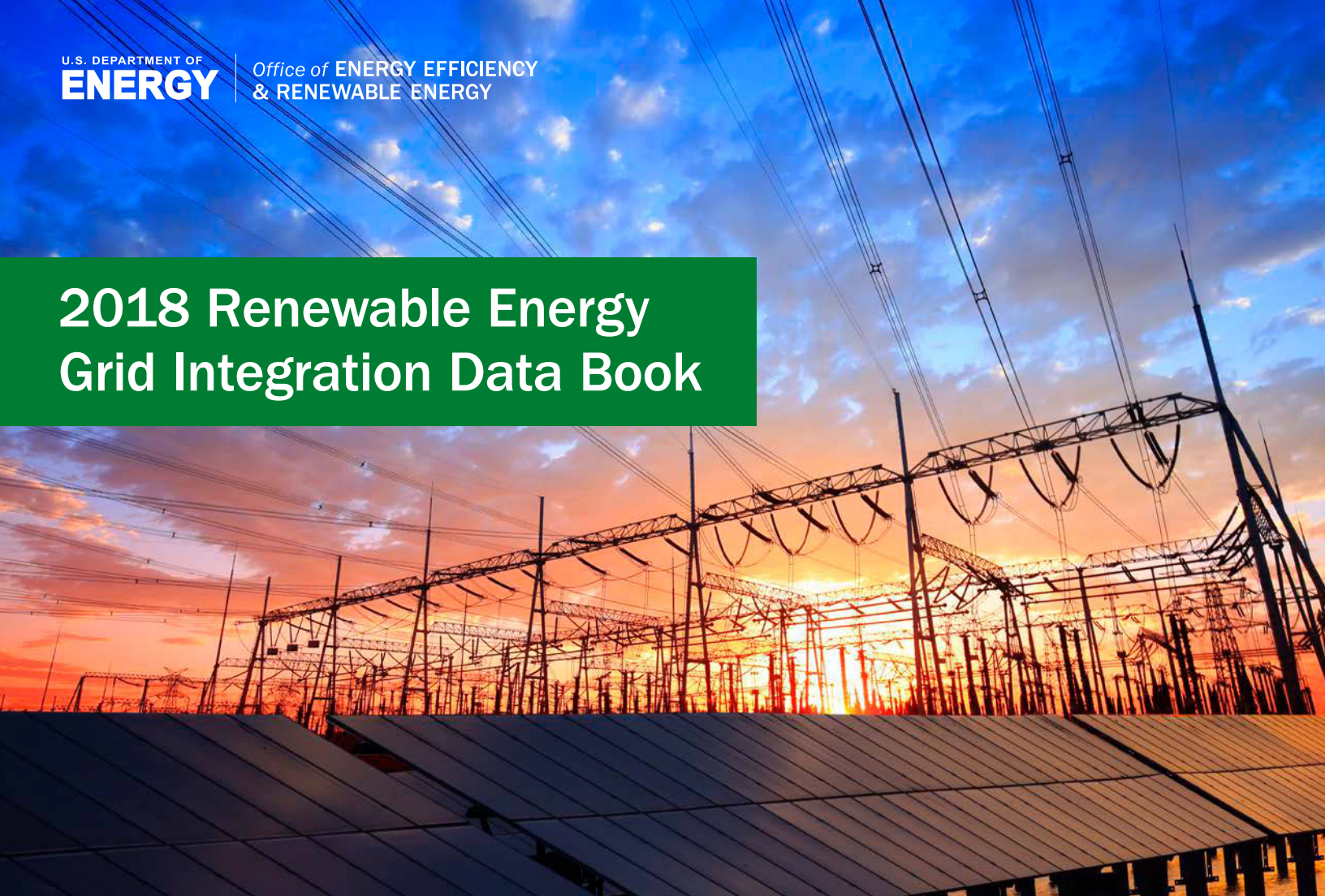
U.S. DEPARTMENT OF ENERGY | Office of ENERGY EFFICIENCY & RENEWABLE ENERGY

2018 Renewable Energy Grid Integration Data Book



Acknowledgments

This data book was produced by Yinong Sun,[1] Sadanand Wachche,[1] Andrew Mills,[2] and Ookie Ma;[3] edited by Mike Meshek; and designed by Stacy Buchanan, Al Hicks, and Billy Roberts of the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). We thank Sai Sameera Gudladona, Kelly Eurek (NREL), Dev Millstein, Seongeun Jeong, Mark Bolinger, Jo Seel of the Lawrence Berkeley National Laboratory (LBNL), and Emily Chen (Princeton University) for contributing data. We greatly appreciate the input, review, and support of Sam Baldwin, Samuel Bockenhauer, Cynthia Bothwell, Abraham Ellis, Patrick Gilman, Kevin Lynn, Sean Porse and Richard Tusing, of the U.S. Department of Energy (DOE), as well as Doug Arent, Murali Baggu, Philipp Beiter, Wesley Cole, Paul Denholm, Mark O'Malley, Barbara O'Neill, Trieu Mai, Gian Porro, and Rich Tusing of NREL. We also thank Lori Bird (World Resources Institute), Kevin Porter (Exeter Associates), Nina Vincent (University of Washington), and Chris Namovicz of the U.S. Energy Information Administration.

Front page photo: iStock 1035403678.

[1] National Renewable Energy Laboratory
[2] Lawrence Berkeley National Laboratory
[3] U.S. Department of Energy

Overview

- The ***2018 Renewable Energy Grid Integration Data Book*** identifies the status and key trends of renewable energy grid integration in a highly visual format.
- This biennial data book is intended to provide an overview of selected grid integration metrics that reflect recent changes to the operation and composition of the power system as variable renewable energy (VRE) sources increase their shares of electricity supply.
- These grid integration metrics indicate how much VRE is currently being integrated onto the grid and highlight factors that may increase or decrease the challenges associated with integrating VRE generation onto the grid.
- The data and content presented focus on 2018. Some historical data and content are included to provide context for the broader electric sector and market environment for VRE integration.
- Any causal inferences should be considered carefully. This publication does not consider the full set of integration issues. Some literature recommendations for further consideration of these topics are provided on page 115.

Key Findings

	Installed Cumulative Capacity of Renewable[1] Energy as a Percentage of Total Generation Capacity (2018)	Annual Average Renewable Energy Generation as a Percentage of Total Generation (2018)
CAISO[2]	42.2% (30.6 gigawatts [GW][3])	39.2% (85.8 terawatt-hours [TWh])
ERCOT[4]	24.1% (24.8 GW)	18.3% (74.0 TWh)
FRCC[5]	4.6% (2.4 GW)	3.6% (8.4 TWh)
ISO-NE[6]	18.4% (5.9 GW)	19.6% (20.6 TWh)
MISO[7]	14.2% (24.2 GW)	10.6% (74.5 TWh)
NYISO[8]	17.9% (7.3 GW)	26.8% (37.2 TWh)
PJM[9]	8.4% (17.0 GW)	6.0% (50.4 TWh)
SERC[10]	12.1% (20.2 GW)	8.8% (62.2 TWh)
SPP[11]	29.9% (24.9 GW)	28.3% (85.0 TWh)
WECC[12]	45.7% (63.7 GW)	42.3% (213.1 TWh)
Contiguous United States	20.8% (221.1 GW)	17.1% (711.3 TWh)

[1] Renewables include utility-scale (i.e., > 1-MW) generation from hydropower, land-based wind, offshore wind, solar photovoltaics (PV), concentrating solar power (CSP), biomass/municipal solid waste/landfill gas, and geothermal. For the purposes of this data book, capacity is reported as summer capacity (see the glossary), unless indicated otherwise.

[2] California Independent System Operator (CAISO); Regions depicted here are shown in page 17

[3] GW = gigawatts

[4] Electric Reliability Council of Texas (ERCOT)

[5] Florida Reliability Coordinating Council (FRCC)

[6] ISO New England (ISO-NE)

[7] Midcontinent Independent System Operator (MISO)

[8] New York Independent System Operator (NYISO)

[9] PJM Interconnection (PJM)

[10] SERC Reliability Corporation (SERC)

[11] Southwest Power Pool (SPP)

[12] Western Electricity Coordinating Council (WECC). Here, WECC refers to non-CAISO WECC. Though it is reported separately in this data book, CAISO is formally part of WECC. Regional aggregation might differ when reporting different metrics in this data book

Sources: EIA (Form EIA-860); S&P Global Market Intelligence database

Note: Regions are listed alphabetically.

Key Findings (continued)

	Installed Cumulative Capacity of Variable Renewable Energy (VRE)[1] as a Percentage of Total Generation Capacity (2018)	Annual Average VRE Generation as a Percentage of Total Generation (2018)
CAISO	29.1% (21.1 GW)	22.6% (49.5 TWh)
ERCOT	23.4% (24.1 GW)	17.9% (72.7 TWh)
FRCC	2.4% (1.3 GW)	0.9% (2.1 TWh)
ISO-NE	7.5% (2.4 GW)	4.6% (4.8 TWh)
MISO	11.5% (19.6 GW)	7.6% (53.1 TWh)
NYISO	5.3% (2.2 GW)	3.1% (4.3 TWh)
PJM	5.6% (11.4 GW)	3.1% (25.8 TWh)
SERC	3.3% (5.5 GW)	1.4% (9.5 TWh)
SPP	24.1% (20.0 GW)	22.6% (68.0 TWh)
WECC	13.1% (18.2 GW)	9.1% (45.6 TWh)
Contiguous United States	11.8% (125.8 GW)	8.1% (335.5 TWh)

[1] For the purposes of this data book, variable renewable energy (VRE) is defined to include utility-scale (i.e., > 1-MW) wind, solar PV, and CSP. See the glossary for a definition of VRE. Note that CSP in combination with storage may not be considered a VRE generation source.

Sources: Form EIA-923 (www.eia.gov/electricity/data/eia923); S&P Global Market Intelligence database

Note: Regions are listed alphabetically

Key Findings (continued)

- Among all ISO/RTO regions, the **annual average VRE penetration** as a fraction of total generation in 2018 was led by SPP (22.6%), CAISO (22.6%), and ERCOT (17.9%). Wind was the dominant source in SPP (98.8% of all VRE generation) and ERCOT (95.5% of all VRE generation), and solar was the dominant source in CAISO (53.0% PV and 5.0% CSP of all VRE generation).

- In 2018, **maximum hourly penetration**[1] **of utility-scale wind and solar generation**[2] reached nearly 62.6% in CAISO (on April 28 when it consisted of 43.1% solar and 19.5% wind), 62.5% in SPP (on April 29, with all generation from wind), and 54.3% in ERCOT (on December 27, with all generation from wind). The highest levels of hourly wind penetration after SPP and ERCOT were 23.6% in MISO (on March 31), 23.0% in CAISO (on April 1), 11.8% in NYISO (on December 29), 10.7% in ISO-NE (on October 16), and 10.1% in PJM (on May 2).

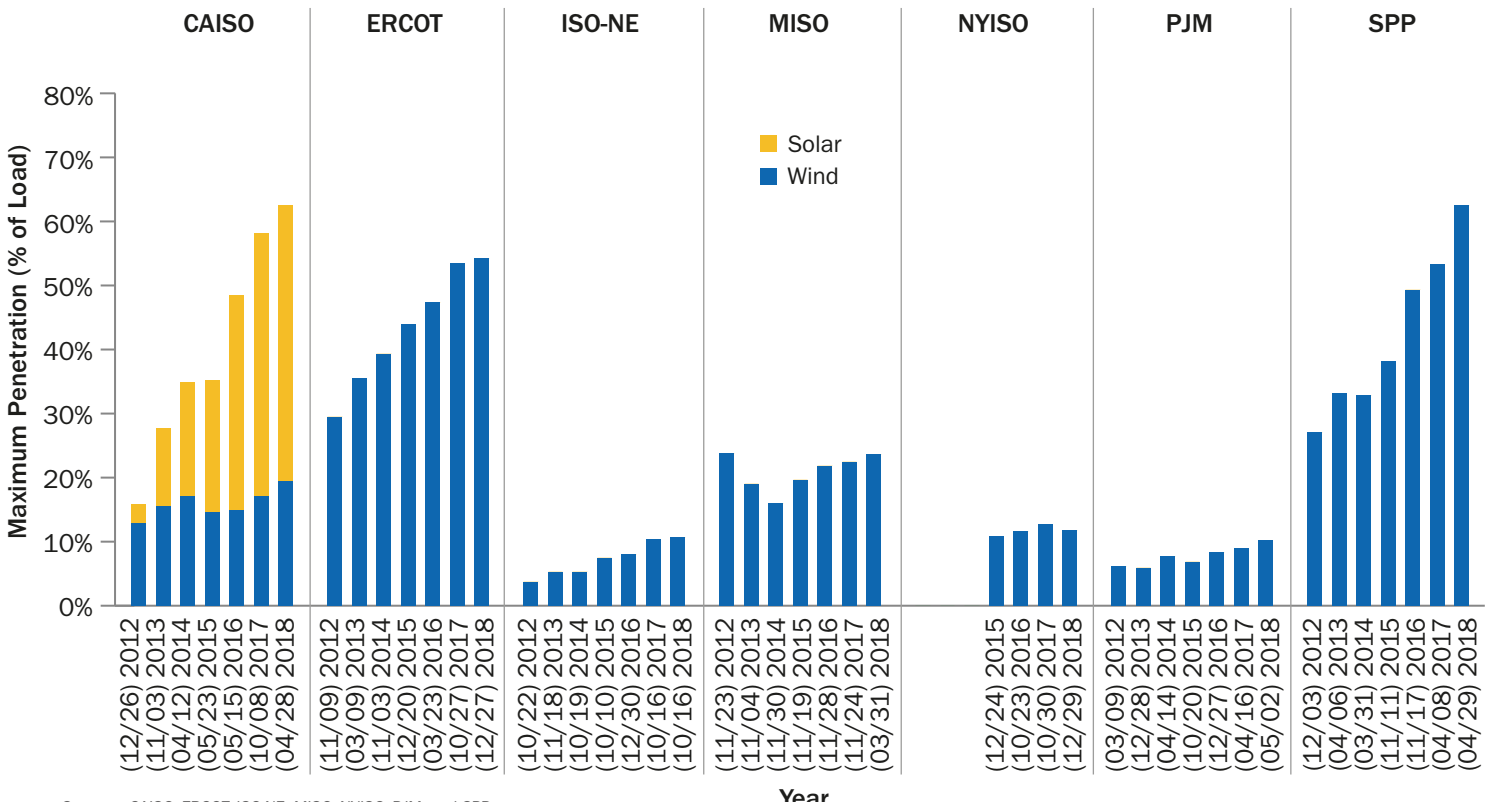
- The **largest 2018 three-hour ramping event** occurred in MISO at 36.2 GW on July 9 (i.e., 0.14% of summer capacity per minute), followed by PJM at 30.0 GW on September 3 (0.09% per minute), CAISO at 19.3 GW on September 6 (0.63% per minute), ERCOT at 17.3 GW on July 22 (0.13% per minute), and SPP at 10.4 GW on April 29 (0.09% per minute).

[1] Maximum hourly penetration refers to the maximum observed ratio of generation from a (set of) generation sources to load over a defined period (commonly a year) during a one hour time interval. Use of more-resolved five-minute market data can result in different values; for example, the maximum five-minute penetration of wind and solar (as a percentage of load) in SPP occurred on April 30 in 2018 (see page 64).

[2] Solar includes solar PV and CSP. Data for behind-the-meter generation, covering the majority of distributed solar PV, is not included due to limited data availability.

Note: Some data and content are included to provide context for the broader electric sector and market environment for renewable energy integration.

Maximum Hourly Penetration of Solar and Wind in Market Regions



Sources: CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: Solar includes solar PV and CSP. Data availability for NYISO before 2016 is limited.

Key Findings (continued)

- In 2018, **reserve margin levels** remained above the NERC-recommended levels in all regions except the ERCOT market. In ERCOT, the 2018 reserve margin level was 10.9%, which is below the region-specific reference margin level of 13.8%.

- In 2018, the **median hourly day-ahead overprediction forecast error**[1] (i.e., actual generation was less than the DA market forecast) of wind was 7.1% in MISO and 4.4% in ERCOT. The **median hourly day-ahead underprediction forecast error** (i.e., actual generation was greater than the forecast) of wind was 7.5% in MISO and 3.9% in ERCOT.

- From 2012 to 2018, **average hourly overprediction forecast errors of wind** generally decreased in ERCOT, from 7.5% in 2012 to 5.6% in 2018. In MISO, the forecast errors increased from 5.5% in 2014 to 9.8% in 2018. And in SPP, they increased from 5.6% in 2014 to 6.1% in 2017. **Average hourly underprediction forecast errors of wind** generally decreased in ERCOT from 7.6% in 2012 to 5.0% in 2018, while they increased in MISO (from 4.5% in 2012 to 9.4% in 2018), and in SPP (from 4.2% in 2012 to 4.9% in 2017).

- The **highest annual average wind curtailment rate** were observed in 2018 in MISO (4.2%), followed by ISO-NE (2.7%), ERCOT (2.5%), NYISO (1.7%), SPP (1.3%), and PJM and CAISO (0.5%).

[1] Forecast error was calculated as the absolute value of the hourly difference between actual and forecasted wind generation over total installed wind capacity.

Note: Some data and content are included to provide context for the broader electric sector and market environment for renewable energy integration.

Key Findings (continued)

- In CAISO, **average annual curtailment levels of solar photovoltaics (PV)** increased from 0.8% of its total generation in 2015 to 1.5% in 2018, as solar penetration increased from 7.3% in 2015 to 13.1% in 2018. ERCOT had over 8% of solar PV curtailment in 2018.

- In 2018, 2.1% of hours saw **negative pricing**[1] **of average hourly**[2] **locational marginal price** (LMP) in the real-time in CAISO market, followed by ISO-NE and SPP (1.1%), ERCOT and NYISO (0.3%), PJM (0.1%), and MISO (0.0%).[3] During those periods, average load was low at 45.1 GW in CAISO (compared to the average load of 53.3 GW across 8,760 hours in 2018), 10.8 GW in ISO-NE (compared to 13.6 GW), 25.4 GW in SPP (compared 31.0 GW), and 30.6 GW in ERCOT (compared to 42.0 GW). VRE penetration during those hours was high at 48.0% in CAISO (compared to annual average hourly penetration of 19.4%), 50.0% in SPP (compared to 25.0%), 3.9% in ISO-NE (compared to 3.1%), and 39.8% in ERCOT (compared to 20.5%). However, the magnitude of negative prices was small, lowering annual average LMPs by about $3/MWh (around 10% of annual average hourly LMPs in each region).

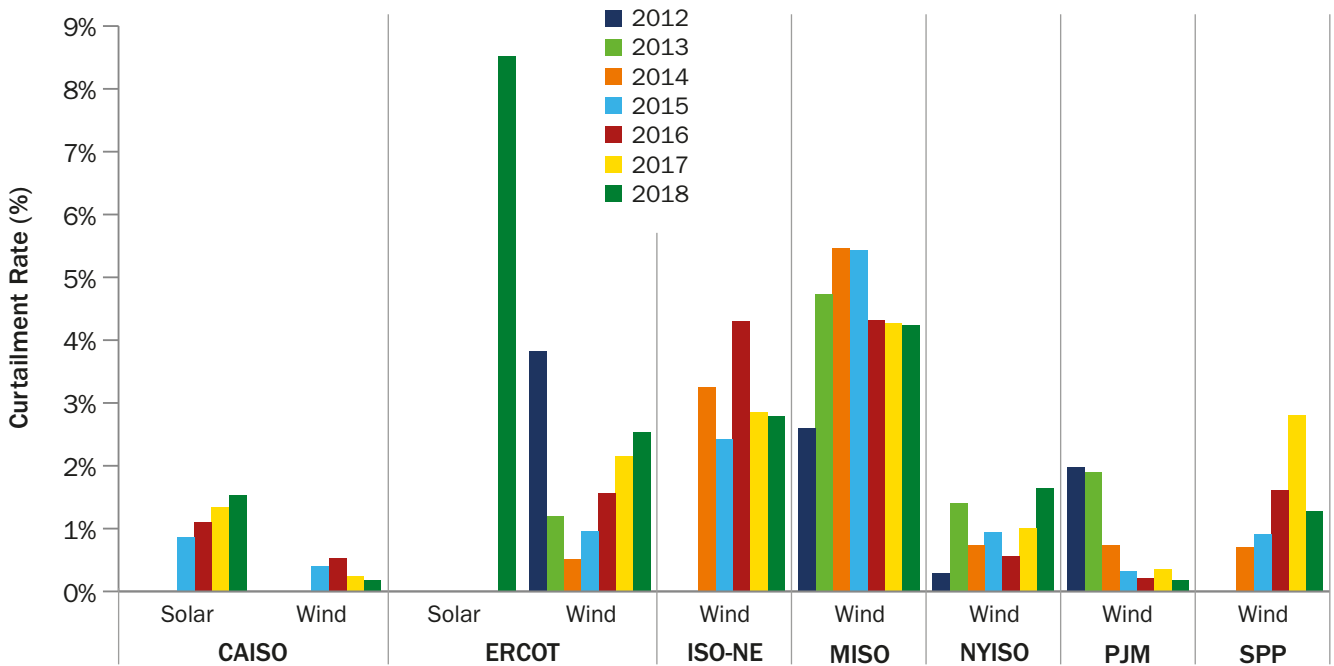
[1] Negative LMP can be the result of a complex interaction among economic, reliability, environmental, safety and incentive scheme factors.

[2] For calculation of average hourly locational marginal price, please see the Methodology and Data Sources section.

[3] For the purposes of this data book, real-time LMP is presented in terms of hourly (load-weighted) averages. Subhourly (e.g., five-minute) negative pricing may occur more frequently. However, five-minute-interval negative LMP pricing may be less frequent as a fraction of five-minute intervals.

Note: Some data and content are included to provide context for the broader electric sector and market environment for renewable energy integration.

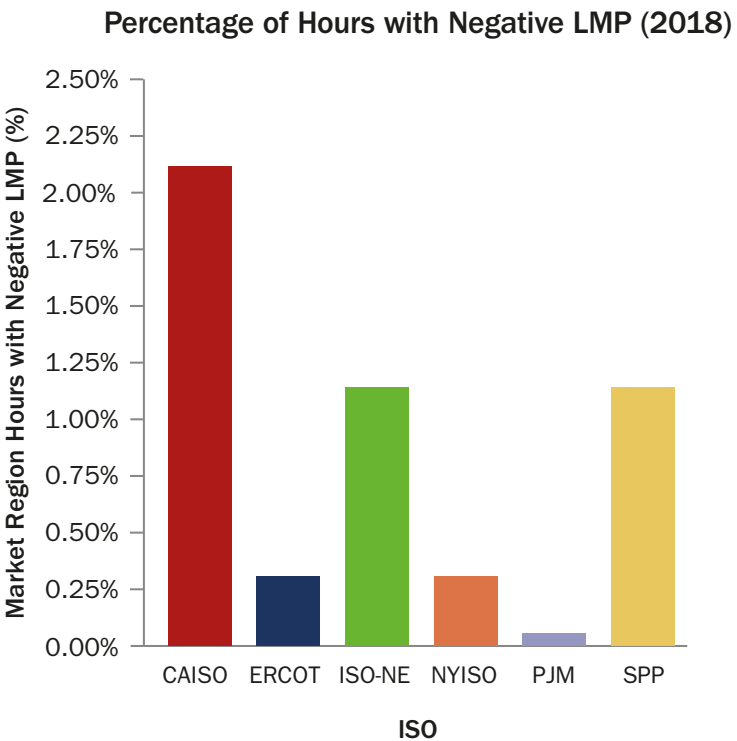
Annual Average Curtailment Rates (2018)

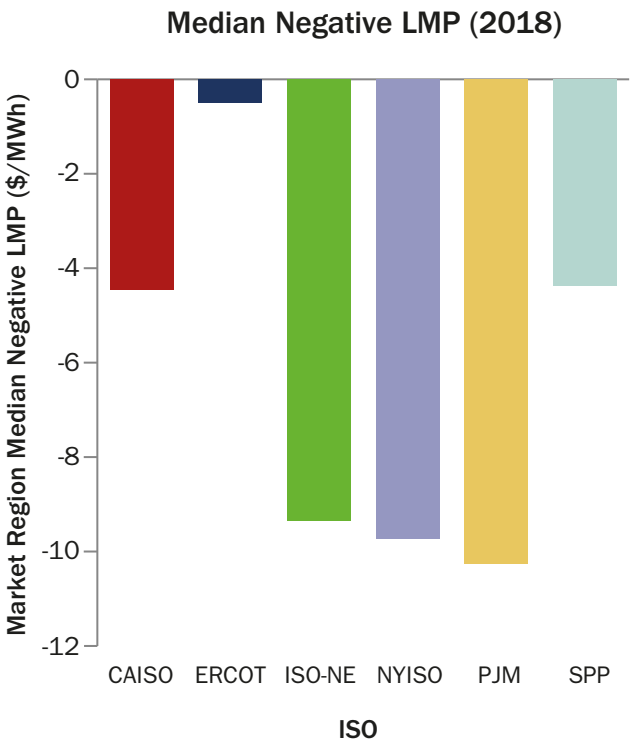


Sources: Curtailment data were collected from ISOs and reported in Wiser and Bolinger (2019) and Bolinger, Seel, and Robson (2019).

Note: The depicted data include both "forced" (i.e., ISO-instructed) and "economic" (i.e., incentivized by prevailing LMP) curtailment. Solar curtailment data availability for ERCOT before 2018 are limited.

Key Findings (continued)





Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" (at zonal hub level) reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: LMP data are reported here as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled up) from zonal price nodes in the RT market.

Table of Contents

I. Methodology and Data Sources

Methodology and Data Sources

- The data depicted in this data book are specific to the United States and were derived from a combination of sources, including:
  - Federal Energy Regulatory Commission (FERC)
  - U.S. Energy Information Administration (EIA)
  - Independent system operators (ISOs) and regional transmission organizations (RTOs), including:
    - California Independent System Operator (CAISO)
    - Electric Reliability Council of Texas (ERCOT)
    - ISO New England (ISO-NE)
    - Midcontinent Independent System Operator (MISO)
    - New York ISO (NYISO)
    - PJM Interconnection (PJM)
    - Southwest Power Pool (SPP)
  - U.S. Department of Energy (DOE).

Methodology and Data Sources (continued)

I

- For transmission investments and operational reliability requirements, data are also shown for North American Electric Reliability Corporation (NERC) regions and subregions, including the Florida Reliability Coordinating Council (FRCC), the Midwest Reliability Organization (MRO), the Northeast Power Coordinating Council (NPCC), Reliability First, the SERC Reliability Corporation (SERC), SPP, the Texas Reliability Entity (TRE), and the Western Electricity Coordinating Council (WECC).
- Data were accessed through the ABB Ability Velocity Suite[1] or directly from the sources listed above. The primary data represented and synthesized in the ***2018 Renewable Energy Grid Integration Data Book*** come from the publicly available data sources identified on pages 117-123.
- Metrics, when available, are reported here for ISO/RTO service territory areas and for areas without centrally organized wholesale electricity markets (referred to herein as non-ISO/RTO regions).
- The types of metrics included are expected to evolve as additional detailed information and data become available.
- Locational marginal price (LMP) data are reported here from the real-time (RT) markets. Generally, RT and day-ahead (DA) LMPs tend to be highly correlated on an annual basis. The focus on RT LMP was chosen because impacts of VRE are arguably observed more readily in this market segment.[2]

[1] "ABB Ability Velocity Suite," ABB, https://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite.

[2] Wiser et al. 2017

Methodology and Data Sources (continued)

I

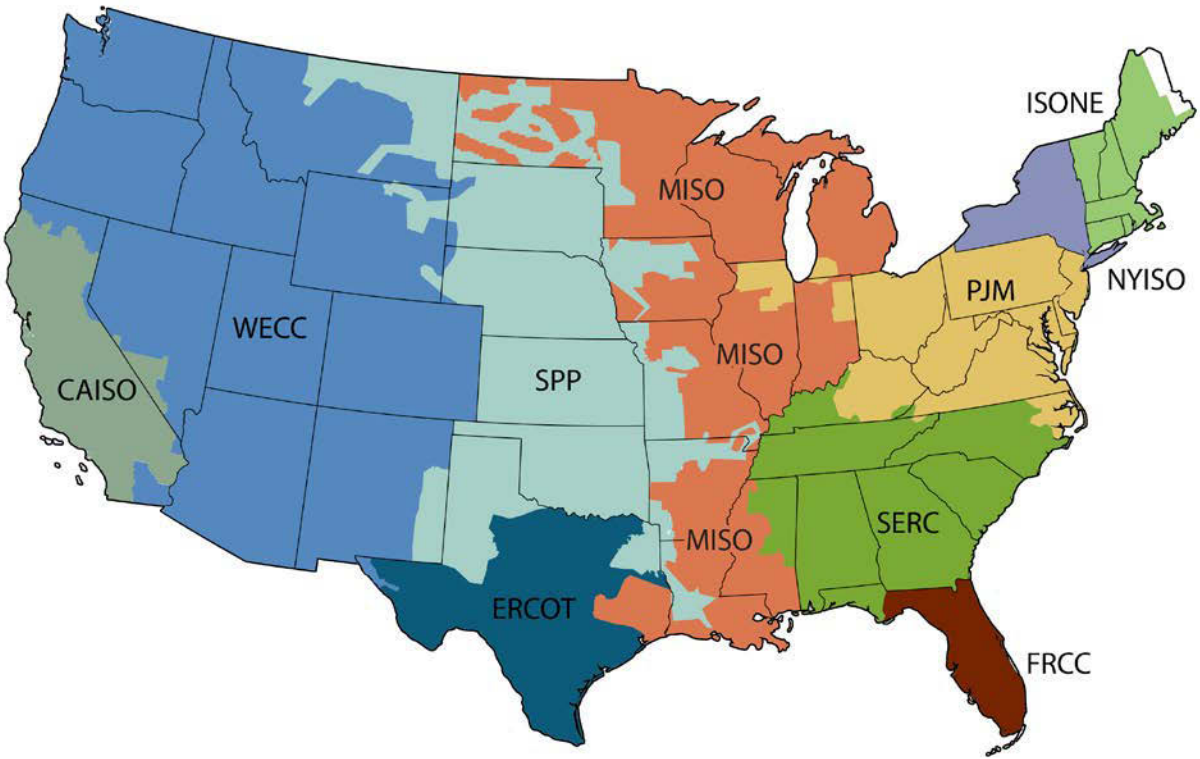
- Zonal prices are hourly (load-weighted) averages in ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP. Zonal LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data. Nodal price map data are hourly (time-weighted) averages in ISO-NE, MISO, NYISO, PJM. Nodal LMP data for CASIO, ERCOT, and SPP are reported as hourly (time-weighted) averages of five-minute data.
- The congestion component of LMP data are reported here as hourly (load-weighted) averages from zonal price nodes in the RT market (ISO-NE, MISO, PJM, and NYISO). These data for CAISO, ERCOT, and SPP are reported as hourly (load-weighted) averages of five-minute data from zonal price nodes in the RT market.
- Data are reported here in watts (typically megawatts [MW] and gigawatts [GW]) of alternating current (AC), unless indicated otherwise. Data reported from Form EIA-860 only include plants with 1 MW or greater of combined nameplate capacity.
- Unless specified, data for behind-the-meter generation, covering the majority of distributed solar PV, are not included in the data for solar PV capacity, generation, and load due to limited data availability.
- Storage does not include behind-the-meter storage.

Note: Data on the following pages are summarized for the regions depicted here. The footprint of these regions was developed based on 2017 ISO/RTO regions and NERC regions for non-RTO/ISO regions. The energy imbalance market (EIM) is not shown because data are presented separately for WECC and CAISO; though it is reported separately in this data book, CAISO is formally part of WECC.

ISO/RTO and NERC Regions Used in this Data Book

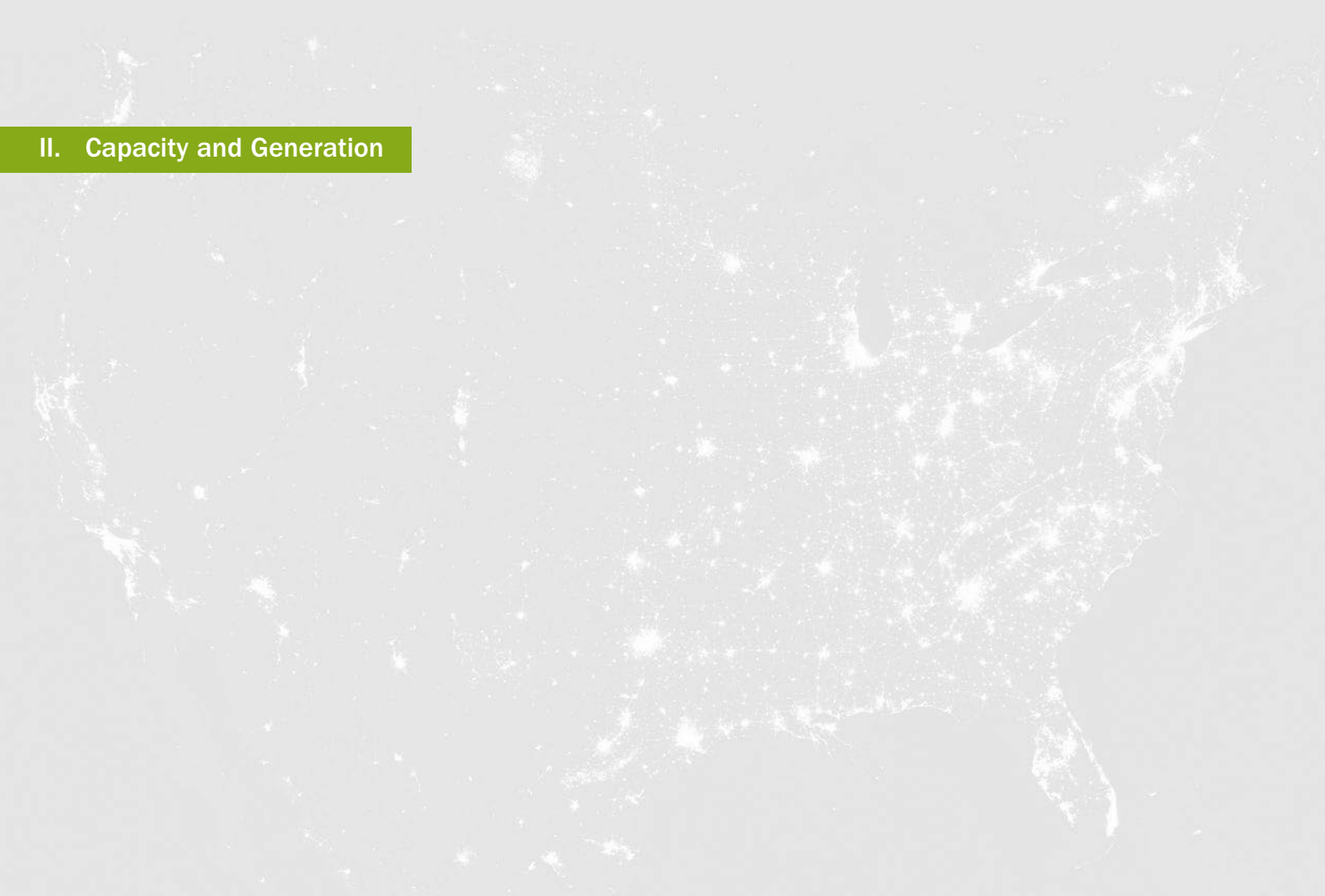
I

ISO/RTO and NERC Regions



Note: Data on the following pages are summarized for the regions depicted here. The footprint of these regions was developed based on 2018 ISO/RTO regions and NERC regions for non-RTO/ISO regions. The EIM is not shown because data are presented separately for WECC and CAISO; though it is reported separately in this data book, CAISO is formally part of WECC.

II. Capacity and Generation



Capacity and Generation: Summary

II

- In 2018, renewable[1] cumulative installed capacities' share of total generation capacity was 45.7% (63.7 GW) in WECC, 42.2% (30.6 GW) in CAISO, 29.9% (24.9 GW) in SPP, 24.1% (24.8 GW) in ERCOT, 18.4% (5.9 GW) in ISO-NE, 17.9% (7.3 GW) in NYISO, 14.2% (24.2 GW) in MISO, 12.1% (20.2 GW) in SERC, 8.4% (17.0 GW) in PJM, and 4.6% (2.4 GW) in FRCC.
- The combined installed capacity of wind and solar[2] as a percentage of total generation capacity in 2018 was 29.1% (21.1 GW) in CAISO, 24.1% (20.0 GW) in SPP, 23.4% (24.1 GW) in ERCOT, 13.1% (18.2 GW) in WECC, 11.5% (19.6 GW) in MISO, 7.5% (2.4 GW) in ISO-NE, 5.6% (11.4 GW) in PJM, 5.3% (2.2 GW) in NYISO, 3.3% (5.5 GW) in SERC, and 2.4% (1.3 GW) in FRCC.
- Across market regions, net capacity additions in 2018 were led by natural gas combined cycle (+19.0 GW), followed by wind (+6.8 GW), solar (+4.9 GW), natural gas combustion turbine (+1.4 GW), storage (+0.2 GW),[3] hydropower (+0.1 GW), geothermal (-0.0 GW), nuclear (-0.2 GW), biomass/municipal solid waste/landfill gas (-0.3 GW), oil-gas-steam (-5.8 GW), and coal (-12.5 GW).
- Solar PV installed capacity grew across all ISO/RTO market regions. In CAISO, installed capacity of utility-scale solar PV grew by 9.8% (+1.0 GW), from 10.1 GW in 2017 to 11.1 GW in 2018.

[1] Renewables include utility-scale (i.e., > 1 MW) generation from hydropower, land-based wind, offshore wind, solar PV, CSP, biomass/municipal solid waste/landfill gas, and geothermal.

[2] Solar includes only utility-scale (i.e., > 1-MW) solar PV and CSP. Solar capacity data are reported in AC.

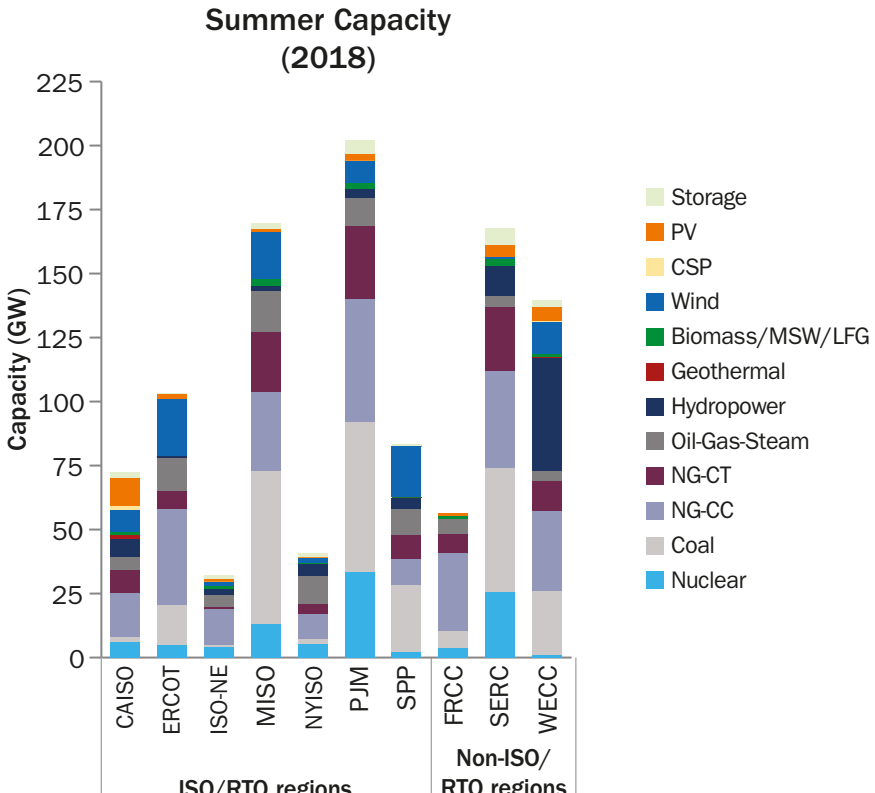
[3] Reported storage capacity only include utility-scale (i.e., > 1-MW) storage.

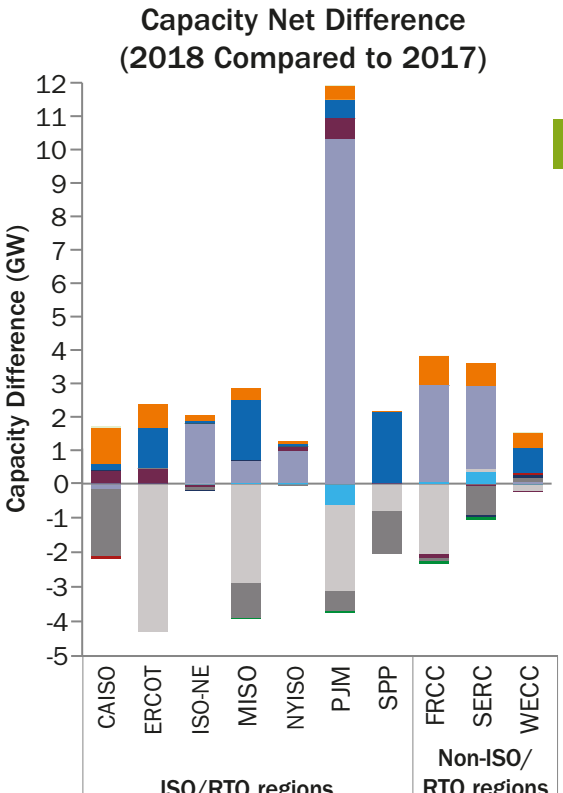
Capacity and Generation: Summary (continued)

II

- CAISO's installed capacity of solar PV was more than twice the amount in the other ISO/RTO markets combined, and grew by 9,991 MW in 2018. However, solar PV growth rates were higher in several other market regions, including:
  - FRCC: +876 MW (+222.5%)
  - ERCOT: +709 MW (+57.8%)
  - NYISO: +94 MW (+56.2%)
  - MISO: +356 MW (+41.5%)
  - ISO-NE: +175 MW (+22.6%)
  - PJM: +430 MW (+19.9%)
  - SERC: +668 MW (+15.4%).
- Installed wind capacity in 2018 grew by 12.1% (+2.1 GW) in SPP to a total of 19.7 GW, by 11.0% (+1.8 GW) in MISO to a total of 18.4 GW, and by 6.7% (+0.6 GW) in PJM to a total of 8.8 GW.
- Natural gas combined cycle net additions were largest in PJM with 10.3 GW (+27.3%) in 2018.
- Installed coal capacity declined by 4.3 GW (-21.6%) in ERCOT, 3.9 GW (-6.4%) in PJM, 2.7 GW (-4.4%) in MISO, 2.0 GW (-23.1%) in FRCC, and 0.8 GW (-2.8%) in SPP in 2018. Oil-gas-steam capacity of 1.9 GW (-26.9%) was retired in CAISO, followed by 1.3 GW (11.3%) in SPP, and 1.0 GW (6.0%) in MISO in 2018.

Capacity



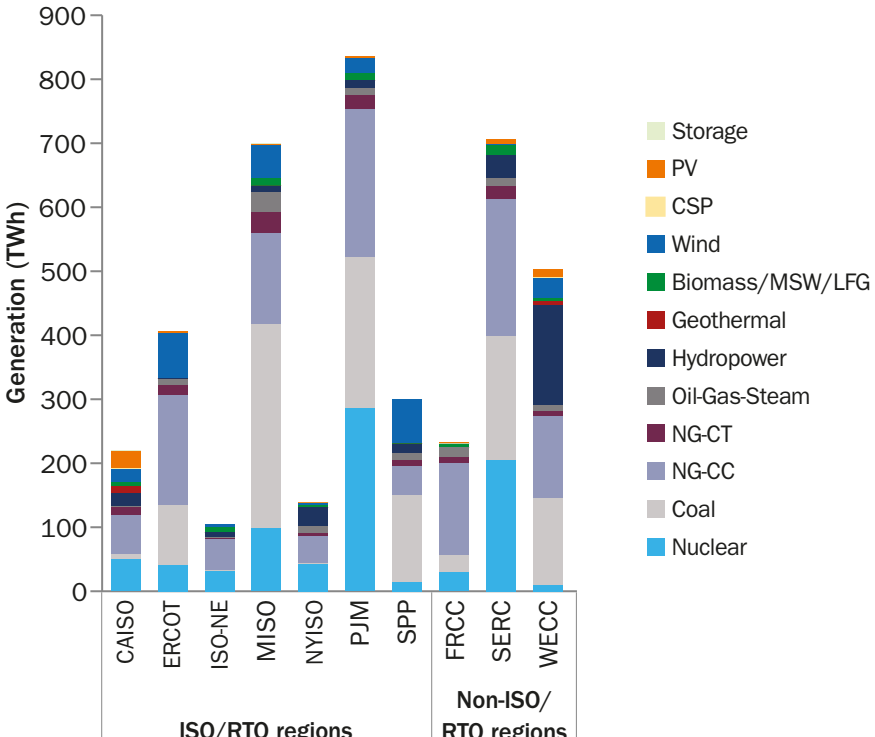


II

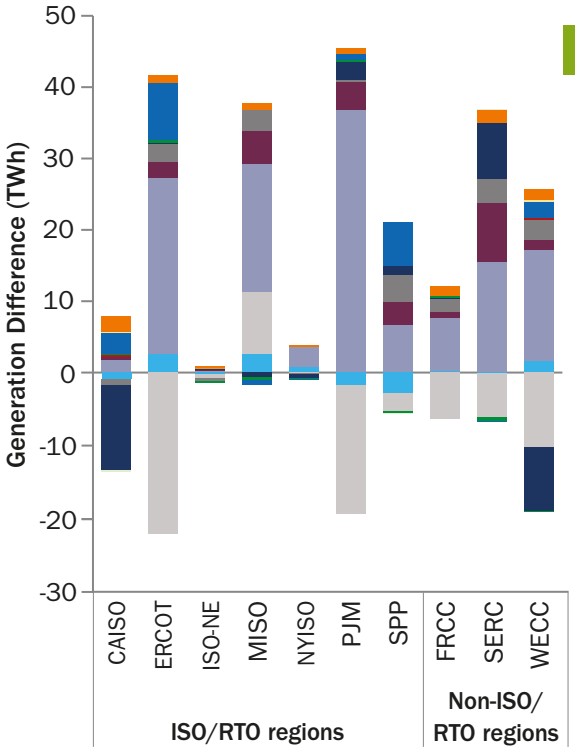
Sources: EIA (Form EIA-860); S&P Global Market Intelligence database

Notes: See the glossary for a definition of "summer capacity." Wind includes offshore wind. "Other" generation sources are excluded. Storage includes pumped hydropower, battery storage, and compressed air energy storage. WECC excludes CAISO. SERC excludes FRCC, MISO, PJM, and SPP. Data are only for generators with a capacity of more than 1 MW.

Annual Generation (2018)



Generation Net Difference (2018 Compared to 2017)



Sources: EIA (Form EIA-923); S&P Global Market Intelligence database

Notes: Wind includes offshore wind. "Other" generation sources are excluded. Storage includes pumped hydropower, battery storage, and compressed air energy storage. WECC excludes CAISO. SERC excludes FRCC, MISO, PJM, and SPP. Data are only for generators with a capacity of more than 1 MW.

Variable Renewable Energy Penetration: Summary

Variable renewable energy (VRE)[1] is commonly understood as renewable energy that is not stored prior to electricity generation. In most U.S. ISO/RTO markets, this includes primarily wind and solar PV energy technologies but may also include technologies such as tidal power and run-of-river hydropower.[2]

- The VRE share of total generation continually increased in ISO/RTO and non-ISO/RTO market regions from 2012 to 2018. During this period, the share of VRE on average more than doubled across ISO/RTO and non-ISO/RTO regions.

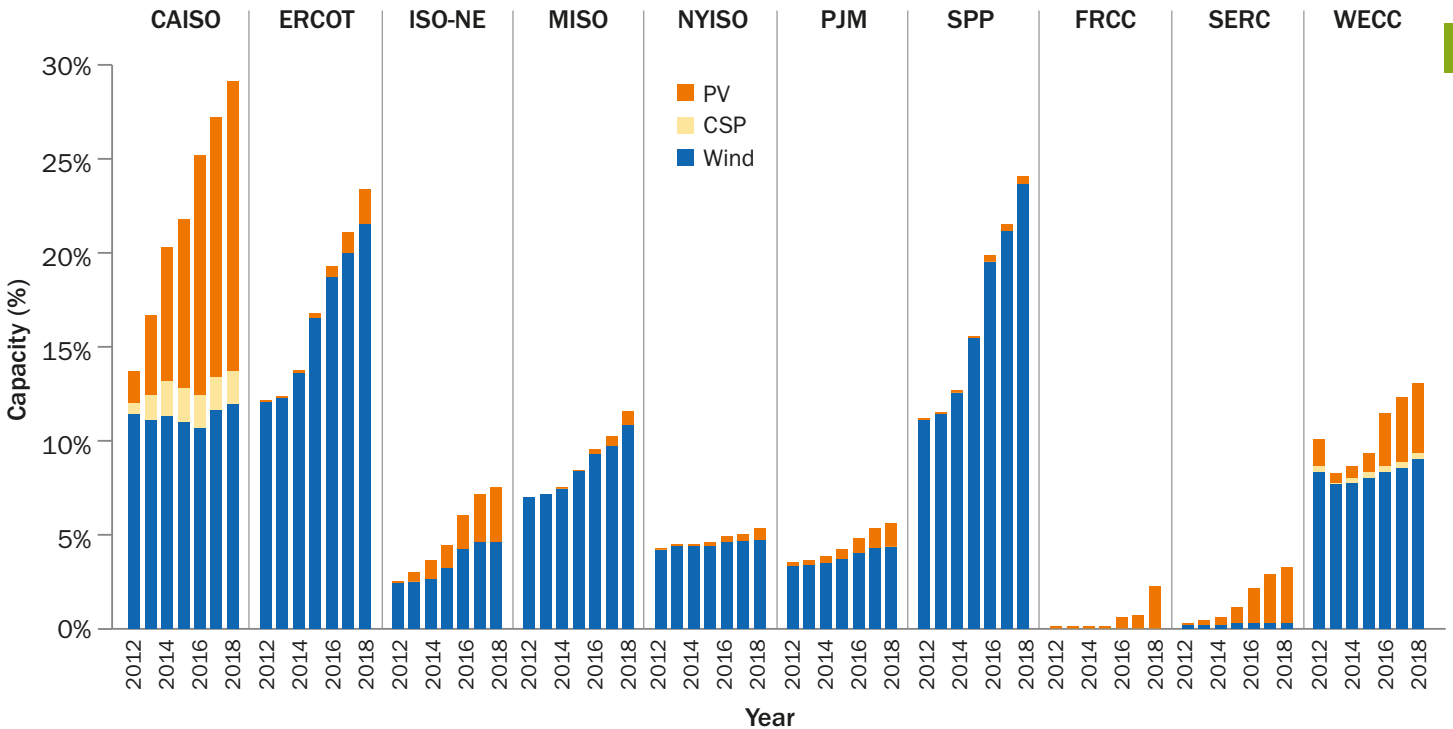
- In 2018, annual average VRE generation as a fraction of total generation ranged from highs of 22.6% in SPP and CAISO, to 17.9% in ERCOT, 7.6% in MISO, 4.6% in ISO-NE, and 3.1% in NYISO and PJM. The annual average VRE penetration in 2018 was led by wind generation in all these markets except CAISO; other regions also experienced increases in solar generation. In CAISO, 2018 shares of VRE generation consisted of solar PV (53%), wind (42%), and concentrating solar power (CSP) (5%).

[1] For the purposes of this data book, VRE is defined to include wind, solar PV, and CSP. See the glossary for a definition of VRE. In general, CSP in combination with storage, tidal power, and run-of-river hydropower may not be considered VRE generation sources.

[2] Cochran et al. 2012

VRE Fraction of Total Capacity

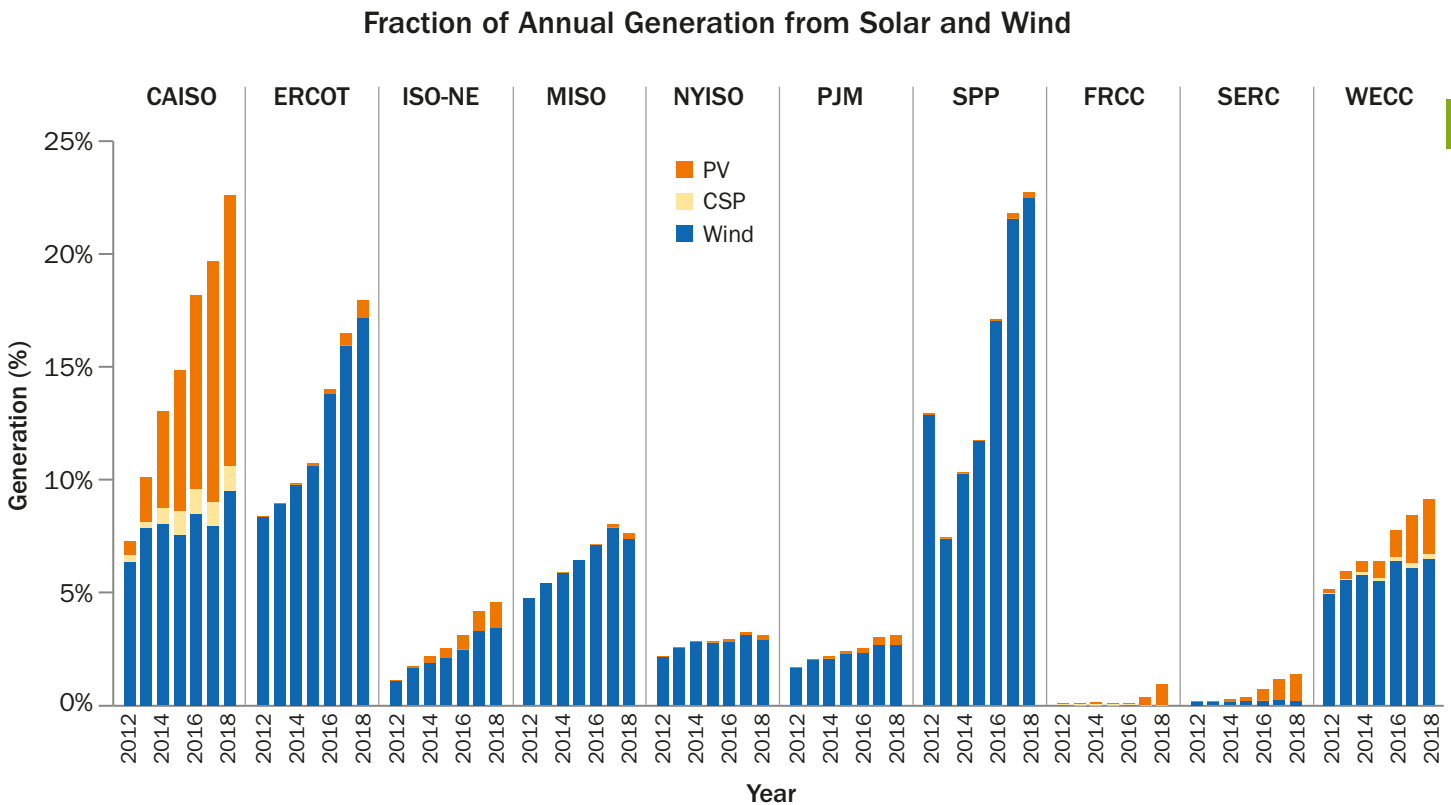
Fraction of Summer Capacity from Solar and Wind



Sources: Form EIA-860; S&P Global Market Intelligence database

Notes: Wind includes offshore wind. See the glossary for a definition of "summer capacity." For solar PV and wind summer capacity, peak net capacity on June 21, clear skies and average wind speed conditions were assumed (Form EIA-860 "Instructions"). WECC excludes CAISO. SERC excludes PJM, MISO, SPP, and FRCC. Data are only for generators above 1 MW.

VRE Fraction of Total Generation



Sources: Form EIA-923; S&P Global Market Intelligence database

Notes: Wind includes offshore wind. WECC excludes CAISO. SERC excludes PJM, MISO, SPP, and FRCC; data only for generators above 1 MW.

Capacity Factor: Summary

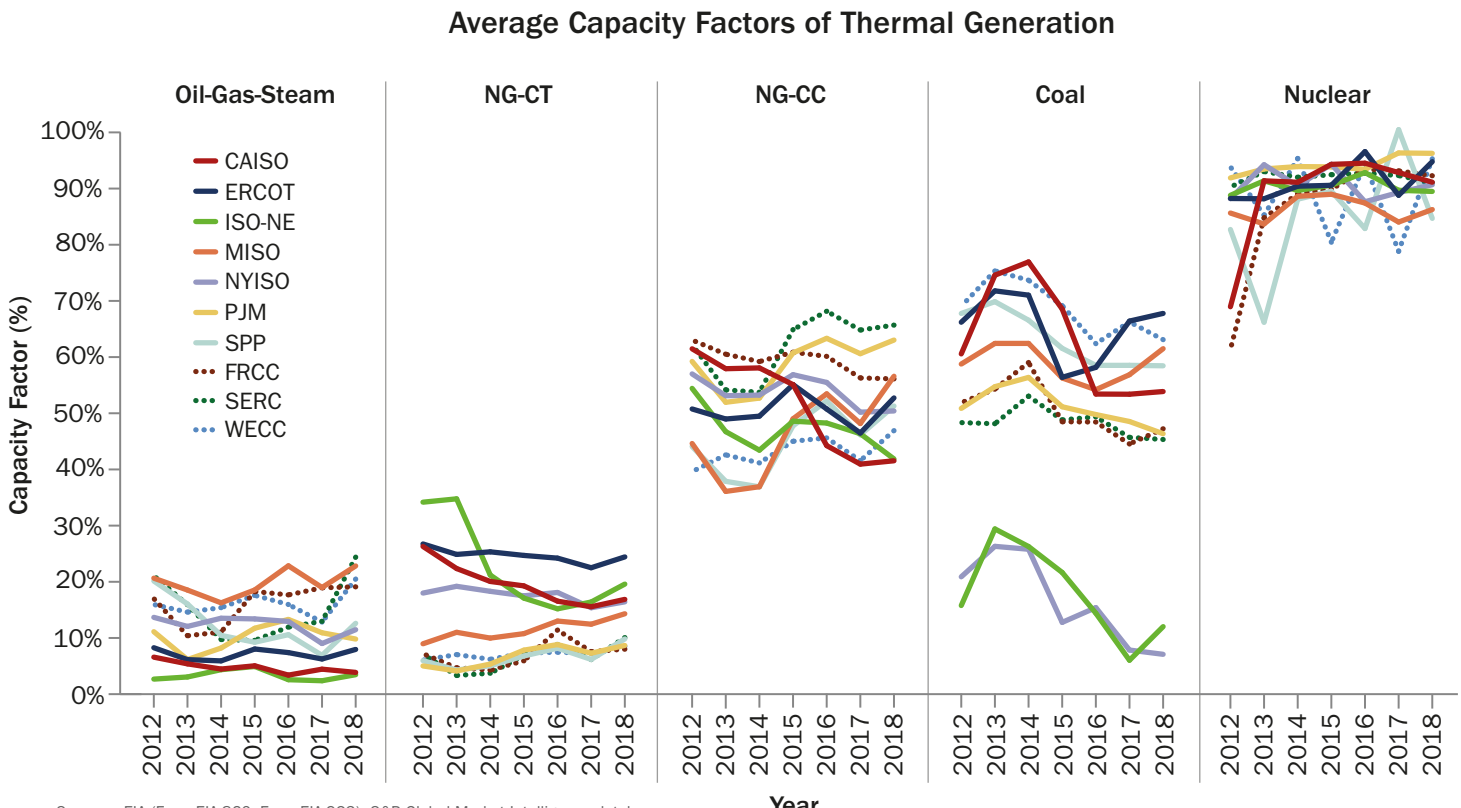
Capacity factor is the unitless ratio of the actual electrical energy output of a generating technology over a given period to the maximum possible electrical energy output over that period.

- Average annual capacity factors[1] typically vary by generation type and between different areas. Between 2012 and 2018, average capacity factors were highest for nuclear (89%), followed by geothermal (77%), biomass/municipal solid waste/landfill gas (58%), natural gas combined cycle (52%), coal (50%), hydropower (39%), wind (31%), solar PV (21%), and CSP (21%).

- Average capacity-weighted annual capacity factors rose from 18.4% in 2012 to 23.0% in 2018 for CSP, from 31.7% in 2012 to 35.0% in 2018 for wind, and from 70.0% in 2012 to 79.0% in 2018 for geothermal, reflecting technology improvements.

[1] Average annual capacity factors are capacity-weighted.

Average Capacity Factors: Thermal Generation



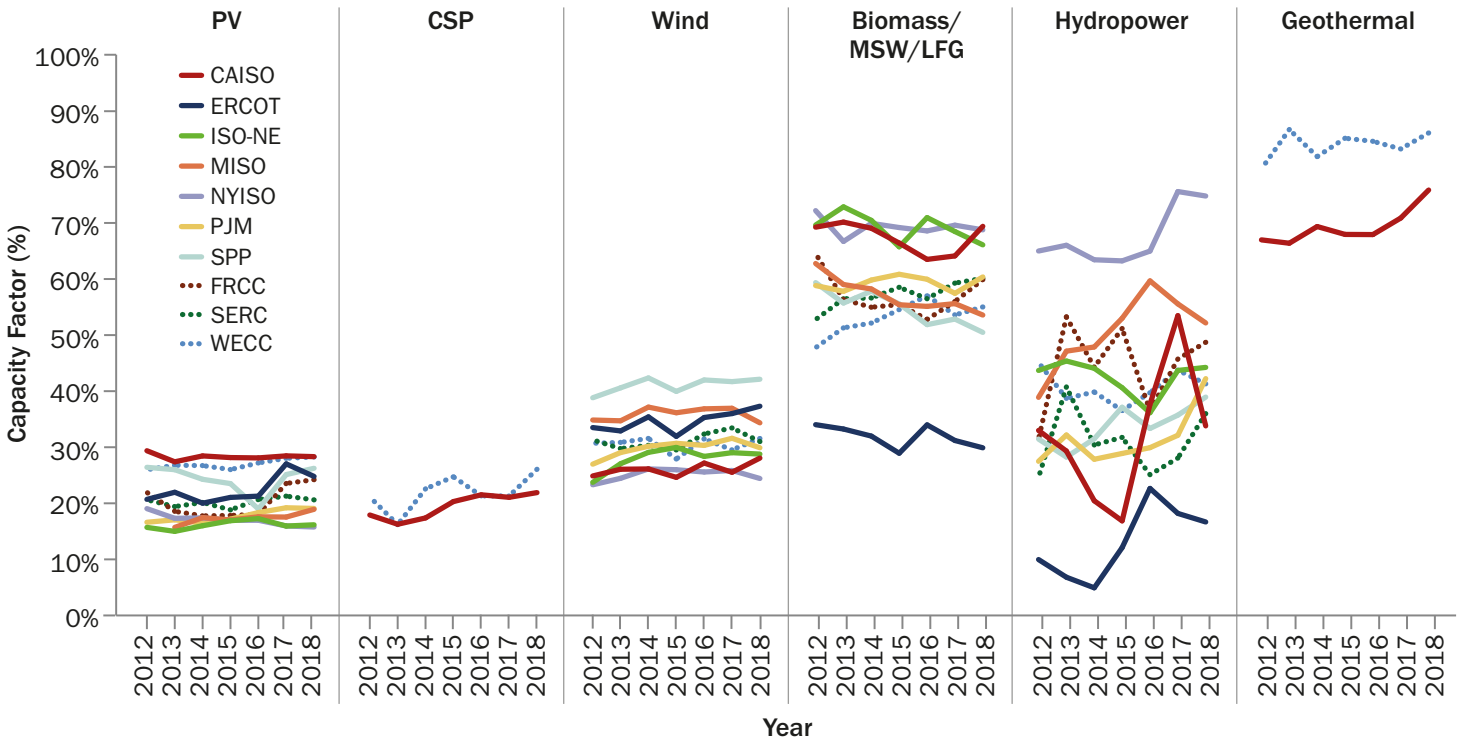
Sources: EIA (Form EIA-860, Form EIA-923); S&P Global Market Intelligence database

Notes: Average capacity factors (1) were calculated by dividing total generation by reported summer capacity times the number of operational hours in a given year and (2) were capacity-weighted. Data are only for generators with a capacity of more than 1 MW. Generators either having 0 MWh of generation during the entire year or reporting errors were excluded. Assignment of fuel types to prime mover in each year correspond those used in the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System model (Cohen et al. 2019).[1]

[1] https://www.nrel.gov/analysis/reeds/

Average Capacity Factors: Renewable Generation

Average Capacity Factors of Renewable Generation



Sources: EIA (Form EIA-860, Form EIA-923); S&P Global Market Intelligence database

Notes: Average capacity factors (1) were calculated by dividing total generation by reported summer capacity times the number of operational hours in a given year and (2) were capacity-weighted. Data are only for generators with a capacity of more than 1 MW. Generators either having 0 MWh of generation during the entire year or reporting errors were excluded. Assignment of fuel types to prime mover correspond those used in NREL's Regional Energy Deployment System model (Cohen et al. 2019).

Storage Capacity: Summary

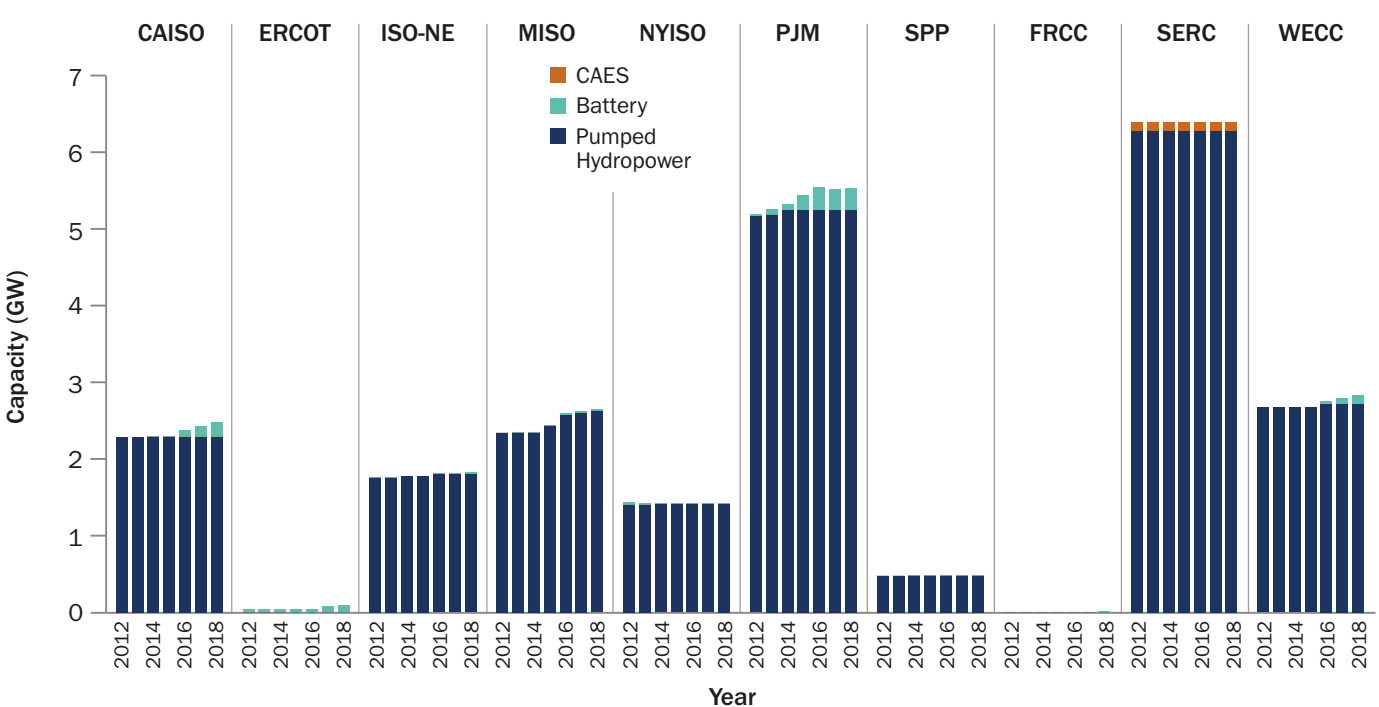
Energy storage technologies[1] can store energy for use on demand. Storage can provide a broad array of grid services that generally make the power system more flexible through energy management and reliability services.[2]

- National total storage deployment remained flat from 2012 (22.6 GW) to 2018 (23.7 GW), corresponding to about 2.2% of total installed generation capacity. Pumped hydropower continued to have the largest share of storage technology deployment (96%) in 2018.

- Though battery storage comprised only 780 MW nationally in 2018 (i.e., 0.7% of total installed generation capacity), the technology's capacity increased by 48% in the contiguous United States between 2016 and 2018. In that period, battery storage grew by 94 MW in CAISO, 70 MW in WECC, 58 MW in ERCOT, 14 MW in FRCC, 10 MW in ISO-NE, 5 MW in SERC, 3 MW in MISO, and 2 MW in SPP.

[1] Reported storage capacity only include utility-scale (i.e., > 1-MW) storage.
[2] NREL 2016

Utility-Scale Capacity from Pumped Hydropower, Battery, and Compressed Air Energy Storage



Source: EIA (Form EIA-860)

Notes: Data excludes storage capacity of less than 1 MW (i.e., behind-the-meter storage is not included).

III. Wholesale Electricity Markets

Locational Marginal Price (LMP): Summary

III

Locational marginal price (LMP)[1] is "the marginal cost of supplying, at least cost, the next increment of electric demand at a specific location (node) on the electric power network, considering both supply (generation/import) bids and demand (load/export) offers and the physical aspects of the electric system, including transmission and other operational constraints." Increased VRE penetration tends to reduce LMPs due to their low operating costs.

- In 2018, the median hourly LMP ranged from $20.80/MWh (SPP) to $31.55/MWh (ISO-NE).
- About 87% of hours fall within an average LMP range of $0/MWh to $50/MWh in ISO/RTO markets—of which 52% fall in a range of $0/MWh to $25/MWh.
- ISO/RTO markets experienced price spikes over some hours in 2018. LMP levels above $300/MWh were experienced by ERCOT during approximately 57 hours (0.7% of total hours), followed by CAISO with approximately 37 hours (0.4% of hours), NYISO at 28 hours (0.3%), ISO-NE at 25 hours (0.3%), and PJM at 14 hours (0.2%).
- Maximum LMP ranged from $2,785/MWh (ERCOT) to $2,447/MWh (ISO-NE), $1,189/MWh (NYISO), $860/MWh (CAISO), $594/MWh (PJM), $510/MWh (MISO), and $454/MWh (SPP).

[1] LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled up) from zonal price nodes in the RT market.

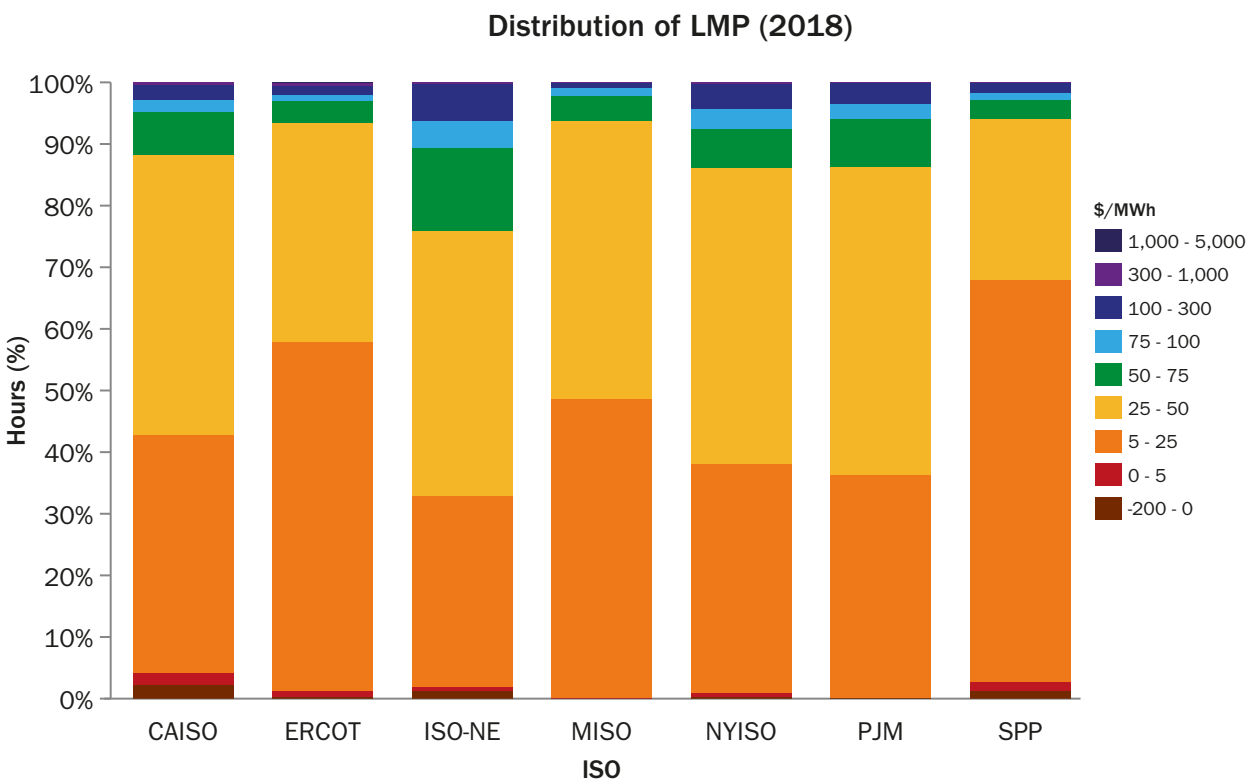
[2] Abdollahi 2013; Kirschen and Strbac 2004; CAISO 2005

Locational Marginal Price (LMP): Summary (continued)

III

- Regions with higher levels of renewable generation usually see higher VRE penetration during hours with lower LMPs. For example, average hourly VRE penetration during hours with an average LMP above $300/MWh is 13.3% in SPP (compared to 25.3% during hours with an average LMP range of $0/MWh to $50/MWh), 10.3% in CAISO (compared to 19.8%), and 7.6% in ERCOT (compared to 21.1%).
- In 2018, annual average LMPs were lowest over the Midwest, primarily in SPP, though pockets of northern New York also saw low average prices.
- Annual average LMPs were generally higher on the coasts in CAISO, PJM, NYISO, and ISO-NE, with some pockets of particularly high average prices in West Texas (ERCOT) and on the Delmarva Peninsula (PJM).

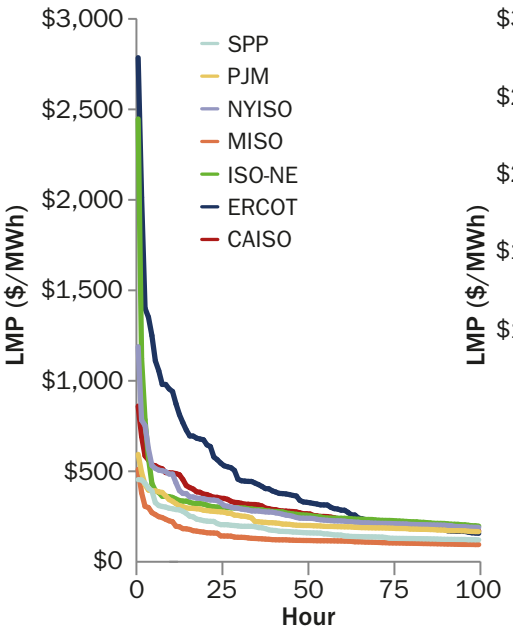
Locational Marginal Price (LMP)



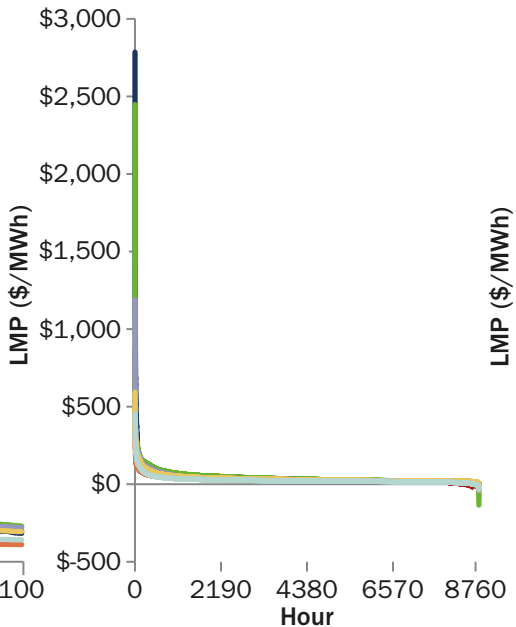
Sources: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: LMP data are reported here as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled up) from zonal price nodes in the RT market.

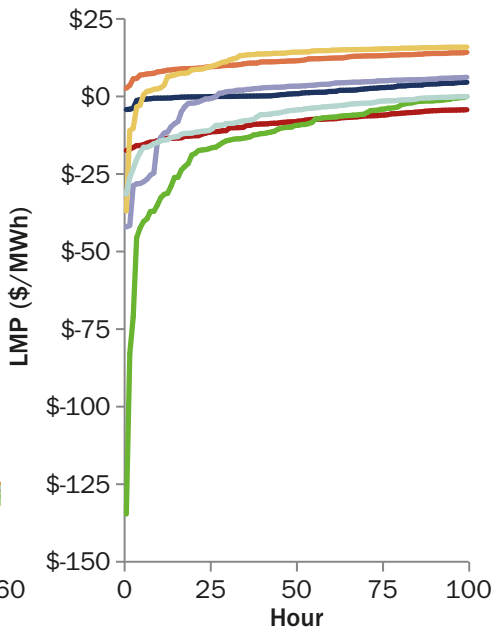
LMP During the 100 Hours with Highest Price Levels (2018)



LMP During 8,760 Hours (2018)



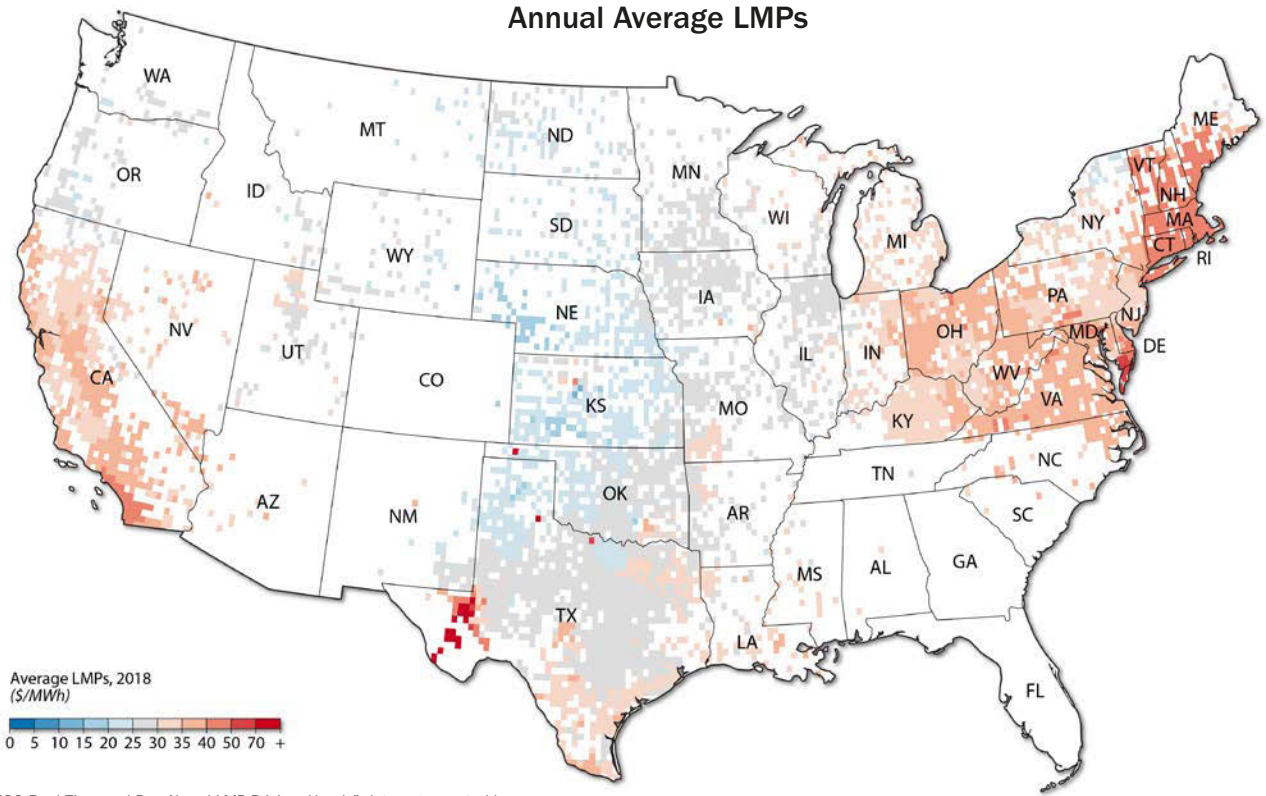
LMP During the 100 Hours with Lowest Price Levels (2018)



Sources: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: LMP data are reported here as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled up) from zonal price nodes in the RT market.

Annual Average LMPs

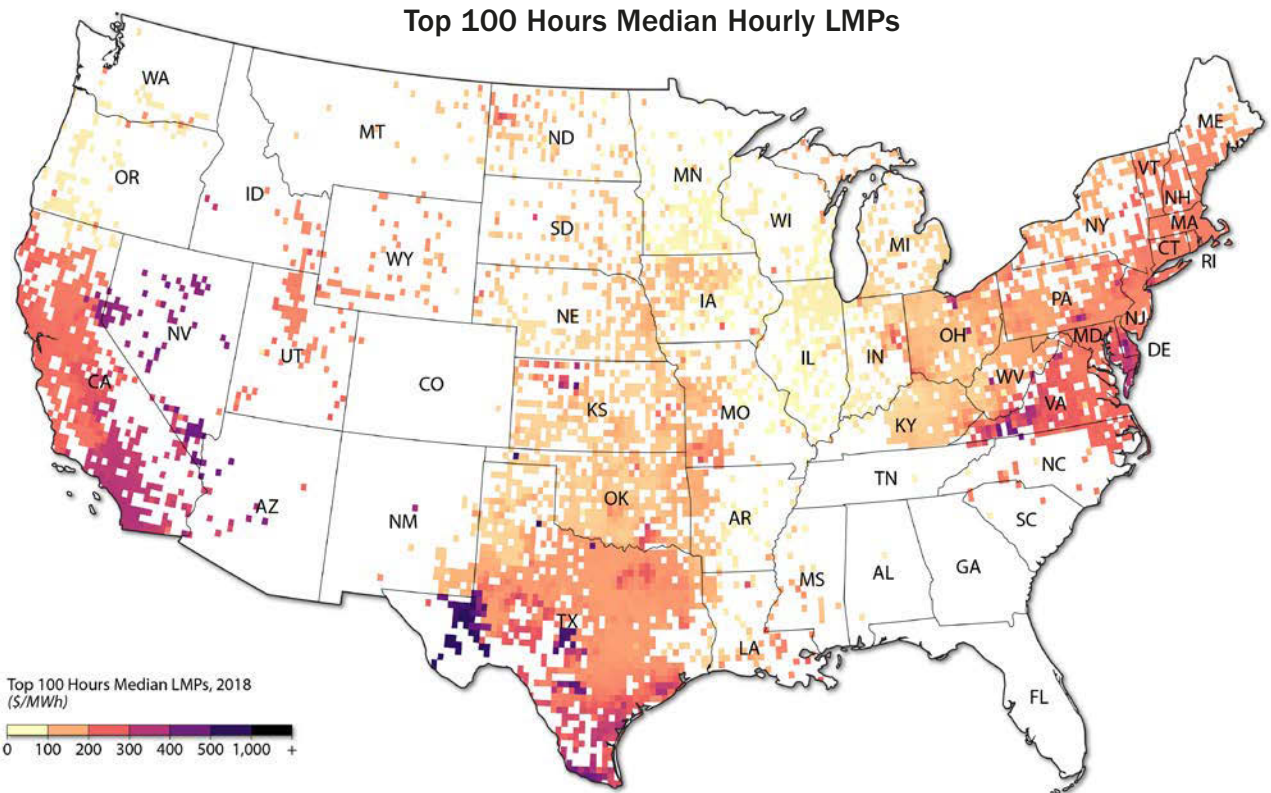


Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Velocity Suite)

Notes: LMP data are reported as hourly (time-weighted) averages from nodal price nodes in the RT market (ISO-NE, MISO, PJM, and NYISO). LMP data for CAISO, ERCOT, and SPP are reported as hourly (time-weighted) averages of five-minute data (rolled-up) from nodal price nodes in the RT market.

Price spikes in Western Texas in ERCOT are due to increased load growth related to oil and natural gas activity in the area and the addition of solar generation in the southern part of the area (ERCOT 2018).

Top 100 Hours Median Hourly LMPs



Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Velocity Suite)

Notes: LMP data are reported as hourly (time-weighted) averages from nodal price nodes in the RT market (ISO-NE, MISO, PJM, and NYISO). LMP data for CAISO, ERCOT, and SPP are reported as hourly (time-weighted) averages of five-minute data (rolled-up) from nodal price nodes in the RT market.

Negative LMP: Summary

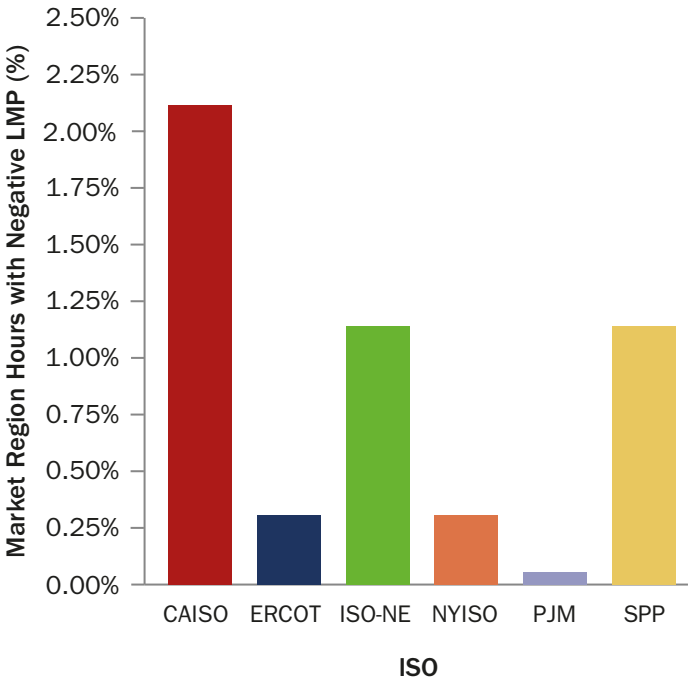
Negative LMP may occur when there is excess generation relative to load.[1] In some cases, market participants submit negative energy bids and are therefore willing to pay for providing power. Excess generation typically results from some combination of low demand, high VRE generation, binding plant-level minimum generation constraints coupled with high startup costs and times, transmission constraints, and economic factors that influence market participants' bidding behavior (including incentives such as the production tax credit).

- In 2018, 2.1% of hours saw negative pricing in CAISO, followed by ISO-NE and SPP (1.1%), ERCOT and NYISO (0.3%), PJM (0.1%), and MISO (0.0%). During those periods, average load was low at 45.1 GW in CAISO (compared to the average load of 53.3 GW across 8,760 hours in 2018), 10.8 GW in ISO-NE (compared to 13.6 GW), 25.4 GW in SPP (compared to 31.0 GW), and 30.6 GW in ERCOT (compared to 42.0 GW). VRE penetration during those hours was high at 48.0% in CAISO (compared to annual average hourly penetration of 19.4%), 50.0% in SPP (compared to 25.0%), 3.9% in ISO-NE (compared to 3.1%), and 39.8% in ERCOT (compared to 20.5%).
- In 2018, the lowest median hourly negative LMPs were observed in PJM (-$10.27/MWh), followed by NYISO (-$9.74/MWh) and ISO-NE (-$9.34/MWh).
- While negative prices occurred in many parts of the county, the magnitude of negative prices lowered annual average LMPs by about $3/MWh, or around 10% of annual average hourly LMPs in each region. In parts of SPP, northern New York and northeastern Maine, however, the impacts of negative prices on average prices were more substantial.

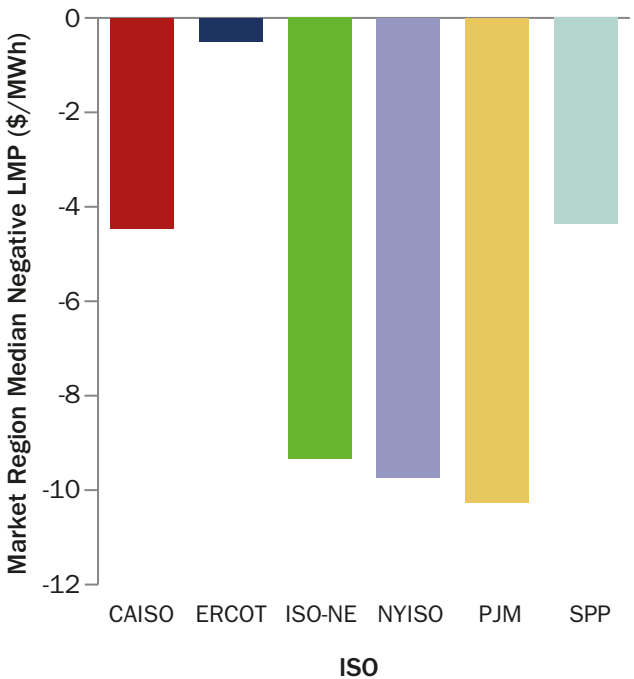
[1] LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled up) from zonal price nodes in the RT market.

Negative LMP

Percentage of Hours with Negative LMP (2018)



Median Negative LMP (2018)



III

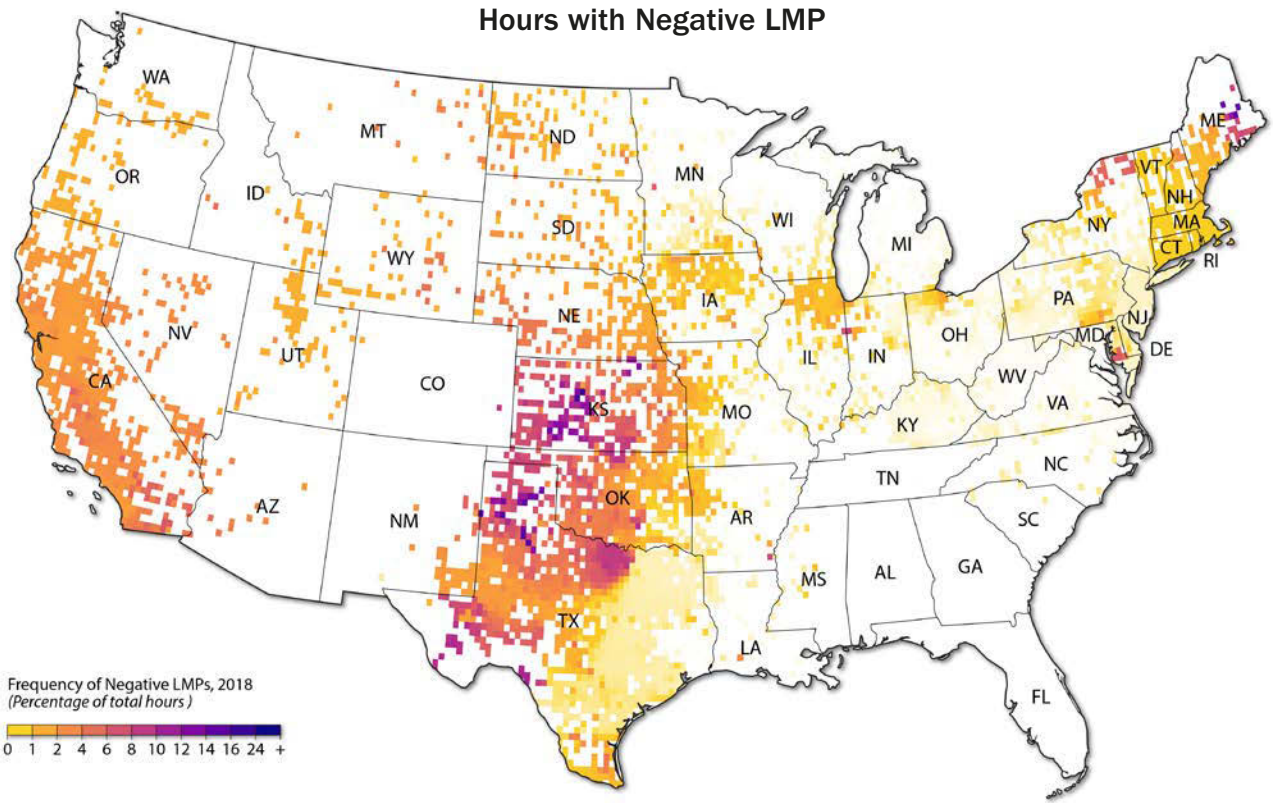
Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" (at zonal hub level) reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: LMP) data are reported here as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled up) from zonal price nodes in the RT market.

Negative LMP (continued)

III

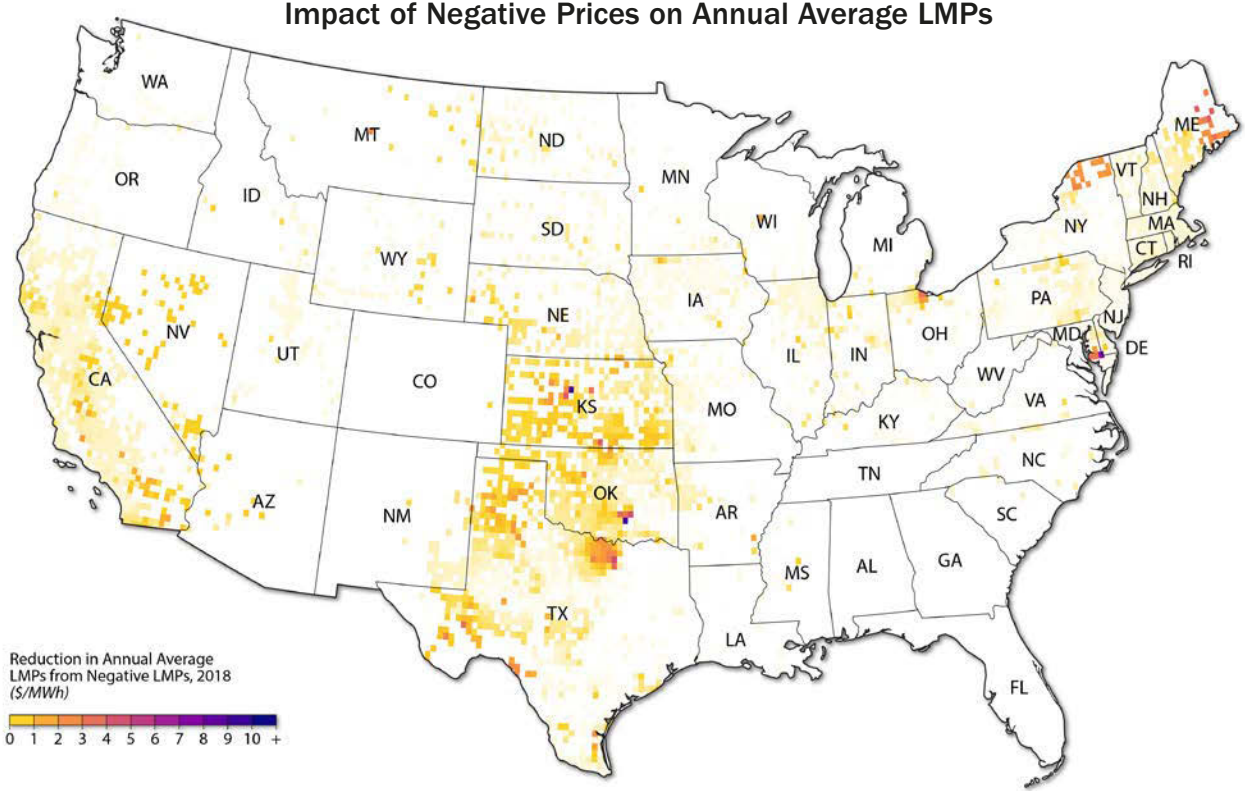
Hours with Negative LMP



Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, AND SPP (accessed through the ABB Velocity Suite)

Notes: Frequency of negative LMPs is based on the number of hours where hourly average LMPs were less than zero.

Impact of Negative Prices on Annual Average LMPs



Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Velocity Suite)

Notes: The impact of negative prices shown is a reduction in annual (time-weighted) average prices due to negative hourly RT prices.

Capacity Pricing: Summary

Organized and centrally administered forward capacity markets in PJM, NYISO, MISO, and ISO-NE are designed to ensure sufficient capacity is available to reliably meet planning reserve margins. Capacity is committed in advance of the delivery year and is allocated to generators through regularly held auctions in several ISO/RTO markets.

- ISO-NE experienced relatively stable capacity prices[1] of $2.95/kW-month to $4.50/kW-month between the delivery years of 2010/2011 and 2015/2016, which were followed by a spike at $9.55/kW-month for delivery year 2018/2019 and then a gradual decrease to $3.80/kW-month for delivery year 2022/2023.

- NYISO capacity prices were higher in the summer than in other seasons within each year. NYISO monthly spot capacity prices were lower in 2017 than 2016. Over both years, they ranged from $5.11/kW-month to $6.65/kW-month between May and October, and they remained between $0.69/kW-month and $1.87/kW-month for the months of January–April and November–December.

[1] For the purpose of this data book, capacity clearing prices are presented as system-wide averages for each ISO/RTO, weighted by the cleared capacity of ISO/RTO capacity zones.

- In delivery years 2007/2008 through 2021/2022, PJM capacity clearing prices fluctuated considerably, with an average year-to-year change of 82.0% and a range of $0.50/kW-month for 2012/2013 to $5.32/kW-month for 2010/2011. The capacity clearing price for 2021/2022 increased to $4.27/kW-month from $2.33/kW-month for 2020/2021.

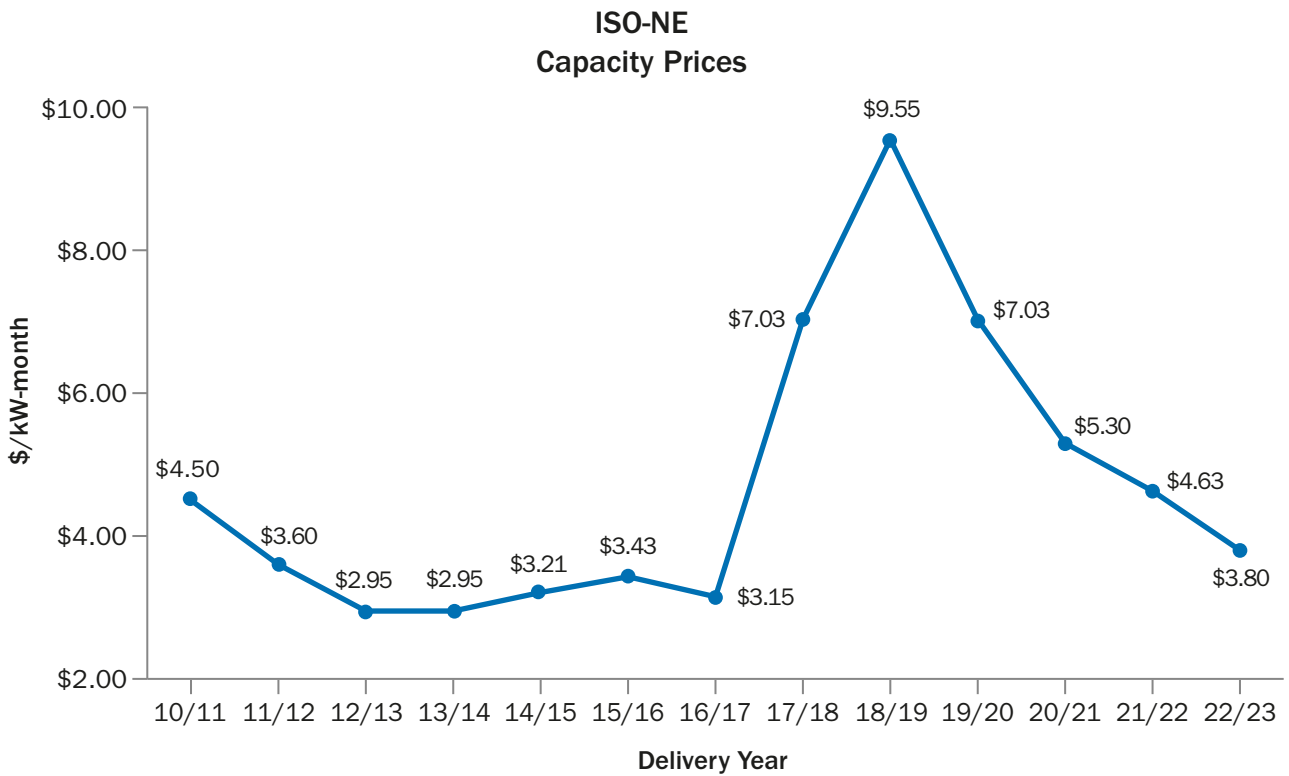
- From delivery year 2020/2021 to delivery year 2021/2022, the share of nuclear in PJM cleared unforced capacity[1] decreased from 17% to 12%, whereas the share of demand response increased from 5% to 7% and the share of energy efficiency increased from 1% to 2%. For delivery year 2021/2022, solar PV comprised 0.3% of total cleared unforced capacity and wind comprised 0.9%.

- Between delivery year 2014/2015 and delivery year 2019/2020, MISO capacity prices ranged from $0.05/kW-month to $1.44/kW-month. MISO experienced a capacity price spike of $1.44/kW-month for delivery year 2016/2017, and then the prices decreased, ranging from $0.05/kW-month to $0.27/kW-month for delivery years 2017/2018 through 2019/2020.

- From delivery years 2016/2017 to 2019/2020, the share of behind-meter generation in MISO cleared capacity increased from 2.6% to 3.0%, and the share of demand response increased from 4.3% to 5.5%.

[1] The unforced capacity, or UCAP, value of a unit is the installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating (PJM 2017).

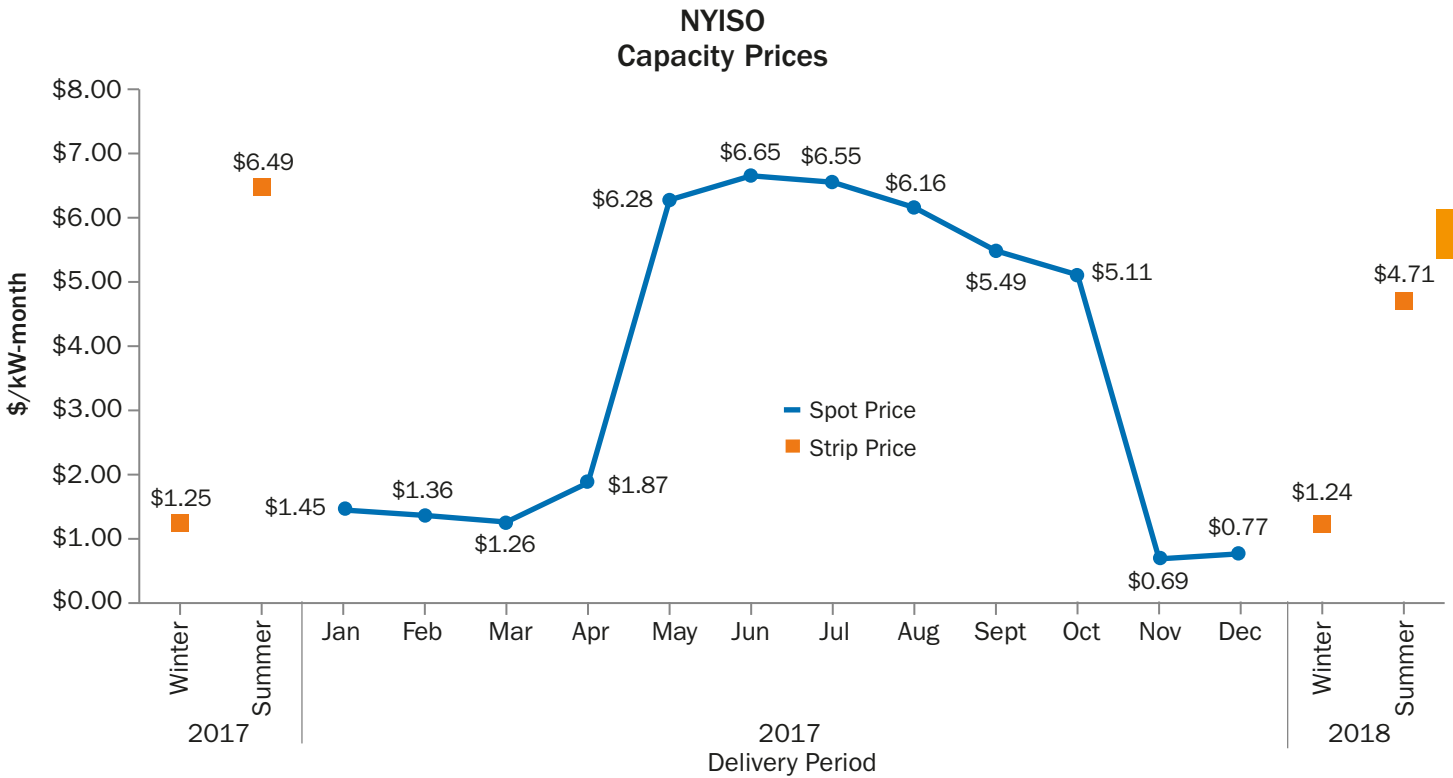
Capacity Prices: ISO-NE



Source: "Markets: Results of the Annual Forward Capacity Auctions," ISO New England, https://www.iso-ne.com/about/key-stats/markets#fcaresults

Note: The chart depicts system-wide clearing price results for existing resources from the ISO-NE "Annual Forward Capacity Auction." Auctions are held for multiple ISO-NE capacity zones and any associated external interfaces (with varying capacity price levels), as well as for new resources. Generating resources receive capacity payments based on their technology-specific capacity value and de-rate factor.

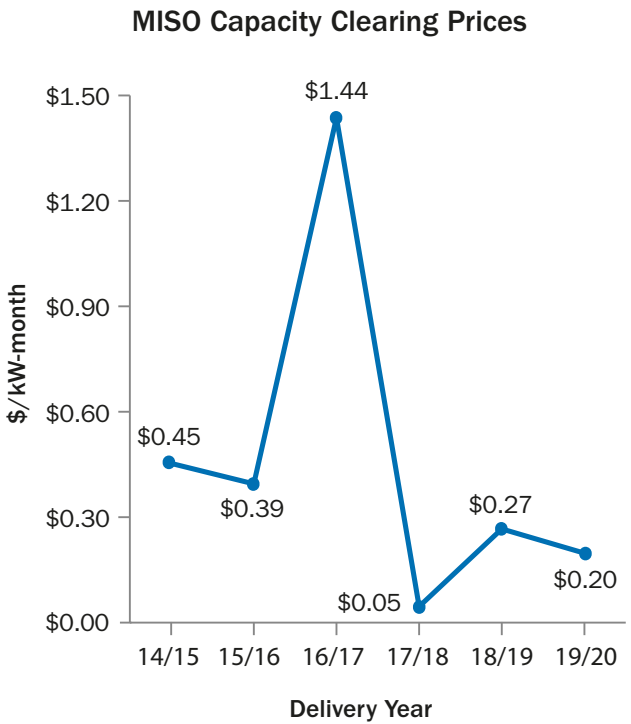
Capacity Prices: NYISO

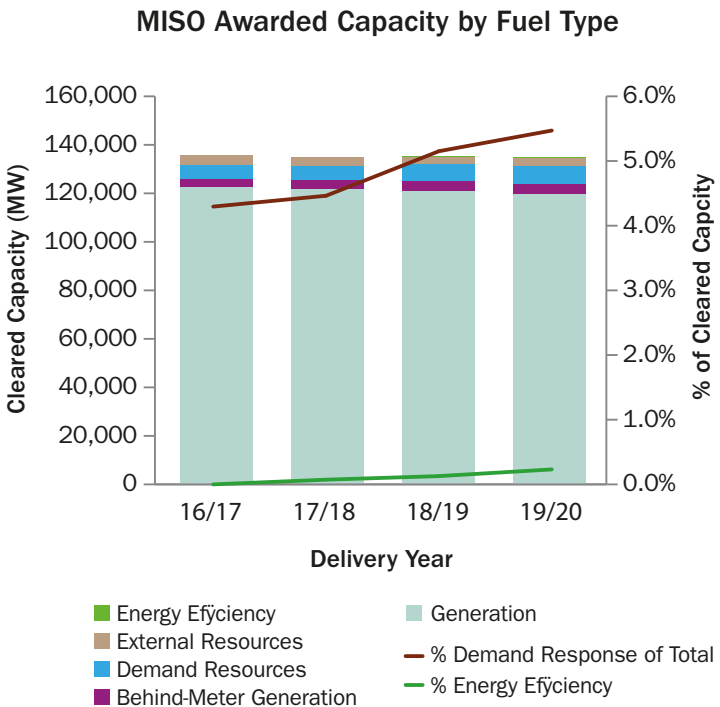


Sources: "ICAP Data and Information," NYISO, http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp; "Strip Auction Summary," NYISO, http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do (accessed August 2019); "Monthly UCAP reports," NYISO, http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do

Note: Strip prices in NYISO are for six-month capability periods of "Summer" and "Winter." Spot prices are determined for monthly delivery periods. The strip and spot clearing price results represent the system-wide average of the NYISO capacity zones, which are weighted by awarded capacity. Auctions are held for multiple NYISO capacity zones (with varying capacity price levels). Generating resources receive capacity payments based on their technology-specific capacity value and de-rate factor.

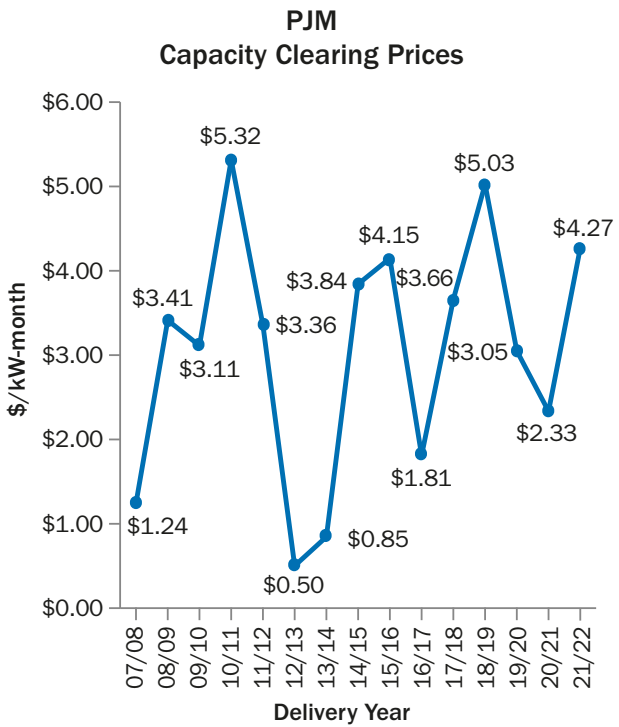
Capacity Prices: MISO

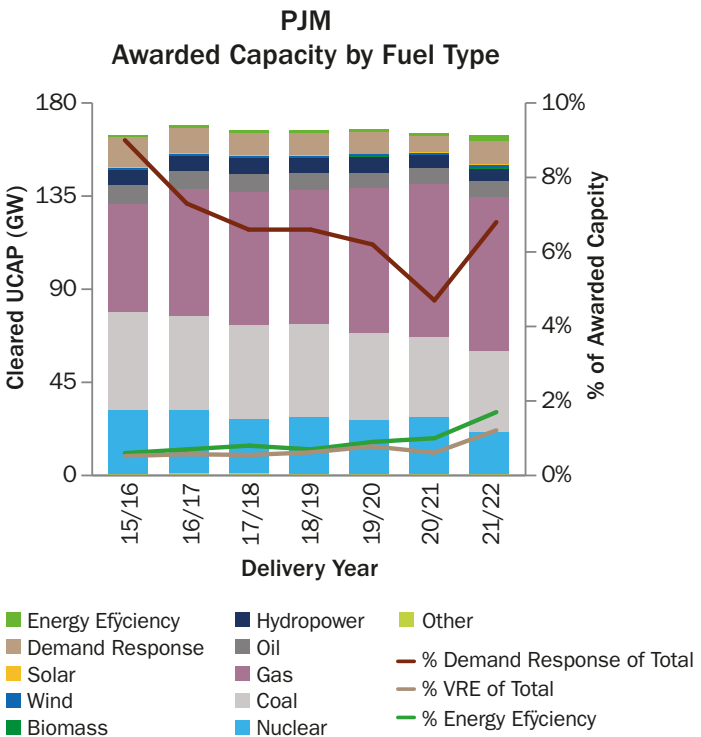




Sources: Annual Planning Resource Auction Results, MISO (2019, 2018, 2017, 2016, 2015, n.d.)
Notes: Price results represent capacity-weighted average system-level price.

Capacity Prices: PJM





Source: "Resource Clearing Prices Auction Summary," PJM, September 28, 2018; "Commitments by Fuel Type and Delivery Year 2007/08 – 2021/22," PJM, May 23, 2018, https://www.pjm.com/markets-and-operations/rpm.aspx

Note: The chart depicts the system-wide clearing price results from the PJM "Annual Base Residual Auction." Auctions are held for multiple PJM capacity zones (with varying capacity price levels). Generating resources receive capacity payments based on their technology-specific capacity value and de-rate factor.

Capacity Credits: Summary

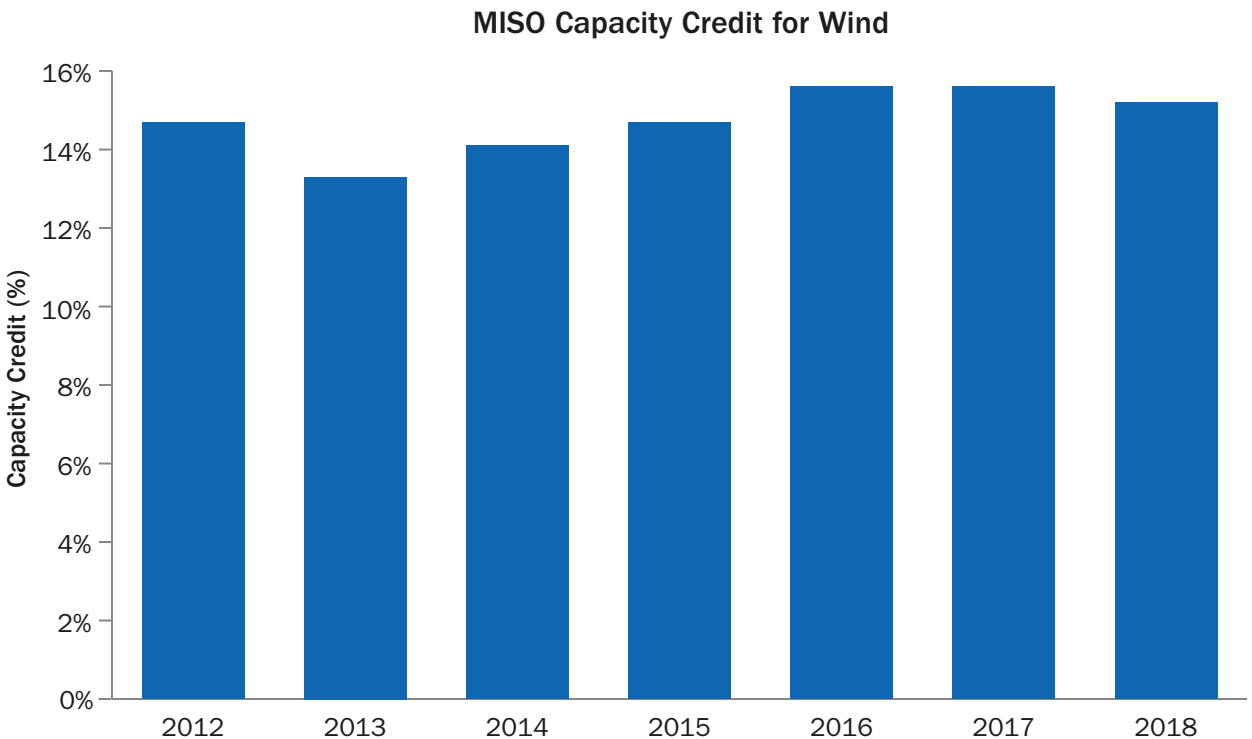
A generator's capacity credit is the contribution to overall system adequacy (i.e., the fraction of nameplate capacity that contributes to the top peak net load hours). It is calculated differently among ISO/RTO market regions.

III

- Wind capacity credits used in MISO resource adequacy planning[1] ranged from 13.3% to 15.6% for planning years 2012 to 2018.
- In ERCOT, capacity credit used in Seasonal Assessment of Resource Adequacy[2] ranged from 41% to 68% for coastal wind, 14% to 36% for non-coastal wind, and 10% to 75% for utility-scale solar PV for different seasons in 2018.
- In a CAISO resource adequacy assessment,[3] wind capacity credit used ranged from 1.5% to 19.0% during the winter season (December, January and February) and between 12.5% and 47.5% during the summer season (June, July and August) from 2012 to 2018, and solar capacity credit used ranged from 0% to 2.4% during winter and between 41% and 85% during summer.

[1] "Resource Adequacy," MISO, https://www.misoenergy.org/planning/resource-adequacy/
[2] "Resource Adequacy," ERCOT, http://www.ercot.com/gridinfo/resource
[3] "Reliability requirements," CAISO, http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

Capacity Credits: MISO

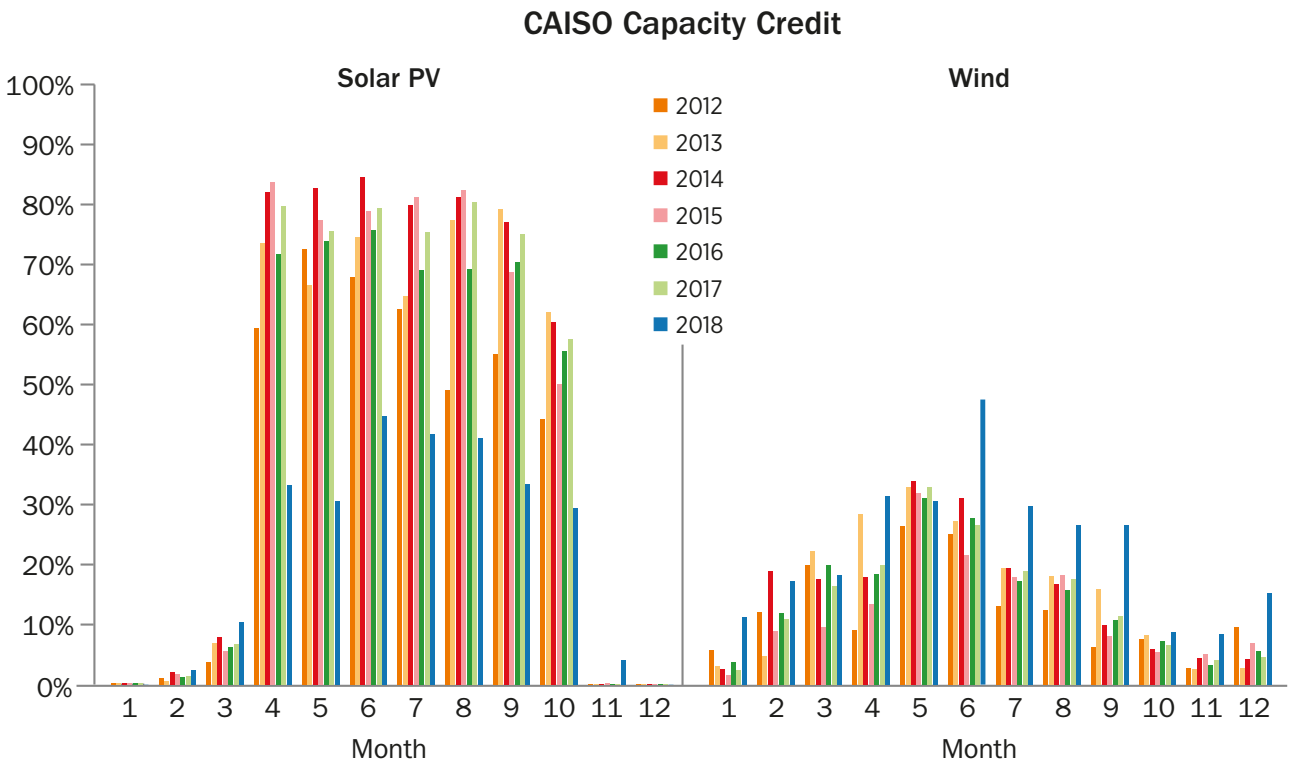


III

Source: "Resource Adequacy," MISO, https://www.misoenergy.org/planning/resource-adequacy/

Notes: The capacity credit calculation in MISO is based on the effective load carrying capacity (ELCC) and the maximum wind penetration in a given year. ELCC is a measure of the additional load that the system can supply with a particular generator of interest, with no net change in reliability (Milligan and Porter 2008).

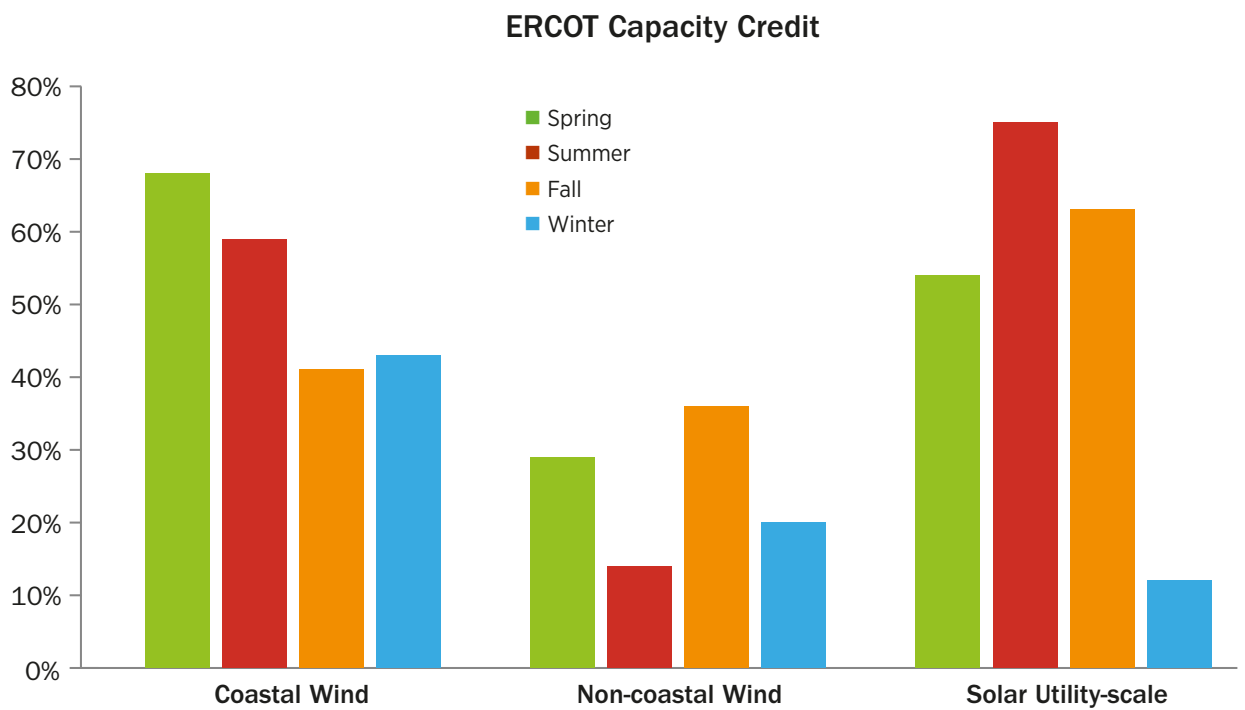
Capacity Credits: CAISO



Source: "Reliability Requirements," CAISO, http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

Notes: Starting in 2018, the capacity credit methodology switched from a time-series exceedance approach to a method based on the ELCC.

Capacity Credits: ERCOT



III

Source: "Resource Adequacy," ERCOT, http://www.ercot.com/gridinfo/resource

ISO/RTO Market Highlights

III

- **February 2018:** FERC issued Order No. 841, requiring the establishment of market rules that recognize the physical and operational characteristics of energy storage resources and facilitate energy storage technology market participation.[1]

- **February 2018:** FERC issued Order 842, (1) requiring new generators, including VRE generators, to install, maintain, and operate a functioning governor or equivalent controls capable of primary frequency response before interconnection and (2) amending pro forma agreements to include certain operating requirements, including maximum droop and deadband parameters, and sustained response provisions.[2]

- **March 2018:** FERC approved the ISO-NE Capacity Auctions with Sponsored Policy Resources plan to address concerns that resources with out-of-market support (e.g., state subsidies) suppress capacity prices.[3]

- **April 2018:** PJM Interconnection implemented five-minute RT settlements for energy and reserve markets.[4]

[1] FERC 2018a
[2] FERC 2018b
[3] FERC 2018c
[4] "5-Minute Settlements," PJM, https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/5-minute-settlements.aspx

ISO/RTO Market Highlights (continued)

III

- **June 2018:** ERCOT increased the allowable percentage of responsive reserve service that load resources may provide from 50% to 60%, and it specified the minimum amount of primary frequency response (generator provided) as 1,150 MW.[1]
- **June 2018:** ISO-NE implemented the Price-Response Demand program to integrate demand response resources into the DA and RT energy markets.[2]
- **June 2018:** FERC rejected the PJM Interconnection proposal to reform its capacity auction and address concerns about price suppression from resources with out-of-market support.[3]
- **July 2018:** MISO implemented five-minute RT settlements for the energy market.[4]
- **February 2019:** ERCOT modified the definition of "responsive reserve" service to include a new "fast frequency response" service, and it added a new ancillary service type called, "contingency reserve service."[5]

[1] Potomac Economics 2019a
[2] ISO-NE 2019
[3] FERC 2018d
[4] "Implement 5-Minute Settlement Calculations (IR026)," MISO, last modified September 17, 2019, https://www.misoenergy.org/stakeholder-engagement/issue-tracking/implement-5-minute-settlement-calculations/
[5] Potomac Economics 2019a

ISO/RTO Market Highlights (continued)

III

- **April 2019:** FERC conditionally approved an SPP proposal to require non-dispatchable variable energy resources to register as dispatchable resources with allowed exemptions.[1]
- **May 2019:** MISO revised rules regarding thresholds for uninstructed energy market deviations and conditions for "price volatility and make whole payments," in part, to address wind over-forecasting.[2]
- **June 2019:** In a letter to its stakeholders, the Bonneville Power Administration announced it had begun the process of joining the Western Energy Imbalance Market.[3]
- **July 2019:** FERC ordered PJM Interconnection to postpone its "base residual auction" planned for August, lacking an agreement on reforms to its capacity market.[4]
- **August 2019:** ERCOT approved the implementation of nodal energy pricing for small generators to replace the current "load zone" energy pricing.[5]

[1] FERC 2019a, 2019b

[2] "Tighten Thresholds for Uninstructed Deviations (IR030)," MISO, last modified June 4, 2019, https://www.misoenergy.org/stakeholder-engagement/issue-tracking/tighten-thresholds-for-uninstructed-deviations/

[3] BPA 2019

[4] FERC 2019c

[5] "Nodal Pricing for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs)," ERCOT, http://www.ercot.com/mktrules/issues/NPRR917#summary

ISO/RTO Market Highlights (continued)

III

- **September 2019:** Basin Electric Power Cooperative, Tri-State Generation and Transmission Association, and the Western Area Power Administration (WAPA) announced they were joining the SPP Western Energy Imbalance Service Market, which is scheduled to launch in 2021.[1]

- **October 2019:** FERC partially approved PJM and SPP filings under Order 841.[2]

[1] https://www.spp.org/newsroom/press-releases/three-regional-utilities-announce-decision-to-join-southwest-power-pool-market/
[2] https://www.ferc.gov/media/news-releases/2019/2019-4/10-17-19-E-1.asp#.Xa3FGOhKiUk

Off-Take Arrangements: Summary

III

Renewable energy projects often utilize off-take agreements to secure cash flows that can contribute to a project's financing.[1] Off-take agreements are usually implemented as a contractual arrangement between the project developer and the party buying the output of the project (i.e., the off-taker) on a long-term basis. Traditionally, an off-take arrangement has primarily taken the form of a power purchase agreement (PPA). Other types of off-take agreements include corporate PPAs, energy hedge agreements, and proxy revenue swaps.[2]

- Electric utilities were the largest off-takers of all new wind capacity built in 2018, where investor-owned utilities supported 34% of new capacity and publicly owned utilities supported 12% of new capacity, followed by direct retail purchasers (24%), merchant/quasi-merchant projects (23%), power marketers[3] (3%), and 17 MW of on-site turbines (0.2%).

- Electric utilities (including both investor-owned and publicly owned utilities) accounted for 100% of all new wind capacity in WECC in 2018, 91% in MISO, 90% in ISO-NE, 52% in CAISO, and 40% in SPP. Direct retail purchasers supported 69% of new wind capacity in PJM, 40% in CAISO, 36% in ERCOT, 26% in NYISO, and 21% in SPP. Merchant/quasi-merchant projects represented 74% of new wind capacity in NYISO, 42% in ERCOT, and 29% in SPP.

[1] Gatti 2019

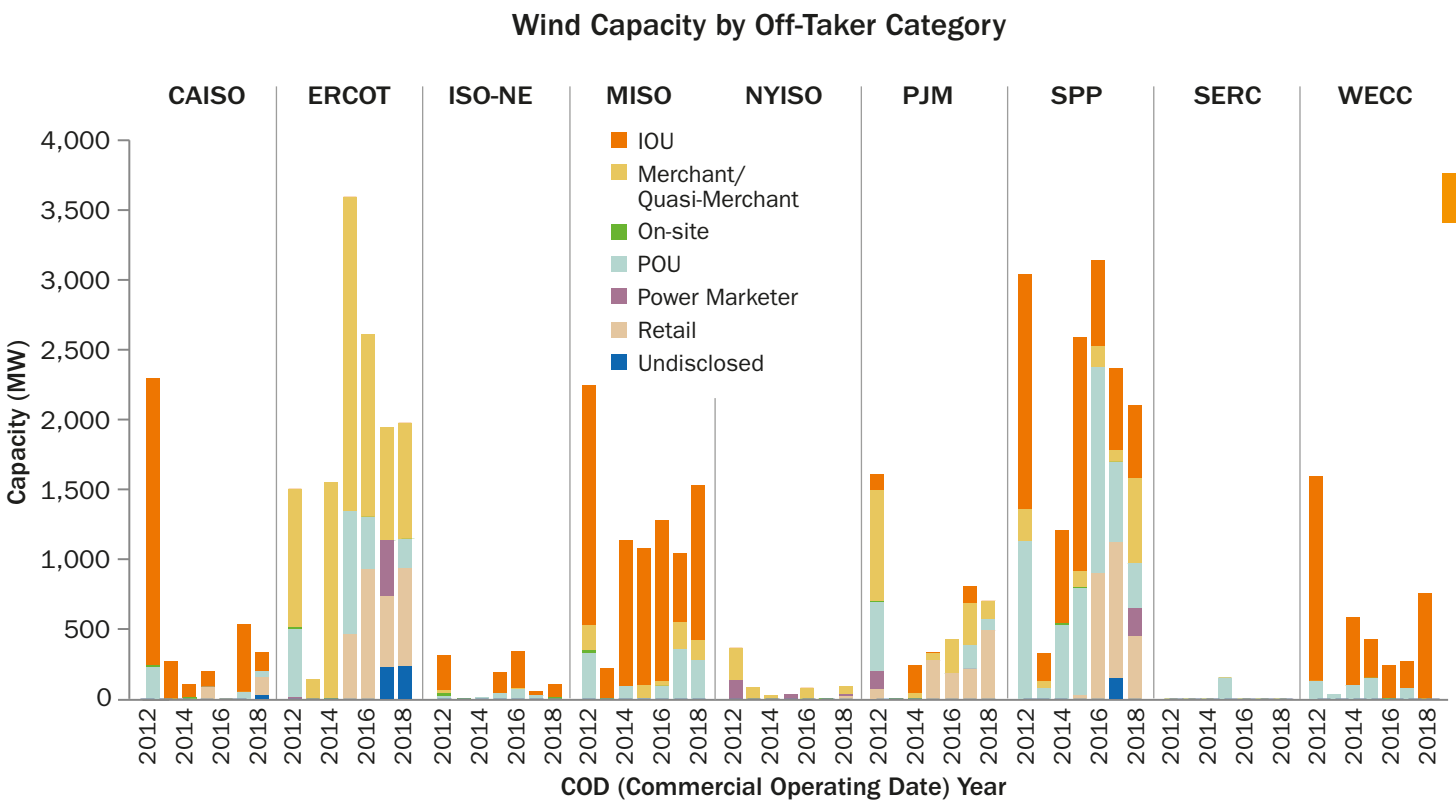
[2] "Offtake Structures for Wind Energy Projects," O'Melveny and Myers LLP, https://www.lexology.com/library/detail.aspx?g=90447330-da9e-4352-8be9-ee0f6ccc8f71

[3] Power marketers are defined here to include commercial intermediaries that purchase power under contract and then resell that power.

Off-Take Arrangements: Summary (continued)

- In 2018, electric utilities were also the largest off-takers for new solar projects in most regions, representing 84% of new solar capacity installed, where investor-owned utilities supported 61% of new capacity and publicly owned utilities supported 23%. Direct retail purchasers accounted for 14% of total new solar capacity in 2018, of which 53% was in PJM and 38% was in ERCOT. Power marketers accounted for 8.0% of 2018 new solar capacity in CAISO.

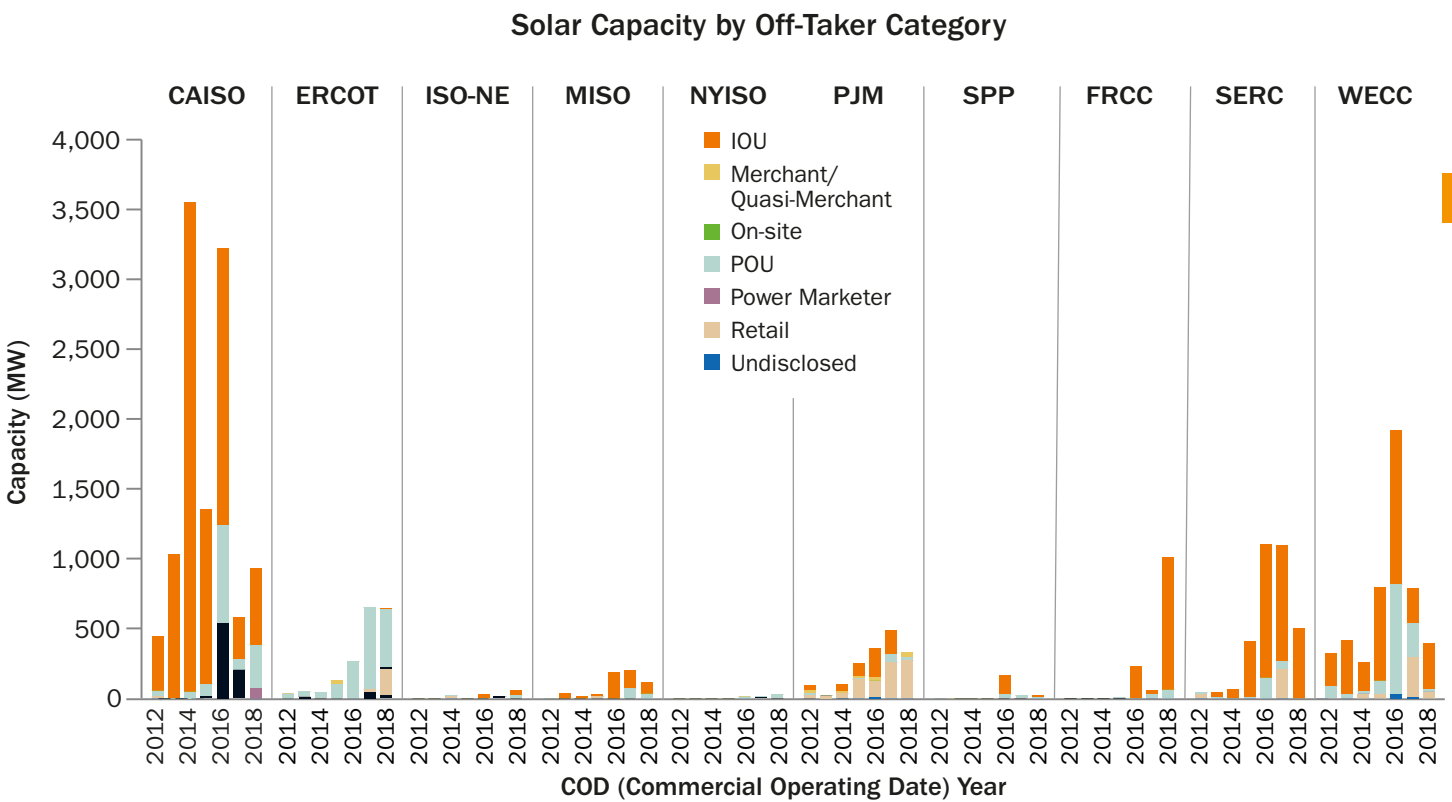
Off-Take Arrangements: Wind



Source: Berkeley Lab estimates as reported in Wiser and Bolinger (2019)

Notes: IOU = investor-owned utility; POU = publicly owned utility; numbers are for new capacity installed in that year rather than cumulative capacity.

Off-Take Arrangements: Solar

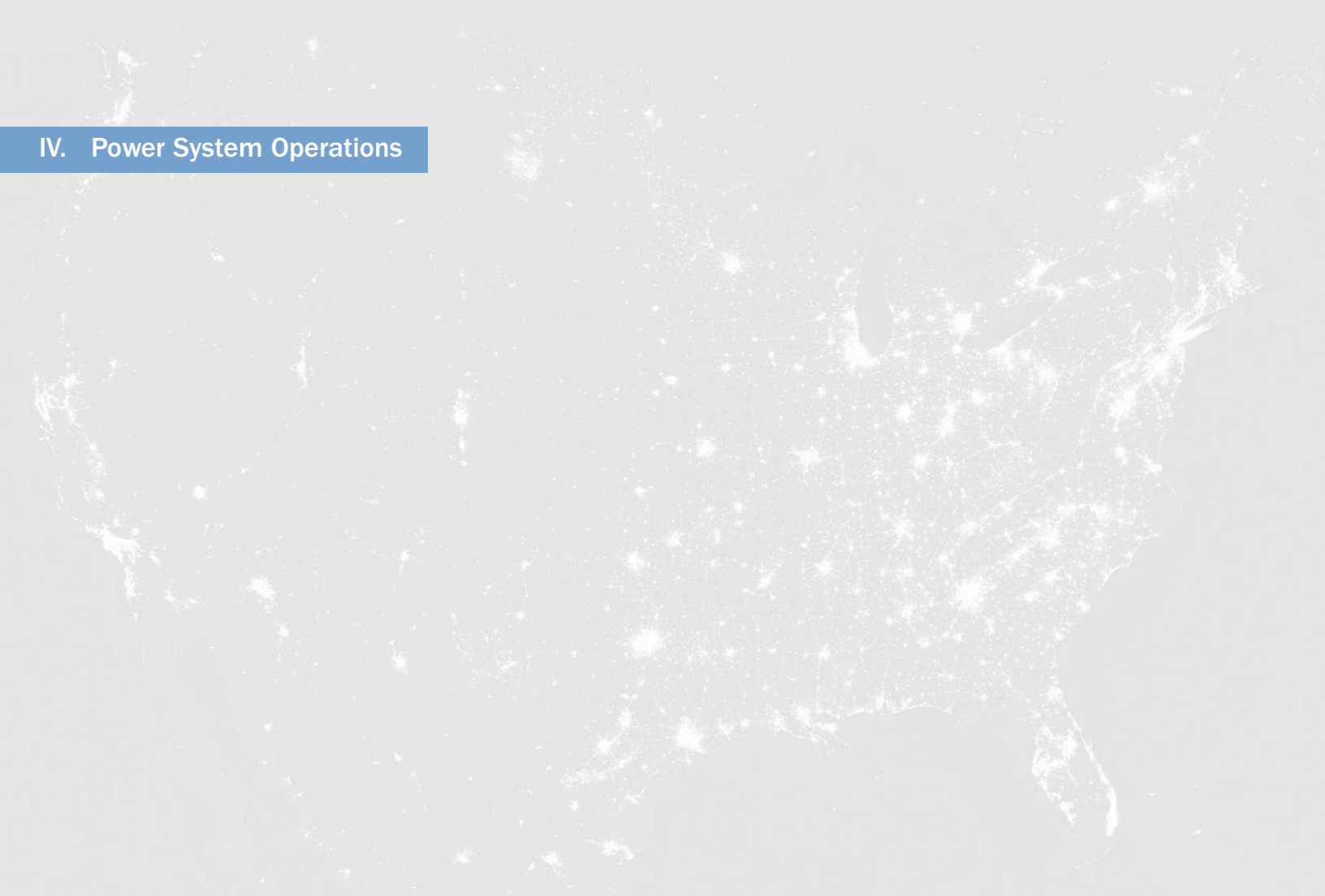


III

Source: Berkeley Lab estimates collected as part of Bolinger, Seel, and Robson (2019)

Notes: Numbers are for new capacity installed in that year rather than cumulative capacity.

IV. Power System Operations



Maximum Hourly VRE Penetration: Summary

Maximum instantaneous penetration refers to the maximum observed ratio of generation from a set of sources to load over a defined period (commonly a year) at a given point in time (an hour for the purposes of this data book).

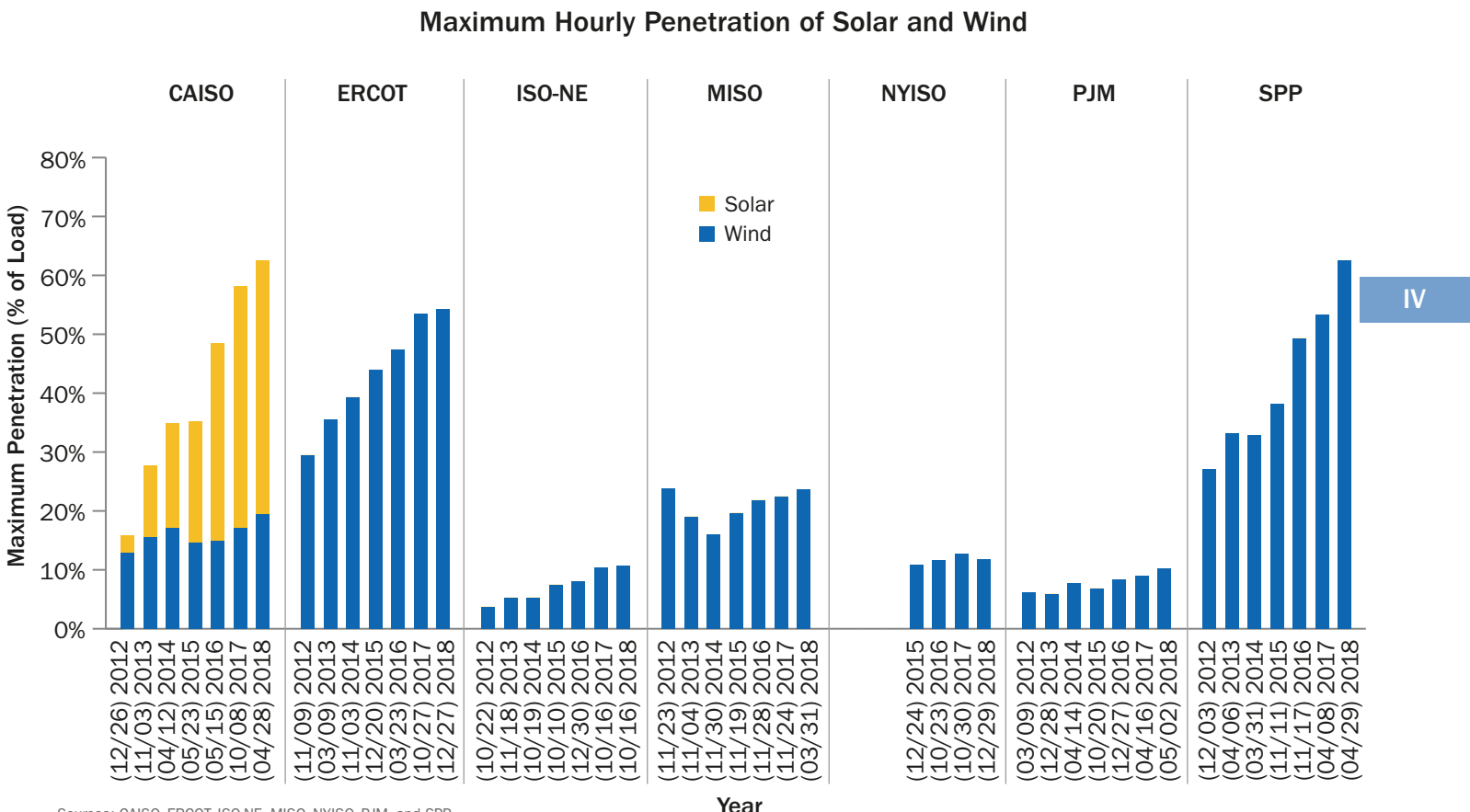
- In 2018, maximum hourly penetration[1] of wind and solar generation reached nearly 62.6% in CAISO (on April 28 when it consisted of 43.1% solar and 19.5% wind), 62.5% in SPP (on April 29), and 54.3% in ERCOT (on December 27). The highest levels of hourly wind penetration were 23.6% in MISO (on March 31), 11.8% in NYISO (on December 29), 10.7% in ISO-NE (on October 16), and 10.2% in PJM (on May 2).

- Internationally, hourly VRE penetration maxima occured in Denmark (139%), Germany (89%) and Ireland (88%).[2]

[1] The values reported here are maximum hourly penetration of wind and solar as a percentage of load. More-resolved five-minute market data can result in different values; for example, maximum five-minute penetration of wind and solar (as a percentage of load) in SPP occurred on April 30 in 2018 (see page 64). Distributed PV is not included in either the generation or the load components of the equation.

[2] Ela 2019

Maximum Hourly Penetration of Solar and Wind



Sources: CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: Solar includes solar PV and CSP. Data availability for NYISO before 2016 is limited.

Reported Maximum VRE Penetration: NYISO

	Maximum Five-minute Penetration of Wind in NYISO						
	2012	2013	2014	2015	2016	2017	2018
Maximum Percentage of Load Served by Wind (%)	10.48%	10.27%	10.97%	11.51%	11.78%	13.05%	11.51%
Year/Date	10/30/2012	11/01/2013	12/25/2014	11/27/2015	10/23/2016	10/30/2017	11/07/2018

IV

Sources: Personal communication from NYISO received on October 31, 2019.

Reported Maximum VRE Penetration: SPP

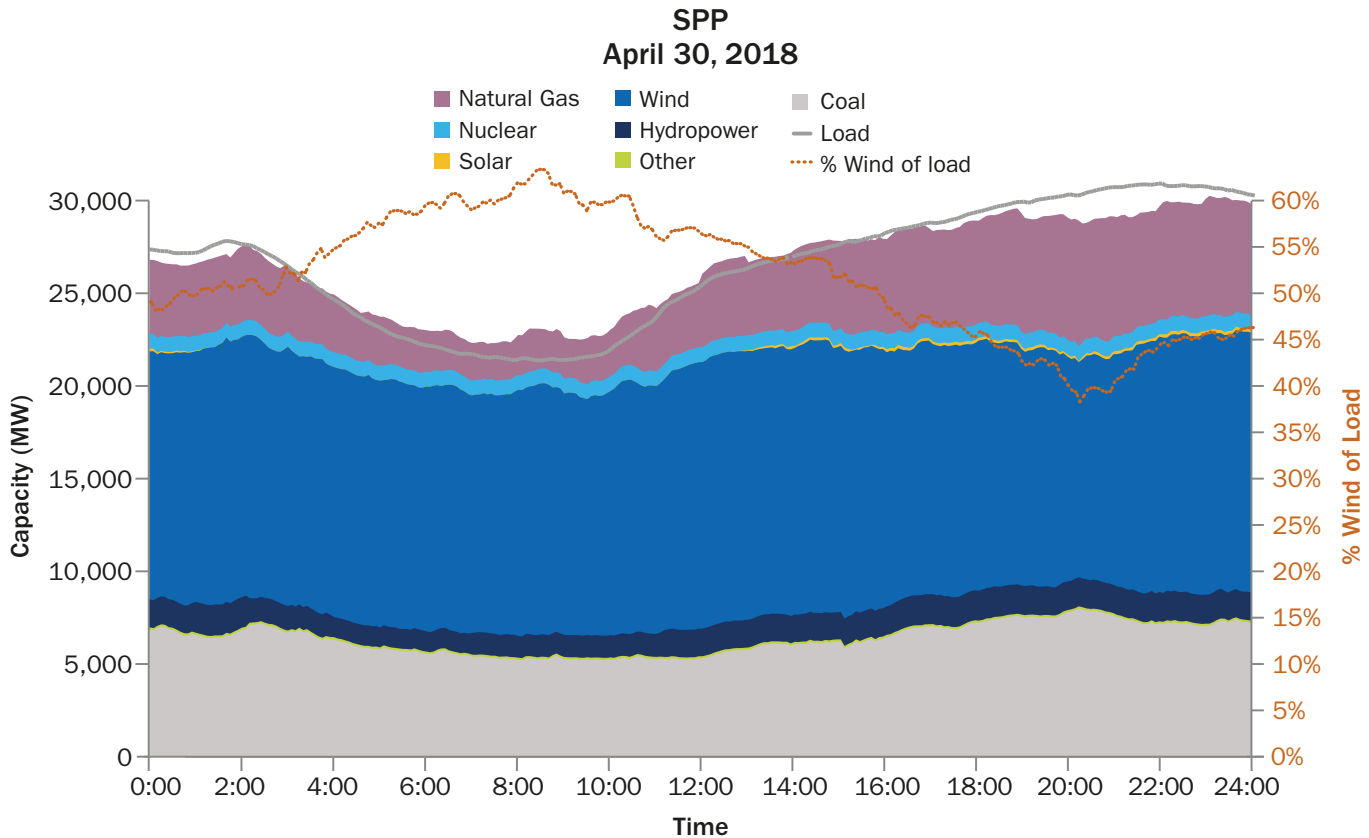
Southwest Power Pool (SPP)

- On April 30, 2018 at 8:30 a.m., SPP reached maximum five-minute VRE generation penetration of 63.38% (13,542 MW) of load. Coincident with load increasing and wind generation declining in the morning hours, generation from coal (+53%) and gas (+253%) increased from 4:00 a.m. to 10:00 a.m.

- Peak load conditions on this day occurred at around 10:55 p.m., when five-minute averaged wind generation contributed 44.54% to load. During this period, thermal power contributed 23.26% (coal) and 19.68% (natural gas) to load.

- Maximum wind generation in 2018 was 16,300 MWh (49.75% of total load) at 2:35 p.m. on December 20.

Maximum Five-Minute VRE Penetration: SPP



Source: "Generation Mix Historical," Southwest Power Pool, https://marketplace.spp.org/pages/generation-mix-historical

Notes: Data are five-minute data. Generation above load is presumably exported, and generation below load presumably represents imports (i.e., load is certainly met by the supply).

IV

Reported Maximum VRE Penetration: CAISO

California Independent System Operator (CAISO)

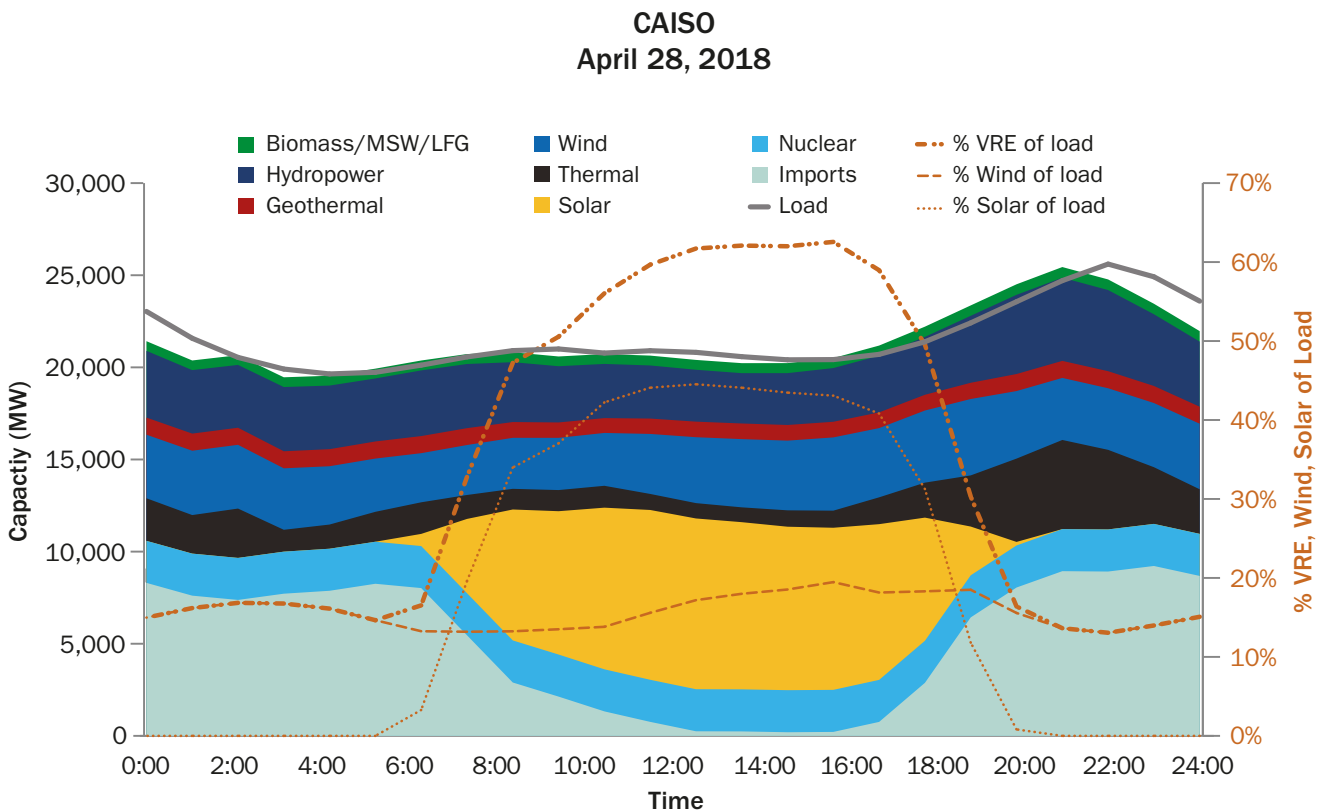
- On April 28, 2018, CAISO reached its maximum hourly VRE generation penetration of 62.6% (12,774 MW) of load at around 4 p.m., when solar contributed 43.1% and wind contributed 19.5% to load. During the same hour, the diverse mix of all renewable generation sources in CAISO (including wind, solar, hydropower, geothermal, and biopower) jointly exceeded 80%. Generation from renewables into the early afternoon hours coincided with downward ramping of imports (-97.6%), hydropower (-23.4%), and thermal generation (-53.1%) from 5 a.m. to 2 p.m.

- Peak load on this day—April 28, 2018—was reached at 10 p.m., when VRE contributed 13.1% to load, while imports (34.8%), hydropower (17.2%), and thermal (16.9%) contributed the largest shares to load.

- Maximum hourly VRE generation occurred on June 9, 2018 at 2 p.m., with 14,731 MW (58.8% of total load). Solar maximum generation in 2018 was 10,729 MW on June 29, 2018 at 1 p.m. Maximum wind generation was 5,006 MW on June 9, 2018 at 5 p.m.

Notes: Data do not include behind-the-meter PV due to limited data availability.

Maximum Hourly VRE Penetration: CAISO



Source: ABB Ability Velocity Suite
Notes: Data are hourly.

Reported Maximum VRE Penetration: ERCOT

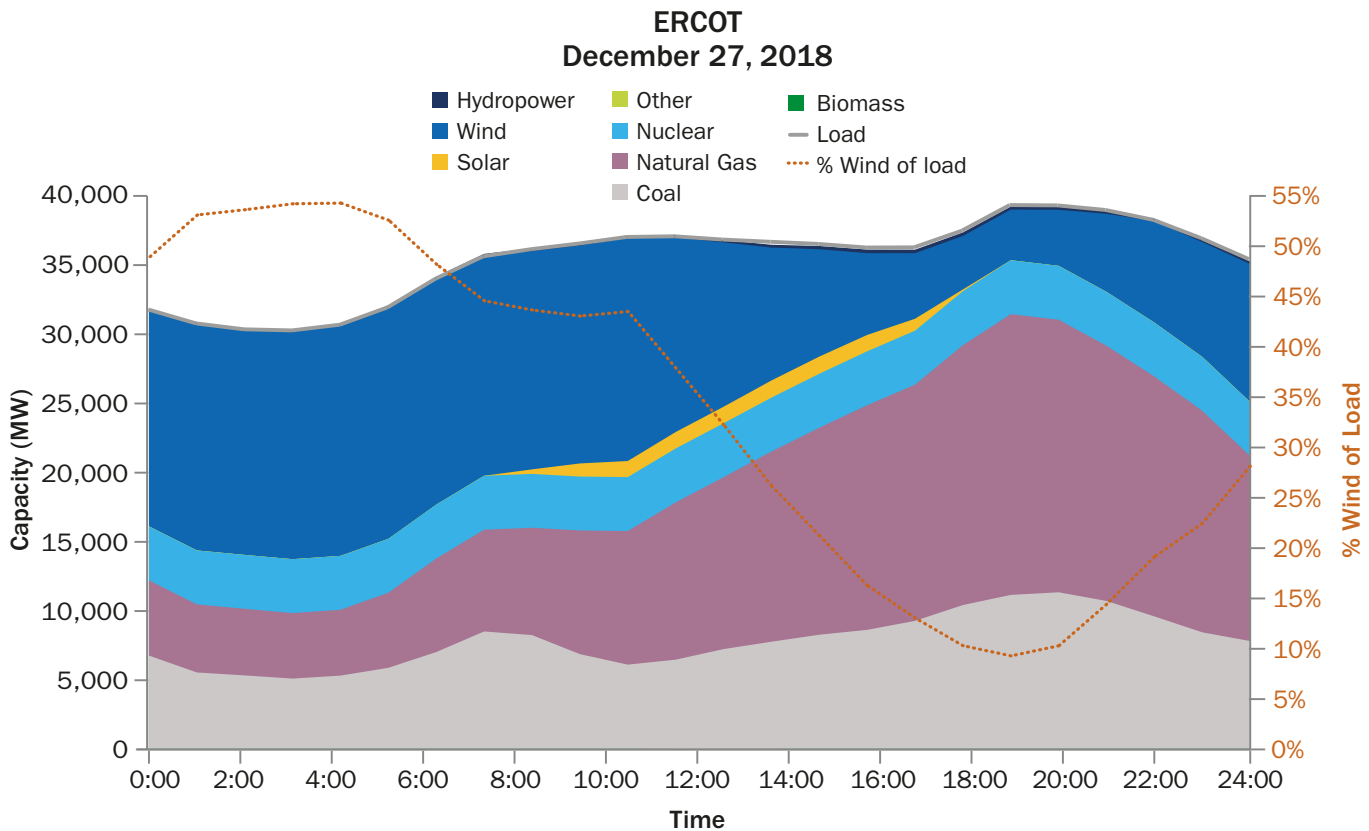
Electric Reliability Council of Texas (ERCOT)

- On December 27, 2018 at 5 a.m., ERCOT reached its maximum hourly VRE generation of 54.3% (16,661 MW) of load. Coincident with load increasing and wind generation declining in the afternoon hours, generation from gas (+110%) and coal (+82.8%) increased from 11 a.m. to 7 p.m.

- Peak load on this day occurred at 6 p.m., when hourly average wind generation contributed 9.3% to load while natural gas (51.6%), coal (28.3%), and nuclear (9.9%) contributed the largest shares to load.

- Maximum hourly wind generation in 2018 occurred on December 14 at 4 a.m. with 18,979 MW (52% of total load).

Maximum Hourly VRE Penetration: ERCOT



Source: ABB Ability Velocity Suite
Notes: Date are hourly.

Net Load and Ramping: Summary

Net load is the total electric demand of a power system minus generation from VRE (i.e., wind and solar[1]). Depicted as a "net load graph" over the duration of a day, the metric can indicate whether VRE increases grid flexibility needs (e.g., upward and downward ramping and minimum generation requirements of thermal generators) and the potential for VRE over-generation under existing technical and institutional constraints on power system operation.[2]

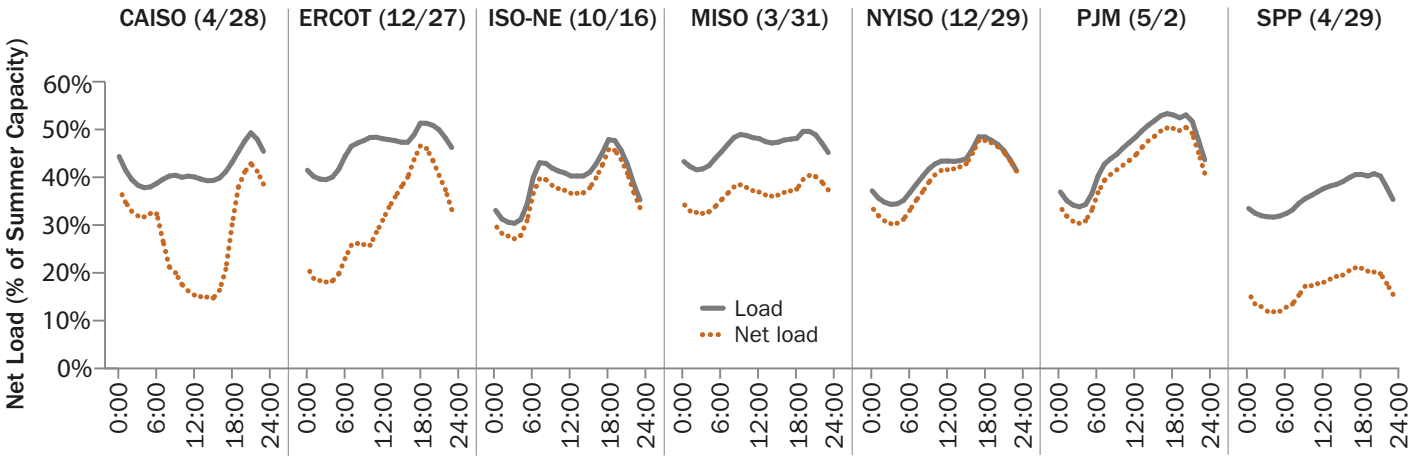
- In CAISO, the net load during the day of highest VRE penetration has increasingly assumed a duck curve[3] shape since 2013. On April 28, 2018—the day with highest VRE penetration in 2018—the difference between the minimum net load at 3 p.m. and the maximum at 9 p.m. amounted to 14,600 MW of ramping demand that the system successfully addressed.
- The largest three-hour ramping event in 2018 occurred in MISO at 36.2 GW on July 9 (i.e., 0.14% of summer capacity per minute), followed by PJM at 30.0 GW on September 3 (0.09% per minute), CAISO at 19.3 GW on September 6 (0.63% per minute), ERCOT at 17.3 GW on July 22 (0.13% per minute), and SPP at 10.4 GW on April 29 (0.09% per minute).

[1] The net load curve calculation here does not consider run-of river hydropower generation or behind-the-meter solar PV.

[2] Denholm et al. 2015

[3] CAISO has used the term "duck curve" to describe the shape of a net load curve that is characterized by a midday solar "belly" and a steep evening "neck."

Net Load Curve for Highest VRE Penetration Day (2018)



Sources: CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: In the net load chart, a representative day was selected for each ISO/RTO region based on the highest penetration of renewable energy generation on an hourly basis during a given year. The net load curve calculation here does not consider run-of river hydropower generation or behind-the-meter solar PV.

Maximum 3-Hour Ramp in 2018

ISO	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Date	4/28	12/27	10/16	3/31	12/29	5/2	4/29
GW	19.3	17.3	4.4	36.2	5.9	29.9	10.4

Sources: CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: Maximum three-hour ramp is calculated in terms of net load (i.e. hourly load minus hourly wind and solar generation).

Reserve Margins: Summary

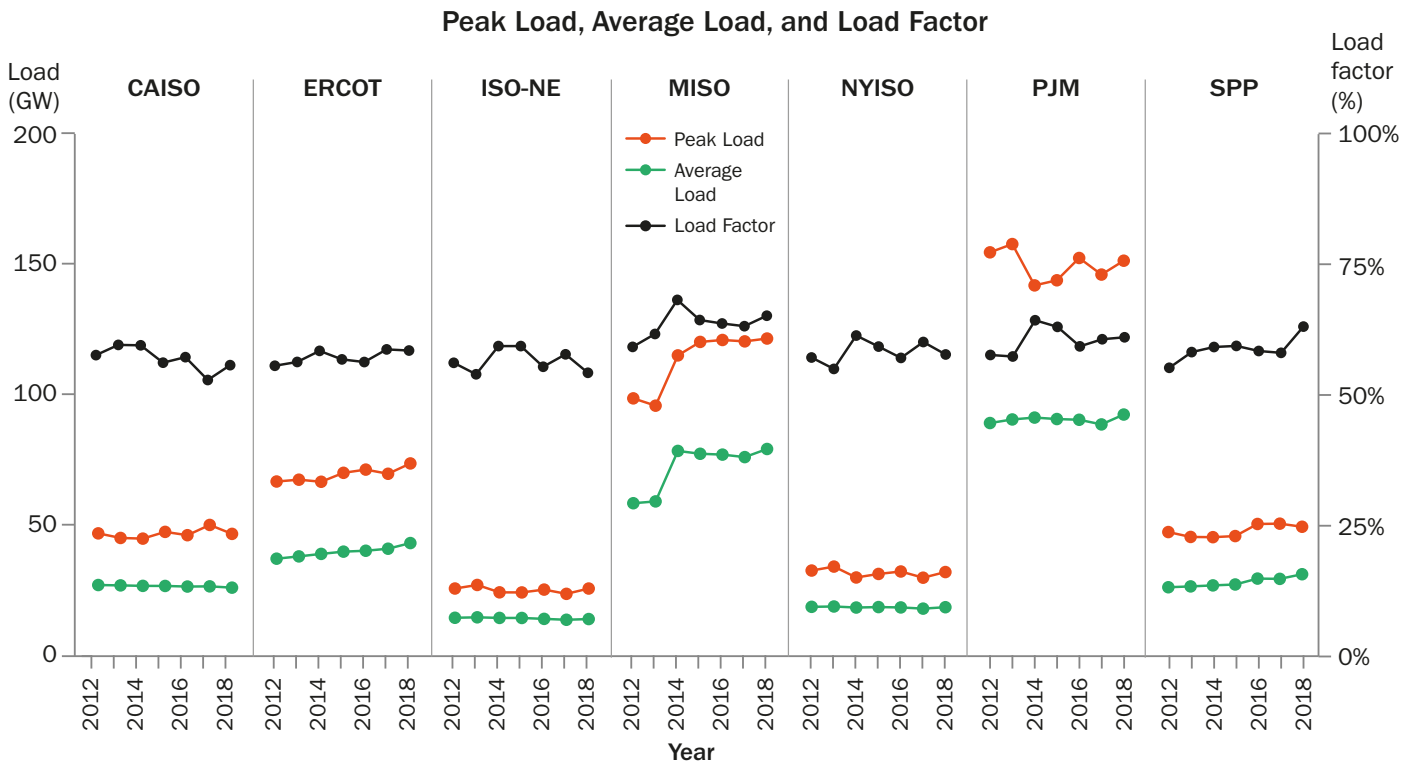
The reserve margin is the expected additional capacity available beyond the projected peak coincident system load.[1] It accounts for peak load forecast error and capacity needed for ancillary services and unexpected outages during peak times. It provides an indication of the resource adequacy between available generation capacity and expected demand within a planning horizon to ensure reliability of the electric power system. NERC's generic reference reserve margin level is 15% for predominately thermal and 10% for predominately hydropower power systems.[2] Region-specific reference margin levels are specified by NERC entities.[3]

- Reserve margin levels generally stayed between 15% and 30% between 2012 and 2018.
- Between 2012 and 2018, reserve margin levels remained above the generic NERC reference reserve margin level, with the exception of the ERCOT market, where reserve margin levels were lower in certain years, in the range of 10.0% to 15.0%.
- In 2018, reserve margin levels ranged from 10.9% (ERCOT) to 32.8% (PJM).

[1] Reserve margin is calculated by dividing the difference between total capacity and noncoincident peak demand by noncoincident peak demand in each region. Data for year 2012 to 2016 are from Form EIA-411, and data for year 2017 and 2018 are the estimated value from NERC (2017), NERC (2018a).

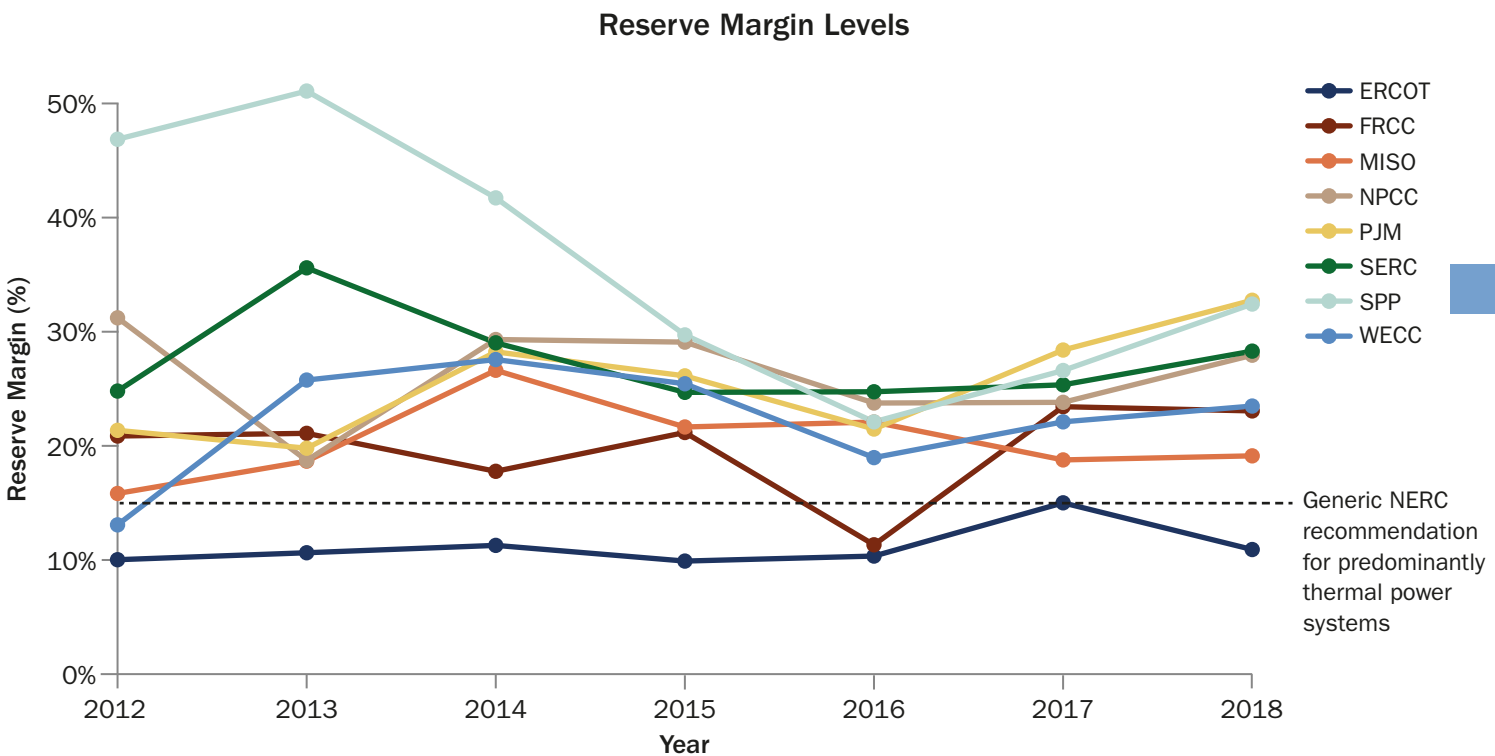
[2] EIA (Form EIA-411)

[3] The NERC reference margin levels for summer/winter of 2019 are 15.0% (FRCC), 17.1% (MISO), 16.9% (NPCC-New England),15.0% (NPCC-New York), 15.9% (PJM), 15.0% (SERC), 12.0% (SPP), 13.8% (TRE-ERCOT), and 19.7% (WECC Northwest Power Pool-US), according to NERC (2018b).



Source: ABB Ability Velocity Suite

Note: Load factors are calculated by dividing the load (GWh) in a year by the product of peak load (GW) and the number of hours of the whole year.



Sources: EIA (Form EIA-411); NERC (2017), NERC (2018a).

Notes: NERC's generic reference reserve margin level is 15% for predominately thermal systems and 10% for predominately hydropower power systems (NERC n.d.). Data for year 2012 to 2016 are from Form EIA-411, and data for year 2017 and 2018 are the estimated value from NERC (2017), NERC (2018a).

Essential Reliability Services: Summary

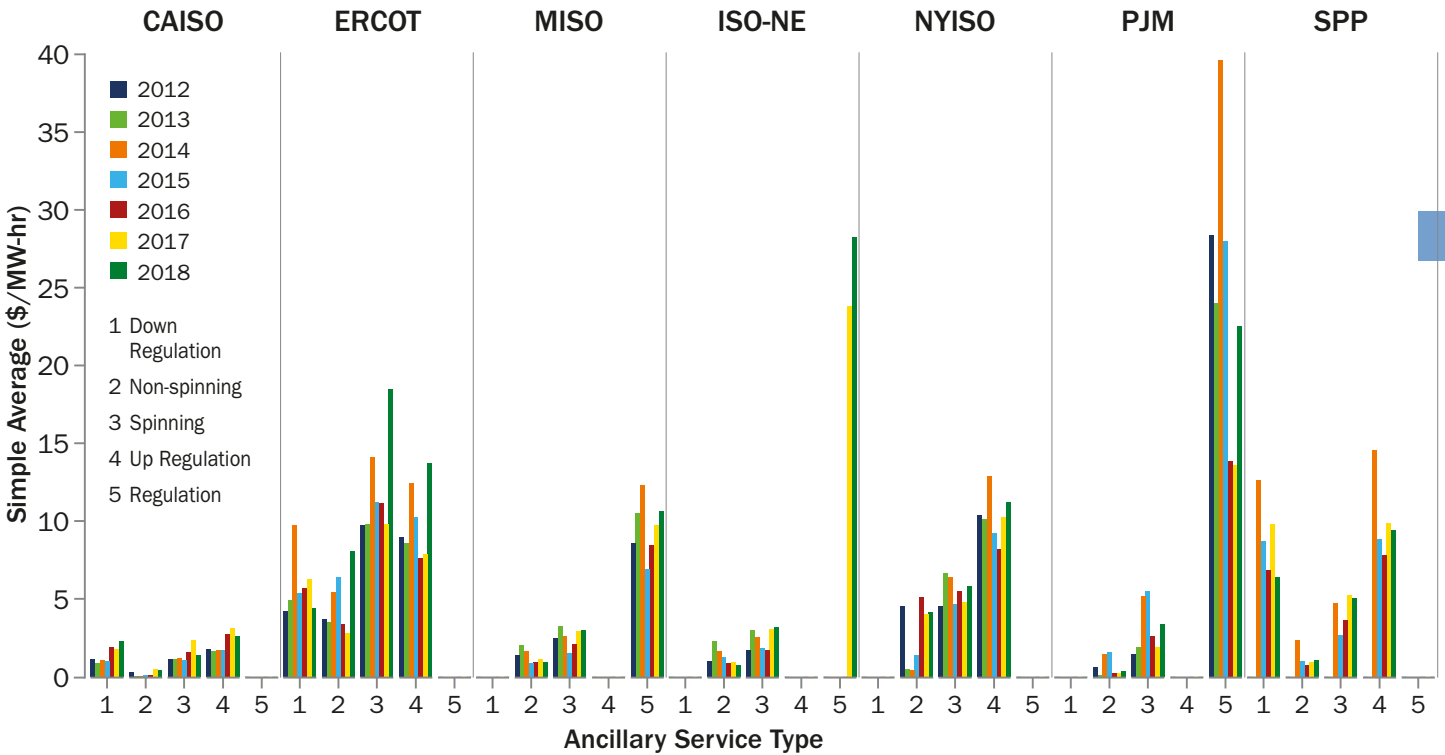
Essential reliability services, also known as ancillary services, are services that help keep the electric grid reliable by ensuring a balance between supply and demand.[1] These services include three categories: frequency support, ramping and balancing, and voltage support. Different markets develop different market products for ancillary services, and the prices and volumes of the products reflect the operational changes with different level of VRE penetration.

- Essential reliability service prices vary across regions and service types. Within each market, average service prices are the highest for regulation service. From 2017 to 2018, the annual average regulation price increased $8.0 per megawatt-hour (MW-hr) (49.5%) in PJM, $4.4/MW-hr (10%) in ISO-NE, $1.0/MW-hr (9.3%) in NYISO, $5.9/MW-hr (74.6%) for up regulation and -$1.9/MW-hr (-29.9%) for down regulation in ERCOT, -$0.5/MW-hr (-4.7%) for up regulation and -$3.4/MW-hr (-34.5%) for down regulation in SPP, and -$0.5/MW-hr (-17.6%) for up regulation and $0.5/MW-hr (27.5%) for down regulation in CAISO.

- In CAISO, annual average service volume was 329 MW-hr for down regulation (0.7% of 2018 peak demand), 241 MW-hr for up regulation (0.5%), 534 MW-hr for spinning reserve (1.2%), and 632 MW-hr for non-spinning reserve (1.4%) in 2018, with changes of +30.8%, -5.3%, +26.4% and +38.6% relative to their 2012 levels. In ERCOT, annual average service volume was 294 MW-hr for down regulation (0.4% of 2018 peak demand), 314 MW-hr for up regulation (0.4%), 2757 MW-hr for responsive reserve (3.8%), and 1563 MW-hr for non-spinning reserve (2.1%) in 2018, with changes of -35.1%, -40.4%, +2.7% and +6.7% relative to their 2012 levels.

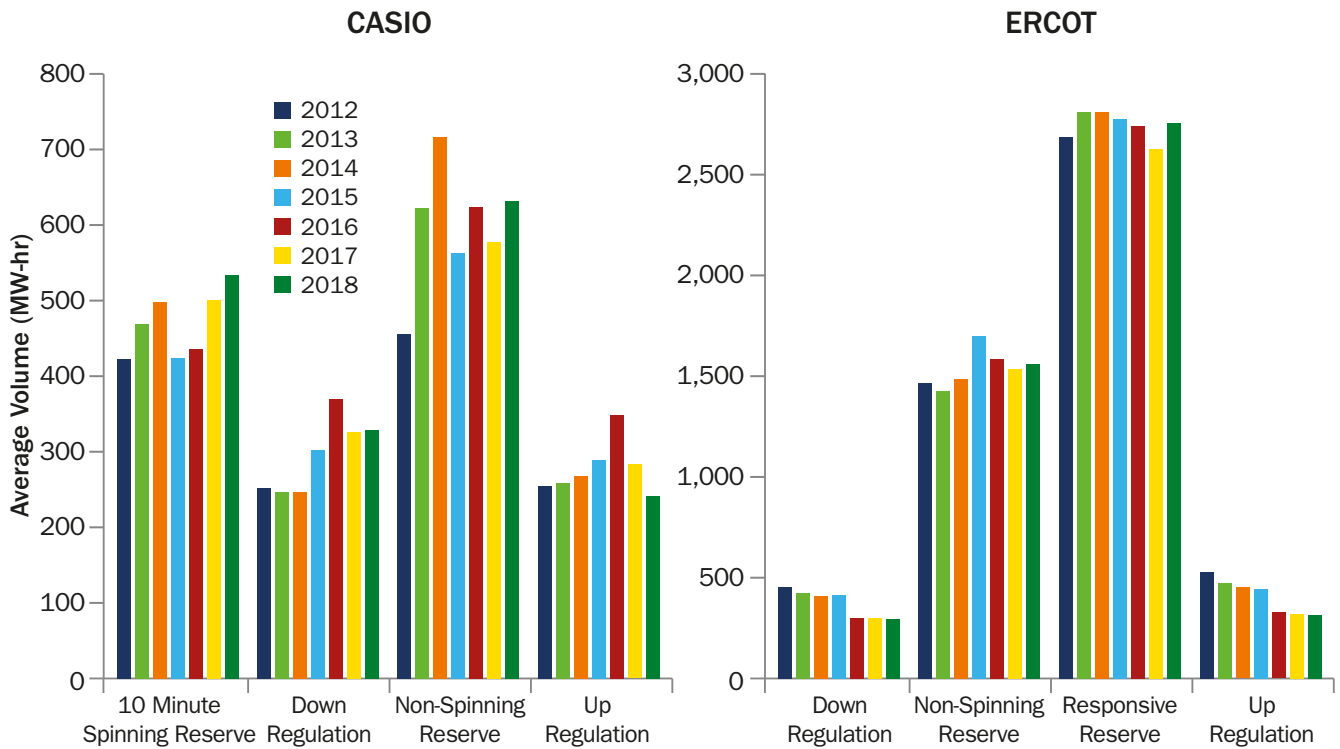
[1] NERC 2016

Annual Average Prices of Essential Reliability Services



Sources: CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: Price data are accessed as annual average service price; CAISO, ERCOT, and NYISO prices are reported in the DA market; ISO-NE, MISO, PJM and SPP prices are reported in the RT market. Values reported for other metrics can be found in each market's annual report (see page 115).



IV

Sources: CAISO and ERCOT (accessed through the ABB Ability Velocity Suite)

Forecast Error: Summary

Forecast error captures the difference between forecasted and actual electric generation during a predefined time interval. Forecast error can affect a range of system operations, including scheduling, dispatch, RT balancing, and maintenance of reserve requirements. High accuracy in forecasting in day-ahead (DA) and intraday scheduling can reduce fuel costs, improve system reliability (e.g., lower reserve margin requirements), and reduce curtailment of renewable resources.[1] The magnitude of forecast error is generally determined by the forecast time-horizon reflected in market operational rules, local geographic conditions (e.g., complex topography or cloud cover), geographic diversity of plant installations, and forecast input data quality.[2]

IV

- From 2012 to 2018, annual average hourly DA overprediction forecast errors of wind[3] (i.e., actual generation less than the DA market forecast) generally decreased in ERCOT from 7.5% in 2012 to 5.6% in 2018. In MISO, the forecast errors increased from 5.5% in 2014 to 9.8% in 2018.[4] And in SPP, they increased by from 5.6% in 2014 to 6.1% in 2017.

- Average hourly DA underprediction forecast errors of wind (i.e., actual generation was greater than the forecast) generally decreased in ERCOT from 7.6% in 2012 to 5.0% in 2018, while they increased in MISO (from 4.5% in 2012 to 9.4% in 2018) and in SPP (from 4.2% in 2012 to 4.9% in 2017).

[1] Greening the Grid 2016

[2] O'Neill 2016

[3] Forecast error was calculated as the absolute value of the hourly difference between actual and forecasted energy over total installed wind capacity.

[4] The forecast errors in MISO for 2015 and 2016 were updated in the ABB Velocity Suite, so the numbers do not match exactly those in the 2016 edition of the data book.

Power System Operations: Summary (continued)

- Forecast errors using forecast generation from the market day were smaller than DA forecast errors. Average hourly overprediction forecast errors of wind using market day forecast (i.e. actual generation less than the market day forecast) was 2.9% in ERCOT (compared to 5.6% DA overprediction), 8.0% in MISO (compared to 9.8%) in 2018 and 2.3% in SPP (compared to 6.1%) in 2017. Average hourly underprediction forecast errors of wind using market day forecast (i.e. actual generation greater than the market day forecast) was 1.9% in ERCOT (compared to 5.0% DA overprediction), 9.8% in MISO (compared to 9.4%) in 2018 and 1.2% in SPP (compared to 4.9%) in 2017.

- In 2018, the maximum hourly DA overprediction of wind was 62.6% in MISO and 36.3% in ERCOT. Maximum hourly overprediction of wind using market day forecast was 30.1% in MISO and 21.2% in ERCOT.

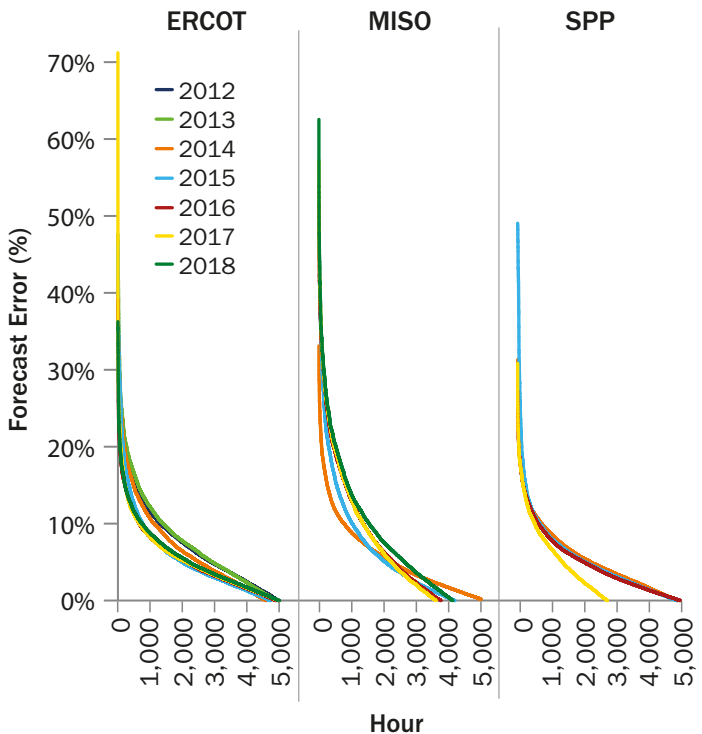
- In 2018, the maximum hourly DA underprediction of wind was 48.2% in MISO and 38.1% in ERCOT. Maximum hourly underprediction of wind using market day forecast was 35.9% in MISO and 16.3% in ERCOT.

- In CAISO, annual median hourly DA overprediction forecast errors of solar increased from 2.0% in 2013 to 3.6% in 2018, while annual median hourly DA underprediction forecast error of solar decreased from 13.1% in 2013 to 6.3% in 2018.[1]

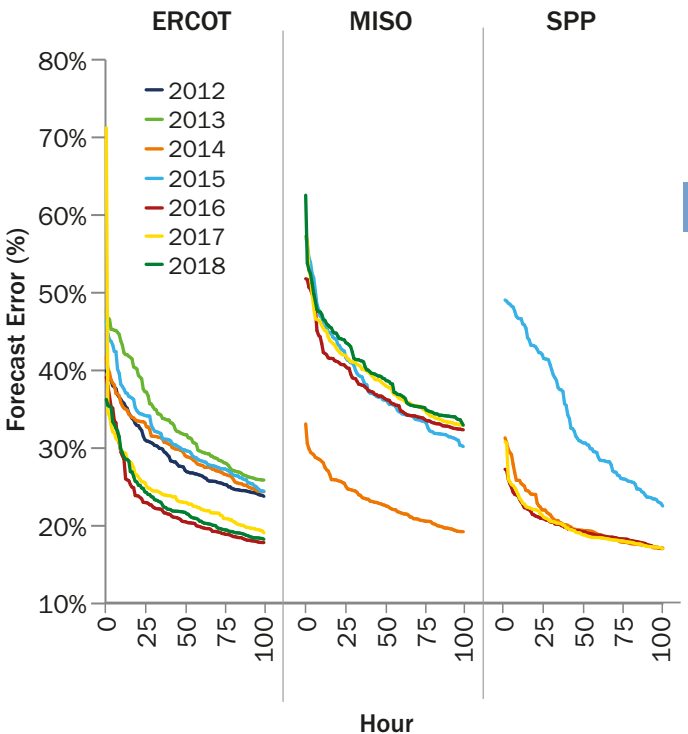
[1] Data for day-ahead hourly solar forecast is from CAISO OASIS (http://oasis.caiso.com/mrioasis/logon.do), and data for hourly solar generation is from ABB Ability Velocity Suite.

Forecast Errors

Overpredictions of Day-Ahead (DA) Wind Forecast



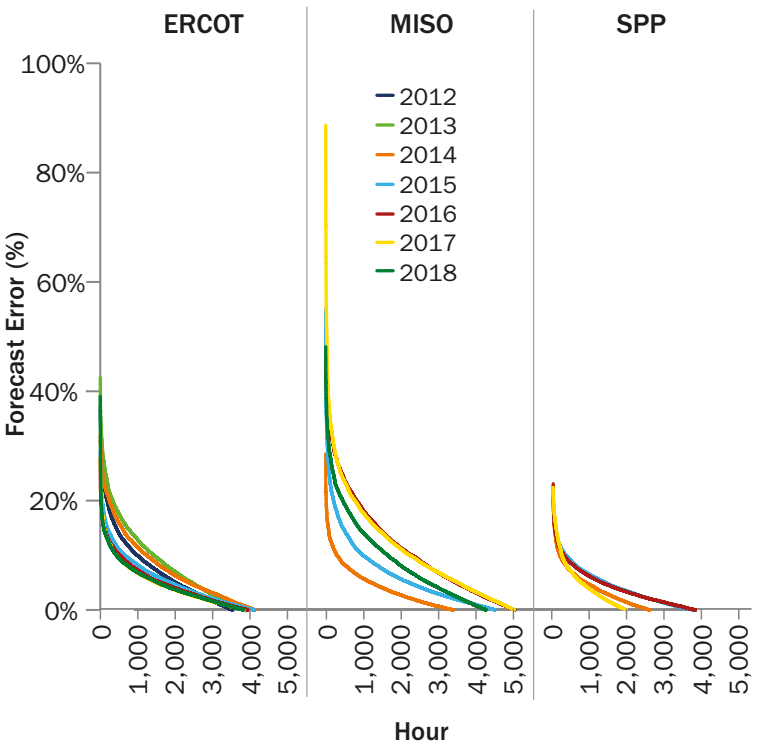
100 Hours of Largest Overpredictions of Day-Ahead Wind Forecast



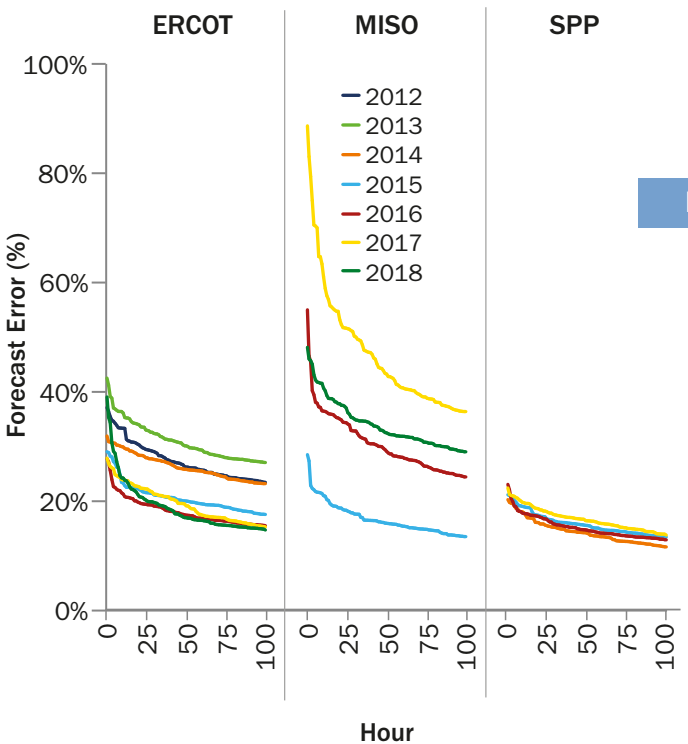
Sources: ERCOT, MISO, and SPP (accessed through the ABB Ability Velocity Suite). Data availability for SPP in 2018 is limited.

Notes: Forecast error was calculated as the absolute value of the hourly difference between actual and forecasted wind generation over total installed wind capacity.

Underpredictions of Day-Ahead Wind Forecast



100 Hours of Largest Underpredictions of Day-Ahead Wind Forecast



Sources: ERCOT, MISO, and SPP (accessed through the ABB Ability Velocity Suite)

Notes: Forecast error was calculated as the absolute value of the hourly difference between actual and forecasted wind generation over total installed wind capacity.

VRE Curtailments: Summary

Curtailment is a prescribed reduction in scheduled capacity or energy delivery. Curtailment of renewables and thermal generators result from transmission congestion, minimum operating levels of thermal generators or hydropower, or back-feeding in the distribution system.[1]

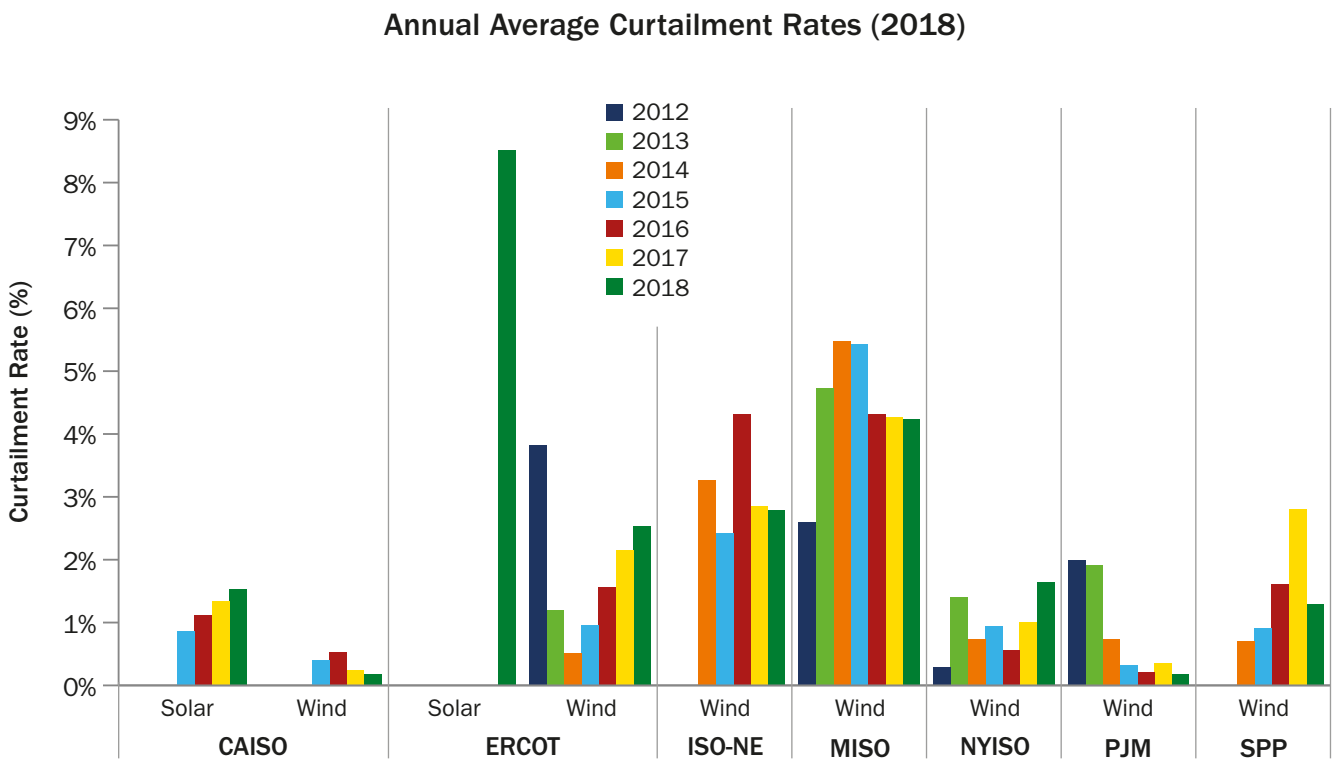
- The highest annual average wind curtailment rates were observed in 2018 in MISO (4.2%), followed by ISO-NE (2.7%), ERCOT (2.5%), NYISO (1.7%), SPP (1.3%), and PJM and CAISO (0.5%).

- In MISO, the annual wind curtailment rate has remained greater than 4% since 2013. In ERCOT, wind curtailment rate increased from 0.9% in 2014 to 2.5% in 2018. PJM experienced a decrease in wind curtailment rate from 2.0% in 2012 to 0.2% in 2018.

- The annual solar curtailment rate in CAISO increased from 0.8% of its total generation in 2015 to 1.5% in 2018, as solar penetration increased from 7.3% in 2015 to 13.1% in 2018. ERCOT had over 8% of solar curtailment in 2018.

[1] Lew et al. 2013

VRE Curtailments

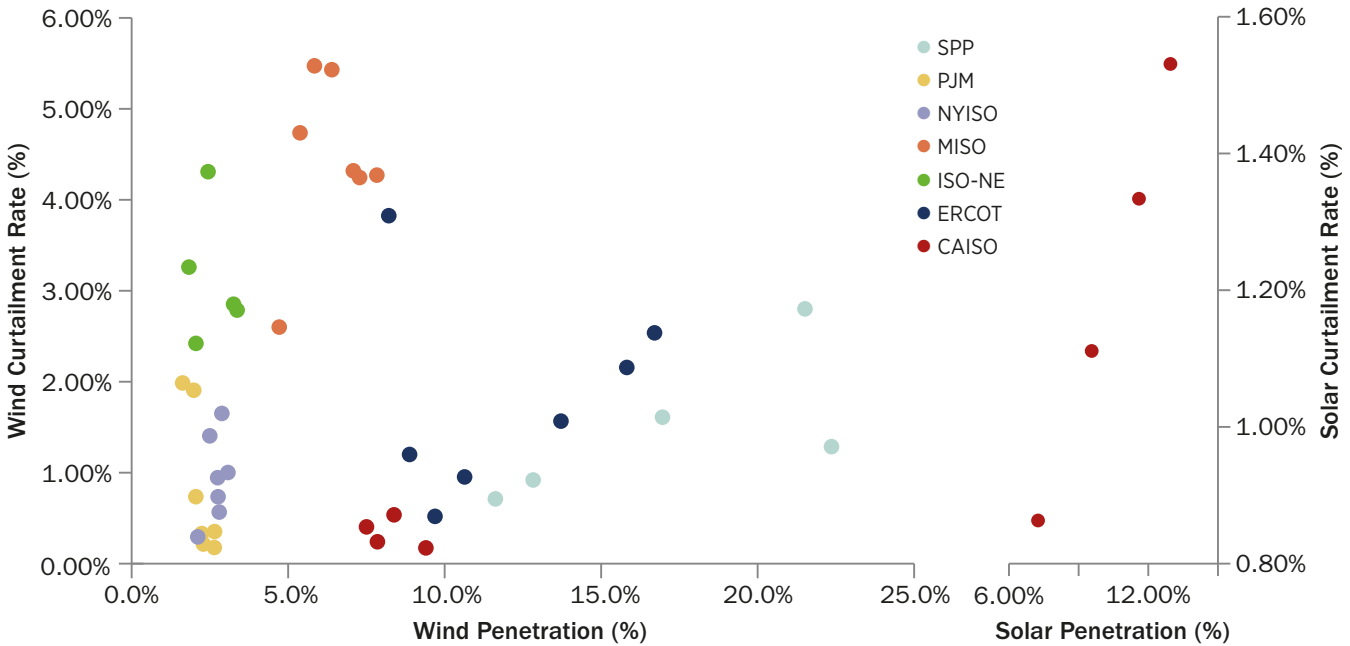


Sources: Curtailment data collected from ISOs and reported in Wiser and Bolinger (2019) and Bolinger, Seel, and Robson (2019)

Notes: The depicted data include both "forced" (i.e., ISO-instructed) and "economic" (i.e., incentivized by prevailing LMP) curtailment. Solar curtailment data availability for ERCOT before 2016 is limited.

Annual Average Wind Curtailment as a Percentage of Wind Penetration

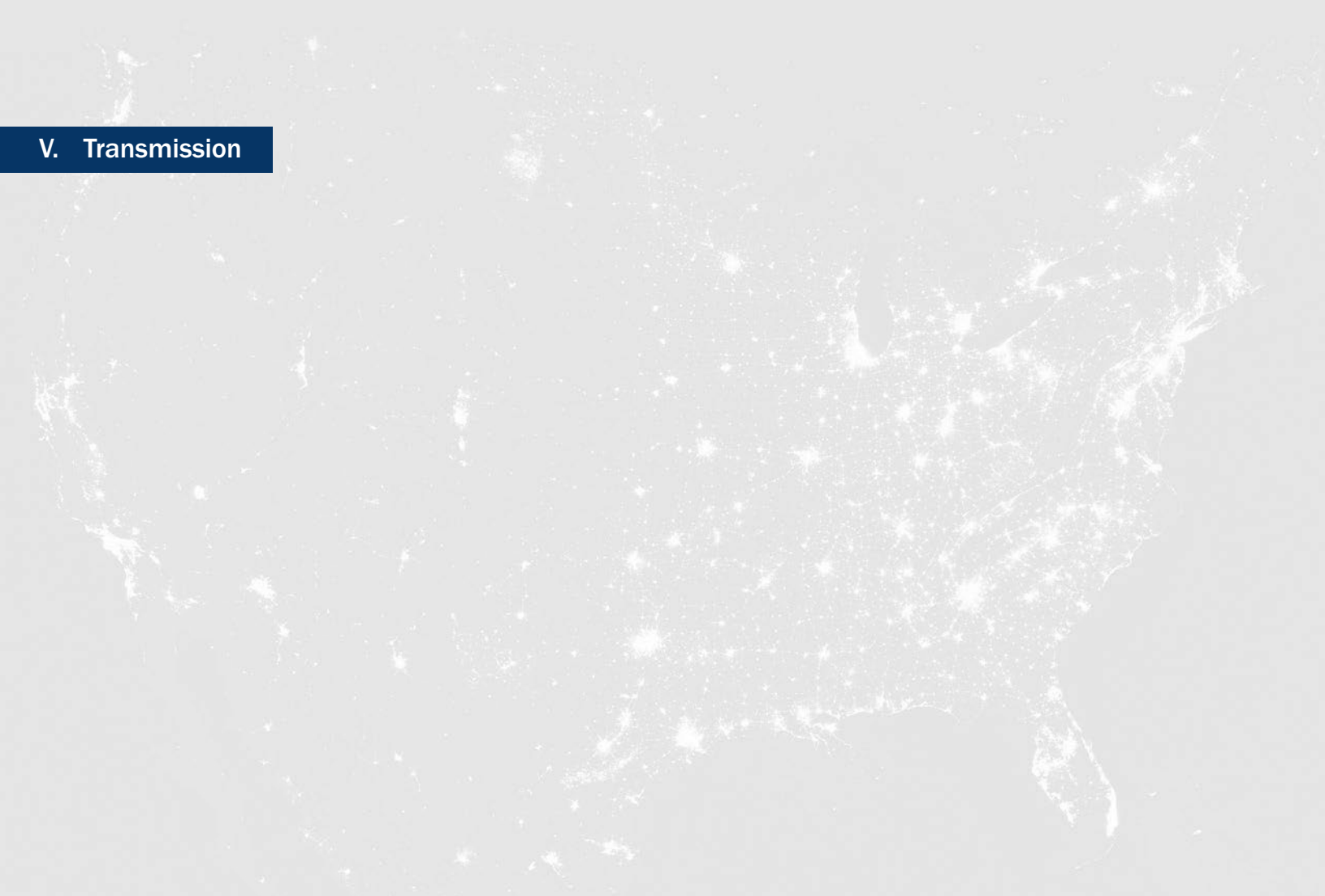
Annual Average CAISO Solar Curtailment as a Percentage of Solar Penetration



Sources: Curtailment data collected from ISOs and reported in Wiser and Bolinger (2019) and Bolinger, Seel, and Robson (2019); EIA (Form EIA-860, Form EIA-923)

Note: Each data point represents a different year from 2012 to 2018.

V. Transmission



Existing and Proposed Long-Distance Transmission Capacities: Summary

The bulk transmission system is the network that connects electricity from utility-scale generators to local substations for distribution to end-use consumers. Sufficient transmission capacity can enable reliable electricity service to customers, relieve congestion, facilitate robust wholesale market competition, integrate a diverse and changing energy portfolio (e.g., by addressing the variability of VRE through connecting areas with uncorrelated [VRE] generation profiles), and mitigate damage and limit customer outages during adverse conditions.[1] Higher-voltage lines generally carry power over longer distances.[2] The vast majority of transmission line circuit miles are in alternating current (AC). More direct current (DC) transmission lines are being proposed, as they transmit electricity over long distances at high DC voltage with typically lower losses.

- By the end of 2018, a total of 431,060 circuit miles of long-distance transmission was available with voltage levels above 100 kilovolts (kV) in the NERC regions, excluding Canada.[3] Of this total, 4,209 circuit miles (1.0%) were DC lines. Across the NERC regions, more than 74.8% of existing circuit miles were between 100 kV and 300 kV.

[1] DOE 2017, 2018

[2] "Glossary of Terms," PSE&G 2017, https://www.psegtransmission.com/about/glossary

[3] The regional aggregation in the charts of existing and proposed transmission is different from the aggregation used in the rest of the data book. Regions in these two charts follow the NERC regions from the NERC website: https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/New%20Regions%20map%20no%20FRCC.jpg; in other words, SERC includes FRCC, and MRO includes SPP.

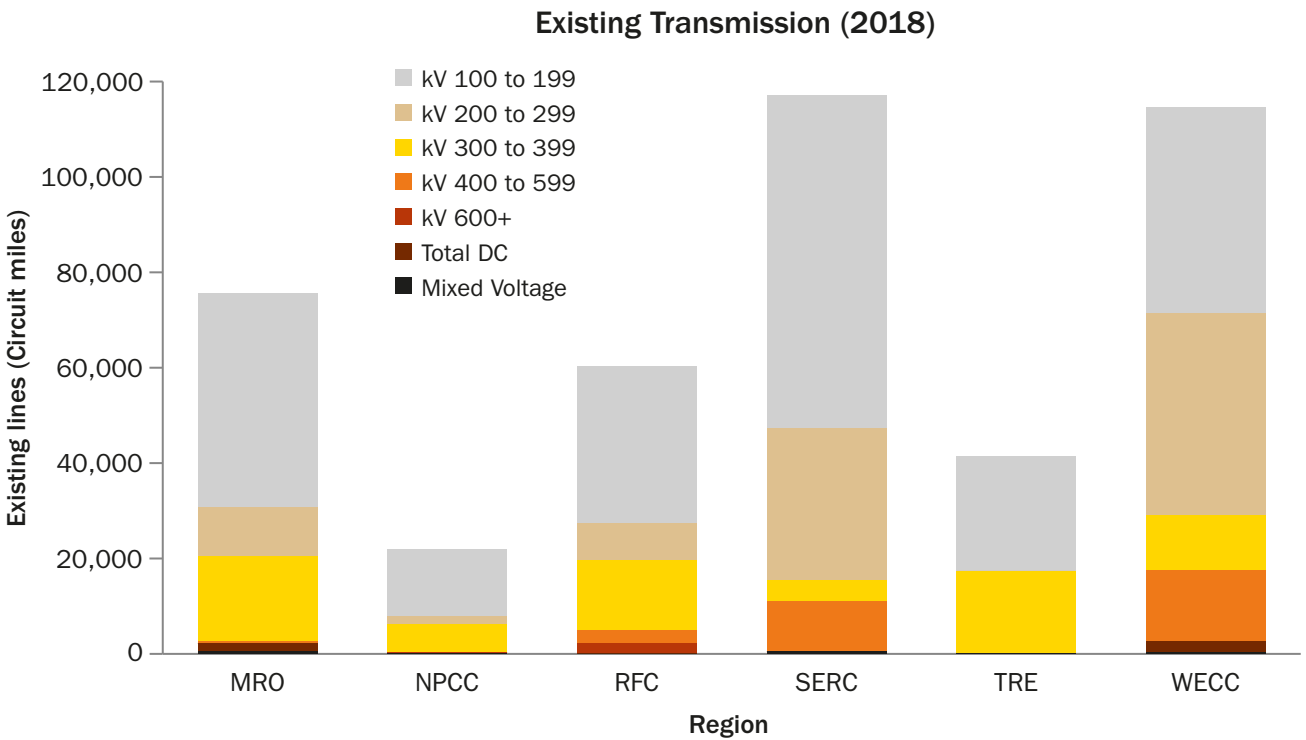
Existing and Proposed Long-Distance Transmission Capacities: Summary (continued)

- A total of 3,326 circuit miles of lines of more than 100 kV are currently under construction[1] in the NERC regions, excluding Canada. Of this total, 59.2% (1,969 circuit miles) are in MRO, 17.7% (588 circuit miles) are in WECC, 7.8% (257 circuit miles) are in SERC, 6.4% (214 circuit miles) are in the ReliabilityFirst NERC regional entity, 4.5% (150 circuit miles) are in TRE, and 4.4% (147 circuit miles) are in NPCC.
- By 2027, the largest additions of transmission projects as a share of total existing regional transmission circuit miles are planned[2] in NPCC (9.8%), followed by WECC (4.1%), and MRO (2.7%). For all NERC regions, 50% of the planned transmission circuit miles by 2027 are expected to be above 300 kV.
- A total of 1,343 DC circuit miles with a potential completion date of 2027 are planned. These planned lines are expected in the NPCC and WECC regions.
- Some interregional transmission projects are in a planning or conceptual phase and are expected to connect renewable energy resource areas (e.g., the Southwest for solar and the Midwest for wind) to load centers (e.g., in CAISO, MISO, the ReliabilityFirst NERC regional entity, and SERC service areas).

[1] Lines under construction include projects where construction has already begun (DOE 2017).

[2] Planned projects include projects for which permits have been approved, a design has been completed, or a project is needed to meet a regulatory requirement (DOE 2017).

Existing Transmission Capacities

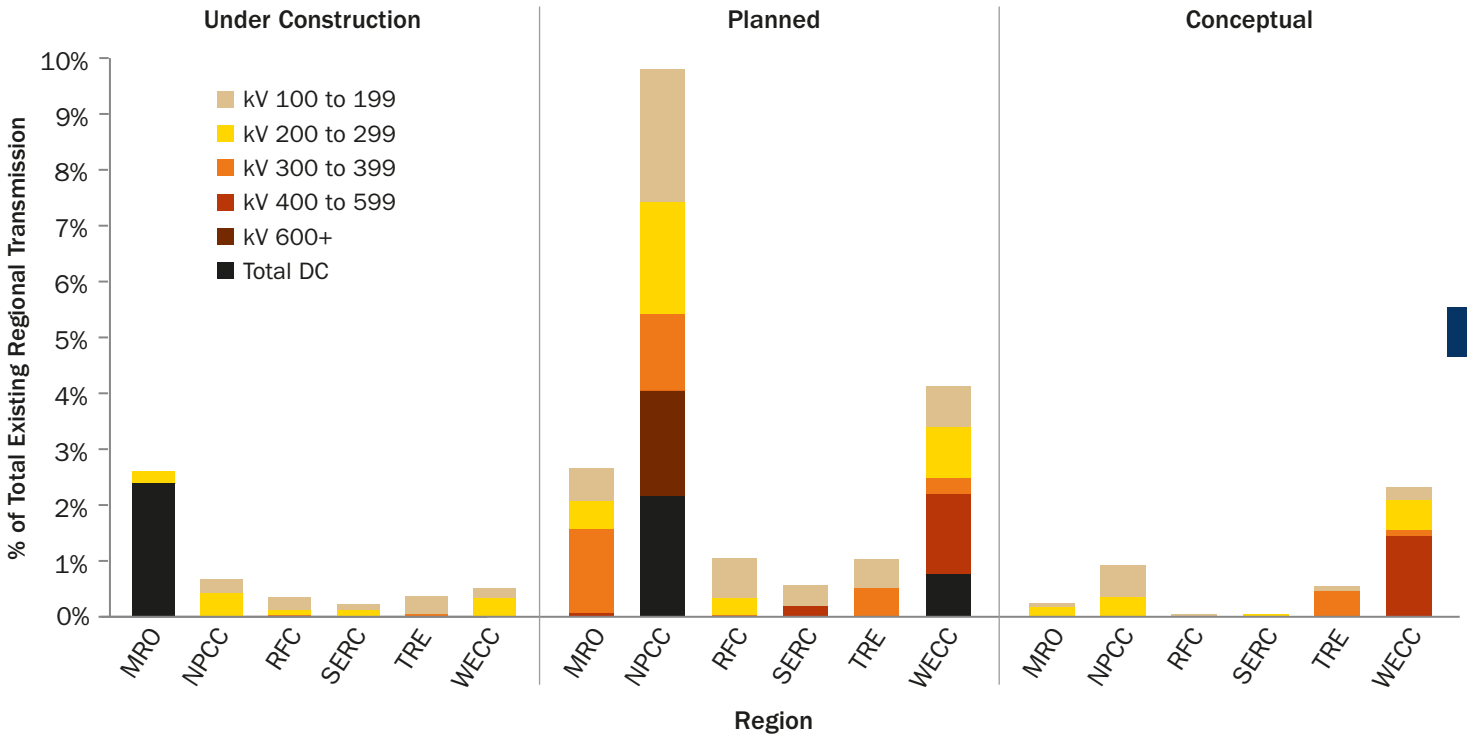


Source: DOE developed this chart using the NERC Transmission Availability Data System, according to personal communication from NERC received on September 10, 2019. For more information, see "Transmission Availability Data System (TADS)," NERC, https://www.nerc.com/pa/RAPA/tads/Pages/default.aspx.

Notes: The transmission data depicted are for NERC regions; for a map of NERC regions, see "Key Players," NERC, https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx.

Proposed Transmission Capacities

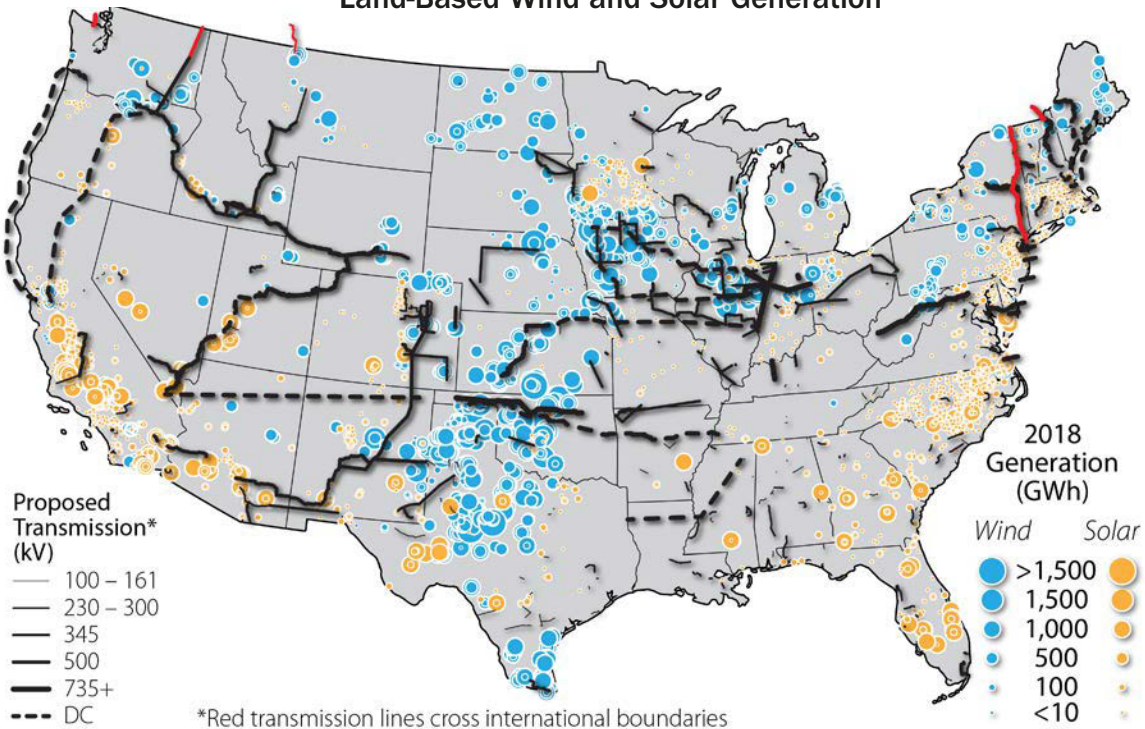
Transmission to be Built by 2027



Source: Electricity Supply & Demand (ES&D), NERC, https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

Notes: Lines under construction include projects where construction of the line has already begun. Planned projects include projects for which permits have been approved, a design has been completed, or a project is needed to meet a regulatory requirement. Conceptual projects are projects that are in a queue but are not included in a regional transmission plan (DOE 2017). The transmission data depicted are for NERC regions; for a map of NERC regions, see "Key Players," NERC, https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx.

Proposed Major Transmission Lines and Coincidence with Land-Based Wind and Solar Generation



Sources: ABB Ability Velocity Suite; EIA (Form EIA-923)

Notes: The map, which is intended for illustrative purposes, excludes transmission capacity of less than 100 kV; cross-border transmission lines are shown in red.

Selection of Proposed Major Interregional Transmission Projects

Area	Region (terminal origin–endpoint)	Project	HVDC	Miles	Capacity (MW)	Voltage Ratings (kV)	Proposed In-Service Date	Estimated Capital Costs ($2018 billion) and Status (as of 2018 Year-End)	Source
EI[1]	Kansas–Indiana	Grain Belt Express Clean Line	HVDC	780	4,000	±600	2023	Estimated capital costs to be $2.00 billion; Advanced development; In permitting process, Missouri, Kansas and Indiana have approved the project, pending approval from Illinois Commerce Comission	https://www.grainbeltexpressclean line.com; https://www.grainbeltexpressclean line.com/sites/grain_belt/media/docs/Grain-Belt-Express-Project-Fact-Sheet.pdf
EI	Manitoba (CAN) – Minnesota	Great Northern Transmission Line	No	220 (U.S.)	883	500	2020	Under construction	http://greatnortherntransmissionline.com/
EI	Ontario (CAN) – Pennsylvania	Lake Erie Connector	HVDC	73	1,000	±320	2023	Advanced Development; fully permitted; currently completing project cost refinements and securing favorable transmission service agreements with prospective counterparties; expect construction in 2020	http://www.itclakeerieconnector.com/
EI	Quebec (CAN) – New York	Champlain-Hudson Power Express	HVDC	333 (U.S.)	1,000	320	2024	Advanced Development; fully permitted;	http://www.chpexpress.com/about.php
EI	New Jersey – New York	Poseidon	HVDC	79	500	200	2021	Early Development; submitted application to New York Public Service Commission	NA
EI	Newfoundland (CAN) – Massachusetts	Atlantic Link	HVDC	375	1,000	320	2022	Early Development. In permitting process: applied for Presidential Permit to DOE; most work on hold after the project was not chosen in MA RFP in 2018	https://www.atlanticlink.com/

Note: The selection of transmission projects is based on "2018 Top 10 Transmission Projects," Energy Acuity, May 30, 2018, https://energyacuity.com/blog/2018-top-10-transmission-projects/; EIA 2018; and Hagerty, Pfeifenberger, and Change 2017. Transmission project capital cost estimates are from Gorman, Mills and Wiser 2019. Transmission lines included in the table do not entirely match the map shown on page 90.

[1] Eastern Interconnection

Selection of Proposed Major Interregional Transmission Projects (continued)

Area	Region (terminal origin–endpoint)	Project	HVDC	Miles	Capacity (MW)	Voltage Ratings (kV)	Proposed In-Service Date	Estimated Capital Costs ($2018 billion) and Status (as of 2018 Year-End)	Source
EI	New Jersey	Atlantic Wind Connection (New Jersey Energy Link)	HVDC	750	6,000	320	NA	Early Development; submitted right-of-way application to Bureau of Ocean Energy Management in 2013	http://atlanticwindconnection.com/projects/
EI	Massachusetts–Maine	Maine Power Express	HVDC	315	1,040	±345	2022	Estimated capital costs to be $2.50 billion; Advanced Development; not selected in MA RFP in 2018	http://www.mainepx.com/
EI	Missouri	Mark Twain Transmission Project	No	96	NA	345	2019	Under construction	https://www.ameren.com/company/mark-twain
EI	Quebec (CAN) – Maine	New England Clean Energy Connect	HVDC	145	1,200	320	2022	Approved by Maine Public Utilities Commission (June 2019)	https://www.necleanenergyconnect.org/project-overview
EI	Vermont	New England Clean Power Link	HVDC	152	1,000	320	2023	Advanced Development; Continued preconstruction activies; not selected in MA RFP, continued pursuing opportunities to commercialize the project	http://www.necplink.com/
EI	New York – Massachusetts	Northeast Renewable Link (NRL)	No	23	600	345	2022	Early Development; failed to be selected in Massachusetts' solicitation for Canadian hydropower and renewables in 2018, currently in open solicitation	https://northeastrenewablelink.com/about/project-overview/

V

Note: The selection of transmission projects is based on "2018 Top 10 Transmission Projects," Energy Acuity, May 30, 2018, https://energyacuity.com/blog/2018-top-10-transmission-projects/; EIA 2018; and Hagerty, Pfeifenberger, and Change 2017.
Transmission project capital cost estimates are from Gorman, Mills and Wiser 2019.
Transmission lines included in the table do not entirely match the map shown on page 90.

Selection of Proposed Major Interregional Transmission Projects (continued)

Area	Region (terminal origin–endpoint)	Project	HVDC	Miles	Capacity (MW)	Voltage Ratings (kV)	Proposed In-Service Date	Estimated Capital Costs ($2018 billion) and Status (as of 2018 Year-End)	Source
ERCOT	Mississippi – Louisiana/Texas	Southern Cross	HVDC	400	2,000	±500	2021	Estimated capital costs to be $1.45 billion; Advanced Development; In permitting process: pending Certificate of Public Convenience and Necessity approval from Mississippi Public Service Commisssion	http://southerncrosstransmission.com/
ERCOT	Texas	Far West Texas Project	No	200	NA	345	2020	Advanced Development; ERCOT approved two lines in 2017; approval from Public Utility Commission of Texas in November 2018	http://www.ercot.com/content/wcm/key_documents_lists/137965/11_Far_West_Regional_Planning_Group_Projects.pdf
WECC	Wyoming – Nevada	Zephyr Power	HVDC	850	3,000	500	2023	Estimated capital costs to be $3.70 billion; Early development. In permitting process, submitted Right-of-way application to Bureau of Land Management	http://www.datcllc.com/projects/zephyr
WECC	Wyoming – Nevada	TransWest Express	HVDC	730	3,000	±600	2023	Estimated capital costs to be $3.00 billion; Advanced Development. Wyoming Industrial Siting Council approves state permit in 2019	http://www.transwestexpress.net
WECC	New Mexico – Arizona	SunZia Southwest	No	520	3,000	500	2020	Estimated capital costs to be $2.00 billion; Advanced Development; The New Mexico Public Regulation Commission denied SunZia's application in September 2018 without prejudice, SunZia plans to file an amended application once the U.S. Bureau of Land Management has completed its environmental assessment	http://www.sunzia.net/

Note: The selection of transmission projects is based on "2018 Top 10 Transmission Projects," Energy Acuity, May 30, 2018, https://energyacuity.com/blog/2018-top-10-transmission-projects/; EIA 2018; and Hagerty, Pfeifenberger, and Change 2017.
Transmission project capital cost estimates are from Gorman, Mills and Wiser 2019.
Transmission lines included in the table do not entirely match the map shown on page 90.

Selection of Proposed Major Interregional Transmission Projects (continued)

Area	Region (terminal origin–endpoint)	Project	HVDC	Miles	Capacity (MW)	Voltage Ratings (kV)	Proposed In-Service Date	Estimated Capital Costs ($2018 billion) and Status (as of 2018 Year-End)	Source
WECC	Arizona – New Mexico	Southline	No	240	1,000	345	2020	Estimated capital costs to be $0.80 billion; Under construction	http://www.southlinetransmissionproject.com/
WECC	Nebraska	Nebraska Transmission Line (R-Project)	No	220	NA	345	2021	Awarded construction contracts; Habitat conservation plan approved, incidental take permit issued (2019)	https://rproject.nppd.com/
WECC	Idaho – Nevada	Southwest Intertie Project (SWIP) - North	No	275	2,000	500	2021	Advanced Development; federally approved route has been secured through a grant issued by Department of the Interior's Bureau of Land Management; approved Construction, Operation & Maintenance Plan and conditional Notice to Proceed	https://www.wapa.gov/regions/DSW/Environment/Pages/southwest-intertie-nepa.aspx
WECC	Wyoming – Idaho	Gateway West	No	1,150	3,000	230-500	2024	Estimated capital costs to be $4.10 billion; Advanced Development. In permitting process: The Carbon County Board of County Commissioners approved the Conditional Use Permit; The Wyoming Industrial Siting Council approved the permit in 2018	https://www.pacificorp.com/transmission/transmission-projects/energy-gateway/gateway-west.html
WECC	Wyoming – Utah	Gateway South	No	400	1,500	500	2024	Estimated capital costs to be $2.00 billion; Advanced Development; In permitting process: Environmental Impact Assessment approved in 2016	https://www.pacificorp.com/transmission/transmission-projects/energy-gateway/gateway-south.html

Note: The selection of transmission projects is based on "2018 Top 10 Transmission Projects," Energy Acuity, May 30, 2018, https://energyacuity.com/blog/2018-top-10-transmission-projects/; EIA 2018; and Hagerty, Pfeifenberger, and Change 2017.
Transmission project capital cost estimates are from Gorman, Mills and Wiser 2019.
Transmission lines included in the table do not entirely match the map shown on page 90.

Selection of Proposed Major Interregional Transmission Projects (continued)

Area	Region (terminal origin–endpoint)	Project	HVDC	Miles	Capacity (MW)	Voltage Ratings (kV)	Proposed In-Service Date	Estimated Capital Costs ($2018 billion) and Status (as of 2018 Year-End)	Source
WECC	California – Arizona	Renewable Energy Express HVDC Conversion Project	HVDC	NA	3,000	500	2026	Proposed	https://www.caiso.com/Documents/2018HVDC_Conversion_Project_Summary_Public.pdf
WECC	Nevada – Utah	Cross-Tie Transmission Project	No	213	1,500	500	2024	Early Development; In permitting process	http://www.transcanyon.com/cross-tie-1.html
WECC	New Mexico	Western Spirit Clean Line	No	165	1,000	345	2021	Estimated capital costs to be $0.15 billion; Early development; FERC approved Public Service Co. of New Mexico to acquire the project (August 2019)	https://westernspirittransmission.com/; https://westernspirittransmission.com/wp-content/uploads/2018/05/Western-Spirit-Transmission_Fact-Sheet_AF_v5.pdf
EI	New York	Empire State Connector	HVDC	265	1,000	320	2024	Estimated capital costs to be $1.60 billion; Early development; In permitting process	http://empirestateconnector.com/
WECC	Texas – New Mexico	Tuco-Yoakum-Hobbs	No	168	NA	345	2020	Under construction	https://www.powerfortheplains.com/Projects/Tuco%E2%80%93Yoakum%E2%80%93Hobbs-345-kV-Transmission-Line

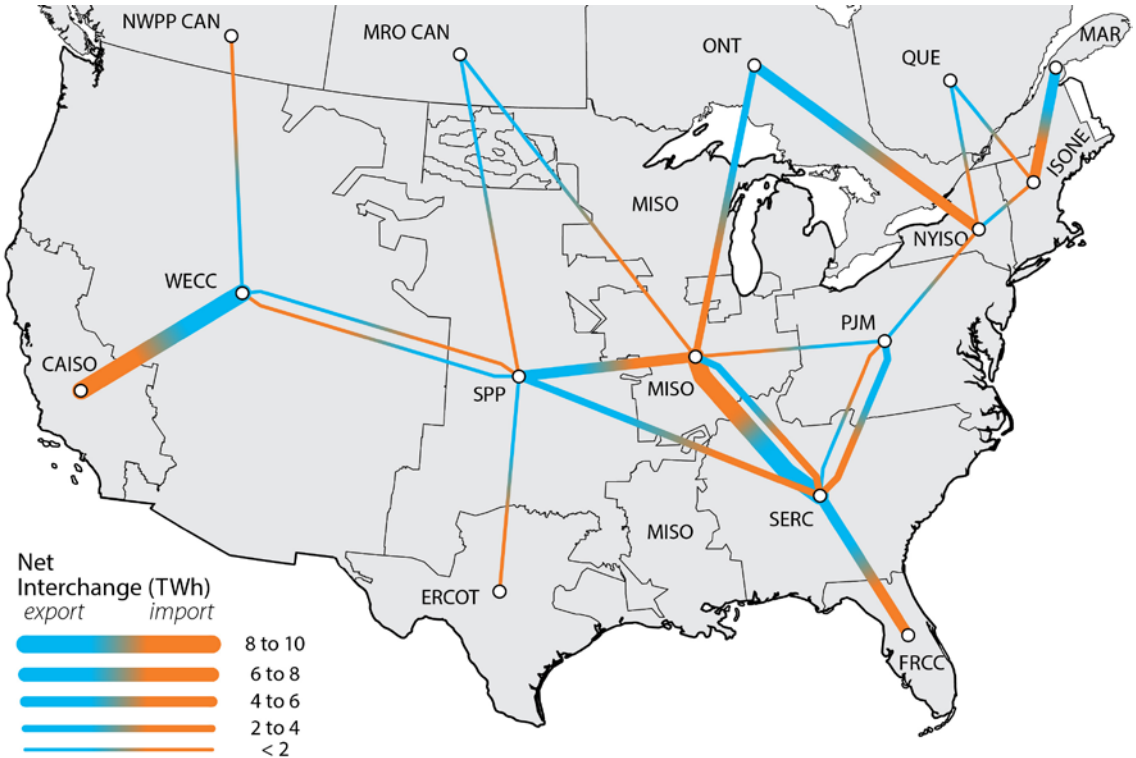
Note: The selection of transmission projects is based on "2018 Top 10 Transmission Projects," Energy Acuity, May 30, 2018, https://energyacuity.com/blog/2018-top-10-transmission-projects/; EIA 2018; and Hagerty, Pfeifenberger, and Change 2017.
Transmission project capital cost estimates are from Gorman, Mills and Wiser 2019.
Transmission lines included in the table do not entirely match the map shown on page 90.

Interchange Flows: Summary

Interchange flows are energy transfers across balancing authority boundaries. In balancing authorities with high penetration of renewables, interchange flows can help balance variable output from VRE by increasing geographic diversity. Interchange flows may be associated with price differences and arbitrage opportunities between balancing authorities.

- In 2018, unidirectional interchange flow was the highest from (non-CAISO) WECC to CAISO (11.0 TWh), followed by interchange flows into MISO from SERC (8.0 TWh), from SPP into MISO (5.1 TWh), and from SERC into FRCC (5.0 TWh).
- Interchange flow from Canada into the U.S. regions of ISO-NE, MISO, WECC, SPP and NYISO markets totaled 10.1 TWh in 2018.

Interchange between ISO/RTO and NERC Regions (2018)



Source: EIA (Form EIA-930)

Notes: The data excludes interchanges of less than 1 TWh. Terminal origin and endpoints of interchange flows are centroids of ISO/RTO regions and NERC subregions. Differences in reported values between balancing authority counterparties were adjusted to represent physical flows of interchange (rather than contractual flows) to the authors' best knowledge. Balancing authority service territories were matched with NERC subregions.

Congestion LMP: Summary

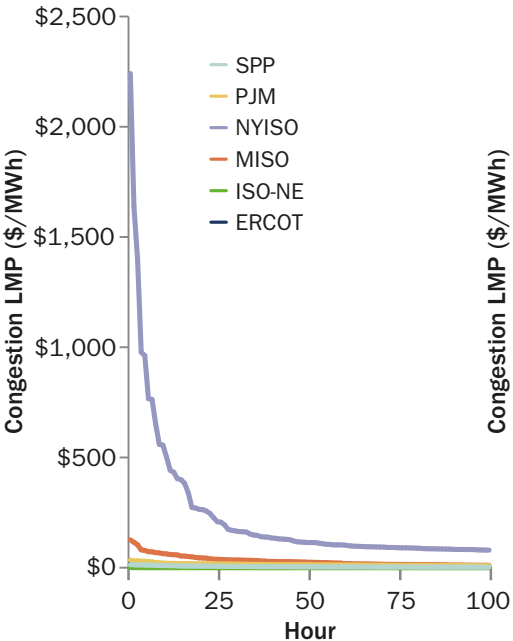
The locational marginal price (LMP) at a particular node on the grid is the sum of a system-wide reference energy price and a location-specific congestion price. This congestion component of the locational marginal price (CLMP)[1] can be interpreted as the additional cost (or savings) to serve customer load that is due to transmission constraints; it helps system operators to establish dispatch, and it may serve as a price signal for location-specific development of new transmission facilities, generation, storage, or demand-response initiatives. CLMPs can be positive or negative, depending on the associated node's location relative to the transmission constraint. When the node is upstream of a binding transmission constraint, CLMPs are negative and generators get negative revenues from congestion effects; when the node is downstream of a binding transmission constraint, CLMPs are positive and generators get positive revenues from congestion effects. In an unconstrained system, CLMPs are zero.

- In 2018, NYISO had the highest CLMP (more than $2,000/MWh), and the lowest CLMP price (less than -$150/MWh occurred) was in MISO.
- In 2018, PJM and the southeastern part of SPP had the most hours of congestion, with 60%–85% of annual hours with CLMP[2] greater than $0/MWh. Long Island and New York City within NYISO, and western ERCOT experienced moderate congestion with CLMP greater $0/MWh for 45%–60% of hours.

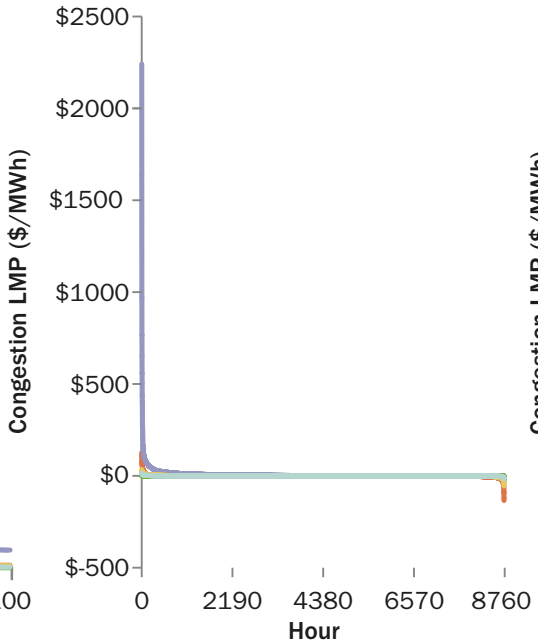
[1] CLMP, a component of the LMP, is the incremental price of congestion at each bus, based on the shadow prices associated with the relief of binding constraints in the security-constrained optimization (Monitoring Analytics 2016, 411).

[2] For the purpose of this data book, CLMP is calculated for each ISO/NERC region as hourly (load-weighted) averages from zonal price nodes in the RT market (ISO-NE, MISO, PJM, and NYISO). CLMP data for CAISO, ERCOT, and SPP are reported as hourly (load-weighted) averages of five-minute data from zonal price nodes in the RT market.

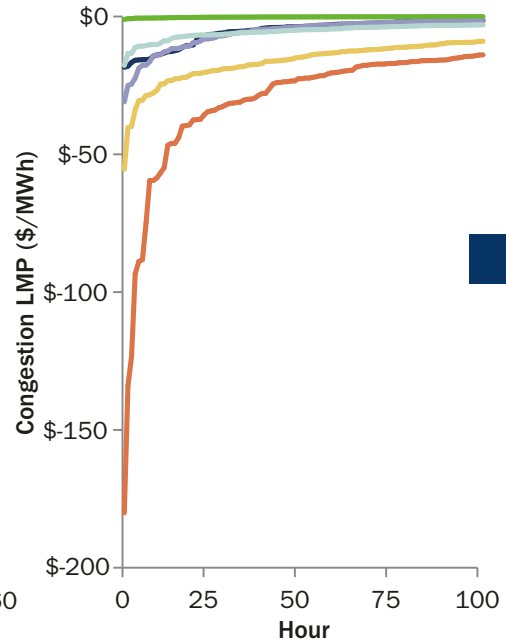
CLMP During the 100 Hours with Highest Price Levels (2018)



CLMP During 8,760 Hours (2018)

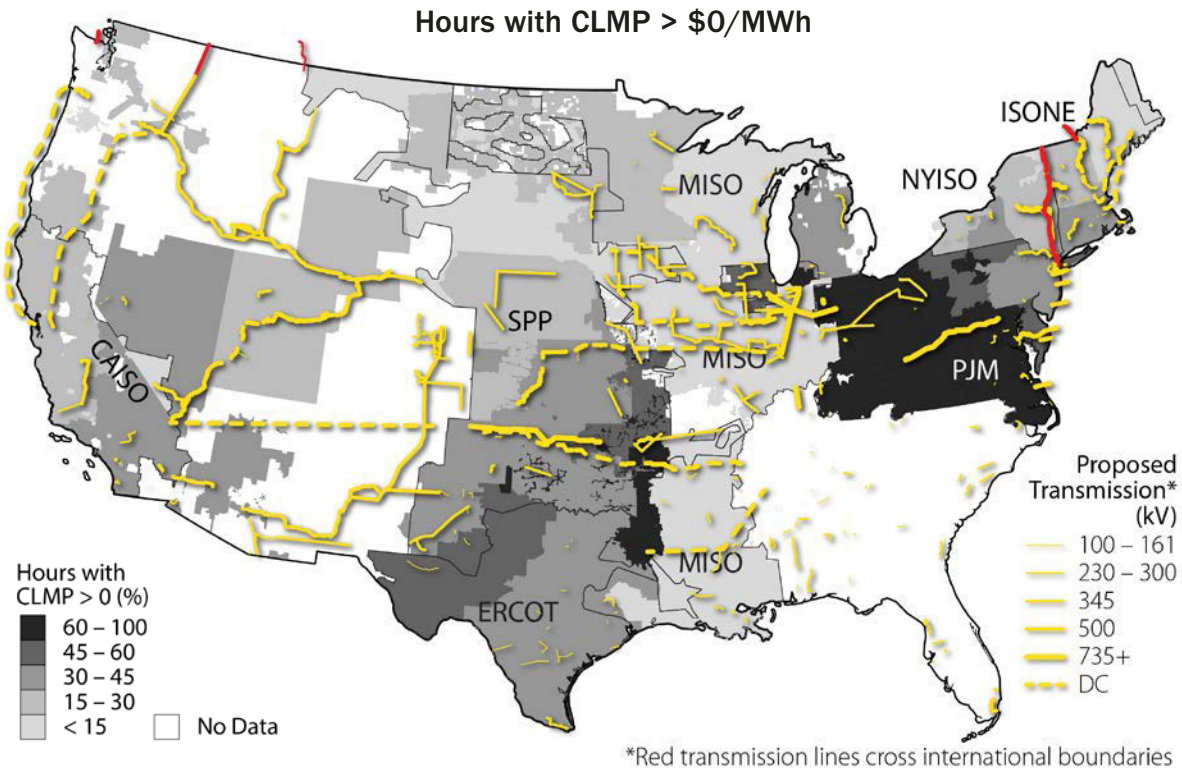


CLMP During the 100 Hours with Lowest Price Levels (2018)



Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite)

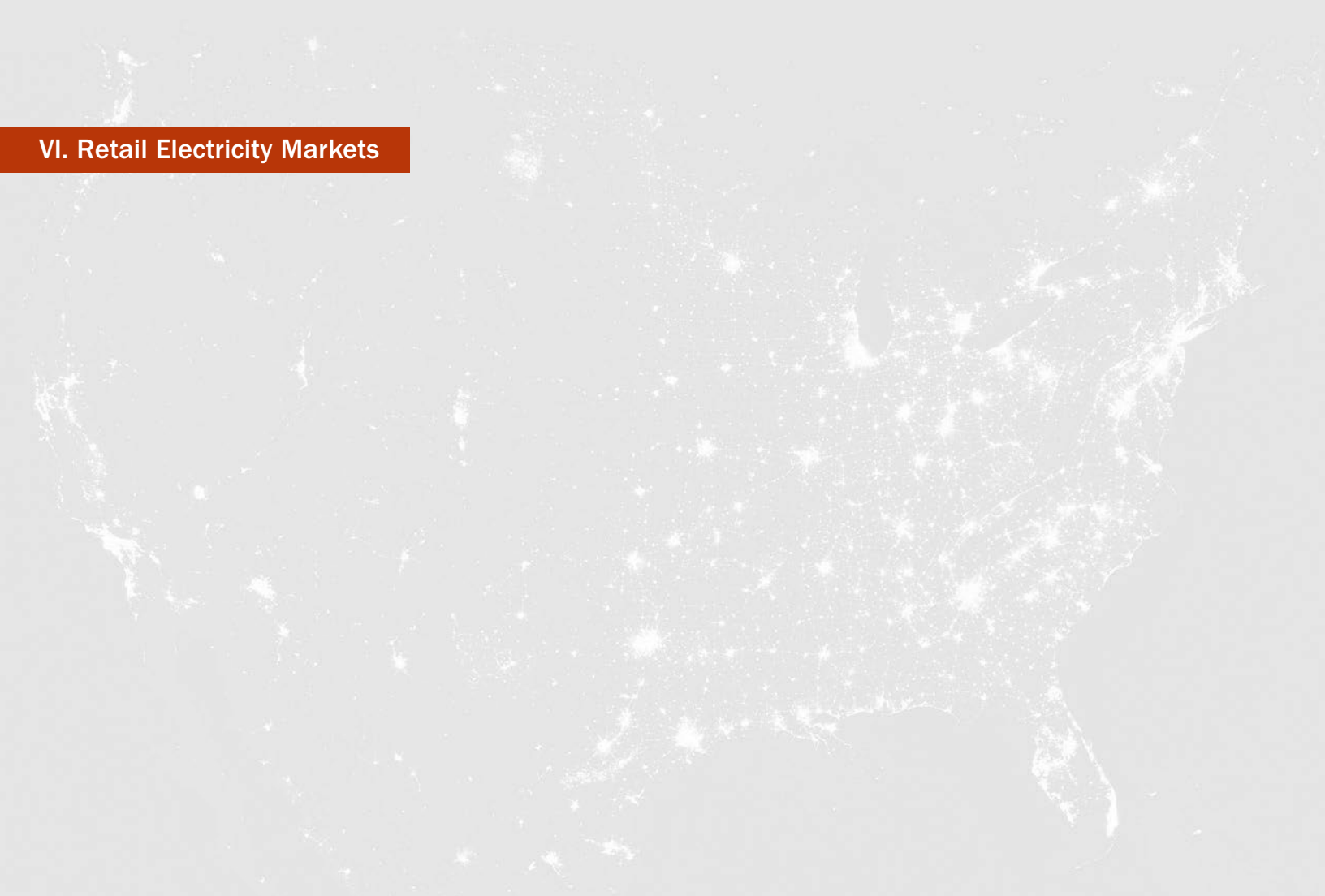
Note: CLMP data are reported here as hourly (load-weighted) averages from zonal price nodes in the RT market (ISO-NE, MISO, PJM, and NYISO). CLMP data for CAISO, ERCOT, and SPP are reported as hourly (load-weighted) averages of five-minute data from zonal price nodes in the RT market.



Sources: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP (accessed through the ABB Ability Velocity Suite); and the ABB Ability Velocity Suite for proposed major transmission lines

Note: CLMP data are reported here as hourly (load-weighted) averages from zonal price nodes in the RT market (ISO-NE, MISO, PJM, and NYISO). CLMP data for CAISO, ERCOT, and SPP are reported as hourly (load-weighted) averages of five-minute data from zonal price nodes in the RT market.

VI. Retail Electricity Markets



Interconnection Standards: Summary

Interconnection standards are processes and technical requirements that regulate how distributed generation systems physically connect to the grid.[1,2] State-level public utilities commissions establish the interconnection standards for their states that are not FERC-jurisdictional, so standards vary by state. Many states adopt technical requirements based on IEEE 1547 and UL 1741 standards, and they follow the Small Generator Interconnection Procedures established by FERC.[3]

- As of June 25, 2019, all states except Alabama, Idaho, North Dakota, Oklahoma,[4] and Tennessee have established interconnection standards and policies.
- Some state-level interconnection standards apply to systems below a certain distributed energy resource size or capacity, and such system capacity limits vary by state. Of states with interconnection standards, 11 states do not have specified limits, 20 states have system capacity limit requirements under 10 MW, and 7 states have limits of 10–100 MW.
- On February 2018, IEEE 1547[5] was revised with updated requirements for interconnecting distributed energy resources with utility electric power systems.

[1] EPA 2015

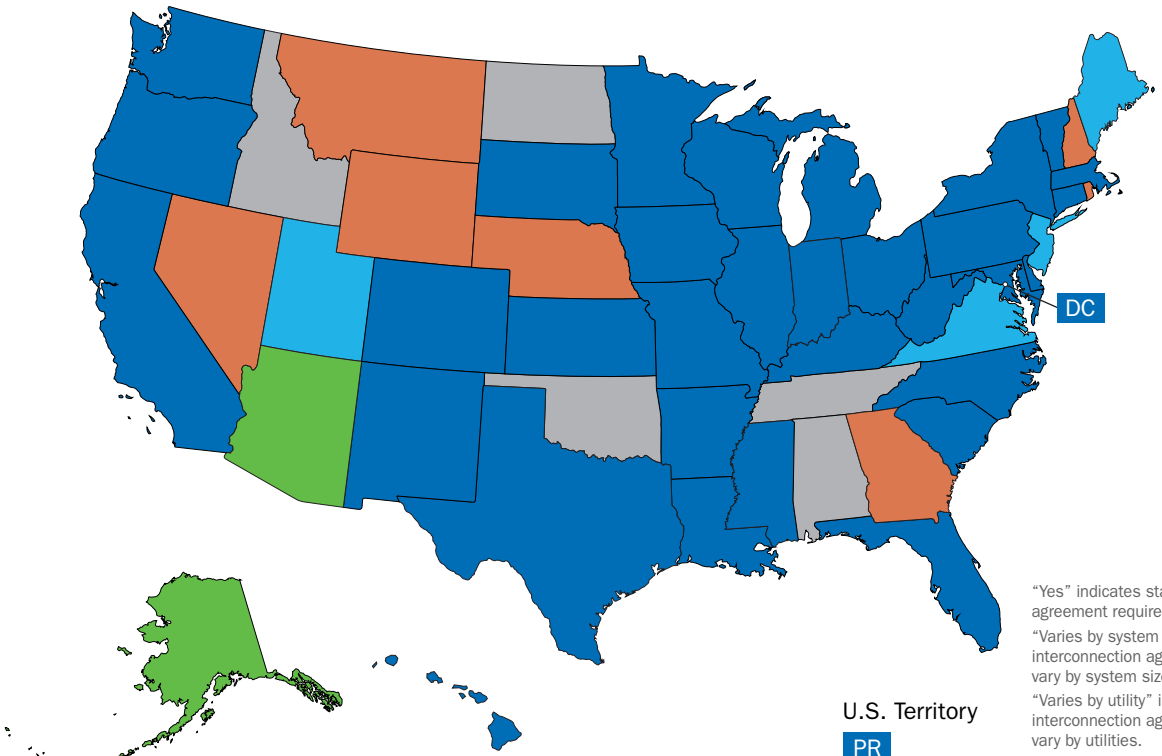
[2] "Interconnection Standards," ACEEE, https://aceee.org/topics/interconnection-standards

[3] See "Interconnection Standards;" NREL, https://www.nrel.gov/state-local-tribal/basics-interconnection-standards.html; "Standard Interconnection Agreements and Procedures for Small Generators," FERC, https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

[4] Oklahoma follows several limited-in-scope interconnection requirements, although the Oklahoma Corporation Commission has not any standardized interconnection procedures, according to "Interconnection Guidelines," DSIRE, https://programs.dsireusa.org/system/program/detail/5525.

[5] "IEEE 1547-2018: IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," IEEE, https://standards.ieee.org/standard/1547-2018.html

Interconnection Standards (June 2019): Standardized Agreement



- Yes (32 states, D.C.; and 1 territory)
- Varies by system size (4 states)
- Varies by utility (2 states)
- No (7 states)
- No state interconnection standard (4 states)

"Yes" indicates states have standardized interconnection agreement requirements throughout the state.

"Varies by system size" indicates states have standardized interconnection agreement requirements, but requirements vary by system sizes.

"Varies by utility" indicates states have standardized interconnection agreement requirements, but requirements vary by utilities.

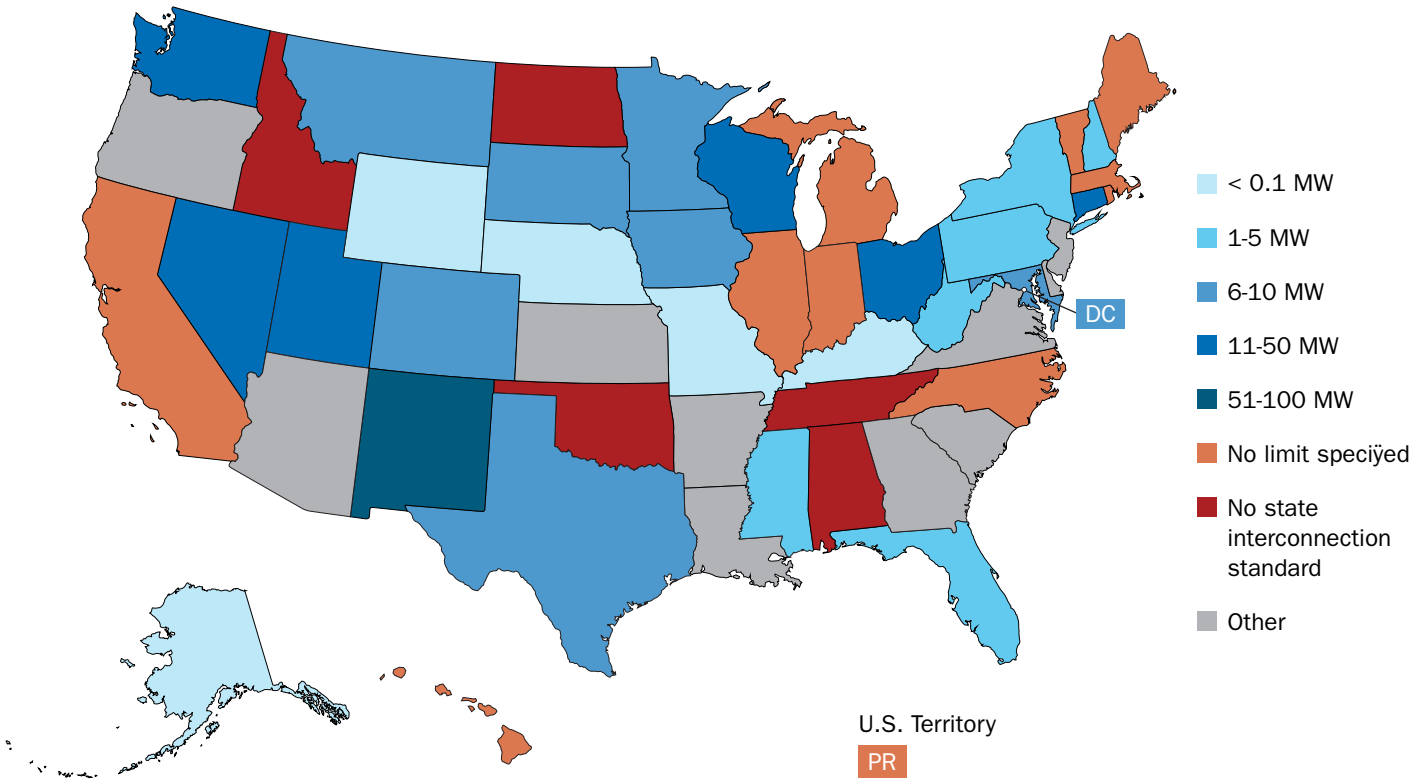
"No" indicates states have interconnection standards but do not have standardized agreement requirements.

"No state interconnection standard" indicates states do not have interconnection standards.

Source: DSIRE n.d.

PR = Puerto Rico.

Interconnection Standards (June 2019): Capacity Limits



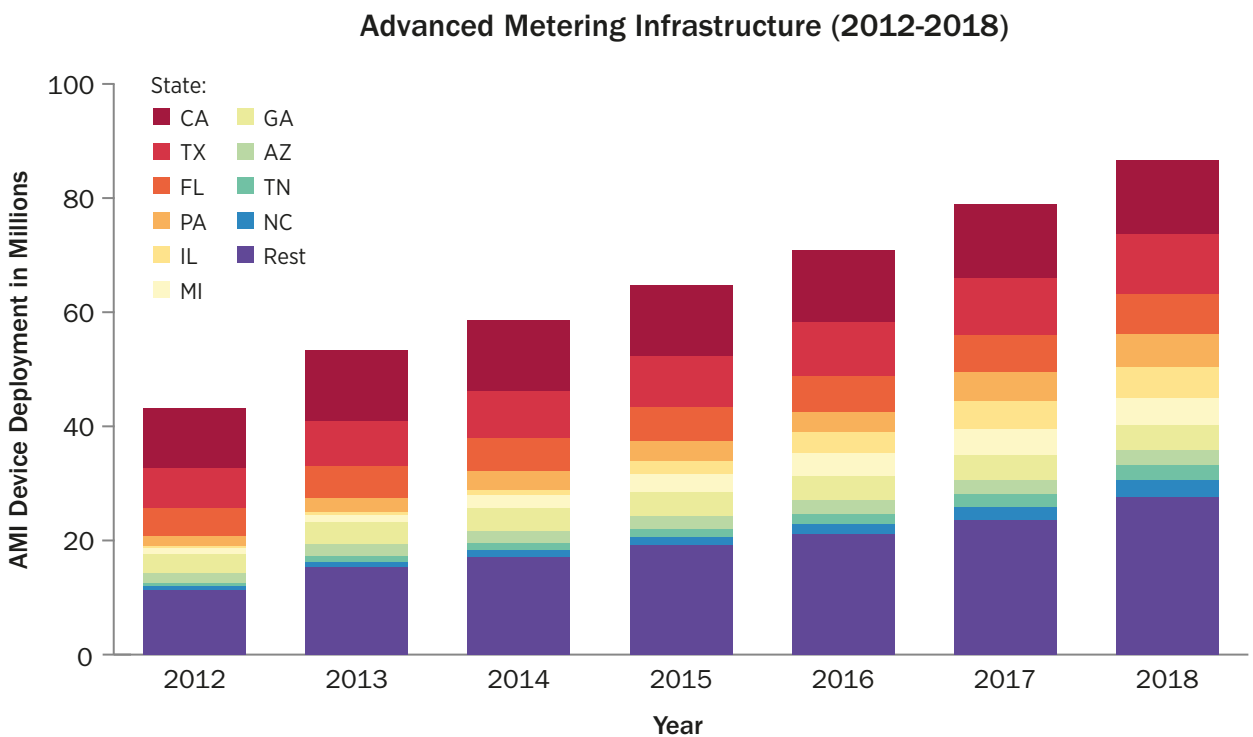
Source: DSIRE n.d.
PR = Puerto Rico

Advanced Metering Infrastructure: Summary

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication capable of recording and transmitting instantaneous data between utilities and customers. AMI enables several new functions for utilities, including automatic and remote electricity usage measurement, meter failure detection, service connection and disconnection, and the capability to provide time-based rate programs.[1] AMI helps utilities with net metering arrangements and reduces barriers to the interconnection of distributed renewable energy technologies (McAllister 2010).

- AMI device deployment increased from 43.2 million units in 2012 to 86.7 million in 2018.
- By 2018, California had the highest AMI device deployment of 13.1 million units, followed by 10.5 million in Texas; 6.9 million in Florida; 5.9 million in Pennsylvania; 5.4 million in Illinois; 4.7 million in Michigan; 4.4 million in Georgia; 3.0 million in North Carolina; 2.6 million in Tennessee; and 2.5 million in Arizona. These ten states comprise 68.1% of total AMI deployment in the United States.

[1] DOE 2016



VI

Source: EIA (Form EIA-861)

Dynamic Pricing: Summary

Dynamic pricing programs are time-based rate programs that aim to modify electricity usage patterns, including both the timing and level of electricity demand.[1] These programs provide incentives for consumers to change their electricity consumption patterns, helping utilities shift loads and better integrate renewable generation. There are five major types of dynamic pricing programs, among others: (1) *time-of-use* price programs set fixed and predefined price schedules, normally with prices that are higher during on-peak periods than in off-peak periods, that customers pay at different times of the day; (2) *real-time* pricing programs send hourly or subhourly retail prices to customers to reflect the real-time wholesale electricity price; (3) *variable peak* pricing programs are a variant of time-of-use programs, where customers set their purchase price schedule on a daily basis for the next day (as opposed to a fixed and predefined schedule); (4) *critical peak* pricing programs set predefined high rates to customers for a limited number of days or hours that might experience higher wholesale market prices or system contingencies, aiming to reduce peak demand; and (5) *critical peak* rebate programs have similar goals as critical peak pricing programs, but by providing rebates to customers for the amount of electricity usage they forgo compared to a baseline consumption amount.

- The total number of customers enrolled in dynamic pricing programs increased from 5,977,281 in 2013 to 9,219,009 in 2018.

[1] EIA (Form EIA-861, Form EIA-861 Instructions)

Dynamic Pricing

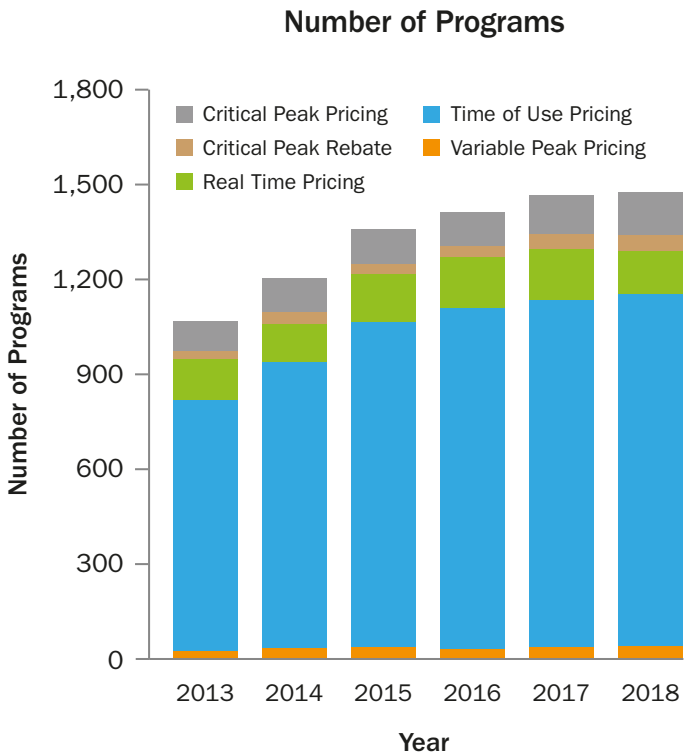
- The relative share of customers in different sectors remains similar across years. In 2018, residential customers accounted for 78.1% of total customers enrolled, followed by 21.2% of commercial customers, 1.4% of industrial customers, and <0.1% of transportation customers.

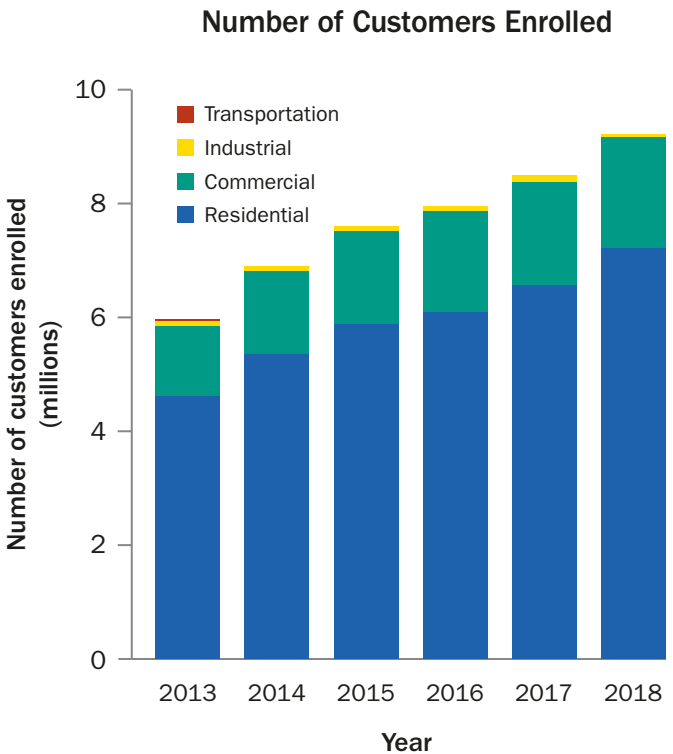
- In 2018, the number of customers enrolled in dynamic pricing programs was the highest in California with 2.54 million customers, followed by 1.83 million customers in Maryland; 0.98 million customers in Arizona; 0.75 million customers in Ohio; 0.71 million customers in Oklahoma; 0.39 million customers in Illinois; and 0.32 million customers in Texas.

- The total number of dynamic pricing programs increased from 1,067 in 2013 to 1,476 in 2018. That year, time-of-use programs accounted for 75.5% of the total number of dynamic pricing programs, followed by critical peak pricing programs (at 9.3% of the total), real-time pricing programs (at 9.1%), critical peak rebate programs (at 3.4%), and variable peak pricing programs (at 2.7%).

- In absolute numbers, the residential sector had the most enrolled customers in 2018. However, the percentages of all dynamic pricing programs targeting the industrial and commercial sectors were 37.1% and 36.5%, while 24.6% of the programs targeted the residential sector and 1.8% targeted the transportation sector.

Dynamic Pricing





VI

Source: EIA (Form EIA-861)

VII. Glossary

Glossary

Alternating Current (AC)

A form of electricity in which the current alternates in direction (and the voltage alternates in polarity) at a frequency defined by the generator, usually between 50 and 60 times per second (i.e., 50–60 hertz). (ABB, "Glossary of Technical Terms Commonly used by ABB," http://new.abb.com/glossary).

Ancillary services

Services that ensure reliability and support the transmission of electricity from generation sites to customer loads; such services may include load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support. (EIA, "Glossary: Electricity," https://www.eia.gov/tools/glossary/?id=electricity).

Capacity

The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer or winter peak demand. (EIA, "Glossary: Net Summer Capacity," https://www.eia.gov/tools/glossary/index.php?id=net%20summer%20capacity).

Capacity Factor

The ratio of the electrical energy produced by a generating unit for a given period to the electrical energy that could have been produced at continuous full power operation during the same period.

Circuit Mile

The total length in miles of separate circuits regardless of the number of conductors used per circuit (EIA, "Glossary: Finance," https://www.eia.gov/tools/glossary/index.php?id=finance).

Congestion Component of the Locational Marginal Price (CLMP)

The incremental price of congestion at each bus, based on the shadow prices associated with the relief of binding constraints in the security constrained optimization; when a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint, and the corresponding congestion costs are positive or negative. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load weighted reference bus. In an unconstrained system, CLMPs are zero (Monitoring Analytics 2016, 411)

Curtailment

A prescribed reduction in scheduled capacity or energy delivery; curtailment can be the result of many factors, including transmission congestion, minimum operating levels of thermal generators or hydropower or back-feeding in the distribution system.

Day-ahead Market

The time period starting at 12:00am and ending at 12:00pm on the day prior to the operating day. (https://www.spp.org/glossary/).

Delivery Year

In ISO/RTO regions with a capacity market, the period during which a generator awarded under a capacity market auction may be instructed by the system operator to fulfill its capacity obligation at times of electricity system stress.

Demand response

A "voluntary program offered by independent system operators/regional transmission organizations, local utility service providers, or third parties, which compensate end-use (retail) customers for reducing and/or changing the pattern of their electricity use (load) over a defined period of time, when requested or automatically instructed to do so during periods of high power prices or when the reliability of the grid is threatened." (DOE, "Quadrennial Energy Review: Second Installment," https://energy.gov/epsa/quadrennial-energy-review-second-installment).

Direct Current (DC)

Electrical current that does not alternate (see Alternating Current); the electrons flow through the circuit in one direction. To transmit electrical power as DC, the alternating current (AC) generated in the power plant must be converted into DC. At the other end of the process, the DC power must be converted back into AC, and fed into the AC-transmission or distribution network. The transmission of DC current has very low losses. In the conversion between the two forms of power, known as rectification, additional power losses are incurred, which makes DC advantageous only when these losses are less than would be incurred by AC transmission, for example when the transmission occurs over very long distances (~1,000 kilometers for overhead lines or ~100 kilometers for underwater). (ABB, "Glossary of Technical Terms Commonly used by ABB," http://new.abb.com/glossary).

Dispatchable Resource

Generally in ISO/RTO markets, when a resource is dispatchable, it submits a supply offer into the energy market that is based on price and reflects the resource's economic and physical operating characteristics. A dispatchable resource can receive dispatch instructions from a grid operator that require the resource to increase or decrease their output. (157 FERC § 61,189).

Forecast Error

The difference between forecasted and actual electric generation during a pre-defined time interval; Forecast error can affect a range of system operations, including scheduling, dispatch, real-time balancing, and reserve requirements. High validity in forecasting in intra-day and day-ahead (DA) scheduling can reduce fuel costs, improve system reliability, and minimize curtailment of renewable resources.

Generation

The total amount of electric energy produced by generating units and measured at the generating terminal in kilowatt-hours (kWh) or megawatt-hours (MWh).

Independent System Operator (ISO)

An independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system (FERC, "Glossary," https://www.ferc.gov/market-oversight/guide/glossary.asp).

Interchange

Energy transfers that cross balancing authority (BA) boundaries (EIA, "Glossary: Electricity," https://www.eia.gov/tools/glossary/?id=electricity).

Locational Marginal Price (LMP)

The marginal cost of supplying, at least cost, the next increment of electric demand at a specific location (node) on the electric power network, considering both supply (generation/import) bids and demand (load/export) offers and the physical aspects of the transmission system, including transmission and other operational constraints (CAISO, http://www.caiso.com/docs/2004/02/13/200402131607358643.pdf).

Maximum Hourly Penetration

Maximum hourly penetration refers to the maximum observed ratio of generation from a (set of) generation sources to load over a defined period (commonly a year) during a one hour time interval.

Megawatt

One million watts of electricity.

Megawatt-hour

One thousand kilowatt-hours or one million watt-hours.

Net Load

The total electric demand on the system minus generation from variable renewable energy (i.e., wind and solar).

North American Electric Reliability Corporation (NERC)

"A not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system in North America" (NERC, http://www.nerc.com/Pages/default.aspx).

Presidential Permit

A permit issued by the U.S. Department of Energy that may grant the construction, connection, operation and/or maintenance of electric transmission lines that cross a U.S. international border (DOE, "Presidential Permits and Export Authorizations: About the Program," https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/international-electricity-regulatio-4).

Ramping

Generally, the deviation between the start and end of an interval; a ramp event may be parametrized by ramping start/end, ramping duration, ramping rate, and ramping magnitude (Cui, Zhang, Feng, Florita, Sun, Hodge, 2017).

Real-time Market

The continuous time period during which the real-time balancing market is operated. (https://www.spp.org/glossary/).

Regional Transmission Organization (RTO)

A voluntary organization of electric transmission owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation and use on a regional (and interregional) basis; operation of transmission facilities by the RTO must be performed on a non-discriminatory basis (FERC, "Glossary," https://www.ferc.gov/market-oversight/guide/glossary.asp).

Renewable Energy Resources

Energy resources that are naturally replenishing but flow-limited; they are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time; renewable energy resources include biomass, hydropower, geothermal, solar, wind, and ocean energy.

Reserve Margin

The expected additional capacity available beyond the projected peak coincident system load that is intended to account for peak load forecast error and capacity needed for Ancillary Services and unexpected capacity outages during peak times.

Right-of-Way (ROW)

"Typically, a strip of land used for a specific purpose, such as the construction, operation, or maintenance of a road or transmission line." (http://greatnortherntransmissionline.com/realestate.html).

Spinning Reserve

Reserve generating capacity that is running at zero load and synchronized to the electric system. (EIA, "Glossary: Electricity," https://www.eia.gov/tools/glossary/?id=electricity).

Spot Auction

In NYISO, capacity spot auctions are held for single calendar month delivery periods.

Strip Auction

In NYISO, capacity strip auctions are held for the six-month capability periods "Summer" (May through October) and "Winter" (November through April).

Summer Capacity (Net)

The maximum output, commonly expressed in megawatts, that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (commonly, June 1 through September 30); this output reflects a reduction in capacity that is due to electricity use for station service or auxiliaries. (EIA, "Glossary," https://www.eia.gov/tools/glossary/).

Thermoelectric Power Plant

A term used to identify a type of electric generating station, capacity, capability, or output in which the source of energy for the prime mover is heat.

Unforced Capacity (UCAP)

Unforced capacity represents the amount of installed capacity that is actually available at any given time after discounting for time that the facility is unavailable (e.g., due to outages such as repairs). (PJM 2018).

Variable Renewable Energy (VRE)

Renewable energy that is not stored prior to electricity generation; this includes primarily wind and solar PV energy technologies, but it may also include technologies such as tidal power and run-of-river hydropower (Cochran et al. 2012).

Voltage (Transmission Line)

A measure of the potential difference between two points in an electrical circuit is, or the force that is pushing electrons between these two points; voltage is measured in volts. A kilovolt (kV) is equal to 1,000 volts. (ABB, "Glossary of Technical Terms Commonly used by ABB," http://new.abb.com/glossary).

Additional Resources for Data on Renewable Energy Grid Integration

- ISO/RTO Market Monitor Reports
  - CAISO: *2018 Annual Report on Market Issues and Performance* (CAISO 2019)
  - ERCOT: *2018 Annual Report on Market Issues and Performance* (Potomac Economics 2019a)
  - ISO-NE: *2018 Annual Markets Report* (ISO-NE 2019)
  - MISO: *2018 State of the Market Report for the MISO Electricity Markets* (Potomac Economics 2019b)
  - NYISO: *2018 State of the Market Report for the New York ISO Markets* (Patton et al. 2019)
  - PJM: *2018 State of the Market Report for PJM* (Monitoring Analytics 2019a, 2019b)
  - SPP: *State of the Markets: 2018* (SPP 2019)
- NERC: *Annual Report 2018* (NERC 2019)
- DOE: *Staff Report to the Secretary on Electricity Markets and Reliability* (DOE 2017)
- FERC: Conference on matters affecting wholesale energy and capacity markets operated by eastern RTOs and ISOs (May 1–2, 2017)[1]
- NERC: *2018 Long-Term Reliability Assessment* (NERC 2018)

[1] "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000) (Washington, DC) (Free Web Cast)," FERC, https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType= &CalendarID=116&Date=&View=Listview

Additional Resources for Data on Renewable Energy Grid Integration

- Grid Modernization: metrics analysis (GMLC 2017)
- Intergovernmental Panel on Climate Change (IPCC): *Renewable Energy Sources and Climate Change Mitigation: Special Report of the Intergovernmental Panel on Climate Change* (IPCC 2012)
- Lawrence Berkeley National Laboratory:
  - *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing, and Costs* (Wiser et al. 2017)
  - *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making* (Seel et al. 2018).
  - *Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017* (Mills et al. 2019).

References

Abdollahi, Mostafa. 2013. "Effects of Generators Reactive Power on Locational Marginal Prices." *International Journal of Academic Research in Applied Science* 2(9): 43-49.

Bade, Gavin. 2018. "'Stunning' APS RFP Could Violate Arizona Gas Moratorium, Critics Say." *Utility Dive*. May 14, 2018 . https://www.utilitydive.com/news/stunning-aps-rfp-could-violate-arizona-gas-moratorium-critics-say/523451/.

BPA (Bonneville Power Administration). 2019. *EIM Participation*. Letter to stakeholders. https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190620-Western-Energy-Imbalance-Market-Letter-to-the-Region.pdf.

CAISO (California Independent System Operator). 2019. *2018 Annual Report on Market Issues and Performance*. http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf.

———. 2005. *Locational Marginal Pricing (LMP): Basics of Nodal Price Calculation*. CRR educational class presentation by R. Treinen. December 8, 2005.

Cochran, Jaquelin, Lori Bird, Jenny Heeter, and Douglas J. Arent. 2012. *Integrating Variable Renewable Energy in Electric Power Markets. National Renewable Energy Laboratory*. Joint Institute for Strategic Energy Analysis (JISEA), Clean Energy Solutions Center, and Clean Energy Ministerial. NREL/TP-6A00-53730. https://doi.org/10.2172/1219662.

Cohen, Stuart, Jon Becker, Dave Bielen, Maxwell Brown, Wesley Cole, Kelly Eurek, Will Frazier, et al. 2019. *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2018*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72023. https://doi.org/10.2172/1505935.

CPUC (California Public Utilities Commission). 2018. *Actions to Limit Utility Costs and Rates: Public Utilities Code Section 913.1 Annual Report to the Governor and Legislature*. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457283.

Denholm, Paul, Matthew O'Connell, Gregory Brinkman, and Jennie Jorgenson. 2015. *Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-6502. https://doi.org/10.2172/1226167.

DOE (U.S. Department of Energy). 2018. *Annual Transmission Review 2017: Data Review*. U.S. Department of Energy.

———. 2017. *Staff Report to the Secretary on Electricity Markets and Reliability.* U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2017/08/f36/Staff Report on Electricity Markets and Reliability_0.pdf.

———. 2016. *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program*. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. https://www.energy.gov/sites/prod/files/2016/12/f34/AMI Summary Report_09-26-16.pdf.

DSIRE. n.d. "Database of State Incentives for Renewables." North Carolina Clean Energy Technology Center. https://nccleantech.ncsu.edu.

EIA (U.S. Energy Information Administration). 2018. *Assessing HVDC Transmission for Impacts of Non-Dispatchable Generation*. https://www.eia.gov/analysis/studies/electricity/hvdctransmission/pdf/transmission.pdf.

———. Form EIA-411. https://www.eia.gov/electricity/data/eia411/.

———. Form EIA-860. https://www.eia.gov/electricity/data/eia860/.

———. Form EIA-861. https://www.eia.gov/electricity/data/eia861/.

———. *Form EIA-860 Instructions: Annual Electric Generator Report*. https://www.eia.gov/survey/form/eia_860/instructions.pdf.

———. *Form EIA-861 Annual Electric Power Industry Report Instructions*. https://elecidc12c.eia.doe.gov/2017 EIA-861 Instructions.pdf.

———. Form EIA-923. https://www.eia.gov/electricity/data/eia923/.

———. Form EIA-930, accessed through U.S. Electric System Operating Data website (https://www.eia.gov/realtime_grid/)

Ela, Erik, et al. 2019. *Future Electricity Markets: Designing for Massive Amounts of Zero-Variable-Cost Renewable Resources*, IEEE Power and Energy Magazine, vol. 17, no. 6, pp. 58-66, Nov.-Dec. 2019. https://ieeexplore.ieee.org/document/8879611

EPA (U.S. Environmental Protection Agency). 2015. "Chapter 7. Electric Utility Policies: Interconnection and Net Metering Standards" (Section 7.3: Interconnection and Net Metering Standards) in *Energy and Environment Guide to Action: State Policies and Best Practices for Advancing Energy Efficiency, Renewable Energy, and Combined Heat and Power, 2015 Edition*. https://www.epa.gov/sites/production/files/2017-06/documents/guide_action_full.pdf

ERCOT (Electric Reliability Council of Texas). 2018. *Report on Existing and Potential Electric System Constraints and Needs*. December 2018. http://www.ercot.com/content/wcm/lists/144927/2018_Constraints_and_Needs_Report.pdf.

FERC (Federal Energy Regulatory Commission). 2019. *Order Conditionally Accepting Tariff Filing and Requiring Compliance Filing*. 167 FERC ¶ 61,028: Docket Nos. ER19-356-000; ER19-356-001. Issued April 12, 2019. https://www.ferc.gov/CalendarFiles/20190412150632-ER19-356-000.pdf.

———. 2019b. *Compliance Filing Regarding Variable Energy Resources*. Docket No. ER19-356-002. Issued June 26, 2019. https://www.spp.org/documents/60176/201900626_order on compliance filing - revisions to require all vers to register and convert to dvers_er19-356-002.pdf.

———. 2019c. *Order on Motion for Supplemental Clarification*. 168 FERC ¶ 61,051. Docket Nos. EL16-49-000, EL18-178-000. Issued July 25, 2019. https://www.ferc.gov/CalendarFiles/20190725135527-EL16-49-000.pdf.

———. 2018a. *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*. 162 FERC ¶ 61,127. CFR Part 35: Docket Nos. RM16-23-000; AD16-20-000; Order No. 841. Issued February 15, 2018. https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf.

———. 2018b. *Essential Reliability Services and the Evolving Bulk-Power System: Primary Frequency Response*. 162 FERC ¶ 61,128. 18 CFR Part 35: Docket No. RM16-6-000; Order No. 842. Issued February 15, 2018. https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-2.pdf.

———. 2018c. *Order on Tariff Filing*. 162 FERC ¶ 61,205. Docket No. ER18-619-000. Issued March 9, 2018. https://www.ferc.gov/CalendarFiles/20180309230225-ER18-619-000.pdf.

———. 2018d. *Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act*. 163 FERC ¶ 61,236. Docket Nos. EL16-49-000. Issued June 29, 2018. https://www.ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf.

Gatti, Stefano. 2019. *Project Finance in Theory and Practice: Designing, Structuring, and Financing Private and Public Projects*. London: Academic Press. https://doi.org/10.1016/C2016-0-01618-2.

GLMC (Grid Modernization Laboratory Consortium). 2017. *Grid Modernization: Metrics Analysis (GMLC1.1), Reference Document, Version 2.1*. Prepared for the U.S. Department of Energy. Richland, WA: Pacific Northwest National Laboratory. https://gmlc.doe.gov/sites/default/files/resources/GMLC1 1_Reference_Manual_2 1_final_2017_06_01_v4_wPNNLNo_1.pdf.

Gorman, Will, Andrew Mills, Ryan Wiser. 2019. *Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy*. Energy Policy 135 (2019), https://doi.org/10.1016/j.enpol.2019.110994.

Greening the Grid. 2016. *Forecasting Wind and Solar Generation: Improving System Operations.* NREL/FS-6A20-65728. January 2016. https://www.nrel.gov/docs/fy16osti/65728.pdf.

Hagerty, J. Michael, Johannes Pfeifenberger, and Judy Chang. 2017. "*Transmission Planning Strategies to Accommodate Renewables*." Presented at EUCI Austin: Renewable Energy Grid Operations, September 11 , 2017. The Brattle Group. https://brattlefiles.blob.core.windows.net/files/5610_transmission_planning_strategies_to_accommodate_renewables.pdf.

Hawaiian Electric. 2019. "*Hawaiian Electric Companies Issue Call for Projects to Accelerate Islands' Renewable Energy Transition*." August 22, 2019. News release. https://www.hawaiianelectric.com/hawaiian-electric-companies-issue-call-for-projects-to-accelerate-islands-renewable-energy-transition.

IPCC (Intergovernmental Panel on Climate Change). 2012. *Renewable Energy Sources and Climate Change Mitigation: Special Report of the Intergovernmental Panel on Climate Change*. Ottmar Edenhofer, Ramón Pichs Madruga, Youba Sokona, Kristin Seyboth, Patrick Matschoss, Susanne Kadner, Patrick Eickemeier, Gerrit Hansen, Steffen Schlömer, and Christoph von Stechow (eds.). New York City: Cambridge University Press. https://www.ipcc.ch/site/assets/uploads/2018/03/SRREN_Full_Report-1.pdf.

ISO-NE (ISO New England). 2019. *2018 Annual Markets Report*. https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf.

Kirschen, D., and G. Strbac. 2004. *Fundamentals of Power System Economics*. Wiley.

Lew, Debra, Lori Bird, Michael Milligan, Bethany Speer, Enrico Maria Carlini, Ana Estanqueiro, Damian Flynn, et al. 2013. "Wind Power into Power Systems as Well as on Transmission Networks for Offshore Wind Power Plants." In *International Workshop on Large-Scale Integration of Wind Power into Power Systems as Well as on Transmission Networks for Offshore Wind Power Plants*. http://orbit.dtu.dk/files/134034514/60245.pdf.

McAllister, Keith. 2010. *Potential Impacts of Advanced Metering Infrastructure on Renewable Energy Policy: A Solar ABCs White Paper*. North Carolina Solar Center, and Interstate Renewable Energy Council. http://www.solarabcs.org/about/publications/reports/advanced-metering/pdfs/ABCS-13whitepaper.pdf.

Milligan, M., and K. Porter. 2008. "Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation: Preprint."

To be presented at WindPower 2008, Houston, Texas, June 1–4, 2008. Golden, CO: National Renewable Energy Laboratory. NREL/CP-500-43433. https://www.nrel.gov/docs/fy08osti/43433.pdf.

Mills, Andrew D., Dev Millstein, Ryan Wiser, Joachim Seel, Juan Pablo Carvallo, Seongeun Jeong, and Will Gorman. 2019. *Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017*. Lawrence Berkeley National Laboratory. http://eta-publications.lbl.gov/sites/default/files/lbnl_-_wind_and_solar_impacts_on_wholesale_prices_approved.pdf.

MISO. 2019. *2019/2020 Planning Resource Auction (PRA) Results*. April 12, 2019. https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf.

———. 2018. *2018/2019 Planning Resource Auction Results*. MISO Resource Adequacy Subcommittee. May 9, 2018. https://cdn.misoenergy.org/20180509%20RASC%20Item%2003a%202018-19%20PRA%20Detailed%20Results191633.pdf.

———. 2017. *2017/2018 Planning Resource Auction Results*. MISO. April 14, 2017. https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf.

———. 2016. *2016/2017 Planning Resource Auction Results*. MISO. April 15, 2016. https://cdn.misoenergy.org/2016-2017%20PRA%20Results87167.pdf.

———. 2015. *2015/2016 Planning Resource Auction Results*. April 14, 2015. MISO. https://cdn.misoenergy.org/2015-2016%20PRA%20Results87078.pdf.

———. n.d. *2014/2015 Planning Resource Auction (PRA)*. MISO. https://cdn.misoenergy.org/2014-2015%20PRA%20Results89073.pdf.

Monitoring Analytics. 2019a. 2018 State of the Market Report for PJM, Volume 1: Introduction. Monitoring Analytics. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume1.pdf.

———. 2019b. *2018 State of the Market Report for PJM, Volume 2: Detailed Analysis. Monitoring Analytics*. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf.

———. 2016. *State of the Market Report for PJM: 2016 Quarterly State of the Market Report for PJM: January through March*. Monitoring Analytics. May 12, 2016. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016q1-som-pjm.pdf.

NERC (North American Electric Reliability Corporation). 2019. *Annual Report 2018*. https://www.nerc.com/gov/Annual Reports/NERC 2018 Annual Report.pdf.

———. 2018a. *2018 Summer Reliability Assessment*. May 2018. Atlanta, GA: NERC. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf.

———. 2018b. *2018 Long-Term Reliability Assessment*. December 2018. Atlanta, GA: NERC. https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_2018_12202018.pdf.

———. 2017. *2017 Summer Reliability Assessment*. May 2017. Atlanta, GA: NERC. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf.

———. 2016. *Essential Reliability Services Whitepaper on Sufficiency Guidelines*. December 2016. https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf.

———. n.d. "M-1 Reserve Margin." Accessed November 2019: https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

NREL (National Renewable Energy Laboratory). 2016. *Energy Storage: Possibilities for Expanding Electric Grid Flexibility*. Golden, CO: National Renewable Energy Laboratory. NREL/BR-6A20-64764 https://www.nrel.gov/docs/fy16osti/64764.pdf .

NYISO (New York Independent System Operator). 2017. *Distributed Energy Resources Market Design Concept Proposal: A Report by the New York Independent System Operator*. https://www.nyiso.com/documents/20142/1391862/Distributed-Energy-Resources-2017-Market-Design-Concept-Proposal.pdf/122a815f-b767-e67f-0a8f-323e5489c2b1

O'Neill, Barbara. 2016. "Forecasting Wind." Presented to the Southeastern Wind Coalition UAG Forecasting and Integration Meeting, Raleigh, North Carolina, March 30, 2016. National Renewable Energy Laboratory. NREL/PR-5D00-66383. https://www.nrel.gov/docs/fy16osti/66383.pdf.

Patton, David B., Pallas LeeVanSchaick, Jie Chen, and Raghu Palavadi Naga. 2019. *2018 State of the Market Report for the New York ISO Markets*. Potomac Economics. https://www.nyiso.com/documents/20142/2223763/2018-State-of-the-Market-Report.pdf.

PJM. 2017. *RPM 101: Overview of Reliability Pricing Model*. April 18, 2017. https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx.

Potomac Economics. 2019a. *2018 State of the Market Report for the ERCOT Electricity Markets. Potomac Economics*. https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf.

———. 2019b. *2018 State of the Market Report for the MISO Electricity Markets*. Potomac Economics. https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-MISO-SOM_Report_Final2.pdf.

Joachim Seel, Andrew Mills, Ryan Wiser, Sidart Deb, Aarthi Asokkumar, Mohammad Hassanzadeh, and Amirsaman Aarabali. 2018. *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making*. Lawrence Berkeley National Laboratory Energy Analysis and Environmental Impacts Division. https://doi.org/10.2172/1437006.

SPP (Southwest Power Pool). 2019. *State of the Markets: 2018*. Southwest Power Pool, Inc. Market Monitoring Unit. https://www.spp.org/documents/59861/2018 annual state of the market report.pdf.

Wiser, Ryan, Andrew Mills, Joachim Seel, Todd Levin, and Audun Botterud. 2017. *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing, and Costs*. Lawrence Berkeley National Laboratory, and Argonne National Laboratory. https://doi.org/10.2172/1411668/.

U.S. DEPARTMENT OF
ENERGY

Office of
ENERGY EFFICIENCY &
RENEWABLE ENERGY

For more information, visit:
energy.gov/eere

DOE/GO-102020-5208
February 2020

Prepared by the National Renewable Energy Laboratory (NREL)
NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC