NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2018 Long-Term Reliability Assessment

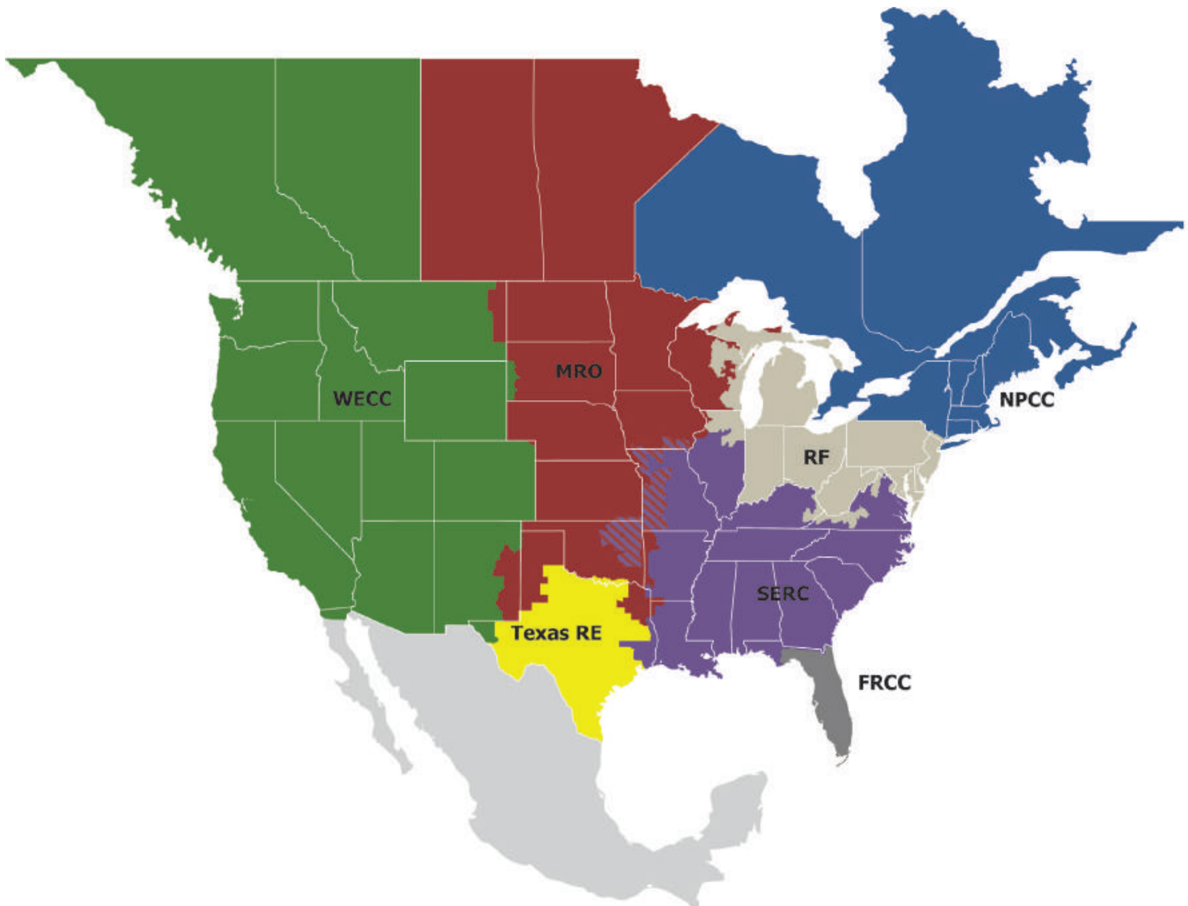
December 2018

Contents

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities (LSEs) participate in one Region while associated Transmission Owners/Operators participate in another.



About This Assessment

Development Process

This assessment was developed based on data and narrative information collected by NERC from the seven REs on an assessment area basis. NERC staff then independently assesses this information to develop the Long-Term Reliability Assessment (LTRA) for the North American BPS. This assessment identifies trends, emerging issues, and potential risks during the 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Planning Committee (PC), supports the development of this assessment through a comprehensive and transparent peer review process that leverages 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 PC and the NERC Board of Trustees (Board), who subsequently accepted this assessment and endorsed the key findings.

The LTRA is developed annually by NERC in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Data Considerations

Projections in this assessment are not predictions of what will happen, but are based on information supplied in July 2018 about known system changes with updates incorporated prior to publication. The assessment period for the 2018 LTRA includes projections for 2019–2028; however, some figures and tables examine data and information for the 2018 year. 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 and operating reliability. 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

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and energy, demand response (DR), resource capacity, and transmission projects. Data and information from each NERC Region are also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and the portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators and to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

In the LTRA, the baseline information on future electricity supply and demand is based on several assumptions, listed below:[5]

- Supply and demand projections are based on industry forecasts submitted in July 2018. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data may be submitted throughout the drafting time frame (May–September).
- Peak demand and planning reserve margins are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Region's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned, planned outages take place as scheduled, and retirements are scheduled as proposed.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "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."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the section: "How NERC Defines Bulk Power System Reliability" on page 5, does not include the reliability of the lower-voltage distribution systems that systems use to account for 80 percent of all electricity supply interruptions to end-use customers.

[5] Forecasts cannot predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50 percent probability that actual demand will be higher than the forecast midpoint and a 50 percent probability that it will be lower (50/50 forecast).

- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency and price-responsive demand response, are reflected in the forecasts of total internal demand.

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

> **Adequacy:** is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
>
> **Operating Reliability:** is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components.

Regarding adequacy, system operators can and should take controlled actions or introduce procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its load-serving entity (LSE) via contract or agreement for curtailment[6]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as five percent).
- Rotating blackouts, the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders

Under the heading of operating reliability are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability (ALR),[7] which is defined by the following BPS characteristics:

> **Adequate Level of Reliability:** the state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when the following reliability performance objectives are met:
>
> - The BES does not experience instability, uncontrolled separation, cascading,[8] collapse under normal operating conditions and/or voltage when subject to predefined disturbances.[9]
> - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
> - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
> - Adverse reliability impacts on the BES following low probability disturbances (e.g., multiple elements out on the BES following contingences, unplanned and uncontrolled equipment outages, cyber security events, and malicious acts) are managed.
> - Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

[6] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards, July 3, 2018, at the following: https://www.nerc.com/files/glossary_of_terms.pdf

[7] NERC ALR: https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf

[8] NERC's Glossary of Terms defines Cascading as follows: "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

[9] NERC's Glossary of Terms defines Disturbance as follows: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

For these less probable severe events, BES owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the BES, even if these events can result in cascading, uncontrolled separation, or voltage collapse. Less probable severe events would include, for example, losing an entire right of way due to a tornado, simultaneous or near simultaneous multiple transmission facilities outages due to a hurricane, sizeable disruptions to natural gas infrastructure impacting multiple generation resources, or other severe phenomena.

Reading this Report

This report is generally compiled with three major parts:

- **NERC Reliability Assessment**
  - Evaluate industry preparations in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Focus the industry, policy makers, and the general public's attention on significant issues facing BPS reliability
  - Make recommendations based on an independent NERC reliability assessment process
- **Emerging Reliability Issues**
  - Identify industry issues that may pose reliability issues in the future that may not be included in the current reference case
- **Regional Reliability Assessment**
  - Summary assessments for each assessment area
  - Focus on region-specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

Executive Summary

The electricity sector is undergoing significant and rapid change, presenting new challenges and opportunities 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 in some areas—primarily wind and solar—are altering the operating characteristics of the grid in some areas. A significant influx of natural gas generation raises new questions about how disruptions on the pipeline system can impact the electric system reliability. Risks and corresponding mitigations may be unique to each area, and industry stakeholders and policymakers should respond with policies and plans to address these emerging issues.

This *2018 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 assessment, NERC has identified the following five key findings:

ERCOT, MRO-MISO, and NPCC-Ontario are projected to be below the Reference Margin Level; probabilistic assessments of future conditions can highlight additional reliability challenges:

- Anticipated Reserve Margins in TRE-ERCOT are projected below the Reference Margin Level for the entire first five-year period, but additional Tier 2 resources may be advanced to preserve reliability.
- MISO and NPCC-Ontario are projected to have Anticipated Reserve Margin shortfalls beginning in 2023, but additional Tier 2 resources may be advanced to preserve reliability.
- Probabilistic evaluations identify resource adequacy risks during non-peak conditions in WECC-CAMX, starting in 2020 and increasing by 2022. While planning reserve margins are adequate for the peak hour in California, loss-of-load studies that evaluate all hours of the year have started to indicate greater risk of a supply deficit.

Reliance on natural gas generation increases in some areas with continuing resource mix changes, and fuel assurance mechanisms are being developed:

- FRCC, TRE-ERCOT, and WECC-CA-MX assessment areas are projecting natural gas generation to contribute greater than 60 percent of on-peak capacity. Natural gas generation provides important flexibility attributes that are essential for managing wind and solar variability.
- A total of 41 GW of Tier 1 natural gas generation capacity is planned through 2028.
- Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural-gas-fired generation and constrained natural gas transportation. Fuel assurance mechanisms come in many forms and have existed for decades within integrated resource planning processes. In market areas, evolving rules and mechanisms continue to target better performance as well as increasing overall fuel assurance by increasing firm pipeline transportation and maintaining back-up oil inventories for gas-fired generation.

Frequency response is expected to remain adequate through 2022:

- Eastern and Western Interconnection dynamic stability analysis shows that the projected generation mix sufficiently supports frequency after simulated disturbances despite reductions in inertia.
- Operational procedures in ERCOT are in place to limit the reliability risk resulting from degraded inertia.

Increasing solar and wind resources requires more flexible capacity to support ramp requirements:

- As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability—such as supporting solar down ramps when the sun goes down and complementing wind pattern changes.
- With continued rapid growth of distributed solar, California Independent System Operator's (CAISO) three-hour ramping needs have reached 14,777 MW, exceeding earlier projections and reinforcing the need to access more flexible resources. By 2022, this need increases to 17,000.
- Changing ramping requirements induced by increasing amounts of wind is largely managed with improved forecasting. Ramp forecasts allow ERCOT operators to curtail wind production and/or reconfigure the system in response to large changes in wind output.

Over 30 GW of new distributed solar photovoltaic is expected by the end of 2023 impact system planning, forecasting, and modeling needs:

- California is projected to have over 18 GW of distributed solar photovoltaic (PV) by 2023, which is nearly 40 percent of its projected peak demand for the same period. New Jersey, Massachusetts, and New York are projected to each have between 3.5 and four GW of distributed solar PV by 2023.
- Increasing installations of distributed energy resources (DERs) modify how distribution and transmission systems interact with each other. Transmission planners and operators may not have complete visibility and control of these resources, but as growth becomes considerable, their contributions must be considered in system planning, forecasting, and modeling.

In addition to the key findings, NERC evaluated the following emerging issues that have the potential to impact reliability in the 10-year horizon:

- Bulk power storage
- Reliability coordination in the Western Interconnection
- Potential risk of significant electricity demand growth
- Reactive power requirements for transmission-connected devices
- System restoration
- Potential impact to system strength and fault current contributions

Recommendations

Based on the identified key findings, NERC formulated the following recommendations:

- **Enhance NERC's Reliability Assessment Process:** In addition to its capacity supply assessment, NERC's Reliability Assessment Subcommittee should lead the electric industry in developing a common approach and identify metrics to assess energy adequacy. As identified in this assessment, the changing resource mix can alter the energy and availability characteristics of the generation fleet. Additional analysis is needed to determine energy sufficiency, particularly during off-peak periods and where energy-limited resources are most prominent.
- **Develop Guidelines to Assess Fuel Limitations and Disruption Scenarios:** Given the increased reliance on natural gas generation, system planners should identify potential system vulnerabilities that could occur under extreme, but realistic, contingencies and under various future supply portfolios. In addition, NERC's Planning Committee should leverage industry experience and develop a reliability guideline that establishes a common framework for assessing fuel disruptions of various types. The industry-developed assessments can then be used to address potential regulatory needs or establish market mechanisms to better promote fuel assurance.
- **Improve Interconnection Frequency Response Modeling:** The analysis in this assessment represents the first-ever, forward-looking interconnection-wide assessment for both the Eastern and Western Interconnections. The analysis highlights several areas for improvement that include the following: improving the generation dispatch to better reflect low-inertia conditions; identifying locational constraints, particularly in the Western Interconnection; and valid representation of DERs in load models. NERC should continue working with the Eastern, Western, and Texas interconnection study groups to develop improved frequency response base case and scenario assessments.
- **Ensure System Studies Incorporate DERs:** In areas with expected growth in DERs, system planners should determine data gathering strategies to ensure the aggregate technical specifications of generation connected to local distribution grids are known to the transmission operator. This data collection is needed to ensure accurate and valid system planning models, load forecasting, coordinated system protection, and real-time situation awareness. In areas with large or emerging DER penetration, future system studies should properly account for DERs in order to accurately represent the system's behavior.
- **Flexible Ramping Resources Needed to Offset Variable Energy Production:** Presently, ramping capacity concerns are largely confined to California. However, as solar generation continues to increase in California and elsewhere across North America, system planners should ensure sufficient flexible ramping capacity, including large-scale energy storage.

Chapter 1: Key Findings

Key Finding 1: ERCOT, MRO-MISO, and NPCC-Ontario Are Projected to Be below the Reference Margin Level; Probabilistic Assessments of Future Conditions can Highlight Additional Reliability Challenges

Key Points:

- Anticipated Reserve Margins in TRE-ERCOT are projected below the Reference Margin Level for the entire first five-year period.
- MISO and NPCC-Ontario are projected to have Anticipated Reserve Margin shortfalls beginning in 2023.
- Probabilistic evaluations identify resource adequacy risks during nonpeak conditions in WECC-CAMX starting in 2020 and increasing by 2022.

For the majority of the BPS, planning reserve margins appear sufficient to maintain reliability during the long-term, ten-year horizon. However, there are challenges facing the electric industry that may shift industry projections and cause NERC's assessment to change. Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, any requisite natural gas infrastructure, and any associated transmission. Although generating plant construction lead times have been significantly reduced, environmental permitting and pipeline and transmission planning and approval still require significant lead times.[10]

As shown in **Figure 1.1**, all assessment areas remain above the Anticipated Reference Margin Level through 2023 with the exception of ERCOT, MISO, and NPCC-Ontario.

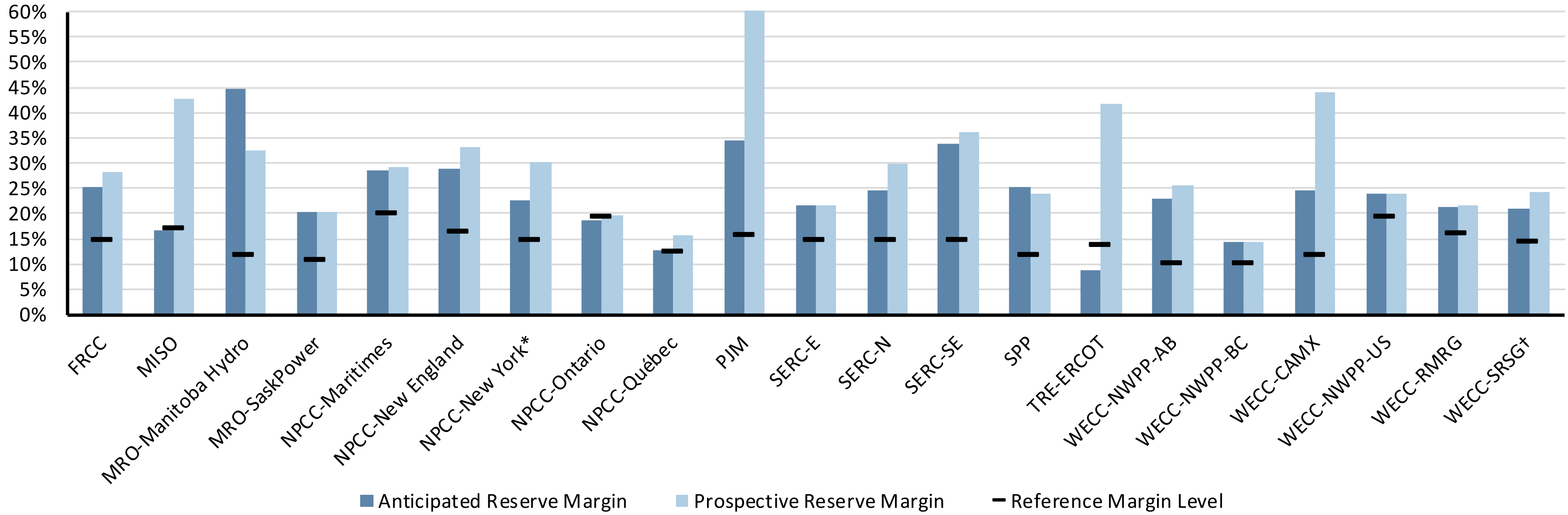


Figure 1.1: Anticipated and Prospective Reserve Margins for 2023 Peak by Assessment Area

[10] Capacity supply and planning reserve margin projections in this assessment do not necessarily take into account all generator retirements that may occur over the next 10 years or account for all replacement resources explicitly linked with potential retiring resources. While some generation plants have already announced and planned for retirement, there are still many economically vulnerable generation resources that have not determined and/or announced their plans for retirement.

How NERC Evaluates Resource Adequacy: NERC assesses resource adequacy by evaluating each assessment area's planning reserve margins relative to its Planning Reference Margin Level—a deterministic method based on traditional capacity planning. The projected resources are reduced by known operating limitations (e.g., fuel availability, transmission and environmental limitations) and compared to the Reference Margin Level, which represents the desired level of risk based on a probability-based loss of load analysis.

On the basis of the five-year projected reserves compared to the established Reference Margin Level, as shown in Figure 1.1, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: Anticipated Reserve Margin is greater than Reference Margin Level and there is a high degree of expectation in meeting all forecast parameters.

Marginal: Anticipated Reserve Margin is greater than Reference Margin Level and there is a low degree of expectation in meeting all forecast parameters, or Anticipated Reserve Margin is slightly below the Reference Margin Level and additional and sufficient Tier 2 resources are projected.

Inadequate: Anticipated Reserve Margin is significantly less than Reference Margin Level and load interruption is likely.

The results of NERC's determination is shown in Table 1.1 on the next page.

As part of NERC's assessment, Table 1.1 identifies these areas as "Marginal" with all other areas identified as "Adequate" through 2023. While MISO and NPCC-Ontario show only a very small shortfall, TRE-ERCOT shows a shortfall of over 4,000 MW.

Table 1.1: NERC's Risk Determination of All Assessment Areas Five-Year Projected Reserve Margins

Assessment Area	2023 Peak Anticipated Reserve Margin	2023 Reference Margin Level	Expected Capacity Surplus or Shortfall (MW)	Assessment Result Through 2023
FRCC	25.33%	15.00%	4,868	Adequate
MRO-MISO	16.84%	17.10%	-313	**Marginal**
MRO-Manitoba	44.60%	12.00%	1,413	Adequate
MRO-SaskPower	20.29%	11.00%	369	Adequate
NPCC-Maritimes	28.45%	20.00%	443	Adequate
NPCC-New England	28.98%	16.36%	3,070	Adequate
NPCC-New York	22.74%	15.00%	2,432	Adequate
NPCC-Ontario	18.62%	19.43%	-175	**Marginal**
NPCC-Quebec	12.86%	12.61%	92	Adequate
PJM	34.53%	15.80%	27,326	Adequate
SERC-E	21.48%	15.00%	2,793	Adequate
SERC-N	24.58%	15.00%	3,861	Adequate
SERC-SE	33.77%	15.00%	8,757	Adequate
SPP	25.15%	12.00%	7,032	Adequate
TRE-ERCOT	8.62%	13.75%	-4,018	**Marginal**
WECC-AB	22.83%	10.14%	1,564	Adequate
WECC-BC	14.23%	10.14%	499	Adequate
WECC-CAMX	24.51%	12.02%	6,267	Adequate
WECC-NWPP US	23.82%	19.56%	2,138	Adequate
WECC-RMRG	21.14%	16.07%	669	Adequate
WECC-SRSG	20.90%	14.47%	1,654	Adequate

Planning Reserve Margins in TRE-ERCOT Are Projected below the Reference Margin Level for the Entire First Five Year Period.

For the second year in a row, the projected Anticipated Reserve Margins in TRE-ERCOT fall below the Reference Margin Level of 13.75 percent starting in Summer 2018 and remains below for the duration of the LTRA forecast period (**Figure 1.2**). The 2019 Anticipated Reserve Margin is projected to be 11.2 percent and goes below 10 percent past the Summer 2022. The shortfall is mainly due to the retirement of over 4,000 MW of coal and natural gas resources in late 2017/early 2018 as well as reported delays in planned resource capacity construction by project developers.

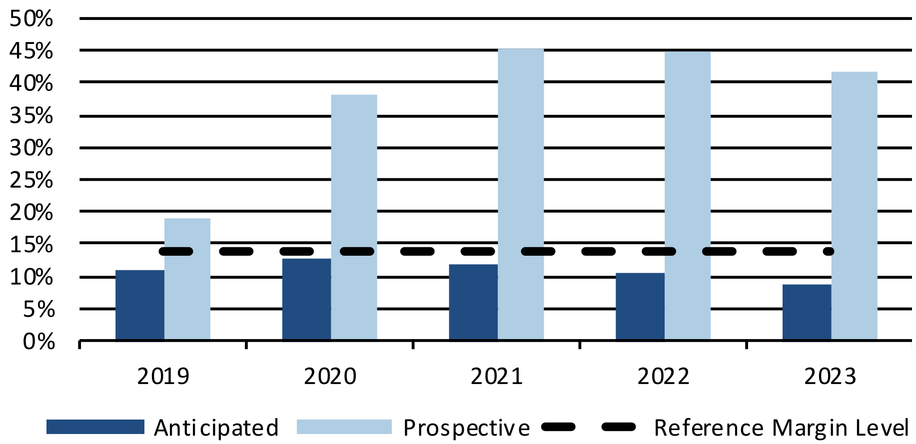


Figure 1.2: TRE-ERCOT 5-year Projected Reserves (Anticipated and Prospective Reserve Margins)

To respond to such cyclical resource investment and retirement trends, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system. For example, there are programs operated by ERCOT, retail electric providers, and distribution utilities that compensate customers for reducing their demand or operating their own generation in response to market prices and anticipated capacity scarcity conditions. ERCOT also has operational tools available to maintain system reliability, such as using DR qualified to provide ancillary services, requesting emergency power across the direct current (dc) ties to neighboring grids, and requesting emergency support from available switchable generators currently serving non-ERCOT grids. However, insufficient reserves during peak hours could lead to an increased risk of entering emergency operating conditions, including the possibility of rotating firm load outages.

Trends for the ERCOT area since 2010 indicate that the reserve margin shortfalls in the long-term outlook represent a "new normal" (**Figure 1.3**). In many ways, this is the expected outcome of managing resource adequacy through an energy-only market construct.[11] In Texas, regulators ensure reliability through a mechanism called scarcity pricing, which allows real-time electricity prices to reach as high as $9,000/megawatt hour (MWh) in response to capacity shortage conditions. Instead of guaranteeing generation revenue through a capacity market, the opportunity of high prices is intended to incentivize generators to build new plants and keep them ready to operate. Recent performance over the last several years has proven the ERCOT market and system operations to be successful with no load shedding events.

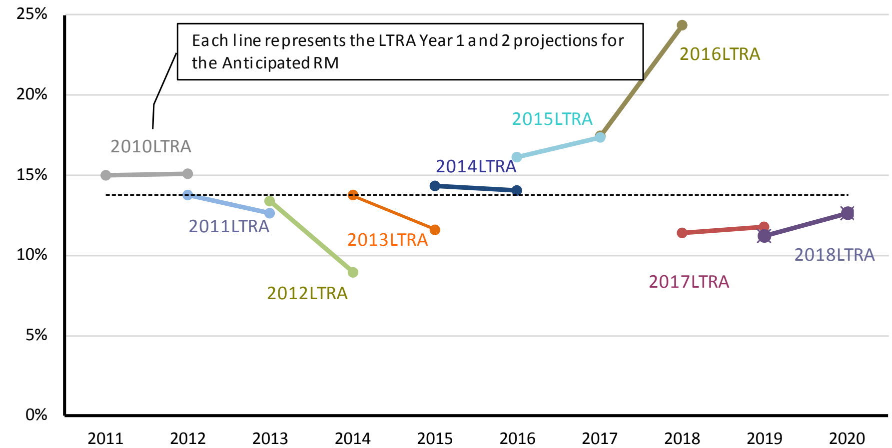


Figure 1.3: TRE-ERCOT Reserve Margin Trends since 2010

[11] Energy-only markets pay generators only when they provide power on a day-to-day basis. Conversely, capacity markets aim to ensure resource adequacy by paying participants to commit generation for delivery years into the future.

MISO and NPCC-Ontario Are Projected to have Anticipated Reserve Margin Shortfalls beginning in 2023

MISO

MISO projects a regional surplus for the summer peaks occurring through 2022 and then falling below the Reference Margin Level for the summer of 2023 (**Figure 1.4**). The 2023 summer peak Anticipated Reserve Margin is projected to be 16.8 percent. These results are driven by a number of factors:

- A decrease in resources committed to serving MISO load mainly focused in most of Illinois and Michigan (Zones 4 and 7)
- An increase in reserve requirements (15.8 percent to 17.1 percent) due to higher forced outage rates, resource mix changes, and unit retirements/suspensions[12]
- An increase in new committed resources from DR and behind-the-meter resources

Individually, all zones within MISO are sufficient from a resource adequacy point of view in the near-term when available capacity and transfer limitations are considered. Each zone within the MISO footprint is expected to have sufficient resources within their boundaries to meet their local resource requirement, which must be contained within its boundaries. Projected regional shortages identified in this assessment are being rectified by MISO and the state regulatory agencies through engagement with stakeholders in a number of resource adequacy forums. For example, there are opportunities to advance Tier 2 and Tier 3 resources to mitigate the projected long term resource shortfalls.

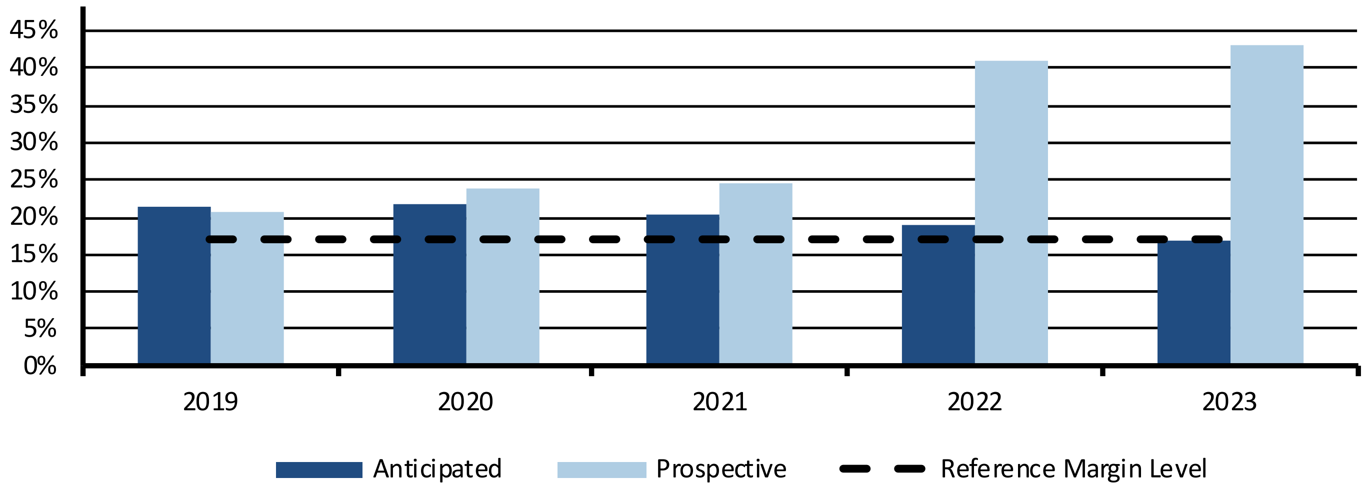


Figure 1.4: MISO 5-year Projected Reserve Margin through 2023 (Anticipated and Prospective Reserve Margins)

Operating at or near the Reference Margin Level creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency on use of DR and behind-the-meter resources.

[12] As directed under Module E-1 of the MISO Tariff, MISO performs a probabilistic analysis annually using the loss of load expectation (LOLE) study to determine the appropriate Reference Margin Level. MISO calculates the Reference Margin Level such that the LOLE for the next planning year is one-day-in-10 years, or 0.1 days per year.

NPCC-Ontario

The Anticipated Reserve Margin falls below the Reference Margin level in the mid-2020s to 18.6 percent (**Figure 1.5**). This is driven by nuclear retirements, the nuclear refurbishment program, and the assumption that certain generation resources will not be available once their generation contracts have expired. That said, there are uncertainties in the projections that could see the shortfall grow or shrink. As a result, the Independent Electricity Service Operator (IESO) will continue to update and refine its forecasts to gain more certainty about the size of the gap. The development of a capacity auction is underway as a means to acquire any necessary resources for 2023, and IESO expects that there are sufficient resources that can be developed with a three-year lead time to meet at 2023 resource gap.

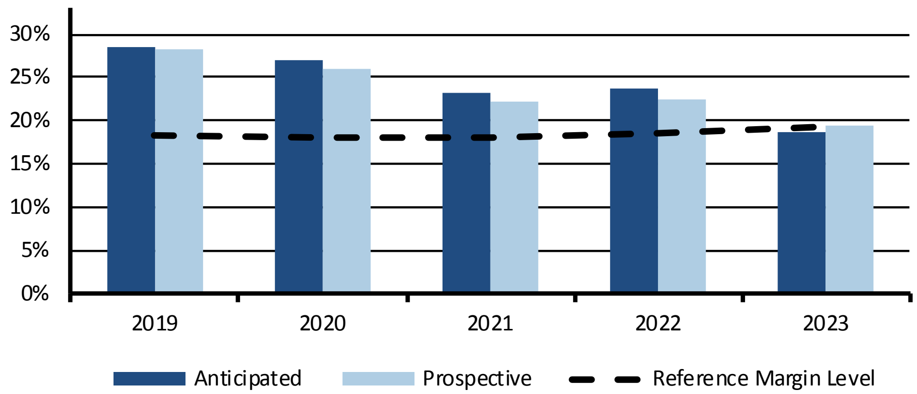


Figure 1.5: Ontario 5-year Projected Reserve Margins through 2023 (Anticipated and Prospective Reserve Margins)

How NERC Defines Future Capacity Supply

Tier 1: Unit that meets at least one of the following guidelines (with consideration for an area's planning processes):

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection Service Agreement (ISA)
- Signed/approved Power purchase agreement (PPA) has been approved
- Signed/approved Interconnection Construction Service Agreement (CSA)
- Signed/approved Wholesale Market Participant Agreement (WMPA)
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)

Tier 2: Unit that meets at least one of the following guidelines (with consideration for an area's planning processes)2:

- Signed/approved Completion of a feasibility study
- Signed/approved Completion of a system impact study
- Signed/approved Completion of a facilities study
- Requested Interconnection Service Agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)

Tier 3: Units in an interconnection queue that do not meet the Tier 2 requirement

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment (ProbA): Biannually, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment.

Loss of Load Hours: Loss of load hours (LOLH) is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve).

LOLH should be evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study horizons. LOLH does not inform of the magnitude or the frequency of loss of load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs, which can be modeled as resources with specific contract limits including hours per year, days per week, and hours per day constraints,
- EE programs, which can be modeled as reductions to load with an hourly load shape impact
- Distributed resources, such as behind the meter PV, which can be modeled as reductions to load with an hourly load shape impact

Expected Unserved Energy: Expected unserved energy (EUE) is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs.

This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). NERC refers to this measure as EUE ppm. Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss of load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is very useful in estimating the size of loss of load events so the planners can estimate the cost and impact. EUE can be used as basis for reference reserve margin to determine capacity credits for variable energy resources. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, the Australian Energy Market Operator is responsible for planning using 0.002 percent EUE as their energy adequacy requirement in Australia.[1] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load loss reliability component.

[1] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Probabilistic evaluations identify resource adequacy risks during nonpeak conditions in WECC-CAMX

The analytical processes used by resource planners range from relatively simple calculations of planning reserve margins to rigorous reliability simulations that calculate system LOLE or loss of load probability (LOLP) values.[13] The one-event-in-10-year (0.1 events per year) LOLE is produced from this type of probabilistic analysis. This planning criterion requires an electric system to maintain sufficient capacity such that system peak load is not likely to exceed available supply more than once in a 10-year period. Utilities, system operators, and regulators across North America rely on variations of the one-event-in-10 year criterion for ensuring and maintaining resource adequacy.[14]

Probabilistic Assessment Results Summary

As part of a biannual process, this *2018 LTRA* includes a probabilistic evaluation for each assessment area and calculates LOLH and EUE for the third and fifth years of the LTRA. This year's analysis calculates the probabilistic resource measures for 2020 and 2022.[15] A summary of the indices are shown in **Table 1.2** on the next page.

[13] A traditional planning criterion used by some resource planners or load-serving entities is maintaining system LOLE below one-day-in-10 years. LOLE is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently, some assessment areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily demand (instead of the daily peak load) at least once during that day.

[14] https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf

[15] 2020* denotes the results from the 2016 ProbA's 2020 projection. The ProbA from the prior iteration is used for comparison because the first year (in this case 2020) is the same study year in both the prior and current ProbA.

Table 1.2: 2020 and 2022 Projected Peak Reserve Margins and Probabilistic Indices by Assessment Area

	Reserve Margin (%)									Annual Probabilistic Indices								
Assessment Area	LTRA Anticipated			LTRA Reference			ProbA Forecast Operable			EUE (MWh)			EUE (ppm)			LOLH (hours/year)		
Year	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022	2020*	2020	2022
WECC-NWPP-US	30.3%	25.9%	22.8%	16.3%	19.7%	19.6%	28.1%	16.1%	15.9%	0.00	1,896	2,553	0.00	6.45	8.58	0.00	0.47	0.58
MRO-SaskPower	25.6%	20.1%	17.7%	11.0%	11.0%	11.0%	22.6%	15.7%	11.7%	65.50	1,148	4,495	2.56	43	167	0.84	11.45	39.02
WECC-CAMX	21.3%	30.6%	23.6%	16.2%	12.3%	12.1%	25.4%	19.5%	22.8%	0.00	2,783	41,468	0.00	10.40	153.80	0.00	0.13	2.30
MRO-Manitoba	18.7%	22.1%	31.6%	12.0%	12.0%	12.0%	20.4%	14.7%	31.0%	0.24	3,259	0.00	0.01	0.12	0.00	0.00	2.39	0.00
TexasRE-ERCOT	20.8%	12.7%	10.6%	13.8%	13.8%	13.8%	11.4%	6.2%	4.6%	0.40	599	1,089	0.00	1.53	2.64	0.00	0.50	0.87
MISO	16.6%	21.7%	18.9%	15.2%	17.1%	17.1%	10.6%	14.2%	13.7%	95.80	14.20	31.60	0.13	0.02	0.04	0.13	0.11	0.21
NPCC-New England	18.2%	29.9%	28.5%	15.9%	17.2%	16.4%	9.4%	20.7%	19.0%	140.80	12.53	2.71	0.98	0.10	0.02	0.19	0.03	0.01
NPCC-New York	26.3%	24.1%	22.5%	15.0%	15.0%	15.0%	18.8%	15.3%	13.7%	2.06	0.07	0.03	0.01	0.00	0.00	0.00	0.00	0.00
FRCC	24.4%	23.7%	24.4%	15.0%	15.0%	15.0%	19.4%	19.1%	20.2%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Maritimes	24.4%	23.5%	25.4%	20.0%	20.0%	20.0%	18.1%	33.0%	33.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Ontario	25.1%	27.1%	23.6%	17.7%	18.0%	19.0%	11.9%	10.5%	11.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Québec	15.8%	16.4%	13.6%	12.7%	12.6%	12.6%	14.2%	9.5%	7.1%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PJM	28.5%	35.5%	35.2%	16.5%	15.9%	15.8%	16.1%	22.7%	22.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SERC-E	16.1%	21.1%	22.3%	15.0%	15.0%	15.0%	11.2%	20.2%	18.0%	49.39	0.00	0.00	0.22	0.00	0.00	0.05	0.00	0.00
SERC-N	18.6%	25.7%	25.2%	15.0%	15.0%	15.0%	18.0%	18.5%	17.7%	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SERC-SE	33.4%	31.3%	32.4%	15.0%	13.2%	14.4%	26.5%	23.6%	24.7%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SPP	22.7%	30.4%	27.2%	12.0%	12.0%	12.0%	15.0%	20.7%	17.1%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-AB	29.6%	25.9%	23.4%	11.0%	10.4%	10.2%	26.8%	23.2%	19.9%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-BC	12.4%	18.8%	15.9%	12.1%	10.4%	10.2%	17.3%	20.4%	22.2%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-RMRG	21.7%	26.6%	23.5%	14.1%	16.8%	16.4%	24.6%	20.8%	18.5%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WECC-SRSG	21.2%	29.4%	24.0%	15.8%	15.1%	14.6%	29.0%	20.1%	16.7%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure 1.6 shows the 2022 projected peak reserve margins compared to the LOLH index.

In its probabilistic analysis, WECC projected that the reserve margin for the WECC-CAMX Region are over 22 percent in 2020 and 21 percent in 2022; however, due in part to the changing resource mix, LOLH is projected to increase from 0.13 hours in 2020 to 2.3 hours in 2022. A summary of the indices for WECC-CAMX are shown in **Table 1.3**. Additionally, the EUE for both years increased with nearly 2,800 MWh projected for 2020 and over 41,000 MWh projected for 2022.

The finding provides evidence that the planning reserve margin metric in areas with higher penetrations of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro) may not be a completely accurate way to measure an area's resource adequacy during all hours of the year. Namely, energy limitations can exist, requiring more advanced stochastic analysis methods to identify risks to reliability.

Table 1.3: Probabilistic Base Case Summary Results for WECC-CAMX

Reserve Margin %			
	2020*	2020	2022
Anticipated	21.3%	22.2%	21.3%
Reference	16.2%	12.3%	12.1%
ProbA Forecast Operable	21.3%	19.5%	22.8%
Annual Probabilistic Indices			
	2020*	2020	2022
EUE (MWh)	0.00	2,783	41,468
EUE (ppm)	0.00	10.4	153.8
LOLH (hours/year)	0.00	0.13	2.3

*2016 Probabilistic Assessment

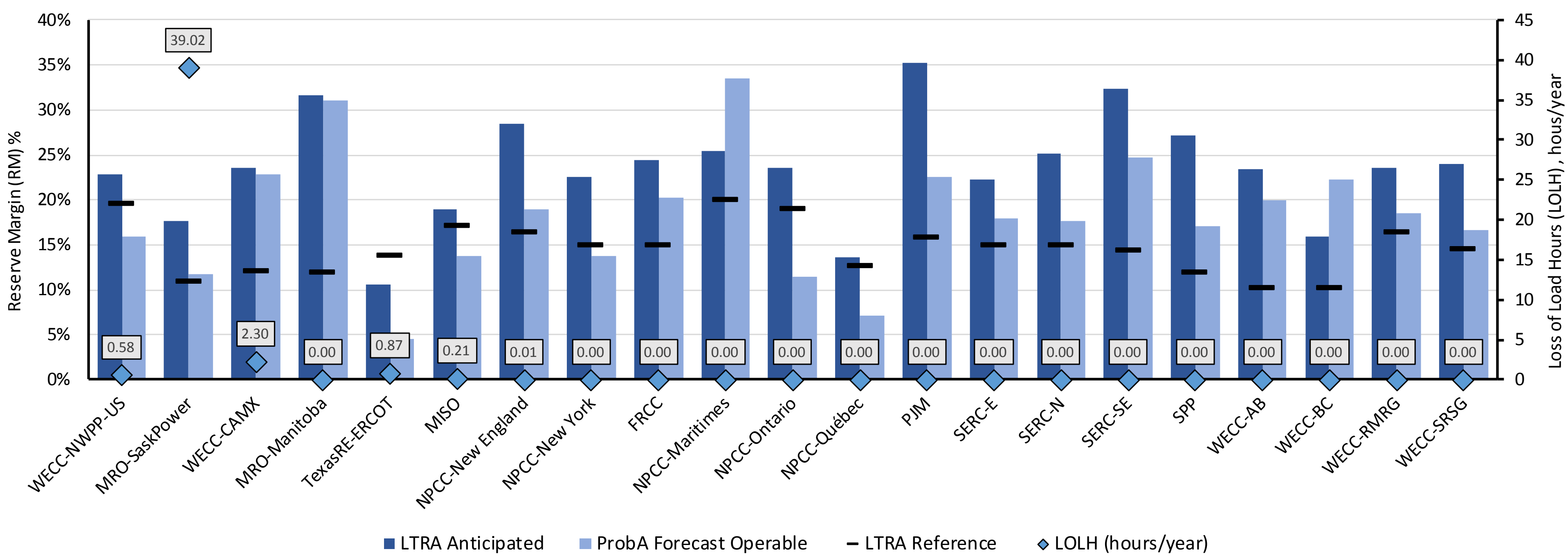


Figure 1.6: 2022 Assessment Area Reserve Margins and Loss of Load Hours (LOLH)

In **Figure 1.7**, a comparison of LOLH is provided that helps identify emerging risk that may not have been identified as a risk in 2016 when the last study was complete. A notable increase in the LOLH index is observed in WECC-NWPP-US, MRO-SaskPower, MRO-Manitoba, WECC-CAMX, and TRE-ERCOT.

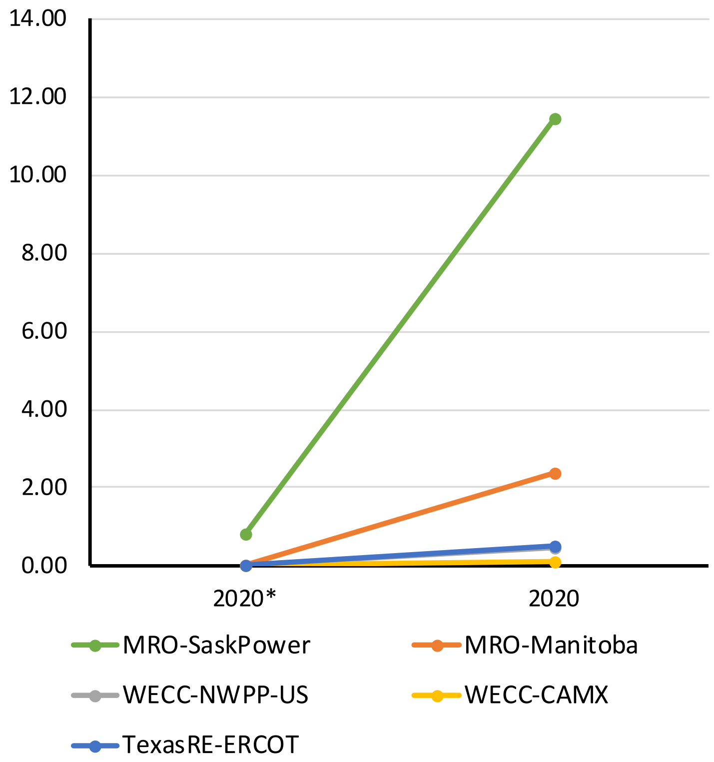


Figure 1.7: Comparison of the 2016 versus the 2018 Probabilistic Analysis, LOLH Notable Trends for the 2020 Study Year

Key Finding 2: Reliance on Natural Gas Generation Increases in some Areas with Continuing Resource Mix Changes

Key Points:

- North America has a diverse fuel mix; however, in some Regions an increasing reliance on natural gas can expose the BPS to fuel supply and delivery vulnerabilities, particularly during extreme weather conditions.
- Over the past decade, natural gas has been the fuel of choice for the majority of new generating capacity additions, particularly for generators designed to provide peaking capability and flexibility to help offset variable energy production
- Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural-gas-fired generation and constrained natural gas transportation. Recent market enhancements, such as capacity performance and pay-for-performance, offer mechanisms to positively improve generator availability.

Fuel Mix Changes

Figure 1.8 identifies the components of the fuel mix for the United States and Canada as a whole. Natural gas capacity continues to increase in many parts of the countries, and from a North American perspective, it increases from 43 percent to 46 percent by 2028. Coal and nuclear are projected to decrease to 19 and nine percent, respectively.

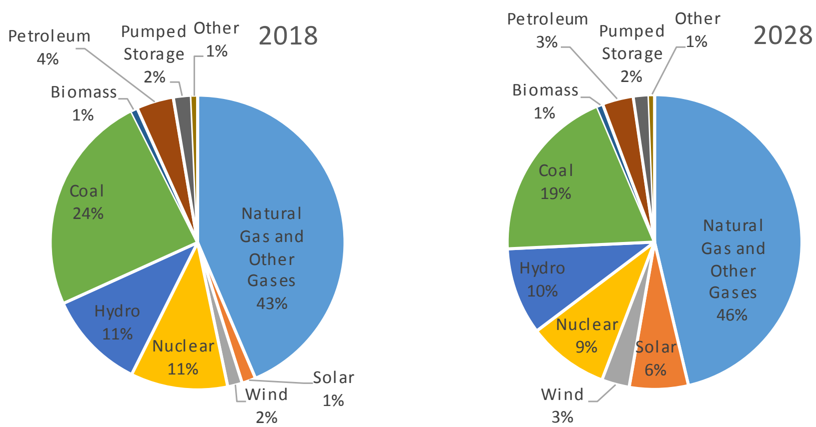


Figure 1.8: 2018 On-Peak Fuel Mix Compared to 2028 On-Peak Fuel Mix

Across North America, natural-gas-fired generation continues to increase beyond projections. From the 2009 through the *2018 Long-Term Reliability Assessment*, actual natural gas additions have outpaced projections; and over the next 10 years, 41 GW of Tier 1 resources are expected—this number expands to 96 GW when considering Tier 2 resources (**Figures 1.9** and **1.10**).

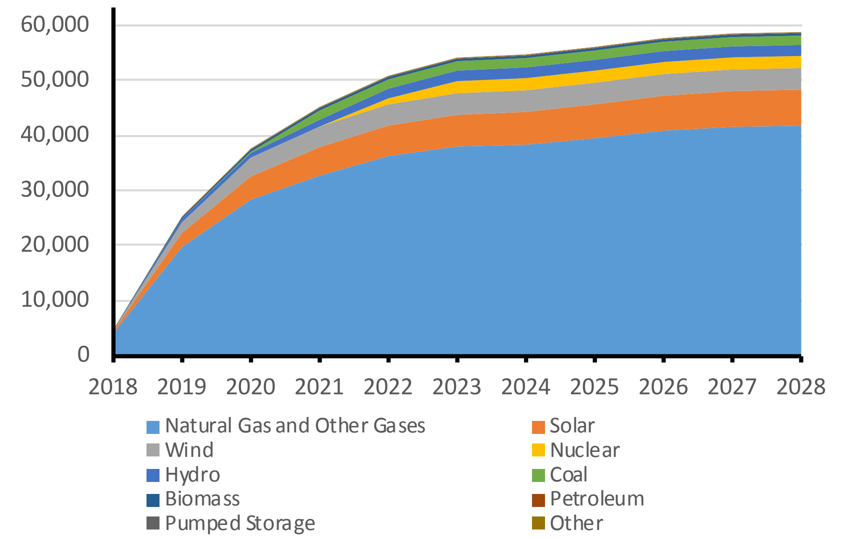


Figure 1.9: Tier 1 Planned Resources Projected Through 2028

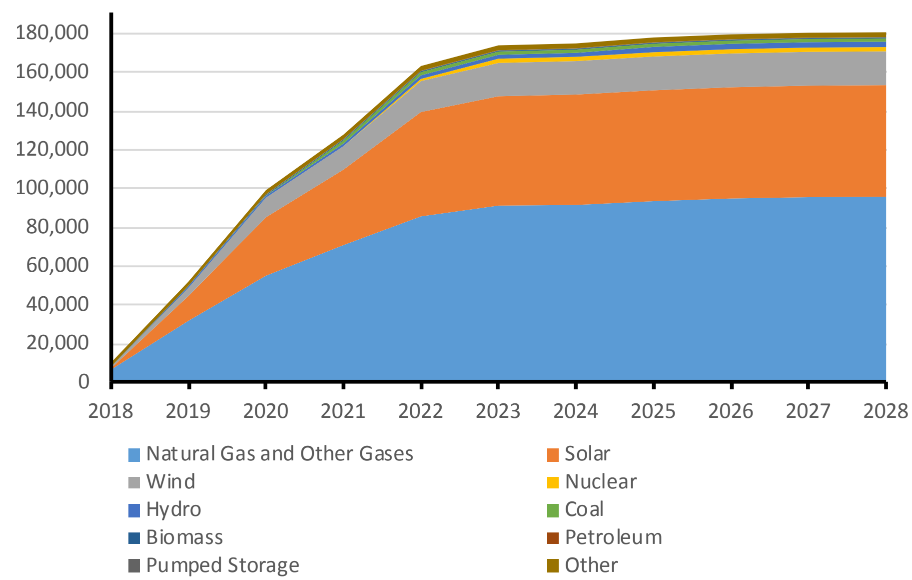


Figure 1.10: Tier 1 and 2 Planned Resources Projected Through 2028

NERC Capacity Supply Categories:

Future capacity additions are reported in three categories:

Tier 1: included in the Anticipated Resources category—planned generating unit or plant that meets at least one of the following requirements:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection service agreement
- Signed/approved power purchase agreement
- Signed/approved Interconnection construction service agreement
- Signed/approved wholesale market participant agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to vertically integrated entities)

Tier 2: included in the Prospective Resources category—planned generating unit or plant that meets at least one of the following requirements:

- Signed/approved completion of a feasibility study
- Signed/approved completion of a system impact study
- Signed/approved completion of a facilities study
- Requested Interconnection service agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to RTOs/ISOs)

Tier 3: other planned generating units or plants that do not meet any Tier 2 requirements.

In addition to natural-gas-fired generation, solar additions provide the second most additions to capacity to the overall North American fuel mix with approximately seven GW of Tier 1 capacity **(Figure 1.9)**. When considering Tier 2 resources, up to 63 GW are projected **(Figure 1.10)**. These projections are used for peak reserve margin purposes and are different than the solar resource nameplate capacity.[16]

A significant amount of wind is also expected; however, because its peak contribution is relatively low, **Figures 1.9**, **1.10**, and **1.11** show that wind does not significantly contribute to peak capacity. While up to 82 GW of nameplate Tier 1 and 2 wind are expected by 2028, only about 20 GW is expected to contribute to peak capacity—about 25 percent.

While some areas of North America have and continue to see more rapid resource mix changes, as a whole North America has a diverse fuel mix and modest changes area currently planned over the 10-year period. A 10-year projection of North America peak capacity is shown in **Figure 1.11**.

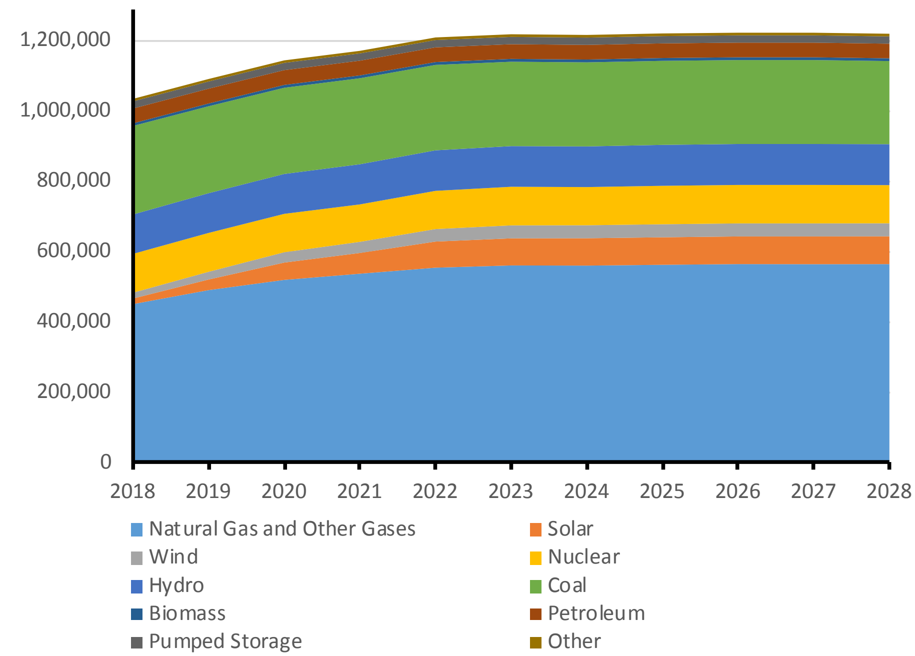


Figure 1.11: Existing, Tier 1, and 2 Planned Resources Projected Through 2028

[16] The nameplate capacity additions for 2028 are 11 GW of Tier 1 capacity and 86 GW of Tier 2 capacity.

Operating Reliability Risks Due to Conventional Generation Retirements: Capacity retirements located near metropolitan areas or large load centers that have limited transmission import capability present the greatest potential risk to reliability. Unless these retirements are replaced with plants in the same vicinity, these load centers will require increased power imports and dynamic reactive resource replacement.[1] If the transmission links between an area and generation sources are relatively weak, voltage instability can be the result. Dynamic reactive power must be provided to prevent voltage collapse. Solutions to preventing voltage instability could range from extensive transmission improvements to optimal placement of static var compensators, synchronous condensers, or locating new generation in the load pocket. Retiring generation units in a generation "pocket" might cause the remaining units to become a "reliability must run" units, which often require additional actions or investments (e.g., transformers, shunt capacitors) in equipment to maintain voltage stability.

1 Dynamic reactive support is measured as the difference between its present var output and its maximum var output. Dynamic reactive support is used to support system state transients occurring post-contingency. NERC's *Reactive Power Planning Reliability Guideline* provides strategies and recommended practices for reactive power planning and voltage control and accounts for operational aspects of maintaining reliable voltages and sufficient reactive power capability on the BPS:

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Reactive%20Power%20Planning.pdf

Conventional Capacity Retirements

As shown in **Figure 1.12**, there have been approximately 39 GW of coal-fired, 13 GW of natural-gas-fired, and 1.1 GW of nuclear-powered capacity retired since 2013. Also shown are the announced retirements of approximately nine GW of coal-fired, seven GW of nuclear, and 10.9 GW of natural-gas-fired generation capacity.

Retirement plans have been announced for 14 nuclear units, totaling 7.1 GW. The fleet of 67 nuclear plants (118 units) in the United States 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 economically viable. See the following additional information:

- Seven plants have closed since 2012, including Gentilly (Québec), Crystal River (Florida), Kewaunee (Wisconsin), San Onofre (California), Vermont Yankee (Vermont), Oyster Creek (New Jersey), and Fort Calhoun (Nebraska).
- Owners of seven plants (14 units) have announced plans to retire within the next decade, including facilities in Ontario, California, New York, Pennsylvania, Michigan, and Massachusetts.

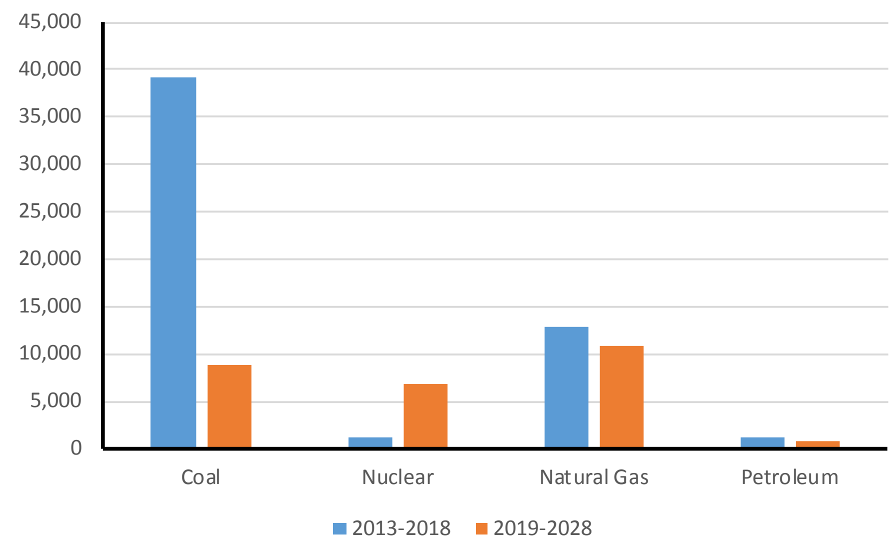


Figure 1.12: Capacity Retirements between 2013 and 2018, and 2019 Projected through 2028

- 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 enacted legislation establishing a zero-emission credit requirement for some upstate nuclear generating facilities.

Natural Gas Capacity Additions

NERC-wide natural-gas-fired on-peak generation has increased from 280 GW in 2009 to 460 GW today with an additional 41 GW planned during the next decade—96 GW when considering Tier 2 additions as shown in Figure 1.13.

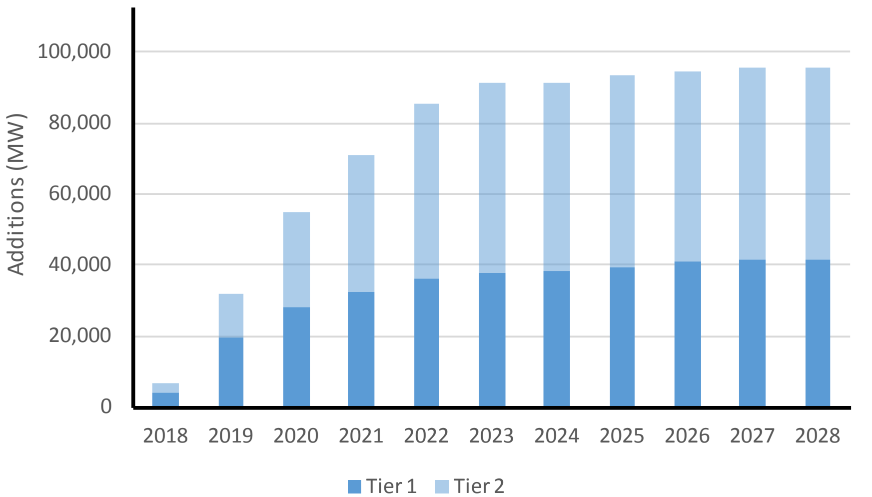


Figure 1.13: Annual Natural Gas Capacity Additions through 2028

During the past decade, several assessment areas have significantly increased dependence on natural-gas-fired generation, a trend that results from lower sustained natural gas prices, lower plant construction costs (compared to nuclear and coal), and environmental regulations that disadvantage coal plant investments. By 2023, FRCC, TRE-ERCOT, NPCC-New England, and most of the WECC assessment areas are expected to have at least 50 percent of their resources composed of natural-gas-fired generation with FRCC expected to near 80 percent as shown in Table 1.4. The notable increase of natural gas generation in these assessment area does not necessarily indicate an increased risk; however, it is an early warning indicator for planners who may need to review their supply, transportation, and back-up fuel sources for any emerging risk.

Table 1.4: Assessment Areas with more than 50 Percent Natural Gas as a Percent of Total Capacity

Assessment Area	2018 (MW)	2023 (MW)	2018 (%)	2023 (%)
FRCC	40,913	44,687	75.0%	77.2%
WECC-CAMX	41,352	36,966	62.0%	59.1%
TRE-ERCOT	49,435	52,449	65%	64%
NPCC-New England	15,712	16,261	51%	52%
WECC-SRSG	17,631	17,273	55.9%	55.6%
WECC-AB	7,682	7,682	50.8%	50.8%

As natural-gas-fired generation continues to increase, the electric industry needs to continue to evaluate and report on the potential BPS reliability effects of an increased reliance on natural gas. During extreme events, and most notably during the 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[17] 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
- Inability to procure natural gas
- Fuel oil gelling

Maintaining Fuel Diversity and Assurance

Replacing coal and nuclear generation with natural-gas-fired and variable generation introduces new considerations for reliability planning, such as ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system. Diverse generation resources reduce risk from fuel supply disruptions (i.e., all of the "eggs" are not in one basket).

[17] 2014 Polar Vortex Review: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural gas and limited pipeline infrastructure. Fuel assurance, while not explicitly defined, refers to the confidence system planners have in a given resources' availability based on its fuel limitations. Table 1.5 identifies some of the mechanisms that can help promote fuel assurance as well as some of the questions BPS planners should be considering as the resource mix changes. In some areas, 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.

Table 1.5: Mechanisms and the Planning Considerations to Promote Fuel Assurance

Mechanisms Promoting Fuel Assurance	Planning Considerations
Fuel Service Agreements	What level of service does each generator maintain?
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 rules are in place to promote generator availability? What tools exist to prepare and study large disruptions?
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?

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. 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 United States since 1997 is dual fuel capable.

With natural gas generation primed to continue its growth as the leading choice for new and replacement capacity, important distinctions around fuel assurance need to be incorporated into long-term planning. Mainly, natural gas generation is fueled using just-in-time transportation and delivery, and therefore, is subject to interruption and/or curtailment. In constrained natural gas markets, generation without firm supply and transportation are not expected to be served during peak pipeline conditions. Many of these plants no longer have the option of burning a liquid fuel. Further, regardless of fuel service arrangements, natural gas generation is subject to curtailment during a force majeure event. These fuel constraints need to be known by planners so they can better understand if there is insufficient energy available in a given system.

Regional Considerations

The electric industry is taking immediate steps to address concerns raised by NERC and other regulatory agencies including FERC, DOE, and individual state utility commissions. Because of both the geographic and regulatory differences across North America, it is important to evaluate how each area is addressing the challenges. Some areas, like Texas, have a significantly "meshed" natural gas pipeline system while others, such as California and New England, have limited access to the interstate pipeline system, storage, and production. Different regulatory structures give rise to different approaches. For instance, regulated states with integrated resource planning processes have the opportunity to incorporate firm pipeline transportation and back-up liquid fuel inventories into their cost-of-service rate structures. While in wholesale electricity markets, generally, generation owners determine their fuel supply arrangements and procure it based on economic risk. These regional perspectives are highlighted below along with the initiatives implemented to address natural fuel assurance risks:

FRCC

- Utilities maintain significant firm natural gas contracts and maintain dual fuel capability.
- Approximately 65 percent of the natural-gas-fired generation fleet can run on back-up fuel.
- Sabal Trail, the third major interstate natural gas pipeline, was added to increase delivery and supply diversity.

TRE-ERCOT

- ERCOT estimates that at least 34,706 MW of its natural-gas-fired fleet has firm natural gas contracts, representing about 58 percent of the fleet total. Using the responses received from the 2017 fuel survey, about 5,454 MW is dual-fuel capable. About 3,667 MW (six percent of the total) maintains at least one day of alternate fuel supply on-site during the winter season.
- Robust pipeline infrastructure significantly reduces risk.
- Recently instituted annual fuel survey of natural-gas-fired generation fleet to gauge alternate fuel capabilities.
- Improved coordination and information-sharing between generator owners and pipeline operators, which include receiving confidential notifications of operational issues occurring on the pipelines at the same time generators are notified.

WECC

- Improved information sharing between generator owners and pipeline operators with active coordination on energy emergencies with the California Energy Commission in response to the Aliso Canyon natural gas storage facility imposed limitations.
- A recent analysis by WECC[18] indicates the configuration of the natural gas–electric system, combined with the potential retirement of Aliso Canyon, creates region-wide reliability issues; this can cause widespread loss of electric load with the Southwest and Southern California areas due to being most vulnerable to major disruption events because of heavy reliance on natural gas generation to meet peak demands and limited natural gas storage capability. Specifically, the configuration of the natural gas–electric system, combined with the potential closure of Aliso Canyon, creates region-wide reliability issues concentrated in Southern California and the greater Phoenix area. Disruption scenarios involving a Desert Southwest pipeline rupture or Permian/San Juan Basin supply freeze-offs routinely result in unserved energy and/or unmet spinning reserves. WECC's analysis also finds that both the modeling scenarios and recent real-world events point towards a system being pushed to its limit, indicating that the Western Interconnection is at an important crossroads.

NPCC-New England

- Only three natural gas plants hold firm mainline transportation contracts that can fuel only one-third to two-thirds of their overall capacity. Only 11 natural-gas-capable plants (natural-gas-only or dual-fuel) hold lateral-only firm transportation contracts.
- The rest of the fleet relies on spot market natural gas supply and unused transportation to fulfill their daily electric commitments.

[18] https://www.wecc.biz/Administrative/WECC%20Natural gas-Electric%20Study%20Public%20Report.pdf

- Preseason fuel inventory surveys for oil and dual fuel units[19] with market rules to offer flexibility and adjustments to the day-ahead energy market. A total of 43 units/stations are natural gas only single fuel source, totaling 10,427 MW winter capacity rating. A total of 61 units/stations are dual fuel capability totaling 9,544 MW winter capacity rating. These units are traditionally peaking units that primarily have a one to three day holding tank for oil storage, and the majority are refueled via trucking.
- Beginning in 2018, the pay-for-performance (PFP) program will provide incentives for units to perform during extreme conditions.
- Winter reliability program incentivizes dual-fuel units, securing fuel inventory, and testing fuel-switching capability.[20]

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

[20] The Winter Reliability Program ends after the 2017–18 winter.

- Improved coordination and information sharing between ISO-NE and operators (including maintenance schedules) and a natural gas usage tool that allows system operators to estimate spare natural gas pipeline capacity (by individual pipe).
- Mystic Station (2,274 MW) retirement request further strains winter season reliability. Because the power plant does not rely on natural gas from the interstate pipeline, it is not impacted by interruptions or curtailments from the pipeline network. However, ISO-NE analysis identifies unacceptable fuel security risks and could cause the system operator to deplete 10-minute operating reserves (a violation of NERC Reliability Standard) on numerous occasions and to possibly trigger load shedding (or rolling blackouts) during the winters of 2022–2023 and 2023–2024.[21]

  The future of Mystic Station remains uncertain as a FERC decision rejected an ISO-NE proposal that requested cost recovery. To address the energy security concern, which could be exacerbated with the Mystic Station retirement request, ISO New England has commenced efforts to develop system operations and market design solutions to be accomplished by mid-2019. This effort responds to a FERC order directing ISO New England to develop and file with the commission improvements to its market design to better address regional fuel security issues by July 1, 2019."[22]

[21] Compounding these issues, the retirement of Mystic Station not only would deprive the New England's BPS of winter generating capacity with what is considered "on-site" fuel, but it also would mean the loss of the Distrigas' biggest LNG customer. ISO-NE procured independent consultation to assess this situation; they found that these actions would substantially diminishing Distrinatural gas's financial viability. See Testimony of Richard L. Levitan and Sara Wilmer at 7:5–8, 19–22:2 (stating that retirement of Mystic 8 and 9 likely would be the start of a "death spiral" for Distrinatural gas because its other business is insufficient to enable it to recover its estimated going-forward costs) ("Levitan/Wilmer Testimony").

[22] https://www.ferc.gov/CalendarFiles/20180702193957-ER18-1509-000.pdf

NPCC-New York

- Increased coordination in operator control room, including a visualization of the Northeast interstate pipeline system highlighted to show when operational flow orders are posted.
- A weekly web-based fuel survey "portal" provides generator fuel information to the operators.
- A communications protocol is in place with New York to improve the speed and efficiency of generator requests to state agencies for emissions waivers if needed for reliability.
- Weekly and daily dashboards are developed during cold weather conditions that indicate fuel and capacity margin status.
- An emergency communication protocol is in place to communicate electric reliability concerns related to fuel availability to pipelines and natural gas LDCs during tight electric operating conditions.

PJM

- Capacity performance rules, incentives, and charges for nonperformance are in place to promote adequate generator availability during peak days.
- Better performance observed in the early 2018 cold snap and in the 2014 Polar Vortex.[23] Positive indicators of the effectiveness of capacity performance include a decrease in restrictive generator operating parameters, reported investment in major reliability work for existing resources, and new resources investing in firm natural gas and transportation contracts.

SERC

- Entities procure firm transportation on various natural gas pipelines and natural gas supply from various natural gas supply basins to ensure reliable system operations for natural-gas-fired plants. Some companies report procuring firm natural gas storage capacity with various natural gas storage providers with access to multiple pipelines to protect against supply disruptions.
- For entities in SERC SE, firm transportation, firm natural gas storage, and fuel oil backup provide for reliable operations and protection from natural gas supply and transportation issues.

[23] https://www.pjm.com/-/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx?la=en

The Stagnation of Pipeline Expansion into New England

Although natural gas production from the Marcellus/Utica basins is projected to increase, New England currently cannot access the full benefits of that natural gas production. Only two minor natural gas pipeline expansion projects were fully put into service: Spectra Energy's Algonquin Incremental Market (AIM) project (Winter 2016/17) and Tennessee Natural gas Pipeline's (TGPs) Connecticut Expansion Project (Winter 2017/18), totaling an incremental 414,000 dekatherms per day of new pipeline capacity.

Enbridge's Atlantic Bridge Project is designed to provide an additional 132,700 Dth/d capacity on its Algonquin Natural gas Transmission (AGT) and Maritimes & Northeast (M&N) pipeline systems to move natural gas into New England and to specific end use markets in the Canadian Maritime provinces; the initial in-service date was November 2017. The new facilities in Connecticut enable AGT to provide firm transportation service for a portion of the Atlantic Bridge's project capacity. However, substantial community push-back has taken place over the proposed new compressor station located in Weymouth, Massachusetts (Fore River); the state of Massachusetts has not issued the necessary air permits for the new compressor project. Since some of the project work has been completed, on October 27, 2017, the FERC granted AGT's request to place the Connecticut facilities into service to provide 40,000 Dth/d day of incremental firm transportation service. The projected in-service dates for the Weymouth compressor is prior to Winter 2018/19 operations.

However, these minor expansion projects and their benefits will be more than offset by the recent retirement of Vermont Yankee nuclear power station (620 MW) as well as the retirement of Brayton Point (~1,500 MW of coal, natural gas, and oil) and the expected retirement of the Pilgrim Nuclear Station (677 MW) in 2019. It is safe to say that, although there have been several past proposals to build new greenfield natural gas pipelines into New England, the combination of local, town, city, and state opposition within both New York and New England has effectively canceled all major pipeline expansion proposals for New England. Several natural gas transportation companies have even halted their business development activities in New England.

One of the improvements to ISO-NE's Forward Capacity Market rules is PFP, which went into effect on June 1, 2018. PFP will create stronger financial incentives for generators to perform when called upon during periods of system stress; a resource that underperforms will effectively forfeit some or all capacity payments, and resources that perform in its place will get the payment instead.[1] PFP will also create incentives to make investments to increase unit availability, such as implementing dual-fuel capability, entering into firm natural gas supply contracts, and investing in new fast-responding assets. By creating financial incentives for generators to firm up their fuel supply, PFP may indirectly provide incentives for the development of on-site CNG, liquid natural gas (LNG), and/or fuel oil storage, or expanded natural gas pipeline infrastructure with dedicated firm contracts within the power sector. However, PFP will not reach full effectiveness until the seven-year phase-in of the new performance rate is complete. Until that time, the Region may be challenged to meet power demand at times when regional natural gas pipeline capacity is being contractually utilized. Conversely, however, the new PFP market rules may hasten the retirement of older, inefficient resources with poor historical performance and heat rates and initiate the entrance of new, efficient, better-performing resources, which hopefully will be dual-fuel-peaking resources (natural gas/oil).

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[1] Under the PFP, all resources with a capacity obligation can be penalized $2,000/MWh for failing to supply energy or reserves when capacity becomes scarce while resources that over-perform relative to their obligation (including those with no obligation) can receive $2,000/MWh of additional revenue. This performance payment rate is scheduled to increase to $5,455/MWh over the coming six years.

Key Finding 3: Frequency Response Is Expected to Remain Adequate Through 2022

Key Points:

- Despite increasing amounts of asynchronous resources and decreasing inertia from generation, each of the four Interconnections expect to have adequate and diverse sources of frequency response, and all have a low likelihood of activating under-frequency load shedding (UFLS) schemes.
- In February of 2018, FERC Order No. 842[24] was issued and mandates all new generating facilities to maintain the capability of providing primary frequency response. While FERC Order No. 842 does not require certain performance of providing frequency response in real-time, it does provide clear direction and assurances that all generation resources connected to the BPS have the capability of providing it.
- Maintaining Interconnection frequency within acceptable boundaries following the sudden loss of generation or load can be accomplished using control functions of inverters, which includes energy storage, and load-shedding relays; this is generally known as fast frequency response (FFR). The application of FFR is expected to continue and support frequency when synchronous inertia is insufficient.
- It is not necessary to monitor Quebec Interconnection frequency response in NERC's future assessment activities due to the operational controls in place as well as the lack of projected resource mix changes over the next 10 years.
- Future changes to the resource mix (e.g., accelerated generation retirements, economics) will impact the results of this analysis and NERC's assessment.

Background: How Does Inertia and Frequency Response Support Reliability?
Frequency support is the response of generators and loads to maintain the system frequency in the event of a system disturbance. Frequency support is provided through the combined interactions of synchronous inertia (traditionally from generators such as natural gas, coal, and nuclear plants as well as from motors at customer locations) and frequency response (from a wide variety of generators and loads). Working in a coordinated way, these characteristics arrest and eventually stabilize frequency. An illustrative example of this behavior is shown in **Figure 1.14**. A critical issue is to stabilize the frequency before it falls below UFLS values or rises above over-frequency relay trip settings.[25]

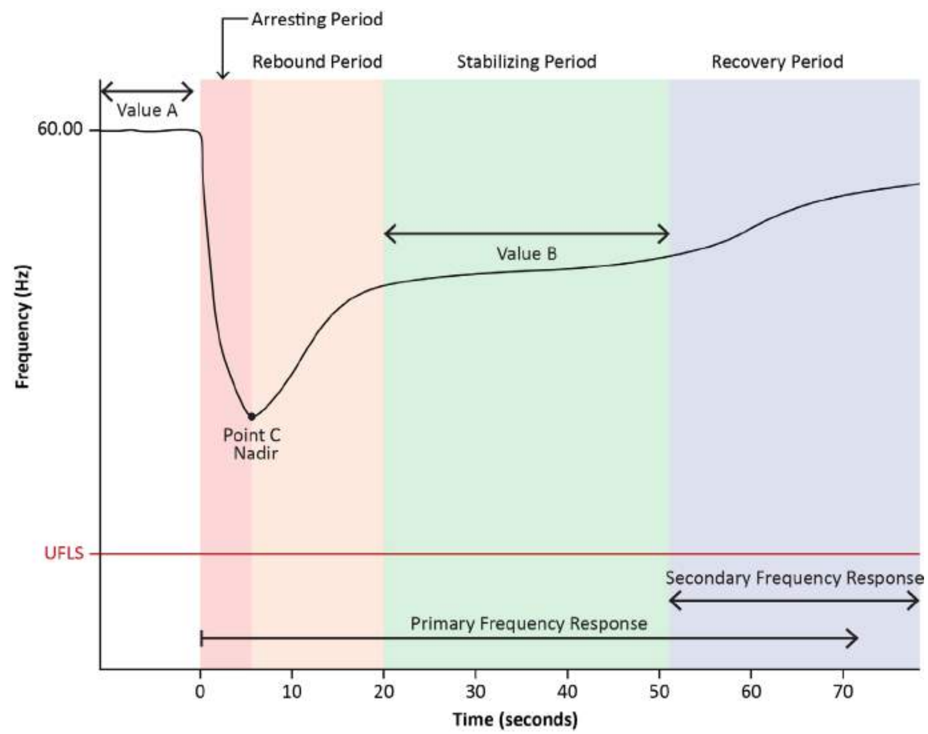

Figure 1.14: Illustrative Example of Inertial and Frequency Response Behavior after a Disturbance

[24] FERC Order No. 842 issued February 15, 2018

[25] NERC-developed instructional videos: *The Basics of Essential Reliability Services*, https://vimeopro.com/nerclearning/erstf-1

Inertia and frequency response are properties of the Interconnection (not to each balancing area individually) and these properties have different characteristics for each Interconnection. For example, if changes to the resource mix alter the relative amounts of synchronous inertial response (SIR) or frequency response, various mitigation actions are possible (such as obtaining faster primary frequency response from other generators or loads) to maintain or improve overall frequency support.

Synchronous inertia is the measure of stored kinetic energy in a rotating generator or machine. Synchronous inertia is a constant, and it is a function of the MVA[26] size and the physical attributes of the generator's rotating mass. During a disturbance, the stored kinetic energy of the resource is injected into the system (SIR) and assists in reducing the rate of change of frequency (RoCoF) and the depth of the frequency decline. Therefore, the Interconnection inertia is a function of the generation resource mix, the amount of load being served, and the time of day.

Reliability Challenges

Asynchronous resources—generators that do not use mechanical rotors that synchronize with system frequency to produce electricity, such as wind, solar, or any other resource that uses inverter technology—cannot directly provide synchronous inertia. However, wind resources, for example, equipped with specific controls can emulate inertia for a limited period of time by extracting stored energy from the rotating wind turbine and increasing the real power output (MW) of the wind turbine. The additional MW injection delivered to the grid during the loss of a system resource will reduce the RoCoF and the depth of the frequency decline; this provides enough time for the primary frequency response to aid in the frequency recovery of the interconnection. This form of frequency-arresting power is commonly referred to as FFR. The concept also applies to solar and energy storage systems connected asynchronously when "headroom"[27] is maintained as part of the dispatch. Like wind resources, storage systems can be used to inject MW during a disturbance to reduce the RoCoF and arrest the decline in the system's frequency.

The Four Factors that Determine Reliable Interconnection Response:[1]

- The size of the resource-loss event
- The Interconnection inertia at the time of the event, which determines the rate of frequency decline
- The speed with which other on-line generators or resources respond to arrest and stabilize frequency (primary frequency response)
- The means by which other generators or resources respond subsequently to restore frequency to its original scheduled value and to restore reserves to their original state of readiness (i.e., secondary and tertiary frequency control)

The four factors stated above identify the variables that help assess an Interconnection's frequency response. Synchronized turbine generator automatic control systems (governors) can sense the decline in frequency and control the generator to increase the amount of energy injected into the interconnection.

Frequency will continue to decline until the amount of energy is rebalanced through the automatic control actions of primary frequency response resources and reduction of system load due to its sensitivity to frequency. Greater inertia reduces the RoCoF, giving more time for governors to respond. Conversely, lower inertia increases the reliability value of faster-acting frequency control resources in reducing the severity of frequency excursions.

[1] Adapted from Frequency Control Requirements for Reliable Interconnection Frequency Response, FERC/LBNL: https://www.ferc.gov/industries/electric/indus-act/reliability/frequency-control-requirements/report.pdf

[26] MVA: [Mega] volt ampere is the unit used for the apparent power in an electrical circuit, equal to the product of root-mean-square (RMS) voltage and RMS current. With a purely resistive load, the apparent power is equal to the real power. Where a reactive (capacitive or inductive) component is present in the load, the apparent power is greater than the real power as voltage and current are no longer in phase. In the limiting case of a purely reactive load, current is drawn but no power is dissipated in the load.

[27] This is the difference between the current operating point of a generator or transmission system and its maximum operating capability. The headroom available at a generator establishes the maximum amount of power that generator theoretically could deliver to oppose a decline in frequency. However, the droop setting for the turbine-governor and the highest set point for UFLS will determine what portion of the available headroom will be able to deliver to contribute to primary frequency control.

In past reliability assessments, NERC had noted concerns related to the potential reductions in the supply of frequency response capability due to the ongoing retirements of synchronous generation and the significant addition of variable energy resources. However, in February 2018, FERC issued Order No. 842[28] mandating all new generating facilities to maintain primary frequency response capability. While FERC Order No. 842 does not require certain performance of providing frequency response in real-time, it does provide clear direction and assurances that all generation resources connected to the BPS should be capable of providing it.

Frequency Response and Inertia Measures

Trends in the frequency measures can be analyzed using historical data and projected into the future using reasonable planning assumptions and models. The NERC PC and Operating Committee (OC) jointly created the Essential Reliability Services Task Force (ERSTF) in 2014 to consider reliability issues that may result from the changing generation resource mix. In 2015, the ERSTF proposed measures for ERS for examination and potential ongoing monitoring to identify trends. The frequency measures are intended to help monitor and identify trends in frequency response performance as the generation mix continues to change.

The holistic frequency measure, called Measure 4 in ERSWG reports, tracks phases of frequency performance for actual disturbance events in each Interconnection (e.g., initial frequency rate of change and timing of the arresting and recovery phases). Other measures look at components of this coordinated frequency response, such as the amount of SIR (Measure 1), and the initial rate of change in frequency following the largest contingency event (RoCoF, Measure 2). These measures are further described in **Table 1.6**.

The current resource contingency criteria (RCC) for each Interconnection is provided in **Table 1.7** on the next page. The values defined correspond to select contingencies used for BAL-003-1.1 requirements and interconnection frequency response obligations. If operating restrictions would limit the RCC, then that will be accounted for as part of the case creation and contingency definition. For example, Hydro Québec limits generation dispatch for low inertia conditions such that 1,700 MW RCC cannot occur; this mitigates a potential severe contingency where inertial conditions are of concern.

Table 1.6: Measures of Frequency Response

Measure	What it Measures	Summary Assessment Findings
SIR (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of nearly 80 GW of conventional synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT's use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
RoCoF (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection's response to the largest credible contingency	Simulations in both Eastern and Western Interconnection show sufficient frequency response in future planning cases.

[28] FERC Order No. 842 issued February 15, 2018

Table 1.7: RCC and UFLS Tripping Set-Points by Interconnection

Eastern Interconnection	Western Interconnection	Texas Interconnection	Quebec Interconnection
4,500 MW	2,740 MW	2,750 MW	1,700 MW
59.5 Hz	59.5 Hz	59.3 Hz	58.5 Hz

Trends and Projected Interconnection Performance

A summary of each Interconnection's results for NERC's assessment is included in **Table 1.8**.[29] Despite increasing amounts of asynchronous resources and decreasing inertia from generation, each of the four Interconnections expect to have adequate and diverse sources of frequency response, and thus, all have a low likelihood of activating UFLS schemes. These results were confirmed by dynamic studies performed for both the Eastern and Western Interconnections and implemented operational procedures for Texas and Quebec Interconnections.

As the resource mix continues to evolve, so is the resulting Interconnection inertia. NERC and the Resources Subcommittee (RS) are working with the Interconnections to monitor their respective annual minimum SIR for trending. A summary of the historic SIR is provided for all Interconnections in **Figure 1.15** on the next page. As observed over the past three years, there has not been a large change in minimum inertia levels and the demand level corresponding with it. More in-depth analysis can be found in NERC's *2018 State of Reliability* report.[30]

One approach in understanding the relationship between minimum SIR and minimum system load is to evaluate the ratio of the two values. There is no consistent critical value that can apply to all Interconnections to determine when reliability is in jeopardy; however, based on recent ERCOT analysis, a critical SIR of 100 GW-seconds has been established. Based on this, one can calculate the critical ratio of minimum system load to minimum SIR, which is approximately 30 percent for ERCOT, using 2018 minimum load value. The 30 percent value can be used as an initial screening to indicate the need for closer evaluation. Beyond this amount, faster frequency response may be needed beyond what is currently available from either non-synchronous sources or load shedding.[31]

Due to the smaller size, the Texas and Quebec Interconnections experience lower system inertia compared to Eastern and Western Interconnections. Currently, wind amounts to more than 17 percent of installed generation capacity in the Texas Interconnection and has served as much as 50 percent of system load during certain periods. In Quebec, 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.

Table 1.8: Summary Table of Results of NERC Frequency Response Sufficiency Assessment

Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation[1]
Eastern Interconnection	5%	0	59.85 Hz	Low
Western Interconnection	15%	0	59.84 Hz	Low
Texas Interconnection	54%	0	N/A	Low
Quebec Interconnection	18%	0	N/A	Low

[29] Likelihood of UFLS determined by the study results and assumptions. Low likelihood indicates that studies are being performed, the expected dynamic response of the system is generally known, and the simulated frequency nadir is above UFLS set-points. If simulated frequency nadir is less than UFLS set-points, then the likelihood is high. Medium likelihood is used to describe an Interconnection that is experiencing a significant shift in resources, may not have the market processes in place to ensure resource performance, and/or studies are not sufficiently representative of system behavior.

[30] NERC 2018 State of Reliability: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

[31] In ERCOT for example, in order to qualify, load response resources must perform within 0.5 seconds. If load is required to perform faster and/or at higher frequency triggers, more frequency arresting power can be made available to support lower levels of system inertia.

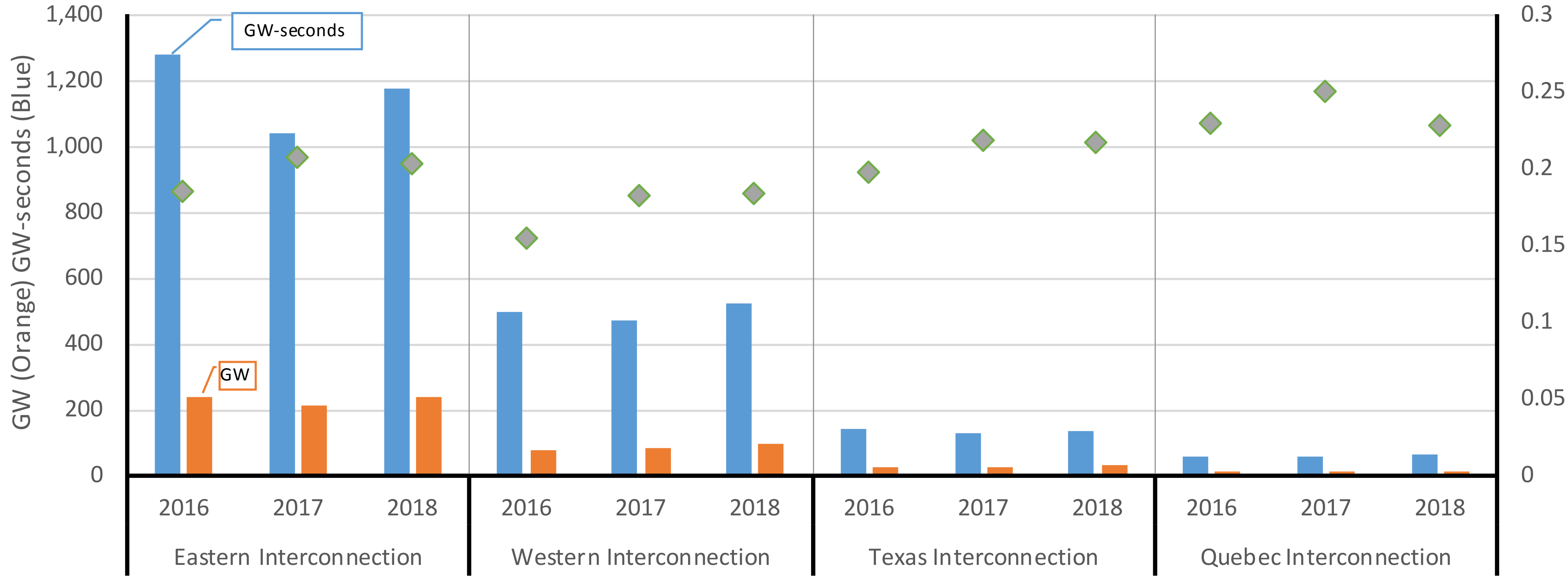

Figure 1.15: Historical Interconnection Minimum Synchronous Inertia (GW-seconds) by Year

In Texas[32] and Québec[33] Interconnections, critical inertial levels are credible within their projected dispatches, and therefore, operators have established operating procedures to manage real-time inertia in their respective systems. Because the two systems are relatively small compared to the Eastern and Western Interconnections, they are more likely to observe and have to manage minimum inertia conditions. While Quebec does not anticipate a significant resource mix change, Texas's resource mix continues to evolve and currently established operational procedures may need to be further adjusted.

Past performance identified in NERC's *2018 State of Reliability Report*[34] shows continued success in ERCOT in managing the increasing amounts of wind resources. One approach ERCOT has taken is to require wind generation to provide downward frequency response through curtailment action. As wind generation continues to increase in the Interconnection, extracting capabilities from asynchronous generation helps support the reliability needs of the BPS, and ERCOT has seen improved frequency performance with both the arresting and stabilizing periods over the last several years. Further, wind load is a positive and statistically significant factor that affects respective frequency response in ERCOT.

[32] ERCOT procures RRS amounts based on the expected system inertia to ensure sufficient frequency response after a 2,750 MW loss. In 2015, ERCOT revised its ancillary service methodology and now determines the minimum RRS requirements based on anticipated system inertia conditions.

[33] Since 2006, Québec has applied a real-time control criteria, called the PPPC limit (MW), that actively restricts the maximum MW loss of generation following a single contingency event. System operators perform generation re-dispatch 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.

[34] NERC 2018 State of Reliability Report: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf

In 2018, ERCOT conducted and released a study[35] that analyzed the system-wide stability impacts for a scenario that included a high penetration of renewable generation. The study analyzed a full suite of stability and dynamics-related issues (beyond frequency response) within a scenario case, totaling 28,000 MW of renewable generation serving about 70 percent of the total system load. At this level of renewable penetration, ERCOT determined there would be significant stability issues that would need to be addressed to maintain a reliable grid.

An overview of analytical processes and methods used in forward looking assessment of four Interconnections are posted on the NERC website in a technical brief.[36]

[35] Dynamic Stability Assessment of High Penetration of Renewable Generation in the ERCOT Grid: http://www.ercot.com/content/wcm/lists/144927/Dynamic_Stability_Assessment_of_High_Penetration_of_Renewable_Generatio....pdf)

[36] Forward Looking Frequency Trends Technical Brief ERS Framework Measures 1, 2, and 4: Forward Looking Frequency Analysis: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Forward_Measures_124_Tech_Brief_03292018_Final.pdf

Key Finding 4: Increasing Solar and Wind Resources Requires more Flexible Capacity to Support Ramp Requirements

Key Points:

- As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability—such as supporting solar down ramps when the sun goes down and complementing wind pattern changes.
- Increasing solar generation in California increases the need for flexible resources. CAISO's 2018 solar generation projection increases CAISO's three-hour ramp requirements to over 17,000 MW, approximately 20 percent greater than the amount projected for 2018.
- Changing ramping requirements induced by increasing amounts of wind is largely managed with improved forecasting. Ramp forecasts allow ERCOT operators to curtail wind production and/or reconfigure the system in response to large changes in wind output.

System Flexibility Needs

In order to maintain load-and-supply balance in real time with higher penetrations of variable supply and less-predictable demand, operators are seeing the need to have more system ramping capability. This can be accomplished by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility. Flexible resources, as described in this section, refer to dispatchable conventional as well as dispatchable variable resources, energy storage devices, and dispatchable loads.

Ramping is related to frequency through balancing of generation and load during daily system operations. Changes in the amount of nondispatchable resources,[37] system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources[38] needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations.[39]

System ramping capability with flexible resources is becoming an important component of planning and operations. For example, CAISO is experiencing challenges with net load[40] ramping and over-supply conditions. High penetrations of variable resources are meeting a large portion of their customers' energy needs during various times of the day, resulting in the need for additional flexibility and ramping capability from the rest of the generation fleet to respond to changes in output. An illustrative example of this is shown in **Figure 1.16** on the next page, which shows that as solar PV is added to a particular system increased ramping capability is needed to support the increased ramping requirements. This is not a completely new concern for operators as some resources and imports have a long history of nondispatchability due to physical or contractual limitations. However, variable resources (particularly solar generation due to its daily production patterns) are the primary driver leading to increased ramping requirements. Other dispatchable resources are needed in reserve to offset the lack of electricity production when variable fuels (e.g., sun, wind) are not available.

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[37] A nondispatchable resource is defined to be any system resource that does not have active power management capability or does not respond to dispatch signals

[38] A flexible resource is defined to be any system resource that is available or can be called upon in a short time to respond to changing system conditions.

[39] 2015 ERSWG Measures Framework Report Final Version

[40] Net Load = Load – Wind and Solar Power Production

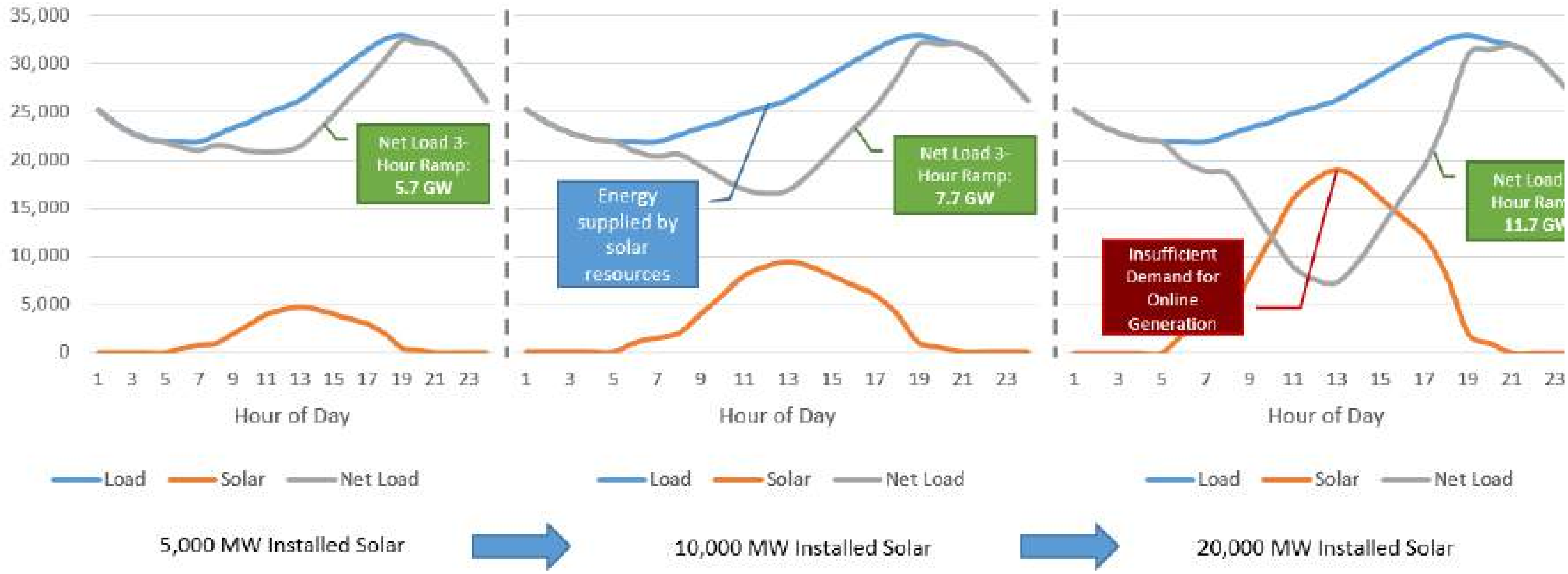


Figure 1.16: Example of Increasing Solar Resources Leading to Increased Ramping Requirements

Ramping is a term used to describe the loading or unloading of generation resources in an effort to balance total generation and load during daily system operations. Changes in the amount of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations. Therefore, a measure to track and project the maximum one-hour and three-hour ramps for each assessment area can help understand how significant the need for flexible resources is.

For areas with high penetrations of nondispatchable resources, these resources are being dispatched at maximum power output in order to supply a large portion of system demand during various times of the day; as a result, there is a need for additional flexibility and ramping capability from the rest of the generation fleet. Ramping and flexible resource needs are difficult to predict as they are dependent on weather, the geographic uniformity of behind-the-meter PV resources, end-use electric consumer behavior, the generation resource mix, and generation dispatch availability. Because solar PV generally performs uniformly over a given area (the smaller the area the more uniform), as more solar PV generation built, the steeper the ramps the system operator will need to offset. Thus, increased ramping capability will be needed on the system from dispatchable and flexible resources.

Solar and Wind Capacity Additions

Table 1.9 identifies solar and wind capacity additions by assessment area. From a nameplate capacity perspective, 97 GW of solar and 110 GW of wind (Tier 1 and 2) are planned to be installed over the next ten years.

Ramping Capability Assessment

For the *2018 LTRA*, a detailed review of the CAISO and ERCOT areas was completed. Of all areas assessed, the RAS has identified ERCOT and CAISO projections of wind and solar as areas of interest regarding ramping challenges. In ERCOT, the concern is driven by significant wind while the drivers in CAISO are solar.

While these areas represent the systems most in need of flexibility, other systems will need to consider flexibility as part of their planning as penetration of wind and solar generating resources increase in those systems. One approach to system flexibility is to gain access to more resources and loads. CAISO's Western Energy Imbalance Market[41] has provided a mechanism to share resources and benefit from the load and renewable energy resource production diversity across the Western Interconnection. This has not only led to significant system cost savings as a result of sharing resources[42] but also reliability benefits, including improved reliability coordination, balancing and ramping, contingency response, and operational flexibility when managing extreme events.

[41] https://www.westerneim.com/pages/default.aspx

[42] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

Table 1.9: Solar and Wind Nameplate Capacity, Existing and Planned Additions through 2028

	Nameplate MW of Solar				Nameplate MW of Wind			
Assessment Area	Existing	Tier 1	Tier 2	Total	Existing	Tier 1	Tier 2	Total
	2018	2028	2028	2028	2018	2028	2028	2028
ERCOT	1,482	2,141	19,401	23,024	21,207	10,599	20,959	52,765
FRCC	398	5,589	0	5,987	0	0	0	0
Manitoba	0	0	0	0	259	0	0	259
Maritimes	1	2	0	3	1,122	114	0	1,236
MISO	244	270	36,738	37,251	16,949	2,853	41,687	61,490
New England	939	90	114	1,142	1,371	33	3,316	4,721
New York	32	25	20	77	1,739	284	691	2,715
Ontario	380	83	0	463	4,412	535	0	4,947
PJM	1,356	2,213	21,106	24,675	7,632	2,876	12,670	23,178
Quebec	0	0	0	0	3,880	43	0	3,922
SaskPower	0	60	0	60	221	1,607	0	1,828
SERC E	502	17	0	519	0	0	0	0
SERC N	10	0	100	110	486	0	0	486
SERC SE	1,251	72	198	1,521	0	0	0	0
SPP	265	15	3	283	17,974	7,712	0	25,686
WECC AB	15	0	0	15	1,445	0	596	2,041
WECC BC	1	0	0	1	702	71	0	773
WECC CAMX	11,972	539	7,989	20,500	6,157	350	1,422	7,929
WECC NWPP US	1,776	208	8	1,992	9,997	504	400	10,901
WECC RMRG	364	191	0	555	3,176	600	30	3,806
WECC SRSG	1,359	23	213	1,595	1,112	0	464	1,576
Total	22,346	11,538	85,890	119,774	99,841	28,181	82,236	210,258

ERCOT Wind Generation and Ramping

ERCOT's historic net-load ramps at minimum load conditions occur in shoulder months (February to March) time frame. The ramps are driven by wind production and have occurred in the early morning (4:00 to 5:00 a.m.) hours before solar resources are available. For this time frame, the 98th percentile three-hour upward net-load ramp can reach 11 GW. In February of 2018, ERCOT set a new wind generation record with total deployed generation capacity of 17,541 MW, which served 47 percent of ERCOT's total demand (37,336 MW). The three-hour net-load downward ramp reached -5.5 GW, and the largest three-hour net-load up ramp was 7.3 GW; however, much larger ramps, exceeding 15 GW, have been observed during different conditions.

Until 2018, regulation services were deployed to make up for a gain or loss of wind generation ramps. In April of 2018, ERCOT added intrahour wind forecasting to their real-time system operations, which increased situational awareness of potential wind generation ramps within each five-minute dispatch interval. This predicted five-minute wind ramp is assumed to be constant over the five-minute interval and has been added to the generation dispatch calculation. This change helps reduce the strain on regulation services previously used to cover the variation in the wind output. Additionally, for disturbances that occur during significant wind ramps, the intrahour wind ramps will be predicted *a priori* to the event and are therefore anticipated to reduce the Interconnection's frequency recovery duration period.

ERCOT is continuing to study net-load variability and wind ramping in their footprint. Since 2014, ERCOT has funded a research and development project on how additional variable energy resources will affect their net-load variability. The long term goal is for this work is to be incorporated into ERCOT's system planning processes. ERCOT plans to analyze the wind ramp forecast performance and update their tools as they acquire more data.

CAISO Photovoltaic Generation and Ramping

Predominant drivers for increasing ramps have been due to changes in California's load patterns, which can be attributed to an increased integration of PV DER generation across its footprint. With continued rapid growth of distributed solar, CAISO's three-hour net-load ramping needs have exceeded 14 GW. This net-load ramp rate exceeds projections made five years earlier in 2013. CAISO's actual maximum three-hour upward ramping needs were 7.6 GW in 2013 when maximum three-hour ramp rate was projected to reach 13 GW by 2020. Surpassing projections reinforces CAISO's near-term need for access to more flexible resources in their footprint:

- Currently, there are more than 11 GW of utility-scale and 6.5 GW of behind-the-meter PV resources in CAISO's footprint, which has the most concentrated area of PV in North America.
- In March 2018, CAISO set a new ramping record with actual three-hour upward net-load ramps reaching 14,777 MW. The maximum one hour net-load upward ramp was 7,545 MW. This record coincided with utility-scale PV serving nearly 50 percent of the CAISO demand during the same time period.
- Behind-the-meter PV has continued to grow in CAISO, and the projected behind-the-meter PV is expected to be 12 GW by 2022.

Based on current projections, maximum three-hour upward net-load ramps are projected to exceed 17,000 MW in March by 2021, approximately 20 percent greater than the amount projected for 2018 (**Figure 1.17** on the next page).

Ramp Monitoring and Planning Considerations

The trends in California and ERCOT highlight the importance for industry to focus on evaluating the ability of the resource mix to adequately meet net-load ramping needs as more renewables are added to their respective systems. NERC's assessment finds the following:

- Ramping should be monitored in any area that projects significant growth in the amount of nondispatchable resources.
- Ramps are most extreme during the off-peak (shoulder) months of the year, typically during low-load conditions in the spring and fall; however, during peaking conditions, flexible resources may be scarce.
- Monitoring and improving individual generator ramp rates will support changing operational schedules.
- The visibility of DERs can present challenges for operators, but these challenges can be managed with net metering or aggregated metering at subtransmission 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 energy storage (e.g., batteries) and scheduling of these resources can assist with reducing ramps and optimizing existing constraints.

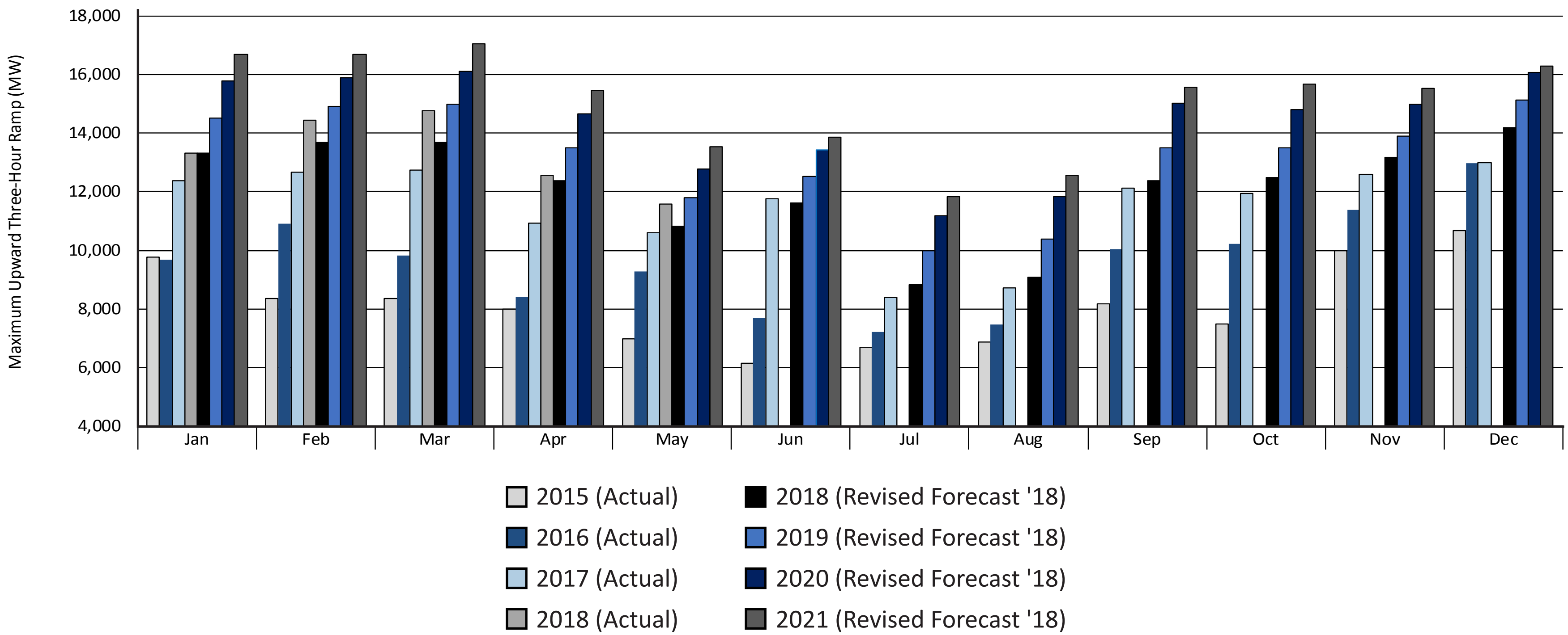


Figure 1.17: Maximum 3-Hour Ramps in CAISO (Actual and Projected) through 2021

Key Finding 5: Over 30 GW of New Distributed Solar Photovoltaic Expected by the End of 2023 to Impact System Planning, Forecasting, and Modeling Needs

Key Points:

- A total of 30 GW of distributed solar PV is expected over the next five years, primarily in states of California, New Jersey, Massachusetts, and New York, increasing the United States total to nearly 51 GW by the end of 2023.
- Increasing installations of DERs modify how distribution and transmission systems interact with each other.
- Transmission planners and operators may not have complete visibility and control of these resources, but as growth becomes considerable, their contributions should be considered in system planning, forecasting, and modeling.

The generation mix is undergoing a transition from large, synchronously connected generators to smaller natural-gas-fired generators, renewable energy, and DR. The growing interest in a more decentralized electric grid and new types of distributed resources further increases the variety of market stakeholders and technologies. Both new and conventional stakeholders are building or planning to build distributed solar PV systems, energy management systems, microgrids, demand services, aggregated generation behind the retail meter, and many other types of distributed generation. Many of these stakeholders have considerable experience with installing such systems on the distribution network for the benefit of industrial or residential customers but may have less familiarity with the BPS and the coordinated activities that ensure system reliability during both normal operation and in response to disturbances.

Progress Made in 2018

The Energy Policy Act of 2005 requires electric utilities to provide interconnection services "based on standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time."[43] In 2018, a new version of the IEEE 1547 (*Standard for Interconnecting Distributed Resources with Electric Power Systems*) was finalized, but it will not be fully implemented until 2020 or later due to further certification and approvals by UL.[44] The new standard now provides specifications that help inverters connected at the distribution system to be aligned with BPS transmission protection requirements in that area. A fact sheet developed by EPRI provides a summary of the detailed specifications and features constructed within the revised standard.[45]

The revised standard provides a foundation for DERs to play an active role in supporting local reliability needs. In the near future, technology advances have the potential to alter DERs from a passive "do no harm" resource to an active "support reliability" resource. From a technological perspective, modern DER units will be capable of providing essential reliability services, such as frequency and voltage support. These technologies are likely to become more widely available in the near future and they present an opportunity to enhance BPS performance when applied in a thoughtful and practical manner.

Also in 2018, NERC implemented a reliability guideline approved by NERC's PC that provides information and guidance relevant for collecting the data needed by system planners to sufficiently represent and model different types of utility-grade DERs and residential-grade DERs in stability analyses.[46] As a growing component of the overall load characteristic, it is important the system planners are able to assess how DER performance impacts the BPS.

[43] EPACT-2005, Public Law 109–58, August 8, 2005

[44] UL 1741 is the UL *Standard for Safety for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources:* https://standardscatalog.ul.com/standards/en/standard_1741_2

[45] EPRI: *IEEE 1547 - New Interconnection Requirements for Distributed Energy Resources Fact Sheet:* https://publicdownload.epri.com/PublicDownload.svc/product=000000003002011346/type=Product

[46] NERC *Reliability Guideline Distributed Energy Resource Modeling*: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

Projection of Distributed Resources

Based on projections from GTM Research,[47] in the United States, nonutility DER installations are expected to increase 30 GW to nearly 51 GW by the end of 2023 (**Figure 1.18**). California, New Jersey, Massachusetts, and New York see the largest increases over the next five years (**Figure 1.19** on the next page). In Canada, Ontario has already installed just over two GW of DER and less than 500 MW are expected in the coming years.

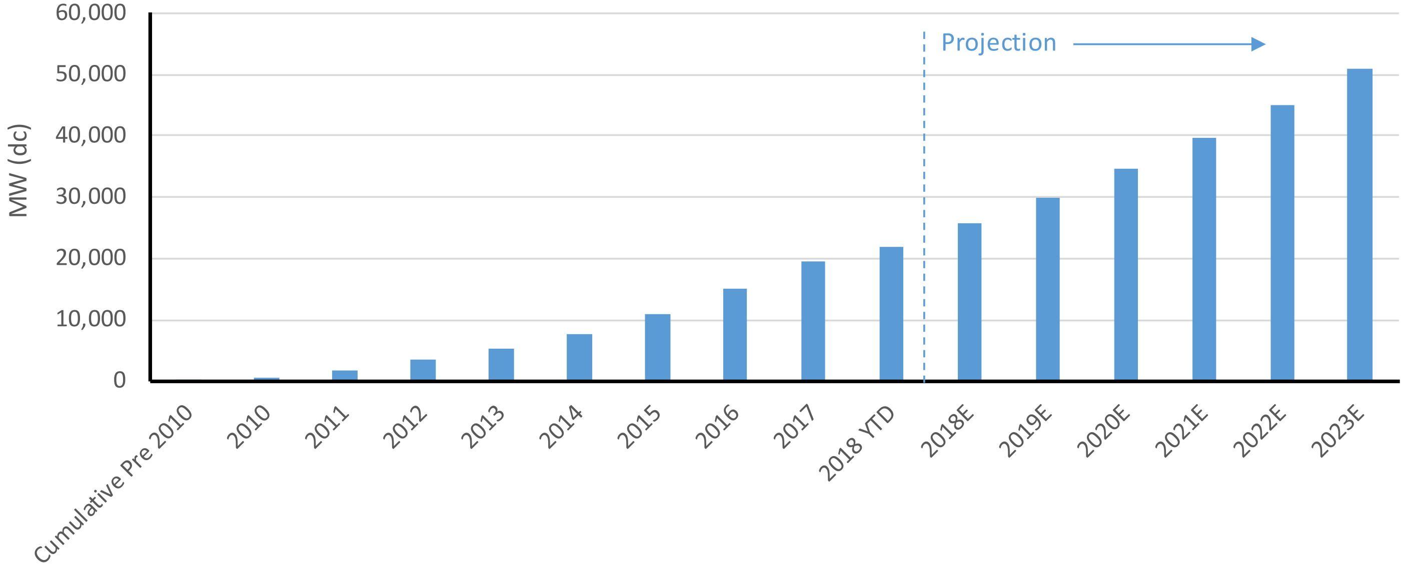


Figure 1.18: United States Cumulative Total Amount of Distributed Solar PV—2010 through 2023

NERC Reliability Guidelines: It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the BES. The NERC technical committees—the OC, the PC, and the Critical Infrastructure Protection Committee (CIPC)—are authorized by the NERC Board to develop reliability (OC and PC) and security (CIPC) guidelines per their charters. These guidelines establish voluntary recommendations, considerations, and industry best practices on particular topics for use by users, owners, and operators of the BES to help assess and ensure BES reliability. These guidelines are prepared in coordination between NERC staff and the NERC technical committees. As a result, these guidelines represent the collective experience, expertise, and judgment of the industry.

The objective of each reliability guideline is to distribute key practices and information on specific issues to support high levels of BES reliability. Reliability guidelines do not provide binding norms and are not subject to compliance and enforcement (unlike Reliability Standards that are monitored and subject to enforcement). Guidelines are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to support reliability for the BES. Further, guidelines are not intended to take precedence over Reliability Standards, regional procedures, or regional requirements.

[47] https://www.greentechmedia.com/research/solar

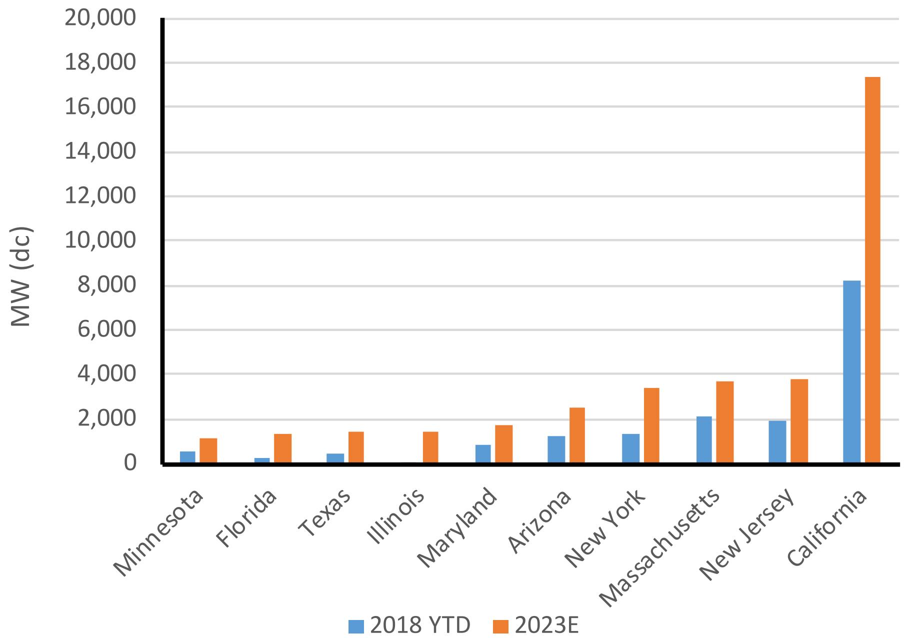


Figure 1.19: Top 10 States with Increasing Amounts of Distributed Solar PV—Total Installed for 2018 and 2023 projection

Reliability Considerations

Increasing amounts of DERs can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and essential reliability services. Overall, reliability risks concerning larger penetrations of DERs can be summarized by three major aspects:

- Difficulty in obtaining and managing the amount of data concerning DER resources, including their size, location, and operational characteristics
- A current inability to observe and control most DER resources in real time
- A need to better understand the impacts on system operations of the increasing amounts of DERs, including ramping, reserve, frequency response, and regulation requirements

Today, the effect of aggregated DERs is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DER could also cause frequency and voltage instability at sufficient DER penetrations. The system operator typically cannot observe or control DERs, so variable output from DERs can contribute to ramping and system balancing challenges. This presents challenges for both the operational and planning functions of the BPS. In certain areas, DERs are being connected on the distribution system at a rapid pace, sometimes with limited coordination between DER installation and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models. These changes will affect not just the flow of power but also the behavior of the system during disturbances. It is important to coordinate the planning, installation, and operation of DERs in relation to the BPS as transition to a new resource mix occurs.

At low penetration levels, the effects of DERs may not present a risk to BPS reliability. However, as penetrations increase, the effect of these resources can present certain reliability challenges that require attention. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS. A recent NERC report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*, provides a detailed assessment of DER and its potential impacts to BPS reliability.[48]

Regional Considerations

Table 1.10 on the next page presents regional considerations by assessment areas or Regions with at least one GW or expecting at least one GW of DERs in the coming years.

[48] *NERC Distributed Energy Resources: Connection, Modeling, and Reliability Considerations:* https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

Table 1.10: Actions by Industry in Response to Growth in DERs	
Assessment Area	**Activities to Address Risks Related to Emerging DERs**
FRCC	FRCC has relatively low penetration levels of DERs with modest growth expected throughout the planning horizon. Multiple FRCC Subcommittees are reviewing recommendations developed by the FRCC Solar Task Force, which was tasked with examining and determining procedures and processes to address the projected growth of central station solar resources within the assessment area.
MISO	The OMS DER[1] survey is part of an ongoing initiative to help state and local regulators make informed decisions as DER adoption increases. MISO has not experienced any operational challenges as of yet but expects to as programs grow in the future.
NPCC-New England	DERs are reflected in planning studies, including resource adequacy, transmission planning, and economic studies. ISO-NE and the states are addressing other potential reliability risks posed by growing penetrations of PV installations, such as by supporting revisions to PV Interconnection requirements found in the relevant IEEE standards.
NPCC-New York	DERs may participate in certain NYISO energy, ancillary services, and capacity markets. In February 2017, the NYISO published a report providing a roadmap that the NYISO will use over the next three to five 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.[2] A solar forecasting system to integrate with the day-ahead and real-time markets was implemented in 2017. Two data streams are being produced: zonal data for behind-the-meter solar PV installations and bus-level data for utility-scale solar PV installations.
NPCC-Ontario	As a result of the increase of DERs in Ontario, the IESO has seen periods where embedded generation had significant offsetting impacts on Ontario demand. Having visibility of these resources is imperative for improving short-term demand forecasting and reliable grid operation. IESO is working through the Grid-LDC Interoperability Standing Committee to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve visibility of the distribution system and therefore reduce short-term forecast errors. To enable greater flexibility, the IESO is initiating control actions, such as manually adjusting variable generation forecasts, committing dispatchable generation, and curtailing intertie transactions. The IESO is now able to schedule additional 30-minute operating reserve to represent flexibility need.
PJM	PJM tracks DER installations through its Generation Attribute Tracking System and allows PJM to incorporate the information into its load forecast. Additionally, a DER Subcommittee was established by the Markets and Reliability Committee on December 7, 2017. Its purpose is to investigate and resolve issues and procedures associated with markets, operations, and planning related to DERs in accordance with existing or new PJM process protocols.
SERC	DERs are not explicitly modeled as generators but are instead modeled as a reduction in bus load, netting the actual bus load and the on-line DER generation. Entities are actively establishing processes to use available data to explicitly model the bus load and DER generation independently to better represent these DER in planning models.
TRE-ERCOT	ERCOT published a whitepaper *Distributed Energy Resources: Reliability Impacts and Recommended Changes*[4] outlining the challenges and potential impacts of DERs. A Nodal Protocol Revision Request (NPRR 866[5]) has been submitted by ERCOT staff that will require the mapping of all existing registered DERs (>1 MW that export) to the Common Information Model at their load points. Once in the model, the DER locations will be known to operators in the ERCOT control room, improving situational awareness, and can also be incorporated into the power flow, state estimator, and load forecast programs. Based on current modeling practice, individual DERs are included in all transmission planning study cases to the extent that they are communicated to ERCOT by the responsible TDSP during the model building process. Generally, these are modelled as a gross reduction of the load at the point of interconnection. However, they are modeled as generators with a negative load in some cases. Although the behavior of many resource technologies (solar PV, landfill natural gas, small hydro, etc.) can be predicted, ERCOT will need more analysis to determine how to incorporate self-dispatched DERs in the studies.
WECC	Largely due to the significant amount of DERs (and utility-grade solar) in California, the entire Interconnection must help support the energy imbalances caused by significant ramping events occurring almost daily. To better understand the implications to the Western Interconnection, WECC is addressing modeling develop and data collection procedures to ensure DERs are represented in Interconnection models.[6] Power flow models can include DERs as data input, but currently none of these models have been approved for use in the Western Interconnections. WECC's Modeling and Validation Work Group (MVWG) is in the process of approving these models for future use.

[1] http://www.misostates.org/images/Documents/Public_OMS_DER_Survey_Results_as_of_July_31_2018.pdf

[2] http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/Distributed_Energy_Resources_Roadmap.pdf

Chapter 2: Emerging Reliability Issues

As part of the annual LTRA, NERC staff, industry representatives, and subject-matter experts identify and assess the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes. The data NERC collected for this assessment incorporates known policy and regulation changes expected to take effect throughout the 10-year time frame assuming a variety of factors, such as economic growth, weather patterns, and system equipment behavior, but it does not predict certain outcomes that have not been formally announced or made public. For example, significant amounts of bulk battery storage have not materialized enough to be observed in the data sets; however, we know the technology is advancing and is on the brink of playing a significant role in reliability in the coming years. While we may not be able to measure the exact quantities being contemplated, analysis can be completed to identify challenges and opportunity to reliability.

Bulk Power Storage

Energy storage has the potential to offer much needed capabilities to maintain grid reliability and stability. With the exception of pumped hydro storage facilities, only a limited number of large-scale energy storage demonstration projects have been built. With increasing requirements for system flexibility as variable generation levels increase and energy storage technology costs decrease, bulk system and distributed stationary energy storage applications may become more viable and prevalent. Storage may be used for load shifting and energy arbitrage—the ability to purchase low-cost, off-peak energy and re-sell the energy during high-peak, high-cost periods. Storage may also provide ancillary services such as regulation, load following, contingency reserves, and capacity. This is true for both bulk storage, which acts in many ways like a central power plant, and distributed storage technologies.

At the end of 2017, approximately 708 MW of utility-scale storage of differing types,[49] such as batteries, flywheels, and compressed air was in operation. In California alone, legislation requires investor owned utilities to procure 1,325 MW of energy storage by 2020.[50] A total of 84 different projects across the United States are currently "planned," according to the U.S. Energy Information Administration.

[49] This does not include pumped hydro storage.

[50] https://www.eia.gov/analysis/studies/electricity/batterystorage/

Reliability Coordination in the West Interconnection

Reliability concerns can arise where seams exist between operating entities. In light of the changes occurring in the Western Interconnection, it is vital that clear and precise operating responsibilities are defined and understood and that coordination occurs between the entities responsible for maintaining reliability. Functional separation of traditional generation, transmission, and distribution responsibilities has amplified the potential for operational conflicts and disagreements over reliability functions and system control authority. System operators need to be aware of and committed to taking necessary actions to preserve reliability. A clearly understood hierarchy must be in place for each defined operating area with well-defined responsibilities for all operating functions. Reliability coordinators (RCs) are responsible for monitoring and assessing the condition of the system over a wide area and must be able to issue directives to other operating authorities in the area to take action to maintain overall system reliability. While the level of physical control given to the RC can vary between organizational models, operating entities must respond promptly to instructions from the RC. When multiple control areas are consolidated, the transfer of control area responsibilities and system operational knowledge must be effective and complete. All parties involved must have the ability and knowledge to reliably operate their systems, as confirmed by appropriate training and testing, before responsibilities are turned over. During this transition period, all parties must be vigilant to ensure that system reliability is maintained.

Peak Reliability (Peak) announced the wind-down of the organization and the transition of RC services from Peak to alternative providers by the end of 2019. During this transition and planning period, Peak will continue to focus on operational excellence as an RC through December 31, 2019. The transition plan will also include discussions between Peak, the presumptive successor RCs (e.g., California Independent System Operator (CAISO), Southwest Power Pool (SPP), and other stakeholders) to assure that reliability and security are maintained.

As of September 14, entities representing 98 percent of the net energy for load (NEL) in the Western Interconnection had expressed nonbinding commitments to join various RCs. The current nonbinding commitments include approximately 72 percent of the load selecting the CAISO RC, approximately 12 percent selecting SPP RC, and approximately seven percent selecting British Columbia Hydro and Power Authority (BCH) (becoming a new RC) as their preferred RC. The Alberta Electric System Operator (AESO) will continue to provide RC services for the Alberta province.

With the formation of multiple RCs, institutional knowledge of operational procedures needs to be reviewed and communicated accordingly. Real-time operational models used for studies need to be coordinated. Operational planning studies should include contingencies and element outages (planned and forced) in adjacent systems and monitor facilities next to the RC footprint to identify third-party and seams impacts.

The RC-to-RC Coordination Group, which includes subject matter experts from BCH, AESO, SPP, CAISO, and Peak have found five major RC task tracks that are now being reviewed. The five tracks are operations planning, operations coordination, wide-area tools, technology and data sharing, and modeling (including remedial action scheme modeling). These tracks have several subgroups working out the specifics of transitioning the necessary activities.

WECC continues to host a series of RC forums to give stakeholders the opportunity to understand and discuss the reliability implications of multiple RCs in the Western Interconnection. Additionally, NERC and WECC staff continue to take part in various RC forums and provide updates at various stakeholder committee and Board meetings to ensure transparency in the creation of and transition to multiple RCs.

Potential Risk of Significant Electricity Demand Growth

A rapid onset of transportation-related or industrial demand could create unexpected load growth. Automobiles are now increasingly battery-powered. 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. Plug-in electric vehicles are projected to account for as much as half of all United States new car sales by 2030. The electricity required to charge these vehicles will increase demand on BPS.

Scenario analysis is the best method to understand these potential risks. For example, how might a three-fold increase in electric vehicle penetration by 2028 affect the reliability of the BPS? Would there be a change in planning and/or operating reserve requirements? Would charging patterns affect ramping needs? Could the increased availability of mobile electric storage devices create market opportunities that could, in turn, affect grid operations? These questions, and more, are likely options for continued assessment of this emerging issue.

Reactive Power Requirements for Transmission-Connected Devices

Increasing amounts of reactive power are being supplied by nonsynchronous sources and power electronics. There are two components to the power supplied by conventional electric generators: real power and reactive power. Reactive devices will increasingly be used to replace dynamic voltage support lost from conventional generation retirements. These devices include static var compensators, static synchronous compensators, and synchronous condensers. While many technologies can provide reactive support, NERC Reliability Standards only apply to generation. There may be a need to more clearly articulate performance specifications of these devices.

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.

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 and 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 need 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.[51]

System Restoration

The changing resource mix introduces new challenges to system restoration and resilience to extreme weather conditions. Retiring conventional generation that has supported the blackstart capability of the system or is critical 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 system operator control rooms. 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 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. 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. More research and study is needed by the electric industry to understand the implications of the changing resource mix to blackstart capability.

[51] **Italy Blackout 2003:** On 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 UVLS 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 over-loading 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.

Potential Impact to System Strength and Fault Current Contributions

As inverter-based resources replace conventional generation, short-circuit current availability can be impacted due to the limited fault current contribution of renewable generation. Low short-circuit conditions increases the likelihood of sub-synchronous behavior and control interactions among neighboring devices that use power electronics, including protection relays.[52] 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 while considering light-load and low fault current conditions. Short-circuit ratio calculations and wide-area relay sensitivity studies should be performed to identify locations susceptible to low fault current issues.

In April 2018, ERCOT conducted an assessment of Texas Panhandle and South Texas stability and system strength.[53] The study analyzed operating conditions for high concentrations of wind generation in the Panhandle area and, for the first time, in the Rio Grande Valley, which also is seeing a significant amount of wind generation development. The study showed that there are electric system stability limitations when wind and solar resources are unable to detect voltage signals due to a lack of thermal/synchronous generation in an area. While previous studies have been conducted to help identify stability limits in the Panhandle, this recent study showed the benefits of using more accurate and detailed models and provided information on the interaction between customer demand and stability limits. ERCOT plans to use this data to help inform future studies and better understand the reliability implications associated with increased variable generation on the electric system. Further, other interconnection study and seams coordination groups would benefit from understanding the analytical approaches and lessons learned from the ERCOT assessment.

Finally, the renewable industry has been working on this issue for a long time, and there are many solutions, including changing control settings to avoid harmful interactions, building transmission to strengthen the grid, or deploying synchronous condensers.

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

[53] http://www.ercot.com/content/wcm/lists/144927/Panhandle_and_South_Texas_Stability_and_System_Strength_Assessment_March....pdf)

Chapter 3: Demand, Resources, and Trends

The following graphic summarizes the projected trends, demand, and capacity resources over the 10-year planning horizon of the LTRA along with the historic changes since 2012.

10-Year Outlook

- A 10-year compound annual growth rate (CAGR) of demand for North America is the lowest on record, at 0.57 percent (summer) and 0.59 percent (winter).
- Load growth in all assessment areas is under two percent, with five assessment areas projecting reduced peak demand.

- Natural-gas-fired capacity has increased to 442 GW from 280 GW in 2009.
- A total of 60 GW of Tier 1 natural gas-fired capacity additions are planned through 2028.
- Natural-gas-fired capacity is the primary on-peak fuel type in 10 assessment areas.

- More than 28 GW (nameplate) of Tier 1 wind additions are planned by 2028—82 GW of Tier 2.
- The amount of peak capacity ranges from 7–34 percent of the total nameplate capacity.

- A total of 46.5 GW of coal-fired generation retirements since 2011, with 19 GW of confirmed retirements planned between 2017 and 2027.
- A total of seven nuclear units have retired since 2012, and 14 plan to retire by 2025.

- Solar resources are expected to increase by 12 GW (nameplate) of Tier 1 planned by 2028—86 GW of Tier 2.
- The amount of peak capacity ranges from 0–68 percent of the total nameplate capacity.

Demand Projections

NERC-wide electricity peak demand and energy growth are at the lowest rates on record with declining demand projected in five assessment areas. The 2018 through 2028 aggregated projections of summer peak demand NERC-wide are slightly lower than last year's projection. A comparison of this year's 10-year forecasted growth to last year's 10-year forecasted growth indicates that peak demand is roughly flat for North America as a whole.

Figure 3.1 identifies the 10-year compound annual growth rate (CAGR) of peak demand as the lowest on record at 0.57 percent (summer) and 0.59 percent (winter). Also, the 10-year energy growth is 0.58 percent per year, compared to more than 1.48 percent just a decade earlier (**Figure 3.2**).[54]

[54] Prior to the *2011 LTRA*, the initial year of the 10-year assessment period is the report year (e.g., the 10-year assessment period for the *1990 LTRA* was 1990–1999). The *2011 LTRA* and subsequent LTRAs examine the initial year of the assessment period as one year out (e.g., the 10-year assessment period for the *2012 LTRA* is 2013–2022).

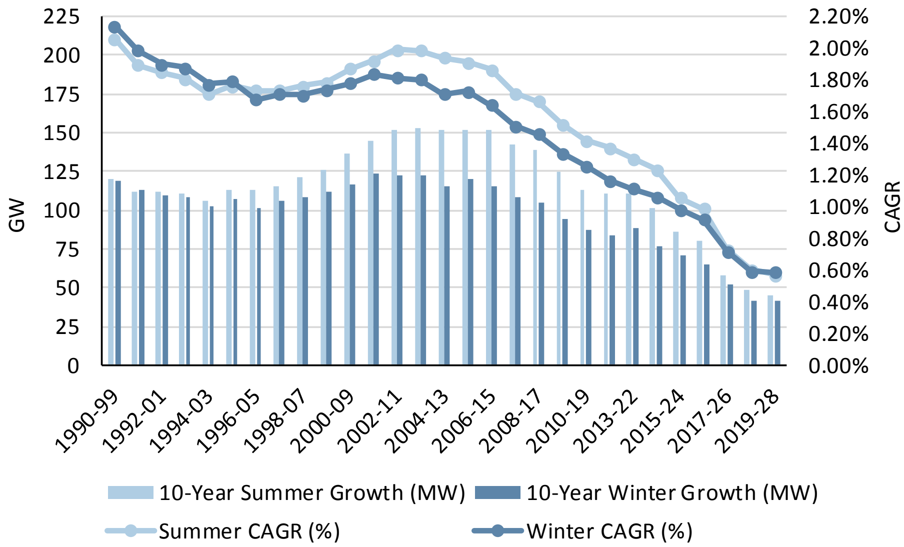


Figure 3.1: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

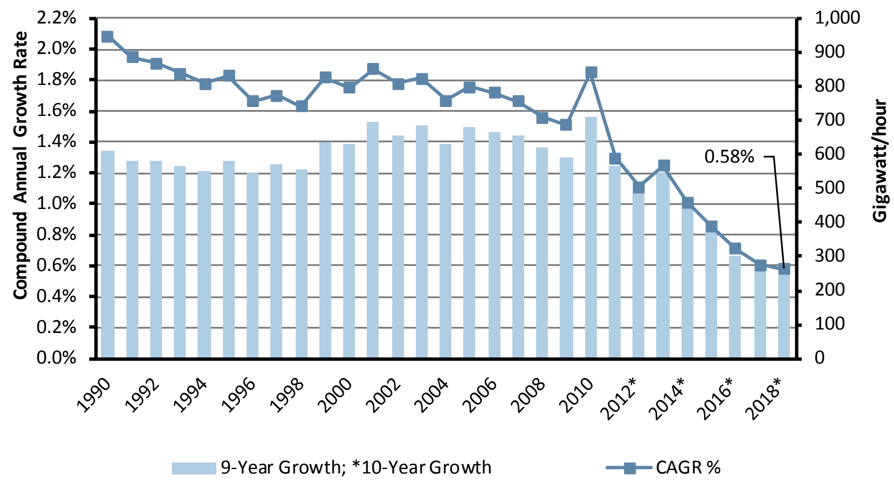


Figure 3.2: 10-Year Net Energy to Load Growth and Rate Projection Trends

Understanding Demand Forecasts: Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise their forecasts on an annual basis or as their resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts, generally as of May 2018, of the individual planning entities and load-serving utilities comprising the REs. These forecasts are typically “equal probability” forecasts. That is, there is a 50 percent chance that the forecast will be exceeded and a 50 percent chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are internal electricity demands that have already been reduced to reflect the effects of demand-side management programs, such as conservation, energy efficiency, and time-of-use rates. It is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, dispatchable and controllable DR is included in net internal demand.

A 10-year demand growth in all assessment areas is under two percent per year with five assessment areas projecting a decline in demand (**Figure 3.3**).

Continued advancements of energy efficiency programs, combined with a general shift in North America to less energy-intensive economic growth, are contributing factors to slower electricity demand growth. Thirty states in the United States have adopted energy efficiency policies that are contributing to reduced peak demand and overall energy use.[55] Additionally, DERs and other behind-the meter resources continue to increase and reduce the net demand for the BPS even further.

The planning reserve margins for the years 2019–2023 are shown in **Tables 3.1** and **3.2** on the next two pages. **Table 3.3** on page 52 shows the reference margin levels for each assessment area.

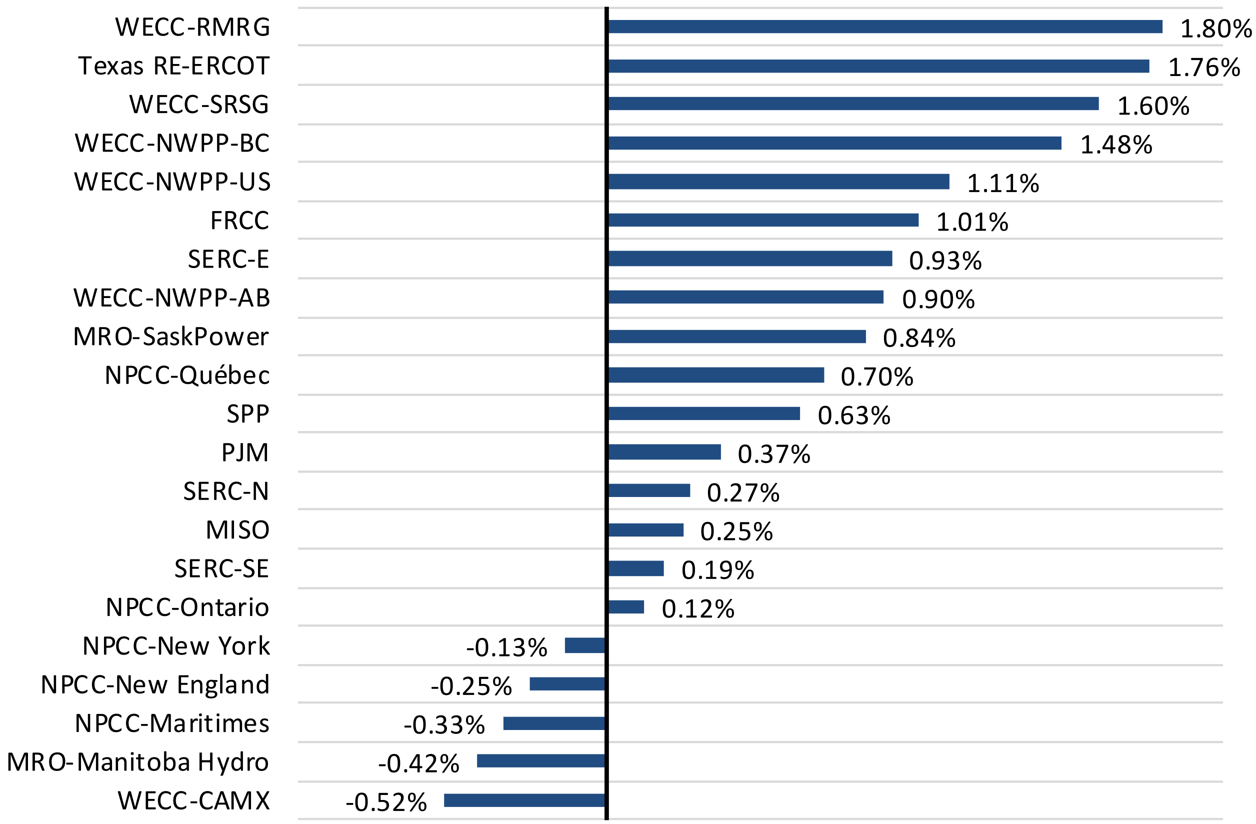


Figure 3.3: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

55 EIA - Today in Energy: Many states have adopted policies to encourage energy efficiency.

Table 3.1: Planning Reserve Margins (2019–2023)											
Assessment Area	**Reserve Margins (%)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
FRCC	Anticipated	23.93	23.70	22.52	24.43	25.33	24.12	22.86	21.59	20.52	20.26
	Prospective	24.93	24.69	23.26	26.15	28.36	28.10	26.79	25.51	25.37	25.11
	Reference Margin Level	15.0	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
MISO	Anticipated	21.28	21.68	20.34	18.86	16.84	15.76	15.04	14.47	14.07	14.41
	Prospective	20.87	23.71	24.46	40.85	42.88	41.45	40.82	39.30	38.54	38.90
	Reference Margin Level	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10
MRO-Manitoba Hydro	Anticipated	22.09	24.11	31.58	43.48	44.60	45.26	45.11	44.83	44.29	45.30
	Prospective	20.66	17.30	19.60	31.40	32.42	33.03	35.73	35.46	37.27	38.34
	Reference Margin Level	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
MRO-SaskPower	Anticipated	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
	Prospective	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
	Reference Margin Level	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00
NPCC-Maritimes	Anticipated	23.46	24.22	25.41	27.56	28.45	29.13	29.78	30.01	30.26	30.39
	Prospective	25.16	25.74	26.22	28.35	29.21	28.01	28.35	22.70	22.94	23.06
	Reference Margin Level	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
NPCC-NewEngland	Anticipated	29.43	29.92	32.28	28.46	28.98	29.36	29.57	29.56	29.40	29.24
	Prospective	31.60	32.49	35.65	32.13	33.33	33.84	34.77	34.77	34.60	34.42
	Reference Margin Level	16.91	17.20	16.36	16.36	16.36	16.36	16.36	16.36	16.36	16.36
NPCC-NewYork	Anticipated	21.57	24.12	21.64	22.53	22.74	22.77	22.68	22.51	22.28	22.02
	Prospective	21.50	26.47	27.31	28.22	30.06	30.09	30.00	29.82	29.57	29.30
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
NPCC-Ontario	Anticipated	28.63	27.08	23.30	23.63	18.62	12.27	16.04	17.18	16.54	12.81
	Prospective	28.24	25.97	22.20	22.52	19.53	10.87	13.70	14.81	14.19	10.46
	Reference Margin Level	18.37	18.05	18.02	18.51	19.43	21.59	22.69	25.43	22.92	21.60
NPCC-Québec	Anticipated	16.35	14.48	13.60	15.04	12.86	12.10	11.35	10.35	9.44	8.57
	Prospective	19.37	17.48	16.58	18.00	15.79	15.02	14.25	13.23	12.30	11.41
	Reference Margin Level	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61
PJM	Anticipated	33.12	35.46	35.66	35.20	34.53	34.00	33.40	32.73	31.98	31.11
	Prospective	42.10	53.95	58.30	61.27	61.36	60.73	60.01	59.21	58.30	57.26
	Reference Margin Level	15.90	15.90	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80

Table 3.2: Planning Reserve Margins (2019–2023)											
Assessment Area	**Reserve Margins (%)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
SERC-E	Anticipated	23.28	21.05	20.93	22.29	21.48	20.36	21.94	23.35	21.78	18.50
	Prospective	23.38	21.14	21.03	22.39	21.57	20.45	22.04	23.45	21.87	18.59
	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	Anticipated	25.70	25.71	25.56	25.21	24.58	24.40	24.02	23.20	22.98	22.80
	Prospective	31.22	31.20	31.04	30.68	30.02	29.84	29.44	28.58	28.35	28.16
	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	Anticipated	32.15	31.67	30.92	32.53	33.77	33.03	32.44	30.58	33.09	34.15
	Prospective	34.25	33.76	33.21	34.82	36.04	35.29	34.69	32.80	35.34	36.42
	Reference Margin Level	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
SPP	Anticipated	32.29	30.37	29.68	27.19	25.15	23.93	23.33	22.31	21.00	19.34
	Prospective	32.06	29.81	29.12	26.65	24.06	22.85	21.94	20.94	19.63	17.90
	Reference Margin Level	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
TRE-ERCOT	Anticipated	11.17	12.66	11.82	10.60	8.62	6.91	5.35	3.64	1.98	0.37
	Prospective	19.06	38.14	45.45	44.90	41.83	39.66	37.63	35.40	33.23	31.12
	Reference Margin Level	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75
WECC-AB	Anticipated	26.76	25.93	24.62	23.44	22.83	21.77	20.52	19.37	18.10	16.91
	Prospective	29.60	28.74	27.41	26.20	25.58	24.50	23.22	22.04	20.74	19.52
	Reference Margin Level	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73
WECC-BC	Anticipated	19.22	18.77	17.65	15.93	14.23	12.75	11.55	10.08	8.27	6.67
	Prospective	19.22	18.77	17.65	15.93	14.23	19.43	18.14	16.59	14.67	12.97
	Reference Margin Level	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73
WECC-CAMX	Anticipated	23.27	30.55	24.26	23.63	24.51	20.65	20.35	20.86	20.67	20.27
	Prospective	32.50	43.28	42.13	42.88	43.89	40.17	39.82	40.40	40.18	39.72
	Reference Margin Level	12.35	12.29	12.10	12.05	12.02	12.05	11.99	11.99	12.02	12.04
WECC-NWPP-US	Anticipated	27.57	25.92	24.62	22.75	23.82	23.64	23.65	23.68	26.46	22.03
	Prospective	27.77	26.12	24.81	22.94	24.01	23.83	23.83	23.86	26.64	22.22
	Reference Margin Level	19.72	19.68	19.53	19.60	19.56	19.49	19.39	19.35	19.27	19.11
WECC-RMRG	Anticipated	33.72	26.56	24.89	23.48	21.14	19.63	18.04	16.78	15.52	14.04
	Prospective	33.72	26.56	24.89	23.48	21.47	19.95	18.36	17.10	15.84	14.35
	Reference Margin Level	16.83	16.76	16.48	16.37	16.07	15.94	15.73	15.58	15.40	15.25
WECC-SRSG	Anticipated	30.80	29.40	27.46	24.03	20.90	18.84	16.64	15.04	11.97	10.54
	Prospective	33.63	32.37	30.87	27.45	24.26	22.14	19.88	18.24	15.11	13.64
	Reference Margin Level	15.10	15.11	14.86	14.63	14.47	14.33	14.17	14.03	13.92	13.82

Table 3.3: Reference Margin Levels for each Assessment Area (2019–2023)					
Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
FRCC	15%[1]	Reliability Criterion	No: Guideline	0.1/Year LOLP	Florida Public Service Commission
MISO	17.1%	Planning Reserve Margin	Yes: Established Annually[2]	0.1/Year LOLE	MISO
MRO-Manitoba Hydro	12%	Reference Margin Level	No	0.1/Year LOLE/LOEE/ LOLH/EUE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20%[3]	Reference Margin Level	No	0.1/Year LOLE	Maritimes Subareas; NPCC
NPCC-New England	16.3–17.2%	Installed Capacity Requirement	Yes: three-year requirement established annually	0.1/Year LOLE	ISO-NE; NPCC Criteria
NPCC-New York	15%	Installed Reserve Margin	Yes: one year requirement; established annually based on full installed capacity values if resources	0.1/Year LOLE	NYSRC; NPCC Criteria
NPCC-Ontario	18–25%	Ontario Reserve Margin Requirement (ORMR)	Yes: established annually for all years	0.1/Year LOLE	IESO; NPCC Criteria
NPCC-Québec	12.6%	Reference Margin Level	No: established Annually	0.1/Year LOLE	Hydro Québec; NPCC Criteria
PJM	15.8–15.9%	IRM	Yes: established Annually for each of three future years	0.1/Year LOLE	PJM Board of Managers; ReliabilityFirst BAL-502-RFC-02 Standard
SERC-E	15%[4]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-N	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-SE	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SPP	12%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1/Year LOLE	SPP RTO Staff and Stakeholders

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

[2] In MISO, the states can override the MISO Planning Reserve Margin

[3] The 20 percent Reference Margin Level is used by the individual jurisdictions in the Maritimes Area with the exception of Prince Edward Island, which uses a margin of 15 percent. Accordingly, 20 percent is applied for the entire area.

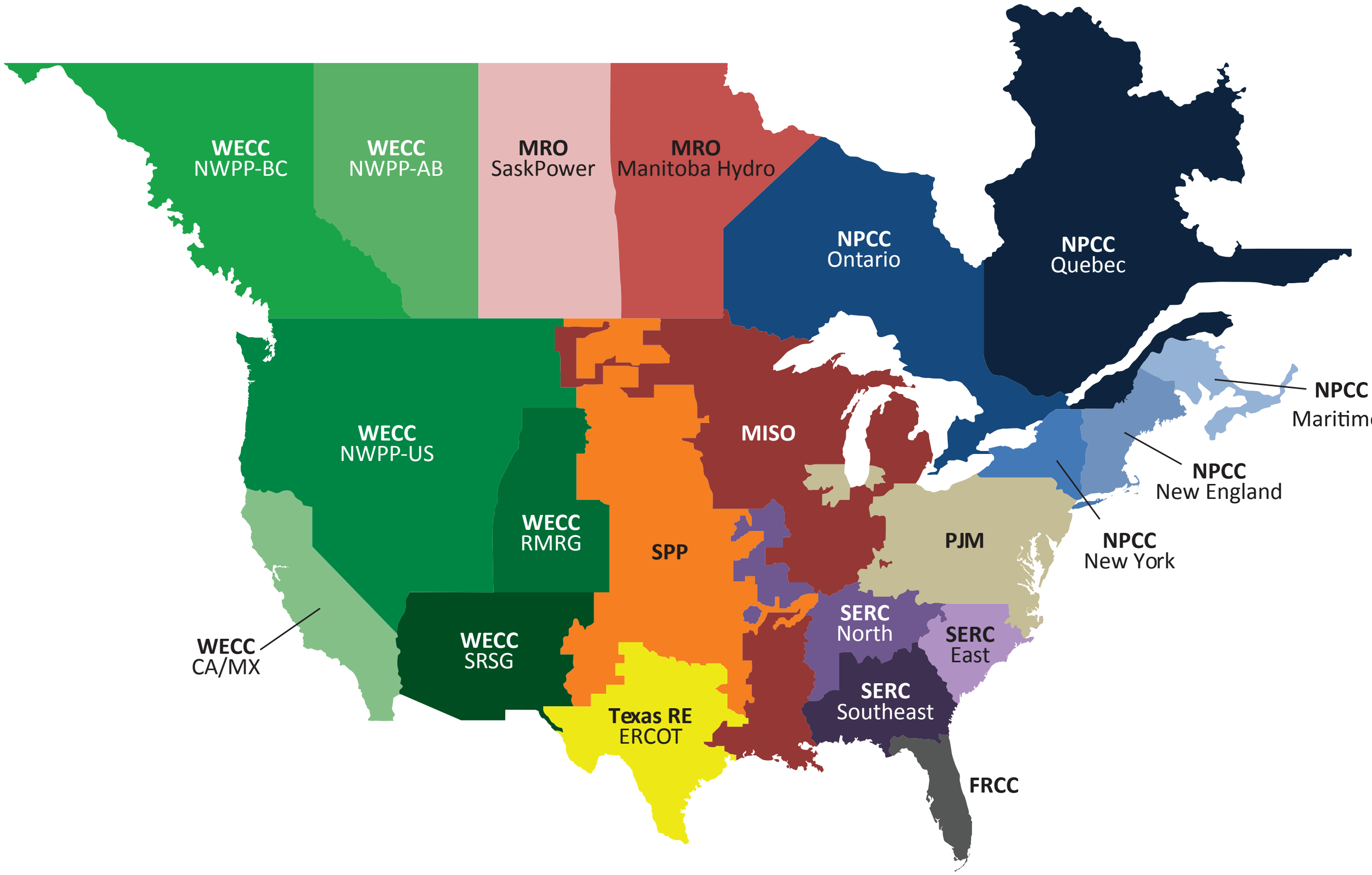
[4] SERC does not provide Reference Margin Levels or resource requirements for its subregions. However, SERC members perform individual assessments to comply with any state requirements.

Table 3.3: Reference Margin Levels for each Assessment Area (2019–2023) (Continued)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
TRE-ERCOT	13.75%	Target Reserve Margin	No	0.1/Year LOLE	ERCOT Board of Directors
WECC-AB	10.14–10.42%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-BC	10.14–10.42%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-CAMX[1]	12.02–12.35%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-NWPP-US	19.56–19.72%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-RMRG	16.07–16.83%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-SRSG	14.07–15.10%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC

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

Regional Assessments Dashboards

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

The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's PC, 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. A summary of the key data is provided in **Table D.1**.

Table D.1: Summary of 2023 Peak Projections by Assessment Area and Interconnection

	Peak Demand (MW)	Annual Net Energy for Load (GWh)	Net Transfers (MW)	Anticipated Capacity Resources	Anticipated Reserve Margin
FRCC	47,144	241,710	1,178	59,083	25.33%
MISO	120,424	679,319	556	140,704	16.84%
MRO-Manitoba	4,336	24,900	125	6,270	44.60%
MRO-Sask	3,977	27,117	100	4,784	20.29%
NPCC-Maritimes	5,245	27,106	0	6,737	28.45%
NPCC-New England	24,317	117,039	81	31,364	28.98%
NPCC-New York	31,414	153,593	1,942	38,558	22.74%
NPCC-Ontario	21,589	133,215	0	25,456	18.62%
PJM	145,885	816,817	0	196,261	34.53%
SERC-E	43,134	218,138	25	52,397	21.48%
SERC-N	40,296	213,861	-952	50,201	24.58%
SERC-SE	46,662	251,006	-1,744	62,418	33.77%
SPP	53,485	271,312	-81	66,935	25.15%
EASTERN INTERCONNECTION	587,908	3,175,132	1,230	741,322	N/A
QUEBEC INTERCONNECTION	37,473	191,567	-145	42,290	12.86%
TEXAS INTERCONNECTION	78,258	422,216	7	85,000	8.62%
WECC-AB	12,321	88,253	0	15,134	22.83%
WECC-BC	12,186	67,068	0	13,920	14.23%
WECC-CAMX	50,201	270,617	0	62,504	24.51%
WECC-NWPP US	50,141	298,914	3,300	62,086	23.82%
WECC-RMRG	13,202	72,988	0	15,993	21.14%
WECC-SRSG	25,712	117,962	0	31,085	20.90%
WESTERN INTERCONNECTION	163,763	915,802	3,300	200,721	N/A

FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity division members and 22 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 36 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.

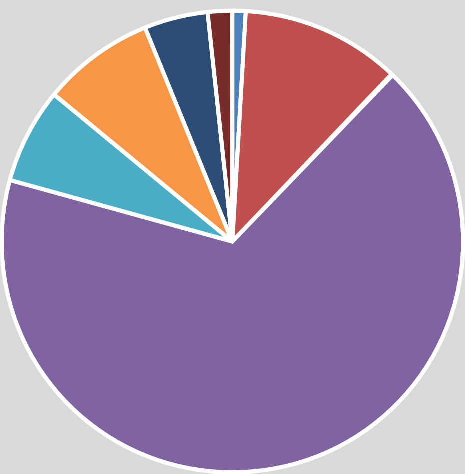
Highlights

- FRCC is not expecting any long-term reliability impacts resulting from fuel supply or transportation constraints. FRCC's planning and operating committees will continue to provide oversight of the regional fuel reliability.
- With the continued addition of natural gas infrastructure into the State of Florida, additional capacity continues to meet actual and projected regional natural gas needs for new generating resources. In addition, studies reviewing key infrastructure outages continue to assess the reliability interdependencies between natural gas and electric facilities as well as actual and projected pipeline capacity requirements, dual-fuel resource capabilities, and operational flexibility of the interconnected pipeline networks.
- FRCC has not identified any other emerging reliability issues. However, FRCC continues to monitor the possible impacts on the long-term reliability of the BES from the changing resource mix, the higher penetration of central station solar generation, and the growing dependency of natural gas.

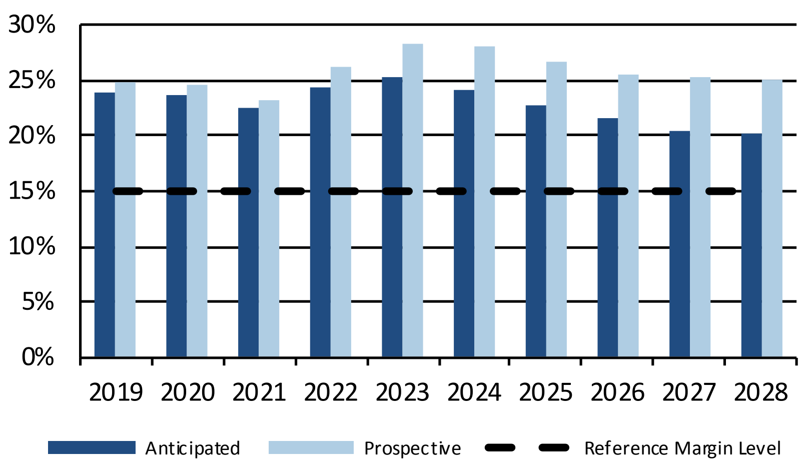
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	48,264	48,739	49,340	49,852	50,374	51,016	51,585	52,205	52,842	52,842
Demand Response	3,047	3,131	3,170	3,199	3,230	3,263	3,295	3,308	3,334	3,334
Net Internal Demand	45,217	45,608	46,170	46,653	47,144	47,753	48,290	48,897	49,508	49,508
Additions: Tier 1	4,259	4,780	5,957	7,945	9,879	10,407	10,617	11,012	11,842	11,876
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	1,452	1,452	1,178	1,203	1,178	1,178	1,178	1,078	1,103	1,103
Existing-Certain and Net Firm Transfers	51,779	51,639	50,609	50,105	49,205	48,866	48,713	48,440	47,825	47,662
Anticipated Reserve Margin (%)	23.93	23.70	22.52	24.43	25.33	24.12	22.86	21.59	20.52	20.26
Prospective Reserve Margin (%)	24.93	24.69	23.26	26.15	28.36	28.10	26.79	25.51	25.37	25.11
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

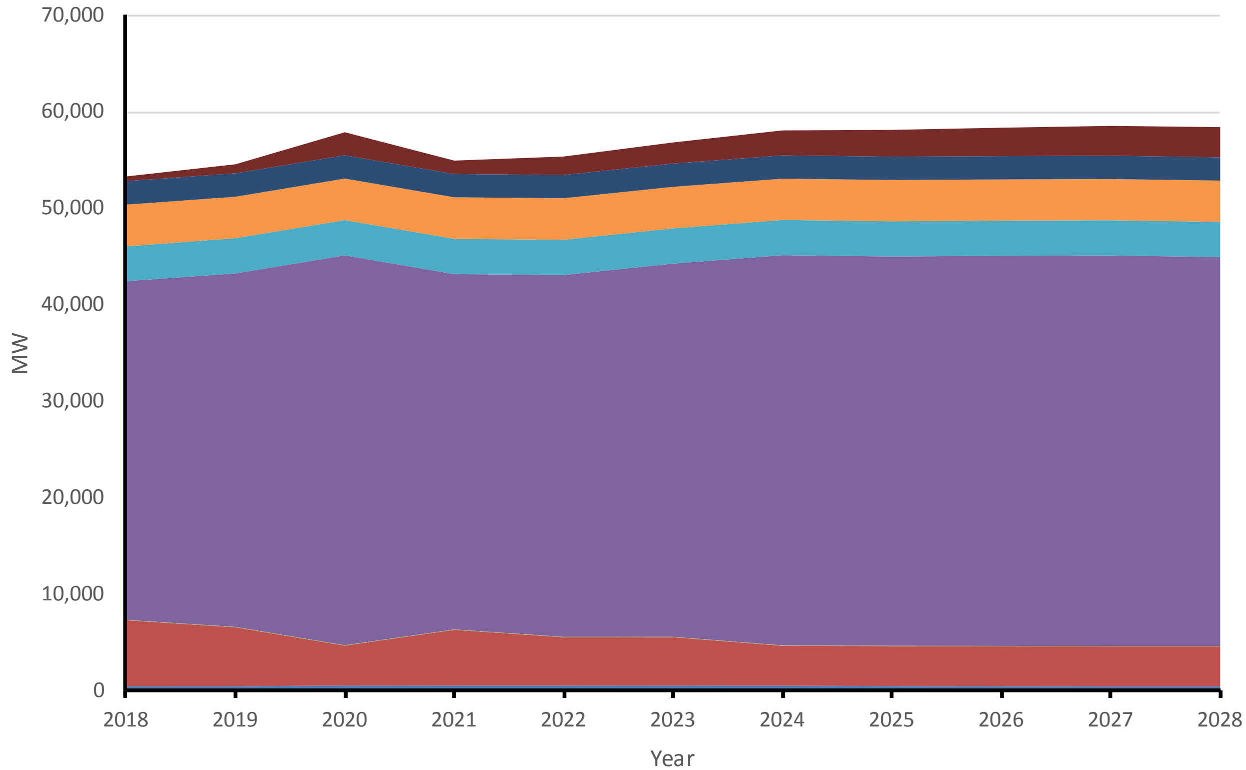
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	506	1%	489	1%
Coal	6,105	11%	4,136	7%
Hydro	44	0%	44	0%
Natural Gas	40,913	75%	44,576	76%
Nuclear	3,652	7%	3,651	6%
Other	0	0%	0	0%
Petroleum	2,436	4%	2,412	4%
Solar	930	2%	3,129	6%
Total	54,586	100%	58,436	100%



Planning Reserve Margins



FRCC Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	506	566	567	572	574	560	522	504	489	489
Coal	6,105	5,783	5,013	5,013	4,136	4,136	4,136	4,136	4,136	4,136
Hydro	44	44	44	44	44	44	44	44	44	44
Natural Gas	40,913	41,107	41,780	42,955	44,687	44,691	44,594	44,684	44,738	44,576
Nuclear	3,652	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651
Other	0	15	15	15	15	15	15	0	0	0
Petroleum	2,436	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412
Solar	930	1,391	1,908	2,187	2,388	2,588	2,779	2,945	3,095	3,129
Total MW	54,586	54,967	55,388	56,847	57,905	58,095	58,151	58,374	58,564	58,436

Planning Reserve Margins: FRCC uses the Florida Public Service Commission's reliability criterion of a 15 percent reserve margin for nonIOUs as the minimum regional total Reserve Margin based on firm load. FRCC regional total Reserve Margin calculations include merchant plant capacity that are under firm contract to LSEs. FRCC assesses the upcoming ten-year projected summer and winter peak hour loads, generating resources, and firm demand side management (DSM) resources on an annual basis to ensure that the regional total Reserve Margin requirement is projected to be satisfied.

Demand: The individual entities within FRCC assessment area develop their load forecasts, and FRCC then aggregates these forecasts to calculate a noncoincident seasonal peak for the Region. Each entity adjusts their forecasts annually to account for their actual peak demand, updated economic outlook, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage pattern. As a result, firm summer peak demand growth is expected to increase to approximately 1.2 percent when compared to last year's forecasted growth rate of 1.1 percent per year. For firm winter peak load, the average growth rate is also expected to increase to 1.1 percent when compared to last year's forecast of 1.0 percent per year.

Demand-Side Management: Each individual reporting entity develops their own independent forecast of firm controllable and dispatchable DR values forecasted to be available at system peak based on their methodology. These individual reporting entities perform and develop independent analyses of the estimated impacts from the firm DR and load management. FRCC then aggregates those estimated impacts for analytical purposes. Controllable DR from interruptible and dispatchable load management programs within FRCC is treated as a load-modifier and is projected to be constant at approximately 6.3 percent of the summer and winter total peak demands for all years of the assessment period. Some of the larger utilities in the Region account for load profile modifiers, such as DERs and electric vehicles in their forecast. Utilities that do not account for such load profile modifiers in their forecast have not yet experienced a large enough penetration rate of these types of facilities to modify their existing load profiles.

Distributed Energy Resources: In general, DERs are modeled with associated loads and netted out since these loads are implicitly accounted for with the load forecasts of entities within FRCC. Currently, the FRCC assessment area has relatively low penetration levels of DER with modest growth expected throughout the planning horizon. Multiple FRCC subcommittees are reviewing recommendations developed by the FRCC Solar Task Force, which was tasked with examining and determining procedures and processes to address the projected growth of central station solar resources within the assessment area. The FRCC Resource Subcommittee (FRCC-RS) coordinated with the FRCC Load Forecast Working Group (LFWG) to develop a pilot data collection to amalgamate estimated statistics (historical and projected) for DER within the Region to better support integration of DERs into infrastructure sufficiency studies of the transmission and distribution system. While the data for the pilot will be aggregate in nature, FRCC-RS is also actively developing a geographical tracking process to evaluate potential DER growth pockets and continues to coordinate with the FRCC Planning Committee on tractable approaches to such disaggregation in the near future (e.g., substations, zip codes, counties).

Generation: FRCC is not expecting any long-term reliability impacts resulting from an increased reliance on natural-gas-fired generation or from generating plant retirements. Planned (known) future generator retirements are incorporated into the FRCC regional transmission planning process via the studies performed by FRCC subcommittees as part of the annual transmission planning study process. In addition, fuel assurance and reliability continue to be reviewed by the FRCC planning and operating committees and its subgroups. Approximately 2,400 MW of coal, along with 2,700 MW of natural gas, will be retired during the assessment period. FRCC is not expecting any long-term reliability impacts resulting from generating plant retirements.

Capacity Transfers: FRCC has not identified any scenarios that would impact transfers into the FRCC assessment area or would result in reliability issues from reduced transfers. All firm on-peak capacity imports into the FRCC assessment area have firm transmission service agreements in place to ensure deliverability into the assessment area, and these capacity resources are accounted for in the calculation of the assessment area's anticipated Reserve Margin. In addition, the interface owners between the FRCC and SERC assessment areas meet quarterly to coordinate and perform joint studies to ensure the reliability and adequacy of the interface.

Transmission: The FRCC assessment area has not identified any specific major projects that are needed to maintain reliability during the planning horizon. The individual entities do have planned projects that are primarily related to system expansion in order to serve forecasted demand growth, resource integration, or to ensure long-term reliability of the transmission systems. The FRCC assessment area has not identified any transmission constrained areas in its planning studies. The studies performed have shown that the performance of the transmission system is adequate and in compliance with all the requirements in the NERC transmission planning standards for the near-term and long-term planning horizon.

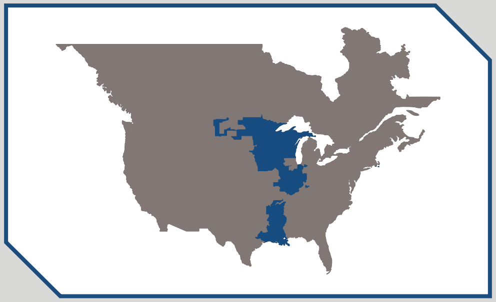
Probabilistic Assessment Overview

- **General Overview:** Sufficient generation resource additions throughout the next ten years result in low LOLH and EUE results for the Base Case study years of 2020 and 2022.
- **Modeling:** FRCC used the tie-line and generation reliability (TIGER) program, which is based on the analytical method of recursive convolution for the computation of LOLH and EUE metrics:
  - FRCC's modeling approach incorporates regional hourly load, generation data, forced outage rates, maintenance schedules, and monthly demand response.
  - Demand response was modeled as a load modifier on a monthly basis with no derates.
  - Solar variable generation resources were modeled at the firm capability available at time of peak. There are no significant wind variable generation resources within the FRCC; therefore, no wind generation was modeled.
  - A load variation Monte Carlo simulation was utilized that provided 500 variations of annual hourly load as an input into TIGER.
  - Based on the results of detailed regional transmission studies, a study model was elected that assumes that all firm capacity resources are deliverable within the FRCC Region. FRCC was modeled as an isolated area with no interconnections with adjacent areas. However, imports were modeled within the FRCC regional generation data and were limited to only firm power purchase agreements.
- **Probabilistic vs. Deterministic:** There are no differences between the reserve margin reported in the LTRA and Probabilistic Assessment (ProbA) Base Case.

Base Case Study

- **Results:** Reserve Margin Levels for the study years are expected to remain above the NERC Reference Margin Level of 15 percent while supporting low LOLH and EUE values. EUE was 0.0003 MWh (2020) and 0.0004 MWh (2022). Projected loss of load only occurred during the summer season.
- **Results Trending:** Comparison of the 2016 and 2018 ProbA analyses show consistent results driven by a sufficient Anticipated Reserve Margin.

Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	23.7	24.4
Prospective	24.7	26.2
Reference	15.0	15.0
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	0.00	0.00
EUE (ppm)	0.00	0.00
LOLH (hours/year)	0.00	0.00



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.

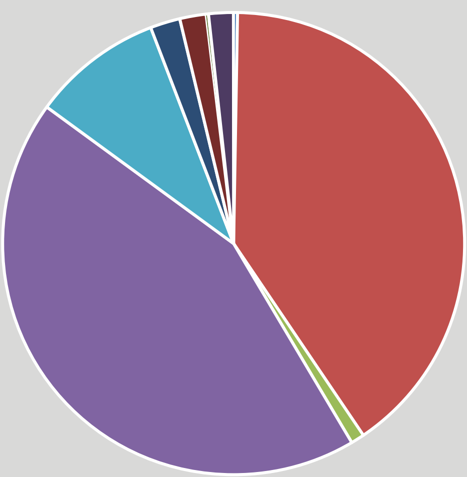
Highlights

- The MISO Region is projected to have 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 resource mix changes will allow transparency around future resource adequacy risk.
- As MISO continues to operate near the planning reserve margin, it is important to ensure efficient conversion of committed capacity to energy able to serve near term load. MISO has embarked on an initiative called Resource Availability and Need to review gaps in this conversion.

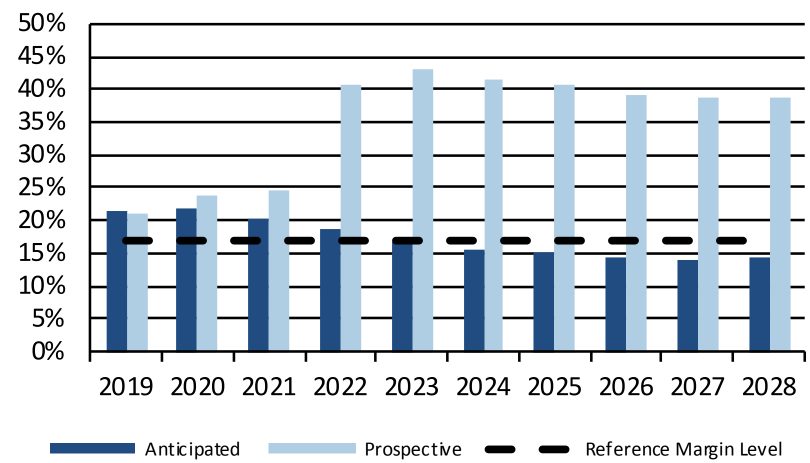
Demand, Resources, and Reserve Margins

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	125,284	125,293	125,636	125,994	126,414	126,779	127,279	127,620	128,217	128,116
Demand Response	5,990	5,990	5,990	5,990	5,990	5,990	5,990	5,990	5,990	5,990
Net Internal Demand	119,294	119,303	119,646	120,003	120,424	120,788	121,289	121,629	122,227	122,126
Additions: Tier 1	2,705	2,866	3,500	3,550	3,640	3,640	3,640	3,640	3,640	3,640
Additions: Tier 2	1,507	5,047	7,671	28,792	33,991	34,016	34,833	34,833	34,833	34,833
Net Firm Capacity Transfers	631	1,064	558	557	556	555	554	553	552	551
Existing-Certain and Net Firm Transfers	141,978	142,304	140,482	139,089	137,064	136,179	135,887	135,589	135,781	136,080
Anticipated Reserve Margin (%)	21.28	21.68	20.34	18.86	16.84	15.76	15.04	14.47	14.07	14.41
Prospective Reserve Margin (%)	20.87	23.71	24.46	40.85	42.88	41.45	40.82	39.30	38.54	38.90
Reference Margin Level (%)	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10	17.10

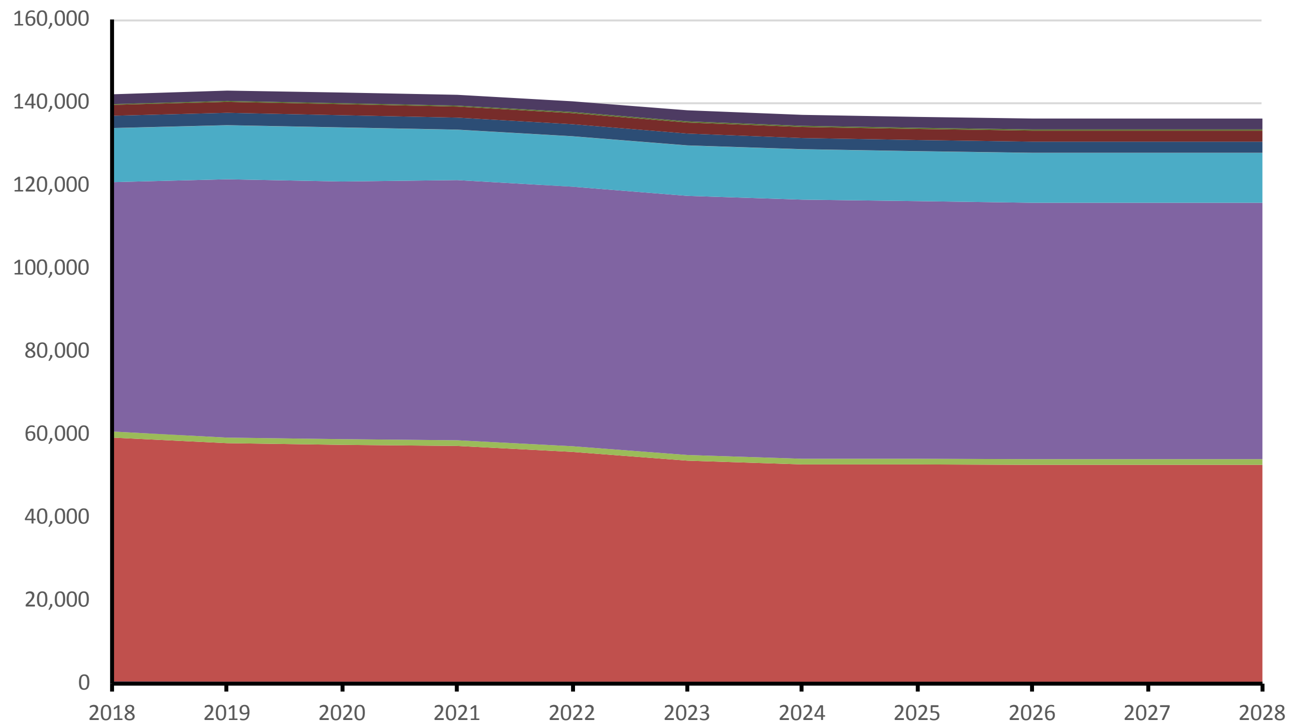
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	399	0%	362	0%
Coal	57,509	40%	52,322	38%
Hydro	1,340	1%	1,368	1%
Natural Gas	62,265	44%	61,797	45%
Nuclear	13,025	9%	12,033	9%
Other	20	0%	20	0%
Petroleum	2,974	2%	2,680	2%
Pumped Storage	2,626	2%	2,661	2%
Solar	240	0%	290	0%
Wind	2,491	2%	2,613	2%
Total	142,888	100%	136,146	100%



Planning Reserve Margins



MISO Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	399	399	385	385	362	362	362	362	362	362
Coal	57,509	57,102	56,856	55,419	53,331	52,422	52,422	52,322	52,322	52,322
Hydro	1,340	1,374	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368
Natural Gas	62,265	62,099	62,703	62,553	62,455	62,451	62,093	61,797	61,797	61,797
Nuclear	13,025	13,025	12,151	12,151	12,151	12,151	12,033	12,033	12,033	12,033
Other	20	20	20	20	20	20	20	20	20	20
Petroleum	2,974	2,936	2,892	2,892	2,844	2,680	2,680	2,680	2,680	2,680
Pumped Storage	2,626	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,661
Solar	240	240	240	290	290	290	290	290	290	290
Wind	2,491	2,566	2,598	2,572	2,662	2,637	2,622	2,620	2,613	2,613
Grand Total	142,888	142,421	141,872	140,309	138,143	137,041	136,550	136,153	136,146	136,146

Probabilistic Assessment Overview

- **General Overview:** MISO is a summer-peaking system that spans 15 states and consists of 36 local balancing areas that are grouped into 10 local resource zones. For the probabilistic assessment, MISO utilized a multiarea modeling technique for the 10 local resource zones internal to MISO. Firm external imports and nonfirm imports are also modeled. This model and accompanying methodology has been thoroughly vetted through MISO's stakeholder process.
- **Modeling:** Each local resource zone was modeled with an import and export limit based on power flow transfer analysis. In addition to the zone-specific import and export limits, a regional directional limits the North/Central (LRZs 1–7) to South (LRZs 8–10) flow to 3,000 MWs and South to North/Central is limited to 2,500 MWs. The modeling of this limit is the main driver for the difference between the probabilistic and deterministic reserve margins. MISO utilizes unit-specific outage, planning, and maintenance outage rates within the analysis based off of five years of Generation Availability Data System (GADS) data. Modeling unit-specific outage rates increases precision in the probabilistic analysis when compared to the utilization of class average outage rates. Additional assumptions include:
  - Annual peak demand in MISO varies by ±5 percent of forecasted MISO demand based upon the 90/10 percent points of load forecast uncertainty (LFU) distributions.
  - Thermal units in MISO follow a two-state on-or-off sequence based on a Monte Carlo simulation that utilizes EFORd based on five years of GADS data, which is equivalent to derating MISO thermal generating resources by 9.28 percent on average.
  - Hydro units in MISO (except for run-of-river) follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes EFORd based on five years of GADS data. Run-of-River resources submit three years of historical data at peak (summer months, peak hours 14–17 HE) that is used to determine capacity values.
  - Variable energy resources (wind and solar) in MISO are a load modifier and reduce hourly demand by each individual resources capacity credit that on average is a 15.2 percent capacity credit for wind and a 50 percent capacity credit for solar.
  - Strategic Energy Risk Valuation Model (SERVM) was the software used for the 2018 ProbA. SERVM is a multi-area model that uses multiple load shapes based on historic weather to more accurately capture variance in load shapes, variance in peak load, seasonal load uncertainty, and frequency and duration of severe weather patterns. For the 2018 ProbA, MISO completed 125 iterations of 30 weather years with five levels of economic uncertainty for a total of 18,750 simulations per case.
- **Probabilistic vs. Deterministic:** The LTRA deterministic reserve margins decrement the capacity constrained within MISO South due to the 2,500 MW limit that reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis and determined if sufficient capacity was available to transfer from South to North and vice versa. The modeling of this limitation produces an increase for the probabilistic assessment forecast planning reserve margin.

Base Case Study

- The bulk of the EUE and the LOLH are accumulated in the summer-peaking months with some off peak risk.
- Increasing loss of load statistics are expected with decreasing reserve margins.
- **Results Trending:** Previous results in the 2016 ProbA resulted in 96 MWh EUE and 0.125 hours/year LOLH. The results from this year's analysis resulted in a slight decrease for 2020 when compared to the analysis completed in the 2016 ProbA.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	16.6	21.7	18.9
Reference	15.2	17.1	17.1
ProbA Forecast Operable	10.6	14.2	13.7
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	95.80	14.2	31.6
EUE (ppm)	0.133	0.019	0.043
LOLH (hours/year)	0.125	0.108	0.211

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate planning reserve margin for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO coincident peak demand for that planning year. The probabilistic analysis uses a LOLE study that assumes no internal transmission limitations within the MISO Region. MISO calculates the planning reserve margin such that the LOLE for the next planning year is one-day-in-10 years, or 0.1 days per year. The minimum amount of capacity above coincident peak demand in the MISO Region required to meet the reliability criteria is used to establish the planning reserve margin. The planning reserve margin is established as an unforced capacity (planning reserve margin UCAP) requirement based upon the weighted average forced outage rate of all planning resources in the MISO Region. The planning reserve margin increased from the *2017 LTRA* of 15.8 percent to 17.1 percent in the *2018 LTRA*. Changes from 2017–2018 planning year values are due to changes in generation verification test capacity, equivalent forced outage rate demand or equivalent forced outage rate demand with adjustment to exclude events outside management control, new units, retirements, suspensions, and changes in the resource mix.

Demand: MISO does not forecast load for the seasonal resource assessments. Instead, LSEs report load projections under the resource adequacy requirements section (Module E-1) of the MISO tariff. LSEs report their annual load projections on a MISO coincident basis as well as their noncoincident load projections for the next 10 years, monthly for the first two years, and seasonally for the remaining eight years. MISO projects the summer coincident peak demand is expected to grow at an average annual rate of 0.3 percent for the 10 year period, which is the same growth rate from the 2017 assessment.

Demand-Side Management: MISO currently separates DR resources into two categories: direct control load management and interruptible load.[56] Direct control load management is the magnitude of customer service (usually residential). During times of peak conditions or when MISO otherwise forecasts the potential for maximum generation conditions. MISO surveys local BAs to obtain the amount of their demand. For this assessment, MISO uses the registered amount of DSM that is procured and cleared through the annual Planning Resource Auction. MISO forecasts 7,137 MW of direct control load management and interruptible load to be available for the assessment period. MISO also forecasts at least 4,576 MW of behind-the-meter generation to be available for assessment period. Energy efficiency is not explicitly forecasted at MISO; any energy efficiency programs are reflected within the demand and energy forecasts.

Distributed Energy Resources: In 2018, the Organization of MISO State (OMS) conducted a survey to collect DER information.[57] This forecast positions MISO to understand emerging technologies and the role they play in transmission planning as there is a specific case on DERs both at a base case level and increased penetration level. MISO has not experienced any operational challenges as of yet, but as programs grow in the future operational challenges may arise.

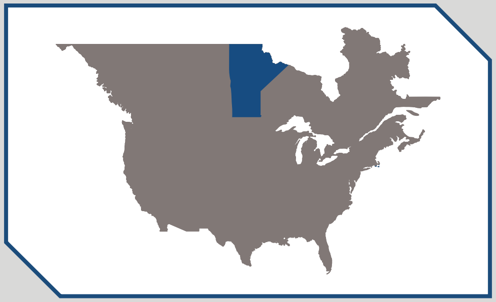
Generation: MISO projects approximately 4.0 GW of generation capacity to retire in 2018. Through the generator interconnection queue and the OMS MISO survey process, MISO anticipates 3.6 GW of future firm capacity additions and uprates along with 7.9 GW of future potential capacity additions to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the generator interconnection queue and the 2018 OMS-MISO survey as of June 2018, which includes the aggregation of active projects.

Capacity Transfers: Interregional planning is critical to maximize the overall value of the transmission system and deliver savings for customers. Interregional studies conducted jointly with MISO's neighboring planning areas are based on an annual review of transmission issues at the seams. Depending on the outcome of those reviews, studies are scoped out and performed. In MTEP, several studies were conducted with both PJM and Southwest Power Pool (SPP).

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 77 baseline reliability projects required to meet NERC Reliability Standards, 23 generator Interconnection projects required to reliably connect new generation to the transmission grid, one market efficiency project to meet requirements for reducing market congestion, and 248 other projects that include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit but do not meet the threshold to qualify as market efficiency projects.

[56] See BPM 011 section 4.3 of the MISO Resource Adequacy Business Practice Manual: https://www.misoenergy.org/legal/business-practice-manuals/

[57] http://www.misostates.org/images/Documents/Public_OMS_DER_Survey_Results_as_of_July_31,_2018.pdf



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.

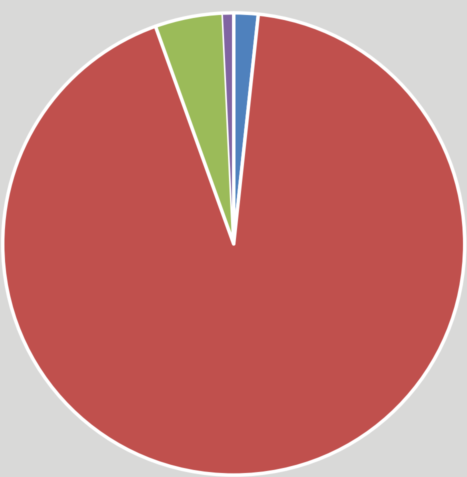
Highlights

- 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 summer 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 EE and conservation efforts.
- The Bipole III HVDC transmission line was put into commercial operation as of July 2018 that improves system reliability and resilience to extreme events.

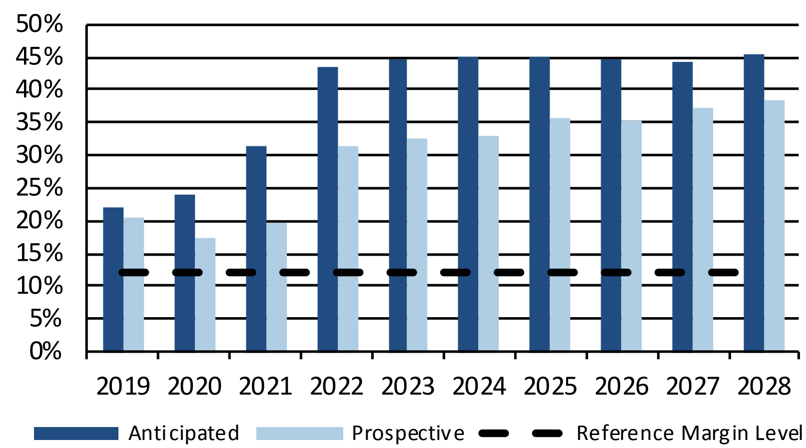
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	4,524	4,482	4,407	4,370	4,336	4,317	4,293	4,302	4,318	4,357
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,524	4,482	4,407	4,370	4,336	4,317	4,293	4,302	4,318	4,357
Additions: Tier 1	0	0	190	640	640	640	640	640	640	640
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-103	-58	100	125	125	125	100	100	100	100
Existing-Certain and Net Firm Transfers	5,523	5,562	5,609	5,630	5,630	5,630	5,590	5,590	5,590	5,690
Anticipated Reserve Margin (%)	22.09	24.11	31.58	43.48	44.60	45.26	45.11	44.83	44.29	45.30
Prospective Reserve Margin (%)	20.66	17.30	19.60	31.40	32.42	33.03	35.73	35.46	37.27	38.34
Reference Margin Level (%)	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

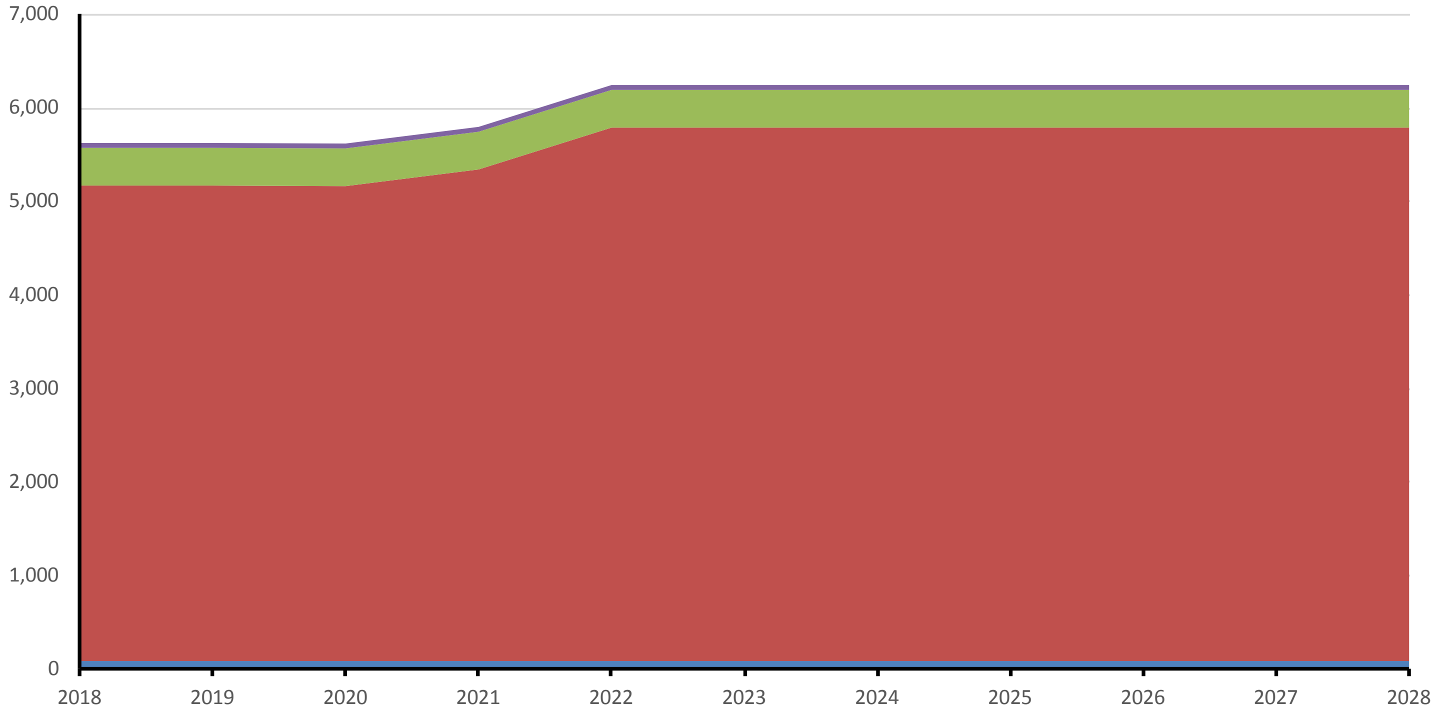
2019 On-Peak Fuel-Mix



Generation Type	2019–20		2028–29	
	MW	Percent	MW	Percent
Coal	93	2%	93	2%
Hydro	5,100	93%	5,710	94%
Natural Gas	261	5%	261	4%
Wind	41	1%	41	1%
Total	5,496	100%	6,106	100%



Planning Reserve Margins



MRO-Manitoba Hydro Fuel Composition

Gen Type	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Coal	92	92	92	92	92	92	92	92	92	92
Hydro	5,079	5,079	5,073	5,251	5,698	5,698	5,698	5,698	5,698	5,698
Natural Gas	403	403	403	403	403	403	403	403	403	403
Wind	52	52	52	52	52	52	52	52	52	52
Total	5,626	5,626	5,620	5,798	6,245	6,245	6,245	6,245	6,245	6,245

Probabilistic Assessment Overview

- **General Overview:** The 2018 Manitoba Hydro ProbA was conducted using the Multi-Area Reliability Simulation program. For 2020 Base Case, small values of EUE and LOLH are observed due to relatively less reserve margin. For 2022 Base Case, the LOLH and EUE are zero.
- **Modeling:** Manitoba Hydro and its neighboring systems are modeled as three areas that consist of Manitoba, Saskatchewan, and the northwest part of MISO. Each of the three interconnected areas is modeled as a copper sheet, and the transmission between areas is modeled with interface transfer limits:
  - Annual peak demand in Manitoba varies by ±5 percent of forecasted Manitoba demand to incorporate uncertainties in peak load forecast. The 8,760 point hourly load records of a typical year were used to model the annual load curve shape.
  - There is a small amount of thermal units representing less than 10 percent of the total installed capacity in Manitoba. These thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes 9.25 failures/year and 21.4 hours of average outage duration, which is equivalent to derating Manitoba thermal generating resources by 2.2 percent on average.
  - Manitoba Hydro system is a winter-peaking system, and the vast majority of its generating facilities are use-limited or energy-limited hydro units. All hydro plants are modeled as energy limited based on the historical flow conditions of the river systems.
  - Wind resources in Manitoba are modeled as deterministic load modifiers that consider the seasonal variations that are approximately equivalent to 16 percent and 20 percent of the maximum wind generation capacity for summer and winter seasons, respectively.
- **Probabilistic vs. Deterministic:** Manitoba Hydro is a winter peak system, and the anticipated reserve margins for 2020 and 2022 are taken from the LTRA 2020 and 2022 values, respectively.
  - DR programs are modeled as a simple load modifier by reducing the peak load.
  - Contractual commitments are modeled as load modifiers that consider the contractual obligations of the power sales and purchase agreements.
  - The external systems were modeled in the same detail as the Manitoba system rather than a simple equivalent model. It is assumed that potential assistances from external systems are based on their anticipated reserve margins for 2020 and 2022 planning years.

Base Case Study

- The LOLH and EUE values calculated in this assessment for the reporting year of 2020 is virtually the same as the values obtained in 2016 assessment for the reporting year of 2018. This is expected because of the similarity in modeling assumptions in these two cases. In 2016 assessment, the in-service-date of the expected addition of a new generating station was assumed to be in 2019. In this assessment, however, the in-service-date of the expected addition of the new generating station is assumed to be in 2021. The LOLH and EUE values calculated for the reporting year of 2022 are zero because of the addition of the new generating station and the increase in the transfer capability between Manitoba and the United States due to the addition of the Great Northern Transmission Line between Minnesota and Manitoba.

Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	22.09	31.58
Reference	12	12
ProbA Forecast Operable	14.7	31.0
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	3259.30	0.0
EUE (ppm)	0.1170	0.0
LOLH (hours/year)	2.39	0.0

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. The Reference Margin Level is based on both system historical adequacy performance analysis and reference to probabilistic resource adequacy studies using the index of LOLE and loss of energy expectation (LOEE).

Demand: Manitoba Hydro's load peaks in the winter, typically in the months of January, February, or December. The primary driver of energy load growth in Manitoba is population (1.1 percent anticipated population growth) with the secondary driver being the economy. Manitoba Hydro uses econometric regression modeling by sector to determine projected energy usage. Subregional load growth projections are utilized for five areas to assist in sub-regional transmission planning.

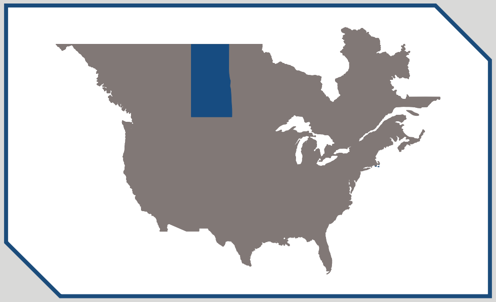
Demand-Side Management: Manitoba Hydro does not have any DSM resources that are considered as controllable and dispatchable DR. Manitoba Hydro does have energy efficiency and conservation initiatives used to reduce overall demand in the assessment area, and the impact of the reductions are included in the load forecast.

Distributed Energy Resources: There is about 31 MW dc of solar DERs in Manitoba as of the end of April 2018. Most of the solar distributed resources were installed in the last year under an incentive program that has ended. Even with high growth rates, Manitoba Hydro is not anticipating the quantity of solar DERs in Manitoba would increase to a level that would cause potential operation impacts in the next five to 10 years.

Generation: The 630 MW (net summer 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 major enhancements to the transmission system that are 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 most significant of the major system enhancements is the addition of the third bipolar high voltage direct current transmission system to improve reliability, especially during extreme events; this is now in commercial operation as of July 2018. In 2021, the new outlet transmission facilities for the Keeyask Generating Station are due to begin commercial operations. Manitoba Hydro is expecting a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020. A new 230kV transmission interconnection between Birtle, Manitoba and Tantallon, Saskatchewan is expected to be in-service in June 2021. In 2022 a new transmission line from Laverendrye to St. Vital is expected to go into service in order to upgrade the 230 kV network in the Winnipeg area into a 230kV ring to protect against extreme events.



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.

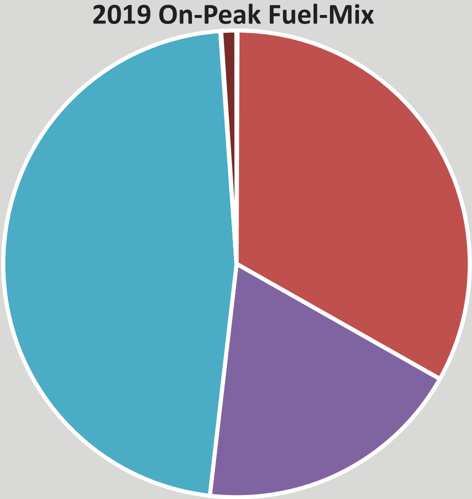
Highlights

- Anticipated reserve margins will remain above the Reference Margin Level (11 percent) throughout the assessment period.
- Approximately 1,772 MW of additional renewal capacity is projected over the assessment period. The expected on-peak contribution from renewables is projected to increase from 22 percent in 2018 to 27 percent in 2028.
- A new 230 kV tie line with Manitoba Hydro is under construction to facilitate a 100 MW firm capacity /energy transfer.

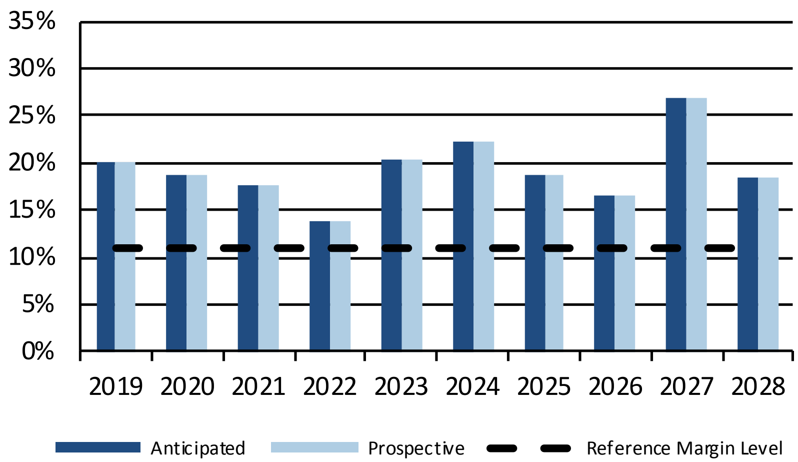
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	3,924	3,973	3,998	4,032	4,062	4,083	4,135	4,169	4,206	4,231
Demand Response	85	85	85	85	85	85	85	85	85	85
Net Internal Demand	3,839	3,888	3,913	3,947	3,977	3,998	4,050	4,084	4,121	4,146
Additions: Tier 1	354	361	396	436	826	866	906	946	1,336	1,376
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	25	25	125	100	100	100	100	100	100	100
Existing-Certain and Net Firm Transfers	4,257	4,257	4,209	4,053	3,958	4,018	3,898	3,815	3,894	3,529
Anticipated Reserve Margin (%)	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
Prospective Reserve Margin (%)	20.12	18.78	17.68	13.74	20.29	22.15	18.64	16.58	26.92	18.34
Reference Margin Level (%)	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00

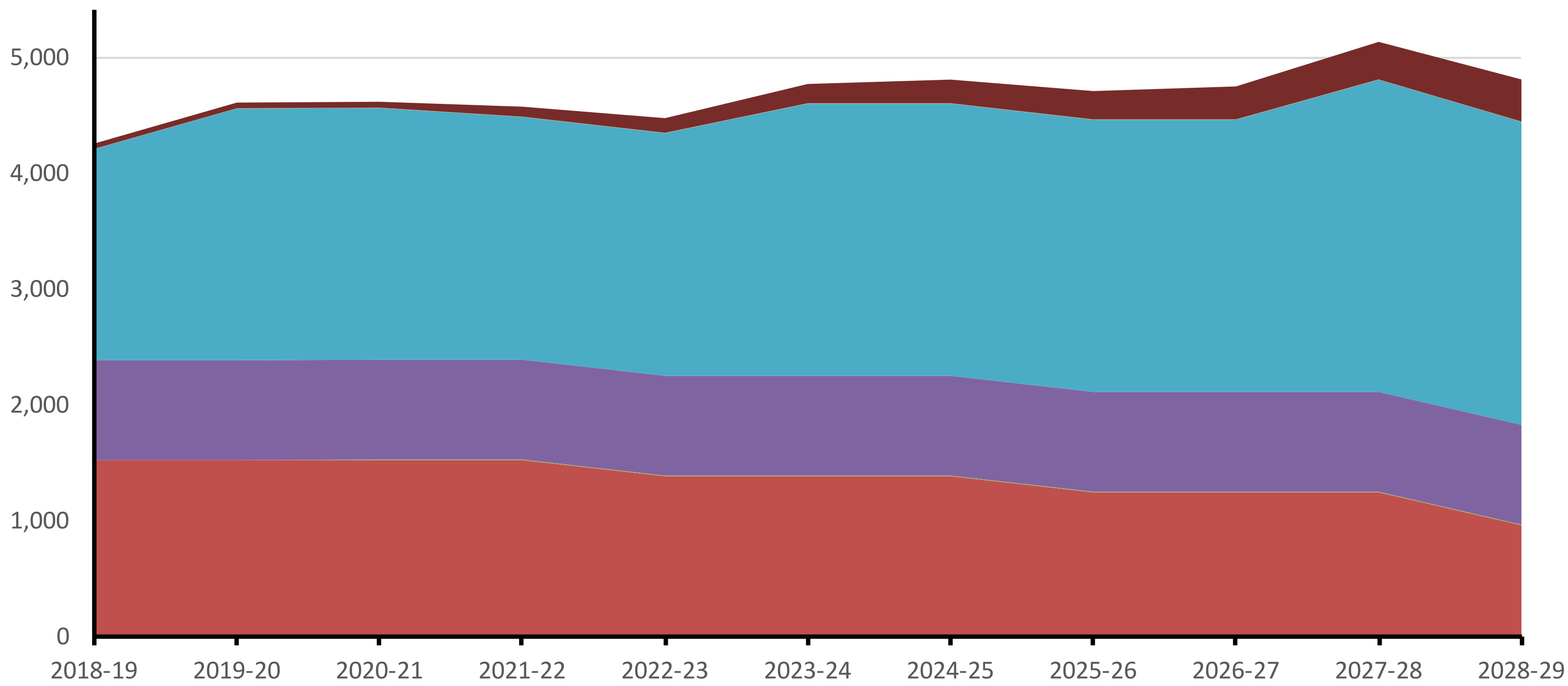
2019 On-Peak Fuel-Mix



Generation Type	2019–20		2028–29	
	MW	Percent	MW	Percent
Biomass	3	0%	3	0%
Coal	1,531	33%	1,253	24%
Geothermal	0	0%	5	0%
Hydro	862	19%	862	17%
Natural Gas	2,173	47%	2,695	52%
Other	3	0%	3	0%
Solar	0	0%	0	0%
Wind	49	1%	324	6%
Total	4,620	100%	5,144	100%



Planning Reserve Margins (Winter)



MRO-SaskPower Fuel Composition

Gen Type		2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Biomass		3	3	3	3	3	3	3	3	3	3
Coal		1,531	1,531	1,531	1,392	1,392	1,392	1,253	1,253	1,253	968
Geothermal			5	5	5	5	5	5	5	5	5
Hydro		862	862	862	862	862	862	862	862	862	862
Natural Gas		2,173	2,173	2,096	2,096	2,351	2,351	2,351	2,351	2,695	2,617
Other		3	3	3	3	3	3	3	3	3	3
Solar			0	0	0	0	0	0	0	0	0
Wind		49	51	86	126	166	204	244	284	324	363
Total		4,620	4,627	4,584	4,485	4,780	4,818	4,719	4,759	5,144	4,820

Probabilistic Assessment Overview

- **General Overview:** Based on the deterministic calculations within this assessment, Saskatchewan's anticipated reserve margin is 20.1 percent and 17.7 percent for year 2020 and 2022, respectively. EUE calculated for the Base Case is 1147.5 MWh/yr and 4494.9 MWh/yr for the year 2020 and 2022, respectively. LOLH follows a similar pattern to EUE.
- **Modeling:** SaskPower utilizes the Multi-Area Reliability Simulation (MARS) program for reliability planning and case runs. The software performs the Monte Carlo simulation by stepping through the time chronologically and calculates the standard reliability indices of daily and hourly LOLE and EUE. Detailed representation of the utility system, such as load forecast, expansion sequence, unit characteristics, maintenance and outages is included in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. The program also calculates the need for initiating emergency operating procedures (EOPs):
  - This reliability study is based on the 50/50 load forecast that includes data like the annual peak, annual target energy, and load profiles. The model distributes the annual energy into hourly data based on the load shape. Saskatchewan develops energy and peak demand forecasts based on provincial econometric model, forecasted industrial load data, and weather normalization model. The forecasts also take into consideration of the Saskatchewan economic forecast, historic energy sales, customer forecasts, weather normalized sales, and system losses.
  - Generating unit forced outage and partial outages are modeled in MARS by inputting a multi-state outage model that represents an equivalent forced outage rate (EFOR) for each unit represented. MARS models capacity unavailability by considering the average and partial outages for each generating unit that has occurred over the most recent five-year period. Forced outages are modeled as two- or three-state models. Natural gas units are typically modeled as a two-state unit so that a natural gas unit is either available to be dispatched up to full load or is on a full forced outage with zero generation. Coal facilities are typically modeled as three-state units. A coal unit can be in a full load, a derated forced outage, or a full forced outage state.
  - For reliability planning purposes, Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak demand.
  - Hydro generation is modeled as an energy limited resource and utilized based on deterministic scheduling on a monthly basis. Hydro units are described by specifying maximum rating, minimum rating, and monthly available energy. The first step is to dispatch the minimum rating for all the hours in the month. Remaining capacity and energy is then scheduled so as to reduce the peak loads as much as possible.
  - DSM is deducted from the load forecast (both the peak load and energy forecasts). Demand response is modelled as an emergency operating procedure by assigning a fixed capacity value.
- **Probabilistic vs. Deterministic:** Reserve margin results for probabilistic assessment is consistent with deterministic assessment.

Base Case Study

- Saskatchewan has planned for adequate resources to meet anticipated load and reserve requirements for the assessment period.
- The major contribution to the LOLH and EUE is in the month of October (> 60 percent) due to maintenances scheduled for some of the largest units. Most of the maintenance is scheduled during off-peak periods and can be rescheduled to mitigate short-term reliability issues.

Results Trending: Since the 2016 ProbA, the reported forecast reserve margin has dropped from 25.6 percent to 20.1 percent. This is mainly due to deferral of Wind-Chaplin (177 MW), Biomass-MLTC (36 MW), and Flare Gas (20 MW) generation projects.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	25.6	20.1	17.7
Reference	11.0	11.0	11.0
ProbA Forecast Operable	22.5	15.7	11.7
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	65.5	1147.5	4494.9
EUE (ppm)	2.6	43	167
LOLH (hours/year)	0.84	11.45	39.02

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: SaskPower uses a criterion of 11 percent as the Reference Reserve Margin for resource adequacy. Saskatchewan has assessed its planning reserve margin for the upcoming ten years while considering the summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and DR for each year. Saskatchewan's anticipated reserve margin ranges from approximately 14 to 27 percent and does not fall below the Reference Margin Level.

Demand: SaskPower's system peak forecast is contributed by econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately one percent throughout the assessment period.

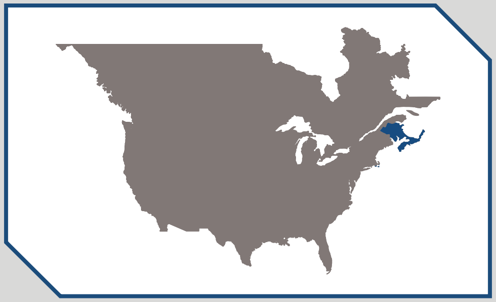
Demand-Side Management: SaskPower's energy efficiency and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measureable and permanent reductions in electrical energy, and demand reductions during peak hours. Energy provided from EE and DSM programs are modeled as load modifiers and are netted from both the peak load and energy forecasts. A steady growth is expected on energy efficiency and conservation over the assessment period. SaskPower's DR program has contracts in place with industrial customers for interruptible load based on defined DR programs. The first of these programs provides a curtailable load, currently up to 85 MW, with a 12 minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources: The penetration level of DERs is currently very low (approximately 14 MW), and therefore, SaskPower does not anticipate operational challenges due to the DERs. The current penetration of DER Solar PV is approximately 0.3 percent of the total load. It is estimated that the penetration would increase to approximately 1.7 percent in the five-year horizon.

Generation: SaskPower is planning to add a total of 2,822 MW (name plate capacity) generation including 1,607 MW of wind, 1,050 MW of natural gas, and 100 MW of firm import. The addition of wind may require curtailing the generation, or have additional fast ramping capacity available from other resources, such as natural gas facilities, to follow the intermittency of the variable resource. SaskPower is not expecting long-term reliability impacts due to increased reliance on natural gas. A total of approximately 833 MW of generation is expected to be retired, which includes 254 MW of natural gas facilities and 562 MW of coal facilities. Replacement resources are being planned before the retirements, and therefore SaskPower is not expecting any long-term reliability impacts due to generation retirements.

Capacity Transfers: Saskatchewan has a contract in place for a firm 25 MW (until March 2022) and a firm 100 MW (starting Summer 2021 and throughout the assessment period) capacity transfers from Manitoba Hydro, including supply source and transmission. A new 230 kV tie-line between Manitoba and Saskatchewan is currently under construction to facilitate the 100 MW capacity transfer. 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. Any planning or operating related issues are coordinated in accordance with the interconnection agreements through respective planning and operating committees between SaskPower and Manitoba Hydro.

Transmission: Saskatchewan has several major transmission projects during the one to five year planning horizon of the assessment period. These projects are driven by load growth and reliability needs and involve the construction of approximately 330 km of 230 kV and 200 km of 138 kV new transmission lines.



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.

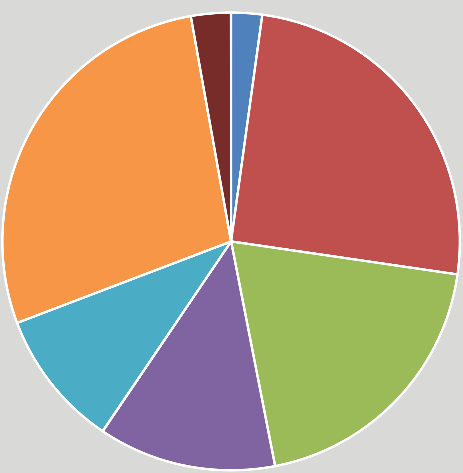
Highlights

- Demand growth is effectively negligible over the duration of the LTRA analysis period.
- An undersea HVDC undersea cable connection to the Canadian province of Newfoundland and Labrador was completed 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.

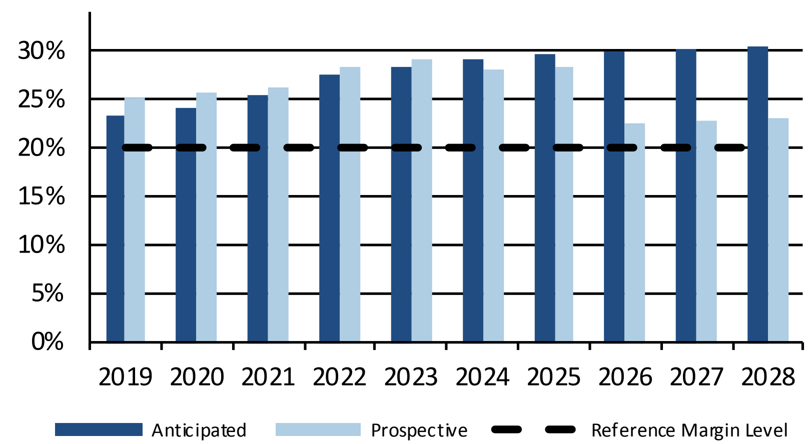
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	5,595	5,603	5,583	5,545	5,508	5,480	5,454	5,445	5,434	5,429
Demand Response	265	264	264	264	264	263	263	263	262	262
Net Internal Demand	5,330	5,339	5,319	5,281	5,245	5,217	5,191	5,182	5,172	5,167
Additions: Tier 1	48	59	95	95	95	95	95	95	95	95
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-110	-69	-66	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	6,532	6,573	6,576	6,642	6,642	6,642	6,642	6,642	6,642	6,642
Anticipated Reserve Margin (%)	23.46	24.22	25.41	27.56	28.45	29.13	29.78	30.01	30.26	30.39
Prospective Reserve Margin (%)	25.16	25.74	26.22	28.35	29.21	28.01	28.35	22.70	22.94	23.06
Reference Margin Level (%)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00

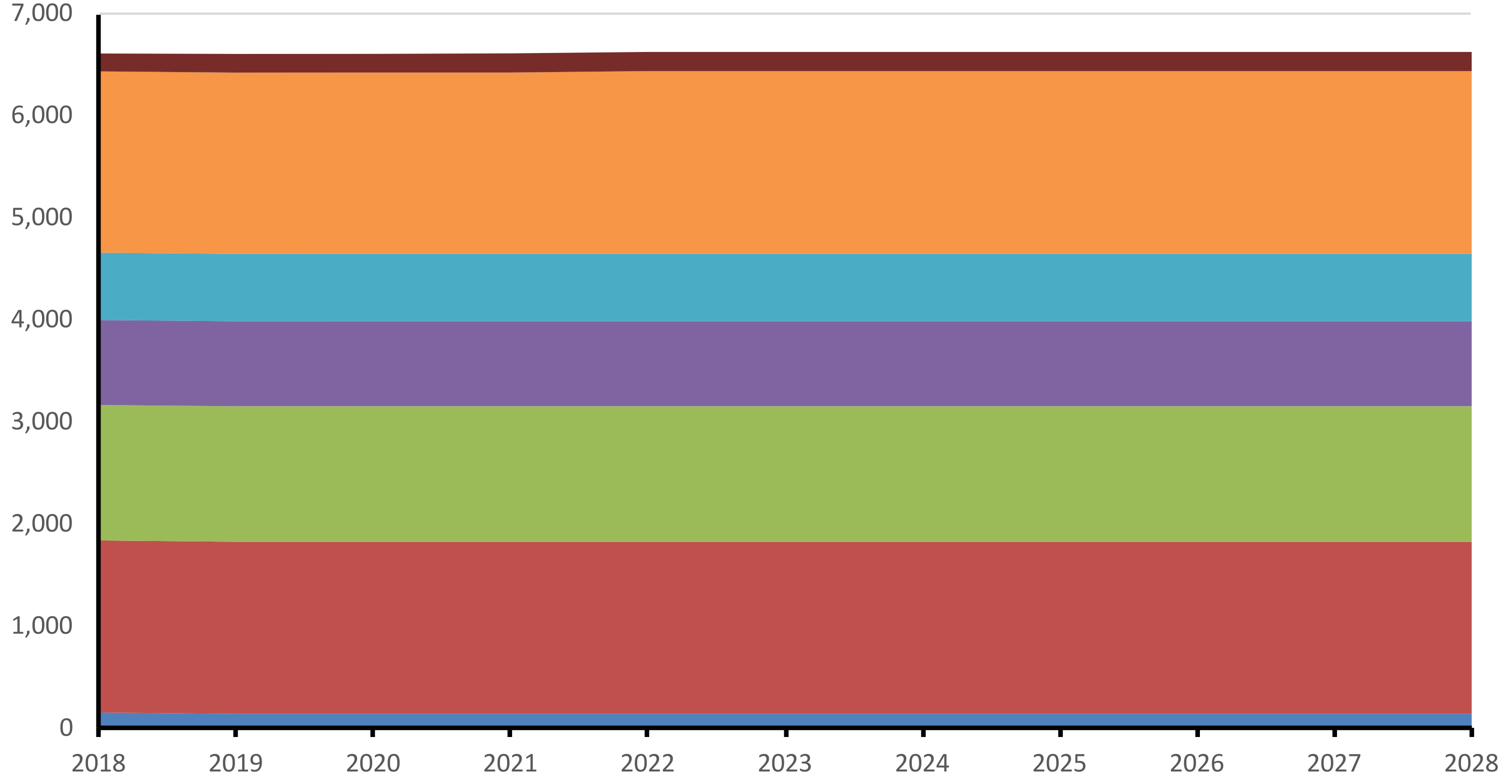
2019 On-Peak Fuel-Mix



Generation Type	2019–2020		2028–2029	
	MW	Percent	MW	Percent
Biomass	148	2%	148	2%
Coal	1,700	25%	1,700	25%
Hydro	1,327	20%	1,328	20%
Natural Gas	850	13%	850	13%
Nuclear	660	10%	660	10%
Petroleum	1,893	28%	1,911	28%
Solar	0	0%	0	0%
Wind	190	3%	195	3%
Total	6,768	100%	6,791	100%



Planning Reserve Margins (Winter)



NPCC-Maritimes Fuel Composition

Gen Type	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Biomass	148	148	148	148	148	148	148	148	148	148
Coal	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Hydro	1,327	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328	1,328
Natural Gas	850	850	850	850	850	850	850	850	850	850
Nuclear	660	660	660	660	660	660	660	660	660	660
Petroleum	1,893	1,893	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911
Solar	0	0	0	0	0	0	0	0	0	0
Wind	190	195	195	195	195	195	195	195	195	195
Total	6,768	6,773	6,791	6,791	6,791	6,791	6,791	6,791	6,791	6,791

Probabilistic Assessment Overview

- **General Overview:** The Maritimes area is a winter-peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. No significant LOLH was observed. The estimated EUE is negligible. The anticipated reserve margins are well above 20 percent in both years. Any contribution to the LOLH and EUE occur during the peak (winter) monthly period.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in NPCC 2018 Long Range Adequacy Overview.[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion:[2]
  - Maritimes area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine subarea that uses a simple scaling factor, all other subareas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modelling, and end use modeling to develop their load forecasts.
  - Combustion turbine capacity for the Maritimes area is seasonal dependable maximum net capability. During summer, these values are derated accordingly.
  - Hydro capacity in the Maritimes area is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.
  - Solar capacity in the Maritimes area is behind-the-meter and netted against load forecasts. It does not currently count as capacity.
  - The Maritimes area provides an hourly historical wind profile for each of its four subareas based on actual wind shapes from the fiscal year of 2011/2012. The data is considered typical.
- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*.[3]
  - The loads for each area were modeled on an hourly, chronological basis. It was based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
  - The Maritimes area modeled operating procedures that included reduced operating reserves before firm load has to be disconnected.
  - Demand response in the Maritimes area is currently comprised of contracted interruptible loads.
  - Transmission additions and retirements assumed were consistent with this *NERC 2018 Long-Term Reliability Assessment*.
  - In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

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1 https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

2 https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

3 Available December 2018 at the follow: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

4 https://www.npcc.org/Library/Other/Forms/Public20List.aspx

- **Results Trending:** The previous study *NERC Probabilistic Assessment – NPCC Region* estimated an annual LOLH = 0.000 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2020.* The 2020 Forecast 50/50 peak demand forecast is lower in this assessment than reported in the previous assessment; Forecast capacity resources are approximately the same as compared to the previous assessment. No material difference in estimated LOLH and EUE is observed between the two assessments.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	24.4	23.5	25.4
Reference	20.0	20.0	20.0
ProbA Forecast Operable	18.1	33.0	33.5
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

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: Maritimes area peak loads are expected to increase by 3.2 percent during the summer but decline by 1.1 percent during the winter 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 New Brunswick (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 2026/27 of controllable direct load control programs that use 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.[58] During the assessment period, annual amounts for summer peak demand reductions associated with energy efficiency programs rise from seven MW to 92 MW while the annual amounts for winter peak demand reductions rise from 51 MW to 541 MW.[59]

Distributed Energy Resources: The current amount of DERs in the NB subarea is insignificant (<5 MW). Should these amounts increase to significant levels, NB 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 (NS) projects 203 MW of directly metered[60] installed DG 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.

[58] 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.

[59] 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.

[60] 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 have led to the development of substantially more wind generation capacity than any other renewable generation type. In NS, the renewable electricity standard 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.[61]

Capacity Transfers: Probabilistic studies show that the Maritimes Area is not reliant on interarea 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 nine 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 NB and Prince Edward Island (PEI). Associated with this project is the addition of a new 138 kV overhead line in NB 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 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 NS by mid-2020. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB 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 NB to mitigate the effects of transformer contingencies at the terminal.

[61] 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.

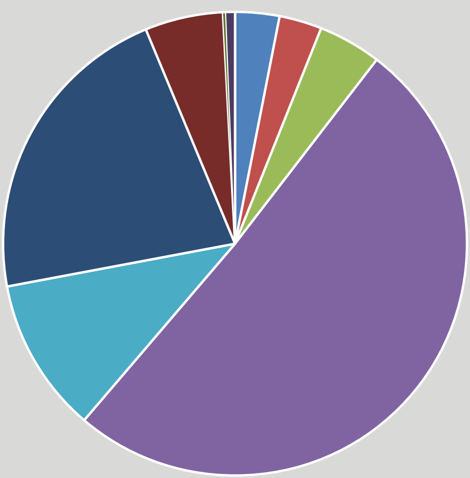
Highlights

- ISO-NE projects sufficient Anticipated Reserve Margins for the entire 2018 LTRA assessment period.
- The Region's most pressing reliability challenge is fuel security or the possibility that the Region's generators will not have, or be able to obtain, the fuel they need to run, particularly during extended cold weather (or other stressed system) conditions.
- ISO-NE is currently engaged with regional stakeholders, including the states, to develop long-term solutions to address the increasing fuel-security challenges facing the Region.
- Coordinating the timing of resource retirement and additions will also be challenging.
- The ISO is forecasting more than 5,000 MW of solar resources to be built during the 2018 LTRA assessment period and has developed solar forecasting tools to help successfully integrate these resources into both planning and operations. At this time, ISO-NE anticipates having adequate fast-start and load-following resources available to accommodate the variability of intermittent resources.
- New England's transmission system is robust, and transmission projects are planned or under construction to meet reliability needs during the 2018 LTRA assessment period. However, additional transmission projects will be required to integrate large amounts of onshore and offshore wind generation or to expand access to wind or hydropower from neighboring systems.

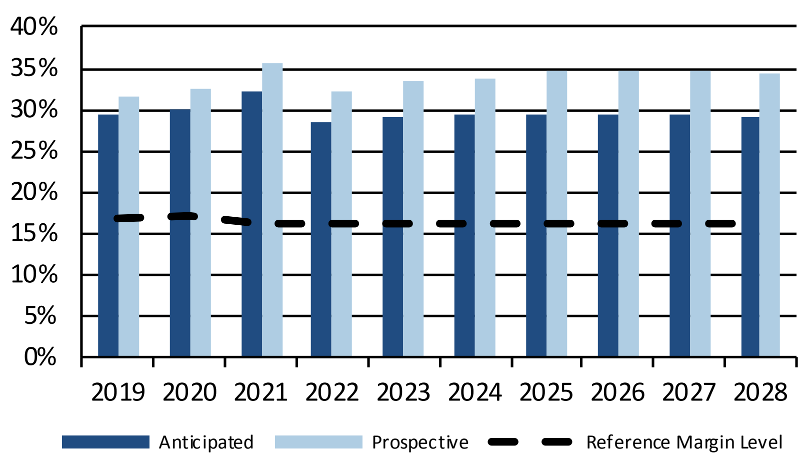
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	25,511	25,298	25,136	25,021	24,942	24,889	24,864	24,874	24,912	24,950
Demand Response	464	420	624	624	624	624	624	624	624	624
Net Internal Demand	25,047	24,878	24,511	24,396	24,317	24,264	24,239	24,249	24,288	24,326
Additions: Tier 1	1,101	1,204	1,689	1,752	1,752	1,752	1,752	1,752	1,752	1,752
Additions: Tier 2	70	166	353	424	584	611	787	787	787	787
Net Firm Capacity Transfers	1,481	1,265	1,247	81	81	81	81	81	81	81
Existing-Certain and Net Firm Transfers	31,317	31,116	30,735	29,586	29,612	29,636	29,654	29,666	29,676	29,686
Anticipated Reserve Margin (%)	29.43	29.92	32.28	28.46	28.98	29.36	29.57	29.56	29.40	29.24
Prospective Reserve Margin (%)	31.60	32.49	35.65	32.13	33.33	33.84	34.77	34.77	34.60	34.42
Reference Margin Level (%)	16.91	17.20	16.36	16.36	16.36	16.36	16.36	16.36	16.36	16.36

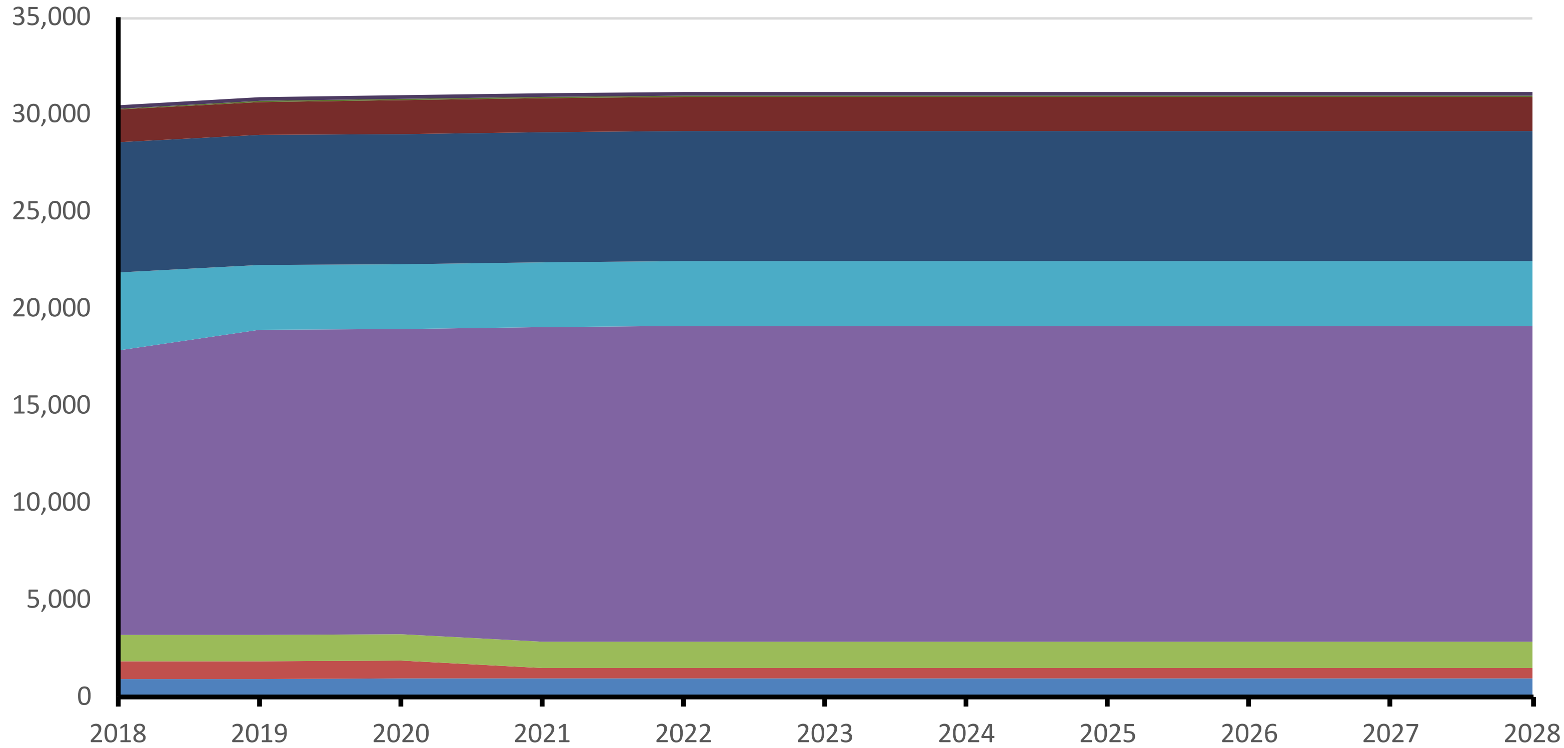
2019 On-Peak Fuel-Mix



Generation Type	2019 MW	2019 Percent	2028 MW	2028 Percent
Biomass	953	3%	990	3%
Coal	917	3%	533	2%
Hydro	1,357	4%	1,355	4%
Natural Gas	15,712	51%	16,261	52%
Nuclear	3,335	11%	3,335	11%
Other	1	0%	1	0%
Petroleum	6,699	22%	6,699	21%
Pumped Storage	1,686	5%	1,752	6%
Solar	66	0%	66	0%
Wind	189	1%	189	1%
Total	30,916	100%	31,182	100%



Planning Reserve Margins



NPCC-New England Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	953	990	990	990	990	990	990	990	990	990
Coal	917	917	533	533	533	533	533	533	533	533
Hydro	1,357	1,357	1,355	1,355	1,355	1,355	1,355	1,355	1,355	1,355
Natural Gas	15,712	15,712	16,197	16,261	16,261	16,261	16,261	16,261	16,261	16,261
Nuclear	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335
Other	1	1	1	1	1	1	1	1	1	1
Petroleum	6,699	6,699	6,699	6,699	6,699	6,699	6,699	6,699	6,699	6,699
Pumped Storage	1,686	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752
Solar	66	66	66	66	66	66	66	66	66	66
Wind	189	189	189	189	189	189	189	189	189	189
Total	30,916	31,019	31,118	31,182	31,182	31,182	31,182	31,182	31,182	31,182

Probabilistic Assessment Overview

- **General Overview:** The New England area is a summer-peaking area. For 2020, the LOLH is 0.027 hours/year and the EUE is 12.5 MWh; in 2022 those values are 0.007 hours/year and 2.713 MWh, respectively. The forecast 50/50 peak demand for 2022 is lower than 2020 with lower forecast capacity resources. The summer months provide the greatest contribution to these annual metrics.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over inter-connections with neighboring Planning Coordinator areas, transmission transfer capabilities, capacity, and/or load relief from available operating procedures as prescribed by the NPCC resource adequacy criterion:[2]
  - New England develops an independent demand forecast for its area using historical hourly demand data from individual member utilities that is based upon revenue quality metering. This data is then used to develop historical demand data on which the regional peak demand and energy forecasts are subsequently based. From this, ISO New England develops a forecast of both state and system seasonal peak and energy demands. The peak demand fore-cast for the Region and the states can be considered a coincident peak demand forecast. This demand forecast is referred to as the gross demand forecast (without reductions).
  - The seasonal claimed capability as established through the claimed capability audit is used to represent the non-intermittent thermal resources in New England. The seasonal claimed capability for intermittent thermal resources is based on their historical median net real power output during reliability hours (2:00–6:00 p.m.).
  - New England uses the seasonal claimed capability as established through the claimed capability audit to represent the hydro resources. The seasonal claimed capability for intermittent hydro resources is based on their historical median net real power output during reliability hours (2:00–6:00 p.m.).
  - The majority of solar resource development in New England consists of the state-sponsored distributed behind-the-meter PV resources that do not partici-pate in wholesale markets but reduce the system load observed by ISO-New England. These resources are modeled as a load modifier on an hourly basis based on the 2002 historical hourly weather profile.
  - New England models wind resources using the seasonal claimed capability that is based on their historical median net real power output during reliability hours (2:00–6:00 p.m.).

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1 https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

2 https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region.*[3] Additional assumptions include the following:
  - The loads for each area were modeled on an hourly, chronological basis. This is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
  - In addition to the annual update to New England's peak demand and energy forecast, ISO New England also forecasts the anticipated growth and impact of behind-the-meter PV resources within the area that do not participate in wholesale markets. ISO-New England's forecast for these resources is developed with stakeholder input.
  - New England also develops a forecast of long-term savings in peak and energy use for the area and for each state stemming from state-sponsored energy-efficiency programs. These programs include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment. ISO New England's forecast of energy-efficiency resources is developed with stakeholder input.
  - The New England area modeled operating procedures that included reduced operating reserves and voltage reduction before firm load has to be disconnected.
  - Starting on June 1, 2018, price-responsive demand response was fully integrated into New England's energy and reserve markets. These resources are treated similarly to generating resources. They are dispatchable and participate in both the daily energy and reserves markets.
  - Transmission additions and retirements were assumed consistent with this NERC *2018 Long-Term Reliability Assessment*.
  - In the NPCC ProbA simulations, all areas within NPCC received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

[3] Available December 2018 at the following: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[4] https://www.npcc.org/Library/Other/Forms/Public%20List.aspx

Base Case Study

- **Results Trending:** The previous study, *NERC Probabilistic Assessment – NPCC Region,* estimated an annual LOLH = 0.189 hours/year and a corresponding EUE equal to 140.9 MWh for the year 2020.* The net forecast 50/50 peak demand for 2020 was lower than reported in the previous study with higher estimated forecast planning and forecast operable reserve margins. As a result, both the LOLH and the EUE have improved for 2020.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	18.2	29.9	28.5
Reference	15.9	17.2	16.4
ProbA Forecast Operable	9.4	20.7	19.0
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	140.9	12.53	2.71
EUE (ppm)	1.00	0.10	0.02
LOLH (hours/year)	0.19	0.03	0.01

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: ISO-NE's Reference Margin Level is based on the capacity needed to meet the NPCC one-day-in-10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the ICR, varies from year-to-year, depending on projected system conditions (demand, generation, transmission, imports, etc.). The ICR is calculated on an annual basis, four years in advance for each forward capacity market auction and results in a Reference Margin Level of 16.9 percent in 2019, 17.2 percent in 2020, and 16.4 percent in 2021 as expressed in terms of the 50/50 peak demand forecast that was published in May 2018. In this assessment, the last calculated Reference Margin Level (16.4 percent) is applied for the remaining seven years of the LTRA forecast. ISO-NE's Anticipated Reserve Margin is expected to stay above the Reference Margin Level during the assessment period.

Demand: ISO-NE develops an independent demand forecast for its BA area using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and states demand forecast is considered coincident. This demand forecast is the gross demand forecast. Annually, ISO-NE also forecasts the load reduction impact of behind-the-meter PV resources and the reductions to peak demand and energy due to passive DR programs, which are comprised mostly of EE. EE in 2019 is 3,066 MW and is forecast to grow to 3,757 MW by 2021 and increase to over 5,229 MW by 2028. Nameplate BTM PV in 2019 is 2,039 MW and is forecast to grow to 2,571 MW by 2021 and increase to 3,867 MW by 2028. The BTM PV and EE forecasts are seen as reductions (net demand forecast) to the gross demand forecast.

ISO-NE is a summer-peaking electrical power system. The reference demand forecast is based on the reference economic forecast, which reflects the regional economic conditions that are expected to occur. Both the summer peak total internal demand (TID) and the net energy for load are forecast to decrease from 2019 to 2028; the TID decreases from 25,511 MW in 2019 to 24,950 MW in 2028. This amounts to a nine-year summer TID CAGR of -0.25 percent. The NEL is expected to decrease from 122,498 GWh in 2019 to 114,766 GWh in 2028, which amounts to an energy CAGR of -0.72 percent.

Demand-Side Management: On June 1, 2018, ISO-NE integrated price-responsive DR into the energy and reserve markets. Approximately 408 MW of DR participate in these markets and are dispatchable (i.e., treated similar to generators). Because of these changes, DR are no longer be considered "emergency resources," which were previously dispatched during actual of forecast capacity deficiencies under system operator EOPs. Within ISO-NE's ICR calculations, DR availability is based on historical DR performance from the past five years. The summer performance of DR was 94 percent, and the winter performance was 95 percent.

Distributed Energy Resources: New England has 188 MW (1,371 MW nameplate) of wind generation and 633 MW (1,727 MW nameplate) of BTM PV. Approximately 8,000 MW (nameplate) of wind generation projects have requested generation interconnection studies. BTM PV is forecast to grow to 1,070 MW (3,867 MW nameplate) by 2028. The BTM PV peak load reduction values are calculated as percentage of ac nameplate. The percentages, which include the effect of diminishing PV production at time of the system peak as increasing PV penetrations shift the timing of peaks later in the day, decrease from 36.6 percent of nameplate in 2018 to about 27 percent in 2028.

Generation: Generating capacity that has been added since the *2017 LTRA* consists primarily of 1,522 MW nameplate of combined-cycle units and 120 MW nameplate of natural gas turbines. Existing certain capacity for 2018 is 30,473 MW. A total of ~1,101 MW of Tier 1 natural-gas-fired capacity is projected to be added by 2019. Tier 2 capacity additions scheduled for 2019 include 70 MW of natural-gas-fired, solar, and wind generation. In 2020, scheduled Tier 2 capacity additions total 166 MW of the same types of technologies.

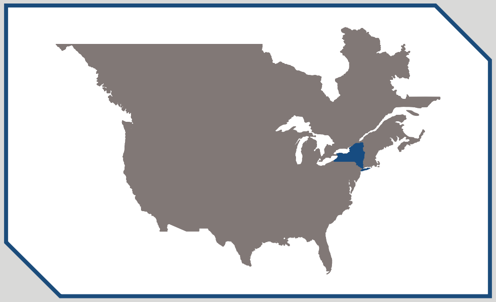
The combination of constrained natural gas pipelines during winter, indeterminate LNG and fuel oil deliveries, and upcoming planned retirements of nuclear and non-natural-gas-fired generation has prompted ISO-NE to undertake an operational fuel security analyses. This new reliability analysis, which focuses on winter operations, has pre-defined electric and natural gas sector topology along with fuel supply assumptions that are used to gauge the impact that certain prolonged, regional fuel infrastructure outages have upon BPS reliability. To address reliability issues relating to fuel/energy security, FERC directed ISO New England (ISO-NE) to file tariff revisions by August 31, 2018, to address fuel security concerns in the near term and by July 1, 2019, to address fuel security concerns over the long term.

Capacity Transfers: New England is interconnected with the three BAs of Quebec, the Maritimes, and New York. ISO-NE takes into account this transfer capability to assure that their limits do not impact regional resource adequacy. ISO-NE's forward capacity market methodology limits the purchase of import capacity based on the interconnection transfer limits.

ISO-NE's capacity imports are assumed to range from 1,600 MW to 1,250 MW during the 2018 to 2021 period and to decrease to 81 MW for the remainder of the LTRA years since the forward capacity market has only secured resources through the 2021 period.

Transmission: There are a number of new projects planned and under construction that are needed to maintain transmission reliability. The most significant area of concern is Boston. The greater Boston transmission project has addressed many of these concerns and most of the project is expected to be in service by December 2019 with the last component possibly delayed until June 2021. The second area that remains a significant concern is the SEMA/RI area. This area has both import constraints and significant constraints on moving power within the area. Similar to the Boston area, system operators will be reliant on the out-of-merit dispatch of local resources and system reconfigurations to meet system needs. Solutions to address time sensitive needs in SEMA/RI have been developed.

Transmission reliability needs in the Greater Hartford-Central Connecticut area are being addressed with projects that are under construction or already in service. Projects to address reliability needs in Southwest Connecticut, which are closely linked to the GHCC project, are also under construction or already in service. The Maine Power Reliability Program added significant 345 kV infrastructure that has already been completed and other parts of the project are now under construction and are expected to be in service by November 2018. In the past, New Hampshire and Vermont had been studied together. Reliability upgrades needed in Vermont are under construction. The New Hampshire portion upgrades are predominantly 115 kV based within the seacoast area with an anticipated in-service date of December 2019. In Western Massachusetts, a suite of reliability based projects is almost complete in the Pittsfield/Greenfield area.



NPCC-New York

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

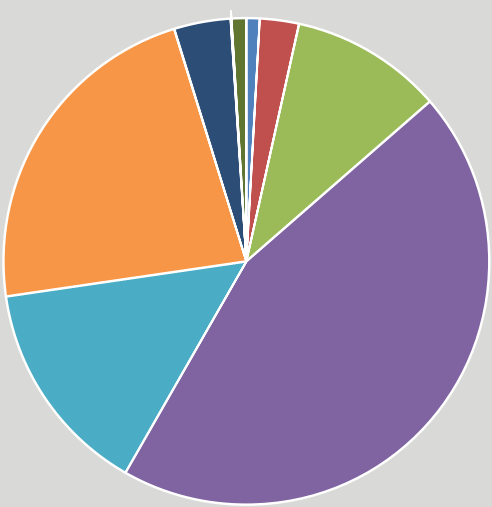
Highlights

- The 2018 final RNA has identified no reliability needs. The base case assumptions include the retirement of over 3,600 MW, including the Indian Point Energy Center (IPEC) and the addition of over 2,300 MW of new supply resources. Additionally, the NYISO completed a generator deactivation assessment in 2017 for IPEC, which concluded there are no generation deactivation reliability needs.
- The ten-year annual average energy and demand growth rates are slightly declining. The baseline forecast includes upward adjustments for usage of electric vehicles and downward adjustments for the impacts of energy efficiency trends, distributed energy resources, and behind-the-meter solar PV.
- The Western New Your public policy project proposed by NextEra (Empire State Line) has been selected by the NYISO's board of directors and is included in the NYISO planning models. Also, the NYISO is currently evaluating the transmission proposals for the ac transmission public policy transmission need to identify the more efficient or cost-effective solutions to add more transfer capability between upstate and downstate New York.
- Demand and consumption in New York are heavily influenced by state energy efficiency and renewable energy public policy programs, such as the clean energy standard that aims to produce 50 percent of state-wide energy consumption from renewables by 2030.

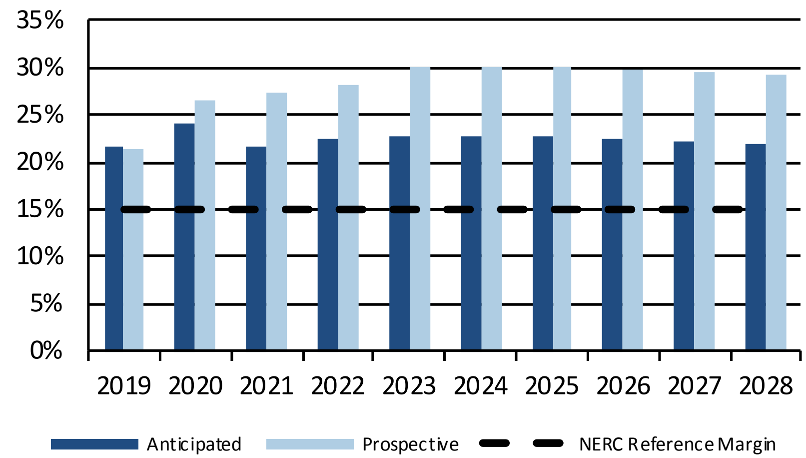
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	32,857	32,629	32,451	32,339	32,284	32,276	32,299	32,343	32,403	32,469
Demand Response	871	871	871	871	871	871	871	871	871	871
Net Internal Demand	31,987	31,759	31,581	31,469	31,414	31,406	31,429	31,473	31,533	31,599
Additions: Tier 1	933	1,978	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
Additions: Tier 2	67	835	1,881	1,881	2,389	2,389	2,389	2,389	2,389	2,389
Net Firm Capacity Transfers	1,279	1,785	1,800	1,942	1,942	1,942	1,942	1,942	1,942	1,942
Existing-Certain and Net Firm Transfers	37,954	37,442	36,419	36,561	36,561	36,561	36,561	36,561	36,561	36,561
Anticipated Reserve Margin (%)	21.57	24.12	21.64	22.53	22.74	22.77	22.68	22.51	22.28	22.02
Prospective Reserve Margin (%)	21.50	26.47	27.31	28.22	30.06	30.09	30.00	29.82	29.57	29.30
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

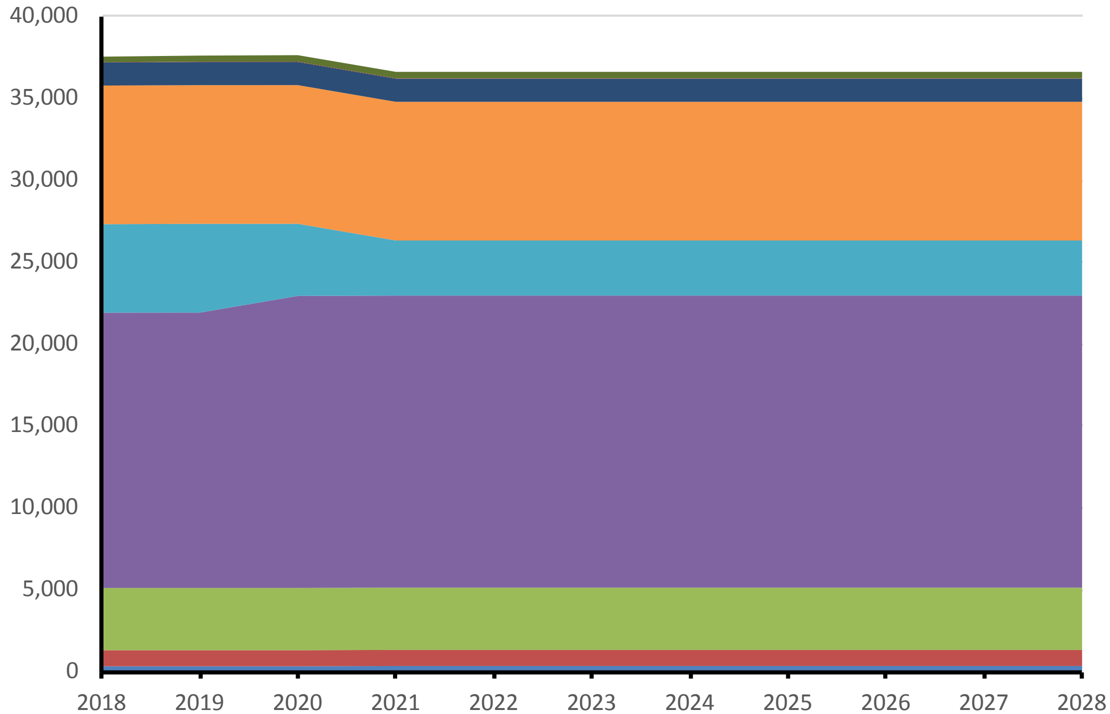
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	331	1%	350	1%
Coal	979	3%	979	3%
Hydro	3,803	10%	3,803	10%
Natural Gas	16,806	45%	17,826	49%
Nuclear	5,420	14%	3,364	9%
Petroleum	8,465	23%	8,465	23%
Pumped Storage	1,409	4%	1,409	4%
Solar	27	0%	27	0%
Wind	369	1%	394	1%
Total	37,609	100%	36,616	100%



Planning Reserve Margins



NPCC-New York Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	331	331	350	350	350	350	350	350	350	350
Coal	979	979	979	979	979	979	979	979	979	979
Hydro	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803
Natural Gas	16,806	17,826	17,826	17,826	17,826	17,826	17,826	17,826	17,826	17,826
Nuclear	5,420	4,401	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364
Petroleum	8,465	8,465	8,465	8,465	8,465	8,465	8,465	8,465	8,465	8,465
Pumped Storage	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409	1,409
Solar	27	27	27	27	27	27	27	27	27	27
Wind	369	394	394	394	394	394	394	394	394	394
Total	37,609	37,635	36,616	36,616	36,616	36,616	36,616	36,616	36,616	36,616

Probabilistic Assessment Overview

- **General Overview:** The New York area is summer-peaking. The LOLH for 2020 and 2022 are 0.001 and 0.000 (hours/year), respectively, with corresponding EUE values of 0.073 and 0.032 (MWh), which trend lower than the past ProbA results. The decreasing trend is mainly due to the decrease in the Forecast 50/50 peak demand.[1]
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[2] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion:[3]
  - New York employs a multi-stage process in developing load forecasts for each of the eleven zones within the New York area. In the first stage, baseline energy and peak models are built based on projections of end-use intensities and economic variables. In the second stage, the incremental impacts of behind-the-meter solar PV and distributed generation are deducted from the forecast, and the incremental impacts of electric vehicle usage are added to the forecast. In the final stage, the New York ISO aggregates load forecasts by load zone.
  - Installed capacity values for thermal units are based on the minimum of seasonal dependable maximum net capability test results and the capacity resource interconnection service MW value. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled using a multi-state representation that represents an equivalent forced outage rate on demand. Planned and scheduled maintenance outages are modeled based upon schedules received by the New York ISO and adjusted for historical maintenance.
  - Large New York hydro units are modeled as thermal units with a corresponding multi-state representation that represents an equivalent forced outage rate on demand. For run-of-river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run-of-river unit seasonality is captured by applying an annual shape for all run-of-river units in each draw.
  - New York provides 8,760 hours of historical solar profiles for each year of the most recent five-year calendar period for each solar plant based on production data. Solar seasonality is captured by applying an annual solar shape for all solar units in each draw.
  - New York provides 8,760 hours of historical wind profiles for each year of the most recent five-year calendar period for each wind plant based on production data. Wind seasonality is captured by randomly selecting an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.
- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*:[4]
  - The loads for each area were modeled on an hourly, chronological basis; this is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[5]
  - The New York area modeled operating procedures that included reduced operating reserves, voltage reduction, and implementation of DR programs before firm load has to be disconnected.

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[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, 2018 through April 30, 2019). The NERC 15 percent Reference Margin Level was used for the entire 10-year assessment period.

[2] https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[3] https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

[4] Available December 2018 at the follow: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[5] https://www.npcc.org/Library/Other/Forms/Public20List.aspx

- New York's Special Case Resources Program and Emergency DR Program are modeled as an operating procedure step activated to minimize the probability of customer load disconnection; the programs are only activated in zones from which they are capable of being delivered.
- Transmission additions and retirements modeled were consistent with the *NERC 2018 Long-Term Reliability Assessment.*
- In the NPCC ProbA simulations, all areas modeled received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

Base Case Study

- **Results Trending:** The previous study, *NERC Probabilistic Assessment – NPCC-NY Region*, estimated an annual LOLH = 0.004 hours/year and a corresponding EUE equal to 2.059 MWh for the year 2020.* The net forecast 50/50 peak demand for 2020 was lower than reported in the previous study with lower estimated forecast capacity resources. As a result, the LOLH has slightly increased.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	26.27	24.1	22.5
Reference	15.0	15.0	15.0
ProbA Forecast Operable	18.8	15.3	13.7
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	2.06	0.07	0.03
EUE (ppm)	0.01	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The NYISO provides significant support to the New York State Reliability Council, which conducts an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and the New York State Reliability Council resource adequacy criterion of a LOLE of no greater than 0.1 days per year. The IRM for the 2018/2019 capability year (May 1 through April 30) is 18.2 percent of the forecasted NYCA peak load (all values in the IRM calculation are based upon full installed capacity values of resources). The IRM has varied historically from 15 percent to 18.2 percent. The NYISO is forecasting adequate installed capacity to meet the 0.1 days/year LOLE for all 10 years of the reliability needs assessment (2019–2028).

Demand: The peak load forecast is based upon a model that incorporates forecasts of economic drivers, end use and technology trends, and normal weather conditions. The NYISO incorporates the impacts of energy efficiency and technology trends directly into the forecast model with additional adjustments for DERs, electric vehicles and behind-the-meter solar PV. The baseline forecast includes upward adjustments for increased usage of electric vehicles and downward adjustments for the impacts of energy efficiency trends, DERs, and behind-the-meter solar PV. The 10-year annual average energy growth rate is about the same as last year (-.14 percent per year in 2018 versus -.23 percent in 2017). The 10-year annual average summer-peak demand growth rate is lower than last year (-.13 percent per year in 2018 versus 0.07 percent in 2017).

Demand-Side Management: The NYISO's planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance.

Distributed Energy Resources: The NYISO published a report in February 2017 that provided a roadmap that will be used over the next three to five years as a framework to develop the market design elements, functional requirements, and tariff language necessary to implement the NYISO's vision to integrate DER into NYISO's energy, ancillary services, and capacity markets. The NYISO also published a market design concept paper in December 2017 and is currently in the process of developing the market design of this initiative. Behind-the-meter solar PV are currently being addressed operationally in the day-ahead and real-time load forecasts. A solar forecasting system to integrate with the day-ahead and real-time markets was implemented in 2017.

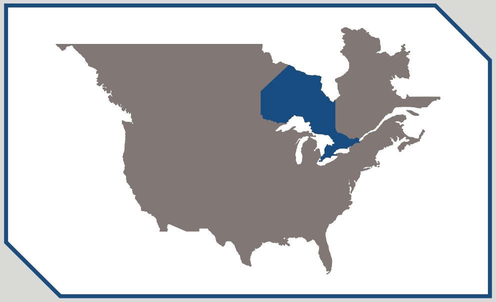
Generation: Entergy has announced its intent to deactivate the Indian Point Energy Center Unit No. 2 and 3 (approximately 2,150 MW total in 2020 and 2021, respectively). The NYISO completed a generator deactivation assessment in 2017 regarding the deactivation of the Indian Point Energy Center Unit No. 2 and 3, which concluded that no generation deactivation reliability needs arise. The NYISO's 2018 reliability planning process includes approximately 2,300 MW of proposed generation, including the 680 MW CPV Valley Energy Center (which entered into service in 2018) and the 1,020 MW Cricket Valley Energy Center (which is expected to enter into service in 2020).

Capacity Transfers: The models used for the NYISO planning studies include the firm capacity transactions (purchases and sales) with the neighboring systems as a base case assumption. The net MW seasonal values are also published in the NYISO's Gold Book[62] and include the yearly election of the unforced capacity deliverability rights and other firm capacity transactions made via the applicable processes.

Transmission: The *2018 Reliability Needs Assessment*[63] identified no reliability needs. The base case assumptions include the retirement of over 3,600 MW, including the Indian Point Energy Center and the addition of over 2,300 MW of resources. The 2018 reliability planning process also includes proposed transmission projects (including the NextEra's Empire State Line project selected under the Western New York public policy transmission planning process) and transmission owner LTPs that have met the RPP inclusion rules.

[62] 2018 NYISO Gold Book https://home.nyiso.com/wp-content/uploads/2018/04/2018-Load-Capacity-Data-Report-Gold-Book.pdf

[63] NYISO 2018 Reliability Needs Assessment: https://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2018-07-19/2018RNA_Report.pdf



NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than one 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.

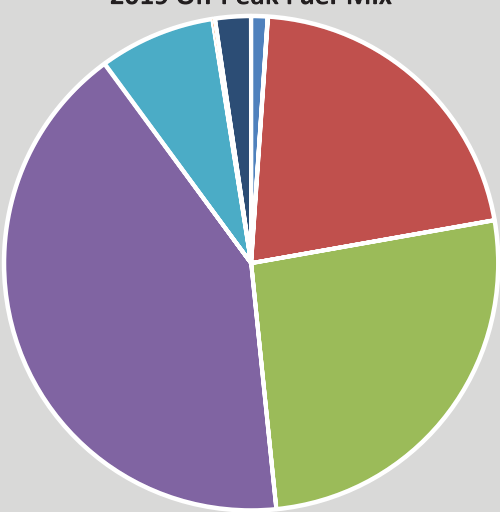
Highlights

- Projected margin shortfalls in the later part of the LTRA horizon are a reflection of substantial resource turnovers driven primarily by nuclear retirements and refurbishments.
- The IESO is actively developing a suite of market renewal initiatives; in particular, an incremental capacity auction will be the primary vehicle to address capacity needs.
- Integration of distributed energy resources and changing demand and supply patterns are creating, and will continue to create, new operating challenges in managing the BPS while also providing greater customer choice and opportunity to optimize grid reliability services. The IESO collaborates with local distribution companies to ensure it has visibility of their operations is able to forecast their output over different time frames, study their impact on reliability, and coordinate their operations to ensure reliability.

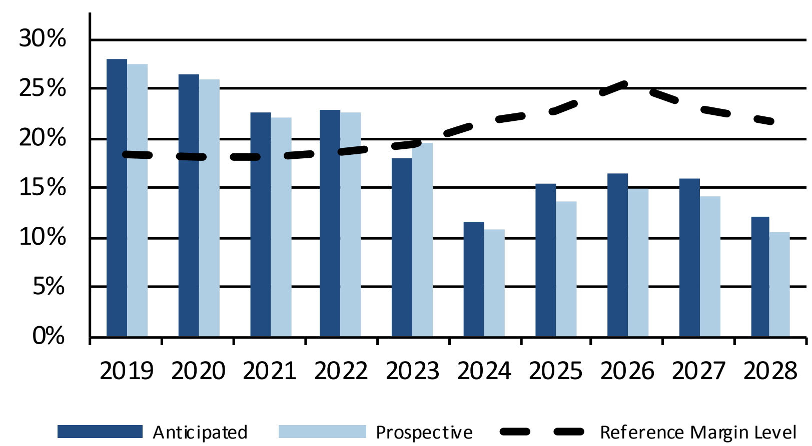
Demand, Resources, and Reserve Margins

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	22,016	22,085	22,155	22,098	22,139	22,251	22,302	22,146	22,263	22,263
Demand Response	533	549	549	549	549	549	549	549	549	549
Net Internal Demand	21,483	21,536	21,606	21,548	21,589	21,701	21,753	21,596	21,713	21,714
Additions: Tier 1	970	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	26,664	26,356	25,628	25,628	24,598	23,352	24,230	24,294	24,294	23,484
Anticipated Reserve Margin (%)	28.63	27.08	23.30	23.63	18.62	12.27	16.04	17.18	16.54	12.81
Prospective Reserve Margin (%)	28.24	25.97	22.20	22.52	19.53	10.87	13.70	14.81	14.19	10.46
Reference Margin Level (%)	18.37	18.05	18.02	18.51	19.43	21.59	22.69	25.43	22.92	21.60

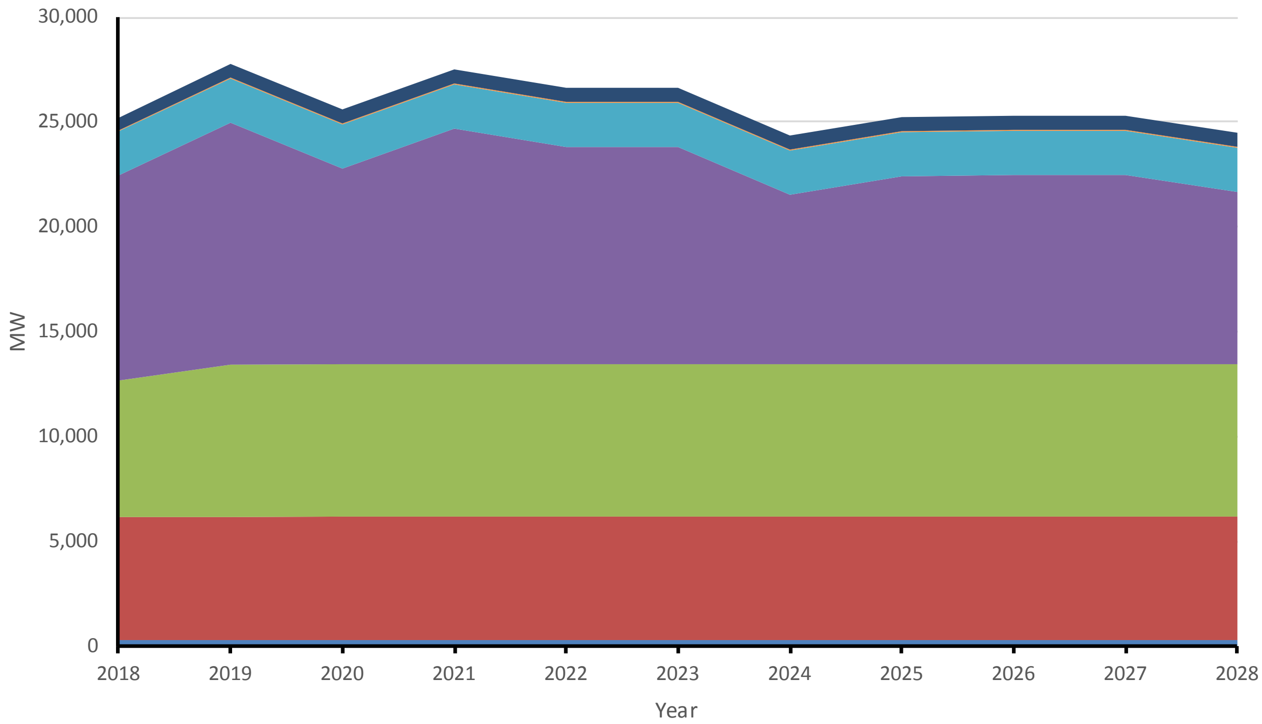
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	300	1%	300	1%
Hydro	5,868	21%	5,888	24%
Natural Gas	7,267	26%	7,267	30%
Nuclear	11,537	42%	8,213	34%
Petroleum	2,107	8%	2,107	9%
Solar	47	0%	47	0%
Wind	650	2%	671	3%
Total	27,775	100%	24,492	100%



Planning Reserve Margins



NPCC-Ontario Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	300	300	300	300	300	300	300	300	300	300
Hydro	5,868	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888	5,888
Natural Gas	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267	7,267
Nuclear	11,537	9,327	11,235	10,357	10,357	8,081	8,959	9,023	9,023	8,213
Petroleum	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107
Solar	47	47	47	47	47	47	47	47	47	47
Wind	650	671	671	671	671	671	671	671	671	671
Total	27,775	25,606	27,514	26,636	26,636	24,360	25,238	25,302	25,302	24,492

Probabilistic Assessment Overview

- **General Overview:** The Ontario area is a summer-peaking area. No significant LOLH was observed. The estimated EUE is negligible. The Anticipated Reserve Margins are well above 18 percent and 19 percent levels in 2020 and 2022, respectively. Any contribution to the LOLH and EUE occur during the peak (summer) monthly period.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion:[2]
    - The Ontario demand forecast includes the impact of conservation, time-of-use rates, and other price impacts as well as the effects of embedded (distribution connected) generation. However, the demand forecast does not include the impacts of “controllable” DR programs, such as dispatchable loads and DR; the capacity from these programs is treated as resource.
    - Ontario capacity values and planned outage schedules for thermal units are based on monthly maximum continuous ratings and planned outage information contained in market participant submissions. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data.
    - Hydroelectric resources are modelled in Ontario as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity, and monthly energy values are determined on an aggregated basis for each zone based on historical data.
    - Solar generation in Ontario is aggregated on a zonal basis and is modelled as load modifiers. The contribution of solar resources is modelled as fixed hourly profiles that vary by month and season.
    - Capacity limitations due to variability of wind generators in Ontario are captured by providing probability density functions from which stochastic selections are made. Wind generation is aggregated on a zonal basis and modelled as an energy limited resource with a cumulative probability density function (CPDF) that represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The cumulative probability density functions vary by month and season.

[1] https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[2] https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

- **Probabilistic vs. Deterministic:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*:[3]
  - The loads for each area were modeled on an hourly, chronological basis; this is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
  - The Ontario area modeled operating procedures that included reduced operating reserves, voltage reduction, and implementation of DR programs before firm load has to be disconnected.
  - The loads for each area were modeled on an hourly, chronological basis; this is based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.
  - The Ontario area modeled operating procedures that included reduced operating reserves, voltage reduction, and public appeals before firm load has to be disconnected.
  - In Ontario, DR is treated as a resource instead of a load modifier.
  - Ontario transmission additions and retirements assumed were consistent with this *NERC 2018 Long-Term Reliability Assessment*.
  - In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

Base Case Study

- **Results Trending:** The previous study *NERC Probabilistic Assessment – NPCC Region* estimated an annual LOLH = 0.000 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2020.* The 2020 Forecast 50/50 peak demand forecast is relatively flat compared to the previous assessment; forecast capacity resources increased as compared to the previous assessment. No material difference in estimated LOLH and EUE is observed between the two assessments.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	26.3	27.1	23.6
Reference	17.7	18.0	18.5
ProbA Forecast Operable	11.9	10.5	11.5
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000

*Represents 2016 ProbA results for 2020.

[3] Available December 2018 at the following: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

[4] https://www.npcc.org/Library/Other/Forms/Public20List.aspx

Planning Reserve Margins: The Anticipated Reserve Margins fall below the Reference Margin level in the mid-2020s driven by nuclear retirements, the nuclear refurbishment program, and the assumption that certain generation resources are not available once their generation contracts have expired. The development of a capacity market in Ontario, to re-acquire off-contract resources or obtain new resources, will be the primary vehicle to address capacity needs. Other options include coordinating outages outside the peak load seasons or periods of potential capacity shortages, the potential for more conservation and demand response, and the reliance of non-firm imports.

Demand: Growth in demand is slight 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.

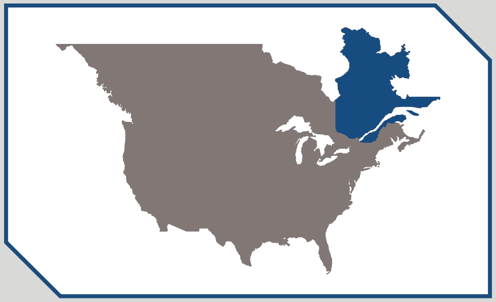
Demand-Side Management: Ontario has two main DR programs: Dispatchable loads and the capacity procured through an annual demand response auction. The IESO's Demand Response Working Group continues to work with DR providers to evolve DR in the IESO-administered markets, including improving the utilization of DR in real time operations.

Distributed Energy Resources: The IESO estimates total DERs in Ontario exceed 4,000 MW, including over 3,000 MW of distribution connected generation capacity on contract with the IESO. In response, The IESO recently concluded two initiatives to better accommodate DERs; the IESO is now able to schedule additional 30-minute operating reserve to assist in addressing flexibility needs, and the IESO procured 55 MW of regulation to expand its capability to schedule more regulation as required. The IESO continues to collaborate with the DER community to enhance the reliability and efficiency of Ontario's electricity grid.

Generation: Retirement of the Pickering Nuclear Generating Station (total capacity of approximately 3,000 MW) is expected by 2025. Nuclear refurbishments at Bruce and Darlington generating stations will reduce the generation capacity available over peak seasons. Over the next 10 years, Ontario expects to add about 1,710 MW of new resources to the grid. The new resources are expected to comprise of about 535 MW of wind, 985 MW of natural-gas-fired generation, 108 MW of hydroelectric, and 83 MW of solar.

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: In anticipation of the Pickering nuclear generation retirement, a new 500/230 kV autotransformer station, Clarington TS, came into service east of the Greater Toronto Area (GTA) in 2018. This new facility is critical to maintaining system and supply reliability in Eastern GTA following the shutdown of the Pickering generating units. In Northwestern Ontario, a new 400–450 km long 230 kV double-circuit transmission line (the East–West Tie) is planned to come into service in 2020. The new line will reinforce the connection of Northwestern Ontario to the rest of the provincial grid and will provide reliable and cost-effective, long-term supply to this area. Other system improvements that have been planned or are under study include the installation of 500 kV line-connected shunt reactors at Lennox GS in Eastern Ontario, to mitigate high system voltages under low demand/low transfer periods, and a review of major equipment, such as phase-shifters and regulators on Ontario's interconnections with New York and Michigan as some of the facilities are approaching their end of service life.



Highlights

- Approximately 400 MW of capacity additions are expected over the assessment period.
- A total of 500 MW of firm import capacity is now available each winter until March 2023 due to a new electricity trade agreement between Québec and Ontario.
- The Chamouchouane to Montréal 735 kV Line is under construction and will be in service by 2019.

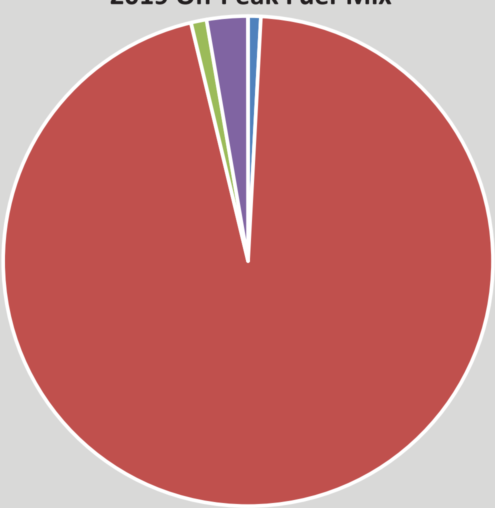
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion 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.

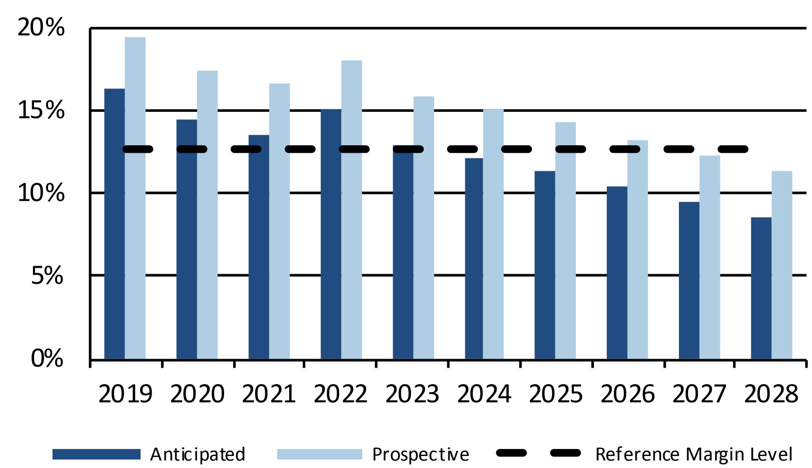
Demand, Resources, and Reserve Margins (MW)

Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	38,782	39,057	39,427	39,737	40,016	40,288	40,561	40,817	41,059	41,311
Demand Response	2,424	2,454	2,504	2,534	2,544	2,564	2,574	2,574	2,574	2,574
Net Internal Demand	36,359	36,604	36,924	37,203	37,473	37,724	37,987	38,243	38,486	38,737
Additions: Tier 1	55	397	397	397	397	397	397	397	397	397
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	202	-541	-499	355	-145	-145	-145	-145	-145	-145
Existing-Certain and Net Firm Transfers	42,248	41,505	41,547	42,401	41,893	41,893	41,902	41,805	41,723	41,659
Anticipated Reserve Margin (%)	16.35	14.48	13.60	15.04	12.86	12.10	11.35	10.35	9.44	8.57
Prospective Reserve Margin (%)	19.37	17.48	16.58	18.00	15.79	15.02	14.25	13.23	12.30	11.41
Reference Margin Level (%)	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61	12.61

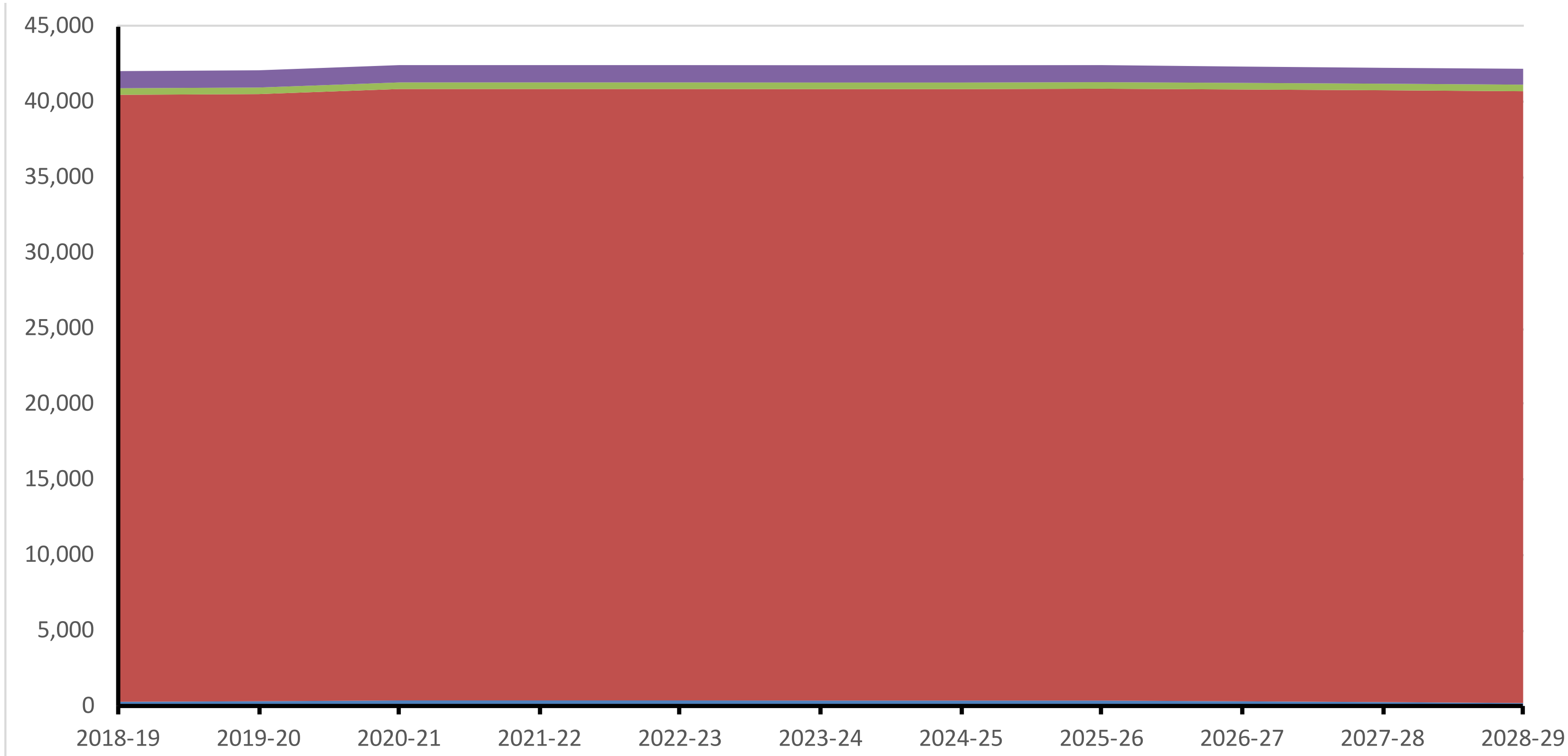
2019 On-Peak Fuel-Mix



Generation Type	2019–2020		2028–2029	
	MW	Percent	MW	Percent
Biomass	352	1%	232	1%
Hydro	40,173	95%	40,484	96%
Petroleum	436	1%	436	1%
Wind	1,140	3%	1,050	2%
Total	42,101	100%	42,201	100%



Planning Reserve Margins



NPCC-Québec Fuel Composition

Gen Type		2019–2020	2020–2021	2021–2022	2022–2023	2023–2024	2024–2025	2025–2026	2026–2027	2027–2028	2028–2029
Biomass		352	403	403	403	395	395	395	347	295	232
Hydro		40,173	40,459	40,459	40,459	40,459	40,459	40,484	40,484	40,484	40,484
Petroleum		436	436	436	436	436	436	436	436	436	436
Wind		1,140	1,146	1,146	1,146	1,146	1,146	1,129	1,080	1,050	1,050
Total		42,101	42,443	42,443	42,443	42,435	42,435	42,444	42,347	42,265	42,201

Probabilistic Assessment Overview

- **General Overview:** The Québec area is a winter-peaking area. No significant LOLH was observed. The estimated EUE is negligible. THe Anticipated Reserve Margins are above the 12.6 percent Reference Margin for both 2020 and 2022. Any contribution to the LOLH and EUE occurs during the peak (winter) monthly period.
- **Modeling:** Assumptions used in this ProbA are consistent with those used in *NPCC 2018 Long Range Adequacy Overview.*[1] The GE MARS model developed by the NPCC CP-8 Working Group was used to model demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion:[2]
  - The Québec demand forecast is built on the forecast from four different consumption sectors—domestic, commercial, small and medium-size industrial, and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.
  - For thermal units, maximum capacity in the Québec area is defined as the net output a unit can sustain over a two-consecutive hour period.
  - In Québec, hydro resources maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.
  - In Québec, behind-the-meter generation (solar and wind) is estimated at 1.5 MW and doesn't affect the load monitored from a network perspective.
  - In Québec, the expected capacity at winter peak is 30 percent of the Installed (nameplate) capacity except for a small amount (roughly three percent) that is derated for all years of the study. For the summer period, wind power generation is derated by 100 percent.
- **Probabilistic vs. Deterministic Assessments:** Details regarding the differences between the probabilistic and deterministic representations can be found in the *NERC 2018 Probabilistic Assessment – NPCC Region*:[3]
  - The loads for each area were modeled on an hourly, chronological basis, based on the 2002 load shape for the summer period and the 2003/04 load shape for the winter period.[4]
  - Québec modeled operating procedures that include reduced operating reserves, voltage reduction, and interruptible load programs before firm load has to be disconnected.
  - DR programs in Québec are specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs.
  - Transmission additions and retirements assumed were consistent with this *NERC 2018 LTRA*.
  - In the NPCC ProbA simulations, all areas received assistance on a shared basis in proportion to their deficiency. In the analysis, each step was initiated simultaneously in all areas and subareas.

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1 https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

2 https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

3 Available December 2018 at the following: https://www.npcc.org/Library/Resource20Adequacy/Forms/Public20List.aspx

4 https://www.npcc.org/Library/Other/Forms/Public20List.aspx

Base Case Study

- **Results Trending:** The previous study *NERC Probabilistic Assessment – NPCC Region* estimated an annual LOLH = 0.000 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2020.* The Forecast 50/50 peak demand is slightly higher than reported in the previous study with lower estimated forecast planning and forecast operable reserve margins. There is no change in the estimated LOLH and EUE in this year's study.

Summary of Results			
Reserve Margin			
	2020*	**2020**	**2022**
Anticipated	15.8	14.5	15.0
Reference	12.7	12.6	12.6
ProbA Forecast Operable	14.2	9.5	7.1
Annual Probabilistic Indices			
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The Anticipated Reserve Margin is below the Reference Margin Level for the last five winter seasons of the assessment period. Under this scenario, the Quebec area has no firm imports and purchases from neighboring areas that 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 except for the last two winter periods. Three years prior to these upcoming winters, the area will launch a call for tenders in order to overcome its capacity needs. 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 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 Quebec area demand forecast average annual growth is 0.7 percent during the 10-year period, similar to last year's forecast.

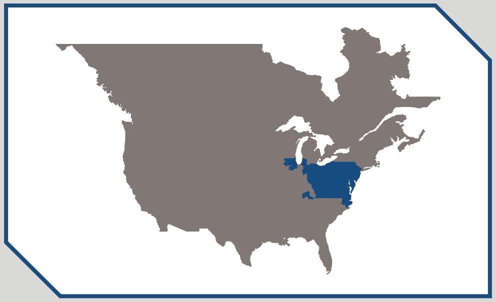
Demand-Side Management: The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program, mainly designed for large industrial customers; it has an impact of 1,784 MW on peak demand. The second type of DR resource consists of a voltage reduction scheme that has a 250 MW of demand reduction at peak. Finally, the area continues to develop new DR programs, including direct control load management and others. A new program that consists mostly of interruptible charges in commercial buildings has shown great results. This program has an anticipated impact of 320 MW in 2018-19 and should reach 540 MW by 2025–26. Energy efficiency will also continue to grow over the entire assessment period. Energy efficiency and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources: Behind the meter generation (including solar PV) is around 1.5 MW and is accounted for in the load forecast.

Generation: Work is underway on the Romaine-4 unit (245 MW), which is expected to be fully operational in 2020. No retrofitting of hydro units is considered over the assessment period. The integration of small hydro units also accounts for 54 MW of new capacity during the assessment period. For other renewable resources, about 371 MW (111 MW on-peak value) of wind capacity has been added to the system since the beginning of 2017 and 43 MW (13 MW on-peak value) is expected to be in service by 2021. Additionally, about 22 MW of biomass was also commissioned in 2017 and 89 MW of new biomass is expected to be in service by 2021.

Capacity Transfers: Since 2011, the power transmission system has undergone significant changes: reduced consumption in the Côte-Nord area and decommissioning of the Tracy and La Citière thermal and Gentilly-2 nuclear generating station. These changes have brought about an increase to the power flow on the lines of the Manic-Québec corridor toward the major load centres 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 of the Romaine River Hydro Complex is presently underway. Romaine-4 (245 MW) will be integrated in 2020 at the Montagnais 735/315 kV substation. The Chamouchouane to Montreal 735 kV is under construction and is being built after planning studies showed a need to reinforce the transmission system to meet the Reliability Standards. The line (about 400 km or 250 miles) will extend from the Chamouchouane substation on the eastern James Bay subsystem to Duvernay substation near Montréal. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses. The line was initially scheduled to be in service before the 2018-19 winter peak period but the project has been delayed to 2019.



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. 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.

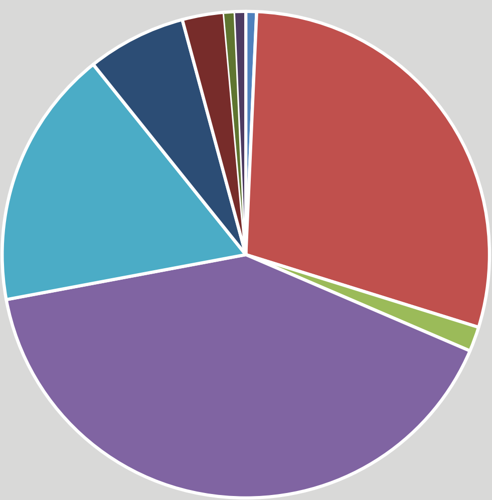
Highlights

- 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.

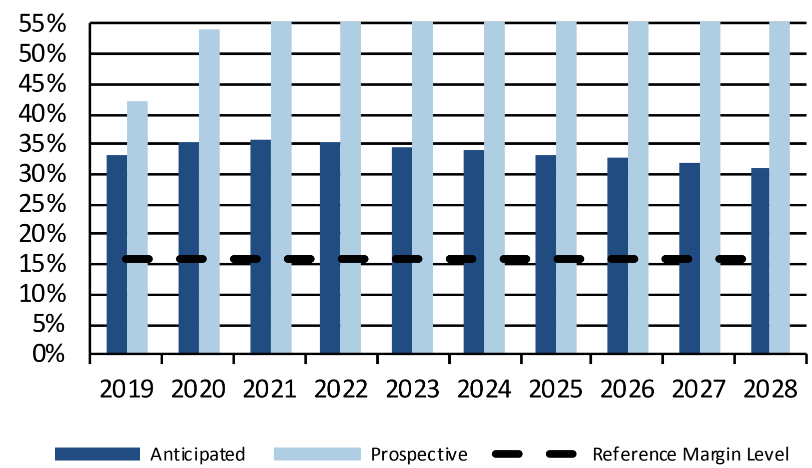
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	152,479	151,962	152,363	152,887	153,632	154,245	154,941	155,724	156,605	157,635
Demand Response	9,113	7,675	7,691	7,721	7,747	7,786	7,823	7,862	7,899	7,947
Net Internal Demand	143,366	144,287	144,672	145,166	145,885	146,459	147,118	147,862	148,706	149,688
Additions: Tier 1	8,357	14,785	18,155	18,155	18,155	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	12,862	27,579	34,075	40,069	41,369	41,369	41,369	41,369	41,369	41,369
Net Firm Capacity Transfers	1,486	1,728	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	182,498	180,667	178,106	178,106	178,106	178,106	178,106	178,106	178,106	178,106
Anticipated Reserve Margin (%)	33.12	35.46	35.66	35.20	34.53	34.00	33.40	32.73	31.98	31.11
Prospective Reserve Margin (%)	42.10	53.95	58.30	61.27	61.36	60.73	60.01	59.21	58.30	57.26
Reference Margin Level (%)	15.90	15.90	15.80	15.80	15.80	15.80	15.80	15.80	15.80	15.80

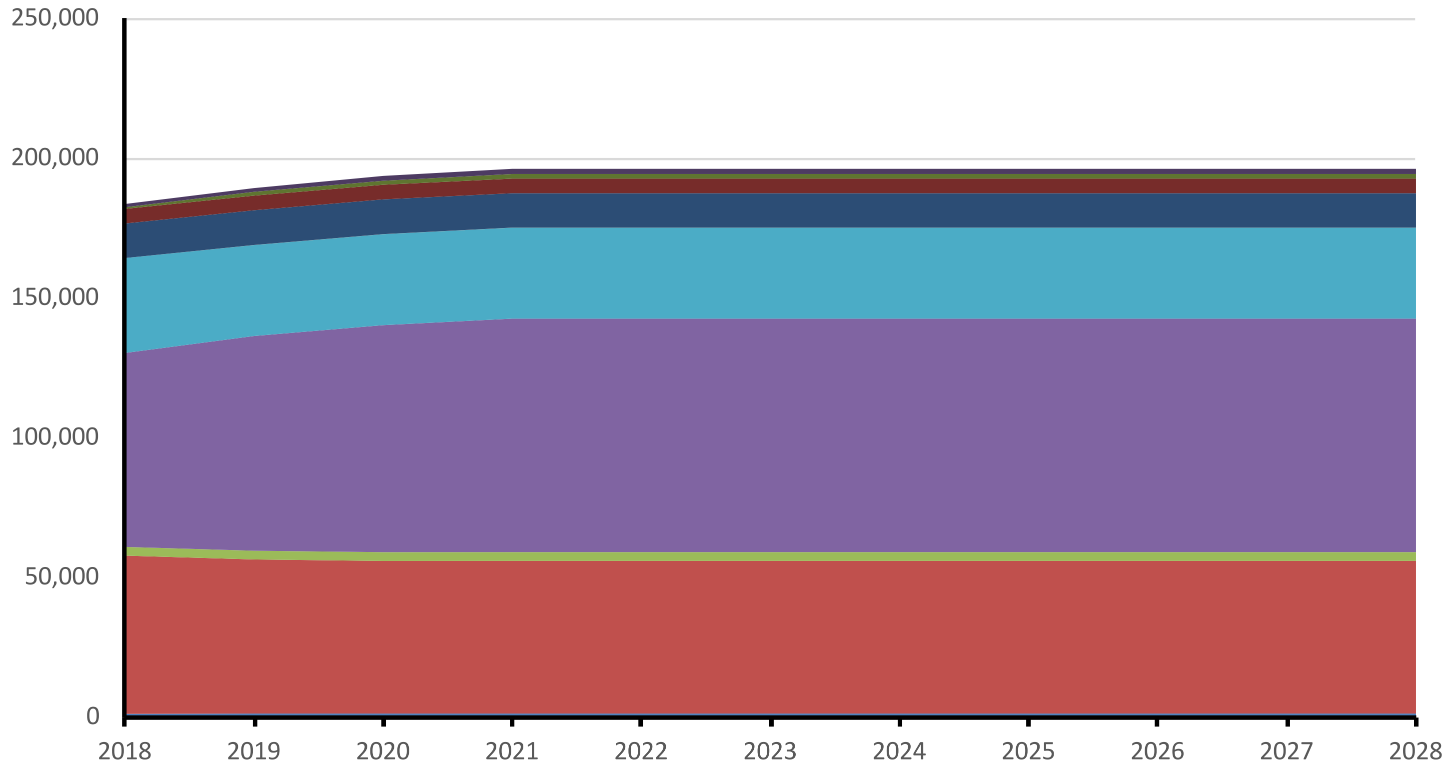
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	1,336	1%	1,336	1%
Coal	55,136	29%	54,620	28%
Hydro	3,123	2%	3,145	2%
Natural Gas	76,838	41%	83,550	43%
Nuclear	32,559	17%	32,560	17%
Other	20	0%	20	0%
Petroleum	12,425	7%	12,296	6%
Pumped Storage	5,229	3%	5,229	3%
Solar	1,376	1%	1,659	1%
Wind	1,327	1%	1,845	1%
Total	54,586	100%	58,436	100%



Planning Reserve Margins



PJM Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336
Coal	55,136	54,597	54,620	54,620	54,620	54,620	54,620	54,620	54,620	54,620
Hydro	3,123	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145	3,145
Natural Gas	76,838	81,235	83,550	83,550	83,550	83,550	83,550	83,550	83,550	83,550
Other	32,559	32,560	32,560	32,560	32,560	32,560	32,560	32,560	32,560	32,560
Nuclear	20	20	20	20	20	20	20	20	20	20
Petroleum	12,425	12,431	12,296	12,296	12,296	12,296	12,296	12,296	12,296	12,296
Pumped Storage	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229	5,229
Solar	1,376	1,431	1,659	1,659	1,659	1,659	1,659	1,659	1,659	1,659
Wind	1,327	1,739	1,845	1,845	1,845	1,845	1,845	1,845	1,845	1,845
Total	189,370	193,724	196,261	196,261	196,261	196,261	196,261	196,261	196,261	196,261

Probabilistic Assessment Overview

- **General Overview:** The ProbA was carried out in GE-MARS using Monte Carlo simulation. Internal and external load shapes were from year 2002 (Summer) and 2004 (Winter) and adjusted to match monthly and annual peak forecast values from the 2018 PJM load forecast. Data on individual unit performance is from the period 2013–2017, and PJM was divided in five subareas interconnected using a transportation/pipeline approach. External areas were modeled using a detailed representation and at planned reserve margin (NPPC, MISO, TVA, VACAR).
- **Modeling:** Load forecast uncertainty was modeled on a monthly basis using a normal distribution discretized into seven partitions and their associated probabilities. DSM was modeled as an emergency operating procedure as most of the DSM in PJM is emergency DSM. Intermittent generators were modeled as a regular resource at their respective capacity values (average capacity value for wind is 13 percent while solar is 38 percent). Firm exports/imports were explicitly modeled while the limits on the transportation/pipeline interfaces were calculated based on a first contingency total transfer capability analysis.
- **Results Trending:** The 2020 LOLH and EUE in the 2018 ProbA are similar to the corresponding values reported in the 2016 ProbA:
  - 2020 LOLH in 2018 ProbA = 0.000 hrs/year vs. 2020 LOLH in 2016 ProbA = 0.000 hrs/year
  - 2020 EUE in 2018 ProbA = 0.000 MWh/year vs. 2020 EUE in 2016 ProbA = 0.001 MWh/year
- **Probabilistic vs. Deterministic Assessments:** For Summer 2020 and Summer 2022, the probabilistic reserve margin in slightly lower than the deterministic value due to 2,500 MW of on-peak capacity derates as a result of above average summer ambient conditions.

Base Case Study

- LOLH and EUE are zero for both 2020 and 2022 due to large forecast planning reserve margins. The reserve margins are significantly above the reference values of 15.9 percent and 15.8 percent, respectively.

Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	35.5	35.2
Prospective	53.9	61.3
Reference	15.9	15.8
ProbA Forecast Planning	33.7	33.5
ProbA Forecast Operable	22.7	22.5
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	0.000	0.000
EUE (ppm)	0.000	0.000
LOLH (hours/year)	0.000	0.000

Planning Reserve Margins: The IRM, 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 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: DSM providers have the ability to participate in 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 DR locations in DRHUB to meet their RPM commitments starting January of the year in which the new DY starts. For the DY 2016/17, DSM providers offering DR resources into RPM have an overall RPM commitment of 8,336 MW of load reductions. DR registrations participating in the capacity market are to respond according to real-time emergency procedures, if called upon.

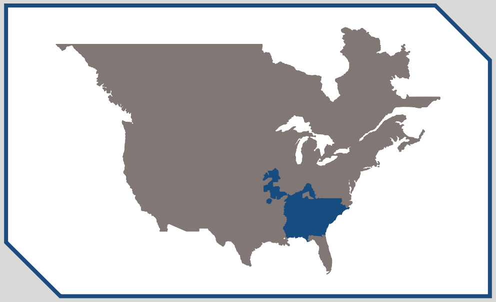
Distributed Energy Resources: In early 2015, recognizing the growing market of solar installations, PJM began to investigate and develop a plan to incorporate distributed solar generation into the long-term load forecast. Environmental Information Services, a wholly owned subsidiary of PJM Technologies, Inc., which is a subsidiary of PJM Interconnection, operates the Generation Attribute Tracking System. The generation data that the Generation Attribute Tracking System 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 dc 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 regional transmission expansion plan (RTEP)[64] 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 of 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 anticipated transfers amount anywhere near two percent.

Transmission: PJM's 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 recommended system enhancements—new facilities and upgrades to existing ones—they formally become part of PJM's overall RTEP.

[64] PJM RTEP: https://www.pjm.com/planning/rtep-development.aspx



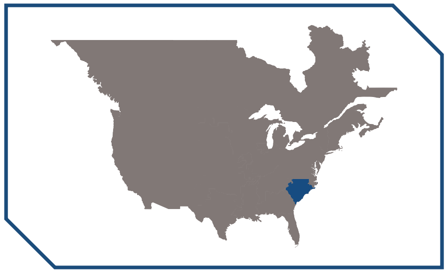
SERC

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).

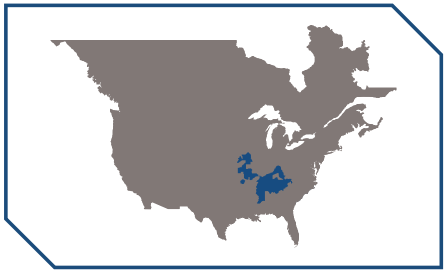
Highlights

- Approximately 21 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years, developing mostly in SERC-E.
- Due to increased winter weather loads (e.g., Polar Vortex, extreme cold weather snaps), entities are reviewing and modifying winter reliability related assumptions (xload forecast, reserve margins).
- SERC assessment areas will transition from NERC's Reference Margin Levels (15 percent) to SERC reserve margins targets developed from SERC's probabilistic assessment biennial studies.

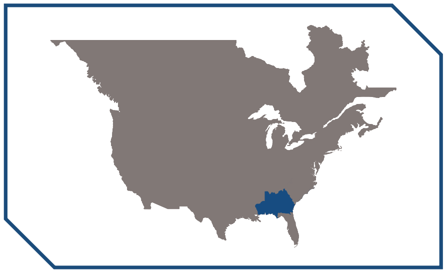
Starting on the next page are summaries of the assessment areas that make up SERC.



SERC-E

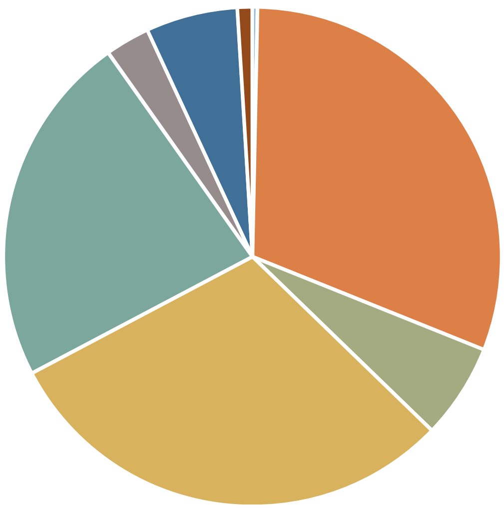


SERC-N



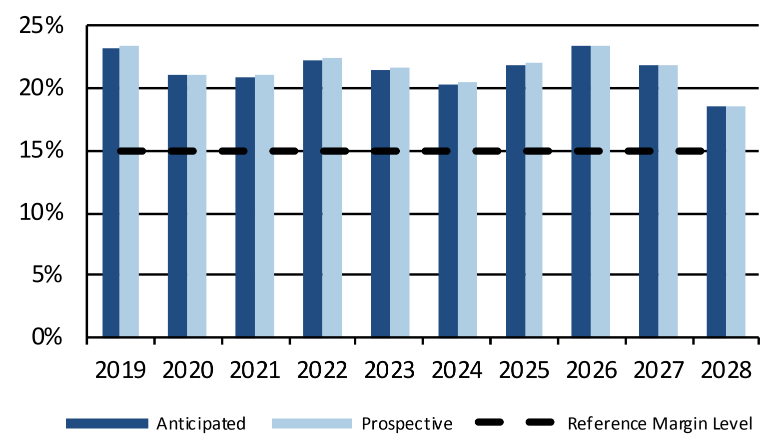
SERC-SE

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	42,684	43,162	43,523	43,902	44,227	44,632	45,010	45,445	45,876	46,375
Demand Response	1,090	1,091	1,093	1,093	1,093	1,094	1,095	1,096	1,098	1,099
Net Internal Demand	41,594	42,071	42,430	42,809	43,134	43,538	43,915	44,349	44,778	45,276
Additions: Tier 1	7	608	608	1,759	1,759	1,759	2,910	4,061	4,061	4,282
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	184	-155	184	25	25	25	25	25	25	25
Existing-Certain and Net Firm Transfers	51,271	50,317	50,704	50,591	50,638	50,642	50,642	50,644	50,468	49,370
Anticipated Reserve Margin (%)	23.28	21.05	20.93	22.29	21.48	20.36	21.94	23.35	21.78	18.50
Prospective Reserve Margin (%)	23.38	21.14	21.03	22.39	21.57	20.45	22.04	23.45	21.87	18.59
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

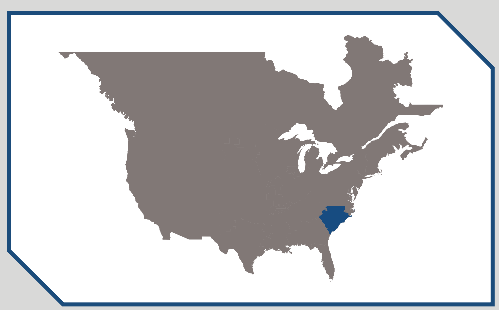


2019 On-Peak Fuel-Mix

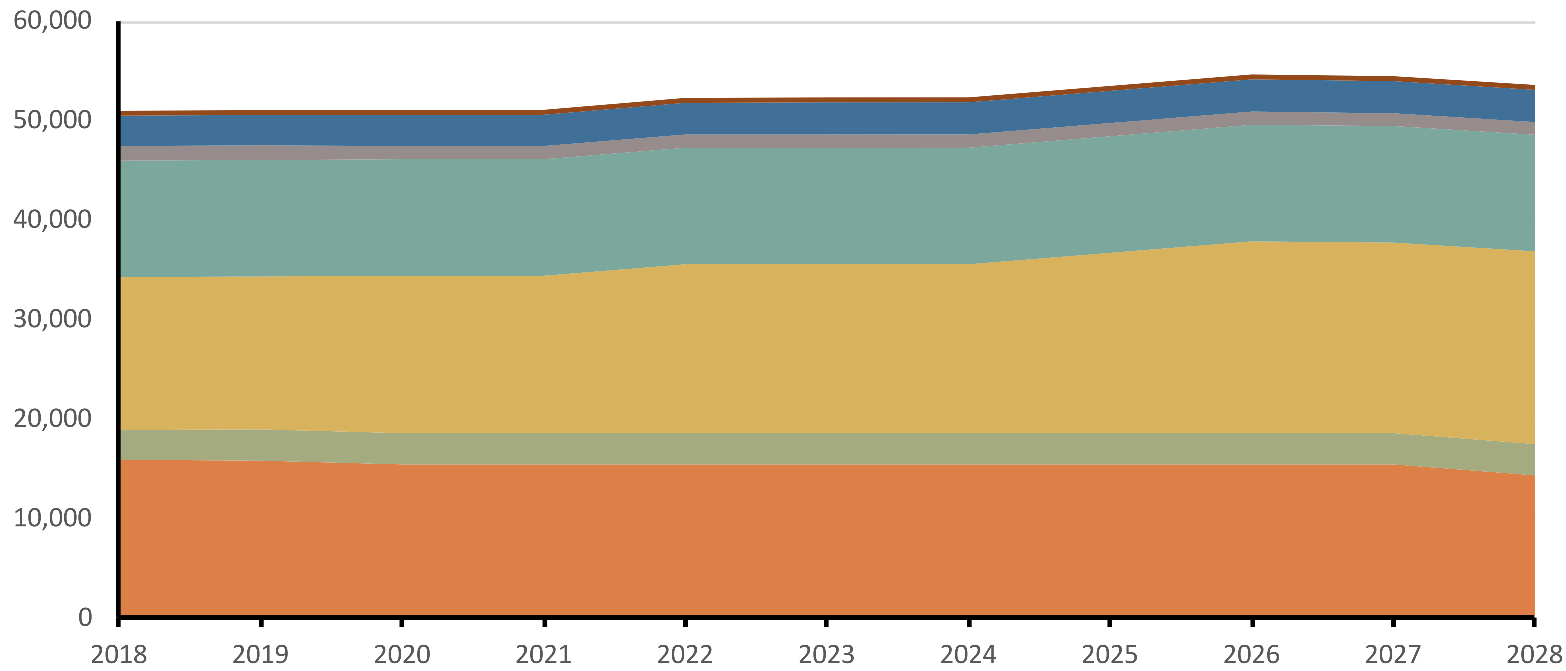
Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	164	0%	164	0%
Coal	15,709	31%	14,233	27%
Hydro	3,143	6%	3,143	6%
Natural Gas	15,363	30%	19,368	36%
Nuclear	11,699	23%	11,711	22%
Petroleum	1,475	3%	1,282	2%
Pumped Storage	3,044	6%	3,230	6%
Solar	497	1%	497	1%
Total	51,094	100%	53,627	100%



SERC-E Planning Reserve Margins



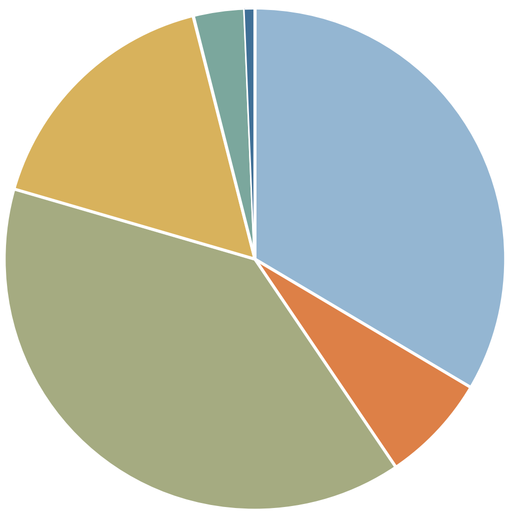
SERC-E



SERC-E Fuel Composition

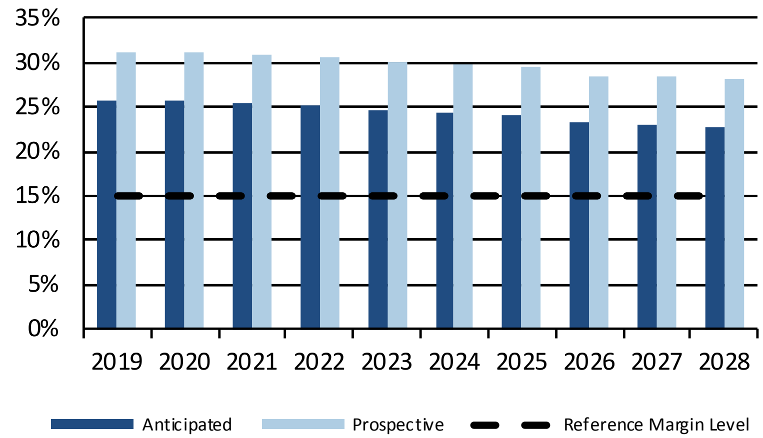
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	164	164	164	164	164	164	164	164	164	164
Coal	15,709	15,331	15,331	15,331	15,331	15,331	15,331	15,331	15,331	14,233
Hydro	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143	3,143
Natural Gas	15,363	15,818	15,818	16,969	16,969	16,969	18,120	19,271	19,147	19,368
Nuclear	11,699	11,703	11,705	11,705	11,705	11,709	11,709	11,711	11,711	11,711
Petroleum	1,475	1,334	1,334	1,334	1,334	1,334	1,334	1,334	1,282	1,282
Pumped Storage	3,044	3,090	3,137	3,183	3,230	3,230	3,230	3,230	3,230	3,230
Solar	497	497	497	497	497	497	497	497	497	497
Total	51,094	51,080	51,128	52,326	52,372	52,376	53,527	54,680	54,504	53,627

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	41,526	41,730	41,784	41,851	42,001	42,025	42,143	42,414	42,486	42,547
Demand Response	1,795	1,795	1,802	1,759	1,705	1,671	1,666	1,666	1,666	1,666
Net Internal Demand	39,731	39,935	39,982	40,092	40,296	40,354	40,477	40,748	40,820	40,881
Additions: Tier 1	0	0	0	0	0	0	0	0	0	0
Additions: Tier 2	68	68	68	68	68	68	68	68	68	68
Net Firm Capacity Transfers	-1,057	-952	-952	-952	-952	-952	-952	-952	-952	-952
Existing-Certain and Net Firm Transfers	49,943	50,201	50,201	50,201	50,201	50,201	50,201	50,201	50,201	50,201
Anticipated Reserve Margin (%)	25.70	25.71	25.56	25.21	24.58	24.40	24.02	23.20	22.98	22.80
Prospective Reserve Margin (%)	31.22	31.20	31.04	30.68	30.02	29.84	29.44	28.58	28.35	28.16
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

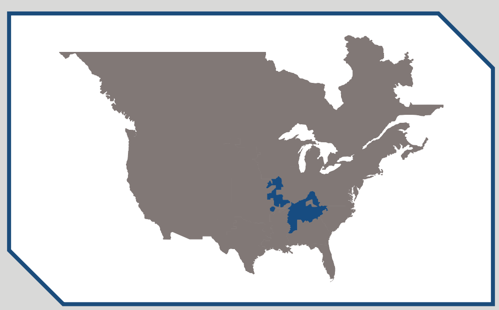


2019 On-Peak Fuel-Mix

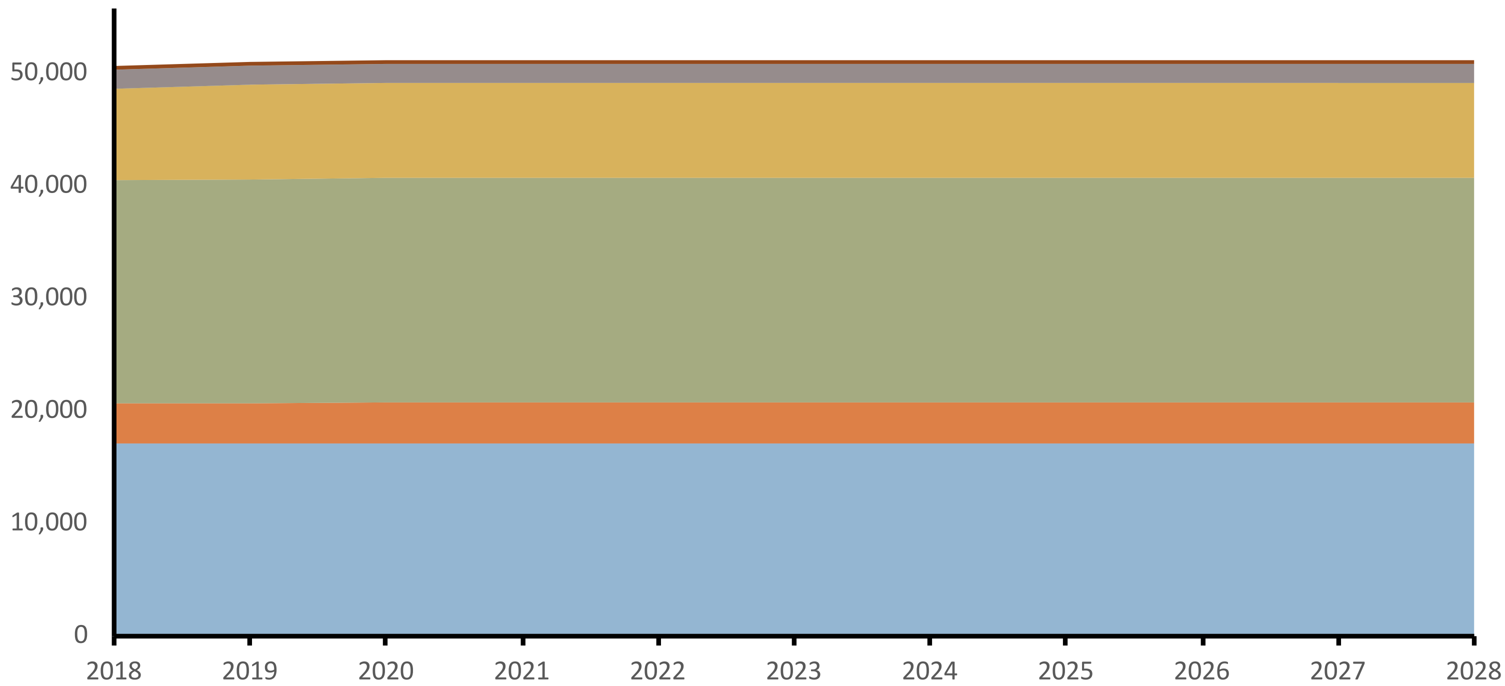
Generation Type	2019		2028	
	MW	Percent	MW	Percent
Coal	17,097	34%	17,097	33%
Hydro	3,566	7%	3,647	7%
Natural Gas	19,885	39%	19,957	39%
Nuclear	8,431	17%	8,431	16%
Pumped Storage	1,680	3%	1,680	3%
Solar	8	0%	8	0%
Wind	333	1%	333	1%
Total	51,094	100%	53,627	100%



SERC-N Planning Reserve Margins



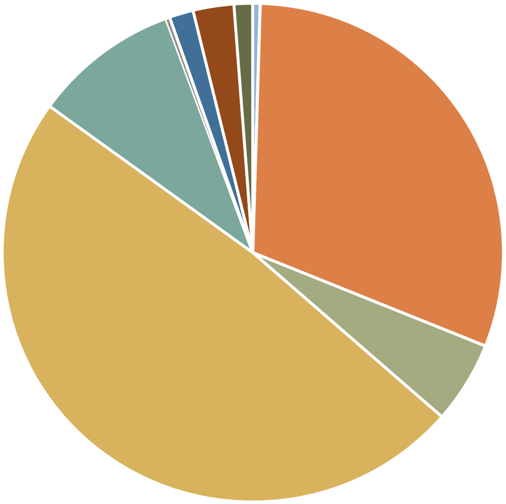
SERC-N



SERC-N Fuel Composition

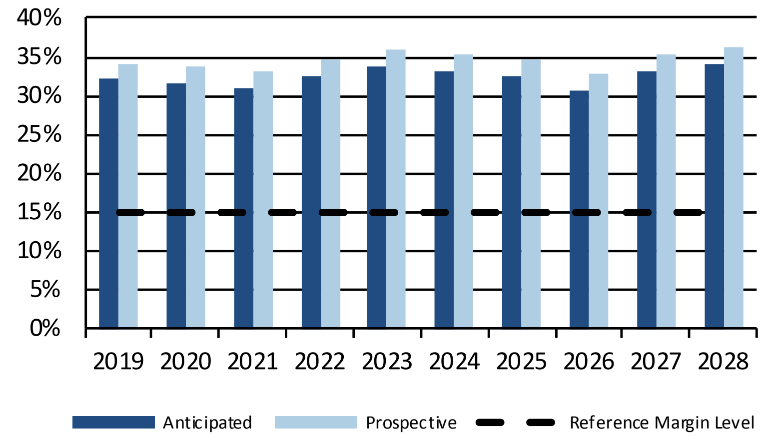
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Coal	17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097
Hydro	3,566	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647
Natural Gas	19,885	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957	19,957
Nuclear	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431
Pumped Storage	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680	1,680
Solar	8	8	8	8	8	8	8	8	8	8
Wind	333	333	333	333	333	333	333	333	333	333
Total	51,000	51,153	51,153	51,153	51,153	51,153	51,153	51,153	51,153	51,153

Demand, Resources, and Reserve Margins										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	47,896	48,085	48,260	48,508	48,765	49,039	49,304	49,980	49,080	48,712
Demand Response	2,101	2,102	2,102	2,102	2,103	2,103	2,103	2,104	2,104	2,105
Net Internal Demand	45,795	45,983	46,158	46,406	46,662	46,936	47,201	47,876	46,976	46,607
Additions: Tier 1	164	164	164	1,264	2,364	2,364	2,364	2,364	2,364	2,364
Additions: Tier 2	100	100	198	198	198	198	198	198	198	198
Net Firm Capacity Transfers	-1,426	-1,406	-1,534	-1,560	-1,744	-1,722	-1,649	-1,645	-1,643	-1,641
Existing-Certain and Net Firm Transfers	60,354	60,383	60,265	60,239	60,055	60,077	60,150	60,154	60,156	60,158
Anticipated Reserve Margin (%)	32.15	31.67	30.92	32.53	33.77	33.03	32.44	30.58	33.09	34.15
Prospective Reserve Margin (%)	34.25	33.76	33.21	34.82	36.04	35.29	34.69	32.80	35.34	36.42
Reference Margin Level (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

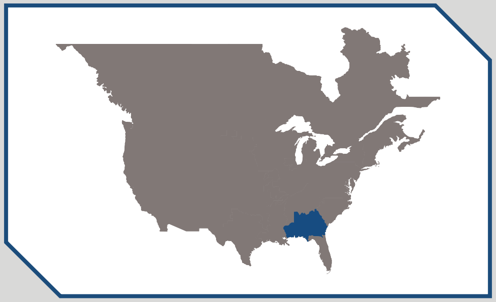


2019 On-Peak Fuel-Mix

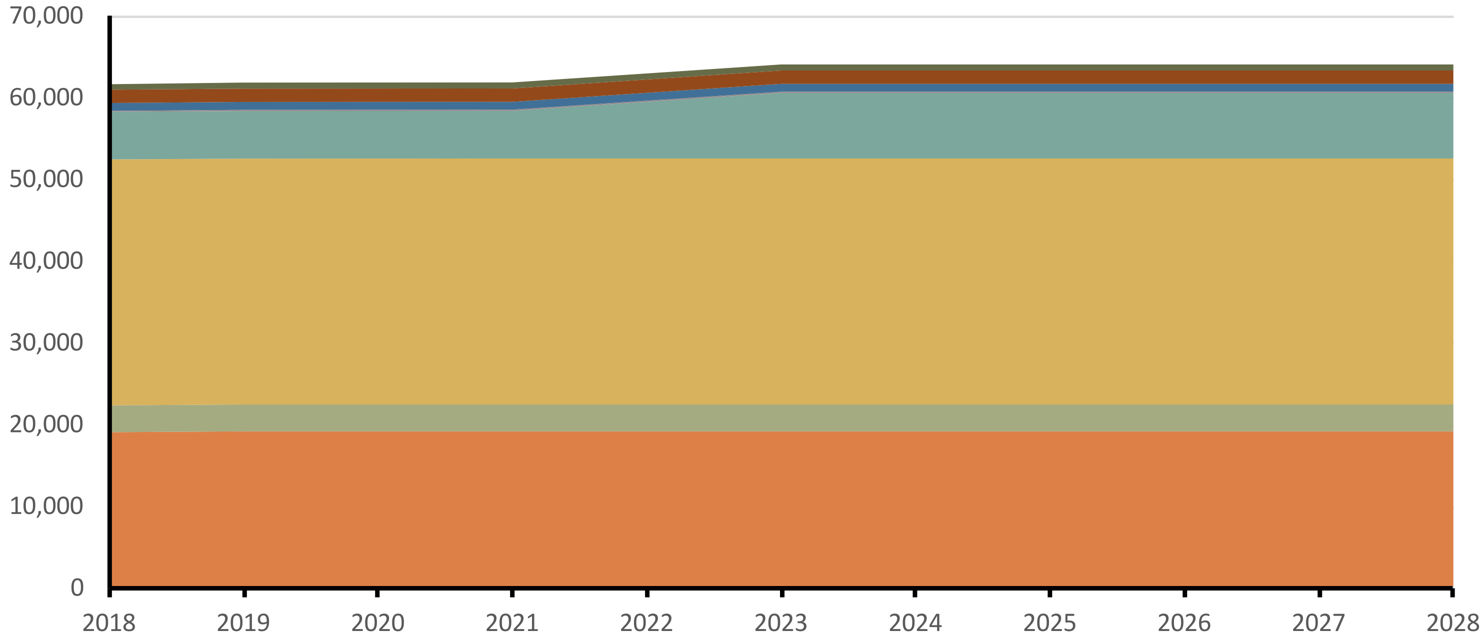
Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	289	0%	289	0%
Coal	18,979	31%	18,979	30%
Hydro	3,288	5%	3,288	5%
Natural Gas	30,083	49%	30,102	47%
Nuclear	5,818	9%	8,018	12%
Other	153	0%	153	0%
Petroleum	961	2%	961	1%
Pumped Storage	1,632	3%	1,632	3%
Solar	740	1%	740	1%
Total	61,944	100%	64,162	100%



SERC-SE Planning Reserve Margins



SERC-SE



SERC-SE Fuel Composition

Gen Type		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass		289	289	289	289	289	289	289	289	289	289
Coal		18,979	18,979	18,979	18,979	18,979	18,979	18,979	18,979	18,979	18,979
Hydro		3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Natural Gas		30,083	30,092	30,102	30,102	30,102	30,102	30,102	30,102	30,102	30,102
Nuclear		5,818	5,818	5,818	6,918	8,018	8,018	8,018	8,018	8,018	8,018
Other		153	153	153	153	153	153	153	153	153	153
Petroleum		961	961	961	961	961	961	961	961	961	961
Pumped Storage		1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Solar		740	740	740	740	740	740	740	740	740	740
Total		61,944	61,953	61,962	63,062	64,162	64,162	64,162	64,162	64,162	64,162

SERC-E Probabilistic Assessment Overview

- **General Overview:** Lowering demand projections in SERC East (SERC-E) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area (3.5 percent decrease from 2016 to 2018 in study year 2020 demand forecast). Additionally, with an 11.5 percent increase in natural gas generation expected on peak by 2022, reserve margins in SERC E consistently trend above 20 percent, leading to zero megawatts of expected loss of load.
- **Modeling:** SERC utilizes General Electric MARS software, an 8760 hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of 15 interconnected areas, three of which are SERC's NERC assessment areas (SERC-E, SERC-N, and SERC-SE):
  - Annual peak demand in SERC-E varies by ± five percent of forecasted SERC-E demand based upon the 90/10 percent points of LFU distributions.
  - Thermal units in SERC-E follow a two-state on-or-off sequence based on a Monte Carlo simulation that utilizes unit class average forced outage rates and failure durations that are equivalent to derating SERC-E thermal generating resources by six percent on average.
  - Hydro units in SERC-E follow a 20 percent dispatch 80 percent remaining energy-limited schedule. This is equivalent to limiting hydro by 18 percent maximum annual output.
  - Variable energy resources (wind and solar) in SERC-E are a load modifier based on 8,760 time series correlation to load, which is 38 percent solar capacity credit.
- **Probabilistic vs. Deterministic Assessments:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the Anticipated Reserve Margin is the same as the ProbA forecast Planning Reserve Margin. However, the SERC-E ProbA has the following differences from the SERC-E LTRA, not already captured in the modeling section above:
  - SERC-E annual peak demand is coincident in the ProbA model (98.6 percent diversity factor) since SERC conducts LFU analysis on coincident peak demands.
  - During the simulation, the monthly peak that the SERC-E area varies with the actual monthly peak experienced during the year randomly chosen from seven annual hourly profiles input into the model (years 2007–2013). The peak months for these annual hourly profiles include three in August, two in July, and one each in February and December.
  - Total controllable DR is treated as a capacity resource with performance rates based on historical demand reduction realization (approximately 76 percent availability for SERC-E).
  - Simultaneous transfer analysis sets interface limits and flows for SERC-E average 535 MW in and 214 MW out.

Base Case Study

- SERC-E resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 24 percent lead to no expected loss of load or EUE.

Results Trending: From 2016–2018, the SERC-E 2020 LOLH decreased from 0.002 to 0.000 primarily driven by lower projected demand mentioned above.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	2020	2022
Anticipated	16.1	27.5	24.9
Prospective	15.0	13.2	14.4
Reference	11.2	20.2	18.0
Annual Probabilistic Indices			
	Base Case		
	2020*	2020	2022
EUE (MWh)	49.39	0.00	0.00
EUE (ppm)	0.22	0.00	0.00
LOLH (hours/year)	0.05	0.00	0.00

*Represents 2016 ProbA results for 2020.

SERC-N Probabilistic Assessment Overview

- **General Overview:** Lowering demand projections in SERC North (SERC-N) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area (3.9 percent decrease from 2016 to 2018 in the study year 2020 demand forecast). Additionally, with anticipated generation resources in the area reported to stay constant over the 10-year period planning horizon, reserve margins in SERC N consistently trend above 20 percent, leading to zero megawatts of expected loss of load.
- **Modeling:** SERC utilizes General Electric MARS software an 8,760 hourly load, generation, and transmission sequential Monte Carlo simulation model consisting of 15 interconnected areas, three of which are SERC's NERC assessment areas (SERC-E, SERC-N, and SERC-SE):
    - Annual peak demand in SERC-N varies by ± five percent of forecasted SERC-N demand based upon the 90/10 percent points of LFU distributions.
    - Thermal units in SERC-N follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes unit class average forced outage rates and failure durations that is equivalent to derating SERC-N thermal generating resources by six percent on average.
    - Hydro units in SERC-N follow a 20 percent dispatch 80 percent remaining energy-limited schedule. This is equivalent to limiting hydro by 45 percent maximum annual output.
    - Variable energy resources (wind and solar) in SERC-N are a load modifier based on 8,760 time series correlation to load, which is 37 percent solar capacity credit and 26 percent wind capacity credit.
- **Probabilistic vs. Deterministic Assessments:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the Anticipated Reserve Margin is the same as the ProbA forecast Planning Reserve Margin. However, the SERC-N ProbA has the following differences from the SERC-N LTRA, not already captured in the Modeling bullet above:
    - SERC-N's annual peak demand is coincident in the ProbA model (98.7 percent diversity factor) since SERC conducts LFU analysis on coincident peak demands.
    - During the simulation, the monthly peak that the SERC-N area varies with the actual monthly peak experienced during the year randomly chosen from seven annual hourly profiles input into the model (years 2007–2013). The peak months for these annual hourly profiles include two in January, August, and July and one in June.
    - Total controllable DR is treated as a capacity resource with performance rates based on historical demand reduction realization (approximately 78 percent availability for SERC-N).
    - Simultaneous transfer analysis sets interface limits and flows for SERC-N average 265 MW in and 303 MW out.

Base Case Study

- SERC-N resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 24 percent lead to no expected loss of load or EUE.

Results Trending: From 2016 to 2018, the SERC-N 2020 LOLH and EUE remain zero. This is primarily driven by lower projected demand and steady resources over the assessment time frame.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	2020	2022
Anticipated	18.6	25.7	24.9
Prospective	15.0	13.2	14.4
Reference	18.0	18.5	17.7
Annual Probabilistic Indices			
	Base Case		
	2020*	2020	2022
EUE (MWh)	0.13	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

SERC-SE Probabilistic Assessment Overview

- **General Overview:** Relatively flat load growth in SERC Southeast (SERC-SE) continues to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area (0.4 percent decrease from 2016 to 2018 in study year 2020 demand forecast). Additionally, with Georgia Power's Vogtle nuclear expansion project (~2,200 MW), reserve margins in SERC-SE consistently trend above 30 percent, leading to zero megawatts of expected loss of load.
- **Modeling:** SERC utilizes General Electric MARS software, an 8,760 hourly load, generation, and transmission sequential Monte Carlo simulation model that consists of 15 interconnected areas. Three of these areas are SERC's NERC assessment areas (SERC-E, SERC-N, and SERC-SE):
  - Annual peak demand in SERC-SE varies by ± eight percent of forecasted SERC-SE demand based upon the 90/10 percent points of LFU distributions.
  - Thermal units in SERC-SE follow a two-state on-or-off sequence based on Monte Carlo simulation that utilizes unit class average forced outage rates and failure durations that on average is equivalent to derating SERC-SE thermal generating resources by 5.7 percent.
  - Hydro units in SERC-SE follow a 20 percent dispatch 80 percent remaining energy-limited schedule. This is equivalent to limiting hydro by 23 percent maximum annual output.
  - Variable energy resources (wind and solar) in SERC-SE are a load modifier based on 8,760 time series correlation to load, which is 32 percent solar capacity credit.
- **Probabilistic vs. Deterministic Assessments:** Since both assessments utilize identical capacity megawatts (existing certain and Tier 1) for thermal generation and determining exact on-peak capacity availability from the ProbA model is difficult, SERC assumes that the Anticipated Reserve Margin is the same as the ProbA forecast Planning Reserve Margin. However, the SERC-N ProbA has the following differences from the SERC-N LTRA, not already captured in the modeling section above:
  - SERC-SE annual peak demand is coincident in the ProbA model (99.6 percent diversity factor) since SERC conducts LFU analysis on coincident peak demands.
  - During the simulation, the monthly peak that the SERC-SE area varies with the actual monthly peak experienced during the year randomly chosen from seven annual hourly profiles input into the model (years 2007–2013). The peak months for these annual hourly profiles include three in August and June and one in July.
  - Total controllable DR is treated as a capacity resource with performance rates based on historical demand reduction realization (approximately 78 percent availability for SERC-SE).
  - Simultaneous transfer analysis sets interface limits and flows for SERC-SE average 606 MW in and 423 MW out.

Base Case Study

- SERC-SE resource adequacy measures are zero in the Base Case, indicating that anticipated reserves above 30 percent lead to no expected loss of load or EUE.

Results Trending: From 2016 to 2018, the SERC-SE 2020 LOLH and EUE remain zero primarily driven by lower projected demand and steady resources over the assessment time frame.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	33.4	31.3	32.4
Prospective	15.0	13.2	14.4
Reference	26.5	23.6	24.7
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: Anticipated Reserve Margins range between 26–28 percent across all assessment areas and do not fall below the 15 percent NERC Reference Margin Level. Specifically for SERC E, resources are planned and added within the assessment period to assist in maintaining the minimum planning reserve margin. With the additional 3,700 MW of natural gas generation serving as replacement generation for the cancelled VC-Summer nuclear plant (2,200 MW), SERC E reserve margins consistently trend above 20 percent.

Demand: Projected demand growth within the assessment areas have decreased to less than one percent over the years. Although some metro areas are experiencing higher growth rates compared to rural areas, entities report load reductions due to behind-the-meter distributed generation and appliance standards. These factors will continue suppressing the load in the future.

Demand Side Management: DR programs are minimal (7,300 MW) and vary amongst the assessment areas (e.g., summer load control, reserve preservation, voltage optimization, five minute, 60 minute, or instantaneous response). These programs are used to control peak demand. Throughout the year, entities monitor and evaluate each program's operational functionality to determine effectiveness and ability to provide demand reduction.

Distributed Energy Resources: Most of the DER growth in the Region has been solar. The queued amount of DERs connected to the non-BES, subtransmission system (roof-top solar, plug-in electric vehicles, etc.) is approximately 2,100 MW. Entities continue to work within SERC's committee forums to determine how to monitor and analyze DERs on the system. In 2017, SERC formed a special working group and task force to address the issues of data collection and analysis methodologies. In 2018, the committees will report on a special study that considers dynamics, power flow, and resource adequacy impacts. To date, there are no notable reliability impacts reported to the Region. However, the Region is working within its data collection processes to collect the appropriate level of data (MWs in the queue) so that these resources can be modeled and analyzed for potential impact to the system.

Generation: SERC entities have sufficient generation to meet demand over the period. New resources are expected, which include a combination of capacity purchases, new nuclear, natural gas, and combined-cycle units. Natural gas (43 percent), coal (32 percent), and nuclear (17 percent) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types (eight percent) are minimal.

Entities in SERC-E will add approximately 3,700 MW of natural gas generation over the period. SERC-SE will have an additional 2,200 MW of nuclear additions available to meet demand in 2021.[65] Overall, the assessment areas will encounter 6,100 MW of net additions and retirements over within the next 10 years. Approximately 21 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years, largely developing in SERC-E.[66]

No reliability issues are expected within the assessment areas, but entities are continuing to monitor the impacts of solar generators as they are added to the interconnection queue. Entities are studying winter season impact of additional solar to the resource mix and load forecast. As more behind-the-meter solar generation is added, some entities anticipate becoming winter-peaking systems, providing additional motivation to enforce winter reserve margins.

Transmission: SERC entities are expecting a total of 862 miles (i.e., 450 miles of >100 kV, 340 miles of >200 kV, 12 miles of >300 kV, 60 miles of >60kV) of transmission additions over the period. These projects are in the design/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers (345/138kV, 161/500kV), reconductoring existing transmission lines, and other system reconfigurations/additions to support transmission system reliability. Entities in SERC-N are currently constructing a 500 kV substation to alleviate decreasing voltages and higher flows on lines caused by increased loads in the area. In addition, a static var compensators is planned for a 500 kV substation to support the stability of local units.

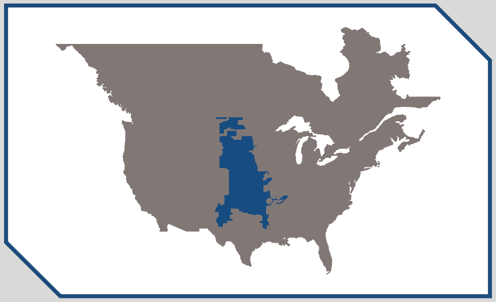
Entities coordinate transmission expansion plans during the Region's annual joint model building and study efforts. These plans are also coordinated with entities external to the Region through annual joint modeling efforts within the

[65] Based on a latest update, timing has been pushed back on Vogtle; both units will be online by 2022 (Unit #3 in 2021 and Unit #4 in 2022). This change was not incorporated into the assessment data; however, NERC evaluated the delay on Plant Vogtle and determined it did not materially change the assessment conclusions.

[66] This includes Tier 1, 2, and 3 resources.

Eastern Interconnection Reliability Assessment Group and the Multi-regional Modeling Working Group. In addition to these forums, several entities participate in open regional transmission planning processes driven by FERC Order 890. 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.

Entities do not anticipate any transmission limitations or constraints that cause significant impacts to reliability. However, limitations exist near generation sites in SERC-N and along the seams due to line loading and transfers on the transmission system. Constraints will be mitigated by future transmission projects (new builds, reactors, etc.), generation adjustments, system reconfiguration, or system purchase.



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 serves a population of 18 million people.

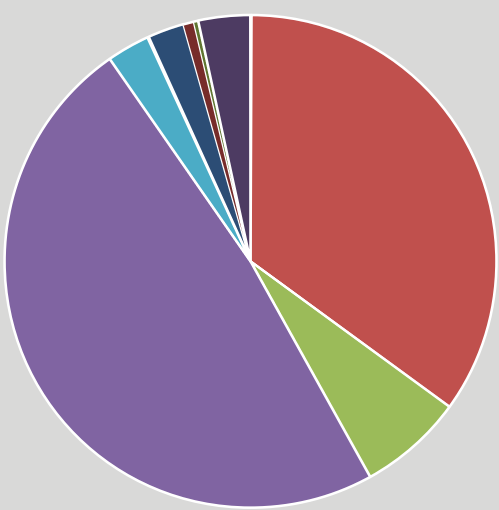
Highlights

- The Anticipated Reserve Margin for the SPP assessment area does not fall below its Reference Margin Level during the assessment period.
- There are no anticipated reliability issues from DERs given their low overall system load.
- SPP continues to see significant increase in wind penetration from a 38 percent peak in 2015 to 63.96 percent in 2018 and continues to create an operational challenges for the area.
- A few load pockets in north Texas, central Oklahoma, and northwestern Kansas require must-run generation for voltage support. Operating guides have been implemented to provide mitigation.

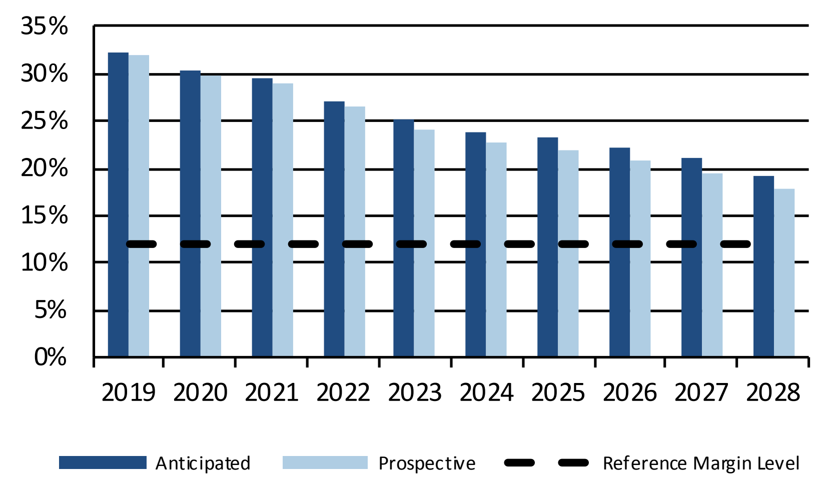
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	52,695	52,941	53,295	54,062	54,351	54,562	54,837	55,114	55,408	55,758
Demand Response	867	897	886	868	866	868	872	877	881	885
Net Internal Demand	51,828	52,044	52,410	53,194	53,485	53,694	53,965	54,238	54,528	54,873
Additions: Tier 1	213	247	247	247	247	247	247	247	247	247
Additions: Tier 2	1	1	1	1	1	1	1	1	1	1
Net Firm Capacity Transfers	19	-569	-115	34	-81	-99	-100	-100	-100	-151
Existing-Certain and Net Firm Transfers	68,350	67,606	67,716	67,413	66,688	66,297	66,307	66,093	65,730	65,237
Anticipated Reserve Margin (%)	32.29	30.37	29.68	27.19	25.15	23.93	23.33	22.31	21.00	19.34
Prospective Reserve Margin (%)	32.06	29.81	29.12	26.65	24.06	22.85	21.94	20.94	19.63	17.90
Reference Margin Level (%)	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00

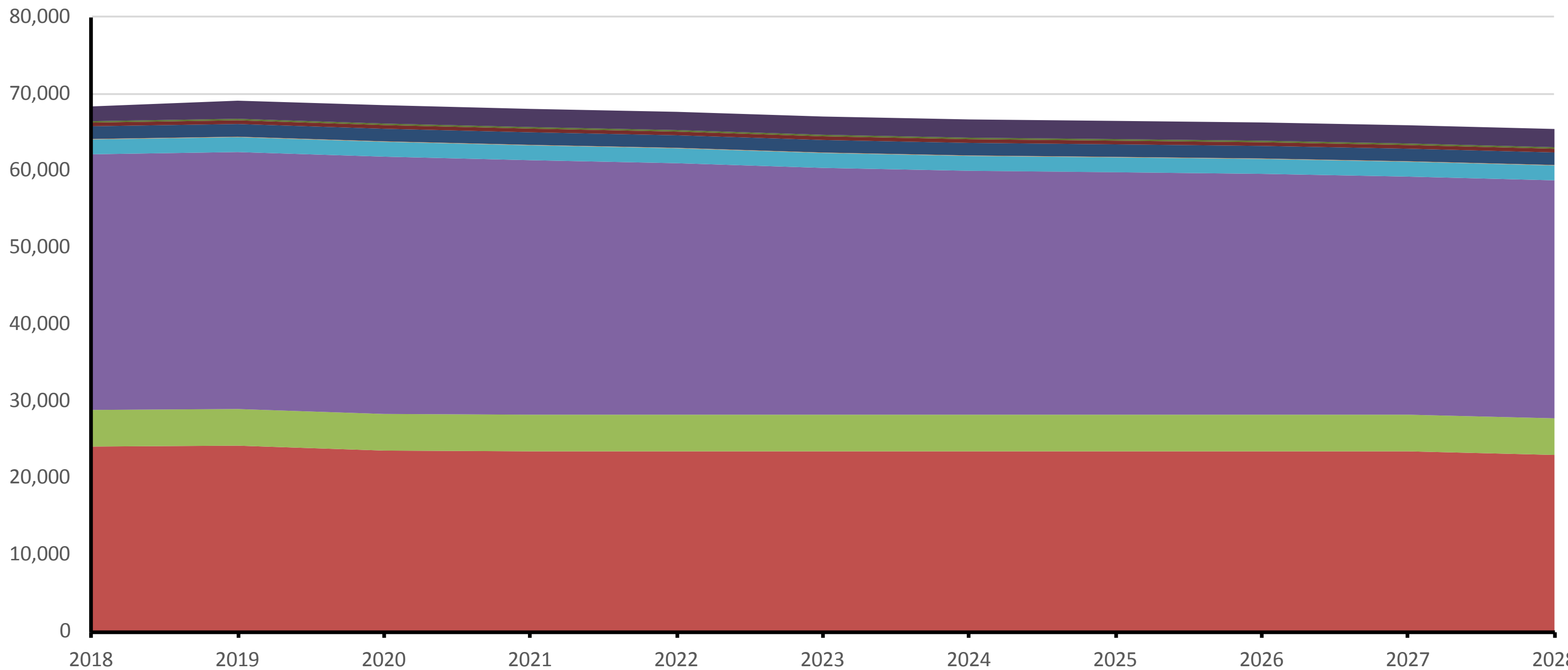
2019 On-Peak Fuel-Mix



Generation Type	2019		2028	
	MW	Percent	MW	Percent
Biomass	39	0%	39	0%
Coal	24,177	35%	22,970	35%
Hydro	4,770	7%	4,770	7%
Natural Gas	33,458	48%	30,983	47%
Nuclear	1,943	3%	1,943	3%
Other	52	0%	52	0%
Petroleum	1,656	2%	1,637	3%
Pumped Storage	482	1%	482	1%
Solar	197	0%	197	0%
Wind	2,359	3%	2,376	4%
Total	69,134	100%	65,450	100%



Planning Reserve Margins



SPP Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	39	39	39	39	39	39	39	39	39	39
Coal	24,177	23,536	23,439	23,439	23,439	23,439	23,439	23,439	23,439	22,970
Hydro	4,770	4,770	4,770	4,770	4,770	4,770	4,770	4,770	4,770	4,770
Natural Gas	33,458	33,499	33,136	32,747	32,134	31,756	31,566	31,361	30,998	30,983
Nuclear	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943
Other	52	52	52	52	52	52	52	52	52	52
Petroleum	1,656	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,637
Pumped Storage	482	482	482	482	482	482	482	482	482	482
Solar	197	197	197	197	197	197	197	197	197	197
Wind	2,359	2,395	2,370	2,376	2,376	2,376	2,376	2,376	2,376	2,376
Total	69,134	68,550	68,065	67,683	67,070	66,692	66,502	66,297	65,934	65,450

Probabilistic Assessment Overview

- **General Overview:** SPP oversees the bulk electric grid and wholesale power market as one consolidated BA area on behalf of a diverse group of utilities and transmission companies in 14 states. Firm imports and exports of capacity were modeled to reflect the firm transactions reported for this *2018 LTRA*. Assumptions and the accompanying methodology have been thoroughly vetted through the SPP stakeholder process. No events for loss of load occurred in the Base Case for the ProbA, and loss of load occurred in one of the sensitivity cases.
- **Modeling:** A Monte-Carlo based software called SERVM was used in the 2018 ProbA by randomly selecting load forecast uncertainty errors, derived from historical probability of occurrence, while varying the availability of thermal, hydro, and DR resources. The generating resources modeled in the ProbA reflect the data supplied in this *2018 LTRA*. Existing and projected resources were included in the ProbA along with reported confirmed and unconfirmed retirements. Thermal units follow a two-state sequence for each simulation and utilize unit-specific outage rates based on five years of NERC GADS data. Wind and solar resources were modeled at historical hourly output values based on 2014 weather year:
    - Data from a total of 17 legacy BA areas were used, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. The load forecast uncertainty factors for each area varied from zero percent at the 50th percentile to five percent at the 90th percentile above a 50/50 forecasted peak demand. No multipliers were modeled below 50/50 forecast in the simulations to only focus on increases of demand. Each local resource zone was modeled with an import and export limit based on power flow transfer analysis. A base case was modeled along with two sensitivity case simulations that increased the forecasted demand and energy from the original Base Case.
- **Probabilistic vs. Deterministic Assessments:** DR values reported in this *2018 LTRA* were modeled as generating resources available during daily on-peak hours instead of reducing the total internal demand. The dc tie transactions were modeled as resources for the full capacity of the firm transmission service reservations instead of limited to the forecasted amounts of flow across the ties.

Base Case Study

- No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP assessment area. Reserve margins are well above 20 percent in both study years, and no major impacts were observed related to resource retirements.
- The 2016 ProbA results for SPP indicated 0.0 EUE and 0.0 Hours/year LOLH for years 2018 and 2020. The 2016 ProbA Base Case results for 2020 were the same for the 2018 Base Case results (i.e., zero loss of load). Also, the ProbA forecast Planning Reserve Margin for the 2020 study year was two percent lower in 2016 ProbA compared to the 2018 Assessment.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	22.7	29.3	25.0
Prospective	15.0	20.7	17.1
Reference	12.0	12.0	12.0
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The SPP assessment area planning reserve margin requirement for the 2018 summer is 12 percent unless a members capacity mix is comprised of at least 75 percent hydro-based generation; if this is the situation, the planning reserve margin is 9.89 percent. Based on the assessment results, the Anticipated Reserve Margin does not fall below the Reference Margin Level for the SPP assessment area.

Demand: The SPP assessment area forecasts the noncoincident total internal demand to peak at 52,056 MW during the 2018 summer season, which is a decrease of approximately 500 MW from in the previous year's LTRA forecast for the 2018 summer season. The SPP assessment area forecasts the noncoincident annual peak growth, based on member submitted data over the 10-year forecast, at an average annual rate of approximately .07 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 DR across the assessment area. The SPP assessment area forecasts the noncoincident summer peak growth at an average annual rate of one percent.

Distributed Energy Resources: SPP assessment area currently has about 250 MW of installed solar generating facilities. There are approximately 7,800 MW of solar projects in the generator interconnection queue of which 170 MW have effective interconnection agreements. SPP model development, economic studies, and the supply adequacy working groups are currently developing policies and procedures around DERs.

Generation: There are some projected retirements in 2018 that are currently expected to be replaced with renewable resources. The impact to the resource adequacy in the assessment area has been studied in the 2017 LOLE study. The reliability impacts to the transmission system were evaluated and addressed in the *2018 Integrated Transmission Plan Near-Term Assessment*.[67] These retirements consist of 896 MW of coal along with 1,145 MW of natural gas and will be retired during the assessment period. SPP is not expecting any long-term reliability impacts resulting from generating plant retirements.

[67] https://www.spp.org/documents/58359/2018_itpnt_report.pdf

Capacity Transfers: The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. Annually, SPP assessment area staff coordinates and agrees on transfers to be modeled between Planning Coordinator footprints. Transfer limits in the SPP LOLE study are limited to the firm contract path only and the full capability of the path. There have been no severe scenarios studied that would limit capacity transfers.

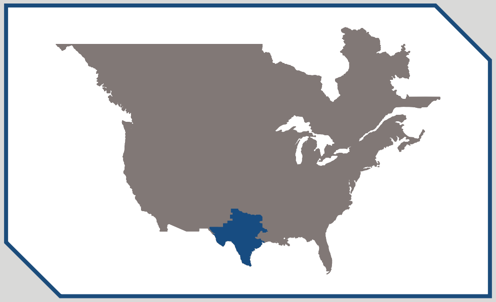
Transmission: The SPP assessment area's board of directors approved the 2017 Integrated Transmission Plan 10-Year Assessment Report[68, 69] and the 2018 Integrated Transmission Planning Near-Term Assessment.[70, 71] Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users.

[68] https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

[69] https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

[70] https://www.spp.org/documents/51179/2017_itp10_report_board%20approved_april2017_final.pdf

[71] https://www.spp.org/documents/56611/2018_spp_transmission_expansion_plan_report.pdf



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.

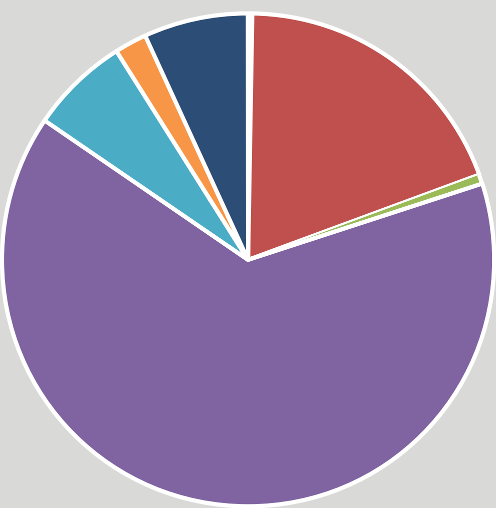
Highlights

- Coal unit retirements and planned generation project delays contribute to lower reserve margins, reflecting the ERCOT market's response to continuing low natural gas and wholesale market prices along with robust growth in low operating cost wind and solar resources.
- To address cyclical generation investment and retirement cycles, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system.
- The ERCOT Regional Transmission Plan includes the addition or upgrade of almost 3,600 MW of 138 kV and 345 kV transmission circuits by 2025. Significant reliability projects focus on far West Texas, the lower Rio Grande Valley, and coastal areas, all experiencing robust load growth.
- ERCOT continues to implement enhancements to tools and processes to address increasing amounts of renewable generation on the ERCOT grid. Examples in 2018 include procurement of a secondary wind forecasting service for redundancy and the start of a project to add intrahour wind forecasting to better prepare for potential ramps in wind generation that may require deployment of off-line reserves.

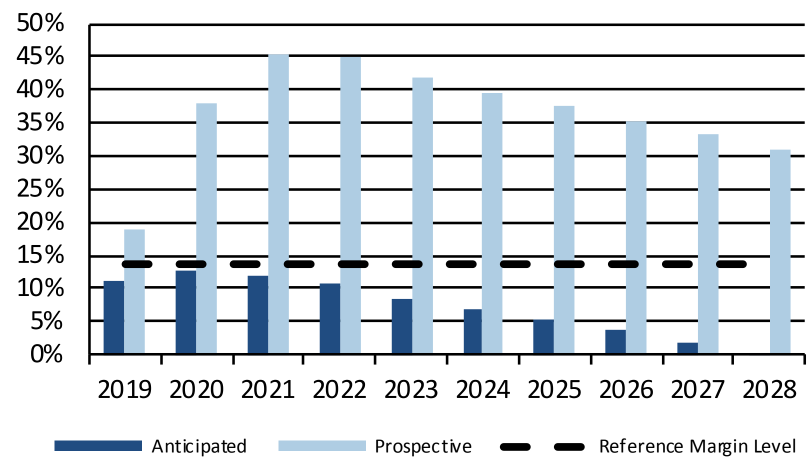
Demand, Resources, and Reserve Margins (MW)

Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	74,203	75,879	77,595	79,027	80,431	81,673	82,850	84,179	85,511	86,850
Demand Response	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173
Net Internal Demand	72,030	73,706	75,422	76,854	78,258	79,500	80,677	82,006	83,338	84,677
Additions: Tier 1	2,969	6,022	7,430	8,084	8,084	8,084	8,084	8,084	8,084	8,084
Additions: Tier 2	4,585	17,736	24,786	25,748	25,748	25,797	25,797	25,797	25,797	25,797
Net Firm Capacity Transfers	262	207	57	7	7	7	7	7	7	7
Existing-Certain and Net Firm Transfers	77,104	77,012	76,906	76,916	76,916	76,906	76,906	76,906	76,906	76,906
Anticipated Reserve Margin (%)	11.17	12.66	11.82	10.60	8.62	6.91	5.35	3.64	1.98	0.37
Prospective Reserve Margin (%)	19.06	38.14	45.45	44.90	41.83	39.66	37.63	35.40	33.23	31.12
Reference Margin Level (%)	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75	13.75

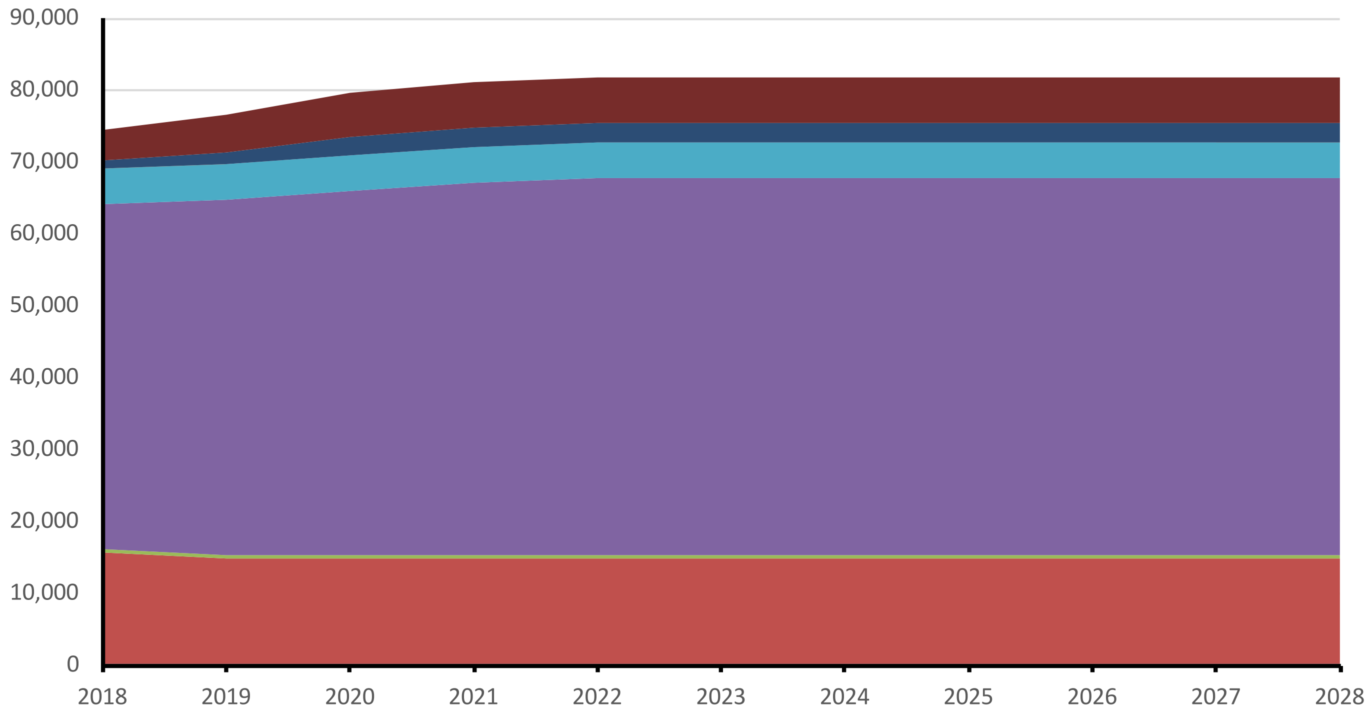
2019 On-Peak Fuel-Mix



Generation Type		2019		2028	
		MW	Percent	MW	Percent
Biomass		202	0%	202	0%
Coal		14,650	19%	14,650	18%
Hydro		466	1%	466	1%
Natural Gas		49,435	65%	52,449	64%
Nuclear		4,960	6%	4,960	6%
Other		0	0%	0	0%
Solar		1,622	2%	2,708	3%
Wind		5,245	7%	6,331	8%
Total		76,580	100%	81,766	100%



Planning Reserve Margins



Texas RE-ERCOT Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	202	202	202	202	202	202	202	202	202	202
Coal	14,650	14,650	14,650	14,650	14,650	14,650	14,650	14,650	14,650	14,650
Hydro	466	466	466	466	466	466	466	466	466	466
Natural Gas	49,435	50,652	51,795	52,449	52,449	52,449	52,449	52,449	52,449	52,449
Nuclear	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960	4,960
Other	0	0	0	0	0	0	0	0	0	0
Solar	1,622	2,558	2,708	2,708	2,708	2,708	2,708	2,708	2,708	2,708
Wind	5,245	6,143	6,331	6,331	6,331	6,331	6,331	6,331	6,331	6,331
Grand Total	76,580	79,631	81,112	81,766	81,766	81,766	81,766	81,766	81,766	81,766

Probabilistic Assessment Overview

- **General Overview:** Projected reserve margins for ERCOT have decreased since the 2016 ProbA, leading to an increased possibility of reliability issues for the study years. The 2020 projected ProbA forecast reserve margin is 12.9 percent. The 2022 projected reserve margin is 10.8 percent.
- **Modeling:** This study used Astrapé Consulting's probabilistic resource adequacy assessment model, SERVM, which simulates chronological hourly unit commitment and economic dispatch. ERCOT was modeled as a single zone connected to SPP and Mexico through dc ties. SERVM captures the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring regions as stochastic variables:
  - The simulations used 15 synthetic load, wind, solar, and hydro profiles, based on historical years 2002–2016, to represent expected conditions in the study years if historical weather conditions were to take place again. ERCOT applied five load forecast uncertainty multipliers to each synthetic weather year. The multipliers, which ranged from -4 percent to +4 percent, capture economic load growth uncertainty.
  - Thermal generator availability was based on GADS data for the past three years submitted by generation entities. SERVM can simulate both full and partial outage using a multi-state Monte Carlo modeling approach.
  - Wind and solar were modeled as capacity resources with hourly profiles that are weather-correlated with the load shapes. The peak capacity contributions were 14 percent for non-coastal wind, 59 percent for coastal wind, and 75 percent for solar.
  - Dispatch heuristics for hydro resources were developed from six years of hourly data from ERCOT, applied to 15 years of monthly data from FERC 923, and modeled with different parameters each month, including monthly total energy output, daily maximum and minimum outputs, and monthly maximum output.
- **Probabilistic vs. Deterministic Assessments:** No changes.

Base Case Study

- The Base Case study results in a number of reliability events during the summer months in the synthetic years with extremely hot temperatures. In addition to firm load shed events, other reliability events occur within the simulation with higher frequency than seen in the 2016 ProbA study. These events include reductions in operating reserves and dispatching of emergency resources. The events occurred predominantly in August, which accounted for 88.0 percent of the LOLH and 92.1 percent of the EUE in 2020. The Anticipated Reserve Margin is lower than the ProbA forecast Planning Reserve Margin due to modeling treatment differences on importing and exporting resources.
- **Results Trending:** Compared to the results from the 2016 ProbA, LOLH increased from 0.000004 to 0.50 for the first study year. The results are driven by a decrease in the Anticipated Reserve Margin. ERCOT has seen over 4 GW of conventional plant retirements and 2.1 GW of planned project deferrals in the past two years.

Summary of Results		
Reserve Margin		
	Base Case	
	2020	**2022**
Anticipated	12.7	10.6
Prospective	38.1	44.9
Reference	13.8	13.8
ProbA Forecast Planning	12.9	10.8
ProbA Forecast Operable	6.2	4.6
Annual Probabilistic Indices		
	Base Case	
	2020	**2022**
EUE (MWh)	598.90	1088.72
EUE (ppm)	1.53	2.64
LOLH (hours/year)	0.50	0.87

Planning Reserve Margins: The Anticipated Reserve Margin falls below the Reference Margin Level of 13.75 percent starting in Summer 2018 and remains below for the duration of the LTRA forecast period. The drop in the reserve margin is mainly due to the retirement of over 4,000 MW of coal and natural gas resources in late 2017 and early 2018 as well as reported delays in planned resource capacity by project developers. To respond to such cyclical resource investment and retirement trends, the ERCOT market is designed to incentivize increases in supply along with temporary reductions in demand to maintain the reliability of the system. For example, there are programs operated by ERCOT, retail electric providers, and distribution utilities that compensate customers for reducing their demand or operating their own generation in response to market prices and anticipated capacity scarcity conditions. ERCOT also has operational tools available to maintain system reliability. Examples include releasing load resource capacity qualified to provide responsive reserve ancillary service, requesting emergency power across the dc ties to neighboring grids, and requesting emergency support from available switchable generators currently serving non-ERCOT grids.

Demand: Based on preliminary data, the TRE-ERCOT Region set an all-time peak demand record of 73,259 MW on July 19, 2018, as compared to the forecasted amount of 72,756 MW used for the *2018 Summer Reliability Assessment*. According to ERCOT's latest long-term peak demand forecast, annual peak demand is expected to increase by a compounded annual rate of 1.8 percent from 2018 through 2028. This forecast is higher than the forecast used for the *2017 LTRA*. The increase is primarily due to a projected increase in economic growth driven by activity in the oil and natural gas exploration sector, petrochemical plant expansion along the Gulf Coast, and an overall stronger employment outlook over the forecast horizon. In addition, Lubbock Power & Light has received approval to have some of its load (almost 500 MW) moved into ERCOT beginning in the summer of 2021. ERCOT's long-term load forecast is based on a set of models describing the hourly load in eight weather zones as a function of the number of premises in various customer classes (residential, business, and industrial), economic variables weather variables (e.g., heating and cooling degree days, temperature, cloud cover, wind speed, dew point) and calendar variables (day of week, holiday).

Demand-Side Management: The DSM forecasted for 2018 comes from dispatchable resources in the form of noncontrollable load resources that provide responsive reserve service[72] (1,119 MW), emergency response service (793 MW, based on actual contracted capacity), and load management programs administered by transmission/distribution service providers (282 MW).[73] These forecasts reflect a gross-up of two percent to reflect avoided transmission line losses. For 2019 and beyond, ERCOT assumes that the load resource capacity amounts remain constant. The ERS capacity forecast for 2019 and beyond is 772 MW. This figure is based on a three-year historical compounded program growth rate along with the two percent gross-up. ERCOT develops its own energy efficiency forecast using annual reports of verified incremental peak load energy efficiency impacts from the Public Utility Commission of Texas and Texas State Energy Conservation Office.[74]

[72] This value reflects a 95 percent confidence level based on historical data for the 3:00 p.m. through 6:00 p.m. time period during the months of June through September over the last three years. The hourly participation is capped at 60 percent of the system-wide obligation for responsive reserve service, which can range from 2,300 to 3,019 MW.

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

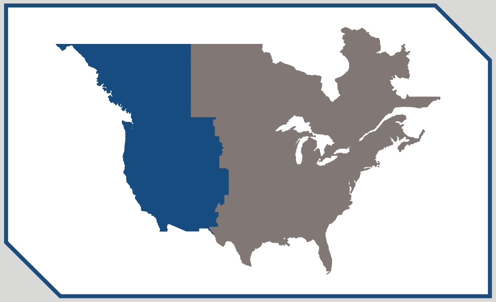
[74] Verified impacts are derived through an Evaluation, Measurement & Verification (EM&V) framework approved by the Public Utility Commission of Texas (PUCT). The statutory EM&V framework is outlined in the Commission's Substantive Rule 25.181, available at the following: https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.181/25.181.pdf, 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.

Distributed Energy Resources: The installed solar DER capacity forecasted for the five-year horizon (ending 2023) is approximately 1,500 MW, reflecting a growth rate significantly higher than assumed for last year's LTRA. Based on current capacity growth and market trends, ERCOT believes that DER does 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.[75] An important ERCOT initiative involves mapping all existing registered DERs (>1 MW and importing into the grid) to the Common Information Model at their load points. Once in the Network Operations Model, the DER locations will be known to ERCOT operators, improving situational awareness and allowing for incorporation into power flow, state estimator, and load forecast programs. A Nodal Protocol Revision Request for implementing the DER mapping was submitted by ERCOT staff in February 2018 and is awaiting board of directors approval.

Generation: Since the 2017 LTRA, about 3,400 MW of utility-scale nameplate capacity has been added to the TRE-ERCOT Region. The percentage contributions by fuel type are wind at 56 percent, natural gas at 23 percent, and solar at 21 percent. A total of 4,540 MW of summer-rated capacity have been retired, primarily due to economic reasons. The breakdown by fuel type is 3,673 MW coal and 867 MW natural gas. ERCOT continues to implement enhancements to tools and processes to address increasing amounts of renewable generation on the ERCOT grid. One such enhancement completed in 2018 was to procure a secondary wind forecasting service to add redundancy to the forecasting process. Moreover, both wind forecast systems are now able to better estimate the impact of extreme weather conditions, such as icing and high speed wind turbine shutdowns. ERCOT is also adding intrahour wind forecasting to better prepare for potential ramps in wind generation that may require deployment of offline reserves.

To estimate the amount of renewable capacity available to meet seasonal peak loads, ERCOT relies on average historical availability during the 20 highest peak load hours for each season over a span of years specific to the renewable generation type. For wind, the historical period for averaging was nine years for noncoastal resources (2009–2017) and eight years for coastal resources (2010–2017). For solar and hydro, the historical period is three years (2015–2017).

[75] ERCOT published a whitepaper, "*Distributed Energy Resources: Reliability Impacts and Recommended Changes,*" March 22, 2017, outlining the challenges and potential impacts of DERs, available at the following: http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf.

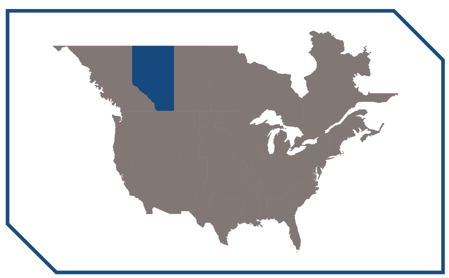


WECC

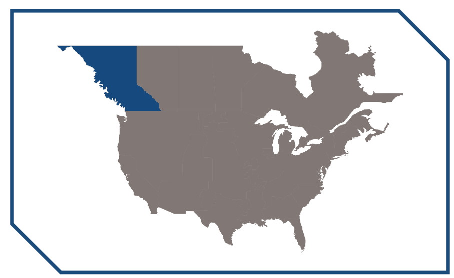
The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving 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

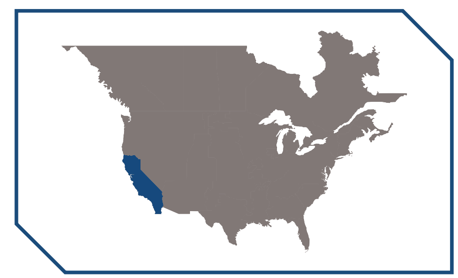
- The Western Interconnection and all the individual subregions are expected to have sufficient generation capacity to exceed the Reference Margin Level during the assessment period.
- The Los Angeles Basin in Southern California continues to be an area of short-term concern due to the reduced availability of the Aliso Canyon natural gas storage facility. WECC continues to study and work with SoCal Gas and California ISO to assess the potential impacts to reliability for the Western Interconnection associated with the limited availability of Aliso Canyon.
- The 2018 summer season has seen increased system stress due to higher-than-average temperatures and a continuing trend of a high number of wildfires; 8,717 fires as of August 2018 compared to 9,000 for all of 2017 (https://www.ncdc.noaa.gov/societal-impacts/wildfires/month/7?params[]=fires&params[]=acres&end_date=2018). The increased temperatures and wildfires are impacting most states and provinces in the Western Interconnection, but the largest incidents are located in California, Arizona, Utah, Idaho, Oregon, and British Columbia.
- WECC has completed a study of the impacts to reliability associated with the interdependence of the natural gas and electric systems. The key findings include the Western Interconnections facing increasing volumetric and flexibility constraints, and disruptions in the natural gas system could potentially translate quickly to loss of load in the Desert Southwest and Southern California regions. The complete study, including recommendations for improvement, can be found here: (https://www.wecc.biz/Administrative/WECC20Gas-Electric20Study20Public20Report.pdf).
- Distributed energy resources continue to be well understood at the LSE level and ongoing analyses continue to be performed regarding increases in penetration, particularly in California. The California ISO has begun an initiative to try to properly account for behind-the-meter generation on their system. This initiative proposes to establish a standard reporting practice for excess behind-the-meter production, determine the appropriate practice for representation of excess BTM production in the ISO market process, and explore the potential impacts of the reporting of gross load and excess BTM on scheduling coordinators that submit meter data to the ISO. More information on this initiative can be found here: (http://www.caiso.com/Documents/IssuePaper-ExcessBehindtheMeterProduction.pdf).
- 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 an RMR contract in September 2017 for the three units located near Oakland, CA.



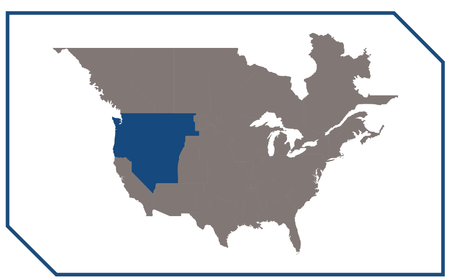
WECC-AB



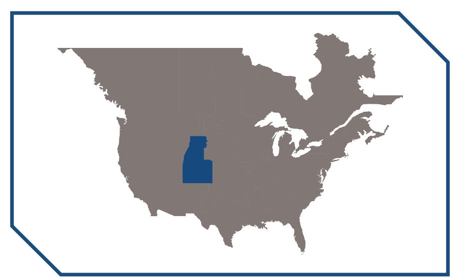
WECC-BC



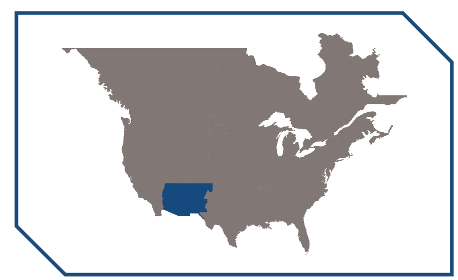
WECC-CAMX



WECC-NWPP-US

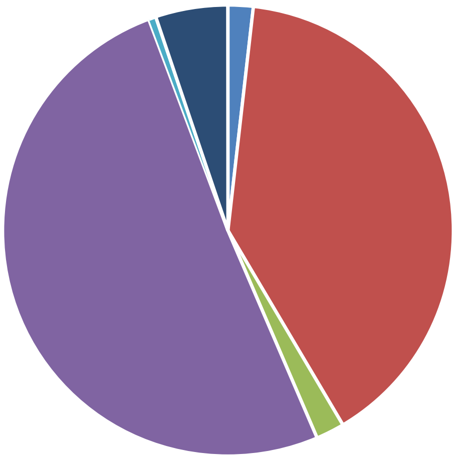


WECC-RMRG



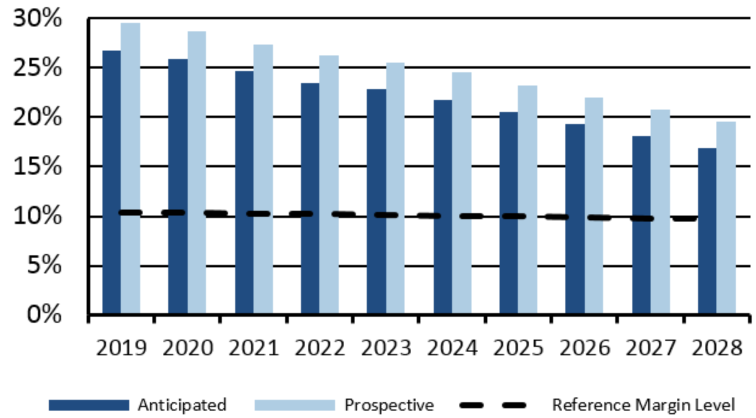
WECC-SRSG

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	11,939	12,018	12,144	12,260	12,321	12,428	12,557	12,678	12,814	12,945
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,939	12,018	12,144	12,260	12,321	12,428	12,557	12,678	12,814	12,945
Additions: Tier 1	43	43	43	43	43	43	43	43	43	43
Additions: Tier 2	338	338	338	338	338	338	338	338	338	338
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	15,091	15,091	15,091	15,091	15,091	15,091	15,091	15,091	15,091	15,091
Anticipated Reserve Margin (%)	26.76	25.93	24.62	23.44	22.83	21.77	20.52	19.37	18.10	16.91
Prospective Reserve Margin (%)	29.60	28.74	27.41	26.20	25.58	24.50	23.22	22.04	20.74	19.52
Reference Margin Level (%)	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73

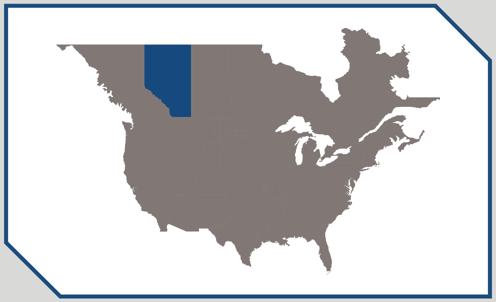


2019 On-Peak Fuel-Mix

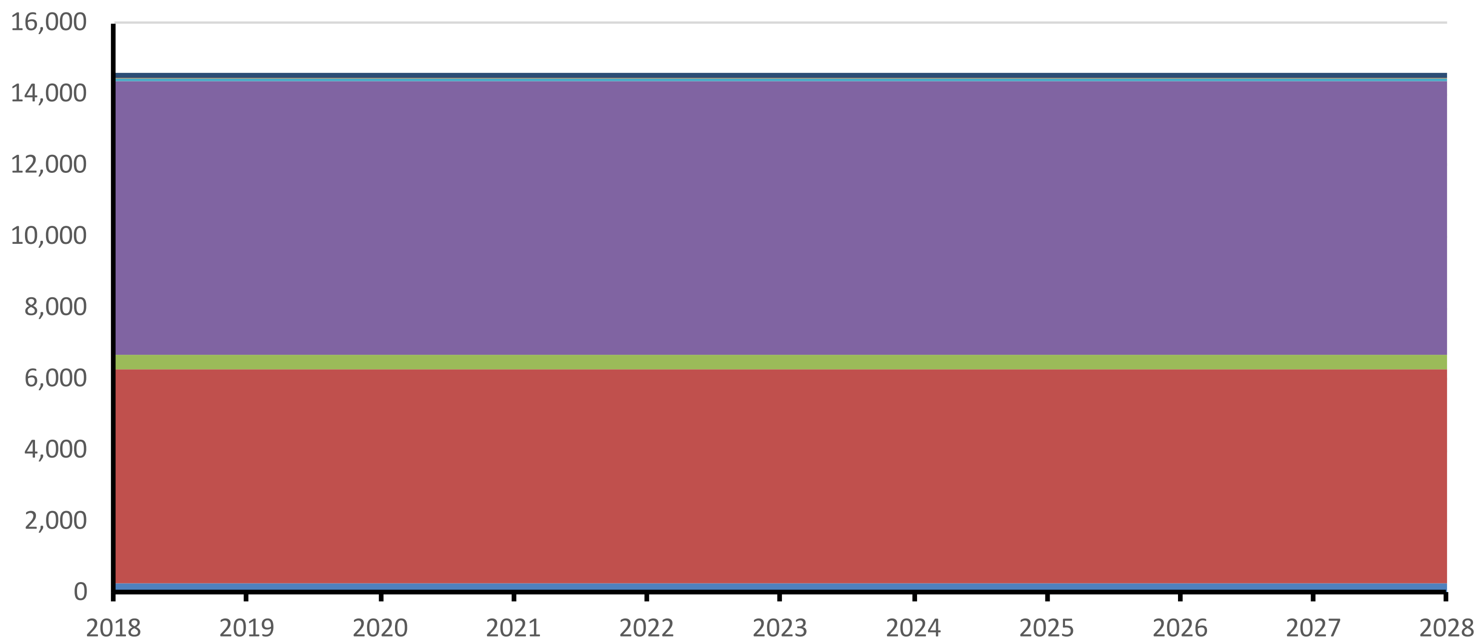
Generation Type	Winter 2019–2020 MW
Biomass	273
Coal	6,275
Hydro	415
Natural Gas	7,533
Other	70
Solar	0
Wind	663



WECC-AB Planning Reserve Margins



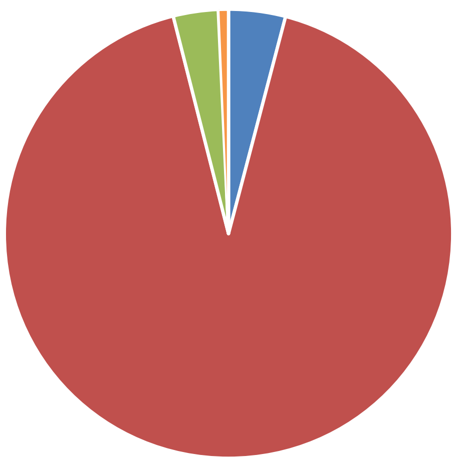
WECC-AB



WECC-AB Fuel Composition

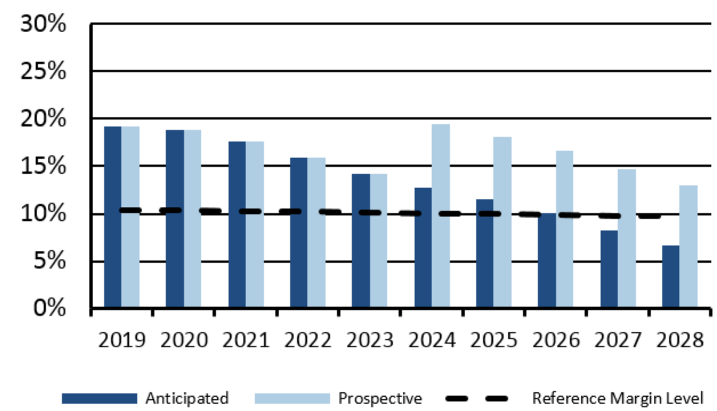
Gen Type	2019–2020	2020–2021	2021–2022	2022–2023	2023–2024	2024–2025	2025–2026	2026–2027	2027–2028	2028–2029
Biomass	272	272	272	272	272	272	272	272	272	272
Coal	6,007	6,007	6,007	6,007	6,007	6,007	6,007	6,007	6,007	6,007
Hydro	409	409	409	409	409	409	409	409	409	409
Natural Gas	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682
Other	78	78	78	78	78	78	78	78	78	78
Solar	14	14	14	14	14	14	14	14	14	14
Wind	142	142	142	142	142	142	142	142	142	142
Total	14,603	14,603	14,603	14,603	14,603	14,603	14,603	14,603	14,603	14,603

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29
Total Internal Demand	11,468	11,616	11,797	11,972	12,186	12,346	12,516	12,682	12,894	13,088
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,468	11,616	11,797	11,972	12,186	12,346	12,516	12,682	12,894	13,088
Additions: Tier 1	498	622	704	704	745	745	786	786	786	786
Additions: Tier 2	0	0	0	0	0	825	825	825	825	825
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,174	13,174	13,174
Anticipated Reserve Margin (%)	19.22	18.77	17.65	15.93	14.23	12.75	11.55	10.08	8.27	6.67
Prospective Reserve Margin (%)	19.22	18.77	17.65	15.93	14.23	19.43	18.14	16.59	14.67	12.97
Reference Margin Level (%)	10.42	10.36	10.28	10.21	10.14	10.05	9.95	9.88	9.80	9.73

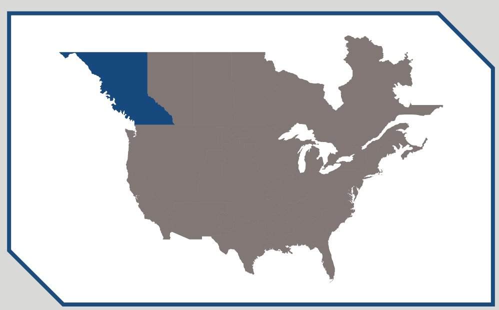


2019 On-Peak Fuel-Mix

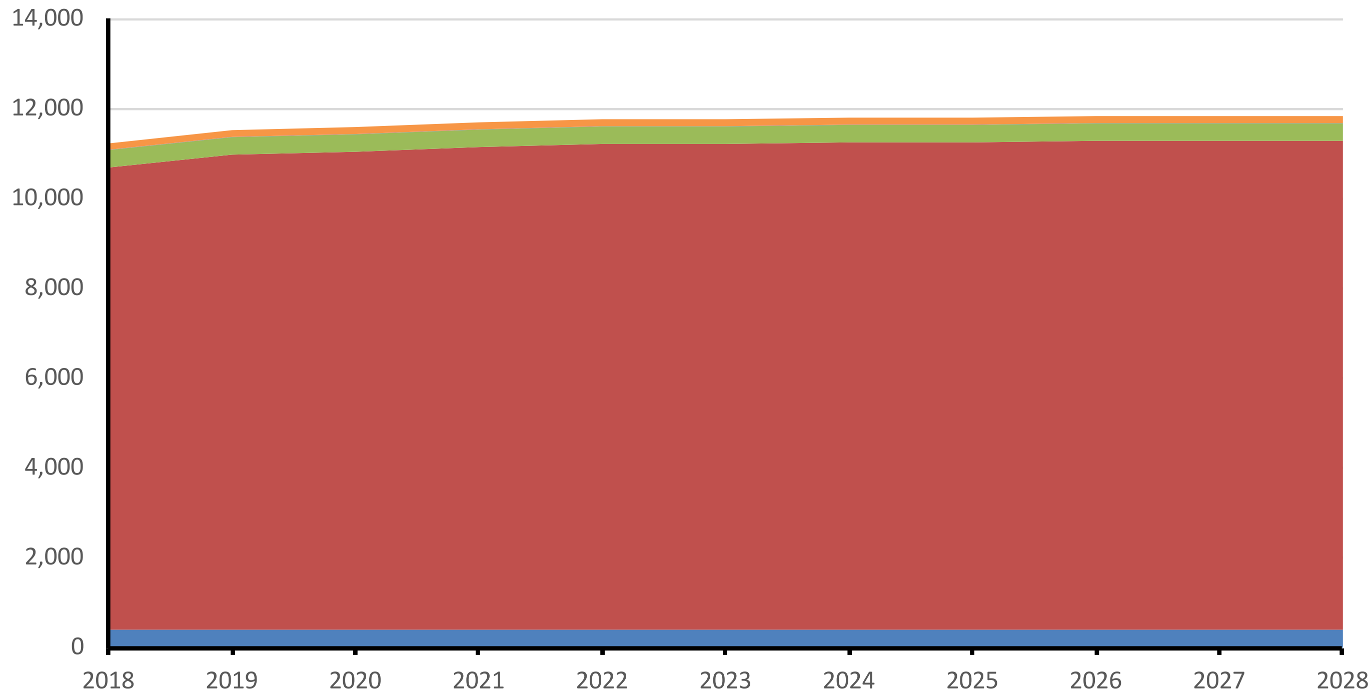
Generation Type	Winter 2019–2020 MW
Biomass	399
Hydro	10,580
Natural Gas	390
Other	5
Solar	1
Wind	150



WECC-BC Planning Reserve Margins



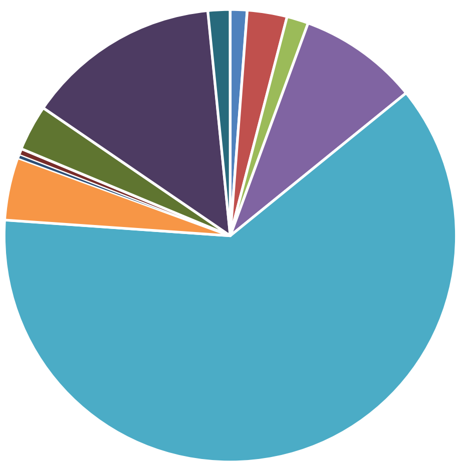
WECC-BC



WECC-BC Fuel Composition

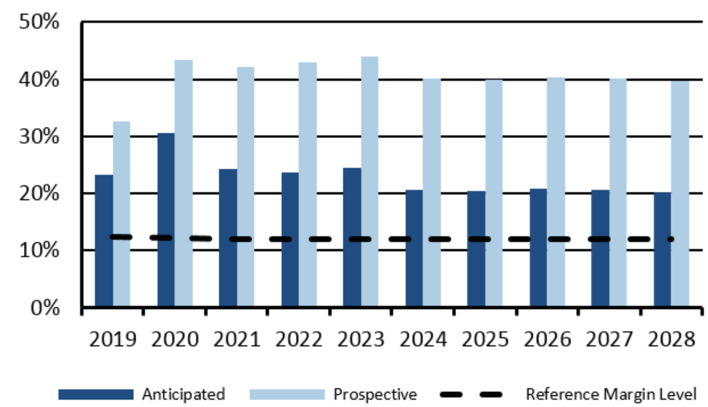
Gen Type	2019–2020	2020–2021	2021–2022	2022–2023	2023–2024	2024–2025	2025–2026	2026–2027	2027–2028	2028–2029
Biomass	399	399	399	399	399	399	399	399	399	399
Hydro	10,580	10,644	10,749	10,818	10,818	10,853	10,853	10,888	10,888	10,888
Natural Gas	390	390	390	390	390	390	390	390	390	390
Other	5	5	5	5	5	5	5	5	5	5
Solar	1	1	1	1	1	1	1	1	1	1
Wind	150	155	155	155	155	155	155	155	155	155
Total	11,525	11,594	11,699	11,768	11,768	11,803	11,803	11,838	11,838	11,838

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	55,109	51,091	51,219	51,476	51,127	52,373	52,510	52,306	52,397	52,571
Demand Response	970	959	944	926	926	926	926	926	926	926
Net Internal Demand	54,139	50,132	50,275	50,550	50,201	51,447	51,584	51,380	51,471	51,645
Additions: Tier 1	1,799	1,861	1,921	1,943	1,953	1,965	1,977	1,990	2,002	2,010
Additions: Tier 2	4,998	6,382	8,984	9,733	9,733	10,044	10,044	10,044	10,044	10,044
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	64,936	63,586	60,550	60,550	60,550	60,106	60,106	60,106	60,106	60,106
Anticipated Reserve Margin (%)	23.27	30.55	24.26	23.63	24.51	20.65	20.35	20.86	20.67	20.27
Prospective Reserve Margin (%)	32.50	43.28	42.13	42.88	43.89	40.17	39.82	40.40	40.18	39.72
Reference Margin Level (%)	12.35	12.29	12.10	12.05	12.02	12.05	11.99	11.99	12.02	12.04



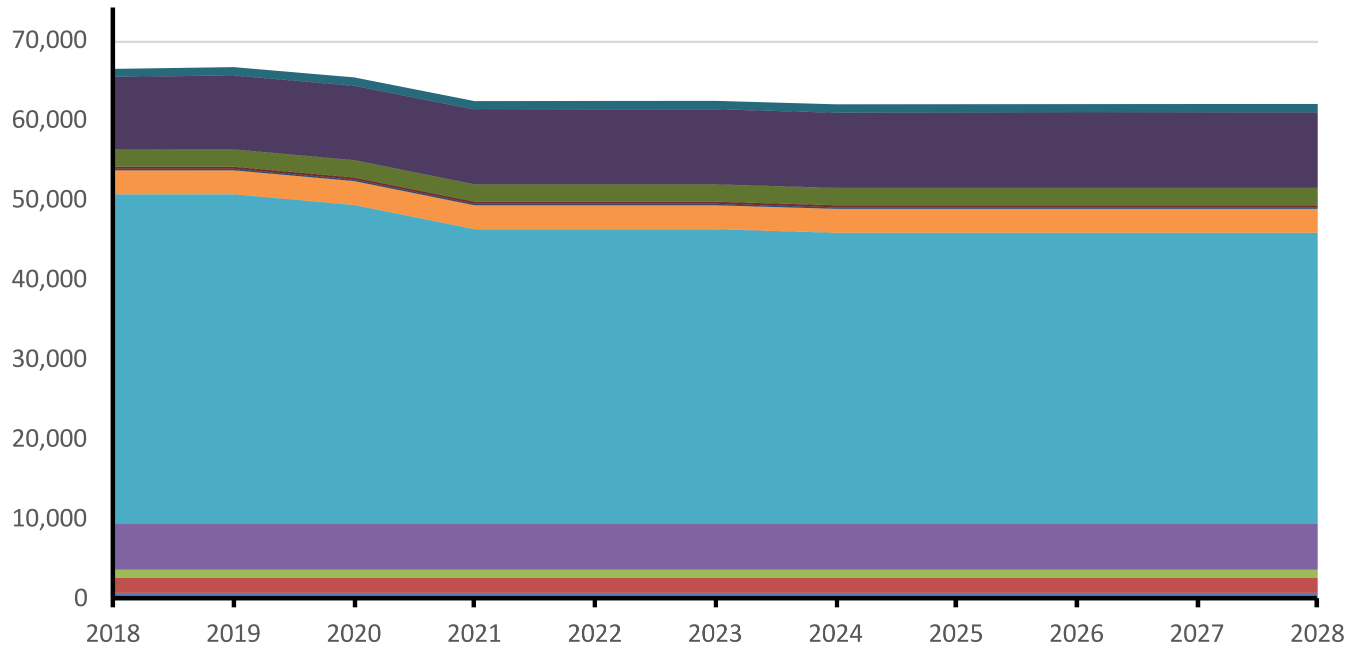
2019 On-Peak Fuel-Mix

Generation Type	Summer 2019 MW
Biomass	803
Coal	1,896
Geothermal	1,030
Hydro	5,709
Natural Gas	41,352
Nuclear	3,000
Other	190
Petroleum	261
Pumped Storage	2,177
Solar	9,265
Wind	1,053



WECC-CAMX Planning Reserve Margins

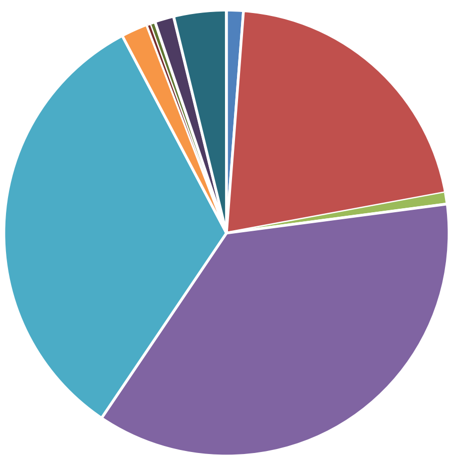
WECC-CAMX



WECC-CAMX Fuel Composition

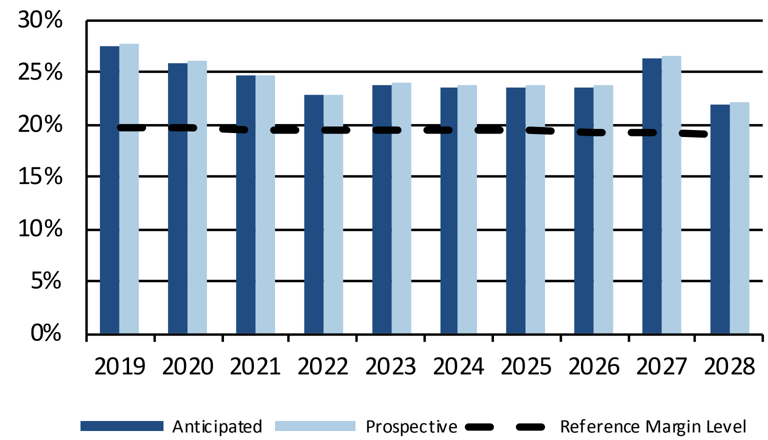
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	803	803	803	803	803	803	803	803	803	803
Coal	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896	1,896
Geothermal	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
Hydro	5,709	5,710	5,710	5,710	5,710	5,710	5,710	5,710	5,710	5,710
Natural Gas	41,352	40,001	36,966	36,966	36,966	36,522	36,522	36,522	36,522	36,522
Nuclear	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Other	190	190	190	190	190	190	190	190	190	190
Petroleum	261	261	261	261	261	261	261	261	261	261
Pumped Storage	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177
Solar	9,265	9,325	9,386	9,407	9,418	9,430	9,441	9,454	9,466	9,473
Wind	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,053	1,054
Grand Total	66,735	65,447	62,472	62,493	62,504	62,072	62,083	62,096	62,108	62,116

Demand, Resources, and Reserve Margins										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	47,643	50,003	50,434	50,625	51,085	51,405	51,717	51,999	52,364	52,628
Demand Response	918	928	939	943	944	949	950	953	955	956
Net Internal Demand	46,725	49,075	49,495	49,682	50,141	50,456	50,767	51,046	51,409	51,672
Additions: Tier 1	53	146	146	236	236	236	236	236	236	236
Additions: Tier 2	94	94	94	94	94	94	94	94	94	94
Net Firm Capacity Transfers	0	2,100	2,620	2,200	3,300	3,600	4,200	4,900	7,000	5,800
Existing-Certain and Net Firm Transfers	59,552	61,652	61,537	60,750	61,850	62,150	62,538	62,898	64,776	62,822
Anticipated Reserve Margin (%)	27.57	25.92	24.62	22.75	23.82	23.64	23.65	23.68	26.46	22.03
Prospective Reserve Margin (%)	27.77	26.12	24.81	22.94	24.01	23.83	23.83	23.86	26.64	22.22
Reference Margin Level (%)	19.72	19.68	19.53	19.60	19.56	19.49	19.39	19.35	19.27	19.11

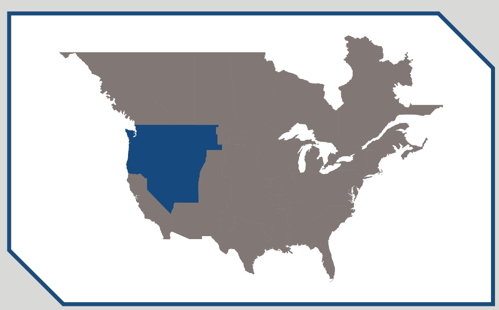


2019 On-Peak Fuel-Mix

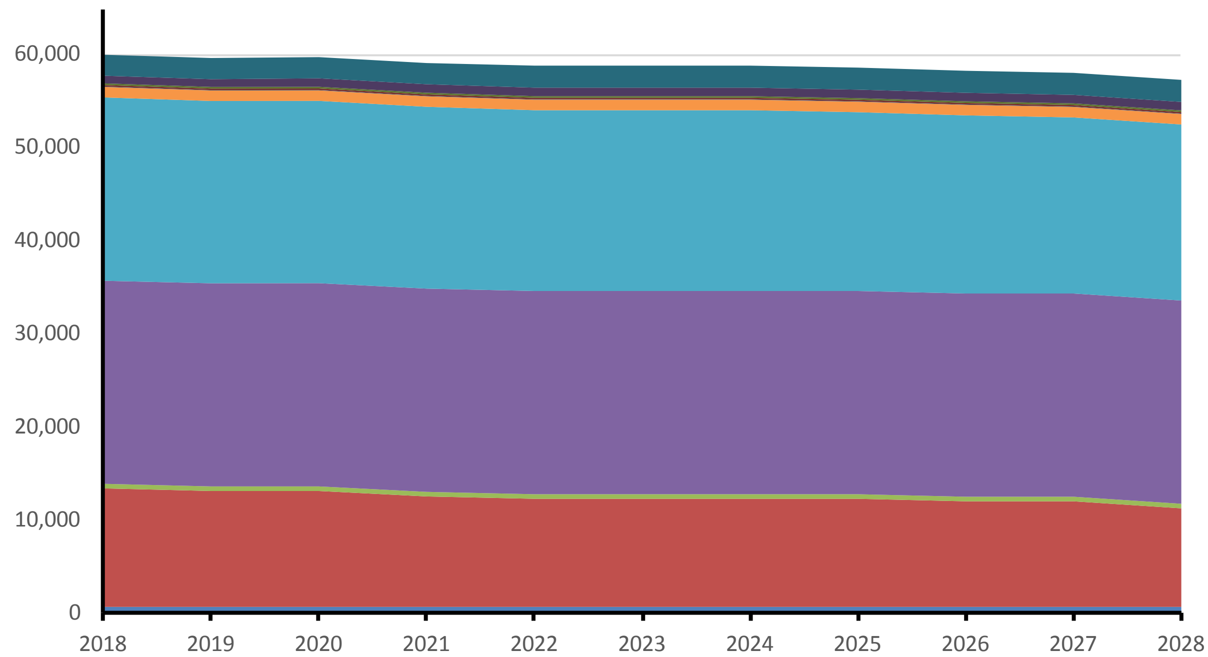
Generation Type	Summer 2019 MW
Biomass	733
Coal	12,431
Geothermal	492
Hydro	21,786
Natural Gas	19,553
Nuclear	1130
Other	44
Petroleum	152
Pumped Storage	182
Solar	830
Wind	2273



WECC NWPP-US Planning Reserve Margins



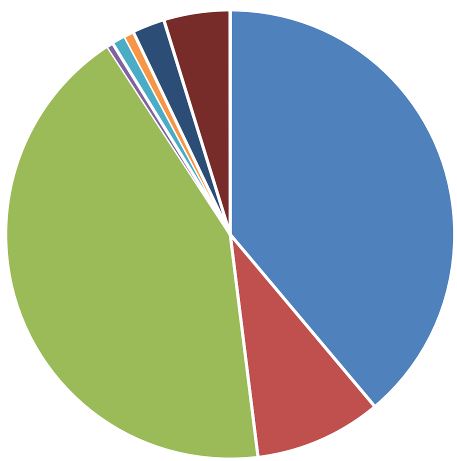
WECC-NWPP-US



WECC-NWPP-US Fuel Composition

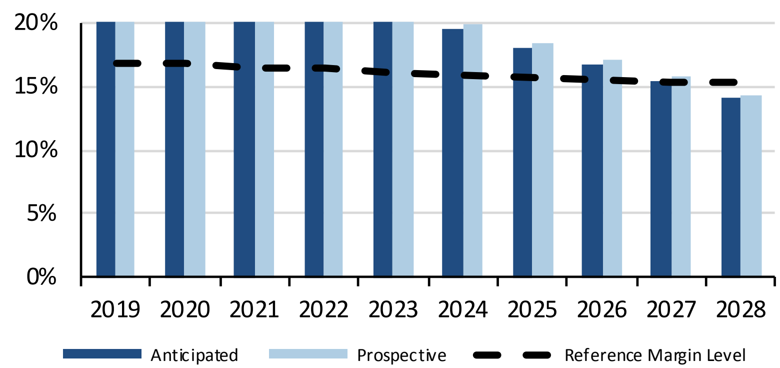
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	733	733	733	733	733	733	733	733	733	733
Coal	12,431	12,431	11,846	11,592	11,592	11,592	11,592	11,324	11,324	10,570
Geothermal	492	492	492	492	492	492	492	492	492	492
Hydro	21,786	21,797	21,797	21,797	21,797	21,797	21,797	21,797	21,797	21,797
Natural Gas	19,553	19,553	19,503	19,390	19,390	19,390	19,178	19,106	18,884	18,884
Nuclear	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130	1,130
Other	44	44	44	44	44	44	44	44	44	44
Petroleum	152	152	152	152	152	152	152	152	152	152
Pumped Storage	182	182	182	182	182	182	182	182	182	182
Solar	830	911	911	911	911	911	911	911	911	911
Wind	2,273	2,273	2,273	2,363	2,363	2,363	2,363	2,363	2,363	2,363
Grand Total	59,605	59,698	59,063	58,786	58,786	58,786	58,574	58,234	58,012	57,258

Demand, Resources, and Reserve Margins										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	12,182	12,925	13,094	13,239	13,489	13,655	13,835	13,980	14,129	14,308
Demand Response	295	288	288	287	287	286	286	285	285	284
Net Internal Demand	11,888	12,637	12,806	12,952	13,202	13,369	13,549	13,695	13,844	14,024
Additions: Tier 1	184	281	281	281	281	281	281	281	281	281
Additions: Tier 2	0	0	0	0	44	44	44	44	44	44
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	15,711	15,711	15,711	15,711	15,711	15,711	15,711	15,711	15,711	15,711
Anticipated Reserve Margin (%)	33.72	26.56	24.89	23.48	21.14	19.63	18.04	16.78	15.52	14.04
Prospective Reserve Margin (%)	33.72	26.56	24.89	23.48	21.47	19.95	18.36	17.10	15.84	14.35
Reference Margin Level (%)	16.83	16.76	16.48	16.37	16.07	15.94	15.73	15.58	15.40	15.25

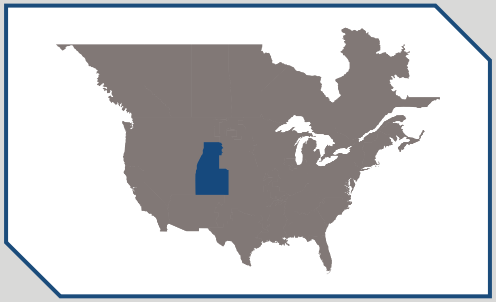


2019 On-Peak Fuel-Mix

Generation Type	Summer 2019 MW
Biomass	3
Coal	6,178
Hydro	1,454
Natural Gas	6,798
Other	70
Petroleum	157
Pumped Storage	108
Solar	370
Wind	759



WECC-RMRG Planning Reserve Margins

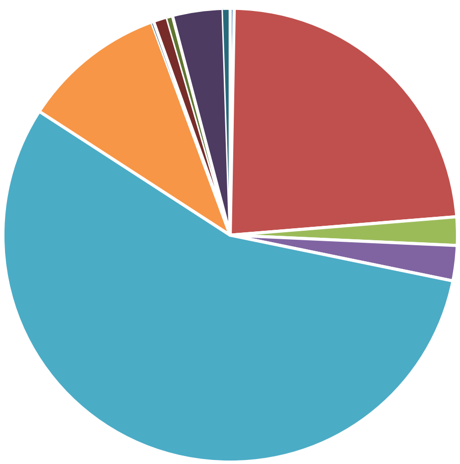


WECC-RMRG

WECC-RMRG Fuel Composition

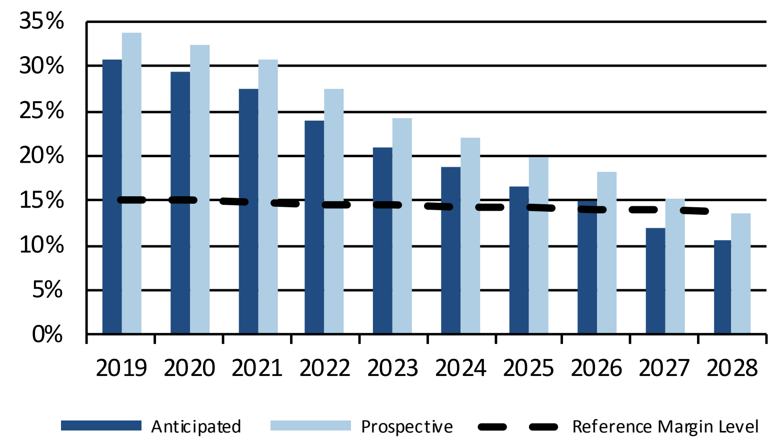
Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	3	3	3	3	3	3	3	3	3	3
Coal	6,178	6,178	6,178	6,178	6,178	6,178	6,178	6,178	6,178	6,178
Hydro	1,454	1,454	1,454	1,454	1,454	1,454	1,454	1,454	1,454	1,454
Natural Gas	6,798	6,798	6,798	6,798	6,798	6,798	6,798	6,798	6,798	6,798
Other	70	70	70	70	70	70	70	70	70	70
Petroleum	157	157	157	157	157	157	157	157	157	157
Pumped Storage	108	108	108	108	108	108	108	108	108	108
Solar	370	466	466	466	466	466	466	466	466	466
Wind	759	759	759	759	759	759	759	759	759	759
Total	15,896	15,993	15,993	15,993	15,993	15,993	15,993	15,993	15,993	15,993

Demand, Resources, and Reserve Margins (MW)										
Quantity	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Total Internal Demand	24,286	24,484	24,854	25,408	25,898	26,344	26,836	27,207	27,659	28,014
Demand Response	186	186	186	186	186	186	186	186	186	186
Net Internal Demand	24,100	24,298	24,668	25,222	25,712	26,158	26,650	27,021	27,473	27,828
Additions: Tier 1	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079	1,079
Additions: Tier 2	681	722	842	864	864	864	864	864	864	864
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	30,445	30,364	30,364	30,203	30,007	30,007	30,007	30,007	29,683	29,683
Anticipated Reserve Margin (%)	30.80	29.40	27.46	24.03	20.90	18.84	16.64	15.04	11.97	10.54
Prospective Reserve Margin (%)	33.63	32.37	30.87	27.45	24.26	22.14	19.88	18.24	15.11	13.64
Reference Margin Level (%)	15.10	15.11	14.86	14.63	14.47	14.33	14.17	14.03	13.92	13.82

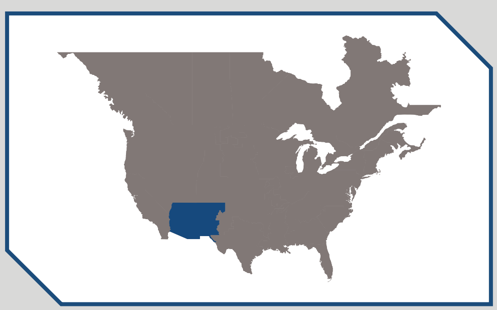


2019 On-Peak Fuel-Mix

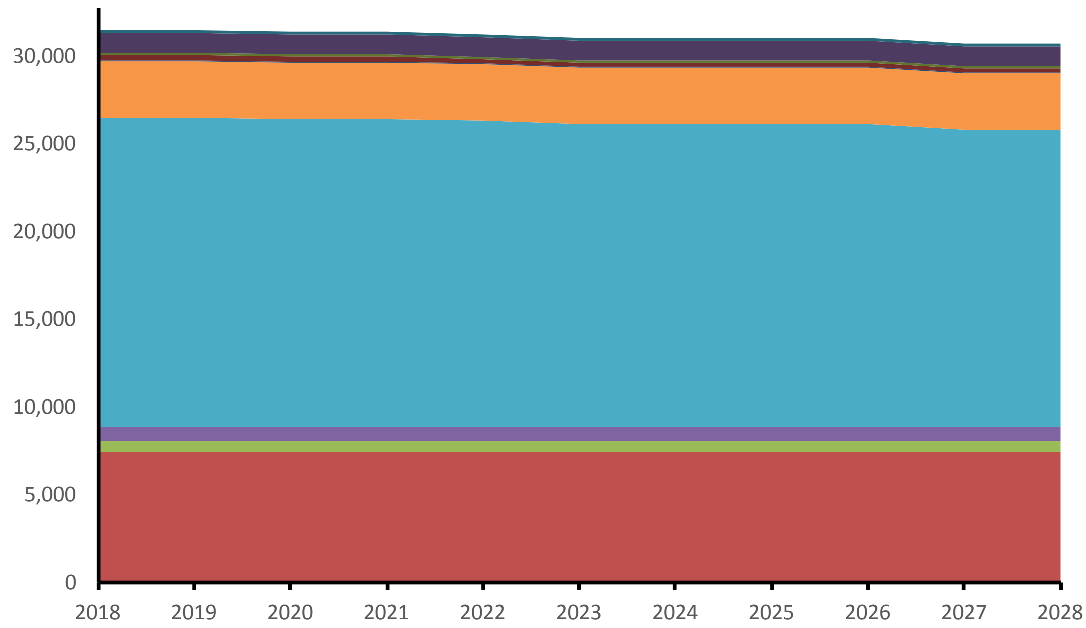
Generation Type	Summer 2019 MW
Biomass	89
Coal	7,385
Geothermal	634
Hydro	794
Natural Gas	17,630
Nuclear	3,217
Other	51
Petroleum	307
Pumped Storage	128
Solar	1,125
Wind	162



WECC-SRSG Planning Reserve Margins



WECC-SRSG



WECC-SRSG Fuel Composition

Gen Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Biomass	89	89	89	89	89	89	89	89	89	89
Coal	7,385	7,385	7,385	7,385	7,385	7,385	7,385	7,385	7,385	7,385
Geothermal	635	635	635	635	635	635	635	635	635	635
Hydro	794	794	794	794	794	794	794	794	794	794
Natural Gas	17,631	17,550	17,550	17,469	17,273	17,273	17,273	17,273	16,949	16,949
Nuclear	3,217	3,217	3,217	3,217	3,217	3,217	3,217	3,217	3,217	3,217
Other	51	51	51	51	51	51	51	51	51	51
Petroleum	307	307	307	227	227	227	227	227	227	227
Pumped Storage	128	128	128	128	128	128	128	128	128	128
Solar	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125
Wind	162	162	162	162	162	162	162	162	162	162
Total	31,523	31,442	31,442	31,281	31,085	31,085	31,085	31,085	30,761	30,761

Probabilistic Assessment Overview: All WECC Areas

The text in this section applies to all WECC areas.

- **Probabilistic vs. Deterministic Assessments:** The main difference between deterministic and ProbAs is their respective import transfer logic. The deterministic assessment imports available energy so that the expected values of demand and resource distributions produce a margin at or above the reference margin; the ProbA imports available energy to separate the tails of the demand and resource distributions.
    - **Demand:** Both assessments use the same hourly demand forecast derived from monthly peak and energy values provided by the region's Balancing Authorities. The ProbA applies uncertainty distributions around the expected demand derived from hourly historical demand.
    - **Thermal Resources:** Both assessments use the same resources; however, the ProbA derates the expected peak hour capacity based on historical derate values utilized in the two-state Monte-Carlo simulation.
    - **Variable Energy Resources:** Both assessments use the same expected hourly generation profiles. The ProbA applies variance distributions derived from historical generation output associated with each hour.
    - **Transmission:** Both assessments use the same topology. The ProbA imports available resources to reduce loss-of-load probability while the deterministic assessment imports available resources to meet reference margins.

Probabilistic Assessment Overview: WECC-AB

- **General Overview:** Reserve margins for the WECC-AB area are over 23 percent in 2020 and 19 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the Multiple Area Variable Resource Integration Convolution (MAVRIC) model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
    - Annual peak demand in the WECC-AB area ranges between approximately five percent below to five percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
    - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-AB thermal generating resources by two percent on average.
    - Hydro units in WECC-AB (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with a combined ~65 percent derate for storage capable and run-of-river resources.
    - Variable energy resources (wind and solar) in WECC-AB are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~45 percent, and solar resources have an expected peak hour derate of ~100 percent.

Base Case Study

- WECC-AB resource adequacy measures are zero in the Base Case, indicating that operable reserves above 20 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA, at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	29.6	25.9	23.4
Prospective	11.0	11.0	10.0
Reference	26.8	23.2	19.9
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-BC

- **General Overview:** Reserve margins for the WECC-BC area are over 20 percent in 2020 and 22 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-BC area ranges between approximately five percent below to nine percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-BC thermal generating resources by one percent on average.
  - Hydro units in WECC-BC (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with a combined ~25 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-BC are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~88 percent, and solar resources have an expected peak hour derate of ~100 percent.

Base Case Study

- WECC-BC resource adequacy measures are zero in the Base Case, indicating that operable reserves above 20 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	12.4	18.7	15.9
Prospective	12.1	13.0	13.0
Reference	11.1	20.4	22.2
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-CAMX

- **General Overview:** Reserve margins for the WECC-CAMX area are over 19 percent in 2020 and 22 percent in 2022; however, due in part to the changing resource mix, LOLH are projected for 2020 (9) and 2022 (95). Additionally, the EUE for both years increased, with ~14k MWh projected for 2020 and ~207k MWh projected for 2022.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-CAMX area ranges between approximately 10 percent below to 23 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-CAMX thermal generating resources by six percent on average.
  - Hydro units in WECC-CAMX (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~46 percent for pumped storage resources and combined ~38 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-CAMX are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~84 percent, and solar resources have an expected peak hour derate of ~24 percent.

Base Case Study

- WECC-CAMX resource adequacy measures are non-zero in the Base Case, indicating that operable reserves above 19 percent for the peak hour are no longer sufficient to have zero expected LOLH or EUE for all hours of the year. A changing resource mix is leading to increased risk in the area. It should be noted that with Tier 2 resources, not included in this assessment, most of the EUE would disappear.
- **Results Trending:** 2020 Annual Probabilistic Indices have increased from the 2016 ProbA.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	21.3	22.2	21.3
Prospective	16.2	12.3	12.1
Reference	21.3	19.5	22.8
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	2,783	41,468
EUE (ppm)	0.00	10.4	153.8
LOLH (hours/year)	0.00	0.13	2.3

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-NWPP-US

- **General Overview:** Reserve margins for the WECC-NWPP-US area are over 16 percent in 2020 and 15 percent in 2022; however, due in part to the changing resource mix, LOLH are projected for 2020 (22) and 2022 (27). Additionally, the EUE for both years increased, with ~14k MWh projected for 2020 and ~18k MWh projected for 2022.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-NWPP-US area ranges between approximately 10 percent below to 23 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-NWPP-US thermal generating resources by 13 percent on average.
  - Hydro units in WECC-NWPP-US (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~79 percent for pumped storage resources and combined ~41 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-NWPP-US are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~77 percent, and solar resources have an expected peak hour derate of ~54 percent.

Base Case Study

- WECC-NWPP-US resource adequacy measures are non-zero in the Base Case, indicating that operable reserves above 16 percent for the peak hour are no longer sufficient to have zero expected LOLH or EUE for all hours of the year. A changing resource mix is leading to increased risk in the area. It should be noted that with Tier 2 resources, not included in this assessment, most of the EUE would disappear.
- **Results Trending:** 2020 Annual Probabilistic Indices have increased from the 2016 ProbA.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	30.3	23.3	20.2
Prospective	16.3	19.7	19.6
Reference	16.5	16.1	15.9
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	1,896	2,553
EUE (ppm)	0.00	6.45	8.58
LOLH (hours/year)	0.00	0.47	0.58

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-RMRG

- **General Overview:** Reserve margins for the WECC-RMRG region are over 14 percent in 2020 and 12 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas.
  - Annual peak demand in the WECC-RMRG region ranges between approximately 12 percent below to 24 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-RMRG thermal generating resources by seven percent on average.
  - Hydro units in WECC-RMRG (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~91 percent for pumped storage resources and combined ~46 percent derate for storage capable and run-of-river resources.
  - Variable energy resources (wind and solar) in WECC-RMRG are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~80 percent, and solar resources have an expected peak hour derate of ~16 percent.

Base Case Study

- WECC-RMRG resource adequacy measures are zero in the base case, indicating that operable reserves above 18 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA, at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	**2020**	**2022**
Anticipated	21.7	27.8	24.7
Prospective	14.0	16.8	16.4
Reference	17.8	20.8	18.5
Annual Probabilistic Indices			
	Base Case		
	2020*	**2020**	**2022**
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Probabilistic Assessment Overview: WECC-SRSG

- **General Overview:** Reserve margins for the WECC-SRSG area are over 21 percent in 2020 and 16 percent in 2022, resulting in insignificant levels of LOLH and EUE.
- **Modeling:** WECC utilizes the MAVRIC model, an 8,760-hourly demand, generation, and transmission sequential convolution model consisting of 39 interconnected areas:
  - Annual peak demand in the WECC-SRSG area ranges between approximately 12 percent below to 24 percent above forecasted demand based upon the 10 percent and 90 percent points of the LFU distributions.
  - Thermal units follow a two-state on-or-off sequence based on Monte Carlo simulation by utilizing unit-specific average forced outage rates and failure durations, which is equivalent to derating WECC-SRSG thermal generating resources by nine percent on average.
  - Hydro units in WECC-SRSG (storage capable, run-of-river, and pump storage) follow an hourly expected generation curve derived from historical generation output associated with each hour. Each type of hydro unit is modeled separately with an expected peak hour derate of ~47 percent for pumped storage resources and combined ~27 percent derate for storage capable and run-of-river resources.
  - Variable resources in WECC-SRSG are capacity resources modeled as expected hourly generation profiles with variance distributions derived from historical generation output associated with each hour. Wind resources have an expected peak hour derate of ~82 percent, and solar resources have an expected peak hour derate of ~20 percent.

Base Case Study

- WECC-SRSG resource adequacy measures are zero in the Base Case, indicating that operable reserves above 15 percent for the peak hour are sufficient to have zero expected LOLH or EUE for all hours of the year.
- **Results Trending:** 2020 Annual Probabilistic Indices are unchanged from the 2016 ProbA at 0.00.

Summary of Results			
Reserve Margin			
	Base Case		
	2020*	2020	2022
Anticipated	21.2	32.0	26.8
Prospective	15.8	15.1	14.6
Reference	20.4	20.1	16.7
Annual Probabilistic Indices			
	Base Case		
	2020*	2020	2022
EUE (MWh)	0.00	0.00	0.00
EUE (ppm)	0.00	0.00	0.00
LOLH (hours/year)	0.00	0.00	0.00

*Represents 2016 ProbA results for 2020.

Planning Reserve Margins: The Reference Margin Level is established by WECC through a Building Block method, which 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 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: Load forecasts are developed by WECC staff by imposing the monthly peak and energy forecasts provided by the 38 individual BAs 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 LSE. The forecasted curves are aggregated to subregional and to 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: A significant portion of the controllable DR 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 who are responsible for their 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 DR. CAISO's DR initiative programs are being developed with a goal to avoid adverse long-term reliability impacts.

EE 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 those programs are administered by the individual LSEs or ISOs and not by WECC.

Distributed Energy Resources: The impacts of DERs on 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 at 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. 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 MVWG is in the process of approving these models for future use.

Generation: In 2015 the *Western Interconnection Flexibility Assessment*[76] 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 five-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 that there will be excessive unplanned re-

[76] WECC Flexibility Assessment Report.

tirements 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 that are used by the Transmission Planners (TPs) 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 areas to summer-peaking areas 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 (e.g., the coal-fired Intermountain Power Project, the Navajo power plant, and the Diablo Canyon nuclear station) are being considered for future retirement.[77]

All natural-gas-fired units are included as available resources when performing resource adequacy assessment, 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. CAISO continues to work with the impacted natural gas company and the neighboring BAs and RCs to provide mitigation plans to minimize and eliminate the risk to the reliability of the electric transmission grid.

[77] These units were not included as certain retirements in this assessment because these retirements were not reported to WECC as they do not qualify for retirements under market rules, or 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.

Capacity Transfers: 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.[78]

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 the LTRA are studied at less than optimal levels and reflect limited and conservative transfers. Transfers with other regional councils, such as MRO and SPP, are not included in this assessment as this would require an assumption regarding the amount of surplus or deficit generation in those councils.

[78] 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: Transmission planning in the Western Interconnection is coordinated by five[79] regional planning groups that create and periodically publish transmission expansion plans: Northern Tier Transmission Group,[80] WestConnect,[81] ColumbiaGrid,[82] California ISO,[83] and Alberta Electric System Operator.[84] 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 Planning Coordinator to study extreme weather scenarios.

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[79] 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., and Columbia Power Corporation.

[80] https://www.nttg.biz/site/index.php?option=com_content&view=article&id=372&Itemid=135

[81] https://doc.westconnect.com/Documents.aspx?NID=12

[82] https://www.columbiagrid.org/notices-detail.cfm?NoticeID=148

[83] http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf

[84] https://www.aeso.ca/assets/Uploads/2015-Long-termTransmissionPlan-WEB.pdf

Data Concepts and Assumptions

Demand (Load Forecast)	
Total Internal Demand	The peak hourly load for the summer and winter of each year. Projected total internal demand is based on normal weather (50/50 distribution)[2] and includes the impacts of distributed resources, EE, and conservation programs.[3]
Net Internal Demand	Total internal demand, reduced by the amount of controllable and dispatchable DR 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	Coincident	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 LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AESO	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-BC	Winter	Noncoincident	Individual BAs: aggregated by WECC
WECC-CAMX	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-NWPP-US	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-RMRG	Summer	Noncoincident	Individual BAs: aggregated by WECC
WECC-SRSG	Summer	Noncoincident	Individual BAs: aggregated by WECC

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) 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 is 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.
	$\text{Anticipated Reserve Margin} = \dfrac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$ $\text{Prospective Reserve Margin} = \dfrac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$
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 increased 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.

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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.

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.