NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 Long-Term Reliability Assessment

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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people. The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map below. To see a map of the 21 assessment area boundaries, see the **Assessment Area Dashboards and Summaries** section.

About This Assessment

This *2017 Long-Term Reliability Assessment* (*2017 LTRA*) was developed by NERC in accordance with the Energy Policy Act of 2005 (Title 18, § 39.11[1] of the Code of Federal Regulations.[2, 3] This assessment also fulfils the ERO's Rules of Procedure, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

2017 Format Update

In response to feedback from NERC's Board of Trustees and other NERC stakeholders, the *2017 LTRA* is presented in a more succinct format to highlight data and information that is especially impactful to the long-term outlook of the North American BPS. This transition to a shorter format was executed without impacting the comprehensive assessment development process described in the Data Concepts and Assumptions section. Interested parties should contact NERC Staff with any questions.

There is an errata for this report. It can be found on page 82.

Development Process

This assessment was developed based on data and narrative information collected by NERC from the eight Regional Entities on an assessment area basis to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the 10-year assessment period.[5]

[1] Section 39.11(b) of the U.S. FERC's regulations provide: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[2] This is also referred to as Section 215 of the Federal Power Act in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the BPS in North America.

[3] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the objectives, scope, data and information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[4] BPS reliability does not include the reliability of the lower-voltage distribution systems, which systems use to account for 80 percent of all electricity supply interruptions to end-use customers.

[5] Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Resources refer to a combination of electricity-generating and transmission facilities that produce and deliver electricity and demand-response programs that reduce customer demand for electricity. Adequacy requires System Operators and planners to account for scheduled and reasonably expected unscheduled outages of equipment while maintaining a constant balance between supply and demand.

The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Planning Committee, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the NERC Planning Committee and the NERC Board of Trustees, who subsequently accepted the report and endorsed the key findings.

Data Considerations

Projections in the *2017 LTRA* are not predictions of what will happen; they are based on information supplied in July 2017 with updates incorporated prior to publication. The assessment period for the *2017 LTRA* is from 2018–2027; however, some figures and tables examine data and information for year 2017. The assessment was developed using a consistent approach for projecting future resource adequacy through the application of NERC's assumptions and assessment methods. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities, which is further explained in the Data Concepts and Assumptions section.

Reliability impacts related to physical and cybersecurity risks are not addressed in this assessment, which is primarily focused on resource adequacy. NERC leads a multi-faceted approach through the Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address these risks, including exercises and information-sharing efforts with the electric industry.

Executive Summary

The electricity sector is undergoing significant and rapid change that presents new challenges for reliability. With appropriate insight, careful planning, and continued support, the electricity sector will continue to navigate the associated challenges in a manner that maintains reliability and resilience. As NERC has identified in recent assessments, retirements of conventional generation and the rapid addition of variable resources (e.g., wind and solar) are altering the operating characteristics of the grid. A significant influx of natural gas generation raises unique considerations regarding risks related to fuel assurance. While related risks and corresponding mitigations are unique to each area, industry stakeholders and policymakers should continue to respond with policies and plans to address fuel availability. This *2017 LTRA* serves as a comprehensive, reliability-focused perspective on the 10-year outlook for the North American BPS and identifies potential risks to inform industry planners and operators, regulators, and policy makers. Based on data and information collected for this *2017 LTRA*, NERC has independently identified the following four key findings:

Key Findings

Recent retirement announcements in Texas RE-ERCOT and the canceled nuclear plant expansion in SERC-E result in projected margin shortfalls for both assessment areas:

- SERC-E Anticipated and Prospective Reserve Margins drop below the Reference Margin Level beginning in Summer 2020.
- Recently announced plant retirements that were approved by ERCOT result in Anticipated Reserve Margins dropping below the Reference Margin Level beginning Summer 2018; Prospective Reserve Margins remain adequate.
- Other assessment areas project sufficient Anticipated Reserve Margins through 2022.

Amid slower demand growth, conventional generation continues to retire with rapid additions of natural gas, wind, and solar resources:

- NERC-wide electricity peak demand and energy growth are at the lowest rates on record with declining demand projected in three areas.
- Conventional generation retirements have outpaced conventional generation additions with continued additions of wind and solar.
- Retirement plans have been announced for 14 nuclear units, totaling 10.5 GW.
- Natural-gas-fired capacity has increased to 442 GW from 280 GW in 2009 with an additional 44.6 GW planned during the next decade.
- Wind generation currently accounts for more than 10 percent of total installed capacity in six areas with 14.8 GW (nameplate) of NERC-wide additions projected during the next decade.
- A total of 37 GW (nameplate) of solar additions are projected by 2022. Of these, 20 GW (nameplate) are distributed, raising visibility concerns for system planners.

The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services and fuel assurance:

- Operating procedures that recognize potential inertia constraints were recently established in ERCOT and Québec.
- With continued rapid growth of distributed solar, CAISO's three-hour ramping needs have reached 13 GW, exceeding earlier projections and reinforcing the need to access more flexible resources.
- Reference Margin Levels vary across North America depending on the resource mix.
- Methods for determining the on-peak availability of wind and solar are improving with growing performance data.
- Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural gas.

A total of 6,200 miles of transmission additions are planned to maintain reliability and meet policy objectives:

- Despite low or flat load growth, a total of 6,200 circuit miles of new transmission is planned throughout the assessment period with more than 1,100 circuit miles currently under construction.
- Actual transmission additions have increased despite lower projected energy growth.

Recommendations

NERC continually assesses the future reliability of the BPS by evaluating long-term plans and identifying risks. Based on the identified key findings, NERC has formulated the following recommendations:

Policy Makers and Regulators:

- **Support essential reliability services:** FERC should support new market products and/or changes to market rules that support the provision of essential reliability services, which includes frequency response and increased system flexibility.
- **Recognize time needed to maintain reliability:** State, federal, and provincial regulators should continue to recognize lead times for the generation, transmission, and natural gas infrastructure needed to maintain reliability as industry strives to meet policy goals and initiatives. Reliable operation of the BPS requires dependable capacity with fuel assurance to address consumer needs, impacts of extreme weather conditions, and sudden disturbances on the system.
- **Consider industry study recommendations when reviewing infrastructure requirements:** Regulators (including DOE and FERC) should consider results and conclusions of industry studies that evaluate the impact of natural gas disruptions to the BPS when evaluating infrastructure requirements.
- **Focus on reliability and resilience attributes to limit exposure to risk:** Regulators should consider the reliability and resilience attributes provided by generation to ensure that the generation resource mix continues evolving in a manner that maintains a reliable and resilient BPS.

Industry:

- **Support technologies that contribute to essential reliability services:** All new resources should have the capability to support voltage and frequency. Various technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.
- **Integrate DERs with increased visibility:** In areas with expected growth in DERs, system operators and planners should gather data about the aggregate technical specifications of DERs connected to local distribution grids to ensure accurate system planning models, coordinated system protection, and real-time situation awareness.
- **Report on expected reliability concerns:** In areas impacted by an increasing share of natural-gas-fired generation, transmission planners and operators should identify and report on expected reliability concerns due to a large share of interruptible natural gas transportation and supplies. Where deregulated markets exist, market operators should develop additional rues or incentives to encourage increased fuel security, particularly during winter months.

NERC:

- **Conduct comprehensive evaluation of Reliability Standards:** NERC should conduct a comprehensive evaluation of its Reliability Standards to ensure compatibility with nonsynchronous and distributed resources as well as for completeness related to essential reliability services, generator performance, system protection and control, and balancing functions.
- **Monitor reserve margin short falls:** In light of the projected reserve margin shortfalls in TRE-ERCOT and SERC-E, NERC and the respective Regional Entities should identify and assess updated industry plans and proactive measures for maintaining reliability given the reduction in expected capacity resources. NERC and the Regions should determine the likelihood of a capacity shortage in these areas, evaluate the measures being taken, and identify updated plans in the 2018 Summer Reliability Assessment. Longer-term challenges will be evaluated in the 2018 LTRA.

Detailed Review of 2017 Findings

Reserve Margin Analysis

The canceled nuclear plant expansion in SERC-E results in a projected margin shortfall. Other Regions project sufficient margins during the next five years.

SERC-E

SERC-E's Anticipated and Prospective Reserve Margins fall below the Reference Margin Level (See **Figure 1**) beginning in Summer 2020. This development is further detailed below:

- The canceled expansion of the V.C. Summer nuclear power plant (approximately 2,200 MW) in SERC-E results in both Anticipated and Prospective Reserve Margins falling below the Reference Margin Level in 2020 and declining for the remainder of the assessment period.
- NERC will be coordinating closely with SERC on this issue in the coming years to assess potential reliability impacts as plans are established to address the shortfall.
- SERC entities are developing plans to replace the canceled plant expansion with other capacity or by acquiring additional resources to meet projected demand.
- SERC continues to monitor reliability impacts through transmission studies and resource adequacy assessments as well as coordination with appropriate state public utility commissions.

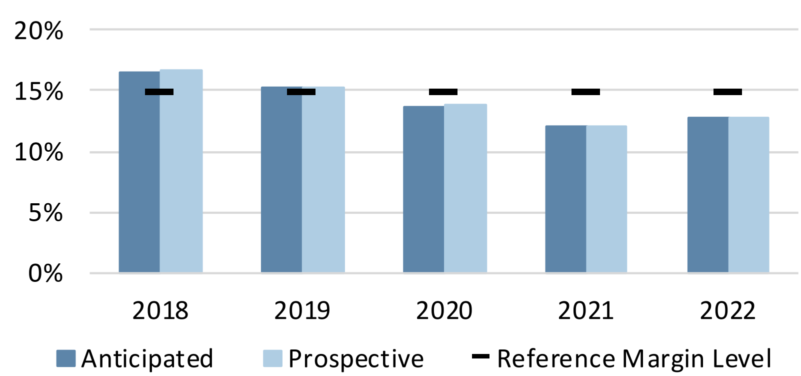


Figure 1: SERC-E Planning Reserve Margins

Texas RE-ERCOT

With ERCOT's approval of recently submitted plant retirements, Anticipated Reserve Margins fall below the Reference Margin Level, beginning in Summer 2018 (see **Figure 2**). ERCOT's Prospective Reserve Margins remain adequate. The details are as follows:

- Between September and October 2017, ERCOT received notice from Generator Owners of seven coal units and a single gas-steam unit about plans to take the units out of service between December 2017 and February 2018.
- The submitted retirements are for 4,600 MW and include the following units: Barney M. Davis Unit 1, Monticello Units 1–3, Big Brown 1 and 2, and Sandow 4 and 5.
- Between October and November 2017, ERCOT determined that these units are not needed for grid reliability and approved all seven retirement requests.
- Due to the late timing of the announcements, these planned retirements, as well as other recent resource updates, are not reflected in the 2017 LTRA Reference Case Reserve Margins.
- As presented in Figure 2, these unit retirements will reduce the summer 2018 Anticipated Reserve Margin by 6.5 percentage points, effectively decreasing it from 18.22 percent to 11.76 percent, below the Reference Margin Level of 13.75 percent.
- This reserve margin reduction does not account for any other resource updates, including replacement capacity that may be added in response to the announced retirements.

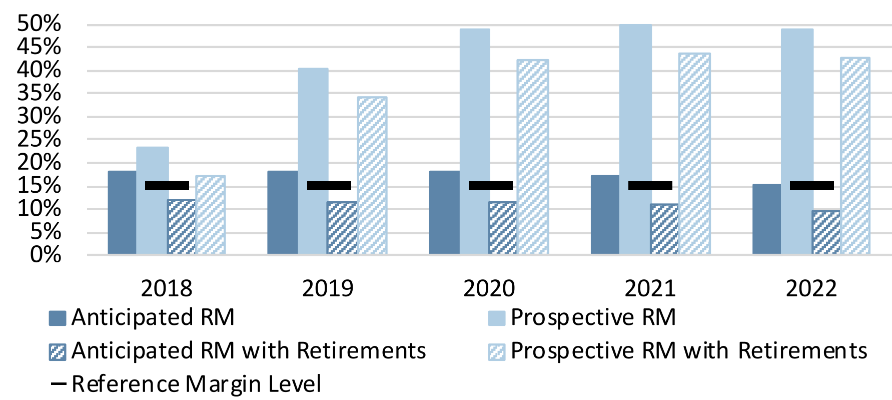


Figure 2: Texas RE-ERCOT Planning Reserve Margins with Announced Retirements

Assessment Area Reserve Margins

The 20 other assessment areas project sufficient short-term (2022) Anticipated Reserve Margins (see **Figure 3**). **Table 1** on the following page provides the Planning Reserve Margins for 2018–2022.

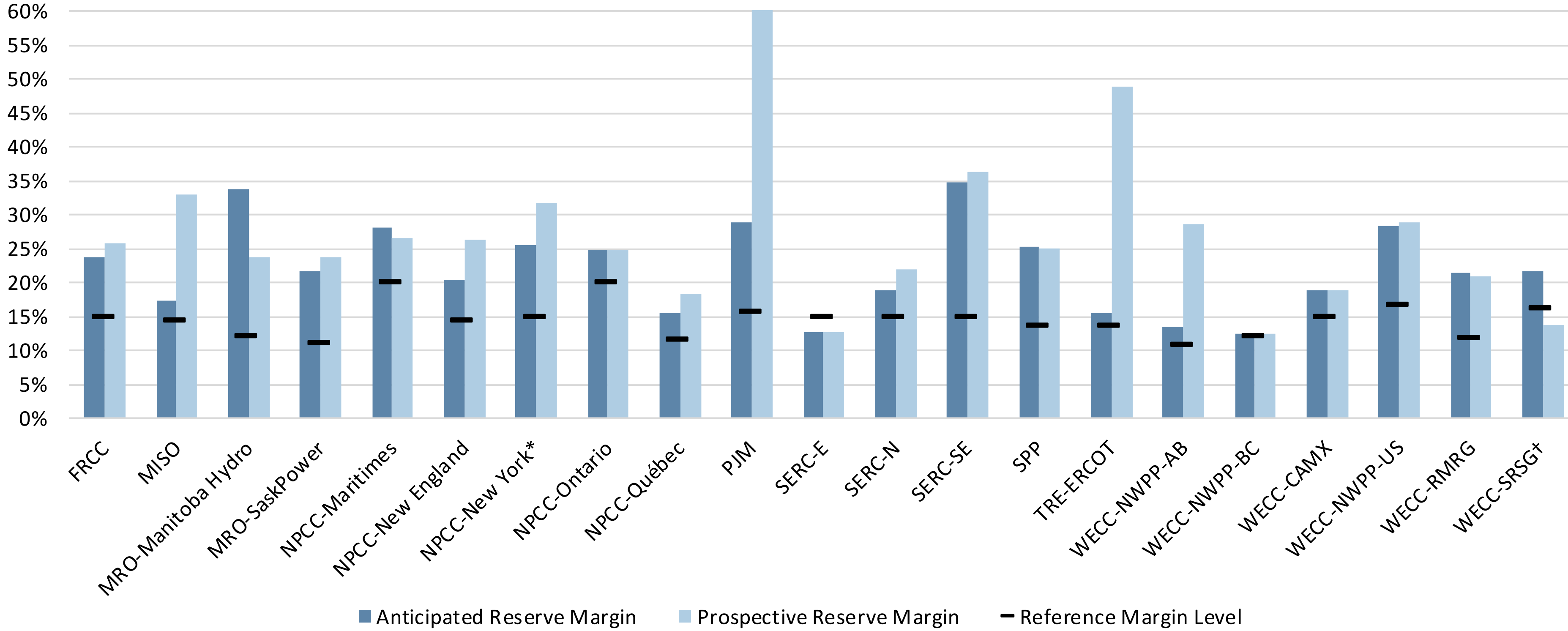


Figure 3: Assessment Area Reserve Margins

* For the NPCC-New York Assessment Area, NYISO uses a probabilistic model with installed capacity and equivalent forced outage rates for all resources in order to identify resource requirements. The result of NYISO's analysis produces the Installed Reserve Margin (IRM) which is established by the New York State Reliability Council (NYSRC) for one "Capability Year" (May 1, 2017 through April 30, 2018). In order to conform with the NERC PC-approved assessment approach, wind, solar, and run-of-river hydro are required to be derated to their "expected on-peak" summer and winter values. The following derates have been applied, based on NYISO's Unforced Capacity (UCAP) values: wind (20% of nameplate), run-of-river hydro (55% of nameplate), and solar (50% of nameplate). NERC has applied the "default" 15% Reference Margin Level for the entire 10-year assessment period. Because the IRM is based on installed capacity values, it should not be used to evaluate reserve margins that take into account resource availability.

† The Prospective Reserve Margin is below the Anticipated Reserve Margin for WECC-SRSG because there are currently more unconfirmed retirements projected than identified planned Tier 2 resources.

Table 1: Planning Reserve Margin Years (2018–2022)

Assessment Area	Reserve Margins	2018	2019	2020	2021	2022
FRCC	Anticipated	21.36	22.50	22.49	21.35	23.78
	Prospective	22.49	23.89	23.65	23.48	25.89
	Reference Margin Level	15.0	15.00	15.00	15.00	15.00
MISO	Anticipated	19.23	19.79	19.38	18.93	17.28
	Prospective	26.18	28.45	33.35	34.04	32.96
	Reference Margin Level	15.80	15.80	15.80	15.80	15.80
MRO-Manitoba Hydro	Anticipated	15.29	18.76	17.65	24.73	33.74
	Prospective	17.85	18.85	12.30	14.64	23.72
	Reference Margin Level	12.00	12.00	12.00	12.00	12.00
MRO-SaskPower	Anticipated	17.02	26.13	29.97	27.73	21.68
	Prospective	17.02	26.13	29.97	29.76	23.74
	Reference Margin Level	11.00	11.00	11.00	11.00	11.00
NPCC-Maritimes	Anticipated	23.12	23.37	26.73	27.98	28.11
	Prospective	23.81	24.78	25.25	26.50	26.63
	Reference Margin Level	20.00	20.00	20.00	20.00	20.00
NPCC-New England	Anticipated	23.73	23.92	23.83	20.13	20.41
	Prospective	25.43	27.96	29.70	26.02	26.31
	Reference Margin Level	16.60	16.70	16.90	16.90	16.90
NPCC-New York	Anticipated	22.54	22.76	24.95	25.64	25.54
	Prospective	23.56	26.98	29.41	31.81	31.70
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00
NPCC-Ontario	Anticipated	24.85	30.09	27.01	24.23	24.73
	Prospective	24.85	30.09	27.01	24.23	24.73
	Reference Margin Level	19.45	18.37	18.17	23.19	23.72
NPCC-Québec	Anticipated	17.71	16.79	15.08	16.36	15.53
	Prospective	20.77	19.83	18.10	19.35	18.49
	Reference Margin Level	12.90	12.90	12.90	12.90	12.90
PJM	Anticipated	32.47	33.43	28.01	28.89	28.85
	Prospective	38.00	46.71	52.51	58.51	60.67
	Reference Margin Level	16.70	16.60	16.60	16.60	16.60
SERC-E	Anticipated	16.53	15.22	13.67	11.99	12.76
	Prospective	16.62	15.31	13.77	12.08	12.86
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00
SERC-N	Anticipated	21.45	20.31	19.93	19.40	18.92
	Prospective	24.56	23.38	22.98	22.44	21.95
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00
SERC-SE	Anticipated	33.72	34.99	35.15	34.22	34.90
	Prospective	35.18	36.44	36.58	35.64	36.31
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00
SPP	Anticipated	32.43	28.78	28.90	27.59	25.40
	Prospective	32.94	28.99	29.11	27.80	25.06
	Reference Margin Level	12.00	12.00	12.00	12.00	12.00
Texas RE-ERCOT	Anticipated	18.22	18.06	17.98	17.06	15.50
	Prospective	23.54	40.51	48.67	49.67	48.76
	Reference Margin Level	13.75	13.75	13.75	13.75	13.75
WECC-AB	Anticipated	21.52	21.35	18.22	15.93	13.61
	Prospective	22.16	26.43	30.29	31.17	28.55
	Reference Margin Level	11.03	11.03	11.03	11.03	11.03
WECC-BC	Anticipated	15.18	14.25	12.84	12.11	12.10
	Prospective	15.18	14.25	12.84	12.11	12.10
	Reference Margin Level	12.10	12.10	12.10	12.10	12.10
WECC-CAMX	Anticipated	19.17	20.70	20.59	22.71	18.85
	Prospective	19.17	20.70	20.59	22.71	18.85
	Reference Margin Level	16.14	16.14	16.14	16.14	16.14
WECC-NWPP-US	Anticipated	22.22	22.80	27.74	25.91	28.45
	Prospective	22.45	23.22	28.16	26.33	28.87
	Reference Margin Level	16.38	16.38	16.38	16.38	16.38
WECC-RMRG	Anticipated	23.66	26.01	25.95	22.86	21.39
	Prospective	23.30	25.38	25.40	22.32	20.86
	Reference Margin Level	14.17	14.17	14.17	14.17	14.17
WECC-SRSG	Anticipated	23.67	23.18	22.63	21.95	21.71
	Prospective	20.17	10.30	14.17	13.66	13.65
	Reference Margin Level	15.83	15.83	15.83	15.83	15.83

Amid slower demand growth, conventional generation continues to retire with rapid additions of natural gas, wind, and solar resources.

	Demand	Natural Gas	Wind	Conventional Generation	Solar PV
What's Happening?	10-year compound annual growth rate (CAGR) of demand for North America is the lowest on record at 0.61% (summer) and 0.60% (winter). Load growth in all assessment areas is under 2% with three NPCC assessment areas projecting negative load growth.	On-peak natural-gas-fired capacity has increased to 442 GW from 280 GW in 2009.[6] 44.7 GW of Tier 1 gas-fired capacity additions are planned during the next decade. Natural-gas-fired capacity is the primary on-peak fuel type in 10 assessment areas.	More than 14.8 GW (nameplate) of Tier 1 wind additions are planned by 2027. Some assessment areas note rapid wind additions and potential reliability risks.	Conventional generation retirements, primarily coal, oil, and steam gas, have outpaced conventional additions during the last decade in the U.S. Low natural gas prices combined with federal, state, and provincial environmental regulations have led to 46.5 GW of coal-fired generation retirements since 2011 with 19 GW of confirmed retirements planned between 2017–2027. 6 nuclear units have retired since 2012 while 14 have announced plans to retire by 2025.	Solar resources are expected to increase by 17 GW (utility scale) and 20 GW (rooftop) during the next decade. Significant amounts of DERs (primarily rooftop PV) are being integrated without the visibility of BPS planners and operators.
Potential Reliability Issues	Declining demand growth rates could quickly be reversed with the potential rapid electrification needs of new technologies (e.g., transportation).	A growing reliance on natural gas in several areas requires further assessment of fuel assurance. Disruptions in natural gas storage and/or delivery infrastructure can impact BPS reliability.	There could be overgeneration during light load periods. Transmission will be needed to interconnect these resources. Inverter-based resources do not inherently provide important ERS attributes, although technologies are available for wind resources, if required or elected.	Conventional generation provides important inherent characteristics, including inertia and reactive support for voltage control, with high levels of fuel assurance Retirements of these inherently larger units have greater impacts on resource adequacy and require advanced planning to identify replacement capacity, operating procedures, or transmission upgrades.	Concentrated, large-scale proliferation of DERs require fast-acting resources to counteract daily ramping characteristics that are introduced. Aggregate impacts of distributed PV with insufficient visibility can impact BPS operations. Inverter-based resources do not inherently provide important ERS attributes, but technologies are available for solar resources if required or elected.
Impacted Assessment Areas	All Areas	WECC-CAMX, Texas RE-ERCOT, FRCC, NPCC-New England	SPP, Texas RE-ERCOT, MISO	SERC-E, PJM, NPCC-New York, NPCC-New England, WECC, TRE-ERCOT, MISO	WECC-CA/MX, NPCC-New York, NPCC-New England, SERC

6 Based on peak season for each assessment area.

Demand Projections

NERC-wide electricity peak demand and energy growth are at the lowest rates on record with declining demand projected in three areas: NPCC-New England, -Ontario, and -Maritimes (see bottom of **Figure 4**). Some of the key drivers and the effects of the drivers are as follows:

- Continued advancements of energy efficiency programs and behind-the meter resources, combined with a general shift in North America to economic growth that is less energy-intensive, are contributing factors to slower electricity demand growth.
- A total of 30 States have adopted energy efficiency policies that are contributing to reduced peak demand and overall energy use.
- The 10-year compound annual growth rate (CAGR) of peak demand is the lowest on record at 0.61 percent (summer) and 0.59 percent (winter). See **Figure 5.**
- The 10-year energy growth is 0.61 percent per year, compared to more than 1.48 percent just a decade earlier.

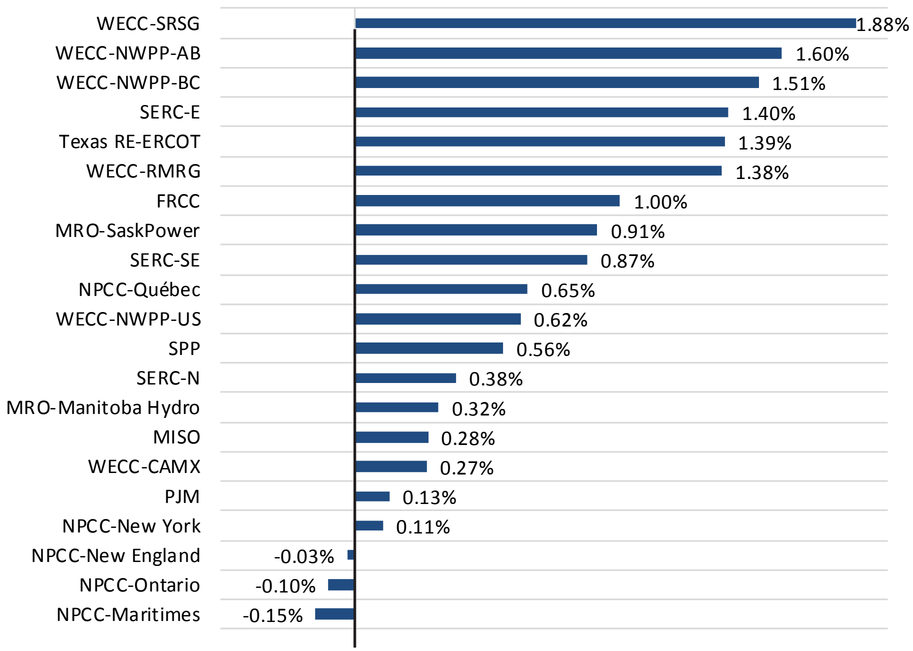


Figure 4: 10-Year Peak Demand Growth by Assessment Area

A rapid onset of emerging technologies, including the rapid penetration of electric vehicles, could create unexpected impacts on load growth that might not be captured in load forecasts (see **Figure 6**). Examples: Automobiles and trucks are now increasingly battery-powered. Plug-in electric vehicles are projected to account for as much as half of all U.S. new car sales by 2030. The electricity required to charge these vehicles will increase demand on the BPS. Electric heating is also driving efficiency increases as heat pumps replace other forms of heating, including natural gas, oil, and direct electric heating on broader scales.

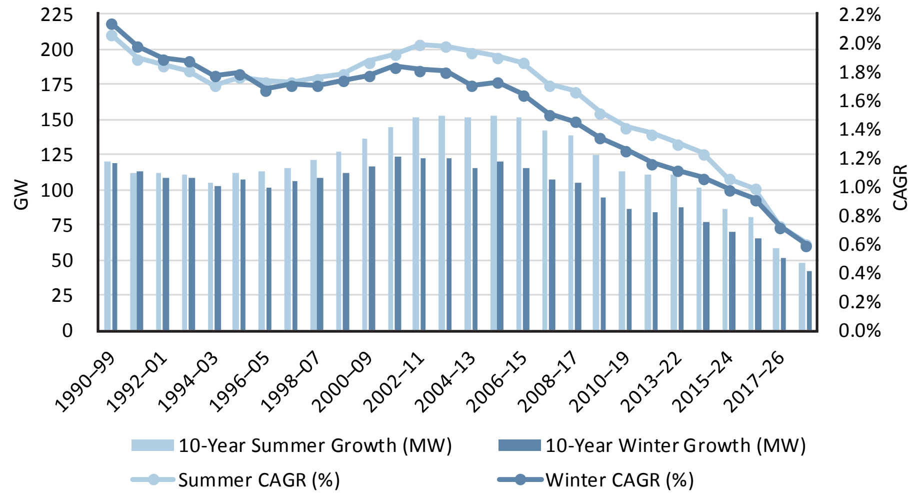


Figure 5: 10-Year Summer and Winter Demand Growth and CAGR by LTRA Year

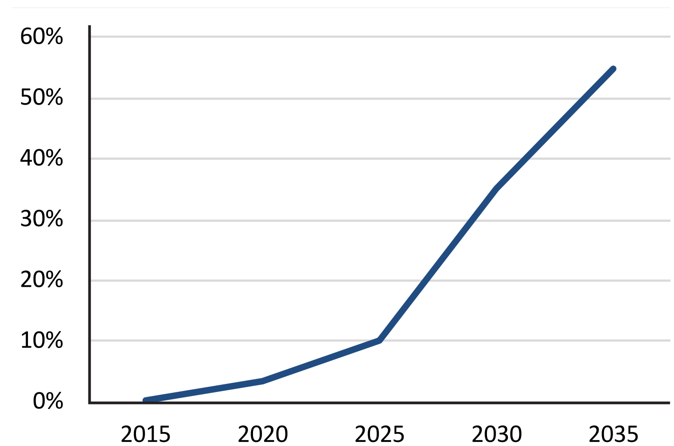


Figure 6: Electric Vehicle Penetration Forecast (Bloomberg)

Changing Resource Mix

Conventional generation retirements have outpaced conventional generation additions. Additionally, large increases in wind and solar have compounded this change in the resource mix. A further explanation of the changing resource mix and some of the implications are as follows:

- Conventional generation from coal, oil, and nuclear units continues to retire as natural gas, wind, and solar lead planned additions. (See **Figures 7 and 9**).
- Conventional generation, including coal and nuclear, have unique attributes of low outage rates, high availability rates, and on-site fuel storage that provides secure and stable capacity to the grid.
- Retirements of primarily coal (46.5 GW) and natural gas steam-driven generation (20 GW)[7] with an additional 19 GW of coal retirements are projected by 2027.
- In the United States, the average size of retiring coal plants (less than 50 MW in 2000) has tripled to more than 150 MW in 2015 while the average size of retiring gas steam-driven plants has doubled.[8]
- The 59 GW of conventional generation additions in the U.S. since 2011 have been primarily combined-cycle natural gas units and steam-driven coal units.[9]
- Natural gas, wind, and solar continue to experience the largest growth in terms of fuel source with natural gas expected to add 44.6 GW of new generation, solar to add 17.0 GW, and wind to add 14.8 GW. (**Figure 8**)

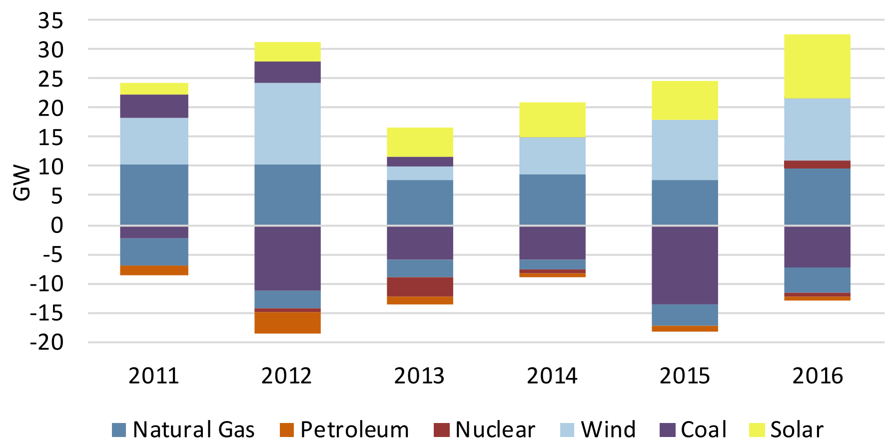


Figure 7: Retirement Projections from 2011–2016[9]

- The changing resource mix, combined with the onset of new technologies (e.g., inverter-based resources), are altering the operational characteristics of the grid and require changes to planning and operating approaches.
- Replacing coal and nuclear retirements with nonsynchronous and natural-gas-fired generation is introducing new considerations for reliability and resilience planning, such as ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system.

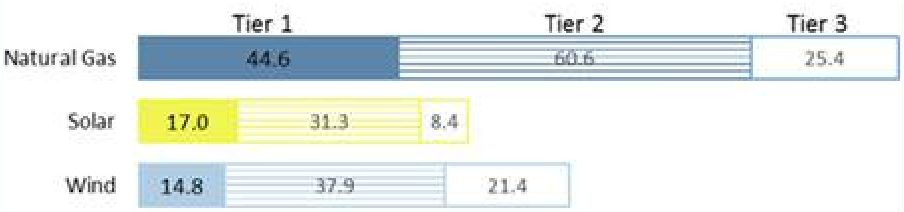


Figure 8: Natural Gas, Solar, and Wind Tier 1, Tier 2, and Tier 3 Additions (Nameplate GW)

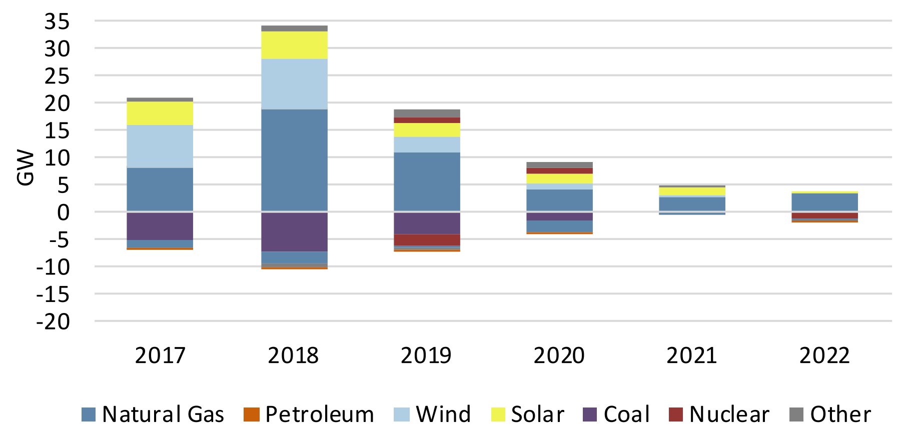


Figure 9: LTRA Reference Case Projections[11]

[7] Source: EIA; ABB Velocity Suite; NERC analysis
[8] Source: ScottMadden Energy Industry Update
[9] Includes U.S. and Canada. Source: EIA; ABB Velocity Suite; NERC analysis

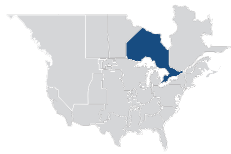
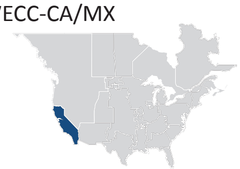
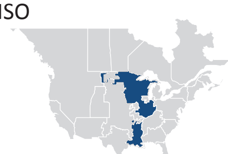
[10] Projections are based on 2017 LTRA Reference Case data, including Tier 1 additions

Nuclear Retirements

Table 2 on the right shows that retirement plans have been announced for 14 nuclear units, totaling 10.5 GW. The details are as follows:

- The fleet of 67 nuclear plants (118 units) in the U.S. and Canada meet over 20 percent and 16 percent of total electricity demand, respectively.
- Low natural gas prices continue to affect the competitiveness of nuclear generation and are a key contributing factor to nuclear generation's difficulty in remaining economic.
- While replacement capacity may be identified to mitigate resource adequacy concerns, nuclear retirements require additional attention from system planners and policy makers related to local transmission adequacy and the potential for reduced resilience. This is because of the unique ability of nuclear resources to operate despite a variety of potential fuel supply disruptions.
- A total of six plants have closed since 2012, including Gentilly (Québec), Crystal River (Florida), Kewaunee (Wisconsin), San Onofre (California), Vermont Yankee (Vermont), and Fort Calhoun (Nebraska).
- As presented in the **Table 2**, owners of seven plants (14 units) have announced plans to retire within the next decade, including facilities in Ontario, California, New York, New Jersey, Pennsylvania, Michigan, and Massachusetts.
- Legislation passed in Illinois created financial incentives through 2026 to support the continued operation of the Quad Cities and Clinton nuclear generation stations.
- The state of New York also established legislation to enact a zero-emission credit requirement for some upstate nuclear generating facilities.

Table 2: Nuclear Retirements by Assessment Area

Assessment Area	Total Capacity	State/Province	Unit Name	Retirement Year	Capacity (MW)
NPCC-Ontario 	3,094	Ontario	Pickering #1	2022	515
			Pickering #4	2022	515
			Pickering #5	2024	516
			Pickering #6	2024	516
			Pickering #7	2024	516
			Pickering #8	2024	516
WECC-CA/MX 	2,300	California	Diablo Canyon #1	2024	1,150*
			Diablo Canyon #2	2025	1,150*
NPCC-New York 	2,150	New York	Indian Point #2	2020	1,070
			Indian Point #3	2021	1,080
PJM 	1,477	New Jersey	Oyster Creek	2019	640
		Pennsylvania	Three-Mile Island	2019	837
MISO 	816	Michigan	Palisades	2018	816*
NPCC-New England 	677	Massachusetts	Pilgrim	2019	677

*Not submitted as a confirmed retirement in *2017 LTRA* Reference Case

Natural Gas Generation Additions

NERC-wide natural-gas-fired on-peak generation has increased from 360 GW in 2009 to 432 GW today with 44.7 GW Tier 1 additions planned during the next decade. This is described further below:

- Natural-gas-fired generation data has been growing beyond projections as **Table 3** indicates. From the *2009 LTRA* through the *2017 LTRA* reference cases, actual natural gas additions have continued to outpace projections (See **Figure 10**).
- NERC has identified that reliance on a single fuel increases vulnerabilities, particularly during extreme weather conditions.
- During the past decade, several assessment areas have significantly increased dependence on natural gas, a trend that results from lower natural gas prices and construction costs (compared to nuclear and coal with carbon capture and sequestration).
- Natural gas provides "just-in-time" fuel and is not stored on site at generators. Maintaining firm transportation and dual fuel capability can significantly reduce the risk of interruption, common-mode failure, and widespread fuel delivery impacts.
- As natural-gas-fired generation continues to increase, the electric industry needs to continue to evaluate and report on the potential effects of an increased reliance on natural gas needed to assure BPS reliability and resilience.
- By 2022, FRCC, Texas RE-ERCOT, NPCC-New England, and most of WECC are expected to have at least 50 percent of their resources composed of natural-gas-fired generation with FRCC expected to be near 80 percent.
- During extreme events and most notably during the recent 2014 Polar Vortex, extended periods of cold temperatures caused direct impacts on fuel availability, especially for natural-gas-fired generation. Higher-than-expected forced outages and common-mode failures were observed during the polar vortex due to the following:
  - Natural gas interruptions (including supply injection), compressor outages, and one pipeline explosion
  - Oil delivery problems
  - Frozen well heads
  - Inability to procure natural gas
  - Fuel oil gelling

Table 3: Areas with More Than 40% Natural Gas as a Percent of Total Capacity

Assessment Area	2018 (MW)	2022 (MW)	2018 (%)	2022 (%)
FRCC	39,976	42,003	75.0%	78.1%
WECC-CAMX	40,299	42,536	65.6%	68.2%
Texas RE-ERCOT	45,842	51,867	61.8%	63.3%
NPCC-New England	14,331	16,308	47.1%	52.3%
WECC-SRSG	16,530	16,774	51.4%	51.8%
WECC-AB	8,514	8,514	49.5%	51.8%
SERC-SE	30,256	30,262	49.1%	46.9%
MRO-SaskPower	1,835	2,087	43.9%	44.0%
SPP	30,413	29,446	48.6%	45.2%
SERC-N	19,250	21,160	37.5%	40.7%
MISO	59,566	60,026	43.3%	42.3%
NPCC-New York	16,030	16,708	44.0%	42.0%

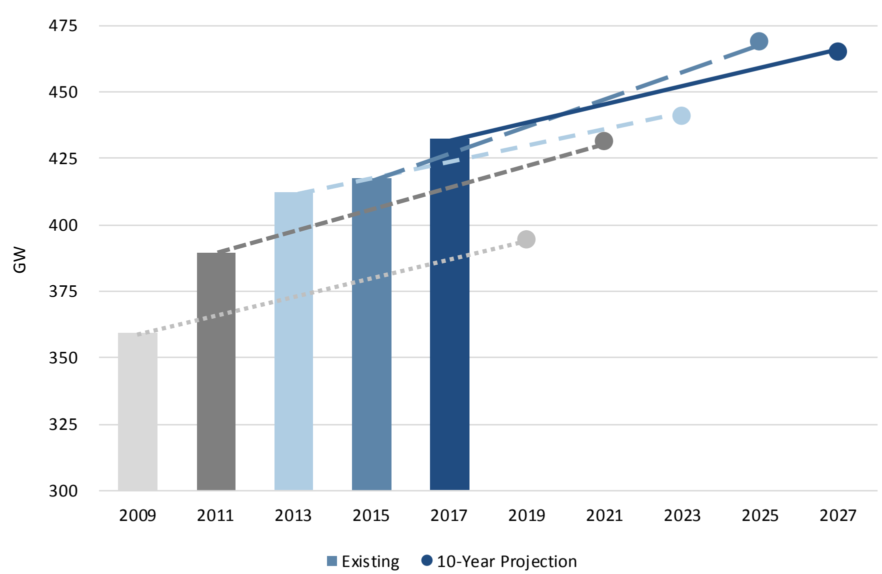


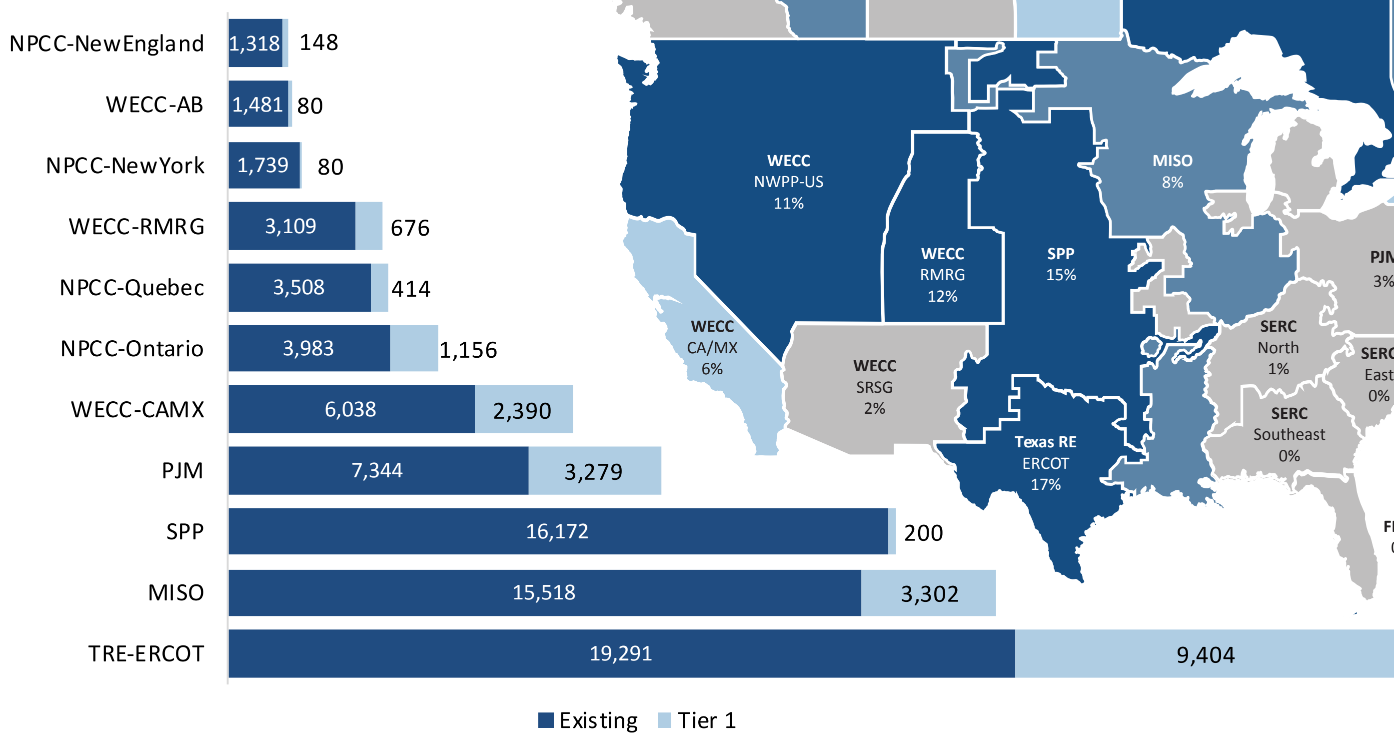
Figure 10: Existing On-Peak Natural Gas and 10-Year Projections by LTRA Reporting Year

Wind Generation Additions

Wind generation currently accounts for more than 10 percent of total installed capacity in six areas with 14.8 GW (nameplate) of NERC-wide additions projected during the next decade. See map in **Figure 11** below. The following is additional information:

- State and provincial renewable portfolio standards (RPS) contribute to projected increases of wind generation in the U.S. and Canada.
- Texas RE-ERCOT is addressing challenges with respect to increasing amounts of wind through improved accuracy of wind forecasting and dynamic consideration of the associated reliability risks.
- In SPP, installed wind-generation capacity grew from 12 GW to more than 16 GW in 2016.
- **Figure 12** shows nameplate wind and 10-year Tier 1 additions by assessment areas that are experiencing the largest growth in wind.

Figure 12: Nameplate Wind and 10-Year Tier 1 Additions by Assessment Area (Includes 2017 Additions)



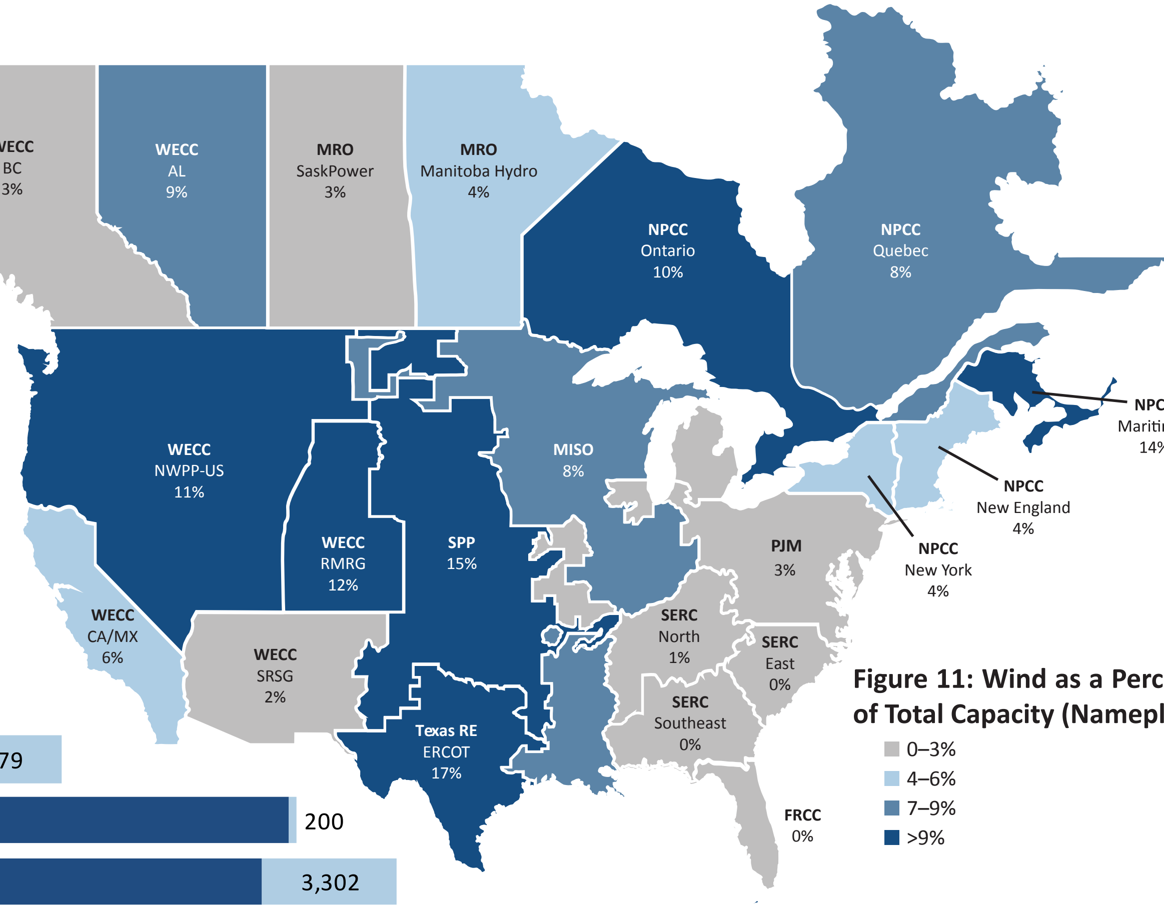


Figure 11: Wind as a Percentage of Total Capacity (Nameplate)

Solar Additions

A total of 37 GW (nameplate) of solar additions are projected by 2022 with 20 GW (nameplate) of those being distributed generation that raise visibility concerns for system planners. Some of the present trends and effects of increased solar generation at both the utility scale as well as at the distribution level are highlighted below:

- Entities in several areas do not explicitly track the installation of non-utility photovoltaic (PV). **Table 4** provides an overview of several assessment areas and how they present non-utility PV.
- Lacking visibility or mechanisms to track DERs can lead to unexpected impacts on areas of the BPS with higher levels of DER penetration when the aggregated impacts begin to affect BPS operations.
- While this exact point is unique to each area, it is important that state and provincial policies are in place to track PV growth before high levels are reached.
- System reliability benefits from advanced forecasting and modeling tools that provide system planners and operators with visibility and control of DERs in some cases.
- California (California Solar Initiative) and New York (NY Sun Program) are examples of two states with programs aimed at maintaining visibility of DERs with the rapid addition of non-utility PV.
- North Carolina (SERC-E) has installed over 2 GW of PV since 2015; however, SERC is still developing and implementing approaches to accurately report installations of DERs by addressing reporting gaps stemming from NERC's 80 MW threshold registration requirements for Generator Owners.
- By 2027, the addition of more than 26 GW of non-utility PV will be added NERC-wide. A representation of this growth is depicted in **Figure 13.**
- California, Texas, and North Carolina are projected to lead solar PV installation through 2021 as shown in **Figure 14.**

[11] GTM U.S. Solar Market Insight – Executive Summary-Q3 2017

[12] California Distributed Generation Statistics is the official public reporting site of the California Solar Initiative (CSI), presented jointly by the CSI Program Administrators, GRID Alternatives, the California Investor Owned Utilities, and the California Public Utilities Commission.

Table 4: Visibility of Non-Utility PV

Assessment Area	Visibility
NPCC-New England	Tracked by ISO surveys of Distribution Owners
NPCC-New York	NYSERDA collects/projects PV installations
NPCC-Ontario	In load forecast projections based on IESO signed or expected contracts
PJM	In load forecast tracked with Generation Attribute Tracking System (GATS)
Texas RE-ERCOT	Currently estimated with plans to track registered PV (>1 MW) within CIM
WECC-CAMX	Tracked by the CSI rebate program for investor-owned utility customers[11]

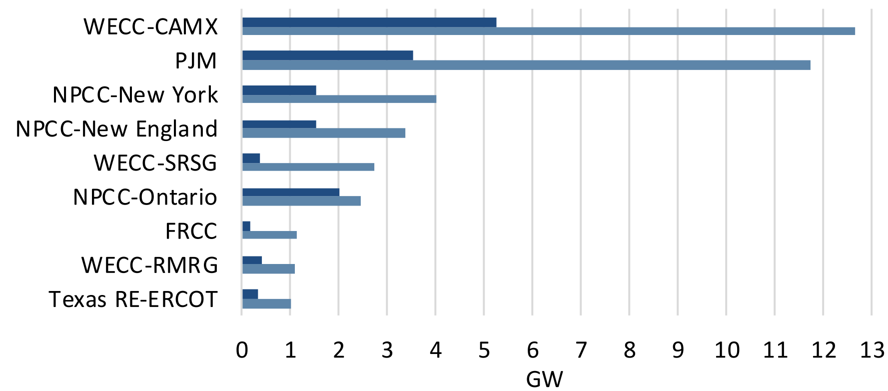
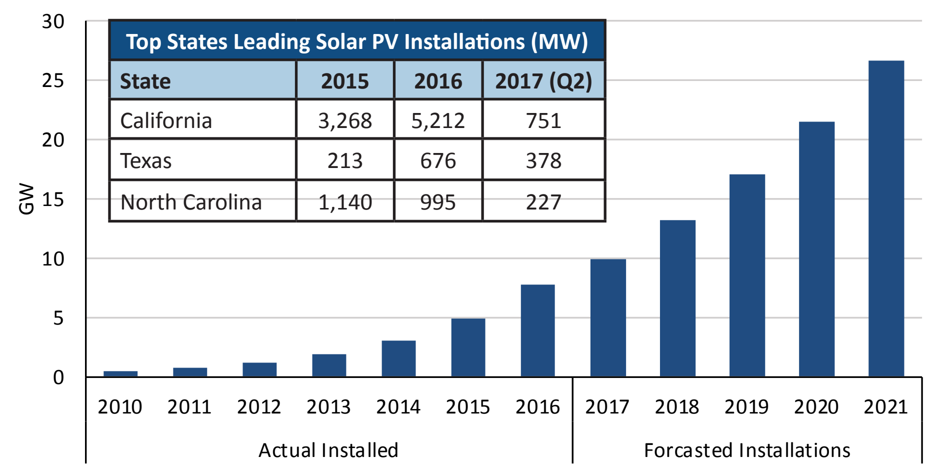


Figure 13: Assessment Areas with High Growth of Non-Utility PV



Top States Leading Solar PV Installations (MW)			
State	2015	2016	2017 (Q2)
California	3,268	5,212	751
Texas	213	676	378
North Carolina	1,140	995	227

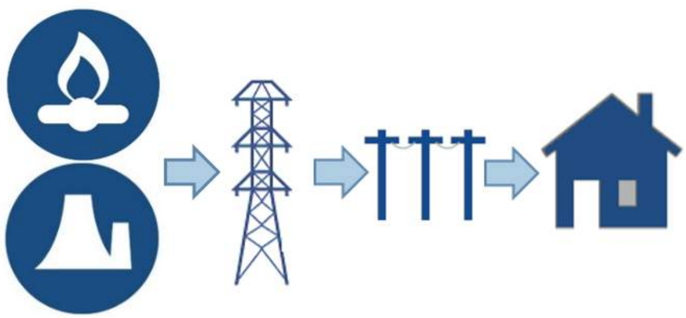
Figure 14: U.S. Non-Utility PV Cumulative Additions

Essential Reliability Services

The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services and fuel assurance. Retiring conventional generation is being replaced with large amounts of wind, solar, and natural gas; planning considerations must adapt with more attention to essential reliability services and mechanisms to promote fuel assurance to maintain the reliable operation of the North American BPS.

System Generation and Delivery | **Reliability Implications** | **Planning Considerations**

Historic Model



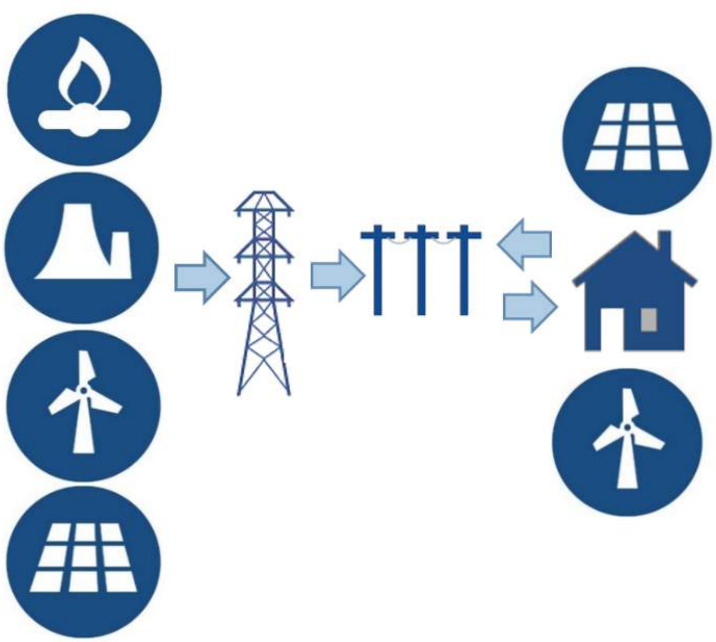
Reliability Implications

- Large units with relatively consistent output, fuel assurance, and low variability
- A fuel diverse generation
- portfolio created redundancies in available resources
- Clear redundancy and resilience
- “Source-to-sink” transmission
- Fewer variables in resource planning
- Inputs to planning reserve margins were less complex
- System was designed to meet peak demand

Planning Considerations

- A system consisting of higher levels of conventional generation provide substantial essential reliability services as a function of large spinning generators and governor control settings, along with reactive support for voltage control
- High levels of coal and nuclear generation with on-site fuel provided fuel assurance.
- Traditional transmission planning has historically focused on building a system to address peak demand

Evolving Resource Mix Composition



Reliability Implications

- Greater reliance on natural gas generation, which may be vulnerable to supply and transportation disruptions
- Wind and solar have higher levels of variability, leading to over-generation and “duck curve” concerns
- Increased DERs leads to a higher potential for a bidirectional flow of energy, blending distribution and transmission
- Additional consideration needed for system inertia, voltage control, frequency response, and ramping abilities
- Planning for off-peak periods (shoulder months) when renewables output can be equal to or higher than demand, which can create reliability concerns.

Planning Considerations

- Essential reliability services are vital to reliable operation of the BPS as system operators use frequency response, voltage control, and ramping, to plan and operate reliably under a variety of system conditions
- Inverter-based variable energy resources can provide essential reliability services, although interconnection processes and market rules may not fully recognize such capabilities
- Areas with higher levels of wind penetration have a longer history of performance, allowing for more accurate projections for on-peak availability of these resources
- Fuel assurance is particularly important and must be reflected in planning reserve margins – especially for areas with high levels of VER

Interconnection Inertia

Operating procedures that recognize potential inertia constraints were recently established in ERCOT and Québec. Due to their smaller size, the ERCOT and Québec Interconnections experience lower system inertia compared to the Eastern and Western Interconnections.

Currently, wind amounts to more than 17 percent of installed generation capacity in ERCOT and has served as much as 50 percent of system load during certain periods. In Québec, hydro accounts for over 95 percent of the generation, which generally has lower inertia compared to synchronous generation of the same size (e.g. coal and combined-cycle units). As a result, ERCOT and Québec have both established unique methods to ensure sufficient frequency performance.

Identifying Synchronous Inertia Response (SIR) in the ERCOT Interconnection:

- ERCOT has defined critical inertia levels that must be maintained for the system to operate reliably[13] with current frequency control practices. See **Figure 15**.
- ERCOT has experienced a general increase in nonsynchronous generation as a percent of system load during minimum inertia conditions as shown in **Figure 16**.
- A series of dynamic simulations were conducted based on cases from ERCOT's Real-Time Transient Security Assessment Tool with inertia conditions ranging from 98 GW to 202 GW to assess how long it takes for frequency to fall from 59.7 Hz to 59.3 Hz after two of the largest units trip.
- Higher amounts of responsive reserve service (RRS)[14] are needed for low-inertia situations to maintain the security and reliability of the grid.

Based on the 2015 dynamic study results that examined minimum primary frequency response,[15] ERCOT procures RRS amounts based on the expected system inertia to ensure sufficient frequency response after a 2,750 MW loss.[16]

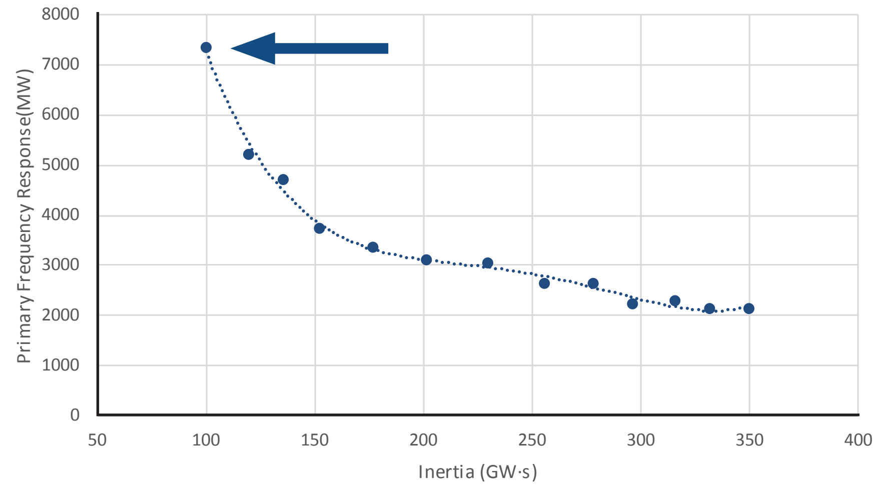


Figure 15: ERCOT has Identified ~100GW/seconds as a Critical Inertia Level

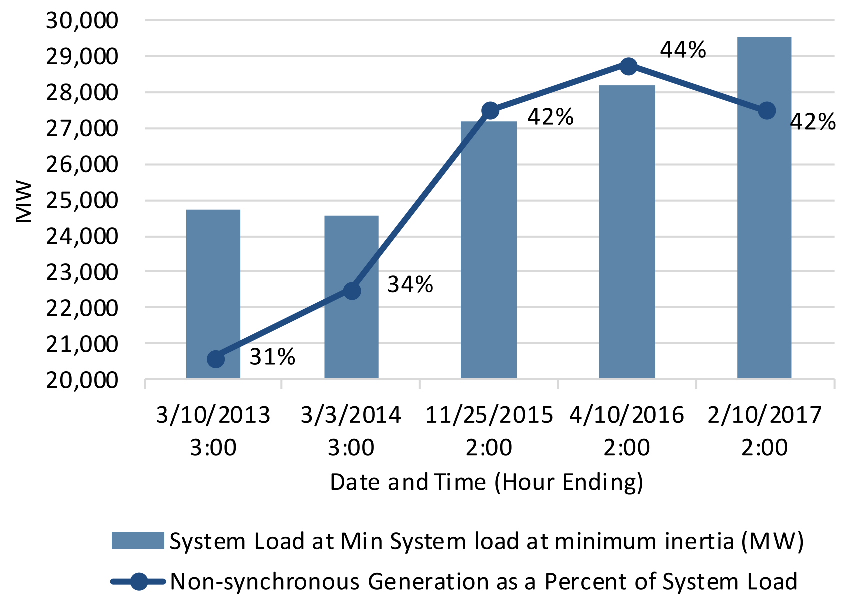


Figure 16: ERCOT's Nonsynchronous Generation as a Percent of System Load

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13 Here "operate reliably" refers to avoiding under-frequency load shedding (UFLS) for the loss of two largest generation units.

14 Responsive Reserve Service is used for frequency containment after generation trip events.

15 The results of the studies have been communicated at ERCOT stakeholder meetings.

16 In 2015, ERCOT revised its ancillary service methodology and now determines the minimum RRS requirements based on anticipated system inertia conditions.

Trends of Minimum SIR in ERCOT:

- Based on historic data from 2013 to 2017, minimum SIR conditions have occurred during shoulder seasons except for 2017, which occurred during the month of February. The minimum SIR in the ERCOT system has occurred during the early-morning during off-peak hours, when the system is at a low load level. See **Table 5** below.
- Nonsynchronous generation and low load are primary contributors to minimum synchronous inertia conditions with the percentage of nonsynchronous generation varying from 31–41 percent.
- Real-time tools were implemented in the ERCOT control room to forecast system inertia in the day-ahead operations and into real-time to evaluate sufficiency of the procured RRS reserves based on forecasted inertia conditions.[17]
    - These tools determine the required amount of RRS based on forecasted inertia conditions and then compare this forecasted value with the procured RRS amounts. If the procured amount of RRS is not sufficient for the forecasted inertia conditions, a supplemental ancillary services market is established to procure additional RRS.

Table 5: ERCOT Minimum SIR (GVA*s) by Year[19]

Date and Time (Hour-Ending)	**2013** 10-Mar-13 3:00 a.m.	**2014** 3-Mar-14 3:00 a.m.	**2015** 25-Nov-15 2:00 a.m.	**2016[20]** 10-Apr-16 2:00 a.m.	**2017[21]** 10-Feb-17 2:00 a.m.
Min Synchronous Inertia H (GVA*s)	132	135	152	143	134
System Load at Min System load at minimum inertia (MW)	24,726	24,540	27,190	28,191	29,515
Nonsynchronous Generation as a Percent of System Load	31	34	42	44	42

[17] If the procured amount of RRS is not sufficient for the forecasted inertia conditions, a supplemental ancillary services market can be opened and additional RRS procured.
[18] GVA*s = giga volt amperes multiplied by seconds.
[19] Inertia data collection began in June 2016.
[20] 2017 lowest inertia is only based on data collected up to June.

Identifying SIR in Québec:

- Since 2006, Québec has applied a control criteria called the PPPC limit,[21] which is a function of the real-time operating conditions.
- The PPPC limit (MW) actively restricts the maximum MW loss of generation following a single contingency event.
- System operators perform generation redispatch in real-time or increase the level of synchronous generation on-line to ensure the PPPC limit is not exceeded and adequate frequency performance is maintained. Wind generating stations with aggregated rated power greater than 10 MW must be equipped with a frequency control system.[22]
    - Such a system enables wind generating stations to help restore system frequency in the advent of disturbances and thus maintain the current level of performance with regards to frequency control on the transmission system.

Minimum SIR and Minimum PPPC Trends in the Québec Interconnection:

- In Québec, the PPPC limit data shows that the minimum can occur in both shoulder and peak seasons.
- The minimum PPPC limit and minimum SIR both have occurred early in the morning (2:00 a.m. to 4:00 a.m.).
- The data in **Figure 17** indicates that nonsynchronous generation is not the driver for minimum interconnection inertia conditions in Québec.
- Québec has not observed significant changes in the minimum synchronous inertia level in recent years and does not anticipate frequency issues regarding the inertia level in the future since no major changes in the resource mix are foreseen.
- Québec has begun to track its minimum synchronous inertia levels with the percent of nonsynchronous generation on-line at that time. This is shown in **Table 6**. Quebec will continue to monitor these conditions going forward.

[21] The term PPPC is an acronym in French: P = Perte = Loss, P = Production = (of) Generation,P = en Première = First (meaning "following a Single"), C = Contingence = Contingency. The PPPC limit is an equation derived from a comprehensive dynamic study of the historic system considering different load and generation dispatch patterns, contingency size and location, effect of synchronous reserve, load behavior, strategic power system stabilizers, etc. In each study scenario, the maximum limits of generation that can trip is determined by simulation so that the frequency does not drop below 58.5 Hz. This study is revised and updated periodically to confirm the accuracy of the equations.

[22] Wind requirements have been presented to the Québec Énergy Board (Régie de l'Énergie) and are pending approval.

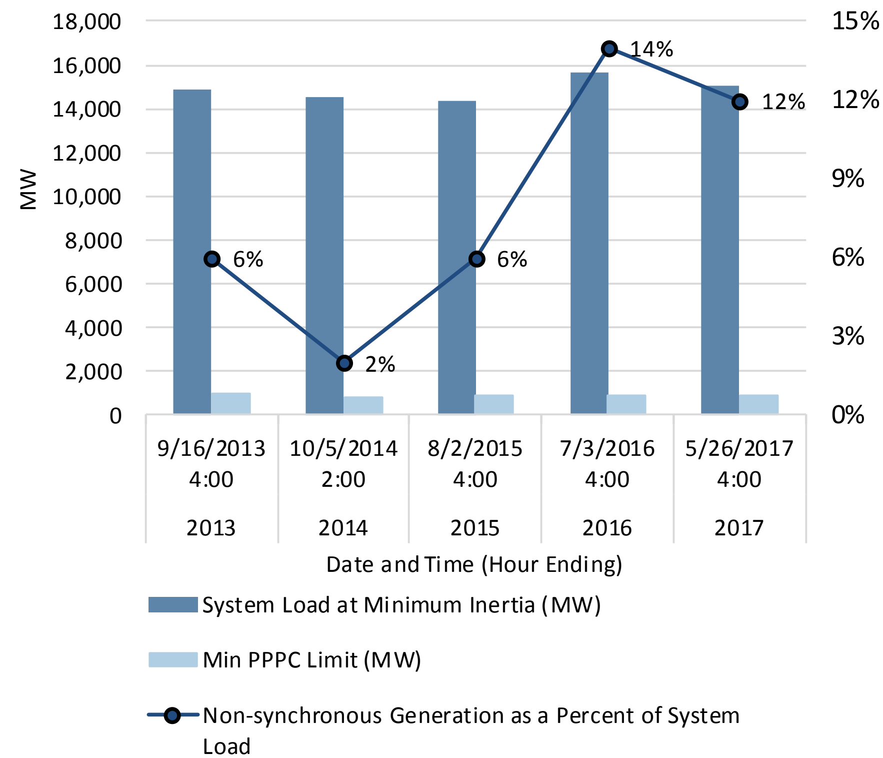


Figure 17: Québec Minimum PPPC Limit (MW)

Table 6: Québec Minimum SIR (GVA*s) by Year		
Date and Time	**2016[24] 08-Oct-16 3:30 a.m.**	**2017 26-May-17 4:30 a.m.**
Min Synchronous Inertia H (GVA*s)	59.09	63.46
System Load at Min H (MW)	13,550	14,710
Percent of Nonsynchronous Generation	13	12

[23] Inertia data collection began in June 2016. 2017 lowest inertia is only based on data collected up to June.

SIR Eastern and Western Interconnections

In comparison to the Québec and ERCOT Interconnections, the Eastern and Western Interconnections are much larger systems with less nonsynchronous generation in comparison to their system's load. Therefore, NERC's Resource Subcommittee is collecting the historically reported minimum SIR conditions for trending.

Minimum SIR Trends in the Eastern and Western Interconnections:

- For both interconnections, the minimum SIR conditions have occurred in shoulder months.
- Neither interconnection has a specific time of day when the minimum SIR conditions may occur.
- Only the Western Interconnection is capturing nonsynchronous generation percentages at this time. The percent of nonsynchronous generation on-line during min SIR condition is negligible.
- Neither interconnection has experienced frequency issues due to minimum SIR, and both interconnections are collaborating with the ERS working group to investigate approaches to forecast future minimum SIR conditions in the Eastern and Western Interconnections. See **Table 7**.

Considerations for forward looking planning cases to perform minimum SIR calculations:

- Planning models that are currently developed annually and are reflective of light spring loads will be used for forward looking studies.
- Through a collaborative effort between NERC and the industry, the light spring load cases will be modified to develop forward looking low inertia cases.
- Modifications to unit commitment and dispatch with the intent of reflecting real-time dispatch scenarios, along with improvements to governor and dead band modeling, will be made to light spring load cases.
- The Eastern Interconnection Planning Collaborative is leading the effort for the Eastern Interconnection, and WECC is leading the effort for the Western Interconnection.

For both interconnections, case development and analysis of forward-looking frequency response performance will be completed in 2018 with the results available for the *2018 LTRA*. These efforts will lead to future-looking studies for ERS frequency response measures, which could be repeated every 2–3 years, with 5 year projections (constantly updated with historic data). Both interconnections will provide study reports to NERC with respective study cases. Eastern and Western Interconnections may also develop a procedure manual for this work to be updated in the future on a periodic basis.

Table 7: Eastern and Western Interconnection's Minimum SIR (GVA*s) by Year

	Eastern Interconnection		Western Interconnection	
Date and time	**2016** 22-Oct-16 9:11 p.m.	**2017** 24-Apr-17 1:58 a.m.	**2016** 16-Oct-16 11:45 a.m.	**2017** 09-Apr-17 7:19 p.m.
Min Synchronous Inertia H (GVA*s)	1,279	1,281	498	472
System Load at Min H (MW)	236,513	218,787	76,821	86,183
Percent of Nonsynchronous Generation	N/A	N/A	10	12

Ramping: A CAISO Perspective

With continued rapid growth of distributed solar, CAISO's three-hour ramping needs have reached 13 GW, exceeding earlier projections and reinforcing the need to access more flexible resources.

Ramping is related to frequency through balancing during system operations. Changes in the amount of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the ramp rates needed to keep the system in balance. For areas with an increasing penetration of nondispatchable resources,[24] the consideration of system ramping capability is an important component of planning and operations.[25] Therefore, a measure to track and project the maximum one-hour and three-hour ramps for each balancing area was established by the Essential Reliability Services Working Group (ERSWG).

Changes in an area's load patterns due to increased integration of photovoltaic (PV) generation in the distribution system and changes to the utility-scale generation mix has changed the ramping needs in California. Ramping needs are difficult to predict dependent on weather, the geographic uniformity of behind-the-meter PV resources, end-use electric consumer behavior, and generation dispatch availability. Moreover, behind-the-meter PV generation will have a smaller impact on ramping as the geographic diversity of rooftop solar increases, reducing local simultaneous weather impacts experienced by close proximity solar resources. These factors contribute to the nature of ramping variability in California.

Ramping (Load-Following) Case Study:[26]

- Currently, there are more than 10 GW of utility-scale and 5 GW of behind-the-meter PV resources in the CAISO footprint, which has the most concentrated area of PV in North America.
- CAISO's actual maximum three-hour upward ramping needs were 7,600 MW in 2013, when growth was projected to reach 13 GW by 2020.
- In 2016, actual hour ramps reached 12.9 GW, which is four years ahead of projections.
- Ramping needs have increased rapidly because roof-top PV has grown faster than projected. Accordingly, CAISO has revised its estimated three-hour upward ramp to exceed 16,800 MW in 2020.[27]
    - These developments in California highlight the importance for industry to focus on evaluating the ability of the resource mix to adequately meet net-load ramping needs as more DERs are added.
- Behind-the-meter PV in CAISO is projected to grow to 12 GW by 2020.
- Ramping should be monitored in any area that projects significant growth in the amount of nondispatchable resources.
    - Monitoring ramp rates will support system planning with the use of tools that can enable system operators to balance load and generation in real-time.
- The following planning activities should also be considered to support future ramp studies:
    - Ramping issues are most prevalent during the off-peak (shoulder) months of the year, typically during low-load conditions in the spring and fall.
    - Visibility of behind-the-meter rooftop PV generation can present challenges for operators, but these challenges can be managed with net metering or aggregated metering at sub-transmission substations.
    - Operating rules in some areas should be considered to determine if alterations are needed to schedule distributed PV resources using net metering.
    - As an alternative to operating changes, strategic installation of batteries and storage and scheduling of these resources will assist with reducing ramps.

[24] Nondispatchable resource is defined to be any system resources that do not have active power management capability or do not respond to dispatch signals

[25] 2016 ERSWG Sufficiency Guideline Report Final Version

[26] Ibid.

[27] Draft Flexible Capacity Needs Assessment for 2018.

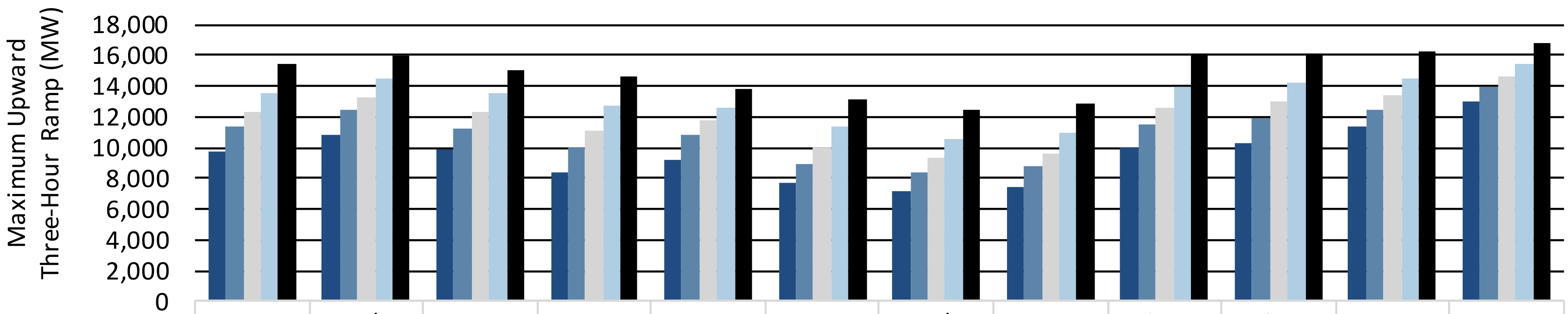
- **Figure 18** shows that the three-hour ramps have manifested approximately four years ahead of initial estimate, revised to exceed 16,800 MW by 2020.
- The increase in three-hour upward ramps in CAISO highlights the importance for the industry to focus on evaluating ramping adequacy.
- As a result of the projected increase, CAISO is at the forefront of many ERS issues and has been leading the efforts to predict and plan to mitigate future ramps with their annual Flexible Capacity Needs Assessment.

Solar Production Increases in CAISO:

- CAISO has begun to observe that solar production is increasing on some days about 15 times-per-minute faster as the load is increasing.
- As shown in **Table 8,** load decreases as the solar production increases during certain sunrise periods.

Table 8: Solar Production Increases in CAISO

	Load	Solar	Net Load
Sunrise Ramp Rate (MW/Min) 7:00–10:00	-6	31	-37
MW Change	-1,023	5,529	-6,724
Sunset Ramp Rate (MW/Min) 16:00–19:00	27	-37	61
MW Change	4,801	-6,703	11,049



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016 (Actual)	9,687	10,891	9,828	8,397	9,263	7,669	7,214	7,463	10,030	10,228	11,375	12,960
2017	11,342	12,465	11,253	9,973	10,878	8,996	8,379	8,768	11,575	11,900	12,391	14,004
2018	12,282	13,313	12,352	11,111	11,803	10,039	9,326	9,617	12,660	12,954	13,376	14,567
2019	13,595	14,543	13,574	12,672	12,631	11,350	10,616	10,982	13,981	14,199	14,553	15,495
2020	15,439	15,984	15,089	14,572	13,859	13,181	12,391	12,821	16,061	16,169	16,293	16,817

Figure 18: CAISO maximum monthly three-hour upward net-load ramps (2016–2020)

Reference Margin Levels

Based on the projected resource mix, the trend of increasing Reference Margin Levels is expected to continue. Reference Margin Levels are established to allow NERC to assess the level of planning reserves, recognizing factors of uncertainty involved in long-term planning (e.g., forced generator outages, extreme weather impacts on demand, fuel availability, and intermittency of variable generation). NERC does not require a certain level of planning reserves; instead, the development of an assessment area's Reference Margin Level depends on the following factors: Resource adequacy criteria (deterministic and probabilistic metrics (e.g., loss-of-load expectation (LOLE); expected unserved energy (EUE)); decisions of a state, provincial authority, ISO/RTO, or other regulatory body; and integrated resource plans and market-based resource procurements.

In all approaches, system planners quantify the amount of capacity above peak demand required on the system to ensure that there is sufficient supply to meet peak loads for each season and year. In theory, a higher Reference Margin Level will reduce the number of loss-of-load events; however, other factors are considered when establishing an appropriate Reference Margin Level, including system costs and the risk averseness of regulating bodies and end-use customers.

Given the static measure of generation reliability, Reference Margin Levels are reviewed and, if necessary, modified as significant system changes occur.

As shown in the **Figure 19**, more planning reserves are needed to maintain the same level of reliability as more variable resources are added to a system, resulting in an increase in the Reference Margin Level.[28]

Figure 20 shows a 10-year comparison and indicates that many assessment areas have increased Reference Margin Levels with a variety of factors, including increasing forced outage rates, growing levels of variable resources, and other factors that result in a need to carry additional planning reserves.

Table 9 on the next page further details important considerations for how Reference Margin Levels are developed in each assessment area.

[28] NREL: Comparing Resource Adequacy Metrics

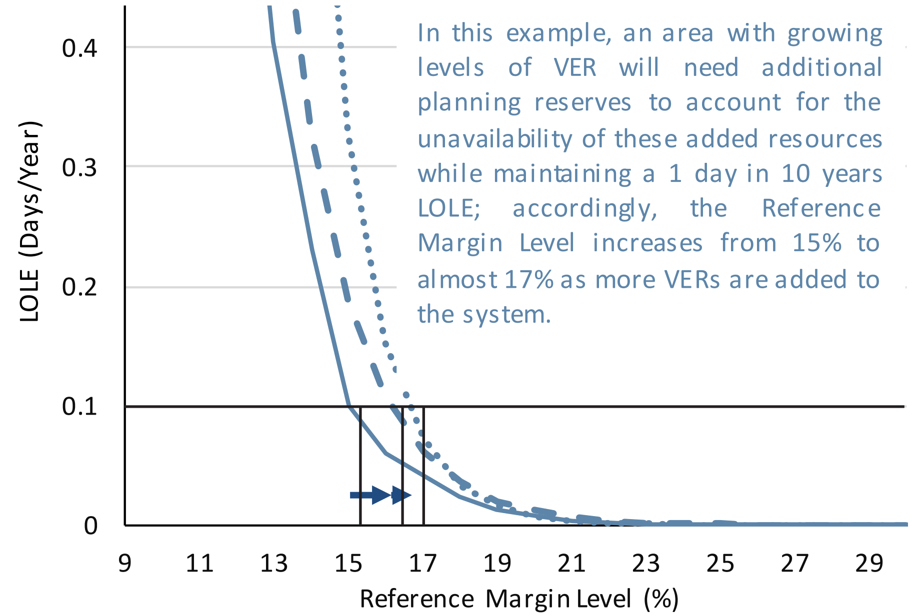


Figure 19: LOLE and Reference Margin Levels with Increasing VERs

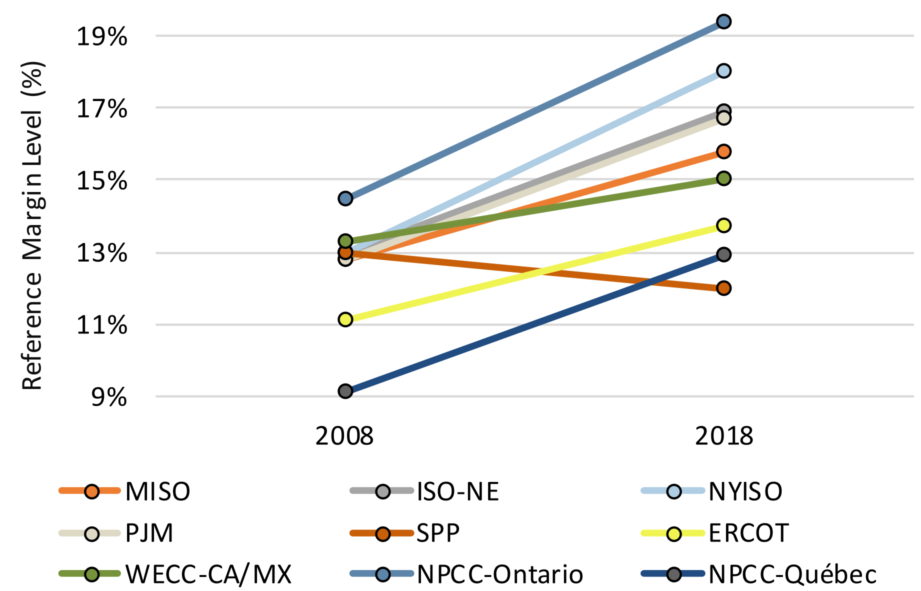


Figure 20: Reference Margin Level Changes (2008 vs. 2018)

Table 9: Reference Margin Levels for Each Assessment Area

Assessment Area	Reference Margin Level	Assessment Area Title	Market or Regulatory Requirement	Methodology	Reviewing or Approving Body
FRCC	15.0%[29]	Reliability Criterion	No; Guideline	0.1/Year LOLP	Florida Public Service Commission
MISO	15.8%	Planning Reserve Margin (PRM)	Yes; Established	0.1/Year LOLE	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	Annually	0.1/Year LOLE/LOEE/	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11.0%	Reference Margin Level	No	LOLH/EUE	SaskPower
NPCC-Maritimes	20.0%[30]	Reference Margin Level	No	EUE and Deterministic Criteria	Maritimes Subareas; NPCC
NPCC-New England	16.6–16.9%	Installed Capacity Requirement (ICR)	No	0.1/Year LOLE	ISO-NE; NPCC Criteria
NPCC-New York	18.0%	Installed Reserve Margin (IRM)	Yes; 3 year requirement established annually	0.1/Year LOLE	NYSRC; NPCC Criteria
NPCC-Ontario	18.2–23.7%	Ontario Reserve Margin Requirement (ORMR)	Yes; established annually for all years	0.1/Year LOLE	IESO; NPCC Criteria
NPCC-Québec	12.9%	Reference Margin Level	No; Established Annually	0.1/Year LOLE	Hydro Québec; NPCC Criteria
PJM	16.6–16.7%	Installed Reserve Margin (IRM)	Yes; Established Annually for each of 3 future years	0.1/Year LOLE	PJM Board of Managers; ReliabilityFirst BAL-502-RFC-02 Standard
SERC-E	15.0%	Reference Margin Level	No; NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-N	15.0%	Reference Margin Level	No; NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-SE	15.0%[31]	Reference Margin Level	No; NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SPP	12.0%	Resource Adequacy Requirement	Yes; Studied on Biennial Basis	0.1/Year LOLE	SPP RTO Staff and Stakeholders
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1/Year LOLE	ERCOT Board of Directors
WECC-AESO	11.03–11.22%	Reference Margin Level	No; Guideline	Building Block Methodology	WECC
WECC-BC	10.60–12.10%	Reference Margin Level	No; Guideline	Building Block Methodology	WECC
WECC-CAMX[32]	14.76–16.14%	Reference Margin Level	No; Guideline	Building Block Methodology	WECC
WECC-NWPP-US	16.38–17.46%	Reference Margin Level	No; Guideline	Building Block Methodology	WECC
WECC-RMRG	11.65–14.17%	Reference Margin Level	No; Guideline	Building Block Methodology	WECC
WECC-SRSG	12.02–15.83%	Reference Margin Level	No; Guideline	Building Block Methodology	WECC

[29] The FRCC uses a 15 percent Reference Reserve Margin. The FRCC criteria, as approved by the Florida Public Service Commission, is set at 15 percent for non-IOUs and recognized as a voluntary 20 percent Reserve Margin criteria for IOUs and recognized as 20 percent Reserve Margin criteria for IOUs; individual utilities may also use additional reliability criteria.

[30] The 20% reference margin is used by the individual jurisdictions in the Maritimes Area with the exception of Prince Edward Island (PEI), which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[31] SERC does not provide Reference Margin Levels or resource requirements for its subregions. However, SERC members perform individual assessments to comply with any state requirements.

[32] California is the only state in the Western Interconnection that has a wide area Planning Reserve Margin requirement, currently 15%.

Variable Energy Resources

On-peak availability of wind and solar is increasing with greater operational experience. For a reserve margin analysis, most assessment areas have developed approaches for modeling and projecting the availability of wind and utility-scale solar during the forecasted peak load hour. However, some assessment areas have developed approaches to model wind and solar hourly over the entire 8,760 annual hours. Output from variable resources (wind and solar) must be reduced when examining the peak hour because their output is contingent on uncontrollable factors, such as cloud cover or wind conditions. **Tables 10** and **11** present different considerations for capturing capacity contributions for variable and conventional resources:

Variable Resources Planning Considerations:

- Higher penetration of VERs results in a larger portion of an area's resource portfolio containing energy-limited resources.
- Many areas are counting a higher percentage of variable resources as available during the peak hour with growing amounts of operational performance data. See **Figures 21, 22,** and **23**.
- Current planning approaches for variable resources fall into four categories:
    - LOLE/LOLP-based calculations of the effective load-carrying capability of variable generation relative to a benchmark conventional unit
    - Calculation of the capacity factor of the variable generation during specified time periods that represent high-risk reliability periods (typically peak hours)
    - A tailored approach for applying a historical performance rolling average (typically 2–3 year)
    - Applications based on policies established through a nontechnical analysis
- Once derates are applied, wind and solar can be incorporated into the Reserve Margin analysis like any other generation type.
- See **Tables 10** and **11** for an overview of assessment areas and their calculations of wind (**page 28**) and solar (**page 29**) contributions

Variability and Uncertainty

There are two major attributes of variable generation that notably impact bulk power system planning and operations:

- **Variability:** The output of variable generation changes according to the availability of the primary fuel (e.g., wind, sunlight, and moving water), resulting in fluctuations in the plant output on all time scales.
- **Uncertainty:** The magnitude and timing of variable generation output is less predictable than for conventional generation.

Conventional Generation Planning Considerations:

- The calculation of the capacity contribution of conventional generating units are generally based on unit performance ratings, forced outage rates, and annual unforced maintenance cycles.
- Resource adequacy can be analyzed through detailed reliability simulations that compare expected demand profiles with specific generating unit's forced outage rates and maintenance schedules to yield LOLE or LOLP values.
- Reliability simulations typically include probabilistic production simulations for meeting a specified demand curve (or chronological curve) from a specified generation fleet while incorporating the forced and unforced outage rates during the simulation period.

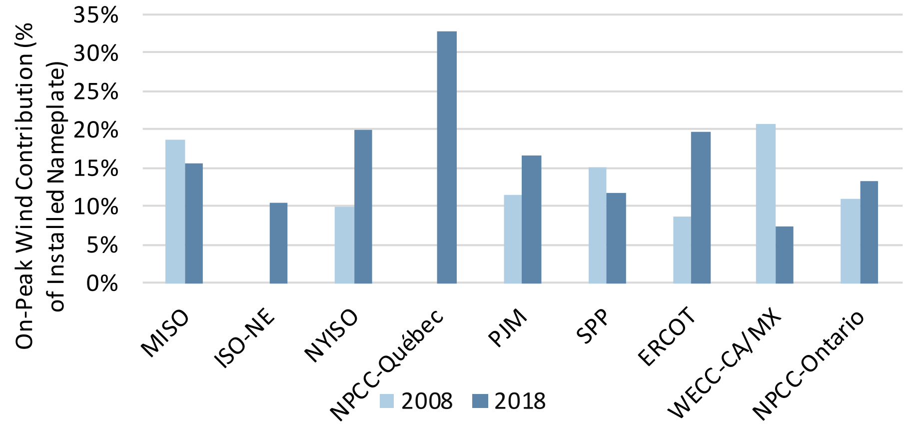


Figure 21: On-Peak Wind Contribution Has Increased in Most Areas

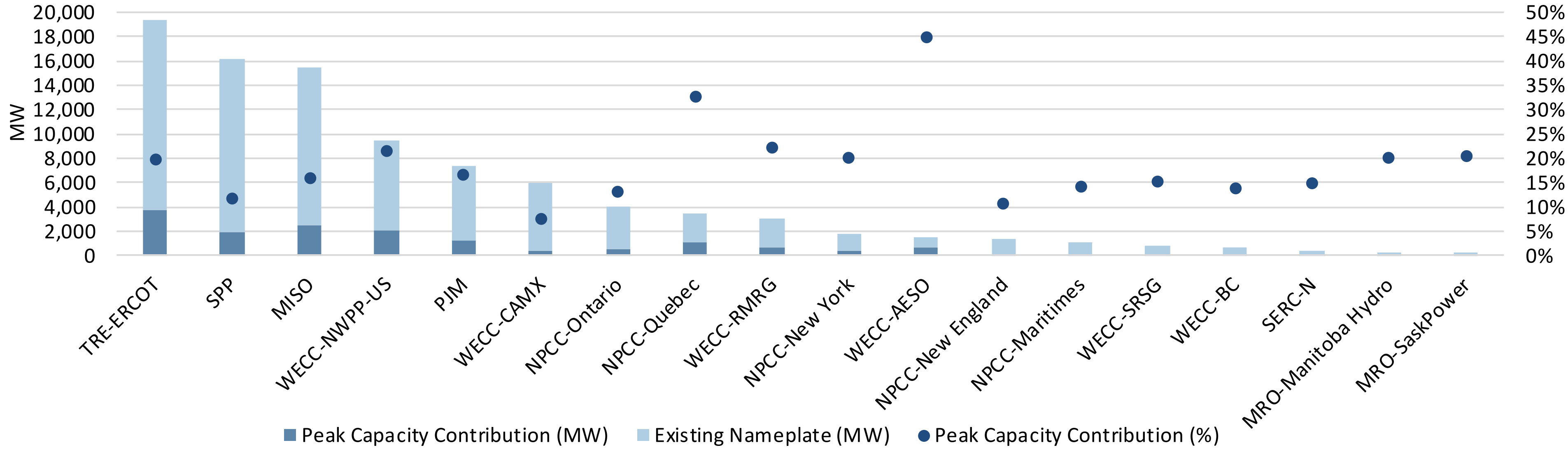


Figure 22: Nameplate and Projected Peak Capacity Contribution of Wind by Assessment Area

Table 10: Assessment Areas and Calculation of Wind Contributions

Assessment Area	Wind Assumptions
MISO	New resources: 15.6 percent capacity credit, as operational data is available, MISO employs a deterministic approach with ELCC using the historical output.
MRO-Manitoba Hydro	A 35 percent capacity value for the summer and a 0 percent capacity value for the winter (peaks in January occur at sunrise or sunset).
MRO-SaskPower	A 10 percent (summer) and 20 percent (winter) of nameplate capacity.
NPCC-Maritimes	Applies a calculated year-round calculated equivalent capacity of 20 percent (NB), 12 percent (NS) and 15 percent (PEI) of nameplate.
NPCC-New England[33]	Based on the Seasonal Claimed Capability (SCC) and equal to the median of the resource's summer net output during reliability hours (14:00–18:00; June-September) of the previous year. Summer values average to approximately 13.2 percent of nameplate rating.
NPCC-New York	Summer and winter unforced capacity based on average four hour production beginning at 14:00 during the summer or 16:00 during the winter.
NPCC-Ontario	Monthly Wind Capacity Contribution (WCC) values used to forecast the contribution. This is based on actual historic median wind performance during the last 10 years at the top 5 contiguous demand hours of the day for each winter and summer season or shoulder period month.
NPCC-Québec	Winter capacity contributions are 30 percent of contractual capacity, with the exception of 104 MW derated to zero. Derated entirely for the summer.
PJM	Initially applies 13 percent of nameplate; after three years of operation, historic performance over seasonal peak periods determine unit's capacity factor.
SERC-N	Varies; provided by entities and reviewed by SERC.
SPP	A 5 percent assumed for first three years if the LSE chooses not to perform the net capability calculation during the first 3 years of operation after which the Net Capability Calculations is applied by selecting the appropriate monthly MW values corresponding to the LSE's peak load month for each season.
Texas RE-ERCOT	Based on average historical availability during the highest 20 seasonal peak load hours for each season (2009–2016). Values recalculated after each season with new historical data. Current Contribution: 58 percent coastal and 14 percent noncoastal (summer), 35 percent coastal and 20 percent noncoastal (winter).
WECC	Based on historic on-peak performance for the expected peak hour for each year, applying actual capacity factors associated with that hour.

[33] ISO-NE uses a different approach for future wind and solar resources.

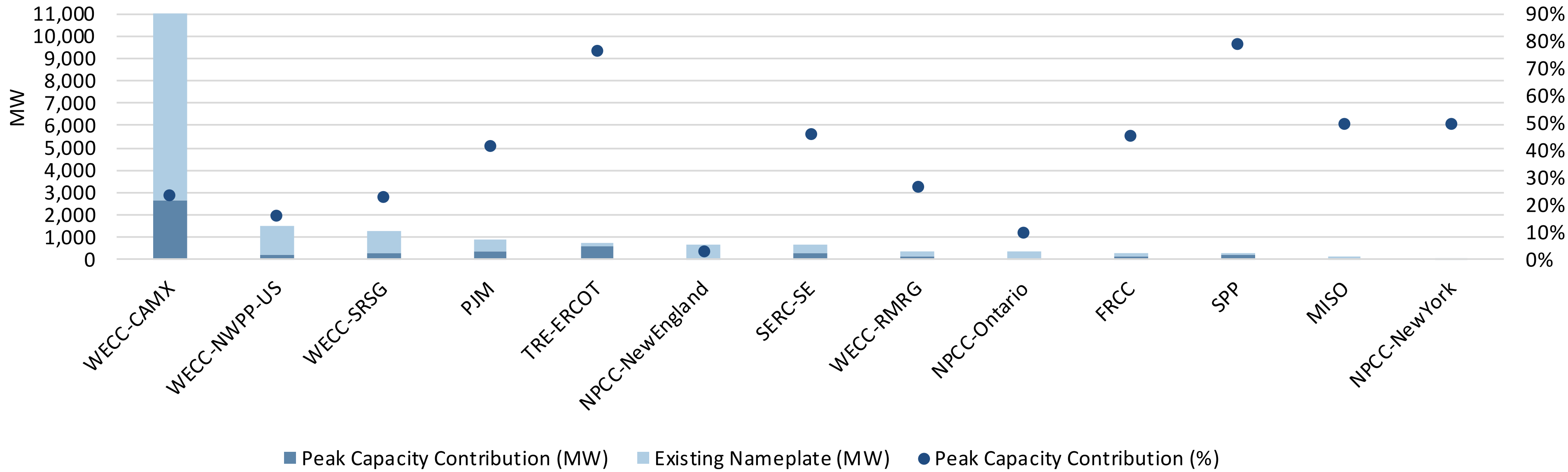


Figure 23: Nameplate and Projected Peak Capacity Contribution of Solar by Assessment Area

Table 11: Assessment Areas and Calculation of Solar Contributions

Assessment Area	Solar Assumptions
FRCC	Based on performance using modeling tools compared to hourly system load profiles.
MISO	New resources receive a 50 percent capacity credit after which the summer on-peak value is applied once actual operation data is available. MISO is considering using ELCC in the future.
NPCC-New England[34]	Based on the Seasonal Claimed Capability (SCC) equal to the median of the resource's summer net output during reliability hours (14:00–18:00; June-September) of the previous year.
NPCC-New York	Summer and winter unforced capacity based on average four-hour production beginning at 14:00 during the summer or 16:00 during the winter (summer and winter months of the prior equivalent capability period).
NPCC-Ontario	Monthly Solar Capacity Contribution (SCC) values are used to forecast the expected contribution.
PJM	Initially applies 38% of nameplate for the summer season; after three years of operation, historic performance over the peak period is used.
SERC	Varies; provided by entities and reviewed by SERC.
SPP	A 10 percent assumed for first 3 years if the LSE chooses not to perform the net capability calculation during the first 3 years of operation; after which the Net Capability Calculations is applied by selecting the appropriate monthly MW values corresponding to the LSE's peak load month for each season.
Texas RE-ERCOT	Based on average historical availability during the highest 20 seasonal peak load hours for each season (2014–2016). Values recalculated after each season with new historical data. Current Contribution: 77 percent (summer) and 5 percent (winter).
WECC	Based on historic on-peak performance based on the expected seasonal peak hour for each year and applying an actual capacity factors associated with that hour. For the interconnection, solar is counted at 20.6 percent (summer) and at 0 percent (winter).[35]

[34] ISO-NE uses a different approach for future wind and solar resources.

[35] The subregions have individual capacity factors but all subregions count winter solar capacity at 0 percent. The summer capacity for CA/MX is counted at 24.0 percent, the RM subregion at 27.0 percent, NWUS is counted at 16.5 percent, with NWCA at 50.0 percent, and SW subregion counted at 23.4 percent.

Fuel Assurance

A diverse resource mix promotes a more reliable supply of electricity, but as more areas are dependent on natural-gas-fired generators, reliability hinges on adequate arrangements for fuel and access to it. Some of the key issues around natural gas fuel assurance are as follows:

- Most natural gas delivery pipelines were built and sized to serve customers of natural gas utilities—not specifically to serve electricity generators.
- Higher reliance on natural gas can lead to fuel-security issues, particularly during extreme cold weather periods when demand on the natural gas delivery system can be stressed, exposing electric generation to fuel supply and delivery vulnerabilities.
- As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability.
- The fuel assurance mechanisms in **Table 12** are used by Planning Coordinators and Transmission Planners to address the natural gas generation fleet's potential exposure to fuel interruptions that could lead to multiple electric generating units becoming unavailable.
- Disruptions to the fuel delivery results from adverse events that may occur, such as line breaks, well freeze-offs, or storage facility outages.
- The pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors), which is compounded when multiple plants are connected through the same pipeline or storage facility.
- Although the ability to use alternate fuel provides a key mitigation effect, only 27 percent of natural gas fired capacity added in the U.S. since 1997 is dual fuel.[36]
- In **Figure 24**, NERC's Generator Availability Data System (GADS) shows that Regions with high levels of natural gas can manage BPS risks through fuel assurance measures described on the next page.

Table 12: Mechanisms and Planning Considerations to Promote Fuel Assurance

Fuel Service Agreements	Considerations
Alternative Fuel Capabilities	What are the fuel-firing capabilities of the unit? Is back-up oil maintained on-site? Is it tested?
Pipeline Connections	How many direct connections are available to the generator, and are they served by different supply sources?
Market and Regulatory Rules	What are the regulatory obligations under a force majeure? What tools exist to prepare and plan for a large disruption?
Vulnerability to Disruptions	What is the generation fleet's risk profile as it relates to reliance on natural gas storage and limited transportation sources?
Pipeline Expansions	Where growth in natural gas generation is occurring, is pipeline expansion also occurring?

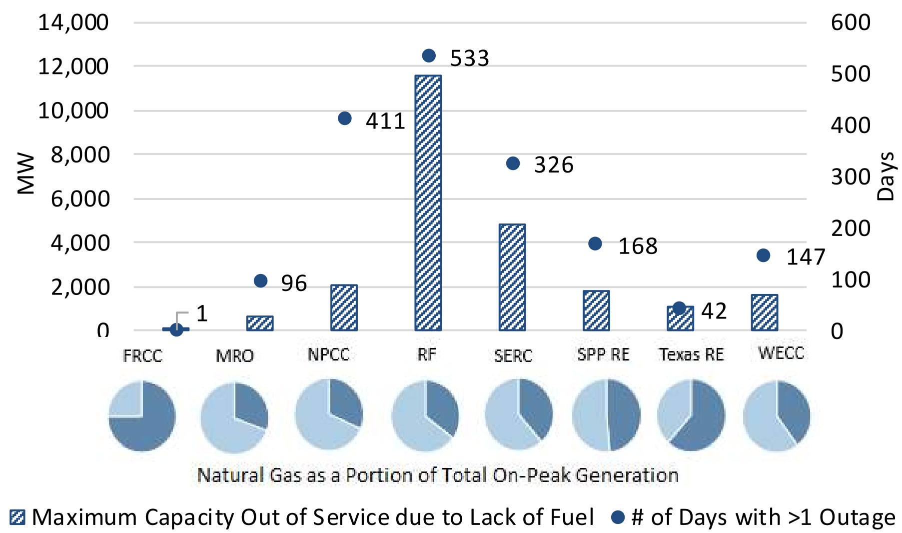


Figure 24: Unscheduled Unavailable Capacity Due to Fuel Shortage (2012–2015)

[36] Testimony of the Foundation for Resilient Societies By Thomas S. Popik, June 19, 2017

Additional Fuel Assurance Initiatives by Assessment Area

See **Figure 25** for natural gas as a percentage of peak capacity. See the following for additional initiatives being implemented in several assessment areas:

FRCC

- Utilities maintain significant firm natural gas contracts and maintain dual fuel capability.
- Approximately 75 percent of natural-gas-fired generation fleet can run on a back-up fuel type.
- Sabal Trail, the 3rd major interstate natural gas pipeline, was added to increase delivery and supply diversity.

Texas RE-ERCOT

- Robust pipeline infrastructure significantly reduces risk.
- Recently instituted annual fuel survey of natural-gas-fired generation fleet gauges alternate fuel capabilities.
- There is improved coordination and information-sharing between generator owners and pipeline operators.
- Most new units have firm transportation service.

WECC-CAMX

- There is improved information sharing between generator owners and pipeline operators with active coordination on energy emergencies with the California Energy Commission.
- WECC is funding a study (expected in 2018) to examine the impacts to reliability from the interdependence of the natural gas and electric systems.

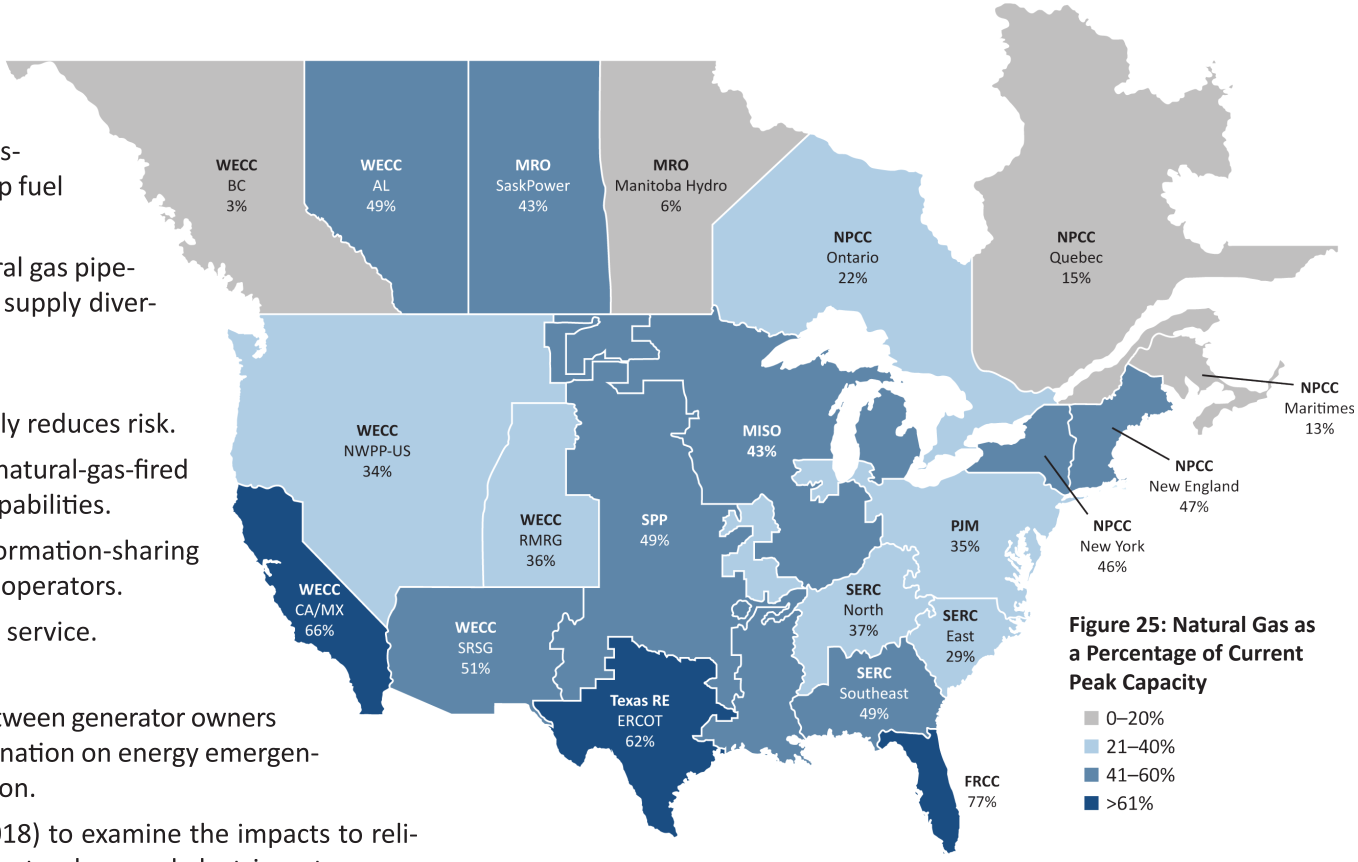


Figure 25: Natural Gas as a Percentage of Current Peak Capacity

NPCC-New England

- There are now preseason fuel inventory surveys for oil and dual fuel units[37] with market rules to offer flexibility and adjustments to day-ahead energy market.
- Beginning in 2018, the Pay-for-Performance program will provide incentives for units to perform during extreme conditions.
- The Winter Reliability Program incentivizes dual-fuel units, securing fuel inventory, and testing fuel-switching capability.[38]
- There is improved coordination and information sharing between ISO-NE and operators (including maintenance schedules) and a Gas Usage Tool that allows system operators to estimate spare natural gas pipeline capacity (by individual pipe).

PJM

- There are now capacity performance rules for incentives and charges for nonperformance to promote adequate generator availability during peak days.

[37] A total of 30 percent of gas-fired fleet is capable of using alternative fuel.

[38] The Winter Reliability Program ends after the 2017–2018 winter.

Transmission Additions

A total of 6,200 miles of transmission additions are planned to maintain reliability and meet policy objectives. Some of the key drivers around incremental transmission projects are highlighted below:

- The North American BPS was designed largely around central-station generation as the primary source of electricity; new transmission will be needed to integrate renewable resources.
- Accommodating new resources, particularly those located in areas different from the existing fleet, will require new transmission facilities and devices, such as static VAR compensators or synchronous condensers. Many states and provinces have policies that promote renewable resources, adding to the need for additional transmission (See **Figure 29** on page 34).
- Transmission expansion is necessary to meet policy goals, and lead times of up to 15 years may be required to permit, site, and construct these projects. See **Table 13** on next page.
- NERC-wide, approximately 6,200 circuit miles of new transmission is planned with over 1,100 circuit miles currently under construction.
- Planned transmission and under construction additions during the next decade are on-pace with actual additions during the last decade, averaging of 600 added circuit miles per year.[39]
- Despite declining energy growth rates, actual transmission additions over a 5-year period have been higher between 2006–2015 compared to 1991–2005. See **Figure 26.**
- Most planned transmission projects are in WECC-RMRG, MISO, SPP, and other assessment areas with high levels of wind penetration.[40] See **Figure 29** as well as **Figure 30** on page 34.
- Over the next ten years, energy growth is expected to remain relatively flat and decline in some areas; however, transmission needs to maintain reliability are increasing.
- Variable resource integration is the primary driver for approximately 13 percent of planned transmission projects with 78 percent attributed to reliability. See **Figure 28**.
- Connecting wind power to load centers and ensuring grid flexibility with those resources continue to be areas of interest for transmission investment.

[39] Source: NERC Transmission Availability Data System (TADS), which is based on existing (inventory) ac transmission, 200–599 kV.

[40] Planned ac transmission projects, 200–599 kV.

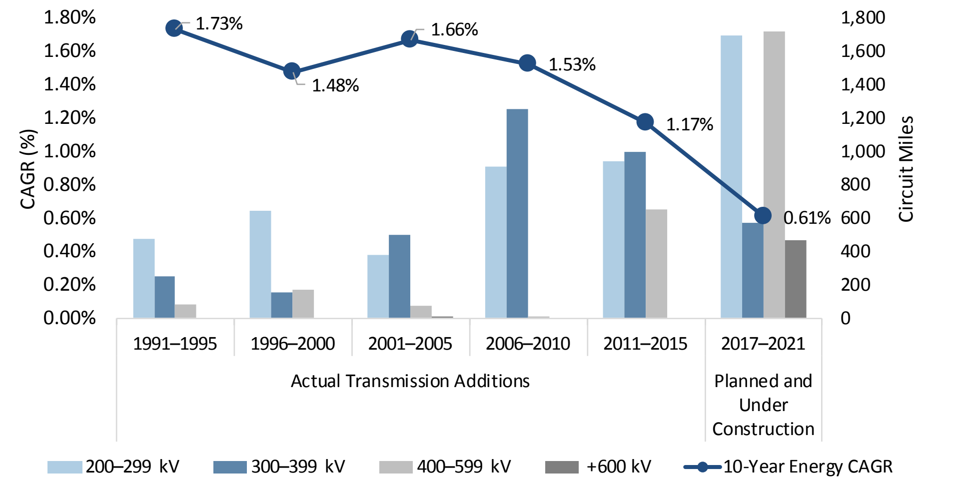


Figure 26: Actual AC Transmission Additions in the U.S. (+200 kV)

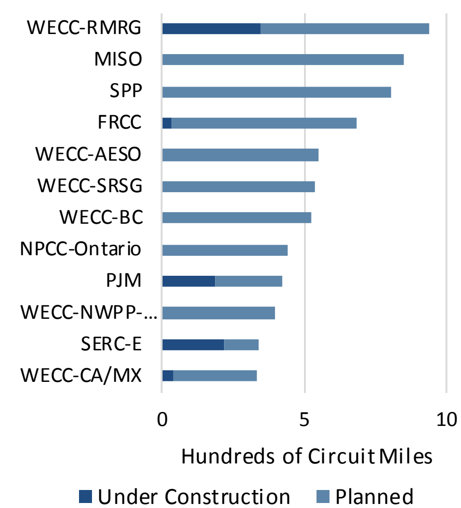


Figure 27: Areas with Most Planned Additions

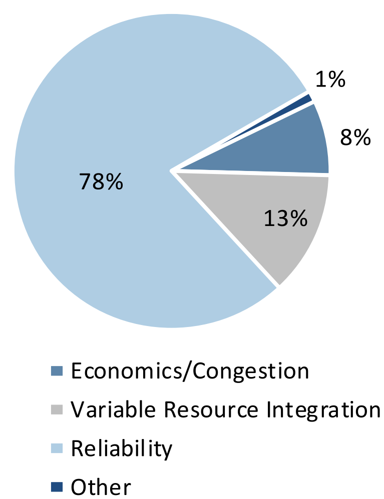


Figure 28: Transmission Project Drivers

Table 13: Major Planned Transmission Projects to Address Load-Growth and Reliability	
Assessment Area	**Project Description**
MRO-Manitoba Hydro	The addition of a third Bipolar HVdc transmission system in 2018 is the largest system enhancement for Manitoba Hydro.
NPCC-Maritimes	A new 138 kV overhead line in New Brunswick (NB) to the new cable terminus will be built in late-2017 with transmission reconfigurations on Prince Edward Island that will further increase capacity to the Island by October 2018. A 475 MW +/-200 kV High Voltage Direct Current (HVDC) undersea cable link (Maritime Link) between Newfoundland and Labrador and Nova Scotia (NS) will be installed by late-2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 153 MW coal-fired unit in NS by mid-2020. The Maritime Link could potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area.
Texas RE-ERCOT	The ERCOT Board of Directors has endorsed a transmission project that includes two new 345-kV lines to help address future reliability concerns in the growing region [and corresponding load growth] of Far West Texas. Increased oil and natural gas exploration in the Permian Basin area in Far West Texas has contributed to high load growth in the Region. Between 2010 and 2016, the average load growth in Far West Texas was about 8 percent. An increase in the number of generation projects, mostly solar, being developed in this area is also a factor. An independent analysis performed by ERCOT confirmed the project's necessity. The project will include a new 345-kV transmission line that will connect the Odessa and Riverton substations. It will span approximately 101 miles across Ector, Winkler, Loving and Reeves counties. In this area alone, peak electricity demand has jumped from 22 MW in 2010 to more than 200 MW in 2016; it is projected to exceed 500 MW by 2021. The second new 345-kW transmission line will be located further south in Pecos County, spanning about 68 miles and connecting the Bakersfield and Solstice substations. ERCOT estimates the project will be completed in the next 4–5 years, pending approval from the Public Utility Commission of Texas.
Texas RE-ERCOT	A new Houston Import Project, a 130-mile 345 kV double circuit line from Limestone to Gibbons Creek to Zenith, is planned to be in-service before the 2018 summer peak.[41] The Houston area demand is met by generation located within the area and by importing power via high voltage lines into the area from the rest of the ERCOT System. This new line will support anticipated long-term load growth in the Houston area. Power imports into the Houston area are expected to be constrained until this new line is in service.
NPCC-Québec	Planning studies have shown the need to reinforce the transmission system with a new 735-kV line in the near future in order to meet Reliability Standards. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a new substation (Judith Jasmin) in Montréal (250 miles). The new 735kV substation is required to fulfill two objectives: provide a new source of electricity supply on the north shore of Montreal and connect the new 735kV line from Chamouchouane to the Montreal metropolitan loop. This project will reduce transfers on other parallel lines on the Southern 735kV Interface, optimizing operation flexibility and reducing losses. The line is scheduled for the 2018–2019 winter peak period. Construction of the power line is underway.

[41] Houston Import Project Information

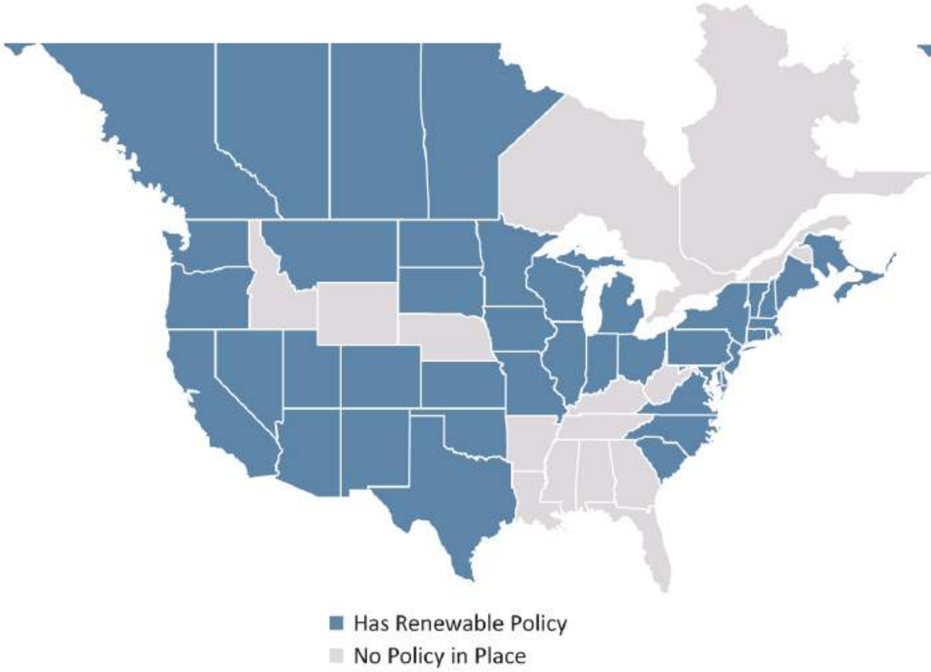


Figure 29: States and Provinces with Policies that Promote Renewable Resources

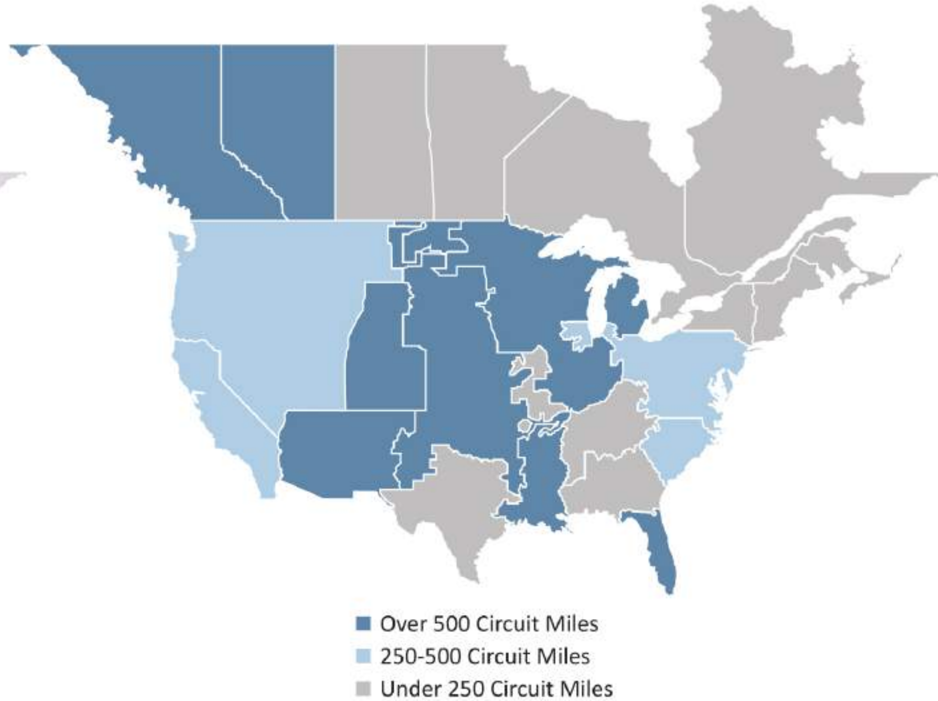


Figure 30: Assessment Areas with High Levels of Transmission Additions

Significant transmission is being planned and constructed in Regions with high levels of wind additions, and it is important that these projects are completed to maintain reliability and policy objectives, including renewable portfolio standards and goals in states and provinces. **Table 14** includes examples of initiatives that have been introduced in various areas to ensure transmission projects keep pace with state policies that require rapid growth of VER penetration:

Table 14: Overview of Areas with Significant Transmission Projects Resulting from Wind Integration

California's Renewable Energy Transmission Initiative (RETI) and CAISO's Energy Imbalance Market	Wind Integration Challenges in SPP	Multi-Value Projects in MISO
• RETI is a joint effort among the California Public Utilities Commission, the Energy Commission, the CAISO, IOS, and public utilities to help identify transmission projects needed to accommodate the stat's renewable energy goals by facilitating transmission corridor designations and identifying siting and permitting needs. • CAISO's western Energy Imbalance Market (EIM) further helps address "overgeneration" periods as energy can be sent outside of the state to serve real-time customer demand across a wide geographic area, allowing shared reserve power to maintain system reliability.	• Installed wind-generation capacity increased by more than 30 percent in 2016, increasing from 12 GW to more than 16 GW. • Even with internal transmission additions, wind generation is growing at a pace that may impact reliability during light-load periods. • Although substantial transmission infrastructure additions are planned or under development, export capabilities may be needed when wind output exceeds internal demand.	• MISOS's long-term transmission planning identified needed projects (known as "Multi-Value Projects") based on the amount of renewables required by each state's renewable portfolio standards. • Estimates were made for locations and production of potential wind and solar projects, and associated lines were identified to integrate them.

Additional Reliability Issues

NERC continues to monitor and report on a variety of other issues that are generally categorized as lower risk. While these issues may not require immediate attention or action, there is a consistent need to assess all system changes or impacts to be aware of any risks.

Monitored Reliability Risks	What's Happening?	Reliability Impacts	Risk Assessment Recommendations
DER Impacts on Automatic Under Frequency/Under Voltage Load Shedding (UFLS/UVLS) Protection Schemes	The effect of aggregated and increasing DERs may not be fully represented in BPS planning models and operating tools.	UFLS/UVLS schemes rely on the rapid disconnection of load during frequency or voltage excursions. These schemes use fast acting relays to disconnect load to help arrest and recover from degrading system frequency or voltage. However, in some cases, DER resources are "netted" with distribution load when measured and modeled. Consequently, the system operator may not be aware of the total load compared to the total interconnected resources that are "behind-the-meter." Should a system excursion exceed the inverter protection settings, it is likely that DERs may automatically disconnect, resulting in both the loss of resources as well as an increase in load that was served by the lost DERs. The increase in net load during such an event can exacerbate the underlying disturbance that caused the voltage or frequency excursion. Additionally, as DERs are integrated with more load, the response in real-time may not result in what was modeled or simulated.	This risk is largely a function of the amount of concentrated DERs at local distribution feeders. As more DERs are added, system planners may needed to adapt their protection schemes to account for the changing system characteristics. There are at least two major events that have occurred on the European power system where the disconnection of DERs played a role in system collapse.[42]
Reactive Power Requirements for Nonsynchronous Generation	Increasing amounts of reactive power are being supplied by nonsynchronous sources.	There are two components to the power supplied by conventional electric generators: real power and reactive power. Reactive power support from nonsynchronous generating resources and transmission-connected power electronic devices will increasingly be used to replace dynamic voltage support from retiring synchronous generating resources. Nonsynchronous generating resources and transmission-connected reactive power devices, including SVCs, static synchronous compensators (STATCOMs), and synchronous condensers, can provide dynamic reactive power support.	NERC Reliability Standards should be assessed to ensure that applicability covers the changing nature of reactive power support across the BPS. Recommended performance specifications and controls coordination studies may be needed to better understand potential interactions and ensure system reliability. As more reactive support is provided by new technologies, it is prudent to monitor their performance to better understand any reliability or system interaction issues. Inventory, projections, and performance data are needed to better evaluate the risk.

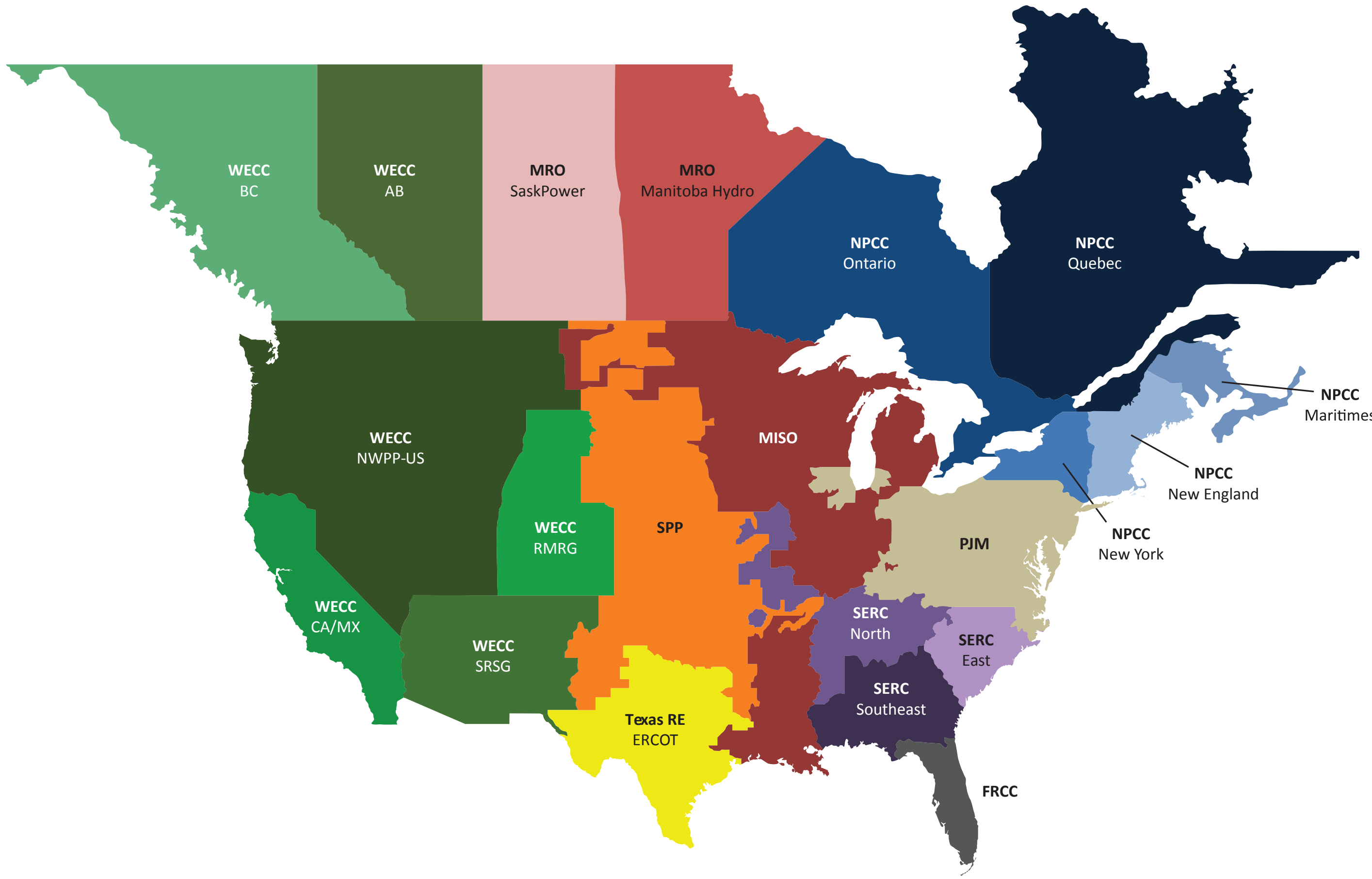
[42] Italy Blackout 2003: On the September 28, 2003, a blackout affected more than 56 million people across Italy and areas of Switzerland. The disruption lasted for more than 48 hours as crews struggled to reconnect areas across the Italian peninsula. The reason for the blackout was that during this phase the under-voltage load shedding could not compensate the additional loss of generation when approximately 7.5 GW of distributed power plants tripped during under-frequency operation. European Blackout 2006: On November 4, 2006, at around 22:10, the UCTE interconnected grid was affected by a serious incident originating from the North German transmission grid that led to power supply disruptions for more than 15 million European households and a splitting of the UCTE synchronously interconnected network into three areas. The imbalance between supply and demand as a result of the splitting was further increased in the first moment due to a significant amount of tripped generation connected to the distribution grid. In the over-frequency area (Northeast), the lack of sufficient control over generation units contributed to the deterioration of system conditions in this area (long lasting over-frequency with severe overloading on high-voltage transmission lines). Generally, the uncontrolled operation of dispersed generation (mainly wind and combined-heat-and-power) during the disturbance complicated the process of re-establishing normal system conditions.

Monitored Reliability Risks	What's Happening?	Reliability Impacts	Risk Assessment Recommendations
System Restoration and Resilience Efforts Impacted by the Changing Resource Mix	The changing resource mix introduces different challenges and risks to system restoration and resilience to extreme weather conditions.	Retiring conventional generation that has supported the blackstart capability of the system or are critical elements to "cranking paths" may impact system resilience in terms of being able to recover rapidly. With more decentralized resources, additional complexity exists in coordinating restoration between these generating units and control rooms. Since a majority of wind and solar units generate the maximum energy possible at any given moment, lack of controllable outputs can further complicate restoration efforts. Additional challenges exist, including availability of energy input (i.e., sunlight, wind) during system restoration and the ability to provide "grid-forming" services during blackstart conditions. Thus, for existing wind and solar photovoltaic (PV) resources to participate in system restoration, they currently must follow and coordinate with a grid voltage and frequency that has been set by a synchronous generation resource. Viable, large-scale capability for blackstart with wind and solar PV are possible if this is a desired feature, but are several years away from commercial availability.	Periodic reviews of restoration plans can mitigate impacts of the changing resource mix.
Potential Impact to System Strength and Fault Current Contributions	As inverter-based resources replace more conventional generation, short circuit current availability can be impacted due to the limited fault current contribution of renewable generation.	Low SCRs increase the likelihood of subsynchronous behavior and control interactions among neighboring devices that use power electronics.[43]	More industry guidance is needed to assess low short-circuit conditions on the BPS, system implications, desired inverter response, and potential solutions to mitigate these issues. Assessment techniques to identify low fault current conditions should continue to be advanced by Transmission Planners by considering light-load and low fault current conditions. Short-circuit ratio calculations and wide-area relay sensitivity studies could be performed to identify locations susceptible to low fault current issues.

[43] ERCOT, System Strength Assessment of the Panhandle System.

Assessment Area Dashboards and Summaries

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the eight Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Planning Committee, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



FRCC—Florida Reliability Coordinating Council
- FRCC

MRO—Midwest Reliability Organization
- MRO-SaskPower
- MRO-Manitoba Hydro
- MISO

SPP RE—Southwest Power Pool Regional Entity
- SPP

Texas RE–Texas Reliability Entity
- ERCOT

NPCC—Northeast Power Coordinating Council
- NPCC-New England
- NPCC-Maritimes
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

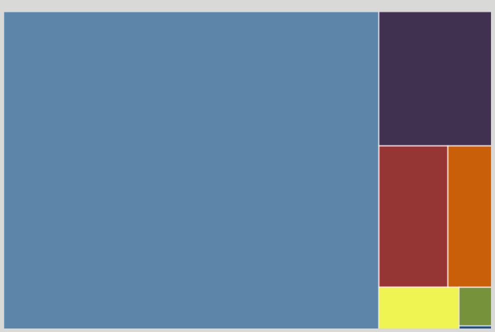
RF—ReliabilityFirst
- PJM

WECC—Western Electricity Coordinating Council
- WECC-BC
- WECC-AB
- WECC-RMRG
- WECC-CA/MX
- WECC-SRSG
- WECC-NWPP-US

SERC—SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity Division members and 23 Member Services Division members composed of investor-owned utilities (IOUs), cooperatives, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities with 47 registered entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of over 16 million people and has a geographic coverage of about 50,000 square miles over Florida.



Highlights

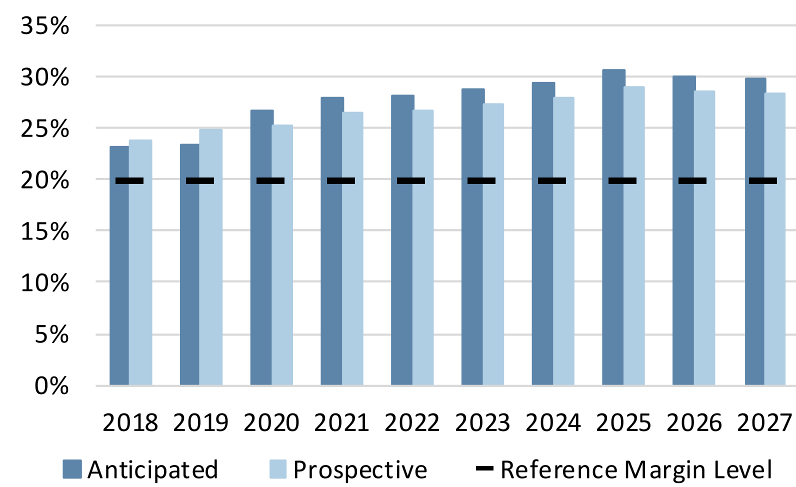
- The FRCC is not expecting any long-term reliability impacts from fuel supply or transportation constraints. The FRCC's Fuel Reliability Working Group (FRWG) will continue to provide oversight of the regional fuel reliability.
- In summer of 2017, another major interstate natural gas pipeline, Sabal Trail (along with an interconnecting transfer hub), was completed to increase delivery and supply diversity to FRCC. In addition, FRCC entities maintain significant firm contracts for natural gas supply and delivery and maintain a significant level of dual fuel capability across the Region.
- Despite severe damage in localized areas of Southwest Florida and catastrophic damage in the Florida Keys (non-BES), Hurricane Irma did not cause any substantial damage to generation facilities, and all BES transmission infrastructure on the mainland was restored within a week.

Demand, Resources, and Reserve Margins (Summer)

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	48,042	48,587	48,947	49,498	49,984	50,600	51,264	51,893	52,525	52,525
Demand Response	3,001	3,054	3,109	3,166	3,190	3,216	3,233	3,235	3,265	3,265
Net Internal Demand	45,041	45,533	45,838	46,332	46,794	47,384	48,031	48,658	49,260	49,260
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	54,664	55,776	56,149	56,222	57,921	59,072	58,654	58,941	59,029	59,029
Prospective	55,169	56,411	56,678	57,211	58,909	60,061	60,247	60,687	60,898	60,898
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	21.36	22.50	22.49	21.35	23.78	24.67	22.12	21.13	19.83	19.83
Prospective	22.49	23.89	23.65	23.48	25.89	26.75	25.43	24.72	23.63	23.63
Reference Margin Level	15.0	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

Existing On-Peak Generation (Summer)

Generation Type	Peak Season Capacity MW	Peak Season Capacity %
Biomass	495	1
Coal	5,737	11
Hydro	44	0
Natural Gas	39,976	75
Nuclear	3,638	7
Petroleum	2,411	5
Solar	1,254	2



Planning Reserve Margins

Planning Reserve Margins

The FRCC uses the Florida Public Service Commission's reliability criterion of 15 percent reserve margin criteria for non-IOUs as the minimum Regional Total Reserve Margin based on firm load. FRCC Reserve Margin calculations include merchant plant capacity that is under firm contract to load-serving entities. The FRCC assesses the upcoming 10-year projected summer and winter peak hour loads, generating resources, and demand side management (DSM) resources on an annual basis to ensure that the Regional Reserve Margin requirement is projected to be met.

Demand

Each individual stakeholder within the FRCC Region develops a forecast that accounts for their actual peak demand. The FRCC then aggregates these forecasts to calculate a noncoincident seasonal peak. Firm summer peak demand growth is expected to remain consistent with previous forecasts at 1.1 percent per year. For firm winter peak demand, the growth rate is also expected to remain consistent to previous forecasts at 1.0 percent per year.

Demand-Side Management

Each individual reporting entity develops independent analyses of the estimated impacts of Demand Response and Load Management. FRCC then aggregates those impacts for analytical purposes. Demand response is projected to be relatively constant at approximately 6.3 percent of the summer and winter total peak demands for all years of the planning horizon. Some of the larger utilities in the Region account for load profile modifiers, such as distributed energy resources (DERs) and electric vehicles in their forecast. Those utilities that do not account for such load profile modifiers in their forecasts have not yet experienced a large enough penetration rate of these types of facilities to modify their existing load profiles.

Distributed Energy Resources (DERs)

DERs are modeled with associated loads and netted out since these loads are implicitly accounted for with the load forecasts of entities within the FRCC. Currently, the FRCC Region has low penetration levels of DERs; however, penetration levels are expected to grow throughout the forecast horizon. There is currently a solar task force tasked with examining and determining procedures and processes to address the projected growth of photovoltaic (PV) penetration within the Region, including DERs. Installed PV capacity is projected to increase from 223 MW in Summer 2018 to 1,132 MW in Summer 2026.

Generation

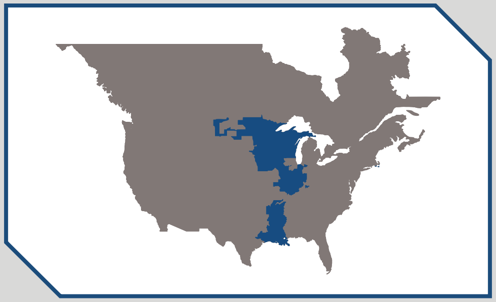
The FRCC is not expecting any long-term reliability impacts from an increased reliance on natural-gas-fired generation. A total of 2,640 MW of coal along with 1,214 MW of natural gas will be retired during the assessment period. The FRCC is not expecting any long-term reliability impacts from generating plant retirements.

Capacity Transfers

All firm on-peak capacity imports into the FRCC Region have firm transmission service agreements in place to ensure deliverability into the FRCC Region; these capacity resources are accounted for in the calculation of the Region's Anticipated Reserve Margin. In addition to real-time and daily operations planning coordination of capacity availability across the interface, the interface owners between the FRCC and SERC assessment areas meet twice a year to coordinate and perform joint planning studies to ensure the reliability and adequacy of the interface. An unplanned outage of one of the major 500 kV tie-lines with SERC would cause an operational reduction of the import/export capability of the Florida/Southern interface. The FRCC's Reliability Coordinator (RC) has established procedures that outline the coordination process between the RC's and the interface owners to facilitate the reduction of flow into the FRCC to an acceptable precontingency operating state and within defined System Operating Limits.

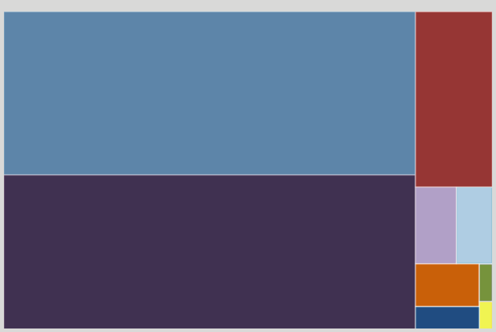
Transmission

The FRCC Region has not identified any major projects that are needed to maintain or enhance reliability during the planning horizon. Planned projects are primarily related to routine expansion in order to serve forecasted growing demand or for reliable resource integration.



MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers the wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

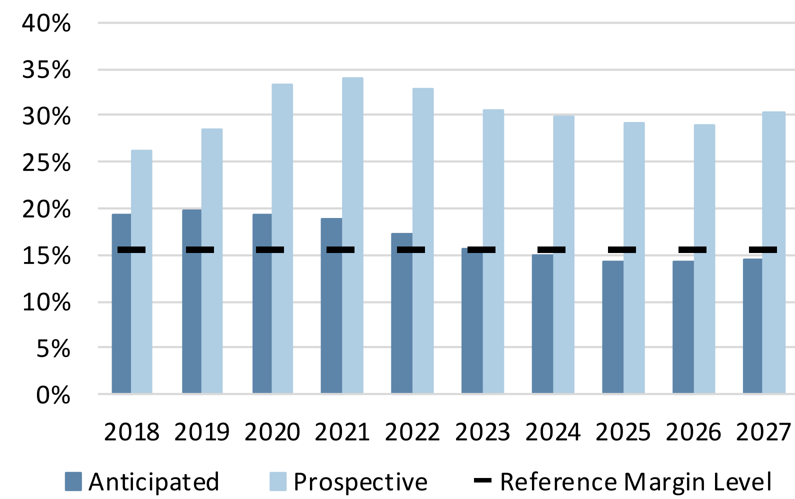


Highlights

- For 2018, MISO is projected to have 2.7 GW to 4.8 GW resources in excess of the regional requirement. Through 2022, regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements.
- Continued focus on load growth variations and generation retirements will allow transparency around future resource adequacy risk.

Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	125,568	126,544	127,022	127,646	128,287	128,897	129,409	129,109	128,913	128,716
Demand Response	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621
Net Internal Demand	119,947	120,923	121,402	122,025	122,666	123,276	123,789	123,488	123,292	123,095
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	143,012	144,857	144,925	145,121	143,866	142,477	142,265	141,079	140,922	141,021
Prospective	151,344	155,322	161,883	163,567	163,093	160,946	160,735	159,548	158,981	160,372
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	19.23	19.79	19.38	18.93	17.28	15.57	14.93	14.24	14.30	14.56
Prospective	26.18	28.45	33.35	34.04	32.96	30.56	29.85	29.20	28.95	30.28
Reference Margin Level	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80

Existing On-Peak Generation (Summer)	Peak Season Capacity	
Generation Type	**MW**	**Percent**
Biomass	439	0.3
Coal	56,226	40.9
Hydro	1,271	0.9
Natural Gas	59,546	43.3
Nuclear	11,955	8.7
Petroleum	2,427	1.8
Pumped Storage	2,775	2.0
Solar	319	0.2
Wind	2,431	1.8



Planning Reserve Margins

Planning Reserve Margins

The Anticipated Reserve Margin remains above the Reference Margin Level of 15.8 percent through the summer of 2022. In 2018, MISO is projected to have 2.7 GW to 4.8 GW of resources in excess of the Planning Reserve Margin Requirement. MISO's regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements in the 2019–2022 time frame.

Demand

MISO projects the summer coincident peak demand to grow at an average annual rate of 0.3 percent for the 10-year period, slightly less than the *2016 LTRA*. Zones 4 and 7 (Lower Peninsula Michigan) have essentially flat load growth rate over the 10-year period; specifically, Zone 4 saw the largest year-over-year change within MISO. This included forecasted load reductions due to expected loss of industrial load paired with a near-flat future growth rate. These are the main drivers in the reduction of regional growth.

Demand-Side Management

MISO forecasts 5,620 MW of direct control load management and interruptible load to be available for the assessment period. MISO also forecasts at least 4,129 MW of behind-the-meter generation to be available for the assessment period. Zone 4 and Zone 7 had a significant increase in DR for the assessment period, due to new registrations by aggregators in MISO's Module E Capacity Tracking Tool. Energy efficiency is not explicitly forecasted at MISO; any energy efficiency programs are reflected within the demand and energy forecasts.

Distributed Energy Resources (DERs)

As part of the MISO Transmission Expansion Plan (MTEP) study, there was an attempt to collect information on DERs. The forecast provides an estimate of DER programs and their impact on peak demand and annual energy savings. This forecast positions MISO to understand emerging technologies and the role they play in transmission planning as there is a specific case on distributed energy resources both at a base case level and increased penetration level. MISO has not experienced any operational challenges as of yet but expects to as programs grow in the future.

Generation

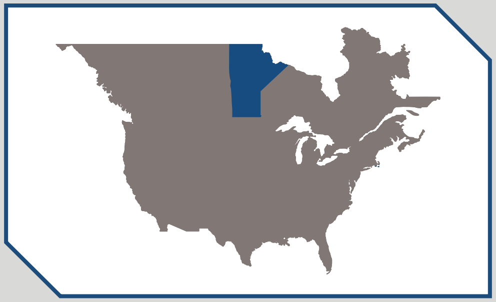
A total of 574 MW of generation capacity is retiring in 2017 and an additional 735 MW of generation capacity will retire in 2018. Through the generator interconnection queue (GIQ) process, MISO anticipates 4,517 MW of future firm capacity additions and uprates along with 4,106 MW of future potential capacity additions to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the GIQ and the 2017 OMS-MISO Survey as of June 2017, which includes the aggregation of active projects.

Capacity Transfers

The SPP settlement agreement has put in place a regional directional transfer limit replacing the Operations Reliability Coordination Agreement operating limit. Specifically, midwest (LRZs 1-7) to south (LRZs 8-10) flow is limited to 3,000 MWs and south to midwest is limited to 2,500 MWs. Without this regional directional transfer limit, there is roughly 3 GW in the near term that would be available to support resource adequacy in the short-term.

Transmission

The annual MISO Transmission Expansion Plan (MTEP) proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in MISO. Major categories of the MTEP include the following: A total of 106 baseline reliability projects required to meet NERC Reliability Standards, 32 generator interconnection projects required to reliably connect new generation to the transmission grid, 1 market efficiency project to meet requirements for reducing market congestion, 1 transmission delivery service project that includes network upgrades driven by transmission service requests, and 243 other projects.



MRO-Manitoba Hydro

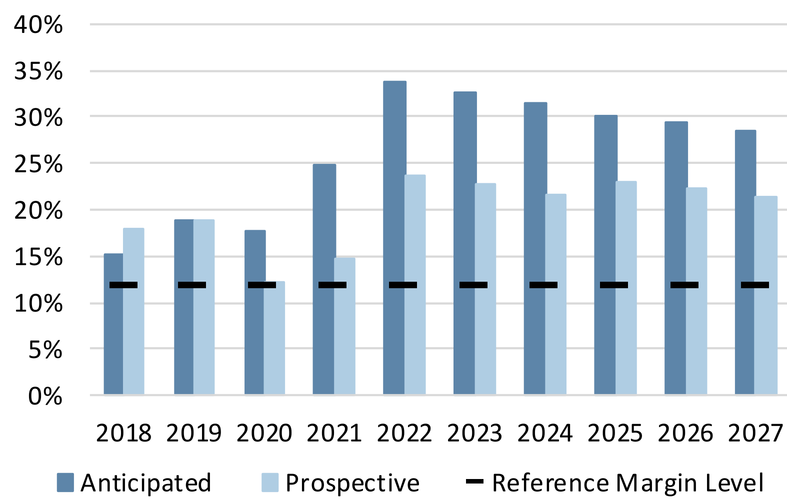
Manitoba Hydro is a provincial crown corporation that provides electricity to 556,000 customers throughout Manitoba and natural gas service to 272,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Highlights

- The Anticipated Reserve Margin does not fall below the Reference Margin Level of 12 percent in any year during the assessment period. The 630 MW (net addition) Keeyask hydro station is expected to come into service beginning in the winter of 2021/2022, which helps ensure resource adequacy in the latter half and after the end of the current assessment period. No resource adequacy issues are expected.
- Demand is flattening over the LTRA horizon as a result of reduced load growth and energy efficiency and conservation efforts.
- The Bipole 3 HVDC transmission line is expected to come into service in 2018 and will improve reliability during extreme events.

Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	4,760	4,642	4,681	4,706	4,739	4,777	4,817	4,840	4,867	4,897
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,760	4,642	4,681	4,706	4,739	4,777	4,817	4,840	4,867	4,897
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	5,488	5,513	5,507	5,870	6,338	6,338	6,338	6,298	6,298	6,298
Prospective	5,609	5,517	5,257	5,395	5,863	5,863	5,863	5,948	5,948	5,948
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	15.29	18.76	17.65	24.73	33.74	32.68	31.58	30.13	29.40	28.61
Prospective	17.85	18.85	12.30	14.64	23.72	22.73	21.71	22.89	22.21	21.46
Reference Margin Level	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

Existing On-Peak Generation (Winter)		
Generation Type	**Peak Season Capacity**	
	MW	**%**
Coal	92	1.7
Hydro	5,095	91.8
Natural Gas	311	5.6
Wind	52	0.9



Planning Reserve Margins (Winter)

Planning Reserve Margins
The Anticipated Reserve Margin does not fall below the Reference Margin Level of 12 percent in any year during the 10-year assessment period.

Demand
The province is divided into five smaller subregions: Northern, Western, Interlake, Eastern and Winnipeg. The localized winter peak growth rate varies from a low of 0.5 percent in the Northern region to a high of 4.4 percent in the Eastern region. The high growth in the Eastern region is due to population growth in the Steinbach area as well accelerated growth on the east side of Lake Winnipeg.

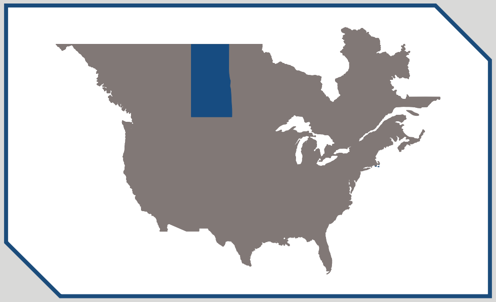
Demand-Side Management
Manitoba Hydro does not have any demand side management resources that are considered as controllable and dispatchable demand response.

Distributed Energy Resources (DERs)
Manitoba Hydro projects that installed DERs will increase from 15.5 MW in 2017 to 30.8 MW in 2027. There is less than 1 MW of solar distributed energy resources in Manitoba. Even with high growth rates, Manitoba Hydro is not anticipating the quantity of solar distributed energy resources to increase to a level that could cause operational impacts during the assessment period.

Generation
The 630 MW (net addition) Keeyask hydro station is anticipated to come into service beginning in the winter of 2021/2022, which will help promote resource adequacy in the latter years of the assessment period and support a related 250 MW capacity transfer into MISO. The only unit currently impacted by environmental requirements is Brandon Unit 5 (coal), which is categorized as an unconfirmed retirement at the end of 2019. The driver of the potential retirement of Brandon Unit 5 is both environmental and end of lifespan. No adverse effect on reliability is anticipated as a result of the potential retirement as this unit is currently planned to be converted into a synchronous condenser for area voltage support once the coal-fired boiler is retired.

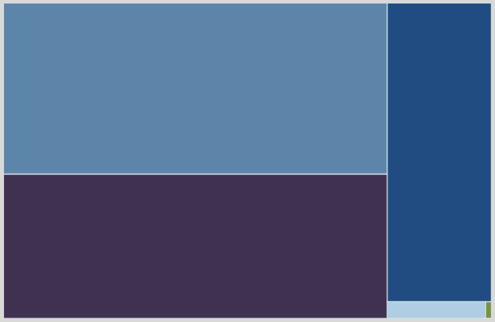
Capacity Transfers
The Manitoba Hydro system is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which is summer-peaking as a whole. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only if the following conditions simultaneously occur: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. The additional hydro generation and the related 250 MW capacity transfer into the MISO Region will tend to increase north to south flows on the Manitoba-MISO interface. A 100 MW capacity transfer from Manitoba to Saskatchewan will tend to increase east to west flow on the Manitoba-Saskatchewan interface. Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and IESO. In accordance with these agreements, planning and operating related issues are discussed and coordinated through respective committees.

Transmission
There are several transmission projects projected to come on-line during the assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads, transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation. The major system enhancement projects include the addition of the third bipolar HVdc transmission system to improve reliability, especially during extreme events; these are expected to come into service in 2018. Manitoba Hydro is expecting a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020. The high growth in the Eastern region is driving the addition of new transmission such as the 115 kV Pine Falls to Manigotagan line and the St. Vital to Letellier 230 kV line. No reliability impacts are anticipated as the localized growth is considered in the subregional transmission planning process. Some transmission projects have been delayed a few years due to lower than expected load growth in the local area. A temporary operating procedure will ensure sufficient generation is on-line in Brandon to support voltages at winter peak, which allows the Dorsey to Portage 230 kV line to be deferred.



MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.



Highlights

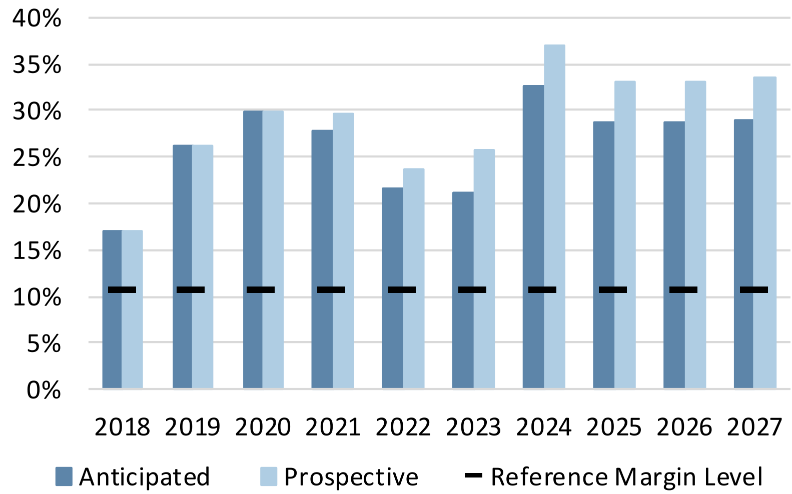
- Anticipated Reserve Margins will remain above the Reference Margin Level (Installed Reserve Margin requirement) throughout the assessment period.
- Approximately 1,972 MW of additional renewable capacity is projected over the assessment period. The on-peak contribution from renewables is projected to increase from 21 percent in 2017 to 30 percent in 2027.
- A new 230 kV tie line with Manitoba Hydro is planned to facilitate a 100 MW firm capacity/energy.

Demand, Resources, and Reserve Margins

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	3,784	3,815	3,878	3,915	3,969	4,005	4,016	4,058	4,086	4,106
Demand Response	85	85	85	85	85	85	85	85	85	85
Net Internal Demand	3,699	3,730	3,793	3,830	3,884	3,920	3,931	3,973	4,001	4,021
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	4,329	4,705	4,930	4,892	4,726	4,751	5,211	5,112	5,152	5,186
Prospective	4,329	4,705	4,930	4,970	4,806	4,926	5,386	5,287	5,327	5,367
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	17.02	26.13	29.97	27.73	21.68	21.20	32.56	28.67	28.77	28.98
Prospective	17.02	26.13	29.97	29.76	23.74	25.66	37.01	33.07	33.14	33.47
Reference Margin Level	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00

Existing On-Peak Generation (Winter)

Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	3	0.1
Coal	1,531	35.8
Hydro	863	20.2
Natural Gas	1,836	42.9
Wind	45	1.1



Planning Reserve Margins (Winter)

Planning Reserve Margins

Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirement throughout the assessment period. Based on the deterministic calculation made within this assessment, Saskatchewan's anticipated reserve margin ranges from approximately 17–32 percent and does not fall below the Reference Margin Level. The Reference Margin Level for Saskatchewan is 11 percent.

Demand

Saskatchewan has not identified any significant demand change localized to a specific portion of the assessment area for the assessment period.

Demand-Side Management

SaskPower's Demand Response program has contracts in place with customers for interruptible load based on defined demand response programs. The first of these programs provides a curtailable load, currently 85 MW, for use as emergency load shedding; it is available with a 12-minute event response time, allowing it to be considered as an emergency operating procedure (EOP) in the probabilistic model for resource adequacy studies. Other programs are in place that provide access to additional curtailable load with two-hour event response time for use when emergency conditions persist or when capacity is anticipated to be constrained but are not considered as EOPs in reliability planning.

Distributed Energy Resources (DERs)

The amount of load that is offset by distributed generation or behind-the-meter generation is reflected in the load forecast used for reliability assessments. It is not anticipated that Saskatchewan will encounter any significant operational impacts due to distributed generation or behind-the-meter generation. DERs are currently considered as reduction in the load forecast for reliability planning purposes. Saskatchewan is reviewing and analyzing the changing market of behind-the-meter solar photovoltaic (PV) installations and how it will integrate into the generation supply mix and affect the overall reliability of the system. Saskatchewan currently has no major concerns on DERs as they are a low percentage of overall system load.

Generation

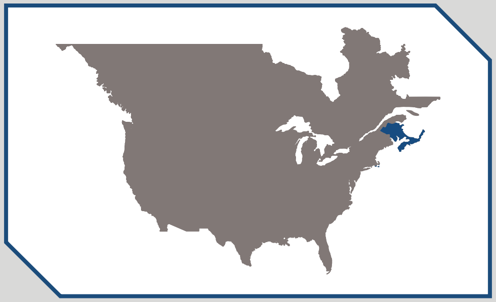
Saskatchewan projects additions of 2,672 MW (nameplate) capacity throughout the assessment period. This consists of 700 MW of natural gas, 1,607 MW of Wind, 100 MW of flare gas, 75 MW of biomass, 20 MW of geothermal, 120 MW of solar, and 50 MW of hydro capacity. Integration of solar into the generation model is still being reviewed and analyzed and is currently not considered to be available during on-peak demand. Although Saskatchewan does not have a provincial renewable portfolio standards (RPS) mandate, a 50 percent increase in renewable generation is projected by 2030 with the addition of 1,972 MW of renewable generation, which includes 100 MW of firm imports from neighboring jurisdictions. Saskatchewan has not identified any significant operational impacts due to the integration of variable resources during the assessment period. The addition of future variable resources may require the ability to curtail the resource or have additional fast-ramping capacity available from other resources to follow the intermittency of the variable resource. Projected unit retirements during the assessment period include approximately 180 MW of natural gas facilities, two-139 MW coal facilities, and an 11 MW wind facility.

Capacity Transfers

Saskatchewan has a contract in place for a firm 25 MW (until March 2022) and a firm 100 MW (starting Summer 2020 and throughout the assessment period) capacity transfers from Manitoba Hydro, including supply source and transmission. From a capacity and transmission reliability perspective, Saskatchewan has coordinated with Manitoba Hydro to ensure that the capacity transfer is correctly modelled in on-going operational and planning studies.

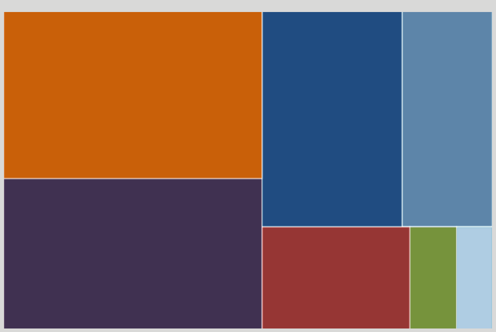
Transmission

Saskatchewan has several major transmission projects for reliability during the near-term planning horizon of the assessment period. These projects are dependent on load growth and reliability and involve the construction of approximately 752 km of new transmission line. The new transmission projects include building approximately 401 km of 230 kV and 201 km of 138 kV transmission line in the Southwest region and approximately 150 km of 230 kV transmission line in the Southeast region of Saskatchewan.



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people.



Highlights

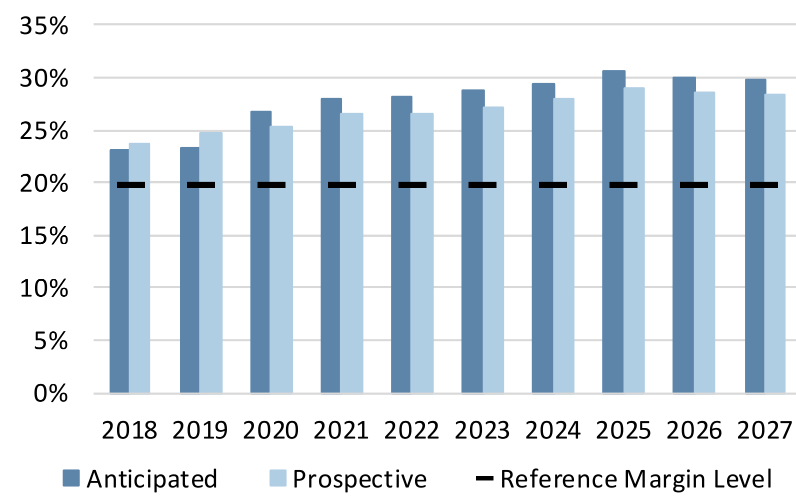
- Demand growth is effectively negligible over the duration of the LTRA analysis period. Any growth in demand has been offset by load reductions from demand side management.
- An undersea HVDC undersea cable connection to the Canadian province of Newfoundland and Labrador will begin service in late 2017. This will allow for the mid-2020 retirement of a 153 MW coal-fired generator with an equivalent amount of firm hydro capacity imported through the cable.

Demand, Resources, and Reserve Margins

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	5,565	5,559	5,571	5,572	5,565	5,538	5,509	5,464	5,484	5,493
Demand Response	263	262	262	262	261	261	261	260	260	260
Net Internal Demand	5,302	5,297	5,309	5,311	5,304	5,277	5,248	5,203	5,224	5,233
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	6,528	6,535	6,729	6,796	6,794	6,794	6,794	6,794	6,792	6,792
Prospective	6,565	6,609	6,650	6,718	6,716	6,716	6,716	6,716	6,714	6,714
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	23.12	23.37	26.73	27.98	28.11	28.75	29.46	30.57	30.02	29.79
Prospective	23.81	24.78	25.25	26.50	26.63	27.27	27.97	29.07	28.52	28.30
Reference Margin Level	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00

Existing On-Peak Generation (Winter)

Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	209	3.1
Coal	1,700	25.1
Hydro	1,318	19.4
Natural Gas	850	12.5
Nuclear	660	9.7
Petroleum	1,888	27.8
Wind	160	2.4



Planning Reserve Margins (Winter)

Planning Reserve Margins

The Anticipated Reserve Margin does not fall below the Reference Margin Level of 20 percent during the 10-year assessment period.

Demand

The Maritimes Area peak loads are expected to increase by 3.2 percent during summer but decline by 1.1 percent during winter seasons over the 10-year assessment period. This translates to average growth rates of 0.3 percent in summer and -0.1 percent in winter. Rural to metropolitan population migration and the introduction of split phase heat pump technology to areas traditionally heated by fossil fuels has created load growth for the southeastern corner of the NB that has outpaced growth in the rest the Maritimes area in recent years. It is expected that these effects will level off in the future.

Demand-Side Management

Plans to develop up to 150 MW by 2026/2027 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist.[1] During the assessment period, annual amounts for summer peak demand reductions associated with energy efficiency programs rise from 7 MW to 92 MW while the annual amounts for winter peak demand reductions rise from 51 MW to 541 MW.[2]

Distributed Energy Resources (DERs)

The current amount of DERs in the New Brunswick subarea is insignificant (<5 MW). Should these amounts increase to significant levels, New Brunswick will consider adding DERs to its load forecasting and resource planning processes and give due consideration to ramping and/or light load issues. Nova Scotia projects 203 MW of directly metered[3] installed distributed generation by 2020. Real-time data is not available for all these sites, which may present operational challenges once all projects are in-service. The situation will be monitored as these projects are phased-in and methods to increase their visibility will be investigated.

[1] The savings for these programs were included as energy efficiency and conservation on the LTRA Form A sheets and will be broken out once the program designs are better understood.

[2] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

[3] Not netted against the load forecast.

Generation

Small amounts of new generation capacity are being installed to introduce alternative renewable energy resources into the capacity mix. Renewable Electricity Standards (RES) have led to the development of substantially more wind generation capacity than any other renewable generation type. In Nova Scotia, the (RES) target for 2017 calls for 25 percent of energy sales to be supplied from renewable resources. This target increases to 40 percent of energy sales from renewable resources in 2020. Currently the 25 percent target is being met primarily by wind generation, hydro, and biomass.[4]

Capacity Transfers

Probabilistic studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

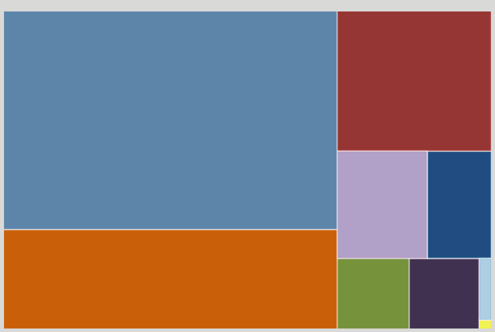
Transmission

Installation of two undersea 138 kV cable connections, each with a capacity of 200 MVA and a length of 9 miles, was completed during the first week of July in 2017 and increases capacity and improves the ability to withstand transmission contingencies in the area between New Brunswick and Prince Edward Island. Associated with this project is the addition of a new 138 kV overhead line in New Brunswick to the new cable terminus during the fall of 2017 and on-island transmission reconfigurations that will also further increase capacity to the Island by October 2018. A 475 MW +/-200 kV high voltage direct current (HVDC) undersea cable link (Maritime Link) between Newfoundland and Labrador and NS will be installed by late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 153 MW coal-fired unit in Nova Scotia by mid-2020. The Maritime Link could also potentially provide a source for imports from Nova Scotia into New Brunswick that would reduce transmission loading in the southeastern New Brunswick area. In addition, during the fall of 2018, a second 345/138 kV transformer will be added in parallel with an existing transformer at the Keswick terminal in New Brunswick to mitigate the effects of transformer contingencies at the terminal.

[4] The incremental renewable requirements of the 40 percent target will largely be met by the energy import from the Muskrat Falls hydro project in Newfoundland and Labrador.

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system and also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

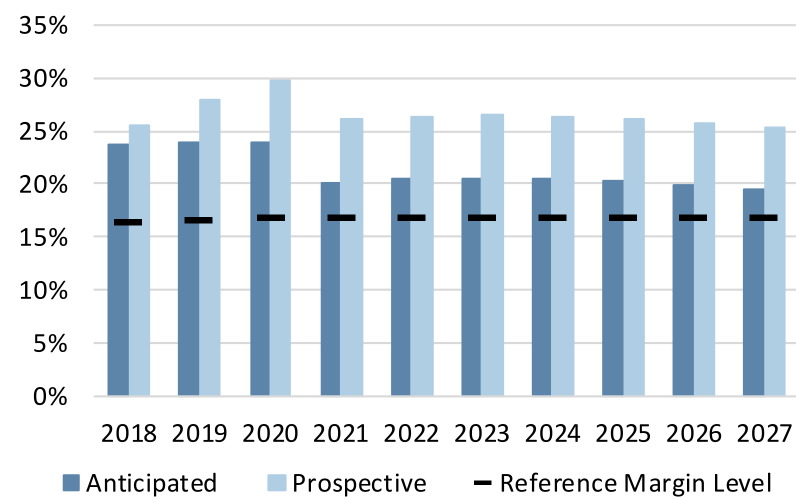


Highlights

- Ensuring adequate fuel availability for generators continues to be a priority, especially during winter seasons. This stems from the lack of firm natural gas supply and pipeline transportation contracts.
- Large-scale proliferation of inverter-based DERs presents challenges, requiring attention to interconnection standards and analysis of declining system inertia.
- Regional and state environmental regulations likely have a greater potential impact on generating units in the Region compared to federal environmental requirements.
- ISO-NE's summer peak and energy demand will decrease from 2018 to 2027, reflecting a CAGR of -0.03 percent.

Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	26,458	26,409	26,298	26,213	26,167	26,155	26,176	26,228	26,310	26,392
Demand Response	546	367	420	420	420	420	420	420	420	420
Net Internal Demand	25,912	26,042	25,878	25,793	25,747	25,735	25,756	25,808	25,890	25,972
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	32,061	32,271	32,044	30,986	31,003	31,018	31,029	31,035	31,040	31,039
Prospective	32,501	33,323	33,563	32,505	32,522	32,537	32,548	32,554	32,559	32,558
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	23.73	23.92	23.83	20.13	20.41	20.53	20.47	20.25	19.89	19.51
Prospective	25.43	27.96	29.70	26.02	26.31	26.43	26.37	26.14	25.76	25.36
Reference Margin Level	16.60	16.70	16.90	16.90	16.90	16.90	16.90	16.90	16.90	16.90

Existing On-Peak Generation (Summer)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Biomass	940	3.3
Coal	917	3.2
Hydro	1,274	4.4
Natural Gas	13,530	47.1
Nuclear	4,001	13.9
Petroleum	6,148	21.4
Pumped Storage	1,786	6.2
Solar	20	0.1
Wind	139	0.5



Planning Reserve Margins

Planning Reserve Margins

The Anticipated Reserve Margin does not fall below ISO New England's reference margin level during the assessment period.

Demand

The annual (summer) peak total internal demand (TID) and the net energy for load, which take into account energy efficiency and conservation as well as behind-the-meter photovoltaic resources, are forecasted to decrease from 2018 to 2027 by a compound annual growth rate (CAGR) of -0.03 percent, as compared to the *2016 LTRA* projection of +0.21 percent. The primary reasons for the decrease in the Total Internal Demand forecast are updated historical demand data coupled with a lower economic growth forecast and an increase in the amount of forecasted energy efficiency and behind-the-meter photovoltaic (PV).

Demand-Side Management

Real-Time Demand Response (RTDR) is procured through ISO-NE's Forward Capacity Market (FCM). Currently, RTDR is activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP-4). Starting on June 1, 2018, RTDR will have to participate in the day-ahead and real-time energy markets and be subject to daily economic dispatch. RTDR is based on the capacity supply obligations (CSOs) obtained through the FCM three years in advance. The CSOs decrease from 546 MW in 2018 to 420 MW in 2020. Based on the FCM auction results, energy efficiency will grow to 2,893 MW by 2020, an increase of 587 MW from 2018.[1] Energy efficiency (EE) has generally been increasing over time and is projected to continue growing throughout the 10-year study period. The amount of EE is projected to increase to over 4,500 MW by 2027.

Distributed Energy Resources (DERs)

The total peak load reduction value of all PV in New England amounted to 831 MW in 2017 and is forecasted to grow to 1,311 MW by 2022 and to 1,475 MW by 2027. These summer peak load reduction values are calculated as percentage of ac nameplate.

Generation

Generating capacity that has been added since the *2016 LTRA* consists of 340 MW of wind, 210 MW of solar, and 16.7 MW of battery storage. Approximately 2,700 MW of Tier 1 capacity is planned by 2019, consisting primarily of natural gas (2,600 MW). Tier 2 capacity additions include 950 MW of natural-gas-fired generation, 430 MW of wind, and 150 MW of solar. Recent retirements include Brayton Point Station, a 1,535 MW coal and oil/gas plant that retired on June 1, 2017. Confirmed retirements include a total of 677 MW Pilgrim Nuclear Power Station, planned for retirement by June 2019. The Pilgrim nuclear plant owners stated that the planned retirement is due to poor market conditions, reduced revenues, and increasing operational costs.

Capacity Transfers

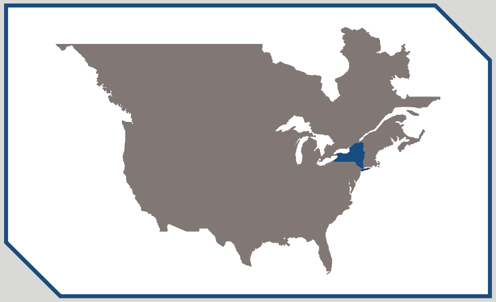
New England is interconnected with three Balancing Authorities of Quebec, the Maritimes, and New York. During the study period, New England assumes, on average, approximately 1,200 MW to 1,500 MW of imports every year from these neighboring systems. In addition, New England has mutual assistance agreements with the balancing authorities within the Northeast Power Coordinating Council to assist each other during capacity shortage conditions.

Transmission

The following projects planned and under-construction are needed to maintain reliability in New England:

- Greater Boston project
- Southeastern Massachusetts/Rhode Island (SEMA/RI)
- Greater Hartford Central Connecticut (GHCC)
- Southwest Connecticut (SWCT)
- Maine Power Reliability Program (MPRP)
- New Hampshire and Vermont
- Pittsfield/Greenfield

[1] For the years beyond the FCM commitment periods, ISO-NE uses an energy efficiency forecasting methodology that takes into account the potential impact of growing energy efficiency and conservation initiatives throughout the region.



NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority (NYBA) 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 over 47,000 square miles and serves the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

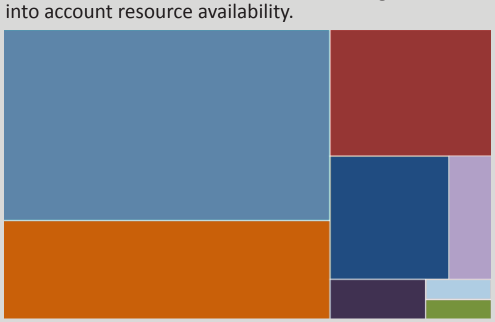
Highlights

- Two nuclear units have withdrawn prior notices of intent to retire. Regulators have announced an agreement to retire the Indian Point Energy Center Unit No. 2 and 3 (approximately 2,150 MW) through 2020–2021.
- To date, the NYISO has not received a completed generator deactivation notice from Entergy that will begin the generator deactivation process to determine if any reliability need will be created by the retirement and what, if any, solution would be required prior to the deactivation of the facility.

Demand, Resources, and Reserve Margins[1]

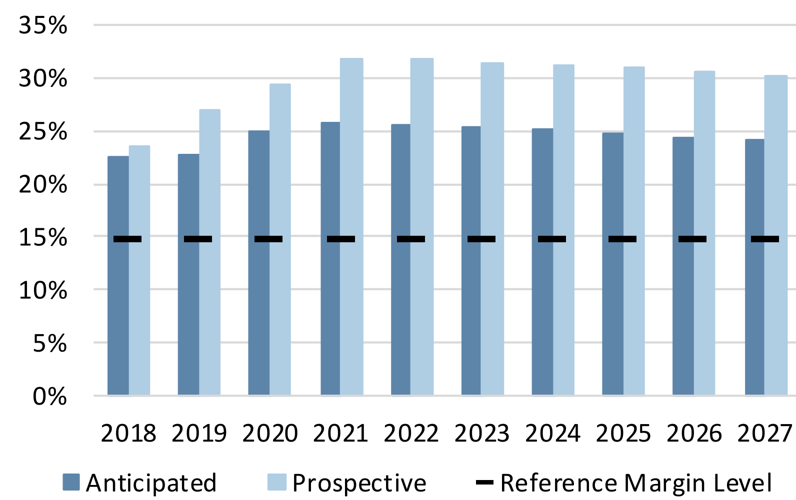
Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	33,078	33,035	32,993	33,009	33,034	33,096	33,152	33,232	33,324	33,398
Demand Response	894	894	894	894	894	894	894	894	894	894
Net Internal Demand	32,184	32,141	32,099	32,115	32,140	32,202	32,258	32,338	32,430	32,504
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	39,438	39,457	40,110	40,349	40,349	40,349	40,349	40,349	40,349	40,349
Prospective	39,766	40,812	41,541	42,330	42,330	42,330	42,330	42,330	42,330	42,330
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	22.54	22.76	24.95	25.64	25.54	25.30	25.08	24.77	24.42	24.13
Prospective	23.56	26.98	29.41	31.81	31.70	31.45	31.22	30.90	30.53	30.23
Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

[1] For the NPCC-New York assessment area, NYISO uses a probabilistic model with installed capacity and equivalent forced outage rates for all resources in order to identify resource requirements. The result of NYISO's analysis produces the Installed Reserve Margin (IRM), which is established by the New York State Reliability Council (NYSRC) for one "Capability Year" (May 1, 2017 through April 30, 2018). In order to conform with the NERC PC-approved assessment approach, wind, solar, and run-of-river hydro are required to be derated to their "expected on-peak" summer and winter values. The following derates have been applied, based on NYISO's Unforced Capacity (UCAP) values: wind (20 percent of nameplate), run-of-river hydro (55 percent of nameplate), and solar (50 percent of nameplate). NERC has applied the "default" 15 percent Reference Margin Level for the 10-year assessment period. Because the IRM is based on installed capacity values, it should not be used to evaluate reserve margins that take into account resource availability.



Existing On-Peak Generation (Summer)

Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	346	0.9
Coal	1,011	2.7
Hydro	3,819	10.3
Natural Gas	16,292	44
Nuclear	5,375	14.5
Petroleum	8,553	22.8
Pumped Storage	1,407	3.8
Solar	16	0.0
Wind	348	0.9



Planning Reserve Margins

Planning Reserve Margins

NPCC-New York's Anticipated Reserve Margin does not fall below the NERC Reference Margin Level of 15 percent during the assessment period. The New York State Reliability Council (NYSRC) conducts an annual Installed Reserve Margin study; this study determines the Installed Reserve Margin (IRM) of 18 percent for the capability year (May 1, 2017 through April 30, 2018). Because the assessment period for the *2017 LTRA* is from the summer of 2018 through the winter of 2027/2028, NERC applied a 15 percent Reference Margin Level.

Demand

New York's peak load demand forecast is based upon an econometric forecast using normal weather with the impacts of energy efficiency, distributed energy resources, and behind-the-meter solar photovoltaic (PV) deducted from the econometric forecast. Based upon the 2017 load forecast over the next ten years, there is a slight decline in the annual energy growth rate while the summer peak demand has a slight increase in growth rate.

Demand-Side Management

New York accounts for demand response resources that participate in NYISO's reliability-based demand response programs built on the enrolled MW derated by historical performance. Demand response resources that only participate in NYISO's energy and ancillary services markets are not separately represented in planning analysis.

Distributed Energy Resources (DERs)

The NYISO published a report in January 2017 that provided a roadmap that will be used over the next 3 to 5 years as a framework to develop the market design elements, functional requirements, and tariff language necessary to implement the NYISO's vision to integrate DERs into NYISO's Energy, ancillary services, and capacity markets. Behind-the-meter solar PV is currently being addressed operationally in the day-ahead and real-time load forecasts with a solar forecasting system integrated with the day-ahead and real-time markets.

Generation

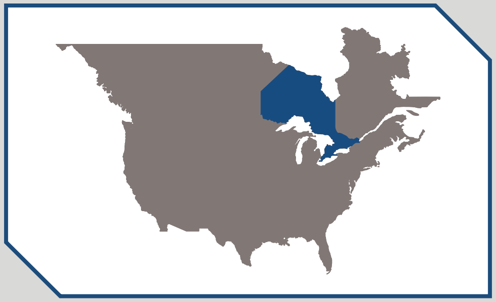
Two nuclear units (R.E. Ginna Nuclear Power plant (582 MW) and FitzPatrick Nuclear Power plant (859 MW)) were reported as proposed retirements in the *2016 LTRA*. Since then, the FitzPatrick Nuclear Power plant has withdrawn its notice of intent to retire and the R.E. Ginna Nuclear Power plant has stated that it will continue to operate. Regulators have announced an agreement to retire the Indian Point Energy Center Unit No. 2 and 3 (approximately 2,150 MW) in 2020–2021. To date, the NYISO has not received a completed Generator Deactivation Notice from Entergy that will commence the Generator Deactivation Process to determine if any reliability need will be created by the retirement and what, if any, solution would be required prior to the deactivation of the facility. Also, 750 MW of new generation is planned to enter into service in 2018 with another 250 MW of market-based generation additions in various planning stages. A 106 MW generating facility has returned to service after completing a coal to natural gas conversion.

Capacity Transfers

New York is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria. There are, however, four controllable tie lines connecting New York to ISO-NE and the PJM RTO. The owners of these lines have unforced capacity deliverability rights (UDR) to deliver up to 1,965 MW of capacity to New York. Each year on August 1, the owners elect and notify New York of the quantity of capacity that will be delivered to New York for the following capability year commencing on May 1. These quantities will be accounted for in the reliability studies that determine New York's Installed Reserve Margin.

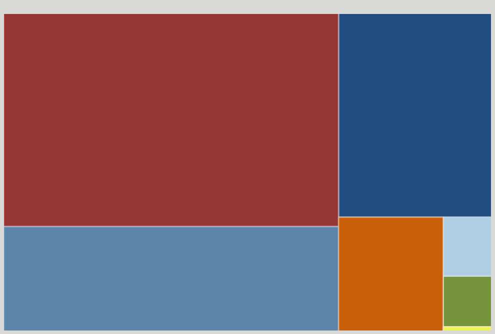
Transmission

The NYISO's 2016 Reliability Needs Assessment identified thermal violations under N-1-1 post-contingency conditions (applying more stringent NPCC criteria) in the Buffalo, Binghamton, Rochester, and Syracuse areas. The NYISO's 2016 Comprehensive Reliability Plan stated that these violations would be resolved with permanent solutions identified in the most recent Transmission Owner local transmission plans. In the Buffalo area, the solution was placed in-service before the end of 2016. The solution in the Binghamton area is scheduled to be completed by the end of 2021. The solution in the Rochester area is scheduled to be completed by Summer 2019. The solutions in the Syracuse area are scheduled to be completed by Summer 2018. In the interim, the local Transmission Owners will implement local operating procedures, if required, to prevent overloads, including the potential for limited load shedding.



NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.



Highlights

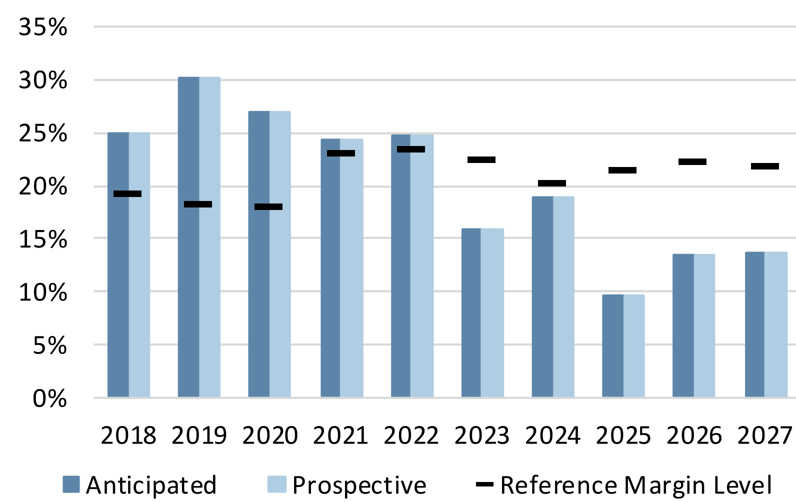
- Ontario is expecting substantial resource turnover that is driven by nuclear retirements and refurbishments.
- Existing programs and additional Market Renewal initiatives, particularly an incremental capacity auction, will address capacity needs in the later part of the LTRA horizon.
- Increasing variable generation, integration of distributed energy resources (DERs), and changing demand and supply patterns are creating and will continue to create new operating challenges in managing the bulk power system. The IESO is working with stakeholders to develop cost-effective solutions to address these challenges, such as expanding the regulation market and increasing flexibility within the energy market.

Demand, Resources, and Reserve Margins

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	22,381	22,295	22,209	22,101	22,016	22,058	22,177	22,229	22,214	22,185
Demand Response	771	847	847	847	847	847	847	847	847	847
Net Internal Demand	21,610	21,448	21,362	21,253	21,169	21,211	21,330	21,382	21,367	21,338
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	26,980	27,901	27,132	26,404	26,404	24,576	25,382	23,428	24,255	24,255
Prospective	26,980	27,901	27,132	26,404	26,404	24,576	25,382	23,428	24,255	24,255
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	24.85	30.09	27.01	24.23	24.73	15.87	19.00	9.57	13.52	13.67
Prospective	24.85	30.09	27.01	24.23	24.73	15.87	19.00	9.57	13.52	13.67
Reference Margin Level	19.45	18.37	18.17	23.19	23.72	22.67	20.40	21.66	22.32	22.03

Existing On-Peak Generation (Summer)

Generation Type	Peak Season Capacity MW	Peak Season Capacity Percent
Biomass	446	1.6
Hydro	5,671	20.2
Natural Gas	6,361	22.6
Nuclear	12,939	46
Petroleum	2,162	7.7
Solar	38	0.1
Wind	523	1.9



Planning Reserve Margins

Planning Reserve Margins

The Anticipated Reserve Margins fall below the Reference Margin level in the mid-2020s. Ontario possesses a range of options to address these capacity needs, including outage rescheduling, more conservation and demand response, and the development of a capacity auction in Ontario.

Demand

Growth in demand is subtle and driven by population growth, economic expansion, and increased penetration of electric devices. Offsetting that growth are reductions from conservation and increased output from embedded generation. The net effect of these competing factors is a reduction of seasonal peaks.

Demand-Side Management

Ontario has four main demand response (DR) programs: dispatchable loads (DL), a residential DR program (called Peaksaver), capacity-based demand response (CBDR), and the capacity procured through an annual DR Auction. Over the planning horizon, CBDR and Peaksaver are being phased out and all DR aside from DL is expected to be procured through the DR auction.

Distributed Energy Resources (DERs)

Previous years saw an increasing amount of generation embedded within the province's distribution system. Supply from distributed energy resources (e.g., solar, wind, waterpower, bioenergy or combined heat and power facilities) and demand response resources were negligible in 2005. By January 2017, DERs had grown to approximately 3,000 MW of installed supply. As a result of this increase, the IESO has seen periods where DERs had significant offsetting impacts on Ontario demand. Having visibility of these resources is necessary for improving short-term demand forecasting and supporting reliable grid operation. As such, the IESO is working to increase coordination between the grid operator and distributed resources directly or through integrated operations with local distribution companies with the aim to improve visibility of the distribution system.

Generation

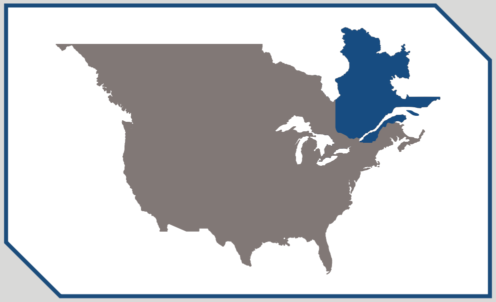
Retirements of two nuclear generating stations (total capacity of approximately 3,000 MW) are expected by 2025. Nuclear refurbishments at three other stations will reduce the generation capacity available over peak seasons. Ontario expects to add about 2,400 MW of new resources to the grid over the next 10 years. The new resources are expected to comprise of about 1,150 MW of wind, 980 MW of natural-gas-fired generation, 130 MW of hydroelectric, and 140 MW of solar. Deviations from the centralized variable generation forecast is highlighting the need for additional regulation and flexible resources capable of responding to dispatch signals to increase their output within 30 minutes. Near-term solutions include getting more flexibility from existing resources and/or enhancing current market mechanisms. An enduring solution for flexibility will be investigated concurrently by the related stakeholder engagement and the IESO's Market Renewal initiative. IESO is procuring more regulation through an RFP.

Capacity Transfers

As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023.

Transmission

The purpose of the IESO's bulk transmission planning is to ensure that there is sufficient transfer capability across the major transmission interfaces in Ontario to reliably supply demand under a wide range of system conditions and to allow for the efficient operation of the IESO markets. Increased DERs and conservation over the last few years has reduced net demand and the amount of resources on-line that are providing dynamic VARs, which has changed the way the IESO carries out bulk planning. The purpose of the IESO's regional planning is to ensure that there continues to be a reliable supply of power to the local distribution companies that are connected to the IESO-controlled grid and to the transmission-connected customers. When developing regional plans, transmission options for addressing a reliability need are compared to local options such as conservation, DERs, and local generation. The lowest cost option that meets the local reliability need is typically recommended.



NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC sub region that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems.

[1] Values reported do not reflect an updated internal load forecast for the Quebec Area to be filed with the Quebec Energy Board in the first Progress Report of the Hydro-Québec Distribution 2017-2026 Supply Plan.

Highlights

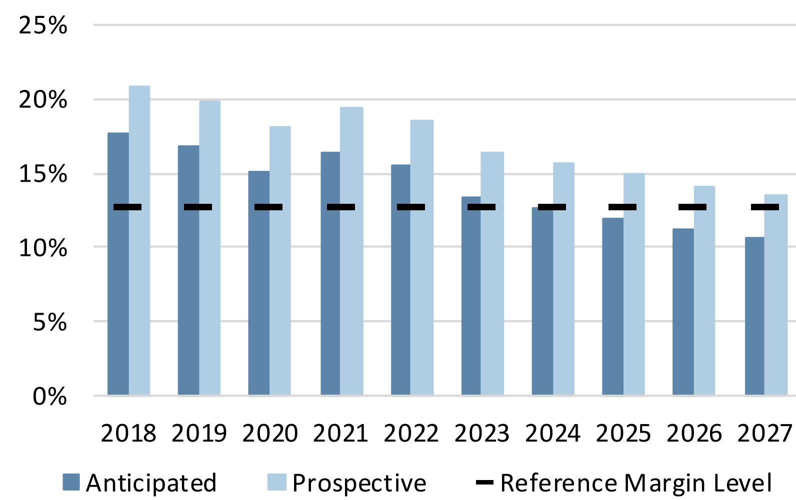
- Approximately 1,240 MW of capacity additions (including 712 MW from hydro) are expected over the assessment period.
- A total of 500 MW of firm import capacity are now available each winter until March 2023 due to a new electricity trade agreement between Québec and Ontario.
- Planning studies showed a need to reinforce the transmission system to meet Reliability standards, so the Chamouchouane to Montréal 735-kV Line is under construction to address those needs.

Demand, Resources, and Reserve Margins[1]

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	38,184	38,414	38,744	39,113	39,379	39,640	39,874	40,088	40,287	40,477
Demand Response	2,248	2,273	2,298	2,298	2,298	2,298	2,298	2,298	2,298	2,298
Net Internal Demand	35,936	36,141	36,446	36,815	37,081	37,342	37,576	37,790	37,989	38,179
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	42,299	42,210	41,942	42,838	42,838	42,338	42,338	42,322	42,258	42,258
Prospective	43,399	43,310	43,042	43,938	43,938	43,438	43,438	43,422	43,358	43,358
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	17.71	16.79	15.08	16.36	15.53	13.38	12.67	11.99	11.24	10.68
Prospective	20.77	19.83	18.10	19.35	18.49	16.32	15.60	14.90	14.13	13.56
Reference Margin Level	12.90	12.90	12.90	12.90	12.90	12.90	12.90	12.90	12.90	12.90

Existing On-Peak Generation (Winter)

Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	343	0.8
Hydro	39,957	95.4
Petroleum	436	1.0
Wind	1,146	2.7



Planning Reserve Margins

Planning Reserve Margins

The Anticipated Reserve Margin is below the Reference Margin Level for the last four winter seasons of the assessment period. Under this scenario, Québec has no firm imports and purchases from neighboring areas would be needed to maintain the Reference Margin Level. The Prospective Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period. Under the Prospective Scenario, a total of 1,100 MW of expected capacity imports are planned by the Québec area. These purchases have not yet been backed by firm long-term contracts. However, on a yearly basis, the Québec area proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements if needed.

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use/sector peak demands is the total monthly peak demand. The Québec area demand forecast average annual growth is 0.7 percent during the 10-year period, similar to last year's forecast.

Demand-Side Management

The Québec area has various types of demand response resources specifically designed for peak shaving during winter operating periods. The first type of demand response resource is the interruptible load program, mainly designed for large industrial customers, with an impact of 1,748 MW during the peak. The second type of demand response resource consists of a voltage reduction scheme with 250 MW of demand reduction at peak. The area is also developing some additional programs, including direct control load management. A recent program, consisting of mostly interruptible charges in commercial buildings, has substantial impacts with 250 MW in 2017–2018 and up to 300 MW by 2020–2021. Energy Efficiency will continue to grow over the entire assessment period and will be integrated in the demand forecasts, accounting for an average annual impact of 130 MW (at winter peak) over the assessment period.

Distributed Energy Resources (DERs)

Behind-the-meter generation (including solar photovoltaic) is negligible (less than 1 MW) and is accounted for in the load forecast.

Generation

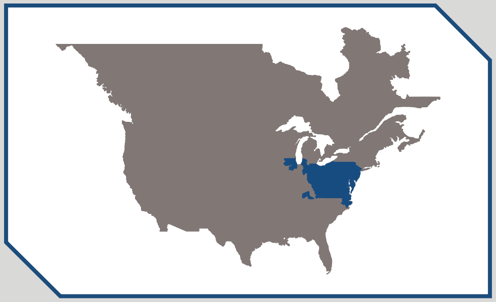
Work is under way on the La Romaine-3 (395 MW) development, which will be fully operational in 2017. Work has also begun on the La Romaine-4 (245 MW) development, which will be fully operational in 2020. The retrofitting of some hydro units should add 12 MW of capacity and the integration of small hydro units also accounts for 60 MW of new capacity during the assessment period. For other renewable resources, about 250 MW of wind capacity have been added to the system since the beginning of 2016, and an additional 414 MW of wind capacity and 110 MW of biomass are expected to be in-service by 2019.

Capacity Transfers

Since 2011, the Québec power transmission system has undergone significant changes: reduced consumption in the Côte-Nord area and decommissioning thermal and nuclear generating stations. These changes have brought about an increase to the power flow on the lines of the Manic-Québec corridor toward the major load centers and decreased the reliability of the transmission system. Hydro-Québec is thus required to take steps in order to restore adequate transmission capacity to the corridor and maintain system reliability. After considering a number of scenarios, Hydro-Québec believes that the best solution is to build a new 735-kV line extending some 250 km (155 miles) between Micoua substation in the Côte-Nord region and Saguenay substation in Saguenay-Lac-Saint-Jean; the project also includes adding equipment to both substations and expanding Saguenay substation. Commissioning of the new equipment is planned in 2022.

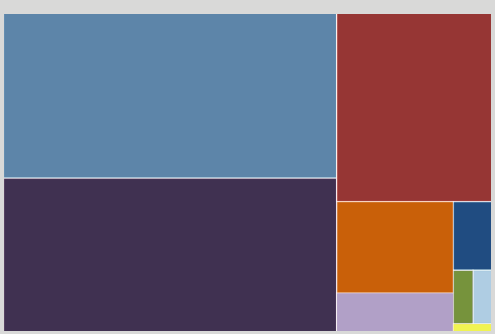
Transmission

Construction the Romaine River Hydro Complex project is presently underway. Romaine-3 (395 MW) will be integrated in 2017 and Romaine-4 (245 MW) in 2020, both at the Montagnais 735/315-kV substation. The Chamouchouane to Montréal 735-kV Line is under construction and addresses concerns from planning studies that show a need to reinforce the transmission system to meet Reliability Standards. It is scheduled to be in-service before the 2018–2019 winter.



PJM

PJM Interconnection is a regional transmission organization (RTO) 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. PJM serves 61 million people and covers 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.



Highlights

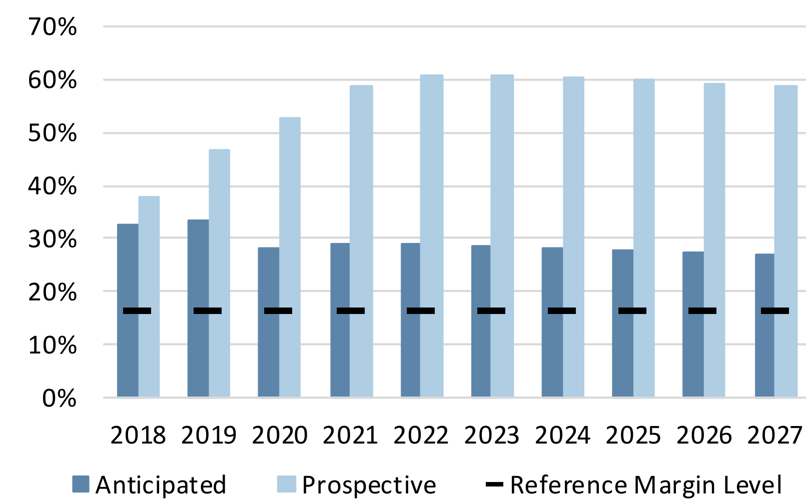
- Anticipated Reserve Margins will remain above the Reference Margin Level (Installed Reserve Margin requirement) throughout the assessment period.
- Demand continues to flatten as load efficiency increases and more rooftop solar installations are added.
- PJM continues to manage an unprecedented generating capacity fuel shift from coal to natural gas.

Demand, Resources, and Reserve Margins

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	153,951	154,278	153,684	153,384	153,425	153,722	154,142	154,572	155,148	155,773
Demand Response	9,187	9,204	6,177	6,169	6,169	6,174	6,187	6,204	6,224	6,237
Net Internal Demand	144,764	145,074	147,507	147,215	147,256	147,548	147,955	148,368	148,924	149,536
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	191,765	193,572	188,818	189,741	189,741	189,741	189,741	189,741	189,741	189,741
Prospective	199,773	212,834	224,970	233,356	236,601	237,105	237,105	237,105	237,105	237,105
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	32.47	33.43	28.01	28.89	28.85	28.60	28.24	27.89	27.41	26.89
Prospective	38.00	46.71	52.51	58.51	60.67	60.70	60.25	59.81	59.21	58.56
Reference Margin Level	16.70	16.60	16.60	16.60	16.60	16.60	16.60	16.60	16.60	16.60

Existing On-Peak Generation (Summer)

Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	1,234	0.7
Coal	59,311	32.9
Hydro	3,141	1.7
Natural Gas	63,629	35.3
Nuclear	33,992	18.8
Petroleum	12,352	6.8
Pumped Storage	5,233	2.9
Solar	366	0.2
Wind	1,213	0.7



Planning Reserve Margins

Planning Reserve Margins

The Installed Reserve Margin (applied as the Reference Margin Level) for the delivery year beginning on June 1, 2018, is 16.7 percent and drops to 16.6 percent for the 2019 delivery year and beyond.

Demand

The PJM Interconnection produces an independent peak load demand forecast by using econometric regression models with daily load as the dependent variable and independent variables, including calendar effects, weather, economics, and end-use characteristics. Daily unrestricted peak load is defined as metered load plus estimated load drops and estimated distributed solar generation. No reliability problems are anticipated due to the overall 0.2 percent summer load growth.

Demand-Side Management

Demand-side management providers have the ability to participate in the PJM Reliability Pricing Model (RPM) Auctions up to three years in advance of the Delivery Year (PJM delivery year (DY) is June–May). DSM Providers may register demand response locations in DRHUB to meet their RPM commitments starting January of the year in which the new DY starts. For the DY 2016/2017, DSM Providers offering demand response resources into RPM have an overall RPM commitment of 8,336 MW of load reductions. Demand response registrations participating in the capacity market are to respond according to real-time emergency procedures if called upon.

Distributed Energy Resources (DERs)

Recognizing the growing market of solar installations, PJM began to investigate and develop a plan in early 2015 to incorporate distributed solar generation into the long-term load forecast. Environmental Information Services (EIS), a wholly owned subsidiary of PJM Technologies, Inc., which is a subsidiary of PJM Interconnection, operates the Generation Attribute Tracking System (GATS). The generation data that GATS collects includes distributed solar generation that is behind-the-meter. Utilizing this collection of data, PJM estimates the amount of distributed solar generation in terms of direct current nameplate capacity. In the last five years, there has been over a 1,000 percent increase of installations in the PJM Region, and the number of installations is expected to continue to grow with a nameplate value of over 11,700 MW in 2027.

Generation

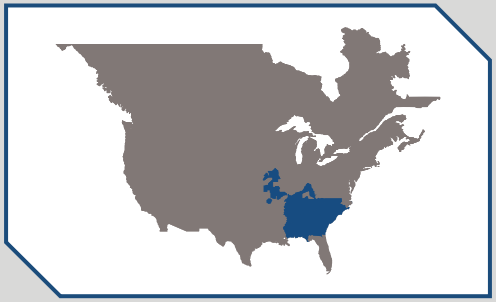
PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics: new generating plants powered by Marcellus and Utica shale natural gas, new wind and solar units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by demand resources and energy efficiency programs. Natural-gas-fired generation capacity now exceeds coal in PJM. Natural gas plants total over 65,600 MW and comprise 86 percent of the generation currently seeking capacity interconnection rights in PJM's new generation queue. As for coal, if formally submitted deactivation plans materialize, more than 25,000 MW 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. To offset lower solar generation during winter peak periods, PJM will allow higher (if historically proven) wind capacity factors.

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer into PJM would amount to less than two percent of PJM's internal generation capability. At no time within this assessment period do PJM's anticipated transfers amount to anywhere near two percent.

Transmission

PJM's Regional Transmission Expansion Plan (RTEP) process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. Doing so gives PJM the ability to identify one optimal, comprehensive set of solutions to resolve reliability criteria violations, operational performance issues, and congestion constraints. Specific system enhancements are justified to meet local reliability requirements and deliver needed power to more distant load centers. Once the PJM Board approves the recommended system enhancements, new facilities, and upgrades to existing ones, they formally become part of PJM's overall RTEP.



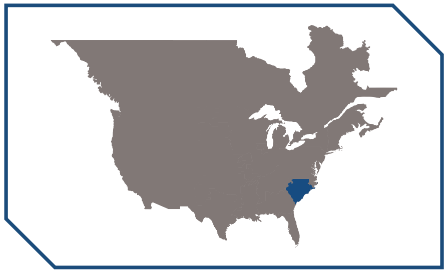
SERC

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into three assessment areas: SERC-E, SERC-N, and SERC-SE. The SERC Region includes 11 Balancing Authorities: Alcoa Power Generating, Inc.–Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas and Duke Energy Progress (Duke), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (Santee Cooper, SCPSA), Southern Company Services, Inc. (Southern), and Tennessee Valley Authority (TVA).

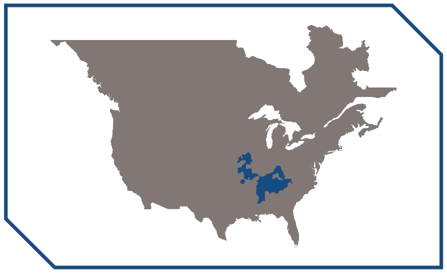
Highlights

- The canceled expansion of the V.C. Summer nuclear plant (approximately 2,200 MW) in SERC-E result in both Anticipated and Prospective Reserve Margins falling below the Reference Margin Level in 2020 and declining for the remainder of the assessment period.
- Studies are underway to address some entities in SERC experiencing effects from utility-scale and distributed solar.
- SERC is working to increase the reporting accuracy of distributed energy resources by addressing reporting gaps stemming from NERC's 80 MW threshold registration requirements for Generator Owners.

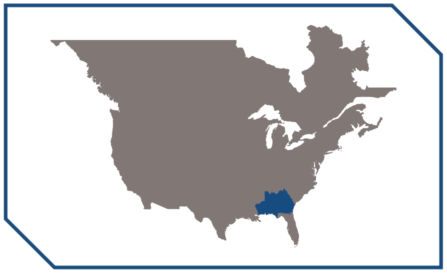
Starting on the next page are summaries of the assessment areas that make up SERC.



SERC-E

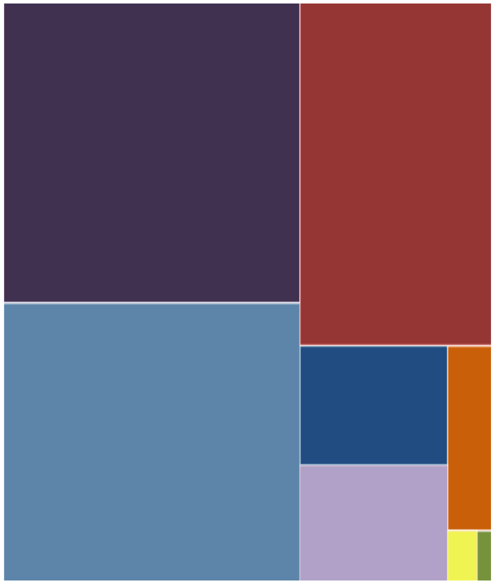


SERC-N

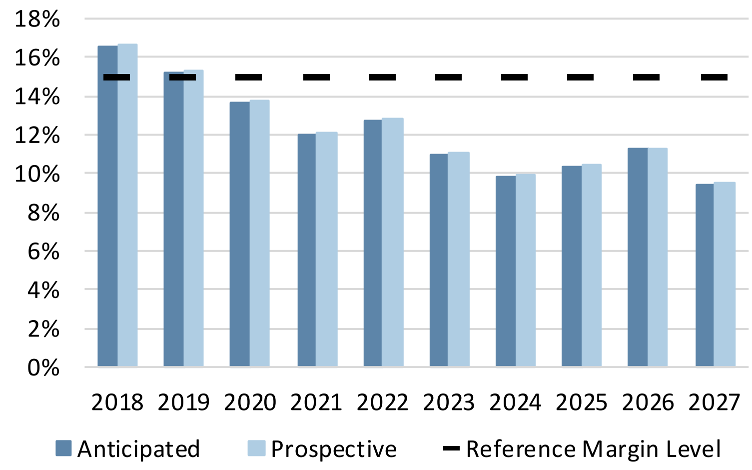


SERC-SE

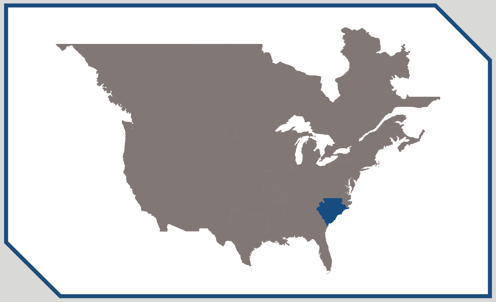
SERC-E Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	44,967	45,467	46,071	46,827	47,444	48,145	48,847	49,669	50,316	50,966
Demand Response	1,387	1,418	1,445	1,461	1,469	1,471	1,473	1,475	1,479	1,481
Net Internal Demand	43,580	44,049	44,626	45,366	45,975	46,674	47,374	48,194	48,837	49,485
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	50,782	50,752	50,728	50,805	51,844	51,811	52,015	53,166	54,319	54,143
Prospective	50,824	50,794	50,770	50,847	51,886	51,853	52,057	53,208	54,361	54,185
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	16.53	15.22	13.67	11.99	12.76	11.01	9.80	10.32	11.23	9.41
Prospective	16.62	15.31	13.77	12.08	12.86	11.10	9.89	10.40	11.31	9.50
Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00



SERC-E Existing On-Peak Generation (Summer)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Biomass	135	0.3
Coal	15,794	31.5
Hydro	3,137	6.3
Natural Gas	14,650	29.2
Nuclear	11,690	23.3
Petroleum	1,459	2.9
Pumped Storage	3,044	6.1
Solar	266	0.5

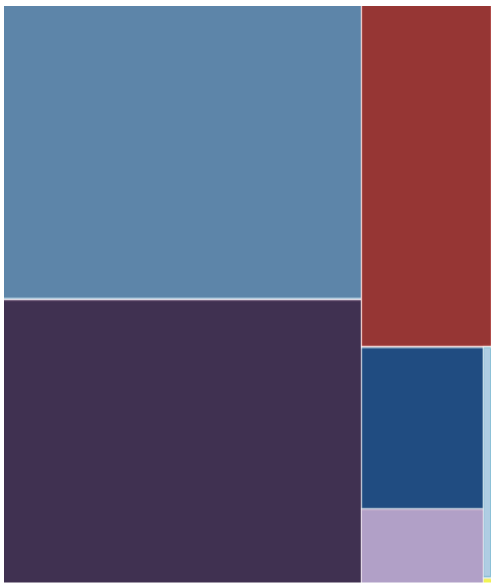


SERC-E Planning Reserve Margins

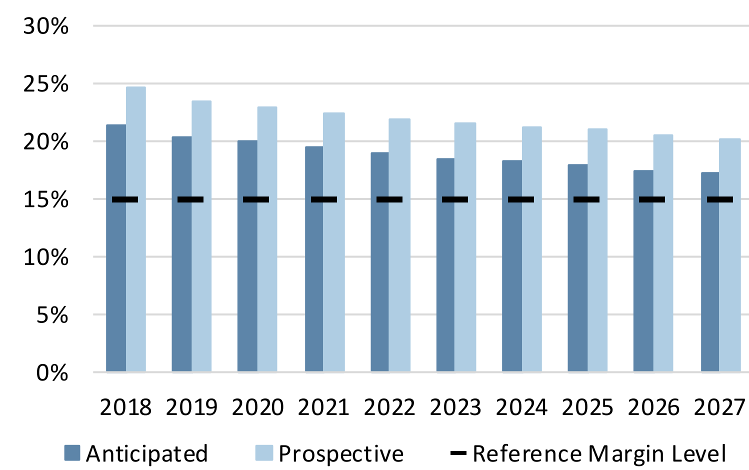


SERC-E

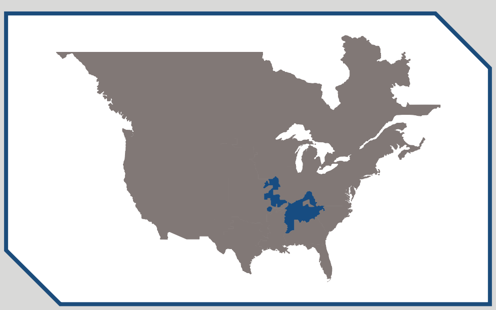
SERC-N Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	42,208	42,861	42,992	43,055	43,152	43,259	43,301	43,381	43,571	43,673
Demand Response	1,719	1,728	1,728	1,609	1,537	1,480	1,444	1,441	1,441	1,441
Net Internal Demand	40,489	41,133	41,264	41,446	41,615	41,779	41,857	41,940	42,130	42,232
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	49,172	49,488	49,488	49,488	49,488	49,488	49,488	49,488	49,488	49,488
Prospective	50,432	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748	50,748
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	21.45	20.31	19.93	19.40	18.92	18.45	18.23	18.00	17.47	17.18
Prospective	24.56	23.38	22.98	22.44	21.95	21.47	21.24	21.00	20.46	20.17
Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00



SERC-N Existing On-Peak Generation (Summer)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Coal	18,150	36.2
Hydro	3,522	7.0
Natural Gas	18,800	37.5
Nuclear	7,912	15.8
Pumped Storage	1,616	3.2
Solar	8	0.0
Wind	67	0.1

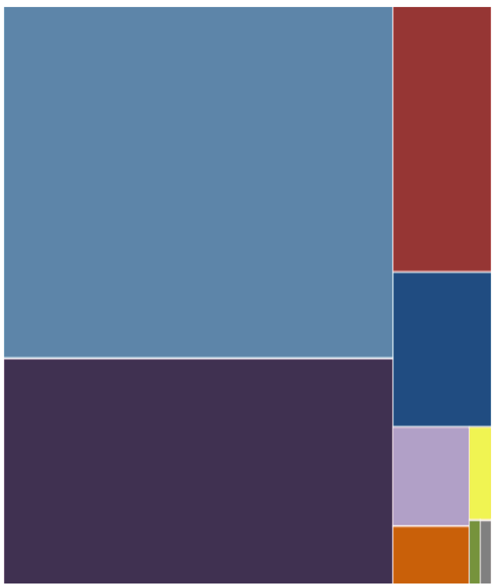


SERC-N Planning Reserve Margins

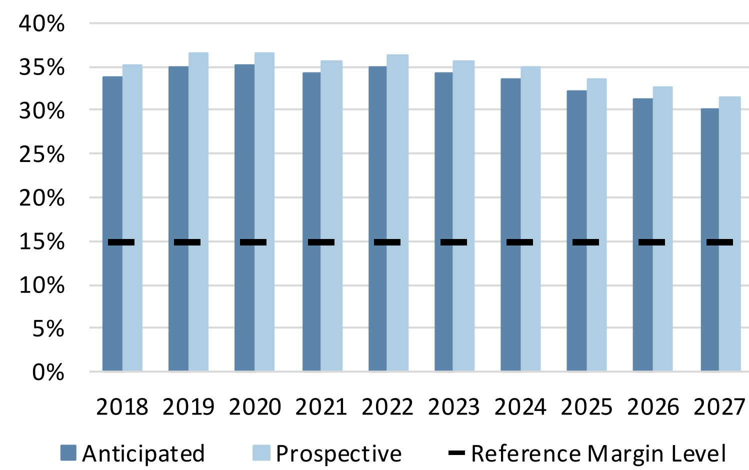


SERC-N

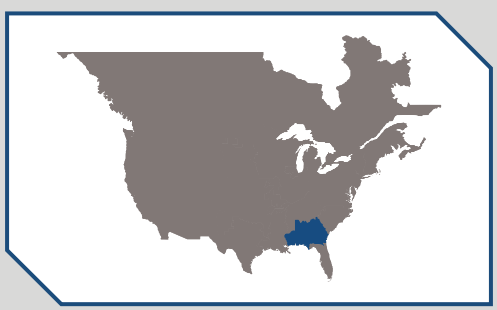
SERC-SE Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	46,453	46,801	47,505	47,843	48,188	48,545	48,789	49,269	49,720	50,232
Demand Response	2,171	2,172	2,172	2,172	2,174	2,174	2,174	2,174	2,176	2,176
Net Internal Demand	44,282	44,629	45,333	45,671	46,014	46,371	46,615	47,095	47,544	48,056
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	59,213	60,243	61,269	61,300	62,073	62,209	62,231	62,255	62,425	62,537
Prospective	59,861	60,891	61,917	61,948	62,721	62,857	62,879	62,903	63,073	63,185
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	33.72	34.99	35.15	34.22	34.90	34.16	33.50	32.19	31.30	30.13
Prospective	35.18	36.44	36.58	35.64	36.31	35.55	34.89	33.57	32.66	31.48
Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00



SERC-SE Existing On-Peak Generation (Summer)		
Generation Type	**Peak Season Capacity**	
	MW	**Perent**
Biomass	154	0.2
Coal	18,979	30.8
Hydro	3,288	5.3
Natural Gas	30,263	49.1
Nuclear	5,818	9.4
Other	153	0.2
Petroleum	961	1.6
Pumped Storage	1,632	2.6
Solar	444	0.7



SERC-SE Planning Reserve Margins



SERC-SE

Planning Reserve Margins—SERC

SERC-E: Members ensure that reserve margins are maintained through use of their own generation and firm-purchased power contracts. Members maintain reserves adequate to cover unexpected events, such as adverse weather conditions, unexpected demand, or an unplanned loss of generation or transmission facilities.

SERC-N: All entities within the SERC-N Region have a sufficient amount of anticipated Reserve Margin levels that do not drop below the Reference Margin Level.

SERC-SE: Current projections for the SERC-SE assessment area show reserve margins in excess of 15 percent throughout the long-term planning horizon.

Demand—SERC

The total internal demand projections are based on average historical weather and are the sum of noncoincident forecast data reported by utilities during respective peak seasons. The entities incorporate the projected EE into the demand forecast and reflect it in the reserve margin projections. The entities also adjust assumptions for both normal weather and current economic conditions for both the U.S. and regional economies. Utilities constantly monitor for transitions in the economy to determine if they need to revise near-term hourly forecast models or adjust the long-term models. The forecasted compound annual growth rate for peak demand in SERC

Demand-Side Management—SERC

The SERC Region has demand response programs that utilize different variations of demand response (DR). The categories of the different variations are as follows: summer load control, reserve preservation, or 5-minute, 60-minute, instantaneous response. During the year, testing of load control programs is performed for operational functionality in addition to load profile analysis to determine performance and verification of demand reduction implementation.

SERC E members have existing portfolios of DR and EE offerings for both residential and nonresidential customers, most of which provide resources during both summer and winter peak periods. The growth of existing programs and introduction of new programs shift to accommodate the needs of the season. For example, as SERC E moves from summer peaking to winter peaking, the focus will shift to maximizing winter capabilities. Recent small business HVAC load control programs with combined DR and EE measures align with this objective. The May 2016 removal of a provision in EPA regulations that allowed generators with emergency classification to be used for demand response led to a significant reduction in enterprise commercial and industrial DR programs; however, SERC anticipates no near-term changes to policy or program rules that would limit the current availability or forecasted growth of DSM programs in the Region.

Distributed Energy Resources (DERs)—SERC

Most of the DER growth in the Region has been solar. The DERs will have little to no impact on winter peak demand reduction and only a small impact on summer peak demand. SERC-E members are continuing to collect data on the impact of solar DERs in the Region and will incorporate the results into the models. The SERC VERWG is assessing solar penetrations within the Region. Currently no major impacts have been identified. For the majority of the SERC-N area, DERs are accounted for in the load forecast (behind-the-meter) or through programs that are in front of the meter and evaluated like a resource. There have been no changes to this methodology since the *2016 LTRA*.

Generation—SERC

The data reported in 2017 by SERC entities indicates that demand growth over the next ten years will be served through a combination of capacity purchases and new nuclear, natural gas, and combined-cycle units. The Westinghouse bankruptcy creates uncertainty throughout the ERO regarding the future of nuclear additions. Although the V.C. Summer facility, which accounts for 2,200 MW of future generation, is no longer viable, the affected entity plans to replace the 2,200 MW with a combination of generation from alternate fuel types and energy purchases. Other entities within the Region are continuing with plans for nuclear or combined-cycle base-load generation during the planning horizon. SERC anticipates that the loss of approximately 2,030 MW in coal-fired capacity by 2026 will be offset by anticipated nuclear and natural gas generation additions.

Natural Gas currently accounts for 41 percent of net operable capacity. Coal and nuclear generation combined account for 48 percent. Hydro, renewables, and other fuel types account for the remaining 11 percent.

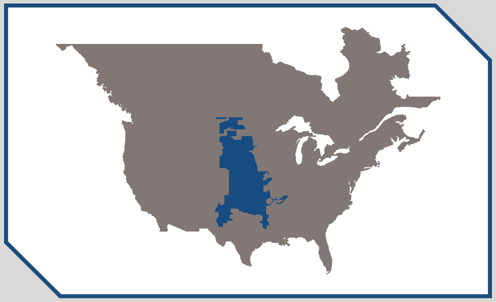
Many long-term capacity additions, including nuclear additions that were previously reported as conceptual, are now reported as future planned in accordance with the NERC reporting definitions. Older and smaller coal-fired generation facilities continue to be evaluated for fuel conversion or retirement for various reasons, including the passage of stricter environmental laws.

Recent increases in variable energy resource (VER) additions, coupled with the challenges associated with rapidly changing inverter-based technologies, has resulted in the need to explore the potential reliability considerations related to VER integration in the SERC Region; as such, the SERC EC formed the VER Task Force (VERTF) in 2016 to identify and assess these considerations and make a recommendation on the need for ongoing focus and communication on these and future issues (as identified). Upon recommendation from the VERTF, the VER working group (VERWG) was formed in 2017.

Transmission—SERC

SERC entities coordinate transmission expansion plans in the Region annually through joint model-building efforts that include the plans of all SERC entities. The coordination of transmission expansion plans with entities outside the Region is achieved through annual participation in joint modeling efforts with the ERAG Multi-regional Modeling Working Group (MMWG). Transmission expansion plans by most SERC entities are dependent on regulatory support at the federal, state, and local levels since the regulatory entities can influence the siting, permitting, and cost recovery of new transmission facilities.

NERC registered entities in the SERC Region are committed to planning for a reliable delivery system. Transmission upgrades and the installation of new facilities will be necessary to ensure compliance with national and local standards, improve both intraregional and interregional transfer capabilities, relieve congestion, and ensure generation deliverability. SERC and SERC's registered entities will continue to assess transmission development and monitor the implications to current and future reliability.



SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 575,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. The SPP Long-Term Assessment is reported based on the Planning Coordinator footprint, which touches parts of the Southwest Power Pool Regional Entity, Midwest Reliability Organization Regional Entity, and Western Electricity Coordinating Council. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of 18 million people.

Highlights

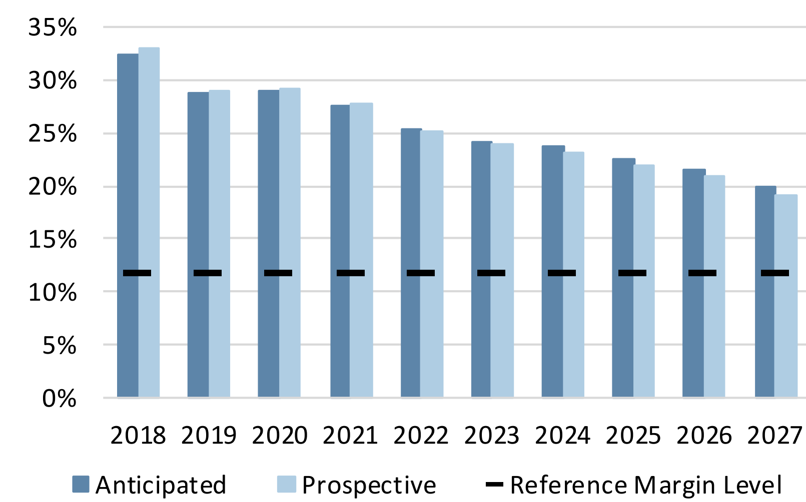
- Installed wind generation capacity increased in 2016 alone by more than 30 percent, up 4,000 MW from 12 GW to more than 16 GW. SPP's maximum simultaneous wind generation peak rose from 9,948 MW in 2015 to 13,342 MW in 2017. Also, wind penetration, the amount of total load served by wind at a given time, has increased from a 38 percent peak in 2015 to 54.4 percent in 2017.
- As renewable resources are added to the system, SPP will eventually reach a point at which it can no longer reliably utilize this generation for SPP's own internal demand needs even with additional transmission infrastructure. At that point, those future renewables will have to be delivered to other Regions.
- SPP has developed a model (scenario 5 (S5)) to analyze the growing wind generation in the RTO. The model maximizes all applicable, confirmed, long-term firm transmission service with its necessary generation dispatch. The S5 model analyzes and emphasizes higher wind transfers and will be used to identify reliability issues in the RTO for near-term planning.

Demand, Resources, and Reserve Margins

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	52,554	53,319	53,361	53,643	53,981	54,179	54,409	54,729	54,929	55,250
Demand Response	867	897	886	868	866	868	872	877	881	885
Net Internal Demand	51,687	52,422	52,476	52,774	53,116	53,311	53,537	53,853	54,049	54,365
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	68,447	67,507	67,642	67,332	66,608	66,217	66,227	66,013	65,649	65,157
Prospective	68,714	67,618	67,754	67,444	66,428	66,037	65,884	65,670	65,307	64,773
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	32.43	28.78	28.90	27.59	25.40	24.21	23.70	22.58	21.46	19.85
Prospective	32.94	28.99	29.11	27.80	25.06	23.87	23.06	21.94	20.83	19.14
Reference Margin Level	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

Existing On-Peak Generation (Summer)

Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	39	0.1
Coal	24,267	35.4
Hydro	4,770	7.0
Natural Gas	33,340	48.6
Nuclear	1,938	2.8
Other	52	0.1
Petroleum	1,656	2.4
Pumped Storage	482	0.7
Solar	197	0.3
Wind	1,878	2.7



Planning Reserve Margins

Planning Reserve Margins

The Anticipated Reserve Margin does not fall below the Reference Margin Level for the SPP assessment area. The SPP assessment area PRM requirement for the 2017 summer is 12 percent, unless a members capacity mix is comprised of at least 75 percent hydro-based generation, then the Planning Reserve Margin is 9.89 percent.

Demand

The SPP assessment area forecasts the noncoincident Total Internal Demand to peak at 51,093 MW during the 2017 summer season, which is an increase of approximately 300 MWs from the *2016 LTRA* forecast. The SPP assessment area forecasts the noncoincident annual peak growth, over the 10-year forecast, at an average annual rate of approximately 1 percent.

Demand-Side Management

The SPP assessment area's energy efficiency and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in energy efficiency and demand response across the assessment area. The SPP assessment area forecasts the noncoincident summer peak growth at an average annual rate of 1 percent.

Distributed Energy Resources (DERs)

SPP currently has approximately 250 MW of installed solar. There is approximately 7,800 MW's of solar projects in the Generation Interconnection queue, but only 170 have Interconnection Agreements in place. SPP Model Development, Economic Studies, and the Supply Adequacy working groups are currently developing policies and procedures around DERs.

Generation

Confirmed retirements in SPP amount to 1,145 MW of natural gas, 896 MW of coal, and 4 MW of Wind. There are no known reliability impacts at this time, but the results of the retirements (expected to be replaced with renewable resources) and the resource adequacy impacts will be studied in the 2017 LOLE study, expected in late 2017 or early 2018.

Capacity Transfers

The SPP assessment area members forecasted net firm capacity transactions of -86 MWs in 2017 to -412 MWs in 2027; all of these capacity transactions have firm transmission service. Resource mix changes are not expected to impact capacity transfers.

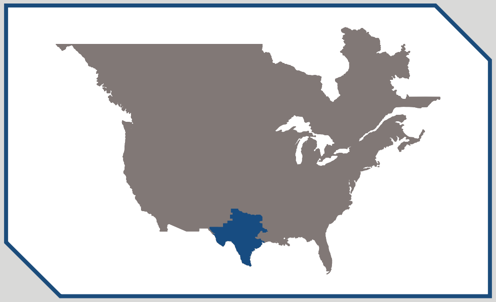
Transmission

The SPP assessment area's Board of Directors approved the 2017 Integrated Transmission Plan 10-Year Assessment Report and the 2017 Integrated Transmission Planning Near-Term Assessment. Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users.

The Integrated Transmission Planning (ITP) process is Southwest Power Pool's iterative 3-year study process that includes 20-Year, 10-Year and Near Term Assessments.

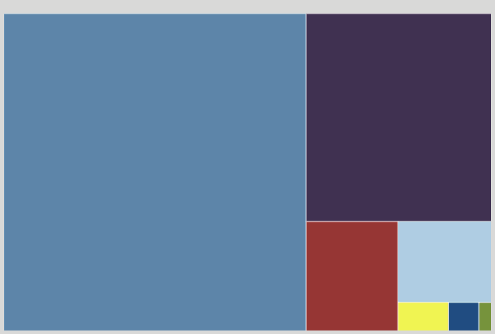
- The 20-Year Assessment identifies transmission projects, generally above 300 kV, needed to provide a grid flexible enough to provide benefits to the Region across multiple scenarios.
- The 10-Year Assessment (ITP10) focuses on facilities 100 kV and above to meet system needs over a 10-year horizon.
- The ITP Near-Term assessment is performed annually and assesses system upgrades, at all applicable voltage levels, required in the near-term planning horizon to address reliability needs.

Along with the Highway/Byway cost allocation methodology, the ITP process promotes transmission investment that will meet reliability, economic, and public policy needs intended to create a cost-effective, flexible, and robust transmission network that will improve access to the Region's diverse generating resources. This report documents the ITP Near-Term (ITPNT) assessment that concluded in April 2017.



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects 40,530 miles of transmission lines, and 566 generation units, and serves 23 million customers. The Texas Reliability Entity (Texas RE) is responsible for the RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.



Highlights

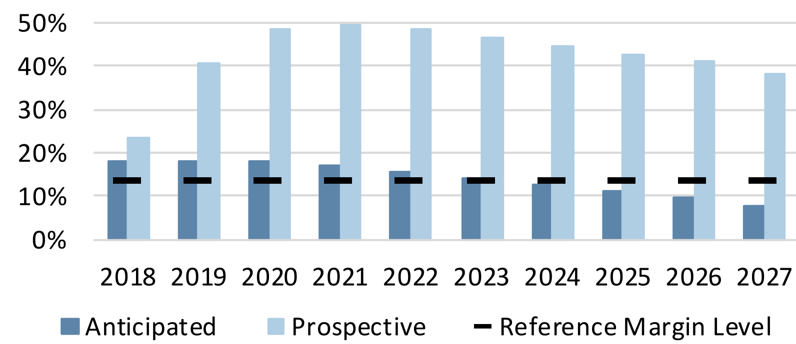
- Anticipated Reserve Margins remains above the 13.75 percent Reference Margin Level until 2024.
- Between September and October 2017, ERCOT received notice from Generator Owners of seven coal units and a single gas-steam unit with plans to take units out of service between December 2017 and February 2018. Submitted retirements totaling 4,600 MW were approved by ERCOT between October and November 2017.
- Texas RE-ERCOT plans to add or upgrade approximately 3,600 MW of 138-kV and 345-kV transmission circuits during the assessment period.
- To address the increasing share of wind and solar generation, ERCOT established a new control room and a renewable reliability risk desk that are focused on reducing forecasting errors and improving the monitoring and real-time analysis of net load ramps, low inertia conditions, and variable ancillary service needs.
- Hurricane/Tropical Storm Harvey is not expected to materially impact system reliability or ERCOT market operations in 2018 and beyond. ERCOT is currently coordinating with transmission providers on their remaining restoration efforts in the affected areas along the southeast coast and in the Houston area.

Demand, Resources, and Reserve Margins

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Internal Demand	74,149	75,588	76,510	77,417	78,377	79,348	80,315	81,261	82,286	83,931
Demand Response	3,137	3,137	3,137	3,137	3,137	3,137	3,137	3,137	3,137	3,137
Net Internal Demand	71,012	72,451	73,373	74,280	75,240	76,211	77,178	78,124	79,149	80,794
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	83,953	85,539	86,564	86,952	86,902	86,902	86,902	86,902	86,902	86,902
Prospective	87,729	101,798	109,087	111,174	111,924	111,557	111,557	111,557	111,557	111,557
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	18.22	18.06	17.98	17.06	15.50	14.03	12.60	11.24	9.80	7.56
Prospective	23.54	40.51	48.67	49.67	48.76	46.38	44.54	42.80	40.95	38.07
Reference Margin Level	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75

Existing On-Peak Generation (Summer)

Generation Type	Peak Season Capacity MW	Peak Season Capacity Percent
Biomass	199	0.3
Coal	19,209	25
Hydro	439	0.6
Natural Gas	47,547	61.8
Nuclear	4,981	6.5
Solar	720	0.9
Wind	3,783	4.9



Planning Reserve Margins

Planning Reserve Margins

The Anticipated Reserve Margin falls below the Reference Margin Level by the summer of 2024. Project developers typically submit interconnection requests to ERCOT no more than three to four years before the facility is expected to enter commercial operations. As a result, the Texas RE-ERCOT Region will always show a flat level of capacity additions and typically declining reserve margins starting four to five years into the LTRA forecast period. This is not indicative of a future resource adequacy problem, but rather that ERCOT does not receive resource planning information from project developers sufficient to develop a long-term resource expansion forecast.

Demand

ERCOT's current peak load forecast (developed in fall 2016) is higher than the *2016 LTRA* forecast primarily due to a projected increase in economic growth driven oil and natural gas exploration, a Gulf Coast petrochemical plant expansion, and overall stronger employment outlook over the forecast horizon. Demand growth in the Coastal zone is significantly above ERCOT's average growth due to the expected addition of LNG plant and petrochemical industry loads over the next five years. The forecast also shows continued strong load growth in the South and Far West weather zones primarily due to oil and natural gas production. The Coastal and Far West annual average peak demand growth rates are forecasted to grow at 2 percent and 2.1 percent respectively from 2017-2022.

Demand-Side Management (DSM)

DSM forecasted for 2018 comes from dispatchable resources in the form of noncontrollable load resources providing responsive reserve service[1] (1,191 MW), emergency response service (1,743 MW), and load management programs administered by transmission/distribution service providers (203 MW).[2] ERCOT also assumes that these DSM amounts remain constant thereafter. ERCOT develops its own energy efficiency forecast using annual reports of verified incremental peak load impacts from the Public Utility Commission of Texas and Texas State Energy Conservation Office.[3]

Distributed Energy Resources (DERs)

Installed solar DER capacity forecasted for the five-year horizon (ending 2022) is 322 MW. Based on current capacity growth and market trends, ERCOT believes that DERs do not pose near-term reliability issues for the grid. Nevertheless, it intends to prepare for a future scenario in which a larger share of the regional generation mix may come from the distribution system. Recommended actions involve mapping all existing registered DERs (>1 MW) to the Common Information Model at their load points. Once in the model, the DG locations will be known to ERCOT operators, improving situational awareness and allowing for incorporating into power flow, state estimator, and load forecast programs. The schedule for this DER mapping project has not been determined; however, ERCOT and Texas RE have met to review DER-related challenges and propose actions to verify these resources meet requirements for maintaining system reliability.

[1] This value reflects a 95 percent confidence level based on historical data for the hours 1500 through 1800 during the months of June through September over the last three years. The hourly participation is capped at 50 percent of the system-wide obligation for Responsive Reserve Service where the system-wide obligation can range from 2,300 MW to 2,800 MW.

[2] Includes a two percent gross-up adjustment for avoided transmission line losses.

[3] Verified impacts are derived through an Evaluation, Measurement & Verification (EM&V) framework approved by the PUCT. The statutory EM&V framework is outlined in the Commission's Substantive Rule 25.181, available at https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.181/25.181.pdf, subsection (q). The verified savings are estimated by a third-party contractor selected by the PUCT. Information on the EM&V program, including the associated Technical Reference Manual, is available at http://www.texasefficiency.com/index.php/emv. Growth trends in the annual verified MW amounts are used to develop the forecast. A 2017 change to the forecast methodology is to incorporate energy efficiency estimates from municipal and cooperative utilities reported to the Texas State Energy Conservation Office. This resulted in a significantly higher energy efficiency impact level for the *2017 LTRA*.

Generation

There are a number of challenges that ERCOT is addressing with respect to increasing amounts of wind and solar generation on the ERCOT grid. In particular, improved accuracy of wind/solar forecasting and dynamic consideration of the reliability risks that wind and solar introduce is becoming more important. To address these challenges, ERCOT completed implementation of its new control room renewable reliability risk desk, which went live in January 2017. This reliability risk desk is focused on reducing wind and solar forecast errors and improving monitoring and real-time analysis of net load ramps, low inertia conditions, and variable ancillary service needs. ERCOT continues to develop new software tools and data collection systems to support these risk mitigation objectives. In addition to implementing the new risk desk and supporting tools and procedures, ERCOT is working with wind facility owners to address wind forecasting problems caused by icing and extreme cold weather. Better communications (telemetry updates and control room notifications) regarding icing and extreme weather events are being fostered.

There have been 4 unit retirements since the release of the *2016 LTRA*, totaling 128 nameplate MW. A total of 3 of the units were old gas-fired steam turbine units at the same plant (Pearsall Plant) while the fourth was a biomass (wood waste) unit whose operations were no longer deemed economic by the unit's owner.[4] ERCOT developed an environmental regulation scenario to support development of ERCOT's 2016 Regional Transmission Plan. Assumptions about generation retirements were developed based on the requirements of the Texas Regional Haze Federal Implementation Plan and other pending environmental regulations, resulting in approximately 6 GW of generation retirements by 2021. The study results indicated the retirement of the resources would have significant impacts on the ERCOT grid, resulting in exceedances of thermal limitations, primarily on the transmission system serving the load in the Dallas-Fort Worth area. A significant amount of transmission system improvements would likely be required to ensure transmission system reliability criteria are met even if a moderate amount of new resources assumed for the study were to be displaced around the Region. The actual extent and timing of any coal unit retirements remains uncertain at this time.

Between September and October 2017, ERCOT received notice from Generator Owners of seven coal units and a single gas-steam unit with plans to take units out of service between December 2017 and February 2018. Submitted retirements included 4,600 MW and the following units: Barney M. Davis Unit 1, Monticello Units 1–3, Big Brown 1 and 2, and Sandow 4–5. Between October and November 2017, ERCOT determined that these units are not needed for grid reliability and approved all seven retirement requests. Due to the late timing of the announcements, these planned retirements, as well as other recent resource updates, are not reflected in the 2017 LTRA Reference Case Reserve Margins. These unit retirements will reduce the Summer 2018 Anticipated Reserve Margin by 6.5 percentage points, effectively decreasing it from 18.22 percent to 11.76 percent, below the Reference Margin Level of 13.75 percent. This reserve margin reduction does not account for any other resource updates, including replacement capacity that may be added in response to the announced retirements.

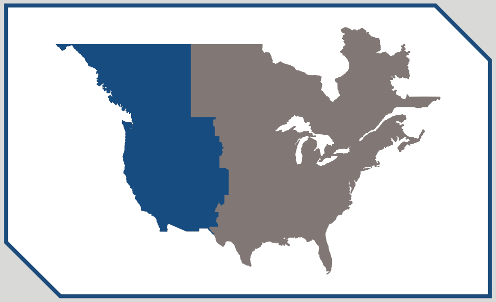
Capacity Transfers

Due to the small impact of dc tie imports to the Texas RE-ERCOT assessment area, there are no severe scenarios investigated for ERCOT's transmission planning studies.

Transmission

The recently updated ERCOT future transmission projects list includes the additions or upgrades of 3,580 miles of 138 kV and 345 kV transmission circuits, 23,904 MVA of 345/138 kV autotransformer capacity, and 3,706 MVar of reactive capability projects that are planned in the Texas RE-ERCOT assessment area between 2017 and 2025.

[4] When a unit owner decides to retire a generating unit, they must submit a Notice of Suspended Operations no less than 90 days prior to the planned retirement date. ERCOT has 60 days to complete a reliability impact study and make a final determination regarding whether the unit is required to support system reliability. Confirmed retirements comprise only those units for which ERCOT has determined that the unit is not needed to support system reliability.



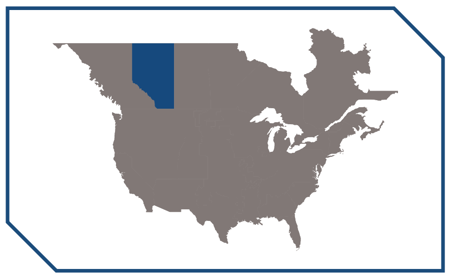
WECC

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 82.2 million people, it is geographically the largest and most diverse of the NERC Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into five subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the NW-Canada and NW-US areas. These subregional divisions are used for this assessment, as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

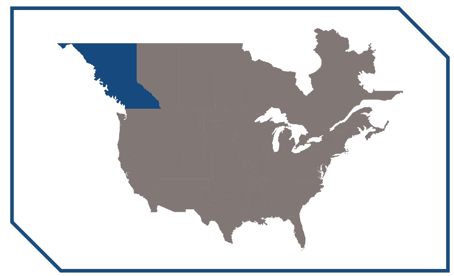
Highlights

- Load-serving entities in the Western Interconnection are forecasted to add over 9,000 MW of solar nameplate capacity and over 5,000 MW of wind nameplate capacity during the assessment period. In addition, over 12,500 MW (nameplate) of rooftop solar is forecasted to be installed over the next decade.
- WECC is funding a study of the impacts to reliability associated with the interdependence of the natural gas and electric systems. This study is expected to be completed in early-2018.
- The Los Angeles Basin in southern California continues to be an area of short-term concern due to the reduced availability of the Aliso Canyon natural gas storage facility. WECC has studied, and continues to study, the potential impacts to reliability for the Western Interconnection associated with the limited availability of Aliso Canyon natural gas storage facility.
- Three 55 MW oil-fired units in CAISO (WECC-CAMX assessment area) 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.

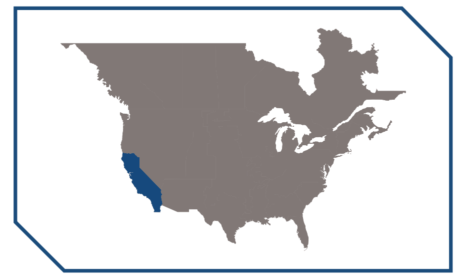
Starting on the next page are summaries of the assessment areas that make up WECC.



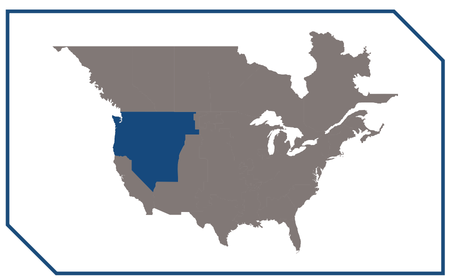
WECC-AB



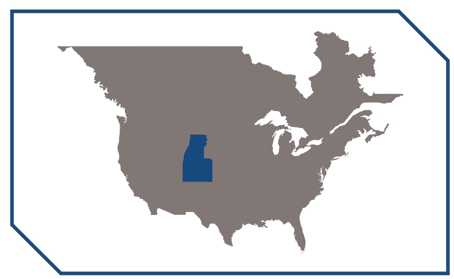
WECC-BC



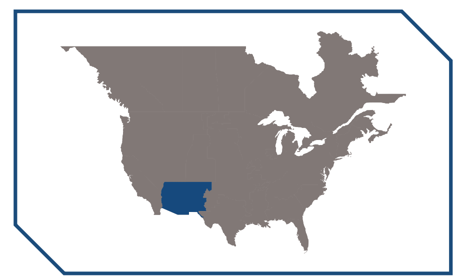
WECC-CAMX



WECC-NWPP-US



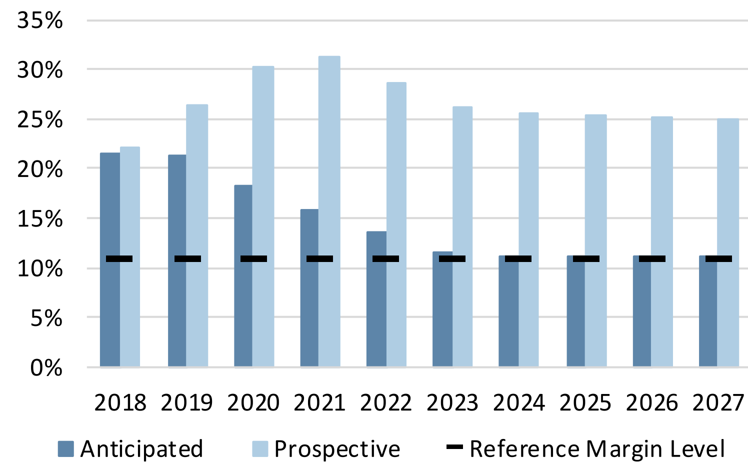
WECC-RMRG



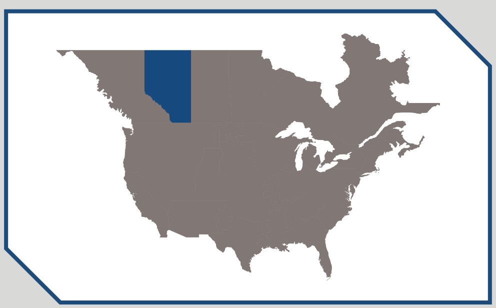
WECC-SRSG

WECC-AB Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	12,581	12,599	12,932	13,188	13,457	13,700	13,903	14,102	14,298	14,516
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,581	12,599	12,932	13,188	13,457	13,700	13,903	14,102	14,298	14,516
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	15,289	15,289	15,289	15,289	15,289	15,289	15,456	15,677	15,895	16,137
Prospective	15,369	15,928	16,848	17,298	17,298	17,298	17,465	17,686	17,904	18,146
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	21.52	21.35	18.22	15.93	13.61	11.59	11.17	11.17	11.17	11.16
Prospective	22.16	26.43	30.29	31.17	28.55	26.27	25.62	25.42	25.22	25.01
Reference Margin Level	11.03	11.03	11.03	11.03	11.03	11.03	11.03	11.03	11.03	11.03

WECC-AB Existing On-Peak Generation (Winter)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Biomass	273	1.8
Coal	6,275	41.2
Hydro	415	2.7
Natural Gas	7,533	49.5
Other	70	0.5
Wind	663	4.4



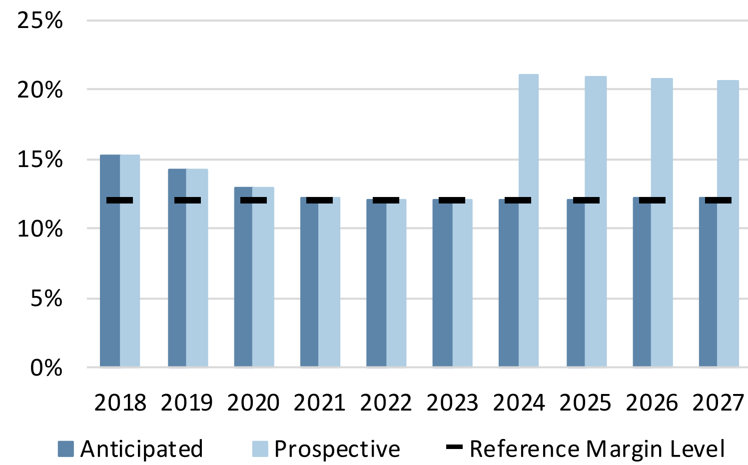
WECC-AB Planning Reserve Margins



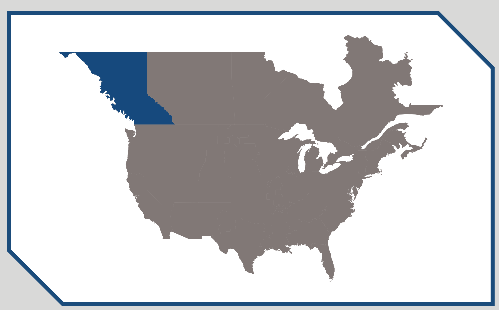
WECC-AB

WECC-BC Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	11,315	11,456	11,599	11,748	11,942	12,160	12,323	12,497	12,665	12,880
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,315	11,456	11,599	11,748	11,942	12,160	12,323	12,497	12,665	12,880
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	13,033	13,088	13,088	13,170	13,387	13,631	13,814	14,009	14,198	14,439
Prospective	13,033	13,088	13,088	13,170	13,387	13,631	14,914	15,109	15,298	15,539
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	15.18	14.25	12.84	12.11	12.10	12.10	12.10	12.10	12.11	12.11
Prospective	15.18	14.25	12.84	12.11	12.10	12.10	21.03	20.90	20.79	20.65
Reference Margin Level	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10	12.10

WECC-BC Existing On-Peak Generation (Winter)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Biomass	491	3.6
Hydro	12,491	92.5
Natural Gas	434	3.2
Wind	93	0.7

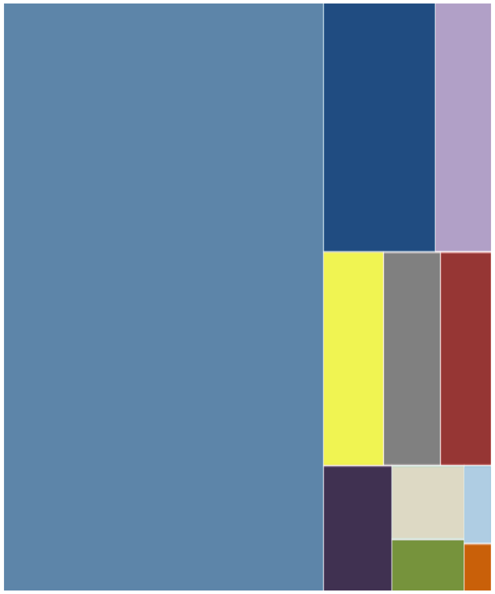


WECC-BC Planning Reserve Margins

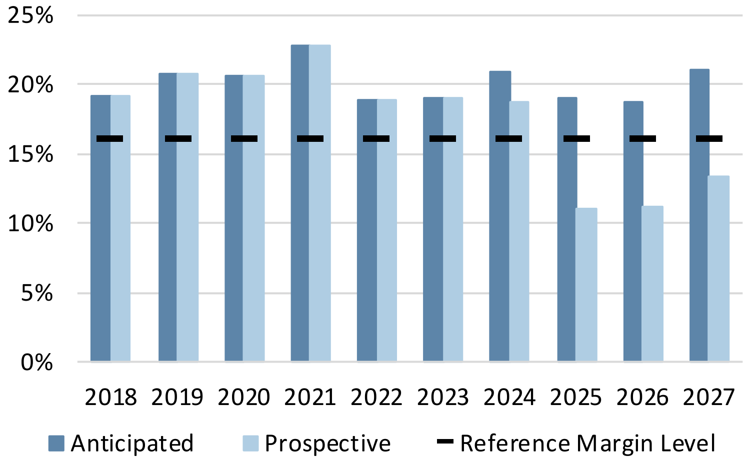


WECC-BC

WECC-CAMX Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	54,112	53,026	55,192	55,578	54,979	54,513	53,205	53,521	55,148	55,445
Demand Response	1,535	1,524	1,550	1,580	1,613	1,648	1,686	1,726	1,768	1,768
Net Internal Demand	52,577	51,502	53,642	53,998	53,366	52,865	51,519	51,795	53,380	53,677
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	62,658	62,162	64,687	66,259	63,423	62,898	62,290	61,597	63,390	64,930
Prospective	62,658	62,162	64,687	66,259	63,423	62,898	61,150	57,517	59,310	60,850
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	19.17	20.70	20.59	22.71	18.85	18.98	20.91	18.92	18.75	20.96
Prospective	19.17	20.70	20.59	22.71	18.85	18.98	18.69	11.05	11.11	13.36
Reference Margin Level	16.14	16.14	16.14	16.14	16.14	16.14	16.14	16.14	16.14	16.14



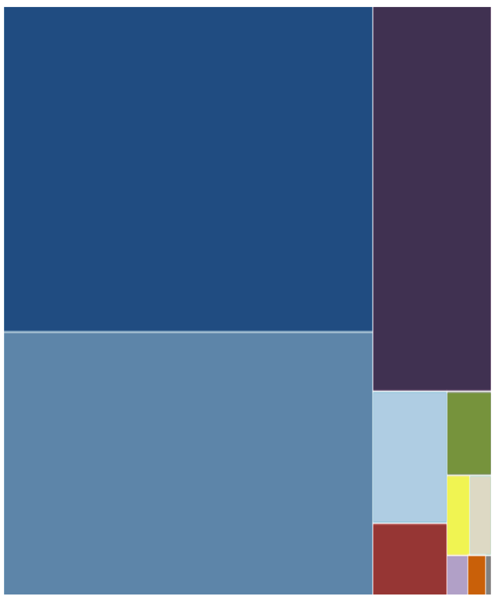
WECC-CAMX Existing On-Peak Generation (Summer)		
Generation Type	Peak Season Capacity	
	MW	Percent
Biomass	792	1.3
Coal	1,808	3.0
Geothermal	1,118	1.8
Hydro	5,865	9.7
Natural Gas	39,679	65.6
Nuclear	2,280	3.8
Other	2,559	4.2
Petroleum	272	0.4
Pumped Storage	2,936	4.9
Solar	2,693	4.5
Wind	445	0.7



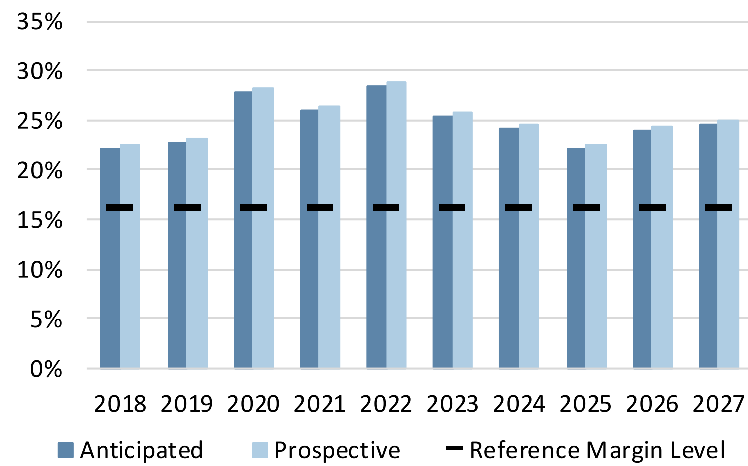
WECC-CAMX Planning Reserve Margins

WECC-CAMX

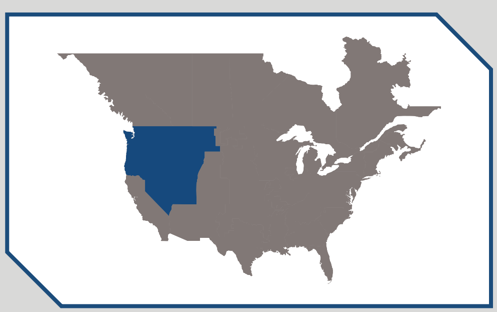
WECC-NWPP-US Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	49,902	50,210	50,517	50,875	51,308	51,356	51,680	52,025	52,384	52,768
Demand Response	1,295	1,310	1,321	1,322	1,330	1,349	1,345	1,396	1,448	1,475
Net Internal Demand	48,607	48,900	49,196	49,553	49,978	50,007	50,335	50,629	50,936	51,293
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	59,409	60,049	62,844	62,392	64,197	62,663	62,499	61,840	63,094	63,873
Prospective	59,517	60,257	63,052	62,600	64,405	62,871	62,707	62,048	63,302	64,081
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	22.22	22.80	27.74	25.91	28.45	25.31	24.17	22.14	23.87	24.53
Prospective	22.45	23.22	28.16	26.33	28.87	25.72	24.58	22.55	24.28	24.93
Reference Margin Level	16.38	16.38	16.38	16.38	16.38	16.38	16.38	16.38	16.38	16.38



WECC-NWPP-US Existing On-Peak Generation (Summer)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Biomass	771	1.3
Coal	9,464	15.9
Geothermal	357	0.6
Hydro	24,927	41.8
Natural Gas	20,254	33.9
Nuclear	1,130	1.9
Other	50	0.1
Petroleum	152	0.3
Pumped Storage	181	0.3
Solar	378	0.6
Wind	2,019	3.4

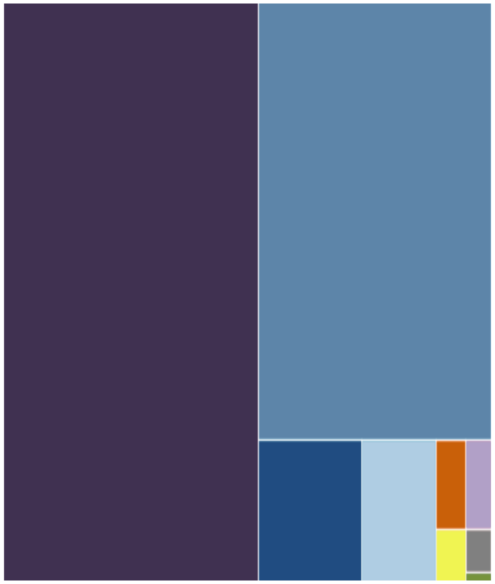


WECC NWPP-US Planning Reserve Margins

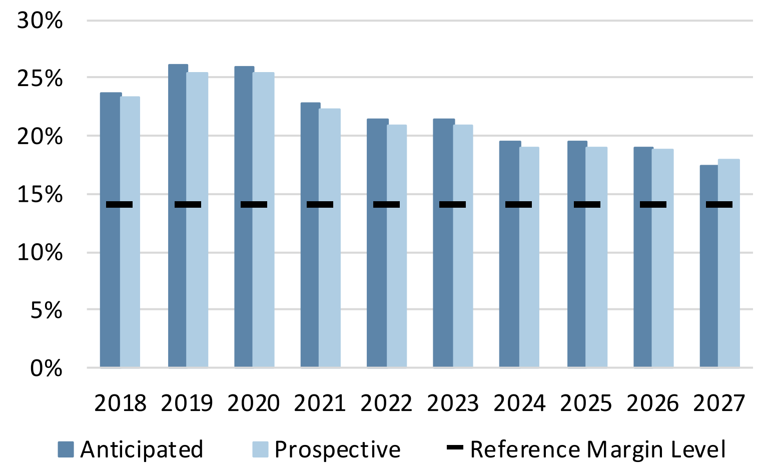


WECC-NWPP-US

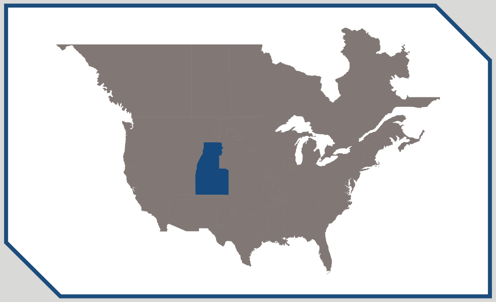
WECC-RMRG Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	12,528	12,678	12,812	13,052	13,208	13,451	13,631	13,803	13,985	14,168
Demand Response	531	538	537	542	546	551	555	553	557	562
Net Internal Demand	11,997	12,140	12,275	12,510	12,662	12,900	13,076	13,250	13,428	13,606
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	14,835	15,298	15,460	15,370	15,370	15,664	15,629	15,825	15,964	15,976
Prospective	14,792	15,221	15,393	15,303	15,303	15,597	15,562	15,758	15,954	16,051
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	23.66	26.01	25.95	22.86	21.39	21.43	19.52	19.43	18.89	17.42
Prospective	23.30	25.38	25.40	22.32	20.86	20.90	19.01	18.93	18.81	17.97
Reference Margin Level	14.17	14.17	14.17	14.17	14.17	14.17	14.17	14.17	14.17	14.17



WECC-RMRG Existing On-Peak Generation (Summer)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Biomass	17	0.1
Coal	9,530	52.3
Hydro	950	5.2
Natural Gas	6,558	36.0
Other	71	0.4
Petroleum	170	0.9
Pumped Storage	147	0.8
Solar	103	0.6
Wind	682	3.7

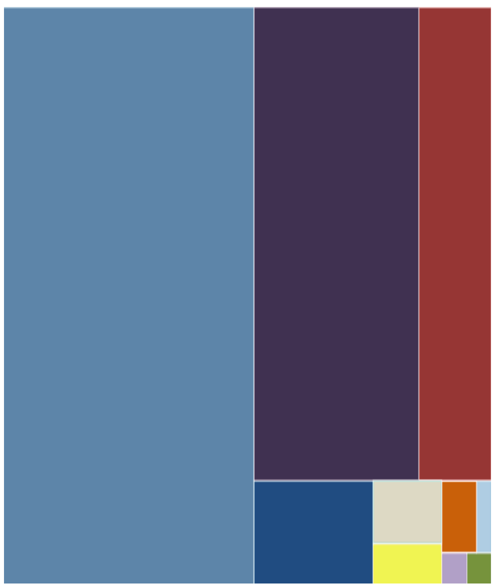


WECC-RMRG Planning Reserve Margins

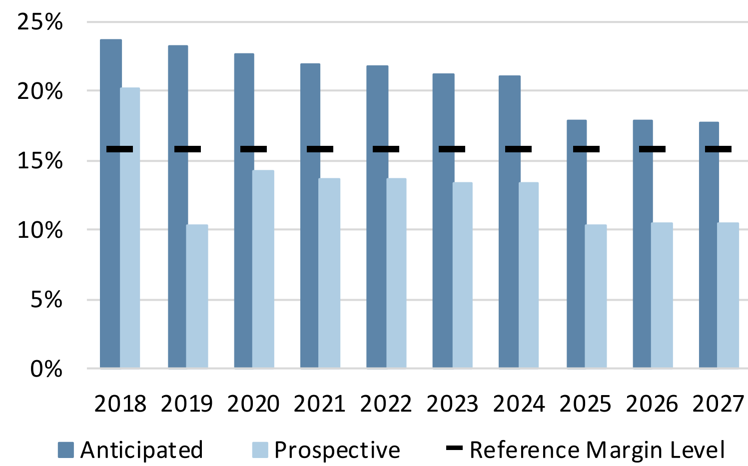


WECC-RMRG

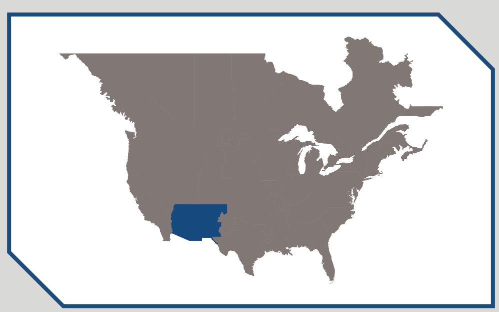
WECC-SRSG Demand, Resources, and Reserve Margins										
Demand (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Internal Demand	23,883	24,227	24,534	24,978	25,664	26,239	26,643	27,267	27,771	28,238
Demand Response	385	525	532	495	496	463	465	466	467	451
Net Internal Demand	23,498	23,702	24,002	24,483	25,168	25,776	26,178	26,801	27,304	27,787
Resources (MW)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	29,061	29,196	29,433	29,856	30,632	31,226	31,695	31,580	32,165	32,706
Prospective	28,237	26,144	27,404	27,827	28,603	29,197	29,666	29,551	30,136	30,677
Reserve Margins (%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Anticipated	23.67	23.18	22.63	21.95	21.71	21.14	21.08	17.83	17.80	17.70
Prospective	20.17	10.30	14.17	13.66	13.65	13.27	13.32	10.26	10.37	10.40
Reference Margin Level	15.83	15.83	15.83	15.83	15.83	15.83	15.83	15.83	15.83	15.83



WECC-SRSG Existing On-Peak Generation (Summer)		
Generation Type	**Peak Season Capacity**	
	MW	**Percent**
Biomass	89	0.3
Coal	8,964	27.7
Geothermal	496	1.5
Hydro	1,422	4.4
Natural Gas	16,642	51.4
Nuclear	3,937	12.2
Petroleum	289	0.9
Pumped Storage	92	0.3
Solar	322	1.0
Wind	122	0.4



WECC-SRSG Planning Reserve Margins



WECC-SRSG

Planning Reserve Margins—WECC

The Reference Margin Level is established by WECC through the Building Block Method that was created by the Loads and Resource Subcommittee. The Building Block Method is not a 1-in-10 loss of load probabilistic study approach, but rather is created by identifying four elements that contribute to Planning Reserves (contingency reserves, regulating reserves, forced outages, and a high temperature adder). No WECC subregion drops below the Reference Margin Level during the assessment period.

Demand—WECC

Load forecasts are developed by WECC staff by imposing the monthly peak and energy forecasts provided by the 38 individual Balancing Authorities (BA) on BA-specific annual hourly (8,760 hours) curves. The BAs update the peak and energy forecasts annually based on expected population growth with expected economic conditions and normalized weather conditions. Forecasted demand is reduced for rooftop solar to reflect demand expected to be served by the load serving entity (LSE). The forecasted curves are aggregated to subregional and Western Interconnection curves to create the coincidental peak for the study cases. The CA/MX subregion has forecasted relatively flat peak demand growth over the next 10 years (0.27 percent) primarily due to the projected increases in rooftop solar installations. Other WECC subregions show growth rates between 0.62 percent and 1.88 percent, which is in line with historic demand forecasts.

Demand-Side Management (DSM)—WECC

A significant portion of the controllable demand response programs within WECC are associated with large industrial facilities, air conditioner cycling programs, and water pumping—both canal and underground potable water and for irrigation use. These programs are created by LSEs that are responsible for the administration and execution when needed. In some areas, the programs are market driven (CAISO and AESO) and can be called upon for economic considerations. However, most areas in the Western Interconnection are not parties to organized markets and DSM programs are approved by local authorities and used only for the benefit of the approved LSE. DSM programs in WECC often have limitations such as limited number of times they can be called on, and some can only be activated during a declared local emergency.

Entities within WECC are not forecasting a significant increase in controllable demand response. The California ISO's demand response initiative programs are being developed with a goal to avoid adverse long-term reliability impacts. Energy efficiency and conservation are viewed as a permanent reduction in demand and are reflected as reductions in the load growth forecasts. WECC does not know the explicit demand reductions associated with these programs as these programs are administered by the individual LSEs or ISOs and not by WECC.

Distributed Energy Resources (DERs)—WECC

The impacts of DERs on the individual LSEs are well understood and are included in local assessments. For example, CAISO has approximately 5,000 MW of rooftop solar and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover or rain. Historically an increase in cloud cover would cause a decrease in demand, but a loss of rooftop solar has the opposite effect and demand increases. Rooftop solar in California is well dispersed throughout the state, which reduces the expectations of widespread generation disruptions due to cloud cover.

It is estimated that there was about 5,500 MW of rooftop solar installed throughout the Western Interconnection by the end of 2016. That number is forecasted to increase to over 10,000 MW by the end of 2022 and over 17,000 MW by the end of 2027. The CAISO expects to have nearly 13,000 MW of rooftop solar installed in their footprint by the end of 2027.

Many power flow models can include DERs as a data input, but currently none of these models have been approved for use in the Western Interconnection. WECC's Modeling and Validation Work Group (MVWG) is in the process of approving these models for future use.

Generation—WECC

In 2015, the Western Interconnection Flexibility Assessment was published, which examines the ability of the western grid to reliably function with the anticipated increase in variable generation. Although this assessment has not been updated, the conclusions presented in this paper appear to remain valid under the current and high-renewable RPS requirements.

CAISO has also started a stakeholder process to create a flexible resource element in the California market.

For reliability assessments, WECC applies variable resource capacity discounts based on historic on-peak generation. This process involves identifying the expected summer and winter peak hour for each assessment year and applying the historic 5-year average wind and solar capacity factors associated with that specific hour. WECC's annual update of the base historical data leads to minor changes in discounts, but the process itself has not been changed for this year's assessment. The method for counting capacity contribution is the same for all resource tiers, but the variability in historic seasonal peak hour generation may produce different capacity factors for each assessment year.

WECC studies expected future study cases that include expected generation retirements. Although it is anticipated that older coal-fired resources will retire in coming years, it is not expected there will be excessive unplanned retirements that cause a severe impact to reliability as these retirements would need approval from state PUCs or ISOs. Individual LSEs and BAs perform retirement studies to determine whether retirements are feasible or to determine the potential impacts to reliability. WECC also develops and compiles 11 Base Cases to be built for the current year study cycle. Those cases include heavy and light load scenarios, which are used by the Transmission Planners and Planning Coordinators to study extreme retirement scenarios.

WECC is not a planning entity and does not approve or reject planned retirements. However, WECC does incorporate announced and planned retirements when creating datasets to be used in planning models. Retirement of generation resources is not currently a major concern as ample generation exists in the Western Interconnection. However, that condition could change over the assessment period. WECC monitors generation retirements and studies the potential impacts to Interconnection-wide reliability associated with announced or planned retirements. The large geographic footprint of the Western Interconnection helps mitigate generation retirements as seasonal transfers, from winter peaking Regions to summer peaking Regions and vice versa, are very common in the Western Interconnection.

Individual state PUCs or the appropriate ISOs conduct studies to determine impacts to reliability. Actual retirements in 2016 were relatively minimal with 475 MW of natural-gas-fired and 290 MW of coal-fired generation retired. Several large generating units, including the coal-fired Intermountain Power Project, the Navajo power plant, and the Diablo Canyon nuclear station, are being considered for future retirement.[1]

All natural-gas-fired units are included as available resources when performing resource adequacy assessments, but WECC performs scenario studies modifying the availability of resources. WECC has studied, and continues to study, the potential impacts to electric reliability associated with the limited availability of the Aliso Canyon natural gas storage facility. Aliso Canyon has been available at a limited capacity for nearly two years, and during that time there have been no electric outages caused by the reduced storage availability. The CAISO continues to work with the impacted natural gas company and the neighboring BAs and Reliability Coordinator to provide mitigation plans to minimize and eliminate the risk to the reliability of the electric transmission grid.

Capacity Transfers—WECC

WECC's assessment process is based on system-wide modeling that aggregates BA-based load and resource forecasts by geographic subregions with conservatively-assumed power transfer capability limits between the zones. The Resource Adequacy Assessment Model calculates transfers between the zones limited to the lesser of excess capacity above the margin needed in the transferring zone or the conservative transmission limit.[2]

Resources that are physically located in one BA area but are owned by an entity or entities located in another BA's geographic footprint are modeled as remote resources. These resources are modeled with transmission links between the resource zone and the owner's zone that are limited to the owner's share of the resource. This treatment allows the owner of the resource, and only the owner, to count the resource for margin calculations. Remote resources are transferred first in WECC's modeling processes and reduce the capacity available for modeled transfers.

The reliability assessments performed by WECC are done with conservative seasonal transfer limits; therefore, the transfer limits included in this assessment are studied at less than optimal levels and reflect limited and conservative transfers. Transfers with other regional councils, such as the Midwest Reliability Organization and the Southwest Power Pool, are not included in this assessment as this would require an assumption regarding the amount of surplus or deficit generation in those councils.

[1] These units were not included as certain retirements in this assessment because: 1) These retirements were not reported to WECC, as they do not qualify for retirements under market rules, or 2) these planned retirements have not been finalized and regulatory approval has not been received. These retirements are included as potential retirements in this assessment and are reflected in the Potential Reserve Margin

[2] Transfers from Existing and Tier 1 resources are classified as firm transfers, and transfers from Tier 2 and Tier 3 resources are classified as Nonfirm transfers. This modeling approach ensures that resources are only counted once within the Region.

Transmission Planning—WECC

Transmission Planning in the Western Interconnection is coordinated by five[3] Regional Planning Groups, which create and periodically publish Transmission Expansion plans:

- Northern Tier Transmission Group
- WestConnect
- ColumbiaGrid
- California ISO
- Alberta Electric System Operator

[3] A sixth Regional Planning Group, The British Columbia Coordinated Planning Group (BCCPG), enables coordination and, where appropriate, integration of the transmission planning functions of transmission owner members. There is no consolidation of the members' long-term transmission plans, however. BCCPG Members include; British Columbia Hydro and Power Authority, FortisBC, Rio Tinto Alcan Inc., Tech Metals Ltd., Columbia Power Corporation.

Several entities have proposed major transmission projects to connect renewable resources on the eastern side of the Western Interconnection to load centers on the Pacific Coast to help satisfy Renewable Portfolio Standards—particularly in California. These projects, however, are often subject to significant development delays due to permitting and other issues. Currently, it is not anticipated that transmission additions will be needed to maintain reliability in the Western Interconnection during the assessment period, but transmission additions will continue to interconnect renewable resources.

Individual LSEs and BAs perform extreme weather scenario studies to determine the potential impacts to reliability. WECC develops the Base Case compilation schedule that details the 11 cases to be built for the current year study cycle. Those cases include heavy and light load scenarios that are used by the TP and PC to study extreme weather scenarios.

Data Concepts and Assumptions

Demand (Load Forecast)	
Total Internal Demand	The peak hourly load for the summer and winter of each year.[1] Projected Total Internal Demand is based on normal weather (50/50 distribution)[2] and includes the impacts of distributed resources, energy efficiency, and conservation programs.[3]
Net Internal Demand	Total Internal Demand, reduced by the amount of Controllable and Dispatchable Demand Response projected to be available during the peak hour. Net Internal Demand is used in all Reserve Margin calculations.

Load Forecasting Assumptions by Assessment Area

Assessment Area	Peak Season	Coincident / Noncoincident[4]	Load Forecasting Entity
FRCC	Summer	Noncoincident	FRCC LSEs
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Noncoincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes Sub Areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-E	Summer	Noncoincident	SERC LSEs
SERC-N	Summer	Noncoincident	SERC LSEs
SERC-SE	Summer	Noncoincident	SERC LSEs
SPP	Summer	Noncoincident	SPP Members
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AESO	Winter	Noncoincident	Individual Balancing Authorities (BA); aggregated by WECC
WECC-BC	Winter	Noncoincident	Individual Balancing Authorities (BA); aggregated by WECC
WECC-CAMX	Summer	Noncoincident	Individual Balancing Authorities (BA); aggregated by WECC
WECC-NWPP-US	Summer	Noncoincident	Individual Balancing Authorities (BA); aggregated by WECC
WECC-RMRG	Summer	Noncoincident	Individual Balancing Authorities (BA); aggregated by WECC
WECC-SRSG	Summer	Noncoincident	Individual Balancing Authorities (BA); aggregated by WECC

[1] The summer season represents June–September and the winter season represents December–February.
[2] Essentially, this means that there is a 50 percent probability that actual demand will be higher and a 50 percent probability that actual demand will be lower than the value provided for a given season/year.
[3] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.
[4] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Resource Categories
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:
Anticipated Resources: • Existing-Certain Generating Capacity: includes operable capacity expected to be available to serve load during the peak hour with firm transmission • Tier 1 Capacity Additions: includes capacity that is either under construction or has received approved planning requirements • Firm Capacity Transfers (Imports Minus Exports): transfers with firm contracts • Less Confirmed Retirements[5]
Prospective Resources (including all Anticipated Resources plus the following): • Existing-other capacity: includes operable capacity that could be available to serve load during the peak hour, but lacks firm transmission and could be unavailable during the peak or a number of reasons • Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements • Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts, but a high probability of future implementation • Less unconfirmed retirements[6]

Planning Reserve Margins	
Planning Reserve Margins	The primary metric used to measure resource adequacy, defined as the difference in resources (Anticipated or Prospective) and Net Internal Demand, divided by Net Internal Demand, shown as a percentile
	Anticipated Reserve Margin = $\frac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$ Prospective Reserve Margin = $\frac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$
Reference Margin Level	The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level a can be determined by using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand, beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels can fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If a Reference Margin Level is not provided by a given assessment area, NERC applies 15 percent for predominately thermal systems and 10 percent for predominately hydro systems.

5 Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

6 Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Errata

March 1, 2018
Page 8: The Y-axis in Figure 2 has been modified to increments of five percent

Page 15: The natural gas on-peak generation data has been updated to promote consistent comparison to previous assessments

Page 35: The reliability impacts and risk assessment recommendations were modified for reactive power requirements for nonsynchronous generation