NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2015 Summer Reliability Assessment

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RELIABILITY | ACCOUNTABILITY




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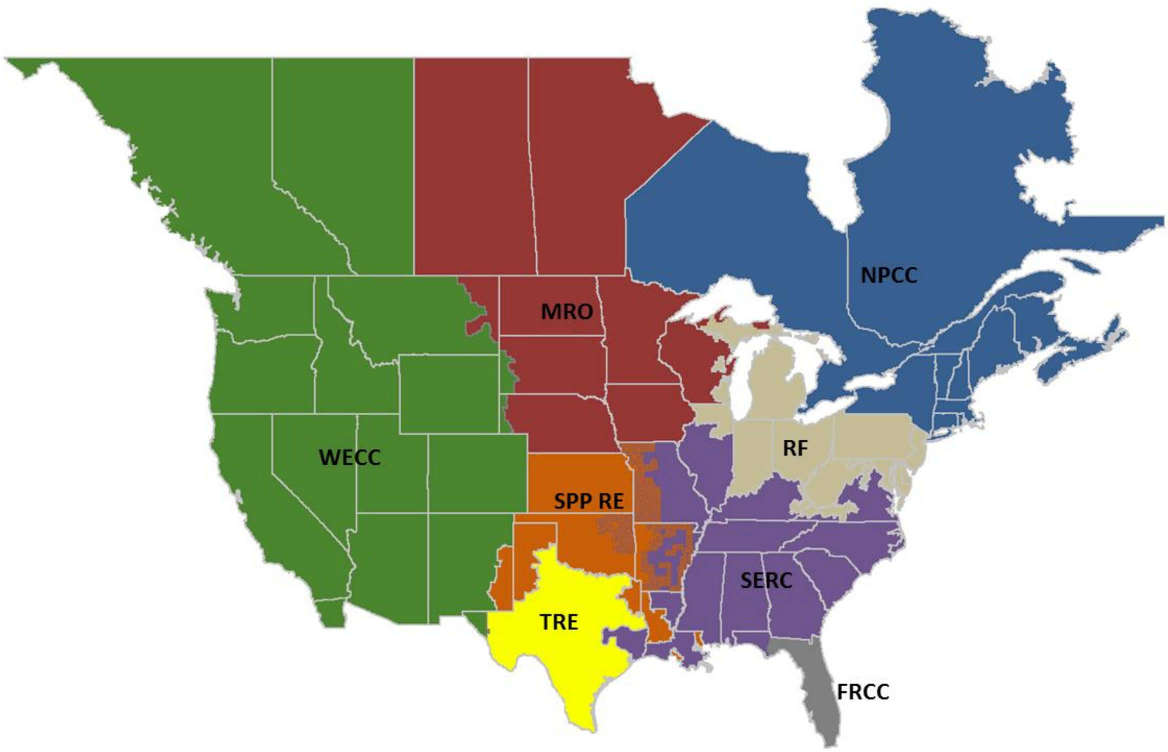
Preface

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.

The North American BPS is divided into several Assessment Areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Assessment Development

The *2015 Summer Reliability Assessment* (SRA) provides an independent assessment of the reliability of the bulk electricity supply and demand in North America between June 2015 and September 2015. The assessment was developed with support from the Reliability Assessment Subcommittee (RAS),[1] at the direction of the NERC Planning Committee (PC).

In April 2015, the eight NERC Regional Entities initially submitted data and information for each of their respective Assessment Areas to NERC and provided periodic updates throughout the development of the report. External data sources are appropriately cited. For this and other seasonal and long-term assessments, NERC uses an active peer review process to leverage a wide group of industry subject matter expertise to provide essential checks and balances for ensuring the accuracy and completeness of the data and information presented. Inquiries regarding the information, data, and analysis in this assessment may be directed to the NERC Reliability Assessment staff (listed below).

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[1] The RAS roster is included in Appendix I.

Executive Summary

The *2015 Summer Reliability Assessment* provides a high-level perspective on the adequacy of the generation resources and transmission systems necessary to meet projected summer peak demands. NERC independently identifies reliability issues of potential concern and regional challenges that may impact BPS reliability. The primary objective of the report is to identify areas of concern regarding the reliability of the North American BPS and to make recommendations as needed. The assessment process enables BPS users, owners, and operators to systematically document their operational preparations for the coming season and to exchange vital system reliability information. NERC is impartial to any particular projects mentioned in this report. NERC evaluates individual regions' resource and transmission adequacy to ensure BPS reliability is maintained for the upcoming season.

As highlighted in numerous recent long-term reliability assessments, the BPS in North America is changing in many ways. Each summer, NERC has observed incremental changes in the resource mix, which has trended toward a generation base that is now predominately (nearly 40 percent) gas-fired generation, an increase of 28 percent from five years ago. The ongoing retirement of fossil-fired generation is largely being addressed by the addition of gas-fired and variable (e.g., wind and solar) resources. The transformation of North America's resource mix poses a unique set of challenges, and NERC continues to monitor key measures that provide greater insight on how this trend is impacting BPS reliability.

Key Findings for Summer 2015

1. Sufficient generation and demand-side resources are in place to meet summer peak demand.
2. Fossil-fired retirements, natural gas, and variable generation trends continue to transform the resource mix.
3. Extreme-case scenario analysis shows the California drought is not expected to impact BPS reliability.
4. Ongoing natural gas infrastructure expansion and outages in New England are not expected to impact summer peak reliability.

For the 2015 seasonal assessments, NERC is introducing a pilot analysis that focuses on operational risks to the BPS. This analysis is used to determine the operational sensitivities of any given system, based on past performance of resources used to serve peak load. This provides a much greater understanding of the capability of a given system as well as its resilience to extreme weather or severe BPS conditions.

Commencement of the Mercury and Air Toxics Standards (MATS)[2] compliance began in April 2015, and this will be the first summer season for meeting the rule's requirements. While this rule has contributed to retirement of fossil-fired generating units, the retirements have not caused the Planning Reserve Margin to fall below the NERC Reference Margin Level. However, there is less resource capacity overall compared to previous summers to manage unforeseen challenges and severe conditions.

[2] EPA MATS.

Key Finding #1:

NERC-wide, sufficient generation and demand-side resources are in place to meet summer peak demand.

From a resource adequacy perspective, all of the Assessment Areas NERC evaluates appear to have sufficient resources to meet peak demand (Figure 1). Some areas continue to see improved Reserve Margins. ERCOT's reserve margins improved compared to previous summers due to on-peak wind capacity contribution changes. Similarly, MISO reported improved Reserve Margins due to their change in methodology by including more MISO-South resources to support the overall MISO Reserve Margin.

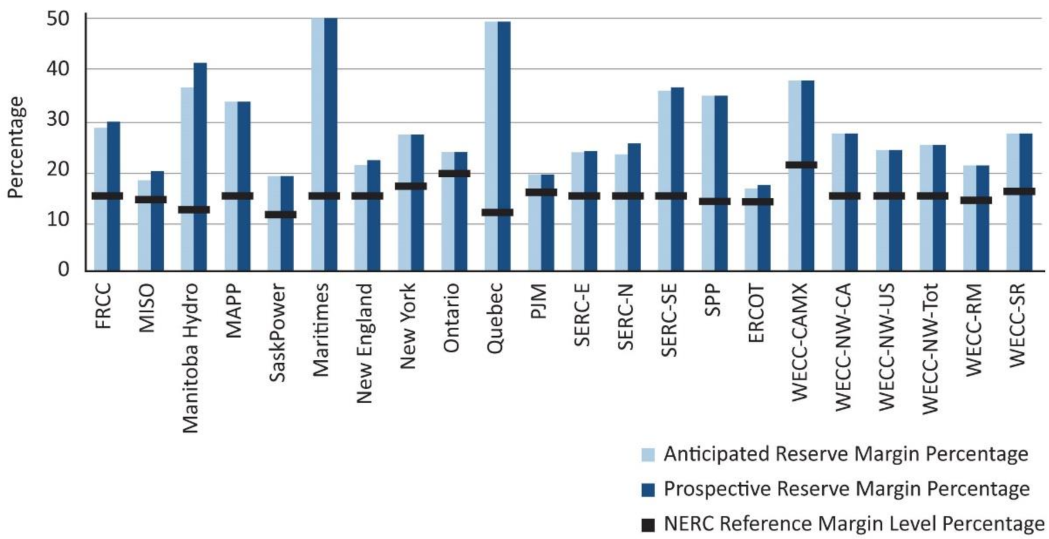


Figure 1: 2015 Anticipated and Prospective Reserve Margins Compared to NERC Reference Margin Levels

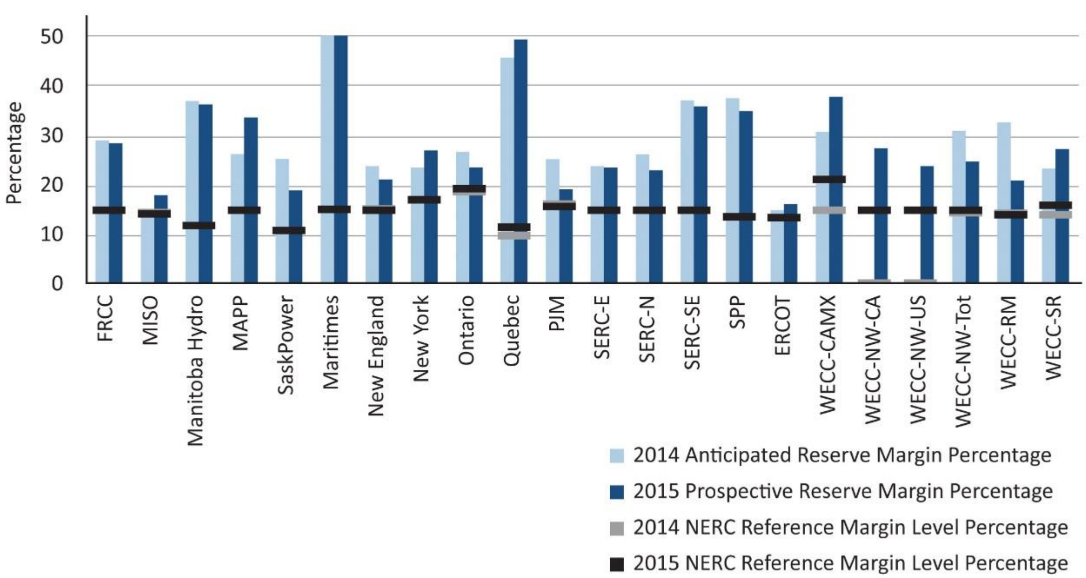


Figure 2: 2014 and 2015 Anticipated Reserve Margins Compared to NERC Reference Margin Levels

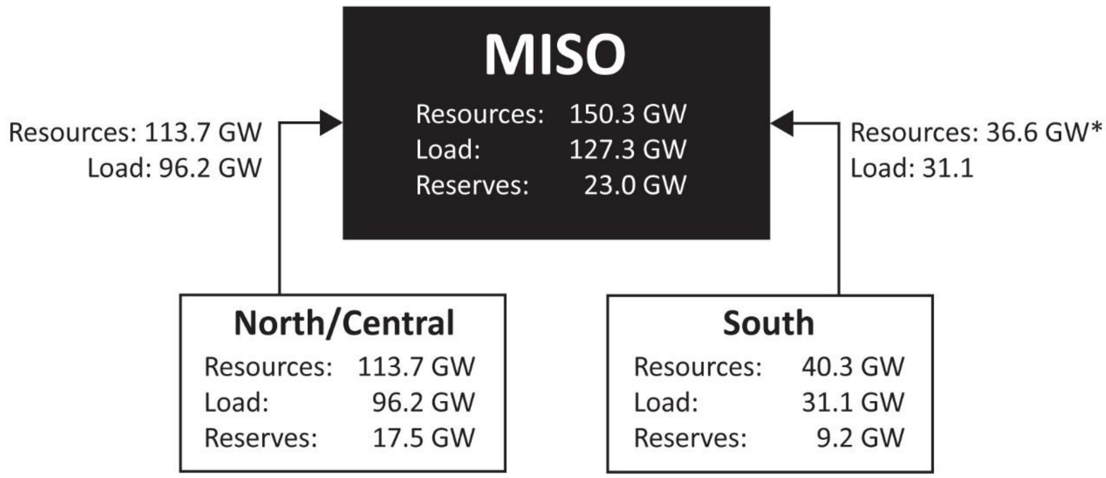
Table 1: 2015 Projected Demand, Resources, and Planning Reserve Margins

Assessment Area	Total Internal Demand (MW)	Net Internal Demand (MW)	Anticipated Resources (MW)	Prospective Resources (MW)	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	NERC Reference Margin Level (%)
FRCC	46,452.0	43,351.0	55,699	56,190	28.48%	29.62%	15.00%
MISO†	127,319.0	122,288.1	144,332	146,686	18.03%	19.95%	14.30%
MRO-Manitoba Hydro	3,151.0	3,151.0	4,301	4,456	36.50%	41.42%	12.00%
MRO-MAPP†	4,974.6	4,880.6	6,523	6,526	33.65%	33.71%	15.00%
MRO-SaskPower	3,237.0	3,072.0	3,654	3,654	18.95%	18.95%	11.00%
NPCC-Maritimes	3,748.0	3,436.0	5,648	5,648	64.38%	64.38%	15.00%
NPCC-New England	26,710.0	26,072.0	31,563	31,825	21.06%	22.07%	15.00%
NPCC-New York	33,567.3	32,442.9	41,222	41,222	27.06%	27.06%	17.00%
NPCC-Ontario	22,991.0	22,399.8	27,695	27,695	23.64%	23.64%	19.50%
NPCC-Québec	21,202.7	21,202.7	31,696	31,696	49.49%	49.49%	11.70%
PJM	155,544.0	147,764.0	176,236	176,236	19.27%	19.27%	15.60%
SERC-E	42,825.0	41,866.0	51,780	51,827	23.68%	23.79%	15.00%
SERC-N	42,097.0	40,540.0	49,888	50,832	23.06%	25.39%	15.00%
SERC-SE	46,473.0	44,271.0	60,116	60,444	35.79%	36.53%	15.00%
SPP	50,529.0	49,245.0	66,431	66,431	34.90%	34.90%	13.60%
TRE-ERCOT	69,057.0	66,714.0	77,551	78,068	16.24%	17.02%	13.75%
WECC-CAMX†	54,751.0	52,830.0	72,829	72,829	37.86%	37.86%	21.00%
WECC-NWPP-CA†	19,070.0	19,070.0	24,300	24,300	27.42%	27.42%	14.90%
WECC-NWPP-US†	49,298.0	48,153.0	59,694	59,694	23.97%	23.97%	14.90%
WECC-NWPP-Tot†	68,368.0	67,223.0	83,993	83,993	24.95%	24.95%	14.90%
WECC-RMRG	12,447.0	11,900.0	14,391	14,391	20.94%	20.94%	13.90%
WECC-SRSG	23,549.0	23,088.0	29,394	29,394	27.31%	27.31%	16.10%
EASTERN INTERCONNECTION	609,617.9	584,779.3	725,086.7	729,671.7	29.17%	30.05%	14.86%
QUÉBEC INTERCONNECTION	21,202.7	21,202.7	31,695.5	31,695.5	49.49%	49.49%	11.70%
TEXAS INTERCONNECTION	69,057.0	66,714.0	77,551.1	78,067.8	16.24%	17.02%	13.75%
WESTERN INTERCONNECTION‡	140,045.0	135,971.0	200,607.7	200,607.7	27.50%	27.50%	16.16%
TOTAL-NERC	**839,922.6**	**808,667.1**	**1,034,941.1**	**1,040,042.8**	**30.60%**	**31.01%**	**14.12%**

Several areas applied changes to their assessment methods and approaches, which are described in further detail below:

MISO

MISO's projected 2015 Reserve Margin increased to 18.0 percent, up from 15.0 percent in 2014. This change is attributed to an additional 4.5 GW for overall MISO capacity resources due to improved accounting for the reduction of contract path-limited resources in MISO-South. As outlined in Figure 3, when including Demand Response and energy efficiency as resources (instead of as load modifiers), MISO-South has 40.3 GW of resources. With a Reserve Margin of 14.3 percent and the inclusion of a 1,000 MW transfer from MISO-South to MISO-North/Central, only 36.6 GW of resources are accounted for in the total MISO Reserve Margin calculation.



**Only 1,000 MWs above South Reserve Margin Requirement used toward aggregate MISO Reserve Margin. (31.1 x (1+14.3%) = 35.6 GW)*

Figure 3: Subregional to Regional Reserve Margin[3]

In both 2014 and 2015, NERC identified that the contract paths from MISO-South to MISO-North/Central limited inter-region flows to 1,000 MW between MISO-South and MISO-North/Central. Therefore, any additional generating capacity in the South region was not included in the overall MISO Anticipated Resources to be used in the Reserve Margin calculations. MISO's calculations for 2015 allow for the South to meet its own Reserve Margin and have generation equal to the 1,000 MW contract path flow into MISO-North/Central, thereby increasing the MISO Reserve Margin.[4]

TRE-ERCOT

In 2014, ERCOT met the 13.75 percent NERC Reserve Margin Level for the first time since 2011. This was due to the installation of 2,112 MW of new capacity, modifications to their load forecast methodology, and an expected mild summer, which forecast only a 0.42 percent increase (228 MW) of their Net Internal Demand. ERCOT's 2015 Reserve Margin increased from 14.98 percent to 16.24 percent due to newly installed capacity and modifications to the methodology for calculating on-peak wind capacity contributions.

Since last year's summer assessment, ERCOT has installed 2,108.9 MW of natural-gas-fired generation, 1,587.7 MW of wind, and 67.6 MW of utility-scale solar. Planned additional capacity to be installed for this summer include 1,011 MW of natural-gas-fired generation and 2,139 MW of nameplate wind capacity. This new capacity amounts to 2,485 MW, or 3.2 percent of ERCOT's 77,551 MW Anticipated Resources. These capacity installations are expected to be available for the 2015 summer peak but will not greatly affect the Reserve Margins in the event they are not available.

In October 2014, ERCOT devised a new methodology for calculating their on-peak wind capacity contributions.[5] ERCOT's previous assessments used probabilistic methods to calculate a region-wide 8.7 percent of effective capacity for their wind resources. The updated methodology uses the highest 20 peak load hours from the past six years of historical performance data to project new effective on-peak wind capacity. The data shows a large increase of performance of their coastal wind resources compared to their non-coastal wind resources and a variation between their summer and winter values. The new

[3] 2015 MISO Summer Readiness Workshop.
[4] Additional details are provided in the MISO section of this report.
[5] http://www.ercot.com/content/news/presentations/2014/2014_One-pager-WindForecast.pdf

summer capacity contributions equal 12 percent of nameplate capacity for non-coastal wind resources and 56 percent of nameplate capacity for coastal wind resources. This new evaluation of ERCOT's wind capacity using historical performance data has accounted for an increase in their Anticipated Resources by 1,314 MW, or 1.7 percent. Using the previous year's methodology for calculating on-peak wind capacity would result in a Reserve Margin of 14.27 percent. Table 2 below shows that ERCOT meets their target Reference Margin Level for either method for calculating wind capacity contributions.

Table 2: TRE-ERCOT 2015 Reserve Margins Using Old/New Wind Capacity Factors

	Anticipated Resources – Wind Only	Total Anticipated Resources	Reserve Margin %
Old Method	1,280 MW	76,237 MW	14.27%
New Method	2,594 MW	77,551 MW	16.24%

Key Finding #2:

Fossil-fired retirements, natural gas, and variable generation trends continue to transform the resource mix.

The North American BPS is currently undergoing a significant change in the mix of generation resources. Driven by a combination of factors, the rate of change in certain areas is having an impact on the planning and operation of the BPS. For example, environmental regulations and low gas prices are contributing to substantial retirement of conventional coal-fired generation, while Renewable Portfolio Standards and other factors are driving the development of Variable Energy Resources (VERs). This shift from coal is an ongoing trend that has contributed to increased natural-gas-fired generation and variable resources. Figure 4 shows coal retirements from 2011 to 2015 (through April 2015).

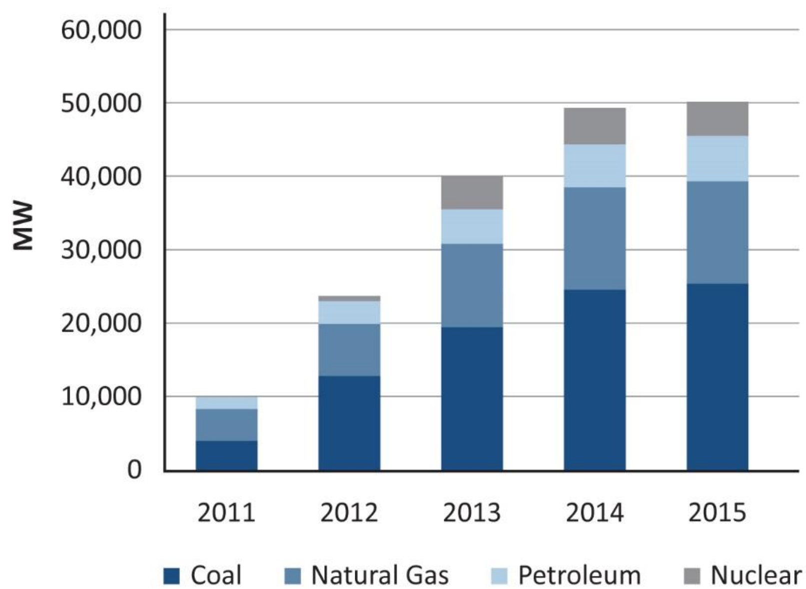


Figure 4: Generator Retirements 2011–2015[6]

As natural-gas-fired generation grows in importance from both a capacity and generation perspective, system planners must address gas and electric interdependency issues. Whereas natural gas distribution companies typically experience peak loads in the winter, the increasing use of natural gas for electric summer-peaking needs

[6] Source: Ventyx Energy Suite.

introduces expanded issues with natural gas and electric interdependencies. Gas distribution companies typically inject a significant portion of their winter-peaking supplies into storage during the summer, which competes with the increased use of natural gas for electric generation during summer months. Figure 5 shows the increase in natural gas generation facilities between 2010 and 2015 (through April 2015). The increase in natural-gas-fired generation highlights the need to have appropriate planning mechanisms in place to address natural gas supply or pipeline contingencies.[7]

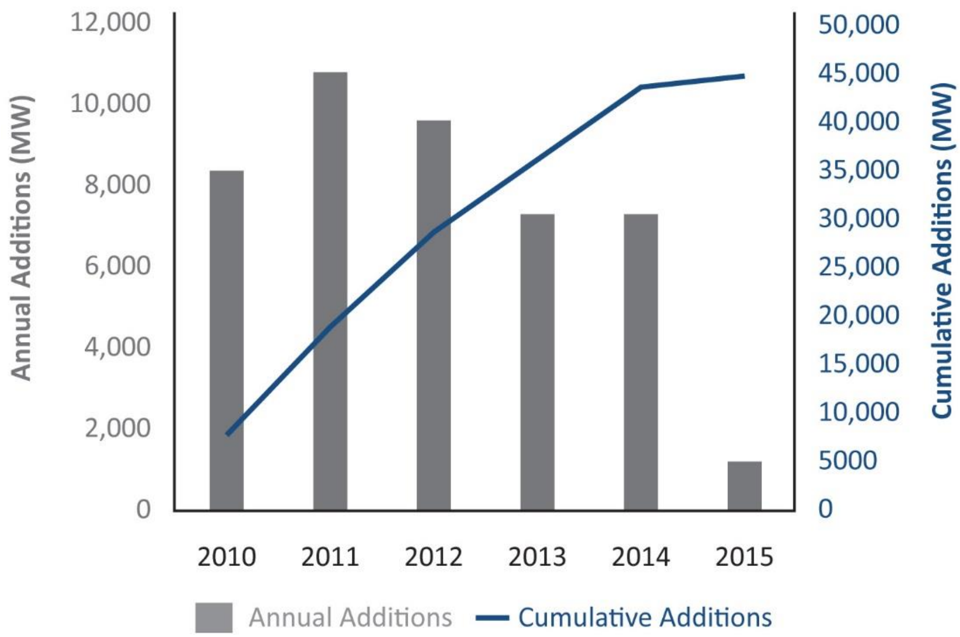


Figure 5: Natural Gas 2011–2015[8]

Variable Generation

Additional variable generation is spurring the need for a more robust set of ancillary services (e.g., frequency response and reserves) and is creating additional planning and operational needs as its market share continues to grow. To accommodate the higher penetration of VERs, operators adjust their practices and rely on more flexible resources to ensure voltage and frequency support are maintained within acceptable margins while maintaining frequency. Figure 6 shows installed nameplate capacity of variable resources in 2014 and 2015, respectively. Table 3 shows the percentage change in renewables from 2014 to 2015.

[7] For more information on this topic, please see NERC's *Phase II Special Assessment on Natural Gas and Electric Interdependencies*.
[8] Source: EIA Form 860.

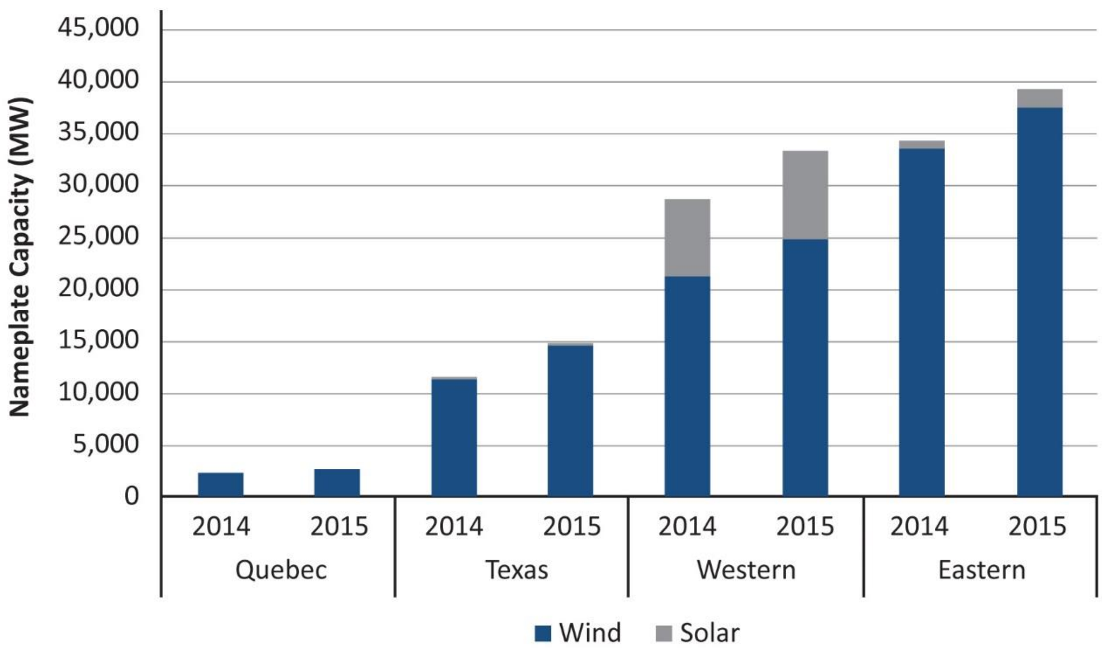


Figure 6: Renewable Change 2014–2015 by Interconnection

Table 3: Renewable Change 2014–2015 by Interconnection

	2014	2015	% Change
Installed Wind Capacity	**68,437 MW**	**80,006 MW**	**16.90%**
Québec Interconnection	2,399 MW	2,880 MW	20.07%
Texas Interconnection	11,375 MW	14,714 MW	29.35%
Western Interconnection	21,129 MW	24,813 MW	17.43%
Eastern Interconnection	33,534 MW	37,599 MW	12.12%
Installed Solar Capacity	**8,608 MW**	**10,207 MW**	**18.57%**
Texas Interconnection	123 MW	184 MW	49.59%
Western Interconnection	7,626 MW	8,447 MW	10.77%
Eastern Interconnection	729 MW	1,576 MW	116.07%

All interconnection areas saw growth in installed nameplate wind capacity between 2014 and 2015. Texas shows the highest-percent change in wind installation among the interconnections in North America. The Eastern, Western, and Texas Interconnections saw growth in installed nameplate solar capacity.

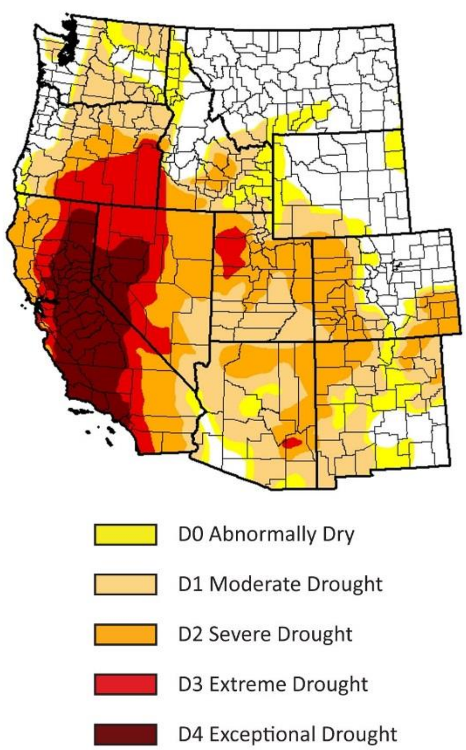
NERC will continue to monitor the trends of renewable generation installations across the ERO.

Key Finding #3:

The California drought is not expected to impact BPS reliability based on extreme-case scenario analysis.

Impacts of ongoing California drought on BPS reliability

The California/Mexico subregion continues to experience an extended drought that has reduced the maximum capability and energy production from hydro generation (see Figure 7). Snowpack in California is at record lows for the second year in a row. Although California's severe drought significantly reduces hydro power supply, the hydro generation reduction will not materially impact the reliability of California Independent System Operator (CAISO) this summer due to significant renewable generation additions, sufficient imports, and moderate peak demand growth, in part the result of ongoing customer behind-the-meter solar generation additions. Over 2,000 MW of new renewable generation has gone into commercial operation in CAISO since June 1, 2014. This increase in generation will help to offset the 3,118 MW derate of nameplate hydro capacity. As California progresses toward the mandated 33 percent Renewable Portfolio Standard by 2020, California's trend of increasing Planning Reserve Margins will continue as new renewable resource additions come on-line. For example, in 2014, the amount of energy produced by hydro generation decreased from that generated in 2013 by 7,800 GWh, and during the same period, solar generation increased by 6,000 GWh. Electricity generated at hydro generation facilities located in California accounted for approximately 7 percent of total California demand in 2014; therefore, a reduction in hydro generation is not expected to adversely impact the reliable operation of the system. Furthermore, California hydro resources are primarily system resources, so the reduction in hydro generation will not impact local reliability areas. During periods of low energy production, hydro resources are still able to contribute to the ancillary services market, freeing up other generation for energy production.



Drought Conditions (Percent Area)

	None	D0-D4	D1-D4	D2-D4	D3-D4	D4
Current	28.21	71.79	61.51	37.95	17.19	7.95
Last Week *4/14/2015*	26.55	73.45	61.00	37.91	17.04	7.63
3 Months Ago *1/20/2015*	35.52	64.48	53.09	33.62	18.52	6.35
Start of Calendar Year *12/30/2014*	34.76	65.24	54.48	33.50	18.68	5.40
Start of Water Year *9/30/2014*	31.48	68.52	55.57	35.65	19.95	8.90
One Year Ago *4/22/2014*	30.11	69.89	61.61	45.09	17.93	4.61

Figure 7: Drought Forecast for U.S. West Region[9]

[9] http://droughtmonitor.unl.edu/.

The California/Mexico subregion continues to put market and operating procedures in place to address operational issues relating to the transition to more renewable resources. CAISO has enhanced its ancillary services market to address the growing need for ramping capability to meet the increasing ramping up and ramping down requirements associated with greater penetrations of solar and other renewable resources. Furthermore, the over-generation of energy, primarily during periods of low demand and high solar generation, is an emerging issue that is receiving significant attention. In addition to using market mechanisms to resolve these issues, CAISO continues to work with market participants and surrounding areas to identify additional solutions. The CAISO energy imbalance market is an example of regional coordination that is helping to address these issues.

The Western Interconnection could also experience localized short-term operational issues due to wildfires associated with the drought. As shown in Figure 8, below-normal precipitation has left large, dry portions of the West ripe for frequent and large wildfires. However, due to the widely dispersed nature of the transmission grid, and transmission owners' compliance with NERC Reliability Standard FAC 003-3, Facility Standard for Transmission Vegetation Management, outages due to wildfires are generally short term, not widespread, and not expected to create reliability concerns.

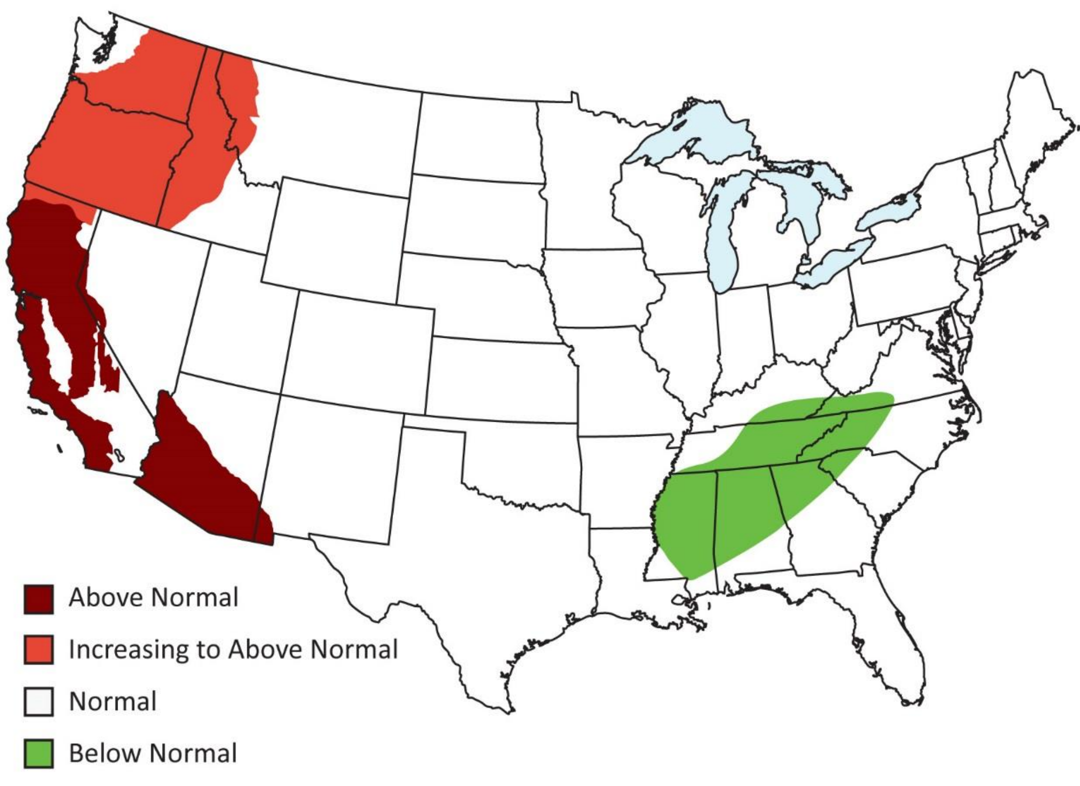


Figure 8: U.S. Wildfire Conditions for June and July[10]

[10] http://www.predictiveservices.nifc.gov/outlooks/extended_outlook.png

Key Finding #4:

Ongoing natural gas infrastructure expansion and outages in New England are not expected to impact summer reliability.

For the 2015 summer assessment period, ISO-NE expects natural gas pipeline maintenance and expansion to occur; however, it does not forecast fuel deliverability issues to affect installed capacity during peak periods. In the recent past, natural gas has become the predominant source of fuel in New England, accounting for 45 percent of their installed capacity. Historically, New England has experienced constraints with gas supply due to a less-than-adequate gas supply infrastructure. However, their gas-electric coordination efforts have proven successful in their long- and short-term planning and real-time operations. A major natural gas pipeline expansion project, Algonquin Incremental Market (AIM),[11] is planned for late summer and, per the project schedule, is expected to affect fuel supply to generating plants (Figure 9). ISO-NE will use this information to coordinate generating plant outages simultaneous with the pipeline outage that feeds the respective plant. This will reduce overall risk to system capacity and reliability. The summer season poses less risk to generating plant fuel supply as demand from local gas distribution companies will be lower in the summer than a typical winter season in New England. ISO-NE and the interstate natural gas pipeline operators have developed a constant communication guideline that will continue to improve the forecast of their combined systems and discuss specific system conditions that will enable the operators and planners to take actions under their existing authorities to avoid reliability problems. In addition, the pipeline operators may be able to provide information on gas availability that will allow ISO-NE to better anticipate and address potential deliverability problems in the event there is insufficient fuel for all gas-fired generators to meet their schedules. ISO-NE has operating procedures they can implement in an event that regional fuel supply of natural gas is restricted. This project is expected to last until 2018, and both ISO-NE and interstate gas pipeline operators are committed to communicating future work so as to minimize impacts to their respective systems. While the natural gas pipeline maintenance and expansion may pose operational challenges in New England, ample measures have been developed to manage reliability risks posed to the BPS.

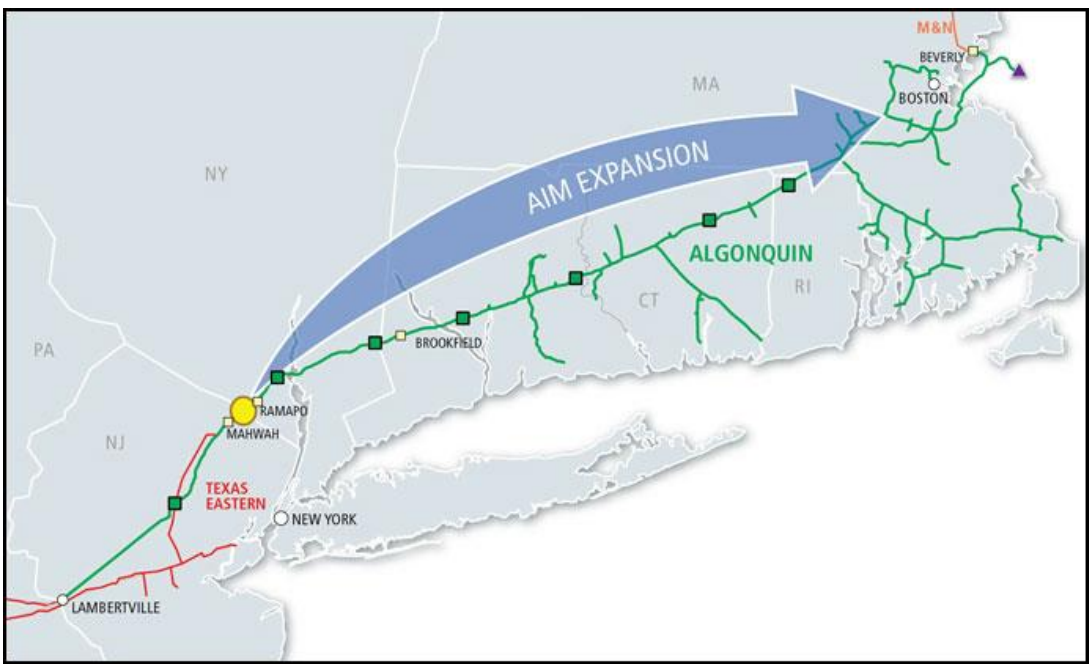


Figure 9: Spectra Energy's Algonquin Incremental Market Project Map

11 http://www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-US/Algonquin-Incremental-Market-AIM-Project/.

Operational Risk Assessment: Pilot Analysis

For the 2015 seasonal assessments, NERC is introducing a pilot analysis that focuses on operational risks to the BPS. This analysis is used to determine the operational sensitivities of any given system, based on past performance of resources used to serve peak load. Traditionally, the seasonal assessments have included reviews of the planning horizon and flexibility of an Assessment Area or Region through a deterministic Planning Reserve Margin analysis. However, this approach does not provide insights on the random and weather-dependent impacts that can affect generation resources. For instance, a particular system may have 10,000 MW of resources to meet peak demand; however, based on past performance and outages that occur throughout the summer, NERC can determine that 2,000 MW, on average, are out of service at all times—due to maintenance or forced outages. This provides much greater understanding about the capability of a given system, as well as its resilience against extreme or severe BPS conditions.

Traditionally, NERC's seasonal assessments have focused on resource adequacy and transmission availability. For a planning analysis, these areas of focus are necessary; however, for the seasonal assessments, operational risks should be integrated into the analysis to understand the range of potential outcomes that can manifest during real-time operations. This further merits the need for careful evaluation and integration of planning as well as operational analysis.

This dynamic warrants a review of a system's expected performance during normal and extreme system conditions. This summer's data request included both a normal demand[12] and severe demand forecast[13] from each Assessment Area. NERC used its Generator Availability Data System (GADS)[14] outage data to determine normal and extreme generator outages for the specific Assessment Area. In some cases, the outage data was obtained from the Regional Entity.[15]

For the *2015 Summer Reliability Assessment*, NERC analyzed two scenarios: (1) normal and (2) severe loads, both compared to average maximum forced and planned generator outages based on limited historical outage data. The second scenario provides insight on low-probability conditions that result in adverse system conditions. While all system operators have operating procedures in place to mitigate adverse reliability impacts by means of Demand Response, voltage reduction, additional power purchases, and public appeals, firm load shedding may also be needed to maintain system stability during these severe conditions.

In winter-peaking Assessment Areas, such as Hydro Quebec, summer severe loads do not pose a challenge as these areas have abundant resources to manage heavy loads. Therefore, NERC's attention for this assessment focuses on summer-peaking areas.

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[12] Load projections are based on a non-coincident 50/50 peak demand forecast, unless otherwise noted. Values represent the baseline values for each season, each with a range of possible outcomes based on probabilities around the baseline or midpoint. Projections are provided on an Assessment Area basis and are highly dependent on the data, methodologies, model structures, and other assumptions that often vary by Region, Reliability Coordinator, Assessment Area, or BA.

[13] NERC requested a load projection based on the 90th percentile probability. In general, this means that the severe load forecast is expected to reach this higher level once in every 10 years.

[14] http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

[15] For NPCC, refer to the NPCC Reliability Assessments at https://www.npcc.org/Library/Seasonal Assessment/Forms/Public List.aspx.

FRCC – As shown in Figure 10, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

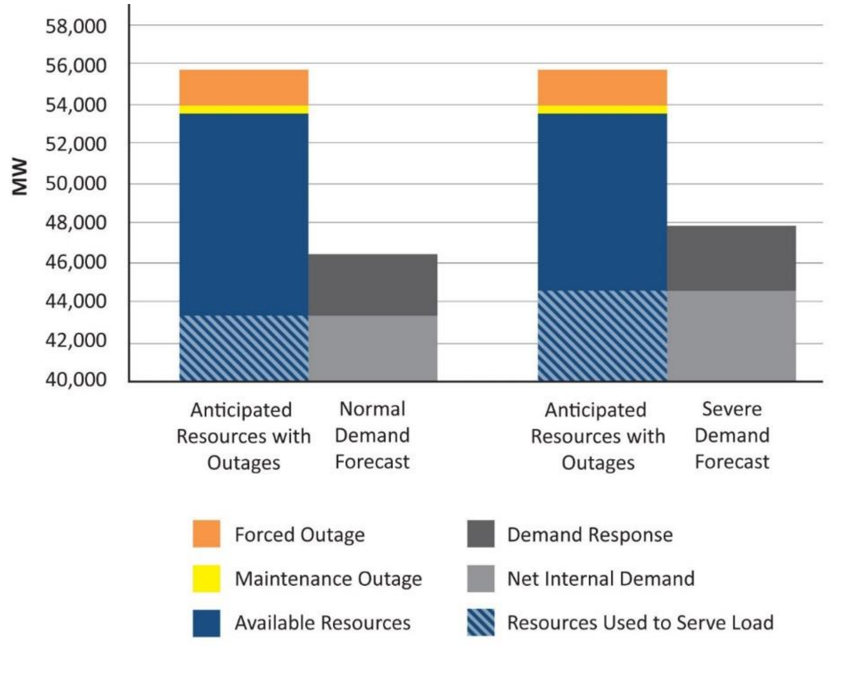


Figure 10: FRCC Operational Analysis

MISO – As shown in Figure 11, for normal load conditions, the anticipated forced and planned generator outages do not pose a concern. However, under severe load levels, Demand Response will clearly be needed, and MISO appears to have sufficient Demand Response to manage the conditions in this scenario.

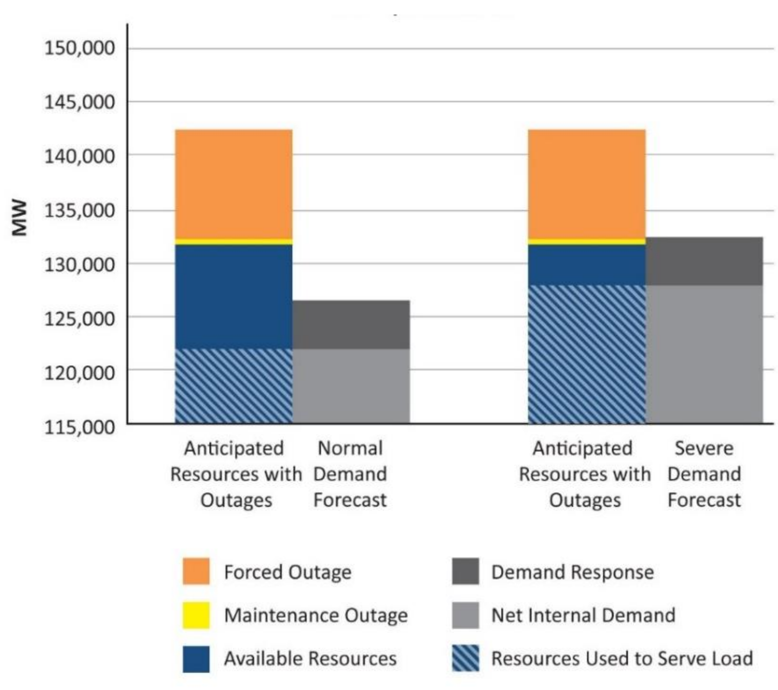


Figure 11: MISO Operational Analysis

ISO-NE – As shown in Figure 12, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

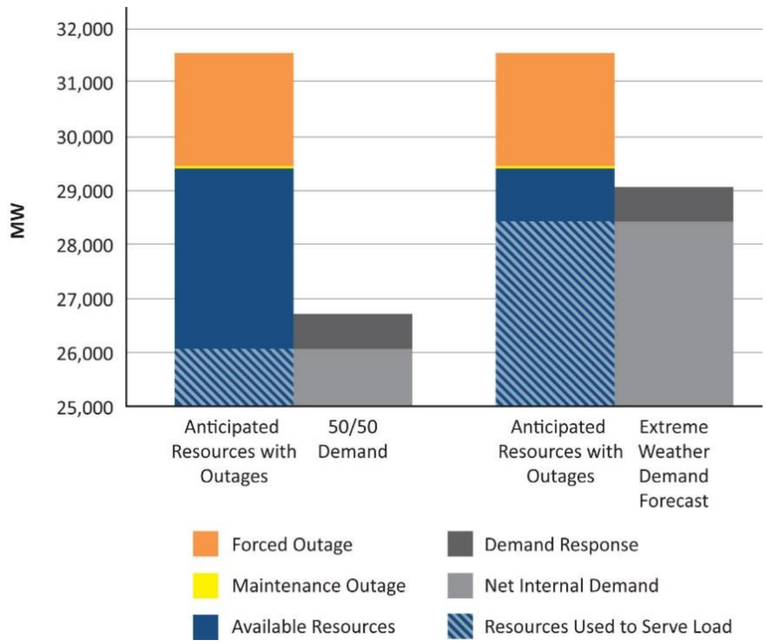


Figure 12: ISO-NE Operational Analysis

NYISO – As shown in Figure 13, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

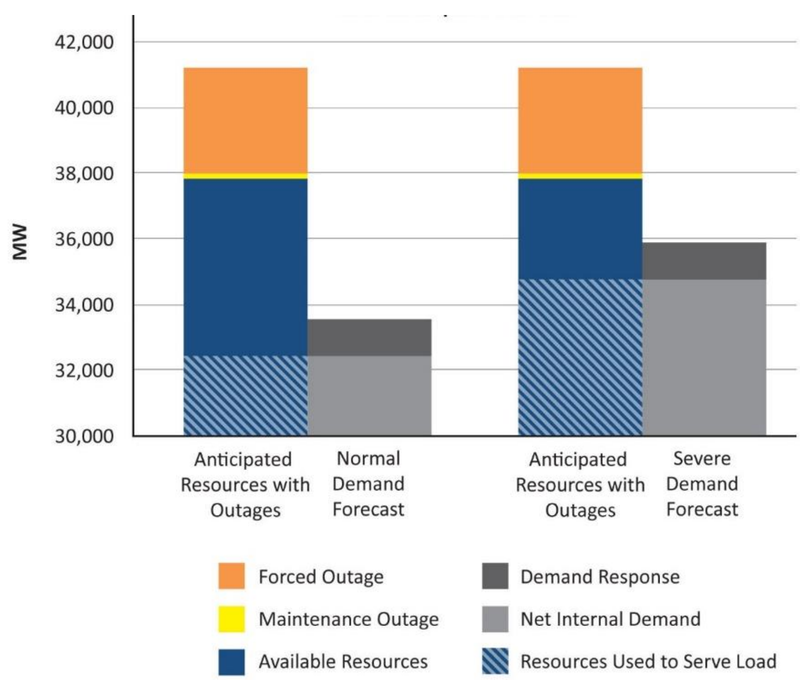


Figure 13: NYISO Operational Analysis

Ontario – As shown in Figure 14, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

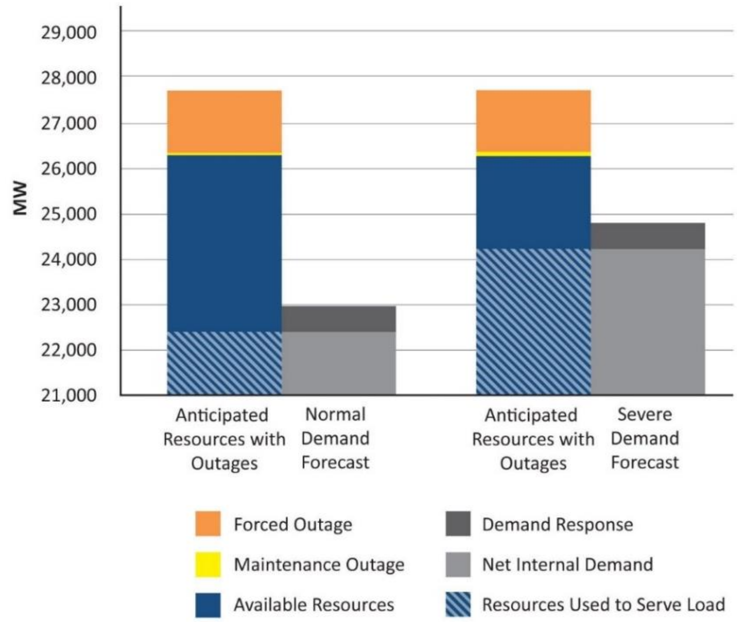


Figure 14: Ontario Operational Analysis

Québec – As shown in Figure 15, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

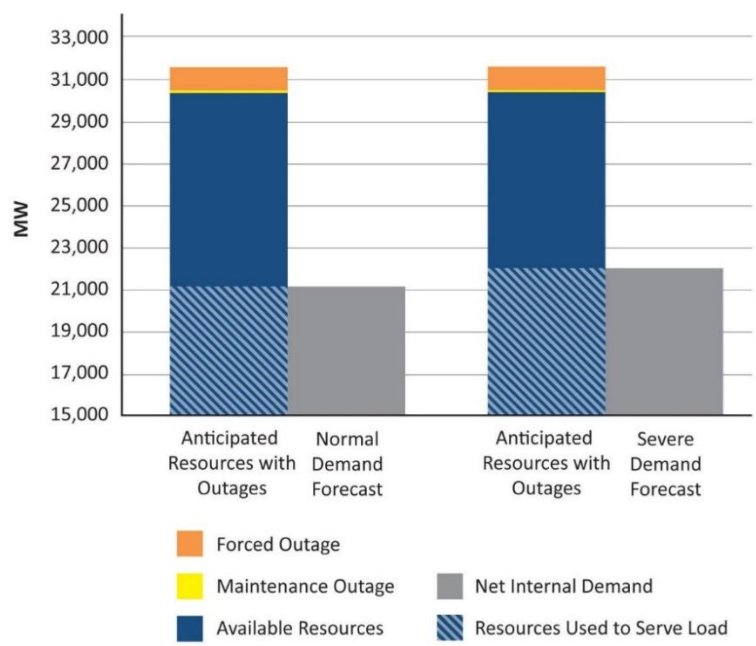


Figure 15: Québec Operational Analysis

PJM – As shown in Figure 16, for normal load conditions, the anticipated forced and planned generator outages do not pose a concern. However, PJM's severe load conditions pose an operational concern, which would be addressed by means of Demand Response, additional power purchases, voltage reduction, and public conservation appeals prior to shedding load.

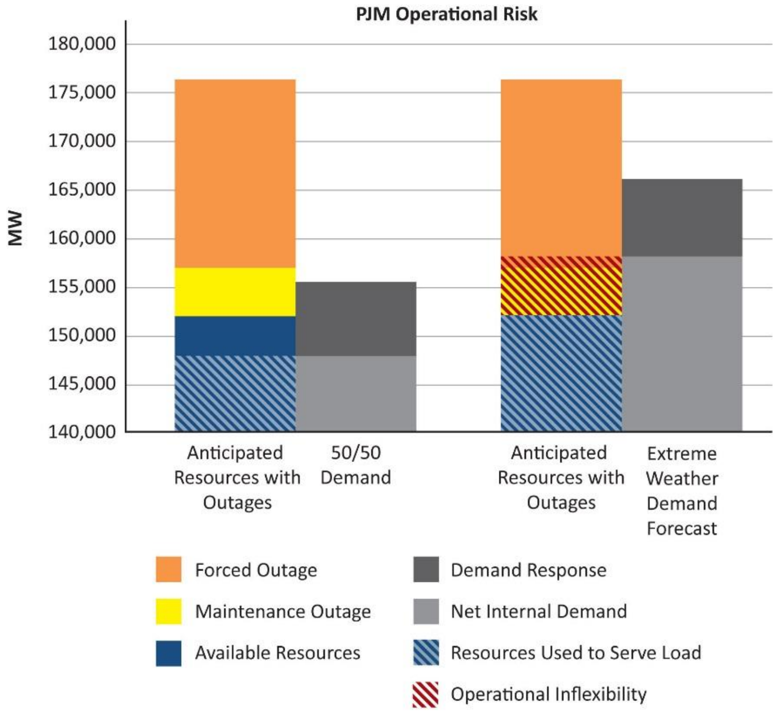


Figure 16: PJM Operational Analysis

SPP – As shown in Figure 17, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

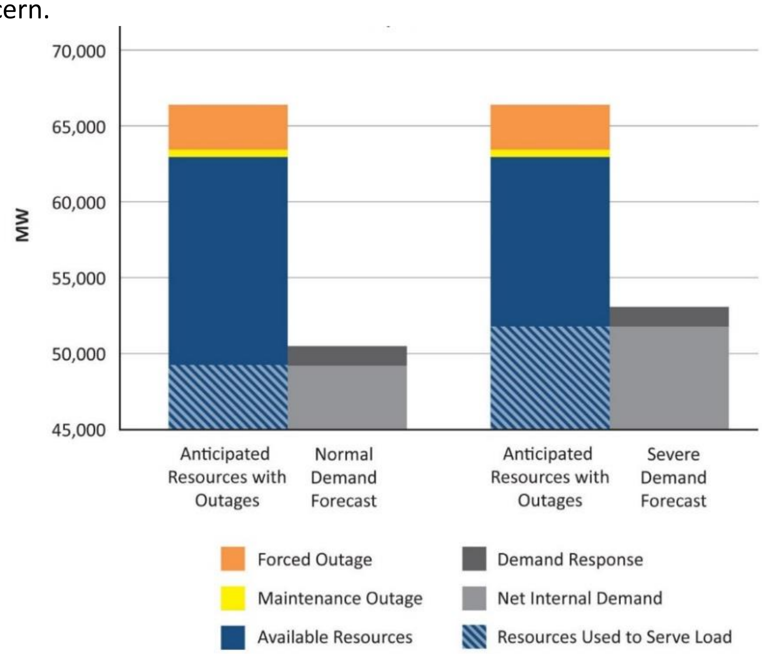


Figure 17: SPP Operational Analysis

ERCOT – As shown in Figure 18, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

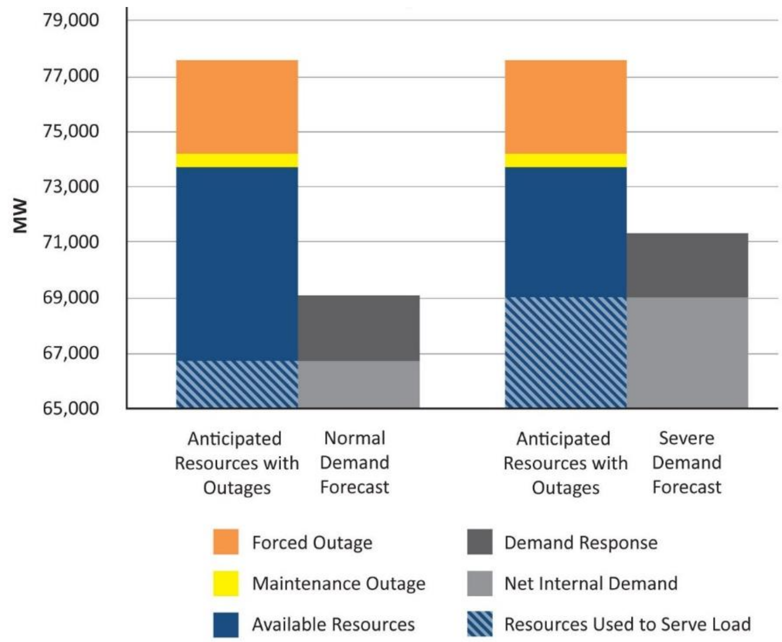


Figure 18: ERCOT Operational Analysis

WECC CAL/MX – As shown in Figure 19, for normal and severe load conditions, the anticipated forced and planned generator outages do not pose a concern.

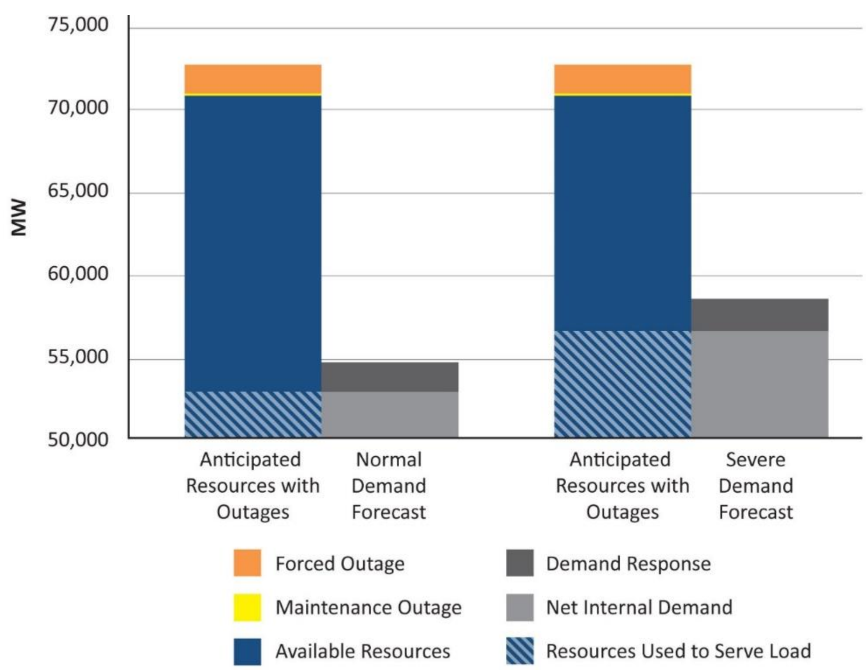


Figure 19: WECC - California - Mexico Operational Analysis

Other Summer Reliability Observations

Coal Inventories

The 2014 SRA referenced power plant coal inventories reaching their lowest level since March 2006. In late 2014 and early 2015, inventories recovered substantially and are not a major concern in regard to impacts to generator availability in summer 2015. Figure 20 demonstrates coal stocks by type between January 2009 and January 2015, showing the historically low levels in 2014 and the subsequent recovery by January 2015.[16]

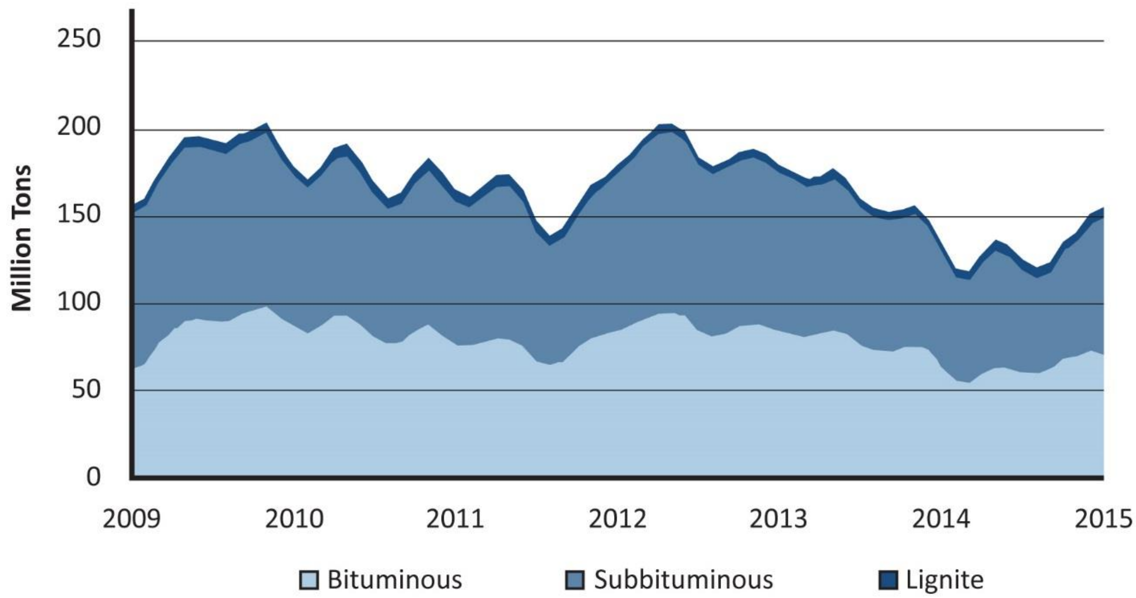


Figure 20: Coal Stocks by Type January 2009 January 2015

[16] http://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.cfm.

Demand Response

NERC has collected Controllable and Dispatchable Demand-Side Management (DSM) data for well over a decade. More recently, NERC began requesting more detailed information on these programs for inclusion in seasonal and long-term assessments.

NERC-wide, Demand Response participation is growing, while the industry continues to gain better understanding of these programs and the ability to incorporate program availability into system planning. For the 2015 summer, NERC-wide Demand Response programs total approximately 34,929 MW, with 31,255 MW expected to be available during the peak. As noted in Figure 21, SERC-N, SERC-E, and PJM show a decline in Demand Response participation with PJM having the largest decline. PJM's Demand Response reported for 2015 is a forecast of actual Demand Response this summer that cleared PJM Capacity market three years ago and is reduced by the amount of DR that will switch to rotating resources (generation).

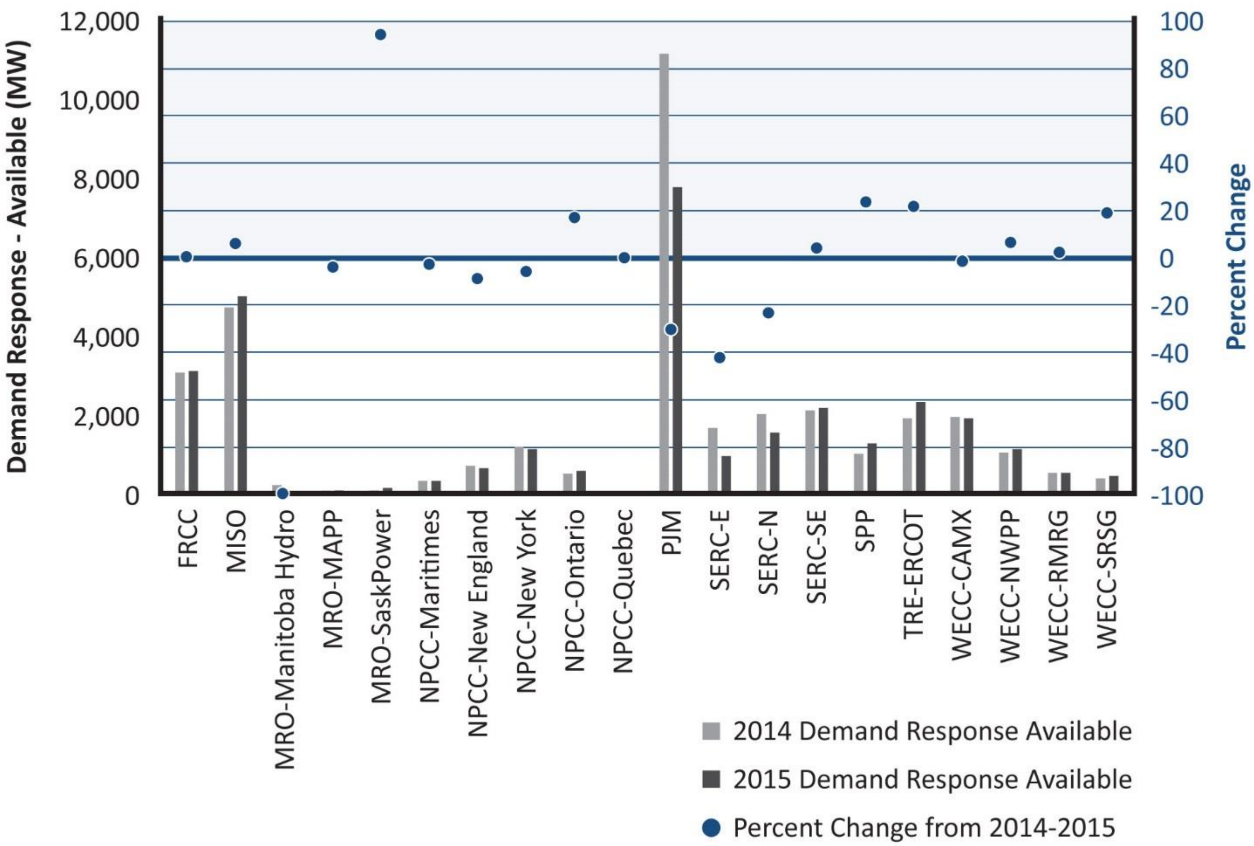


Figure 21: Demand Response Changes from 2014 to 2015

FRCC

Demand	Megawatts (MW)
Total Internal Demand	**46,452**
Total Demand Response – Available	3,101
Net Internal Demand	**43,351**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	53,673
Net Firm Capacity Transfers	2,026
Anticipated Resources	**55,699**
Existing-Other Capacity	492
Prospective Resources	**56,190**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**28.48%**
Prospective Reserve Margin	**29.62%**
NERC Reference Margin Level	**15.00%**

The Florida Reliability Coordinating Council's (FRCC) membership includes 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 (BAs) with 70 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.

The Reference Margin Level for FRCC is 15 percent and, based on the expected load and generation capacity, the Anticipated Reserve Margin is projected to be at 28 percent for the upcoming summer season. FRCC is forecast to reach its 2015 summer non-coincident Net Internal Demand of 43,351 MW in August. This projection for the 2015 summer is consistent with historical weather-normalized FRCC demand growth. The FRCC Region is projecting a decrease of 0.5 percent in the 2015 summer peak demand as compared to the previous year's projection for 2015.

Demand Response within the FRCC Region is treated as a load modifier and not as a capacity resource. Based on past experience, demand reduction is used on a limited basis and is expected to be fully available when called upon. FRCC does not anticipate any issues with the availability of Demand Response during the 2015 summer season. Demand Response is not projected to change since last summer and will be approximately 6.7 percent of the upcoming summer total peak demand.

For the upcoming summer season, the FRCC Region is not expecting any issues that could lead to large-scale impacts to generator availability. Since the last summer assessment, the Region had 1,211.8 MW of natural gas generation energized (June 2014) and will be retiring 53 MW of oil-fired generation prior to the upcoming summer season. The FRCC Region has 1,341 MW of generation under firm contract available to be imported into the Region from the SERC-SE Assessment Area throughout the summer season, and another 828 MW of member-owned generation, which is dynamically dispatched out of the SERC-SE Assessment Area. All of the firm on-peak capacity imports into the FRCC Region have firm transmission service agreements in place to ensure deliverability into the FRCC Region. Coordination between the FRCC Region and the SERC-SE Assessment Area is performed by the Operations Planning Working Group (OPWG) under the direction of the FRCC Operations Planning Coordinator. Weekly conference calls are held to coordinate planned outages (Generation, Transmission, Transformers, and Bus outages) and discuss any potential operational issues.

FRCC has not identified any specific large-scale transmission projects needed to maintain or enhance reliability during the 2015 summer season. The existing projects in the FRCC Region are primarily related to system expansion in order to serve localized load growth and maintain the reliability of the Bulk Electric System (BES) in the longer-term planning horizon. FRCC performed a Summer Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the BES within the FRCC Region under expected 2015 summer peak load and under anticipated system conditions (taking into account generation and transmission maintenance activities). This regional assessment and operational study analyzed the performance of the transmission system under normal conditions, single-contingency events, and selected multiple-contingency events determined relevant by past studies. The results were coordinated and peer reviewed by FRCC's OPWG to ensure the BES performs adequately throughout the summer time frame. The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria will be successfully mitigated under normal conditions, single-contingency events, and selected multiple-contingency events. The BES within the FRCC Region is expected to perform reliably for the anticipated 2015 summer peak season system operating conditions.

MISO

Demand	Megawatts (MW)
Total Internal Demand	**127,319**
Total Demand Response – Available	5,031
Net Internal Demand	**122,288**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	144,388
Net Firm Capacity Transfers	-56
Anticipated Resources	**144,332**
Existing-Other Capacity	2,354
Prospective Resources	**146,686**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**18.03%**
Prospective Reserve Margin	**19.95%**
NERC Reference Margin Level	**14.30%**

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering 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 reserves markets that consist of 36 local BAs and 394 market participants, serving approximately 42 million customers. The MAPP portion of the MISO Reliability Coordination Area is reported separately in the MRO-MAPP section of this report. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Footprint Changes: December 2013: Integration of MISO-South resulted in an expanded footprint.[17]

The MISO Planning Reserve Margin requirement (applied as the NERC Reference Margin Level for this assessment) is 14.3 percent for the 2015–2016 planning year, which runs from June 1, 2015, through May 31, 2016. The Anticipated Reserve Margin of 18.0 percent is 3.7 percentage points above MISO's Reference Margin Level. The 2015 Anticipated Reserve Margin is 3.0 percentage points higher than the 2014 Anticipated Reserve Margin of 15 percent. This change is not due to a substantial change in demand or resources, as demand and capacity varied little between the two years. Instead, the change was in how MISO accounted for limitations due to the contract path between MISO-North/Central and MISO-South in each year's study.

Due to a contract path limitation, MISO limited the transfer of capacity from the South region to the North/Central region to 1,000 MW in the 2014 and 2015 resource assessments. Any capacity in the South above its requirements and 1,000 MW was therefore excluded from the MISO-wide capacity reserves in these assessments, since this capacity was assumed unavailable for the North/Central region's capacity needs.

- In 2014, the South capacity was limited to the sum of the amount required to meet projected load and the 1,000 MW contract path.
- In 2015, the South capacity was limited to the sum of the amount required to meet projected load, the 1,000 MW contract path, and the amount required to meet the South Reference Margin of 14.3 percent.
- This allowed for 4.5 GW of capacity in the South to be used to meet the Reference Margin in the South in 2015, while this same capacity was assumed unavailable in the 2014 assessment.

It should be noted that the transmission system can support flows above this 1,000 MW contract path, and that these flows are allowed in the operational time frame. Flows between MISO-North/Central and MISO-South will be subject to the Operations Reliability Coordination Agreement (ORCA), where MISO will operationally limit flows to 3,000 MW. The ORCA is set to expire April 1, 2016.

The curtailment of firm load is a low-probability event for the 2015 summer season based on a probabilistic analysis performed by MISO in which a Planning Reserve Margin model is run at varying resource levels above and

[17] Includes Entergy Arkansas, Inc., Entergy Texas, Inc., Entergy Mississippi, Inc., Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., Entergy New Orleans, Inc., Cleco Power LLC, Lafayette Utilities System, Louisiana Energy & Power Authority, South Mississippi Electric Power Authority, and Louisiana Generating, LLC.

below the base resource level. However, it is always possible for a combination of higher loads, higher forced-outage rates, fuel limitations, and other factors to lead to an amount of reserves below MISO's Planning Reserve Margin.

MISO expects the coincident Total Internal Demand to peak at 127,319 MW during the 2015 summer season, which has increased by 0.06% from the 2014 Summer Reliability Assessment's Total Internal Demand of 127,247 MW. The actual peak demand observed for Summer 2014 was 115,043 MW. The % annual coincident peak demand growth rate in each localized area does not significantly vary from the overall % annual demand growth rate in the MISO Assessment Area. This forecast includes transmission losses which align with NERC reliability assessment guidelines. Including transmission losses provides a more accurate representation of peak system demand relative to generation requirements. MISO allows demand-side management (DSM) programs to be included in the Planning Resource Auction. The amount of DSM programs that are expected to be available on-peak this summer is 5,031. These DSMs result in MISO's coincident Net Internal Demand to be projected at 122,256 MW.

MISO projects 144,388 MW of Existing-Certain capacity to be available during summer 2015. Included in this capacity is 4,413 MW of behind-the-meter capacity. For the planning year 2015 2,486 MW of Nameplate Capacity was integrated into the MISO system since the prior summer assessment. Of these additions, the contributions based on generation types are: 26 MW from Petroleum, 1,305 MW from Natural Gas, 91 MW from Hydro, 47 MW from Biomass, and 1,017 MW from Wind. MISO's wind resources receive a wind capacity credit based on the effective load-carrying capability of wind generation. The average wind capacity credit for MISO is 14.7 percent. Included in the Existing-Certain capacity, MISO expects 1,325 MW of wind to be available to serve load this summer, which is approximately 10 percent of wind-registered capacity. The remaining 4.7 percent of wind capacity credits are not included as Existing-Certain because they are Transmission-Limited and Energy-Only resources.

All other intermittent resources receive their unforced capacity ratings based on historical summer performance up to the amount that they have Network Resource Interconnection Service (NRIS) or firm point-to-point Interconnection Service Right. MISO categorized 2,354 MW of Energy-Only resources that don't have firm point-to-point transmission right as Existing-Other capacity. MISO's capacity transactions amount to a net firm export of 56 MW.

To support reliable and efficient transmission service, MISO develops its MISO Transmission Expansion Plan (MTEP) annually to identify, assess, and address reliability issues within its BES footprint. The last MTEP study, MTEP14, was approved by the MISO Board of Directors in December 2014. The study tested the existing transmission plan using NERC Reliability Standards and developed additional mitigation as required to address any identified issues. A full list of transmission investment is available in Appendix A of the *MISO Transmission Expansion Plan* (MTEP) report.[18] The investments described in the MTEP14 report ensure that the MISO Region is compliant with all applicable NERC and Regional Entity standards.

Similar to previous years, MISO is conducting a Summer Readiness Workshop in which they collaborate with stakeholders to maximize preparedness for the summer period. This workshop includes an assessment of MISO's resources and the expected Planning Reserve Margin given a forecast peak load, an assessment of the transmission system under stressed conditions, and a review of key emergency operating procedures to ensure familiarity with steps and expectations. The Summer Readiness Workshop presentation is scheduled for May 6, 2015, and the *Summer Resource Assessment* report will be ready later in May. All seasonal assessment reports are publicly posted on the MISO website.[19]

[18] MISO Transmission Expansion Plan (MTEP) report.
[19] MISO Website.

During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local BAs to obtain the amount of Demand Response resources that would be available under a given notification time (e.g., two hours). If MISO reaches the point of needing to call on these resources, then MISO will deploy only the amount needed with the expectation that all the deployed resources will perform. The use of these resources is part of the progression through the RTO-EOP-002 Capacity Emergency procedure.[20] If Demand Response resources don't perform, subsequent steps of the RTO-EOP-002 procedure are implemented as necessary.

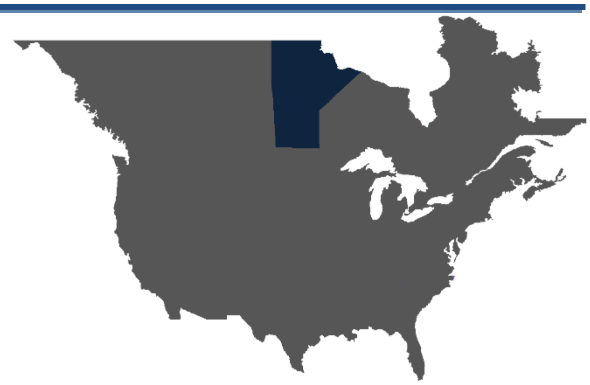
MISO does not foresee significant impacts to reliability during the 2015 summer season due to environmental or regulatory restrictions. MISO does anticipate that developing EPA regulations will impact MISO in the future, but the main impacts are anticipated beyond the 2015 summer season.

MISO works extensively with neighboring Reliability Coordinators (RCs) for the seasonal assessment and outage coordination processes and via scheduled, daily conference calls and ad-hoc communications as need arises in real-time operations.

[20] RTO-EOP-002 Capacity Emergency procedure.

MRO-Manitoba Hydro

Demand	Megawatts (MW)
Total Internal Demand	**3,151**
Total Demand Response – Available	0
Net Internal Demand	**3,151**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	5,396
Net Firm Capacity Transfers	-1,095
Anticipated Resources	**4,301**
Existing-Other Capacity	155
Prospective Resources	**4,456**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**36.00%**
Prospective Reserve Margin	**41.00%**
NERC Reference Margin Level	**12.00%**



Manitoba Hydro is a Provincial Crown Corporation that provides electricity to 548,000 customers throughout Manitoba and natural gas service to 270,000 customers in various communities throughout southern Manitoba. The Province of Manitoba is 250,946 square miles. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Authority (PA) and BA. Manitoba Hydro is a coordinating member of the Midcontinent Independent System Operator (MISO). MISO is the RC for Manitoba Hydro.

For the 2015 Summer Reliability Assessment, Manitoba Hydro's Anticipated Reserve Margin of 36 percent is projected to be higher than the Reference Margin Level of 12 percent.

The summer demand peak forecast for 2015 is 3,151 MW, which is the maximum hourly load required to serve Manitoba Hydro's customers on the integrated system. There were no significant changes to the summer demand forecast since the previous summer. The decrease in the demand forecast includes an increase in indirect DSM efforts from the previous summer assessment and inclusion of Manitoba Hydro's curtailable load program in the calculation of Total Internal Demand. The curtailable load program was previously captured under DSM in the seasonal assessments; however, under NERC's new definition of DSM, it no longer applies to this category for the *2015 Summer Reliability Assessment*. The forecast includes only one member demand, that of Manitoba Hydro, and does not have any projected growth in localized areas. Manitoba Hydro's summer hourly peak typically occurs in the late afternoon during an extremely hot weekday and, thus, the load forecast inherently includes an extreme weather effect due to the climate experienced in Manitoba. Manitoba Hydro produces a peak load 90/10 forecast to capture load forecast uncertainty based on historic load variability. The value provided in the data form is based on this 90/10 load forecast uncertainty calculation.

Manitoba Hydro has a curtailable load program that is not directly controllable but may be used in an emergency or to re-establish contingency reserves following a disturbance. Initiation is by telephone or electronic signal from the Manitoba Hydro System Control Centre. The load class is large industrial (>30 kV), and the total available curtailment for the assessment period is 224 MW. The curtailable load program is accounted for in the Total Internal Demand as indirect DSM in the 2015 summer assessment. The impact of Demand Response programs to the reliability of the Manitoba Hydro system is minimal. Manitoba Hydro only uses Demand Response programs in an emergency or to re-establish operating reserves following a disturbance.

No new capacity additions have been added or are expected this summer in the Assessment Area since the previous summer assessment. Manitoba Hydro does not have any known concerns that could impact generator availability during the upcoming summer season.

There are no changes to the methods in how expected on-peak capacity values are calculated for variable resources. The expected on-peak capacity values for hydro are determined using testing and data processing procedures in accordance with the Midwest Reliability Organization (MRO) Generator Testing Guidelines approved on March 29, 2007. Manitoba Hydro uses a modified version of the MRO Generator Testing Guidelines to comply with the Midcontinent Independent System Operator (MISO) Resource Adequacy business practices. The expected on-peak capacity that a unit can sustain is computed using the test results. These values are adjusted for ambient conditions and don't include any capacity utilized for station service. Manitoba Hydro calculates these adjustments using a longer period of record than stated in MRO Guidelines, and only the peak load hours for each month. These enhancements, which are in compliance with MISO business practices, provide more representative and stable capability values for hydro units. For wind generation in the spring, fall, and summer months, Manitoba Hydro assumes a capacity value of 14.7 percent, based on the Effective Load Carrying Capability (ELCC) analysis in MISO's *Planning Year 2015–2016 Wind Capacity Credit* report.

Manitoba Hydro has 1095 MW of on-peak capacity exports, of which 80 MW are new since the previous summer assessment, and no imports during the assessment period. For the 2015 summer assessment period, the majority of exports are to MISO.

Manitoba Hydro performs an operational study annually to determine storage reserve requirements necessary to meet demand under the lowest historic flow on record and a high load forecast. There have been no unique operational challenges recently observed. Manitoba Hydro has contracts for various types of curtailable load where, for the majority of these resources, the maximum number of deployments ranges between 15 and 25/yr. There are no environmental or regulatory restrictions that would impact reliability. Manitoba Hydro is not aware of any significant issues from neighboring Assessment Areas that would impact operations.

MRO-MAPP

Demand	Megawatts (MW)
Total Internal Demand	**4,975**
Total Demand Response – Available	94
Net Internal Demand	**4,881**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	7,087
Net Firm Capacity Transfers	-564
Anticipated Resources	**6,523**
Existing-Other Capacity	3
Prospective Resources	**6,526**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**33.65%**
Prospective Reserve Margin	**33.71%**
NERC Reference Margin Level	**15.00%**

***Footprint Changes**: There have been some membership changes since the previous summer assessment: Ames Municipal Electric System (AMES) and Rochester Public Utilities (RPU) have withdrawn from the MAPP Planning Authority. The Integrated System (IS), Western Area Power Administration (WAPA) Upper Great Plains, Basin Electric, and Heartland Consumers Power District (Heartland) will be joining the SPP Planning Authority on October 1, 2015. The integration of these entities, primarily located in North and South Dakota, would add approximately 4,700 MW of load and 9,500 miles of transmission to SPP.*

MAPP's Reserve Margins of 34 percent (Existing, Anticipated, and Prospective) exceed the target Reference Margin of 15 percent for thermal systems and 10 percent for hydro systems due to its strong generation portfolio and DSM programs for the 2015 summer season.

The Basin Electric membership continues to grow with the oil activity in northwestern North Dakota leading the demand growth. The 2015 summer assessment forecast includes 148 MW of projected load growth compared to the 2014 summer forecast. The withdrawal of AMES and RPU account for a 228 MW decrease in demand forecast for the 2015 summer.

Northwestern North Dakota (Williston Basin) leads the demand growth due to the oil activity. No reductions in growth from that area are expected anytime soon. Currently, there are two 345 kV transmission lines being constructed to this area to help improve reliability.

Basin Electric has also recently built six natural gas combustion turbine generators in the northwestern North Dakota area (total of 248 MW of accredited summer capacity) with about another 202 MW coming online in 2016. NorthWestern plans to add 100 MW of wind by the end of March 2015 with the addition of Oak Tree Wind by Clark, South Dakota connecting to its 69 kV system, and B&H Wind, which is connecting to MAPP's 115 kV bus in Tripp Jct Sub. NorthWestern anticipates B&H connecting 80 MW of wind by March 2015. Both wind farms are contracted as PPAs. The Big Stone Plant, of which NorthWestern is part owner, is going down for a major outage to install a new AQCS system this spring. The plant will be down from the end of February 2015 to the beginning of June 2015.

For the upcoming summer season, Missouri River main stem water levels may affect hydro generation. The US Army Corps of Engineers' current forecast indicates that anticipated runoff for the year is on target to provide average generation unless a significant change in runoff occurs.

Constraints on Grand Forks-Falconer 115 kV may occur during the summer season. Plans to upgrade the line have been delayed over the last couple years, and the upgrades are expected to take place sometime in 2015 or early 2016. Currently the overloads are handled with the Grand Forks-Falconer 115 kV Operating Guide, which prescribes temperature-adjusted ratings for the line that mitigate most issues; however, if temperature-adjusted ratings do not work, transmission lines in northwest Minnesota will be sectionalized, which will increase exposure to blink outages.

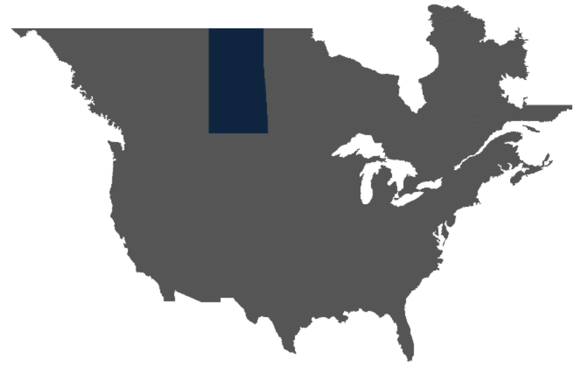
The Northwestern North Dakota region continues to experience significant load growth. Basin Electric Power Cooperative has installed seven 15 MVar mobile capacitors to support the load growth in the region until additional planned transmission is in service in 2016.

The Dry Creek 230/115 kV Substation is scheduled to be placed in service in July 2015. It will provide an additional 230 kV delivery to the Rapid City, SD area.

WAUE has installed UVLS in four local load pockets—Williston, North Dakota; Killdeer, North Dakota; Rapid City, South Dakota; and Pierre, South Dakota—to prevent localized low voltages during system disturbances. The Williston UVLS is capable of tripping 37.8 MW of load to prevent localized low voltages. Since the installation of this UVLS, improvements in the area have removed its need under normal contingency conditions. However, the Williston UVLS scheme remains in service to provide a safety net for multiple outages that may occur due to severe weather conditions. Killdeer UVLS is capable of tripping 34.3 MW of load to prevent localized low voltages. The Rapid City UVLS is capable of tripping 26.3 MW of load to prevent localized low voltages. The Pierre UVLS is capable of tripping 29.3 MW of load to prevent localized low voltages. These localized UVLS schemes are NOT considered a "UVLS Program" under applicable NERC Reliability Standards as they protect non-BES facilities.

MRO-SaskPower

Demand	Megawatts (MW)
Total Internal Demand	**3,237**
Total Demand Response – Available	165
Net Internal Demand	**3,072**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	3,654
Net Firm Capacity Transfers	0
Anticipated Resources	**3,654**
Existing-Other Capacity	0
Prospective Resources	**6,654**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**18.95%**
Prospective Reserve Margin	**18.95%**
NERC Reference Margin Level	**11.00%**



Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and RC 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 BES and its interconnections.

SaskPower Seasonal operational margins are expected to be adequate for the summer, and no significant seasonal constraints have been identified. Peak demand for the Saskatchewan system is experienced in the winter. Saskatchewan uses an 11 percent NERC Reference Margin Level, which has not changed since the prior summer assessment. An adequate Anticipated Reserve Margin of 19 percent is projected for SaskPower during the 2015 summer assessment period.

SaskPower is not expecting significant changes in the demand forecast. Saskatchewan’s total internal hourly interval demand is forecast to be 3,237 MW for the 2015 summer assessment period, resulting in no change from last year.

During the summer assessment period, Saskatchewan will be adding 23 MW of wind and 192 MW of natural gas generation to the system. There are no firm imports or exports for the 2015 summer assessment period involving Saskatchewan, and Saskatchewan is not planning for reliance on emergency imports for the current assessment period.

The 2015 summer season joint operating study with Manitoba Hydro, with input from Basin Electric (North Dakota), determines the import/export capabilities with neighboring BAs for the 2015 summer assessment period. As part of the study, applicable guidelines are issued to respective control rooms before the summer season begins. No significant seasonal constraints have been identified.

NPCC-Maritimes

Demand	Megawatts (MW)
Total Internal Demand	**3,748**
Total Demand Response – Available	312
Net Internal Demand	**3,436**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	5,648
Net Firm Capacity Transfers	0
Anticipated Resources	**5,648**
Existing-Other Capacity	0
Prospective Resources	**5,648**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**64.38%**
Prospective Reserve Margin	**64.38%**
NERC Reference Margin Level	**15.00%**

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

The Maritimes Area serves a population of approximately 1,910,000. It includes New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator (parts of northern and eastern Maine). There are two BAs, New Brunswick and Nova Scotia. The New Brunswick System Operator is the RC for the Maritimes Area, which covers approximately 57,800 square miles.

The Maritimes Area is a winter-peaking system and projects adequate surplus capacity margins above its operating reserve requirements for the 2015 summer assessment period. A 20 percent reserve criterion for planning purposes, equal to 20% x (Forecast Peak Load MW – Interruptible Load MW) is assumed, which exceeds the NERC Reference Margin Level of 15 percent. For the Operational Horizon a positive Reserve Margin is acceptable, provided all system requirements have been met (i.e., ancillary services, energy requirements, etc.).

There are no significant changes in the demand forecast from the previous summer. Forecast peak for the 2014 summer was 3,738 MW and for 2015 summer is 3,748 MW, an increase of 10 MW. The only Demand Response considered in resource adequacy assessment for the Maritimes Area is interruptible load, which comes from industrial customers under contract. Because of the variability of industrial load at any time and the small amount of megawatts, these values do not carry much weight when a seasonal reliability assessment is being completed. No generation retirements are scheduled during this summer assessment period. New generation projects are adding 162 MW of new capacity scheduled to be put in service this summer assessment period. The additions include two wind projects that total 158.6 MW and a 3.4 MW biomass project. All new additions are scheduled to be in service by September 6, 2015.

The generation type is very diverse within the Maritimes Area. Maritimes is not dependent on a single fuel source, which allows for greater system reliability: Nuclear: 8.7 percent, Natural Gas: 7.0 percent, Heavy Fuel Oil/Natural Gas: 4.2 percent, Coal: 22.2 percent, Oil: 15.3 percent, Wind: 14.1 percent, Hydro/Tidal: 17.3 percent, and other: 11.2 percent (biomass, diesel).

Because the Maritimes is a winter-peaking area, light system loads along with high wind generator outputs could occur. To mitigate such occurrences, the Maritimes has established procedures that take corrective actions (up to and including the curtailment of wind resources). Any internal operating condition within the Maritimes will be handled with a Short Term Operating Procedure (STOP).

NPCC-New England

Demand	Megawatts (MW)
Total Internal Demand	**26,710**
Total Demand Response – Available	638
Net Internal Demand	**26,072**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	30,326
Net Firm Capacity Transfers	1,237
Anticipated Resources	**31,563**
Existing-Other Capacity	262
Prospective Resources	**31,825**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**21.06%**
Prospective Reserve Margin	**22.07%**
NERC Reference Margin Level	**15.00%**

ISO New England (ISO-NE) Inc. is a regional transmission organization (RTO) serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system and also administers the region'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.

During the forecast peak demand week of July 19, 2015, ISO New England (ISO-NE) forecasts Existing-Certain Generation of 30,239 MW to meet the coincident Net Internal Demand of 26,710 MW for the 2015 summer. The Anticipated Reserve Margin is 21 percent, which is above the NERC Reference Margin Level of 15 percent. The Existing-Certain generation value originates from the Seasonal Claimed Capability (SCC) of 30,239 MW. New England is accounting for 1,337 MW in imports and 100 MW in exports, for a net import of 1,237 MW. Existing-Certain generation and Net Firm Transfers total 31,476 MW. There are 87 MW of Planned Tier 1 capacity expected for the summer 2015 operating period. When accounting for 262 MW of additional other capacity, this will reflect a New England Prospective Reserve Margin of 22 percent.

The amount of capacity for ISO-NE to meet the loss-of-load expectation (LOLE) criterion of disconnecting firm load due to resource deficiencies on average no more than 0.1 day per year is purchased through the Forward Capacity Market. This market has an annual auction three years in advance of the capacity year. After this primary auction, there are annual reconfiguration auctions prior to the commencement year to readjust installed capacity purchases and ensure adequate capacity to meet system needs. The capacity needs can vary from year to year depending on system conditions. It is possible for New England to meet system capacity needs based on Installed Capacity Requirement (ICR) as required by the markets and not meet the NERC Reserve Margins. The Anticipated Reserve Margin of 21 percent and Prospective Reserve Margin of 22 percent include the seasonal claimed capabilities of generators and do not include the short-term capacity and energy purchases from neighboring systems that are anticipated to meet the system demand. If ISO-NE were to consider generator capacity supply obligations procured through the annual energy markets, ISO-NE would expect an Anticipated Reserve Margin of 19 percent and Prospective Reserve Margin of 20 percent, respectively. Firm net transfers of 1,237 MW are only a portion of the import Total Transfer Capability (TTC) for New England.

ISO-NE expects to have 638 MW of dispatchable demand resources available during summer 2015. The active demand resources consist of Real-Time Demand Response (446 MW) and Real-Time Emergency Generation (RTEG) (192 MW). This can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP 4). These active Demand Response resources help mitigate actual or Anticipated Capacity deficiencies. OP 4 Action 2 is the dispatch of Real-Time Demand Resources and is implemented to manage operating reserve requirements. OP 4 Action 6 dispatches RTEG resources and may be implemented to maintain 10-minute reserve. Dispatchable Real-Time Demand Response and Real-Time Emergency Generation resources show significant variation in performance depending on factors such as weather, day of week, time of dispatch, and planned or forced facility shutdowns. Overall performance has been consistent with the large number and diversity of individual assets, although high variability of performance from one resource to another and from one dispatch zone to another during OP4 dispatches and audits has ranged from 74 percent to 137 percent.

On-peak and seasonal peak demand resources (i.e., energy efficiency, load management, and distributed generation) of 1,685 MW are considered demand reducers. These non-dispatchable resources include installed measures (e.g., products, equipment, systems, services, practices, or strategies) on end-use customer facilities. These resources are additional demonstrable reductions in energy use during the peak demand hours. Based on performance auditing during the most recent summer season (2014), ISO-NE verified that these resources provided their capacity supply obligations across all load zones, with load zonal performance ranging from 100 percent to 146 percent.

New England currently accounts for 1,337 MW of imports and 100 MW of exports, providing a net import transfer of 1,237 MW for the assessment period. ISO-NE meets annually with their adjacent RCs to review applicable operating agreements and operating procedures. ISO-NE routinely evaluates changes to the transmission system that could have an impact on import and export capabilities. Any adjustments to the established limits will then be shared with the adjacent RC for review in determining a safe and reliable transfer limit. If changes are required, efforts are coordinated for a simultaneous implementation.

While natural gas has become the predominant fuel source in New England to produce electricity, ISO-NE continues to monitor factors impacting natural gas deliverability throughout the winter and summer reliability assessment periods. For the 2015 summer capacity period, ISO-NE has reviewed any known natural gas pipeline maintenance. In review of the proposed schedules, the work to be performed through the summer capacity period should have no material impact to the New England natural-gas-fired generating fleet. ISO-NE does expect some impact in late September as Spectra Energy will be performing maintenance and expansion of their pipeline as part of the Algonquin Incremental Market (AIM) project. These maintenance activities are expected to be more restrictive and will be taken into consideration as part of the transmission and generation outage scheduling process.

New bulk power transmission facilities are anticipated to be placed into service in New England for the 2015 summer capacity period. The first three are identified as the 3024 line from Albion Road to Coopers Mill, the 3025 line from Coopers Mill to Larrabee, and the Coopers Mill 345/115 kV step-down autotransformer. These elements are located in an area that joins the Northern and Central Loop regions in Maine and will significantly reinforce power transfers into and out of the area. In Maine, significant improvements from the Maine Power Reliability Project (MPRP) include two new 345 kV transmission lines, one 345/115 kV transformer, two 40 MVar shunt reactors, and the retirement of many Remedial Action Schemes.

Upon completion of the multi-year MPRP transmission project, more than 450 miles of new or rebuilt 345 kV and 115 kV transmission lines will be placed into service, as well as five new substations and completion of six major substation modifications. In addition, six Remedial Action Schemes and one Automatic Closing Scheme will be retired. Improved load serving and energy transfer capabilities will be seen across multiple interfaces within Maine, as well as import/export capabilities with the Maritimes.

The Interstate Reliability Project (IRP), a portion of the New England East-West Solution (NEEWS), is another major transmission project that further improves New England's transmission system. Commissioning of the 3271 line from Card to Lake Road will increase Connecticut's import and export transfer capabilities. The new 345 kV line also reduces generation limitations that are imposed during transmission outage conditions. While the IRP project continues to proceed and new equipment is commissioned, the local facility out-generation limitations will be mitigated and energy transfer capability will be greatly improved across New England for Connecticut, Rhode Island, eastern and western load areas.

NPCC-New York

Demand	Megawatts (MW)
Total Internal Demand	**33,567**
Total Demand Response – Available	1,124
Net Internal Demand	**32,443**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	38,700
Net Firm Capacity Transfers	2,522
Anticipated Resources	**41,222**
Existing-Other Capacity	0
Prospective Resources	**41,222**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**27.06%**
Prospective Reserve Margin	**27.06%**
NERC Reference Margin Level	**17.00%**

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, encompassing 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.

The New York Independent System Operator (NYISO) is registered as the sole BA and RC for the New York Control Area (NYCA), which encompasses the state of New York.

The weather-normalized 2014 peak was 33,291 MW, 375 MW (1.11 percent) lower than the forecast of 33,666 MW prepared in December 2013. The current 2015 peak forecast is 33,567 MW and was updated in December 2014. It is lower than the December 2013 forecast by 99 MW (0.29 percent). This is attributed to a decrease in industrial load in an upstate area; annual growth rates in other areas of the state were the same or nearly the same as last year. There are two higher-than-expected scenarios forecast. One is a forecast without the impacts of energy efficiency programs or behind-the-meter solar photovoltaic generation. The high-growth forecast for the summer of 2015 is 33,890 MW. The second is a forecast based on extreme weather conditions, set to the 90th percentile of typical peak-producing weather conditions. The extreme weather forecast for 2015 is 35,862 MW.

The New York State Reliability Council (NYSRC) has determined that an Installed Reserve Margin (IRM) of 17.0 percent in excess of the NYCA seasonal peak demand forecasts for the Capability Year 2015–16 is required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion. The 2015–16 Capability Year IRM is unchanged from Capability Year 2014–15.

Since the summer of 2014, there have been net nameplate additions of 775 MW. The Danskammer plant, located in the Hudson Valley, was repowered in fall 2014. It was converted from coal to natural gas. Other net nameplate additions are 227 MW of dual fuel (oil/natural gas) and 16 MW of wind generation.

In March 2015, a new substation, Eastover Road, went into service, tapping the 230 kV Rotterdam-Bear Swamp line between New York and New England. The station is located in New York near Albany and, consequently, changes the NY-NE interface definition to Eastover Road-Bear Swamp. It connects to the local 115 kV system. Also, expected to be completed by June 2015, a new tap station is being constructed on the 345 kV Homer City-Watercure line between New York and PJM called Mainsburg. The new station changes the NY-PJM interface definition by replacing Homer City-Watercure (30) line with the Homer City-Mainesburg (47) line and adding a tie on the high side of the Mainesburg 345/115 transformer.

No unique operational problems are anticipated for the summer of 2015. NYISO maintains joint operating agreements with each of its adjacent RCs that include provisions for the procurement or supply of emergency energy and provisions for wheeling emergency energy from remote areas if required. Prior to the operating month, NYISO identifies to neighboring control areas the capacity-backed transactions that are expected to be both imported into and exported from NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2015 summer season, the New York BA expects to have 2,522 MW of net import capacity available.

NYISO anticipates sufficient resources to meet peak demand without the need to resort to emergency operations. The Emergency Demand Response Program (EDRP) and ICAP/Special Case Resource program (ICAP/SCR) are designed to promote participation, and the expectation is for full participation of these programs in the summer of 2015. For the summer 2015 capability period, NYISO projects to have 1124.4 MW of Special Case Resources (SCRs) and 85.6 MW of EDRP resources available. There is no limitation as to the number of times a resource can be called upon to provide a response. The SCRs are required to respond when notice has been provided in accordance with NYISO's procedures; response from the EDRP is voluntary for all events. Further control actions are outlined in NYISO policies and procedures.

NPCC-Ontario

Demand	Megawatts (MW)
Total Internal Demand	**22,991**
Total Demand Response – Available	591
Net Internal Demand	**22,400**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	27,695
Net Firm Capacity Transfers	0
Anticipated Resources	**27,695**
Existing-Other Capacity	0
Prospective Resources	**27,695**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**23.64%**
Prospective Reserve Margin	**23.64%**
NERC Reference Margin Level	**19.50%**

Ontario's electrical power system is geographically one of the largest in North America, covering an area of 415,000 square miles and serving the power needs of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

For the summer peak, the Reference Reserve Margin is 19.5 percent. Both the Anticipated and the Prospective Planning Reserve Margins are above the Reference Reserve Margin for Ontario during the upcoming summer season. There are no foreseen reliability concerns related to transmission constraints, environmental regulation, or generator availability.

The forecast peak demand for the 2015 summer is 22,991 MW under the normal weather scenario and 24,814 MW under the extreme weather scenario. These forecasts represent a continued trend of small declines from the forecasts over previous summers. The impact of conservation, critical peak pricing (the Industrial Conservation Initiative and Time-of-Use Rates) and growth in distributed generation all combine to reduce summer peak demands.

For the upcoming summer, the amount of Demand Response is not expected to change (591 MW available). The Demand Response programs consist of dispatchable loads, Demand Response 3, and Peaksaver. Dispatchable loads bid into the market like any resource, Demand Response 3 is triggered based on market prices, and Peaksaver is an air-conditioning cycling program. These programs have been in use for a number of summers.

Since the last summer assessment, Ontario has seen 60 MW of new installed wind capacity, 343 MW of new installed hydro capacity, and 40 MW of new installed solar capacity connected to the transmission system. One 153 MW coal unit was also converted from coal to advanced biomass. In addition, 83 MW of distribution-connected wind and 345 MW of distribution-connected solar were added in Ontario.

Planned resources that are expected to be in service prior to the forecast summer peak demand include 989 MW of wind, 140 MW of solar and 40 MW of biomass capacity.

NPCC-Québec

Demand	Megawatts (MW)
Total Internal Demand	**21,203**
Total Demand Response – Available	0
Net Internal Demand	**21,203**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	33,651
Net Firm Capacity Transfers	-1,955
Anticipated Resources	**31,696**
Existing-Other Capacity	0
Prospective Resources	**31,696**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**49.49%**
Prospective Reserve Margin	**49.49%**
NERC Reference Margin Level	**11.70%**

The Québec Assessment Area is located in the northeastern part of the NPCC Region. It covers 643,803 square miles and a population of 8 million people (Province of Québec). The Area has ties with Ontario, New York, New England, and the Maritimes, consisting of either HVDC ties, radial generation, or radial load. Transmission voltages are 735, 315, 230, 161, 120, and 69 kV with a ± 450 kV HVDC multi-terminal line. Transmission line length totals 21,243 miles (34,187 km) as of December 31, 2014.

The Québec system is winter peaking because a large amount of space heating load is present during winter operating periods.

The Reference Margin Level is calculated for the winter period only and is evaluated at 11.7 percent. It is drawn from the NPCC 2014 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee in December 2014. The Anticipated Reserve Margin for the 2015 Summer Operating period is 49.5 percent, well above the Reference Margin Level. The demand forecast for the 2015 summer peak period is 21,203 MW, with no significant changes since last summer forecast (21,100 MW). As the Québec area is winter peaking, there are no Demand Response programs for the summer period. Therefore, no particular resource adequacy problems are forecast.

For the 2015 summer assessment, nameplate wind capacity of the Québec area is 2881 MW, a 482 MW increase since the last summer assessment. Also, the hydroelectric generating station La Romaine-2 (640 MW) has been fully in service since the end of 2014. There have been no major unit retirements.

Given the amount of available capacity and the load forecast level in the summer, there are no significant impacts associated with exports capacity, and the Québec area does not rely on imports during the summer period. The firm and expected transactions have been coordinated and treated consistently with the neighboring Assessment Areas.

In the Québec area, most transmission line, transformer, and generating unit maintenance is done during the summer period. Summer peak load is typically about 56 percent of winter peak load, and resource availability is not a problem at all during summer operating periods even though exports to summer-peaking subregions of NPCC are sustained during peak hours. Internal generating unit and transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales, and margins. Interconnection maintenance outages are scheduled outside peak periods and are coordinated with neighboring system authorities. Therefore, no impact on internal reliability and inter-area capabilities with neighboring systems is projected.

PJM

Demand	Megawatts (MW)
Total Internal Demand	**155,544**
Total Demand Response – Available	7,780
Net Internal Demand	**147,764**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	173,612
Net Firm Capacity Transfers	2,624
Anticipated Resources	**176,236**
Existing-Other Capacity	0
Prospective Resources	**176,236**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**19.27%**
Prospective Reserve Margin	**19.27%**
NERC Reference Margin Level	**15.60%**

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 BA, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and RC.

The PJM Anticipated Reserve Margin will not be below the Reference Margin Level for the upcoming summer. The Anticipated Reserve Margin is 19.3 percent. The Reserve Requirement is 15.6 percent. The PJM 2015 summer peak demand forecast is 155,544 MW. PJM has incorporated a factor into the load forecast that reduces load forecasts because of the trend of increased energy efficiency effects noted over the last several years. This summer's load forecast is 3 percent lower than what was forecast for 2015 last year. No localized areas within PJM are experiencing growths that are out of line with the other localized areas and previous forecasts.

For 2015, PJM has introduced DSM that can be called all year and DSM that can be called an unlimited number of times during the summer. The normal type of DSM that can be called only during the summer and only 10 times during that summer is still the most subscribed segment available. Total load management for summer 2015 in PJM will amount to 7,780 MW, which will allow up to 5.0 percent of forecast peak load to be removed under Demand Response.

PJM's total Anticipated Capacity this summer will be 173,612 MW. This is a total net loss of 6,163 MW over the 2014 value.

This summer, imports into PJM amount to 4,019 MW, and exports amount to 1,395 MW. The net is 2,624 MW into PJM. This is only 1.6 percent of the forecast peak load. Capacity and net transfers amount to 176,236 MW of resources.

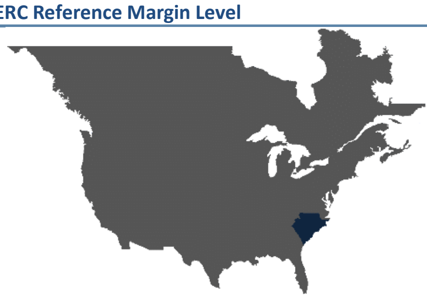
Six static var compensators (SVCs) were added since last summer. PJM also added 210 MVar of capacitors, eight BES transformers, two 230 kV lines, and 200 MVars of shunt reactors.

PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs versus the cost of constructing a new natural-gas-fired turbine. This at-risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint; however, there may be localized reliability concerns that have been addressed either with replacement generation capacity or transmission upgrades if necessary. PJM continues to track and coordinate retirements, retrofits, and scheduled transmission upgrades to ensure Reserve Margins and reliability are maintained.

PJM has secured sufficient capacity and Demand Response resources to cover PJM's reserve requirements. EPA regulations have resulted in the retirement of approximately 22,000 MW over the last five years. The PJM Capacity Market continues to secure new capacity, and PJM is expected to meet reserve requirements into the future.

SERC

	SERC-E	SERC-N	SERC-SE
Demand	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand	**42,825**	**42,097**	**46,473**
Total Demand Response – Available	959	1,557	2,202
Net Internal Demand	**41,866**	**40,540**	**44,271**
Projected Resource Categories	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Existing-Certain Capacity	50,630	50,836	62,954
Net Firm Capacity Transfers	1,150	-948	-2,838
Anticipated Resources	**51,780**	**49,888**	**60,116**
Existing-Other Capacity	47	944	328
Prospective Resources	**51,827**	**50,832**	**60,444**
Planning Reserve Margins	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**23.68%**	**23.06%**	**35.79%**
Prospective Reserve Margin	**23.79%**	**25.39%**	**36.53%**
NERC Reference Margin Level	**15.00%**	**15.00%**	**15.00%**



SERC-E

SERC-N

SERC-SE

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).

SERC member systems have incorporated expected future energy efficiency standards into their sales models and have developed a Statistically Adjusted End-use (SAE) model incorporating the end-use details into econometric methodologies for the demand forecast.

Entities within SERC's Assessment Area take into account generation outages and load forecasts in various long-term and operations planning activities. Considered factors include improved economy, changes to electricity and natural gas prices, extreme summer heat conditions, and the potential addition of any expected new customers. Demand Response and energy conservation programs are available during the summer season and are considered as resources or load modifiers depending on the type of program offered and the contractual agreements involved.

There have been no significant increases in variable resources in the SERC Assessment Area or any changes to how expected on-peak capacity values are calculated. Wind and solar resources are analyzed based on historical patterns and are included for on-peak capacity and Reserve Margin, but at some level of reduced capacity equivalent. Capacity and energy dispatched from hydro resources are based on comprehensive modeling of the water management of necessary conservation requirements. Considering the relative capacity and the operational nature of these resources, expected on-peak capacity values are predictable and consistent.

Past experiences and studies have indicated two main areas with reactive power limits for certain situations. Those areas are Philadelphia, MS and Northeast Tennessee. For the Philadelphia, MS area, an operating guide provides requirements for dispatching local area generation to provide voltage support for the area during the upcoming summer season. For the Northeast Tennessee area, an operating guide was created to address voltage issues if the Volunteer-Phipps Bend 500 kV line is lost during heavy line-loading conditions. This operating guide provides system operators with mitigation options (e.g., transmission loading relief (TLR), transmission reconfiguration, generation redispatch, etc.) for preventing voltage stability issues.

SERC entities participate through SERC's Near-Term Study Group (NTSG) in a summer peak season evaluation. Through this, the NTSG works closely with the operations area of the respective systems to identify peak season activities that could impact the performance of the BPS facilities. This includes generation and transmission outages, unavailable capacity, and known or expected power transfers under both normal and contingency conditions.

Due to the expansion of the RTO footprint and the MISO BA Area in December 2013, SERC member committees are continuing to assess the reliability impacts of this change within the SERC footprint. The issues under assessment are market flows, modeling, and study analysis. Recently, the Operations Reliability Coordination Agreement (ORCA)[21] was extended with newly defined parameters until April 1, 2016. This will limit the amount of transfers between the MISO subregions in order to limit reliability impacts on neighboring systems. In addition, the SERC Reliability Studies Steering Committee (RSSC)[22] has created a task force to address modeling issues due to MOD-032 changes and to provide a more accurate representation of market flows in the SERC Region. SERC's study groups are working with MISO and PJM to develop a comparison study to enhance reliability across interfaces on regional and subregional levels.

21 Operations Reliability Coordination Agreement (ORCA).

22 SERC Reliability Studies Steering Committee (RSSC).

SPP

Demand	Megawatts (MW)
Total Internal Demand	**50,529**
Total Demand Response – Available	1,284
Net Internal Demand	**49,245**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	64,898
Net Firm Capacity Transfers	1,533
Anticipated Resources	**66,431**
Existing-Other Capacity	0
Prospective Resources	**66,431**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**34.90%**
Prospective Reserve Margin	**34.90%**
NERC Reference Margin Level	**13.60%**

Southwest Power Pool (SPP) is a NERC Regional Entity (RE) that covers 370,000 square miles and encompasses all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas, serving approximately 6.2 million households. The SPP Winter Assessment is reported based on the Planning Coordinator footprint. Along with the SPP RE footprint, it also includes Nebraska Public Power District, Omaha Public Power District, and Lincoln Electric System, which are registered with the Midwest Reliability Organization Regional Entity. The SPP Assessment Area footprint has 48,368 miles of transmission lines, 915 generating plants, and 6,408 transmission-class substations.

The SPP Assessment Area non-coincident Total Internal Demand forecast for the 2015 summer is 50,529 MW. The SPP Assessment Area Anticipated Reserve Margin is forecast to be 32 percent, which remains well above the reserve requirement of 13.6 percent.

Demand Response in the SPP Assessment Area is primarily treated as a summer peak load modifier and is expected to perform if called upon. For the most part, SPP Assessment Area members include their own DR and energy efficiency programs as reductions in their load forecasts. SPP does not anticipate any issues with the availability of Demand Response during the 2015 summer season.

SPP expects to integrate 2,173 MW of Nameplate Capacity by the end of the 2015 summer time frame. The expected contributions are 305 MW from natural gas, and 1,868 MW from wind.

SPP has identified several flowgates as being constraints on the transmission system. These constraints can be mitigated by redispatching generation, and no reliability issues are expected. SPP has identified a few areas that require must-run generation for voltage support during times of heavy load, loss of equipment, or unavailability of local peaker units responding. Operating guides have been put into place to provide mitigation.

SPP Assessment Area members forecast 2,547 MW of firm imports and 1,014 MW of firm exports for the 2015 summer. All of these capacity transactions have firm transmission service. The SPP Assessment Area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers.

SPP is not aware of any significant issues in neighboring areas that are expected to affect the reliability of the system. SPP Assessment Area operators have daily calls with neighboring areas to discuss potential issues and their impacts on SPP. If an issue is determined to impact reliability, then proper mitigation actions are deployed.

The Operations Reliability Coordination Agreement (ORCA) has recently been extended to April 1, 2016 and has new operational limits that allow MISO to dispatch up to 3000 MW between MISO-North and South. Similar to the previous ORCA, MISO must take initial relief obligations during congestion down to 2000 MW of dispatch flow, at which time normal Transmission Limiting Relief (TLR) is used. This revised ORCA procedure is coordinated between SPP, MISO, and the joint parties. 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 redispatch the most cost-effective generation between the two markets to relieve the congestion. SPP and MISO still rely on TLR to curtail the impact of transactions from entities other than SPP or MISO.

TRE-ERCOT

Demand	Megawatts (MW)
Total Internal Demand	**69,057**
Total Demand Response – Available	2,343
Net Internal Demand	**66,714**
Projected Resource Categories	Megawatts (MW)
Existing-Certain Capacity	73,115
Net Firm Capacity Transfers	776
Anticipated Resources	**77,551**
Existing-Other Capacity	517
Prospective Resources	**78,068**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**16.24%**
Prospective Reserve Margin	**17.02%**
NERC Reference Margin Level	**13.75%**

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; 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.

For the 2015 summer season, the ERCOT Region is expected to exceed its Reference Margin of 13.75 percent. Based on ERCOT's peak load forecast and the resource capacity expected to be available, the Anticipated Resource Margin is projected to be 16.24 percent. ERCOT's peak demand forecast (Total Internal Demand) for summer 2015 is 69,057 MW and is expected to occur in early August. The forecast is 1.4 percent higher than last summer's peak demand forecast of 68,096 MW.

Regarding generation resource additions, 2,109 MW of natural gas (summer-rated capacity), 1,588 MW of installed wind, and 68 MW of installed utility-scale solar entered commercial service since the last summer assessment. Planned gas resources for the upcoming summer season include the Panda Temple 2 natural gas combined-cycle project and the Goldsmith Peaker project with summer capacity ratings of 717 MW and 294 MW, respectively. Planned wind resources total 2,139 MW of installed capacity, which translates into an on-peak capacity contribution of 346 MW. About 40 percent of this capacity is located in the coastal region, comprising 11 counties that border the Gulf of Mexico. An additional 403 MW of capacity that was on extended outages due to insufficient cooling water will now be available for the summer.

ERCOT implemented a new methodology for calculating the on-peak capacity contribution of wind in October 2014 that uses historical operational data at the time of seasonal peak load hours in place of the modeled Effective Load Carrying Capability (ELCC) approach used previously. The new methodology includes calculation of summer and winter season capacity contribution percentages, as well as percentages for coastal and non-coastal resources reflecting the significantly different diurnal wind patterns for these regions. For this summer assessment, the summer capacity contribution percentages are 12 percent for non-coastal resources and 56 percent for coastal resources. In comparison, ERCOT used a percentage value of 8.7 percent for all wind resources in last year's summer assessment. The impact of the new methodology is to increase anticipated summer on-peak wind capacity by 1,314 MW (1,280 MW to 2,594 MW) for this summer assessment.

ERCOT continues to rely on a variety of Demand Response programs administered by both ERCOT and several Transmission and Distribution Service Providers (TDSPs) to support summer resource adequacy under emergency conditions. For summer 2015, ERCOT estimates that it will have 1,251 MW of Load Resources (LRs) providing ancillary services that are contractually committed to ERCOT during summer peak hours. ERCOT also has Emergency Response Service (ERS), a 10- and 30-minute Demand Response, and distributed generation service, designed to be deployed in the late stages of a grid emergency prior to shedding involuntary firm load. ERCOT expects 827 MW of essential reliability services to be available for the 2015 summer season. Finally, the summer 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 265 MW of additional Demand

Response capacity this summer and are subject to concurrent deployment with existing ERCOT Demand Response programs, pursuant to agreements between ERCOT and the TDSPs. In aggregate, these Demand Response programs represent 3.4 percent of the ERCOT Region's Total Internal Demand forecast.

ERCOT continues to closely monitor resource risks attributable to extended drought conditions in Texas as well as new environmental regulations that will be in effect during the 2015 summer season, the Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) in particular. Concerning the ongoing drought, recent rains have significantly improved drought conditions. ERCOT does not expect unit outages to occur during the summer due to inadequate water levels.

ERCOT also does not anticipate impacts to reliability during the upcoming summer season resulting from compliance requirements for CSAPR and MATS based on surveys and discussions with resource owners. These regulations primarily impact coal-fired generation resources. Compliance with CSAPR began in January 2015, and the MATS compliance date is in April 2015, though many coal-fired units in ERCOT have obtained a one-year compliance extension. ERCOT surveyed generation resources on the impact of these and other regulations in August 2014 and followed up with coal-fired resource owners on CSAPR and MATS compliance in March 2015. For CSAPR, most generators reported either no impacts or that they have purchased, or may need to purchase, allowances by the end of the 2015. For MATS, about 6 GW of coal capacity was reported as being compliant by April 2015, while another 14 GW have control equipment modifications pending and received a one-year compliance extension to April 2016. Of this 14 GW, about 7 GW have completed the modifications and are conducting system testing.

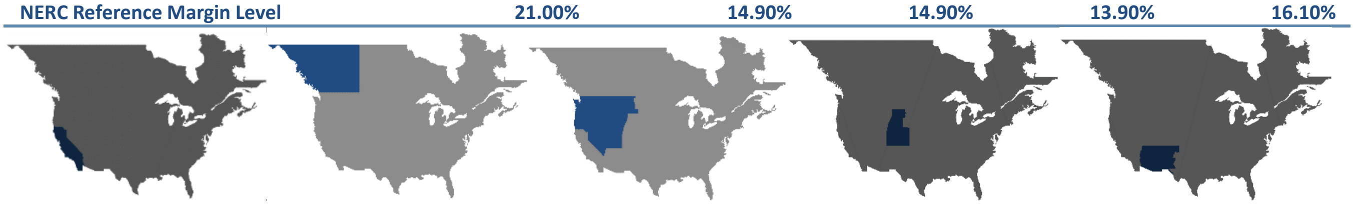
With respect to transmission planning, ERCOT's 2014 Regional Transmission Plan, released in December 2014, identified the list of projected 2015 summer peak reliability constraints that will not have a transmission project in place to resolve the constraints prior to summer 2015. While planned transmission upgrades in the west Texas area are on schedule, constraints for which transmission project upgrades are not yet in place to resolve continue to exist at the Permian Basin natural gas exploration and production areas where demand has increased faster than previously anticipated. Operational solutions have been designed in collaboration with associated Transmission Owners for all unresolved 2015 reliability constraints identified in the Regional Transmission Plan. Operational solutions may include temporarily reconfiguring the system, running less-efficient generation or, in some cases, establishing a procedure to shed load in the event that a contingency occurs.

On March 24, 2015, the U.S. Department of Energy granted the owners of the Frontera Facility (a 524 MW Switchable Generation Resource) authorization to export the plant's power to the Mexican power grid. Due to the loss of this capacity, ERCOT has been concerned about power supply sufficiency and transmission stability in the Rio Grande Valley during the 2015–16 time frame when other generation or transmission facilities serving that region are not available and power demand is high. To address this concern, the Frontera Facility's owner agreed to remain partially available in the ERCOT market until new 345 kV lines are energized in the Valley by summer 2016 and agreed to reliability safeguards for ensuring the plant will be available to ERCOT if needed in an emergency. ERCOT has developed mitigation measures for the area until the new lines are energized.

Completion of the joint ERCOT-Transmission Owner synchrophasor demonstration project occurred in December 2014, resulting in the installation of 76 phasor measurement units (PMUs). The Lower Colorado River Authority (LCRA) also started sending data to ERCOT from 21 of their PMUs beginning in March 2015. No other significant new transmission equipment is planned to be in service before the upcoming summer.

WECC

	CAMX	NWPP-CA	NWPP-US	RMRG	SRSG
Demand	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand	**54,751**	**19,070**	**49,298**	**12,447**	**23,549**
Total Demand Response – Available	1,921	0	1,145	547	461
Net Internal Demand	**52,830**	**19,070**	**48,153**	**11,900**	**23,088**
Projected Resource Categories	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Existing-Certain Capacity	65,579	26,091	58,535	14,882	33,389
Net Firm Capacity Transfers	7,250	-1,791	1,159	-491	-3,995
Anticipated Resources	**72,829**	**24,300**	**59,694**	**14,391**	**29,394**
Existing-Other Capacity	0	0	0	0	0
Prospective Resources	**72,829**	**24,300**	**59,694**	**14,391**	**29,394**
Planning Reserve Margins	Percent (%)	Percent (%)	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**37.86%**	**27.42%**	**23.97%**	**20.94%**	**27.31%**
Prospective Reserve Margin	**37.86%**	**27.42%**	**23.97%**	**20.94%**	**27.31%**
NERC Reference Margin Level	**21.00%**	**14.90%**	**14.90%**	**13.90%**	**16.10%**



CAMX **NWPP-CA** **NWPP-US** **RMRG** **SRSG**

The Western Electricity Coordinating Council (WECC) is one of eight electric reliability councils in North America and is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, including 38 BAs, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 82.2 million people, it is the largest and most diverse of NERC's 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. For the summer assessment, the WECC Assessment Area is divided into five subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the NW-Canada and NW-US areas. These subregional divisions are used for this study as they are structured around Reserve Sharing groups that have similar annual demand patterns and similar operating practices.

Footprint Changes*: Silver State Energy Association, comprised of Southern Nevada Water Authority, City of Boulder City Nevada, Overton Power District No. 5, Lincoln County Power District No. 1, and The Colorado River Commission of Nevada, has moved from the NEVP BA area to the WALC BA area. This BA footprint change has a nominal effect on either area as the summer peak demand is only about 200 MW.*

The Existing and Anticipated Reserve Margins for WECC, its five subregions, and all zones within the subregions, are expected to exceed their respective NERC Reference Reserve Margins for the upcoming summer season. The Reference Reserve Margins are calculated using a building block methodology[23] created by WECC's Reliability Assessment Work Group (formerly Loads and Resources Subcommittee). The four elements of the building block margin calculation are consistent from year to year, but the regional and subregional calculations can, and do, have slight variances as the building block elements are updated annually. The Reserve Margins are adequate largely due to the construction of power plants in anticipation of a load growth that was interrupted by the economic recession and to facilities that satisfy various state-mandated renewable resource acquisition policies. It should be noted that abnormal weather conditions would result in different Reserve Margins, and severe adverse weather conditions or unexpected equipment failure may result in localized power supply or delivery limitations.

The aggregate WECC 2015 summer total coincident peak demand is forecast to be 153,956 MW and is projected to occur in August. The 2015 summer coincident peak demand forecast is 0.3 percent above last summer's forecast coincident peak demand of 153,426 MW, reflecting increases in energy efficiency, increases in rooftop solar installations, and a continuation of slow demand growth associated with the economic downturn. Controllable and dispatchable Demand Response accounts for slightly less than 2.4 percent of the total peak demand. All forecast margin results assume demands associated with normal weather conditions.

[23] Elements of the Building Block Target are detailed in NERC's Attachment II: Seasonal Assessment – Methods and Assumptions.

Net nameplate existing and under-construction resource changes since last summer's assessment total approximately 4,100 MW, with almost 6,100 MW of additions and approximately 2,000 MW of retirements. The additions include over 2,300 MW of solar facilities and almost 900 MW of wind-powered resources. Natural-gas-fired generation increased by about 1,600 MW, hydro generation by over 750 MW, geothermal generation by 330 MW, and other renewables generation by about 220 MW. The retirements include over 1,050 MW of natural-gas-fired generation associated with California's once-through cooling requirements, 750 MW of coal-fired generation, and about 200 MW of old technology wind and solar generation built in the mid-1980s.

WECC continues to track and study the impacts on reliability, as well as 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 as natural gas becomes the primary fuel for new thermal generation. WECC and Peak Reliability staff, as part of ongoing efforts, are meeting and working with the natural gas industry to better understand potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.

The California/Mexico subregion continues to experience an extended drought that has reduced energy production from hydro generation. However, within CAISO, over 2,000 MW of new renewable generation has gone into commercial operation over the last 12 months that will offset the derates in hydro capability. As California progresses toward the mandated 33 percent Renewable Portfolio Standard by 2020, California's trend of increasing Planning Reserve Margins will continue as new renewable resource additions come on-line. For example, in 2014, the amount of energy produced by hydro generation decreased from that generated in 2013 by 7,800 GWh, and during the same period, solar generation increased by 6,000 GWh. While California hydro resources are primarily system resources, the reduction in hydro generation may cause operational issues in certain localized areas that may not be addressed by renewable generation additions. CAISO expects that any localized issues will be addressed through existing operating procedures.

Electricity generated at hydro generation facilities located in California accounted for approximately 7 percent of total California demand in 2014; therefore, a reduction in hydro generation is not expected to adversely impact the reliable operation of the system. WECC staff conducted scenario studies that modeled cases with 50 percent and 100 percent reductions in California hydroelectric generation. The results of these studies indicate that a 50 percent hydro reduction produces a 35.3 percent Anticipated Reserve Margin for the entire California/Mexico subregion, and the 100 percent reduction case produces a 22.0 percent Anticipated Reserve Margin. The expected margins are above the Planning Reserve Margin of 21.0 percent and well above the operating margin of around 6.0 percent. It should be noted that the WECC modeling was associated with overall interconnection conditions and did not investigate potential impacts to localized internal California load areas.

Additionally, the California/Mexico subregion continues to put market and operating procedures in place to address operational issues relating to the transition to more renewable resources. CAISO has enhanced its ancillary services market to address the growing need for ramping capability to meet the increasing ramping up and ramping down requirements associated with greater penetrations of solar and other renewable resources. Furthermore, the over-generation of energy, primarily during periods of low demand and high solar generation, is an emerging issue that is receiving significant attention. In addition to using market mechanisms to resolve these issues, CAISO continues to work with market participants and surrounding areas to identify additional solutions. The CAISO energy imbalance market is an example of regional coordination and cooperation that is helping to address these issues.

Localized short-term operational issues may also occur due to wildfires. Below-normal precipitation has left large portions of the West in an extremely dry condition that is ripe for frequent and large wildfires. Due to the widely dispersed nature of the transmission grid, outages due to wildfires are generally not widespread, but some metropolitan load centers may be adversely impacted by short-term outages of major interconnections.

WECC staff does not perform special operating studies concerning extreme weather or drought conditions for the seasonal assessments. However, these studies are performed by the individual Load-Serving Entities and BAs within WECC, and none of these entities have reported any extreme-weather-related issues. For example, CAISO has investigated extreme scenarios that address impacts of continued drought conditions and other adverse conditions.[24] In the event of extreme weather, margins may drop below planning margins, but it is not expected that any subregion will need to cut firm demand in order to maintain operating Reserve Margins.

The Pacific DC Intertie (PDCI), a high-voltage transmission line that runs from the Pacific Northwest to the Los Angeles area, is currently undergoing upgrades to increase transmission capability.[25] The upgrade work requires a reduction in line transfer capacity of 1,100 MW (from 3,100 MW to 2,000 MW) during the upgrade process. Despite the derate of the PDCI, the BPS is expected to be adequate to handle normal intra-area transfers, and no impacts to reliability are expected.

Detailed information regarding Northwest[26] and California[27] 2015 summer conditions is available online.

24 Briefing on preliminary 2015 Summer Loads & Resources Assessment.
25 Pacific Northwest to the Los Angeles area, transmission upgrades.
26 Northwest Power Pool Area Assessment.
27 CAISO 2015 Summer Reliability Assessment.

Appendix I: Reliability Assessment Subcommittee Roster

Name	Organization
Layne Brown (Chairman)	Western Electricity Coordinating Council
Mohammed Ahmed	AEP
Alan C Wahlstrom	Southwest Power Pool, Inc.
Barbara A Doland	SERC Reliability Corporation
Brad Woods	Texas Reliability Entity, Inc.
Chris Haley	Southwest Power Pool, Inc.
Hubert C Young	South Carolina Electric & Gas Co.
James Leigh-Kendall	Sacramento Municipal Utility District
Jin Chen	SERC Reliability Corporation
John G Mosier	Northeast Power Coordinating Council
John Reinhart	MISO
K. R Chakravarthi	Southern Company Services, Inc.
Lewis De La Rosa	Texas Reliability Entity, Inc.
Mark J. Kuras	PJM Interconnection, L.L.C.
Matt Hart	Southern Company
Michael Courchesne	ISO New England, Inc.
Peter Warnken	ERCOT
Peter Wong	ISO New England, Inc.
Philip A Fedora	Northeast Power Coordinating Council
Richard Becker	Florida Reliability Coordinating Council
Ryan Westphal (Vice-Chair)	MISO
Salva R. Andiappan	Midwest Reliability Organization
Srinivas Kappagantula	PJM Interconnection, L.L.C.
Tim Fryfogle	ReliabilityFirst
Travis Tate	SERC Reliability Corporation
William B Kunkel	Midwest Reliability Organization

Appendix II: Seasonal Reliability Concepts

Demand	Definition
Total Internal Demand	The 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 (forecast). Total Internal Demand includes adjustments for the indirect Demand-Side Management programs such as Conservation programs, improvements in efficiency of electricity use, and all nondispatchable Demand Response programs.
Demand Response – Available	The amount of controllable and dispatchable Demand-Side Management programs expected to be available during peak demand. DSM is defined as all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use. For NERC assessments, the following four Demand Response programs are included: Direct Control Load Management (DCLM), Interruptible Load (IR), Critical Peak-Pricing (CPP) with Load Control, and Load as a Capacity Resource (LCR).
Net Internal Demand	Total Internal Demand, less Demand Response – Available (Direct Control Load Management (DCLM), Interruptible Load (IR), Critical Peak-Pricing (CPP) with Load Control, and Load as a Capacity Resource (LCR).
Demand Response	Definition
Direct Control Load Management (DCLM)	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand. Note: This type of control usually reduces the demand of residential or small commercial customers. [Source: NERC Demand Response Availability Data Systems Definitions]. "Program Total" represents total enrolled in this program. "Available" represents the estimated amount of customer demand that will be interruptible at the time of peak hour demand by direct control of a system operator by interrupting power supply to individual appliances or equipment on customer premises.
Interruptible Load (IR)	A program where the electrical consumption is subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce Load during system contingencies. In some instances, the Demand Reduction may be affected by action of the System Operator, called “remote tripping,” after notice to the customer in accordance with contractual provisions. [Source: NERC Demand Response Availability Data Systems Definitions]. "Available" represents the estimated magnitude of customer demand that will be interruptible at the time of peak hour demand by direct control of a system operator by interrupting power supply to individual appliances or equipment on customer premises. "Program Total" represents the total amount of customer demand categorized as Interruptible Load (IL).
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. [Source: NERC Demand Response Availability Data Systems Definitions] "Program Total" represents the total amount of customer demand enrolled in CPP programs. "Available" represents the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of peak hour demand by direct control of the System Operator or by action of the customer by responding to high prices of energy triggered by system contingencies or high wholesale market prices.
Load as a Capacity Resource (LCR)	Customers that commit to making pre-specified load reductions when system contingencies arise. [Source: NERC Demand Response Availability Data Systems Definitions] "Program Total" represents total amount of customer demand enrolled in LCR programs. "Available" represents the magnitude of customer demand that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon when system contingencies arise.
Projected Resource Categories	Definition
On-Peak Capacity	Includes Existing-Certain and Planned-Tier 1 capacity projected to be operable and available to deliver power during peak demand.
Net Firm Transfers	Total firm imports into the Assessment Area, minus firm exports out of the Assessment Area. All transfers are based on the existence of firm contracts.
Anticipated Resources	On-peak Capacity, plus Net Firm Transfers
Existing-Other	Existing or planned generation resources that may be operable and available to deliver power during the peak demand, but may be curtailed or interrupted for various reasons.
Prospective Resources	Anticipated Resource, plus Existing-Other resources.
Planning Reserve Margins	Definition
Anticipated Reserve Margin	Anticipated Resources, minus Net Internal Demand, Divided by Net Internal Demand
Prospective Reserve Margin	Prospective Resources, minus Net Internal Demand, Divided by Net Internal Demand
NERC Reference Margin Level	The NERC Reference Margin Levels identified throughout the assessment are Planning Reserve Margins and firm load would not be disrupted to maintain these margins. Rather, the margins are reference points that indicate areas that have lower reserves and tighter margins. The tighter margins are not forecasts of resource shortages. However, areas with tighter margins have a higher possibility, although not likelihood, of resource shortages associated with extreme events such as record-setting temperature deviations. Each Region/subregion may have their own specific margin level (or method) based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Assessment Area’s Target Reserve Margin Level is adopted as the NERC Reference Margin Level. If not, NERC assigned 15 percent and 10 percent for predominately thermal and hydro systems, respectively.

Appendix III: Data for Pilot Assessment of NERC Regions and Assessment Areas

FRCC

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	55,699		55,699	
Forced Outage	1,864		1,864	
Maintenance Outage	373		373	
Available Resources	53,462		53,462	
Net Internal Demand		43,351		44,789
DR		3,101		3,101
Capacity Deficit[28]		0		0

MISO

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	144,332		144,332	
Forced Outage	10,995		10,995	
Maintenance Outage	387		387	
Available Resources	132,950		132,950	
Net Internal Demand		122,288		128,568
DR		5,031		5,031
Capacity Deficit		0		0

ISO-NE

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	31,563		31,563	
Forced Outage	2,100		2,100	
Maintenance Outage	60		60	
Available Resources	29,403		29,403	
Net Internal Demand		26,072		28,422
DR		638		638
Capacity Deficit		0		0

NYISO

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	41,222		41,222	
Forced Outage	3,248		3,248	
Maintenance Outage	106		106	
Available Resources	37,868		37,868	
Net Internal Demand		32,443		34,738
DR		1,124		1,124
Capacity Deficit		0		0

[28] Operationally, capacity deficits would be mitigated by Demand Response, additional power purchases, voltage reduction, and public conservation appeals prior to resorting to firm load shedding.

Ontario

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	27,695		27,695	
Forced Outage	1,350		1,350	
Maintenance Outage	71		71	
Available Resources	26,273		26,273	
Net Internal Demand		22,400		24,223
DR		591		591
Capacity Deficit		0		0

Quebec

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	31,696		31,696	
Forced Outage	1,200		1,200	
Maintenance Outage	82		82	
Available Resources	30,414		30,414	
Net Internal Demand		21,203		22,049
DR		0		0
Capacity Deficit		0		0

PJM

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	176,236		176,236	
Forced Outage	19,353		19,353	
Maintenance Outage	5,059		5,059	
Available Resources	151,824		151,824	
Net Internal Demand		147,764		157,177
DR		7,780		7,780
Capacity Deficit		0		**6,353**

SPP

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	66,431		66,431	
Forced Outage	2,978		2,978	
Maintenance Outage	426		426	
Available Resources	63,027		63,027	
Net Internal Demand		49,245		51,771
DR		1,284		1,284
Capacity Deficit		0		0

ERCOT

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	77,551		77,551	
Forced Outage	3,309		3,309	
Maintenance Outage	527		527	
Available Resources	73,715		73,715	
Net Internal Demand		66,714		69,012
DR		2,343		2,343
Capacity Deficit		0		0

CA/MX

	Anticipated Resources with Outages	Normal Demand Forecast	Anticipated Resources with Outages	Severe Demand Forecast
Anticipated	72,829		72,829	
Forced Outage	1,789		1,789	
Maintenance Outage	189		189	
Available Resources	70,851		70,851	
Net Internal Demand		52,830		56,615
DR		1,921		1,921
Capacity Deficit		0		0

NERC

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