NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2016 Long-Term Reliability Assessment

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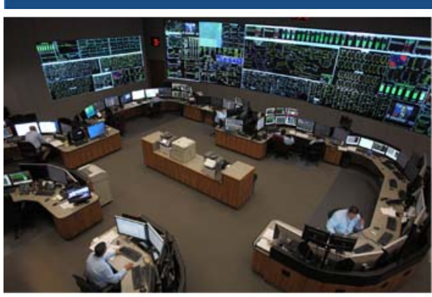
RELIABILITY | ACCOUNTABILITY

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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

NERC Regions and Assessment Areas

FRCC–Florida Reliability Coordinating Council
- FRCC

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

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

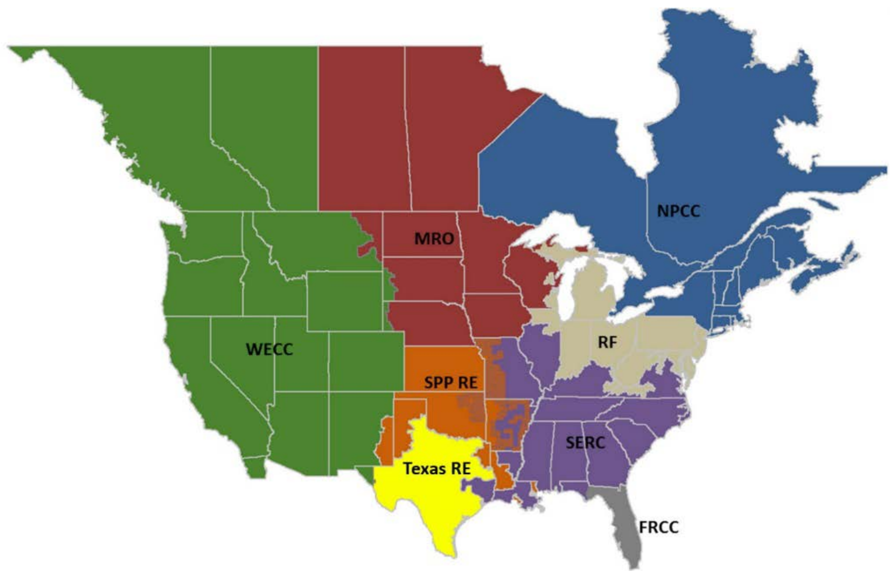
RF–ReliabilityFirst
- PJM

SERC–SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

SPP RE–Southwest Power Pool Regional Entity
- SPP

Texas RE–Texas Reliability Entity
- Texas RE-ERCOT

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



Introduction

NERC prepares seasonal and long-term assessments to examine current and future adequacy and operational reliability of the North American BPS. For these assessments, the BPS is divided into 21 assessment areas[1] both within and across the eight Regional Entity boundaries as shown in the corresponding table and maps in the preface.[2] The preparation of these assessments involves NERC's collection and consolidation of data from the Regional Entities. Reference Case data 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, emerging issues, and potential concerns (see Chapter 6). 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.

NERC's primary objective with the *LTRA* is to assess resource and transmission adequacy across the NERC footprint, and to assess emerging issues that have an impact on BPS reliability over the next ten years. NERC assesses this reliability by comparing projected reserve margins to Reference Margin Levels established by the assessment area or to a default Reference Margin Level. Reserve margins are typically developed using probabilistic methods that calculate the loss of load expectation (LOLE) that could occur less than or equal to one time in ten years based on daily peak information. Whereas these analyses typically evaluate resource adequacy in order to meet a peak day requirement. NERC recognizes that a changing resource mix with a significant portion of it being energy-limited, changes in off-peak demand, single points of disruption, and other factors can have an effect on resource adequacy. As a result, NERC is incorporating more probabilistic approaches into this assessment and other ongoing analyses that provide further insights into how to best establish adequate reserve margins amidst a BPS undergoing unprecedented changes.

Additional issues that may potentially impact the reliability of the BPS, such as physical and cybersecurity, are not specifically reviewed by this assessment. These issues present constant and evolving challenges. NERC continues to lead a multi-faceted approach to enhancing cybersecurity, through mandatory standards, improved information-sharing through the Electricity-Information Sharing and Analysis Center (E-ISAC),[3] and exercises to increase learning about threats and vulnerabilities.

NERC has prepared the following assessment in accordance with the Energy Policy Act of 2005 in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the BPS in North America.[4] This assessment is based on data and information collected by NERC from the Regions on an assessment area basis as of September 2016. The Reliability Assessment Subcommittee (RAS), at the direction of the Planning Committee (PC), supports the LTRA's development. Specifically, NERC and the RAS perform a thorough peer review that leverages the knowledge and experience of industry subject matter experts while providing a balance to ensure the validity of data and information provided by the Regions. Each assessment area section is peer reviewed by members from other Regions to achieve a comprehensive review that is verified by the RAS in open meetings. The review process ensures the accuracy and completeness of the data and information provided by each Region. This assessment has been reviewed and accepted by the PC. The NERC Board of Trustees also reviewed and approved this report.

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[1] The number of assessment areas has remained the same since the release of the *2015 LTRA*. The previous MRO-MAPP footprint now resides in the SPP, MISO, and WECC-NWPP-US assessment areas. The previous WECC-CA has split into the WECC-BC and WECC-Alberta.

[2] Maps created using ABB Velocity Suite.

[3] NERC Electricity ISAC

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

Executive Summary

The *2016 Long-Term Reliability Assessment* (*2016 LTRA*) provides a wide-area perspective of the generation, demand-side resources, and transmission system adequacy needed during the next decade. This assessment includes NERC's independent technical analysis to identify issues that may impact North American bulk power system (BPS) reliability, and this enables industry, regulators, and policy makers to develop mitigation plans or strategies to address them. NERC collected projections from system planners in each assessment area, assessed the data independently, and then identified emerging issues. These reliability issues require consideration to reduce BPS reliability risks and are summarized here in six focus areas:

- **Resource Adequacy:** Factors that are included when performing a resource adequacy assessment include a reserve margin analysis and the study of emerging reliability issues that can impact generation and demand projections. The results of this study identified four assessment areas as having a medium resource adequacy risk in the first five years of the assessment period:
  - **MISO:** The Anticipated Reserve Margin falls to 13.8 percent, below MISO's Reference Margin Level of 15.2 percent, in 2022. Due to the uncertain outcome of pending regulatory requirements in MISO's footprint, 3.3 GW of capacity are categorized as unconfirmed retirements. When applying these additional potential retirements, MISO's Anticipated Reserve Margin decreases to 14.9 percent in 2018, which is below the Reference Margin Level of 15.2 percent.
  - **NPCC-New England:** Reserve margins in NPCC-New England are projected above the Reference margin level for all years of the assessment. However, an increased reliance on natural gas, coupled with limited gas storage capability and dual-fuel switching challenges, indicate a medium resource adequacy risk, particularly during the winter peak season.
  - **Texas RE-ERCOT:** Anticipated Reserve Margins are projected to be sufficient for all ten years of the assessment period. Due to the uncertain outcome of pending regulatory requirements, approximately 7 GW of capacity are categorized as unconfirmed retirements. With considerations for unconfirmed retirements and assuming no potential replacement capacity, Texas RE-ERCOT's Anticipated Reserve Margin decreases to 11.3 percent by 2021, which is below the Reference Margin Level of 13.75 percent.
  - **WECC-CAMX:** Anticipated Reserve Margins are projected to be sufficient for all ten years of the assessment period. However, an increased reliance on natural gas, limited dual-fuel capability, and natural gas storage facility outages indicate a medium resource adequacy risk. Additional challenges are posed in maintaining adequate essential reliability services (ERSs), such as maintaining ramping capability.
- **Single-Fuel Dependency:** NERC has identified that reliance on a single fuel increases vulnerabilities, particularly during extreme weather conditions. Over the past decade, several areas have significantly increased their dependence on natural gas. This trend has continued amidst historically low natural gas prices and regulatory rulings that continue to promote increased natural gas generation. NERC's assessment identifies four assessment areas with high penetration of natural gas generation:
  - **Texas RE-ERCOT:** Natural-gas-fired generation comprises 63 percent of on-peak anticipated capacity by 2021. Gas-fired generators in ERCOT have some dual-fuel capability (14 percent). However, pipeline infrastructure in Texas is tightly meshed, and natural gas generators often have multiple connections and access to natural gas.
  - **FRCC:** Natural-gas-fired generation will comprise 69 percent of on-peak anticipated capacity by 2021. Natural gas is not widely used for residential heating; therefore, the pipeline system has largely been built to support its gas-fired generation customers. Gas-fired generation in Florida is largely fueled with firm transportation services that is approved by the public utility commission to ensure a reliable

source of fuel. Additionally, a majority of gas-fired generation is dual-fuel capable, and limited inventory is kept on-site for use in emergencies.

- **NPCC-New England:** Natural-gas-fired generation will comprise 52 percent of on-peak anticipated capacity by 2021. The risk in New England is increasing due to the limited addition of new interstate pipeline capacity and the fact that natural gas storage does not appear to keep pace with natural gas generation additions. Additionally, recent winter experiences have created challenges in both maintaining back-up fuel inventories and successfully switching from gas to oil. However, emerging market rules in ISO-NE, beginning in 2018, are expected to support reliability and the resilience of the generation fleet.
- **WECC-CAMX:** Natural-gas-fired generation comprises 68 percent of on-peak anticipated capacity by 2021. Minimal dual-fuel capable units and immediate resource constraints from the outage at the Aliso Canyon underground natural gas storage facility increase the risks associated with single-fuel dependency.

- **Nuclear Uncertainty:** Low natural gas prices continue to affect the competitiveness of nuclear generation and are a key contributing factor to nuclear generation's difficulty in remaining economic with competing fuel sources. While new nuclear facilities are being built in Georgia, Tennessee, and South Carolina, potential retirements have been announced for nuclear facilities in Illinois, California, Nebraska, Massachusetts, and New York, creating longer-term uncertainty for system operators and planners. While replacement capacity may be advanced to mitigate resource adequacy concerns, unconfirmed nuclear retirements create uncertainty around local transmission adequacy and the ability to plan for future resource and demand needs due to their large baseload contribution.
- **Probabilistic Analysis**: The changing resource mix introduces additional complexities to assessing resource adequacy and diminishes the value of a single deterministic planning metric (e.g., reserve margins). NERC's probabilistic assessment (see Chapter 2) provides key indices that, together, assess resource adequacy risks for all hours of the study year.
- **Essential Reliability Services:** The addition of a large number of variable energy resources (VERs) onto the BPS has resulted in the need for operational flexibility to accommodate demand while also effectively managing the resource portfolio. As VERs are becoming more significant, NERC is developing sufficiency guidelines in order to establish requisite levels of ERSs. ERSs are comprised of primary frequency response (PFR), voltage support, and ramping capability, all needed for the continued reliable operation of the BPS. Significant ramping capabilities are needed to address the challenges presented from VER operational impacts. Ramping issues requiring increased operational flexibility have been most notable in California, where they occurred four years earlier than originally projected. Texas RE-ERCOT is also beginning to project potential ramping issues, but current real-time market design, operating practices, and the flexibility of existing generation provide ERCOT with sufficient capability to manage ramping requirements.
- **Distributed Energy Resources:** Increasing installations of distributed energy resources (DERs) modify how distribution and transmission systems interact with each other. Many utilities currently lack sufficient visibility and operational control of these resources, increasing the risk to BPS reliability. This visibility is a crucial aspect of power system planning, forecasting, and modeling that requires adequate data and information exchanges across the transmission and distribution interface. The most significant growth in DER penetration is occurring in NPCC and WECC. NERC's Distributed Energy Resources Task Force will release their initial their report in Q1 of 2017. This report will review current impact to reliability and considerations for resource and transmission planning.

Recommendations

NERC has developed the following recommendations through its stakeholder process to alleviate the potential impacts of the reliability issues identified in this assessment:

- Regulators and legislators should evaluate the changes occurring on the BPS irrespective of the final rulings on pending regulation, such as the Clean Power Plan (CPP). While there is uncertainty around the ultimate validity and timing of the CPP, NERC has determined that many of the changes are occurring regardless of the final ruling. As the resource mix continues to change, the need for more investments in transmission and natural gas infrastructure is currently projected. The lengthy schedule involved in acquiring, siting, and permitting adequate properties for this infrastructure should also be considered when assessing reliability impacts. Policy makers should closely monitor and evaluate the measures being taken to address the evolving resource adequacy trends in MISO and Texas RE-ERCOT.

- As natural-gas-fired resources continue to increase, system planners and operators should evaluate the potential effects of an increased reliance on natural gas on BPS reliability. Natural gas provides "just-in time" fuel; therefore, firm transportation and maintaining dual-fuel capability can significantly reduce the risk of common-mode failure and wider-spread reliability challenges. 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 affect electric reliability.

- Regulators and legislators should consider the uncertainties in resource retirements and resource mix changes projected by resource planners and the interconnection-wide impacts, including generation retirements, curtailments, and transmission constraints that can manifest if ERSs are not maintained. The implementation of a regulatory framework to provide an adequate level of ERSs could help to address these uncertainties. Planning Coordinators and Transmission Planners should consider supplementing planning processes with additional measures that support maintaining sufficient ERSs. In 2017, NERC will draft sufficiency guidelines for ERSs to support planning evaluations and assessments of how the resource mix can impact BPS reliability; NERC recommends incorporating sufficiency measures within planning processes.

Chapter 1: Reliability Issues

This section highlights several issues that are emerging and have the potential to increase risks to reliability. The *2016 LTRA* identifies these issues to include: resource adequacy, single-fuel dependency, nuclear uncertainty, essential reliability services (ERSs), and distributed energy resources (DERs).

Reserve Margins

General Assumptions: The reserve margin calculation is an important industry planning metric used to examine future resource adequacy. This deterministic approach examines the forecast peak demand (load) and projected availability of resources to serve the forecast peak demand for the summer and winter of the 10-year outlook (2017–26).

Demand Assumptions: Electricity demand projections, or load forecasts, are provided by each assessment area. Load forecasts include peak hourly load, or total internal demand, for the summer and winter of each year. Total internal demand projections are based on normal weather (50/50 distribution) and are provided on a coincident basis for most assessment areas. Net internal demand equals the total internal demand minus the controllable & dispatchable demand response (DR) considered available across the peak.

Resource Assumptions: NERC collects projections for the amount of existing and planned capacity as well as net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:

Anticipated Resources

- **Existing-Certain generating capacity:** includes operable capacity expected to be available to serve load during the peak hour with firm transmission.
- **Tier 1 capacity additions:** includes capacity that has completed construction, is under construction, has a signed or approved ISA/PPA/CSA/WMPA, is included in an integrated resource plan, or is under a regulatory environment that mandates a resource adequacy requirement.
- **Firm Capacity Transfers (Imports minus Exports):** transfers with firm contracts

Prospective Resources**:** Includes all anticipated resources, plus:

- **Existing-Other capacity:** includes operable capacity that could be available to serve load during the peak hour, but lacks firm transmission and could be unavailable for a number of reasons.
- **Tier 2 capacity additions:** includes capacity that has been requested but that has not received approval for planning requirements.
- **Expected (non-firm) Capacity Transfers (Imports minus Exports): t**ransfers without firm contracts, but a high probability of future implementation.

Reserve Margins**:** the primary metric used to measure resource adequacy. It is defined as the difference in resources (anticipated, or prospective) and net internal demand divided by net internal demand, shown as a percent.

$$\textbf{Anticipated Reserve Margin} = \frac{\text{(Anticipated Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

$$\textbf{Prospective Reserve Margin} = \frac{\text{(Prospective Resources – Net Internal Demand)}}{\text{Net Internal Demand}}$$

Reference Margin Level**:** The assumptions of this metric vary by assessment area. Generally, the Reference Margin Level is based on load, generation, and transmission characteristics for each assessment area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISOs/RTOs, or other regulatory bodies. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If one is not provided by a given assessment area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.

Resource Adequacy

The Anticipated Reserve Margin is the primary metric that is used to evaluate the adequacy of projected resources to serve forecasted peak load. Figure 1.1 provides an examination of the Anticipated Reserve Margin and how to interpret the results of the analysis. Having a shortfall of reserves indicates that an assessment area would fall below their target Reference Margin Level, and increases the risk to reliability by increasing the likelihood of a potential loss of load.

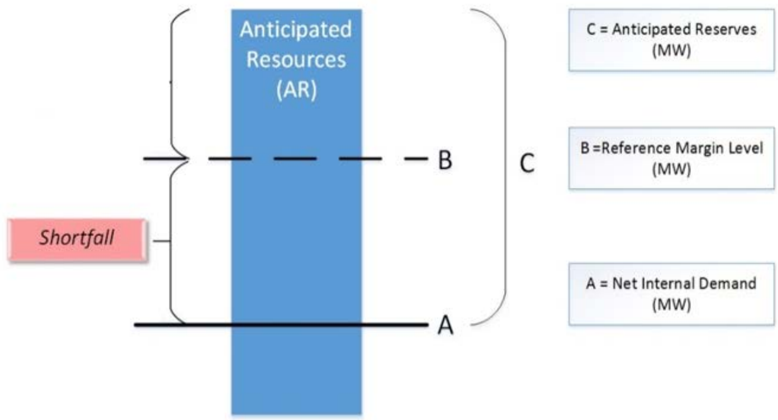


Figure 1.1: Examination of Anticipated Reserve Margin

Based on the data and information provided to NERC, all assessment areas Anticipated Reserve Margins that meet or exceed their Reference Margin Levels. While three areas fall below their respective Reference Margin Levels in the 6- to 10-year time frame, there are measures that can be taken to address potential shortfalls. Examples include advancing designated planned resources within the generation queue, securing neighboring capacity through transmission expansions, and firm transmission contracts. Generally, shortfalls identified in the latter years of the assessment period pose a less significant risk to resource adequacy due to more time and available mitigation options. Alternatively, an assessment area with additional planning reserves may not maintain the requisite level of ERSs, thereby introducing complexity into an assessment of resources to consider other measures of sufficiency in addition to reserve margins.[5]

Figure 1.2 and Figure 1.3 show the five- and ten-year planning reserve margins respectively. All assessment areas meet or exceed their Anticipated Reserve Margins through the first five years of the assessment while three assessment areas Anticipated Reserve Margins do fall under their designated Reference Margin Level by year ten.

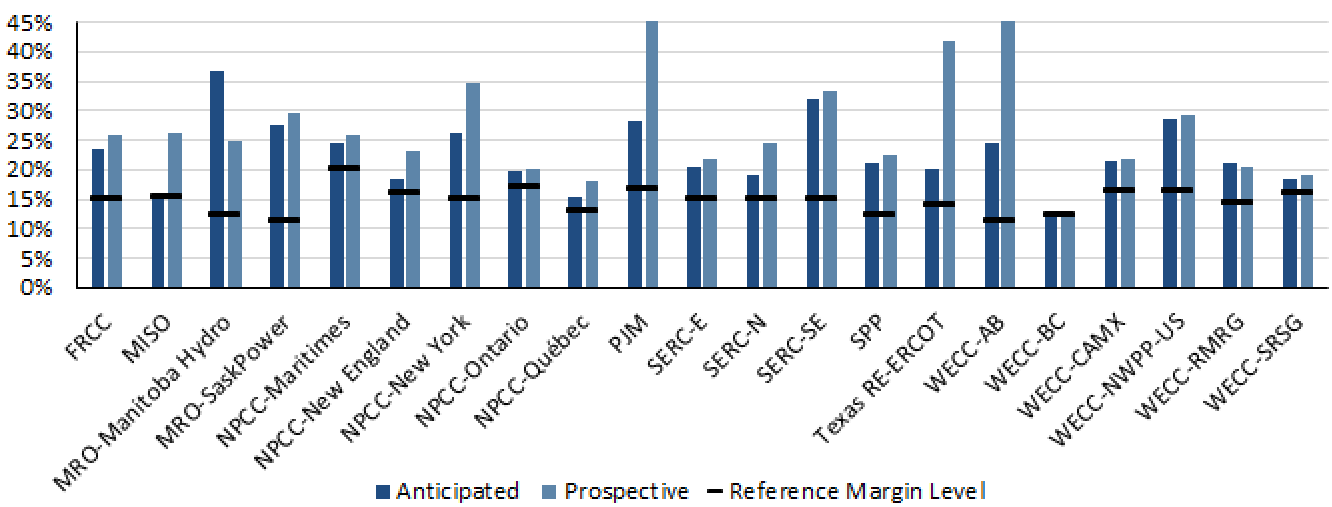


Figure 1.2: Planning Reserve Margins for Year 5 (2021)

[5] Requisite levels of ERSs will be determined by the Sufficiency Guidelines currently under development with the NERC Essential Reliability Services Working Group

MISO is currently projected to fall below their target of 15.20 percent to an Anticipated Reserve Margin of 13.89 percent in 2022 and continue to decrease to 9.07 percent by the year 2026. NPCC-Québec is currently projected to fall below their target of 12.70 percent to 12.28 percent in 2025 followed by a decrease to 11.59 percent by 2026. WECC-BC is currently projected to fall below their target of 12.10 percent to 11.60 percent in 2025 followed by a decrease to 9.79 percent by 2026.

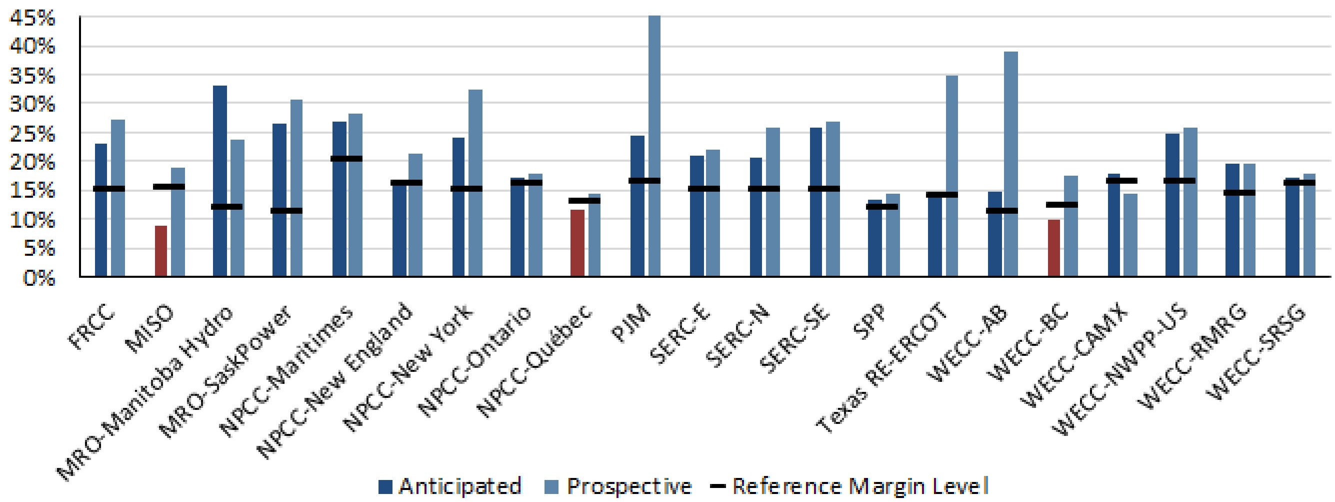


Figure 1.3: Planning Reserve Margins for Year 10 (2026)

Figure 1.4 below contains a qualitative risk process flowchart for the short-term (1-to-5 years) outlook and a chart showing the corresponding resource adequacy risk of a capacity shortage by assessment area. The 6-to-10 year outlook flowchart is a direct extension of the 1-to-5 year. The flowchart outcomes for this qualitative analysis result in flagging an assessment area as: 1) a high concern (shown by a red circle indicator), 2) a medium concern (shown by a yellow circle indicator), or 3) a low concern (shown by a green circle indicator).

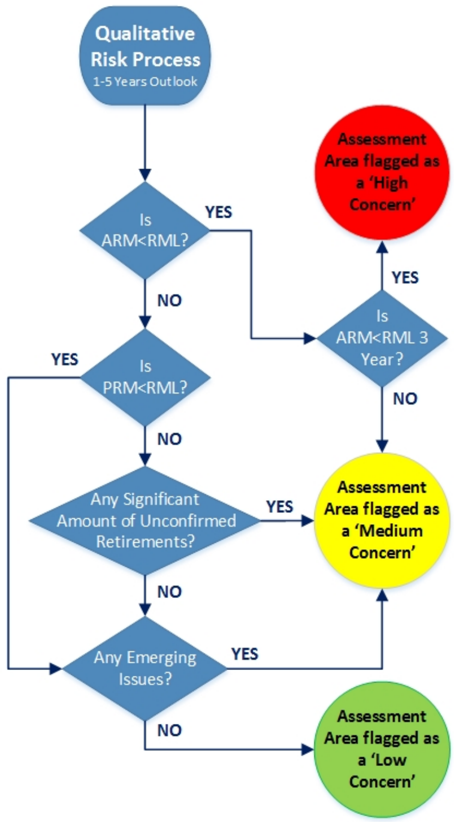
For example: an area is flagged as high concern when a Region's Anticipated Reserve Margin (ARM) is less than the Reference Margin Level (RML) in both the 1-to-5 year outlook and the 1-to-3 year time frame. When one or a combination of factors contribute to risk, the area is flagged as a medium concern. The factors that are considered are as follows: Prospective Reserve Margin (PRM), ARM, RML, unconfirmed retirements, and emerging and sustaining issues. Lastly, if an area is not flagged as high or medium, it is identified as having a low concern with respect to near- and long-term resource adequacy risk.

Confirmed and Unconfirmed Retirements

NERC collects two separate line items for retirements in the development of the *Long-Term Reliability Assessment*:

- Units whose retirements are designated as "confirmed" have formally announced plans to retire and these units must have an approved generator deactivation request where applicable. These units are individually identified within the data collection.

- "Unconfirmed" retirements are collected but aggregated by fuel type. These include units that have been earmarked for retirement but have not met the same requirements as those given as confirmed. These include units that are expected to retire based on the result of a generator survey or assessment area resource adequacy study.



Perceived Resource Adequacy Risk by Assessment Area (Low, Medium, or High Concern)		
Regions	**1 to 5 Years: Risk**	**6 to 10 Years: Risk**
FRCC	🟢	🟢
MISO	🟡	🟡
MRO-Manitoba Hydro	🟢	🟢
MRO-SaskPower	🟢	🟢
NPCC-Maritimes	🟢	🟢
NPCC-New England	🟡	🟡
NPCC-New York	🟢	🟢
NPCC-Ontario	🟢	🟢
NPCC-Québec	🟢	🟡
PJM	🟢	🟢
SERC-E	🟢	🟢
SERC-N	🟢	🟢
SERC-SE	🟢	🟢
SPP	🟢	🟢
Texas RE-ERCOT	🟡	🟡
WECC-AB	🟢	🟢
WECC-BC	🟢	🟡
WECC-CAMX	🟡	🟡
WECC-NEWPP-US	🟢	🟢
WECC-RMRG	🟢	🟢
WECC-SRSG	🟢	🟢

ARM: Anticipated Reserve Margin **PRM: Prospective Reserve Margin** **RML: Reference Margin Level**

Figure 1.4: Qualitative Risk Process Flowchart (left) and Corresponding Perceived Resource Adequacy Risk

Results of this qualitative risk analysis indicate that a total of four assessment areas have a medium reliability concern in the short-term and six assessment areas for the long-term. Assessment areas that indicated a medium risk in the short term are reviewed in more detail. These include:

- **MISO:** Lower Anticipated Reserve Margins and a significant amount of unconfirmed retirements due to the potential outcome of pending regulatory requirements indicate a medium resource adequacy risk.
- **NPCC-New England:** A growing reliance on natural gas, the lack of dual-fuel compatible units, and limited gas storage capability indicate a medium resource adequacy risk.
- **Texas RE-ERCOT:** Significant amounts of unconfirmed retirements due to the potential impacts of pending environmental regulations and a high reliance on natural-gas-fired generation indicate a medium resource adequacy risk.
- **WECC-CAMX:** A high reliance on natural gas, limited dual-fuel capability, and the potential reduction in adequate ERSs indicate a medium resource adequacy risk.

Recent environmental and other regulatory requirements have introduced greater uncertainty around the future of some resources. In addition to the other challenges brought forward by the incorporation of a changing resource mix, this increasing uncertainty of future resources is compounded by advanced retirements of conventional fossil-fired generating units and the capacity contributions expected from an increasing amount of variable generation. **Figure 1.5** shows the total amount of capacity retirements projected to occur in 2015 and 2016 using forecasted and actual data. The actual 2015 retirements totaled 24.3 GW, which was 3.3 GW more, or 15 percent, than the 21 GW forecasted by the *2015 LTRA*. Similarly, the *2015 LTRA* forecasted 9.3 GW of retirements to occur in 2016, but the *2016 LTRA* estimates an additional 3.4 GW, or 36 percent, more than the prior year's assessment.

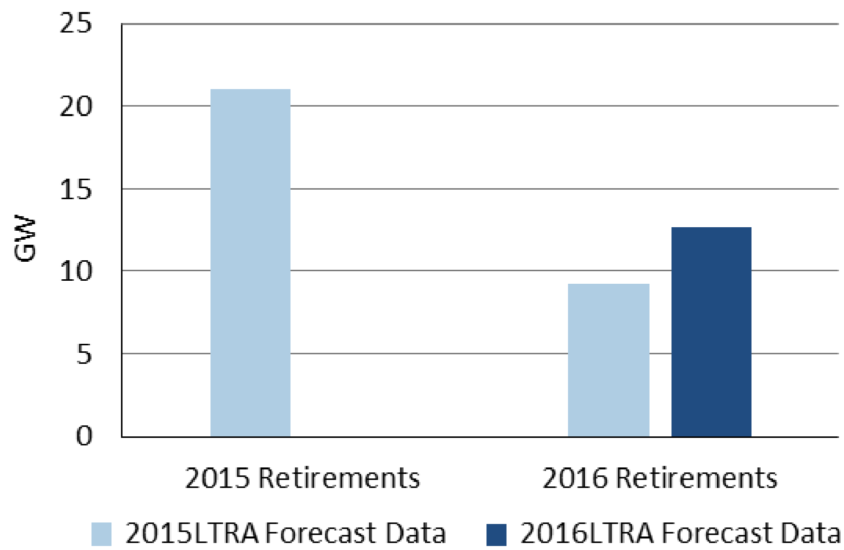
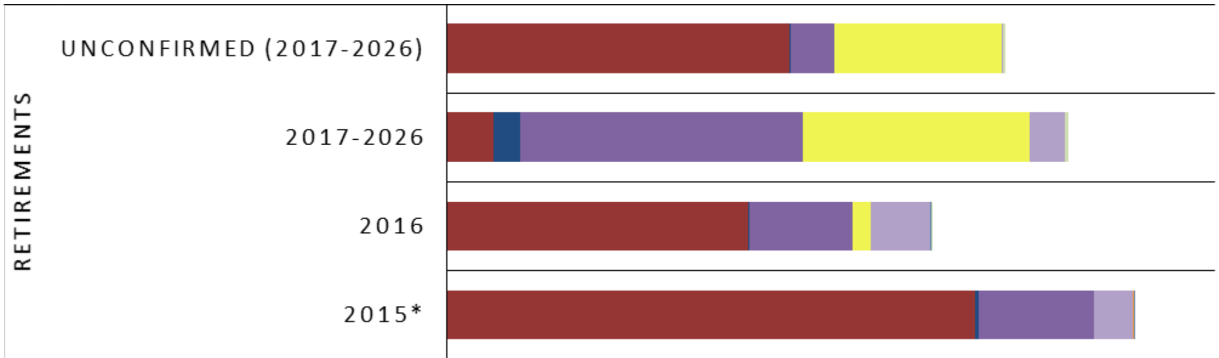


Figure 1.5: Total Projected Confirmed Retirements Increase between Assessment Years

As the outcome of retirement decisions are made public, upward adjustments on expected retirements continue to be incorporated into NERC's projections. Since 2012, approximately 40 GW of coal-fired and 30 GW of oil-fired generation have been retired in North America, roughly 7 percent of 2016 summer peak demand.

NERC examines both confirmed and unconfirmed generation retirements in the 10-year forecast. The Anticipated Reserve Margin includes only generation retirements that have been confirmed. However, given federal, state, and provincial policies, a number of power plants have an increased risk of retirement, and this should be considered when evaluating planning reserve margins. NERC's assessment found both the MISO and Texas RE-ERCOT assessment areas showing significant changes to their reserve margin forecasts when considering unconfirmed retirements and assuming no potential replacement capacity.

Figure 1.6 shows the total amount of actual nameplate capacity retirements from 2015 and the projected retirements for years 2016–2026 by fuel type. The data indicates there were significant coal retirements in 2015, greater than the total retirements projected for the ten-year assessment period.



	Retirements			
	2015*	2016	2017-2026	Unconfirmed (2017-2026)
Coal	13,747	7,850	1,195	8,927
Hydro	104	21	692	20
Natural Gas	3,001	2,680	7,395	1,148
Nuclear	-	502	5,901	4,374
Petroleum	1,013	1,548	929	6
Solar	44	1	-	-
Wind	36	3	-	-
Other	-	10	87	67

Figure 1.6: NERC-Wide MW Nameplate Capacity Retirements from 2015 to 2026 by Fuel Type
***Actual Data[6]**

NERC also conducted a sensitivity analysis in which no Tier 2 capacity was built and all unconfirmed retirements were taken out of service. The aggregated unconfirmed retirements were provided from MISO through the Organization of MISO States (OMS) survey results for 2016.[7] This provides insight on the potential retirement of many resources in the MISO footprint. The survey results provide a greater confidence factor to apply the unconfirmed retirements into a reserve margin sensitivity analysis. Similarly, ERCOT released their 2016 CDR, providing additional detail on power plant retirement risks and generation fleet changes.[8] While both MISO and ERCOT have sufficient Tier 2 resources in the queue, depending on the timing of the retirements (Tier 2 resources may not be available to advance their in-service dates), which could increase the risk of an electricity supply shortage.

MISO

Similar to the *2014 LTRA* and *2015 LTRA* reference cases, the *2016 LTRA* reference case projects a shortfall in MISO's Anticipated Reserve Margins during the assessment period. The shortfall in projections is due to generation retirements outpacing the addition of Tier 1 resources; there is sufficient Tier 2 and Tier 3 generation that could be advanced to mitigate these capacity concerns. MISO is projecting an Anticipated Reserve Margin of 13.8 percent for the 2022 summer peak, which continues to trend downward to 9.0 percent by the end of 2026. MISO will require approximately 8 GW of additional resources by the end of the 10-year forecast in order to maintain the Reference Margin requirements of 15.2 percent. Considerations should be given to the assessment area's need for sufficient ERSs. These may include generation additions that are mostly asynchronous and may offer a reduced level of voltage, frequency, and/or ramping support, depending on equipment characteristics and facility design. Shown in **Figure 1.7**, the Reference Margin requirements are up by 0.9 percent compared to the *2015 LTRA* reference case due to resource adequacy study assumptions. These changes are mostly due to the

[6] Actual data for 2015 collected from EIA Electric Power Monthly
[7] Organization of MISO States Survey Results; 2016
[8] Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2016-2025; May 2016

2014–2015 planning year being the first year of integrating the MISO South Zone with limited data being available.[9]

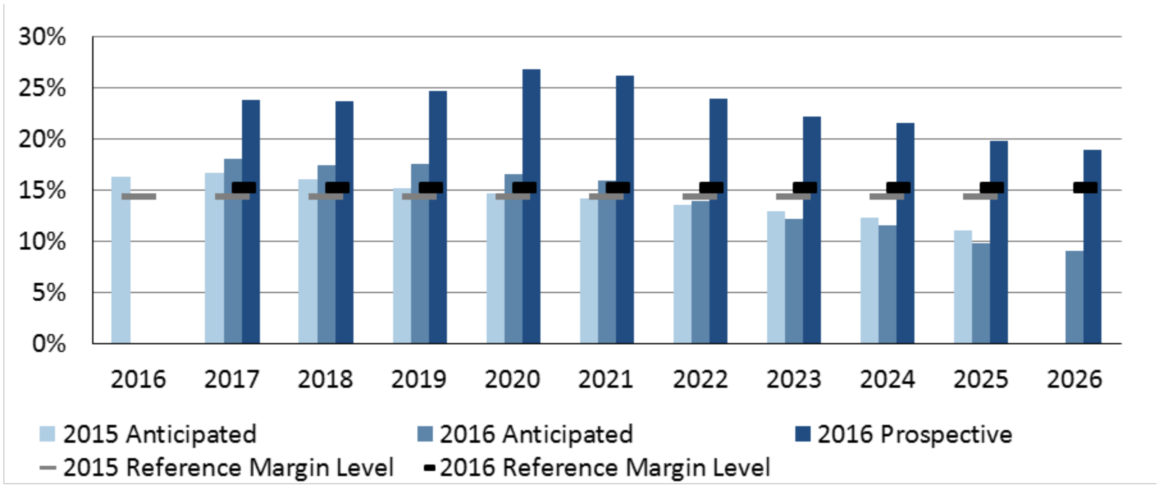


Figure 1.7: MISO 2015 LTRA and 2016 LTRA Reserve Margin Comparison

MISO gathered data for the past three years through the OMS Survey as part of their resource adequacy study. Survey results indicate that certain locations within the assessment area will have to rely on imports as early as 2017 from their neighboring zones, such as Missouri and Lower Michigan. The survey resulted in an estimation of 3.3 GW plant retirements by 2026. NERC considers these retirements as unconfirmed and are the major contributor in the advanced Reserve Margin shortfalls. ReliabilityFirst's *2016 Long-Term Resource Report* also identified these potential risks highlighted by the OMS survey results.[10]

Deliverability of New Resources

One of the major challenges in long-term system planning is the changing nature and location of available resources to load. The North American BPS does not provide infinite routes for all generation; therefore, the transition from a central-station model to a more dispersed BPS creates some challenges in power delivery and transmission. System planners use modeling software to simulate current and projected grid components and characteristics. From these models, transmission planners will identify potential future contingencies on lines and evaluate options, such as uprating or building new lines to mitigate contingencies before they occur. Having new resources built long distances from the load requires that new lines be built to effectively deliver this new generation to where it is needed. Transmission congested lines and operational challenges are likely to escalate within an area if the constraints are not alleviated.

Figure 1.8 includes the resulting unconfirmed retirement sensitivity analysis impacts on MISO's Anticipated Reserve Margins, which will fall below the Reference Margin Level by 2018. While the reference margin is not met in the five-year period given unconfirmed retirements, MISO appears to have sufficient Tier 2 resources to meet the Reference Margin Level. The long-term resource adequacy forecast is generally low risk, but as variable resources increase, Reference Margin Level requirements may increase beyond the current 15.2 percent in the future years.

[9] MISO Loss of Load Expectation Study Report: Planning year 2016-2017
[10] ReliabilityFirst 2016 Assessment-Long Term Resource; August 2016

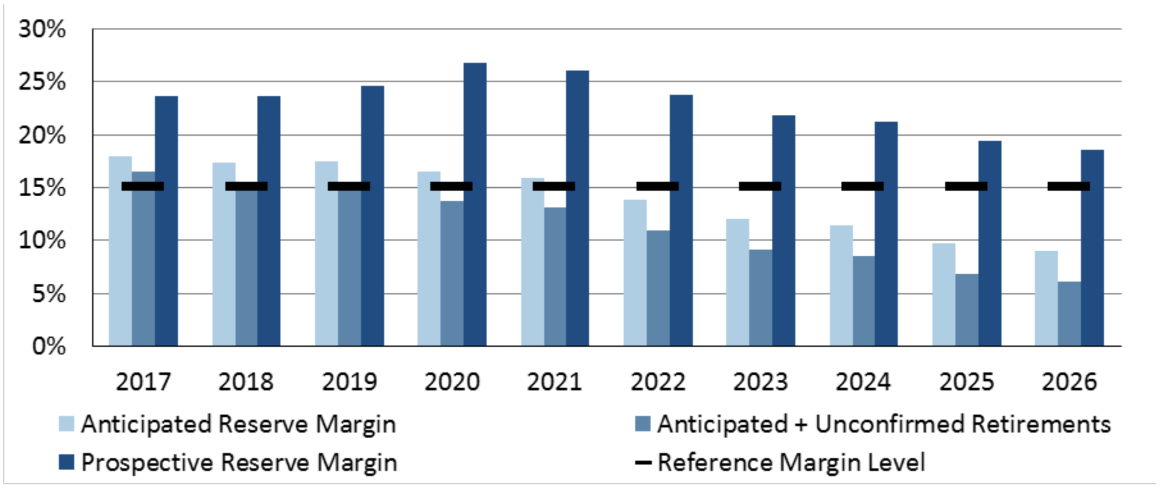


Figure 1.8: MISO Reserve Margins with Unconfirmed Retirements

MISO's long-term resource challenges are exacerbated by increasing transmission requirements. The MISO forecast includes a significant expansion of wind resources. Because of the geographic diversity of wind resources to load, more long-distance and networked transmission will be needed. Ensuring the deliverability of these resources is challenging when resources are located distant from the load. For example, forced curtailments of wind resources are sometimes required to prevent congestion on transmission lines. An August 2016 report by the U.S. Department of Energy[11] showed that the percentage of wind curtailment in MW to the total potential wind generation has increased in MISO from under 2 percent in 2007 to over 5.5 percent in 2015. An increase in wind curtailments could be a result of transmission inadequacy, minimum generation limits, other forms of grid inflexibility, and/or environmental restrictions. This could lead to an increased risk of real-time capacity deficiencies.[12]

NPCC-New England

The Anticipated Reserve Margins for NPCC-New England, shown below in **Figure 1.9**, exceed the Reference Margin Level for all years of the assessment period. Compared to the *2015 LTRA* reserve margin analysis, the Anticipated Reserve Margins have increased by 0.5 percent in 2017 and by 3.32 percent by year 2025. The majority of this change is due to a slight reduction in the ten-year peak load forecast.

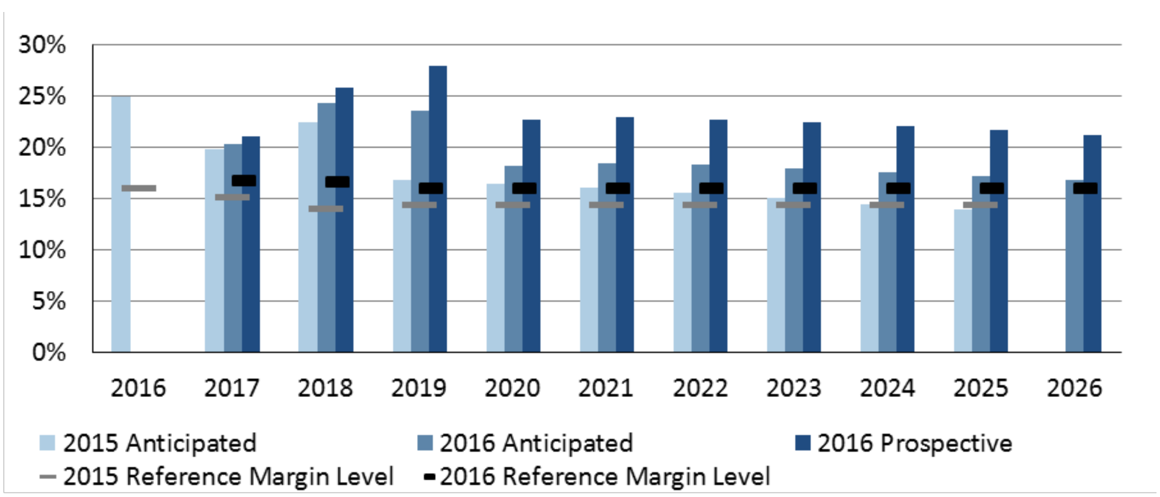


Figure 1.9: NPCC-New England 2015 LTRA and 2016 LTRA Reserve Margin Comparison

11 Department of Energy: Wind Technologies Market Report - August 2016

12 *Ibid*.

The results from the qualitative risk analysis, as presented in the Qualitative Risk Process flowchart (**Figure 1.4**), highlighted NPCC-New England as having a perceived medium resource adequacy risk. While the results of the reserve margin analysis indicate that NPCC-New England has sufficient capacity to remain above their Reference Margin Level, there are other standing or emerging issues that must be considered when performing a more holistic overview of the assessment area's potential risks to reliability.

NPCC-New England faces additional challenges due to a high dependency on natural gas, a reduced dual-fuel capable fleet, and limited storage capability. These challenges are exacerbated by high winter gas demand competitiveness from customers other than electric generating facilities and inadequate natural gas pipeline infrastructure.[13]

Texas RE-ERCOT

NERC's *2015 LTRA* reference case showed Texas RE-ERCOT projections below the Reference Margin level of 13.75 percent to 13 percent by 2022, and continuing to decline to 9.4 percent by 2025. Comparing last year's data in **Figure 1.10**, the *2016 LTRA* reference case indicates that ERCOT is now not projected to fall below its Reference Margin Level within the ten-year assessment. This is due to a decrease in net internal demand forecasted in future years and an increase in planned capacity. Comparing forecasted peak load by the year 2025, ERCOT is showing a decrease of 1.2 GW, or a 1.5 percent reduction, from last year's assessment. Similarly, ERCOT is showing an increase in their anticipated resources by 3.8 GW or 4.6 percent increase when compared to last year.

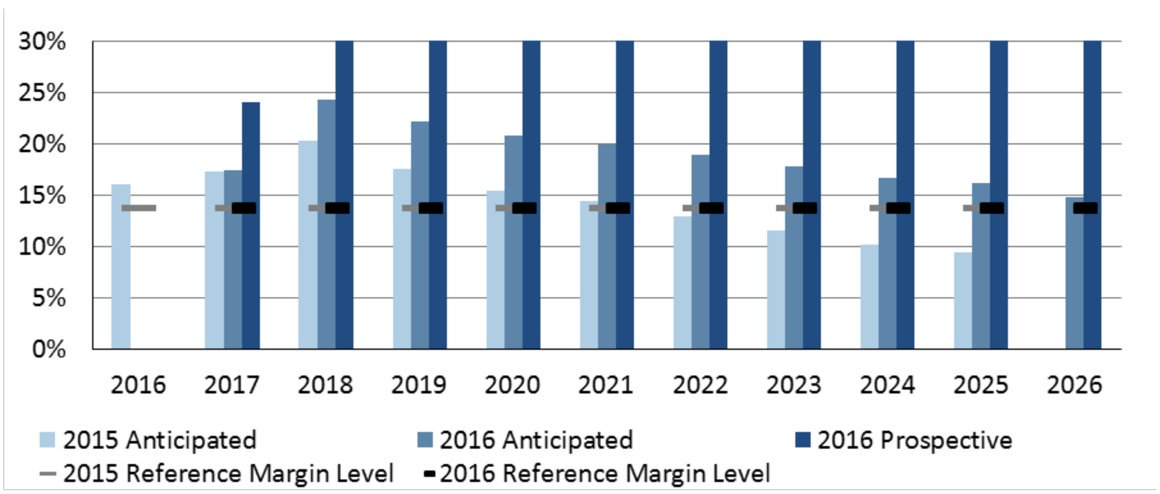


Figure 1.10: Texas RE-ERCOT 2015 LTRA and 2016 LTRA Reserve Margin Comparison

Figure 1.11 shows the results of a sensitivity analysis whereby all 6.9 GW of unconfirmed coal and natural gas retirements are included in the Anticipated Reserve Margin. From this unconfirmed retirement scenario, ERCOT would fall below their Reference Margin Level of 13.75 percent to 11.1 percent in 2021 and continue to decline to 5.8 percent by the end of the assessment period. The Prospective Reserve Margin indicates that there are sufficient Tier 2 generation in the queue that may need to be advanced to mitigate a capacity concern.

[13] ISONE- Natural Gas Infrastructure Constraints ; September 28, 2016

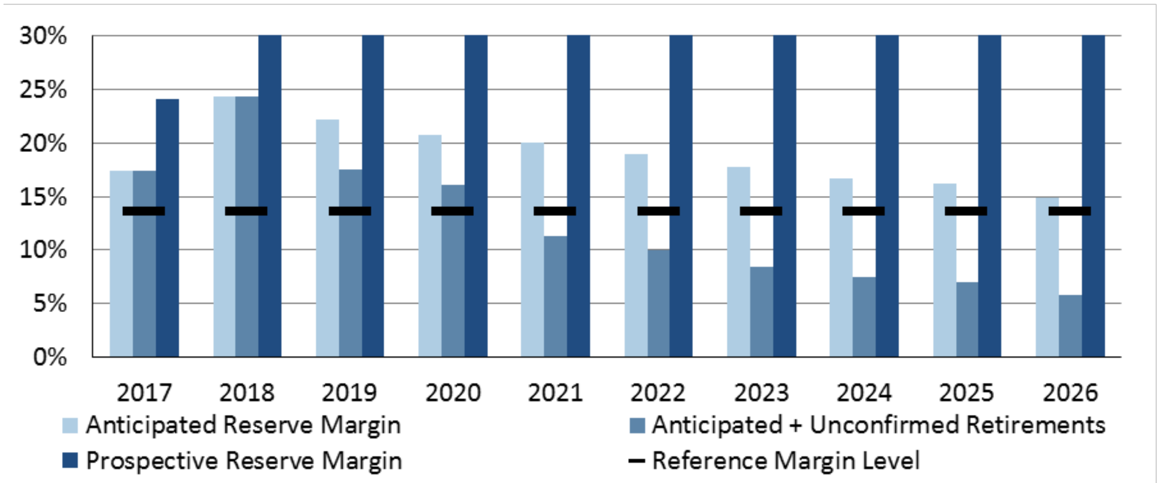


Figure 1.11: Texas RE-ERCOT Reserve Margins with Unconfirmed Retirements

Over the next ten years, installed resources in the ERCOT Region grow from 16.3 to 26.9 GW nameplate when accounting for Tier 1 planned resources. This would increase the percentage of installed nameplate wind to a total nameplate capacity from 16.5 percent to 22.6 percent. When adding wind and solar, as shown in **Figure 1.12**, variable resources are projected to be 25.3 percent of the anticipated resource capacity and 42.1 percent of the prospective resource capacity. Actual wind and solar penetration at any time of the year are dependent on weather, irradiance, and resource controllability. Very high penetration levels of variable energy resources (VERs) increases the need for ERSs to effectively dispatch conventional generating units and maintain system reliability.

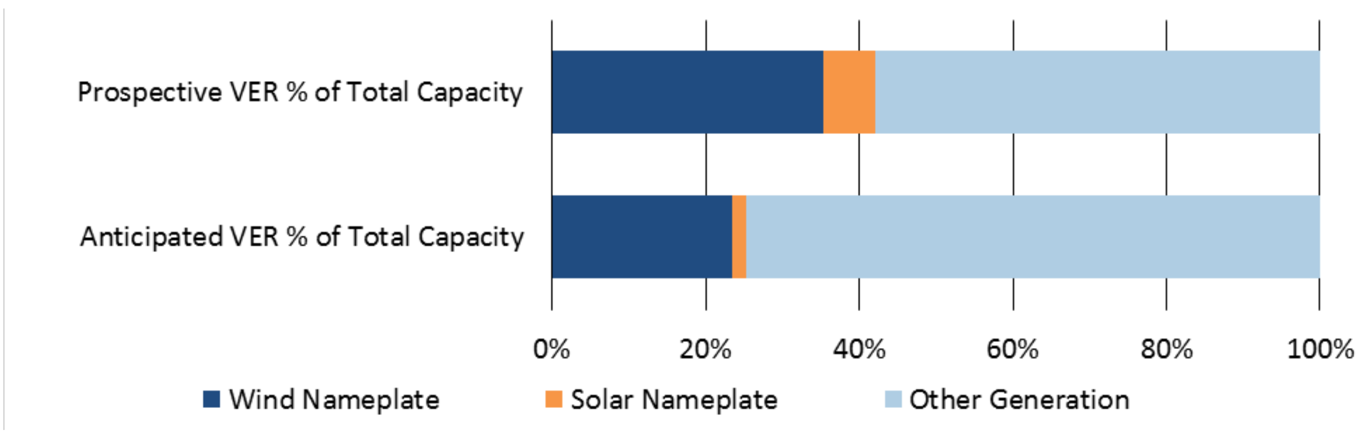


Figure 1.12: Maximum VER Penetration in ERCOT for the 2026 Summer Peak

Figure 1.13 shows the total anticipated capacity between years 2017 and 2026 for ERCOT by fuel type. Total expected net changes across the summer peak include 6.0 GW of natural-gas-fired generation and 0.8 GW of utility-scale VER additions.

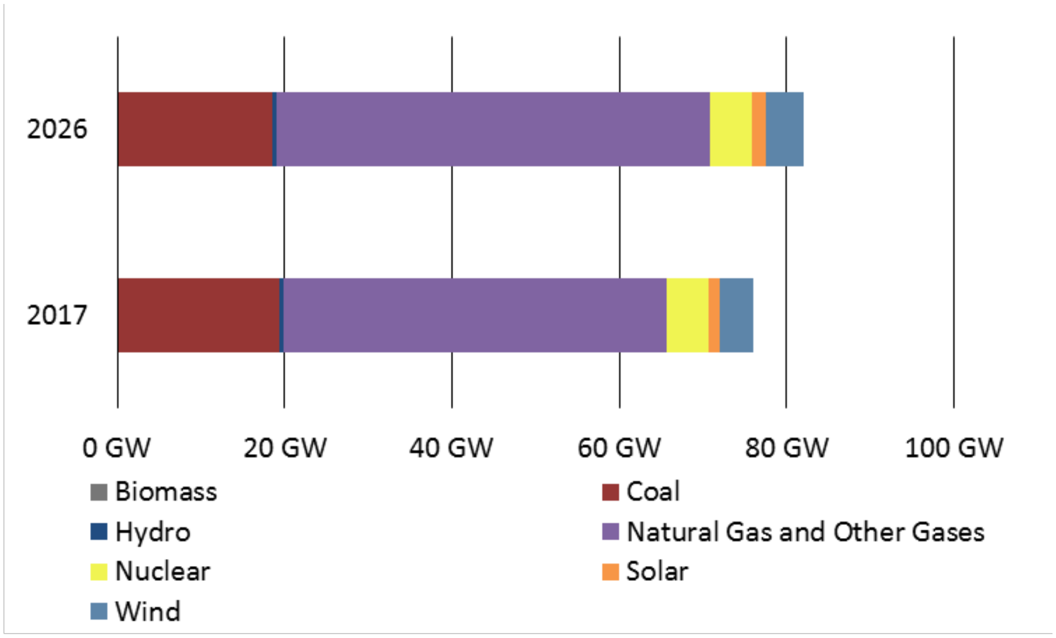


Figure 1.13: ERCOT Total Anticipated Capacity by Fuel Type

In August of 2016, ERCOT set multiple new hourly peak demand records based on preliminary data, settling on 71,197 MW on August 11th between 4:00 p.m. and 5:00 p.m.[14] At the time of this peak, 4,783 MW of wind was generating on the system, or approximately 6.72 percent of total energy over the hour.[15] System operations indicate that the system is currently capable of delivering energy generated from these wind turbines throughout the assessment area. For parts of the BPS that experience localized events where generation is over-producing in transmission constrained areas, operators must be able to control wind and solar production to prevent contingencies from overloading transmission lines. Similar to the Department of Energy study for MISO, wind curtailments were observed in ERCOT between 2007 and 2015, as shown in their August 2016 report.[16]

In December of 2015, Congress passed the *Consolidated Appropriations Act,* which extended federal renewable electricity production tax credits through the end of 2019.[17] These tax credits may encourage new renewable energy development in Texas before sufficient transmission is added that is necessary to effectively deliver this new energy to system load. ERCOT could also experience increased retirements of some fossil fuel generation due to the expected EPA's final regional haze rule[18, 19] and, if upheld by the courts, the potential impacts of the Clean Power Plan (CPP). An initial study by ERCOT also concluded that the "Regional Haze requirement would have a significant local and regional impact on the reliability of the ERCOT transmission system."[20] Both of these regulations have been stayed at this time,[21] which creates some uncertainty around the contents of their final ruling. These are currently subject to change.

[14] ERCOT Bulletin: "ERCOT Breaks Peak Record Again, Tops 71,000MW for First Time"; August 11th, 2016
[15] ERCOT Wind Integration Reports
[16] U.S. Department of Energy: 2015 Wind Technologies Market Report: Summary; August 2016
[17] Renewable Electricity Production Tax Credit Program Info; Energy.gov
[18] EPA: Visibility - Regional Haze Program
[19] EPA: Air Issues in Texas
[20] ERCOT Presentation: Transmission Impact of the Regional Haze Environmental Regulation; October 15, 2015
[21] U.S. Court of Appeals for the 5th Circuit: State of Texas et al. v. U.S. Environmental Protection Agency et al., July 15, 2016

WECC-CAMX

Similar to NPCC-New England, there are no risks identified to resource adequacy when only applying a reserve margin analysis. The Anticipated Reserve Margins, shown in **Figure 1.14**, remain above the Reference Margin Level for all years of the assessment, indicating that there are sufficient resources anticipated to be available to serve peak load.

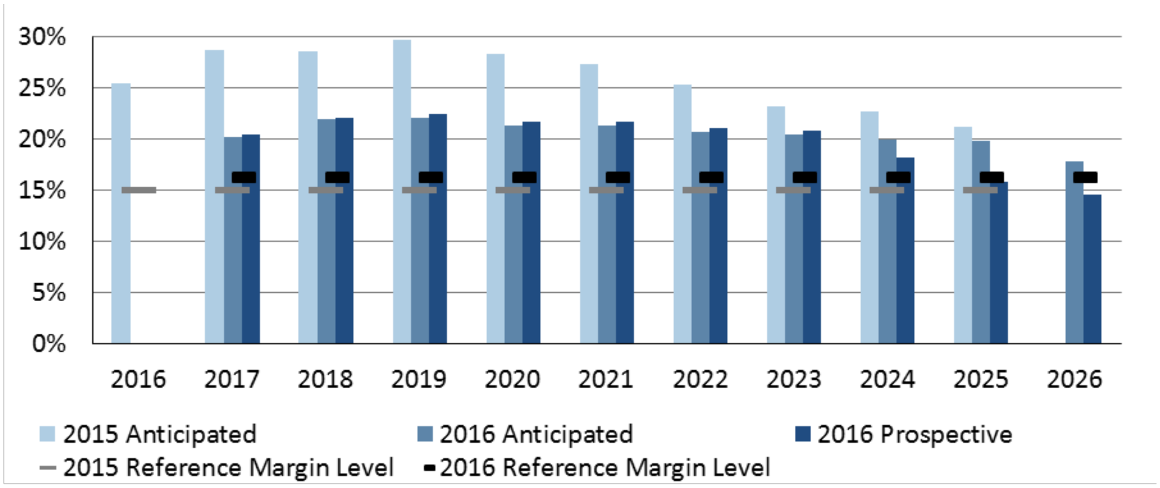


Figure 1.14: WECC-CAMX 2015 LTRA and 2016 LTRA Reserve Margin Comparison

However, once additional emerging and standing issues are incorporated into the overall resource adequacy risk analysis, the *2016 LTRA* identifies WECC-CAMX as having a medium risk to resource adequacy. This is primarily due to a high reliance on natural-gas-fired generation, limited dual-fuel capability, and the potential reduction in adequate ERSs. Additional study into WECC-CAMX's ramping sufficiency concerns are presented in the Essential Reliability Services Chapter 3.

Single Fuel Dependency

Natural gas continues to be the predominant fuel type in many assessment areas. The ten-year projection for natural gas continues to show an upward slope in the amount of natural-gas-fired resources coming onto the grid, as well as the rate for new-natural-gas fired resources to enter the BPS. Key drivers for this increase include regional initiatives; state renewable portfolio standards; past and potential future regulatory rulings, such as MATS and the CPP; and recent shale gas production. This results in historically low natural gas prices.

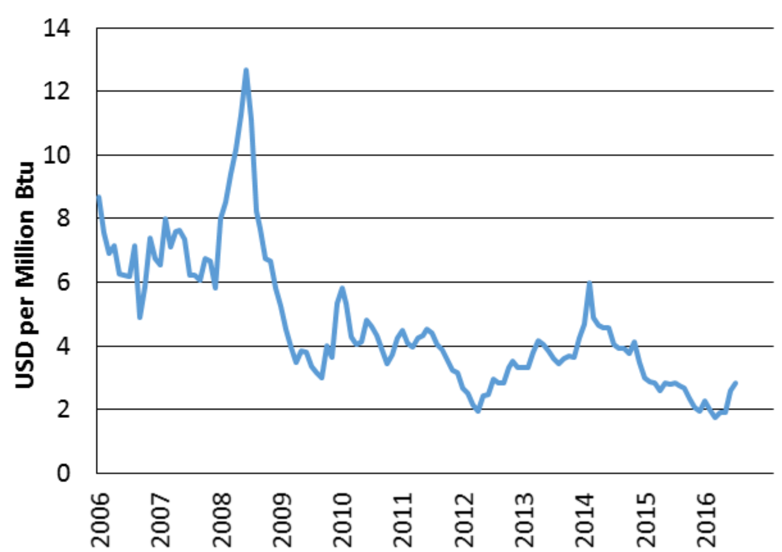


Figure 1.15: Natural Gas Spot Prices—Henry Hub

Spot natural gas prices have declined from roughly \$13/MMBtu in 2008 to below \$3/MMBtu in 2016 as shown in **Figure 1.15**.[22] This decline in prices has been a large factor in the increase in natural-gas-fired generation. Outside of the effects from regulatory rulings, the low price of natural gas has resulted in additional coal units being shut down as well as the announcement of a significant number of nuclear retirements.

Due to historically low gas prices, natural gas use for electricity generation has developed a strong market incentive over all other fuel types within the ERO footprint. The U.S. Energy Information Administration (EIA) routinely monitors monthly energy usage and forecasts. **Figure 1.16** shows natural gas usage surpassing coal for the first time in 2015 and for a majority of the time in 2016.[23]

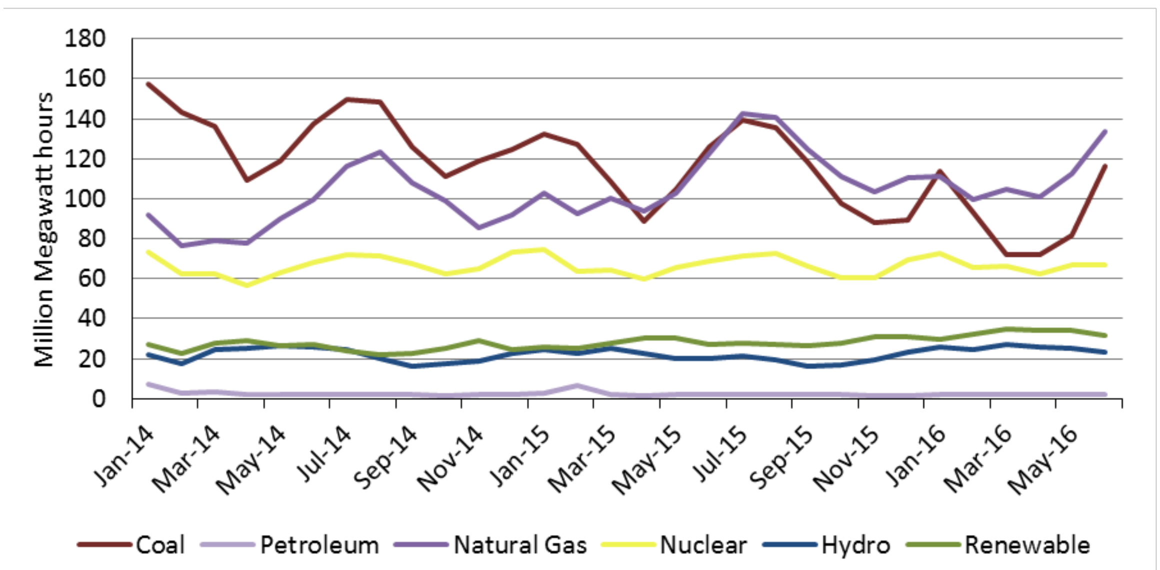


Figure 1.16: Monthly Net Electricity Generation by Fuel Type

[22] EIA Henry Hub Natural Gas Spot Prices

[23] EIA Short-Term Energy Outlook - July 2016

NERC continues to monitor and report on changes to the resource mix and the potential reliability risks associated with these changes. Several ongoing trends have been identified in past LTRAs, such as increasing natural gas, increasing wind and solar, decreasing coal, and uncertainty around the future of nuclear. These previously identified trends indicate an under-forecasted rate of change from assessment to assessment; these rates of change similarly increased in the *2016 LTRA* reference case.

Figure 1.17 shows natural-gas-fired generation data from the *2008 LTRA* through the *2016 LTRA* reference cases. While the proximity of anticipated natural gas forecasts for year two of each assessment is close to the actual amount installed, there continues to be wide margins between the outer years of each assessment. For example, in 2024 (year ten of the *2014 LTRA* and year eight of the *2016 LTRA*) there was a forecasted increase of 29.8 GW of net anticipated natural gas; this net change includes both Tier 1 designated planned additions and confirmed retirements.

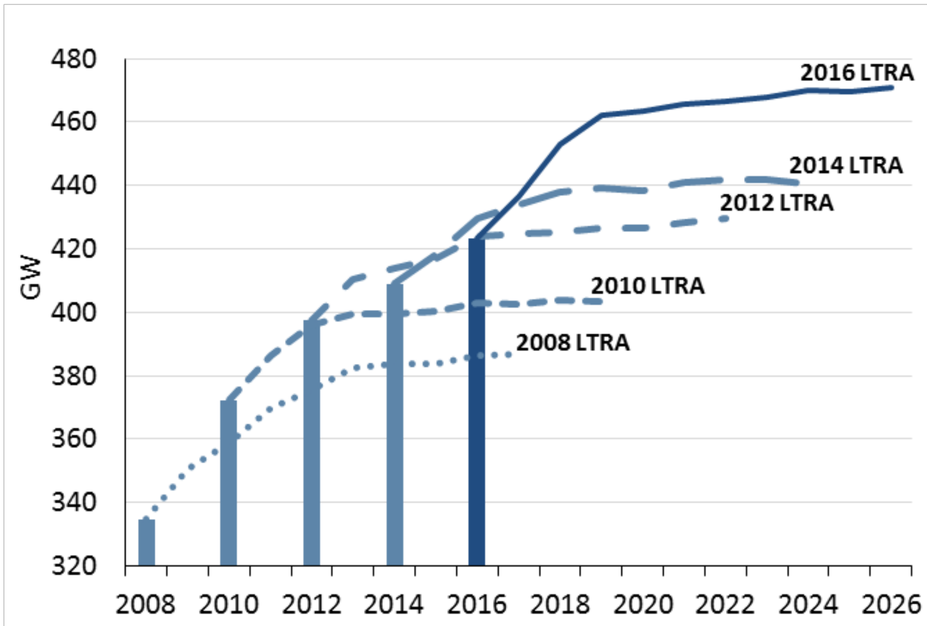


Figure 1.17: Anticipated Natural Gas Capacity by LTRA Reporting Year

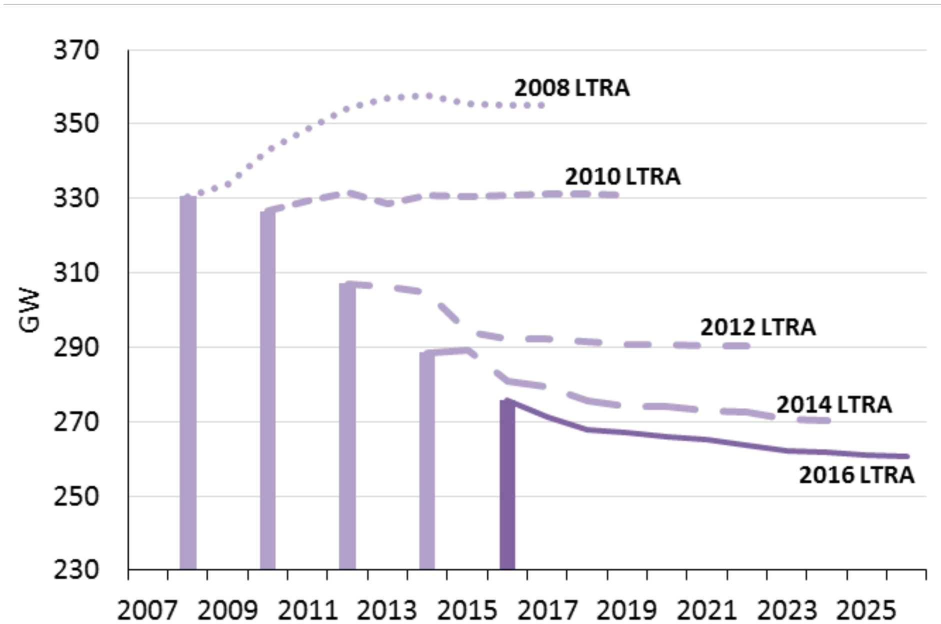


Figure 1.18: Anticipated Coal Capacity by LTRA Reporting Year

The rate of change of retirements of coal plants have continuously increased from assessment to assessment. As shown in **Figure 1.18**, coal-fired generation data from the *2008 LTRA* through the *2016 LTRA* reference cases show consistent marginal gaps between assessments. For example, by 2024 of the *2014 LTRA* and *2016 LTRA*, there was a decrease in the system-wide forecast by 8.5 GW. This trend indicates that coal generation retirements have and are continuing to outpace retirement projections.

Table 1.1 shows that a growing number of the assessment areas are trending towards an increasing dependency on this single fuel source. The table shows a breakdown by assessment area for natural-gas-fired capacity as a percentage of the area's total anticipated capacity. NERC has identified a dependency on a single fuel as a potential reliability risk requiring mitigation. Natural gas has crossed over 50 percent of peak capacity in several areas amidst continued historically low prices and regulatory rulings, which continue to promote increased natural gas generation.

Table 1.1: Natural Gas Percentage of Peak Season Total Anticipated Capacity

	2017 (MW)	2021 (MW)	2017 Gas of Total Capacity (%)	2021 Gas of Total Capacity (%)
FRCC	35,583	39,598	66.19%	69.05%
WECC-CAMX	40,299	42,536	68.39%	68.23%
Texas RE-ERCOT	45,842	51,867	60.34%	63.26%
NPCC-New England	14,331	16,308	48.17%	52.33%
WECC-SRSG	16,530	16,774	51.24%	51.84%
WECC-AB	8,514	8,514	52.02%	51.79%
SERC-SE	30,256	30,262	48.53%	46.88%
MRO-SaskPower	1,835	2,087	42.90%	43.97%
SPP	30,413	29,446	45.92%	45.22%
SERC-N	19,250	21,160	37.96%	40.68%
MISO	59,566	60,026	41.74%	42.26%
NPCC-New York	16,030	16,708	41.07%	41.98%
PJM	66,760	76,335	35.80%	38.71%
WECC-RMRG	6,695	6,914	36.36%	38.51%
WECC-NWPP-US	20,860	20,565	34.67%	34.80%
SERC-E	15,762	17,754	30.67%	32.25%
NPCC-Ontario	6,568	7,340	22.99%	24.91%
NPCC-Maritimes	856	856	12.56%	12.66%
MRO-Manitoba Hydro	311	404	5.51%	6.33%
WECC-BC	434	442	3.45%	3.48%
NPCC-Québec	-	570	0.00%	1.33%

Figure 1.19 shows the aggregated summer capacity heat map for all operating and planned natural gas generating units within the ERO footprint. This figure clearly shows that large pockets of natural gas generation are occurring throughout the footprint and evenly spread out. This causes some areas to potentially be more reliant on this single fuel type.

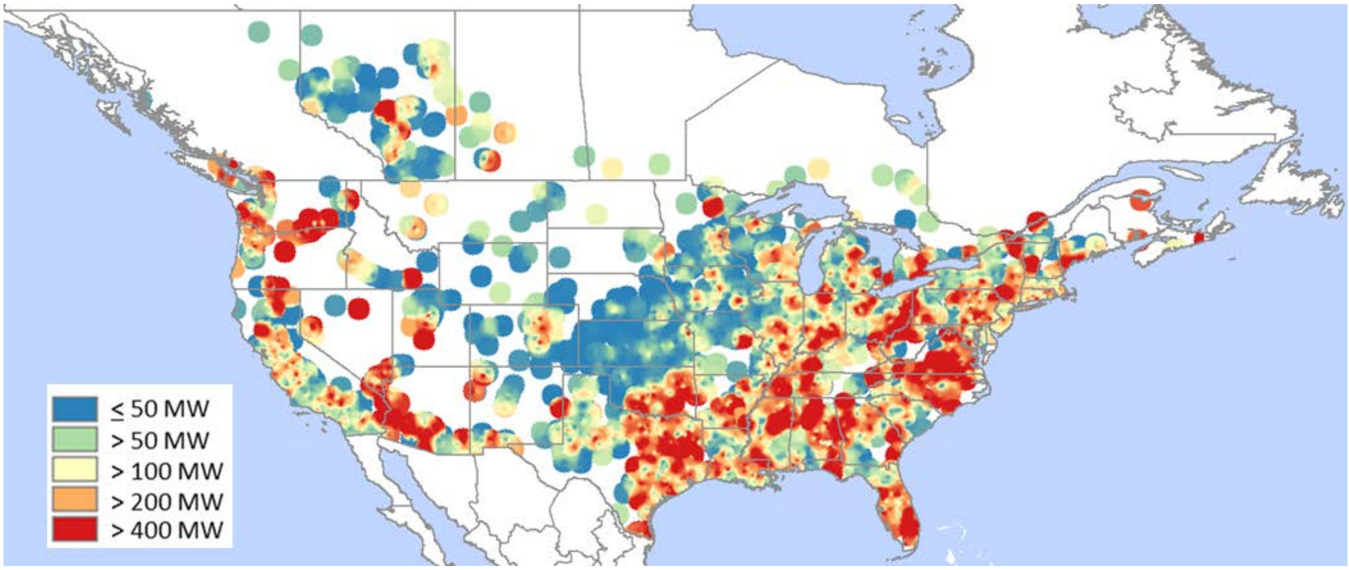


Figure 1.19: Natural Gas Generating Units–MW Summer Capacity Heat Map

NERC conducted a short-term special assessment in 2016 that included an operational risk analysis using NERC's Generation Availability Data System (GADS) database to project natural-gas-fired outages.[24] Using a deterministic approach, all evaluated assessment areas showed no concerns in meeting reserve margin requirements as a result of this operational risk assessment. However, when a single point of disruption, such as unavailable storage facilities, pipeline rupture, or other gas infrastructure failure was considered, reserve margins were jeopardized in some areas. For example, the Aliso Canyon outage in Southern California illustrates the effects of a potential single point of disruption. This one underground gas storage facility in SoCal Gas' service territory contains 86 BCF of gas capacity, providing fuel to approximately 9,800 MWs of electric generation. The facility also supports ramping requirements to accommodate the variability of renewable energy resources. This outage has the potential to cause rolling black outs in Southern California until the facility is completely operational again or other mitigation approaches have been employed.

[24] NERC: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation; May 2016

Gas storage facilities have historically had clear delineations between a summer injection season and winter withdrawal season. **Figure 1.20** shows the daily total injections and withdrawals to and from underground gas storage facilities from April–August 2016. Multiple days within this time period have seen net changes that resulted in more withdrawals than injections. While this is not the first time that system-wide underground storage facilities saw a net withdrawal during the summer season, any continuing changes to use trends for natural gas storage inventories should be monitored and evaluated for potential impacts to future gas availability.

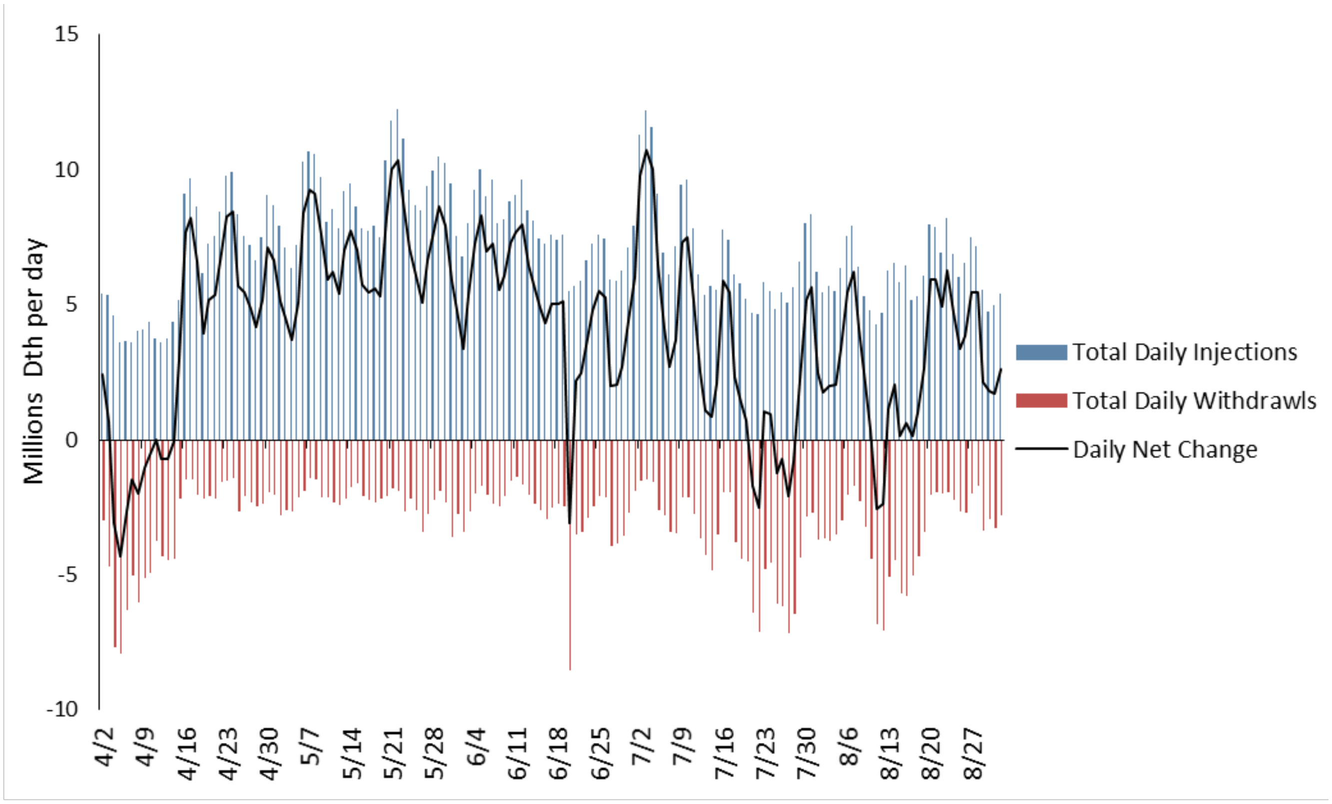


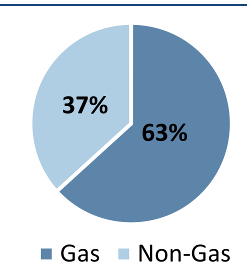
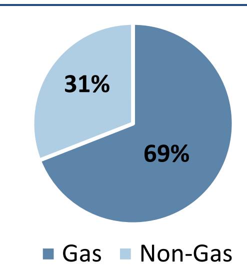
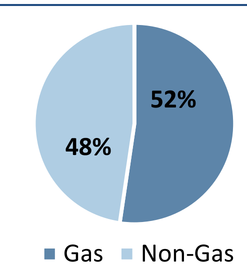
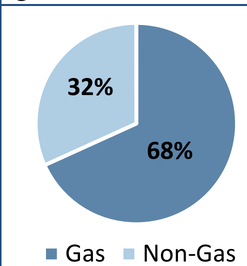
Figure 1.20: 2016 Weekly Natural Gas Inventory Changes

Many factors must be considered when assessing the potential for reliability risks in resource planning, as outlined in TPL-001-4[25]. Each assessment area is comprised of a unique set of variables that include existing resources, electric transmission, and natural gas infrastructure. NERC has identified areas that are increasingly reliant on a single fuel type, which increases vulnerabilities, particularly during extreme weather events and conditions. Over the past decade, several areas have significantly increased their dependence on natural gas. This trend has continued amidst historically low natural gas prices and regulatory rulings that continue to promote increased natural gas generation. The assessment identifies four assessment areas with high penetrations of natural gas generation and therefore increased risk through single-fuel dependency: Texas RE-ERCOT, FRCC, NPCC-New England, and WECC-CAMX. **Table 1.2** provides a summary of various independent factors that influence these four assessment areas' capability to mitigate an increasing reliability risk.

[25] NERC TPL-001-4

Table 1.2: Single Fuel Dependency Risk Summaries				
	Texas RE-ERCOT	**FRCC**	**NPCC-New England**	**WECC-CAMX**
Factors that Reduce Risk				
Alternative Fuel Capabilities Evaluate capabilities across generator fleet, maintain back-up fuel inventories at key stations, and annually test fuel-switching capability	14% of gas-fired generation is capable of using alternative fuel. No requirement to maintain back-up fuel inventory Testing of fuel switching is not required Annual winterization and cold weather preparation workshops share lessons learned and best practices to improve reliability during extreme cold weather.	73% of gas-fired generation is capable of using alternative fuel. Back-up fuel inventories are required by the state public utility commission.	30% of gas-fired generation is capable of using alternative fuel. Winter Reliability Program (through 2018) provides payments for adding dual-fuel capability, securing fuel inventory, and testing fuel-switching capability; compensation for any unused fuel inventory.	4% of gas-fired generation is capable of using alternative fuel. Very limited back-up fuel kept in inventory; holding tanks have largely been removed.
Market and Regulatory Rules Provide additional incentives for behavior and investments that support reliability and resiliency	No regulatory or market rules exist for maintaining dual-fuel capability and/or firm natural gas transportation.	Regulatory rules exist for maintaining dual-fuel capability and firm natural gas transportation services and contracts.	Recent market rule changes include energy market offer flexibility, timing adjustments to Day-Ahead Energy Market, Winter Fuel Reliability Program, and Pay-for-Performance (which starts in June 2018) By creating incentives, the market may indirectly provide incentives for the development of on-site oil, LNG fuel storage, or expanded gas pipeline infrastructure.	No regulatory or market rules exist for maintaining dual-fuel capability and/or firm natural gas transportation within CAISO.

Single Points of Disruption Assess reliability under extreme conditions, loss of major pipeline infrastructure or supply	Meshed pipeline infrastructure significantly reduces this risk	The fleet of dual fuel capable generation and ensuring sufficient fuel inventory reduces this risk.	Area is situated in bottlenecked and physical end of the interstate pipeline system. Two major interstate pipelines connected from southeast; one from the northwest.	Area is situated in bottlenecked and physical end of the interstate pipeline system. Two major interstate pipelines connected from southeast; one from the northeast. Aliso Canyon Storage Facility outage continues to impact fuel deliveries.
Pipeline Expansion Keep pace with generation expansion and increasing electricity production	No signs of concern with lagging pipeline expansion Natural gas generation is coming on-line with Firm transportation service.	Two projects to be completed in 2017 reduce this risk: Sabal Trail Transmission and Florida Southeast Connection. Dual-fuel capabilities reduce the risk	State policies and pressures have not led to the construction of natural gas pipelines Recent suspension of pipeline projects aimed to support electric generation	No interstate transmission projects that increase pipeline capacity approved by FERC since 2009. Intra-state projects are more likely; however, political opposition continues to challenge expansion (such as in the SoCal Gas North-South Project)
Limited Exposure to Supply Chain Failure Increase resiliency by maintaining alternative supply chains and paths	Robust supply sources within service area; conventional, shale, and gulf sources	Gas supplied from conventional, shale, and gulf sources and transported to Florida; potential LNG import. No local production	Gas supplied from conventional, shale, and gulf sources and transported to New England; limited LNG import (supplies Mystic Generation Station~2,000 MW) No local production; no storage	Gas supplied from conventional, shale, and gulf sources and transported to California. Some local production

Maintaining Situational Awareness Electric system operators need awareness of pipeline conditions and must be able to predict generators that may become unavailable	Pre-season surveys of fuel inventories Coordination with pipeline operators	No significant changes	Pre-season surveys of fuel inventories Improved coordination and information-sharing with natural gas pipeline operators Coordination of generator and pipeline maintenance schedules. Gas Usage Tool estimates the remaining gas pipeline capacity by individual pipe for use by ISO-NE system operators	Improved coordination and information-sharing with natural gas pipeline operators Joint Agency Daily Reliability Communication (throughout Aliso Canyon outage) Development of gas curtailment methodology and scenario planning Active coordination on energy emergencies with California Energy Commission; action plans to respond to Aliso Canyon Storage Facility outage.
Risks Communicated to Policymakers Results and conclusions of studies that evaluate electric reliability should be shared and clarified with state, federal, and provincial policymakers and regulators	Gas Curtailment Risk Study (2012) Annual LTRA NERC will evaluate single points of disruption in a 2017 special assessment.	Annual LTRA NERC will evaluate single points of disruption in a 2017 special assessment.	Annual LTRA Key participant in the Eastern Interconnection Planning Collaborative (EIPC) gas-electric interface study NERC will evaluate single points of disruption in a 2017 special assessment.	Annual LTRA NERC will evaluate single points of disruption in a 2017 special assessment. WECC is working with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.
Maintain Fuel Diversity Maintaining fuel diversity provides inherent resiliency to common-mode risk				

Recognizing the increased dependence on natural gas as a fuel for electricity generation, FERC has already taken steps to improve the coordination of wholesale natural gas and electricity market scheduling:

- FERC Order No. 787, issued on November 15, 2013 (Rulemaking RM13-17-000),[26] provides explicit authority to interstate natural gas pipelines and public electric utilities participating in the interstate commerce to share nonpublic operational information with each other to promote reliable service or operational planning on their systems.
- FERC Order 809, issued on April 16, 2015 (Rulemaking RM14-2-000),[27] provides for better coordination of the scheduling practices of the wholesale natural gas and electric industries, as well as additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts.

However, regulatory and policy solutions that help expand pipeline access, reliability, and the needs of electric generation have a not surfaced. The recent suspension of Kinder Morgan's AED and Algonquin's proposal to facilitate electric utility purchase of pipeline capacity demonstrates the need for regulatory solutions to facilitate electric generator commitments. This is particularly true for generation operating in wholesale electric markets.

Recommendations

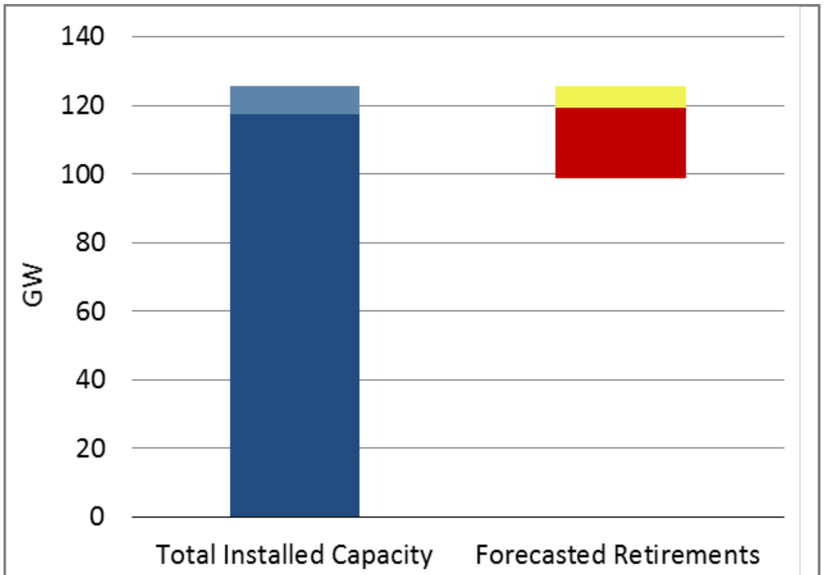
As natural-gas-fired resources continue to increase, system planners and operators should evaluate the potential effects of an increased reliance on natural gas as it pertains to BPS reliability. Natural gas provides "just-in-time" fuel; therefore, firm transportation and maintaining dual-fuel capability can significantly reduce the risk of common-mode failure and wider-spread reliability challenges. 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. Regulatory action may be needed to better calibrate electric and gas industries.

[26] FERC Order 787; U.S. Docket No. RM13-17-000

[27] FERC Order 809; U.S. Docket No. RM14-2-000

Nuclear Uncertainty

Lower natural gas prices driven by abundant domestic supply, along with other economic and regulatory factors, have pressured the economic viability of 99 operable nuclear units. Confirmed and unconfirmed retirements of facilities are projected in California (Diablo Canyon), Illinois (Quad Cities and Clinton), Massachusetts (Pilgrim), and Nebraska (Fort Calhoun) during the next ten years. Other at-risk units are located in the northeastern states. Uncertainties and contributing factors to nuclear retirements include high operating costs with low prevailing power prices, regulatory issues, and public opposition.[28] **Figure 1.21** shows the forecasted and potentially advanced total nuclear capacity that could be affected. It is projected that 6.4 GW of capacity is ready to retire; this makes up five percent of the total installed capacity by 2026. The High Nuclear Retirement Case capacity values from NERC's *Clean Power Plan; Phase II Assessment*[29] indicate that a potential total of 26.8 GW, or 21 percent of all anticipated nuclear capacity, could be at risk to retire under this scenario.



Total Installed Capacity (GW)	**125,587**
Existing as of 2016	117,649
Projected	7,938
CPP High Nuclear Retirement Case (GW)	**26,800**
Forecasted LTRA	6,403
Additional to reach CPP case	20,397

Figure 1.21: Anticipated Nuclear Capacity by 2026

New York regulators recently introduced an energy plan that will preserve the economic viability of three upstate units. However, the retirement of seven remaining at-risk units would continue a recent trend since 2012 of decommissioned units in Florida (Crystal River), Wisconsin (Kewaunee), California (San Onofre), and Vermont (Vermont Yankee). Despite economic pressures on existing units, the Tennessee Valley Authority (TVA) started the Watts Bar two unit in mid-2016, following nearly three decades of a sluggish pace for new unit builds. According to the *2016 LTRA* Reference Case, four additional units are expected to be completed by 2021. These additions, combined with ongoing uprates to existing units in the United States, will result in a continued steady contribution of nuclear power over the next ten years.

Similar legislation was passed by the Illinois General Assembly that would authorize subsidies totaling $2.4 billion over the next decade to allow both Quad Cities and Clinton nuclear facilities to remain open.[30]

Recommendations

NERC should continue to monitor the potential effects of nuclear retirements on overall resource adequacy as well as potential mitigating factors such as state regulatory measures that provide incentives for nuclear facilities to remain operational.

[28] World Nuclear: Nuclear Power in the USA; September 26, 2016
[29] Potential Reliability Impacts of EPA's Clean Power Plan Phase II; May 2016
[30] Illinois General Assembly: Bill Status of SB2814

Chapter 2: Probabilistic Analysis

Probabilistic analyses describe events in terms of how probable they are and include performance characteristics of BPS components, such as generator outage rates, resource realizations in terms of energy produced, load characteristics, and transmission congestions or constraints. A prediction of future reliability must be expressed in terms of the expected performance of the system components and the uncertainty in those expectations. Probabilistic methods typically rely on either statistical analyses of historical performance or enumeration techniques that are capable of simulating large numbers of contingencies. However, the choice of methods and selection of acceptable reliability levels are still matters of judgment and differ from Region to Region (and from utility to utility in some cases).

The analytical processes used by resource planners range from relatively simple calculations of planning reserve margins to rigorous reliability simulations that calculate system Loss of Load Expectation (LOLE) or Loss of Load Probability (LOLP) values.[31] The one-event-in-ten-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 ten-year period. Utilities, system operators, and regulators across North America rely on variations of the one-event-in-ten year criterion for ensuring and maintaining resource adequacy.

Sensitivity Model

Sensitivity analyses around Monto-Carlo-simulated reserve margins can be run by treating specific (independent) variables as random. To demonstrate how any independent variables impact reserve margin results, a simulation was run for a generic summer-peaking system. **Figure 2.1** shows the resulting reserve margin uncertainties from 2018 to 2026 using probabilistic distributions of wind and solar power from actual time series profiles. Due to the random variability of the simulated wind and solar, the uncertainty around the calculated reserve margin mean is demonstrated. This is indicated in the figure whereby the area in blue shows the resulting bandwidth of one standard deviation from the mean and the grey shows two standard deviations from the mean.

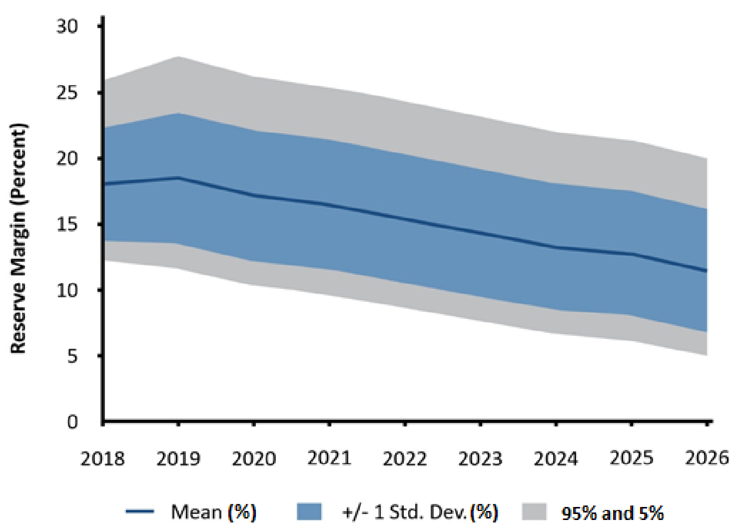


Figure 2.1: Reserve Margin Uncertainty Due to Wind and Solar Variability

[31] A traditional planning criterion used by some resource planners or load-serving entities is maintaining system LOLE below one day in ten years. Loss-of-Load Expectation (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 load demand (instead of the daily peak load) at least once during that day.

This generic model was further explored by running additional simulations to other applied independent variables. DSM, Tier 1 capacity resources, and firm transactions risk profiles are developed based on historical statistical performance data provided in the NERC 2015 Electricity Supply & Demand database and the use of engineering judgments. **Figure 2.2** shows a tornado diagram highlighting the sensitivity of these other input parameters and ranking them by their effect on reserve margin mean values for 2016. The figure ranks the sensitivity of an output reserve margin from different independent variables. The following variables were considered for this analysis: demand, wind, solar, demand-side management (DSM), existing-certain resources, Tier 1 resources, and firm capacity imports and exports. **Figure 2.2** shows how much a one standard deviation change in input variables affects the output reserve margins. The width of each parameter directly represents the impact an independent variable can have on reserve margins and the degree of which uncertainty can be assumed.

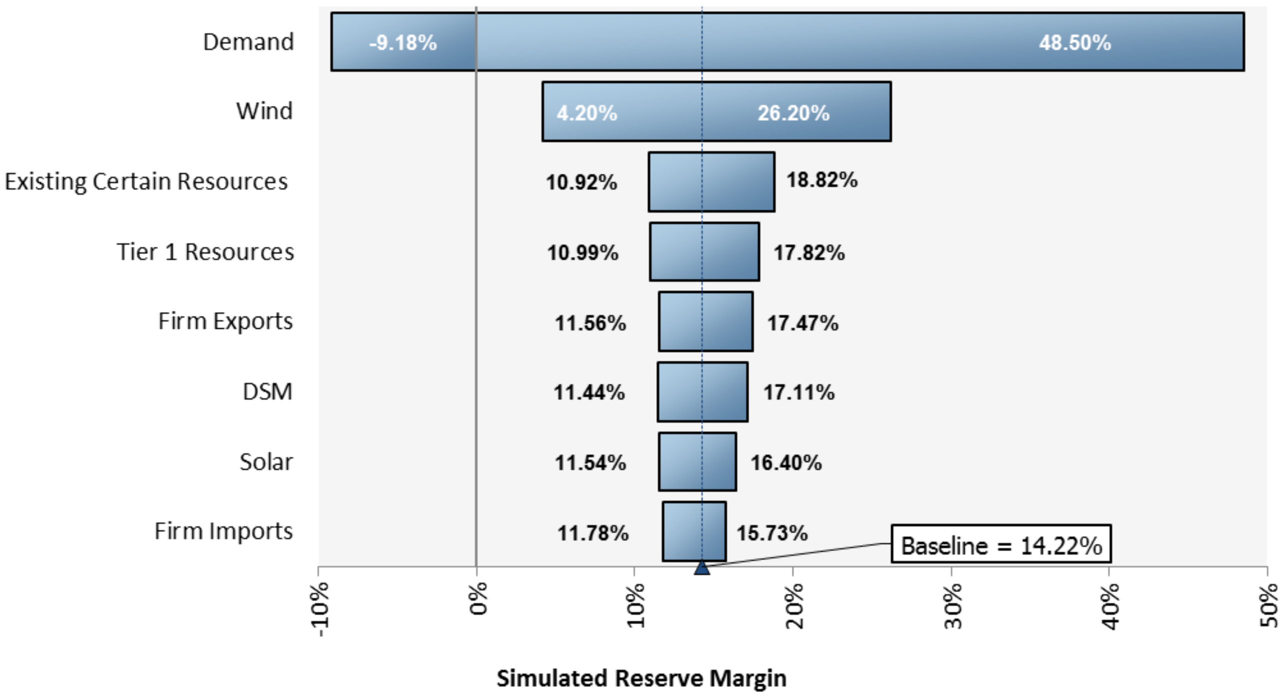


Figure 2.2: Tornado Plot for 2016 Simulated Reserve Margin Ranked by Effect of the Reserve Margin's Mean

Probabilistic distributions were assigned to hourly demand, wind, and solar power profiles. Additionally, risk profiles were applied to DSM, Tier 1 capacity resources, and firm transactions based on past performances. The results in **Figure 2.2** shows that demand is the most impactful parameter that drives this generic system's simulated reserve margin. Specifically, accurate load modeling and forecast uncertainty modeling are critical aspects for effective resource adequacy planning. The second most sensitive parameter is wind power due to the large percent share of the system's generation mix. This analysis also shows the least sensitive and least influential input parameter is solar due its relatively small percent share of the generation mix.

As each system includes a unique set of independent variables, and this type of analysis is helpful in determining the most significant parameters of a given system. Planners can then judge which risks to take and which ones to avoid in maintaining resource adequacy while allowing for best operational and planning decisions under prevalent uncertainty.

VER Capacity Contributions

For a reserve margin analysis, the capacity contributions of installed variable energy resources (VERs) are the values that are expected to be available to an assessment area across the peak load hour. The calculation of the capacity contribution of conventional generating units are straightforward and are based on unit performance ratings, forced outage rates, and annual unforced maintenance cycles. However, the capacity contributions of VERs are not intuitive due to their inherent characteristics. There are two major attributes of variable generation that notably impact bulk power system planning and operations:[32]

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

Many factors are affecting the system-wide increases of renewable resources and are the predominant choice for renewable energy integration. In high-VER penetration conditions, a larger portion of the total resource portfolio will be comprised of energy-limited resources when applied to today's power system. This fact somewhat complicates, but does not fundamentally change, existing resource adequacy planning processes as they are still driven by a reliability-based set of metrics. Resource adequacy can be confirmed through detailed reliability simulations that compare expected demand profiles with specific generating unit's forced outage rates and maintenance schedules to yield LOLE or LOLP values. Reliability simulations typically include probabilistic production cost simulations for meeting a specified demand curve (or chronological curve) from a specified generation fleet while incorporating the forced and unforced outage rates over the simulation period.

Current approaches used by resource planners fall into four basic categories:[33]

- A rigorous LOLE/LOLP-based calculation of the effective load-carrying capability (ELCC) of variable generation relative to a benchmark conventional unit
- Calculation of the capacity factor of the variable generation during specified time periods that represent high-risk reliability periods (typically peak hours)
- A tailored approach for applying a historical performance rolling average (typically 2–3 year)
- Applications based on policies established through a nontechnical analysis

[32] More details on variable generation attributes can be found on the now-disbanded Integration of Variable Generation Task Force Special report on Standard Models for Variable Generation

[33] More information of these approaches can be found in NERC's Special Reliability Assessment: Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning

The capacity contribution component of VERs differs greatly from that of conventional generation. Conventional generation uses typical summer and winter ratings that do not differ greatly from the nameplate capacity rating. Because the capacity contributions from VERs are a statistical representation of normal operations, NERC monitors the methods and assumptions for calculating these components. In addition to assessment areas using varying methods to calculate capacity contributions for future generation, additional variances arise when considering areas with capacity market structures. **Figure 2.3** and **Figure 2.4** show the wind and solar nameplate values and their on-peak capacity contributions anticipated by all applicable assessment areas for 2021.

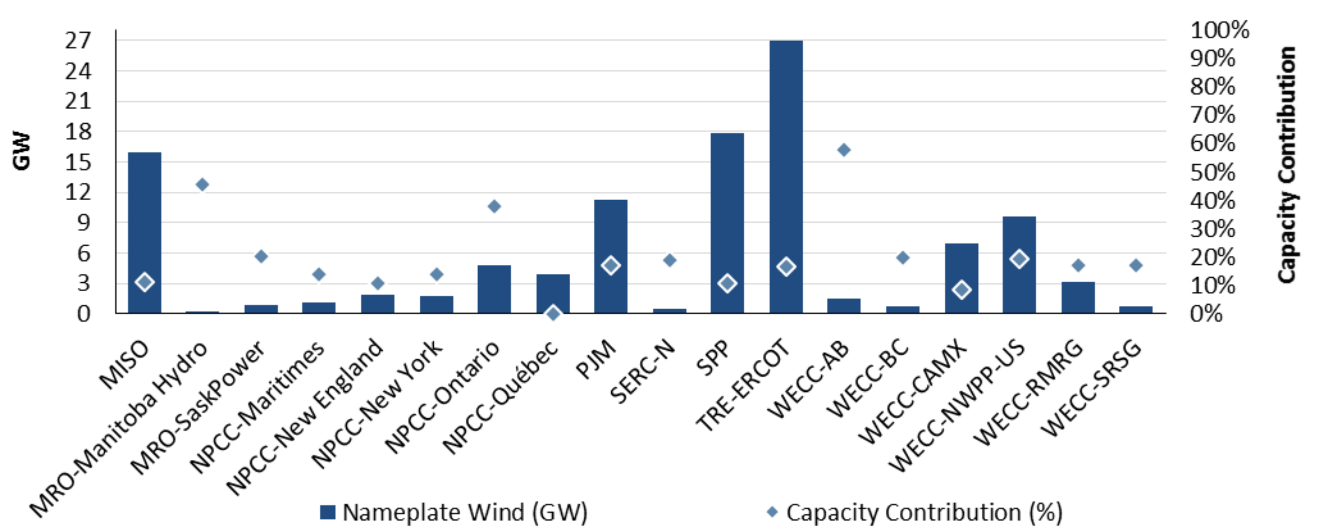


Figure 2.3: 2026 Existing and Tier 1 Wind

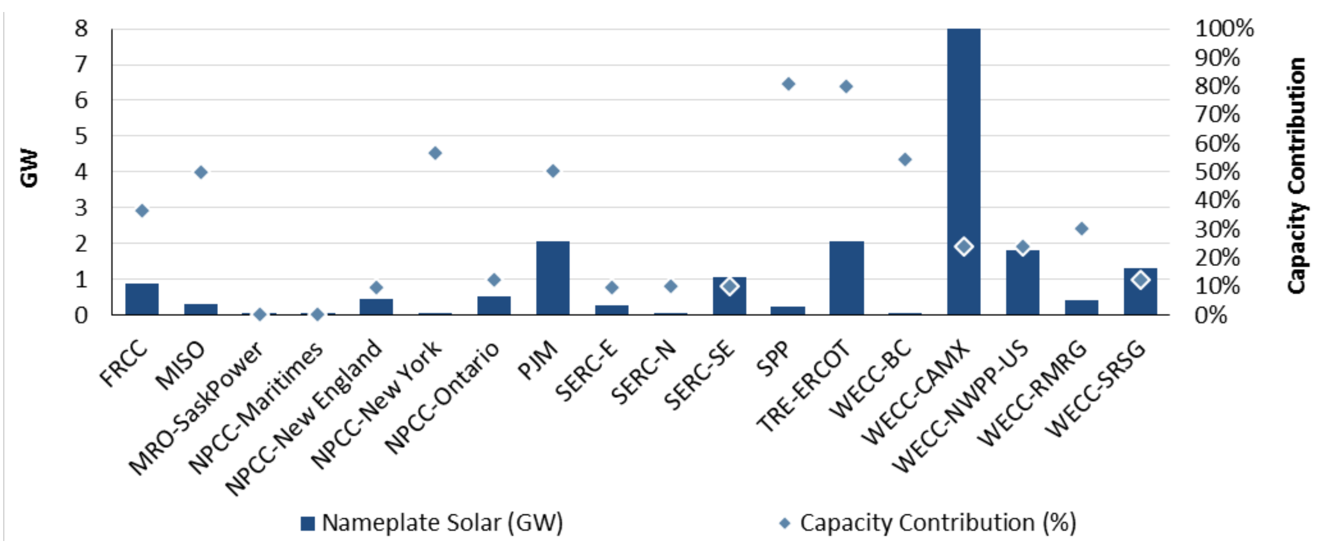


Figure 2.4: 2026 Existing and Tier 1 Solar

A generic summer-peaking model was further explored to analyze any changes to reserve margin requirements due to changes in VER capacity contribution levels. This additional analysis maintained an equal quantity of all resource types but applied a high and low capacity contribution for both solar and wind units. **Figure 2.5** shows that for higher VER capacity contributions, the Reference Margin Level would need to be increased to maintain a constant LOLE of 0.1 days per year. If capacity contributions are calculated accurately or conservatively, then the current Reference Margin Level would be sufficient.

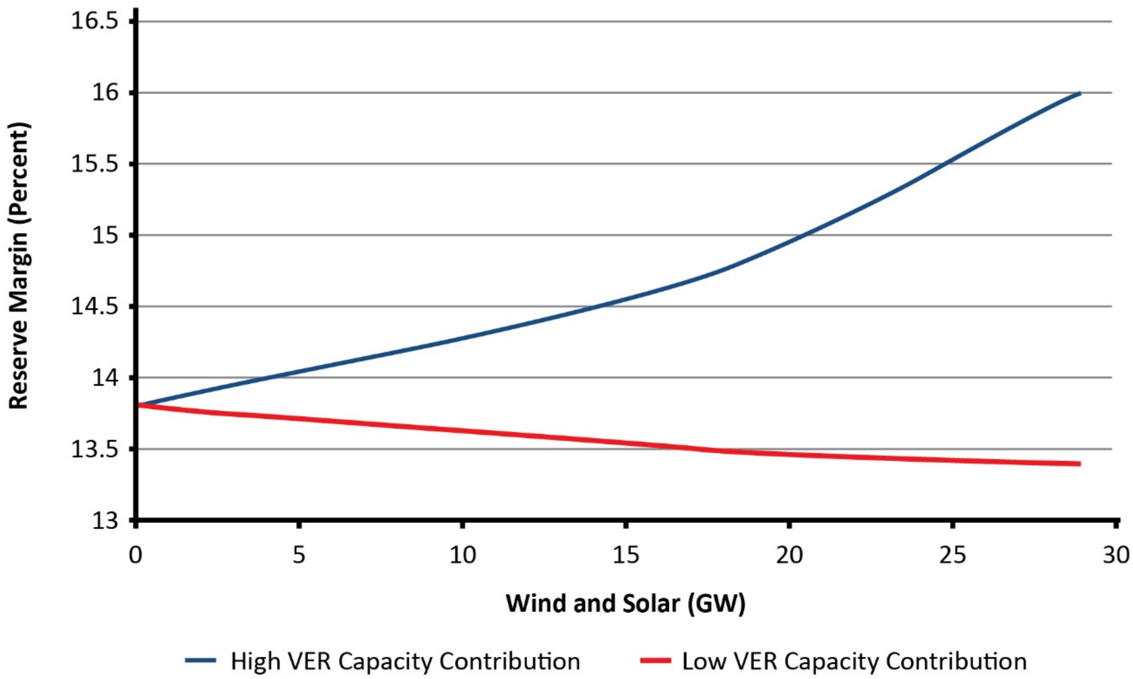


Figure 2.5: Reference Margin Level Increases with Added VER

Due to the identified relationship between Reference Margin Level and VER capacity contributions, consistent and accurate methods are needed. There are existing simplified approaches to calculate VER capacity values, and these can be easily extended to cover other forms of variable generation. In general, these methods calculate the resource's capacity factor over a time period that corresponds to system peaks. These approaches can provide a reasonable, simple approximation for capacity values. However, system characteristics, in some cases, may result in a mismatch between a rigorously calculated ELCC and a peak-period capacity factor as an approximation of capacity value. Simplified approaches should be benchmarked and calibrated to the rigorous ELCC calculations to ensure the validity of any approximation.

Chapter 3: Essential Reliability Services

The North American electric grid is experiencing a shift in the resource mix, driven by a variety of factors that include retirements of conventional resources and the integration of new resources. This leads to potential impacts on essential reliability services (ERSs), such as frequency, voltage, and ramping capability. This transformation in the resource mix will change the planning and operation practices of the current electric grid. Although many resources are able to provide the essential services needed to maintain BPS reliability, understanding system characteristics and related behaviors will aide in successful integration of new technologies. BPS planning and operations will be tailored to incorporate this transformation in order to maintain reliability.

In order to study these implications, NERC formed the Essential Reliability Services Task Force (ERSTF), which produced its final report in December 2015.[34] The report studied the three reliability blocks: 1) Frequency Support, 2) Voltage Support, and 3) Net Demand Ramping Variability. The task force developed a total of nine measures for the essential services, conducted data analyses for five of them using three years of historical data and three years of forward looking data, and proposed considerations for industry practices for the remaining measures. In addition, the task force studied the potential impact of a substantial penetration of distributed energy resources (DERs) that, in aggregate, could impact the reliability of the BPS. Finally, the report recommended the developed measures be continually monitored for any trends that could potentially impact reliability. A summary of the recommendations from the framework report are listed below:

- All new resources should have the capability to support voltage and frequency. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.
- The measures are intended to highlight aspects of reliability that could suggest future reliability concerns. They should be addressed with suitable planning and engineering practices.
- Planning and operating entities should use industry practices that will help ensure that emerging concerns are addressed with system specific planning and engineering practices.
- The task force recognized that DERs will increasingly affect the net distribution load that is observed by the BPS. Pursuant with NERC's reliability assessment obligations, the ERSTF further recommends that NERC establish a working group to examine the forecasting, visibility, control, and participation of DERs as an active part of the BPS. With prudent planning, operating and engineering practices, and policy oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.[35]
- The reliability of the system can be maintained or improved as the resource mix evolves, provided that sufficient amounts of ERSs are available. This can be achieved by sharing of experiences and lessons learned around the industry.

In 2016, the ERSTF transitioned to a working group (now known as ERSWG) and was charged with examining methodologies to determine sufficient levels of each ERS. In addition, this working group was asked to form a task force under their purview to address challenges and potential risks from increasing DERs.

The ERSWG is presently formulating a whitepaper that focuses on methods to develop sufficiency guidelines around the proposed ERSTF measures. These sufficiency guidelines are more process oriented and include the following: frequency response, voltage limits, and ramping models that tend to vary by particular area and Balancing Authority. The whitepaper further explores important technical considerations so the industry can understand, evaluate, and prepare for the increased deployment of variable energy resources (VERs), retirements of conventional coal units, increases in demand response (DR) and distributed technologies, and other changes to the traditional characteristics of generation and load resources. The working group is currently in the process of

[34] ERSTF Final Measures Framework Report

[35] The Distributed Energy Resources Task Force (DERTF) was created in early 2016

collecting data for the proposed measures and evaluating them by using the sufficiency methodology, the results of which will be finalized by end of 2017.

Frequency Support

Frequency support is provided through the combined interactions of synchronous inertia, primary frequency response (PFR), and secondary frequency response. Working in a coordinated fashion, these characteristics and services arrest the decline in frequency and eventually return the frequency to the desired level. **Figure 3.1** below shows a typical frequency excursion and recovery, whereby the red line indicates the initial rate of change of frequency (RoCoF) due to inertial responses from synchronous machines.

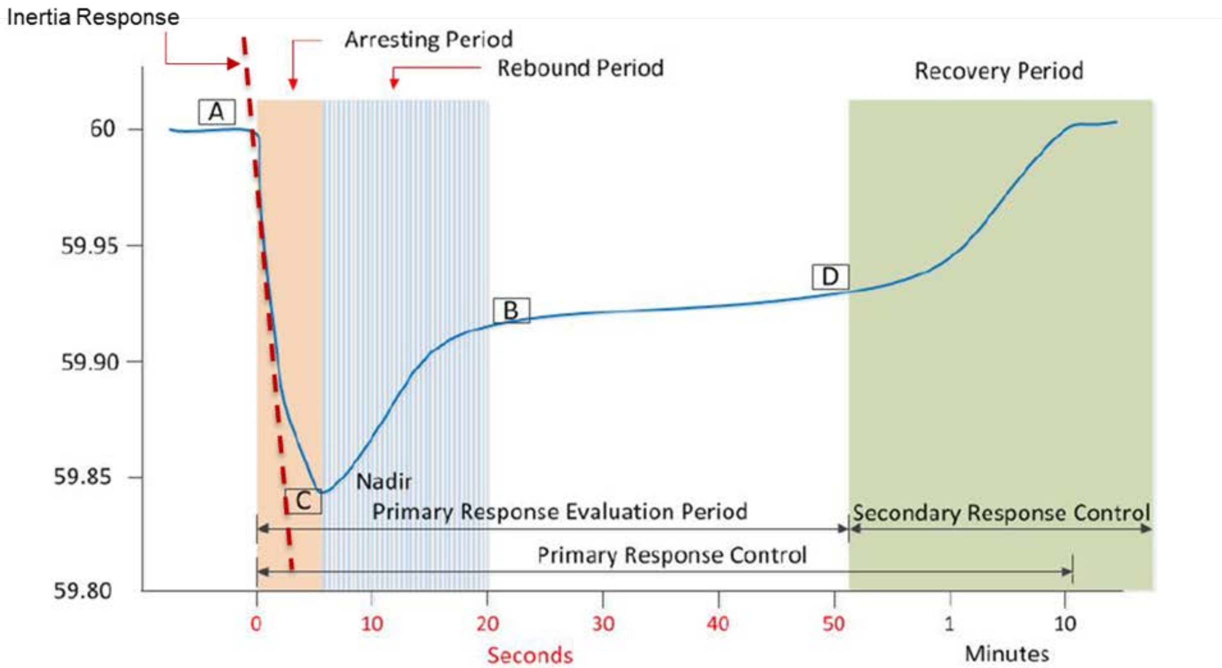


Figure 3.1: Typical Frequency Excursion and Recovery

It is important to determine various levels of inertia for a future resource mix to ensure that the system doesn't fall below a minimum level. Some newer technologies, such as wind turbines, provide the capability to inject real power at a fast rate during a frequency excursion, and thus all resources need to be taken into account in planning and operating considerations of a system. With the increasing use of nonsynchronous generation and other electronically-coupled resources (both generators and loads), the level of synchronous inertial response is reduced. This leads to a need to consider both the amounts of synchronous inertia and the available amounts of PFR based on expected conditions.

Frequency support encompasses inertia, nadir, PFR, and secondary frequency response. While inertia is just a component of overall frequency response, it plays an important role in arresting the RoCoF and prevents the nadir from reaching the level of under-frequency load shedding. Measure 4 evaluates the detailed anatomy of a frequency excursion, such as adding the calculation of Point C and time parameters in a typical event as shown in **Figure 3.1**. Measure 4 will be analyzed further in the 2017 State of Reliability Report for analysis of qualified 2016 frequency events. Measures 1–3 in the *ERSTF Framework Report* analyze the inertia and associated RoCoF. The results of data gathering for inertia and RoCoF measures for ERCOT and the Eastern Interconnection (EI) are presented here.

ERCOT

In Texas, ERCOT determined it is important to track system-level inertia in real-time to ensure system reliability. **Figure 3.2** shows the snapshot of ERCOT's real-time dashboard for inertia. The operator is able to observe total inertia and load in this single display. The dashboard also shows 24-hour inertia contributions by generator type. Monitoring by types of resources is done to enable more granular analysis of inertia trends in real-time.

Figure 3.2: ERCOT Dashboard to monitor real-time inertia

As part of the trend monitoring of ERSWG Measures 1-3, ERCOT (and other interconnections) started collecting the inertia data on June 1, 2016.

Figure 3.3 represents the inertia data for ERCOT by hour in box plot format. On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, the whiskers correspond to +/- 2.7 sigma (i.e., represent 99.3 percent coverage, assuming the data are normally distributed), and the outliers are plotted individually (red crosses).

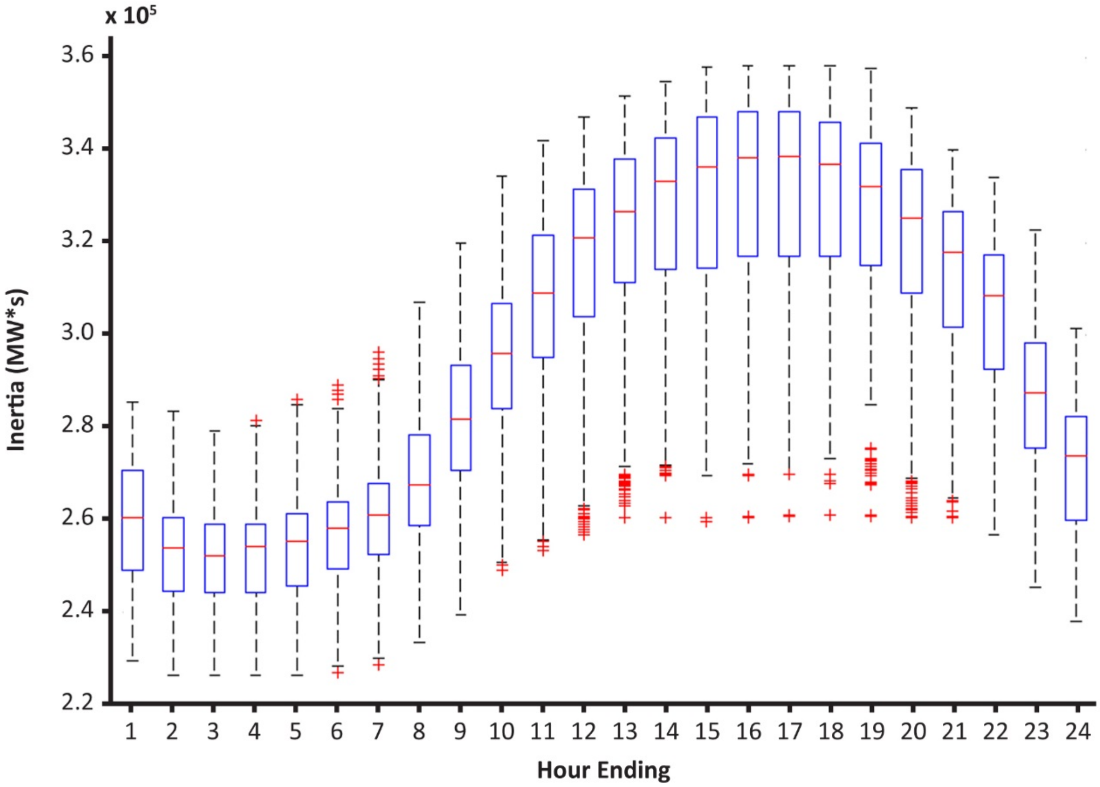


Figure 3.3: ERCOT Inertia by Hour of Day (June 1–July 15 2016)

Figure 3.4 represents a more granular version of **Figure 3.3** in that it shows ERCOT's inertia data in 15-minute intervals. Ultimately, both figures display the pattern of system inertia that mostly coincides with load levels. Inertia at low load levels becomes a challenge for providing frequency response in case of a frequency excursion.

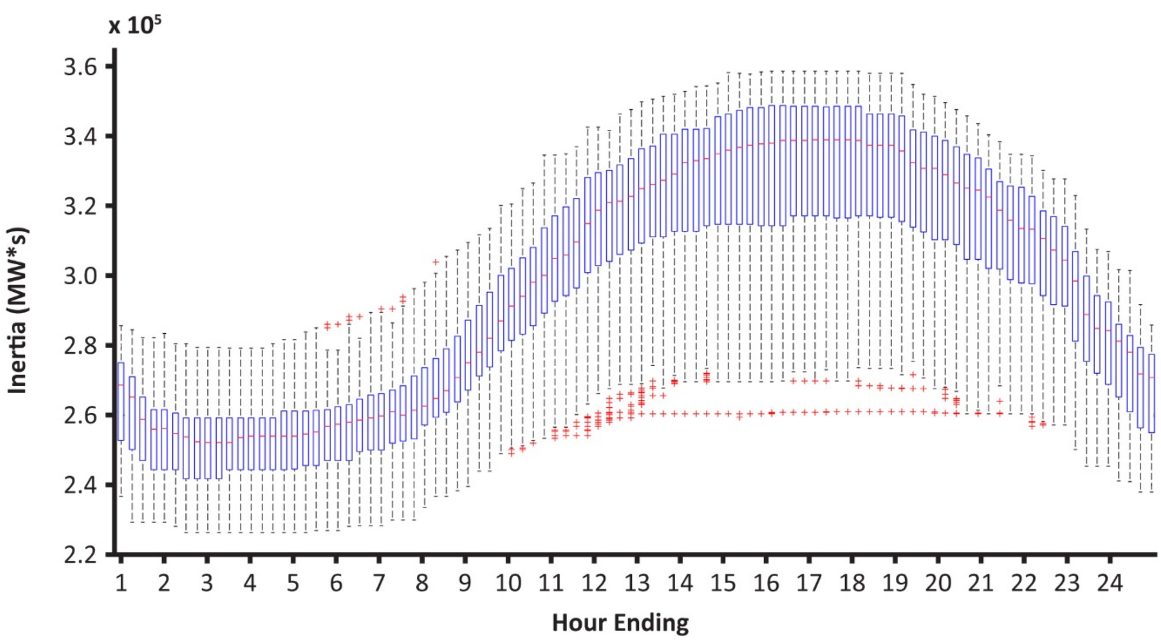


Figure 3.4: ERCOT Inertia by 15-minute Interval of Day (June 1–July 15 2016)

Eastern Interconnection

The Eastern Interconnection (EI) has significant levels of synchronous generation that allow sufficient contributions of inertia as shown in **Figure 3.5** below. The figure shows the total interconnection inertia contributions following changes to load levels. Based on the availability of data, system level monitoring of inertia and thus potential frequency response can be evaluated.

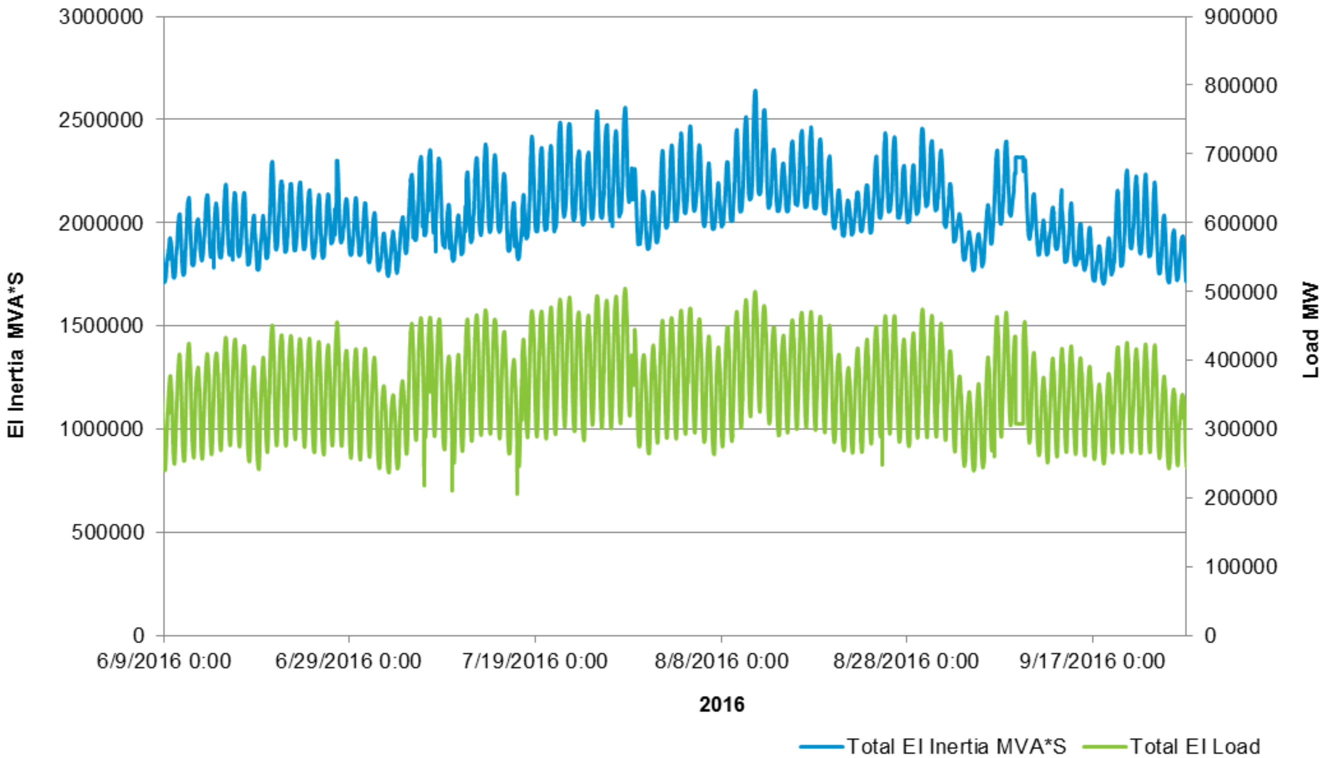


Figure 3.5: Eastern Interconnection System Inertia

Primary Frequency Response Analysis

PFR, as shown in **Figure 3.1**, has been identified by NERC's Operating Committee and Planning Committee as an ERS that will be affected by the changing grid characteristics of the North American BPS. The changing grid will be characterized by an increased penetration of new technology resources and the retirement of conventional generating resources.

NERC is studying PFRs, which relate the size of the resource lost to the resulting net change in system frequency during the period when stabilizing frequency is determined following the initiating event. To study the changing characteristics and PFR performance of the grid, NERC will use power system computer planning models. These planning models will be used to develop scenarios of the future system that will be studied to gain a detailed understanding of various factors affecting PFRs and the resulting under-frequency load shedding (UFLS) system operation. UFLS systems are designed as a backstop to prevent such events from cascading across the BPS. Primary frequency controls are deemed adequate if, following the sudden loss of the largest generator, the primary frequency control response provided by on-line resources successfully arrests and stabilizes frequency decline. This should be prior to initiating any UFLS action to arrest further frequency decline by dropping firm customer loads.[36]

[36] Largest generation loss is defined as largest category C (N-2) event; except for Eastern Interconnection, which uses largest event in the last 10 years.

NERC will perform various analyses to study the effect of replacing conventional generation with increased penetrations of new technology resources. These analyses will determine how various future scenarios of NTR plant additions and Clean Power Plan (CPP) retirements impact the system PFR. With understanding from these analyses, NERC will develop an objective basis for understanding the reliability implications of varying levels of integration and penetrations of NTRs on PFR. This study therefore has three major purposes:

- Understand the interconnection-wide reliability implications of the changing resource mix on frequency response.
- Evaluate policy issues, such as the CPP implementation, with sensitivities of the changing resource mix, control strategies, and other assumptions.
- Support future proposals for rule making.

The final report will be an assessment of the reliability risks and it will recommend technical guidance to mitigate risks of encountering system conditions that will result in UFLS protective actions. This report will document the results of the PFR evaluations, provide a firm basis for future system reliability risk determinations, and identify potential solutions that will assure a continuation of an adequate level of frequency response is maintained for the reliable operation of the BPS using conventional and new technology resources.

This frequency response study will be completed in three phases over approximately three years.

1. Phase I will study PFR for the EI by using detailed frequency modeling for existing and future plants with a load modeled by the ZIP Load Model. The ZIP Load model is characterized by coefficients of a load model comprised of constant impedance (Z), constant current (I), and constant power loads (P).
2. Phase II will study PFR for the EI by using detailed frequency modeling for existing and future plants with load modeled by a complex load model (CLM). The CLM model will replace the constant MVA, current, and impedance load with a composition of loads consisting of large and small induction motors, discharge lighting, constant MVA load, and a static load response.
3. Phase III will study PFR for the Eastern Interconnection, ERCOT, and the Western Electricity Coordinating Council by using detailed frequency modeling for existing and future plants, loads modeled by a CLM model, DER modeling, and energy storage modeling.

Net Load Ramping

Changes in the amount of nondispatchable resources, transmission system constraints, load behaviors, and resource mix can impact the ramp rates needed to keep the system load and generation in balance. Most areas that have wide-scale integration of DERs may experience planning or operational issues due to large load ramps. For example, solar photovoltaic (PV) is heavily integrated into the electric system in California ISO (CAISO), and operators there are faced with multi-hour ramps during the evening hours partly coinciding with sunset. Hence, CAISO must ensure that enough system ramping capability is available to follow the fast net load fluctuations.

With the increasing penetration of generation resources for which the BA may have limited ability to control the level of output, consideration of system ramping capability becomes an even more important component of planning and operations. CAISO has been experiencing challenges with ramping inter- and intra- hour; these challenges were studied and presented through the duck curve,[37] shown below in **Figure 3.6**. On May 15, 2016, actual net-load dropped to 11,663 MW from the projected 2016 load of just over 15,000 MW, which is four years ahead of the original "duck curve" estimate. Thus CAISO is experiencing the issues with ramping in advance of the previously predicted time frame.

[37] CAISO - Flexible Resources to Help Renewable - Fast Facts

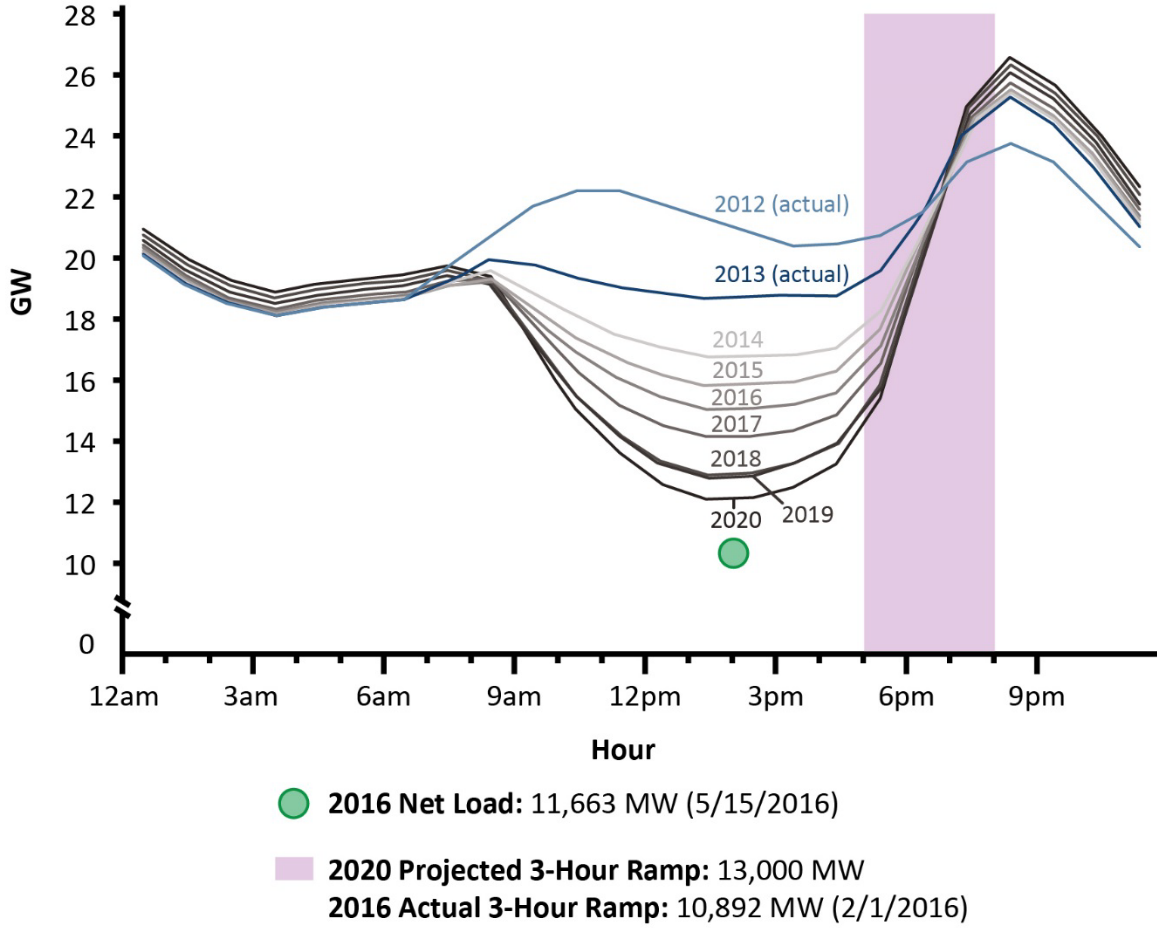
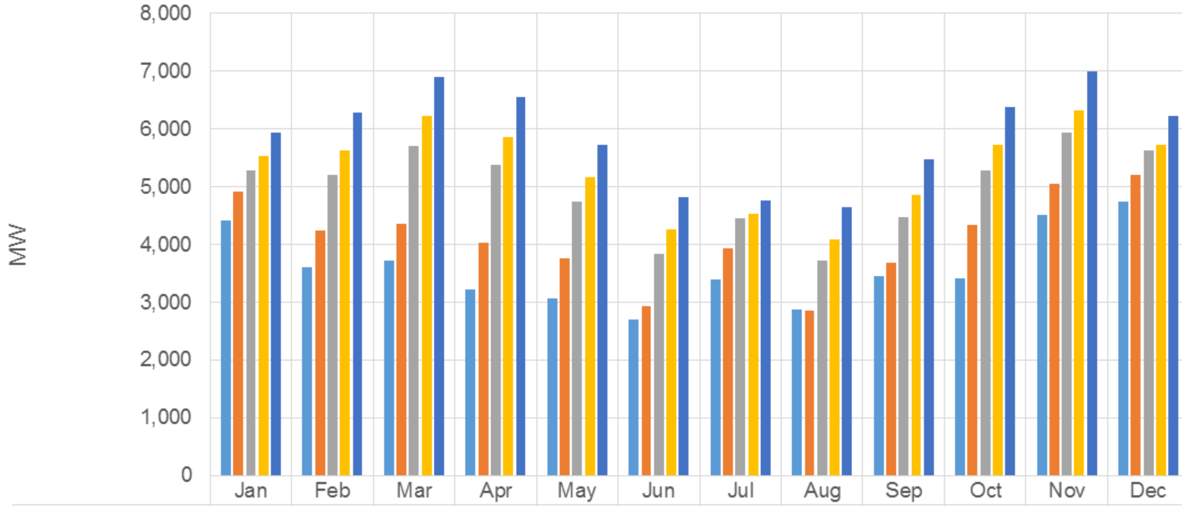


Figure 3.6: Analysis of CAISO Duck Curve

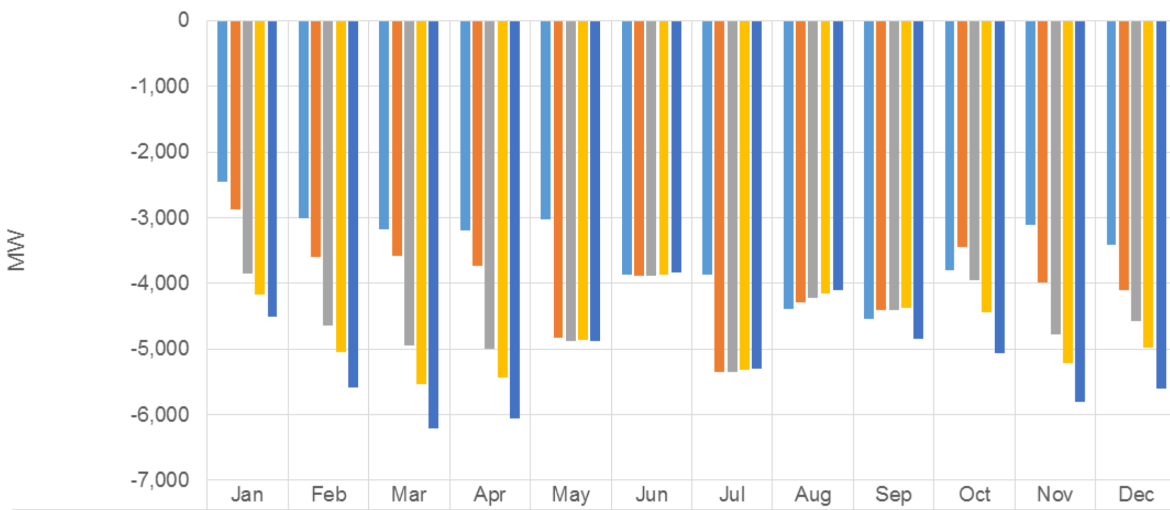
Based on the experience with net load ramping, CAISO projects the future ramps to be higher than previously projected. Below are the projections for CAISO's ramping from 2015 actual ramps to 2019 projected one-hour upward and downward ramps, shown in **Figure 3.7** and in **Figure 3.8** respectively. The three-hour upward and downward ramp projections are shown in **Figure 3.9** and **Figure 3.10** respectively.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_1HR_Actual	4,421	3,610	3,723	3,215	3,064	2,698	3,395	2,879	3,462	3,406	4,503	4,753
2016_1HR_Rmp	4,908	4,250	4,366	4,039	3,753	2,926	3,929	2,854	3,684	4,342	5,061	5,197
2017_1HR_Rmp	5,285	5,214	5,711	5,372	4,745	3,847	4,445	3,725	4,474	5,280	5,938	5,632
2018_1HR_Rmp	5,529	5,635	6,230	5,856	5,172	4,265	4,539	4,088	4,865	5,717	6,330	5,725
2019_1HR_Rmp	5,941	6,279	6,891	6,544	5,725	4,818	4,763	4,648	5,479	6,372	6,990	6,232

2015_1HR_Actual 2016_1HR_Rmp 2017_1HR_Rmp 2018_1HR_Rmp 2019_1HR_Rmp

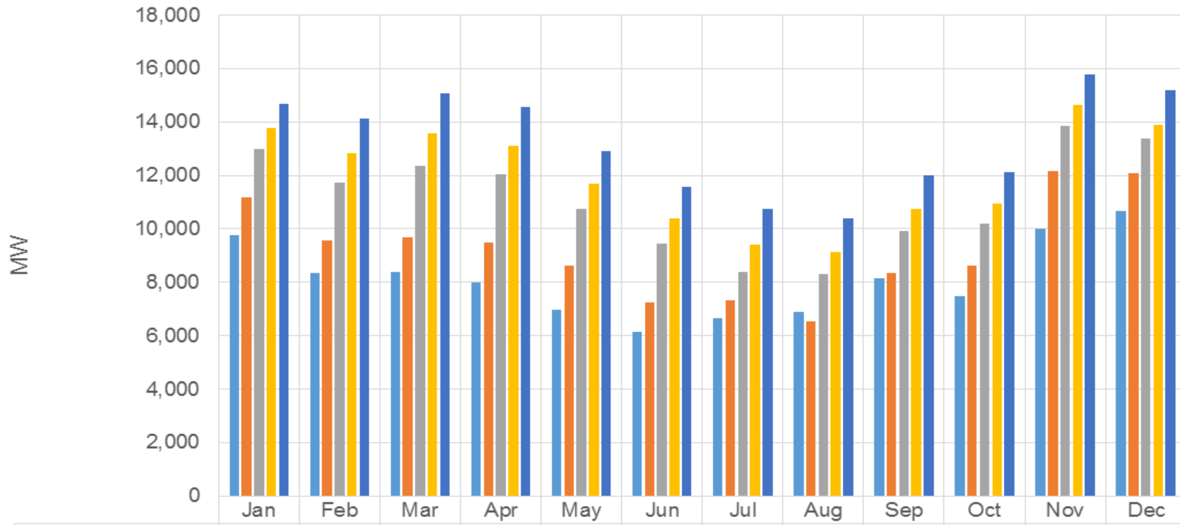
Figure 3.7: CAISO 2015–2019 Monthly One-Hour Upward Ramps



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_1HR_Actual	-2,454	-3,013	-3,168	-3,201	-3,027	-3,864	-3,875	-4,389	-4,535	-3,799	-3,102	-3,408
2016_1HR_Rmp	-2,868	-3,591	-3,574	-3,726	-4,826	-3,890	-5,351	-4,288	-4,407	-3,443	-3,981	-4,109
2017_1HR_Rmp	-3,849	-4,645	-4,941	-4,994	-4,872	-3,879	-5,349	-4,214	-4,402	-3,952	-4,782	-4,582
2018_1HR_Rmp	-4,168	-5,038	-5,543	-5,437	-4,855	-3,863	-5,319	-4,151	-4,366	-4,440	-5,222	-4,977
2019_1HR_Rmp	-4,509	-5,587	-6,205	-6,051	-4,870	-3,833	-5,303	-4,110	-4,837	-5,057	-5,806	-5,608

2015_1HR_Actual 2016_1HR_Rmp 2017_1HR_Rmp 2018_1HR_Rmp 2019_1HR_Rmp

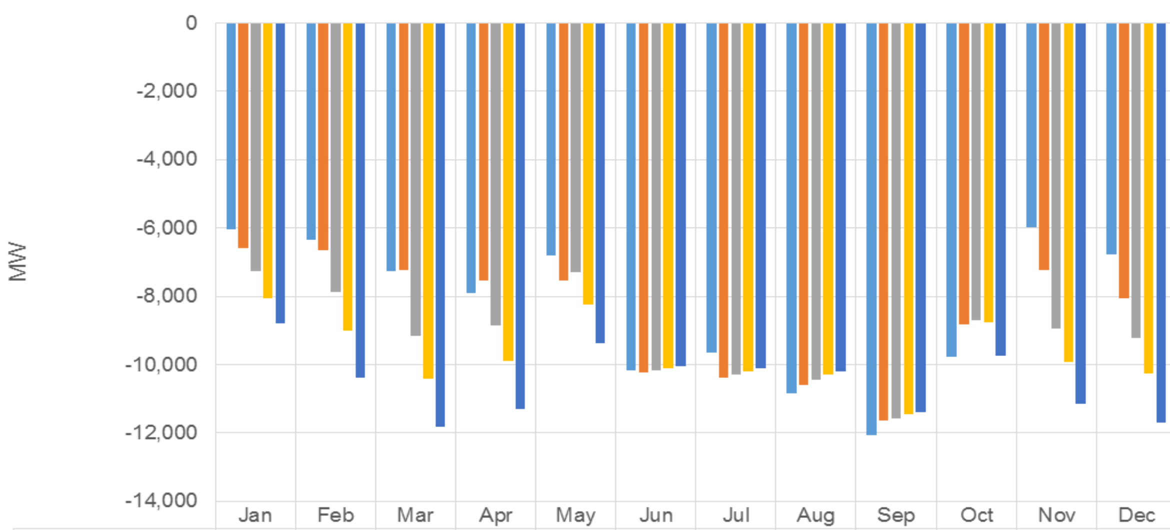
Figure 3.8: CAISO 2015–2019 Monthly One-Hour Downward Ramps



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_3HR_Actual	9,775	8,366	8,367	8,001	6,962	6,153	6,672	6,882	8,158	7,469	9,987	10,684
2016_3HR_Rmp	11,191	9,578	9,700	9,484	8,629	7,262	7,335	6,540	8,353	8,640	12,155	12,096
2017_3HR_Rmp	12,970	11,729	12,364	12,054	10,737	9,464	8,397	8,295	9,918	10,196	13,835	13,399
2018_3HR_Rmp	13,758	12,846	13,596	13,117	11,672	10,383	9,402	9,123	10,728	10,939	14,636	13,896
2019_3HR_Rmp	14,691	14,114	15,067	14,543	12,904	11,571	10,750	10,407	12,003	12,121	15,781	15,186

2015_3HR_Actual 2016_3HR_Rmp 2017_3HR_Rmp 2018_3HR_Rmp 2019_3HR_Rmp

Figure 3.9: CAISO 2015–2019 Monthly Three-Hour Upward Ramps



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015_3HR_Actual	-6,033	-6,353	-7,276	-7,903	-6,795	-10,179	-9,658	-10,837	-12,059	-9,756	-5,974	-6,766
2016_3HR_Rmp	-6,578	-6,652	-7,217	-7,549	-7,525	-10,224	-10,375	-10,606	-11,652	-8,834	-7,245	-8,067
2017_3HR_Rmp	-7,277	-7,882	-9,162	-8,842	-7,284	-10,166	-10,288	-10,442	-11,571	-8,712	-8,958	-9,224
2018_3HR_Rmp	-8,065	-9,003	-10,424	-9,901	-8,237	-10,110	-10,185	-10,301	-11,455	-8,767	-9,928	-10,270
2019_3HR_Rmp	-8,803	-10,375	-11,822	-11,292	-9,384	-10,043	-10,110	-10,212	-11,392	-9,730	-11,152	-11,690

2015_3HR_Actual 2016_3HR_Rmp 2017_3HR_Rmp 2018_3HR_Rmp 2019_3HR_Rmp

Figure 3.10: CAISO 2015–2019 Monthly Three-Hour Downward Ramps

ERCOT's Resource Flexibility Analysis Method

EPRI has created several flexibility metrics that can be helpful for performing ramping analysis. One metric is periods of flexibility deficit, which is a count of the number of intervals in the study period where net flexibility is below zero. Periods of flexibility deficit is calculated for a specific time horizon as well as for ramp direction. Another metric is expected unserved ramp, which is the total magnitude of negative net flexibility.

ERCOT is using the methodology for performing this analysis. The methodology assumes that the study period is a full year and the time resolution is five minutes, but it can be modified to accommodate different study periods and time resolutions.

The first step in performing the flexibility study for a future year is to prepare a generator database of all generators that will be active in the study year; this includes existing generators that are not scheduled to retire before the study year as well as planned generators that are scheduled to be on-line during the study year.

The next step is to obtain hourly profiles for wind, solar, and load for the study year, and then interpolate these profiles into a higher resolution.

The hourly wind, solar, and load profiles are used as inputs into a production cost simulation tool along with the generator database prepared earlier. Any resources with fixed schedules or must-run units should be modeled as such in the production cost simulation. ERCOT uses Energy Exemplar's Plexos to perform 365 daily optimization runs with a one-day look ahead in order to obtain unit commitments for the entire study year.

Each unit's commitment status must be found for each hour of the year from the hourly production cost simulation run, and the temporal resolution of the hourly wind, solar, and load profiles must be increased to a five-minute resolution. Once this is due, a sequential production cost simulation should be performed in order to obtain each unit's five-minute dispatch for the study year to serve the given net load. Again, in this dispatch run, capacity reserved for provision of the AS is not available for dispatch except for nonspinning reserves that are generally available in ERCOT in energy scarcity situations. This dispatch data, along with the generator database and the five-minute load data, are the inputs to EPRI's InFLEXion tool. The InFLEXion tool can perform all of the analysis described in this document as well as additional ramping/flexibility analyses.

ERCOT's Sample results

Figure 3.11 below shows the average one-hour net load ramps for each hour of each day in the same time period. Negative numbers in this figure represent hours where the average net load ramp was in the downward direction rather than upward.

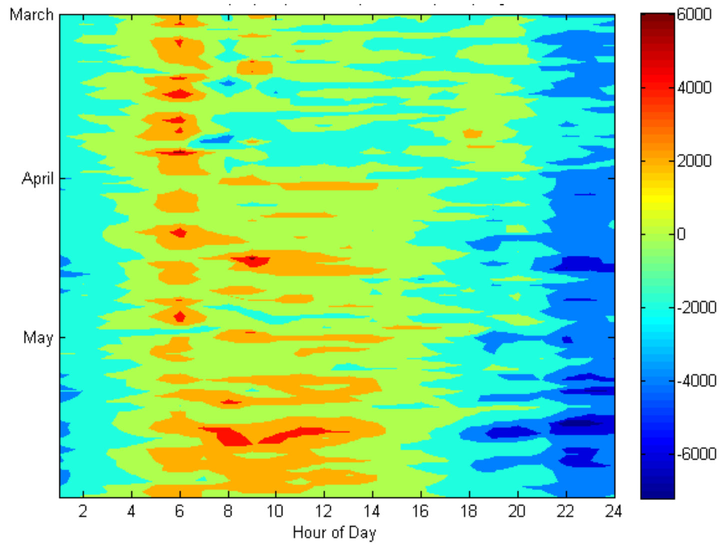


Figure 3.11: ERCOT's Net Load One Hour Ramps for Spring 2017

The heat map **Figure 3.11** shows the pattern of upward or downward ramps for the spring of 2017 by the hour of the day. The pattern forecasts ramps to occur during the early morning and at late night.

In addition to calculating the ramp up, ERCOT forecasted available flexibility resources that can be used to meet the ramps. **Figure 3.12** below shows the average amount of available upward flexibility that can be provided by the resource fleet to serve one-hour net load ramps for each hour of each day in the spring of 2017. The available flexibility is calculated based on what units are on-line and able to increase generation from their current operation point (as obtained from production cost simulation) as well as units that are off-line but could start up quickly enough to help serve the ramp (if necessary), including off-line nonspinning reserves. Note that in this level of analysis, all reserves are considered available to follow expected net load ramps

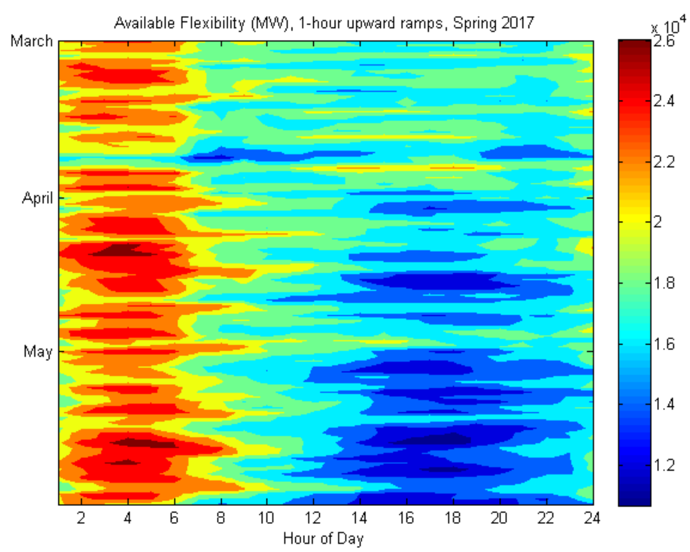


Figure 3.12: ERCOT's Available Flexibility for One Hour Ramps in Spring 2017

ERCOT is currently working on improving unit commitments to include the tradeoff between using coal and natural gas fuels. The PLEXUS tool is optimal for plant startup and run times, but it doesn't consider human behavior as well as shortened or prolonged maintenance schedules. In addition, EPRI is considering improving the process for their InFLEXion tool to include transmission constraints.

Hourly CPS1 Evaluation on Interconnection Basis

For areas where ramping is not a significant challenge, there needs to be a different method of evaluating whether that area is or would be experiencing ramping-related challenges. Historical Control Performance Standard (CPS) hourly data can be an indication of potential ramping issues. A BA can evaluate its historical ramps against its real-time control performance standard (CPS1)[38] to determine whether it is beginning to experience ramping problems. This can be accomplished by evaluating hourly CPS performance data for trends, such as CPS1 scores less than 100 percent for certain hours of the day and certain months of the year. It should be noted that this evaluation of CPS1 on an hourly basis does not imply any NERC standards requirements; this is simply a methodology for evaluating ramping needs of a given area.

Figure 3.13 below shows the CPS1 score exceedances by BA on an hourly basis for the Eastern Interconnection (EI). The bottom graph (Grey) shows the availability of CPS1 data from the BA, the middle graph (Red) shows number of hourly CPS1 exceedances for three or more consecutive hours, and the top graph (Black) shows the number of hourly CPS1 exceedances. The last column, which is highlighted in a blue box, represents the total score of hourly CPS1 for EI in each respective area.

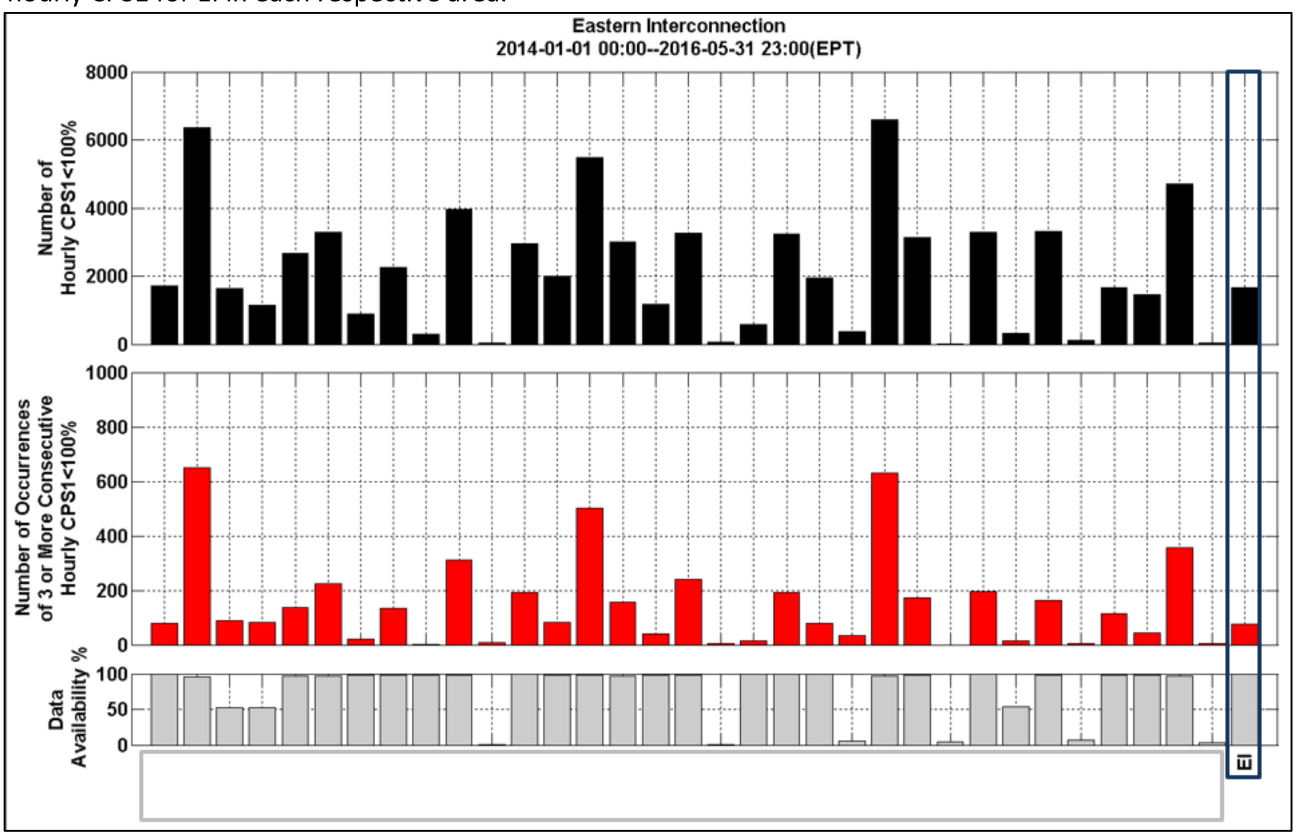


Figure 3.13: Eastern Interconnection—CPS1 exceedance counts per BA on an hourly basis

[38] CPS1 is a statistical measure of a BA's area control error (ACE) variability in combination with the interconnection frequency error from scheduled frequency. It measures the covariance between the ACE of a BA and the frequency deviation of the interconnection, which is equal to the sum of the ACEs of all of the BAs. CPS1 assigns each BA a share of the responsibility for controlling the interconnection's steady-state frequency. The CPS1 score is reported to NERC on a monthly basis and averaged over a 12-month moving window. A violation of CPS1 occurs whenever a BA's CPS1 score for the 12-month moving window falls below 100 percent.

Similarly, **Figure 3.14** shows the CPS1 exceedances for Western Interconnection (WI). Note that the WI chart does not include BA's that use variable bias settings to calculate their ACE.

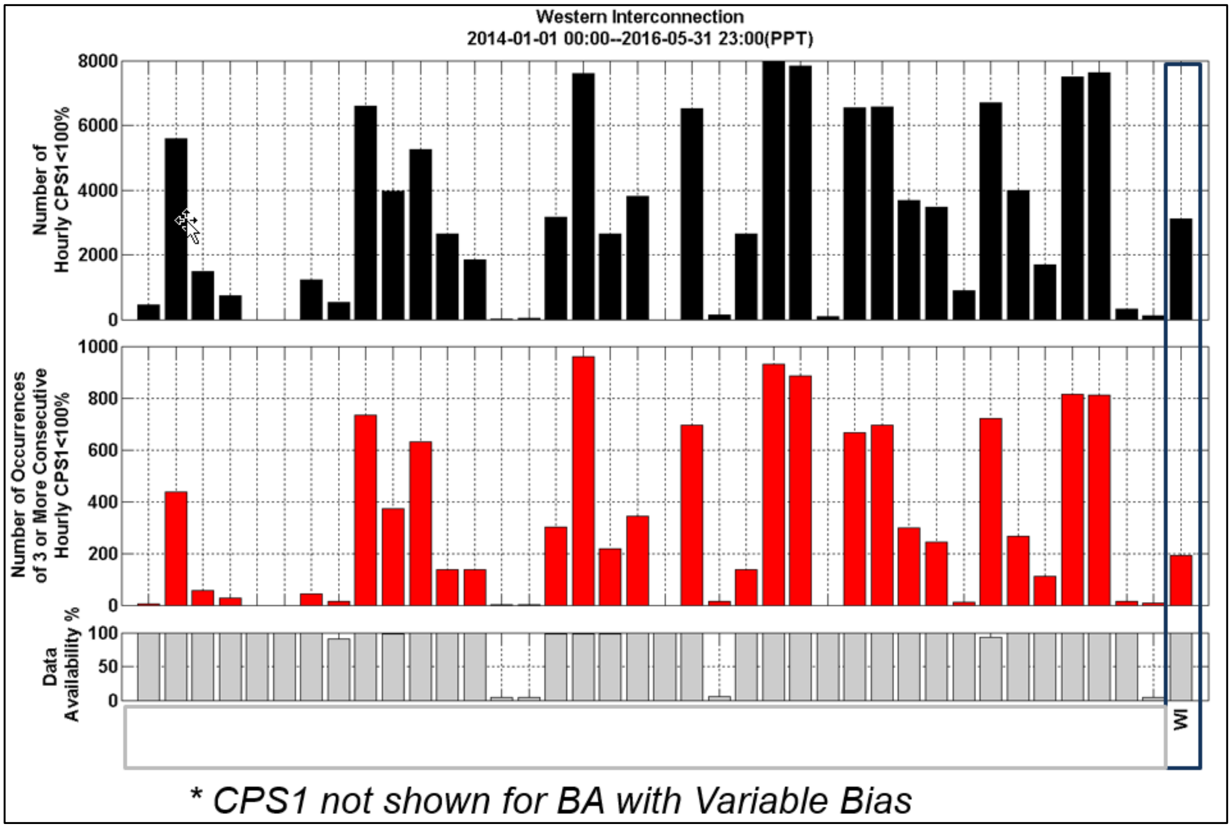


Figure 3.14: Western Interconnection—CPS1 exceedance counts per BA on an hourly basis[39]

Several assessment areas, including MISO, Manitoba Hydro, and NPCC-Maritimes, evaluated their respective area for ramping-related challenges. From their results, the ramping measure continues to be monitored, but does not currently pose a challenge to reliability.

[39] Balancing Authorities unnamed to maintain confidentiality.

Distributed Energy Resources

An increasing quantity of DERs are being installed behind-the-meter and they may or may not be known assets on the distribution system. **Figure 3.15** shows the cumulative installations of nonutility scale solar generation in the U.S. from 2010–2015. Additional installations are forecasted to 2021.[40] Behind-the-meter generation units essentially means that, despite some knowledge of how much potential capacity is installed, there is no individual metering of these units that would indicate their actual energy produced during any time frame. Including generation from these units and the real demand of the system results in a netted system load that can complicate system operations. In low penetrations of DERs to local system load, there is much less potential for any issues to be escalated into the BPS. The potential for issues to impact the BPS grows in some relation with increased DER penetration levels. Both the potential issues to system reliability and the changing characteristics of the load due to increasing DER installations must be studied further.

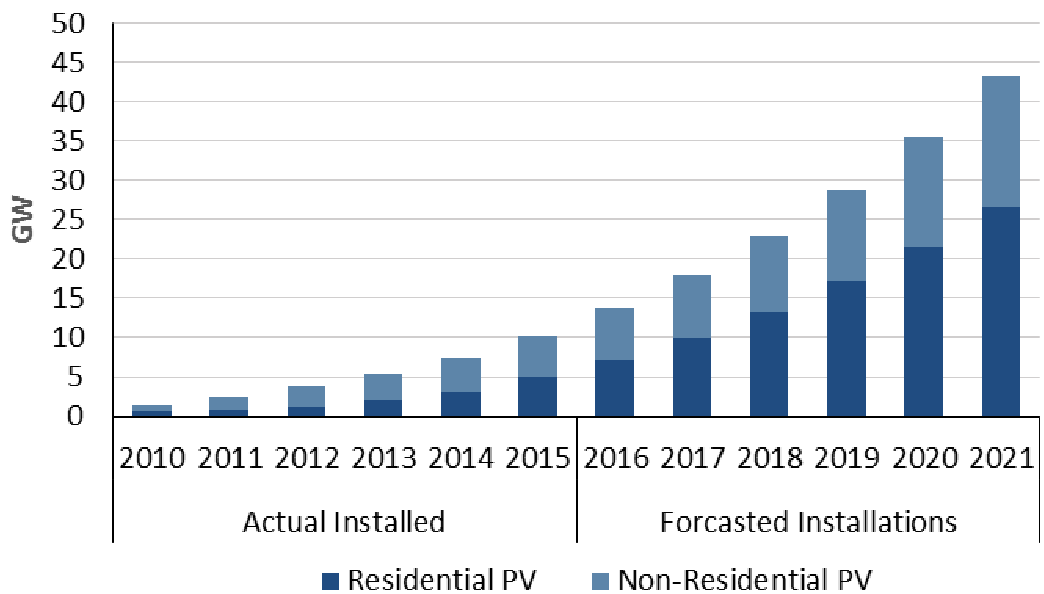


Figure 3.15: Cumulative Installations of Non-Utility Photovoltaic

Historical data sets enable characterization and trending of key performance metrics, including factors that contribute to resource availability and adequacy. DERs, such as rooftop solar, do not have long-term historical data sets, and this lack of data limits the understanding of the long-term implications of DER performance. The potential output levels of DERs show a large degree of variance over a vast geographic scale, so the ideal type and capacity contributions of DER generation will differ by region. Several studies for capacity value calculations, however, differ in results due to differences in DERs and load characteristics in the regions under study.

Calculating capacity values for existing DERs requires chronological generation data that are synchronized with load data and other relevant system properties. Existing power system data bases can be used to track this data, which would be useful in helping to better understand DER performance and operational issues. However, consistent and accurate methods are needed to calculate capacity credits (sometimes called capacity values) attributable to DERs. Defining a compendium of "best practices" for evaluating DER contribution to resource adequacy would assist in providing some alignment of these different methods.

Data and information exchange across the transmission and distribution interface is a crucial aspect of power system planning, forecasting, and DER modeling. Both transmission and distribution entities should develop a

[40] GTM Research: Solar Market Insight Report 2016 Q2

common framework where this type of data exchange can be facilitated to ensure the reliability of the BPS. In addition, adequate operator observability and controllability of the BPS will require access to information and data concerning existing and planned DERs. System planners, both transmission and distribution, should be assessing the penetration of large amounts of DERs that may require changes to forecasting, dispatch, and control of the bulk power system. In states where policies haven't yet incentivized the installation of DERs, policy makers should consider the potential reliability threats and incorporate system upgrades into future policy decisions. State policy makers should leverage the experience in California, New York, other states and provinces that continue to refine their respective policies for accommodating high levels of distributed generation in a reliable manner.

Diminishing On-Peak Impact of DER

At a certain penetration level of distributed or behind-the-meter energy resources, additional installations of photovoltaic (PV) resources have a diminished impact on peak load. This is mainly due to these resources being considered passive load modifiers rather than dispatchable resources, thus netting their generated energy in with the load. A generic summer-peaking system was modeled to study the impacts of increasing DERs; this result is depicted in **Figure 3.16**, which shows that increased solar penetration can shift the critical hours to later in the day with a largely coincident summer-peaking load profile. Due to lower solar irradiances in late hours of the day, the more solar added to the system, the less significant it becomes at peak demand. This affects the timing of reliability in critical hours and decreases the capacity contributions that can be expected to serve load during critical hours. **Figure 3.16** shows net load has been shifted 2–3 hours at high levels of solar penetration (i.e., from 10 percent to 50 percent solar).

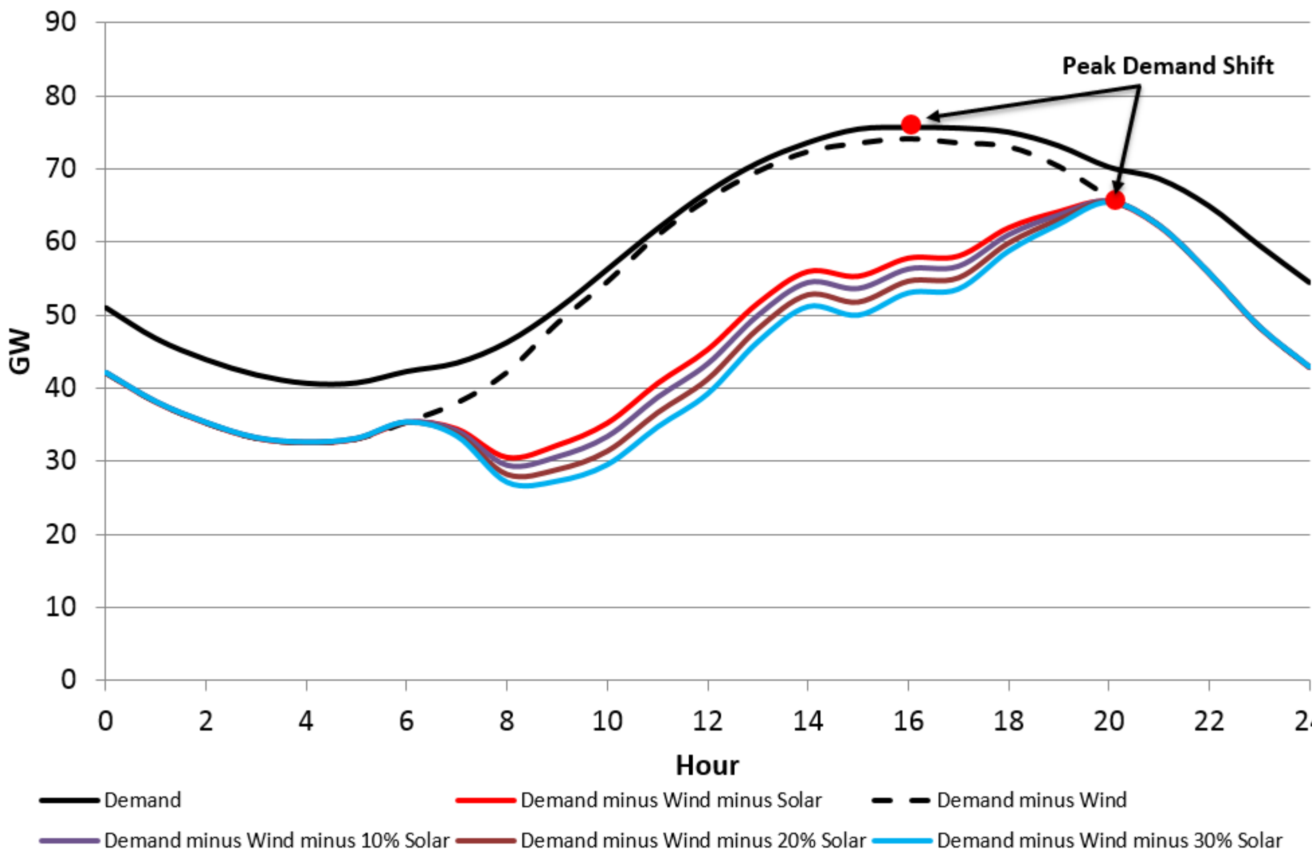


Figure 3.16: Demand and Net Demand Shapes at Different DER Penetration Levels

Furthermore, **Figure 3.17** shows that solar capacity factors reach near-zero levels as solar penetration increases. This ultimately supports the results of this system analysis whereby net load is shifted 2–3 hours due to capacity factors reaching near-zero levels and as solar energy radiation in the evening is negligible.

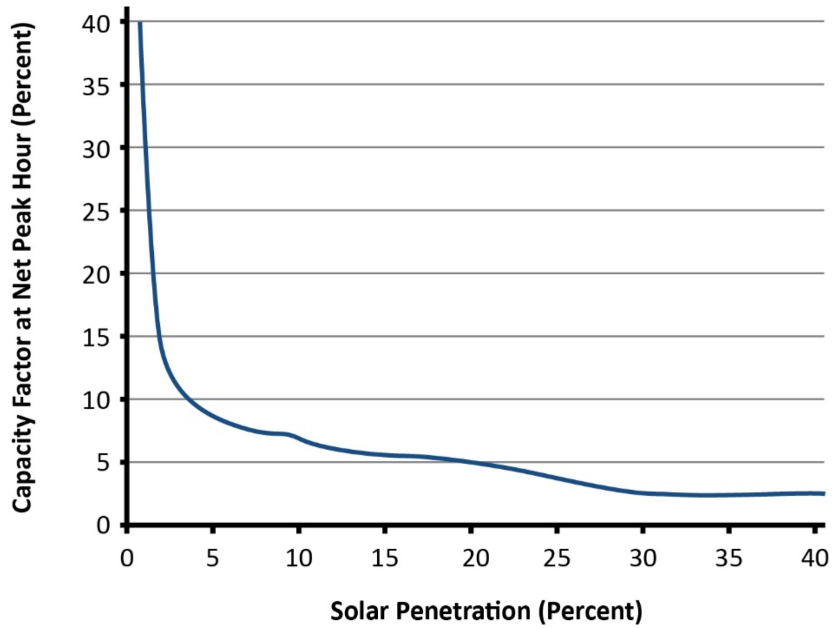


Figure 3.17: Solar Power Capacity Factor

Distributed Energy Resources Task Force

The Distributed Energy Resources Task Force (DERTF) was established in response to a recommendation of the *Essential Reliability Services Task Force* (ERSTF) *Measures Framework Report*.[41] This task force will develop a report by Q1 of 2017 that will examine existing practices for incorporating DERs in to planning models and studies, identify operational impacts to the BPS, and review existing NERC standards to ensure that DERs can be integrated reliably into the BPS. The report will also explore existing policies oriented to support the reliable integration of DERs on the BPS and further examine the interplay with other ERSs. In developing this report, the task force will review the NERC Functional Model, existing NERC Reliability Standards, and coordinate with Electrical and Electronics Engineers (IEEE) 1547 related efforts. Additionally, the task force will review definitions for behind-the-meter generation, distributed generation, and other related terms to provide clear distinctions between each category.

[41] NERC Essential Reliability Services Task Force Measures Framework Report; November 2015

Chapter 4: Reliability Assessment Trends and Analysis

This section provides an overview of the key projections collected and analyzed for this assessment, including reserve margins, demand and energy, demand-side management (DSM), generation fuel mix, and transmission adequacy. These data and resulting analyses are crucial components in the assessment and identification of the reliability issues in focus.

Reserve Margins

Understanding the relation between changes to an area's demand needs, and available generating capacity is traditionally performed through a planning reserve margin analysis. Generally, this analysis compares the forecasted peak load to the amount of capacity that could be considered available to serve peak load. Included in these values are considerations for passive or controllable peak load reduction programs, also referred to as DSM. When compared to an individual area's target reserve margin level (or Reference Margin Level), this deterministic-based calculation provides a straightforward viewpoint on the adequacy of a system's resources for all ten years of the assessment.

Both an Anticipated Reserve Margin and Prospective Reserve Margin are calculated using a deterministic reserve margin analysis, essentially providing two different benchmarks for varying degrees of certainty in future generation. More details on the components to both of these reserve margin calculations can be found in Appendix II. **Table 4.1**,[42] **Table 4.2**, and **Table 4.3** below show the overall demand, resources, and planning reserve margins for Years 1, 5, and 10 of the assessment period for all assessment areas and interconnection subtotals.

Table 4.1: Peak Season 2017(S) / 2017–2018(W): Projected Demand, Resources, & Planning Reserve Margins

Assessment Area/ Interconnection	Demand (MW)		Resources (MW)		Reserve Margins (%)		Reference Margin Level
	Total Internal	Net Internal	Anticipated	Prospective	Anticipated	Prospective	
FRCC	48,125	45,111	55,015	55,436	21.95%	22.89%	15.00%
MISO	127,641	121,814	143,844	150,779	18.09%	23.78%	15.20%
MRO-Manitoba Hydro*	4,826	4,826	5,419	5,526	12.29%	14.51%	12.00%
MRO-SaskPower*	3,724	3,639	4,303	4,303	18.24%	18.24%	11.00%
NPCC-Maritimes*	5,584	5,312	6,716	6,735	26.42%	26.79%	20.00%
NPCC-New England	26,698	25,857	31,112	31,313	20.32%	21.10%	16.74%
NPCC-New York	33,363	32,115	39,613	40,382	23.35%	25.74%	15.00%
NPCC-Ontario	22,680	22,000	26,822	26,822	21.92%	21.92%	18.13%
NPCC-Québec*	38,150	35,982	41,217	42,317	14.55%	17.61%	12.20%
PJM	154,149	145,266	190,456	194,577	31.11%	33.95%	16.50%
SERC-E	43,213	42,558	51,175	51,722	20.25%	21.53%	15.00%
SERC-N	42,540	40,751	48,910	51,265	20.02%	25.80%	15.00%
SERC-SE	47,762	45,534	60,062	60,596	31.91%	33.08%	15.00%
SPP	51,936	51,184	65,083	65,004	27.16%	27.00%	12.00%
Texas RE-ERCOT	71,416	68,548	80,510	85,050	17.45%	24.07%	13.75%
WECC-AB*	-	-	-	-	33.56%	43.44%	11.03%
WECC-BC*	-	-	-	-	12.39%	12.39%	12.10%
WECC-CAMX	54,774	53,027	63,765	63,859	20.25%	20.43%	16.16%
WECC-NWPP-US	50,013	48,794	62,374	62,568	27.83%	28.23%	16.32%
WECC-RMRG	12,392	11,847	15,364	15,364	29.68%	29.68%	14.14%
WECC-SRSG	23,207	22,787	29,094	29,095	27.68%	27.68%	15.82%

[42] Per WECC's request, data is not presented publically for Alberta and British Columbia subregions.

Eastern Interconnection	612,242	585,967	728,531	744,461	24.33%	27.05%	-
Québec Interconnection	38,150	35,982	41,217	42,317	14.55%	17.61%	12.20%
ERCOT Interconnection	71,416	68,548	80,510	85,050	17.45%	24.07%	13.75%
Western Interconnection	155,147	151,216	189,941	191,194	25.61%	26.44%	15.37%
TOTAL-NERC	876,955	841,713	1,040,199	1,063,021	23.58%	26.29%	-

*Winter Peaking System

Table 4.2: Peak Season 2021(S) / 2021–2022(W): Projected Demand, Resources, & Planning Reserve Margins							
Assessment Area / Interconnection	**Demand (MW)**		**Resources (MW)**		**Reserve Margins (%)**		**Reference Margin Level**
	Total Internal	**Net Internal**	**Anticipated**	**Prospective**	**Anticipated**	**Prospective**	
FRCC	50,461	47,256	58,379	59,445	23.54%	25.79%	15.00%
MISO	130,728	124,901	144,850	157,590	15.97%	26.17%	15.20%
MRO-Manitoba Hydro*	4,685	4,685	6,412	5,844	36.86%	24.74%	12.00%
MRO-SaskPower*	3,901	3,816	4,872	4,950	27.67%	29.71%	11.00%
NPCC-Maritimes*	5,622	5,350	6,661	6,735	24.49%	25.89%	20.00%
NPCC-New England	26,816	26,438	31,330	32,516	18.50%	22.99%	15.93%
NPCC-New York	33,555	32,307	40,727	43,474	26.06%	34.56%	15.00%
NPCC-Ontario	22,479	21,878	26,235	26,290	19.92%	20.17%	17.00%
NPCC-Québec*	39,415	37,097	42,746	43,846	15.23%	18.19%	12.70%
PJM	157,358	153,934	197,178	234,816	28.09%	52.54%	16.50%
SERC-E	46,126	45,454	54,798	55,345	20.56%	21.76%	15.00%
SERC-N	43,800	42,105	50,177	52,460	19.17%	24.59%	15.00%
SERC-SE	49,325	47,065	62,126	62,669	32.00%	33.16%	15.00%
SPP	53,779	52,868	64,046	64,775	21.14%	22.52%	12.00%
Texas RE-ERCOT	74,966	72,098	86,522	102,281	20.01%	41.86%	13.75%
WECC-AB*	13,198	13,198	16,439	19,902	24.56%	50.80%	11.03%
WECC-BC*	12,242	12,242	13,757	13,757	12.38%	12.38%	12.10%
WECC-CAMX	54,162	52,455	63,626	63,827	21.30%	21.68%	16.16%
WECC-NWPP-US	51,693	50,498	64,879	65,288	28.48%	29.29%	16.32%
WECC-RMRG	13,194	12,585	15,230	15,159	21.02%	20.45%	14.14%
WECC-SRSG	24,978	24,623	29,182	29,346	18.52%	19.18%	15.82%
Eastern Interconnection	628,635	608,057	747,790	806,910	22.98%	32.70%	-
Québec Interconnection	39,415	37,097	42,746	43,846	15.23%	18.19%	12.70%
ERCOT Interconnection	74,966	72,098	86,522	102,281	20.01%	41.86%	13.75%
Western Interconnection	160,616	156,750	193,574	197,160	23.49%	25.78%	15.37%
TOTAL-NERC	903,632	874,003	1,070,632	1,150,197	22.50%	31.60%	-

*Winter Peaking System

Table 4.3: Peak Season 2026(S) / 2026–2027(W): Projected Demand, Resources, & Planning Reserve Margins							
Assessment Area / Interconnection	**Demand (MW)**		**Resources (MW)**		**Reserve Margins (%)**		**Reference Margin Level**
	Total Internal	**Net Internal**	**Anticipated**	**Prospective**	**Anticipated**	**Prospective**	
FRCC	52,803	49,499	60,976	62,978	23.19%	27.23%	15.00%
MISO	134,462	128,635	140,297	153,047	9.07%	18.98%	15.20%
MRO-Manitoba Hydro*	4,821	4,821	6,412	5,969	33.00%	23.82%	12.00%
MRO-SaskPower*	4,159	4,074	5,152	5,327	26.46%	30.75%	11.00%
NPCC-Maritimes*	5,518	5,248	6,655	6,724	26.81%	28.13%	20.00%
NPCC-New England	27,218	26,841	31,353	32,539	16.81%	21.23%	15.93%
NPCC-New York	34,056	32,808	40,727	43,474	24.14%	32.51%	15.00%
NPCC-Ontario	22,265	21,056	24,646	24,837	17.05%	17.96%	16.00%
NPCC-Québec*	40,625	38,307	42,746	43,846	11.59%	14.46%	12.70%
PJM	161,891	158,367	197,178	235,353	24.51%	48.61%	16.50%
SERC-E	49,309	48,625	58,863	59,410	21.06%	22.18%	15.00%
SERC-N	45,690	44,146	53,247	55,530	20.62%	25.79%	15.00%
SERC-SE	52,083	49,810	62,636	63,179	25.75%	26.84%	15.00%
SPP	56,048	55,144	62,592	63,011	13.51%	14.27%	12.00%
Texas RE-ERCOT	78,572	75,704	86,972	102,129	14.88%	34.91%	13.75%
WECC-AB*	14,304	14,304	16,424	19,878	14.82%	38.97%	11.03%
WECC-BC*	13,040	13,040	14,316	15,306	9.79%	17.38%	12.10%
WECC-CAMX	54,005	52,298	61,639	59,898	17.86%	14.53%	16.16%
WECC-NWPP-US	53,294	52,101	65,079	65,562	24.91%	25.84%	16.32%
WECC-RMRG	14,094	13,459	16,088	16,088	19.53%	19.53%	14.14%
WECC-SRSG	27,424	27,069	31,763	31,927	17.34%	17.95%	15.82%
Eastern Interconnection	650,324	629,074	750,733	811,379	19.34%	28.98%	-
Québec Interconnection	40,625	38,307	42,746	43,846	11.59%	14.46%	12.70%
ERCOT Interconnection	78,572	75,704	86,972	102,129	14.88%	34.91%	13.75%
Western Interconnection	166,468	162,578	192,724	194,961	18.54%	19.92%	15.37%
TOTAL-NERC	935,988	905,662	1,073,175	1,152,315	18.50%	27.23%	-

*Winter Peaking System

Demand and Energy

To better understand the demand requirements of an assessment area, both the seasonal on-peak demand and annual energy requirements must be studied. NERC analyses a ten-year compounded annual growth rate (CAGR)[43] for both demand and energy using forecasted data from 1990 to the present. Both **Figure 4.1** and **Figure 4.2** below show a consistent downward trend in demand and energy forecast data. The *2016 LTRA* reference case calculates a compounded annual growth rate of 0.73 percent for summer demand, 0.72 percent for winter demand, and 0.71 percent for annual net energy.

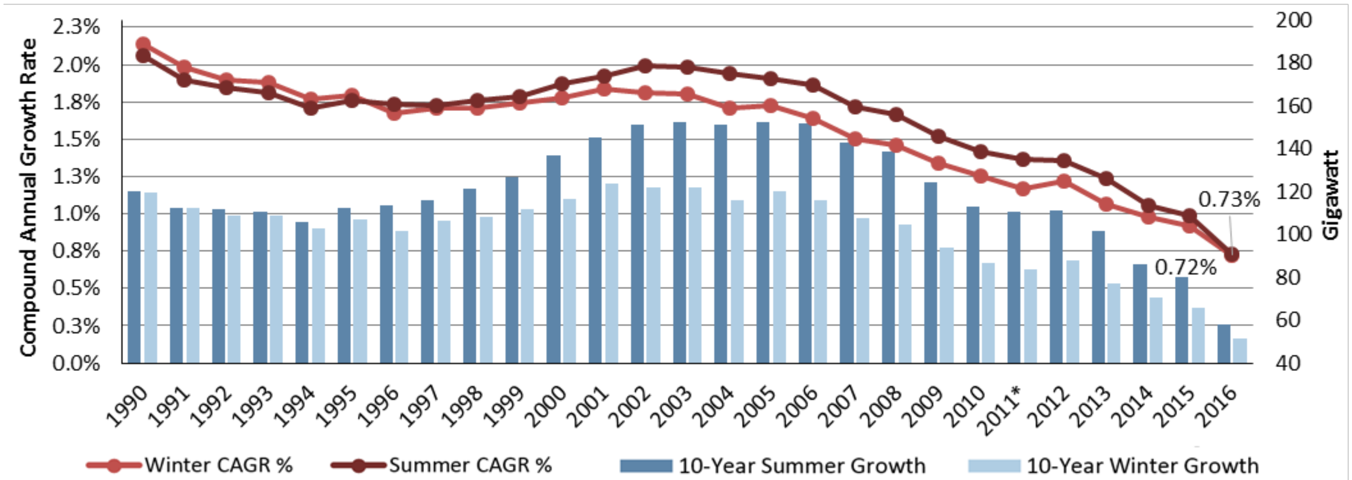


Figure 4.1: Compound Annual Growth Rate–Demand

*Prior to the *2011LTRA*, the initial year of the 10-year assessment period is the report year (e.g., the 10-year assessment period for the *1990LTRA* 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 *2011 LTRA* is 2012–2023).

The decreasing growth rate in energy is most notably detected in 2010; this is a deviation from the nearly flat energy growth rate observed in prior years. In the last year alone, the growth rate dropped by half from 0.8 to 0.7 percent.

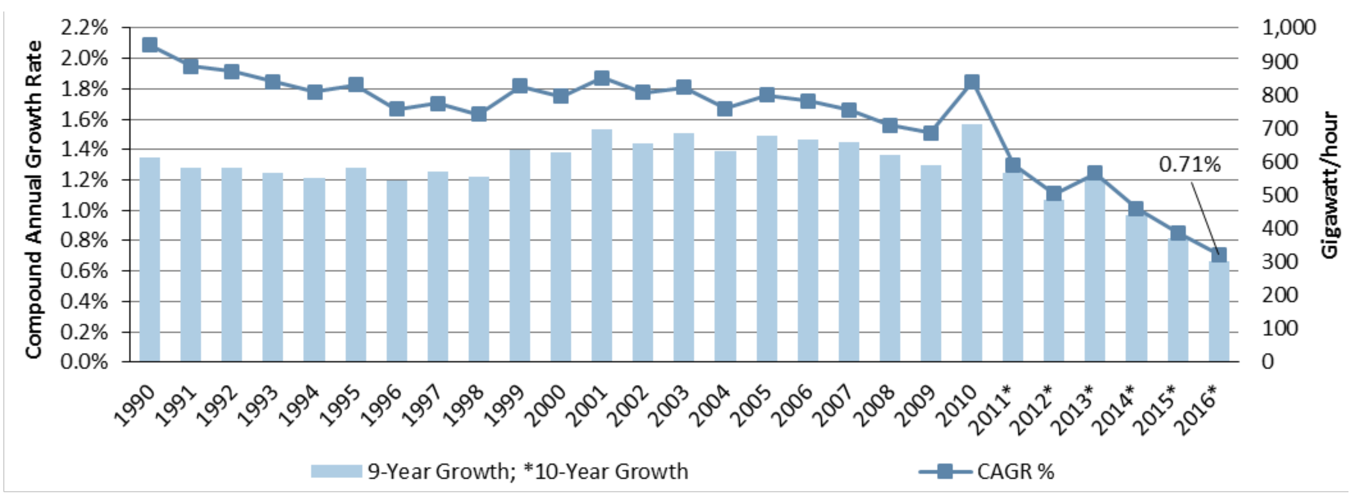


Figure 4.2: Compound Annual Growth Rate–Energy[44]

[43] Compounded annual growth rate (CAGR) provides the year-over-year growth rate over the duration of the assessment period. It is derived as follows: CAGR = (Year 10 TID / Year 1 TID)^(1 / 9) – 1

[44] 10 Year Growth Rate starting in 2011; only 9 years were used prior to 2011

Most assessment areas continue to experience a flattening growth rate in both their ten-year peak demand and energy forecasts. This is largely due to widespread implementation of energy efficiency and conservation programs, DSM, and increasing installations of distributed energy resources (DERs) that are nonobservable by utilities and treated as passive load modifiers. **Figure 4.3** shows the compounded annual demand growth rate by assessment area.

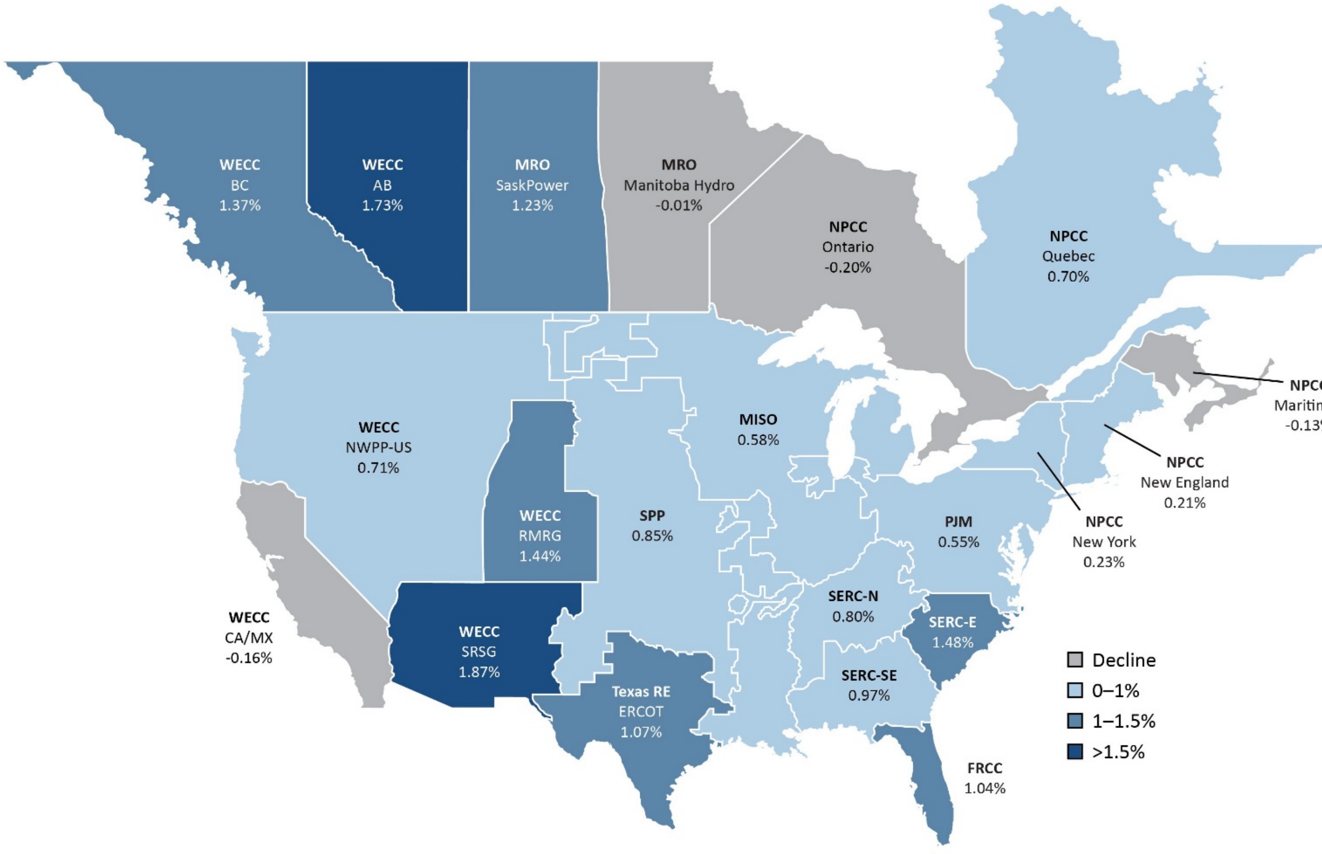


Figure 4.3: GR-Map: Compound Annual Growth Rate by Assessment Area–Demand

Historically, while utilities have worked to implement a variety of programs to reduce their peak load obligation; these reductions in energy forecasts also point to a growing change to the system as the currently metered energy needed in future years is decreasing. This is verified by examining the energy reported in past years. **Figure 4.4** shows the actual energy served from 2010 to 2015. The calculated trend line shows a decrease from the 4,555 TWhs used in 2010 to 4,526 TWhs in 2015; this is a reduction of 29 TWhs or 0.64 percent.

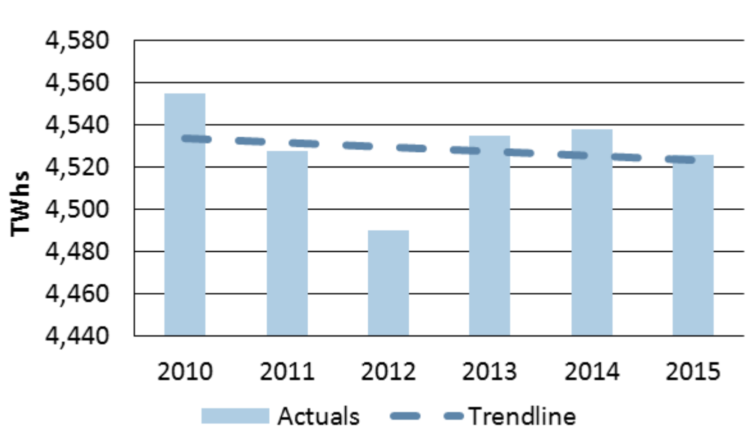


Figure 4.4: 2010–2015 Actual Energy Used to Serve Load

As a majority of renewable energy is not generated across the peak. The increasing amounts of behind-the-meter and renewable generation will continue to decrease net energy used to serve load while not similarly decreasing peak load obligations. This trend should continue unless the energy generated by behind-the-meter generation is both observable and contributing to energy profiles instead of being treated as a passive load modifier. Economic conditions also have an important impact on annual energy usage.

New energy efficiency programs are still a key component for assessment areas to use to manage both peak demand and energy throughout the year. **Figure 4.5** below shows the *2016 LTRA* reference case projections of new programs expected to decrease overall system peak load demand by 26.3 GW through the end of the assessment period, or approximately 2.8 percent of the overall 945.7 GW of expected peak load.

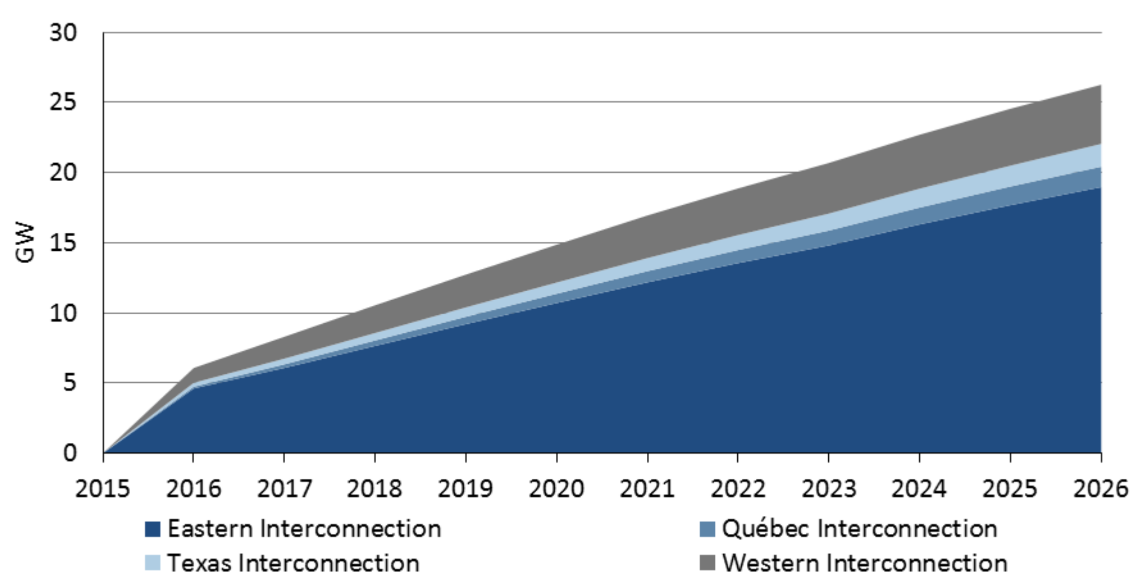


Figure 4.5: Energy Efficiency Projections by Interconnection through 2026

Demand-Side Management

There are a variety of demand response (DR) programs that contribute to an assessment area's ability to manage load; these may consist of behind-the-meter supply resources and/or load-reducing programs that are available at specific times of the year. For the purposes of this assessment, only the expected amount that are likely to respond when called to reduce peak load are collected. Each assessment area may have different mechanisms in place for accounting for this available DR and forecasting these program's availability ten years out. Any significant changes to these forecasting methods are presented and reviewed annually by the Reliability Assessment Subcommittee.

Figure 4.6 below shows the total system DR considered available for the first year's summer and winter peak from each of the last six LTRAs. A decade ago, when there was a strong focus on the development of DR programs, growth projections were high for the new programs. Comparing the total, system-wide DR for year one of the *2011 LTRA* and the *2016 LTRA* yields a drop in the summer from 44.0 GW to 31.9 GW (27.5 percent) and in the winter from 42.7 GW to 21.6 GW (49.4 percent). Contributing factors to this decline include increased energy efficiency and solar installations. These have reduced the amount of discretionary load that is available to be reduced on demand, maturation of DR programs and their participants' understanding of them, and regulatory and market rule changes that apply to DR.

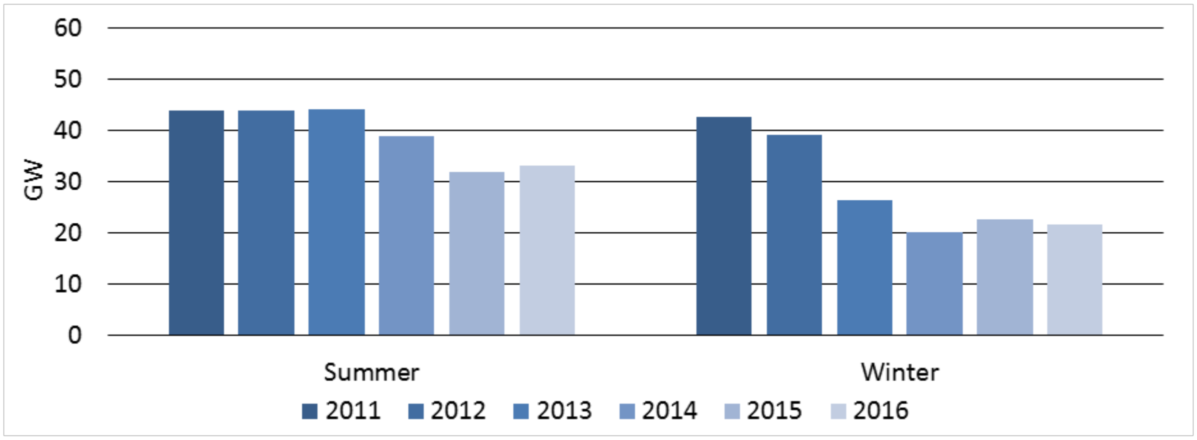


Figure 4.6: Demand Response Available in Year One of 2011LTRA–2016 LTRA

In October of 2008, FERC issued Order No. 719,[45] which required wholesale markets to accept most DR bids in all markets. In March 2011, FERC issued Order No. 745,[46] which required that wholesale energy markets provide equal compensation to DR providers for conserving energy at the same market rate as generators are paid for producing it. Order No. 745 was brought to the Court of Appeals for the District of Columbia Circuit and challenged as beyond the authority of FERC. Although the decision of the Court of Appeals and subsequent appeal to the Supreme Court created some uncertainty for the future of market-based DR programs, available DR does not appear to have been significantly affected. In January of 2016, the Supreme Court ruled that the Federal Power Act does authorize FERC to regulate "the sale of electric energy at wholesale in interstate commerce" and "to ensure that rules or practices affecting wholesale rates are just and reasonable."[47]

The moderate changes shown in the annual forecasts of enrollments of DR in the past three years may reflect changes to market rules or market structures, improvements in technologies to facilitate participation, and local utility commission drivers to increase load management capabilities through DR.

Generation Fuel Mix

Examining the existing and projected generation mix is crucial to assessing potential risks to reliability. Specifically, whether or not the projected capacity additions will provide adequate levels of essential reliability services (ERS) components to support the overall state of the system. A total of 1,280 GW of nameplate capacity are expected to be available to serve load by the end of 2016. **Figure 4.7** shows this system-wide, 1,280 GW of anticipated nameplate capacity by generation type. Many additional generating units are planned for the next ten years to meet a combination

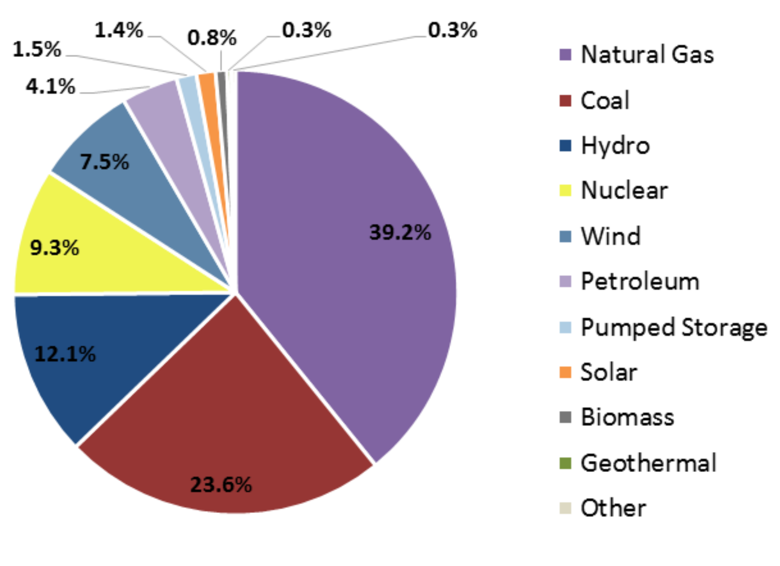


Figure 4.7: 2016 Existing & Tier 1 Nameplate Capacity by Fuel Type

[45] FERC Order No. 719: Wholesale Competition in Regions with Organized Electric Markets
[46] FERC Order No. 745: Demand Response Compensation in Organized Wholesale Energy Markets
[47] Supreme Court Decision: January 25, 2016

of demand growth and the need for replacement generation as other units retire. **Figure 4.8** shows the system's aggregated planned additions separated by generation type and planned tier designator. The three tiers, shown in **Figure 4.8**, indicate some degree of certainty for each unit. Generation in Tier 1 is considered to be very certain and can be expected to be available for the assessment while Tier 2 is less certain and Tier 3 is not included in a reserve margin analysis. While there are many resource types in the queue for resource planning expectations, a significant majority of all planned generation will rely on natural gas.

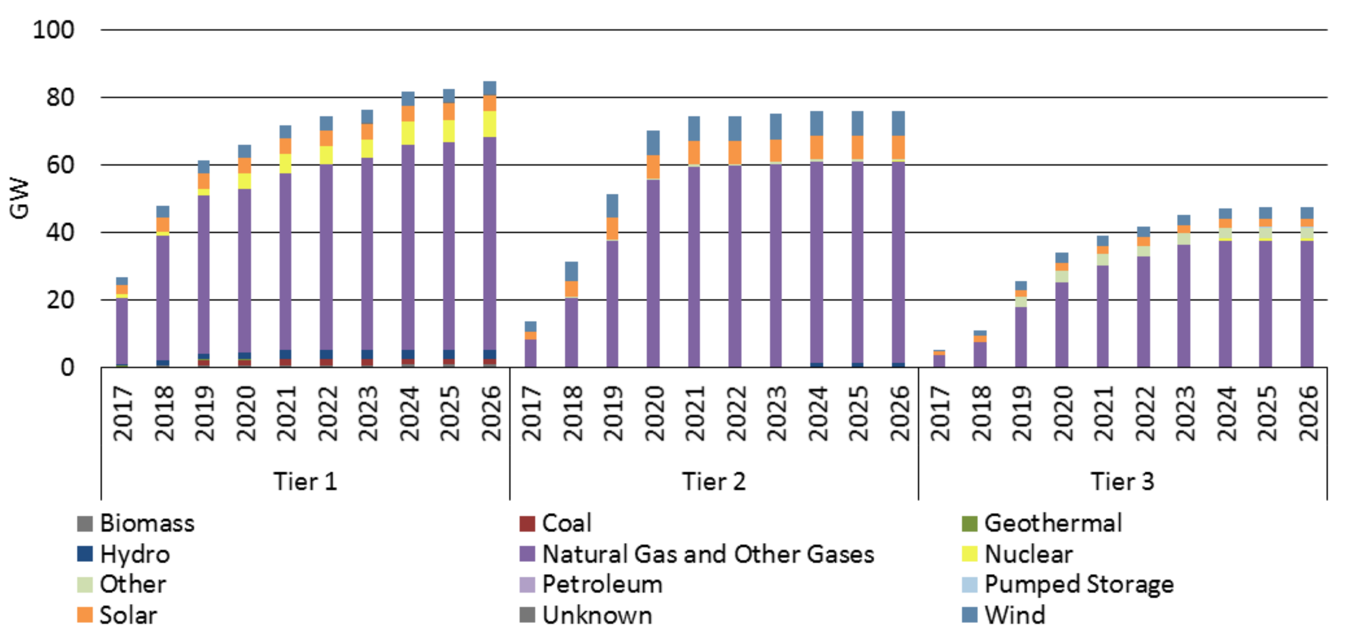


Figure 4.8: Planned Nameplate Capacity Additions by Generation Type and Tier

Table 4.4, **Table 4.5**, **Table 4.6**, and **Table 4.7** show the total nameplate capacity for each fuel type by Interconnection. These include actual values reported for 2015 and all planned additions and confirmed retirements projected through 2026.

Table 4.4: Eastern Interconnection Total Anticipated Nameplate Capacity by Fuel Type

	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	6,379	6,812	433	6.8%
Coal	242,371	233,825	(8,546)	-3.5%
Geothermal	-	20	20	-
Hydro	43,736	44,845	1,109	2.5%
Natural Gas	332,998	386,298	53,300	16.0%
Nuclear	104,702	106,238	1,535	1.5%
Other	889	889	-	0.0%
Petroleum	50,950	48,814	(2,136)	-4.2%
Pumped Storage	16,165	16,165	-	0.0%
Solar	1,634	6,233	4,599	281.5%
Wind	46,324	57,424	11,100	24.0%
Total	846,148	907,563	61,415	7.3%

Table 4.5: Texas Interconnection Total Anticipated Nameplate Capacity by Fuel Type				
	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	210	210	-	0.0%
Coal	20,796	20,796	-	0.0%
Hydro	544	544	-	0.0%
Natural Gas	50,114	58,110	7,996	16.0%
Nuclear	5,268	5,268	-	0.0%
Solar	288	2,053	1,765	613.5%
Wind	15,909	26,934	11,025	69.3%
Total	93,129	113,915	20,786	22.3%

Table 4.6: Québec Interconnection Total Anticipated Nameplate Capacity by Fuel Type				
	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	327	447	119	36.5%
Hydro	40,943	41,673	729	1.8%
Natural Gas	570	570	-	0.0%
Petroleum	436	436	-	0.0%
Wind	3,260	3,923	663	20.3%
Total	45,536	47,048	1,512	3.3%

Table 4.7: Western Interconnection Total Anticipated Nameplate Capacity by Fuel Type				
	2015 Nameplate (MW)	2026 Nameplate (MW)	Capacity Change (MW)	Capacity Change (%)
Biomass	3,616	3,764	148	4.1%
Coal	38,379	36,245	(2,134)	-5.6%
Geothermal	3,862	4,171	309	8.0%
Hydro	68,736	69,622	886	1.3%
Natural Gas	101,972	105,872	3,900	3.8%
Nuclear	7,679	7,679	-	0.0%
Other	2,962	2,974	12	0.4%
Petroleum	1,143	1,133	(10)	-0.9%
Pumped Storage	2,450	3,020	570	23.3%
Solar	9,476	16,907	7,431	78.4%
Wind	21,118	22,715	1,597	7.6%
Total	261,392	274,101	12,709	4.9%

Transmission Adequacy

Maintaining sufficient transmission capacity is a key component of understanding and analyzing an assessment area's transmission adequacy. Load and resources are subject to a variety of factors that could lead to rapid changes to electric transmission infrastructure. This is generally restricted by slow planning, siting, and construction. While many generating units do require years to plan and build, unexpected retirements and the addition of generation with much shorter build times can stress the current transmission system. Through modeling and power flow studies, system planners provide the foundation for these essential transmission projects to be developed.

A FERC technical conference was held in August of 2016 that discussed competitive transmission development processes wherein Panel Four of this discussion involved Interregional Transmission Coordination Issues.[48] Amidst the discussion was an overview of several reports from The Brattle Group that highlighted studied transmission planning needs, trends, and recommendations.[49] As unprecedented shifts in the makeup of available generating resources and load occur, policy makers and regulators should advocate for developed processes that allow for transmission solutions that meet both reliability requirements and anticipated changes to due to environmental regulations. Tabulated below are the summarized major transmission project expansions provided in this report.

FRCC

The FRCC Region has not identified any major projects that are needed to maintain or enhance reliability during the planning horizon. Planned projects, shown in **Table 4.8**, are primarily related to expansion in order to serve forecasted growing demand, and they are related to maintaining the reliability of the BES in the longer-term planning horizon or for resource integration.

Table 4.8: FRCC Planned Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Levee–Midway	Florida Power & Light Company	Reliability	150	500kV (ac)	2023

MISO

MISO's Transmission Expansion Plan[50] (MTEP15) includes proposals for over $2.75 billion[51] in transmission infrastructure investment through 2024, and these fall into the following categories:

- **90 Baseline Reliability Projects (BRP) totaling $1.2 billion:** BRPs are required to meet NERC reliability standards.
- **12 Generator Interconnection Projects (GIP) totaling $73.6 million:** GIPs are required to reliably connect new generation to the transmission grid.
- **1 Market Efficiency Project (MEP) totaling $67.4 million:** MEPs meet Attachment FF requirements for reduction in market congestion.
- **242 Other Projects totaling $1.38 billion:** Other projects 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.

[48] FERC Docket No. AD16-18-000; Notice Inviting Post-Technical Conference Comments; August 3, 2016
[49] The Brattle Group: Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future; June 6, 2016
[50] MISO's Transmission Expansion Plan
[51] The MTEP15 report and project totals reflect all project approvals during the MTEP15 cycle, including those approved on an out-of-cycle basis prior to December 2015.

Several of MISO's major transmission projects are shown in **Table 4.9**.

Table 4.9: MISO Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
Great Northern Transmission Line–partial segment	Minnesota Power (Allete, Inc.)	Hydro Integration	220	500kV (ac)	2020
MVP Portfolio 1–Ellendale to Big Stone South	Otter Tail Power Company	Reliability	165	345kV (ac)	2019
MVP Portfolio 1: N LaCrosse–N Madison-Cardinal-Eden-Hickory Creek	American Transmission Co. LLC	Reliability	161.8	345kV (ac)	2024
Great Northern Transmission Line–partial segment-	Minnesota Power (Allete, Inc.)	Hydro Integration	160	500kV (ac)	2020
MVP Portfolio 1: Lakefield Jct.–Winnebago–Winco–Kossuth County & Obrien County–Kossuth County–Webster	Ameren Services Company	Reliability	122	345kV (ac)	2018

Manitoba Hydro

Manitoba Hydro has plans for a significant number of system enhancement projects, including those listed in **Table 4.10.** Manitoba Hydro is planning for an addition of the third 2,000 MW Bipolar HVdc transmission system in 2018. Bipole III provides an alternative path to serve Manitoba load in the event of a major station loss or corridor loss associated with Bipole I and II. Manitoba Hydro is expecting a new 500 kV interconnection from Dorsey to Iron Range (Duluth, Minnesota) to come into service in 2020, as a result of an 883 MW transmission service request. Manitoba Hydro is also expecting a new 230 kV interconnection from Birtle South (Manitoba) to Tantallon (Saskatchewan) station with an in-service-date of 2020, as a result of a 140 MW transmission service request. The reliability impact of the 230 kV line is not evaluated in this assessment because a construction agreement has not been finalized with the customer yet.

Table 4.10: Manitoba Hydro Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
Bipole 3–Riel	Manitoba Hydro	Reliability	1800	500kV (dc)	2018
Great Northern Transmission Line (Canadian Portion)	Manitoba Hydro	Reliability	146	500kV (ac)	2020

SaskPower

Saskatchewan has several major transmission projects for reliability during near-term of the assessment period. These projects, identified in **Table 4.11**, are heavily dependent on load growth, and involve the construction of approximately 570 miles (918 km) of transmission lines.

Table 4.11: SaskPower Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
Pasqua–Swift Current Area Reinforcement	SaskPower	Reliability	125	138kV (ac)	2019
Pasqua–Swift Current Area Reinforcement	SaskPower	Reliability	125	230kV (ac)	2019
Aberdeen–Wolverine Area Reinforcement	SaskPower	Reliability	68	230kV (ac)	2017
Tantallon Area Reinforcement	SaskPower	Reliability	62	230kV (ac)	2017
Regina–Moose Jaw Area Reinforcement	SaskPower	Reliability	62	230kV (ac)	2020
Regina–Moose Jaw Area Reinforcement	SaskPower	Reliability	62	230kV (ac)	2019
Aberdeen–Wolverine Area Reinforcement	SaskPower	Reliability	35	138kV (ac)	2017
Tantallon–AMBirtle line	SaskPower	Reliability	31	230kV (ac)	2020

Maritimes

Transmission development in the Maritimes area during the assessment period includes projects shown in Table 4.12. Additional projects include the installation of a 345 kV breaker in series with an existing breaker at NB's Point Lepreau terminal in Spring 2016. This was done to mitigate contingencies and reduce import restrictions from New England. During the winter of 2016/17, the installation of two undersea 138 kV cable connections, each with a capacity of 200 MVA and a length of nine miles, will be completed and will increase capacity. This was done to improve the ability to withstand transmission contingencies in the area between NB and PEI. A 475 MW High Voltage Direct Current (HVdc) undersea cable link (Maritime Link) between Newfoundland, Labrador, and NS will be installed by early 2018. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 153 MW coal-fired unit in NS by mid-2020. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area. In addition, during the fall of 2018, a second 345/138 kV transformer will be added in parallel with an existing transformer at the Keswick terminal in NB. This is to mitigate the effects of transformer contingencies at the terminal.

Table 4.12: Maritimes Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
NS-NL Tie (Newfoundla—Nova Scotia)	Nova Scotia Power	Variable/ Renewable Integration	100	200kV (dc)	2017
Y-104 (West Royalty—Church Road)	Maritimes Electric	Variable/ Renewable Integration	50	138kV (ac)	2017
Harbour East (Dartmouth East—Eastern Passage)	Nova Scotia Power	Reliability	10	138kV (ac)	2018

New England

Several major transmission projects for New England are identified in **Table 4.13**. One significant 345 kV project that is important to the continuation or enhancement of system or subarea reliability is projected to come on-line during the assessment period. This project is the result of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England, and then developing and implementing solutions to address existing and projected transmission system needs. The major project under development in New England is the Greater Boston project. The Greater Boston upgrades, which are certified to be in service by 2019, are critical to improving the ability to move power into the Greater Boston area, and also to move power from northern New England to southern New England. This set of upgrades includes a +/- 200 MVAR 345 kV interconnected static synchronous compensators (STATCOMs) in Maine that will also help to address concerns with the potential for system separation due to significant contingencies in southern New England.

Table 4.13: New England Major Transmission Projects					
Name	**Company**	**Driver**	**Line Length (Circuit Miles)**	**Operating Voltage/Type**	**Expected In-Service Year**
Northern Pass Transmission Project	Northern Pass Transmission LLC	Other	98	320kV (dc)	2019
Northern Pass Transmission Project	Northern Pass Transmission LLC	Other	60 (Under Ground)	320kV (dc)	2019
Northern Pass Transmission Project	Northern Pass Transmission LLC	Other	34	345kV (ac)	2019

New York

The Transmission Owner Transmission Solutions (TOTS) consists of three transmission projects in central New York, downstate New York, and New York City. The TOTS are part of the Con Edison and the New York Power Authority (NYPA) filing in response to a November 2012 Order from the NYSPSC that recognized significant reliability needs would occur if the Indian Point Energy Center (IPEC) were to become unavailable.[52] The TOTS transmission projects are described in the following three projects:

Project One: The Ramapo-Rock Tavern project will establish a second 345 kV line from Con Edison's Ramapo 345 kV substation to Central Hudson Gas and Electric Corporation's (CHGE) Rock Tavern 345 kV substation. The project will increase the import capability into Southeastern New York (SENY); this includes New York City, during normal and emergency conditions and will provide a partial solution for system reliability should the IPEC retire. The

[52] New York Public Utilities Commission; Order Instituting Proceeding and Soliciting Indian Point Contingency Plan; November 2012

project will be located in Orange and Rockland Counties in New York along the right-of-way for the existing Con Edison 345 kV Feeder 77 (Ramapo to Rock Tavern) and use existing transmission towers. The transmission line terminals are located in NYBA’s Zone G. This project involves work that will be performed by Orange & Rockland Utilities (O&R) and CHGE, as such, Con Edison has and will continue to coordinate this effort with both O&R and CHGE.

Project Two: The Marcy South Series Compensation project is a transmission improvement project that adds switchable series compensation to increase power transfer. This is done by reducing series impedance over the existing 345 kV Marcy South lines. Specifically, the project adds 40 percent compensation to the Marcy-Coopers Corners 345 kV line, 25 percent compensation to the Edic-Fraser 345 kV line, and 25 percent compensation to the Fraser-Coopers Corners 345 kV line through installation of series capacitors. The project also involves upgrades at Marcy and Fraser 345 kV substations. These upgrades involve reconductoring approximately 21.8 miles of the NYSEG-owned Fraser-Coopers Corners 345 kV line (FCC-33) with a higher thermal-rated conductor. The project increases thermal transfer limits across the Total East Interface and the UPNY/SENY Interface.

Project Three: The third project splits an existing feeder between Goethals and Linden Cogen substations, and it will provide a similar solution at a lower cost and with lower environmental impacts. This project is located in Staten Island and Brooklyn, New York; and Union County (Linden), New Jersey.

Ontario

Several major transmission projects for Ontario are identified in **Table 4.14**. Northwestern Ontario is connected to the rest of the province by the 230 kV double-circuit East–West Tie. Local load growth is forecasted as a result of an active mining sector in the region. To address load growth, additional capacity is required to maintain reliable supply to this area under the wide range of possible system conditions. Anticipated to be in service in 2020, the expansion of the East–West Tie with the addition of a 230 kV new double-circuit transmission line will provide reliable and cost-effective long-term supply to the Northwest.

Table 4.14: Ontario Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
QFW	Hydro One	Economics/ Congestion	93	320kV (dc)	Delayed/ Unknown
East-West Tie	Hydro One	Reliability	240	320kV (dc)	2020
West of Thunder Bay Lines	Hydro One	Reliability	250	345kV (ac)	2022

Forecasted demand growth in the areas west of Thunder Bay and north of Dryden will require increased transfer limits west of Mackenzie Transformer Station (TS). Development work is proceeding for a new 230 kV double-circuit line between Lakehead TS and Mackenzie TS, and a new single-circuit line between Mackenzie TS and Dryden TS.

Forecasted demand growth in the Ottawa area will require reinforcements to the transmission system to relieve future thermal constraints. Plans including line reconductoring are already underway to address the thermal constraints.

Ontario is monitoring the progress of the continued operation of nuclear units at Pickering Nuclear Generating Station. Pickering Nuclear Generating Station units connect directly to the 230 kV system at Cherrywood Transformer Station, which is located in the east side of the greater Toronto area. The retirement of Pickering Nuclear Generating Station requires an additional 230 kV supply source for the area. This will be provided by the new Clarington 500/230 kV transformer station with a planned 2018 in-service date. Clarington Transformer Station will also improve load restoration capabilities east of Cherrywood following certain contingencies.

Bulk power transfers into the GTA from the west are expected to increase as a result of the planned shutdown of Pickering Generating Station, major refurbishment of other nuclear generating units, and the incorporation of significant amounts of renewable generation in Ontario. Because of the increased bulk power transfers and increasing local demand, the capacity of the transmission lines between Trafalgar TS and Richview TS and the 500/230 kV transformers at Claireville TS and Trafalgar TS are forecasted to be exceeded by 2022. Planning studies are being finalized. Planning options have been assessed and are expected to include the installation of 500/230 kV autotransformers at the existing Milton Switching Station, with eight 230 kV circuit terminations, and 12 km of new double-circuit line sections connecting the new Milton TS to Hurontario Switching Station.

Hydro Québec

The major transmission projects in the Hydro Québec footprint are: the Romaine River Hydro Complex Integration, the Chamouchouane–Montréal 735-kV Line, the Northern Pass Transmission Project, and the Champlain-Hudson Power Express Project.

The Romaine River Hydro Complex Integration

Construction the Romaine River Hydro Complex project is presently underway. Its total capacity will be 1,550 MW. Romaine-2 (640 MW) was commissioned in December 2014, and Romaine-1 (270 MW) in December 2015. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated in 2017–2020 at Montagnais 735/315-kV substation. The Québec area is reiterating its commitment to sustainable development by focusing on renewable energy at the Romaine complex, which will help meet current needs without jeopardizing the energy supply of future generations.

Main system upgrades for this project has required construction of a new 735-kV switching station Aux Outardes, which is located between existing Micoua and Manicouagan substations. Two 735-kV lines have been redirected into the new station, and one new 735-kV line (5 km or 3 miles) has been built between Aux Outardes and Micoua substations. This upgrade was commissioned in Summer 2015.

The Chamouchouane–Montréal 735-kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735-kV line in the near future in order to meet the reliability standards. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a new substation (Judith Jasmin) in Montréal (about 400 km or 250 miles). The new 735kV substation is required to fulfill two objectives: providing a new source of electricity supply on the north shore of Montreal and connecting the new 735kV line from Chamouchouane to the Montreal metropolitan loop. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses. The line is scheduled for the 2018–2019 winter peak period. Public information meetings have been held and the construction phase has begun.

The Northern Pass Transmission Project

This project to increase transfer capability between Québec and New England by 1,090 MW is currently under study. It involves the construction of a ±320-kV dc transmission line about 49 miles (79 km) long from Des Cantons 735/230-kV substation to the Canada–United States border. This line will be extended into the United States to a new substation built in Franklin, New Hampshire. The project in Québec also includes the construction of an HVdc converter at Des Cantons and a 320-kV dc switchyard. The planned in-service date is 2019.

The Champlain-Hudson Power Express Project

This project to increase transfer capability between Québec and New York by 1,000 MW is currently under study. It involves the construction of a ±320-kV dc underground transmission line about 50 km (31 miles) long from Hertel

735/315-kV substation just south of Montréal to the Canada–United States border. This line will be extended underground and underwater (Lake Champlain and the Hudson River) to Astoria station in New York City. The project in Québec also includes the construction of an HVdc converter at Hertel. The planned in-service date is currently under review.

Upcoming Regional Projects

Other regional substation and/or line projects are in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas. There are another dozen in other areas with in service dates from 2016 to 2020, consisting mostly of 315/25-kV and 230/25-kV distribution substations to replace 120-kV and 69-kV infrastructures. Two of these more notable regional transmission projects are shown in **Table 4.15**.

Table 4.15: Québec Regional Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
La Romaine 3-4	Hydro-Québec	Hydro Integration	129	315kV (ac)	2017
Line CHM-MTL	Hydro-Québec	Reliability	250	735kV (ac)	2018

SERC

The major transmission projects in the SERC footprint are as follows:

- Construction of the Union-Tupelo and Selmer-West Adamsville 161 kV lines support voltage and the changing flows in the area.
- Pin Hook needs an additional 500/161 kV transformer to alleviate overloads in the SERC-N area.
- Construction of the Plateau 500 kV Substation will alleviate decreasing voltages and higher flows on lines caused by increased loads in the area.
- A new static VAR compensator (SVC) installation at the Davidson 500 kV substation will increase dynamic reactive reserves for support.
- Construction of the 55 mile Vogtle to Thompson 500 kV line will support the addition of future generation.
- New 230 kV transmission projects are under construction in conjunction with VC Summer Nuclear Units 2 and 3.

SPP

The SPP assessment area's 2016 Board-of-Directors-approved SPP Transmission Expansion Plan Report (STEP) provides details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users. The 2016 SPP Transmission Expansion Plan (STEP) contains a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. These projects consist of $6.1 billion in new transmission and upgrades. Several of these major transmission projects are shown in **Table 4.16**.

Table 4.16: SPP Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Sibley—Mullin Creek	TSMO	Economics/ Congestion	105	345kV (ac)	2016
Cherry Co.—Gentleman	NPPD	Reliability	110	345kV (ac)	2018
Cherry Co.—Holt Co.	NPPD	Reliability	117	345kV (ac)	2018
Tuco—Yoakum	SPS	Reliability	107	345kV (ac)	2020

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

- The 20-Year Assessment (ITP20), performed once every three (3) years, identifies transmission projects, generally above 300 kV, needed to develop a grid flexible enough to provide benefits to the region across multiple scenarios.
- The 10-Year Assessment (ITP10), performed once every three (3) years, focuses on facilities 100 kV and above to meet system needs over a 10-year horizon.
- The Near-Term Assessment (ITPNT), performed annually, assesses system upgrades, at all applicable voltage levels, required in the near-term planning horizon to address reliability needs.

The goal of transmission integration studies[53] to evaluate the adequacy of each Integrating Entity's transmission facilities at the time of their integration date and whether they are in compliance with NERC Reliability Standards, SPP Criteria, and Transmission Owner-specific planning criteria (if a waiver allows for the SPP or NERC Criteria to be superseded).

An initial integration study was conducted in 2013 for the Integrating Entities that identified projects needed before and after the October 2015 integration date. This latest study was a refresh of the initial study to determine if any supplemental issues emerged when considering more current information.

SPP leveraged the 2016 ITP Near-Term model set as the starting point for the analysis. The Integrating Entities provided updates to topology, generation dispatch, and load information.

Texas RE-ERCOT

Several of Texas RE-ERCOT's major transmission projects are shown in **Table 4.17**. The recently updated ERCOT future transmission projects list includes the additions or upgrades of 3,954 miles of 138-kV and 345-kV transmission circuits, 24,159 MVA of 345/138-kV autotransformer capacity, and 3,005 MVar of reactive capability projects. These are planned in the TRE-ERCOT Region between 2016 and 2024.

Table 4.17: TRE-ERCOT Major Transmission Projects

Name	Company	Driver	Line Length (Circuit Miles)	Operating Voltage/Type	Expected In-Service Year
Lobo to North Edinburg: Construct 345 kV Line	ETT	Reliability		345kV (ac)	2016
Add second circuit to SLU panhandle loop	SHRY	Economics/ Congestion		345kV (ac)	2018
New 345kV line from Loma Alta to N Edinburgh	SLU	Reliability		345kV (ac)	2016

A new Houston Import Project, 130-mile 345 kV double circuit line (each circuit rated at 5000 Amps) from Limestone to Gibbons Creek to Zenith, is planned to be in service before the summer peak of 2018.[54] The Houston area is one of the two largest demand centers in the ERCOT system and the fourth largest city in the United States. The Houston area demand is met by generation located within the area and by importing power via high-voltage lines into the area from the rest of the ERCOT System. This new line will support anticipated long-term load growth

[53] SPP Integrated Transmission Planning
[54] ERCOT: Houston Import RPG Project; April 8, 2014

in the Houston region. Power imports into the Houston area are expected to be constrained until the new import line is constructed.

In July 2014, the owners of the Frontera generation plant, a 524 MW natural gas facility located on the west side of the Lower Rio Grande Valley (LRGV), announced that they were planning to switch part of the facility (170 MW) out of the ERCOT market in 2015. This entire facility would no longer be available to ERCOT in 2016. In June, 2016, the ERCOT Board of Directors endorsed the reliability need for the two 300 MVAr SVCs located inside the LRGV to be in service prior to summer of 2021 to meet ERCOT and NERC reliability criteria for the LRGV.

Chapter 5: Additional Reliability Issues

NERC continues to monitor and report on a variety of other issues that are generally categorized as lower risk. While these may not require immediate attention or action, there is a consistent need to assess all system changes or impacts to be aware of any risks before they develop. The *2016 LTRA* identifies the following items as issues, trends, and events that warrant further attention and study:

- EPA Clean Power Plan (CPP)
- Grid energy storage
- System short circuit strength
- Modeling
- Reactive power requirements for nonsynchronous generation
- System restoration
- Reactive power supporting devices
- 2017 solar eclipse

Clean Power Plan

On August 3, 2015, the EPA issued its final rule, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units*.[55] Initial compliance of the final rule was set to begin in 2022 with final compliance in 2030. The final rule aims to cut CO_2 emissions from existing power plants to 32 percent below 2005 levels by 2030. NERC conducted an analysis of the final rule in order to assess potential reliability risks to the BPS as a result of the rule.[56]

As a result of the analysis, NERC determined that already occurring changes to the resource mix would accelerate if the final rule were to be implemented. Among NERC's key findings of its analysis are the following:

- The CPP is expected to accelerate a fundamental change in the electricity generation mix in the United States and transform grid-level reliability services, diversity, and flexibility.
- Integration of large amounts of renewables are expected to occur on the BPS regardless of the CPP.
- The CPP is expected to further flatten annual energy demand growth.
- Resource mix changes have regional significance, spurring the need for additional transmission and pipeline infrastructure.

NERC recommended that, due to the wide ranging effects of the CPP, planning processes should already be underway to ensure that requisite transmission and pipeline infrastructure be built in a timely manner. NERC further recommended that planning coordinators and transmission planners should conduct system reliability evaluations to identify areas of concern. NERC continues to hold itself out as a resource for states and planners as state submittals are being formulated. Finally, NERC also recommended that work should be continued around sufficiency guidelines for essential reliability services (ERSs) and evaluation of the effects that distributed energy has on the BPS.

On February 9, 2016, the Supreme Court stayed implementation of the CPP pending judicial review. The stay will remain in effect through the review of the CPP by the Court of Appeals for the District of Columbia Circuit (D.C.

[55] EPA: Clean Power Plan for Existing Units
[56] NERC Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Circuit) *and* until the Supreme Court decides the matter in the event that it is ultimately appealed to the Supreme Court. This legal process could continue into the middle of 2018. The stay of the final rule has an impact on the ultimate validity of the final rule as well as the timing of it should it ultimately be upheld by the courts. It is also important to note that NERC determined that many of the changes occurring on the BPS are occurring regardless of the CPP and should therefore be incorporated into system and operational planning.

System Short-Circuit Strength

The safe, reliable operation of electrical power systems requires the ability to predict and model the sources of fault current in order to select equipment properly rated for the required duty and to properly set protective relays for selective operation. Nonsynchronous powered generating plants are also sources of fault current and are considered in addition to typical synchronous generating sources.

Synchronous machines in the electric power grid, their operation, and respective short-circuit behavior have been established and are well understood in comparison to some types of nonsynchronous power plant fault current and performance. A nonsynchronous power plant is separated from conventional generation by its unique short-circuit behavior. The unique short-circuit characteristic for nonsynchronous machines emanates from either when an induction generator is directly connected to the grid or when the nonsynchronous machine is decoupled from the grid through power electronic devices (e.g., inverters). Therefore, accurate short-circuit studies are needed to determine that the maximum short-circuit contribution from a given machine is within the limits of the circuit breakers and that protective devices are coordinated to function properly over a specific range of potential conditions.

Short-Circuit Fault Contribution of Nonsynchronous Resources

The short-circuit fault contribution from large nonsynchronous plants that are connected to the transmission voltages are a primary concern to safe and reliable operations of the bulk electric power system. Nonsynchronous plants of interest typically consist of multiple wind turbines/photovoltaic (PV) systems connected to transmission facilities (greater than 100kV). Here, the importance of both balanced and unbalanced short-circuit fault analysis to determine the worst case fault given select components of a nonsynchronous plant is discussed. This section does not focus on nonsynchronous collector systems nor internal plant protective relaying problems.

Nonsynchronous Plant Types

A significant difference between a nonsynchronous plant and a typical power plant is the total number of machines/units employed at a transmission bus. A typical conventional power plant (i.e., combustion, hydro, or steam) might consist of a single unit or a few large units. Therefore, the components for short-circuit modeling of a conventional power plant includes each generator and its respectively sized step-up transformer. In contrast, a nonsynchronous power plant of similar MW size to the conventional generator will consist of many machines/units, their individual step-up transformers, a medium voltage collector system (i.e., cabling), and a substation transformer in order to be modeled correctly for short circuit studies.

Industry has divided large megawatt rated wind turbines into five different groups based on their machine type, speed control capabilities, and operational characteristics. The following list provides the wind turbine groups by their type and associated machine:

- Type I, squirrel cage induction generator
- Type II, squirrel cage wound rotor induction generator with external rotor resistance
- Type III, double fed asynchronous generator
- Type IV, full power converter generator (PV/wind)
- Type V, synchronous generator mechanically connected through a torque converter

For short-circuit fault current, Types I through IV are of greater concern than Type V wind turbines. The detailed behavior and characteristics of fault contributions of nonsynchronous plants can be very specific to a particular turbine design. Turbine manufacturers must provide accurate information on balanced and unbalanced fault performance for the particular turbines in a specific plant. Photovoltaic (PV) systems generally use a full power dc-ac converter and typically produce similar fault characteristics to the Type IV wind turbine.

System Strength

As the number of inverter-based resources increases, and as the number of dispatched synchronous sources decreases, there will be an operating point when the grid is no longer strong enough to support stable operation of the power electronic converters connected within the wind and PV plants. Very few systems have faced this issue in actual operation (e.g., South Texas Sub-Synchronous Resonance Event of 2009). Knowledge of this issue is built upon converter performance tests and detailed analysis using transient simulation tools, such as Power Systems Computer Aided Design (PSCAD) and Electromagnetic Transients Program (EMTP). Since such tools and analytical methods are not well suited to studying large-scale risks for many plants over wide geographic areas, the challenge is to take what is learned from detailed analysis of a few plants and extend that learning across larger regions using more practical methods.

Short circuit ratio (SCR) is a calculation used to screen for weak grid conditions near power electronic converters. This method has been borrowed from screening for weak grid conditions near HVdc converters and is currently being applied to nonsynchronous plants.[57]

An adequate SCR for today's nonsynchronous inverter designs is defined at the point of interconnection and typically has a calculated ratio in the range of 3-5, where 3 is the minimum ratio to be considered sufficiently robust and 5 is considered vigorous. When the calculated SCR at a plant interconnection point is lower than 3, there is significant concern that the internal plant controls will not function in a stable manner (i.e., the positive sequence stability representation of the plant may not represent the true behavior of the plant or be mathematically stable). Low SCRs increases the chance of subsynchronous behavior and control interactions among neighboring devices employing power electronics.[58]

The low SCR problem is typically identified and addressed during interconnection study stages of a nonsynchronous plant. This issue is fundamentally a local problem and can be remedied with upgrades, such as synchronous condensers. However, it is an ongoing issue because as synchronous generators retire or network topology changes take place, it is possible that an area in which nonsynchronous generators have been interconnected can evolve into a weaker system. As a result, the SCR should be used to re-evaluate the strength of the interconnection points due to temporal network modifications.

The SCR ratio is not included in daily system operations as it is not achievable to determine critically diminished points in the system and then be able to implement immediate corrective actions (i.e., install equipment). This is to ensure a sufficiently robust solution over a reasonable range of typical operating conditions.

Modeling

NERC is committed to assessing the quality of the power system models used to plan the BPS. NERC is also committed to support the development and advancement of models and modeling practices to ensure that long-term and short-term planning engineers have the tools and capabilities to plan and operate the BPS. Currently under evaluation or a development plan are case quality metrics, dynamic load modeling, and adequate modeling of DERs.

[57] SCR is the ratio of the available system strength (measured in short circuit MVA) to the MW rating of the wind or PV plant.
[58] ERCOT: System Strength Assessment of the Panhandle System 2016

Case Quality Metrics

NERC performed its *Phase 2 Assessment of Case Quality Metrics*[59] future-year planning cases for the Eastern, Western, and Texas Interconnections. This included reassessment of the Phase 1 metrics[60] as well as development of new metrics for Phase 2, particularly with respect to dynamic models. NERC is working with the case creation entities designated, pursuant to MOD-032, to incorporate the metrics (as appropriate) for their interconnections to improve the performance scores for their models moving forward. A number of dynamics case modeling issues were identified in the Phase 2 assessment, such as power development fractions for turbine-governor models, generator time constants and inertia constants, and generator saturation factors. Reassessment of the Phase 1 metrics showed no adverse trends between the two case years, and NERC will continue analyzing case quality to build these trends over the longer-term.

Dynamic Load Modeling

Dynamic load models, such as composite load models, are capable of capturing the dynamic response of various end-use loads, namely induction motor load as required per TPL-001-4.[61] The NERC Load Modeling Task Force[62] (LMTF) is supporting the development and robust implementation of these models as well as the phased adoption of these models while gaining experience with the model in stability studies. LMTF has created a forum for utility planning engineers to share experiences and modeling efforts with other utility engineers, software developers, and subject matter experts.

End-use loads are rapidly changing due to energy efficiency standards and economics. "Grid friendly" loads that exhibit electrical characteristics that support the power grid during abnormal conditions (such as faults) are being replaced with electronically coupled loads controlled by converter technology. These electronically coupled loads may not exhibit this "grid friendly" characteristic; rather, they tend to have controls that maintain constant power consumption regardless of system voltage or frequency (with current limiters for protection purposes). The make-up and characteristics of end-use load technology are continually and rapidly evolving with the continued penetration of electronically coupled loads such as electric vehicles, plug-in electric hybrids, higher efficiency single-phase air conditioners, compact fluorescent lighting, LED lighting, LCD and LED televisions, variable-frequency drives, and electronically commutated motors.

NERC is also coordinating with the electric utility industry to understand the end-use load response needed for future reliability of the electric grid such that the BPS maintains stable equilibrium for major grid events. Preliminary studies have developed approaches for the "ideal" response of large-power electronic (electronically coupled) loads, such as electric vehicle chargers. In addition, NERC has been a contributor to the development of IEEE 1547,[63] particularly with respect to sharing BPS reliability perspectives and the impact that aggregated DERs can have on BPS performance.

Distributed Energy Resource Modeling

As the penetration of DERs continues to increase across the North American BPS, it becomes increasingly important to ensure that steady-state and dynamic models are able to sufficiently represent the individual or aggregate response of DERs for planning and operations purposes. The NERC Essential Reliability Services Working Group (ERSWG) and LMTF technical groups are exploring the modeling practices used for capturing these resources and any modeling improvements or recommended modeling practices for the electric utility industry to consider. While the industry is still learning much from areas with high penetration of DERs, including international experience, NERC supports information sharing and proactive exploration of the tools, models, and practices to

[59] NERC Phase 2 Case Quality Metrics

[60] NERC Case Metrics - 2015 Summer Base Case Quality Assessment; Phase I - Powerflow and Dynamics Case Quality Metrics

[61] NERC Standard TPL-001-4 -- Transmission System Planning Performance Requirements

[62] NERC Load Modeling Task Force

[63] IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

help ensure reliability of the BPS moving forward. The ERSWG and LMTF are preparing technical materials developed by these industry stakeholder groups to share with the industry.

Reactive Power Requirements for Nonsynchronous Generation: FERC Order 827

FERC issued Order No. 827[64] on June 16, 2016, eliminating the exemptions for wind generators from the requirement to provide reactive power by revising the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G of the LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA). While some ISOs have reactive power standards for variable energy resources (VERs), FERC Order 827 states that all new interconnecting nonsynchronous generators will be required to provide reactive power at the "high-side of the generator substation as a condition of interconnection." FERC found that, due to technological advancements, the cost of providing reactive power no longer creates an obstacle to wind power development, and this decline in cost results in the current exemptions being "unjust, unreasonable, and unduly discriminatory and preferential." Key items for reliability addressed by FERC in its order[65] include:

- **Power Factor Range:** All newly interconnecting nonsynchronous generators must "design their Generating Facilities to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation. At that point the non-synchronous generator must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis."
- **Point of Measurement:** Order 827 specifies the point of measurement for reactive power as the high-side of the generator substation**.** To clarify this location, the Commission states: "As an example, the generator substation would be the substation for a wind generator that separates the low-voltage collector system from the higher voltage elements of the Interconnection Customer Interconnection Facilities that bring the generator's energy to the Point of Interconnection."
- **Dynamic Reactive Power Capability Requirements:** Order 827 states that reactive power capability can be achieved by "systems using a combination of dynamic capability from the inverters plus static reactive power devices to make up for losses." This gives the Generator Owner flexibility to "[u]se static reactive power devices to make up for losses that occur between the inverters and the high-side of the of the generator substation, so long as the generators maintain 0.95 leading to 0.95 lagging dynamic reactive power capability at the high-side of the generator substation."
- **Real Power Output Threshold:** All newly interconnecting nonsynchronous generation must meet the reactive power requirements at all real power output levels. FERC provided an example of a 100 MW generator required to provide 33 MVAR at 100 MW output and 3.3 MVAR at 10 MW output. This essentially is a triangle-shaped capability curve based on the amount of active power being delivered at the point of measurement.

NERC is developing technical guidance to support Order 827, and will include this material as part of the *Reliability Guideline on Reactive Power Planning* currently being developed by the System Analysis and Modeling Subcommittee under the NERC Planning Committee.

[64] Federal Energy Regulatory Commission, Order No. 872, 16 June 2016

[65] NERC provided comments on the Notice of Proposed Rulemaking (NOPR) preceding this Final Rule.

System Restoration

Past NERC assessments have identified blackstart units as a potentially emerging issue as more conventional generation type units that have traditionally provided blackstart capability are retiring than are being built across the system. Blackstart units are generally smaller in output and are essential towards the implementation of system restoration plans that allow sections of the grid to return to service following a disturbance. As the determination of total installed capacity for a reserve margin calculation make no distinction between generation types, having fewer blackstart units in an area would have little to no impact on this deterministic resource adequacy metric. However, a large reduction in these units could significantly extend the duration of a blackout or otherwise limit a localized effort to mitigate immediate power quality issues.

Additionally, as many new, variable, and decentralized resources are installed, there is increasing difficulty with providing stable communication between these generating units and control rooms. Since a majority of wind and solar units generate the maximum energy possible at any given moment, a growing amount of generation without controllable outputs and ability to respond to system needs further complicates maintaining system resiliency. With the retirement of these conventional units, transmission owners and other applicable registered entities should review their individual needs to restore the interconnection and maintaining system reliability.

Practice and functionality for using renewables for system restoration and blackstart requirements are still at early stages of research and development. There are two approaches being considered for using VERs in system restoration: grid-forming and grid-following. This restoration research is currently focused on using the variable resources for grid-following. The likely outcome of the research will be to maintain the top-down restoration approach of energizing the high-voltage/100kV system using conventional generation and then using the VERs primarily to aid in island balancing and frequency regulation. There are challenges with using variable renewables for restoration; these resources are dependent on their energy inputs (i.e., sunlight, wind) being available during system restoration, and today's utility-scale, commercially available wind or solar PV resources were not specified and tested with the ability to start or run into a black system in mind. 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. Viable, large-scale capability for blackstart with wind and solar PV are possible if this is a desired feature, but are several years away from commercial availability.

NERC's *2012 LTRA*[66] identified PJM as one area that had experienced a recent downward shift in blackstart-capable units. To review their own needs more thoroughly, PJM initiated the System Restoration Strategy Task Force (SRSTF)[67] to examine the current system restoration planning process. PJM did this to determine its viability and efficiency moving forward and to recommend any changes to any associated procurement, cost allocation, and compensation methods for system restoration. The task force recommended a number of changes to the existing rules for blackstart generation and the identification of critical load. It also developed the *PJM RTO Wide Five-Year Selection Process Black Start RFP*. The RTO-wide RFP is issued every five years and any unit that is interested in providing blackstart service can offer in to PJM's market. PJM would then review the existing blackstart units along with the new units offering into the RFP and optimize blackstart generation throughout the RTO.[68]

Reactive Power Supporting Devices

There are two components to the power supplied by conventional electric generators: real power and reactive power. Real power capacity performs the work of lighting, heating, cooling, and operating motors for a variety of uses, and can be replaced either locally or very remotely. This is a characteristic distinctive to real power since it can travel long distances via the BPS without losing effectiveness. However, the reactive power necessary to support BPS voltage, and to avoid collapse as real power flows across the BPS, has to be provided locally.

[66] NERC 2012 Long-Term Reliability Assessment
[67] System Restoration Strategy Task Force
[68] PJM Black Start / System Restoration; presentation October 5, 2015

Reactive generators will increasingly be utilized to replace dynamic voltage support lost from conventional retirements. These include SVCs; static synchronous compensators (STATCOMs); other electronic flexible alternating current transmission system devices; and synchronous condensers, which are large motors configured to provide voltage support. Low-voltage ride-through capability and effective protection and control of the reactive devices are included in minimum BPS reliability criteria, especially as reactive generator penetration increases. Current BPS inventory of these devices as time passes and undesirable events are caused or exacerbated by their inability for low voltage ride-through are worth developing and monitoring.

Advanced Capabilities of New Technology Resources

Deployment of new VERs, primarily wind and solar generation, has been rapid in recent years. The amount and rate that new additions are being made continues to increase yearly. Presently available technology on these resources offer the options to provide great flexibility for operation. These resources can change output power very quickly, which is extremely helpful to stabilize the frequency during disturbances and system restoration. The vast majority of new wind generation are Types 3 and 4 machines, which have capabilities to provide frequency response control. These controls have inertia-based and governor controls that provide complementary functionalities.

Inertia-based Controls

Most new Type 3 and 4 wind generators have built-in capabilities to provide fast frequency response. This response is based on temporarily using the stored inertial energy in the rotating mass of the wind turbine. These are often referred to as synthetic inertia controls and they respond rapidly for a frequency drop in a 1–10 second time frame. The primary function of this “fast frequency response” is to provide arresting power, shown in **Figure *5.1***. These controls use the inertial energy from the rotating wind turbine to supply power to the electric power system. Under undisturbed operation, the mechanical power input and electrical output are balanced. During a large under-frequency event when this wind generator control is enabled, the electrical output is greater than the mechanical input during the inertia response period, extracting inertial energy out of the rotor and causing the machine speed to decrease, thereby allowing the turbine to provide a very fast injection of additional power during the arresting phase of the frequency event. After the arresting period subsides and primary frequency response (PFR) action takes over, the mechanical energy must be recovered to bring the wind turbine back to the predisturbance rotational speed (and mechanical power). The turbine again reaches equilibrium when mechanical power input equals electrical power output. Because the turbine loses some efficiency during the time when it is slowed from its optimal operating points, the energy recovery during periods of moderate wind speed will typically to be on the order of twice or more arresting energy delivered. The control is progressively more effective at higher wind speeds, and the recovery energy is supplied by the wind (with little if any energy recovery period needed) when the turbine is operating at its rated output and wind speeds are sufficient to provide additional energy.

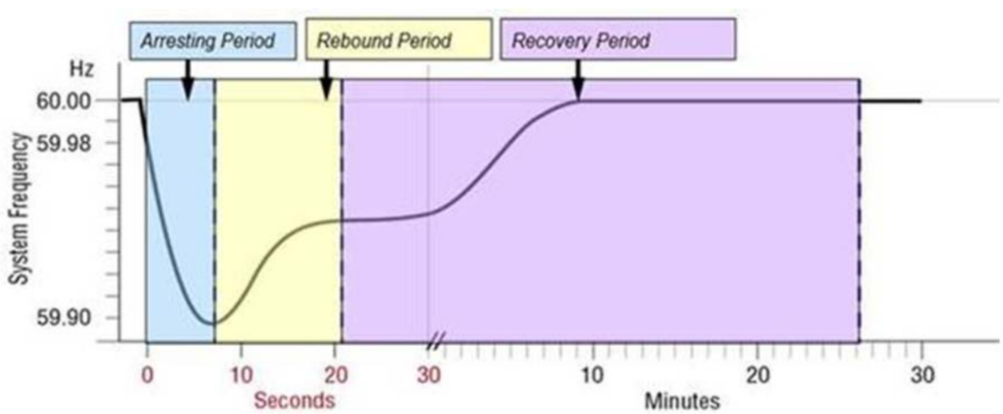


Figure 5.1: Time Frames of Frequency Response

Governor Control

Most existing and new Type 3 and 4 wind turbines, solar thermal, and new solar PV resources have the built-in control capability to provide PFR for both over frequency and under frequency events in the 5–60 second response time frame. This type of control is very similar to the governor control of synchronous thermal and hydro generation. It is often called governor control, which is unlike synchronous generation that reacts to and controls turbine speed (as a proxy for grid frequency), PFR relates the size of the resource lost to the resulting net change in system frequency. This is done during the period when stabilizing frequency is determined following the initiating system disturbance event. This is illustrated in **Figure 5.2**.

In **Figure 5.2**, results of an investigation of the EI show how governor controls could impact grid frequency. In **Figure 5.2**, a condition with a significant amount of wind generation is subjected to a very large loss of generation event. The cases (one with just governor response, in red, and one with both governor and inertial fast frequency response, in green) show a substantial improvement in the key metric, frequency nadir, over the reference case (in blue). In this case, the wind governors are deliberately set to respond with a similar speed as incumbent thermal resources. While this setting can be increased, having some fast-responding resources compared to others can result in unintended consequences with respect to system frequency. These frequency response time frames are set based on the response times of most combined-cycle units.

In order to provide the governor response for under frequency events, the wind or solar resource would have to be operating in a curtailed state to retain headroom for increasing its power output. This precurtailment is not required for wind or solar to respond to over frequency events or for the "synthetic inertia" response from wind turbines.

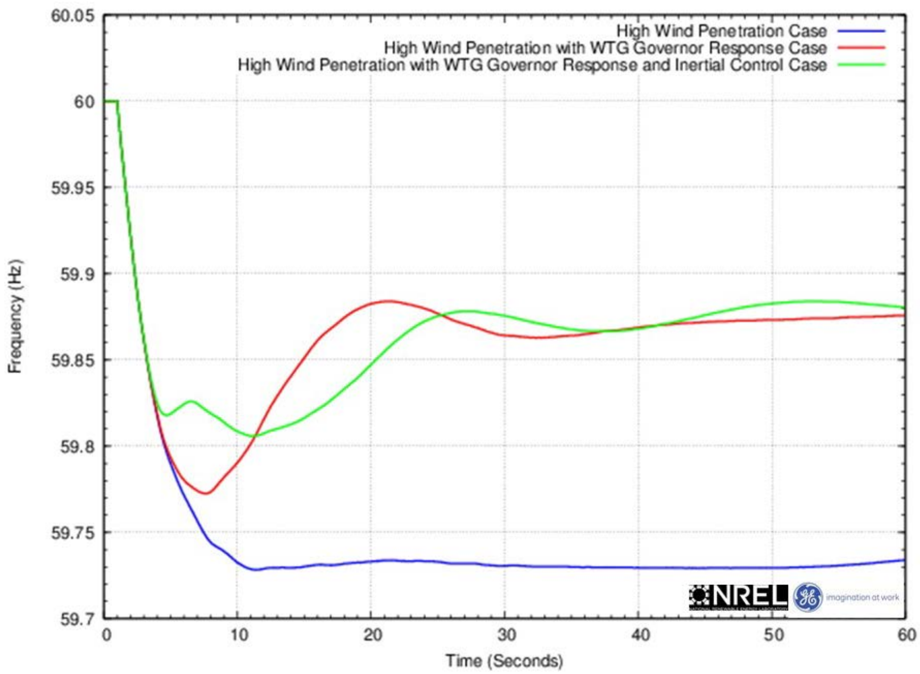


Figure 5.2: Illustration of Wind Turbine Frequency Controls[69]

[69] NREL: Eastern Frequency Response Study; May 2013

Solar Eclipse

North America will experience a total solar eclipse on August 21, 2017, similar to the total eclipse that passed over continental Europe, Nordic countries, and Great Britain in 2015. The path of the 2017 solar eclipse has been predicted by NASA[70] along with the affected levels of solar gradation outward from the path. A total solar eclipse is a precisely predictable event that causes substantial effects to wide-scale solar generation within a very short amount of time. The output generated by PV/solar systems will be either diminished or drastically reduced within the window of this event. Sudden widespread diminishing of solar irradiance may heavily affect areas with large amounts of utility scale PV energy installations or behind-the-meter DERs.

To further examine the potential impacts of this event, NERC will perform analysis and release a whitepaper summarizing the impact of the North American Solar Eclipse on the BPS in the first quarter of 2017. The assessment will leverage studies on past eclipse events to conduct an analysis on areas with high amounts of solar penetration along the path of the eclipse. NERC will identify any reliability concerns surrounding the BPS's ability to withstand/endure the event.

As the number of VERs in the power system increases, there is a greater dependency in the power system on intermittent energy sources. As a result, there is an emerging concern on maintaining a reliable and operable system during periodic astronomical events (i.e., solar eclipses, geomagnetic storms). For example, **Figure 5.3** below shows the path of the upcoming North American total solar eclipse of 2017 and the future total solar eclipse of 2024. Both eclipse routes move from the west to the east direction across North America. The map above shows that the August 21, 2017, eclipse proceeds across the U.S.A. in southerly movement with first and last total eclipse observations occurring in Oregon and South Carolina respectively. The April 8, 2024, eclipse advances northerly; the total eclipse will be first viewable in Sinaloa, Mexico, and lastly visible in Newfoundland and Labrador, Canada. Although both eclipse events occur (over by 1:30 p.m.) before historical time of day peak periods, the effect of eclipses on the BPS will become more relevant as more variable generation is installed in the system. Future detailed studies and coordination may be needed to ensure the effect of astronomical events on the behavior of wide-area BPS facilities are predictable and maintainable.

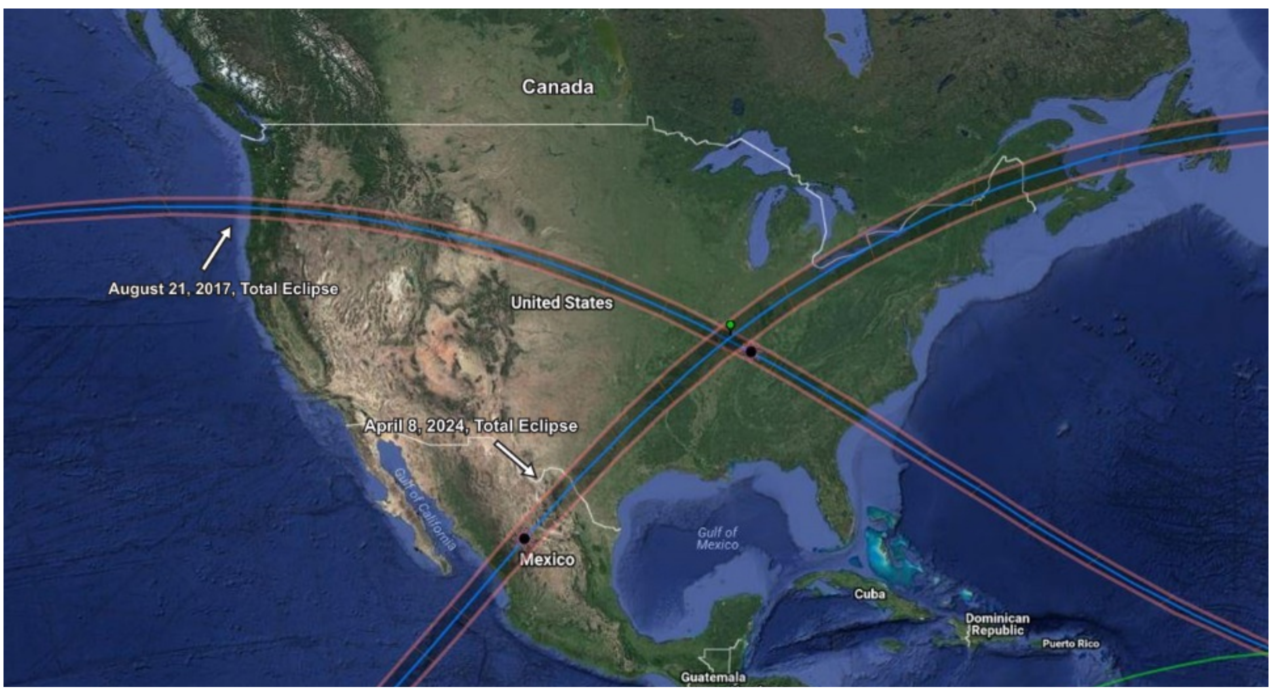


Figure 5.3: Solar Map—Projected Trajectory of the 2017 and 2024 Solar Eclipses

[70] Total Solar Eclipse of 2017 AUG 21; NASA.Gov

Chapter 6: Regional Overview

This chapter provides an overview of the results of this assessment for all Regional Entities by assessment area. Through joint efforts, NERC and the Reliability Assessment Subcommittee (RAS) built the process and analyses used for this assessment. In addition to the collection of data, NERC guides the creation of a set of narrative questions that seek to explain and clarify the potential risks to reliability that are identified throughout the BPS. Both the data and the narrative responses undergo a thorough peer review process within the RAS on an assessment area level and by the Regional Entities in a separate narrative question and review period. Presented here are highlights of the emerging issues and details by assessment area obtained through this comprehensive process.

Highlights of Emerging Issues

An intrinsic component of the peer-reviewed narratives is identifying emerging issues and potential risks to reliability that have been studied through additional assessments. Detailed here are the highlights of these emerging issues by assessment area.

FRCC

Weather events in the Gulf of Mexico could potentially have an impact on the availability and transportation of natural gas. However, dual-fuel capability, the increase of onshore (outside of Florida) gas resources, and a third gas pipeline currently under construction in central Florida (in service mid-2017) would mitigate natural gas transportation and supply issues in extreme weather events, such as hurricanes. FRCC’s Fuel Reliability Working Group (FRWG) provides oversight of the Regional Entity fuel reliability forum that studies fuel availability and coordinates responses to fuel issues and emergencies.

MISO

Policy and changing generation trends continue to drive new potential risks to resource adequacy and will require continued transparency and vigilance to ensure long-term needs. MISO projects that reserve margins will continue to tighten over the next five years, which approaches the reserve margin requirement. Operating at the reserve margin 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 in use of load modifying resources, such as behind-the-meter generation and demand response (DR). A number of large resources continue to feel economic pressure, which could lead to further plant retirements and drive the reserve margin lower.

MRO-Manitoba Hydro

There are potential new electricity export opportunities between Manitoba and Saskatchewan, which would likely require new transmission in western Manitoba. There is uncertainty as to the availability of local voltage support due to the potential shutdown of Brandon Unit 5 in 2020 in western Manitoba. It is expected that post-disturbance voltage will become an emerging concern in the period beyond 2025 depending on the timing of various projects. Plans to address this are under study.

MRO-SaskPower

The requirement to reduce emissions from thermal generating facilities will call for ongoing planning to ensure that proposed thermal generation retirements are successfully implemented. Saskatchewan is also working with the provincial and federal governments on emission regulations and agreements to confirm the schedule for retirements. Saskatchewan will have an increase in wind generation in the near- and long-term planning horizons. The inclusion of more intermittent resources may have operational impacts such as changes to net demand ramping variability that need to be studied to determine the power system effects on both Saskatchewan and neighboring jurisdictions.

NPCC-Maritimes

The Maritimes Area has begun tracking the ramp rate variability trend but does not yet have enough years of data for the area as a whole to identify any trends. Given the essentially flat load growth and small degree of anticipated variable energy resource (VER) installations, little change in either ramp rates or the area's resource mix is expected to occur for the duration of the LTRA assessment period. The maximum net demand ramping variability 1 hour up, 1 hour down, 3 hours up, and 3 hours down values for two historical years of 2014 and 2015 and a future year of 2020 were calculated along with the percentage contributions of VERs versus the loads. The majority of the maximums occurred during the late fall shoulder and winter peak seasons

NPCC-New England

Solar PV resources constitute the largest segment of distributed generation resources throughout New England. The region has experienced significant growth in the development of PV resources over the past few years and continued growth of PV is anticipated. In order to determine what impacts future PV could have on the regional power grid, the ISO created a forecast of future PV. ISO-NE's solar forecast separates the PV into two categories: 1) Markets and 2) Behind-the-Meter. PV in the Markets category consists of resources participating in the forward capacity market and PV as energy-only generating assets that participate in the energy market. Behind-the-Meter PV comprises approximately two-thirds of the total PV capacity and is treated as a load reducer. ISO-NE has limited information on the characteristics of behind-the-meter PV resources. ISO-NE does not collect behind-the-meter PV metered data, but can estimate its operational characteristics by using available historical PV production data along with total installed nameplate capacity. The total peak load reduction value of all PV in New England amounted to 588 MW in 2016 and it is forecasted to grow to 964 MW by 2021 and to 1,127 MW by 2026. These summer peak load reduction values are calculated as a percentage of ac nameplate. The percentages, which include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day, decrease from 40 percent of nameplate in 2015 to about 34 percent in 2026.

The ISO surveys Distribution Owners several times a year to determine the historical installations of PV and other types of distributed generation. The ISO annually projects PV installations by state and distributes them by dispatch zone. The forecast is based on state policies and reflects inputs from stakeholders. With the exception of PV, distributed generation is growing slowly and is accounted for within the ISO's demand forecast. The ISO is currently conducting scenario analyses that reflect large scale development of PV. These long-term planning studies, scheduled for completion in 2017, will assess the potential impacts on operating reserves, ramping, and regulations.

NPCC-New York

On January 25, 2016, the New York State Department of Public Service Staff (DPS) issued a whitepaper outlining its recommendations to the NYSPSC for implementing the state's Clean Energy Standard (CES).[71] The CES is intended to increase the amount of renewable energy generation in New York State to 50 percent of total generation by 2030 while retaining upstate nuclear power plants in support of the state's carbon dioxide emissions reduction goals.

The current solar integration study concluded that the BPS can reliably manage (over the five-minute time horizon) the increase in net load variability associated with the solar PV and wind penetration levels up to 4,500 MW wind and 9,000 MW solar PV. The solar study also concluded that the large-scale implementation of behind-the-meter solar PV will impact NYISO's load profile and associated system operations. Also, the lack of frequency and voltage ride-through requirements for solar PV facilities could worsen system contingencies when solar PV deactivates in response to frequency and voltage excursions

[71] New York Department of Public Service: Staff White Paper on Clean Energy Standard; January 2016

New York only determines an annual installed reserve margin (IRM) to meet a one-day-in-ten loss of load expectation (LOLE). Estimating the impact of the above-referenced issues on the IRM is difficult due to so many different input variables that would increase or decrease the margins. However, the addition of intermittent resources, such as solar and wind in the amounts proposed by certain initiatives, would have the tendency to increase the IRM requirements over time.

NPCC-Ontario

With the growth in distributed generation capacity, demand forecasting has become increasingly more complex. Traditionally, demand was mainly a function of weather conditions, economic cycles, and population growth. With multiple new factors influencing demand, such as increased distribution-connected VER and increased consumer price-responsiveness, determining the causality of demand changes has become increasingly nuanced.

The introduction of VERs (e.g., solar and wind), the removal of flexible generation (coal), and lower demand and limitations in operational flexibility of gas and hydro resources have added new challenges to maintaining a reliable system. The results of a recent operability assessment indicated that there is a system need for enhanced flexibility to balance supply and demand, more regulation, and additional grid voltage control. It is important that the supply mix remains robust in meeting industry planning standards, flexible to meet the ever-changing demands of system operations, and balanced to manage inherent risks (e.g., fuel security and critical infrastructure needs). To that end, the IESO has launched an initiative to augment resource flexibility and issued a Request for Information for additional regulation service in June 2016. The IESO has an energy storage pilot program underway to test the capability of storage technologies to provide grid services as well. Activities are also underway with transmitters to plan and install additional dynamic and static voltage control devices to help with voltage control.

Increasing amounts of VERs and relatively flat demand levels have contributed to a rise in surplus baseload generation (SBG) in Ontario. Over the next few years, more VERs are expected, but the effects on SBG will be tempered by the impact of the planned nuclear refurbishments and retirements. The IESO has mechanisms in place to manage SBG, including economic exports, wind and solar dispatch, and nuclear maneuvers or shutdowns.

NPCC-Québec

While technical developments in recent years have contributed to build a more reliable system, sustainable system reliability may be challenged by emerging issues, such as potential operational issues due to the changing resource mix. In the Québec area, wind generation capacity has increased by 2,500 MW over the last five years, but the area's total installed capacity is still mainly composed of large reservoir hydro complexes (more than 90 percent) that can react quickly to adjust their generation output and meet the sharp changes in electricity net demand. The forecasted change to resource mix is not expected to have any influence on the ramp rate trends or any other reliability issue.

PJM

PJM has experienced some thermal overload problems during light load conditions with relatively high wind generator output. PJM's light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity at light load. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level, such as high wind output.

Interchange levels for the various PJM zones will reflect a statistical average of typical previous years' interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous off-peak periods. The flowgates ultimately used in the light load reliability analysis are determined by the following: running all contingencies maintained by PJM planning and monitoring all PJM market-monitored facilities and all BPS facilities. The contingencies used for light load reliability analysis will include NERC TPL P1, P2, P4, P5, and P7. For NERC TPL P0, normal system conditions will also be studied.

SERC

With respect to MISO, a settlement agreement was reached between MISO, SPP, and the Joint Parties (TVA, SOCO, LG&E/KU, AECI and PowerSouth). The settlement agreement is now in effect (and superseded the ORCA on February 1, 2016) to reliably manage the magnitude of power transfers between MISO South and Midwest. The settlement agreement limits transfers between MISO-South and MISO-Midwest to 2,500 MW and between MISO-Midwest to MISO-South to 3,000 MW in order to limit reliability impacts on neighboring systems. The increase in flow from 1,000 to 2,500/3,000 MW represents a new operating condition that has been studied and experienced under certain historical operating conditions. However, this is a significant change that will be closely monitored in operations for adverse reliability impacts. Although a settlement agreement is in place, SERC is committed to ensuring reliability of the region and the interconnection. The region implemented a Joint Loop flow study initiative with market and nonmarket entities to recreate and study loop flows within the area. The purpose of these studies are to ensure there are not potential IROL conditions that can lead to cascading, separation, or blackout conditions

SPP

SPP, along with other joint parties in the Region, and MISO are currently managing reliability concerns from MISO's recent operational changes under the provisions of the Operations Reliability Coordination Agreement (ORCA).[72] On March 1, 2015, SPP and MISO began using Market-to-Market mechanisms to more efficiently and economically control congestion on SPP and MISO flowgates, in which both markets have a significant impact. During congestion on an SPP market-to-market flowgate, SPP will initiate the market-to-market process, and SPP and MISO will coordinate through an iterative process to identify and dispatch the most cost-effective generation between the two markets to relieve the congestion.

Texas RE-ERCOT

The Texas panhandle region is currently experiencing significantly more wind generation developer interest than what was initially planned for the area. ERCOT and Texas-RE are conducting a study while participating in a recent NERC pilot project related to ramping issues associated with high levels of VERs. In addition, ERCOT is performing steady state, dynamic, and short-circuit assessments to identify weak system areas and in particular to assess the reliability impacts in areas with high renewable penetrations. The assessment area is also projecting potential high increases in small distributed generation additions, such as rooftop solar. ERCOT is accelerating its efforts to more accurately map distributed energy resources (DERs) to the transmission grid.

WECC

Load-serving entities historically experience two rapid increases in customer demand: early morning and late afternoon. These rapid changes were typically balanced by increased hydroelectric and thermal generation. However, with greater generation contribution of intermittent resources, hydro and thermal units are required to follow larger daily demand fluctuations. The CA/MX subregion is seeing a large increase in distributed resources. There is currently about 4,300 MW of rooftop solar installed in the Western Interconnection with about 4,000 MW of that total installed in the CA/MX subregion. By 2026, that total is expected to increase to over 12,000 MW in the interconnection with over 11,000 MW installed in the CA/MX subregion. Due to the importance of hydro generation from the northwest, WECC monitors hydro conditions in that region. Under the Pacific Northwest Coordination Agreement, entities within the Northwest PowerPool have the obligation to coordinate the operations and long-term planning for the northwest Hydro system. WECC relies on their obligation and expertise to monitor and manage NW hydro issues.

[72] Operations Reliability Coordination Agreement; June 2013

California is continually working to coordinate the integration of VERs. The California ISO's energy imbalance market (EIM) provides a way to share energy reserves and renewable energy through a real-time energy market. The EIM operates in parts of California, Nevada, Utah, Idaho, Washington, Oregon, and Wyoming, and will expand into parts of Arizona in 2016. The ability to dispatch resources throughout the Western Interconnection has increased the flexibility needed to incorporate VERs into the grid.

Probability-Based Resource Adequacy Assessment

NERC recognizes that a changing resource mix with significant increases in energy-limited resources, changes in off-peak demand, and other factors can have an effect on resource adequacy. As a result, NERC is incorporating more probabilistic approaches into this assessment as well as other ongoing analyses that will provide further insights into how to best establish adequate reserve margins amidst a BPS undergoing unprecedented changes. Historically, NERC has gauged resource adequacy through planning reserve margins, which are deterministic assessment metrics. Planning reserve margins are a measure of available capacity over and above the capacity needed to meet normal (50/50) forecast peak demand.[73, 74]

Background

In 2010, the Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) concluded that existing reliability models could be used to develop one common composite generation and transmission assessment. The task force also noted the importance of having complete coverage of the North American BPS as well as the elimination of overlaps. As this premise is already adopted and executed annually in the LTRA, the approach for the probabilistic assessment follows suit. The assessment areas (i.e., Regions, Planning Coordinators (PCs), independent system operators (ISOs), and regional transmission organizations (RTOs)) used for this assessment are identical to those used for the LTRA.

NERC produced a series of probabilistic assessment reports conducted by the Regions and assessment areas, covering all of the NERC Assessment Areas.

In this effort to improve NERC's continuing probabilistic and deterministic assessments, the Probabilistic Assessment Improvement Task Force[1] (PAITF) was formed in May, 2015, from members of the Planning Committee (PC), the Reliability Assessment Subcommittee (RAS), and selected observers from industry. Its purpose is to support the identification of improvement opportunities for NERC's Long-Term Reliability Assessment and complementary probabilistic analysis.

PAITTF has developed two reports. The first is the NERC Probabilistic Assessment Improvement Plan report, published in December 2015. This report provided possible recommendations by PAITF based on recent LTRA key findings for NERC core and proposed coordinated special probabilistic assessment reports. The second report was the NERC Technical Guideline document published in August, 2016. This report provided detailed probabilistic modeling guidelines and technical recommendations that serve as a platform for detailing probabilistic analytical enhancements that apply to resource adequacy.

73 NERC Reliability Assessments

74 NERC Probabilistic Assessment Improvement Task Force

In the development of the *NERC 2016 Probabilistic Assessment*, NERC RAS and RAS-ProbA team implemented the following main PAITF technical guideline recommendations:

- Regions and assessment areas calculate monthly resource adequacy metrics. As resource and demand characteristics change over time, annual loss of load may start accruing during historically off-peak months. Therefore, the monthly aggregation of these metrics [loss of load hours (LOLH) and expected unserved energy (EUE)] will better inform industry of potential resource adequacy risks throughout the year.

- Assessment areas performed sensitivity modeling within the core probabilistic assessment framework. The NERC RAS identified the variable data elements relevant to each sensitivity model. NERC, with input from the RAS, ERO-RAPA, and the Planning Committee (PC), identified the Sensitivity Case to be an increase in load growth for the 2016 core probabilistic assessment. The purpose of this Sensitivity Case is to demonstrate the robustness of the loss of load measures:
  - Increase on-peak demand by two percent in the second study year, 2018, and by four percent in the fourth study year, 2020.
  - Increase MWh net energy by two percent in second study year, 2018, and by two percent in the fourth study year, 2020.

Summary statistic results of the forecast planning reserve margin, the forecast operable reserve margin,[75] annual and monthly LOLH and EUE measures for the Base Case and the Sensitivity Case, and high-level key findings are presented in the Assessment Area Granular Review section of the report.

Assessment Area Granular Review

Provided in more detail here are the more granular reviews of each assessment area's footprint, methods, assumptions used for this assessment, and additional information and data. This section includes dashboards that review both the deterministic and probabilistic data and results. Individually, these present a straightforward overview of the different assessment areas that make up the BPS and the variations between them.

[75] Forecast Operable Reserve Margin is defined as the ratio of anticipated resources derated by forced outage rates less on peak demand.

FRCC

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

Summary of Methods and Assumptions

Reference Margin Level
The FRCC Region utilizes the NERC 15 percent reference margin.

Load Forecast Method
Noncoincident, based on individual forecasts

Peak Season
Summer

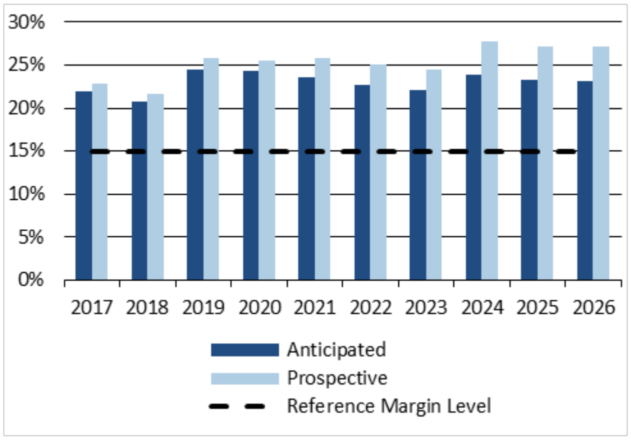
Planning Considerations for Wind Resources
No wind capacity

Planning Considerations for Solar Resources
Small amount of solar capacity; based on historical average at peak

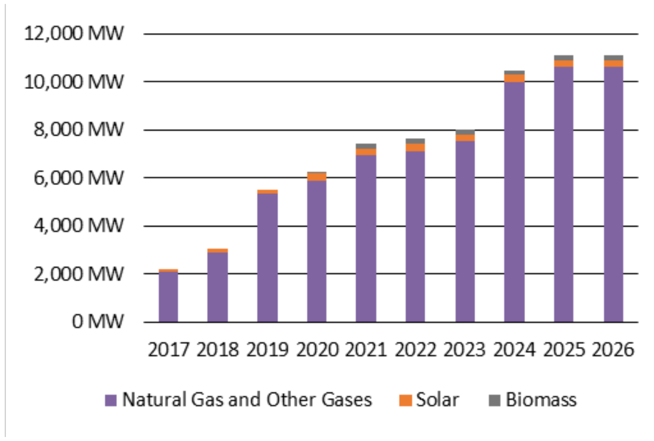
Footprint Changes
Region is the assessment area footprint; no recent changes

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	48,125	48,648	49,266	49,873	50,461	50,973	51,514	52,125	52,803	52,803
Demand Response	3,014	3,070	3,123	3,167	3,205	3,255	3,271	3,271	3,304	3,304
Net Internal Demand	45,111	45,578	46,143	46,706	47,256	47,718	48,243	48,854	49,499	49,499
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	55,015	55,019	57,442	58,088	58,379	58,551	58,916	60,533	60,994	60,976
Prospective	55,436	55,440	58,024	58,656	59,445	59,657	60,062	62,405	62,981	62,978
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	21.95%	20.71%	24.49%	24.37%	23.54%	22.70%	22.12%	23.91%	23.22%	23.19%
Prospective	22.89%	21.64%	25.75%	25.59%	25.79%	25.02%	24.50%	27.74%	27.24%	27.23%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** FRCC used the Tie Line and Generation Reliability (TIGER) program, which is based on the analytical method of recursive convolution for the computation of LOLH and EUE metrics.
- **Modeling:** The current modeling approach incorporates regional hourly load, generation data, forced outage rates, maintenance schedules, and monthly DR. Additionally, a load variation model was utilized that provided 500 variations of annual hourly load as an input into TIGER. FRCC was modeled as an isolated area with no interconnections with other areas and allowing only firm imports.
- **Results Trending:** 2018 was studied in both the 2014 and the 2016 ProbA to evaluate any changes or trends. The 2014 ProbA Base Case analysis resulted in an EUE of 0.070 MWh and an LOLH of 0.0002 hours per year. The results from the 2016 ProbA Base Case analysis showed a negligible decrease.
- **Probabilistic vs. Deterministic Reserve Margin Results:** There are no differences between the reserve margin reported in the LTRA and ProbA Base Case.

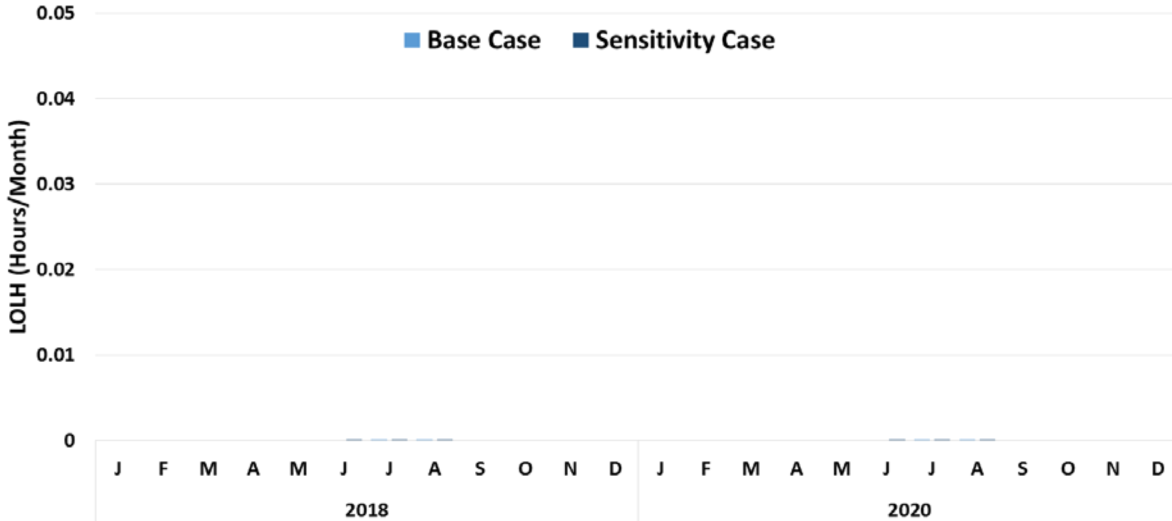
Base Case Study

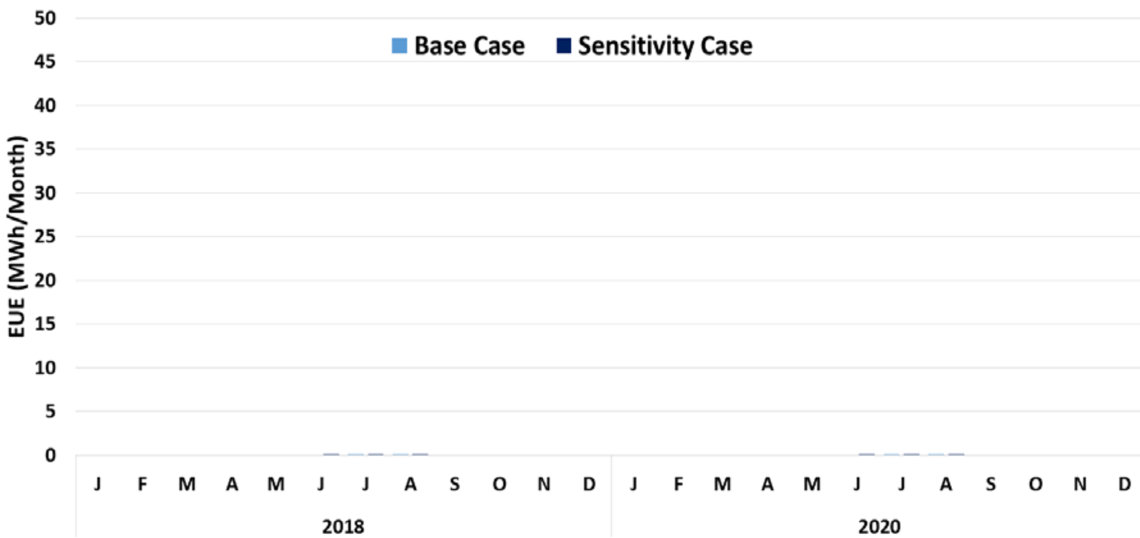
Reserve margins for the study years are well above the NERC reference margin of 15 percent, resulting in low LOLH and EUE values. The EUE was 0.0013 MWh in 2018 and 0.0002 MWh in 2020. Projected loss of load only occurred during the summer season.

Sensitivity Case Study

With the increase of load in the Sensitivity Case, reserve margins remain above the NERC reference margin of 15 percent, and the EUE increased slightly from the Base Case to 0.0493 MWh in 2018 and 0.0333 MWh in 2020. Similar to the Base Case, a nonzero loss of load values are projected only during the summer season with highest values in August.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	20.7	24.4	18.2	19.3
Prospective	21.6	25.6	19.1	20.4
Reference	15.0	15.0	15.0	15.0
ProbA Forecast Planning	20.7	24.4	18.2	19.3
ProbA Forecast Operable	15.8	19.4	13.4	14.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.0013	0.0002	0.0493	0.0333
EUE (ppm)	0.0000	0.0000	0.0000	0.0000
LOLH (hours/year)	0.0000	0.0000	0.0002	0.0001





Planning Reserve Margins, Demand

FRCC has a reliability criterion of a 15 percent minimum regional total reserve margin based on firm load. FRCC reserve margin calculations include merchant plant capacity that is under firm contract to load-serving entities. FRCC assesses the upcoming ten-year projected summer and winter peak hour loads, generating resources, and demand-side management (DSM) resources on an annual basis to ensure that the regional reserve margin requirement is projected to be satisfied. The three Florida Investor Owned Utilities, Florida Power & Light Company (FPL), Duke Energy Florida (DEF), and Tampa Electric Company (TEC) are utilizing, along with other reliability criteria, a 20 percent minimum total reserve margin planning criterion consistent with a voluntary stipulation agreed to by the Florida Public Service Commission (FPSC).[76] Other utilities employ a 15 percent to 18 percent minimum total reserve margin planning criterion.[77] Based on the expected load and generation capacity, all projected reserve margins are above the NERC Reference Margin Level of 15 percent for the FRCC assessment area with FRCC reserve margins remaining above 20 percent for all seasons during the assessment period.

[76] Docket No. 981890-EU Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida, Order No. PSC-99-2507-S-EU, issued December 22, 1999 (http://www.psc.state.fl.us/library/Orders/99/15628-99.pdf)

[77] Florida Administrative Code Rule 25-6.035 Adequacy of Resources (https://www.flrules.org/gateway/ruleno.asp?id=25-6.035)

FRCC continues to project growth in peak load, but the projected growth is less than in the previous forecast. The net energy for load (NEL) and summer peak demands are forecasted to be lower than in the previous forecasts. The current average annual growth rate for NEL is 0.8 percent per year compared to 1.1 percent per year in the previous forecast. Firm summer peak demand is expected to grow by 1.1 percent per year compared to 1.5 percent peak demand growth rate in the previous forecast. This is primarily due to more utilities starting to capture appliance efficiency in their load forecast models or using updated appliance efficiency assumptions. For firm winter peak demand, the average growth rate is now expected to be 1.0 percent per year compared to 0.9 percent per year in the previous forecast.

Demand-Side Management

The FRCC Region is projecting some decrease in the growth rate of utility program energy-efficiency due to two factors: (1) significant decreases in DSM cost-effectiveness caused by lower fuel costs, etc. and (2) increased impacts from federal and state energy-efficiency codes and standards (e.g., 2005 National Energy Policy Act, 2007 Energy Independence and Security Act). The impacts from these energy-efficiency codes and standards is lowering the potential for utility energy efficiency programs to lower demand and energy usage for appliances and equipment addressed by the codes and standards. However, these codes and standards are resulting in significant reductions in demand and energy that are accounted for in load forecasts. DR from interruptible and load management programs within FRCC is treated as a load-modifier and is projected to be relatively constant at approximately 6.4 percent of the summer and winter total peak demands for all years of the planning horizon.

The Florida Public Service Commission (FPSC) evaluates and revises its DSM goals every five years. New DSM Goals were set in 2014.[78] Because of diminished cost-effectiveness of DSM programs, and the fact that energy-efficiency codes and standards have lowered the potential for DSM programs, the FPSC set lower DSM Goals for Florida utilities than had been previously set in 2009. DR from interruptible and load management programs within FRCC is treated as a load-modifier, and is projected to be relatively constant at approximately 6.4 percent of the summer and winter total peak demands for all years of the planning horizon.

Generation

FRCC is projecting approximately 12,000 MW of summer and 12,262 MW of winter Tier 1 capacity to be added during the assessment period. The Tier 1 capacity will consist of mainly natural gas capacity with approximately 300 MW of firm solar (PV) and 180 MW of biomass. There are also 548 MW of planned uprates during the assessment period. The proposed generation additions are studied by the interconnecting Transmission Owner as well as by the FRCC Transmission Working Group (TWG) through FRCC's "Transmission Service and Generator Interconnection Service Request Assessment Area Deliverability Evaluation Process."[79]

Entities within FRCC have capacity transfers that have firm contracts available to be imported into the assessment area from SERC. There is approximately 830 MW of FRCC member-owned generation that is dynamically dispatched out of the SERC assessment area. These imports have firm transmission service to ensure deliverability into the FRCC assessment area. All firm on-peak capacity imports into the FRCC Region have firm transmission service agreements in place to ensure deliverability into the FRCC Region with these capacity resources included in the calculation of the Region's Anticipated Reserve Margin. In addition, the interface owners between FRCC and SERC assessment areas meet quarterly to coordinate and perform joint studies to ensure the reliability and adequacy of the interface.

The FRCC assessment area is projecting approximately 3,900 MW of summer generation to be retired through the assessment period. These retirements will include approximately 2,400 MW of natural gas generation, 1000 MW of coal, and 500 MW of oil. Also, a 400 MW natural gas unit will be converted to a synchronous condenser to

[78] Order No. PSC-14-0696-FOF-EU (http://www.floridapsc.com/library/FILINGS/14/06758-14/06758-14.pdf)

[79] FRCC Reliability Evaluation Process For Generator and Transmission Service Requests; FRCC-MS-PL-054; 6-1-2016

provide voltage support. Based on the annual FRCC long-range study, FRCC is not anticipating any reliability impacts resulting from these unit retirements, which are studied as part of the FRCC long-range study process performed annually by the TWG to mitigate potential reliability impacts to the Grid and the FRCC reserve margin criteria.

FRCC is not anticipating any larger generator unavailability during system peak. All known scheduled generation outages in the long-term horizon are incorporated into the annual FRCC long-range study process to mitigate any potential reliability impacts to the BPS.

FRCC's Fuel Reliability Working Group (FRWG) provides oversight of the Regional fuel reliability forum that studies the fuel availability and coordinates responses to fuel issues and emergencies. FRCC is not expecting any long-term reliability impacts resulting from an increase mixture of natural-gas-fired generation.

Transmission and System Enhancements

The FRCC Region has not identified any major projects that are needed to maintain or enhance reliability during the planning horizon. Planned projects are primarily related to expansion in order to serve forecasted growing demand and maintain the reliability of the BPS in the longer- term planning horizon.

The FRCC Region is not anticipating any additional reliability impacts resulting from potential environmental regulations. The State of Florida has not developed a renewable portfolio standard establishing target renewable thresholds. The 2013 MATS study performed by the FRCC's Transmission Working Group identified reliability impacts resulting from the retirement of two coal units at the same site. These units were granted an extension and will be able to run through 2018. These units will be replaced in the year 2018 by two gas-fired combined cycle units to maintain the reliability of the BPS within the FRCC Region. However, FRCC will continue to monitor the progress of the Clean Power Plan (CPP) to determine the potential impact to reliability once the current legal challenge has been resolved, which may result in changes in the timing and/or substance of the current CPP final rules.

Long-Term Reliability Issues

FRCC has not identified any long-term reliability issues. The FRCC Region performed an extreme weather (105 percent of peak) sensitivity scenario into its 2015 annual long-range planning study process to identify any potential reliability impacts to the BPS. The FRCC region is not expecting any reliability impacts during the shoulder periods. For the FRCC region, the shoulder periods are the spring and fall seasons. These seasons are studied in the operational horizon by the Operational Planning Working Group (OPWG) and by the TWG in the long-term horizon (off-peak cases) as part of the annual long range assessment. Additionally, FRCC has not identified any other emerging reliability issues. However, FRCC continues to monitor the possible impacts on the long-term reliability of the BPS from pending environmental legislations (CSAPR, NESHAP, RICE, MATS, and CPP).

MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit member-based organization. MISO administers 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.

Summary of Methods and Assumptions

Reference Margin Level
15.2 percent This increase is mainly driven by a process change within the LOLE study.

Load Forecast Method
Coincident

Peak Season
Summer

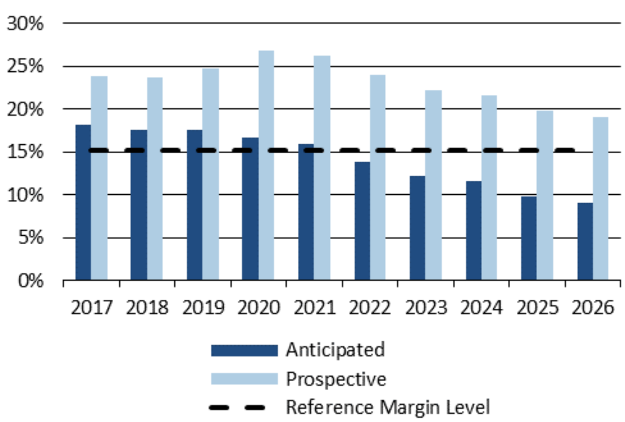
Planning Considerations for Wind Resources
Effective load-carrying capability (ELCC); varies by wind node

Planning Considerations for Solar Resources
No utility-scale solar resources in MISO

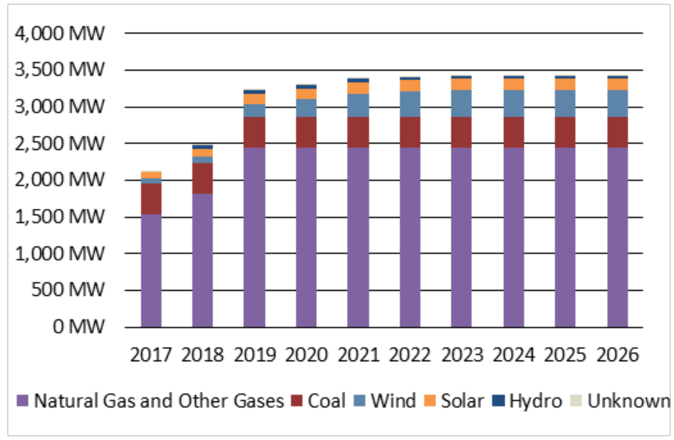
Footprint Changes
Minnesota is reporting under MISO this year

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	127,641	128,270	129,367	130,076	130,728	131,517	132,261	132,959	133,581	134,462
Demand Response	5,827	5,827	5,827	5,827	5,827	5,827	5,827	5,827	5,827	5,827
Net Internal Demand	121,814	122,443	123,540	124,249	124,901	125,690	126,434	127,132	127,754	128,635
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	143,844	143,866	145,316	144,875	144,850	143,154	141,817	141,805	140,311	140,297
Prospective	150,779	151,474	154,063	157,614	157,590	155,722	154,517	154,506	153,062	153,047
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	18.09%	17.50%	17.63%	16.60%	15.97%	13.89%	12.17%	11.54%	9.83%	9.07%
Prospective	23.78%	23.71%	24.71%	26.85%	26.17%	23.89%	22.21%	21.53%	19.81%	18.98%
Reference Margin Level	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	1,640	3,836	4,651	6,862	7,890
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** MISO is a summer-peaking system that spans 15 states and consists of 36 local Balancing Authorities that are grouped into 10 local resource zones. For the ProbA, MISO utilized a multi-area modeling technique for the 10 local resource zones internal to MISO. Firm external imports and non-firm imports are also modeled. This multi-area modeling technique for resource zones 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 limit was modeled that limits the Midwest (local resource zones 1–7) to south (local resource zones 8–10) flow to 3,000 MWs and the south to Midwest 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 on 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.

- **Results Trending:** Previous results in the *2014 Probabilistic Assessment* resulted in 182.2 MWh EUE and 0.09 Hours per year LOLH. The results from this year's analysis resulted in a slight decrease for 2018 when compared to the analysis completed in the *2014 Probabilistic Assessment*.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The LTRA deterministic reserve margins decrease capacity that is constrained within MISO south due to the 2,500 MW limit which 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 ProbA forecast planning reserve margin.

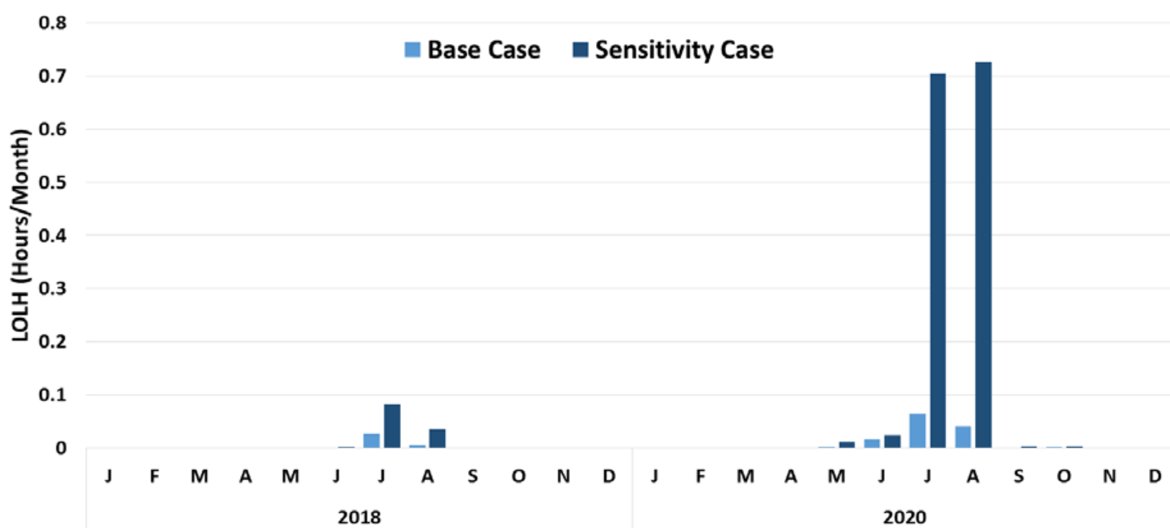
Base Case Study

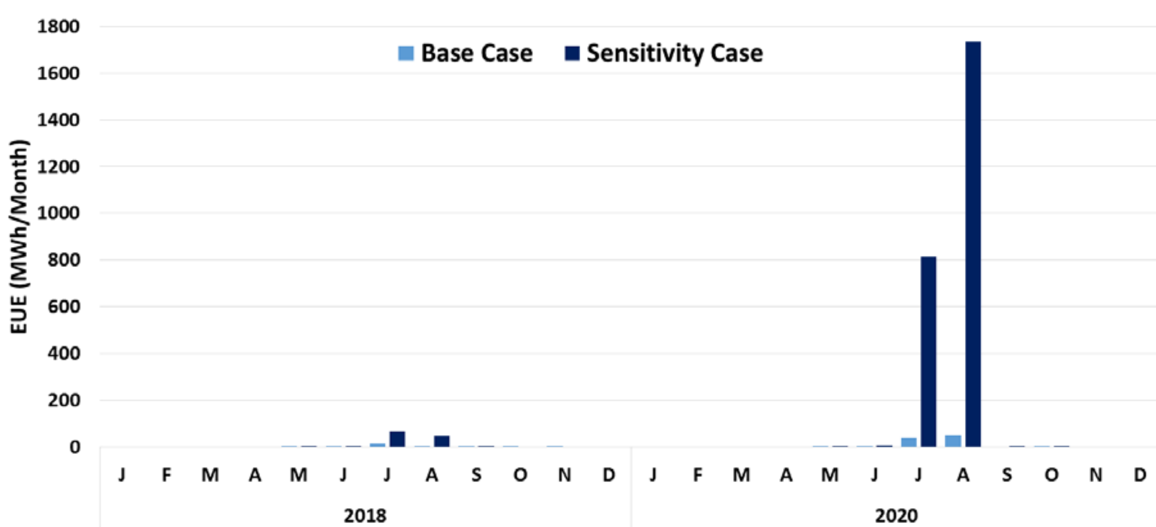
- The bulk of the EUE and LOLH are accumulated in the summer peaking months with some off-peak risk.
- Increases in loss of load statistics are expected with decreasing reserve margins.

Sensitivity Case Study

- The Sensitivity Case is a good proxy for increased retirement risk and/or increased load forecasts. The 2018 2 percent increase is equal to a 2,565 MW increase and the 2020 4 percent increase is equal to a 5,203 MW increase.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	17.5	16.6	-	-
Prospective	23.7	26.9	-	-
Reference	15.2	15.2	-	-
ProbA Forecast Planning	21.7	20.2	19.2	15.4
ProbA Forecast Operable	12.0	10.6	9.7	6.1
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	17.95	95.80	113.83	2565.70
EUE (ppm)	0.026	0.133	0.160	3.430
LOLH (hours/year)	0.033	0.125	0.119	1.474





Overview

MISO projects a regional surplus for the summer of 2017 with potential regional shortfall starting in 2018. These results show a potential regional short fall two years earlier than the *2015 MISO LTRA* results. These results are driven by a number of factors:

- A decrease in resources committed to serving MISO's load mainly by independent power producers (IPP).
- A decrease in load forecasts where the biggest drop was in Zone 6 (Indiana).
- The increase in committed resources (Tier 1) in Zone 7 (Michigan).
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet their local clearing requirements or the amount of their local resource requirement (which must be contained within their boundaries).
- Several zones are short against their total zonal reserve requirement when only resources within their boundaries (or are contracted to serve their loads) are considered. However, those zones have sufficient import capability, and the MISO region has sufficient surplus capacity in others zones to support this transfer. Surplus generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO load-serving entities.
- 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. Regional shortages in later years may be rectified by the utilities; MISO is engaged with stakeholders in a number of resource adequacy reforms to help rectify these later year's shortages.

Policy and changing generation trends continue to drive new potential risks to resource adequacy, requiring continued transparency and vigilance to ensure long-term needs.

- MISO projects that reserve margins will continue to tighten over the next five years and approach the reserve margin requirement.
- Operating at the reserve margin 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 in use of Load Modifying Resources, such as behind-the-meter generation and DR.

The SPP settlement agreement has put in place a Regional Directional Transfer Limit replacing the ORCA operating limit. Specifically the Midwest (LRZs 1-7) to south (LRZs 8-10) flow is limited to 3,000 MWs and south to Midwest is limited to 2,500 MWs.[80]

This year marks the third iteration of the Organization of MISO States (OMS) MISO survey, which helps provide forward visibility into the resource adequacy position of the MISO region. The survey also helped identify resources that had a low certainty of being available for each planning year.

The LTRA results represent a point in time forecast, and MISO expects these figures will change significantly as future capacity plans are solidified by load-serving entities and States. For example, there are enough resources in Tier 2 and 3 to mitigate any long-term resource shortfalls.

MISO forecasts the coincident Total Internal Demand to peak at 127,607 MW during the 2017 summer season. This is a decrease of roughly 2,700 MWs from last year's projection for 2017. This decrease is mainly driven by load reductions in Zones 5 (Missouri) and aluminum smelter closures in Zone 6 (Indiana). MISO projects the

[80] MISO Presentation: SPP Settlement Update; October 2015

summer coincident peak demand to grow at an average annual rate of 0.6 percent, which is less than the growth rate from the 2015 assessment.

As a result of the OMS-MISO survey, resources with a low certainty of being available for the given year are more visible. This number is small in Years 1–3 and then ramps up in the future. The reductions of these low certainty resources are more than offset with Tier 2 and 3 resources and should not cause any resource adequacy issues. However, MISO continues to see a number of large resources, generally IPPs, that are “at-risk” for retirement due to economics. Local reliability issues could result with some of the unannounced retirements.

The annual MISO Transmission Expansion Plan (MTEP)[81] proposes transmission projects to maintain a reliable electric grid and deliver the lowest-cost energy to customers in the MISO region. As part of MTEP15, MISO staff recommends $2.75 billion of new transmission expansion through 2024, as described in Appendix A of the MTEP report,[82] to the MISO Board of Directors for review, approval, and subsequent construction.

The 345 new projects in MTEP15 Appendix A represent $2.75 billion[83] in transmission infrastructure investment and fall into the following four categories:

> **90 Baseline Reliability Projects (BRP) totaling $1.2 billion:** BRPs are required to meet NERC reliability standards.
>
> **12 Generator Interconnection Projects (GIP) totaling $73.6 millio**n: GIPs are required to reliably connect new generation to the transmission grid.
>
> **1 Market Efficiency Project (MEP) totaling $67.4 millio**n: MEPs meet requirements for reduction in market congestion.
>
> **242 Other Projects totaling $1.38 billion:** Other projects 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.

MISO is working with stakeholders to create resource adequacy reforms to move to a seasonal construct. The seasonal construct would create a summer and a winter planning reserve margin requirement and seasonal resource parameters (on peak capacity, EFORd, etc.). The seasonal construct will better reflect the seasonality of the wind, solar, etc. and increase the visibility of reliability in the winter season.

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[81] MISO Transmission Expansion Planning (MTEP)

[82] MISO Transmission Expansion Plan 2015

[83] The MTEP15 report and project totals reflect all project approvals during the MTEP15 cycle, including those approved on an out-of-cycle basis prior to December 2015.

MRO-Manitoba Hydro

Manitoba Hydro is a Provincial Crown Corporation that provides electricity to 561,869 customers throughout Manitoba and natural gas service to 274,817 customers in various communities throughout southern Manitoba. The province of Manitoba is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of the MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Summary of Methods and Assumptions

Reference Margin Level

The capacity criterion, as determined by Manitoba Hydro, requires a minimum 12 percent planning reserve margin, applied as the Reference Margin Level in this assessment.

Load Forecast Method

Coincident

Peak Season

Winter

Planning Considerations for Wind Resources

Effective Load-Carrying Capability (ELCC) of 15.6 percent for the summer and 20 percent for the winter.

Planning Considerations for Solar Resources

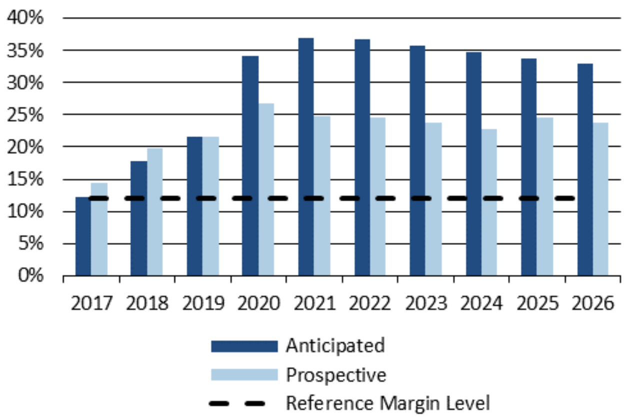
No utility-scale solar resources

Footprint Changes

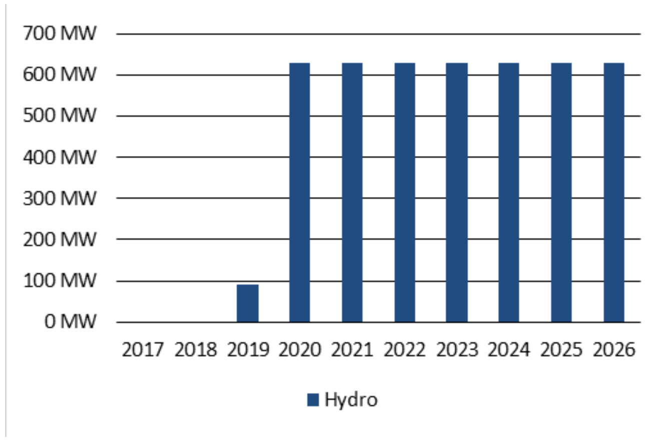
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	4,826	4,713	4,646	4,703	4,685	4,710	4,743	4,781	4,793	4,821
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,826	4,713	4,646	4,703	4,685	4,710	4,743	4,781	4,793	4,821
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	5,419	5,557	5,647	6,304	6,412	6,437	6,437	6,437	6,412	6,412
Prospective	5,526	5,649	5,646	5,961	5,844	5,869	5,869	5,869	5,969	5,969
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	12.29%	17.90%	21.53%	34.04%	36.86%	36.66%	35.72%	34.65%	33.79%	33.00%
Prospective	14.51%	19.86%	21.53%	26.75%	24.74%	24.61%	23.76%	22.77%	24.56%	23.82%
Reference Margin Level	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Manitoba Hydro system is a winter-peaking system, and the vast majority of its generating facilities are use-limited or energy-limited hydro units. The 2016 Manitoba Hydro probabilistic assessment was conducted using the Multi-Area Reliability Simulation (MARS) program. The data used in the MARS simulation model are consistent with the data reported in the *2016 LTRA* submittals from Manitoba Hydro to NERC.

- **Modeling Characteristics:** Manitoba Hydro and its neighboring systems are modeled as two areas consisting of Manitoba and the northwest part of MISO. Each of the two interconnected areas are modeled connected directly and the transmission between Manitoba and MISO is modeled with interface transfer limits. Three different types of resources are modeled for Manitoba Hydro system: hydro resources, thermal resources (including both coal and gas units), and intermittent wind resources. The 8,760 point hourly load records of a typical year were used to model the annual load curve shape. Load forecast uncertainty is modeled in both the Base and Sensitivity Cases. DR programs are modeled as a simple load modifier by reducing the peak load. Contractual obligations are modeled as load modifiers considering the contractual obligations of the power sales and purchase agreements.

- **Results trending:** The LOLH and EUE values obtained in the *2014 Probabilistic Assessment* are zero. The nonzero LOLH and EUE values are obtained for both the Base and Sensitivity cases in *2016 Probabilistic Assessment*. The slight increase in the reliability indices is mainly due to the changes in modeling assumptions. The following specific changes are made in 2016 assessment as compared to 2014 assessment: 1) Multiple flow conditions, including an extreme drought scenario, are modeled and the indices calculated are weighted averages of the indices obtained for different water conditions. 2) Increased standard deviation of the seven-step load forecast uncertainty from four percent to five percent.

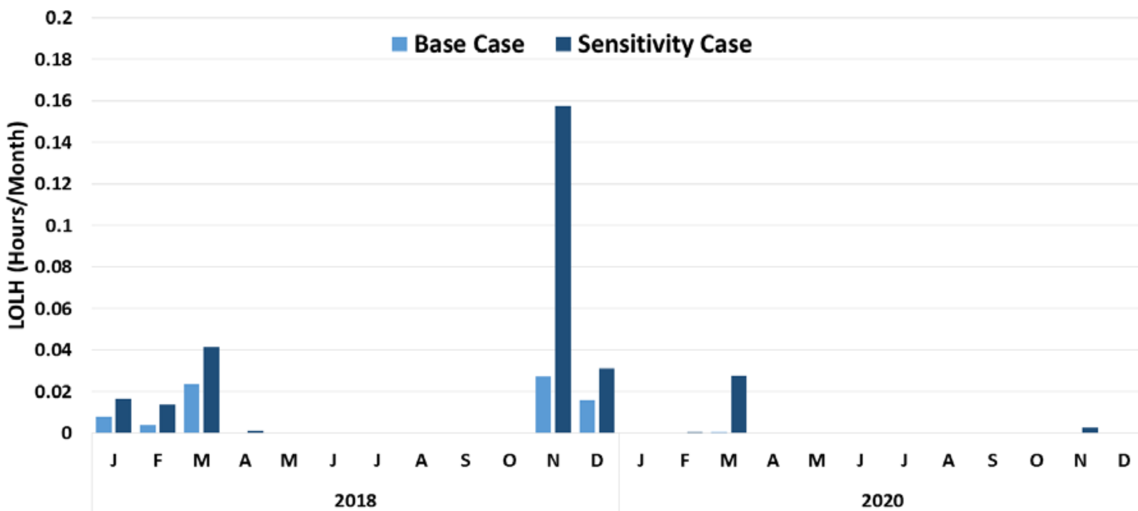
Base Case Study

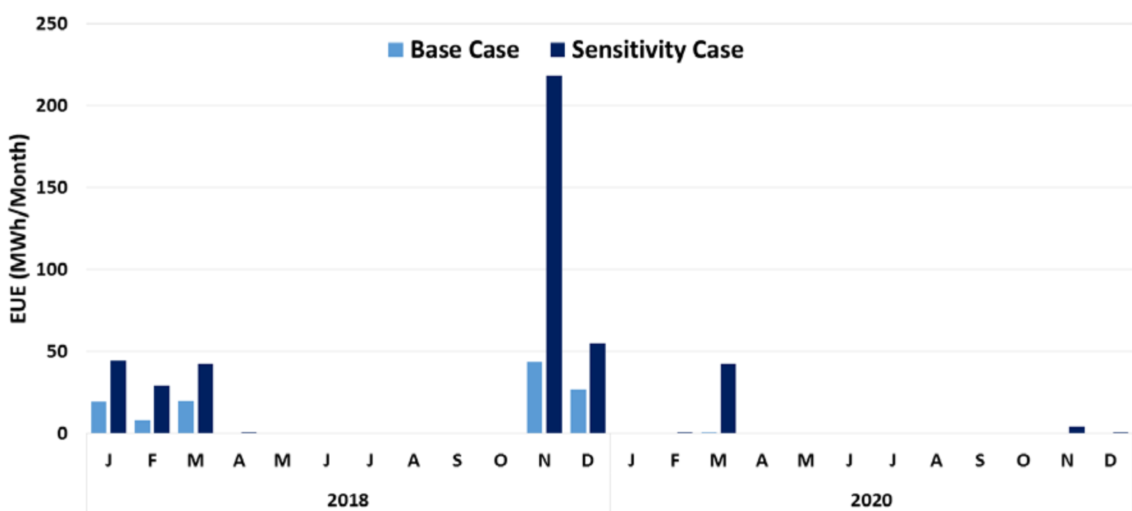
For 2018 Base Case, small values of EUE and LOLE are observed due to a relatively smaller reserve margin. For 2020 Base Case, the reserve margin is increased significantly due to the expected addition of a new generating station and therefore the LOLE and EUE are virtually zero. All loss of load events are in winter season and the highest contribution to loss of load is from the winter month of November.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
Anticipated	17.90	18.67	-	-
Prospective	19.86	30.15	-	-
Reference	12	12	12	12
ProbA Forecast Planning	13.7	22.9	11.4	18.2
ProbA Forecast Operable	11.0	20.4	8.8	15.8
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
EUE (MWh)	117.06	0.24	389.88	47.27
EUE (ppm)	4.45	0.01	14.53	1.72
LOLH (hours/year)	0.0783	0.0001	0.2608	0.0304

Sensitivity Case Study

As expected, the reliability indices are increased in the Sensitivity Cases for both the 2018 and 2020 planning years, and all loss of load events are in winter season. Although the planning reserve margin drops below the reference value of 12 percent for a 2 percent increase in peak load, the EUE and LOLE are still small for 2018 planning year. The minor changes in the LOLE and EUE indices for 2020 planning year is mainly due to the decrease in reserve margin for a 4 percent increase in peak load. The highest contribution to the loss of load event is still from the winter month of November for 2018 while it is from the winter month of March for 2020 planning year.





Demand, Resources and Reserve Margins

Manitoba Hydro is projecting reserve margins above the Reference Margin Level during the assessment period.

Since the previous assessment, the demand forecast is projected to be 1.4 percent lower by 2025/26, and this is primarily attributable to an increase in the forecast of DSM activity. The forecast of DSM in 2025/26 is increasing from 516 MW forecast in the previous assessment to 685 MW in the current assessment. No changes were made to the load forecasting methodology from the last assessment period.

Energy efficiency and conservation savings are forecast higher than prior year's assessment due to enhancements to existing programs (e.g., increasing program incentives, adding alternative program delivery methods, or adding new measures to the program).

There have been no capacity additions in Manitoba since the *2015 LTRA*. The Keeyask Hydro Generating Station is now under construction and is considered a Tier 1 capacity addition. Manitoba Hydro is anticipating the first units of the 630 MW of net capacity addition from the Keeyask Hydro Generating Station would begin to come into service in late 2019. Brandon Unit 5, Manitoba Hydro's sole remaining coal-fired generating unit, is assumed to remain available until December 31, 2019, when it is considered to be an unconfirmed retirement. This potential retirement of Brandon Unit 5's approximately 95 MW of capacity is not expected to have an impact on reliability as other resources are expected to come into service at that time.

Manitoba Hydro has up to 925 MW of firm and/or expected capacity exports in the winter, up to 625 MW of firm and/or expected capacity imports in the winter, and up to 1,525 MW of firm and/or expected capacity exports in the summer. There are associated firm transmission reservations over the 10 year assessment period. Manitoba Hydro does not have any capacity imports during the summer. Manitoba Hydro does not have any capacity transactions beyond the contract terms. Included in the firm exports are up to 475 MW of firm contracts in relation to the 630 MW Keeyask generating station, which is anticipated to come into service around 2020.

Manitoba does not have a legislated renewable mandate, such as an RPS, and no legislation is currently anticipated.

MRO-SaskPower

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

Summary of Methods and Assumptions

Reference Margin Level

No change in Reference Margin Level since the *2015 LTRA*. The reserve margin for SaskPower's generation system must not fall below 11 percent of adjusted net demand. This percentage represents the amount of excess generation SaskPower will have after serving the highest projected load during the peak month.

Load Forecast Method

Coincident, 50/50 forecast

Peak Season

Winter

Planning Considerations for Wind Resources

10 percent of nameplate (summer); 20 percent of nameplate (winter)

Planning Considerations for Solar Resources

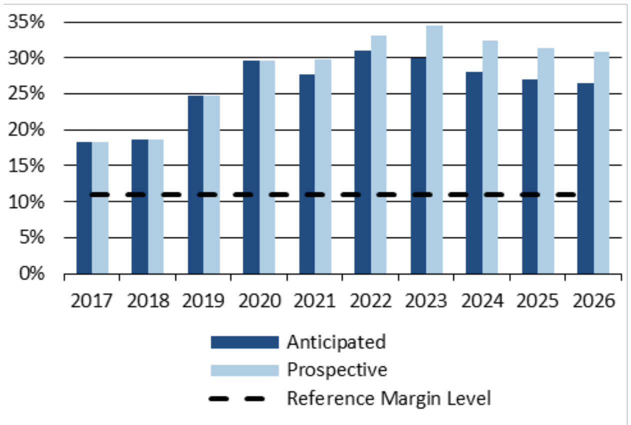
No utility-scale solar resources

Footprint Changes

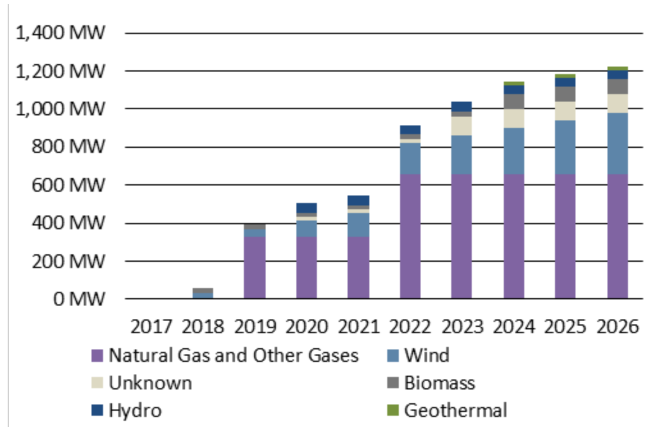
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	3,724	3,761	3,852	3,874	3,901	3,959	4,007	4,048	4,111	4,159
Demand Response	85	85	85	85	85	85	85	85	85	85
Net Internal Demand	3,639	3,676	3,767	3,789	3,816	3,874	3,922	3,963	4,026	4,074
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	4,303	4,364	4,700	4,910	4,872	5,076	5,101	5,072	5,112	5,152
Prospective	4,303	4,364	4,700	4,910	4,950	5,156	5,276	5,247	5,287	5,327
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	18.24%	18.72%	24.76%	29.58%	27.67%	31.01%	30.04%	27.97%	26.96%	26.46%
Prospective	18.24%	18.72%	24.76%	29.58%	29.71%	33.07%	34.50%	32.38%	31.31%	30.75%
Reference Margin Level	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Saskatchewan is a winter-peaking area (December). The Saskatchewan Power Corporation (SaskPower) is the principal supplier of electricity in the province of Saskatchewan, Canada. SaskPower is a provincial Crown Corporation, which under the provincial legislation, is responsible for the reliability oversight of the Saskatchewan bulk electric system and is obligated to serve its domestic load.
- **Modeling Characteristics:** SaskPower utilized the Multi-Area Reliability Simulation (MARS) program for the purpose of this study. This reliability study is based on the DSM adjusted 50/50 load forecast.
- **Results Trending:** Since the *2014 Probabilistic Assessment*, the reported forecast reserve margin for year 2018 has gone down slightly from 20.6 percent to 17.8 percent mainly due to a change in the expansion sequence. As expected, EUE and LOLH have increased when compared to analysis completed in 2014.
- **Probabilistic vs. Deterministic Reserve Margin Results:** Most of the data is consistent with the LTRA except the energy forecast and the expansion sequence, which has been updated to reflect the most recent projections.

Base Case Study

The major contribution to the 2018 LOLH and EUE is in the month of October (around 60 percent). There are maintenances scheduled to the largest coal and large natural gas units in that month. Most of the maintenance is scheduled during off-peak periods and can be rescheduled to mitigate short-term reliability issues.

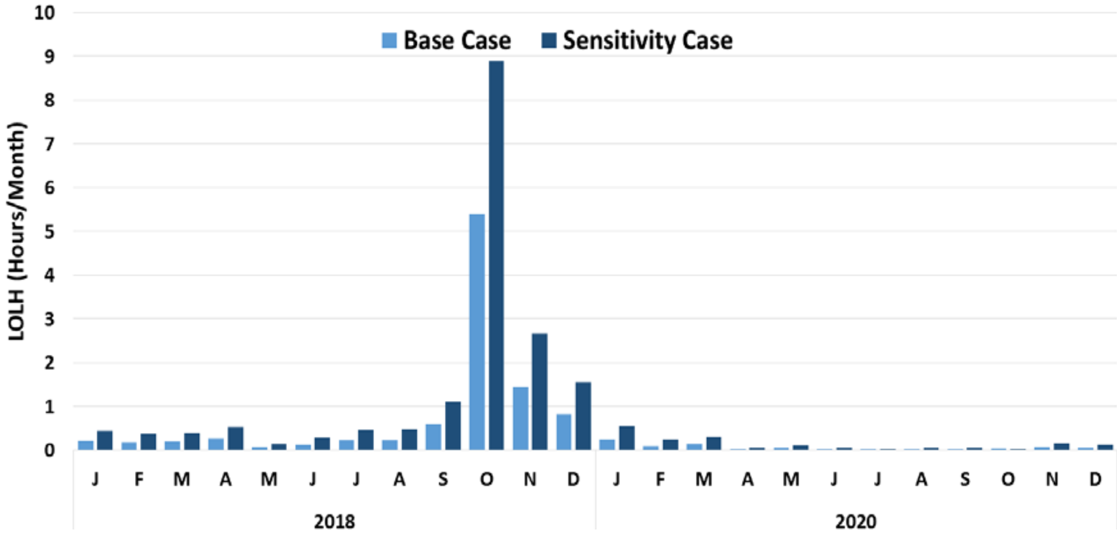
In the year of 2020, the LOLH and EUE are highest in January due to higher load.

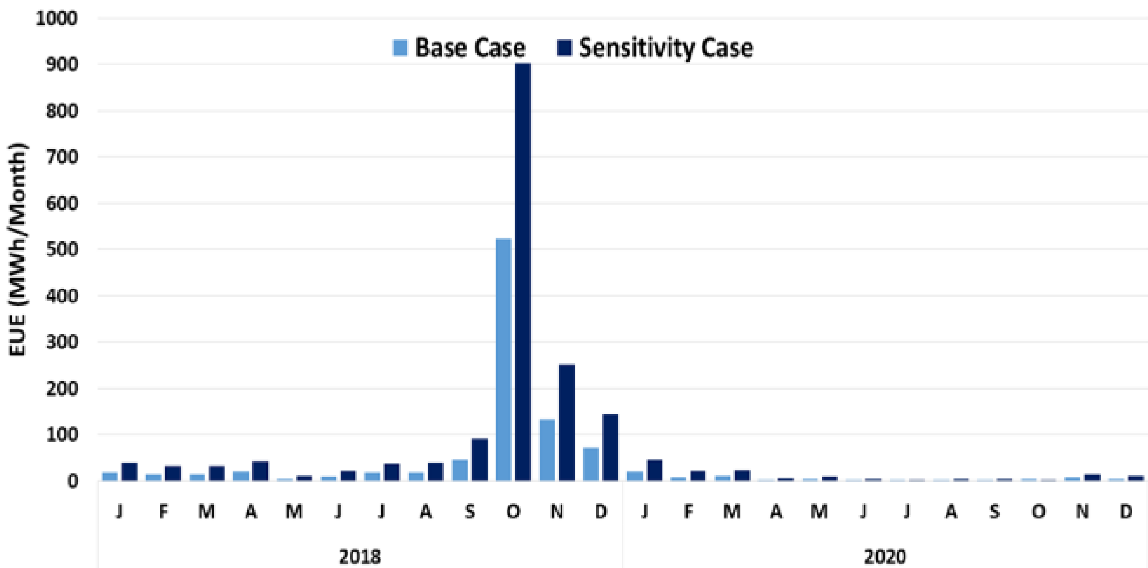
Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	17.8	25.6	15.4	20.7
Prospective	17.8	25.6	15.4	20.7
Reference	11	11	11	11
ProbA Forecast Planning	17.8	25.6	15.4	20.7
ProbA Forecast Operable	14.6	22.6	12.3	17.7
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	893.6	65.5	1639.5	147.0
EUE (ppm)	36.16	2.56	65.05	5.64
LOLH (hours/year)	9.78	0.836	17.31	1.77

Sensitivity Case Study

A similar monthly trend is observed in the Sensitivity Case. As compared to the Base Case, the reserve margin has decreased from 17.8 percent to 15.4 percent and from 25.6 percent to 20.7 percent for year 2018 and 2020, respectively.

The effect of higher load growth is evident on the reliability metrics. EUE is almost doubled from the Base Case in both study years. EUE reported for Sensitivity Case is 1639.5 MWh/yr and 147 MWh/yr for the year 2018 and 2020, respectively.





Demand, Resources, and Planning Reserve Margins

Saskatchewan plans to meet projected load requirements with anticipated resources throughout the assessment period. Saskatchewan's Anticipated Reserve Margin exceeds the 11 percent Reference Margin Level for the assessment period.

Saskatchewan experiences peak demand in the winter. The average annual growth rate for total internal demand is 1.4 percent during the assessment period, which is slightly lower than last year's forecast (1.89 percent). The slight decrease is mainly caused by the deferral of oil pipeline projects. The growth is expected to be generally spread throughout the province. Saskatchewan is planning for a seven percent yearly average growth of energy efficiency and conservation programs, and DR programs are projected to remain unchanged.

In Saskatchewan, projected unit retirements for the assessment period include 174 MW of natural gas facilities, 11 MW of wind facilities, and two-139 MW coal facilities. There were 228 MW (nameplate) added in the Assessment area since the *2015 LTRA*. Throughout the assessment period, a total capacity of 2633 MW (nameplate) of Tier 1 resources is projected to come on-line. This total consists of 660 MW of natural gas, 1607 MW of wind, 120 MW of solar, 76 MW of biomass resources, 100 MW of flare gas resources, 20 MW of geothermal, and 50 MW of hydro resources.

For capacity transfers, Saskatchewan has a firm import contract for 25 MW until the spring of 2022. Saskatchewan also has a firm import of 100 MW from July 2020 until the end of the assessment period. There are no anticipated firm exports for the assessment period. Saskatchewan only imports and exports based on economics. Import also increases supply mix diversification for Saskatchewan.

Transmission Outlook and System Enhancements

Saskatchewan plans to invest in transmission infrastructure over the assessment period in order to maintain and enhance reliability. The related projects are dependent on load growth and include the construction of 918 km of new 138 kV and 230 kV transmission line. Saskatchewan is also adding a static VAR system in the South-Central Region of the province to help with voltage control in the area by the end of 2016.

Long-Term Reliability Issues

It is not expected that extreme weather events will impact long-term reliability in Saskatchewan; however, operation of the Saskatchewan system would be performed on a best-effort basis under extreme weather events. Demand would be offset by planning reserves and external markets. If necessary, operational measures include DR, interruptible load contracts, public appeals, and rotating outages.

Typically, a significant amount of unit maintenance (partial and total unit outage) is planned for the shoulder periods in Saskatchewan. If short-term reliability issues are identified during a shoulder period, unit maintenance will be rescheduled.

Saskatchewan does not expect any long-term reliability impacts resulting from fuel supply and/or transportation constraints. Fuel disruptions are minimized as much as possible by system design practices and Saskatchewan's diverse energy mix of resources. Coal resources have firm contracts, are mine-to-mouth, and stockpiles are maintained at each facility in the event that mine operations are unable to meet the required demand of the generating facility. Natural gas resources have firm transportation contracts with large natural gas storage facilities located within the province capable of supporting those contractual requirements. Hydro facilities/reservoirs are fully controlled by Saskatchewan, and long term hydrological conditions are monitored.

Essential Reliability Services

The Saskatchewan net demand ramping trend for historical years (2013, 2014, and 2015) shows a gradual increase by approximately five percent each year. Contribution of the VERs to the increase in ramp rate was, however, minimum as there has been no significant increase in VERs in the historical years in Saskatchewan. Projected 2016 ramp rates also show approximately a five percent increase from the historical years. Projected 2020 ramp rates show an increase by approximately 70 percent from the 2016 and historical year ramp rates.

Saskatchewan system inertia did not change significantly for the 2015, 2016, and 2018 years. There has not been a significant change in installed generation capacity in these years.

NPCC-Maritimes

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

Summary of Methods and Assumptions

Reference Margin Level
20 percent

Load Forecast Method
Coincident; 50/50 forecast

Peak Season
Winter

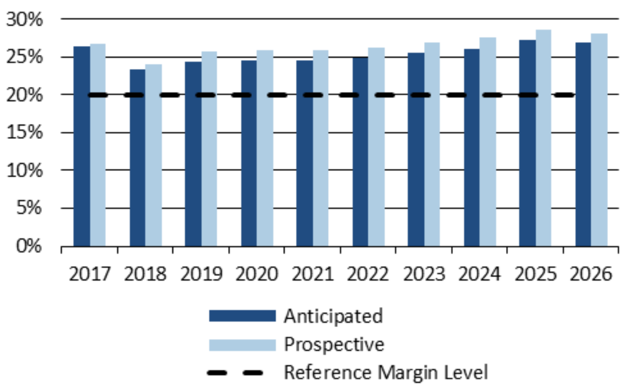
Planning Considerations for Wind Resources
Estimated capacity is derived from a combination of mandated capacity factors and reliability impacts.

Planning Considerations for Solar Resources
N/A

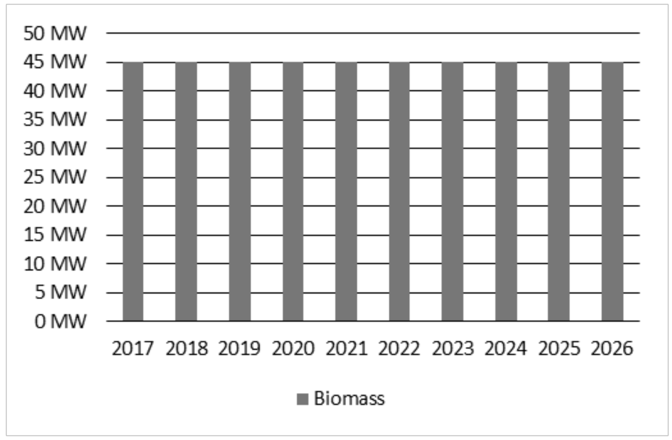
Footprint Changes
A conceptual tie line to the Canadian province of Newfoundland and Labrador could potentially impact the Maritimes footprint.

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	5,584	5,608	5,627	5,623	5,622	5,608	5,580	5,552	5,509	5,518
Demand Response	272	272	272	272	271	271	271	271	271	270
Net Internal Demand	5,312	5,336	5,355	5,351	5,350	5,336	5,309	5,281	5,238	5,248
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	6,716	6,585	6,661	6,661	6,661	6,661	6,661	6,661	6,661	6,655
Prospective	6,735	6,621	6,735	6,735	6,735	6,735	6,735	6,735	6,735	6,724
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	26.42%	23.40%	24.37%	24.47%	24.49%	24.82%	25.47%	26.13%	27.16%	26.81%
Prospective	26.79%	24.08%	25.77%	25.87%	25.89%	26.21%	26.88%	27.54%	28.59%	28.13%
Reference Margin Level	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The Maritimes Area is a winter peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. The GE MARS model, developed by the NPCC CP-8 Working Group, was used for the following: demand uncertainty modeling, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion (i.e., NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[84]

- **Results Trending:** The previous study, the *NERC RAS Probabilistic Assessment—NPCC Region*,[85] estimated an annual LOLH = 0.001 hours per year and a corresponding EUE equal to 0.0 (ppm) for the year 2018. The 2018 forecast 50/50 peak demand forecast is 262 MW greater in this assessment than reported in the previous assessment. This reflects increases in electric heating loads that were not quite offset by declines in industrial loads and demand shifting programs. Forecast capacity resources increased by 81 MW in the *2016 Probabilistic Assessment* as compared to the previous assessment. No material difference in estimated LOLH and EUE is observed between the two assessments. Increased capacity resources, coupled with reliance on operating procedures and tie benefits, contribute to this result.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The Maritimes Area employs a reserve criterion of 20 percent of firm load. To relate the Maritimes Area reserve criterion of 20 percent to the NPCC resource adequacy criterion, LOLE was evaluated with the Maritimes Area firm load scaled so that the reserve was equal to 20 percent. The results showed that a Maritimes Area reserve of 20 percent corresponds to an LOLE of approximately 0.086 days per year.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in the *NPCC 2016 Long Range Adequacy Overview* and described in the *2016 NERC RAS Probabilistic Assessment—NPCC Region*.[86]

[84] NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System; September 2015
[85] NERC RAS Probabilistic Assessment: NPCC Region; March 2015
[86] NPCC Library - Resource Adequacy

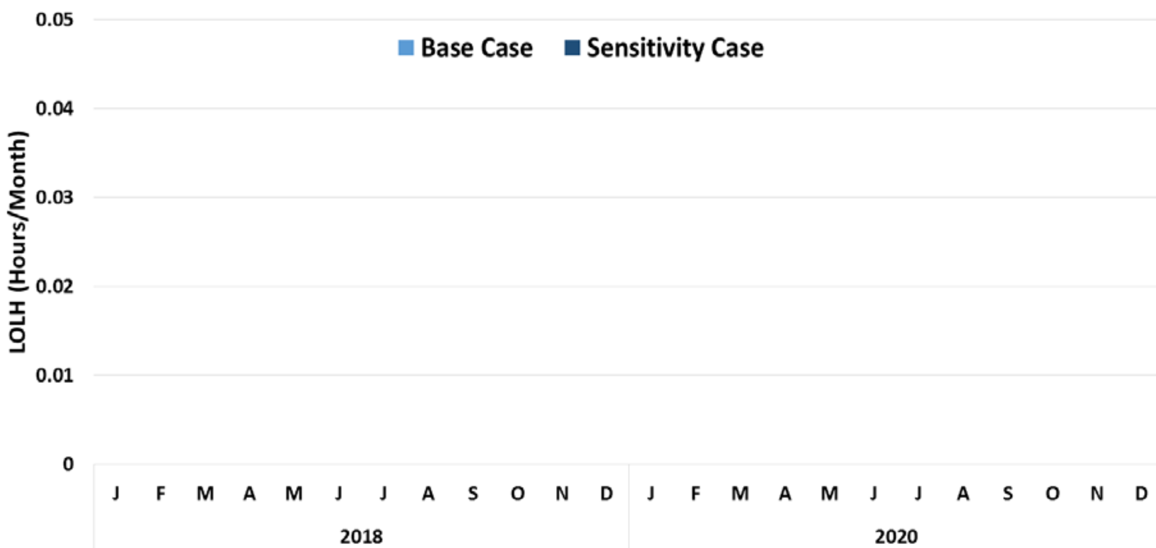
Base Case Study

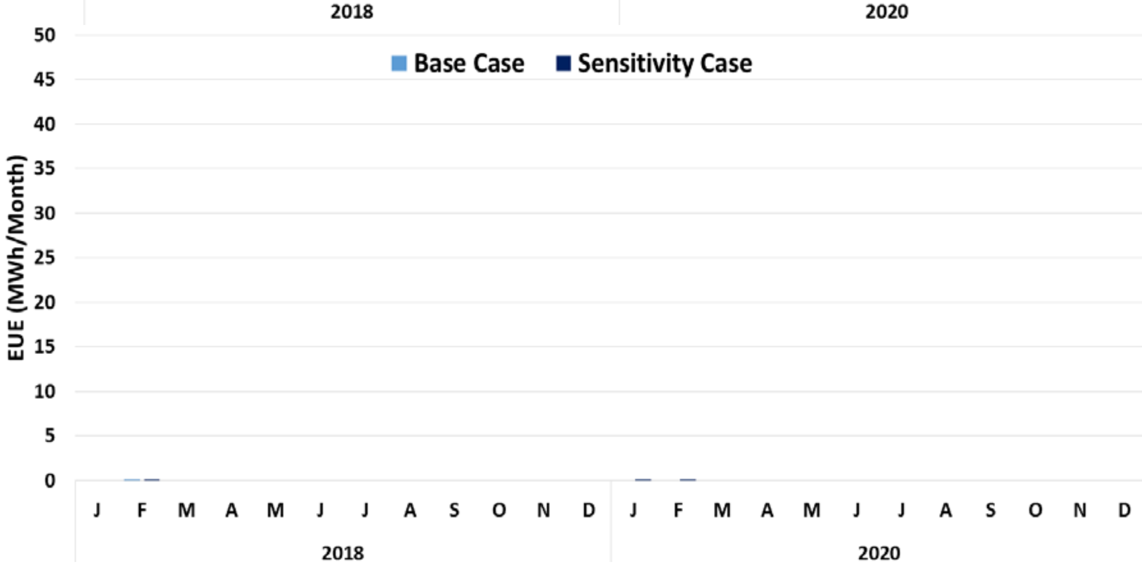
No significant LOLH is observed. EUE is 0.005 in 2018 and negligible in 2020. Anticipated Reserve Margins are well above 20 percent in both years. The greatest contribution to the LOLH and EUE occur during the peak (winter) monthly period.

Sensitivity Case Study

LOLH is also not significant in this case, the EUE values are negligible: 0.03 and 0.004 MWh for 2018 and 2020, respectively. Anticipated Reserve Margins remain above 20 percent in 2018 and near 20 percent in 2020.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	26.42	24.37	23.8	19.4
Prospective	26.79	25.77	-	-
Reference	20.0	20.0	-	-
ProbA Forecast Planning	26.4	24.4	23.8	19.4
ProbA Forecast Operable	20.0	18.1	17.5	13.3
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.005	0.000	0.030	0.004
EUE (ppm)	0.000	0.000	0.001	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000





Overview

The Maritimes Area is comprised of four subareas: New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM), where a 20 percent reserve margin target is used. This reserve level correlates closely to the amount of reserve necessary to meet the 0.1 days per year LOLE criterion required by the Northeast Power Coordinating Council (NPCC). The close correlation is confirmed annually during NPCC resource adequacy reviews.

Resources in the Maritimes Area are subject to capacity deratings that account for variances in seasons in the case of variable generation and the likelihood of the resource being available if called upon. If derated resources result in inadequate margins looking forward in time, then new resources must be acquired.

The aggregated load growth for the four combined subareas of the Maritimes Area is practically flat for both the summer and winter seasonal peak load periods. They have an average growth rates of 0.2 percent per year in summer and a decline of 0.13 percent per year in winter.

Load growth for the southeastern corner of the NB subarea (including the much smaller PEI subarea) is not specifically identified in the load projections, but NB has historically outpaced growth in the rest the Maritimes Area. NB Power has added under-voltage load shedding equipment at two new sites and applied temperature compensation to restricting lines to increase transfer capabilities. In addition, demand side management (DSM) programs aimed at reducing and shifting peak demands and potential imports to NB from NS could reduce transmission loading in the southeastern NB area. These imports may begin after the completion of the high-voltage direct current (HVdc) interconnection to the Canadian province of Newfoundland and Labrador. No other reinforcements are planned at this time.

During the 10-year LTRA assessment period in the Maritimes Area, annual amounts for summer peak demand reductions associated with energy efficiency programs rose from 7 MW to 92 MW, and the annual amounts for winter peak demand reductions rose from 43 MW to 555 MW. Most of this amount is related to intensive demand shifting programs in New Brunswick that will focus mainly on reducing and/or shifting water and space heater demands during peak load periods. This is done by using smart metering technology to control their consumption patterns. Interruptible loads are the only specifically forecasted DR programs in the Maritimes Area. During the assessment period, no significant changes from previously reported amounts for interruptible loads are expected to occur.

Nova Scotia is projecting three installed capacity additions by January 2020: 49 MW of wind, 3.6 MW of solar, and 23 MW of biomass/biogas. In addition, transmission restrictions on a 45 MW formerly energy-only biomass generator in Nova Scotia are being removed before January 2018, and the generator’s capacity will then be counted as firm capacity. Also, an unconfirmed retirement of a 153 MW coal-fired unit in Nova Scotia is expected in mid-2020. This capacity will be offset by an expected firm purchase of hydro capacity over the new HVdc link with the Canadian province of Newfoundland and Labrador. The retirement of the coal unit will be correspondingly delayed should a delay occur in the introduction of energy from the new hydro capacity.

Renewable energy standards (RESs) have led to the development of substantially more wind generation capacity than any other renewable generation type. Reduced frequency response is associated with wind generation and may, with increasing levels in the future, require displacement of wind generation with conventional generation during light load periods. With the significant amount of large scale wind energy currently being balanced on the NB system, the next phase of renewable energy development in NB will focus on smaller scale projects with a particular emphasis on nonintermittent forms of generation, such as wood-based biomass. In NS, the Maritimes Link project will provide renewable hydro resources that may otherwise have been provided by intermittent resources and would have further reduced frequency response capability.

With respect to capacity deratings for renewable variable generation, NB derates wind capacity using a calculated year-round equivalent capacity of 20 percent for the Maritimes Area. NS and PEI derate wind capacity to 12 percent and 15 percent of nameplate based on calculated year-round equivalent capacities for their respective sub areas. NM derates wind to 26 percent and 46 percent of nameplate based on summer and winter seasonal capacity factors, respectively.

There are no trends developing for either imports or exports; however, a long-term import contract starting in mid-2020 is expected to offset the unconfirmed retirement of a coal unit in Nova Scotia. This offset is expected to be with replacement hydro capacity over the HVdc cable link (currently under construction to Newfoundland and Labrador. The capacity of the import and the unit retirement are comparable and are planned to coincide in timing, thus overall resource adequacy is unaffected by these changes.

Transmission development in the Maritimes Area during the assessment period includes installation of a 345 kV breaker in series with an existing breaker at NB's Point Lepreau terminal in the spring of 2016. This will mitigate contingencies and reduce import restrictions from New England. During the winter of 2016/17, the installation of two undersea 138 kV cable connections, each with a capacity of 200 MVA and a length of 9 miles, will be completed. This will increase capacity and improve the ability to withstand transmission contingencies in the area between NB and PEI. A 475 MW HVdc undersea cable link (Maritime Link) between Newfoundland and Labrador and NS will be installed by early 2018. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the southeastern NB area. In addition, during the fall of 2018, a second 345/138 kV transformer will be added in parallel with an existing unit at the Keswick terminal in NB to mitigate the effects of transformer contingencies at the terminal. No delays are expected for these projects.

No modifications have been made to the assessment area's planning assumptions or methods in response to extreme weather events. The hydro-electric power supply system in the Maritimes Area, with a capacity of approximately 1330 MW, is predominantly run-of-the-river as opposed to storage based. Large quantities of energy cannot be held in reserve to stave off drought conditions. If such conditions occur, the hydro system would still be used to follow load in the area and respond to sudden short-term capacity requirements. Thermal units would be used to keep the small storage capability of the hydro systems available only for load following and/or peak supply. The Maritimes Area is not overly reliant on wind capacity to meet resource adequacy requirements. The lack of wind during peaks (or very high wind speeds and/or icing conditions that would cause wind farms to suddenly shut down) should not affect the dependability of supply to the area. This is because ample spinning reserve is available to cover the loss of the largest base loaded generator in the area. The latter situation is mitigated further by wide geographic dispersal of wind resources across the area.

The Maritimes Area has a diversified mix of capacity resources fueled by nuclear, oil, coal, natural gas, dual fuel oil/natural gas, hydro, wind (derated), and biomass with no one type feeding more than about 26 percent of the total capacity in the area. There is not a high degree of reliance upon any one type or source of fuel. The Maritimes Area does not anticipate fuel disruptions that pose significant challenges to resource adequacy in the area during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions.

The Maritimes Area has begun tracking the ramp rate variability trend, but does not yet have enough historical years of data for the area as a whole to identify any trends. Given the essentially flat load growth and small degree of anticipated VER installations, little change in either ramp rates or the area's resource mix is expected to occur for the duration of the LTRA assessment period. The maximum net demand ramping variability (1 hour up, 1 hour down, 3 hours up, and 3 hours down values) for two historical years of 2014 and 2015 and a future year of 2020 were calculated along with the percentage contributions of VERs versus the loads. The majority of the maximums occurred during the late fall shoulder and winter peak seasons. The Maritimes Area is a winter peaking area. Five minute interval samples were used for these calculations. The values for 2020 were scaled up from the actuals used for 2015.

The following table outlines the results of the Maritimes area review. NDRV stands for net demand ramping variability, and VER stands for variable energy resource.

Year	Variable	NDRV (MW)	Date	VER (MW)	Load (MW)	VER/load (%)
2014	1 hour UP	637	Dec. 8, 2014	281	4,295	6.5
2014	1 hour DOWN	-617	Nov. 17, 2014	576	3,372	17.1
2014	3 hours UP	1262	Dec. 5, 2014	415	3,622	11.5
2014	3 hours DOWN	-1072	Nov. 17, 2014	546	3,683	14.8
2015	1 hour UP	606	Feb. 2, 2015	354	4,653	7.6
2015	1 hour DOWN	-416	Dec. 17,2015	485	3,546	13.7
2015	3 hours UP	1172	Oct. 28, 2015	417	2,702	15.4
2015	3 hours DOWN	-953	Dec. 17,2015	403	3,785	10.6
2020	1 hour UP	629	Feb. 2, 2020	373	4,828	7.7
2020	1 hour DOWN	-434	Dec. 17,2020	511	3,679	13.9
2020	3 hours UP	1219	Oct. 28, 2020	439	2,804	15.7
2020	3 hours DOWN	-993	Dec. 17,2020	425	3,927	10.8

NPCC-New England

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

Summary of Methods and Assumptions

Reference Margin Level
The installed capacity requirement (ICR) results in a Reference Margin Level of 16.74 percent in 2017, declining to 16.55 percent in 2018 and expected to be 15.93 percent for the remainder of the assessment period.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

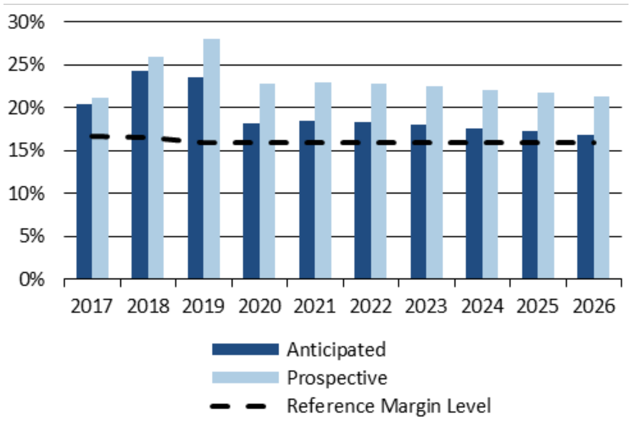
Planning Considerations for Wind Resources
A value of 5 percent of the total nameplate for on-shore and 20 percent of nameplate for off-shore resources

Planning Considerations for Solar Resources
A value of 38 percent of nameplate in 2017, decreasing annually to 34 percent in 2026

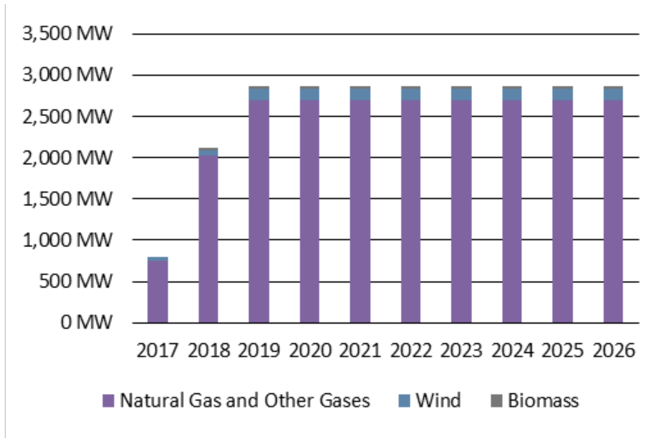
Footprint Changes
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	26,698	26,765	26,783	26,789	26,816	26,870	26,942	27,026	27,122	27,218
Demand Response	841	597	378	378	378	378	378	378	378	378
Net Internal Demand	25,857	26,168	26,405	26,411	26,438	26,492	26,564	26,648	26,744	26,841
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	31,112	32,529	32,617	31,226	31,330	31,336	31,342	31,347	31,353	31,353
Prospective	31,313	32,935	33,803	32,412	32,516	32,522	32,528	32,533	32,539	32,539
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.32%	24.31%	23.52%	18.23%	18.50%	18.28%	17.99%	17.63%	17.23%	16.81%
Prospective	21.10%	25.86%	28.02%	22.72%	22.99%	22.76%	22.45%	22.08%	21.67%	21.23%
Reference Margin Level	16.74%	16.55%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- The New England Area is a summer peaking area comprised of New Hampshire, Rhode Island, and Vermont. The GE MARS model developed by the NPCC CP-8 Working Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures. This is as prescribed by the NPCC resource adequacy criterion (ref: NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[87]

- **Results trending:** The previous study (*NERC RAS Long-Term Reliability Assessment—NPCC Region*)[88] estimated an annual LOLH equal to 0.288 hours per year and a corresponding EUE equal to 253.8 MWh for the year 2018. The Forecast 50/50 peak demand for 2018 was lower than reported in the previous study with higher estimated forecast planning and forecast operable reserve margins. As a result, both the LOLH and the EUE have improved for 2018.

- **Probabilistic vs. Deterministic Reserve Margin Results:** New England's reference reserve margin is determined based on the NPCC resource adequacy criterion; this results in a reference reserve margin level of 16.6 percent in 2018, and 15.9 percent for 2020.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in *NPCC 2016 Long Range Adequacy Overview*, and are consistent with those described in the *2016 NERC RAS Probabilistic Assessment—NPCC Region.*[89]

[87] NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System; September 2015
[88] NPCC RAS Probabilistic Assessment; March 2015
[89] NPCC Library - Resource Adequacy

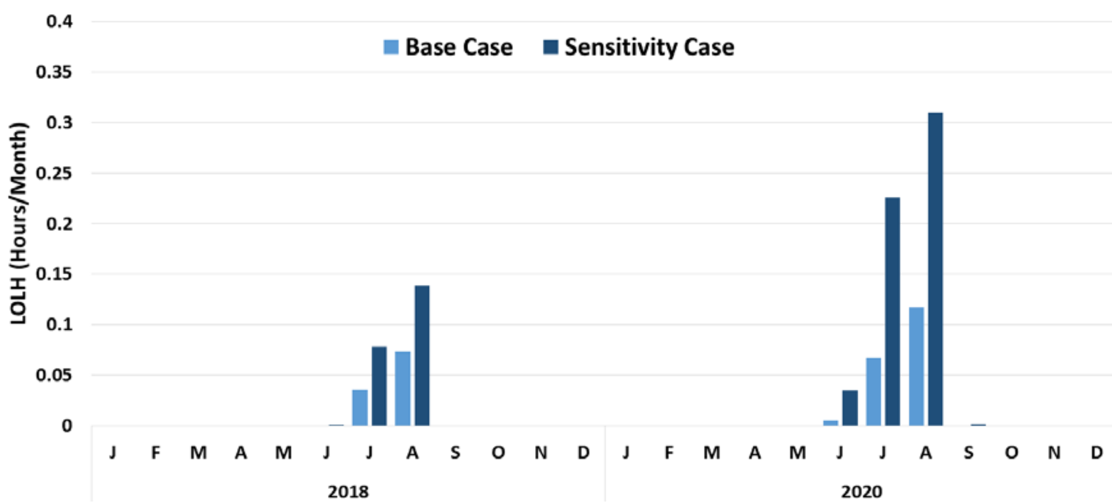
Base Case Study

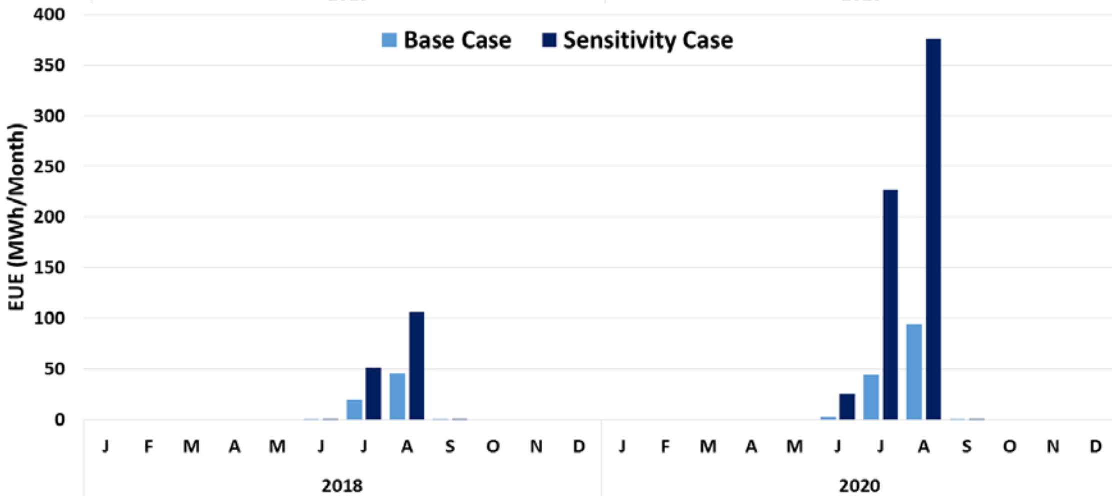
In 2018, LOLH is 0.109 h/year and EUE is 65.2 MWh while in 2020 those values are 0.189 h/year and 140.8 MWh, respectively. The increases are consistent with a decline in reserve margins. The metrics are primarily driven by the results in July and August.

Sensitivity Case Study

LOLH and EUE increase exponentially with the decline in reserve margins. LOLH is 0.218 and 0.573 h/year for 2018 and 2020, respectively. EUE is 157.7 and 528.6 MWh for those two years. As it was the case in the Base Case, July and August have the biggest share of the annual metrics.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	24.31	18.23	21.5	13.4
Prospective	25.86	22.72	-	-
Reference	16.6	15.9	-	-
ProbA Forecast Planning	24.0	18.0	21.5	13.4
ProbA Forecast Operable	15.4	9.4	13.1	5.1
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	65.2	140.8	157.7	628.6
EUE (ppm)	0.460	0.977	1.090	4.191
LOLH (hours/year)	0.109	0.189	0.218	0.573





Overview

ISO New England's (ISO-NE) Reference Margin Level is based on the capacity needed to meet the Northeast Power Coordinating Council (NPCC) 1-in-10-year LOLE resource planning reliability criterion. The amount of capacity needed, referred to as the installed capacity requirement (ICR), varies from year-to-year, depending on expected system conditions. The capacity needed to meet the LOLE criterion is purchased through annual forward capacity auctions three years in advance. Reconfiguration auctions occur annually prior to the commencement year to assure an opportunity to adjust capacity purchases to meet changing requirements.

ISO-NE's Anticipated Reserve Margin, which ranges from a high of 24.3 percent in 2018 to a low of 16.8 percent in 2026, remains above the Reference Margin Level through the assessment period.

The summer peak total internal demand (TID), which takes into account energy efficiency and conservation as well as behind-the-meter photovoltaic (PV) resources, is forecasted to increase from 26,698 MW in 2017 to 27,218 MW in 2026. This amounts to a nine-year summer TID compound annual growth rate (CAGR) of 0.21 percent, as compared to the *2015 LTRA* projection of 0.48 percent. The primary reasons for the decrease in the demand forecast are updated historical data, and an increased amount of behind-the-meter PV. As behind-the-meter PV resources increase, New England could experience daily load profiles that would require different resource operating attributes to manage reserve, ramping, and regulation requirements.

Both passive and active DR are procured through ISO-NE's forward capacity market (FCM). Passive DR, which consists of energy efficiency and conservation, will grow to 2,561 MW by 2019 in the FCM. For the years beyond the FCM commitment periods, ISO-NE uses an energy efficiency forecasting methodology that takes into account the potential impact of growing energy efficiency and conservation initiatives throughout the region. Energy efficiency has generally been increasing over time and is projected to continue growing throughout the study period. The amount of energy efficiency is projected to increase to over 4,000 MW by 2026. Active demand resources consist of DR and emergency generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4: *Action during a Capacity Deficiency* (OP-4).[90] The capacity supply obligations (CSOs) for these resources, which are obtained through ISO-NE's FCM, decrease from 556 MW in 2016 to 378 MW in 2019.

A total of 319 MW of new capacity consisting primarily of PV and wind resources have been added since the *2015 LTRA*. Approximately 2,900 MW of Tier 1 capacity, including over 2,700 MW of natural-gas-fired plants, will be added by 2019. The largest natural gas projects are the Footprint Combined Cycle Plant (674 MW), which is projected to be in service in 2017, and the CPV Towantic Energy Center (725 MW) as well as PSEG's Bridgeport Harbor Expansion (484 MW), both of which are to be in service in 2018. Also included in the Tier 1 category is 133 MW of on-peak wind capacity (806 MW nameplate). Tier 2 capacity additions totaling 1,012 MW include 982 MW of natural-gas-fired generation and 125 MW of nameplate wind.

The amount of renewable resources in New England continues to grow. In addition to behind-the-meter PV that reduces the load forecast, there has been growth in PV participating in ISO-NE markets, with on-peak capacity increasing from 264 MW in 2017 to 329 MW in 2025. Although the amount of Existing and Tier 1 wind capacity only amounts to 229 MW on peak, there is an additional 3,400 MW of nameplate wind capacity in the ISO-NE generator interconnection queue.

Over 2,100 MW of retirements are expected in New England by 2019. Brayton Point Station, which is a 1,535 MW coal and oil plant, will be retiring by June 2017. The 680 MW Pilgrim Nuclear Power Station is planned for retirement by June 2019. Even with these retirements, ISO-NE's reserve margin is not expected to fall below the 15.9 percent Reference Margin Level during the assessment period. If capacity is required to meet the regional resource

[90] OP-4 is used by ISO-NE operators when resources are insufficient to meet the anticipated load plus operating reserve requirement.

adequacy, ISO-NE will purchase the needed capacity through its forward capacity market (FCM). Currently, over 680 MW of Tier 2 capacity has a capacity supply obligation in the FCM.

The major transmission project currently under development in New England is the Greater Boston project. The Greater Boston upgrades are critical to improve the ability to move power into the Greater Boston area and from northern New England to southern New England. This set of upgrades includes new and upgraded 345 kV and 115 kV lines, new autotransformers, and additional reactive support. The project is certified to be in service by June 2019.

For over a decade, the region has been working on gas-related challenges and will continue to do so. New England's generation fleet is changing rapidly with the retirement of older fossil-fueled resources and their replacement by new gas-fired generators. The region's reliance on natural gas for power generation has been increasing and will likely continue to do so in the future. ISO is addressing the gas-related challenges with market rule changes and operational enhancements. Recent market rules, such as those addressing energy market offer flexibility, allow resources to more accurately reflect their variable costs in their energy offers during the operating day, which improves incentives to perform. Another new market rule has changed the timing of the day-ahead energy market to align more closely with natural gas trading deadlines. In addition, the ISO has improved coordination and information-sharing with natural gas pipeline operators, such as working with the pipelines to coordinate generator and pipeline maintenance schedules. The ISO has also developed a natural gas usage tool that estimates the remaining gas pipeline capacity, by individual pipe, for use by ISO-NE system operators to determine whether the electric sector gas demand can be accommodated.

A winter fuel-reliability program has been acting as a bridge between now and 2018 when the longer-term pay-for-performance (PFP) capacity market changes go into effect. The winter reliability program addresses regional winter reliability challenges created by New England's increased reliance on natural-gas-fired generation and lack of adequate gas infrastructure. Resources participating in the program provide incremental energy inventory during the winter months to help ensure reliable system conditions. Components of the program include payment to generators for adding dual-fuel capability, securing fuel inventory, testing fuel-switching capability, compensation for any unused fuel inventory, and nonperformance charges.

PFP, which starts in June 2018, will help improve reliability while ensuring resource adequacy. PFP is a two-part settlement in which a base payment is set in the forward capacity auction and a performance payment is determined during the delivery year. The performance payment may be positive or negative, depending on resource performance during a shortage condition. Over-performing resources are paid a premium through revenue transfers from under-performing resources. PFP creates an incentive for investment in generators that are either: 1) low-cost and highly reliable (nearly always operating), or 2) highly flexible and highly reliable (goes on-line quickly and reliably). PFP will encourage generators to increase unit availability by implementing dual-fuel capability, entering into firm gas-supply contracts, and investing in new fast-responding assets. By creating incentives for generators to firm up their fuel supply, PFP may indirectly provide incentives for the development of on-site oil, LNG fuel storage, or expanded gas pipeline infrastructure.

In summary, New England has adequate capacity resources to meet the NERC Reference Margin Level throughout the *2016 LTRA* study period. ISO New England has been faced with gas-related challenges for more than a decade. These challenges will remain as additional non-gas-fired resources retire and are replaced by gas-fired generation. ISO New England expects and continues to make operational and market enhancements to address these challenges. ISO New England is cognizant of possible operational issues that a high penetration of intermittent resources may pose in the future. The region has conducted and will continue to conduct studies to identify means to address these future operational issues. Furthermore, New England has a robust transmission planning process. Existing and planned transmission upgrades will ensure regional system reliability.

NPCC-New York

The New York Independent System Operator (NYISO) is the only BA within the state of New York (NYBA). NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid, which encompasses approximately 11,000 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.5 million New Yorkers. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

Summary of Methods and Assumptions

Reference Margin Level

The New York State Reliability Council (NYSRC) installed reserve margin (IRM) of 17.5 percent applies to the period May 2016 to April 2017. New York's IRM is set annually.

Load Forecast Method

The New York Balancing Authority (NYBA) forecast is based upon an econometric forecast of annual energy and seasonal peak demands. The New York State Reliability Council (NYSRC) has adjustments for energy efficiency and DERs, including behind-the-meter solar PV.

Peak Season

The seasonal peak demands (summer and winter) are based upon annual energy and seasonal load factors. The forecast load factors are based upon recent historic data and then trended for the future.

Planning Considerations for Wind Resources

The expected on-peak capacity for wind resources is 14 percent.

Planning Considerations for Solar Resources

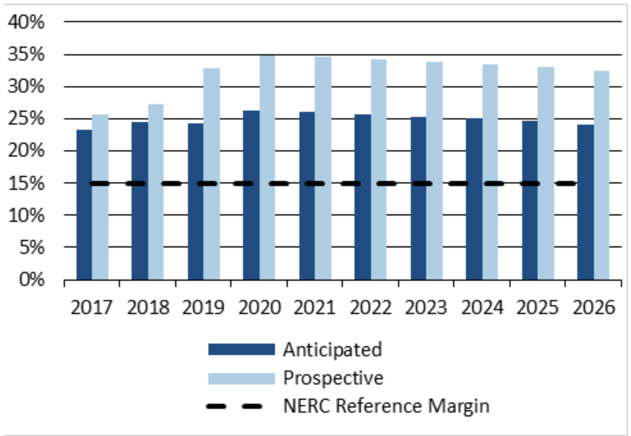
On peak resources for solar PV include a number of factors, such as inverter sizing and efficiency, the impact of cloud cover and other atmospheric conditions that attenuate solar irradiance, and the seasonal and diurnal variations in solar irradiance.

Footprint Changes – N/A

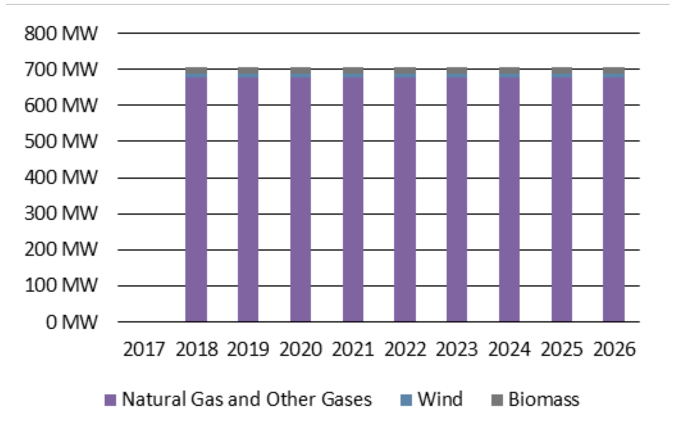
Peak Season Demand, Resources, Reserve Margins, and Shortfall

Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	33,363	33,404	33,477	33,501	33,555	33,650	33,748	33,833	33,926	34,056
Demand Response	1,248	1,248	1,248	1,248	1,248	1,248	1,248	1,248	1,248	1,248
Net Internal Demand	32,115	32,156	32,229	32,253	32,307	32,402	32,500	32,585	32,678	32,808
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	39,613	40,056	40,065	40,727	40,727	40,727	40,727	40,727	40,727	40,727
Prospective	40,382	40,923	42,805	43,474	43,474	43,474	43,474	43,474	43,474	43,474
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	23.35%	24.57%	24.31%	26.27%	26.06%	25.69%	25.31%	24.99%	24.63%	24.14%
Prospective	25.74%	27.26%	32.81%	34.79%	34.56%	34.17%	33.76%	33.42%	33.04%	32.51%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The New York Area is a summer peaking area. The GE MARS model developed by the NPCC CP-8 Work Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion.[91]

- **Results Trending:** The previous study, the *NERC RAS Long-Term Reliability Assessment – NPCC Region*[92] estimated an annual LOLH = 0.032 hours per year and a corresponding EUE equal to 9.3 MWh for the year 2018. The Forecast 50/50 Peak Demand for 2018 was lower than reported in the previous study, but with higher estimated forecast planning and forecast operable reserve margins. As a result, both the LOLH and the EUE have improved for 2018.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The New York IRM of 17.5 percent applies to the period May 2016 to April 2017.[93] New York's IRM is set annually. New York does not have a future reference reserve margin beyond the current capability period thus the NERC reference reserve margin is used.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in the *NPCC 2016 Long Range Adequacy Overview,* and it is described in the *2016 NERC RAS Probabilistic Assessment – NPCC Region.*[94] All New York published reports and probabilistic studies report reserve margins based on the full ICAP value of all resources.

[91] NPCC Regional Reliability Reference Directory #1: Design and Operation of the Bulk Power System; September 2015
[92] NPCC NERC RAS Probabilistic Assessment; March 2015
[93] New York State Reliability Council: New York Control Area Installed Capacity Requirements Reports
[94] NPCC Library - Resource Adequacy

Base Case Study

LOLH for 2018 and 2020 are 0.004 (hours per year) with EUE values of 1.448 and 2.059 (MWh). The EUEs are negligible. Results are similarly driven by a comparable planning reserve margin in both years. The summer months (June–August) have the greatest contribution to these metrics.

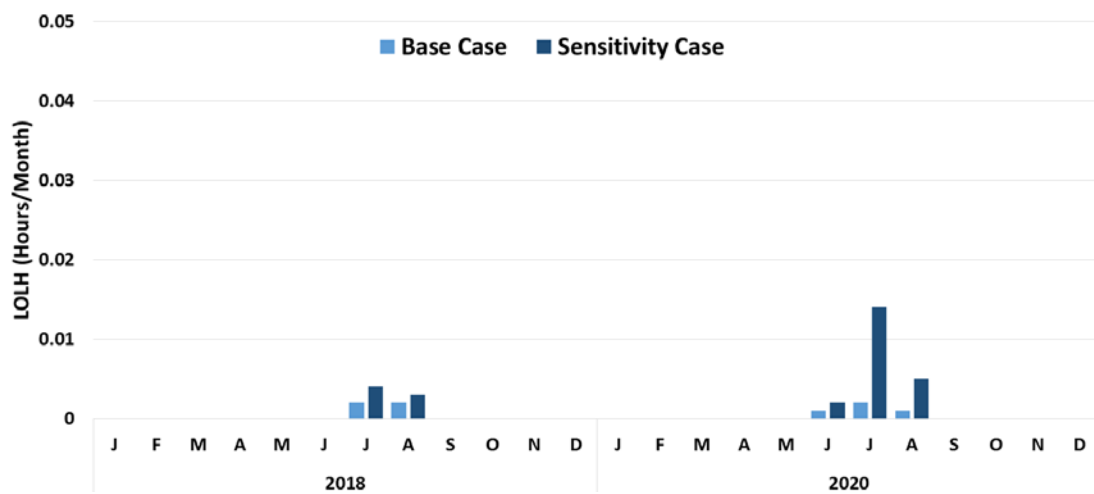
Sensitivity Case Study

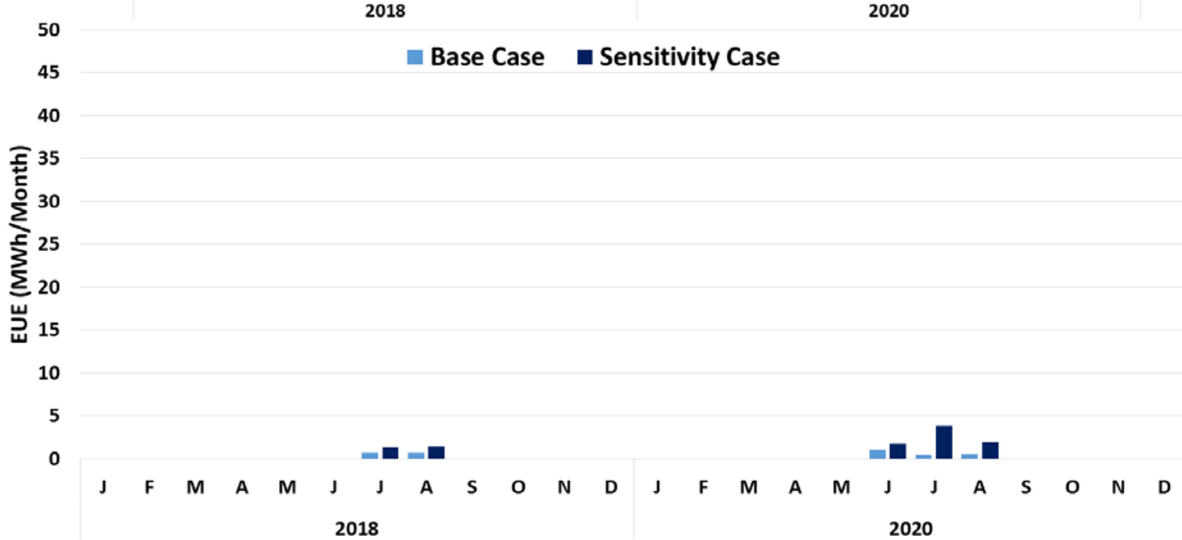
LOLH values are 0.007 and 0.021 for 2018 and 2020, respectively. EUE results are 2.8 and 7.6 MWh for those same two years. The monthly contribution is similar to that observed in the Base Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
Anticipated *	24.57	26.27	23.6	20.8
Prospective *	27.26	34.79	-	-
NERC Reference	15	15		
ProbA Forecast Planning **	28.6	30.3	26.0	25.1
ProbA Forecast Operable **	17.1	18.8	14.7	14.0
Annual Probabilistic Indices				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	1.448	2.059	2.777	7.557
EUE (ppm)	0.009	0.013	0.017	0.046
LOLH (hours/year)	0.004	0.004	0.007	0.021

* NERC LTRA reserve margin calculations are based on a 14 percent wind unit peak capacity factor.

** Wind units modeled in the probabilistic assessment as hourly load modifiers are based on 2013 production data, and ProbA capacity resource interconnection service values are used for reserve margin calculations.





Planning Reserve Margins

The annual IRM for the New York Balancing Area (NYBA) is calculated through a technical study conducted by the New York State Reliability Council (NYSRC) in accordance with NERC Reliability Standards, the Northeast Power Coordinating Council (NPCC) reliability criteria, and the NYSRC Reliability Rules. For the 2016–2017 capability year, the NYSRC approved an IRM requirement of 17.5 percent. New York does not have a future reference reserve margin beyond the current capability period, ending April 2017.

The New York IRM assumed that the ~1,455 MW of wind capacity will likely operate at a 14 percent capacity factor during the summer peak period. This assumed capacity factor is based on an analysis of actual hourly wind generation data collected for wind facilities in New York State during the June through August 2013 period between 2:00 and 5:00 p.m. This test period was chosen because it covers the time during which virtually all of the annual NYCA LOLE occurrences are. For the calculation of New York IRM, wind generators are modeled as hourly load modifiers. In the probabilistic determination of the New York IRM, the output of each unit varies between 0 MW and the capacity resource interconnection service value based on 2013 production data.

All generator values for the IRM requirement calculation are based on generator installed capability values as reported in the 2016 NERC LTRA and the current *Load and Capacity Data Report* issued by the New York Independent System Operator, Inc. (NYISO). For reporting purposes, the capacity values provided for New York existing and planned resource facilities are consistent on its dependable maximum net capability (DMNC). In circumstances where the ability to deliver power to the grid is restricted, the value of the resource is limited to its capacity resource interconnection service (CRIS) value. The source of DMNC ratings for existing facilities are seasonal tests required by procedures in the *NYISO Installed Capacity Manual* and are documented in the *New York Gold Book*.[95]

Demand

The baseline energy forecast for the years 2016–2026 is expected to decline at an average rate of -0.16 percent per year, while the baseline summer peak demand forecast for the years 2016–2026 is expected to grow at annual average rate of 0.21 percent. The lower forecasted growth in energy usage for years 2016–2026 is largely attributable to an increase in the impacts of energy efficiency initiatives and the growth of distributed behind-the-meter energy resources.

Demand-Side Management

There were no significant changes to NYISO's DR programs since last year's *LTRA*. The 2016 forecast includes peak demand impacts of 1) energy efficiency initiatives in the amount of 1,859 MW, 2) solar PV in the amount of 747 MW, and 3) distributed generation in the amount of 356 MW. These are cumulative impacts expected by the year 2026.

DR enrollments are currently trending at approximately 4.3 percent of the NYBA's peak load, and there is no indication that there will be a significant increase in enrollment in the near future. The NYISO does not anticipate significant long-term reliability impacts from a modest increase in the DR enrollments from the current enrollment levels.

Generation

Since the *2015 LTRA*, there were no new resource additions installed in the NYBA. Tier 1 resource additions total 775 MW and are expected to be in service for Summer 2018. Tier 2 resources total 4,140 MW and are at various stages in the NYISO interconnection process. However, the NYBA had 637.8 MW of summer capacity deactivate, and they have another 1,734.8 MW of capacity scheduled to deactivate over the assessment period. The NYISO

[95] NYISO: 2016 Load & Capacity Data

did not identify any near-term reliability needs resulting from these deactivations. Other than these deactivations, no large generators are expected to be unavailable over the assessment period.

In response to an April 2016 order from the Federal Energy Regulatory Commission (FERC), NYISO is further developing a tariff process to be filed in September 2016 to address reliability needs that arise from generator deactivations and the planning process for identifying solutions; this includes the potential need for a reliability-must-run agreement to keep the deactivating generator in service until permanent solutions can be provided.

The forecast for distributed behind-the-meter generation for the summer peak demand is 313 MW in 2021 and 356 MW in 2026. DERs are expected to increase in the future with behind-the-meter solar growing at the fastest rate. Projected additions are based upon current rates of growth in each NYBA zone, together with an expectation of how future state incentives for distributed generation will affect installation of these resources.

Changing Resource Mix

New York State had a renewable portfolio standard (RPS) that has been supplanted by other state programs, including a large-scale renewables program under the New York State Clean Energy Fund (CEF). The RPS program purchased renewable energy credits from seventy active projects that represented 2,152 MW. These programs produced more than 5,000 GWH in 2015 and more than 90 percent of this renewable generation was produced by wind resources. Currently, the New York State Energy Plan calls for 50 percent of energy generation to come from renewable energy sources by 2030. The New York State Public Service Commission (NYSPSC) is currently developing a clean energy standard that is intended to achieve the goals of the New York State Energy Plan and to preserve the financial viability of the existing nuclear generators in New York. The New York State Department of Public Service staff estimates that the proposal calls for 75,000 GWH of annual renewable energy production by 2030. The NYSPSC has not yet finalized the specific types of renewable generation that will be included under the CES.

One of New York State's initiatives, the NY-Sun Incentive Program (NY-Sun), is designed to have 3,000 MW of installed solar PV capacity on the system by the end of 2023. In April 2014, following two successful years of solar PV installations, a commitment of nearly $1 billion was made to NY-Sun for further installation of solar PV.

In response to the increasing amount of VERs and New York State's initiatives, the NYISO studied a number of specific grid operation needs potentially affected by the increasing penetration of intermittent solar PV and wind resources. The study found, among other things, that 1) the bulk power system can reliably manage over the five-minute time horizon the increase in net load variability associated with the solar PV and wind penetration levels up to 4,500 MW wind and 9,000 MW solar PV, 2) the large-scale implementation of behind-the-meter solar PV will impact the NYISO's load profile and associated system operations, and 3) the lack of frequency and voltage ride-through requirements for solar PV facilities in New York could worsen system contingencies when solar PV deactivates in response to frequency and voltage excursions. Likewise, wind resources in New York are increasing and now total approximately four percent of the generation fleet by fuel source. A 2010 NYISO wind generation study[96] examined the impact of adding up to 8,000 MW of wind resources and it indicated that, above 3,500 MW of wind penetration, regulation requirements are projected to increase at the rate of 25 MW for every 1,000 MW increase in wind generation.

NYISO has not changed the methods that it uses to determine the on-peak capacity values for wind, solar, and hydro. Hourly unit output data for wind, run of river hydro, and solar units are collected for the summer peak hours (i.e., 2:00 p.m.–5:00 p.m.) from June 1 through August 31. The on-peak capacity for these resources is determined using an assumed capability for each resource class; this is based upon unit historic operating data and engineering judgment. For reserve margin calculations, NYISO uses the full on-peak capability of the units,

[96] NYISO: Growing Wind: Final Report of the NYISO 2010 Wind Generation Study; September 2010

which represents the aggregate capacity for each resource class (i.e., wind, solar, and hydro). The expected on-peak capacity factors for wind, solar, and hydro are 14 percent, 56.5 percent, and 54 percent respectively.

Capacity Transfers

NYISO has three classifications of capacity transfers:

- The first includes grandfathered contracts and external capacity resource interconnection service (CRIS) rights. These total 2170 MW and cover the entire *2016 LTRA* assessment period.
- The second class is unforced deliverability rights (UDRs). These are rights to deliver capacity over controllable tie lines. For the NYBA, the total UDR capability is 1,965 MW across the four controllable tie lines. The owners of the UDRs notify NYISO each year of the amount of capacity that will be delivered. UDR election levels are treated by NYISO as confidential information. Any transfer capability not utilized is available to provide emergency assistance in both the NYISO's planning studies and operationally, if the need arises.
- The third classification of capacity transfers is import rights. For 2016, import rights totaled 530 MW and are available month to month on a first-come, first-served basis in the capacity auctions.

Capacity transactions modeled in the NYISO's assessments have met the capacity resource requirements, as defined in the NYISO's tariffs. Both NYISO and its respective neighboring assessment areas have agreed upon the terms of the capacity transaction including the MW value, the duration, the contract path, the source of capacity, and the capacity rating of the resource.

Transmission and System Enhancements

The NYBA has three major transmission projects located in central New York, downstate New York, and New York City, all placed into service in June 2016. These include Marcy-South Series Compensation and Fraser-Coopers Corners 345 kV line reconductoring, construction of a second Rock Tavern-Ramapo 345 kV line, and Phase I (i.e., cable separation) of upgrading underground transmission circuits from Staten Island to the rest of New York City (collectively, "Transmission Owner Transmission Solutions" or "TOTS"). Approved by the NYSPSC as part of New York's Energy Highway initiative, the TOTS projects are expected to increase transfer capability into southeastern New York by 450 MW and mitigate against potential reliability needs if the Indian Point Energy Center were to become unavailable.

In the 2014 *Reliability Needs Assessment* (*RNA*), NYISO identified thermal violations under N-1-1 post-contingency conditions (applying more stringent NPCC criteria) that would limit transmission in the Rochester and Syracuse areas. For the Rochester area, the overloads are on 345/115kV transformers that supply the Rochester area upon loss of other 345/115kV transformers in the same area; the Syracuse area overloads on 115kV facilities upon loss of parallel lines. These violations are anticipated to be resolved with permanent solutions identified in the most recent Transmission Owner local transmission plans, scheduled to be completed by Summer 2017 in the Rochester area and the end of 2017 in the Syracuse area. In the interim, the local transmission owners will implement local operating procedures, if required, to prevent overloads, including the potential for limited load shedding in the Rochester and Syracuse areas; voltage-constrained transfer limits are evaluated and determined by NYISO for all major interfaces within New York. BPS transmission security is maintained by limiting power transfers according to the determined voltage-constrained transfer limits. Local nonbulk voltage performance is evaluated by the local Transmission Owner and addressed through the Local transmission planning process.

Transmission security of the NYBA BPS is maintained by limiting power transfers according to the determined transfer limits, including voltage-constrained transfer limits. New York has three interfaces that were found to be voltage limited, and NYISO maintains voltage limits in these constrained areas by limiting power transfers to mitigate dynamic and static reactive power issues. Based on the foregoing, NYISO does not expect to use under-voltage load shedding schemes.

Depending on assumed system conditions, the Central East interface is limited at certain times due to dynamic instability. As part of the annual NYISO Area Transmission Review (ATR), the flows on the evaluated interfaces were tested at a value of at least 10 percent above the more restrictive of the emergency thermal or voltage transfer limits in accordance with NYISO Transmission Planning Guideline #3-0.[97] The 2014 intermediate ATR performed dynamic stability simulations for NERC contingencies that were expected to produce the more severe system results or impacts based on examination of actual system events and assessment of changes to the planned system. BPS transmission security is maintained by limiting power transfers according to the determined stability limits.

The New York Balancing Authority will also have additions and removals of special protection systems (SPSs) since the last LTRA. Generation rejection SPSs are being retired at the Niagara hydro facility and the St. Lawrence Moses hydro facility, which will become effective upon completion of the NPCC approval process. Both facilities have added power system stabilizers to their units and a study showed that thermal limits, voltage, and stability would be maintained for the contingencies at those facilities. Additionally, an SPS is being added to mitigate subsynchronous resonance issues when the new series compensated lines in the TOTS projects are placed in service in Summer 2016. The SPS will detect certain outage conditions and signal to bypass the series compensation.

Long-Term Reliability Issues

NYISO continues to plan for extreme weather and has not made any modifications to its planning assumptions or methods for such events. NYISO continues to conduct its reliability studies using the 50/50 load forecast as the base assumption and account for weather events with a load forecast uncertainty (LFU). Additionally, NYISO, in conjunction with its stakeholders, is exploring market rule changes to help assure fuel availability during cold weather conditions. Improvements will be considered in reporting seasonal fuel inventories and daily replenishment schedules. NYISO will work with New York State regulatory agencies to develop a formal process to identify reliability needs that would be mitigated by generator requests for certain waivers.

NYISO only conducts dynamic stability studies for the off-peak periods and, in doing so, identified no concerns. Generators in the fleet use the off-peak period to schedule and perform their routine maintenance in preparation for the summer and winter peak seasons. NYISO monitors and approves maintenance schedules to maintain system reliability and can cancel scheduled maintenance if system conditions warrant it.

As a part of NYISO's *2014 Comprehensive Reliability Plan*[98] and the *2015 Power Trends report*[99], NYISO identified several risk factors to maintaining reliability in New York. These factors include the following:

- **Changes to System Performance:** The aging generation infrastructure may lead to more frequent and longer outages as well as increasing costs, which may drive more retirements. Since 2000, more than 11,000 MW of generation has been added while more than 6,000 MW are no longer active. Of the current generation fleet, 8.5 GW are produced by generators that are more than 50 years old. This figure is expected to double by 2025 in the absence of new generation being built to replace aging assets. Accelerated or unplanned retirements can present challenges to system reliability. Furthermore, the preliminary results of the 2016 *RNA* show that if the remaining nuclear generation units on the system were to deactivate, NYISO would see immediate resource adequacy needs.

[97] NYISO Transmission Expansion and Interconnection Manual; October 2015
[98] NYISO 2014 Comprehensive Reliability Plan; March 2015
[99] NYISO Power Trends: Rightsizing the Grid; 2015

- **Changes to System Load:** The potential for higher-than-forecasted system loads under the 50-50 probability level could expose the system to potential reliability issues, including greater levels of load shedding in the interim operating procedures in some localized areas of the state.
- **Changes to System Resources:** Expected capacity resources (new or upgrades) within the study do not materialize, additional generating units become unavailable or retired beyond those already identified, or capacity resources could decide to offer into other markets and, therefore, not be available to New York.
- **Natural Gas Coordination:** Coordinating with New York's reliance on natural gas as the primary fuel for electric generation, NYISO is performing four ongoing studies and efforts focused on 1) improving communication and coordination between the sectors; 2) addressing market structure enhancements, such as the closing time of the natural gas markets; 3) providing for back-up fuel (primarily distillate oil) assurance to generation; and 4) addressing the electric system reliability impact of the sudden catastrophic loss of gas.
- **Federal and State Environmental Regulations:** The five regulatory programs with the largest reliability risk potential include: 1) facility specific operational limitations, 2) the Cross State Air Pollution Rule (CSAPR) cap and trade program for NOx and SO2, 3) the Mercury and Air Toxics Standards (MATS) for hazardous air pollutants from new and existing coal and oil-fired units, 4) the CPP, which is the proposed EPA greenhouse gas standards for existing sources, and 5) the revised Ozone National Ambient Air Quality Standard (NAAQS).

Furthermore, the New York State CES seeks to reduce the state's carbon dioxide emissions by 40 percent; the CES seeks to do this through increasing the amount of renewable energy generation in New York State to 50 percent of total energy production by 2030. The New York State Department of Public Service staff estimates that to meet the CES's goals by 2030, energy from renewables would need to increase by 33,700 GWh from the current levels. Based on historical demonstrated capacity factors, NYISO estimates that this increase will require the development of approximately 25,000 MWs of solar capacity, approximately 15,000 MWs of wind capacity, or approximately 4,000 MWs of hydroelectric capacity. NYISO continues to study the impacts of the relative capability of intermittent resources to reliably supply power demands and fulfill IRM requirements.

Essential Reliability Services

NYISO is conducting a study on the reliability impacts of the EPA CPP. A portion of this study will examine changes to essential reliability service (ERS) metrics as the resource mix changes, and as the inertia and kinetic energy, as presented in the NERC ERS Task Force Measures Framework Report. This assessment will be performed by compiling the inertia and MVA rating for all NYBA generators and tabulating in each hour, based on future model run year output, which generators are operating and the aggregate system kinetic energy that corresponds.

NPCC-Ontario

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

Summary of Methods and Assumptions

Reference Margin Level
The IESO-established reserve margin requirement is applied as the Reference Margin Level.[100]

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled, based on historic performance and historic weather data

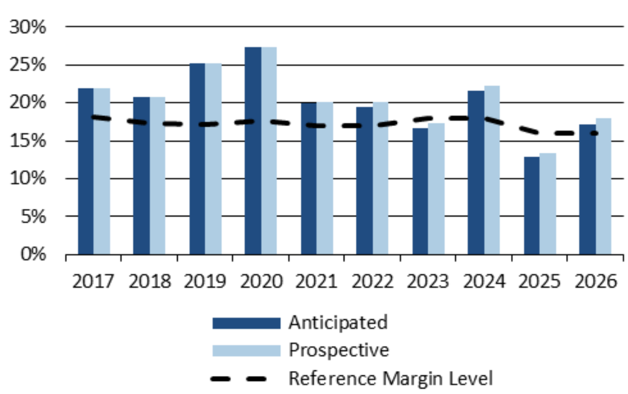
Planning Considerations for Solar Resources
Modeled, based on historic weather data

Footprint Changes
N/A

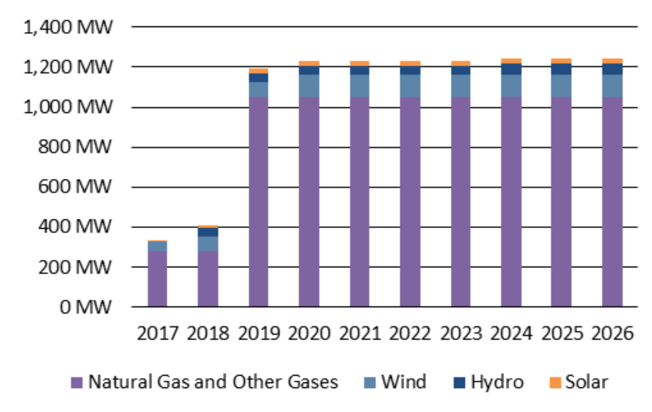
Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	22,680	22,519	22,357	22,192	22,479	22,255	22,190	22,194	22,326	22,265
Demand Response	680	641	601	601	601	601	804	1,007	1,210	1,210
Net Internal Demand	22,000	21,878	21,756	21,591	21,878	21,654	21,386	21,188	21,116	21,056
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	26,822	26,431	27,216	27,478	26,235	25,872	24,957	25,773	23,819	24,646
Prospective	26,822	26,431	27,216	27,478	26,290	26,000	25,085	25,901	23,947	24,837
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	21.92%	20.81%	25.10%	27.27%	19.92%	19.48%	16.70%	21.64%	12.80%	17.05%
Prospective	21.92%	20.81%	25.10%	27.27%	20.17%	20.07%	17.30%	22.25%	13.41%	17.96%
Reference Margin Level	18.13%	17.31%	17.13%	17.67%	17.00%	17.00%	18.00%	18.00%	16.00%	16.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	278	-	676	-
Prospective	-	-	-	-	-	-	150	-	548	-

[100] Ontario IESO, for its own assessments, treats demand response as a resource instead of as a load modifier. As a consequence, the net internal demand, planning reserve margins, and target reserve margin numbers differ in IESO reports when compared to NERC reports. The Ontario reports would show lower reserve margins.

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The Ontario Area is a summer peaking area. The GE MARS model developed by the NPCC CP-8 Working Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion (ref: NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[101]

- **Results Trending:** The previous study, *NERC RAS Long-Term Reliability Assessment – NPCC Region*,[102] estimated an annual LOLH = 0.0 hours per year and a corresponding EUE equal to 0.0 (ppm) for the year 2018. The 2018 forecast 50/50 peak demand forecast is 218 MW greater in this assessment than reported in the previous assessment. This reflects the interplay of economic expansion, population growth, increasing penetration of electrically powered devices, conservation programs, increasing embedded generation output, and energy price changes that act to reduce the amount of grid-supplied electricity needed. There is no change in the estimated LOLH and EUE between the two assessments mainly due to the contributions of various DR programs, operating procedures, and tie benefits.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The Ontario IESO, in its own assessments, treats DR as a resource instead of a load modifier. As a consequence, reserve margin calculations are lower in IESO reports when compared to NERC assessments.

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in *NPCC 2016 Long Range Adequacy Overview* and described in the *2016 NERC RAS Probabilistic Assessment – NPCC Region.*[103]

[101] NPCC: Regional Reliability Reference Directory #1

[102] NERC RAS Probabilistic Assessment: NPCC Region; March 31, 2015

[103] NPCC Library - Resource Adequacy

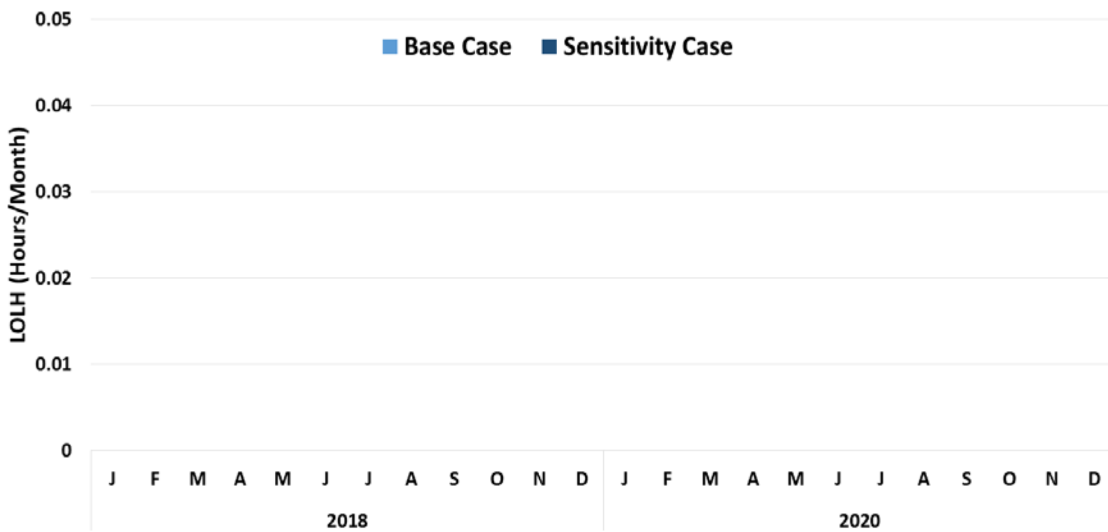
Base Case Study

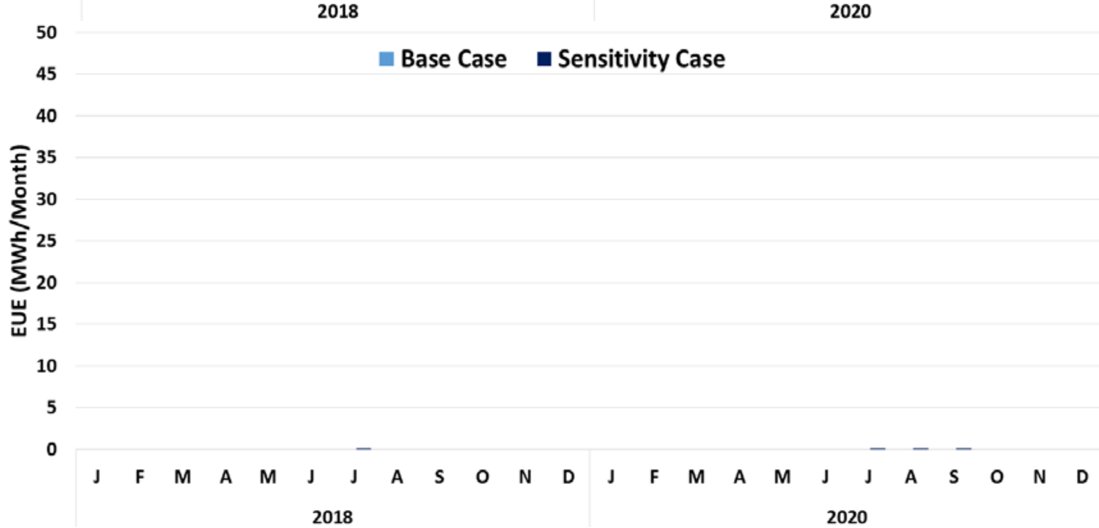
There was no significant LOLH or EUE observed for the Base Case study for either 2018 or 2020. Anticipated Reserve Margins are above 17.31 percent and 17.76 percent in 2018 and 2020, respectively.

Sensitivity Case Study

LOLH values are not significant in this case, and the EUE are negligible: .004 and .074 MWh for 2018 and 2020, respectively. Anticipated Reserve Margins remain above the Base Case reference reserve margin in both years. The greatest contribution to EUE occurs during the peak (summer) monthly period.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	20.81	25.10	18.4	22.2
Prospective	20.81	27.27	-	-
Reference	17.31	17.67	-	-
ProbA Forecast Planning	20.8	27.3	18.4	22.2
ProbA Forecast Operable	4.7	11.9	2.6	7.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.004	0.074
EUE (ppm)	0.000	0.000	0.000	0.001
LOLH (hours/year)	0.000	0.000	0.000	0.000





Supply-Demand Balance and Resource Adequacy

Ontario has enough confirmed planned resources (Tier 1) to meet its Reference Margin Levels in all years except for 2023 and 2025. The analysis shows that the earliest need for additional resources may arise in 2023, and that need is expected to be less than 1 GW. Ontario possesses a range of options to address these needs, including market-based mechanisms and capacity imports.

Over the next ten years, Ontario expects grid-connected electricity demand to decline slightly, both in terms of annual energy and summer peak. While modest economic and population growth is expected, increases in demand are expected to be offset by three key factors:

- Growth in distributed generation, driven in large part by government renewable capacity targets and feed-in tariff programs
- 13 TWh of annual conservation savings (incremental to today's demand levels), driven by updates to codes and standards, conservation incentives, and energy efficiency programs
- The continuing success of peak-reduction incentive programs that are already in-place, such as the Industrial Conservation Initiative and time-of-use rates

Over the past ten years, Ontario has invested heavily in electricity infrastructure to enable the phase-out of coal-fired generation and to reduce the carbon footprint of Ontario's electricity supply. The next ten years will also be marked by further change as the system continues its transformation.

Retirements

Pickering nuclear station, with an installed capacity of about 3 GW or 8.6 percent of Ontario's current supply, is expected to be decommissioned between 2022 and 2024.

Nuclear Refurbishments

8.5 GW of nuclear supply at Darlington and Bruce nuclear plants is expected to undergo mid-life refurbishment between 2016 and 2033. Much of this occurs during the assessment period, with up to 4 nuclear unit's off-line during a refurbishment outage simultaneously during the peak refurbishment year. The development of the refurbishment programs was supported by Ontario's past experience and the plan will be implemented in a way that minimizes risk.

Capacity Additions

Ontario expects to add 3.5 GW of grid-connected generating capacity over the assessment period, of which just over 1 GW is natural gas, and the balance is renewable resources such as wind and solar.

Demand Response

IESO continues to transition the procurement of DR from capacity-based DR (CBDR) programs to an annual DR auction. This is a transparent and cost-effective way to select the most competitive providers of DRs while ensuring that all providers are held to the same performance obligations. The first DR competitive auction was held in December 2015, where nearly 400 MW were procured. Ontario currently has approximately 550 MW of CBDR and DR Auction capacity under contract, a similar level to that in last year's LTRA. At minimum, this level of capacity will be maintained through subsequent auctions with additional capacity-based DR expected to be acquired between 2021 and 2025, consistent with government targets, to a total of 1,200 MW by 2025.

Ontario currently has over 1.1 GW of DR capability. It is anticipated that DR capacity will reach 1.8 GW by the end of the assessment period, consistent with government targets.

Distributed Generation

Over the assessment period, a further 1.1 GW of variable generation is expected to be added to the distribution system. This is in addition to the 3.7 GW of variable generation currently connected at the distribution level.

Transmission Outlook and System Enhancements

Transmission planning to address changes to the supply mix and ensure reliability throughout the province is ongoing. Two major system enhancement projects are underway: 1) a new 230 kV double-circuit East-West Tie line in Northwestern Ontario and 2) a new 500 to 230 kV transformer station (TS), Clarington TS, in the Eastern portion of the Greater Toronto Area. The expected in-service date for the new East–West Tie line is 2020, and the Clarington transformer station is scheduled to be in service in 2018.

Planning studies are being finalized to manage the loading on the transmission lines between Trafalgar TS and Richview TS and the 500/230 kV transformers at Claireville TS and Trafalgar TS, which are forecasted to be exceeded by 2022. Planning options have been assessed and are expected to include the installation of 500/230 kV autotransformers at the existing Milton Switching Station (SS) with eight 230 kV circuit terminations and 12 km of new double-circuit line sections connecting the new Milton TS to Hurontario SS.

Southern Ontario experiences high voltages during light load periods, and with the planned shutdown of Pickering GS and the removal of its reactive absorption capability, the situation is expected to persist. Planning work for the installation of new voltage control devices is being finalized.

Long-Term Reliability Issues

With the growth in distributed generation capacity, demand forecasting has become increasingly more complex. Traditionally, demand was mainly a function of weather conditions, economic cycles, and population growth. With multiple new factors influencing demand, such as increased distribution-connected variable generation and increased consumer price-responsiveness, determining the causality of demand changes has become increasingly nuanced.

The introduction of variable generation (e.g., solar and wind) and the removal of flexible generation (e.g., coal), combined with lower demand and limitations in operational flexibility of gas and hydro resources, have added new challenges to maintaining a reliable system. The results of a recent operability assessment indicated that there is a system need for enhanced flexibility to balance supply and demand, more regulation, and additional grid voltage control. It is important that the supply mix remain robust in meeting industry planning standards, flexible to meet the ever-changing demands of system operations, and balanced in managing inherent risks, such as fuel security and critical infrastructure needs. To that end, the IESO has launched an initiative to augment resource flexibility and issued a request for information for additional regulation service in June 2016. IESO has an energy storage pilot program underway to test the capability of storage technologies to provide grid services as well. Activities are also underway with transmitters to plan and install additional dynamic and static voltage control devices to help with voltage control.

Increasing amounts of variable generation, coupled with relatively flat demand levels, have contributed to a rise in surplus baseload generation (SBG) in Ontario. Over the next few years, more variable generation is expected, but the effects on SBG will be tempered by the impact of the planned nuclear refurbishments and retirements. The IESO has mechanisms in place to manage SBG, including economic exports, wind and solar dispatch, and nuclear maneuvers or shutdowns.

NPCC- Québec

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

Summary of Methods and Assumptions

Reference Margin Level
Reference margin levels are drawn from the Québec Area *2015 Interim Review of Resource Adequacy*, which was approved by NPCC's Reliability Coordinating Committee in December 2015.

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Winter

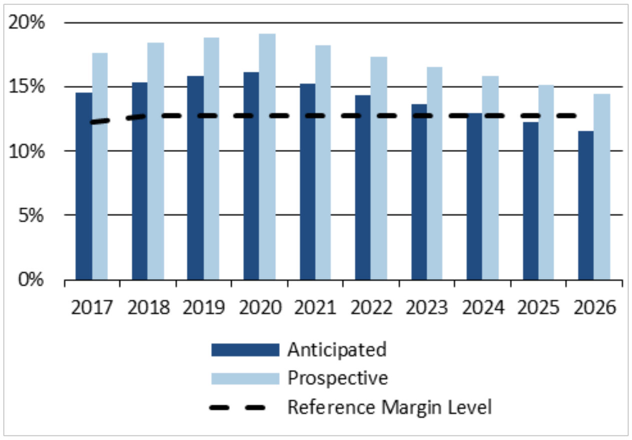
Planning Considerations for Wind Resources
On-peak contribution is approximately 30 percent of the total

Planning Considerations for Solar Resources
N/A

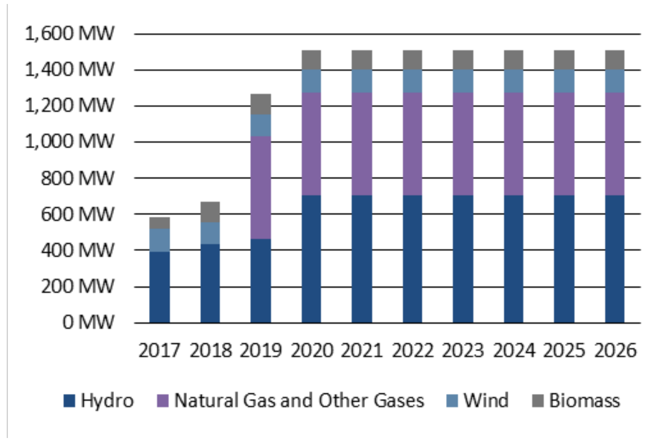
Footprint Changes
N/A

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	38,150	38,521	38,875	39,130	39,415	39,689	39,939	40,167	40,388	40,625
Demand Response	2,168	2,238	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318
Net Internal Demand	35,982	36,283	36,557	36,812	37,097	37,371	37,621	37,849	38,070	38,307
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	41,217	41,847	42,348	42,746	42,746	42,746	42,746	42,746	42,746	42,746
Prospective	42,317	42,947	43,448	43,846	43,846	43,846	43,846	43,846	43,846	43,846
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	14.55%	15.34%	15.84%	16.12%	15.23%	14.38%	13.62%	12.94%	12.28%	11.59%
Prospective	17.61%	18.37%	18.85%	19.11%	18.19%	17.33%	16.55%	15.85%	15.17%	14.46%
Reference Margin Level	12.20%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%	12.70%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	159	426
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Québec is a winter peaking area. The GE MARS model developed by the NPCC CP-8 Working Group was used for the following: modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion (ref: NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System*).[104]

- **Results Trending:** The previous study, *NERC RAS Long-Term Reliability Assessment – NPCC Region,*[105] estimated an annual LOLH = 0.0 hours per year and a corresponding EUE equal to 0.0 for the year 2018. The forecast 50/50 peak demand for 2018 was lower than reported in the previous study with a slightly higher estimated forecast planning and forecast operable reserve margins. As a result, there is no change in the estimated LOLH and EUE in this year's study.

- **Probabilistic vs. Deterministic Reserve Margin Results:** Québec's Reference Reserve Margin is determined based on the NPCC resource adequacy criterion; results indicate a Reference Reserve Margin of 12.7 percent.[106]

- **Modeling:** Assumptions used in this probabilistic assessment are consistent with those used in *NPCC 2016 Long Range Adequacy Overview* and described in the *2016 NERC RAS Probabilistic Assessment – NPCC Region.*[107]

[104] NPCC: Regional Reliability Reference Directory #1
[105] NERC RAS Probabilistic Assessment: NPCC Region; March 31, 2015
[106] NPCC 2015 Québec Balancing Authority Area Interim Review of Resource Adequacy; December 1 2015
[107] NPCC Library - Resource Adequacy

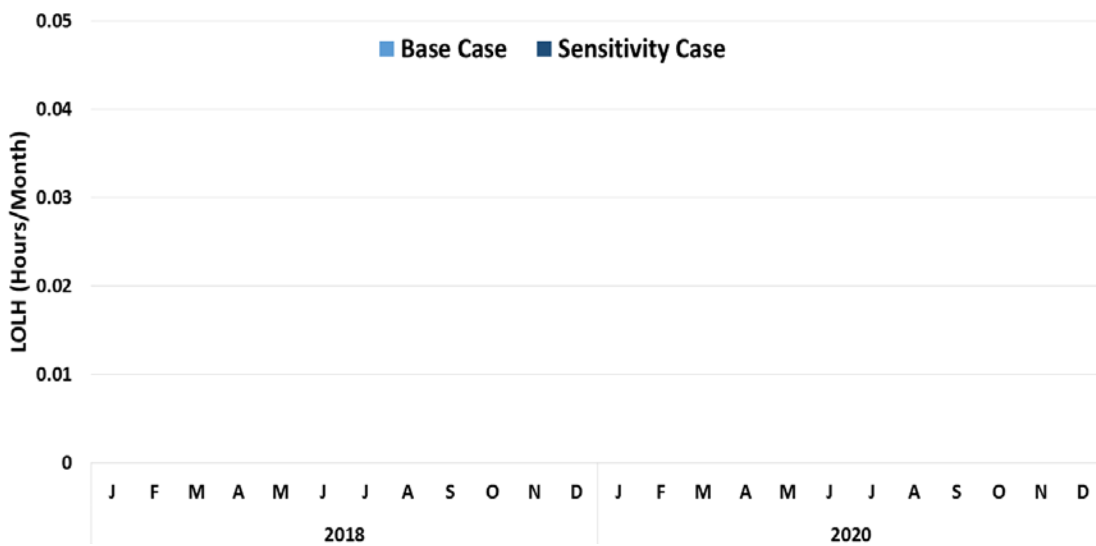
Base Case Study

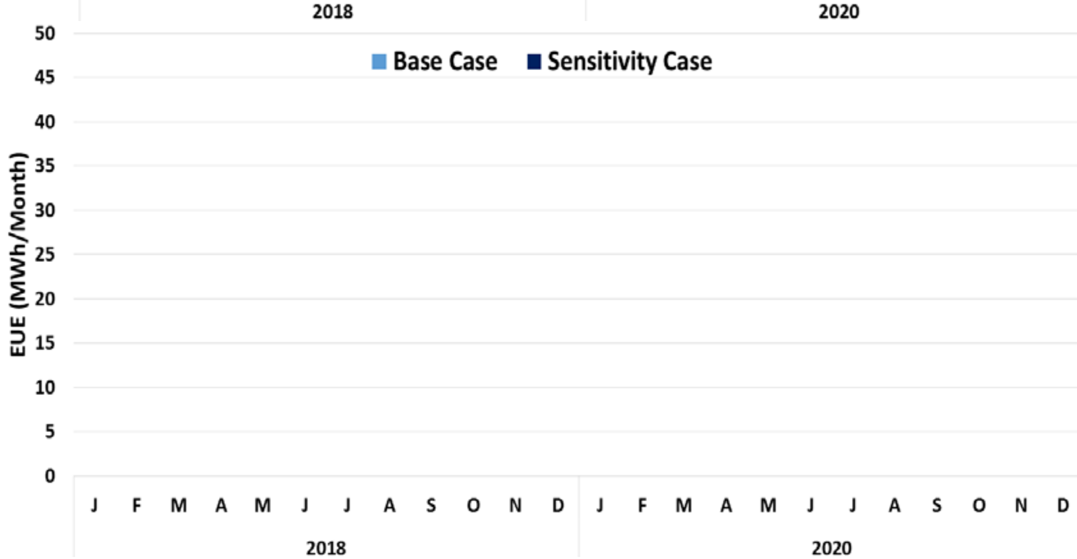
No LOLH or EUE was estimated for 2018 or 2020. The Anticipated Reserve Margins are above the Reference Reserve Margins for 2018 and 2020, respectively.

Sensitivity Case Study

No LOLH or EUE was estimated for 2018 or 2020. The Anticipated Reserve Margins are near the Reference Reserve Margins.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	14.55	15.84	12.2	11.1
Prospective	17.61	18.85	-	-
Reference	12.7	12.7	-	-
ProbA Forecast Planning	14.5	15.8	12.2	11.1
ProbA Forecast Operable	12.9	14.2	10.6	9.6
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000





Demand, Resources, and Planning Reserve Margins

The Prospective Reserve Margin remains above the Reference Margin Level for all seasons and years during the assessment period. Under the Prospective Reserve Margin, a total of 1,100 MW of expected capacity imports are planned by the Québec Area. These purchases have not yet been backed by firm long-term contracts; however, on a yearly basis, the Québec Area proceeds with short-term capacity purchases (UCAP) if needed to meet its capacity requirements.

The Québec area demand forecast average annual growth is 0.7 percent during the 10-year period; this is similar to last year's forecast. Total internal demand is calculated for the Québec area as a single entity and the area's peak demand forecast is coincident.

DR programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs (for large industrial customers), totaling 1,748 MW for the 2017–2018 winter period. The total on-peak DR for the 2026–2027 winter period is projected to be 2,318 MW.

In 2015, the generating station La Romaine-1 was integrated for a total of 270 MW of new added hydro capacity. Work is under way on the La Romaine-3 (395 MW) development which will be fully operational in 2017. Some preparatory work has also begun on the La Romaine-4 (245 MW) development, which will be fully operational in 2020. The integration of small hydro units also account for 83 MW of new capacity during the assessment period. For other renewable resources, about 350 MW (105 MW on-peak value) of wind capacity and 5 MW of biomass have been added to the system since the beginning of 2015. Additionally, 663 MW (199 MW on-peak value) of wind capacity and 128 MW of biomass are expected to be in service by 2018.

The Québec Area will support firm capacity sales totalling 750 MW during the 2017–2018 winter peak period, declining to 145 MW for the 2020–2021 winter period and after.

Transmission Outlook and System Enhancements

This section reviews several major transmission projects currently underway.

The Romaine River Hydro Complex Integration

Construction of the Romaine River Hydro Complex project is presently underway. Its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in December 2014, and Romaine-1 (270 MW) in December 2015. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated in 2017–2020 at Montagnais 735/315-kV substation. The Québec area is reiterating its commitment to sustainable development by focusing on renewable energy at the Romaine complex, which will help meet current needs without jeopardizing the energy supply of future generations.

Main system upgrades for this project have required construction of the new Aux Outardes 735-kV switching station, located between existing Micoua and Manicouagan substations. Two 735-kV lines have been redirected into the new station, and one new 735-kV line (5 km or 3 miles) has been built between Aux Outardes and Micoua substations. This upgrade has been commissioned in Summer 2015.

The Chamouchouane–Montréal 735-kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735-kV line in the near future in order to meet the Reliability Standards. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a new substation (Judith Jasmin) in Montréal (about 400 km or 250 miles). The new 735kV substation is required to fulfill two objectives: 1) providing a new source of electricity supply on the north shore of Montreal and 2) connecting the new 735kV line from Chamouchouane to the Montreal metropolitan loop. This project will reduce transfers on other parallel lines on the Southern 735-kV Interface, thus optimizing operation flexibility and reducing losses. The line is scheduled for the 2018–2019 winter peak period. Public information meetings have been held and construction phase has begun.

Upcoming Regional Projects

Other regional substations and/or line projects are in the planning/permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas. There are another dozen projects in other areas with in service dates from 2016 to 2020, consisting mostly of 315/25-kV and 230/25-kV distribution substations to replace 120-kV and 69-kV infrastructures.

Long-Term Reliability Issues

While technical developments in recent years have contributed to create a more reliable system, sustainable system reliability may be challenged by emerging issues, such as potential operational issues due to the changing resource mix. In Québec area, wind generation capacity has increased by 2,500 MW over the five last years, but the area's total installed capacity is still mainly composed of large reservoir hydro complexes (more than 90 percent). These complexes can react quickly to adjust their generation output and meet the sharp changes in electricity net demand. The forecasted change to resource mix is not expected to have any influence on the ramp rate trends or any other reliability issue.

PJM

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM companies serve 61 million people and cover 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Summary of Methods and Assumptions

Reference Margin Level

The PJM RTO reserve requirement is applied as the Reference Margin Level for this assessment.

Load Forecast Method

PJM has significantly revised its load forecast model. The treatment of weather has been restructured to provide more variable load response across a wide range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency. Distributed solar generation is now reflected in the historical load data used to estimate the models. This is done with a separately-derived solar forecast that is used to adjust load forecasts.

Peak Season

Summer

Planning Considerations for Wind Resources

Initially, 13 percent of nameplate replaced with historic information tracked over the peak period

Planning Considerations for Solar Resources

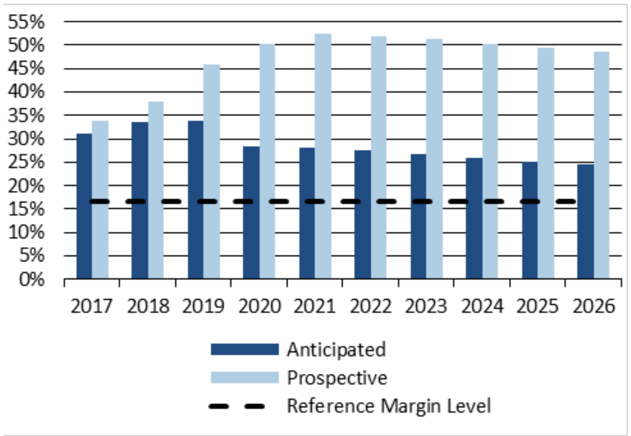
Initially, 38 percent of nameplate replaced with historic information tracked over the peak period

Footprint Changes

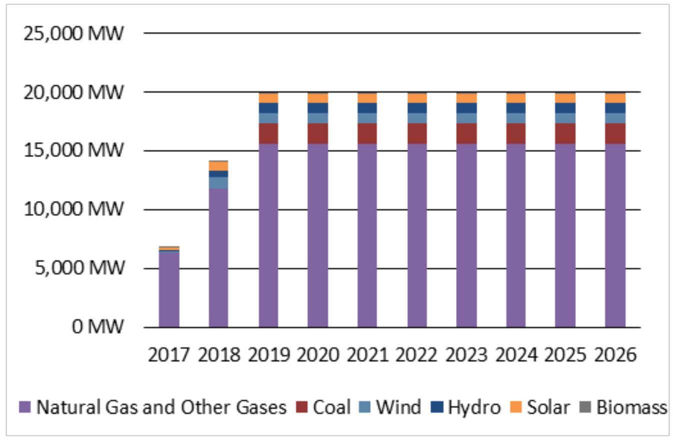
The East Kentucky Power Cooperative (EKPC), which integrated into the PJM RTO on June 1, 2013, is now part of PJM's load and generation data.

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	154,149	155,913	156,958	156,887	157,358	157,986	158,975	159,991	160,947	161,891
Demand Response	8,883	8,977	9,035	3,416	3,424	3,436	3,450	3,478	3,499	3,524
Net Internal Demand	145,266	146,936	147,923	153,471	153,934	154,550	155,525	156,513	157,448	158,367
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	190,456	196,163	197,903	197,178	197,178	197,178	197,178	197,178	197,178	197,178
Prospective	194,577	202,598	215,980	230,792	234,816	234,849	235,353	235,353	235,353	235,353
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	31.11%	33.50%	33.79%	28.48%	28.09%	27.58%	26.78%	25.98%	25.23%	24.51%
Prospective	33.95%	37.88%	46.01%	50.38%	52.54%	51.96%	51.33%	50.37%	49.48%	48.61%
Reference Margin Level	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%	16.50%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** The probabilistic assessment was carried out in GE-MARS using Monte Carlo simulation. Internal and external load shapes were from year 2002 (Summer) and 2004 (Winter) adjusted to match monthly and annual peak forecast values from the 2016 PJM load forecast. Data on individual unit performance is from the period 2011–2015. PJM was divided in five subareas interconnected using a transportation/pipeline approach. External areas were modeled using a detailed representation (NPCC) and at planned reserve margin (MISO, TVA, VACAR).

- **Modeling:** Load forecast uncertainty was modeled on a monthly basis using a normal distribution discretized in seven steps[108]. Demand side management (DSM) was modeled as an emergency operating procedure as most of the DSM in PJM is emergency DSM. Intermittent generators were modeled as a regular resource at their respective capacity values (average capacity value for wind is 13 percent while for solar is 38 percent). Firm exports/imports were explicitly modeled while the limits on the transportation/pipeline interfaces were calculated based on a First Contingency Total Transfer Capability (FCTTC) analysis.

- **Results trending:** The 2018 LOLH and EUE in the 2016 ProbA are smaller than the corresponding values reported in the 2014 ProbA:
  - 2018 LOLH in 2016 ProbA = 0.000 hrs/year vs. 2018 LOLH in 2014 ProbA = 0.009 hrs/year
  - 2018 EUE in 2016 ProbA = 0.003 MWh/year vs. 2018 EUE in 2014 ProbA = 9.300 MWh/year

  This difference can be explained by the larger planning and operable reserves for 2018 in the 2016 ProbA compared to those in the 2014 ProbA. The increase in 2018 reserves is due to a reduction in net internal demand and an increase in forecast capacity resources. In particular, the increase in forecast capacity resources is due to the fact that, by the time the 2014 ProbA was run, none of the 2018 capacity market auctions had been cleared. In contrast, the forecast capacity resources for 2018 considered in the 2016 ProbA include capacity secured via capacity market auctions.

- **Probabilistic vs. Deterministic Reserve Margin Results:** For Summer 2018 and Summer 2020, the probabilistic reserve margin in slightly lower than the deterministic value due to 2,500 MW of on-peak capacity derates as a result of above average summer ambient conditions.

[108] PJM: Load Forecasting and Analysis; June 2016

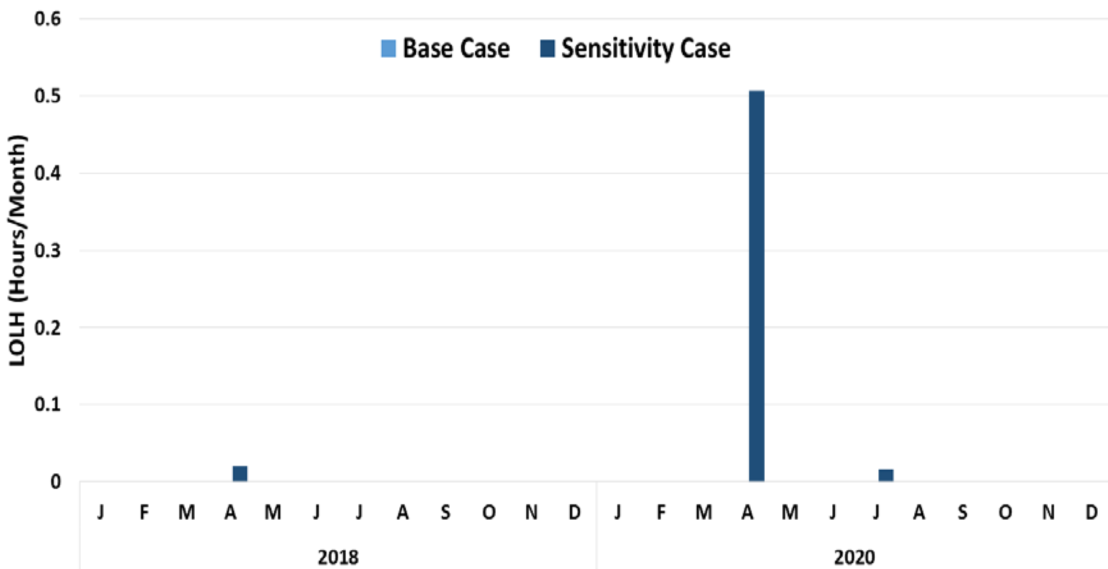
Base Case Study

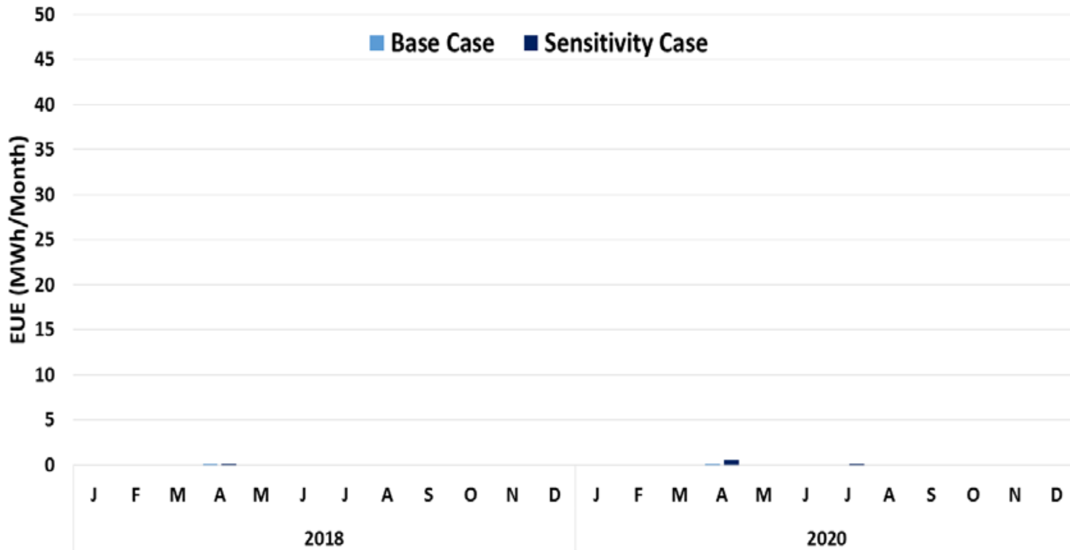
- LOLH is zero for both 2018 and 2020 due to large forecast planning reserve margins (significantly above the reference value of 16.5 percent).
- EUE is virtually zero (though technically nonzero) for both 2018 and 2020. The only month that contributes a discernible amount of EUE in both years is April due to planned maintenance and large load uncertainty for some of the areas within PJM.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	33.5	28.5	30.7	23.4
Prospective	37.9	50.4	35.0	44.5
Reference	16.5	16.5	16.5	16.5
ProbA Forecast Planning	31.8	26.8	29.1	21.9
ProbA Forecast Operable	20.8	16.1	18.3	11.6
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.003	0.001	0.020	0.523
EUE (ppm)	0.000	0.000	0.000	0.001
LOLH (hours/year)	0.000	0.000	0.000	0.001

Sensitivity Case Study

- LOLH is still zero for 2018. For year 2020, LOLH exhibits a very mild uptick (i.e., 0.001 hours per year) during April due to a large amount of planned maintenance and large load uncertainty for some of the areas within PJM.
- EUE is slightly higher than under the Base Case for both 2018 and 2020 but still very close to zero. Months that contribute to the EUE in the Sensitivity Case are April (due to the reasons mentioned above explaining the LOLH uptick in 2020) and July (where the PJM annual peak occurs).





Summary

The PJM RTO reserve requirement, as calculated by PJM, is 16.4 percent for the 2016/2017 planning period, which runs from June 1, 2016 through May 31, 2017. The PJM RTO reserve requirement is 0.8 percentage points higher this year compared to the 2015/2016. About three-eighths of this increase can be attributed to changes in the PJM load model: shorter historical time period, greater energy efficiency and distributed generation, and more granular weather monitoring. Another three-eighths can be attributed to worse performance by the generation units while the remaining quarter is due to reduced emergency imports from the world (i.e., outside the PJM area). Since the modeling of the PJM peak is nearer to the world peak, there is a lack of diversity with the world peak. A 16.5 percent PJM RTO reserve requirement is applicable for the rest of the assessment period. PJM RTO will have an adequate Anticipated Reserve Margin though the entire assessment period. The prospective margin is also adequate for the entire assessment period.

Since the 2015 report, PJM has significantly revised its load forecast model. The treatment of weather has been restructured to provide more variable load response to weather across a wide range of conditions. Three variables (cooling, heating, and other) were added to account for trends in equipment/appliance saturation and efficiency. Distributed solar generation is now reflected in the historical load data used to estimate the models with a separately-derived solar forecast used to adjust load forecasts.[109]

The winter load forecast has smaller changes compared to the summer load forecast. This is due to two impacts acting against one another to minimize changes to previous forecasts: 1) the result of shortening the historical period that PJM uses to produce weather scenarios and 2) this lowered the resulting winter forecast. The other impact is related to refinements to the weather specification that addressed the previous model's tendency to understate the elasticity of load to weather at peak conditions.

The PJM Capacity Performance initiative (a PJM program to incentivize better generator performance) starts to show up in future DR accounting since DR is considered capacity in PJM. This program actually decreases DR by more than half since performance is required the entire year and some DR programs that include air conditioning reductions cannot reduce air conditioning load that is not there. A PJM committee is investigating a seasonal aspect to capacity that may influence the amount of DR accepted by PJM in the future.

PJM has begun to track residential PV installations through the PJM Generation Attribute Tracking System (GATS) since there is an effect on the PJM load forecast. Estimates (of the effect) for 2016 are 574 MW, and this increases

[109] Detailed information on the development of the distributed solar generation forecast can be found on the PJM website.

to 1,523 MW in 2026. This is less than one percent of the PJM forecasted peak load, so these energy sources will have little effect on adequacy or reliability in PJM. PJM Environmental Information Services (EIS) operates the GATS. EIS is a wholly owned subsidiary of PJM Technologies, Inc., which is a subsidiary of PJM Interconnection. The functional design of the GATS has been developed through considerable deliberation of a stakeholder group that included representatives from various state agencies (public utility commissions, environmental protection offices, energy offices, and consumer advocates), market participants, environmental advocates, and PJM staff. The design of the GATS is an “unbundled” certificates-based tracking system. This means that the attributes or characteristics of the generation are separated from the megawatt hour (MWh) of Energy and recorded onto a certificate after the MWh of energy is produced.

Variable resources are only partially counted for PJM resource adequacy studies. Both wind and solar initially utilize class average capacity factors: 13 percent for wind and 38 percent for solar. Performance over the peak period is tracked and the class average capacity factor is supplanted with historic information. After three years of operation, only historic performance over the peak period is used to determine the individual unit's capacity factor. Biomass and hydro are counted at 100 percent of reported existing-certain resources because these resources are typically only fully utilized over the peak period of the day. Some run-of-the-river hydro capacity has always been reported as a lower value than total plant nameplate in PJM due to the full capability of the plant not typically being available.

PJM has 6,748 MW of firm imports and 1,395 MW of firm exports (resulting in a net firm import of 5,353 MW) scheduled for the 2016–2017 planning period (June 1, 2016 to May 31, 2017). Firm imports drop to 5,364 MW, 1,413 MW of firm exports with a net firm import of 3,951 MW in 2017–2018 planning period. PJM has 4,126 MW of firm imports, 1,395 MW of firm exports with a next firm import of 2,731 MW scheduled for the 2018–2019 planning period. The same imports and exports as the 2018–2019 planning period are expected for the remaining years of the assessment.

PJM has recently experienced below average winter temperatures. PJM’s winter peak reliability analysis indicates that the transmission system is capable of delivering the system generating capacity at winter peak.

PJM has experienced some thermal overload problems during light load conditions with relatively high wind generator output. PJM’s light load reliability analysis[110] ensures that the transmission system is capable of delivering the system generating capacity during light load conditions. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level like high wind output.

Interchange levels for the various PJM zones will reflect a statistical average of typical previous years interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas that impact PJM facilities are based on statistical averages for previous off-peak periods. The flowgates ultimately used in the light-load reliability analysis are determined by running all contingencies maintained by PJM planning. These are also determined through monitoring all PJM market monitored facilities and BPS facilities. The contingencies used for light load reliability analysis will include NERC TPL P1, P2, P4, P5, and P7. NERC TPL P0, normal system conditions will also be studied.

There has been a steady retirement of coal resources that are being replaced by combined cycle natural-gas-powered resources. No difference has been seen in net demand ramping variability related to this change in resource mix within PJM.

[110] PJM Analysis of Light Load Historical Data and Light Load Reliability Criterion; July 9, 2015

SERC

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

Summary of Methods and Assumptions

Reference Margin Level
Entities within the SERC footprint adhere to state-set targets that vary throughout the footprint. For this assessment, NERC applies a 15 percent Reference Margin Level for all SERC subregions.

Load Forecast Method
Noncoincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
As reported by individual Generator Owners

Planning Considerations for Solar Resources
As reported by individual Generator Owners

Footprint Changes
None to report

SERC-East Assessment Area Footprint

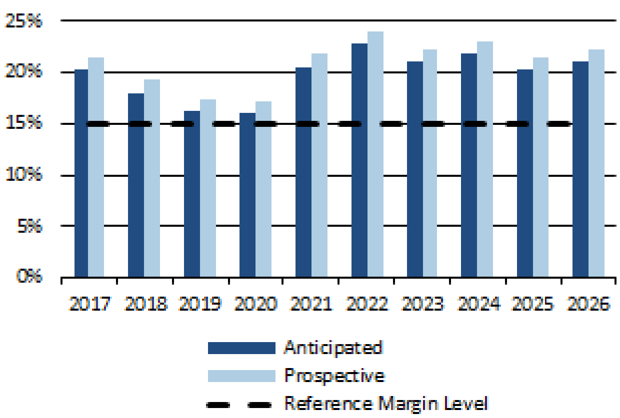
SERC-North Assessment Area Footprint

SERC-Southeast Assessment Area Footprint

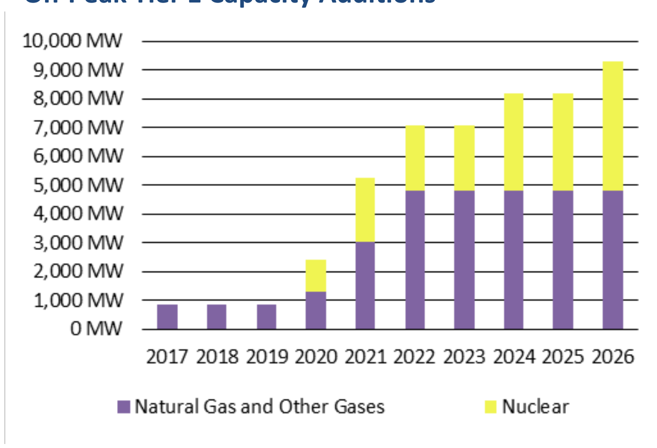
SERC-East

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	43,213	43,999	44,672	45,440	46,126	46,774	47,449	48,053	48,668	49,309
Demand Response	655	663	667	669	672	674	676	679	681	684
Net Internal Demand	42,558	43,336	44,005	44,771	45,454	46,100	46,773	47,374	47,987	48,625
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	51,175	51,139	51,149	51,958	54,798	56,629	56,629	57,746	57,746	58,863
Prospective	51,722	51,686	51,696	52,505	55,345	57,176	57,176	58,293	58,293	59,410
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.25%	18.01%	16.23%	16.05%	20.56%	22.84%	21.07%	21.89%	20.34%	21.06%
Prospective	21.53%	19.27%	17.48%	17.27%	21.76%	24.03%	22.24%	23.05%	21.48%	22.18%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** SERC utilizes an 8,760 hourly load, generation, and transmission simulation model that consists of three internal NERC assessment areas (SERC-E, SERC-N, and SERC-SE) and seven connected external areas (10 total external areas). First Contingency Incremental Transfer Capability (FCITC) analysis sets limits for nonfirm support amongst internal and external areas while positive and negative demand side resources represent net firm interchange schedules. Forecast assumptions for normal (50/50) coincident demand, net energy for load, and anticipated resources from the LTRA are input for the model. Then further analysis determines uncertainty parameters such as load forecast uncertainty, generator forced outage rates, etc.

  In addition to SERC's portion of the *NERC 2016 Probabilistic Resource Assessment* (*PRA*), SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analyses of incremental adjustments to load, resource performance, and interface limits. Also, although the U.S. Supreme Court granted a stay that halted the implementation of the Environmental Protection Agency's (EPA) CPP, a CPP scenario will address the potential resource adequacy implications of retiring coal-fired generation, further reliance on variable energy resources (VERs), and increased dependence on gas-fired generation.

The full SERC report to be published in quarter one of 2017 will showcase enhancements to the 2016 SERC *PRA*, as compared to the 2014 study, as well as SERC's full sensitivity and scenario analysis.[111]

Lowering demand projections in SERC-E (five percent decrease from 2014 to 2016 in the study year 2018 forecast) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area. Although near zero, SERC-E LOLH and EUE for both the 2018 and 2020 Base Cases contribute nearly 100 percent of the totals for the SERC assessment area footprint (SERC-E, SERC-N, and SERC-SE). However, higher excess capacity exists in the other two SERC areas. Furthermore, at anticipated load growth and reserve levels, SERC-E meets an industry standard resource planning criteria of 1-day-in-10-years LOLE in 2020.

- **Results Trending:** From the *2014* to *2016 PRA*, the SERC-E LOLH decreased by approximately 97 percent (0.085 to 0.002) for the same study year 2018. This is primarily driven by the lower projected demand mentioned above as well as the 2016 modeling corrections. The SERC *PRA* model now includes expected firm capacity transfers and improvements to winter historical load profiles.[112] After accounting for lower demand and modeling corrections, SERC-E Base Case 2018 results remain static from 2014.
- **Probabilistic vs. Deterministic Reserve Margin Results:** For all SERC assessment areas, the probabilistic assessment (ProbA) forecast planning reserve margin is higher than the deterministic Anticipated Reserve Margin. This is due to the following differences in ProbA vs. deterministic modeling:
  - The average probabilistic total internal demand is lower than the deterministic total internal demand due to the use of multiple load shapes with some annual peaks during non-summer months.
  - The ProbA model optimizes scheduled maintenance so that, on average, zero maintenance occurs on peak.
  - Controllable DR programs' effective load reduction realization is higher in the ProbA model based on statistical performance rates than the deterministic value.
  - VER performance in the ProbA model is based on a time series correlation analysis, which may be better than the expected on peak MW in the deterministic study.

[111] SERC Reliability and Performance Analysis (RAPA) homepage

[112] Approximations: 0.085 (2014 PRA- 2018 LOLH) minus 0.080 (decrease load forecasts from 2014 to 2016) minus 0.003 (modeling corrections) equals 0.002

Base Case Study

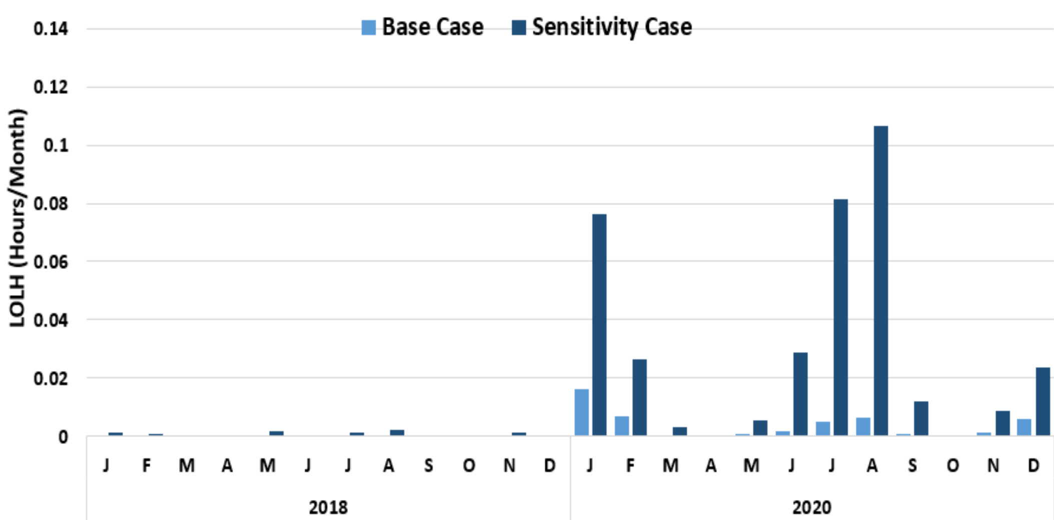
SERC-E LOLH increases to 0.002 hours per year in 2018 and 0.046 hours per year in 2020. EUE increases 1.4 MWh in 2018 and to 49.4 MWh in 2020. This is due to an approximate 3 percent increase in peak demand and minimal increase in anticipated resources. However, the rise of the metrics in 2020 is not concerning considering the MW size of SERC-E. Measures not modeled in the 2016 PRA such as, but not limited to, voluntary and noncontrollable DR, operating procedures to cut nonfirm schedules or maintenance, public appeals, and other mechanisms should mitigate 49.4 MWh of annual EUE within SERC-E.

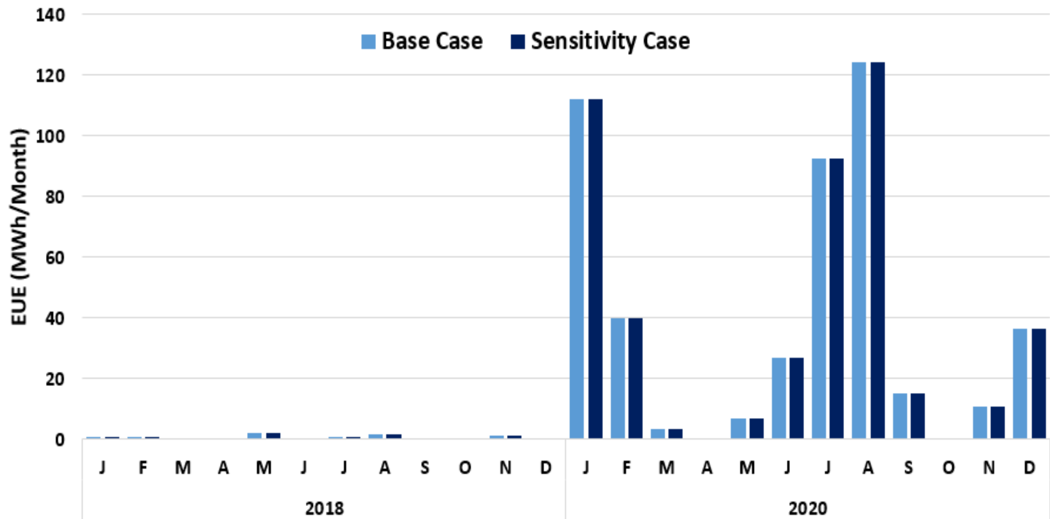
Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	18.01	16.05	-	-
Prospective	19.27	17.27	-	-
Reference	15	15	15	15
ProbA Forecast Planning	19.3	19.1	16.9	14.4
ProbA Forecast Operable	11.3	11.2	9.1	6.8
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	1.415	49.394	7.615	457.709
EUE (ppm)	0.006	0.218	0.034	1.983
LOLH (hours/year)	0.002	0.046	0.009	0.373

LOLH and EUE accrue relatively evenly across all months of the year in 2018; however, with increases in demand by 2020, the majority of LOLH and EUE accrues during the peak seasons of summer and winter. Actually, between 60 and 70 percent occurs during the winter months. This is contributable to a high annual 50/50 demand per unit and higher winter load forecast uncertainty due to off-normal events. A recent off-normal event was the 2014 Polar Vortex when annual peaks occurred for many entities within SERC-E during winter months.

Sensitivity Case Study

- SERC-E entities expect a 1.44 percent compound annual growth rate (CAGR). The NERC Sensitivity Case doubles the SERC-E CAGR to 2.90 percent. In this load growth scenario, SERC-E LOLH increases to 0.009 hours per year in 2018 and 0.373 hours per year in 2020. EUE increases 7.6 MWh in 2018 and to 467.7 MWh in 2020.
- SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. This assessment will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

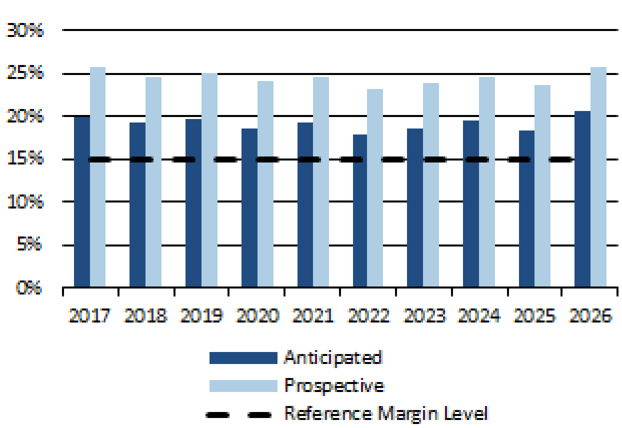




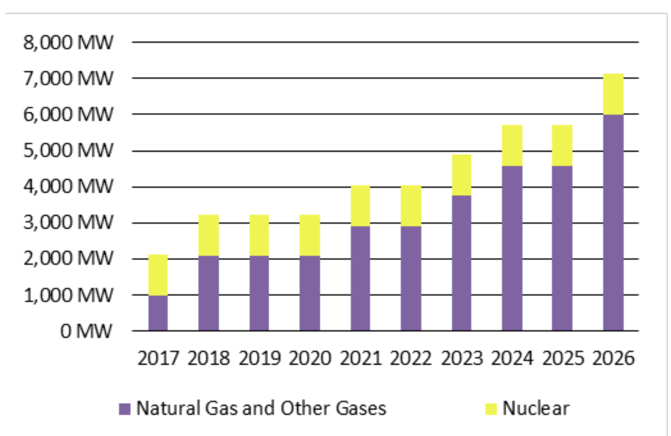
SERC-North

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	42,540	42,955	43,051	43,419	43,800	44,184	44,572	44,954	45,331	45,690
Demand Response	1,789	1,792	1,811	1,813	1,695	1,632	1,588	1,552	1,549	1,544
Net Internal Demand	40,751	41,163	41,240	41,606	42,105	42,552	42,984	43,402	43,782	44,146
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	48,910	49,068	49,337	49,337	50,177	50,177	51,017	51,857	51,857	53,247
Prospective	51,265	51,351	51,620	51,620	52,460	52,460	53,300	54,140	54,140	55,530
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.02%	19.20%	19.63%	18.58%	19.17%	17.92%	18.69%	19.48%	18.44%	20.62%
Prospective	25.80%	24.75%	25.17%	24.07%	24.59%	23.28%	24.00%	24.74%	23.66%	25.79%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** SERC utilizes an 8,760 hourly load, generation, and transmission simulation model that consists of three internal NERC assessment areas (SERC-E, SERC-N, and SERC-SE) and seven connected external areas (10 total external areas). First Contingency Incremental Transfer Capability (FCITC) analysis sets limits for nonfirm support amongst internal and external areas while positive and negative demand side resources represent net firm interchange schedules. Forecast assumptions for normal (50/50) coincident demand, net energy for load, and anticipated resources from the LTRA are input for the model. Then further analysis determines uncertainty parameters such as load forecast uncertainty, generator forced outage rates, etc.

  In addition to SERC's portion of the *NERC 2016 Probabilistic Resource Assessment* (*PRA*), SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analyses of incremental adjustments to load, resource performance, and interface limits. Also, although the U.S. Supreme Court granted a stay that halted the implementation of the Environmental Protection Agency's (EPA) CPP, a CPP scenario will address the potential resource adequacy implications of retiring coal-fired generation, further reliance on variable energy resources (VERs), and increased dependence on gas-fired generation.

  The full SERC report to be published in quarter one of 2017 will showcase enhancements to the 2016 SERC *PRA*, as compared to the 2014 study, as well as SERC's full sensitivity and scenario analysis.[113]

  The demand projections in SERC-N decrease 3 percent in 2018 from the 2014 to 2016 study year. This decrease in demand forecasts continues to increase reserve margin and decrease the resource adequacy measures in the assessment area. Due to a high forecasted reserve margin of 27 percent, SERC-N experiences zero LOLH and near zero EUE for 2018 and 2020 Cases.

- **Results Trending:** From the *2014 PRA* to the *2016 PRA*, the SERC-N LOLH decreased in similar fashion to SERC-E, which was from 0.023 to 0.000 for the same study year of 2018. Again this is largely driven by the decreasing load projections. See SERC-E section for a complete synopsis of changes.

- **Probabilistic vs. Deterministic Reserve Margin Results:** For all SERC assessment areas, the probabilistic assessment (ProbA) forecast planning reserve margin is higher than the deterministic Anticipated Reserve Margin. This is due to the following differences in ProbA vs. deterministic modeling:
  - The average probabilistic total internal demand is lower than the deterministic total internal demand due to the use of multiple load shapes with some annual peaks during non-summer months.
  - The ProbA model optimizes scheduled maintenance so that, on average, zero maintenance occurs on peak.
  - Controllable DR programs' effective load reduction realization is higher in the ProbA model based on statistical performance rates than the deterministic value.
  - VER performance in the ProbA model is based on a time series correlation analysis, which may be better than the expected on peak MW in the deterministic study.

[113] SERC Reliability and Performance Analysis (RAPA) homepage

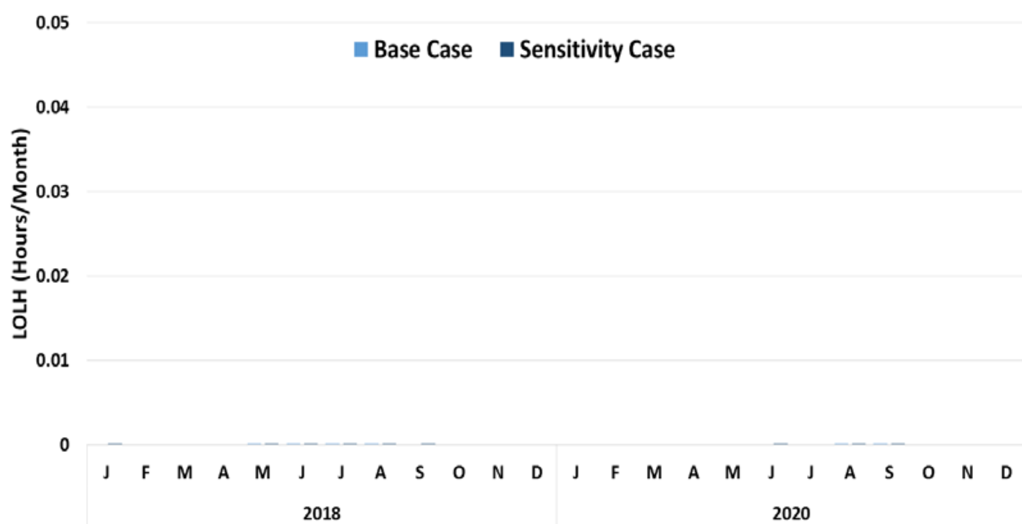
Base Case Study

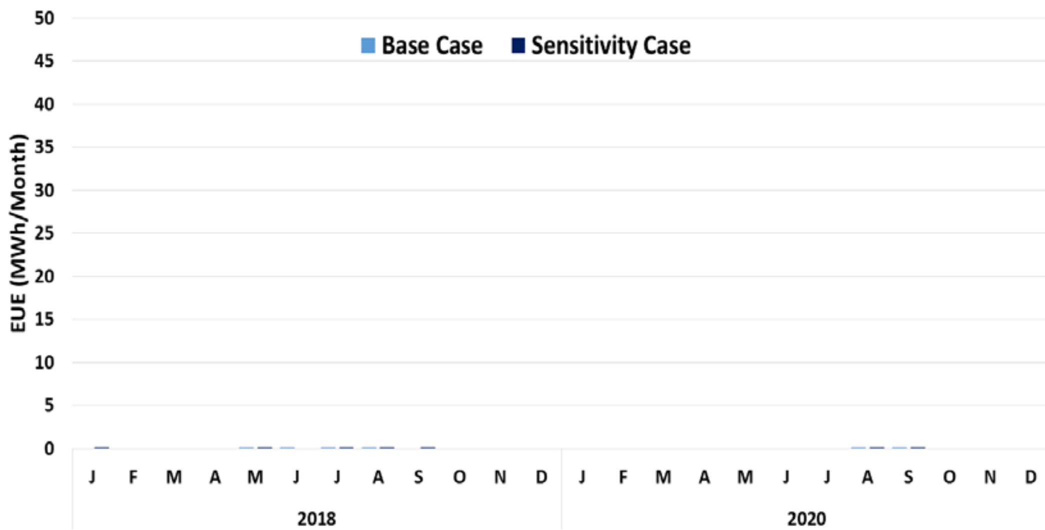
- Zero LOLH and EUE.
- SERC-N entities expect a 0.81 percent CAGR. However, the model results for 2020 base summer yielded near zero percent growth from 2018. However, since the expected growth is below 1 percent, the resulting impact on the indices is negligible.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	19.2	18.58	-	-
Prospective	24.75	24.07	-	-
Reference	15	15	15	15
ProbA Forecast Planning	27.1	27.1	24.4	21.9
ProbA Forecast Operable	18.0	18.0	15.6	13.2
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.173	0.131	1.781	0.780
EUE (ppm)	0.001	0.001	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.003	0.001

Sensitivity Case Study

- The NERC Sensitivity Case doubles the SERC-N CAGR to 1.74 percent. In this load growth scenario, SERC-N LOLH and EUE increase but of minimal consequence to resource adequacy. LOLH increases to 0.003 hours per year in 2018 and 0.001 hours per year in 2020. EUE increases to 1.8 MWh in 2018 and to 0.8 MWh in 2020. The resulting metrics for 2020 are lower than 2018 due to gas-fired generation additions to SERC-N mid-year 2018. Subsequently, the winter months in 2020 reflect lower accrual of LOLH and EUE than in 2018.
- SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. This assessment will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

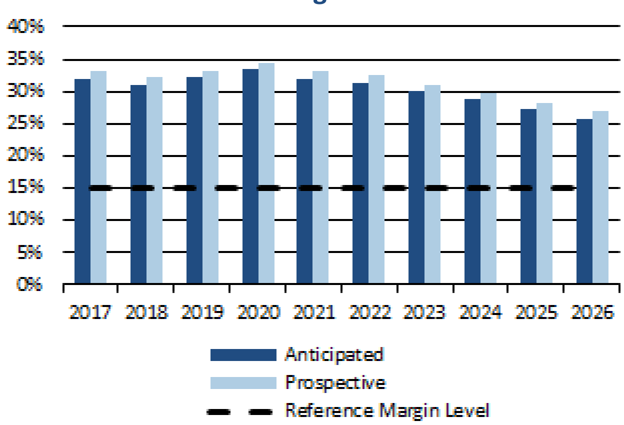




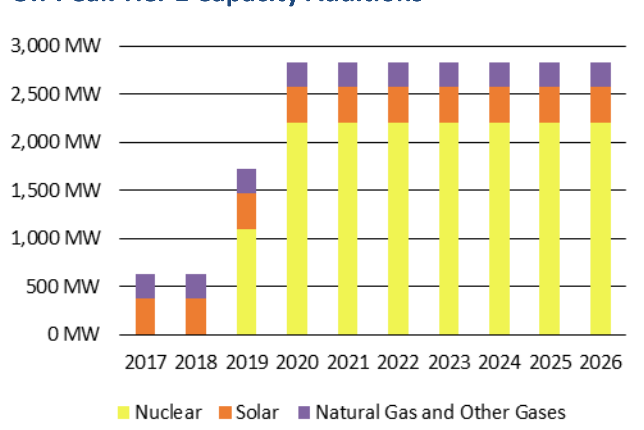
SERC-Southeast

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	47,762	48,124	48,507	48,903	49,325	49,756	50,281	50,859	51,461	52,083
Demand Response	2,228	2,238	2,247	2,256	2,260	2,262	2,265	2,267	2,270	2,273
Net Internal Demand	45,534	45,886	46,260	46,647	47,065	47,494	48,016	48,592	49,191	49,810
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	60,062	60,115	61,101	62,222	62,126	62,396	62,397	62,560	62,562	62,636
Prospective	60,596	60,659	61,645	62,765	62,669	62,939	62,940	63,103	63,105	63,179
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	31.91%	31.01%	32.08%	33.39%	32.00%	31.38%	29.95%	28.75%	27.18%	25.75%
Prospective	33.08%	32.20%	33.26%	34.55%	33.16%	32.52%	31.08%	29.86%	28.29%	26.84%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

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  In addition to SERC's portion of the *NERC 2016 Probabilistic Resource Assessment* (*PRA*), SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analyses of incremental adjustments to load, resource performance, and interface limits. Also, although the U.S. Supreme Court granted a stay that halted the implementation of the Environmental Protection Agency's (EPA) CPP, a CPP scenario will address the potential resource adequacy implications of retiring coal-fired generation, further reliance on variable energy resources (VERs), and increased dependence on gas-fired generation.

  The full SERC report to be published in quarter one of 2017 will showcase enhancements to the 2016 SERC *PRA*, as compared to the 2014 study, as well as SERC's full sensitivity and scenario analysis.[114]

  Lowering demand projections in SERC-SE (four percent decrease from 2014 to 2016 in study year 2018 forecast) continue to increase Anticipated Reserve Margins and decrease the resource adequacy measures in the assessment area. Due to a high forecasted reserve margin of 35 percent, SERC-SE experiences zero LOLH and near zero EUE for 2018 and 2020 Base Cases.

- **Results Trending:** From the 2014 to 2016 *PRA*, the SERC-SE LOLH decreased in similar fashion to SERC-E and SERC-N, which was from 0.029 to 0.000 for the same study year of 2018. This is largely driven by the decreasing load projections. See the SERC-E section for a synopsis of corrected modeling errors from 2014.

- **Probabilistic vs. Deterministic Reserve Margin Results:** For all SERC assessment areas, the probabilistic assessment (ProbA) forecast planning reserve margin is higher than the deterministic Anticipated Reserve Margin. This is due to the following differences in ProbA vs. deterministic modeling:
  - The average probabilistic total internal demand is lower than the deterministic total internal demand due to the use of multiple load shapes with some annual peaks during non-summer months.
  - The ProbA model optimizes scheduled maintenance so that, on average, zero maintenance occurs on peak.
  - Controllable DR programs' effective load reduction realization is higher in the ProbA model based on statistical performance rates than the deterministic value.
  - VER performance in the ProbA model is based on a time series correlation analysis, which may be better than the expected on peak MW in the deterministic study.

[114] SERC Reliability and Performance Analysis (RAPA) homepage

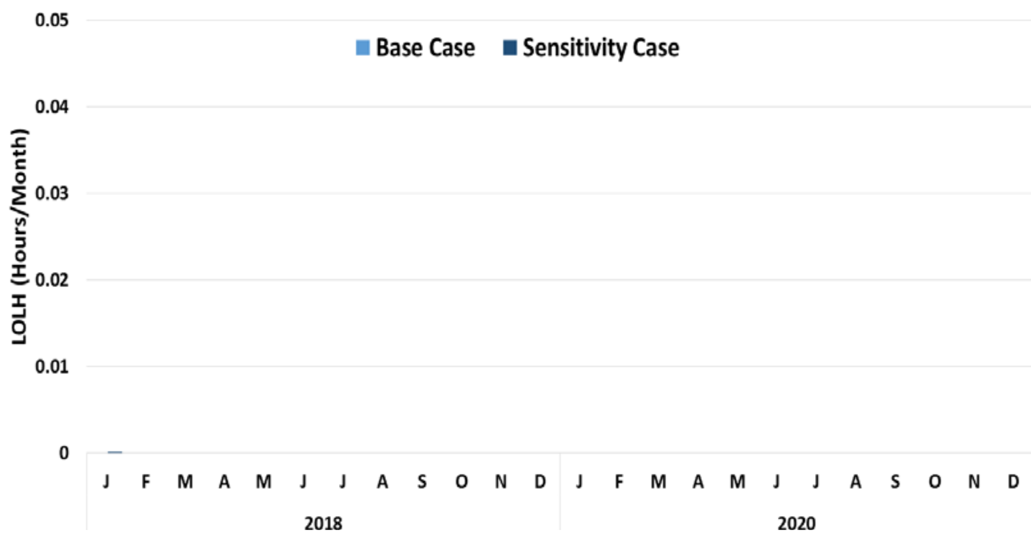
Base Case Study

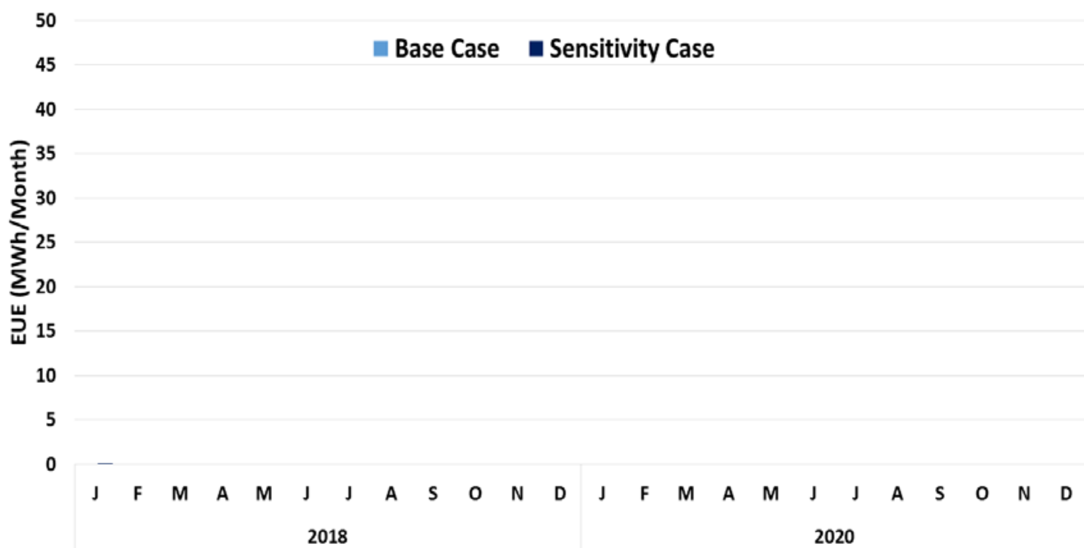
- Zero LOLH and EUE.

Sensitivity Case Study

- SERC-SE entities expect a 1.20 percent CAGR. The NERC Sensitivity Case doubles the SERC-SE CAGR to 2.52 percent. In this load growth scenario, SERC-SE LOLH and EUE still remain zero.
- SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. This assessment will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	31.01	33.39	-	-
Prospective	32.2	34.55	-	-
Reference	15	15	15	15
ProbA Forecast Planning	35.1	37.7	32.3	32.1
ProbA Forecast Operable	23.9	26.5	21.3	21.4
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.003	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000





SERC Summary

Current projections for the SERC non-RTO assessment area show reserve margins in excess of 15 percent throughout the long-term planning horizon. In the near term (2016–2020), the Region's reserve margin will range from 21.7 to 24.6 percent. The reserve margin decreases that are projected throughout subsequent long-term years (2020–2025) are due to the uncertainty of resource additions. To maintain reserve margin levels, SERC non-RTO entities continuously plan for new capacity, acquire or request power purchase agreements, acquire additional assets, and implant new energy efficiency and DR programs. Uncommitted generating capacity in the SERC Region is not included in comparison with the NERC Reference Reserve Margin; because uncommitted capacity exists in the Region, there will continue to be additional generation above what is reported in the reserve margin. SERC expects this uncommitted capacity to continue to provide additional peaking resources for short-term utility purchases, but the impact on the Region's 2016 summer reserve margin is uncertain. Availability of uncertain capacity cannot be assured because portions of this capacity may be designated to serve load outside of the SERC Region.

Although there is no notable change in demand for the Region, some member entities report slightly decreased demand projections that they attribute to economic factors, DERs, and other energy efficiency programs. Throughout the Region, entities have various programs in place for energy efficiency and conservation: the entities incorporate the projected energy efficiency into the demand forecast, which is reflected back in their reserve margin projections, and entities can also utilize a variety of DR programs as load modifiers during high-load system conditions with implementation times that range from instantaneous to 60 minutes. Upcoming EPA policy changes related to emission standards may limit emergency stationary generator ability to operate without extensive emissions controls in response to a utility's request to reduce demand. This may have an undetermined effect for generators within the Region participating in DR programs.

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

The regional long-term studies identified no reliability impacts due to announced retirements or significant generation outages during the assessment period. To better assess highlighted impacts in *NERC's CPP Phase II Assessment* from potential environmental regulations, SERC is coordinating a power-flow study utilizing the Aurora data and assumptions from the phase II assessment. In addition, several transmission upgrades are currently underway to maintain reliability within specific areas of the Region.

With respect to MISO, a settlement agreement was reached between MISO, SPP, and the Joint Parties (TVA, SOCO, LG&E/KU, AECI and PowerSouth). This agreement is now in place (this superseded the ORCA on February 1, 2016) to reliably manage the magnitude of power transfers between MISO South and Midwest. The settlement agreement limits transfers between MISO-South and MISO-Midwest to 2500 MW and MISO-Midwest to MISO-South to 3000 MW in order to limit reliability impacts on neighboring systems. The increase in flow from 1,000 to 2,500/3,000 MW represents a new operating condition that has been studied and experienced under certain historical operating conditions. However, this is a significant change that will be closely monitored in operations for adverse reliability impacts. Although a settlement agreement is in place, SERC is committed to ensuring reliability of the Region and the interconnection. The Region implemented a joint loop flow study initiative with market and nonmarket entities to recreate and study loop flows within the area. The purpose of these studies is to ensure there are not potential IROL conditions that can lead to cascading, separation, or blackout conditions. SERC also plans to track and trend DERs within the Region to assess what possible impacts large penetrations of DERs may have on future BPS reliability.

SPP

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

Summary of Methods and Assumptions

Reference Margin Level
SPP established target of 12.0 percent

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
On-peak contribution of 3 percent of nameplate capacity

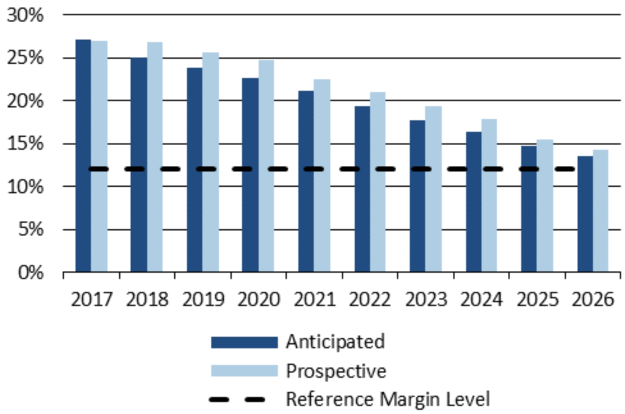
Planning Considerations for Solar Resources
On-peak contribution of 10 percent of nameplate capacity

Footprint Changes
The Integrated System (IS), formally part of WAPA, is reporting under the SPP assessment area this year.

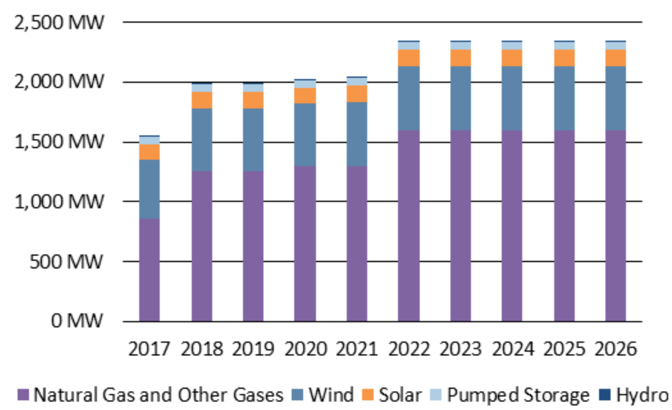
Peak Season Demand, Resources, Reserve Margins, and Shortfall

Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	51,936	52,819	53,235	53,409	53,779	54,336	54,703	55,119	55,581	56,048
Demand Response	753	829	876	898	911	916	913	909	907	904
Net Internal Demand	51,184	51,989	52,359	52,511	52,868	53,420	53,790	54,210	54,674	55,144
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	65,083	65,025	64,868	64,427	64,046	63,735	63,282	63,075	62,681	62,592
Prospective	65,004	65,925	65,768	65,497	64,775	64,665	64,212	63,901	63,101	63,011
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	27.16%	25.07%	23.89%	22.69%	21.14%	19.31%	17.65%	16.35%	14.65%	13.51%
Prospective	27.00%	26.80%	25.61%	24.73%	22.52%	21.05%	19.37%	17.88%	15.41%	14.27%
Reference Margin Level	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** SPP oversees the bulk electric grid and wholesale power market as one consolidated Balancing Authority area on behalf of a diverse group of utilities and transmission companies in 14 states. SPP utilized a nodal modeling technique for the probabilistic assessment. Firm imports and exports of capacity were modelled to reflect the firm transactions reported for the *2016 LTRA*. Assumptions and the accompanying methodology have been thoroughly vetted through the SPP stakeholder process. No events for loss of load occurred in the Base Case and Sensitivity Case studies for the probabilistic assessment.

- **Modeling**: A Monte-Carlo-based software was used in the probabilistic assessment by randomly selecting load forecast uncertainty errors derived from historical probability of occurrence while varying the availability of thermal, hydro, and DR resources. Unit specific ramp rates, outage durations, and equivalent forced outage rates were used when varying the availability of resources in the SPP assessment area. Four thousand iterations were performed for each simulation. The generating resources modelled in the probabilistic assessment reflect the supplied data for the *2016 LTRA*. Existing and Tier 1 resources were included in the probabilistic assessment along with reported confirmed retirements and projected in-service dates of new resources. Wind and solar resources were modelled at historical hourly output values.

  A nodal representation of transmission, load, and generation was modeled for the SPP assessment area, and transmission elements 100 kV and above were monitored to not exceed their normal rating limits. SPP flowgate and interface limitations with generation or load-related issues were considered when performing the simulations. Firm capacity transactions with firm transmission service from assessment areas external to SPP were reflected as to be continuously available during simulations, and nonfirm capacity assistance from neighboring assessment areas were not included. SPP depleted all operating reserves before shedding firm load in the probabilistic assessment.

- **Results Trending:** *The 2014 Probabilistic Assessment* results for SPP indicated 0.0 EUE and 0.0 hours per year LOLH for years 2016 and 2018. *The 2014 Probabilistic Assessment* Base Case results for 2018 were the same for the 2016 Base Case results. Also, the ProbA forecast planning reserve margin for the 2018 study year was 3 percent lower in 2014 compared to 2016.

- **Probabilistic vs. Deterministic Reserve Margin Results:** DR values reported in this report were modelled as generating resources available during daily on peak hours instead of reducing the total internal demand. Tier 1 wind resources with wind interconnection agreements that have not obtained firm transmission service were not included in the probabilistic assessment.

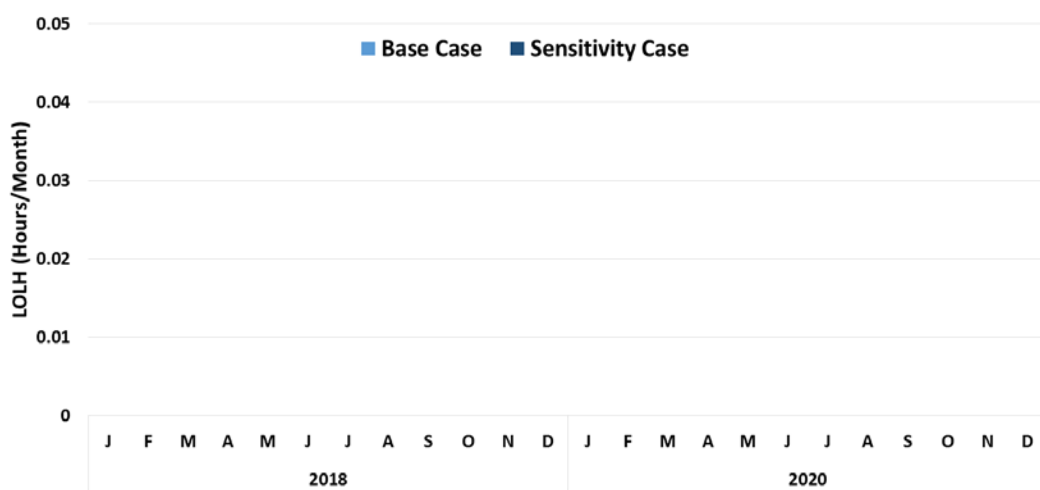
Base Case Study

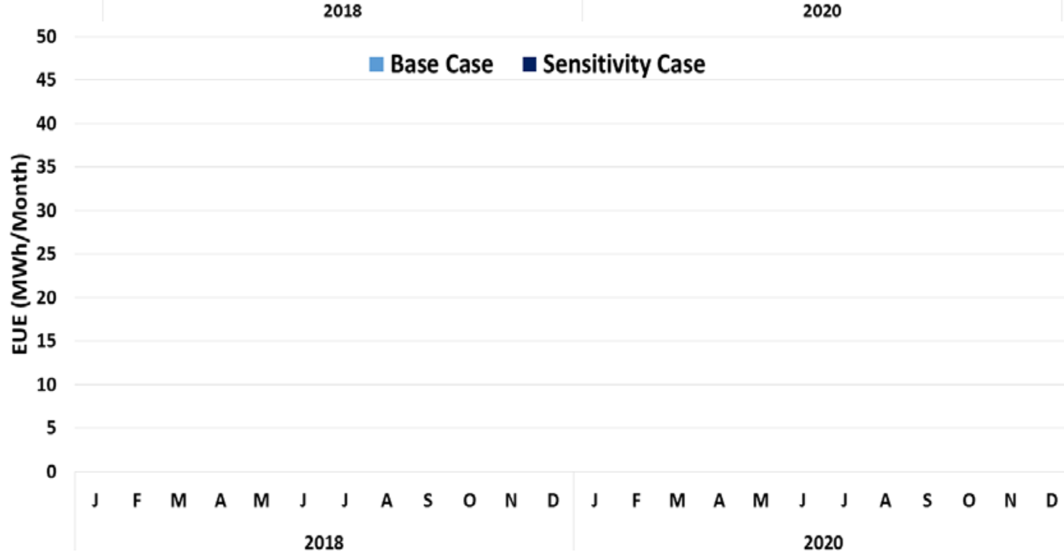
No loss of load events were indicated for the Base Case study due to a surplus of capacity in the SPP assessment area. Reserve margins are well above 20 percent in both study years and no major impacts were observed related to resource retirements.

Sensitivity Case Study

No loss of load events were indicated for the Sensitivity Case study due to a surplus of capacity in the SPP assessment area.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
Anticipated	25.1	22.7	22.6	18.0
Prospective	26.8	24.7	--	--
Reference	12.0	12.0	--	--
ProbA Forecast Planning	24.5	22.2	22.0	17.4
ProbA Forecast Operable	17.2	15.0	14.9	10.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
EUE (MWh)	0.0	0.0	0.0	0.0
EUE (ppm)	0.0	0.0	0.0	0.0
LOLH (hours/year)	0.0	0.0	0.0	0.0





Summary

The SPP assessment area is forecasted to meet the 12 percent target reserve margin through the year 2026.

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

The SPP assessment area studies different scenarios in short-term and long-term planning to address the impacts of renewable portfolio standards, the integration of variable resources, and the changes in resource mix. Early in 2016, the SPP assessment area saw nearly 50 percent of SPP's load being served by wind generation at certain points, setting numerous wind penetration records. SPP has been able to reliably accommodate this kind of growth so far due to its ability to anticipate it in planning efforts. SPP continues to plan transmission to meet renewable portfolio standards within the SPP assessment area.

Since the previous LTRA, the SPP assessment area has not changed how on-peak capacity values for wind, solar, and hydro are calculated. The expected on-peak capacity values for variable generation are determined by guidelines established in SPP Planning Criteria section 7.1.5.3(g).[115]

The SPP assessment area's 2016 Board of Directors approved *SPP Transmission Expansion Plan* (STEP) provides details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users. The *2016 STEP*[116] contains a comprehensive listing of all transmission projects in the SPP for the 20-year planning horizon, which consist of $6.1 billion in new transmission and upgrades.

The SPP assessment area is currently not anticipating unique emerging reliability issues over the assessment time frame. However, as renewable resources continue to expand, SPP will eventually be unable to reliably utilize this generation to address internal demand needs even with additional transmission infrastructure. This will increase the need for future renewables to be delivered to other regions. SPP will continue to monitor the uncertainty of potential policy changes concerning plant retirements over the assessment period.

Historically, similar to other regions, SPP has not been successful in regard to large-scale interregional transmission development. Developing the grid needed to reliably and cost-effectively accommodate expected future resource mixes will require Regions to more effectively work together to jointly plan and share costs of interregional transmission expansion.

115 SPP Planning Criteria; January 2016
116 2016 SPP Transmission Expansion Plan Report; January 2016

Texas RE-ERCOT

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

Summary of Methods and Assumptions

Reference Margin Level
ERCOT-established Reference Margin of 13.75 percent

Load Forecast Method
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Peak Capacity Contribution of 55 percent for Coastal units and 12 percent for Noncoastal

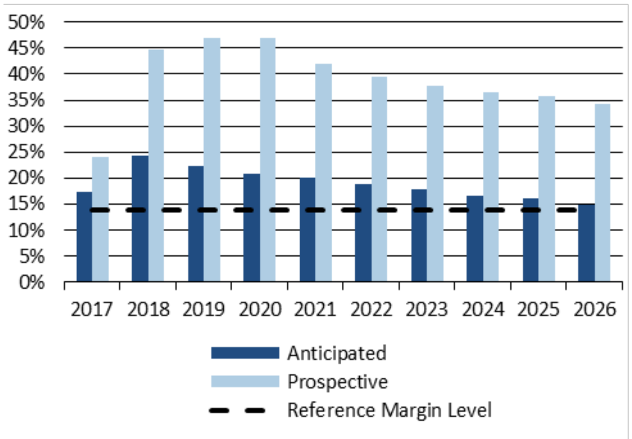
Planning Considerations for Solar Resources
ERCOT incorporates 80 percent capacity contribution

Footprint Changes
N/A

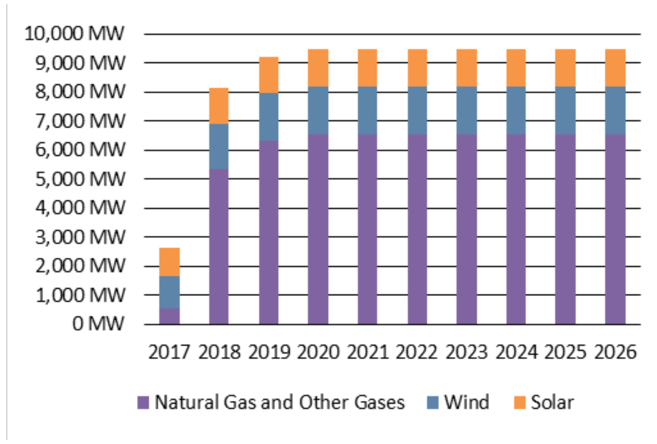
Peak Season Demand, Resources, Reserve Margins, and Shortfall

Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	71,416	72,277	73,663	74,288	74,966	75,660	76,350	77,036	77,732	78,572
Demand Response	2,868	2,868	2,868	2,868	2,868	2,868	2,868	2,868	2,868	2,868
Net Internal Demand	68,548	69,409	70,795	71,420	72,098	72,792	73,482	74,168	74,864	75,704
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	80,510	86,313	86,532	86,251	86,522	86,582	86,582	86,572	86,972	86,972
Prospective	85,050	100,361	104,007	104,930	102,281	102,106	101,739	101,729	102,129	102,129
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	17.45%	24.35%	22.23%	20.77%	20.01%	18.94%	17.83%	16.72%	16.17%	14.88%
Prospective	24.07%	44.59%	46.91%	46.92%	41.86%	40.27%	38.45%	37.16%	36.42%	34.91%
Reference Margin Level	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** Reserve margins for the ERCOT Region have increased since the 2014 probabilistic assessment to over 24 percent for 2018 and 20 percent in 2020, resulting in lower and insignificant levels of LOLH and EUE.

- **Modeling:** The 50/50 load forecast used for the study is based on 13 load shapes representing weather years for 2002-2014. ERCOT applied five load forecast uncertainty multipliers (ranging from -4 percent to +4 percent) to capture load forecast uncertainty in the sequential Monte Carlo simulation model. This year's study incorporated all new hourly values for the load, wind, and hydro shapes as well as updated generator outage data. Additionally, the probabilistic model topology was simplified from six to two zones. This was done to be consistent with the ERCOT Region along with an external zone, reflecting the historical peak-period availability of capacity across five dc ties connected to SPP and Mexico. This simplification was prompted by the 2014 study results that demonstrated that internal constraints between zones had an immaterial impact on the reliability metric results. ERCOT modeled DR resources with dispatch price thresholds, call priority rankings, and availability constraints (hours-per-season and hours-per-year).

- **Results Trending:** Compared to the 2018 results for the *2014 PRA Assessment*, LOLH decreased from 0.338 to 0.000004 while EUE decreased from 285.59 MWh to 0.005 MWh. These reductions are due to an increase in the Anticipated Reserve Margin from 13.6 percent to 24.4 percent for the 2018 forecast year. This reserve margin increase is attributable to both a lower peak load forecast as well as an increase in anticipated resources relative to those included in the *2014 LTRA*.

- **Probabilistic vs. Deterministic Reserve Margin Results:** No changes.

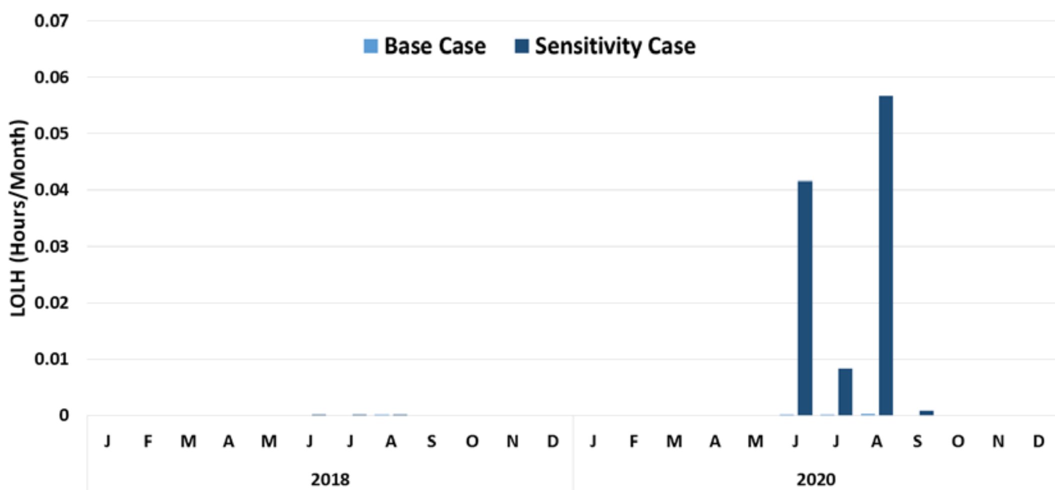
Base Case Study

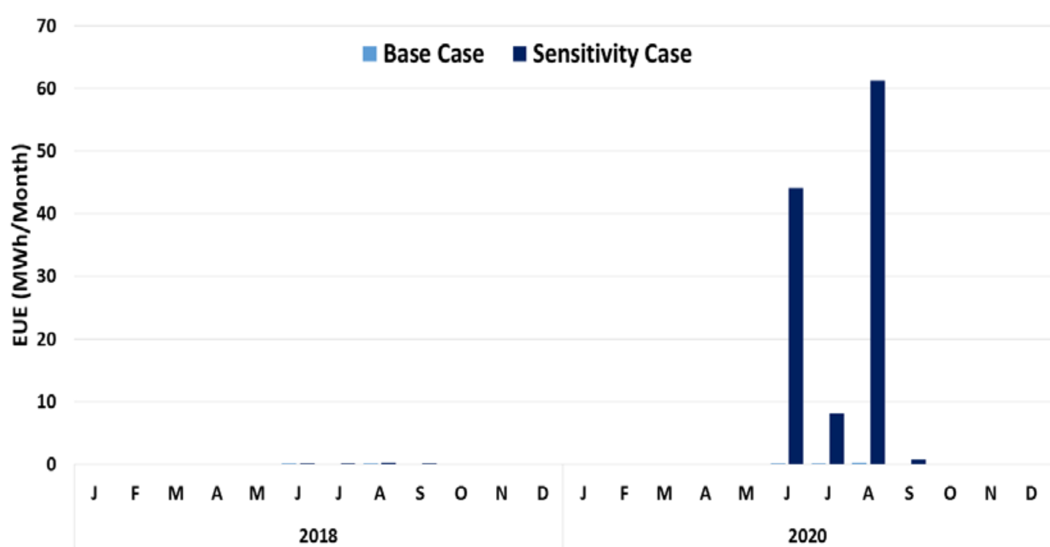
For the Base Case study, EUE and LOLH values were insignificant due to Planning Reserve Margins exceeding 20 percent for both forecast years. Loss of load occurred only during the summer season, with the majority in August. For example, in 2018, 78 percent of the EUE occurred in August. Relatively high values in June are driven by the 2012 weather year used to produce the load forecast. The second highest annual peak load from 2002 through 2014 occurred in June 2012.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
Anticipated	24.35	20.77	21.82	15.94
Prospective	44.59	46.92	41.64	41.05
Reference	13.75	13.75	13.75	13.75
ProbA Forecast Planning	24.35	20.77	21.82	15.94
ProbA Forecast Operable	14.83	11.42	12.49	6.97
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
EUE (MWh)	0.005	0.395	0.243	114.19
EUE (ppm)	0.000	0.001	0.001	0.292
LOLH (hours/year)	0.000	0.001	0.000	0.107

Sensitivity Case Study

The results show that, as the reserve margin falls below 20 percent, the EUE remains low but begins to increase exponentially. This remains well above the target reserve margin used for the 2016 LTRA.





Summary

The Anticipated Reserve Margin is expected to remain above the Reference Margin Level (13.75 percent) for the duration of the assessment period. This is an improvement relative to the *2015 LTRA*, which indicated that planning reserves would drop below the Reference Margin Level beginning in 2022. This improvement is due to a relative increase of 2,800 MW in Tier 1 capacity additions starting in 2018, which increases to over 3,800 MW for 2020 and beyond. Note that project developers typically submit interconnection requests to ERCOT no more than three to four years before the facility is expected to enter commercial operations. As a result, the Texas RE-ERCOT Region will always show a flat level of capacity additions and typically declining reserve margins starting four to five years into the LTRA forecast period.

ERCOT's peak load forecast, updated in the fall of 2015, indicates system peak demand increasing at an average annual growth rate (AAGR) of approximately 1.1 percent from 2016 to 2026. Historically, summer peak demand has grown at an AAGR of 1.3 percent from 2006 to 2015. The 2016 summer peak forecast is 70,588 MW, and grows to 78,572 MW for 2026. This new peak load forecast is within about 1 percent of the one used for the *2015 LTRA*, and assumes higher growth in the near- and medium-terms, but lower growth in the out years (2023 and onward). These changes in peak load growth are due to updated economic assumptions as well as an out-of-model adjustment that adds 655 MW of load to ERCOT's coastal zone to account for the expected 2019 completion of the Freeport Liquefied Natural Gas plant.

ERCOT continues to rely on a variety of DR programs administered by both ERCOT and several transmission and distribution service providers (TDSPs) to support resource adequacy under emergency conditions. For Summer 2017, ERCOT estimates that it will have about 1,153 MW of load resources providing ancillary services that are contractually committed to ERCOT during summer peak hours. ERCOT also has emergency response service, a 10- and 30-minute DR and distributed generation service, designed to be deployed in the late stages of a grid emergency prior to shedding involuntary firm load. For the Summer 2016 peak hours, there are 859 MW of emergency response service contracted from 1:00 to 4:00 p.m. and 824 MW from 4:00 to 7:00 p.m. This is a six percent decrease over the same time period for Summer 2015. The most significant factor contributing to the change in participation from previous years was the U.S. Environmental Protection Agency's rule changes; these rule changes pertain to reciprocating internal combustion engines and their ability to participate in emergency DR programs. Additionally, this assessment accounts for individual TDSP contractual programs with loads that can respond to instructions to reduce total energy usage. These programs are expected to attract approximately 208 MW of additional DR capacity, and are subject to concurrent deployment with existing ERCOT DR programs, pursuant to agreements between ERCOT and the TDSPs. In aggregate, these DR programs represent 3.5 percent of the Texas RE-ERCOT Region's total internal demand forecast.

Regarding new generation resources, the Texas RE-ERCOT Region saw almost 700 MW of summer-rated capacity added since the *2015 LTRA*. The resource additions were dominated by wind (425 MW) and natural gas (216 MW), followed by utility-scale solar photovoltaic (72 MW). Notable new installed plants include the gas-fired Ector Country Energy Center (294 MW summer rating) and the OCI Alamo 5 solar project (95 MW nameplate, 76 MW summer rating). Additionally, there were 24 wind facilities that entered commercial service with a nameplate capacity of 3,072 MW. Notable new Tier 1 plant additions include the Colorado Bend gas combined-cycle facility (1,148 MW summer rating), Halyard Wharton Energy Center (gas peaking, 419 MW summer rating), Pinecrest G gas combined-cycle facility (785 MW summer rating), Indeck Wharton Energy Center (gas peaking, 654 MW summer rating), and Red Gate internal combustion plant (225 MW summer rating). The most significant cancelled Tier 1 project is Pondera King, an 882-MW combined-cycle plant planned for the Houston area.

ERCOT does not expect that any of the six currently mothballed units will return to active status. ERCOT recently entered into a two-year Reliability Must Run (RMR) contract with an announced mothballed unit called Greens Bayou Unit 5. This 374 MW gas-steam unit is located in the Houston area, and was determined by ERCOT to be needed during the summer months for transmission reliability. This contract currently extends to June 30, 2018, subject to ERCOT Board of Director approval.

With respect to transmission projects, the recently updated projects list includes the additions or upgrades of 3,954 miles of 138-kV and 345-kV transmission circuits, 24,159 MVA of 345/138-kV autotransformer capacity, and 3,005 MVAR of reactive capability projects that are planned in the Texas RE-ERCOT Region between 2016 and 2024. A new Houston Import Project, 130-mile 345 kV double circuit line (each circuit rated at 5000 Amps) from Limestone to Gibbons Creek to Zenith, is planned to be in service before the summer peak of 2018. The Houston area demand is met by generation located within the area and by importing power via high-voltage lines into the area from the rest of the ERCOT system. This new line will support anticipated long-term load growth in the Houston region. Power imports into the Houston area are expected to be constrained until the new import line is constructed.

In July 2014, the owners of the Frontera generation plant, a 524 MW natural gas facility located on the west side of the Lower Rio Grande Valley (LRGV), announced that they were planning to switch part of the facility (170 MW) out of the ERCOT market in 2015, and the entire facility would no longer be available to ERCOT starting in the fall of 2016. In June, 2016, the ERCOT Board of Directors endorsed the reliability need for two 300 MVAr SVCs located inside the LRGV to be in service prior to Summer 2021 to meet ERCOT and NERC reliability criteria for the LRGV. ERCOT also completed under-voltage assessment and observed potential under-voltage load shedding and slow voltage recovery at 2021 summer peak load conditions in the LRGV area. Transmission upgrades were identified for this region to support the voltage recovery and meet the NERC and ERCOT planning criteria by year 2021. The upgrades include two 300 MVAR Static VAR Compensators (SVCs) in the LGRV area. In June 2016, the ERCOT Board of Directors endorsed the reliability need for these two 300 MVAr SVCs.

The Texas Panhandle region is currently experiencing significantly more interest from wind generation developers than what was initially planned for the area. The ERCOT Panhandle grid is remote from synchronous generators and requires long distance power transfer to the load centers in the Texas RE-ERCOT Region. All wind generation projects in the Panhandle are expected to be equipped with advanced power electronic devices that will further weaken the system due to limited short-circuit current contributions. Stability challenges and weak system strength are expected to be significant constraints for Panhandle export. The ERCOT Transmission Planning Department has been performing ongoing analysis to assess reliability when incorporating all wind generation in the Panhandle that satisfy the requirements of ERCOT’s transmission planning process. The stability and system strength are evaluated to ensure that reliable operations can be maintained through proper implementation of Panhandle export limits.

In terms of long-term resource adequacy and reliability risks, the retirement of multiple coal-fired generating units during the assessment period due to federal environmental regulations and market economics remains the greatest known risk. A number of coal units in the Texas RE-ERCOT Region are at risk for retirement due to requirements to upgrade existing flue gas desulfurization (FGD) equipment or install new equipment under the EPA’s Texas Federal Implementation Plan (FIP) for regional haze. Under the Texas FIP, 12 coal-fired units in ERCOT (totaling about 8,500 MW) will require FGD investments either by February 2019 (for units requiring upgrades) or February 2021 (for units requiring new equipment). In June 2016, the U.S. Court of Appeals for the 5th Circuit placed a judicial stay on implementation of the EPA's rule, thereby likely postponing the need for the unit owners to invest in new scrubbers or scrubber upgrades. As a result, there is large uncertainty regarding if and when coal units are retired. Nevertheless, ERCOT’s transmission reliability study, conducted in the fall of 2015 to analyze the impacts of multiple coal unit retirement scenarios, indicated that local or regional transmission impacts (transmission and transformer overloads) would be expected for all scenarios. To address transmission issues caused by specific retiring units, ERCOT and its stakeholders would pursue necessary transmission infrastructure upgrades or other alternatives (such as installation of voltage control devices or interruptible load procurement) through ERCOT’s transmission planning and project review process.

WECC

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting BPS reliability in the Western Interconnection. WECC's 329 members, which include 38 BAs, represent a wide spectrum of organizations with an interest in the BPS. Serving an area of nearly 1.8 million square miles and approximately 82.2 million people, it is geographically the largest and most diverse of the NERC regional reliability organizations.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into five subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the BC, AB, and NWPP-US areas. These subregional divisions are used for this study as they are structured around Reserve Sharing groups that have similar annual demand patterns and similar operating practices.

Summary of Methods and Assumptions

Reference Margin Level
Determined by WECC's building block method for each subregion.

Load Forecast Method
Coincident for each subregion; normal weather (50/50)

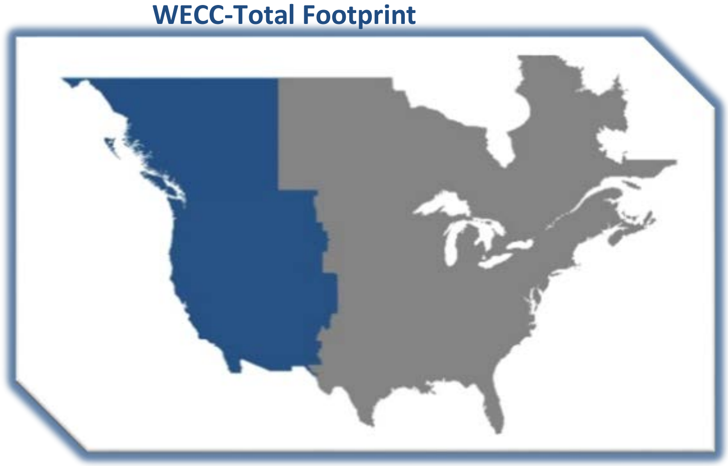
Peak Season
Summer: CA/MX, RMRG, SRSG, and NWPP-US
Winter: AB and BC

Planning Considerations for Wind Resources
Modeling, primarily based on up to five years of historic data

Planning Considerations for Solar Resources
Modeling, primarily based on up to five years of historic data

Footprint Changes
N/A

WECC-Total Footprint



WECC-AB Assessment Area Footprint

WECC-BC Assessment Area Footprint

WECC-CA/MX Assessment Area Footprint

WECC-NWPP-US Assessment Area Footprint

WECC-RMRG Assessment Area Footprint

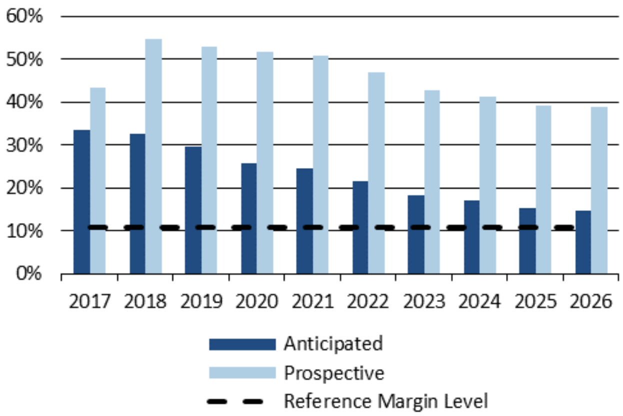
WECC-SRSG Assessment Area Footprint

WECC-AB

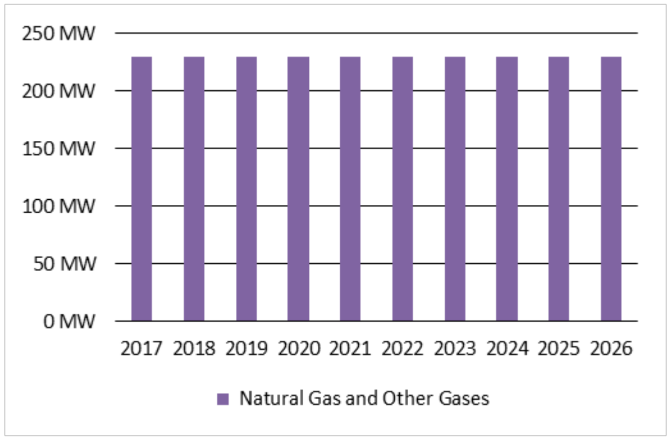
Peak Season Demand, Resources, Reserve Margins, and Shortfall [117]										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	-	-	-	12,942	13,198	13,460	13,705	13,910	14,114	14,304
Demand Response	-	-	-	0	0	0	0	0	0	0
Net Internal Demand	-	-	-	12,942	13,198	13,460	13,705	13,910	14,114	14,304
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	16,287	16,439	16,366	16,235	16,282	16,287	16,424
Prospective	-	-	-	19,648	19,902	19,788	19,565	19,643	19,648	19,878
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	33.56%	32.80%	29.62%	25.84%	24.56%	21.59%	18.46%	17.05%	15.39%	14.82%
Prospective	43.44%	54.86%	53.04%	51.81%	50.80%	47.01%	42.76%	41.22%	39.21%	38.97%
Reference Margin Level	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%	11.03%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

[117] Per WECC's request, data is not presented publically for Alberta and British Columbia subregions.

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-AB is a winter-peaking system that covers the province of Alberta Canada. For the probabilistic assessment, WECC utilized the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling**: Each Balancing Authority was modeled with import and export limits, consistent with the LTRA, based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's Generation Availability Data System (GADS). Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE; however, the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of near zero.
- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions whereas the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

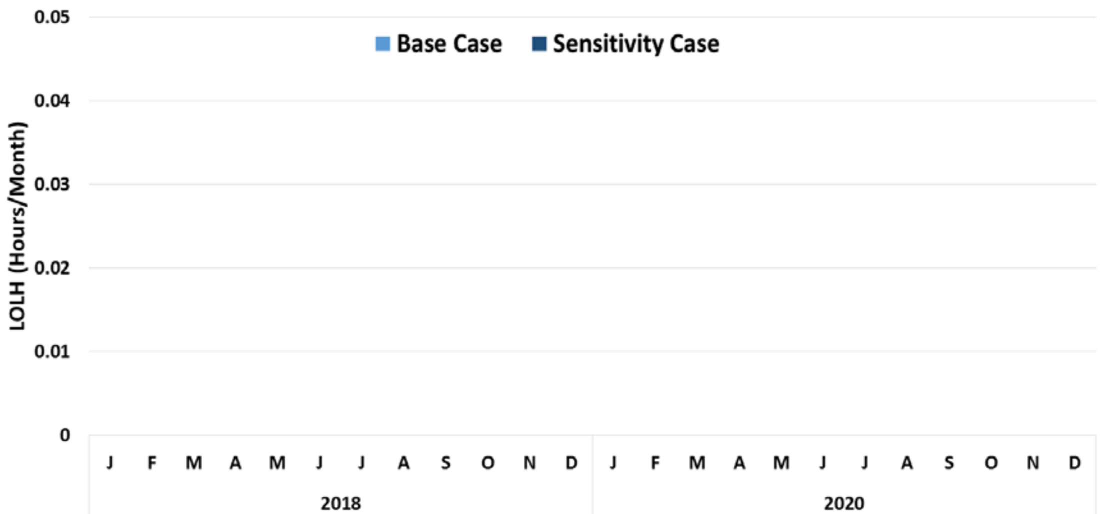
Base Case Study

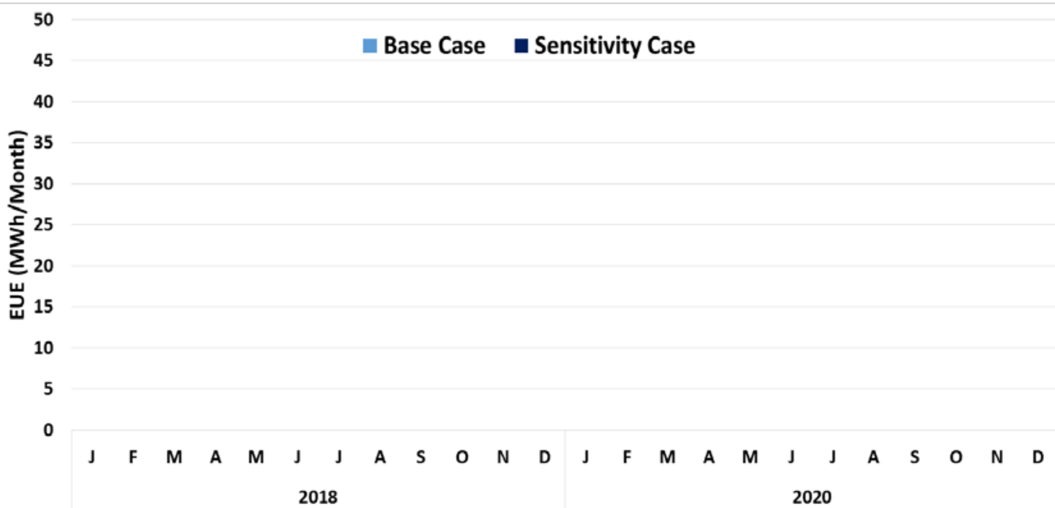
For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 33 percent and 29 percent for 2018 and 2020 respectively.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
Anticipated	33.6	29.6	-	-
Prospective	43.4	53.0	-	-
Reference	11.0	11.0	-	-
ProbA Forecast Planning	33.6	29.6	30.9	24.6
ProbA Forecast Operable	30.7	26.8	28.1	21.9
Annual Probabilistic Indices				
	Base Case		**Sensitivity Case**	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000



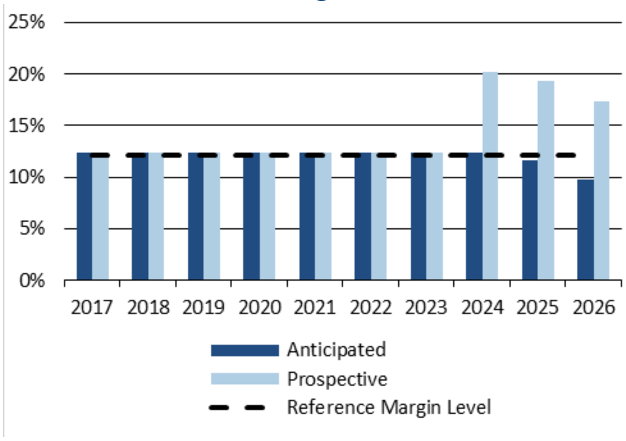


WECC-BC

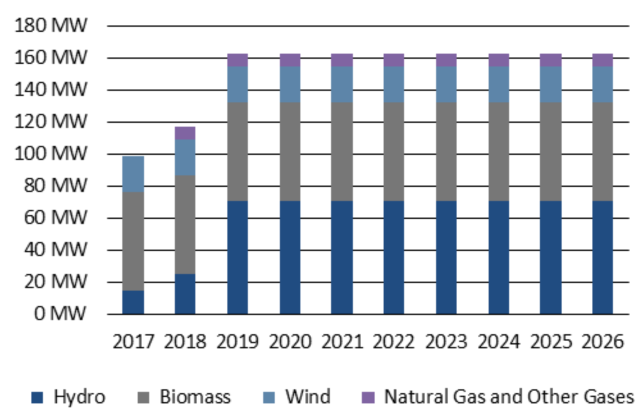
Peak Season Demand, Resources, Reserve Margins, and Shortfall [118]										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	-	-	-	12,140	12,242	12,401	12,524	12,690	12,853	13,040
Demand Response	-	-	-	0	0	0	0	0	0	0
Net Internal Demand	-	-	-	12,140	12,242	12,401	12,524	12,690	12,853	13,040
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	13,642	13,757	13,935	14,073	14,260	14,344	14,316
Prospective	-	-	-	13,642	13,757	13,935	14,073	15,250	15,334	15,306
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	12.39%	12.39%	12.38%	12.37%	12.38%	12.37%	12.37%	12.37%	11.60%	9.79%
Prospective	12.39%	12.39%	12.38%	12.37%	12.38%	12.37%	12.37%	20.17%	19.31%	17.38%
Reference Margin Level	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	64	302
Prospective	-	-	-	-	-	-	-	-	-	-

[118] Per WECC's request, data is not presented publically for Alberta and British Columbia subregions.

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-BC is a winter-peaking system that covers the province of British Columbia Canada. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling**: Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as demand distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.
- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

Base Case Study

For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 23% and 20% for 2018 and 2020 respectively.

Sensitivity Case Study

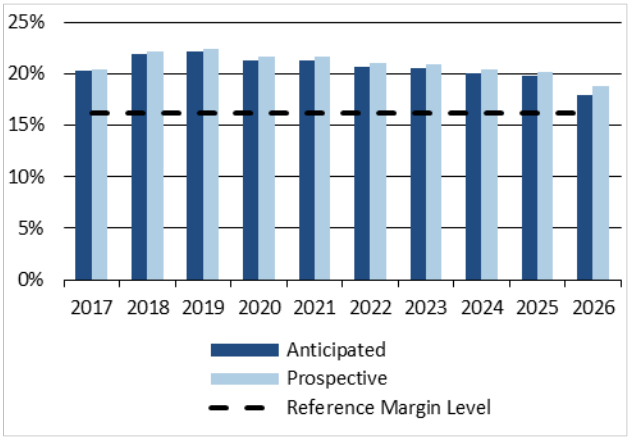
The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	12.4	12.4		
Prospective	12.4	12.4		
Reference	12.1	12.1		
ProbA Forecast Planning	23.5	20.0	21.1	15.4
ProbA Forecast Operable	20.7	17.3	18.4	12.8
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000

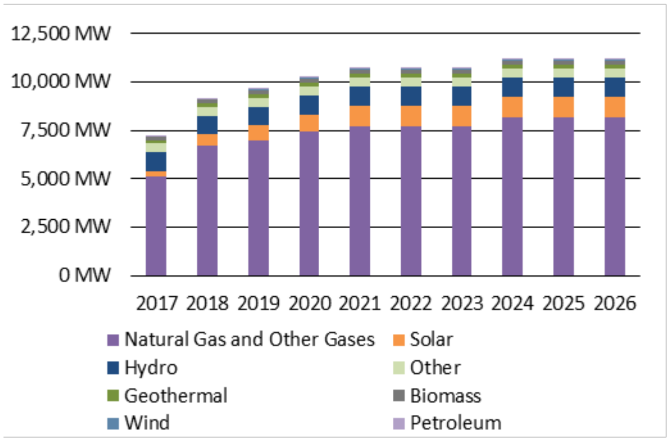
WECC-CA/MX

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	54,774	54,554	54,335	54,221	54,162	54,287	54,301	54,260	54,129	54,005
Demand Response	1,747	1,706	1,707	1,707	1,707	1,707	1,707	1,707	1,707	1,707
Net Internal Demand	53,027	52,848	52,628	52,514	52,455	52,580	52,594	52,553	52,422	52,298
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	63,765	64,428	64,261	63,711	63,626	63,441	63,364	63,068	62,796	61,639
Prospective	63,859	64,522	64,427	63,912	63,827	63,642	63,565	62,139	60,736	59,898
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	20.25%	21.91%	22.10%	21.32%	21.30%	20.66%	20.48%	20.01%	19.79%	17.86%
Prospective	20.43%	22.09%	22.42%	21.70%	21.68%	21.04%	20.86%	18.24%	15.86%	14.53%
Reference Margin Level	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%	16.16%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	157	851

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-CAMX is a summer-peaking system that covers the state of California and portions of Baja Mexico. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

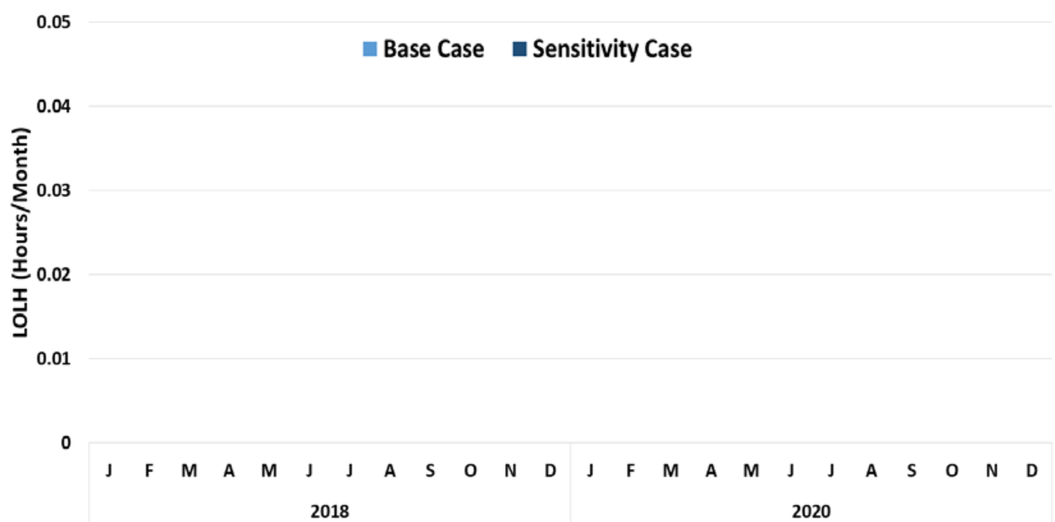
Base Case Study

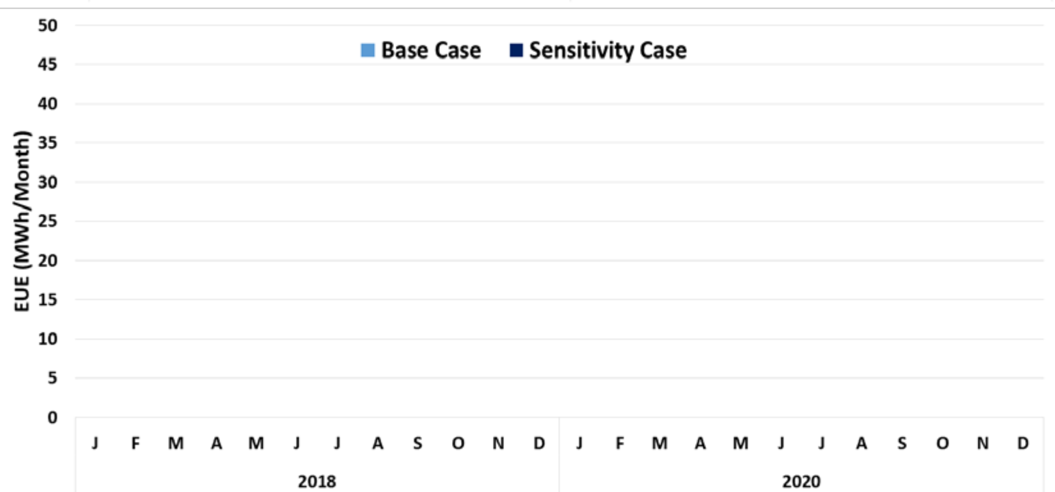
For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 32 percent and 36 percent for 2018 and 2020 respectively.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
Anticipated	21.9	21.3	-	-
Prospective	22.1	21.7	-	-
Reference	16.2	16.2	-	-
ProbA Forecast Planning	32.4	36.1	29.7	30.7
ProbA Forecast Operable	21.9	25.4	19.4	20.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	2020	2018	2020
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000

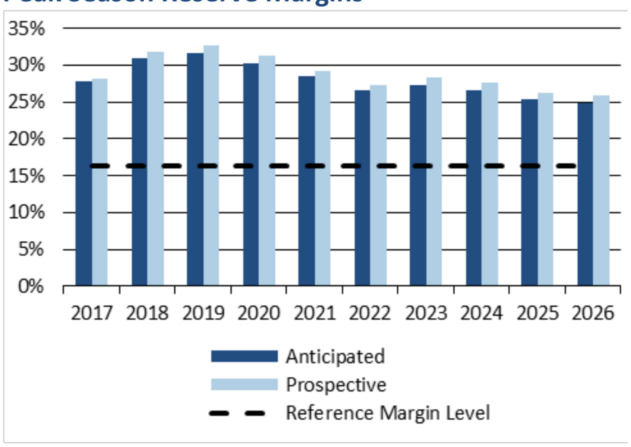




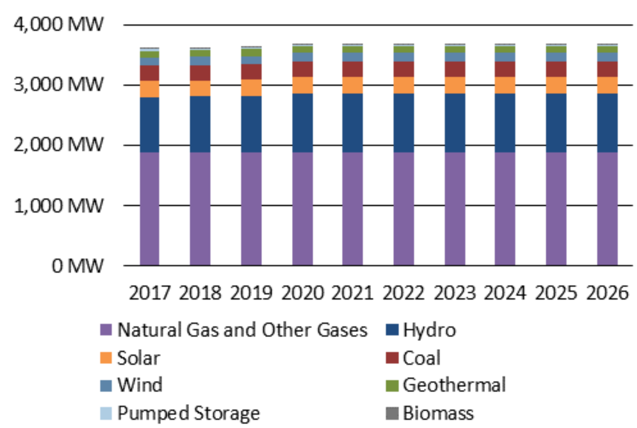
WECC-NWPP-US

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	50,013	50,438	50,851	51,319	51,693	52,119	52,479	52,869	53,439	53,294
Demand Response	1,219	1,186	1,196	1,195	1,195	1,193	1,213	1,189	1,187	1,193
Net Internal Demand	48,794	49,252	49,655	50,124	50,498	50,926	51,266	51,680	52,252	52,101
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	62,374	64,519	65,385	65,313	64,879	64,453	65,266	65,446	65,505	65,079
Prospective	62,568	64,913	65,927	65,811	65,288	64,819	65,792	65,987	66,003	65,562
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	27.83%	31.00%	31.68%	30.30%	28.48%	26.56%	27.31%	26.64%	25.36%	24.91%
Prospective	28.23%	31.80%	32.77%	31.30%	29.29%	27.28%	28.34%	27.68%	26.32%	25.84%
Reference Margin Level	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%	16.32%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-NWUS is a summer-peaking system that covers a triangle of states from Washington to Montana and down through Nevada. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

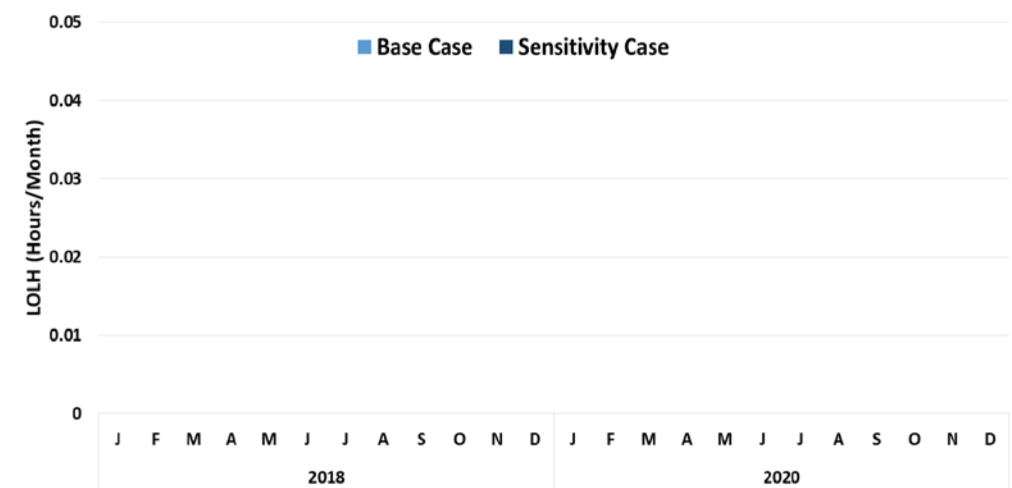
Base Case Study

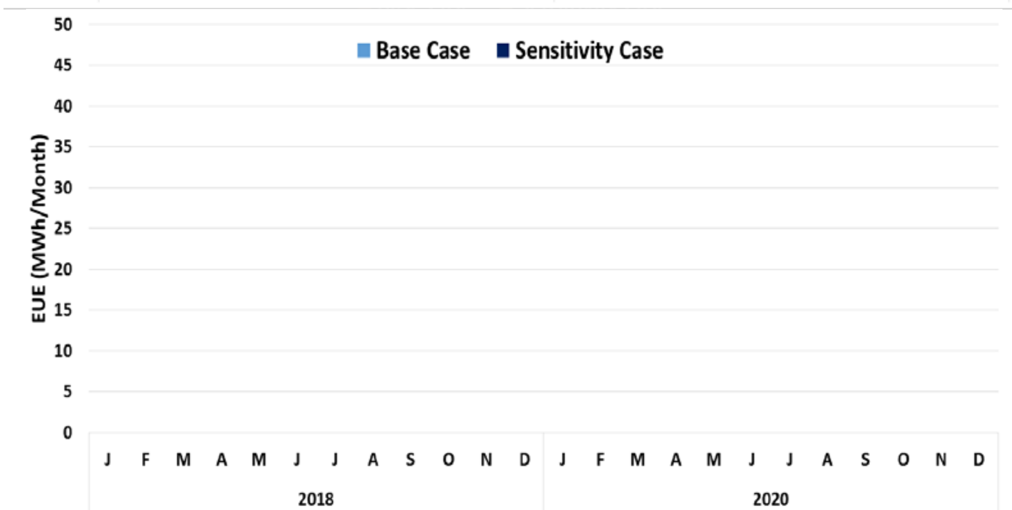
For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 41 percent and 37 percent for 2018 and 2020 respectively

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	31.0	30.3	-	-
Prospective	31.8	31.3	-	-
Reference	16.3	16.3	-	-
ProbA Forecast Planning	41.7	37.9	38.9	32.5
ProbA Forecast Operable	30.3	28.1	27.7	23.1
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000

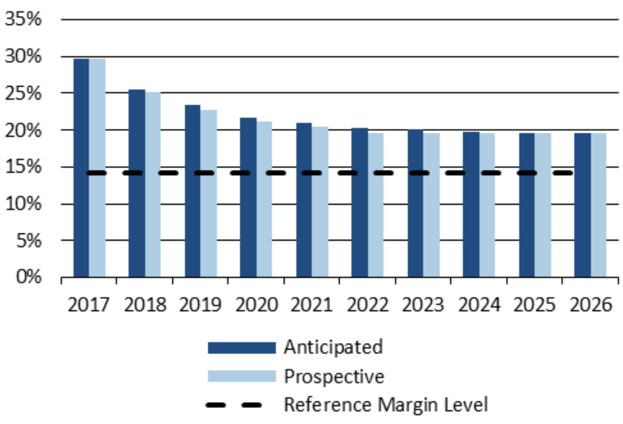




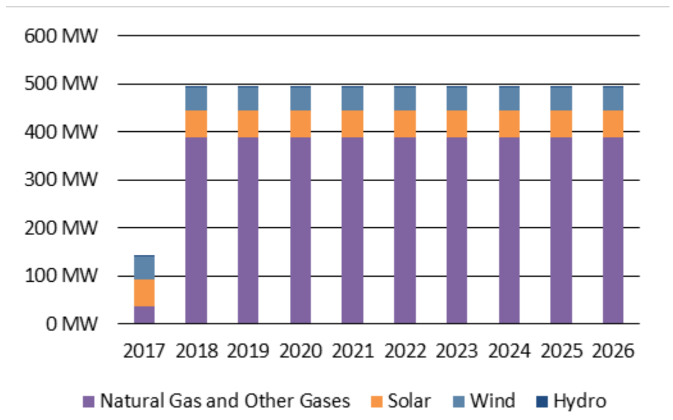
WECC-RMRG

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	12,392	12,530	12,759	12,947	13,194	13,375	13,552	13,739	13,910	14,094
Demand Response	545	562	581	603	609	615	620	626	631	635
Net Internal Demand	11,847	11,968	12,178	12,344	12,585	12,760	12,932	13,113	13,279	13,459
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	15,364	15,018	15,026	15,022	15,230	15,338	15,539	15,711	15,879	16,088
Prospective	15,364	14,975	14,945	14,951	15,159	15,270	15,472	15,685	15,879	16,088
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	29.68%	25.49%	23.39%	21.69%	21.02%	20.20%	20.16%	19.81%	19.58%	19.53%
Prospective	29.68%	25.13%	22.72%	21.12%	20.45%	19.67%	19.64%	19.61%	19.58%	19.53%
Reference Margin Level	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-RMRG is a summer peaking system that covers the states of Wyoming and Colorado. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.
- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.
- **Unit Modeling:** For base-load resources (nuclear, thermal, and geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.
- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

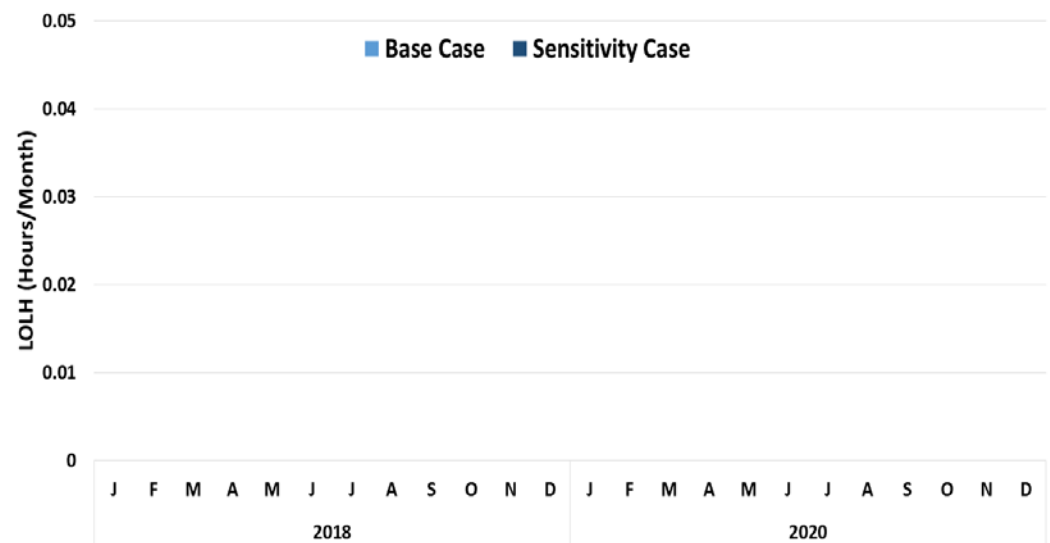
Base Case Study

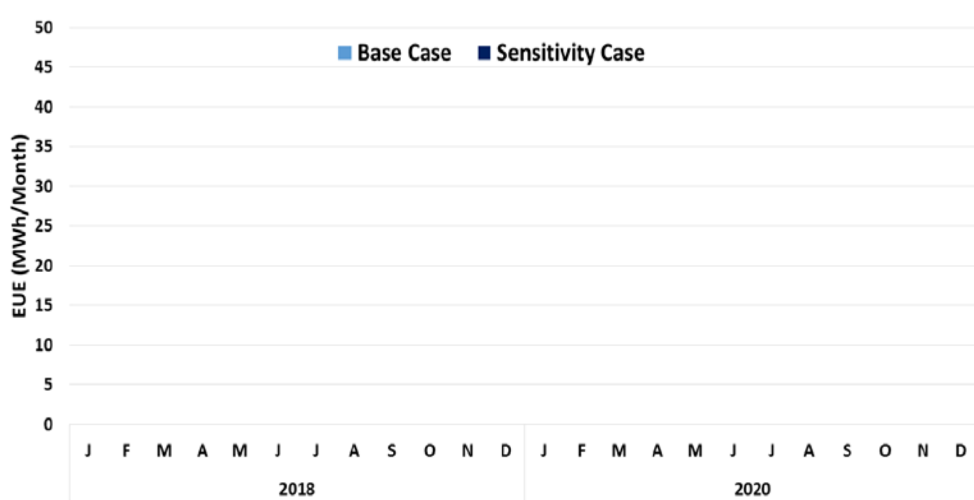
For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 39 percent and 34 percent for 2018 and 2020.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	25.5	21.7	-	-
Prospective	25.1	21.1	-	-
Reference	14.1	14.1	-	-
ProbA Forecast Planning	39.1	34.9	36.3	29.5
ProbA Forecast Operable	28.4	24.6	25.8	19.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000

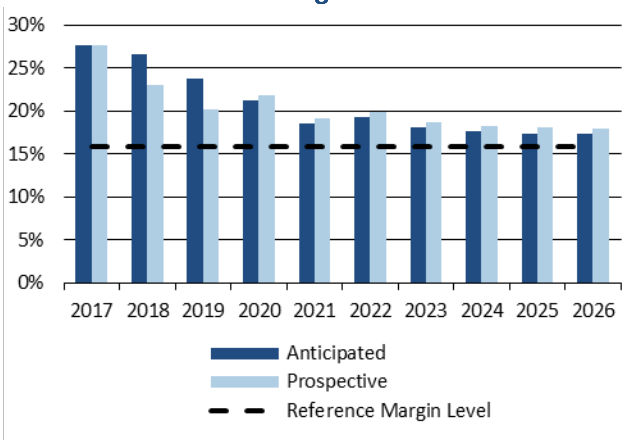




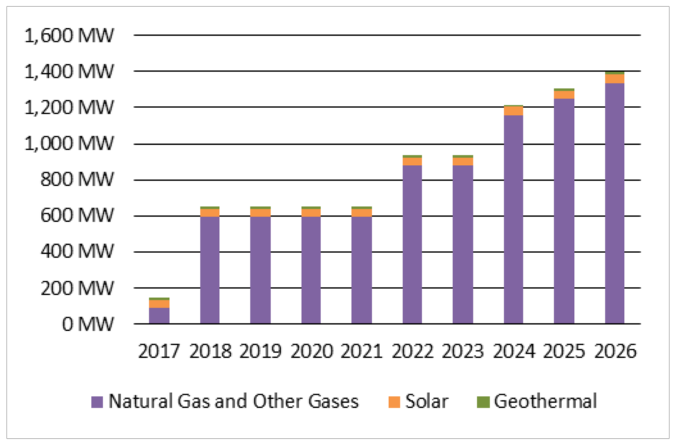
WECC-SRSG

Peak Season Demand, Resources, Reserve Margins, and Shortfall										
Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Internal Demand	23,207	23,534	24,023	24,479	24,978	25,319	25,766	26,211	26,871	27,424
Demand Response	420	359	363	355	355	355	355	355	355	355
Net Internal Demand	22,787	23,175	23,660	24,124	24,623	24,964	25,411	25,856	26,516	27,069
Resources (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	29,094	29,339	29,289	29,231	29,182	29,771	29,995	30,422	31,136	31,763
Prospective	29,095	28,504	28,454	29,395	29,346	29,936	30,160	30,586	31,300	31,927
Reserve Margins (%)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	27.68%	26.60%	23.79%	21.17%	18.52%	19.26%	18.04%	17.66%	17.42%	17.34%
Prospective	27.68%	22.99%	20.26%	21.85%	19.18%	19.92%	18.69%	18.29%	18.04%	17.95%
Reference Margin Level	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%	15.82%
Shortfall (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Anticipated	-	-	-	-	-	-	-	-	-	-
Prospective	-	-	-	-	-	-	-	-	-	-

Peak Season Reserve Margins



On-Peak Tier 1 Capacity Additions



Probabilistic Assessment Overview

- **General Overview:** WECC-SRSG is a summer peaking system that covers the states of New Mexico and Arizona and a portion of California. For the probabilistic assessment, WECC utilized the MAVRIC model. MAVRIC utilizes the convolution method of probabilistic studies. It is designed to study all possible subsets of probability distributions associated with demand, generation, and transmission to determine the extent of possible loss of load in each of the systems.

- **Transmission Modeling:** Each Balancing Authority was modeled with import and export limits consistent with the LTRA based on expected power flow transfers.

- **Unit Modeling:** For base-load resources (nuclear, thermal, geothermal), WECC utilized unit specific outage, planning, and maintenance outage rates within the probabilistic assessment that were based on 10 years of data from NERC's GADS. Seven years of historical hourly generation was utilized to develop availability probability distributions for renewable resources (hydro, wind, and solar) as well as Demand Distributions.

- **Results Trending:** The previous assessment showed slightly greater than zero LOLH and EUE however the results were insignificant and below the reporting threshold. This year's assessment reflected a decrease in expected demand as compared to previous assessments resulting in LOLH and EUE of zero.

- **Probabilistic vs. Deterministic Reserve Margin Results:** The probabilistic assessment reserve margins are based on the transfer capability between regions where as the LTRA deterministic reserve margins are based on transfers needed to maintain reference margins.

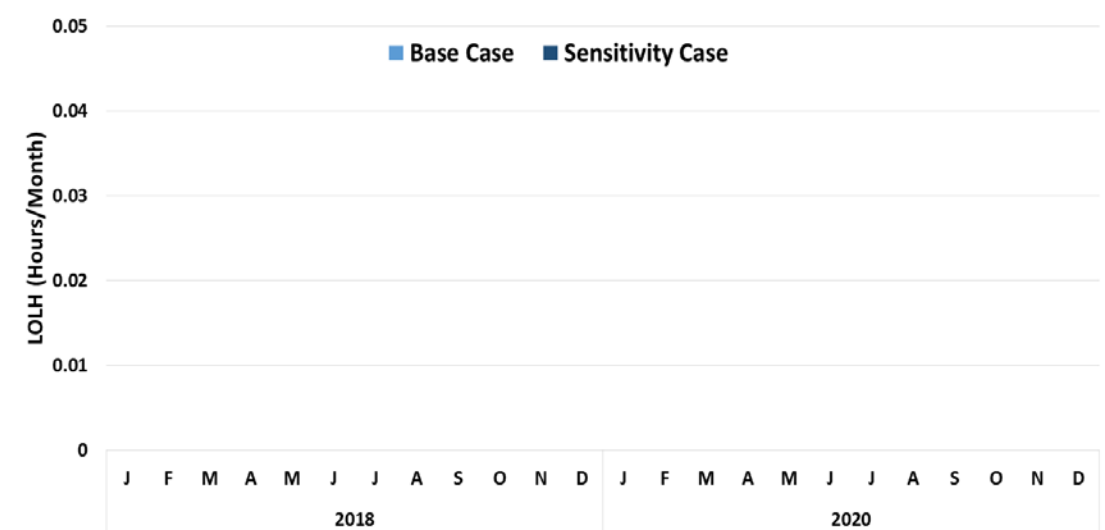
Base Case Study

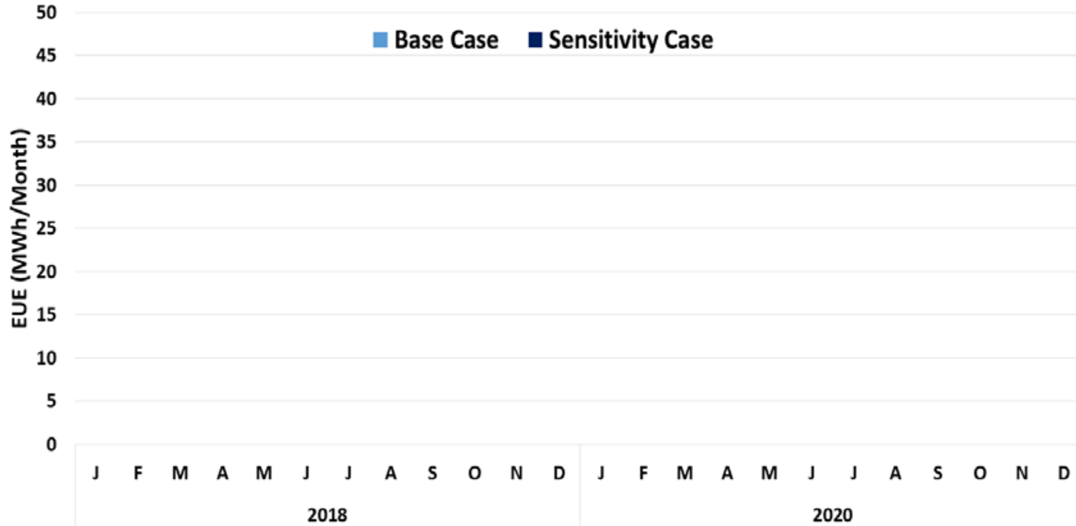
For the Base Case study, EUE and LOLH values were insignificant due to planning reserve margins exceeding 40 percent and 34 percent for 2018 and 2020 respectively.

Sensitivity Case Study

The EUE and LOLH remain nil for the Sensitivity Case.

Summary of Results				
Reserve Margin (RM) %				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
Anticipated	26.6	21.2	-	-
Prospective	23.0	21.9	-	-
Reference	15.8	15.8	-	-
ProbA Forecast Planning	40.3	34.2	37.5	29.0
ProbA Forecast Operable	37.5	29.0	26.3	18.5
Annual Probabilistic Indices				
	Base Case		Sensitivity Case	
	2018	**2020**	**2018**	**2020**
EUE (MWh)	0.000	0.000	0.000	0.000
EUE (ppm)	0.000	0.000	0.000	0.000
LOLH (hours/year)	0.000	0.000	0.000	0.000





Planning Reserve Margins

Throughout the ten-year assessment period, the NERC Reference Margins range between 11 and 17 percent for the subregions. The NERC Reference Margin Levels have not changed significantly compared to those reported in last year's assessment. The NERC Reference Margin Levels are calculated using a WECC building block methodology[119] created by WECC's Reliability Assessment Work Group (RAWG), for its annual Power Supply Assessment (PSA).[120] The elements of the building block margin calculation are consistent from year to year but the calculations can, and do, have slight annual variances by region and subregion.

By the summer of 2026, the difference between WECC's prospective resources (196,392 MW) and WECC's net internal demand (162,578 MW) is anticipated to be 33,814 MW (20.80 percent margin). As the expected resources in excess of net internal demand significantly exceed target margins, it is reasonable to assume that only a portion of the reported resource additions will ultimately enter commercial service within the planning horizon.

The planning reserve margins for the WECC subregions remain above NERC Reference Margin Level throughout the assessment period. Beginning in 2025, one area within the NW-Canada subregion indicates a margin dropping 66 MW below its Reference Margin due to scheduled maintenance and WECC's conservative reporting of hydro energy. The nominal deficit is of no particular concern as there are ample (over 600 MW) prospective resources planned to be installed and operating by that period.

In the resource adequacy process, each BA is responsible for complying with the requirements of the state or provincial areas in which they operate. Some BAs perform resource adequacy studies as part of their Integrated Resource Plans, which usually provide a 20-year outlook. Other BAs perform resource adequacy studies that focus on the very short term (i.e., one to two years), but most projections provide at least a 10-year outlook. WECC's PSA uses a study period of 10 years and the same zonal reserve target margins throughout the entire period.

Similar to WECC's PSA, resources that are energy-only or energy-limited (e.g., the portion of wind resources that is not projected to provide generation at the time of peak) are not counted toward meeting resource adequacy in this assessment. Also, resources such as distributed or behind-the-meter generators that are not monitored by the BA's energy management systems are excluded from the resource adequacy calculation.

[119] Elements of the Building Block Target are detailed in the NERC: Long-Term Assessment – Methods and Assumptions report.
[120] WECC's Power Supply Assessments.

Demand

Total internal demand for the summer, the peak season for the entire WECC Region, increased by 2.5 percent from 147,466 MW in 2014 to 150,830 MW in 2015, mostly due to high temperatures early in the summer season. Peak demand is forecast to increase at less than 1.0 percent per year from 2017 through 2026; this is lower than last year's 10-year compound load growth forecast of 1.1 percent. The annual energy load is projected to increase by less than 1.0 percent per year for the 2017–2026 time period, which is lower than the 1.2 percent projected last year for the 2016–2025 period.

Of interest is the negative demand growth forecasted for the CA/MX subregion due to anticipated increases in rooftop solar installations and a continued focus on energy conservation. Also of note is the more than 2,000 MW reduction in demand forecast for 2026 (2016 compared to 2015) in the NW-Canada subregion, associated with the expected decrease in oil extraction in the tar-sands region of Alberta.

Demand-Side Management

The WECC total internal demand forecast includes summer DR that varies from 4,102 MW in 2017 to 3,993 MW in 2026. The direct control DSM capability is located mostly in the California/Mexico subregion, totaling 1,772 MW in 2017 and decreasing to 1,731 MW in 2026. The most prevalent DR programs in WECC involve air-conditioner cycling as well as interruptible load programs that focus on the demand of large water pumping operations and large industrial operations (e.g., irrigation and mining). Currently, the most significant DR development activity within WECC is taking place in California; the California ISO (CAISO) is actively engaged with stakeholders in developing viable wholesale DR products with direct market participation capability. Also of note is CAISO's DR product implementation that facilitates the participation of existing retail demand programs in the CAISO market. Further information regarding these initiatives is available on CAISO's website.[121]

Overall DR program growth has been rather static and is expected to remain fairly constant over the 10-year planning horizon. The various DSM programs within WECC are treated as load modifiers that reduce total internal demand when calculating planning margins. In some situations, these programs may be activated by load-serving entities during high-power cost periods, but in general are only activated during periods in which local power supply issues arise. Generally, DR programs in WECC have limitations, such as having a limited number of times they can be activated.[122]

Generation

All of the balancing authorities within the Western Interconnection provided the generation data for this assessment, and WECC staff processed the data. The reported generation additions generally reflect extractions from generation queues.

DERs, including rooftop solar and behind-the-meter generation, currently represent a very small portion of existing resources. As the load served by these resources is not included in the actual or forecast peak demands and energy loads, these resources are excluded from the resource adequacy calculation. Unseen generation could begin to have impacts on the reliably operation of the interconnection as the amount of rooftop solar and other behind-the-meter generation increases. For example, rooftop solar installations in the CA/MX subregion are projected to grow substantially during the assessment period. It is projected that by 2026 there could be well over 11,000 MW of rooftop solar installed in that subregion alone, up from the current total of nearly 4,000 MW.

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121 California ISO Demand Response Initiatives.

122 NERC's assessment process assumes that demand response may be shared among load serving entities, balancing authorities, and subregions. However, DSM sharing is not a contractual arrangement. Consequently, reserve margins may be overstated as they do not reflect demand response that could potentially be unavailable to respond to external energy emergencies. Energy efficiency and conservation programs vary by location and are generally offered by the load serving entities. The reduction to demand associated with these programs is reflected in the load forecasts supplied by the balancing authorities.

A few utilities attributed planned and actual coal-fired plant retirements and fuel conversions to existing air emissions regulations. Based on news media accounts and information related to western coal-fired plant environmental regulation cost exposure, it is expected that future LTRA information will report additional retirements and fuel conversions as more plant owners establish their preferred approaches for addressing emission regulations. California regulations essentially specify that existing long-term contracts with coal-fired plants will be allowed to run to expiration though not renewed.[123] This regulation may result in the sale, retirement, or repowering of some power plants during the assessment period. Due to the somewhat fluid situation in California regarding retirements associated with once-through cooling (OTC) regulations, potential associated capacity reductions have not necessarily been reported for this year's LTRA for all potentially affected plants. Current information regarding the California OTC is available on the California Energy Commission's website.[124] It is expected that any future capacity reductions will be offset by new plants that may or may not be reflected in the current generation queue data.

The existing-certain and anticipated resources projected for the 2017 summer peak period total 202,567 MW and reflect the monthly shaping of variable generation and the seasonal ratings of conventional resources. The expected capacity modeling for wind and solar resources are based on curves created using at least five years of actual generation data. Hydro generation is dispatched economically, limited by expected annual energy generated during an adverse hydro year. Biomass and geothermal capabilities are based on nominal plant ratings.

Greater wind and solar generation has resulted in an increased fluctuation in intermittent generation and a need for increased operating reserves to compensate for the wind-induced fluctuations. Improved wind forecasting procedures and reduced scheduling intervals have only partially addressed the wind variability issue. Increased wind generation has also exacerbated high generation issues in the Bonneville Power Administration (BPA) area during light load and high hydroelectric generation conditions; BPA provides current information regarding the issue on its website.[125]

A short-term concern that could affect generation in the Los Angeles basin in southern California is the outage of the Aliso Canyon natural gas storage facility. This facility helps to supply fuel to approximately 10,000 MW of generation in and around the Los Angeles basin. The Los Angeles Department of Water and Power, the California ISO, and SoCal Gas are developing short-term procedures to mitigate impacts to the power grid that could be caused by the Aliso Canyon outage. More information can be found in the Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin.[126]

Capacity Transfers

WECC does not rely on imports from outside the Region when calculating peak demand reliability margins. The Region also does not model exports to areas outside of WECC. However, imports may be scheduled across three back-to-back dc ties with SPP and five back-to-back dc ties with the MRO.

Inter-subregional transfers are derived from resource allocation computer simulations that incorporate transmission constraints among various path-constrained zones within WECC.[127] The WECC resource allocation model places conservative transmission limits on paths between 19 load groupings (zones) when calculating the transfers between these areas. These load zones were developed for WECC's PSA studies. The aggregation of PSA load zones into WECC subregions may obscure differences in adequacy or deliverability between zones within the subregion.

[123] CEC Emission Performance Standards.
[124] CEC Once-Through Cooling, and February 2016 Status.
[125] BPA Oversupply Management Protocol.
[126] CAISO: Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin
[127] WECC reports feasible transfers, not contracted transfers. This is done to eliminate double counting of resources. This treatment is different from the other NERC Assessment Areas.

The resource data for the individual subregions includes transfers between subregions that either are plant-contingent transfers or reflect projected transfers with a high probability of occurrence. Plant-contingent transfers represent both joint plant ownership and plant-specific transfers from one subregion to another. Projected transfers reflect the potential use of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest as well as other economy and short-term purchases that may occur between subregions. Transfers that are supplied by existing and Tier 1 resources are classified as firm transfers while transfers from Tier 2 and Tier 3 resources are classified as expected transfers.

While these transactions may not be contracted, they reflect a reasonable modeling expectation given the history and extensive activity of the western markets as well as the otherwise underused transmission from the Northwest to the other subregions. When examining all Adjusted-Potential Resources, all subregions maintain adequate reserves (above respective targets) throughout the assessment period.

Transmission and System Enhancements

WECC is spread over a wide geographic area with significant distances between generation and load centers. In addition, the northern portion of the assessment area is winter-peaking while the southern portion of the assessment area is summer-peaking. Consequently, entities within the Western Interconnection may seasonally exchange significant amounts of surplus electric energy. These conditions result in periodic full utilization of numerous transmission lines that does not adversely impact reliability. Due to the inter-subregional transmission constraints, reliability in the Western Interconnection is best examined at a subregional level.

To help monitor the impact of new generation resources on the transmission systems, individual entities within the Western Interconnection have established generator interconnection requirements that include power flow and stability studies to identify any adverse impact from proposed projects. In addition, WECC has established a review procedure that is applied to larger transmission projects that may impact the interconnected system. The details of this review procedure are located in WECC's Project Coordination and Path Rating Processes.[128] These processes identify potential deliverability issues that may result in actions such as the implementation of system protection schemes designed to enhance deliverability and to mitigate possible adverse power system conditions.

The power transfer capabilities of most major subregion transmission interconnections within WECC are limited by system stability constraints rather than by thermal limitations. These stability constraints are sensitive to system conditions and may often be increased significantly at nominal cost by applying special protection systems (SPSs) or Remedial Action Schemes (RASs). In addition, transmission operators may install SPSs or RASs to address localized transmission overloads related to single- and multiple-contingency transmission outages. The future use of such relatively inexpensive schemes in lieu of costly transmission facility additions—whether they will be permanent or temporary additions—will depend on not yet determined system conditions.

Load-serving entities within WECC are rapidly expanding the use of smart meters and the associated interface equipment. The impacts of such facilities relative to power system reliability have not yet been quantified. Area entities are also taking steps to install and interface with equipment that may morph into full-fledged smart grid installations. The pace and extent of such changes is presently unknown. CAISO's website presents its smart grid initiatives; these are typical of activities within the assessment area.[129]

Long-Term Reliability Issues

WECC continues to track and study the impacts on reliability and other issues associated with the retirement of large thermal generating units in response to higher air emission and water quality standards. Associated with the retirement of large coal generating units is the increased demand on natural gas supply and transportation;

[128] WECC's Project Coordination, Path Rating, and Progress Report Processes.
[129] CAISO Smart Grid Roadmap

natural gas has become the primary fuel for new thermal generation. WECC is working with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.

The CA/MX subregion is seeing a large increase in distributed resources. There is currently about 4,300 MW of rooftop solar installed in the Western Interconnection, with about 4,000 MW of that total installed in the CA/MX subregion. By 2026 that total is expected to increase to over 12,000 MW in the interconnection with over 11,000 MW installed in the CA/MX subregion. Although current operations indicate rooftop solar has not been a reliability issue, it is an issue that WECC and the CAISO are tracking was rooftop solar becomes a larger component of electric demand.

A joint NERC/CAISO study addresses some potential operational impacts from higher levels of variable resources (e.g., ancillary services for ramp rates). WECC studies to date have not identified significant issues relative to inertia and frequency response, but at some as yet unidentified penetration level, inertia and frequency response may become an issue. WECC continues to work with entities within the Interconnection to identify and study reliability concerns associated with the increasing levels of variable generation, including behind-the-meter rooftop solar facilities.

Retirement of Diablo Canyon Nuclear Generating Station

In June 2016, Pacific Gas and Electric (PG&E) announced plans to retire the 2,300 MW Diablo Canyon Nuclear facility, located in northern California. The first reactor is set to be retired by November of 2024, and the second reactor by August of 2025. PG&E indicates it will use the 9-year transition period to replace the generation with new greenhouse gas-free energy. The new energy supply options include energy efficiency, renewable power, and electric storage.

Western Reliability Summit

WECC, as the Regional Entity responsible for assuring the electric reliability in the Western Interconnection, hosted the first Western Reliability Summit. The two day summit, held on May 17–18, focused primarily on three reliability based topics: high reliability organizations, changing resources, and keeping pace with change. The summit was a unique opportunity to discuss thoughts and concerns about electric reliability challenges the Western Interconnection may face in coming years. WECC intends to hold similar summits that are focused on evolving reliability topics in the future.

Appendix I: Reliability Assessment Glossary

Term	Definition
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice (Source: NERC Glossary of Terms)
Anticipated Resources	Includes Existing-Certain Capacity, Net Firm Transfers (Imports – Exports), and Tier 1 Capacity Additions.
Anticipated Reserve Margin	Anticipated Resources minus Net Internal Demand, divided by Net Internal Demand, shown as a percentile.
Assessment Area	Based on existing ISO/RTO footprints; otherwise, based on individual Planning Coordinator or group of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated.
Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. (Source: NERC Glossary of Terms)
Bulk Electric System	See NERC Glossary of Terms
Bulk-Power System	A) Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
Capacity Transfers (Transactions)	There are three types of capacity transfers (transactions): Firm: “Firm” transfers that require the execution of a contract that is in effect during the projected peak. The net of all Firm transfers (imports minus exports) are applied towards Anticipated Resources. Modeled: transfers that are applicable for assessment areas that model potential feasible transfers (imports/exports). While these transfers do not have Firm contracts, modeling of the existing transmission, including transfer capability, has been executed to verify these transfers can occur during the peak season. The net of all Modeled transfers (imports minus exports) are applied towards Anticipated Resources. Expected: transfers without the execution of a Firm contract, but with a high expectation that a Firm contract will be executed in the future and will be in effect during the projected peak. The net of all Modeled transfers (imports minus exports) are applied towards prospective resources.
Conservation (Energy Conservation)	A reduction in energy consumption that corresponds with a reduction in service demand. Service demand can include buildings-sector end uses such as lighting, refrigeration, and heating; industrial processes; or vehicle transportation. Unlike energy efficiency, which is typically a technological measure, conservation is better associated with behavior. Examples of conservation include adjusting the thermostat to reduce the output of a heating unit, using occupancy sensors that turn off lights or appliances, and car-pooling. (Source: DOE-EIA)
Critical Peak-Pricing (CPP) with Load Control	Price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours. Critical Peak Pricing (CPP) with Direct Load Control combines Direct Load Control with a pre-specified high price for use during designated critical peak periods triggered by system contingencies or high wholesale market prices. Subset of Controllable and Dispatchable Demand Response. Dispatchable and Controllable Demand-Side Management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.
Curtailment	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction. (Source: NERC Glossary of Terms)
Demand	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

	2. The rate at which energy is being used by the customer.
Demand Response	Changes in electric use by Demand-Side resources from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when required to maintain system reliability. Demand Response can be counted in resource adequacy studies either as a load-modifier, or as a resource. Controllable and Dispatchable Demand Response requires the System Operator to have physical command of the resources (Controllable) or be able to activate it based on instruction from a control center. Controllable and Dispatchable Demand Response includes four categories: Critical Peak Pricing (CPP) with Load Control; Direct Control Load Management (dcLM); Load as a Capacity Resource (LCR); and Interruptible Load (IL).
Demand-Side Management	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand. (Source: NERC Glossary of Terms)
Derate	The amount of capacity that is expected to be unavailable during the seasonal peak.
Designated Network Resource	Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis, except for purposes of fulfilling obligations under a Commission-approved reserve sharing program.
Distributed Energy Resources (DERs)	Distributed energy resources (DERs) are smaller power sources that can be aggregated to provide power necessary to meet regular demand. As the electricity grid continues to modernize, DERs such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid. (Source: EPRI)
Distributed Generation	See *Distributed Energy Resources*
Energy Efficiency	Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVac) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems. Results in permanent changes to electricity use by replacement of end-use devices with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions. (Source: DOE-EIA)
Estimated Diversity	The electric utility system's load is made up of many individual loads that make demands on the system, with peaks occurring at different times throughout the day. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.
Existing-Certain Capacity	Included in this category are existing generator units (expressed in MW), or portions of existing generator units, that are physically located within the assessment area that meet at least one of the following requirements when examining the projected peak for the summer and winter of each year: (1) unit must have a Firm capability (defined as the commitment of generation service to a customer under a contractual agreement to which the parties to the service anticipate no planned interruption (applies to generation and transmission), a Power Purchase Agreement (PPA), and Firm transmission; (2) unit must be classified as a Designated Network Resource; (3) where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
Disturbance	An unplanned event that produces an abnormal system condition; any perturbation to the electric system, or the unexpected change in ACE that is caused by the sudden failure of generation or interruption of load. (Source: NERC Glossary of Terms)
Existing-Other Capacity	Included in this category are existing generator units, or portions of existing generator units, that are physically located within the assessment area that do not qualify as Existing-Certain when examining the projected peak for the summer and winter of each year. Accordingly, these are the units, or portions of units, may not be available to serve peak demand for each season/year.

Energy-Only	Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area. Designated energy –only resources do not have capacity rights.
Expected Unserved Energy (EUE)	This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. Additionally, this measure can be normalized based on various components of an assessment area (i.e., total of peak demand, Net Energy for Load, etc.). Normalizing the EUE provides a measure relative to the size of a given assessment area. One example of calculating a Normalized EUE is defined as [(Expected Unserved Energy) / (Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.
Firm (Transmission Service)	The highest quality (priority) service offered to customers under a fixed rate schedule that anticipates no planned interruption. (Source: NERC Glossary of Terms)
Forced Outage	The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. Also, the condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)
Frequency Regulation	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control. (NERC Glossary of Terms)
Frequency Response	Equipment: The ability of a system or elements of the system to react or respond to a change in system frequency. System: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). (Source: NERC Glossary of Terms)
Expected (Provisional) Capacity Transfers	Future transfers that do not currently have a Firm contract, but there is a reasonable expectation that a Firm contract will be signed. These transfers are included in the Prospective Resources.
Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services. (NERC Glossary of Terms)
Generator Owner	Entity that owns and maintains generating units. (NERC Glossary of Terms)
Independent Power Producer	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity. (NERC Glossary of Terms)
Interconnection	When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Québec. (NERC Glossary of Terms)
Interruptible Load or Interruptible Demand	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (NERC Glossary of Terms)
Load	An end-use device or customer that receives power from the electric system. (NERC Glossary of Terms)
Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers. (NERC Glossary of Terms)
Loss of Load Probability (LOLP)	This is defined as the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. The probability can be calculated either using only the daily peak loads (or daily peak variation curve) or all the hourly loads (or the load duration curve) in a given study period.
Loss of Load Expectation (LOLE)	This 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 classic 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 load demand (instead of the daily peak load) at least once during that day.
Loss of Load Hour (LOLH)	This is generally defined as the expected number of hours per 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) instead of using only the daily peak in the classic LOLE

	calculation. To distinguish this expected value from the classic calculation, the hourly LOLE is often called LOLH. It must be noted that the classic LOLE in days per year is not interchangeable with the LOLH in hours per year (i.e., LOLE of 0.1 days per year is not equivalent to a LOLH of 2.4 hours per year.) Unlike the classic LOLE metric, there is currently no generally acceptable LOLH criterion.
Net Energy for Load (NEL)	The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amount of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred in the transmission and distribution. (Source: FERC-714)
	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities. (NERC Glossary of Terms)
Net Load	The difference between actual or forecasted load and actual or expected electricity production from variable generation resources.
Net Internal Demand	Total Internal Demand reduced by dispatchable and controllable Demand Response. (NERC Glossary of Terms)
Nonfirm Transmission Service	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption. (NERC Glossary of Terms)
Nonspinning Reserves	The portion of Operating Reserve consisting of (1) generating reserve not connected to the system but capable of serving demand within a specified time; or (2) interruptible load that can be removed from the system in a specified time.(NERC Glossary of Terms)
Off-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (NERC Glossary of Terms)
On-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand. (NERC Glossary of Terms)
Open Access Same Time Information Service	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously. (NERC Glossary of Terms)
Open Access Transmission Tariff	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with nondiscriminating service comparable to that provided by Transmission Owners to themselves. (NERC Glossary of Terms)
Operating Reserves	The capability above Firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and nonspinning reserve.
Planning Coordinator (Planning Authority)	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. (NERC Glossary of Terms)
Planning Reserve Margins	Anticipated Reserve Margin: Anticipated Resources, less Net Internal Demand, divided by Net Internal Demand. Prospective Reserve Margin: prospective resources, less Net Internal Demand, divided by Net Internal Demand. Adjusted-Potential Reserve Margin: Adjusted-Potential Resources, less Net Internal Demand, divided by Net Internal Demand.
Peak Demand	The highest hourly integrated Net Energy For Load (or highest instantaneous demand) within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). (NERC Glossary of Terms)
Power Purchase Agreement	Guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner.
Prospective Capacity Resources	Anticipated resources plus existing-other capacity plus Tier 2 Capacity plus net Expected transfers.
Prospective Capacity Reserve Margin	Prospective capacity resources minus net internal demand shown divided by net internal demand, shown as a percentile.

Ramp Rate (Ramp)	Schedule: the rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. Generator: the rate, expressed in megawatts per minute, that a generator changes its output. (NERC Glossary of Terms)
Rating	The operational limits of a transmission system element under a set of specified conditions. (NERC Glossary of Terms)
Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (Kvar) or megavars (MVar). (NERC Glossary of Terms)
Real Power	The portion of electricity that supplies energy to the load. (NERC Glossary of Terms)
Reference Margin Level	This metric is typically based on the load, generation, and transmission characteristics for each assessment area. In some cases, it is a requirement implemented by the respective state(s), provincial authority, ISO/RTO, or other regulatory body. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level may fluctuate for each season of the assessment period. If a Reference Margin Level is not provided by an assessment area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.
Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. (NERC Glossary of Terms)
Renewable Energy (Renewables	Energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource. (Source: DOE-EIA)
Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group. (Source: NERC Glossary of Terms)
Stand-by Load under Contract	Demand which is normally served by behind-the-meter generation, which has a contract to provide power if the generator becomes unavailable.
Spinning Reserves	Unloaded generation that is synchronized and ready to serve additional demand.(NERC Glossary of Terms)
Time-of-Use (TOU)	Rate and/or price structures with different unit prices for use during different blocks of time. Time-Sensitive Pricing (Nondispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost or peak periods.
Total Internal Demand	Projected sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Total Internal Demand should be reduced by indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all nondispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs). Adjustments for controllable Demand Response should not be included in this value.

	The demand of a metered system, which includes the Firm demand, plus any Controllable and Dispatchable DSM load and the load due to the energy losses incurred within the boundary of the metered system. (Source: NERC Glossary of Terms)
Transmission-Limited Resources	The amount of transmission-limited generation resources that have deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates takes precedence.
Uncertainty	The magnitude and timing of variable generation output is less predictable than for conventional generation.
Variable Energy Resources	Resources with output that are highly variable subject to weather fluctuations such as wind speed and cloud cover.
Variability	The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.

Appendix II: Assessment Preparation, Design, and Data Concepts

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Assessment Data Questions

Direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the NERC *2016 LTRA*. However, extensive reproduction of tables and/or charts will require permission from NERC staff.

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Assessment Preparation and Design

The *2016 Long-Term Reliability Assessment* (*2016 LTRA*) is based on resource adequacy[130] information collected from the eight Regional Entities (Regions) that is used to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks. The LTRA is developed annually by NERC in accordance with the ERO's Rules of Procedure,[131] as well as Title 18, § 39.11[132] of the Code of Federal Regulations,[133] also referred to as Section 215 of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[134]

This assessment is based on data and information collected by NERC from the Regions on an assessment area basis as of September 2016. The Reliability Assessment Subcommittee (RAS), at the direction of the Planning Committee (PC), supports the LTRA development. Specifically, NERC and the RAS perform a thorough peer review that leverages the knowledge and experience of industry subject matter experts while providing a balance to ensure the validity of data and information provided by the Regions. Each assessment area section is peer reviewed by members from other Regions to achieve a comprehensive review that is verified by the RAS in open meetings. The review process ensures the accuracy and completeness of the data and information provided by each Region. This assessment has been reviewed and accepted by the PC. The NERC Board of Trustees also reviewed and approved this report.

The *2016 LTRA* reference case does not reflect impacts that may result from the D.C. Circuit Court's mandate to vacate FERC Order No. 745,[135] nor the impacts that may arise from the EPA's CPP (Clean Air Act–Section 111(d)). While NERC provides a summary of the EPA's CPP, quantitative impacts from these developments will be considered for inclusion in future NERC assessments.

Data Concepts and Assumptions Guide

This section explains data concepts and important assumptions used throughout this assessment.

General Assumptions
The Reserve Margin calculation is an important industry planning metric used to examine future resource adequacy. This deterministic approach examines the forecast peak demand (load) and projected availability of resources to serve the forecast peak demand for the summer and winter of the 10-year outlook (2017–26).
All data in this assessment are based on existing federal, state, and provincial laws and regulations.
Demand Assumptions
Electricity demand projections, or load forecasts, are provided by each assessment area.
Load forecasts include peak hourly load,[136] or total internal demand, for the summer and winter of each year.[137]

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

131 NERC Rules of Procedure - Section 803.

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

133 Title 18, § 39.11 of the Code of Federal Regulations.

134 BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that systems use to account for 80% of all electricity supply interruptions to end-use customers.

135 United States Court of Appeals for the District of Columbia Circuit - No.11-1486.

136 Glossary of Terms Used in NERC Reliability Standards.

137 The summer season represents June–September and the winter season represents December–February.

Total internal demand projections are based on normal weather (50/50 distribution)[138] and are provided on a coincident basis for most assessment areas.[139]
Total internal demand includes considerations for reduction in electricity use due to projected impacts of energy efficiency and conservation programs.
Net Internal Demand, used in all Reserve Margin calculations, is equal to total internal demand, reduced by the amount of Controllable and Dispatchable demand response (DR) projected to be available during the peak hour.
Resource Assumptions
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy:
Anticipated Resources: • **Existing-certain generating capacity:** Includes operable capacity expected to be available to serve load during the peak hour with firm transmission. • Tier 1 capacity additions: Includes capacity that has completed construction, is under construction, has a signed or approved ISA/PPA/CSA/WMPA, is included in an integrated resource plan, or is under a regulatory environment that mandates a resource adequacy requirement. • **Firm Capacity Transfers (Imports minus Exports):** Transfers with firm contracts.
Prospective Resources: Includes all Anticipated Resources, plus: • **Existing-other capacity:** Includes operable capacity that could be available to serve load during the peak hour, but lacks firm transmission and could be unavailable for a number of reasons. • **Tier 2 capacity additions:** Includes capacity that has been requested, but not received approval for planning requirements. Tier 2 capacity is counted toward the prospective resources category. • **Expected (nonfirm) Capacity Transfers (Imports minus Exports): Transfers** without firm contracts, but a high probability of future implementation.
Reserve Margins
Reserve Margins: The primary metric used to measure resource adequacy, defined as the difference in resources (anticipated, or prospective) and net internal demand, divided by net internal demand, shown as a percentile.
Anticipated Reserve Margin = (Anticipated Resources – Net Internal Demand) / Net Internal Demand **Prospective Reserve Margin** = (Prospective Resources – Net Internal Demand) / Net Internal Demand
Reference Margin Level: The assumptions of this metric vary by assessment area. Generally, the Reference Margin Level is typically based on load, generation, and transmission characteristics for each assessment area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If one is not provided by a given assessment area, NERC applies a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.
Fuel Types

[138] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[139] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

NERC collects and presents data on the generation mix based on the general fuel type identified for each unit. The fuel type is based on the prime movers and primary fuel type codes identified in the Form EIA-860 and provided below:[140]

- ***Coal***: Anthracite (ANT), Bituminous (BIT), Lignite (LIG), Subbituminous (SUB), Waste/Other (WC), Refined (RC)
- ***Petroleum***: Distillate Fuel Oil (DFO), Jet Fuel (JF), Kerosene (KER), Petroleum Coke (PC), Residual Fuel Oil (RFO), Waste/Other Oil (WO)
- ***Natural Gas***: Blast Furnace (BFG), Natural (NG), Other (OG), Propane (PG), Synthesis from Petroleum Coke Gas (SGP), Coal-Derived Synthesis Gas (SGC)
- ***Biomass***: Agricultural By-Products (AB) Municipal Solid Waste (MSW) Other Biomass Solids (OBS), Wood/Wood Waste Solids (WDS), Other Biomass Liquids (OBL), Sludge Waste (SLW), Black Liquor (BLQ), Wood Waste Liquids (WDL), Landfill Gas (LFG), Other Biomass Gas (OBG)
- ***Renewables***: Solar (SUN), Wind (WND), Geothermal (GEO), Hydroelectric (fuel type: WAT; primary mover: HY)
- ***Pumped Storage***: Pumped Storage (fuel type: WAT; primary mover: PS)
- ***Nuclear***: Nuclear (NUC)

[140] Additional information on fuel codes and prime movers are available in the Form EIA-860.