Informing the **Transmission Discussion**

A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States

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WIRES

Preface

This report was prepared by ScottMadden, Inc. for WIRES.[1] The study includes a comprehensive overview of the current state of play of the electric industry and conducts a region-by-region examination of the challenges posed by changing energy resources, increasing electrification, and a greater need and preference for location-constrained renewables integration, in addition to addressing growing concerns about and risks to the resilience of the North American electric power system. The study also explores how these issues should be considered from an interregional transmission development perspective.

One of the clear takeaways from the report is that transmission can, and should, play a significant role in addressing the challenges raised by these factors. In particular, as more states, utilities, and other companies are mandating or committing to clean energy targets and agendas, it will not be possible to meet those goals without additional transmission to connect desired resources to load. Similarly, the current transmission system will need further expansion and hardening beyond the traditional focus on meeting reliability needs if the system is to be adequately designed and constructed to withstand and timely recover from disruptive or low probability, high-impact events affecting the resilience of the bulk power system.

To the extent all of these signs point toward a need for more transmission, time is of the essence. In the current environment, transmission is increasingly more difficult to build and operate. With transmission projects taking ten years or longer to be built and put into service, decisions regarding any transmission projects required to meet renewables integration and resilience concerns must be made with sufficient lead time if they are to play a role in meeting needs existing today, much less in the future. WIRES offers this report to facilitate a comprehensive review and discussion by planners, policy makers, regulators, and all those who are interested in the development of a robust transmission grid that is adequate to meet environmental and resilience goals.

WIRES solicits and looks forward to comments and questions regarding the study, which can be submitted to www.wiresgroup.com.[2]

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[1] WIRES is an international non-profit trade association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, renewable energy developers, and engineering, environmental, and economic policy consulting firms. WIRES' principles, its studies, and all public comments are available at www.wiresgroup.com.

[2] WIRES would like to acknowledge and thank the team of experts at ScottMadden, Inc., led by Cristin Lyons and Greg Litra, for their industry knowledge and insightful analysis as reflected in this study. In addition, we express our appreciation to former WIRES Counsel and Advisor James J. Hoecker for his leadership in initiating this study.

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Executive Summary

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Objectives of This Study

- Much has been written discussing the role of and need for transmission for integration of renewables and grid resiliency issues in the wake of heightened cybersecurity awareness (given global geopolitics) and other natural events (e.g., superstorms and hurricanes, bomb cyclones, extreme cold snaps, and wildfires).
- Many examinations of these topics have been conceptual, addressing policy issues with broad recommendations. Other treatments have been more technical, looking at specific physical insufficiencies in infrastructure.
- The challenge of these issues, and previous discussions of them, is the desire for a “universal solvent” that will remedy transmission infrastructure gaps across the nation; however, many of these issues are inherently regional. Each location has its endowment of existing infrastructure (including power generation and transmission), load sinks, renewable resource potential, and potential risks from widespread resilience events. Moreover, states have a meaningful role in siting and permitting electric facilities, mandating renewables procurement, and cost recovery. Indeed, different states are forcing the issue on renewables integration as they announce aggressive clean energy standards.
- This study focuses, region-by-region, on the key issues of renewables integration and resilience challenges. It reviews the current transmission landscape, renewable integration issues, recent resilience concerns, what regional transmission planners have done to address these, and what they believe ought to be done going forward to ensure reliability and resilient accommodation of growing amounts of renewable resources.
- It also examines some of the interregional needs and barriers to transmission development, summarizing key interregional issues in integrating renewables, identifying how regional organizations and others are dealing with these issues, and gleaning any lessons learned.

The goal of this study is to inform policymakers and the public of region-specific needs, issues, and challenges including the integration of location-constrained renewable resources and resilience. This review is done with a view of where and how transmission can and should play a role in addressing these needs.

Industry Backdrop

The electric industry has undergone a tremendous amount of growth and change over the past two decades, and it continues to evolve as policy and customer preferences, improving technology costs, and increasing focus on reducing greenhouse gas emissions (GHG) drive shifts in energy resources and consumption patterns. This transformation is driven by four key developments:

Changing Energy Mix	Deployment of Distributed Energy Resources (DERs) and Energy Storage	Aspirations for Beneficial Electrification	Strong Interest in Renewable and Greenhouse Gas Emissions-Free Resources
▪ Abundant and inexpensive natural gas making gas-fired power generation attractive ▪ Continued retirement of conventional fossil power plants nearer to load, as well as some nuclear plants ▪ Growing amounts of utility-scale wind and solar generation being proposed, but highly location-specific	▪ Growth in smaller DERs on the distribution system, both behind-the-meter and in larger-scale applications like microgrids, spurred by policy support and declining costs, and subject to favorable benefit-cost analysis ▪ Potential for support of local reliability and resilience ▪ However, lack of visibility and control, and uncertain impacts on demand behavior	▪ Customer, select policy interest in “deep decarbonization” and utility interest in increasing system load ▪ Electric industry and stakeholders looking at beneficial electrification to displace some traditional non-electric applications (e.g., light- and heavy-duty vehicles, space heating) ▪ GHG emissions “exchange” with electrification highly dependent upon power supply fuel mix	▪ Renewable portfolio standards (RPS), in place for years, increasing in scale ▪ States announcing ambitious clean energy (i.e., non-GHG-emitting energy resources) goals ▪ Large corporate buyers looking for renewable energy supply for national and global operations, for value and brand equity ▪ Latest trend: clean energy and net-zero emissions targets announced by some electric utilities

The developments noted above warrant consideration of impacts on the bulk power system and transmission in particular.

Regional Transmission Summary – ISO-New England

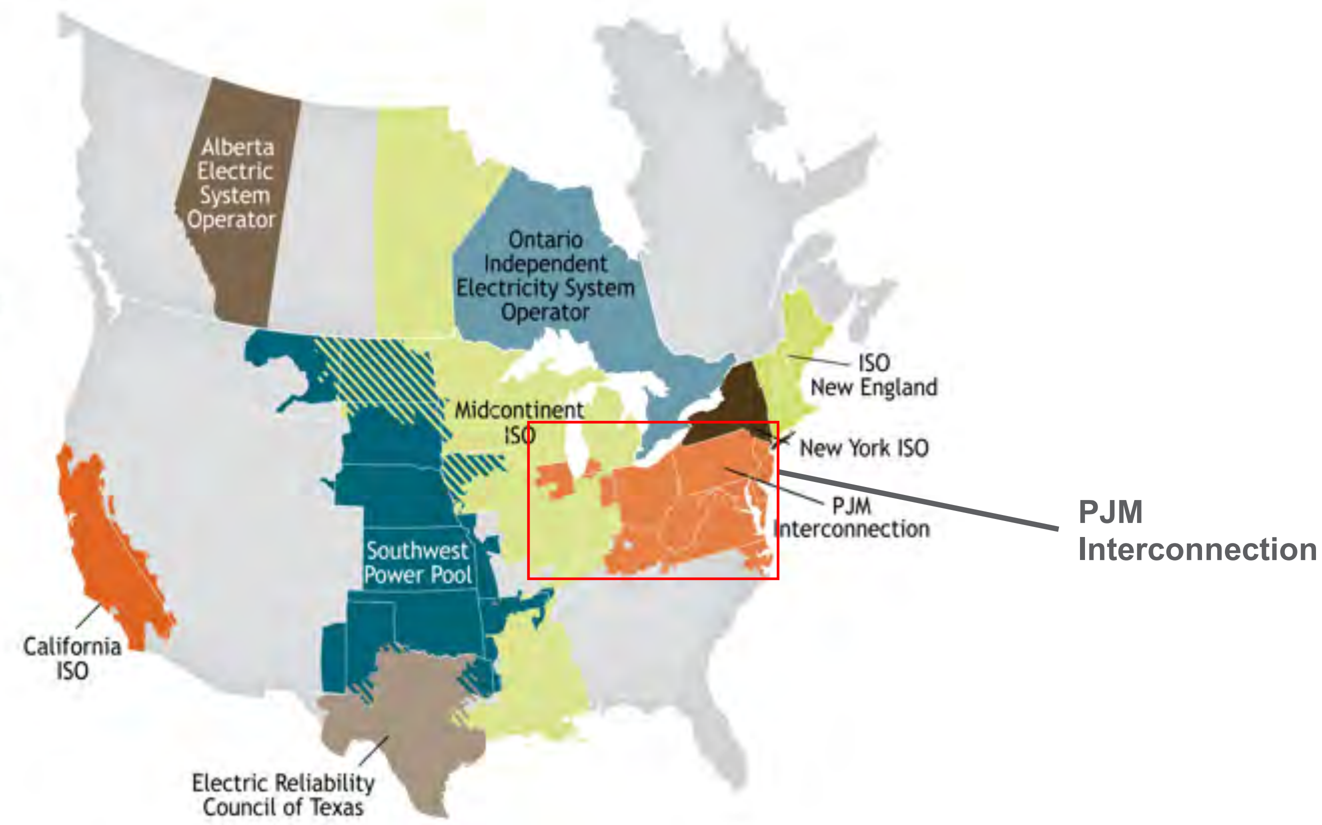
ISO-New England

- Ambitious clean energy goals in all six states: Ranging from 25.2% by 2025 in New Hampshire at the low end to 100% by 2050 in Maine at the high end, with demand expected to exceed supply in 2030, opening opportunity for more imports from Canada.
- Large offshore wind development target requires related offshore grid build-out, and onshore wind development in Northern Maine requires capacity to move wind to load
- Retiring nuclear and other thermal generation and significant reliance on natural gas generation creates fuel and energy availability risk.
- Resilience concerns, including extreme cold weather gas constraints for generation fuel, opens possible need for increased capacity at interfaces – "gas by wire" from PJM (via NYISO), hydropower from Canada (Quebec, in particular).

Regional Transmission Summary – New York ISO

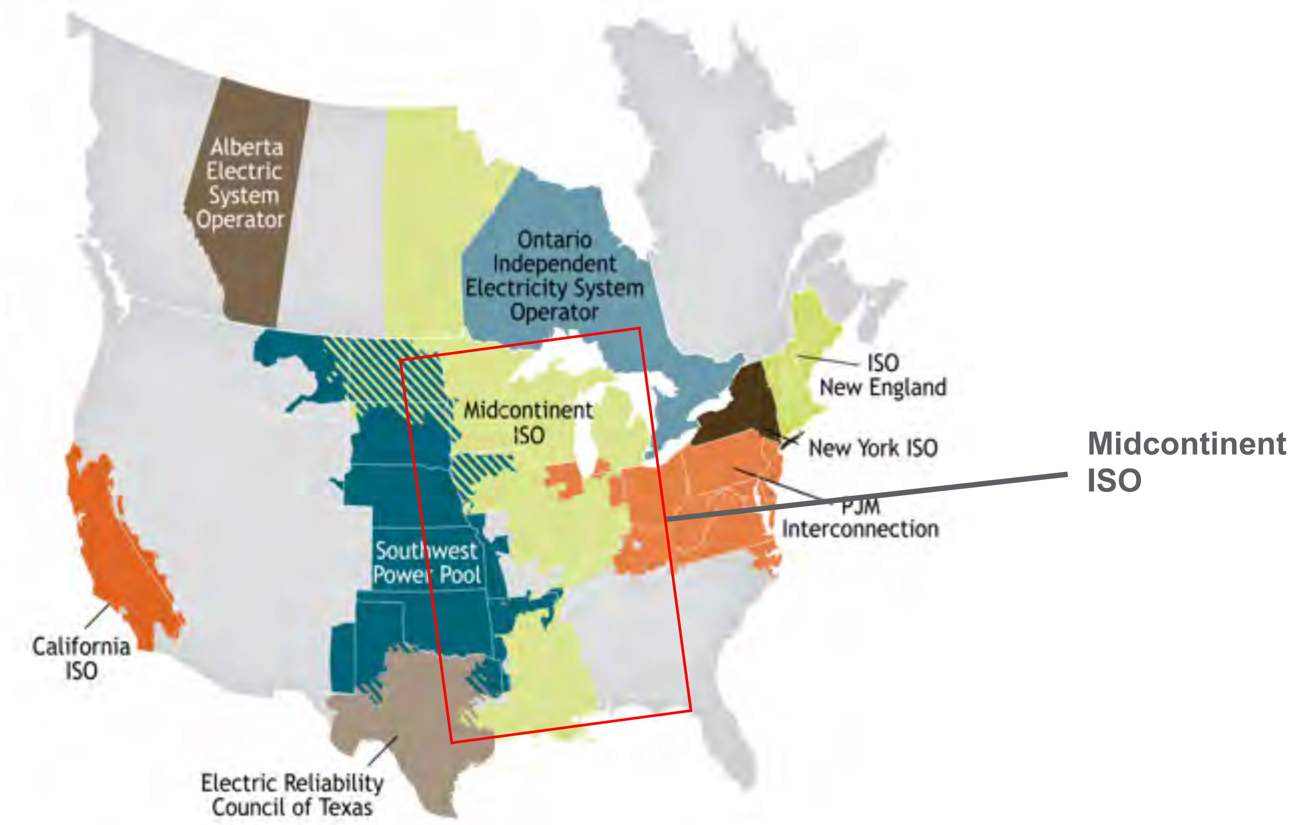
- Ambitious clean energy goals: 70% by 2040 and possibly inadequate in-state renewables supply opens opportunity for imports from Canada, west.
- Large offshore wind development target requires related offshore grid build-out.
- Ongoing “de-bottlenecking” of upstate renewables for deliverability to downstate load centers.
- Retiring nuclear and other thermal generation and significant reliance on natural gas generation downstate creates fuel and energy availability risk.
- Resilience concerns, including extreme cold weather gas constraints for generation fuel, opens possible need for increased transmission capacity at interfaces – “gas by wire” from PJM, hydropower from Canada.

Regional Transmission Summary – PJM Interconnection



- Disparate clean energy goals among the states within the region has led to a contentious capacity market ruling by Federal Energy Regulatory Commission (FERC), issued in December 2019 and likely to generate more debate when PJM makes it compliance filing.
- New wind and gas generation development has driven interconnection needs in recent years, but new solar represents the majority of capacity currently in the queue.
- More renewable resources than policy demand in region, and more gas capacity than needed; opportunity for export.
- Transmission investment has trended toward more local and lower voltage “Supplemental Projects” recently, driven by asset performance, condition, and risk, as congestion in the region has been reduced.
- Retiring nuclear and other thermal generation and significant reliance on natural gas generation creates fuel and energy availability risk.
- Resilience concerns, including extreme cold weather gas constraints for generation fuel, opens possible need for increased capacity at interfaces with MISO and NYISO.
- Complications to expansion in region: Public policy differences among states, low to negative load growth expectation for the planning horizon.

Regional Transmission Summary – Midcontinent ISO



- Diverse region with three distinct areas: wind-heavy west; thermal baseload-heavy central (with growing retirements); and gas-fired generation-heavy south.
- While wind development, especially in the west northwest of region is a big part of resource development, increasing amount of solar across region, potentially creating some different and more localized transmission needs.
- Significantly more renewable resources than policy demand in region; opportunity for export.
- Potential for targeted transmission needs in Midcontinent ISO (MISO) West as region contemplates potential for long-term "tipping point" of 30% to 40% wind penetration.
- Reducing congestion has been a goal, and multi-value projects completed since 2011 have lowered congestion and allowed for lower marginal cost wind greater market access and has removed need for $300M in baseline reliability upgrades.
- Market-to-market payments indicate potential for east-west interregional enhanced transfer capability with PJM and load centers to the east.
- Resilience challenges different within region, largely seasonal extreme weather; potential for transmission capacity between north and south to diversify resources, energy transfers during times of system stress.
- Potential for expansion of transfer capacity on north-south constraint between MISO North/Central and MISO South – off-peak wind moving south, low cost gas, solar power moving north.
- Complications to expansion in region: 2015 settlement agreement upon addition of MISO South; public policy differences between MISO South states and MISO North/Central states.

Regional Transmission Summary – Southeast

- Vertically integrated, rate-of-return market area, with generation and transmission considered mostly using traditional integrated resource planning – transmission "built to suit."
- Growing renewable resources in region (especially utility-scale solar), more than policy-generated demand in region, but still small in comparison to thermal resources, including growing gas-fired and new nuclear generation units.
- Long-term potential for offshore wind, but limited activity to date.
- Limited renewable integration issues to date; region is now studying potential impacts, including effect of increased solar in increasingly winter-peaking region.
- Some resilience challenges driven by tropical cyclones and ice storms; opportunity for grid hardening.
- Increasingly winter-peaking with exposure to extreme cold weather (cold snaps); increased gas dependence raises issues around single point of disruption (pipeline interruption or reduced gas availability).

Regional Transmission Summary – Southwest Power Pool

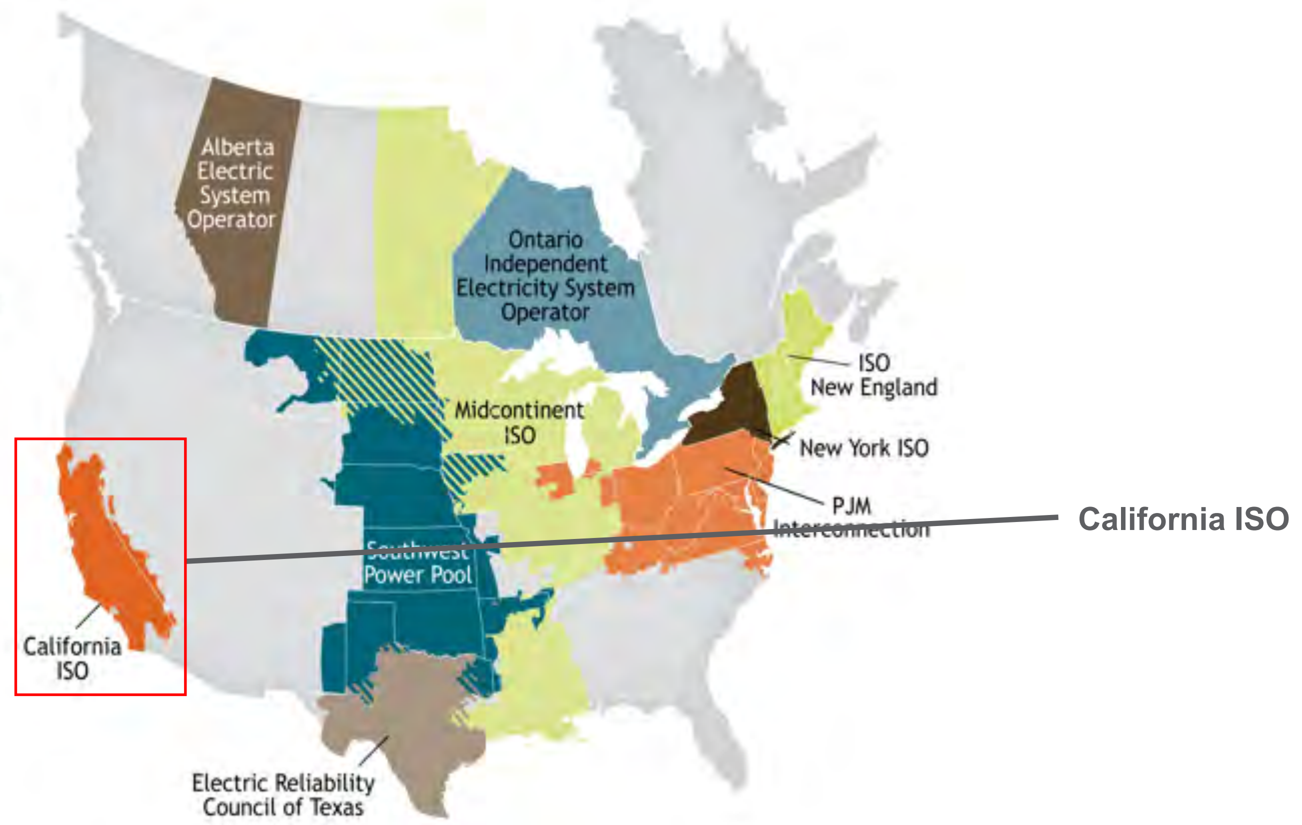
- "Tale of two grids" with high wind penetration in north and west approaching levels that typically cause integration issues, with population centers south and east.
- Large wind potential in region, in north and south, with large (51 GWs) interconnection queue, with growing interest in solar (28+ GWs in queue) in south.
- Significantly more renewable resources than policy demand in region; opportunity for export.
- The region has developed a high-voltage backbone, which has been well-utilized as renewable resources have come online.
- Potential west-to-east transmission for relief of "pinch points" in central Kansas/southwest Missouri to accommodate northeast-to-southwest Southwest Power Pool (SPP) flows.
- Potential for increased integration with Western Interconnection for broader footprint for renewable resource optimization; being tested with SPP's Western Energy Imbalance Service and reliability coordinator role.
- Potential for increased integration with MISO for west-to-east flows of increasing wind and solar resources to load centers, resilience support.

Regional Transmission Summary – Western U.S. (Excl. California ISO)

- Diverse and expansive region with varying climate and weather patterns, including access to some of the richest wind (east central portion) and solar (southern portion) resource areas in the United States; New Mexico and Wyoming are hot spots for wind development due to prevalence of low-cost and temporally uncorrelated wind, and the Southwest is seeing strong buildout of solar, including utility scale and DERs.
- Heterogeneity of state policies related to renewables creates challenges for multi-state backbone projects; Colorado, New Mexico, Nevada, Oregon, and Washington have targets of 50% or higher; Idaho and Wyoming have no standard.
- Abundant hydro resources in the Northwest could play a role in balancing increasing amounts of variable generation across the Western Interconnection if there is sufficient long-haul transmission capacity to other parts of the region.
- Majority of transmission projects in recent years have been executed within the four discrete planning areas in WECC*, though six interregional projects are currently being developed across seams.
- Opportunities to increase transfer capacity across seams with Canada, SPP, ERCOT**, and California ISO for broader footprint for renewable resource optimization, particularly to accommodate growing demand for renewables within California, as well as the need to reduce curtailments at times of excess generation within California.
- Developing long-distance, high-voltage transmission through remotely populated Western areas poses unique challenges: terrain, distance, and impacts on federal, native lands.

*Western Electric Coordinating Council
**Electric Reliability Council of Texas

Regional Transmission Summary – California ISO



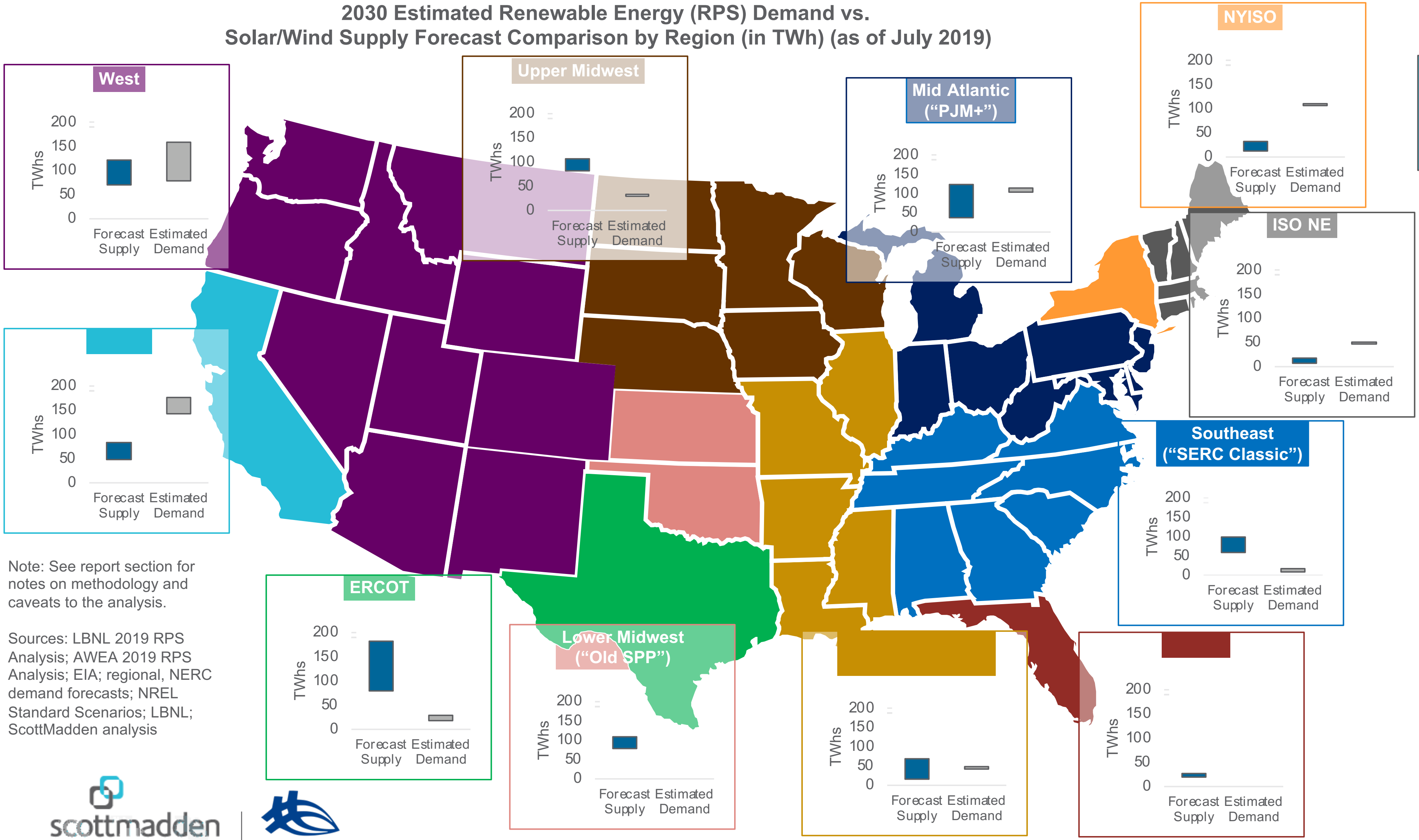
- Ambitious clean energy goals: 50% by 2030 and potential for in-state demand to vastly exceed in-state renewables supply suggests opportunity for more imports from adjacent regions, particularly increasing transfer capacity with the Northwest.
- Increasing curtailments of in-state renewables at times of oversupply could create opportunities to move power to areas where it can be used.
- Expansion of the Western Energy Imbalance Market, which includes almost three-fourths of the load in the Western Interconnection, continues; introduction of a day-ahead market may create opportunities to streamline intraregional and interregional transmission planning.
- New wind and gas generation development has driven interconnection needs in recent years, but new solar represents the majority of capacity currently in the queue.
- Resilience concerns, including wildfires and gas-power interdependence, points to potential need for increased capacity at interfaces with other regions in WECC.
- Complications to expansion in region: Preference for non-wires alternatives, siting and permitting.

Interregional Considerations

- **Regional to interregional:** Generally, the regional view takes into account grid characteristics and resources. Policy across the country has evolved and been implemented based upon this regional view. However, as the need for integration of renewables and access to low cost energy resources grows, the need for interregional transmission is increasing. Renewables are not evenly distributed; they are concentrated in various regions which don't necessarily align with where the greatest needs are emerging.
- **Benefits of a larger grid footprint:** A larger grid footprint or balancing area provides advantages for both integration of all types of generation and resilience. A number of studies have pointed to the benefits of increased interregional transmission to accommodate higher penetrations of renewable resources:
  - A study of the Western Interconnection found that increasing balancing area coordination with more transmission connecting larger geographic areas helped diversify the variability of both load and resources and created cost savings due to increased reserve sharing.
  - A similar study of the Eastern Interconnection found that with increased (up to 30% with a significant portion being wind) renewable resources, greater levels of interconnection through transmission led to increased interregional power flows and illustrates that interregional transmission is one way to potentially reduce operational impacts of increasing RPS requirements.
  - More recently, the National Renewable Energy Laboratory has been conducting an Interconnection Seams Study, still to be completed. But it has identified opportunities for increased integration among the U.S. interconnections as providing opportunities for cost savings and possibly resilience, by bringing low cost resources, including remote renewables, to market.
- **Case studies:** Additional case studies point to benefits of interregional transmission capacity. The Western Energy Imbalance Market leverages excess transmission capacity to move excess midday solar energy from California to other areas of the West, as well as allowing for support for late-day ramping needs in California and elsewhere, leading to cost savings for all participants. Moreover, Europe has been expanding its transmission grid to aid in integrating hydro, offshore wind, and onshore wind as it seeks to meet European Union power sector emissions targets.
- **Renewable portfolio standard (RPS) supply vs. demand:** Finally, as RPS's become more ambitious and clean energy goals advance at the state and utility level, and renewables development is mixed and geographically diverse, RPS supply-demand "imbalances" are potential indicators of increased needs for import and export capability across regions

Interregional Considerations (Cont'd)

2030 Estimated Renewable Energy (RPS) Demand vs. Solar/Wind Supply Forecast Comparison by Region (in TWh) (as of July 2019)



2030 estimates
Clean energy demand (standards): 600 TWh (per LBNL) to 714 TWh (latter is ~17% of U.S. retail sales)

Key Takeaways

- As shown here, by 2030, many regions are projected to have adequate or excess renewable supply compared with "headline" clean energy demand.
- The West (including California), New England, and New York appear to have opportunities for additional supply, perhaps through imports from other regions.
- This analysis does not include corporate, utility, or state clean energy "goals" that do not have regulatory or legislative force; thus, additional potential regional demand for renewables may be higher.

Note: See report section for notes on methodology and caveats to the analysis.

Sources: LBNL 2019 RPS Analysis; AWEA 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Resilience

- **FERC definition:** FERC defines resilience as the ability [of the electric system] to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.
- **NERC's framework:** The North American Electric Reliability Corporation (NERC), the designated electric reliability organization, has proposed a framework envisions four elements, reflecting different parts of an event occurrence:
  - Robustness – the ability to absorb shocks and continue operating
  - Resourcefulness – the ability to detect and manage a crisis as it unfolds
  - Rapid Recovery – the ability to get services back as quickly as possible in a coordinated and controlled manner, taking into consideration the extent of the damage
  - Adaptability – the ability to incorporate lessons learned from past events to improve resilience
- **Regional variations:** Resilience issues vary between regions and even within large regions. Some resilience issues are common because they are global in nature. Many threats vary because of location and vulnerability of infrastructure, proximity to resources (including fuel), weather patterns, climatic trends, and seismic conditions. Many regions are concerned about extreme weather as reliability, and often termed as resilience, risks. In particular, extreme cold weather and its impact on an increasingly natural gas-dependent fleet as well as very high penetration of variable energy resources, are being studied.
- **Transmission as potentially enhancing resilience:** Transmission is a component of a more resilient system in providing access to reserves and energy during extreme conditions, leveraging weather diversity. Moreover, as facilities in an aging U.S. transmission system are replaced, they are being upgraded with capabilities that improve resilience, such as technologies for situational awareness and hardened structures.

Resilience vs. Reliability: Different Stakeholders, Cost-Bearers, Responsibilities, and Levels of Planning Maturity

Planning criteria	Well-established N-2 planning	Unspecified or incipient "black swan" planning
Scenarios considered	Stated contingencies	Unlikely/unknown contingencies beyond reliability planning
Primary focus	Prevention, protection, and risk mitigation	Critical infrastructure recovery; social stability
Potential value of event "insurance"	Estimable through system modeling	Difficult to ascertain; policy-driven
Costs borne by	Ratepayers	Taxpayers
Funded by	Utility capital expenditures	• Federal emergency funds • State infrastructure • Municipal, county government
First response responsibility	Utility	Government, community response
Stakeholder coordination	Utility, ISO led	Government led

There remains a planning gap between reliability and resilience. Transmission planners, operators, and owners continue to focus on reliability, including weather and fuel dependency, as those are most clearly actionable and related to electric infrastructure investment. Resilience has broader societal implications involving more stakeholders with government as a key facilitator. And its costs are more properly a societal decision. While transmission has an important role to play, it is only one piece of resilience preparation.

Sources: ScottMadden analysis; 2019 State of Reliability

Challenges

- **Siting and permitting:** The issues with siting and permitting across multiple jurisdictions have long been highlighted as challenges to building both intra- and interregional transmission.
- **Policy evolution needed:** The fact that transmission is needed across the country to support both reliability and integration of renewable resources is well-documented; the evolution of policy has not supported this basic understanding. Incentive policy, which drove significant investments through the 2000s is changing, and returns on equity and adders are being reduced.
- **Legacy of Order 1000:** Order 1000 interregional processes have not materialized to facilitate broader integration across markets. The same cost-allocation challenges, which we once discussed at the regional level, have now moved to the interregional level, identifying beneficiaries and allocating costs appropriately, particularly across regions with different methodologies is challenging.
- **Need for forcing function:** Until a forcing function requires these regions to develop a methodology that facilitates largely public policy projects, the hope of interregional transmission meeting national needs for transmission (to serve any purpose, let alone clean energy) will remain elusive.
  - State and local policy continues to stymie transmission development through siting and permitting processes that are poorly aligned.
  - Environmental interests stack up on both sides of the transmission development debate. Some organizations acknowledge the degree to which transmission is needed to facilitate renewables integration. Others focus on the environmental impacts of specific corridors, slowing or stopping permitting and construction. There is also a view that DERs can offset the need for central station (utility-scale) generation and transmission.
  - Economic development always points to local resources serving local load; states are focusing on in-state resources to meet RPS and clean energy targets, making the case for interregional collaboration more difficult.

What has changed in the last two years or so is the degree to which states, utilities, and other companies are committing to 100% carbon free portfolios. It is not possible to meet these goals without intraregional, and in some cases interregional, transmission connecting these resources to load.

Policy Implications

- **Targeted federal policy:** Significant transmission development followed the Energy Policy Act of 2005 and FERC incentives policy that followed; similar national policy could be beneficial in creating a framework for transmission development that would be supported by myriad stakeholders.
- **Fostering interregional transmission:** In the absence of a national framework, the following should be considered to spur interregional transmission development:
  - FERC should step forward and begin to assess more proactive approaches to creating the framework for interregional collaboration in light of company, state, and regional goals related to clean energy.
  - There is an opportunity to reconsider the current trend in transmission incentives if there is a desire to have companies undertake these large interregional projects.
  - Stakeholders focused on clean energy need to further articulate the critical role of transmission in facilitating company, state, and regional goals for clean energy.
  - As utilities (and others) put forward clean energy and carbon free goals, they should also highlight the role that transmission plays in facilitating this transition.
- **Education:** The network and other positive effects of transmission need to be more broadly understood and communicated.
- **Role of transmission:** As regions and states develop and communicate clean energy goals, they should work with the RTO/ISO to understand the degree to which these goals must be facilitated by transmission (both intra- and interregional).

There is the potential to align myriad stakeholders in support of transmission development. The benefits to these divergent groups need to be clearly communicated to garner support for this infrastructure.

Structure of the Report

- This report is structured in sections.
  – Section 1 is this Executive Summary, which highlights key points of the report including a snapshot of the regions profiled herein.
  – Section 2, titled Industry Backdrop, describes four important trends in the electric industry in North America and how electric transmission plays a role or complements these trends.
  – Section 3, titled Regional Discussions, and further divided into regional subsections, provides an overview of the regions reviewed in this study (and summarized earlier in this executive summary) consisting of key statistics, a view of the region's transmission topography and investment, trends and drivers of renewables development, resilience issues, and a summary of issues for transmission in the region.
  – Section 4, titled Interregional Considerations, examines studies, case studies, and drivers for interregional transmission, considering grid needs driven by renewables supply and demand as well as resilience considerations.
  – Section 5, titled Resilience, examines non-region-specific resilience issues, including the industry's evolving resilience framework, selected events and how the grid enabled a robust response, and potential investment in grid capabilities to support resilience.
  – Section 6, titled Challenges and Policy Implications, looks at some of the issues regarding interregional planning, cost allocation, resilience planning, and local siting and permitting of transmission, and considerations for policymakers and stakeholders.

Notes and Acknowledgments

Notes

- This report uses publicly available sources and is dependent upon accuracy and completeness of these resources. Data and information provided in this report is valid to the best of our knowledge as of October 2019.
- The energy industry, and the power transmission sector in particular, is a dynamic, changing business, legal, and regulatory environment. Any changes and developments, including commission or agency findings and decisions, updated planning documents, and other resources relied upon herein occurring or released after October 2019 are not necessarily reflected in this report.

Acknowledgments

- The report was informed by input from WIRES member organization representatives. We extend our thanks to the WIRES Group, its members, and in particular the working group that was engaged in discussing and reviewing this report. Their assistance and insights, particularly into (but not limited to) regional dynamics, were invaluable. Errors and omissions in this report are ours alone.

Industry Backdrop

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Major Trends in the Electric Industry

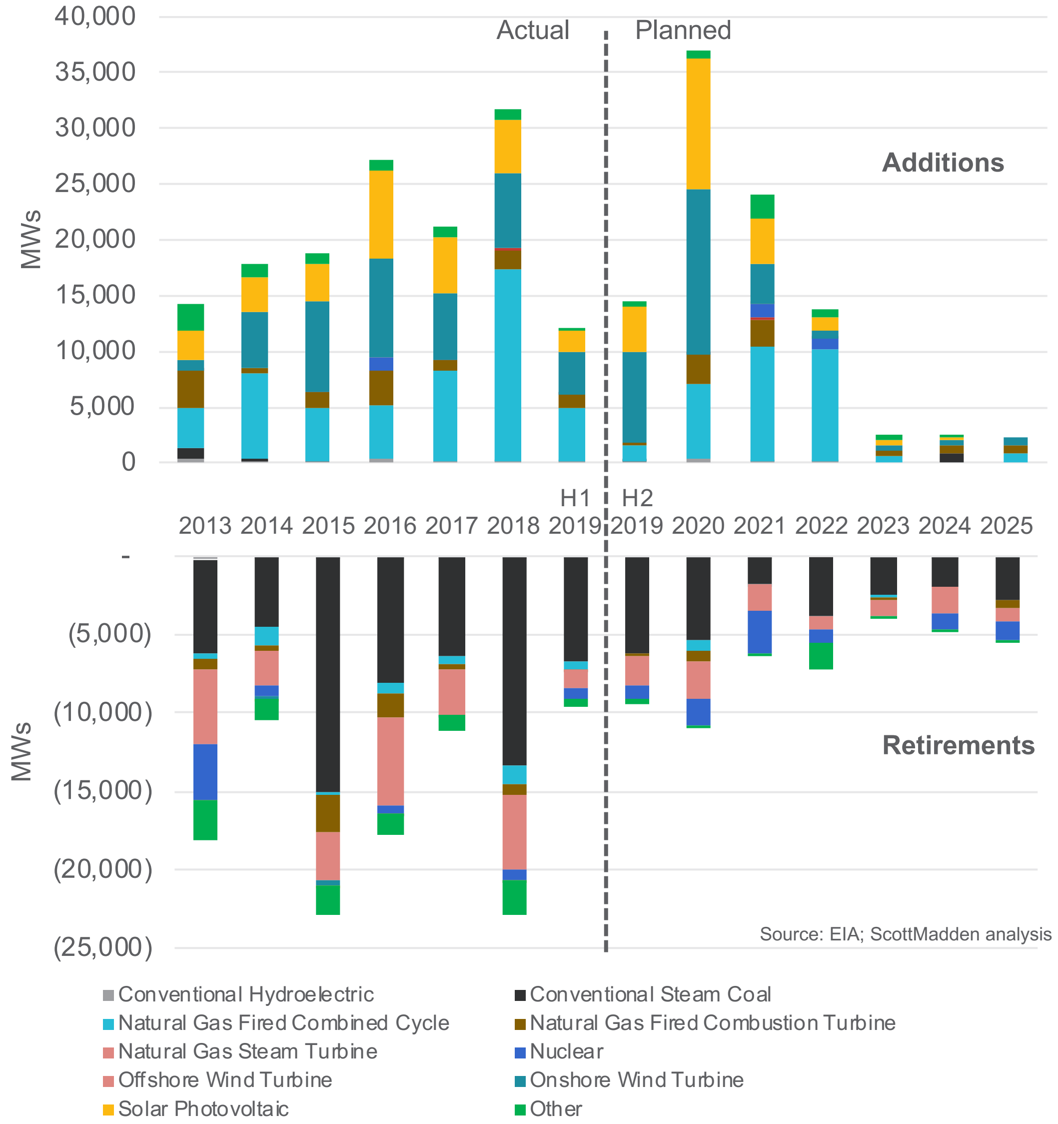
- The electric industry has undergone a tremendous amount of growth and change over the past [20] years, and it continues to evolve as policy and customer preferences, improving technology costs, and increasing focus on reducing greenhouse gas emissions (GHG) drive shifts in energy resources and consumption patterns.
- In particular, the electric industry is undergoing a gradual transformation driven by four key developments:
  - **A changing energy mix:** Abundant and inexpensive natural gas, in large part enabled by hydraulic fracturing, has increased the attractiveness of development of gas-fired power generation. The economics of gas generation has also worked to displace and force retirement of older coal-fired and, in some areas, emissions-free nuclear generation. In addition, growing amounts of utility-scale wind and solar generation are being proposed across the country, but their output capability and economic viability is highly location-dependent.
  - **Deployment of distributed energy resources (DERs) and energy storage:** The Midcontinent ISO (MISO) terms this trend as decentralization. The growth in smaller energy resources on the distribution system, whether behind-the-meter (rooftop solar, storage, and demand response) or larger distributed generation and storage interconnected at the distribution level (including microgrids), continues; as interest grows, costs for those resources decline, and policy support and favorable benefit-cost analysis warrants their consideration. While these resources may support local reliability and resiliency, the bulk power system may lack visibility and control of these resources, creating planning and operating challenges.
  - **Aspirations for beneficial electrification:** Consumers are interested in emissions reduction and decarbonization, and utilities are interested in growing load (to improve load factor) and displacing carbon-intensive applications with energy from a less carbon-intensive resource mix. As a result, utilities and policymakers are investigating electrification of a number of activities that traditionally use other fuels, such as space heating and particularly light- and heavy-duty vehicles. While this can provide some incremental load growth, absent price and other incentives, electrification may affect the level, growth, and patterns of electricity demand in ways we cannot yet determine.
  - **Strong interest in renewable and other GHG emissions-free resources:** While renewable portfolio standards (RPS) have been in place in a number of jurisdictions for years, more states and utilities have established or increased clean energy goals on an ambitious pace, acting in the absence of federal policy. Supplementing this is continued interest by large corporate buyers in renewable energy. All of this may provide tailwinds for further development of renewable resources to meet this demand.
- Overlaying these trends is concern, in some minds urgent, about the resilience of the U.S. electric system to cyber security and physical threats, as well as extreme weather-related threats to power infrastructure from direct damage, fuel availability issues, and grid flexibility during times of system stress.

Trend: A Changing Energy Mix

Conventional Capacity Retiring and New Gas-Fired Capacity Coming Online

- **Shift to gas:** The electric system has long relied on large, dispatchable units located relatively near load centers. However, as those units have aged and natural gas prices have made it more attractive as a fuel, they are being replaced with gas-fired units, not necessarily close to load. Many of those units have an advantage of being flexible for ramping duties, an important characteristic with more variable energy (discussed later).
- **Conventional capacity retirements:** NERC estimates that approximately 39 GWs of coal-fired, 13 GWs of natural gas-fired, and 1.1 GWs of nuclear power capacity have retired since 2013. It also notes the announced retirement of nearly 27 GWs (9 GWs coal-fired, 7 GWs of nuclear, and 10.9 GWs of gas-fired generation) through 2028. Another estimate by Bloomberg totaled 35 GWs of announced coal capacity to retire between 2019 and 2025.
- **Watching potential resilience and reliability impacts:** Increased reliance on natural gas may have reliability and resilience effects. Some regions currently have significant penetration of natural gas capacity as a percentage of total capacity. More than 50% of capacity in California, Texas, Florida, New England, and the Desert Southwest, for example, is natural gas-fired. Industry and regulators continue to examine fuel assurance and the impact of potential gas disruptions.
- **Reconfiguring the grid:** NERC has noted that capacity retirements near large load centers with limited transmission import capability pose the greatest potential risk to reliability, unless replaced with plants in the same vicinity. Voltage issues could arise with increased imports, and reliability coordinators and system operators are analyzing these potential impacts as units retire.
- **More variable energy resources are entering the mix, and many of the dispatchable resources historically located near load are being retired and, in some cases, being replaced by gas-fired capacity.**

U.S. Power Plant Additions and Planned Additions (in Net Summer MWs)



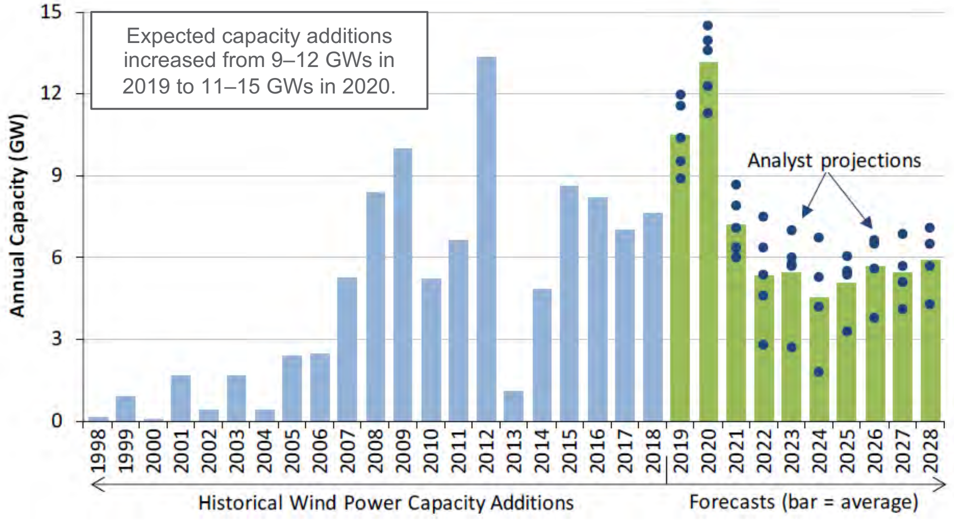
Sources: NERC, 2018 Long-Term Reliability Assessment (Dec. 2018); Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2019 Sustainable Energy in America Factbook (Feb. 2019).

Trend: A Changing Energy Mix (Cont’d)

Growing Renewable Resources

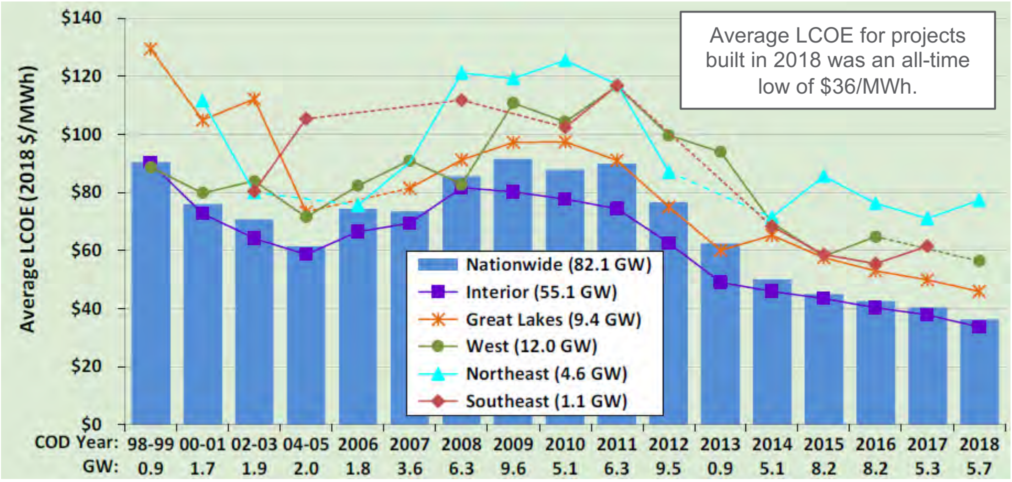
- **Utility-scale growing:** There are significant amounts of renewable resources—principally utility-scale wind and solar generation—expected to be built over the next several years and beyond. In addition to customer and policy preferences (discussed elsewhere), improving installed and levelized costs have made these resources more attractive.
- **Wind additions:** Cumulative wind capacity is more than 96 GWs in the United States. According to the Department of Energy (DOE), wind comprised 28% of all U.S. capacity additions over the last decade and an even larger fraction of new capacity in the Interior (56%) and Great Lakes (40%) regions. Its contribution to generation capacity growth over the last decade is somewhat smaller in the West (18%) and Northeast (13%) and considerably less in the Southeast (1%). A key uncertainty for wind power is whether the federal production tax credit is extended beyond its current final “under construction” year of 2019, as shown in the spike in expected additions in 2019–2020 (below left). As stated by the DOE, “expectations for continued low natural gas prices and modest growth in electricity demand also put a damper on [wind capacity] growth expectations, as do limited transmission infrastructure and competition from other resources (natural gas and—increasingly—solar, in particular) in certain regions of the country.”

Wind Power Capacity Additions: Historical Installations and Projected Growth



Source: DOE

Generation-Weighted Average Wind Levelized Cost of Energy (1998–2018): National and Regional



Source: DOE

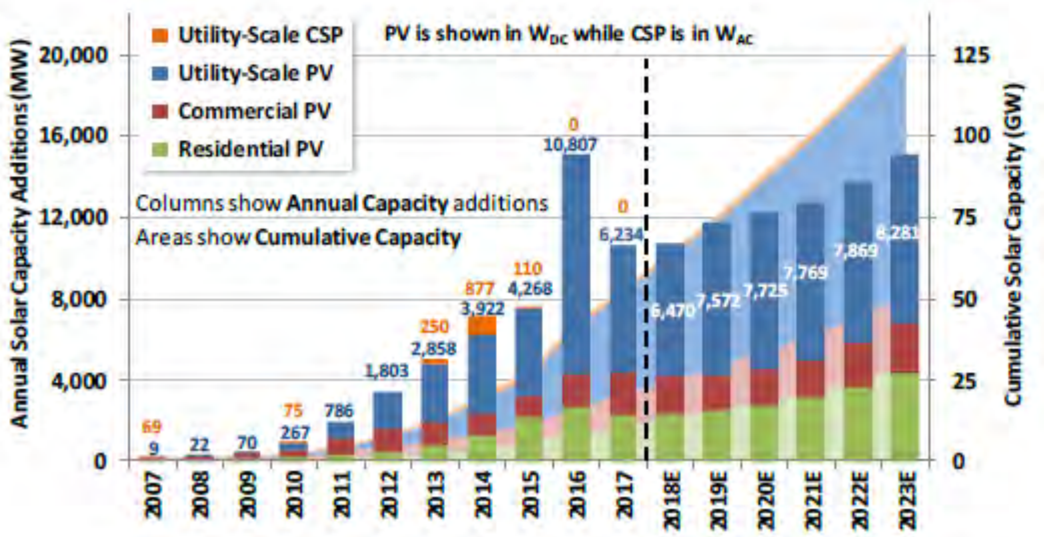
Source: DOE, 2018 Wind Technologies Report (Aug. 2019)

Trend: A Changing Energy Mix (Cont'd)

Growing Renewable Resources (Cont'd)

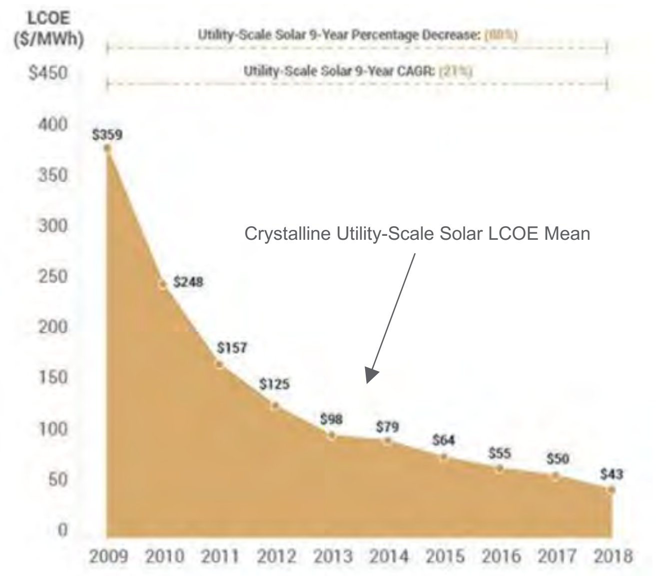
- **Solar's recent gains:** Solar has recently emerged as the second-largest increment of new generation capacity, behind gas and ahead of utility-scale wind. Wind capacity, however, totaled about 98 GWs in 2018, roughly equal to nuclear power in terms of carbon emissions-free generating capacity. As of year end 2018, installed solar capacity totaled 65 GWs, with utility-scale solar photovoltaic (PV) capacity comprising about 39 GWdc (about 33 GWac).
- **More solar coming:** According to Wood Mackenzie and the Solar Energy Industries Association, there is nearly 2.5 times the existing utility-scale PV capacity in the development pipeline, with nearly 38 GWdc contracted (8.6 GWdc of that under construction) and more than 56 GWdc announced.

Solar Capacity Additions:
Historical Installations and Projected Growth



Source: LBNL

Reduction in Solar Levelized Cost of Energy:
Down 88% Since 2009



Source: ACORE (citing Lazard)

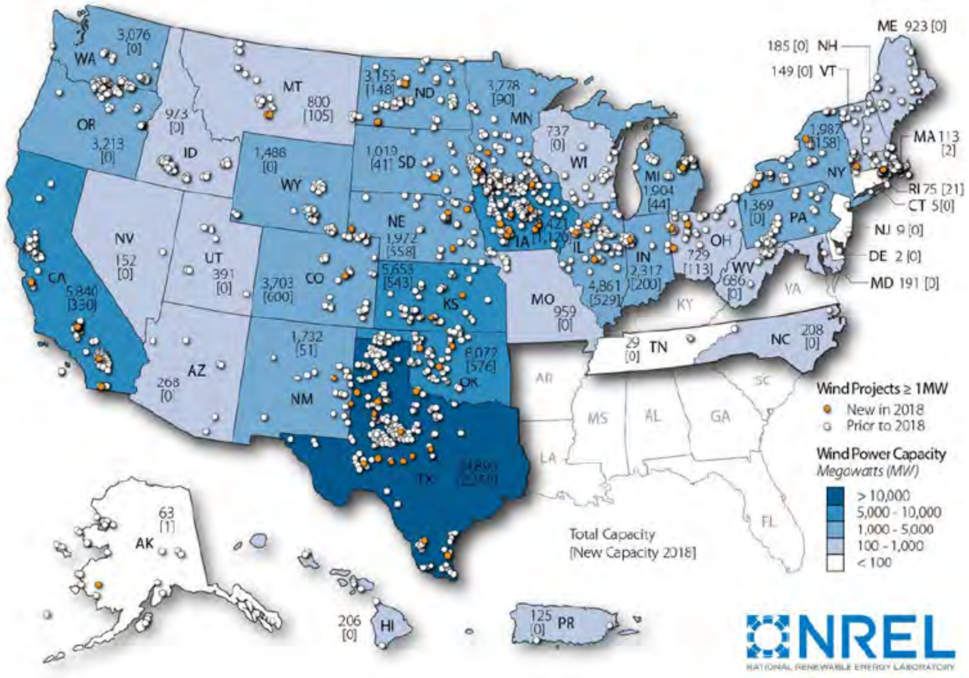
Sources: Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2019 Sustainable Energy in America Factbook (Feb. 2019); American Council on Renewable Energy, Renewable Energy: U.S. Trends and Drivers (Apr. 11, 2019); SEIA/Wood Mackenzie, Solar Market Insight Report 2019 Q3 (Sept. 2019); Lawrence Berkeley Nat'l Lab, Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States (Sept. 2018)

Trend: A Changing Energy Mix (Cont'd)

Location Matters

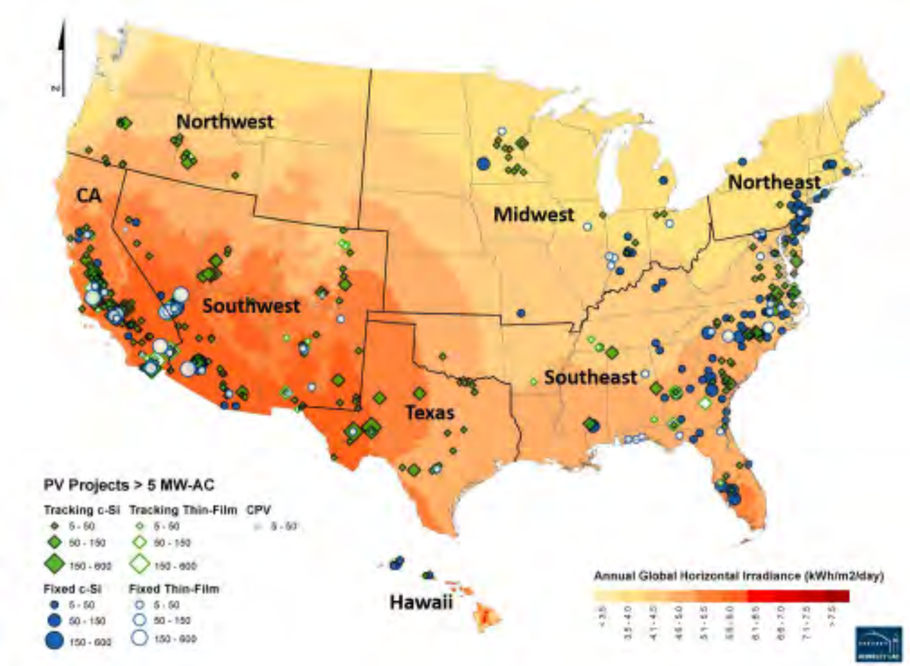
- **Resources dictate location:** Wind and solar potential is dependent upon the available resource potential. Thus, wind speeds and solar irradiance dictate, in large part, the location for development of these resources. In some cases, there is an overlap of the resources (e.g., the Texas Panhandle), but as the maps below show, recent development of these respective resources is concentrated in different regions.
- **Solar vs. wind:** Solar has been concentrated in California, the Southwest, Texas, and increasingly in the Southeast. Wind has historically been concentrated in the Plains, upper Midwest (including around the Great Lakes), and Texas, although increasing development is occurring in the Mountain West, New York, and New England.

Location Of Wind Power Development in the United States (2018)



Source: NREL

Global Horizontal Irradiance (GHI) and Utility-Scale PV Projects (2018)



Source: DOE

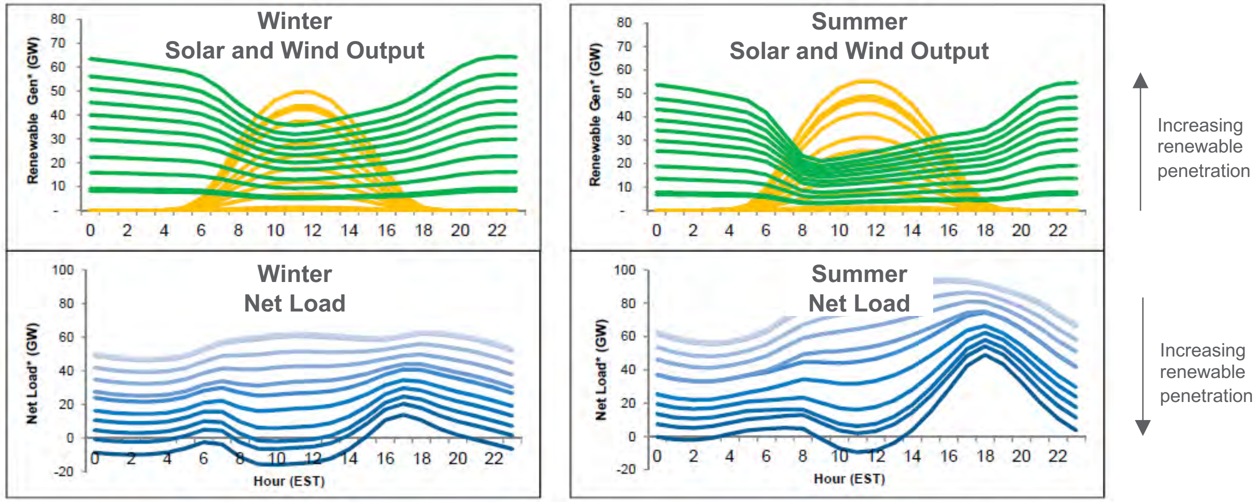
Source: DOE, 2018 Wind Technologies Report (Aug. 2019); Lawrence Berkeley Nat'l Lab, Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States (Sept. 2018); AWEA, U.S. Wind Industry Annual Market Report 2018 (Aug. 2019)

Trend: A Changing Energy Mix (Cont'd)

Different Operating Profile

- **New issues:** With the introduction of growing amounts of renewable resources, policymakers and grid operators and planners are interested in how those resources perform and what modification needs to be considered to system resources and incentives for both grid reliability and resilience.
- **Performance profiles:** For example, while solar is typically coincident with peak load, high levels of penetration can create a spike in net load (demand less solar and wind output), increasing the need for always available resources to meet late afternoon load (see below). There is some complementarity between solar and wind, since onshore wind is most productive from evening until morning and during winter, when there are fewer daylight hours. But late afternoon/early evening power needs during summer may require conventional thermal generation to be available.
- **Smoothing variability:** Some of the variability in these resources can be smoothed through geographic dispersion (diversifying cloud and wind patterns). Further, there are a growing number of solar installations paired with storage systems to help balance these shortfalls, but so far they constitute a small percentage of projects.
- **Intermittency:** Solar and wind resources, while providing low-marginal cost energy, are by nature intermittent. Onshore wind typically operates at a 38% to 55% capacity factor, while large-scale solar PV can range from 21% to 34%. Performance also depends upon the type of system (e.g., tracking solar) and region.

Illustrative Solar and Wind Output and Net Load at Growing Penetration Levels in the Midwest



Source: MISO

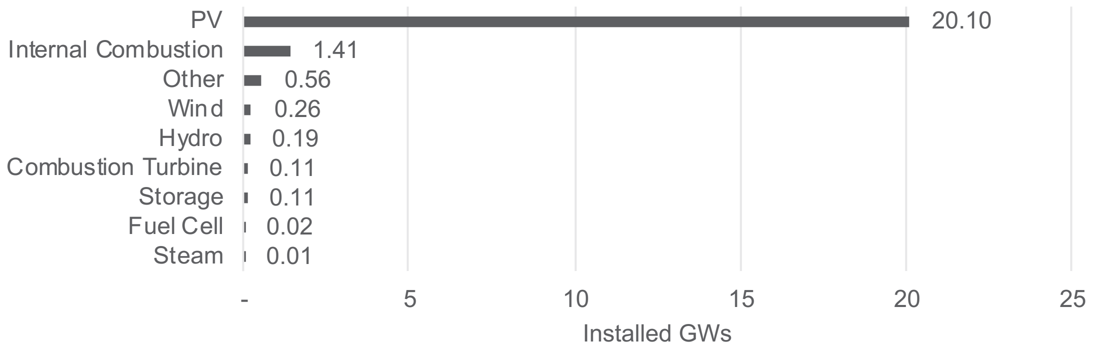
Sources: National Renewable Energy Laboratory, 2018 Wind Technologies Report (Aug. 2019); Lawrence Berkeley Nat'l Lab, Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States (Sept. 2018); Midcontinent ISO, Renewable Integration Impact Assessment, Presentation to Planning Advisory Committee (Apr. 18, 2018, updated June 18, 2018); Lazard, Lazard's Levelized Cost of Energy Analysis – Version 13.0 (Nov. 2019) (capacity factor assumptions).

Trend: DERs and Energy Storage

Growing DERs, Particularly Solar PV

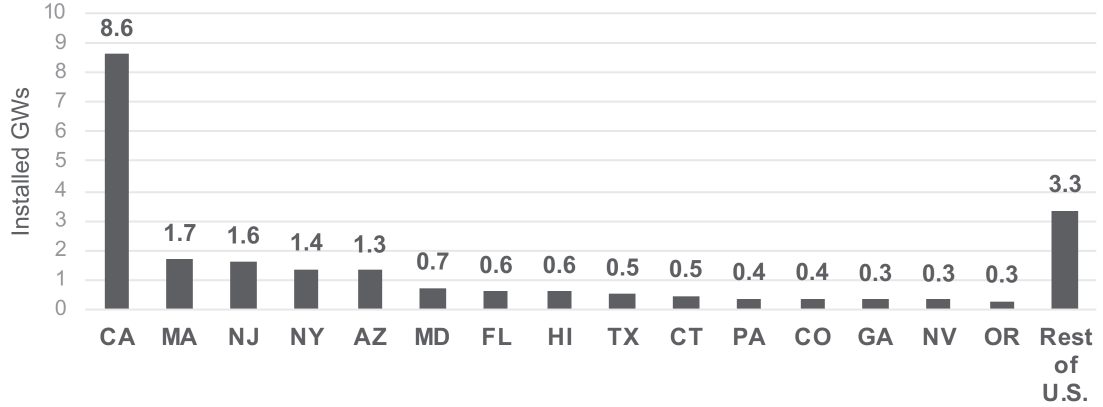
- **Declining installed costs:** As installed costs have declined, more distributed resources, particularly small-scale residential and commercial solar systems are being installed. Policies, such as net metering, mandates (such as California's mandate that new residential construction be equipped with rooftop solar), more aggressive RPS, and tax credits continue to encourage development of those systems. Development is also growing in areas with high-solar irradiance (e.g., Arizona, Florida, and Texas). However, distributed solar remains relatively costly compared with utility-scale resources, with unsubsidized levelized cost of energy (without subsidies) ranging from $73 to $267 per MWh, depending upon whether it is community solar, commercial, or residential installation.
- **Expected growth, albeit uneven:** DERs are expected to continue growing in selected regions. Wood Mackenzie projects growth ranging from 2% to 19% for residential rooftop solar systems because of resource fundamentals as well as policy developments. The federal investment tax credit step down for customer-owned systems in 2022 may briefly slow growth, but its effect is expected to be temporary.

Installed U.S. Distributed Generation by Type (2018) (GWs*)



Source: EIA

Installed U.S. Distributed Generation by State (GWs*) (Top 15 and Rest)



Source: EIA

Note: *Largely MW-ac, but includes some MW-dc.

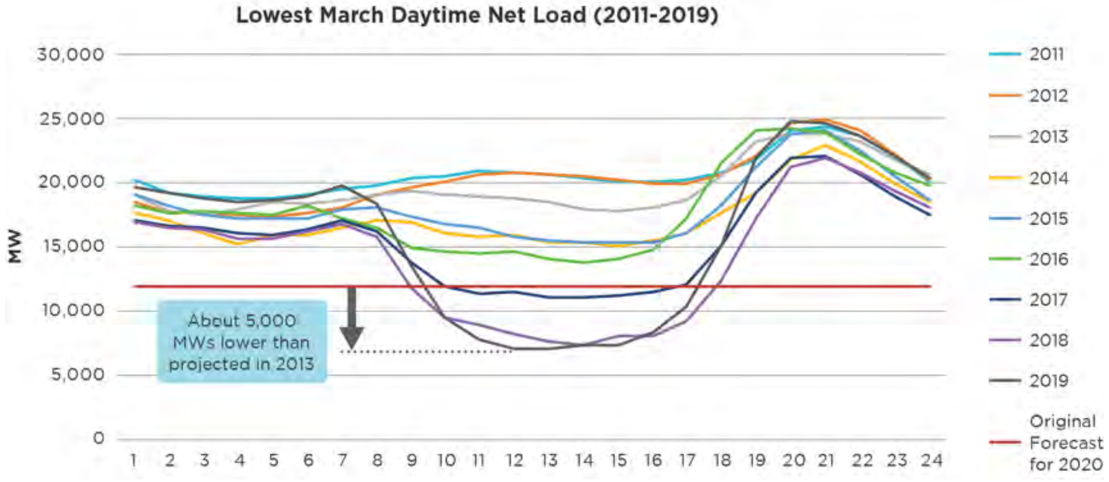
Sources: Lazard, Lazard's Levelized Cost of Energy Analysis – Ver. 12.0 (Nov. 2018); SEIA/Wood Mackenzie Power & Renewables, Executive Summary (Public Version), U.S. Solar Market Insight Report 2019 Q3 (Sept. 2019), available at https://www.seia.org/research-resources/solar-market-insight-report-2019-q3; EIA Form ; EIA, Electric Power Monthly (Sept. 2019); ScottMadden analysis

Trend: DERs and Energy Storage (Cont'd)

Growing DERs, Particularly Solar PV (Cont'd)

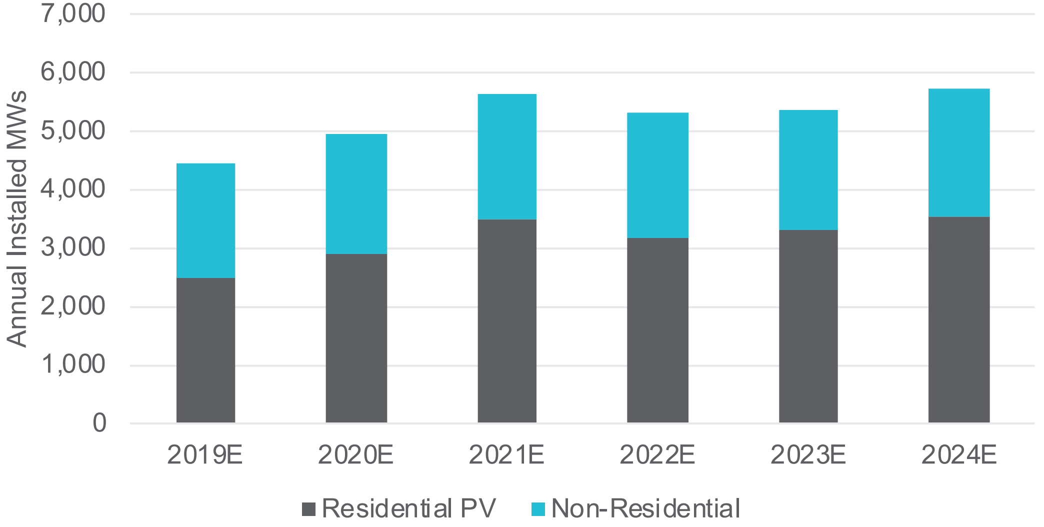
- **System impacts:** As DERs proliferate in some regions, large concentrations can affect the bulk power system in a number of ways. They can contribute to operational issues because of duck curve effects—lower net load conditions (load less solar and wind) followed by significant ramping needs in late afternoon during certain times of the year. In addition, DERs create variability in load (from self-supply) and potential backflows from the distribution system to the sub-transmission system, and they are not always visible to system operators. Transmission and distribution (T&D) system operators will have to manage increasing instances of control area energy imbalances and voltage fluctuations.
- **Megawatts in context:** With U.S. installed residential and commercial distributed solar totaling about 21 GWs, compared with installed utility-scale generation of nearly 1,100 GWs, DERs remain a small portion of total energy resources.

Duck Curve Effects from Utility-Scale Renewables and Lower Load (from Rooftop Solar Self-Supply)



Sources: CAISO; ScottMadden analysis

Projected U.S. Distributed Solar PV Installations by Year (Residential and Non-Residential) (MWs-dc)

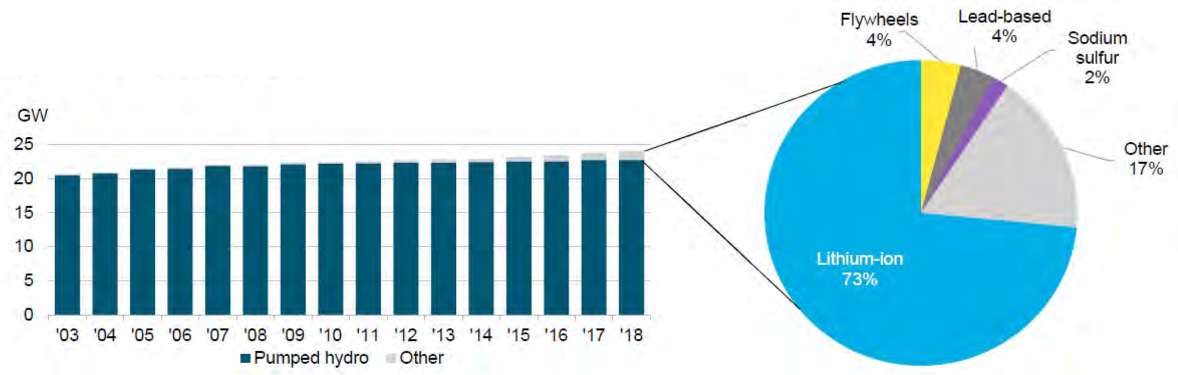


Source: SEIA/Wood Mackenzie

Sources: Lazard, Lazard's Levelized Cost of Energy Analysis – Ver. 12.0 (Nov. 2018); SEIA/Wood Mackenzie Power & Renewables, Executive Summary (Public Version), U.S. Solar Market Insight Report 2019 Q3 (Sept. 2019), available at https://www.seia.org/research-resources/solar-market-insight-report-2019-q3

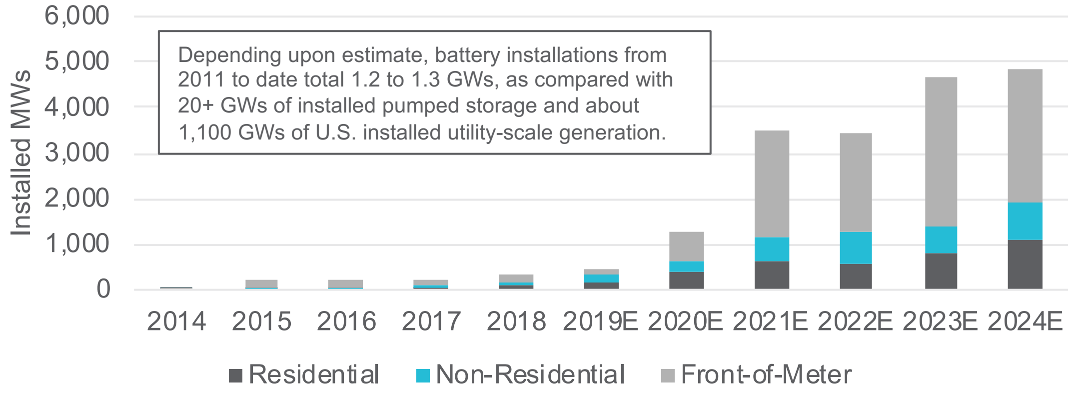
Trend: DERs and Energy Storage (Cont'd)

U.S. Storage Installations by Type



Source: BloombergNEF/BCSE

Actual and Projected Annual U.S. Battery Storage Installations by Year and Segment (MWs)



Source: Wood Mackenzie/Energy Storage Ass'n

Energy Storage Developments

- **Broad category:** Storage is a broad category of technologies that can store electric energy for later use. Pumped storage hydropower, a mature technology, accounts for 95% of installed storage capacity in the United States. Most new storage installations since 2011 have been lithium-ion (Li-ion) batteries. While typically not considered energy storage in policy discussions, reservoir hydropower has storage-like characteristics.
- **Drivers of storage:** Key drivers of energy storage include:
  - **Technology:** Advances in battery storage technology, in particular, battery chemistry, battery duration, and efficiency.
  - **Variable resource penetration:** Increasing penetration of renewable generation and DERs and the resultant need to integrate increasing numbers of variable resources into the grid.
  - **Declining cost:** Rapidly declining cost of energy storage systems, especially Li-ion driven by electric vehicle demand, is causing energy storage costs to fall sharply enhancing its cost competitiveness.
  - **State mandates and incentives:** For example, California (1,300 MWs by 2020), Massachusetts (200 MWhs by 2020), New York (3,000 MWs by 2030), and New Jersey (600 MWs by 2021; 2,000 MWs by 2030) have mandated storage procurement requirements.
  - **Federal policy:** FERC Order 841, issued in early 2018, is expected to encourage energy storage development. The rule mandates that organized power markets establish a participation model for electric storage resources, which consist of market rules that properly recognize the physical and operational characteristics of those resources.

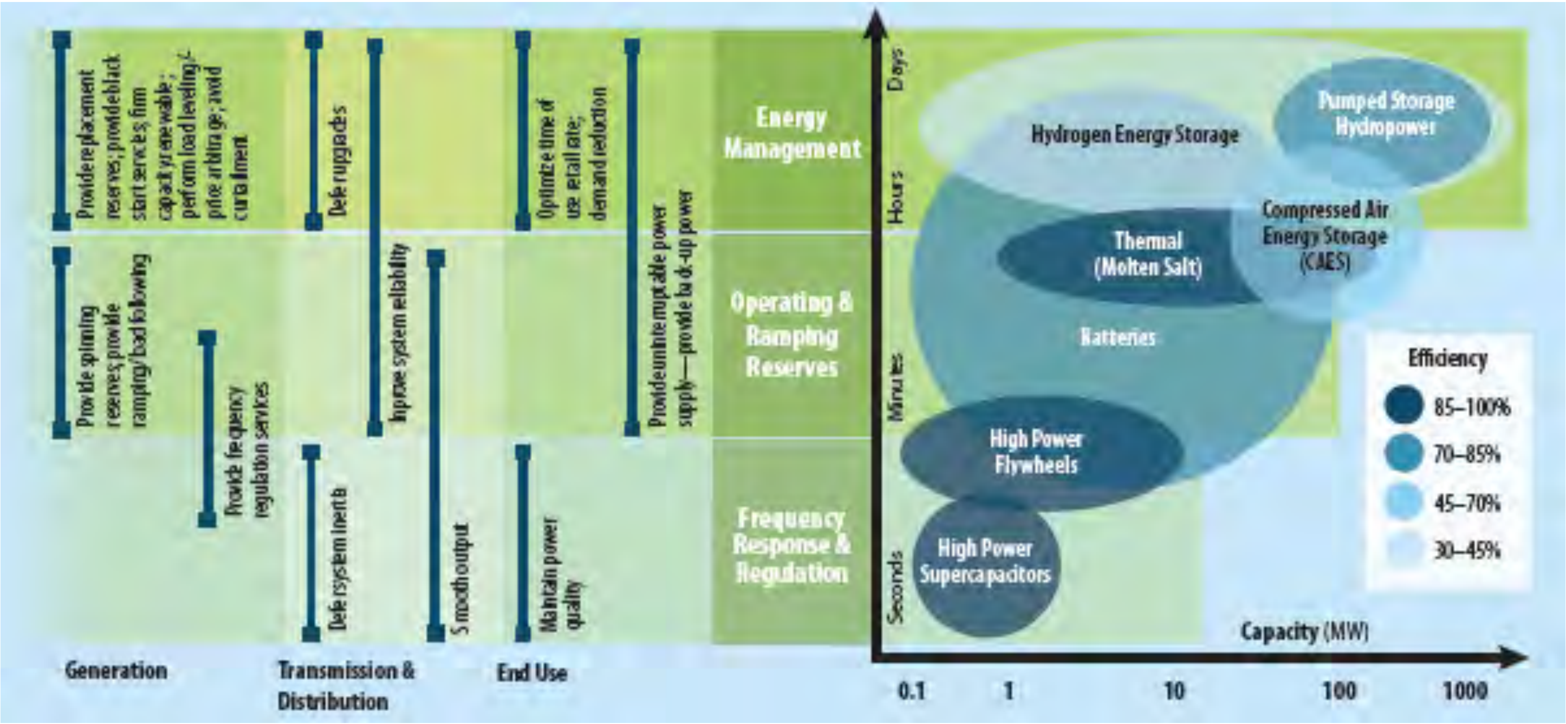
Sources: Wood Mackenzie Power & Renewables/Energy Storage Ass'n, Executive Summary (Public Version), U.S. Energy Storage Monitor Q3 2019 (Sept. 2019), available at https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor; Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2019 Sustainable Energy in America Factbook (Feb. 2019)

Trend: DERs and Energy Storage (Cont'd)

Energy Storage Developments (Cont'd)

- **Multiple services:** Energy storage can perform a variety of applications across the power system, whether as a customer resource, a grid resource, or as a bulk electric system resource, both behind- and front-of-the-meter. Depending upon its size and discharge duration, storage can be treated as a distributed resource or a bulk power (wholesale) resource. This enhances the value of storage, as it can perform multiple roles (e.g., peak reduction, ancillary services, capacity or T&D upgrade deferral) (see graphic below).

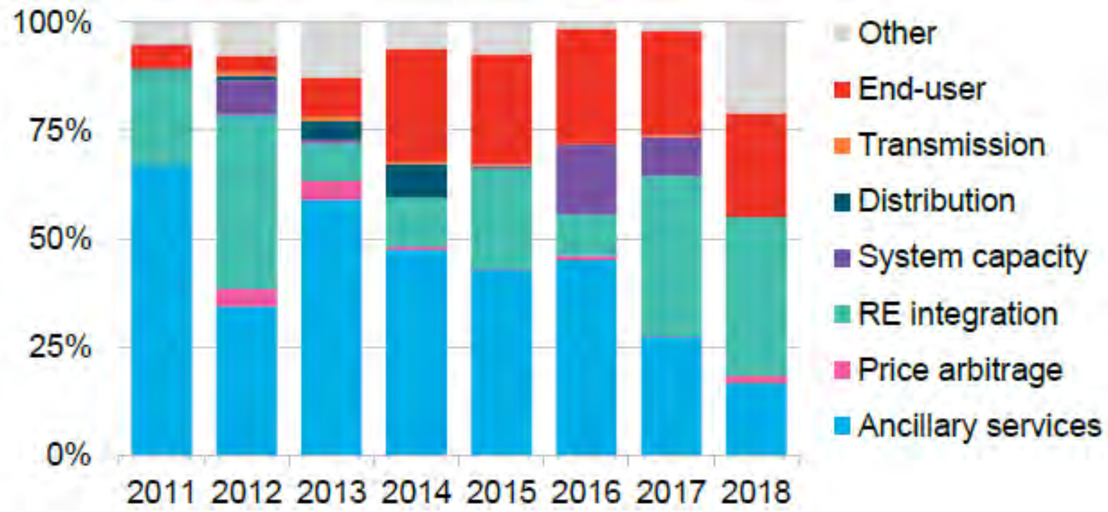
Storage Technology Characteristics and Potential Grid Applications



Sources: Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2019 Sustainable Energy in America Factbook (Feb. 2019); NREL, Energy Storage: Possibilities for Expanding Electric Grid Flexibility (Feb. 2016); AWEA, Grid Vision: The Electric Highway to a 21st Century Economy (May 2019)

Trend: DERs and Energy Storage (Cont’d)

U.S. Storage Applications (% of MWs)



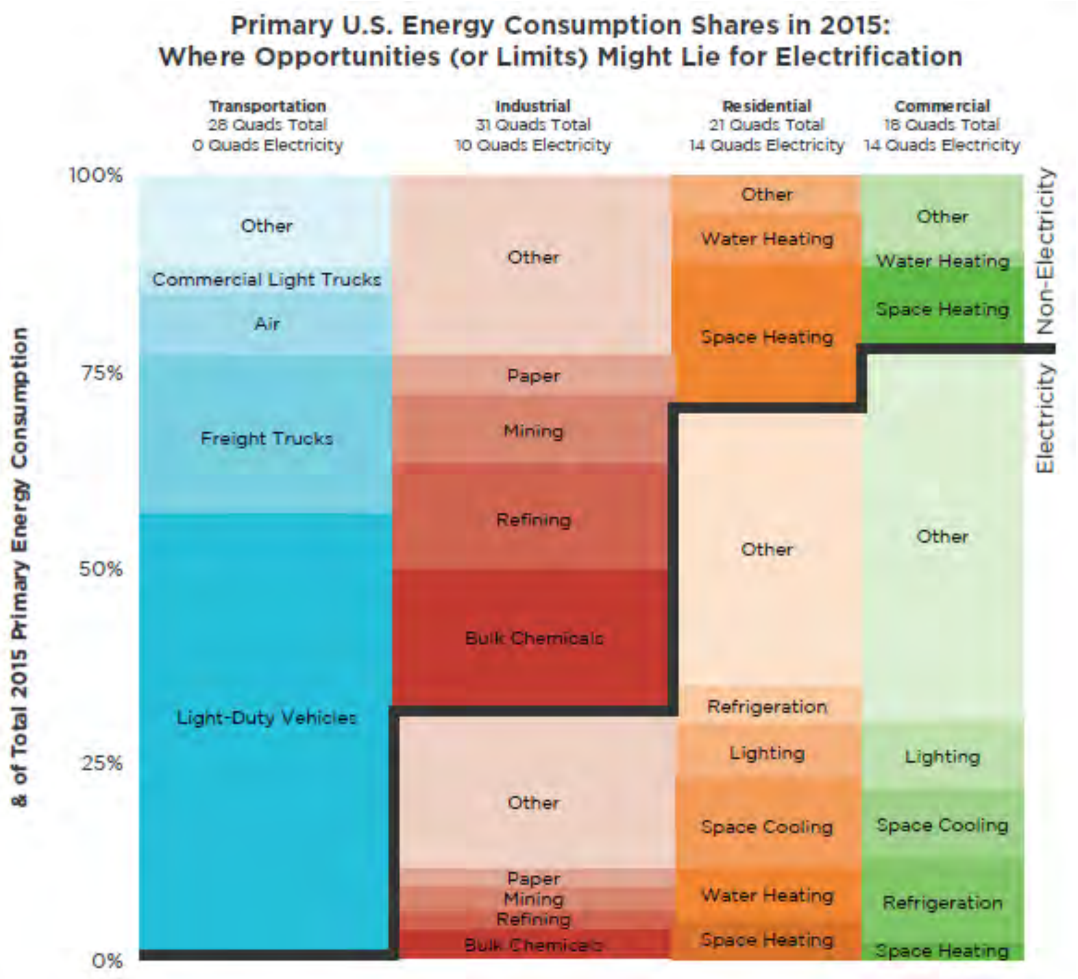
Energy Storage Developments (Cont’d)

- **Grid ally, with limits:** Storage can help provide frequency and voltage support from grid perturbations as well as from variability from renewable resources. It can also serve as a sink for excess variable resource output and support output for evening ramps. A growing amount of solar plus battery storage installations reflects this grid support function. This can also support microgrid and other grid isolation applications to increase resilience in the event of short-term events. But while batteries provide good short-term (up to four hours duration) output, they are not currently well-equipped to provide longer-term duration (i.e., eight hours plus) of output and which, at current cost and scaled to gigawatts, could be prohibitively expensive. Some observers contend that high penetrations of wind and solar resources in a low-carbon grid will require energy storage of greater duration than hours, perhaps monthly or seasonal.
- **While storage holds promise to add value across various parts of the power system, the benefits are typically focused locally. Pumped storage hydro, the largest installed storage resource, is dependent upon geography and geology, making it location-specific and dependent upon transmission. For large-scale, long-distance, high-efficiency movement of energy, current and foreseeable energy storage technology can complement, but not replace, power transmission’s capabilities.**

Sources: Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2019 Sustainable Energy in America Factbook (Feb. 2019); NREL, Energy Storage: Possibilities for Expanding Electric Grid Flexibility (Feb. 2016); AWEA, Grid Vision: The Electric Highway to a 21st Century Economy (May 2019)

Trend: Electrification

- **After flat load growth, electrification potential:** A combination of efficiency and structural changes in the economy (less energy intensity) has reduced electricity demand. However, environmental and climate change advocates, as well as some electric utilities, see environmental benefits from increased electrification (termed beneficial or efficient electrification), with a less carbon-intensive generation mix, as a key component for cost-effective reduction in global emissions.
- **Transportation is key:** Transportation is now the largest source of U.S. carbon emissions, and it has the highest and most immediate potential for electrification (especially light-duty vehicles), while electricity could continue to displace natural gas in the buildings sector, particularly for space and water heating.
- **Growth potential of about 1% per year:** In a national electrification assessment, the Electric Power Research Institute (EPRI) examined scenarios for increased electric use in current non-electric applications. It estimated 32% electricity growth between 2015 and 2050 (0.8%/year), and a higher 1.2%/year growth for a more aggressive electrification scenario (with a significant carbon price). The National Renewable Energy Laboratory (NREL) performed a similar analysis, finding increased use and a potentially higher load factor (see charts on next page).



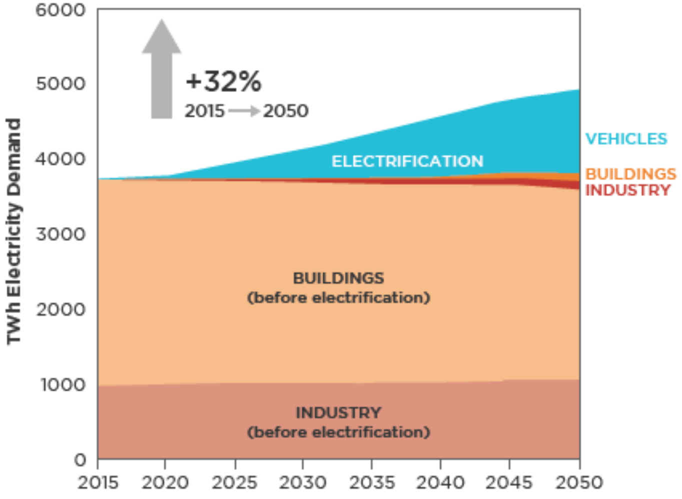
Source: NREL

Sources: Electric Power Research Institute, U.S. National Electrification Assessment (April 2018); National Renewable Energy Laboratory, Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States (July 2018); WIRES/The Brattle Group, The Coming Electrification of the North American Economy (Mar. 2019)

Trend: Electrification (Cont'd)

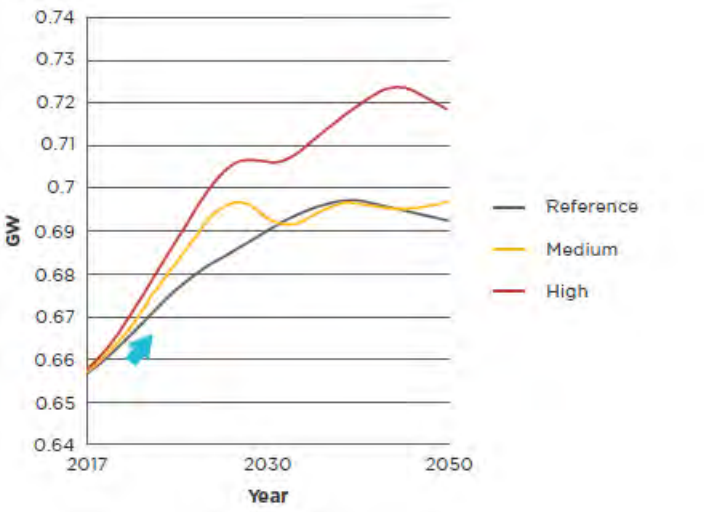
- **Cost challenges and key assumptions:** High upfront costs, low natural gas prices, incumbency technology advantages, and technological challenges may prevent the widespread electrification of some applications. For example, location matters for some "electrified" applications, such as heat pumps, which have historically not performed as well in very cold climates (although there have been some efficiency improvements) and often require a supplemental heat source. To achieve EPRI's scenarios, the share of electrification of transportation and building space-heating by 2050 is significant (40% and 50%, respectively). The required investment and policy incentives to achieve these levels of penetration are as yet undetermined.
- **Uncertainty and transmission impacts:** As noted by The Brattle Group, increased vehicle electrification could require reconfiguration or at least increased transmission capacity that would supply fast-charger facilities along highway corridors and in urban areas. Increased electrification of space-heating may increase winter-peak loads, a phenomenon being observed in the Southeast. To achieve emissions reductions, cost-effective renewable generation will likely have to be connected to load to meet at least a portion of incremental electrification demand.

EPRI Reference Electrification Scenario: Electricity Demand (TWh) by Sector



Source: EPRI

Load Factor Estimates for NREL Electrification Scenarios (Current and in 2050)

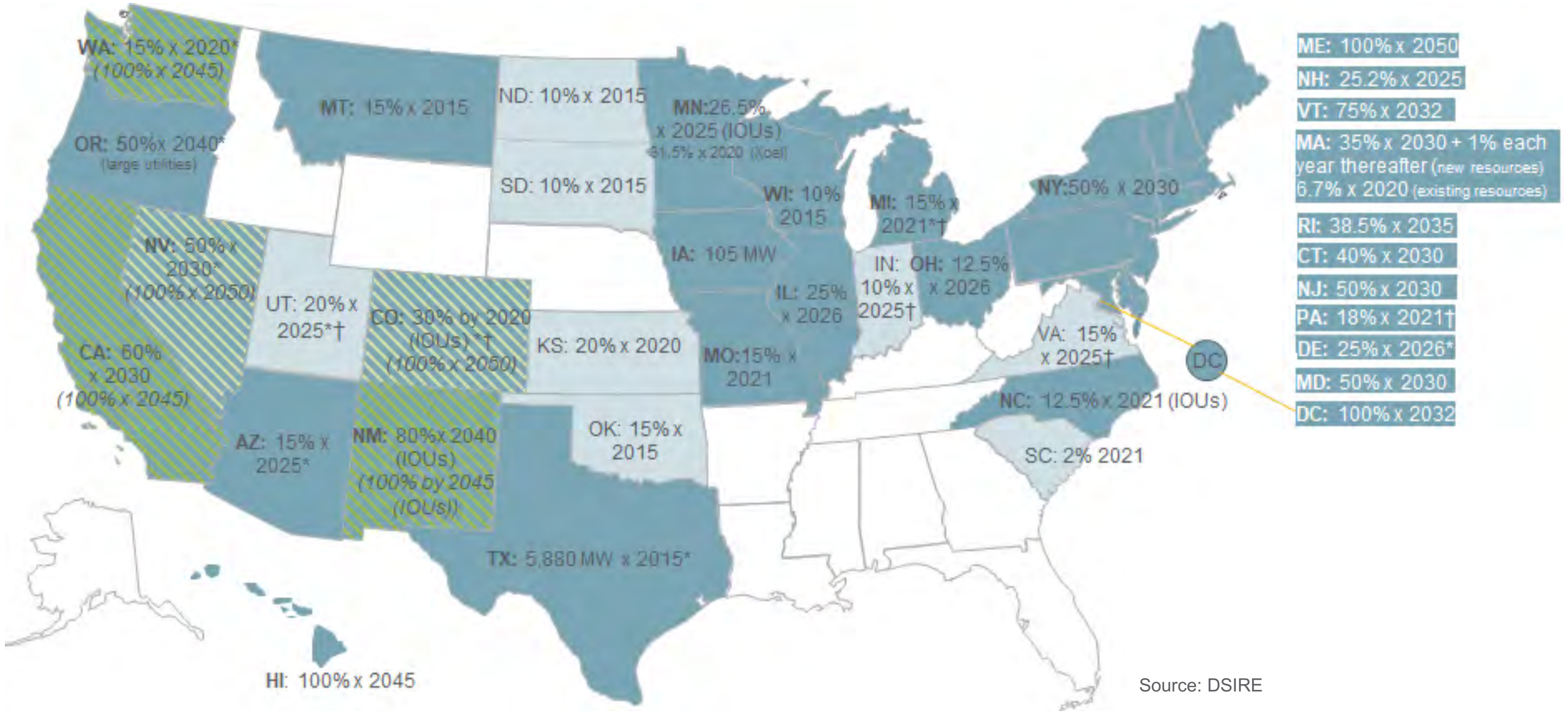


Source: NREL

Sources: Electric Power Research Institute, U.S. National Electrification Assessment (April 2018); National Renewable Energy Laboratory, Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States (July 2018); WIRES/The Brattle Group, The Coming Electrification of the North American Economy (Mar. 2019); American Gas Association, Implications of Policy-Driven Residential Electrification (July 2018)

Trend: Increasing Clean Energy Goals and Preferences

State Renewable and Clean Energy Goals (as of June 2019)



Source: DSIRE

Renewable portfolio standard	*Clean energy standard*	* Extra credit for solar or customer-sited renewables
Renewable portfolio goal	*Clean energy goal*	† Includes non-renewable alternative resources

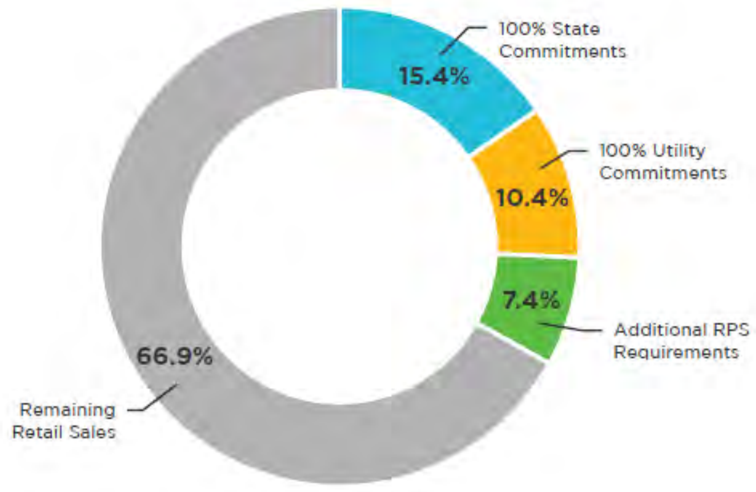
- **States ratchet up goals and standards:** Driven by citizen interest and customer preferences, states are increasing their renewable targets and/or establishing clean energy standards. Those targets are typically tied to retail sales, although some states express them as a percentage of generation. Twenty-nine states plus the District of Columbia have RPS, while three have clean energy standards.
- **Different approaches:** Clean energy standards are typically one of three types: (1) carbon-neutral (net-zero carbon), which doesn't require full decarbonization of the sector but allows for carbon-offsetting or capturing applications; (2) carbon-free, which can include both renewable and non-carbon-emitting technologies like nuclear power; and (3) renewables-only, which typically target a percentage of generation or load to be served with non-hydro renewables.
- **Longer-term goals:** Some states have set long-term aspirations for 100% clean or carbon-free energy by dates ranging from 2040 to 2050.
- **Declarations-only for some states:** A few states (e.g., Virginia and Colorado) have had pronouncements by their respective governors setting targets and charging regulators with advancing them, but the goals have not been codified in legislation.

Sources: S&P Global Market Intelligence, "US states face uneven paths in movement for 100% 'clean energy'" (Aug. 21, 2019); S&P Global Market Intelligence, "Renewables, distributed energy make a splash at regulators' summer meetings" (Aug. 5, 2019); Database of State Incentives for Renewables & Efficiency (DSIRE)

Trend: Increasing Clean Energy Goals and Preferences (Cont'd)

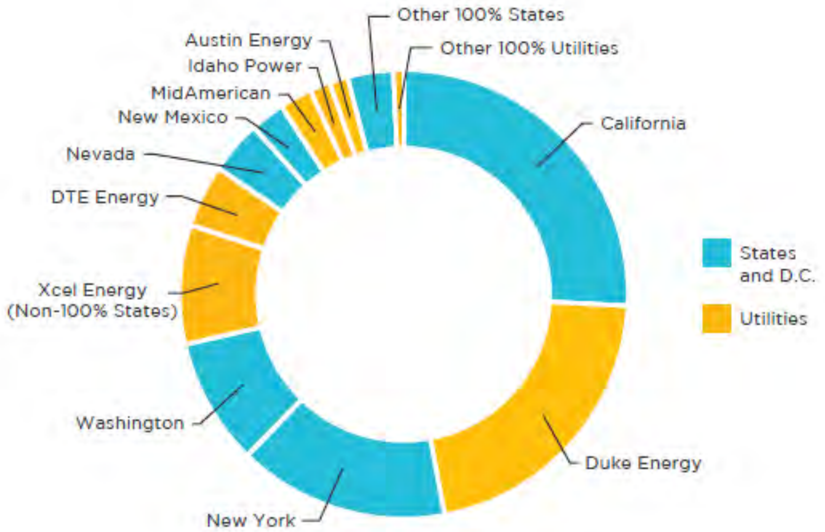
- **Utilities moving even without state action:** Some utilities have committed to clean energy goals, even in the absence of state mandates. Xcel Energy, Duke Energy, and DTE Energy are the largest utilities (in retail sales) to date that have committed to 100% clean energy or net-zero carbon emission by 2050, and others have made similar commitments (see charts below).
- **Corporate buyers remain active:** Even as states and utilities increase commitments to renewable and clean energy, large corporate purchasers are establishing targets for purchase of renewable energy. According to Bloomberg New Energy Finance (NEF), through 2018, 158 companies have pledged to source 100% of their energy consumption from renewables by signing onto the "RE100" initiative; 32% of these firms are domiciled in the United States. Further, renewable power purchase agreements between generators and corporate purchasers surged to 8.6 GWs in 2018; 2.5 GWs of that amount were contracted by Facebook (see next page).

100% Clean Energy Commitments and RPS Requirements (as Percentage of 2018 Retail Electricity Sales)



Sources: Industry news; EIA data; ScottMadden analysis

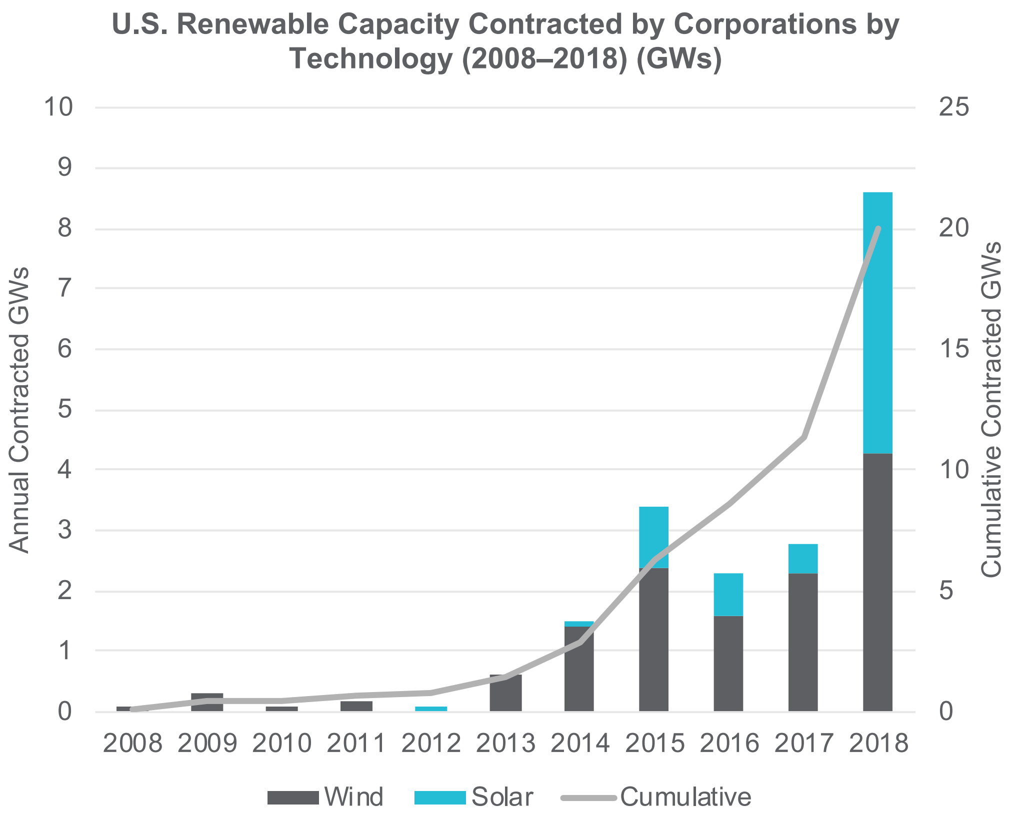
100% Clean Energy Commitments by State and Utility (Based on 2018 Retail Electricity Sales)



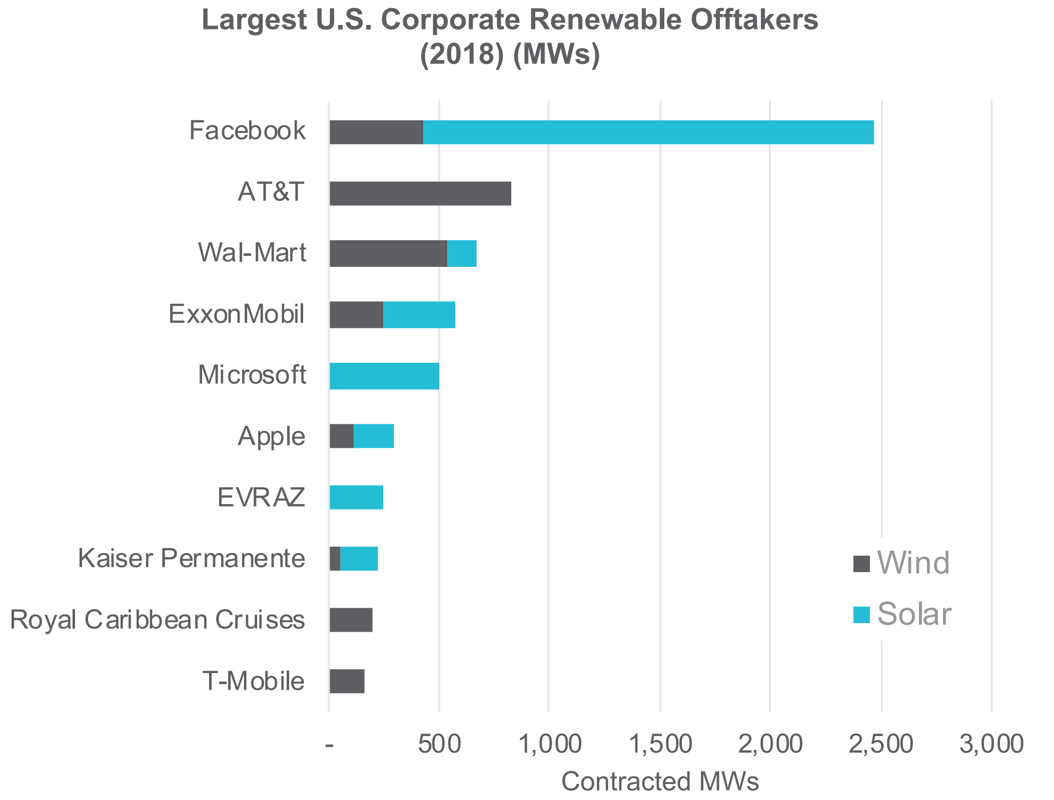
Note: Only the state commitment is counted if both the state and an electric utility have 100% clean energy commitments.
Sources: Industry news; EIA data; ScottMadden analysis

Sources: Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2019 Sustainable Energy in America Factbook (Feb. 2019); industry news; EIA data; ScottMadden analysis

Trend: Increasing Clean Energy Goals and Preferences (Cont'd)



Source: BloombergNEF



Source: BloombergNEF

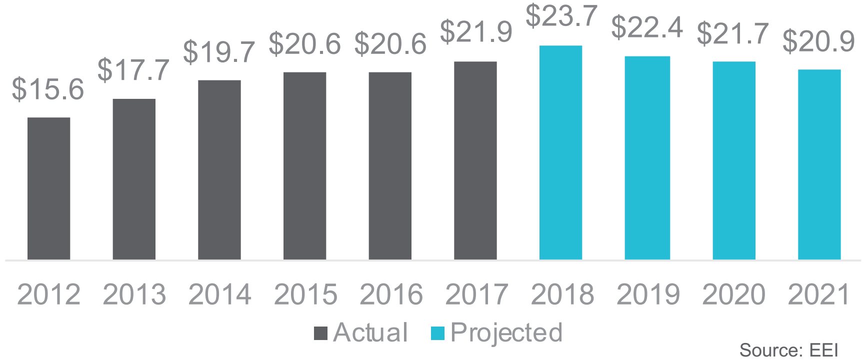
- With the anticipated demand for renewable and non-emitting generation created by these standards and goals, there is widespread expectation of continued renewable generation development and the capability to deliver clean power to jurisdictions that mandate it.

Sources: Bloomberg New Energy Finance/Business Council for Sustainable Energy, 2019 Sustainable Energy in America Factbook (Feb. 2019); industry news; EIA data; ScottMadden analysis

Considering Transmission – Why It Matters

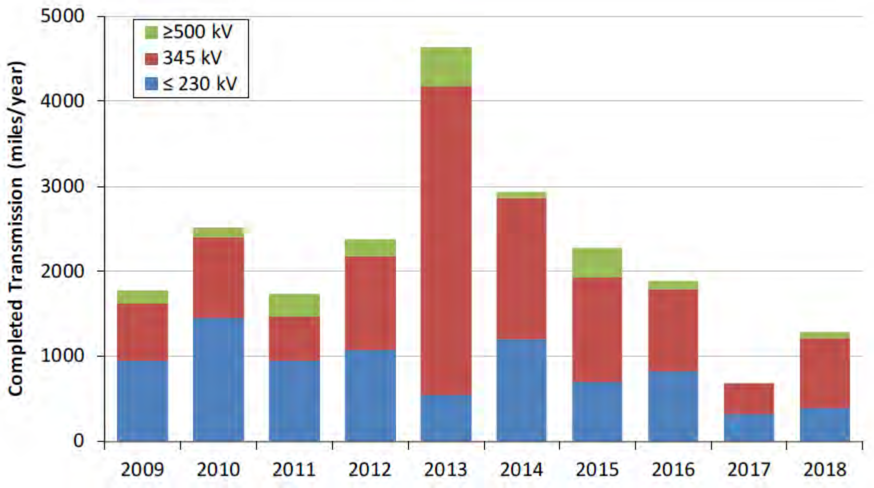
- Transmission investment has continued apace in recent years (see top right). However, only about 1,300 miles of transmission was completed in 2018 versus a recent peak in 2013 (see bottom right). That peak was largely due to the completion of Texas' Competitive Renewable Energy Zones, which established a "build it and they will come" approach to transmission development to accommodate renewable integration.
- Based upon the foregoing, there are some significant potential impacts of these trends on our nation's transmission system, which warrant revisiting the need for transmission investment. Those impacts are described further below:
  - **Transmission expansion and changing energy mix:** With the anticipated growth in renewable resources, power flows will be more intermittent and time-varying. While gas-fired capacity and storage can help mitigate some variability, transmission can provide flexibility to balance the system with diverse resources, provide long-distance, efficient backbone to move renewable resources, and provide congestion relief to better utilize zero-marginal cost resources.
  - **DERs and energy storage introduce benefits and some complexity:** The introduction of DERs can provide the ability to serve, or reduce, load in a dispersed manner. This can provide some resilience benefits during extreme weather events when distribution facilities are temporarily compromised.
    - **Demand-side variability:** However, these resources introduce demand-side variability and can tax the transmission system with potential backflow issues. Massachusetts is already examining these issues, requiring transmission planners to look at system impacts and the potential need for upgrades.

Historical & Projected Transmission Investment* ($ Billions) (as of Oct. 2018)



Source: EEI

Miles of Transmission Projects Completed by Year and Voltage



Source: DOE; FERC

Note: *By investor-owned electric companies and stand-alone transmission companies
Sources: DOE; FERC; Edison Electric Institute (EEI), at www.eei.org/issuesandpolicy/transmission/Pages/default.aspx

Considering Transmission – Why It Matters (Cont'd)

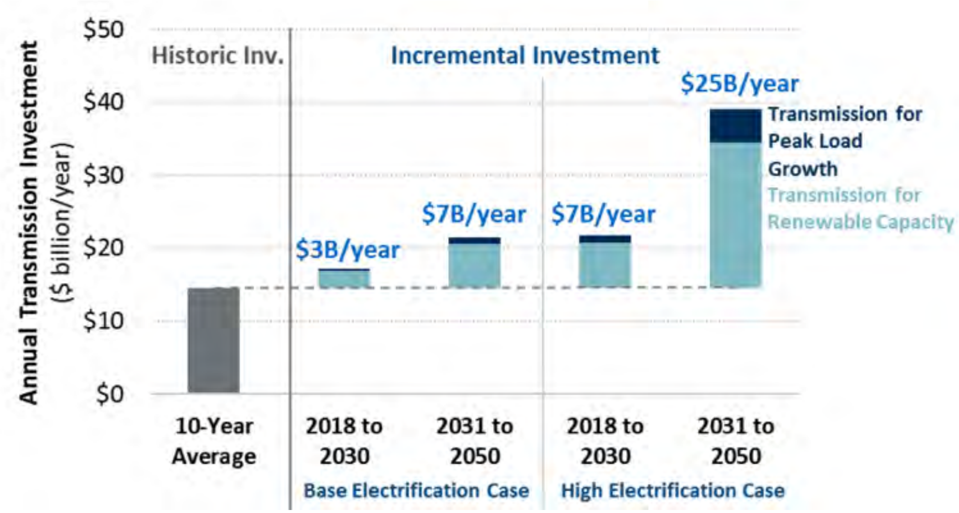
- **DERs and energy storage introduce benefits and some complexity (cont'd)**
  - **Storage pros and cons:** Energy storage can be a partner with transmission in supporting the grid with ramping capability, ancillary services, and absorbing excess low or negative cost energy during off-peak hours. In some regions, these facilities are being teamed with variable resources (both solar and wind) to provide some temporal smoothing of energy output as intra-day solar generation increases and declines and to moderate temporary reductions in wind output when wind abates. But even the best battery storage is limited in duration, from four hours to eight hours, and longer durations will require a significant scaling of storage capacity. And scaling that capacity will require a level of investment that is not yet contemplated in development forecasts.
  - **Reservoir hydropower:** As mentioned earlier, reservoir hydropower has storage-like characteristics and is abundant in Canada, adjacent to U.S. markets. Canada has 81 GWs of installed hydro (including pumped storage) (over 40 GWs in Quebec alone) and the technical potential for development of an additional 155 GWs.
  - **Transmission's role:** Transmission capacity can provide flexibility to move, at an aggregated level, avoided energy and to optimize cost of energy for all customers, providing option value in moving resources where needed factoring in congestion, grid needs, economics, and customer preferences. It can also provide broader market access for storage resources, including reservoir hydropower as noted above. In addition, investment in increased visibility into DERs and flexibility and control systems to accommodate non-traditional, more granular resources, such as storage, may be needed as these resources continue to come online. However, a one-size-fits-all approach will be ill-suited to considering transmission, as policies and resource potential (e.g., solar irradiance) varies among regions and states.
- **Electrification-driven demand may change locational needs of grid:** It is unclear whether efforts to electrify the grid will result in substantial growth in demand. But the potential for conversion of primarily transportation and building electrification and the possible impacts on demand—and hence incremental deliverability of new resources—must be considered, given the roughly 10 or more years timeline for development of U.S. transmission projects.
  - **Impacts of electrification:** A recent study by The Brattle Group and WIRES noted that electrification may have two impacts: higher secular demand for electricity and increased need to access renewable energy supply—wherever it has the greatest technical and economic potential—to provide marginal energy resources that have the "beneficial" clean characteristics either demanded by customers or reducing "social costs" in the form of lower emissions.
  - **Vehicle electrification as key driver:** Studies of electrification potential, notably including EPRI's latest national electrification assessment, project the greatest impact on demand from electrification as deriving from transportation electrification. Why does this matter? Widespread vehicle electrification is forecast to require significant build-out of charging infrastructure, both in municipalities as well as along major highways and thoroughfares. The WIRES/Brattle report noted above pointed to the potential need for DC fast-charging infrastructure in urban environments as well as along highways, which could drive demand for transmission assets in new locations.

Sources: WaterPower Canada, at https://waterpowercanada.ca/learn/; Hydro-Quebec, Decarbonizing the Northeast (Jul. 26, 2018); WIRES/The Brattle Group, The Coming Electrification of the North American Economy (Mar. 2019)

Considering Transmission – Why It Matters (Cont'd)

- **Electrification-driven demand may change locational needs of grid (cont'd)**
  - **Transmission potential:** EPRI estimates that electrification could drive 1%+ annual growth in electric demand growth. Brattle estimates a potential for near-term (through 2030) demand growth of 5% to 15% per year and a potential need for $30 to $90 billion in incremental transmission investment over the same period. That investment is principally to connect renewable resources to serve total energy demand and to ensure system reliability with increasing peak demands (see graph at right). Without ascertaining specific needs, beneficial electrification will entail linking renewable supplies with changing demand locations (e.g., highways) and patterns.
- **Clean energy targets will drive the continued need to bring non-emitting resources to market:** Over the intermediate to long term, demand for renewable resources to meet ambitious clean energy and net-zero carbon emissions targets will encourage continued development of renewables, but particularly utility-scale wind and solar resources.
  - But this development is taking place in patchwork form, differing by region and even adjacent states. For some states, the pace of development may be at a speed not heretofore contemplated.
  - Transmission investment will be required to help states and utilities with clean power targets meet their energy needs with the most cost-effective and abundant resources. The United Nations Intergovernmental Panel on Climate Change (IPCC) recently acknowledged that significant electricity transmission investment will be needed globally as part of a mitigation pathway targeting a limit of global warming of 1.5°C above pre-industrial levels.
  - Frictions may occur, however, as the lack of policy alignment among states sharing a market area or region can create conflict over who should pay for transmission investment, despite potential overall market benefits including added resilience.

Annual Incremental Transmission Investment Due to Electrification*



Source: The Brattle Group/WIRES

Note: *The historical average reflects transmission investments from 2006 to 2016 based on transmission capital expenditures reported on FERC Form 1.

Sources: The Brattle Group/WIRES, The Coming Electrification of the North American Economy (Mar. 2019); U.N. IPCC, Global Warming of 1.5°C: An IPCC Special Report (2018)

Considering Transmission – Why It Matters (Cont'd)

Key Points

- Clean energy goals are getting more common and ambitious, with potential transmission investment needs for the integration of new renewable resources.
- With the growth in decentralization of resources, visibility and control at the transmission level will be critical and investment in technology to facilitating grid reliability and efficiency.
- A key unknown is the potential for load growth through beneficial electrification. With significant electric vehicle adoption, space-heating conversion, and other potential electrification pathways, grid investment (including transmission) will be needed to accommodate new demand characteristics.
- However, renewable integration and resilience issues can be regional in nature, as each has its own blend of existing generation and transmission assets, load profiles, renewable resource potential, electrification potential, and risks from widespread resilience events. Due deference should be given to those regional differences, but broader interregional and societal goals should be considered as well.

Regional Discussion

ISO NEW ENGLAND

Contents

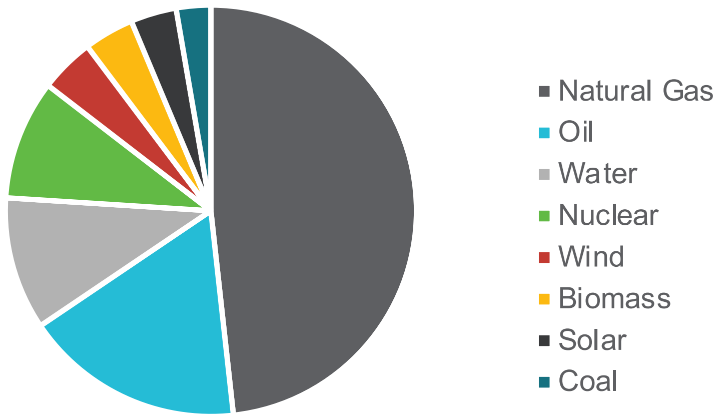
Overview

Introduction

- ISO New England Inc. (ISO-NE) is the regional transmission organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, created in 1997.
- The New England regional electric power system is comprised of 9,000 miles of transmission lines over 68,000 square miles and serves approximately 14.5 million people.
- ISO-NE reports that roughly 7,000 MWs of generation have retired since 2013 or will retire in the next few years, with another 5,000 MWs from coal- and oil-fired plants at risk of retirement in the coming years, although it does not expect reliability impacts from retirements.

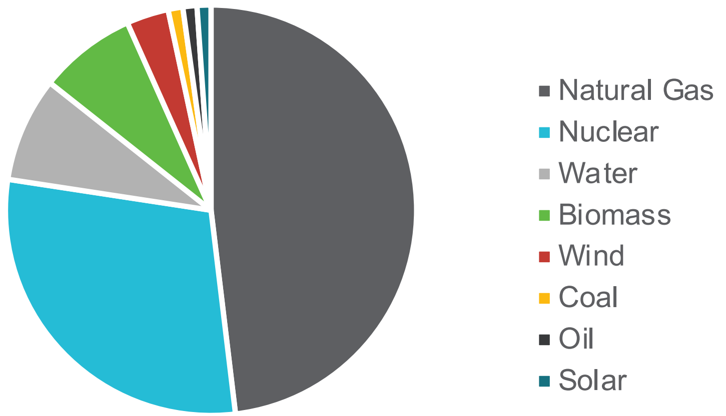
Key Regional Statistics	
States Covered	CT, MA, ME, NH, RI, VT
Square Mi. Covered	~68,000
No. of Utilities	13 investor-owned utilities; 47 munis; 4 generation and transmission co-ops
No. of Customers/Pop. Served	14.5MM population
Installed Capacity	30,916 MWs
Transmission Line Miles	~9,000 miles
Peak Hour Demand (2018)†	23,868 MWs summer (20,599 MWs winter)
Energy Production (2018)	103,702 GWhs
Forecast Growth (Annual)	-0.41% peak load growth† -0.40% energy growth

2019 Summer Capacity by Fuel Type



Source: ISO-NE

2018 Net Energy by Fuel Type



Source: ISO-NE

Sources: NERC 2018 LTRA; 2019 Regional Electricity Outlook; ISO-NE Stats
Notes: † Non-coincident.

Overview (Cont'd)

Key Study Areas for Planning and Issue Resolution

- For ISO studies of the New England transmission system, the region is subdivided into key study areas for practical work management reasons or for focus on a particular technical issue. The ISO regularly conducts needs assessments and other assessments in these key study areas pursuant to the Open Access Transmission Tariff (Section II of the ISO Tariff). The assessments and studies involve stakeholder review and input, primarily by the Planning Advisory Committee, and form the foundation for the Regional System Plan.

Key Study Areas

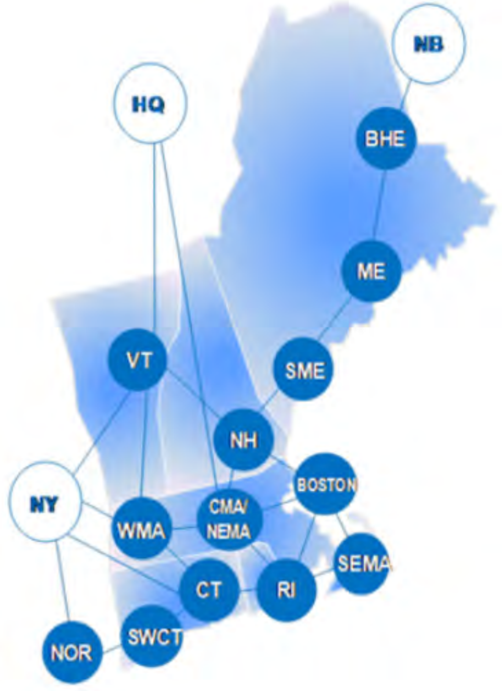
Source: ISO New England

System Planning Subareas

- The ISO has 13 planning subareas, which are depicted at right along with the three neighboring power systems.
- ISO-NE System Planning Areas:

Subarea	Region or State
BHE	Northeastern Maine
ME	Western and central Maine/Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern, and central New Hampshire/eastern Vermont and SW Maine
VT	Vermont/southwestern New Hampshire
Boston	Greater Boston, including the North Shore
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts
WMA	Western Massachusetts
SEMA	Southeastern Massachusetts/Newport, Rhode Island
RI	Rhode Island/bordering MA
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk/Stamford, Connecticut
NB, NY, and HQ	New Brunswick (Maritimes), New York, and Hydro-Québec external Reliability Coordinator areas

System Planning Subareas



Source: ISO New England

Source: ISO-NE (https://www.iso-ne.com/about/key-stats/maps-and-diagrams/)

Overview (Cont'd)

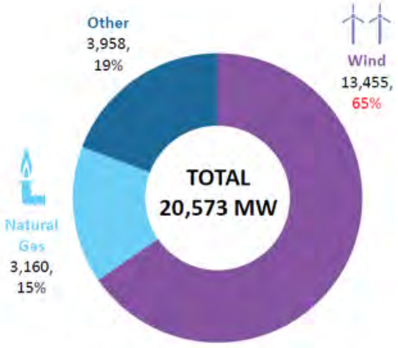
Evolving Resource Mix

- The generation fleet in ISO-NE is shifting from resources with on-site fuel (coal, oil, and nuclear) toward:
  - Resources with just-in-time fuel delivery (natural gas)
  - Weather dependent resources (wind, solar)
  - Distributed resources at homes and businesses (distributed solar PV)
- Retirements: More than 5,200 MWs of generation have retired or announced plans for retirement in coming years, and another 5,000 MWs of remaining coal and oil are at risk of retirement.
- Proposed additions: With 13,455 MWs in the interconnection queue, wind makes up the majority (65%) of total proposed additions. With 3,160 MWs, natural gas generation represents 15% of the queue, and the remaining 3,958 MWs is comprised of a mix of other fuels.

Peak Demand vs. Annual Energy Use

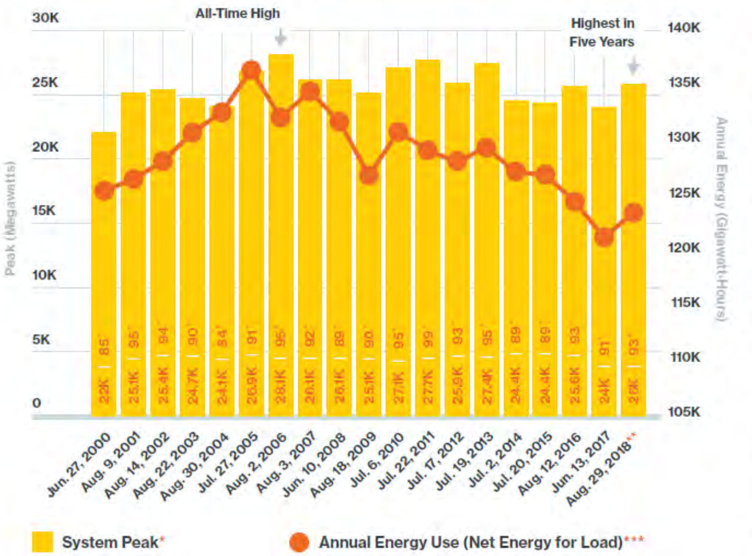
- Despite overall declines in grid energy use on an annual basis, spikes in electricity demand still occur, and ISO-NE's power system is planned and operated to meet those peaks even if they aren't historically high.
- Despite forecasts of declining load, ISO-NE must procure resources (i.e., generation, demand resources, and import capacity) to provide the capacity needed to meet the regional net installed capacity requirement (ICR), which is based on gross load and behind-the-meter PV load reductions. The representative net ICR is expected to grow from 34,300 MWs in 2022 to 35,700 MWs in 2026.

Proposed Generation in ISO-NE



Source: ISO Generator Interconnection Queue (January 2019)
FERC and Non-FERC Jurisdictional Proposals; Nameplate Capacity Ratings
Note: Some natural gas proposals include battery storage and dual-fuel units (oil). Some wind proposals include battery storage.

Peak Demand vs. Annual Energy Use on New England Power System



*The sum of metered generation and metered net interchange, minus demand from pumped storage units. Starting with full market integration of demand response on June 1, 2018, this total also includes the grossed up demand-response value.

**Annual peak, as of January 2019. Values are preliminary and subject to adjustment.

***Net energy for load (NEL) is the total amount of grid electricity produced by generators in New England and imported from other regions during the year to satisfy all residential, commercial, and industrial customer demand.

Source: ISO New England, *Seasonal Peaks since 1980 Report, Hourly Real-Time System Demand Report,* and *Annual Generation and Load Data for ISO NE and the Six New England States Report.*

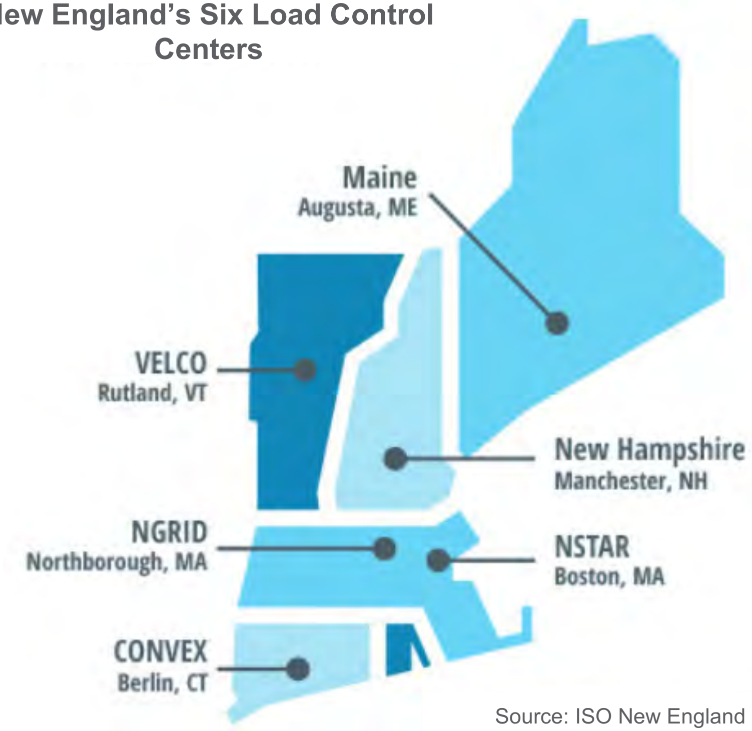
Source: ISO-NE

Transmission Topography and Investment

Local Control Centers (LCCs)

- From its master control center (MCC), ISO-NE is responsible for operating all transmission facilities rated 115 kV and above. New England also has six LCCs, which are run by transmission owners and are responsible for operating transmission facilities rated 69 kV and below, with certain exceptions.

New England's Six Load Control Centers

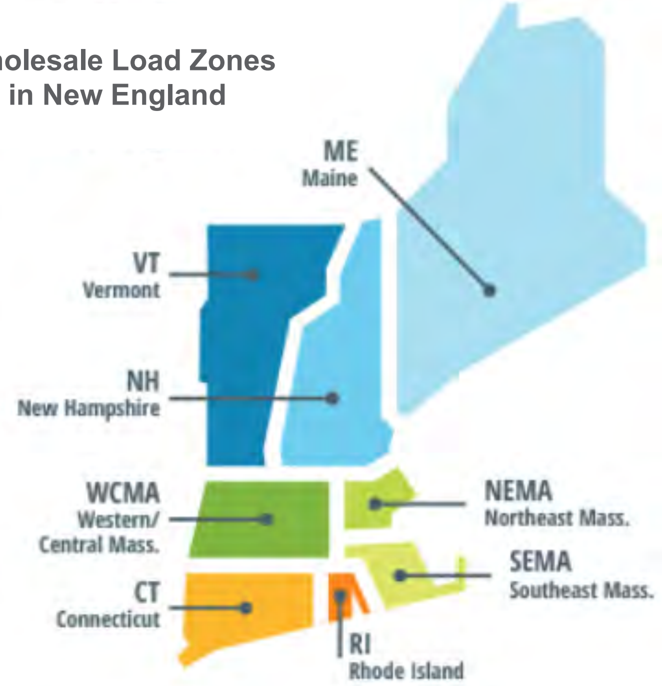


Source: ISO New England

Load Zones

- Pricing in the wholesale electricity marketplace is calculated at individual generating units, about 900 load nodes (specific points on the transmission system), eight load zones (aggregations of load nodes), and the Hub (a collection of locations in central New England where little congestion is evident). This map depicts the eight load zones.

Wholesale Load Zones in New England



Source: ISO New England

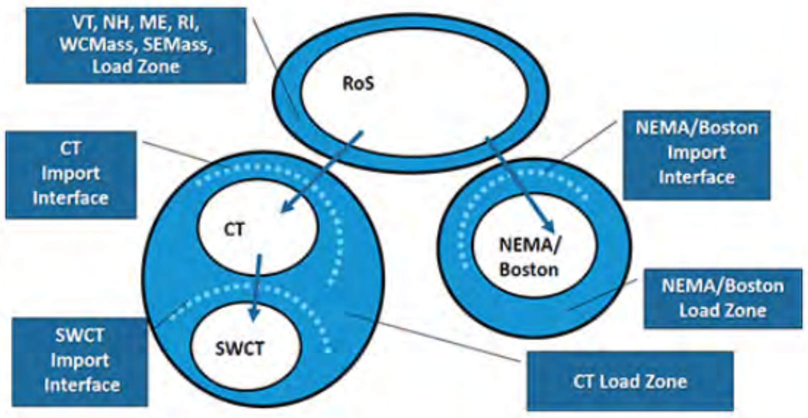
Source: ISO-NE (https://www.iso-ne.com/about/key-stats/maps-and-diagrams/)

Transmission Topography and Investment (Cont'd)

Reserve Zones

- The Forward Reserve Market procures reserve capacity for the region, which is divided into four reserve zones:
  - Greater Connecticut
  - Greater Southwest Connecticut (SWCT)
  - Northeast Massachusetts and Boston area (NEMA/Boston)
  - Rest of the system (Rest-of-System, ROS), which excludes the other, local reserve zones
- This diagram below illustrates the relationship between the reserve zones, load zones, and interfaces.

Reserve Zones and Load Zones

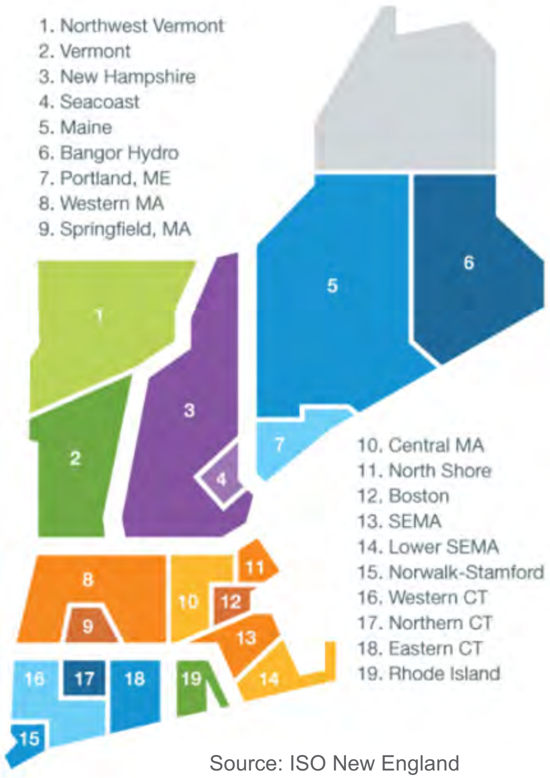


Source: ISO New England

Dispatch Zones

- The region is divided into 19 dispatch zones for the purpose of administering active demand resources. The zones, which are groups of pricing nodes, allow for a more granular aggregation of active demand resources at the locations and quantities needed to address potential system problems.

New England Dispatch Zones



Source: ISO New England

Source: ISO-NE (https://www.iso-ne.com/about/key-stats/maps-and-diagrams/)

Transmission Topography and Investment (Cont'd)

Ties to Neighboring Electric Power Grids

- ISO- NE has 13 total interconnections to three different neighboring systems:
  - New York (ties 1–9), which ties New England to the Eastern Interconnection
  - Hydro Québec (ties 10–11), which ties New England to the Québec Interconnection through direct-current (DC) transmission
  - New Brunswick (ties 12–13), which is tied to the Eastern Interconnection through New England

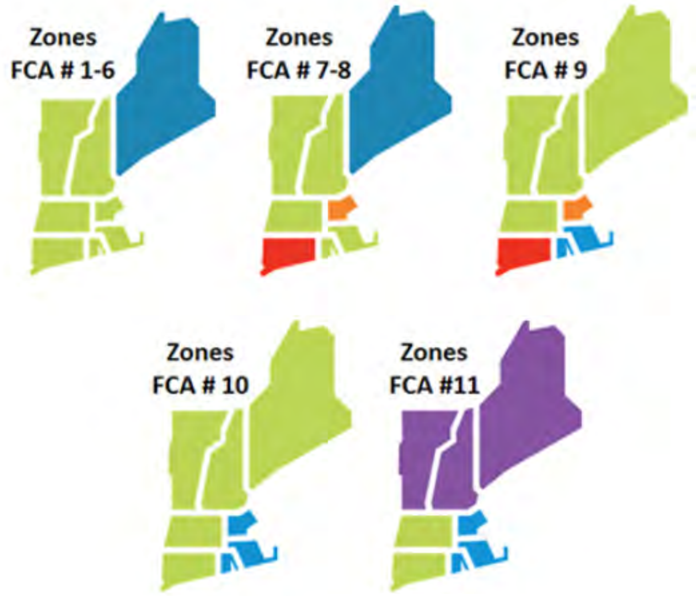
Capacity Zones

- Capacity zones are a key input into the Forward Capacity Auction (FCA) and subsequent annual reconfiguration auctions because the amount of capacity purchased is based on these boundaries. They are specific geographic subregions (a combination of load zones) of the region's electric power system that are designated before each FCA. The ISO establishes capacity zones on an annual basis and evaluates all transmission interface transfer limits that could be relevant to capacity zone modeling.

Ties to Neighboring Grids

Source: ISO New England

Capacity Zones



Source: ISO New England

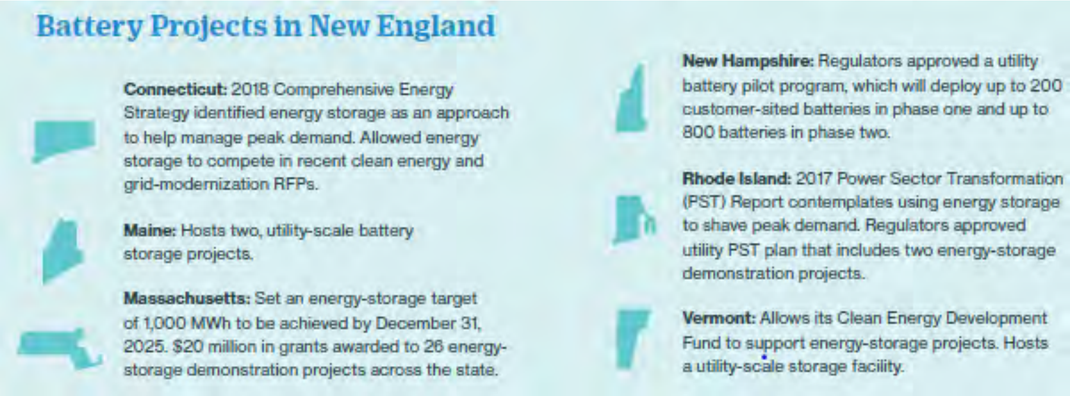
Transmission Topography and Investment (Cont'd)

Transmission Planning

- ISO-NE develops a regional system plan (RSP) every two years, and the regional system planning process identifies the region's needs and the plans for meeting those needs over a 10-year time horizon. Each RSP updates the plan from two years earlier by discussing study proposals, scopes of work, assumptions, draft and final study results, and other materials.
- According to the latest version of the RSP, the overall need for major additional reliability-based transmission projects is expected to decline over the planning horizon. The low growth of net peak load means it no longer is a major driver of the need for new reliability-based transmission projects, and the development of Forward Capacity Market (FCM) resources in favorable system locations also defers the need for major new projects.
- The latest RSP shows the continuing need for certain transmission system upgrades. Per the 2019 RSP, $10.9 billion was invested in the ISO-NE transmission system from 2002 to June 2019, and an additional $1.9 billion is planned over the planning horizon, many of which are in siting or under construction. Looking ahead, integrating large-scale renewable energy resources, addressing the dynamic characteristics of load and the expansion of distributed resources, upgrading and refurbishing aging infrastructure, adding interchange capability with neighboring systems, and complying with new NERC standards are potential drivers for transmission. Per the 2019 RSP, "with these [planned] system upgrades in place, combined with the changes in assumptions to needs assessments, the need for additional reliability-based transmission upgrades may decline over the planning horizon, however additional needs may be driven by generation retirement and the impact of increased energy efficiency and photovoltaic programs."
- Through the Northeastern ISO/RTO Planning Protocol, ISO-NE coordinates interregional studies, including interconnection queue studies, and satisfies interregional planning requirements under Order No. 1000. New England, the New York ISO (NYISO), and PJM presented system needs to the Interregional Planning Stakeholder Advisory Committee, but the ISO/RTOs and stakeholders have not identified the need for new ties with New England (as of June 2019).

Planning for Energy Storage

- In addition to the two large-scale pumped-hydro energy-storage facilities in ISO-NE that can supply almost 2,000 MWs, several other state initiatives led to the development of new battery energy storage projects in the region.



Source: ISO-NE; 2017 Regional System Plan

Transmission Topography and Investment (Cont'd)

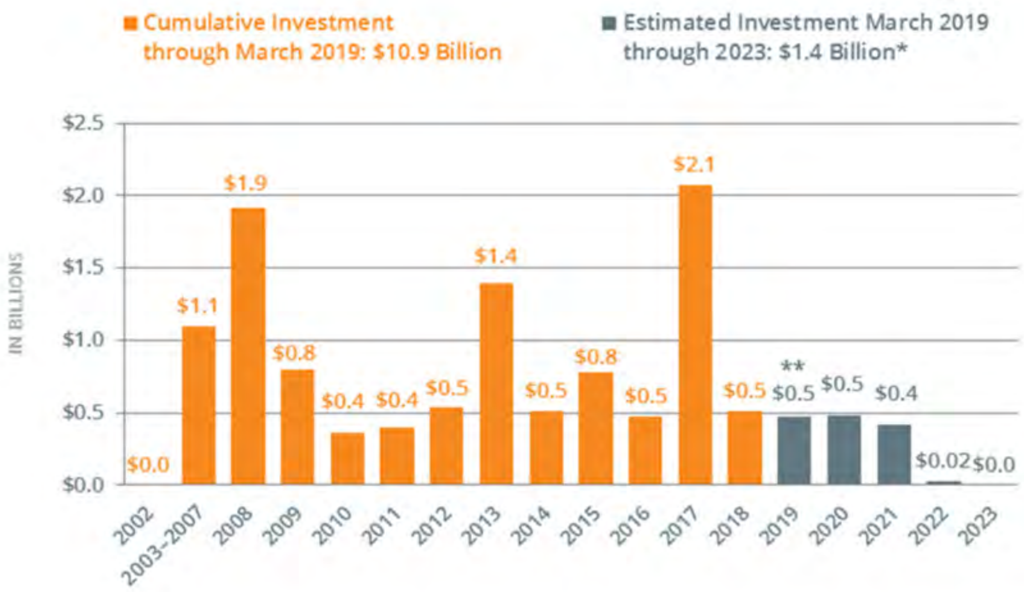
Transmission Investments

- The ISO's continuous study and analysis of the transmission system has helped guide regional investment to fix weak spots and bottlenecks on the system that greatly improved its economic performance and maintained reliability of service.

Decreasing Congestion Costs

- Transmission system upgrades have contributed to decreases in congestion costs in the New England energy market and have, with the aid of low natural gas prices and other factors, helped drive down and mitigate "uplift" payments to run specific generators to meet local reliability needs.

Transmission Investment in New England to Maintain Reliability

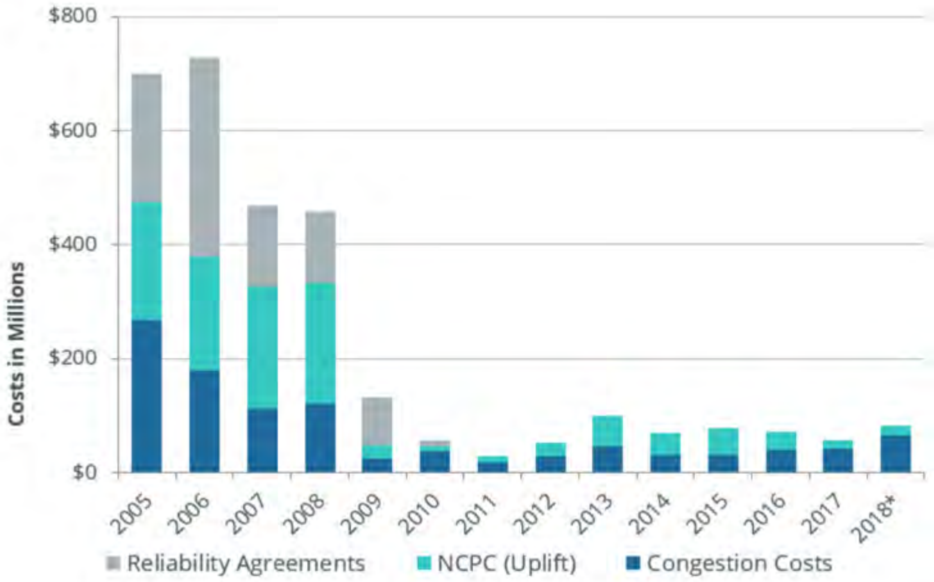


* Estimated future investment includes projects under construction, planned, and proposed. Totals may not add up due to rounding.

** $0.0 billion was in service through March 2019. $0.50 billion was estimated for the remainder of 2019.

Source: ISO New England, *RSP Transmission Project List* (March 2019)

New England Costs for Congestion, Uplift, and Reliability Agreements



Note: Reliability agreements have not been used in the region since 2010.

*Data are subject to adjustments.

Source: ISO New England

Source: ISO-NE (https://www.iso-ne.com/about/key-stats/transmission/)

Transmission Topography and Investment (Cont'd)

FERC-Jurisdictional Investment Base

- In New England, transmission owners recover transmission revenue requirements through a combination of local and regional open access transmission tariff (OATT) rates. The transmission owners provide regional network service (RNS) over their regional high-voltage lines pursuant to ISO-NE's OATT, and the rate for RNS is calculated annually using a formula rate for all pool transmission facilities (PTF) in New England. The RNS formula rate applies only to PTFs, those assets that have been turned over to the operational control of ISO-NE by transmission owners in New England.
- According to data from formula rate updates filed with FERC in 2018, year-on-year growth in aggregate transmission investment base among 11 companies in ISO-NE from rate year 2017–2018 to rate year 2018–2019 was moderate, rising from $8.467 billion to $9.077 billion, an increase of 7.20%. This compares to transmission rate base growth for those same 11 companies of 6.26% from rate year 2016–2017 to rate year 2017–2018, 7.16% from rate year 2015–2016 to rate year 2016–2017, and 4.64% from rate year 201–2015 to rate year 2015–2016.
- The tables at right provide a summary of the operating subsidiaries of each holding company in ISO-NE that utilizes formula-based rates with FERC, including authorized ROE incentives as applicable.

ISO-NE Transmission Formula Rate Summary

Ticker	Parent company	Filing entity	Trans. investment base 2017-2018 ($000)	Trans. investment base 2018-2019 ($000)	Investment base growth 2017-2018 to 2018-2019 (%)	Base ROE (%)*	Investment subject to incentive ROE ($000)	Incent. ROE (%)*
AGR	AVANGRID	Central Maine Power	1,143,917	1,104,754	(3.42)	11.07	968,238	11.74
AGR	AVANGRID	United Illuminating	535,456	539,112	0.68	11.07	370,397	11.74
EMA	Emera Inc.	Emera Maine	247,793	228,831	(7.65)	11.07	None	NA
ES	Eversource Energy	Connecticut Light & Power	2,274,460	2,456,226	7.99	11.07	1,273,540	11.74
ES	Eversource Energy	NSTAR Electric	1,228,858	1,293,099	5.23	11.07	202,708	11.74
ES	Eversource Energy	Public Service Co. of New Hampshire	651,299	715,270	9.82	11.07	77,711	11.74
ES	Eversource Energy	Western Massachusetts Electric	615,517	687,987	11.77	11.07	370,442	11.74
NEE	NextEra Energy	New Hampshire Transmission	35,716	43,487	21.76	11.07	None	NA
UTL	Unitil	Fitchburg Gas & Electric	3,011	2,795	(7.17)	11.07	None	NA
NA	National Grid USA	New England Power	1,030,976	1,186,573	15.09	11.07	253,206	11.74
NA	NA	Vermont Transco	699,917	818,484	16.94	11.07	179,121	11.74

* Inclusive of 50 basis point incentive adder for membership in ISO-NE. Total ROE capped at 11.74% inclusive of all incentive adders pursuant to FERC Opinions 531, 531-A and 531-B.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

ISO-NE Transmission Investment Base Values ($M)

Ticker	Parent Company	Filing Entity	2011-'12	2012-'13	2013-'14	2014-'15	2015-'16	2016-'17	2017-'18	2018-'19	CAGR (2011-'12 to 2018-'19) (%)
AGR	AVANGRID	Central Maine Power	177.5	533.7	418	651.4	855.4	1,136.3	1,143.9	1,104.8	29.85
AGR	AVANGRID	United Illuminating	386.7	377.5	409.3	449.6	458.7	480.5	535.5	539.1	4.86
EMA	Emera Inc.	Emera Maine	161.8	178.5	229.2	241.4	236.7	248.1	247.8	228.8	5.07
ES	Eversource Energy	Connecticut Light & Power	1,849.2	1,756.0	1,778.5	1,915.7	2,004.0	2,172.4	2,274.5	2,456.2	4.14
ES	Eversource Energy	NSTAR Electric	605.9	601.5	731.3	952.8	981.9	1,055.8	1,228.9	1,293.1	11.44
ES	Eversource Energy	Public Service Co. of New Hampshire	313.7	360.7	385.3	448	493.1	554.2	651.3	715.3	12.5
ES	Eversource Energy	Western Massachusetts Electric	139.5	185.6	443.5	564.1	553.7	583.8	615.5	688	25.61
NEE	NextEra Energy	New Hampshire Transmission	39.3	36.8	37.5	37.9	37.1	40	35.7	43.5	1.46
UTL	Until	Fitchburg Gas & Electric	0.5	0.7	0.9	2.6	2.7	2.7	3	2.8	28.97
NA	National Grid USA	New England Power	643.1	696.4	729.9	857.3	963.1	1,013.2	1,031.0	1,186.6	9.14
NA	NA	Vermont Transco	541	543.6	598.4	644.1	654.9	681.1	699.9	818.5	6.09

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Sources: S&P Global Market Intelligence; Annual Markets Report; NEPOOL Participants Comm. Report

Transmission Topography and Investment (Cont'd)

Transmission Projects

- Several major transmission projects in ISO-NE have been developed in response to state solicitations for carbon-free energy, designed to move hydro power and renewables from Canada, New York, and remote areas in northern New England to load centers further south.
  - New England Clean Power Link: The $1.2 billion 300 kV to 320 kV line would run approximately 98 miles underwater from the Canadian border through Lake Champlain to Benson, Vermont, before running another 56 miles to a new converter station slated in Ludlow, Vermont.
  - New England Clean Energy Connect: The 145 mile 300 kV to 320 kV line would connect Quebec to Maine, enabling the transfer of hydropower from Hydro-Quebec to New England load centers, with an estimated cost of $950 million.
  - Maine Power Express HVDC: Despite losing out on a solicitation from Massachusetts, the project may still see its power lines run more than 300 miles underground and undersea from southern Aroostook County, Maine, to a converter station in Boston.
  - Northeast Renewable Link: With an in-service date of late 2021 or early 2022, the 345 kV project is designed to transmit a mix of new wind, solar, and small hydropower generated in New York and would run 23 miles from Nassau, New York, to an Eversource substation in Hinsdale, Massachusetts.
- Others, such as the Vineyard Wind Connector project, have been designed to move offshore wind into New England. The project, comprised of submarine and onshore underground electrical transmission along with a new substation, will connect the Vineyard Wind offshore wind project, located 15 miles south of Martha's Vineyard and Nantucket and 34 miles from the coast of Cape Cod, to an existing substation in Barnstable owned by Eversource Energy subsidiary NSTAR Electric.

Project Name	Project Owner(s)	Length (miles)	Voltage (kV)	From State or Province	To State or Province	From ISO	To ISO	Year in Service	Current Status	Project Type	Estimated Max Const. Costs ($000)
Atlantic Link 320 kV	Clean Power Northeast Development	375	320	New Brunswick	Massachusetts	New Brunswick	New England	2022	Early Development	New	NA
Evergreen Express	NextEra, New Hampshire Transmission	114	345	New Brunswick	Maine	New Brunswick	New England	NA	Early Development	New	NA
Line A201/B202 Rebuild (Granite State Power Link Segment B)	Citizens Energy Corp., GridAmerica Holdings Inc.	109	345	New Hampshire	New Hampshire	New England	New England	2022	Early Development	Rebuild	NA
Maine Power Express HVDC	Loring Holdings, LLC, National Resources Energy, LLC, Transmission Developers Inc.	315	345	Maine	Massachusetts	New England	New England	2022	Early Development	New	NA
New England Clean Energy Connect	Central Maine Power	145	320	Quebec	Maine	NA	New England	2022	Advanced Development	New	950,000
New England Clean Power Link	Transmission Developers Inc.	152	320	Vermont	Vermont	New England	New England	2022	Advanced Development	New	1,200,000
Vineyard Wind Connector	Avangrid Renewables LLC, Offshore MW LLC, Vineyard Power Cooperative	27	220	Massachusetts	Massachusetts	New England	New England	2021	Advanced Development	New	NA

Note: Includes all projects greater than 115 kV and line length greater than 10 miles
Sources: S&P Global Market Intelligence; ScottMadden analysis

Resilience Issues

Overview

- ISO-NE has experienced several major resilience events over the past decade. Those events are summarized in the table on the next page. Most events affecting the power system in recent years are driven by severe weather events, but other events such as vandalism, suspicious activity, and system operation have played a role (see table at right).
- As a frame of reference for the potential economic impact of a resilience event, the combined 2018 annual GDP for all six states in New England was $4.3 trillion, representing more than 5% of the total for the United States.

Fuel Security in the Northeast United States

- Although the region is projected to have sufficient resources to meet capacity requirements and enough transmission facilities to meet reliability criteria, fuel security remains a primary issue the region must resolve to meet its energy supply needs. The limited availability of the natural gas transportation infrastructure to supply gas to generating units can present fuel security risks to the region, especially during winter-operating periods, even as New England's current reliance on natural gas as a primary fuel for generating units is projected to grow.
- The challenge is "assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."
- Range of solutions being considered and discussed with stakeholders include:
  - Changes to "pay for performance" parameters
  - Market designs that increase incentives for forward fuel supply and resupply
  - Inclusion of opportunity costs associated with scarce fuels and emission allowances

Reported Electric Disturbance Events Affecting New England (2017–Apr. 2019)

Cause	2017	2018	2019 YTD
Fuel Supply Deficiency	0	0	0
Severe Weather	4	8	1
Vandalism	0	1	0
Suspected Physical Attack	0	0	0
Actual Physical Attack	0	0	0
Suspicious Activity	1	0	0
Transmission Interruption	0	0	0
System Operations	0	2	0

Note: For multiple causes, classified under one only.
Source: DOE OE-417; ScottMadden analysis

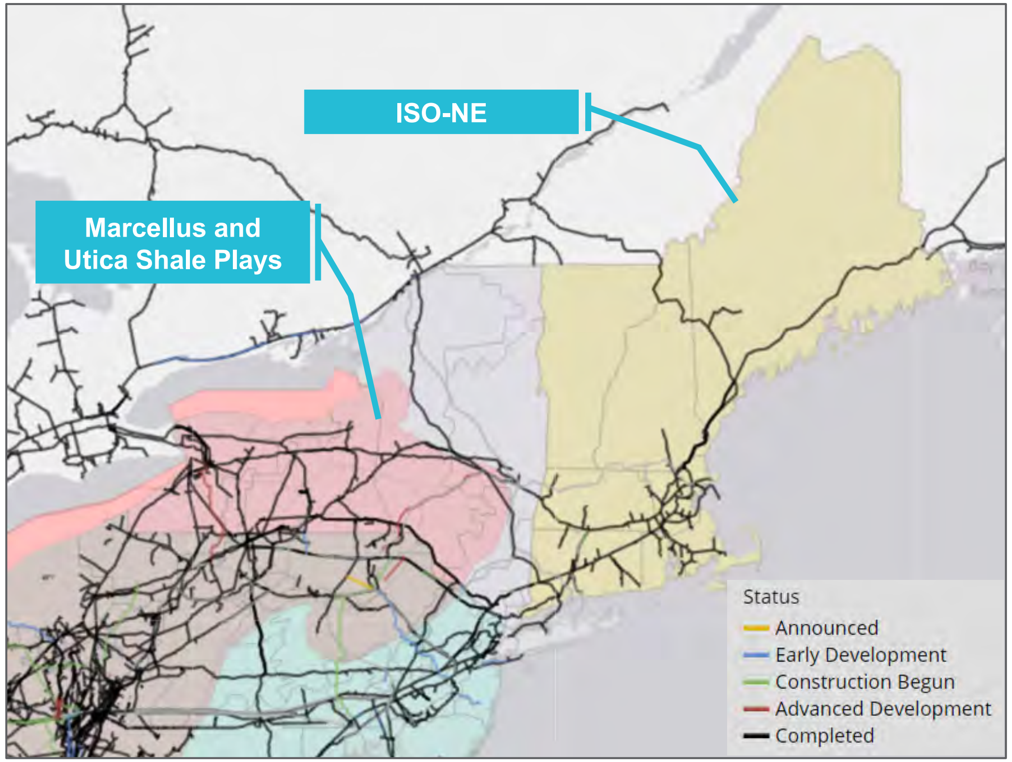
Sources: Bureau of Economic Analysis; ISO-NE Resilience Filing; U.S. Dept. of Energy

Resilience Issues (Cont'd)

Fuel Security in the Northeast United States (Cont'd)

- Despite ISO-NE's close proximity to plentiful natural gas from shale production in the Marcellus (and Utica), pipeline capacity constraints into ISO-NE have limited the volume that can be delivered into the region.
- A handful of new pipeline projects and expansions completed in recent years have provided limited additional capacity:
  - Algonquin Incremental Market (AIM) – 342,000 Dth, 37.6 miles (NY to MA)
  - Portland Natural Gas Project – 168,000 MMcf/d, 295 miles (NH to ME)
  - Maritimes and Northeast – 418,100 Dth, 1.7 miles (NB to ME)
- However, siting and permitting in the densely populated New England region is particularly challenging, and regulatory and stakeholder pushback has delayed and/or forestalled other pipeline projects, and there are no projects currently permitted or under construction in the region.
- Oil-fired plants, which typically do not run often, become critical on cold winter days when the fuel for natural gas-fired generators is limited and expensive. But during cold weather, oil and dual-fuel (natural gas/oil) plants can rapidly deplete their on-site oil supply or reach environmental limits on their run times.
  - Extreme cold weather also creates a number of obstacles to restocking oil supplies, as was illustrated during the 2017–2018 winter cold spell: severe weather and sea and river ice hampered resupply by oil barges and delayed oil truck deliveries.
  - With extended days of burning oil, several resources either had concerns about hitting federal and state emissions limitations or were impacted by emissions limitations. Over two weeks during the 2017–2018 winter, power providers in ISO-NE used two million barrels of oil—twice the average yearly amount.
- In one controversial case, after receiving a request to delist Mystic River Units 8 and 9, FERC granted an ISO-NE request that the units remain online as a reliability must-run price taking unit until reliability and fuel security concerns can be resolved.

Select Current and Planned Pipelines Projects in the Northeastern United States



Sources: S&P Global Market Intelligence; 2019 Regional Electricity Outlook; ScottMadden analysis

Resilience Issues (Cont'd)

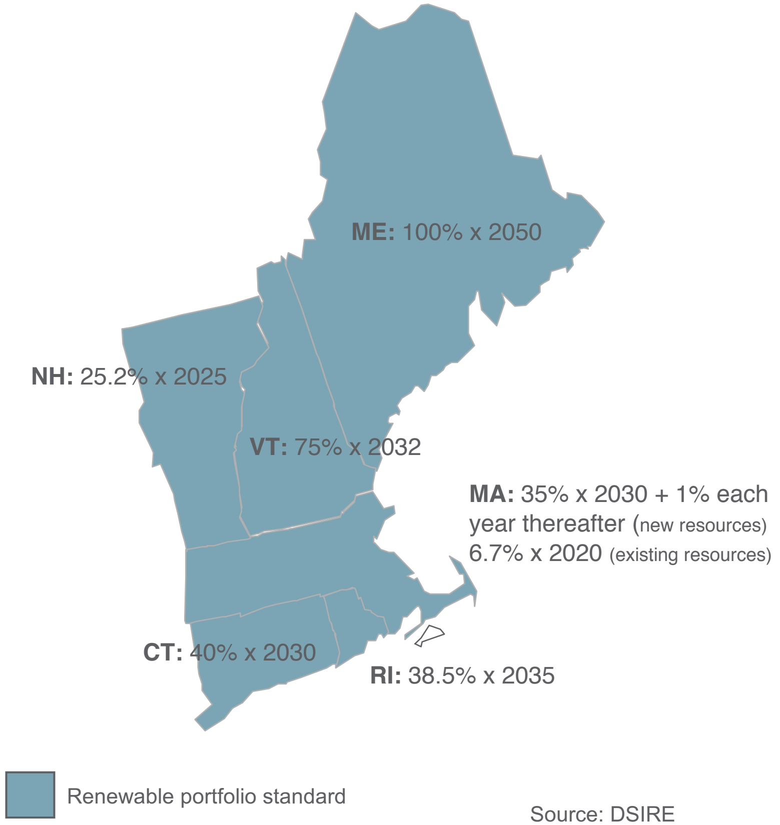
Selected Major Bulk Power Events Affecting New England

Event	Description
Northeast Snowstorm (Oct. 29–30, 2011)	• An unprecedented fall snowstorm hit the Northeastern United States, breaking all previous October records. Parts of New York, New Jersey, and Pennsylvania also received more than a foot of snow. The quantity of snow held by the unusually top-heavy trees, coupled with the soft, wet ground, resulted in a great number of healthy trees, most outside of utility rights-of-way, being uprooted and falling onto distribution and transmission lines. • On the morning of October 30, near the end of the storm, more than 3.2 million homes and businesses were without power. Thousands were without power for more than a week, some for as long as 11 days. Estimates put storm costs between approximately $1 billion and $3 billion.
Polar Vortex (Jan. 2014)	• In early January 2014, the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20°F to 30°F below average. NYISO recorded its all-time peak winter load on January 7. • For NPCC (including New England [and Canada]), nearly 2 GWs of cold weather generation outages were reported, with about 770 MWs related to fuel-gelling issues. Some dual-fuel units experienced challenges ranging from a lack of natural gas required for starting the alternate fuel to fuel freezing in the injectors. Outages related to curtailments and interruptions of natural gas delivery were the significant contributor of the NPCC generator outages. These outages totaled a maximum of 3,296 MWs of generators, and they significantly impacted NPCC's generation resources starting at approximately 10:00 a.m. on January 7, 2014.
Winter Storms Riley and Quinn (Mar. 1–20, 2018)	• In March 2018, Winter Storm Riley, a powerful nor'easter caused major impacts in the Northeastern, Mid-Atlantic, and Southeastern United States, bringing hurricane force winds to coastal New England and producing more than two feet of snow in some areas. Although the most severe damage was caused by flooding, as well as snow, unusually high tides and storm surges along the coast, wind, and downed trees caused very large inland power outages. Recovery efforts were also hampered as a second nor'easter, Winter Storm Quinn began to impact the area just a few days later • At least two million customers lost power at some point during the storm throughout the week in 13 states. The storm was called a "bomb cyclone" because of how quickly pressure dropped—24 millibars in 24 hours.

Sources: NERC; Utility Dive; National Oceanic and Atmospheric Administration

Renewables Integration

State Renewable Portfolio Goals within the ISO-NE Footprint (as of June 2019)



Source: DSIRE

Demand-Side Considerations: Renewable Portfolio Standards

- New England states have established ambitious clean and renewable energy goals, many of which have recently been increased, and those policies are expected to significantly impact energy and demand resources in ISO-NE:
  - Connecticut (raised in 2018): 40% by 2030
    - Class I: Traditional renewables; Class II: Trash-to-energy; Class III: CHP and waste heat
  - Maine (raised in 2019): 80% renewables by 2030, 100% total by 2050
    - Class I: New resources; Class II: Existing renewables
  - Massachusetts (raised 2018): 35% by 2030 + 1% every year thereafter
    - Class I: New resources; Class II: Existing resources
  - New Hampshire: 25.2% by 2025
    - Class I: New renewables –15% by 2025; Class II: New solar – 0.7%; Class III: Existing biomass – 8%; Class IV: Existing hydro – 1.5%
  - Rhode Island: 14.5% by 2019; 38.5% by 2035 (No classes)
  - Vermont: 55% by 2017, increasing 4% every 3 years, to 75% by 2032
    - Tier I: Traditional renewables; Tier II: New distributed renewables (< 5 MWs); Tier III: New distributed renewables or fossil-fuel savings equivalent
- Two utilities in the ISO-NE footprint have introduced clean energy commitments (see below).

Utility Name (States of Operation)	Goal Type	Target Dates	Description (Date Implemented)
Green Mountain Power (VT)	Emission Reduction	2025	100% carbon-free energy by 2025
National Grid (MA)	Emission Reduction	2020 2050	45% reduction in GHG emissions by 2020 80% reduction by 2050

Source: SEPA

Sources: 2019 Regional Electricity Outlook; NEPOOL Participants Comm. Report

Renewables Integration (Cont'd)

States Accelerate Procurement of Renewable Energy

State(s)	State Procurement Initiatives for Large-Scale Clean Energy Resources	Resources Eligible/ Procured	Target MW (nameplate)
MA, CT, RI	2015 Multi-State Clean Energy RFP	Solar, Wind	390 MW
MA	2017 Section 83D Clean Energy RFP	Hydro Import	Approx. 1,200 MW (9,554,000 MWh)
MA, RI	2017 Section 83C Offshore Wind RFP	Offshore Wind	1,600 MW (MA) 400 MW
CT	2018 Renewable Energy RFP	Offshore Wind, Fuel Cells, Anaerobic Digestion	254 MW
CT	2018 Zero-Carbon Resources RFP	Nuclear, Hydro, Class I Renewables Energy Storage	Approx. 1,400 MW (12,000,000 MWh)
RI	2018 Renewable Energy RFP	Solar, Wind, Biomass, Small Hydro, Fuel Cells and other Renewables	400 MW

Demand-Side Considerations: Additional State Procurement of Renewables

- With laws mandating steep reductions in greenhouse gas emissions, some New England states began offering additional incentives to bring more solar, hydro, and wind power online over the past few years.
- More recently, several New England states have established public policies that direct electric power companies to enter into long-term contracts for carbon-free energy that would cover most, if not all, of the resource's costs. Massachusetts, for example, directed its utilities to sign 20-year contracts committing the state's electricity customers to pay for the development of large-scale offshore wind and hydroelectricity import projects. In all, three of the six states are seeking to develop or retain approximately 5,600 MWs of clean energy and storage resources, and the Massachusetts Department of Energy Resources (DOER) recently analyzed costs and benefits of additional procurement and recommended proceeding with solicitation of 1,600 MWs of additional offshore wind.
- The federal Bureau of Ocean Energy Management (BOEM) recently auctioned leases in offshore Massachusetts for additional wind development (see graphic on the following slides). This public policy trend is expected to grow as legislators in all New England states seek to accelerate the transition to a clean energy economy.
- All New England states also participate in the Regional Greenhouse Gas Initiative (RGGI), a cooperative effort of New England and Mid-Atlantic states to cap and reduce CO_2 emissions from the power sector. It is a mandatory, market-based CO_2 emissions limits. Through a program review in 2017, the RGGI states agreed to a number of program changes, including a 30% cap reduction between 2020 and 2030, essentially ratcheting down the availability of allowances to generators that produce greenhouse gases.

Sources: 2019 Regional Electricity Outlook; NEPOOL Participants Comm. Report

Renewables Integration (Cont'd)

Supply-Side Considerations: Retirement of Coal, Oil, and Nuclear Capacity

- More than 5,200 MWs of oil, coal, and nuclear power plants will have retired from 2013 to 2022, and another 5,000 MWs of coal- and oil-fired generation could be retiring in coming years (see "at risk" to the right).
- The region's remaining two nuclear facilities (Millstone and Seabrook, which comprise a combined 3,300 MWs) will continue to be important components of the grid because they are carbon free and have a dependable, on-site fuel supply.
- Nuclear power currently supplies a quarter of the grid electricity consumed in the region per year.
- Notable recent exits:
  - Brayton Point Station (1,535 MWs from oil and coal)
  - Salem Harbor Station (749 MWs from oil and coal)
  - Vermont Yankee (604 MWs from nuclear power)
  - Pilgrim Nuclear Station (677 MWs from nuclear power)
  - Norwalk Harbor Station (342 MWs from oil)
  - Mount Tom Station (143 MWs from coal)
  - Bridgeport Harbor Station (564 MWs from coal)

New, Closed or Retiring, and At Risk Generation Resources in ISO-NE

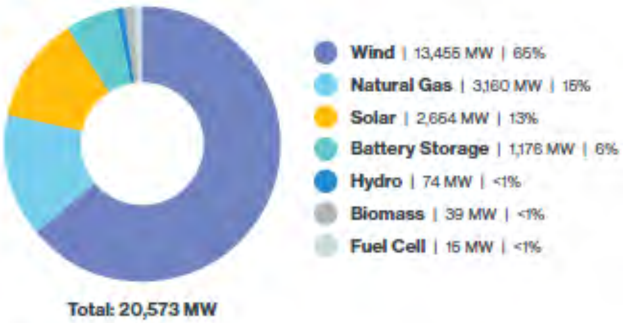
Source: ISO-NE (https://www.iso-ne.com/about/key-stats/resource-mix/)

Renewables Integration (Cont'd)

Supply-Side Considerations: New Renewables and Natural Gas-Fired Generation

- In 2018, the amount of new wind power seeking interconnection in ISO-NE was for the first time more than double the amount of natural gas-fired generation proposed—and today, there are four times more wind power proposals than natural gas. Of the roughly 13,500 MWs (nameplate) of wind power being proposed regionally (as of January 2019), about 9,500 MWs would be offshore of Massachusetts, Rhode Island, and Connecticut, with most of the remaining 4,000 MWs located onshore in Maine.
- Massachusetts utilities have executed contracts (subject to regulatory approval) for 800 MWs of offshore wind to be online by 2023, and the winning bid has been selected for an additional 800 MWs of offshore wind by 2027. Connecticut and Rhode Island utilities have also negotiated contracts for offshore wind to be online by 2023.

Proposed Generation Projects in ISO-NE by Fuel and Technology (MW)



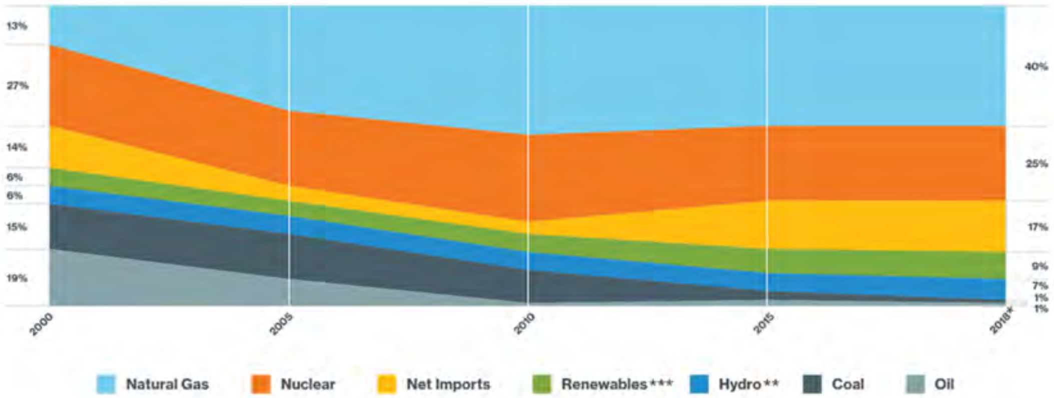
Proposals by State

Massachusetts	10,426 MW	Rhode Island	1,366 MW
Maine	4,578 MW	New Hampshire	302 MW
Connecticut	3,682 MW	Vermont	218 MW

Source: ISO Generator Interconnection Queue (January 2019)

Note: Not all proposed new projects are built; historically, 70% of megawatts have ultimately withdrawn.

ISO-NE Percent of Electric Energy by Fuel Type (2000–2019)



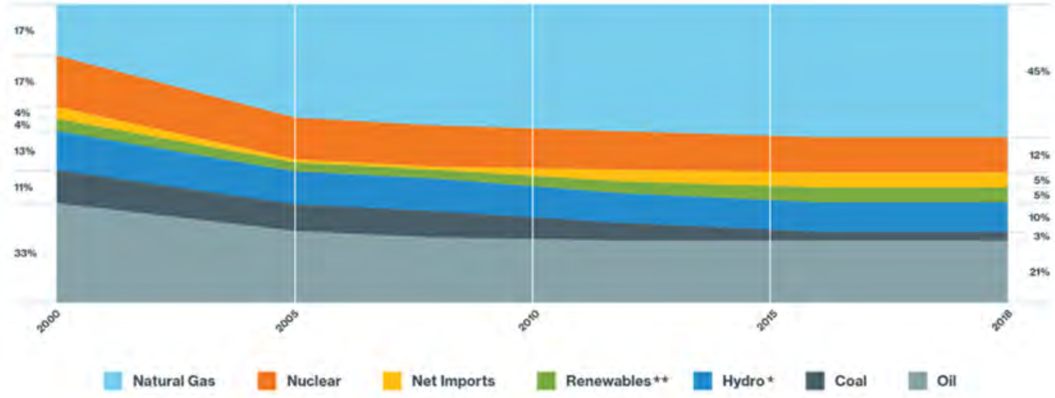
*Data are subject to adjustments. This chart approximates the amount of generation by individual fuels used by dual-fuel units, such as natural-gas-fired generators that can switch to run on oil and vice versa. Before 2016, generation from such units was attributed only to the primary fuel type registered for the unit.

**Includes pondage, run-of-river, and pumped storage.

***Renewables include landfill gas, biomass, other biomass gas, wind, grid-scale solar, municipal solid waste, and miscellaneous fuels. Hydro is not included in this category primarily because the various sources that make up hydroelectric generation (i.e., conventional hydroelectric, run-of-river, pumped storage) are not universally defined as renewable in the six New England states.

Source: ISO New England

ISO-NE Percent of Capacity by Fuel Type (2000–2019)



*Includes pondage, run-of-river, and pumped storage.

**Renewables include landfill gas, biomass, other biomass gas, wind, grid-scale solar, municipal solid waste, and miscellaneous fuels. Hydro is not included in this category primarily because the various sources that make up hydroelectric generation (i.e., conventional hydroelectric, run-of-river, pumped storage) are not universally defined as renewable in the six New England states.

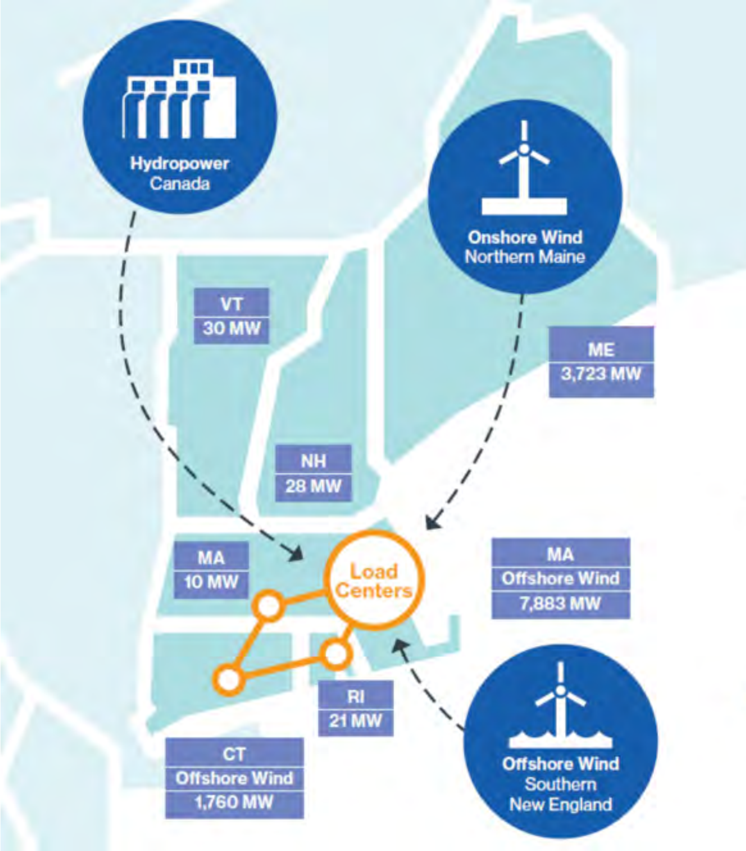
Source: ISO New England

Sources: BOEM; ISO-NE (https://www.iso-ne.com/about/key-stats/resource-mix/)

Renewables Integration (Cont'd)

Supply-Side Considerations: Elective Transmission Upgrades (ETUs)

- Investments in the regional transmission grid will facilitate the states' policy directives for renewable energy and enable the transportation of low-carbon electricity into the region. Because of the long distances from some of the proposed onshore wind power projects to the existing grid, major transmission system upgrades will be needed to deliver more of this power from these remote, weaker areas of the system to far-away consumers.
- In 2015, the ISO-NE improved its interconnection study process for elective transmission upgrades (i.e., not reliability-driven upgrades) and introduced new rules that ensure that renewable resources are able to deliver capacity and energy into the power markets.
- ETUs are transmission lines funded by private parties—not through regional cost-sharing. While not necessary from a reliability standpoint, they can help enhance generator deliverability or facilitate the integration of renewable resources, such as remote wind resources, by enhancing portions of the grid.
- Today, private developers are competing in state procurements to build transmission projects that would enable the delivery of thousands of megawatts of clean energy, mostly from wind resources in northern Maine and hydro resources in Canada (not all proposed wind projects in New England would be delivered through ETUs). As of June 2019, 14 ETU projects are under study, and three have received approval of their proposed plan applications. State procurement programs will be major deciders of which projects will move forward.
- In 2017, the ISO implemented a new "clustering" methodology that enables interconnection requests from multiple generators and ETUs in the same area to be studied together. This is helping to advance the requests in northern and western Maine where thousands of megawatts of proposed new resources, mostly wind, are seeking to interconnect to the regional grid.



Lines represent types of large-scale elective transmission upgrades (ETUs) private developers have proposed in recent years that could deliver clean energy to load centers. Not all proposed wind projects would be delivered through ETUs.

The total amount of wind power seeking to be built, or interconnect, in the states totals about 13,500 MW.

Source: *ISO Generator Interconnection Queue* (January 2019)

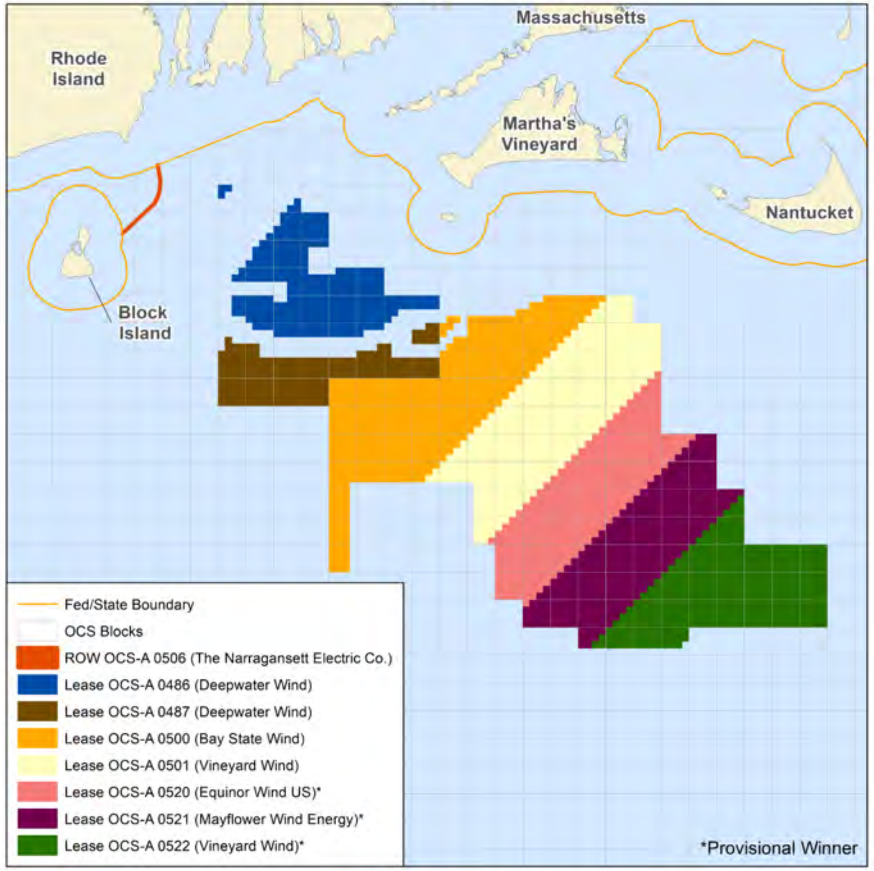
Source: ISO-NE (https://www.iso-ne.com/about/key-stats/transmission/)

Renewables Integration (Cont'd)

Supply-Side Considerations: Demand for Offshore Wind Developments

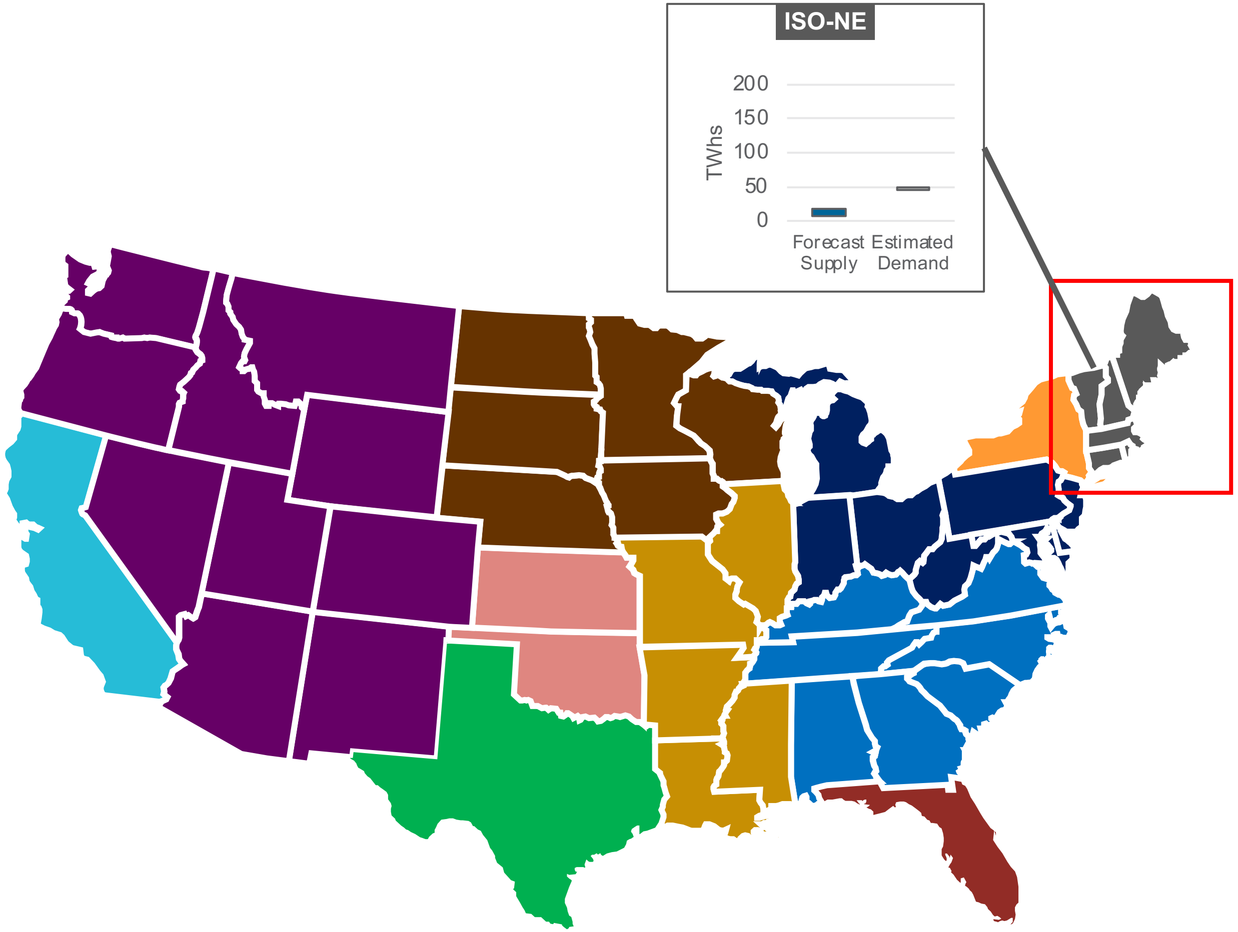
- **Rhode Island:** In 2011, BOEM published a "Call for Information and Nominations for Commercial Leasing for Wind Power on the OCS Offshore Rhode Island and Massachusetts." A call area was then identified in consultation with Rhode Island, and two leases were ultimately signed in 2013 for more than 164,000 acres, representing the first commercial leases in the United States.
  - In 2016, the 30 MW Block Island Offshore Wind, developed by Deepwater Wind New England, became the first offshore wind project in the United States.
  - Rhode Island subsequently joined the solicitation process led by Massachusetts (described below).
- **Massachusetts:** After receiving positive responses to an initial request for interest (RFI) in offshore commercial wind leases in 2010, BOEM worked with Massachusetts to identify a wind energy area. In 2014, it was announced that 742,000 acres would be made available for commercial wind energy leasing, and two leases were ultimately signed in 2015.
  - In 2016, Massachusetts Governor Charlie Baker signed into law a bill that committed the state to offshore wind. An Act Relative to Energy Diversity (H. 4568) requires Massachusetts electricity distribution companies to procure 1,600 MWs of cost-effective offshore wind energy by 2027, with the first solicitation taking place in June 2017.
  - Two projects, Bay State Wind and Vineyard Wind, were selected in the first solicitation, and both are proceeding with environmental and site reviews with the goal of having projects online in 2022–2023. On November 20, 2019, Massachusetts selected Mayflower Wind to supply the Commonwealth with an additional 804 MWs, satisfying the balance of the 1,600 MWs requirement.
- **Maine:** In 2011, BOEM received an unsolicited bid for a commercial lease for a wind energy project off the coast of Maine. Though BOEM determined that there was no commercial interest in the lease, thereby proceeding with the non-competitive lease process, Statoil since withdrew its lease request.
- **Connecticut:** Connecticut, in June 2019, passed a bill to enable solicitations for offshore wind beginning in 2019, with the first solicitation expected to total 2,000 MWs, all of which must be achieved by 2030, with the estimated year of first commissioning expected in 2023.

Commercial Wind Energy Areas Off the Coasts of Rhode Island and Massachusetts



Sources: ISO-NE; BOEM; MassCEC Offshore Wind

Renewables Integration (Cont'd)

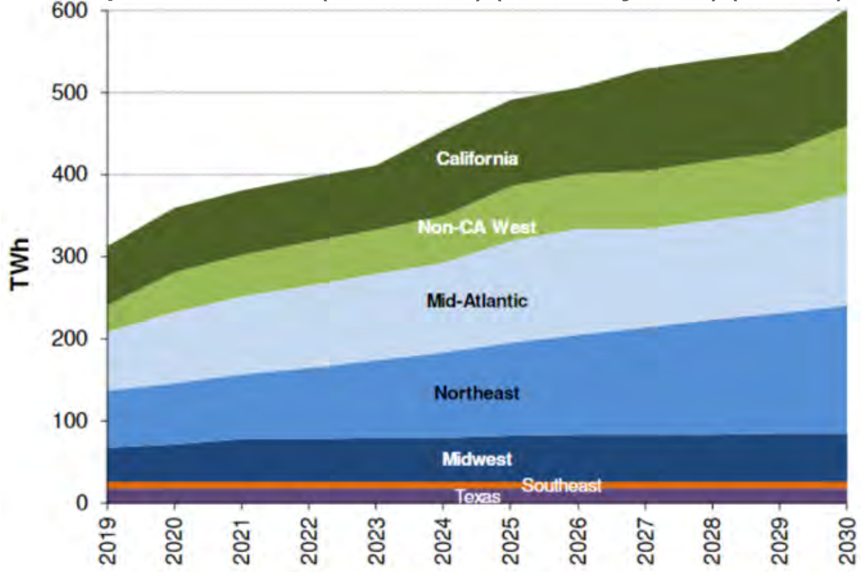


Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Integration Challenges – Renewable Portfolio Standard (RPS) Supply and Demand

- As seen in the map at left and the Northeast section of the chart below, the estimated demand for renewable resources in the ISO-NE region is expected to significantly outpace the forecast supply of renewables in the region, suggesting that future demand, at least in part, will need to be met by resources from outside the ISO-NE region.
- According to the Lawrence Berkeley National Laboratory (LBNL), while the Northeast (including New England) is a relatively small market, almost all renewable energy capacity additions are serving RPS demand.

Projected U.S. RPS Demand (Total Compliance Requirements) per DOE LBNL (2019–2030) (as of July 2019) (in TWh)



Source: LBNL

Sources: LBNL 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
New England ISO	▪ Severe weather is the largest cause of electrical disturbances, particularly due to system stress sustained during severe winter weather events in recent years ▪ Growing concerns about “fuel security” due to retirements of baseload nuclear, coal, and oil-fired units (5.2 GWs retired since 2013 or retiring soon) and increasing reliance on gas-fired generation capacity and variable renewable energy (3.2 GWs of gas and 13.5 GWs of wind generation in the queue) ▪ Thirteen (13) interconnections with neighboring regions in New York and eastern Canada used to meet 17% of the region’s demand in 2018, and interconnection with different time zones provides additional diversity ▪ Retirement of oil-fired and dual-fuel capacity that has served as a lifeline for the region during recent winter weather events	▪ Current capacity and penetration of wind/solar is modest ▪ Significant growth in renewable capacity in the region will be needed to meet RPS-driven demand ▪ State procurement initiatives for large-scale clean energy resources have included significant capacity targets for new and existing capacity from solar, wind (including offshore), fuel cells, energy storage, biomass, and hydro imports ▪ Currently, 20 ETU interconnection requests in the queue, many to deliver zero- or low-carbon resources to or within the region ▪ More than 150,000 behind-the-meter solar PV installations, with a combined nameplate capacity of 2.9 GWs, with favorable state policies incentivizing continued growth of distributed solar	▪ More than 30 GWs of new distributed solar PV expected by 2023 may impact planning assumptions ▪ 20 MWs of grid-scale storage online since 2015, with proposals for 1.3 more by 2022, in addition to existing 1,800 MWs of pumped storage capacity in the region ▪ Most recent capacity auction cleared 4,040 MWs of efficiency and demand response, including 654 MWs of new resources ▪ Congestion considered to be minor concern in most areas, and mitigation by additional transmission upgrades is not currently warranted; uplift and congestion charges have been low since 2011 ▪ Fairly consistent state policies across the footprint, all with aggressive renewable energy goals and mandates	▪ Focus on moving hydropower from Canada, onshore wind from northern Maine, and offshore wind from southern New England ▪ Growing potential opportunity for offshore wind, with expected co-benefit to resilience to a point (wind resources may be curtailed below certain design temperatures during severe winter weather events) ▪ Investment of $10.9 billion from 2002 to 2019 in reliability-driven, regional cost-shared projects, and $1.3 billion planned over the planning horizon (as of June 2019) ▪ Opportunity to enhance degrading system frequency response capability from declining inertia

Sources

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- S&P Global Market Intelligence

Regional Discussion

NEW YORK ISO

Contents

Overview

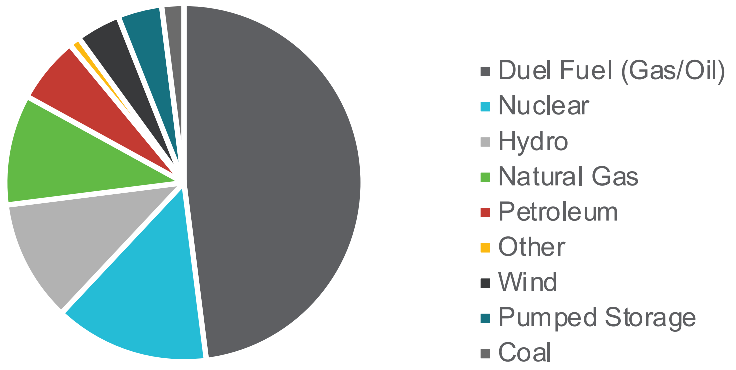
Description of Region

- The New York Independent System Operator (NYISO) is the only Balancing Authority within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999.
- NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines and more than 47,000 square miles and serves the electric needs of 19.5 million people.

Characteristics and Trends of Energy Demand

- New York is summer-peaking, driven by air conditioning during heatwaves. New York experienced its all-time peak load of 33,956 MWs in the summer of 2013 at the end of a week-long heat wave. Its all-time winter peak was 25,738 MWs, achieved in January 2014. Overall peak-load growth has been trending downward in recent years.
- Demand and consumption in New York are heavily influenced by the state's energy efficiency and renewable energy public policy programs, such as the clean energy standard that aims to produce 50% of state-wide energy consumption from renewables by 2030.
- New York's latest projections through 2039 show baseline peak demand growing at only 0.05% annually with energy usage almost flat at 0.18% annually (both are expected to decline in the next 10 years).
  - The higher forecasted growth in energy usage can be attributed in part to the increasing impact of electric vehicle usage, especially in the later years. NYISO estimates that transportation electrification will add 4.2 million MWhs in energy use by 2030 and 410 MWs to the summer peak in that year.
  - Significant load-reducing impacts occur due to energy efficiency initiatives and the growth of distributed behind-the-meter energy resources, such as solar PV. Much of these impacts are due to New York State's energy policies and programs, including the Clean Energy Standard (CES), the Clean Energy Fund (CEF), the NY-SUN initiative, the energy storage initiative, and other programs developed as part of the Reforming the Energy Vision (REV) proceedings.

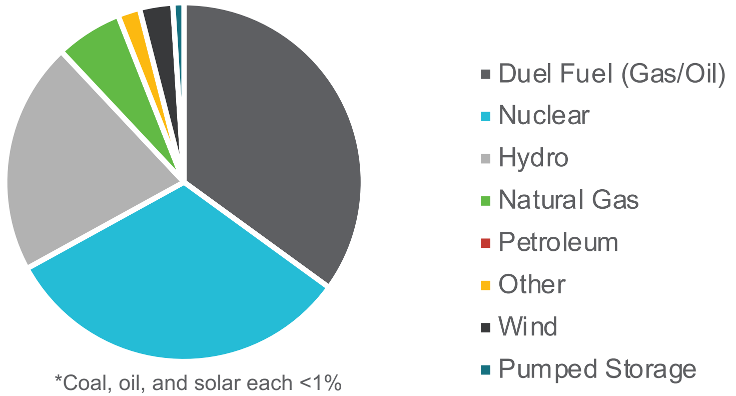
2019 Summer Capacity by Fuel Type*



*Solar <1%

Sources: NYISO Gold Book

2018 Net Energy by Fuel Type*



*Coal, oil, and solar each <1%

Sources: NYISO Gold Book

Sources: NERC 2018 LTRA; NYISO Power Trends; NYISO Gold Book

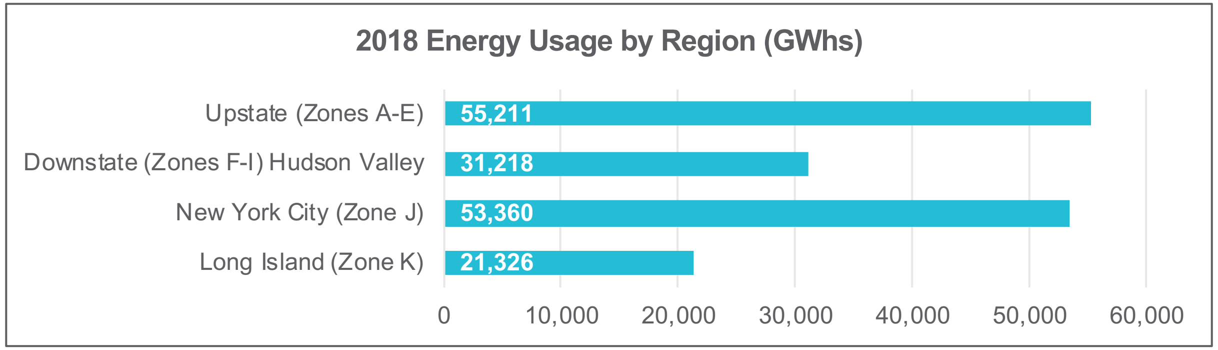
Overview (Cont'd)

Grid Configuration

- New York's grid is actually two grids, with different resources depending upon region: north/west or south/east (see map at top right). Upstate contains many existing and potential renewable-generating resources, including large hydro as well as existing and potential wind resources.
- The grid is divided into 11 zones. Since 2000, nearly 13 GWs of new capacity has been added to the New York grid, about 80% of which has been added in downstate zones (F–K) (see map at lower right), where demand is greatest (see below). Downstate regions (New York City, Long Island, and the Hudson Valley – Zones F–K) consumed 66% of the state's electric energy in 2018.

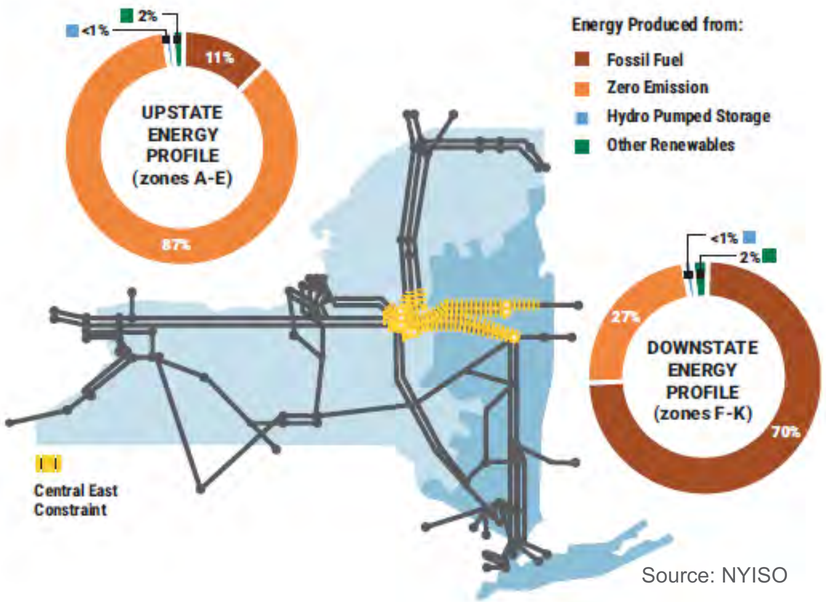
Resource Trends

- Since 2000, about 7.3 GWs of capacity have retired or suspended operations. Further, more than 8.3 GWs of aging gas and steam turbine capacity could face retirement. Nuclear station Indian Point Energy Center, with two units comprising more than 2 GWs of capacity in Zone H, will retire in 2020–21. Tighter proposed New York regulations on smog-forming emissions from peaking units could affect 3.3 GWs of peaking capacity in New York City and Long Island beginning between 2023 and 2025, perhaps forcing their retirement as well.
- New York is also preparing to integrate an anticipated 3.8 GWs of energy storage (wholesale and behind the meter) by 2039 (2 GWs by 2029), much of it in the downstate. These resources are expected to provide peak-load reductions over time.



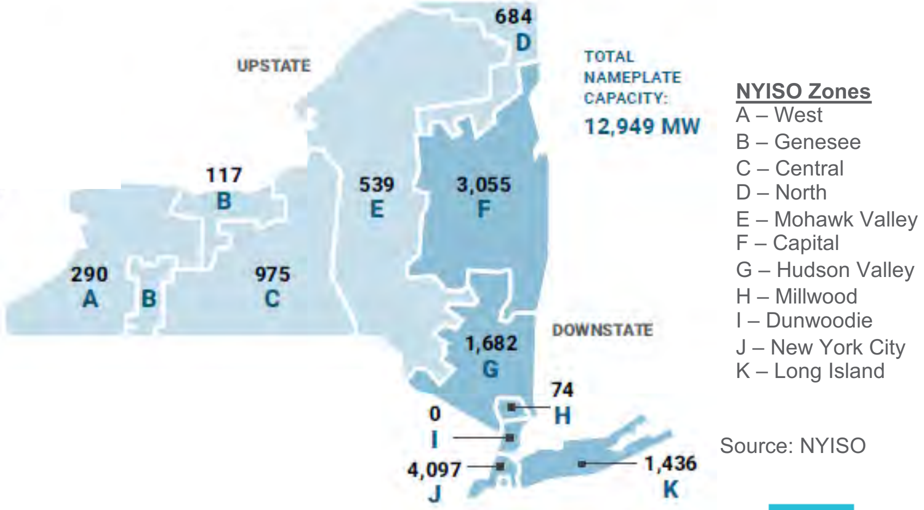
Source: NYISO

NYISO Energy Mix by Region (2018)



Source: NYISO

NYISO New, Upgraded, and Reactivated Capacity by Zone

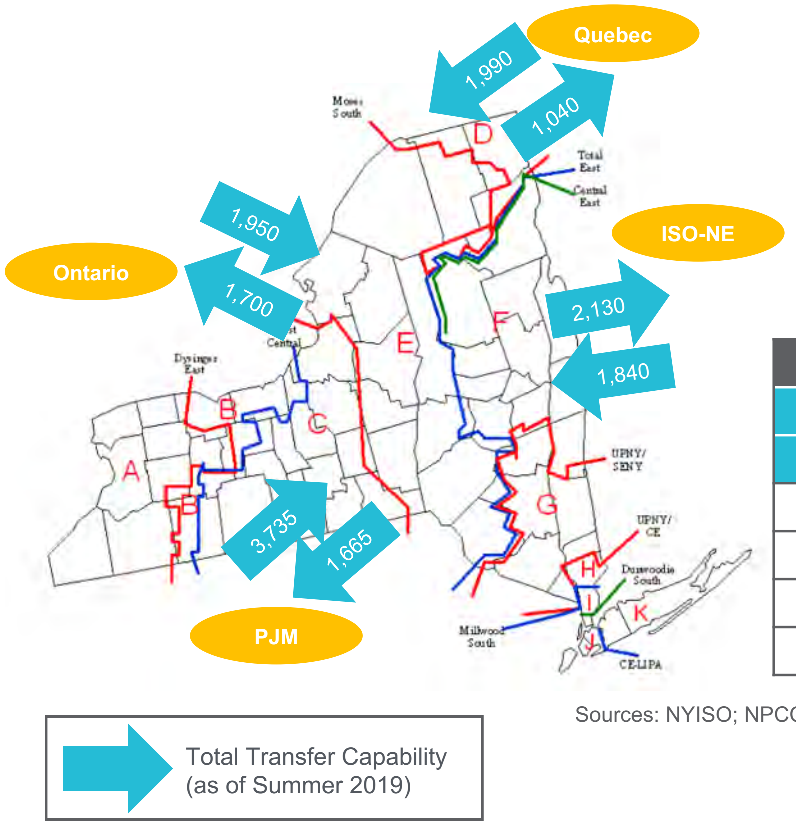


Source: NYISO

Source: NYISO Power Trends

Transmission Topography and Investment

New York Control Area Interfaces, Total Transfer Capability, and Locational-Based Marginal Price Load Zones



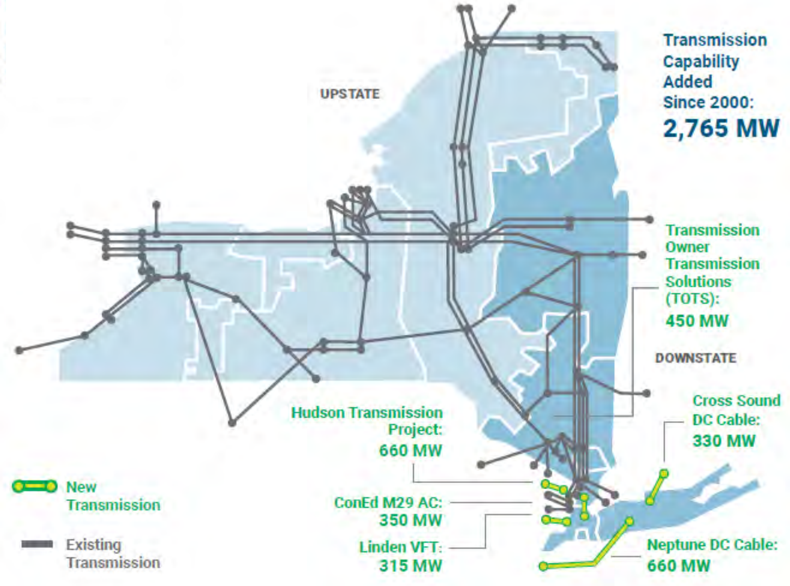
NYCA Scheduled Inter-Area Transfers	
Region	**Transaction (MW)**
To	**2023**
ISO-NE	88
Hydro-Quebec	-1110
PJM and Others	-817
Ontario	0

Sources: NYISO; NPCC

Current Capability

- As discussed previously, NYISO is the sole balancing authority in New York, and its grid is divided into 11 zones. The NYISO monitors and evaluates the 11 major interfaces between the zones within the New York Control Area (NYCA) (see map at left).
- NYCA has scheduled large-scale imports from Quebec and PJM, totaling nearly 2 GWs in 2023.
- Enhancing transmission capability into the downstate area, particularly New York City and Long Island, has been a priority for NYCA. More than 2.7 GWs of capability have been added since 2000 (see map below).

New Transmission in New York State: 2000–2018

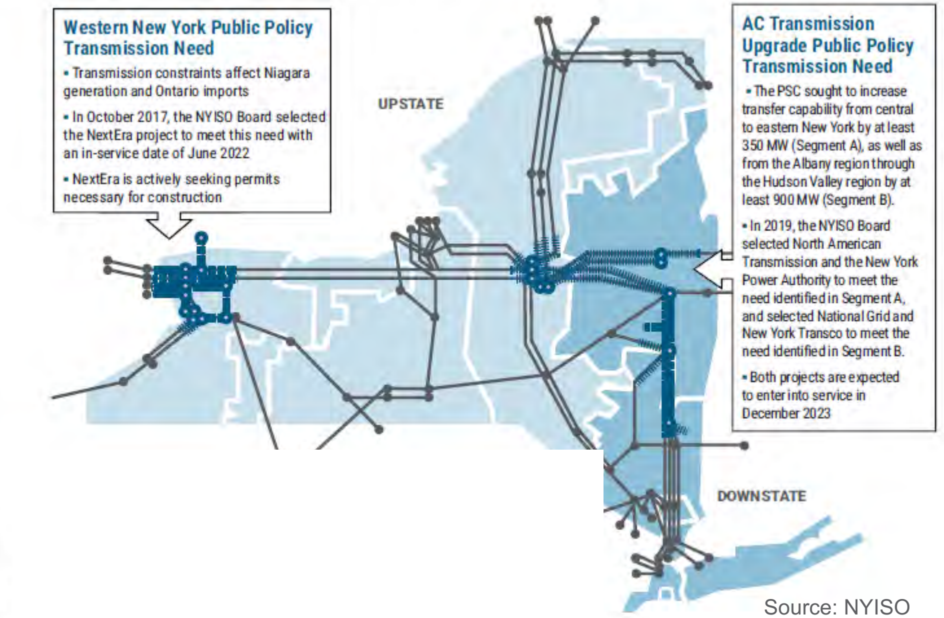


Source: NYISO

Sources: 2018 Transmission Review; NPCC Reliability Assessment, at pp. 45-46 and App. III; NYISO Power Trends

Transmission Topography and Investment (Cont'd)

Public Policy Transmission Needs in New York State



Source: NYISO

Planned Transmission Additions

- New York's policy is also promoting new planned transmission capacity (see map at left).
  - The Empire State Line furthers Western New York public policy objectives, which include adding new transmission capability between Buffalo and Rochester and addressing bulk power system constraints that limit output of the New York Power Authority's Niagara hydroelectric facility.
  - New York also has an AC Transmission Public Policy initiative, which aims to expand transmission capability within existing rights-of-way in the Central New York and Hudson Valley transmission corridors. NYISO has received proposals for upgrades between central and eastern New York and from Albany south through the Hudson Valley region
- With the planned closure of Indian Point Energy Center, state and New York City officials are supportive of the proposed and permitted Champlain Hudson Power Express (CHPE) project, which will bring up to 1 GW of hydropower to the New York City metro area. CHPE is a proposed 330-mile long buried HVDC transmission line that will transport clean energy into the New York metropolitan area. Project developer, Transmission Developers Inc., is targeting to start construction in 2020. Construction of the line will take approximately 3.5 years, so operations would commence in 2024. The total project construction cost is approximately $3 billion.

Transmission Planning Process

- NYISO has a number of transmission assessments it regularly performs, including a reliability needs assessment, a comprehensive reliability plan, an annual transmission review, a public policy transmission planning report, and periodic special policy-related analyses. Reliability and resilience requirements are set forth by NERC, the Northeast Power Coordinating Council, and the New York State Reliability Council.
- NYISO is also reviewing its coordinated system planning process to improve efficiency in developing a more robust and resilient transmission system, as state policy envisions a future that involves significantly increased production from solar, onshore and offshore wind resources, and a proactive consumer sector driving increasing levels of distributed generation and shifting historical patterns of energy consumption.

Sources: NYISO Power Trends; NYISO website (www.nyiso.com\planning)

Resilience Issues

Context

- New York has experienced several major resilience events over the past decade. Those events are summarized in the table on the next page. In recent years, many significant events affecting the power system are driven by weather events. But other events, such as physical attacks and other risks, have played a role (see table at right).
- As a frame of reference for the potential economic impact of a resilience event, New York's 2018 annual GDP was $1.7 trillion. Downstate New York is home to a large presence of the nation's financial sector, a critical capability for the economic health of the United States.

Gas Dependency

- As New York and other regions have become more dependent upon gas-fired generating capacity, fuel availability has emerged as an area of focus. In New York, natural gas makes up more than half of the state's total generating capacity, and as of early 2018, about 70% of natural gas capacity could switch to oil. Dual-fuel generation has provided some redundancy when gas transportation is constrained and/or where firm pipeline capacity is unavailable to generators. However, in extreme conditions (see discussion of the 2014 Polar Vortex), without proper preparation, this generation is not a panacea. Moreover, tighter environmental rules (see infra) could affect some of those units.
- New York's policy has eschewed expanding or building new gas pipelines to bring shale gas from the Marcellus and Utica plays just south and west of the state. In lieu of new pipeline construction, Con Edison announced two agreements with existing pipeline companies to add capacity by upgrading compression facilities. These projects would provide incremental capacity increases to alleviate constraints, and both could enter service by November 2023.
  - In April 2019, Con Edison reached an agreement with Kinder Morgan's Tennessee Gas Pipeline to bring additional capacity into Westchester County.
  - In May 2019, Con Edison announced another agreement, with Iroquois Gas Transmission System, L.P., to provide incremental natural gas capacity to the Bronx and parts of Manhattan and Queens.
- Additional electric import capability could enhance electric resilience on the coldest days when firm gas delivery for end-use customers is highest.

Reported Electric Disturbance Events Affecting New York (2017–April 2019)

Cause	2017	2018	2019 YTD
Fuel Supply Deficiency	2	1	0
Severe Weather	2	9	0
Vandalism	0	1	0
Suspected Physical Attack	0	1	0
Actual Physical Attack	1	0	0
Suspicious Activity	0	1	0
Transmission Interruption	0	1	0
System Operations	0	0	1

Note: For multiple causes, classified under one only.
Source: DOE OE-417; ScottMadden analysis

Sources: NYISO Resilience Testimony; DOE; EIA; industry news

Resilience Issues (Cont'd)

Fuel and Energy Security Study

- Commissioned in late 2018, NYISO engaged Analysis Group to conduct a study of the "winter resilience of the system," with special consideration given to fuel availability as reliance on gas-fired (including dual-fuel) resources is increasing. Specifically, the study focused on "event-driven system vulnerabilities under harsh winter conditions."
- The study examines a number of scenarios, accounting for different assumptions about the following system factors: (i) generation retirements and additions; (ii) availability of natural gas; (iii) initial oil inventories and the ability to refuel; (iv) power transfers in and out of the region (system configuration); and (v) physical disruptions. The scenarios included long-duration (2+ weeks) events. The study resembles a similar scenario-based fuel security study performed by PJM in late 2018.
- Key observations were as follows:
  - **Well-equipped to manage fuel risks:** New York is well-equipped to manage energy/fuel security risks and has taken steps to monitor, evaluate, and address potential risks associated with the availability of fuel and responsiveness of supply resources. These steps include market rules and operating procedures. Reliability challenges are comprised of low-probability combinations of system conditions and physical disruptions.
  - **But gas availability is of concern:** The loss of gas-fired generation capacity presents significant concerns. Reduced gas scenarios run into trouble quickly when combined with other system conditions (reduced imports, potential "peaker rule" retirement) and fuel interruptions.
  - **Dual-fuel is vital:** Significant loss of load events appear where there is reduced operation of oil-fired generating assets, particularly in downstate regions (especially Long Island). Thus, dual-fuel capability (oil backup to gas) is "vital" for reliability. A lack of refill capability has large impacts.
  - **Transmission is valuable, including access to offshore wind:** As stated by Analysis Group, "Maintaining power imports during cold weather conditions and meeting the state's renewable resource goals can provide valuable reliability support and this may be particularly true with respect to offshore wind." With development of offshore wind resources and the potential for its injection into Zones J (New York City) and K (Long Island), those resources can improve capability from other resource types. In particular, offshore wind production can supplant some oil-fired generation and slow the rate of decline of oil inventory (see graph on next page).
  - **Additional study needed:** Additional study of the effects of the requirements of the recently enacted Climate Leadership and Community Protection Act (or CLCPA), including the pace and magnitude of change, is needed to fully assess winter operational risks.

Source: Analysis Group, "NYISO Fuel and Energy Security Initiative Study Results and Observations," presentation to NYISO ICAPWG/MIWG (Sept. 24, 2019)

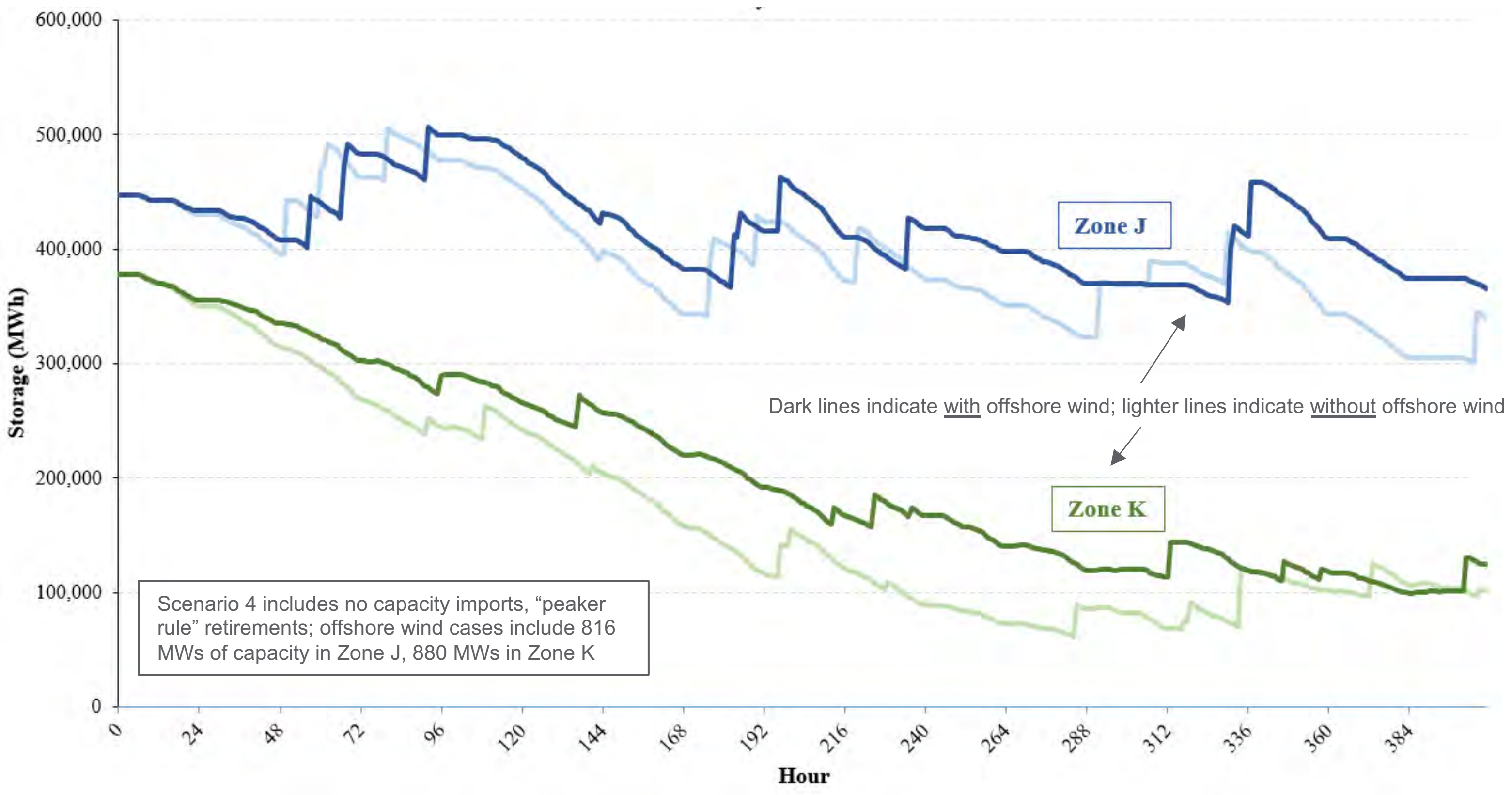
Resilience Issues (Cont’d)

Fuel and Energy Security Study (Cont’d)

- The study noted that the addition of offshore wind farms in Zones J (816 MWs) and K (880 MWs) would reduce the amount of oil needed to be burned, preserving oil reserves for later in the period modeled.
- Offshore wind reduces the number and severity of hours with potential for lost load across all cases where there is a reliability risk, especially in cases where initial fuel inventory before an event is low.

During stressed winter system conditions, transmission import capability—whether from adjacent regions or from NYISO-linked (prospective) offshore wind installations—is a valuable capability to preserve resilience of the grid and to help avoid loss of load.

NYISO Fuel and Energy Security Initiative Study
Zones J (New York City) and K (Long Island) Oil Storage (in MWh Equivalent)
Scenario 4: Low Fuel Inventory with and without Offshore Wind



Source: Analysis Group, “NYISO Fuel and Energy Security Initiative Study Results and Observations”, presentation to NYISO ICAPWG/MIWG (Sept. 24, 2019)

Resilience Issues (Cont'd)

Selected Major Bulk Power Events Affecting New York	
Event	**Description**
Northeast Snowstorm (Oct. 29-30, 2011)	▪ An unprecedented fall snowstorm hit the northeastern United States, breaking all previous October records. Parts of New York, New Jersey, and Pennsylvania also received more than a foot of snow. The quantity of snow held by the unusually top-heavy trees, coupled with the soft, wet ground, resulted in a great number of healthy trees, most outside of utility rights of way, being uprooted and falling onto distribution and transmission lines. ▪ On the morning of October 30, near the end of the storm, more than 3.2 million homes and businesses were without power. Thousands were without power for more than a week, some for as long as 11 days. Estimates put storm costs between approximately $1 billion and $3 billion.
Superstorm Sandy (Oct. 29, 2012)	▪ Hurricane Sandy made landfall on the New Jersey shore Monday, October 29, at approximately 8:00 p.m. Eastern as a post-tropical cyclone with winds of 80 MPH with a record-breaking storm surge. ▪ Transmission owners reported that due to the storm surge being so extensive, low-lying stations were flooded and became completely inoperable. Generating facilities over a very wide footprint were either forced or tripped off-line, and some generators were rendered unavailable due to the loss of interconnecting transmission. Over the course of the event, 20,007 MWs of generation capacity were rendered unavailable. The distribution system was also severely damaged. By late Monday, October 29, approximately 8.352 million electric customer outages were reported across the impacted area (more than 2.2 million in NYISO). Most entities returned 95% of their customers to service between November 1, 2012, and November 9, 2012. ▪ Despite the catastrophic nature of the storm and the high number of transmission line outages, the hard hit areas of Long Island and New York City remained connected to the Eastern Interconnection. Throughout the storm and during the recovery period, utilities were able to operate within power transfer limits. NYISO's restorage time was 12 days.
Polar Vortex (Jan. 2014)	▪ In early January 2014, the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20°F to 30°F below average. NYISO recorded its all-time peak winter load on January 7. ▪ For NPCC (including New England), nearly 2 GWs of cold weather generation outages were reported, with about 770 MWs related to fuel-gelling issues. Some dual-fuel units experienced challenges ranging from a lack of natural gas required for starting the alternate fuel to fuel freezing in the injectors. Outages related to curtailments and interruptions of natural gas delivery were the significant contributor of the NPCC generator outages. These outages totaled a maximum of 3,296 MWs of generators, and they significantly impacted NPCC's generation resources, starting at approximately 10:00 a.m. on January 7, 2014.

Source: NERC

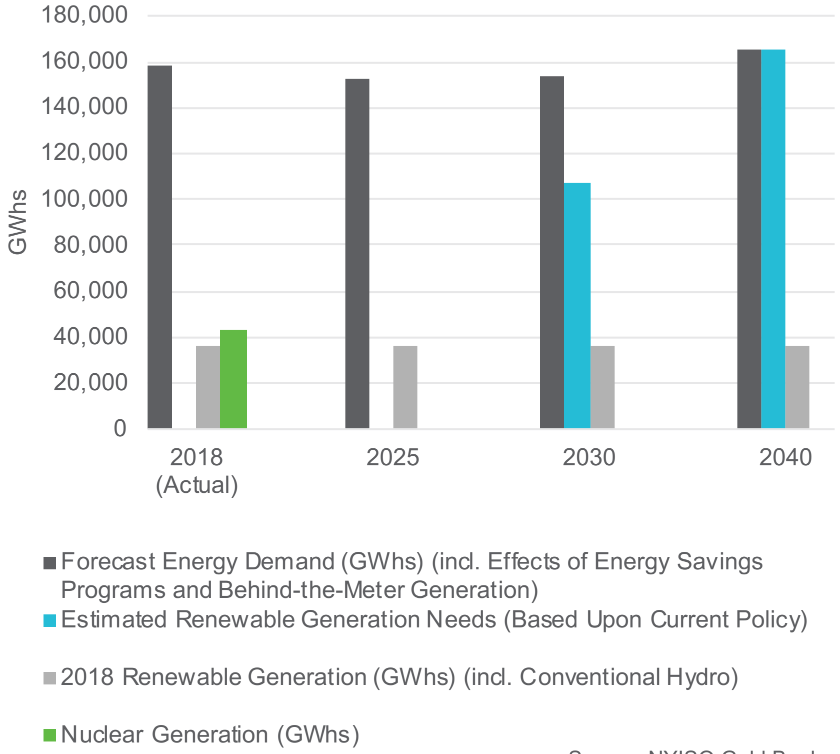
Resilience Issues (Cont'd)

Selected Major Bulk Power Events Affecting New York (Cont'd)	
Event	**Description**
Winter Storms Quinn and Riley (Mar. 2018)	▪ Back-to-back winter nor'easters Quinn and Riley battered the Northeast in March 2018. The storms caused New York-area outages, second only to Superstorm Sandy, despite a storm-hardening investment of $1 billion. Key challenges, which all utilities will have to consider for future planning given increases in storm intensity, were as follows: – Storm strength far exceeded weather forecasts, especially wind gusts. – Storm breadth interfered with ability to secure mutual assistance crews. – Quick succession of storms meant a second caused additional damage before repairs to damage from the first were completed. – Significant grid damage was caused by trees not in the utility's right-of-way.

Sources: NERC; Consolidated Edison Co. of New York

Renewables Integration

Forecast Energy Consumption vs. Actual and Projected Renewable Energy Needs (GWhs)



Source: NYISO Gold Book

Demand-Side Considerations

- New York has established some ambitious clean and renewable goals. These policy drivers significantly impact energy and demand resources in NYCA.
  - In August 2016, New York promulgated a clean energy standard requiring that 50% of electricity consumed in New York State be generated from renewable resources by 2030. Per NYISO, the clean energy policy incentivizes development of about 17 GWs of new, largely intermittent capacity to enter grid and markets. It also avoids premature deactivation of more than 3.1 GWs of nuclear capacity.
  - In June 2019, the New York legislature enacted the Climate Leadership and Community Protection Act (CLCPA), requiring that 70% of electricity supplying state-regulated load-serving entities come from renewables by 2030, up from an existing renewable standard of 50%, and achieving a carbon-free power grid with 100% clean electricity sources by 2040.
    - The bill is designed to achieve the administration's goals of quadrupling the state's offshore wind capacity to 9,000 MWs by 2035 while doubling distributed solar deployment to 6,000 MWs by 2025 and deploying 3,000 MWs of energy storage by 2030.
    - CLCPA aims to eliminate 85% of the state's economy-wide carbon emissions by 2050, with the remaining 15% to be offset or captured through the use of carbon capture and sequestration technology and the expansion of natural carbon sinks.
- New York is also a member of the Regional Greenhouse Gas Initiative (RGGI), which is a cooperative effort of New England and Mid-Atlantic states to cap and reduce CO_2 emissions from the power sector. It is a mandatory, market-based CO_2 emissions limits. Through a program review in 2017, RGGI states agreed to a number of program changes, including a 30% cap reduction between 2020 and 2030, essentially ratcheting down the availability of allowances to generators that produce greenhouse gases.

Sources: NYISO Power Trends; NYISO Gold Book

Renewables Integration (Cont'd)

Demand-Side Considerations (Cont'd)

- NYISO has identified a number of environmental and energy policy drivers that influence decisions for grid investment for reliability as well as price signals for resources.

Key Environmental and Energy Policies in New York State		
Public Policy Initiative	**Policy Goal**	**Policy Implications**
Accelerated Energy Efficiency Targets (Dec. 2018)	Reduce end-use energy consumption by 185 trillion BTUs by **2025**, including potential electrification to reduce fossil fuel use in buildings	Declining load and potentially changing load patterns, such as electrification of building heating systems, impact long-term forecasting and investment signals
Clean Energy Standard (CES) (August 2016), updated by CLCPA (July 2019)	50% of electricity consumed in New York State generated from renewable resources by **2030**, increased by CLCPA to **70%** by **2030**. Retain upstate nuclear capacity. Zero electric sector emissions by **2040**.	Incent about **17,000 MWs** of new, largely intermittent capacity to enter grid and markets. Avoid premature deactivation of more than 3,100 MWs of nuclear capacity. Under CLCPA, procurement targets of **6 GWs** solar PV by **2025**; **3 GWs** energy storage by **2030**; and **9 GWs** of offshore wind by **2035**.
Indian Point Deactivation	Deactivate Indian Point units 2 and 3 by **2020** and **2021**, respectively	NYISO Deactivation Assessment found no reliability need with loss of **2,311 MWs** based on addition of expected resources
New York City Residual Oil Elimination	Eliminate combustion of fuel oil numbers 6 and 4 in New York City by **2020** and **2025**, respectively	**2,964 MWs** of installed capacity affected
Offshore Wind Development	Develop 2,400 MWs of offshore wind capacity by **2030**	As much as **2,400 MWs** of new intermittent capacity interconnecting to the grid in southeastern New York by 2030
CO_2 Performance Standards for Major Electric Generating Facilities	Establish restrictions on carbon dioxide emissions for fossil fuel-fired facilities in New York by **2020**	**Approximately 860 MWs** of coal-fired capacity expected to deactivate or re-power
Regional Greenhouse Gas Initiative (RGGI)	Reduce carbon dioxide emissions cap by 30% from **2020** to **2030** and expand applicability to currently exempt "peaking units" below current 25 MWs threshold	**26,100 MWs** of installed capacity participate in RGGI
"Peaker Rule" – Ozone Season Oxides of Nitrogen (NOx) Emissions Limited for simple cycle and regenerative combustion turbines	Reduce ozone-contributing pollutants associated with New York State-based peaking unit generation	DEC rule proposal impacts approximately **3,300 MWs** of peaking unit capacity in New York State
Storage Deployment Target	Reduce costs, support renewable resource integration, and increase storage capacity through bulk system, distribution, and customer-based installations	Installation and market integration of **1,500 MWs** of battery storage capacity by 2025 and **3,000 MWs** by 2030
U.S. Clean Water Act	Adoption of "Best Technology Available for Cooling Water Intake" to protect aquatic biota	**16,900 MWs** of installed capacity must achieve compliance upon licensing renewal

*Add: CLCPA (?)

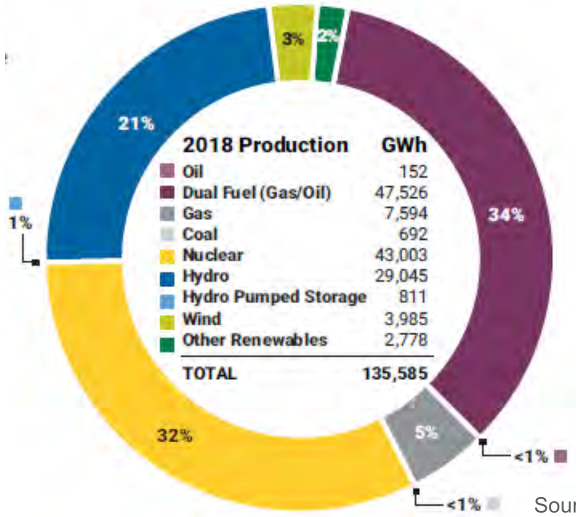
Source: NYISO Power Trends; industry news

Renewables Integration (Cont’d)

Supply-Side Considerations

- Renewable resources, particularly wind resources, have been growing in New York for the past decade. However, gas and dual-fuel (thermal) assets have grown over the same period (see graph lower right).
- Clean resources (renewable and nuclear) provided 56% of end-use energy in 2018, but only 26% of energy was served by renewables. New York has significant hydro resources, representing about 21% of New York’s energy in 2018, and most marginal hydro units (those setting market prices) provide some storage capacity.
- NYISO reports about 21 GWs (nameplate) of proposed renewable resources and nearly 2 GWs of proposed energy storage. More than 7 GWs are solar and wind facilities upstate. However, as mentioned earlier, New York’s policymakers have promoted New York’s offshore wind potential, and nearly 13 GWs have been proposed near downstate load centers.

2018 New York Net Generation by Fuel Type



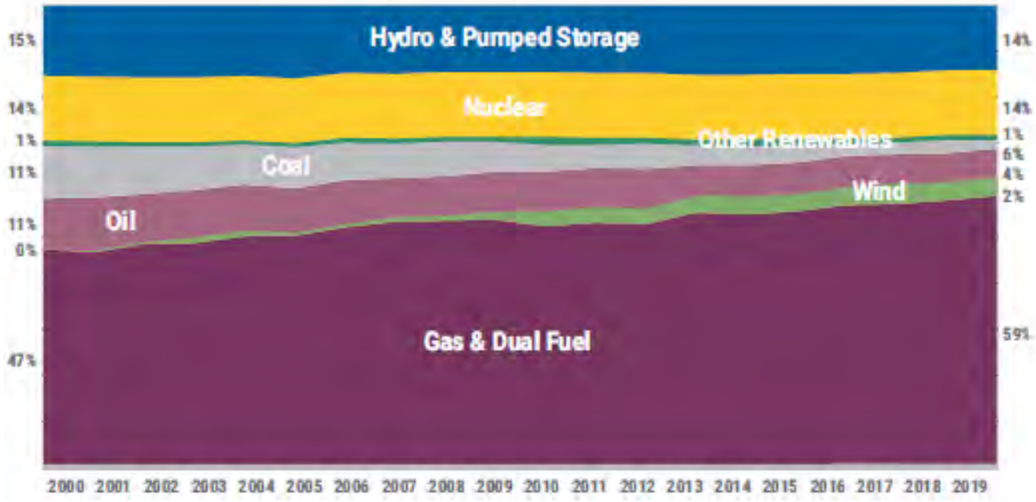
Source: NYISO

Existing and Proposed Wind, Solar, and Energy Storage Nameplate Capability in New York State (MW)

	UPSTATE (zones A-E)	DOWNSTATE (zones F-K)
Proposed land-based wind	4,313	0
Existing land-based wind	1,985	0
Proposed offshore wind	0	12,908
Proposed solar	2,966	1,072
Existing solar	0	57
Proposed energy storage	540	1,432
Existing energy storage	0	30

Source: NYISO

New York State Capacity Mix by Fuel Type (2000–2019)



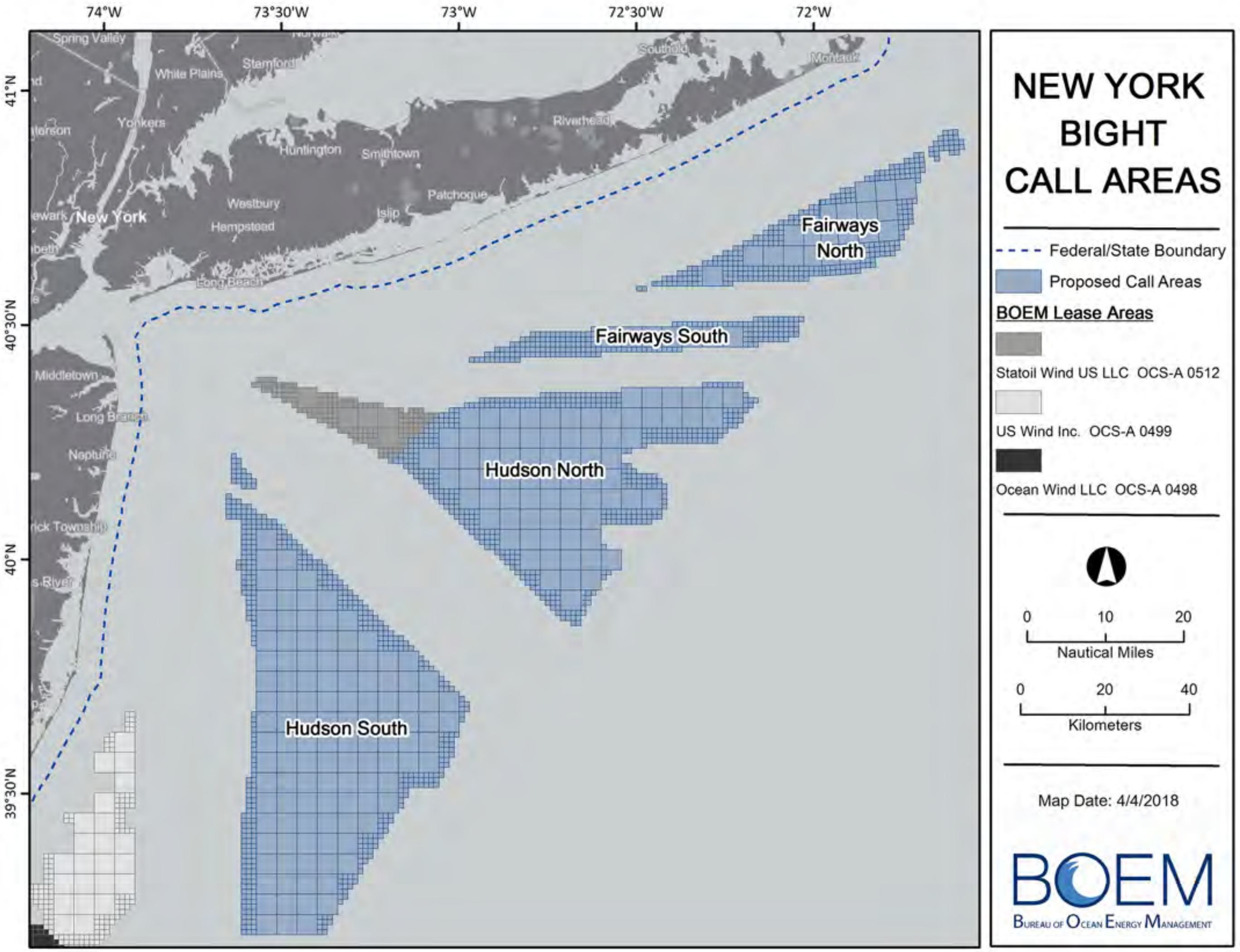
Source: NYISO

Sources: NYISO Power Trends; 2018 SOM Report, at p. 7

Renewables Integration (Cont'd)

Supply-Side Considerations (Cont'd)

- After a period of study, the U.S. Bureau of Ocean Energy Management (BOEM) is moving forward with wind energy planning efforts on the Outer Continental Shelf in the New York Bight region, which represents an area of shallow waters between Long Island (to the north and east) and the New Jersey coast (to the south and west).
- The four Call Areas for potential wind development include 222 whole OCS blocks and 172 partial blocks and comprise approximately 2,047 square nautical miles (nmi) (702,192 hectares) (see map at right).
- New York selected two offshore wind projects, one (816 MWs) proposed by Norway's Equinor ASA, called Empire Wind, and another (880 MWs) by a joint venture between Denmark's Ørsted A/S and U.S. utility Eversource Energy, called Sunrise Wind.
  - Sunrise Wind will be located 30 miles east of Long Island's Montauk Point. The joint venture has established a memorandum of understanding to work with Con Edison Transmission Inc. and state-owned New York Power Authority on a transmission component.
  - Empire Wind will be located 15 to 30 miles southeast of Long Island, with the power supplying New York City.



Source: BOEM

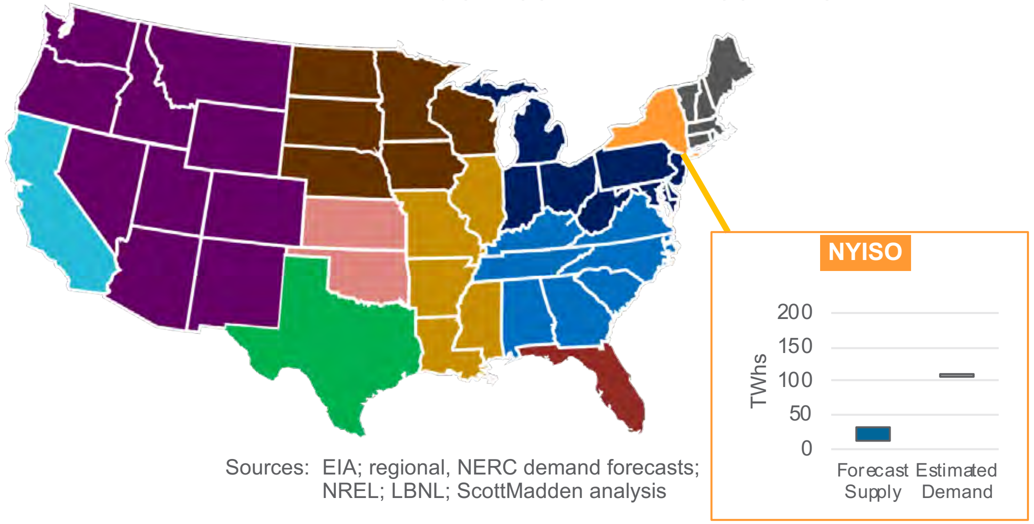
Sources: Bureau of Ocean Energy Management; S&P Global Market Intelligence, "New York selects 2 projects for 1,700 MW of offshore wind" (July 18, 2019), and "US East Coast states to add more than 19,000 MW of offshore wind by 2035" (Aug. 22, 2019)

Renewables Integration (Cont'd)

Integration Challenges – RPS Supply-Demand Balance

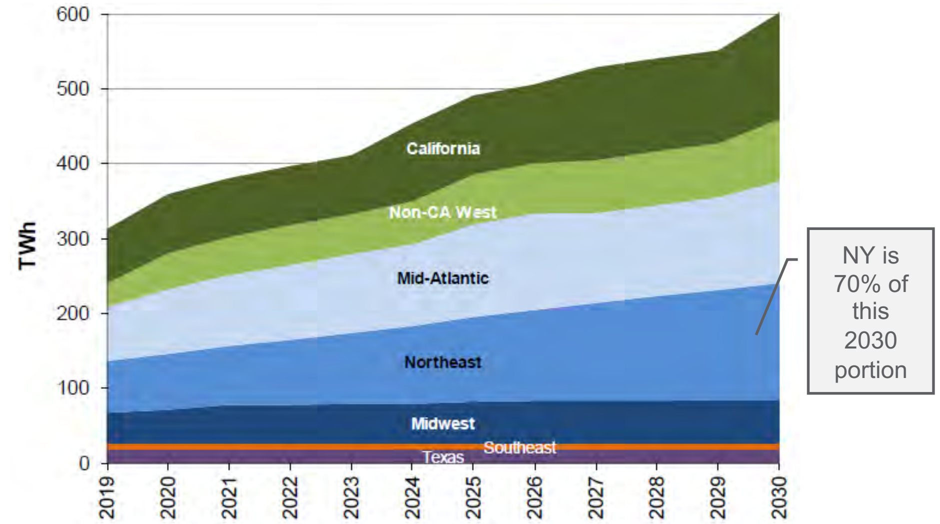
- New York's ambitious renewable portfolio standards (RPS), as well as its 2040 100% clean energy goal, will require the installation or import of significant amounts of renewable resources and other initiatives, such as energy efficiency, distributed energy resources, energy storage, and carbon capture and storage.
- Lawrence Berkeley National Laboratory (LBNL) estimates that renewable demand in the Northeast grows to nearly 156 TWhs by 2030 (see graph below right), of which New York accounts for about 70% (108.8 TWhs) of that total. By 2050, LBNL estimates that RPS-driven demand will be 113 TWhs by 2050, about 16% of U.S. RPS demand. That total does not include potential demand from broader clean electric standards.
- A separate analysis by the American Wind Energy Association estimated that wind-eligible demand* in New York totaled 7.9 GWs by 2030. Installed wind generation totaled less than 2 GWs as of 2018 (see page 13).
- As shown below left, currently EIA forecasts 2030 utility-scale wind and solar supply will likely be insufficient to meet New York's estimated demand, requiring additional development and transmission investment, either for import or moving supply from resource centers to demand centers (see next page).

New York Potential Policy-Driven Renewable Energy Demand and Forecast Supply (2030) (as of June 2019) (in TWh)



Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Projected U.S. RPS Demand (Total Compliance Requirements) per DOE LBNL (2019–2030) (as of July 2019) (in TWh)

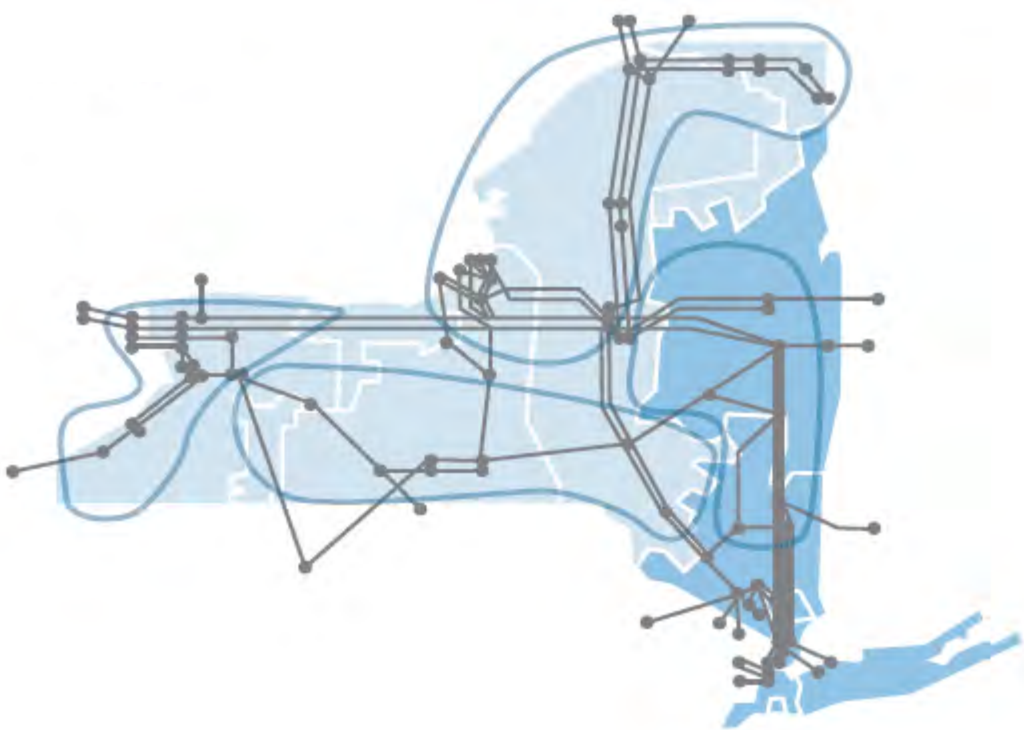


Notes: Per AWEA, wind-eligible demand is the amount of renewable energy needed to meet RPS requirements for which wind is an eligible technology. This excludes technology carve-outs, separate resource classes, and energy efficiency requirements. This category represents the remaining RPS procurement needs that wind is eligible to capture and the maximum RPS market opportunity for wind.

Sources: LBNL 2019 RPS Analysis; AWEA 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Renewables Integration (Cont'd)

New York Renewable Generation Pockets



Source: NYISO

Integration Challenges (Cont'd) – New York Resource Development and Integration

- As mentioned previously, much of the renewable resources available in New York are upstate and primarily wind. Much of the wind resource is located in upstate New York, and its scale outstrips nearby consumption. At present, NYISO has identified upstate generation pockets where existing and anticipated renewable resources will be "bottled up" absent transmission expansion. New York policymakers and NYISO are focused on relieving north-to-south constraints to move more energy downstate to major load centers (see earlier discussion of transmission projects). NYISO believes high-voltage transmission would "un-bottle" these renewables.
- In addition, New York is looking to incorporate more energy storage into its resource portfolio. New York's Public Service Commission has established an initiative to procure 1.5 GWs of energy storage capability by 2025 and 3 GWs by 2030. Storage can help grid operators manage peak demand, smooth variability of intermittent resources, and potentially defer transmission and distribution-related investments. Energy storage resources (ESRs) are heterogeneous in type, and grid owners and operators will have to consider carefully how to integrate them. Some examples of ESRs include capacitors, superconductors, pumped hydro, vehicle-to-grid (battery), thermal, flow batteries, and lithium batteries.
- Offshore wind development is accelerating in New England, New York, and the Mid-Atlantic. Governor Cuomo has called for construction of up to 9 GWs of offshore wind capacity by 2035. New York developed an Offshore Wind Master Plan, issued in early 2018, that looked at the injection of 2.4 GWs of wind by 2030 off the coast of Long Island and New York City. NYISO found that it is feasible to accommodate the injection of 2.4 GWs of offshore wind into Zones J (New York) and K (Long Island) from a thermal bulk transmission security perspective. Additional analysis is needed to determine the nature of the offshore transmission network and interconnection needs, but additional investment will be required to support such development. NYISO is studying whether developers should determine on a project-by-project basis how to connect on land or whether the state should develop an offshore grid to provide interconnection points for multiple future developers.

Sources: NYISO Power Trends; Bureau of Ocean Energy Management; S&P Global Market Intelligence, "New York selects 2 projects for 1,700 MW of offshore wind" (July 18, 2019), and "US East Coast states to add more than 19,000 MW of offshore wind by 2035" (Aug. 22, 2019)

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
New York ISO	▪ Exposure to system stress during sustained heat waves and cold snaps ▪ Projected gas-fired capacity of 49% of on-peak capacity by 2028; some exposure to fuel availability ▪ Gas pipeline constraints; limited pipeline capacity expansion for delivery of Marcellus, Utica play commodity ▪ Interregional coordination with ISO-NE, PJM during stressed system operations—economic exchange in winter 2017–18 to New England; emergency energy to PJM in winter 2014 polar vortex ▪ Leveraging phasor measurement units for system awareness during stressed system conditions ▪ Using N-1-1 contingency events for system planning for enhanced resiliency	▪ Renewable resource unevenly distributed in state—large hydro and wind upstate, offshore wind potential downstate ▪ Significant hydropower upstate; accounts for 21% of energy statewide ▪ Modest wind capacity (about 2 GWs), negligible solar capacity at present ▪ Record wind production of 9% of demand in Feb. 2019; fell dramatically to 3% the following day ▪ Proposed offshore wind of nearly 13 GWs; governor's goal of 9 GWs by 2035 ▪ Current large solar queue of 4 GWs and proposed onshore wind of 4.3 GWs ▪ 2018 maximum monthly wind curtailment of about 5% of total energy; may increase with additional development absent transmission upgrades	▪ Flat to negative load growth, with efficiency expected to reduce peak demand by about 4.8 GWs by 2029; EV usage adds to demand but doesn't change load trajectory ▪ Aggressive public policy goal—70% from renewables by 2030, with 100% clean energy by 2040—anticipates 17 GWs of clean energy development upstate ▪ Significant hydro capacity upstate, providing some storage-like characteristics ▪ Other policy actions affecting downstate—fuel oil generator elimination, Indian Point 2–3 closure, and peaker emissions rules (esp. affecting Long Island)—create resource and deliverability needs ▪ Potential changes in planning assumptions: 1.25 GWs hydro imports from Quebec, 6 GWs offshore wind by 2030	▪ Focus on "unbottling" upstate renewables to serve downstate load centers ▪ Near-term two segments identified: central to eastern NY (350 MWs; double circuit) and Albany south through Hudson Valley region (900 MWs), for $1.23B to be completed by end of 2023 ▪ Increased integration with adjacent ISOs for emergency energy, reserves, access to dual-fuel capable resources ▪ Potential for development of offshore wind per NYSERDA study; accommodate 2.4+ GWs by 2030—potential procurement ▪ Increased import capabilities for resilience: gas "by wire," Canadian hydro by wire ▪ Potential need for renewables import capability given TWh clean energy goals vs. EIA-projected wind, solar generation

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Regional Discussion

PJM INTERCONNECTION

Contents

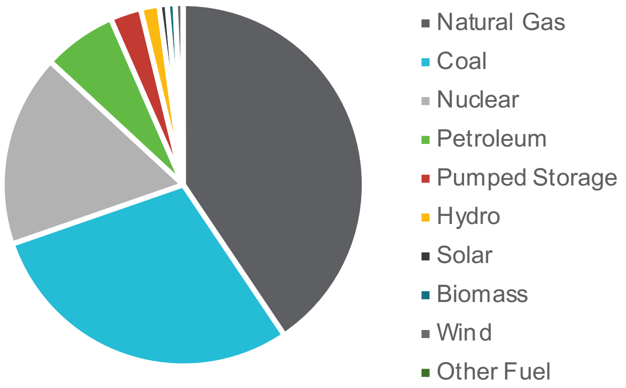
Overview

Description of Region

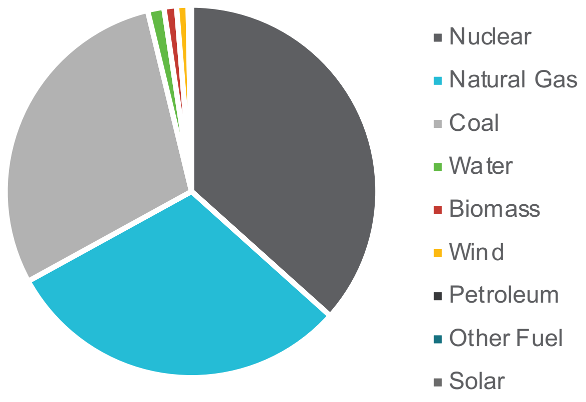
- PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
- Anticipated reserve margins will remain above the reference margin level (installed reserve margin requirement) throughout the assessment period (through 2028).
- PJM serves as balancing authority, planning coordinator, transmission planner, resource planner, interchange authority, transmission operator, transmission service provider, and reliability coordinator for its members.

Key Regional Statistics	
States Covered	DC, DE, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, VA, and WV
Square Miles Covered	369,089
No. of Utilities	Members include 1,018 different entities
No. of Customers/Pop. Served	65M customers
Installed Capacity	54,586 MWs
Transmission Line Miles	84,200
Peak Hour Demand (2018)†	145,637 MWs summer (137,465 MWs winter)
Net Energy for Load	773,646 GWhs
Forecast Growth (Annual)	-0.34%-0.66% peak load growth -0.04%-0.90% demand (usage) growth

2018 Capacity Mix by Fuel



2018 Energy Mix by Fuel



Sources: NERC 2018 LTRA, NERC ES&D; S&P Global Market Intelligence
† Note: Not necessarily coincident; constitutes a sum of assessment area peak-hour demand.

Overview (Cont'd)

Generation Fleet in PJM

- **Adequate Resources for Now**: PJM has more capacity than it needs to meet planning reserve margins. Until 2019, expansion of gas-fired generation has outpaced the retirement of coal and nuclear generation, pushing reserve margins higher. With the pipeline of firm, new gas generation projects declining, reserve margins are expected to decline over the next 10 years as retirements outpace additions. Still, reserves are likely to remain above targets, especially now that Ohio has moved to subsidize the Perry and Davis-Besse nuclear plants and prevent them from deactivation.
- **Retirements**: From 2011 through 2018, 31,722 MWs of generation has retired, including more than 24,000 MWs from 125 coal-fired units, some more than 45 years old.
  - Coal: If formally submitted deactivation plans materialize, more than 25,000 MWs of coal-fired generation will have deactivated between 2011 and 2020. The economic impacts of environmental public policy coupled with the age of these plants make ongoing operation prohibitively expensive.
- **Replacements Mostly with Gas Generation**: Retiring units have been replaced by more than 38,000 MWs of new resources, including more than 29,500 MWs of additional Marcellus and Utica shale natural gas-fired generation and 5,910 MWs of renewable wind and solar generation.
  - Natural gas-fired generation capacity now exceeds coal in PJM. Natural gas plants total more than 65,600 MWs and comprise 86% of the generation currently seeking capacity interconnection rights in PJM's new generation queue.
  - The expansion of natural gas production within the PJM footprint has led to a surge in natural gas generation's share, from 12% in 2010 to 28% by 2017. Despite little new-added generation after 2019, favorable price trends are projected to push gas generation's share in the PJM market to nearly 45% in 2022–2023. Part of this growth is attributable to announced retirement of nuclear plants in the region.

PJM Generator Deactivation Requests
(January 1 through December 31, 2018)

PJM New Capacity and Reserve Margin Forecast (2020-2029)

Sources: NERC 2018 LTRA; Benefits White Paper; S&P Global Market Intelligence

Transmission Topography and Investment

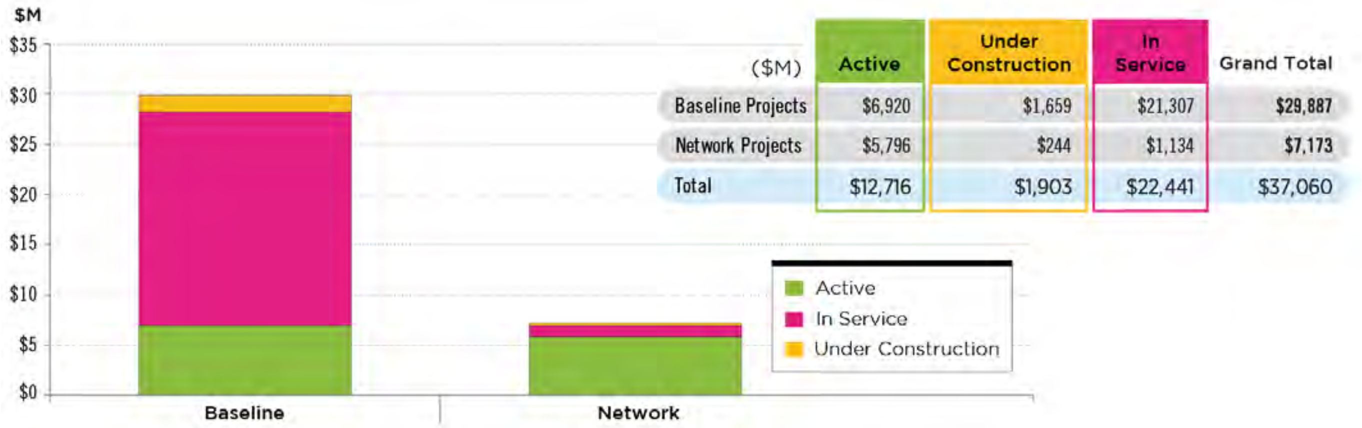
PJM Board-Approved Transmission Expenditures

- **Historical Investment**: Since 1999, PJM's board has approved transmission system enhancements totaling $37.1 billion. Of this, $29.9 billion represent baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria, and address market efficiency congestion relief. An additional $7.2 billion represent network facilities to enable more than 85,000 MWs of new generation to interconnect reliably.
- **2018 Additions**: The numbers depicted at right provide a snapshot of one point in time, as with an end-of-year balance sheet. The $37.1 billion total reflects a net $2 billion increase over December 31, 2017.

Shifting Regional Transmission Expansion Plans (RTEP) Dynamics

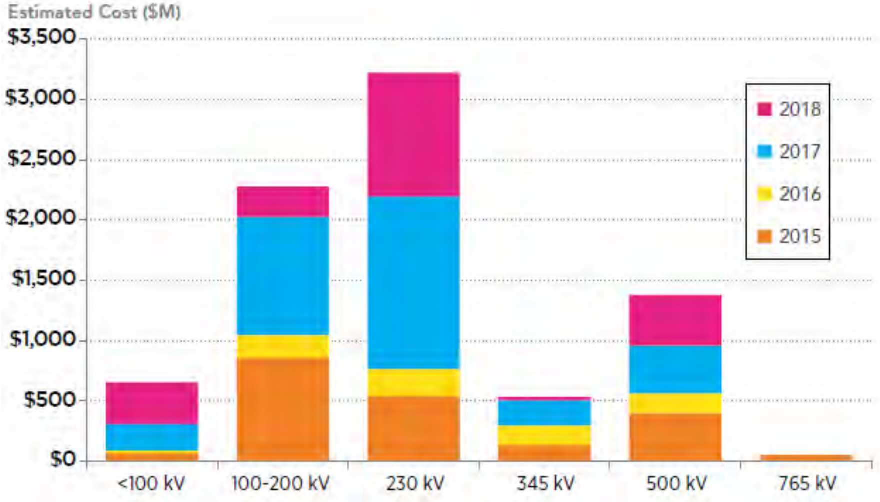
- **Shift in Drivers**: Flat-load growth, energy efficiency, generation shifts, and aging infrastructure drivers, among other factors, continue to shift transmission needs away from large-scale, cross-system backbone projects toward projects that are driven by local needs and individual transmission owner criteria (also referred to as "supplemental projects").
- **Congestion and Local Reliability**: PJM's board-approved projects in 2018 will address market efficiency congestion and solve localized reliability criteria violations. The bottom-right figure reflects lower investments at 345 kV and above over the past four years and higher levels of transmission investments at voltages 230 kV and lower.

Approved RTEP Projects (December 31, 2018)



($M)	Active	Under Construction	In Service	Grand Total
Baseline Projects	$6,920	$1,659	$21,307	$29,887
Network Projects	$5,796	$244	$1,134	$7,173
Total	$12,716	$1,903	$22,441	$37,060

Approved Baseline Projects by Voltage (2015-2018)



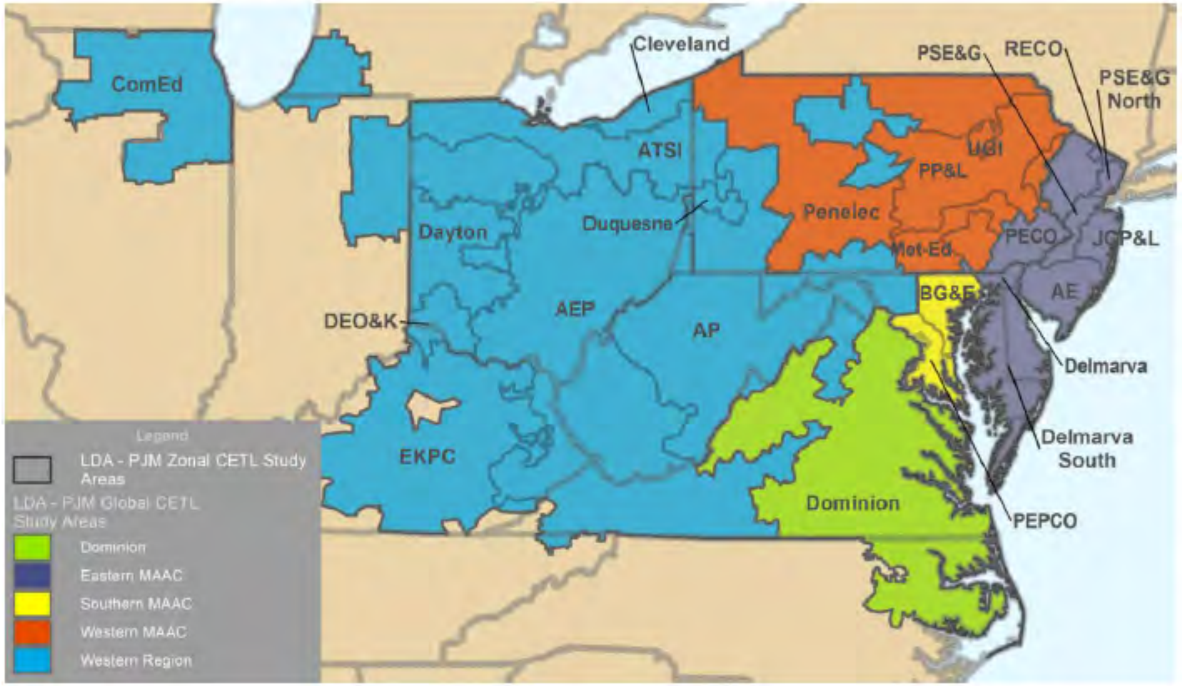
Sources: Benefits White Paper; 2018 RTEP

Transmission Topography and Investment (Cont'd)

Three Planning Paths in PJM

- The three paths for transmission in PJM include planning activities associated with (i) Baseline Projects, (ii) Supplemental Projects, and (iii) Customer-Funded Upgrades.
  1. **Baseline Projects** include projects planned for (i) reliability, (ii) operational performance, (iii) FERC Form No. 715 criteria, (iv) economic planning, and (v) public policy planning (state agreement approach).
  2. **Supplemental Projects** refer to transmission expansion or enhancements not needed to comply with PJM reliability, operational performance, FERC Form No. 715, economic criteria, or state agreement approach projects. Transmission owners plan supplemental projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process include those that expand or enhance the transmission system and could include needs addressing transmission facilities at the end of their useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes.
  3. **Customer-Funded Upgrades** refer to network upgrades, local upgrades, or merchant network upgrades identified pursuant to OATT Parts II, III, and VI and paid for by the interconnection customer or eligible customer or voluntarily undertaken by a new service customer in fulfillment of an upgrade request.

PJM Locational Deliverability Areas



Entity Name	Description
AE	Atlantic Electric
AEP	American Electric Power
APS	Allegheny Power
ATSI	American Transmission Systems, Incorporated
BGE	Baltimore Gas and Electric
Cleveland	Cleveland Area
ComEd	Commonwealth Edison
DAYTON	Dayton Power and Light
DEO&K	Duke Energy Ohio and Kentucky
DLCO	Duquesne Light Company
Dominion	Dominion Virginia Power
DPL	Delmarva Power and Light
Delmarva South	Southern Portion of DPL
Eastern Mid-Atlantic	Global area – JCP&L, PECO, PSE&G, AE, DPL, RECO
EKPC	East Kentucky Power Cooperative
JCP&L	Jersey Central Power and Light
METED	Metropolitan Edison
Mid-Atlantic	Global Area – Penelec, METED, JCP&L, PPL, PECO, PSE&G, BGE, PEPCO, AE, DPL, RECO
PECO	PECO
PENELEC	Pennsylvania Electric
PEPCO	Potomac Electric Power Company
PPL	PPL Electric Utilities Corporation, UGI
PSE&G	Public Service Electric and Gas
PSE&G North	Northern Portion of PSE&G
Southern Mid-Atlantic	Global area – BGE and PEPCO
Western Mid-Atlantic	Global Area – Penelec, METED, PPL
Western PJM	Global Area – APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, OVEC

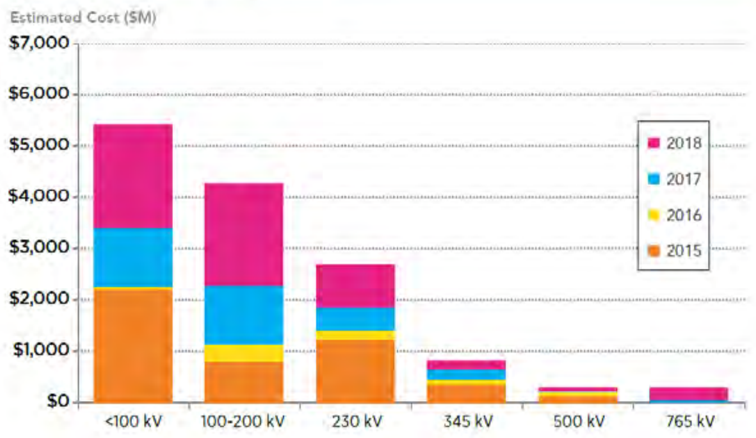
Source: Benefits White Paper

Transmission Topography and Investment (Cont'd)

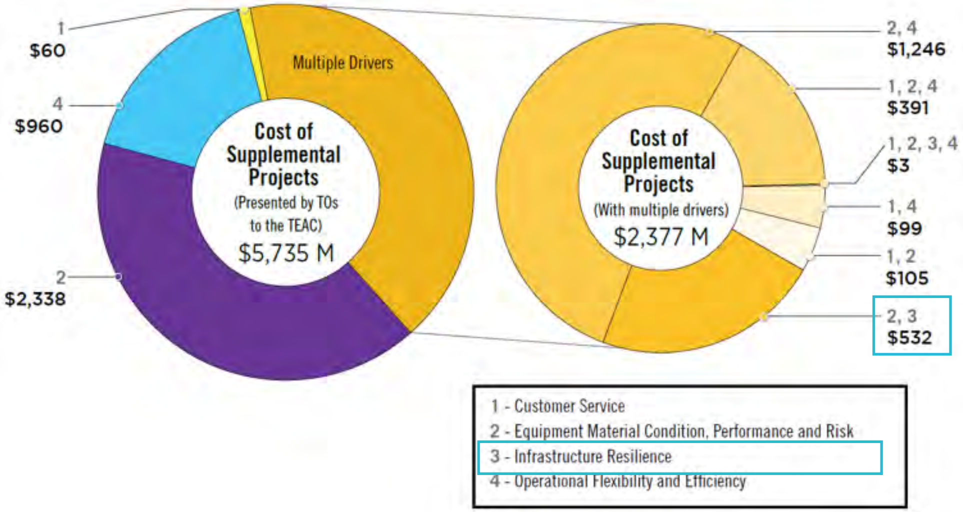
Shifting Transmission Project Drivers

- **Fewer Baseline Projects**: Baseline transmission projects in PJM that are driven by market efficiency and reliability have represented a declining portion of all projects in PJM in the past few years, and supplemental projects have comprised an increasing fraction of planned projects, representing nearly 73% of all projects in 2018. The next largest driver in 2018 was generator deactivations at 13%. Of the 51 baseline projects in PJM's 2018 RTEP, 49 are cost allocated to a single zone, indicating that projects are mostly driven by local need as opposed to PJM's intraregional needs.
  - **Supplemental Projects Defined**: Supplemental projects are not required for system reliability, operating performance, or market-efficiency economic criteria as defined by PJM. And, while not subject to PJM's board approval, each project is reviewed to ensure that it does not introduce other reliability criteria violations and is included in RTEP models.
  - **Drivers of Supplemental Projects**: Supplemental projects are identified by individual transmission owners to address local issues on the transmission owner's system. They tend to be at lower voltages compared to baseline projects, and they have five drivers:
    1. *Equipment Material Condition, Performance, and Risk*: Degraded equipment performance, material condition, obsolescence, equipment failure, employee and public safety, and environmental impact.
    2. *Operational Flexibility and Efficiency*: Optimizing system configuration, equipment duty cycles, and restoration capability; minimizing outages.
    3. *Infrastructure Resilience*: Improve system's ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather, geo-magnetic disturbances, physical and cyber security challenges, and critical infrastructure reduction. (Noted as a co-benefit of projects estimated to cost $532 million bottom right.)
    4. *Customer Service*: Service to new and existing customers. Interconnect new customer load. Address distribution load growth, customer outage exposure, and equipment loading.
    5. *Other Drivers*: Meet objectives not included in other definitions.

Supplemental Projects by Voltage (2015–2018)



2018 Supplemental Projects by Driver



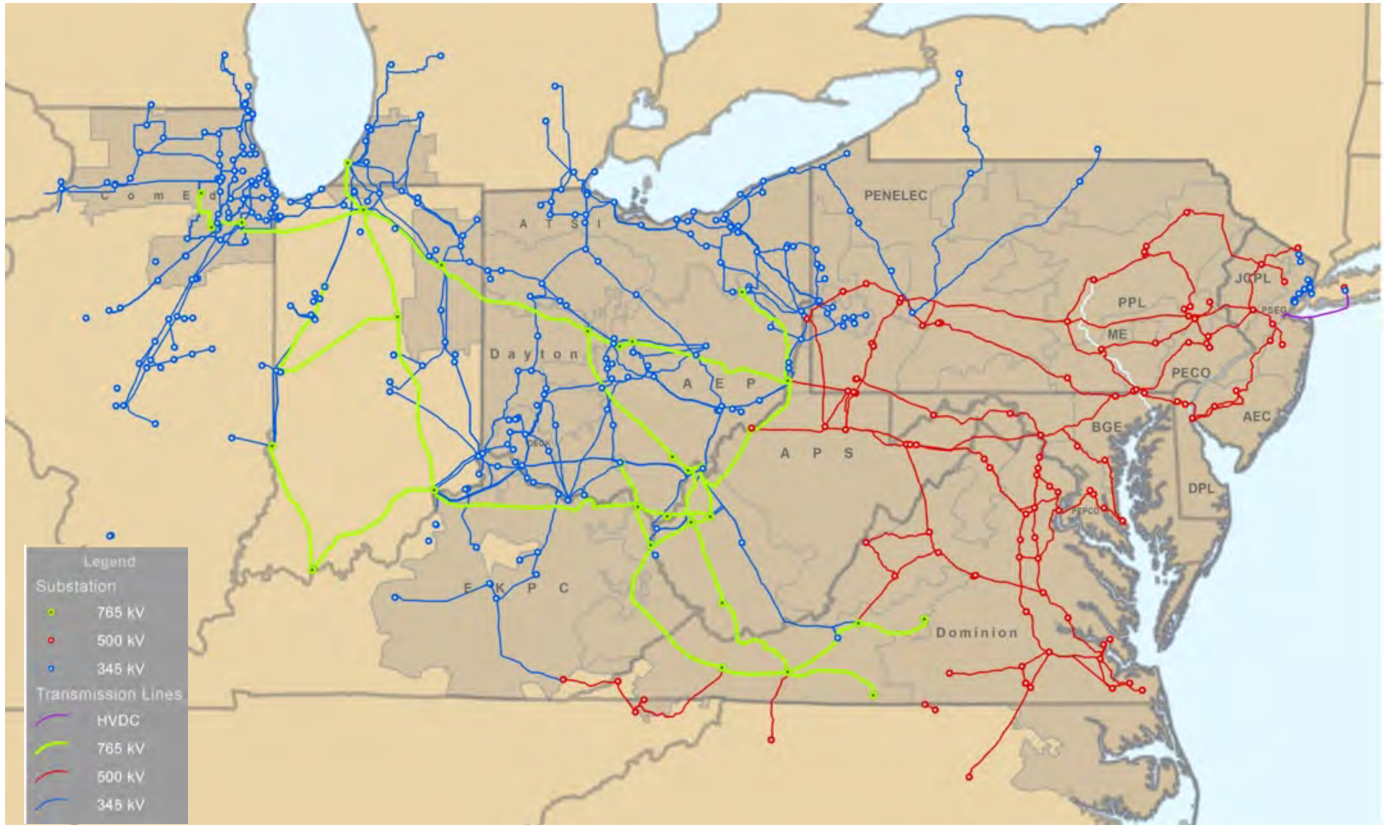
Source: Benefits White Paper

Transmission Topography and Investment (Cont'd)

Cost Allocation for Board-Approved Projects

- Per PJM, its FERC-approved cost allocation procedures reflect the regional "everyone benefits" reality.
- Reliability-Driven Projects
  - The cost for new reliability-driven transmission assets—approved by the PJM board of managers out of PJM's RTEP process—that will operate at 765 kV and 500 kV or comprise double-circuit 345 kV construction are allocated 50% via load-ratio share across all transmission owner zones and 50% via distribution factors based on the impact of a new asset.
  - The socialized component of the allocation acknowledges that a definitive benefit from the elimination of a reliability criteria violation accrues to all consumers of electricity across the PJM footprint.
- Market Efficiency-Driven Projects
  - Board-approved market efficiency-driven RTEP projects that will operate at 765 kV and 500 kV or comprising double-circuit 345 kV construction are allocated 50% via load-ratio share and 50% via zonal benefit from decreased load payments.

PJM Transmission Backbone (December 31, 2018)



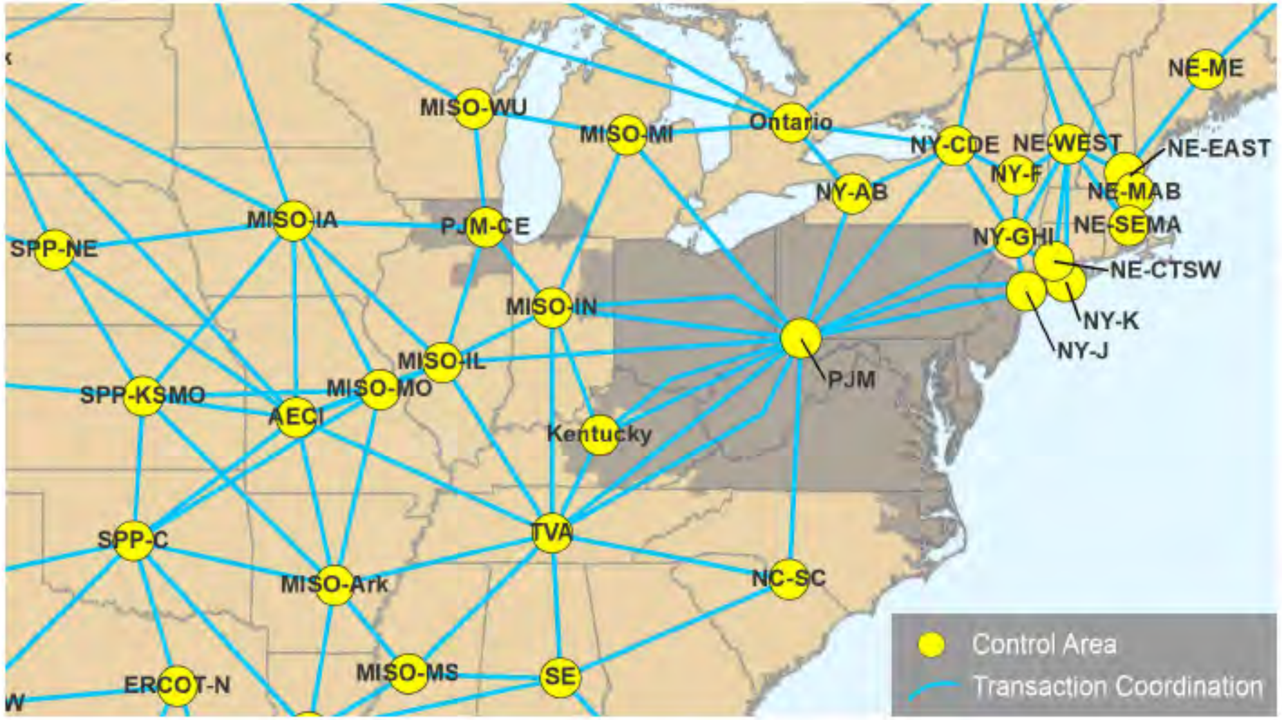
Source: Benefits White Paper

Transmission Topography and Investment (Cont'd)

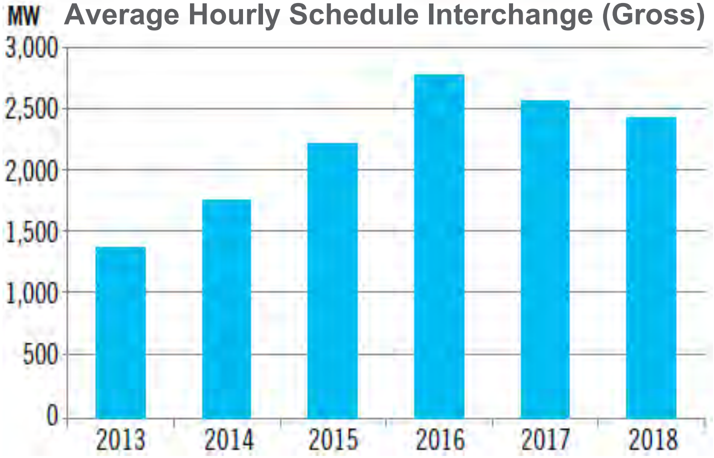
Interregional Transmission Coordination

- Interregional Power Sales
  - PJM has transmission lines connecting to adjoining systems:
    - North – NYISO, ISO-NE, Canadian utilities
    - West – MISO
    - South – Tennessee Valley Authority (TVA), Duke Energy Progress, Louisville Gas and Electric
  - Interregional transmission tie lines permit external generators to be "pseudo-tied" to PJM and participate in PJM's capacity, energy, and ancillary services markets as if they were inside PJM's footprint.
  - Since 2016, PJM has integrated more than 5,000 MWs of pseudo-tied generation into and out of PJM, accounting for the decrease in scheduled interchange since 2016, as shown below.

Interregional Power Sales and Purchases



Average Hourly Schedule Interchange (Gross)



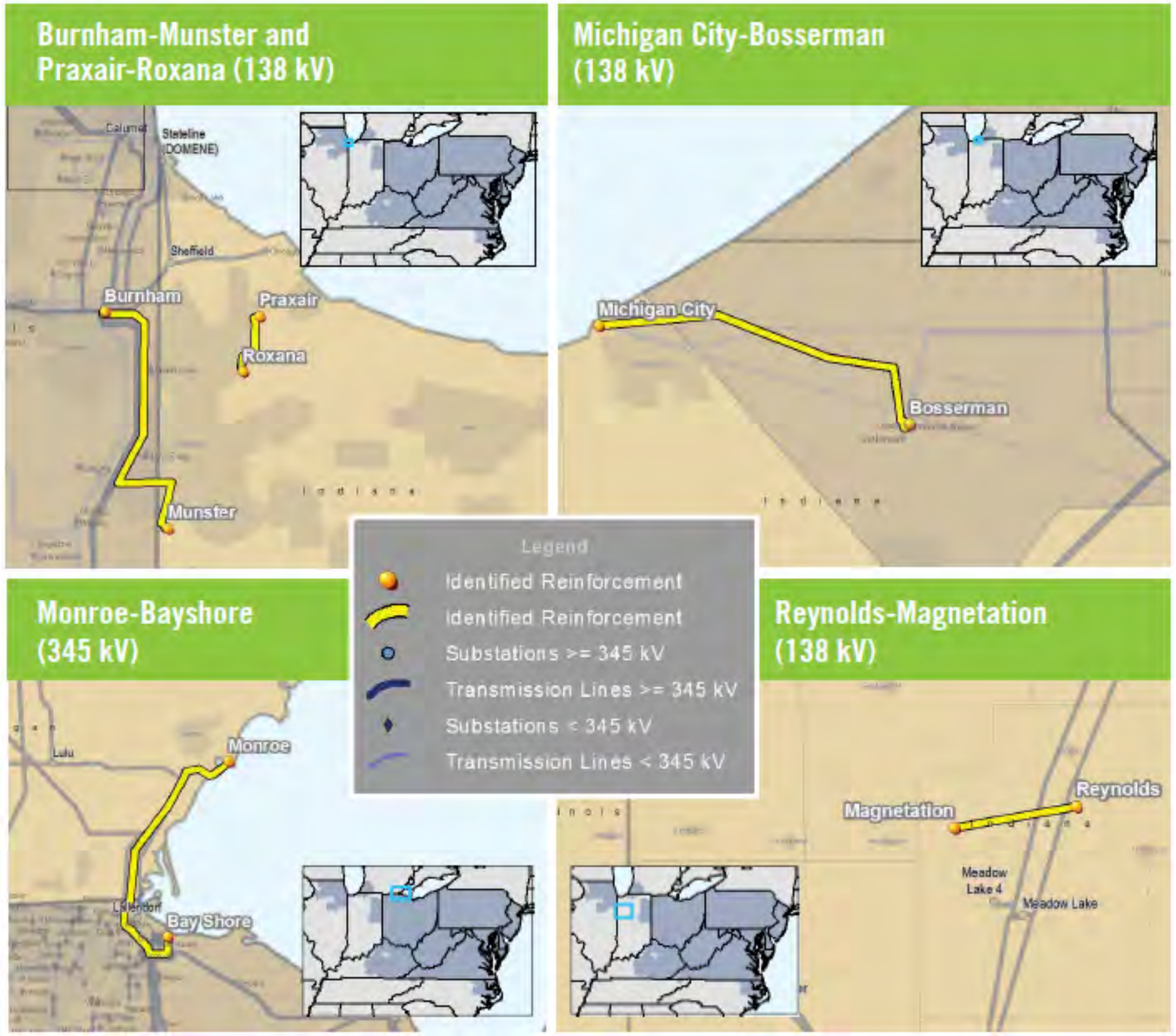
Source: Benefits White Paper

Transmission Topography and Investment (Cont'd)

Interregional Transmission Coordination (Cont'd)

- Targeted Market Efficiency Projects (TMEPs)
  - In December 2017, the PJM and MISO boards approved a portfolio of five TMEPs to address historical congestion along the PJM/MISO boundary.
  - TMEPs are focused on developing low-cost, short lead-time, high-impact projects to address market-to-market congestion.
  - TMEP projects must yield four-year market congestion savings that are equal to or greater than the estimated project capital cost.
  - The total capital cost for the five projects is approximately $20 million, with an estimated congestion savings benefit of $100 million over the first four years of commercial operation.
- Shared Reserve Activation with NPCC
  - PJM participates in reserve-sharing agreements with neighboring systems to assist both PJM and its neighbors with recovery from disturbances, including, in many instances, the loss of a generator greater than 500 MWs.
  - PJM's interregional agreement with the Northeast Power Coordinating Council (NPCC) includes provisions for shared reserves to help with disturbance control. This permits PJM to recover from an imbalance between supply and demand faster than with internal reserves alone. The help is reciprocal, and PJM provides NPCC with shared reserves when called upon.

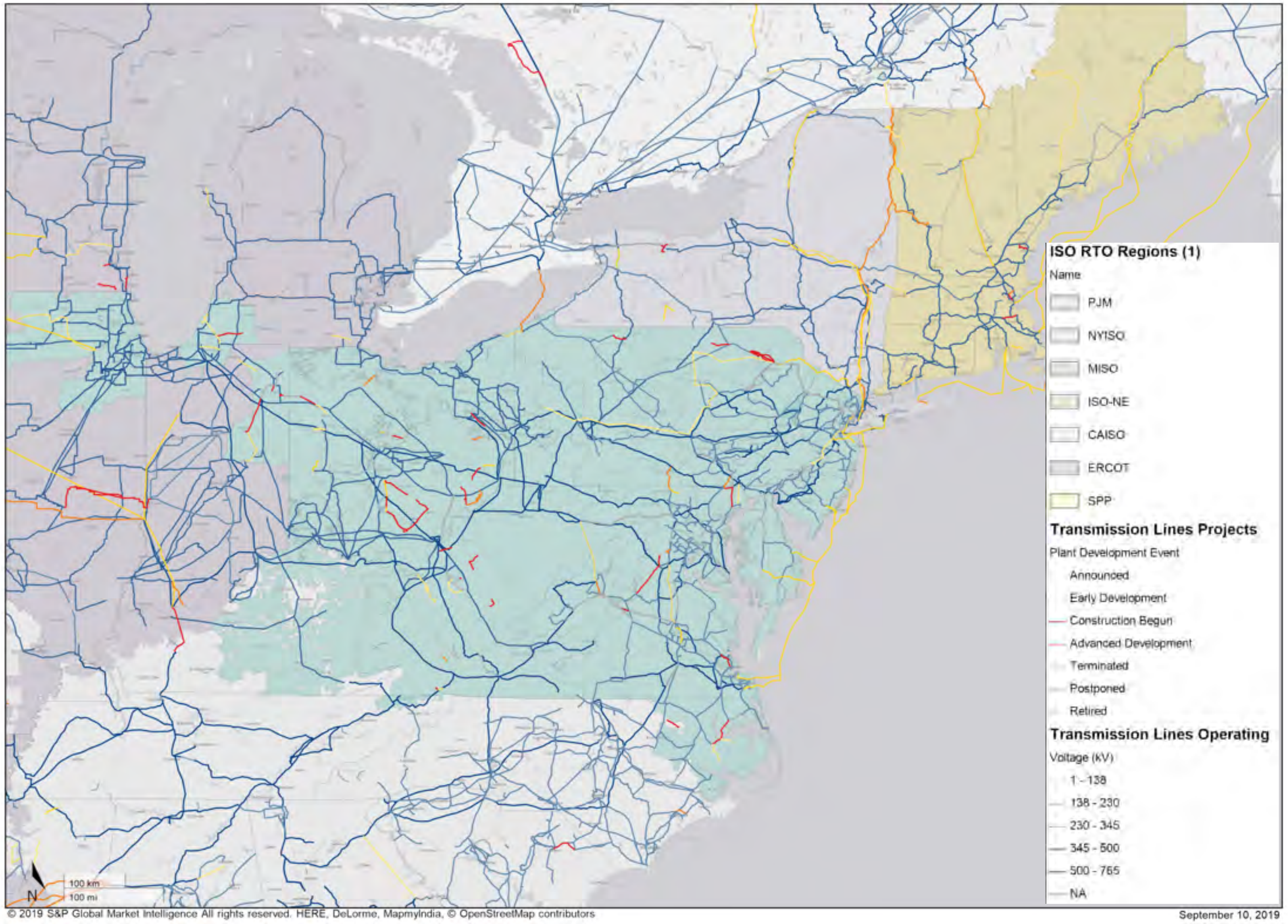
PJM/MISO Approved Targeted Market Efficiency Projects



Source: Benefits White Paper

Transmission Topography and Investment (Cont'd)

Selected PJM Transmission Lines



Transmission Projects

- **Transfer Capability**: There is significant internal transfer capability within PJM, which allows for transfers between subregions. In addition, as described earlier, PJM is interconnected with various adjoining system operators.
- **Planned Lines**: According to NERC, approximately 848 miles of new transmission lines are either in planned stages or under construction as of late 2018, and an additional 25 miles are in the conceptual phase (see table below).
- **Reliability-Driven**: Of the 74 PJM projects cited by NERC, all are driven primarily by reliability, and economics/congestion is listed as the second driver for all projects.

Proposed Transmission Projects (Line Length in Circuit Miles) in PJM (as of Dec. 2018)

Operating Voltage Class (kV)	Conceptual	Planned	Under Construction
100–120	0	119.6	3
121–150	25.1	309.9	144.5
151–199	0	0	
200–299	0	192.6	55.7
300–399	0	12	11
400–599	0		
Grand Total	25.1	634.1	214.2

Source: NERC 2018 Electricity Supply & Demand

Sources: NERC 2018 LTRA; NERC ES&D; S&P Global Market Intelligence

Transmission Topography and Investment (Cont'd)

Transmission Projects (Cont'd)

- **Merchant Projects**: Several transmission projects in PJM, most of which are merchant, are being developed to facilitate the delivery of renewable energy generated in remote areas to load centers. Progress has been limited, though, as many have only been announced or in early development for a number of years.
  - Atlantic Wind Connection: Though initially conceived as a project to move offshore wind to load centers on the East Coast, the project was "essentially divorced" from the nascent offshore wind industry in 2014 after the developer determined that the project could stand on its own as an outlet for congestion in New Jersey. Other benefits purported by the project's developer include "storm-hardening [New Jersey's] electric grid to make it stronger in the face of severe weather."
  - Poseidon Transmission: The 79-mile project, which will provide a connection from New Jersey to a substation in New York, is described as supplying up to 500 MWs from renewable energy from generating facilities in PJM to a load center in New York.
  - SOO Green Renewable Rail HVDC: The 349-mile project connecting Iowa to Illinois (MISO to PJM) will run along the route of an existing railroad, providing 2,100 MWs of capacity using 525 kV of high-voltage, direct-current technology that will be buried underground and connect wind power generated in Iowa to load centers further east.
- The following is a list of proposed projects as of year-end 2018:

Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From ISO	To ISO	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
Albion-South Goshen Transmission Line Rebuild	Indiana Michigan Power Company	21.00	138	IN	IN	PJM	PJM	2019	Announced	Upgrade	NA
Atlantic Wind Connection (New Jersey Link) Phase A	Trans-Elect Development Company, LLC	150.00	320	NJ	NJ	PJM	PJM	NA	Early Development	New	1,800,000
Atlantic Wind Connection – Bay Link	Trans-Elect Development Company, LLC	38.00	320	NJ	DE	PJM	PJM	NA	Early Development	New	NA
Atlantic Wind Connection (New Jersey Link) Phase A	Trans-Elect Development Company, LLC	606.00	320	NJ	VA	PJM	PJM	NA	Early Development	New	NA
Barnesville-Summerfield 138 kV Transmission Line Rebuild	AEP Ohio Transmission Company, Inc.	16.00	138	OH	OH	PJM	PJM	2020	Construction Begun	Rebuild	NA
Beury Mountain to Brackens Creek 138 kV Line (Fayette County Area)	AEP West Virginia Transmission Co.	12.00	138	WV	WV	PJM	PJM	NA	Construction Begun	New	NA
Boone County Area Improvements (Boone - Cabin Creek) (Phase 1)	AEP West Virginia Transmission Co., Appalachian Power Co.	16.00	138	WV	WV	PJM	PJM	2019	Announced	Rebuild	NA
Boone County Area Improvements (Boone - South Charleston) (Phase 2)	AEP West Virginia Transmission Co., Appalachian Power Co.	18.00	69	WV	WV	PJM	PJM	2020	Announced	Rebuild	NA
Bristers to Ladysmith Upgrade	Virginia Electric and Power Company	37.00	500	VA	VA	PJM	PJM	2023	Announced	Upgrade	110,250
Carrollton-Sunnyside 138 kV Transmission Line Rebuild	AEP Ohio Transmission Company, Inc.	20.00	138	OH	OH	PJM	PJM	2019	Construction Begun	Rebuild	50,000
Cass County Area Improvements (Kenzie Creek to Corey)	Indiana Michigan Power Company	29.00	138	MI	MI	PJM	PJM	2019	Construction Begun	Rebuild	NA
Clendenin – Walton Area Improvements (Part 2)	AEP Trans. Holding Co., LLC, Evergy	23.00	138	WV	WV	PJM	PJM	2019	Construction Begun	New	NA
Compass (Phase 1)	PPL Electric Utilities Corporation	95.00	345	NY	PA	NYISO	PJM	2023	Early Development	New	600,000

Note: Includes projects 10 miles or greater and 115 kV and higher and projects in announced, early development, advanced development, and under construction statuses. Data accessed June 2019.
Sources: S&P Global Market Intelligence; transmission project websites; NERC ES&D

Transmission Topography and Investment (Cont'd)

Transmission Projects (Cont'd)

Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From ISO	To ISO	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
Compass Transmission Line (Segment 2)	PPL Electric Utilities Corporation	380.00	345	PA	PA	PJM	PJM	NA	Announced	New	NA
Delano-Scioto Trail 138 kV Rebuild	AEP Ohio Transmission Company, Inc.	12.00	138	OH	OH	PJM	PJM	NA	Construction Begun	Rebuild	NA
Dennison – Yager-Desert Road Rebuild (Eastern Ohio Tri-County)	AEP Ohio Transmission Company, Inc.	15.00	138	OH	OH	PJM	PJM	NA	Adv. Development	Rebuild	NA
Dooms To Cunningham 500 kV Rebuild	Virginia Electric and Power Company	33.00	500	VA	VA	PJM	PJM	2019	Construction Begun	Rebuild	65,000
Dooms – Valley Rebuild Transmission Line	Virginia Electric and Power Company	18.00	500	VA	VA	PJM	PJM	2020	Adv. Development	Rebuild	55,900
East Towanda-South Troy Transmission Rebuild	Trans-Allegheny Interstate Line Company	20.00	230	PA	PA	PJM	PJM	NA	Construction Begun	Rebuild	40,000
Edenton-Trowbridge 230 kV Conversion	Dominion Energy, Inc.	34.00	230	NC	NC	PJM	PJM	NA	Construction Begun	Upgrade	NA
Elmont to Ladysmith Rebuild	Virginia Electric and Power Company	26.00	500	VA	VA	PJM	PJM	2022	Announced	Rebuild	87,000
Erie West to Ashtabula 345 kV Line	Northeast Transmission Development	22.00	345	PA	OH	PJM	PJM	NA	Announced	New	44,900
Fostoria-Fremont Transmission Line Rebuild (Buckley Road-Fremont Center)	AEP Ohio Transmission Company, Inc.	15.00	138	OH	OH	PJM	PJM	2020	Adv. Development	Rebuild	NA
Fulton-Windfall Switch 138 kV Rebuild Transmission Line	AEP Ohio Transmission Company, Inc.	10.00	138	OH	OH	PJM	PJM	2020	Early Development	Rebuild	15,600
Furnace Run-Conastone 230 kV Transmission Line (9A) (Transource IEC)	AEP Trans. Holding Co., LLC, Evergy.	16.00	230	PA	MD	PJM	PJM	2020	Adv. Development	New	NA
Glencoe - Speidel 138 kV Rebuild Transmission Line	AEP Ohio Transmission Company, Inc.	13.00	138	OH	OH	PJM	PJM	2020	Early Development	Rebuild	26,042
Good Hope-Harrison 138 kV Transmission Line (Rebuild)	AEP Ohio Transmission Company, Inc.	30.00	138	OH	OH	PJM	PJM	NA	Construction Begun	Rebuild	NA
Granger - Benton Harbor Transmission Line Rebuild	Indiana Michigan Power Company	46.00	138	IN	MI	PJM	PJM	2022	Announced	Rebuild	NA
Green Power Express (Plano to Hazleton)	ITC Green Power Express, LLC	215.00	765	IL	IA	PJM	MISO	2020	Early Development	New	NA
Harrison-Ross 138 kV Transmission Line Rebuild	AEP Ohio Transmission Company, Inc.	40.00	138	OH	OH	PJM	PJM	NA	Early Development	Rebuild	NA
Haviland – North Delphos Rebuild Transmission Line	American Electric Power Company, Inc.	17.00	138	OH	OH	PJM	PJM	NA	Construction Begun	Rebuild	20,000
Hedding Road - Fulton 138 kV Transmission Line Rebuild	AEP Ohio Transmission Company, Inc.	10.00	138	OH	OH	PJM	PJM	2019	Construction Begun	Rebuild	14,759
Jackson-Ross County Area Improvements Rebuild Line	AEP Ohio Transmission Company, Inc., Ohio Power Company	35.00	138	OH	OH	PJM	PJM	2019	Early Development	Rebuild	NA
Lackawanna-North Meshoppen 230 kV Transmission Line Rebuild	Mid-Atlantic Interstate Transmission, LLC	27.00	230	PA	PA	PJM	PJM	2020	Construction Begun	Rebuild	64,200
Lake Erie Connector	ITC Holdings Corp.	73.00	320	PA	ON	PJM	IESO	2023	Adv. Development	New	1,000,000
Lakeside to Chesterfield Rebuild	Virginia Electric and Power Company	21.00	230	VA	VA	PJM	PJM	2020	Early Development	Rebuild	31,000

Note: Includes projects 10 miles or greater and 115 kV and higher and projects in announced, early development, advanced development, and under construction statuses.
Sources: S&P Global Market Intelligence; NERC ES&D

Transmission Topography and Investment (Cont'd)

Transmission Projects (Cont'd)

Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From ISO	To ISO	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
Leon-Ripley 138 kV Transmission Rebuild	AEP West Virginia Transmission Company, Inc., Appalachian Power Co.	14.00	138	WV	WV	PJM	PJM	2019	Construction Begun	Rebuild	NA
Lincoln – Logan Power Upgrade	AEP West Virginia Transmission Company, Inc.	24.00	138	WV	WV	PJM	PJM	2021	Announced	Upgrade	NA
Mackeys to Creswell Rebuild Transmission Line	Dominion Energy, Inc.	14.00	115	NC	NC	PJM	PJM	NA	Announced	Rebuild	NA
McClung to Brackens Creek 138 kV Rebuild (Fayette County Area)	AEP West Virginia Transmission Company, Inc.	14.00	138	WV	WV	PJM	PJM	NA	Construction Begun	Rebuild	NA
Metuchen to Trenton 230 kV Transmission Line Rebuild	Public Service Electric and Gas Co.	30.00	230	NJ	NJ	PJM	PJM	2022	Announced	Rebuild	NA
Monmouth County Reliability	Jersey Central Power & Light Company	10.00	230	NJ	NJ	PJM	PJM	2019	Early Development	New	NA
Mt. Storm-Valley 500 kV Rebuild	Virginia Electric and Power Company	64.00	500	WV	VA	PJM	PJM	2021	Announced	Rebuild	285,000
Muncie - Marion Transmission Line Rebuild	Indiana Michigan Power Company	20.00	138	IN	IN	PJM	PJM	2021	Announced	Rebuild	NA
North Delphos – Rockhill Rebuild Transmission Line	American Electric Power Company, Inc.	16.00	138	OH	OH	PJM	PJM	2020	Announced	Rebuild	24,500
Northeast Transmission System Improvement (Conastone- Raphael)	Baltimore Gas and Electric Company	29.00	230	MD	MD	PJM	PJM	NA	Construction Begun	Upgrade	111,000
Pantego-Trowbridge Reliability	Dominion Energy, Inc.	22.00	115	NC	NC	PJM	PJM	NA	Announced	New	NA
Peach Bottom to Old Post 230 kV Transmission Line	ITC Holdings Corp.	26.00	230	PA	MD	PJM	PJM	2021	Announced	New	73,600
Pierce Brook-Lewis Run Transmission Line	Mid-Atlantic Interstate Transmission, LLC	16.00	230	PA	PA	PJM	PJM	NA	Construction Begun	New	15,800
Poseidon Transmission	Anbaric Development Partners, LLC, Exelon Transmission Company, LLC	79.00	200	NY	NJ	NYISO	PJM	2021	Early Development	New	NA
Poston-Hocking 138 kV Transmission Line Rebuild	AEP Ohio Transmission Company, Inc.	16.00	138	OH	OH	PJM	PJM	NA	Construction Begun	Rebuild	9,278
Poston-Lick 138 kV Rebuild Line	AEP Ohio Transmission Company, Inc.	22.00	138	OH	OH	PJM	PJM	NA	Construction Begun	Rebuild	19,680
Remington CT to Warrenton (Warrenton Wheeler Gainesville 230 kV)	Virginia Electric and Power Company	12.00	230	VA	VA	PJM	PJM	NA	Construction Begun	Upgrade	NA
Remington to Gordonsville 230 kV Rebuild	Virginia Electric and Power Company	38.00	230	VA	VA	PJM	PJM	2020	Construction Begun	Rebuild	NA
Rice-Ringgold 230 kV Transmission Line (9A) (Transource IEC)	AEP Trans. Holding Co., LLC, Evergy	29.00	230	PA	NA	PJM	PJM	2020	Adv. Development	New	NA
Ringgold to Catoctin 230 kV Rebuild	Potomac Edison Company	10.00	230	NA	MD	PJM	PJM	2020	Early Development	Rebuild	NA
Roanoke – Marion Transmission Rebuild Line	Indiana Michigan Power Company	37.00	138	IN	IN	PJM	PJM	2020	Construction Begun	Rebuild	85,000
Scotland Neck – South Justice Branch Reliability	Dominion Energy, Inc.	15.00	115	NC	NC	PJM	PJM	NA	Construction Begun	New	NA
Skiffes Creek-Whealton 230 kV Line	Virginia Electric and Power Company	20.00	230	VA	VA	PJM	PJM	NA	Construction Begun	New	72,180

Note: Includes projects 10 miles or greater and 115 kV and higher and projects in announced, early development, advanced development, and under construction statuses.
Sources: S&P Global Market Intelligence; NERC ES&D

Transmission Topography and Investment (Cont'd)

Transmission Projects (Cont'd)

Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From ISO	To ISO	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
SOO Green Renewable Rail HVDC Transmission	Soo Green Renewable Rail Llc	349.00	525	IA	IL	MISO	PJM	2024	Announced	New	2,500,000
Southeast Ohio Area Improvements (Bell Ridge-Devola)	AEP Ohio Transmission Company, Inc.	10.00	138	OH	OH	PJM	PJM	2021	Adv. Development	Rebuild	NA
Southeast Ohio Area Improvements (Macksburg-Devola Rebuild)	AEP Ohio Transmission Company, Inc., Buckeye Power, Inc., Ohio Power Company, Washington Electric Cooperative, Inc.	17.00	138	Ohio	Ohio	PJM	PJM	2019	Adv. Development	Rebuild	30,000
Southeast Ohio Area Improvements (Rouse-Bell Ridge)	AEP Ohio Transmission Company, Inc.	13.00	138	OH	OH	PJM	PJM	2021	Adv. Development	Rebuild	NA
Trenton to Burlington 230 kV Transmission Line Rebuild	Public Service Electric and Gas Company	22.00	230	NJ	NJ	PJM	PJM	2022	Announced	Rebuild	NA
Vint Hill-Wheeler-Gainesville Upgrade (Warrenton Wheeler Gainesville 230 kV)	Virginia Electric and Power Company	12.00	230	VA	VA	PJM	PJM	NA	Adv. Development	Upgrade	NA
Wapakoneta Area Improvements Line	AEP Ohio Transmission Company, Inc.	15.00	138	OH	OH	PJM	PJM	2021	Announced	New	NA
West Milton-Eldean 138 kV Transmission Line	Dayton Power and Light Company	17.00	138	OH	OH	PJM	PJM	2022	Early Development	New	16,000

Note: Includes projects 10 miles or greater and 115 kV and higher and projects in announced, early development, advanced development, and under construction statuses.
Sources: S&P Global Market Intelligence; NERC ES&D

Resilience Issues

General Resilience Issues and Approach

- **Context**: The area covered by PJM is a broad area with a diverse array of industries and weather. As a frame of reference for the potential economic impact of a resilience event, PJM's 2018 annual GDP for those states in its footprint was $23.5 trillion.*
- **Cold Snap Analysis**: PJM conducted a stress test analysis, examining resilience during a 14-day cold snap under various scenarios of generator retirements, pipeline disruptions, gas availability, and forced outages. It found:
  - With announced retirements, its system remains reliable under extreme winter-load scenarios.
  - However, with accelerated retirements and extreme winter load, its system is at risk for voltage reduction and localized manual load shed, in addition to demand response deployment and reserve shortage.
  - With extended extreme cold weather, the key variables become non-firm gas availability, pipeline configuration, on-site fuel inventory, and oil deliverability.
- **Role of Transmission Planning**: PJM uses its transmission planning process to address resilience, with a view to provide diverse resources to effectively respond to events through real-time operations. Further, PJM has initiated efforts to implement RTEP process criteria and metrics in order to enhance grid resilience beyond that in place today and suggest that resilience criteria could be incorporated in the planning process through three decision-making approaches:
  - Do no harm, so that the solution to an identified reliability criteria violation does not introduce new resilience issues.
  - Leverage project opportunities already identified under reliability, market-efficiency needs, or public policy needs to enhance resilience.
  - Respond proactively with new projects to mitigate resilience risks.
- **Other Initiatives**: While PJM continues to pursue formal implementation of these transmission planning approaches, parallel transmission resilience initiatives continue in several areas: spare transformer need, phasor measurement unit implementation and cascading event analysis tool development (more on the following page).

Reported Electric Disturbance Events Affecting PJM (2017–April 2019)

Cause	2017	2018	2019 YTD
Fuel Supply Deficiency	0	0	0
Severe Weather	9	25	8
Vandalism	2	1	3
Actual Physical Attack	0	0	1
Suspicious Activity	0	2	0
Transmission Interruption	1	1	2
Generation Inadequacy	0	0	0
System Operations	0	10	4

Note: For multiple causes, classified under one only.
Sources: DOE OE-417; ScottMadden analysis

*Note: Figure applies to states of DE, IL, IN, KY, MD, MI, NC, NJ, OH, PA, TN, VA, WV, and DC.
Sources: PJM Resilience Testimony; Bureau of Economic Analysis; EIPC Study

Resilience Issues (Cont'd)

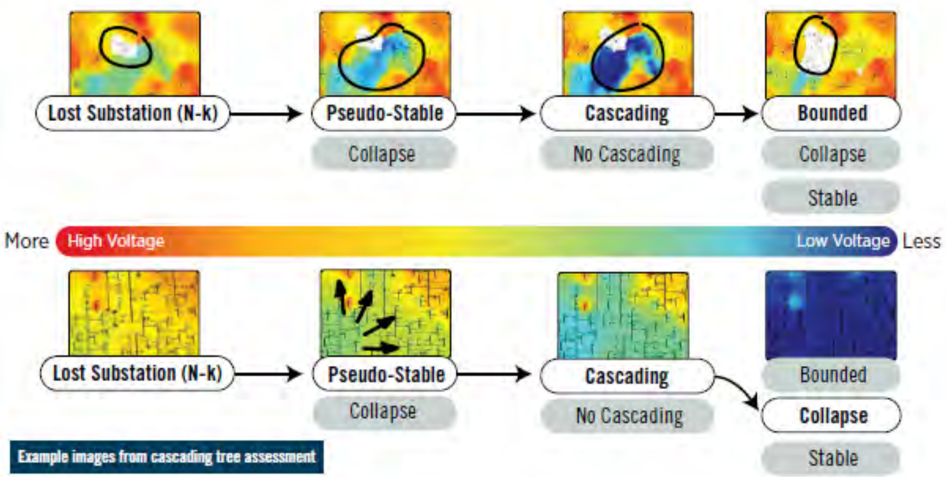
Planning for Resilience in the RTEP Process

- PJM's operations, planning, markets, physical security, and cybersecurity functions are part of ongoing collaborative, organization-wide efforts to establish processes, develop tools, and enhance communication linkages to maximize grid resilience.
- From a transmission perspective, PJM has initiated efforts to implement RTEP process criteria and metrics to enhance grid resilience beyond that in place today by virtue of compliance with NERC standards TPL-001-4, TPL-007-1, and CIP-014. PJM is working with its members to incorporate resilience into the transmission planning process.

Other PJM Resilience Initiatives

- **Spare transformers**: Beginning in 2006, PJM identified the need to have spare transformers as a reliability concern, and PJM runs a probabilistic risk assessment (PRA) model biennially to identify potential risks of failure, potential replacement costs, and the installation time for new transformers.
- **Deployment of phasor measurement units**: With the aid of a $14 million U.S. Department of Energy stimulus grant, PJM and its member transmission owners have installed more than 400 phasor measurement units (PMUs) in more than 120 substations in 10 states, improving the granularity and quality of situational awareness on the system.
- **Cascading event analysis tool**: Current efforts have narrowed into the development of a new planning tool and methodology, using a "cascading trees" event analysis, which complements existing studies by simulating and testing system resilience (see diagram at right).
  - The methodology provides a way to simulate severe contingency events, such as the loss of a substation at extreme conditions, to quantify the probability of a cascading system and the loss of load and generation, and to determine if the event is bounded, unbounded, or unstable.
  - Monte Carlo analysis is then performed to identify the repeat offenders or lines/substations that are impacted more frequently and reinforce those facilities.
  - Beyond extreme events, PJM uses this methodology to compare competing projects to measure which one increases or decreases the probability of cascading or resilience. PJM has adopted three approaches to integrating resilience into the RTEP and the RTEP decision-making process.
  - Further development of the resilience process and how it fits into the RTEP process will continue into 2019 by way of PJM planning committee meetings.

Cascading Tree Concept



Source: PJM

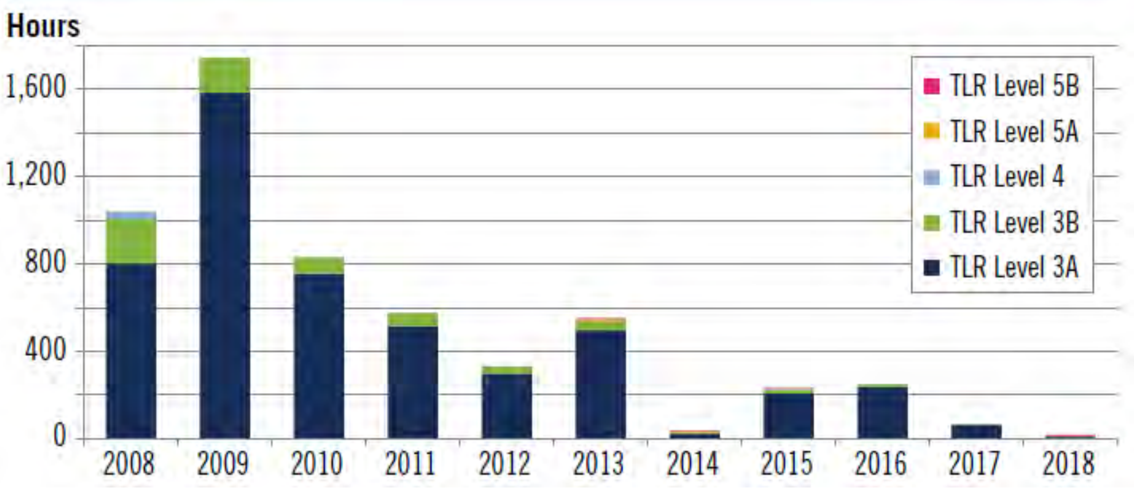
Source: Benefits White Paper

Resilience Issues (Cont'd)

Benefits of Transmission Enhancements

- PJM has observed positive trends in the number of transmission loading relief (TLR) procedure hours (top right), the number of voltage actions (bottom right), and a decline in annual reactive services uplift charges (bottom left)—all of which PJM attributes as benefits resulting from recent investments in the transmission system.
  - TLR: TLR procedures curtail power sales between transmission entities to manage cross-border transmission constraints. The increasing robustness of the transmission system and improving interregional interoperability allows PJM to manage the transmission system using fewer TLR procedures.
  - Voltage actions: PJM's regional planning process has always included system analysis under peak-load conditions, during which low-voltage criteria violations have been identified and solutions implemented over time. Identifying high-voltage conditions has been a much more recent system phenomenon, typically during periods of low customer demand.

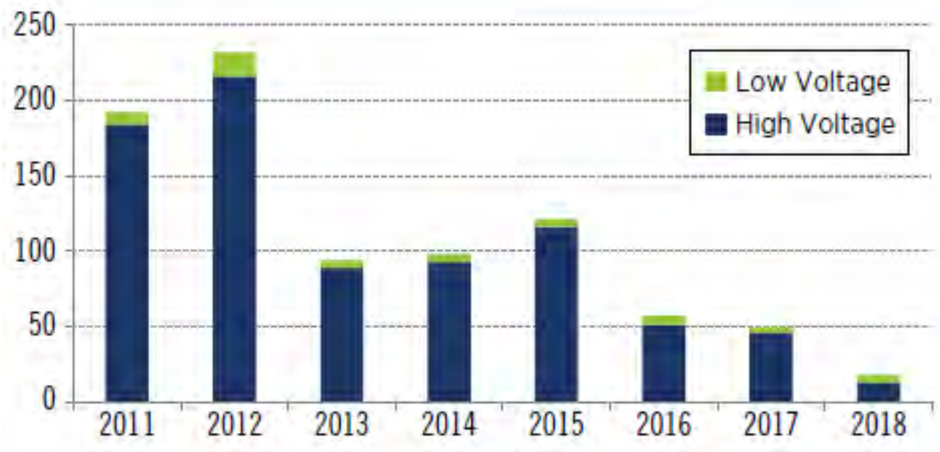
Transmission Loading Relief (TLR) Procedure Hours (2008–2018)



Annual Reactive Services Uplift Charges (2011–2018)

PJM notes that for the 2013 Reactive Services uplift, the DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $2.538, $1.900 and $0.690 per MWh.

Voltage Actions on the PJM System (2011–2018)



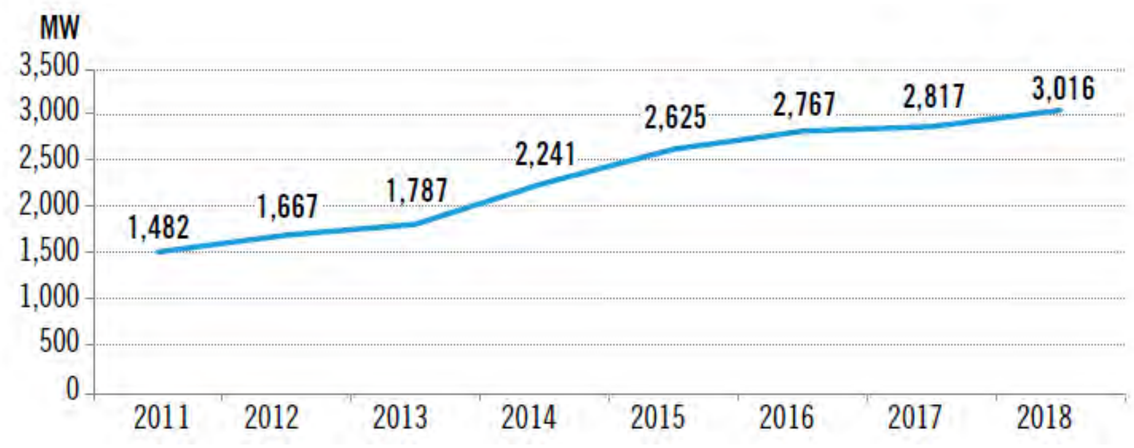
Source: Benefits White Paper

Resilience Issues (Cont'd)

Improved Transfer Interface Margins

- PJM further reports that it has observed interconnection reliability operating limits (IROL) operating margins have increased as a result of the additional transfer capability provided by new transmission assets, providing the operator with additional flexibility to exchange power with neighboring regions as needed to address reliability and resilience needs. Greater transfer capability increases economic efficiency through greater opportunity for bilateral power purchases and sales by participants in PJM markets.
- The average margin in PJM across all IROL interfaces was 1,482 MWs in 2011, which more than doubled to an average margin of 3,016 MWs in 2018 (see figure below). While generation patterns shift over time and impact the margin, new transmission enhancements have contributed to this increase as well.

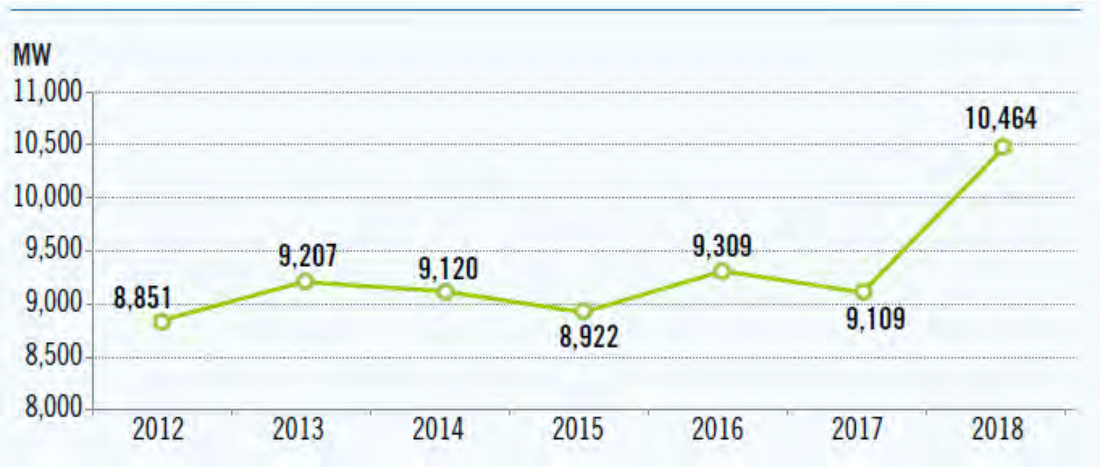
PJM IROL Margin Improvement (2011–2018)



Case Study: Eastern Transfer Interface Limit Margin

- PJM's Eastern Interface offers a case study that demonstrates how transmission enhancements have increased the amount of power that can be transferred across it. The ability to transfer power across that interface was boosted by the completion of the Susquehanna-Lackawanna-Hopatcong-Roseland 500 kV transmission line.
- The completion of the line in May 2015, coupled with other lower-voltage transmission enhancements in eastern PJM, has increased the transfer capability across the Eastern Interface since 2015. Between 2012 and 2018, the maximum annual Eastern Interface IROL transfer capability increased from 8,851 MWs to 10,464 MWs.

Maximum Annual Eastern Transfer Interface IROL (2012–2018)



Source: Benefits White Paper

Resilience Issues (Cont'd)

Selected Major Bulk Power Events Affecting PJM	
Event	**Description**
Northeast Snowstorm (Oct. 29-30, 2011)	• An unprecedented fall snowstorm hit the northeastern U.S., breaking all previous October records. Parts of New York, New Jersey, and Pennsylvania also received well over a foot of snow. The quantity of snow held by the unusually top-heavy trees, coupled with the soft, wet ground, resulted in a great number of healthy trees, most outside of utility rights-of-way, being uprooted and falling onto distribution and transmission lines. • On the morning of October 30, near the end of the storm, more than 3.2 million homes and businesses were without power. Thousands were without power for more than a week, some for as long as eleven days. Estimates put storm costs between approximately \$1 billion and \$3 billion.
Polar Vortex (Jan. 2014)	• In early January of 2014, the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30° F below average. NYISO recorded its all-time peak winter load on Jan. 7. • For PJM, nearly 2 GWs of cold weather generation outages were reported, with about 770 MWs related to fuel-gelling issues. Some dual-fuel units experienced challenges ranging from a lack of natural gas required for starting the alternate fuel to fuel freezing in the injectors. Outages related to curtailments and interruptions of natural gas delivery were the significant contributor of the NPCC generator outages. These outages totaled a maximum of 3,296 MWs of generators, and they significantly impacted NPCC's generation resources starting at approximately 10:00 a.m. on Jan. 7, 2014.
Winter Storms Riley and Quinn (March 1-20, 2018)	• In March 2018, winter storm Riley, a powerful nor'easter caused major impacts in the Northeastern, Mid-Atlantic, and Southeastern U.S., bringing hurricane force winds to coastal New England and producing more than two feet of snow in some areas. Although the most severe damage was caused by flooding and snow, unusually high tides and storm surges along the coast, wind, and downed trees caused very large inland power outages. Recovery efforts were also hampered as a second nor'easter, winter storm Quinn, began to impact the area just a few days later. • At least two million customers in 13 states lost power at some point during the storm. The storm was called a "bomb cyclone" because of how quickly the pressure dropped—24 millibars in 24 hours.

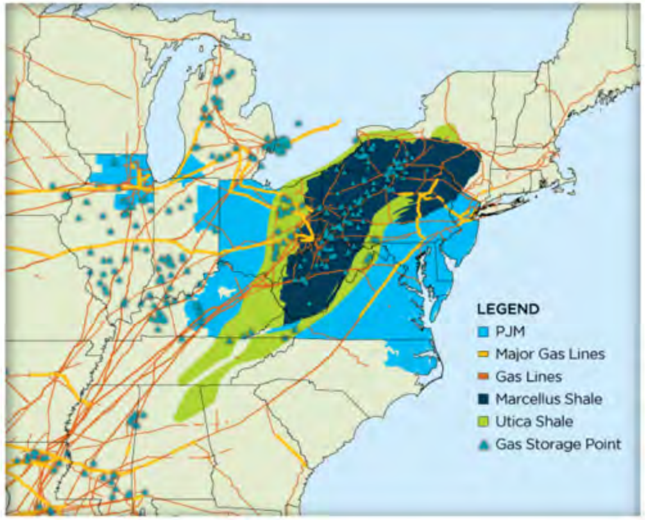
Sources: PJM Polar Vortex Report; PPUC Riley-Quinn Report

Resilience Issues (Cont'd)

Gas Infrastructure Dependency Analyses

- **Studying Effects of Large Gas Fleet**: With a large and growing set of natural gas-fired resources, PJM has been studying gas-electric coordination and potential effects of resilience events.
  - NERC conducted a special study of potential reliability impacts of disruption of natural gas delivery. It identified 24 geographic clusters with more than 2 GWs of gas-fired generation. Eighteen areas were found with a reliability risk, and two of those areas were in PJM's footprint: southern coastal Virginia and western Pennsylvania, near the borders with Maryland and Ohio (see map lower right).
  - In 2015, the Eastern Interconnection Planning Collaborative (EIPC) conducted a study of, among other things, adequacy of gas infrastructure to serve electric system demand. It found some areas with "affected generation" in PJM in high-winter peak-load conditions in 2023, particularly in the Delmarva Peninsula, Maryland, and Virginia due to constraints on the Columbia, Dominion, Eastern Shore, and Transco pipelines (Note: "Affected generation" does not imply a risk to electric reliability.)
- **Coordination Challenges**: As the generation fleet in PJM is transformed from largely coal-fired to increasing amounts of natural gas-fired generation, the challenges related to gas-electric coordination will increase.
- **Nearby Plentiful Gas Resource**: However, PJM also has the advantage of being located on two of the largest shale reserves in the United States, Marcellus and Utica.
  - Due to the close proximity to the Marcellus and Utica shale plays, natural gas-fired generators in PJM enjoy access to some of the cheapest gas in the United States.
  - Gas generators in PJM also have less fuel supply risk due to pipeline capacity constraints compared to other regions of the United States, such as ISO-NE, due to proximity to the commodity.
  - During periods of high-winter peak demand, gas-fired generators compete with retail-heating demand from gas LDCs, and some pipelines in PJM run at or near 100% capacity which creates deliverability risks.
  - With the implementation of the capacity performance product in PJM's capacity market (referred to as the reliability-pricing model or RPM), which includes stiff penalties for generators unable to meet their commitments when called upon, there is increasing evidence that generators in PJM have been firming up their fuel supply contracts.

PJM Footprint and Shale Gas Plays



Source: PJM

NERC-Identified Clusters Where Power Flow Issues Were Identified Upon Gas Delivery Disruption

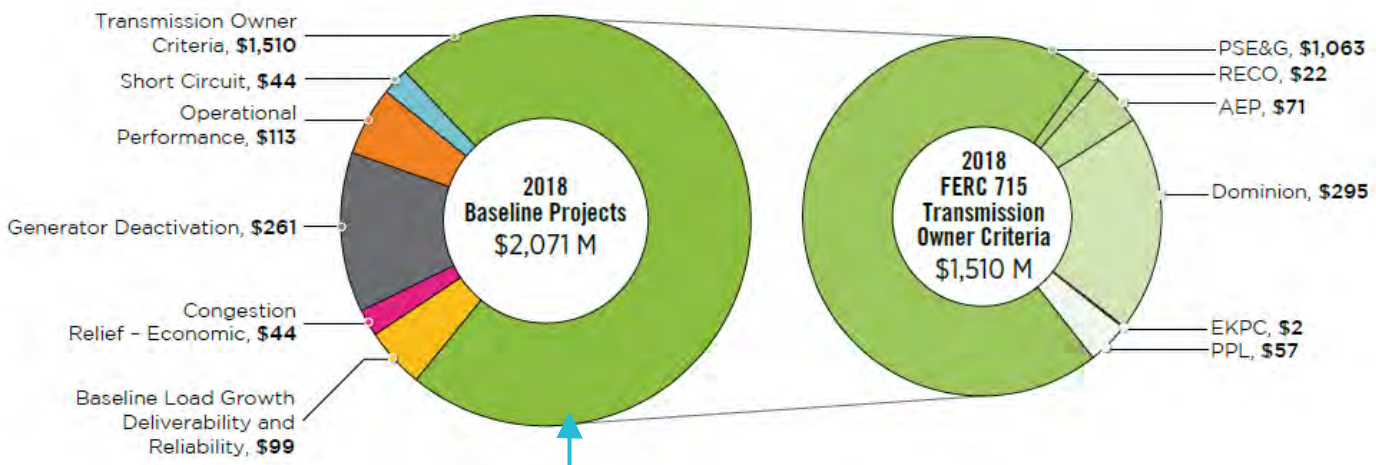
Sources: EIPC Study; NERC SPOD; PJM Resource Mix White Paper; 2018 Fuel Security Analysis

Resilience Issues (Cont'd)

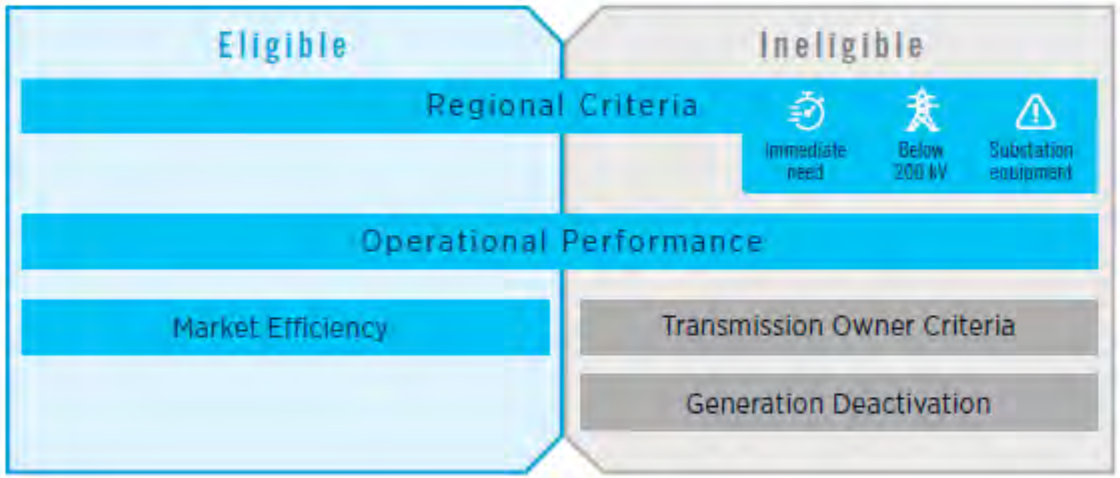
Aging Infrastructure

- PJM has observed that transmission owner aging infrastructure criteria are increasingly driving the need for baseline projects, and a review of facilities built in the 1960s and earlier has revealed deteriorating facilities.
- As depicted at right, the majority of baseline transmission projects included in the latest RTEP are driven by local transmission owner criteria, some to address aging infrastructure, others to address local loss-of-load thresholds (particularly on radial facilities).
- As outlined below, PJM assigns projects that are driven by local transmission owner criteria to the incumbent transmission owner, and those projects are not eligible for proposal window consideration.

2018 RTEP Baseline Projects by Driver



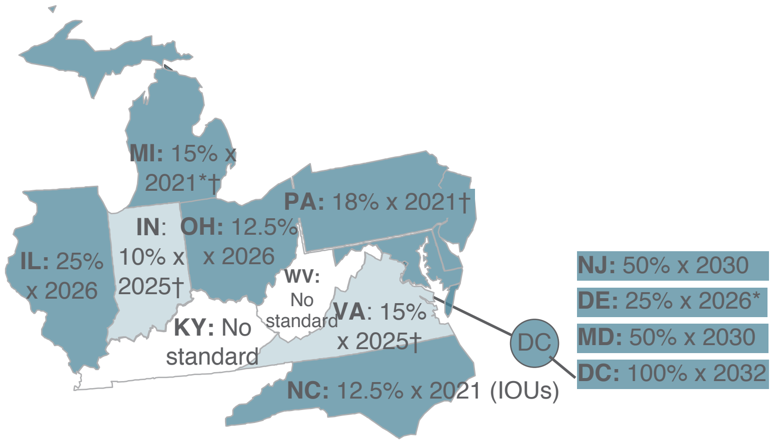
Proposal Window Eligibility by Project Driver



Sources: Benefits White Paper; 2018 RTEP

Renewables Integration

PJM State Renewable Portfolio Standards and Goals (as of June 2019)



Source: DSIREUSA.org, June 2019

- Renewable portfolio standard
- Renewable portfolio goal
- *Clean energy standard*
- *Clean energy goal*
- * Extra credit for solar or customer-sited renewables
- † Includes non-renewable alternative resources

Demand-Side Considerations

- **Low-Load Growth**: Overall demand growth in the region is expected to be less than 1% annually through 2028, although some metro areas across PJM are experiencing higher growth than rural areas. Energy efficiency and controllable, dispatchable demand response programs in the region are substantial in the summer (about 9.1 GWs or 6% of peak load) but less so in the winter (1.3 GWs or 1% of peak load). PJM also estimates that 4.5 GWs of distributed solar generation are present on the grid behind the meter.
- **Renewable Policy Differences**: PJM has a mix of states with moderate clean energy goals and standards, states with no standards at all, and the District of Columbia (see map at left). Washington D.C. has a 100% target by 2032. New Jersey and Maryland have 50% targets, whereas Kentucky and West Virginia do not have standards or targets in place.
- **Utility and Corporate Goals**: Some utilities in states touched by PJM'S footprint have also introduced clean and renewable energy commitments (see next page). PJM also notes that corporate and voluntary purchases of renewable energy are becoming an increasingly significant driver for renewable energy development in the region.
- **Policy Support for Some Generation**: In an attempt to strike a balance among the competing desires of states to subsidize certain resources and resource types (including renewable resources and also nuclear and coal resources in different cases) with the directives of the market, PJM recently proposed a revision to its capacity market rules.
  - However, FERC, in June 2018, determined that PJM's proposed capacity market rules were unjust and unreasonable because they failed to protect the market from the price-suppressive impacts of out-of-market support being provided by states to certain resources, such as renewable and nuclear generation.
  - The same order rejected two options that PJM asked FERC to choose between for fixing the problem. Instead, FERC floated its own proposed solution to ensure the rates produced by PJM's capacity auctions are just and reasonable, referred to as a replacement rate. It also instituted a paper hearing to determine the appropriate way to move ahead. A final decision from FERC is forthcoming.

Sources: NERC 2018 LTRA; DSIRE; SEPA; S&P Global Market Intelligence

Renewables Integration (Cont'd)

Listing of Utility Companies with Operations in PJM That Have Announced Emission Reductions or Renewable Energy Goals (as of September 2019)

Utility Name (States of Operation)	Goal Type	Target Dates	Description (Date Implemented)
AEP Ohio	Emission Reduction	2050	80% emissions reduction below 2000 levels by 2050 (2018)
AES Corporation	Carbon Reduction	2030	70% carbon reduction through 2030 (revised its prior goal of 50% reduction from a 2016 baseline) (2018)
Alliant Energy	Emission Reduction/Renewables	2050	40% below 2005 levels by 2030 and 80% of total emissions by 2050 (also eliminating all coal by 2050) - 30% renewable energy by 2024 (2017)
Ameren	Emission Reduction	2050	80% emissions reduction by 2050 compared to 2005 levels (2017)
Commonwealth Edison	Renewables	2025	25% renewables by 2025
Consumers Energy	Emission Reduction	2040	80% emissions reduction by 2040 (2018)
Dominion Energy	Emission Reduction	2030	60% reduction of carbon emissions from 2000 levels by 2030; 50% reduction in methane emissions from 2010 levels by 2030
DTE Energy	Emission Reduction	2040	80% emissions reduction by 2040 (2019)
Duke Energy	Emission Reduction	2032	40% reduction in carbon emissions from 2005 levels by 2032. 45% reduction in carbon intensity from 2005 levels
FirstEnergy	Emission Reduction	2045	90% reduction in CO_2 emissions from 2005 levels by 2045
MidAmerican Energy (IA, IL, SD)	Renewables	N/A	100% renewables (2016)
NiSource, Inc./NIPSCO	Carbon/Coal Reduction	2030	90% carbon emissions reduction from 2005 levels by 2030 (2019); moving to coal free by 2028 (2018)
Public Service Enterprise Group	Emission Reduction	2050	80% reduction in carbon emissions by 2046, and net-zero carbon emissions by 2050
Tennessee Valley Authority	Emission Reduction	2020	60% reduction in CO_2 emissions from 2005 levels and 55% carbon-free power supply by 2020
Vectren Corp	Emission Reduction	2023	60% emissions reduction by 2023 (2018)

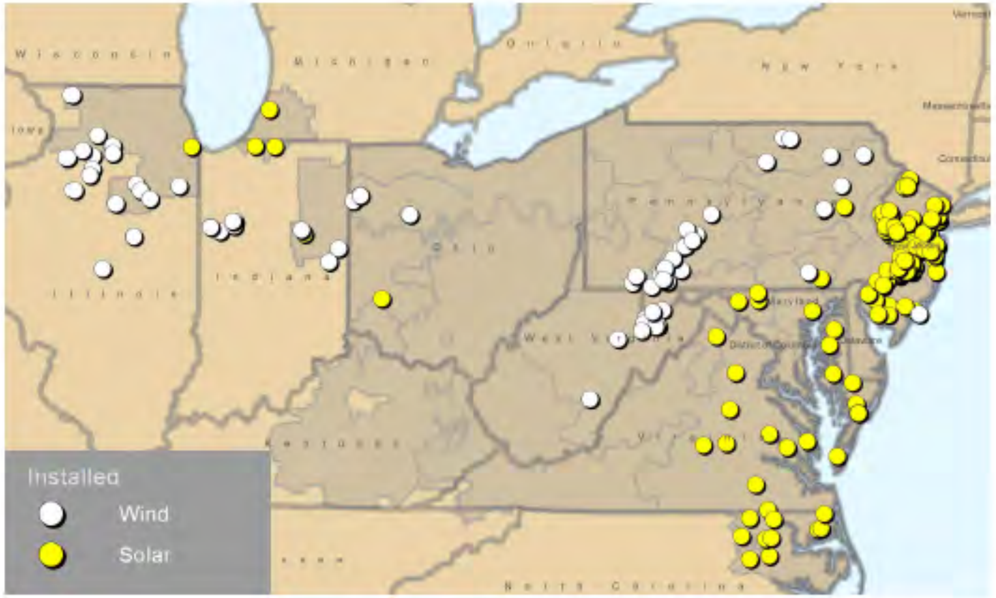
Sources: SEPA; S&P Global Market Intelligence

Renewables Integration (Cont'd)

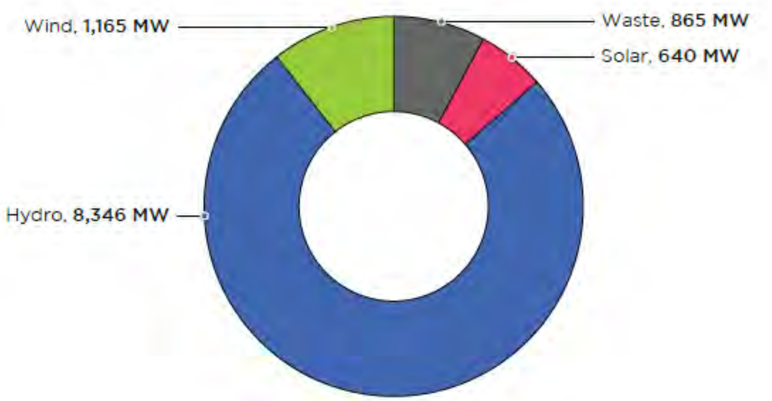
Supply-Side Considerations: Existing and Planned Renewables

- **Nearly 6 GWs Added**: Between 2011 and 2018, 5,910 MWs of wind and solar energy were interconnected to the PJM transmission grid to reach consumers across the region. The figure at top right shows the breakdown of existing renewable generation capacity by fuel.
- **Resource Location**: The majority of the wind capacity is located in the central and western portions of the PJM footprint, while most of the installed solar capacity is located in the east.
- **Solar Growing**: While wind capacity today is almost double the solar capacity in the region, the majority of the capacity in the queue is solar (see bottom right).

Installed Wind- and Solar-Powered Generation in PJM (As of 12/31/18)

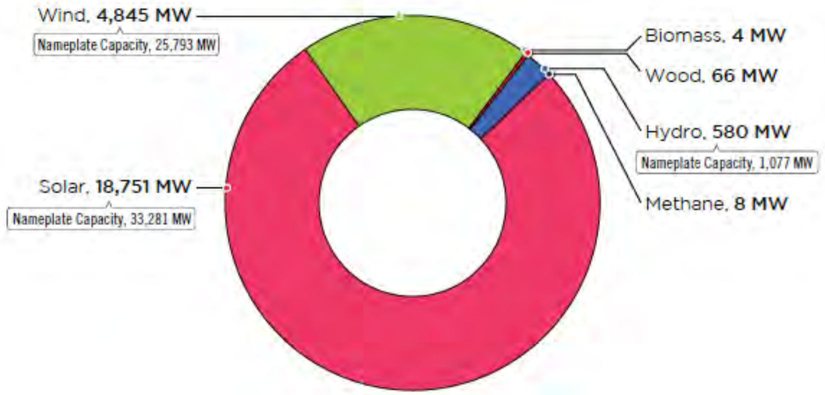


Existing Renewable Capacity in PJM (As of 12/31/18)



The majority of existing renewable capacity in PJM is hydro.

Queued Renewable Capacity in PJM (As of 12/31/18)



The majority of the interconnection queue is comprised of solar.

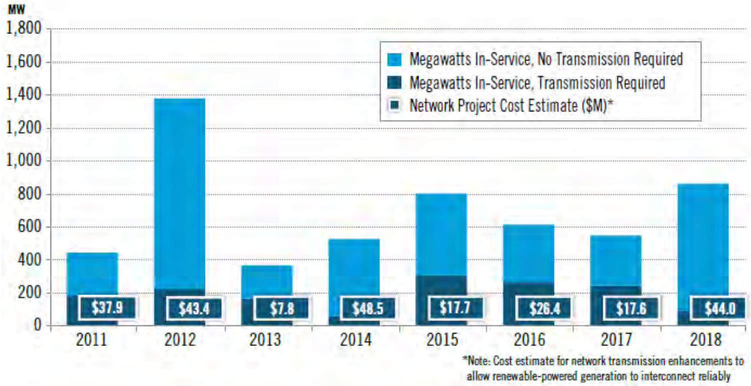
Sources: Benefits White Paper; 2018 RTEP

Renewables Integration (Cont'd)

Supply-Side Considerations: System Capacity to Accommodate Renewables

- PJM has produced a series of papers examining how aspects of its operations, planning, and markets could and should evolve given the changing landscape of the electric power industry.
- **Up to 30%**: First, PJM commissioned a study in 2011 to analyze the impacts to grid operations if renewable energy goals over the next 15 years are achieved or exceeded. Scenarios of up to 30% penetration of various combinations of variable wind and solar were analyzed, and the study found that the PJM system, with adequate transmission expansion and additional regulating reserves, will not have any significant issues operating with up to 30% of its energy provided by wind and solar generation (emphasis added).
- **2017 Study**: PJM conducted a follow-up study and issued a report in 2017 called "PJM's Evolving Resource Mix and Reliability," which was initiated by questions about "fuel diversity" that evaluated the changing resource mix in PJM given environmental regulations, the preponderance of low-cost natural gas, the increasing penetration of renewable resources and demand response, and the potential for retirements of nuclear power resources. Select findings included:
  - *Mixed Effects*: As the potential future resource mix moves in the direction of less coal and nuclear generation, generator reliability attributes of frequency response, reactive capability, and fuel assurance decrease, but flexibility and ramping attributes increase.
  - *Operational Reliability Issues*: A marked decrease in operational reliability for portfolios with significantly increased amounts of wind and solar capacity (compared to expected near-term portfolio) suggests performance-based upper bounds on the percent of system capacity from those resource types. Additionally, most portfolios with solar capacity shares of 20% or higher were classified infeasible because they resulted in violations at night. Nevertheless, PJM could maintain reliability with unprecedented levels of wind and solar resources, assuming a portfolio of other resources that provides a sufficient amount of reliability services.
  - *High Gas-Fired Generator Penetration*: Portfolios composed of up to 86% natural gas-fired resources maintained operational reliability. Thus, this analysis did not identify an upper bound for natural gas. However, additional risks, such as gas deliverability during polar vortex-type conditions and uncertainties, were not fully captured in the analysis.

Network Transmission Enhancements for New Generation – Renewable Fuels



While additional transmission investment may be needed to support the integration of renewables in PJM, other factors such as negative load growth, reduced congestion, and preference for for in-state renewables may temper future transmission needs.

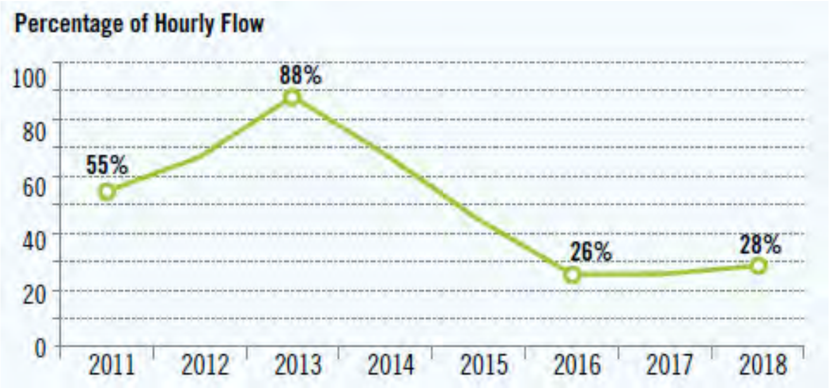
Source: PJM Resource Mix White Paper

Renewables Integration (Cont'd)

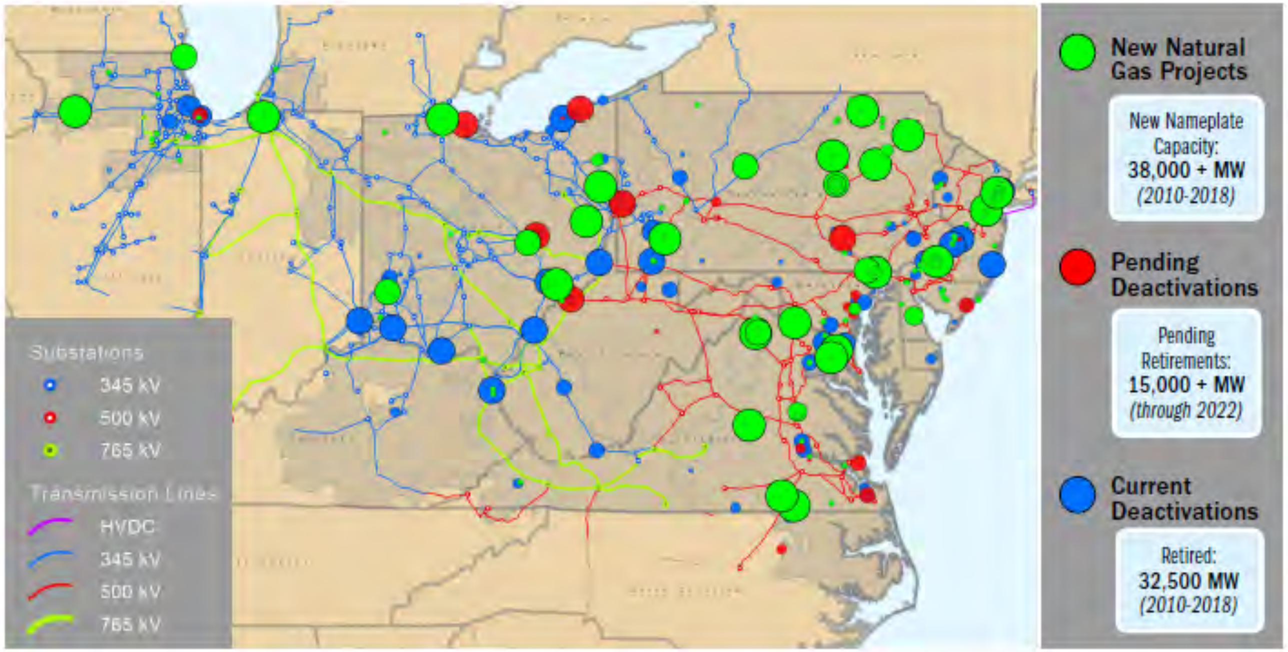
Supply-Side Considerations: Changing Power Flows

- **Historically West-to-East**: Historically, power flow across PJM transmission lines has moved from west to east. High-voltage transmission assets were approved to deliver lower-priced western PJM coal-fired generation reliably to eastern PJM load centers, but that power flow is moderating.
- **Flows Declining**: The combination of generation retirements across the PJM footprint coupled with the increase of natural gas generation in the east is driving a shift on some transfer interfaces, as shown below. PJM has observed reduced west-to-east power flows.

Average Hourly West-to-East Power Flow at the Central Interface



Generation Capacity Entry and Exit Since 2010

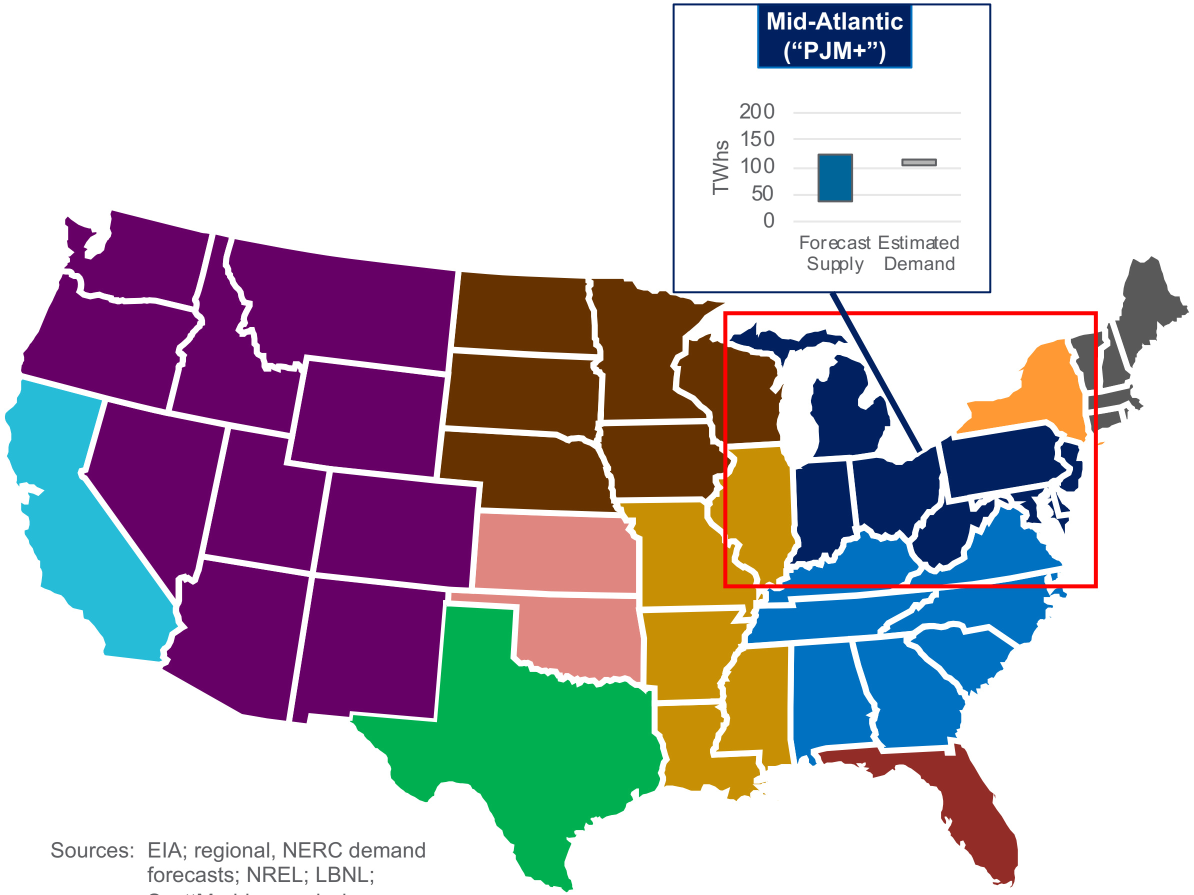


PJM credits the operational flexibility of its transmission assets for encouraging new generation within PJM's footprint, particularly natural gas-fired generation using Marcellus and Utica shale gas. In other words, transmission assets are accommodating a historic fuel shift, while keeping the system reliable. Transmission is assisting this shift by allowing more generators to compete so that the lowest-cost generation serves customer load throughout the footprint.

Sources: Benefits White Paper; 2018 RTEP

Renewables Integration (Cont'd)

PJM-Area U.S. Potential Policy-Driven Renewable Energy Demand and Forecast Supply (2030) (as of June 2019)

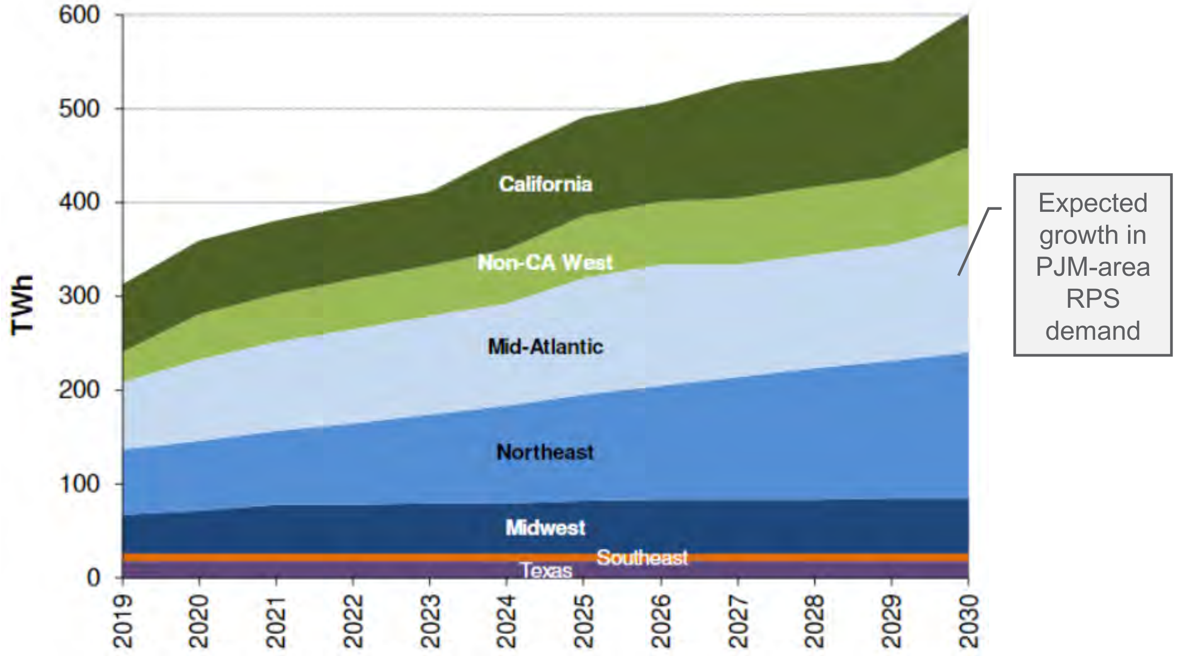


Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Integration Challenges – Renewables Supply and Demand Balance

- As seen in the map at left and the Mid-Atlantic section of the chart below, the estimated demand for renewable resources in the PJM region is expected to be at the high end of the range of forecasted supply of renewables in the region, suggesting that much of the demand may be met by resources inside the PJM region.

Projected U.S. RPS Demand (Total Compliance Requirements) per DOE LBNL (2019–2030) (as of July 2019) (in TWh)



Source: LBNL

Sources: LBNL 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
PJM Interconnection	▪ Resource portfolio "transformation" to gas-fired and intermittent resources—deactivation of 27 GWs of coal from 2011 to 2020, including 12 GWs submitted to PJM in 2018, with 50.6 GWs of gas generation in the queue ▪ Exposure to system stress during sustained heat waves and cold snaps ▪ Severe weather greatest cause of electric disturbances: tropical cyclones and severe winter weather ▪ Ongoing resilience initiatives related to spare transformers, deployment of PMUs, and modeling-simulated severe contingency events	▪ Hydropower represents 4.5% of total market-eligible existing installed capacity in PJM, and wind, solar, and waste each represent less than 1% ▪ Current queue includes 18,751 MWs of solar and 4,845 MWs of wind, representing 33,281 MWs and 25,793 MWs of nameplate capacity, respectively ▪ The highest quality wind resources are located in the western portion of the footprint ▪ New but growing deployment of distributed solar in some areas	▪ Widely varying state policies related to renewable energy; aggressive clean energy goals in DC, NJ, and MD; moderate or no goals in other states ▪ Disparate clean energy goals among the states within the region has led to a contentious capacity market ruling by Federal Energy Regulatory Commission (FERC), issued in December 2019 and likely to generate more debate when PJM makes it compliance filing. ▪ Long on gas generation capacity, with expected additional capacity developed due to proximity to shale gas plays ▪ Congestion considered to be minor in most areas, and mitigation by additional transmission upgrades is not currently warranted; uplift and congestion charges have been low since 2011 ▪ Low to negative load growth expectation in the region for the planning horizon	▪ $37.1B invested in transmission since 1999, including $2.1B new baseline projects and $1B in new network projects approved in the 2018 RTEP ▪ Continued opportunity for transmission owners to replace and upgrade aging assets via supplemental projects, most of which are driven by material condition, performance, and risk ▪ Opportunity to address remaining load pockets in certain areas on the East Coast ▪ Potential to connect and integrate offshore wind under consideration and in development in the Atlantic ▪ "Gas-by-wire" could provide opportunities to meet demands in neighboring regions with cheap gas-fired power generated closer to shale gas sources

Sources

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- Regulatory Research Associates, An Overview of Transmission Ratemaking in Non-RTO/ISO Regions – 2018 Update (Dec. 6, 2018)
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- S&P Global Market Intelligence, "Facing Increasingly Grim Economics, U.S. Coal Plant Retirements May Surge Again" (June 24, 2019)
- Smart Electric Power Alliance, Interactive State Decarbonization Tracker, available at https://sepapower.org/decarbonization-tracker/ (accessed July 23, 2019) (state and utility decarbonization targets) (SEPA)
- U.S. Dept. of Commerce, Bureau of Ecommerce Analysis
- Regional, state, NERC demand growth forecasts
- S&P Global Market Intelligence

Appendix: Transmission Project Selection Criteria

Planning Process

- RTEP identifies system upgrades and enhancements to meet planning and reliability criteria over a 15-year time horizon

Project Identification

- PJM calculates a benefit/cost ratio to determine if there is a market efficiency justification for a particular transmission enhancement. The benefit/cost ratio is calculated by comparing the net present value of annual benefits over the first 15 years of the project's life to the net present value of the project's revenue requirement for the same period. Market efficiency proposed transmission enhancements that meet or exceed a 1.25 benefit/cost ratio are further assessed to examine their economic, system reliability, and constructability impacts

Criteria for Competitive Projects

- Long-lead reliability projects (needed in five+ years)
- Short-term reliability projects (needed in four to five years)
- Immediate need reliability projects (needed in two years or less) may or may not be eligible for competition
- Market-efficiency projects

Evaluation Criteria

- Short-term project or long-lead project must address and solve the posted violation, system condition, or economic constraint
- Must meet a benefit/cost ratio threshold of at least 1.25:1
- Secondary benefits (additional reliability, operational, economic, and public policy benefits)

Sources: PJM, Order 1000 Compliance Filing with FERC

Regional Discussion

MIDCONTINENT ISO

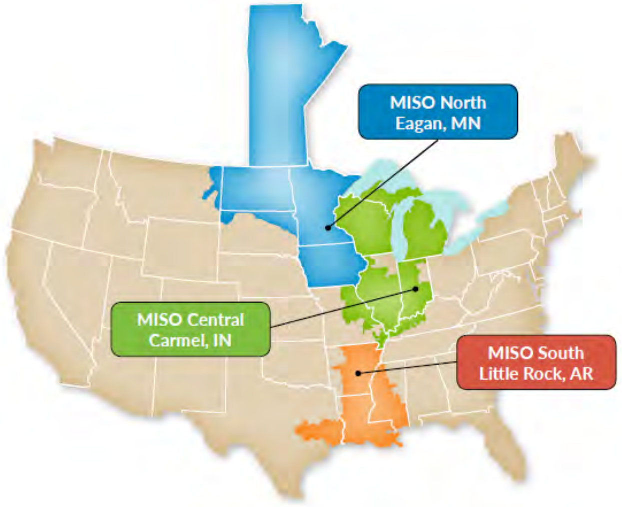
Contents

Overview

- The Midcontinent ISO (MISO) footprint covers about 900,000 square miles and encompasses all or parts of 15 states (and the province of Manitoba).
- Wind penetration in MISO has increased significantly, with 19 GWs of registered in-service capacity.
- In its latest transmission plan, MISO projects thermal generation retirements of about 3.8 GWs in 2018 and 0.4 GWs in 2019.

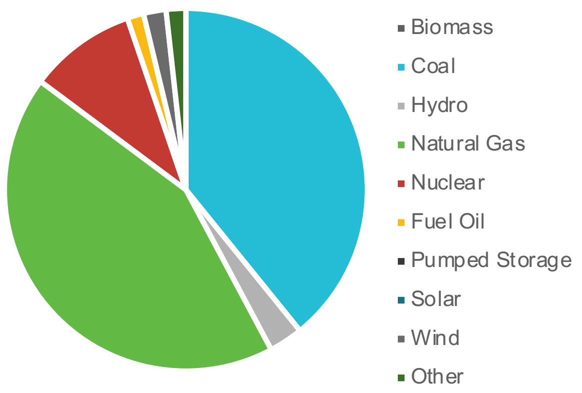
Key Regional Statistics	
States Covered	AR, IA, IL, IN, KY, LA, MI, MN, MO, MS, MT, ND, SD, TX, WI
Square Mi. Covered	~900,000
No. of Utilities	51 transmission owner-members; 37 local balancing authorities
No. of Customers/Pop. Served	~42MM people served
Installed Capacity	175,528 MWs (market); 190,432 MWs (reliability)
Transmission Line Miles	71,800 miles
Peak Hour Demand (all time)	Summer: 127,125 MWs (market), 130,917 MWs (reliability) Winter: 109,336 MWs (market), 117,903 MWs (reliability)
Net Energy for Load (2018)	683,593 GWhs
Forecast Growth (Annual)	0.3% peak load growth† 0.5% energy growth

MISO's Reliability Footprint and Locations of Regional Control Centers



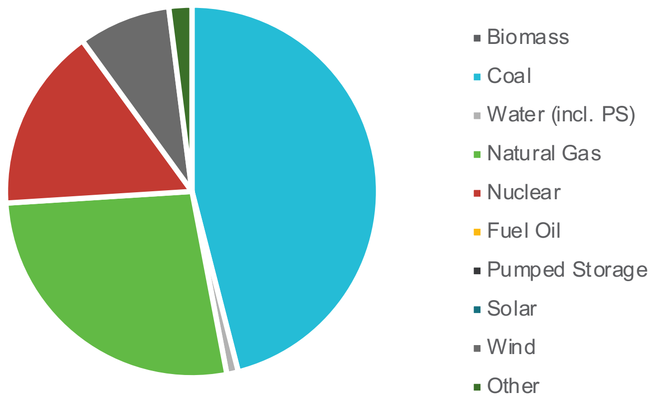
MISO's Market Footprint

2018 Capacity Mix by Fuel



Source: MISO 2018 SOM

2018 Energy Mix* by Fuel

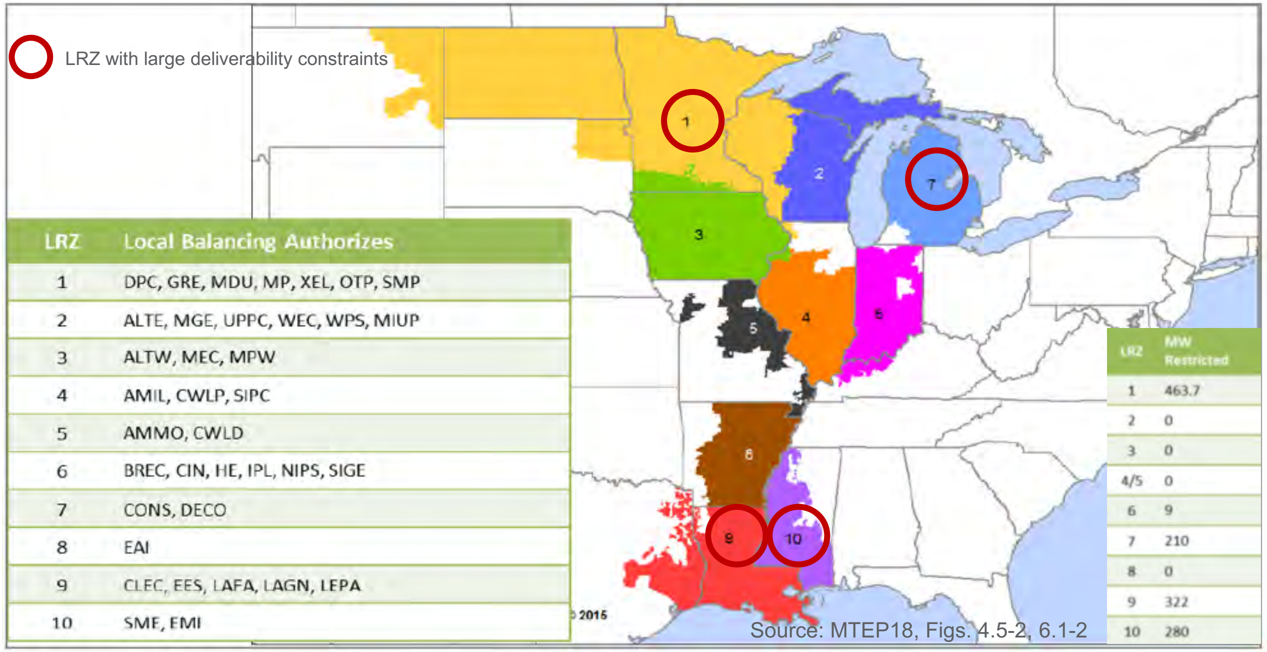


Source: MISO 2018 SOM

Sources: NERC 2018 LTRA; MISO Fact Sheet; NERC ES&D (net energy for load); MTEP18; MISO 2018 SOM
Notes: Peak-load statistics and forecasts are coincident unless otherwise indicated. Capacity shown is unforced capacity.

Overview (Cont'd)

MISO's Local Resource Zones, Balancing Authorities, and Resource Deliverability Constraints



Source: MTEP18, Figs. 4.5-2, 6.1-2

- For determination of resource adequacy, MISO is comprised of local resource zones (LRZs)* (see map at left).
- To evaluate resources (supply and demand-side resources) sufficient for reliability, for each planning year, MISO determines a per unit zonal local reliability requirement for each LRZ. This is defined as the amount of resources a particular area needs to meet the loss of load planning criteria of one day in 10 years without the benefit of importing capacity.
- In the near term, some restrictions on deliverability of resources are in the northern regions (more wind capability) and in the south (more gas-fired generation).
- Because of the diversity (population size, economic factors, weather patterns, retail electric sales, programs like energy efficiency) and geographic breadth of the MISO footprint, the LRZs also serve as sub-regional proxies for load (GWhs) and non-coincident peak load (GWs) growth and for wind capacity credits.

	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
Energy and Peak Demand Annual Growth Forecasts (2019–2028)										
Energy Growth (with EE adjustments)* (%)	0.95	.063	.087	0.06	0.20	1.03	0.22	0.70	0.59	1.46
Peak Demand (summer non-coincident without EE adjustment)** (%)	1.07	0.97	1.37	0.45	0.42	1.09	0.38	1.08	0.63	1.46
Import and Export Limits										
Capacity Import Limits**	4,415	2,595	3,369	6,411	4,332	7,941	3,785	4,834	3,622	2,688
Capacity Export Limits**	516	2,017	5,430	4,280	2,122	3,249	2,578	2,424	2,149	1,824

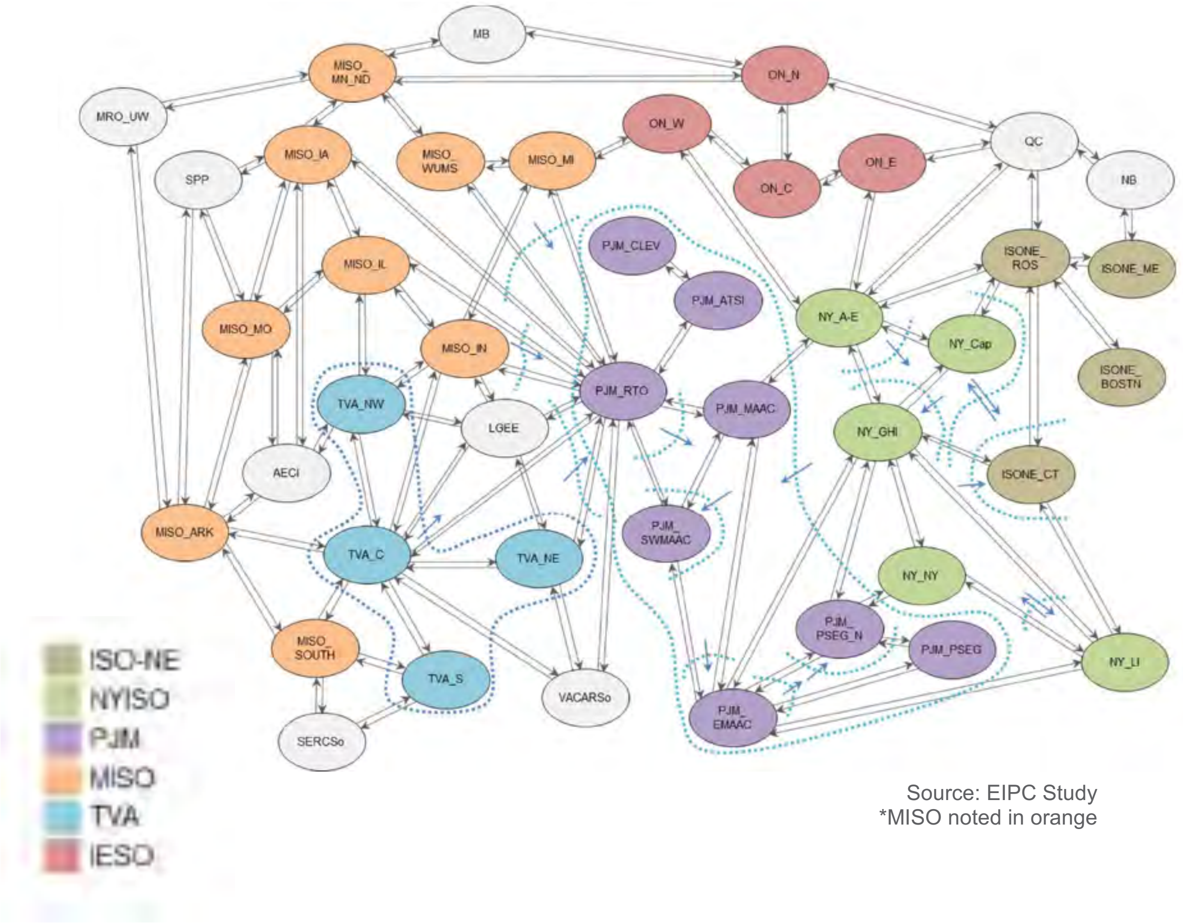
*GWh **MWs

Notes: *Local Resource Zones are geographic regions established based upon: (1) the electrical boundaries of local balancing authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between local balancing authorities; (4) the results of loss of load expectation studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers.

Sources: MTEP18; MISO LRZ Forecast; MISO Tariff, sec. 68A.3.

Transmission Topography and Investment

MISO Transmission Topography and Interconnections*



Source: EIPC Study
*MISO noted in orange

- MISO has an extensive transmission network, reaching from Canada to Texas, with nearly 24,480 miles of transmission 230 kV or above (34% of its system).
- Its region is bounded by the Southwest Power Pool (SPP) to the west, SERC to the southeast, the PJM Interconnection to the east, and the Independent Electricity System Operator of Ontario to the north.
- It has expanded over the past 20 years. Formed in 1998 and initially covering the upper Midwest of the United States, MISO has added transmission owners over time. It became the first FERC-approved RTO in December 2001. In December 2013, 10 transmission-owning companies (including the Entergy system) joined MISO to form the MISO South region.
- MISO is the sole-balancing authority for the region, executed through three regional control centers (see previous page).
- Historically, the majority of MISO North and MISO Central regions' dispatched generation comes from coal, while in MISO South gas is the primary dispatched generation. Gas-fired units set the system-wide price in 53% of hours in 2018, including almost all-peak hours. After the integration of MISO South, the percentage of generation from coal units began to decrease, and the integration of the region aids in fuel diversity.
- North-south intra-market flows between MISO Midwest (Central/North) and MISO South are limited under a settlement agreement with SPP. North-to-south flows are limited to 3 GWs (1 GW firm/2 GWs non-firm, as available). South-to-north flows are limited to 2.5 GWs (1 GW firm/1.5 GWs non-firm, as available).
- Transmission flows are generally characterized by increasing west-to-east flows, as higher levels of wind resources mean higher generation and capacity resources in western and central MISO than in the eastern part of the Midwest region.

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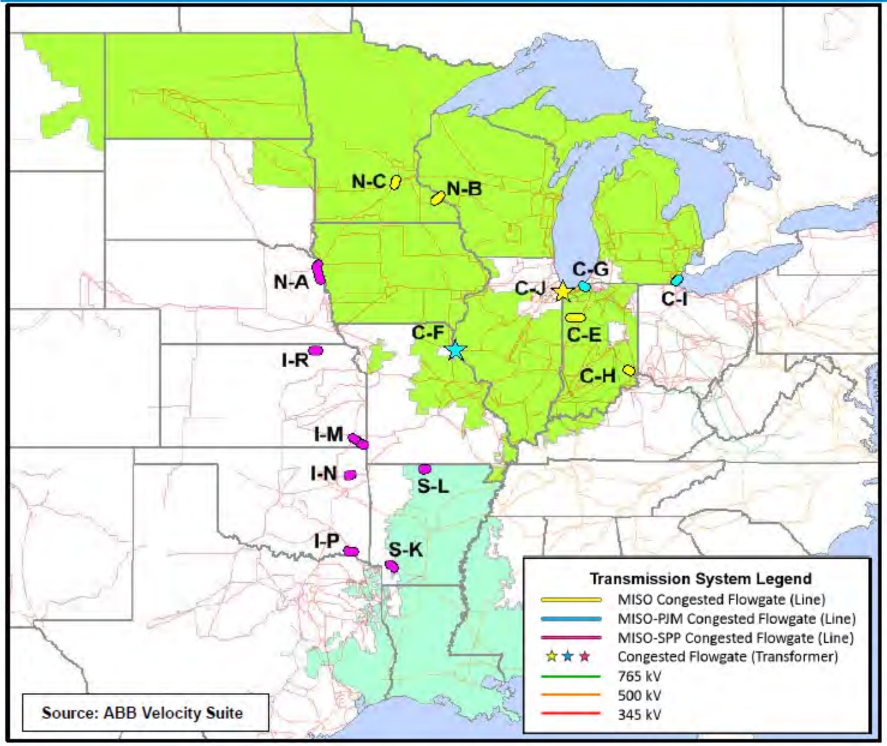
Sources: EIPC Study; MISO, "Celebrating 15 Years of Regional Transmission Services," available at http://timeline.misomatters.org/ (accessed Aug. 1, 2019); 2018 SOM; Jan. 2018 Event Report; DOE 2015 Congestion Study

Transmission Topography and Investment (Cont'd)

- As part of its current transmission expansion planning process, MISO has identified and is considering enhancements to its top congested flowgates, both within the region and with adjacent regions.
- As shown on the map at the right, top internal congested flowgates are in the upper Midwest (especially Minnesota) and lower Midwest (principally Indiana, near PJM).
  - Minnesota area congestion is largely driven by wind generation in LRZs 1–3.
  - Lower Midwest congestion (esp. C–F and C–G) is driven by generator retirements.

MTEP19 Market Congestion Planning Study Top Congested Flowgates



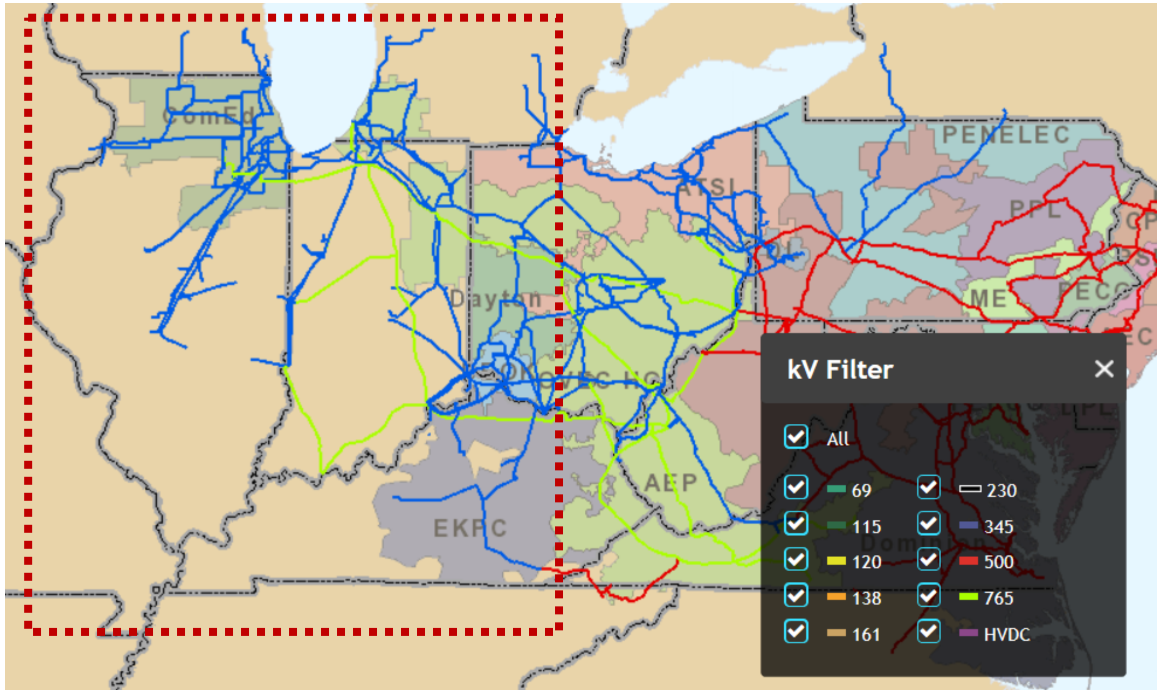
ID	Monitored Element	Area	Focus
N-A	Raun to Tekamah 161kV	MEC-NPPD	N/C, MISO-SPP
N-B	Wabaco to Alma 161kV	DPC	N/C
N-C	Helena to Scott County 345kV	NSP	N/C
C-E	Goodland to Reynolds 138kV	NIPS	N/C
C-F	Marblehead N Transformer 161/138kV	AMIL	N/C, MISO-PJM
C-G	Bosserman to Trail Creek 138kV	NIPS-AEP	N/C, MISO-PJM
C-H	Hubble to Batesville 138kV	HE-DUK-IN	N/C
C-I	Lallendorf to Monroe 345kV	FE-ATSI - DECO	N/C, MISO-PJM
C-J	Munster Transformer 345/138kV	NIPS	N/C
S-K	Fulton to Patmos 115kV	EES-AR	South, MISO-SPP
S-L	Bull Shoals to Midway Jordan 161kV	EES-AR	South, MISO-SPP
I-M	Neosho to Riverton 161kV	SPP	MISO-SPP
I-N	Kerr to Maid 161kV Ckt 2	SPP	MISO-SPP
I-P	Hugo to Valliant 138kV	SPP	MISO-SPP
I-R	Marshall to Smittyville 115kV	SPP	MISO-SPP
RDT	North – South Interface	MISO	N-S Interface

Source: MISO July 25 MCPS

Source: July 25 MCPS

Transmission Topography and Investment (Cont'd)

MISO-PJM Transmission System Interfaces



MSO/PJM interface area

Source: PJM

- The region is characterized by transmission seams to the west (with SPP) and to the east (with PJM). On its western boundary with SPP, MISO has 171 tie lines in voltages ranging from 69 kV to 500 kV (see table below). To the east, MISO has 146 interties with PJM.
- Imports and exports have 12 interfaces with a total interface capability of 14 GWs. Interface prices play a major role in deciding whether to schedule imports and exports with adjacent areas. MISO is typically a net importer, most actively scheduling with PJM. In 2018, total day-ahead and real-time net imports averaged 4.2 GWs and 4.8 GWs, respectively, with average hourly real-time imports from PJM of 1.9 GWs. However, on average, MISO's system marginal price was almost 20% lower than PJM's suggesting that MISO should be exporting to PJM.
- MISO has joint-operating agreements with PJM and SPP, allowing it to engage in market-to-market coordination. This allows redispatch from the other RTO's units to manage congestion if less costly than its own redispatch. MISO and PJM are also pseudo-tied; this allows each RTO to control capacity in the other. Through this mechanism, increasing amounts of capacity have been exported to PJM.

SPP-MISO AC Ties	
Voltage Level (kV)	**# of Tie-Lines**
69	78
115	28
138	4
161	24
230	20
345	14
500	3
Total	171

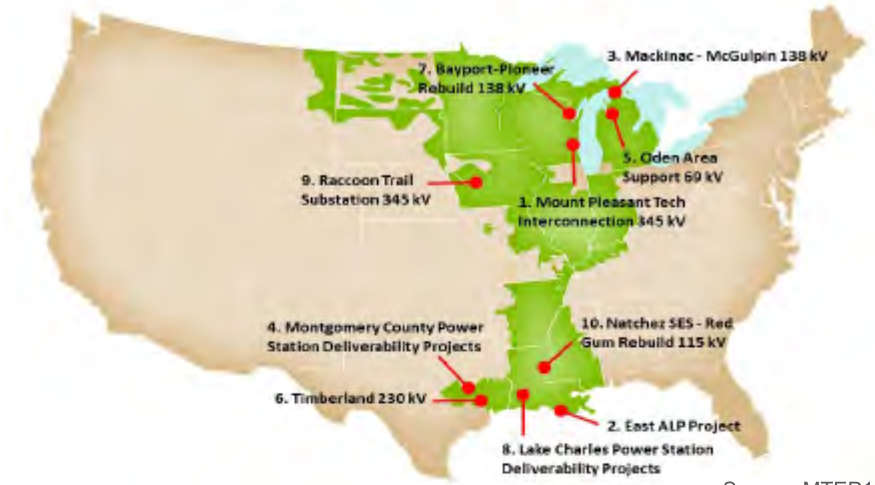
Source: OMS-RSC Seams White Paper

Sources: MISO 2018 SOM; PJM mapping (at https://gis.pjm.com/esm/default.html); OMS-RSC Seams White Paper

Transmission Topography and Investment (Cont'd)

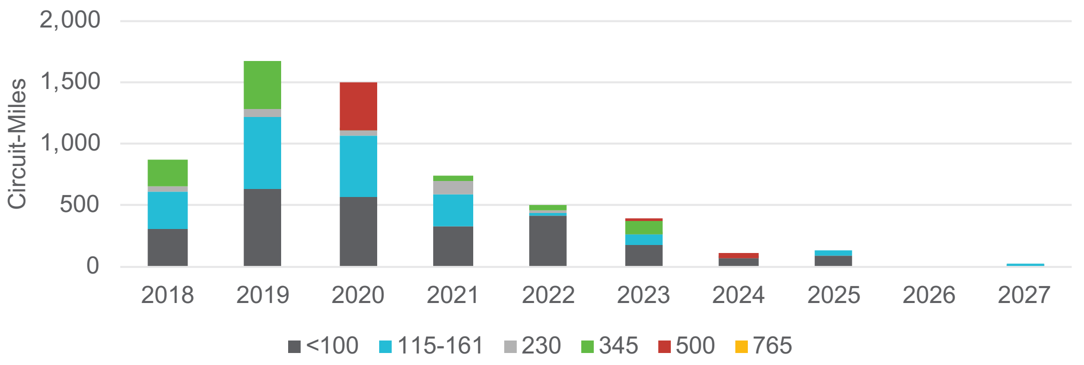
- In its latest transmission plan, MISO has identified $3.3 billion in transmission infrastructure investment. The top 10 projects represent 23% of that cost and are largely in the far north and south of the region (see upper right).
- Since its 2006 planning cycle, MISO has directed $10.7 billion in cost-shared projects; $6.5 billion were multi-value projects, which provide MISO region-wide public policy (e.g., renewables integration) and economic and/or reliability benefits (see lower right). MVPs were introduced to address large-scale emergence of wind resources.
- MISO has planned an addition of 5,900 circuit miles of new transmission, much of it (4,400 miles) at lower transmission levels (161 kV or less). Additions consist of 4,000 circuit miles of upgrades on existing corridors and 1,900 circuit miles of new lines on new corridors.
- Project spending in MISO's latest transmission plan is split roughly equally between new and upgraded lines and substation or switching station related construction and maintenance (including terminal equipment, circuit breaker additions and replacements, or new transformers).

MISO's Transmission Expansion Plan 10 Largest Projects (as of Dec. 2018)



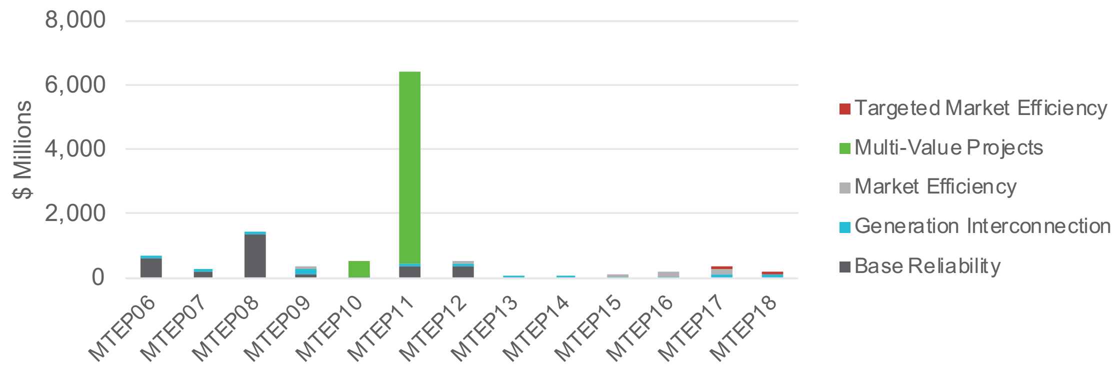
Source: MTEP18

MISO 2018 Transmission Plan Planned New or Upgraded Transmission Circuit-Miles by Voltage Class (kV) and Year



Source: MTEP18

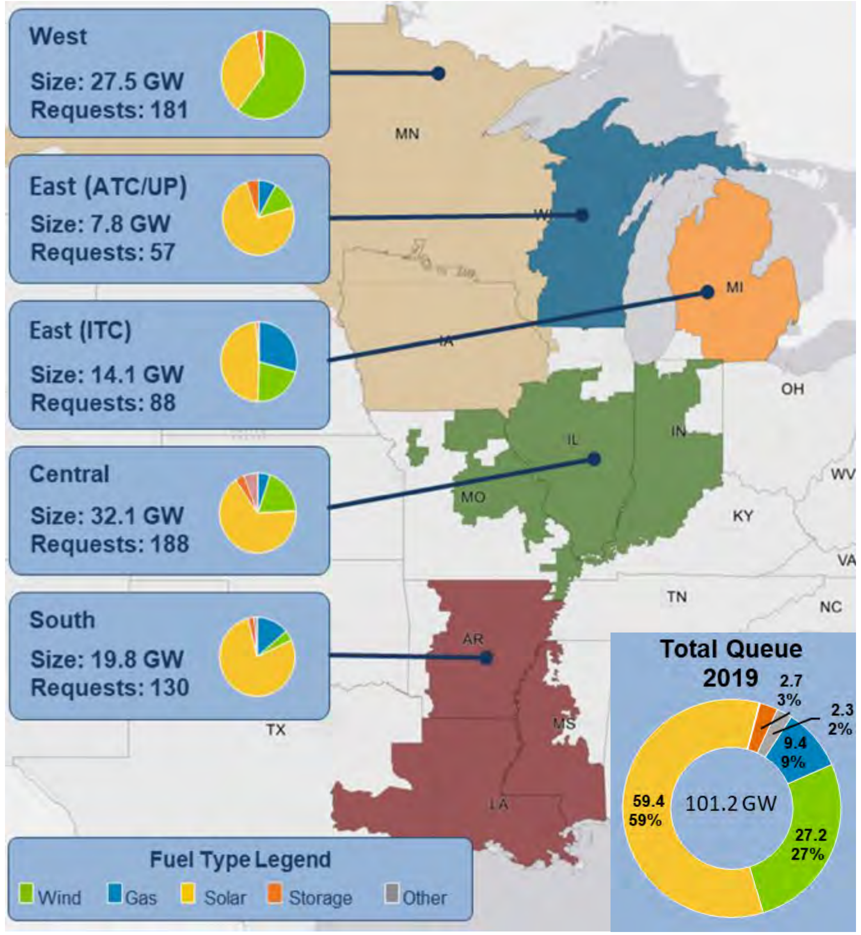
MTEP06 to MTEP18 Cost Shared Project Costs by MTEP Cycle and Project Type (in $Millions)



Source: MTEP18

Transmission Topography and Investment (Cont'd)

MISO Generator Interconnection Active Queue by Fuel Type and Region (as of June 2019)



Source: MISO

- MISO's latest analysis shows less congestion across its footprint than in prior planning cycles. It has invested in mitigating congestion, and the effects of competitive fuel prices and "stagnant" net demand growth have reduced congestion. However, it observes that the changing generation fleet (i.e., thermal generation retirements) and renewable additions may lead to congestion in specific areas.
- As of the release of its last transmission enhancement plan, MISO's generator interconnection queue consisted of 483 projects totaling 81.5 GWs (compare MISO's capacity of 175 GWs), a majority of which are solar and wind projects. The queue has grown to more than 101 GWs (with nearly 89 GWs of solar and wind) as of June 2019 (see chart at left). MISO is incorporating resource adequacy considerations in planning, as generation retires and is replaced by lower-capacity wind and solar resources.

MISO 2018 Transmission Enhancement Plan Appendix A Cost-Shared Projects

Category	Description	# of Projects	Total ($B)*	Largest Region Spend ($M)*
Baseline Reliability	Required for NERC, regional reliability	81	$0.7	South ($333)
Generator Interconnection Projects	Required to connect new generation to grid	16	$0.3	South ($149)
Other	Various, including lower voltage systems, local economic benefit, or don't meet market efficiency threshold	341	$2.3	West ($1,197)
Transmission Deliverability Service Projects	Network upgrades driven by transmission service requests	2	<$1M	South ($0.3)
Targeted Market Efficiency Projects	Interregional projects with PJM	2	$0.004	Central ($4.5)

*Rounded

Source: MTEP18

Source: MTEP18; June 2019 Resource Update

Resilience Issues

General Resilience Issues and Approach

- The area covered by MISO is broad with a diverse array of industries and weather. As a frame of reference for the potential economic impact of a resilience event, MISO's 2018 annual GDP for those states in its footprint (excluding Texas) was $3.8 trillion.*
- In MISO's comments to FERC in its grid resilience docket, it cites the following resilience risks in its region:
  - Because of its large geographic footprint, it can be susceptible to multiple events at one time. Key disruption types include communications interruptions; natural disasters, including potential effect on natural gas supply; and physical facility and cyber threats.
  - MISO considers its changing resource portfolio as having implications for resilience and related reliability efforts. Increased amounts of variable resources, both at the bulk (utility-scale) and sub-transmission and distribution level (distributed), together with reduced baseload resources require a fundamentally more flexible system. MISO has established a dispatchable intermittent resource capability product to provide operating flexibility and congestion management to accommodate large-scale wind.
  - MISO observes that most loss of load and interruption events occur at the distribution level, although transmission disruptions cover a broader area.
- MISO uses its transmission expansion-planning process to address resilience, with a view to provide diverse resources to effectively respond to events through real-time operations. Bulk system attributes evaluated through the transmission planning process include protection systems, reclosing schemes, redundant and backup protection schemes, and line ratings with sufficient margins. System analysis and visibility, such as data provided through synchrophasors and dynamic modelling, provide input to operations and planning efforts.
- MISO has multiple, active (staffed) control centers (MISO's headquarters in Indiana and two regional centers in Minnesota and Arkansas) and data centers that provide flexibility to operate in the event of a disruption.
- MISO believes that default use of transmission line relief (TLR) and curtailment of power transfers pursuant to TLRs are a less desirable approach to resilient operations, because they may block or curtail transfers across the Eastern Interconnection, even when redispatch options are available to reliably facilitate the original transaction. MISO believes that seams coordination and market-to-market transactions, together with redispatch, are more reliable and cost effective for relieving congestion.

*Note: Figure applies to states of AR, IA, IL, IN, KY, LA, MI, MN, MO, MS, MT, ND, SD, WI; excludes TX.
Sources: MISO Resilience Testimony; Bureau of Economic Analysis; EIPC Study

Resilience Issues (Cont’d)

Gas Infrastructure Dependency Analyses

- With a large and growing set of natural gas-fired resources, MISO has been studying gas-electric coordination and potential effects of resilience events.
  - NERC conducted a special study of potential reliability impacts of disruption of natural gas delivery. It identified 24 geographic clusters with more than 2 GWs of gas-fired generation. Eighteen areas were found with a reliability risk, and two of those areas were in MISO’s footprint—on the Missouri/Illinois border and around the Amite South load pocket in southeast Louisiana (see map at lower right). MISO has determined that those are not single source (N-1) issues, and the NERC analysis did not account for a generator’s ability to procure fuel from an alternate pipeline.
  - In 2015, the Eastern Interconnection Planning Collaborative (EIPC) conducted a study of, among other things, adequacy of gas infrastructure to serve electric system demand. It found “affected generation” totaling 2.6 GWhs (5%) in eastern Wisconsin in high-winter peak-load conditions. However, “affected generation” does not imply a risk to electric reliability.
- MISO plans to address testing and verification of dual-fuel units in the future. However, EIPC has observed that there may be some limitations on backup fuel use because of air permit conditions, cost of conversion to dual fuel, and the EPA’s new source rule implications.
- Since 2015, MISO has modeled gas infrastructure interruptions in its transmission planning. It now uses 31 gas contingencies, as extreme events, to evaluate system needs. It has found no cascading events, although in only one scenario—the extreme and long-term event of the loss of the largest natural gas pipeline for the entire summer-peak season—did planners observe a slightly elevated regional loss of load risk.
- In 2018, MISO investigated gas contingency risks, specifically historical (Jan. 2013 to Jan. 2018) pipeline and gas generator outages and found three things. First, the probability of any pipeline event occurring (regardless of size) is very small. Second, the impact of gas unit outage (due to fuel delivery disruption) to resource availability is mostly during winter months and within a narrow portion of the footprint, with a maximum of 915 MWs impacted in any operating hour. Third, the majority of gas generator outages are not related to a physical disruption.

Developing Gas Grid Flow Patterns and LNG Imports/Exports

Source: MISO Gas-Electric Planning Update

NERC-Identified Clusters Where Power Flow Issues Were Identified Upon Gas Delivery Disruption

Sources: MISO Gas-Electric Planning Update; NERC SPOD

Sources: EIPC Study; NERC SPOD; Gas-Electric Planning Update; Gas Study Results

Resilience Issues (Cont'd)

Recent Resilience Issue: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

- **Summary:** On January 17, 2018, a large area of the south central region of the United States experienced unusually cold weather. Below average temperatures began to occur as early as Friday, January 12, from the Great Plains south through the Mississippi Valley. Going into the work week beginning Monday, January 15, MISO and other adjacent areas knew that Wednesday, January 17, was likely going to be the coldest day of an extremely cold week for much of their respective footprints. The below average temperatures in this area resulted in 183 individual-generating units within the footprints of MISO, TVA, and SERC experiencing either an outage, a de-rate, or a failure to start between January 15 and January 19.
- **Outages and De-Rates:** Between Monday, January 15, and the morning peak hour (between 7:00 a.m. and 8:00 a.m. CST) on Wednesday, January 17, approximately 14,000 MWs of generation experienced an outage, de-rate, or failure to start. Inadequate winterization was deemed a key factor.
    - Including generation already on planned or unplanned outages or de-rated before January 15, the four regions had more than 30,000 MWs of generation unavailable in the south central portion of their footprint by the January 17 morning peak hour.
    - Generator owners attributed at least 35% of the generation outages and de-rates on January 17 to the extreme weather condition—19% to freezing-related mechanical issues and 16% to cold-related fuel supply issues.
    - From January 15 to 19, natural gas-fired units were 70% of the unplanned generation outages and de-rates, when calculated by numbers of units, and 74%, when calculated by MW.
    - During the same period, gas supply issues caused by the extreme cold temperatures, including interruptible supply, low gas pressure, and other pipeline and gas supply issues, led to outages of 38 units, for a total of approximately 2,200 MWs.
- **Peak Winter Demand:** At the same time (January 17 morning), power demand in MISO south and MISO was above their respective winter "extreme" forecast peak, while adjacent TVA and Southern Company footprints were above their expected "50/50" winter peak.
- **MISO Energy Emergency**: Under normal conditions, this region is not capacity limited. However, with generator outages, MISO declared an energy emergency, because it had insufficient reserves to balance generation and load in the south portion of its footprint, while all four regions experienced system constraints. MISO was limited in its ability to move power southward within its region to 3,000 MWs, but it exceeded that limit (reaching a maximum of 4,331 MWs) subject to any potential reliability effects on adjacent regions. MISO experienced parallel flows that challenged operators.
- **Deliverability:** There was ample wind generation available in the northern portion of MISO. Deliverability of reserves was the principal issue.

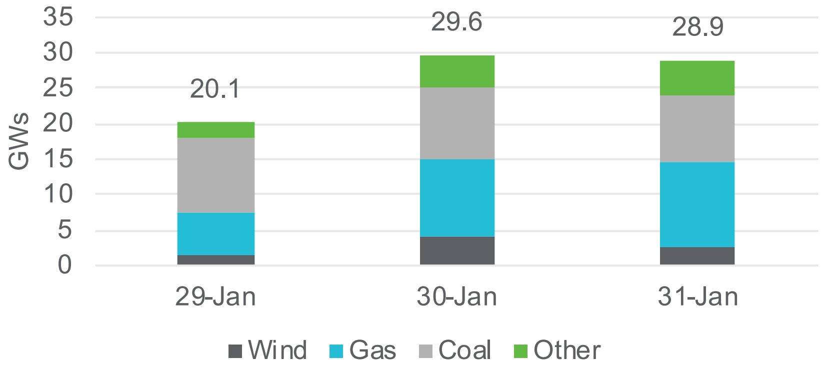
Source: Jan. 2018 Event Report

Resilience Issues (Cont'd)

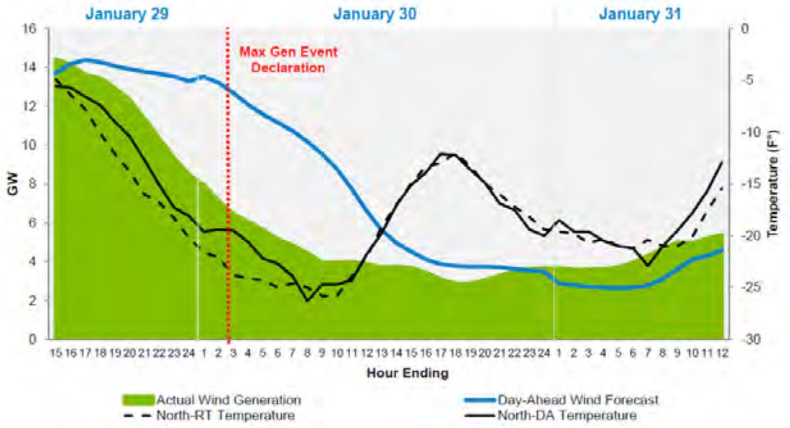
Recent Resilience Issue: Midcontinent ISO North and Central Region Maximum Generation Cold Weather Event (Jan. 30–31, 2019)

- **Summary:** On January 30-31, 2018, a strong Arctic high-pressure system brought historic cold to the North and Central Regions of MISO. North Region's low temperatures were 6°F colder than during the 2014 Polar Vortex event.
- **Outages, De-Rates, and Maximum Generation Declaration:** Cold-related mechanical issues and fuel supply limitations affected all generation types, with unplanned outages occurring across fuel technologies during the event (see chart top right).* Cold affected wind facilities as well (extreme cold can affect lubricants for wind gearboxes and bearings), causing an earlier than expected drop in wind output in the early morning of January 30 (see chart bottom right), increasing risk of resource insufficiency to meet the morning peak load and triggering a call of a Step 1 maximum generation event (call on emergency resources and to modify dispatch ranges). Subsequent conventional generation forced outages, uncertainty in the load forecast, and risk of additional outages caused additional emergency steps (Steps 2a-b: load management procedures).
- **System Response:** Voluntary load management, including school and business closings and deployment of load management resources, aided in reducing demand below expectations. Emergency pricing encouraged imports, including from south to north (compare January 2018 event on previous page). Imports into the North and Central Regions totaled in excess of 5 GWs during the January 30 evening peak and into the January 31 morning peak.
- **Results and Lessons Learned:** MISO successfully met planned and actual obligations, given the extreme temperatures, public safety concerns, forced outage risk, and import volume uncertainty. One lesson from the event was recognition of the need to incorporate additional generation resource-operating parameters, particularly temperature thresholds. Others included identified changes in load-forecasting variables as well as increasing visibility into performance and availability of load-modifying resources.

MISO North/Central Daly Average Unplanned Generation Outages* (GWs)



Forecast vs. Actual Wind Generation (GWs) and Temperature

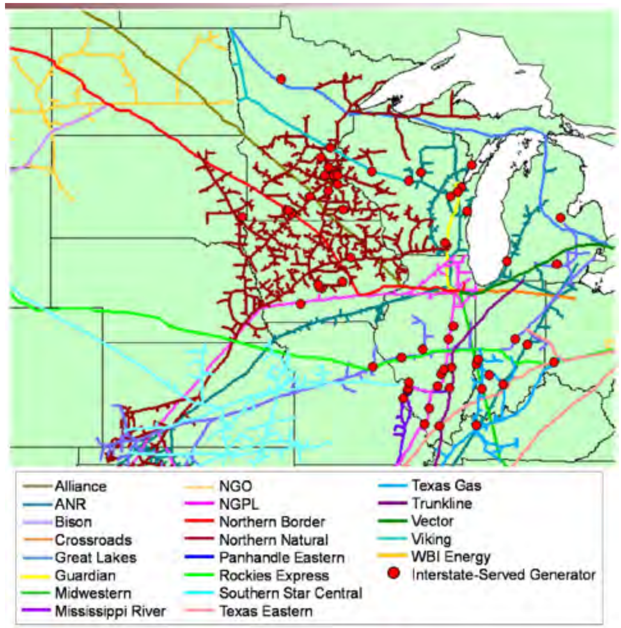


Note: *On January 30, 28% of wind capacity and 34% of gas capacity were in unplanned outages, or 25% overall during the entire event.
Source: Jan. 2019 Event Overview

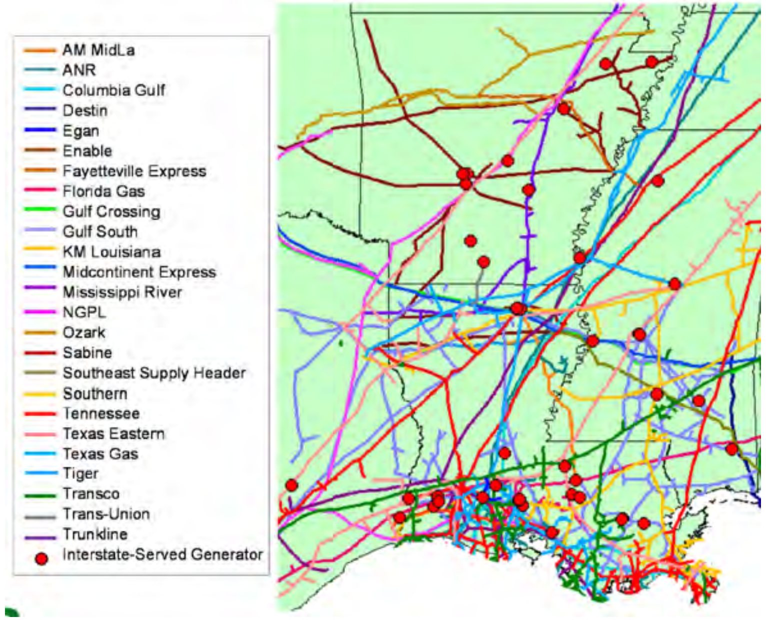
Resilience Issues (Cont’d)

- MISO’s energy resource technologies vary, but it is mostly dependent upon wind, coal, and natural gas-fired generation. Gas-fired generation is particularly concentrated in the southern part of its footprint.
- There is abundant gas pipeline availability and access in the southern portion of the region, particularly in Texas and Louisiana. In the North/Central region, pipeline resources are characterized by a few large pipelines from the northwest and southwest feeding toward Chicago, with a larger network in the Minnesota/Wisconsin area.

Interstate Pipelines Serving MISO North/Central and Connected Generators (2015)



Interstate Pipelines Serving MISO South and Connected Generators (2015)

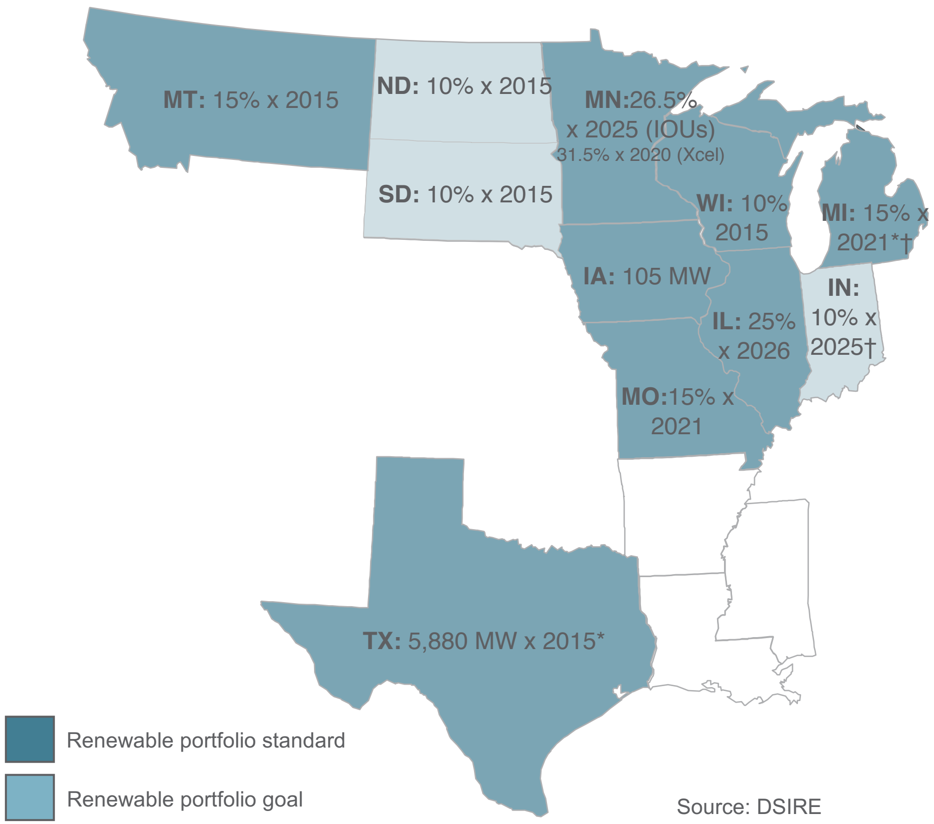


Source: EIPC Study

Sources: MISO Fact Sheet; EIA; EIPC Study

Renewables Integration

State Renewable Portfolio and Clean Energy Standards and Goals within the MISO Footprint (as of June 2019)



Source: DSIRE

* Extra credit for solar or customer-sited renewables

† Includes non-renewable alternative sources

Demand-Side Considerations

- Overall power consumption generally in the region was 683 TWhs in 2018, growing 4% from 657 TWhs in 2017. Longer term, MISO's demand and energy growth rates for planning purposes have declined over time. Its latest planning assumptions forecast a 0.29% compound annual growth rate in demand and 0.43% in energy through 2033.
- A number of states, both within and adjacent to MISO's footprint, have renewable and/or clean energy standards (see left). Minnesota has a relatively ambitious renewables standard, requiring investor-owned utilities to procure 26.5% of their power renewables by 2025. Illinois has targeted 25% renewables by 2026.
- Some utilities in states touched by MISO'S footprint have also introduced clean and renewable energy commitments (see next page).

Sources: MISO Fact Sheet; SEPA; DSIRE; NERC ES&D

Renewables Integration (Cont'd)

Utility Name (States of Operation)	Goal Type	Target Dates	Description (Date Implemented)
AEP Ohio	Emission Reduction	2050	80% emissions reduction below 2000 levels by 2050 (2018)
AES Corporation	Carbon Reduction	2030	70% carbon reduction through 2030 (revised its prior goal of 50% reduction from a 2016 baseline) (2018)
Alliant Energy	Emission Reduction/Renewable Energy	2050	40% below 2005 levels by 2030 and 80% of total emissions by 2050 (also eliminating all coal by 2050); 30% renewable energy by 2024 (2017)
Ameren	Emission Reduction	2050	80% emissions reduction by 2050 compared to 2005 levels (2017)
CMS Energy Corporation	Emission Reduction/Coal Elimination	2040	80% emissions reduction and no longer using coal by 2040 (2018)
DTE Energy	Emission Reduction	2040	80% emissions reduction by 2040 (2019)
Great River Energy	Renewable Energy	2030	50% by 2030 renewable energy (2018)
Madison Gas and Electric	Emission Reduction	2050	Net-zero carbon electricity by 2050
MidAmerican Energy (IA, IL, SD)	Renewables	N/A	100% renewables (2016)
NiSource, Inc./NIPSCO	Carbon/Coal Reduction	2030	90% carbon emissions reduction from 2005 levels by 2030 (2019); moving to coal free by 2028 (2018)
Otter Tail Corporation (MN, ND)	Renewable Energy	2031	30% renewables by 2031 (2017)
Vectren Corp	Emission Reduction	2023	60% emissions reduction by 2023 (2018)
WEC Energy Group	Emission Reduction	2030	40% emissions reduction below 2005 levels by 2030 (2018)
Xcel Energy (CO, MI, MN, NM, ND, SD, TX, WI)	Emission Reduction/ Carbon Reduction	2017 2030 2050	35% emissions reduction by 2017 (achieved) 80% below 2005 levels by 2030 Zero carbon by 2050 (2015)

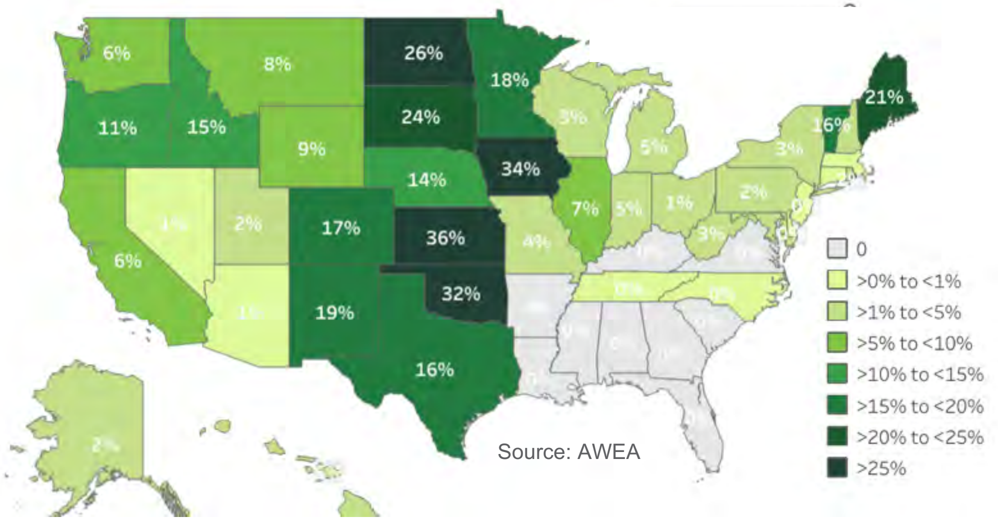
Source: SEPA (as of July 2019)

Renewables Integration (Cont'd)

Supply-Side Considerations

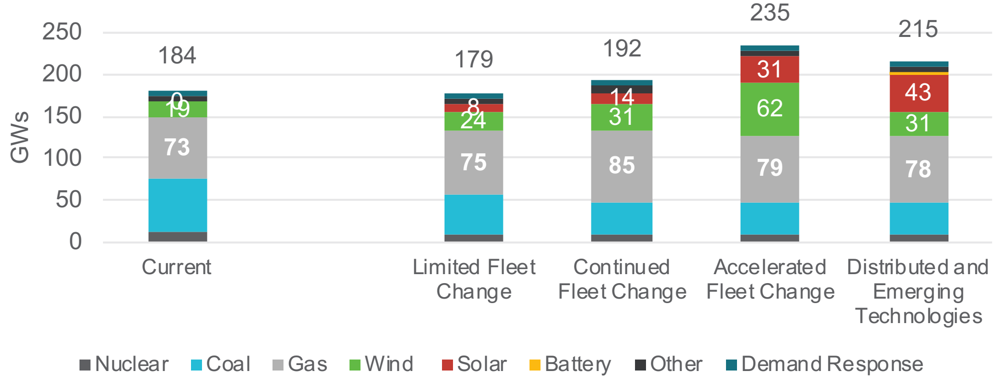
- MISO has significant potential wind resources, although wind power constitutes only about 15% of installed capacity (10% of market capacity).
- In its most recent forward-looking scenarios for transmission planning, MISO has bounded 2033 installed wind capacity between 24 GWs and 62 GWs, up from an existing 19 GWs. This would comprise between 13% to 26% of 2033 market capacity. About 27%, or 27 GWs, of the generation interconnection queue at June 2019 was wind.
- Solar is emerging as a growing resource in MISO's footprint as well. For planning purposes, MISO's bounds expected installed capacity of utility-scale solar resources between 8 and 43 GWs, from a negligible amount today (314 MWs front-of-meter solar as of June 2019). In fact, 59% of the generation interconnection queue as of June 2019 (or 59.4 GWs) constituted solar (see lower right).
- Under its planning scenarios (see below), renewables penetration varies significantly. MISO assumes renewables penetration levels between 15% and 39% of capacity by 2033.

Wind Energy's Share of Electricity Generation by State (2018)



Source: AWEA

MTEP19 Futures Installed Capacity (GWs) by Type and Scenario (2018 vs. 2033)



Source: MISO

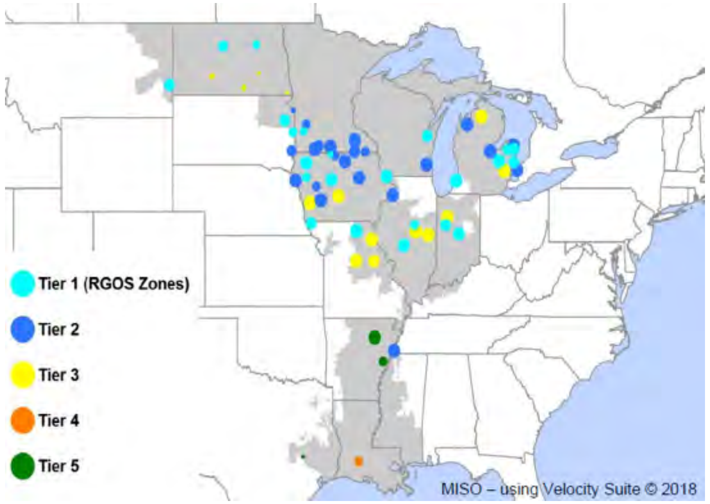
MISO Queue: Historical Trend of Requested Generation by Fuel Type (GWs) and by Queue Date Year

Source: MISO

Sources: AWEA; MISO Fact Sheet; MTEP19 Futures Summary; June 2019 Resource Update; ELCC Study

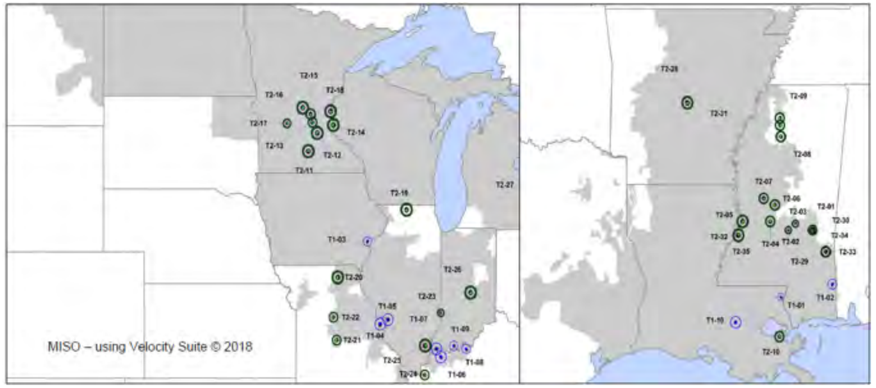
Renewables Integration (Cont'd)

Wind Regional Resource Forecast Unit Siting: 3.6 to 10.8 GWs Depending Upon Scenario



Source: MTEP19 Futures

Solar Regional Resource Forecast Unit Siting: 7.2 to 42.7 GWs* Depending Upon Scenario

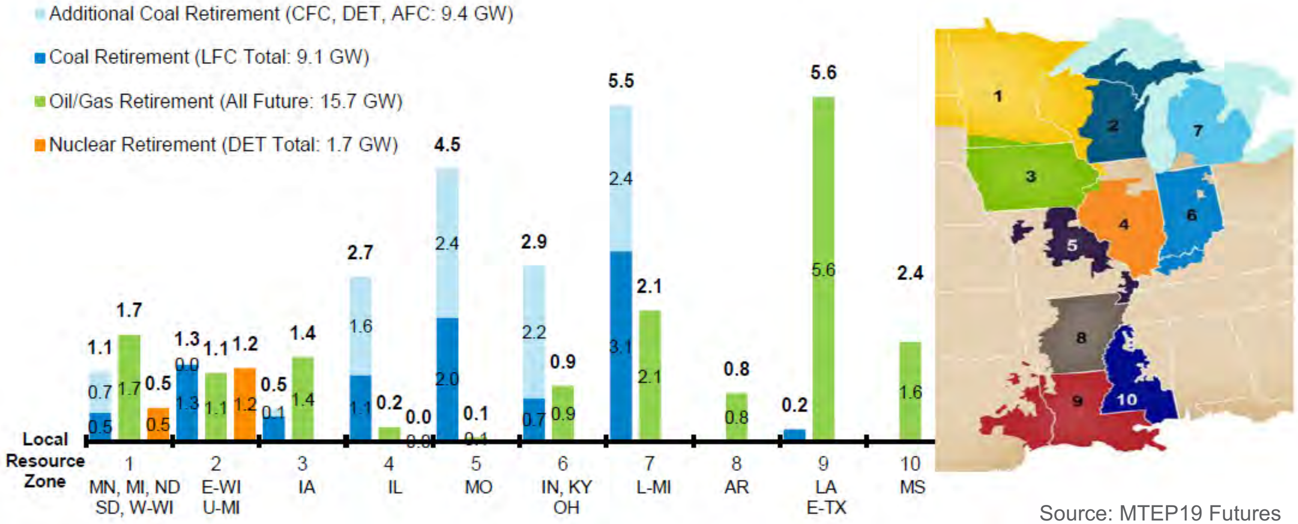


Source: MTEP19 Futures

Supply-Side Considerations – Retirements and Locational Considerations

- While renewables and some gas-fired generation dominate projected capacity additions, MISO expects significant retirements of coal, oil, and gas capacity. Its planning assumptions have thermal generation retirements of 25 GWs by 2033 in its most conservative case to more than 35 GWs in its more aggressive case of renewables development and carbon-reduction policies (see below).
- These assumed retirements are distributed through the footprint, but they are particularly prevalent in Illinois, Missouri, Indiana, Michigan, and Louisiana, while renewable additions are concentrated in the upper Midwest and Mississippi (see maps at left).

Assumed Thermal Generation Retirements by 2019 Planning Scenario and Local Resource Zone (GWs)

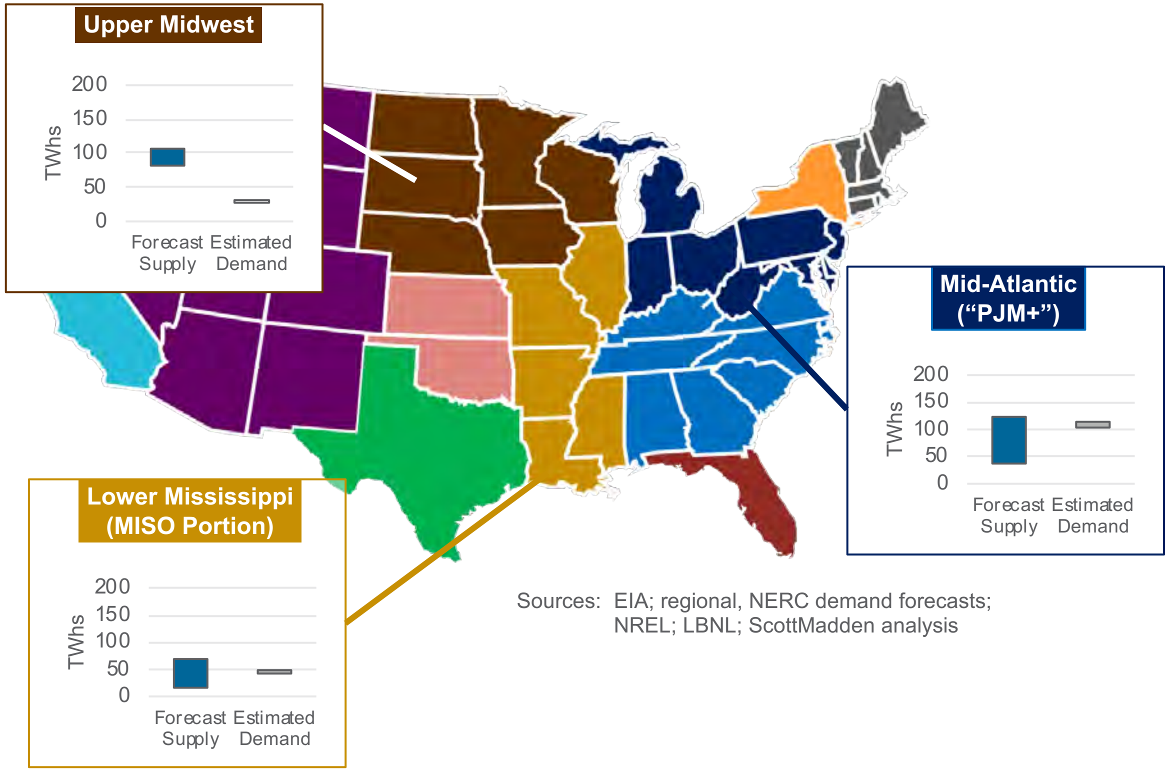


Source: MTEP19 Futures

Source: MTEP19 Futures
Notes: Tiers indicate priority and likelihood of completion. *Solar figures include 2.4 to 28.4 GWs of distributed solar resources.

Renewables Integration (Cont'd)

Midcontinent ISO-Area U.S. Potential Policy-Driven Renewable Energy Demand and Forecast Supply (2030) (as of June 2019)

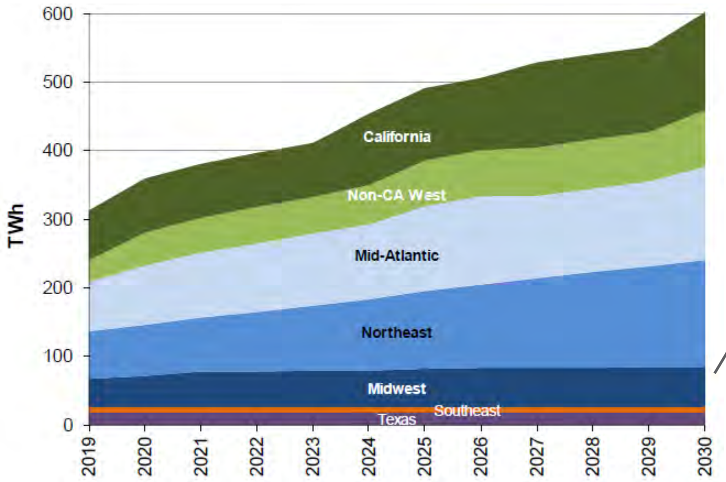


Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Integration Challenges – RPS Supply-Demand Balance

- Forecast renewables supply is greater than anticipated renewable portfolio standard (RPS) policy-driven growth in the Midwest, in particular the MISO market area. While there has been significant wind development, some has been contracted to utilities with RPS needs.
- A separate analysis by the American Wind Energy Association estimated that wind-eligible demand* in the Midwest (Indiana, Iowa, Michigan, Minnesota, Missouri, and Wisconsin) totals 3 GWs by 2030. As noted earlier, as of June 2019, more than 27 GWs of wind resources were in the generation interconnection queue in MISO.
- Lawrence Berkeley National Laboratory (LBNL) notes that RPS capacity additions (10% or 9 GWs) extend to 13 states without an RPS, with the most significant including MISO states Indiana and North Dakota as well as Wyoming. Two others with no further RPS obligations—Kansas and MISO state Iowa—host significant RPS capacity for others.
- This RPS supply-demand imbalance illustrates the role of interstate transmission capacity for interstate commerce for RPS compliance.

Projected U.S. RPS Demand (Total Compliance Requirements) per DOE LBNL (2019–2030) (as of July 2019) (in TWh)



Limited growth in RPS demand in the Midwest

Notes: *Per AWEA, wind eligible demand is the amount of renewable energy needed to meet RPS requirements for which wind is an eligible technology. This excludes technology carve-outs, separate resource classes, and energy efficiency requirements. This category represents the remaining RPS procurement needs that wind is eligible to capture and the maximum RPS market opportunity for wind.

Sources: LBNL 2019 RPS Analysis; AWEA 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

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Renewables Integration (Cont'd)

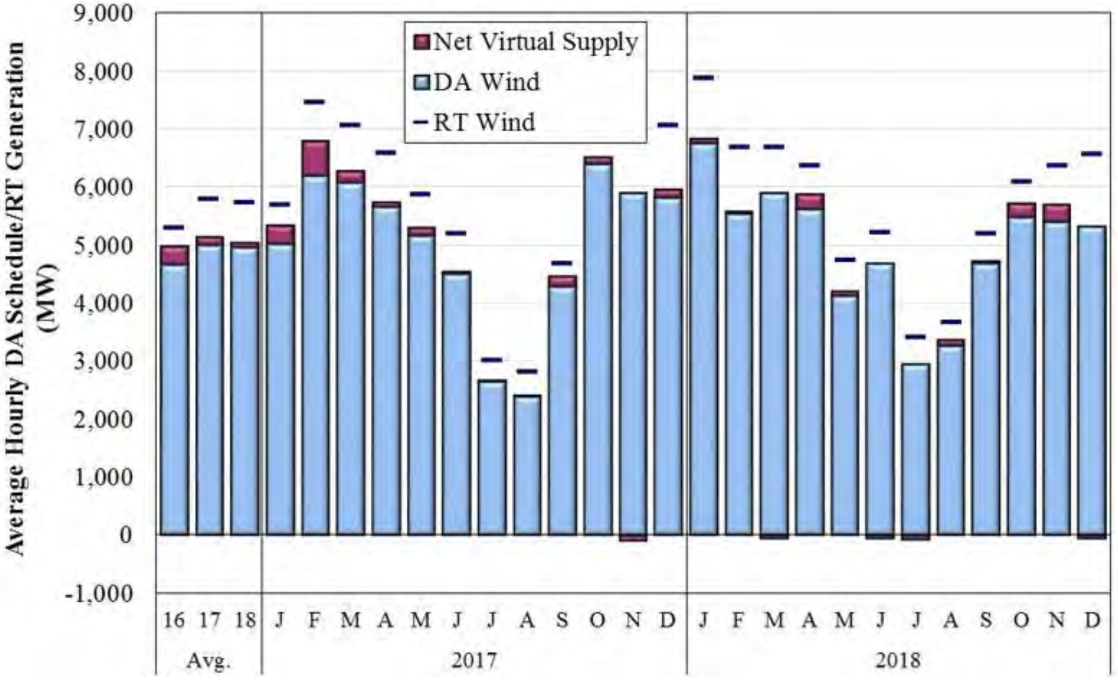
Integration Challenges (Cont'd) – Other Integration Issues

- Wind and solar integration bring low-cost generation to the MISO region, but accredited capacity associated with those technologies is lower than their nameplate capacity because of probabilistic estimates and historical performance of those resources. The effective load-carrying capacity (ELCC) is the amount of incremental load a resource can dependably and reliably serve and is based upon. This capacity value (as % of nameplate) is used to determine resource adequacy in a local resource zone for reliability, particularly to plan to less than one day in 10 years for expected loss of load (unserved load). ELCC does not necessarily indicate energy output over time or at a particular time.
  - MISO performs an annual analysis of installed wind and solar capacity to determine ELCC and in particular MISO's capacity credit. MISO analyzed 215 nodes where 2,855 MWs of wind generation were present. For the 2019–2020 planning year, MISO-wide wind capacity credit is 15.7%, an increase of 0.5% from MISO's 2018 capacity credit. Wind output is lower during summer months than during shoulder months, which reduces its reliability value.
  - Because of the small amount of solar resources on its system and pending sufficient-operating history of summer performance, MISO applies a 50% class average credit to solar resources. In its long-term planning, and assuming higher penetration of solar and wind resources on its system, MISO projects that the solar capacity credit will fall to 30% by 2033.
  - Per its 2018 transmission plan, MISO assumes less capacity availability because of the on-peak performance of generators (including renewable resources), transmission limitations, and energy-only capacity; MISO assumes on-peak capacity of 148.6 GWs, significantly less than its current nameplate capacity (170.5 GWs).
  - Diversity of resources—technology diversity (i.e., solar and wind evaluated together) and geographic diversity—improves overall renewable ELCC.
- Wind generation accounted for 8% of generation in 2018. Installed capacity exceeded 19 GWs, with 1.9 GWs entering the market in 2018 with more expected. Because of its variability, wind presents operational challenges, particularly as its share of total output increases. It should be noted that real-time wind generation averaged 5.7 GWs per hour (about 30% of total wind capacity), and its all-time record was on March 15, 2019, at 16.3 GWs (about 86% of total wind capacity).
  - One issue MISO faces is under-scheduling wind. Wind suppliers often under-schedule their output in the day-ahead market than their real-time output (see next page). This is in part because of some supply contract terms and wind producers' management of financial risk of under-delivery. Under-scheduling of wind averaged 770 MWs per hour in 2018 and exceeded 1,000 MWs (more than 5% of wind capacity) in three months. This creates price volatility (as other resources must be procured to cover potential shortfalls) and congestion that must be alleviated.
  - Another issue is the opposite concern—over-forecasting wind output in real time. Since wind resources are low or no marginal cost, they are scheduled for dispatch first; under-delivery due to forecast error results in dispatch deviations. MISO's market monitor has observed that the over-forecasting rate is higher in summer months, even as wind output is lower during those months (see next page).

Sources: MTEP18; ELCC Study; MISO 2018 SOM; Apr. 2018 RIIA Update

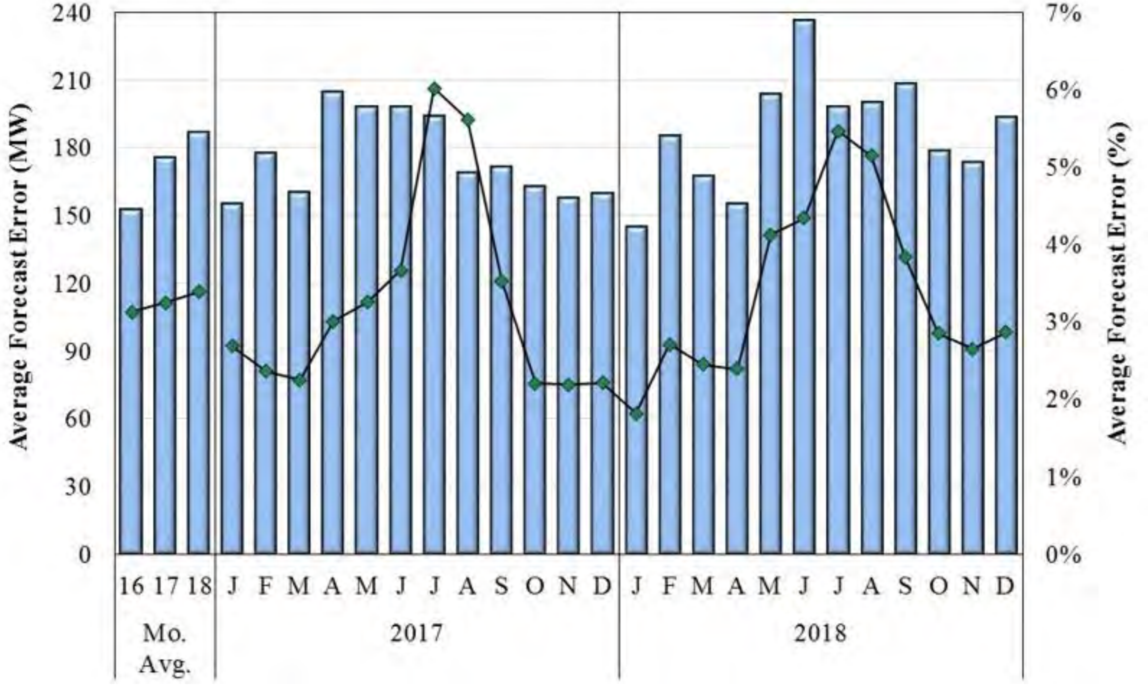
Renewables Integration (Cont'd)

Day-Ahead and Real-Time Wind Generation and Net Virtual Supply (2017–18)



Source: MISO 2018 SOM, Fig. 24

Generation Wind Over-Forecasting Levels (2017–18)



Source: MISO 2018 SOM, Fig. 25

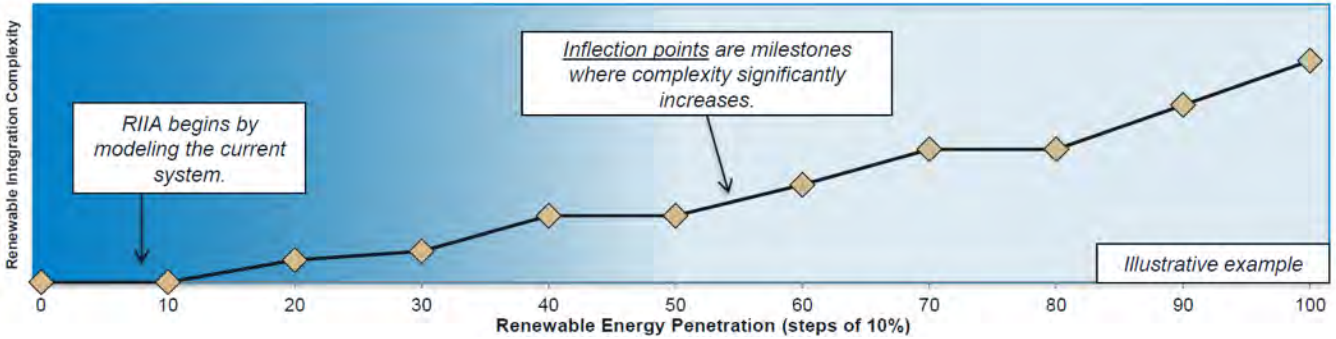
- MISO is working on market fixes to aid wind integration, including a ramp product, shortage pricing, and incentives for improved wind forecasts.

Renewables Integration (Cont'd)

Integration Challenges – Renewable Integration Impact Assessment (RIIA)

- Renewable resources, specifically wind and solar resources, have been the fastest-growing class of resources in MISO. MISO has observed that many of its legacy power plants that generated the bulk of its electricity have or will retire and be replaced by natural gas-fired and renewable resources. It has also observed the increased interest in energy efficiency, demand-side programs, energy storage, and distributed energy systems (like rooftop solar).
- In 2017, MISO launched an effort to develop a framework that considers grid impacts, including transmission and system performance. The purpose of the RIIA study is to find system inflection points—levels of renewable penetration as they affect complexity, including system stability, resource adequacy, and operational control (see graphic below).
- In the RIIA, MISO has been looking at inflection points driven by 10% increments of increased renewable energy penetration at which underlying infrastructure and/or system operations must be changed to accommodate that next level of renewables. The analysis is split into modules, which consider various system adequacy issues (see table at right). It also considers a range of potential solutions to mitigate impacts identified (see table at right).

RIIA Conceptual Approach: Finding Inflection Points of Renewable Integration Complexity



Source: Nov. 2018 RIIA Update

RIIA Impact Identification Metrics

Operational Adequacy	Steady-State Adequacy	Stability Adequacy	Resource Adequacy
• System ramp • Over/under generation • Transmission congestion • Operating and ramping reserves	• Voltage support • Frequency support • Short-circuit length	• Voltage stability • Frequency stability • Transient stability	• Loss of load expectation • Renewable capacity credit

Source: RIIA Concept Paper

RIIA Impact Mitigation Potential Solutions

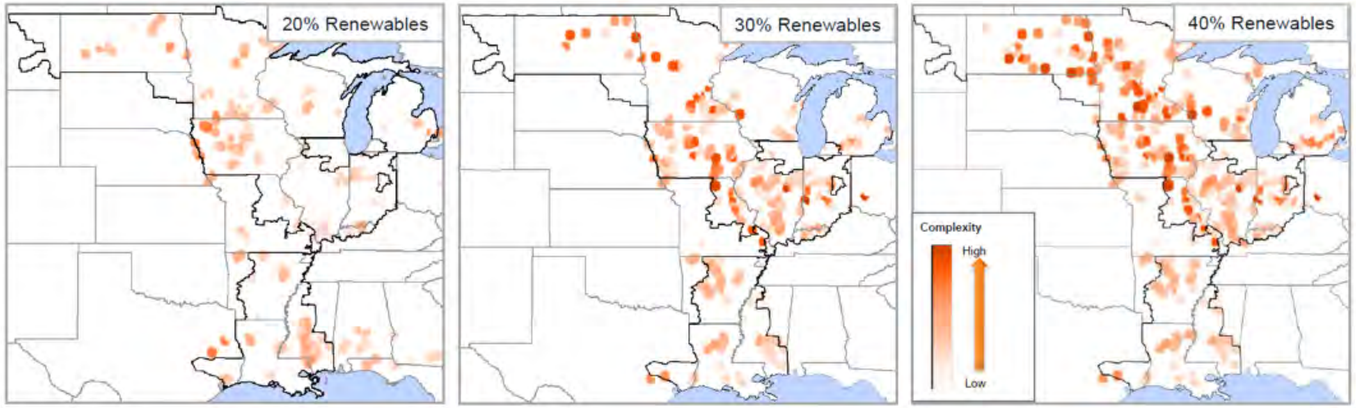
Transmission	Resources	Operations
• Lines • Buses • FACTS • Synchronous condensers • Energy storage	• Demand response • Fast-ramping generation • Require units to provide frequency response, inertia, and/or dispatchability • Energy storage	• Increased coordination • Increased operating reserves • Maintenance of frequency performance

Source: RIIA Concept Paper

Sources: RIIA Concept Paper; Apr. 2018 RIIA Update; Nov. 2018 RIIA Update

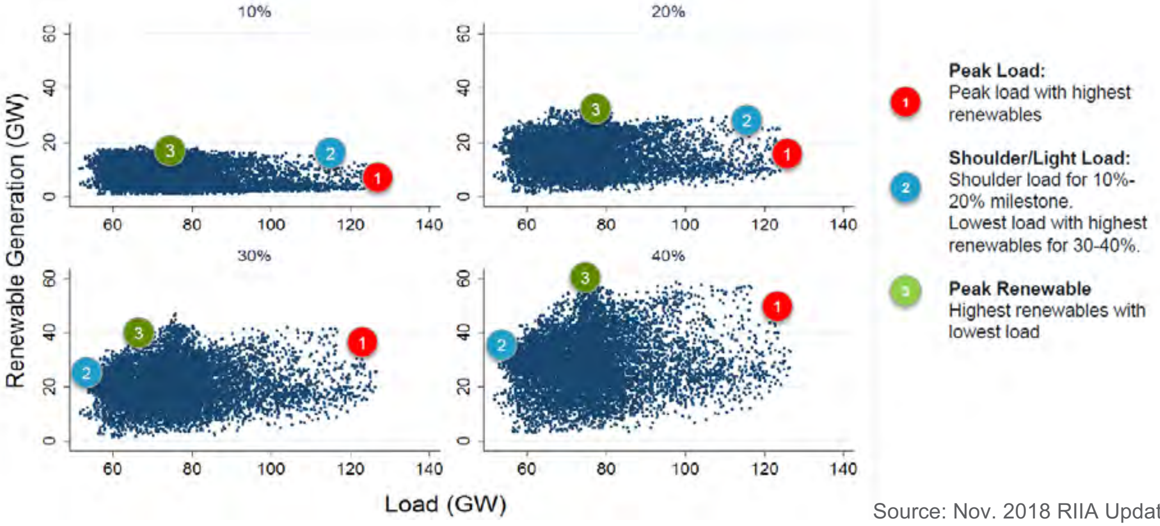
Renewables Integration (Cont’d)

Change in Steady State Solution Complexity With Increase in Penetration Level



Source: Nov. 2018 RIIA Update

Points of Transmission Stress Change as Renewables Penetration Grows



Source: Nov. 2018 RIIA Update

Integration Challenges – RIIA (Cont’d)

- As of late 2018, MISO’s early findings in its RIIA analysis were as follows:
  - Integration complexity increases sharply from 30% to 40%, with that inflection point driven by energy adequacy.
  - Beginning at about 20% penetration, integration challenges (particularly renewable curtailment of anywhere from 6% to 18%) grow.
  - Curtailment, particularly of wind, is used to accommodate maximum variability swings (ramping). In the 40% penetration RIIA case, only 32% of MISO’s load is served by renewable energy. At 40%, transmission expansion is needed to use the diverse variable resources across MISO’s footprint.
  - Integration complexity (see maps at left) is measured as the approximate cost of the transmission fixes needed for steady state reliability issues, with the majority of the integration cost from fixes for transmission thermal violations. At 20%, complexity is relatively mild, but it increases with increasing penetration.
  - As renewable penetration increases, the risk of losing load compresses into a small number of hours and shifts to later in the day, from mid-afternoon to around 6:00 pm. However, the available energy from wind and solar during high-risk hours decreases. A thermal unit’s average hourly generation decreases with increased penetration, but ramping volumes (as % of maximum capacity) increase.
  - Transmission stress changes (see lower left) with higher penetration—no longer concentrated on high-load periods, but also causing stress during shoulder/light load periods.

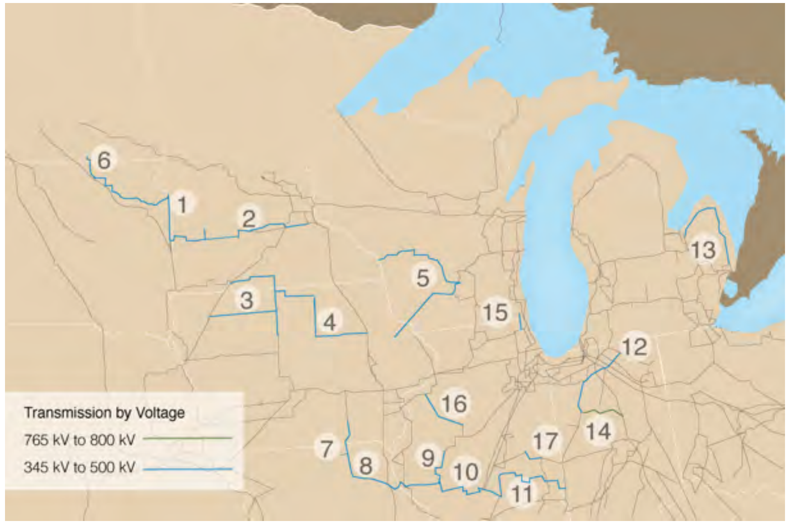
Sources: Apr. 2018 RIIA Update; Nov. 2018 RIIA Update; IAEE

Renewables Integration (Cont'd)

Integration Challenges – Multi-Value Projects (MVPs)

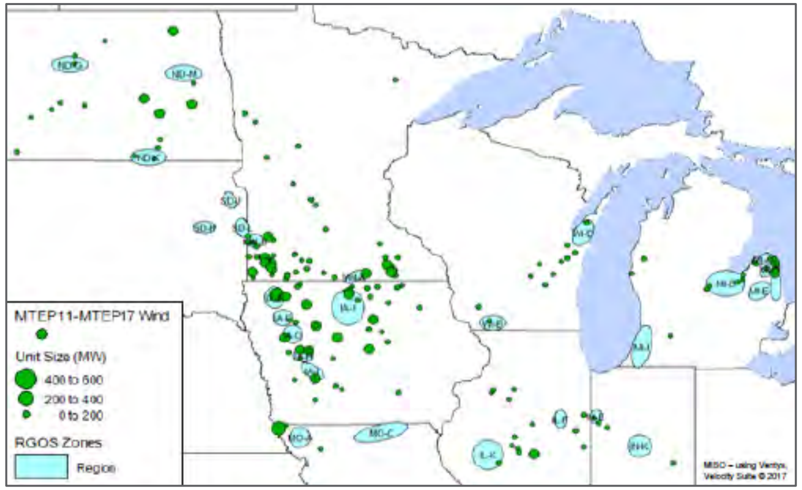
- MISO introduced MVPs in its 2011 transmission planning process to address increasing renewable resources, policy mandates (e.g., renewable energy mandates), and economic enhancements in its footprint. These regional transmission solutions are designed to meet one or more of three goals:
  - Reliably and economically enable regional public policy needs
  - Provide multiple types of regional economic value
  - Provide a combination of regional reliability and economic value
- The MVP portfolio is reviewed annually in MISO's transmission planning cycle, with more comprehensive reviews triennially. Those reviews include cost-benefit analysis, as projects are completed; system benefits, such as congestion relief; and fuel savings.
  - The 2018 annual review found the improved cost-benefit ratio of MVPs over their initial estimates, ranging from 2.0 to 3.1. The largest economics benefits consisted of congestion and fuel savings (about $16 billion to $56 billion) to MISO's North and Central regions and regional wind turbine investment ($1.2 billion to $1.4 billion).
  - According to MISO, 11.3 GWs of dispatched wind generation would be curtailed without the MVP portfolio. The MVP portfolio enables nearly 53 million MWhs of renewable energy to meet renewable mandates and goals through 2031. It also enables more than 5.1 GWs of incremental installed wind capacity over that same period, much of that in Michigan, Wisconsin, and Indiana. Much of the wind enabled is in the North and Central regions.
  - MVPs provide qualitative benefits, such as decreasing natural gas risk (fuel diversity), increasing geographical distance between wind generators (allowing for resource diversity), and enabling deliverability of all types of generation.

MISO Multi-Value Project Portfolio



Source: 2017 Triennial Review

MISO North/Central Wind Projects (2012–Apr. 2017) and RGOS* Zones



Source: 2017 Triennial Review

Sources: 2017 Triennial Review; MTEP18
Note: MVP benefits are estimated based upon a 20- to 40-year present value.
*RGOS means Regional Generation Outlet Study, a precursor to MVPs, that identified a set of value-based transmission projects necessary to enable load-serving entities to meet their RPS mandates.

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
Midcontinent ISO	▪ Resource portfolio “transformation” to gas, intermittent resources—net gas capacity additions of 57 GWs from 2017–2021 ▪ Seasonal weather risks: extreme cold, heatwaves, flooding ▪ Geographic diversity (broad north-south footprint) affords weather diversity as well as multi-threat exposure ▪ Some gas infrastructure interruption exposure with major event, esp. in MO/IL border and south	▪ Interconnection queue of 101.2 GWs as of June 2019: 59.2 GWs solar, 27.2 GWs wind ▪ Wind capacity credit only about 15% of nameplate ▪ Renewables accounted for 9% of energy in 2017 and growing ▪ Increasing complexity with higher-renewable penetration: ramping needs, shifting net peak load later (from 3 PM to 6 PM) over smaller number of hours ▪ High curtailment (~60% of 2031 wind energy) without MVP projects ▪ Regional differences, with targeted integration issues in MISO West, which has much greater renewables penetration levels	▪ Scenario planning (10–15 years) examines various levels of penetration, with an energy mix from 13% to 36% wind and solar and up to 32% gas ▪ Tariff approach: dispatchable intermittent resource product aids incremental wind in real-time due to better forecasting ▪ Expected retirements of ~16 GWs largely thermal; while resource adequacy sufficient, increasing emergency events ▪ Public policy differences between north and south of region	▪ Increased north/south transfer limits to support resource diversity, resilience needs during gas events in south ▪ Increased internal capacity to co-optimize resources, reduce curtailment, and limit price volatility ▪ Pursuing coordinated system plan with PJM to reduce congestion on market-to-market flow gates ▪ Per latest MTEP, $3.3B in transmission planned in 2018; about 2/3 of lines are upgrades on existing corridors, 1/3 to be new lines ▪ Investment of nearly $6.5B in cost-shared multi-value projects from 2006 to 2017, but reflects 2011 circumstances (policy, anticipated renewables build, etc.)—opportunity for updated study ▪ Possible upgrades in anticipation of “tipping point” of 30%–40% renewables penetration in some MISO zones

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Regional Discussion

SOUTHEAST

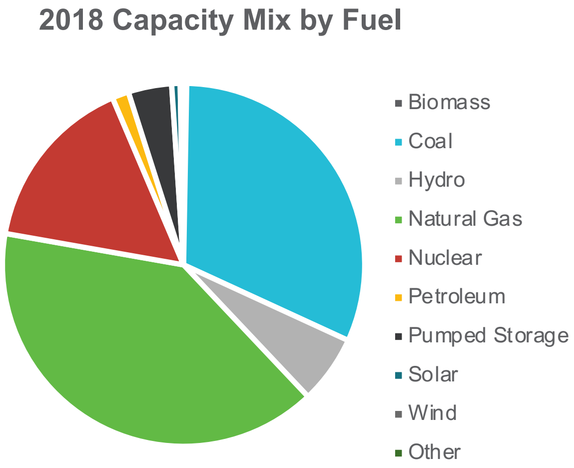
Contents

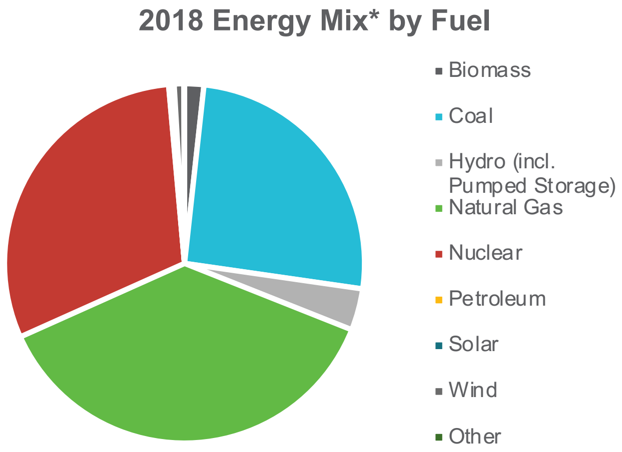
Overview

Description of Region

- The Southeast is principally comprised of vertically integrated investor-owned utilities, a large federal utility, and a number of cooperative and municipal and state utilities.
- SERC, the reliability assessment area covering the Southeast region, is a summer-peaking assessment area, although winter peak exceeded summer in 2018. SERC is divided into three assessment areas: SERC-E, SERC-N, and SERC-SE.
- Reserve margins for the region are expected to remain above 20% through 2027(compared with a 15% target margin level).

Key Regional Statistics	
States Covered	NC, SC, TN, KY, GA, AL, MS, MO
Square Mi. Covered	~308,900
No. of Utilities	14 co-ops; 3 federal/state systems; 10 munis; 12 investor-owned utilities
No. of Customers/Pop. Served	39.4MM population
Installed Capacity	164,037 MWs
Transmission Line Miles	71,564 miles
Peak Hour Demand (2018)†	127,116 MWs summer (136,112 MWs winter)
Net Energy for Load	670,218 GWhs
Forecast Growth (Annual)	0.27%–0.82% peak load growth 0.1%–0.8% demand (usage) growth





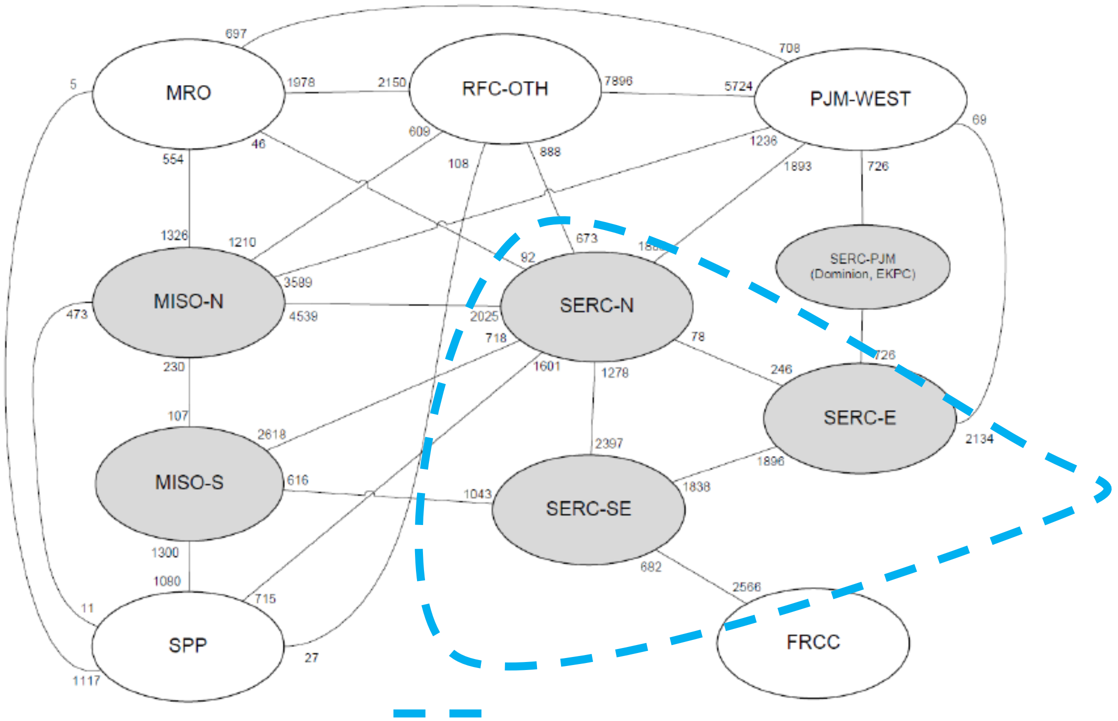
Sources: NERC 2018 LTRA

Notes: SERC recently reorganized into its current three assessment areas. It had traditionally covered some areas of PJM (in VA) as well as MISO-Central (IL, MO) and MISO-South (AR, MS, LA, TX). For some statistics noted here, those legacy areas may be included because the most recent information from SERC includes them (e.g., 2018 SERC Reliability Review Committee Annual Assessment). Those are noted herein with an *.

† Note: Not necessarily coincident; constitutes a sum of subregional peak hour demand for SERC-E, SERC-N, and SERC-SE; net internal demand is net of demand response.

Transmission Topography and Investment

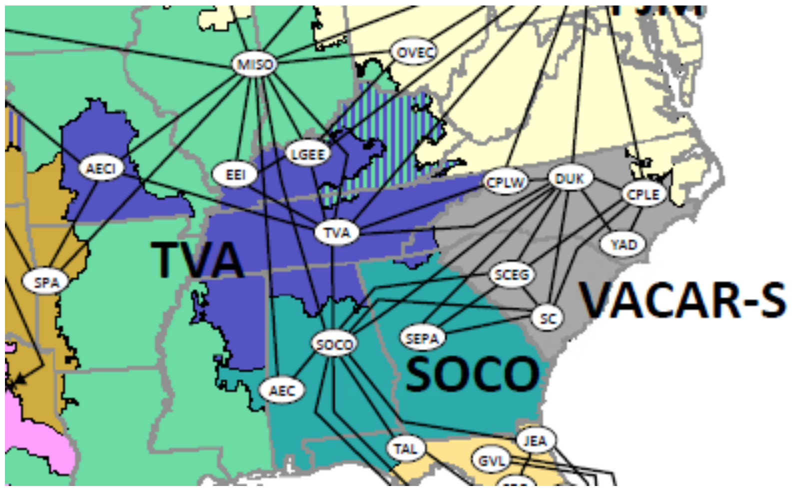
System Transfer Limits (MWs) (Estimated Summer 2020)



Source: 2018 SERC Probabilistic Assessment, Fig. 2

- The Southeast includes 11 balancing authorities as shown in the map below (SOCO, VACAR-S, and TVA). By comparison, PJM and MISO each serve as a single-balancing authority for their respective regions.
- A few large utility systems—Duke Energy, Southern Company, and Tennessee Valley Authority—comprise much of the region. However, a number of other smaller investor-owned utilities and electric cooperatives serve load in the region.
- Georgia has an integrated transmission system, a majority of which is jointly owned by Georgia Power Company (Southern Co. subsidiary), Georgia Transmission Corporation (GTC), the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton.

Southeastern Balancing Authorities as of Oct. 2015 (excl. FL)



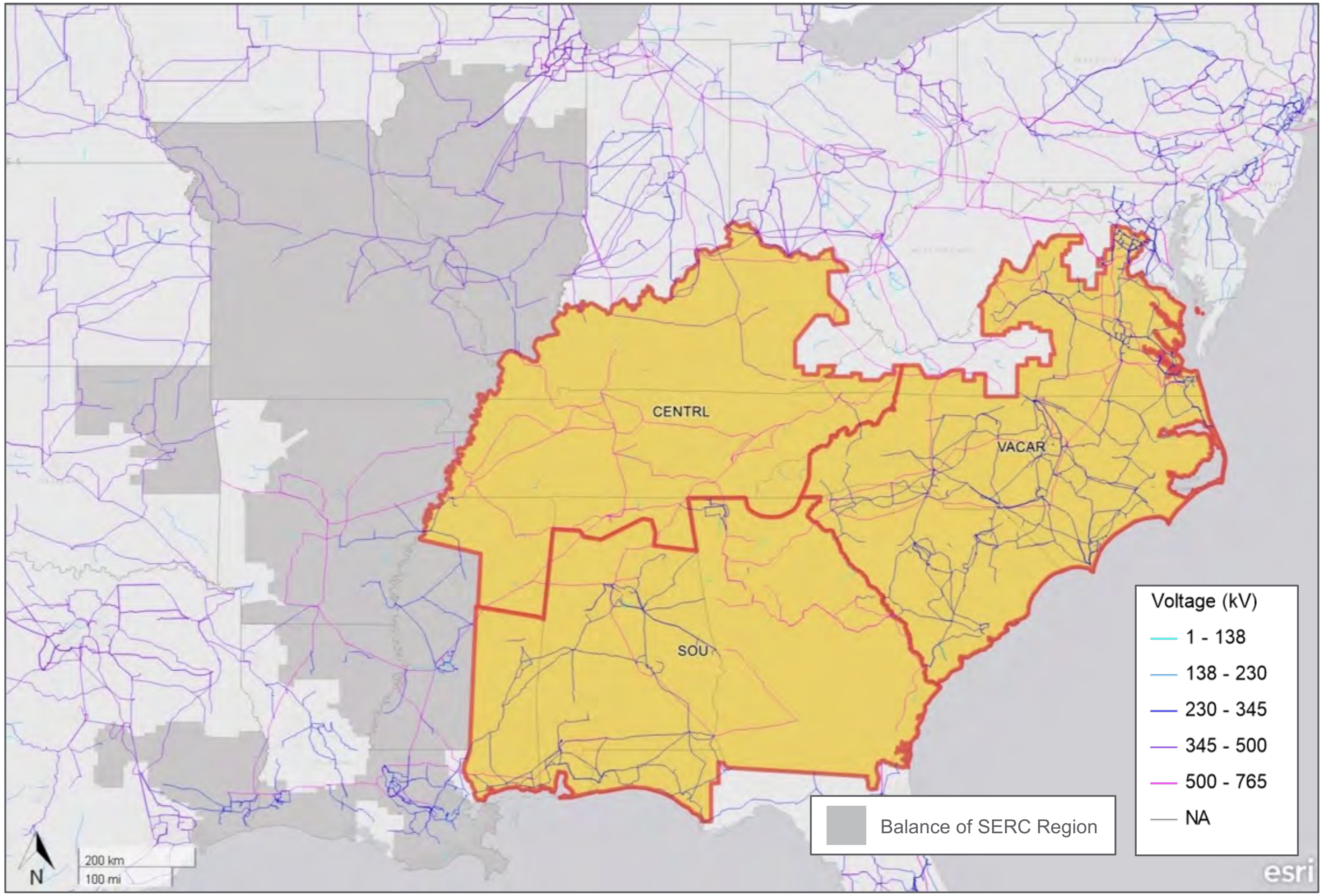
*Note: Per NERC, Duke affiliates shown are treated as a single-balancing authority.

VACAR-S	
CPLW	Duke Energy Progress West*
CPLE	Duke Energy Progress East*
DUK	Duke Energy Carolinas*
YAD	Alcoa Power Gen. – Yadkin Div.
SCEG	South Carolina Electric & Gas
SC	South Carolina Public Serv. Auth.
SOCO	
SEPA	Southeastern Power Admin.
SOCO	Southern Company
AEC	PowerSouth Energy Cooperative
TVA	
TVA	Tennessee Valley Authority
LGEE	Louisville Gas & Electric
EEI	Electric Energy, Inc.
AECI	Associated Elec. Cooperative

Sources: SERC; NERC

Transmission Topography and Investment (Cont'd)

Selected SERC Subregions (VACAR, Southeastern, and Central) Operating Transmission Lines



Source: S&P Global Market Intelligence

- There is significant internal transfer capability, which allows for transfers between subregions. In addition, SERC's subregions are interconnected with PJM, MISO, the Southwest Power Pool, and Florida.
- According to NERC, approximately 721 miles of new transmission lines are either in the planning stages or under construction as of late 2018 (see table below). All but one project was primarily driven by reliability; one large project was driven by nuclear integration with new reactors at Southern Company's Vogtle nuclear station.

Proposed Transmission Projects (Line Length in Circuit Miles) in SERC-E, -N, and –SE (as of Dec. 2018)

Operating Voltage Class (kV)	Conceptual	Planned	Under Construction
100-120		130.6	31.7
151-199	17	75.12	79.96
200-299	47	170	98
300-399		12.35	
400-599		60	
Grand Total	64	448.07	209.66

Source: NERC 2018 Electricity Supply & Demand

Sources: NERC 2018 LTRA; NERC ES&D: SERC 2018 Annual Assessment; S&P Global Market Intelligence

Transmission Topography and Investment (Cont'd)

- Utilities in the Southeast collaborate and coordinate in transmission planning through the Southeastern Regional Transmission Planning (SERTP) process, which provides an open and transparent transmission planning forum for transmission providers to engage with stakeholders regarding transmission plans in the region.
  - SERTP was originally developed to provide an open and transparent regional transmission planning process and to otherwise comply with the Federal Energy Regulatory Commission's (FERC) Order 890 issued in February 2007.
  - SERTP has expanded several times, both in the scope and size of the region, since its initial voluntary formation and now includes the following sponsors: Southern Company (SCS), Dalton Utilities, GTC, MEAG, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), Associated Electric Cooperative Inc. (AECI), the Tennessee Valley Authority (TVA), and Duke Energy (Duke Energy Carolinas, LLC and Duke Energy Progress, LLC).
  - SERTP's region is one of the largest regional transmission planning processes in the United States.
- Regional planners are looking at impacts of high south-to-north and north-to-south transfers due to market conditions. In 2018, they performed economic studies of potential enhancements (1,000 MWs) to improve flows from Georgia into downstate South Carolina and from downstate South Carolina into North Carolina (and in the reverse).
- In 2019, SERTP is planning on analyzing five scenarios in economic planning transmission studies:

Source BAA*	Sink	Load Level	Transfer Capability (MWs)	Year
Southern Company	Santee Cooper	Summer Peak	500	2020
Duke Energy Carolinas	Santee Cooper	Summer Peak	500	2020
Southern Company	Santee Cooper	Summer Peak	800	2020
Duke Energy Carolinas	Santee Cooper	Winter Peak	500	2024
Southern Company	Santee Cooper	Winter Peak	1,000	2024

*Balancing Authority Area

Source: SERTP 2019 Economic Planning Studies Scope Document

Sources: SERTP website, at http://www.southeasternrtp.com/home.cshtml; NERC 2018 LTRA; NERC ES&D; 2018 Annual Assessment

Resilience Issues

Resilience Risks

- The greater Southeast is a broad area with a variety of industries. As a frame of reference for the potential economic impact of a resilience event, its 2018 annual GDP for those states in the SERC-N, -E, and -SE footprint was $2.6 trillion.*
- Historically, the Southeast has been vulnerable to tropical cyclones, winter ice storms, and heat waves that impact both demand and energy infrastructure. Extreme heat also affects thermal generation, as ambient air and water temperatures can cause de-rates. The subregions in their summer reliability assessments use scenario planning that factor in up to 1 to 1.5 GWs in de-rates in each.
- With the addition of behind-the-meter solar facilities, some utilities in the Southeast anticipate becoming winter-peaking systems (as traditional summer peak loads are reduced). In addition to this shift, as utility-scale solar continues to be added to the resource mix, regional grid operators are closely following winter reserve margins.
- SERC has identified key risks – reliability-focused, but with resilience implications below (see table). Extreme weather risk, ranked second, is a risk factor, particularly with effects on fuel availability.

Reported Electric Disturbance Events Affecting Selected Southeastern States (2017- Apr. 2019)

Cause	2017	2018	2019 YTD
Generation Inadequacy	2		
Severe Weather	24	26	5
Vandalism	8	3	
Actual Physical Attack	2		
Suspicious Activity			1
Transmission Interruption		1	1
System Operations	1	10	1

Note: For multiple causes, classified under one only. Includes states of NC, SC, TN, KY, GA, AL, MS, MO.
Sources: DOE OE-417; ScottMadden analysis

2017 Ranked Regional Risk Elements

Engineering Risks	Operational Risks	Critical Infrastructure Protection (CIP) Risks
Resource uncertainty or changing mix, along with generation retirements	Parallel/loop flow issues	Intentional or non-intentional manipulation or misuse of assets
Fuel diversity/fuel availability	Extreme weather	Extreme physical events (man-made): sabotage
Generator governor frequency response	Loss of major application (EMS/SCADA)**	Unauthorized electronic access – lose or deny functionality, visibility, or control of assets

Source: 2018 Annual Assessment, Table 3

Notes: *Figure applies to states of NC, SC, TN, KY, GA, AL, MS, MO.
**EMS is energy management system; SCADA is supervisory control and data acquisition.
Sources: NERC 2018 Summer Reliability Assessment; Bureau of Economic Analysis; NERC 2018 LTRA; 2018 Annual Assessment

Resilience Issues (Cont'd)

Selected Recent Major Bulk Power Events Affecting the Southeast	
Event	**Description**
Total Solar Eclipse (Aug. 21, 2017)	▪ On August 21, 2017, parts of the United States experienced the effects a total or near-total eclipse of the sun. NERC and other reliability coordinators planned for this event and its potential reliability implications, focusing on areas where there was the most solar photovoltaic energy resources, particularly where those were coincident with peak load. A number of states, including North Carolina, were subject to special examination because of their higher amounts of solar resources and expected high-obscuration levels. ▪ NERC projected an increase in load due to lower distributed PV output, although not extreme. It recommended that advanced coordination to mitigate ramping and balancing issues may be needed and recommended that utilities in North Carolina perform detailed studies and retain necessary resources to meet the increased and varying load. The event did not produce any reliability issues because of advanced planning, which extended to neighboring regions such as PJM.
Hurricane Florence (Sept. 2018)	▪ Hurricane Florence made landfall as a NOAA-Category 1 storm on September 14, 2018, near Wrightsville Beach, NC. The hurricane had 2,300 MWs in forced outages/de-rates for the worst part of the storm, as it tracked along portions of the North and South Carolina coasts. The total number of customer outages approached 1.4 million. As many as 50 bulk power system transmission assets sustained damage/outage, and flooding threatened several generation sites in the path of the storm. Generation capacity was sufficient for recovery, but damage and disruption to transmission assets posed a continued problem during the restoration period.
Hurricane Michael (Oct. 2018)	▪ Hurricane Michael made landfall as a NOAA-Category 5 storm on October 10, 2018. The hurricane had 575 MWs in forced generation outages and wavered between 210 and 500 MWs in restricted operation for one nuclear plant. The total number of customer outages was approximately 1.1 million, far exceeding the originally estimated 540,000 distribution customers. ▪ The storm's path was from Florida to Virginia, including Georgia and the Carolinas. The majority of the storm's damage to the electricity system was on the distribution side; however, the transmission system sustained outages to numerous 230 kV and 115 kV lines. Generation damage was limited mainly to renewable solar plants.

Sources: NERC, 2018 and 2019 State of Reliability reports; NERC Eclipse White Paper

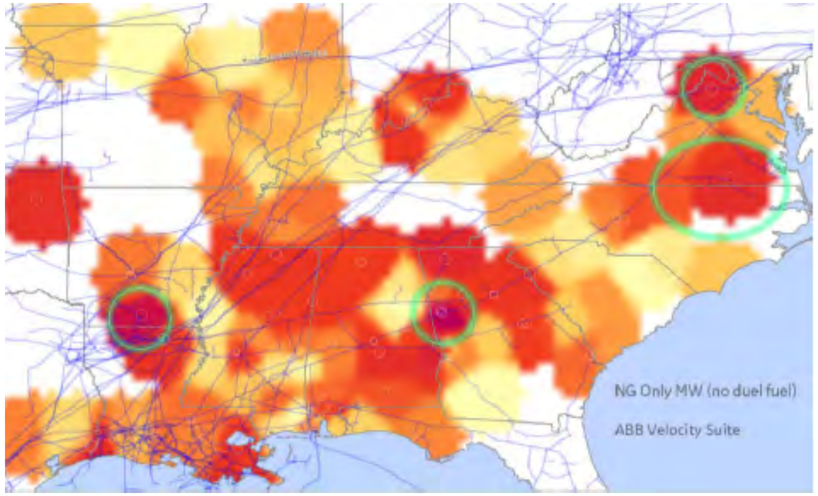
Resilience Issues (Cont’d)

- Finally, the significant influx of gas-fired generation in the region has increased interest on the potential impact of disruptions of key natural gas facilities, including interstate pipelines, branch lines, and storage facilities. Of particular interest are clusters of single-sourced generators (i.e., not dual fuel) (see map at top right).

GE 2018 Probabilistic Assessment

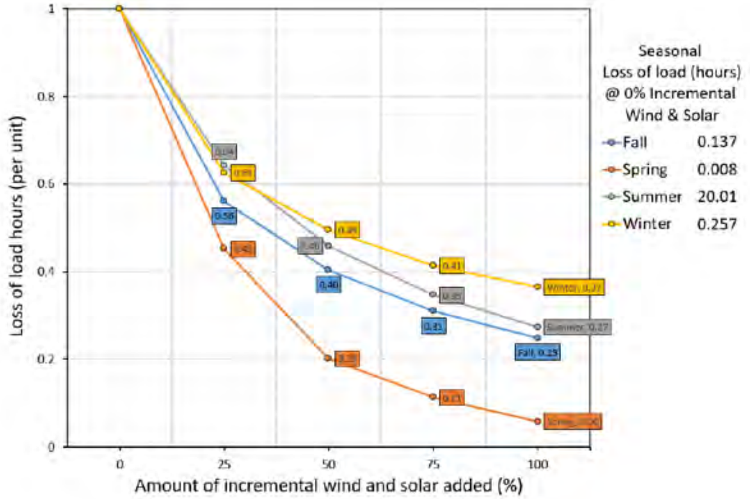
- In 2018, SERC commissioned GE Energy Consulting to conduct a probabilistic assessment of reliability of the region, particularly loss of load and expected “unserved energy,” based upon a few key assumptions:
  - Changes in planning reserve margin levels as a result of thermal generation retirements and replacement with variable energy resources
  - Impacts of potential natural gas single points of disruption impacts
- The assessment found the following:
  - Lower reserve margins across the area (2/3 of initial reserve margins) entailed few loss of load events (mostly in SERC-SE and SERC-E); at 1/3 of initial reserve margins showed significant loss of load in SERC-SE, SERC-E, and SERC-N
  - Addition of wind and solar improves reliability metrics, but not proportional to capacity. Riskiest hours are pushed to later in the day, where incremental solar is less effective. But this varies by season: most reliability improvement is in the spring, least is in winter (see graph at lower right).
  - Single point of disruption sensitivities for summer (August) and winter (January) looked at gas supply outages: only two scenarios (of 40 modeled) produced “meaningful” loss of load. Risk is largely confined to SERC-SE and the summer season.

Clusters of Single-Sourced Natural Gas Generators



Source: SERC

Seasonal Reliability Improvements (Modeled) with Increased Renewable Penetration

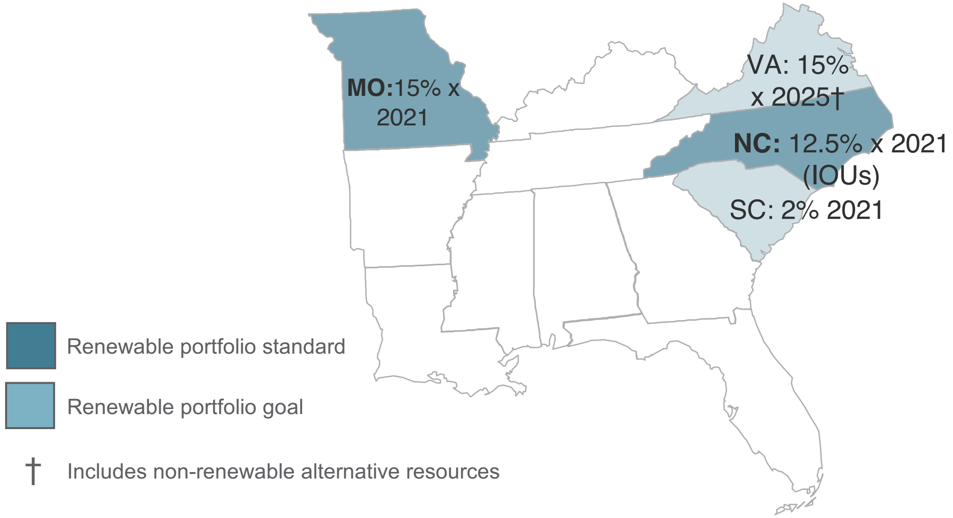


Source: GE/SERC

Sources: NERC 2018 Summer Reliability Assessment; SERC 2018 RRS Annual Assessment; 2018 Probabilistic Assessment

Renewables Integration

Southeastern U.S. Renewable Portfolio Standards and Goals (as of June 2019)



Source: DSIRE

Demand-Side Considerations

- Overall demand growth in the region is generally less than 1% annually, although metro areas are experiencing higher growth than rural areas.
  - Some utilities report demand reduction because of behind-the-meter distributed generation and appliance standards and expect these trends to continue into the future. Most distributed energy resources (DERs) are solar, and the queued amount connected to the sub-transmission system is about 2.1 GWs (roof-top solar, electric vehicles, etc.).
  - Demand response programs in the region are minimal (about 7.3 GWs) in comparison with peak load.
- The Southeast has few renewable or clean energy standards. Only North Carolina and Missouri have renewable portfolio standards. South Carolina and Virginia each have renewable energy goals (see map at left). For states in the SERC-N, -E, and –SE subregions, relevant portfolio goals/standards are targeted for compliance by 2021.
- A few large utilities in the region have announced carbon reduction initiatives:
  - Southern Company has announced that it is targeting a 50% reduction in CO_2 emissions by 2030, with a further reduction to low or no carbon resources by 2050.
  - TVA has pledged to reduce its rate of CO_2 emissions by 60% by 2020. It also targets 55% carbon-free power supply by 2020.
  - Duke Energy's subsidiaries in North Carolina file annual integrated resource plans (IRP) regarding compliance with the state's renewable energy and efficiency requirements. Those IRPs call for reducing CO_2 emissions by at least 40% from 2005 levels by 2030 with approximately 60% of its electricity coming from carbon-free clean energy sources.
  - In September 2019, Duke Energy announced that it will reduce carbon emissions by at least 50% or more (from 2005 levels) by 2030, an increase from a previous target of 40%. It also announced a new goal of net-zero carbon emissions from electric generation by 2050. Duke will adjust resource plans to reflect these goals. It has stated a goal of doubling its renewable portfolio by 2025.

Sources: NERC 2018 LTRA; DSIRE; SEPA

Renewables Integration (Cont'd)

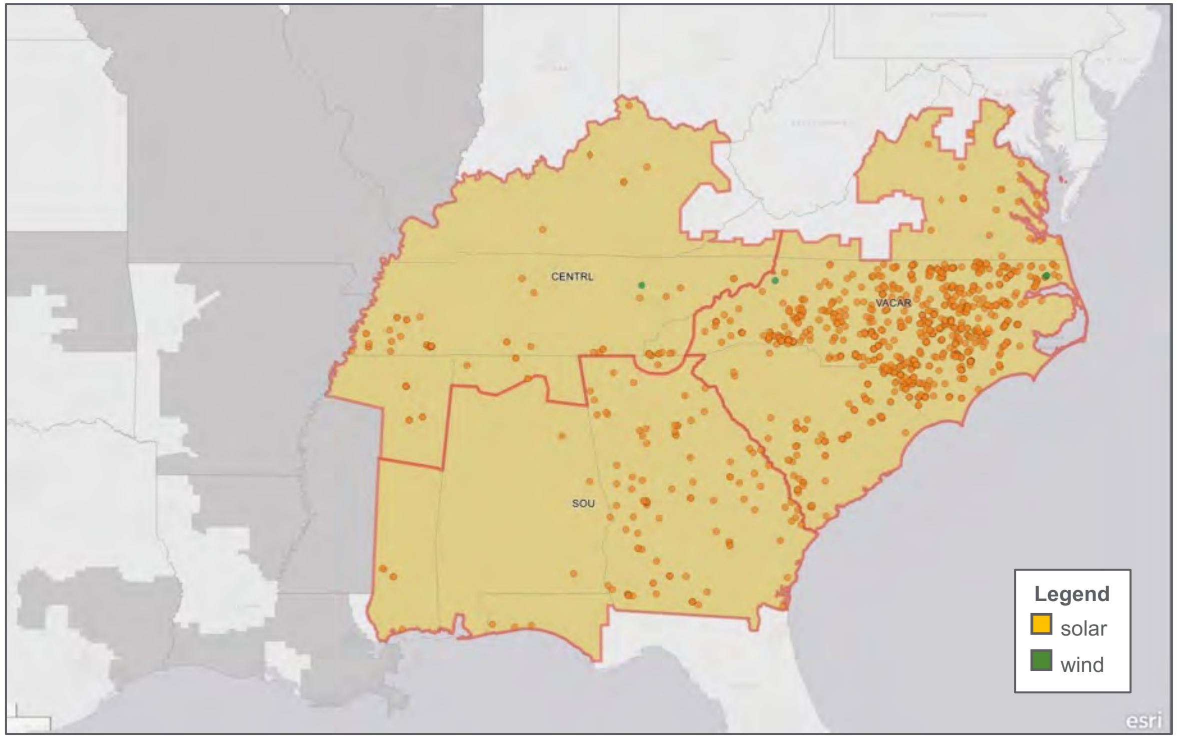
Supply-Side Considerations

- The Southeast has been adding renewable resources, largely solar, over the past decade. Since 2010, the legacy Central, Southeast, and VACAR subregions have added 6.5 GWs of solar and nearly 1.9 GWs of wind generation. But solar and wind each remain less than 1% of the capacity mix in each of SERC-E, -SE, and -N.
- SERC expects that 21 GWs of utility-scale solar will be in the interconnection queue over the next five years, largely for development in the SERC-E subregion (the Carolinas). Interestingly, SERC's reliability projections do not project significant wind or solar additions, but identified 3.7 GWs of new natural gas-fired generation in SERC-E and 2.2 GWs of new nuclear in SERC-SE.
- IRPs tell a slightly different story. Major utilities Duke Energy (its North and South Carolina operating companies), Georgia Power, and the Tennessee Valley Authority, all project meaningful renewable additions over the next decade (see table below).

Selected Integrated Resource Plan Projected Renewable Capacity Additions			
	2019	2033	Change (GWs)
Duke Energy Progress†	2.7	4.2	1.5
Duke Energy Carolinas†	1.2	3.4	2.2
Tennessee Valley Authority††	0.3*	3.4	3.1
Georgia Power Company			0.95**

†Solar only (other figures not meaningful). ††All renewables (excl. hydro).
*2018 figure. **Reflects RFPs for utility-scale renewable capacity with 2022 and 2024 commercial operation dates.

Selected SERC Subregions (VACAR, Southeastern, and Central) Operating and Planned Solar and Wind Capacity (as of Oct. 2019)



Source: S&P Global Market Intelligence

Sources: NERC 2018 LTRA; S&P Global Market Intelligence; Duke Energy, Georgia Power, TVA IRPs; Southeastern Wind Coalition

Renewables Integration (Cont'd)

Potential Onshore Wind Capacity in Southeast States (MW)

State	80 m Hub Height	110 m Hub Height	140 m Hub Height
Alabama	25	16,814	193,376
Arkansas	2,126	180,978	185,713
Florida	0	11,164	153,485
Georgia	35	6,786	188,657
Kentucky	0	76,606	128,123
Louisiana	0	92,823	165,431
Mississippi	0	43,578	188,275
North Carolina	2,201	7,174	102,730
South Carolina	557	10,299	98,638
Tennessee	99	60,329	110,717
Virginia	2,273	9,539	72,112

Source: Department of Energy, Office of Energy Efficiency & Renewable Energy's WINDExchange

Potential Offshore Wind Capacity in Southeast States (MW)

State	0 to 3 Nautical Miles	3 to 12 Nautical Miles	12 to 50 Nautical Miles
Georgia	426	2,648	38,248
Louisiana	776	8,123	75,163
North Carolina	35,136	44,923	288,219
South Carolina	3,083	23,316	122,961
Virginia	23,794	15,233	89,923

Source: Department of Energy, Office of Energy Efficiency & Renewable Energy's WINDExchange

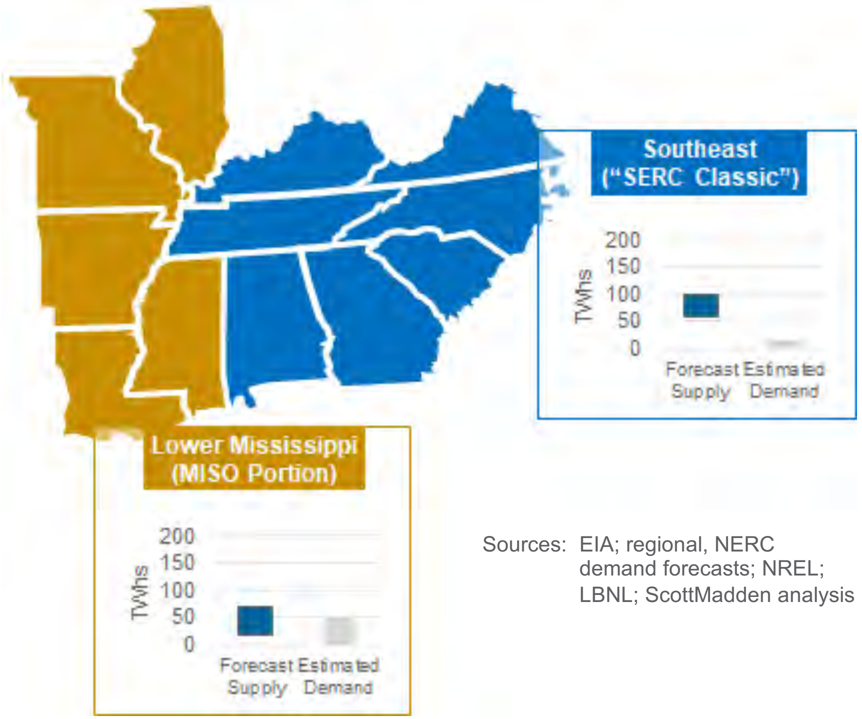
Supply-Side Considerations (Cont'd)

- Wind development in the Southeast has been limited to date.
  - Wind advocates, the U.S. Department of Energy and the Bureau of Ocean Energy Management, are looking at the potential for development across the Eastern Seaboard, including the Southeast.
  - According to the National Renewable Energy Lab, Virginia, North Carolina, South Carolina, and Georgia have 82% of the East Coast's resource in shallow water and more than 12 miles offshore (enabling locating facilities further offshore) and 45% of the total East Coast's offshore wind resource (see Appendix).
- A key concern among policymakers has been the potential hazards posed by turbines for military aviation as well as effects on agriculture. In North Carolina, the state legislature has discussed a potential compromise on onshore and offshore wind that would lift an existing ban on those facilities.
- In Virginia (not within the Southeast footprint but nearby), construction work on an offshore wind project (Coastal Virginia Offshore Wind)—the first in the Mid-Atlantic—began in summer 2019. The project consists of two 6-megawatt turbines, expected to be in operation by late 2020.
- In 2017, the U.S. Bureau of Ocean Energy Management held a lease auction for the 122,405-acre Wind Energy Area (WEA) 24-nautical miles off the coast of Kitty Hawk, NC (see Appendix), which was awarded to Avangrid Renewables. Avangrid has been granted an extension of the preliminary term of this lease through November 2019. According to the Southeastern Wind Coalition, the lease area has the potential to generate 2,500 MWs and could begin construction as early as 2024.

Sources: Southeastern Wind Coalition, at http://www.sewind.org/what-we-do/offshore-wind; Dominion Energy; 2017 SEWC White Paper; Bureau of Ocean Energy Management

Renewables Integration (Cont'd)

Southeastern U.S. Potential Policy-Driven Renewable Energy Demand and Forecast Supply (2030) (as of June 2019)



Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Integration Challenges

- As can be seen at left, the Southeast and adjacent Lower Mississippi (parts of which are in certain SERC subregions), have more projected supply of renewable generation than expected demand (at least at this time, based upon renewable portfolio standards).
- In the current and last planning cycle, SERTP did not receive any input or proposals for possible transmission needs driven by public policy requirements, such as renewable requirements.
- In its latest final transmission plan (2018), SERTP's members incorporated the following projections of utility-scale renewable additions through 2028 (excluding uprates of hydro and pumped storage facilities):
  - Southern Company: 879 MWs solar; 116 MWs biomass
  - Georgia Transmission Corp.: 199 MWs solar
  - Tennessee Valley Authority: 742 MWs solar
- SERC is studying the potential impacts of increasing inverter-based resources, both utility and distributed. It has identified and is monitoring issues, particularly harmonic distortion. SERC's Dynamics Working Group is looking at the potential impact of renewables on frequency response of SERC (as an electric island) and/or the Eastern Interconnection. As stated by SERC, "Other than the effect on frequency response and wide area power flows, the impact of renewables [is] believed to be more of a local area issue than a SERC-wide area issue."

Sources: SERTP; 2018 SERTP Annual Assumption Planning Summit; 2018 Annual Assessment, at p. 43; LBNL 2019 RPS Analysis; AWEA 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
Southeast	▪ Severe weather greatest cause of electric disturbances: tropical cyclones and tornadoes primary resilience risks; distribution systems also being affected by ice storms ▪ Deeper push of Arctic cold snaps and shift to winter peaks (increased heating load) pose risks to resource availability during low-frequency extreme cold conditions ▪ Baseload-heavy, but increasing amount of gas-fired resources and possible exposure of single source generators to pipeline interruptions; about 3.6 GWs of affected capacity in GA, SC	▪ Projections of renewables additions vary – SERC expects 21 GWs in next 5 years – Duke Energy and Tennessee Valley Authority plan on nearly 7 GWs by 2033 ▪ Solar is primary technology; limited onshore wind development ▪ Investigation of offshore wind opportunity of up to 2.5 GWs, but development is in early stages ▪ Minimal renewables integration issues; managed generation portfolios ▪ Large, well-distributed baseload and load-following resources provide adequate ramping frequency response capability	▪ Relatively modest policy drivers in region if any; limited RPS or clean energy standards but some utility-driven goals advancing (e.g., net zero-carbon emissions by 2050, 50% reduction by 2030) ▪ Some larger integrated utilities are undertaking carbon reduction or clean energy initiatives ▪ SERC studying potential issues with increased non-synchronous inverter-based resources (e.g., voltage, telecommunication interference, thermal heating on transformers and rotating machinery, and mis-operation of protective relays and user equipment) ▪ Vertically integrated, rate-of-return regulated environment: resilience and integration issues addressed through IRP, equipment-sharing programs	▪ Limited needs for interregional transmission for renewables integration—significantly more regional supply than policy demand ▪ With increased renewables over a 10-year time horizon, potential upgrades needed ▪ Integrated utilities are studying resilience issues, including impacts of thermal generator retirements, increase in variable energy resources (esp. for winter resources adequacy ▪ Long-term potential for integration of offshore wind

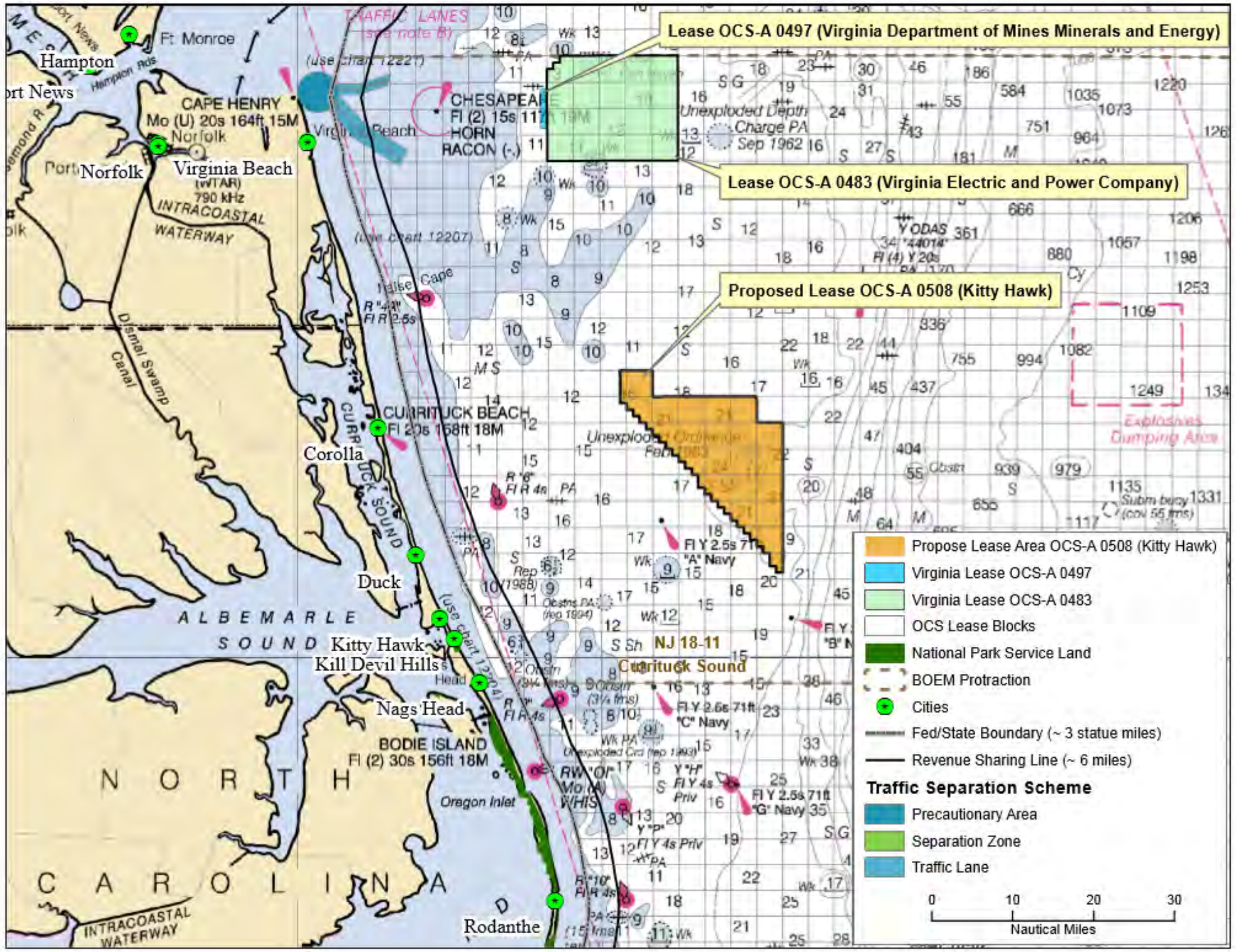
Sources

- 2018 Duke Energy Carolinas and Duke Energy Progress Integrated Resource and REPS Compliance Plans (filed Sept. 5, 2018)
- 2019 Georgia Power Company Integrated Resource Plan, Docket No. 42310 (filed Jan. 31, 2019)
- 2019 Tennessee Valley Authority Integrated Resource Plan (June 28, 2019)
- American Wind Energy Association, 2019 State RPS Market Assessment (Mar. 13, 2019) (AWEA 2019 RPS Analysis)
- Database of State Incentives for Renewables & Efficiency, NC Clean Energy Technology Center, at www.dsireusa.org (DSIRE)
- Energy Information Administration (EIA), Annual Energy Outlook 2019 (Feb. 2019)
- FERC Staff Report, Energy Primer: A Handbook of Energy Market Basics (Nov. 2015)
- GE Consulting, SERC 2018 Probabilistic Assessment (Nov. 13, 2018) (2018 Probabilistic Assessment)
- Lawrence Berkeley National Laboratory (LBNL), U.S. Renewables Portfolio Standards: 2019 Annual Status Update (July 2019) (LBNL 2019 RPS Analysis)
- NERC, 2018 Long-Term Reliability Assessment (Dec. 2018) (NERC 2018 LTRA)
- NERC, 2018 Electricity Supply & Demand (Dec. 2018) (NERC ES&D)
- NERC, Summer Reliability Assessment (June 2019)
- NERC, State of Reliability Report (June 2018)
- NERC, State of Reliability Report (June 2019)
- NERC, A Wide-Area Perspective on the August 21, 2017 Total Solar Eclipse (Apr. 2017) (NERC Eclipse White Paper)
- National Renewable Energy Laboratory, NREL Standard Scenarios (as of July 8, 2019), available at https://openei.org/apps/reeds/#
- SERC Reliability Corporation, 2018 Information Summary
- SERC Reliability Corporation Reliability Review Subcommittee, 2018 Annual Assessment (2018 Annual Assessment)
- Southeastern Regional Transmission Planning (SERTP), SERTP 4th Quarter Meeting: Annual Transmission Planning Summit & Assumptions Input Meeting (Dec. 13, 2018) (2018 SERTP Annual Assumption Planning Summit)
- SERTP, 2019 Economic Planning Studies Scope Document (May 14, 2019)

Sources (Cont’d)

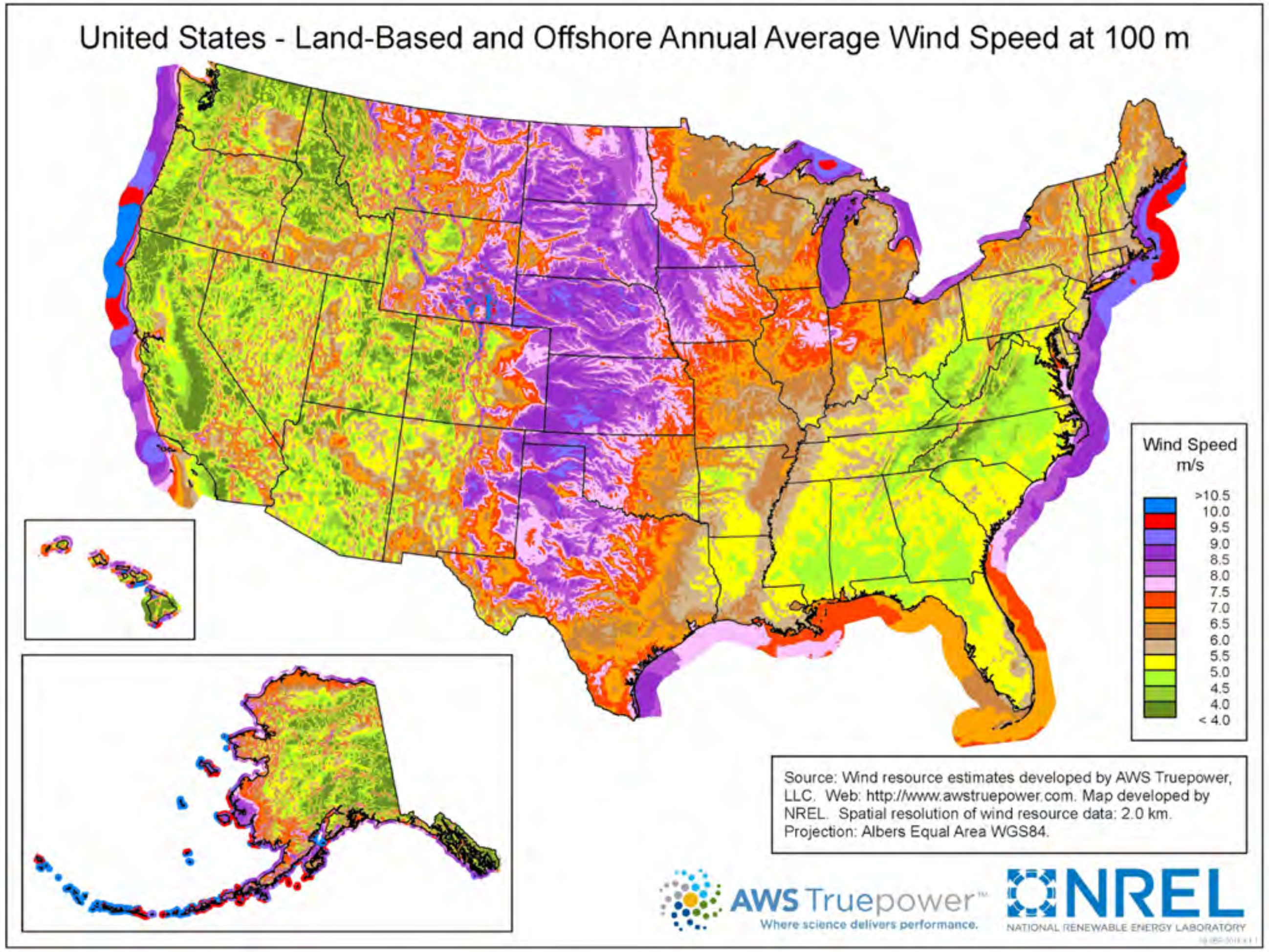
- SERTP website, at www.southeasternrtp.com/home.cshtml
- Smart Electric Power Alliance Decarbonization Tracker, at https://sepapower.org/decarbonization-tracker/ (state and utility decarbonization targets)
- Southeastern Wind Coalition, at www.sewind.org
- Southeastern Wind Coalition-ScottMadden, “Understanding Wind Energy Potential in the Southeast” (Sept. 2017) (2017 SEWC White Paper)
- U.S. Bureau of Ocean Energy Management, Commercial Wind Leasing Offshore North Carolina, https://www.boem.gov/Commercial-Wind-Leasing-Offshore-North-Carolina/
- U.S. Dept. of Energy, Office of Energy Efficiency and Renewable Energy, WINDExchange, at https://windexchange.energy.gov/
- Regional, state, NERC demand growth forecasts
- S&P Global Market Intelligence

Appendix: BOEM Lease Areas – NC and VA



Source: BOEM Commercial Wind Leasing Offshore North Carolina

Appendix: Wind Average Speed



Source: BOEM website and DOE EERE WINDExchange

Regional Discussion

SOUTHWEST POWER POOL

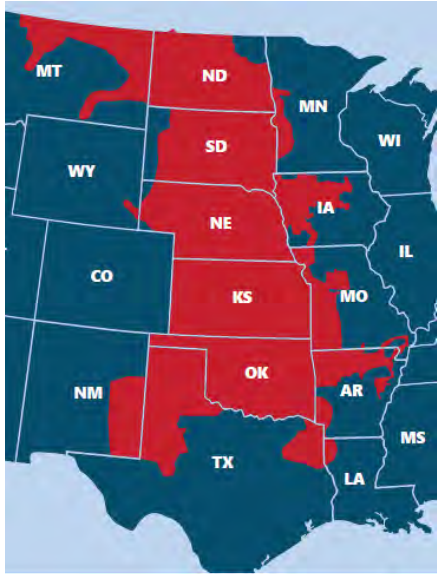
Contents

Overview

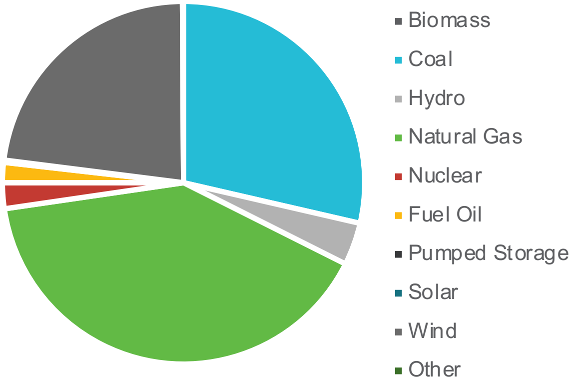
- The Southwest Power Pool (SPP) footprint covers 575,000 square miles and encompasses all or parts of 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.
- Wind penetration in SPP has increased significantly, from 38% of peak in 2015 to nearly 70% of peak in 2018.
- In its latest reliability report, SPP projects thermal generation retirements of nearly 2 GWs over the next 10 years: 896 MWs of coal along with 1,145 MWs of natural gas, although it does not expect reliability impacts from retirements.

Key Regional Statistics	
States Covered	AR, IA, KS, LA, MN, MO, MT, NE, NM, ND, OK, SD, TX, WY
Square Mi. Covered	~546,000
No. of Utilities	16 investor-owned utilities; 14 munis; 20 generation & transmission co-ops; 8 state agencies; 1 federal agency
No. of Customers/Pop. Served	17.5MM population
Installed Capacity	164,037 MWs
Transmission Line Miles	66,892 miles
Peak Hour Demand (2018)†	49,926 MWs summer (43,584 MWs winter)
Energy Production (2018)	275,887 GWhs
Forecast Growth (Annual)	0.07% peak load growth† 0.92% energy growth

SPP's Regional Footprint

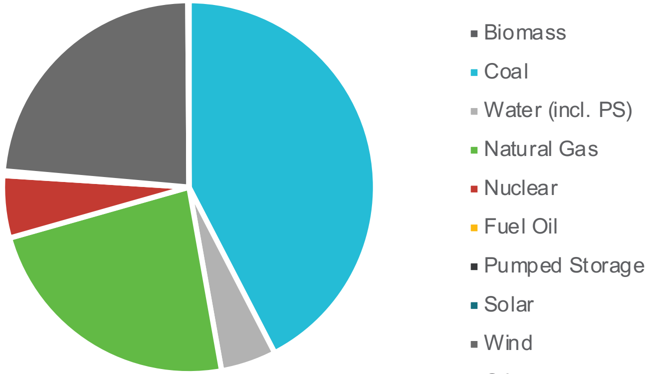


2018 Capacity Mix by Fuel



Source: SPP

2018 Energy Mix* by Fuel

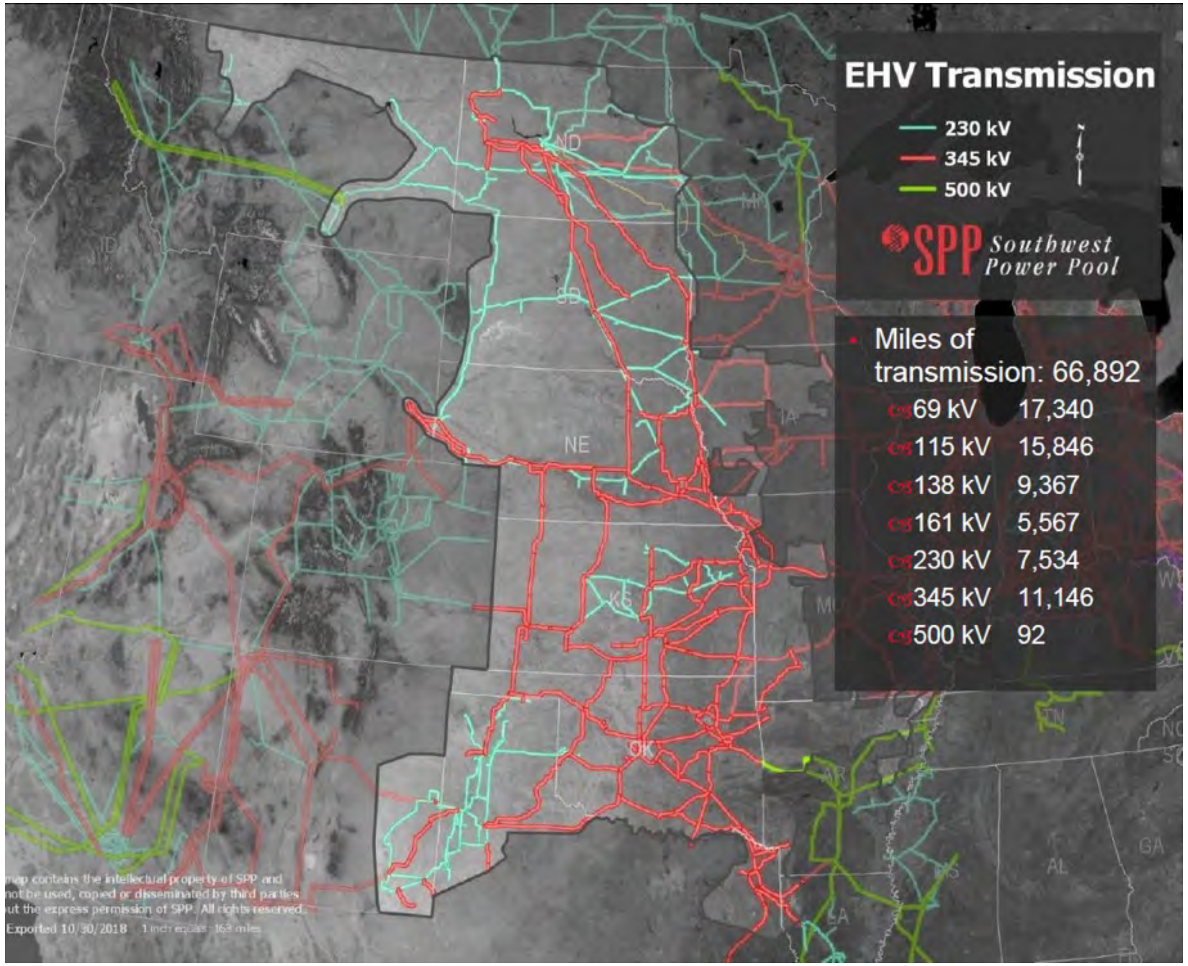


Source: SPP

Sources: NERC 2018 LTRA; Intro to SPP; SPP 101; SPP SOM 2018
Notes: † Non-coincident.

Transmission Topography and Investment

SPP's High-Voltage Transmission System



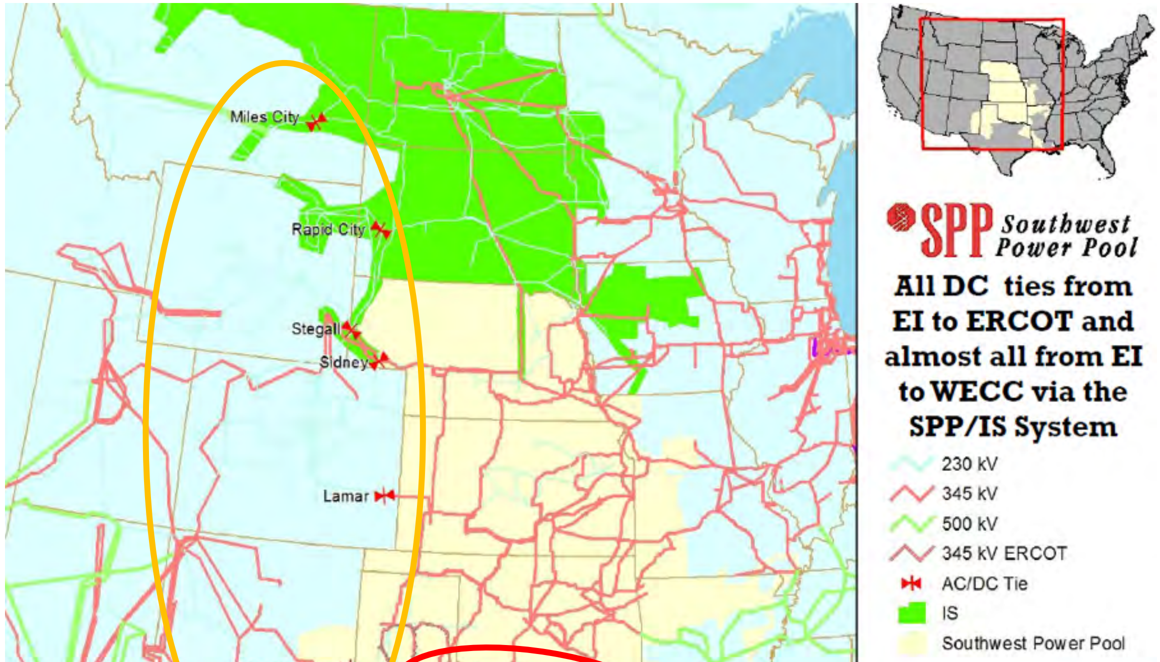
Source: SPP

- SPP has an extensive transmission network, reaching from Canada to Texas, with nearly 19,000 miles of transmission 230 kV or above (28% of its system).
- Its region is bounded by the Midcontinent ISO (MISO) to the east, SERC to the southeast, the Electric Reliability Council of Texas (ERCOT) to the south, and the Western Interconnection to the west.
- It has expanded over the past 15 years. Initially covering Kansas, Oklahoma, the Texas Panhandle, areas in Missouri, Arkansas, New Mexico, and Louisiana upon its creation in 2004. It now extends northward to the Canadian border, eastward into Iowa, and westward into Montana.
  - April 1, 2009 – SPP added Lincoln Electric Systems, Nebraska Public Power District, and Omaha Public Power District.
  - October 1, 2015 – SPP added the Integrated System (WAPA-Upper Great Plains, Basin Electric Power Cooperatives, Heartland Consumers Power District, and Northwestern Energy).
- SPP is the sole-balancing authority for the region. The region is comprised of five resource zones.
- Transmission flows are generally characterized by southward and eastward flows, particularly from high-wind power resources to load centers. Five of the largest load centers are among the top 100 cities in the United States: Kansas City, Oklahoma City, Tulsa, Omaha, and Wichita.
- According to SPP's market monitor, most of the highest congested corridors on the SPP system are significantly impacted by inexpensive wind generation. Of the 10 most congested flow gates, those affected the most by wind generation are the west-to-east flows through the Hays, Kansas area, and west-to-east flows in eastern Oklahoma. The southwest Missouri area is also impacted by wind and external flows. Projects are planned throughout the SPP footprint which provide for more transfer of wind generation from west to east.

Sources: SPP 101; OMS-RSC Seams White Paper; SPP SOM 2018

Transmission Topography and Investment (Cont'd)

SPP-WECC and SPP-ERCOT DC Ties



SPP-WECC ties SPP-ERCOT ties

Source: SPP 101

- The region is characterized by transmission seams to the west (with the Western Interconnection and the Western Electric Coordinating Council in particular), to the south (with the Electric Reliability Council of Texas), and to the east (with MISO).
- There are seven HVDC ties between SPP and the Western Interconnection with transfer capacity ranging from 100 MWs to 200 MWs.
- On its eastern boundary with MISO, SPP has 171 total tie lines in voltages ranging from 69 kV to 500 kV.

SPP-Western Interconnection DC Ties

HVDC Station	Location	kV	Power (MW)
David A. Hamel	Stegall, NE	50	100
Eddy County	Artesia, NM	82	200
Blackwater	Clovis, NM	60	200
Miles City	Miles City, MT	82	200
Virginia Smith	Sidney, NE	50	200
Rapid City	Rapid City, SD	13	200
Lamar	Lamar, CO	63.6	210

Source: SPP Seams Study Update

SPP-MISO AC Ties

Voltage Level (kV)	# of Tie-Lines
69	78
115	28
138	4
161	24
230	20
345	14
500	3
Total	171

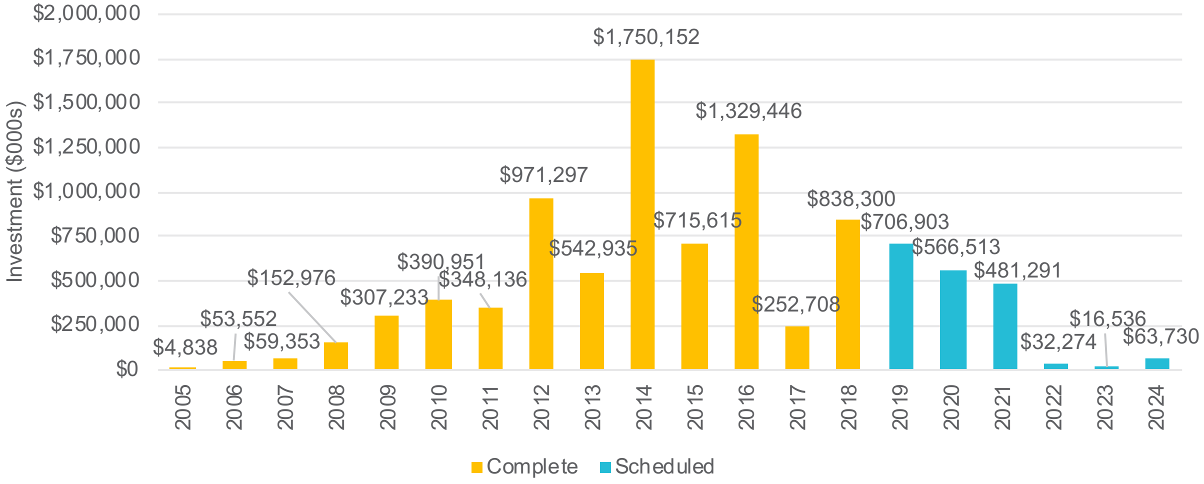
Source: OMS-RSC Seams White Paper

Sources: SPP 101; OMS-RSC Seams White Paper; Seams Study Update

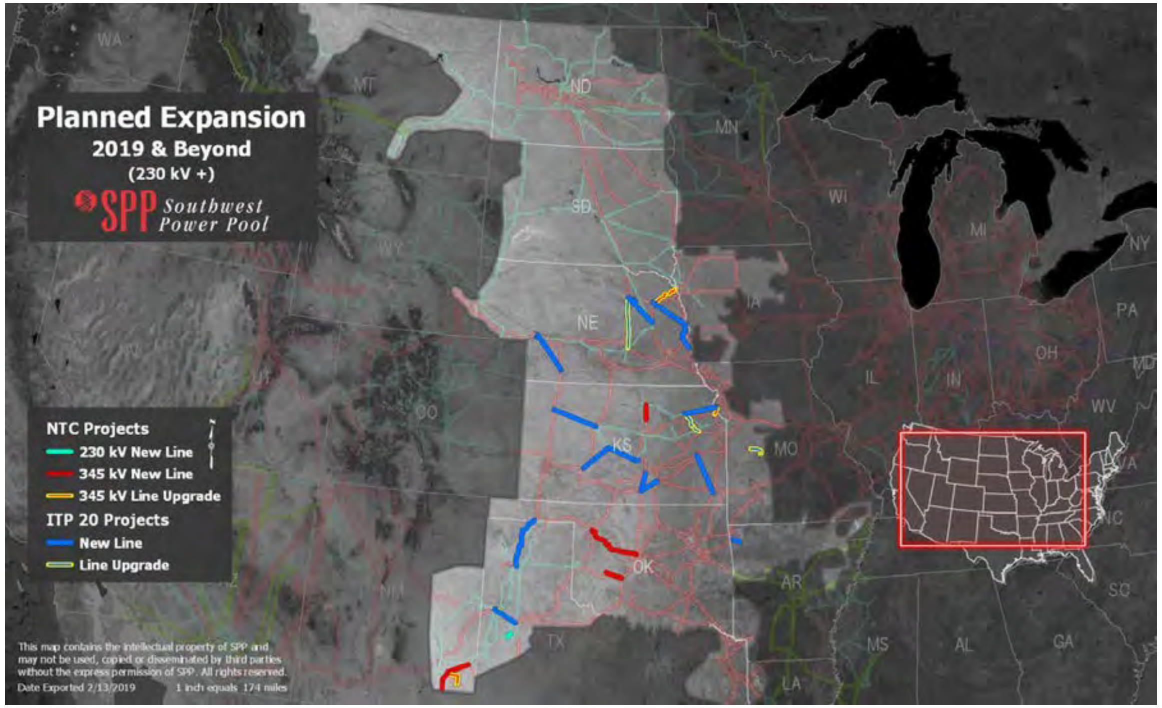
Transmission Topography and Investment (Cont'd)

- Transmission congestion in central Kansas, eastern Oklahoma, and southwest Missouri is the focus of near-term upgrades and new high-voltage lines per SPP's transmission plan (see right). Note, however, that ITP's 20 projects are planned upgrades and not commitments.
- Since 2005, SPP has directed $7.7 billion in completed projects and $1.9 billion in scheduled projects (see below).
- SPP planning weighs the cost of transmission investment against the cost savings in the form of reduced outages, congestion, losses, and lower production cost. SPP recently analyzed $3.4 billion in investment during 2012-14 (including extra high-voltage projects) and estimated a benefit-to-cost ratio of 3.5x over a 40-year period, with production cost savings benefits of $16.6 billion. This did not factor in public policy or reliability benefits.

Transmission Investment Directed by SPP (2005–2024)



SPP's Transmission Expansion Plan (as of Feb. 2019)



Source: SPP State of the Market 2018

Sources: SPP 101; OMS-RSC Seams White Paper; SPP SOM 2018; SPP Value of Transmission
Notes: NTC means notification to construct (i.e., received a written notice from SPP to construct a transmission project that was approved by the SPP board of directors). ITP 20 means long-term integrated transmission plan recommended upgrades.

Resilience Issues

- The area covered by SPP is a broad area with a diverse array of industries and weather. As a frame of reference for the potential economic impact of a resilience event, SPP's 2018 annual GDP for those states in its footprint (excluding Texas) was $2 trillion.*
- In SPP's comments to FERC in its grid resilience docket, it cites the following resilience risks in its region:
  - Weather events are the primary naturally occurring risks to resilience, including severe events such as tornadoes, which can destroy significant portions of the bulk power system.
  - SPP has also experienced drought conditions, which could result in impacts to hydroelectric generation and supplies of cooling water for thermal generation.
  - The region can also experience ice storms that can result in significant system outages.
  - SPP also identified other potential naturally-occurring issues including: (1) upper-atmosphere instability resulting in sudden ramping of wind generation; (2) unseasonably high temperatures resulting in high-loading during generators' scheduled maintenance periods; (3) flooding of substations and power plants near waterways; (4) electromagnetic pulse or geomagnetic disturbance events that damage control systems and/or protection systems of multiple substations; (5) grass fires; and (6) severe earthquakes damaging infrastructure.
- A key human threat is vandalism, which SPP characterizes as usually localized in terms of impact, but could conceivably be attempted on a larger scale. Vandalism or sabotage events can include cyber-attacks impacting critical systems or infrastructure, sabotage of substations or transmission lines, and damage to communication infrastructure. Other potential human-caused issues include fires in control centers and software errors or limitations causing malfunction of critical systems.
- SPP also considers capacity availability an important characteristic of resilience and points to its fuel-indifferent approach to transmission system planning that it has developed to ensure resourcefulness. SPP pointed to the approval and development of more than $10 billion in transmission infrastructure that has enabled resources of all fuel types to help meet customer demand during a range of potential threats to reliability and resilience.
- As planning coordinator, SPP has coordinated with transmission planners in the footprint to identify potential for lower frequency (N-2) extreme events. In addition to identifying potential impacts, SPP also reviews annually the state of equipment with long lead times (i.e., that would take more than a year to replace).

*Note: Figure applies to states of AR, IA, KS, LA, MN, MO, MT, NE, NM, ND, OK, SD, WY
Sources: SPP Resilience Testimony; Bureau of Economic Analysis

Resilience Issues (Cont'd)

Recent Resilience Issue: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

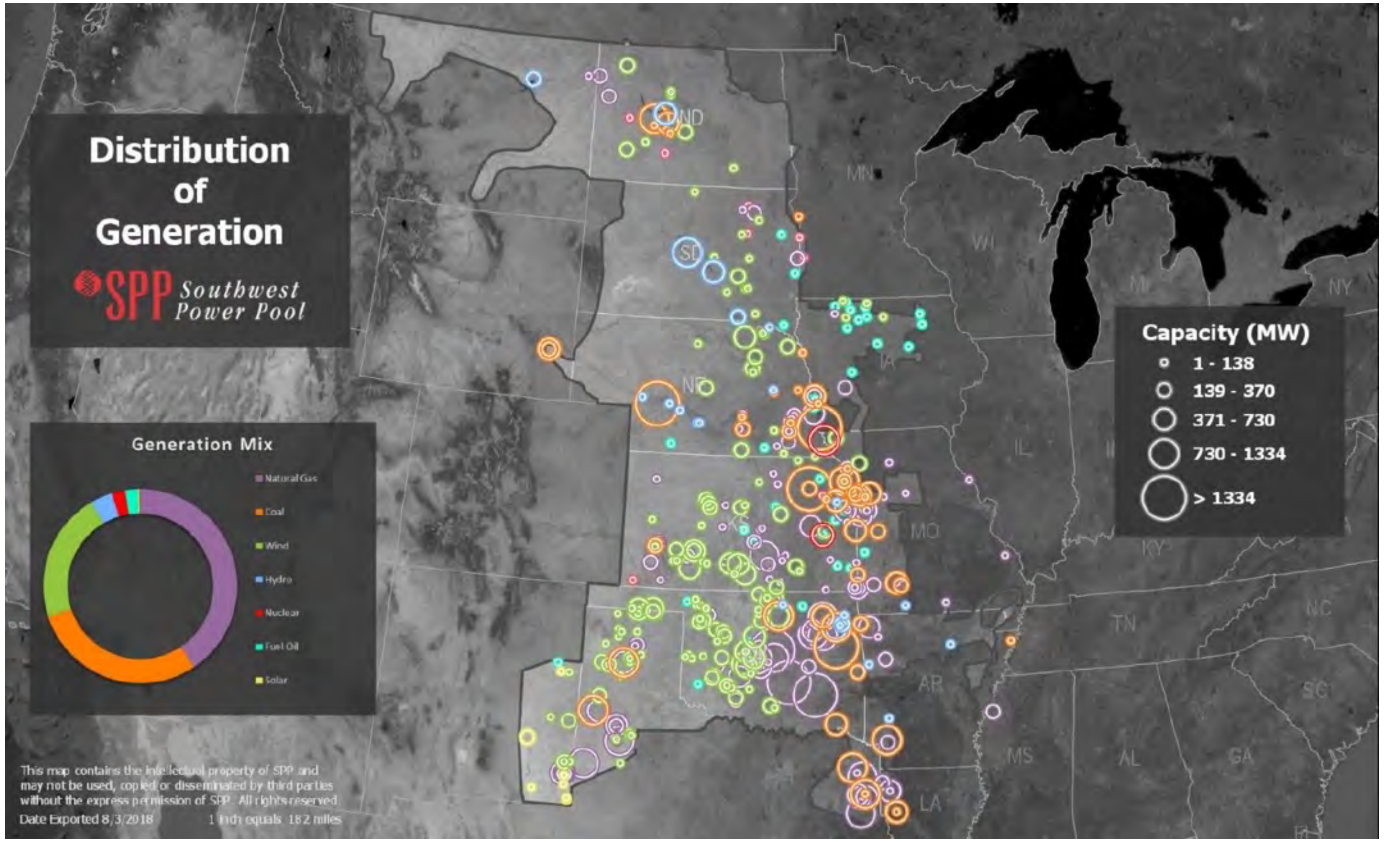
- **Summary:** On January 17, 2018, a large area of the south central region of the United States experienced unusually cold weather. Below average temperatures began to occur as early as Friday, January 12, from the Great Plains south through the Mississippi Valley. Going into the work week beginning Monday, January 15, MISO, SPP, and other adjacent areas knew that Wednesday, January 17, was likely going to be the coldest day of an extremely cold week for much of their respective footprints. The below average temperatures in this area resulted in 183 individual-generating units within the footprints of SPP, MISO, TVA, and SERC experiencing either an outage, a de-rate, or a failure to start between January 15 and January 19.
- **Outages and De-rates:** Between Monday, January 15, and the morning peak hour (between 7 a.m. and 8 a.m. CST) on Wednesday, January 17, approximately 14,000 MWs of generation experienced an outage, de-rate, or failure to start. Inadequate winterization was deemed a key factor.
    - Including generation already on planned or unplanned outages or de-rated before January 15, the four regions had more than 30,000 MWs of generation unavailable in the south central portions of their footprints by the January 17 morning peak hour.
    - Generator owners attributed at least 35% of the generation outages and de-rates on January 17 to the extreme weather conditions: 19% to freezing-related mechanical issues and 16% to cold-related fuel supply issues.
    - From January 15 to 19, natural gas-fired units were 70% of the unplanned generation outages and de-rates when calculated by numbers of units and 74% when calculated by MW.
    - During the same period, gas supply issues caused by the extreme cold temperatures, including interruptible supply, low gas pressure, and other pipeline and gas supply issues, led to outages of 38 units, for a total of approximately 2,200 MWs.
- **Peak Winter Demand:** At the same time (January 17 morning), power demand in MISO south and SPP was above their respective winter "extreme" forecast peak, while adjacent TVA and Southern Company footprints were above their expected "50/50" winter peak.
- **MISO Energy Emergency**: Under normal conditions, the MISO region is not capacity limited. However, with generator outages, MISO declared an energy emergency, because it had insufficient reserves to balance generation and load in the MISO South portion of its footprint, while all four MISO regions experienced system constraints. MISO was limited in its ability to move power southward within its region to 3,000 MWs, but it exceeded that limit (reaching a maximum of 4,331 MWs) subject to any potential reliability effects on adjacent regions. SPP experienced parallel flows that challenged operators.
- **Deliverability:** There was ample wind generation available in the northern portions of MISO and SPP. Deliverability of reserves was the principal issue.

Source: Jan. 2018 Event Report

Resilience Issues (Cont'd)

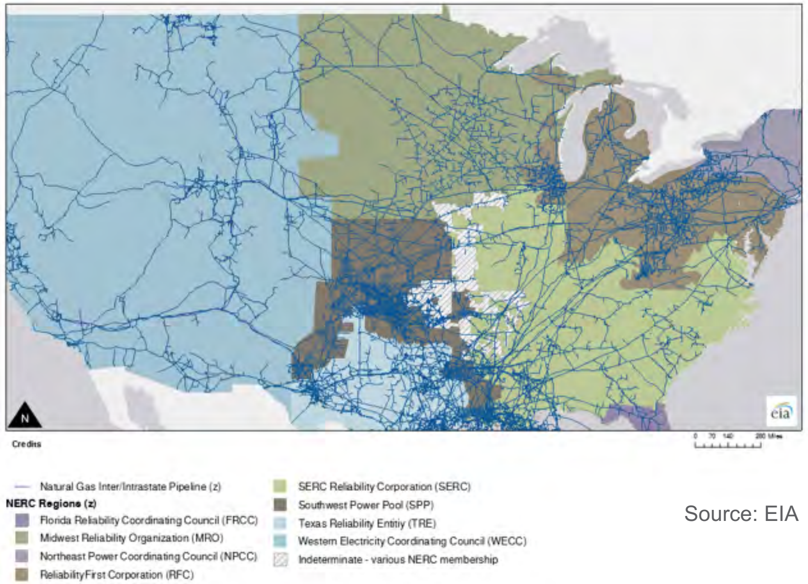
- SPP's resources are varied, but the region is mostly dependent upon wind, coal, and natural gas-fired generation. Coal and gas-fired generation are particularly concentrated in the southern and eastern part of its footprint.
- There is abundant gas pipeline availability and access in the southern portion of the region, particularly in Oklahoma, Texas, and Louisiana (see below).

SPP's Generation Capacity by Location, Size, and Fuel Type



Source: SPP 101

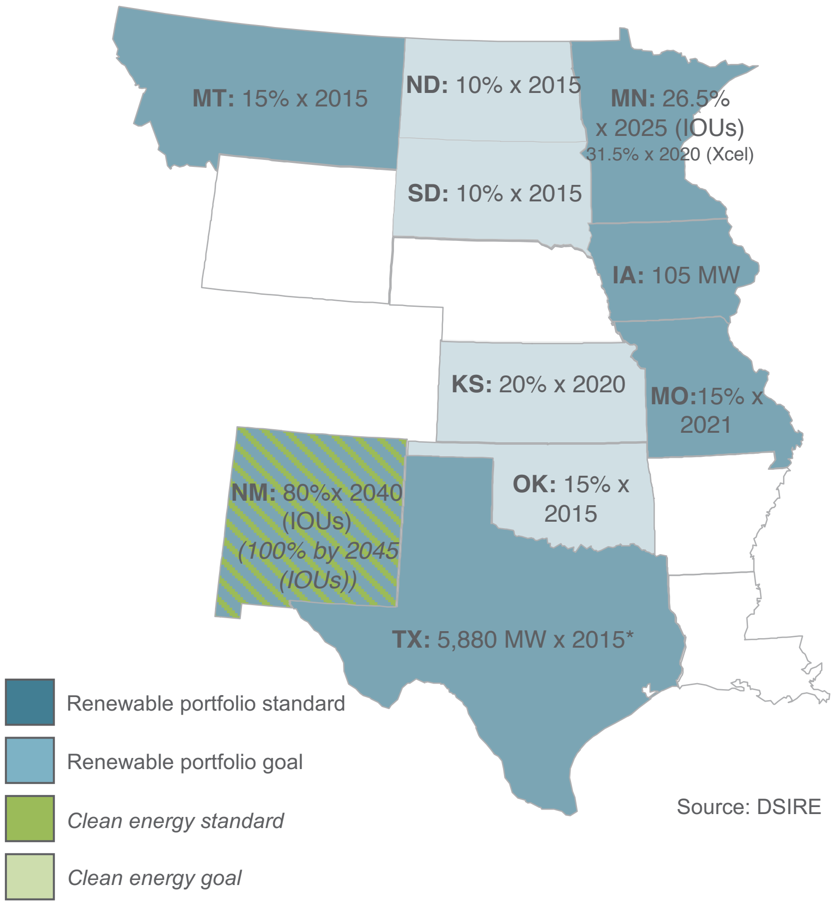
Natural Gas Pipelines by Selected NERC Region



Source: EIA

Renewables Integration

State Renewable Portfolio and Clean Energy Standards and Goals within the SPP Footprint (as of June 2019)



Source: DSIRE

* Extra credit for solar or customer-sited renewables

Demand-Side Considerations

- Overall power consumption generally in the region was 248.4 TWh in 2016, fell to 246 TWh in 2017 after a cool August, but rose in 2018 by 6% to 259.6 TWh. Long-term, NERC's latest assessment forecasts a 0.5% compound annual growth rate in net energy for load over the next 10 years.
- A number of states both within and adjacent to SPP's footprint have renewable and/or clean energy standards (see left). New Mexico has instituted aggressive long-term clean energy goals (100% by 2045). Minnesota has another relatively ambitious renewables standard, requiring investor-owned utilities to procure 26.5% of their power renewables by 2025.
- Some utilities in states touched by SPP's footprint have also introduced clean energy commitments (see below).

Utility Name (States of Operation)	Goal Type	Target Dates	Description (Date Implemented)
Kansas City Power and Light (KS, MO)	Emission Reduction	2020 2021	Plan to exceed states' (KS and MO) RPS; 15% emissions reduction by 2021 in Missouri and 20% emissions reduction by 2020 in Kansas (2018)
MidAmerican Energy (IA, IL, SD)	Renewables	N/A	100% renewables (2016)
Otter Tail Corporation (MN, ND)	Renewable Energy	2031	30% renewables by 2031 (2017)
Public Service Company of New Mexico (NM)	Emission Reduction	2040	100% emissions-free energy by 2040
Xcel Energy (CO, MI, MN, NM, ND, SD, TX, WI)	Emission Reduction/ Carbon Reduction	2017 2030 2050	35% emissions reduction by 2017 (achieved), 80% below 2005 levels by 2030, and zero-carbon by 2050 (2015)

Source: SEPA

Sources: SPP 101; SEPA; DSIRE; NERC ES&D

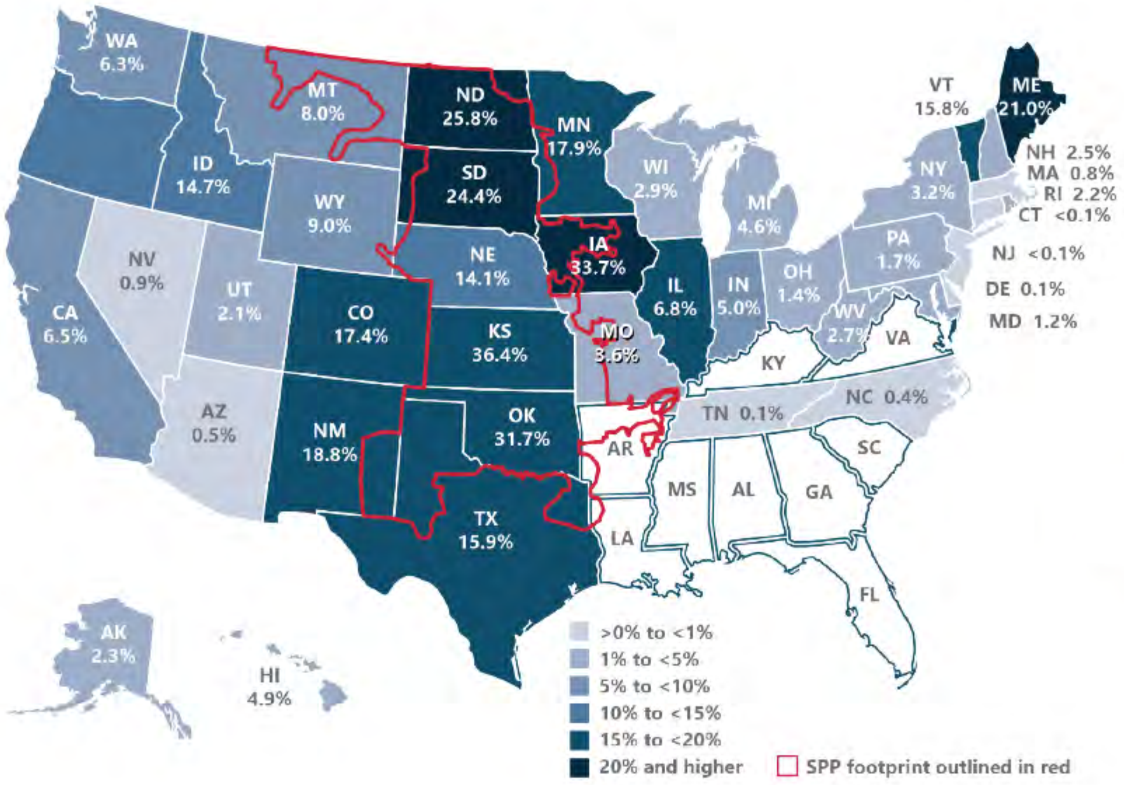
Renewables Integration (Cont’d)

Supply-Side Considerations – Wind Resources

- SPP has significant wind resources, both installed and potential. Outside of offshore areas, SPP’s footprint, highlighted on the map, is covered with some of the highest wind speeds in the country.
- According to EIA, U.S. wind generation totaled 275 million MWhs in 2018, with more than half coming from four states: Texas, Oklahoma, Iowa, and Kansas.
  - Texas accounted for more than 25% of U.S. wind electricity generation in each of the past three years. Most wind-generating capacity in Texas is located in the rural northern and western areas of the state.
  - Oklahoma accounted for 10% of wind generation in 2018, and its wind capacity doubled between 2014 and 2018.
  - Iowa’s wind production has doubled since 2011 and accounted for 34% of electricity generation in the state, second only to natural gas (44%).
  - Kansas became the fourth-largest wind power producer in 2016, and wind accounted for 36% of electricity generation in 2018, the largest proportion of any state.

Source: EIA

Wind Energy’s Share of Electricity Generation by State (2018)



Source: SPP (citing EIA)

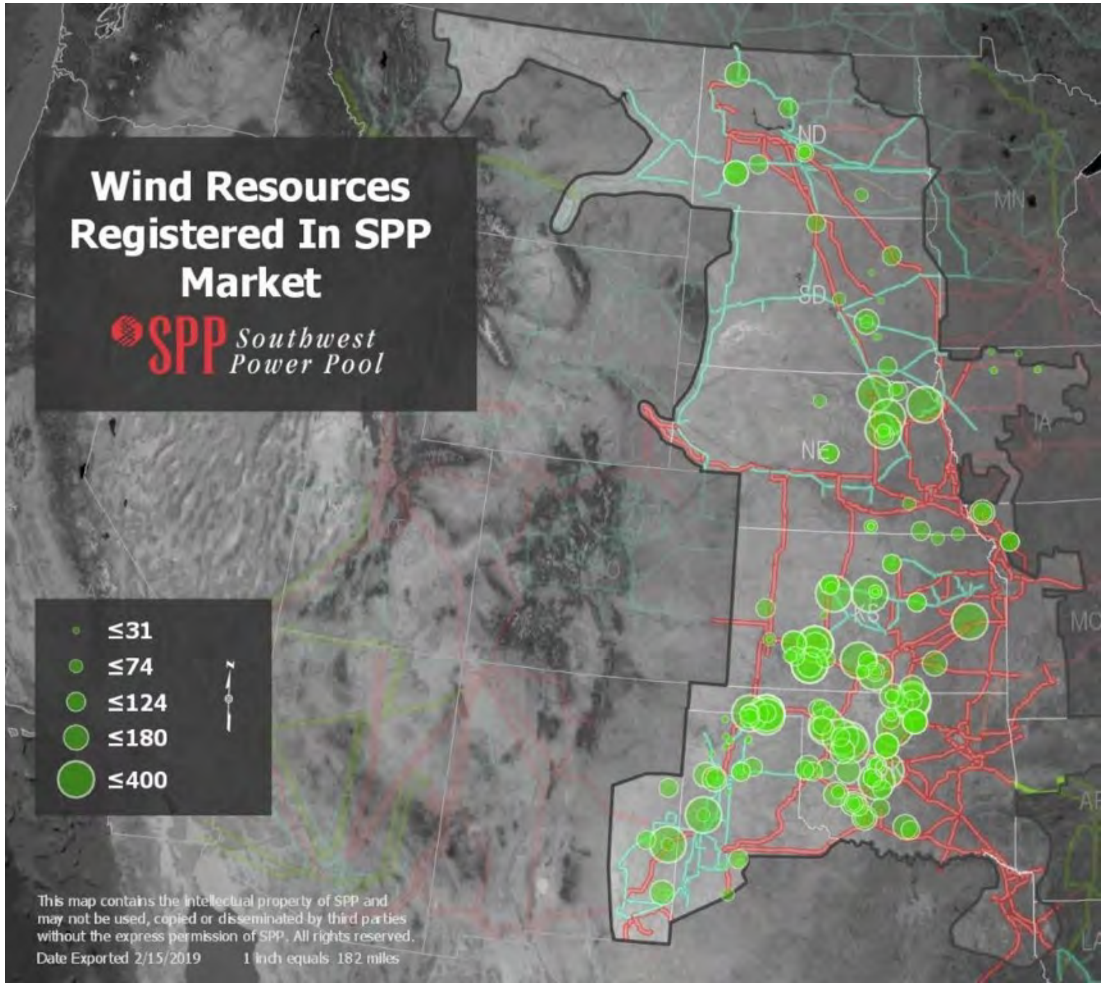
Sources: SPP 101; EIA; SPP SOM 2018

Renewables Integration (Cont'd)

Supply-Side Considerations – Wind Resources (Cont'd)

- SPP has about 21 GWs of wind installed today, comprised of 11,029 turbines at 207 wind resource locations (most are 80-meter hub height).
  - Across SPP, the average 2018 wind penetration was 25%.
  - But minimum and maximum output can see wide swings: the maximum one-day wind swing was more than 13 GWs (in 18 hours) and the maximum 1-hour ramp was 3.7 GWs.
  - Typically, wind generation fluctuates seasonally as summer is the low-wind season, while spring and fall are high-wind seasons. Wind also typically has lower production during on-peak hours than off-peak. Higher levels of wind generation tend to coincide with the morning ramp periods.
- In the pipeline, the region has about 9 GWs of unbuilt wind facilities with signed interconnection agreements and a total of about 50 GWs of wind generation in all stages of study and development as of June 2019.
- SPP forecasts about 23 GWs of wind installations by 2020 (more than its current minimum load) and 28 to 33 GWs forecast total installed wind generation in 2025.

Installed and Registered Wind Resources in SPP's Market

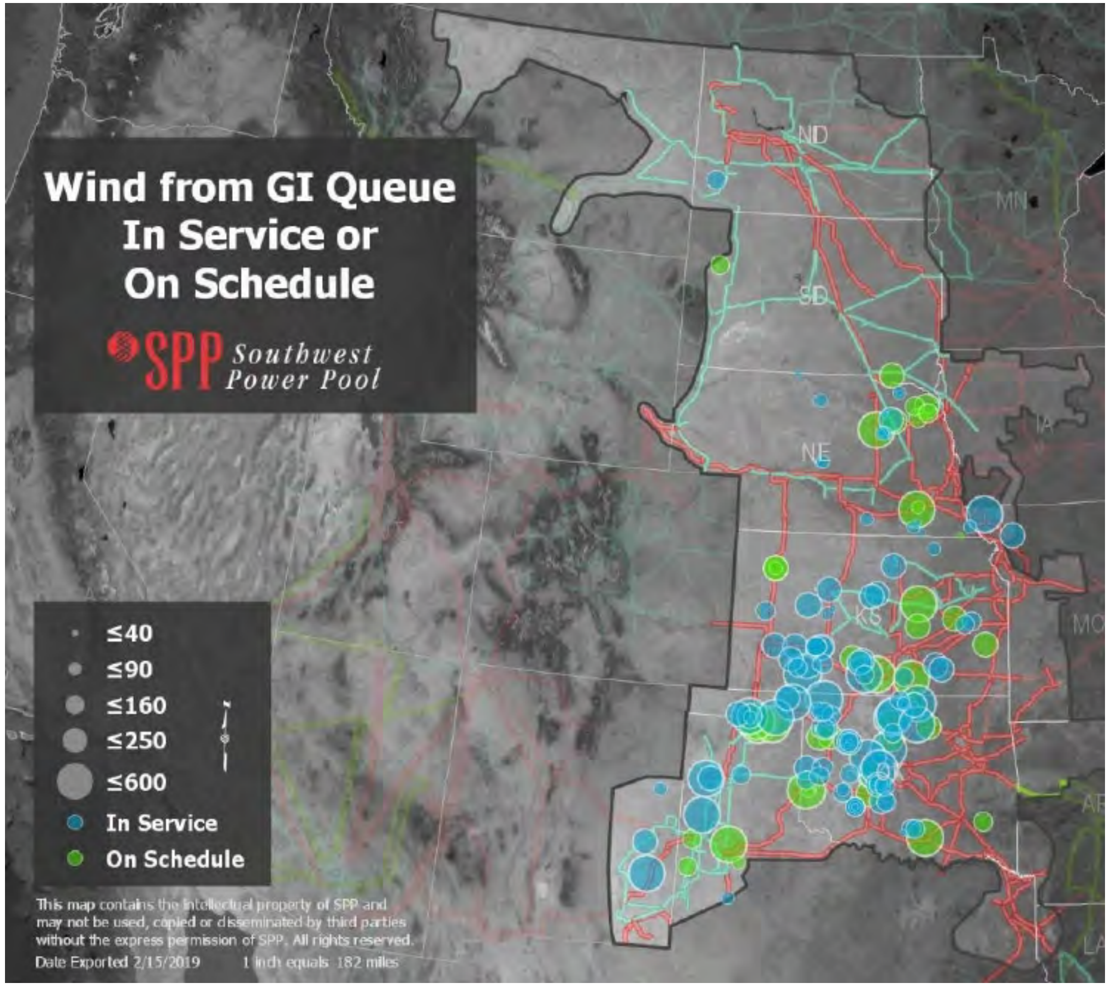


Source: SPP 101

Sources: SPP 101, at pp. 39, 123; SPP SOM 2018

Renewables Integration (Cont'd)

Wind Resources in SPP's Generation Interconnection Queue In-Service or On Schedule (as of Feb. 2019)

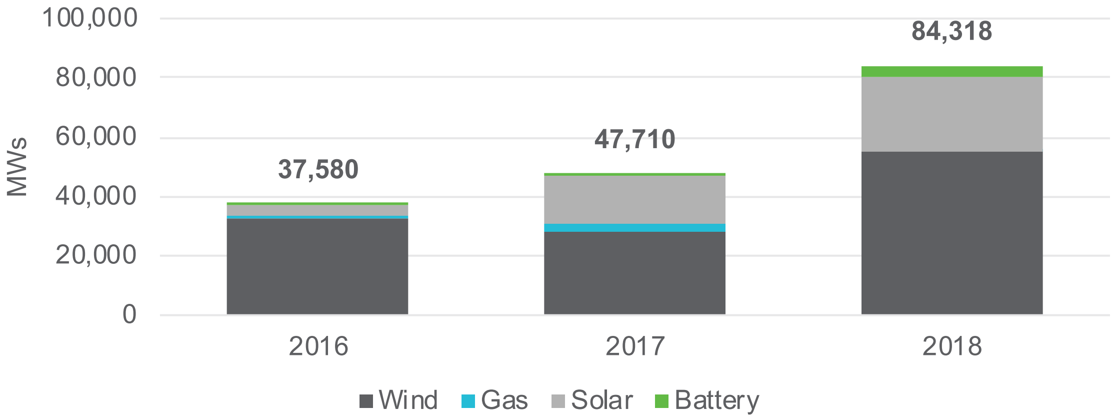


Source: SPP 101

Supply-Side Considerations – Wind Resources (Cont'd)

- Wind resources continue to seek interconnection largely in the southern half of SPP (see next page).
- Increasingly, however, solar power resources are being considered in the footprint as well. Currently, there are 215 MWs of solar capacity in SPP, largely concentrated near the Texas-New Mexico border, where solar irradiance is more supportive of solar photovoltaic power generation. More than 24 GWs of solar capacity had generation interconnection requests in the queue at the end of 2018.
- Battery interconnection requests have increased as well, growing along with solar interconnection requests (see below).

Active Generation Interconnection Requests (MWs) (as of Year-End 2016–2018)

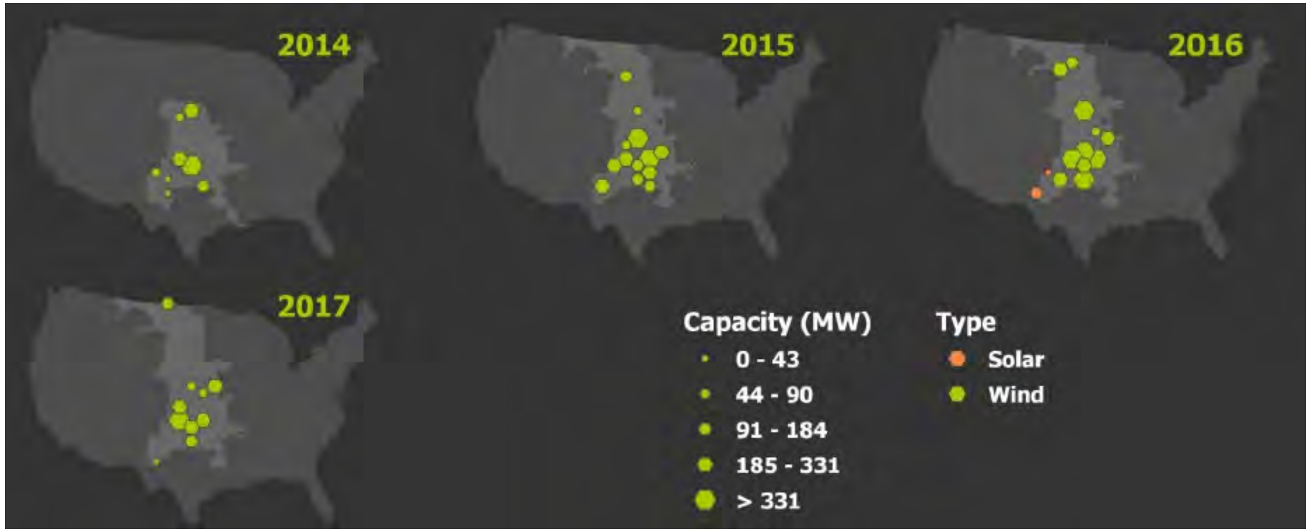


Source: SPP 2018 State of the Market, Fig. 2-15

Sources: SPP 101; SPP SOM 2018

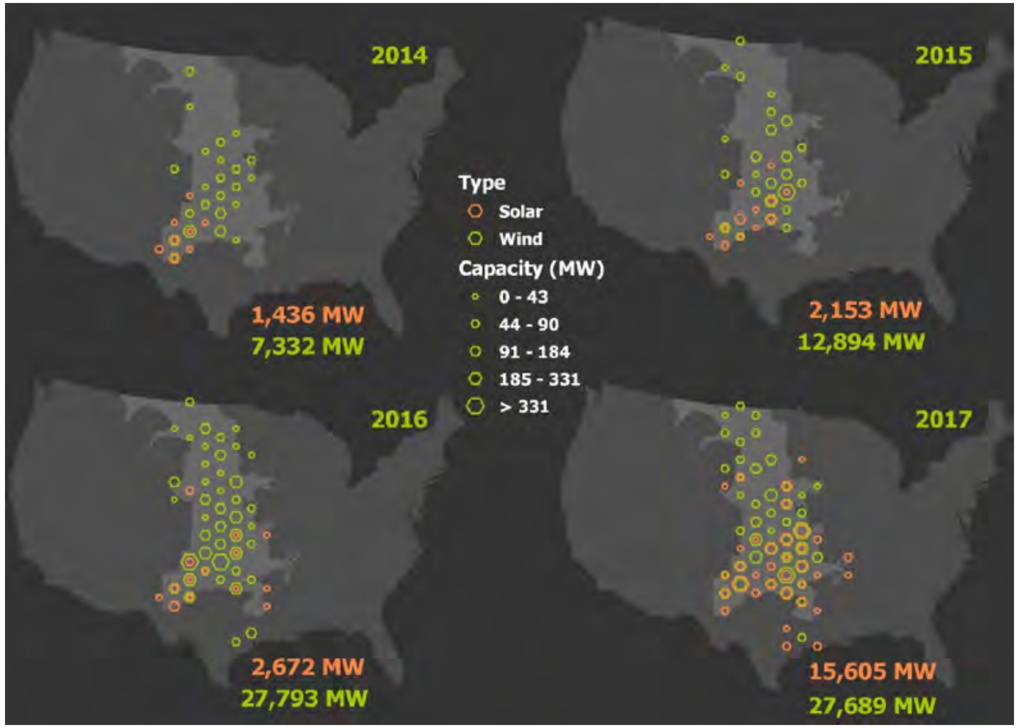
Renewables Integration (Cont'd)

Comparative Distribution of New Renewable Resources (2014–17)



Source: SPP 101

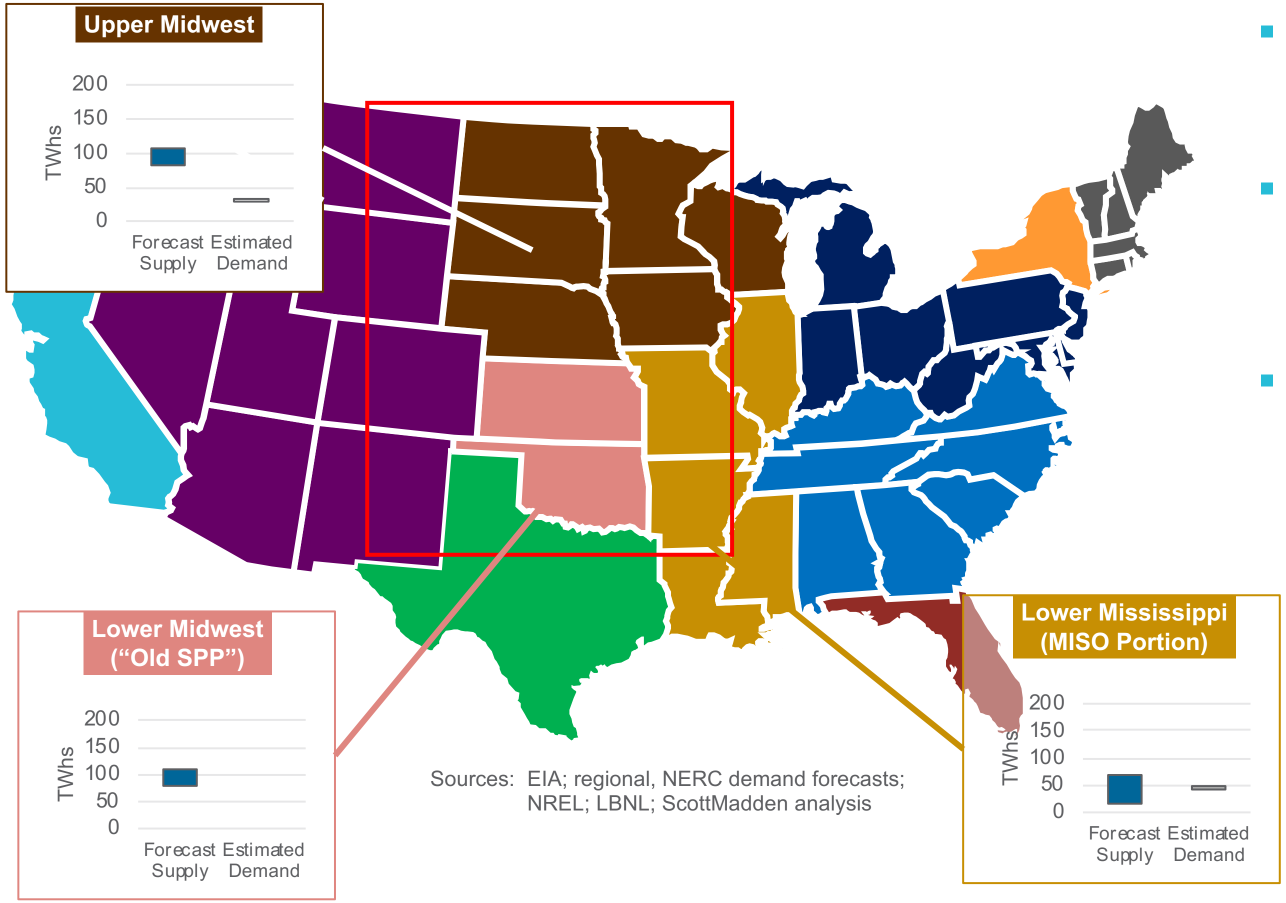
Comparative Distribution of Renewable Interconnection Requests (2014–17)



Source: SPP 101

Source: SPP 101

Renewables Integration (Cont'd)

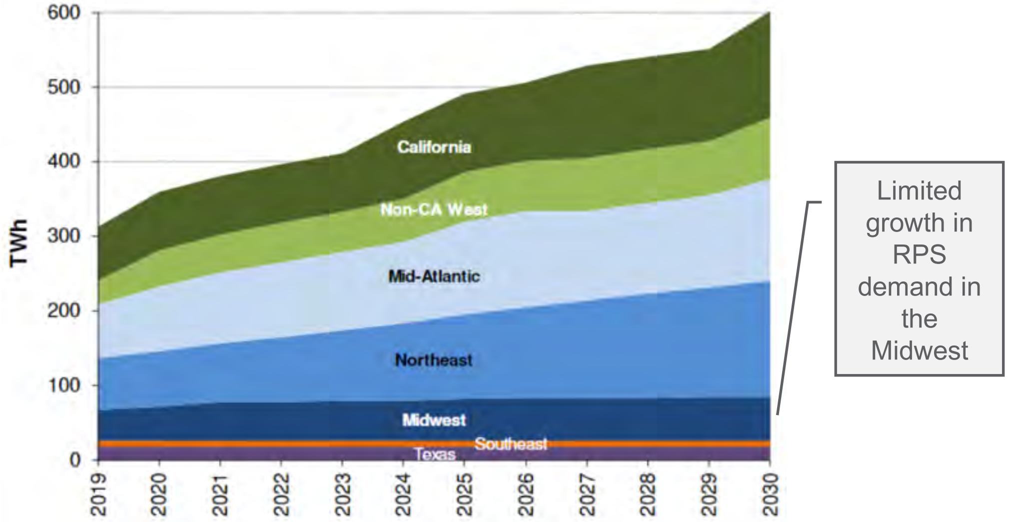


Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Integration Challenges – RPS Supply and Demand

- As seen in the map at left and the Midwest section of the chart below, the SPP region has abundant anticipated renewable resource supply in comparison with projected renewables demand, which is supposed to grow only modestly through 2030 under current state policies.
- Lawrence Berkeley National Laboratory (LBNL) notes that RPS capacity additions (10% or 9 GWs) extend to 13 states without an RPS, with the most significant including MISO states Indiana and North Dakota as well as Wyoming. Two others with no further RPS obligations—Kansas and Iowa (each part of SPP)—host significant RPS capacity for others.
- This RPS supply-demand imbalance illustrates the role of interstate transmission capacity for interstate commerce for RPS compliance.

Projected U.S. RPS Demand (Total Compliance Requirements) per DOE LBNL (2019–2030) (as of July 2019) (in TWh)



Source: LBNL

Sources: LBNL 2019 RPS Analysis; AWEA 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Renewables Integration (Cont'd)

Integration Challenges (Cont'd)

- Wind integration brings low-cost generation to the SPP region but does not count for much accredited capacity.
- According to SPP's market monitor, there are a number of operational challenges in dealing with substantial wind capacity:
  - Wind energy output varies by season and time of day. This variability is estimated to be about three times more than load when measured on an hour-to-hour basis.
  - Wind is counter-cyclical to load. As load increases (both seasonally and daily), wind production typically declines. The increasing magnitude of wind capacity additions since 2007, along with the concentration, volatility, and timeliness of wind, can create challenges for grid operators with regard to managing transmission congestion and resolution of ramping constraints (which began being reflected in scarcity pricing in May 2017) as well as challenges for short- and long-run reliability.
  - Wind forecast errors are also the leading cause of day-ahead and real-time price divergence, and forecast errors have led to several price spikes.
- Some "legacy" wind and other qualifying resources were allowed to register as non-dispatchable variable energy resources, provided the resource had an interconnection agreement by May 21, 2011, and commercially operated by mid-October 2012.
  - About 29% (nearly 6 GWs) of existing wind resources in SPP are non-dispatchable variable energy resources (NDVERs). These resources generally produce without regard to price, but operators must issue manual instructions to reduce or limit output at certain times.
  - Penetration of these NDVERs has led to occasional reduction in dispatchable wind resources, largely to alleviate congestion bottlenecks.
  - An increase in dispatchable wind capacity has helped in the management of congestion caused by high levels of wind generation in some of the western parts of the SPP footprint.
- Substantial transmission upgrades in SPP's footprint over the past few years have provided an increase in transmission capability for wind-producing regions, helping to address concerns related to high-wind production and resulting congestion. The increased transmission capability directly reduces localized congestion, creating a more integrated system with higher diversity and greater flexibility in managing high levels of wind production. However, given the historical trends toward growing wind capacity and indicators of future additions in the generation interconnection queue, additional transmission upgrades may entice further development of wind capacity.

Source: SPP SOM 2018

Renewables Integration (Cont'd)

Integration Challenges – Integrated Marketplace

- SPP operates an Integrated Marketplace, with greater than 6 GWs of AC interties with MISO to the east, 810 MWs of DC ties to ERCOT to the south, and more than 1 GW of DC ties to WECC to the west. Additionally, SPP has more than 1,500 MWs of interties with the Southwestern Power Administration (SPA) in Arkansas, Missouri, and Oklahoma, and more than 5 GWs of AC interties the Associated Electric Cooperative (AECI) in Oklahoma and Missouri.
- SPP has been a net exporter in real-time since 2016. Notably, because of the addition of the Integrated System to SPP in October 2015, transactions that were external imports from WAPA became internal transactions within the SPP footprint. SPP's exports closely follow wind production for the day.
- The Integrated Marketplace has reliably managed wind generation even when it represented more than 60% of load. While use of manual dispatch is limited and SPP's dispatchable wind fleet is growing, SPP needs ramping capability. Ramp shortages have been reflected in prices since May 2017.
- One issue SPP is addressing is "price chasing," where a NDVER on manual control responds to lower real-time prices by curtailing output and increasing output when prices rise. The latter can cause breaches on flow gates, causing suboptimal dispatch and reduced market efficiency.
- SPP has proposed expanding its current market offering to include a Western Energy Imbalance Service (WEIS), extending into the Western Interconnection. This five-minute energy imbalance market will use non-firm, "as-available" transmission service with lowest priority offered at zero cost. By incorporating a wide variety of dispatchable resources (including dispatchable variable energy resources), the objectives of WEIS are to optimize the use of the Western Interconnection's transmission system and minimize overall costs of energy and capacity.

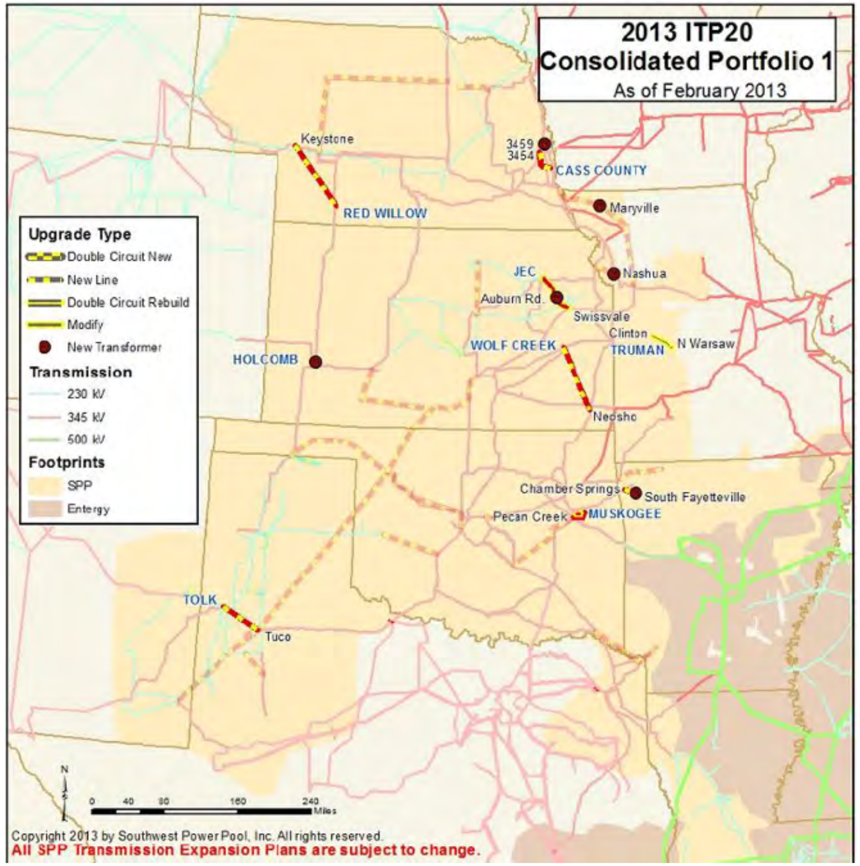
Sources: SPP SOM 2018; WEIS Proposal

Renewables Integration (Cont’d)

Renewables Integration – ITP20

- SPP performs a long-range (20-year) planning exercise every five years (termed ITP20). Its latest ITP20, issued in mid-2013, looked at five scenarios, each driven by policy considerations, such as state renewable mandates, a potential federal renewable standard, EPA regulations, and additional wind development for export.
- SPP’s recommended portfolio of transmission projects assumed 9 GWs of wind capacity additions (NB: less than currently projected) allocated through the region in six states. This assumed meeting then-existing state renewable mandates. It also assumed that 15.2 GWs of gas-fired resources (7.5 GWs combined cycle and 7.7 GWs combustion turbine) would be added to the system.
- Under its base case plan, SPP’s model found that there was additional congestion, leading to curtailment of scheduled wind energy output. Levels of curtailment varied by scenario, with greater wind capacity leading to more curtailment.
- Using N-1 planning, ITP20 identified eight reliability, three economic, and one seams projects, respectively, totaling $560 million in engineering and construction costs.
  - In evaluating extra-high voltage (EHV) transmission, solutions recommended were primarily 345 kV technology.
  - However, in higher wind penetration scenarios (e.g., 16.5 GWs for internal transfers plus 10 GWs for exports), 765 kV and HVDC solutions were considered. In higher wind penetration scenarios (15 to 25 GWs compared with 9 GWs), incremental transmission investment of $1.3 billion to $5.1 billion would be required.
- Note that this plan predates the expansion of SPP to the north.

2013 ITP20 Transmission Plan



Source: ITP20, Fig. 0.1

Source: ITP20

Renewables Integration (Cont'd)

Integration Issues – 2016 Wind Integration Study

- In 2014, SPP launched its Integrated Marketplace. In 2015, the Integrated System* was added as a SPP member. With a broader footprint and market structure in place across its footprint, SPP conducted a wind integration to determine operational and reliability impacts of additional wind generation in SPP, including in the Integrated System's region in the north.
- In 2016, SPP conducted a wind integration study in which scenarios with 30%, 45%, and 60% wind generation were analyzed. It found that up to 60% of wind penetration could be accommodated, but additional investments and capabilities would be required.
- Key findings from the study:
  - Thermal and voltage analysis indicated that approved ITP projects needed to be expedited, and the study identified additional transmission needs.
  - Voltage stability analysis showed that renewable penetration levels were (at the time of the study) approaching their limits, requiring dynamic reactive reserves.
  - Wind has a small impact and large ramps showed a small increase, but time periods during which large-ramping occurs are less predictable. New ancillary services products to address intra-hour ramping or situational awareness tools (e.g., phasor management unit applications) to address inter-hour ramping may be needed.
  - All N-1 constraints were able to be resolved with redispatch, albeit with heavy-wind curtailments in higher penetration cases, leaving thousands of MWs of low-variable cost generation "on the table" due to significant transmission constraints.
  - Even without transmission outages, significant overloads were observed on multiple facilities.

Integration Issues – 2017 Variable Generation Integration Study

- In a subsequent technical integration study of SPP variable generation (wind and solar), SPP looked at N-2 fault locations, primarily focused on system frequency behavior with loss of selected large-generating units as well as five-minute analysis for ramping. The study found the following:
  - The SPP system could withstand high levels of wind resources, but scenarios were identified when the loss of certain output of one generator (Wolf Creek, KS, 1,255 MWs) could jeopardize system security.
  - While no ramping issues were identified, those scenarios assumed correct forecasts. The study recommended further analysis to quantify the risk and expectation for forecast errors. Ramping deviation can have significant impacts, especially during winter mornings, when 2 to 3 GWs of generation might require start-up at a time of negative system prices.

Note: *The Integrated System covers a seven state area (IA, NE, SD, WY, MN, ND, and MT) and consists of more than 9,300 miles of transmission lines. It is jointly owned by Heartland Consumers Power District, Western Area Power Administration's Upper Great Plains Region, and Basin Electric Power Cooperative.
ITP means integrated transmission plan.
Sources: 2016 Wind Study; 2017 Variable Gen. Study

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
Southwest Power Pool	▪ Key risks largely weather-related: severe events (tornadoes), drought, ice storms ▪ Monitor N-2 extreme events; annual review of long lead-time equipment ▪ Geographic diversity (broad north-south footprint) affords weather diversity as well as multi-threat exposure	▪ About 21.5 GWs of wind, with penetration of 25% average generation as % of load; only a small amount of solar ▪ Renewable (wind) penetration record of 71% in April 2019 ▪ Operational challenges as nearly a third of wind capacity is non-dispatchable ▪ Significant renewables and storage (99%) in planning queue: 51 GWs wind, 28.5 GWs solar, and 5.8 GWs storage ▪ Forecast 28–33 GWs installed wind by 2025 ▪ Some ramp shortages occurring; daily variation in resources requires optimization over broader area, diverse fuels (e.g., max wind swing of 13.3 GWs over 24 hours) ▪ Congestion is declining across footprint, but regional effects remain: northwest/southeast split of region, with wind causing congestion in central KS and southwest MO	▪ Scenario planning (20 years) through SPP's 2013 ITP20 examines various levels of wind penetration, from 10 GWs to 26.5 GWs – Scenarios included federal renewable energy standards, exports – Did not account for significant solar now seen in queue ▪ Relatively homogeneous state policy environment across footprint; modest clean energy goals except for NM, MN ▪ 2016 analysis showed that $3.4B in transmission expansion projects in 2012–14 including 1,800 miles of extra high-voltage backbone projects expected to yield benefits of $16.6B over 40 years, including $10.5B of production cost reductions and $1.3 billion in optimal wind development	▪ About $10B in transmission infrastructure investment made to improve resource deliverability ▪ Potential increased integration with western balancing authorities, TX ▪ Resilience benefits from transmission for renewable integration ▪ About $1.9B in scheduled transmission investment (2019–2024) ▪ Last 20-year plan identified $845M for 12 projects (8 reliability, 3 economic, 1 seams) at 345 kV assuming only 9 GWs of wind capacity ▪ Investigating seams coordination with MISO to east; latest (2016) coordinated system plan identified 7 targeted needs and identified one interregional project ▪ 2018 plan calls for 13 projects totaling $37M, largely in SD, KS, MO, AR, TX; $32M for lower voltages (115, 69 kV) ▪ Continued development of west-to-east transfer capability to relieve "pinch points"

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Sources

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- SPP, 2016 Wind Integration Study (Jan. 5, 2016) (2016 Wind Study)
- SPP, 2017 Variable Generation Integration Study (Feb. 21, 2017) (2017 Variable Gen. Study)
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- S&P Global Market Intelligence
- U.S. Dept. of Commerce, Bureau of Economic Analysis

Regional Discussion

WESTERN ELECTRICITY COORDINATING COUNSEL (WECC) (EXCLUDING CAISO)

Contents

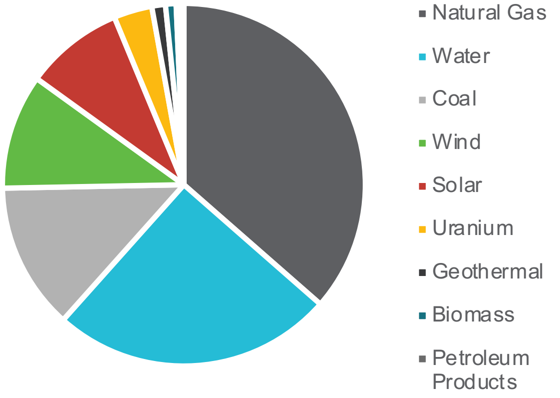
Overview

Description of Region

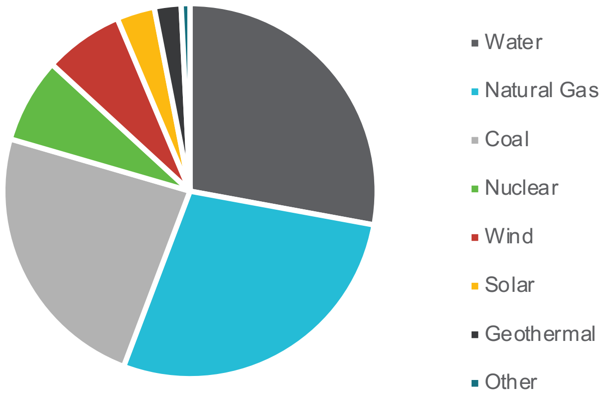
- The Western Interconnect is principally comprised of vertically integrated investor-owned utilities, a large federal utility, and a number of cooperative and municipal and state utilities.
- WECC, the reliability assessment area covering the Western Interconnect, is the largest and most diverse of the regional entities.
- WECC is s a summer-peaking assessment area, and WECC is divided into four U.S. assessment areas: California/Mexico (CAMX), Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), and Southwest Reserve Sharing Group (SRSG).
- No WECC subregion is expected to drop below the reference margin level before 2027.

Key Regional Statistics	
States Covered	AZ, CA, CO, ID, MT, NE, NM, NV, OR, SD, TX, UT, WA, WY
Square Mi. Covered	~1,800,000
No. of Utilities	6 co-ops; 5 fed/state systems; 3 munis; 12 investor-owned utilities
No. of Customers/Pop. Served	82.2MM population
Installed Capacity	171,119 MWs
Transmission Line Miles	126,285
Peak Hour Demand (2018)†	141,740 MWs summer (109,652 MWs winter)
Net Energy for Load	734,344 GWhs
Forecast Growth (Annual)	0.50%-2.30% peak load growth -0.52%-0.1.54% demand (usage) growth

2018 Capacity Mix by Fuel



2018 Energy Mix by Fuel



Sources: NERC 2018 LTRA, NERC ES&D, SPGMI
Notes: WECC figures on this page include CAISO, CAISO has not been netted out (but the two subregions in Canada, Alberta and British Columbia, have been removed)
† Note: Not necessarily coincident; constitutes a sum of sub-regional peak hour demand for CAMX, NWPP-US, RMRG, and SRSG; net internal demand is net of demand response.

Overview (Cont'd)

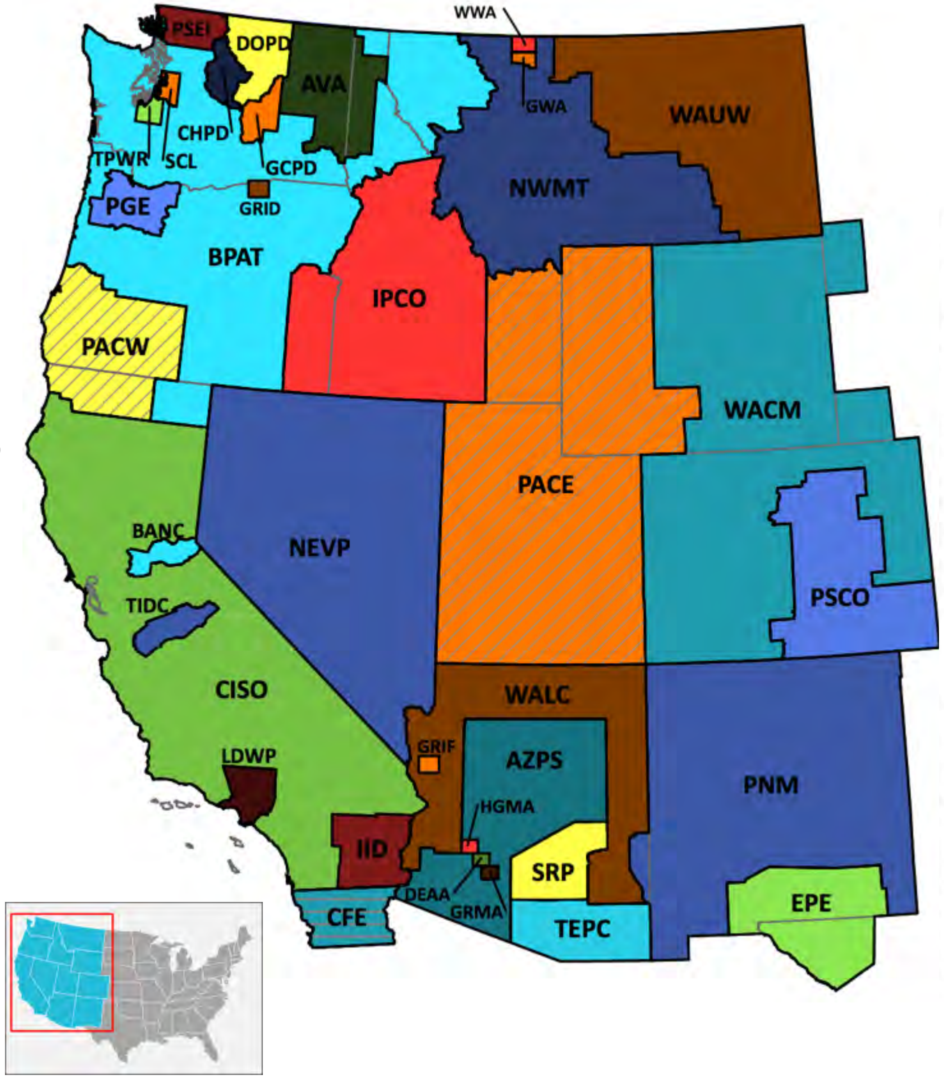
WECC is the regional entity for the Western Interconnection and is charged with coordinating and promoting bulk electric system reliability.

- WECC coordinates the operating and planning activities of its Western Interconnection members.
- Geographically, it is the largest and most diverse of the eight regional entities in NERC.
- WECC is comprised of four subregions:
  - Canada Mexico Power Area (CAMX)
  - Northwest Power Pool (NWPP)
  - Rocky Mountain Power Area (RMPA)
  - Arizona-New Mexico-Southern Nevada Power Area (AZ-NM-SNV)
- Different subregions of the West have different resource portfolios. Hydro units are dominant in the Northwest, while California and the Southwest rely heavily on natural gas. Solar units have become prevalent, especially in California, as wind capacity has grown in the Rocky Mountains and along the Columbia River.

Balancing Authorities

- WECC has 329 member organizations, including 38 different balancing authorities (pictured at right).
- Each balancing authority is responsible for balancing loads and resources within their respective boundaries. Such an organizational structure often presents challenges to reliability, particularly when integrating large amounts of variable generation.

Western Electricity Coordinating Council Balancing Areas



Legend

AESO - Alberta Electric System Operator
AVA - Avista Corporation
AZPS - Arizona Public Service Company
BANC - Balancing Authority of Northern California
BCHA - British Columbia Hydro Authority
BPAT - Bonneville Power Administration - Transmission
CFE - Comision Federal de Electricidad
CHPD - PUD No. 1 of Chelan County
CISO - California Independent System Operator
DEAA - Arlington Valley, LLC
DOPD - PUD No. 1 of Douglas County
EPE - El Paso Electric Company
GCPD - PUD No. 2 of Grant County
GRID - Gridforce
GRIF - Griffith Energy, LLC
GRMA - Sun Devil Power Holdings, LLC
GWA - NaturEner Power Watch, LLC
HGMA - New Harquahala Generating Company, LLC
IID - Imperial Irrigation District
IPCO - Idaho Power Company
LDWP - Los Angeles Department of Water and Power
NEVP - Nevada Power Company
NWMT - NorthWestern Energy
PACE - PacifiCorp East
PACW - PacifiCorp West
PGE - Portland General Electric Company
PNM - Public Service Company of New Mexico
PSCO - Public Service Company of Colorado
PSEI - Puget Sound Energy
SCL - Seattle City Light
SRP - Salt River Project
TEPC - Tucson Electric Power Company
TIDC - Turlock Irrigation District
TPWR - City of Tacoma, Department of Public Utilities
WACM - Western Area Power Administration, Colorado-Missouri Region
WALC - Western Area Power Administration, Lower Colorado Region
WAUW - Western Area Power Administration, Upper Great Plains West
WWA - NaturEner Wind Watch, LLC

Sources: WECC; NERC 2018 LTRA

Overview (Cont'd)

Transmission Planning Regions

- WECC is comprised of four different regional planning groups (Western Planning Regions, or WPRs), arrayed at right by approximate geographical location across the Western Interconnect:
  - California ISO (CAISO)
  - ColumbiaGrid
  - Northern Tier Transmission Group (NTTG)
  - WestConnect
- Each WPR develops its own transmission expansion plan, and an interregional transmission planning process is conducted to identify and approve transmission solutions which span multiple WPRs (discussed in the next section). An interregional coordination team (ICT) comprised of representatives from each region identifies interregional solutions.
- Though each region has different participants in geographically distinct regions across the western United States, the four planning regions have coordinated to establish a common language and common processes in response to FERC orders through the years.

Resource Adequacy

- According to NERC's 2018 LTRA, "The Western Interconnection and all of the individual subregions are expected to have sufficient generation capacity to exceed the Reference Margin Level during the assessment period."
- Other subregional resource adequacy assessments have been conducted by the Northwest Power Conservation Council (NPCC), with the help of the Resource Adequacy Advisory Council (RAAC), which found that the power supply in the Northwest is likely to become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants (1,330 MWs combined). The loss of load probability (LOLP) for that year is estimated to be more than 6%, which exceeds the NPCC's standard of 5%.

ColumbiaGrid

NTTG

CAISO

WestConnect Planning Region

Sources: WECC; CAISO; ColumbiaGrid; NTTG; WestConnect

Overview (Cont'd)

ColumbiaGrid

- Members and participating utilities include:
  - Avista Corporation
  - Bonneville Power Administration
  - Chelan County Power
  - Cowlitz PUD
  - Douglas County PUD*
  - Grant PUD
  - MATL LLP
  - Puget Sound Energy, Inc.
  - Seattle City Light
  - Snohomish PUD
  - Tacoma Power

ColumbiaGrid Transmission Facilities

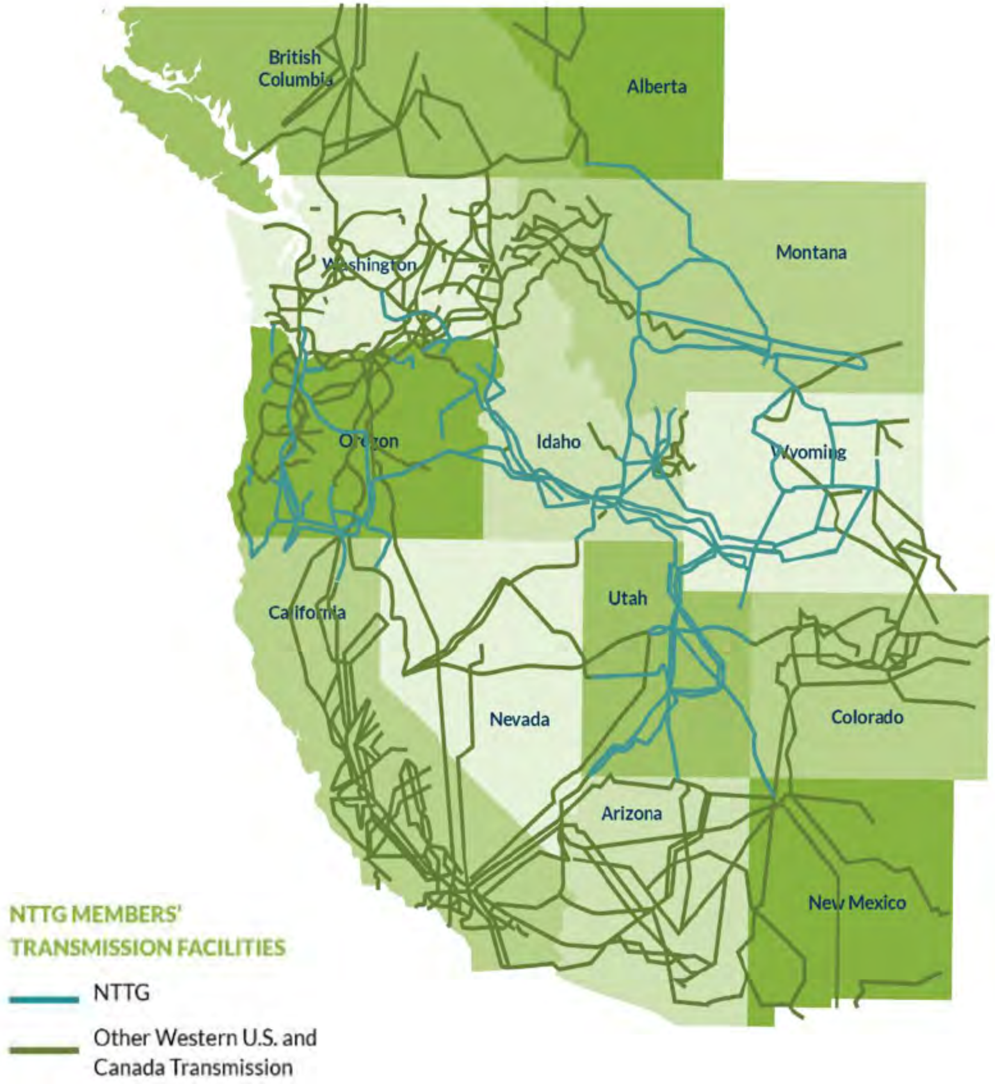
*Non-member PEFA planning participant
Sources: WECC; ColumbiaGrid

Overview (Cont'd)

NTTG

- Participating utilities include:
  - Deseret Power Electric Cooperative
  - Idaho Power
  - MATL LLP
  - Northwestern Energy
  - Pacificorp
  - Portland General Electric
  - Utah Associated Municipal Systems
- Participating state agencies include:
  - Idaho Public Utilities Commission
  - Montana Consumer Counsel
  - Montana Public Service Commission
  - Oregon Public Utility Commission
  - Utah Office of Consumer Services
  - Utah Public Service Commission
  - Wyoming Office of Consumer Advocates
  - Wyoming Public Service Commission

NTTG Map of Transmission Facilities



Sources: WECC; NTTG

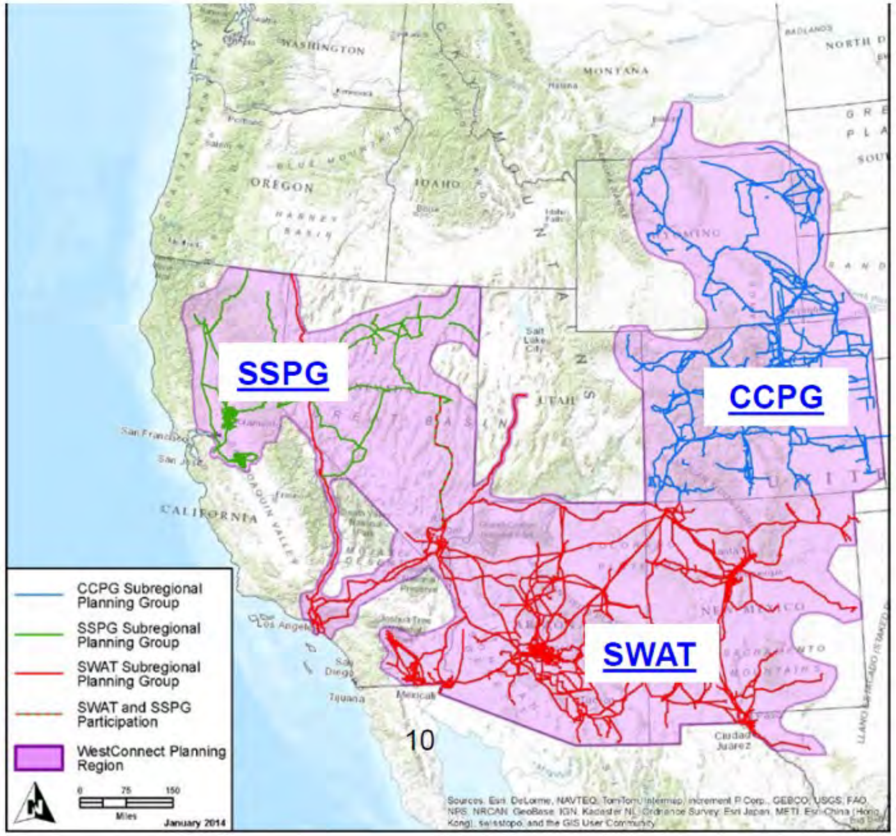
Overview (Cont'd)

WestConnect

- Enrolled transmission owners include:
  - Arizona Public Service
  - Black Hills*
  - El Paso Electric
  - NV Energy*
  - Public Service of New Mexico
  - Tucson Electric
  - Xcel –PSCo*
- Coordinating transmission owners include:
  - Arizona Electric Power Coop.
  - Basin Electric*
  - Colorado Springs Utilities
  - Imperial Irrigation District
  - L.A. Dept. of Water and Power
  - Platte River
  - Sacramento Municipal Utility District
  - Salt River Project
  - Transmission Agency of Northern California
  - Tri-State G&T
  - Western Area Power Administration

WestConnect Planning Region

WestConnect Subregional Planning Groups



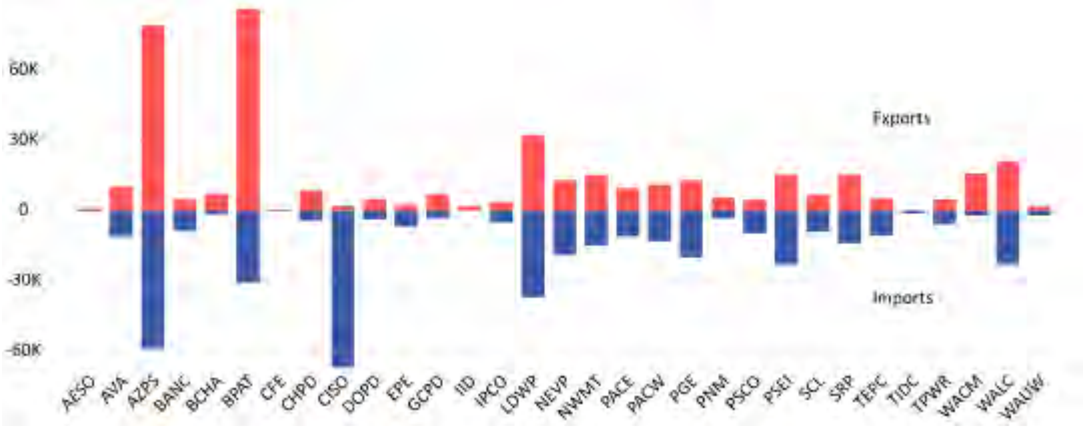
*Note: 2018 eligible transmission developer
Sources: WECC; WestConnect

Transmission Topography and Investment

California is the largest importer of electricity in the West, importing and consuming energy generated in neighboring regions.

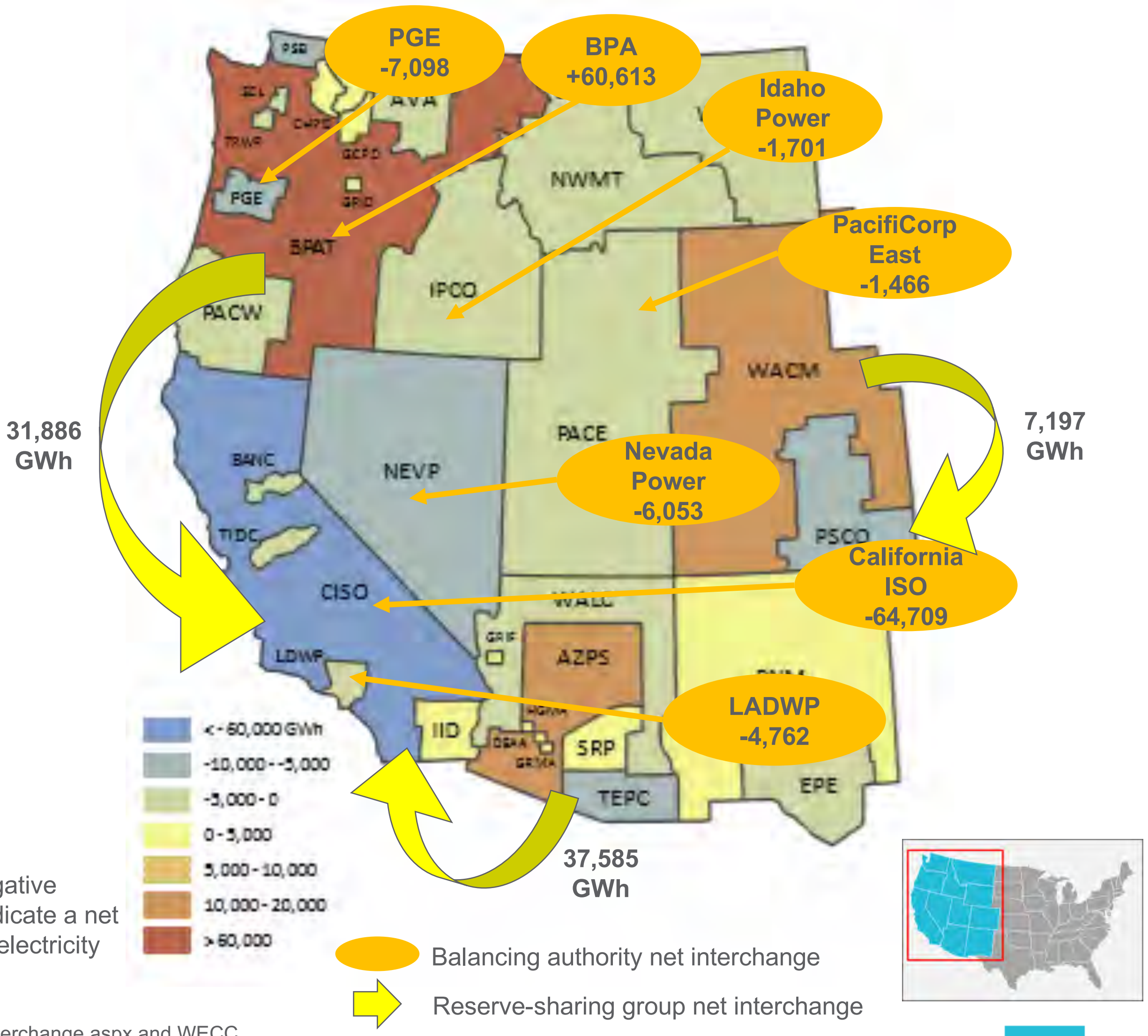
- Regional variation in seasonal demand and an abundance of generation capacity in the Pacific Northwest (with large amounts of hydro power) and the Southwest, combined with high demand in California, cause electricity to flow in a "doughnut" pattern.
- In 2016, the California-Mexico subregion had net imports of about 70,000 GWhs, equivalent to about 30% of CAISO net energy for demand. Volumes from the Northwest were slightly less than those from the Southwest.
- Net interchange is the difference between exports and imports.
  - The map at right shows balancing authorities that import energy (blue) compared to regions that primarily export energy (red-brown).
  - The yellow arrows show where large amounts of energy flow between reserve-sharing regions.

Imports and Exports by Balancing Authority (GWhs)



Note: Negative values indicate a net import of electricity

2016 Net Interchange by Balancing Authority (GWh)



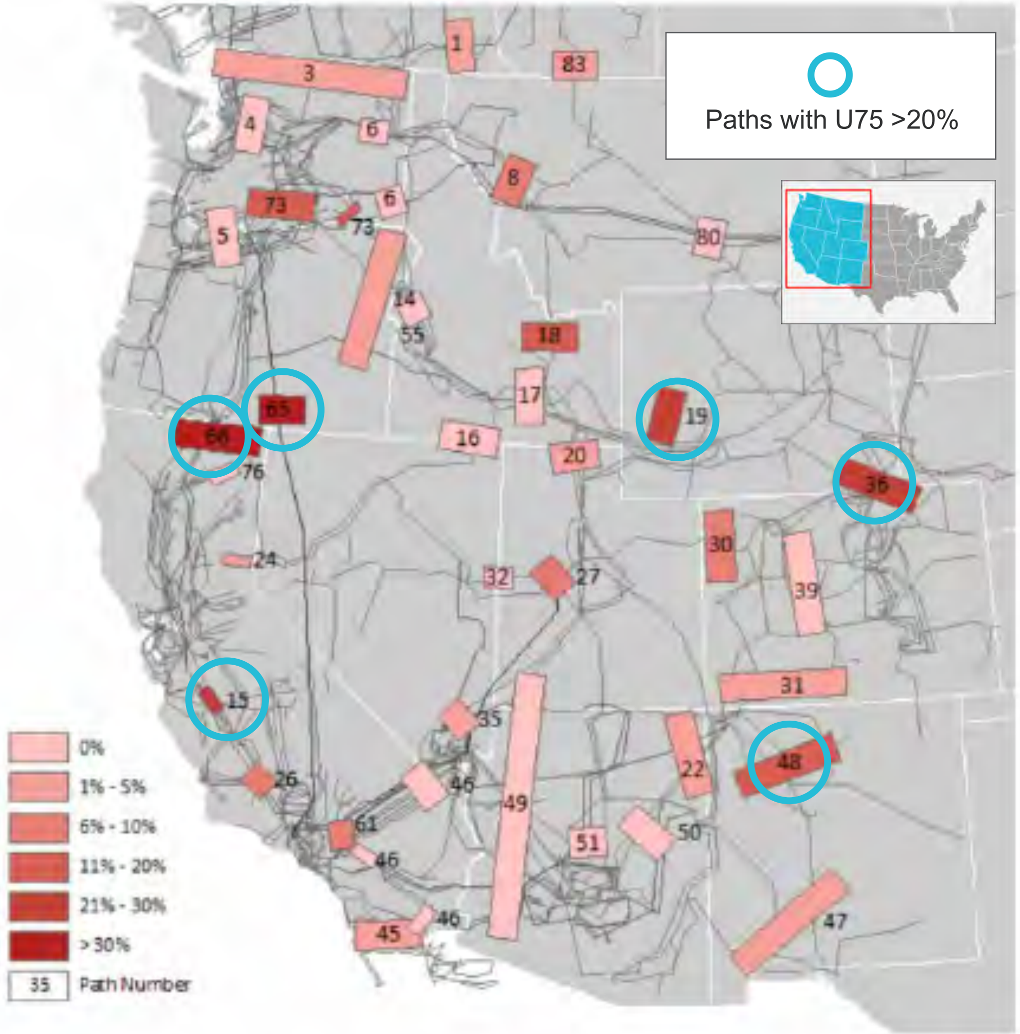
Sources: WECC, State of the Interconnection, at https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Interchange.aspx and WECC, State of the Interconnection Digest (Summer 2018) (Aug 8, 2018)

Transmission Topography and Investment (Cont'd)

WECC Transmission Paths

- WECC is characterized by long transmission lines connecting remote generation to load centers. Key transmission lines are grouped into 66 numbered paths for planning and operational purposes and illustrated in the map below.
  - One measure of congestion on WECC paths is the U75 metric, which measures the percent of time the flow on the path is above 75% of the path's operating limit.
  - A low U75 does not necessarily indicate a path is underutilized. Inversely, a high U75 does not necessarily indicate congestion. Many factors determine operating limits.
  - Some paths (e.g., Path 19) were built to carry electricity from large plants. High levels of flow are not unusual for these paths.
- The most congested paths are those in and around northern California, central California, northern New Mexico, and southwest and southeast Wyoming.

2017 U75 for WECC Major Transfer Paths



Source: WECC

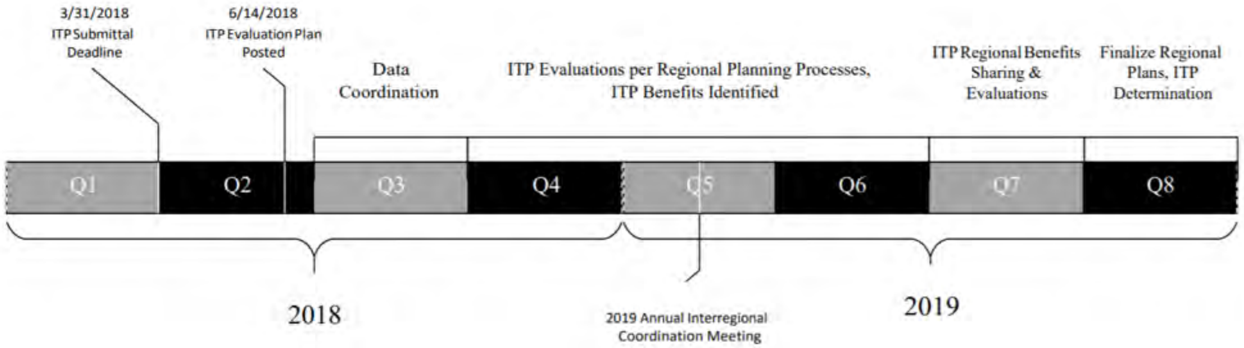
Sources: WECC, State of the Interconnection, at https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Interchange.aspx and WECC, State of the Interconnection Digest (Summer 2018) (Aug 8, 2018)

Transmission Topography and Investment (Cont'd)

Interregional Transmission Planning (ITP)

- The goal of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP.
- ITP proposals may be introduced by any of the WPRs, and relevant planning regions and cost allocation methods are identified at the time of project proposal.
- The Transmission Expansion Planning Policy Committee (TEPPC), with the assistance of WECC, conducts an interconnection-wide transmission planning activity every two years. This activity consists of developing input assumptions for the planning models, collecting and helping to develop planning scenarios, and running the planning models for 10- and 20-year scenarios.

ITP Evaluation Timeline



ITP Proposal – Cross Tie Transmission Project (Illustrative)

New ITPs Proposed in the 2018–2019 Planning Process

No	ITP Name	Submitted to	Project Proponent
1	TransWest DC	NTTG, WestConnect	TransWest Express LLC
2	TransWest AC/DC	NTTG, WestConnect	TransWest Express LLC
3	SDG&E HVDC Conversion	CAISO, WestConnect	San Diego Gas and Electric
4	TransCanyon Cross-Tie	NTTG, WestConnect	TRANSCANYON
5	SWIP North	CAISO, NTTG, WestConnect	Great Basin Transmission
6	North Gila-Imperial Valley #2	CAISO, NTTG, WestConnect	ITC Grid Development

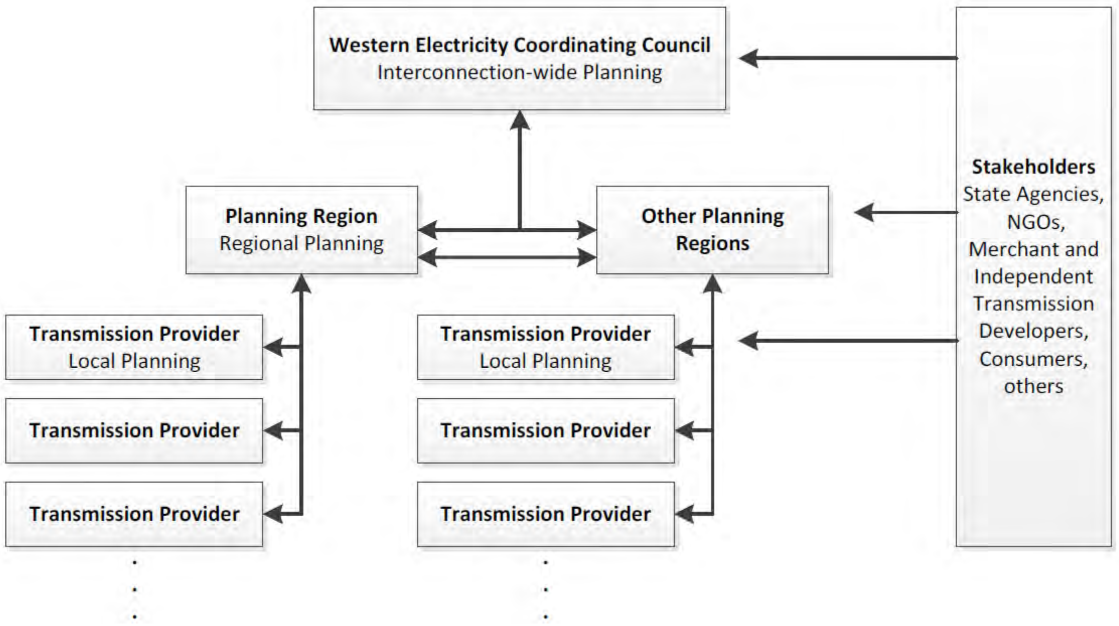
Sources: CAISO; ColumbiaGrid; NTTG; ITP Evaluation Process Plan

Transmission Topography and Investment (Cont'd)

Interregional Transmission Planning (ITP) (Cont'd)

- Needs assessments in each of the planning regions are conducted to identify three different types of needs:
  - **Reliability** – conducted to ensure compliance with NERC and WECC criteria
    - Assessment includes steady state contingency analysis and transient stability analysis.
    - Transmission elements of 100 kV and above will be monitored for performance along with any member-specified lower-voltage bulk electric system (BES) elements.
  - **Economic** – conducted to create base case for modeling
    - Assessment includes review of metrics such as congested hours and congestion cost for regional transmission elements greater than 100 kV and WECC transfer paths along with any member-specified lower-voltage BES elements.
    - Regional transmission with significant congestion is identified and verified through planning subcommittee review, historical benchmarking, and follow-up study.
  - **Public policy** – conducted to study potential needs driven by public policies that impact local transmission owners (TOs)
    - If the assessments identify regional issues that are related to enacted public policy, these may constitute a public policy-driven transmission need.
    - There is also an opportunity to make suggestions as to whether a TO's policy-driven project may constitute a public policy-driven regional transmission need.

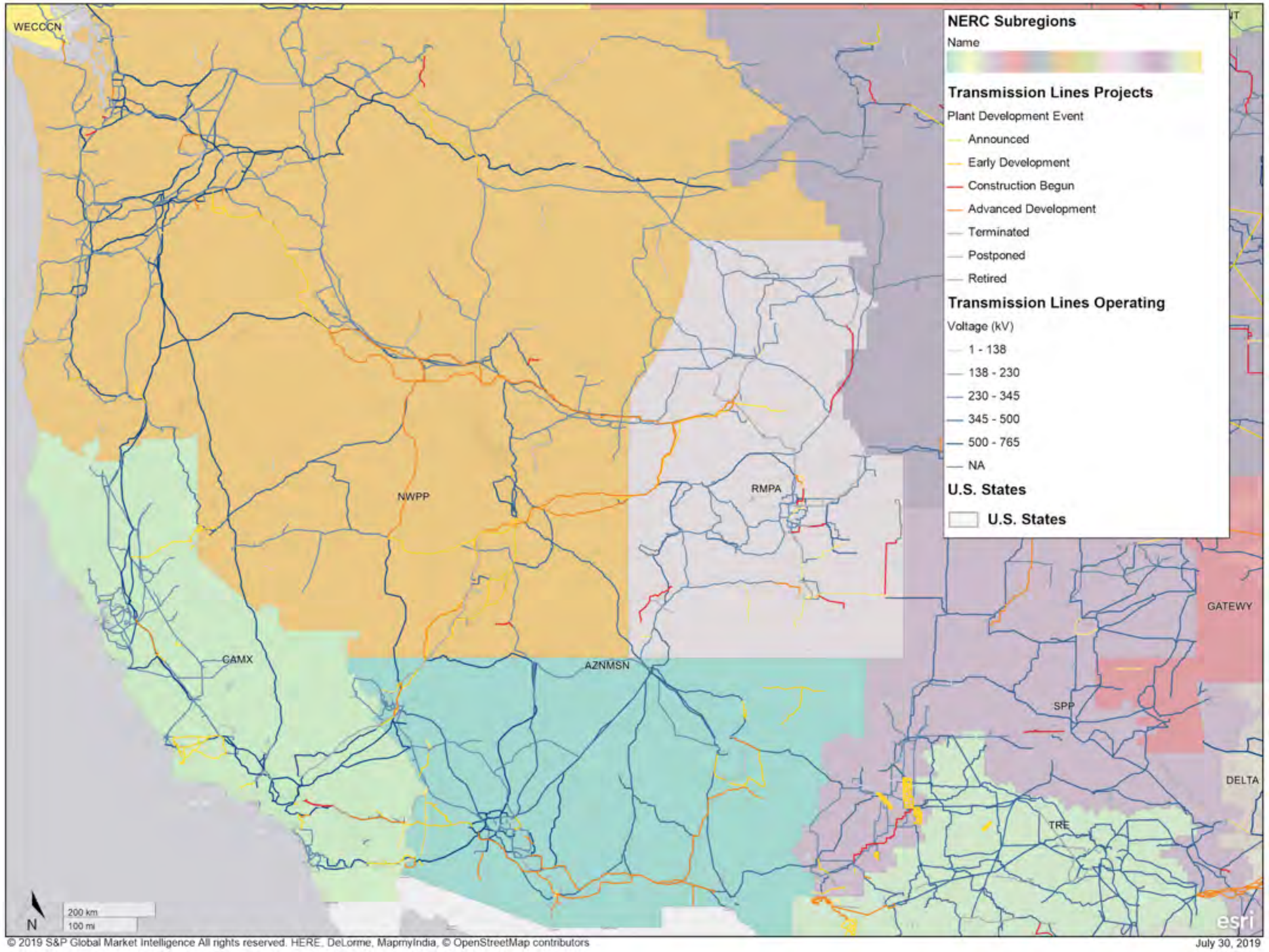
Transmission Planning Stakeholder Hierarchy



Sources: WestConnect; FERC Docket No. ER13-1447-001, et al (https://nttg.biz/site/index.php?option=com_docman&view=download&alias=2427-ferc-interregional-compliance-order-06-01-2015&category_slug=ferc-order-1000-interregional&Itemid=31)

Transmission Topography and Investment (Cont'd)

Selected WECC Subregions Transmission Lines



July 30, 2019

- There is significant internal transfer capability within WECC, which allows for transfers between subregions. In addition, WECC is interconnected with SPP and ERCOT.
- According to NERC, approximately 1,902 miles of new transmission lines are either planned stages or under construction as of late 2018, and an additional 884 miles are in the conceptual phase (see table below).
- Of the 169 projects cited by NERC, 121 are driven by reliability; 8 projects are driven by variable renewable integration, and 40 projects are driven by other needs.

Proposed Transmission Projects (Line Length in Circuit Miles) in WECC, Excluding CAISO (as of Dec. 2018)

Operating Voltage Class (kV)	Conceptual	Planned	Under Construction
100–120	76.5	468.93	64.44
121–150	12	0	0
151–199	51.7	0	0
200–299	316.4	255	349.1
300–399	0	115	85
400–599	428	565	0
Grand Total	884.6	1,403.93	498.54

Source: NERC 2018 Electricity Supply & Demand

Sources: S&P Global Market Intelligence; NERC 2018 LTRA; NERC ES&D

Transmission Topography and Investment (Cont'd)

Projected Transmission Expenditures

- Columbia Grid – According to its latest biennial transmission expansion plan published in February 2019, ColumbiaGrid estimates that total expenditures on transmission will be approximately $2.4 billion over the 10-year study period (through 2028).
- NTTG – According to its latest regional transmission plan published in June 2019, NTTG estimates that the incremental cost of all projects in the approved plan will be $879.7 million.
- WestConnect – Per its 2018–2019 base transmission plan, which includes planned transmission projects and high probability interregional transmission projects, WestConnect has $933 million in planned investment over the study period.

Joint Areas of Concern Identified in ColumbiaGrid's 2019 Biennial Transmission Expansion Plan (BTEP)

New Projects Identified in NTTG's 2018-2019 Regional Transmission Plan

Submitter	From	To	Voltage	Circuit	Type	Regionally Significant	Committed	Projects (In-service Year)
Idaho Power	Hemingway	Longhorn	500 kV	1	LTP & pRTP	Yes	No	B2H Project (2026)
	Hemingway	Bowmont	230 kV	2	LTP	Yes	No	New Line - associated with Boardman to Hemingway (2026)
	Bowmont	Hubbard	230 kV	1	LTP	Yes	No	New Line - associated with Boardman to Hemingway (2026)
	Hubbard	Cloverdale	230 kV	1	LTP	No	No	New Line (2021)
	Midpoint	Hemingway	500 kV	2	LTP	Yes	No	Gateway West Segment #8 (joint with PacifiCorp East) (2024)
	Cedar Hill	Hemingway	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #9 (joint with PacifiCorp East) (2024)
	Cedar Hill	Midpoint	500 kV	1	LTP	Yes	No	Gateway West Segment #10 (2024)
	Midpoint	Borah	500 kV	1	LTP & pRTP	Yes	No	(convert existing from 345 kV operation) (2024)
	Ketchum	Wood River	138 kV	2	LTP	No	No	New Line (2020)
	Willis	Star	138 kV	1	LTP	No	No	New Line (2019)
Enbridge	SE Alberta		DC	1	LTP	Yes	No	MATL 600 MW Back to Back DC Converter (2024)
PacifiCorp East	Aeolus	Clover	500 kV	1	LTP & pRTP	Yes	No	Gateway South Project – Segment #2 (2024)
	Aeolus	Anticline	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segments 2&3 (2020)
	Anticline	Jim Bridger	500 kV	1	LTP & pRTP	Yes	No	345/500 kV Tie (2020)
	Anticline	Populus	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #4 (2024)
	Populus	Borah	500 kV	1	LTP	Yes	No	Gateway West Segment #5 (2024)
	Populus	Cedar Hill	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #7 (2024)
	Antelope	Goshen	345 kV	1	LTP	Yes	No	Nuclear Resource Integration (2026)
	Antelope	Borah	345 kV	1	LTP	Yes	No	Nuclear Resource Integration (2026)
	Windstar	Aeolus	230 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #1W (2024)
	Oquirrh	Terminal	345 kV	2	LTP	Yes	Yes	Gateway Central
	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with Idaho Power) (2024)
	Shirley Basin	Standpipe	230 kV	1	LTP	Yes	No	Local Wind Integration (2020)
PacifiCorp West	Wallula	McNary	230 kV	2	LTP	Yes	Yes	Gateway West Segment A (2020)
Portland General	Blue Lake	Gresham	230 kV	1	LTP	No	Yes	New Line (2018)
	Blue Lake	Troutdale	230 kV	1	LTP	No	Yes	Rebuild (2018)
	Blue Lake	Troutdale	230 kV	2	LTP	No	Yes	New Line (2018)
	Horizon	Springville Jct	230 kV	1	LTP	No	Yes	New Line (Trojan-St Marys-Horizon) (2020)
	Horizon	Harborton	230 kV	1	LTP	No	Yes	New Line (re-terminates Horizon Line) (2020)
	Trojan	Harborton	230 kV	1	LTP	No	Yes	Re-termination to Harborton (2020)
	St Marys	Harborton	230 kV	1	LTP	No	Yes	Re-termination to Harborton (2020)
	Rivergate	Harborton	230 kV	1	LTP	No	Yes	Re-termination to Harborton (2020)
	Trojan	Harborton	230 kV	2	LTP	No	Yes	Re-termination to Harborton (2020)
			115 kV	1	LTP	No	Yes	Various Load Service Additions (2019-2024)

Note: LTP is Full Funder Local Transmission Plan, PRTP is Prior Regional Transmission Plan
Sources: ColumbiaGrid; NTTG; WestConnect

Transmission Topography and Investment (Cont'd)

Transmission Projects

- Several transmission projects in WECC are being developed to facilitate the importation of renewable energy generated in states other than California.
  - TransWest Express: The 730-mile project from Wyoming to Nevada, with an expected in-service date of 2023 and a budget of $3 billion, is intended to provide transmission capacity to connect Wyoming wind resources with loads in California.
  - Ten West Link Transmission Line: The 114-mile project would interconnect future renewable energy resources in both Arizona and California to the bulk transmission grid in what was designated in 2007 as a National Interest Electric Transmission Corridor, largely following the established corridor used by the existing Devers-Palo Verde 500 kV No. 1 line that connects APS transmission facilities in Arizona to Southern California Edison (SCE) in California.

Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From ISO	To ISO	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
Aeolus to Standpipe 230kV Line Rebuild	PacifiCorp	16.00	230	Wyoming	Wyoming	WECC	WECC	2020	Adv. Development	Rebuild	NA
BB2 Line (Clines Corners 345 kV - Norton - BA Line)	NA	45.00	345	New Mexico	New Mexico	WECC	WECC	2020	Adv. Development	New	NA
Boardman (Longhorn) to Hemingway Transmission (B2H)	BPA, Idaho Power Company, PacifiCorp	297.00	500	Oregon	Idaho	WECC	WECC	2026	Early Development	New	1,200,000
Boone-La Junta Line Rebuild	Black Hills Colorado.	45.00	115	Colorado	Colorado	WECC	WECC	2020	Construction Begun	Rebuild	20,900
Gateway South – Segment F (Aeolus-Mona 500-kV)	PacifiCorp	400.00	500	Wyoming	Utah	WECC	WECC	2024	Adv. Development	New	NA
Gateway West – Segment 10 (Midpoint - Cedar Hill)	Idaho Power Company, PacifiCorp	34.00	500	Idaho	Idaho	WECC	WECC	2020	Adv. Development	New	NA
Gateway West – Segment 1Wa - (Shirley Basin to Aeolus)	PacifiCorp	17.00	230	Wyoming	Wyoming	WECC	WECC	2020	Adv. Development	New	NA
Gateway West – Segment 2 and 3 - (Aeolus to Anticline)	PacifiCorp	140.00	500	Wyoming	Wyoming	WECC	WECC	2020	Adv. Development	New	NA
Gateway West – Segment 4 - (Anticline/Jim Bridger to Populus)	PacifiCorp	203.00	500	Wyoming	Idaho	WECC	WECC	2024	Adv. Development	New	NA
Gateway West – Segment 5 - (Populus to Borah)	PacifiCorp	55.00	500	Idaho	Idaho	WECC	WECC	2024	Adv. Development	New	NA
Gateway West – Segment 6 (Borah - Midpoint) Upgrade	Idaho Power Company	88.00	500	Idaho	Idaho	WECC	WECC	2024	Adv. Development	Upgrade	NA
Gateway West – Segment 7 (Populus - Cedar Hill)	PacifiCorp	118.00	500	Idaho	Idaho	WECC	WECC	2024	Adv. Development	New	NA
Gateway West – Segment 8 (Midpoint - Hemingway)	Idaho Power Company, PacifiCorp	126.00	500	Idaho	Idaho	WECC	WECC	2020	Adv. Development	New	408,000
Gateway West – Segment 9 (Cedar Hill to Hemingway)	Idaho Power Company, PacifiCorp	161.00	500	Idaho	Idaho	WECC	WECC	2024	Adv. Development	New	NA

Note: Includes projects 15 miles or greater and 115 kV and higher and projects in Early Development, Advanced Development, and Under Construction statuses (does not include Announced)

Sources: S&P Global Market Intelligence; NERC

Transmission Topography and Investment (Cont'd)

Transmission Projects (Cont'd)

Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From NERC	To NERC	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
Gila Bend to Ajo 230 kV Transmission	Ajo Improvement Company	47.00	230	Arizona	Arizona	WECC	WECC	NA	Adv. Development	New	NA
Grants Pass – Table Rock 230-kV (Sam's Valley)	PacifiCorp	18.00	230	Oregon	Oregon	WECC	WECC	2019	Early Development	New	NA
Great Basin Energy	NA	125.00	450	Nevada	Nevada	WECC	WECC	2020	Early Development	New	850,000
Harcuvar Transmission (Bouse to D-CR)	Central AZ Water Conservation District	65.00	230	Arizona	Arizona	WECC	WECC	2020	Early Development	New	NA
Harcuvar Transmission (Bouse – Harquahala)	Central AZ Water Conservation District	30.00	230	Arizona	Arizona	WECC	WECC	2020	Early Development	New	NA
Hooper Springs- Lower Valley Energy	Lower Valley Energy, Inc.	24.00	115	Idaho	Idaho	WECC	WECC	2020	Construction Begun	New	65,000
Hot Springs-Anaconda Transmission Line Rebuild 230 kV	BPA	120.00	230	Montana	Montana	WECC	WECC	2021	Early Development	Rebuild	NA
Kalispell - Kerr Transmission Line Rebuild	BPA	41.00	115	Montana	Montana	WECC	WECC	NA	Construction Begun	Rebuild	NA
Lamar – Front Range Transmission (Burlington – Lamar)	NA	107.00	345	Colorado	Colorado	WECC	WECC	2023	Construction Begun	New	53,000
Lucky Corridor Transmission Line	Lucky Corridor, LLC	62.00	345	New Mexico	New Mexico	WECC	WECC	2023	Early Development	New	131,100
Mora Transmission Line	Lucky Corridor, LLC	110.00	115	New Mexico	New Mexico	WECC	WECC	2020	Early Development	New	65,000
Palo Verde – Saguaro 500kV Transmission line	Arizona Electric Power Cooperative, Inc.	130.00	500	Arizona	Arizona	WECC	WECC	NA	Adv. Development	New	340,000
Southline Transmission (Afton to Apache)	Southline Transmission LLC	205.00	345	New Mexico	Arizona	WECC	WECC	2020	Adv. Development	New	325,000
Southline Transmission (NM Highway 9 to Interstate 10)	Southline Transmission LLC	30.00	345	New Mexico	New Mexico	WECC	WECC	2022	Adv. Development	New	NA
Southwest Intertie – Northern (SWIP-N)	NA	275.00	500	Idaho	Nevada	WECC	WECC	2021	Adv. Development	New	525,000
Vantage-Pomona Heights 230 kV Transmission Line	PacifiCorp	41.00	230	Washington	Washington	WECC	WECC	2020	Adv. Development	New	28,900

Sources: S&P Global Market Intelligence; NERC

Resilience Issues

Overview

- WECC covers a broad area, covering roughly half of the U.S. land mass. It includes all of the population centers in the Pacific Northwest, the Rocky Mountains, and the Desert Southwest, and it also includes a vast expanse of sparsely populated rural areas.
- WECC contains a broad range of geological and weather areas, including arid plateaus and plains in the Desert Southwest; forested mountains, including two major ranges, the American Sierra Nevada and Rocky Mountains; the vast coastal shoreline of the American Pacific Coast; and the rain forests of the Pacific Northwest.
- As a frame of reference for the potential economic impact of a resilience event, the 2018 annual GDP for the states in WECC's footprint (excluding California), was $8.5 trillion, or approximately 10% of the total GDP for the United States in 2018.*
- In WECC's comments to FERC in its grid resilience docket, it cites the following resilience risk in the region:

  "An acceleration of changes in the resource mix from more synchronous generation to more non-synchronous generation, like wind and solar photovoltaics, as the region has some of the most aggressive RPS standards in the U.S. The concern is that under future scenarios with high penetrations of non-synchronous generation, there may be insufficient primary frequency response to arrest a decline in frequency and to avoid load shedding."
- WECC also confirmed that two of the assertions from the U.S. DOE staff report were observed in the region:
  - Many coal-fired generating units that were used for baseload generation in the past are no longer operating in that role at this time. Research by the Western Interstate Energy Board (WIEB) found that baseload operation of the coal fleet in the West has decreased from 52% of coal unit-operating days in 2001 to 22% in 2016.
  - Bulk power system reliability is adequate today, but there has not yet been much analysis of how much primary frequency response will be needed as the composition of the grid changes, nor how best to complement primary frequency response from traditional sources.

Reported Electric Disturbance Events Affecting WECC (2017–Apr. 2019)

Cause	2017	2018	2019 YTD
Fuel Supply Deficiency	0	0	0
Severe Weather	7	5	4
Vandalism	16	16	6
Suspected Physical Attack	1	0	0
Actual Physical Attack	3	2	3
Suspicious Activity	1	1	1
Transmission Interruption	6	4	3
Generation Inadequacy	0	0	1
System Operations	1	4	4

Note: For multiple causes, classified under one only.
Sources: DOE OE-417; ScottMadden analysis

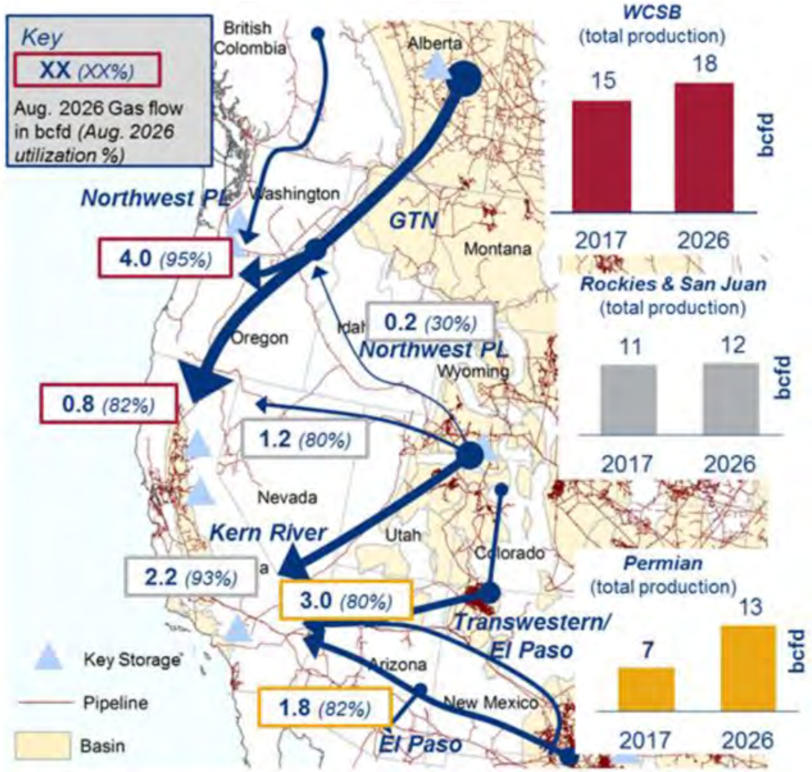
*Note: Figure applies to states of AZ, CO, ID, MT, NV, NM, OR, UT, WA, and WY (excl. CA)
Sources: NERC 2019 Summer Reliability Assessment; Bureau of Economic Analysis; NERC 2018 LTRA

Resilience Issues (Cont'd)

Fuel Security in the Western United States

- The Western Interconnection has access to diverse, abundant, and economic natural gas supply sources between the Western Canada, Permian, Rockies and San Juan basins. The combined reserves represent 350 tcf available at break evens of less than $4/MMBtu for dry gas and $50/barrel for associated gas. However, this wealth of resources is dependent on a limited number of long-haul pipelines to deliver natural gas from supply areas to large demand centers in the Pacific Northwest (PNW), California, and the Desert Southwest (DSW):
  - DSW markets (e.g., Phoenix) are essentially dependent on the El Paso and Transwestern pipelines.
  - PNW markets rely upon Northwest and GTN pipelines for their natural gas as well as gas storage.
  - Northern California markets are supplied by GTN and, to a lesser extent, Ruby pipelines as well as gas storage.
  - Southern California markets are reliant on El Paso, Transwestern, and Kern River pipelines as well as gas storage.
- This widespread reliance on long-haul pipelines results in reliability risk due to the potential for disruptions in delivery capability; a major gas disruption at a single point can have additional effects in several different markets.
- Most major interstate pipelines in the West are expected to be highly utilized (80%–95% on peak month basis, of which about half of the demand comes from power generation). Natural gas supply to the Desert Southwest will become increasingly supplied from the Permian basin, as San Juan production is expected to slowly decline over time. This switch will create a greater reliance on Permian and West Canadian gas for the WECC region, with potential reliability risks in DSW and Southern California as well as PNW.
- Gas burn is expected to increase significantly, driven by baseload coal and nuclear retirements as well as overall load growth in the region. While additional renewables capacity provides some mitigation, it will not be enough to offset the 11 GWs of retirements and will also introduce additional volatility and uncertainty into intra-day swings.
- Maintenance, and possibly expansion, of the gas system's infrastructure will likely be needed to meet reliability needs.
- The Western Interconnection has access to ample supply from several different supply basins, but its reliance on long-haul gas pipelines poses reliability risk due to the ability of a single disruption to impact multiple markets.

Western United States and Canadian Gas Pipes and Producing Basins



Source: Wood Mackenzie, Western Interconnection Gas-Electric Interface Study (Jun. 2018)

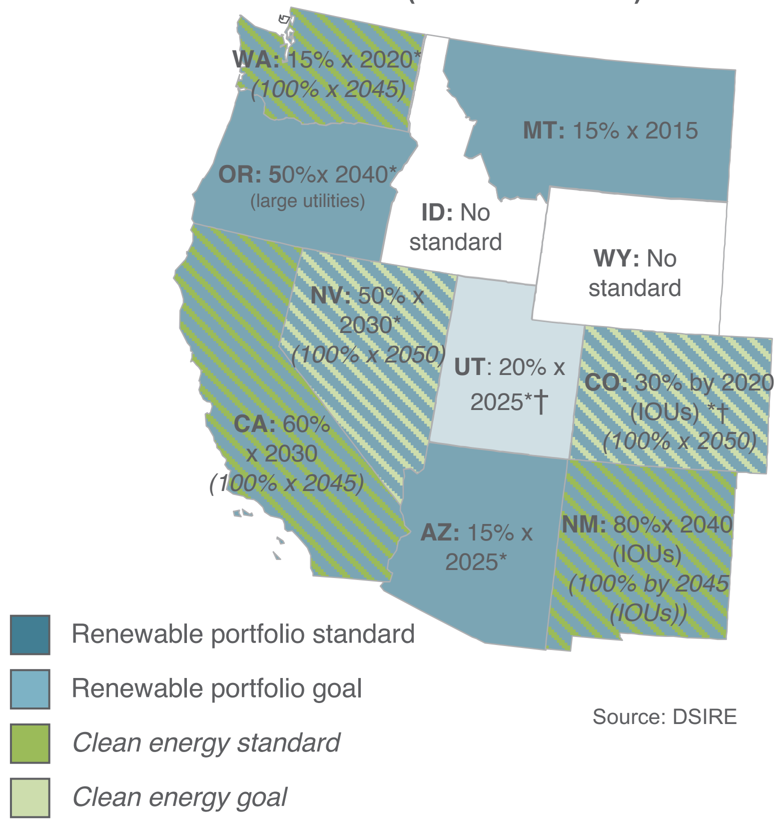
Resilience Issues (Cont'd)

Selected Major Bulk Power Events Affecting WECC	
Event	**Description**
Pacific Northwest Seismic Risk	• The potential for a Cascadian Subduction Zone (CSZ) event in the Pacific Northwest has been discussed and analyzed, and the resulting earthquake tsunami combination is expected to cause devastating damage across the coastline from northern California to southern British Columbia. • Per Oregon's Public Utility Commission, more than 50% of substations would be damaged beyond repair in the event of a magnitude 9.0 earthquake. • In addition, the vulnerability of the electric grid is highly interdependent with other critical infrastructure systems, including roads, water and sewage treatment, and natural gas pipelines. In the event of a major earthquake, damage to road networks could make it impossible to repair transmission and distribution lines, thereby preventing the restoration of all other electricity dependent lifeline services (water, sewage, telecommunications).
Pacific Northwest Hydro	• As climate change alters the seasonality of water runoffs in the Pacific Northwest, hydro electricity generation, as well as the operation and maintenance of hydroelectric dams, are expected to face challenges. • In addition to current electric power generation demand, there are also multiple competing uses for the water in the Pacific Northwest, including future (summer) electric power generation, flood control, biological opinion requirements resulting from the Endangered Species Act, as well as special river operations for recreation, irrigation, navigation, and the refilling of the reservoirs each year.
Droughts, Heat Waves, and Wildfires	• The 2018 summer season saw increased system stress due to higher than average temperatures and a continuing trend of a high number of wildfires—8,717 fires as of August 2018 compared to 9,000 for all of 2017. • The increased temperatures and wildfires are impacting most states and provinces in the Western Interconnection, but the largest incidents are located in California, Arizona, Utah, Idaho, Oregon, and British Columbia.
Gas-Power Interdependence	• Key findings from several recent studies conclude that the Western Interconnection is facing increasing volumetric and flexibility constraints, and disruptions in the natural gas system could potentially translate quickly to loss of load in the Desert Southwest and Southern California regions. • As more coal-fired generation capacity in the region is retired in coming years, the region will rely more heavily on natural gas-fired generation to balance the increasing amount of solar and wind on the system.
Cyber/Physical Security	• On April 16, 2013, a rifle attack on a PG&E substation in Metcalf, California, knocked out 17 transformers, increasing the risk of loss of electric service to large parts of Silicon Valley. While a widespread outage was avoided, the incident raised concerns about the vulnerability of the U.S. electric sector to more widespread attacks. The incident prompted utilities across the country to reevaluate and restructure their physical security programs, and it set in motion proceedings in Congress and at FERC which resulted in a new mandatory Physical Security Reliability Standard (CIP-014) for bulk power asset owners promulgated by NERC.

Sources: NERC; NWPP; Utility Dive; National Oceanic and Atmospheric Administration; Johns Hopkins and Swiss Re, Lights Out, The Risks of Climate and Natural Disaster Related Disruption to the Electric Grid (2017)

Renewables Integration

WECC State Renewable Portfolio Standards and Goals (as of June 2019)



* Extra credit for solar or customer-sited renewables

† Includes non-renewable alternative resources

Demand-Side Considerations

- Overall demand growth in the region is generally less than 1% annually, although metro areas across the West are experiencing higher growth than rural areas.
  - Some utilities report demand reduction because of behind-the-meter distributed generation and appliance standards and expect these trends to continue into the future. Most distributed energy resources (DERs) are solar, and the current capacity of rooftop solar for WECC is 8.7 GWs (6.6 GWs of which is in California).
  - Energy efficiency and controllable and dispatchable demand response programs in the region are minimal (about 3.5 GWs in the summer and 2.9 GWs in the winter) compared with peak load.
- WECC has a mix of states with some of the most aggressive clean energy goals and standards in the United States and states with no standards at all (see map at left).
  - California, Colorado, Nevada, New Mexico, and Washington all have 100% targets, reflecting broad-based support for clean energy in those states. Oregon's target is only 50%, but the political climate there closely resembles the states with 100% goals.
  - Idaho and Wyoming have no stated standards or targets, and Wyoming has been hostile to renewable energy development initiatives, introducing, but not passing a law in 2017 that would have required 95% of utility electricity to come from sources other than wind or solar (or essentially the opposite of a renewable portfolio standard or RPS).
- A few large utilities in the region have announced carbon reduction initiatives (see following slide).

Sources: NERC 2018 LTRA; DSIRE; SEPA; S&P Global Market Intelligence

Renewables Integration (Cont'd)

Listing of Utility Companies with Operations in WECC That Have Announced Emission Reductions or Renewable Energy Goals (as of October 2019)

Utility Name (States of Operation)	Goal Type	Target Dates	Description (Date Implemented)
Arizona Public Service Company (AZ)	Emission Reduction	2032	48% reduction in carbon intensity by 2032 from 2005 levels
Avista Utilities (ID, WA)	Emission Reduction	2027 2045	Carbon neutral electricity supply by the end of 2027 100% clean energy by 2045
El Paso Electric (NM, TX)	Emission Reduction	2025 2035	25% reduction in carbon footprint from 2015 levels by 2025 40% reduction in carbon footprint from 2015 levels by 2035
Holy Cross Energy (CO)	Emission Reduction	2030	70% reduction in GHG emissions from 2014 levels by 2030
Idaho Power Company (ID, OR)	Emission Reduction	2020 2045	Average CO_2 emissions intensity of energy sources from 2010 to 2020 is 15% to 20% lower than 2005 levels, 100% clean energy by 2045
Platte River Power Authority (CO)	Renewable Energy	2030	100% non-carbon energy mix by 2030
Portland General Electric (OR)	Emission Reduction	2030 2050	Eliminate coal from energy mix by 2050 80% reduction in GHG emissions by 2050
Poudre Valley Rural Electric Association (CO)	Emission Reduction	2030	80% carbon-free energy by 2030
Public Service Company of New Mexico (NM)	Emission Reduction	2032 2040	70% emissions free energy by 2032 100% emissions free energy by 2040
Puget Sound Energy (WA)	Emission Reduction	2040	50% reduction in carbon footprint by 2040
Salt River Project (AZ)	Emission Reduction	2035 2050	62% reduction in CO_2 emissions from 2005 levels by 2035 90% reduction in CO_2 emissions from 2005 levels by 2050
Xcel Energy (CO, MI, MN, NM, ND, SD, TX, WI)	Emission Reduction/ Carbon Reduction	2017 2030 2050	35% emissions reduction by 2017 (achieved) 80% below 2005 levels by 2030 and zero-carbon by 2050 (2015)

Source: SEPA

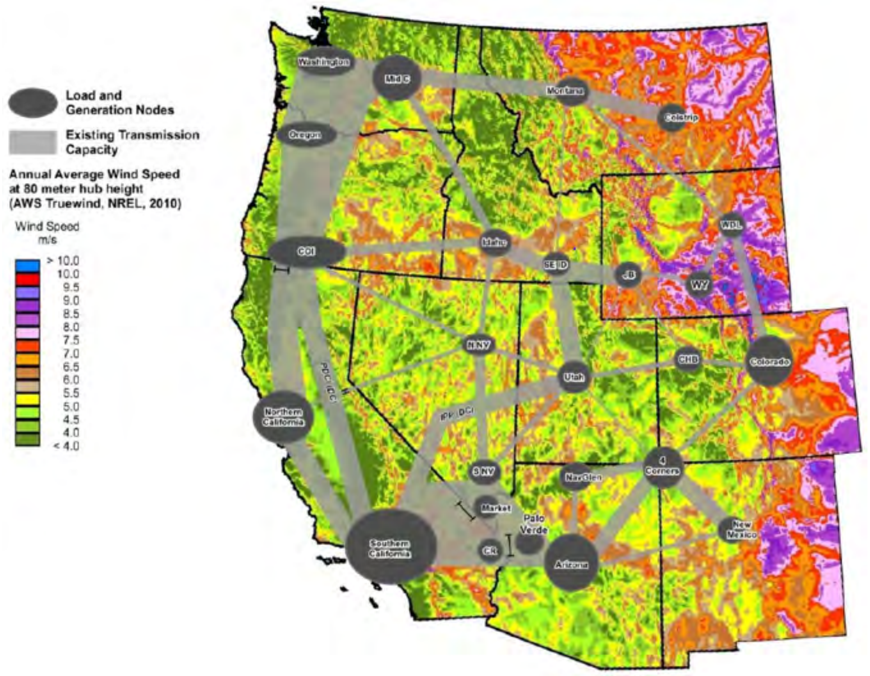
Source: SEPA

Renewables Integration (Cont'd)

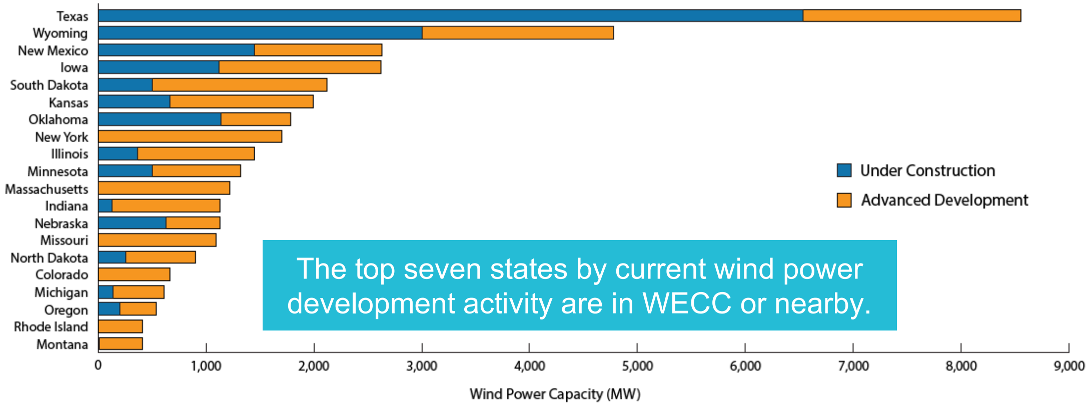
Demand-Side Considerations: Transmission Expansion to Meet California Demand

- Transmission expansion proposals and configurations
  - The highest-quality wind resources in the United States are located in the eastern area of the Western Interconnect.
  - Many planned and contemplated transmission projects in various stages propose to deliver those resources from across the West, although Wyoming and New Mexico are the most common sources given the prevalence of high-quality, low-cost, and temporally uncorrelated wind in those areas. In addition to resource delivery benefits, congestion relief, reliability enhancements, and future market efficiency would likely be realized upon the projects' completion.
- Northwest hydro: Conceptually, the idea of ramping down hydro to take advantage of low-cost excess solar is a potential economic solution. However, the Northwest hydro system has a springtime overgeneration issue (when it is a "seller") and has a series of complex flexibility limitations attributable to the physical layout of the dams and strict environmental constraints.
- Out-of-state resource and transmission combinations
  - There are several advanced transmission and resource project combinations that could provide California's utilities with realistic and actionable cost information to replace the conceptual, generic information currently used in planning.
  - California entities could use a request for information (RFI) as a tool to gather commercial-grade information from renewable developers, in partnership with existing and prospective transmission service providers. This would provide utilities and regulators with unique and detailed insights into what the procurement of out-of-state renewable resources and transmission might look like from an economic and technical perspective.
  - Grid expansion to remote resources has been in the planning stages for more than 10 years by entrepreneurial enterprises. Now, on the cusp of the next major RPS planning effort, may be a good time to allow this community to respond to California's developing need for a geographically broad and technologically diverse resource set.

Wind Resources within WECC and Existing Transmission



Top U.S. States by Wind Power Development



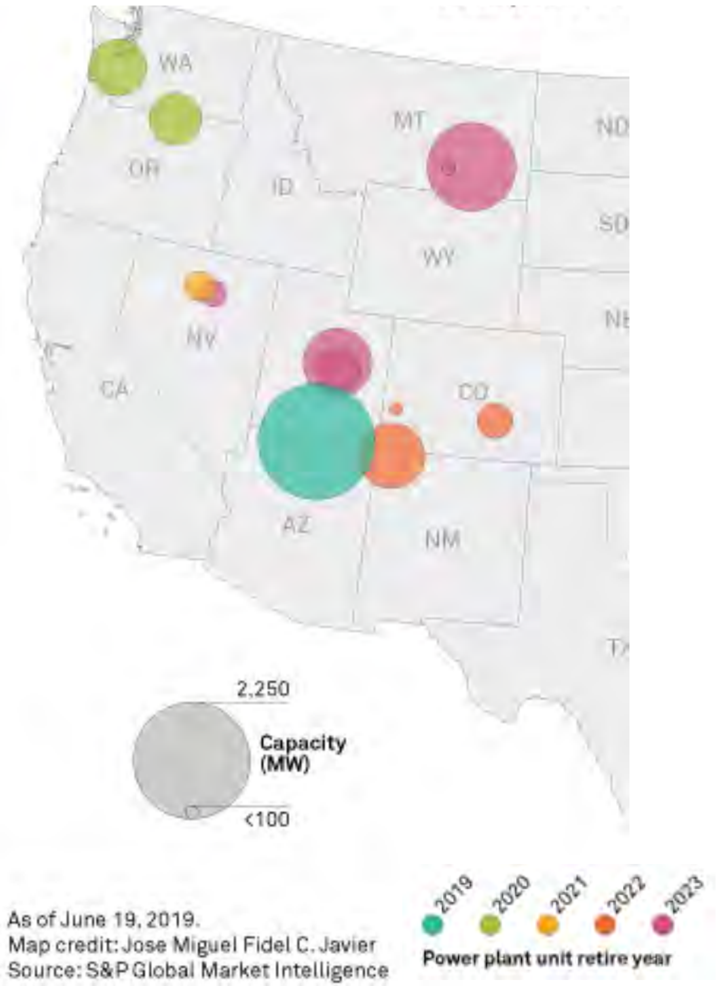
Sources: RETI 2.0 Report; AWEA Q1 2019 Market Report

Renewables Integration (Cont'd)

Supply-Side Considerations: Retirement of Large Baseload Facilities in the Western Interconnect

- Substantial coal-fired resources in WECC have been retired, and more will be retired soon.
  - More than 2,700 MWs in the Northwest are expected to be retired by 2025–28.
  - Approximately 2,400 MWs in the Navajo and Four Corners region has been retired or will be retired by 2019–29.
  - Up to 1,800 MWs could be retired in central Utah in 2025–30 and 800 MWs in Nevada by the end of 2019.
  - In aggregate, this represents at least 7,700 MWs of coal generation that will be retired in WECC over the next 10 years, and the actual number of MWs retired could be higher.
- Key findings from a recent resource adequacy study conducted to examine impacts of deep decarbonization in the Pacific Northwest conclude:
  - It is possible to maintain resource adequacy for a deeply decarbonized Northwest electricity grid, as long as sufficient firm capacity is available during periods of low wind, solar, and hydro production; natural gas generation is the most economic source of firm capacity today.
  - It would be extremely costly and impractical to replace all carbon-emitting firm generation capacity with solar, wind, and storage due to the very large quantities of these resources that would be required.
  - The Northwest is expected to need new capacity in the near term in order to maintain an acceptable level of resource adequacy after planned coal retirements.
  - Current planning practices risk underinvestment in the new capacity needed to ensure resource adequacy at acceptable levels.

Expected Coal Plant Retirements in WECC (2019–2023)



Sources: S&P Global Market Intelligence; RETI 2.0 Report; E3 Consulting, Resource Adequacy in the Pacific Northwest (Mar. 2019)

Renewables Integration (Cont'd)

Supply-Side Considerations: Retirement of Large Baseload Facilities in the Western Interconnect (Cont'd)

- Based on WECC's current planning data set, called the Anchor Data Set (ADS), 3,267 MWs of coal and gas-fired generation is expected to be retired in coming years, and 4,906 MWs of new capacity is planned to replace retiring capacity. Planned new capacity is comprised of four technologies:
  - Gas-fired internal combustion and combined cycle (310 MWs)
  - Onshore wind turbines (2,353 MWs)
  - Solar PV (2,143 MWs)
  - Battery storage (100 MWs)
- Opportunities for repurposing existing transmission at retired/retiring baseload facilities:
  - Due to the location of new renewable resources in locations close to coal capacity being retired, it may be possible to repurpose some of the transmission capacity that may be freed up by those retirements.
  - This type of "repurposing" is currently proposed in New Mexico, where several wind projects plan to utilize some of the transmission capacity made available by the retirement of units at Four Corners to deliver wind energy to California. This potential for latent capacity utilization could also open new markets for renewable energy development to replace retired coal resources.
  - Retirements throughout WECC may free up existing transmission capacity to provide access to renewable-rich locations, reducing the need for new transmission capacity.

WECC Plant Retirement Details

State	Anchor Data Set (ADS) Unit Name	Unit Type and Fuel	Expected Retirement Date	Capacity (MW)
Arizona	H Wilson Sundt ST1	ST-NatGas	8/31/2019	75
	H Wilson Sundt ST2	ST-NatGas	8/31/2019	75
			AZ Total	**150**
California	Harbor CC	CCWhole-NatGas-Industrial	12/31/2026	63
	Haynes 1	ST-NatGas	12/31/2023	222
	Haynes 2	ST-NatGas	12/31/2023	222
	Scattergood 2	ST-NatGas	12/31/2024	177
	El Centro 4	ST-NatGas	6/1/2023	70
	DivisnNavalCC-Total	CCWhole-NatGas-Aero	12/31/2019	55
	NorthIslandCC-Total	CCWhole-NatGas-Industrial	12/31/2019	43
			CA Total	**852**
Colorado	Comanche 1	ST-Coal	12/31/2022	325
	Comanche 2	ST-Coal	12/31/2025	335
				660
Nevada	NorthValmy1	ST-Coal	12/31/2025	254
	NorthValmy2	ST-Coal	12/31/2025	268
			NV Total	**522**
Wyoming	Dave_Johnston_1	ST-Coal	12/31/2027	106
	Dave_Johnston_2	ST-Coal	12/31/2027	106
	Dave_Johnston_3	ST-Coal	12/31/2027	220
	Dave_Johnston_4	ST-Coal	12/31/2027	330
	Naughton3Gas	ST-NatGas	12/31/2018	330
			WY Total	**1,092**
			WECC Total	**3,276**

Planned Additions in WECC

State	Technology	Capacity (MW)
Arizona	Internal Combustion	189
	Arizona Total	**189**
Colorado	SolarPV-Tracking	707
	WT-Onshore	969
	Colorado Total	**1,676**
New Mexico	WT-Onshore	215
	SolarPV-Tracking	50
	New Mexico Total	**265**
Nevada	Combined Cycle	121
	SolarPV-Tracking	1,001
	Battery Storage	100
	Nevada Total	**1,222**
Wyoming	WT-Onshore	570
	Wyoming Total	**570**
Montana	WT-Onshore	460
	SolarPV-Tracking	80
	Montana Total	**540**
Oregon	WT-Onshore	60
	SolarPV-Tracking	199
	Oregon Total	**259**
Utah	WT-Onshore	79
	SolarPV-Tracking	106
	Utah Total	**185**
WECC Total		4,906

Sources: WECC Anchor Data Set (ADS) assumptions

Renewables Integration (Cont’d)

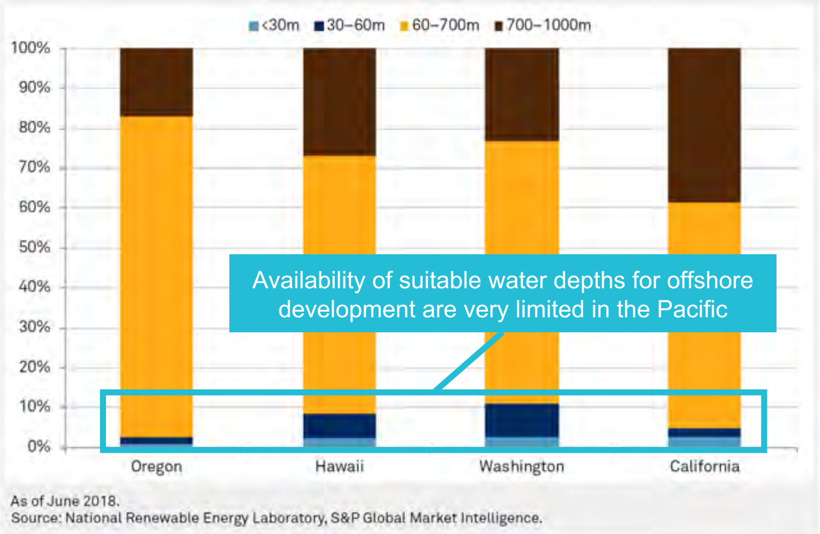
Supply-Side Considerations: Offshore Wind Is Not A Commercially Feasible Option with Today’s Technology

- Offshore wind feasibility is limited with current technology, so all new wind capacity in WECC will be terrestrial for the foreseeable future (see graphic at right).
  - Though offshore wind has the potential to address both clean energy goals and resilience needs in the eastern United States, floating solutions will be required in order for offshore wind to be feasible in the Pacific due to water depths.
  - Floating foundations for offshore wind are technologically unproven and uneconomical at this time, but that could change with technology breakthroughs.

Supply-Side Considerations: Potential Market Solutions

- EIM and other potential regional market expansion options: As discussed separately in the sections on CAISO and SPP, discussions are underway to consider the expansion of existing organized markets in the West. The California ISO has expanded the footprint of the Western Energy Imbalance Market to cover territory in California, Oregon, Washington, Idaho, Utah, Wyoming, Nevada, and Arizona. Additionally, on October 13, 2017, the Mountain West Transmission Group released a proposal to expand the SPP market to cover territories in Colorado, Wyoming, New Mexico, Arizona, Utah, Montana, Nebraska, and South Dakota.
- Non-firm transmission: Non-firm or conditional firm transmission are potential means to increase transmission utilization and deliver more renewable resources to California using the existing grid. However, some stakeholders have cautioned that, historically, financiers of renewable generation projects were disinclined to have a facility’s output curtailed in instances when non-firm or conditional firm transmission was unavailable.
- New power market products for overgeneration conditions: New power market products could be developed to take advantage of California’s renewable energy overgeneration in the day-ahead and longer-term markets. New products could also be used to encourage and facilitate imports into California to meet morning and evening ramping needs.

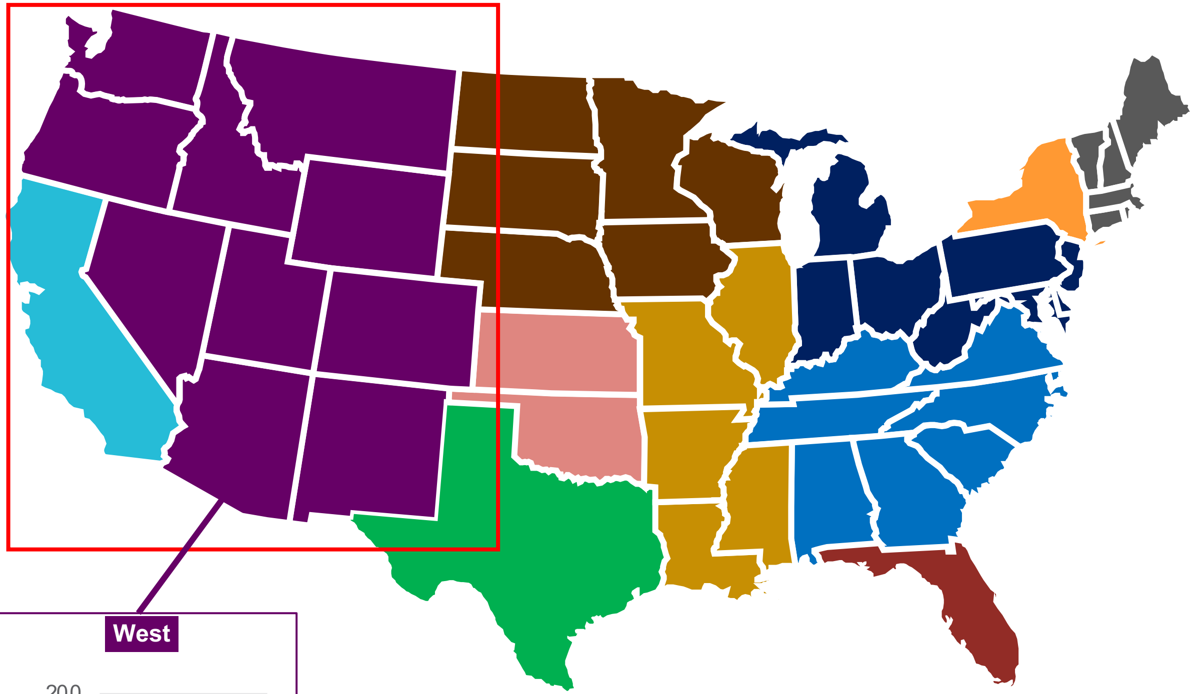
Water Depths in the Pacific Coast by State

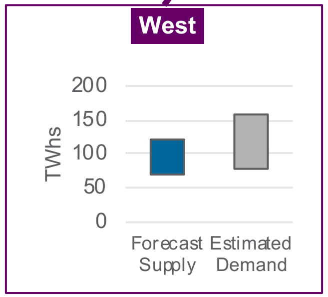


Sixty meters is the maximum depth to which grounded foundations can be built for offshore wind, and availability of suitable depths for development in the Pacific is extremely limited—and mostly located very close to land where land use conflicts with shipping and fishing and concerns about line of sight would be more likely

Sources: RETI 2.0 Report; AWEA Q1 2019 Market Report

Renewables Integration (Cont'd)



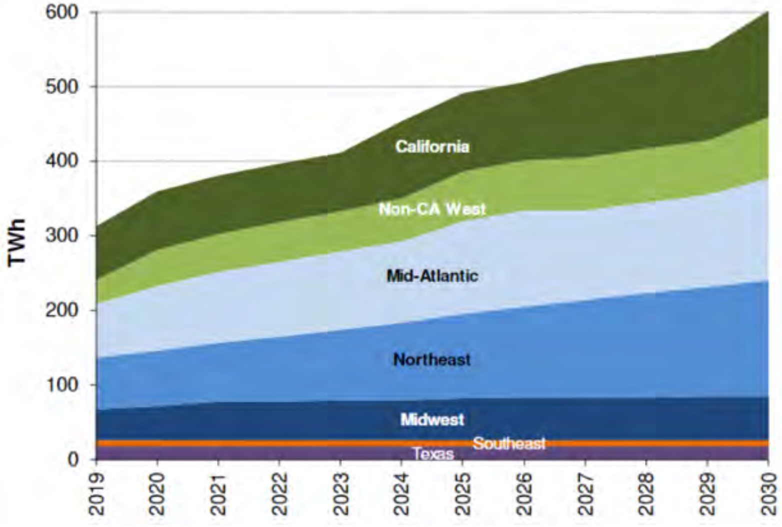


Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Integration Challenges – Renewables Supply and Demand

- As seen in the map at left and the non-California western U.S. section of the chart below, the WECC region has a projected demand for renewables that exceeds the forecast supply through 2030. As much of the forecast supply of renewables in the non-CAISO areas of WECC are being developed on the rationale of delivering power into CAISO, the mismatch between supply and demand may be further exacerbated.
- According to Lawrence Berkeley National Laboratory (LBNL), renewable portfolio standards policies have been a large driver in the bulk of renewable energy additions in the West, split evenly between California and other western states.
- A key question is how much and how quickly Washington's recently enacted clean energy standard will drive demand for new, non-hydro renewable resources.

Projected U.S. RPS Demand (Total Compliance Requirements) per DOE LBNL (2019–2030) (as of July 2019) (in TWh)



Source: LBNL

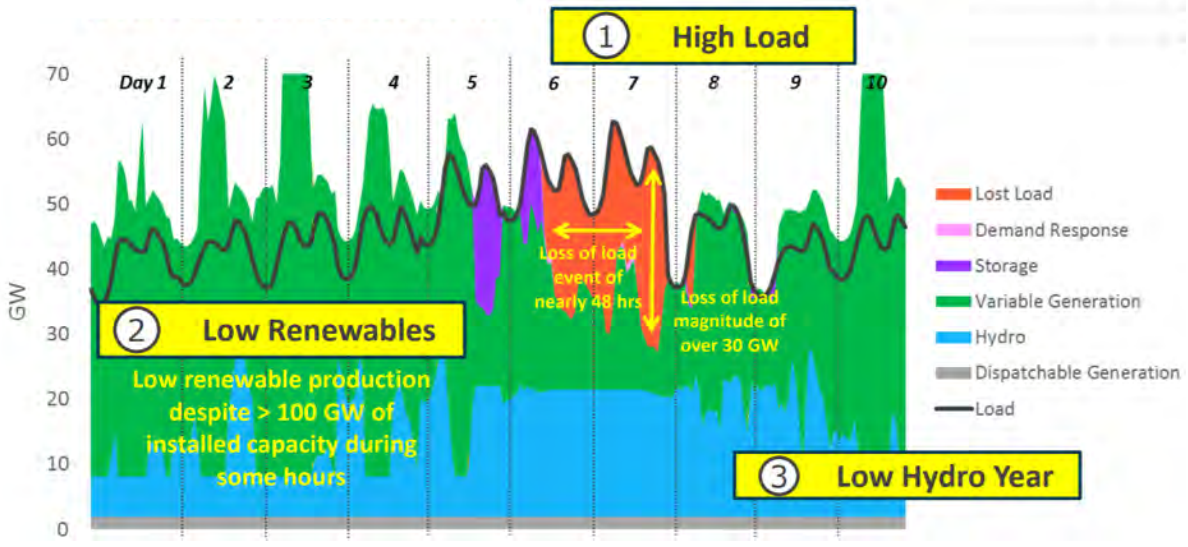
Sources: LBNL 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

Renewables Integration (Cont'd)

Integration Challenges – Renewables Supply and Demand (Cont'd)

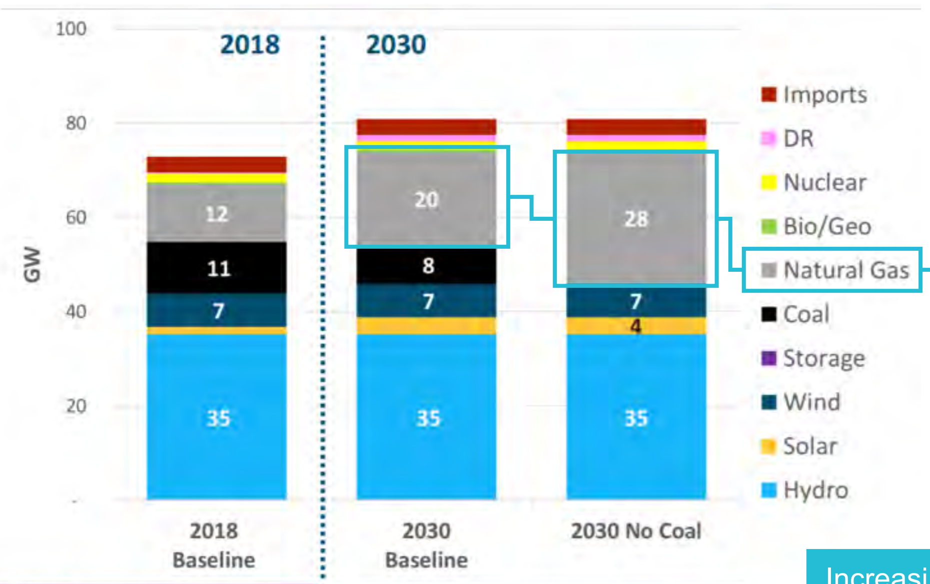
- Power systems that depend on wind and solar to provide a significant proportion of energy are more vulnerable to low-production events.
- Additional firm capacity will be required to maintain resource adequacy during periods of low wind, solar, and hydro generation production.

Integration Challenges with High Penetrations of Wind and Solar



The most difficult conditions for reliable electric service are multi-day high-load, low-renewable production events.

2030 Generation Portfolios for the Pacific Northwest



	2030 Baseline	2030 No Coal
GHG Free Generation (%)	61%	61%
Carbon (MMT CO2)	67	42
% GHG Reduction from 1990 Level	-12%*	31%

**Assumes 60% coal capacity factor*

Increasing reliance on natural gas, particularly if all coal is retired

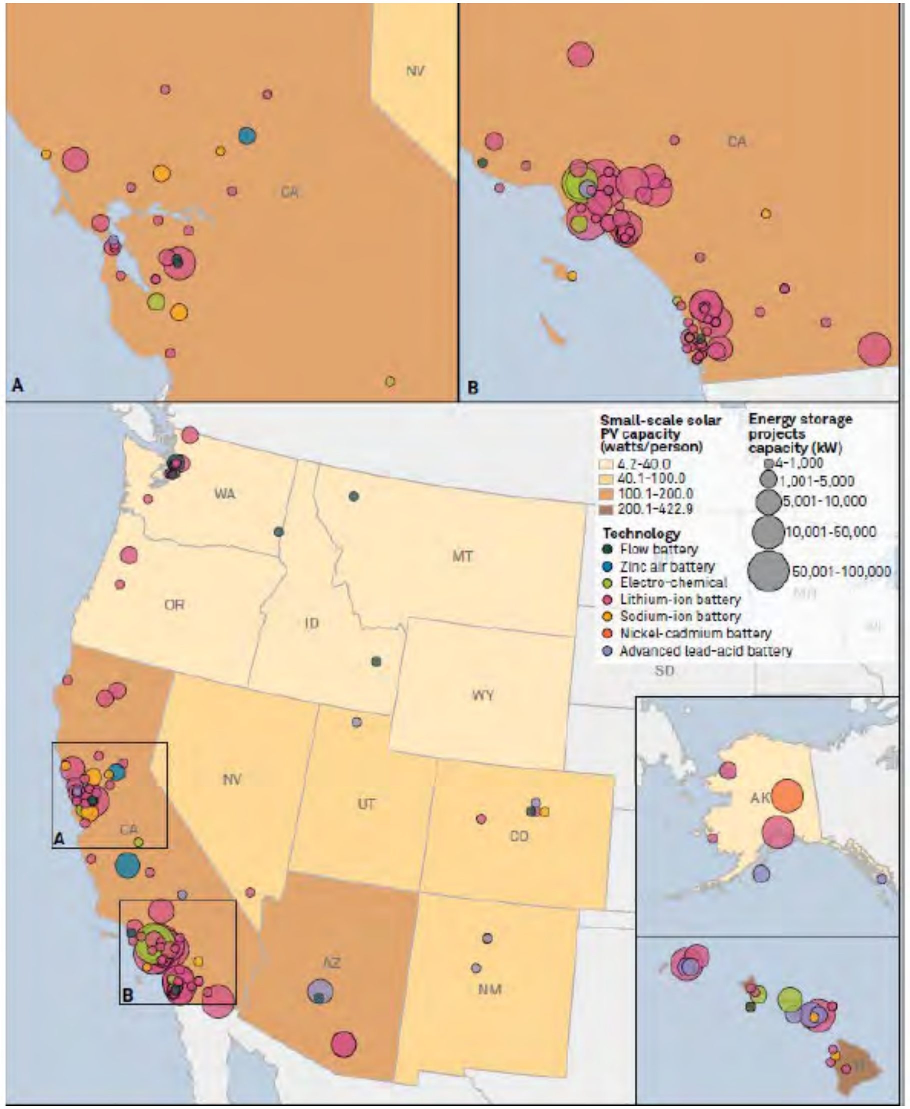
Sources: E3 Consulting, Resource Adequacy in the Pacific Northwest (Mar. 2019)

Renewables Integration (Cont’d)

Integration Challenges – Renewables Supply and Demand (Cont’d)

- Energy storage may assist with the integration of renewable energy in WECC, depending on where storage projects are located relative to renewables, and several stakeholders in the region have set aggressive energy storage targets.
  - Arizona: Energy storage is increasingly being paired with solar projects in the state as the cost of solar and storage components continues to decrease.
  - California: Legislation passed in 2018 requires IOUs in the state to procure 1,325 MWs of energy storage by 2020.
  - Colorado: Xcel Energy subsidiary Public Service Co. of Colorado announced a plan to add at least 1,100 MWs of wind, 700 MWs of solar, and 275 MWs of battery storage in support of its decarbonization efforts.
- Increasing penetration of DERs may create integration challenges, particularly in areas where penetration levels result in back feeding onto the sub-transmission and transmission voltage equipment, requiring transmission operators to develop new approaches. California is the obvious leader, as discussed separately in the CAISO section of the report, but other states in WECC are seeing significant DER developments:
  - Arizona: Arizona has the best available solar resources in the United States, and implementation of Renewable Energy Standard and Tariff (REST) legislation, which established Arizona’s RPS, has helped spur solar energy development to take advantage. Beginning in 2012, 30% of the requirement was required to come from renewable distributed generation. Half of this must come from residential applications.
  - Nevada: In addition 3,000 MWs of installed utility-scale solar and an additional 4,000 MWs in the queue, the state has 280 MWs of solar DERs.
  - Oregon: The state does not currently have much solar capacity, but legislation requires 8% of aggregate IOU capacity be derived from small-scale projects of 20 MWs or less by 2025, and legislation requires utilities to develop 20 MWs of solar projects by 2020.

Small-Scale Solar Capacity (Watts/Person) and Energy Storage Projects



Sources: S&P Global Market Intelligence; ScottMadden analysis

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
Western Electric Coordinating Council (excl. California)	▪ Key risks related to severe weather, wildfires, and seismic events ▪ Resource "transformation" from coal to gas, intermittent resources, though to a lesser degree than other regions in the eastern United States—coal has declined from 52% of generation in 2001 to 22% in 2016, and 7.7 additional GWs of coal is expected to retire across the region over the next 10 years ▪ Amount of available hydro generation capacity in the Pacific Northwest varies with rainfall and snow melt each year ▪ There are volumetric and flexibility constraints on the natural gas system, and a disruption in the gas system could potentially translate quickly to a loss of load in the Desert Southwest, particularly due to growing reliance on long-haul pipelines	▪ Planned additions of wind and solar across the region total almost 5 GWs, comprised mostly of utility-scale solar and onshore wind capacity ▪ Highest-quality wind resources are located along the eastern portion of the footprint, stretching from MT to NM, and the highest-quality solar resources are in the Desert Southwest, stretching from southern CA to NM	▪ Extremely large geographic footprint provides weather and resource diversity ▪ Heterogeneity of state policies related to renewables creates challenges for multi-state backbone projects, and four separate planning areas within WECC create challenges; CO, NM, NV, OR, and WA have targets of 50% or higher; ID and WY have no standard ▪ Developing long-distance, high-voltage transmission through remotely populated Western areas poses unique challenges: terrain, distance, and impacts on federal, native lands ▪ Distributed solar penetration is significant only in AZ today, but it is a growing resource in NV, UT, NM, and parts of CO ▪ Frequency response adequacy is still in the study and data collection phase, but some high-renewable penetration scenarios have suggested potential future needs	▪ Opportunities to move renewable power generated where resources and land are plentiful and cheap to load centers on the coast via increased intraregional connectivity, though the majority of projects identified in the most recent plans are local, driven by needs within each of the four planning regions in WECC ▪ Interregional coordination process among the four planning regions in WECC identified six projects across seams, with varying degrees of interregional cost sharing among planning regions based on location of the projects ▪ Potential to increase transfer capacity across seams with SPP and CAISO, particularly to accommodate growing demand for renewables within CA, as well as the need to reduce curtailments at times of excess generation within CA ▪ Projected demand for renewables is expected to exceed forecast supply, suggesting more opportunity for transmission

Sources

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- S&P Global Market Intelligence

Regional Discussion

CALIFORNIA ISO

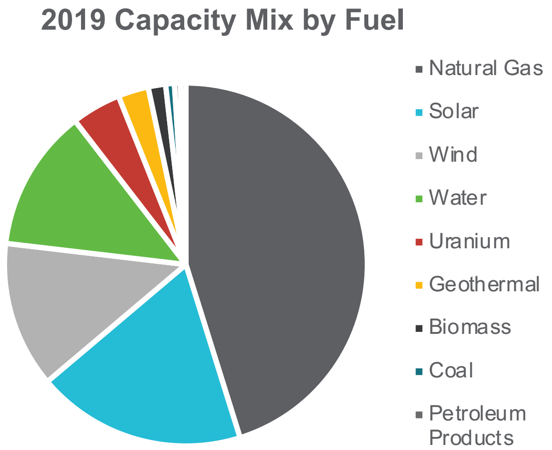
Contents

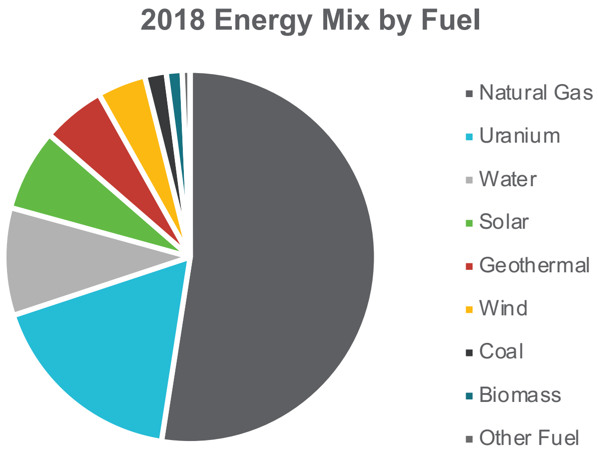
Overview

Description of Region

- California ISO (CAISO) is the balancing authority for the majority of the state of California, and it serves as the only ISO in the Western Interconnect.
- CAISO manages the majority of the grid in the state of California that encompasses about 26,000 miles of transmission lines over more than 155,000 square miles, serving 30 million people.
- Reserve margins for the region are expected to be more than 19% in 2020 and 22% in 2022 (compared with a 15% target margin level).

Key Regional Statistics	
States Covered	California
Square Miles Covered	~155,000
No. of Utilities	6 investor-owned utilities, 18 retail electric service providers, 20 CCAs, 4 cooperatives
No. of Customers/Pop. Served	39.8 M population
Installed Capacity	66,736 MWs
Transmission Line Miles	27,000 miles
Peak Hour Demand (2018)	186,040 MWs summer (179,759 MWs winter)
Net Energy for Load	286,000 GWhs
Forecast Growth (Annual)	-0.54%-1.22% peak load growth 0.99%-1.59% demand (usage) growth





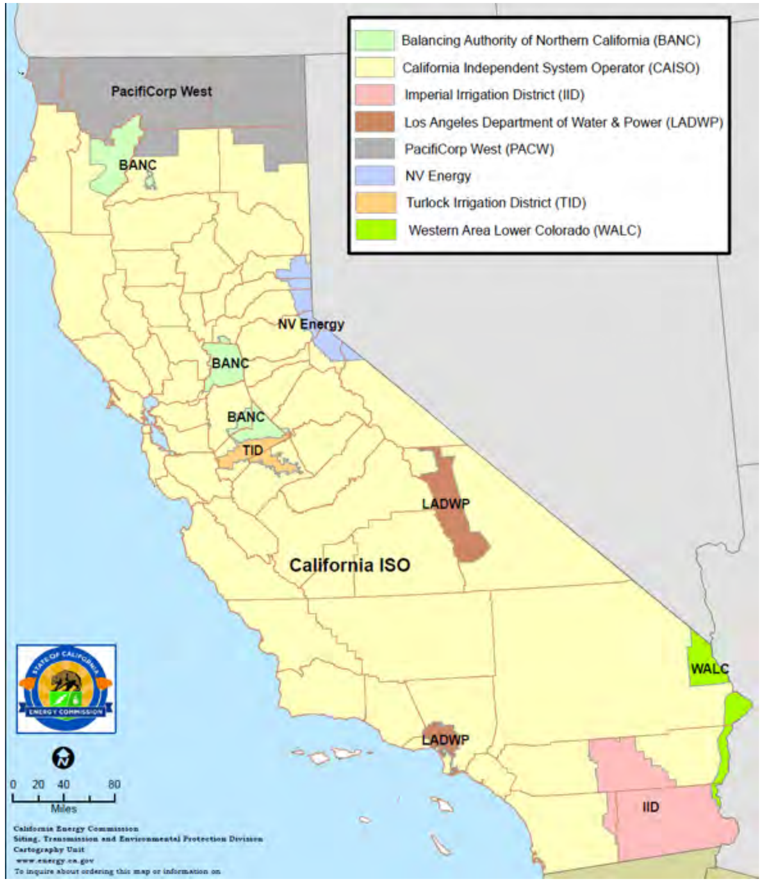
Sources: NERC 2018 LTRA; 2018 CED
Notes: Not necessarily coincident; net internal demand is net of demand response; California is the only state in the Western Interconnection that has a wide-area Planning Reserve Margin requirement, currently 15%.

Overview (Cont'd)

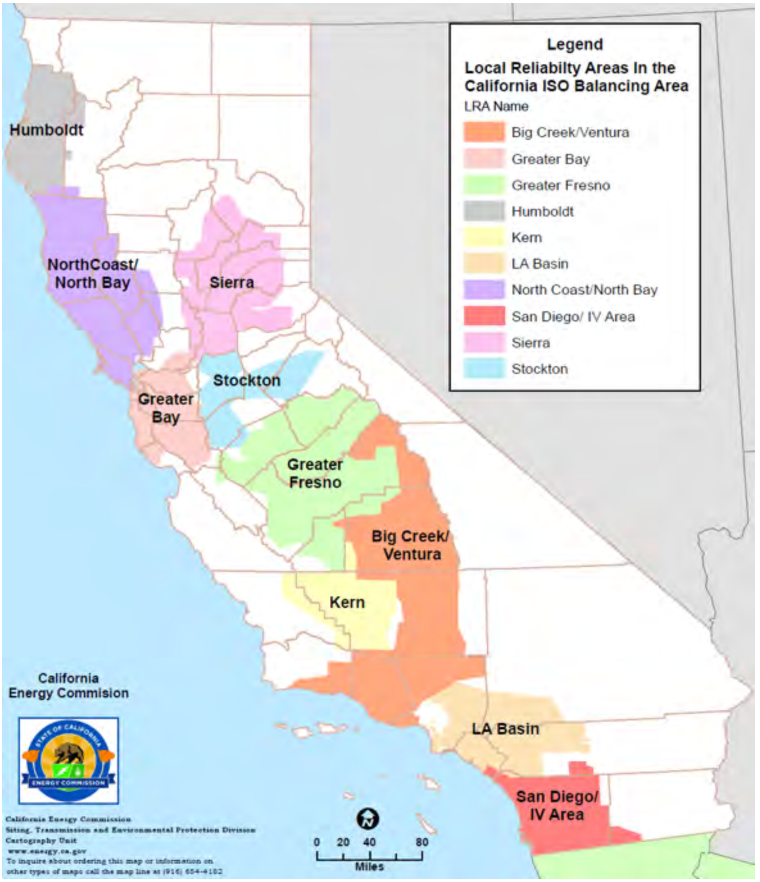
Balancing Authorities (BAs) and Local Reliability Areas

- CAISO serves as the balancing authority for the majority of the contiguous area of the state of California, with a few exceptions:
  - Balancing Authority of Northern California (BANC)
  - Imperial Irrigation District (IID)
  - Los Angeles Department of Water & Power (LADWP)
  - PacifiCorp West (PACW)
  - NV Energy (Nevada Power)
  - Turlock Irrigation District (TID)
  - Western Area Lower Colorado (WALC)
- CAISO is comprised of multiple local reliability areas within CAISO's balancing area.

Balancing Authorities in California



Local Reliability Areas in CAISO



Source: California Energy Commission (CEC)

Overview (Cont'd)

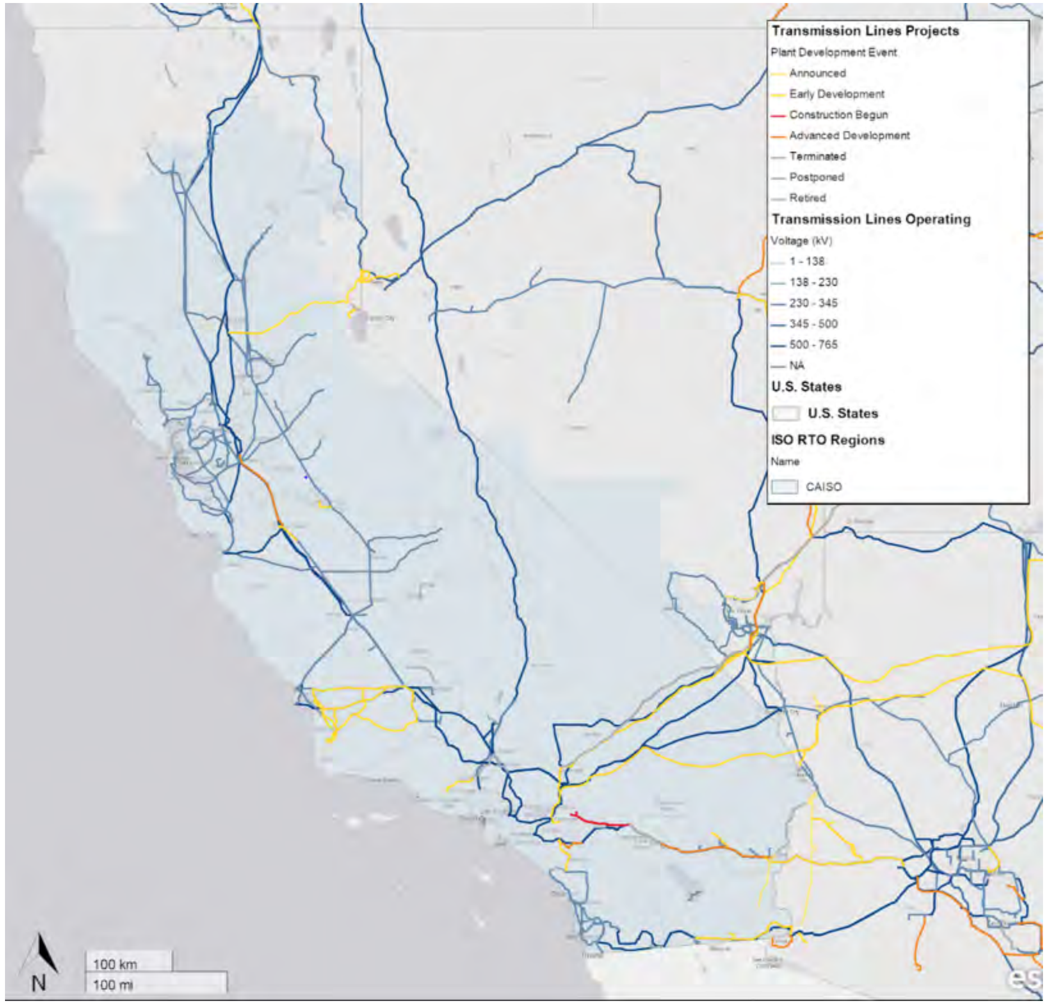
Reliability Assessment Study Areas

- Reliability assessments are performed at the bulk system (north and south), as well as local study areas on the CAISO-controlled grid:
  - Northern California (bulk) system – 500 kV facilities and selected 230 kV facilities in the PG&E system
  - Southern California (bulk) system – 500 kV facilities in the SCE and SDG&E areas and the 230 kV facilities that interconnect the two areas
  - Pacific Gas and Electric (PG&E) Local Areas
    - Humboldt area
    - North Coast and North Bay areas
    - North Valley area
    - Central Valley area
    - Greater Bay area
    - Greater Fresno area
    - Kern Area
    - Central Coast and Los Padres areas
  - Southern California Edison (SCE) local areas:
    - Tehachapi and Big Creek Corridor
    - North of Lugo area
    - East of Lugo area
    - Eastern area
    - Metro area
  - San Diego Gas & Electric (SDG&E) main transmission/subtransmission
  - Valley Electric Association (VEA) area*

*Note: GridLiance West LLC (GLW) owns 230kV facilities in VEA's service territory. VEA operates and maintains GLW's 230kV facilities.
Source: CEC IEPR

Overview (Cont'd)

Operating and Planned Transmission Lines by Status and Voltage



- There is significant internal transfer capability within CAISO, which allows for transfers within the system. In addition to the other BAs located in California listed earlier, CAISO is also interconnected with BAs and control areas outside of California, including Arizona Public Service (APS), Comision Federal de Electricidad (CFE), Salt River Project (SRP), Sierra Pacific Power, and Western Area Power Administrator (WAPA).
- According to NERC, approximately 190 miles of new transmission lines are either in the planning stages or under construction as of late 2018 (see table below). The majority of the 22 projects were primarily driven by reliability; two projects were driven by variable generation integration; and two projects were driven by economics and congestion.

Proposed Transmission Projects (Line Length in Circuit Miles) in CAISO (as of Dec. 2018)

Operating Voltage Class (kV)	Conceptual	Planned	Under Construction
100–120	30	25	-
121–150	-	-	-
200–299	65	17.3	48
400–599	-	4.6	-
Grand Total	95	46.9	48

Source: NERC 2018 Electricity Supply & Demand

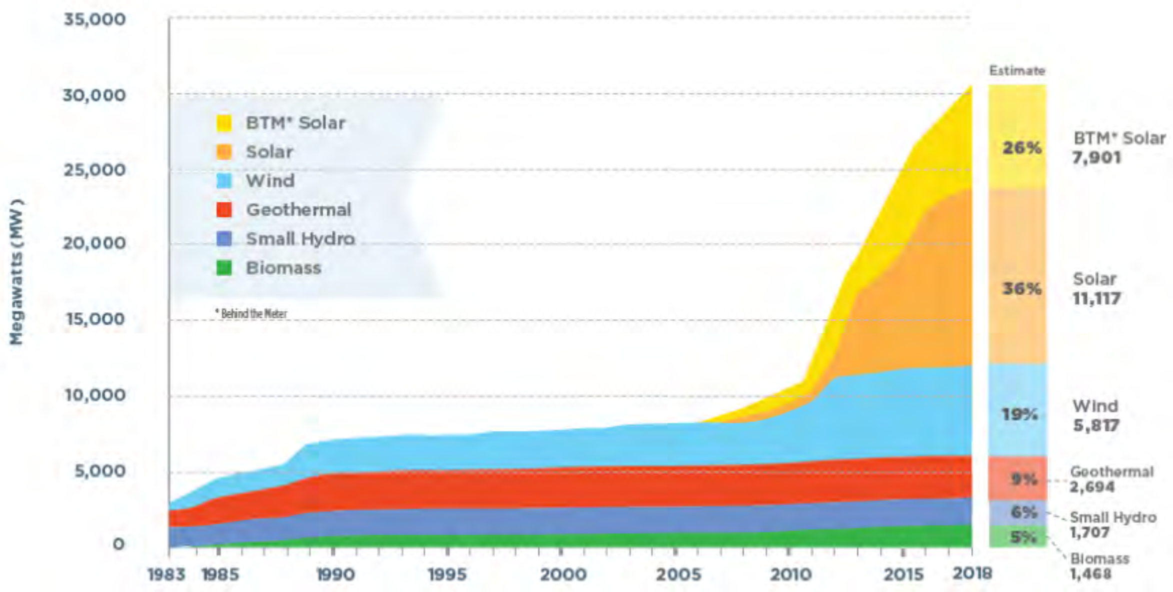
Sources: NERC 2018 LTRA; NERC ES&D; CAISO

Overview (Cont'd)

Unique Market Characteristics

- CAISO is a region that has already experienced a significant build-out of variable renewable energy capacity, including utility-scale capacity, as well as behind-the-meter solar capacity.
- Renewable generation projects outside of California have contracted with California's load serving entities (LSEs) to provide clean power to meet in-state demand, and out-of-state renewable capacity represents approximately 25% of the total renewable capacity reported by California today (as qualified to meet renewable portfolio standard's requirements).
- The retail power market in California is also in the midst of a major transition, as a significant portion of the load served today by the three large investor-owned utilities (IOUs) in California are in the process of migrating to alternative providers called Community Choice Aggregators (CCAs). The implications of this transition are significant:
  - In its evaluation of integrated resource plan (IRP) filings of IOUs and CCAs, the latter filing for the first time in 2018, the California Public Utility Company (CPUC) found that the majority of new resource build-out is being driven by CCA load growth. While the IOUs proposed to invest in approximately 1,000 MWs of new resources by 2030, CCA proposed more than 10,000 MWs.
  - Of that total planned resource investment, more than 60% is solar photovoltaic (PV). Another 10% is expected to come from battery storage, with the remainder comprised of biogas, biomass, geothermal, and wind.
  - CPUC expressed concerns about how plans and priorities of the different parties will be balanced to maintain stability in the future (see quote at right).

Annual Cumulative Installed Renewable Capacity (Incl. Behind-the-Meter Solar)



Source:

"Overall, the CCAs have shown, in their individual IRPs collectively, a preference for solar and wind resources, as well as four-hour batteries, supplemented by imported hydroelectric power. However, to balance the system between now and 2030, the resource balance will need to include a mix of existing and new resources, a mix of baseload and intermittent resources, and a mix of renewable, storage, and conventional fossil-fueled resources. In analyzing the IRPs of all of the LSEs, there is inconsistent, and in some cases, nonexistent, recognition of these realities." (CPUC, Decision 19-04-040, May 1, 2019)

Sources: CEC IEPR; CPUC, Proceeding R. 16-02-007, Decision 19-04-040

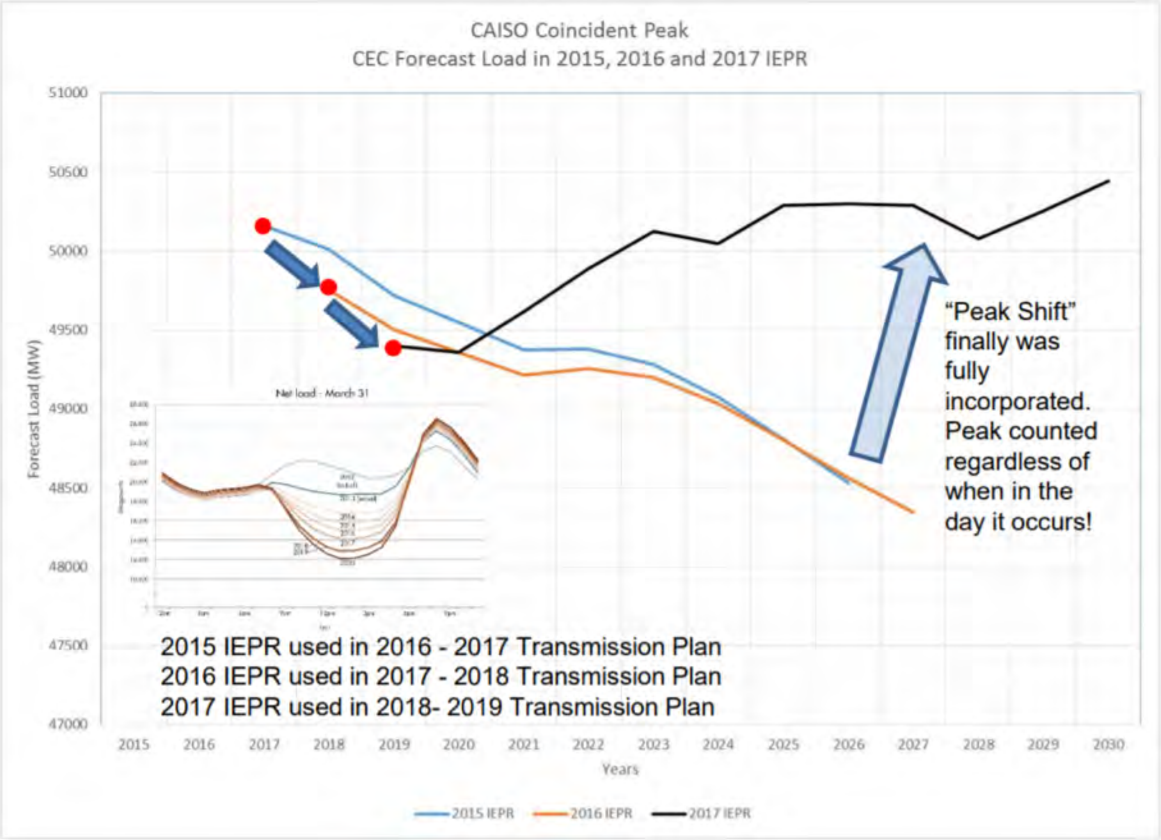
Transmission Topography and Investment

Congestion Impacts on System Prices

- Locational price differences due to congestion in both the day-ahead and 15-minute markets increased in 2018, particularly on constraints associated with major transmission limits separating northern and southern California (Path 26) in the third quarter. Key congestion trends during the year include the following:
  - For the year, congestion increased day-ahead prices in the SCE area by $1.87/MWh and in the SDG&E area by about $4.19/MWh. Congestion decreased day-ahead prices in the PG&E area by $2.73/MWh.
  - In the 15-minute market, patterns of congestion were similar to the day-ahead market. The primary constraints were associated with Path 26, the Serrano 500/230 kV transformer, and the Round Mountain-Table Mountain nomogram. These constraints increased prices in southern California, in the Western Energy Imbalance Market areas with significant transmission capacity into southern California, and decreased prices elsewhere.
  - In the fourth quarter of 2018, significant congestion on the Tracy-Los Banos outage nomogram increased prices in northern California and EIM areas north of the constraint and decreased prices south of the constraint. Over the course of the fourth quarter, this south-to-north congestion offset much of the impact of continued congestion on Path 26 and other constraints, so the overall net average impact of congestion on prices was relatively low for the fourth quarter.
  - The frequency and impact of congestion in the day-ahead market on most major interties was lower in 2018 compared to 2017. This was primarily driven by lower congestion on interties connecting the independent system operator (ISO) to the Pacific Northwest (Malin and NOB).

Shifting Peak Demand from Mid-day to Late Afternoon

- Hourly load shapes were incorporated in the planning process beginning in 2017 (for 2018–2028 timeframe), and they clearly indicated the shifting shape of the hourly demand curve in the region.



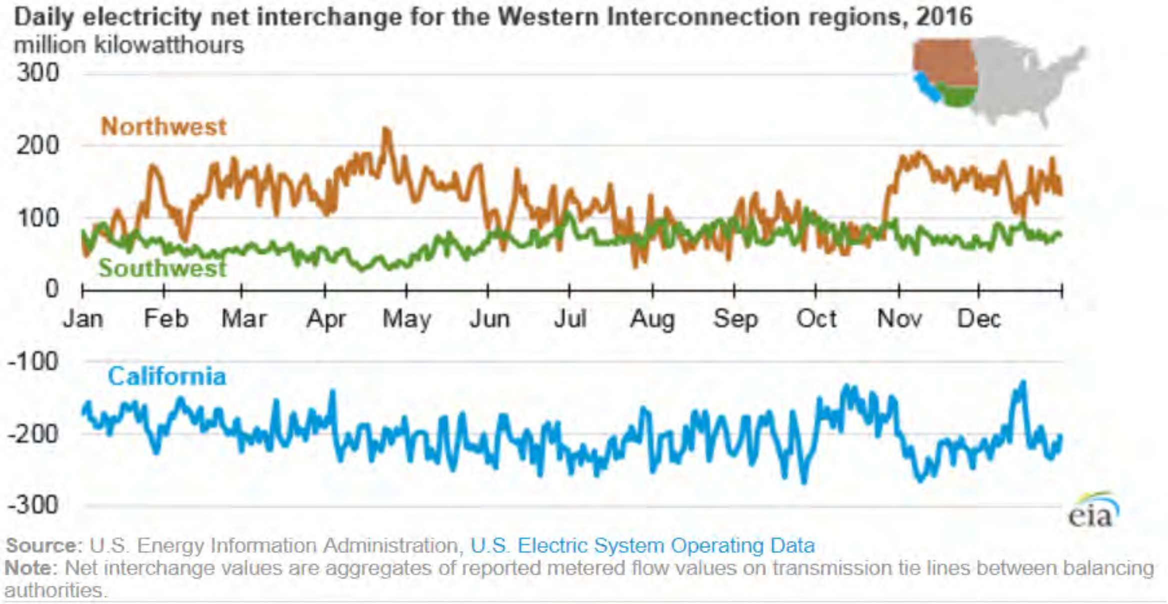
Source:

Sources: 2018 Market Performance Report; CEC IEPR

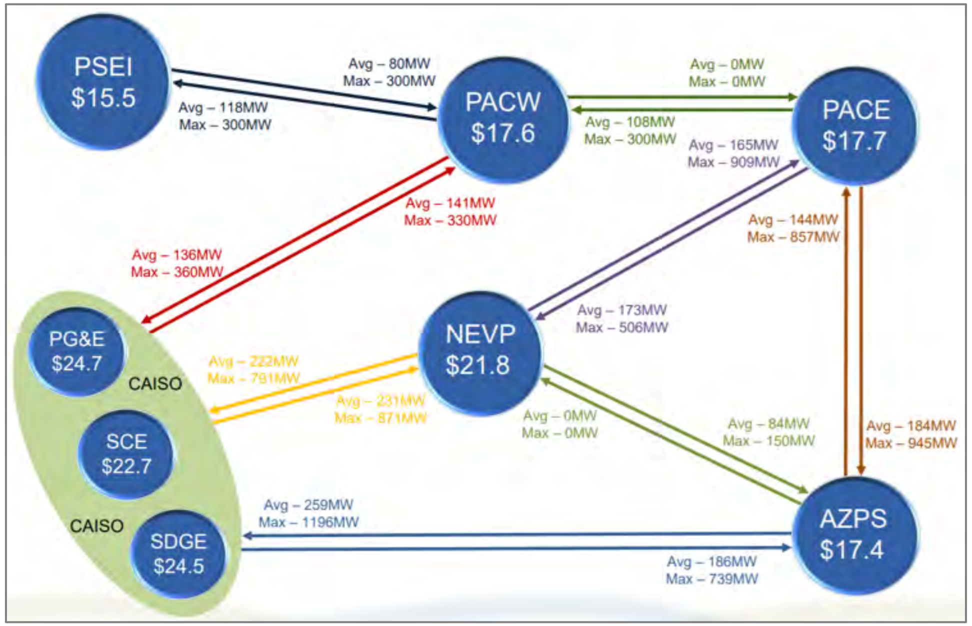
Transmission Topography and Investment (Cont'd)

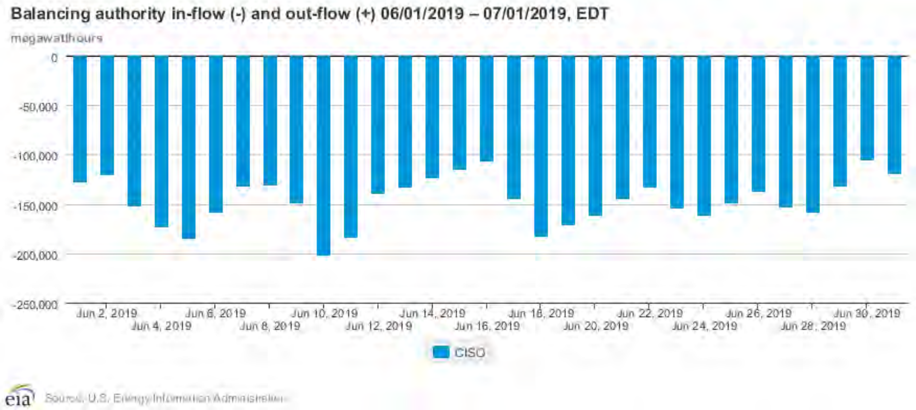
Imports and Exports Play a Large Role in the Region

- In 2016, CAISO imported a net daily average of 201 million kWh throughout the year from other western regions, or about 26% of its average daily demand. Those imports were supplied by the other two regions that make up the Western Interconnect.
  - The Northwest region supplied a daily average of 122 million kWh (61%).
  - The Southwest region supplied the bulk of the remainder 68 million kWh per day on average (34%).
- Year-to-date 2019, net interchange is down slightly from 2016 levels (bottom right), but it still represents a substantial portion of how the region serves its load.



Energy Transfers Among Regions in the WECC (Q1, 2017)





Sources: 2018 Market Performance Report; CEC IEPR

Transmission Topography and Investment (Cont’d)

FERC-Jurisdictional Investment Base

- FERC policy has been to permit a utility to establish transmission rates using a formula-based approach that updates rates annually, and approximately 100 utilities nationwide currently employ formula rates for transmission. Among companies in CAISO, SCE and SDG&E currently employ formula-based rates. SDG&E has been operating under a formula-based framework since 2007, and SCE transitioned from a stated rate to a formula-based framework in 2012. PG&E has historically operated under a traditional rate case framework, but the company proposed shifting to a formula-based approach in October 2018. The two independent transcos, DATC Path 15 and Trans Bay Cable, operate under traditional rate case frameworks, with new rate cases typically filed at FERC every three years.
- California utilities calculate both wholesale and retail base revenue requirements; the wholesale base revenue requirement values are presented at the right. These revenue requirements are generally recovered through CAISO’s transmission access charge (TAC). CAISO’s current TAC structure is a two-part rate charged to each MWh of internal load and exports. Revenue requirements associated with facilities rated 200 kV and above are recovered through a system-wide “postage stamp” rate, known as the high voltage or “regional” rate, whereas revenue requirements for facilities rated below 200 kV are recovered via utility-specific rates charged to load within the utility’s service territory, known as the low-voltage or “local” rate. The regional TAC recovers the revenue requirement for all participating transmission owners, which CAISO then distributes to each individual transmission owner based on its FERC-approved revenue requirement.
- The tables at the right provide a summary of the operating subsidiaries of each holding company in CAISO, including trends in rate base over the past nine years and authorized ROE incentives as applicable.

Current California ISO Transmission Rate Base Summary

Filing Entity	2018 Trans. Rate Base ($000)	2019 Trans. Rate Base ($000)	2018-19 Rate Base Change (%)	Base ROE (%)	Portion of Rate Base Subject to Incentive ROE ($000)	Portion of Rate Base Subject to Incentive ROE (%)	Incentive ROE (%)
Southern California Edison	5,451,343	5,624,393	3.17	10.90*	150,232	2.67	11.55*
					687,752	12.23	11.90*
					2,728,701	48.51	12.05*
Pacific Gas and Electric	6,935,253	6.927,768	-0.11	12.50*	None	NA	NA
San Diego Gas & Electric	3,244,395	3,685,149	12.97	11.20*	None	NA	NA
DATC Path 15	104,850	104,850	0	13.5	None	NA	NA
Trans Bay Cable	476,383	476,383	0	NA	None	NA	NA

Notes: As of Jan. 10, 2019. NA = not available or not applicable. *Inclusive of 50 basis point adder for membership in CAISO
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Transmission Rate Base Values for California ISO Utilities ($000)

Filing Entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR 2011-19 (%)
Southern California Edison	2,064,394	2,569,533	3,256,238	4,076,161	4,679,376	5,171,547	5,483,030	5,451,343	5,624,393	13.35
Pacific Gas and Electric	2,717,253	3,045,904	3,967,792	3,765,968	4,086,597	5,120,000	6,712,509	6,935,253	6,927,769	12.41
San Diego Gas & Electric	1,001,092	1,085,868	1,185,324	1,222,194	2,820,111	2,895,781	3,207,000	3,244,395	3,665,149	17.61

Notes: As of Jan. 10, 2019. CAGR = compound annual growth rate
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Transmission Topography and Investment (Cont'd)

Transmission Projects

- Several transmission projects in CAISO are being developed to facilitate the importation of renewable energy generated in states other than California.
  - TransWest Express: The 730-mile project from Wyoming to Nevada, with an expected in-service date of 2023 and a budget of $3 billion, is intended to provide transmission capacity to connect Wyoming wind resources with loads in California.
  - Ten West Link Transmission Line: The 114-mile project would interconnect future renewable energy resources in both Arizona and California to the bulk transmission grid in what was designated in 2007 as a National Interest Electric Transmission Corridor, largely following the established corridor used by the existing Devers-Palo Verde 500-kV No. 1 line that connects APS transmission facilities in Arizona to Southern California Edison (SCE) in California.

Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From ISO	To ISO	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
Apex-Crystal Transmission Line	Southern California Public Power Authority	11.00	525	Nevada	Nevada	CAISO	CAISO	2022	Early Development	New	65,000
Bighorn-Eldorado	NV Energy, Inc.	24.00	500	Nevada	Nevada	CAISO	CAISO	2026	Early Development	New	55,000
Blythe to Goldmine Tap Line Upgrade	Western Area Power Administration	42.00	230	California	California	CAISO	CAISO	NA	Announced	Rebuild	53,800
Bouse to Kofa Upgrade	Western Area Power Administration	76.00	230	Arizona	Arizona	CAISO	NA	2024	Announced	Upgrade	31,100
Centennial II (Harry Allen – Northwest 500 kV Line)	NV Energy, Inc.	30.00	500	Nevada	Nevada	CAISO	CAISO	2027	Announced	New	NA
Desert Southwest Transmission (Keim Station to Devers Stn.)	Imperial Irrigation District	118.00	500	California	California	CAISO	CAISO	NA	Adv. Development	New	350,000
Devers – El Casco (West of Devers Upgrade)	Southern California Edison Company	30.00	220	California	California	CAISO	CAISO	2021	Constr. Begun	Rebuild	NA
Devers – San Bernardino (West of Devers Upgrade)	Southern California Edison Company	43.00	220	California	California	CAISO	CAISO	2021	Constr. Begun	Rebuild	NA
Devers – Vista No. 1 and No. 2 (West of Devers Upgrade)	Southern California Edison Company	45.00	220	California	California	CAISO	CAISO	2021	Constr. Begun	Rebuild	NA
Eagle Mountain Transmission Line	Eagle Crest Energy Company	16.00	500	California	California	CAISO	CAISO	2020	Early Development	New	NA
El Casco – San Bernardino (West of Devers Upgrade)	Southern California Edison Company	14.00	220	California	California	CAISO	CAISO	2021	Constr. Begun	Rebuild	NA
Etiwanda-San Bernardino (West of Devers Upgrade)	Southern California Edison Company	3.50	220	California	California	CAISO	CAISO	2021	Constr. Begun	Rebuild	NA
Great Basin Energy	Genova Energy Link, Llc, Lk Energy LLC, Rooney Engineering, Inc.	125.00	450	Nevada	California	NA	CAISO	2020	Early Development	New	850,000
Griffith to North Havasu Transmission Line	Tucson Electric Power Company	40.00	230	Arizona	Arizona	CAISO	CAISO	NA	Early Development	New	106,000
Harcuvar Transmission (Bouse to D-CR)	Central Arizona Water Conservation District	65.00	230	Arizona	Arizona	CAISO	NA	2020	Early Development	New	NA

Sources: S&P Global Market Intelligence; NERC

Transmission Topography and Investment (Cont'd)

Transmission Projects (Cont'd)

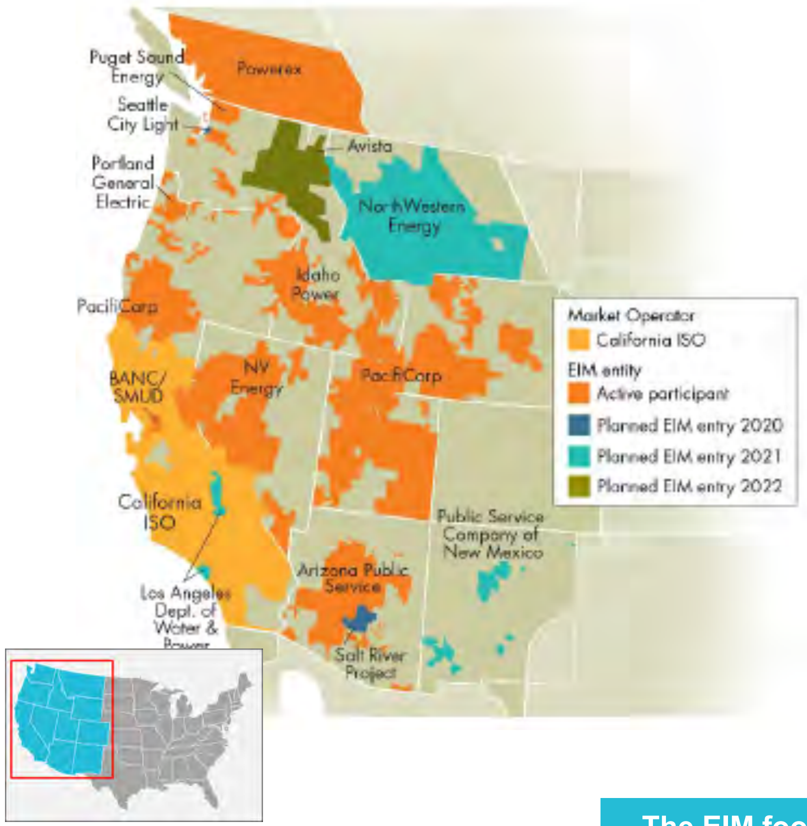
Project Name	Project Owner(s)	Project Length (miles)	Project Voltage (kV)	From State	To State	From ISO	To ISO	Yr. in Svc.	Current Development Status	Project Type	Est. Const. Costs ($000)
Harcuvar Transmission (Bouse - Harquahala)	Central Arizona Water Conservation District	30.00	230	Arizona	Arizona	NA	CAISO	2020	Early Development	New	NA
Harry Allen-Eldorado Transmission Line (ON Line Expansion)	LS Power Development, LLC	60.00	500	Nevada	Nevada	CAISO	CAISO	2020	Adv. Development	New	145,500
Line 625 (Kings Beach - Tahoe City) Upgrade	Emera Incorporated, Liberty Power	15.00	120	California	California	CAISO	CAISO	2019	Early Development	Upgrade	NA
Los Banos - San Luis 230kV Transmission Line	Western Area Power Administration	3.00	230	California	California	CAISO	CAISO	2023	Early Development	New	NA
Merced South 115 kV Transmission Line	Merced Irrigation District	14.00	115	California	California	CAISO	CAISO	NA	Early Development	New	NA
Midway-Santa Maria Upgrade (Midway- Andrew 230 kV)	Pacific Gas and Electric Company	100.00	230	California	California	CAISO	CAISO	2025	Early Development	Upgrade	NA
Moorpark-Pardee 230-kV No. 4 Circuit Line	Southern California Edison Company	26.00	230	California	California	CAISO	CAISO	2020	Early Development	New	NA
North Gila-Imperial Valley #2_Green Path	Southwest Transmission Partners, Llc	97.00	500	California	Arizona	CAISO	CAISO	2022	Early Development	New	NA
Parker to Bouse Rebuild Transmission Line	Western Area Power Administration	15.00	230	California	Arizona	CAISO	CAISO	NA	Announced	Rebuild	NA
Parker to Headgate Rock Rebuild	Western Area Power Administration	16.00	161	California	Arizona	CAISO	CAISO	NA	Announced	Rebuild	NA
Pathfinder Transmission (Zephyr)	American Transmission Company LLC, Duke Energy Corporation	850.00	500	Wyoming	Nevada	NA	CAISO	2023	Early Development	New	2,600,000
Renewable Transmission Initiative (Bordertown To California)	NV Energy, Inc.	12.00	120	California	California	CAISO	CAISO	NA	Early Development	New	11,800
Riverside Transmission Reliability	Riverside City of, Southern California Edison Company	10.00	230	California	California	CAISO	CAISO	2023	Early Development	New	NA
San Bernardino – Vista Line Rebuild (Segment 2 - West of Devers)	Southern California Edison Company	3.50	220	California	California	CAISO	CAISO	2021	Constr. Begun	Rebuild	NA
San Luis - Dos Amigos 230 kV Transmission Line	Western Area Power Administration	20.00	230	California	California	CAISO	CAISO	2023	Early Development	New	NA
Talega Escondido/Valley Serrano Interconnect (Northern)	Nevada Hydro Company	16.00	500	California	California	CAISO	CAISO	NA	Early Development	New	NA
Talega Escondido/Valley Serrano Interconnect (Southern)	Nevada Hydro Company	16.00	500	California	California	CAISO	CAISO	NA	Early Development	New	NA
Ten West Link Transmission Line (Delaney – Colorado River)	Abengoa, S. A., Starwood Energy Group Global, LLC	114.00	500	Arizona	California	NA	CAISO	2020	Early Development	New	300,000
Tracy - Los Banos 230 kV Transmission Line	Western Area Power Administration	62.00	500	California	California	CAISO	CAISO	2023	Advanced Development	New	NA
TransWest Express	TransWest Express, LLC	730.00	600	Wyoming	Nevada	NA	CAISO	2023	Advanced Development	New	3,000,000
Valley-Ivyglen Subtransmission	Southern California Edison Company	27.00	115	California	California	CAISO	CAISO	2021	Advanced Development	New	NA

Sources: S&P Global Market Intelligence; NERC

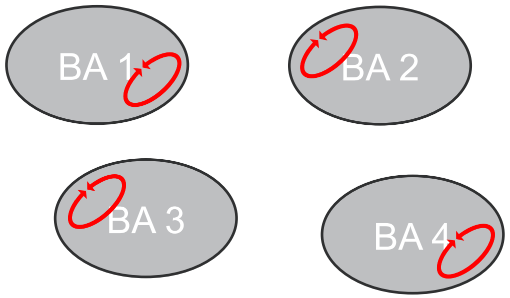
Transmission Topography and Investment (Cont'd)

Western Energy Imbalance Market (EIM)

- The Western EIM is the system launched in 2014 that balances electricity supply and demand imbalances every five minutes with the lowest cost energy available in the western United States across EIM entities with a more diversified portfolio of generation resources.
- Through participation in this market, each balancing authority will preserve autonomy, improve renewable energy integration, reduce costs for customers, and enhance reliability.

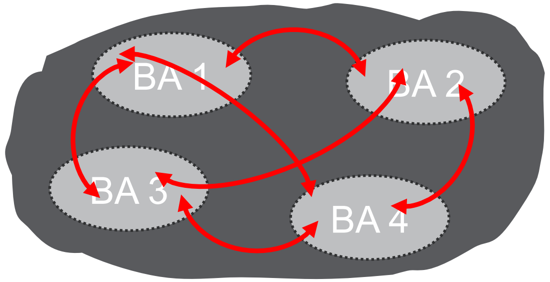


Before EIM:
Each BA balances supply and demand independently.



- Smaller pools of balancing resources result in a less efficient way to manage risk
- More expensive
- More challenging to integrate wind and solar

After EIM:
EIM offers balancing across participating BAs* throughout the region.



- More diverse resource portfolio results in more efficiency (just like stocks and bonds)
- Best reliability for least cost
- Increased flexibility and responsiveness for wind and solar integration

*Note: Recent tariff revisions have added the ability of transmission owners located between participants to provide additional capacity for transfers, potentially further increasing efficiencies.

The EIM footprint now includes portions of Arizona, California, Canada, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming.

Source: CAISO

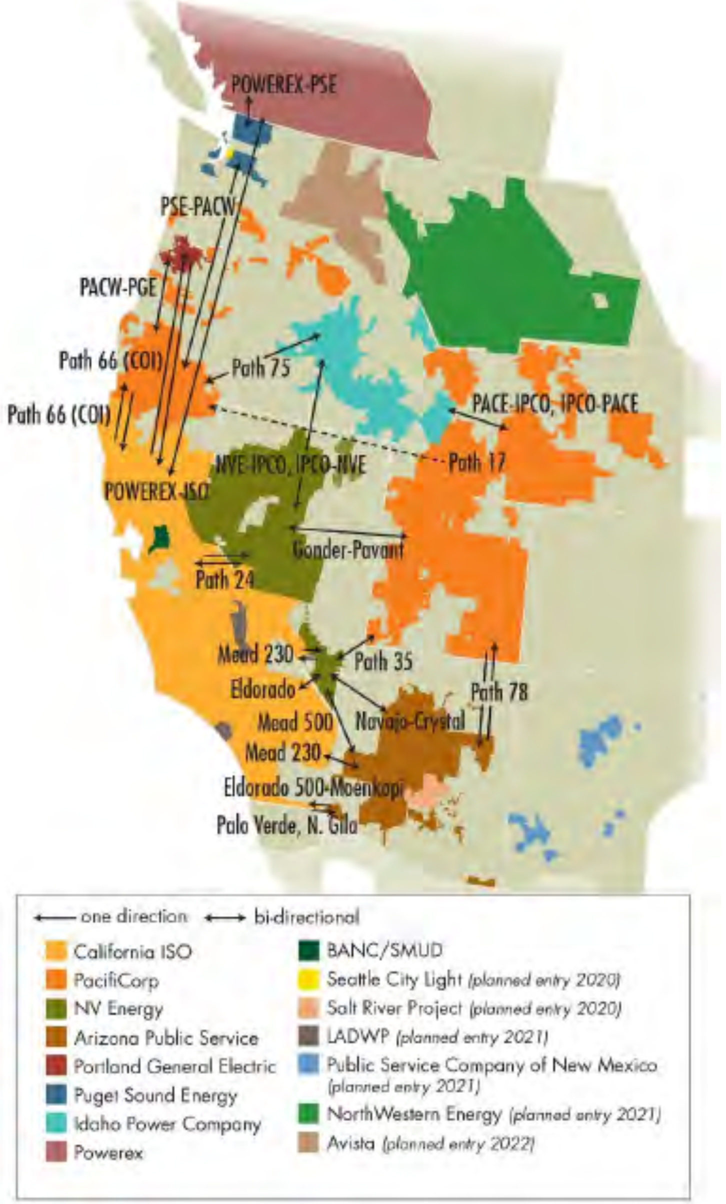
Transmission Topography and Investment (Cont'd)

Western EIM (Cont'd)

- Benefits of the EIM: Total aggregate benefits are estimated to be $650.26 million from EIM inception in 2014 through Q1 2019.
  - Recent highlights:
    - More efficient dispatch, both interregionally and intraregionally, in the 15-minute market and real-time dispatch (RTD). Q1 2019 estimated savings are $85.38 million. This figure represents cost savings and the use of surplus renewable energy to displace conventional generating resources.
    - Reduced renewable energy curtailment. Q1 estimated reduction is 52,254 MWs, displacing approximately 22,365 metric tons of CO_2.
    - Reduced flexibility ramping reserves needed in all BA areas. Q1 reduction is 2,320 MWs in the upward direction and 2,320 MWs in the downward direction.

First Quarter 2019 EIM Benefits by Region (in $ Millions)

Region	January	February	March	Total
APS	$1.10	$4.76	$2.34	$8.20
CAISO	$1.25	$5.63	$6.20	$13.08
IPCO	$1.64	$4.21	$2.60	$8.45
NV Energy	$1.09	$2.20	$2.42	$5.71
PacifiCorp	$5.56	$11.01	$7.19	$23.76
PGE	$1.36	$5.36	$5.02	$11.74
PWRX	$1.23	$2.91	$3.09	$7.23
PSE	$0.85	$4.18	$2.18	$7.21
Total	**$14.08**	**$40.26**	**$31.04**	**$85.38**



Source: EIM Benefits Report

Resilience Issues

Overview

- California is the third largest state by area, and it is the most populous state in the United States, with more than 39 million residents. As a frame of reference, the annual GDP for California in 2018 was $11.9 trillion, by far the largest state economy in the United States.
- Historically, California has been vulnerable to wildfires and heat waves that impact both demand and energy infrastructure, and the state has been impacted by many large, well-publicized wildfires in recent years. Extreme heat also affects thermal generation, as ambient air and water temperatures can cause de-rates.
- While CAISO determined that the system had a very low probability of a system capacity shortage that would potentially necessitate demand curtailments in the summer of 2019, it did find a higher potential for shortages of upward ramping capability during certain times of the day, which would create operational risks. These upward ramping shortages are most prevalent in the late afternoon when solar generation output decreases while system demand is still high. Without sufficient upward ramping capability within CAISO to offset the loss of solar output during these times, neighboring BA areas would have to provide the necessary support to balance supply and demand to maintain system frequency under normal conditions.
- CAISO will be at the greatest operational risk during late summer, as the availability of hydro energy wanes and potential high peak demands in neighboring BA areas decrease the availability of imports into CAISO. The continuing decline in dispatchable generation as gas units retire creates further challenges for meeting CAISO's flexible capacity requirement and the peak demand, which is now occurring later in the day when solar output is at or near zero.
- Three 55 MWs oil-fired units in CAISO will be needed through 2018 to ensure reliability. CAISO's board of governors extended a reliability must-run (RMR) contract in September 2017 for the three units located near Oakland, CA.
- A study by WECC, which includes CAISO as one of four U.S. reliability assessment areas, examined the impacts to reliability associated with the interdependence of the natural gas and electric systems. The key findings include the Western Interconnections facing increasing volumetric and flexibility constraints, and disruptions in the natural gas system could potentially translate quickly to loss of load in the Desert Southwest and Southern California regions.

Reported Electric Disturbance Events Affecting California (2017- Apr. 2019)

Cause	2017	2018	2019 YTD
Fuel Supply Deficiency	5	0	1
Severe Weather	13	7	4
Vandalism	2	12	5
Suspected Physical Attack	0	0	0
Actual Physical Attack	0	0	0
Suspicious Activity	1	3	1
Transmission Interruption	2	1	0
System Operations	2	3	1
Generation Inadequacy	2	0	0

Note: For multiple causes, classified under one only.
Source: DOE OE-417; ScottMadden analysis

Transmission Projects in the San Onofre Area

	Transmission Projects	Sponsor	Target In-Service Dates
1	Talega Synchronous Condensers (2x225 MVAR)	SDG&E	In-service 8/7/2015
2	Extension of Huntington Beach Synchronous Condensers (280 MVAR)	SCE	Retired 12/31/2017
3	Imperial Valley Phase Shifting Transformers (2x400 MVAR)	SDG&E	In-service 5/1/2017
4	Sycamore Canyon–Peñasquitos 230kV Line	SDG&E	In service 8/29/2018
5	Miguel Synchronous Condensers (450/-242 MVAR)	SDG&E	In-service 4/28/2017
6	San Luis Rey Synchronous Condensers (2x225 MVAR)	SDG&E	In-service 12/29/2017
7	San Onofre Synchronous Condensers (1x225 MVAR)	SDG&E	In service 10/16/2018
8	Santiago Synchronous Condensers (1x225 MVAR)	SCE	In-service 12/31/2017
9	Mesa Loop-In Project and South of Mesa 230kV Line Upgrades	SCE	Delayed until 3/1/2022

Source: California Energy Commission

Sources: CAISO; NERC 2018 LTRA; WECC; DOE

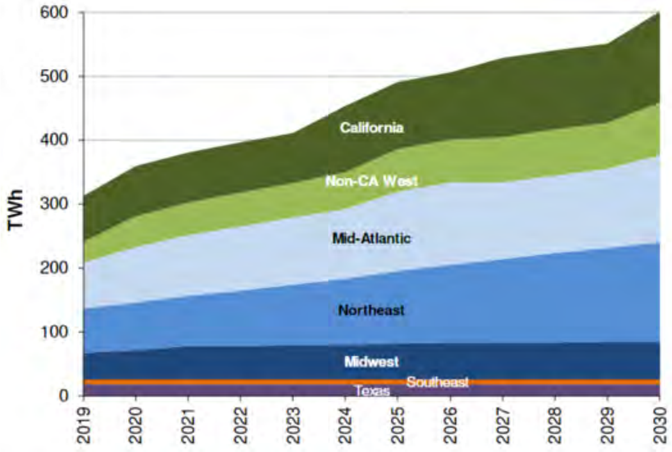
Resilience Issues (Cont'd)

Selected Major Bulk Power Events Affecting California	
Event	**Description**
System Challenges in Southern California	▪ Southern California has been the focus of major electric reliability concerns beginning with the outage of the two San Onofre Nuclear Generating Station (SONGS) units in January 2012, followed by the decision to retire SONGS in 2013, and the major gas leak discovered in October 2015, at the Aliso Canyon natural gas storage facility. ▪ Those events, coupled with the expected compliance-related closure of several southern California coastal power plants that use ocean water for cooling, as well as the ongoing natural gas pipeline outages on Southern California Gas's system, are tightening the region's energy supply.
Wildfires: ▪ Blue Cut (Aug. 16, 2016) ▪ Canyon 2 (Oct. 9, 2017) ▪ Camp (2018) ▪ Kincade, Tick, et al (2019)	▪ Over the 2000–2016 period, wildfires in parts of California cost utilities more than $700 million in transmission and distribution related damages. Total wildfire damages to all sectors of the economy were naturally much larger. Over the past two years, California has experienced the deadliest and most destructive wildfires in its history. A relatively small number of catastrophic wildfires were responsible for a disproportionate share of the transmission and distribution related damages. These wildfires are difficult to defend against and very hard to predict—as evidenced by the massive wildfires that occurred in 2017 and 2018 and continue to occur in 2019. California utilities have been preemptively cutting power to large numbers of customers in fire prone areas in 2019 attempting to prevent fires from starting in the first place, and the state continues to battle multiple ongoing fires as of this writing despite those efforts. ▪ The Blue Cut fire began in the Cajon Pass, just east of Interstate 15. The fire quickly moved toward an important transmission corridor that is comprised of three 500 kV lines owned by SCE and two 287 kV lines owned by the Los Angeles Department of Water and Power (LADWP). By the end of the day, the SCE transmission system experienced thirteen 500 kV line faults, and the LADWP system experienced two 287 kV faults as a result of the fire. ▪ The Canyon 2 fire caused two transmission system faults near the Serrano substation east of Los Angeles. The first fault was on a 220 kV transmission line, and the second fault was on a 500 kV transmission line. Both resulted in the reduction of solar PV generation across a wide region of SCE's footprint.
Seismic Activity	▪ The resilience of California's natural gas transmission and distribution system was tested when the most powerful earthquake in 20 years struck a remote area of the state on July 5, 2019. Initial assessments indicate that the system held up, despite reports tying several fires to gas pipeline ruptures during the quake and a smaller one the previous day. ▪ A 6.4 magnitude tremor struck the area along the border between Kern and San Bernardino counties July 4, followed by a 7.1 magnitude quake July 5. In the aftermath, state and local officials linked a handful of fires to ruptured gas lines resulting from the quakes, Reuters reported.
Gas-Power Interdependence	▪ In addition to the challenges outlined above that are unique to southern California, the issue of gas-power market interdependence represents a resilience risk for the entire CAISO market. Some degree of gas-fired generation will be required to balance variable renewable generation in CAISO, and those generation resources will be competing for constrained fuel supplies with end-use load from gas LDCs in the winter and other generators in the region in the summer.

Sources: S&P Global Market Intelligence; 4th CA Climate Assessment

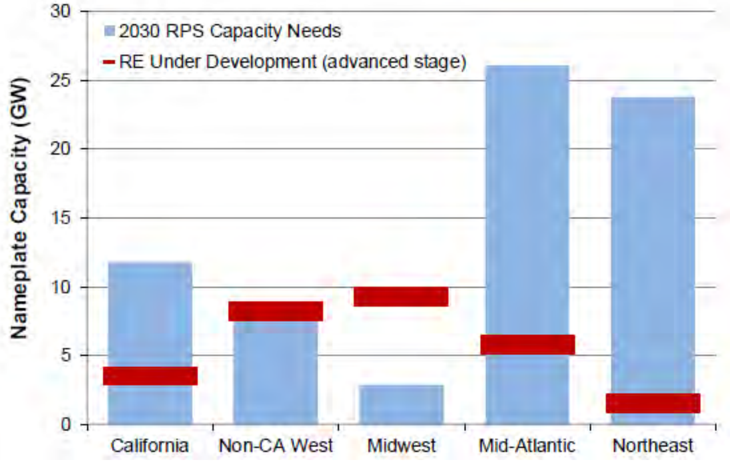
Renewables Integration

Projected U.S. RPS Demand (Total Compliance Requirements) per DOE LBNL (2019–2030) (as of July 2019) (in TWh)



Source: LBNL

Required RPS Capacity Additions (GW) (LBNL Estimates)



Source: LBNL

Demand-Side Considerations: Renewable Portfolio Standards

- RPS-driven demand has led to significant additions of renewable energy capacity to date, and projected demand for renewable resources in the CAISO region is expected to be substantial as depicted in the California section of the graph top left.
- Further, as depicted bottom left and on the next page, the demand for renewable energy is expected to far exceed the capacity currently under development. As discussed separately in the section of this report on WECC outside of California, many projects in other regions of the western U.S. are being developed on the basis of delivering renewable energy into CAISO.
- Several utilities in California have also introduced clean energy commitments (see below).

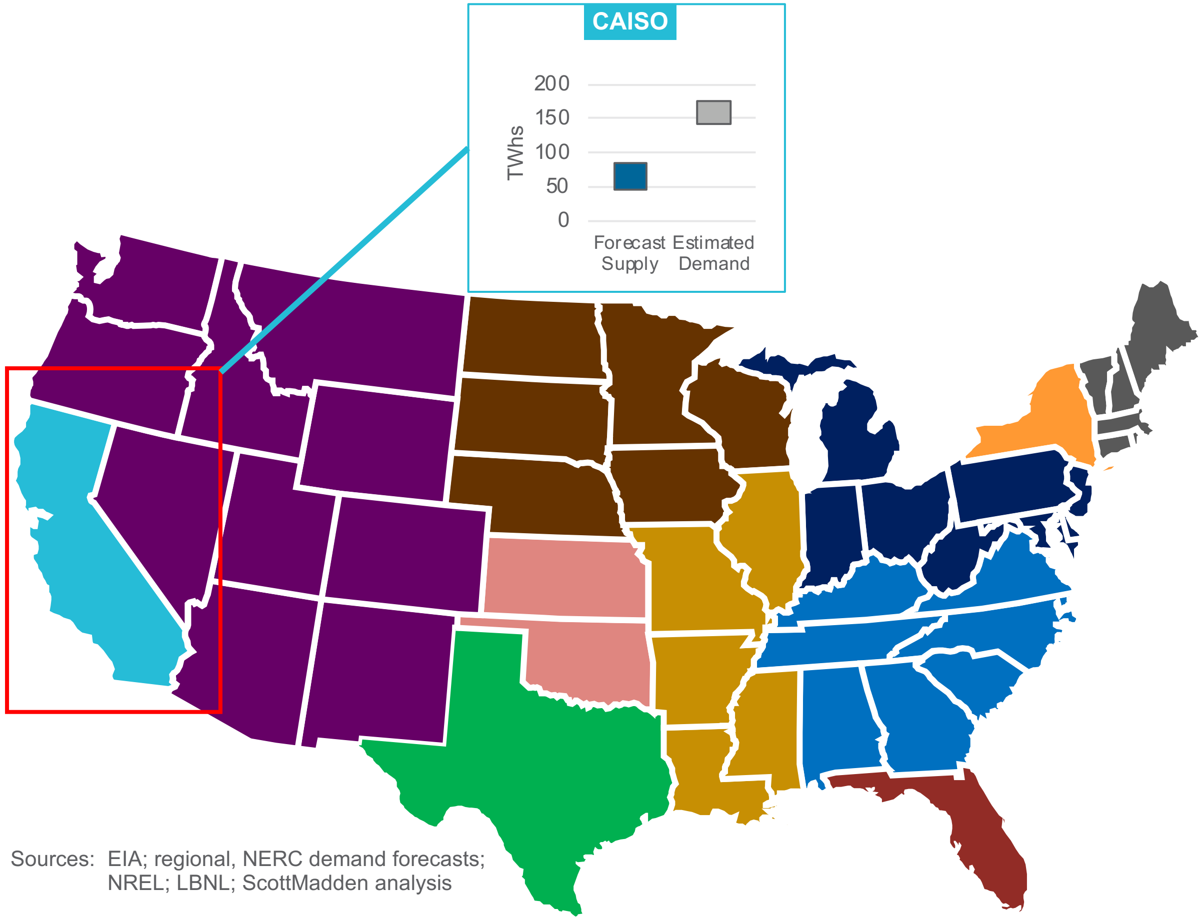
Utility Name (States of Operation)	Goal Type	Target Dates	Description (Date Implemented)
Los Angeles Department of Water and Power (CA)	Emission Reduction	2050	100% net-zero emissions by 2050
Pacific Gas & Electric (CA)	Emission Reduction	2022 2030	▪ Reduce 1 million tons of GHG emissions from company operations by the end of 2022 ▪ 40% reduction in GHG emissions from 1990 levels by 2030
Sacramento Municipal Utility District (CA)	Emission Reduction	2040	100% net-zero emissions by 2050
Southern California Edison (CA)	Emission Reduction	2030 2050	▪ 40% reduction in GHG emissions from 1990 levels by 2030 ▪ 80% reduction in GHG emissions from 1990 levels by 2050

Source: SEPA

Sources: LBNL 2019 RPS Analysis; SEPA

Renewables Integration (Cont'd)

CAISO Potential Policy-Driven Renewable Energy Demand and Forecast Supply (2030) (as of June 2019)



Sources: EIA; regional, NERC demand forecasts; NREL; LBNL; ScottMadden analysis

Demand-Side Considerations:
Renewable Portfolio Standards (RPS) Supply-Demand Balance

- As seen in the map at left, the estimated demand for renewable resources in the CAISO region is expected to significantly outpace the forecast supply of renewables in the region, suggesting that future demand, at least in part, will need to be met by resources from outside the CAISO region.
- Legislative initiatives have helped drive much of the growth of renewables in California's electricity sector. California's RPS, enacted in 2002, has evolved to require increasing amounts of renewable resources in the state's electricity system. In 2015, Senate Bill 350 increased the RPS requirement from 33% to 50% by 2030. Senate Bill 100 sets a planning target of 100% renewable and zero-carbon electricity resources by 2045 and increases the 2030 RPS target from 50% to 60%.
- Transmission planning: In its last three transmission planning cycles (2015–2016, 2016–2017, and 2017–2018), CAISO did not identify new projects necessary to meet California's 33% RPS, as many previously identified projects have been approved or are in the permitting process. Future CAISO transmission planning process (TPP) cycles will focus on moving beyond the 33% framework when new generation portfolios are developed under the resource planning processes.
- Regulatory approval process: The first step in the regulatory process to develop a new transmission project is an approval based on a finding of need by CAISO in its annual TPP or by another BA in a similar planning process. For projects sponsored by IOUs, CPUC next considers CAISO's approved projects and reviews them for California Environmental Quality Act (CEQA) compliance. CPUC issues certificates of public convenience and necessity for transmission lines at 200 kV and above or permits to construct for projects between 50 kV and 200 kV. CPUC issues a notice of exempt construction for the replacement of existing transmission lines, which are exempt from CPUC CEQA review under CPUC General Order 131-D, Section III, Subsections A or B.1. For a project sponsored by a POU, the POU board of directors can act as CEQA lead agency.

Sources: LBNL 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; CEC IEPR; CEC Progress Report; ScottMadden analysis

Renewables Integration (Cont'd)

Subset of Transmission Projects Tracked by CEC due to Potential to Expand Integration and Delivery of Renewables (June 2018)

Transmission Project	California ISO Status[1]	CPUC Status	Construction Status	Actual and Expected In-Service Date
1 – Sunrise Powerlink 500 kV line	Approved	CPCN Approved	Operational	2012
14 – Imperial Valley-Liebert (formerly Collector) 230 kV line[2]	Approved Policy	N/A	N/A	N/A
15 – Sycamore Canyon-Peñasquitos 230 kV Line	Approved Policy with Reliability Benefits	CPCN Approved[3]	Planning/Design	2018
2 – Tehachapi 500 kV line	Approved	CPCN Approved	Operational[4]	2016
3 – Colorado River-Valley 500 kV line	Approved	CPCN and PTC Approved	Operational	2013
4 – West of Devers 230 kV Reconductoring[5]	LGIA	CPCN Approved	Under Construction[6]	2022
5 – Eldorado-Ivanpah 230 kV line	LGIA	CPCN Approved	Operational	2013
6 – South of Contra Costa 230 kV Reconductoring	LGIA	CPCN Approved	Operational	2012
7 – Pisgah-Lugo 500 kV line[7]	N/A	N/A	N/A	N/A
8 – Borden-Gregg 230 kV Reconductoring	LGIA	NOC/CPCN TBD	On Hold	Unknown
9 – Carrizo-Midway 230 kV Reconductoring	LGIA	NOC Approved	Operational	2013

Source: CEC

Demand-Side Considerations:
Transmission Projects to Support Renewable Portfolio Standards

- Transmission projects tracked for the potential to support the state's renewable energy goals are a small subset of the reliability, economic, and policy projects approved and assessed by CAISO in the TPP. The 2017–2018 transmission plan identifies 13 new transmission projects needed for reliability and 4 new transmission projects needed for economic purposes. All but one of the newly approved transmission projects are expected to cost less than $50 million (each). The plan identifies no new transmission projects needed to meet the current transmission planning cycle target for achieving the 33% RPS by 2020.
- The plan identifies 28 previously approved transmission projects costing $50 million or more (each), including 9 lines in progress and 4 lines on hold. The plan identifies 122 previously approved transmission projects costing less than $50 million (each), including 10 lines in progress, 1 line on hold, and 10 lines canceled.
- With the completion of its 2017–2018 TPP cycle, CAISO has concluded its three-year, in-depth review of previously approved projects. For the third consecutive cycle, CAISO has canceled a significant number of previously approved transmission projects at significant cost savings.
  - In the 2015–2016 TPP, 13 projects were canceled, savings not stated.
  - In the 2016–2017 TPP, 13 projects were canceled, savings not stated.
  - In the 2017–2018 TPP, 20 projects were canceled, saving at least $2.6 billion.
- The 2017–2018 review has been the most comprehensive to date, resulting in cancellations of projects no longer needed and modifications of projects to better match changing expectations about need. The project cancellations and modifications involve mostly smaller projects that were not moving forward. The reassessment was initiated in response to changing peak load forecasts. CAISO concluded that decreased demand was compounded by greater than expected growth of behind-the-meter solar PV generation, which shifted the traditional peak demand hour later in the day in some parts of the state.

Source: CEC Tracking Progress Report

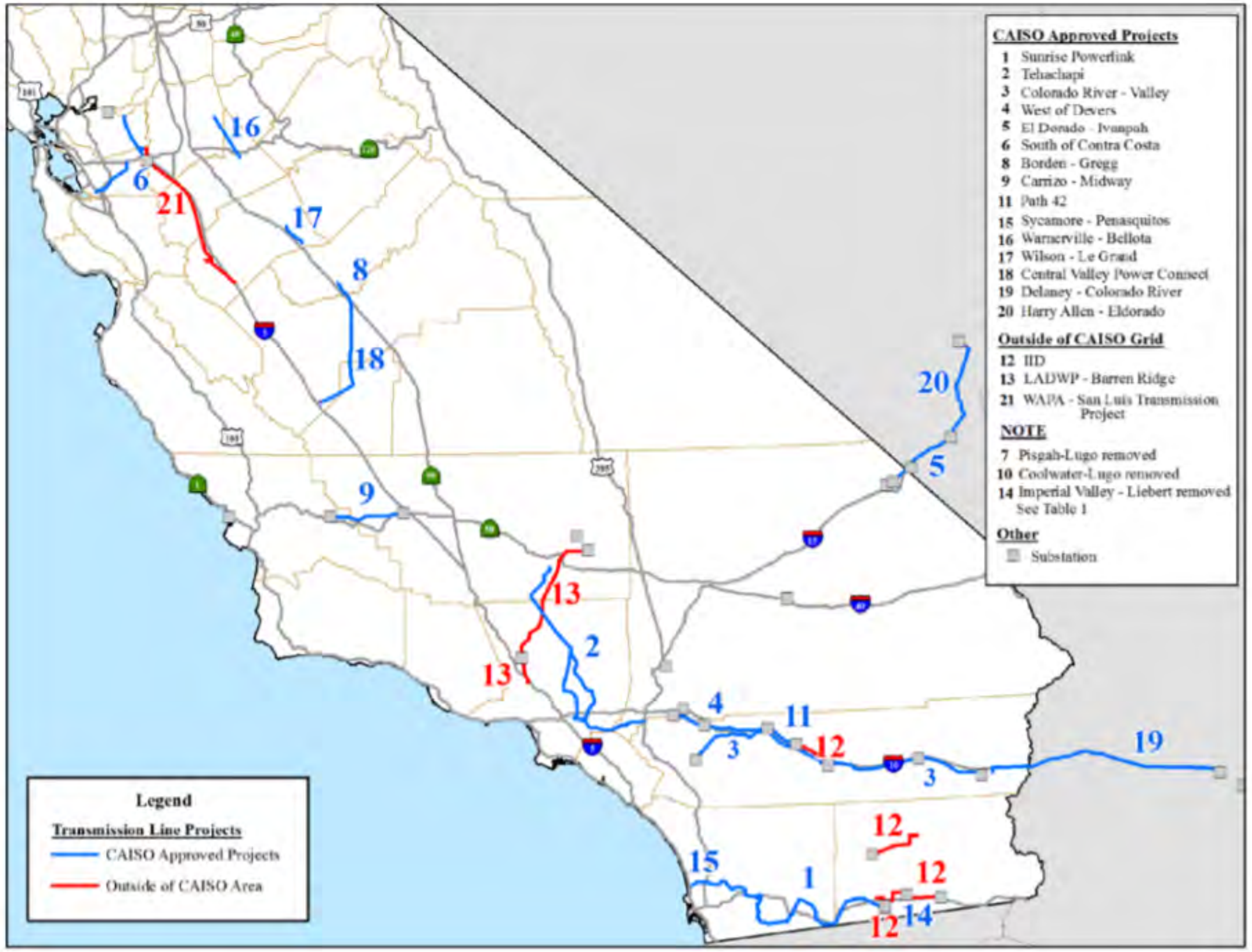
Renewables Integration (Cont'd)

Subset of Transmission Projects Tracked by CEC due to Potential to Expand Integration and Delivery of Renewables (June 2018) (Cont'd)

Transmission Project	California ISO Status[1]	CPUC Status	Construction Status	Actual and Expected In-Service Date
10 – Cool Water-Lugo 230 kV line[8]	LGIA	N/A	N/A	N/A
11 – Path 42 230 kV Reconductoring	Approved Policy	N/A	Operational	2016
12 – IID: Path 42 230 kV Reconductoring and additional upgrades (Outside CAISO Grid)	N/A	IID/SCE/BLM Joint Final Mitigated Negative Declaration Adopted	Construction suspended[9]	N/A
13 – LADWP: Barren Ridge 230 kV line (Outside CAISO Grid)	N/A	LADWP/U.S. Forest Service/BLM Joint Final EIS/EIR Adopted	Operational	2016
16 – Warnerville-Bellota 230 kV Reconductoring	Approved Policy	NOC Approved	Engineering/ Design	2024
17 – Wilson-Le Grand 115 kV Reconductoring	Approved Policy	NOC Approved	Engineering/ Design	2020
18 – Central Valley Power Connect (formerly Gates-Gregg 230 kV line)	Approved Reliability With Policy Benefits	CPCN to be Filed	On Hold[10]	2022
19 – Ten West Link 500 kV Transmission Line Project (Delaney-Colorado River 500 kV line)	Approved Economic With Reliability and Policy Benefits	CPCN Filed	Competitive Solicitation Process[11]	2020
20 – Harry Allen- Eldorado 500 kV line	Approved Economic With Reliability and Policy Benefits	N/A (line is located entirely in Nevada)	Competitive Solicitation Process[12]	2020
21 – San Luis Transmission Project	N/A	Western/San Luis & Delta-Mendota Water Authority Joint Final EIS/EIR adopted[13]	Engineering/ Design	2022

Source: CEC

Map of CAISO and Outside CAISO Grid-Approved Transmission Projects



Source: CEC

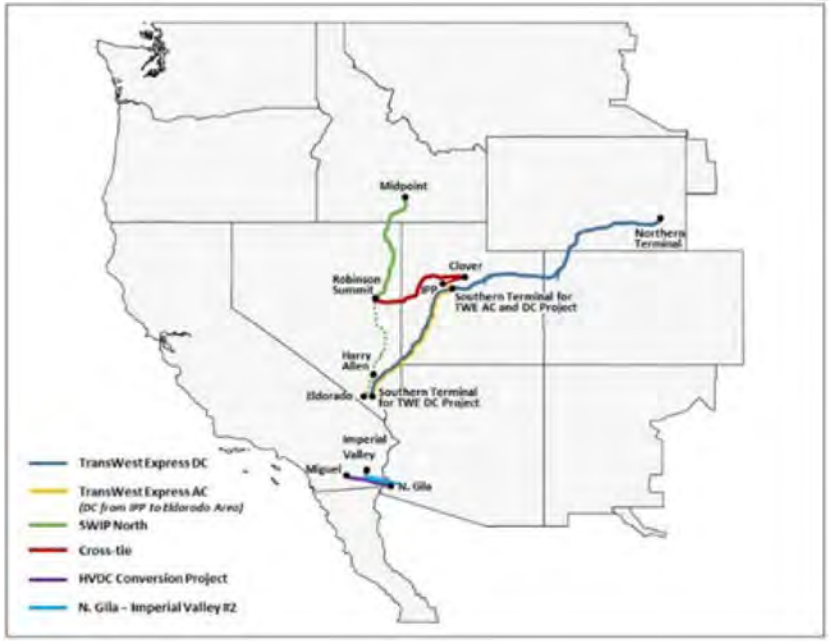
Source: CEC Tracking Progress Report

Renewables Integration (Cont’d)

Supply-Side Considerations: Interregional Planning

- CAISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with FERC Order No. 1000. The ISO’s 2018–2019 transmission planning cycle marks the beginning of the second biennial cycle since these coordination processes were put in place, replacing other mechanisms that pre-dated FERC Order No. 1000. This cycle reflects the complete transition from old process to new, taking into account the status of the policy drivers and the progress achieved in implementing the new interregional processes.
- In order to support state policy directives related to increasing renewable energy, CAISO partnered with CEC and CPUC to conduct the renewable energy transmission initiative (RETI) 2.0 to help identify potential transmission opportunities that could access and integrate renewable energy opportunities from regions outside of California. Through its involvement in interregional coordination activities, the ISO considered the interregional transmission projects (ITPs) proposed in the 2016–2017 interregional coordination cycle as a reasonable measure to assess the potential out-of-state transmission opportunities for California and, as such, proposed they be considered within the RETI 2.0 assessment framework. As a result, these ITPs were assessed and considered in the ISO’s 2016–2017 and 2017–2018 planning cycles as “special studies” of the 50% RPS that had been established at that time.
- During the course of the 2018–2019 transmission planning cycle, CAISO considered all six ITPs that were submitted during the ITP submission period. Project sponsor’s identified need, and the ISO’s identified need as determined by the ISO’s assessment varied, but there were two common themes among multiple projects:
  - Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables.
  - Decrease San Diego and greater IV/San Diego local capacity requirement (LCR).

Interregional Transmission Projects (ITPs) Submitted to CAISO (2018–2019)



Proposed ITP	Sponsor Identified Need	Cost Allocation	ISO Identified Need in this Planning Cycle
Cross-Tie	Strengthen interconnection between PacifiCorp and Nevada; facilitate California’s RPS and GHG needs	ISO, NTTG, WestConnect	None: Based on 2018-2019 plan assumptions
HVDC Conversion	Improve/remove existing reliability limitation; decrease San Diego and greater IV/San Diego LCR requirement	Not Requested	Reliability: None Economic: None - BCR less than 1.0
NG-IV#2	Decrease San Diego and greater IV/San Diego LCR requirement	ISO, WestConnect	Reliability: None Economic: None - BCR less than 1.0
SWIP - North	Economic, policy, reliability, reduce congestion on COI, facilitate access to renewables in PacifiCorp	ISO, NTTG, WestConnect	Reliability: None Economic: None - BCR less than 1.0
TransWest Express AC/DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions
TransWest Express DC	Provide needed transmission capacity between the Wyoming wind resource area and California, facilitate California access to renewables	ISO, WestConnect	None: Based on 2018-2019 plan assumptions

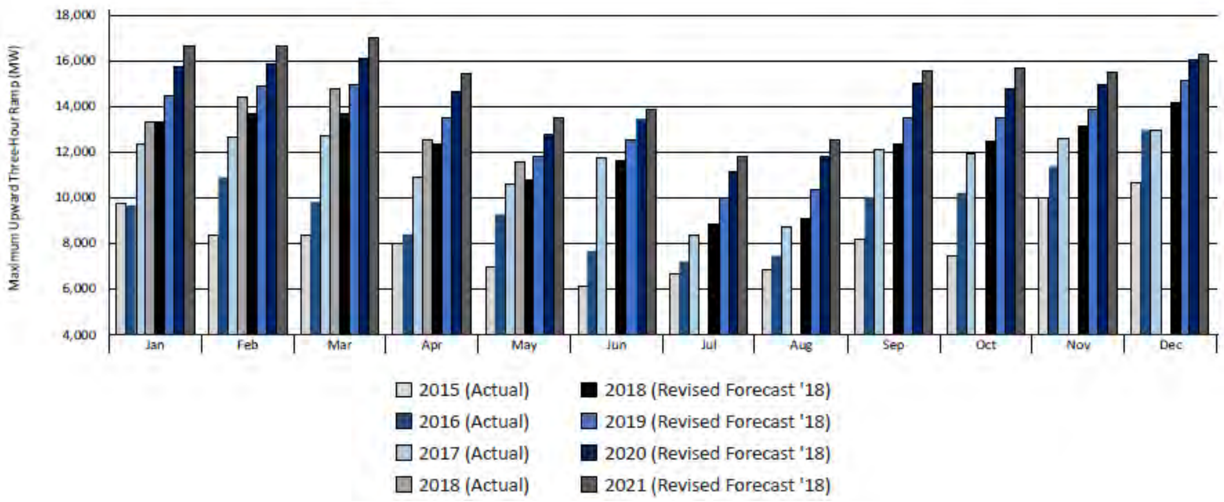
Source: CAISO Transmission Plan

Renewables Integration (Cont'd)

Integration Challenges: The Growing Need for Resource Flexibility

- With continued growth in renewables in recent years, there has been growing recognition that system operators need additional flexible capabilities to balance supply and demand. This additional flexibility is required to accommodate morning and late-afternoon ramps in energy net load (load minus solar and wind generation) resulting from solar resource output.
- According to CAISO, ramps and minimum loads are four years ahead of its initial estimates, primarily due to growth in renewable energy projects. Furthermore, because of expected changes in the dispatchable natural gas-fired fleet, CAISO is concerned that it needs greater operational control over resources with flexible capacity.
- With continued rapid growth of distributed solar, CAISO's three-hour ramping needs have reached 14,777 MWs (new record set in March 2018), exceeding earlier projections and reinforcing the need to access more flexible resources. The maximum one-hour net-load upward ramp was 7,545 MWs. This record coincided with utility-scale PV serving nearly 50% of CAISO's demand during the same time period. By 2022, this need increases to 17,000.
- Currently, there are more than 11 GWs of utility-scale and 6.5 GWs of behind-the-meter PV resources in CAISO's footprint, which has the most concentrated area of PV in North America.
- Behind-the-meter PV has continued to grow in CAISO, and the projected behind-the-meter PV is expected to be 12 GWs by 2022.

Maximum Three-Hour Ramps in CAISO (Actual and Projected) Through 2021



Recent and Ongoing Initiatives to Increase Flexibility

- **Flexible Ramping Product:** In 2016, CAISO introduced a formal flexible ramping product into its market system.
- **Day-Ahead Market Enhancement (DAME):** Currently, CAISO is attempting to improve its forecasting methods and apply them to a newly configured day-ahead market (DAH) via the DAME stakeholder process. By moving the DAH market from an hourly forecast to a fifteen-minute forecast, CAISO intends to improve market efficiency and better align resources to meet ramping needs.
- **EIM Expansion:** Expanding the geographic footprint of the market can help in two ways. First, greater diversity of renewable resources can reduce the coincidence of production patterns. Second, loads in larger regions outside CAISO can help absorb excess production, and generating resources in those regions may be able to assist California with upward ramping requirements.

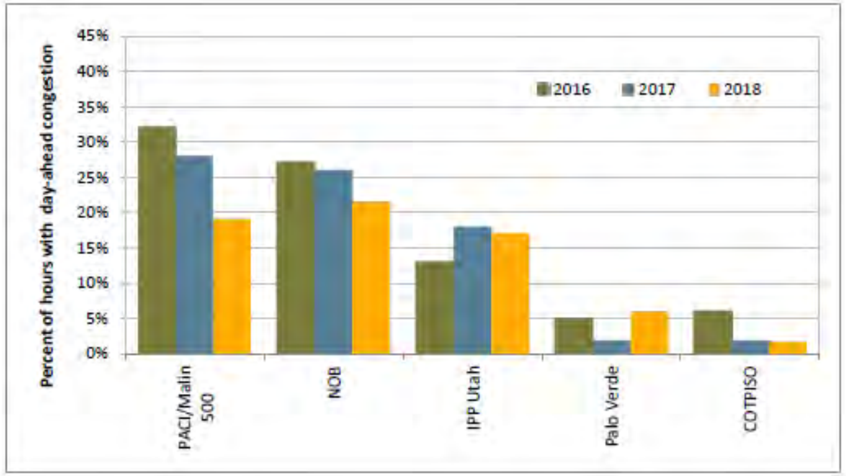
Sources: NERC 2018 LTRA; CEC IEPR

Renewables Integration (Cont'd)

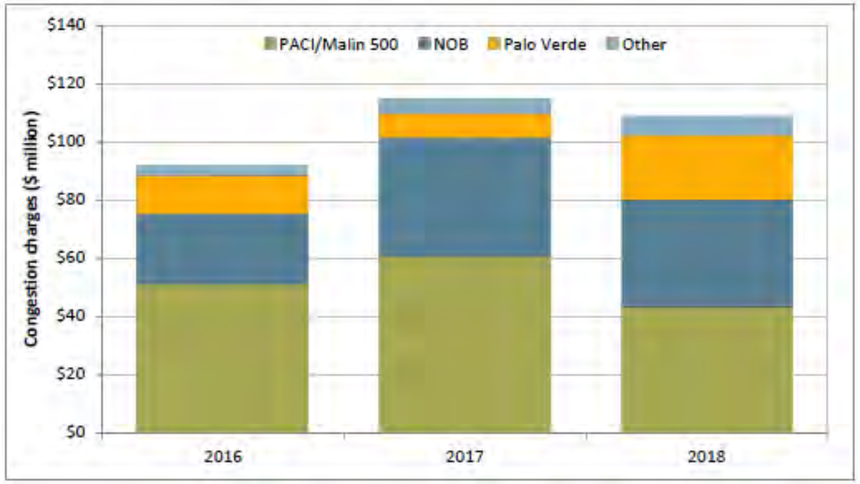
Integration Challenges: Hydro Generation from the Pacific Northwest

- CEC and CPUC issued a letter to CAISO requesting evaluation of options to increase transfer of low-carbon electricity between the Pacific Northwest and California.
- Expanded transmission capability, and increasing the transfer of low-carbon supplies to and from the Northwest in particular, was seen to be one of the multiple puzzle pieces that the agencies must examine to build a cumulative phase-out strategy of Aliso Canyon usage and address potential impacts on the gas-fired generation fleet.
- Three scenarios were outlined in the request and addressed in CAISO's 2018–2019 transmission plan:
  - Increase the capacity of AC and DC interties
  - Increase dynamic transfer capacity
  - Implementing sub-hourly scheduling on Pacific DC Interties (also called Path 65)
  - Assigning resource adequacy value to firm zero-carbon imports
- To ensure availability of Pacific Northwest resources to supply load in California in the long term, some market or policy initiatives and regulations may be required. However, details of such market structures, policies, or regulations were beyond the scope of CAISO's study.
- CAISO has initiated a resource adequacy enhancements stakeholder initiative that will include an assessment of the rules for import resource adequacy and a review of the maximum import capability. In addition, CPUC has ongoing resource adequacy and integrated resource plan proceedings that may address these issues.

Percent of Hours with Congestion on Major Interties



Import Congestion Charges on Major Interties



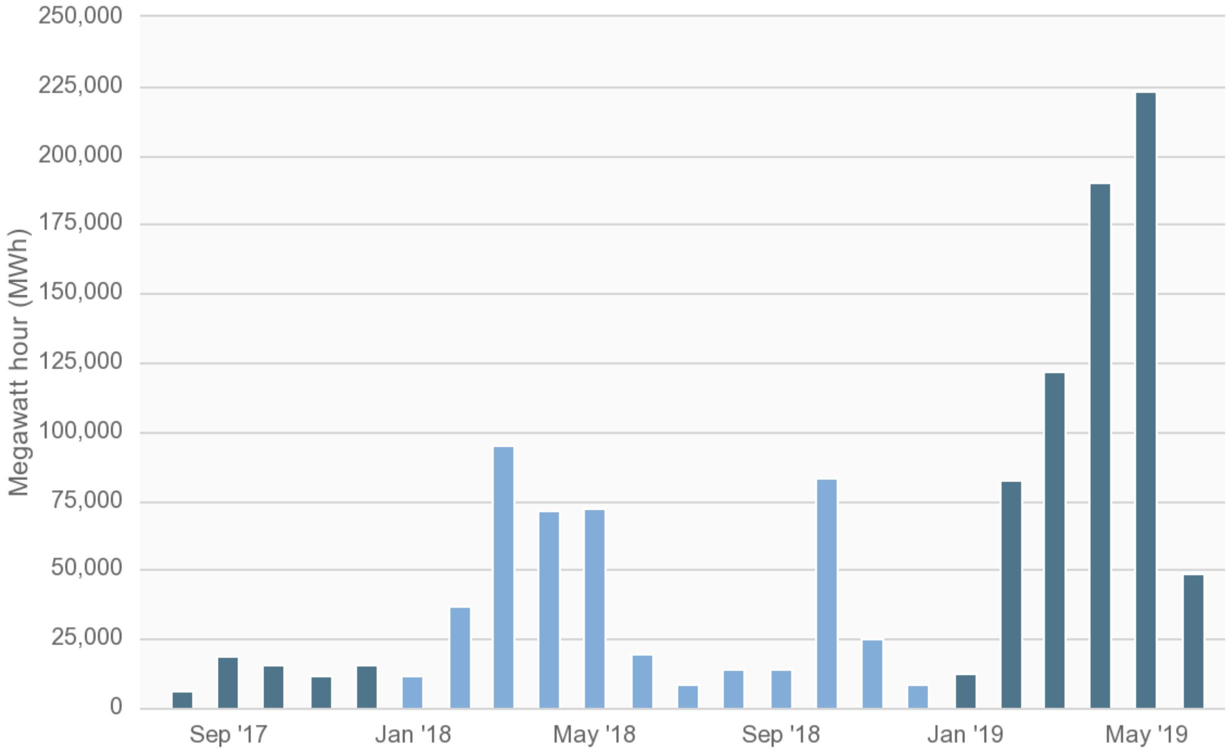
Source: CAISO (http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf)

Renewables Integration (Cont'd)

Integration Challenges: The Renewable Curtailment Opportunity

- As discussed in the section on the Western EIM, one value that market serves is putting to use over generation from renewable resources in times when it exceeds the corresponding demand for power in each region. And, the Western EIM has provided significant value in avoided curtailments to date.
- However, the rate at which renewables are being added in CAISO, particularly in just the past 12 months, is far outpacing the ability of the Western EIM to absorb and avoid curtailments, as evidenced by the trend at the right, creating several potential challenges:
  - Market Risk – If renewables continue to be overbuilt at increasing rates, they will drive real-time prices lower, distorting price signals in the market.
  - Project Risk – If the attractiveness of new renewable project economics is diminished, projects may not get built.
- Transmission projects, along with demand and energy storage, will represent some of the few emission-free solutions to these risks for the region as renewable penetration increases.

Wind and Solar Curtailment Totals by Month



Source: CAISO

Renewables Integration (Cont'd)

Integration Challenges: Headwinds for Transmission Development

- Preference for non-wires alternatives
  - In its energy action plan (EAP), originally jointly adopted in 2003 and updated and reiterated in 2005 and 2008 (EAP II), the CPUC and the CEC defined a "loading order" for energy resources to prioritize future energy investments. Preferred resources, in order of priority, include the following:
    - Energy efficiency
    - Demand-side resources
    - Renewable generation and energy storage
    - Clean conventional electricity supply
  - The EAP represents a coordinated implementation plan for various state energy and environmental policies, principally to address climate change and reduce greenhouse gas emissions.
  - The principles established in the EAP serve as inputs for the long-term procurement proceedings, in which CPUC establishes upfront standards for CAISO's procurement activities and cost recovery by reviewing and approving procurement plans.
  - The most recent proceeding was divided into four different tracks:
    - Track 1 considered issues related to the overall long-term need for new local reliability resources to meet long-term LCRs through 2022. Such long-term LCRs are expected to result from the retirement of thousands of megawatts from current once-through cooling generators to comply with State Water Quality Control Board regulations. Other changes in supply and demand over time will also impact long-term LCRs. As part of each procurement authorization, CPUC has included limits on conventional gas-fired resources and minimum thresholds for meeting requirements with energy storage and other preferred resources.
    - Track 2 considered procurement of system reliability resources for the three major electric IOUs and adopted final planning assumptions and scenarios. These assumptions were used for forecasting system reliability needs for California's electricity grid, and CPUC requested that CAISO use those same assumptions in modeling operational flexibility needs.
    - Track 3 considered a number of rule and policy issues related to IOUs' procurement practices.
    - Track 4 considered additional resource needs related to the long-term outage (and subsequent permanent closure in June 2013) of SONGS.

Source: CEC Energy Action Plans

Implications for Transmission

	Resilience	Integration of Renewables	Other Factors	Transmission Opportunities
California ISO	▪ Key risks related to severe weather (wildfires and heat waves) and seismic events; recent wildfires have resulted in historic levels of damage ▪ Severe weather and vandalism have been the largest causes of electrical disturbances reported in recent years ▪ There are volumetric and flexibility constraints on the natural gas system, and a disruption in the gas system could potentially translate quickly to a loss of load in southern California ▪ CAISO is heavily dependent on out-of-state imports from the northwest and the southwest to meet system needs	▪ Currently, there are more than 11 GWs of utility scale and 6.5 GWs of distributed solar in the footprint, and distributed solar is expected to grow to 12 GWs by 2022 ▪ Wind, geothermal, biomass, biogas, and small hydro comprise the remaining renewable capacity in CAISO, representing an additional 3.7 GWs in aggregate ▪ Renewable generation resources located outside the state represent 25% of total renewable capacity reported as qualified to meet RPS requirements today ▪ Renewable Energy Transmission Initiative (RETI) has led to the consideration of six different interregional transmission projects to move remote out-of-state renewables into CA ▪ Offshore wind development is contingent upon technology improvements, but developers have recently pointed to potential interest among CCAs	▪ Single-state footprint with very aggressive policies related to renewable energy: 100% by 2045 and 2030 target increased recently from 50% to 60% ▪ State environmental requirements make siting and permitting challenging and costly ▪ Resource planning via IRPs will be increasingly driven by CCAs going forward, and CCAs have an implicit bias toward local generation resources vs. distant resources delivered long distances via high-voltage transmission lines ▪ CEC and CPUC have defined a preferred "loading order" that prioritizes non-wire alternatives over transmission solutions ▪ Congestion continues to be a major concern driving needs for mitigation with new transmission projects in some areas of the footprint	▪ Potential to increase transfer capacity between wind and solar resource areas outside CAISO and demand centers in CA to meet policy needs ▪ Increasing transfer capacity with Pacific Northwest (for hydro imports) identified as an important tool for mitigating risks related to phasing out Aliso Canyon gas storage ▪ CAISO's Energy Imbalance Market (EIM) continues to expand its reach into new territory. Even with the EIM, renewable curtailments have continued increasing sharply, suggesting opportunities to put that to use via additional transmission capacity ▪ Additional transmission capacity can provide additional flexibility and diversity to address the growing need for ramping capability, resource adequacy ▪ Possible integration of offshore wind

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- U.S. Dept. of Commerce, Bureau of Ecommerce Analysis
- Regional, state, NERC demand growth forecasts
- S&P Global Market Intelligence

Appendix: Transmission Project Selection Criteria

Planning Process

- ISO Transmission Plan – An annual process that provides an evaluation of the ISO control grid, examines conventional grid reliability requirements and projects, summarizes key collaborative activities, and provides details on key study areas and associated findings.

Project Identification

- Transmission Economic Assessment Methodology (TEAM) groups benefits into the following categories:
  - Production benefits: Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade.
  - Capacity benefits: Benefits resulting from increased importing capability into CAISO's BA or into an LCR area. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.
  - Public-policy benefit: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in a remote area or by avoiding overbuild.
  - Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as oversupply and curtailment, by allowing sharing energy and ancillary services among multiple BAs.
  - Avoided cost of other projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project.

Criteria for Competitive Projects

- All regional projects (all more than 200 kV, some less than 200 kV)
- Upgrades/additions to existing lines or on existing rights of way/substations are exempt

Evaluation Criteria

- Capabilities of the project sponsor and its team to finance/license/construct/O&M
- Ability to acquire right of way
- Proposed schedule and demonstrated ability to meet schedule
- Technical and engineering qualifications and experience

Interregional Considerations

Contents

Filling Gaps: Considering Interregional Issues

Need to Augment View with an Interregional Lens

- **Regional legacy:** Regional characteristics help provide important context to what kinds of demand, resources, and resiliency risks are peculiar to a geography. However, those characteristics are driven by the historical growth of the bulk power systems in those areas—that is, the legacy transmission topography of a given area. Some of these legacy regional configurations are historical artifacts of grid and economic development, ownership (municipal, cooperative, or investor-owned utilities), and industry consolidation. In addition, a regional view does not fully acknowledge the potential for super-regional or interconnection-wide opportunities for grid support and renewable integration.
- **Pros and cons:** Of course, there are competing considerations with increasing linkages between regional grids. For resilience, the ability to island smaller grid components in the event of a major reliability event can be useful. Indeed, regional reliability coordination had its origins in a widespread power outage in 1965, and risks still existed in 2003 when the northeastern United States and southern Canada had a blackout that affected 50 million customers. Those risks—in part caused by system maintenance and lack of system understanding and situational awareness—are being mitigated through NERC standards.
- **Resilience and regionality:** However, interruptions due to resilience events can also be ameliorated by increasing access to power supply when local resources are inadequate or unavailable. Particularly as resource mixes in areas such as New England have grown more dependent upon gas-fired generation, increased access through transmission connectivity to other resources outside its control area, imported from adjacent regions, can enhance resilience against fuel-related risks.
- **Resource locations:** Another limitation of the regional view is that the regional location of resources for power production (fossil-fuel resources, solar irradiance, and productive wind speeds) may not be near major demand areas. For example, while Marcellus and Utica gas is plentiful in the Appalachian Basin areas of Pennsylvania, Ohio, New York, and West Virginia, some large demand areas lie west in the Great Lakes region and east along the Atlantic seaboard. While those resources can be piped to end-use demand locations, including power generation near load, pipeline development has become a protracted process. Further, solar and wind resources cannot be transferred between regions except through power transmission facilities.
- **Role of interregional linkages:** Consideration, then, needs to be given to how interregional approaches may enhance either renewable integration, specifically access to remote resources, and/or resilience through, for example, access to diverse resources.

Filling Gaps: Considering Interregional Issues (Cont'd)

Potential Benefits of an Enhanced Transmission Footprint

- **Foundational principle:** In the wake of the Northeast blackout of 1965, which affected 30 million customers over an 80,000 square mile region, the Federal Power Commission (now FERC) concluded: "Isolated systems are not well adapted to modern needs either for purposes of economy or service" and recommended "…an acceleration of the present trend toward stronger transmission networks within each system and stronger interconnections between systems in order to achieve more reliable service at the lowest possible cost." This remains a foundational principle for interregional links. In particular, according to WIRES and The Brattle Group, "If an adverse event overwhelms the regional ability to absorb or manage the event, interregional transmission connections allow regional operators to 'lean' on neighbors for emergency support.... Recognition that stronger interregional transmission links could have prevented these outages led to the expansion of the transmission grid into the large regional networks we have today." (WIRES Grid Resilience Docket Comments, at Appendix p. 5)
- **Load diversity:** Even within large regions, enhanced access to resources across a wide geographic area can provide benefits that reduce the cost of serving customers. PJM recently studied the value of transmission within its footprint. It determined that with broader market integration, the system benefited from load diversity and generator diversity. Diversity of customer demand (or load diversity*) across the PJM region has increased from 1% to 3.5% since 2002, allowing resources to be reallocated and sent from a lower-demand zone to a higher-demand zone during peak periods. This increases reliability and captures larger economies of scale, including lowering required levels of capacity reserves (by about 2,500 MWs in PJM), thus reducing customer costs. (Benefits White Paper, at pp. 4, 19–20).
- **Generator diversity:** Benefits of generator diversity are manifested in several ways. There is a capacity benefit in that there is a wider pool of resources with diversity in fuel type, size, flexibility and duty cycle, and location that allows the next lowest cost resource to serve load. This wider pool also potentially provides less correlation of maintenance and forced outages, leading to greater overall availability. Those benefits are dependent upon fuel diversity, including pipeline, rail, solar irradiance, and wind availability.

*Note: Load diversity is defined as the sum of all zonal non-coincident MW annual peaks minus RTO coincident MW annual peak.

Filling Gaps: Considering Interregional Issues (Cont'd)

Unique Characteristics of Renewable Resources

- **Less predictable in real time:** Renewable energy resources are variable energy resources, uncertain both in output and timing versus conventional thermal resources, and inherently less predictable. These resources, however, have low or zero marginal cost, so their energy output is attractive from an economic standpoint. The environmental characteristics of this energy are attractive as well. Power systems have been designed to manage variable nature of loads, but only recently have supply resources included a significant amount of variable resources in some regions, posing challenges for system operators.
- **Solar variability and coincidence with load:** Despite its variability, renewable resource output is not completely unpredictable. And their variability differs both daily and seasonally. Solar energy output over the course of a day is predictable because solar movement is well-understood as is its seasonal variation (e.g., fewer daylight hours in winter, more daylight hours in summer). Less predictable is the presence of clouds that may pass over solar power plants and reduce output for periods of time, typically for shorter intervals (minutes versus hours). Cloud cover can rapidly reduce output in individual photovoltaic (PV) systems. Overall grid impacts are minimized, however, when solar projects are spread out geographically to account for both solar movement and weather systems. Solar output is greater during the middle of the day, sometimes coincident with peak load.
- **Wind variability and less coincidence with load:** By contrast, wind can be less predictable than solar, but still subject to daily and seasonal patterns. Wind energy is often more abundant during the nighttime hours and the wintertime. Changes in wind output from a particular facility, however, can occur quickly and last for hours as weather systems move through an area. The non-coincidence of load and wind—that is, relatively high-wind production during low-load nighttime hours—creates challenges for grid operators and other generators. In high-wind penetration areas, thermal-baseload generation may have to be "turned down" or run at minimum-operating levels.
- **Scale and potential ramping needs:** Another important differentiator between wind, solar, and other resources is scale. A typical wind farm (i.e., an incremental unit of independent capacity) in the United States ranges from 10 MWs to 300 MWs. Utility-scale solar capacity is typically in smaller increments, mostly in the 5 MWs to 100 MWs range. This affects the amount of ramping capability, up or down, required to meet demand and maintain system integrity should those resources become unavailable or provide unusually large amounts of output.

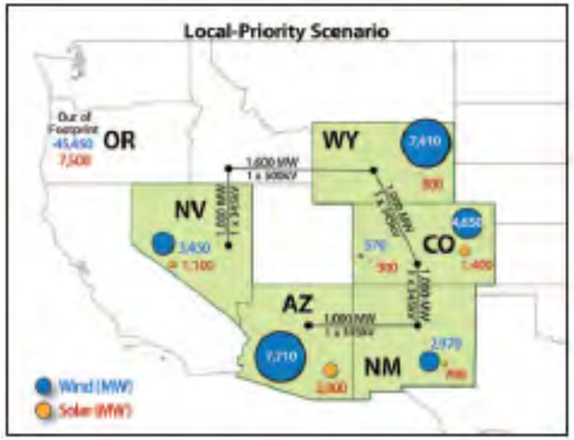
Many have observed that a diversity of technologies and geography improves the ability of renewable resources to mitigate the risk of losing load. Transmission enhancements can provide the linkage to provide that diversity across a broader footprint and improve renewables' load-serving capability (particularly in high-penetration scenarios), as well as providing access to needed ramping capability and reliable interconnection of new resources.

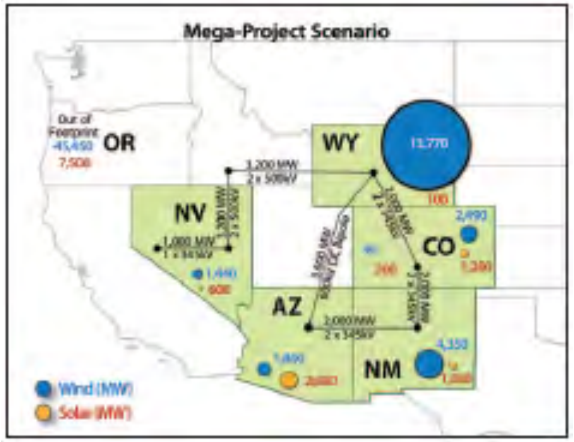
Renewable Integration Studies

Western Regional Analysis

- The electric industry has studied renewable integration for a number of years, in the wake of state policy changes incorporating renewable portfolio standards (RPS), declining installed costs for renewable resources, and industry and stakeholder interest in development of renewable resources, including replacing retiring thermal units. Those studies looked at renewable penetrations at various levels by interconnection.
- In a 2010 report, well before the current proliferation of variable energy resources, the National Renewable Energy Laboratory (NREL) looked at various scenarios of integrating up to 35% of wind and solar power in the Western grid, specifically in the WestConnect footprint. That study examined the potential for penetration of up to 30% wind and 5% solar energy for load and implications for particular technical and physical barriers for transmission system operations. Although it was not a transmission planning or reliability study, it proves instructive for understanding interregional needs. NREL found that integration of 35% wind and solar energy could be achieved if the following changes, among others, were made:
  - **Substantially increase balancing area cooperation or consolidation, either real or virtual.** Balancing area cooperation is essential since aggregating diverse renewable resources over larger geographic areas reduces the overall variability of the renewables, aggregating the load reduces the overall variability of the load, and aggregating the non-renewable balance of generation provides access to more balancing and more flexible resources. This is particularly true for smaller areas. Balancing area cooperation leads to cost savings because reserves can be shared.
  - **Build transmission as appropriate to accommodate renewable energy expansion.** The study did not find a need to build-out interstate transmission at lower penetrations or where more locally sourced renewables were preferred or prioritized. However, where targets were met using an area-wide evaluation of the best available solar and wind resources, additional transmission totaling 2,100 to 6,900 gigawatt-miles would be needed, mostly to bring Wyoming wind resources to load centers (see figure at right).

Two Scenarios Show Need for More Transmission to Integrate Wind and Solar





Source: NREL

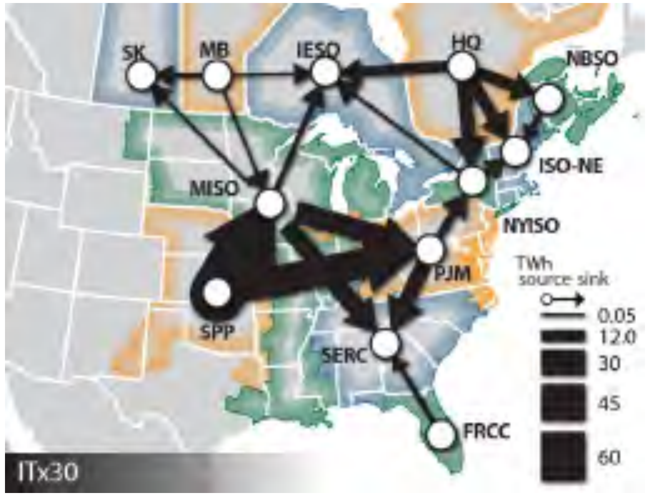
Sources: NREL, Western Wind and Solar Integration Study (May 2010)

Renewable Integration Studies (Cont'd)

Eastern Regional Analysis

- In 2016, NREL performed a similar analysis of high-renewables penetration in the Eastern Interconnection (EI): the Eastern Renewable Generation Integration Study (ERGIS). ERGIS was an operational impacts study; it was not designed to identify the most optimal mix of generation and transmission or analyze dynamic power system characteristics. It used a scenario-based approach to understand system-wide operational impacts of high amounts of variable generation on the EI under different transmission grid configurations.
  - ERGIS used different levels of renewable target penetration levels and assumed transmission capacity at different levels from minimal to substantial, based upon scenarios for needed transmission identified by the Eastern Interconnection Planning Collaborative. Those transmission scenarios were (i) business as usual (limited renewable or carbon policy requirements), (ii) a national RPS of 30%, and (iii) a national carbon constraint. While current national policy does not embrace (ii) and (iii), selected state policy action provides some momentum toward scenario (ii), which can be instructive.
  - The NREL analysis found the following in high-penetration scenarios:
    - As coal and gas combined cycle units are displaced by increased wind and solar, daily operational patterns change, with increased ramping before and after peak solar generation. These operational impacts are greater where there is more solar and less interregional transmission.
    - Daily transmission flows between regions change more as more renewables are added to the system, in part due to assumed increased transmission build-out, but also seen at high-renewable penetration levels.
    - One caveat to the study's analysis was that it assumed that all areas in the EI possessed characteristics of a structured market. However, the EI is comprised of both organized and vertically integrated markets, which may have different incentives for power exchanges.

Potential Net Energy Interchange in 30% Renewables, HVDC-Enabled Scenario



Scenario above:
- About 30% utility-scale variable generation (25% wind, 5% solar)
- Emphasis on the best wind and PV resources in the U.S. EI
- Assumed interregional transmission expansion with large high-voltage direct current (HVDC) lines (2 lines x 3.5 GWs each) between
  - SPP and PJM
  - MISO and PJM
  - Western MISO and Eastern MISO

Source: NREL

Sources: NREL, Eastern Renewable Generation Integration Study (Aug. 2016)

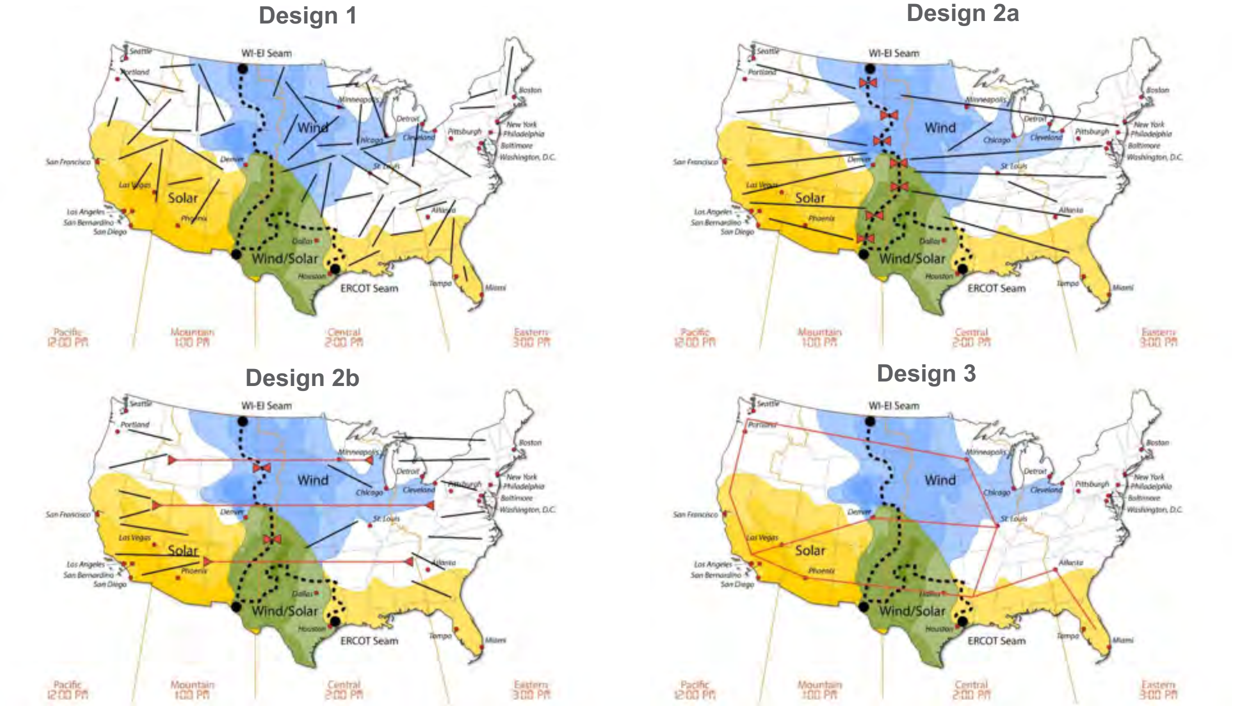
Renewable Integration Studies (Cont'd)

Interconnection Seams Study

- In 2018, NREL presented analysis of several scenarios for U.S. grid design, with consideration given to moving locationally concentrated variable energy resources (specifically wind and solar) to demand centers. The analysis considered potential movement of resources across interconnections (East, West, and Texas). Scenarios ranged from replacement of existing AC facilities at current capacity levels with new transmission and generation optimized to minimize system-wide costs to a national scale high-voltage DC network (see maps at right). Note that only 1,300 MWs of capacity exists joining Eastern and Western Interconnections.
- NREL's preliminary results found that increased capacity, including capacity across the interconnection seams, has a positive benefit-to-cost ratio and provides production cost savings from $800 million to $2.5 billion under current policy (i.e., no national carbon tax and RPS as of 2017). Substantial AC transmission capacity is added in all cases.
- The analysis also found that the system is reliable from a resource adequacy perspective, and all load was met under N-1 constraints. Additional analysis for reliability and resilience is required.
- The study, however, made certain assumptions, including a centralized dispatch approach to modeling (versus real-world regional dispatch decisions) and that economic transmission is able to be constructed. It also modeled a single year and did not perform a probabilistic analysis.

While only a modeling exercise, the seams study highlights the potential for increased transmission capacity to provide cost savings opportunities through better delivery of renewable resources to market.

Design Alternatives for NREL Interconnection Seams Study*



1	2a	2b	3
Existing B2B facilities are replaced at their current (2017) capacity level and new AC transmission and generation are co-optimized to minimize system-wide costs.	Existing B2B facilities are replaced at a capacity rating that is co-optimized along with other investments in AC transmission and generation.	Three HVDC transmission segments are built between the Eastern and Western Interconnections, and existing B2B facilities are co-optimized with other investments in AC transmission and generation.	A national scale HVDC transmission network, Macro Grid, is built and other investments in AC transmission and generation.

Source: NREL

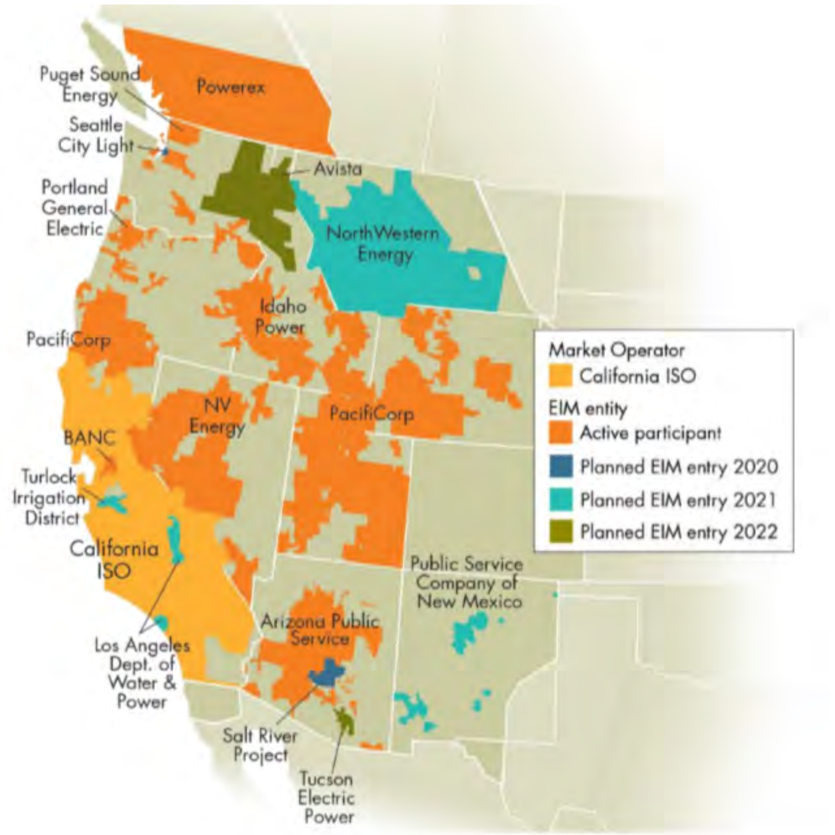
Notes: *Maps show high-solar and wind resource regions; cities shown are Top 25 U.S. population centers.
Sources: NREL Interconnection Seams Study, Presentation by A. Bloom, TransGrid-X Symposium (July 26, 2018)

Case Studies

Western Energy Imbalance Market

- Ambitious California clean energy goals: California was an early actor on renewable energy goals and has increased its already ambitious renewable energy goals to target 60% of its energy needs from renewables by 2030 and 100% carbon emissions-free energy by 2045. In pursuit of those goals, significant amounts of utility-scale and distributed energy resources (DERs), largely solar, have been installed on the system, administered by the California ISO (CAISO).
- Ramping and curtailment: As these resources have increased, net load (load less utility-scale wind and solar output) has seen dramatic drops coinciding with the solar cycle, dropping in early morning and rising significantly in late afternoon, with significant solar energy surplus during the middle of the day, particularly in low-load seasons of spring and fall (known as the “duck curve”). CAISO has had to curtail solar output for system stability in those overages. In addition, as thermal generation has been retiring, the steep ramps in late afternoon/early evening have created increased demand for ramping capability. Steadily decreasing net load (see next page) exacerbates these challenges.
- Imbalance market formed: CAISO formed the Western Energy Imbalance Market (WEIM) with northern neighbor PacifiCorp in late 2014. The WEIM is a real-time, five-minute market that uses “as available” transmission to move energy across a larger geographic area—and different time zones—allowing for more flexibility in scheduling and dispatching. The WEIM covers eight western states and more than half of the real-time energy in the region. As of August 2019, there are nine active participants, with eight more pending. There is some discussion of potentially expanding the market to include day-ahead transactions.

WEIM Market Participants (Current and Pending)



Source: California ISO

Sources: Western Energy Imbalance Market website, at www.westerneim.com

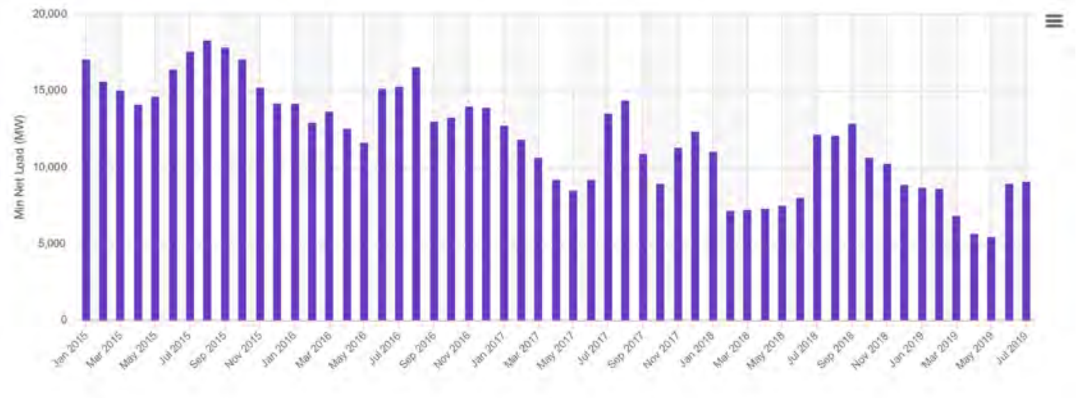
Case Studies (Cont'd)

Western Energy Imbalance Market (Cont'd)

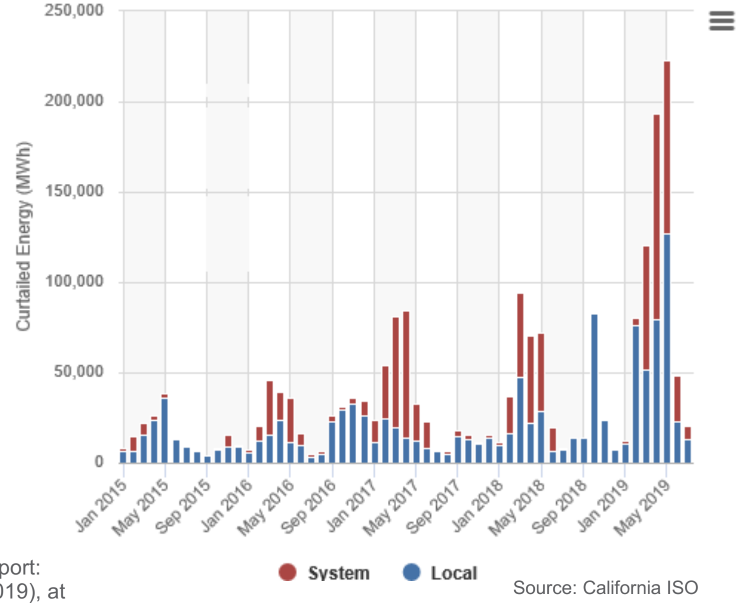
- **Savings and benefits:** The reach of resources across a wider area has generated benefits and savings related to uncurtailed renewable energy, including hydro and wind power from the Northwest. Savings from the WEIM since its inception total more than $700 million through Q2 2019, growing as participation in the WEIM as expanded. In Q2 2019, nearly 57,000 metric tons of CO_2 emissions were avoided through avoided curtailment and an estimated 45% reduction in flexibility reserves across the WEIM footprint.
- **Continued needs:** Despite this growth, California has seen a growth in economic curtailment of resources (solar, mostly), attributable to a mix of local and system conditions. This could signal opportunity for transmission expansion as well as increasing membership in WEIM.
- **Alternative approaches:** California system operators and state energy agencies are also considering other approaches to managing variability of increasing energy storage, energy efficiency, and demand response systems so that energy users can reduce use when the grid is low on supply; offering time-of-use rates that better match energy production times and are an incentive to reduce energy use; integrating electric vehicles and encouraging owners to charge when supply is high; and improving flexibility of power plants.

WEIM demonstrates that access to and high utilization of transmission resources across a large footprint with variable energy resources increase its market reach. Organized Eastern power markets have had real-time markets for some time, and congestion costs signal the opportunity to invest in transmission upgrades to access more diverse resources.

CAISO Monthly Minimum Net Load (Jan. 2015 – July 2019)



Monthly Economic Curtailment in the WEIM 5-minute Market (RTD) by System Condition



Source: California ISO

Sources: Western Energy Imbalance Market website, at www.westerneim.com; CAISO, Western EIM Benefits Report: Second Quarter 2019 (July 31, 2019); California ISO, Monthly Renewables Performance Report (July 2019), at http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Jul2019.html

Case Studies (Cont'd)

European Grid Expansion

- **Ambitious renewables goals:** In Europe, countries have begun a process of aggressively shifting to a generation mix that incorporates significantly more renewables. For example, Germany's energy transition has reduced nuclear-generating capacity and seeks to reduce its coal-fired generation, supplanting both with wind, solar, and imported hydro.
- **Resource location:** Renewable resources, however, are not evenly distributed through the continent. Large amounts of offshore wind and hydro are in the north and northwest with solar potential in the south.
- **Planning for uncertain grid characteristics**: In addition, grid planners have to deal with planning uncertainty for new demand sources (electric heat pumps and electric vehicles) and distributed resources. Planners also have to deal with declining levels of system inertia in areas like Ireland, which are small, weakly interconnected, and have abundant variable energy resources.
- **EU interconnection target:** One approach to grid integration has been the European Union's (EU) target of 10% interconnection by 2020, moving to 15% by 2030. Under this target, each EU member state should have in place "electricity cables" that allow at least 10% of the electricity that is produced by their power plants to be transported across its borders to its neighboring countries. Expected interconnection levels for 2020 range from 12% to 59%. This integration is being accomplished through "projects of common interest" to increase grid reinforcement.
- **Grid scenario planning:** ENTSO-E, the European electric system operator, uses scenario-based planning to develop 10-year network development plans. Key metrics it uses in evaluating options include unserved energy (load), curtailed energy, CO_2 emissions, cost differentials between regions (average hourly cost and marginal cost yearly average), and cross-border and country-internal bottlenecks. In its most recent plan, ENTSO-E looked out to 2030 and 2040, evaluating market evolutions options, such as steady renewables growth (but short of 2050 climate targets), large-scale renewables growth, and increasing distributed generation (e.g., small-scale decentralized generation, batteries, and fuel switching). Scenarios considered moving from about 15% wind and solar continent-wide in 2020 to around 30% by 2030 and 37% to 50% by 2040 (ENTSO-E TYNDP 2018 System Needs Analysis, at p. 36). **Its analysis showed that internal reinforcements and interregional capacity increases would save customers €43 billion per year versus less integration.**

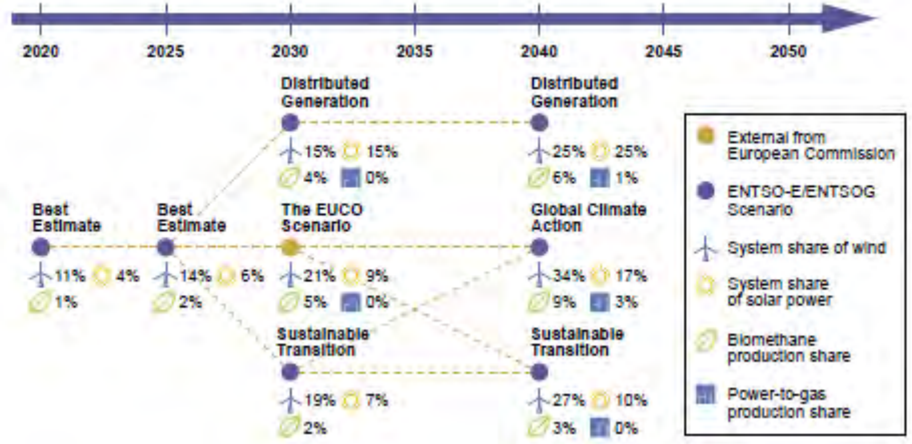
Sources: ENTSO-E, European Power System 2040: Completing the Map, Ten-Year Network Development Plan, 2018 System Needs Analysis (Feb. 2018); ENTSO-E, TYNDP 2018 Executive Report: Connecting Europe: Electricity 2025-2030-2040 (Dec. 2018); European Commission, Communication on Strengthening Europe's Energy Networks, COM (2017) 718 (Nov. 23, 2017)

Case Studies (Cont’d)

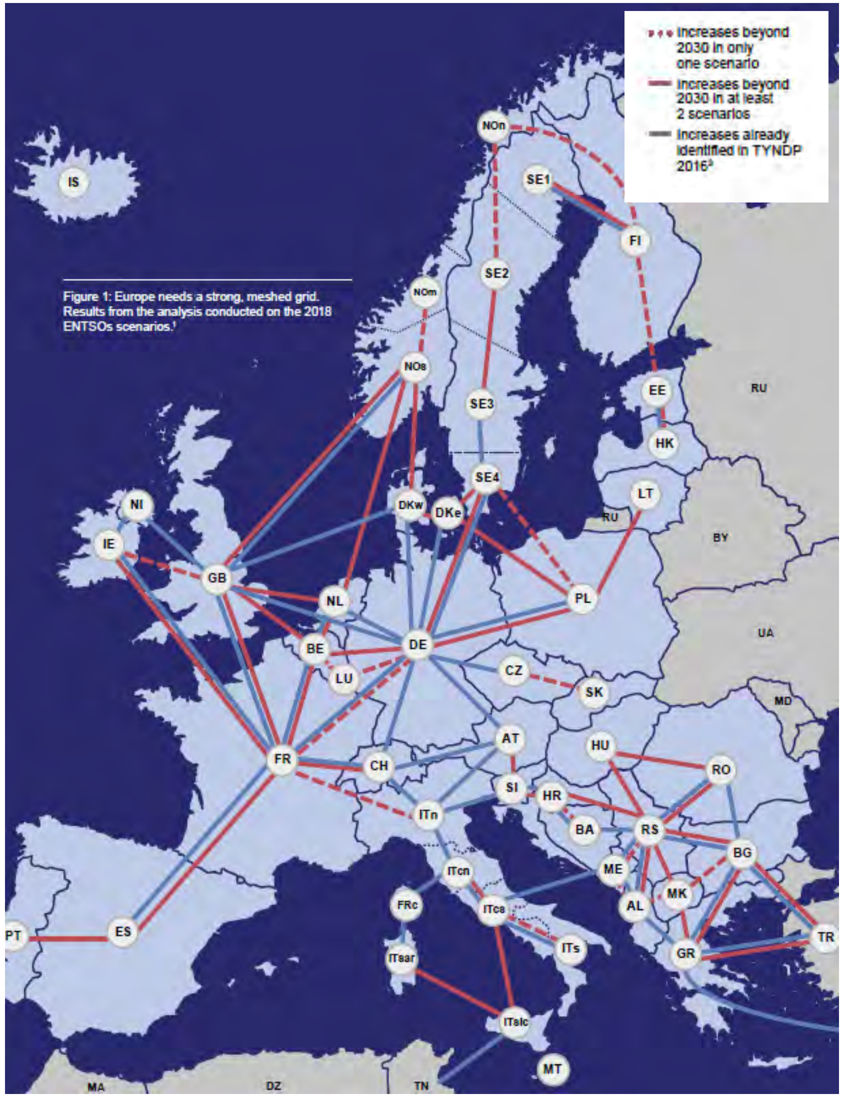
European Grid Expansion (Cont’d)

- **First step in planning:** The European 10-year development plan is not prescriptive, but it provides a framework for evaluation of projects, including more detailed regional and member state planning incorporating local considerations; system needs (stability, voltage, and other technical issues); and technology options.
- **Possible lessons:** Of course, one difference between the European and North American industry environments is the alignment of policy objectives around EU’s commitments on climate and other relevant policy objectives. **However, European grid development, in response to greater development of renewable resources, may be a view into the future in North America, and it may provide some useful lessons for higher-interregional linkages.**

ENTSO-E Scenarios for 2018 System Needs Analysis



Source: ENTSO-E



Source: ENTSO-E

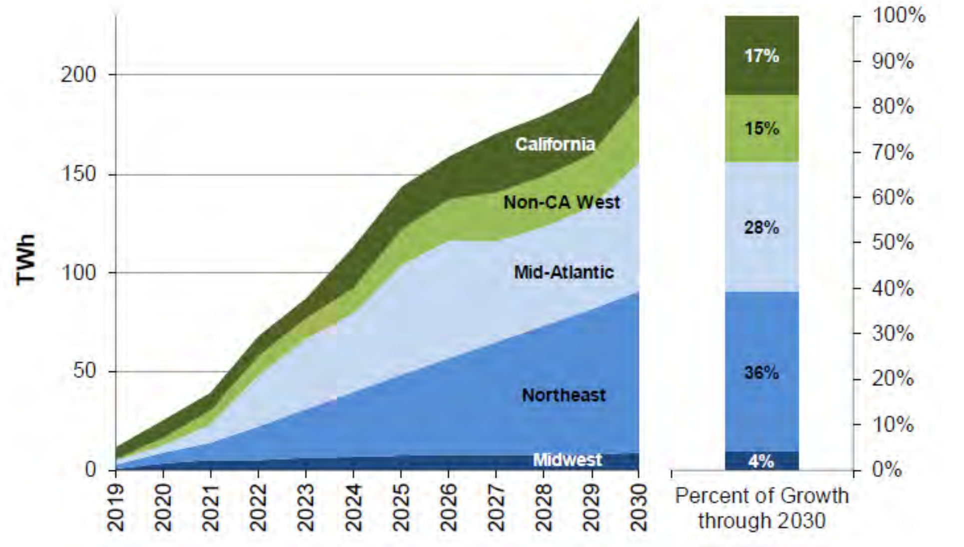
ENTSO-E 2018 System Needs Analysis: Summary of Identified Border Increases in 2040

Clean/Renewable Energy Supply-Demand Balance

Clean Energy Goals Continue to Advance

- **Interregional benefits:** Both renewables and transmission advocates have long made the case that interregional transmission can yield benefits by moving large, utility-scale, zero-marginal cost solar and wind power from the best resource areas to load centers.
- **Large project queues:** As installed costs for both wind and solar installations have declined, more renewable energy projects have been proposed in the United States, as evidenced by interconnection queues nationwide. As noted by AWEA, 89 GWs of proposed wind capacity was added to interconnection queues nationwide in 2018, the largest volume of new additions since 2008. About 137 GWs of solar capacity was added to interconnection queues in 2018. At the end of 2018, wind and solar capacity in interconnection queues totaled 225 GWs and 282 GWs, respectively, followed by 86 GWs of gas-fired capacity (see chart on next page). Of course, only a small share of projects are built, in part, because of (historically) low-queue entry and exit requirements (AWEA 2018 Market Report, at p. 125).
- **Intraregional efforts:** Intraregional development has been taking place, helping integrate new resources, alleviate congestion, and reduce curtailment. Project portfolios, such as MISO's Multi-Value Projects and CapX2020 and SPP's Priority Projects, have been critical in providing market access to higher-quality renewable resources.
- **Analyzing renewable supply and demand:** To help inform the potential needs for interregional transmission to meet clean energy and RPS demands, we took a long-term look at projected utility-scale wind and solar generation potential and compared that with estimated regional demand for clean energy. **While this analysis is indicative and not prescriptive, it may point to additional "trail signs" of opportunities for enhanced interregional transfer capabilities.**

Required Increase in Renewable Portfolio Standard Compliance Generation Through 2030 by Region (TWh) (LBNL Est.)



Source: LBNL

Lawrence Berkeley National Laboratory estimates a required 270 TWh (about 50%) increase in renewable generation by 2030.

Clean energy standards introduce a new dynamic: As development continues in resource-rich regions, what has changed in recent years is that more states and utilities—including areas that may be less renewable resource-rich—are proposing clean energy and more ambitious RPS and targets. These new and updated standards will likely drive resource development and additional transmission needs to ensure deliverability to jurisdictions and utilities that have prioritized clean energy.

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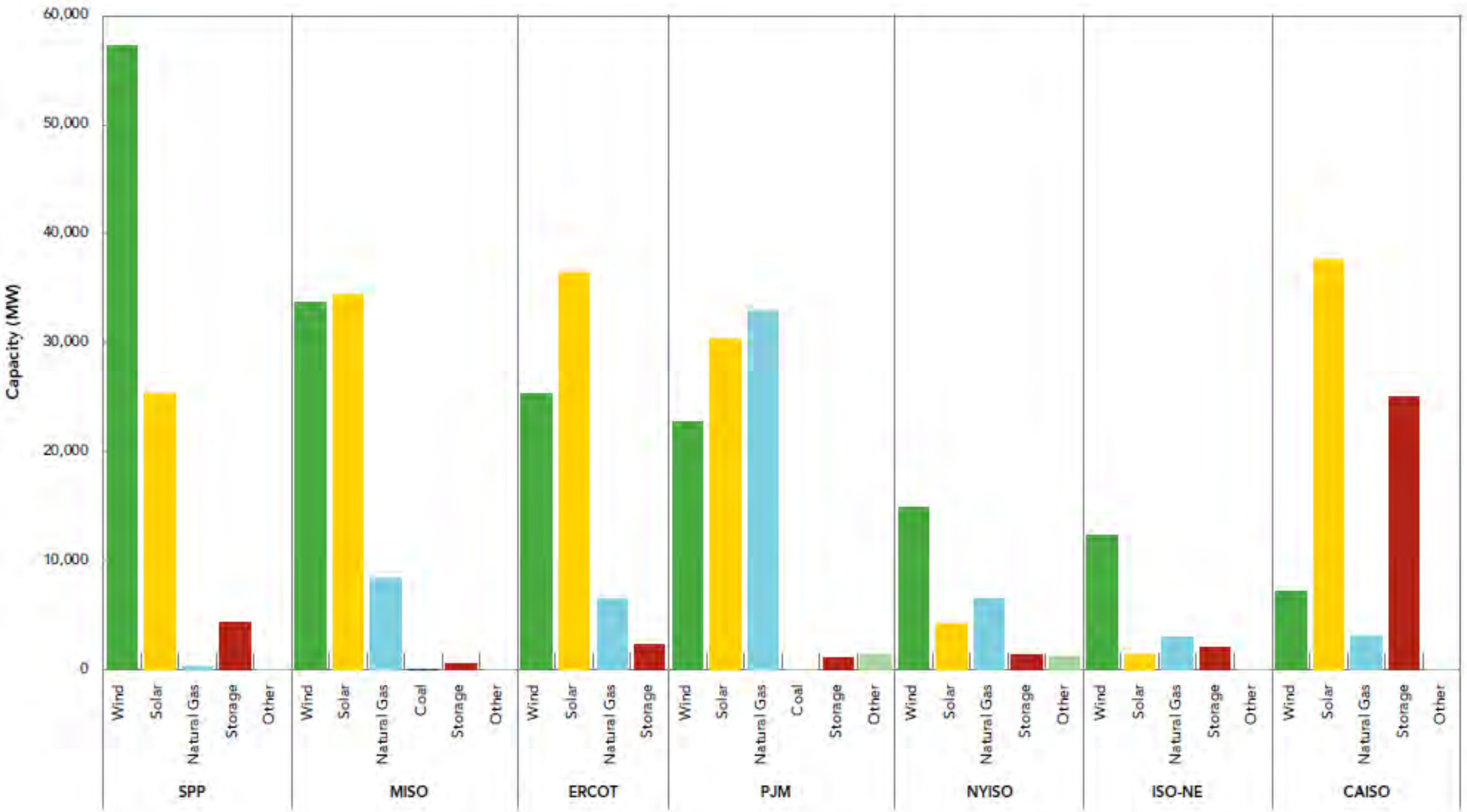
Sources: AWEA; SPP, MISO transmission planning materials; LBNL

Clean/Renewable Energy Supply-Demand Balance (Cont'd)

Clean Energy Goals Continue to Advance (Cont'd)

Interconnection Queue Activity Across RTOs by Technology Type (Year-End 2018)



While renewable resources, particularly wind and solar, are being developed nationwide, the regions in which they are being developed do not necessarily coincide with areas requiring RPS-driven energy (per the previous page).

Source: AWEA

Clean/Renewable Energy Supply-Demand Balance (Cont'd)

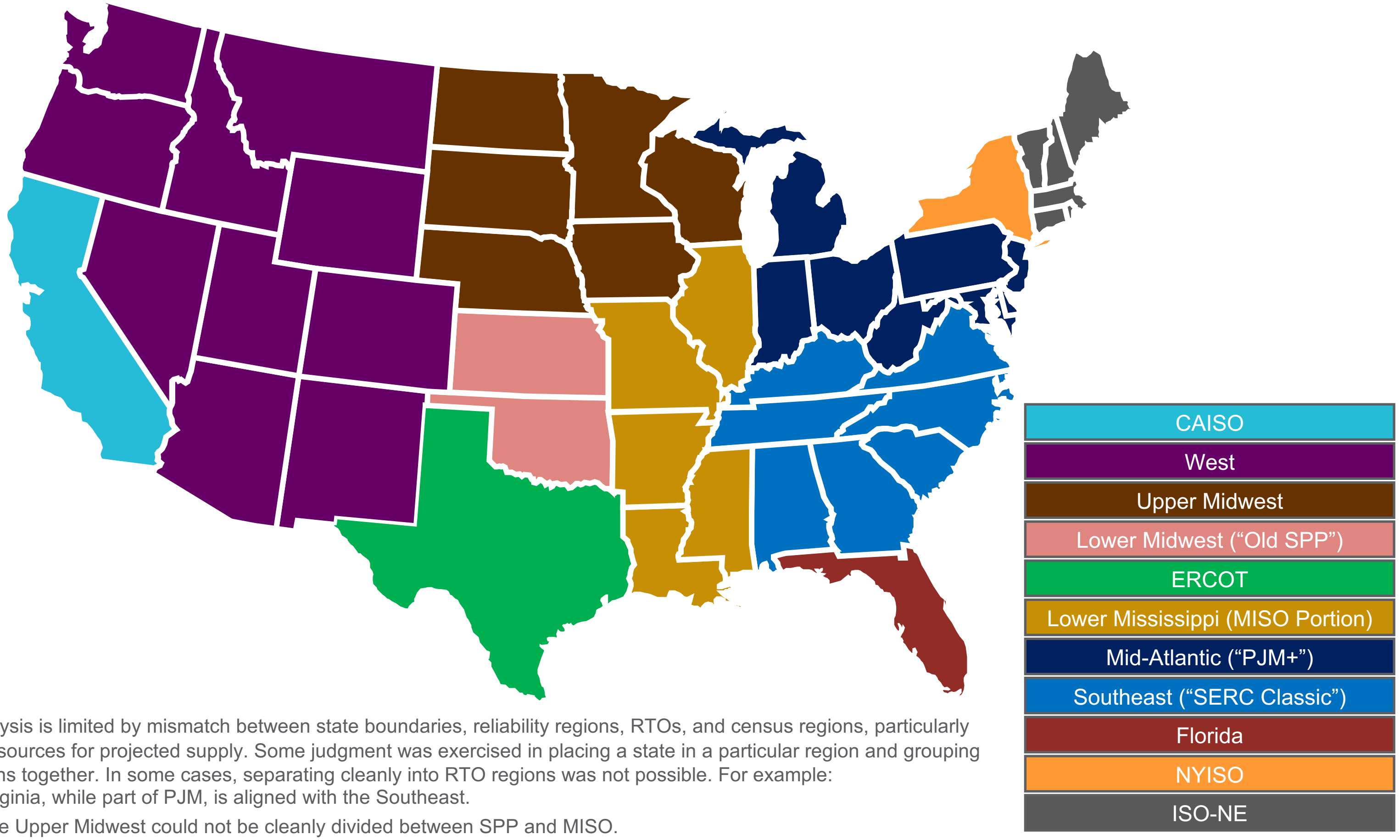
Supply/Demand Analysis Overview

- To complement our regional analysis, we looked at each region's expected supply of wind and solar resources (typically the primary resources intended to fulfil renewables policy mandates) and expected renewables demand, driven by retail sales growth and renewable or clean energy standards targets.
- Renewable power supply was based upon Energy Information Administration's (EIA) annual energy outlook, which projects multi-decadal electricity resources by technology. For near-term analysis, we triangulated against AWEA and SEIA/Wood Mackenzie forecasts of installed utility-scale wind and solar.*
- Renewable demand was based upon state's RPS/clean energy goals as of August 2019, existing state-level retail sales**, and forecast load growth (at the state level or the most granular level available).
- This analysis indicates potential imbalances between state renewable and clean energy targets and forecast solar and wind resources in the respective regions.

Analysis Regions

- Regions were grouped as closely as possible to the regional breakdown elsewhere in this report (RTOs plus Southeast and West regions) (shown at right).

Regional Groupings for Clean Energy Supply/Demand Comparison Analysis

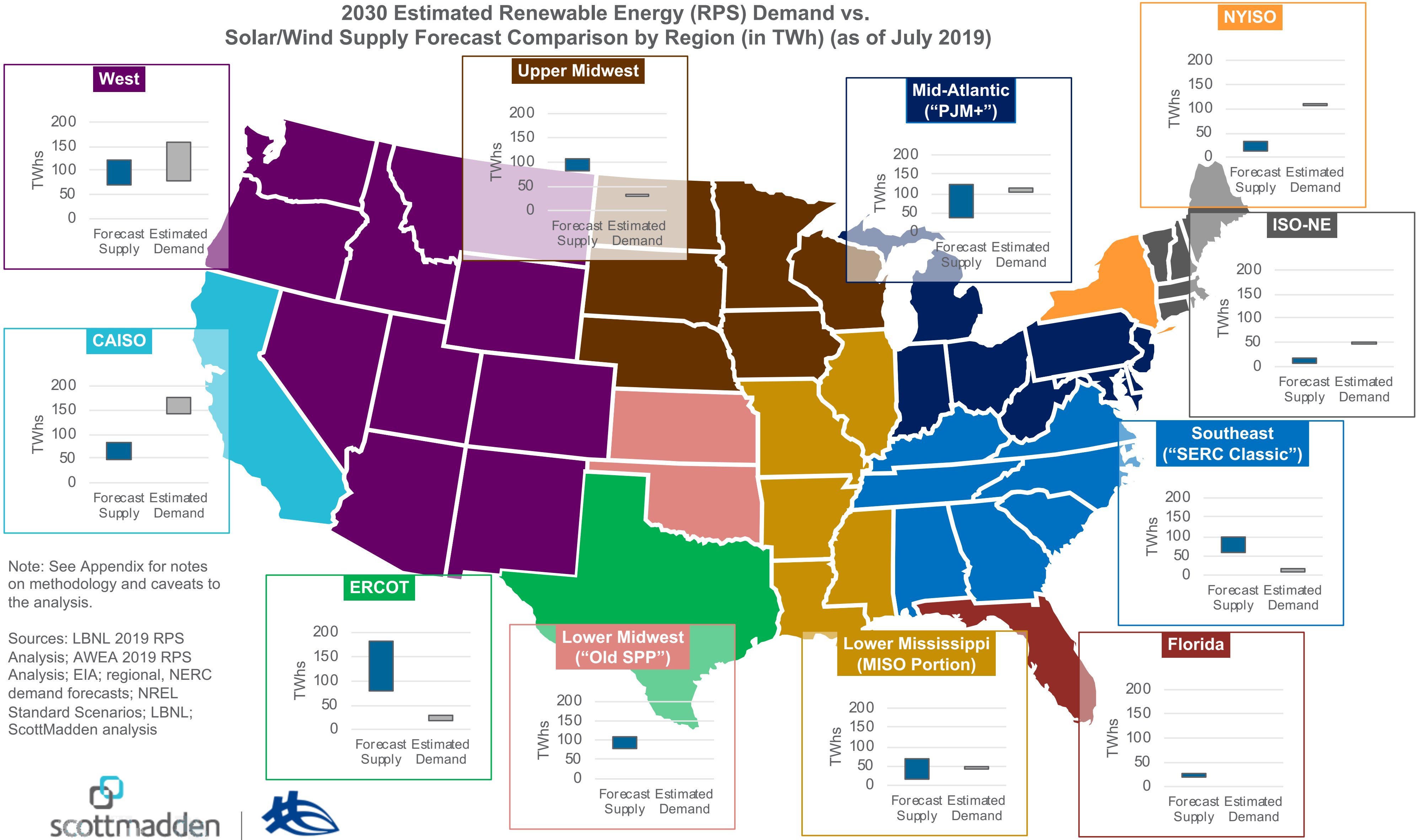


Notes:
This analysis is limited by mismatch between state boundaries, reliability regions, RTOs, and census regions, particularly the data sources for projected supply. Some judgment was exercised in placing a state in a particular region and grouping subregions together. In some cases, separating cleanly into RTO regions was not possible. For example:
- Virginia, while part of PJM, is aligned with the Southeast.
- The Upper Midwest could not be cleanly divided between SPP and MISO.
- SPP's old footprint (KS, OK) is shown as a standalone region, although it is managed electrically with states to the north.

*American Wind Energy Association; Solar Energy Industries Association

**Lawrence Berkeley National Lab analysis was used to apply the renewable demand analysis only to sales that would be subject to RPS goals, where they were limited to certain utility types (e.g., investor-owned utilities).

Clean/Renewable Energy Supply-Demand Balance (Cont'd)



2030 estimates
Clean energy demand (standards): 600 TWh (per LBNL) to 714 TWh (latter is ~17% of estimated 2030 U.S. retail sales)

Key Takeaways

- As shown here, by 2030, many regions are projected to have adequate or excess renewable supply compared with "headline" clean energy demand.
- The West (including California), New England, and New York appear to have opportunities for additional supply, perhaps through imports from other regions.
- This analysis does not include corporate, utility, or state clean energy "goals" that do not have regulatory or legislative force; thus, additional potential regional demand may be higher.

Note: See Appendix for notes on methodology and caveats to the analysis.

Sources: LBNL 2019 RPS Analysis; AWEA 2019 RPS Analysis; EIA; regional, NERC demand forecasts; NREL Standard Scenarios; LBNL; ScottMadden analysis

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- PJM Interconnection, The Benefits of the PJM Transmission System (Apr. 16, 2019) (Benefits White Paper)
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- Western Energy Imbalance Market website, at www.westerneim.com
- S&P Global Market Intelligence
- Industry news

Appendix: Clean Energy Supply/Demand Balance Analysis Notes

Some Caveats and Notes on Methodology

- **Simplified assumptions:** This analysis is a view of order of magnitude differences between renewable or clean energy needs and supply and not a precise supply-demand forecast for meeting RPS obligations. This analysis does not account for carve-outs for local renewables development nor technology (including, e.g., distributed solar, hydro, or nuclear) or the role of energy efficiency or demand-side management resources to meet RPS demand was not factored even where states allow. Further, it does not factor in credit multipliers that some jurisdictions include for certain preferred technologies. Nor does it make distinctions between classes of resources or limits on certain types of technologies (e.g., wind or solar eligibility limits). It assumes that utility scale wind and solar will be the principal technologies to meet renewable portfolio standards demand.
- **Banked RECs not considered:** A few states have already reached their targets. This analysis does not analyze the impact of banked renewable energy credits (RECs) on future year compliance (and hence potential demand reduction or supply met by RECs).
- **Forecast capacity and generation:** Potential solar and wind capacity development was estimated using renewable industry forecasts in the near term. Further out (beyond five years), installed capacity and generation was taken from forecasts using the EIA's latest Annual Energy Outlook and the NREL's Standard Scenarios (Mid-Case Scenario), which is reflected in the range of renewable supply by region. Note that NREL's Mid-Case Scenario includes some assumptions about transmission expansion that informs projections of resource development. That forecast capacity was converted to estimated MWhs generation using assumed, typical capacity factors. Note that this comparison assumes that U.S. utility-scale solar and wind (onshore and offshore) generation will be the supply resources to meet RPS demand.
- **Forecast demand and RPS demand:** Clean energy demand was based upon 2018 retail sales (escalated annually by a growth rate) as most clean and renewable energy standards are based upon retail sales. Usage growth rates (in some cases negative) were applied to project future retail electricity sales. Those assumptions came from the most specific sources possible. For those without state-specific growth rates, regional growth rates from NERC were applied. RPS and clean energy targets were weighted (using DOE Berkeley National Laboratory analysis) based upon utility type, as many states impose different requirements on investor-owned utilities versus others. RPS demand was based upon state RPS targets as of July 2019. Clean energy goals were not included unless they included a correlative RPS; for Washington state, based upon the clean energy goal legislation's language, we assumed the clean energy standard effectively created an 80% renewable target in 2030.

Differences in Demand Assumptions Driving Range of RPS Demand

- The range of demand assumptions is bounded by ScottMadden analysis and LBNL analysis of projected RPS demand. Small differences arise from use of the simplifying assumptions above (carve-outs, exclusions, banked RECs, etc.). The larger ranges are principally in the West, reflecting the following differences:
  - Assumptions for California retail sales growth
  - Change in clean energy (and assumed RPS) target for Washington from recent legislation

Resilience

Contents

Resilience Background

- **Defined:** FERC defines resilience as the ability [of the electric system] to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.
- **Regional variation:** Resilience issues vary between regions and even within large regions. Some resilience issues are common because they are global in nature or not peculiar to a region, including cyber and physical threats, geomagnetic disturbances, or electro-magnetic pulses. Many threats vary because of location and vulnerability of infrastructure, proximity to resources (including fuel), weather patterns, climatic trends, and seismic conditions.
- **NERC Framework:** NERC, along with the National Infrastructure Advisory Council (NIAC) and numerous other state and federal agencies, have been studying resilience needs for the U.S. electric system. NERC, tasked with overseeing bulk power system reliability, is also developing a resilience framework. These resilience activities are especially focused on long-duration events that can impact other critical infrastructure as well as first response and core social services. NERC's framework envisions four elements, reflecting different parts of an event occurrence:
  - Robustness – the ability to absorb shocks and continue operating
  - Resourcefulness – the ability to detect and manage a crisis as it unfolds
  - Rapid Recovery – the ability to get services back as quickly as possible in a coordinated and controlled manner, taking into consideration the extent of the damage
  - Adaptability – the ability to incorporate lessons learned from past events to improve resilience
- **Enhancement focus:** As the DOE has observed, resilience enhancement is generally focused on three primary goals: "(1) preventing or minimizing damage to help avoid or reduce adverse events; (2) expanding alternatives and enabling systems to continue operating despite damage; and/or (3) promoting a rapid return to normal operations when a disruption occurs (i.e., speed the rate of recovery). Resilience relates both to system improvements that prevent or reduce the impact of risks on reliability and to the ability of the system to recover more quickly." (QER2, at p. 4-42)
- **Two key questions:** One key question is how the increasing proliferation of renewable resources and their integration may affect these resilience elements and what kinds of complementary capabilities might grid integration bring to system robustness, resourcefulness, and recovery. Another important question is how can transmission investment support resilience.

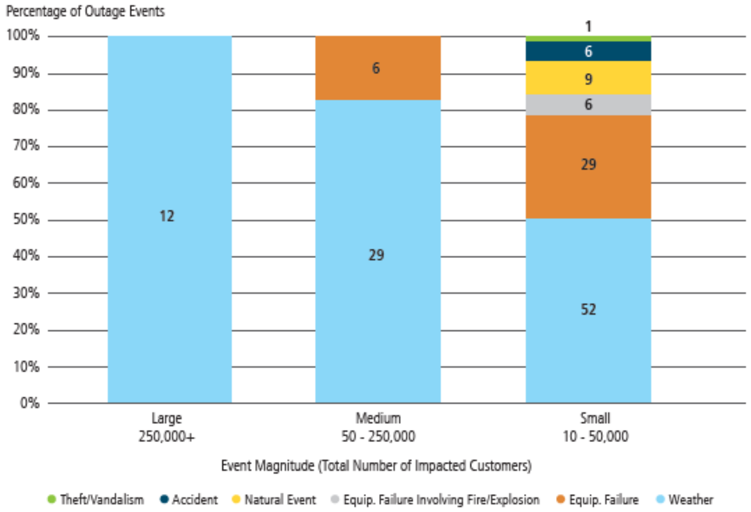
Sources: NIAC; NERC Steering Comm.; QER2

Access to Reserves in Fuel-Constrained Situations

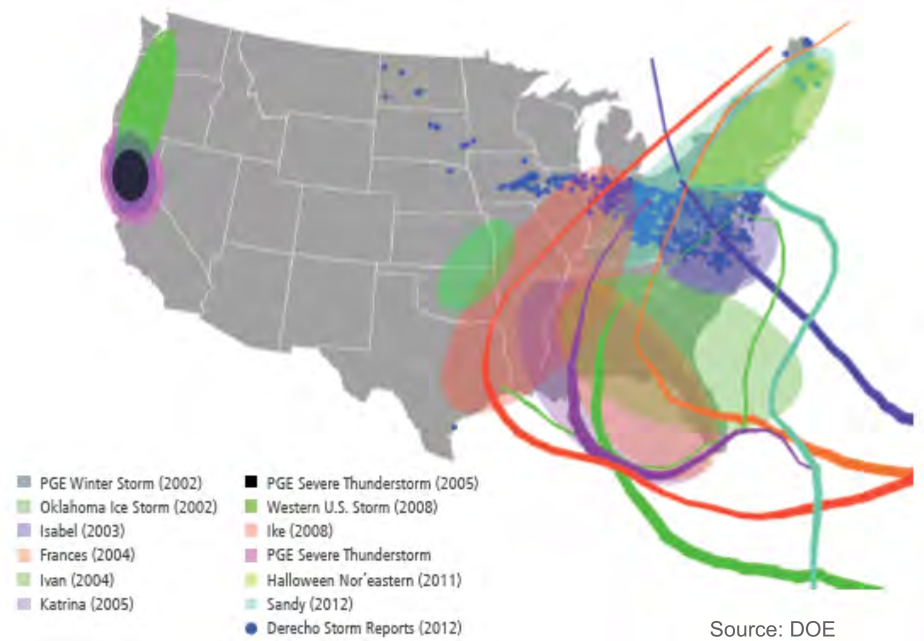
Access to Reserves in Fuel-Constrained Situations

- **Role of Weather:** Extreme weather continues to be a significant cause of outages, particularly widespread outages that affect large numbers of customers.
- **Generation shift:** Meanwhile, the grid is undergoing a shift in its generation mix. Driven by state policies and extended low natural gas prices, older thermal generation is being displaced by new, significant quantities of gas-fired and renewable (principally wind and solar) generation.
- **Limits of "just-in-time" resources:** These changes can have positive effects on emissions profiles and furtherance of state climate policy goals. But recent winter weather events have tested the increased dependency of the power system on dispatchable, gas-fired generation, which can comprise "just-in-time" resources in gas-constrained areas, because they rely on just-in-time delivery of natural gas across interstate pipelines to the region's generating stations. During cold winter conditions in regions like New England (but increasingly affecting other regions), these pipelines rapidly reach capacity and are either unable to fuel power plants or ambient conditions may cause performance issues for gas-fired generators. It must be acknowledged that renewable resources, which can be variable in output, can also constitute just-in-time resources.

U.S. Electric Outage Events by Cause and Magnitude (2015)



Major Weather-Related Outages Requiring a National Response (2002–2012)



Source: DOE

Sources: QER2; ISO-NE Fuel Security Analysis; ISO-NE Improvements

Access to Reserves in Fuel-Constrained Situations (Cont'd)

Access to Reserves – New England Case Study

- **Fuel challenges in New England:** According to ISO-New England (ISO-NE), the ISO, on multiple occasions in recent winters, has had to manage the system with uncertainty about whether power plants could arrange for the fuel—primarily natural gas—needed to run. It has addressed the effects of insufficient fuel supplies on the power system by employing real-time emergency-operating procedures and implementing market design changes to incentivize generators to arrange for adequate fuel supplies. The ISO has also worked on improving communication and coordination with natural gas pipeline operators.
- **Role of emergency procedures:** The ISO has been able to maintain power system reliability during severe winter conditions without using all of its emergency procedures. However, with its evolving generation mix, the region is vulnerable to variable and uncertain factors: gas pipeline constraints, liquefied natural gas and fuel oil import logistics, weather impacts on fuel deliveries, and the amount and timing of renewable energy generation.
- **Cold weather scenario planning and interregional transmission needs:** ISO-NE studied various resource combinations in a winter 2024–25 scenario, which included retirements of coal- and oil-fired generators, the availability of LNG, dual-fuel generators' oil tank inventories (i.e., how often on-site fuel tanks can be filled at dual-fuel generators that can switch between natural gas and oil), electricity imports, and addition of renewable resources on the ISO-NE system. ISO-NE's analysis revealed the following:
  - The loss of some key facilities would result in frequent energy shortages that would require frequent and long periods of rolling blackouts.
  - The New England system will largely depend upon two key elements: sufficient injections of LNG and electricity imports from neighboring regions.
  - Robust levels of imported electricity from neighboring power systems are essential to continued power system reliability. However, imports also present a degree of uncertainty and risk, since neighboring areas Québec, New York, and New Brunswick all experience similar winter weather as New England. The question is whether New England's neighbors have sufficient supply to serve their own customers and supply New England with its needs.
  - Renewable energy can mitigate the region's fuel-security risk, but it depends upon the resource type and deliverability. Winter peak occurs after sunset. While solar arrays can help reduce consumption of oil and natural gas for power generation on sunny winter days, preserving more oil and gas to help meet peak demand, solar PV itself does not help meet the daily winter peak in demand. Wind energy is not always available, but offshore wind tends to produce more steadily than onshore wind. Development of wind facilities and import capacity for clean energy will require more transmission investment.

The New England experience, then, demonstrates that additional transmission can be a tool for diversification and optionality of resources, including renewables, from both within New England (from onshore and offshore wind development) as well as adjacent regions.

Source: ISO-NE Fuel Security Analysis

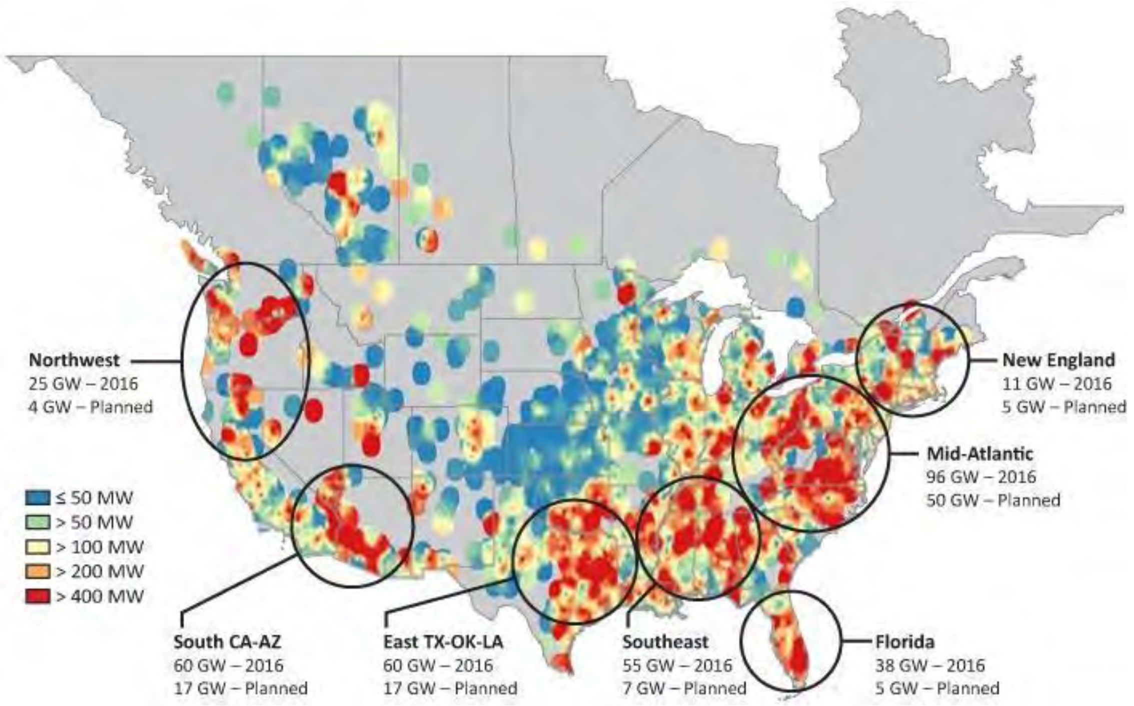
Access to Reserves in Fuel-Constrained Situations (Cont'd)

Access to Reserves – Southern California and Arizona Case Study

- **Southwest U.S. gas dependency:** Similar mitigation efforts for fuel constraints have been effected in southern California and Arizona. According to NERC, "This area has a high degree of dependence on natural gas storage, notably the Aliso Canyon storage facility. Ramping needs, due to an increased penetration of DERs and utility-scale solar PV, have made storage needs more significant in this area." (NERC SPOD, at p. 6)
  - **Aliso Canyon impacts:** In winter 2015, a significant leak was discovered in the Aliso Canyon facility, affecting price and supply of natural gas to the region. While there were no reliability effects, there was concern about gas curtailments that could result in electricity interruptions. Through operational coordination, tariff changes, and demand-side actions, risk was mitigated. Other mitigation measures included transmission upgrades, including a 500 kV line, phase shifters, synchronous condensers, and series reactors.
  - **NERC view:** As noted by NERC, "During peak demand or system element contingencies, additional generation may be needed to meet electric reliability. If natural gas supply cannot accommodate additional generation, southern California entities may need to rely on assistance from neighboring Balancing Authorities. This assumes ample supply outside southern California and adequate transmission capacity to move that power into the southern California system." (NERC SPOD, at pp. 30-31)

Transmission capacity can provide reliability and resilience benefits, where gas infrastructure is inadequate or constrained, and to mitigate impacts of disruptive and potentially long-lived events, like gas line breaks, freeze-offs, or storage facility outages.

Large Generation Clusters That Could Be Susceptible to Natural Gas Disruption

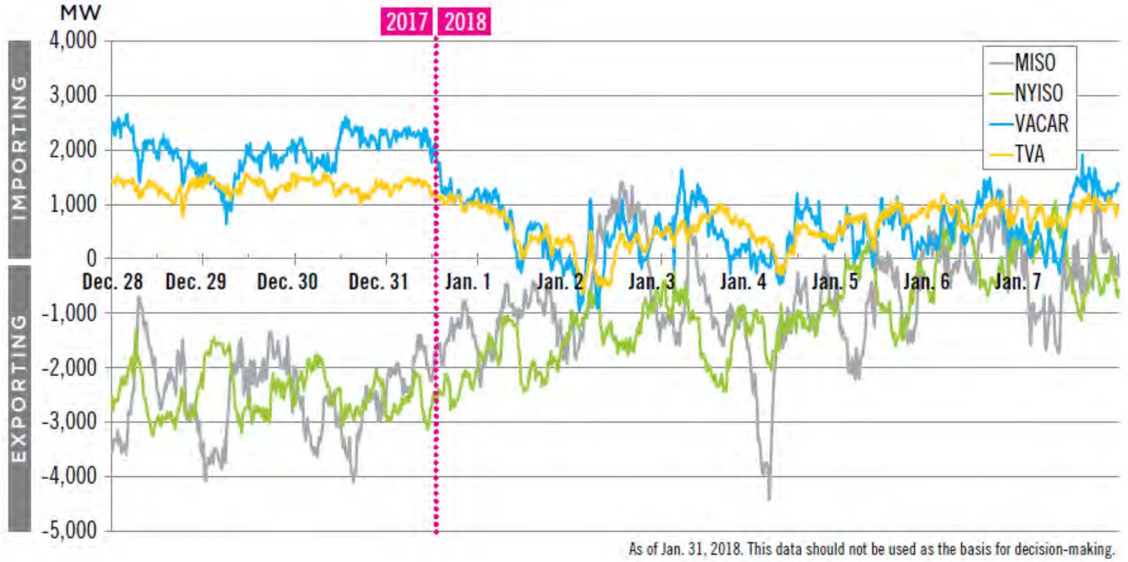


Source: NERC
Note: Each cluster represents at least 2 GWs of natural gas-fired power plants.

Sources: NERC SPOD; Southwest Blackout Even Report

Energy Imports and Exports During Extreme Conditions

PJM Transmission Tie Line Interchange
(December 28, 2017 through January 7, 2018)



Source: PJM Interconnection

Energy Imports and Exports During Extreme Conditions – PJM "Bomb Cyclone" Experience

- A cold snap from December 27, 2017, to January 7, 2018, was accompanied by a "bomb cyclone" event from January 2 to 5. Prolonged cold temperatures were seen along the Eastern Seaboard, with snow and ice as far south as northern Florida.
- During the bomb cyclone week, prices in eastern PJM were about three times higher than in western PJM. For example, in Virginia, prices averaged about $222/MWh versus $76/MWh in northern Illinois (see Grid Vision, at p. 14).
- As PJM notes, during late December, PJM's interchange with its neighbors tracked normal patterns, importing from neighboring southern regions and exporting to MISO and NYISO. On January 1, transactions started flowing southward to VACAR (Virginia-Carolinas) and Tennessee Valley Authority (TVA), as they were experiencing some of their coldest weather. The flows did not return to normal until the end of the cold snap (PJM Benefits of Transmission, at pp. 36–37).

By maximizing the power transfer capability of the system in the most resilient way possible (using heavy-load voltage schedules and warnings), transmission played a key role in dealing with energy needs during extreme weather.

Sources: PJM Benefits of Transmission; Grid Vision

Situational Awareness, System Visibility, and Flexible Grid Technologies

Situational Awareness, System Visibility, and Flexible Grid Technologies*

- **Situational awareness is key:** System visibility and situational awareness are key elements of reliability, enhanced by processes, tools, and capabilities. Those capabilities are also critical in resilience terms of resourcefulness (i.e., the ability to detect and manage an unfolding crisis).
- **Changing nature of resources:** As grid operations become more reliant on accommodations of variable energy resources on both the bulk side (utility-scale wind and solar) and on the user side (DERs, energy efficiency, and demand response), one challenge is that the latter are less visible to bulk system operators. Indeed, as NERC has stated, “Increasing installations of DERs modify how distribution and transmission systems interact with each other. Transmission planners and operators may not have complete visibility and control of these resources, but as growth becomes considerable, their contributions must be considered in system planning, forecasting, and modeling.” (NERC 2018 LTRA, p. 9)
- **Lessons from past events:**
  - A key cause of the Northeast blackout of 2003 was the loss of a transmission line together with operational errors as a localized failure in northern Ohio cascaded throughout the region, resulting in a blackout affecting 50 million customers in the United States and Canada and lasting, for some, up to four days. The event caused $7 billion to $10 billion in economic losses. As summarized by The Brattle Group and WIRES, “When that transmission line tripped offline, power flowed through alternative routes, overloading those lines, and causing cascading failures before operators were able to understand and react to the event. While the power system is planned to withstand the loss of one or several major elements, operators were initially unaware of the system outages and then failed to communicate with neighboring systems” (WIRES Grid Resilience Docket Comments, at Appendix p. 12). Among the identified causes were lack of visibility of loss of key transmission elements and awareness of the vulnerability of the system to the next contingency (Northeast Blackout Report, p. 108).
  - In September 2011, about 2.7 million customers in the Pacific Southwest lost power, with an estimated economic impact of more than $100 million. According to NERC, “The outages affected parts of Arizona, southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly 1.5 million customers losing power, some for up to 12 hours. The disturbance occurred near rush hour, on a business day, snarling traffic for hours. Schools and businesses closed, some flights and public transportation were disrupted, water and sewage pumping stations lost power, and beaches were closed due to sewage spills. Millions went without air conditioning on a hot day.” The root cause was the loss of Arizona Public Service Company’s Hassayampa-North Gila 500 kV transmission line, but the event was attributed to grid operators’ lack of real-time situational awareness of conditions throughout the Western Interconnection (Southwest Blackout Event Report, at p. 7).

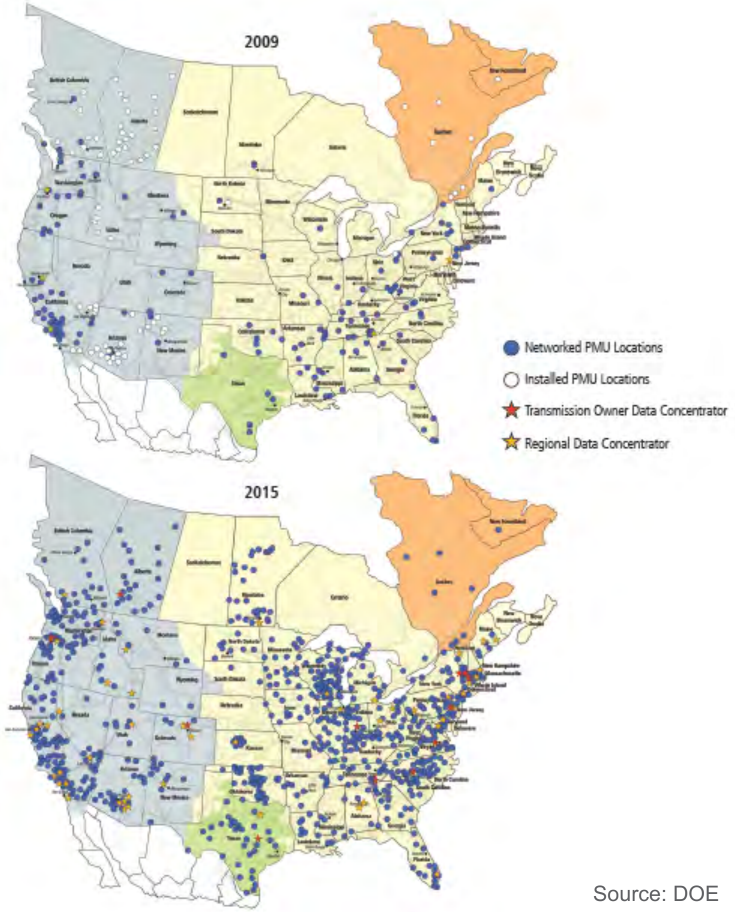
Note: *FERC has characterized flexible grid technologies as “grid-enhancing technologies” in recent technical conferences.
Sources: Nat’l Academies Studies; QER2; NERC 2018 LTRA; WIRES Grid Resilience Docket Comments; Northeast Blackout Report; Southwest Blackout Even Report; DOE; Grid-Enhancing Technologies Workshop

Situational Awareness (Cont'd)

Transmission Technologies

- **New and established transmission technologies:** Deployment of both emerging and well-established technologies have potential benefits. Deploying these as part of a broader reliability/resilience strategy will yield benefits for both. For example, certain transmission technologies can be employed to provide deeper awareness of the grid situation and increased flexibility of the system in response to changing grid conditions in the event of weather-related and other threats (such as wildfires) to resilience, as well as the ability to monitor and respond to unexpected changes in variable resource output and flows. For example, dynamic line-rating systems can aid in wind integration, by providing higher line capacity during periods of higher wind farm output. This technology can also provide critical information during high ambient temperatures, such as heatwaves and wildfires.
  - Phasor measurement units: Synchrophasor technology is being used to improve system awareness. Conventional instrumentation provides measurement of system conditions every two to four seconds. With the installation of phasor measurement units (PMUs) communicating up to 30 times per second, transmission operators have greater and more timely insight into system disturbances, improving efficiency, reliability, and resiliency of the system by detecting and correcting instabilities before an interruption of service (QER2, at pp. 4–50; PJM Benefits of Transmission, at pp. 59–60). Of course, sensors alone are insufficient; to secure full benefits of PMUs, other enabling monitoring and analysis technologies must be implemented in tandem.
  - Other technologies: Increasing variable resources and low shoulder seasonal and overnight loads are leading to higher-voltage variability on the transmission system. Flexible AC Transmission System (FACTS) devices, such as static VAR compensators, reactors, and static compensators, help regulate system stability, particularly at high-voltage levels. These are increasingly of interest: for example, more than $1.3 billion in reactors and static VAR compensators were installed on the PJM system between 2008 and 2018 (PJM Benefits of Transmission, at pp, 39–40, 61).*

North American Deployment of Phasor Measurement Units



Source: DOE

Note: *FERC has characterized flexible grid technologies as "grid-enhancing technologies" in recent technical conferences.
Sources: LBNL Resilience; QER2; PJM Benefits of Transmission; MIT Future of the Grid; Grid-Enhancing Technologies Workshop

Situational Awareness (Cont'd)

Transmission Technologies (Cont'd)

- **New and established transmission technologies (Cont'd)**
  - Dynamic line ratings: Current transmission system operations rely on fixed ratings of transmission line capacity that are established to maintain reliability during worst-case conditions (e.g., hot weather) or reduced based upon ambient conditions. There are times when the conditions associated with establishing line ratings are not constraining, and transmission lines could be operated at higher-usage levels. Dynamic line-rating systems help operators provide real-time awareness, identify available capacity, and increase line transmission capacity by 10% to 15%, potentially facilitating integration of wind generation. (QER2, at pp. 4–44). There remain discussions about the reliability and operational complexity of dynamic line ratings, now being examined by FERC (see, e.g., Grid-Enhancing Technologies Workshop, FERC Docket No. AD19-19-000).
- **New technologies and higher interconnectivity to provide inertia:** Generators and motors that are synchronously connected to a power system store kinetic energy from rotating masses. This energy, called synchronous inertia, helps provide system frequency support upon the sudden loss of generation. If frequency goes below a certain level, then the system risks under-frequency load shedding. Inertia arrests and stabilizes frequency (ERCOT Inertia Report, at pp. 4–5).
  - Traditionally, synchronous inertia was provided from natural gas, coal, and nuclear plants, but some of those units are retiring. Increasing amounts of non-synchronous, inverter-based resources, such as wind and solar resources, reduce the amount of synchronous inertia. For example, ERCOT, the Texas grid operator, has faced increasing challenges as more wind generation has come online and comprises a bigger part of the resource mix, as much as 50% of system mix at times (NERC 2018 LTRA, at pp. 30–35).
  - Wind can, when properly equipped, provide some synthetic inertia. Moreover, fast frequency response reserves can provide frequency support; those resources include solar and energy storage systems. Smart inverters have capabilities that can mimic inertia, but they are not yet widely deployed to provide that service. **Importantly, new transmission-related technologies, such as synchronous condensers, are being used for inertia support. Moreover, inertia levels are assessed by NERC on an interconnection-wide level, reinforcing the importance of transmission linkages between regions.**

In summary, investments in grid modernization, particularly in new technologies, will have resilience benefits for system visibility and flexibility. And both transmission solutions, such as synchronous condensers and increasing interconnectivity, can help alleviate declining inertia.

Sources: QER2; FERC Staff DLR Report; ERCOT Inertia Report; NERC 2018 LTRA; Grid-Enhancing Technologies Workshop

Upgrading an Aging Transmission System

- **The aging power system:** A concern for both reliability and resilience is the aging of the nation's transmission infrastructure, including lines, transformers, and substations. According to PJM: "Transmission facilities continue to age. Some assets date to the 1960s or even earlier. Two-thirds of all system assets in PJM are more than 40 years old; over one-third are more than 50 years old. Some local, lower-voltage transmission facilities, especially below 230 kV, are approaching 90 years old. Asset owners are identifying serious structural deterioration leading to system enhancements to avoid facility failure and customer service interruptions. These replacements have economic benefits as well and have, in certain instances, reduced average annual congestion costs by an order of magnitude or more. Asset modernization goes beyond simple replacement. Such projects have provided the opportunity to learn from history and adopt new knowledge, capabilities and technologies that did not exist when the original facilities were built." (PJM Benefits of Transmission, p. 5)
- **Upgrade with replacement:** In 2017, Hurricane Maria devastated Puerto Rico's power grid, requiring a significant, and ongoing, rebuilding of its electric infrastructure. But it has found that significant investment in getting its grid up and running will require replacement to make the Puerto Rican grid truly resilient against other similar events. According to the DOE, recommended long-term planning should include "ensuring that investments will result in modern, intelligent infrastructure systems that are affordable, reliable, and resilient." (LBNL Resilience, at p. 34).
- **New construction evaluation criteria:** Upgrading is not limited to replacement. In New York, for example, two approved major public policy projects included some heavier duty structural design, such as drilled shaft concrete foundations (versus crushed rock backfill foundations), full-length concrete poles (versus multi-piece steel poles), and more dead-end structures. While more expensive than standard construction (e.g., concrete foundations are about 2.5 times the cost of direct embedded rock foundations), these features were factored into the project evaluation because of the incremental resilience benefit to withstand icing and wind events (NYISO Policy Plan Addendum, at pp. 11–13).

Sources: PJM Benefits of Transmission; LBNL Resilience; NYISO Policy Plan Addendum

Upgrading an Aging Transmission System (Cont'd)

- **Tailored regional needs:** Of course, resilience needs are region-specific, based upon likely risks and lessons learned from past high-impact, low-frequency events, like major hurricanes. Other considerations are resource mix, current system configuration and age, and interdependencies with other essential services. Grid hardening has been pursued by, for example, Florida and New Jersey utilities in the wake of major weather events.
  - New Jersey was impacted significantly by Hurricane Irene (August 2011) and Superstorm Sandy (October 2012). For Newark-based Public Service Electric & Gas, Sandy damaged 31 substations, 1,000 transformers, and 2,500 utility poles (Northeast Storm Report, at pp. 8–10). Damage came from wind and significant flooding. In the wake of the storms, the utility established a $1.22 billion Energy Strong program to proactively protect its electric and gas systems against severe weather damage. About $620 million of this investment is for protecting, raising, or relocating 29 switching and substations.
  - In Florida, in the wake of 2005's Hurricane Wilma, which caused more than three million customers to lose power, Florida Power & Light has hardened its system, spending $3 billion since 2006 on pole inspection and replacement (using steel and concrete poles), vegetation clearing, and targeted undergrounding. Average time required to restore power after 2017's Hurricane Irma was 2.1 days compared to 5.4 days after Hurricane Wilma. Additional work on feeders and undergrounding is under way.

The grid is aging and many of its components are approaching the end of their useful lives. Further, major events that prematurely damage parts of the grid can afford an opportunity to consider and weigh resilience-enhancing transmission investments in their wake. A well-planned, strategic investment strategy can provide the opportunity to upgrade an aging grid with better than like-for-like components and to enhance system resilience.

Sources: PSEG; FP&L; industry news

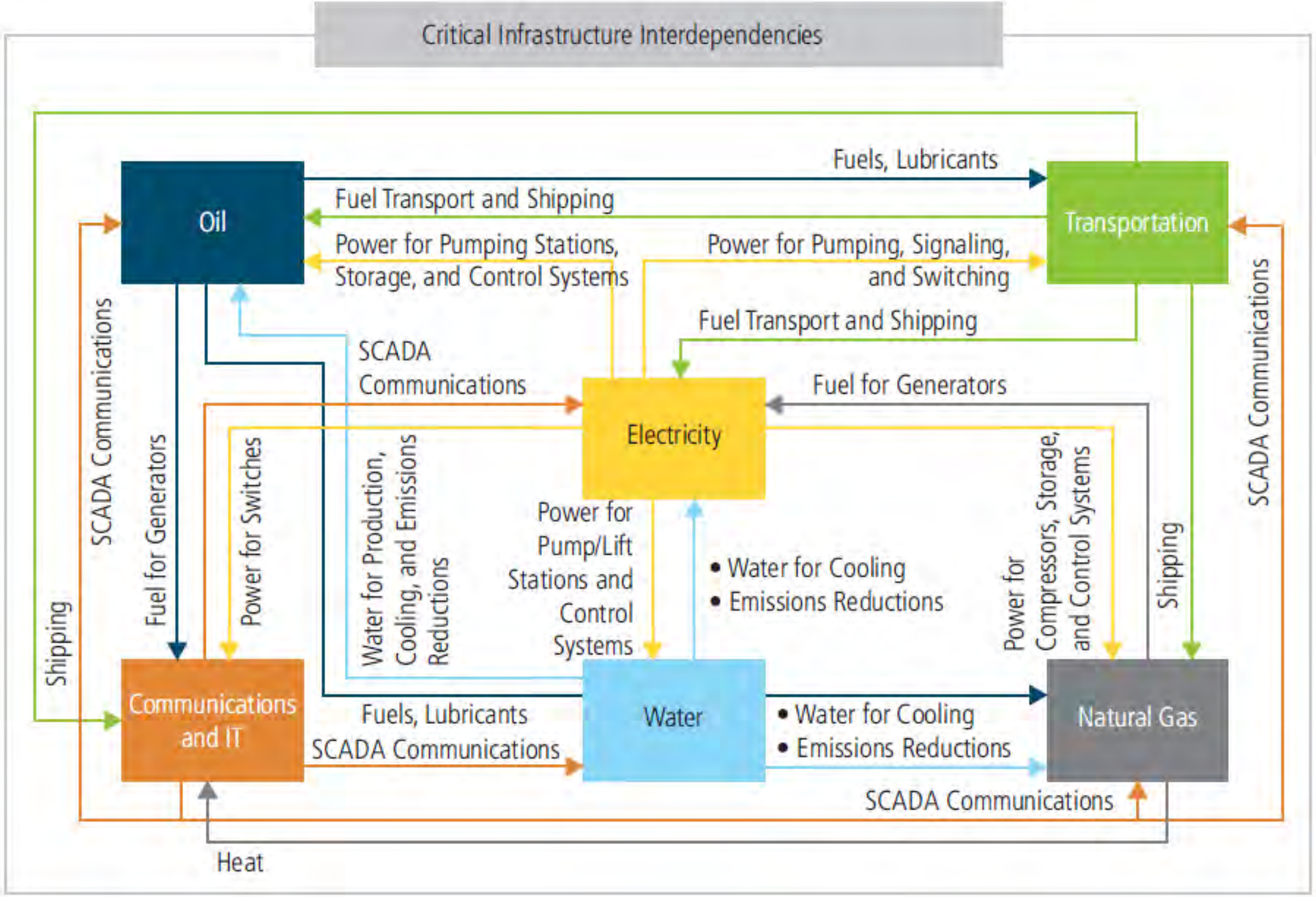
Preparing for High-Impact, Low-Frequency Events

Initiatives to Prepare for a High-Impact, Low-Frequency Event Affecting the Grid

- **Programs and equipment for transmission system recovery:** Recovery of the transmission system from a significant event involves the ability to coordinate with bordering grid operators and governmental authorities, to inspect and repair or replace damaged facilities, and to re-energize the grid. In preparation for response to major resilience events, utilities collaborate in regional mutual assistance groups, which provide access to skilled utility workers to respond to large-scale events (WIRES/Brattle, at pp. 13–14). Utilities also maintain spare components (poles, transformers, etc.), and there are currently a number of industry-sharing programs through NERC, the Edison Electric Institute, and other programs. In particular, the industry is focused on large power transformers (LPTs), which are costly and lengthy. The loss of several LPTs can overwhelm the bulk power system and cause widespread outages, possibly affecting multiple regions. DOE and the industry are considering risks, including design concepts, and the potential need for a strategic transformer reserve (QER2, at pp. 4–48).
- **Worst-case planning and interrelated infrastructure considerations of increasing interest:** The utility industry performs tabletop exercises, such as GridEx, that consider widespread power outages, including those caused by cyber-physical events. However, increasing attention is being paid to the potential impact of a catastrophic power outage, which is severe, widespread, and long-lasting. This risk goes beyond that of a large storm, but it would be of a magnitude beyond experience, causing an outage for months or years and involving cascading loss of critical services that could impede re-energizing the grid. NIAC recently highlighted some potential recommendations to address cross-sector failures that would hamper recovery efforts (see cross-sector linkages next page). In particular, it recommended (i) development of a national approach to catastrophic power outage planning, response, and recovery, and (ii) identification of cascading failures impacting key sectors and identifying actions to improve resilience (NIAC, at p. 7). Of course, establishing design criteria and appropriate incentives for the power sector remain key issues to consider before making changes to existing good planning practices (see Challenges and Policy Implications).

Sources: QER2; NIAC; https://www.energy.gov/oe/addressing-security-and-reliability-concerns-large-power-transformers; National Academies Study

Preparing for High-Impact, Low-Frequency Events (Cont'd)



Source: National Academies Study, Fig. 4.5

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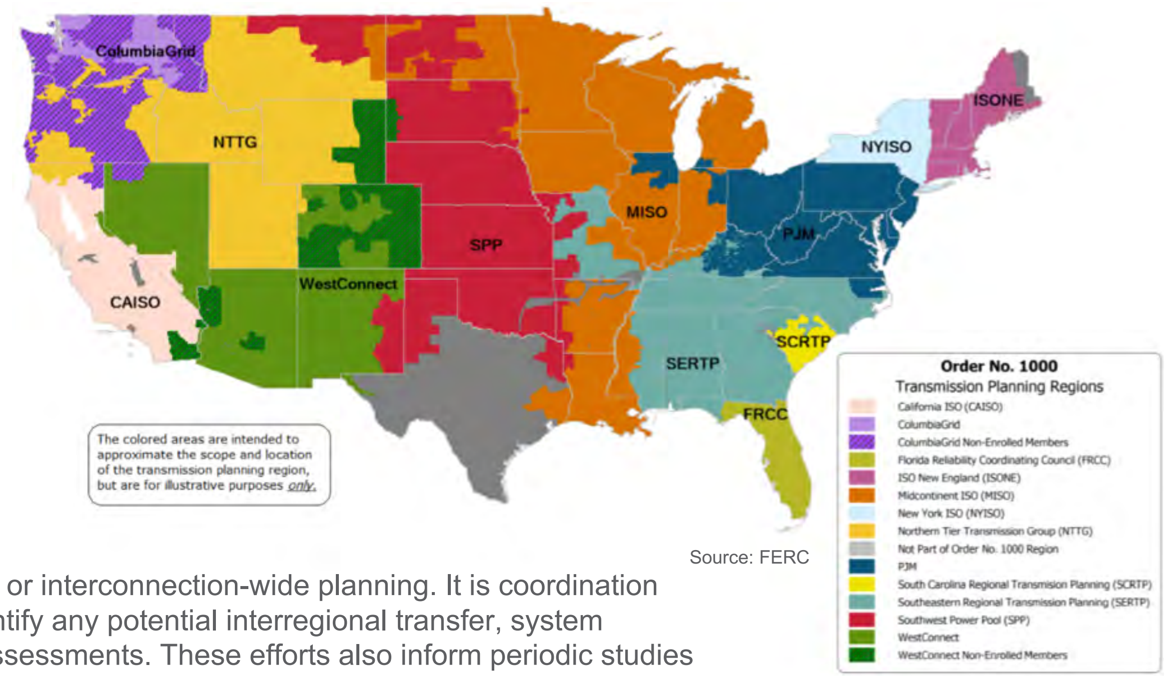
Challenges and Policy Implications

Contents

Interregional Planning and Cost Allocation

- **Balkanization**: The balkanized history of the North American grid has historically been accompanied by coordinated but independent planning of the transmission system. Regions can have very different industry structures, with some dominated by vertically integrated utility systems which seek to optimize transmission investment while serving customers with their own generation resources. Other regions, specifically RTOs and ISOs, have planning processes that yield periodic, multi-year transmission expansion plans, with significant amounts of stakeholder involvement.
- **Role of Order 1000**: Order 1000, promulgated in 2011, provided specific requirements for (1) regional transmission planning; (2) consideration of transmission needs driven by public policy requirements; (3) non-incumbent transmission development; (4) interregional transmission coordination; and (5) cost allocation for transmission facilities selected in a regional transmission plan for purposes of cost allocation. Interregional coordination occurs on an interconnection-wide basis, through each of the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee and the Eastern Interconnection Planning Collaborative (DOE Transmission Data Review, at p. 79).

FERC Order 1000 Transmission Planning Regions



Source: FERC

- **Interregional planning approach:** Interregional planning is not integrated multi-regional or interconnection-wide planning. It is coordination focused on stitching together regional transmission plans into “roll-up reports,” which identify any potential interregional transfer, system overload, or other issues that could impact reliability, supplementing regional reliability assessments. These efforts also inform periodic studies of interregional seams. The horizon for these reviews is over a planning horizon of 5 to 10 years (see EIPC State of the Eastern Interconnection). While these coordination efforts consider long-term changes in the resource mix, they are not focused on optimizing the cost-effectiveness of public policy requirements (e.g., renewable and clean energy mandates) or deliverability of those resources. Planning for those priorities is left to the regions.

Sources: FERC Order 1000; DOE Transmission Data Review; EIPC State of the Eastern Interconnection

Interregional Planning and Cost Allocation (Cont’d)

- **Shortcomings of current interregional planning construct:** When compared to implementation of the regional planning processes under Order No. 1000, interregional planning processes are in their infancy and remain incomplete. Order 1000 was intended to resolve a number of transmission development issues, including improving interregional planning. But challenges remain to achieving the investment in large-scale transmission envisioned by the FERC when it promulgated that order. The general view across the industry is that interregional planning processes are at best, stalled, and at worst, ineffective in identifying valuable projects. Some of this can be attributed to the level of effort that has been required of planners to implement transmission planning and cost allocation within their own regions, leaving limited time to focus on addressing issues with interregional processes. As recently noted by AWEA, “FERC Order 1000 was a well-intentioned attempt to fix two of the main obstacles holding back transmission investment, barriers to planning and paying for regional and inter-regional transmission. However, unintended consequences and lackluster implementation, particularly for inter-regional transmission, have left all sides unhappy” (Grid Vision, at p. 71).
- **Some planning issues:** Several of the issues that have limited the effectiveness of interregional planning include:
  - <u>Voltage level or project size restrictions</u>: Some interregional planning processes exclude upgrades below a specific project size or voltage-level threshold, resulting in some beneficial projects not being considered. For instance, the MISO and SPP interregional planning process does not include projects under 345 kV. MISO recently noted that of the 300 current interconnections between these two RTOs, only 12 are at or above 345 kV.
  - <u>Project type restrictions</u>: Interregional planning processes allow only for the evaluation of projects that address an identical need in both regions. For example, an interregional project meeting a reliability need in MISO but not meeting a reliability need in PJM cannot be considered, even if providing some other benefit (e.g., public policy, market effectiveness) in PJM.
  - <u>Multiple benefit-to-cost ratios</u>: In some interregional planning processes, projects have faced a “triple hurdle” in that they have to meet an interregional benefit-to-cost ratio and meet internal benefit-to-cost standards of each of the two regions involved. Some of those (SPP/MISO; MISO/PJM) hurdles have been relieved, although different planning parameters and cost-benefit approaches between regions remain.
- **Possible scale mismatches:** Not peculiar to, but relevant to, interregional planning for increasing amounts of utility-scale wind and solar resources is the difference in scale between those projects and investment in the transmission system. Historically, resource development occurred in relatively large increments—hundreds or thousands of megawatts—near load centers. Wind and solar resources are location specific based upon the resource. In addition, as noted earlier, the increment of addition in capacity terms of solar and wind farms are most often in the tens to hundreds of megawatts, while high-voltage transmission lines are “often most efficiently constructed at scales designed to serve a gigawatt of capacity or more” (MIT Future of the Grid, at p. 96). This can mean that large-scale projects may be deferred until a critical mass of renewable facilities can cost-effectively interconnect.

Sources: Grid Vision; ScottMadden; “FERC Order 1000: Five Years On” (June 2016); MIT Future of the Grid; WIRES/Brattle Planning Paper

Interregional Planning and Cost Allocation (Cont'd)

- **Cost allocation principles:** Cost allocation is an issue for interregional transmission projects. The cost of the lines crossing regional borders are typically divided between regions on a project by project basis. However, as most of the cost is recovered from network usage charges, the efficiency and fairness of transmission cost allocation become critical issues. Order 1000 requires that costs should be allocated in a way that is roughly commensurate with estimated benefits. This contrasts with cost "socialization" where all transmission users cover total costs on a pro rata basis. Order 1000 goes further, noting that a planning process may consider benefits including "the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestions relief, and/or meeting Public Policy Requirements [such as renewable portfolio standards]...." (FERC Order 1000, at p. 421)
- **Challenges in identifying and allocating benefits:** However, effective implementation of these principles has proven challenging. As one analysis has noted, "[I]dentifying who benefits from transmission services and by how much is an analytically complex task in power systems planning and operation. The expansion of interregional transmission capacity and subsequent exchange of energy produce differentiated distributional effects in each region, independently of whether a new tie line creates an aggregated net benefit. These distributional effects create winners and losers at each side of the transmission tie lines, which may create opposition to the projects or simply threaten their sustainability, as each region needs to balance their own benefits and costs." (Prada & Ilic, at pp. 4–5) Further, the benefits of, for example, congestion relief may result in cost improvements or have positive resilience impacts that are difficult to disentangle and allocate between regions and beneficiaries.

When integrating renewables across long distances, issues of equity across states and regions, economic development. and political complications exacerbate an already difficult problem.

Sources: FERC Order 1000; Prada & Ilic

Resilience Planning and Cost

- **Traditional planning approach focuses on reliability, not resilience:** Traditional transmission planning processes are rightly focused on delivering an adequate level of reliability, that is, so the bulk electric system does not experience instability, uncontrolled separation, cascading, and collapse under normal operating conditions, and/or voltage when subject to predefined disturbances, and frequency and voltage are maintained within defined parameters under normal operating conditions and when subject to predefined disturbances. Typical planning accounts for N-1 contingencies and increasingly N-2+ parameters—the loss of one or more critical system components.
- **Ill-suited for resilience planning:** But as major weather disturbances, cyber-events, and other low-frequency, high-impact events threaten the electric grid, existing planning approaches show gaps. As NERC has noted, for less probable severe events, "bulk electric system owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the bulk electric system even if these events can result in cascading, uncontrolled separation, or voltage collapse. Less probable severe events would include, for example, losing an entire right of way due to a tornado, simultaneous or near simultaneous multiple transmission facilities outages due to a hurricane, sizeable disruptions to natural gas infrastructure impacting multiple generation resources, or other severe phenomena." (2019 State of Reliability, at p. 2)

Resilience vs. Reliability: Different Stakeholders, Cost-Bearers, Responsibilities, and Levels of Planning Maturity

Planning criteria	Well-established N-2 planning	Unspecified or incipient "black swan" planning
Scenarios considered	Stated contingencies	Unlikely/unknown contingencies beyond reliability planning
Primary focus	Prevention, protection, and risk mitigation	Critical infrastructure recovery; social stability
Potential value of event "insurance"	Estimable through system modeling	Difficult to ascertain; policy-driven
Costs borne by	Ratepayers	Taxpayers
Funded by	Utility capital expenditures	• Federal emergency funds • State infrastructure • Municipal, county government
First response responsibility	Utility	Government, community response
Stakeholder coordination	Utility, ISO led	Government led

There remains a planning gap between reliability and resilience. Transmission planners, operators, and owners continue to focus on reliability, including weather and fuel dependency, as those are most clearly actionable and related to electric infrastructure investment. Resilience has broader societal implications involving more stakeholders with government as a key facilitator. And its costs are more properly a societal decision. While transmission has an important role to play, it is only one piece of resilience preparation.

Sources: ScottMadden analysis; 2019 State of Reliability

Resilience Planning and Cost (Cont'd)

- **One approach to updating planning:** As WIRES and The Brattle Group noted in comments to FERC's resilience docket in May 2018, transmission planning should incorporate resilience considerations. Resilience can be a part of the evaluation of multi-value transmission projects (MVPs) as part of the transmission planning process as a complementary benefit. It touches upon each of the reliability, economic, and public policy objectives of MVPs. Resilience benefits could be quantified, expanding the range of potential outcomes or scenarios to incorporate more extreme scenarios (see WIRES/Brattle Resilience, at pp. 16–19).
- **North American Energy Resilience Model under development:** DOE is now engaged in an effort to develop a first-of-its-kind comprehensive resilience-modeling system to assess threats and consequences for the North American electric power systems, as well as associated dependencies on natural gas and other critical energy infrastructures (see NAERM, at p. 2). Threats to be considered include extreme weather and cyber, as well as next unknown "worst-case" threats, such as those potentially inflicted by nation-state actors. Planning objectives, potential investments, and cost-benefit trade-offs will be important outputs.
- **Some issues to address:** Some key issues for incorporating resilience into planning include the following:
  - Design criteria: How to design a resilient system—what are key design criteria and what level of resilience is needed—are important considerations. According to NIAC, there is no common agreement on the level of redundancy or resilience that should be built into critical utilities to lessen risks and impacts of a long-term catastrophic power outage. The council notes that without design basis guidance, "it is difficult for owners and operators to justify investments, receive regulatory approval, or even know what standards are realistic and sensible to build to." (NIAC, at p. 11) Scenario identification and testing may to be augmented to consider "black sky" or other events not envisioned for standard reliability planning. A related issue is the degree of uniformity those design criteria should have. Regional risks may differ, and so may design criteria.
  - Cost: Cost-effectiveness is also a consideration. Designing a system against any threat will be cost-prohibitive and unlikely to be supported by regulators and customers. How to balance cost against potential impacts and possible benefits remains a challenge. Indeed, planning and designing for graceful degradation and rapid recovery may be appropriate instead of hardening against all risks. Benefits will need to be considered; transmission enhancements to alleviate congestion or increase deliverability of resources may have resilience benefits and vice versa.
  - Cost Allocation: Who should pay is a critical question to answer in securing resilience for the transmission system. Resilience can be considered a "social good" given the reliance of key sectors on the power system for ongoing operations. Those include governmental agencies, critical infrastructure (communications, water, wastewater and sewage, natural gas, fuel processing and distribution), and financial institutions. All of these provide essential services necessary to sustain communities during a long-lived outage. While transmission capital investment is, with proper regulatory oversight, an important factor in fostering resilience, there is the question of whether transmission customers are the sole beneficiaries of resilience benefits or whether government or other sectors should pay some of the costs of resilience efforts.

Sources: WIRES/Brattle Resilience; NAERM; NIAC

Resilience Planning and Cost (Cont'd)

- **Some issues to address (cont'd)**
  - Incentives: How to provide incentives, or to de-risk resilience investments, is another important consideration for transmission owners. In its comments on FERC's Notice of Inquiry Regarding the Commission's Electric Transmission Incentives Policy, American Electric Power recommended that FERC establish an incentive for FERC-approved company-specific resilience and action plans. This, in its view, would encourage proactive grid resilience efforts that go beyond minimum reliability standards (AEP Filing, at pp. 13–20). This is one approach, but other approaches may be appropriate. Given the challenges of transmission development under normal planning assumptions, adding resilience, a much more diffuse and difficult to quantify benefit, to planning may require additional support.

In resilience planning, the balance between utility versus other infrastructure—government or non-utility—needs to be assessed and consideration given to "where the line should be" between those investments. Regional entities (utilities, ISOs/RTOs) should guide policymakers to discern between what utilities can do (and what it will cost) and what other entities should do. These questions will require mostly regional answers, based upon the nature of resilience threats.

Source: AEP Filing

Local Siting and Permitting Issues

- **Local opposition:** Large-capacity interregional projects are subject to federal, state, and local siting and permitting requirements before construction of facilities can commence. For some, intervenors in these processes are not satisfied with any project for any reason, even those which might improve regional access to lower emitting resources. Objections range from aesthetic or environmental impacts to lack of local benefits from a project to hostility to any eminent domain.
- **Multiple required approvals:** State authorizations for transmission projects largely hinge on determination of need, and state regulators often focus on in-state cost and benefits in approving projects and may be required to do so under state law. Determination of those costs and benefits may be subject to varying legal interpretations. There is a compounding effect with larger, longer proposed lines, as increasing numbers of state governmental and regulatory authorities and individual landowners become involved. In recent years, some large projects aimed at moving large-scale renewable resources between regions have been slowed or stopped due to state or local action (see right). Those projects were participant funded, that is, a proposed line was independently funded and not part of a regional transmission expansion plan.

Example of Interregional Project Hurdles:
Plains & Eastern Clean Line Project

- Clean Line Energy Partners proposed a large 700 mile, $2.2 billion, 3.5 GWs high-voltage DC line to extend from the Oklahoma and Texas panhandles eastward across Arkansas and into Tennessee. The Plains & Eastern project would have brought low-cost wind power eastward. The project was proposed in 2010.
- The DOE partnered with Clean Line on the project in March 2016, specifically in using federal powers of eminent domain to obtain rights of way for the line's route. The Trump administration in January 2018 included the line on its priority list for infrastructure projects.
- However, many local and tribal interests, especially in Arkansas, opposed the project.
- The DOE withdrew from its partnership in 2018, hampering further development. Clean Line has sold the Oklahoma portion of the project to renewables developer NextEra Energy.

This project illustrates that despite meaningful federal support, local issues remain significant barriers to large-scale interregional transmission development.

Sources: MIT Future of the Grid; QER2; Clean Line Energy Partners; industry news; RTO Insider

Local Siting and Permitting Issues (Cont'd)

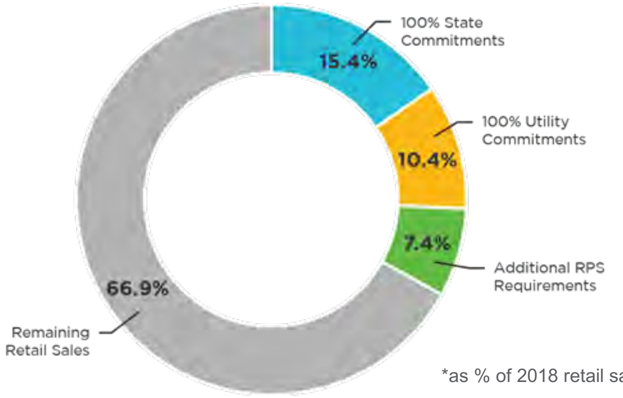
- **Strong policy support helps:** Successful projects have been characterized by strong policy support in the states that the facilities traverse. For example, Central Maine Power has proposed a $1.1 billion, 1,200 MWs high-voltage DC line, called New England Clean Energy Connect. The project is aimed at bringing hydro power from Quebec into New England, and particularly Massachusetts, which has ambitious clean energy goals. The project has been supported by Maine's governor and the Conservation Law Foundation and traverses only Maine, where it interconnects with existing 345 kV facilities.
- **FERC's backstop siting authority:** FERC's authority to overcome these local issues has not been exercised. Section 216 of the Energy Policy Act of 2005 contemplated the development of FERC's backstop siting authority, allowing for FERC to approve siting if a state "withheld approval" of a file application for more than a year. This authority could be invoked only if a proposed line was in a DOE-designated "corridor" facing transmission congestion "that adversely affects consumers." However, this authority has been challenged—both in what constitutes "withheld approval" as well as corridor designation—effectively neutralizing this authority. The DOE continues to assess congestion on a periodic basis, but it has yet to identify or reaffirm any corridors.

Sources: Industry news

Policy Implications

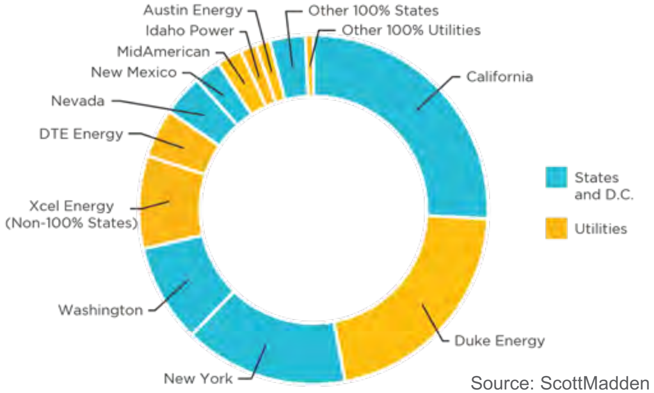
- **Historical issues persist:** The fact that transmission is needed across the country to support both reliability and integration of renewable resources is well-documented; the evolution of policy has not supported this basic understanding. Incentive policy, which drove significant investments through the 2000s is changing, and returns on equity and adders are being reduced. Order 1000 interregional processes have not materialized to facilitate broader integration across markets. The same cost-allocation challenges, which were once discussed at the regional level, have now moved to the interregional level, identifying beneficiaries and allocating costs appropriately, particularly across regions with different methodologies is challenging.
- **Need for forcing function:** Until a forcing function requires these regions to develop a methodology that facilitates largely public policy projects, the hope of interregional transmission meeting national needs for transmission (to serve any purpose, let alone clean energy) will remain elusive.
  - State and local policy continues to stymie transmission development through siting and permitting processes that are poorly aligned.
  - Environmental interests stack up on both sides of the transmission development debate. Some organizations acknowledge the degree to which transmission is needed to facilitate renewables integration. Others focus on the environmental impacts of specific corridors, slowing or stopping permitting and construction. There is also a view that DERs can offset the need for central station (utility-scale) generation and transmission.
  - Economic development always points to local resources serving local load; states are focusing on in-state resources to meet RPS and clean energy targets making the case for interregional collaboration more difficult.
- **Ground-up developments:** What has changed in the last two years or so is the degree to which states, utilities, and other companies are committing to 100% carbon free portfolios (see graphs at right). It is not possible to meet these goals without intraregional, and in some cases interregional, transmission connecting these resources to load. Myriad studies support the notion that higher penetrations of renewables are possible with significant transmission development; however, the balkanized nature of the grid makes the "highway" system approach to transmission unworkable.

100% Clean Energy Commitments and RPS Requirements*



*as % of 2018 retail sales

100% Clean Energy Commitments by State and Utility**



Source: ScottMadden analysis

Notes: 100% clean energy commitments often include renewable resources plus carbon free generation (e.g., nuclear, carbon capture, etc.). Only the state commitment is counted if both the state and an electric utility have 100% clean energy commitments. Data as of July 2019. *As % of 2018 retail sales. **Based on 2018 retail electricity sales.

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Policy Implications (Cont'd)

- **Intraregional for now:** This means that the regions are left to attempt to meet their own renewables goals with intraregional resources or to find a way to collaborate with their neighbors to further integrate resources and needs. Absent a framework, this is unlikely to happen.
- **Possible actions until a national framework emerges:** It is unclear whether the current political and policy environment will provide some kind of national framework for optimal clean, affordable, and resilient transmission grid. Assuming a national framework is not forthcoming in the near term, the following are some potential actions to advance needed investment:
  - FERC should step forward and begin to assess more proactive approaches to creating the framework for interregional collaboration in light of company, state, and regional goals related to clean energy. Cooperation between regions exists, especially where there are significant cross-seam flows (e.g., MISO/SPP, MISO/PJM). Building on those seams, processes may be an easier path to improving interregional processes.
  - There is an opportunity to reconsider the current trend in transmission incentives if there is a desire to have companies undertake these large interregional projects.
  - The myriad stakeholders focused on clean energy—market operators, labor, states, and clean energy advocates, among others—need to further articulate the critical role of transmission in facilitating company, state, and regional goals for clean energy. While environmental concerns about critical habitats and siting need to be acknowledged and managed, the role of high-voltage transmission in facilitating a transition to a cleaner fuel mix needs to be communicated, again and again. This communication can't come from utilities or transmission owners; this needs to originate with those advocating for aggressive carbon goals. The idea that DERs will either solve the clean energy challenge or ameliorate the need for more transmission needs to be revisited; while DERs may provide local benefits, they cannot replace utility-scale renewables in meeting clean energy objectives.
  - As utilities (like Xcel Energy) put forward clean energy and carbon free goals, they should also highlight the role that transmission plays in facilitating this transition.
- **Articulating network effects:** The network and other positive effects of transmission need to be more broadly understood and communicated. The current cost/benefit methodology for defining needs or articulating the benefits of transmission do not adequately account for the future uses of these facilities.
  - The network effects of previous projects should be communicated. For example, AEP's 765 kV transmission overlay, including its proposed Pioneer Transmission project, relieves congested lower-voltage lines, enhances reliability of the regional transmission system, improves operational and maintenance flexibility, offsets the need for smaller, incremental upgrades on lower-voltage lines, lowers costs by reducing congestion and system losses, and enables further development of new generation resources. Today's project built for reliability will facilitate transfers of "greener" power, but we can't necessarily articulate when and how much. Transmission should be viewed as a "no regrets" investment because it facilitates myriad future scenarios.

Policy Implications (Cont'd)

- **Aligning system needs with clean energy goals:** As regions and states develop and communicate clean energy goals, they should work with the RTO/ISO to understand the degree to which these goals must be facilitated by transmission. In its original announcement of its 50/30 clean energy goals, New York did not acknowledge this dependence on transmission causing a public debate between New York officials and the NYISO. This requires education and commitment to a collaborative process, even at the state level. Clean energy advocates, in addition to utilities, must also play a role in educating the needs to enhance grid capacity to facilitate large-scale development required by some state policies.

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