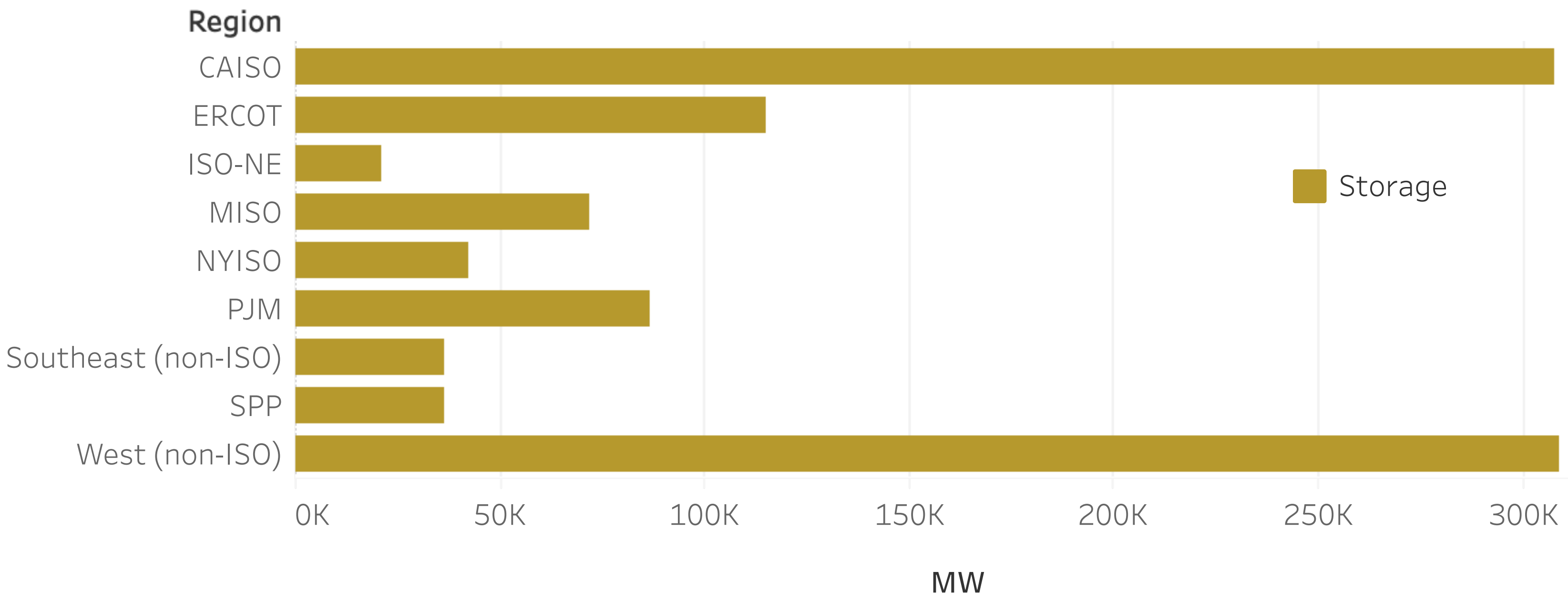
Total MW in this data set

1,028,025

Region-level data notes:

- This data set is thought to be the most complete, at 2.6 TW.
- Includes capacity in standalone and hybrid configurations.
- Hybrid storage capacity is estimated for some projects - therefore total "Storage" capacity is approximate.
- Reforms in CAISO and PJM paused or slowed new interconnection requests in 2022. MISO paused in 2023.

Regional queues by resource -- **Cumulative / Storage**



For more research on interconnection queues visit emp.lbl.gov/queues.

Map of ISO and non-ISO regions courtesy of Hitachi Energy Velocity Suite.

U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022

Vignesh Ramasamy,[1] Jarett Zuboy,[1] Eric O'Shaughnessy,[2]
David Feldman,[1] Jal Desai,[1] Michael Woodhouse,[1]
Paul Basore,[3] and Robert Margolis[1]

1 National Renewable Energy Laboratory
2 Clean Kilowatts, LLC
3 U.S. Department of Energy Solar Energy Technologies Office

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-7A40-83586
September 2022

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Suggested Citation
Ramasamy, Vignesh, Jarett Zuboy, Eric O'Shaughnessy, David Feldman, Jal Desai, Michael Woodhouse, Paul Basore, and Robert Margolis. 2022. *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-83586. https://www.nrel.gov/docs/fy22osti/83586.pdf.

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Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-7A40-83586
September 2022

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Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

List of Acronyms

ac	alternating current
AD/CVD	antidumping and countervailing duties
BESS	battery energy storage system
BLS	U.S. Bureau of Labor Statistics
BNEF	BloombergNEF
BOS	balance of system
CBP	U.S. Customs and Border Protection
CPI	Consumer Price Index
dc	direct current
DOE	U.S. Department of Energy
EPC	engineering, procurement, and construction
GAAP	U.S. Generally Accepted Accounting Principles
HVAC	heating, ventilating, and air conditioning
IFRS	International Financial Reporting Standards
ILR	inverter loading ratio
IRR	internal rate of return
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LFP	lithium iron phosphate
Li-ion	lithium-ion
MMP	modeled market price
MSP	minimum sustainable price
MW_{ac}	megawatts alternating current
MW_{dc}	megawatts direct current
MSRP	manufacturer's suggested retail price
NEM	net energy metering
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PII	permitting, inspection, and interconnection
PPA	power-purchase agreement
PV	photovoltaic(s)
PVCS	PV combining switchgear
Q	quarter
R&D	research and development
RTE	round-trip efficiency
SAM	System Advisor Model
SAPC	Solar Access to Public Capital
SEIA	Solar Energy Industries Association
SETO	U.S. Department of Energy Solar Energy Technologies Office
SG&A	selling, general, and administrative
SOC	state of charge
STC	standard test conditions
UFLPA	Uyghur Forced Labor Prevention Act

USD	U.S. dollars
V_{dc}	volts direct current
W_{ac}	watts alternating current
W_{dc}	watts direct current
WRO	withhold release order

Executive Summary

The U.S. Department of Energy's Solar Energy Technologies Office (SETO) aims to accelerate the advancement and deployment of solar technology in support of an equitable transition to a decarbonized economy no later than 2050, starting with a decarbonized power sector by 2035. Its approach to achieving this goal includes driving innovations in technology and soft cost reductions to make solar affordable and accessible for all. As part of this effort, SETO must track solar technology and soft cost trends so it can focus its research and development (R&D) on the highest-impact activities.

The National Renewable Energy Laboratory (NREL) publishes benchmark reports that disaggregate photovoltaic (PV) and energy storage (battery) system installation costs to inform SETO's R&D investment decisions. For this Q1 2022 report, we introduce new analyses that help distinguish underlying, long-term technology-cost trends from the cost impacts of short-term distortions caused by policy and market events.

Market and Policy Context in Q1 2022

For the U.S. PV and energy storage industries, the period from Q1 2021 through Q1 2022 featured multiple market and policy events that affected businesses and customers throughout the manufacturing and installation sectors. The ongoing COVID-19 pandemic caused or complicated multiple issues. Prices jumped throughout the economy, with industry-specific events and trade policies driving up PV and battery prices in particular. Change happened rapidly and fell unevenly across stakeholders. This volatility increased the difficulty of producing representative cost benchmarks. In accordance with established practices, we drew from updated data and conducted interviews with numerous industry participants to develop the Q1 2022 cost estimates shown in this report. Yet we acknowledge that these U.S average estimates do not reflect the observations and experiences of all stakeholders during this period.

Purpose and Scope of the NREL Benchmarks

It is important to understand what the NREL benchmarks are and are not, and for what purposes they should be used. The benchmarks are bottom-up cost estimates of all major inputs to typical PV and energy storage system configurations and installation practices. Bottom-up costs are based on national averages and do not necessarily represent typical costs in all local markets.

The primary purpose of the NREL benchmarks is to provide insight into the long-term trajectories of PV and storage system costs, including which system components may be driving installed prices and where there are opportunities for price reductions. The benchmarks are also used to project future system prices, provide transparency, and facilitate engagement with industry stakeholders.

NREL's benchmarks are often compared with other PV and storage system cost metrics, including reported prices and other modeled benchmarks. However, there is significant variation within and between these metrics because of the various methods and assumptions used to develop them, and different benchmarks are useful for different purposes.

It is also critical to understand the distinction between the two benchmark types analyzed in this report: minimum sustainable price (MSP) and modeled market price (MMP). Table ES-1 summarizes the meaning, approach, and purpose of each benchmark in comparison to reported market prices. Reported market prices and the MMP benchmark are affected by market and policy conditions unique to the analysis period. Consistent with our previous benchmarking efforts, our MMP benchmarks can be interpreted as the sales prices that a developer would have charged in Q1 2022. In contrast, our MSP benchmark is a theoretical construct meant to capture the long-term cost impacts of technological evolution while muting the impacts of policy distortions and short-term market fluctuations. It does not represent dynamic market conditions and should not be used for near-term policy or market analysis. MSP cannot be directly observed; instead, it must be deduced from observable factors such as underlying costs, market input prices (e.g., for feedstock), and feedback from industry stakeholders. In this benchmark report, we apply several methods to infer MSP. Both MSP and MMP are calculated for representative PV, storage, and PV-plus-storage systems in each market sector.

The NREL benchmarks convert complex processes and inputs into highly simplified individual estimates to facilitate the tracking and projecting of technological progress. However, no individual estimate under any approach can reflect the diversity of the PV and storage manufacturing and installation industries. For instance, MMP benchmarks are based on national average costs and do not necessarily reflect the distinct experiences of engineering, procurement, and construction contractors in local markets. The benchmarks also explicitly exclude certain costs that reflect key system components for certain customers. For instance, many residential customers finance their PV systems, yet the benchmarks exclude financing costs, which can represent around 20% of reported market prices. These caveats should be considered when interpreting the summary of results that follows.

Table ES-1. Definitions of NREL MSP and MMP Benchmarks vs. Reported Market Prices

	Minimum Sustainable Price (MSP) Benchmark	Modeled Market Price (MMP) Benchmark	Reported Market Prices*
Description	Estimated bottom-up overnight capital costs (i.e., cash costs)[1] of representative PV and storage components. To mute the short-term impacts of market and policy events, MSP is modeled at the lowest prices at which product suppliers can remain financially solvent in the long term, based on input costs that represent the lowest prices each input supplier can charge to remain financially solvent in the long term.	Estimated bottom-up overnight capital costs (i.e., cash costs) of representative PV and storage components under market conditions experienced during the analysis period.	Reported prices quoted by installers and paid by customers for a range of technologies and configurations, often inclusive of financing costs. Market prices can include items such as smaller-market-share PV systems (e.g., those with premium efficiency panels), atypical system configurations due to site irregularities (e.g., additional land grading) or customer preferences (e.g., pest traps), and regulations (e.g., unionized labor).
Approach	Distorted input costs are removed from model calculations. If there is more than one typical technology or configuration, the most common one is modeled.[2]	Based on reported market costs and prices of different subcost components for representative systems. MSP and MMP use the same technology and PV system and battery configurations.	Price metrics aggregated (e.g., median, mean) from sources that collect market price data.
Purpose	Long-term analysis and projections; informing R&D investment decisions.	Near-term policy and market analysis based on disaggregated system costs.	Near-term analysis based on reported prices.

*Only summarized in this report. For reported market price details, see Barbose et al. (2021a).

PV Benchmarks

Figure ES-1 compares our MSP and MMP benchmarks for PV systems in the residential, commercial, and utility-scale sectors. The MMP benchmark is higher than the MSP benchmark for all sectors, because the MMP benchmark captures the inflationary market distortion that occurred in Q1 2022. The MMP benchmarks in Q1 2022 are also higher than comparable benchmarks in Q1 2021 (not graphed) because of the market distortion in Q1 2022, although

---

[1] Cash costs do not include any financing costs, which are often eligible to be included in a system's cost basis for calculating tax credits and depreciation. In the residential sector, costs have been observed related to the setup of loan and lease products for customers as well as interest rate "buy-downs." In the utility-scale space, common financing costs also include construction loan interest payments and prepaid operations and maintenance (O&M) contracts.

[2] For example, in the residential sector, we model the installation of microinverters, although string inverters with dc optimizers are also common.

different input parameters across the two years also affect the year-to-year comparison (see Section 4.6).

For Q1 2022, our representative residential PV system uses microinverters and is installed by small-scale installers. The MMP benchmark ($2.95 per watt direct current [W_{dc}]) is 15% higher than the MSP benchmark ($2.55/$W_{dc}$) and 2% higher than our comparable microinverter-based system benchmark from Q1 2021 in 2021 U.S. dollars (USD).

For commercial systems, our MMP benchmarks ($1.84/$W_{dc}$ for rooftop and $1.94/$W_{dc}$ for ground mount) are roughly 13% higher than our MSP benchmarks ($1.63/$W_{dc}$ and $1.71/ W_{dc}, respectively), and they are approximately 8% higher than their counterparts in Q1 2021 in 2021 USD.

For utility-scale systems with one-axis tracking, our MMP benchmark ($0.99/$W_{dc}$) is 14% higher than our MSP benchmark ($0.87/$W_{dc}$) and 6% higher than its counterpart in Q1 2021 in 2021 USD.

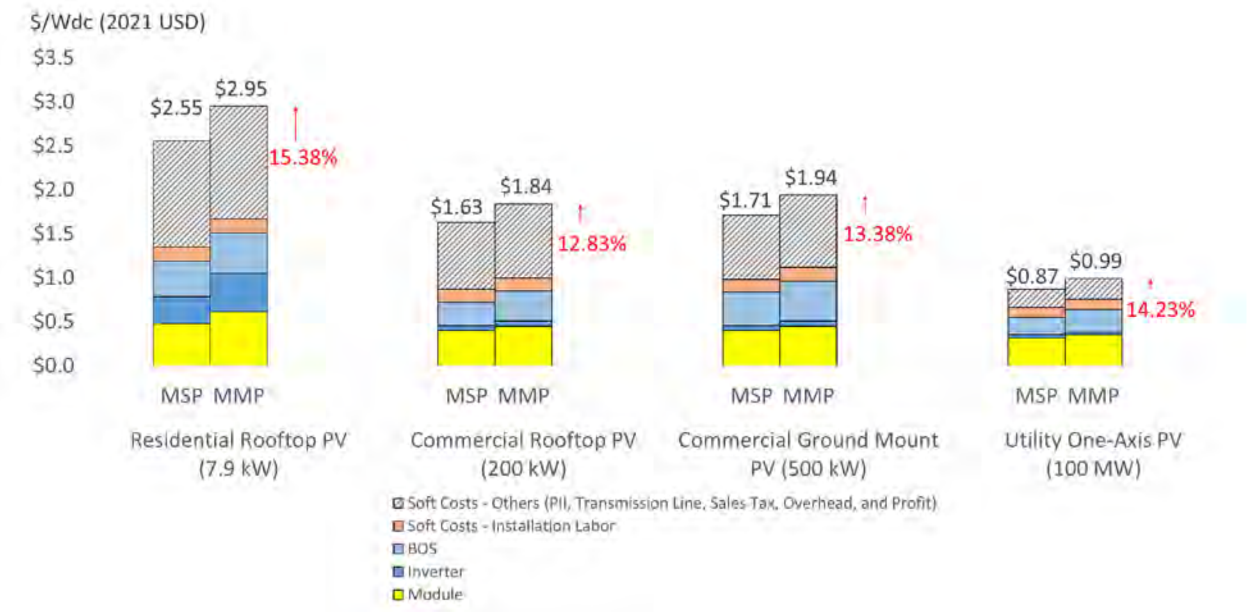

Figure ES-1. Q1 2022 U.S. PV cost benchmarks

Standalone Battery Energy Storage Benchmarks

Figure ES-2 compares our MSP and MMP benchmarks for standalone battery energy storage systems in the residential, commercial, and utility-scale sectors. Again, for all sectors, the MMP benchmarks are higher than the MSP benchmarks (and the comparable Q1 2021 benchmarks, which are not graphed here), because the MMP benchmarks capture the inflationary market distortion that occurred in Q1 2022. See Section 4.6 for the different input parameters in Q1 2022 vs. Q1 2021.

For residential systems, our MMP benchmark ($1,503/kWh) is 10% higher than our MSP benchmark ($1,371/kWh) and 2% higher than its counterpart in Q1 2021 in 2021 USD.

For commercial systems, our MMP benchmark ($672/kWh) is 10% higher than our MSP benchmark ($610/kWh). Because of a major change in system configuration between Q1 2021 and Q1 2022, the benchmark costs across those years cannot be compared directly.

For utility-scale systems, our MMP benchmark ($446/kWh) is 13% higher than our MSP benchmark ($394/kWh million) and 12% higher than its counterpart in Q1 2021 in 2021 USD.

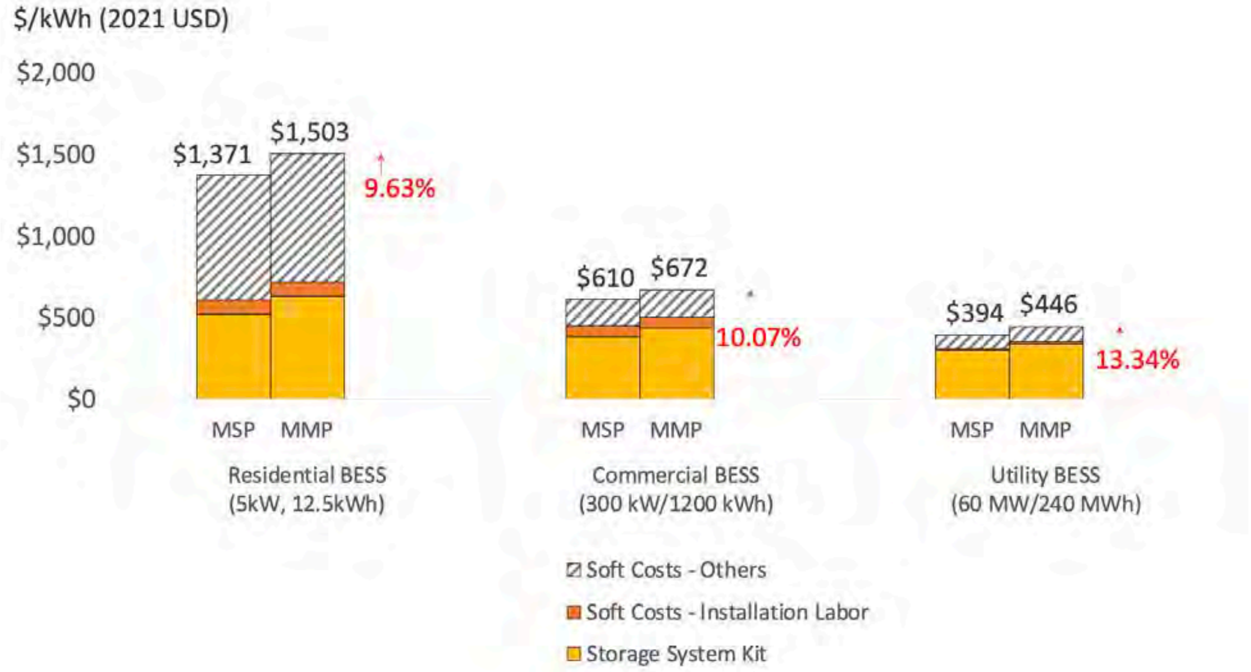

Figure ES-2. Q1 2022 U.S. standalone battery energy storage system (BESS) cost benchmarks

PV-Plus-Storage Benchmarks

Figure ES-3, Figure ES-4, and Figure ES-5 compare our MSP and MMP benchmarks—in total system cost terms—for PV-plus-storage systems in the residential, commercial, and utility-scale sectors. Again, the MMP benchmarks are higher than the MSP benchmarks (and higher than the comparable Q1 2021 benchmarks, not graphed) for all sectors, because the MMP benchmark captures the inflationary market distortion that occurred in Q1 2022. See Section 4.6 for different input parameters in Q1 2022 vs. Q1 2021.

For residential systems, our MMP benchmark ($38,295) is 13% higher than our MSP benchmark ($33,858) and 6% higher than its counterpart in Q1 2021 in 2021 USD.

For commercial systems, our MMP benchmark ($1.44 million) is 13% higher than our MSP benchmark ($1.27 million). Because of a major change in system configuration between Q1 2021 and Q1 2022, the benchmark costs across those years cannot be compared directly.

For utility-scale systems, our MMP benchmark ($195 million) is 15% higher than our MSP benchmark ($170 million) and 11% higher than its counterpart in Q1 2021 in 2021 USD.

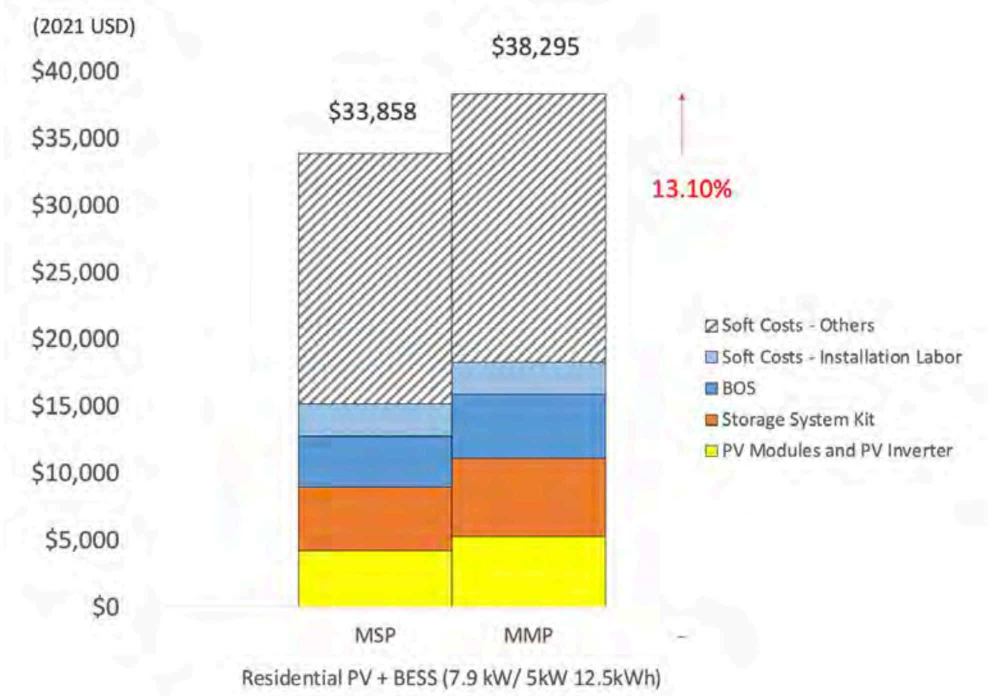

Figure ES-3. Q1 2022 U.S. benchmark: residential PV-plus-storage system

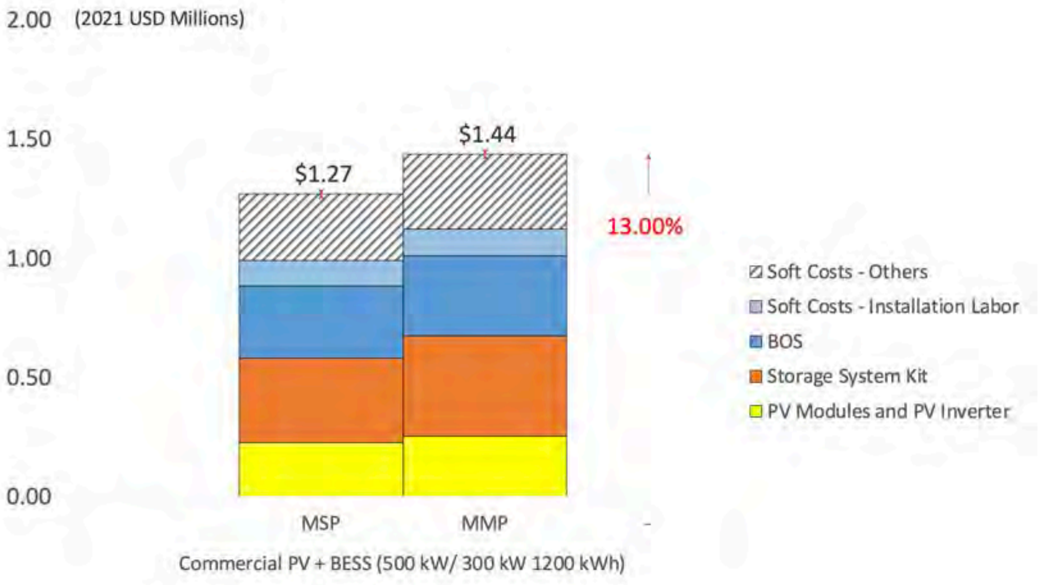

Figure ES-4. Q1 2022 U.S. benchmark: commercial ground-mounted, alternating current (ac) coupled PV-plus-storage system (4-hour duration)

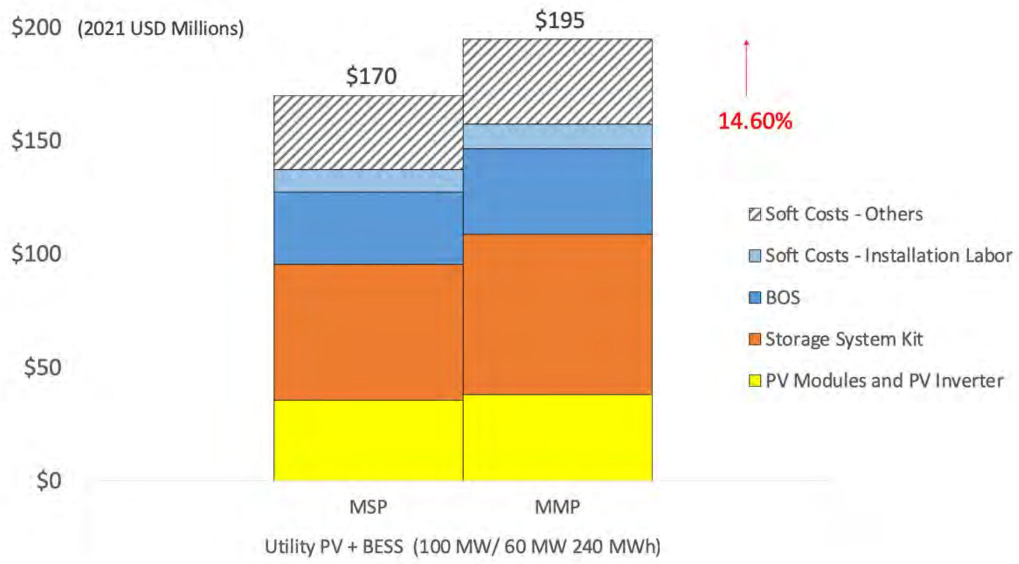

Figure ES-5. Q1 2022 U.S. benchmark: utility-scale ac-coupled tracking PV-plus-storage system (4-hour duration)

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1 Introduction

The U.S. Department of Energy's (DOE's) Solar Energy Technologies Office (SETO) aims to accelerate the advancement and deployment of solar technology in support of an equitable transition to a decarbonized economy no later than 2050, starting with a decarbonized power sector by 2035. Its approach to achieving this goal includes driving innovations in technology and soft cost reductions to make solar affordable and accessible for all. As part of this effort, SETO must track solar technology and soft cost trends so it can focus its research and development (R&D) on the highest-impact activities.

The National Renewable Energy Laboratory (NREL) facilitates SETO's decisions on R&D investments by publishing benchmark reports that disaggregate photovoltaic (PV) costs and—more recently—energy storage (battery) costs. Previous benchmark reports have sought to provide estimates of typical costs for all system components plus a sustainable margin (from the perspective of the developer/installer), relying largely on market prices for components. Using market prices to track progress has pros and cons. Tracking market prices of PV and storage systems is critical for understanding their competitiveness with other generation technologies. On the other hand, PV and storage market prices are influenced by short-term policy and market drivers that can obscure the underlying technological development that shapes prices over the longer term. For example, recent events related to trade policy, inflation, and pandemic-related supply chain constraints have pushed PV and storage prices up, even as those technologies have continued to improve. Short-term market trends are important for the PV and storage industries, as private-sector entities compete to improve their market share and profitability. SETO, however, focuses on optimizing R&D investments over the longer term to continue driving innovations in technology and soft cost reductions.

To support this longer-term perspective, NREL's Q1 2022 benchmark report is introducing new analyses, which help distinguish underlying, long-term technology-cost trends from the price impacts of short-term distortions caused by policy and market events. By muting the impacts of policy distortions and short-term market fluctuations, the new minimum sustainable price (MSP) benchmarks provide an effective basis for long-term PV cost analysis. However, they do not represent dynamic market conditions and should not be used for near-term policy or market analysis. To help provide perspective on current market conditions, the report also provides modeled market price (MMP) analysis, which is more in line with previous benchmark reports, by using similar methods to track the costs of U.S. residential, commercial, and utility-scale PV, energy storage, and PV-plus-storage systems built in Q1 2022. These methods capture the impact of market trends during this period, and the results are meant to reflect typical component costs as experienced by U.S. installers and passed on to U.S. consumers.[3]

Additional details about the goals, methods, and limitations of the Q1 2022 benchmark report—along with a brief discussion of this period's unique market and policy context—are provided in Sections 2, 3, and 4. Sections 5 through 10 present the results of our Q1 2022 capital cost modeling for residential, commercial, and utility-scale PV, energy storage, and PV-plus-storage

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[3] All previous benchmark reports can be found at NREL's Solar Technology Cost Analysis web page at www.nrel.gov/solar/solar-cost-analysis.html.

systems. Section 11 presents the results of our operations and maintenance (O&M) cost analysis. Section 12 uses our capital cost and O&M cost results to calculate the levelized cost of electricity (LCOE) for PV and PV-plus-storage systems. Section 13 offers a summary and conclusions.

2 Overview of the NREL Benchmarking Process

NREL has been developing PV and storage system cost models over the past decade. Each year, we adjust model elements based on industry trends—derived from research organizations and sources such as the California net energy metering (NEM) database—as well as feedback from stakeholders. In Q1 2022, we interviewed 21 stakeholders, including third-party research organizations; PV installers and integrators; engineering, procurement, and construction (EPC) developers; advocacy groups; intergovernmental organizations; and government agencies.

We align our model inputs as closely as possible to the analysis period, which for this report is Q1 2022. We obtain most of the specific cost inputs (material costs, component and subcomponent costs, installation rental equipment rates, and labor rates) from sources such as RSMeans, the U.S. Bureau of Labor Statistics, RENVU, EcoDirect, altE Store, BloombergNEF (BNEF), Wood Mackenzie, and the Solar Energy Industries Association (SEIA). Table 3 in Section 4.4.1 provides an example of cost components that are populated using such sources. We base additional inputs—particularly soft costs such as customer acquisition costs; overhead; permitting, inspection, and interconnection (PII) costs; and profit—on analysis of multiple years of industry interviews. Currently, we model the MSP of PV modules using NREL's bottom-up module cost model. We also tailor the configuration of our representative systems to the analysis period. For example, for the residential PV sector in Q1 2022, we modeled small installers and microinverters based on the market shares of these choices.

Once we configure our representative systems and populate our models using the hundreds of inputs, the models yield disaggregated system cost results in terms of dollars per watt of direct current ($\$/W_{dc}$), dollars per kilowatt-hour ($/kWh), and dollars per system. We then send these results for validation to the stakeholders we interviewed. After making any necessary adjustments based on stakeholder feedback, we produce a draft report, which we send to industry stakeholders as well as NREL and SETO reviewers. We use feedback from this process to finalize the report, and then we publish the report on NREL's website, typically during the fourth quarter of the year (e.g., Q1 2021 results were published in November 2021). See all the reports at NREL's Solar Technology Cost Analysis web page: www.nrel.gov/solar/market-research-analysis/solar-cost-analysis.html.

3 Market and Policy Context in Q1 2022

The PV and energy storage industries are in constant flux, and each of NREL's benchmark reports has been produced within a unique historical context. By any measure, however, the period from Q1 2021 through Q1 2022 was extraordinary. Dramatic market and policy events affected businesses and customers throughout the PV and storage manufacturing and installation sectors, with the ongoing COVID-19 pandemic causing or complicating issues. Change happened rapidly and fell unevenly across stakeholders.

This volatility increased the difficulty of producing representative cost benchmarks. In accordance with established practices, we drew from updated data and conducted interviews with numerous industry participants to develop the Q1 2022 cost estimates shown in this report. Yet we acknowledge that these estimates do not reflect the observations and experiences of all stakeholders during this period. Section 4 describes the purpose, meaning, and limitations of our benchmarks in general. Below we give a brief, noncomprehensive overview of developments that characterized the period from Q1 2021 through Q1 2022 and contributed to unusually high—and highly variable—PV and storage market costs and prices in Q1 2022. Table 1 lists select events that occurred during this period.

Table 1. Select Events ca. Q1 2021–Q1 2022

Event	Date
Withhold release order (WRO) issued for PV products containing Hoshine polysilicon	June 2021
Antidumping and countervailing duties (AD/CVD) circumvention investigation requested by anonymous U.S. PV manufacturers	Aug 2021
Anonymous AD/CVD circumvention case dismissed	Nov 2021
Bifacial PV exemption from Section 201 tariffs reinstated; tariffs reduced from 18% to 15%	Nov 2021
Polysilicon spot price peak caused by constrained silicon metal and power in China	Nov 2021
Uyghur Forced Labor Prevention Act (UFLPA) signed into law (enforced as of June 2022)	Dec 2021
Section 201 tariffs extended with bifacial exemption and increased cell quota	Feb 2022
Invasion of Ukraine by Russia	Feb 2022
AD/CVD circumvention investigation requested by Auxin Solar	Feb 2022
AD/CVD circumvention investigation initiated by U.S. Department of Commerce	April 2022
Disruption of polysilicon supply and PV component shipping by COVID-19 lockdowns in China	April 2022

Costs and prices jumped throughout the economy between Q1 2021 and Q1 2022, largely driven by effects of the COVID-19 pandemic. Large influxes of government stimulus funds during the pandemic helped drive strong demand for goods and services worldwide, while pandemic-induced bottlenecks constrained supply (McCausland 2022, Thomsen 2022). As part of the supply crunch, containerized freight prices rose as much as 190% between April 2021 and April 2022, finishing the period at a 130% increase (Mercom 2022). Russia's invasion of Ukraine in February 2022 drove global oil prices up further, which added to the economywide inflation (Egan 2022, Kaplan and Hoff 2022). Between April 2021 and April 2022, the Consumer Price Index (CPI) rose 9% (FRED 2022a), and global commodity prices rose 48% (FRED 2022b). The PV industry felt the effects of these events in addition to PV-specific cost drivers. Spot prices rose across the monocrystalline silicon PV supply chain between April 2021 and April 2022: 88% for polysilicon, 29% for cells, and 19% for modules (BNEF 2022). Figure 1 illustrates some of the price increases that occurred during this period.

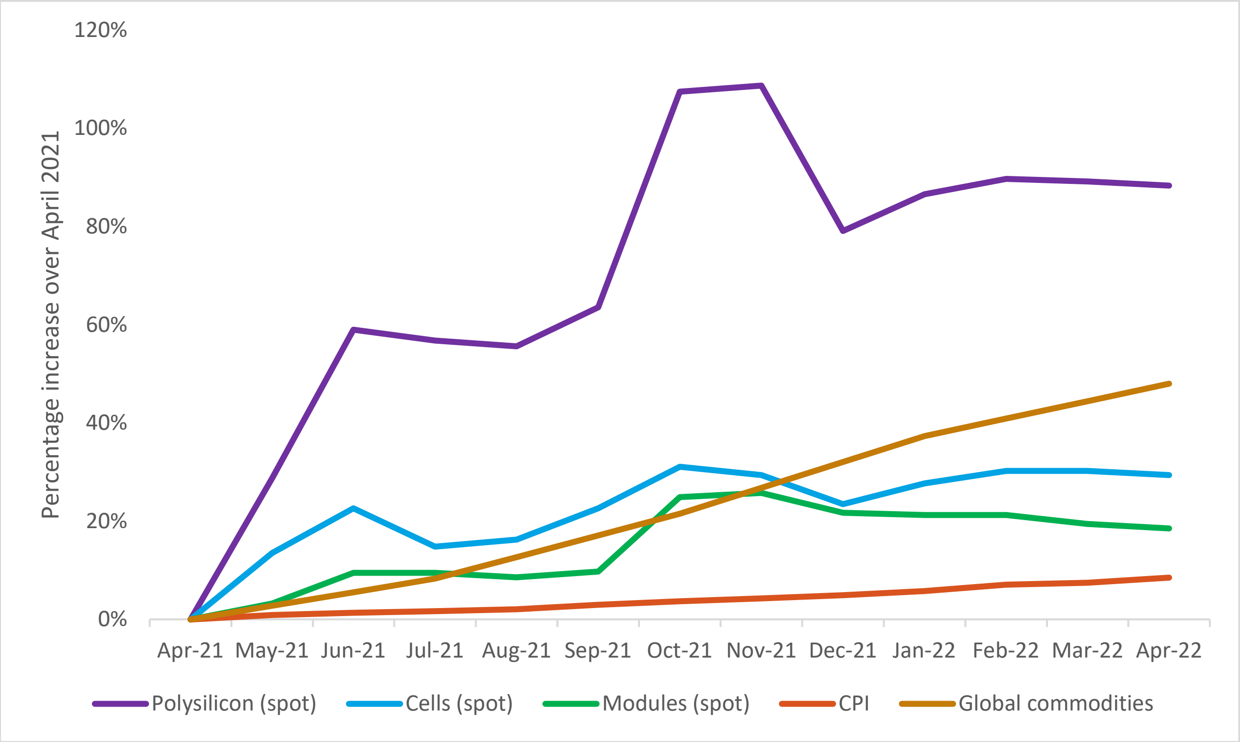

Figure 1. Select price increase indicators, April 2021–April 2022

Sources: BNEF (2022), FRED (2022a, 2022b)

The U.S. PV industry was also affected by specific trade policies. In June 2021, U.S. Customs and Border Protection issued a withhold release order (WRO) against Hoshine Silicon—instructing U.S. ports to detain shipments containing silica-based products made by Hoshine and its subsidiaries—because of published reports that Hoshine was using forced labor in China's Xinjiang Uyghur Autonomous Region (CBP 2021). In December 2021, this policy was reinforced by the passage of the Uyghur Forced Labor Prevention Act (UFLPA), which banned—beginning in June 2022—U.S. imports of products from China's Xinjiang region unless importers provide "clear and convincing evidence" that forced labor was not used in their production (CBP 2022). The detainments and uncertainty associated with the WRO and UFLPA further constrained module availability in the United States. In August 2021, an anonymous group of U.S. PV manufacturers petitioned the U.S. Department of Commerce to investigate whether Chinese PV manufacturers were circumventing antidumping and countervailing duties by working in Malaysia, Thailand, and Vietnam. Although the Department of Commerce rejected the petition in November 2021, the uncertainty created by the petition put additional pressure on the U.S. module supply chain (Woodmac and SEIA 2022). In February 2022, Auxin Solar filed a similar anticircumvention petition, which instigated a Department of Commerce investigation at the beginning of Q2 2022; the impacts of that investigation, which have been significant, are not considered in this Q1 2022 benchmark report. Also in February 2022, the U.S. Section 201 tariffs were extended along with the tariff exemption for bifacial modules. Average U.S. prices for monofacial monocrystalline silicon modules rose 9% between Q1 2021 and Q1 2022 (Woodmac and SEIA 2022). Component cost increases are reflected in our MMP benchmarks in Sections 5–10.

Component cost increases were a major topic during our Q1 2022 interviews with industry stakeholders. In addition to stating that all prices had gone up since the previous year, residential and commercial installers noted significant price increases specifically for modules, batteries, electrical panels, circuit breakers, and wire. Utility-scale stakeholders mentioned significantly higher prices for modules, inverters, site preparation, transformers, switchgears, copper, steel, PVC, and shipping. Because of tight supply chains, obtaining components in a timely manner could incur additional premiums, according to some interviewees. Some also stated that the availability and price of components could change rapidly week to week and that module price increases varied unevenly across installers. Large residential and commercial installers as well as utility-scale installers reported that they could buy containerload quantities directly from module manufacturers, which yielded the lowest costs. Smaller installers, however, said that they either could not handle enough volume to obtain direct, containerload pricing, or that warehousing costs for high-volume purchases were prohibitive. For this reason, smaller installers reported that they paid higher module prices through distributors.

Our interviews also suggested that a tightening labor market contributed to higher costs for U.S. PV systems in Q1 2022. The U.S. unemployment rate rose from 3.5% immediately before the onset of the COVID-19 pandemic to 14.7% in April 2020 and then dropped again, reaching 3.8% in February 2022. These fluctuations have been accompanied by an increased rate of workers quitting their jobs, in a phenomenon that has been called the “Great Resignation” (BLS 2022a). The tight labor market was reflected in EnergySage’s 2021 installer survey, which identified a lack of trained labor as the most frequent barrier to growing installation businesses (EnergySage 2022). Our Q1 2022 industry interviews highlighted how higher labor costs contributed to higher PV system costs. Multiple participants noted significantly increased labor costs and linked them with labor shortages; in some areas, high demand for installations meant that workers could pick and choose projects and demand higher wages. Some installers also reported that, because local labor was unavailable, workers needed to travel to job sites—thus incurring additional costs for items such as hotel rooms and meals.

4 NREL Benchmarks’ Purpose and Scope

In all industries, numerous metrics reflect product costs and prices. These metrics say different things and are useful for different purposes. For instance, an investor may be interested in the costs to produce a new product, a stock trader may want to know the real-time trading price of a good, and a forecaster may seek a long-term average cost. It is therefore important to understand what the NREL benchmarks are and are not, and for what purposes they should be used. This section describes the meaning of the NREL benchmarks, their intended purposes, how they vary from other market metrics, and their limitations. The final subsection notes changes to the benchmark report in Q1 2022.

4.1 Meaning of the NREL Benchmarks

Industry, analysts, policymakers, and other stakeholders are interested in the *prices* of new technologies and the underlying *costs* to produce those technologies. In the U.S. PV industry, prices are readily observable and documented in resources such as Barbose et al. (2021a). However, installed system prices do not provide insight into underlying system cost drivers. Disaggregating installed system prices into underlying cost drivers requires identifying all relevant inputs to PV installations and assigning costs to those inputs. Broadly, this cost disaggregation can be done through top-down or bottom-up cost modeling. Top-down modeling observes a final price, then develops a method to distribute that price across individual cost components. Bottom-up cost modeling estimates the costs of individual components based on how they are made, then adds those costs up to a modeled total price.

The NREL benchmarks are bottom-up cost estimates of all major inputs to PV and storage installations. Bottom-up costs are based on national averages and do not necessarily represent typical costs in all local markets. As we discuss in Section 4.4, this year's report includes two distinct sets of benchmarks: MSP benchmarks and MMP benchmarks. MSP benchmarks can be interpreted as the minimum sustainable price a company needs to charge to remain financially solvent in the long term based on the minimum sustainable prices of all inputs. MMP benchmarks can be interpreted as the actual sales price the company charges in the current market. In a stable, balanced, competitive market that is free of limited-duration trade policy distortions, MMP is equal to MSP.

4.2 Purpose

The primary purpose of the NREL benchmarks is to provide insight into the long-term trajectories of PV and storage system costs. The NREL benchmarks inform and track progress toward SETO's Government Performance and Reporting Act cost targets. Industry analysts also use NREL benchmarks to project future system prices. In addition, the benchmarks provide insight into the disaggregated costs of individual system components. Analysts use disaggregated costs to identify which system components are driving installed prices and where there are opportunities for system price reductions.

The NREL benchmarks also provide transparency and facilitate engagement with industry stakeholders. Other organizations provide bottom-up analysis of PV and storage component costs for a fee, whereas NREL's results are provided publicly and free of charge. Thus, all stakeholders can observe and comment on our assumptions, methods, and results. Opinions about the correct ways to calculate and report representative benchmark costs across the large, diverse U.S. PV and storage markets will always vary. However, NREL continues to strive for a consistent, transparent approach that can be used as a common foundation for understanding the U.S. market by all stakeholders. Understanding assumptions and methods is critical; stakeholders should not use the results without first understanding how they were developed and what they mean. To enhance this effort, NREL is developing a complementary online cost modeling tool.

4.3 NREL Benchmarks Compared With Other Metrics

Cost and price metrics can vary significantly because of the various methods and assumptions used in their development. Here, we illustrate that variation using PV metrics. Figure 2 compares 2020 metrics across several sources and all three PV market sectors. Each source contains numerous details about data and methods, which are beyond the scope of this report to list in full. Rather, we make several general observations to contextualize the benchmarks provided in our current report; for more detailed study of PV cost and price tracking, see the sources listed below.

- The Lawrence Berkeley National Laboratory (LBNL) values are based on reported prices for projects installed in 2020, and they include median values as well as 20th and 80th percentile values (Barbose et al. 2021a, Bolinger et al. 2021).
- The SunPower, Sunrun, and Vivint data are the sums of reported average installation, sales, and general and administrative costs averaged across four quarters in 2020, as derived from shareholder reports (Barbose et al. 2021a).
- The EnergySage values are median price quotes in 2020, as calculated by LBNL from EnergySage data (Barbose et al. 2021a).
- The Woodmac values are based on modeled turnkey prices averaged across quarters (Barbose et al. 2021a, Woodmac and SEIA 2021).
- The NREL values are MMP benchmarks for a 7-kW$_{dc}$ residential system, a 200-kW$_{dc}$ commercial system, and a 100-MW$_{dc}$ utility-scale system (Feldman et al. 2021).

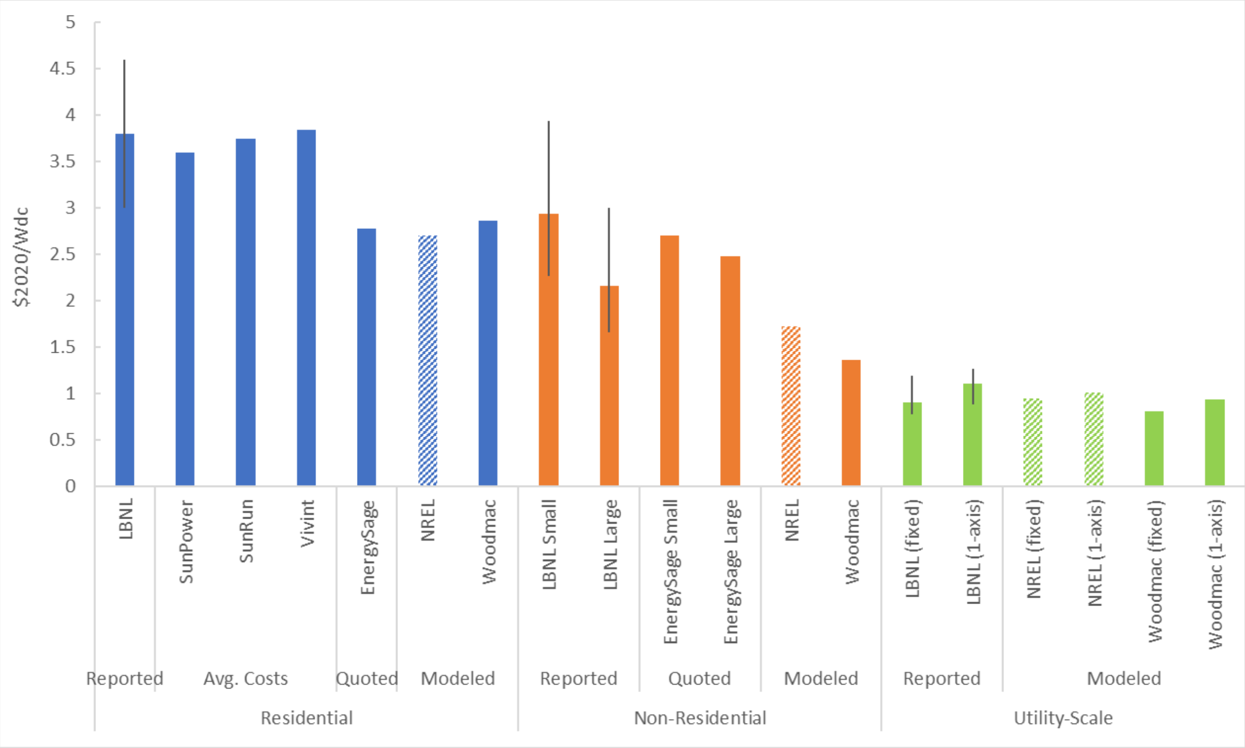

Figure 2. Comparison of 2020 PV price metrics across sources and sectors

Definitions of nonresidential systems vary across the sources, but in general, they include rooftop and ground-mounted systems that are larger than residential systems, smaller than utility-scale systems, and are not installed on residences. They often include systems that are defined as “commercial” systems.

As Figure 2 shows, price metrics can vary significantly within PV sectors, depending on the sources of those metrics. Barbose et al. (2021a) attribute this variation to differences across sources in underlying methods and inputs, including system vintage, system location, use of price versus cost, which costs are accounted for, characteristics of installers, presence of value-based pricing, system size, and system design.

Significant variation occurs even within the LBNL reported prices. The range between the 20th and 80th percentiles is about $1.60/W$_{dc}$ for residential systems, $1.70/W$_{dc}$ for small nonresidential systems, \$1.30/W_{dc} for large nonresidential systems, and \$0.40/W_{dc} for utility-scale systems. Put another way, prices within the 20th to 80th percentiles are up to 20% different from the median for residential systems, 40% different for nonresidential systems, and 30% different for utility-scale systems. For example, it would not be unusual—based on these reported data—to encounter a typical U.S. residential installation priced at \$3.00/W_{dc} and another at \$4.60/W_{dc} in 2020. This range demonstrates the limitation of representing prices with a single benchmark value. Tracking a single value consistently over time is a useful way to gauge technological progress, but when interpreting such values, the underlying variability in real-world prices should be kept in mind.

The largest absolute difference between NREL's MMP benchmark and the median reported LBNL price for a comparable system (about \$1.1/W_{dc}) is in the residential sector. There are three primary reasons for this disparity. First, the NREL MMP benchmark is based on costs incurred by a typical, experienced installer in a competitive market, whereas the U.S. residential installation industry comprises around 3,000 firms—ranging from small, local installers with diverse cost structures to large-scale firms whose prices reflect heterogeneous cost structures and long-term market strategies. Second, the MMP benchmark includes costs only for a specific, representative system installation. In contrast, reported prices may include premium system features (e.g., premium inverters) and costs of complementary services such as additional electrical work (e.g., building main panel upgrades), securing financing, additional roofing services, and other home upgrades. Thus, the MMP benchmark can be compared to the manufacturer's suggested retail price (MSRP) of a car without any premium features. Just as MSRP is consistently lower than actual car sales prices, so will MMP benchmarks be consistently lower than average PV market prices. Third, NREL does not have robust data on profit margins, and the profit margins reflected in reported system prices may be lower or higher than NREL's assumptions in any given year.

The differences between NREL's MMP benchmark and comparable median reported prices are smaller for the nonresidential sector (\$0.4/W_{dc}) and the utility-scale sector (up to \$0.1/W_{dc}). Fewer companies work on nonresidential and utility-scale projects than on residential projects, and the business operations, supply chains, and cost structures of the companies that take on larger projects are different and more uniform than those of retail-oriented residential installation companies—resulting in more standardized prices. This is particularly apparent for the utility-scale values shown in Figure 2, which are relatively consistent across the reported and modeled sources. The nonresidential sector is more heterogeneous than the utility-scale sector with regard to installers, customers, and system sizes and types, so the variation across price benchmarks is larger.

In summary, different price benchmarks are useful for different purposes. NREL's benchmarks are primarily used for long-term projections and insights into underlying cost drivers, whereas reported market prices are useful for understanding real market dynamics. NREL benchmarks should *not* be used for purposes better met by market prices and vice versa. For instance, if an analyst wants to know the actual prices paid by real customers in a specific location at a specific time, the analyst should use reported market prices. Conversely, if an analyst wants to understand the trajectory of underlying cost drivers, the analyst should use NREL benchmarks across multiple years.

It is also critical to understand the distinction between NREL's MSP and MMP benchmarks when using the benchmark results. These two types of benchmarks are described next.

4.4 Minimum Sustainable Price (MSP) and Modeled Market Price (MMP) Benchmarks

For the first time, this Q1 2022 report provides modeled capital cost results using two benchmarks:

1. An **MSP benchmark** meant to identify the lowest prices at which product suppliers can remain financially solvent in the long term, based on input costs that represent the lowest prices that each input supplier can charge to remain financially solvent in the long term.
2. An **MMP benchmark** that maintains continuity with previous benchmark reports by capturing the impact of market trends during Q1 2022, reflecting typical national system costs as experienced by U.S. installers and passed on to U.S. consumers.

Both MSP and MMP are calculated for representative systems in each PV market sector. The MSP benchmark reflects the lowest sustainable price based on a long-term view of market conditions, whereas the MMP benchmark reflects the base price of the market price distribution based on market conditions during the analysis period. Table 2 summarizes the meaning, approach, and purpose of each benchmark in comparison to reported market prices (which are only summarized in this report). The two benchmarks are described further in the following subsections.

Table 2. Definitions of NREL MSP and MMP Benchmarks vs. Reported Market Prices

	Minimum Sustainable Price (MSP) Benchmark	Modeled Market Price (MMP) Benchmark	Reported Market Prices*
Description	Estimated bottom-up overnight capital costs (i.e., cash costs)[4] of representative PV and storage components. To mute the short-term impacts of market and policy events, MSP is modeled at the lowest prices at which product suppliers can remain financially solvent in the long term, based on input costs that represent the lowest prices each input supplier can charge to remain financially solvent in the long term.	Estimated bottom-up overnight capital costs (i.e., cash costs) of representative PV and storage components under market conditions experienced during the analysis period.	Reported prices quoted by installers and paid by customers for a range of technologies and configurations, often inclusive of financing costs. Market prices can include items such as smaller-market-share PV systems (e.g., those with premium efficiency panels), atypical system configurations due to site irregularities (e.g., additional land grading) or customer preferences (e.g., pest traps), and regulations (e.g., unionized labor).
Approach	Distorted input costs are removed from model calculations. If there is more than one typical technology or configuration, the most common one is modeled.[5]	Based on reported market costs and prices of different subcost components for representative systems. MSP and MMP use the same technology and PV system and battery configurations.	Price metrics aggregated (e.g., median, mean) from sources that collect market price data.
Purpose	Long-term analysis and projections; informing R&D investment decisions.	Near-term policy and market analysis based on disaggregated system costs.	Near-term analysis based on reported prices.

*Only summarized in this report. For reported market price details, see Barbose et al. (2021a).

4.4.1 Minimum Sustainable Price Benchmark

Reported market prices and the MMP benchmark are affected by market and policy conditions unique to the analysis period. In contrast, our MSP benchmark is meant to capture the long-term cost impacts of technological evolution while muting the impacts of policy distortions and short-term market fluctuations. The MMP benchmark described in Section 4.4.2 can be thought of as the MSP distorted by short-term market and policy phenomena that occurred in Q1 2022.

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[4] Cash costs do not include any financing costs, which are often eligible to be included in a system's cost basis for calculating tax credits and depreciation. In the residential sector, costs have been observed related to the setup of loan and lease products for customers as well as interest rate "buy-downs." In the utility-scale space, common financing costs also include construction loan interest payments and prepaid O&M contracts.

[5] For example, in the residential sector, we model the installation of microinverters, although string inverters with dc optimizers are also common.

The MSP is an economic concept that was developed to estimate theoretical sustainable PV prices and cost projections (Goodrich et al. 2013, Powell et al. 2013). The MSP cannot be directly observed; rather, it must be deduced from observable factors such as underlying costs, market input prices (e.g., for feedstock), and feedback from industry stakeholders. A comprehensive understanding of MSP would require in-depth knowledge about the prices each input supplier must charge to remain financially solvent in the long term within their complex and ever-changing market and policy contexts—from the company that extracts raw materials to component manufacturers, assemblers, and installers. For this reason, development of our MSP benchmarks can be thought of as a journey of continuous improvement. For the Q1 2022 MSP benchmarks, we apply two general approaches to infer MSP for the various PV and storage system components: detailed bottom-up cost modeling and mitigation of distorted input values. For all soft costs, including labor costs, we use the same values for the MSP and MMP benchmarks, because we do not currently have a basis for differentiating these values using MSP principles. These approaches represent initial efforts to characterize MSP. We will improve on them in future benchmark reports with the help of feedback from PV and energy storage stakeholders.

Detailed Bottom-Up Component Cost Modeling

We apply detailed bottom-up cost modeling to calculate module MSP. NREL has been applying bottom-up cost modeling techniques across the PV supply chain for more than 12 years. Items included within these models capture the variable and fixed costs experienced by firms following the U.S. Generally Accepted Accounting Principles (GAAP) and the International Financial Reporting Standards (IFRS). Figure 3 provides an overview of the bottom-up component cost modeling input data. We first work with researchers and companies to define the process flow. Then, we contact materials and equipment suppliers representing each step in the manufacturing process to develop inputs for the top-left box in Figure 3. The inputs needed to calculate depreciation include equipment throughput and price and floorspace requirements. The inputs needed to calculate variable (or "cash") costs include materials, utilities, labor, and maintenance. Yield losses are also incorporated into the model calculations, as are location-specific cost indices, including local labor and utility rates. Overhead and minimum sustainable profit margins are included in the calculation of factory-gate MSP, and shipping costs are included in the calculation of the final delivery price to PV and storage projects. For this year's benchmark report, we used bottom-up cost modeling only for modules. For additional details, see Smith et al. (2021) and Woodhouse et al. (2020).

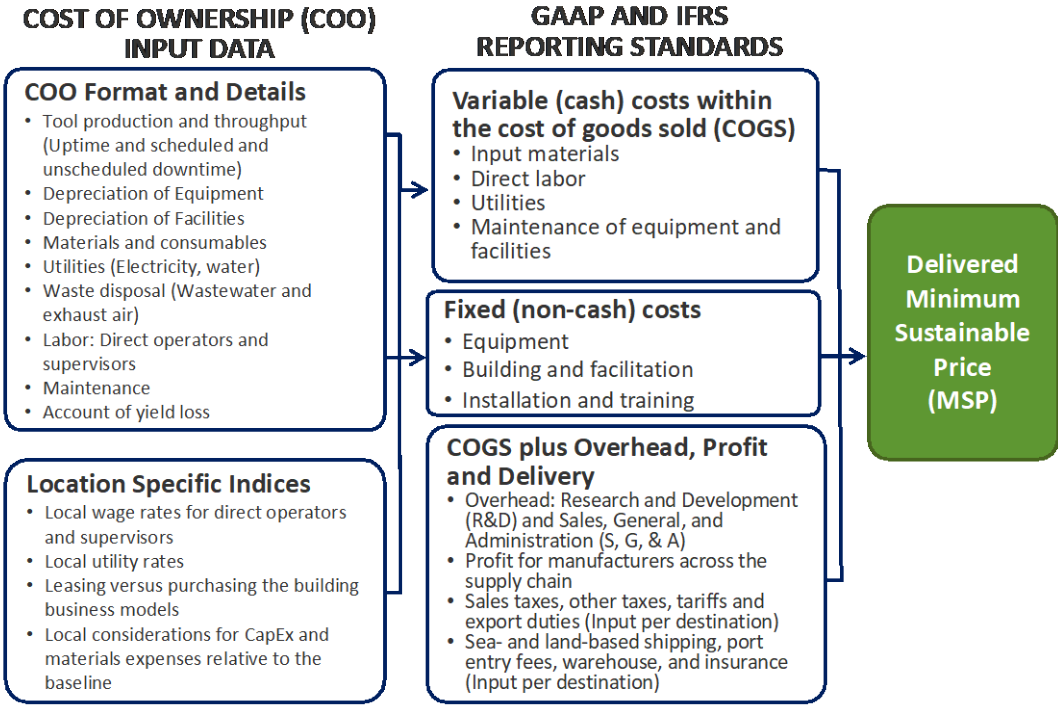

Figure 3. Overview of bottom-up cost modeling input data

Addressing Distorted Input Values

Although all market prices fluctuate with near-term changes in supply and demand, aggregated market prices in mature, competitive industries tend to follow long-term trends. Significant deviations from these long-term trends provide evidence of temporary market distortions such as supply shocks or significant policy reforms. These temporary distortions can provide important information about real-time market conditions but muddle understanding of long-term price trajectories. We use this basic concept to develop a rule for adjusting input prices that are significantly distorted by temporary market and policy shocks.

The Consumer Price Index (CPI) provides evidence of significant pandemic-driven market distortions in 2021 and 2022. As illustrated in Figure 4, the CPI in Q1 2022 was more than two standard deviations above a linear fit to 20 years of CPI data. We interpret this deviation as indicating a level of distortion that can separate PV and storage input prices from underlying cost fundamentals. While we intend to continue refining our methodology over time, we propose to use the rule of a two standard deviation variation from a 20-year linear fit as a criterion for identifying periods of significant price distortion. We apply this approach to calculate costs related to inverters, structural balance of system (BOS), electrical BOS, and transmission lines.

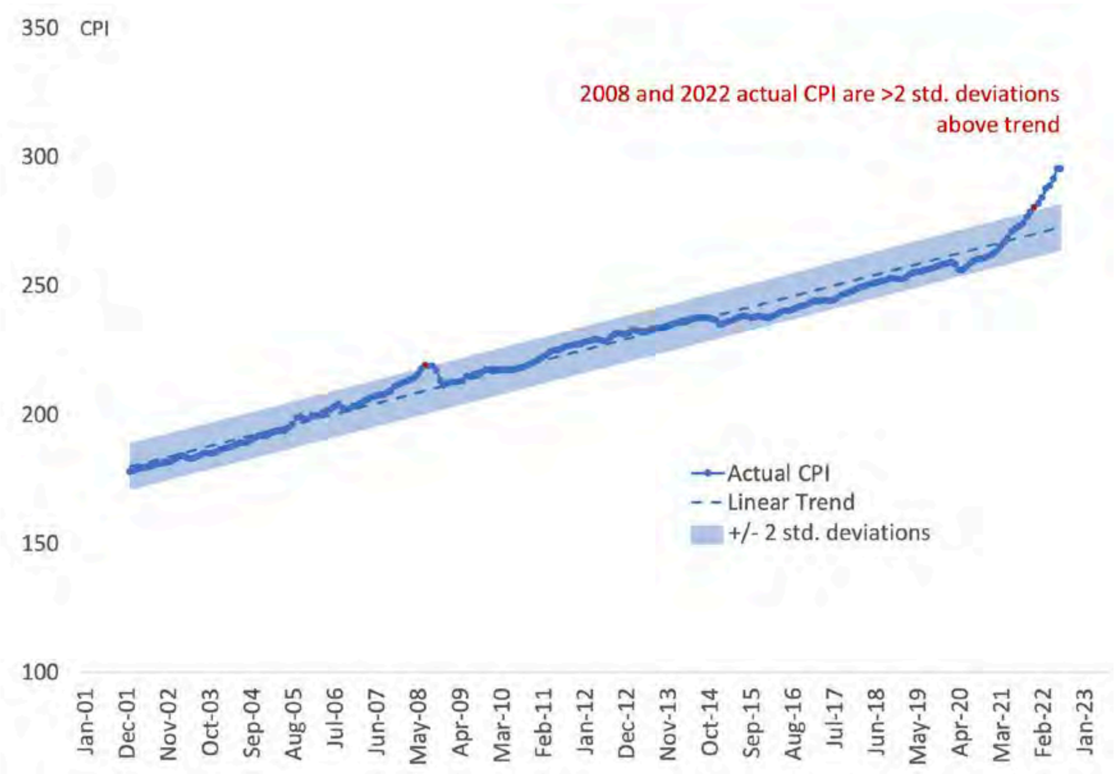

Figure 4. CPI data and linear fit, 2002–2022, showing high deviation of data from fit during 2022

Data are from "Consumer Price Index for All Urban Consumers: All Items in U.S. City Average," index 1982–1984 = 100, monthly, seasonally adjusted (FRED 2022a)

We show an example of our approach using utility-scale and commercial ground-mount systems. Table 3 lists BOS hardware, installation equipment, and transmission line cost components for these systems. We calculate prices for these inputs by excluding 2022 values and averaging values for the period the data are available between 2017 and 2021 (typically 3–5 years of data). Data are averaged because the available time series is inadequate to discern consistent time trends; this method could be modified to make MSP adjustments based on a linear fit once sufficient time-series data are available.

An example of our MSP calculation for these cost components is shown in Figure 5, for preconstruction survey material and equipment costs. In the top panel of Figure 5, the high 2022 preconstruction survey material cost of $45 per acre is excluded, and the remaining 2017–2021 costs ($19, $22, $23, $24, and $35 per acre) are averaged to yield an MSP for this component of $24 per acre. Thus, a preconstruction survey material cost of $24 per acre is input into our bottom-up cost model as part of the MSP benchmark calculation. The bottom panel shows the same process for the preconstruction survey equipment cost; here, the 2022 value is lower than the MSP calculated by averaging the 2017–2021 values. We remove the 2022 value in all cases, regardless of whether it appears to be high, low, or on-trend. We simply assume that 2022 is a distorted year and that any costs in that year are distorted. We may refine this simplification in future analyses.

Table 3. Utility and Commercial Ground-Mount PV Cost Components for BOS Hardware, Installation Equipment, and Transmission Lines

Preconstruction surveys	Staging
Access roads and parking	
Security fencing	
Temporary office	
Storage box	
O&M building	
Site preparation (geotechnical investigation)	Site preparation
Site preparation (clearing and grubbing)	
Site preparation (soil stripping and stockpiling)	
Site preparation (grading)	
Site preparation (compaction)	
Foundation for inverter/transformer/ PVCS (PV combining switchgear)	Structural work
Trenches	
Foundation for vertical support	
Horizontal support structures	
Welding or bolting	
Module mounting	
T-connection	
U-joint and driveline	Tracker
Gearbox	
Motor and controller equipment	
Conduit, wiring	dc work
Grounding, dc cable	
Junction/combiner boxes	
Inverter house	Alternating current (ac) work
On-site transmission	
PVCS	
On-site transformer and substation	
Site preparation (clearing and grubbing)	230-kV transmission line (4 miles): tower
Tower: foundation installation	
Tower: structure costs	
Tower: top assembly	
Conductor and cable	
Misc. assembly units	
Site preparation (clearing and grubbing)	35-kV distribution line (1 mile): wood pole
Wood pole: foundation installation	
Wood pole: structure costs	
Wood pole: top assembly	
Conductor and cable	
Misc. assembly units	

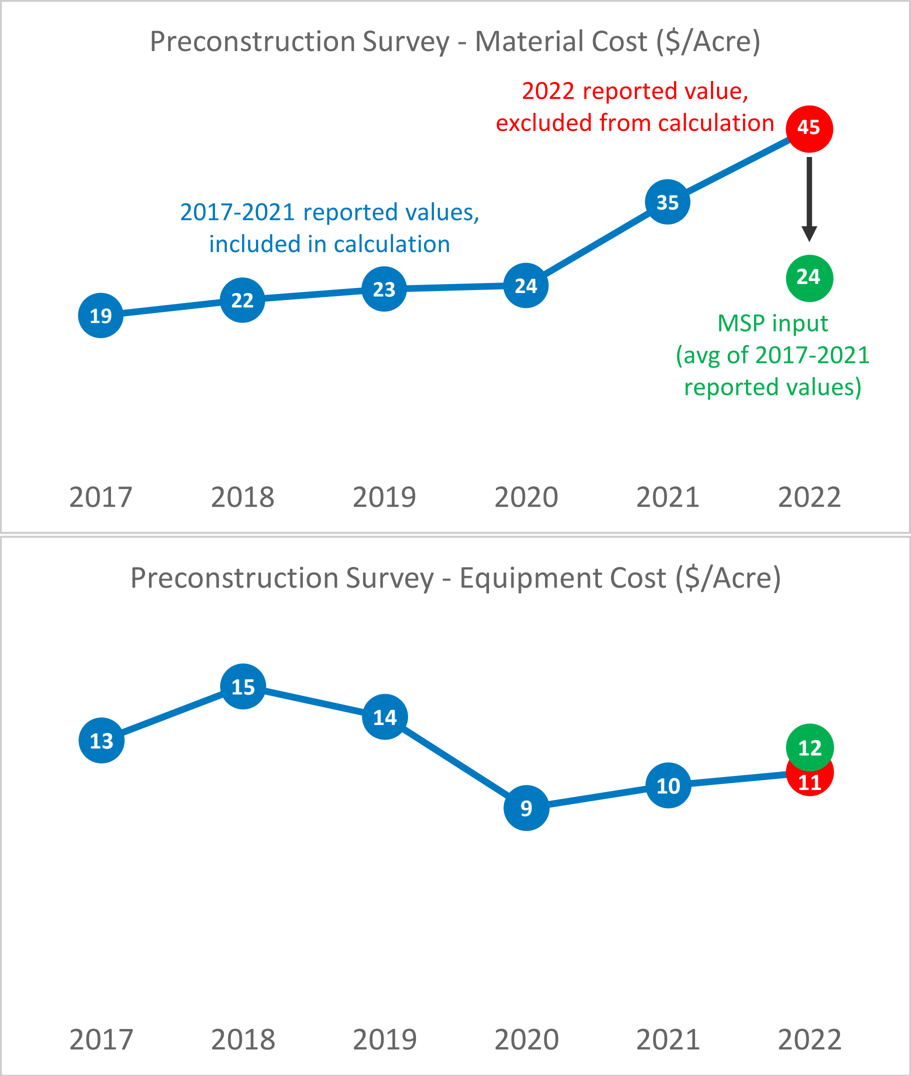

Figure 5. Example of calculating MSP inputs for a structural BOS cost

We calculate MSP inputs for installation labor costs differently. Labor wage data from the U.S. Bureau of Labor Statistics (BLS) are not available for 2022. Thus, we analyze labor wage data for distortion through 2021 (Figure 6). During this period, all data points are within the two standard deviation range. For this reason, we use the 2021 labor costs (adjusted for inflation) for 2022 in both the MSP and MMP benchmarks. This observation contributed to our decision to assume that MSP is equal to MMP for soft costs.

Likewise, battery pack and battery inverter prices were unavailable for 2022, and historical data for these components are insufficient to analyze anomalies. Thus, for the MMP benchmarks, we simply adjust the prices of these commoditized items to 2022 rates by accounting for inflation. For the battery pack MSP, we reduce the 2021 MMP by about 17% for 2022, based on the average cost reduction rate of turnkey battery systems over the past 5 years (BNEF 2021). For the battery inverter MSP, we reduce the MMP by 25% to eliminate the effect of the Section 301 tariff for residential and commercial systems; we assume that Section 301 tariffs do not apply to battery inverters used in utility-scale systems, so no adjustment is made for those system types.

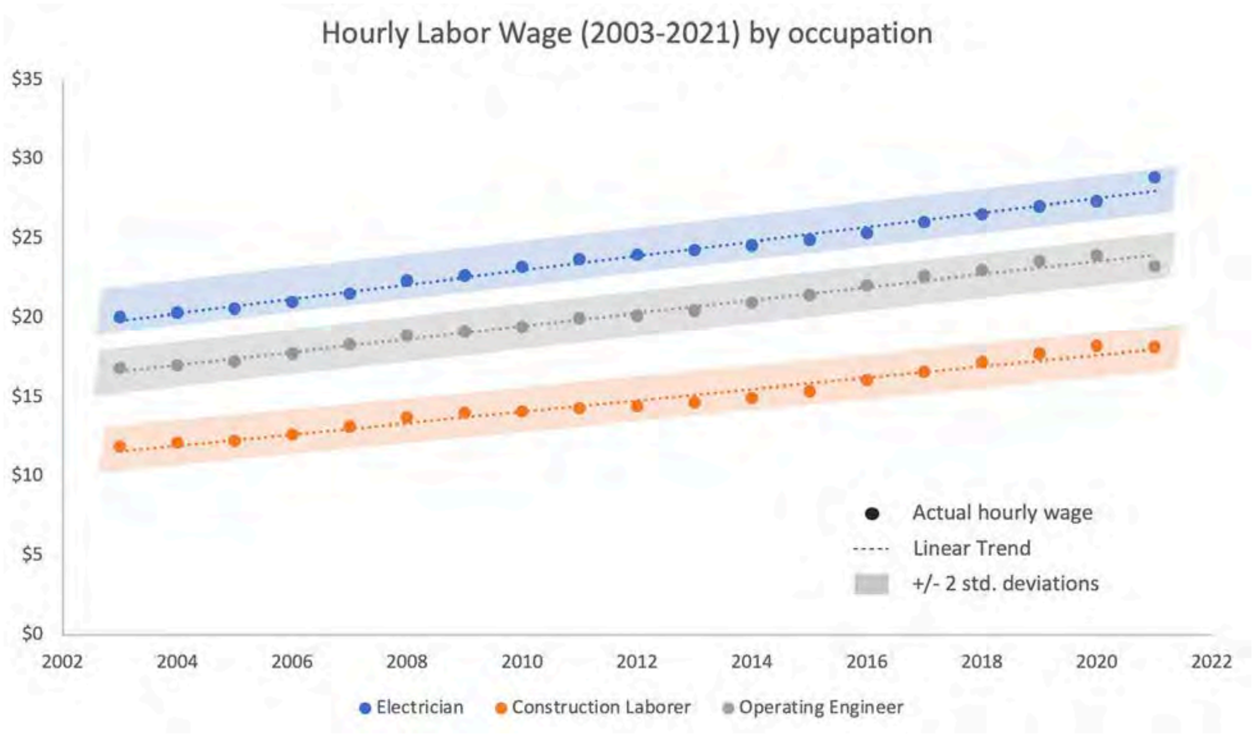

Figure 6. Example of calculating MSP inputs for installation labor

Source: BLS (2022b)

4.4.2 MMP Benchmark

The Q1 2022 MMP benchmark employs methods like those used in NREL's recent benchmarking efforts, including the Q1 2021 report (Ramasamy et al. 2021). This benchmark has been produced in conjunction with several related research activities at NREL and LBNL, which are documented by Feldman et al. (2021), Barbose et al. (2020), Bolinger et al. (2020),[6] Chung et al. (2015), Feldman et al. (2015), and Fu et al. (2016).

The MMP benchmark includes bottom-up accounting for all necessary system and project development costs incurred when installing PV and storage systems. It uses Q1 2022 costs and excludes any previous supply agreements or contracts. We attempt to model the typical installation techniques and business operations from an installed-cost perspective. All MMP benchmarks include variation—accounting for the differences in size, equipment, and operational use (particularly for storage) that are currently available in the marketplace. All MMP and MSP benchmarks assume nonunionized construction labor; residential and commercial PV systems predominantly use nonunionized labor, and the type of labor required for utility-scale PV systems depends heavily on the development process. All MMP and MSP benchmarks assume the use of monofacial monocrystalline silicon PV modules. Benchmarking

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[6] Lawrence Berkeley National Laboratory compares the bottom-up cost results of various entities, including our results.

using cadmium telluride or bifacial modules could result in significantly different results.[7] Likewise, the MMP and MSP benchmarks assume installation of containerized battery systems shipped as cabinets that include lithium iron phosphate (LFP) battery packs and battery racks, as well as a battery management system, thermal management system, and fire suppression system.

Our MMP benchmarks can be interpreted as sales prices that a developer would have charged in Q1 2022. There is wide variation in developer profits; project pricing depends on region and project specifics such as local retail electricity rate structures, local rebate and incentive structures, the competitive environment, and overall project or deal structures. The profit margins that we assume are meant to represent typical profit margins achieved over the long term in a competitive market.

4.5 Limitations

The NREL benchmarks convert complex processes and inputs into highly simplified individual estimates. These simplified estimates are useful for tracking and projecting technological progress. However, no individual estimate under any approach can reflect the diversity of the PV and storage manufacturing and installation industries. The MMP benchmarks are designed to reflect typical costs, but these costs do not reflect the experiences of all installers and customers. For instance, MMP benchmarks are based on national average costs and do not necessarily reflect the distinct experiences of developers in local markets (Figure 7). The benchmarks also explicitly exclude certain costs that reflect key system components for certain customers. For instance, many residential customers finance their PV systems, but the benchmarks exclude financing costs, which can represent around 20% of reported market prices. For further research on the complexity of PV markets and reported market prices, see Gillingham et al. (2016) and Barbose et al. (2021a).

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[7] In this report, we focus on the installation costs of crystalline silicon modules, but a significant portion of U.S. utility-scale PV systems use cadmium telluride modules. From 2010 to 2020, cadmium telluride modules accounted for approximately 29% of U.S. utility-scale PV deployment (EIA 2021). This portion of the market is particularly notable given that cadmium telluride modules represented only 4% of global PV shipments over the same period. Similarly, a growing number of U.S. systems are beginning to use bifacial modules with transparent backs, which generate electricity from both sides of the module—as opposed to traditional monofacial modules, which typically have opaque backsheets. Because of the newness of bifacial modules, we do not have sufficient data on their current U.S. market share.

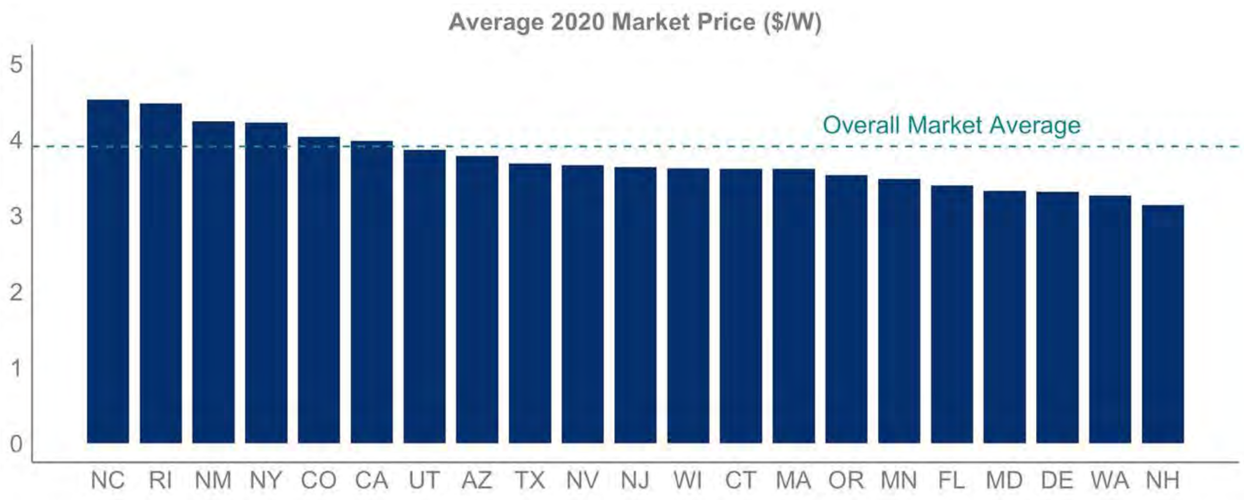

Figure 7. Average 2020 residential PV market prices by state

Based on data from Barbose et al. (2021a)

Finally, any comparison of NREL benchmarks with reported market prices or other price benchmarks should be implemented with caution. As already discussed, market prices and different price benchmarks reflect different assumptions and should be used for different purposes. In the case of the MSP benchmarks, the MSP is a theoretical construct that may never be observed in imperfectly competitive markets in the real world. The NREL MSP benchmarks are meant to provide stable estimates of input costs based on long-term trends that are useful for making long-term decisions, including R&D directions. In contrast, the NREL MMP benchmarks are meant to reflect current market conditions relevant to making short-term decisions, including policy recommendations.

4.6 Changes to the NREL Benchmark in Q1 2022

Based on our industry research, we made several changes to the NREL benchmark report between last year's report (Q1 2021) and this year's report (Q1 2022). This year, we added a supply chain premium for residential battery pack cost, commercial battery pack cost, and commercial PV module cost based on information from our stakeholder interviews. For residential systems, we assume only a microinverter option and small-scale installers, instead of the weighted approach used in Q1 2021 that assumes three inverter types and two installer types. These choices simplify the system cost analysis by focusing on the most common installation choices, making the results easier to interpret. In Q1 2022, microinverters and string inverters with power optimizers were the dominant inverter technologies for residential PV, but the share of microinverters has been increasing over the past several years, while the share of inverters with power optimizers has been declining (Wood Mackenzie 2022a). Similarly, this year, our commercial benchmark system only assumes use of a string inverter, because that technology was most common in the commercial PV sector in Q1 2022 (Wood Mackenzie 2022a). We infer the predominance of small-scale installers in the residential sector using data on residential system financing (Wood Mackenzie 2022b). The higher efficiency of modules assumed for Q1 2022 (CA NEM 2022) results in larger residential PV system sizes compared with systems in Q1 2021. Additional details on model inputs are provided in the following sections.

5 Residential PV Model

This section describes our residential PV model's structure and parameters in intrinsic units (Section 5.1) as well as its output (Section 5.2). Residential PV systems are typically in the range of 4 kW_{dc} to 10 kW_{dc} (Barbose et al. 2021a). Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

5.1 Model Structure and Representative System Parameters

We model a 22-module (7.9-kW_{dc}) residential rooftop system installed by a small enterprise using 20.3%-efficient, 1.77-m^2, 360-W_{dc} monocrystalline modules from a Tier 1 supplier (CA NEM 2022) with roughly 300-W_{ac} microinverters and a flush-mounted, pitched-roof racking system. Figure 8 presents the cost drivers, cost categories, inputs, and outputs of the model. Table 4 details the modeled parameters in their intrinsic units.

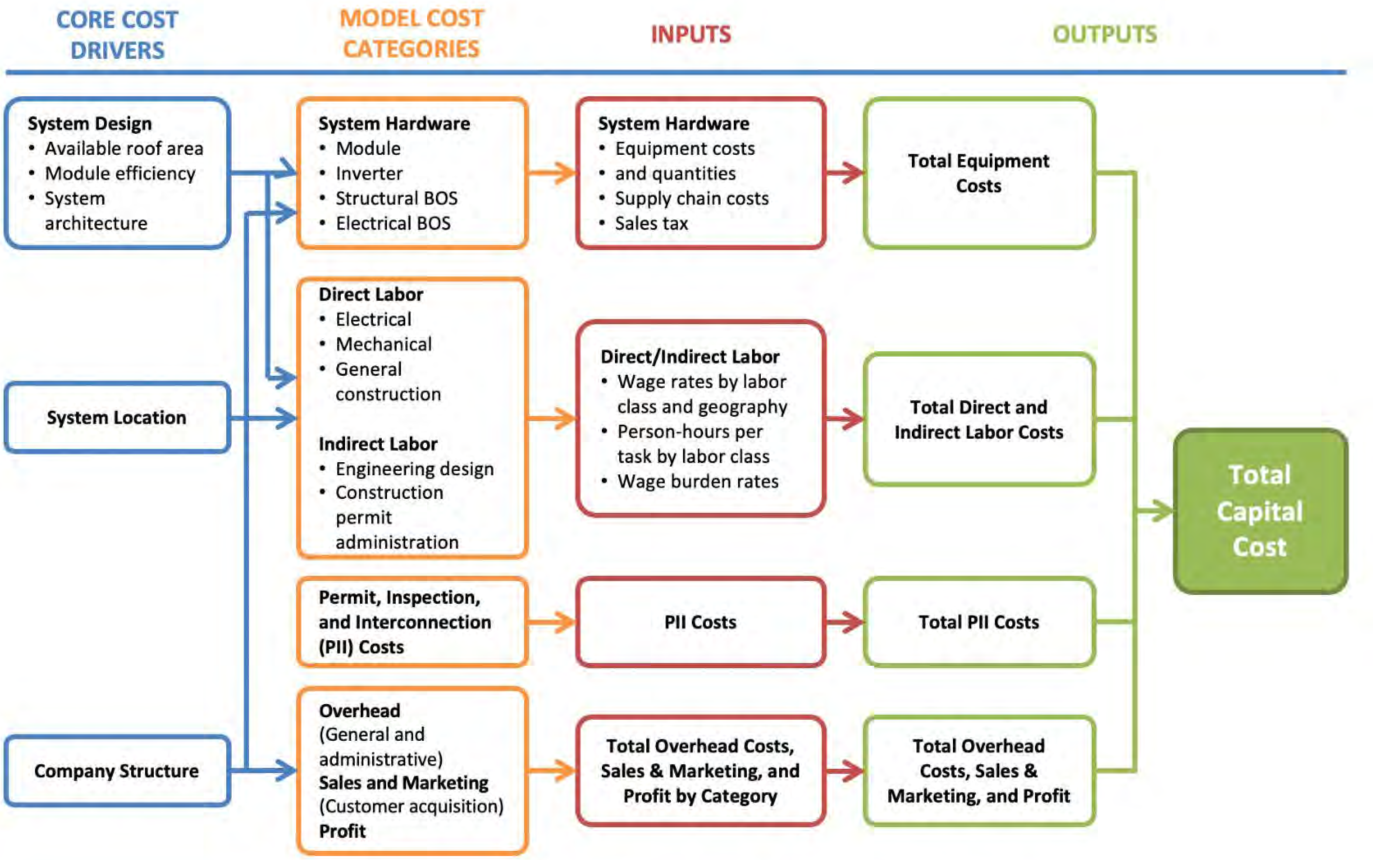

Figure 8. Residential PV: model structure

BOS = balance of system

Table 4. Residential PV: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
System size	7.9 kW_{dc}—representative 22-module system using the following formula: number of modules * module efficiency * module area * average radiation under standard test conditions (STC) = 22 * 20.3% * 1.77 m^2 * 1,000 W_{dc}/m^2 = 7.9 kW_{dc}		CA NEM (2022)
Module efficiency	20.3%—average module efficiency		CA NEM (2022)
Module power	360 W_{dc}—rated module power module efficiency * module area * average radiation under STC = 20.3% * 1.77 m^2 * 1,000 W_{dc}/m^2 = 360 W_{dc}		CA NEM (2022)
Module price	\$0.48/W_{dc} Value derived from bottom-up cost modeling Assumes modules from Southeast Asia, excludes U.S. tariffs in PV supply chain, includes supply chain premium for small installers[a]	\$0.54/W_{dc} Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules Assumes modules from Southeast Asia, influenced by U.S. tariffs in PV supply chain, includes supply chain premium for small installers[a]	MSP from NREL modeling, MMP from Woodmac and SEIA (2022)
Microinverter price	\$0.36/W_{ac} (inverter loading ratio [ILR] = 1.21) Avg of 2017–2021 costs (distorted 2022 costs removed)/(1+25%) Excludes 25% Section 301 tariff Includes supply chain premium for small installers[a]	\$0.53/W_{ac} (ILR = 1.21) Ex-factory gate (first buyer) price, Tier 1 inverters Includes supply chain premium for small installers[a]	Barbose et al. (2021a), Woodmac and SEIA (2022), USITR (2018)
Structural BOS (racking)	\$19.1/m^2 Includes flashing for roof penetrations and all rails and clamps Avg of 2019–2021 costs (distorted 2022 costs removed) Includes supply chain premium for small installers[a]	\$31.5/m^2 Includes flashing for roof penetrations and all rails and clamps 2022 online racking material cost Includes supply chain premium for small installers[a]	Online Material Cost: RENVU (2022), EcoDirect (2022), altE Store (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Electrical BOS	$\$37.2/m^2$ + \$1,016 Conductors, switches, combiners, and transition boxes, as well as conduit, grounding equipment, monitoring system or production meters, fuses, and breakers Avg of 2019–2021 costs (distorted 2022 costs removed) Includes supply chain premium for small installers[a]	$\$43.7/m^2$ + \$1,231 Conductors, switches, combiners, and transition boxes, as well as conduit, grounding equipment, monitoring system or production meters, fuses, and breakers 2022 online electrical material cost Includes supply chain premium for small installers[a]	Online Material Cost: RENVU (2022), EcoDirect (2022), altE Store (2022)
Sales tax	National average—5.1% Sales tax on materials and equipment		RSMeans (2022)
Installation labor	0.56 hours/m^2 for module and racking installation at \$24.00/hour (construction laborer), 0.51 hours/m^2 for electrical installation at \$38.15/hour (electrician)[b] Modeled national average labor rates		BLS (2022b), NREL (2022), RSMeans (2022)
Permitting, inspection, and interconnection (PII)	\$1,628 per system installation Completed and submitted applications, fees, design changes, and field inspection		NREL (2022), Cook et al. (2021)
Sales and marketing (customer acquisition)	\$3,139 per system installation Initial and final drawing plans, advertising, lead generation, sales pitch, contract negotiation, and customer interfacing		NREL (2022)
Overhead (general and administrative)	\$2,060 per system installation Rent, building, equipment, and staff expenses not directly tied to PII, customer acquisition, or direct installation labor		NREL (2022)
Profit	17% Fixed percentage margin applied to all direct costs, including hardware, installation labor, sales tax, installation, and permitting fees		NREL (2022), Fu et al. (2017)

[a] Premiums are 53% for modules, 41% for inverters, and 15% for BOS (LMI 2022, NREL 2022). For all cost values given in dollars per square meter ($\$/m^2$) terms, the denominator refers to square meters of total module surface area.

[b] Labor rates include a 32.3% burden for workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability, based on the total nationwide average from RSMeans (2022).

5.2 Model Output

Figure 9 compares our MSP and MMP benchmarks for residential systems. For Q1 2022, we assume PV systems use microinverters and are installed by small-scale installers (see Section 4.6). In contrast, the Q1 2021 benchmark was derived from a weighted average of three inverter types as well as installation by small and large installers.

For Q1 2022, our MSP benchmark (\$2.55/W_{dc}) is 14% lower than our MMP benchmark (\$2.95/W_{dc}). Our Q1 2022 MMP benchmark is 2% higher than our comparable microinverter-based system benchmark from Q1 2021, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

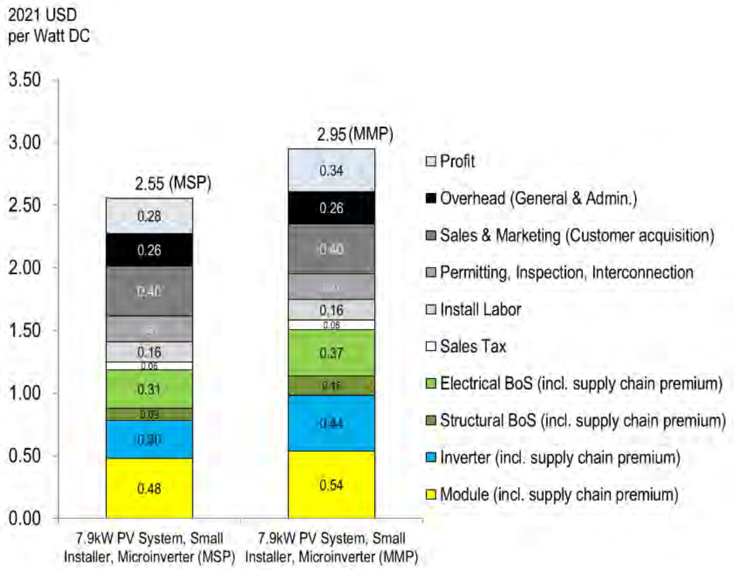

Figure 9. Q1 2022 U.S. benchmark: 7.9-kW_{dc} residential PV system cost (2021 USD/W_{dc})

6 Commercial PV Model

This section describes our commercial PV model's structure and parameters in intrinsic units (Section 6.1) as well as its output (Section 6.2). Commercial PV systems are roughly in the range of 100 kW_{dc} (small nonresidential) to 5 MW_{ac} (large nonresidential) (Barbose et al. 2021a). Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

6.1 Model Structure and Representative System Parameters

We model a 200-kW_{dc}, 1,000-volt dc (V_{dc}) commercial-scale flat-roof system using a ballasted racking solution on a membrane roof as well as a 500-kW_{dc}, 1,000-V_{dc} commercial-scale fixed-tilt ground-mounted system using driven-pile foundations. The ground-mounted system is larger because U.S. ground-mounted systems are larger than rooftop systems on average. Both the rooftop and the ground-mounted PV systems are modeled with three-phase string inverters with an ILR of 1.23. Both use 20.3%-efficient monocrystalline silicon modules from a Tier 1 supplier (CA NEM 2022).

Figure 10 is a schematic of our commercial-scale system cost model, and Table 5 details the modeled parameters in intrinsic units. We separate our cost estimate into EPC and project development functions. Although some firms engage in both activities in an integrated manner, and potentially achieve lower costs and pricing by reducing the total margin across functions, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function.

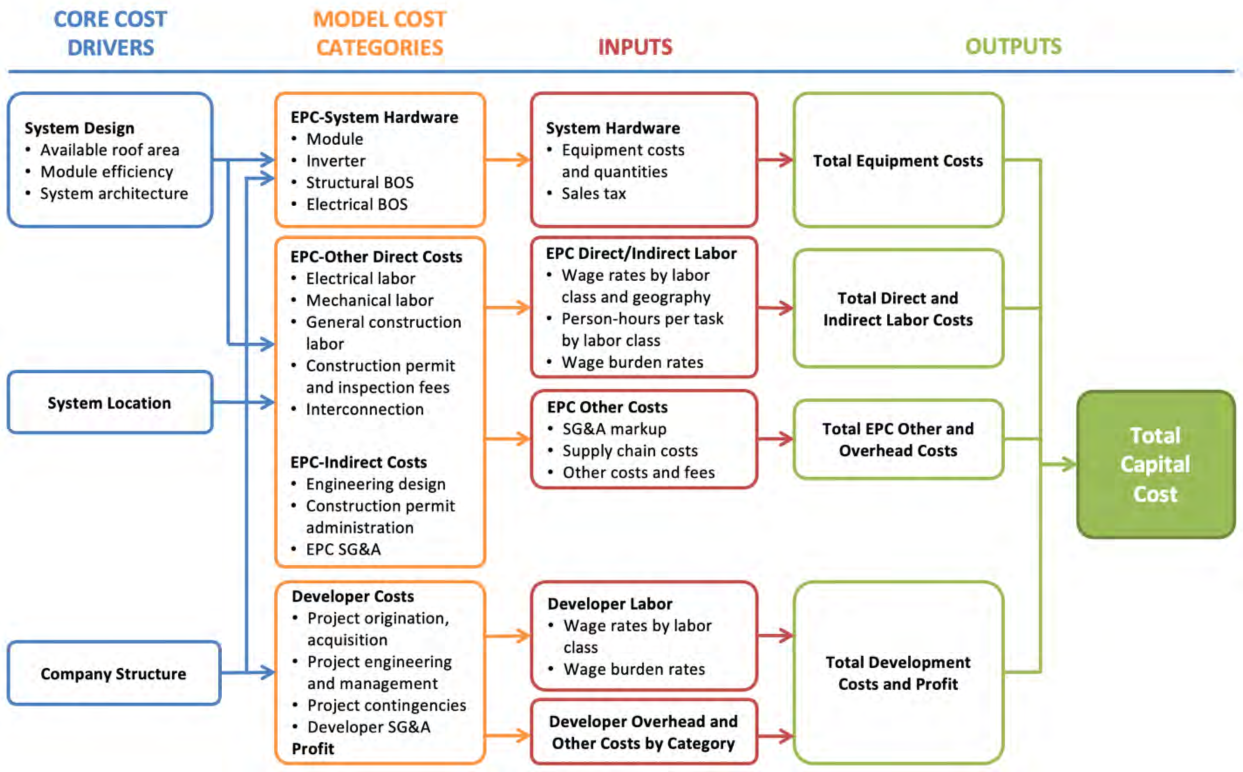

Figure 10. Commercial PV: model structure

SG&A = selling, general, and administrative

Table 5. Commercial PV: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
System size	200 kW_{dc} (rooftop) and 500 kW_{dc} (ground mount)		NREL assumption
Module efficiency	20.3%—national average module efficiency in 2021		CA NEM (2022)
Module power	405 W_{dc}—rated module power module efficiency * module area * average radiation under STC = 20.3% * 1.99 m^2 * 1,000 W_{dc}/m^2 = 405 W_{dc}		CA NEM (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Module price	\$0.40/$\mathrm{W_{dc}}$ Bottom-up cost modeling Includes supply chain premium for a local installer[a]	\$0.45/$\mathrm{W_{dc}}$ Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules Includes supply chain premium for a local installer[a]	MSP from NREL modeling, MMP from Woodmac and SEIA (2022)
Three-phase string inverter price	\$0.06/$\mathrm{W_{ac}}$ (ILR = 1.23) Avg of 2017–2021 costs (distorted 2022 costs removed)/(1+25%) Excludes 25% Section 301 Tariff	\$0.07/$\mathrm{W_{ac}}$ (ILR = 1.23) Ex-factory gate (first buyer) price, Tier 1 inverters	Barbose et al. (2021a), Woodmac and SEIA (2022), USITR (2018)
Structural BOS (racking)	\$25/m^2 (rooftop), \$24/m^2 (ground mount) Flat-roof ballasted racking system or fixed-tilt ground-mounted racking system Assumes national average wind and snow loading[b] Avg of 2017–2021 costs (distorted 2022 costs removed)	\$27/m^2 (rooftop), \$35/m^2 (ground mount) Flat-roof ballasted racking system or fixed-tilt ground-mounted racking system Assumes national average wind and snow loading[b] Q1 2022 material cost	RSMeans (2022), NREL (2022)
Electrical BOS	\$27/m^2 + \$2,360 (rooftop), \$47/m^2 + \$18,282 (ground mount) Conductors, conduit and fittings, transition boxes, switchgear, panel boards, and other parts Avg of 2017–2021 costs (distorted 2022 costs removed)	\$38/m^2 + \$3,816 (rooftop), \$50/m^2 + \$19,481 (ground mount) Conductors, conduit and fittings, transition boxes, switchgear, panel boards, and other parts Q1 2022 material cost	NREL (2022), RSMeans (2022)
Installation rental equipment	\$3.85/m^2 (rooftop), \$11.90/m^2 (ground mount) Avg of 2017–2021 costs (distorted 2022 costs removed)	\$3.95/m^2 (rooftop), \$14.60/m^2 (ground mount) Q1 2022 rental equipment cost	RSMeans (2022)
Installation labor	1.16 hours/m^2 at \$22.84/hour (rooftop), 0.88 hours/m^2 at \$20.19/hour (ground mount) for civil and electrical work Modeled national average, nonunionized labor rates		BLS (2022b), NREL (2022)
PII	\$18,053 (rooftop) and \$19,873 (ground mount) including \$5,713 fixed permitting cost Construction permit fees, interconnection study fees for existing substation, testing, and commissioning		NREL (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
EPC overhead (percentage of equipment costs)	13% for module, inverter, and BOS material and equipment costs, 54% for labor costs[c] (rooftop) 13% for BOS material and equipment costs, 54% for labor costs[c] (ground mount) Costs and fees associated with EPC overhead, installation labor burden, inventory, shipping, and handling		NREL (2022)
Sales tax	National average—5.8% Sales tax on hardware, BOS materials and equipment		RSMeans (2022)
Developer overhead	30% of module, inverter, BOS materials, rental equipment, labor, and EPC overhead (rooftop) 30% of module, inverter, BOS materials, rental equipment, labor, PII, EPC overhead, and sales tax (ground mount) Assumed to include overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		NREL (2022)
Contingency	4% of module, inverter, BOS materials, rental equipment, labor, and EPC overhead (rooftop) 4% of module, inverter, BOS materials, rental equipment, labor, PII, EPC overhead, and sales tax (ground mount)		NREL (2022)
Profit	7% (rooftop), 8% (ground mount) Applies a fixed percentage margin to all costs, including module, inverter, BOS materials, installation labor and equipment, PII, EPC overhead, sales tax, contingency, and developer overhead		NREL (2022)

[a] 26.9% procurement premium for local installers (LMI 2022, NREL 2022).

[b] Racking companies currently meet the national standard, so there is not as much differentiation by state in the market within rooftop systems. The ground-mounted racking system requires more material, equipment, and labor than the ballasted racking system. However, installation of ground-mounted PV systems at utility scale helps reduce the BOS cost of these systems because of economies of scale. Note that, for all cost values given in dollars per square meter ($\$/m^2$) terms, the denominator refers to square meters of total module surface area.

[c] The 54% for labor costs includes a labor burden rate of 41.7%—representing workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability—plus an average of 12% labor overhead (RSMeans 2022).

6.2 Model Output

Figure 11 compares our MSP and MMP benchmarks for commercial systems. For Q1 2022, our MSP benchmarks ($\$1.63/W_{dc}$ for rooftop, $\$1.71/W_{dc}$ for ground mount) are 11% and 12% lower than our MMP benchmarks ($\$1.84/W_{dc}$ and $\$1.94/W_{dc}$), respectively. Our Q1 2022 MMP benchmarks are roughly 8% higher than their counterparts in Q1 2021, because the MMP benchmarks are affected by the market distortion that occurred in Q1 2022.

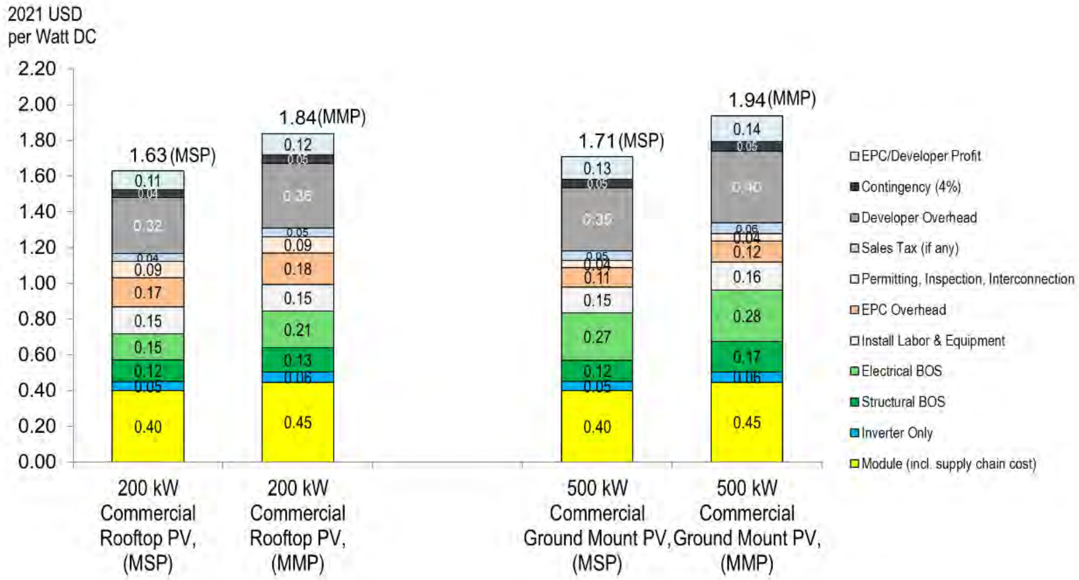

Figure 11. Q1 2022 U.S. benchmark: commercial PV system cost (2021 USD/W_{dc})

7 Utility-Scale PV Model

This section describes our utility-scale PV model's structure and parameters in intrinsic units (Section 7.1) as well as its output (Section 7.2). We assume utility-scale PV systems typically have a system size greater than or equal to 5 MW_{dc}. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

7.1 Model Structure and Representative System Parameters

We model a baseline 100-MW_{dc}, 1,500-V_{dc} tracking utility-scale system using 20.3%-efficient, 1.99-m^2 monofacial monocrystalline silicon modules from a Tier 1 supplier and three-phase central inverters with an ILR of 1.34. We separate our cost estimates into EPC and project-development functions. Although some firms engage in both activities in an integrated manner, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function. Figure 12 is a schematic of our utility-scale system cost model, and Table 6 details its parameters in intrinsic units.

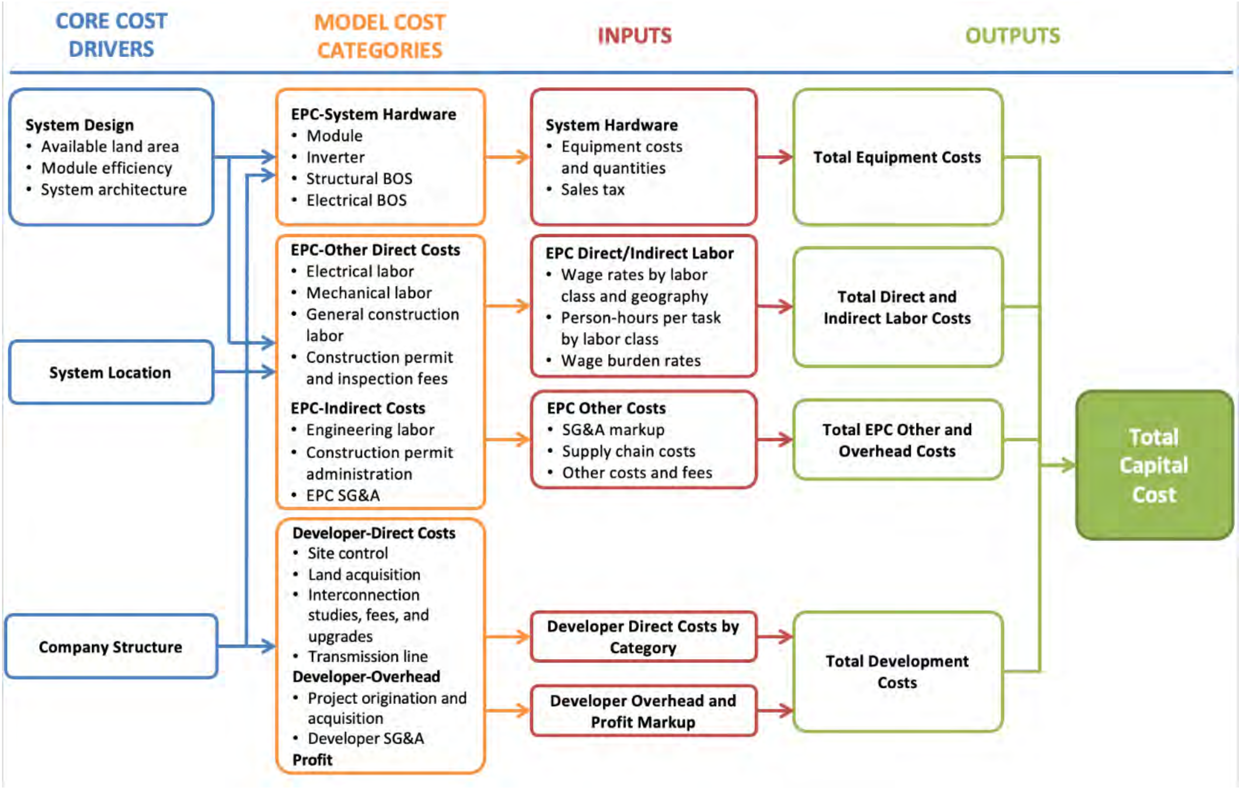

Figure 12. Utility-scale PV: model structure

Table 6. Utility-Scale PV: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
System size	100 $\mathrm{MW_{dc}}$—a large single-axis tracking utility-scale system capacity		Model assumption
Module efficiency	20.3%—national average silicon module efficiency		CA NEM (2022)
Module power	405 $\mathrm{W_{dc}}$—rated module power module efficiency * module area * average radiation under STC = 20.3% * 1.99 $\mathrm{m^2}$ * 1,000 $\mathrm{W_{dc}/m^2}$ = 405 $\mathrm{W_{dc}}$		CA NEM (2022)
Module price	\$0.31/$\mathrm{W_{dc}}$ Bottom-up cost modeling No supply chain premium owing to large orders	\$0.35/$\mathrm{W_{dc}}$ Ex-factory gate (first buyer) price, Tier 1 monocrystalline modules No supply chain premium owing to large orders	MSP from NREL modeling, MMP from Woodmac and SEIA (2022)
Inverter price	\$0.05/$\mathrm{W_{ac}}$ (ILR = 1.34) Avg of 2017–2021 costs (distorted 2022 costs removed)[a]	\$0.04/$\mathrm{W_{ac}}$ (ILR = 1.34) Ex-factory gate (first buyer) price, Tier 1 inverters	Woodmac and SEIA (2022), Bolinger et al. (2021)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Structural BOS (racking)	\$24.5/m^2 (tracking)[b] Avg of 2017–2021 costs (distorted 2022 costs removed)	\$35.9/m^2 (tracking) Q1 2022 material cost	Model assumptions, RSMeans (2022), NREL (2022)
Electrical BOS	\$15.4/m^2 + \$64,865 Modeled 1,500-V$_{dc}$ system, including conductors, conduit and fittings, transition boxes, switchgear, panel boards, on-site transmission, and other electrical connections Avg of 2017–2021 costs (distorted 2022 costs removed)	\$16.2/m^2 + \$73,000 Modeled 1,500-V$_{dc}$ system, including conductors, conduit and fittings, transition boxes, switchgear, panel boards, on-site transmission, and other electrical connections Q1 2022 material cost	Model assumptions, RSMeans (2022), NREL (2022)
EPC overhead (percentage of equipment costs)	\$106,000 + 8.3% * (electrical BOS, structural BOS, and installation rental equipment) + 54% * direct installation labor[c] Costs associated with installation labor burden, EPC SG&A, warehousing, shipping, and logistics		NREL (2022)
Installation rental equipment	\$11.1/m^2 (100-MW tracking) Avg of 2017–2021 costs (distorted 2022 costs removed)	\$13.5/m^2 (100-MW tracking) Q1 2022 rental equipment cost	RSMeans (2022)
Direct installation labor	0.7 hours/m^2 for all civil and electrical work at \$15.6/hour Modeled national average, nonunionized labor rates		BLS (2022b), NREL (2022)
Sales tax	National average—5.8% Sales tax on hardware, material, and equipment costs		RSMeans (2022)
PII	\$0.02/W$_{ac}$ + \$209,466 Construction permit fees, interconnection, testing, and commissioning		NREL (2022)
Transmission line (gen-tie line)	\$600,734/mile 1.7 miles[d] Avg of 2017–2021 costs (distorted 2022 costs removed)	\$765,941/mile 1.7 miles[d] Q1 2022 material cost	Model assumptions, NREL (2022), RSMeans (2022)
Developer overhead	\$550,000 + 1.5% * (module, inverter, structural and electrical BOS, installation labor and equipment, EPC overhead, PII, and sales tax) Assumed to include overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		Model assumptions, NREL (2022)

Category	**MSP Value (2021 Real USD)**	**MMP Value (2021 Real USD)**	**Sources**
Contingency	3% Estimated as markup on module, inverter, BOS material and equipment, sales tax, EPC overhead, and permitting cost		NREL (2022)
Profit	$200,000 + 4.9% * (all system costs) Applies a percentage margin to all costs, including module, inverter, structural and electrical BOS, labor and equipment, EPC overhead, PII, sales tax, developer overhead, contingency, and transmission		NREL (2022)

[a] Most central utility-scale inverters installed in the United States are manufactured in Europe and are not subject to Section 301 U.S. tariffs on Chinese products (Wood Mackenzie 2022c, Woodmac and SEIA 2021). For this reason, we do not adjust the MSP value for Section 301 tariffs.

[b] Note that, for all cost values given in dollars per square meter ($\$/\text{m}^2$), the denominator refers to square meters of total module surface area.

[c] The 54% for labor costs includes a labor burden rate of 41.7%—representing workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability—plus an average of 12% labor overhead (RSMeans 2022).

[d] System < 10 MW_{dc} uses 0 miles for gen-tie line, thus no transmission cost; system > 200 MW_{dc} uses 5 miles for gen-tie line; and system = 10–200 MW_{dc} uses linear interpolation.

7.2 Model Output

Figure 13 compares our MSP and MMP benchmarks for single-axis-tracker 100-MW_{dc} utility-scale PV systems. For Q1 2022, our MSP benchmark with tracking ($\$0.87/\text{W}_{\text{dc}}$) is 12% lower than our MMP benchmark with tracking ($\$0.99/\text{W}_{\text{dc}}$). Our Q1 2022 MMP benchmark with tracking is 6% higher than its counterpart in Q1 2021, because of the market distortion that occurred in Q1 2022.

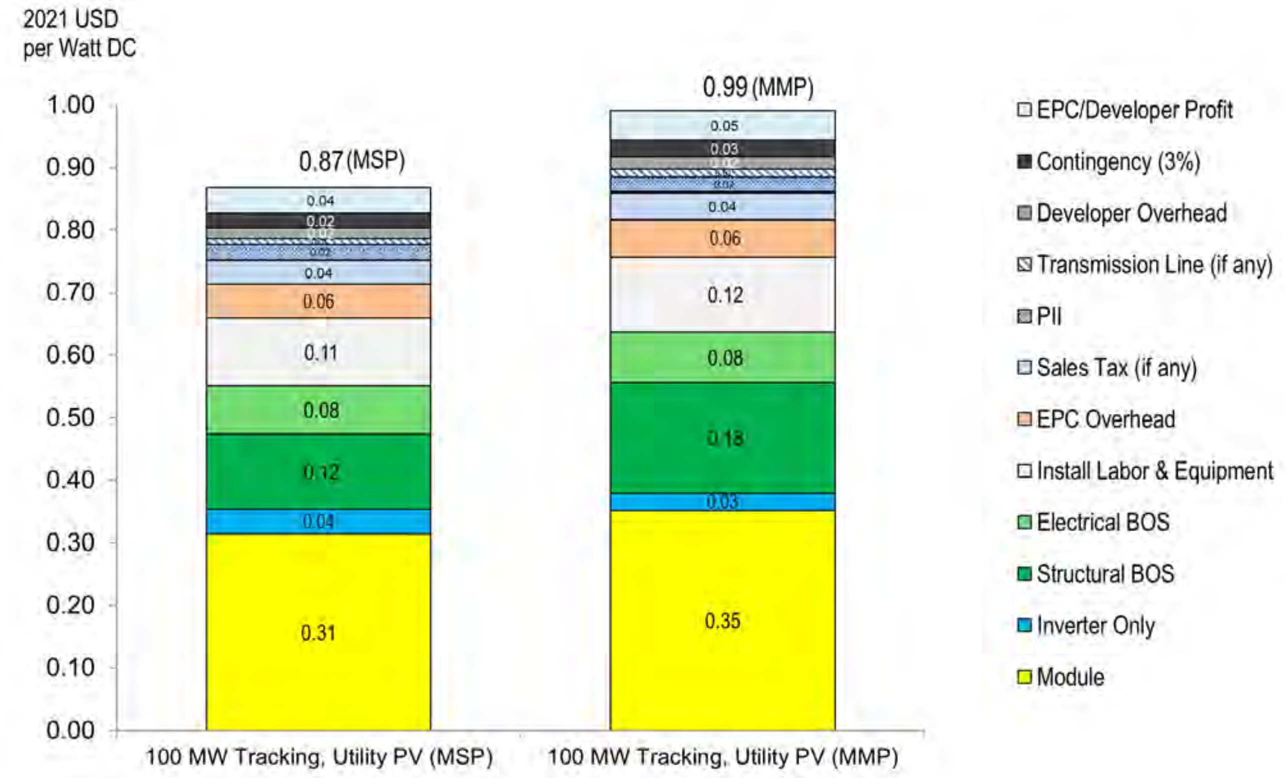

Figure 13. Q1 2022 U.S. benchmark: utility-scale PV systems (2021 USD/W_{dc})

8 Residential Storage and PV-Plus-Storage Model

To analyze component costs and system prices for PV-plus-storage systems installed in Q1 2022, we adapt NREL's component- and system-level modeling approach for standalone PV. For this report, system configuration refers to five characteristics that determine a PV-plus-storage system's functionality:

- PV system rated power capacity (kW_{dc})
- Inverter rated power capacity (kW_{ac})
- Battery energy capacity (kWh)
- Battery power capacity (kW_{dc})
- Whether the battery is dc- or ac-coupled.[8]

Customer preference for specific characteristics is based on several factors, including cost, load profile, and planned use of the system for load shifting (storing energy in one period for use in a later period). In general, customers who have loads with high peaks of short duration may desire a high-power (high-kW) battery capable of meeting the high peak. Customers who have flatter loads with lower peaks of longer duration may prefer a high-energy (high-kWh) battery capable of longer-duration energy discharge. Because of the historical levels of residential PV-plus-storage installations, we now have significantly more system characteristic data on which to base our benchmark (unlike previous benchmarking reports, in which we used optimization calculations). We benchmark a 5-kW_{dc} (12.5-kWh_{dc}) residential battery system, based on data reported by Barbose et al. (2021b).

A PV array, a battery, and at least one inverter are the fundamental components of every PV-plus-storage system. Additional component requirements are determined by whether the system is dc- or ac-coupled.[9] A dc-coupled system often requires a charge controller to step down the PV output voltage to a level that is safe for the battery, whereas an ac-coupled system requires a grid-tied inverter to feed PV output directly to the customer's load or the grid.[10] For a detailed discussion of the differences and considerations related to dc- versus ac-coupled system configurations, see Ardani et al. (2017).

Sections 8.1 and 8.2 present the residential storage and PV-plus-storage cost models, and Section 8.3 shows the model outputs. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

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[8] NREL's modeled dc-coupled system includes a single dual-function inverter that is tied to both the PV array and the battery. In our ac-coupled system, to charge a battery, PV power is first converted (dc to ac) through a grid-tied inverter and then converted (ac to dc) through a battery-based inverter.

[9] Our discussion is simplified to explain the basic technical differences between ac- and dc-coupled systems. The decision to use ac- or dc-coupling might also be driven by nontechnical factors such as policy, contractual obligations, and economics.

[10] Some Li-ion battery packs have built-in safety controls, such as those integrated in a battery management system, but some do not. For consistency, our model assumes there is a dedicated charge controller.

8.1 Lithium-Ion Standalone Storage System Cost Model

The residential storage market is predominantly composed of fully integrated storage kits, which include lithium-ion (Li-ion) battery packs, inverters, field wiring, disconnect, and casing. Although this equipment is sold as one product, we model these components separately to compare costs across storage kit sizes and configurations. Table 7 presents the modeled parameters in intrinsic units for the residential standalone storage costs (no PV).

Table 7. Residential Storage Only: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Rated (nameplate) system size	5-kW_{dc}/12.5-kWh_{dc} storage with an 8-kW_{ac} inverter Typical U.S. residential battery system 1.5-m^2 footprint per battery pack		Barbose et al. (2021b)
Battery pack cost	$235/kWh MMP*(1–17.04%) Accounts for average cost reduction rate of turnkey battery systems between 2017 and 2021	$283/kWh 2-hour battery pack cost adjusted to inflation (+) 31.5% residential battery supply premium	BNEF (2021), NREL (2022)
Battery-based inverter cost	$0.23/$\text{W}_{\text{ac}}$ MMP/(1+25%) Removes Section 301 tariff	$0.29/$\text{W}_{\text{ac}}$ 2020 BNEF battery inverter cost adjusted for inflation	BNEF (2020), NREL (2022), USITR (2018)
BOS cost	$1,362 (ac-coupled) Revenue-grade meter, communications device, ac main panel, dc disconnect, maximum power point tracking, charge controller, subpanel (breaker box) for critical load, conduit, wiring, dc cable Avg of 2017–2021 costs (distorted 2022 costs removed)	$1,567 (ac-coupled) Revenue-grade meter, communications device, ac main panel, dc disconnect, maximum power point tracking, charge controller, subpanel (breaker box) for critical load, conduit, wiring, dc cable 2022 online material cost	Online Material Cost: RENVU (2022), EcoDirect (2022), altE Store (2022)
Supply chain costs	6.5% of cost of battery, battery inverter, and BOS		NREL (2022), LMI (2022)
Engineering fee	$95 per system Engineering design and professional engineer-stamped calculations and drawings		NREL (2022)
PII	$1,633 including $286 permit fee per system		NREL (2022)
Sales tax	National average—5.1% Sales tax on battery, battery inverter, BOS, and permitting cost		RSMeans (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Direct installation labor	20.8 hours/m^2 at $34.7/hour for hardware installation and electrical work[a] National average, nonunionized labor rates		BLS (2022b), NREL (2022)
Sales and marketing (customer acquisition)	$3,851 per system installation Cost associated with selling a storage system		NREL (2022)
Overhead (general and administrative)	$2,285 per system installation Assumed to include rent, building, equipment, and staff expenses not directly tied to PII, customer acquisition, or direct installation labor		NREL (2022)
Profit (%)	17% Fixed percentage margin applied to battery, battery inverter, BOS, install labor, supply chain, and sales tax		NREL (2022)

[a] Note that, for all values given in per square meter (m^2) terms, the denominator refers to square meters of battery pack footprint. The representative system has 8.3 kWh/m^2. Labor rates include a 54% burden for workers' compensation, federal and state unemployment insurance, Federal Insurance Contributions Act, builder's risk, and public liability, based on the total nationwide average from RSMeans (2022).

Figure 14 compares our MSP and MMP benchmarks for ac-coupled residential standalone storage systems. For Q1 2022, our MSP benchmark ($17,139) is 9% lower than our MMP benchmark ($18,791). Our Q1 2022 MMP benchmark is 2% higher than our benchmark from Q1 2021 in 2021 USD, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

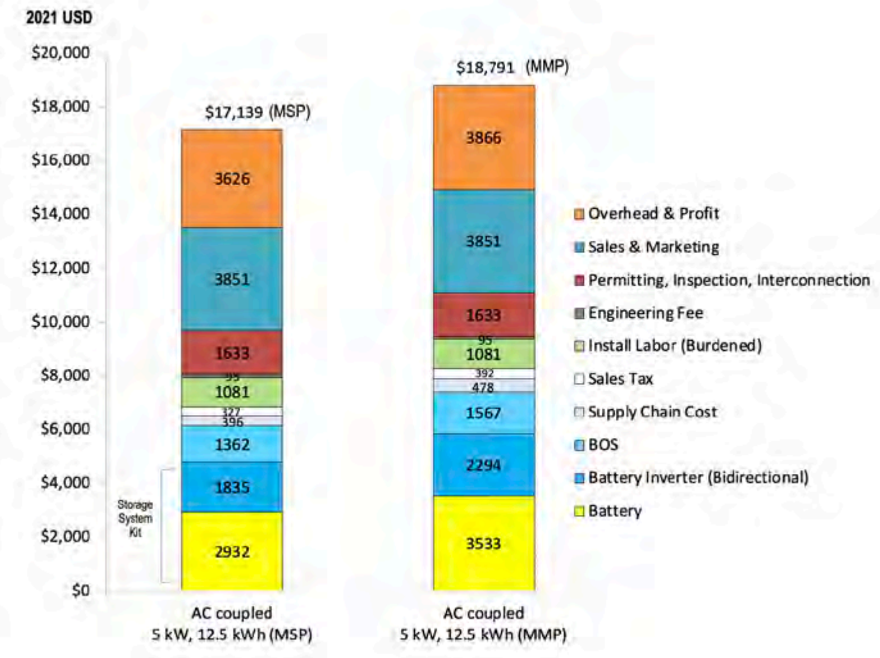
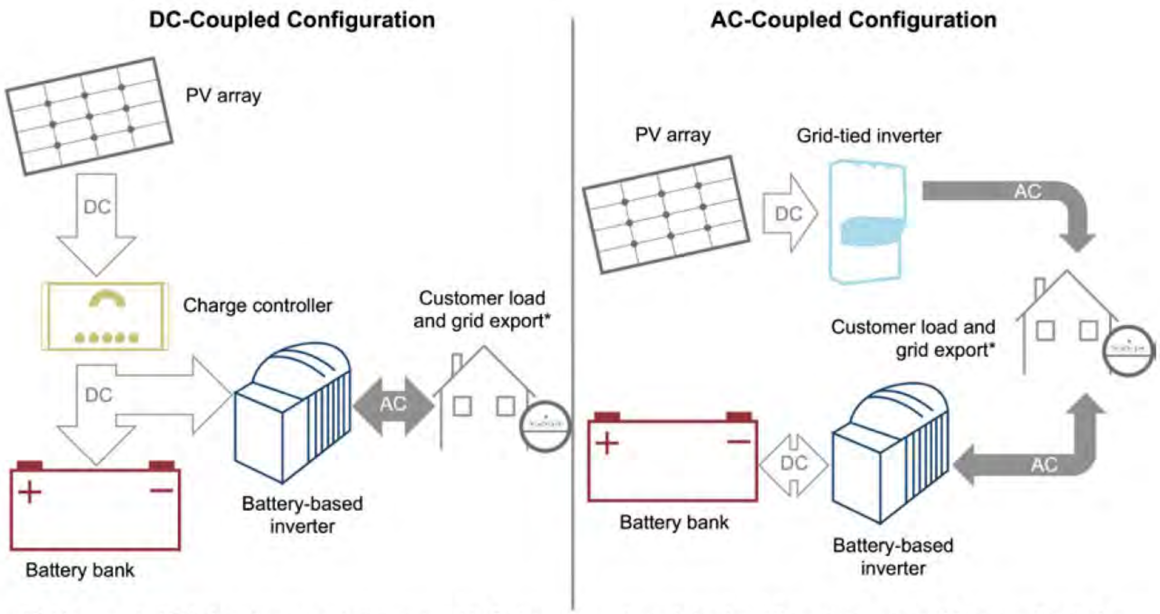


Figure 14. Q1 2022 U.S. benchmark: standalone residential storage system

8.2 PV-Plus-Storage System Cost Model

We model a 7.9-kW$_{dc}$ PV system coupled with a 5-kW$_{dc}$/12.5-kWh$_{dc}$ storage system using the same PV parameters we use with our standalone PV system and standalone storage system, except we consider the symbiotic benefit of ac coupling. Figure 20 is a schematic of typical dc- and ac-coupled PV systems with on-site battery storage. Table 8 presents changes to the standalone residential PV and storage system cost models when PV and storage are combined.



*Grid-connected PV plus storage systems are used to first meet a customer's load and then export excess PV generation to the grid. When wired for back-up power, it is common to install a critical loads sub-panel and use PV plus storage systems to provide power to essential loads (e.g. refrigeration, essential lighting, well pumps) in the case of a grid-outage event.

Figure 15. Modeled dc- and ac-coupled system configurations

Figure is simplified for illustrative purposes.
Source: Feldman et al. (2021)

Table 8. Changes to Residential PV and Storage Models When PV and Storage Are Combined

Category	Modeled Value	Description
Electrical BOS	90% of the combined BOS costs for PV and battery standalone systems	Duplicative parts are removed
Installation labor	90% of the combined installation labor costs for PV and battery standalone systems	Duplicative work is removed
PII	Only includes PII associated with standalone PV system	Duplicative work is removed
Profit	Assumes 15% markup on PV modules, battery, PV and battery inverter, BOS material, and installation labor	Cost of combined system is lower than the cost of separate systems, so the profit markup is lower as well

8.3 Model Output

Figure 16 compares our MSP and MMP benchmarks for ac-coupled residential PV-plus-storage systems. For Q1 2022, our MSP benchmark ($33,858) is 12% lower than our MMP benchmark ($38,295). Also, the Q1 2022 MMP of the ac-coupled PV-plus-storage system is 6% higher than the Q1 2021 benchmark system cost adjusted to 2021 USD.

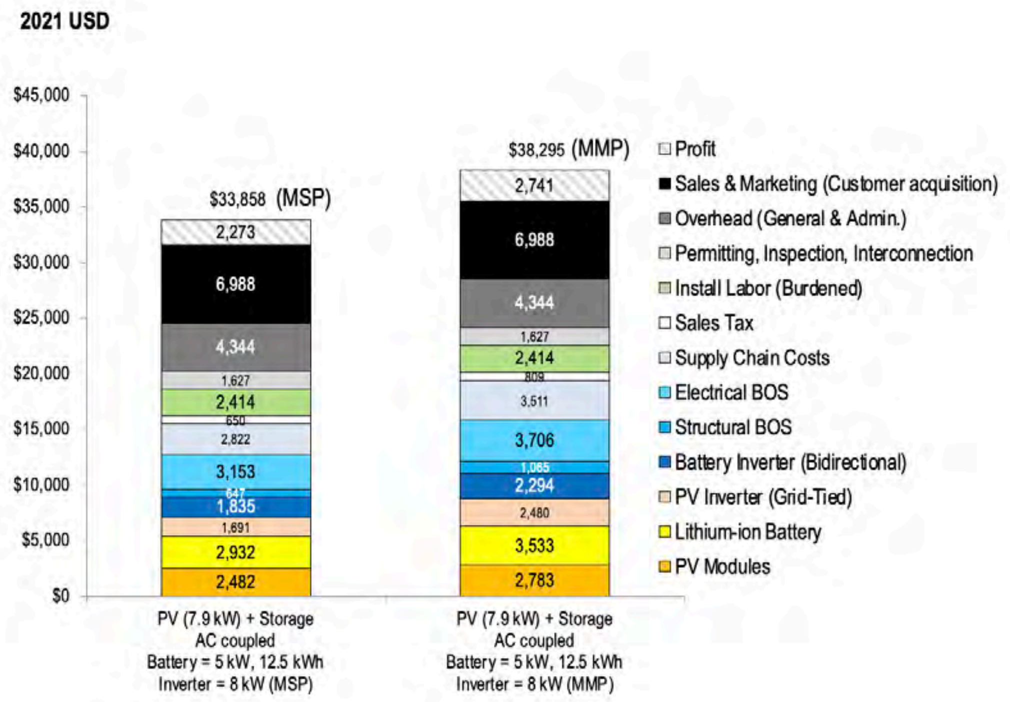


Figure 16. Q1 2022 U.S. benchmark: ac-coupled residential PV-plus-storage systems

9 Commercial Storage and PV-Plus-Storage Model

To analyze component costs and system prices for commercial PV-plus-storage systems installed in Q1 2022, we adapt NREL's component- and system-level modeling approach for standalone PV and standalone storage in a similar manner as for the residential PV-plus-storage system. Customer preference for specific characteristics is based on several factors, including cost, load profile, and planned use of the system for load shifting (storing energy in one period for use in a later period). In general, customers who have loads with high peaks of short duration may desire a high-power (high-kW) battery capable of meeting the high peak. Customers who have flatter loads with lower peaks of longer duration may prefer a high-energy (high-kWh) battery capable of longer-duration energy discharge.

Sections 9.1 and 9.2 present the commercial storage and PV-plus-storage cost models, and Section 9.3 shows the model outputs. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

9.1 Lithium-Ion Standalone Storage System Cost Model

To reduce installation costs, some battery manufacturers combine Li-ion battery cells, a battery management system, and the battery inverter in one compact unit as an ac battery (Sonnen Batterie 2018). However, in this report, we focus on traditional dc batteries typically configured with the components shown in Figure 17 and Figure 18.

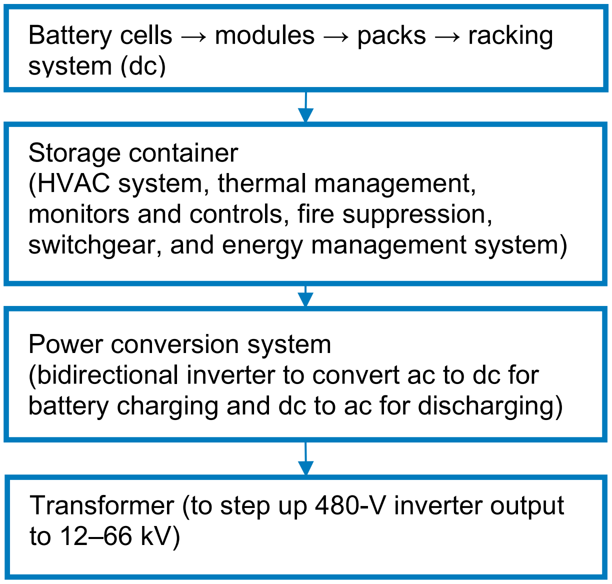


Figure 17. Traditional commercial and utility-scale Li-ion energy storage components

HVAC = heating, ventilating, and air conditioning

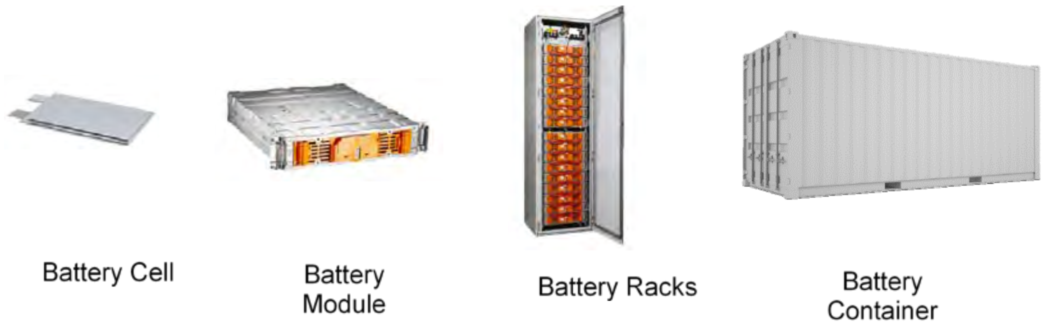


Figure 18. Battery system components

Source: 2018 North American Generator Forum/Energy Systems Integration Group Workshop

Table 9 lists our modeled parameters in intrinsic units for a commercial energy storage system. This year, we assumed the battery size to be 300 kW_{dc} because it is an appropriate match to the representative 500-kW_{dc} benchmark commercial PV system.

Table 9. Commercial Li-ion Energy Storage System: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Battery total size	300 kW rated dc power with a 300-kW_{ac} bidirectional inverter 1.20 MWh rated (usable) dc energy storage		Denholm et al. (2017), NREL (2022)
Duration	4.0 hours Duration = rated energy / rated power		NREL (2022)
Battery size per container	1.8 MWh per 20-ft container with 15-m^2 footprint area[a]		NREL (2022)
Round-trip efficiency (RTE)	90% Round-trip efficiency		NREL (2022)
Min. state of charge (SOC) and max. SOC	10% and 90% Minimum and maximum state of charge Affects the usable energy storage rating		NREL (2022)
Li-ion battery price ($/kWh)	4 hours: $157/kWh MMP*(1–17.04%) Accounts for average cost reduction rate of turnkey battery systems between 2017 and 2021	4 hours: $190/kWh BNEF 2021 price adjusted for inflation (+) 15% commercial battery supply premium	BNEF (2021), NREL (2022)
Battery central inverter price	$0.05/$W_{ac}$ MMP/(1+25%) Removes Section 301 tariff	$0.06/$W_{ac}$ 2019 Woodmac battery inverter cost adjusted for inflation	Wood Mackenzie (2019)
Battery cabinet	$332/kWh For a 1,200-kWh system Includes battery packs, containers, thermal management system, and fire suppression system Battery MSP + avg of other material costs from 2017–2021 (distorted 2022 costs removed)	$393/kWh For a 1,200-kWh system Includes battery packs, containers, thermal management system, and fire suppression system 2022 typical material cost	NREL (2022)
Structural BOS	$1,681/$m^2$ For a 1,200-kWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers Avg of 2017–2021 material costs (distorted 2022 costs removed)	$1,377/$m^2$ For a 1,200-kWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers 2022 typical material cost	NREL (2022), RSMeans (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Electrical BOS	$5,503/m^2 For a 1,200-kWh system Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing Avg of 2017–2021 material costs (distorted 2022 costs removed)	$5,533/m^2 For a 1,200-kWh system Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing 2022 typical material cost	NREL (2022), RSMeans (2022)
Sales tax	National average—5.8% Sales tax on battery cabinet, inverter, and BOS material		RSMeans (2022)
PII	$16,348, includes $8,661 for permitting fee For a 1,200-kWh system Construction permit fees, interconnection study, interconnection inspection, and interconnection fee		NREL (2022)
Direct installation labor	223 hours/m^2 at $24/hour National average, nonunionized labor rates		BLS (2022b), NREL (2022)
Installation equipment	$6/m^2 Avg of 2017–2021 costs (distorted 2022 costs removed)	$6/m^2 Q1 2022 rental equipment cost	RSMeans (2022)
EPC overhead (percentage of equipment costs)	13% of BOS equipment and material costs + 54% * direct installation labor Assumes costs and fees associated with EPC overhead, inventory, shipping, and handling		NREL (2022)
Developer overhead	6% of battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, and EPC overhead Assumed to include overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		NREL (2022)
Contingency	4% Estimated as markup on the battery pack, inverter, BOS, installation labor and equipment, sales tax, and EPC overhead		NREL (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
EPC/developer net profit	5% Applies a percentage margin to all costs, including battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, contingency, EPC overhead, and developer overhead		NREL (2022)

[a] Note that, for all values given in per square meter (m^2) terms, the denominator refers to square meters of battery pack footprint. The representative system has 80 kWh/m^2.

Figure 19 compares our MSP and MMP benchmarks for a 300-kW_{dc}, 4-hour commercial standalone storage system. For Q1 2022, our MSP benchmark ($732,395) is 9% lower than our MMP benchmark ($806,132). Because of a major change in system configuration between Q1 2021 and Q1 2022 (the Q1 2021 benchmark assumes a 600-kW_{dc} system as opposed to a 300-kW_{dc} system), the benchmark costs across those years cannot be compared directly.

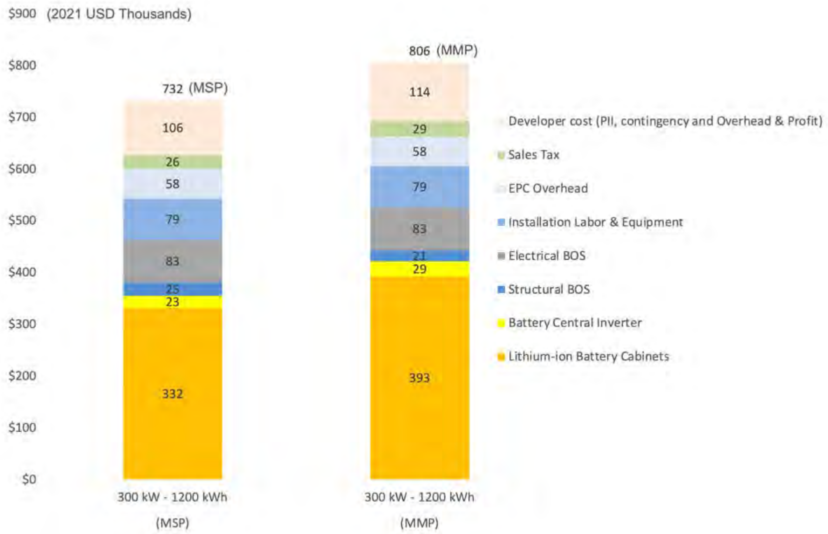


Figure 19. Q1 2022 U.S. benchmark: standalone commercial Li-ion battery storage system

9.2 PV-Plus-Storage System Cost Model

We model a 500-kW_{dc} fixed-tilt, ground-mounted commercial PV system coupled to a 300-kW_{dc} storage system, with 4 hours (1,200 kWh) of storage, using the same PV parameters we use with our standalone PV system and the same storage parameters we use with our standalone storage system, except for the effects of on-site coupling listed in Table 10.

Table 10. Changes to Commercial PV and Storage Model When PV and Storage Are Combined

Category	Modeled Value	Description
Electrical BOS	PV electrical BOS + storage electrical BOS + (3% * storage electrical BOS)	Assumes higher wiring/conduit and dc cabling requirement for coupled configurations
Installation labor	75% * (PV installation labor and equipment + storage installation labor and equipment)	Duplicative work related to site staging and site preparation are removed assuming more efficient labor utilization
EPC overhead	13% * (structural BOS + electrical BOS + installation labor)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
Sales tax	5.8% * (PV modules, battery cabinet, inverters, and BOS materials)	Cost of sales tax multipliers is lower for combined system than for separate systems, so the tax is lower
PII	Storage PII * 1.02	Assumes slightly higher PII cost than standalone storage system due to additional hardware installed at the point of interconnect
Contingency	3% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of contingency multipliers is lower for combined system than for separate systems, so the contingency cost is lower
Developer overhead	6% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
EPC/developer net profit	8% * (PV modules, battery cabinet, inverters, BOS materials, PII, contingency, developer overhead)	Cost of profit multipliers is lower for combined system than for separate systems, so the profit is lower

9.3 Model Output

Figure 20 compares our MSP and MMP benchmarks for an ac-coupled commercial storage system with a 500-kW_{dc} PV system. For Q1 2022, our MSP benchmark ($1.27 million) is 12% lower than our MMP benchmark ($1.44 million). Because of a major change in system configuration between Q1 2021 and Q1 2022 (the Q1 2021 benchmark assumes a 600-kW_{dc} storage system as opposed to a 300-kW_{dc} system), the benchmark costs across those years cannot be compared directly.

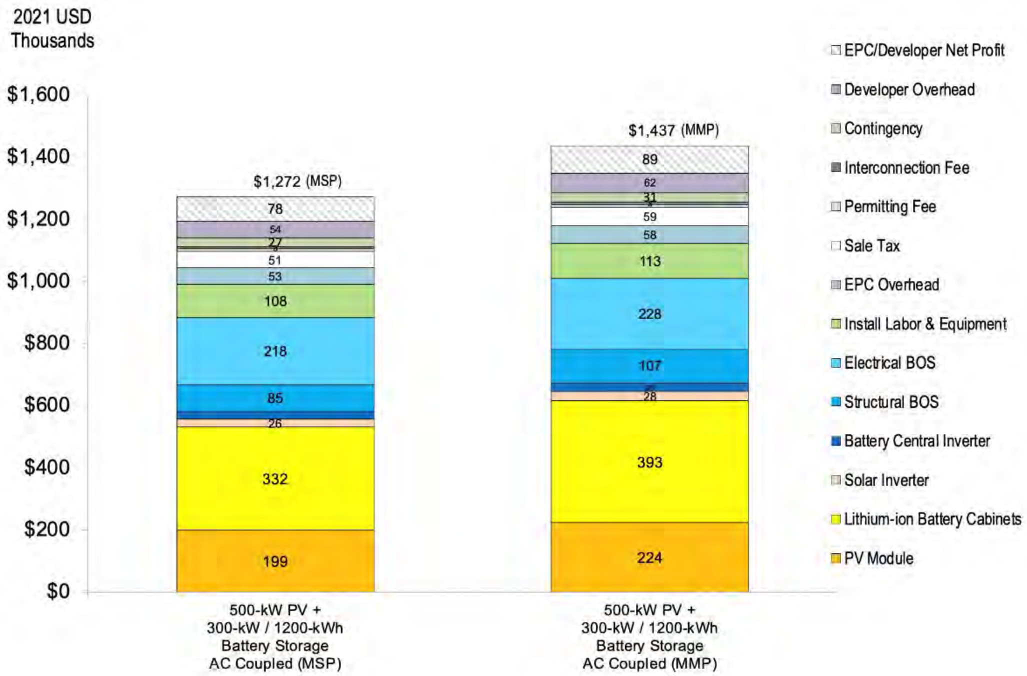


Figure 20. Q1 2022 U.S. benchmark: commercial ac-coupled PV-plus-storage systems (4-hour duration)

Figure 21 summarizes our MSP results for several system types and configurations:

- Standalone 500-kW$_{dc}$ commercial fixed-tilt ground-mounted PV system ($0.85 million)
- Standalone 300-kW$_{dc}$/1.2-MWh, 4-hour-duration energy storage system ($0.73 million)
- ac-coupled PV (500 kW$_{dc}$) plus storage (300 kW$_{dc}$/1.2 MWh, 4-hour duration) system ($1.27 million)
- PV (500 kW$_{dc}$) plus storage (300 kW$_{dc}$/1.2 MWh, 4-hour duration) system with PV and storage components sited in different locations ($1.59 million).

Co-locating the PV and storage subsystems produces cost savings by reducing costs related to site preparation, permitting and interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit. The cost of the ac-coupled system is 20% lower than the cost of the system with PV and storage sited separately.

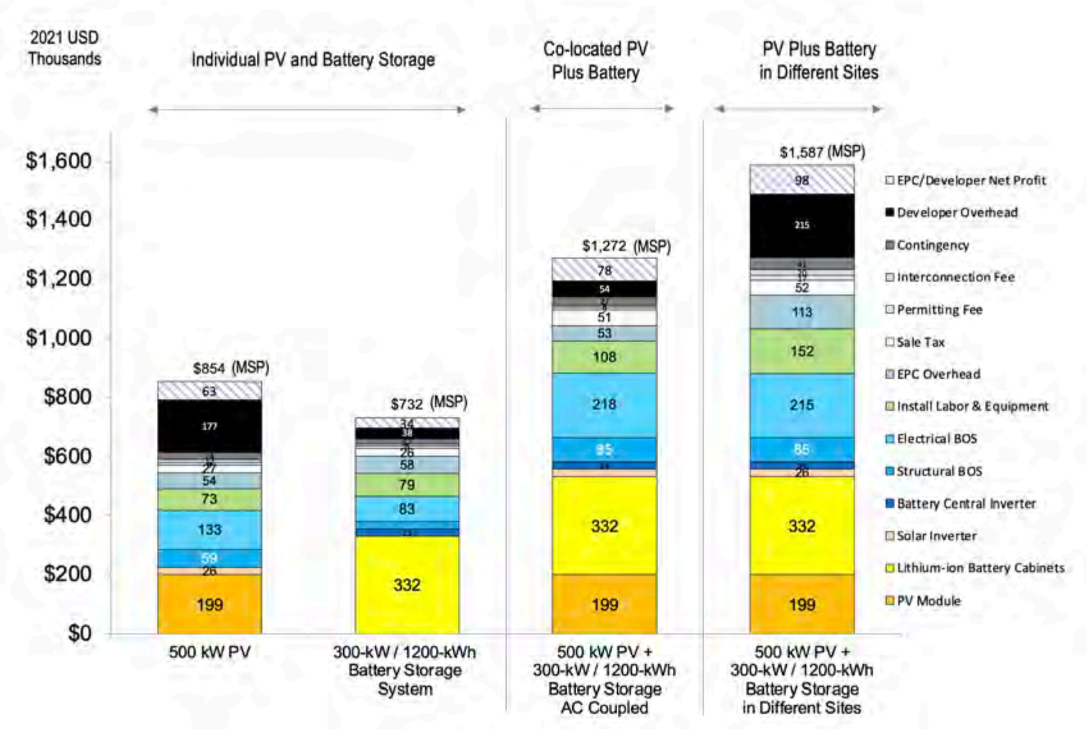


Figure 21. Q1 2022 commercial PV-plus-storage system MSP benchmark (4-hour duration) in different sites and the same site (ac-coupled)

10 Utility-Scale Storage and PV-Plus-Storage Model

To analyze component costs and system prices for utility-scale PV-plus-storage systems installed in Q1 2022, we adapt NREL's component- and system-level modeling approach for standalone PV and standalone storage in a similar manner as for the residential and commercial PV-plus-storage systems.

Sections 10.1 and 10.2 present the utility-scale storage and PV-plus-storage cost models, and Section 10.3 shows the model outputs. Note that the cost results are in 2021 USD; if the results were in 2022 USD, they would be about 5% higher.

10.1 Lithium-Ion Standalone Storage System Cost Model

Figure 22 details the bottom-up cost structure of our standalone utility-scale storage model, which uses a structure like that of our bottom-up PV cost model (Ramasamy et al. 2021). Total system upfront capital costs are broken into EPC costs and developer costs. EPC nonhardware, or "soft," costs are driven by labor rates and labor productivities. We adapt engineering design and cost-estimating models from RSMeans (2022) to determine the EPC hardware costs (including module/battery racking, mounting, wiring, containerization, and foundation) and related EPC soft costs (including related labor and equipment hours).

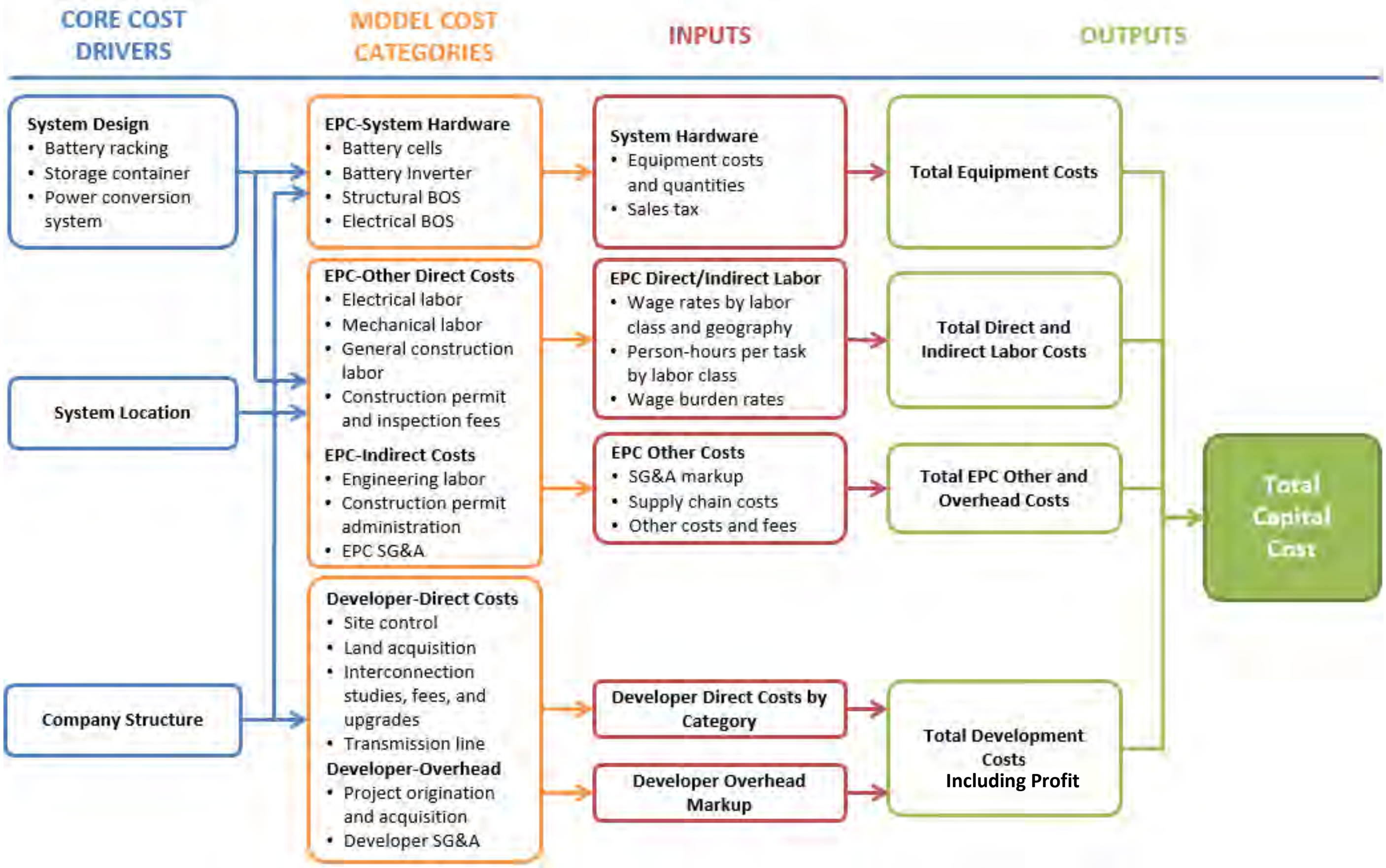


Figure 22. Utility-scale standalone storage: model structure

The major storage components we model for utility-scale standalone storage systems are the same as those summarized in Figure 17 and Figure 18 (page 36) for the commercial standalone storage model. Table 11 lists our modeled parameters in intrinsic units for such a utility-scale energy storage system. We select the battery size (60 MW_{dc} and 240 MWh) to be compatible with our benchmark utility-scale PV system.[11]

Table 11. Utility-Scale Li-ion Energy Storage System: Modeled Cost Parameters in Intrinsic Units

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Battery total size	60 MW rated dc power with a 60-MW_{ac} bidirectional inverter 240 MWh rated (usable) energy storage		Denholm et al. (2017), NREL (2022)
Duration	4.0 hours Duration = rated energy / rated power		NREL (2022)
Battery size per container	4 MWh per 40-ft container with 30-m^2 footprint area[a]		NREL (2022)

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[11] For a 100-MW_{dc} PV system with an ILR of 1.34.

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
RTE	90% Round-trip efficiency		NREL (2022)
Min. SOC and max. SOC	10% and 90% Minimum and maximum state of charge Used to determine rated battery energy storage		NREL (2022)
Li-ion battery price ($/kWh)	4 hours: $137/kWh MMP*(1–17.04%) Accounts for average cost reduction rate of turnkey battery systems between 2017 and 2021	4 hours: $165/kWh BNEF 2021 price adjusted for inflation	BNEF (2021), NREL (2022)
Bidirectional inverter price	$0.07/$W_{ac}$ 2019 Woodmac battery inverter cost adjusted for inflation		Wood Mackenzie (2019)
Battery cabinet	$226/kWh For a 240-MWh system Includes battery packs, containers, thermal management system, and fire suppression system Battery MSP + avg of other material costs from 2017–2021 (distorted 2022 costs removed)	$270/kWh For a 240-MWh system Includes battery packs, containers, thermal management system, and fire suppression system 2022 typical material cost	NREL (2022)
Structural BOS	$500/m^2 For a 240-MWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers Avg of 2017–2021 material costs (distorted 2022 costs removed)	$476/m^2 For a 240-MWh system Includes foundation and inverter house; costs impacted by numbers of inverters and transformers 2022 typical material cost	NREL (2022), RSMeans (2022)
Electrical BOS	$5,936/m^2 Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing	$5,978/m^2 Includes conduit, wiring, dc cable, energy management system, switchgear, transformer, and monitor and controls for each container; costs impacted by number of containers, number of transformers, and row spacing	NREL (2022), RSMeans (2022)

Category	MSP Value (2021 Real USD)	MMP Value (2021 Real USD)	Sources
Sales tax	National average—5.8% Sales tax on battery cabinet, inverter, and BOS material		RSMeans (2022)
PII	$1,549,755 per system,[b] includes a permitting fee of $184,876 Assumed to include construction permit fees, interconnection study, interconnection inspection, and interconnection fee		NREL (2022)
Direct installation labor	95 hours/m^2 at $17/hour National average, nonunionized labor rates		BLS (2022b), NREL (2022)
Installation equipment	$9/m^2 Avg of 2017–2021 costs (distorted 2022 costs removed)	$10/m^2 Q1 2022 rental equipment cost	RSMeans (2022)
EPC overhead (percentage of equipment costs)	8.67% of BOS material and equipment costs + 54% * direct installation labor costs[b] Costs and fees associated with EPC overhead, inventory, shipping, and handling		NREL (2022)
Developer overhead	3% of battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, and EPC overhead[b] Includes overhead expenses such as payroll, facilities, travel, legal fees, administration, business development, finance, and other corporate functions		NREL (2022)
Contingency	3% Estimated as markup on the battery pack, inverter, BOS, installation labor and equipment, sales tax, and EPC overhead		NREL (2022)
EPC/developer net profit	5%[b] Applies a percentage margin to all costs, including battery cabinet, inverter, BOS, installation labor and equipment, permitting fee, sales tax, contingency, EPC overhead, and developer overhead		NREL (2022)

[a] Note that, for all values given in per square meter (m^2) terms, the denominator refers to square meters of battery pack footprint. The representative system has 133 kWh/m^2.

[b] In contrast with the utility-scale PV parameters (Table 6), PII, EPC overhead, developer overhead, and EPC/developer net profit are given here as single values for 60-MW/240-MWh utility-scale storage systems only, because we do not have data that enables us to estimate how these values scale with different system sizes.

Figure 23 compares our MSP and MMP benchmarks for a 60-MW$_{dc}$, 4-hour utility-scale standalone storage system. For Q1 2022, our MSP benchmark ($95 million) is 12% lower than our MMP benchmark ($107 million). The Q1 2022 MMP benchmark is 12% higher than its counterpart in Q1 2021, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

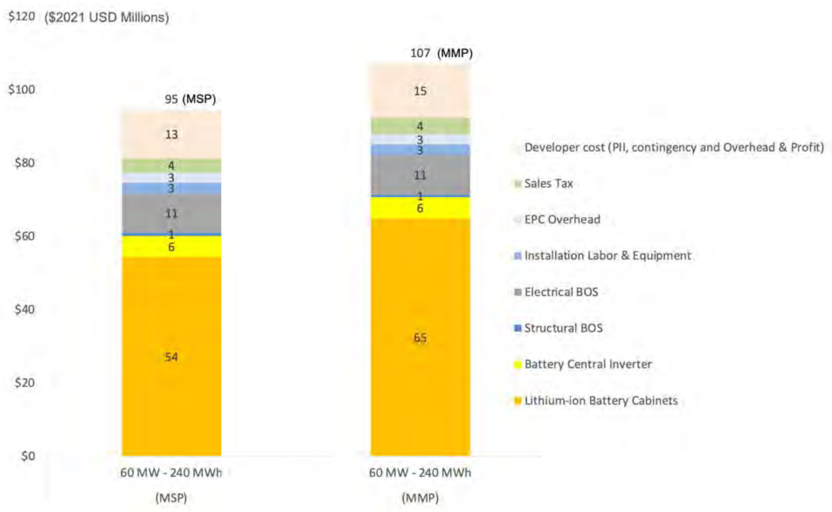

Figure 23. Q1 2022 U.S. benchmark: standalone utility-scale Li-ion battery storage system

10.2 PV-Plus-Storage System Cost Model

Here, we combine our energy storage cost model with our PV system cost model in various configurations, including PV and storage sited together versus separately. As shown in Table 12, coupling enables sharing of several hardware components by the PV and energy storage systems, which can reduce costs. Coupling can also reduce soft costs related to site preparation, land acquisition, permitting and interconnection, installation labor, and EPC/developer overhead and profit.

Table 12. Cost Factors for Siting PV and Storage Together Versus Separately

Model Component	Coupled PV Plus Storage	PV and Storage at Different Sites
Site preparation[a]	Once	Twice
Land acquisition cost	Lower	Higher
Hardware sharing between PV and energy storage	Yes (step-up transformer, switchgear, monitor, and controls)	No
Installation labor cost	Lower (due to hardware sharing and single labor mobilization)	Higher
EPC/developer overhead and profit	Lower (due to lower labor cost, BOS, and total system cost)	Higher
Interconnection and permitting	Once	Twice

[a] Site preparation is a subcategory of labor cost, so it is not shown in the cost breakdown chart.

When PV and battery storage are co-located, the subsystems can be connected in either a dc-coupled or an ac-coupled configuration (Figure 24). A dc-coupled system built using a bidirectional inverter[12] connects battery storage directly to the PV array via dc-dc converters. In contrast, an ac-coupled system needs both a PV inverter and a bidirectional inverter, and there

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[12] PV inverters can be used in place of bidirectional inverters as well.

are multiple conversion steps between dc and ac to charge or discharge the battery. The bidirectional inverter used in both dc-coupled and ac-coupled configurations enables grid-charging capabilities. The transmission line can be used for both PV and battery storage systems.

We model only ac-coupled systems for this report. Table 13 shows changes to our utility-scale PV and storage model when PV and storage are combined. The advantages of the ac-coupled system include the following:

- For a retrofit project (adding battery storage to an existing PV array), an ac-coupled battery may be more practical than a dc-coupled battery, because the existing PV system may not need to be redesigned. Thus, the additional costs of replacing the inverter and rewiring the system could make retrofit costs higher for a dc-coupled system than for an ac-coupled system (Ardani et al. 2017).
- Because ac-coupled systems have independent PV and battery systems with separate inverters, this coupled configuration enables redundancy. For instance, if the battery-based inverter fails to operate, the PV system can operate independently, as long as the grid is up. In addition, the PV and storage can be upgraded independently of each other.

Reasons an installer or a developer may pursue a dc-coupled system include the following:

- Installing a dc-coupled system with a single bidirectional inverter[13] reduces additional costs for the inverter, inverter wiring, and inverter housing.
- Dc-coupled systems have higher round-trip efficiency (RTE) than ac-coupled systems because they mitigate the extra conversion of energy from dc to ac to dc. However, as power electronics are becoming more efficient, the actual efficiency difference is becoming smaller (Enphase 2019).
- Because the battery is connected directly to the PV system via the dc-dc converter, excess PV generation that falls outside the inverter limits can be sent directly to the battery, thus increasing overall output for the same interconnection capacity (DiOrio and Hobbs 2018).

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[13] Dc-coupled systems can use a unidirectional inverter as well. This configuration can lead to a lower total system installed cost than a dc-coupled system using a bidirectional inverter, but at the same time, it prevents the system from grid charging.

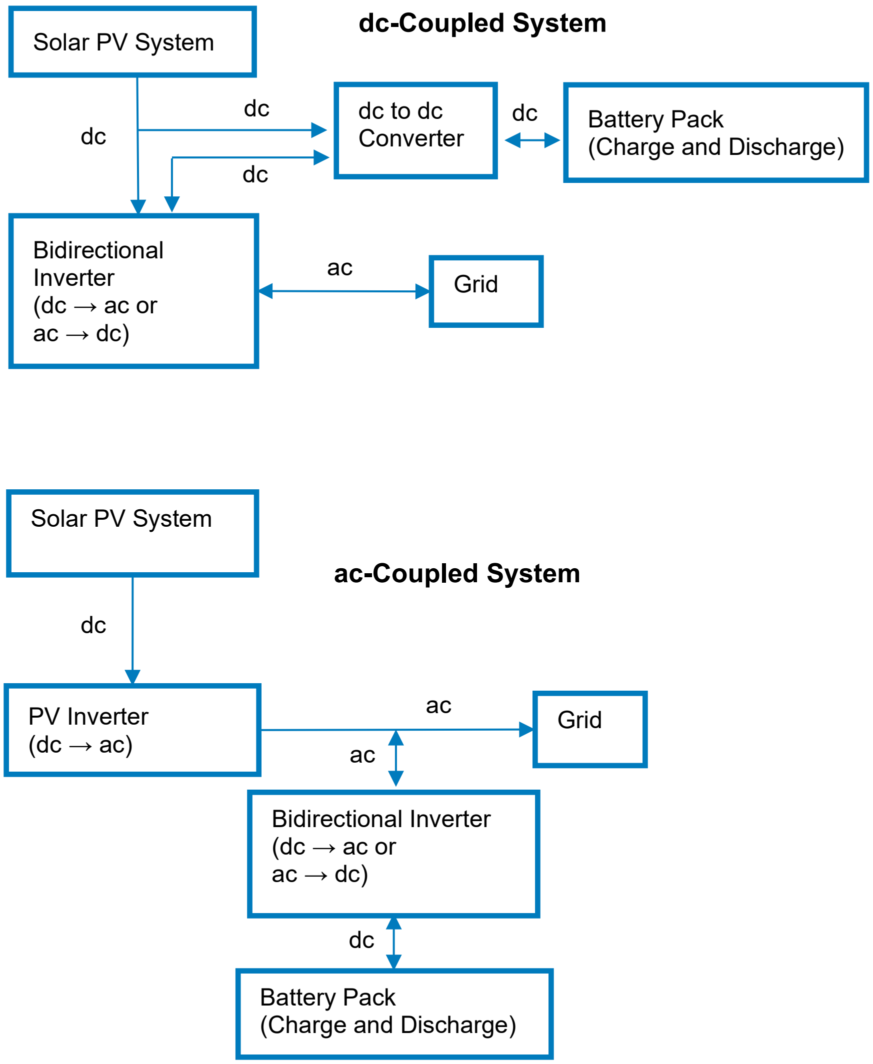

Figure 24. dc-coupled and ac-coupled PV-plus-storage system configurations

Table 13. Changes to Utility-Scale PV and Storage Model When PV and Storage Are Combined

Category	Modeled Value	Description
Electrical BOS	PV electrical BOS + storage electrical BOS + (4% * storage electrical BOS)	Assumes higher wiring/conduit and dc cabling requirement for coupled configurations
Installation labor	75% * (PV installation labor and equipment + storage installation labor and equipment)	Duplicative work related to site staging and site preparation are removed assuming more efficient labor utilization
EPC overhead	13% * (structural BOS + electrical BOS + installation labor)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
Sales tax	5.8% * (PV modules, battery cabinet, inverters, and BOS materials)	Cost of sales tax multipliers is lower for combined system than for separate systems, so the tax is lower

Category	Modeled Value	Description
PII	(Storage permitting fee + PV interconnection fee) * 1.02	Assumes slightly higher PII cost than standalone storage system due to additional hardware installed at the point of interconnect
Contingency	3% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of contingency multipliers is lower for combined system than for separate systems, so the contingency cost is lower
Developer overhead	4% * (PV modules, battery cabinet, inverters, BOS materials, PII)	Cost of overhead multipliers is lower for combined system than for separate systems, so the overhead is lower
EPC/developer net profit	5% * (PV modules, battery cabinet, inverters, BOS materials, PII, contingency, developer overhead)	Cost of profit multipliers is lower for combined system than for separate systems, so the profit is lower

10.3 Model Output

Figure 25 compares our MSP and MMP benchmarks for an ac-coupled utility-scale storage system with a 100-MW$_{dc}$ PV system. For Q1 2022, our MSP benchmark ($170 million) is 13% lower than our MMP benchmark ($195 million). Our Q1 2022 MMP benchmark is 11% higher than its counterpart in Q1 2021, because the MMP benchmark is affected by the market distortion that occurred in Q1 2022.

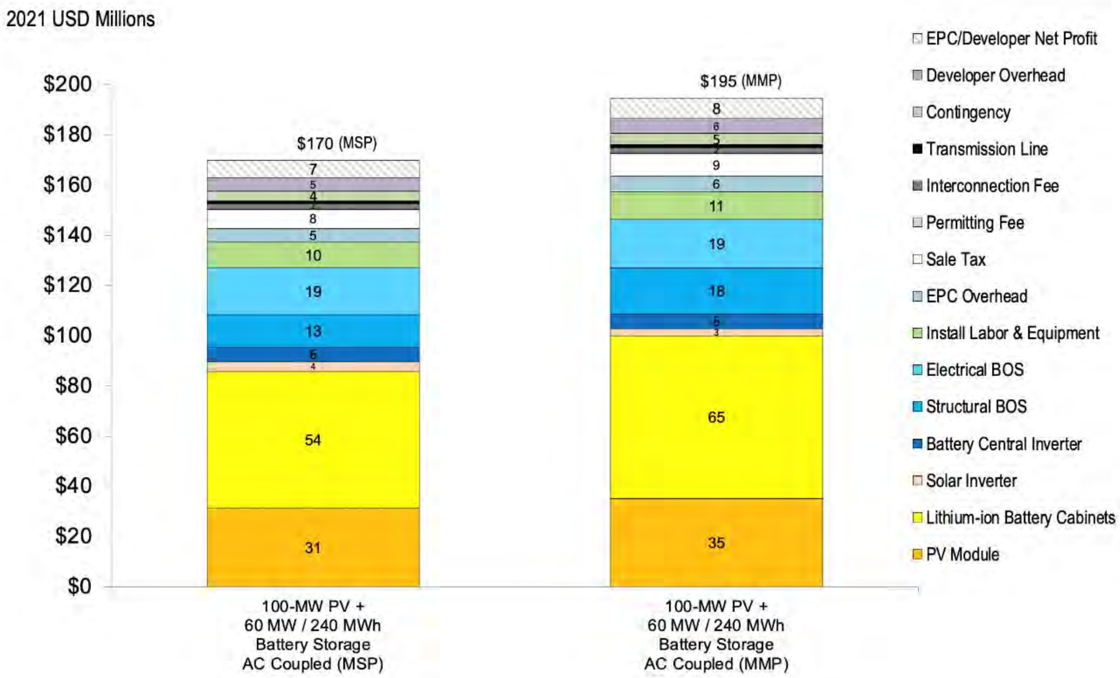

Figure 25. Q1 2022 U.S. benchmark: utility-scale ac-coupled PV-plus-storage systems (4-hour duration)

Figure 26 summarizes our MSP results for several system types and configurations:

- Standalone benchmark 100-MW_{dc} tracking ground-mounted PV system ($87 million)
- Standalone 60-MW_{dc}/240-MWh, 4-hour-duration energy storage system ($95 million)
- ac-coupled benchmark PV (100 MW_{dc}) plus storage (60 MW_{dc}/240 MWh, 4-hour duration) system ($170 million)
- Separate benchmark PV (100 MW_{dc}) and storage (60 MW_{dc}/240 MWh, 4-hour duration) systems sited in different locations ($181 million).

Co-locating the PV and storage subsystems produces cost savings by reducing costs related to site preparation, permitting and interconnection, installation labor, hardware (via sharing of hardware such as switchgears, transformers, and controls), overhead, and profit. The cost of the coupled system is 7% lower than the cost of the system with PV and storage sited separately.

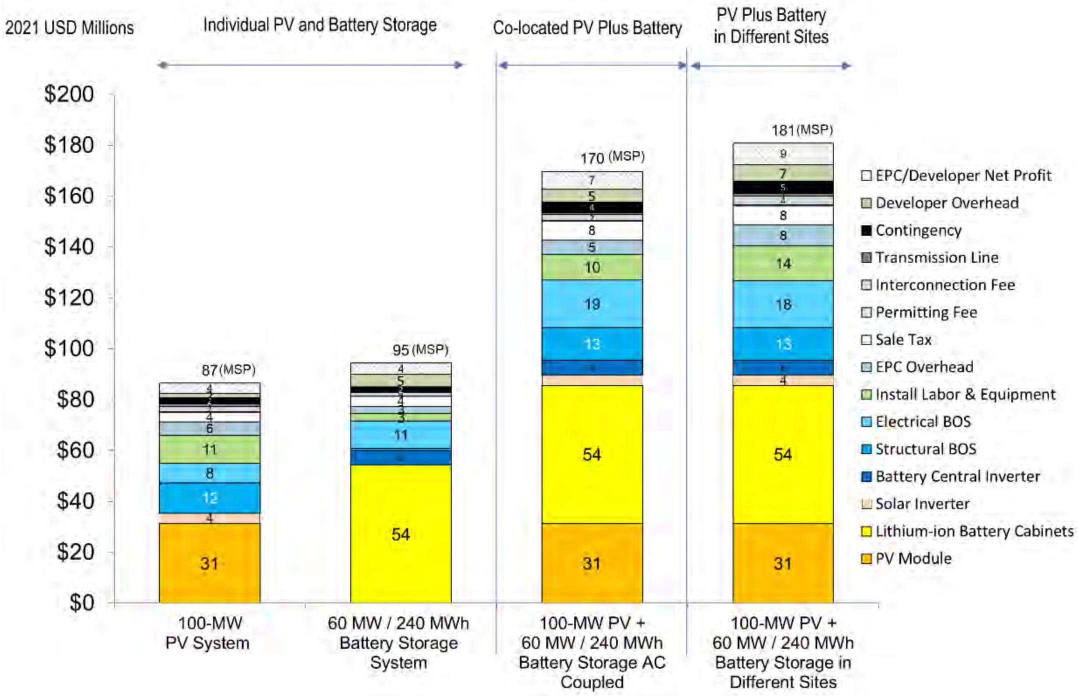

Figure 26. Q1 2022 utility-scale PV-plus-storage system MSP benchmark (4-hour duration) at different sites and at the same site (ac-coupled)

11 Operations and Maintenance

Benchmark PV operations and maintenance (O&M) costs are estimated using a model (Walker et al. 2020) that provides a line-item cost estimate of measures that correspond to the PV O&M services described in *Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems, 3rd Edition* (NREL et al. 2018). O&M cost drivers for PV modules and inverters in the model are informed by actuarial failure and repair data from Sandia National Laboratories (Klise et al. 2018). Current default values for other measures that occur on fixed intervals or for which the failure rate data are unavailable reflect the best judgement of a SETO-sponsored working group.[14]

Like the system cost modeling in this report, two sets of O&M cost numbers were estimated: one with MMP parameters and another with MSP parameters. For Q1 2022, the labor rates, discount rate, and inflation rate are updated; these items are common across the MSP and MMP calculations. In addition, MSP- and MMP-specific module and inverter replacement and capital costs are used. Actuarial failure and repair data are not updated from last year. Five additional line measures (land lease, property taxes, insurance, asset management, and security) were added in Q1 2020, based on feedback from U.S. solar industry professionals collected by Lawrence Berkeley National Laboratory (Wiser et al. 2020); of these, only the insurance line item was updated in Q1 2021. For Q1 2022, no changes are made to those line items. In Q1 2021, some of the 133 line measures were deleted if they were either outdated or not applicable to certain types of systems, especially residential and utility systems (one-axis tracking), based on high-level market research. For Q1 2022, no line measures were deleted.

The Q1 2020 benchmark O&M costs included PV module cleaning and several types of inspections in the residential case. These costs were removed from the Q1 2021 and Q1 2022 benchmarks, because residential cleaning is often not recommended, and inspections of residential systems are uncommon. Vegetation and pest control remain as annual costs in the Q1 2022 benchmark for residential PV system O&M.

Adding insurance costs increased the annual cost substantially in the Q1 2021 report. For Q1 2022, no changes are made to assumptions related to insurance. Types of insurance that may be needed by a PV plant operator are listed in *Insurance in the Operation of Photovoltaic Plants* (Schwab et al. 2020). Two major categories of insurance are (1) property insurance, which insures the PV plant hardware against hazards, and (2) liability insurance, which insures against claims of harm by others. Property insurance is included in the benchmark insurance cost because it can be associated with a single PV plant, whereas liability and other types of insurance (e.g., commercial vehicle and workers' compensation insurance) are often written as an umbrella policy to cover exposure of a company rather than a specific PV plant. Costs for these other types of insurance (i.e., other than property insurance) may be substantial, even though they are not included in this per-PV-plant benchmark cost.

The property insurance premium is estimated as a fraction multiplied by the replacement value for which the plant is insured; as a proxy for replacement value, we use the benchmark capital cost of the PV plant as the premium basis. For residential systems, the factor may vary from 0.004 to 0.006. For the benchmark value, we use 0.00454[15] times the capital cost per year, which

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[14] The Solar Access to Public Capital (SAPC) Working Group was convened in 2014 to open capital market investment in the solar asset class. It consisted of solar developers, financiers and capital managers, law firms, rating agencies, accounting and engineering firms, and other stakeholders engaged in solar asset deployment. In 2016, a subset of the SAPC Working Group merged with Sandia National Laboratories' Technical O&M Working Group to unify efforts by the U.S. Department of Energy (DOE) to improve O&M practices, data standards, and costs. This combined body—the PV O&M Working Group—is administrated by NREL, Sandia National Laboratories, SunSpec Alliance, and Roger Hill.

[15] Luke Ortgessen, Country Companies, August 1, 2021.

translates to \$12.08/kW$_{dc}$/year under MSP parameters and \$13.71/kW$_{dc}$/year under MMP parameters. For commercial and utility-scale plants, the factor varies from 0.0015 to 0.009, depending on hazards in an area and the extent of coverage. We use a benchmark value of 0.0025[16] times the capital cost per year for property insurance (escalated each year for inflation and discounted for levelized cost). This translates to a range of \$2.55–\$15.3/kW$_{dc}$/year under MSP parameters and \$2.93–\$17.55/kW$_{dc}$/year under MMP parameters.

Microinverters are assumed for residential systems, and three-phase string inverters are assumed for commercial rooftop systems. A commercial rooftop string inverter with a 12-year warranty incurs a slightly higher replacement cost than a residential rooftop microinverter with a 25-year warranty. Also, the analysis period is 30 years for the commercial system and 25 years for the residential system; because of the commercial system's longer lifetime, the commercial rooftop PV project owners will need to repair the inverter more often, and the inverters are more likely to be out of the warranty period. No updates are made to the analysis and warranty period in this year's report. Table 14 summarizes key modeled O&M parameters.

Table 14. Summary of Key Modeled O&M Parameters

Category	Residential	Commercial	Utility-Scale
Property insurance premium	0.00454 * system capital cost	0.0025 * system capital cost	0.0025 * system capital cost
Inverter type	Microinverter	Three-phase string inverter	Central inverter
Inverter warranty period	25 years	12 years	10 years
PV module warranty period	25 years	25 years	25 years
Analysis period	25 years	30 years	30 years
Inflation	2.5%	2.5%	2.5%
Nominal discount rate	5.71%	6.53%	6.24%

Costs in the PV O&M model include preventive maintenance scheduled at regular intervals, with costs increasing at the rate of general inflation, as well as corrective maintenance to replace components. The model derives corrective maintenance by multiplying the replacement cost, including labor, by the probability that a failure will occur each year, based on actuarial data. Component failure probabilities for each year are calculated using a Weibull, log-normal, or other distribution based on actual data, when possible (Gunda and Homan 2020).

For MSP, the measures in the cost model are sorted into inverter replacement, operations, module and component replacement, inspection, monitoring, module cleaning, vegetation and pest control, land lease, property taxes, insurance, asset management, and security (Figure 27). The current benchmarks are \$29.49/kW$_{dc}$/yr (residential), \$18.11/kW$_{dc}$/yr (commercial, rooftop),

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[16] Sara Cane, CAC Specialty Insurance, August 3, 2021.

$17.21/kW$_{dc}$/yr (commercial, ground-mounted), and $16.11/kW$_{dc}$/yr (utility-scale, single-axis tracking).

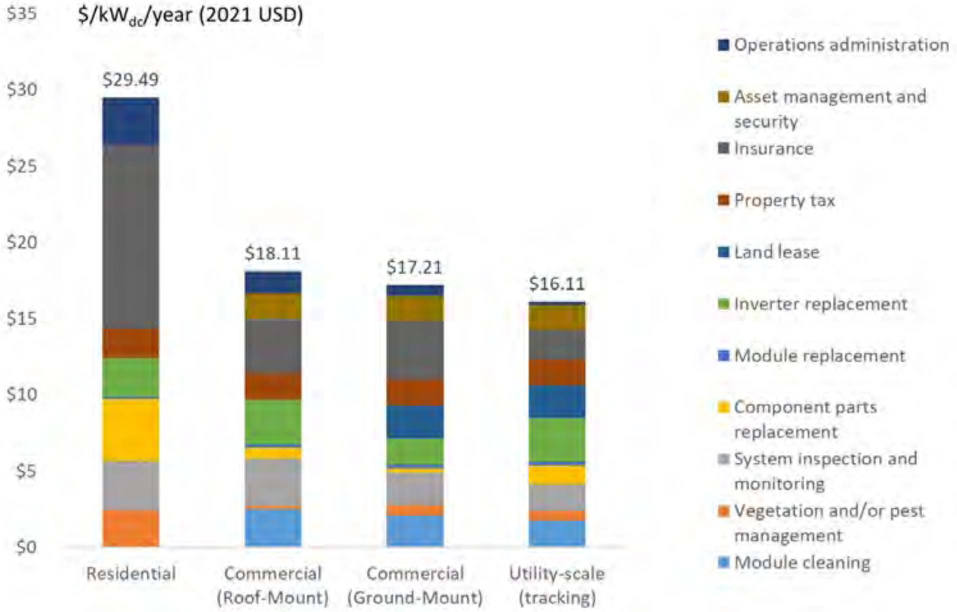

Figure 27. Q1 2022 residential, commercial, and utility-scale PV MSP O&M costs by category

For MMP, the current benchmarks are $31.12/kW$_{dc}$/yr (residential), $19.06/kW$_{dc}$/yr (commercial, rooftop), $18.03/kW$_{dc}$/yr (commercial, ground-mounted), and $16.42/kW$_{dc}$/yr (utility-scale, single-axis tracking) (Figure 28).

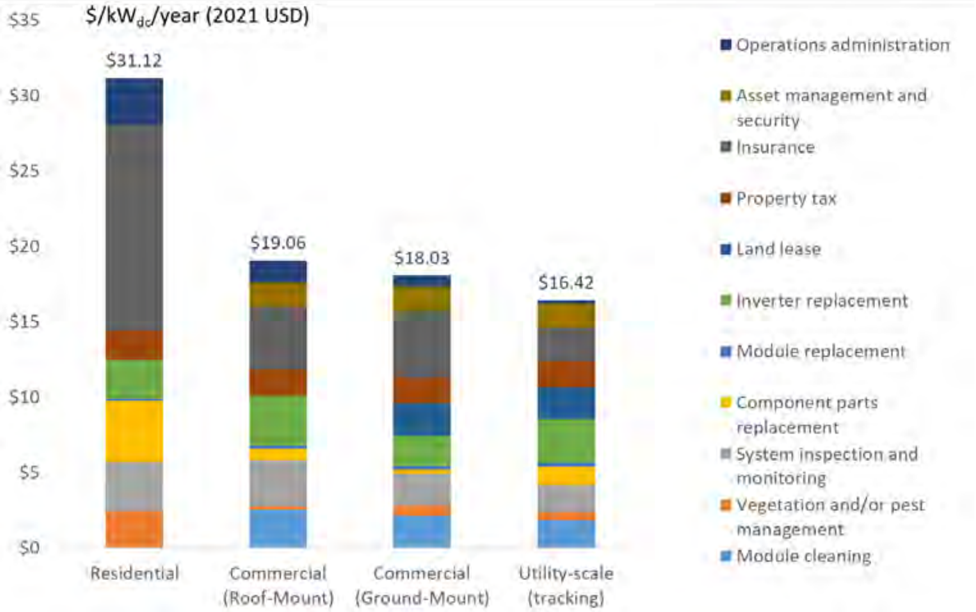

Figure 28. Q1 2022 residential, commercial, and utility-scale PV MMP O&M costs by category

As stated previously, the values in Figure 27 and Figure 28 represent line-item estimates of costs associated with best practices; therefore, actual costs may vary. For example, in a residential system, a homeowner may not increase the coverage of their property insurance after they get a system to avoid additional costs (saving money if no damages occur to the PV system, but putting themselves at risk if damages do occur). Additionally, we put a value on the time of a homeowner (i.e., "operations administration"), even though they are not getting paid for their activities. Therefore, a homeowner may only perceive O&M costs of \$14.36/kW$_{dc}$/yr,[17] but they are likely underinsuring against risk and not properly accounting for the efforts of maintaining a PV system on their home.

12 Levelized Cost of Energy of Standalone PV Systems

Although LCOE is an imperfect metric for the competiveness of PV within the energy marketplace, it does incorporate many PV metrics—beyond upfront installation costs—that are important to energy costs. We input standalone PV system parameters into NREL's System Advisor Model (SAM), a performance and financial model,[18] to calculate real LCOEs (considering inflation). In SAM, we use the PVWatts® single-owner model for estimating the LCOE of standalone PV systems for the residential, commercial, and utility-scale market sectors. While the financial parameters across these sectors and technologies vary, they remain the same as in the previous edition of the benchmark report (Ramasamy et al. 2021). We calculate LCOE assuming long-term, steady-state financing, with no investment tax credit and with interest rates higher than the previous historically low levels. The residential PV SAM model uses the default PVWatts performance model and the distributed residential owner financial model.

For the commercial and utility-scale SAM models, we specify internal rate of return (IRR) targets of 8.75% and 7.75%, respectively, to estimate the LCOE. Based on the specified IRR target, SAM optimizes for a power-purchase agreement (PPA) price to estimate the gross PPA revenue using the net energy generated by the system and made available to the grid.

Table 15 lists our parameters and results for calculating the benchmark LCOE of standalone PV. The values are based on our MSP benchmarks for system capital cost. Figure 29 shows our modeled PV LCOE estimates over time.

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[17] Total residential O&M MSP (\$29.49/kW$_{dc}$/yr) – insurance cost (\$12.08/kW$_{dc}$/yr) – operations administration cost (\$3.05/kW$_{dc}$/yr) = \$14.36/kW$_{dc}$/yr.

[18] See https://sam.nrel.gov/.

Table 15. Q1 2022 LCOE Input Parameters and Results for Standalone PV, Based on MSP Benchmarks (2021 USD)

	Residential PV (7.9 kW_{dc})	Commercial PV (Rooftop, 200 kW_{dc})	Utility-Scale PV (One-Axis Tracking, 100 MW_{dc})
Installed cost ($/$W_{dc}$)	2.55	1.63	0.87
Annual degradation (%)	1.00	0.70	0.70
Levelized O&M expenses over life of asset ($/$kW_{dc}$-yr)	29	18	16
Preinverter derate (%)[a]	85.9	85.9	85.9
Inverter efficiency (%)	96.0	96.0	96.0
Inverter loading ratio	1.21	1.23	1.34
Inflation rate (%)	2.5	2.5	2.5
Equity discount rate (real) (%)	10.2	6.1	5.1
Debt interest rate (%)	4.5	5.0	5.0
Debt fraction (%)	100	71.8	71.8
Debt term (years)	25	18	18
Entity	Homeowner	Corporation	Corporation
Analysis period (years)	25	30	30
Initial energy yield (kWh/kW_{dc})	1,491	1,398	1,694
Real LCOE (2021 US$)	**11.1 ¢/kWh**	**8.7 ¢/kWh**	**4.1 ¢/kWh**

[a] We use the default values for system losses in SAM for all sectors, which sum to 14.1% (equivalent to a preinverter derate value of 85.9%): soiling (2%), shading (3%), mismatch (2%), wiring (2%), connections (0.5%), light-induced degradation (1.5%), nameplate (1%), and availability (3%).

Other key assumptions are as follows. (1) The corporation has a federal corporate tax rate of 21% and a state corporate tax rate of 6%, and uses the Modified Accelerated Cost Recovery System depreciation schedule. (2) The homeowner uses a mortgage loan that is interest deductible, with a federal personal tax rate of 15% and a personal state tax rate of 6%. (3) No state or local subsidies. (4) Corporations have a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning an interest rate of 1.75%), a 6-month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system, and $1.1 million of upfront financial transaction costs for a $100-million third-party ownership transaction of a pool of commercial projects. (5) 2022 capacity factors are based on Fredonia, Kansas (which is near the geographic center of the 48 conterminous states and corresponds with the area-weighted capacity factor of the 48 conterminous states, as outlined in the 2022 Annual Technology Baseline), with a tilt/azimuth of 20/214 (residential) (Barbose et al. 2020), 10/190 (commercial rooftop) (Barbose et al. 2020), and tracking/180 (utility-scale).

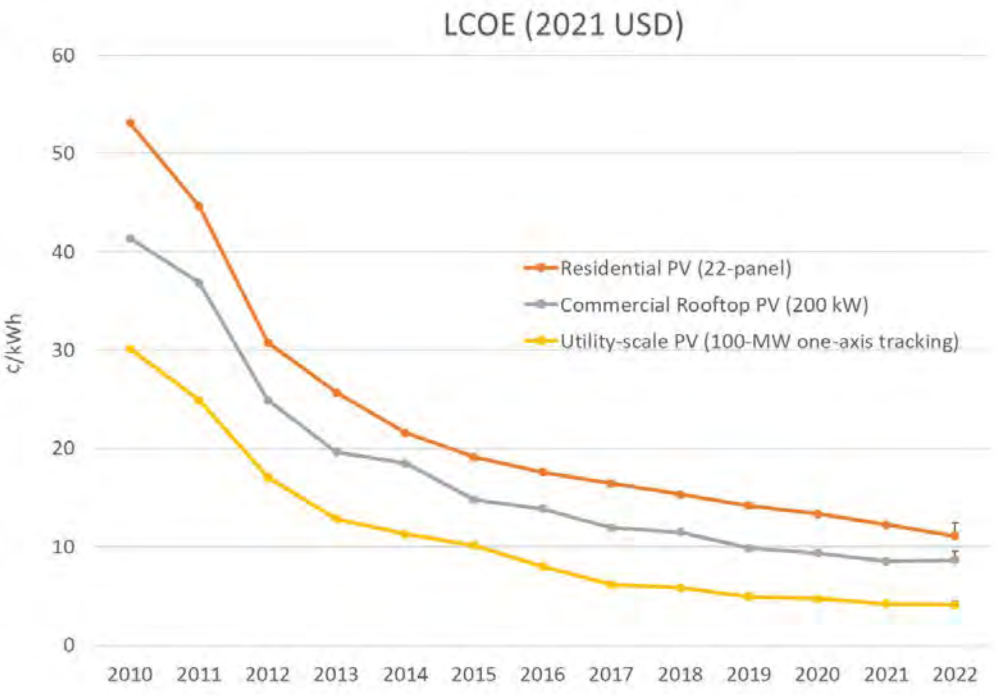

Figure 29. NREL-modeled PV LCOE over time

In 2022, the colored dots represent LCOEs calculated using MSP benchmarks, and the tops of the error bars represent LCOEs calculated using MMP benchmarks. Methods vary for calculating the LCOE values before 2022, but those methods are most similar to the MMP method used in this Q1 2022 report. In previous years, there was much less market distortion that would have affected the difference between MSP and MMP.

13 Conclusions

NREL's bottom-up cost models can be used to assess the MSP and MMP of PV, storage, and PV-plus storage systems with various configurations. While MSP can be used to estimate potential system cost-reduction opportunities—thus helping guide R&D aimed at advancing cost-effective system configuration—MMP can be used to understand system costs under recent market conditions. The MSP data in this annual benchmarking report will be used to inform and track progress toward SETO's Government Performance and Reporting Act cost targets.

Based on our bottom-up modeling, the Q1 2022 cost benchmarks are listed in Table 16.

Table 16. Q1 2022 PV and PV-Plus-Storage MSP and MMP Benchmarks (2021 USD)

MSP Benchmarks	MMP Benchmarks	System
Residential Systems		
$\$2.55/W_{dc}$ ($\$3.09/W_{ac}$)	$\$2.95/W_{dc}$ ($\$3.57/W_{ac}$)	7.9-kW$_{dc}$ rooftop PV
$33,858	$38,295	7.9-kW$_{dc}$ rooftop PV with 5 kW$_{dc}$/12.5 kWh of storage
Commercial Systems		
$\$1.63/W_{dc}$ ($\$2.00/W_{ac}$)	$\$1.84/W_{dc}$ ($\$2.26/W_{ac}$)	200-kW$_{dc}$ rooftop PV
$\$1.71/W_{dc}$ ($\$2.10/W_{ac}$)	$\$1.94/W_{dc}$ ($\$2.38/W_{ac}$)	500-kW$_{dc}$ ground-mounted PV
$1.27 million	$1.44 million	500-kW$_{dc}$ ground-mounted PV co-located with 300 kW$_{dc}$/1.2 MWh of storage
Utility-Scale Systems		
$\$0.87/W_{dc}$ ($\$1.17/W_{ac}$)	$\$0.99/W_{dc}$ ($\$1.33/W_{ac}$)	100-MW$_{dc}$ one-axis-tracking utility-scale PV
$170 million	$195 million	100-MW$_{dc}$ one-axis-tracking PV co-located with 60 MW$_{dc}$/240 MWh of storage

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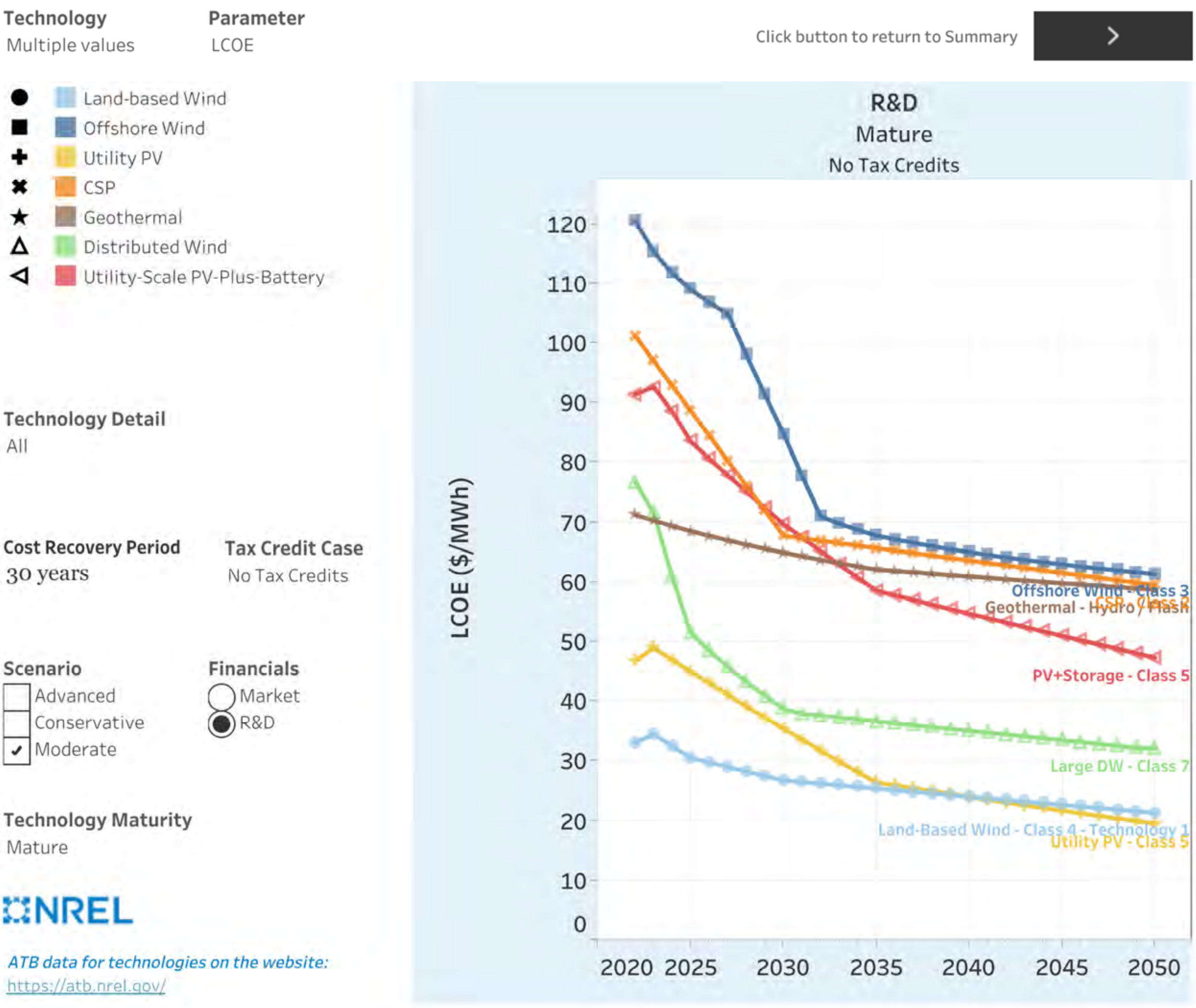

Technology
Multiple values

Parameter
LCOE

Click button to return to Summary

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- ✚ Utility PV
- ✖ CSP
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- △ Distributed Wind
- ◁ Utility-Scale PV-Plus-Battery

Technology Detail
All

Cost Recovery Period
30 years

Tax Credit Case
No Tax Credits

Scenario
☐ Advanced
☐ Conservative
☑ Moderate

Financials
○ Market
● R&D

Technology Maturity
Mature

ATB data for technologies on the website:
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Land-Based Wind Market Report: 2022 Edition

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Preparation and Authorship

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Acknowledgments

For their support of this ongoing report series, the authors thank the entire U.S. Department of Energy (DOE) Wind Energy Technologies Office team. In particular, we acknowledge Gage Reber and Patrick Gilman. For reviewing elements of this report or providing key input, we also thank: Manussawee Sukunta (U.S. Energy Information Administration); Andrew David (Silverado Policy Accelerator); Charlie Smith (Energy Systems Integration Group); Feng Zhao (Global Wind Energy Council); David Milborrow (consultant); John Hensley (American Clean Power Association); Mattox Hall (Vestas); Aaron Barr (Wood Mackenzie); and Patrick Gilman, Gage Reber, and Liz Hartman (DOE). For providing data that underlie aspects of the report, we thank the U.S. Energy Information Administration, BloombergNEF, Wood Mackenzie, Global Wind Energy Council, and the American Clean Power Association. Thanks also to Donna Heimiller (NREL) for assistance in mapping wind resource quality; and to Amy Howerton, Carol Laurie and Alexsandra Lemke (NREL), and Liz Hartman and Heather Doty (DOE) for assistance with layout, formatting, production, and communications. Lawrence Berkeley National Laboratory's contributions to this report were funded by the Wind Energy Technologies Office, Office of Energy Efficiency and Renewable Energy of the DOE under Contract No. DE-AC02-05CH11231. The authors are solely responsible for any omissions or errors contained herein.

List of Acronyms

ACP	American Clean Power Association
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
COD	commercial operation date
CCA	community choice aggregator
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
GE	General Electric Corporation
GW	gigawatt
HTS	Harmonized Tariff Schedule
IOU	investor-owned utility
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
ITC	investment tax credit
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
m^2	square meter
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	operations and maintenance
OEM	original equipment manufacturer
PJM	PJM Interconnection
POU	publicly owned utility
PPA	power purchase agreement
PTC	production tax credit
REC	renewable energy certificate

RPS	renewables portfolio standard
RTO	regional transmission organization
SGRE	Siemens Gamesa Renewable Energy
SPP	Southwest Power Pool
W	watt
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council

Executive Summary

Wind power additions in the United States totaled 13.4 gigawatts (GW) in 2021. Recent growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind capacity additions, even as supply chain constraints due to increased commodity and transportation costs and COVID-19 restrictions push costs higher.

Key findings from this year's *Land-Based Wind Market Report*—which primarily focuses on land-based, utility-scale wind—include:

Installation Trends

- **U.S. wind power capacity grew at a strong pace in 2021, with 13.4 GW of new capacity added and $20 billion invested.** Cumulative wind capacity grew to nearly 136 gigawatts (GW) by the end of 2021. In addition, 1.6 GW of existing wind plants were partially repowered in 2021, mostly by upgrading rotors and nacelle components.
- **Wind power represented the second largest source of U.S. electric-power capacity additions in 2021, at 32%, behind solar's 45%.** Wind power constituted 32% of all generation and storage capacity additions in 2021. Over the last decade, wind represented 30% of total capacity additions, and a larger fraction of new capacity in SPP (83%), ERCOT (52%), MISO (52%), and the non-ISO West (33%).[1]
- **Globally, the United States again ranked second in annual wind capacity, but remained well behind the market leaders in wind energy penetration**. Global grid-connected wind additions totaled 94 GW in 2021, yielding a cumulative 839 GW. The United States remained the second-leading market in terms of annual and cumulative capacity, behind China. A number of countries have achieved high levels of wind penetration, with wind supplying 44% of Denmark's total electricity generation in 2021, and over 20% in Ireland, Portugal, Spain, Germany, and the U.K. In the United States, wind supplied 9.1%.
- **Texas installed the most wind capacity in 2021 with 3,343 MW, followed by Oklahoma, New Mexico and Kansas; eleven states exceeded 20% wind energy penetration.** Texas also remained the leader on a cumulative basis, with nearly 36 GW of capacity. Notably, the wind capacity installed in Iowa supplied 55% of all in-state electricity generation in 2021, while South Dakota (52%), Kansas (45%), Oklahoma (41%), and North Dakota (34%) were all above 30%. Within independent system operators (ISOs), wind penetration (expressed as a percentage of load) was 34.8% in SPP, 24.2% in ERCOT, 12.0% in MISO, 8.4% in CAISO, 3.5% in PJM, 3.0% in ISO-NE, and 2.7% in NYISO.
- **Hybrid wind plants that pair wind with storage and other resources saw limited growth in 2021, with just two new projects completed.** There were 41 hybrid wind power plants in operation at the end of 2021, representing 2.4 GW of wind and 0.9 GW of co-located assets. The most common wind hybrid project combines wind and storage technology, where 1.4 GW of wind has been paired with 0.2 GW of battery storage. The average storage duration of these projects is 0.6 hours, suggesting a focus on ancillary services and limited capacity to shift large amounts of energy across time. While only two new wind hybrids were commissioned in 2021, solar hybrids expanded rapidly with 67 new PV+storage projects coming online in 2021.

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[1] The nine regions most commonly used in this report are the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and New York Independent System Operator (NYISO), and the non-ISO West and Southeast.

- **A record-high 247 GW of wind power capacity now exists in transmission interconnection queues, but solar and storage are growing at a much more rapid pace.** At the end of 2021, there were 247 GW of wind capacity seeking transmission interconnection, including 77 GW of offshore wind and 19 GW of hybrid wind projects (in the latter case, mostly wind paired with storage). In 2021, 73 GW of wind capacity entered interconnection queues. Energy storage interconnection requests have increased rapidly in recent years, both for stand-alone and hybrid plants, most-often pairing solar with storage. The West (non-ISO), SPP, and NYISO regions had the greatest quantity of wind in their queues at the end of 2021. Roughly one-third of all wind capacity added to queues in 2021 was for offshore wind plants.

Industry Trends

- **Just four turbine manufacturers, led by GE, supplied all of the U.S. wind power capacity installed in 2021.** In 2021, GE captured 47% of the U.S. market for turbine installations, followed by Vestas at 26% and Siemens-Gamesa Renewable Energy (SGRE) and Nordex, both at 13%.[2]
- **The domestic wind industry supply chain contracted in 2021, with a 50% decline in blade manufacturing capability.** Domestic nacelle assembly and tower manufacturing capability declined modestly in 2021, to an equivalent 12.3 GW and 9.2 GW per year, respectively. Blade manufacturing capability plummeted by 50%, however, as three domestic manufacturing facilities closed or idled, and stood at 4.6 GW per year. More broadly, fierce competition and supply-chain constraints resulted in low profit margins for turbine manufacturers. Nonetheless, wind-related job totals in the United States increased in 2021, to 120,164.
- **Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports, which totaled $3.1 billion in 2021.** The United States imports wind equipment from many countries, including most prominently in 2021: Mexico, Spain, and India. Domestic content is highest for nacelle assembly (>85%) and towers (55%–70%). For blades, it declined precipitously to just 15–25% in 2021 as competitive pressures made blade imports more economical than domestically produced blades.
- **Independent power producers own the majority of wind assets built in 2021, following historical trends.** Independent power producers (IPPs) own 75% of the new wind capacity installed in the United States in 2021, with the remaining assets (25%) owned by investor-owned utilities.
- **Direct retail sales and merchant offtake arrangements for wind, in combination, matched or surpassed long-term contracted wind sales to utilities in 2021.** Electric utilities either own (25%) or buy electricity (19%) from wind projects that, in total, represent 44% of the new wind capacity installed in 2021. But direct retail purchasers of wind—including corporate offtakers—account for at least 35%, while merchant/quasi-merchant projects and power marketers make up at least another 7% and 2%, respectively. The remainder (11%) is presently undisclosed.

Technology Trends

- **Turbine capacity, rotor diameter, and hub height have all increased significantly over the long term.** To optimize project cost and performance, and thus minimize overall cost of energy, turbines continue to grow in size. The average rated (nameplate) capacity of newly installed wind turbines in the United States in 2021 was 3.0 MW, up 9% from the previous year and 319% since 1998−1999. The average rotor diameter of newly installed turbines in 2021 was 127.5 meters, a 2% increase over 2020 and 164% over 1998−1999, while the average hub height was 93.9 meters, up 4% from 2020 and 66% since 1998−1999.

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[2] Numerical values presented here and elsewhere may not add to 100%, due to rounding.

- **Turbines originally designed for lower wind speed sites dominate the market, but the trend towards lower specific power has reversed over the last two years.** With growth in swept rotor area outpacing growth in nameplate capacity, there has been a decline in the average “specific power”[3] (in W/m^2), from 393 W/m^2 among projects installed in 1998–1999 to 231 W/m^2 among projects installed in 2021—though specific power has modestly increased over the last two years. Turbines with low specific power were originally designed for lower wind speed sites, but are now being used at many sites as the most attractive technology.

- **Wind turbines were deployed in somewhat lower wind-speed sites in 2021 than in the previous seven years.** Wind turbines installed in 2021 were located in sites with an average estimated long-term wind speed of 8.0 meters per second at a height of 100 meters above the ground—this is the lowest average long-term wind speed among newly built projects in the last eight years. Federal Aviation Administration (FAA) and industry data on projects that are either under construction or in development suggest that the sites likely to be built out over the next few years will, on average, have even lower average wind speeds. Increasing hub heights help to partially offset these trends, enabling turbines to access higher wind speeds.

- **Low-specific-power turbines are deployed on a widespread basis; taller towers are seeing increased use in a wider variety of sites.** Low specific power turbines continue to be deployed in all regions, and at both lower and higher wind speed sites. The tallest towers (i.e., those above 100 meters) are found in greater relative frequency in the upper Midwest and Northeastern regions.

- **Wind projects planned for the near future are poised to continue the trend of ever-taller turbines.** The average “tip height” (from ground to blade tip extended directly overhead) among projects that came online in 2021 is 517 feet (158 meters). FAA data suggest that future projects will deploy even taller turbines. Among “proposed” turbines in the FAA permitting process, the average tip height reaches an average of 643 feet (196 meters).

- **In 2021, twelve wind projects were partially repowered, most of which now feature significantly larger rotors and lower specific power ratings.** Partially repowered projects in 2021 totaled 1.6 GW prior to repowering, a decline from the roughly 3 GW of projects partially repowered in each of the previous two years. Of the changes made to the turbines, larger rotors dominated, reducing specific power from 312 to 223 W/m^2. The primary motivations for partial repowering have been to re-qualify for the PTC, while at the same time increasing energy production and extending the useful life of the projects.

Performance Trends

- **The average capacity factor in 2021 was 35% on a fleet-wide basis and 39% among wind projects built in recent years**. The average 2021 capacity factor among projects built from 2014 to 2020 was 39%, compared to an average of 26% among projects built from 2004 to 2011, and 19% among projects built from 1998 to 2001. This improvement among more-recently built projects has pushed the cumulative fleet-wide capacity factor higher over time; it was 35% in 2021. The 2021 capacity factor for projects built in 2020 was 38%, somewhat lower than for projects built from 2014 to 2020.

- **State and regional variations in capacity factors reflect the strength of the wind resource; capacity factors are highest in the central part of the country.** Based on projects built from 2016 to 2020, average capacity factors in 2021 were highest in central states and lower closer to the coasts. Not surprisingly, the state and regional rankings are roughly consistent with the relative quality of the wind resource in each region.

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[3] A wind turbine’s specific power is the ratio of its nameplate capacity rating to its rotor-swept area. All else equal, a decline in specific power should lead to an increase in capacity factor.

- **Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor over the long term**. The decline in specific power has been a major contributor to higher capacity factors, but has been offset in part by a tendency toward building projects at sites with lower annual average wind speeds. As a result, average capacity factors over the last eight years have been reasonable stable, with some evidence of modest declines most recently as specific power has drifted upwards and site quality has modestly decreased.
- **Wind power curtailment in 2021 across seven regions averaged 4.8%, up from a low of 2.1% in 2016.** Across all ISOs, wind energy curtailment in 2021 stood at 4.8%—generally rising over the last five years. This average masks variation across regions and projects. SPP (6.4%), ERCOT (5.2%), and MISO (4.7%) experienced the highest rates of wind curtailment, while the other four ISOs were each at 2% or less.
- **2021 was an average wind resource year across most of the country.** The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation impacts project performance from year to year. In 2021, the national wind index stood at its long-term average, as most regions experienced a fairly average wind year (CAISO and NYISO excepted).
- **Wind project performance degradation also explains why older projects did not perform as well in 2021**. Capacity factor data suggest some amount of performance decline with project age, though perhaps mostly once projects age beyond 10 years. The apparent decline in capacity factors as projects progress into their second decade partially explains why older projects—e.g., those built from 1998 to 2001—did not perform as well as newer projects in 2021. From year 15 to 20, project performance appears to average roughly 75% of early-year performance.

Cost Trends

- **Wind turbine prices increased by an average of 5% to 10% in 2021 given supply chain pressures.** Wind turbine prices declined by 50% between 2008 and 2020. However, recent supply-chain pressures and rising commodity prices led to increased turbine prices in 2021. Data indicate recent pricing generally in the range of \$800/kW to \$950/kW,[4] roughly 5% to 10% higher than a year prior.
- **Installed project costs in 2021 held steady at an average of \$1,500/kW even as turbine prices rose.** The capacity-weighted average installed cost within a sample of 2021 projects stood at \$1,500/kW. This is a decrease of more than 40% from the peak in average costs in 2009 and 2010, but is roughly on par with the costs experienced in the early 2000s—albeit with much larger turbines and improved performance today. Installed costs have largely held steady over the last four years. Given the time-lag between turbine orders and project commissioning, installed project costs may rise in 2022.
- **Installed costs differed by region, from \$1,350/kW to \$1,600/kW.** ERCOT and the (non-California) Western states hosted the lowest-cost projects built in 2021, with average costs of \$1,350/kW and \$1,380/kW respectively. Higher average costs were experienced in other regions for projects installed in 2021; for example, average costs in SPP and MISO were \$1,500/kW and \$1,600/kW, respectively.
- **Installed costs (per megawatt) generally decline with project size; are lowest for projects over 200 MW.** Installed costs exhibit economies of scale, with costs declining as project capacity increases.
- **Operations and maintenance costs varied by project age and commercial operations date.** Despite limited data availability, projects installed over the past 15 years have, on average, incurred lower operations and maintenance (O&M) costs than older projects in their first years of operation. The data also suggest that O&M costs tend to increase as projects age, at least for the older projects in the sample.

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[4] All cost figures presented in the report are denominated in real 2021 dollars.

Power Sales Price and Levelized Cost Trends

- **Wind power purchase agreement prices have been drifting higher since about 2018, with a recent range from below $20/MWh to more than $30/MWh.** The combination of declining CapEx and OpEx and improved performance drove wind PPA prices to all-time lows through 2018, though prices have since stabilized and even increased somewhat—in part due to supply-chain pressures and perhaps also due to the ongoing phase-down of the PTC. In the Central region of the country, recent pricing is around $20/MWh. In the West and East, prices tend to average above $30/MWh.

- **LevelTen Energy's PPA price indices confirm rising PPA prices, and regional variations.** In contrast to the PPAs summarized above, which principally involve utility purchasers, LevelTen Energy provides an index of wind PPA offers made to large, end-use customers. These data also show that prices have generally risen over the last couple years, and vary by ISO. Among regions reporting data, CAISO features the highest pricing (~$52/MWh once converted to 2021 dollar terms); the lowest prices are found in ERCOT and SPP (~$25/MWh in 2021 dollars). In real dollar terms, LevelTen's reported price trends since 2018 are similar to the real-dollar denominated PPA trends described in the prior section.

- **The (unsubsidized) average levelized cost of wind energy has fallen to around $32/MWh.** Trends in the levelized cost of energy (LCOE) generally follow PPA trends, at least over the long term. Wind's LCOE generally decreased from 1998 to 2005, rose through 2009, and then declined through 2018, with a subsequent plateau over the last several years. The national average LCOE of wind projects built in 2021—excluding the PTC—was $32/MWh. As supply chain pressures continue, LCOE may be expected to rise in the near term.

- **Levelized costs vary by region, with the lowest costs in ERCOT, SPP, and the non-ISO West**. The lowest LCOEs for projects constructed in 2021—only considering regions with a larger sample—are found in ERCOT ($28/MWh), SPP ($30/MWh), and the non-ISO West ($29/MWh).

Cost and Value Comparisons

- **Despite low PPA prices, wind faces competition from solar and gas**. The once-wide gap between wind and solar PPA prices has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices. With the support of federal tax incentives, both wind and solar PPA prices are now below the projected cost of burning natural gas in gas-fired combined cycle units.

- **The grid-system market value of wind rebounded in 2021 to levels last seen in 2018, and is roughly consistent with recent PPA prices of under $20/MWh to $40/MWh.** Following the sharp drop in wholesale electricity prices (and, hence, wind energy market value) in 2009, average wind PPA prices tended to exceed the wholesale market value of wind through 2012. Continued declines in wind PPA prices brought those prices back in line with the market value of wind in 2013, and wind has generally remained competitive in subsequent years. In 2021, wind energy value rebounded from the 2020 low associated with the pandemic. The national average market value of wind in 2021 was $26/MWh. With high natural gas and wholesale power prices so far in 2022, wind's average market value may increase again this year.

- **The grid-system market value of wind in 2021 varied by project location, from an average of $16/MWh in MISO to $48/MWh in CAISO.** Regionally, wind market value in 2021 was lowest in MISO and SPP (average of $16/MWh and $19/MWh, respectively) and highest in CAISO and ISO-NE ($48/MWh and $44/MWh). The market value across all wind projects located in ISOs spanned $7/MWh to $48/MWh in 2021 (10th–90th percentile range). Within a region, transmission congestion can noticeably reduce the grid-value of wind plants. In some situations, wind patterns are locally differentiated, and can lead to value enhancements or reductions versus plants located elsewhere.

- **The grid-system market value of wind tends to decline with wind penetration, impacted by generation profile, transmission congestion, and curtailment.** The regions with the highest wind penetrations (SPP at 35%, ERCOT at 24%, and MISO at 12%) have generally experienced the largest reduction in wind's value relative to average wholesale prices. In 2021, wind's value was roughly 40%, 50%, 60%, and 80%, lower than average wholesale prices in NYISO, MISO, SPP, and ERCOT, respectively; but was only roughly 10% lower in ISO-NE and CAISO, and ~20% lower in PJM. These value reductions were primarily caused by a combination of transmission congestion and wind generation profiles that were negatively correlated with wholesale prices. Curtailment had only a minimal impact.
- **The health and climate benefits of wind are larger than its grid-system value, and the combination of all three far exceeds the levelized cost of wind.** Wind reduces emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide, providing public health and climate benefits. Nationally and considering all wind plants, these benefits can be quantified in monetary terms, averaging $80/MWh-wind in 2021. Benefits were largest, ranging from $83/MWh to $125/MWh, in the Central, Midwest, and Mid-Atlantic regions. Values were lowest in New York ($32/MWh) and New England ($28/MWh). Focusing only on the set of wind plants built in 2021, the average climate, health, and grid-system value sums to almost four times the average LCOE. Climate, health, and grid value averaged $53/MWh, $39/MWh and $24/MWh, respectively, compared to an average LCOE of $32/MWh.

Future Outlook

- **Energy analysts project that total annual wind additions will generally decline through 2023 before rebounding.** Specifically, expected additions drop to an average of 7 GW in 2023 before increasing to as much as 13 GW in 2025. These projected trends are driven in part by expectations about the expiration of the federal PTC, and by anticipated growth in offshore wind in the mid-2020s. Near-term additions are also influenced by the cost and performance of wind technologies, corporate wind energy purchases, and state-level renewable energy policies. Limited transmission infrastructure and competition from solar dampen growth expectations, while continuing supply chain pressures also impact deployment levels.

- **Longer term, the prospects for wind energy will be influenced by the sector's ability to continue to improve its economic position even in the face of challenging competition and near-term supply chain constraints.** Corporate demand for clean energy and state-level policies will also continue to impact wind deployment, as will the buildout of transmission infrastructure and uncertain future natural gas prices. Finally, there have been recent legislative proposals for a long-term extension of the PTC and other national policies to support a clean energy transition. The fate of these proposals will impact the sector's upside potential to exceed the projections shown above.

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1 Introduction

Wind power capacity additions in the United States totaled 13.4 gigawatts (GW) in 2021. Recent growth is supported by the industry's primary federal incentive—the production tax credit (PTC)—as well as a myriad of state-level policies. Long-term improvements in the cost and performance of wind power technologies have also been key drivers for wind capacity additions, yielding low-priced wind energy for utility, corporate, and other power purchasers even as supply chain constraints due to increased commodity and transportation costs and COVID-19 restrictions begin to push costs higher.

This annual report—now in its sixteenth year—provides an overview of trends in the U.S. wind power market, with a particular focus on the year 2021. The report begins with an overview of installation-related trends: U.S. wind power capacity growth; how that growth compares to other countries and generation sources; the amount and percentage of wind energy in individual U.S. states; hybridization with storage and other sources of generation; and the quantity of proposed wind power capacity in interconnection queues in the United States. Next, the report covers an array of wind industry trends: developments in turbine manufacturer market share; manufacturing and supply-chain developments; wind turbine and component imports into the United States; project financing developments; and trends among wind power project owners and power purchasers. The report then turns to a summary of wind turbine technology trends: turbine capacity, hub height, rotor diameter, and specific power, as well as changes in site-average wind speed and recent repowering activity. After that, the report discusses wind performance, cost, and pricing. In doing so, it describes trends in capacity factors, wind turbine prices, installed project costs, and operations and maintenance (O&M) expenses. Levelized costs are calculated based on these input parameters. The report also reviews the prices paid for wind power through power purchase agreements (PPAs) and how those prices compare to the value of wind generation in wholesale energy markets, forecasts of future natural gas prices, and sales prices for solar power. An additional comparison assesses the levelized cost of wind energy relative to its societal value, defined somewhat narrowly here to include the grid-system value of wind along with its health and climate benefits. Finally, the report concludes with a preview of possible near-term market developments based on the findings of other analysts.

Many of these trends vary by state or region, depending in part on the strength of the local wind resource. To that end, Figure 1 superimposes the boundaries of nine regions, seven of which align with organized wholesale power markets (i.e., independent system operators)[5], on a map of average annual U.S. wind speed at 100 meters above the ground. These nine regions will be referenced on many occasions throughout this report.

This edition of the annual report updates data presented in previous editions while highlighting recent trends and new developments. The report concentrates on larger, utility-scale wind turbines, defined here as individual turbines that *exceed* 100 kW in size.[6] The U.S. wind power sector is multifaceted, and also includes smaller, customer-sited wind turbines used to power residences, farms, and businesses. Further information on *distributed wind power*, which includes smaller wind turbines as well as the use of larger turbines in distributed applications, is available through a separate annual report funded by the U.S. Department of Energy (DOE)—the Distributed Wind Market Report. In Chapters 2, 3, and 9—where it is sometimes difficult to separate offshore and land-based wind—this report emphasizes land-based and offshore wind, in combination. Other chapters exclusively focus on land-based wind. A companion study funded by DOE that focuses exclusively on *offshore wind power* is also available—the Offshore Wind Market Report.

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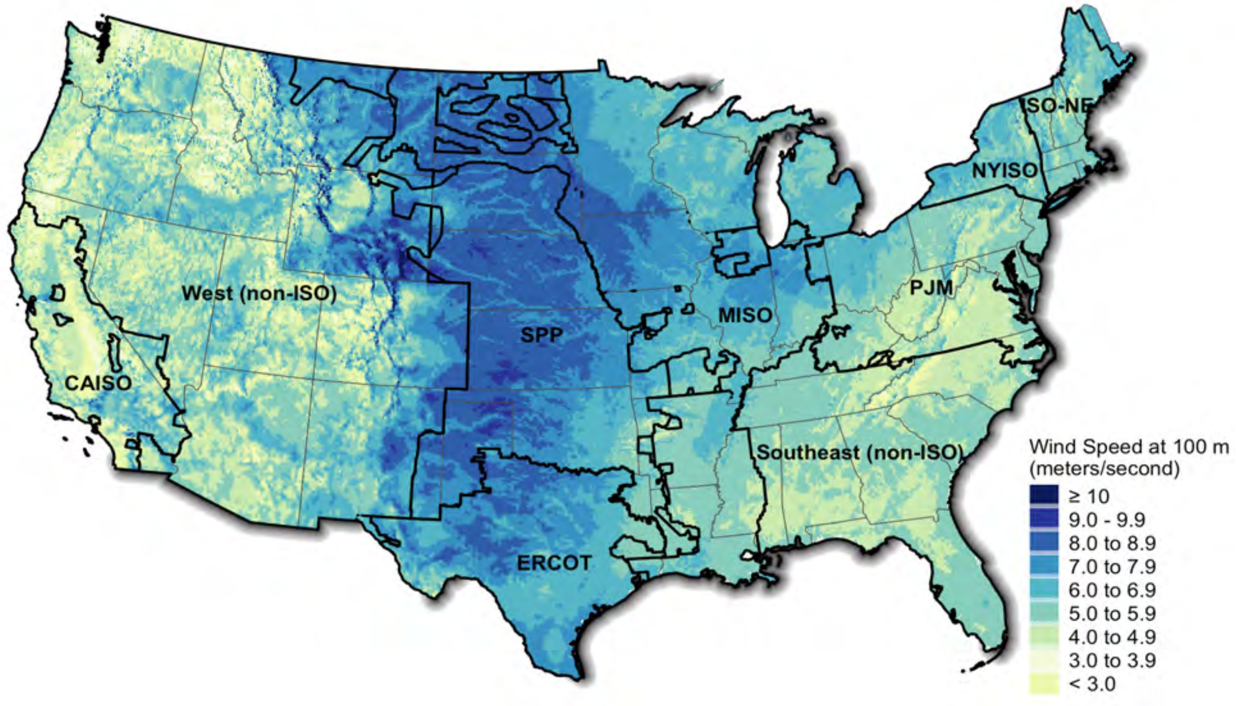
[5] The seven independent system operators (ISOs) include the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), ISO New England (ISO-NE), PJM Interconnection (PJM), and New York Independent System Operator (NYISO).

[6] This 100-kW threshold between "smaller" and "larger" wind turbines is applied starting with 2011 projects to better match the American Clean Power Association's historical methodology, and is also justified by the fact that the U.S. tax code makes a similar distinction. In years prior to 2011, different cut-offs are used to better match ACP's reported capacity numbers and to ensure that older utility-scale wind power projects in California are not excluded from the sample.



Sources: AWS Truepower, National Renewable Energy Laboratory (NREL)

Figure 1. Regional boundaries overlaid on a map of average annual wind speed at 100 meters

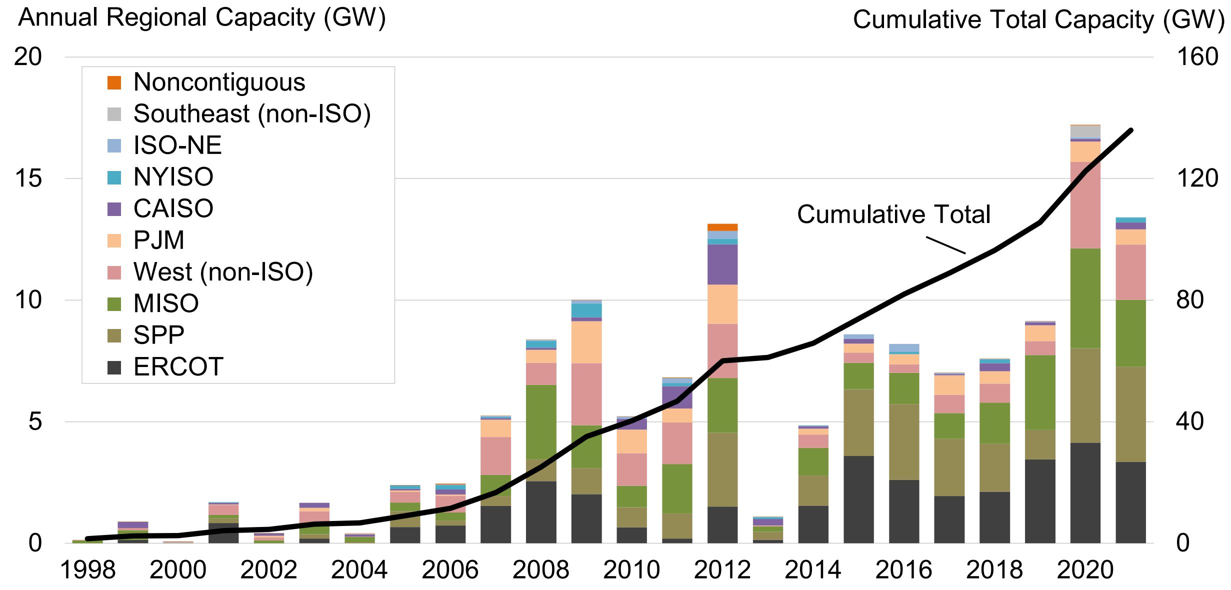
Much of the data included in this report were compiled by DOE's Lawrence Berkeley National Laboratory (Berkeley Lab) from a variety of sources, including the U.S. Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), and the American Clean Power Association (ACP—along with its predecessor, the American Wind Energy Association). The Appendix provides a summary of the many data sources. In some cases, the data shown represent only a sample of actual wind power projects installed in the United States; furthermore, the data vary in quality. Emphasis should therefore be placed on overall trends, rather than on individual data points. Finally, each section of this report primarily focuses on historical and recent data. With some limited exceptions—including the final section of the report—the report does not seek to forecast wind energy trends.

2 Installation Trends

U.S. wind power capacity grew at a strong pace in 2021, with 13.4 GW of new capacity added and $20 billion invested

U.S. wind capacity additions equaled 13.4 GW in 2021, bringing the cumulative total to nearly 136 GW at the end of the year (Figure 2).[7] This growth represented $20 billion of investment in new wind power project installations in 2021, for a cumulative investment total of roughly $270 billion since the beginning of the 1980s.[8,9] Nearly 75% of the new wind capacity installed in 2021 is located in ERCOT, MISO and SPP.

A relatively new trend is that of partial wind project repowering, in which major components of turbines are replaced. Such efforts provide access to favorable tax incentives, increase energy production with more-advanced turbine technology, and extend project life. As detailed further in Chapter 4, in addition to the newly installed capacity reported above, 1.6 GW of existing wind plants were partially repowered in 2021, mostly in the form of increased rotor diameters and the replacement of major nacelle components; this is a decline from the previous two years, when roughly 3 GW were retrofitted each year.[10]



Source: ACP

Figure 2. Annual and cumulative growth in U.S. wind power capacity

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[7] The nearly 136 GW of cumulative capacity includes the 30 MW Block Island offshore wind plant and the 12 MW Coastal Virginia Offshore Wind pilot project. When reporting annual capacity additions, this report focuses on *gross* additions, and does not consider partial repowering. The *net* increase in capacity each year can be somewhat lower, reflecting turbine decommissioning, or higher, reflecting partial repowering that increases nameplate capacities. Cumulative capacity ('Total' in Figure 2) includes both decommissioning and repowering.

[8] All cost and price data are reported in real 2021 dollars.

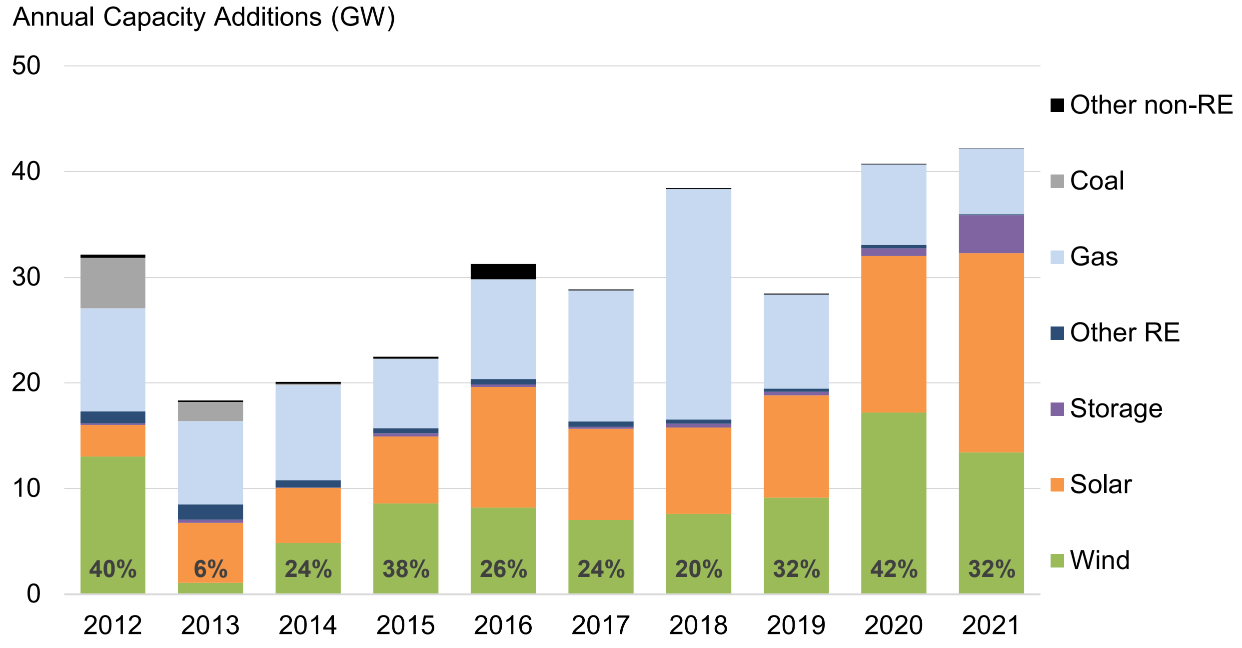
[9] These investment figures are based on an extrapolation of the average project-level capital costs reported later in this report and do not include investments in manufacturing facilities, research and development expenditures, or O&M costs; nor do they include investments to partially repowered plants.

[10] The 1.6 GW of partially repowered capacity reflects the initial capacity, prior to refurbishment. Any change in capacity from partial repowering is included in the cumulative data but not the annual data reported in Figure 2.

As in previous years, growth was driven in part by long-term improvements in the cost and performance of wind power technologies. The federal PTC, state renewables portfolio standards (RPS), and corporate demand for renewable energy also played important roles. Meanwhile, the ability of partially repowered wind projects to access the PTC has been the primary motivator for the growth in partial repowering in recent years. The industry also contended with headwinds in 2021, however, related to supply chain pressures, policy uncertainty, and interconnection delays, which together reportedly caused 5 GW of wind projects previously planned for completion in 2021to slip to later years (ACP 2022).

Wind power represented the second largest source of U.S. electric-power capacity additions in 2021, at 32%, behind solar's 45%

Wind power has comprised a sizable share of capacity additions in recent years. In 2021, it constituted 32% of all U.S. generation and storage capacity additions, second only to solar power at 45% (Figure 3).[11] Natural gas and other non-renewable capacity additions continued their recent decline, falling to their lowest level in more than 20 years.



Sources: Hitachi, ACP, EIA, Berkeley Lab

Figure 3. Relative contribution of generation types and storage to U.S. annual capacity additions

Over the last decade, wind power represented 30% of total U.S. generation and storage capacity additions, and an even larger fraction of new capacity in SPP (83%), ERCOT (52%), MISO (52%), and the non-ISO West (33%) (Figure 4; see Figure 1 for regional definitions). Wind power's contribution to capacity growth over the last decade is somewhat smaller—but still significant—in PJM (12%), NYISO (11%), ISO-NE (10%), and CAISO (8%), and considerably less in the Southeast (1%).

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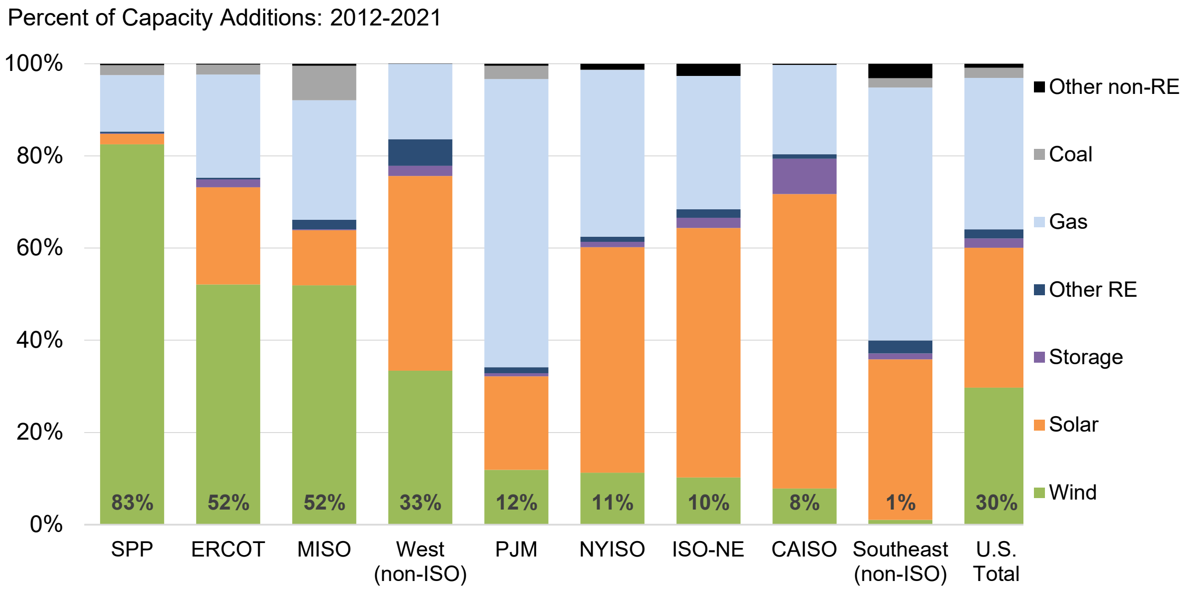
[11] Data presented here are based on gross capacity additions, not considering retirements or partial repowering. For solar, both utility-scale and distributed applications are included. Data include only the 50 U.S. states, not U.S. territories.



**U.S. Total also includes AK and HI, in addition to the regions listed*

Sources: Hitachi, ACP, EIA, Berkeley Lab

Figure 4. Generation and storage capacity additions by region over last ten years

Globally, the United States again ranked second in annual wind capacity, but remained well behind the market leaders in wind energy penetration

Global wind additions totaled 94 GW in 2021 (including both land-based and offshore wind, and focusing on capacity that was been connected to the grid). With its 13.4 GW representing 14% of new global installed capacity in 2021, the United States continued to maintain its second-place position behind China (Table 1). Cumulative global wind capacity totaled 839 GW at the end of the year (GWEC 2022),[12] with the United States accounting for 16%—also a distant second to China.

Table 1. International Rankings of Total Wind Power Capacity

Annual Capacity (2021, GW)	
China	47.6
United States	**13.4**
Brazil	3.8
Vietnam	3.5
United Kingdom	2.6
Sweden	2.1
Germany	1.9
Australia	1.7
India	1.5
Turkey	1.4
Rest of World	14.7
TOTAL	**94.3**

Cumulative Capacity (end of 2021, GW)	
China	338.3
United States	**135.9**
Germany	64.5
India	40.1
Spain	28.3
United Kingdom	26.6
Brazil	21.6
France	19.1
Canada	14.3
Sweden	12.1
Rest of World	138.1
TOTAL	**838.9**

Sources: GWEC (2022); ACP for U.S.

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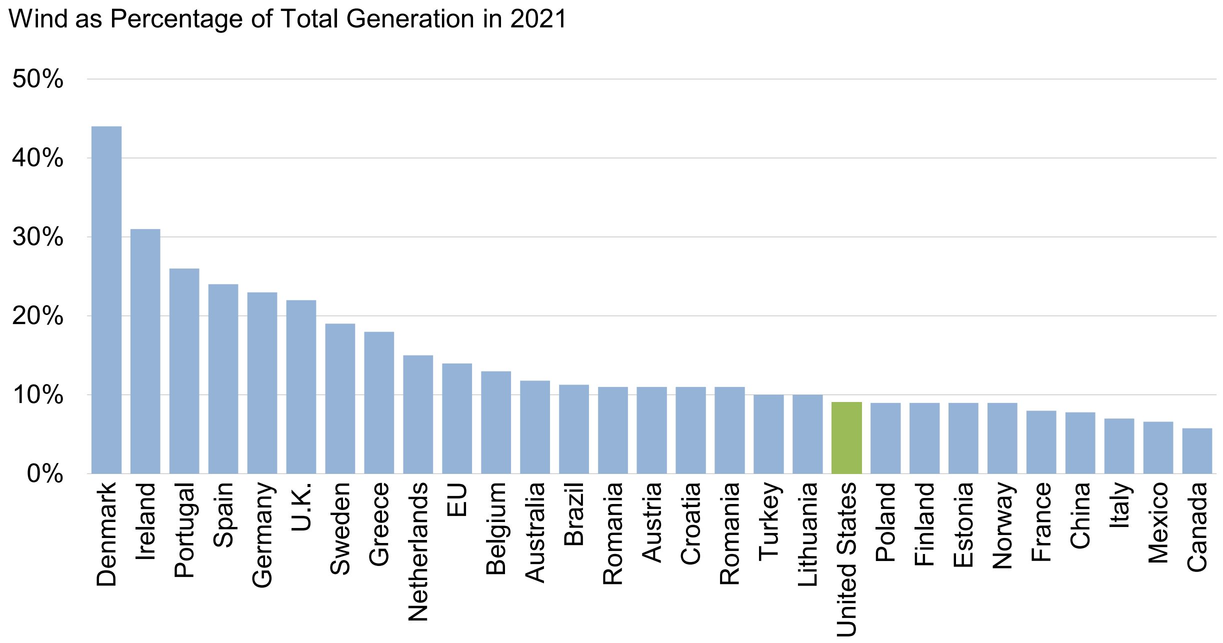
[12] Yearly and cumulative installed wind power capacity in the United States are from the present report, while global wind power capacity comes from GWEC (2022) but are updated, where necessary, with the U.S. data presented here.

A number of countries have achieved relatively high levels of wind energy penetration (i.e., wind generation as a percentage of total generation) in their electricity grids. Figure 5 presents data on a subset of countries. Wind penetration was 44% in Denmark in 2021, and was between 22% and 31% in Ireland, Portugal, Spain, Germany, and the U.K. In the United States, wind supplied 9.1% of total electricity generation in 2021 (see Table 2 for additional details).



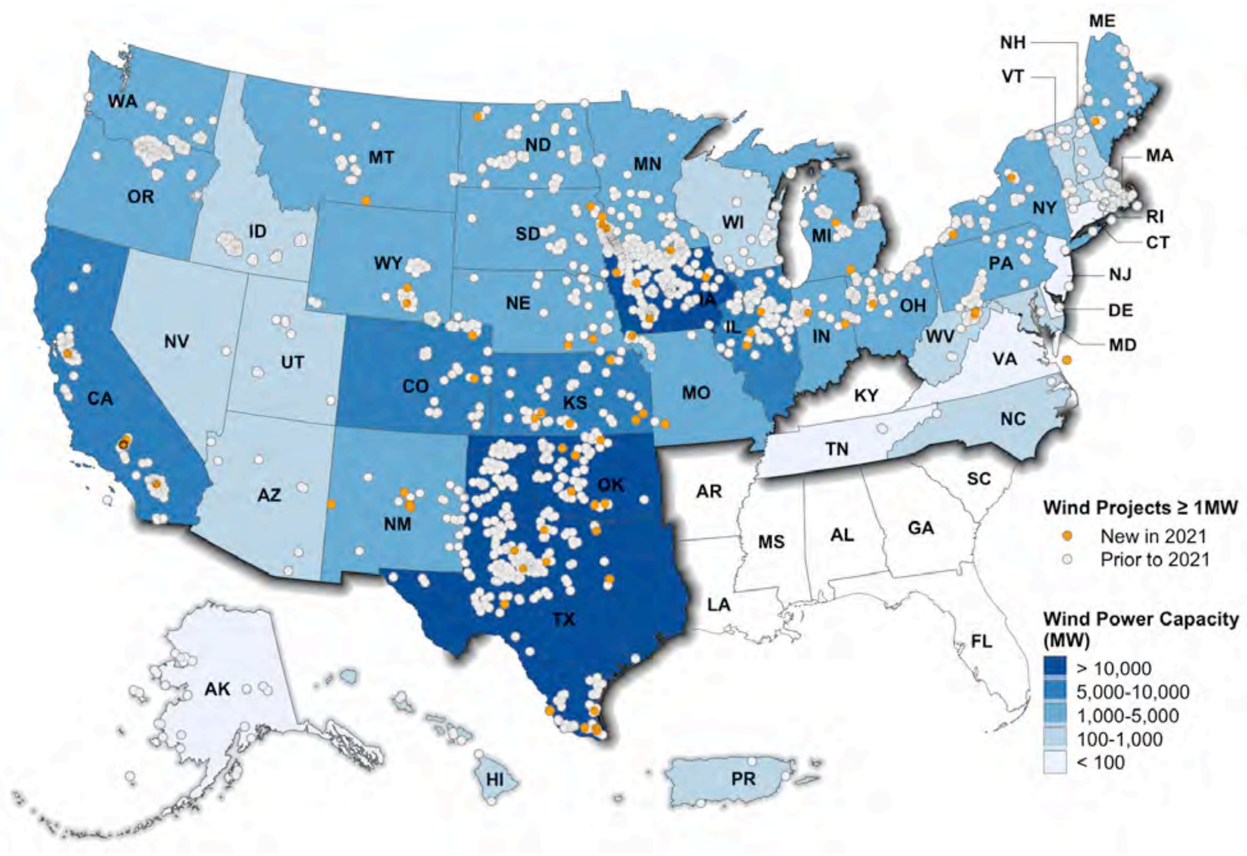
Source: ACP

Figure 5. Wind energy penetration in subset of top global wind markets

Texas installed the most wind capacity in 2021 with 3,343 MW, followed by Oklahoma, New Mexico and Kansas; eleven states exceeded 20% wind energy penetration

New utility-scale wind turbines were installed in 22 states in 2021 (including a 12 MW pilot offshore wind project in Virginia). Texas once again installed the most new wind capacity of any state, adding 3,343 MW. As shown in Figure 6 and in Table 2, other leading states—in terms of new capacity—included Oklahoma, New Mexico, and Kansas, all of which added more than 1,000 MW (i.e., 1 GW) of new wind in 2021.

On a cumulative basis, Texas remained the clear leader, with 36 GW installed at the end of 2021—almost three times as much as the next-highest state (Iowa). In fact, Texas has more wind capacity than all but four countries (Table 1). States distantly following Texas in cumulative installed capacity include Iowa (>12 GW), Oklahoma (~11 GW), Kansas (>8 GW), Illinois (~7 GW), and California (>6 GW). Thirty-five states, plus Puerto Rico, had more than 100 MW of wind capacity as of the end of 2021, with 23 of these above 1 GW, 19 above 2 GW, and 15 above 3 GW.



Sources: ACP, Berkeley Lab

Figure 6. Location of wind power development in the United States

Some states have reached high levels of wind energy penetration. The right half of Table 2 lists the top 20 states based on actual wind electricity generation in 2021 divided by total in-state electricity generation and by in-state electricity sales in 2021. Electric transmission networks enable most states to both import and export power in real time, and states do so in varying amounts. Denominating in-state wind generation as both a proportion of in-state generation and as a proportion of in-state sales is relevant, but both should be viewed with some caution given varying amounts of imports and exports. As a fraction of in-state generation, Iowa leads the list, with 55% of electricity generated in the state coming from wind, followed by South Dakota, Kansas, Oklahoma, and North Dakota. As a fraction of in-state sales, South Dakota is the leading state, with nearly 72% of the electricity sold in the state being met by wind, followed by Iowa, North Dakota, and Kansas (all over 60%), and then Wyoming and Oklahoma (both over 50%). Eleven states have achieved wind penetration levels of 20% or higher when expressed either as a percentage of generation or as a percentage of sales.

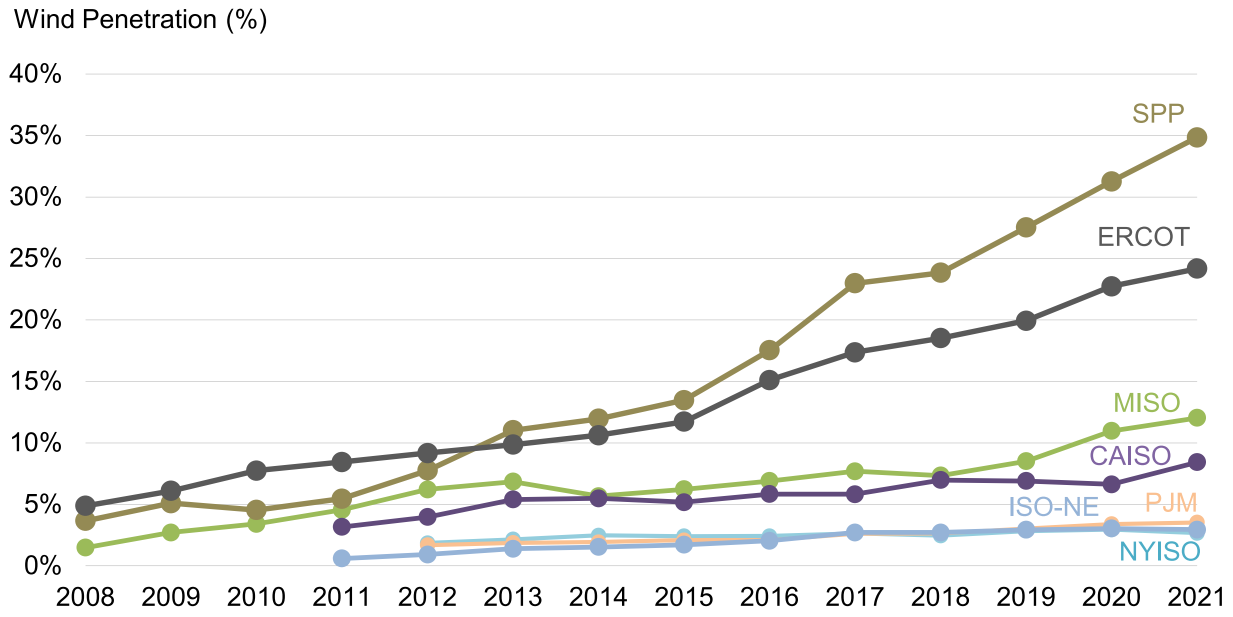
Table 2. U.S. Wind Power Rankings: The Top 20 States

Installed Capacity (MW)				2021 Wind Generation as a Percentage of:			
Annual (2021)		Cumulative (end of 2021)		In-State Generation		In-State Sales	
Texas	3,343	Texas	35,969	Iowa	55.1%	South Dakota	71.6%
Oklahoma	1,403	Iowa	12,219	South Dakota	52.3%	Iowa	69.1%
New Mexico	1,368	Oklahoma	10,994	Kansas	45.1%	North Dakota	63.3%
Kansas	1,228	Kansas	8,245	Oklahoma	41.4%	Kansas	63.0%
South Dakota	610	Illinois	6,997	North Dakota	34.0%	Wyoming	53.3%
Iowa	600	California	6,142	New Mexico	29.8%	Oklahoma	51.5%
Illinois	580	Colorado	5,035	Colorado	26.0%	New Mexico	41.4%
Michigan	550	Minnesota	4,591	Nebraska	25.1%	Nebraska	30.5%
Indiana	500	North Dakota	4,302	Maine	23.0%	Colorado	26.4%
Missouri	448	New Mexico	4,001	Minnesota	21.6%	Texas	23.5%
Nebraska	388	Oregon	3,842	Texas	20.6%	Maine	22.2%
Wyoming	349	Indiana	3,468	Wyoming	19.3%	Minnesota	19.6%
Colorado	305	Washington	3,396	Oregon	15.6%	Montana	18.9%
North Dakota	299	Wyoming	3,178	Idaho	15.6%	Oregon	18.5%
California	288	Michigan	3,159	Vermont	14.5%	Illinois	13.8%
Minnesota	266	Nebraska	2,942	Montana	11.5%	Washington	10.8%
Ohio	247	South Dakota	2,915	Illinois	10.2%	Idaho	10.5%
Montana	240	Missouri	2,435	Washington	8.7%	Missouri	8.4%
New York	205	New York	2,191	Missouri	8.4%	Indiana	7.9%
West Virginia	169	Pennsylvania	1,459	Indiana	8.3%	Michigan	7.9%
Rest of U.S.	*27*	*Rest of U.S.*	*8,405*	*Rest of U.S.*	*1.6%*	*Rest of U.S.*	*1.5%*
TOTAL	13,413	TOTAL	135,886	TOTAL	9.1%	TOTAL	10.0%

Note: Based on 2021 wind and total generation and retail sales by state from EIA's Electric Power Monthly.

Sources: ACP, EIA

Given the ability to trade power across state boundaries, estimates of wind penetration within entire multi-state markets operated by the major independent system operators (ISOs) are also relevant. In 2021, wind penetration (expressed as a percentage of load) was 34.8% in SPP, 24.2% in ERCOT, 12.0% in MISO, 8.4% in CAISO, 3.5% in PJM, 3.0% in ISO-NE, and 2.7% in NYISO (Figure 7).



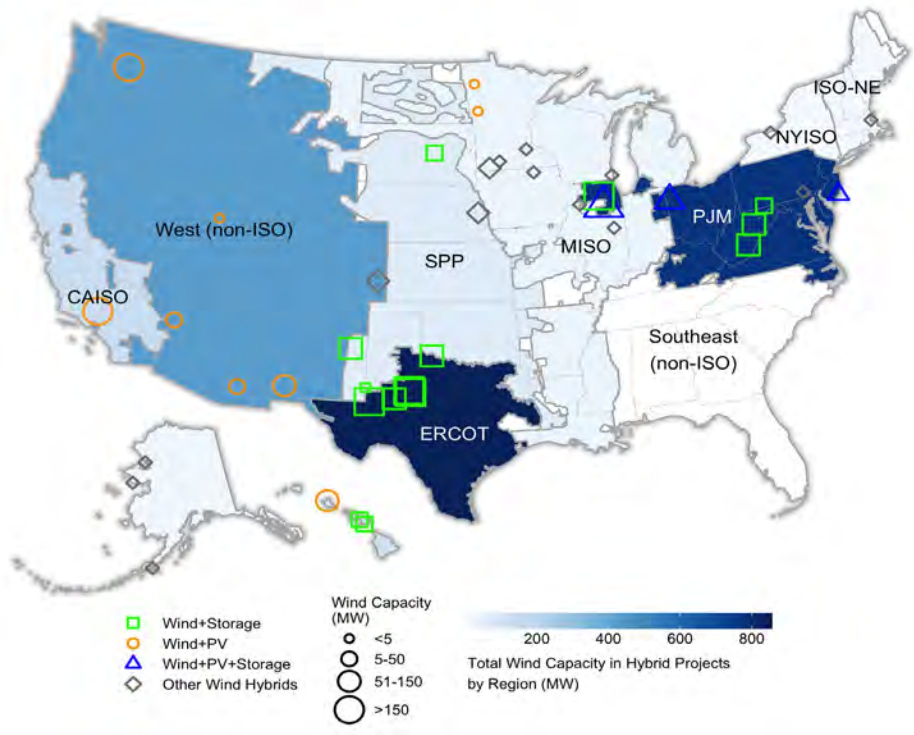
Sources: SPP, ERCOT, MISO, CAISO, PJM, ISO-NE, NYISO

Figure 7. Wind penetration as a proportion of load by independent system operator regions

Hybrid wind plants that pair wind with storage and other resources saw limited growth in 2021, with just two new projects completed

Though only two new wind hybrid projects were commissioned in 2021, there were 41 hybrid wind power plants in operation at the end of 2021, representing 2.4 GW of wind and 0.9 GW of co-located assets (storage, PV, or fossil-fueled generators). Some of these represent full hybrids where, for example, wind and storage are co-located and the design, configuration, and operation of the constituent technologies are fully integrated. In other cases, plants are co-located, sharing a point of interconnection, but are designed, configured, and operated more independently (e.g., hybrids that pair wind and gas plants).

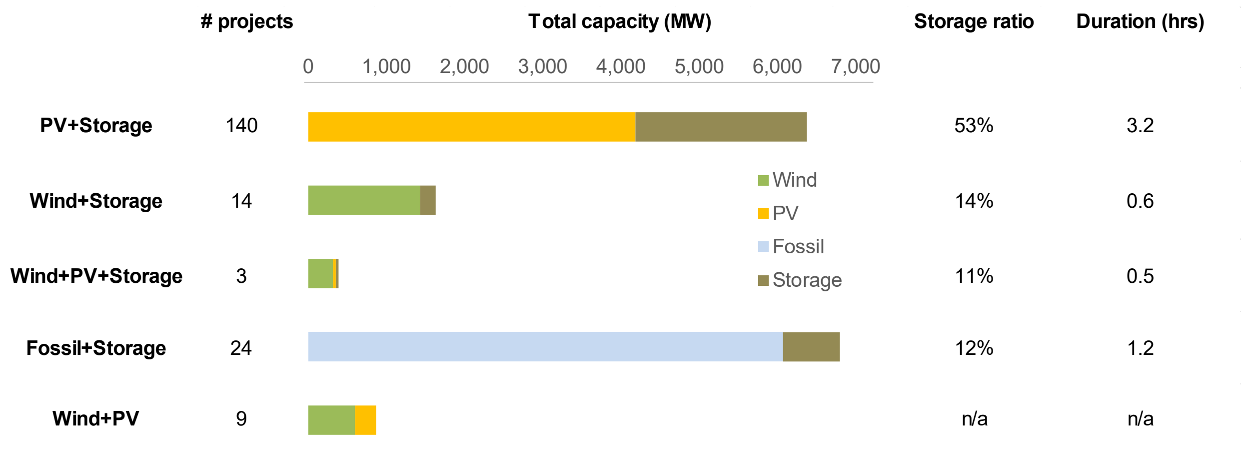
The most common type of wind hybrid project combines wind and storage technology, where 1.4 GW of wind has been paired with 0.2 GW of battery storage across 14 plants. However, no new projects of this type were installed in 2021. Other combinations include wind and PV; wind, PV, and storage; wind and gas; and more (Figure 8). The ERCOT region hosts the largest amount of wind capacity in hybrid plants (0.86 GW), followed by PJM (0.77 GW) and the non-ISO West (0.43 GW). Wind capacity tends to be largest for wind+storage hybrids than for other hybrid configurations.



Sources: EIA-860 2021 Early Release, Berkeley Lab

Figure 8. Location and capacity of hybrid wind plants in the United States

Figure 9 displays design characteristics for a subset of the more-common hybrid plant configurations, including those that do not incorporate wind. Wind+storage hybrids have a 14% storage-to-generator ratio with an average storage duration of just 0.6 hours, suggesting a focus on providing ancillary services and only limited capacity to shift large amounts of energy across time. Fossil+storage hybrids have similar storage-to-generator ratios (12%) but longer battery durations (1.2 hours). PV+storage hybrids have significantly higher average storage-to-generator ratios (53%) and battery durations (3.2 hours). Based on data from proposed projects, presented in the next section on interconnection queues, there is growing interest in hybridizing with larger storage-to-generator ratios and longer storage durations.



Notes: Not included in the figure are 108 hybrid projects with other configurations. Storage ratio defined as total storage capacity divided by total generator capacity for a given project type.

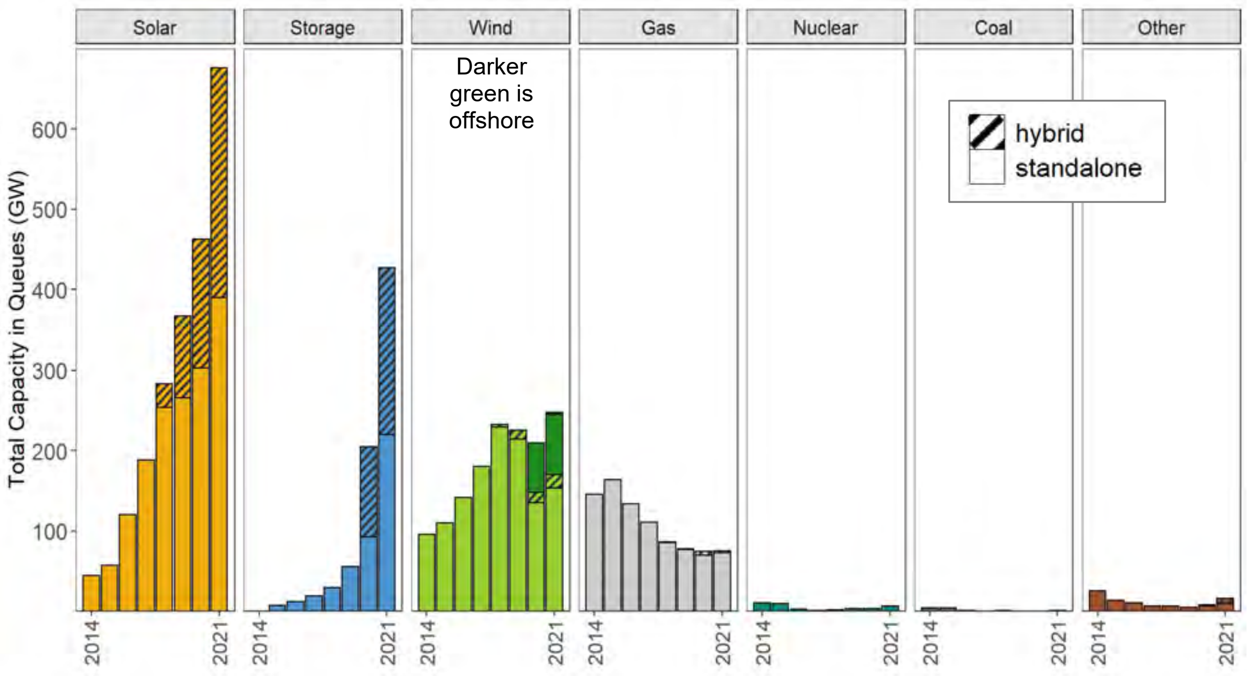
Sources: EIA-860 2021 Early Release, Berkeley Lab

Figure 9. Design characteristics of hybrid power plants operating in the United States, for a subset of configurations

The trend to co-locate wind with other assets has progressed at a slow, steady pace since 2006, with two new wind hybrids commencing operation in 2021: one Wind+PV and the other Wind+PV+Storage. In contrast, commercial interest in solar hybrids has expanded rapidly, with 67 new PV+storage projects coming online in 2021.

A record-high 247 GW of wind power capacity now exists in transmission interconnection queues, but solar and storage are growing at a much more rapid pace

One testament to the amount of developer and purchaser interest in wind energy is the amount of wind power capacity working its way through the major transmission interconnection queues across the country. Figure 10 provides this information over the last eight years for wind power and other resources aggregated across more than 40 different interconnection queues administered by ISOs and utilities.[13] These data should be interpreted with caution: placing a project in the interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built. An analysis of five ISO queues found an overall average completion rate of 23% for projects of all types proposed from 2000 to 2016 (Rand et al. 2022). Some projects are speculative in nature, and duplicate projects also complicate interpretation.



Notes: Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data; storage capacity in hybrids was not estimated for years prior to 2020; offshore wind was not separately identified prior to 2020.

Source: Berkeley Lab review of interconnection queues

Figure 10. Generation capacity in interconnection queues from 2014 to 2021, by resource type

Even with this important caveat, the amount of wind capacity in the nation's interconnection queues still provides at least some indication of the amount of developer interest. At the end of 2021, there were 247 GW

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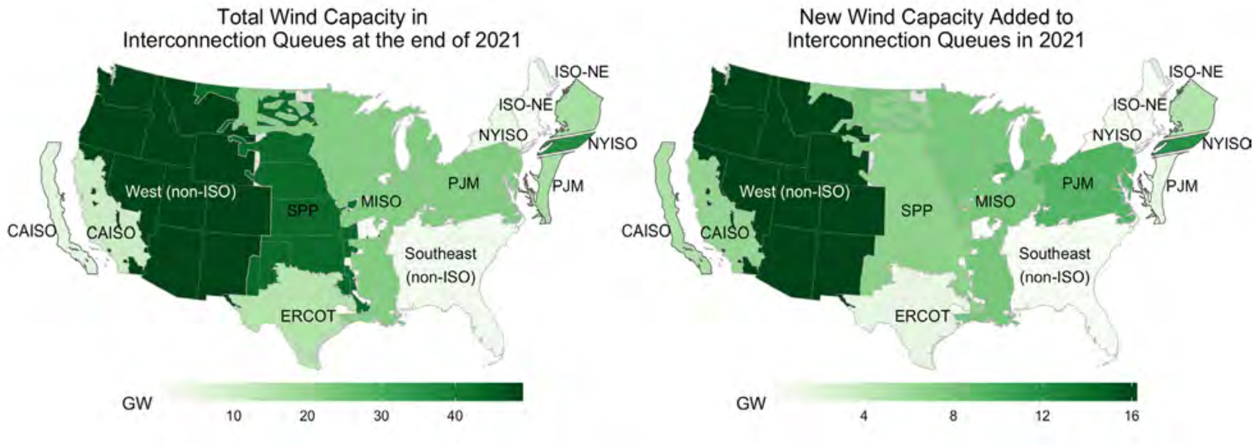
[13] The queues surveyed include PJM, MISO, NYISO, ISO-NE, CAISO, ERCOT, SPP, Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), and a large number of other individual utilities. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of over 85% of the U.S. total. The figures in this section only include projects that were active in the queues at the times specified but that had not yet been built; suspended projects are not included.

of wind capacity in the queues reviewed for this report—a marked increase from the 209 GW in the queues the previous year and supported by continued growth in offshore wind in the queues. In 2021, 73 GW of new wind capacity entered the queues, 12 GW of which were in hybrid configurations and 24 GW of which were for offshore wind. Solar additions to interconnection queues far outpaced wind in 2021, with 265 GW added. Storage additions to the queues have increased much more rapidly than wind in recent years as well, both for standalone plants and hybridized with solar or wind. Overall, wind represented 17% of all capacity in the queues at the end of 2021, compared to 47% for solar, 29% for storage, and just 5% for natural gas.

The total wind capacity in the interconnection queues is spread across the United States, as shown in Figure 11 (left image), with the largest amounts in the West (non-ISO) (20%), SPP (17%), NYISO (16%), and PJM (16%). Smaller amounts are found in MISO (9%), CAISO (7%), ISO-NE (7%), ERCOT (6%), and the Southeast (non-ISO) (1%). A majority (56%) of wind capacity in the queues has requested to come online by the end of 2024, and 16% of wind capacity has a fully executed interconnection agreement.

Focusing just on wind power additions to the queues in 2021 (Figure 11, right image), the West (non-ISO), NYISO, CAISO, and PJM experienced especially large annual additions, with NYISO's additions being almost entirely for offshore wind (>11 GW each). Across all queues, 31% (77 GW) of all wind capacity in the queues at the end of 2021 was offshore, and 33% (24 GW) of the wind added to queues in 2021 was offshore. Offshore wind capacity was added on both the East Coast (NYISO, PJM, ISO-NE) and the West Coast (CAISO).



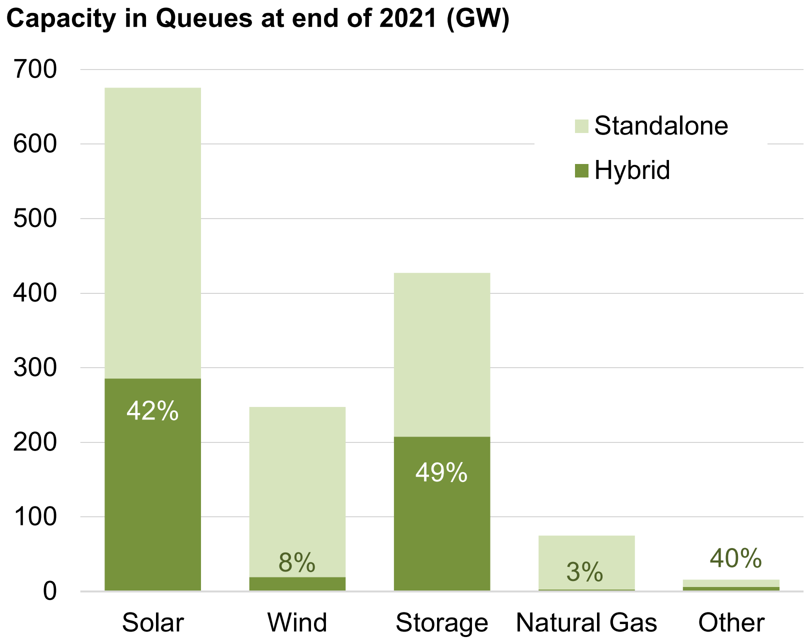
Total Wind Capacity in Interconnection Queues at the end of 2021

New Wind Capacity Added to Interconnection Queues in 2021

Source: Berkeley Lab review of interconnection queues

Figure 11. Wind power capacity interconnection queues at end of 2021, by region

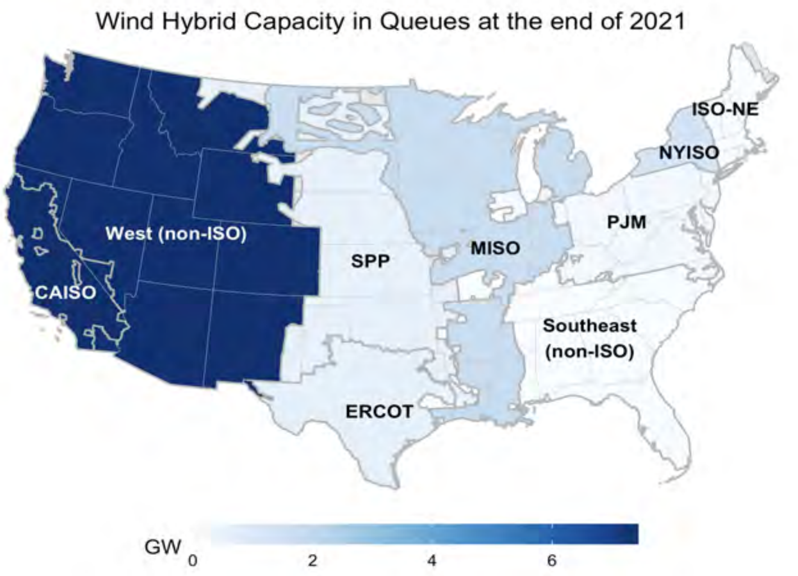
As shown in Figure 12, 42% of the solar capacity in interconnection queues at the end of 2021 has been proposed as hybrid plants, whereas only 8% of the wind capacity is paired with storage or another generation resource. In part this is due to policy design—the investment tax credit for solar can also be used for paired storage, whereas the production tax credit regularly used by wind plants has no such storage allowance. Of the 19 GW of proposed wind capacity in hybrid configurations, the majority (12 GW) is paired with storage, with less paired with solar (4 GW) or both solar and storage (2 GW).



Source: Berkeley Lab review of interconnection queues

Figure 12. Generation capacity in interconnection queues, including hybrid power plants

As shown in Figure 13, commercial interest in wind hybrid plants is highest in California and the West (non-ISO). In fact, 42% of the wind in CAISO's queues is proposed as a hybrid, as is 15% of the wind in the West.



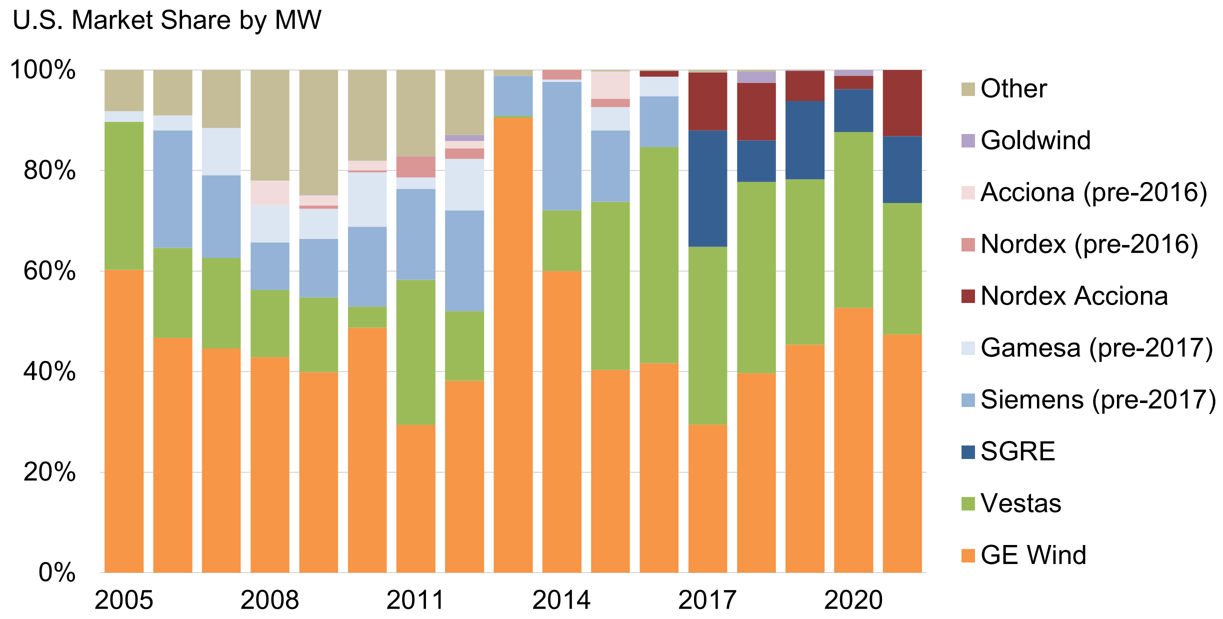
Source: Berkeley Lab review of interconnection queues

Figure 13. Hybrid wind power plants in interconnection queues at the end of 2021

3 Industry Trends

Just four turbine manufacturers, led by GE, supplied all of the U.S. wind power capacity installed in 2021

Of the 13.4 GW of wind installed in the United States in 2021, GE Wind supplied 47%, with Vestas coming in second (26%), followed by Siemens Gamesa Renewable Energy (SGRE, 13%) and Nordex (13%) essentially tied in third (Figure 14).[14] GE and Vestas have dominated the U.S. market for some time, with SGRE and Nordex vying for third.



Source: ACP

Figure 14. Annual U.S. market share of wind turbine manufacturers by MW, 2005–2021

The domestic wind industry supply chain contracted in 2021, with a 50% decline in blade manufacturing capability

Figure 15 identifies the many wind turbine component manufacturing, assembly, and other supply chain facilities operating in the United States at the end of 2021. Three of the major turbine OEMs that serve the U.S. wind industry—GE, Vestas, and SGRE—are represented within this total, each having one or more operating manufacturing facility. The figure also highlights the geographic breadth of the domestic supply chain.

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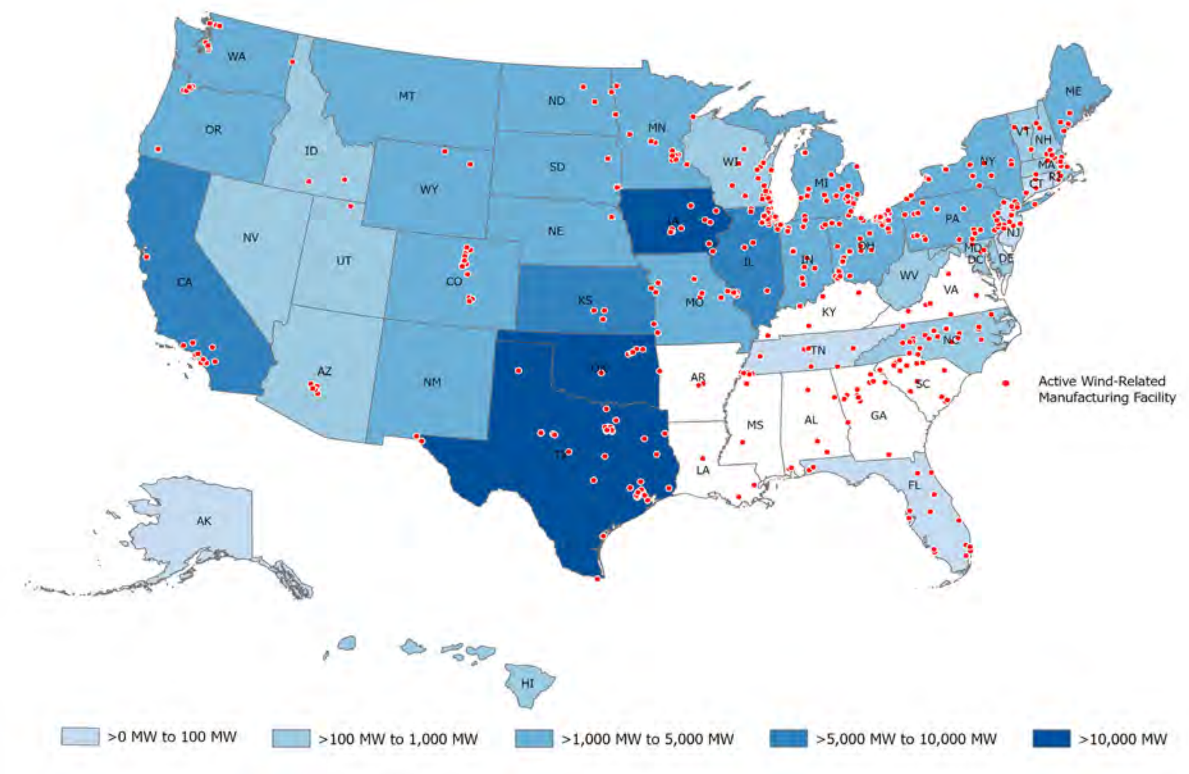
[14] Market share is reported in MW terms and is based on project installations in the year in question.



Source: ACP

Figure 15. Location of turbine and component manufacturing facilities

In aggregate, domestic turbine nacelle assembly[15] capability—defined here as the maximum annual nacelle assembly capability of U.S. plants if all were operating at full utilization—grew from less than 1.5 GW in 2006 to more than 13 GW in 2012, fell to roughly 10 GW in 2015, and then rose to 15 GW in 2020 before declining to 12.3 GW in 2021 (Figure 16).

In addition, from 2012 through 2020, domestic blade and tower manufacturing capability was largely stable or growing, in each case increasing from around 7 to 8 GW/year in 2012 to around 10 GW/year. In 2021, however, the supply chain contracted—modestly for nacelle assembly and towers, but a 50% drop in blade manufacturing capability to ~4.6 GW/year. Based on ACP (2022), three blade manufacturing plants closed or idled production in 2021: TPI Composites (Newton, IA), Molded Fiber Glass (Aberdeen, SD), and Vestas (Brighton, CO). Arcosa (Clinton, IL), meanwhile, idled one of its tower manufacturing facilities. A combination of competition from foreign suppliers and uncertain future deployment for land-based wind in the United States are conspiring to weaken domestic wind manufacturing capabilities.

Figure 16 contrasts this equipment manufacturing capability with past U.S. wind additions as well as near-term forecasts of future new installations (see Chapter 9, "Future Outlook"). It demonstrates that domestic manufacturing capability for towers and nacelle assembly remains reasonably well balanced with projected wind additions in the United States, but that blade manufacturing capability has fallen well below near-term wind additions as international suppliers outcompete domestic ones. Note that manufacturing facilities do not typically operate at maximum capability; see the next section of the report for estimates of domestic manufacturing content.

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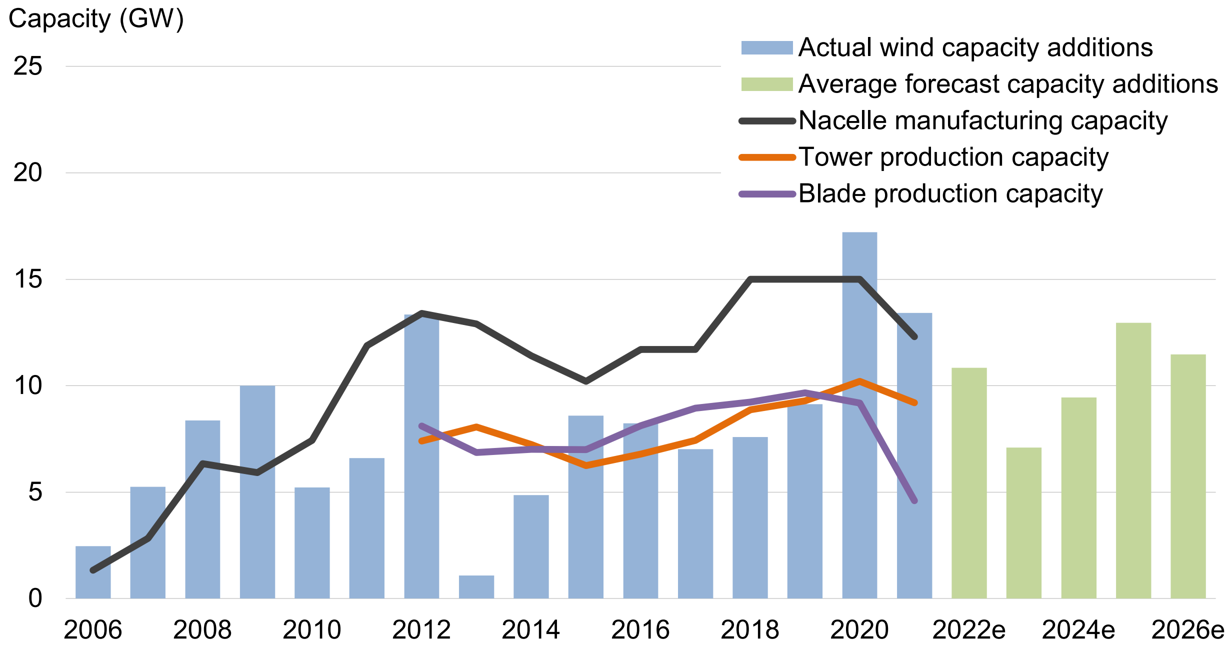
[15] Nacelle assembly is defined as the process of combining the multitude of components included in a turbine nacelle, such as the gearbox and generator, to produce a complete turbine nacelle unit.



Sources: ACP, independent analyst projections, Berkeley Lab

Figure 16. Domestic wind manufacturing capability vs. U.S. wind power capacity installations

More generally, fierce competition among manufacturers has generally reduced turbine OEM profitability over the last several years. High recent commodity and transportation costs along with COVID-19 restrictions have also limited manufacturer profitability (Figure 17).[16]

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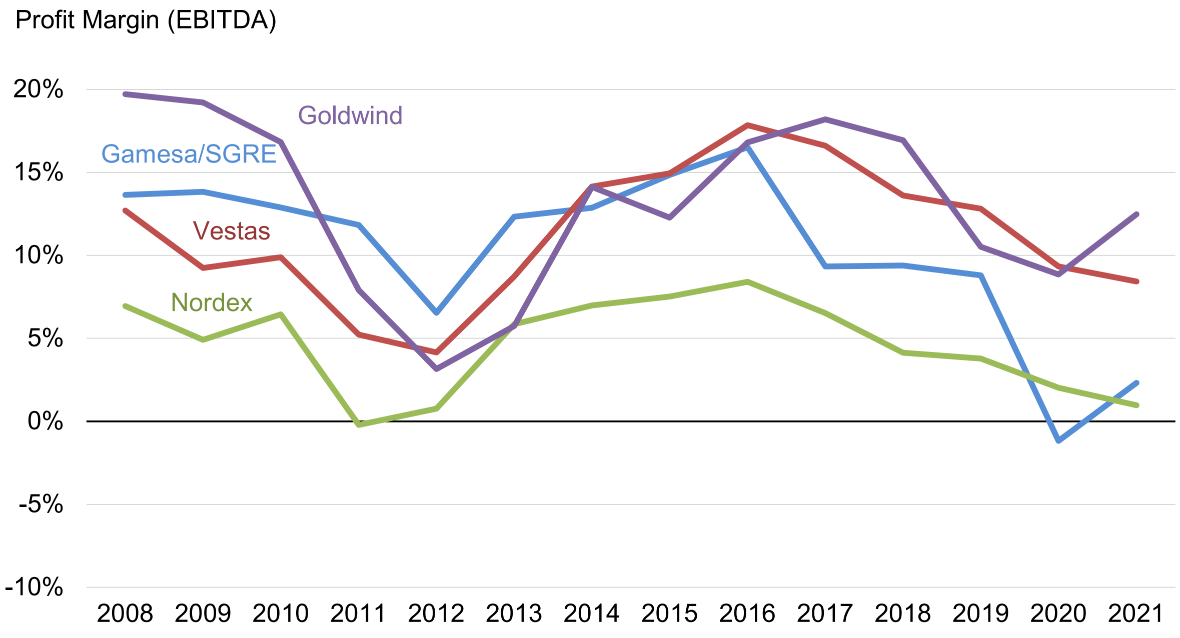
[16] Although it is one of the largest turbine suppliers in the U.S. market, GE is not included because it is a multi-national conglomerate that does not report segmented financial data for its wind turbine division.



Note: EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization

Sources: OEM annual reports and financial statements

Figure 17. Turbine OEM global profitability

Despite these supply-chain challenges, wind-related job totals in the United States increased by 2.9% in 2021, to 120,164 full-time workers—benefitting from continued robust development (DOE 2022). These jobs include, among others, those in construction (43,371) and manufacturing (23,644).

Domestic manufacturing content is strong for some wind turbine components, but the U.S. wind industry remains reliant on imports, which totaled $3.1 billion in 2021

Despite the breadth of the domestic wind industry supply chain, the U.S. wind sector is reliant on imports of wind equipment. The level of dependence varies by component: some components have a relatively high domestic share, whereas others remain largely imported. These trends are revealed, in part, by data on wind equipment trade from the U.S. Department of Commerce.[17]

Figure 18 presents data on the dollar value of estimated imports to the United States of wind-related equipment that can be tracked through trade codes. The figure shows imports of wind-powered generating sets and parts, including nacelles (i.e., nacelles with blades, nacelles without blades, and, in some cases, other turbine components internal to the nacelle) as well as imports of other select turbine components shipped separately from the generating sets and nacelles.[18] The turbine components included in the figure consist only of those that can be tracked through trade codes: towers, generators (as well as generator parts), and blades and hubs.[19]

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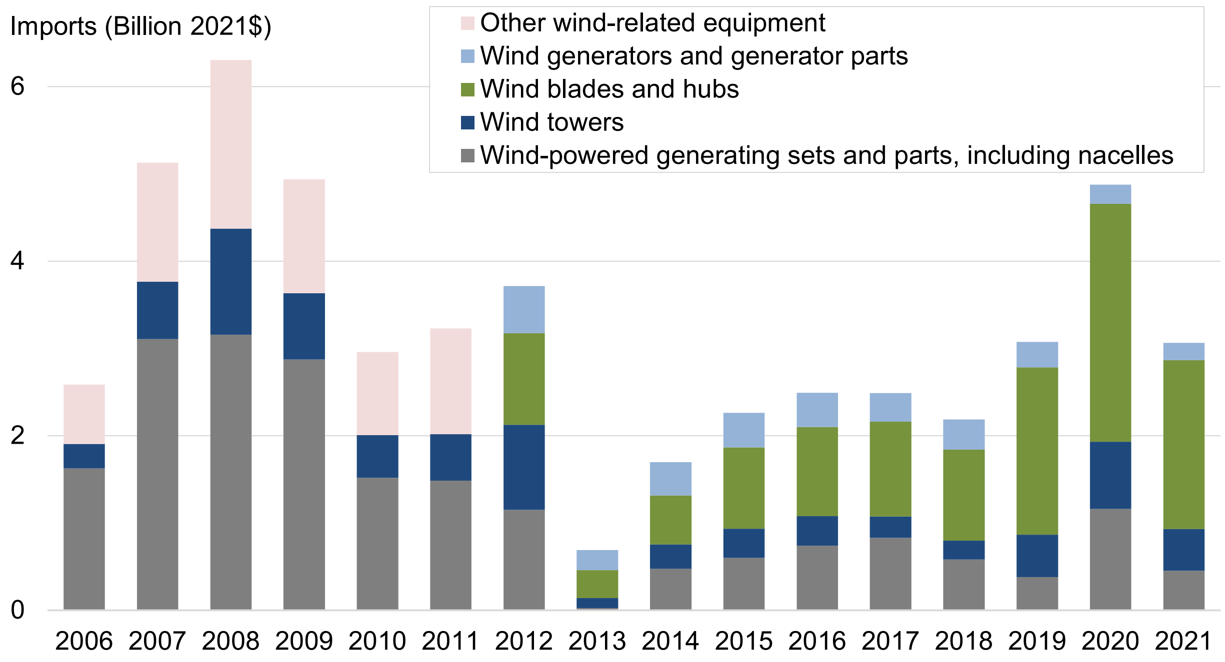
[17] See the Appendix for further details on data sources and methods used in this section, including the specific trade codes considered.

[18] Wind turbine components such as blades, towers, and generators are included in the data on wind-powered generating sets and nacelles if shipped in the same transaction. Otherwise, these component imports are reported separately.

[19] Though all of the import estimates are specific to wind equipment in 2020 and 2021, import trends should be viewed with particular caution because the underlying data from earlier years used to produce Figure 17 are based on trade categories that are not all exclusive to wind. Some of the import estimates shown in Figure 17 for years prior to 2020 therefore required



Note: Wind-related trade codes and definitions are not consistent over the full time period.

Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 18. Imports of wind-related equipment that can tracked with trade codes

The estimated imports of tracked wind-related equipment into the United States increased substantially from 2006 to 2008, before falling through 2010, increasing somewhat in 2011 and 2012, and then plummeting in 2013 with the simultaneous drop in U.S. wind installations. From 2014 through 2021, imports of wind-related turbine equipment generally followed U.S. wind installation trends, bouncing back from the low of 2013 and then with a marked decline in 2021 as wind plant installations declined from the previous year. Interpreting time trends in these data is challenging, however, given changes in annual wind additions from year to year, time lags between equipment import and installation, and fluctuations in wind turbine and equipment pricing. Also, because imports of component parts occur in additional, broad trade categories different from those included in Figure 18, the data presented here understate the aggregate amount of wind equipment imports.

Figure 19 shows the total value of tracked wind-specific imports to the United States in 2021, by country of origin, as well as states of entry. Major countries from which the U.S. imports wind equipment include Mexico, Spain, and India, which together account for more than $1.5 billion in wind-specific exports to the U.S. in 2021. Texas is the dominant entry point, a persisting trend in the last five years, with over $2 billion of wind-specific equipment flowing through it in 2021, followed distantly by Illinois, Michigan, Louisiana, and Florida.

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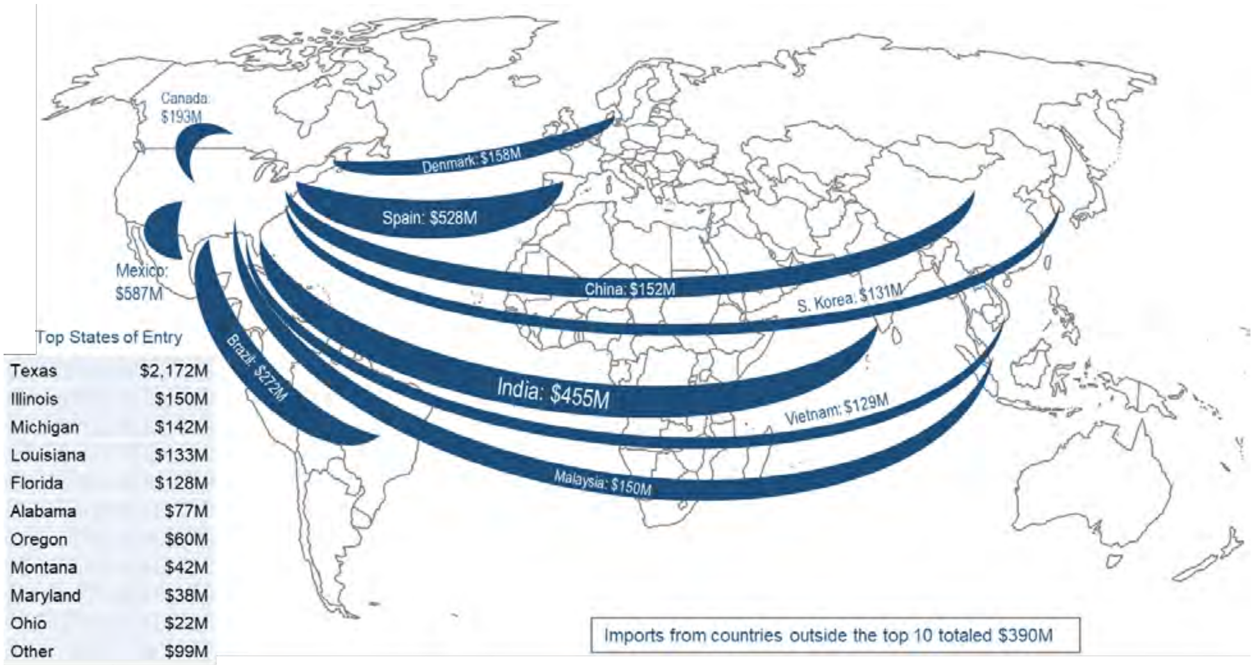
assumptions about the fraction of larger trade categories likely to be represented by wind turbine components. For example, from 2013 through 2019, nacelles (when shipped alone) are included in a trade category that is not largely exclusive to wind. The trade code for tower imports is also not entirely exclusive to wind, but is believed to be dominated by wind since 2011—we assume that 100% of imports from this trade category, since 2011, represent wind equipment.



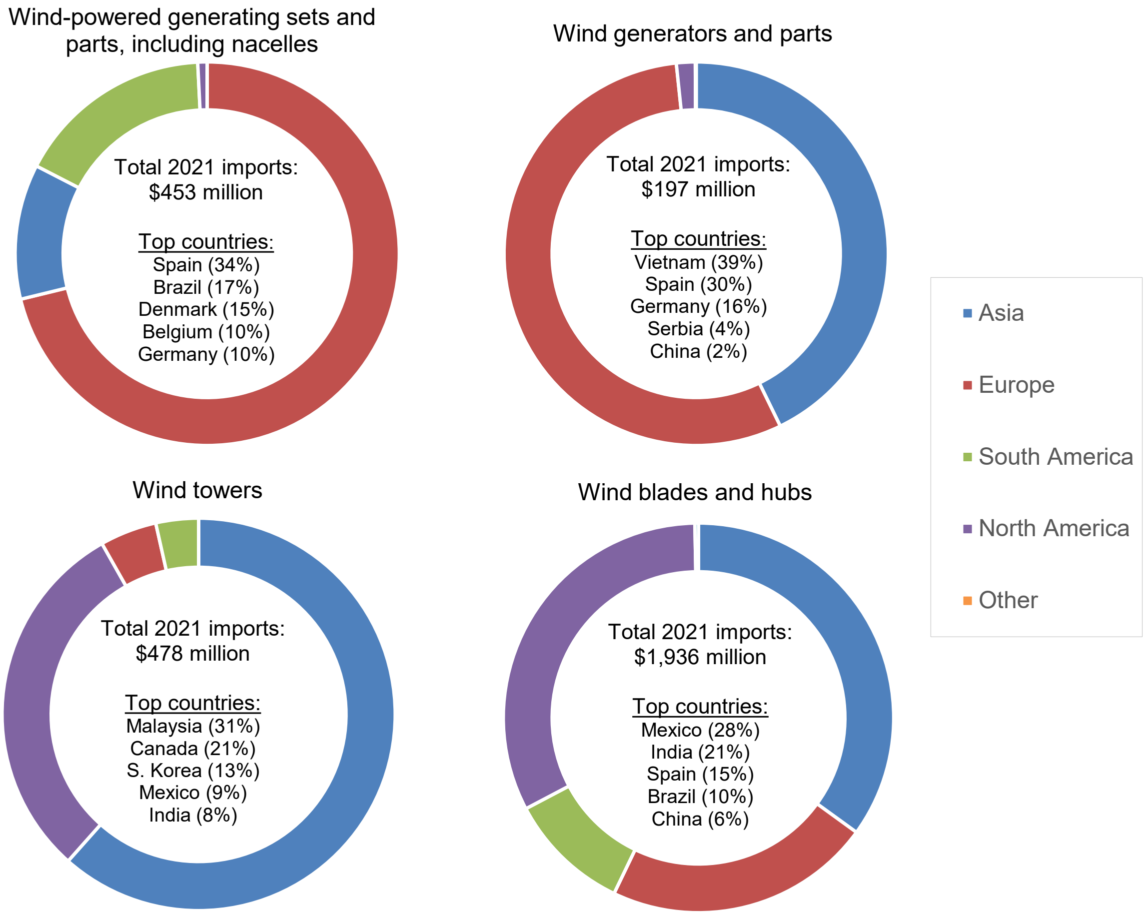
Top States of Entry

Texas	$2,172M
Illinois	$150M
Michigan	$142M
Louisiana	$133M
Florida	$128M
Alabama	$77M
Oregon	$60M
Montana	$42M
Maryland	$38M
Ohio	$22M
Other	$99M

Note: Line widths are proportional to import amount by country. Figure does not intend to depict the destination of these imports, by state.
Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 19. Summary map of tracked wind-specific imports in 2021: top-10 countries of origin and states of entry

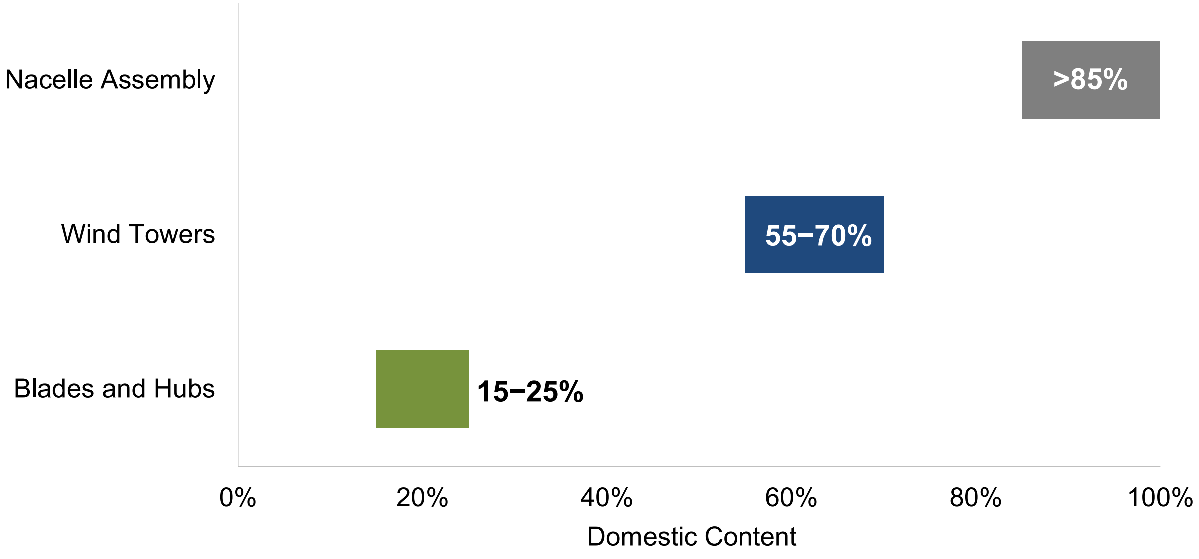
Looking behind these data, Spain, followed by Brazil, Denmark, Belgium, and Germany, were the primary source countries for wind-powered generating sets and parts, including nacelles, in 2021 (Figure 20). Tower imports came from a mix of countries near and far—Malaysia, Canada, South Korea, Mexico, and India. With regard to blades and hubs, Mexico and India accounted for almost 50% of imports, with Spain, Brazil, and China the next largest source countries in 2021. Finally, over two thirds of wind-related generators and generator parts in 2021 came from Vietnam and Spain, the rest primarily coming from Germany, Serbia, and China.



Source: Berkeley Lab analysis of data from USA Trade Online, https://usatrade.census.gov

Figure 20. Origins of U.S. imports of selected wind turbine equipment in 2021

Figure 21 presents rough estimates of the domestic content for a subset of the major wind turbine components used in new (and repowered) U.S. wind projects in 2021. Domestic content remains relatively strong for larger components such as towers and also for nacelle assembly. The domestic manufacturing content of blades, on the other hand, has declined precipitously in recent years. More broadly, these figures may understate the wind industry's reliance on foreign suppliers, because significant wind-related imports occur under trade categories not captured in this figure, including equipment (such as mainframes, converters, pitch and yaw systems, main shafts, bearings, bolts, controls) and manufacturing inputs (such as foreign steel in domestic manufacturing).



Source: Berkeley Lab analysis

Figure 21. Approximate domestic content of major components in 2021

Independent power producers own the majority of wind assets built in 2021, following historical trends

Independent power producers (IPPs) own 9,995 MW or 75% of the 13.4 GW of new wind capacity installed in the United States in 2021 (Figure 22, right pie chart). Investor-owned utilities (IOUs)—most notably Pacificorp (589 MW), AEP's PSO and SWEPCO (486 MW), the Empire District Electric Company (450 MW), and Xcel Energy (436 MW), but including ten IOUs in all—installed a total of 3,418 MW (25%). Of the cumulative installed wind power capacity at the end of 2021 (Figure 22, left chart), IPPs own 80% and utilities own 18% (17% IOU and 1% publicly owned utility, or POU), with the remaining 1% falling into the "other" category of projects owned by neither IPPs nor utilities (e.g., owned by towns, schools, businesses, farmers).[20]

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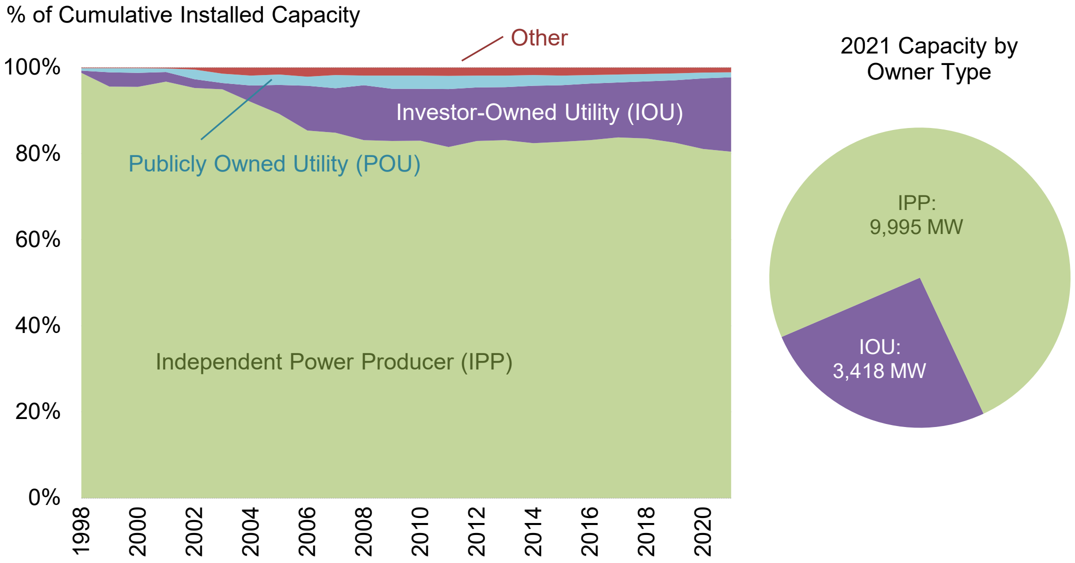
[20] Many of the "other" projects, along with some IPP- and POU-owned projects, might also be considered "community wind" projects that are owned by or benefit one or more members of the local community to a greater extent than typically occurs with a commercial wind project.



Source: Berkeley Lab estimates based on ACP

Figure 22. Cumulative and 2021 wind power capacity categorized by owner type

Direct retail sales and merchant offtake arrangements for wind, in combination, matched or surpassed long-term contracted wind sales to utilities in 2021

Electric utilities either own (25%) or buy the electricity from wind projects (19%) that, in total, represent 44% of the new capacity installed last year (with the 44% split between 32% IOU and 12% POU—Figure 23, right pie chart). On a cumulative basis, utilities own (18%) or buy (42%) power from 60% of all wind power capacity installed in the United States (with the 60% split between 42% IOU and 18% POU, with the POU category including community choice aggregators (CCAs)).

Direct retail purchasers of wind power, including a diverse and growing set of corporate and non-corporate offtakers, are supporting at least 35% of the new wind power capacity installed in the United States in 2021 (and 13% of cumulative wind power capacity). Such purchasers historically have spanned a wide range of organizations, from technology companies, retailers, finance, and telecommunication firms to governments and universities. Merchant/quasi-merchant projects accounted for at least 7% of all new 2021 capacity and 20% of cumulative capacity.[21] Finally, power marketers—defined here to include commercial intermediaries that purchase power under contract and then resell that power to others[22]—are buying at least the remaining 2% of new 2021 wind capacity and 5% of cumulative capacity. We qualify the level of support from these non-utility offtakers as "at least" because it is likely that much of the 1.5 GW of 2021 capacity that has not yet disclosed an offtaker is being sold to corporate buyers, power marketers, or into merchant arrangements, rather than to utilities.

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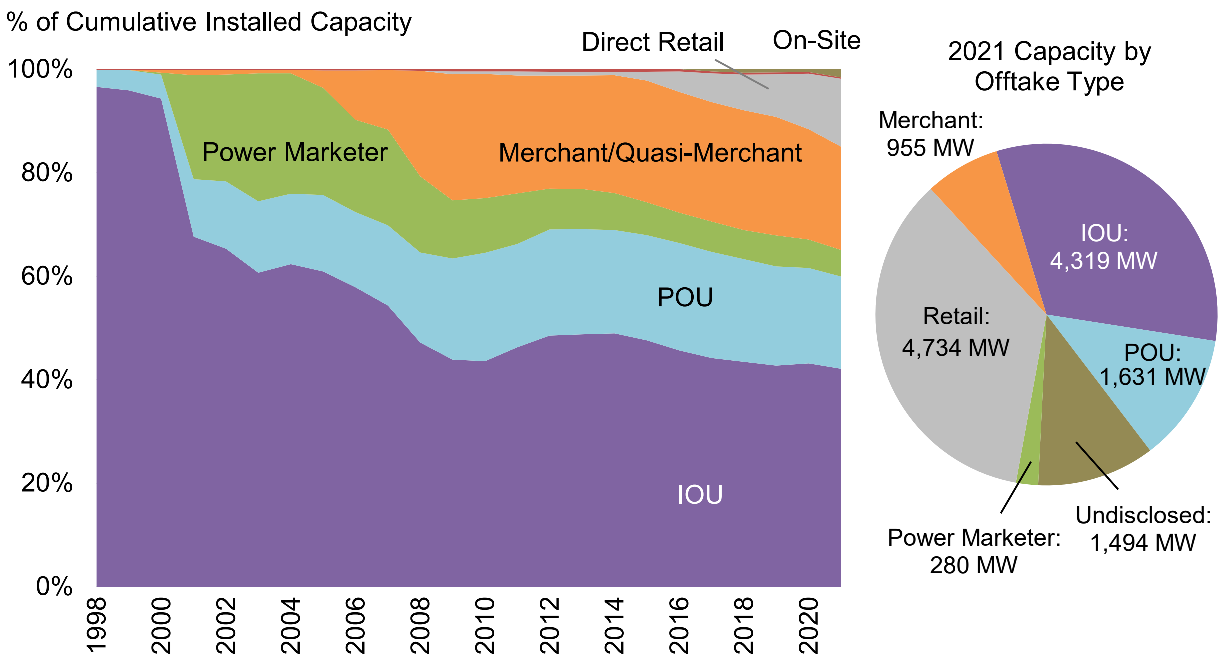
[21] Merchant/quasi-merchant projects are those whose electricity sales revenue is tied to short-term contracts and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 10- to 12-year period), rather than being locked in through a long-term PPA. Most of these projects are located within ERCOT, though there are some merchant/quasi-merchant projects within other markets, including PJM, MISO, SPP, and NYISO. Associated hedges are often structured as a "fixed-for-floating" power price swap—a purely financial arrangement whereby the wind power project swaps the "floating" revenue stream that it earns from spot power sales for a "fixed" revenue stream based on an agreed-upon strike price with the swap counterparty.

[22] These intermediaries include the wholesale marketing affiliates of large IOUs, which may buy wind on behalf of their load-serving affiliates.



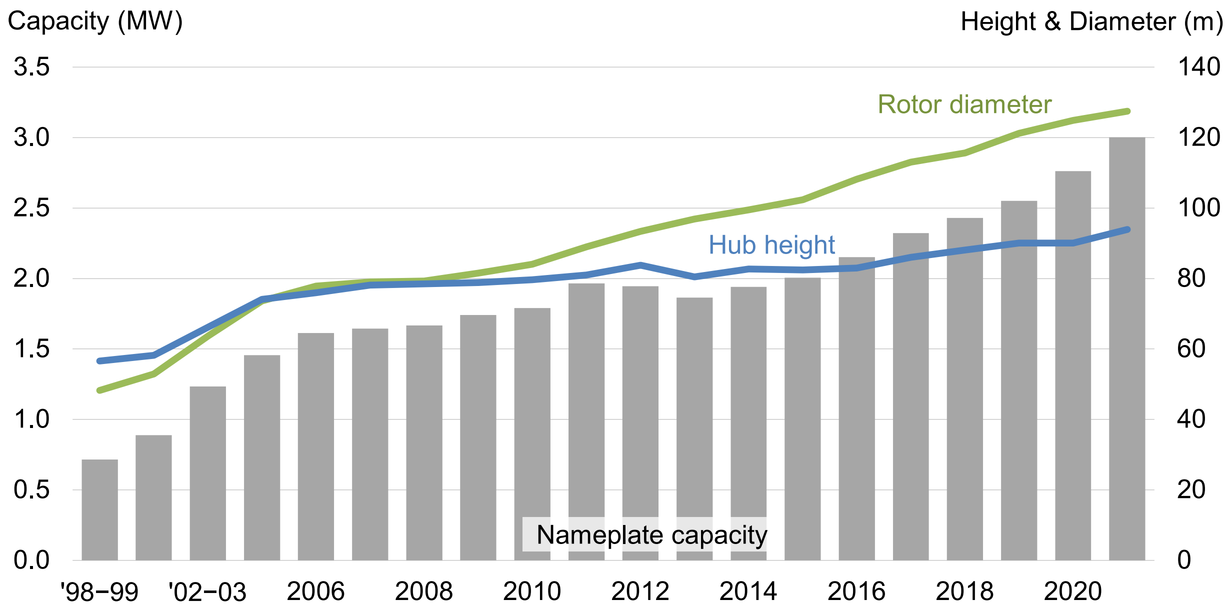
Source: Berkeley Lab estimates based on ACP

Figure 23. Cumulative and 2021 wind power capacity categorized by power offtake arrangement

4 Technology Trends

Turbine capacity, rotor diameter, and hub height have all increased significantly over the long term

The average nameplate capacity of newly installed wind turbines in the United States in 2021 was 3.0 MW, 9% larger than in 2020 and up 319% since 1998–1999 (Figure 24).[23] The average hub height of turbines installed in 2021 was 93.9 meters, 4% larger than in 2020 and up 66% since 1998–1999. The average rotor diameter in 2021 was 127.5 meters, 2% larger than in 2020 and up 164% since 1998–1999. Trends in rotor scaling in particular, but also hub height, are two of several factors impacting the project-level capacity factors highlighted later in this report.



Sources: ACP, Berkeley Lab

Figure 24. Average turbine nameplate capacity, hub height, and rotor diameter for land-based wind projects

Figure 25 presents these same trends since 2011, but with additional detail on the relative distribution of turbines with different capacities, hub heights, and rotor diameters. For example, 2021 saw an increase in the proportion of turbines installed in the 2.75–3.5 MW range, while the proportion of turbines at 3.5 MW or larger also increased. The percentage of turbines with hub heights larger than 100 meters increased in 2021, to 28%—up from just 15% in 2020. Finally, the steady progression toward larger rotors continued. In 2011, no turbines employed rotors that were 115 meters in diameter or larger, while 89% of newly installed turbines featured such rotors in 2021 (and 23% of those were at least 130 meters).

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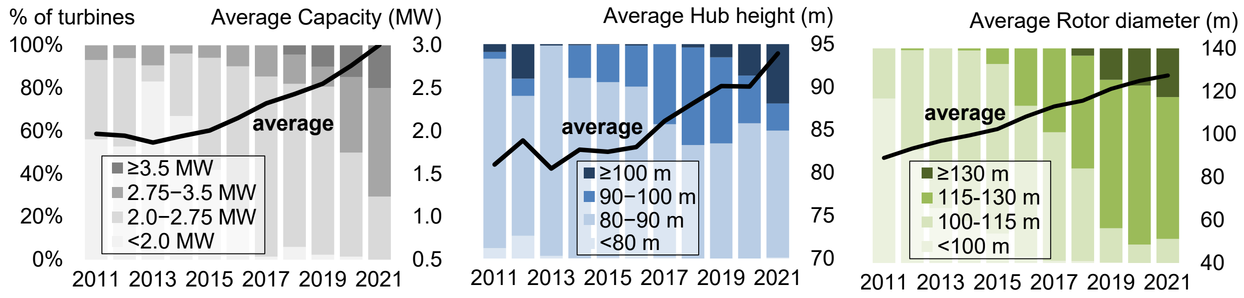
[23] Figure 24 and a number of the other figures and tables included in this report combine data into both one- and two-year periods in order to avoid distortions related to small sample size in the PTC lapse years of 2000, 2002, and 2004; although not a PTC lapse year, 1998 is grouped with 1999 due to the small sample of 1998 projects. Though 2013 was a slow year for wind additions, it is shown separately here despite the small sample size.



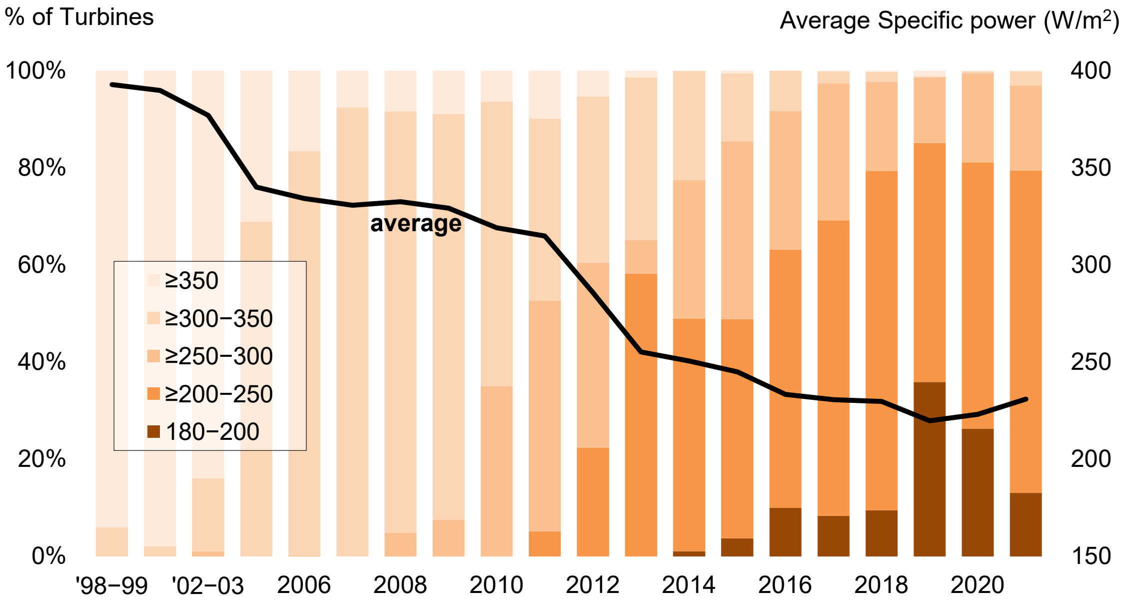
Sources: ACP, Berkeley Lab

Figure 25. Trends in turbine nameplate capacity, hub height, and rotor diameter

Turbines originally designed for lower wind speed sites dominate the market, but the trend towards lower specific power has reversed over the last two years

The growth in the average swept area (in m^2) of rotors has been especially rapid over the last two decades, outpacing growth in average nameplate capacity (in W). This has resulted in a decline in the average "specific power" (in W/m^2) among the U.S. turbine fleet over time, from 393 W/m^2 among projects installed in 1998–1999 to 231 W/m^2 among projects installed in 2021. However, as shown in Figure 26, the long-term decline in specific power has reversed in recent years, with specific power rising slightly in both 2020 and 2021.

All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. This means that the generator is likely to run closer to or at its rated capacity more often. In general, turbines with low specific power were originally designed for lower wind speed sites, intended to maximize energy capture in areas where large-rotor machines would not be placed under excessive physical stress due to high or turbulent winds. As suggested in Figure 26 and as detailed later, however, such turbines are in widespread use in the United States—even in sites with relatively high wind speeds. The impact of lower specific-power turbines on project-level capacity factors is discussed in more detail in Chapter 5.



Sources: ACP, Berkeley Lab

Figure 26. Trends in turbine specific power

Wind turbines were deployed in somewhat lower wind-speed sites in 2021 than in the previous seven years

Figure 27 shows the long-term average wind resource at wind project sites, by commercial operation date. The figure depicts both the long-term site-average wind speed (in meters per second) at 100 meters for projects installed in each year (right scale) and an index of wind resource quality at 100 meters (left scale).[24]

Wind plants that came online in 2021 are located—on average—at sites with an estimated long-term average 100-meter wind speed of 8.0 meters per second (m/s). This is the lowest average site wind speed in the last eight years. Federal Aviation Administration (FAA) and industry data on projects that are "under construction," in "advanced development," "pending," or "proposed" suggest that the sites likely to be built out over the several years will, on average, have even lower long-term average wind speeds.[25] Trends in the wind resource quality index—which represents estimates of the gross capacity factor for each turbine location, indexed to the 1998–1999 installations—are broadly similar. These trends signal changes in site-average wind speeds at a common reference height of 100 meters. Increasing hub heights over this period, thereby accessing higher wind speeds, help to partially offset these trends in 100-meter wind speeds and resource quality.

Several factors could have driven these observed trends in average site quality at 100 meters. First, the availability of low-wind-speed turbines that feature lower specific power have enabled the economic build-out of lower-wind-speed sites. Second, transmission constraints (or other siting constraints, or even just regionally differentiated wholesale electricity prices) may have, over time, increasingly focused developer attention on those projects in their pipeline that have access to transmission (or higher-priced markets, or readily available sites without long permitting times), even if located in somewhat lower wind resource sites. The build-out of new transmission (for example, the completion of major transmission additions in West Texas in 2013), however, may at times have offered the chance to install new projects in more energetic sites. Other forms of federal and/or state policy could also play a role. For example, wind projects built in the four-year period from 2009 through 2012 were able to access a 30% cash grant (or ITC) in lieu of the PTC. Many projects availed themselves of this incentive and, because the dollar amount of the grant (or ITC) was not dependent on how much electricity a project generates, it is possible that developers also seized this limited opportunity to build out the less-energetic sites in their development pipelines. Finally, state policies sometimes motivate in-state or in-region wind development in lower wind resource regimes.

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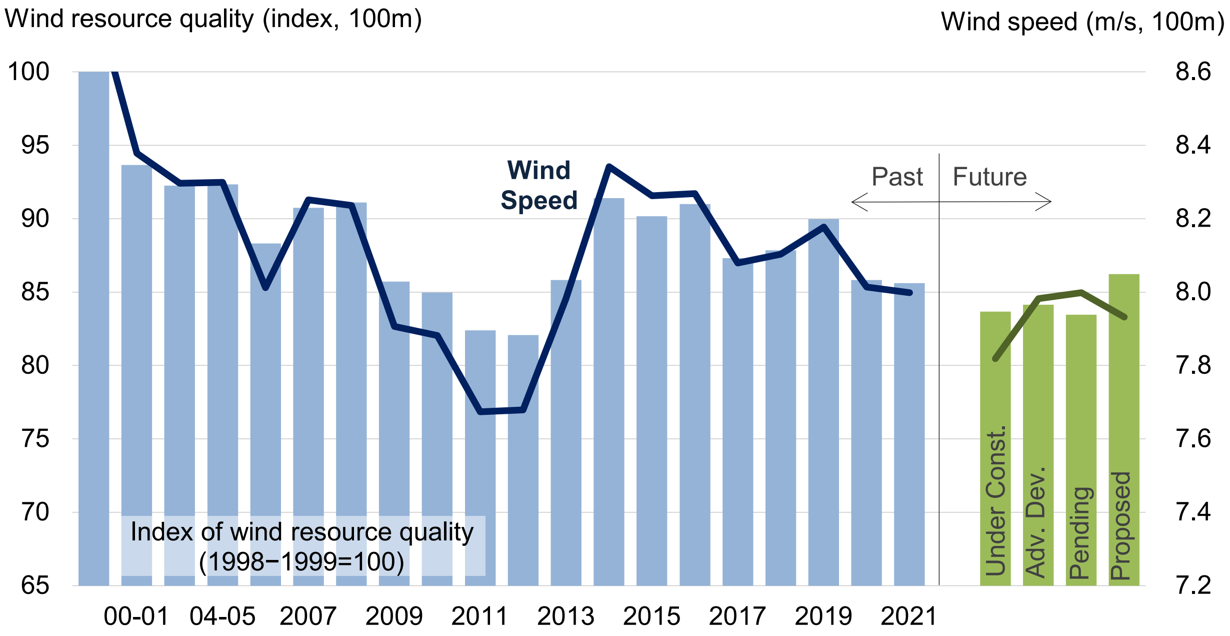
[24] The wind resource quality index is based on site estimates of gross capacity factor at 100 meters by AWS Truepower. A single, common wind turbine power curve is used across all sites and timeframes in this case, and no losses are assumed. The values are indexed to projects built in 1998–1999. Further details are found in the Appendix. A benefit of this wind resource quality index is that changes in the index value will better approximate expected changes in actual wind project performance than will changes in average annual wind speed.

[25] "Under construction" turbines are part of a project where construction has begun, but the project has not yet been commissioned. Turbines in "advanced development" have one of the following in place: a signed PPA (or similar long-term contract), a firm turbine order, or an announcement to proceed under utility ownership, indicating a high-likelihood that they will be built. "Pending" turbines are those that have received a "No Hazard" determination by the FAA and are not set to expire for another 18 months, while "proposed" turbines have not yet received any determination. Pending and proposed turbines may not all ultimately be built. However, analysis of past data suggests that FAA pending and proposed turbines offer a reasonable proxy for turbines built in subsequent years.

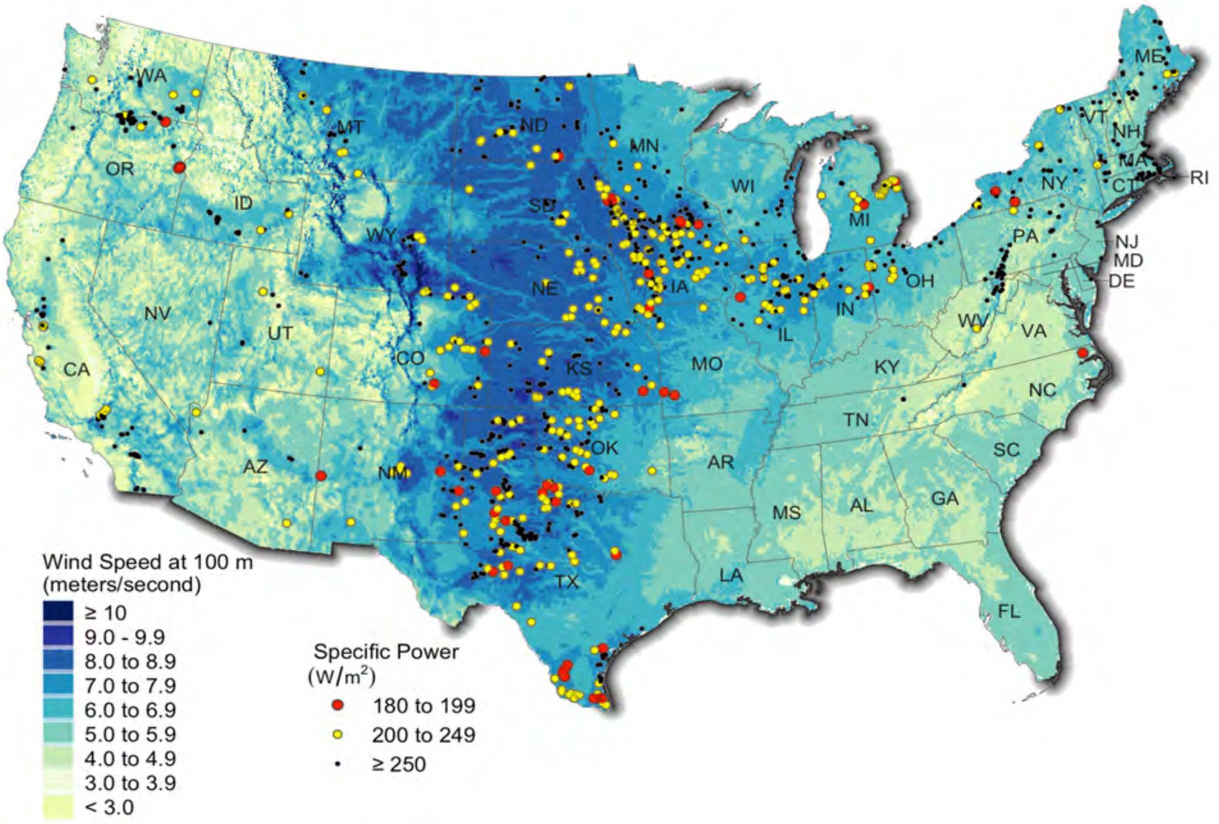


Sources: ACP, Berkeley Lab, AWS Truepower, FAA Obstacle Evaluation / Airport Airspace Analysis files

Figure 27. Wind resource quality at 100 meter height by year of installation

Low-specific-power turbines are deployed on a widespread basis; taller towers are seeing increased use in a wider variety of sites

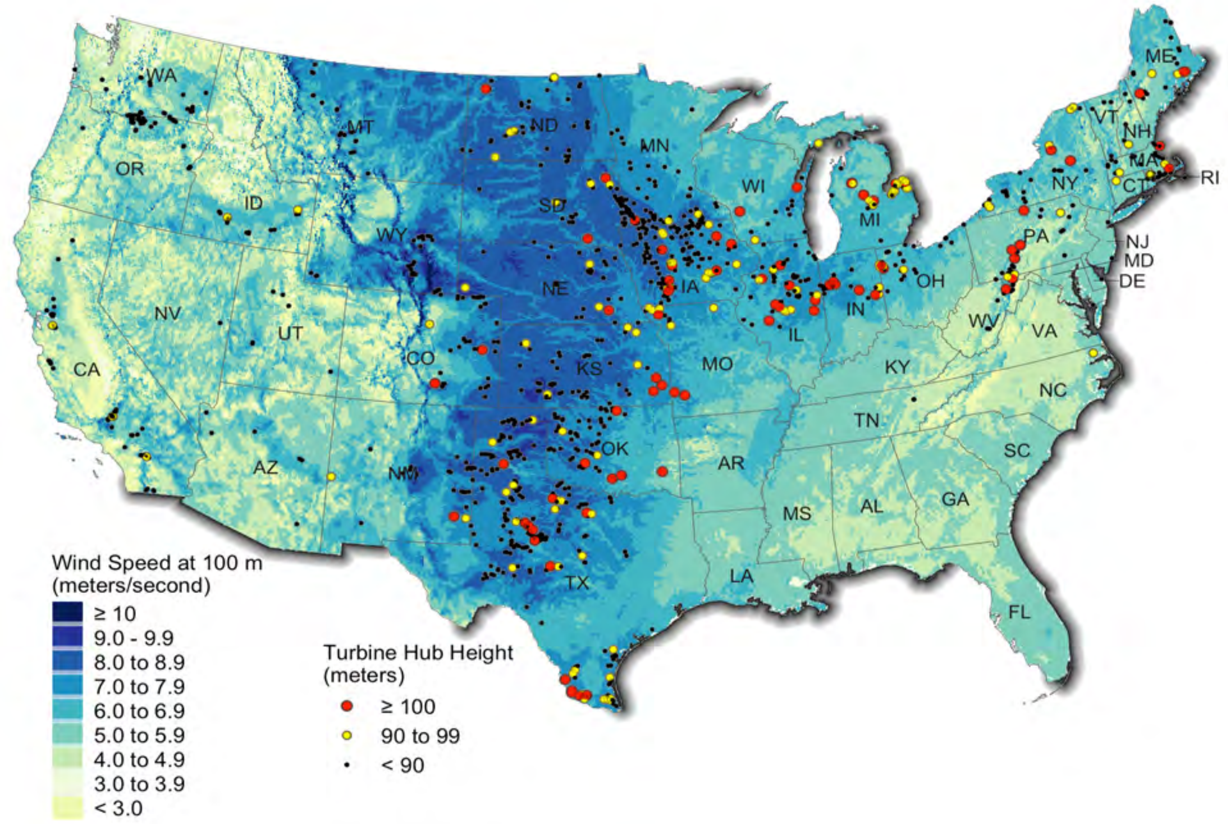
One might expect that the increasing market share of low-specific-power turbines (defined here as turbines with specific power < 250 W/m^2) would be due to a movement by developers to deploy turbines in lower wind speed sites. There is some evidence of this movement historically (see Figure 27), but it is clear in Figure 28 (which shows all U.S. wind projects) that low-specific-power turbines have established a strong foothold across the nation and over a wide range of wind speeds.



Sources: ACP, U.S. Wind Turbine Database, AWS Truepower, Berkeley Lab

Figure 28: Location of low specific power turbine installations: all U.S. wind plants

Likewise, taller towers are also being deployed across a wide array of sites (Figure 29). That said, very tall towers (>100m) still tend to be most concentrated within the upper Midwest and Northeast regions, two regions known to have higher-than-average wind shear (i.e., greater increases in wind speed with height), which makes taller towers more economical.



Sources: ACP, U.S. Wind Turbine Database, AWS Truepower, Berkeley Lab

Figure 29: Location of tall tower turbine installations: all U.S. wind plants

Wind projects planned for the near future are poised to continue the trend of ever-taller turbines

FAA data on total proposed turbine heights (from ground to blade tip extended directly overhead) in permit applications are reported in Figure 30. Note that these data represent total turbine height or "tip height"—not hub height—and include the combined effect of both the tower and half the rotor. Figure 30 shows the average FAA tip height, along with the distribution, for actual 2021 installations as well as turbines under construction, in advanced development, pending, and proposed.[26]

Average tip heights for projects that came online in 2021 are 517 feet (158 meters), and seem destined to climb higher in the next few years, reaching an average of 643 feet (196 meters) among the "proposed" turbines. The tallest turbines in the permitting process are over 750 feet (229 meters), while turbines of at least 650 feet appear likely to be installed in every region of the United States (Figure 31).

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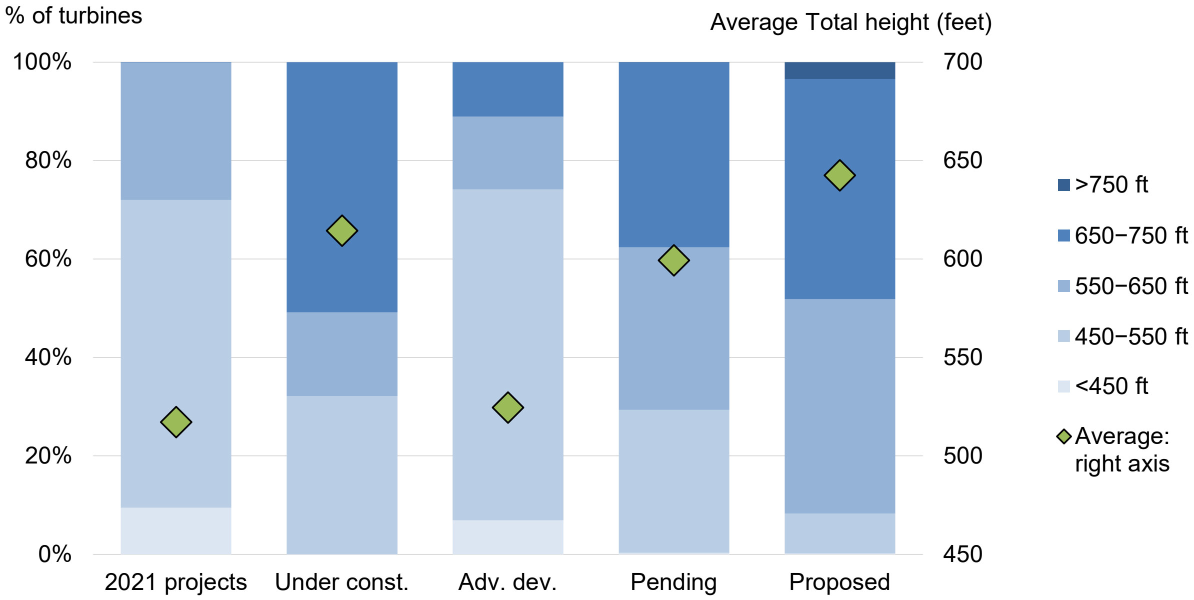
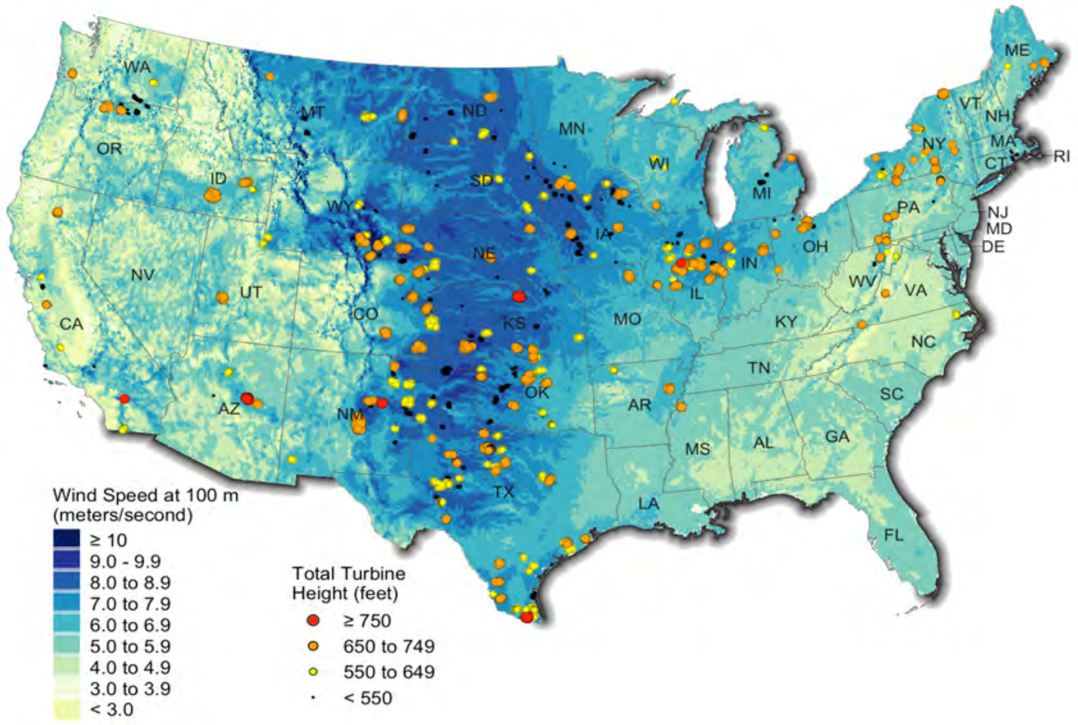
[26] Turbine heights reported in FAA permit applications represent the maximum height and can differ from what is ultimately installed. Historically, however, the FAA permit datasets have strongly conformed to subsequent actual installations on average.



Sources: ACP, FAA files, Berkeley Lab

Figure 30. Total turbine heights proposed in FAA applications, over time



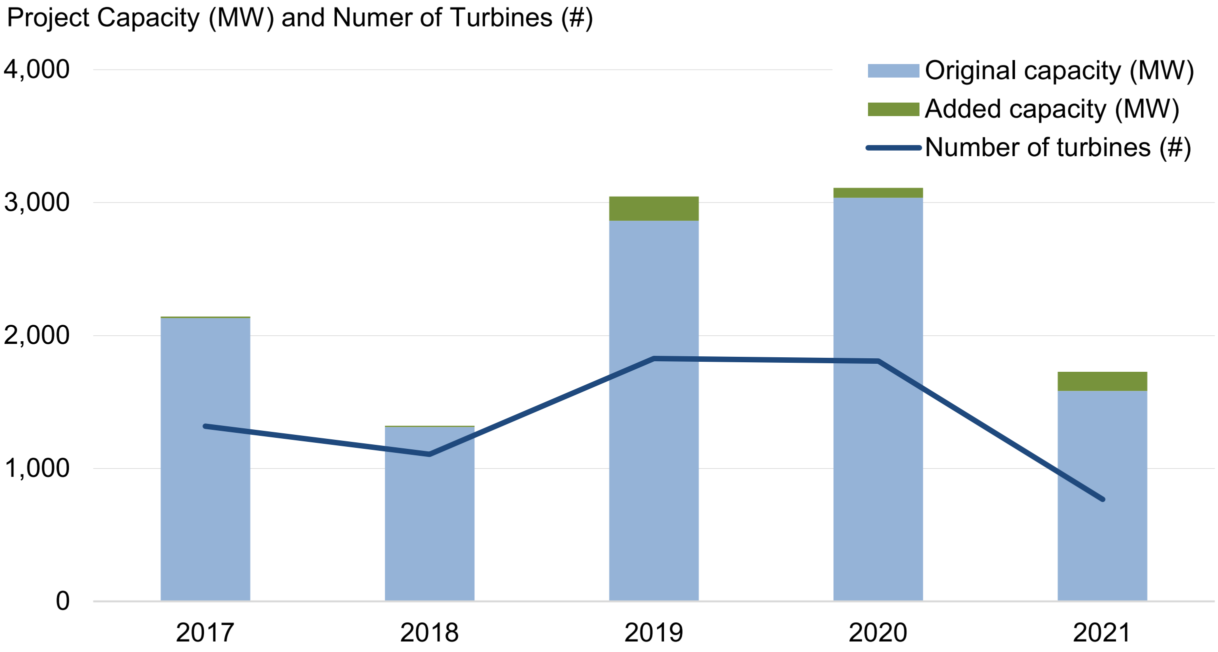
Note: Figure includes FAA data on under-construction, advanced development, pending, and proposed turbines

Sources: FAA Obstacle Evaluation / Airport Airspace Analysis files, AWS Truepower, ACP, Berkeley Lab

Figure 31. Total turbine heights proposed in FAA applications, by location

In 2021, twelve wind projects were partially repowered, most of which now feature significantly larger rotors and lower specific power ratings

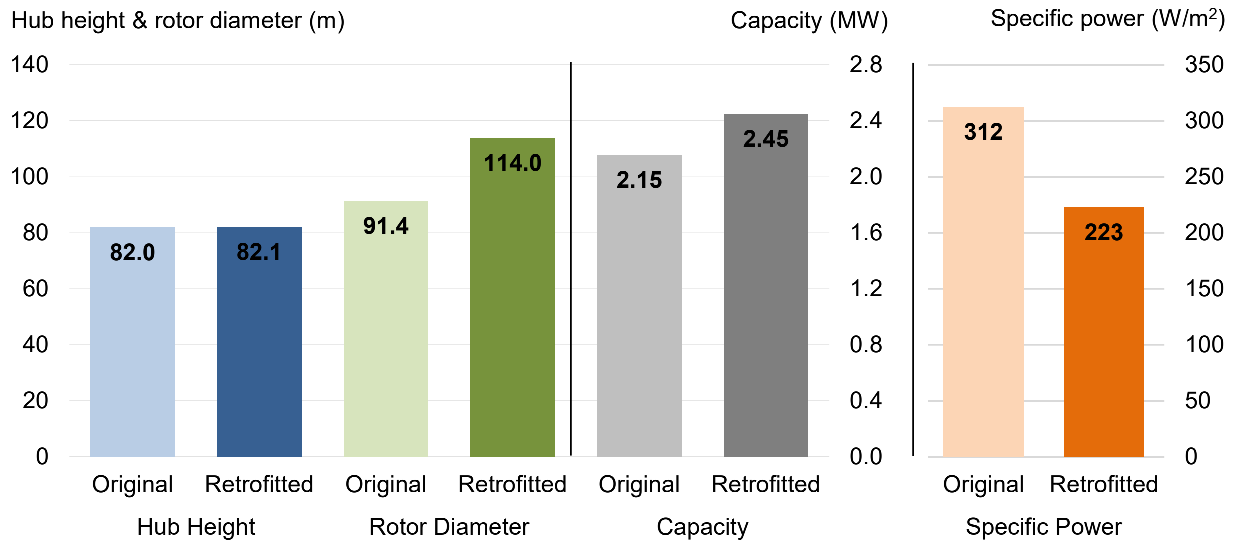
The trend of partial wind project repowering continued in 2021, albeit at a slower pace, and involved replacing major components of turbines with more-advanced technology to increase energy production, extend project life, and access favorable tax incentives. In 2021, 12 projects were partially repowered, involving 769 turbines that totaled 1.6 GW prior to repowering. Retrofitted turbines ranged in age from 9 to 16 years old; the median was 10 years. The 1.6 GW of retrofitted turbines in 2021 is a decline from the previous two years, when roughly 3 GW were retrofitted each year (Figure 32).



Sources: ACP, Berkeley Lab, turbine manufacturers

Figure 32. Annual amount of partially repowered wind power capacity and number of turbines

The most common retrofit in 2021 was the replacement of shorter with longer blades, but changes in turbine nameplate capacity were also common. Overall, the average turbine nameplate capacity of the retrofitted projects increased modestly, but rotor diameters strongly increased (Figure 33). A very small number of the turbines saw changes in hub heights. With the relatively small change in capacity but the larger change in rotor diameter, these retrofits drove a significant decrease in average specific power.



Sources: ACP, Berkeley Lab, turbine manufacturers

Figure 33. Change in average physical specifications of all turbines that were partially repowered in 2021

5 Performance Trends

The average capacity factor in 2021 was 35% on a fleet-wide basis and 39% among wind projects built in recent years

Following the previous discussion of technology trends, this chapter presents data from a compilation of project-level capacity factors.[27] The full data sample consists of 989 wind projects built between 1998 and 2020 and totaling 103.1 GW. Excluded from this assessment are older projects installed prior to 1998. In addition, projects that either partially or fully repowered in 2021 are excluded from the 2021 capacity factor sample, given that they were at least partly offline during a portion of the year. Unless otherwise noted, all capacity factors in this chapter are reported on an as-observed and unadjusted basis (i.e., after any losses from curtailment, less-than-full availability, wake effects, ice or soil on blades, etc.). When looking at performance degradation over time, however, adjustments are made for inter-annual variability in the wind resource.

To start, Figure 34 shows both individual project and average capacity factors in 2021, broken out by commercial operation date.[28] Projects built in 2021 are excluded, as full-year performance data are not yet available for those projects. From left to right, Figure 34 shows an increase in weighted-average 2021 capacity factors when moving from projects installed in the 1998–2001 period to those installed in the 2004–2005 period. Subsequent project vintages through 2011 show little if any improvement in average capacity factors recorded in 2021. This pattern of stagnation is broken by projects installed in 2012–2013, and even more so by those that achieved commercial operations in 2014–2020.[29]

The average 2021 capacity factor among projects built from 2014 to 2020 was 39%, compared to an average of 26% among all projects built from 2004 to 2011, and 19% among all projects built from 1998 to 2001. Cumulative, fleet-wide performance has also increased over time, growing from under 27% in 1999 (not shown) to 35% in 2021 (shown in Figure 34). The improvement in capacity factor among more-recently built projects is impacted by several factors that are explored later, including project location and the quality of the wind resource at each site, turbine scaling and design, and performance degradation over time. The 2021 capacity factor for projects built most recently, in 2020, was 38%, somewhat lower than for projects built from 2014 to 2020 and continuing a capacity factor decline that began with wind projects built in 2019.

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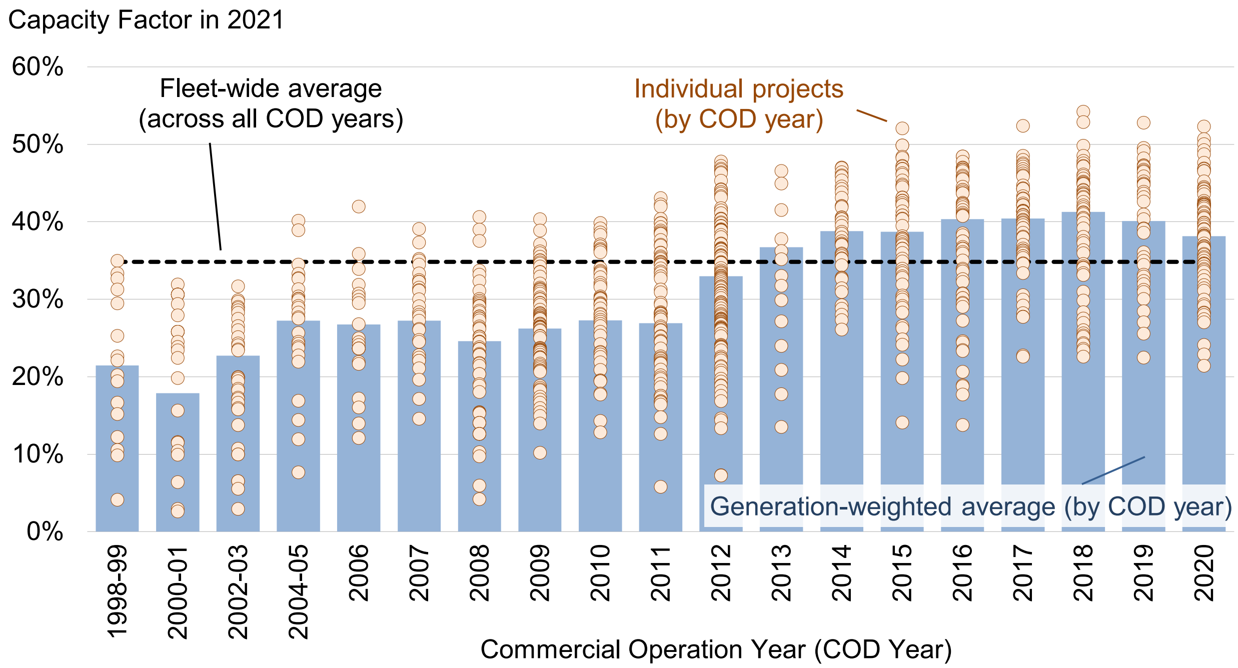
[27] Capacity factor is a measure of the actual energy generated by a project over a given timeframe (typically annually) relative to the maximum possible amount of energy that could have been generated over that same timeframe if the project had been operating at full capacity the entire time.

[28] Focusing on capacity factors in a single year, 2021, controls (at least loosely) for time-varying influences such as the degree of wind power curtailment or inter-annual variability in the strength of the wind resource. But it also means that the *absolute* capacity factors shown in Figure 33 may not be representative over longer terms if 2021 was not a representative year in terms of curtailment or the strength of the wind resource (though, as noted later, 2021 was a fairly average wind year overall).

[29] The 2021 capacity factor of projects that were built in 2020 may be biased low, due to possible first-year "teething" issues, as projects may take a few months to achieve normal, steady-state production after first achieving commercial operations.

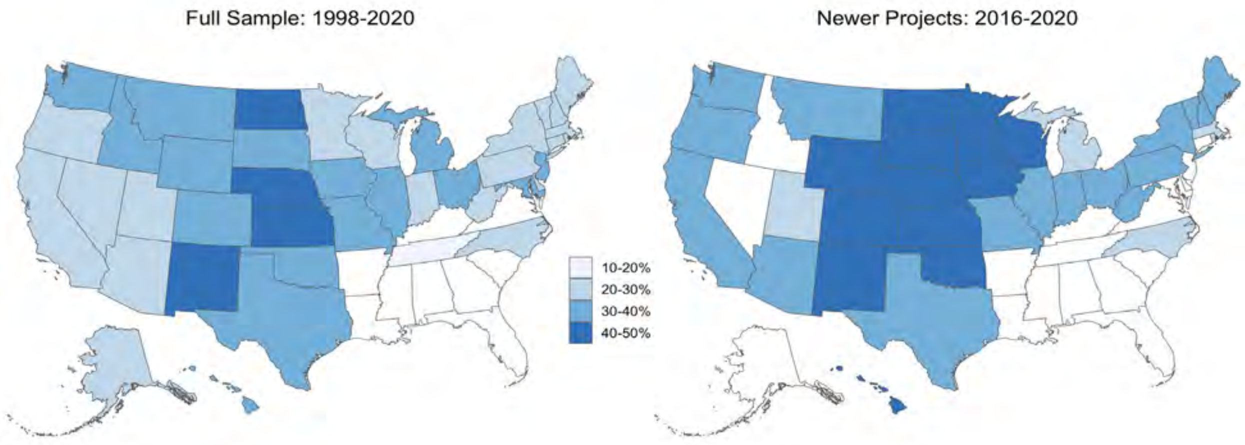


Sources: EIA, FERC, Berkeley Lab

Figure 34. Calendar year 2021 capacity factors by commercial operation date

State and regional variations in capacity factors reflect the strength of the wind resource; capacity factors are highest in the central part of the country

The project-level spread in capacity factors shown in Figure 34 is enormous, with capacity factors in 2021 ranging from a minimum of 21% to a maximum of 52% among those projects built in 2020. Some of the spread—for projects built in 2020 and earlier—is attributable to regional variations in average wind resource quality. Figure 35 includes data on the full sample of projects built from 1998 through 2020 and also a subset of newer projects built from 2016 through 2020, and shows average state-level capacity factors in 2021. The overall range runs from 12%–46%, with considerably higher capacity factors in the interior of the country—where the wind resource is the strongest.



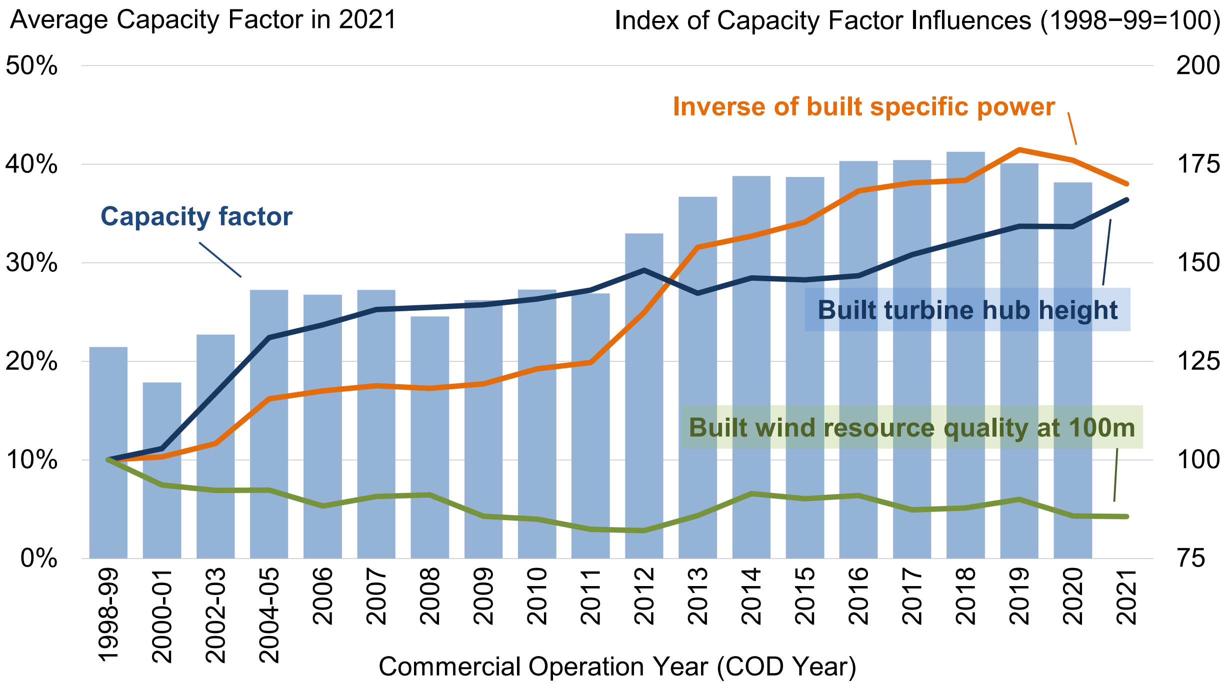
Note: States shaded in white have no projects in full sample (left) or in newer sample (right)

Sources: EIA, FERC, Berkeley Lab

Figure 35. Average calendar year 2021 capacity factor by state

Turbine design and site characteristics influence performance, with declining specific power leading to sizable increases in capacity factor over the long term

The trends in average capacity factor by commercial operation date seen in Figure 34 can largely be explained by several underlying influences described in Chapter 4 and shown again in Figure 36. First, as documented in Chapter 4, there has been a trend toward lower specific power and higher hub heights. These two drivers are shown again in Figure 36 in index form, relative to projects built in 1998–1999 (with specific power shown in the inverse, to correlate with capacity factor movements). All else equal, a lower specific power will boost capacity factors, because there is more swept rotor area available (resulting in greater energy capture) for each watt of rated turbine capacity. Meanwhile, increasing turbine hub heights generally helps the rotor access higher wind speeds. Second, and potentially counterbalancing these drivers, there has been a tendency to build new wind projects in areas that feature lower average wind speeds,[30] especially among projects installed from 2009 through 2012 as shown by the wind resource quality index in Figure 36. This trend reversed course in 2013 and 2014, but has since drifted lower once again (these wind resource trends are easier to see in Figure 27, where the y-axis scale is less-expansive). Finally, as shown later, two other drivers might include project age (given the possible degradation in performance among older projects) and increasing curtailment over the past few years (curtailment is baked into the capacity factors shown throughout this chapter).



Note: In order to have all three indices be directionally consistent with their influence on capacity factor, this figure indexes the inverse of specific power (i.e., a decline in specific power causes the index to increase rather than decrease).

Sources: EIA, FERC, Berkeley Lab

Figure 36. 2021 capacity factors and various drivers by commercial operation date

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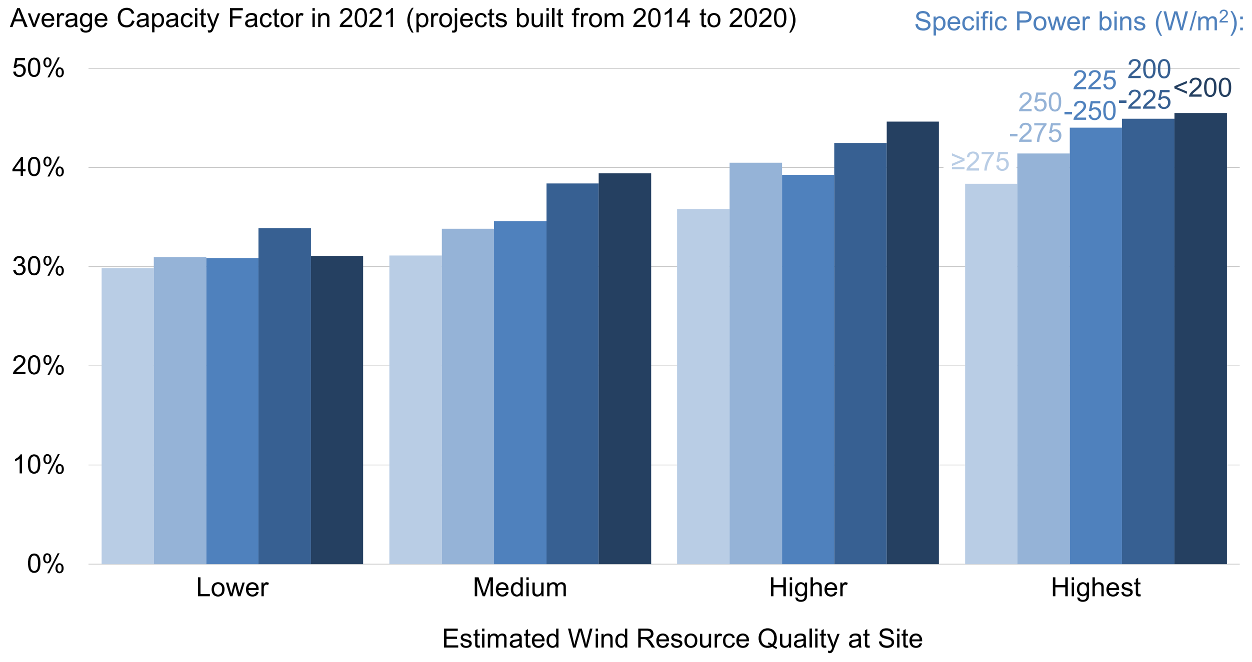
[30] As described earlier relating to Figure 27 (with further details in the Appendix), estimates of wind resource quality are based on site estimates of *gross* capacity factor at 100 meters, as derived from nationwide wind resource maps created for NREL by AWS Truepower. Those site estimates are indexed to projects built in 1998–1999.

In Figure 36, the significant improvement in average 2021 capacity factors from among those projects built in 1998–2001 to those built in 2004–2005 is driven by both an increase in hub height and a decline in specific power, despite a shift toward somewhat lower-quality wind resource sites. The stagnation in average capacity factors that subsequently persists through 2011-vintage projects reflects relatively flat trends in both hub height and specific power, coupled with an ongoing decline in wind resource quality at built sites. The sharp increase in average capacity factors among projects built after 2011 is driven by a steep reduction in average specific power coupled with—for a time—a marked improvement in the quality of wind resource sites. Average hub height increased modestly over this period. Finally, projects built most recently have somewhat lower 2021 capacity factors, perhaps due in part to teething issues that often confront projects in their first years but also due to a slight rise in specific power and a continuing move towards lower-quality wind resource sites. Looking ahead to 2022, projects with commercial operation dates in 2021 could possibly record lower capacity factors on average than those built in 2020, in light of a slight increase in average specific power coupled with a slight decline in average site quality.

To help disentangle the primary and sometimes competing influences of turbine design evolution and wind resource quality on capacity factor, Figure 37 controls for each. Across the x-axis, projects built from 2014 to2020 are grouped into four different categories, depending on the wind resource quality estimated for each site. Within each wind resource category, projects are further differentiated by their specific power. As would be expected, projects sited in higher wind speed areas generally realized higher capacity factors in 2021 than those in lower wind speed areas, regardless of specific power. Likewise, within the three higher wind resource categories in particular, projects that fall into a lower specific power range realized higher capacity factors in 2021 than those in a higher specific power range.



Note: The Appendix provides details on how the wind resource quality at each individual project site is estimated.

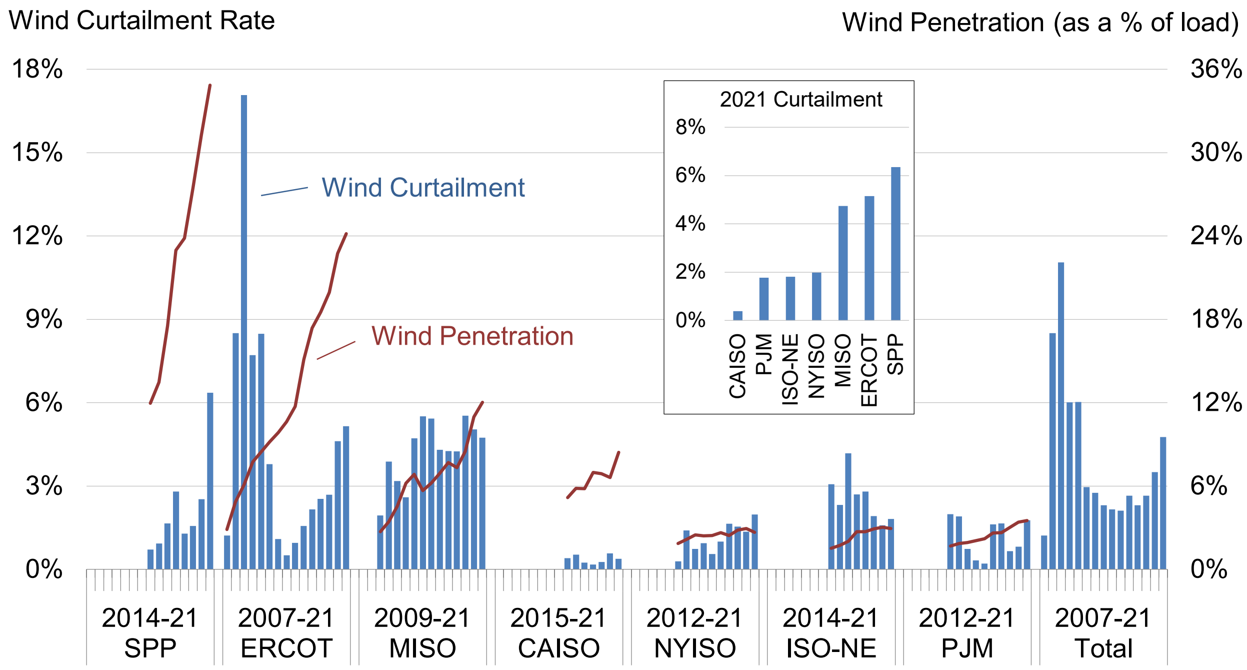
Sources: EIA, FERC, Berkeley Lab

Figure 37. Calendar year 2021 capacity factors by wind resource quality and specific power: 2014-2020 projects

Wind power curtailment in 2021 across seven regions averaged 4.8%, up from a low of 2.1% in 2016

Curtailment of wind project output results from transmission inadequacy and other forms of grid and generator inflexibility in concert with wind over-supply. For example, over-generation can occur when wind generation is high but transmission capacity is insufficient to move excess generation to other load centers, or thermal generators cannot feasibly ramp down any further or quickly enough. This can push local wholesale power prices negative, thereby potentially triggering wind curtailment especially among projects not earning the PTC.

Curtailment might be expected to increase as wind energy penetrations rise, though—as shown in Figure 38—this has not always been the case. Moreover, in areas where curtailment has been particularly acute in the past, steps taken to address the issue have borne fruit. For example, Figure 38 shows that just 0.5% of potential wind energy generation within ERCOT was curtailed in 2014, down sharply from 17% in 2009. This decline in curtailment corresponds to a significant build-out of new transmission serving West Texas, most of which was completed by the end of 2013. Since 2014, however, wind penetration has continued to increase in ERCOT, and so too has wind curtailment, which rose to 5.2% in 2021 (just ahead of MISO's 4.7% but less than SPP's 6.4%—which itself represents more than a doubling from 2020's 2.5%).



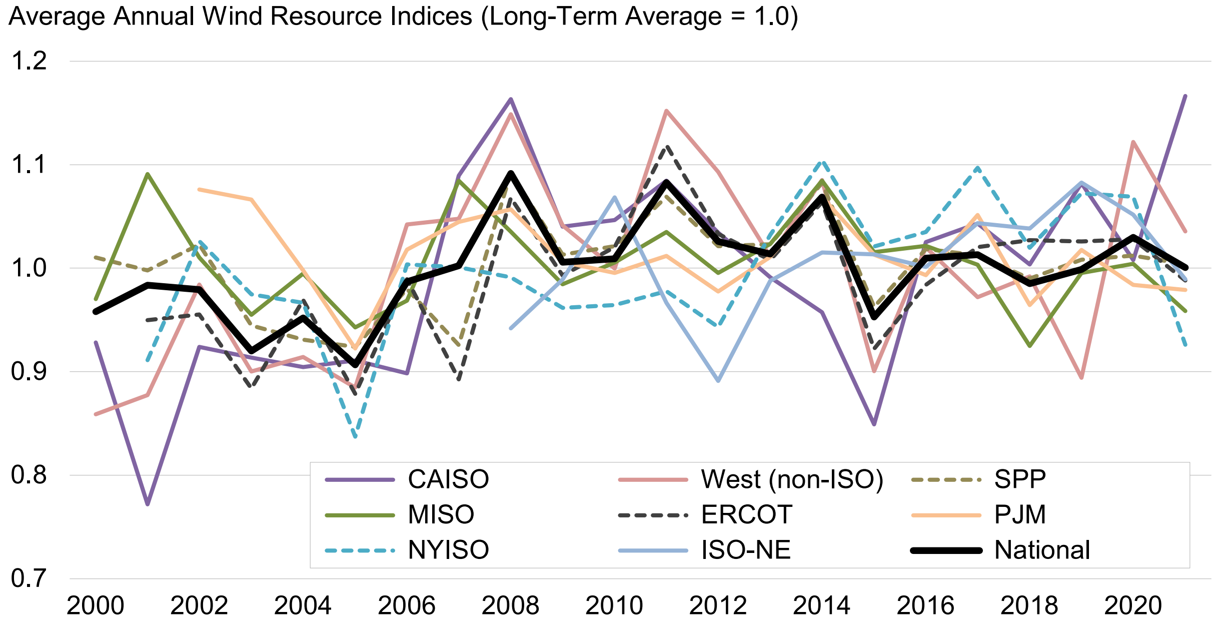
Sources: ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP

Figure 38. Wind curtailment and penetration rates by ISO

Outside of SPP, ERCOT, and MISO, curtailment percentages in 2021 were relatively low: 2.0% in NYISO, 1.8% in ISO-NE and PJM, and 0.4% in CAISO. The overall wind power curtailment rate in 2021 across all seven regions was 4.8%, up from a low of 2.1% in 2016.

2021 was an average wind resource year across most of the country

The strength of the wind resource varies from year to year; moreover, the degree of inter-annual variation differs from site to site (and, hence, also region to region). This temporal and spatial variation, in turn, impacts project performance from year to year. Figure 39 shows national and regional indices of the historical inter-annual variability in the wind resource among the U.S. fleet over time.[31] Though inter-annual variation has, at times, exceeded +/-20% at the regional level, geographical averaging has enabled nationwide variation to remain within +/-10%. In 2021, the national wind index stood at its long-term average, as most regions experienced a fairly average wind year (CAISO and NYISO excepted).



Sources: ERA, Berkeley Lab; methodology behind the index of inter-annual variability is explained in the Appendix

Figure 39. Inter-annual variability in the wind resource by region and nationally

Wind project performance degradation also explains why older projects did not perform as well in 2021

A final variable that could influence the improvement in 2021 capacity factors among more recent projects is project age. If wind turbine (and project) performance tends to degrade over time, then older projects—e.g., those built from 1998 to 2001—may have performed worse in 2021 than more recent projects simply due to their relative age. Figure 40 explores this question by graphing median (and 25th to 75th percentile ranges) "weather-normalized" (i.e., correcting for inter-annual variability in the strength of the wind resource) capacity factors over time. Here, time is defined as the number of full calendar years after each individual project's commercial operation date, and each project's capacity factor is indexed to 100% in year two in order to focus solely on changes in capacity factor over time, rather than on absolute capacity factor values. Year two is chosen as the index base to reflect the initial production ramp-up period commonly experienced by wind projects as their operators work through and resolve initial "teething" issues during the first year of operations.

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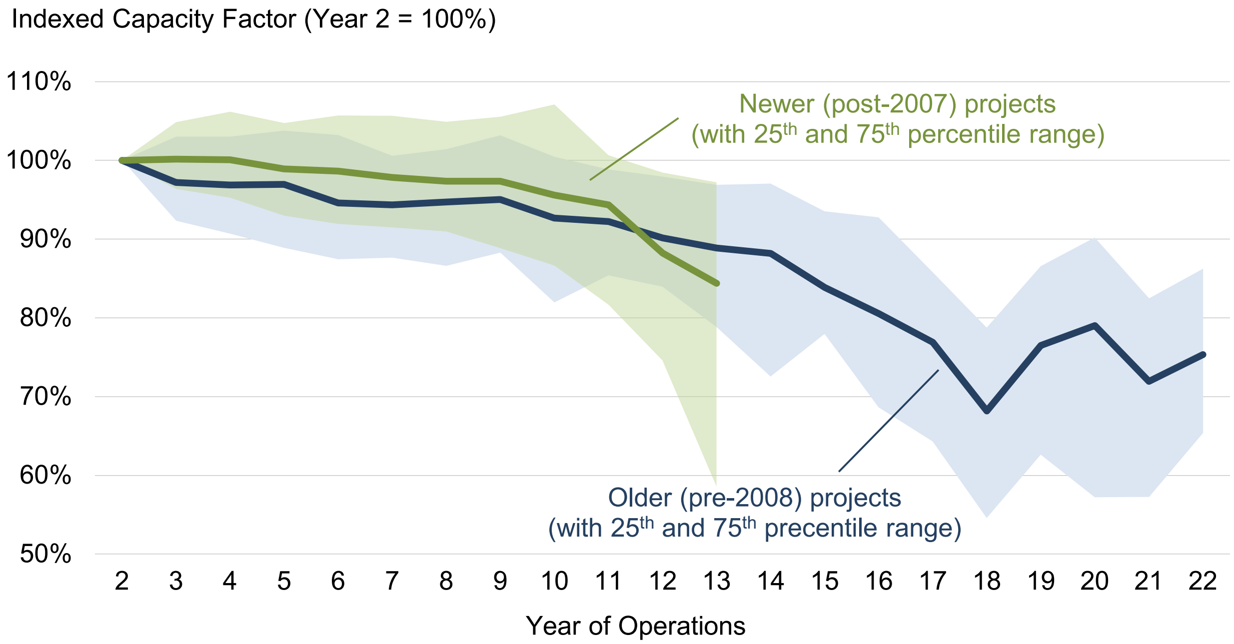
[31] These indices estimate changes in the strength of the average region- or fleet-wide wind resource from year to year (see the Appendix for more details). Note that these indices of inter-annual variability differ from the AWS Truepower wind resource quality data presented elsewhere, in that the former show variability from year to year across the entire region or fleet, while the latter focus on the multi-year long-term average wind resource at specific wind project sites.

Figure 40 suggests some amount of performance decline, especially in later years and among older projects built before 2008. Projects built in 2008 and later appear, on average, to have experienced only a modest decline in capacity factor during their first decade, followed by a turn for the worse in the few years thereafter—perhaps reflecting a change in how projects are operated once they age beyond the 10-year PTC window. Hamilton et al. (2020) explore these performance trends in more depth. Overall, from year 15 to 20, average project performance appears to be roughly 75% of early-year performance.



Sources: EIA, FERC, Berkeley Lab

Figure 40. Changes in project-level capacity factors as projects age

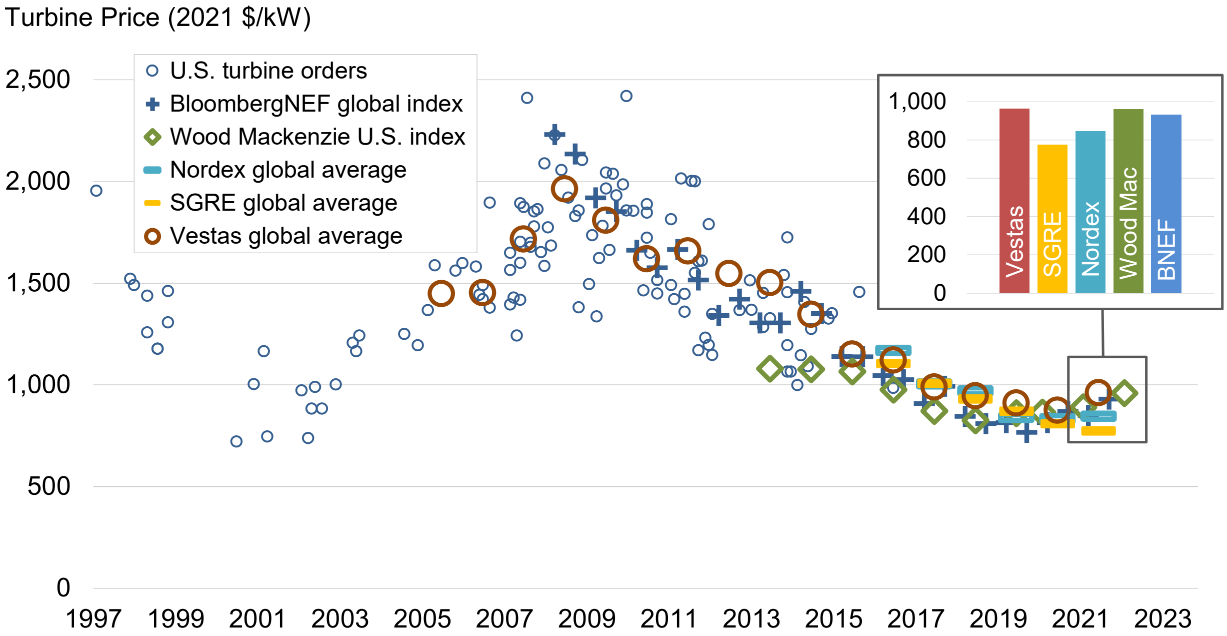
Taken together, Figure 34 through Figure 40 suggest that, in order to understand trends in empirical capacity factors, one needs to consider (and ideally control for) a variety of parameters. These include not only wind power curtailment and the evolution in turbine design, but also a variety of spatial and temporal wind resource considerations—such as the quality of the wind resource where projects are located, inter-year wind resource variability, and even project age.

6 Cost Trends

Wind turbine prices increased by an average of 5% to 10% in 2021 given supply chain pressures

Wind turbine prices have dropped substantially since 2008, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. However, with supply chain pressures and rising materials prices, turbine prices generally increased in 2021.

Figure 41 depicts wind turbine transaction prices from a variety of sources: (1) Vestas, SGRE, and Nordex, on those companies' global average turbine pricing, as reported in corporate financial reports; (2) BloombergNEF (2021a) and Wood Mackenzie (2022a), on those companies' turbine price indices by contract signing date; and (3) 121 U.S. wind turbine transactions announced from 1997 through 2016, as previously collected by Berkeley Lab. Wind turbine transactions can differ in the services included (e.g., whether towers are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and the timing of future turbine delivery. These differences drive some of the observed intra-year variability in transaction prices. Most of the prices and transactions reported in the figure are inclusive of towers and delivery to the site.



Sources: Berkeley Lab, annual financial reports, forecast providers

Figure 41. Reported wind turbine transaction prices over time

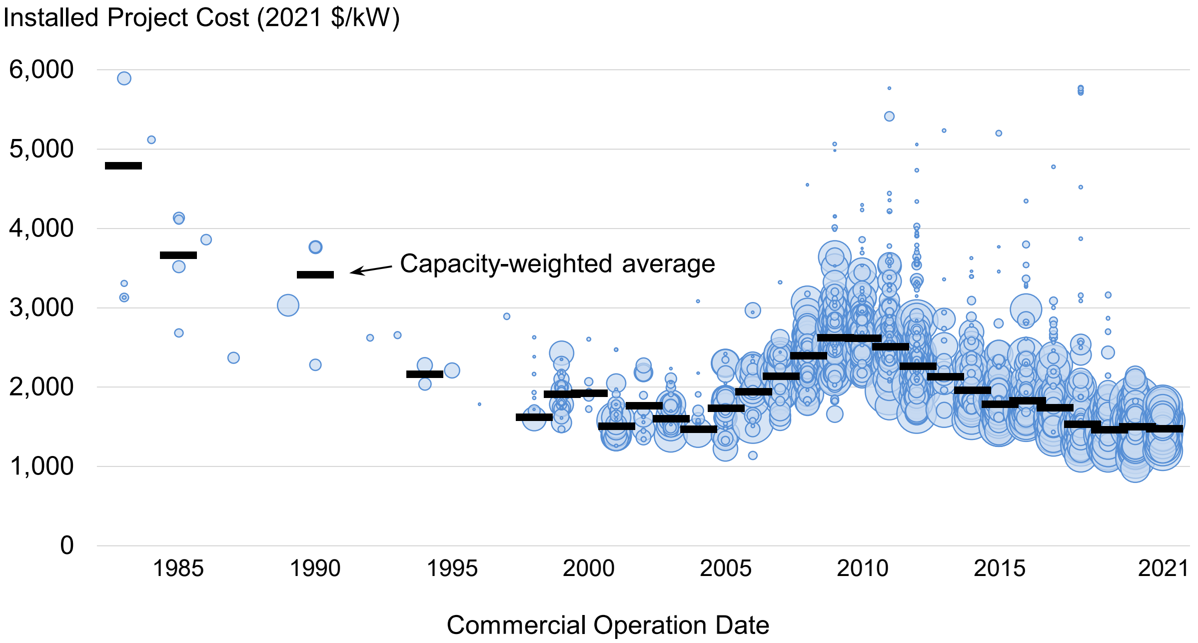
After hitting an initial low of roughly $900/kW, on average, from 2000 to 2002, wind turbine prices increased by approximately $1000/kW through 2008, rising to an average of $1,900/kW. This increase in turbine prices was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability due in part to strong demand growth; and increased costs for turbine warranty provisions (Moné et al. 2017).

Wind turbine prices have declined by 50% since 2008, in part reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as significant cost-cutting measures on the part of turbine and component suppliers. Nonetheless, recent supply-chain pressures and rising commodity prices led to increased turbine prices in 2021 (IEA 2021, 2022). Data indicate recent average pricing generally in the range of $800/kW to $950/kW, roughly 5% to 10% higher than a year prior.

Installed project costs in 2021 held steady at an average of $1,500/kW even as turbine prices rose

Berkeley Lab also compiles data on the total installed cost of wind projects in the United States, including data on 31 projects completed in 2021 and totaling 6.5 GW, or 48% of the wind power capacity installed in that year. In aggregate, the dataset includes 1,159 completed wind power projects in the continental United States totaling 113.5 GW and equaling roughly 84% of all wind power capacity installed as of the end of 2021. In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses. Data sources are diverse, however, and are not all of equal credibility, so emphasis should be placed on overall trends in the data rather than on individual project-level estimates.

As shown in Figure 42, the average installed costs of projects declined from the beginning of the U.S. wind industry in the 1980s through the early 2000s, and then increased—reflecting turbine price changes—through the latter part of the last decade. Costs peaked in 2009–2010. Though project-level costs have declined since 2010, they have largely held steady over the last few years—and with rising turbine prices may increase in the near term given the lag between turbine orders and project commissioning.



Note: Area of "bubble" is proportional to project capacity

Sources: Berkeley Lab, EIA (some data points suppressed to protect confidentiality)

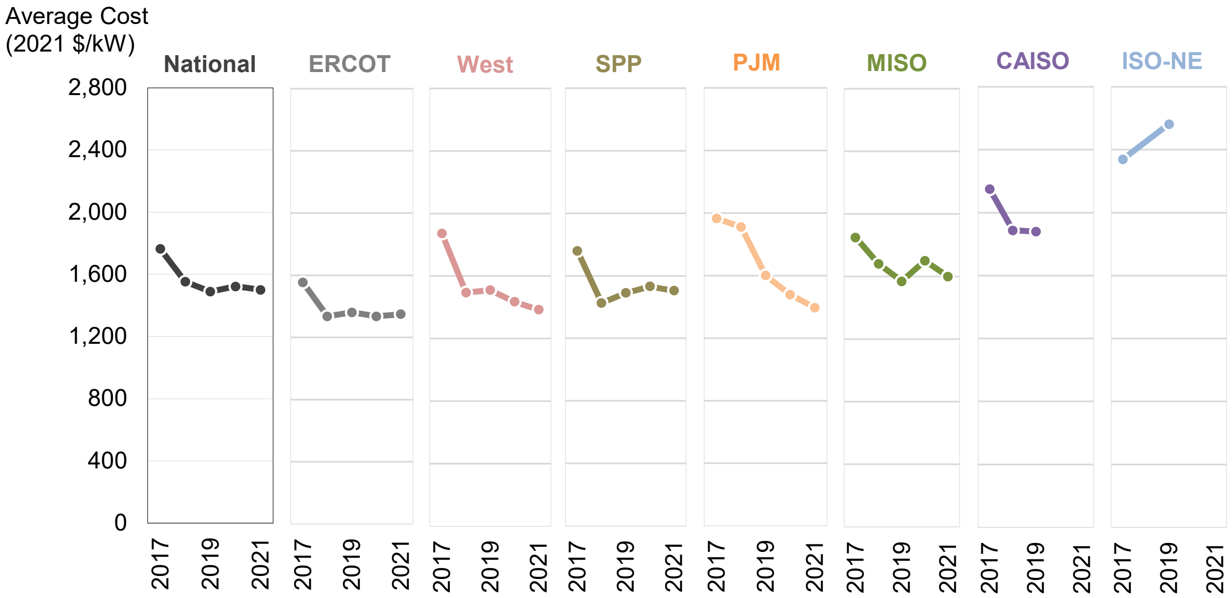
Figure 42. Installed wind power project costs over time

In 2021, the capacity-weighted average installed project cost within the sample stood at $1,500/kW. This is down by more than 40% from the average reported costs in 2009 and 2010, but is roughly on par with the installed costs experienced in the early 2000s.

Installed costs differed by region, from $1,350/kW to $1,600/kW

Regional differences in average project costs are also apparent and may occur due to variations in labor costs, development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures—as well as variations in average project size and the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources).

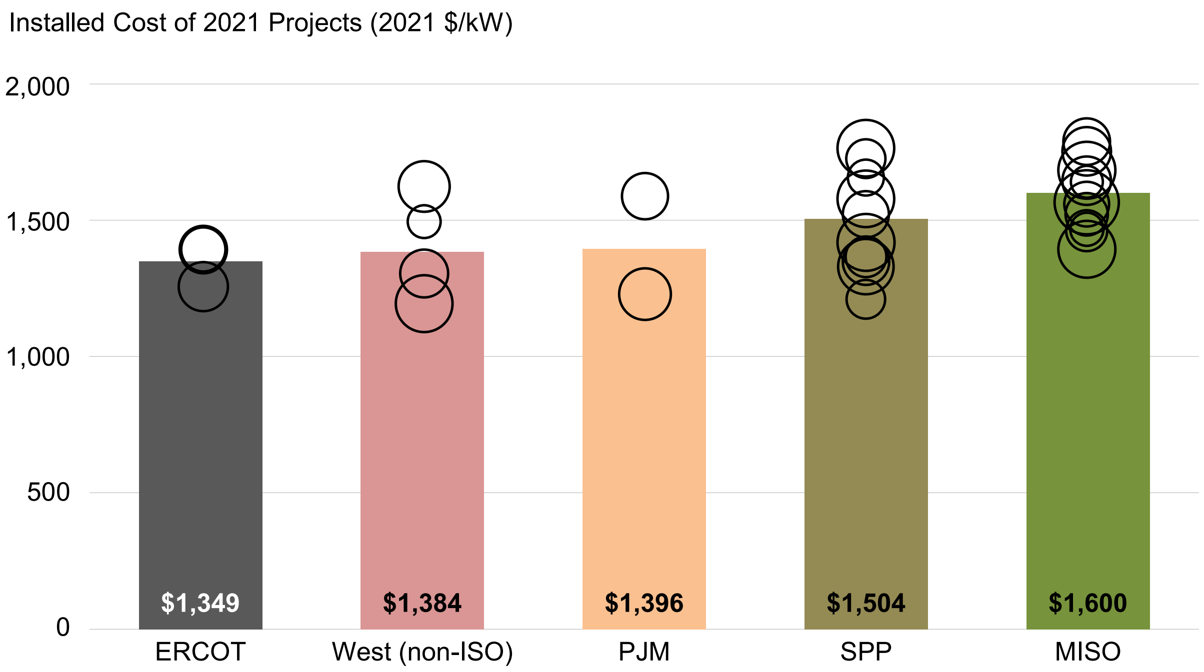
Figure 43 presents capacity-weighted average installed costs over the previous five years, by region. Figure 44 presents data only from the latest year—2021. Sample size is limited in some regions and years; for example, the data for ERCOT and PJM as shown in Figure 44 are very limited. Nonetheless, costs have generally held steady over the last four years, with the exception of projects in PJM, which have exhibited a steady decline. The lowest-cost projects installed in 2021 were located in ERCOT and the Western states (excluding California), with average costs of $1,350/kW and $1,380/kW respectively. Average costs in SPP and MISO were $1,500/kW and $1,600/kW, respectively.



Note: Data for NYISO and the Southeast are not available over this period. Other regions are missing data for specific years.

Sources: Berkeley Lab, EIA

Figure 43. Installed wind power project costs by region, over time



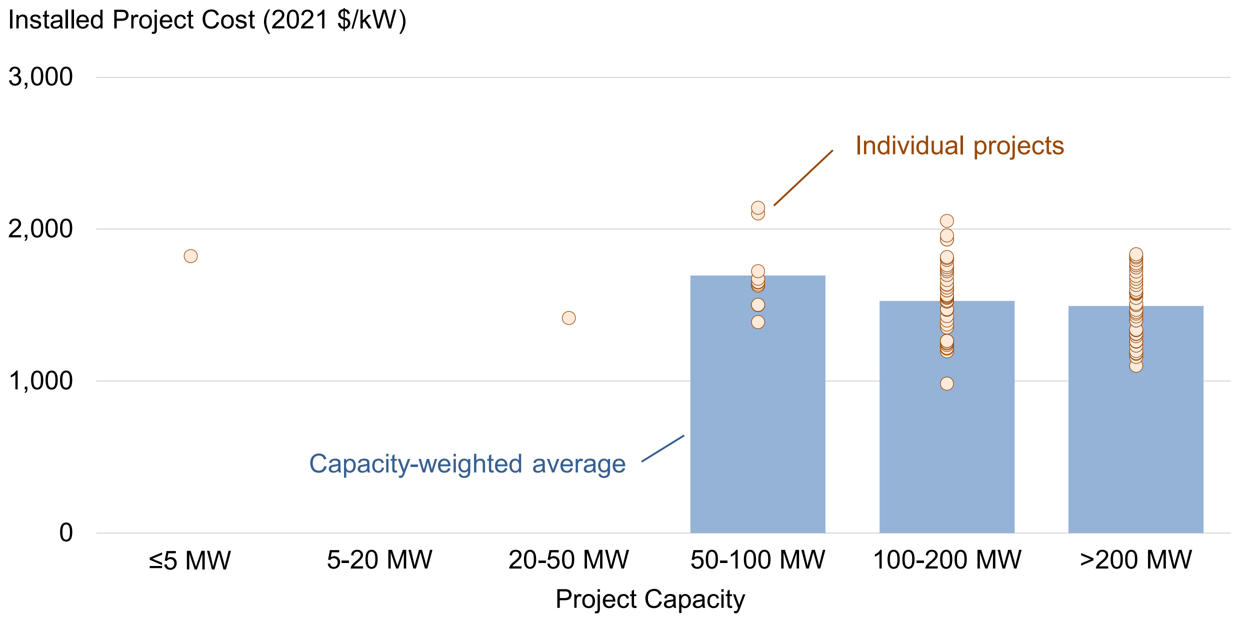
Note: Size of bubble reflects project capacity. Other regions lack adequate data for inclusion.

Sources: Berkeley Lab

Figure 44. Installed wind power project costs by region, in 2021

Installed costs (per megawatt) generally decline with project size; are lowest for projects over 200 MW

Installed costs exhibit economies of scale, which is perhaps the primary reason why small projects are increasingly rare. Among a sample of projects installed in 2020 and 2021 (Figure 45), there is not enough sample size to calculate average costs for the lower-capacity bins, but economies of scale are evident when moving from projects in the 50–100 MW range to those that are 100–200 MW or >200 MW.



Source: Berkeley Lab

Figure 45. Installed wind power project costs by project size: 2020 and 2021 projects

Operations and maintenance costs varied by project age and commercial operations date

Operations and maintenance (O&M) costs are an important component of the overall cost of wind energy and can vary substantially among projects. Unfortunately, publicly available data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the changes in wind turbine technology that have occurred over time (see Chapter 4).

Berkeley Lab has compiled limited O&M cost data for 202 installed wind power projects, totaling 22,393 MW and with commercial operation dates of 1982 through 2020.[32] These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects and so may not be broadly representative. A full time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M data are available for just a subset of years of project operations. Although not all data sources clearly define what items are included in O&M costs, in most cases the reported values include the costs of wages and materials associated with operating and maintaining the wind project, as well as rent.[33] Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance are generally not included. As such, Figure 46 and Figure 47 are not representative of *total* operating expenses for wind power projects.

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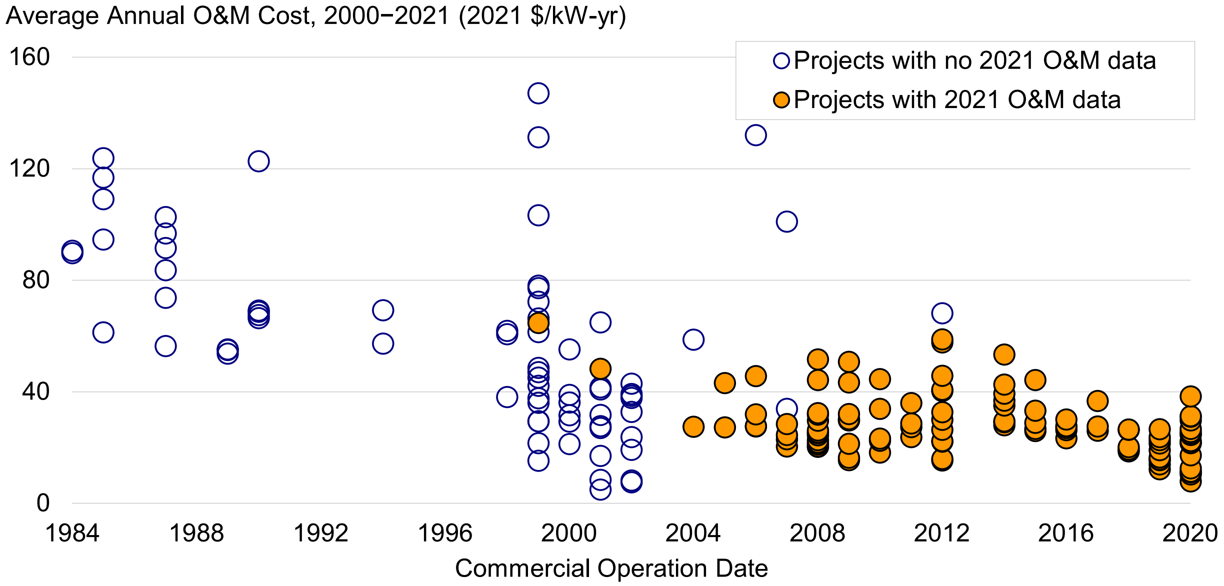
[32] For projects installed in multiple phases, the commercial operation date of the largest phase is used. For repowered projects, the date at which repowering was completed is used. No data for projects installed in 2021 are included, as such projects would not have a full-year of O&M data available by the end of 2021.

[33] The vast majority of the recent data derive from FERC Form 1, which uses the Uniform System of Accounts to define what should be reported under "operating expenses"—namely, those operational costs associated with supervision and engineering, maintenance, rents, and training. Though not entirely clear, there does appear to be some leeway within the Uniform System of Accounts for project owners to capitalize certain replacement costs for turbines and turbine components and report them under "electric plant" accounts rather than maintenance accounts.

Figure 46 shows O&M costs by commercial operation date. Here, each project's O&M costs are depicted as average annual O&M costs from 2000 through 2021, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2020, only 2021 data are available, and that is what is shown. Many other projects only have data for a subset of years, so each data point in the chart may represent a different averaging period within the overall 2000–2021 period. The chart highlights the 112 projects, totaling 18,330 MW, for which 2021 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.

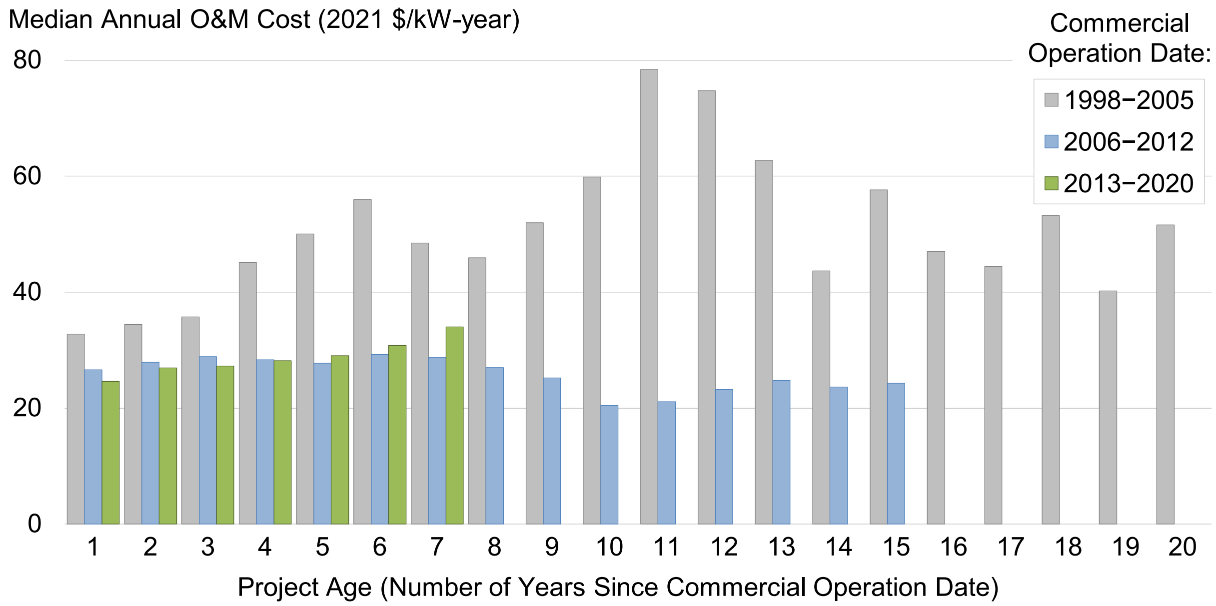


Source: Berkeley Lab; some data points suppressed to protect confidentiality

Figure 46. Average O&M costs for available data years from 2000 to 2021, by commercial operation date

The data demonstrate that O&M costs are far from uniform across projects. Figure 46 also suggests that projects installed in the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2021 O&M costs for the 24 projects in the sample constructed in the 1980s equal $79/kW-year, dropping to $64/kW-year for the 37 projects installed in the 1990s, to $29/kW-year for the 65 projects installed in the 2000s, and $21/kW-year for the 76 projects installed since 2010. This decline may be due to at least two factors: (1) O&M costs generally increase as turbines age and component failures become more common; and (2) projects installed more recently, with larger and more mature turbines and more sophisticated O&M practices, may experience lower overall O&M costs.

Limitations in the underlying data do not permit the influence of these two factors to be clearly distinguished. Nonetheless, to help illustrate key trends, Figure 47 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Though sample size is limited, the data show a general upward trend in project-level O&M costs as projects age, at least among the oldest projects in the sample. Figure 47 also shows that projects installed over the last 15 years have had, in general, lower O&M costs than those installed in the earlier years of 1998–2005, at least for the first 15 years of operation.



Source: Berkeley Lab; medians shown only for groups of two or more projects, and only projects >5 MW are included

Figure 47. Median annual O&M costs by project age and commercial operation date

As indicated previously, these data include only a subset of total operating expenses. A U.S. wind industry survey of total operating costs shows that these expenses for recently installed projects are anticipated to average between $33/kW-year and $59/kW-year, with a mid-point of ~$44/kW-year (Wiser et al. 2019). The disparity between these estimates of total operating costs and the costs reported in Figure 46 and Figure 47 reflects, in large part, differences in the scope of expenses reported; the survey noted that turbine O&M is expected to constitute less than half of total operating costs (Wiser et al. 2019).

7 Power Sales Price and Levelized Cost Trends

Wind power purchase agreement prices have been drifting higher since about 2018, with a recent range from below $20/MWh to more than $30/MWh

Earlier chapters documented trends in capacity factors, installed project costs, O&M costs, and project financing—all of which are determinants of the wind power purchase agreement (PPA) prices and levelized cost of energy (LCOE) estimates presented in this chapter.

Berkeley Lab collects data on wind PPA prices, resulting in a dataset that includes 525 PPAs totaling nearly 53 GW from wind projects that have either been built or are planned for installation later in 2022 or beyond. All of these PPAs bundle together the sale of electricity, capacity, and renewable energy certificates (RECs; a later text box highlights REC prices), and most of them have a utility as the counterparty.[34] Except where noted, PPA prices are expressed on a levelized basis over the full term of each contract and are reported in real 2021 dollars.[35] Whenever individual PPA prices are averaged together, the average is generation-weighted. Whenever they are broken out by time, the date on (or year in) which the PPA was executed is used. Because PPA prices are reduced by the receipt of state and federal incentives and are influenced by various local policies and market characteristics, they do not directly represent wind energy generation costs. Accordingly, at the end of this chapter, the data presented earlier in this report are leveraged to estimate project-level and average wind LCOE for a large sample of U.S. wind projects.

Figure 48 plots contract-level levelized wind PPA prices by contract execution date, showing a clear decline in PPA prices since 2009–2010, both overall and by region. As a result of the low average project costs and high average capacity factors shown earlier in this report, ERCOT and SPP tend to be the lowest-priced regions. Of note, PPA prices have not smoothly declined over time. Instead, prices declined through 2003, then rose though 2009 with the increased turbine and installed costs presented earlier as well as with general price increases during this period in the power and natural gas markets. Following that rise was a steep reduction and, more recently, stabilization and then an increase in PPA prices—partly due to supply chain pressures, including higher material prices and transportation costs, and perhaps also due to the gradual phase-out of the PTC.

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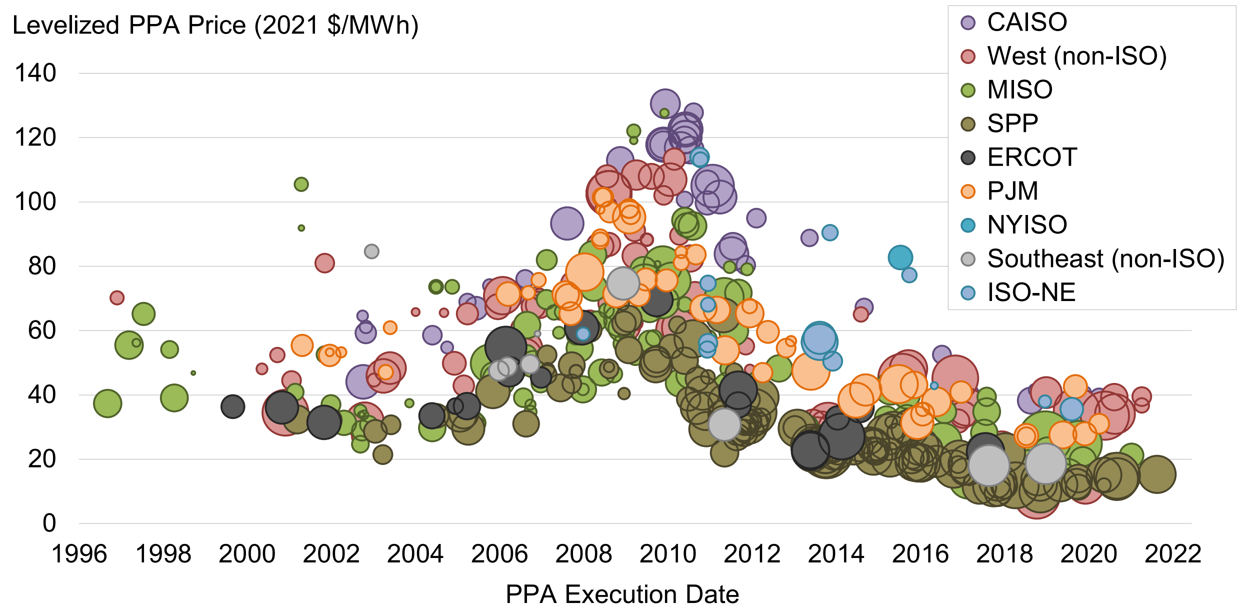
[34] Though some PPAs with corporate offtakers are included in the sample, in many cases such PPAs are synthetic or financial arrangements in which the project sponsor enters into a "contract for differences" with the corporate offtaker around an agreed-upon strike price. Because the strike price is not directly linked to the sale of electricity, it is rarely disclosed (at least through traditional sources, like regulatory filings).

[35] Having full-term price data (i.e., pricing data for the full duration of each PPA, rather than just historical PPA prices) enables these PPA prices to be presented on a levelized basis (levelized over the full contract term), which provides a complete picture of wind power pricing (e.g., by capturing any escalation over the duration of the contract). Contract terms range from 5 to 35 years, with 20 years being by far the most common (at 54% of the sample; 87% of contracts in the sample are for terms ranging from 15 to 25 years). Prices are levelized using a 4% real discount rate.

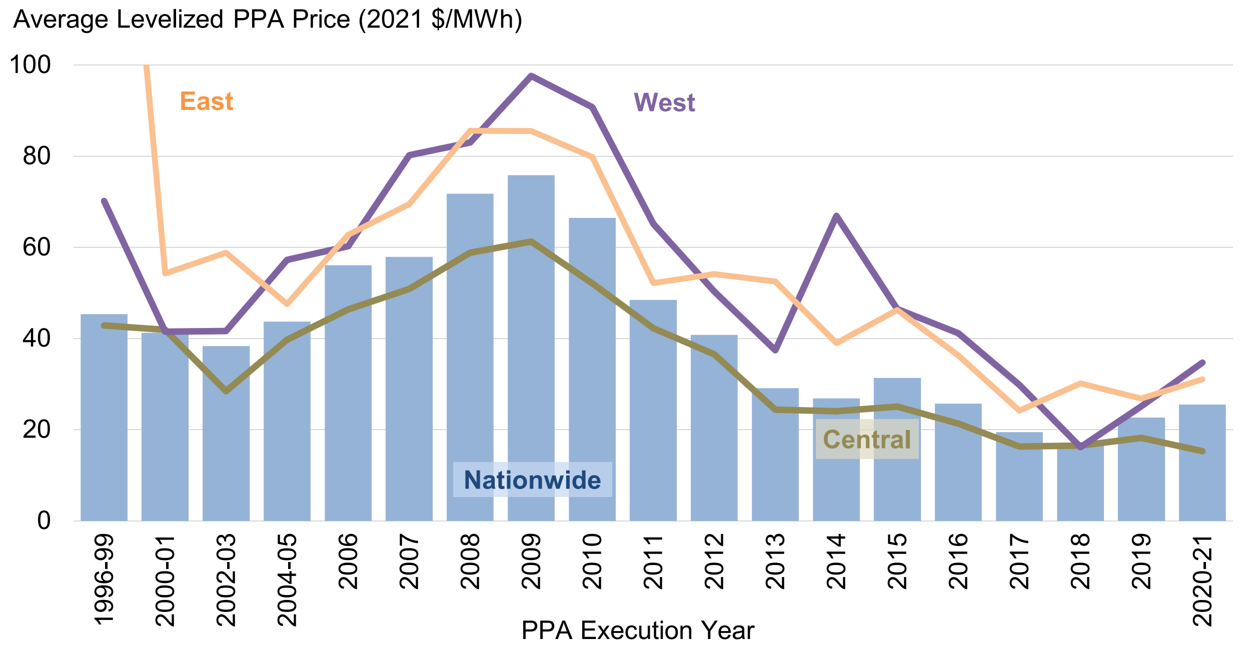


Note: Size of bubble reflects contract capacity.

Source: Berkeley Lab, FERC

Figure 48. Levelized wind PPA prices by PPA execution date and region (full sample)

Figure 49 provides a smoother look at the time trend nationwide and regionally by averaging the individual levelized PPA prices shown in Figure 48, and consolidating the regional breakdown into just three categories: West, Central, and East. After topping out above $75/MWh for PPAs executed in 2009, the national average levelized price of wind PPAs within the Berkeley Lab sample has dropped. In the Central region of the country, recent pricing is around $20/MWh. In the West and East, prices tend to average above $30/MWh. On average, however, PPA prices have risen over the last several years, since roughly 2018.



Note: West = CAISO, West (non-ISO); Central = MISO, SPP, ERCOT; East = PJM, NYISO, ISO-NE, Southeast (non-ISO)

Source: Berkeley Lab, FERC

Figure 49. Generation-weighted average levelized wind PPA prices by PPA execution date and region

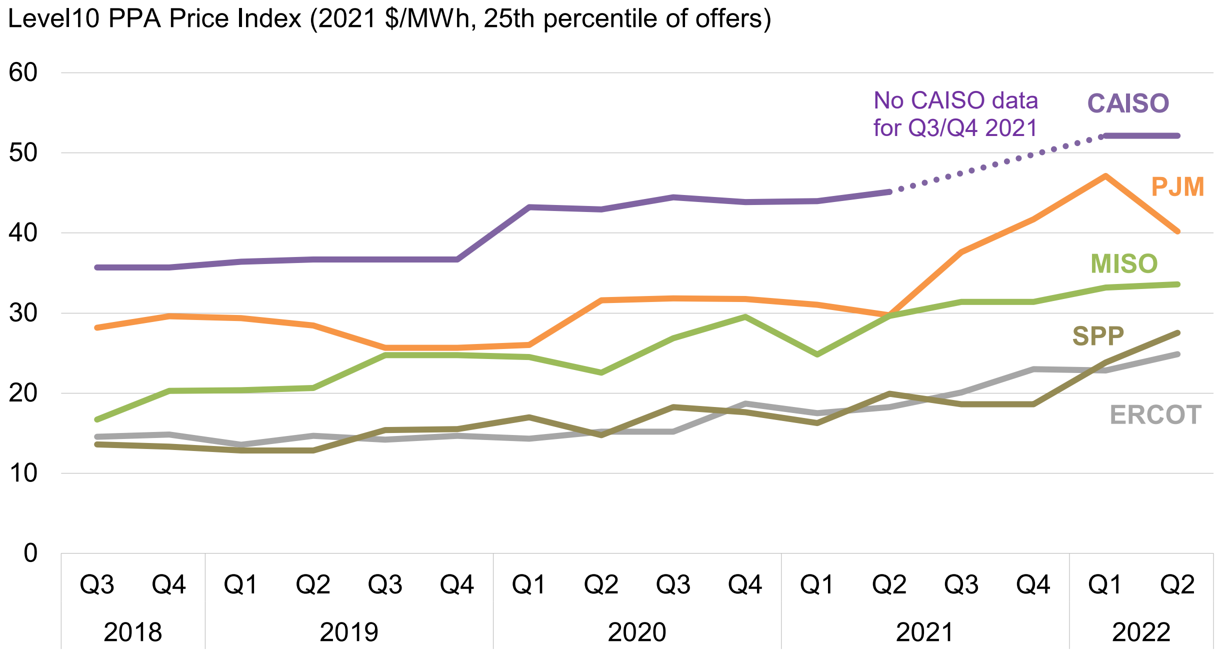
These PPA price trends are directionally consistent with the turbine price and installed project cost trends shown earlier in Chapter 6. In addition, the turbine scaling described in Chapter 4 has, on average, boosted the capacity factors of more recent projects, as documented in Chapter 5. Scaling has also enabled reductions in operating costs, as described in Chapter 6. This combination of declining CapEx and OpEx and improved performance drove wind PPA prices to all-time lows through 2018, though prices have since increased.

LevelTen Energy's PPA price indices confirm rising PPA prices, and regional variations

In contrast to the PPAs summarized above, which principally involve utility purchasers, LevelTen Energy (2022) provides an index of wind PPA offers made to large, end-use customers.

Each quarter, the LevelTen Energy PPA Price Index reports the prices that wind and solar developers have offered for PPAs available on the LevelTen Marketplace. Contract terms tend to range from 10 to15 years, reflective of the shorter terms typically pursued by end-use customers that purchase wind energy relative to the utility PPAs summarized earlier. Price data are aggregated and reported in nominal dollars on a 'P25' basis, referring to the most competitive 25th percentile of offer prices.

As shown in Figure 50, prices have risen over the last couple years, and vary by ISO; here, LevelTen data are converted to real, levelized 2021$ to enhance comparability with data presented elsewhere in this report. Among regions reporting data, CAISO features the highest wind PPA pricing (~$52/MWh when converted to real dollar terms), whereas the lowest prices are found in ERCOT and SPP (~$25/MWh). In real dollar terms, LevelTen's reported price trends since 2018 are similar to those described in the prior section.



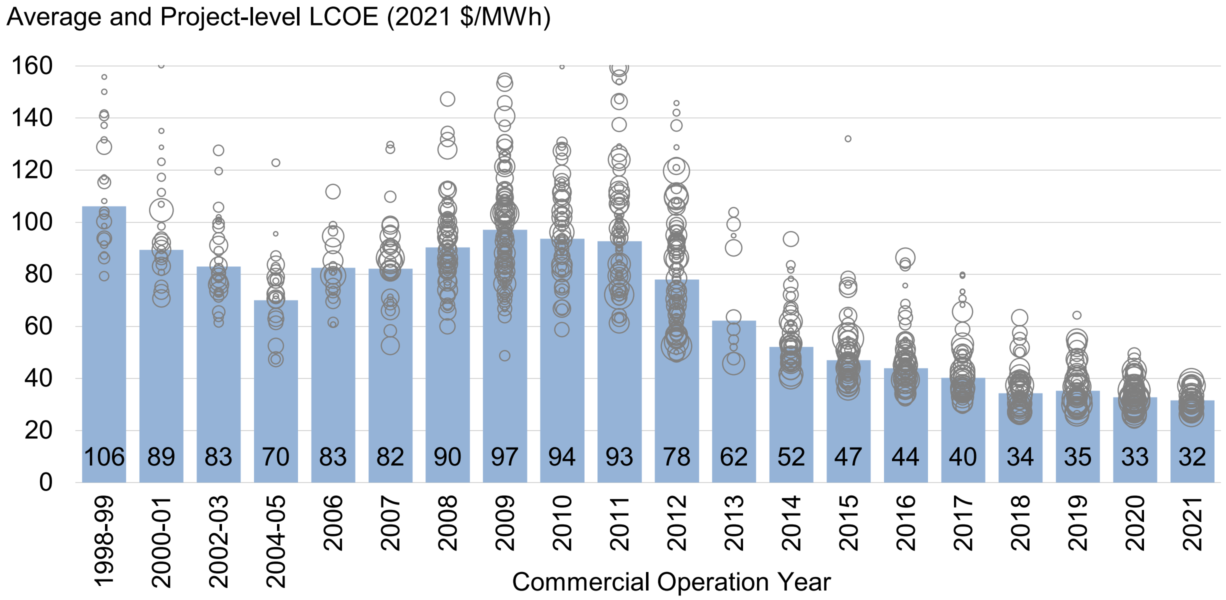
Source: LevelTen Energy

Figure 50. LevelTen Energy wind PPA price index by quarter of offer

The (unsubsidized) average levelized cost of wind energy has fallen to around $32/MWh

In a competitive market, long-term PPA prices can be thought of as reflecting the LCOE reduced by the value of any incentives received (e.g., the PTC). Hence, as a first-order approximation, LCOE can be estimated simply by adding the levelized value of incentives received to the levelized PPA prices. LCOE can also be estimated more directly from its components, and Berkeley Lab has data on both the installed cost and capacity factor of 112 GW of wind power projects installed from 1998 through 2021, representing 83% of all capacity built over that period. Here, those data are used, in conjunction with estimates of operational costs, financing costs, project life and other factors, to estimate LCOE in real 2021 dollars (see the Appendix for details on the data and calculations). One benefit of this "bottom up" approach to estimating LCOE is that it relies on a large sample of project-level installed cost and performance data, covering more projects than the PPA sample.

Figure 51 depicts the resulting average LCOE values over time on a national basis. As shown, average wind LCOE declined from $106/MWh in 1988−1999 to $70/MWh in 2004−2005, before rising to $97/MWh in 2009. Subsequently, average LCOE declined rapidly through 2018, to $34/MWh. The national average LCOE of newly built wind projects has largely held steady since 2018, and stood at $32/MWh in 2021.With rising turbine prices and stagnating capacity factor improvements, LCOE may increase in 2022.



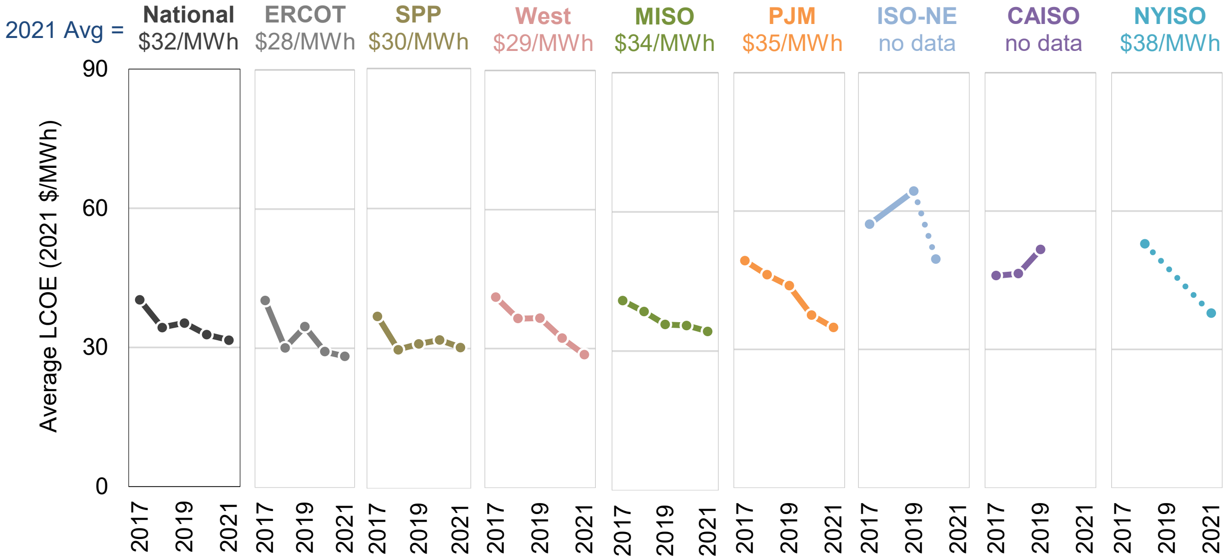
Note: Size of bubble reflects project capacity.

Source: Berkeley Lab

Figure 51. Estimated levelized cost of wind energy by commercial operation date

Levelized costs vary by region, with the lowest costs in ERCOT, SPP, and the non-ISO West

Regional LCOE estimates span a wide range, and sample size is small in some regions and years. Nonetheless, the lowest average LCOEs for projects built in 2021—only considering regions with a larger sample—are found in ERCOT ($28/MWh), SPP ($30/MWh), and the non-ISO West ($29/MWh).



Source: Berkeley Lab

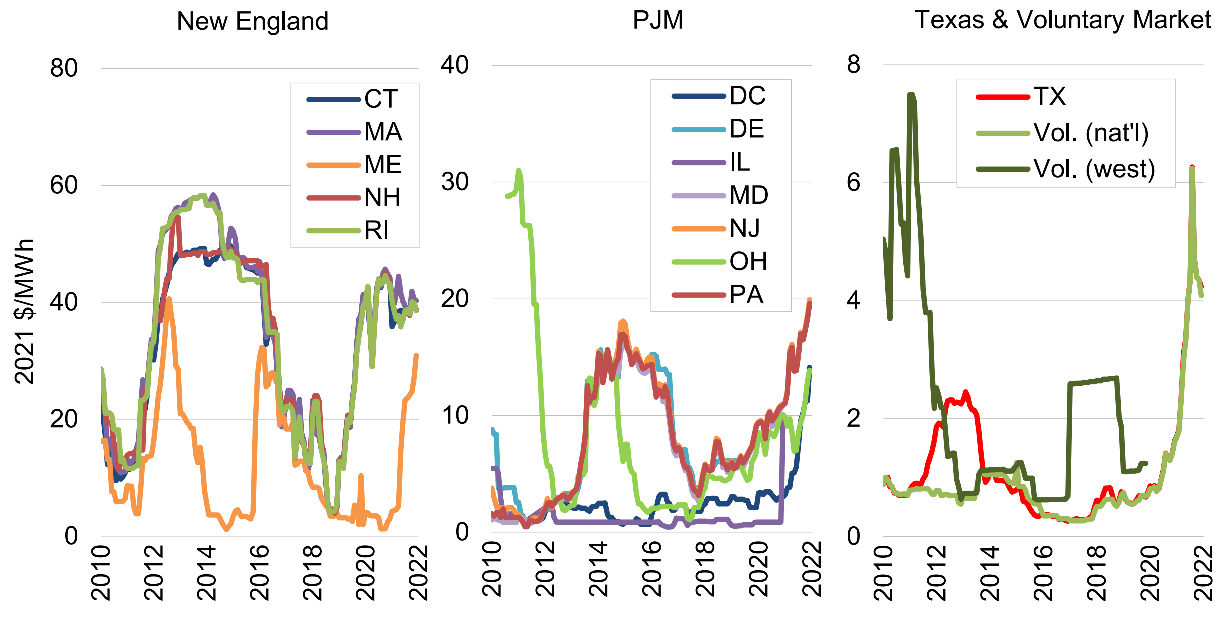
Figure 52. Estimated levelized cost of wind energy, by region

Renewable Energy Certificate (REC) Prices

Wind power sales prices presented in this report reflect bundled sales of both electricity and RECs. Projects that sell RECs separately from electricity, thereby generating two sources of revenue, are excluded. REC markets are fragmented, but consist of two distinct segments: compliance markets, in which RECs are purchased to meet state RPS obligations, and green power markets, in which RECs are purchased on a voluntary basis. Mandatory RPS programs exist in 29 states and Washington, D.C. In recent years, roughly one-third of these states have increased their RPS targets, in many cases to levels ranging from 50% to 100% of retail electricity sales. Voluntary markets for renewable energy have also grown.

The figure below presents indicative data of spot-market REC prices in both compliance and voluntary markets. Clearly, spot REC prices have varied substantially, both over time and across states, though prices across states within common regional power markets (New England and PJM) are linked to varying degrees.

In New England, REC prices in 2021 (outside of ME) stabilized around $40/MWh, following a steep rise over the preceding years. These prices remain well below the relevant alternative compliance payment (ACP) rates in these states, suggestive of balanced RPS supply and demand. In PJM, REC prices continued on their upward trajectory of the past several years, reflecting a gradual tightening of supplies. Within the premium markets of MD, NJ, and PA, prices ended the year just above $20/MWh, an all-time high. Prices for RECs offered in the national voluntary market and for RPS compliance in Texas, which track each other closely, witnessed an unprecedented spike in 2021, rising to more than $6/MWh before falling slightly by year-end. Though the causes of this rise are not altogether known, some in the industry attribute it to rising corporate demand for green energy purchases and higher project development costs.



Notes: Data for compliance markets focus on "Class I" or "Tier I" RPS requirements; these are the requirements for more-preferred resource types or vintages and are therefore the markets in which wind would typically participate. Plotted values are the monthly averages of daily closing prices for REC vintages from the current or nearest future year traded.

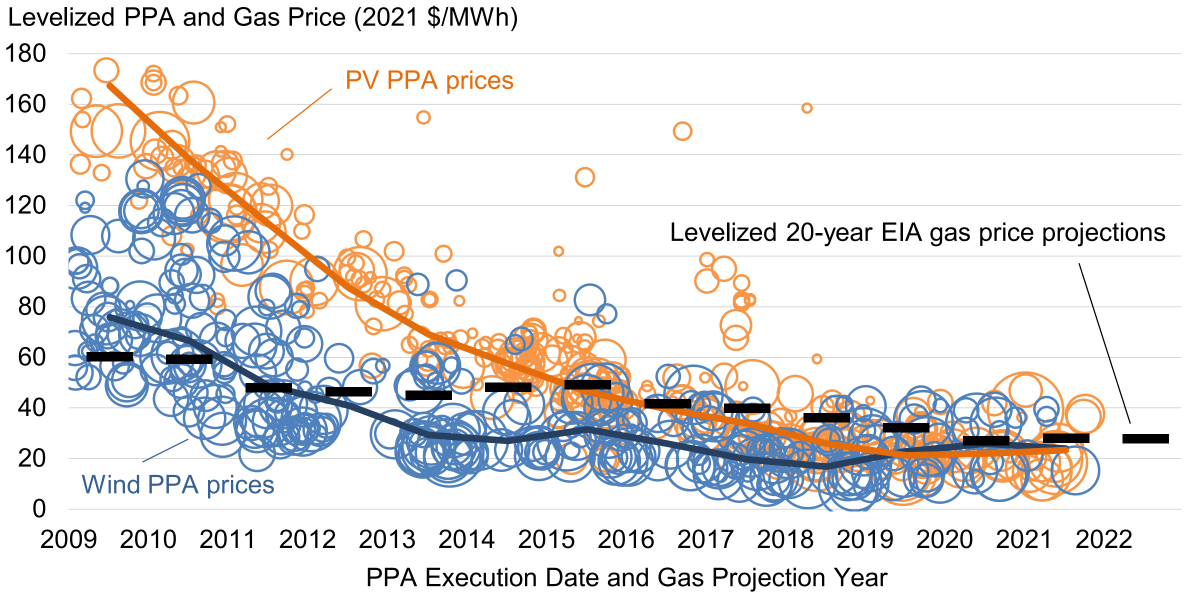
Source: Marex Spectron

8 Cost and Value Comparisons

Despite low PPA prices, wind faces competition from solar and gas

Figure 53 plots wind PPA prices against utility-scale solar PPA prices on a levelized basis since 2009 (the dashed blue and gold lines show the generation-weighted average wind and solar PPA prices in each year, respectively). Although the gap between wind and solar PPA prices was quite wide a decade ago, that gap has narrowed considerably in recent years, as solar prices have fallen more rapidly than wind prices.[36]

The figure also shows that wind PPA prices—and, more recently, utility-scale solar PPA prices—have, in many cases, been competitive with the projected fuel costs of gas-fired combined cycle generators. Specifically, the black dash markers show the 20-year levelized fuel costs—converted from natural gas to power terms at an assumed heat rate of 7.5 million British Thermal Units (MMBtu) per MWh—from then-current EIA projections of natural gas prices delivered to electricity generators.[37] Supported by federal tax incentives, the average levelized wind and solar PPA prices within this contract sample have, for several years now, been below the projected levelized cost of burning natural gas in existing gas-fired combined cycle units.



Note: Smallest bubble sizes reflect smallest-volume PPAs (<5 MW), whereas largest reflect largest-volume PPAs (400 MW)

Sources: Berkeley Lab, FERC, EIA

Figure 53. Levelized wind and solar PPA prices and levelized gas price projections

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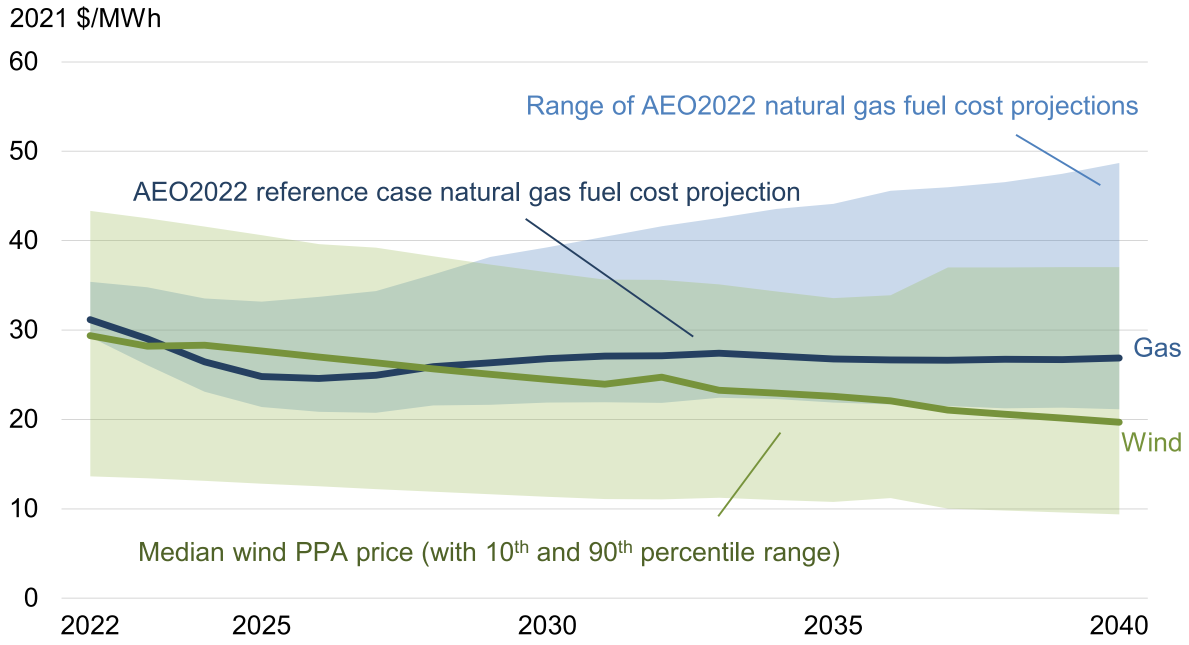
[36] The solar PPA prices are sourced from Berkeley Lab's "Utility-Scale Solar" data series.

[37] For example, the black dash marker in 2009 shows the 20-year levelized gas price projection from Annual Energy Outlook 2009, while the black dash in 2022 shows the same from Annual Energy Outlook 2022 (both converted to $/MWh terms at a constant heat rate of 7.5 MMBtu/MWh).

Rather than levelizing the wind PPA prices and gas price projections, Figure 54 plots the future stream of wind PPA prices (the 10th, 50th, and 90th percentile prices are shown) from PPAs executed in 2019–2021 against the EIA's latest projections of just the fuel costs of natural gas-fired generation.[38] As shown, median wind PPA prices from contracts executed in the past three years roughly track the median gas price projection until the late 2020s, after which the median wind price falls below the median gas price (and eventually even below the low gas price in the second half of the 2030s). Meanwhile, the 90th percentile wind PPA prices are initially above the high end of the fuel cost range, but fall within the overall range by 2030. Wind PPA pricing declines over time, in real 2021$.



Sources: Berkeley Lab, FERC, EIA

Figure 54. Wind PPA prices and natural gas fuel cost projections by calendar year over time

Figure 54 also hints at the long-term value that wind power might provide as a "hedge" against rising and/or uncertain natural gas prices. The wind PPA prices that are shown have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain. Actual fuel costs could ultimately be lower or higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

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[38] The fuel cost projections come from the EIA's *Annual Energy Outlook 2022* publication. The upper and lower bounds of the fuel cost range reflect the low (and high, respectively) oil and gas resource and technology cases. All fuel prices are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (which start at roughly 7.7 MMBtu/MWh in 2022 and gradually decline to roughly 7.0 MMBtu/MWh by 2040).

The grid-system market value of wind rebounded in 2021 to levels last seen in 2018, and is roughly consistent with recent PPA prices of under $20/MWh to $40/MWh

In many regions of the country, wind projects participate in organized wholesale electricity markets. In some cases, wind projects directly bid into those markets, and earn the prevailing market price. In other cases—especially when a PPA is in place—the wind purchaser will schedule the wind energy into the market, paying the wind project owner the pre-negotiated PPA price but earning revenue from the prevailing wholesale market price. PPAs between wind generators and commercial customers are often a hybrid of these two models.

In all of these cases, the revenue earned (or that could have been earned) from the sale of wind into wholesale markets is reflective of the market value of that generation from the perspective of the electricity system. In the case of merchant wind projects, the link is direct and affects the revenue of the plant. In the case of wind projects sold under a PPA, on the other hand, the pre-negotiated PPA price establishes plant revenue and, depending of the specifics of the PPA, pricing may or may not be linked to wholesale market prices. In this latter case, however, the revenue earned or that would have been earned by the sale of wind in the wholesale market still reflects the underlying market value of that wind—but in this instance, for the purchaser, in the form of an avoided cost. This is because wholesale electricity prices reflect the timing of when energy is cheap or expensive and embed the cost of transmission congestion and losses. A purchaser could, in theory, obtain power from the wholesale market instead of from a wind project. A wind project's estimated revenue were it participating in the wholesale market therefore reflects costs avoided by the purchaser of wind under a PPA.

This (potential) revenue—or value—can be segmented into "energy" market value and, where capacity markets or requirements exist, "capacity" value. Wholesale energy prices vary over time, and by location. They are strongly influenced by the cost of natural gas. Because wind power deployment is sometimes concentrated in areas with limited transmission capacity, wholesale energy prices at the local pricing nodes to which wind plants interconnect are often suppressed and the relationship to the cost of natural gas is diminished. Even absent transmission constraints, wind plants push wholesale energy prices lower when wind output is high. More generally, the temporal profile of wind output is not always well-aligned with customer load and system needs, potentially further reducing the energy market value of wind generation. Some of these tendencies also apply to wind's capacity value, which is impacted by the cost of capacity but also by regional rules that define the credit that wind receives for providing capacity.

Figure 55 estimates the historical wholesale energy and capacity market value of wind across a number of different regions of the country. Specifically, the energy market value of wind is estimated using plant-level hourly wind output profiles and real-time hourly wholesale energy pricing patterns at the nearest pricing node (i.e., locational marginal prices, LMPs). Plant-level capacity values are estimated based on the relevant capacity price or cost for the region in question, and local rules for wind's capacity credit.[39] Energy and capacity are summed for each plant, and plant-level total value estimates are then averaged to estimate regional values. As a result, the analysis considers the output profile of wind, the location of wind, and how those characteristics interact with local wholesale energy and capacity prices and rules, ultimately yielding an estimate of the revenue that would have been earned had wind sold its output at the hourly LMP and also considering any possible capacity-based revenue. The figure then contrasts those wholesale market value estimates for wind with nationwide generation-weighted average levelized wind PPA prices (with error bars denoting the 10th and 90th percentiles) based on the years in which the PPAs were executed. The comparison between market value estimates and PPA prices is relevant in as much as PPA prices reflect the cost of wind to the purchaser, whereas wholesale market value reflects a portion of the value of that wind generation.

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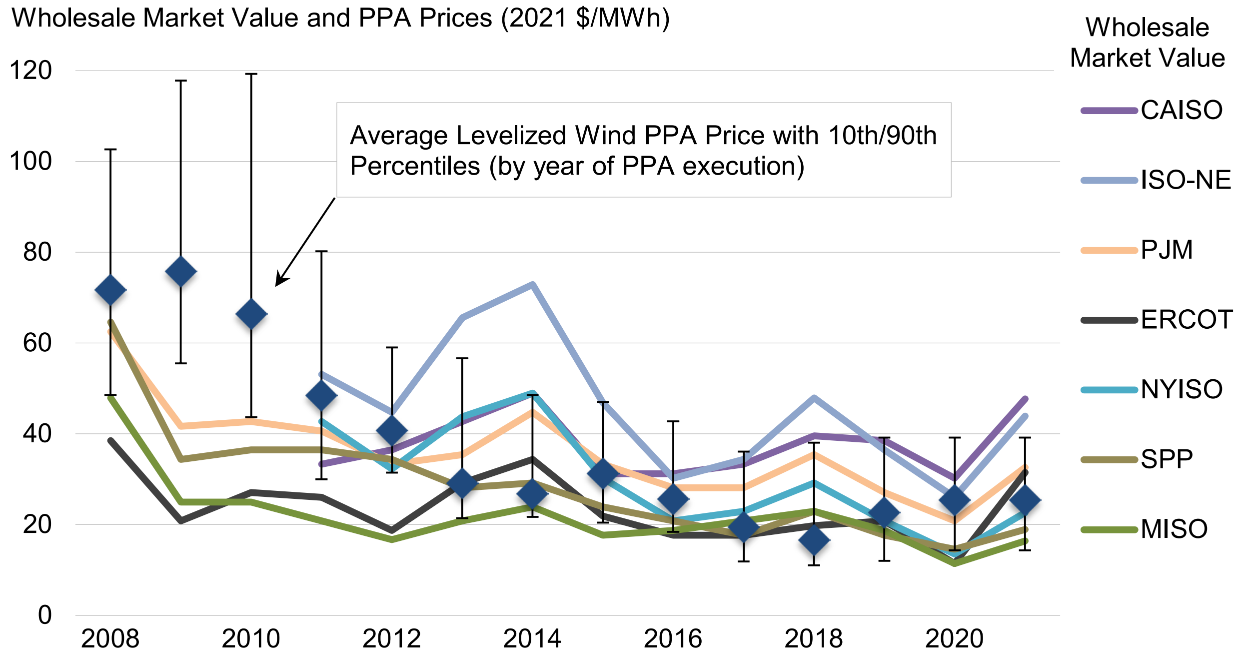
[39] The Appendix provides additional details on the methods used to estimate the wholesale energy and capacity value of wind.

These estimates show that the wholesale market value of wind has generally declined over the last 13 years and varies by region. With the sharp drop in wholesale prices and therefore market value of wind in 2009, average wind PPA prices tended to well-exceed the wholesale market value of wind from 2009 to 2012. With continued declines in PPA prices, however, those prices reconnected with the market value of wind in 2013 and have remained generally in competitive territory in subsequent years. This suggests that—with the help of the PTC, which reduces PPA prices—wind developers and offtakers are successfully contracting at levels that are generally comparable in terms of both cost and value. In 2020, natural gas and wholesale electricity prices hit new lows, in part a result of the economic impacts of the pandemic. Natural gas prices have since risen substantially above 2020 levels, however, and for 2021 averaged higher than in any year since 2014 (in real dollar terms, based on the Henry Hub spot price). With the increase in natural gas and electricity prices, 2021 wind market values rebounded to levels last seen in 2018, and are roughly consistent with recent PPA prices. With even higher natural gas and wholesale electricity prices so far in 2022, wind's market value may increase again this year.



Note: Hourly wind output profiles and wholesale prices are not available for all historical years for all regions.

Sources: Berkeley Lab, Hitachi, ISOs

Figure 55. Regional wholesale market value of wind and average levelized long-term wind PPA prices over time

Important Note on Price and Value Comparisons

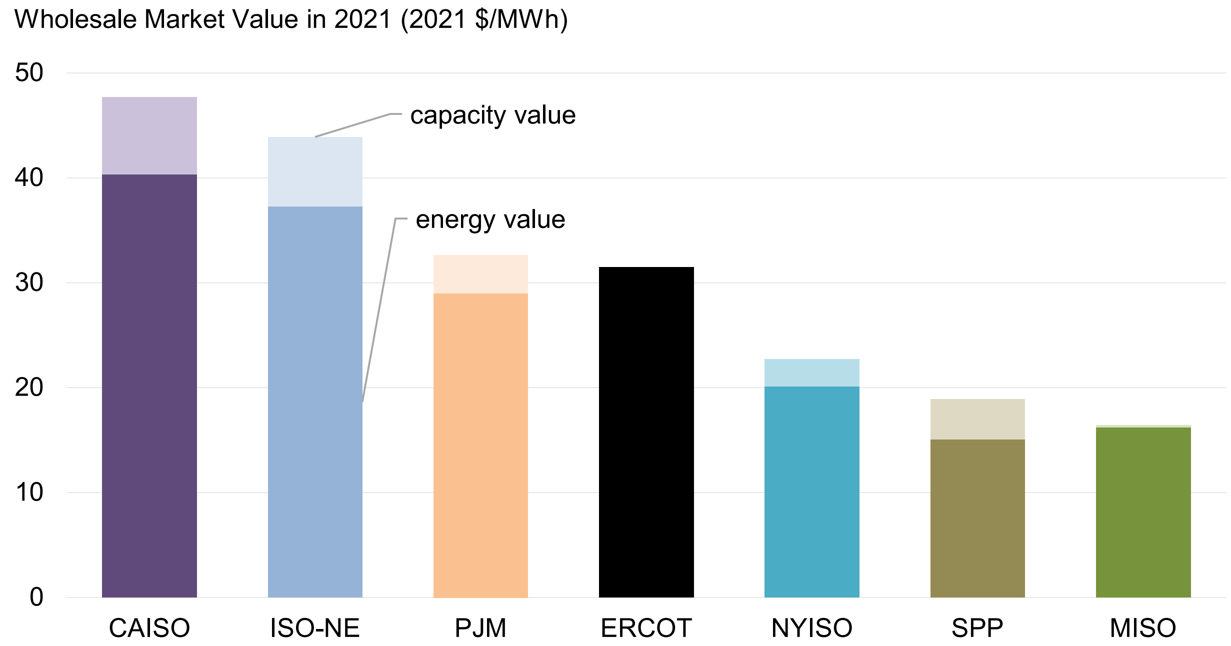
Notwithstanding the comparisons made in this chapter, neither the wind prices nor wholesale market value estimates (nor fuel cost projections) reflect the full social costs of power generation and delivery. Among the various shortcomings of comparing wind (and solar) PPA prices with wholesale value and natural-gas cost estimates in this manner are the following:

- Wind (and solar) PPA prices are reduced by federal and state incentives. Similarly, wholesale electricity prices (or fuel cost projections) are reduced by any financial incentives provided to thermal generation and its fuel production. Wholesale prices may also not fully account for the health and environmental costs of various generation technologies (though a later section within this chapter assesses the health and climate benefits of wind), and for other societal concerns such as fuel diversity and resilience.
- Wind (and solar) PPA prices do not fully reflect integration, resource adequacy, or transmission costs, while wholesale electricity prices (or fuel cost projections) also do not fully reflect transmission costs, and may not fully reflect capital and fixed operating costs.
- Wind and solar PPA prices—once established—are fixed and known. The estimated wholesale market value of wind represents historical values, whereas future natural gas prices are uncertain. Said another way, levelized wind (and solar) PPA prices represent a future stream of prices that has been locked in (and that often extends for 20 years or longer), whereas the wholesale value estimates are pertinent to just the specific historical years evaluated, and future natural gas prices reflect uncertain forecasts.

In short, comparing levelized long-term wind PPA prices with either yearly estimates of the wholesale market value of wind or forecasts of the fuel costs of natural gas-fired generation is not appropriate if one's goal is to account fully for the costs and benefits of wind energy relative to other generation sources. Nonetheless, these comparisons still provide some sense for the short-term competitive environment facing wind energy, and convey how those conditions have shifted over time.

The grid-system market value of wind in 2021 varied by project location, from an average of $16/MWh in MISO to $48/MWh in CAISO

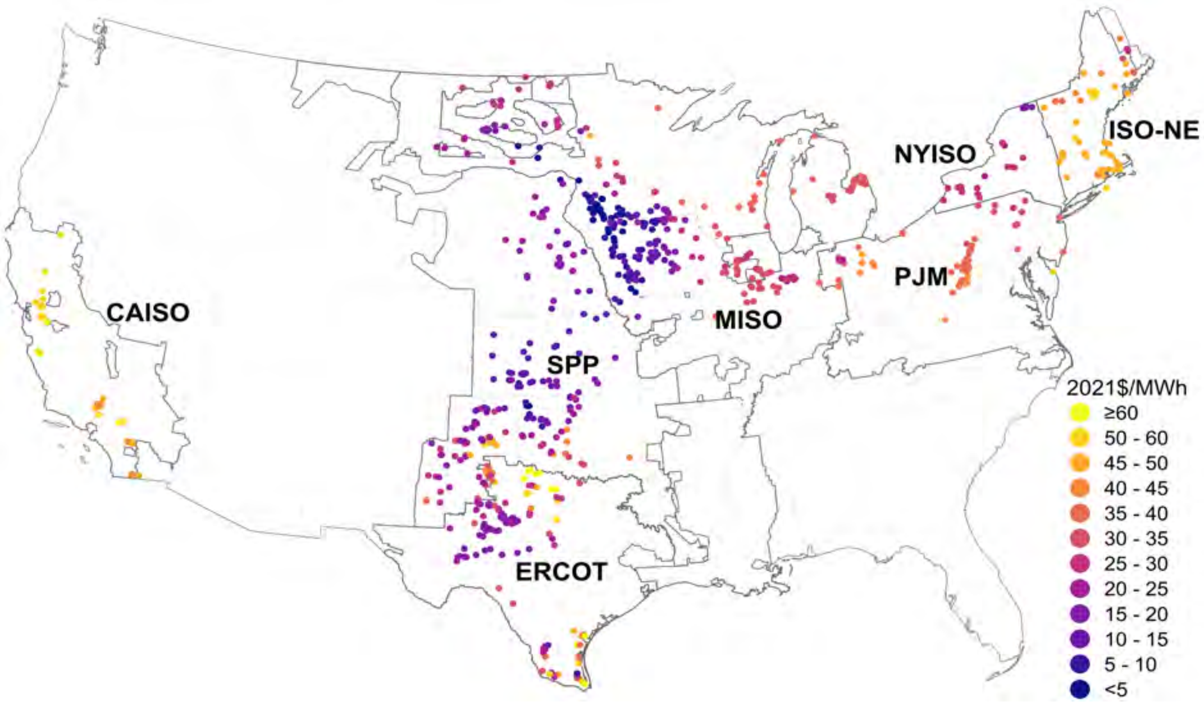
Figure 56 presents estimates of wind's wholesale market value, by region, but only for the latest year—2021. The figure also disaggregates the market value estimates into their constituent parts: energy and capacity. The average market value of wind in 2021 was the lowest in MISO ($16/MWh), SPP ($19/MWh) and NYISO ($23/MWh), whereas the higher-value markets were CAISO ($48/MWh), ISO-NE ($44/MWh), and PJM ($33/MWh). Unlike recent past years, wind's value in ERCOT ($31/MWh) was relatively high compared to several other regions, in part due to high prices associated with extreme weather in the region in 2021. In all regions, energy value represented the largest share of the total value, with capacity value varying widely regionally and being considerably lower in absolute magnitude.



Sources: Berkeley Lab, Hitachi, ISOs

Figure 56. Regional wholesale market value of wind in 2021, by region

Figure 57 presents the 2021 wind power market value estimates at a project level. These estimates span a wide range in 2021, with the 10th, 50th, and 90th percentile values equaling $7, $25, and $48 per MWh, respectively. The figure shows variability in market value within each region, with areas facing transmission congestion and high wind penetrations generally experiencing lower market value. Higher market value estimates are found in uncongested areas, areas with higher average wholesale prices, and areas where wind output profiles are more-correlated with electricity demand. (Developments related to new transmission and wind energy are discussion in an accompanying text box).

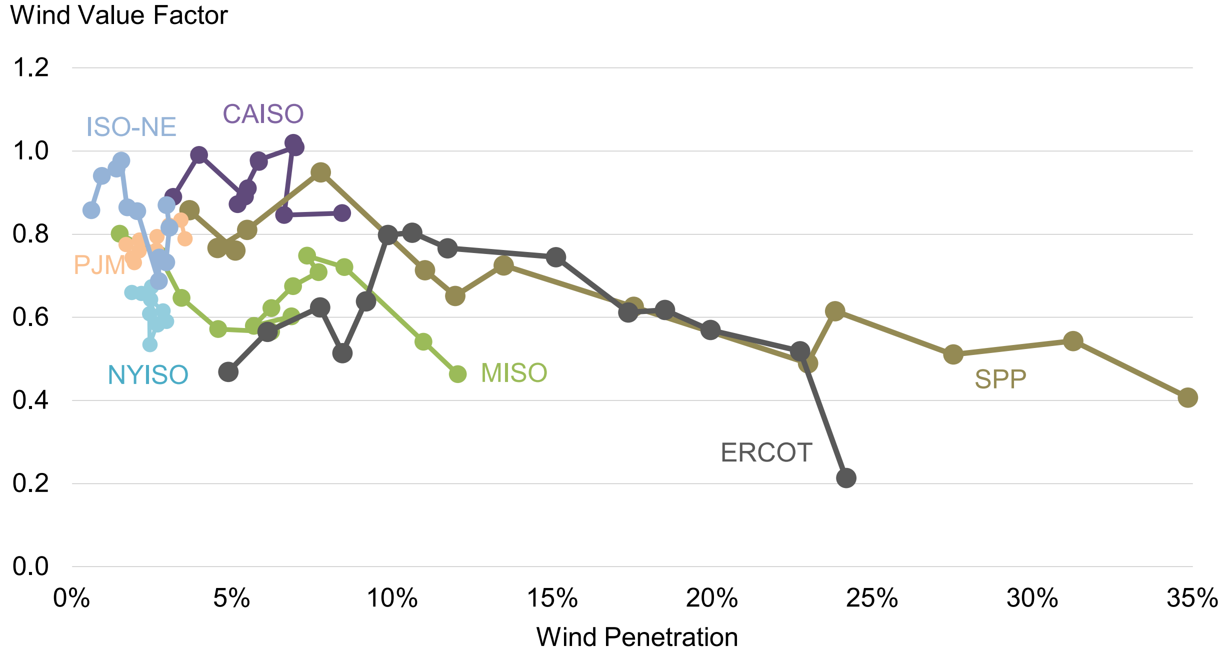


Sources: Berkeley Lab, Hitachi, ISOs

Figure 57. Project-level wholesale market value of wind in 2021

The grid-system market value of wind tends to decline with wind penetration, impacted by generation profile, transmission congestion, and curtailment

The regions with the highest wind penetrations (SPP at 35%, ERCOT at 24%, and MISO at 12%) have generally experienced the largest reduction in wind's value relative to the regional average value of a 24x7 flat-profile generator. The "value factor" of wind generation in 2021 was roughly 0.4, 0.2, and 0.5 in each of these high-penetration regions, respectively. Value factor is calculated separately in each region and represents the ratio of the average value of wind generation to the average value of a 24x7 flat profile at all generator locations. The 2021 wind value factor in NYISO was 0.6, but was higher in ISO-NE (0.9), CAISO (0.9), and PJM (0.8). The progression of each region's value factor with wind penetration can be seen in Figure 58. While there is a loose correlation between penetration level and value factor, each region's value factor progressed along a convoluted path as penetration increased. Millstein et al. (2021) show that differences between the regions' transmission infrastructure, and upgrades to that infrastructure, is one of the primary reasons value factor does not correlate more closely with penetration level.



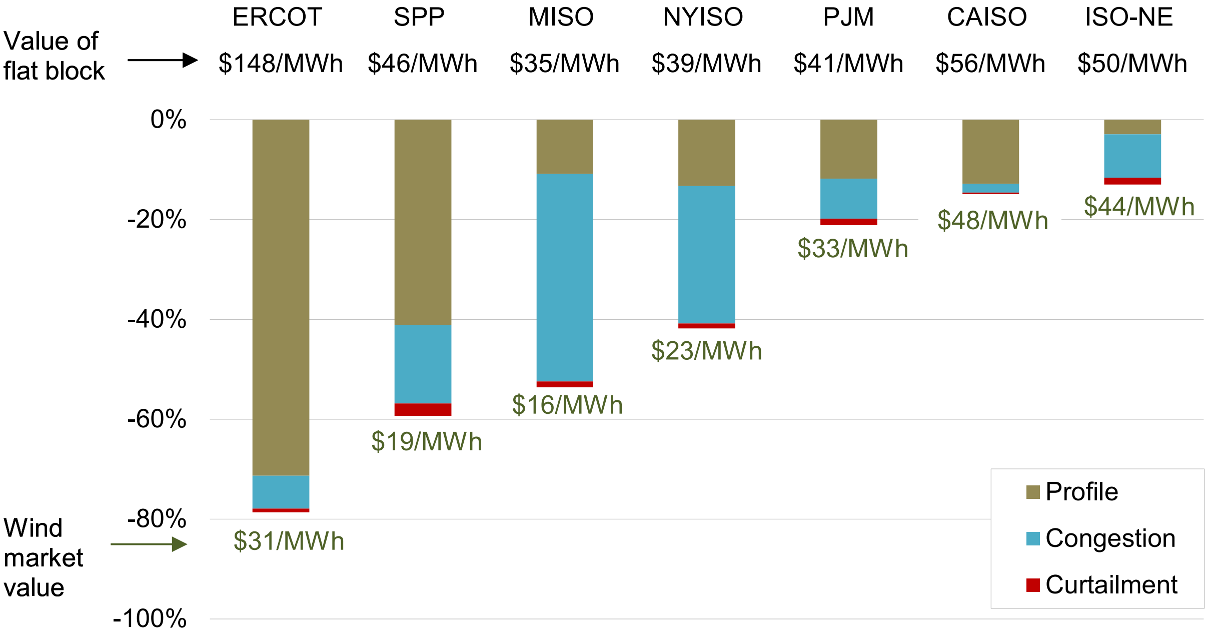
Sources: Berkeley Lab, Hitachi, ISOs

Figure 58. Trends in wind value factor as wind penetrations increase

Using methods further described in Millstein et al. (2021), Figure 59 shows the impact of three separate causes of reduction to the value of wind generation in 2021. As used here, the term value reduction is the opposite of value factor: a total value reduction of 40% would indicate a value factor of 0.6. The three causes of value reduction are: (1) profile value reductions: caused by the temporal correlation of wind generation with low market prices, (2) congestion value reductions: caused by the inability to serve the most valuable locations in a region due to transmission congestion, and (3) curtailment value reductions: caused by curtailment of output, typically due to wind plant operator response to low (usually negative) local prices.

Figure 59 shows that the causes of wind value reductions vary from region to region. In contrast to recent years, 2021 ERCOT and SPP value reductions were dominated by profile-based value reductions (as opposed to congestion value reductions). In ERCOT and SPP, 2021 profile value reductions were 71% and 41%, respectively, much larger than the 7% and 16% value reductions from congestion in those regions. ERCOT and SPP both faced episodes of extreme weather that drove annual average pricing and value trends for the year. If these particular weather conditions do not repeat in future years, the 2021 profile value reductions observed in ERCOT and, to a lesser extent in SPP, are not likely to be representative of future years.

MISO and NYISO faced large congestion value reductions in 2021 of 42% and 27%, respectively. Curtailment value reductions did not reach above 2% in any region. The value reductions associated with congestion could potentially be addressed with new within-region transmission infrastructure. Conversely, mitigating the large profile value reductions found in ERCOT and SPP in 2021 (or the more consistent but slightly smaller profile value reductions found in those regions in recent past years) would require strategies beyond expansion of within-regional transmission. Millstein et al. (2021) discusses a range of possible strategies to address profile value reductions, including cross-regional transmission and storage deployment, new demand sources (e.g., coordinated electric vehicle charging), and regulatory and rate changes supporting responsive load.



Sources: Berkeley Lab, Hitachi, ISOs

Figure 59. Impact of transmission congestion, output profile, and curtailment on wind energy market value in 2021

The health and climate benefits of wind are larger than its grid-system value, and the combination of all three far exceeds the levelized cost of wind

The benefits of wind in reducing health and climate burdens from polluting energy sources are not included in the earlier estimates of grid-system value and the comparisons of that value with PPA prices. Wind generation reduces power-sector emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), and sulfur dioxide (SO_2). These reductions, in turn, provide public health and climate benefits (Millstein et al. 2017). In this section, the health and climate benefits of wind power are estimated and compared, along with grid-system value, to the unsubsidized levelized cost of new wind plants built in 2021.[40]

Using methods described in detail in the Appendix,[41] Figure 60 presents the summed health and climate benefits from wind by region in the year 2021, considering all wind plants. Nationally, health and climate benefits together averaged $80/MWh-wind. Benefits were largest, ranging from $83/MWh to $120/MWh, in the Central, Midwest, and Mid-Atlantic regions (incorporating SPP, MISO, and PJM). In these regions, wind offsets more-polluting power plants than in other regions. Health and climate benefits were lowest in New York ($32/MWh) and New England ($28/MWh); and are not reported in the Southeast due to the small number of wind plants in that region. Regional and national values presented here include both in-region emission impacts as well as cross-region impacts due to electricity trade across regional boundaries.

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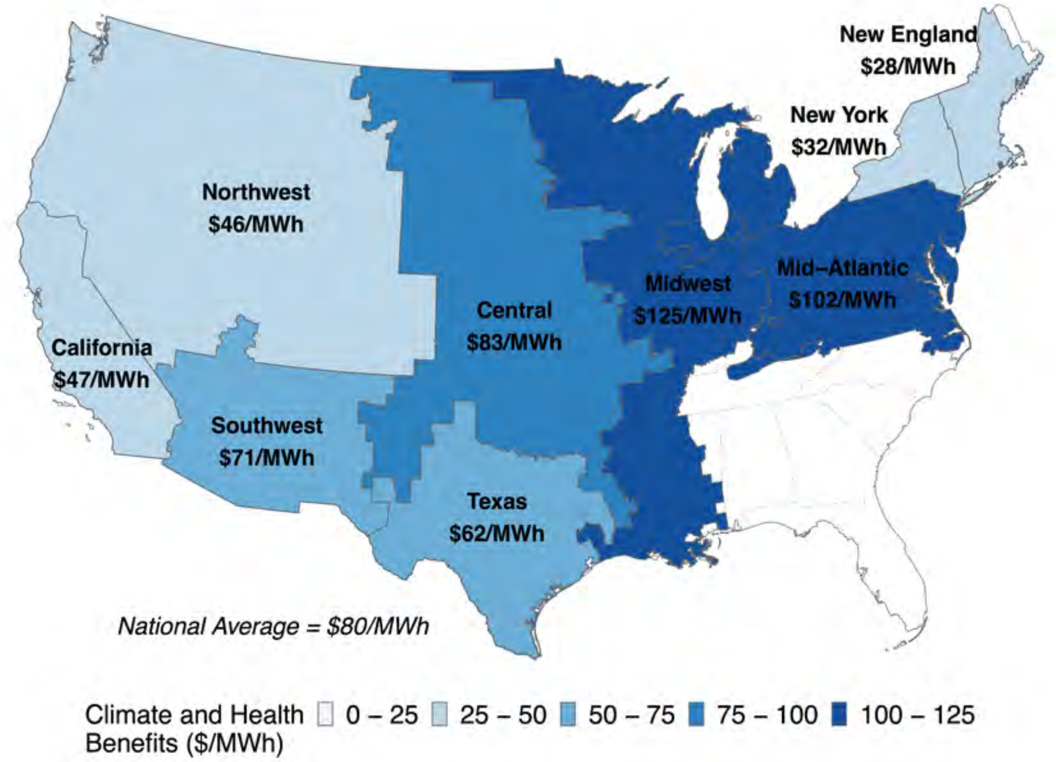
[40] The goal was to compare the most important cost and benefit components from a societal perspective, but this comparison is not exhaustive. Not included are considerations of employment; local environmental, ecological, land-use, and community impacts; water use; mercury and primary particulate matter; and transmission or grid-integration costs not covered by grid-value estimates.

[41] Briefly, the per-MWh health and climate benefits of wind were estimated through a two-step process: first, determine the marginal avoided emission rate; second, multiply avoided emissions by a regional damage rate (i.e., health or climate impacts per ton of pollutant emitted). Marginal avoided emission rates are derived from Fell and Johnson (2021). Damage rates for CO_2 emissions are set to equal the social cost of carbon (IWG 2021; 2.5% discount rate), and health damage rates for SO_2 and NO_x come from EPA (2015). Health damage rates vary by the region in which the emissions occurred.

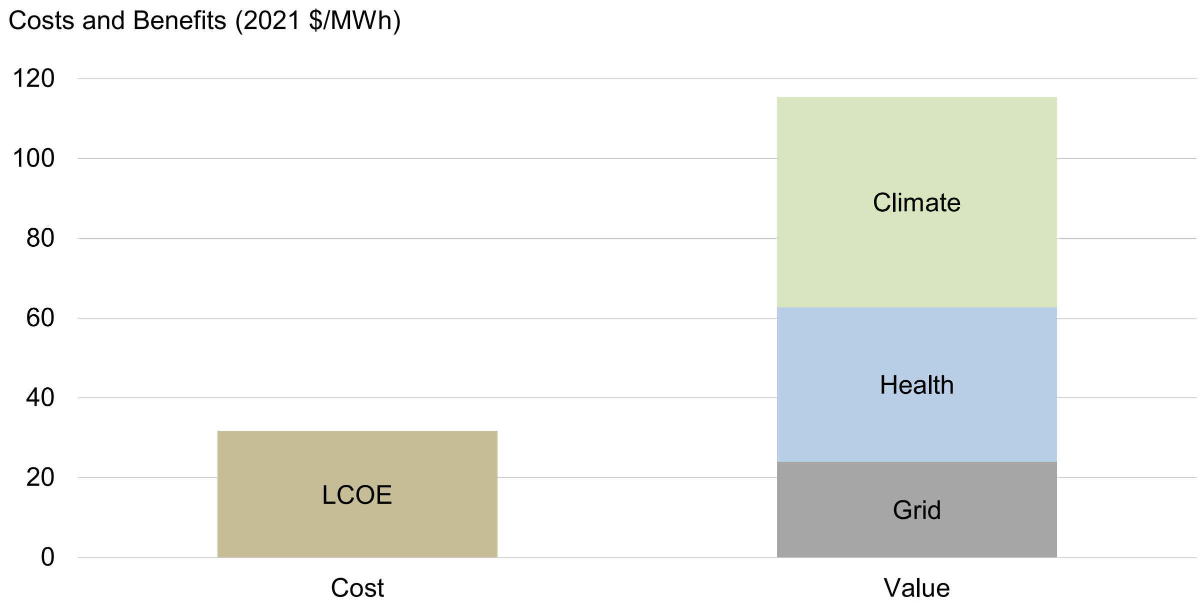


Note: Estimates not provided for Southeast due to small number of wind plants in that region.

Sources: Berkeley Lab, Form EIA-930, Fell and Johnson (2021)

Figure 60. Marginal health and climate benefits from wind generation by region in 2021

Focusing just on the smaller subset of wind plants that came online in 2021, the average climate, health, and grid-system value sums to almost four times the average LCOE (see Figure 61). Specifically, climate, health, and grid-system values averaged $53/MWh, $39/MWh and $24/MWh, respectively, compared to an average LCOE of $32/MWh.



Sources: Berkeley Lab, EIA Form 930, Fell and Johnson (2021)

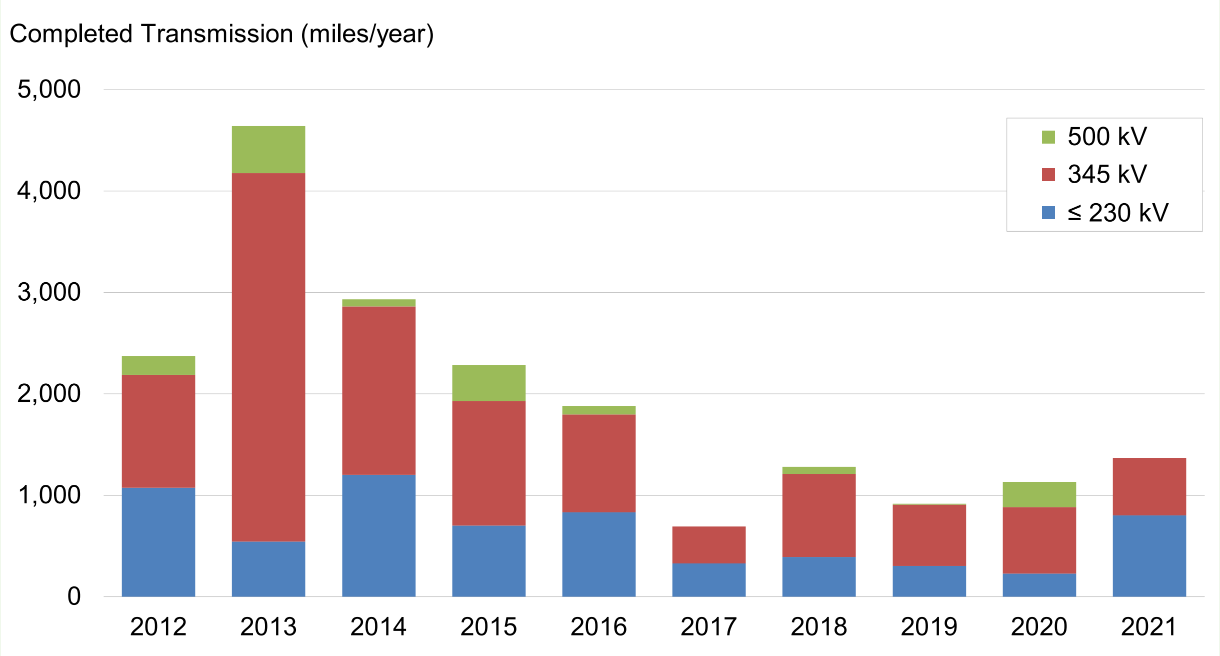
Figure 61. Marginal health, climate and grid-value benefits from new wind plants versus LCOE in 2021

For simplicity, single values for health and climate benefits are presented. However, these values represent central estimates from a range of plausible values. The central health values presented here are based on the average of high and low estimates, which are ±40% relative to the central value (representing a range of equally valid epidemiological research on the impact of human exposure to air pollutants). The climate benefits use a representative social cost of carbon from IWG (2021), but a range of estimates exist in the literature. Further discussion on the range of health impacts can be found in Millstein et al. (2017). Likewise, further discussion of the range of social cost of carbon estimates can be found in IWG (2021).

Transmission Investments and Wind Power

The areas with the greatest wind speeds are often distant from electricity load centers, making wind dependent on transmission infrastructure. Related, the low grid-system market value of wind in some areas of the country is, in part, driven by limited transmission and the resulting grid congestion.

Transmission additions remained relatively low in 2021, with about 1,400 miles of new transmission lines coming online according to the Federal Energy Regulatory Commission (see figure below). The decline since the peak in 2013 is partly due to the completion of the transmission buildout in West Texas in 2013, as well as a significant buildout of larger-scale transmission in SPP and MISO in that same timeframe. Since that time, much of the transmission buildout in the Unites States has focused on local reliability projects, and not the large-scale, long distance new transmission intended in part to access wind resources.



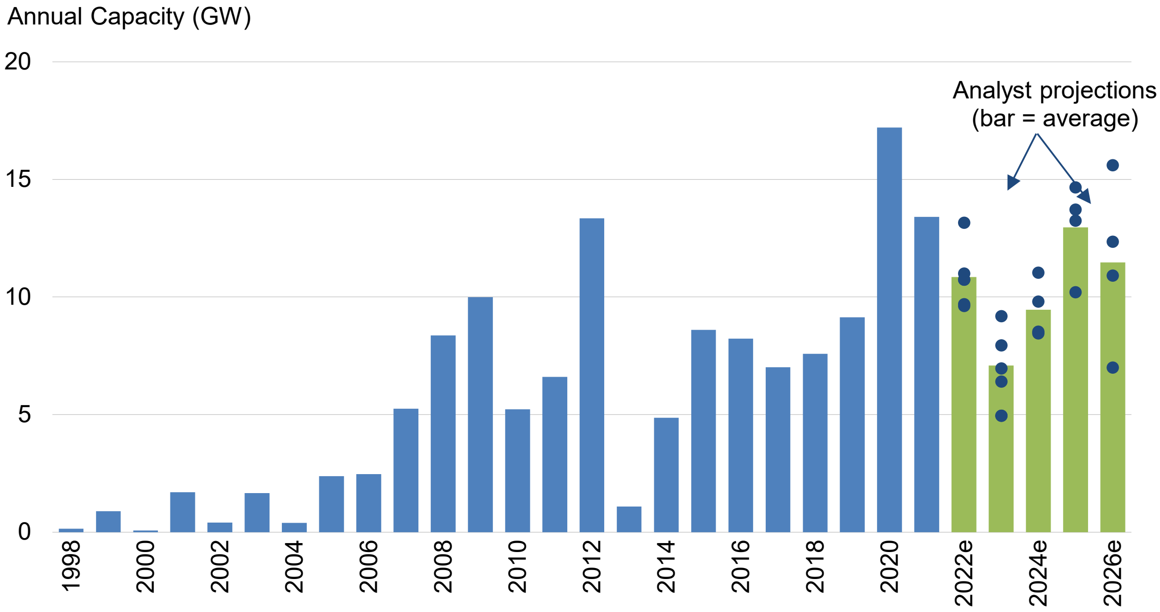
Source: FERC monthly infrastructure reports

9 Future Outlook

Energy analysts project that total annual wind additions will generally decline through 2023 before rebounding

Energy analysts project that annual wind additions will generally decline through 2023 (BloombergNEF 2022, Wood Mackenzie 2022b, GWEC 2022, EIA 2022c, IEA 2021, IEA 2022). Among the forecasts for the domestic market presented in Figure 62, expected capacity additions range from 9.6 GW to 13.2 GW in 2022 and 5.0 GW to 9.2 GW in 2023. Expected annual additions then increase, supported by anticipated growth in offshore wind; all forecasts reported here include both land-based and offshore wind.

These projected trends are driven in part by expectations about the expiration of the federal PTC, and by anticipated growth in offshore wind in the mid-2020s. Near-term additions are also influenced by the cost and performance of wind technologies, corporate wind energy purchases, and state-level renewable energy policies. Limited transmission infrastructure and competition from solar dampen growth expectations, while continuing supply chain pressures also impact expected deployment levels.



Sources: ACP, BloombergNEF (2022), Wood Mackenzie (2022b), GWEC (2022), EIA (2022c), IEA (2021, 2022)

Figure 62. Wind power capacity additions: historical installations and projected growth

Longer term, the prospects for wind energy will be influenced by the sector's ability to continue to improve its economic position even in the face of challenging competition and near-term supply chain constraints.

The prospects for wind energy in the longer term will be influenced by the sector's ability to continue to improve its economic position even in the face of challenging competition from other generation resources, such as solar and natural gas. Additionally, the speed with which supply chain constraints are addressed will impact deployment volumes. Corporate demand for clean energy and state-level policies will also continue to impact wind power deployment, as will the buildout of transmission infrastructure and the future uncertain cost of natural gas. Finally, the Biden Administration has established strong goals for clean energy, including a zero-carbon power sector by 2035 (The White House 2021). Consistent with those goals, there have been recent legislative proposals for a long-term extension of the PTC and other national policies to support a clean energy transition. The fate of these legislative proposals will greatly impact the sector's upside potential to exceed the projections shown above.

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Appendix: Sources of Data Presented in this Report

Installation Trends

Data on wind power additions and repowering in the United States (as well as certain details on the underlying wind power projects) are sourced largely from ACP (2022). Annual wind power capital investment estimates derive from multiplying wind power capacity data by weighted-average capital cost data (provided elsewhere in the report). Data on non-wind electric capacity additions come from Hitachi's Velocity Suite database, except that solar data come from Wood Mackenzie Power & Renewables.

Global cumulative (and 2021 annual) wind power capacity data are sourced from GWEC (2022) but are revised, as necessary, to include the U.S. wind power capacity used in the present report. Country-level wind energy penetration is compiled by ACP (2022).

The wind project installation map was created based on ACP's project database. Wind energy as a percentage contribution to statewide electricity generation and consumption is based on EIA data for wind generation divided by in-state total electricity generation or consumption in 2021. Data on online hybrid power plants comes largely from EIA (updated, when erroneous data are discovered).

The wind hybrid/co-located data are compiled from the 2021 early release EIA 860 dataset. Projects are identified as hybrids with two approaches. The first approach involves identifying distinct power plants (e.g. wind and storage) that share the same EIA ID. This approach identifies the majority of the hybrid data summarized in the report. The second approach involves compiling data from Hitachi's Velocity Suite and matching power plants that have the same Hitachi Plant ID but different fuel types. These plants were then found in the EIA dataset and cross-checked against latitude and longitude information to confirm co-location.

Data on wind power capacity in various interconnection queues come from a review of publicly available data provided by each ISO or utility. For more information see Rand et al. (2022).

Industry Trends

Turbine manufacturer market share data are derived from the ACP project database. Data on recent U.S. nacelle assembly capability come from ACP (2022), as do data on U.S. tower and blade manufacturing capability. Manufacturer profitability data come from corporate financial reports.

Data on U.S. imports of selected wind turbine equipment come from the Department of Commerce, accessed through the U.S. Census Bureau, and obtained from the U.S. Census's USA Trade Online data tool (https://usatrade.census.gov/). The analysis of the trade data relies on the "customs value" of imports as opposed to the "landed value" and hence does not include costs relating to shipping or duties. The table below lists the specific trade codes used in the analysis presented in this report.

All trade codes used to track wind equipment imported in 2020 and 2021 are exclusive to wind. In some previous years, some codes are exclusive to wind, whereas others are not. Assumptions are made for the proportion of wind-related equipment in each of the non-wind-specific HTS trade categories. These assumptions are based on: an analysis of trade data where separate, wind-specific trade categories exist; a review of the countries of origin for the imports; personal communications with U.S. International Trade Commission and wind industry experts; U.S. International Trade Commission trade cases; and import patterns in the larger HTS trade categories.

Table A1. Harmonized Tariff Schedule (HTS) Codes and Categories Used in Wind Import Analysis

HTS Code	Description	Years applicable	Notes
8502.31.0000	wind-powered generating sets	2005–2021	includes both utility-scale and small wind turbines
7308.20.0000	towers and lattice masts	2006–2010	not exclusive to wind turbine components
7308.20.0020	towers - tubular	2011–2021	mostly for wind turbines
8501.64.0020	AC generators (alternators) from 750 to 10,000 kVA	2006–2011	not exclusive to wind turbine components
8501.64.0021	AC generators (alternators) from 750 to 10,000 kVA for wind-powered generating sets	2012–2021	exclusive to wind turbine components
8412.90.9080	other parts of engines and motors	2006–2011	not exclusive to wind turbine components
8412.90.9081	wind turbine blades and hubs	2012–2021	exclusive to wind turbine components
8503.00.9545	parts of generators (other than commutators, stators, and rotors)	2006–2011	not exclusive to wind turbine components
8503.00.9546	parts of generators for wind-powered generating sets	2012–2021	exclusive to wind turbine components
8503.00.9560	machinery parts suitable for various machinery (including wind-powered generating sets)	2014–2019	not exclusive to wind turbine components; nacelles when shipped without blades can be included in this category[42]
8503.00.9570	machinery parts for wind-powered generating sets	2020–2021	exclusive to wind turbine components; nacelles when shipped without blades are included in this category

Information on wind power financing trends was compiled by Berkeley Lab, based in part on data from the Intercontinental Exchange, Bloomberg NEF, and Norton Rose Fulbright. Wind project ownership and power purchaser trends are based on a Berkeley Lab analysis of ACP's project database.

Technology Trends

Information on turbine nameplate capacity, hub height, rotor diameter, and specific power was compiled by Berkeley Lab within the U.S. Wind Turbine Database based on information provided by ACP, turbine manufacturers, standard turbine specifications, the FAA, web searches, and other sources. The data include projects with turbines greater than or equal to 100 kW that began operation in 1998 through 2021. Estimates of the quality of the wind resource in which turbines are located were generated as discussed below.

FAA "Obstacle Evaluation / Airport Airspace Analysis" data containing prospective turbine locations and total proposed heights, in combination with ACP data on near-term installations, were used to estimate future technology trends. Any data with expiration dates between March 02, 2022 and September 02, 2023 were categorized as either "pending" turbines (for those that already had received an evaluation of "no hazard") or "proposed" turbines (for those that were still being evaluated). A portion of those turbines are categorized by Berkeley Lab, with input from ACP data and Hitachi's Velocity Suite data, as either "under construction" or in "advanced development." The former are projects that have been partially or fully constructed but have not

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[42] The explicit inclusion of nacelles without blades was effective in 2014 as a result of Customs and Border Protection ruling number HQ H148455 (April 4, 2014). That ruling stated that nacelles alone do not constitute wind-powered generating sets, as they do not include blades—which are essential to wind-powered generating sets as defined in the HTS.

been fully commissioned. The latter are not under construction but are highly likely to be in the next few years and have one of the following in place: a signed PPA (or similar long-term contract), a firm turbine order, or an announcement to proceed under utility ownership.

Performance Trends

Wind project performance data were compiled overwhelmingly from two main sources: FERC's *Electronic Quarterly Reports* and EIA Form 923. Additional data come from FERC Form 1 filings and, in several instances, other sources. Where discrepancies exist among the data sources, those discrepancies are handled based on the judgment of Berkeley Lab staff. Data on curtailment are from ERCOT, MISO, PJM, NYISO, SPP, ISO-NE, and CAISO.

The following procedure was used to estimate the quality of the wind resource in which wind projects are (or are planned to be) located. First, within the U.S. Wind Turbine Database, the location of individual wind turbines and the year in which those turbines were (or are planned to be) installed were identified using FAA Digital Obstacle (i.e., obstruction) files and FAA Obstacle Evaluation / Airport Airspace Analysis files, combined with Berkeley Lab and ACP data on individual wind projects. Second, NREL used 200-meter resolution data from AWS Truepower—specifically, gross capacity factor estimates—to estimate the quality of the wind resource for each of those turbine locations. These gross capacity factors are derived from the average mapped 100-meter wind speed estimates, wind speed distribution estimates, and site elevation data, all of which are run through a standard wind turbine power curve (common to all sites) and assuming no losses. To create an index of wind resource quality, the resultant average wind resource quality (i.e., gross capacity factor) estimate for turbines installed in the 1998–1999 period is used as the benchmark, with an index value of 100%. Comparative percentage changes in average wind resource quality for turbines installed after 1998–1999 are calculated based on that 1998–1999 benchmark year. When segmenting wind resource quality into categories, the following AWS Truepower gross capacity factors are used: the "lower" category, which includes all projects or turbines with an estimated gross capacity factor of less than 42%; the "medium" category, which corresponds to ≥42%–48%; the "higher" category, which corresponds to ≥48%–54%; and the "highest" category, which corresponds to ≥54%. Not all turbines could be mapped by Berkeley Lab for this purpose; the final sample included 66,774 turbines of the 67,143 installed from 1998 through 2021 in the continental United States (i.e., over 99%). Most of the turbines that are *not* mapped are more than a decade old.

Separate from the above, the relative strength of the average "fleet-wide" wind resource from year to year is estimated based on weighting each operational project-level wind resource (or "wind index") by its share of the total operational fleet-wide capacity for the particular year. For each individual wind plant, an annual wind index is calculated as the ratio of a particular year's predicted capacity factor to the long-term average predicted capacity factor (with the long-term average calculated from 1998-2021). Site-level available wind resources are calculated for each hour of each year based on ERA5 reanalysis wind speed data for each plant's location. ERA5 has a horizontal resolution of ~30 km × 30 km. Site-specific estimated wind speeds (with the geographic resolution previously noted) are interpolated between ERA5 model heights to the corresponding representative hub-height for each wind project. Hourly wind speeds at each project are then converted to wind power by applying project-specific power curves. In this case, power curves are based on the set of turbine-specific power curves reported by *thewindpower.net*, which provides power curves for more than 750 separate turbines; some newer power curves are derived from NREL's System Advisor Model, v2020.11.29 and based on turbine characteristics, such as specific power. Although many projects contain only a single type of turbine, some projects contain multiple turbine types. For the latter projects, a turbine power curve is selected that most closely matches the average turbine capacity, rotor diameter, and specific power across the project. The wind indices are calculated without accounting for wake, electrical, or other losses, or curtailment, and are based only on the ERA5 wind speeds. These indices are used to represent changes in the wind resource from one year to the next, and reflect the ERA5-based strength of the total potential wind resource given the types of turbines that are deployed at each site. Note that these data and indices are used to characterize year-to-year variations in the strength of the wind resource, whereas AWS Truepower estimates are used to characterize the strength of the site-specific long-term annual average wind resource. The analyses uses AWS Truepower estimates for the latter need due to their higher geographic resolution.

Cost Trends

Historical U.S. wind turbine transaction prices were, in part, compiled by Berkeley Lab. Sources of transaction price data vary, but most derive from press releases, press reports, and Securities and Exchange Commission and other regulatory filings. Additional data come from Vestas, SGRE and Nordex corporate reports, BloombergNEF, and Wood Mackenzie.

Berkeley Lab used a variety of public and some private sources of data to compile capital cost data for a large number of U.S. wind projects. Data sources range from pre-installation corporate press releases to verified post-construction cost data. Specific sources of data include EIA Form 412, EIA Form 860, FERC Form 1, various Securities and Exchange Commission filings, filings with state public utilities commissions, *Windpower Monthly* magazine, AWEA's *Wind Energy Weekly*, the DOE and Electric Power Research Institute Turbine Verification Program, *Project Finance* magazine, various analytic case studies, and general web searches for news stories, presentations, or information from project developers. For 2009–2012 projects, data from the Section 1603 Treasury Grant program were used extensively; for projects installed from 2013 through 2019, EIA Form 860 data are used extensively. Some data points are suppressed in the figures to protect data confidentiality. Because the data sources are not all equally credible, less emphasis should be placed on individual project-level data; instead, the trends in those underlying data offer greater insight. Only cost data from the contiguous lower-48 states are included.

Wind project O&M costs come primarily from two sources: EIA Form 412 data from 2001 to 2003 for private power projects and projects owned by POUs, and FERC Form 1 data for IOU-owned projects. A small number of data points are suppressed in the figures to protect data confidentiality.

Sales Price and Levelized Cost Trends

Wind PPA price data are based on multiple sources, including prices reported in FERC's *Electronic Quarterly Reports*, FERC Form 1, avoided-cost data filed by utilities, pre-offering research conducted by bond rating agencies, and a Berkeley Lab collection of PPAs. Supplemental data from Level10 Energy are also reported, in both nominal (as reported—see associated data file) and real 2021 dollars. The 2021 dollar conversion assumes that LevelTen's reported prices in each quarter are for 12-year, flat-priced (in nominal dollars) PPAs that commence in the following calendar year. In each quarter, we deflate the 12-year nominal dollar price series to 2021 dollars using the GDP deflator (actual deflators historically, along with projected future deflators from the EIA's *Annual Energy Outlook 2022*), and then levelize the resulting 12-year real-dollar price series using a 4% real discount rate. REC price data were compiled by Berkeley Lab based on information provided by Marex Spectron.

The analysis calculates the LCOE of wind based on LCOE input data collected, in large part, by Berkeley Lab and presented elsewhere in this report—and assessed as *expected* LCOE as of the listed commercial operation dates. These inputs include capital costs, capacity factors, operational expenses, financing costs, and assumptions about useful life. Specifically:

- For capacity factors, project-level data are levelized over the assumed useful life of each plant, applying degradation assumptions from Hamilton et al. (2020) as appropriate. For projects built in 2021 (that have not yet been operating for a full year), capacity factors are assumed to match the average capacity factor of projects built in the same regions from 2017 to 2019.
- Based on Wiser et al. (2019), total operational expenses are assumed to fall from a levelized cost of \$88/kW-year in 1998 (expressed in 2021 dollars) to \$66/kW-year by 2003, \$56/kW-year by 2010, and \$47/kW-year by 2018 (and are interpolated linearly between these years). Projects built from 2019-2021 are indexed to the 2018 value but vary by COD year based on BloombergNEF's North American wind

O&M price index (BloombergNEF 2021b). Note that these are projected future costs; actual operational expenditures could diverge from industry expectations, as they have in the past.

- The weighted average cost of capital assumes a 70%:30% debt-to-equity split (possible in the absence of the PTC), with the cost of debt varying over time based on historical changes in the 20- and 30-year swap rates and bank spread, while the cost of equity declines from 15% in 1998 to 8.25% in 2021. Financing costs are estimated as if the PTC were not available. These are assumptions for future returns; actual returns could differ depending on how performance, operational expenditures and project lifetimes track expectations.
- Project life is assumed to increase linearly from 20 years for projects built in 1998 to 30 years for projects built in 2020 and after, based on industry expectations (see Wiser and Bolinger 2019).
- A 35% corporate tax rate is assumed from 1998–2017 and 21% thereafter, with a constant 5% state tax rate over the entire period. Inflation expectations range from 1.9% to 3.0%. Five-year accelerated depreciation is applied for all vintages of wind projects.

Cost and Value Comparisons

To compare the price of wind to the cost of future natural gas-fired generation, the range of fuel cost projections from the EIA's *Annual Energy Outlook 2022* is converted from $/MMBtu into $/MWh using heat rates derived from the modeling output.

To calculate the historical wholesale energy market value of wind, estimated hourly wind generation profiles are matched to hourly nodal real-time wholesale prices. The capacity value at each plant is also calculated, based on the modeled wind profiles and ISO-specific rules for wind's capacity credit and ISO-zone-specific capacity prices. The resulting estimates reflect the average $/MWh energy and capacity value for each plant and year. ISO-level average values are estimated by weighting plant-level value estimates by plant output.

To calculate the average energy and capacity value in $/MWh, the numerator is based on actual hourly generation after curtailment but the denominator is based on the total generation without curtailment. Curtailment is accounted for only in the numerator so that increased levels of curtailment will reduce the average $/MWh value. The MWh, in this case, reflect potential wind generation before curtailment. Note that public data do not broadly exist for hourly wind output profiles at the plant level. Consequently, the modeled wind generation estimates described earlier are leveraged, albeit adjusted for *curtailment* and corrected for *bias*. For the 2021 modeled hourly profiles we use a different input meteorological model than was used for the wind index calculation described earlier. Instead of ERA5 we use HRRR. Compared to ERA5, HRRR reduces biases and increases hourly correlation to recorded generation (Davidson and Millstein 2022). We are not able to use HRRR for the long term wind index calculation because the HRRR records begin in 2014 (and HRRR methodology is updated over time). By applying a bias correction process to the generation estimates we are able to incorporate publicly available information on actual generation as well as site-specific HRRR modeled wind speeds. One exception to this process is for plants located in ERCOT. ERCOT provided high time-resolution records of plant level generation and curtailment going back to 2013, and, where available, those reported values are utilized.

Total *curtailment* is reported by each ISO for either each hour or each month. To correct HRRR output estimates for curtailment, plants are divided into three groups: plants receiving the PTC, plants that have aged out of the PTC, and plants that elected the 1603 Treasury Grant instead of the PTC. Total reported hourly curtailment is distributed evenly across all plants within a particular ISO that face local hourly prices below a threshold defined for each group (initially, –$23/MWh for PTC plants and $0/MWh for the other two groups). A similar process is used to distribute monthly curtailment data.

Bias correction involves an iterative linear scaling approach so that: (1) the sum of estimated generation across all plants within each ISO matches the total wind generation reported by each ISO in each hour and (2) the annual total generation from each individual plant matches its expected annual output. The expected annual output is based on the modeled annual output adjusted for age-related performance decline (Hamilton et al.

2020) and curtailment. Also, a region-wide annual correction factor was applied based on EIA reported plant-level generation from the prior year (2020). These region-wide correction factors were generally small, MISO and SPP correction factors were 0.99 and 1.02 for example, but HRRR generation estimates were biased high in some regions, for example CAISO and NYISO correction factors were 1.18 and 1.17. Overall, this ensures that both the hourly distribution of generation and the total annual generation matches both modeled and recorded ISO-level data.

Hourly nodal real-time wholesale electricity prices and hourly regional wind output profiles are from Hitachi's Velocity Suite database. Curtailment data are downloaded directly from each ISO, or in some cases, from Hitachi's Velocity Suite database. For each wind power plant, the nearest or most-representative pricing node is identified, which allows representative prices to be matched to each plant. For some regions, hourly wind output profiles are only available for a subset of the relevant years of the analysis; as such, estimates of the wholesale energy value of wind are not available for all years for all regions.

Capacity value is estimated for each plant based on the bias-corrected, modeled wind profiles and ISO and ISO-zone specific capacity prices or costs, as well as relevant regional rules for wind's capacity credit. A separate capacity value is not calculated for ERCOT, because ERCOT runs an energy-only market that does not require load-serving entities to meet a resource adequacy obligation. In ERCOT, however, hourly Operating Reserve Demand Curve prices are added to nodal energy prices. Capacity value in ERCOT is essentially incorporated into the energy markets. As for capacity prices and costs, many regions have organized capacity markets. In those cases, the analysis uses market-clearing prices from capacity market auctions in concert with ISO-rules or estimates for the capacity credit of wind. For regions where load-serving entities have a resource adequacy obligation but lack organized capacity markets, the analysis uses data from regulatory bodies to approximate capacity costs and regional estimates or rules for wind's capacity credit.

The analysis calculates the difference between wind value and flat-profile value (called "value reduction") and then further decomposes the value reduction into three separate causes: profile, congestion, and curtailment. Flat profile value is calculated in two steps. First, the average value of flat ("always-on") generation is calculated at all power plant pricing nodes in a region (both wind and other types of power plants). The regional flat value is then calculated by taking the weighted-average value across all these power plants with weights based on recorded energy output at each plant. The profile value of wind is calculated in a similar manner to the regional flat value, but instead of using a flat profile, a wind plant output profile is applied to all power plants in a region (both wind and other types) and the regional weighted average value is calculated. This process is repeated for the profiles for all wind plants in a region to develop the regional average wind plant profile value. The reduction in wind value due to its profile is then calculated as the difference between the regional wind profile value and the regional flat value. Next, the value of wind generation at each wind plant is calculated given its output profile, and the regional average value is calculated across all wind plants. This provides a value of wind profiles at wind plants—in effect, the value of wind generation (not yet adjusted for curtailment). The profile value calculation finds the value of wind output at all generator locations and the wind generation value finds wind value only at wind generators, so the difference represents the impact of transmission congestion. Finally, the value of wind is adjusted for curtailment by increasing the total energy over which energy and capacity revenue are normalized. This final adjustment provides the overall value of wind at each plant. These methods are described in further detail in Millstein et al. (2021).

Turning to health and climate benefits, the marginal rate of health benefits is estimated based on a two-step process. First, the marginal rate of avoided emissions for wind is calculated based on estimates developed by Fell and Johnson (2021) for nine regions of the United States. Fell and Johnson (2021) also estimate the impact of wind on emissions in neighboring regions, and these additional impacts are included in the present analysis. An exception is that Fell and Johnson (2021) do not estimate the emission impacts on neighboring regions for wind generation within New York, New England, and Texas. Fell and Johnson (2021) do, however, estimate wind's per MWh impact on net exports for all regions. This impact on net exports is used in the present analysis to estimate the cross region impact on emissions where Fell and Johnson (2021) do not calculate it directly. The exported wind energy is assumed here to cause a reduction to natural gas generation, with natural gas emission rates by region calculated based on the EPA's eGRID2019 data.

Note that the Fell and Johnson (2021) estimates are based on regressions that used data over the period July 2018 through March 2020; as such, the emission factors used here do not precisely reflect calendar year 2021. That said, power sector emission rates (i.e., per MWh) of SO_2, NO_x, and CO_2, have undergone little change from 2019. Note also that the Fell and Johnson (2021) regressions find that an increase in wind offsets a small amount of hydropower. Over the course of a year, however, hydropower generation can be assumed to be fixed. To estimate the emissions impacts of wind in the current analysis, wind is assumed to shift hydropower generation in time, which in turn reduces another source of generation. The type of generation reduced in response to the shifting of hydropower is unknown; to maintain a conservative estimate, natural gas is assumed to be reduced, again employing regional emissions rates from eGRID2019.

A reduced-order health impacts model is then used to estimate the value of the avoided emissions from wind. Reduced-order health impacts models use the results of full meteorological and air quality models to provide more generalized estimates of the marginal impacts of emissions from specific regions. This analyses uses a model developed in EPA (2015), which contains marginal impact estimates (as dollars of health damage per ton of emitted SO_2 and NO_x emissions) for power-sector emissions in three large regions for 2020. Marginal impact estimates were adjusted for inflation to a 2021 dollar year. EPA (2015) provides a high and low estimate for the marginal damage rate, based on differing epidemiological studies. This analysis uses marginal damage estimates from the EPA based on a 3% discount rate. The product of these damage estimates with the marginal emission rate provides a monetized marginal benefit per MWh of wind generation. The estimated health benefits include reduced hospitalizations and reduced work-days missed, but the monetization is dominated by the cost of premature mortality due to population exposure to air pollution.

The value of avoided CO_2 emissions due to wind was calculated in a similar manner. Specifically, marginal CO_2 emissions factors were also derived from Fell and Johnson (2021), and include the additional processing described above to account for hydropower impacts in all regions and exports in New York, New England, and Texas. The marginal emission factors were then multiplied by the social cost of carbon from IWG (2021), using the 2.5% discount rate case, and were adjusted for inflation (to 2021$) to derive a monetized per-MWh benefit for wind generation by region.

Both estimates of health and climate benefits are subject to uncertainty. Central estimates of these benefits are presented, though both estimates have a wide range of plausible values. More detail about this uncertainty is available in Millstein et al. (2017) and Fell and Johnson (2021).

Land-Based Wind Market Report: 2022 Edition

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*Cover details: California Wind Farm
Photo courtesy of Ed Collier Photography*

Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh

November 26, 2023

BloombergNEF's annual battery price survey finds a 14% drop from 2022 to 2023

New York, November 27, 2023 – Following unprecedented price increases in 2022, battery prices are falling again this year. The price of lithium-ion battery packs has dropped 14% to a record low of $139/kWh, according to analysis by research provider BloombergNEF (BNEF). This was driven by raw material and component prices falling as production capacity increased across all parts of the battery value chain, while demand growth fell short of some industry expectations.

The analysis indicates that battery demand across electric vehicles and stationary energy storage is still on track to grow at a remarkable pace of 53% year-on-year, reaching 950 gigawatt-hours in 2023. Despite this growth, major battery manufacturers reported lower utilization rates for their plants, while demand and revenue fell short of many companies' expectations. As a result, many EV and battery makers revisited their production targets, which in turn impacted battery prices. Lithium prices reached a high point at the end of 2022, but fears that prices would remain high have largely subsided since then and prices are now falling again.

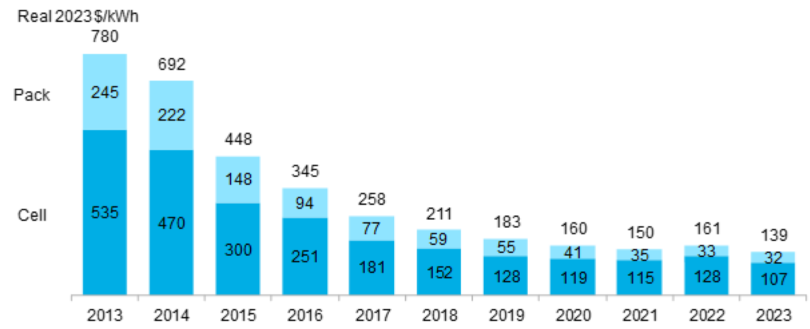
Evelina Stoikou, energy storage senior associate at BNEF and lead author of the report, said: "It is another year where battery prices closely followed raw material prices. In the many years that we've been doing this survey, falling prices have been driven by scale learnings and technological innovation, but that dynamic has changed. The drop in prices this year was attributed to significant growth in production capacity across the value chain in combination with weaker-than-expected demand."

The figures represent an average across multiple battery end-uses, including different types of electric vehicles, buses and stationary storage projects. For battery electric vehicle (BEV) packs, prices were $128/kWh on a volume-weighted average basis in 2023. At the cell level, average prices for BEVs were just $89/kWh. This indicates that on average, cells account for 78% of the total pack price. Over the last four years, the cell-to-pack cost ratio has risen from the traditional 70:30 split. This is partially due to changes to pack design, such as the

On a regional basis, average battery pack prices were lowest in China, at $126/kWh. Packs in the US and Europe were 11% and 20% higher, respectively. Higher prices reflect the relative immaturity of these markets, higher production costs, lower volumes, and the diverse range of applications. There was also intense price competition domestically in China this year as battery manufacturers ramped up production capacity aiming to grab a share of the growing battery demand.

The industry continues to switch to the low-cost cathode chemistry known as lithium iron phosphate (LFP). These packs and cells had the lowest global weighted-average prices, at $130/kWh and $95/kWh, respectively. This is the first year that BNEF's analysis found LFP average cell prices falling below $100/kWh. On average, LFP cells were 32% cheaper than lithium nickel manganese cobalt oxide (NMC) cells in 2023.

Figure 1: Volume-weighted average lithium-ion battery pack and cell price split, 2013-2023



Source: BloombergNEF. Historical prices have been updated to reflect real 2023 dollars. Weighted average survey value includes 303 data points from passenger cars, buses, commercial vehicles, and stationary storage.

Miners and metals traders surveyed expect prices for key battery metals like lithium, nickel and cobalt to ease further in 2024. Given this, BNEF expects average battery pack prices to drop again next year, reaching $133/kWh (in real 2023 dollars). Technological innovation and manufacturing improvement should drive further declines in battery pack prices in the coming years, to $113/kWh in 2025 and $80/kWh in 2030.

Yayoi Sekine, head of energy storage at BNEF, said: “Battery prices have been on a rollercoaster over the past two years. Large markets like the US and Europe are building up their local cell manufacturing and we’re keenly watching how production incentives and tightening regulations on critical minerals will impact battery prices. These localization efforts will add a layer of complexity to how battery prices shape up regionally in coming years.”

Localization of battery manufacturing in regions such as the US and Europe could exert upward pressure on battery pack prices as the local industries scale up. Battery manufacturing in the US and Europe have higher costs due to higher energy, equipment, land and labor costs compared to Asia, where most batteries are currently produced. Local policies such as the $45/kWh production tax credit for cells and packs under the Inflation Reduction Act in the US could offset part of the cost, although the IRA’s impact on pricing is not yet clear.

Continued investment in R&D, manufacturing process improvements, and capacity expansion across the supply chain will help improve battery technology and reduce costs over the next decade. BloombergNEF expects next-generation technologies, such as silicon and lithium metal anodes, solid-state electrolytes, new cathode material, and new cell manufacturing processes to play an important role in enabling further price reductions.

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EIA, Battery Storage in the United States: An Update on Market Trends (2023 Early Release Battery Storage Figures)
https://www.eia.gov/analysis/studies/electricity/batterystorage/

Battery Energy Storage Report Figure Data: June 2023

2022 Early Release

Figure 1a. Large-scale battery storage capacity additions by region (2010–2022)

Annual Additions

Power Capacity

Megawatts (MW)

	PJM	CISO	ERCO	MISO	ISNE	SWPP	NYIS	AK and HI	Other CA	Other	Other with	cumulative capacity
2003	0	0	0	0	0	0	3	40	0	0	0	43
2004	0	0	0	0	0	0	0	0	0	0	0	43
2005	0	0	0	0	0	0	0	0	0	0	0	43
2006	0	0	0	0	0	0	0	0	0	0	0	43
2007	0	0	0	0	0	0	0	0	0	0	0	43
2008	0	0	0	0	0	0	0	0	0	0	0	43
2009	4	0	0	0	0	0	0	0	0	0	0	47
2010	0	0	4	0	0	0	0	0	0	0	0	51
2011	16	0	0	0	0	0	0	15	0	0.8	0.8	82.8
2012	0	4	36	0	0	1	0	24	0	1.8	2.8	149.6
2013	4.5	6	0	1.1	0	0	0	0	0	5	5	151.2
2014	24	2	0	0	0	0	0	1.5	0	1.2	1.2	179.9
2015	136.6	5.5	0	0	2	0	0	7.2	0	2	2	333.2
2016	54.2	74.4	1	20.5	17.5	0	0	1	30	3	3	534.8
2017	1	43.5	32	0.3	3.8	1.2	1	15	2	24.4	25.6	659
2018	40.8	52.1	21.3	17.2	4	0.8	7	20	20	39.2	40	878.7
2019	20.4	17.3	19.9	6	42.3	12	45	1	1.5	25.5	37.5	1066.7
2020	0	283.3	108.9	10.3	55.9	11.5	14.1	0	0	12	23.5	1559.3
2021	18.2	1946.1	569.3	2.8	109.2	1.4	20.5	15.9	0	703.3	704.7	4935.5
2022	12	2262.3	1294.9	16.3	70.7	0	22.7	85.5	0	193.8	193.8	8827.1

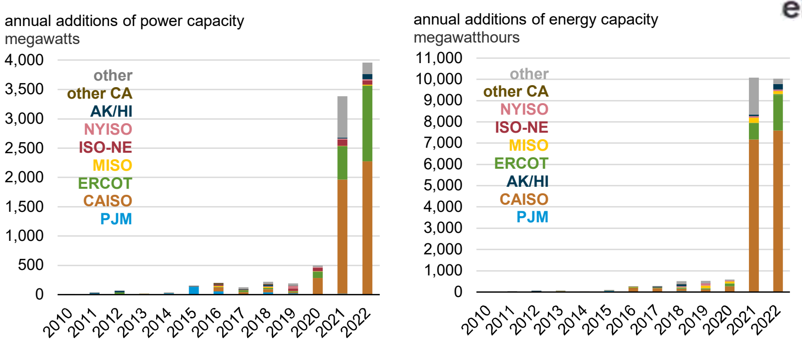
Annual Additions (MWh)

Energy Capacity

Megawatthours (MWh)

	PJM	CISO	ERCO	MISO	ISNE	SWPP	NYIS	AK and HI	Other CA	Other	Other with	cumulative capacity
2003	0	0	0	0	0	0	3	11	0	0	0	14
2004	0	0	0	0	0	0	0	0	0	0	0	14
2005	0	0	0	0	0	0	0	0	0	0	0	14
2006	0	0	0	0	0	0	0	0	0	0	0	14
2007	0	0	0	0	0	0	0	0	0	0	0	14
2008	0	0	0	0	0	0	0	0	0	0	0	14
2009	4	0	0	0	0	0	0	0	0	0	0	18
2010	0	0	4	0	0	0	0	0	0	0	0	22
2011	16	0	0	0	0	0	0	15	0	1.3	1.3	54.3
2012	0	13.8	13.6	0	0	1	0	27.4	0	8.3	9.3	118.4
2013	1	42	0	7.6	0	0	0	0	0	5	5	159
2014	10.3	6	0	0	0	0	0	1	0	3.2	3.2	179.5
2015	60.7	10.5	0	0	3.4	0	0	5.6	0	2.5	2.5	262.2
2016	33.3	165.9	0.3	20.5	13.9	0	0	0.3	20	4.9	4.9	521.3
2017	1	180	13.3	0.5	8.2	1.5	1.3	54	1	16.7	18.2	798.8
2018	40.8	109.7	22.8	35	10.2	0.8	44.2	100	10	133.5	134.3	1301.6
2019	21.9	96.8	52	9.6	120.9	26.2	108.4	0.9	1.5	84.3	110.5	1808.2
2020	0	269.8	125.6	10.6	92.8	23	38.3	0	0	18.2	41.2	2378.2
2021	22.4	7156.8	767.1	3.4	255.5	6	69.2	71.9	0	1730.5	1736.5	12413.5
2022	28.9	7561.3	1684.4	43.4	134.1	0	78.1	249	0	261.1	261.1	22385.1

Figure 1a. Large-scale battery storage capacity additions by region (2010–2022)



Data source: U.S. Energy Information Administration, *2022 Form EIA-860 Early Release, Annual Electric Generator Report*

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Eastern U.S. Region Non-Speculative Resources

State	Proved Reserves (2021, Bcf)	Annual Production (2022, MMcf)
Alabama	1,333	95,790
Arkansas	6,087	416,196
Connecticut	0	0
Delaware	0	0
Florida	0	8,433
Georgia	0	0
Illinois	0	2,003
Indiana	0	3,836
Iowa	0	0
Kansas	2,406	147,846
Kentucky	1,345	85,513
Louisiana	40,008	4,070,087
Maryland	0	5
Massachusetts	0	0
Michigan	1,165	69,542
Minnesota	0	0
Mississippi	246	28,493
Missouri	0	0
Nebraska	0	295
New Hampshire	0	0
New Jersey	0	0
New Mexico (East) ***	24,870	1,865,509
New York	92	9,734
North Carolina	0	0
Ohio	32,247	2,244,971
Oklahoma	39,488	2,764,019
Pennsylvania	106,963	7,511,179
Rhode Island	0	0
South Carolina	0	0
Tennessee	0	3,016
Texas	149,062	11,602,524
Vermont	0	0
Virginia	2,094	89,009
West Virginia	46,938	2,920,613
Wisconsin	0	0
Subtotal	**454,344**	**33,938,613**

Potential Gas Committee Area and Type (Bcf):	Probable	Possible	Total
Atlantic: Conventional, Tight, Shale	449,060	512,540	961,600
Atlantic: Coalbed Gas Resources	1,345	12,600	13,945
North Central: Conventional, Tight, Shale	1,920	3,470	5,390
North Central: Coalbed Gas Resources	410	1,440	1,850
Mid-Continent: Conventional, Tight, Shale	181,350	283,860	465,210
Mid-Continent: Coalbed Gas Resources	230	470	700
Gulf Coast: Conventional, Tight, Shale	128,105	173,660	301,765
Gulf Coast: Coalbed Gas Resources	0	0	0
	762,420	988,040	1,750,460
Total Proved + Probable + Possible:	2,204,804		

Sources: Proven reserve and annual production data is from the U.S. Energy Information Administration (last visited March 2024) (https://www.eia.gov/dnav/ng/ng_enr_wals_a_EPG0_R21_Bcf_a.htm an https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm). Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee, 2023.

* Natural Gas Proved Reserves, Wet After Lease Separation. PGC Report at 17 states "wet gas from EIA is … similar to the total gas assessed by the PGC."

** Production represents gross withdrawals.

*** New Mexico (East) is estimated by multiplying New Mexico Production by the ratio of New Mexico (East) Proven Resources/New Mexico Total Proven Resources.