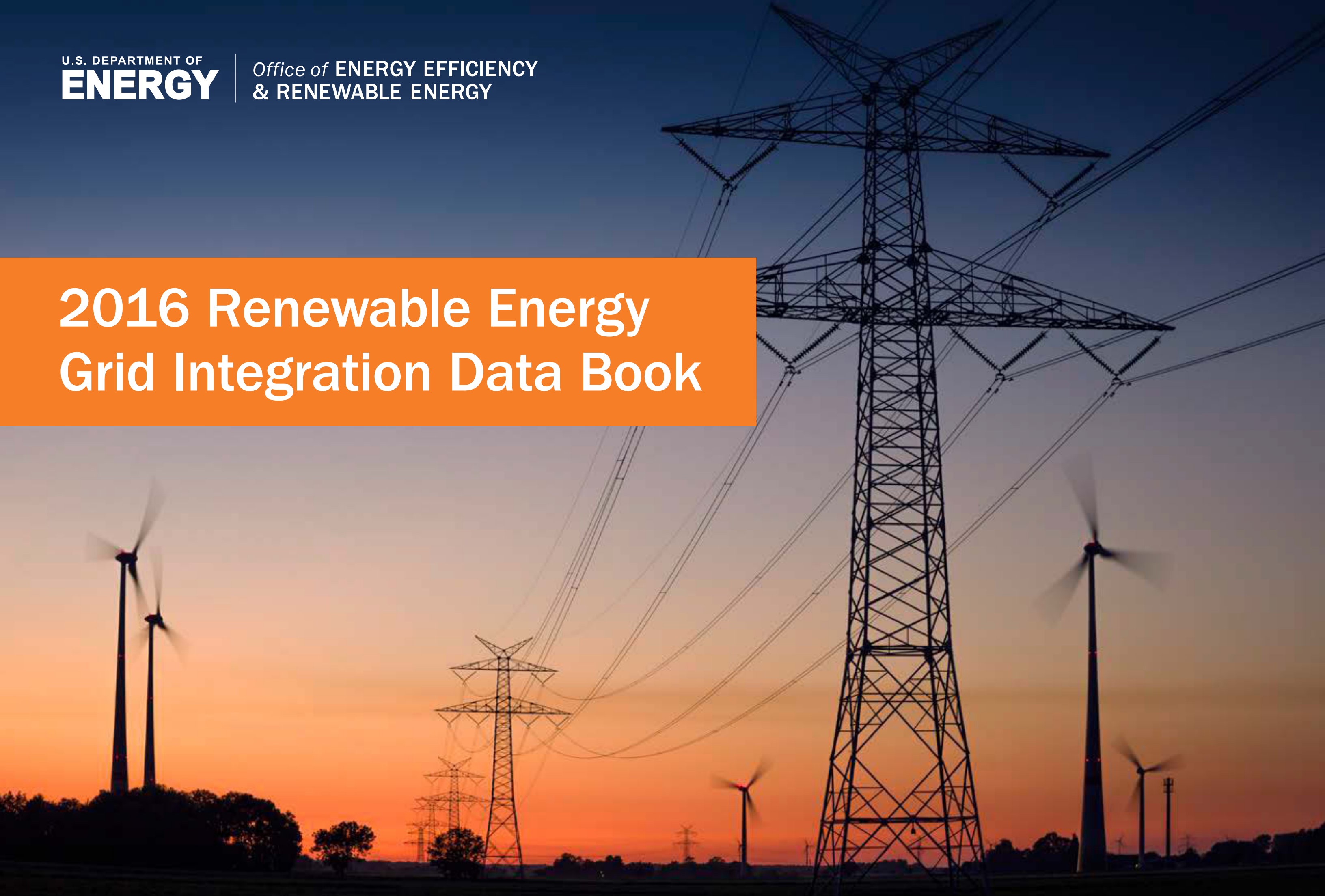
U.S. DEPARTMENT OF ENERGY | Office of ENERGY EFFICIENCY & RENEWABLE ENERGY

2016 Renewable Energy Grid Integration Data Book



Acknowledgments

This report was produced by Philipp Beiter,[1] Nina Vincent,[1] and Ookie Ma;[2] edited by Mike Meshek; and designed by Stacy Buchanan and Billy Roberts of the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). We greatly appreciate the input, review, and support of Hoyt Battey, Steve Capanna, Clark Charlton, Paul Donohoo-Vallett, Alex Fitzsimmons, Courtney Grosvenor, Kevin Lynn, Lawrence Mansueti, Josh Mengers, and Paul Spitsen of the U.S. Department of Energy (DOE), as well as Doug Arent, Clayton Barrows, Lori Bird, Aaron Bloom, Emily Chen, Jaquelin Cochran, Karlynn Cory, Jerry Davis, Paul Denholm, Bethany Frew, Donna Heimiller, Robert Leland, Jeff Logan, Jessica Lau, David Mooney, Robin Newmark, Mark O'Malley, Gian Porro, Gary Schmitz, Dan Steinberg, and Karen Yu of NREL. We also thank Andrew Mills and Ryan Wiser of the Lawrence Berkeley National Laboratory (LBNL), Beth Garza, Pallas LeeVanSchaick, Pratik Mehta, and Raghu Palavadi Naga of Potomac Economics, Aaron Bergman and Cara Marcy of the U.S. Energy Information Administration (EIA), and Charlie Smith of the Utility Variable-Generation Integration Group (UVIG).

Front page photo: 501095406; section photos: NASA Earth Observatory image by Robert Simmon, using Suomi NPP VIIRS data provided courtesy of Chris Elvidge (NOAA National Geophysical Data Center).

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

Overview

- The *2016 Renewable Energy Grid Integration Data Book* identifies the status, key trends, and challenges of approaches to renewable energy grid integration in a highly visual format.
- This, the inaugural version of the Data Book, is intended to provide an overview of selected key grid integration metrics that represent complex interactions among generation characteristics, market rules, and environmental and safety factors, which may vary by geography, season, and time of day.
- All of these metrics either indicate how much variable renewable energy (VRE) is currently being integrated onto the grid, or measure factors that may increase or decrease the challenges associated with integrating VRE generation onto the grid.
- Some data and content is included to provide context on the broader electric sector and market environment for renewable energy integration.
- The costs and barriers to VRE integration can be lowered through a number of strategies, including improved wind and solar forecasting, additional transmission and storage, increased coordination across balancing authorities, and many others.
- Any causal inferences should be considered carefully. This publication does not consider the full set of integration challenges and mitigation opportunities in this research area. Some literature recommendations for further consideration of these topics are provided on page 87.

Key Findings

	Installed cumulative capacity of renewable[1] energy as a percentage of total generation capacity (2016)
CAISO[2]	40.5% (26.1 GW[3])
ERCOT[4]	19.8% (19.9 GW)
SPP[5]	23.9% (20.0 GW)
WECC[6]	43.4% (63.3 GW)
MISO[7]	11.6% (20.0 GW)
ISO-NE[8]	16.9% (5.5 GW)
PJM[9]	7.7% (14.7 GW)
NYISO[10]	17.3% (7.2 GW)
SERC[11]	11.7% (20.2 GW)
FRCC[12]	2.7% (1.5 GW)

[1] Renewables include utility-scale (greater than 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 glossary), unless indicated otherwise.

[2] California Independent System Operator (CAISO)

[3] GW = gigawatts

[4] Electric Reliability Council of Texas (ERCOT)

[5] Southwest Power Pool (SPP)

[6] Western Electricity Coordinating Council (WECC)

[7] Midcontinent Independent System Operator (MISO)

[8] ISO New England (ISO-NE)

[9] PJM Interconnection (PJM)

[10] New York Independent System Operator (NYISO)

[11] SERC Reliability Corporation (SERC)

[12] Florida Reliability Coordinating Council (FRCC)

Sources: Form EIA-860 (www.eia.gov/electricity/data/eia860); S&P Global Market Intelligence database

Key Findings (continued)

	Installed Cumulative Capacity of Variable Renewable Energy (VRE)[13] as a Percentage of Total Generation Capacity (2016)	Annual Average VRE Generation as a Percentage of Total Generation (2016)
CAISO	26.1% (16.8 GW)	21.0%
ERCOT	19.1% (19.2 GW)	13.8%
SPP	18.1% (15.2 GW)	16.1%
WECC	12.0% (17.5 GW)	7.7%
MISO	9.0% (15.5 GW)	6.9%
ISO-NE	5.8% (1.9 GW)	3.1%
PJM	4.7% (9.0 GW)	2.5%
NYISO	4.7% (1.9 GW)	2.9%
SERC	3.1% (5.3 GW)	1.6%
FRCC	0.6% (0.3 GW)	0.1%

[13] For the purposes of this Data Book, variable renewable energy (VRE) is defined to include 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

Key Findings (continued)

- The **annual average VRE penetration in 2016 was led by wind generation** except for CAISO and FRCC. In CAISO, 2016 VRE penetration was comprised of solar photovoltaics (PV) (49.1%), wind (44.2%), and concentrating solar power (CSP) (6.7%).

- In 2016, **maximum hourly penetration[14] of wind and solar[15] generation reached nearly 49.8% in SPP** (on November 17), 48.5% in CAISO (on May 15 when it was comprised of 33.5% solar and 15% wind), and 47.4% in ERCOT (on March 23). The highest levels of hourly wind penetration were 21.8% in MISO (on November 28), 11.7% in NYISO (on October 23), and 8.6% in PJM (on December 27).

- In 2016, a total of **2,850 circuit miles of high voltage transmission greater than 100 kilovolts (kV) were under construction[16]** in the North American Electric Reliability Corporation (NERC) regions. By 2025, the largest additions of transmission projects as a share of total existing regional transmission circuit miles are planned[17] in the Midwest Reliability Organization (MRO) (8.9%), followed by the Florida Reliability Coordinating Council (FRCC) (6.8%), and the Southwest Power Pool Regional Entity (SPP RE) (5.0%).

[14] 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.

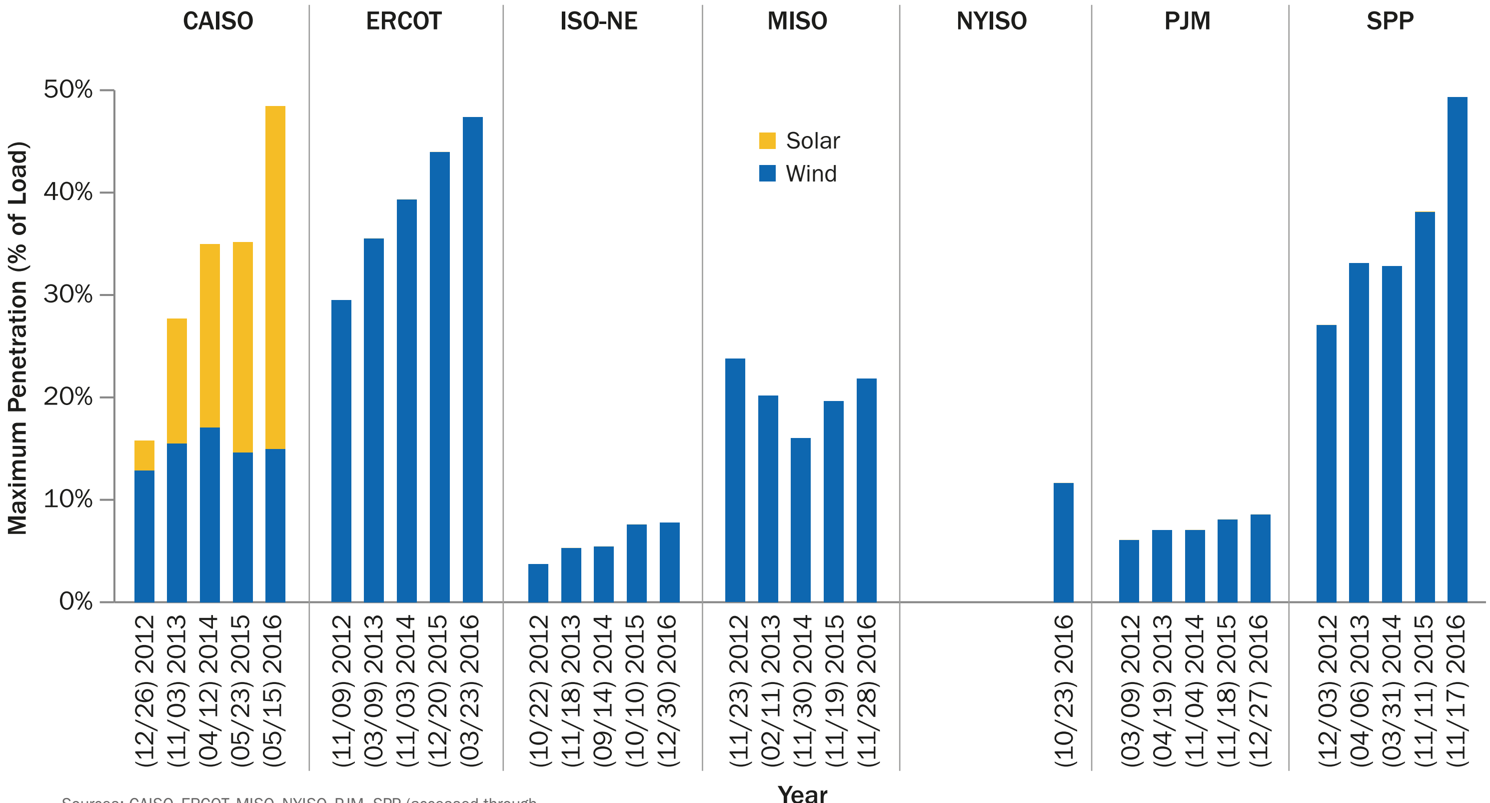
[15] Solar includes solar PV and CSP.

[16] Under construction: projects where construction of the line has already begun (DOE 2017)

[17] Planned: projects where (a) permits have been approved, (b) a design is complete, or (c) the project is necessary to meet a regulatory requirement (DOE 2017)

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

Maximum Hourly Penetration of Solar and Wind



Sources: CAISO, ERCOT, MISO, NYISO, PJM, SPP (accessed through the ABB Velocity Suite) and ISO-NE (2017).

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

Key Findings (continued)

- In CAISO, the **net load during the day of highest VRE penetration has increasingly assumed a "duck curve" shape[18] between 2012 and 2016.** On May 15, 2016—the day with highest VRE penetration in 2016—the difference between the minimum net load at 12 p.m. and the maximum at 8 p.m. amounted to 12,000 MW (approximately 74% of total generating capacity from non-VRE sources during this time period) of ramping demand that the system successfully addressed. This compares to a difference of 8,500 MW within 11 hours in 2012.

- Among the non-CAISO independent system operator (ISO)/regional transmission organization (RTO) markets, a **CAISO-like net load "duck curve" does not seem to be clearly distinguishable.** In PJM in 2016, the maximum ramping during a three-hour period was 30.5 GW (on July 23), followed by MISO with 24.6 GW (on July 21) and ERCOT (15.6 GW on August 4).

- Between 2012 and 2016, **reserve margin levels stayed above the generic NERC-recommended reserve margin level of 15% in all regions except the ERCOT market.** In ERCOT, reserve margin levels were in the range of 10.0%–11.3%, which is below the generic target level of 15% and the region-specific reference margin level of 13.8%.

- In 2016, the **maximum hourly day-ahead overprediction forecast error[19]** of wind was 39.4% in ERCOT, 28.9% in SPP, and 27.0% in MISO.

[18] 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 steep evening "necks" (see page 61 for the CAISO duck curve in 2016).

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

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

Key Findings (continued)

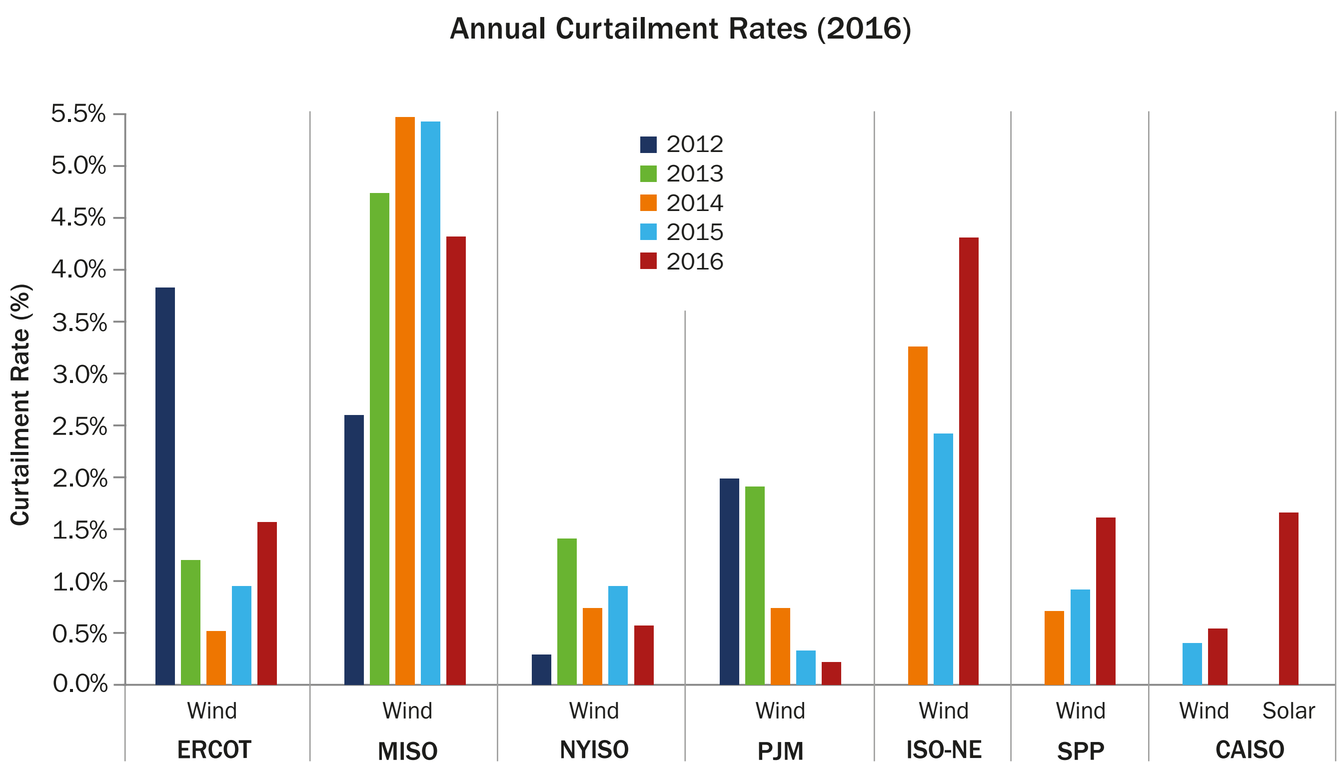
- In 2016, **the maximum average hourly day-ahead underprediction forecast error** of wind was 28.0% in ERCOT, 24.5% in SPP, and 24.4% in MISO.
- The **highest average wind curtailment rates** were observed in 2016 in MISO (4.3%), which was followed by ISO-NE (4.3%), SPP (1.6%), ERCOT (1.6%), NYISO (0.6%), CAISO (0.5%), and PJM (0.2%).
- In CAISO, the only region which saw significant **solar photovoltaics (PV) curtailment**, average curtailment levels of solar PV were 1.7% of its total generation in 2016.
- About 93% of hours fall within average LMP—between \$0/MWh and \$50/MWh among ISO/RTO markets—of which 62% fall in a range of \$0/MWh to \$25/MWh. The **lowest real-time average hourly LMPs** were observed in NYISO (-\$189.95/MWh) and ISO-NE (-\$155.90/MWh) in 2016.[11]
- During 2016, 5% of hours saw **negative pricing[20] of average hourly[21] locational marginal price** (LMP) in the real-time CAISO market, which was followed by ISO-NE (2.1%), SPP (1.6%), ERCOT (1.5%), NYISO (0.5%), PJM (0.2%), and MISO (0.1%).[22]
- In 2016, the **lowest median negative real-time LMP** was observed in ISO-NE (-\$20.64/MWh), which was followed by CAISO (-\$8.52/MWh). The highest median negative LMP in ISO/RTO areas was experienced by ERCOT (-\$0.54/MWh).[22]

[20] Negative LMP can be the result of a complex interaction among economic, reliability, environmental, safety and incentive scheme factors. Please see page 38 for more details.

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

[22] For the purposes of the Data Book, real-time LMP is presented in terms of hourly (load-weighted) averages. Sub-hourly (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.

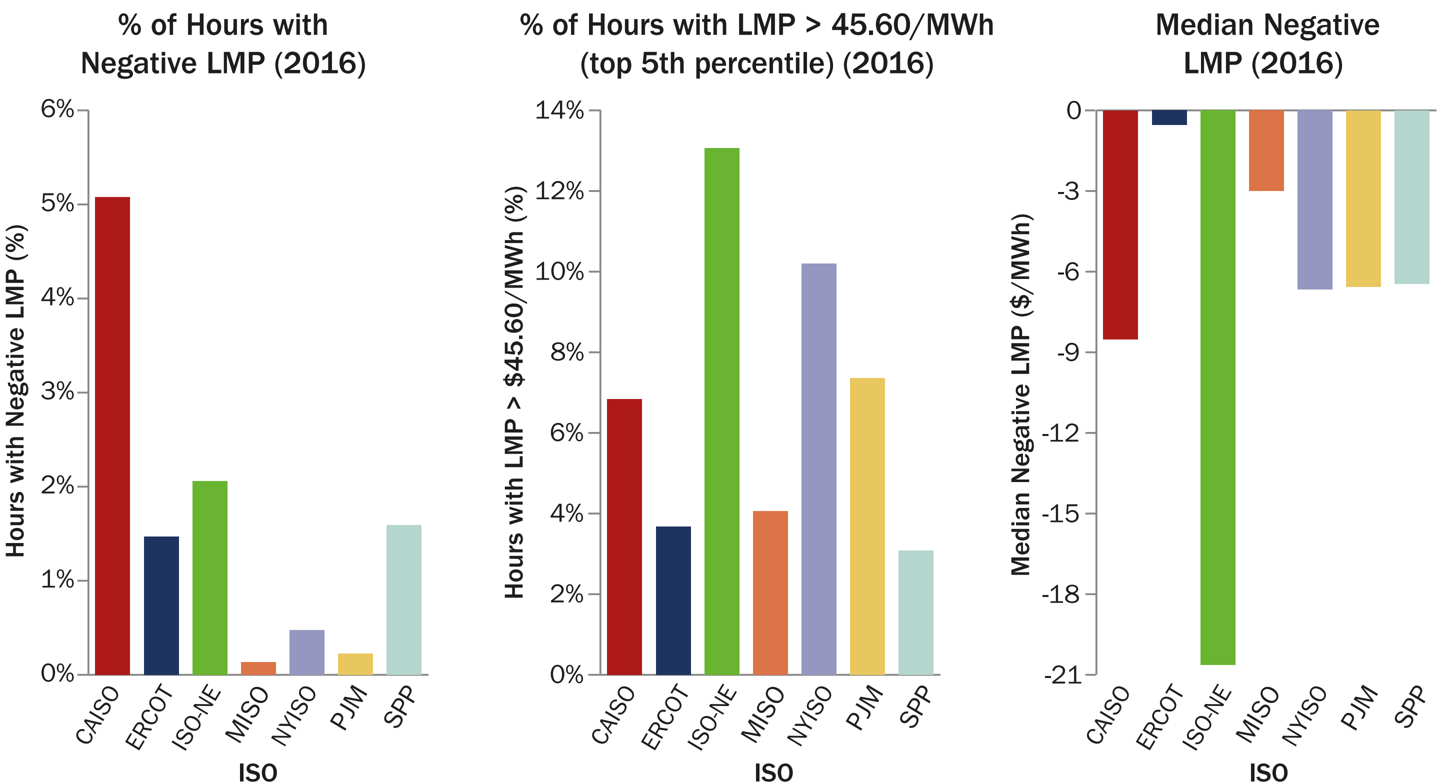
Note: Some data and content is included to provide context on the broader electric sector and market environment for renewable energy integration.



Sources: Wiser and Bolinger (2017) for wind data and CAISO (2017b) for solar data

Note: Depicted data include both "forced" (i.e., ISO-instructed) and "economic" (i.e., incentivized by prevailing LMP) curtailment.

Key Findings (continued)



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

Note: The threshold of $45.60 represents the top 5th percentile of average LMPs during 2016; Locational Marginal Price (LMP) data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO). 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 depicted data 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)
  - Bonneville Power Administration
  - U.S. Department of Energy (DOE).

Methodology and Data Sources (continued)

- Data are also shown for NERC regions and subregions, including the Florida Reliability Coordinating Council (FRCC), the Midwest Reliability Organization (MRO), the Northeast Power Coordinating Council (NPCC), Reliability First (RF), the SERC Reliability Corporation (SERC), the Southwest Power Pool, RE (SPP-RE), the Texas Reliability Entity (TRE), and the Western Electricity Coordinating Council (WECC).
- Data were accessed through the ABB Velocity Suite (ABB n.d.) or directly from the sources listed above. The primary data represented and synthesized in the *2016 Renewable Energy Grid Integration Data Book* come from the publicly available data sources, identified on pages 88–92.
- Metrics, when available, are reported for ISO/RTO service territory areas and for areas without centrally organized wholesale electricity markets (referred to herein as Non-ISO/RTO regions).
- The type of metrics included are expected to evolve as more detailed information and data become available.
- Data and content is focused on 2016. Historic data is included for the depiction of trends and context.

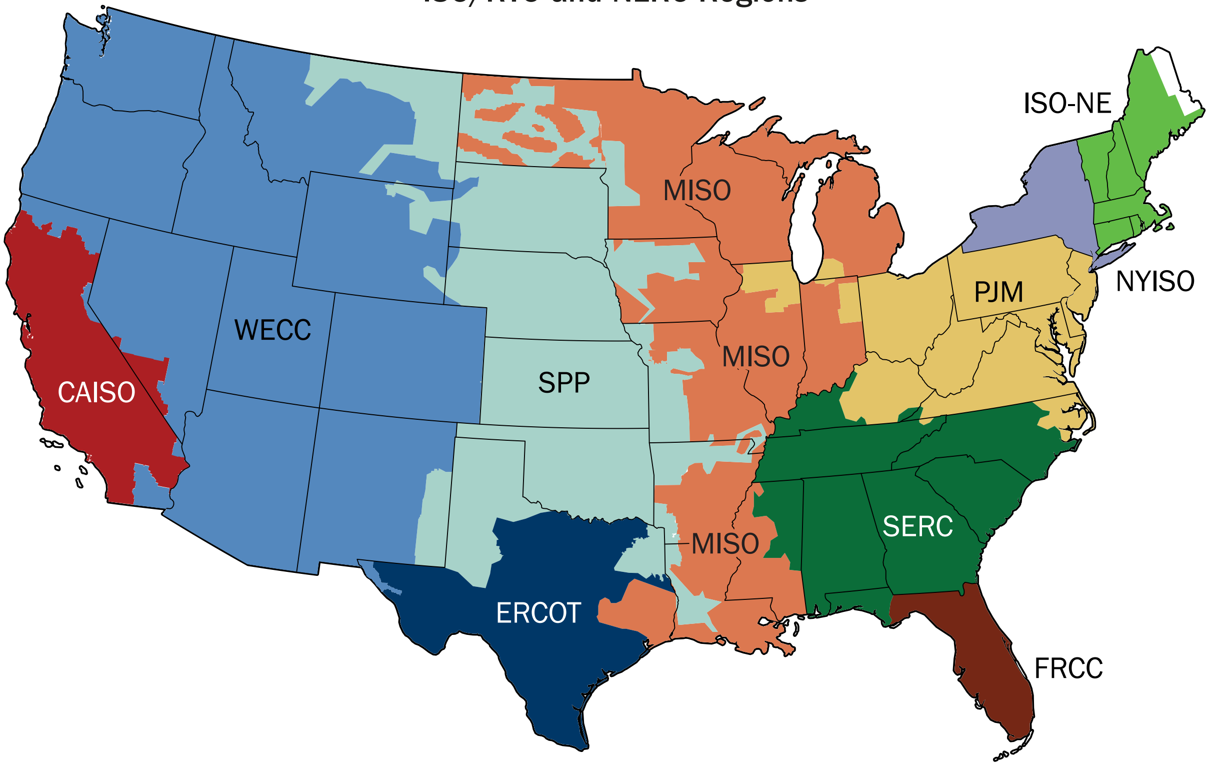
Methodology and Data Sources (continued)

- Locational marginal price (LMP) data are reported as hourly (load-weighted) averages from zonal price nodes in the real-time (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 from zonal price nodes in the RT market. 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.[1]
- The congestion component of LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (MISO, PJM, ISO-NE, 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 in watts (typically megawatts and gigawatts) of alternating current (AC) and include utility-scale generation with project capacity of 1 MW or larger, unless indicated otherwise.
- Solar PV does not include distributed (i.e., behind-the-meter) PV energy.

[1] Wiser et al. 2017

ISO/RTO and NERC Regions Used in this Data Book

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 2017 ISO/RTO regions and NERC regions for non-RTO/ISO regions. The Energy Imbalance Market is not shown because data are presented separately for WECC and CAISO; note that while it is reported separately in this Data Book, CAISO is formally part of WECC.

II. Capacity and Generation

Capacity and Generation: Summary

- In 2016, the share from renewable[1] cumulative installed capacity of total generation capacity comprised 43.4% (63.3 GW) in WECC, 40.5% (26.1 GW) in CAISO, 23.9% (20.0 GW) in SPP, 19.8% (19.9 GW) in ERCOT, 17.3% (7.2 GW) in NYISO, 16.9% (5.5 GW) in ISO-NE, 11.7% (20.2 GW) in SERC, 11.6% (20.0 GW) in MISO, 7.7% (14.7 GW) in PJM, and 2.7 (1.5 GW) in FRCC.

- In 2016, combined wind and solar[2] installed capacity as a percentage of total generation comprised 26.1% (16.8 GW) in CAISO, 19.1% (19.2 GW) in ERCOT, 18.1% (15.2 GW) in SPP, 12.0% (17.5 GW) in WECC, 9.0% (15.5 GW) in MISO, 5.8% (1.9 GW) in ISO-NE, 4.7% in PJM (9.0 GW), 4.7% (1.9 GW) in NYISO, 3.1% (5.3 GW) in SERC, and 0.6% (0.3 GW) in FRCC.

- Across market regions, net capacity additions in 2016 were led by wind (+8.8 GW), followed by solar (+8.3 GW), natural gas combined cycle (NG-CC) (+6.9 GW), nuclear (+1.4 GW)[3], storage (+0.5 GW)[4], hydropower (+0.2 GW), natural gas combustion turbine (NG-CT) (+0.1 GW), geothermal (+0.0 GW), oil-gas-steam (-0.3 GW), and coal (-9.5 GW).

- Solar PV installed capacity grew across all ISO/RTO market regions. In CAISO, installed utility-scale solar PV capacity grew by 42.9% (+2.6 GW) to an installed capacity of 8.8 GW in 2016.

[1] Renewables include utility-scale (greater than 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 (greater than 1 MW) solar PV and CSP. Solar capacity data are reported in AC.

[3] The growth in nuclear capacity in 2016 can mostly be attributed to the commencement of commercial operation of unit 2 of the Watts Bar nuclear plant in SERC.

[4] In this Data Book version, only utility-scale storage (> 1 MW) is included.

Capacity and Generation: Summary (continued)

II

- While CAISO's solar PV installed capacity is more than twice what it is in the other ISO/ RTO markets combined and grew by 2,630 MW (+42.9%) in 2016, solar PV growth rates were higher in several market regions, including FRCC (+ 240 MW [+296.2%]), SPP (+180 MW [+190.2%]), MISO (+280 MW [+186.4%]), SERC (+1,650 [+119.0%]), WECC (+2,260 MW [+101.9%]), ERCOT (+260 MW [+85.7%]), PJM (+550 MW [+53.7%]), and ISO-NE (+190 MW [+50.1%]).
- Installed wind capacity in 2016 grew by 35.5% (+ 0.4 GW) in ISO-NE to 1.3 GW, by 32.0% (+3.6 GW) in SPP to a total of 14.9 GW, and 15.7% (+ 2.5 GW) in ERCOT to a total of 18.7 GW.
- Natural gas combined cycle (NG-CC) net additions were highest in MISO with 3.2 GW (+26.5%) in 2016.
- Installed coal capacity declined by 3.2 GW (-5.7%) in SERC, 2.5 GW (-3.8%) in MISO, 1.9 GW (-2.9%) in PJM and 1.6 GW (-5.4%) in SPP in 2016. Oil-gas-steam capacity of 1.5 GW (-16.4%) was retired in CAISO in 2016.
- Average annual capacity factors[5] typically vary by generation type and between different ISO/ RTO and non-ISO/RTO areas. Between 2012 and 2016, average capacity factors were highest for nuclear (90%), followed by biomass/municipal solid waste/landfill gas (57%), coal (52%), NG-CC (44%), hydropower (37%), wind (32%), solar PV (20%), and CSP (20%).

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

Variable Renewable Energy Penetration

Variable renewable energy (VRE) 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.[6]

- The share of VRE[7] of total generation continually increased in ISO/RTO and non-ISO/RTO market regions between 2012 and 2016. During this period, the share of VRE on average more than doubled across ISO/RTO and non-ISO/RTO regions.

- In 2016, annual average VRE generation as a fraction of total generation ranged from a high of 20.9% in CAISO to 16.5% in SPP, 14.0% in ERCOT, 6.9% in MISO, 2.9% in NYISO, and 2.5% in PJM. The annual average VRE penetration in 2016 was led by wind generation in these markets except for CAISO. In CAISO, 2016 VRE penetration was comprised of solar PV (49.1%), wind (44.2%), and CSP (6.7%).

[6] Cochran et al. 2012

[7] For the purposes of this Data Book, variable renewable energy (VRE) is defined to include wind, solar PV, and CSP. See the glossary for a definition of VRE. Note that CSP in combination with storage, tidal power, and run-of-river hydropower may not be considered VRE generation sources.

Maximum Hourly VRE Penetration

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 2016, maximum hourly penetration of wind and solar generation reached nearly 49.8% in SPP (on November 17), 48.5% in CAISO (on May 15 when it was comprised of 33.5% solar and 15% wind), and 47.4% in ERCOT (on March 23). The highest levels of hourly wind penetration were 21.8% in MISO (on November 28), 11.7% in NYISO (on October 23), and 8.6% in PJM (on December 27).

- Internationally, hourly VRE penetration maxima were set recently, for instance in Denmark (139% on July 26, 2015)[8] and Germany (85% on April 30, 2017)[9]

[8] Energinet.dk 2017
[9] Agora Energiewende 2017

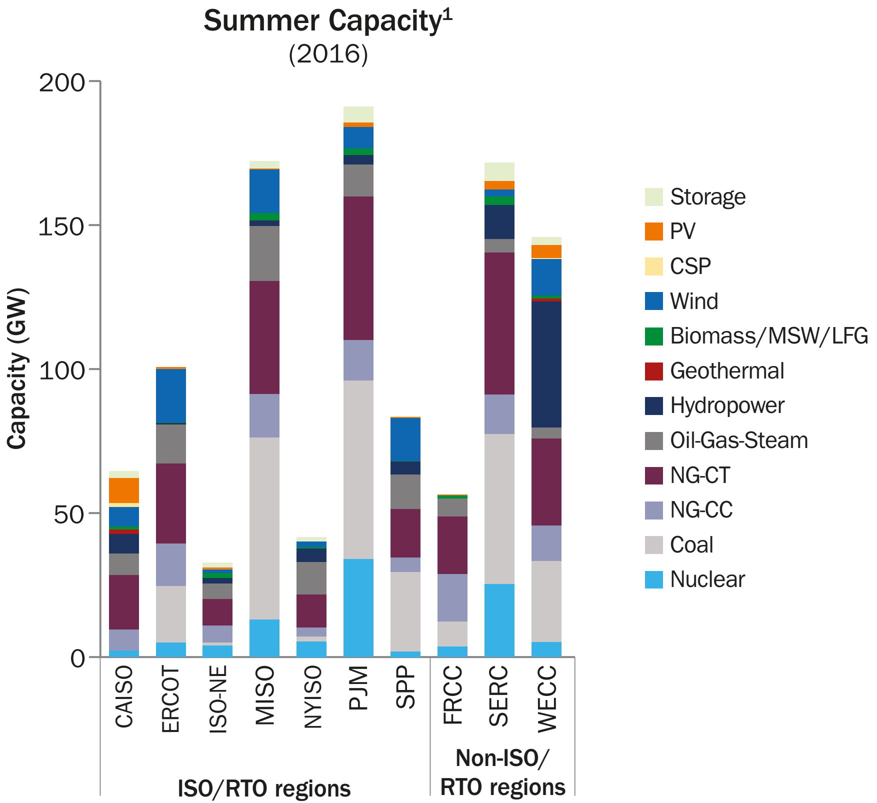
Storage Capacity

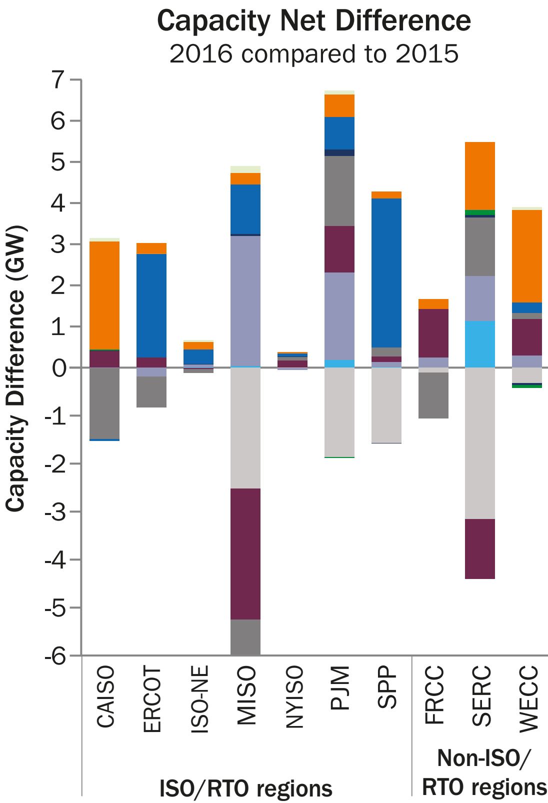
Storage[10] can provide a broad array of grid services that generally make the power system more flexible through energy management and reliability services.[11]

- Between 2012 and 2016, most storage capacity was derived from pumped hydropower (22.8 GW) in ISO/RTO and non-ISO/RTO markets, which corresponds to 2.1% of total installed generation capacity.[12] Pumped hydropower capacity remained relatively flat in all regions except MISO, where capacity grew 9.9% between 2012 and 2016.

- While battery storage comprised only 530 MW nationally in 2016 (less than 0.5% of total installed generation capacity[12]), the technology has grown in some regions. However, in the continental U.S., battery storage has increased by 51% annually (Compound Annual Growth Rate [CAGR]) between 2012–2016. In PJM, battery storage grew by 262 MW between 2012 and 2016, by 90 MW in CAISO, 41 MW in ERCOT, 41 MW in WECC, 21 MW in MISO, and 19 MW in ISO-NE.

[10] In this Data Book version, only utility-scale storage (> 1 MW) is included.
[11] NREL 2016
[12] includes all generation types in CAISO, ERCOT, ISO-NE, NYISO, MISO, PJM, SPP, FRCC, SERC, and WECC.





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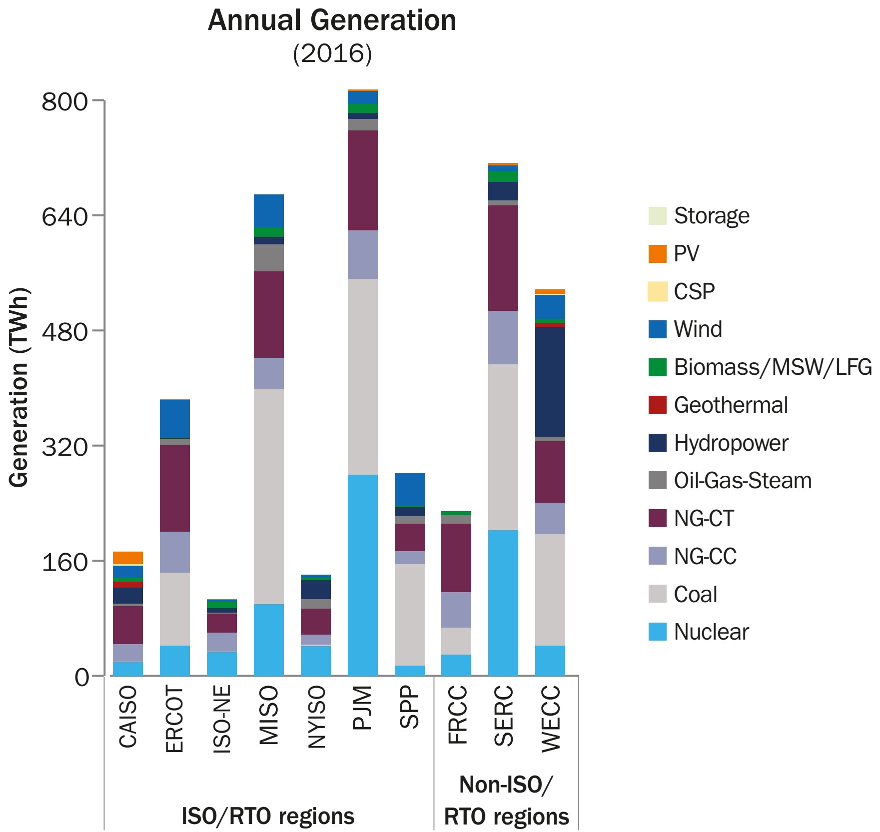
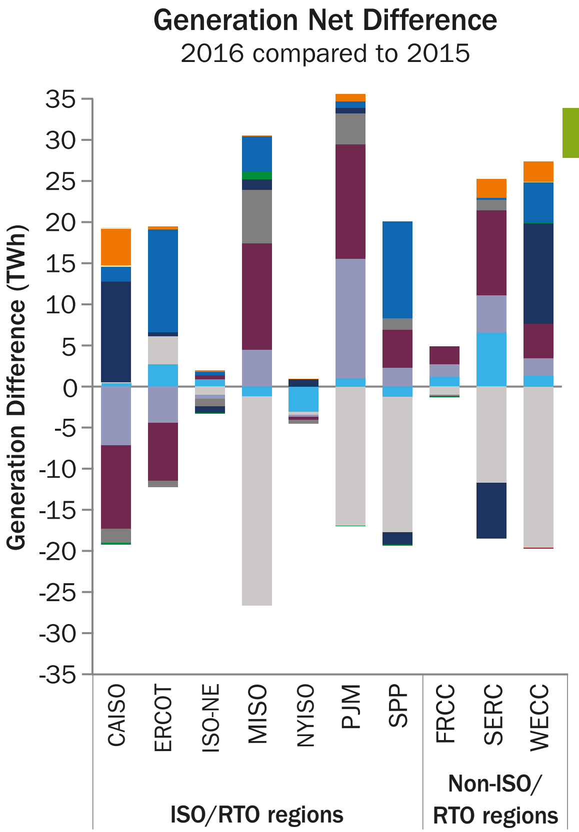
[1] See the glossary for a definition of "summer capacity."

Sources: Form EIA-860 (www.eia.gov/electricity/data/eia860); S&P Global Market Intelligence database

Notes: Wind includes offshore wind. "Other" generation sources excluded. Storage includes pumped hydropower, battery storage, and compressed air energy storage (CAES). WECC excludes CAISO. SERC excludes PJM, MISO, SPP, and FRCC. Data are only for generators above 1 MW.

Generation





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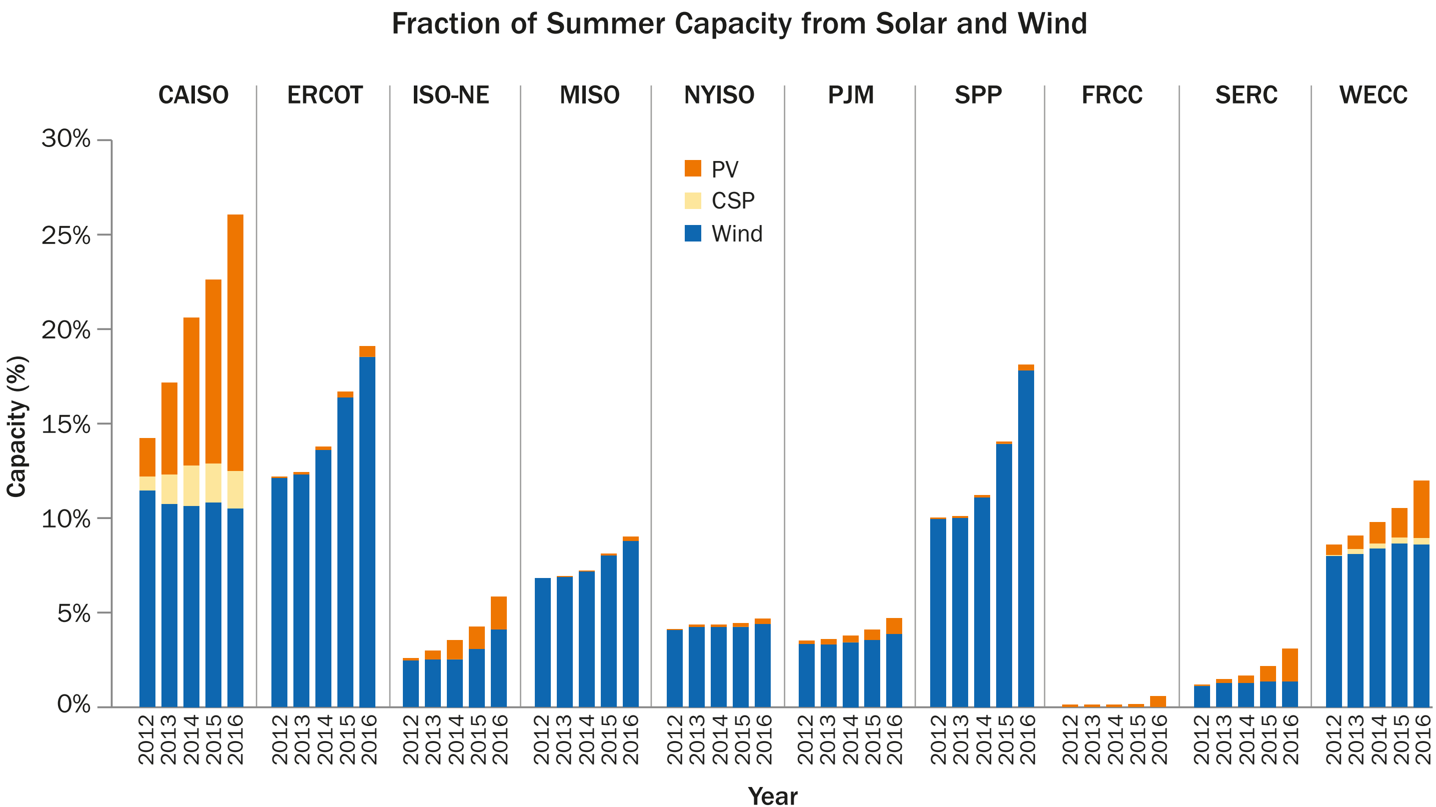
Sources: Form EIA-923 (www.eia.gov/electricity/data/eia923); S&P Global Market Intelligence database

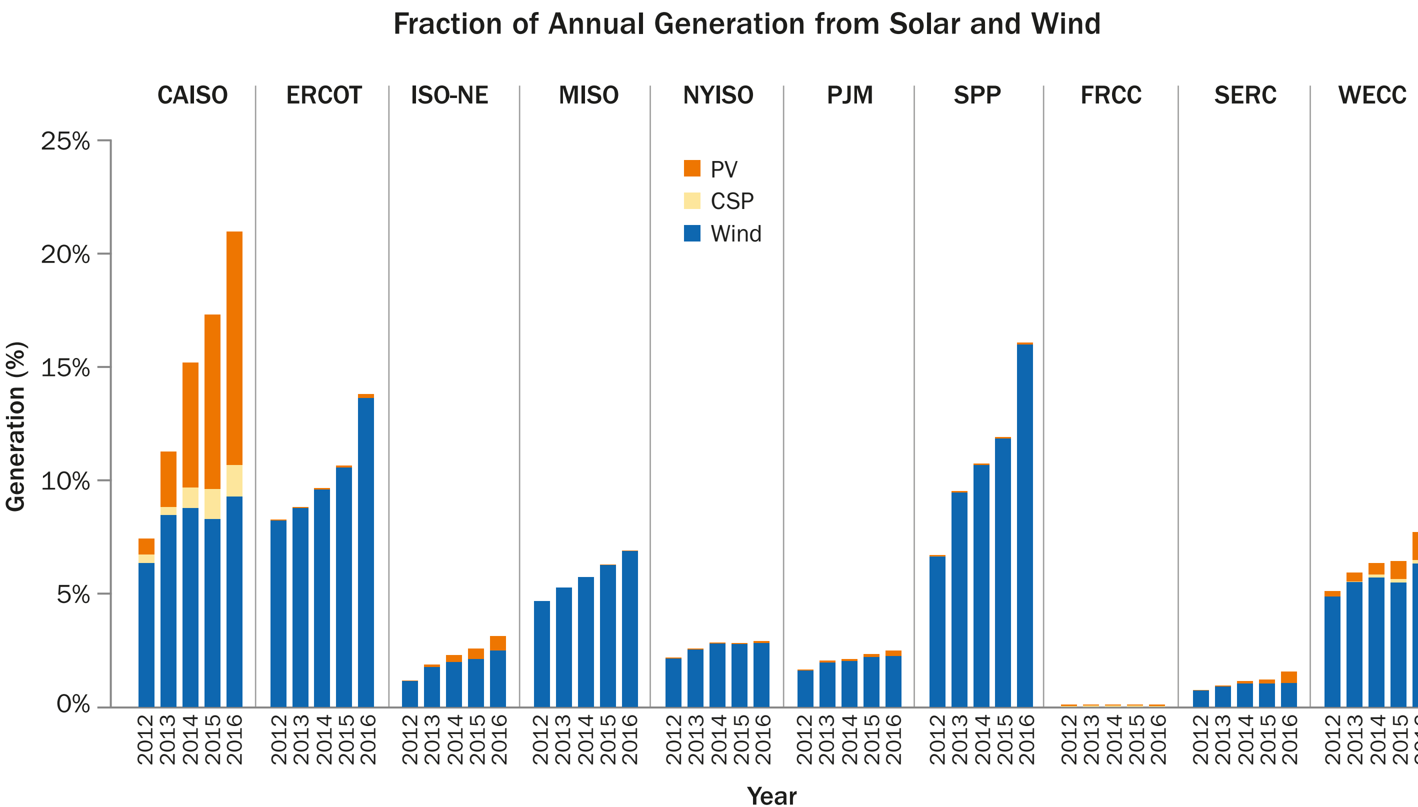
Notes: Wind includes offshore wind. "Other" excluded. Storage includes pumped hydropower, battery storage, and CAES. WECC excludes CAISO. SERC excludes PJM, MISO, SPP, and FRCC. Data are only for generators above 1 MW.



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.

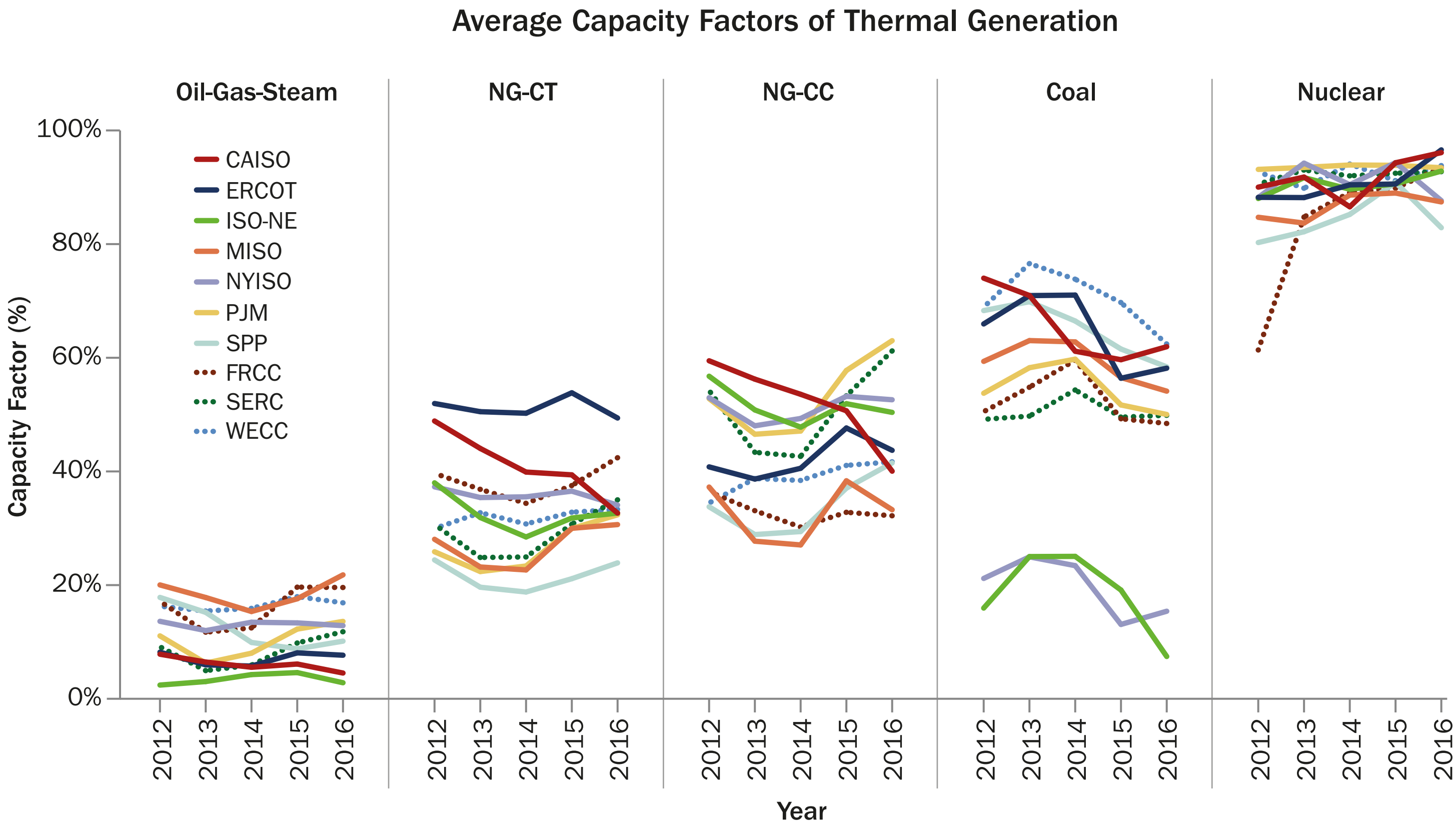
VRE Fraction of Total Generation



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.

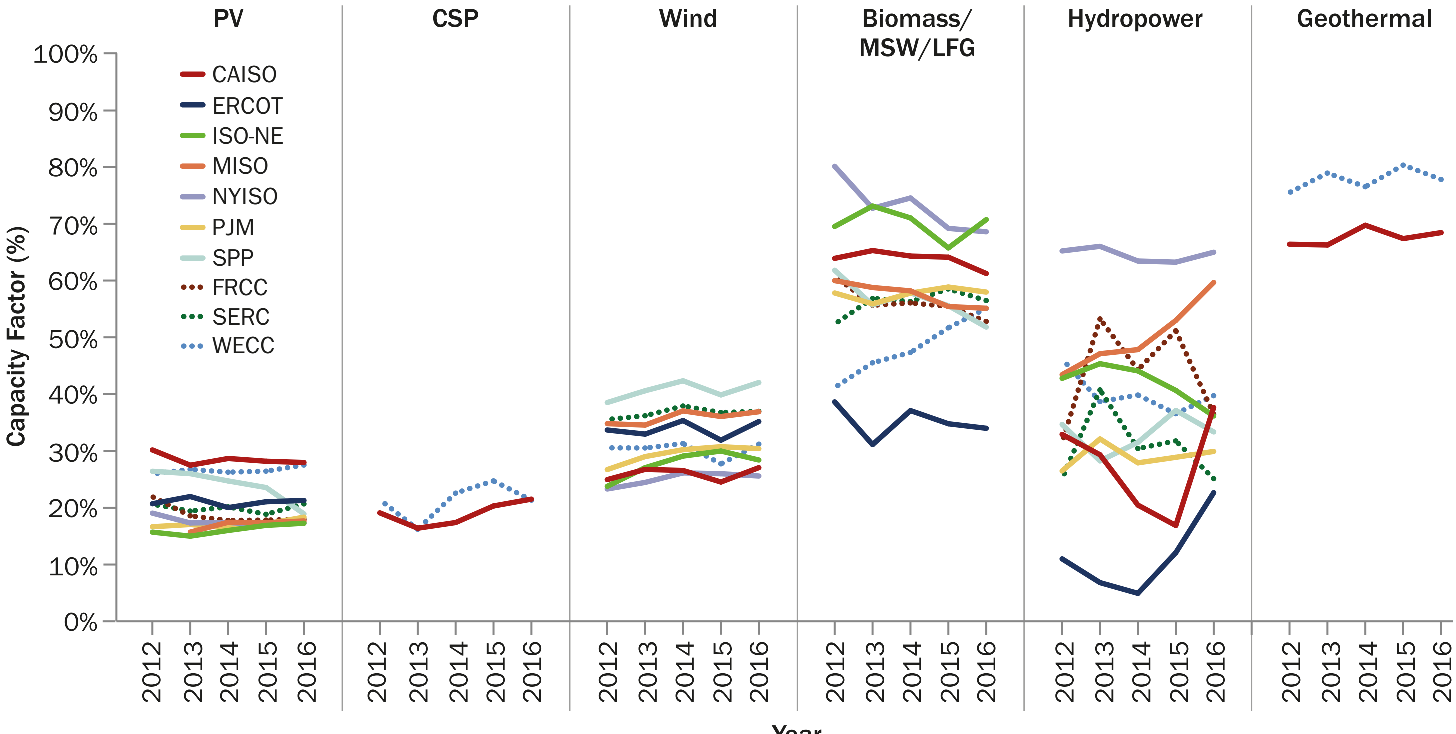
Average Capacity Factors



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

Notes: Average capacity factors were calculated by dividing total generation over reported summer capacity times number of operational hours in a given year and were capacity-weighted. Data are only for generators above 1 MW. Generators with 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 (Eurek et al. 2016).

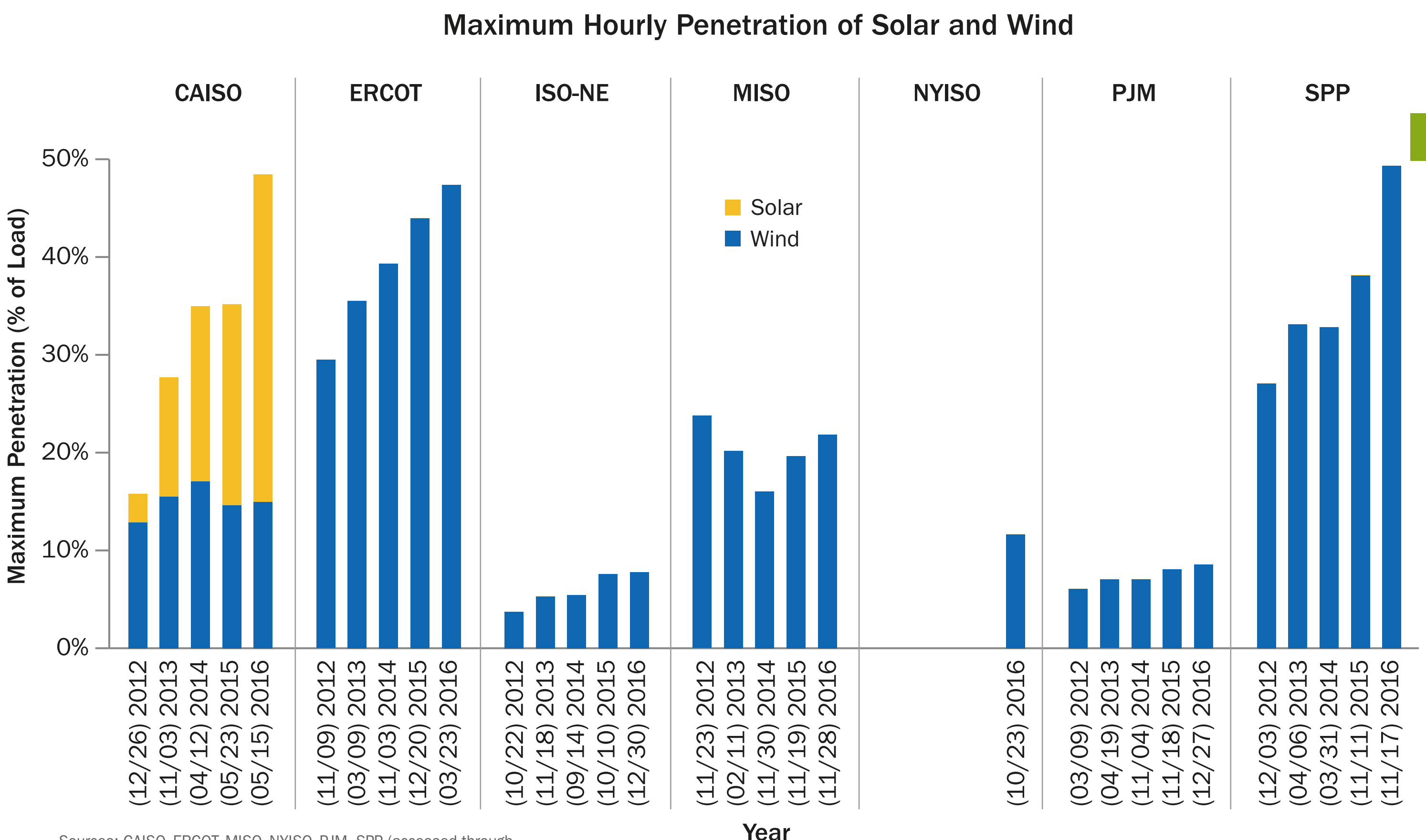
Average Capacity Factors of Renewable Generation



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

Notes: Average capacity factors were calculated by dividing total generation over reported summer capacity times number of operational hours in a given year and were capacity-weighted. Data are only for generators above 1 MW. Generators with 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 (Eurek et al. 2016).

Maximum Hourly Penetration of Solar and Wind



Sources: CAISO, ERCOT, MISO, NYISO, PJM, SPP (accessed through the ABB Velocity Suite) and ISO-NE (2017).

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

Reported Maximum VRE Penetration

II

SPP

- On November 17, 2016 at 2:35 a.m., SPP reached maximum wind generation penetration of 49.8% (10,780 MW) of load. Coincident with load increasing and wind generation declining in the morning hours (between 4:30 a.m. and 10:00 a.m.), generation from coal (+72%) and gas (+41%) increased.

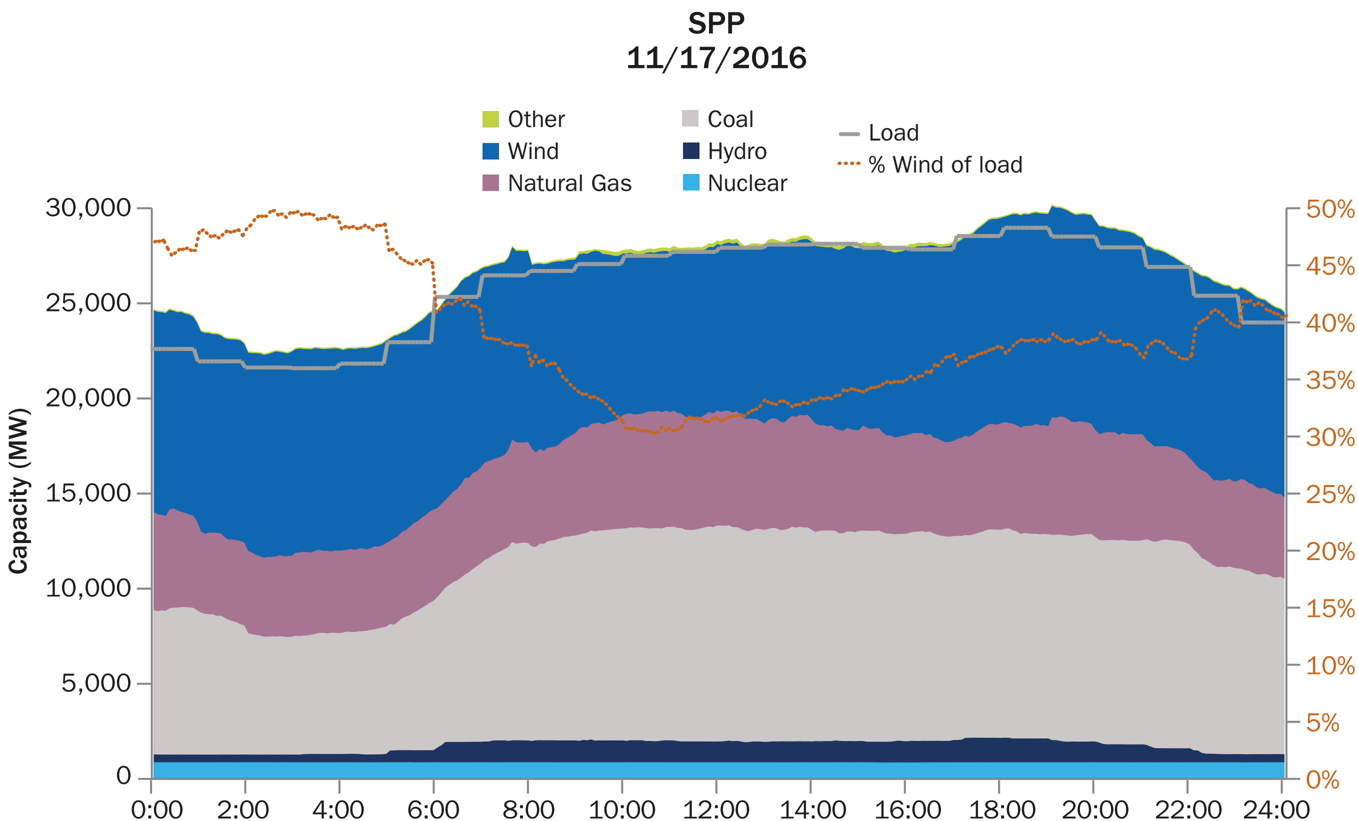
- Peak load conditions on this day occurred between 6 p.m. and 7 p.m., when hourly average wind generation contributed 38.2% to load. During this period, thermal power contributed 37.4% (coal) and 19.5% (natural gas) to load.

- Maximum wind generation in 2016 was 12,103 MW (42.6% of total load) at 5:00 a.m. on December 30.

- The 2016 VRE penetration maximum was superseded with 52.1% of load served by utility-scale wind power on February 12, 2017 at 4:30 a.m., making SPP the first RTO in North America to surpass 50% of load at a given point in time.[1]

[1] SPP 2017a
Note: Only utility-scale generation (greater than 1 MW) is considered.

Maximum Hourly Penetration



II

Source: SPP (2017c)
Note: Five-minute data

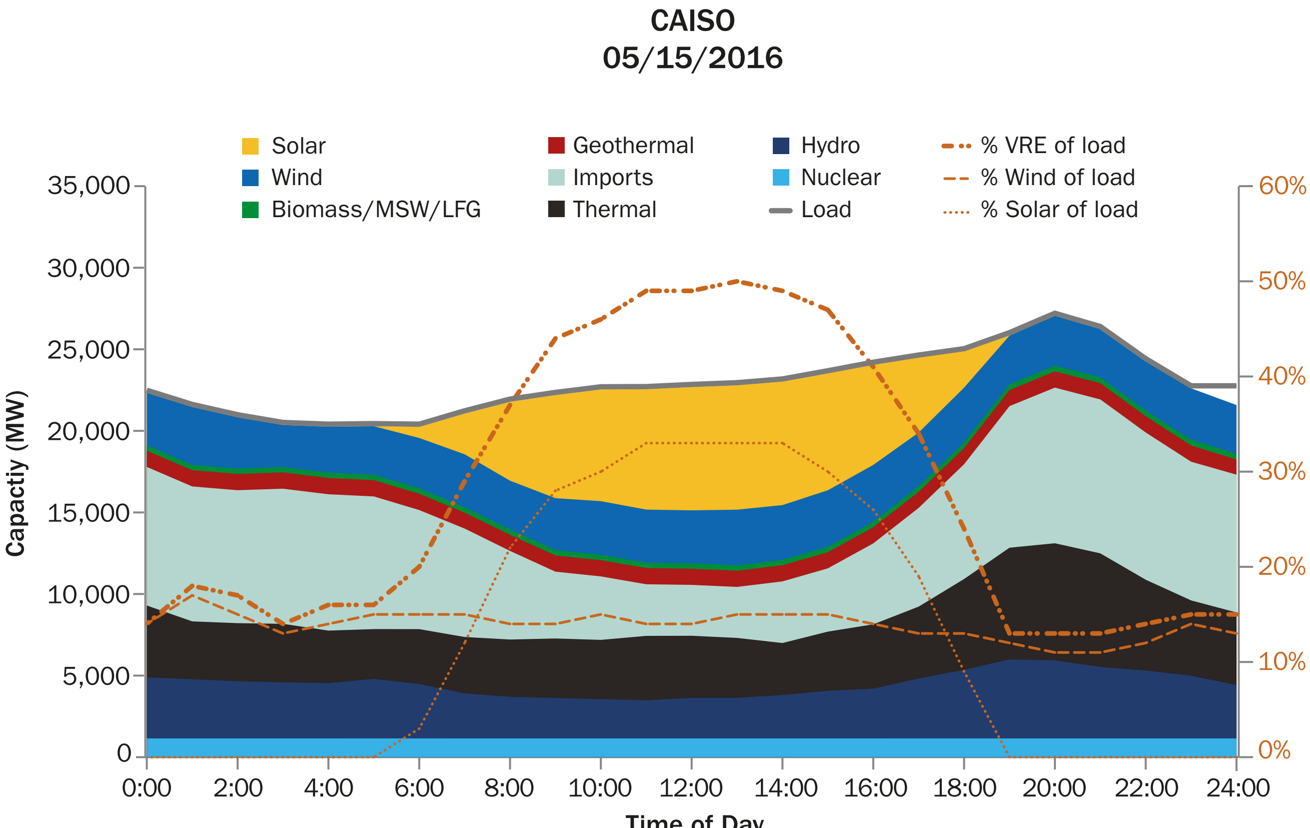
CAISO

- In 2016, CAISO reached maximum VRE generation penetration of 48.5% (11,040 MW) of load between 1 p.m. and 2 p.m. on May 15, 2016, when solar contributed 33.5% and wind contributed 15% 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 65%. Generation from renewables into the early afternoon hours coincided with downward ramping of imports (-54%) and hydropower (-27%), while thermal generation remained relatively flat (+4%) between 5 a.m. and 2 p.m.

- Peak load on this day— May 15, 2016—was reached at 8 p.m., when VRE contributed 11.3% to load while imports (35.3%), thermal (26.6%), and hydropower (15.8%) contributed the largest shares of load.

- Maximum hourly VRE generation occurred on September 12, 2016 at 1 p.m., with 11,870 MW (40.0% of total load). Solar maximum generation during 2016 was 8,530 on September 14, 2016 at 12 p.m. Wind maximum generation was 4,680 MW on May 25, 2016 at 5 p.m.

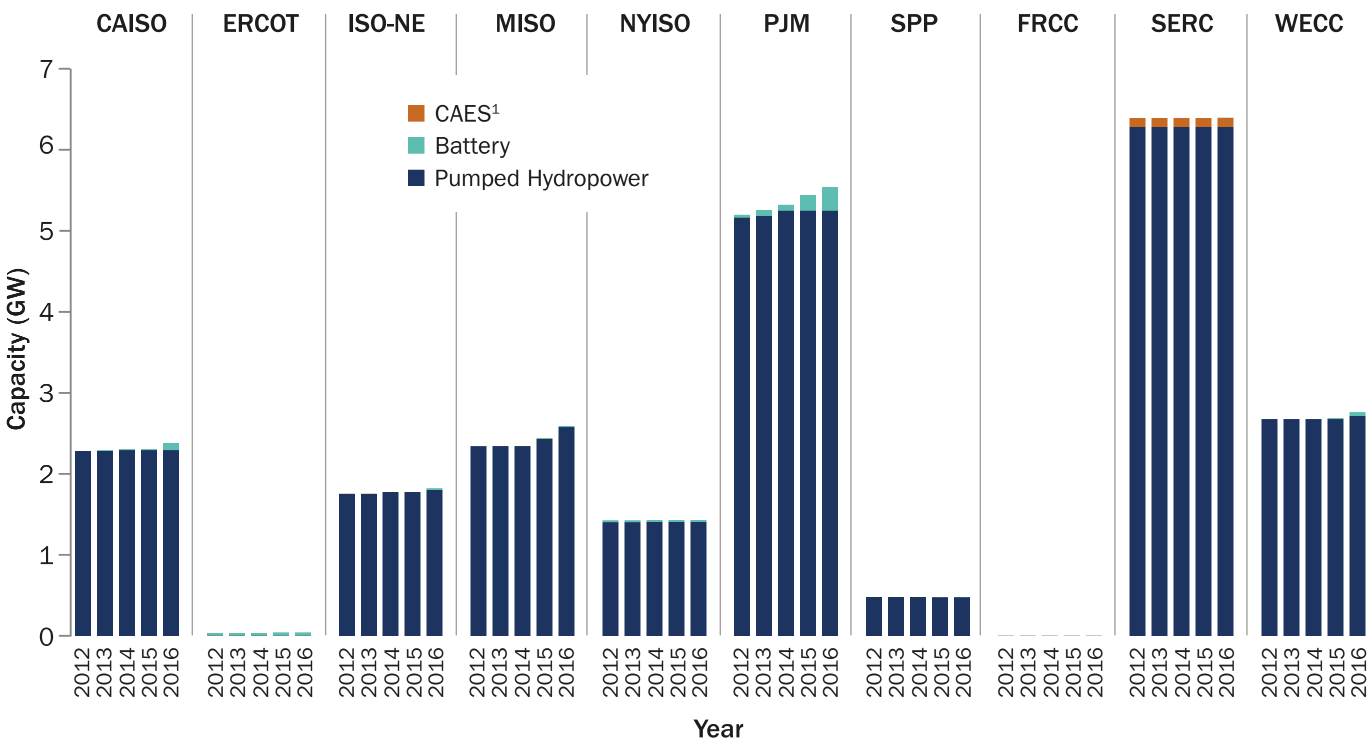
Maximum Hourly Penetration



Source: CAISO (2017c) and ABB Velocity Suite

Note: Hourly data

Utility-Scale Capacity From Pumped Hydropower, Battery, and CAES[1] Storage



[1] Compressed air energy storage

Source: Form EIA-860

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

III. Wholesale Electricity Markets

III

Locational Marginal Price (LMP)

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.[2]

- In 2016, the median hourly LMP ranged from $19.02/MWh (SPP) to $24.89/MWh (CAISO).
- About 93% of hours fall within an average LMP range of $0/MWh to $50/MWh among ISO/RTO markets—of which 62% fall in a range of $0/MWh to $25/MWh.
- ISO/RTO markets experienced price spikes over some hours during 2016. LMP levels above $300/MWh were experienced by CAISO during approximately 50 hours (0.6% of total hours), followed by ERCOT with approximately 22 hours (0.3% of hours), NYISO at 15 hours (0.2%), and ISO-NE at 12 hours (0.1%).
- Maximum LMP ranged from $1,436/MWh (ISO-NE) to $1,008/MWh (NYISO), $794/MWh (CAISO), $679/MWh (ERCOT), $382/MWh (SPP), $222/MWh (MISO), and $213/MWh (PJM).

[1] LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO. 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] Source: Based on CAISO (2005)

Negative LMP

Negative LMP may occur when there is excess generation in comparison to load, and it may imply a generator pays for providing power. Negative LMP[3] can be the result of a complex interaction among economic, reliability, environmental, safety and incentive factors that depend on the region, season, and time of day. It often reflects some combination of excess generation (from VRE generation or due to plant-level minimum generation constraints and high startup costs and times), transmission constraints, and economic factors that influence generator's bidding behavior (including incentives like the Production Tax Credit). In some cases, market participants submit negative energy bids and are therefore willing to pay for providing power.[3]

- In 2016, 5% of hours saw negative pricing in CAISO, followed by ISO-NE (2.1%), SPP (1.6%), ERCOT (1.5%), NYISO (0.5%), PJM (0.2%), and MISO (0.13%).
- The lowest real-time LMPs were observed in NYISO (-$189.95/MWh) and ISO-NE (-$155.90/MWh) in 2016.

[3] LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO). 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.

- In 2016, considering the median negative LMPs, the lowest was observed in ISO-NE (-$20.64/MWh), followed by CAISO (-$8.52/MWh).
- The impact of negative pricing events on an annual average DA or RT LMP has generally been limited.[4]

Capacity Pricing

Organized and centrally-administered forward capacity markets in PJM, NYISO, 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 allocated to generators through regularly held auctions in several ISO/RTO markets. The contribution to overall system adequacy (i.e., the fraction of nameplate capacity that contributes to the top peak net load hours) is a generator's capacity credit, which is calculated differently among ISO/RTO market regions.

- ISO-NE experienced relatively stable capacity prices[5] of $2.95 to $4.50/kW-month between delivery years of 2010/2011 and 2015/2016 but then rose to $9.55 for delivery year 2018/2019.

[4] DOE 2017; Wiser et al. 2017

[5] 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.

Wholesale Electricity Markets and Price Events: Summary (continued)

III

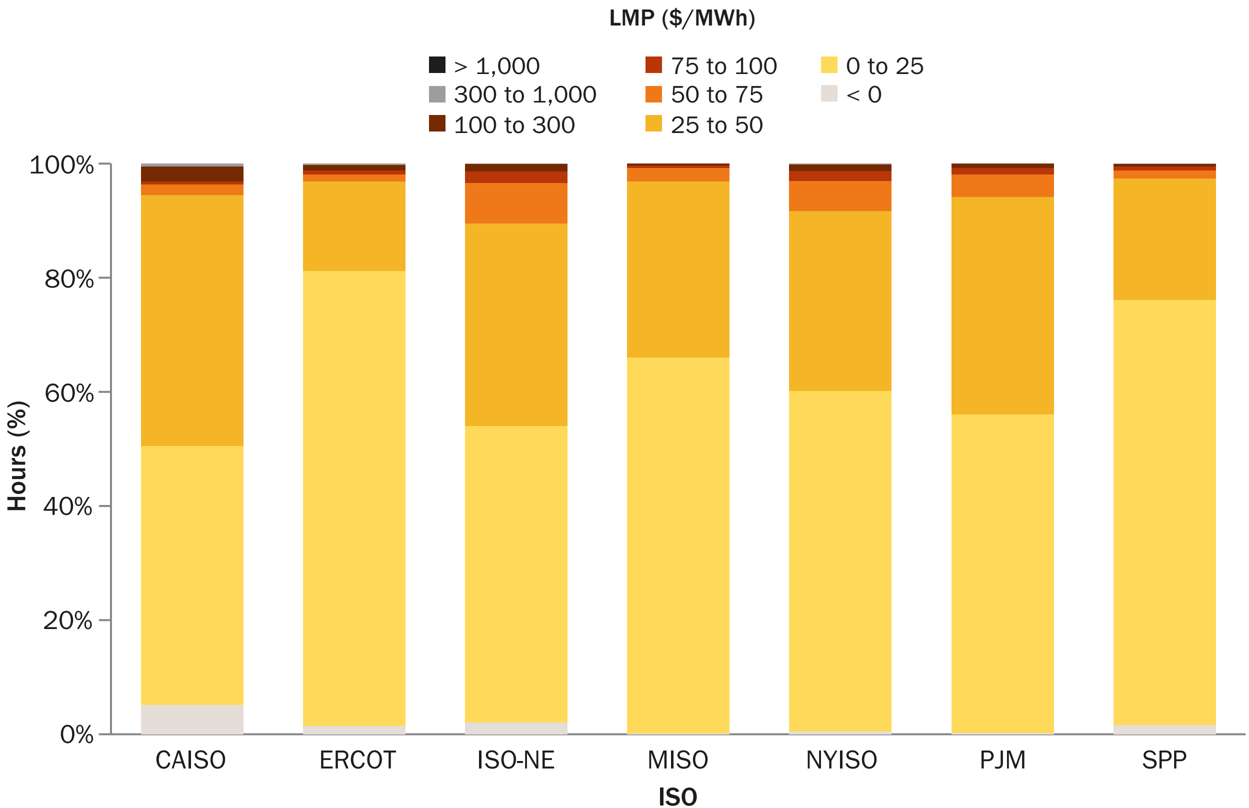
- For 2016, NYISO capacity prices were significantly higher in the summer, declining from $7.13 to $5.73/kW-month between May and October, and ranging between $1.54 and $2.45/kW-month for the months of January–April and November–December.

- In delivery years 2007/2008 through 2020/2021, PJM capacity clearing prices fluctuated considerably with an average year-to-year change of 81.9% and a range of $0.50/kW-month for 2012/2013 and $5.32/kW-month for 2010/2011.

- When comparing delivery years 2015/2016 and 2020/2021 in PJM, cleared unforced capacity (UCAP)[6] increased for natural gas (+40%), solar PV (+123%), wind (+12%), and energy efficiency (85%) while it decreased for demand response (-47%), coal (-18%), nuclear (-11%), hydropower (-14%), oil and kerosene (-14%), and biomass (-12%). Between delivery years 2015/2016 and 2020/2021, solar PV comprises 0.09% of total cleared UCAP on average and wind 0.52% of total cleared UCAP on average.

[6] 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, "Learning Center", PJM 2018)

Distribution of LMP (2016)



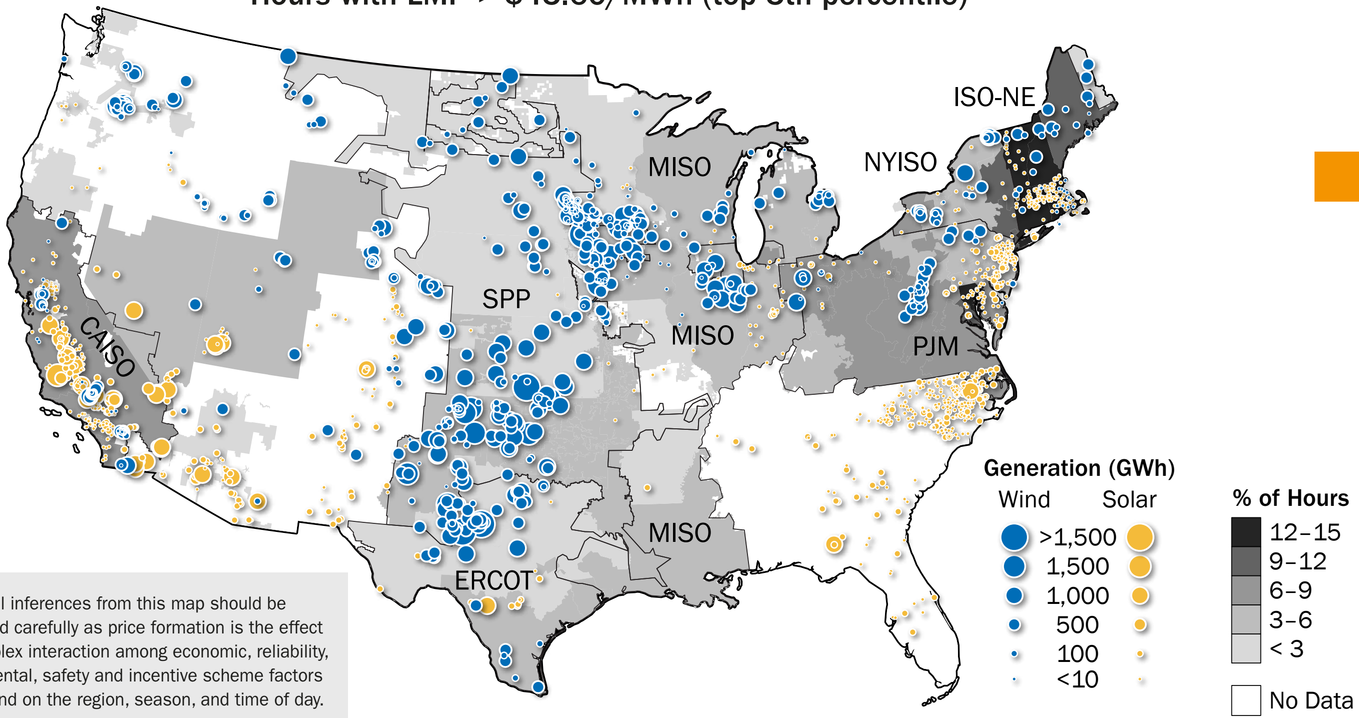
Sources: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by NYISO, PJM, ISO-NE, CAISO, ERCOT, SPP, MISO (accessed through the ABB Velocity Suite); Form EIA-923 and the ABB Velocity Suite for data on solar PV and wind power plants

Note: LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO). 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.

Wholesale Electricity Prices

III

Hours with LMP > $45.60/MWh (top 5th percentile)

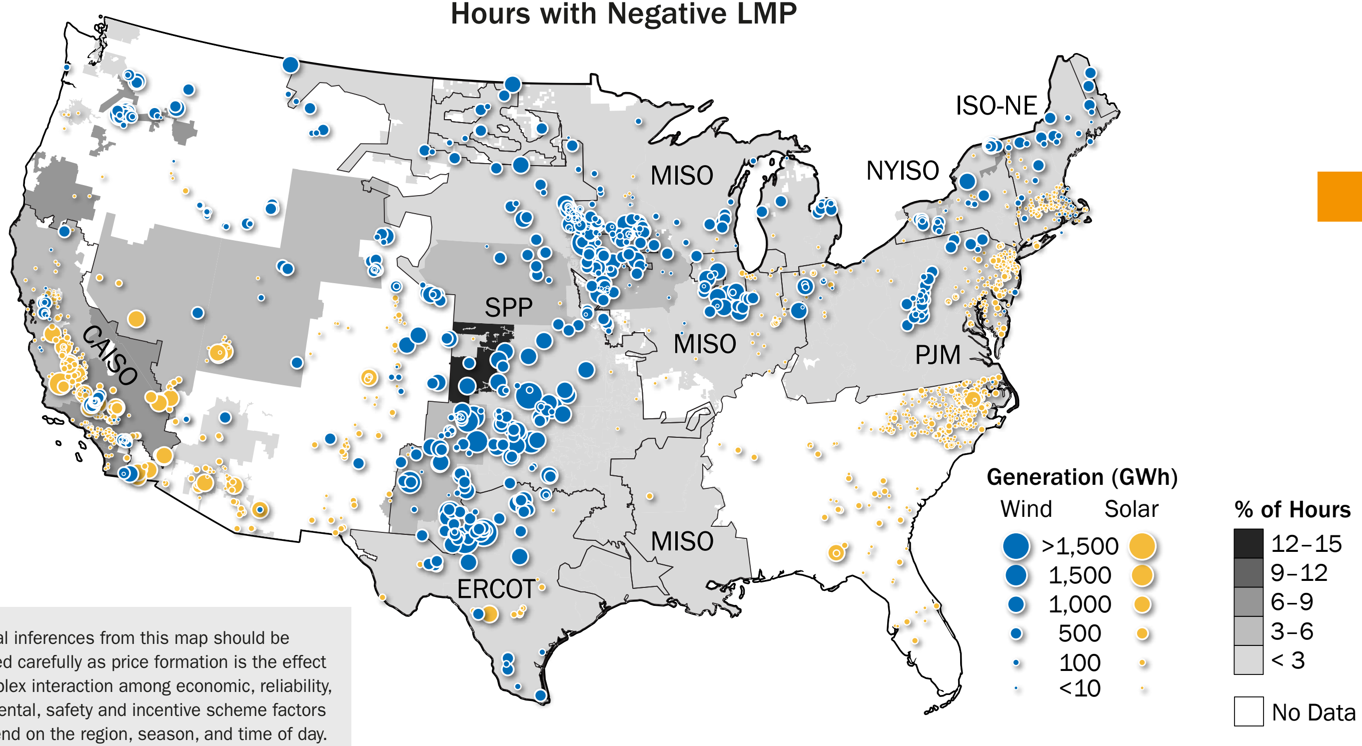


Any causal inferences from this map should be considered carefully as price formation is the effect of a complex interaction among economic, reliability, environmental, safety and incentive scheme factors that depend on the region, season, and time of day.

Sources: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by NYISO, PJM, ISO-NE, CAISO, ERCOT, SPP, MISO (accessed through the ABB Velocity Suite); Form EIA-923 and the ABB Velocity Suite for data on solar PV and wind power plants

Note: The threshold of $45.60 represents the top 5th percentile of average LMPs during 2016; solar PV and wind power plant data only shown for greater 1 MW; Locational Marginal Price (LMP) data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO). 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.

Hours with Negative LMP



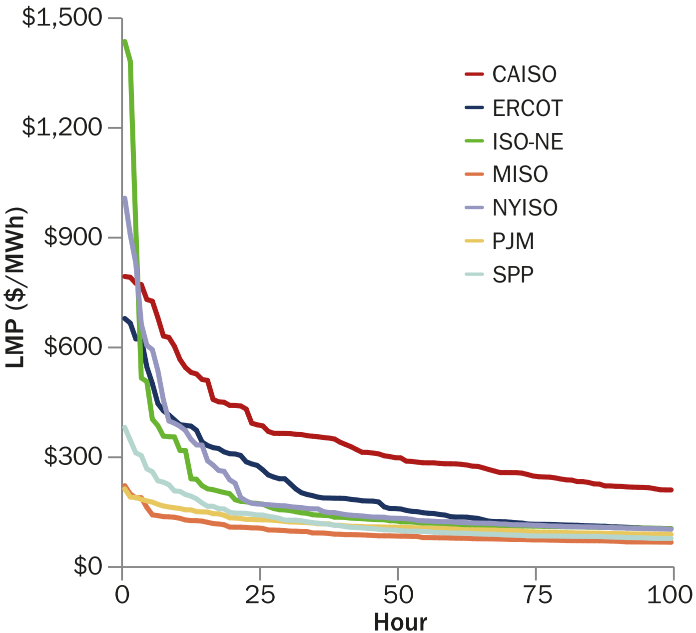
Any causal inferences from this map should be considered carefully as price formation is the effect of a complex interaction among economic, reliability, environmental, safety and incentive scheme factors that depend on the region, season, and time of day.

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

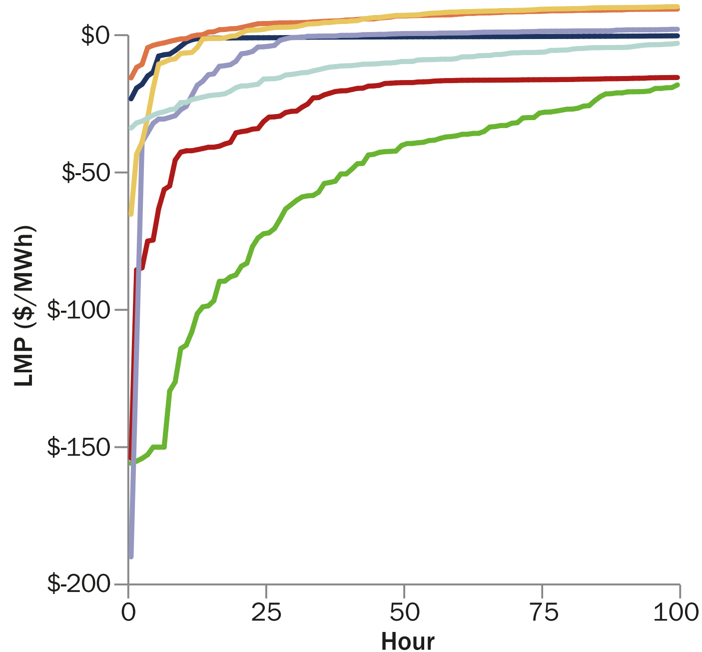
Note: LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled-up) from zonal price nodes in the RT market.

Price Duration Curves (2016)

Highest LMP Levels (100 Hours)



Lowest LMP Levels (100 Hours)



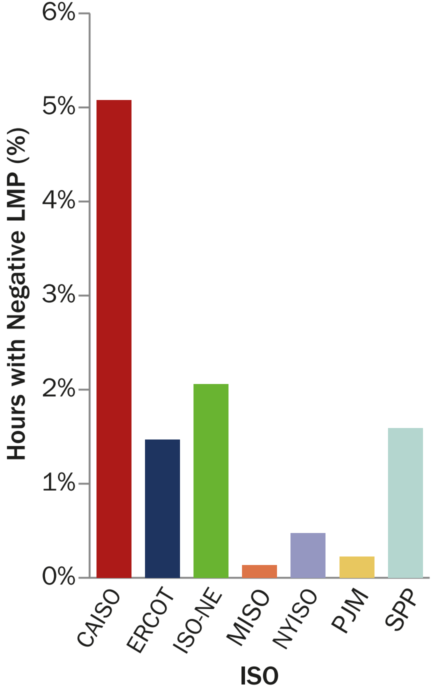
III

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

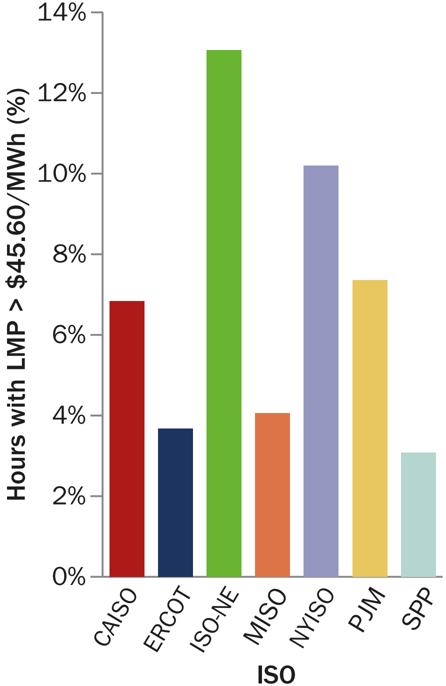
Note: LMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO). LMP data for CAISO are reported as hourly (load-weighted) averages of five-minute data (rolled-up) from zonal price nodes in the RT market.

Wholesale Electricity Prices (continued)

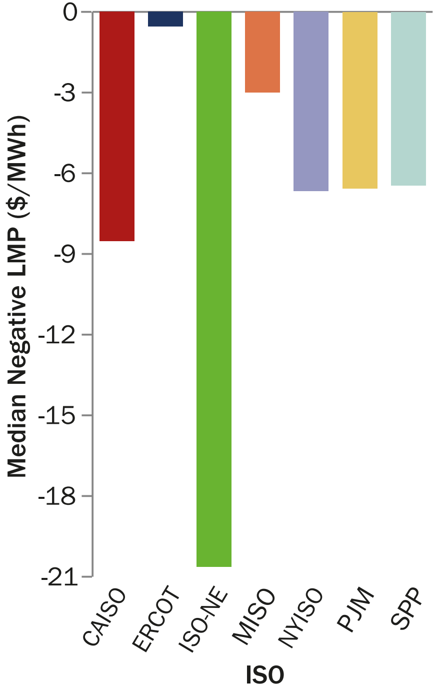
% of Hours with Negative LMP (2016)



% of Hours with LMP > 45.60/MWh (top 5th percentile) (2016)



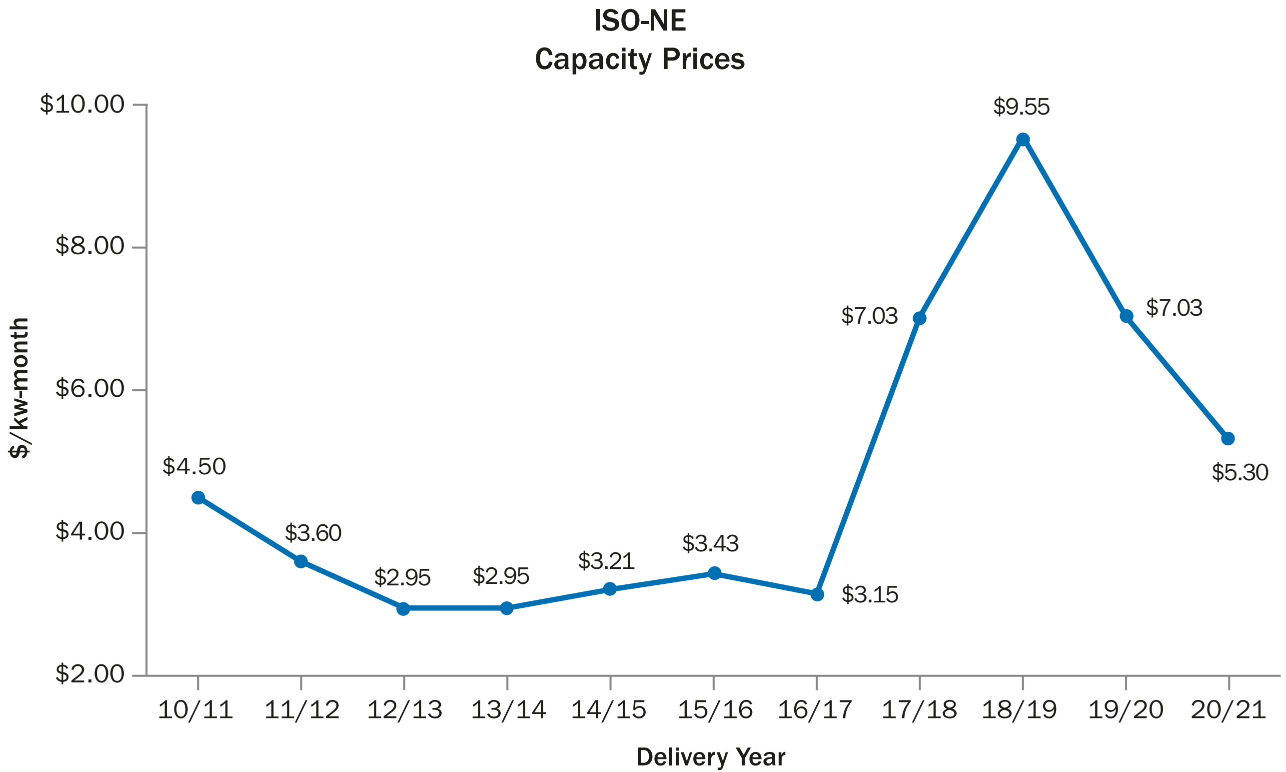
Median Negative LMP (2016)



III

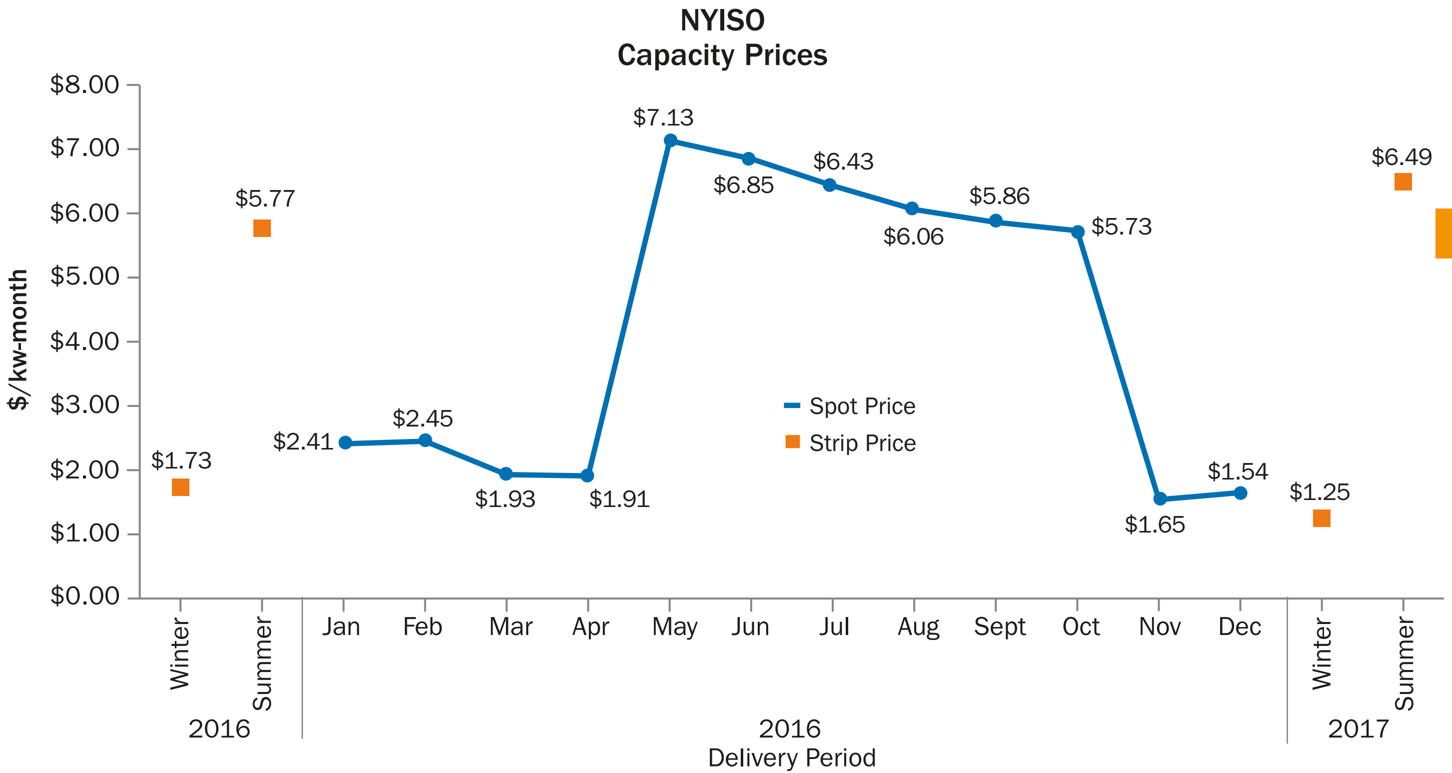
Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" (at zonal hub level) reported by NYISO, PJM, ISO-NE, CAISO, ERCOT, SPP, MISO (accessed through the ABB Velocity Suite)

Note: The threshold of $45.60 represents the top 5th percentile of average LMPs during 2016; Locational Marginal Price (LMP) data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (ERCOT, SPP, MISO, PJM, ISO-NE, and NYISO). 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.



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

Note: Graph depicts system-wide clearing price results for existing resources from the ISO-NE "Annual Forward Capacity Auction." Note that 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.

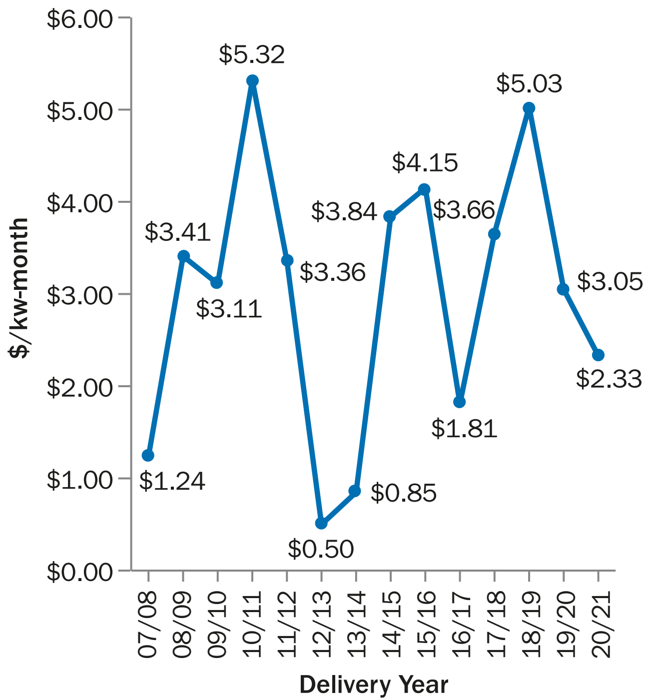


Sources: NYISO (New York Independent System Operator). "ICAP Data and Information" (http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp) and NYISO. "Strip Auction Summary," accessed November 2017: http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do

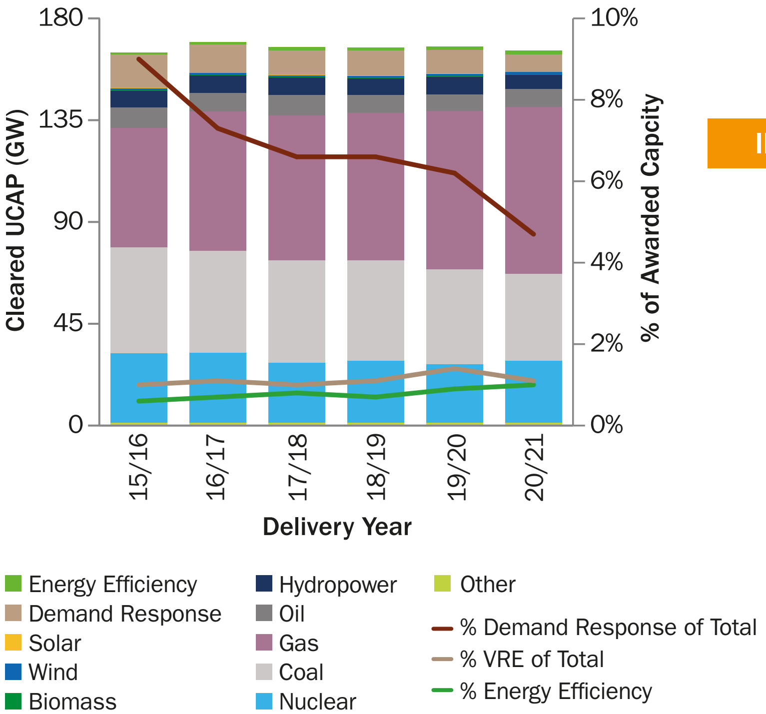
"Monthly UCAP reports" (http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do)

Note: Strip prices in NYISO are for six-month capability periods "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. Note that 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.

PJM Capacity Clearing Prices

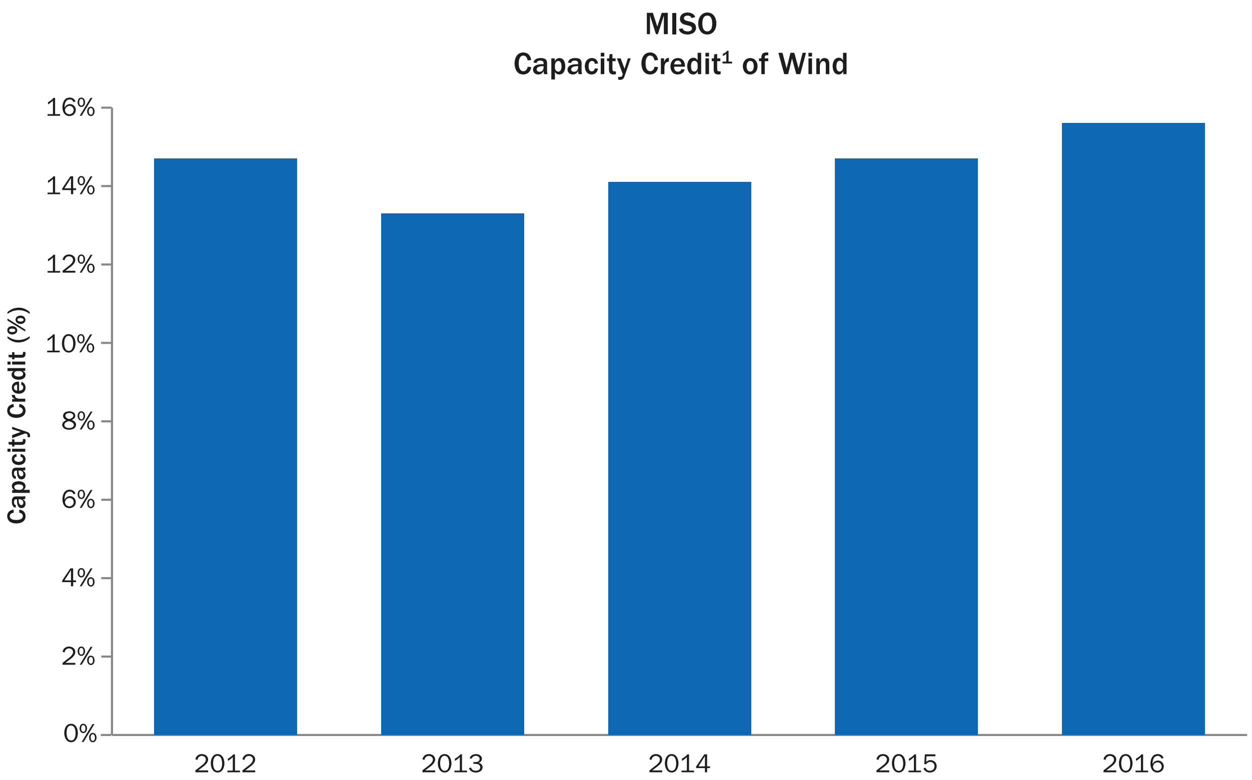


PJM Awarded Capacity by Fuel Type



Source: PJM, "Resource Clearing Prices Auction Summary," October 3, 2017, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auctions-resource-clearing-price-summary.ashx

Note: Graph depicts the system-wide clearing price results from the PJM "Annual Base Residual Auction." Note that 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.



Source: MISO 2017

[1] 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 the particular generator of interest, with no net change in reliability (Milligan and Porter 2008).

Selection of Market Reform Activities

III

- **April 2016:** NYISO submits proposed compliance revisions to its tariff to revise mitigation measures of buyer-side capacity market power to exempt certain narrowly defined renewable and self-supply resources from offer floor mitigation.[1]

- **April 2016–February 2017:** FERC continues to uphold the ISO-NE limited exemption from the minimum offer price rule for certain renewable resources up to 200 MW in any forward capacity auction.[2]

- **May 2016:** MISO implements its Ramp Capability Product to manage net load variability. This has contributed to reducing price volatility.[3]

- **October 2016:** The Western Energy Imbalance Market adds Arizona Public Service and Puget Sound Energy (along with Nevada Energy and PacifiCorp). CAISO estimates that in Q4 2016, 23,390 MWh of surplus renewable energy was able to be used because of the Energy Imbalance Market.[4]

[1] NYISO 2016

[2] 155 FERC § 61,023 (https://www.ferc.gov/CalendarFiles/20160408181020-ER14-1639-004.pdf); 158 FERC § 61,138 (https://www.iso-ne.com/static-assets/documents/2017/02/er14-1639-005_02-03017_order_deny_rehearing_renewables.pdf)

[3] Potomac Economics 2017a

[4] CAISO 2017a

Selection of Market Reform Activities (continued)

- **November 2016:** CAISO implements a "flexible ramping product" to replace the "flexible ramping constraint" in order to compensate generation capacity that provides upward and downward flexible ramping capacity in the 15-minute and 5-minute markets.[5]

- **December 2016:** ISO-NE makes a rule change that 1,200 MW of wind power become "dispatchable" by 2018 (157 FERC § 61,189). In SPP by end of 2016, over 60% of wind capacity was "dispatchable", compared with 46% at the end of 2015 and 27% at the end of 2014.[6]

- **December 2016:** PJM continues a capacity market redesign effort, in part to address how the Minimum Offer Price Rule (MOPR) affects state-sponsored capacity. The market monitor for PJM, Monitoring Analytics, proposes a compromise that includes a MOPR exemption for capacity procured through a state renewable portfolio standard.[7]

[5] CAISO 2017b
[6] SPP 2017b
[7] Bowring 2017

Selection of Market Reform Activities (continued)

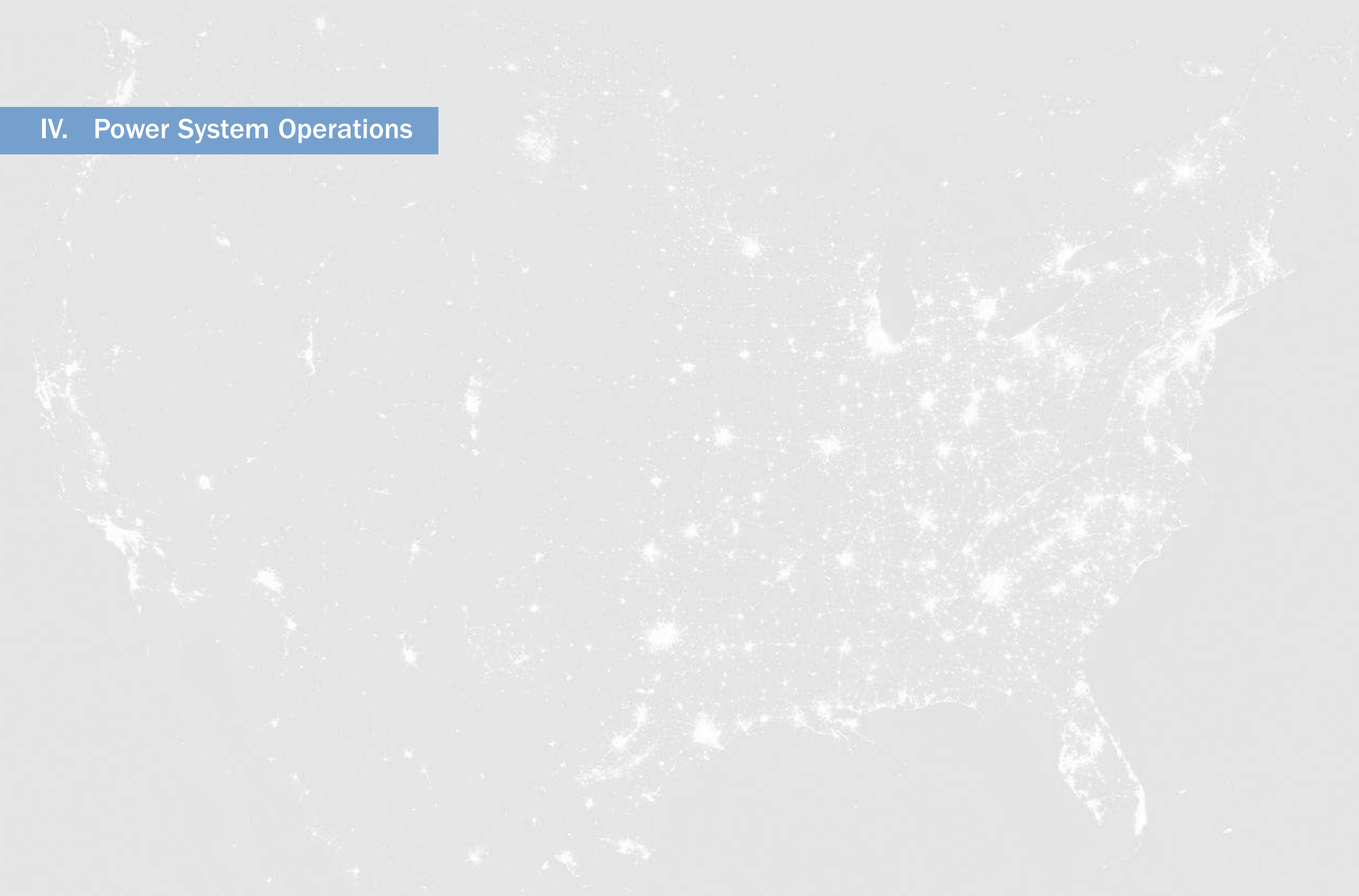
- **2016–2017:** In several states, rules governing the avoided cost rates paid to renewable generators under the Public Utility Regulatory Policies Act (PURPA)[8] changed. These include:
  - **Montana:** A NorthWestern Energy application was approved that reduced the standard contract length from 25 to 15 years and energy rates from $66/MWh to $31/MWh that are available to renewable energy projects less than 3 MW in capacity (Dkt. No. D2016.5.39, Nov. 24, 2017).[9]
  - **Connecticut:** Ruling of Connecticut Public Utilities Regulatory Authority for bundling of renewable energy credits with sales to electric utilities by PURPA qualifying facilities (156 FERC § 61,042).
  - **Idaho:** A Rocky Mountain Power proposal was approved that lowered the wind integration rate from $3.06/MWh to $0.57/MWh and set the solar integration at $0.60/MWh (Case No. PAC-E-17-11, Final Order No. 33937).
  - **North Carolina:** Fixed-price PURPA contracts were limited to projects of 1 MW and smaller (from the then current 5 MW), and contract duration was reduced from 15 to 10 years. A competitive procurement model was introduced (HB 589).

III

[8] PURPA requires electric utilities to purchase energy produced at Qualifying Facilities at the utility's avoided cost. The increased renewables deployment under PURPA has led to changes in rule-making in some states (Warren 2017).

[9] Durish Cook 2017

IV. Power System Operations



Net Load

Net load is the total electric demand of a power system minus generation from VRE (i.e., wind and solar). 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 overgeneration under existing technical and institutional constraints on power system operation.[1]

- In CAISO, the net load during the day of highest VRE penetration increasingly assumed a duck curve[2] shape between 2012 and 2016. On May 15, 2016—the day with highest VRE penetration in 2016—the difference between the minimum net load at 12 p.m. and the maximum at 8 p.m. amounted to 12,000 MW (approximately 74% of total generating capacity from non-VRE sources during this time period) of ramping demand that the system successfully addressed.

- Among the non-CAISO independent system operator (ISO)/regional transmission organization (RTO) markets, a CAISO net load "duck curve" does not seem to be clearly distinguishable.

[1] Denholm et al. 2015

[2] 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 steep evening "necks."

Reserve Margins

Reserve margin is the expected additional capacity available beyond the projected peak coincident system load to account 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.[3] Region-specific reference margin levels are specified by NERC entities.[4]

- Reserve margin levels generally stayed between 15% and 30% from 2012 to 2016.
- Between 2012 and 2016, reserve margin levels stayed above the generic NERC reference reserve margin level with exception of the ERCOT market, where reserve margin levels were lower, in the range of 10.0%–11.3%.

[3] EIA-411 form

[4] The NERC reference margin levels for summer/winter of 2016 are 15.0% (FRCC), 14.3% (MISO), 15.9% (NPCC-New England), 17.0% (NPCC-New York), 15.5% (PJM), 15.0% (SERC), 13.6% (SPP), 13.8% (TRE-ERCOT), 15.0% (WECC), and 11.6% (WECC-Northwest Power Pool (NWPP)-CA), according to NERC (2015).

- In SPP, reserve margin levels decreased from a maximum of above 51% in 2013 to approximately 22% in 2016. While the reserve margin stayed at around 20% between 2012 and 2015 in FRCC, it fell to 11% in 2016. WECC's reserve margin level increased from approximately 13% in 2012 to nearly 19% in 2016.

- In 2016, reserve margin levels ranged from 10.3% (ERCOT) to 24.7% (SERC).

Forecast Error

Forecast error captures 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, RT balancing, and reserve requirements. High validity in forecasting in day-ahead (DA) and intraday scheduling can reduce fuel costs, improve system reliability (e.g., lower reserve margin requirements), and minimize curtailment of renewable resources.[5] 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.[6]

[5] Greening the Grid 2016
[6] O'Neill 2016

Power System Operations: Summary (continued)

- From 2012 to 2016, average hourly overprediction forecast errors of wind[7] (i.e., actual generation was less than the DA market forecast) generally decreased in ERCOT (decline in forecast error of 42.4% between 2012 and 2016) to 5.4% in 2016. In MISO, the forecast errors decreased by 59.0% between 2014 and 2016 to 3.7% in 2016. And in SPP, they decreased by 13.1% between 2014 and 2016 to 5.4% in 2016.

- Average hourly underprediction forecast errors of wind (i.e., actual generation was greater than the forecast) generally decreased in ERCOT (-34.5% between 2012 and 2016) to 4.9% in 2016, while they increased in MISO (+45.0% between 2014 and 2016) to 5.8% and in SPP (+31.0% between 2014 and 2016) to 4.6% in 2016.

- In 2016, the maximum average hourly DA overprediction of wind was 39.4% in ERCOT, 28.9% in SPP, and 27.0% in MISO.

- In 2016, the maximum hourly DA underprediction of wind was 28.0% in ERCOT and 24.5% in SPP and 24.4% in MISO.

IV

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

IV

VRE Curtailments

Curtailment is a prescribed reduction scheduled capacity or energy delivery. Curtailment of renewables and thermal generators can be the result of transmission congestion, minimum operating levels of thermal generators or hydropower, or back-feeding in the distribution system.[8]

- The highest annual average wind curtailment rates were observed in 2016 in MISO (4.3%), which was followed by ISO-NE (4.3%), SPP (1.6%), ERCOT (1.6%), NYISO (0.6%), CAISO (0.5%), and PJM (0.2%).

- ERCOT experienced a reduction in annual wind curtailment rate from 3.8% in 2012 to 1.6% in 2016; similarly, PJM saw a reduction in annual wind curtailment rate from 2.0% in 2012 to 0.2% in 2016.

- In SPP the annual wind curtailment rate increased from 0.7% in 2014 to 1.6% in 2016. In NYISO, the annual wind curtailment rate increased from 0.3% in 2012 to 0.6% in 2016.

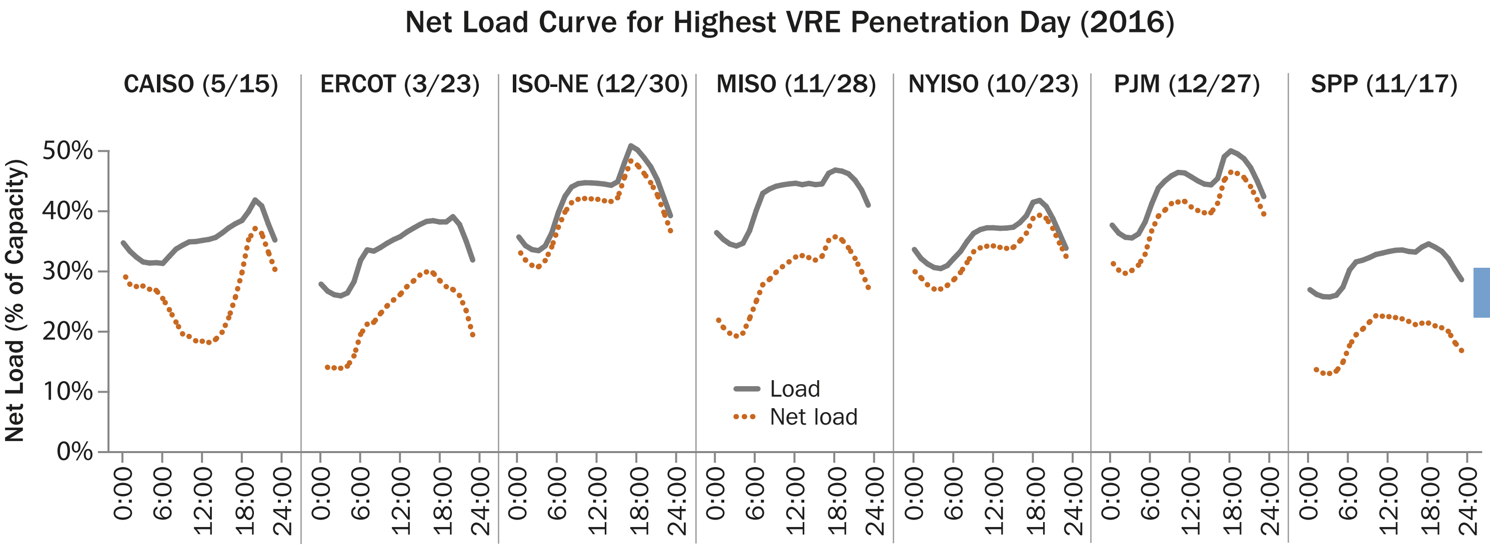
[8] Lew et al. 2013

Power System Operations: Summary (continued)

- Wind monthly average curtailment levels in CAISO were highest in the months of December (0.6%), November (0.5%), and April (0.5%) of 2016.
- In CAISO, the only regions which saw significant solar PV curtailment, annual average curtailment levels of solar PV were 1.7% of its total generation in 2016. Solar monthly average curtailment levels in CAISO were highest in the months of March (3.5%), April (2.6%), and December (2.5%) of 2016.

[8] Lew et al. 2013

Net Load Patterns



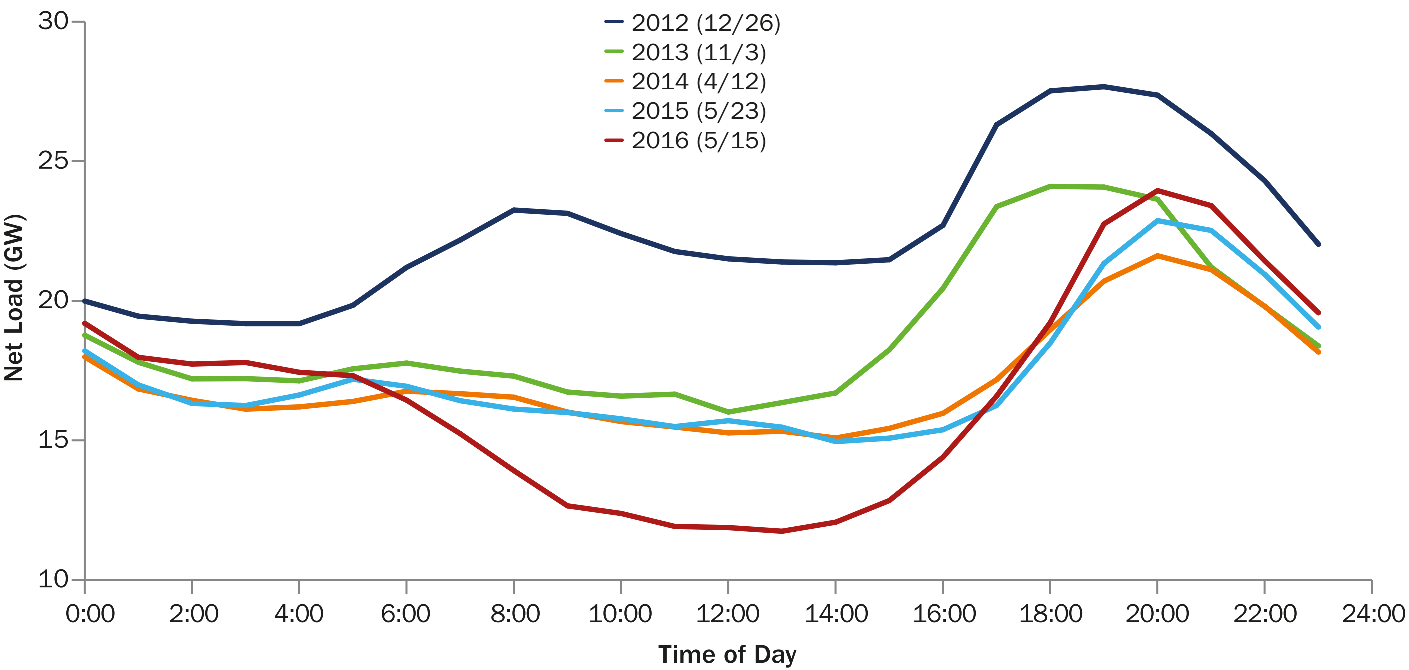
Maximum 3-Hour Ramp in 2016

ISO	CAISO	ERCOT	MISO	NYISO	PJM	SPP
Date	12/18	8/4	7/21	8/13	7/23	6/17
GW	12.4	15.6	24.6	6.0	30.5	10.9

Sources: CAISO, ERCOT, MISO, PJM, SPP (accessed through the ABB Velocity Suite)

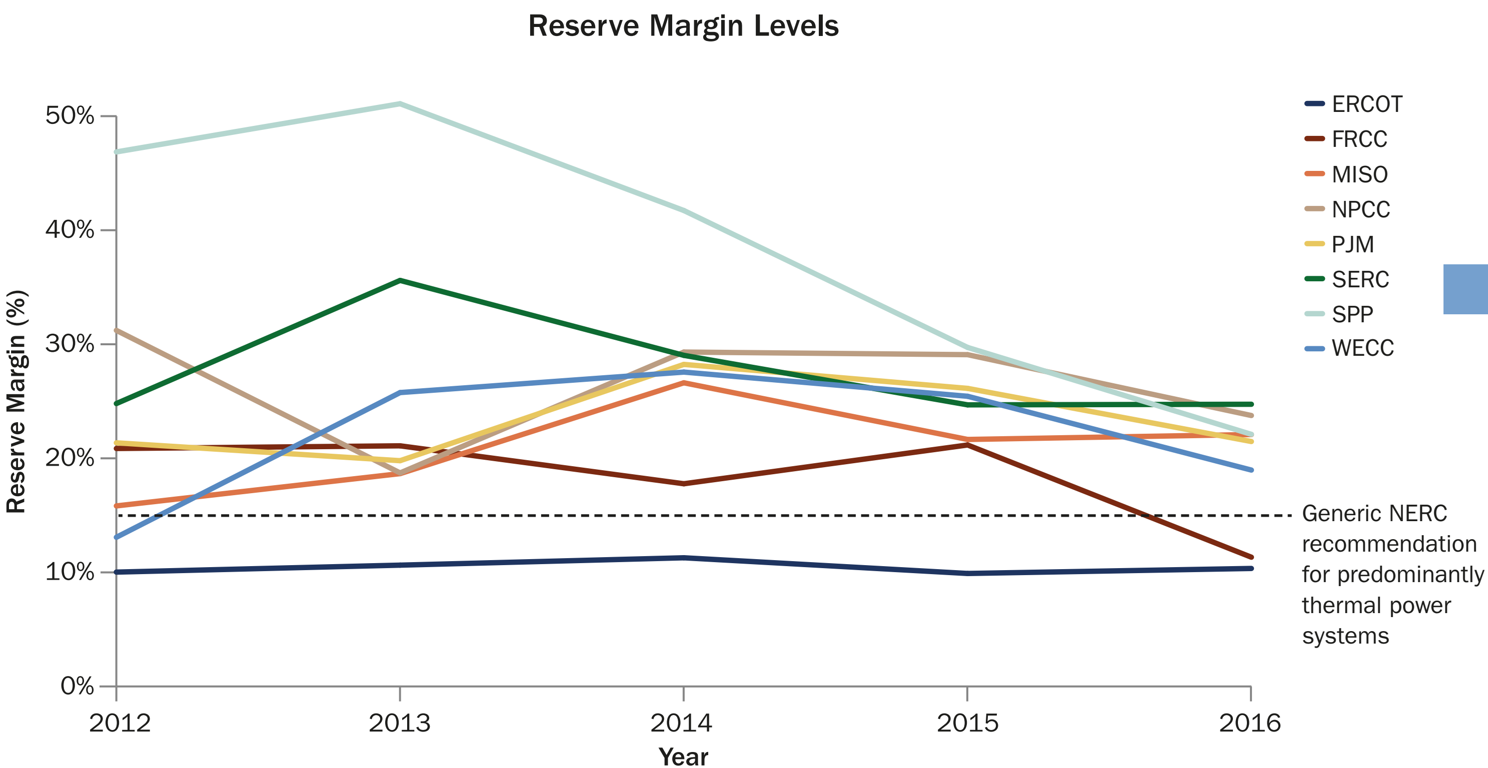
Notes: In the “Net Load” graph, a representative day was selected for each ISO/RTO region based on the highest penetration of renewable energy generation on an hourly basis during a given year. CAISO has consistently reported net load for the same day (March 31) each year (CAISO 2016).

CAISO Duck Curve for Highest VRE Penetration Days



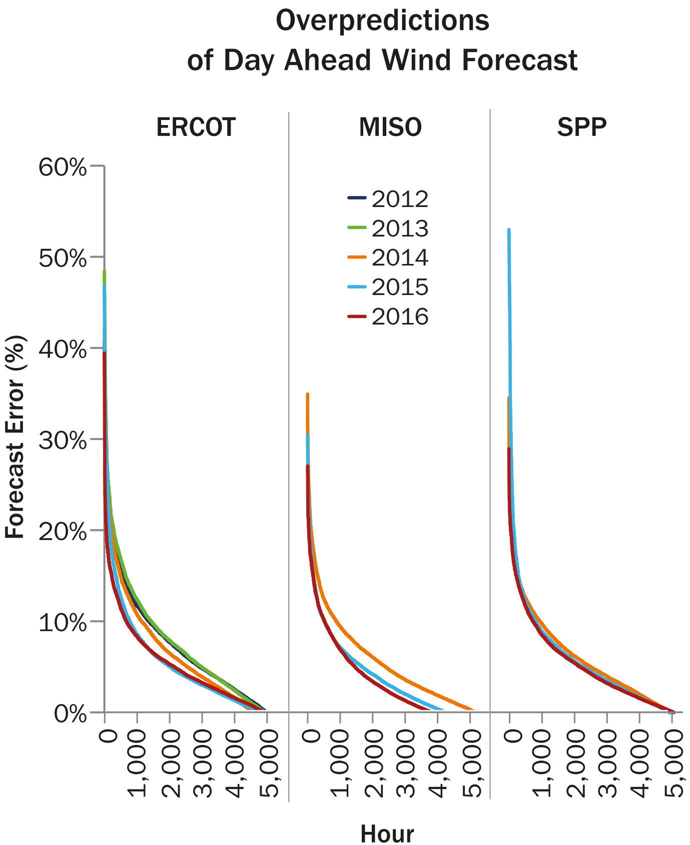
Sources: CAISO, ERCOT, MISO, PJM, SPP (accessed through the ABB Velocity Suite)

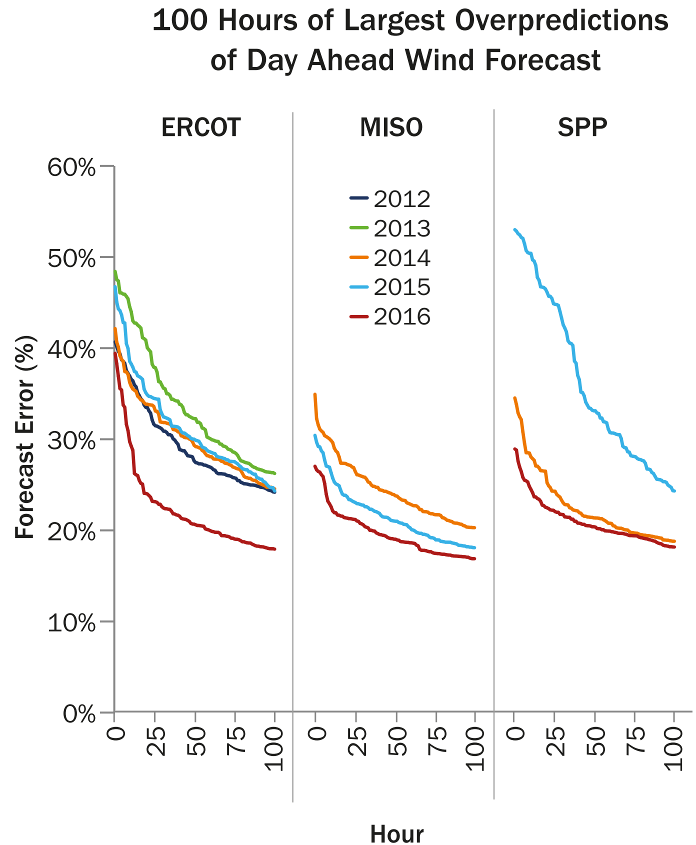
Notes: A representative day was selected based on the highest penetration of renewable energy generation on an hourly basis during a given year. CAISO has consistently reported net load for the same day (March 31) each year (CAISO 2016).



Source: Form EIA-411 (calculated by dividing the difference between total capacity and noncoincident peak by noncoincident peak demand)

Notes: NERC's generic reference reserve margin level is 15% for predominately thermal systems and 10% for predominately hydropower power systems (NERC n.d.). The region-specific NERC reference margin levels for summer/winter of 2016 are 15.0% (FRCC), 14.3% (MISO), 15.9% (NPCC-New England), 17.0% (NPCC-New York), 15.5% (PJM), 15.0% (SERC), 13.6% (SPP), 13.8% (TRE-ERCOT), 15.0% (WECC), and 11.6% (WECC-NWPP-CA), according to NERC (2015).

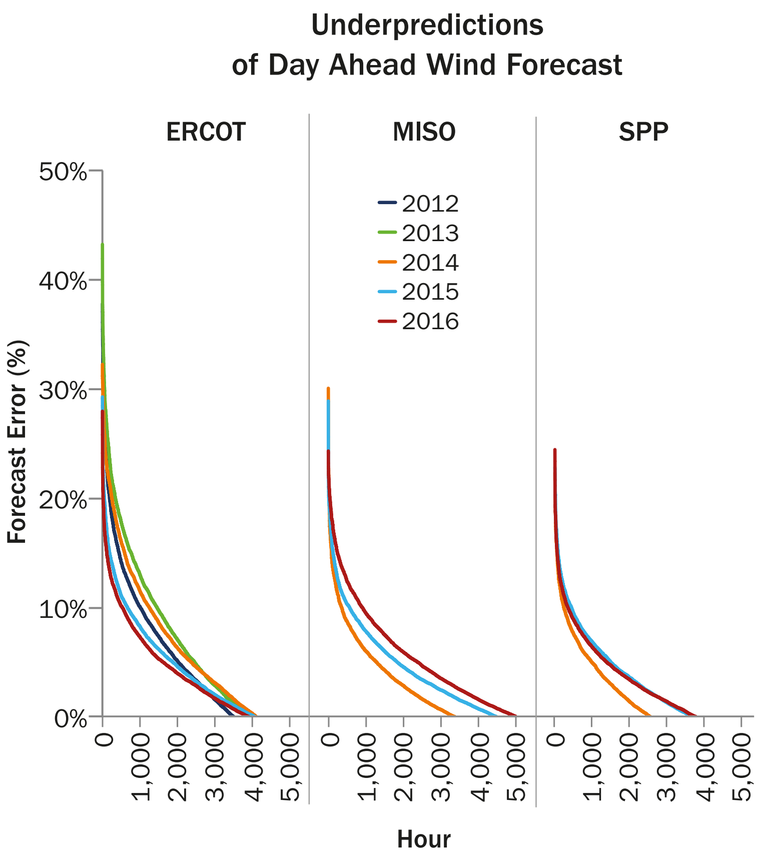


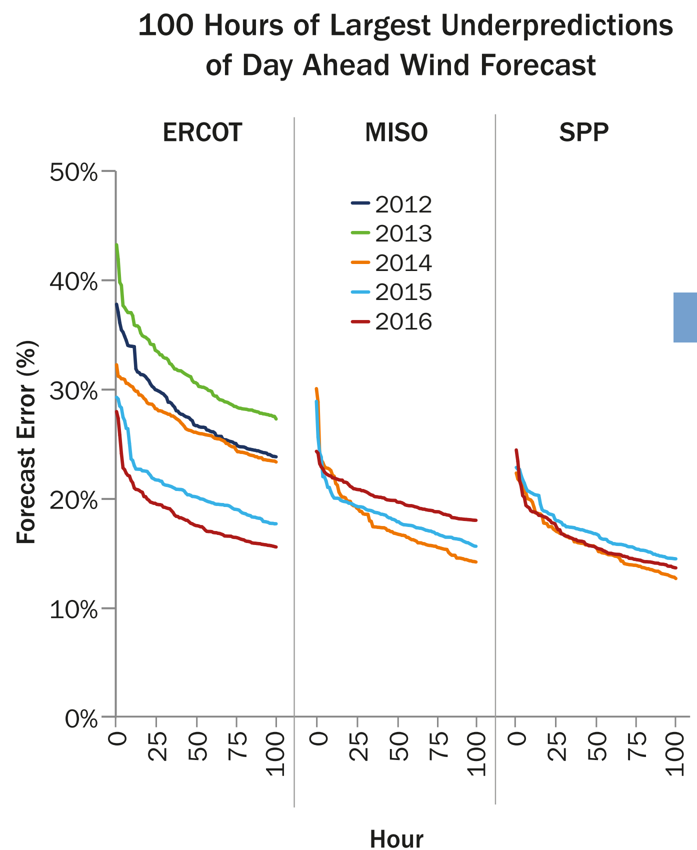


Sources: ERCOT, MISO, SPP (accessed through the ABB Velocity Suite)

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

Forecast Errors (continued)



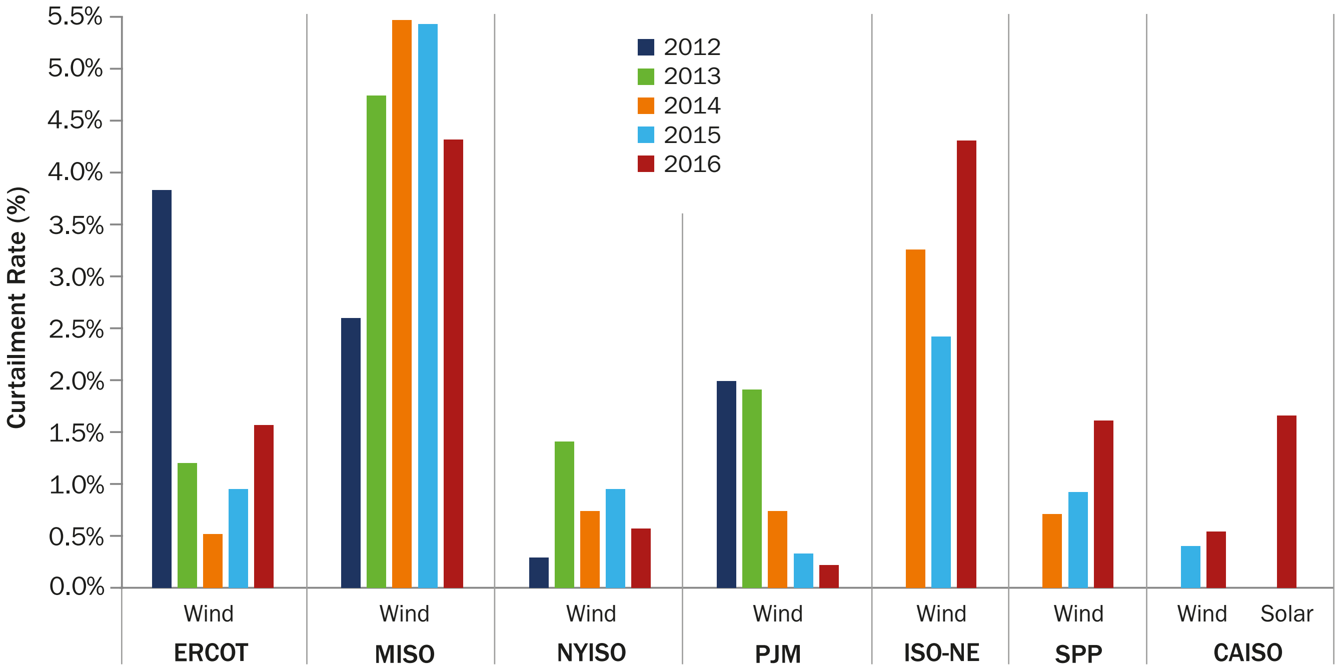


Sources: ERCOT, MISO, SPP (accessed through the ABB Velocity Suite)

Note: Forecast error was calculated as the absolute value of the hourly difference between actual and forecasted energy by total installed wind capacity.

VRE Curtailments

Annual Curtailment Rates (2016)



Sources: Wiser and Bolinger (2017) for wind data and CAISO (2017b) for solar data

Note: Depicted data include both "forced" (i.e., ISO-instructed) and "economic" (i.e., incentivized by prevailing LMP) curtailment.

V. Transmission

Existing and Proposed Long-Distance Transmission Capacities

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.[1,2] Higher-voltage lines generally carry power over longer distances.[3] The vast majority of transmission line circuit miles are in alternating current (AC). Though less common, direct current (DC) transmission lines can transmit electricity over long distances at high DC voltage and with typically lower losses.

- By the end of 2016, a total of 394,570 circuit miles of long-distance transmission was available with voltage levels above 100 kV in the NERC regions.[4] Of this total, 3,970 circuit miles (1.0%) were DC lines. Across the NERC regions, more than 75.4% of existing circuit miles are between 100 kV and 300 kV.

[1] DOE 2017
[2] DOE 2018;
[3] PSE&G 2017
[4] Excludes Canada

Long-Distance Transmission and Interchange Flows: Summary (continued)

- A total of 2,850 circuit miles above 100 kV are currently under construction[5] in the NERC regions (Canada excluded). Of this total, 29.9% are under construction in the ReliabilityFirst (RF) NERC regional entity (852 circuit miles), 28.3% in the Texas Reliability Entity (TRE) (806 circuit miles), 17.6% in WECC (502 circuit miles), 13.3% in MRO (379 circuit miles), 9.2% in SERC (261 circuit miles), 0.9% in the Northeast Power Coordinating Council (NPCC) (27 circuit miles), 0.9% in the FRCC (25 circuit miles), and 0.0% in the SPP RE (0.0 circuit miles).
- By 2025, the largest additions of transmission projects as a share of total existing regional transmission circuit miles are planned[6] in MRO (8.9%), followed by the FRCC (6.8%) and SPP RE (5.0%). Among all NERC regions, 45% of the planned transmission circuit miles by 2025 are expected to be above 300 kV.
- A total of 240 DC circuit miles are planned and 405 DC circuit miles are in a conceptual[7] phase with a potential completion date by 2025. These planned and conceptual lines are expected in the NPCC region.
- 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 generation) to load centers (e.g., in MISO, SERC, CAISO, and PJM service areas).

[5] Under construction: projects where construction of the line has already begun (DOE 2017)

[6] Planned: projects where (a) permits have been approved, (b) a design is complete, or (c) the project is necessary to meet a regulatory requirement (DOE 2017)

[7] Conceptual: projects that are in a project queue, but not included in a regional transmission plan (DOE 2017)

Note: The regional boundaries of the NERC regions reference here can be accessed at www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx (NERC "Key Players").

Interchange Flows

Interchange flows are energy transfers that cross balancing authority (BA) boundaries. In BAs with high penetration of renewables, interchange flows can help balance variable output from VRE through increased geographic diversity. Interchange flows may be associated with price differences and arbitrage opportunities between BAs.

- In 2016, uni-directional interchange flow was the highest from (non-CAISO) WECC to CAISO (81.2 terawatt-hours [TWh], followed by interchange flows into MISO from PJM (20.8 TWh); from SPP into MISO (15.9 TWh); and from MISO to SERC (13.7 TWh).

- Interchange flow from Canada into the U.S. regions of ISO-NE, MISO, WECC, and NYISO markets totaled 65.4 TWh in 2016.

Congestion

The congestion component of the Locational Marginal Price (CLMP)[8] may be interpreted as the additional cost (or savings) to serve customer load due to transmission constraints and 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 location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system, they are zero. A positive CLMP during times of congestion indicates the “shadow price” at which mitigating a binding constraint is valued.[9]

V

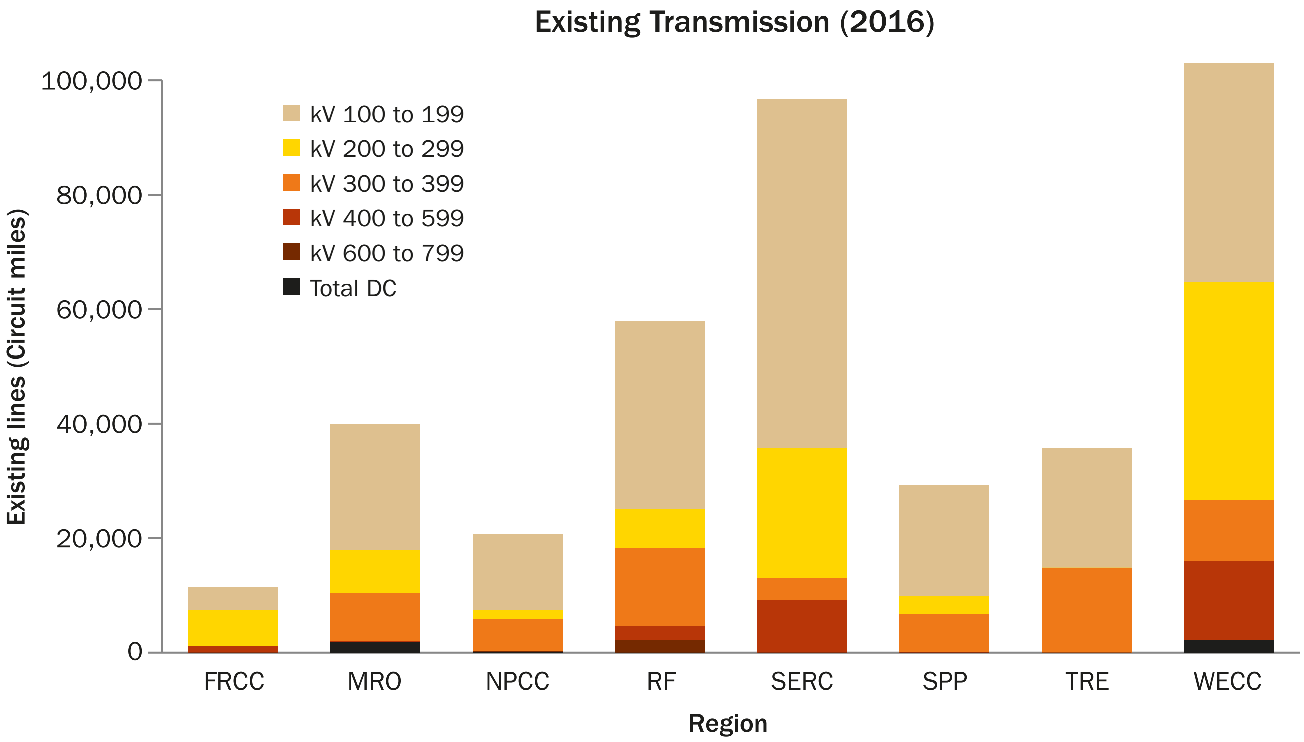
- In 2016, PJM and the southeastern part of SPP had the most hours of congestion as reflected by 60%–85% of annual hours with CLMP[10] greater than $0/MWh. Among the highest CLMP within PJM was Central Maryland, with CLMP exceeding $10/MWh for 25%–30% of hours during 2016. In SPP, parts of Oklahoma experienced the highest CLMP, exceeding $10/MWh for 15%–20% of hours during 2016.
- In 2016, Eastern ERCOT, southern and eastern MISO, and Long Island within NYISO experienced moderate congestion with CLMP greater $0/MWh for 45%–60% of hours.

[8] 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).

[9] Source: Monitoring Analytics 2016

[10] 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 (MISO, PJM, ISO-NE, 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.

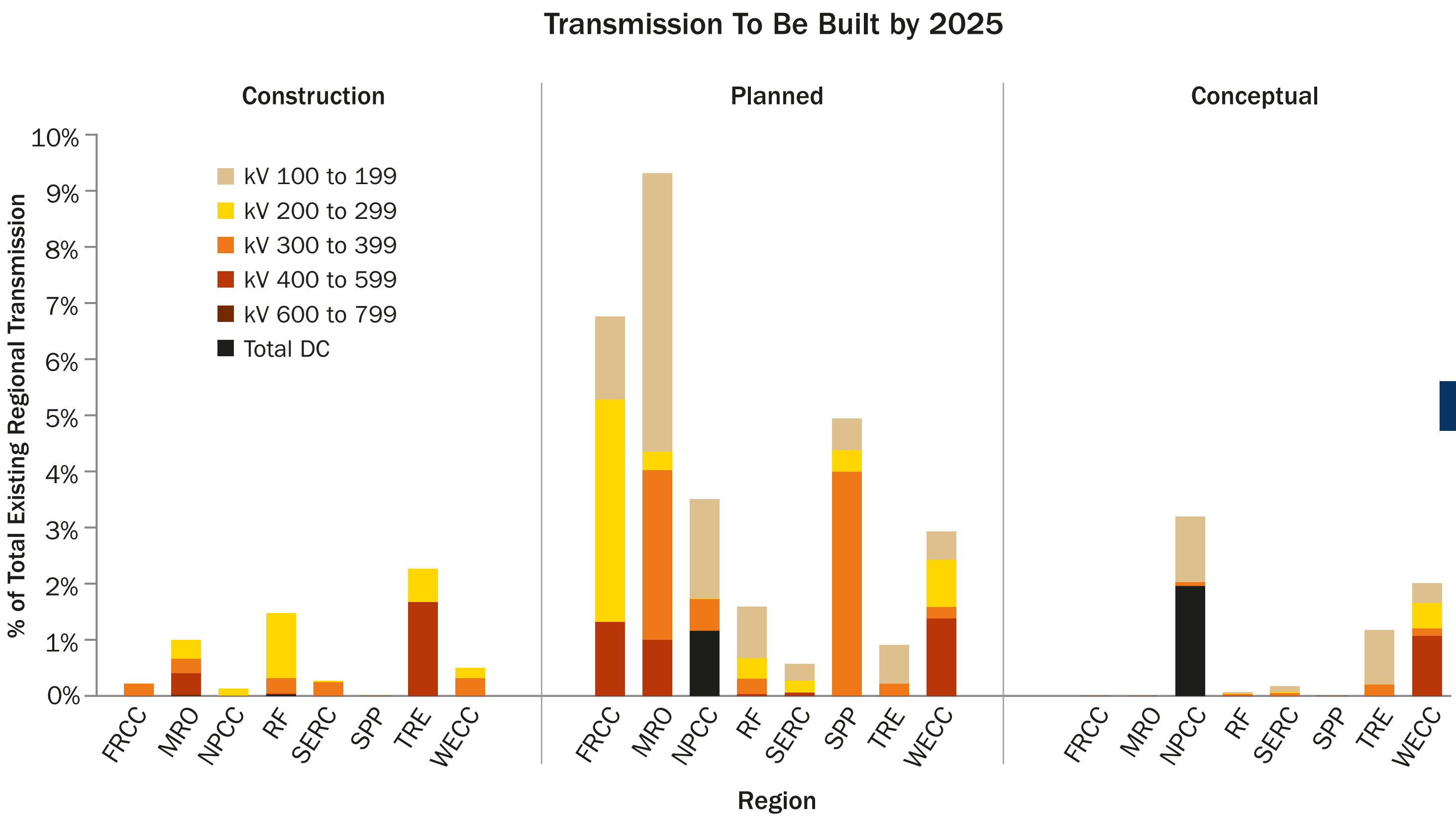
Existing Transmission Capacities



Source: DOE 2018

Notes: The transmission data are depicted for NERC regions. A map of NERC regions can be found at www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx (NERC "Key Players").

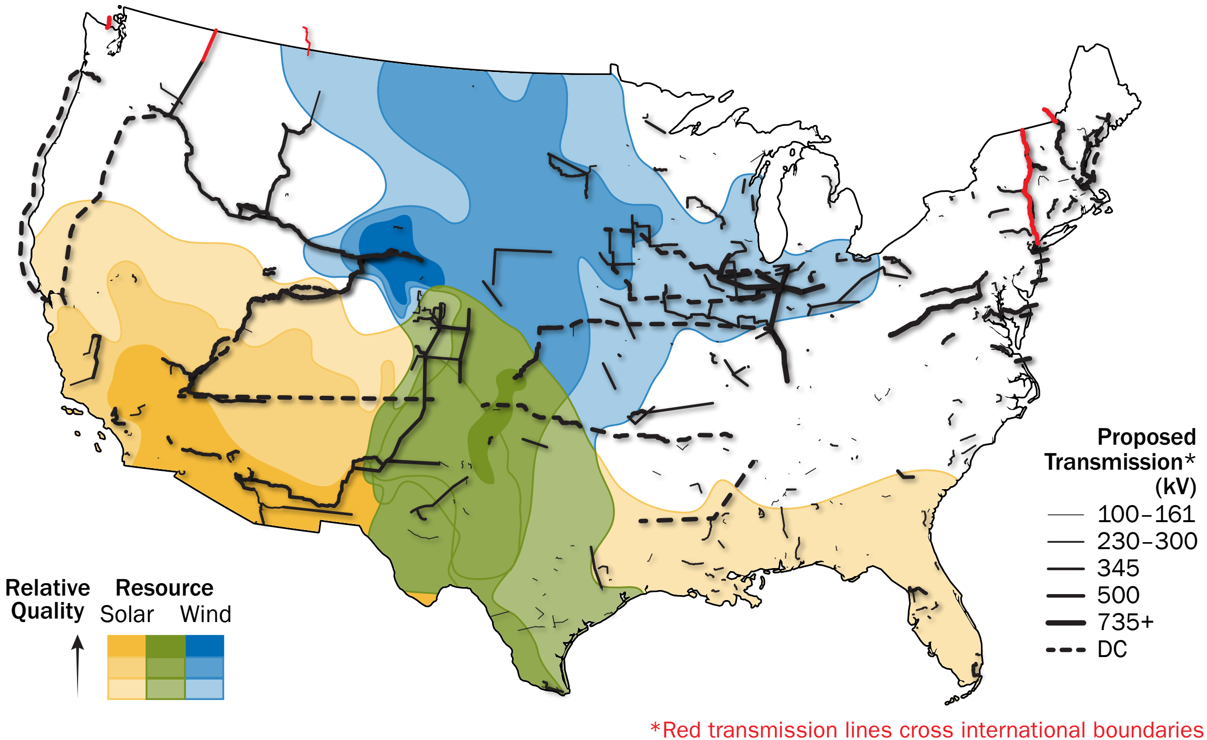
V



Source: DOE 2018

Notes: *Under construction:* projects where construction of the line has already begun; *Planned:* projects where (a) permits have been approved, (b) a design is complete, or (c) the project is necessary to meet a regulatory requirement; *Conceptual:* projects that are in a project queue but not included in a regional transmission plan (DOE 2017). The transmission data are depicted for NERC regions. A map of NERC regions can be found at www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx (NERC "Key Players").

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



Sources: ABB Velocity Suite; NREL illustration for wind and solar resource

Notes: Excludes transmission capacity less than 100 kV; Cross-border transmission lines are shown in red. This map is intended for illustrative purposes.

Proposed Major Interregional Transmission Projects (Selection) (2016–2017)

Region (terminal origin–endpoint)	Project[a]	Miles	Capacity (MW)	Proposed In-Service Date	Status (as of 2017 Year-End)	Source
Wyoming–Nevada	Zephyr Power	950	3,000	2023	N/A	DATC n.d.
Wyoming–Nevada	TransWest Express	730	3,000	2020	U.S. Department of Interior issued record of decision approving the project.	TransWest Express project website (www.transwestexpress.net)
New Mexico–Arizona	SunZia Southwest	515	3,000	2020	SunZia executed federal right-of-way (ROW) grant.	SunZia Southwest Transmission Project website (www.sunzia.net)
Arizona–New Mexico	Southline	240	1,000	2020	Bureau of Land Management (BLM) and Western Area Power Administration released their records of decision approving the issuance of a ROW grant. The New Mexico Public Regulation Commission approved project location and determination of ROW width.	Southline Transmission Project website (www.southlinetransmissionproject.com)
New Mexico–California	Centennial West Clean Line	900	3,500	2019	N/A	Centennial West Clean Line project website (www.centennialwestcleanline.com)
Oklahoma–Tennessee	Plains and Eastern Clean Line	700	4,000	2020	Oklahoma portion is sold to NextEra Energy Resources	Plains and Eastern Clean Line project website (www.plainsandeasterncleanline.com); DOE 2016b
Kansas–Indiana	Grain Belt Express Clean Line	780	4,000	2021	Pending rehearing at Missouri Court of Appeals on Missouri PSC denial	Grain Belt Express Clean Line project website (www.grainbeltexpresscleanline.com); Eto 2016
Iowa–Illinois	Rock Island Clean Line	500	3,500	N/A	Review of Appellate Court decision by Illinois Supreme Court	Rock Island Clean Line project website (www.rockislandcleanline.com)

[a] The selection of transmission projects is based on Brattle Group (2017).

Note: Transmission lines included in this table do not entirely match the map shown on page 43.

Proposed Major Interregional Transmission Projects (Selection) (2016–2017) (continued)

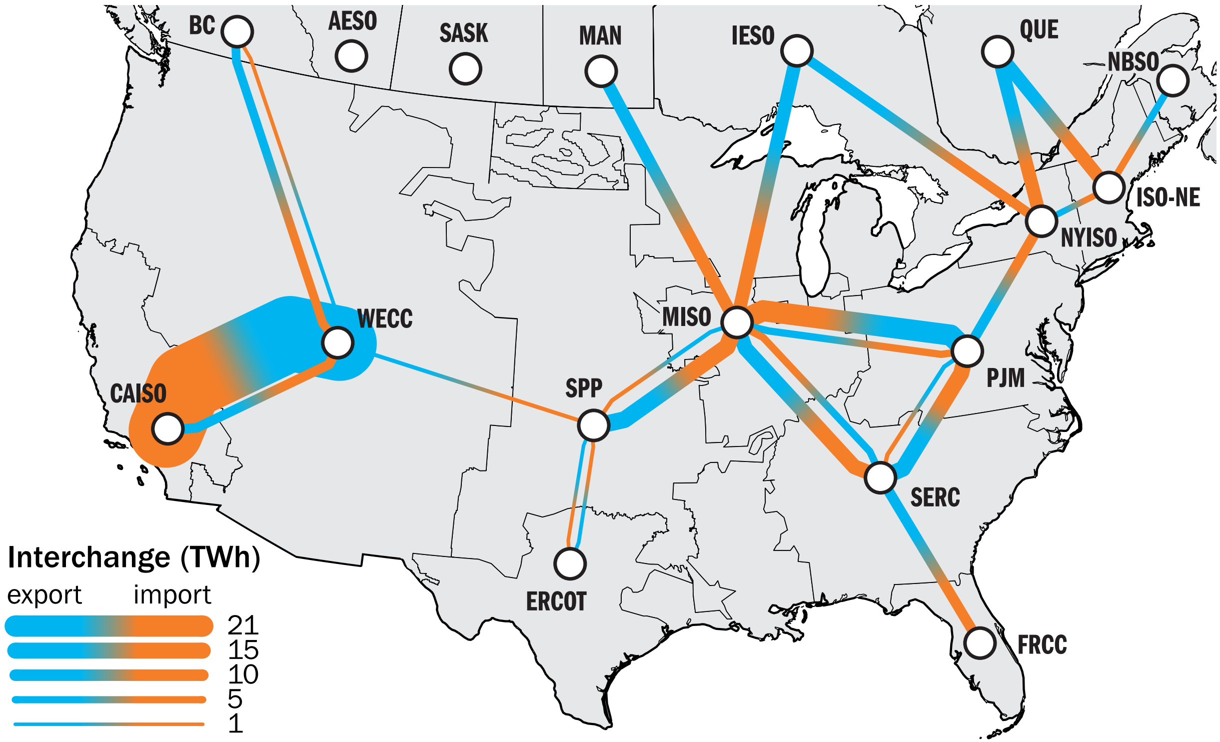
Region (terminal origin–endpoint)	Project[a]	Miles	Capacity (MW)	Proposed In-Service Date	Status (as of 2017 Year-End)	Source
Manitoba–Minnesota	Great Northern Transmission Line	220 (U.S.)	883	2020	ROW activities in process; Presidential permit obtained	Great Northern Transmission Line project website (greatnortherntransmissionline.com)
Ontario–Pennsylvania	Lake Erie Connector	73	1,000	2021	Permit applications filed	ITC Lake Erie Connector Project website (www.itclakeerieconnector.com)
Quebec–New York	Champlain Hudson Power Express	333 (U.S.)	1,000	2022	Presidential permit obtained	Champlain Hudson Power Express website (www.chpexpress.com)
Quebec–New Hampshire	Northern Pass	192	1,090	2020	Presidential permit obtained	The Northern Pass website (www.northernpass.us)
New Jersey–New York	Poseidon	79	500	2020	Interconnection process; Environmental assessment in progress	Poseidon Transmission Project (poseidon-project.com); "Underground, Underwater 500 MW HVDC Poseidon Transmission Project to be in Service in June 2016," https://www.hubs.com/power/explore/2013/07/underground-underwater-500-mw-hvdc-poseidon-transmission-project-to-be-in-service-in-june-2016
Newfoundland and Labrador–Massachusetts	Atlantic Link	375	1,000	2022	Permit approval process initiated	Atlantic Link project website (www.atlanticlink.com/the-project); Emera 2017
Mississippi–Louisiana/Texas	Southern Cross (including Rusk to Panola)	400	2,000	2021	In permitting process	Southern Cross Transmission Project website (southerncrosstransmission.com)

[a] The selection of transmission projects is based on Brattle Group (2017).

Note: Transmission lines included in this table do not entirely match those shown in the map shown on page 43.

Interregional Electricity Imports and Exports

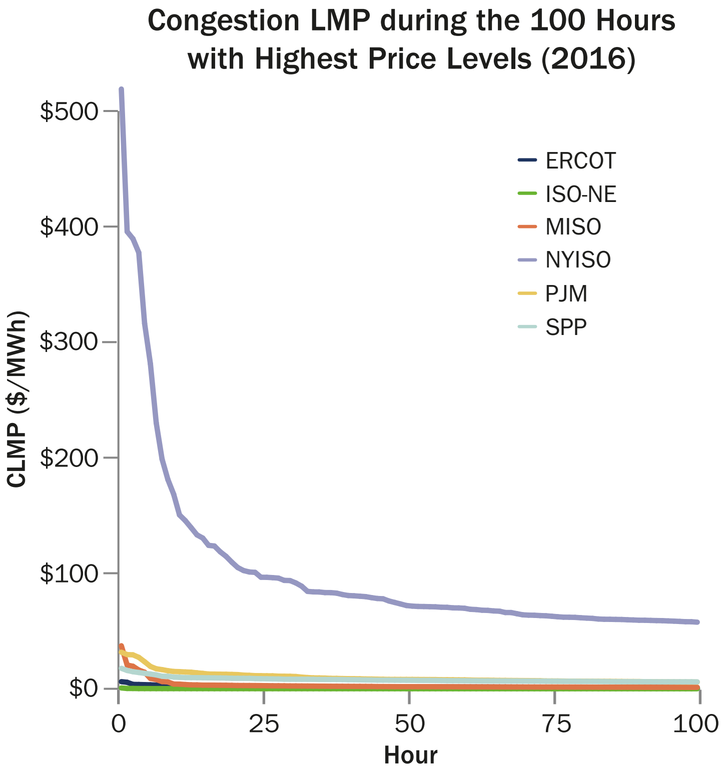
Interchange between ISO/RTO and NERC Regions (2016)

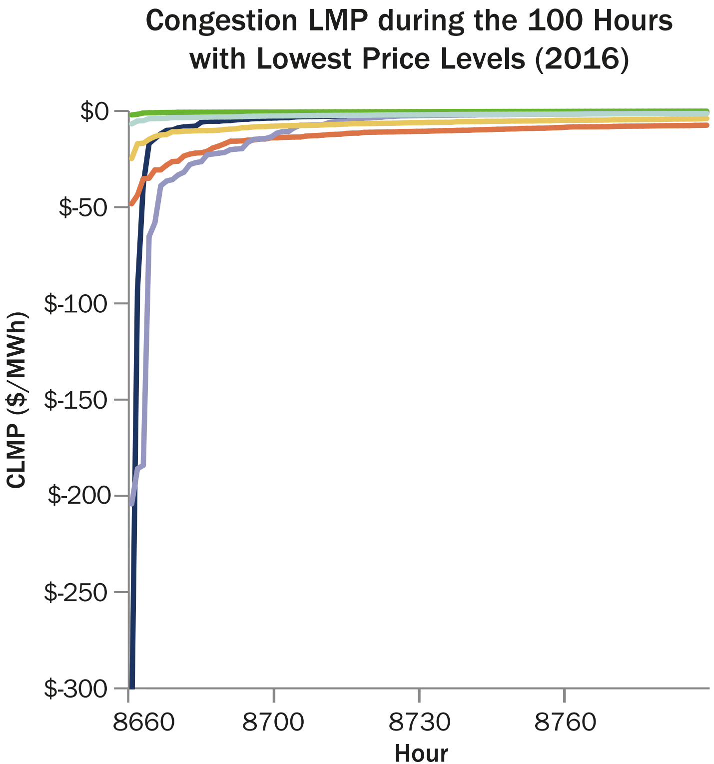


Source: EIA-930 (accessed through U.S. Electric System Operating Data website)

Notes: The data excludes interchange 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 BA counterparties were adjusted to represent physical flows of interchange (rather than contractual flows) to the authors' best knowledge. BA service territories were matched with NERC subregions.

V

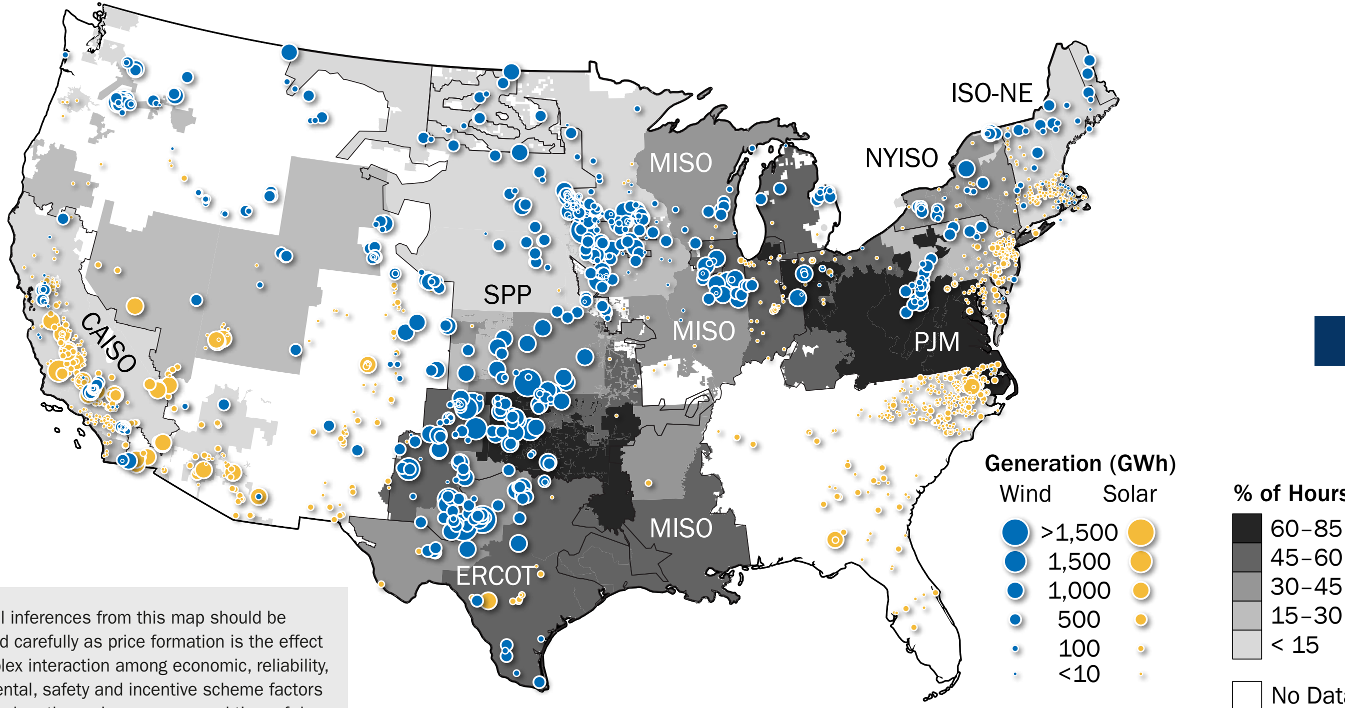




Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by NYISO, PJM, ISO-NE, ERCOT, SPP, MISO (accessed through the ABB Velocity Suite)

Note: The congestion component of LMP (CLMP) data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (MISO, PJM, ISO-NE, 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.

Hours with Congestion LMP > $0/MWh



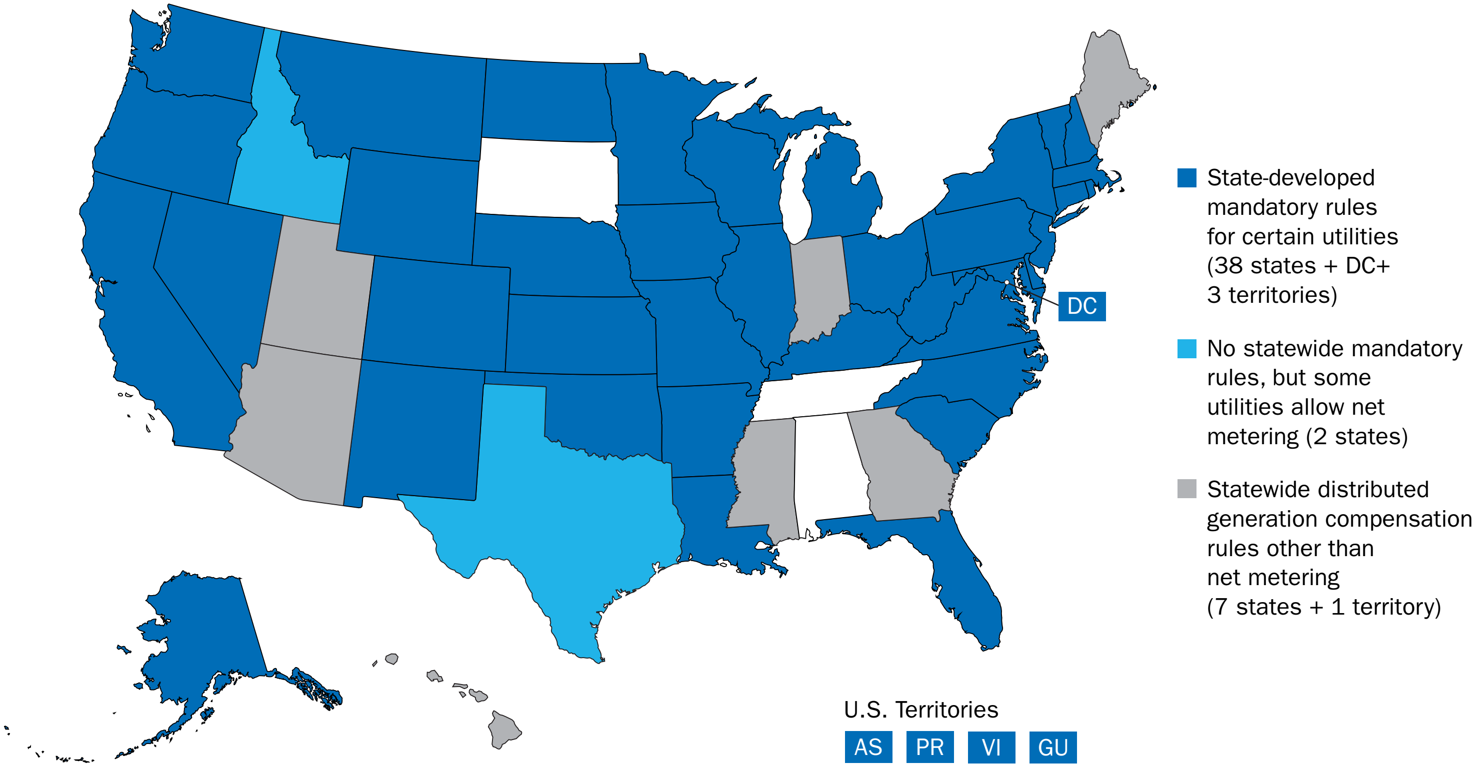
Any causal inferences from this map should be considered carefully as price formation is the effect of a complex interaction among economic, reliability, environmental, safety and incentive scheme factors that depend on the region, season, and time of day.

Source: "ISO Real Time and Day Ahead LMP Pricing: Hourly" data set reported by NYISO, PJM, ISO-NE, ERCOT, SPP, MISO (accessed through the ABB Velocity Suite); Form EIA-923 and the ABB Velocity Suite for data on solar PV and wind power plants

Note: CLMP data are reported as hourly (load-weighted) averages from zonal price nodes in the RT market (MISO, PJM, ISO-NE, 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

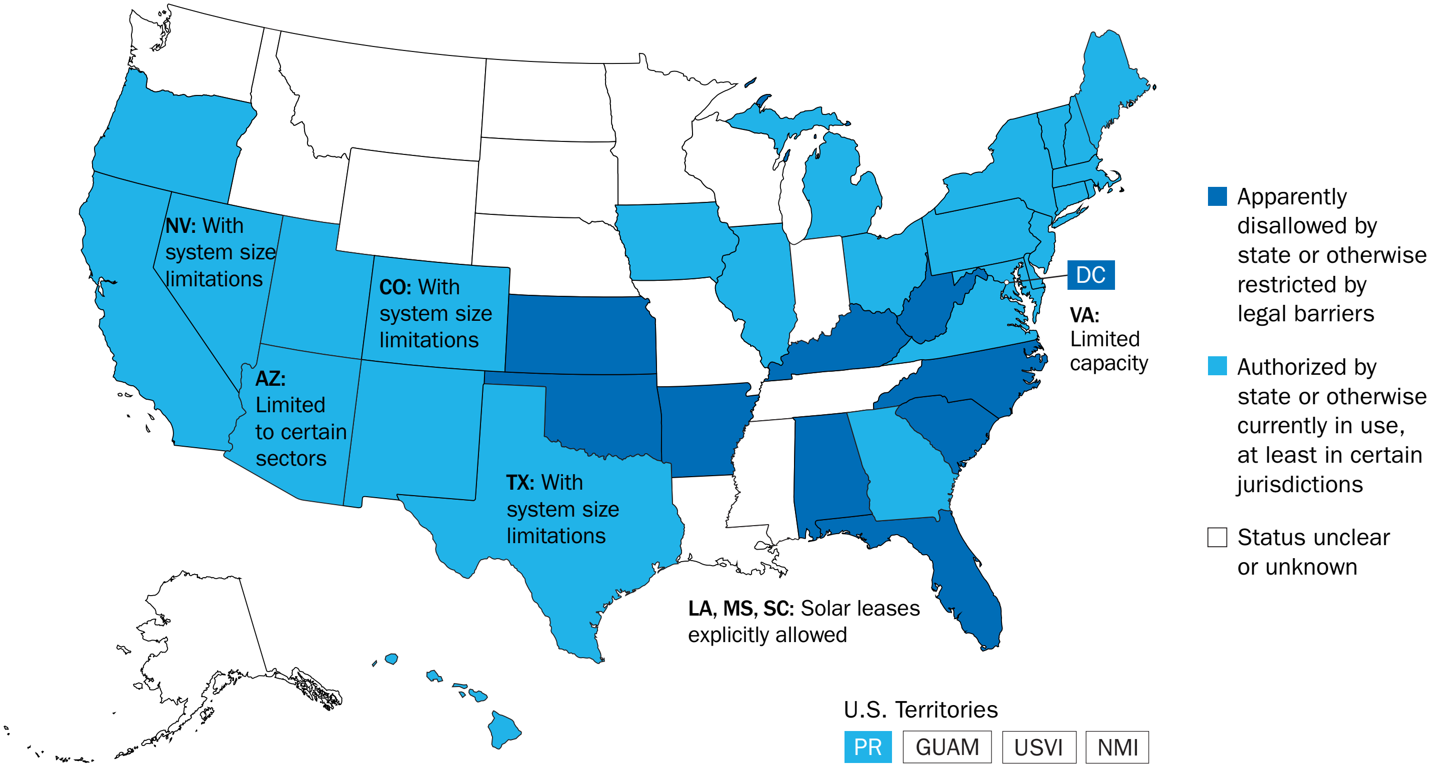
Status of Net Metering (November 2017)



VI

Source: DSIRE n.d.

Third Party Solar PV Power Purchase Agreement (PPA) (April 2017)



VI

Source: DSIRE n.d.

VII. 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/2004/02/13/2004021316073586 43.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:** CAISO (2017b)
- **ERCOT:** Potomac Economics (2017b)
- **ISO-NE:** Patton, David B., Pallas LeeVanSchaick, and Jie Chen (2017a)
- **MISO:** Potomac Economics (2017a)
- **NYISO:** Patton, David B., Pallas LeeVanSchaick, and Jie Chen (2017b)
- **PJM:** Monitoring Analytics (2017)
- **SPP:** SPP Market Monitoring Unit (2017)

NERC 2016 Annual Report

- NERC (2017)

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)

- FERC (n.d.)

Grid Modernization: Metrics Analysis

- PNNL (2017)

Intergovernmental Panel on Climate Change (IPCC) report on Renewable Energy Sources and Climate Change Mitigation

- IPCC (2012)

LBNL report on Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs

- Wiser et al. (2017)

LBNL report on Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making

- Seel, Mills and Wiser (2018)

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