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414 Nicollet Mall
Minneapolis, MN 55401

November 21, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: NERC 2018 LONG-TERM RELIABILITY ASSESSMENT
2019 BIENNIAL TRANSMISSION PROJECTS REPORT
DOCKET NO. E999/M-19-205

Dear Mr. Wolf:

On October 31, 2019, on behalf of the Minnesota Transmission Operators (MTO), we submitted the 2019 Biennial Transmission Projects Report for approval by the Minnesota Public Utilities Commission. On November 14, 2019, in accordance with Minn. R. 7848.1800, subp. 3, the Department of Commerce filed comments with the Commission on the completeness of the report. No other comments were filed addressing completeness.[1]

The Department of Commerce reviewed the 2019 Biennial Report to determine whether it contained the information required by Minn. R. 7848.1300. The only piece of additional information the Department thought should be included in the Biennial Report was the load and capability report from the regional reliability council, required under part (B) of the Rule. Since the Mid-continent Area Power Pool (MAPP) no longer exists, the Department recommended that the MTO submit a copy of the Midwest Reliability Organization's (MRO) load and capability report found in the North American Electric Reliability Corporation's (NERC) 2018 Long-Term Reliability Assessment.

Accordingly, the MTO is submitting the pertinent pages for the MRO-MAPP load and capability report from the 2018 NERC Assessment. The entire NERC

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[1] On November 19, 2019, the Southwest Regional Development Commission filed a staff memo summarizing the Biennial Report, but the memo does not raise any issues related to completeness.

Assessment for 2018 can be found here, along with Assessments for other years: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

If you have any other questions about this filing, please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY AND STRATEGIC ANALYSIS

Enclosure
c: Service List

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2018 Long-Term Reliability Assessment

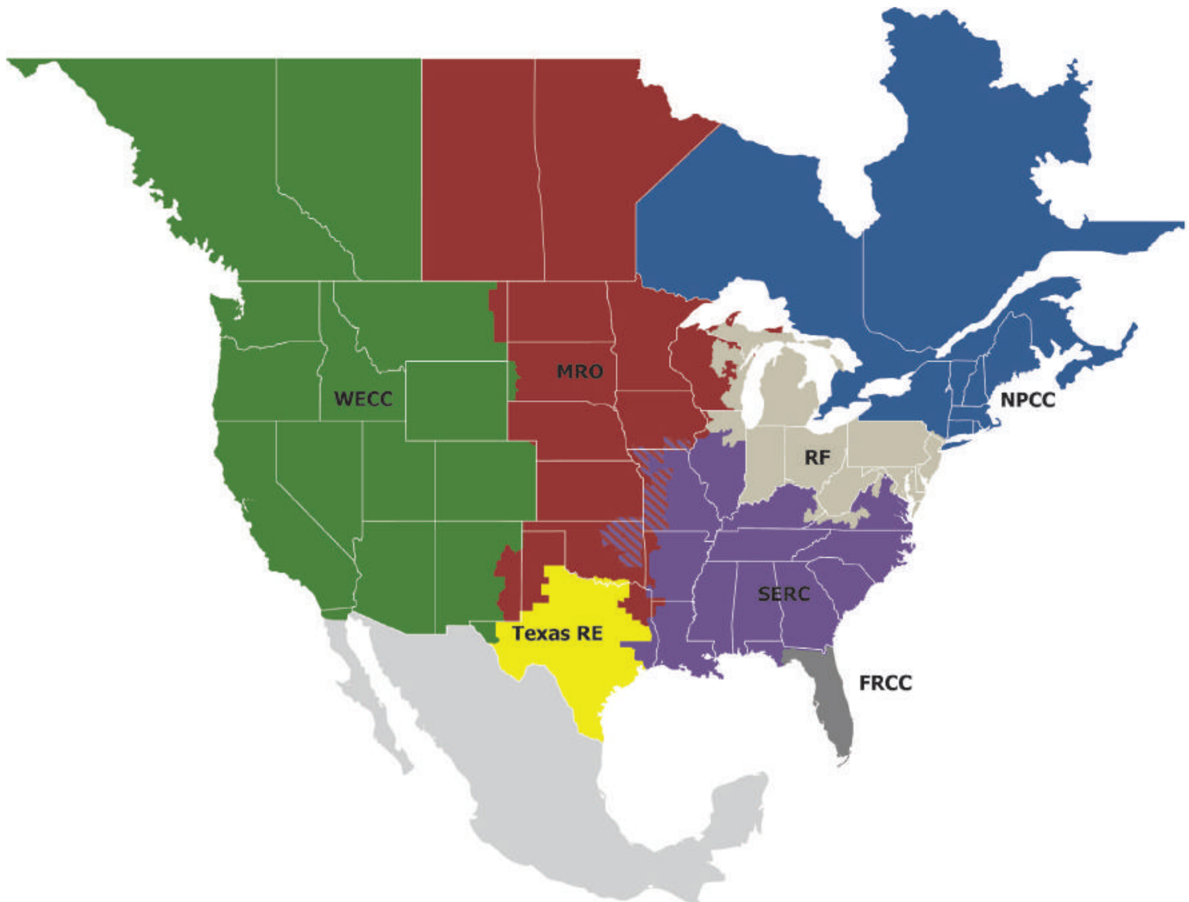
December 2018

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.

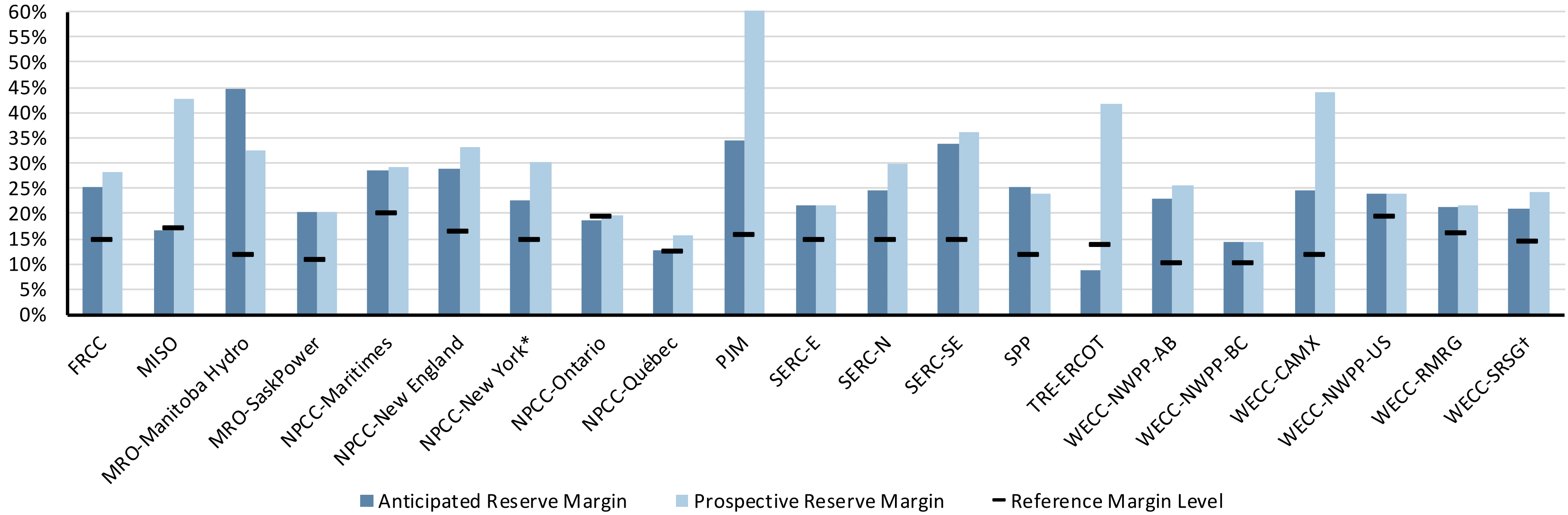


Figure 1.1: Anticipated and Prospective Reserve Margins for 2023 Peak by Assessment Area

[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.

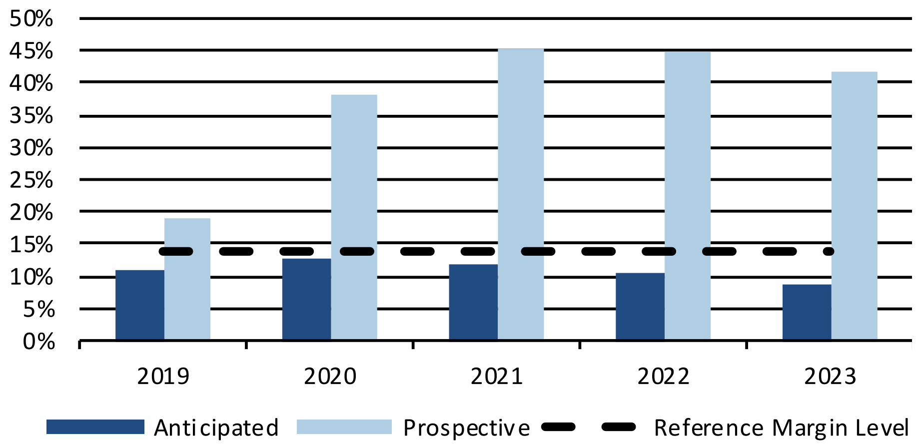


Figure 1.2: TRE-ERCOT 5-year Projected Reserves (Anticipated and Prospective Reserve Margins)

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.

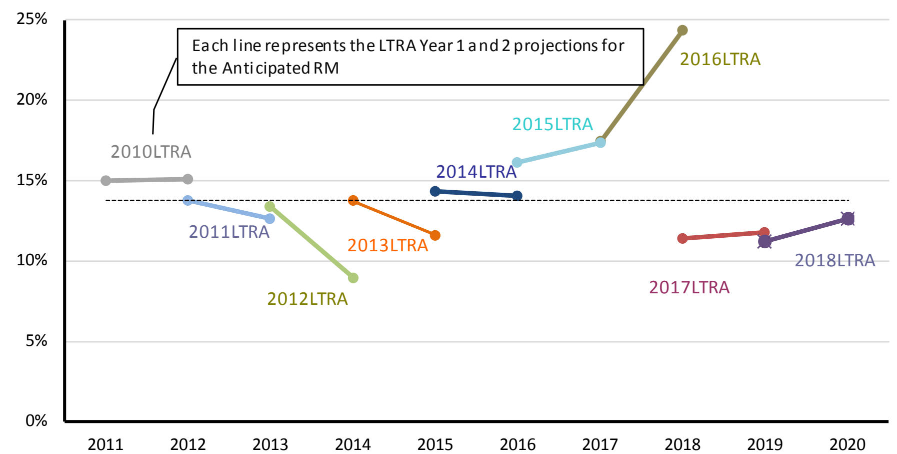


Figure 1.3: TRE-ERCOT Reserve Margin Trends since 2010

[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.

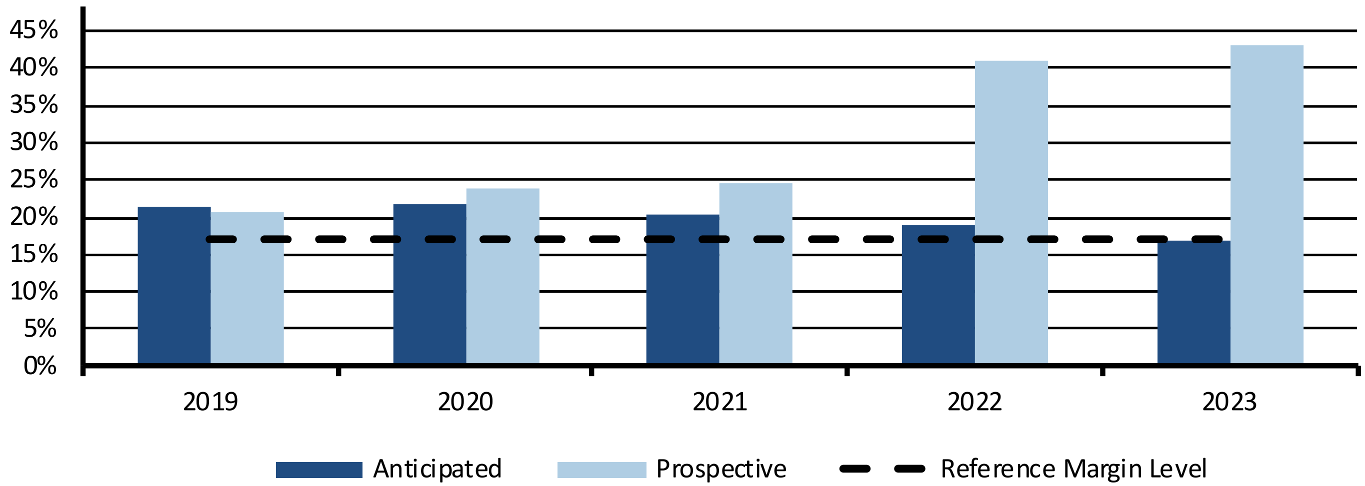


Figure 1.4: MISO 5-year Projected Reserve Margin through 2023 (Anticipated and Prospective Reserve Margins)

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.

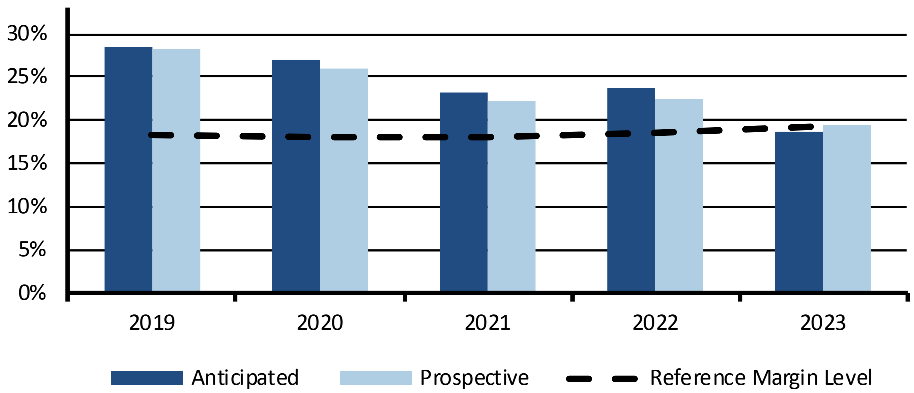


Figure 1.5: Ontario 5-year Projected Reserve Margins through 2023 (Anticipated and Prospective Reserve Margins)

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

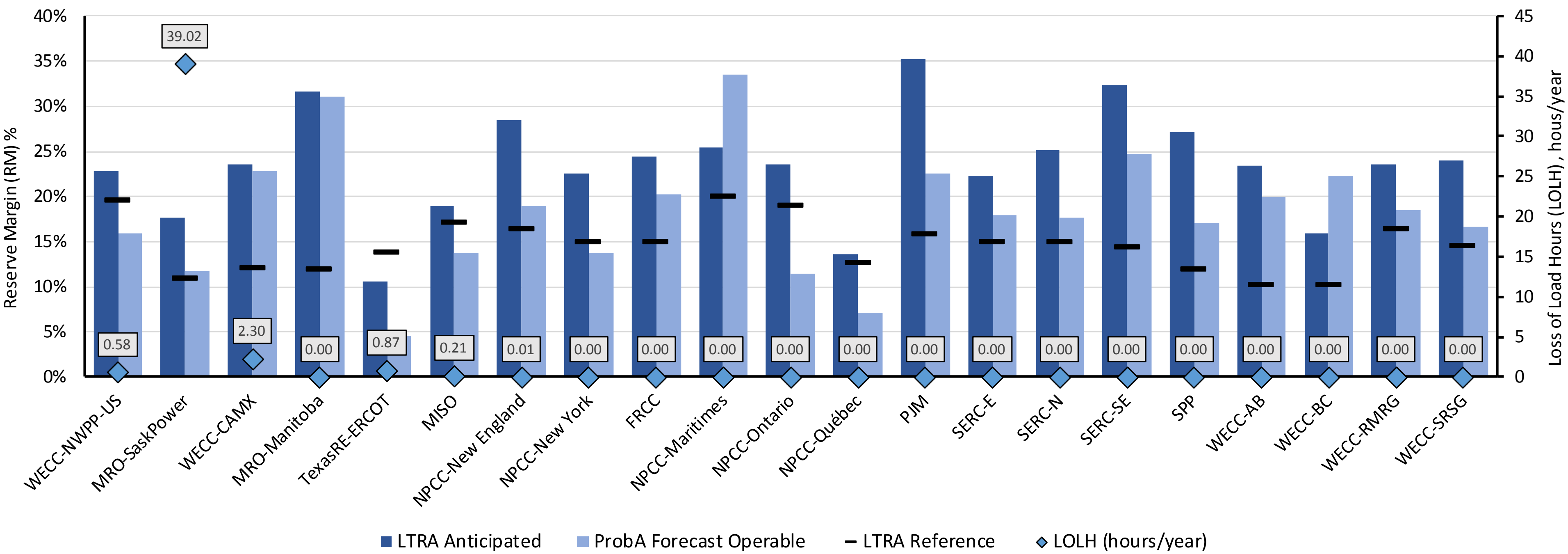


Figure 1.6: 2022 Assessment Area Reserve Margins and Loss of Load Hours (LOLH)

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.

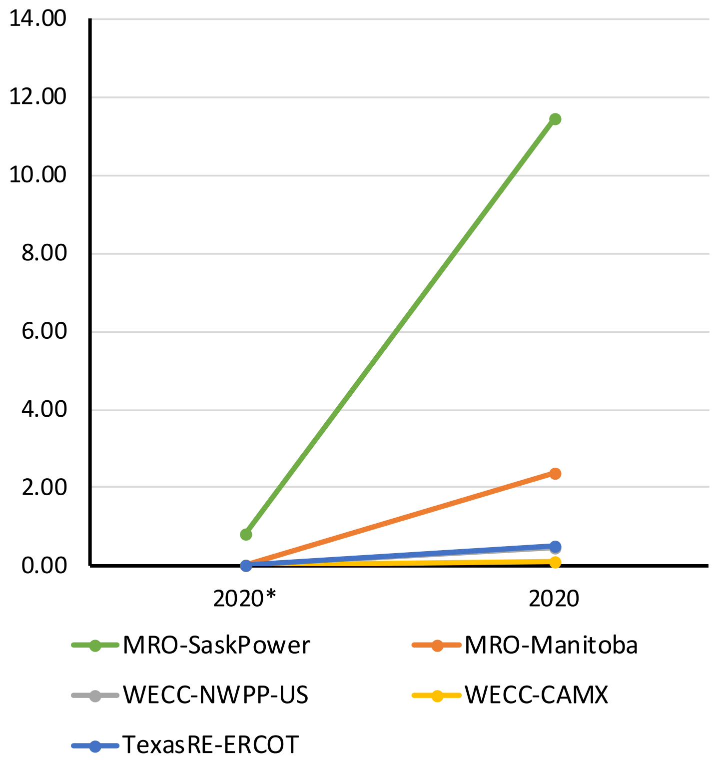


Figure 1.7: Comparison of the 2016 versus the 2018 Probabilistic Analysis, LOLH Notable Trends for the 2020 Study Year

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.

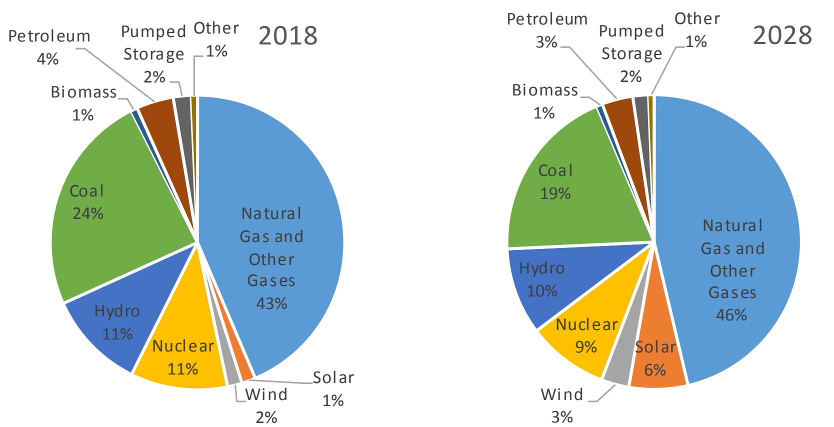


Figure 1.8: 2018 On-Peak Fuel Mix Compared to 2028 On-Peak Fuel Mix

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).

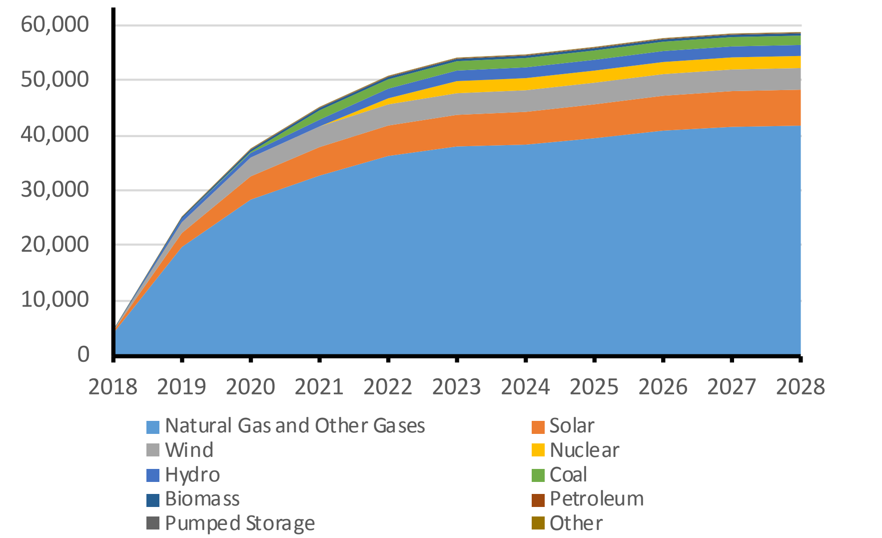


Figure 1.9: Tier 1 Planned Resources Projected Through 2028

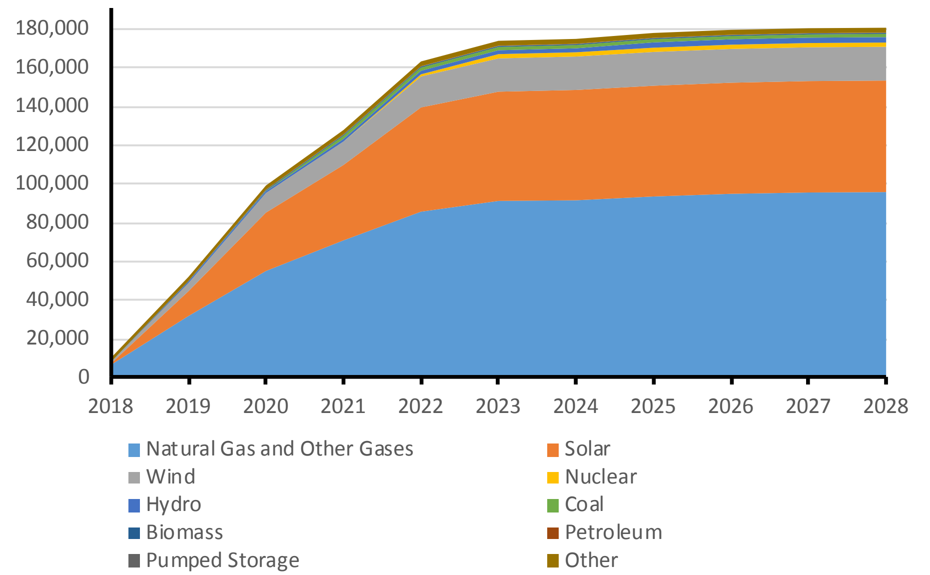


Figure 1.10: Tier 1 and 2 Planned Resources Projected Through 2028

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**.

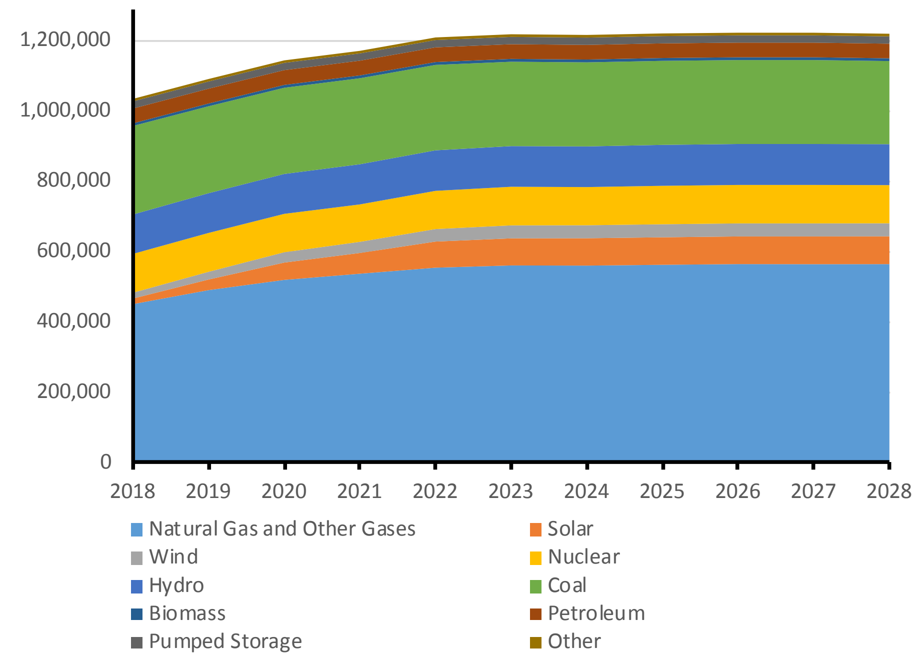


Figure 1.11: Existing, Tier 1, and 2 Planned Resources Projected Through 2028

[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.

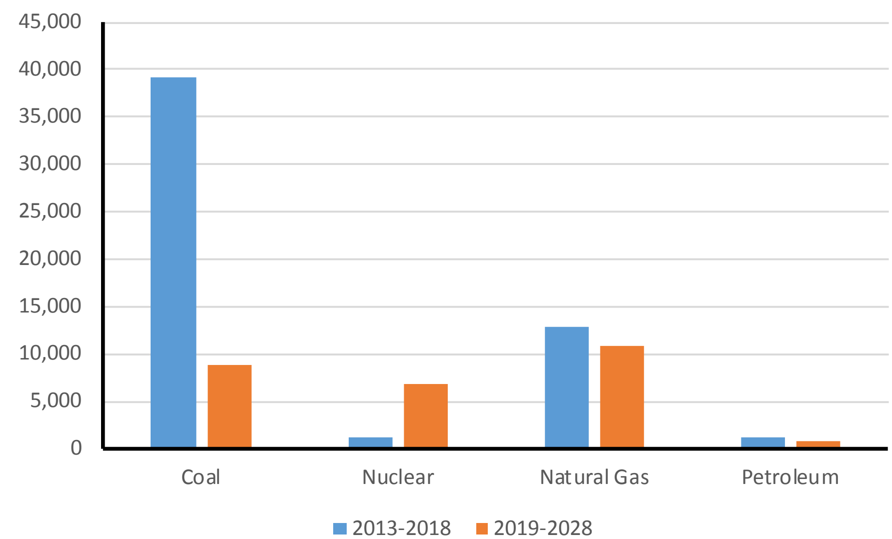


Figure 1.12: Capacity Retirements between 2013 and 2018, and 2019 Projected through 2028

- 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.

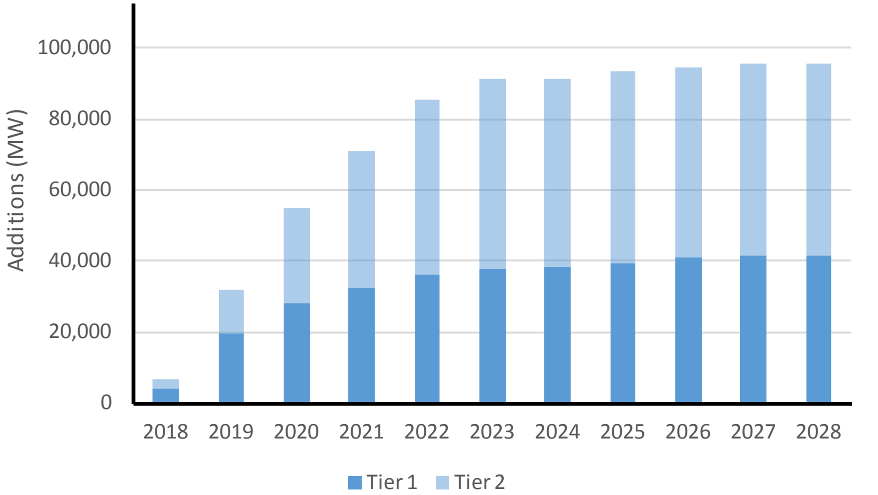


Figure 1.13: Annual Natural Gas Capacity Additions through 2028

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]

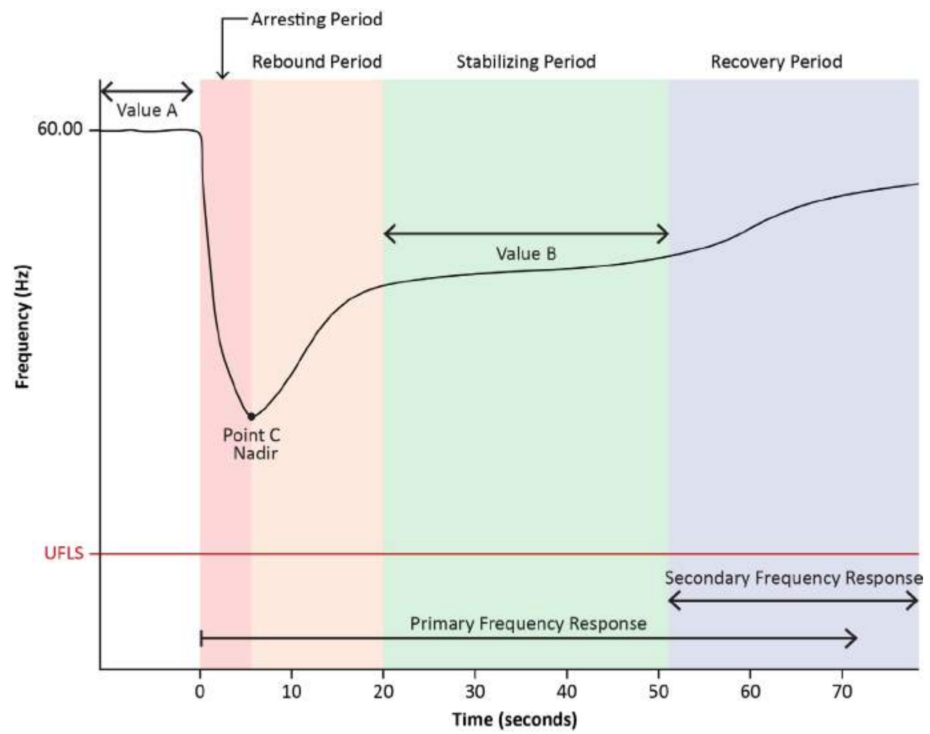


Figure 1.14: Illustrative Example of Inertial and Frequency Response Behavior after a Disturbance

[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]

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

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.

[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.

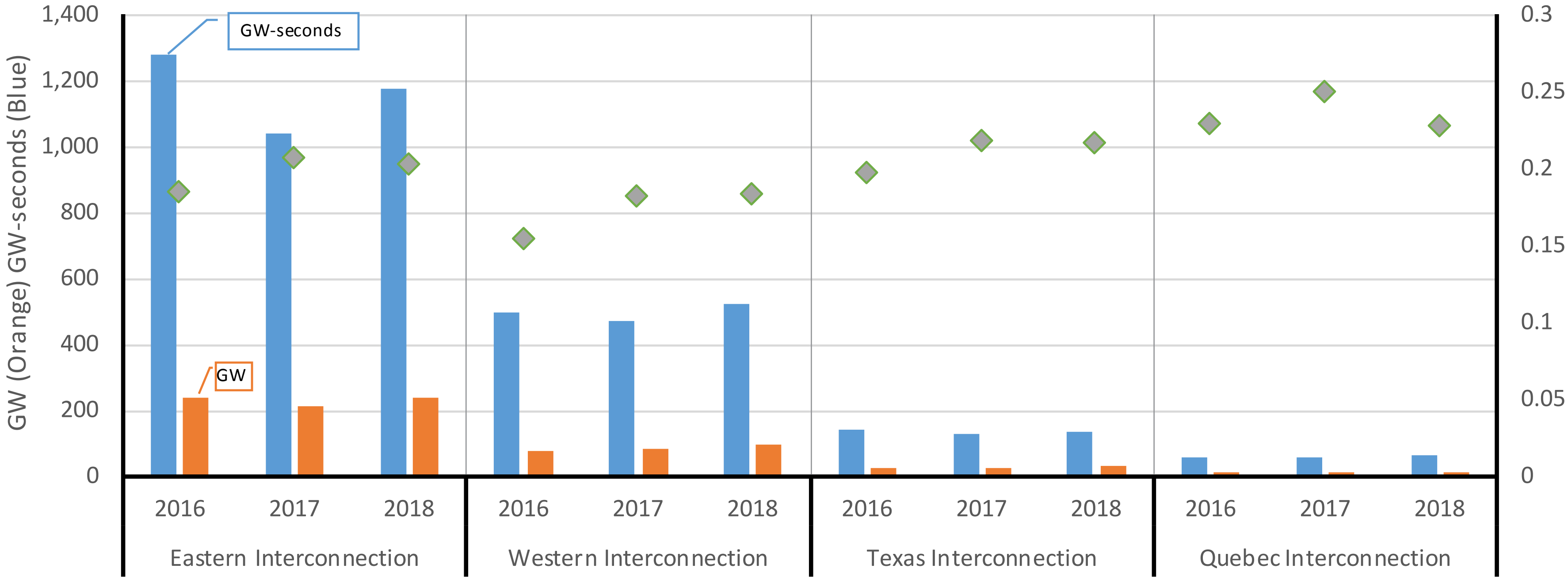


Figure 1.15: Historical Interconnection Minimum Synchronous Inertia (GW-seconds) by Year

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]

[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

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.

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

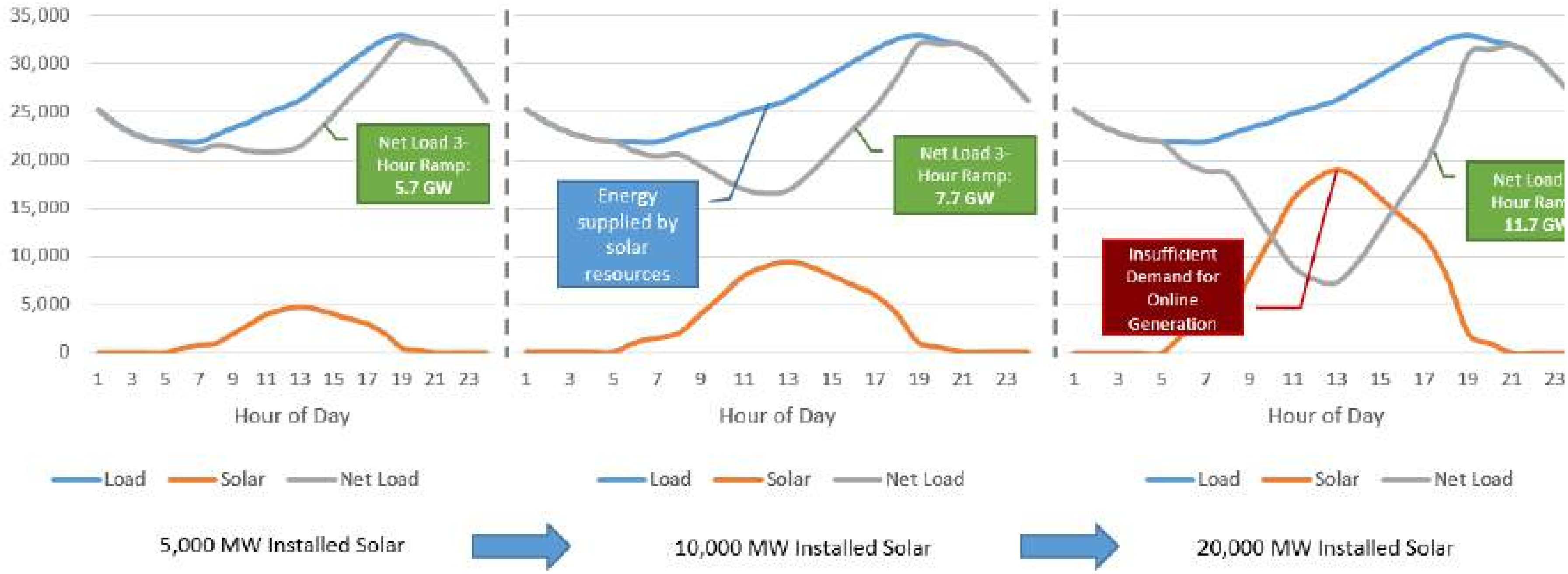


Figure 1.16: Example of Increasing Solar Resources Leading to Increased Ramping Requirements

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

Assessment Area	Nameplate MW of Solar				Nameplate MW of Wind			
	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.

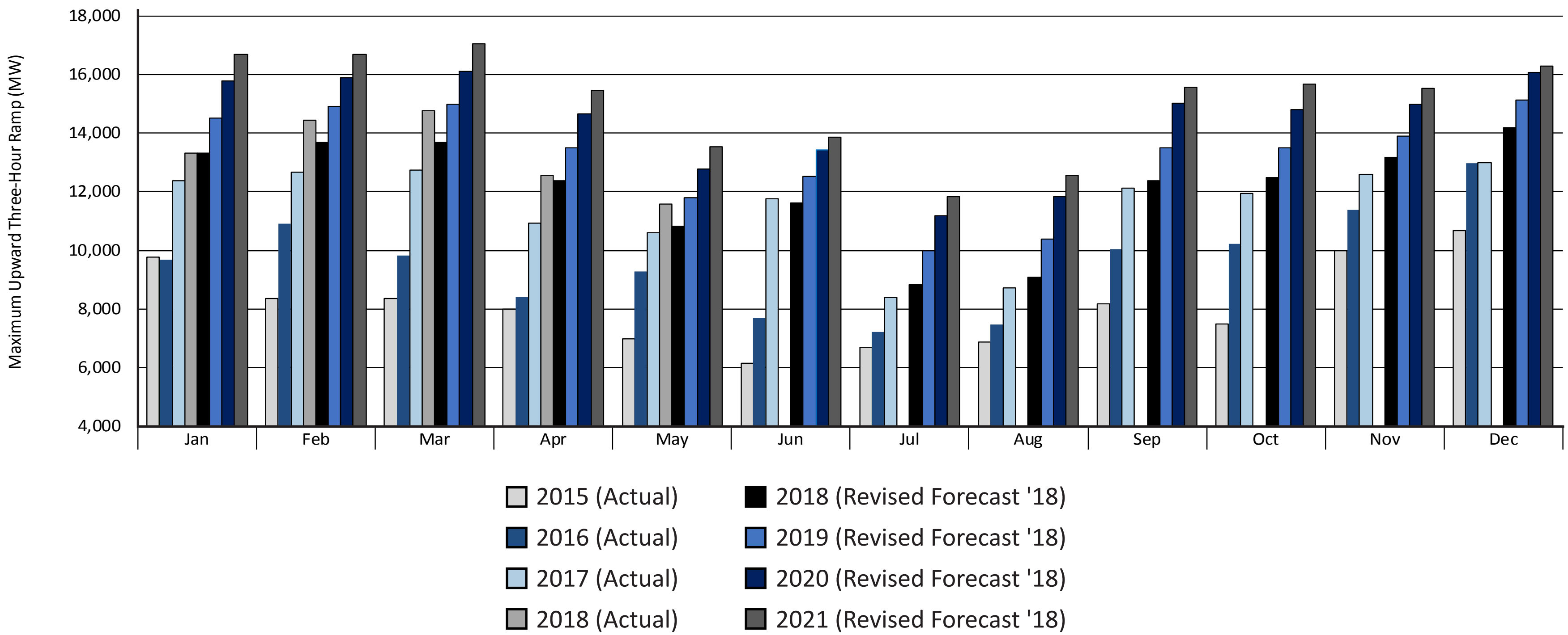


Figure 1.17: Maximum 3-Hour Ramps in CAISO (Actual and Projected) through 2021

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.

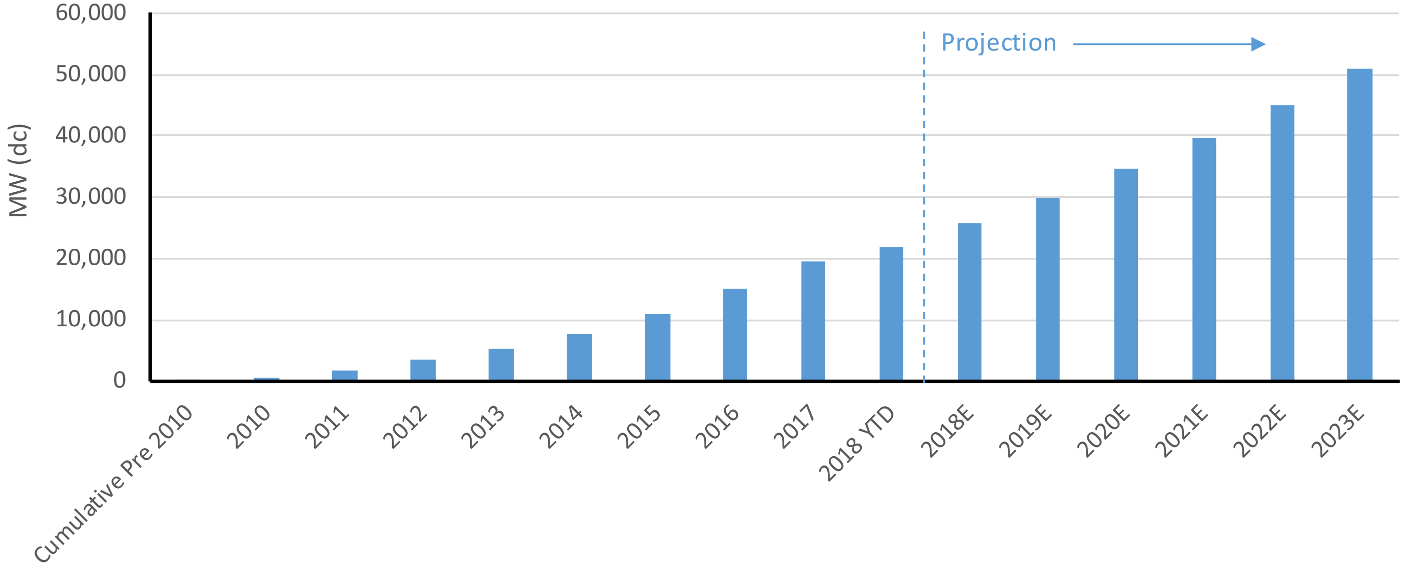


Figure 1.18: United States Cumulative Total Amount of Distributed Solar PV—2010 through 2023

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

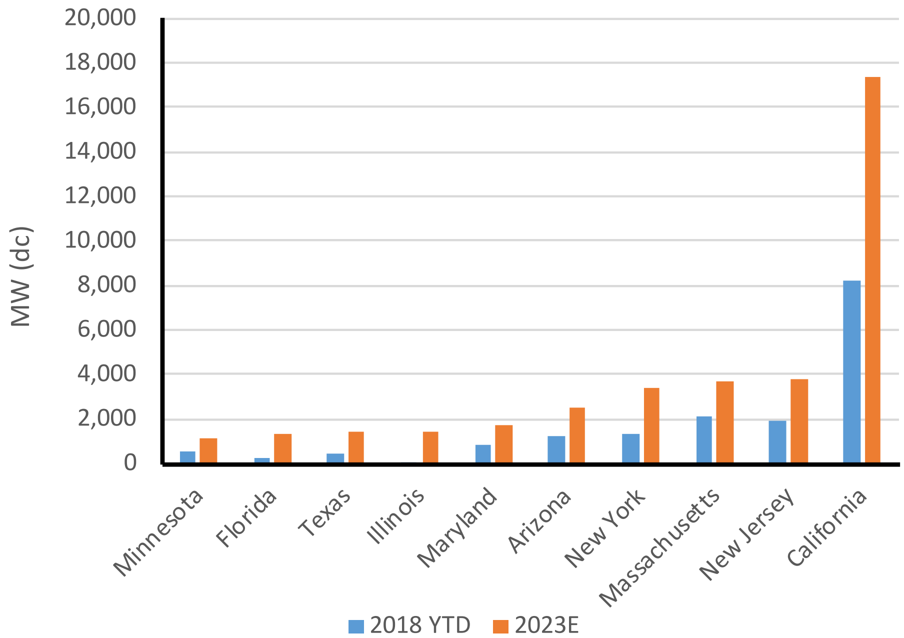


Figure 1.19: Top 10 States with Increasing Amounts of Distributed Solar PV—Total Installed for 2018 and 2023 projection

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 overloading on high-voltage transmission lines). Generally, the uncontrolled operation of dispersed generation (mainly wind and combined-heat-and-power) during the disturbance complicated the process of re-establishing normal system conditions.

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).

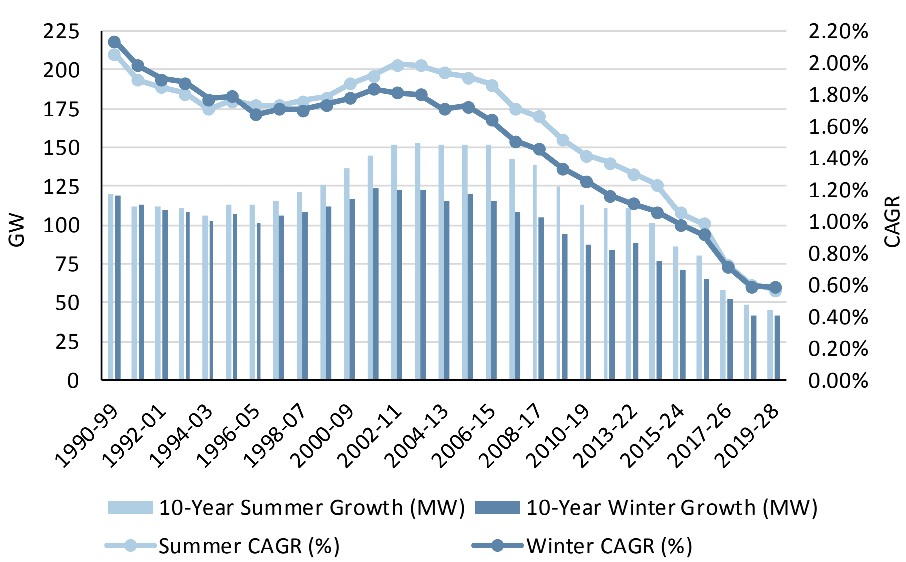


Figure 3.1: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

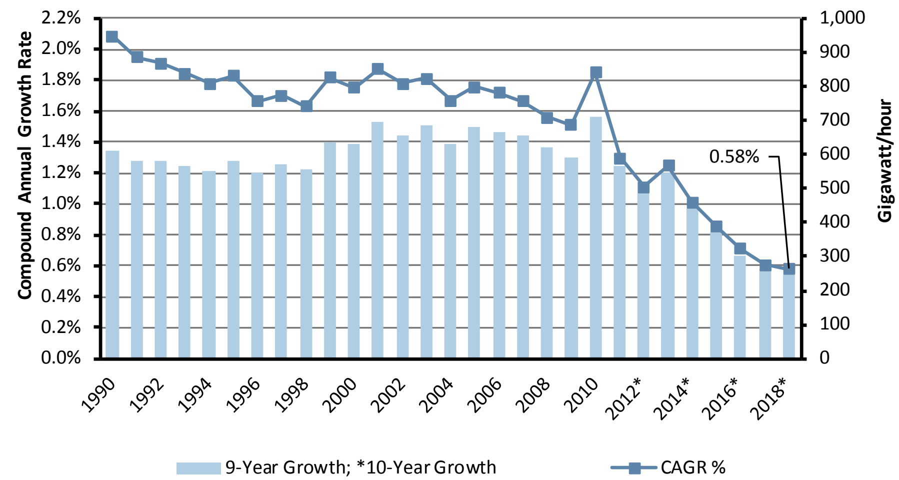


Figure 3.2: 10-Year Net Energy to Load Growth and Rate Projection Trends

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.

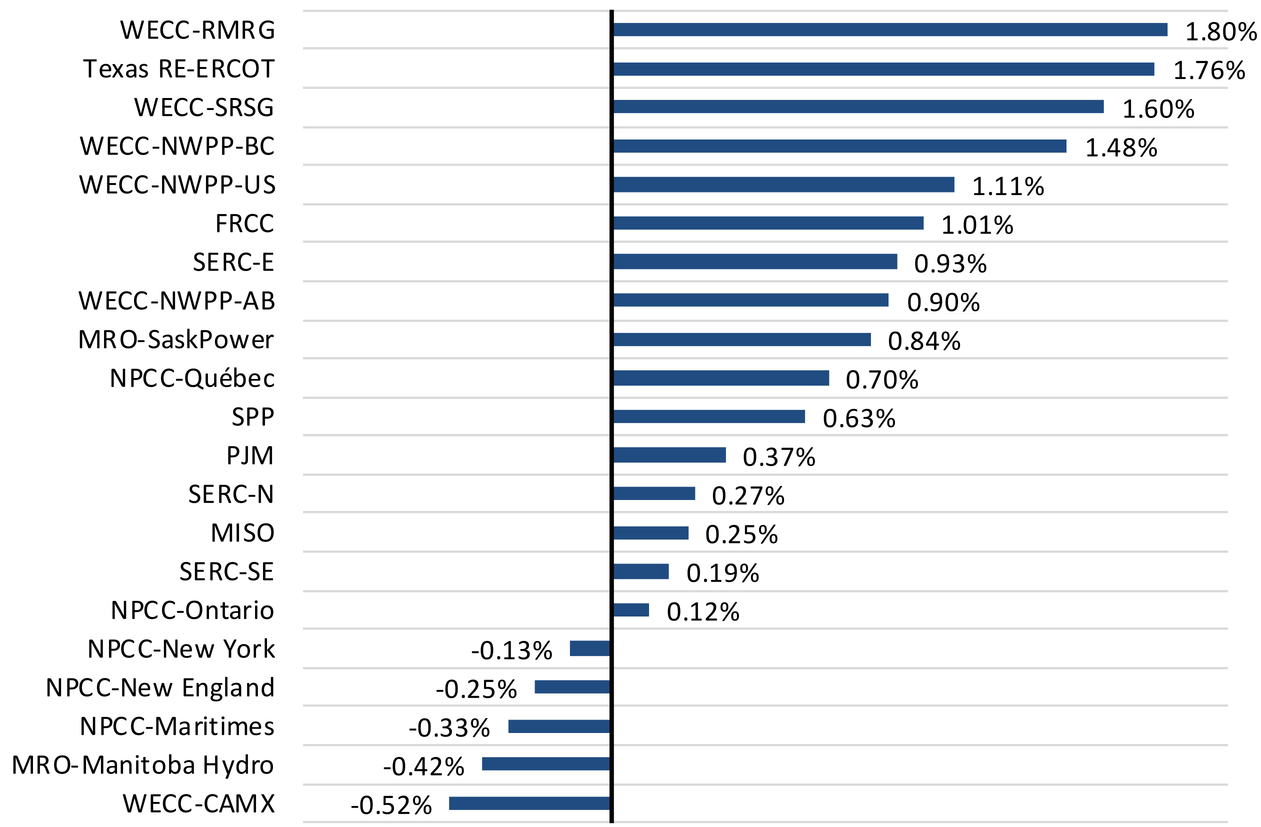


Figure 3.3: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

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.

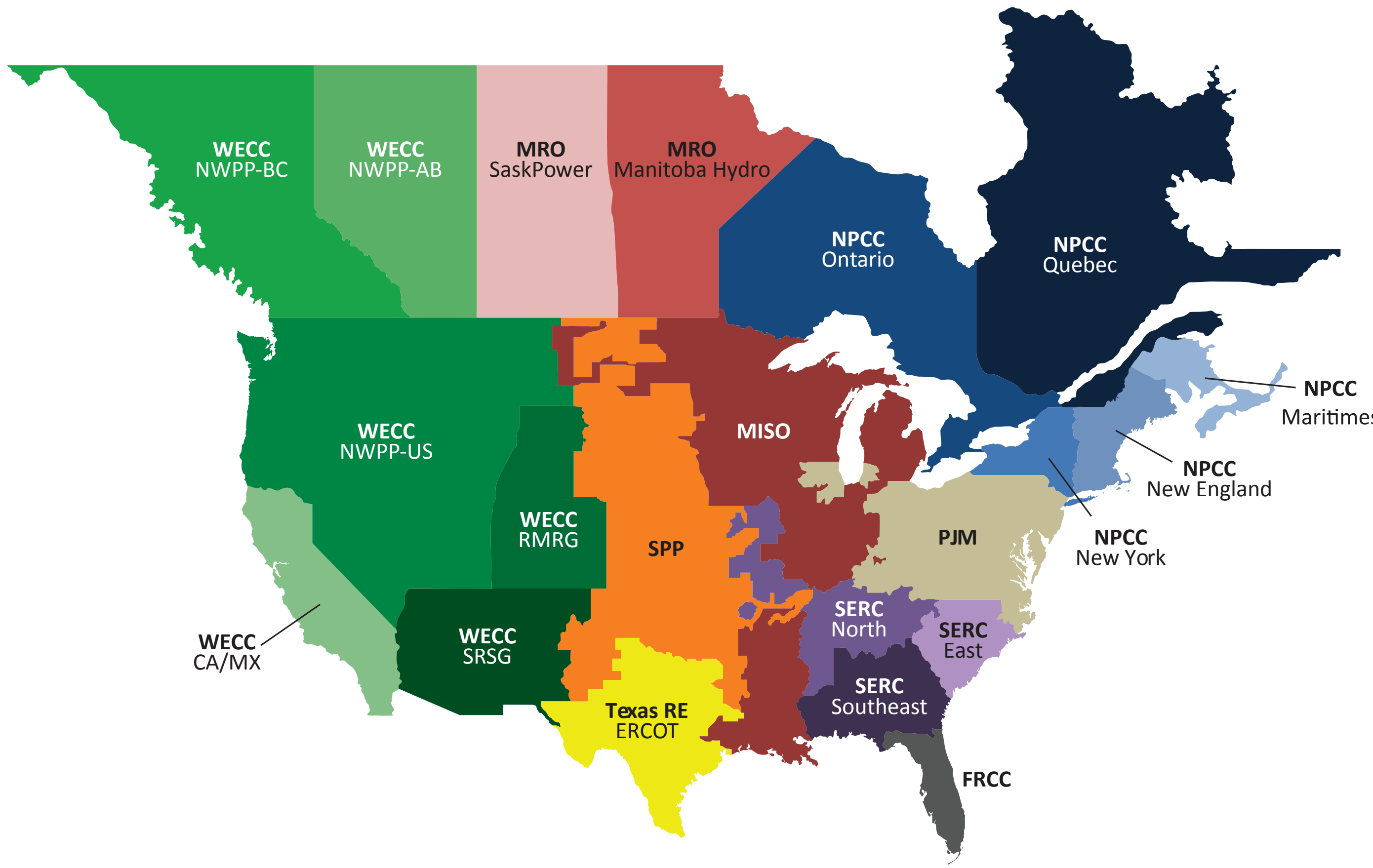
[4] SERC does not provide Reference Margin Levels or resource requirements for its subregions. However, SERC members perform individual assessments to comply with any state requirements.

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

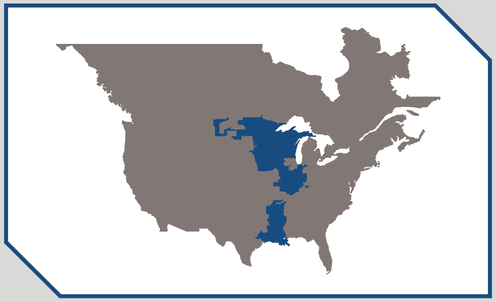
WECC—Western Electricity Coordinating Council
- WECC-BC
- WECC-AB
- WECC-RMRG
- WECC-CA/MX
- WECC-SRSG
- WECC-NWPP-US

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



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.

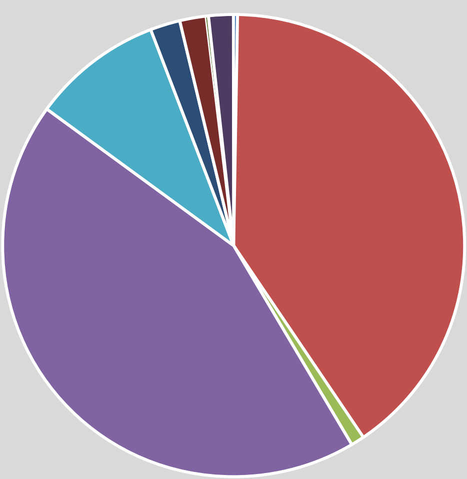
Highlights

- 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.

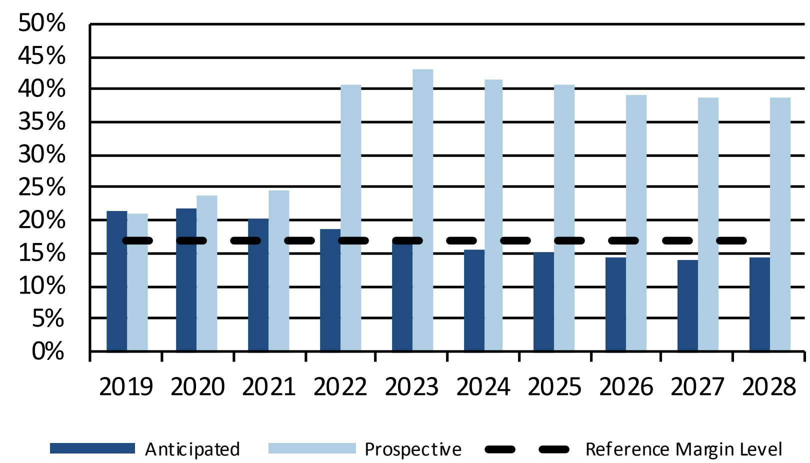
Demand, Resources, and Reserve Margins

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

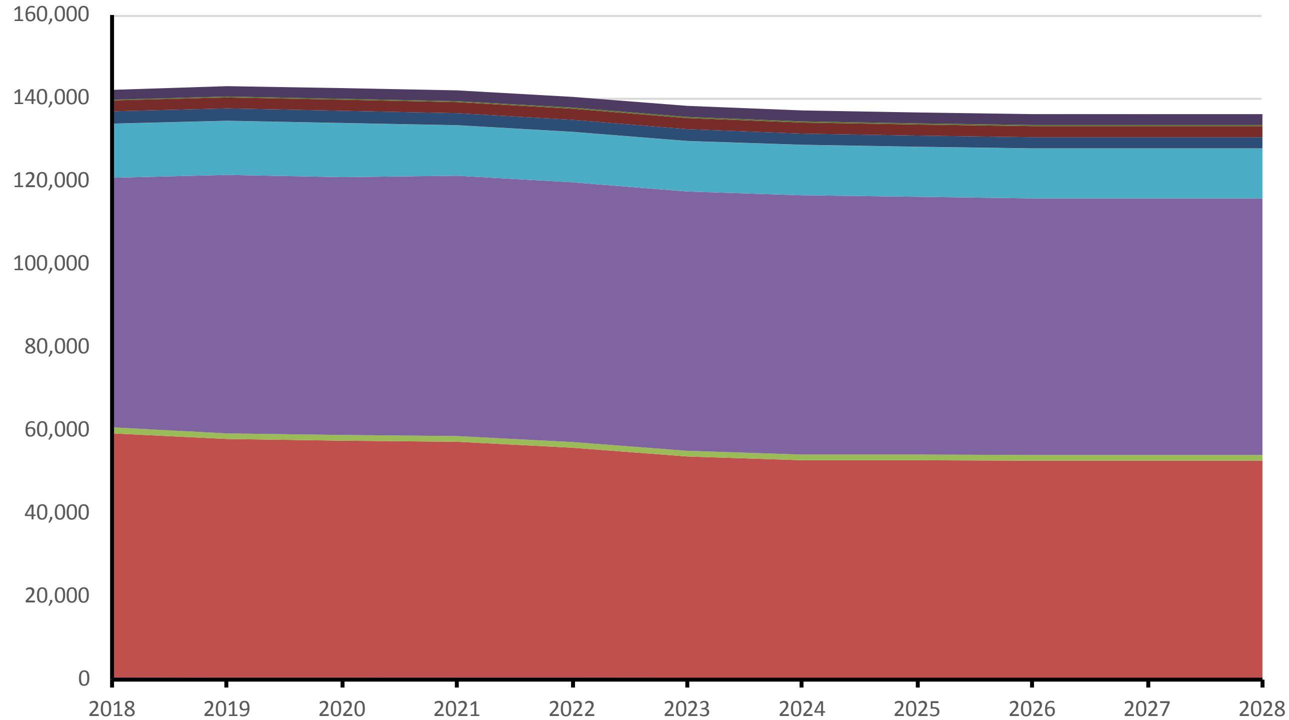
2019 On-Peak Fuel-Mix



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

CERTIFICATE OF SERVICE

I, Paget Pengelly, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E999/M-19-205

Dated this 21st day of November 2019

/s/

____

Paget Pengelly
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_19-205_M-19-205
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services	3724 West Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Electronic Service	No	OFF_SL_19-205_M-19-205
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_19-205_M-19-205
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-205_M-19-205
Stacy	Dahl	sdahl@minnkota.com	Minnkota Power Cooperative, Inc.	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_19-205_M-19-205
Lorene	Damsits	lorened@cmpasgroup.org	Central MN MPA	459 S Grove St Blue Earth, MN 56013	Electronic Service	No	OFF_SL_19-205_M-19-205
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_19-205_M-19-205
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_19-205_M-19-205
Michael	Greiveldinger	MichaelGreiveldinger@alliantenergy.com	Wisconsin Power and Light	4902 North Biltmore Lane Madison, WI 53718	Electronic Service	No	OFF_SL_19-205_M-19-205

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Grover	dgrover@itctransco.com	ITC Midwest	100 South 5th Street Suite 1925 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_19-205_M-19-205
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_19-205_M-19-205
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_19-205_M-19-205
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_19-205_M-19-205
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_19-205_M-19-205
Mike	Malone	mmalone@hcpd.com	Heartland Consumer Power District	P.O. Box 248 Madison, SD 570420248	Electronic Service	No	OFF_SL_19-205_M-19-205
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_19-205_M-19-205

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency	123 2nd St W Thief River Falls, MN 56701	Electronic Service	No	OFF_SL_19-205_M-19-205
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company	215 South Cascade Street Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_19-205_M-19-205
David	Raatz	draatz@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	OFF_SL_19-205_M-19-205
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_19-205_M-19-205
Laura	Sandwick	lm.sandwick@smmpa.org	Southern MN Municipal Power Agency	500 1st Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_19-205_M-19-205
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_19-205_M-19-205
Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_19-205_M-19-205

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
William E.	Schwandt	bschwandt@mpsutility.com	Moorhead Public Service	500 Cedar Ave PO Box 779 Moorhead, MN 565610779	Electronic Service	No	OFF_SL_19-205_M-19-205
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_19-205_M-19-205
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_19-205_M-19-205
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	200 S 6th St Ste 470 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_19-205_M-19-205
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_19-205_M-19-205
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_19-205_M-19-205
Jesse	Tomford	jtomford@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56538-0496	Electronic Service	No	OFF_SL_19-205_M-19-205
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_19-205_M-19-205

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Voelker	mvoelker@eastriver.coop	East River Electric Power Coop., Inc.	211 S Harth Ave Madison, SD 57042	Paper Service	No	OFF_SL_19-205_M-19-205
Jason	Weiers	jweiers@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 56538	Electronic Service	No	OFF_SL_19-205_M-19-205
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	OFF_SL_19-205_M-19-205