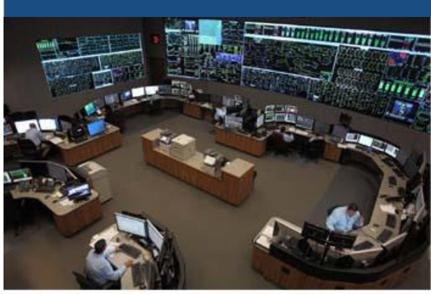
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2014–2015 Winter Reliability Assessment

November 2014

RELIABILITY | ACCOUNTABILITY



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Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.[1] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[2]

Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electric system. These standards are developed by the industry using a balanced, open, fair, and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set Reliability Standards for resource adequacy (e.g., reserve margin criteria) or to order the construction of resources or transmission, NERC can independently assess where reliability issues may arise and identify emerging risks. This information, along with NERC recommendations, is then made available to policy makers and federal, state, and provincial regulators to support decision making within the electric sector.

NERC prepares seasonal and long-term assessments to examine the current and future reliability, adequacy, and security of the North American BPS. For these assessments, the BPS is divided into 20 Assessment Areas,[3] both within and across the eight Regional Entity boundaries, as shown in the corresponding table and maps below.[4] The preparation of these assessments involves NERC's collection and consolidation of data from the Regional Entities. Reference case data includes projected on-peak demand and energy, Demand Response (DR), resource capacity, and transmission projects. Data and information from each NERC Region is also collected and used to identify notable trends, emerging issues, and potential concerns. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators and to aid NERC in achieving its mission—to assure the reliability of the North American BPS.

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

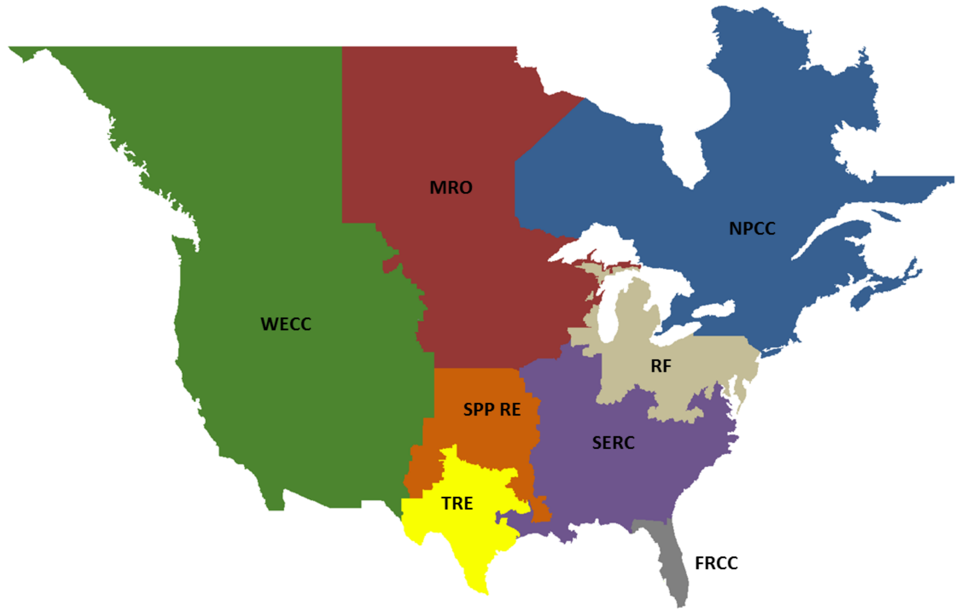
[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC's reliability management system agreement, which only applies to Baja California Norte.

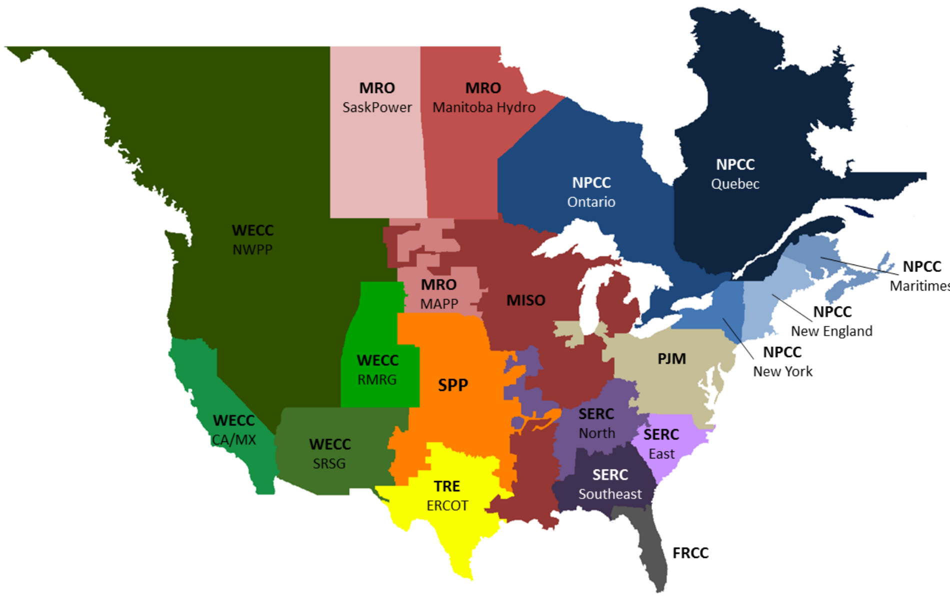
[3] The number of Assessment Areas has been reduced from 26 to 20 since the release of the 2013-2014 WRA.

[4] Maps created using Ventyx Velocity Suite.

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council	
	FRCC[5]
MRO – Midwest Reliability Organization	
	MISO[6]
	MRO-Manitoba Hydro
	MRO-MAPP
	MRO-SaskPower
NPCC – Northeast Power Coordinating Council	
	NPCC-Maritimes:
	NPCC-New England
	NPCC-New York
	NPCC-Ontario
	NPCC-Québec
RF – ReliabilityFirst	
	PJM[7]
SERC – SERC Reliability Corporation	
	SERC-East
	SERC-North
	SERC-Southeast
SPP RE – Southwest Power Pool Regional Entity	
	SPP
TRE – Texas Reliability Entity	
	TRE-ERCOT
WECC – Western Electricity Coordinating Council	
	WECC-CA/MX
	WECC-NWPP
	WECC-RMRG
	WECC-SRSG





[5] FRCC Region and Assessment Area boundaries are the same.

[6] The MISO footprint is primarily located in the MRO Region, with smaller portions in the SERC and RF Regions. For NERC's assessments, the MRO Region oversees the collection of data and information from MISO.

[7] The PJM footprint is primarily located in the RF Region, with smaller portions in the SERC Region. For NERC's assessments, the RF Region oversees the collection of data and information from PJM.

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Assessment Data Questions
Please direct all data inquiries to NERC staff (assessments@nerc.net).

Referencing This Assessment
References to the data or findings of the assessment are welcome with appropriate attribution of the source to the NERC *2014–2015 Winter Reliability Assessment*. However, approval from NERC staff (assessment@nerc.net) must be obtained prior to extensive reproduction of tables or charts.

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About this Report

The primary objective of this assessment is to identify the reliability concerns of the North American bulk power system (BPS) and make recommendations for action as needed. The assessment process enables BPS users, owners, and operators to systematically document and communicate their operational preparations for the coming season and exchange vital system reliability information.

This assessment is based on data and information collected by NERC from the Regions on an Assessment Area-basis as of October 2014. The Reliability Assessment Subcommittee (RAS), at the direction of the Planning Committee (PC), supports the Winter Reliability Assessment (WRA) development. Specifically, NERC and the RAS perform a thorough peer review that leverages the knowledge and experience of industry subject matter experts while providing an unbiased view to ensure the validity of data and information provided by the Regions. Each Assessment Area section is peer reviewed by members from other Regions to achieve a comprehensive review that is verified by the RAS members in open meetings. This assessment has been reviewed and endorsed by the PC. The NERC Board of Trustees also reviewed and approved this report.

The reference case data summary, reliability assessment glossary, and polar vortex review are found in Appendices I, II, and III, respectively.

Executive Summary

The *2014–2015 WRA* is an independent assessment of the reliability of the bulk electricity supply and demand in North America from December 2014 through February 2015. It provides a high-level reliability assessment of the 2014–2015 winter resource adequacy and highlights individual Assessment Areas' operating challenges.

NERC independently assessed demand and generation projections based on data provided by industry. All Assessment Areas project sufficient resources to meet normal peak load for the 2014–2015 winter operating period.

The following key findings point to common themes across North America or Region-specific challenges:

- Resources are adequate to meet 2014–2015 forecast normal winter peak demand.
- Prolonged and extreme cold weather in parts of North America may cause an increase in generator unavailability due to natural gas and coal constraints.
- An increasing reliance on gas-fired generation requires new approaches for assessing reliability.

Observations and lessons learned from the 2014 polar vortex provided valuable insight to NERC's assessment of the upcoming winter. In order to gain an understanding of how a polar vortex-like event could impact reliability in future winter seasons, NERC conducted extreme weather scenarios based on the conditions observed during the 2014 polar vortex. The scenarios were performed for the areas most impacted by the 2014 polar vortex (MISO, PJM, SERC-E, and TRE-ERCOT). The findings from the scenario analysis show that existing resources can meet the extreme-case demand; however, reserve margins decrease significantly from the reference case. The results help provide additional perspective on how sensitive demand and generation are to extreme weather. The details and results of this extreme weather scenario are provided in Appendix III.

Based on this assessment's findings and evaluations, NERC recommends the following:

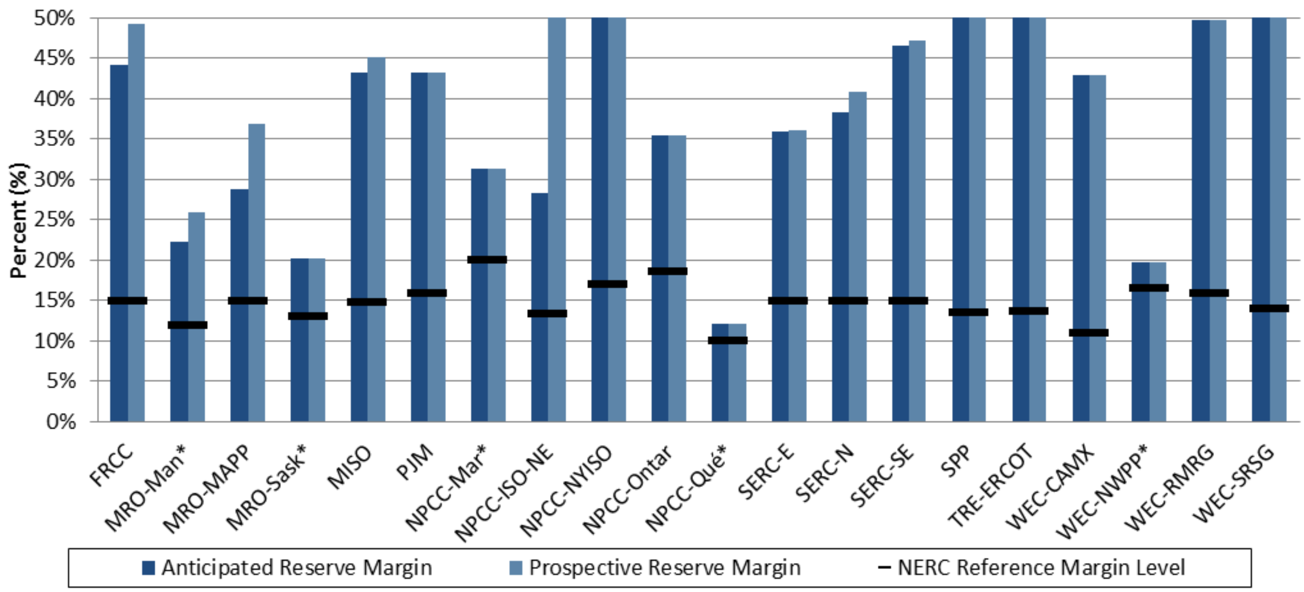
- Industry should review and supplement, if needed, short-term operational plans in preparation for this winter.
- In future seasonal reliability assessments, NERC should specifically consider fuel availability and deliverability and integrate both into the resource adequacy assessment.
- NERC should include seasonal scenario analyses in future seasonal reliability assessments. These scenarios should include an analysis that incorporates higher-than-expected load levels and generator outages.
- NERC and the Regions should begin developing new approaches for assessing reliability during extreme weather conditions, such as calculating a winter-specific Reference Margin Level for reserve margin assessment.

Key Reliability Findings

NERC presents the following key findings for the *2014–2015 Winter Reliability Assessment*:

Key Finding 1: Resources are adequate to meet 2014–2015 forecast normal winter peak demand.

All Assessment Areas are projecting sufficient resources to meet the normal peak demands for the 2014–2015 winter operating period. Planning Reserve Margins appear sufficient to manage normal deviations in the demand forecasts and normal levels of forced-out generation. The Planning Reserve Margins for the forecast winter peak are shown in Figure 1 and are provided in more detail within the individual Assessment Area section of this report.



*Indicates a winter-peaking Assessment Area

Figure 1: 2014–2015 Winter Peak Planning Reserve Margins by Assessment Area[8]

Key Reliability Finding #1
Resources are adequate to meet 2014–2015 forecast normal winter peak demand.

Observation

All Assessment Areas project sufficient resources to meet the normal winter peak demands for the 2014–2015 winter operating period and exhibit adequate reserve margins.

[8] The y axis is limited to 50 percent Planning Reserve Margins. In some areas, margins are above 50 percent.

Key Finding 2: Prolonged and extreme cold weather in parts of North America may cause an increase in generator unavailability due to natural gas and coal constraints.

Natural Gas Impacts during Extreme Weather Conditions

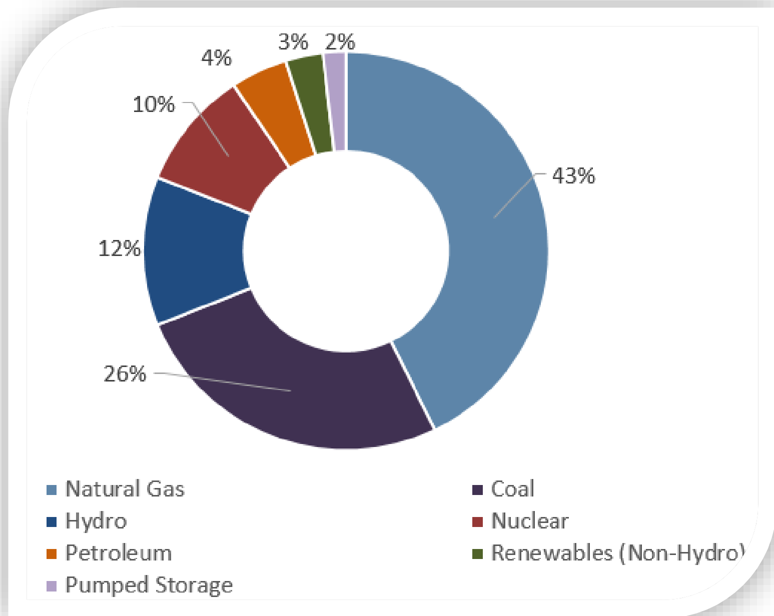


Figure 2: Total NERC-wide 2014–2015 Winter Capacity On-peak Resource Mix

A continuing trend in recent NERC long-term reliability assessments and the topic of two published NERC special assessments is the increase of gas-fired generation coupled with the reduction in fuel diversity across the overall resource portfolio. The extent of this trend varies from region to region; however, the concerns are high priority in areas where (1) power generators rely on interruptible[9] gas pipeline transportation, (2) natural gas interstate pipelines are constrained to meet demand beyond what has been contracted and committed, and (3) gas use for power generation is increasing. NERC's special assessment on gas concluded that as natural-gas-fired generation increases, more attention is needed from system planners and operators to better understand the interaction between the electric and gas systems. Furthermore, the reliability ramifications of a substantial reliance on just-in-time fuel delivery and the potential for single points of failure and common-mode outages across natural gas infrastructure must be taken into account when considering resource adequacy assessments.

Natural gas is the largest fuel type, comprising up to 43 percent of the total 2014–2015 NERC-wide winter capacity on-peak resource mix (Figure 2). Limited gas pipeline infrastructure has been constructed compared to new gas-fired generation. The U.S. capacity from gas-fired generation increased by almost 5 GW since last year; however, only 252 miles of new pipeline (4.5 Bcf) were added in 2012—the lowest pipeline addition since 1997.[10] More than half of new pipeline projects that entered commercial service in 2012 and 2013 were in the Northeast, but most of that capacity was added outside of New England's constrained areas, where there is an increasing reliance on gas-fired generation. Announcements for new pipeline capacity from 2014 through 2016 show infrastructure enhancements to pipelines in the Northeast, but these projects do not alleviate the constraints across the New England interface. Therefore, from a natural gas availability perspective, similar conditions as last year can be expected. For New England, this includes the potential for natural gas interruption to gas-fired generators and a reliance on backup fuel (generally oil) to meet peak demand.

The gas and electric industries have made substantial progress to enhance coordination and develop strategies to address BPS reliability concerns. NERC's *2014 Long-Term Reliability Assessment* highlights industry progress and efforts to address the concerns relating to natural gas generation.[11]

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[9] Including both interruptible services and firm capacity released or resold by the primary capacity holder.
[10] EIA Article: Over half of U.S. natural gas pipeline projects in 2012 were in the Northeast
[11] *2014LTRA*

Regional Challenges Regarding Natural Gas-Fired Generation

While Planning Reserve Margins provide a relative indication as to whether a system can sufficiently meet peak demand under normal weather conditions, additional scenario and sensitivity analyses are needed to understand how extreme weather can impact demand and resources. The BPS's effectiveness at responding to unusually high stress depends on how prolonged and extreme the weather is, the region it is affecting, and what the resource mix is. For example, New England (and other areas with significant amounts of natural gas) may be vulnerable to extreme cold weather, particularly if many of the natural gas power plants have interruptible (or non-Firm) natural gas transportation services. During the 2013–2014 winter, ISO-NE lost more than 8,000 MW of gas-fired generation during its peak hour (Figure 3). A majority of the generators that were unavailable were forced out of service due to a lack of fuel, which stemmed from the non-Firm fuel delivery arrangements. While significant progress has been and is being made to address these concerns, the risk extends through the upcoming winter period, as a significant amount of additional pipeline capacity has not been constructed in the past year.

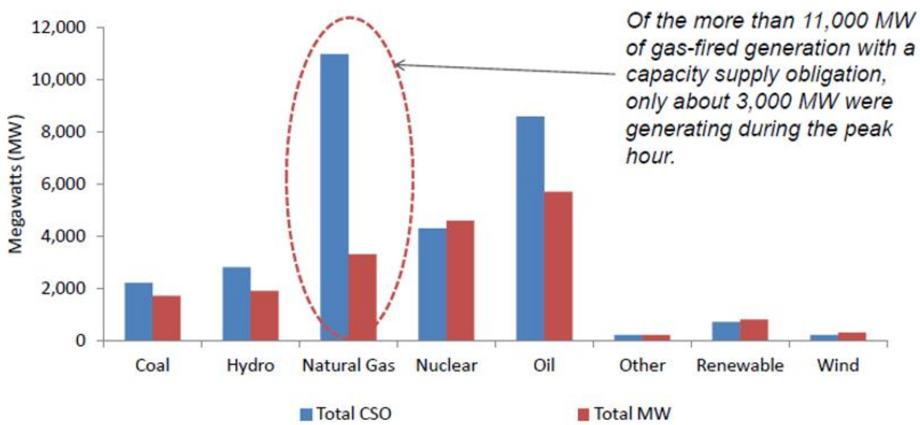


Figure 3: ISO-NE Generator Capacity Supply Obligations vs. Output (January 28, 2014)

Natural-gas-fired capacity accounts for large portions of both the total and on-peak generation mix in several Assessment Areas (Table 1). While the example above is from New England, for the upcoming winter, an increasing reliance on gas-fired capacity can be found in other areas, such as MISO, PJM, and WECC.

Table 1: Areas with Gas-Fired Capacity Over One-Third of Existing Nameplate Capacity

	Nameplate Capacity (GW)		On-Peak Capacity (GW)	
Assessment Area	Gas-Fired	Portion of Total (%)	Gas-Fired	Portion of Total (%)
FRCC	40.2	64	33.9	63
MISO	69.0	39	58.7	41
NPCC-New England	18.6	54	13.3	43
NPCC-New York	21.0	55	14.2	40
PJM	80.0	43	56.5	32
SERC-SE	31.2	47	28.4	46
SPP	32.3	40	30.2	47
TRE-ERCOT	48.4	54	45.2	63
WECC-CA/MX	47.7	61	43.9	70
WECC-RMRG	7.2	36	6.2	41
WECC-SRSG	19.5	47	16.3	50

New England

State and federal environmental regulations combined with low natural gas prices have prompted a number of coal and nuclear generation retirements, resulting in greater reliance on gas-fired generation. This may pose a reliability challenge, given that most generators in the Northeast do not have firm capacity on pipelines for a number of reasons, such as economics. New England and some other Eastern Interconnection regions witnessed a number of cold snaps that increased energy consumption last winter. In addition, many generators could not access fuel supplies or had operational issues because of extreme weather conditions or after prolonged operations at peak capacity. New England has performed gas studies and other plans to address the issue in New England.

ISO-NE's Winter Reliability Program addresses concerns about the ability of resources to perform when dispatched, especially during cold weather conditions. Enhancements implemented include:

- Incentives for oil and dual-fuel generators, natural-gas-fired generators to contract for liquefied natural gas (LNG) to augment pipeline gas, and for new demand-response resources to be available.
- Improved information sharing and coordination with pipelines
- Energy Market Offer Flexibility
- Increased scarcity pricing

Additional information about New England's efforts are discussed in the NPCC-New England section.

MISO, NPCC-New York, and WECC

The retirement of large coal generating units is one of the factors causing an increased demand for natural gas supply and transportation as natural gas becomes the primary fuel for new thermal generation. These areas are working with the natural gas industry to study potential impacts to reliability as they become more reliant on natural-gas-fired generation. Additional detail is provided in the respective sections of this report.

Coal Delivery Constraints

During the extreme weather of the 2014 polar vortex event, frozen coal stock piles had a negative impact on generator availability. In some Assessment Areas, several generators are replenishing coal stock piles drawn down during the previous winter; however, the amount of coal inventory—as well as coal delivery—during winter months is still a potential concern for some generators. Low coal stocks may restrict coal unit availability during the winter period when coal units are depended on as a backup generations if gas-fired generations are unavailable.

Rail congestion is impeding coal producers from delivering enough coal to replenish the dwindled power plant stock piles. Demand for coal from the Powder River Basin mining region is increasing faster than railroad traffic can accommodate. Assessment Areas including SERC, SPP, MISO, and ERCOT have concerns that there is a potential for coal inventories to decline. According to EIA's data, the electric power sector coal stocks are significantly less than the last four years (Figure 4).

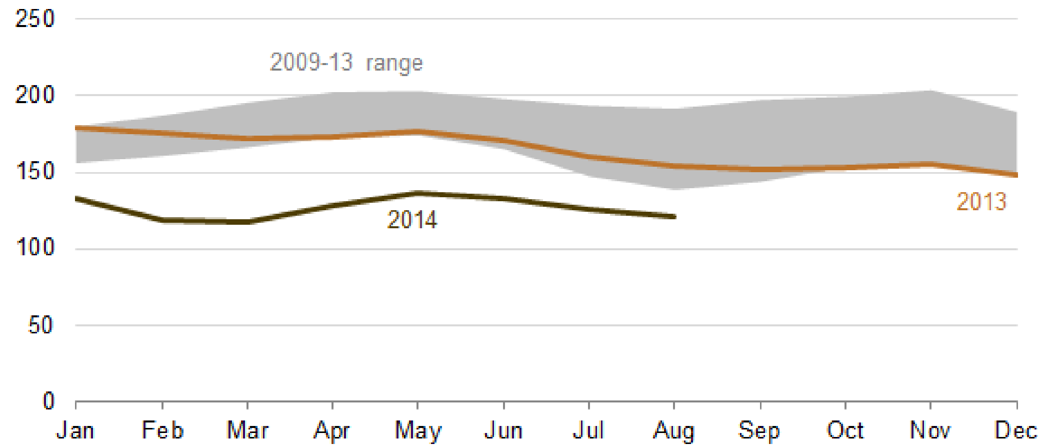


Figure 4: Monthly coal stockpile levels at electric power plants 2009–August 2014[12]

As parts of North America recover from the 2013–14 winter, the amount of coal inventory as well as coal delivery during winter months is an ongoing concern. Regions experiencing coal delivery congestion reported the following:

- SPP does not expect an impact to generator availability but has noted that coal supplies could potentially be reduced or delayed due to railroad congestion.
- One SERC entity reports that coal pile inventories are exceptionally low due to insufficient rail deliveries. If gas supplies were to become constrained over the winter, the combined effect could impact generator availability within the entity's area. However, there is no expected impact to overall generator availability during the winter season. To mitigate risks that could lead to generator unavailability, SERC entities use inventory management, communications with and monitoring of the coal and gas industries, and dual-fuel capabilities. Additionally, several gas plants own gas storage facilities or connect to multiple pipelines.
- Some ERCOT generation owners have reported low coal supply inventories due to rail transportation issues associated with Powder River Basin deliveries, and are thus restricting unit availability during off-peak hours. However, ERCOT does not expect coal supply constraints to impact capacity availability during peak load hours.
- In MISO, a utility warned that an ongoing railroad backlog could force the idling of its 379-MW coal-fired power plant in southwestern Wisconsin in January, risking reliability problems in the middle of winter. However, BNSF railroad has agreed to step up coal deliveries to Genoa No. 3. The amount of coal inventory as well as coal delivery during winter months is an ongoing concern for Midwest utilities who are still recovering from the 2013–14 winter. Frozen coal or fuel deliverability limitations could also result from unusually cold weather.

As a part of NERC's independent assessment of reliability and ongoing coordination with the electric industry, NERC continues to evaluate and monitor potential coal delivery issues for the upcoming winter season. In this assessment, NERC highlighted that while some coal plants have indicated low coal inventory levels due to coal delivery constraints, the issue is isolated and not widespread. Over the past few months, system operators and planners with impacted plants have been actively managing their coal-replenishment and coal-burn strategy with their projected supply and delivery forecasts. However, if coal delivery constraints persist and severe winter weather conditions arise, a few isolated coal units in MISO, SERC, SPP, and ERCOT may not be able to operate.

[12] EIA Article: Coal stockpiles at coal-fired power plants smaller than in recent years

NERC expects that RCs and local entities would begin to assess reliability assurance options. NERC will continue monitoring this situation and work with RCs as needed.

Key Reliability Finding #2

Prolonged cold weather events in parts of North America may cause an increase in generator unavailability due to natural gas and coal constraints.

Observation

With the changing resource mix in North America and the increased dependency of natural gas demand for power production, increased coordination between the electric and gas sectors is necessary to ensure sufficient resource availability for a reliable operation of the Bulk Electric System.

As the electric industry relies more heavily on natural gas as a fuel source, the potential for reliability impacts increases. This results not only from lack of diversity, but from natural gas as a just-in-time fuel source. Furthermore, since residential heating and firm customers are given priority in the event of a shortage, natural gas supply to gas-fired generators without firm pipeline capacity is more susceptible to interruption.

Recommendations

Industry should review and supplement, if needed, short-term operational plans in preparation for this winter. Assessment Areas with high penetration of gas-fired generation should have operational plans in place to address and manage potential reliability concerns, such as fuel deliverability constraints.

NERC should specifically consider fuel availability and deliverability and integrate both into resource adequacy assessments. In parts of North America, where natural gas is constrained due to the lack of available pipeline capacity, gas-fired generation without a firm fuel contract or other back-up fuel is essentially energy limited. Therefore, similar to other energy-limited resources (e.g., wind, hydro), resource adequacy assessments should also consider the fuel and capacity constraints of gas-fired generation.

Key Finding 3: An increased reliance on gas-fired generation requires new approaches for assessing reliability.

Thorough harmonized efforts between electric and gas sectors are needed in order to meet future infrastructure needs to supply and transport fuel. System planners in certain areas (i.e., those with high levels of natural-gas-fired resources) should examine system reliability needs to determine if more Firm fuel transportation or units with dual-fuel capability are needed. Additionally, fuel availability and deliverability should be specifically considered and integrated into resource adequacy and other planning assessments. This calls for a new approach to assess reliability given the potential energy limitations of natural-gas-fired generation without firm fuel commitments.

Lessons from 2014 Polar Vortex

In early January 2014, the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30°F below average. Some areas faced days that were 35°F or more below their average temperatures. These temperatures resulted in record high electrical demand for these areas on January 6 and January 7, 2014. Table 2 shows the RCs' new winter peak records compared to their historic winter peaks. NERC published the *Polar Vortex Review*[13] in September 2014 and found that the grid was resilient during this extreme weather event, despite the fact that the number of forced outages was higher than normal.

Table 2: Historic Winter Peak Loads vs Polar Vortex Loads by Percentage[14]

	MISO	PJM	NYISO	ISO-NE	South-eastern RC	TVA	VACAR South	SPP	ERCOT	FRCC
	MW (% of previous peak)									
Previous Winter peak	99,855	136,675	25,541	22,818	46,259	43,384	42,983	32,635	57,265	36,926
6-Jan-14	109,307 (109.5)	131,142 (95.5)	23,197 (90.8)	18,500 (81.1)	44,871 (97.0)	43,277 (99.8)	50,659 (117.9)	36,602 (112.2)	56,031 (97.8)	30,231 (81.9)
7-Jan-14	104,746 (104.9)	140,510 (103.5)	25,738 (100.8)	21,300 (93.3)	48,279 (104.4)	44,285 (102.1)	44,654 (103.9)	36,079 (110.6)	57,277 (100.0)	35,638 (96.5)
8-Jan-14	100,154 (100.3)	133,288 (98.1)	24,551 (96.1)	20,800 (91.2)	47,005 (101.6)	39,820 (91.8)	43,203 (100.5)	31,944 (97.9)	45,281 (79.1)	29,251 (79.2)

Regional Winter Preparation Efforts

ERCOT

As a result of the polar vortex event, ERCOT is taking precautions for the 2014–2015 winter season. ERCOT is placing more formal processes around advanced communications in preparation of severe weather events among operations, outage coordination, meteorology, and other support staff. ERCOT is working with the Texas Commission on Environmental Quality (TCEQ) to update procedures for notifying Qualified Scheduling Entities (QSEs) that they may generate past their permits. A market notice indicating the new procedure is forthcoming. ERCOT is reviewing the procedure modifications to deploy all Responsive Reserve Service (RRS) generation

[13] *Polar Vortex Review*.

[14] Highlighted blue squares represent new all-time winter peak loads.

resources during a Level 2 Energy Emergency Alert (EEA2) to ensure Security-Constrained Economic Dispatch (SCED) has all possible capacity to deploy. ERCOT should increase support staff to study increased loads that exceeded load forecasts to help identify any short-term outage concerns in advance of severe cold weather.

Other considerations for ERCOT for this winter include:

- Reassessing Equivalent Forced Outage Rate demand (EFORd) calculations used for future seasonal assessment of resource adequacy (SARA) reports to ensure derates are appropriately included,
- Continuing winterization site visits,
- Giving advanced notice to market participants when cold weather approaches to avoid transmission outage and resource outage delays,
- Continuing an annual winter preparation seminar to share lessons learned and best practices,
- Continuing to review forecast cold weather with multiple departments including internal meteorologists in advance of approaching severe cold weather to support operational readiness, and
- Considering formalizing the process of committing (1) units with start-up times that require a commitment decision prior to the day-ahead reliability unit commitment and (2) units that notified ERCOT of fuel restriction to switch to alternate fuel in advance of severe cold weather.

MISO

MISO is continuing to explore opportunities to improve its cold weather operations. In preparation for the upcoming winter, MISO is conducting a Winter Readiness workshop in which it collaborates with stakeholders to maximize winter readiness. Additionally, MISO will build on the lessons learned during the polar vortex. More information can be found in MISO's section. MISO will be implementing the following initiatives to prepare for the upcoming winter:

- Investigating the current DR construct.
    - Voluntary Load Management (VLM) reporting enhancements should improve visibility for current and future operating days.
    - The Supply Adequacy Working Group has been tasked with evaluating moving to a seasonal construct for DR as a result of Electric and Natural Gas Coordination Task Force (ENGCTF) recommendations.
- Enhancing coordination between the electric and natural gas industries to ensure an effective management system of assets.
- Improving market pricing during emergency conditions to ensure market signals are not distorted, but are reflective of actual system operating conditions and system marginal costs and influence efficient behavior by generators, load, and interchange.
- Evaluating an energy offer cap and reviewing the value of lost load (VOLL) pricing.
- Reviewing the unit commitment process and leveraging all tools available to improve commitment results.
- Examining the post-event analysis procedures.
- Reviewing the tools, communication, and procedures processes to ensure reliable and effective operations.

PJM

PJM commenced extensive advance communications to its stakeholders, state and federal officials, and the public in order to ensure they had full information and were aware of system conditions during the polar vortex. The value of increased communication of information was clearly demonstrated by the states and stakeholders. The public and the summer-only DR customers were asked to voluntarily reduce demand.

Taking into account their experience from last winter, for the upcoming winter, PJM is implementing the following changes:[15]

- Use a cold weather resource capability testing and preparation checklist.
- Make additional operations data (e.g., dual-fuel capability and availability) and any resource limitations, such as environmental restrictions, available.
- Improve tracking of performance of external capacity resources.
- Improve data sharing and coordination with the gas industry.
- Clarify the process to seek environmental waivers and what PJM's role is.
- Improve interregional coordination and situational awareness during emergencies.
- Improve emergency procedures (e.g., voltage reduction and emergency bid procedures).
- Implement a new unit testing procedure for units that have not run in eight weeks.
- Use gas unit dispatch in real-time operations to include clarity in dispatcher communications and sharing of updated unit parameters and time frames for long lead time units.
- Use a capacity performance product to improve unit performance, improve operational flexibility, and incentivize fuel security.

NERC Extreme Weather Scenario and Sensitivity Analysis

Higher-than-expected forced outages and higher-than-expected forecast peak demand were observed during the polar vortex, particularly for natural-gas-fired generators. As a result of the polar vortex, NERC examined this winter's resource adequacy for the affected areas to evaluate their reserve margins, using demand and generation forced outage assumptions similar to those from the polar vortex.

To examine the potential impacts of a similar event for the 2014–2015 and the 2015–2016 winter periods, NERC ran scenarios on select Assessment Areas (SERC-E, PJM, MISO, and TRE-ERCOT) that experienced significant loss of generation during the 2014 polar vortex event.[16] Based on the results of the scenarios, if similar extreme weather events occur in the future, projected reserve margins are lower and thus could potentially impact BPS reliability. The complete scenario is included as Appendix III.

[15] PJM's full report on operation events last winter is available on PJM's website: Analysis of Operational Events and Market Impacts
[16] 2015-2016 data uses 2014LTRA data as the reference case.

Key Reliability Finding #3
An increased reliance on gas-fired generation requires new approaches for assessing reliability.

Observation

Conventional reserve margin levels may not adequately reflect generator availability and load forecast under certain winter weather conditions as many areas calculate this value based on summer peak Reference Margin Levels. Therefore, the conventional method of measuring resource adequacy with respect to existing reference margin levels used by Assessment Areas may not be sufficient for winter periods.

NERC supports the electric industry's ongoing evaluation of fuel availability and deliverability of the gas infrastructure supply. Studies between the electric and gas industries are critical in identifying pipeline constraints and potential impacts to the BPS.

Recommendations

NERC, Regional Entities, and the industry should assess scenarios that reflect severe winter conditions. The following are possible scenario assumptions to consider when modeling and studying extreme system conditions for the winter peak assessment:

- Apply higher-than-normal peak load (e.g., 90/10 load forecast).
- Consider higher forced outage rates of generators to reflect weather impacts on generation performance (e.g., gas unavailability, frozen equipment, frozen coal piles, rail congestions, and fuel gelling).

NERC and the Regions should begin developing new approaches for assessing resource adequacy reliability in extreme weather conditions, such as calculating a winter-specific Reference Margin Level for a reserve margin analysis. The calculated winter reserve margin level can include EFORd values obtained from generators during the extreme weather performance and higher-than-normal peak load. These EFORd values should be derived from extreme weather calculations rather than normalized monthly generator EFORd values. The new Anticipated Reserve Margin value can be an indicator of the system requirements to meet load on extreme winter conditions.

FRCC

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**44,636**
Load-Modifying DCLM	2,543
Load-Modifying Contractually Interruptible	435
Net Internal Demand	**41,658**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transfers	2,185
Existing-Certain & Future-Planned Capacity	57,858
Anticipated Resources	**60,043**
Existing-Other, Future-Other Capacity	2,124
Prospective Resources	**62,167**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**44.13**
Prospective Reserve Margin	**49.23**
NERC Reference Margin Level	**15.00**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level
FRCC uses a 15 percent reserve margin as the NERC Reference Margin criterion.
Load Forecast Method
Noncoincident, based on individual LSE forecasts
Peak Season
Summer
Planning Considerations for Wind Resources
No wind capacity; no formalized method
Planning Considerations for Solar Resources
Small amount of solar capacity; no formalized method
Footprint Changes
Region is the Assessment Area footprint; no recent changes

Assessment Area Overview

FRCC's membership includes 30 Regional Entity division members composed of investor-owned utilities, electric cooperatives, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities (BAs), with 68 registered entities (both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of more than 16 million people and has a geographic coverage of about 50,000 square miles over peninsular Florida.

FRCC uses a 15 percent Reserve Margin as the NERC Reference Reserve Margin criterion. In regard to individual utilities, the non-investor-owned utilities typically utilize at least a 15 percent Reserve Margin, and the investor-owned utilities utilize a 20 percent Reserve Margin. Based on the expected load and generation capacity, the projected Reserve Margin is above 40 percent for the season during the assessment period (winter 2014–2015). A rebound in the economy could potentially increase the forecast demand, energy, and load projections beyond the normal weather forecast.

FRCC is forecast to reach its 2014–2015 winter noncoincident peak net internal demand of 41,658 MW in January. This projection is consistent with historical weather-normalized FRCC demand growth and is 5.5 percent lower than last year's winter forecast of 44,060 MW. The current forecast of 41,658 MW is also 7.6 percent above the actual 2013–2014 winter demand of 38,701 MW. During the 2013–2014 winter, FRCC experienced very mild temperatures, resulting in lower internal demand. In addition, some FRCC utilities have added appliance energy efficiency variables, or have otherwise accounted for the projected impact of energy efficiency codes and standards in their load forecasting models since the prior winter assessment.

DR programs are projected to decrease by 3.1 percent since last winter and are approximately 6.7 percent of the winter total peak demand. The impact of energy efficiency/conservation programs is expected to increase by 20 MW since last winter to 156 MW.

The FRCC Region is not expecting any issues that could lead to large-scale impacts to generator availability during the winter season. At the beginning of 2014, 19 MWs of mainly oil-fired generation units were retired. Also, 1,344 MWs of natural gas generation and 103 MW of biomass were installed, and 832 MW of oil-fired generation returned from a scheduled maintenance. For the upcoming winter season, 112 MW (4 units) of natural gas generation and 77 MW (1 unit) of oil-fired generation are set to retire. Additionally, a 563 MW unit has recently been forced out of service through the upcoming winter season. These activities are not expected to have an impact on generation scheduled to serve load. There are 1,340 MW of generation under firm contract, available to be imported into the Region from the SERC-SE Assessment Area throughout the winter season, and another 845 MW of member-owned generation, which is dynamically dispatched out of the SERC-SE Assessment Area.

Currently, the FRCC Region expects to have up to 10 staggered 230 kV transmission facilities out of service throughout the 2014–2015 winter season. None of these BES facilities will be out of service for the entire winter season. These outages were studied as part of the FRCC Winter Operational Seasonal Study process and are not anticipated to affect reliability within the FRCC Region. The FRCC Region will have one new permanent Special Protection System (SPS) placed in service prior to the 2014–2015 winter peak. The new SPS is designed to preserve dynamic voltage stability on a long radial line in the Florida Keys.

In addition, the FRCC Region is not anticipating any significant issues resulting from neighboring areas. FRCC's Operations Planning Working Group (OPWG), under the direction of the FRCC Operations Planning Coordinator, holds weekly conference calls to coordinate outages and discuss any potential operational issues. TOPs from the FRCC Region, as well as adjacent TOPs from the SERC Region, participate on the call.

FRCC expects the BES to perform adequately over various system operating conditions with the ability to deliver the resources to meet the load requirements at the time of the winter peak demand. FRCC performed a Winter Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the BES within the FRCC Region under the expected 2014–2015 winter peak load and under anticipated system conditions (taking into account generation and transmission maintenance activities). The 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 the FRCC's OPWG to ensure the BES performs adequately throughout the winter time frame. The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria will be successfully mitigated under each situation analyzed.

MISO

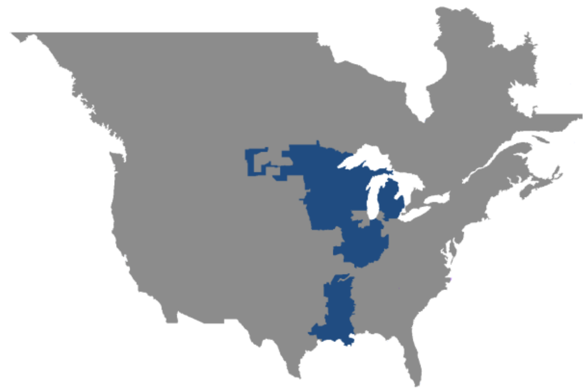
Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**103,238**
Load-Modifying DCLM	348
Load-Modifying Contractually Interruptible	2,198
Net Internal Demand	**100,692**

Resource Projections	MW
Net Firm Capacity Transfers	2,023
Existing-Certain & Future-Planned Capacity	142,126
Anticipated Resources	**144,149**
Existing-Other, Future-Other Capacity	1,966
Prospective Resources	**146,115**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**43.16**
Prospective Reserve Margin	**45.11**
NERC Reference Margin Level	**14.80**

Assessment Area Footprint



Summary of Methods and Assumptions

Reference Margin Level
For planning year 2014–2015, MISO's System-Installed Generation Planning Reserve Margin requirement (PRMR) is 14.8 percent, which is applied as the Reference Margin Level for all 10 years.
Load Forecast Method
Coincident
Peak Season
Summer
Planning Considerations for Wind Resources
Effective Load-Carrying Capability (ELCC); varies by wind node
Planning Considerations for Solar Resources
No utility-scale solar resources in MISO
Footprint Changes
n/a

Assessment Area Overview

The Midcontinent Independent System Operator, Inc. (MISO) reliability area consists of 36 local BAs and 394 Market Participants who serve approximately 42 million people. On Dec. 19, 2013, MISO began coordinating all RTO activities in the newly combined footprint consisting of all or parts of 15 states with the integration of the MISO South entities (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).

For planning year 2014, MISO's System Installed Generation Planning Reserve Margin Requirement (PRMR) on a MISO coincident load basis is 14.8 percent, which is 0.6 percentage points higher than last year's requirement. However, the PRMR for zone 8, the state of Arkansas, was set by the Local Clearing Requirement 8 because the local 1-day-in-10 reliability criteria was higher than the system requirement. This resulted in a higher PRMR for zone 8. The major drivers of the change are the integration on the MISO southern entities, adjustment to the amount of external support that can be used in time of need, and the Load Forecast Uncertainty (LFU) values, which continue to be enhanced and improved.

MISO forecasts a 43.2 percent Anticipated Reserve Margin for the 2014 winter peak, which is 28.4 percentage points higher than the planning year 2014 Planning Reserve Margin Requirement of 14.8 percent. For this assessment, only 1,000 MW of capacity is transferred from MISO South to the MISO North/Central Region, pending the outcome of regulatory issues currently at FERC. Any surplus capacity in MISO South above the 1,000 MW transfer and the MISO South PRMR was removed.

MISO's coincident Total Internal Demand is forecast to peak at 103,238 MW during the 2014–2015 winter season. The amount of DR expected to be available on peak this winter is 2,546 MW; this consists of 348 MW of Direct Control Load Management and 2,198 MW of Interruptible Load. MISO's projected coincident Net Internal Demand, 100,692 MW, is the result of the Total Internal Demand less the amount of DR expected.

MISO projects 142,126 MW of Existing-Certain capacity to be available during winter 2014–2015. Included in this capacity is 1,614 MW of behind-the-meter capacity. 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 14.1 percent. Included in the Existing-Certain capacity, MISO expects 1,070 MW of wind to be available to serve load this winter.

All other intermittent resources receive their unforced capacity ratings based on historical winter performance up to the amount that they have Network Resource Interconnection Service (NRIS) or firm point-to-point Interconnection Service Right.

Transmission limitations resulted in 6,649 MW of derated capacity; the majority of this limit is due to the South Region surplus above PRMR except for 1,000 MW being excluded, respecting the contract path between MISO South and MISO North/Central. Also, 1,966 MW of Energy-Only resources that don't have firm point-to-point transmission rights were categorized as Existing-Other capacity.

MISO assumes a forecast of 3,157 MW of capacity from outside the MISO footprint to be designated firm for use during the assessment period and not able to be recalled by the source Transmission Provider. This capacity was designated to serve load within MISO through the Module E process for summer 2014. MISO assumes a forecast of 1,134 MW of firm capacity exports in 2014 to PJM based on PJM's Base Residual Auction cleared results. MISO's capacity transactions amount to a net firm import of 2,023 MW.

MISO is conducting a Winter Readiness workshop in which they collaborate with stakeholders to maximize preparedness for the winter 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. Through MISO Communication System (MCS), MISO surveys local BAs to obtain the amount of DR resources that would be available under a given notification time (e.g., two hours) on a daily basis. If MISO reaches the point of needing to call on these resources, it will deploy only the amount needed, with the expectation that all will perform with a 12-hour notification. The use of these resources is part of the progression through the Capacity Emergency procedure. If DR resources don't perform, subsequent steps of the procedure are implemented as necessary.

MISO does not foresee significant impacts to reliability during the 2014-2015 winter season due to environmental or regulatory restrictions. MISO does anticipate that recently finalized and developing EPA regulations will impact MISO in the future, but the main impacts are anticipated beyond this winter season. MISO conducts ongoing studies to determine the amount of generation maintenance that could be scheduled in a given season, assuming a reduced capacity level as a result of environmental regulations.

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.

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, MTEP13, was approved by the MISO Board of Directors in December 2013. The study tested the existing transmission plan using NERC standards and developed additional mitigation as required to address any identified issues. Below is a list of the top new transmission projects approved in MTEP13 with in-service dates prior to this winter season:

- Stone Lake – Edgewater 161 kV (Xcel Energy); December 2014
- Overton Transformer Replacement (Ameren Missouri); November 2014
- Lafayette 230kV Substation Bus Modernization (Duke Indiana); Phase 1 December 2014; Phase 2 December 2016

The unusually cold temperatures and heavy snowfall that characterized the 2013–2014 winter season posed significant operational challenges for MISO. Many of the natural-gas-fired power plants in MISO's footprint were temporarily forced off-line by the extreme weather conditions. Despite the weather-related challenges, MISO successfully maintained the reliability of the BPS during the January 6–7 polar vortex, as well as several other unusually cold stretches of the 2013–2014 winter season.

MISO performed a comprehensive review of the polar vortex event to ensure observations and lessons learned were identified and appropriately considered. Key takeaways to date include:

1. The current DR construct should be investigated:
    a. Voluntary Load Management (VLM) reporting enhancements should improve visibility for current and future operating days.
    b. The Supply Adequacy Working Group has been tasked with evaluating moving to a seasonal construct for DR as the result of an Electric and Natural Gas Coordination Task Force (ENGCTF) recommendation.
2. Enhancing coordination between the electric and natural gas industries is needed to ensure MISO effectively manages system assets.
3. Market pricing improvements during emergency conditions are necessary to ensure market signals are not distorted, but are reflective of actual system operating conditions and system marginal cost, and that they influence efficient behavior by generators, load, and interchange.
4. MISO will evaluate an energy offer cap and review VOLL pricing and consider a change of both if analysis results warrant in the MISO energy markets.
5. MISO will review its unit commitment process and look to leverage all tools available to improve commitment results.
6. MISO will examine post-event analysis procedures. Accurate analysis is essential for the evaluation of tools, processes, and procedures to ensure effectiveness and to uncover potential opportunities for improvement.
7. MISO will review the tools, communication, and processes to ensure reliable and effective operations.

MRO-Manitoba Hydro

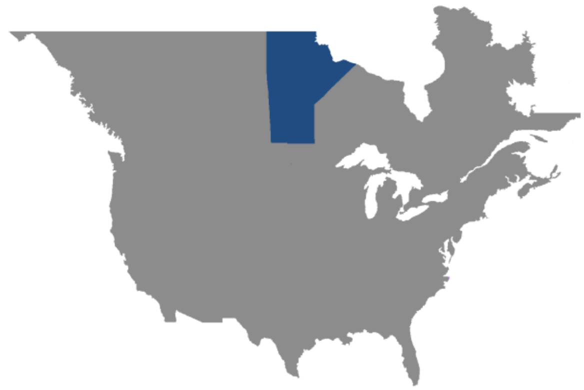
Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**4,591**
Load-Modifying Contractually Interruptible	241
Net Internal Demand	**4,350**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transfers	-110
Existing-Certain & Future-Planned Capacity	5,428
Anticipated Resources	**5,318**
Prospective Resources	**5,474**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**22.25**
Prospective Reserve Margin	**25.83**
NERC Reference Margin Level	**12.00**

Assessment Area Footprint



Summary of Methods and Assumptions

Reference Margin Level

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

Load Forecast Method

Coincident

Peak Season

Winter

Planning Considerations for Wind Resources

Effective Load-Carrying Capability (ELCC) of 14.1 percent for the summer; wind is derated entirely for the winter season.

Planning Considerations for Solar Resources

No utility-scale solar resources

Footprint Changes

Assessment Area Overview

Manitoba Hydro is a Provincial Crown Corporation providing 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. Manitoba Hydro is winter peaking. 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 Reliability Coordinator (RC) for Manitoba Hydro.

The capacity reserve margin criteria, which is considered the Reference Margin Level, requires a minimum 12 percent reserve above the forecast peak demand. This criteria is stricter than the NERC default assignment of a Planning Reserve Margin of 10 percent for predominately hydro systems, and has not changed since the prior assessment.

There are no changes to the load forecasting methods since the prior winter assessment. Manitoba Hydro provides a probability-based load variability forecast for each month to capture uncertainty in the forecast based on historical load variability.

Manitoba Hydro has recently updated its energy efficiency/conservation plan. The 2014 Power Smart Plan includes higher forecast energy and demand savings compared to the 2013 Power Smart Plan. Total savings outlined in the 2014 Power Smart Plan are 1136 MW and 3978 GWh. These 15-year savings from the 2014 Power Smart Plan are approximately 2.3 times higher for demand savings and 2.6 times higher for energy savings. The increased savings are the result of enhancements to existing programs and the addition of new programs based on opportunities identified in the market. There are no significant changes in the DR program since the prior summer assessment.

Manitoba Hydro has 660 MW of on-peak capacity exports and 550 MW of on-peak capacity imports during the assessment period.

For variable wind generation, Manitoba Hydro assumes a capacity value of zero for the months of December, January, and February, which are the three months during which the annual peak load will occur, given the winter peaking load. The zero value is used as the winter peak load is expected to occur at temperatures below -30 C, when wind generation is expected to shut down due to low temperature operating restrictions. For spring, fall, and summer months, Manitoba Hydro assumed a capacity value of 14.1 percent, based on the Effective Load Carrying Capability (ELCC) analysis in MISO’s Planning Year 2014–2015 Wind Capacity Credit report. This methodology is unchanged from the previous year.

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 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 the MRO Guidelines, and only the peak load hours for each month. These enhancements, which are in compliance with MISO’s business practices, provide more representative and stable capability values for hydro units. This methodology is unchanged from the previous year.

At a minimum annual basis, Manitoba Hydro performs an operational study to determine storage reserve requirements necessary to meet demand under the lowest historic flow on record and a high load forecast. No unique operational problems have been observed.

The integration of wind generation in Manitoba to date has not significantly impacted operational procedures. As no additional wind generation is anticipated, additional operations impacts are not expected during the upcoming winter.

Since January 1, 2010, the Province of Manitoba’s Climate Change and Emissions Reductions Act has precluded the use of coal to generate power, except to support emergency operations. This does not preclude operation to support system reliability.

There are no significant issues identified in neighboring area that have the potential to impact the reliability of Manitoba Hydro’s operations.

There are no known significant issues or concerns that could lead to large-scale impact to generator availability during the winter season.

There are no expected fuel-related challenges for this winter season. Manitoba Hydro system is predominantly hydro-based and does not rely on natural gas as a primary fuel source. Reservoir levels are sufficient to meet both peak demand and daily energy demand for this winter season.

MRO-MAPP

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**5,736**
Load-Modifying DCLM	370
Load-Modifying Contractually Interruptible	0
Net Internal Demand	**5,366**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transactions (Transfers)	-258
Existing-Certain & Future-Planned Capacity	7,163
Anticipated Resources	**6,905**
Existing-Other, Future-Other Capacity	440
Prospective Resources	**7,345**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**28.69**
Prospective Reserve Margin	**36.89**
NERC Reference Margin Level	**15.00**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level
MAPP members use a range of reserve margin targets depending on each individual member's system. However, MAPP provides a 15 percent Reference Margin Level.
Load Forecast Method
Coincident; normal weather (50/50)
Peak Season
Summer; however, recent projections indicate higher Total Internal Demand during the winter seasons.
Planning Considerations for Wind Resources
Historical data
Planning Considerations for Solar Resources
No utility-scale solar resources
Footprint Changes
There have been some membership changes since the previous winter assessment. Minnesota Municipal Utilities Association (MMUA) and Ames Municipal Electric System (AMES) have withdrawn from the MAPP Planning Region.

Assessment Area Overview

The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of the following states: Iowa, Minnesota, Montana, North Dakota, and South Dakota. Currently, the MAPP Planning Authority includes entities in two BA areas (WAUE and MISO) and 12 Load-Serving Entities. The MAPP Planning Authority covers an area of approximately 200,000 square miles and serves a population of about 3.5 million. MAPP typically experiences its annual peak demand in summer, but recently started projecting peak internal demand during the winter seasons. Since the previous winter assessment, Minnesota Municipal Utilities Association (MMUA) and Ames Municipal Electric System (AMES) have withdrawn from the MAPP Planning Region.

The MAPP Planning Reserve Margins (Anticipated and Prospective) are expected to exceed the target Reference Margins of 15 percent for thermal systems and 10 percent for hydro systems due to MAPP's strong generation portfolio and demand-side management programs for the 2014–2015 winter season. With the withdrawal of MMUA and AMES, the demand expected in the MAPP Assessment Area is expected to be lower than what had been forecast for the 2013–14 winter season. The Basin Electric membership continues to grow with the sustained high load growth due to the oil-related activity in northwestern North Dakota, leading its demand growth to account for 148 MW of projected load growth compared to the 2013–2014 reported winter peak. To address this high load growth, Basin Electric has added two combustion turbines, supplying 90 MW of additional capacity, and expects to add another two units, totaling another 90 MW of capacity additions during the 2014–2015 winter season. In addition to the Basin Electric units, NorthWestern is planning on adding an additional 60 MW of wind capacity to its system. MAPP is projecting 510 MW of imports and 769 MW of exports, retaining the status of a net exporting region with a net export of 259 MW. Several transmission projects will have been completed prior to or during the 2014–2015 winter season, all of which are intended to increase the reliability of the MAPP transmission system. Despite the sustained high load growth due to the oil-related activity in the northwestern North Dakota area, and some minor instability that is currently being studied, the MAPP Assessment Area does not foresee any reliability, capacity, or fuel supply issues becoming problematic during the upcoming winter.

TOPs in the MAPP Assessment Area perform seasonal studies using the contingencies developed for the MAPP Transmission Reliability Assessment. These contingency files contain contingencies within the MAPP footprint plus neighboring systems in the Dakotas, Canada, Iowa, Minnesota, and Nebraska that are selected to produce the most severe system results and impacts. These seasonal studies are performed for the upcoming operating season and include extended planned outages that will occur during the upcoming season. The studies include sensitivities looking at known areas of concern. Instability issues at the Langdon Wind Farm are being studied by a third-party expert. Instability may occur during unexpected line switching from faults and could result in inadvertent load tripping. Similar instability exists at the Pillsbury Wind Farm as well, but with no risk of tripping load. WAPA, in conjunction with Basin Electric, has performed extensive studies in the northwestern North Dakota region due to load growth in the area.

With respect to last winter's extreme weather, natural gas availability and extreme cold conditions are being monitored as potential issues that could impact generator availability during the 2014–2015 winter season. Basin Electric's peaking generation is connected directly to the Northern Border Pipeline, which is not expected to experience any fuel supply shortage. In addition, there are multiple units in the MAPP region that can utilize a secondary fuel source in the event of any fuel supply issues.

MRO-SaskPower

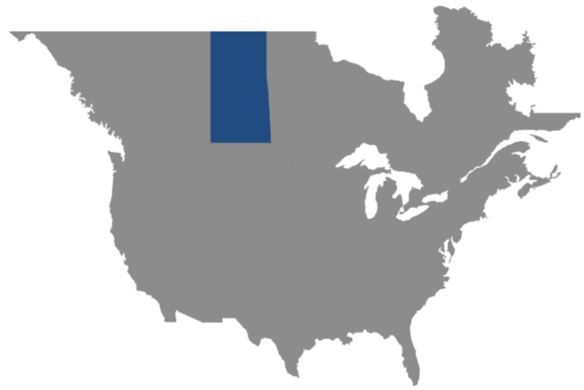
Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**3,469**
Load-Modifying Contractually Interruptible	86
Net Internal Demand	**3,383**

Resource Projections	Megawatts (MW)
Existing-Certain & Future-Planned Capacity	4,064
Anticipated Resources	**4,064**
Prospective Resources	**4,064**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**20.13**
Prospective Reserve Margin	**20.13**
NERC Reference Margin Level	**11.00**

Assessment Area Footprint



Summary of Methods and Assumptions

Reference Margin Level
Saskatchewan uses an Expected Unserved Energy (EUE) analysis to project its Planning Reserve Margins and as the criterion for adding new generation resources. This 11 percent margin is applied as the Reference Margin Level for this assessment.
Load Forecast Method
Coincident, 50/50 forecast
Peak Season
Winter
Planning Considerations for Wind Resources
20 percent of nameplate (winter); 10 percent of nameplate (summer)
Planning Considerations for Solar Resources
No utility-scale solar resources
Footprint Changes
n/a

Assessment Area Overview

Saskatchewan, a Canadian province, comprises a geographic area of 651,900 square kilometers and serves approximately one million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the sole Planning Authority, Reliability Coordinator, BA, and principal supplier of electricity for Saskatchewan. It is a Provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections.

The Saskatchewan Power Corporation (SaskPower) is the Reliability Coordinator and Planning Authority for the province of Saskatchewan and is the principal supplier of electricity in the province. Significant footprint changes have not occurred during the past two years and are not expected in future years.

Seasonal operational margins are expected to be adequate for the winter, and no significant seasonal constraints have been identified. Peak demand for the SaskPower system is experienced in the winter. An adequate Planning Reserve Margin (20 percent) is projected for SaskPower during the 2014–2015 winter assessment period. SaskPower's criterion for adding new generation resources is based on Expected Unserved Energy (EUE). A probabilistic analysis is performed to determine the requirement for adding new generation resources. The probabilistic EUE value equates to an approximate 11 percent Reserve Margin.

SaskPower is not expecting significant changes in the demand forecast since forecast growth has not materialized. Saskatchewan's total internal hourly interval demand is forecast to be 3,469 MW for the 2014–2015 winter assessment period, resulting in no change from last year.

No significant generator uprates, derates, or additions are planned for the upcoming winter. Since the prior winter assessment, a 66 MW (gross) coal unit was retired. There are no firm imports or exports for the 2014–2015 winter assessment period involving SaskPower, and SaskPower is not planning to rely on emergency imports for the current assessment period.

SaskPower has one transmission project planned for the 2014–2015 winter to improve local transmission reliability. Two new 300 MVA 230–138 kV autotransformers are being installed at a station in the Regina area (southeastern Saskatchewan). One of these transformers will replace an existing 200 MVA transformer, and the second will be installed in parallel to increase load-serving capability.

The winter season joint study with Manitoba Hydro (with input from Basin Electric) is underway to determine the import/export capabilities with neighboring control areas for the 2014–2015 winter assessment period. As part of the study, a joint report is prepared, and applicable guidelines are issued to respective control rooms before the winter season starts. Any potential seasonal transmission constraints and corrective actions are to be covered in the report.

NPCC-Maritimes

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**5,398**
Load-Modifying Contractually Interruptible	259
Net Internal Demand	**5,139**

Resource Projections	Megawatts (MW)
Existing-Certain & Future-Planned Capacity	6,750
Anticipated Resources	**6,750**
Prospective Resources	**6,750**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**31.35**
Prospective Reserve Margin	**31.35**
NERC Reference Margin Level	**20.00**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level
20 percent
Load Forecast Method
Coincident, 50/50 forecast
Peak Season
Winter
Planning Considerations for Wind Resources
Estimated capacity is derived from a combination of mandated capacity factors and reliability impacts.
Planning Considerations for Solar Resources
n/a
Footprint Changes
n/a

Assessment Area Overview

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). New Brunswick and Nova Scotia are the two BAs. The New Brunswick Power System Operator is the RC for the Maritimes Area, which covers approximately 57,800 square miles.

NPCC-Maritimes is a winter-peaking system and is projecting adequate surplus capacity margins above its operating reserve requirements for the 2014–2015 winter 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 reserve margin of 15 percent.

No significant changes in the demand forecast are expected since the previous winter. The forecast peak for the 2013–2104 winter was 5,376 MW and for 2014–2015 winter is 5,398 MW, an increase of 22 MW. The only DR considered in resource adequacy assessments for the Maritimes Area is interruptible load, which comes from industrial customers under contract. The forecast values vary between 239 MW and 319 MW over the assessment period. Because of the variability of industrial load at any one time, it is impossible to predict the actual amount available except in real time. No generation retirements are scheduled during this winter's assessment period. The only generation that is expected to be added over the assessment period is wind generation, which is approximately 50 MW.

Generation in the Maritimes Area includes nuclear, natural gas, HFO/natural gas, coal/pet coke, light oil, diesel, bunker, hydro/tidal, biomass/biogas, and wind. There is 36 percent from coal/pet coke, 18 percent from hydro/tidal, 9 percent nuclear, 7 percent natural, and 30 percent from the remaining sources.

The Maine Power Reliability Program (MPRP) project in New England and the refurbishment of the Eel River HVDC station both have the ability to impact the amount of energy transfers between New Brunswick/New England and New Brunswick/Hydro Québec. The respective operation groups of New Brunswick Power and ISO-New England coordinate the MPRP project, which involves setting any transfer limits up to and including real time. The Eel River outage is a fixed de-rate on the interface during its outage and is scheduled to be back in service (commercial) by mid-November. Neither of these outages should cause any reliability issues, because the Maritimes is not reliant on energy transfers to meet its requirements.

NPCC-New England

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**21,086**
Load as a Capacity Resource	656
Net Internal Demand	**20,430**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transfers	812
Existing-Certain & Future-Planned Capacity	25,389
Anticipated Resources	**26,201**
Existing-Other, Future-Other Capacity	7,054
Prospective Resources	**33,255**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**28.25**
Prospective Reserve Margin	**62.78**
NERC Reference Margin Level	**15.70**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level

The Installed Capacity Requirement (ICR) results in a Reference Margin Level of 15.7 percent in 2015, declining to 14.3 percent in 2017 and remaining at that level for the duration of the period.

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Summer

Planning Considerations for Wind Resources

25 percent of the total

Planning Considerations for Solar Resources

Seasonal claimed capability

Footprint Changes

n/a

Assessment Area Overview

The New England electric grid is an 8,500 mile, high-voltage transmission system that connects electric utilities, publicly owned electric companies, over 350 power generators, suppliers and alternative resources and serves 6.5 million households and businesses—a population comprised of 14 million residents across more than 66,500 square miles. New England has 13 transmission ties with neighboring power systems that allow electricity trade with New York, New Brunswick, and Québec.

The New England (ISO-NE) Reference Margin Level is based on the capacity (megawatts) needed to meet the NPCC one-in-10-years loss-of-load expectation (LOLE) resource planning reliability criterion. The amount of capacity needed, referred to as the Installed Capacity Requirement (ICR), varies from year to year depending on expected system conditions. On an annual basis, ISO-NE calculates the ICR for each Forward Capacity Auction (FCA), which is held three years in advance of when the capacity will need to be available. For this winter assessment, the resulting Reference Margin Level is 15.7 percent during the 2014–2015 capacity commitment period.

In previous years, ISO-NE did not have a fixed capacity or Reserve Margin Requirement, meaning an ICR-based target was not used in those assessments. Instead, ISO-NE assumed a 15 percent Reference Margin Level that NERC assigned for predominantly thermal systems. ISO-NE does not anticipate Planning Reserve Margins to fall below the Reference Margin for the 2014–2015 winter period. Because the ICR is based on the summer peak levels for the summer-peaking ISO-NE system, ISO-NE should have adequate capacity during the lower-peaking winter period.

For winter 2014–2015, ISO-NE's Anticipated Resources total 32,433 MW. After accounting for planned maintenance, gas at risk, and unplanned outages, the Existing-Certain value is 25,379 MW. This results in an Existing-Certain plus Net Firm Transfer Margin level of 28.2 percent, an Anticipated Reserve Margin level of 28.2 percent, and the Prospective Reserve Margin level of 62.8 percent of the 20,430 MW net internal demand forecast.

ISO-NE's reference demand forecast, which does not take into account DR, is 21,086 MW for the 2014–2015 winter assessment period. This is 213 MW (1.01 percent) lower than the 2013–2014 winter peak demand forecast of 21,138 MW and 367 MW (1.73 percent) lower than ISO-NE's 2013–2014 winter-metered peak demand of 21,453 MW. The reason for the lower 2014–2015 winter demand forecast compared to the 2013–2014 winter demand forecast is the lower economic growth forecast.

Although the ISO-NE's load curve has changed during the spring and fall due to the effect of behind-the-meter solar generation, this will not be a factor in 2014–2015 winter except during off-peak hours. The demand forecast has not changed significantly since last winter. New England did experience periods of extremely low temperatures and, if it experiences similar periods of low temperatures this winter, could expect the winter peak load to be higher than last year. ISO-NE has seen a significant decrease in its winter peak load since the region's record peak load in January of 2004 due to the effects of the recession and energy-efficiency measures fostered by the six New England states.

During the 2014–2015 winter period, a total of 2,145 MW of demand resources is expected to be available on peak. This includes 1,489 MW of energy efficiency/conservation and 656 MW of active demand resources. Both categories of demand resources are treated as capacity within ISO-NE's Forward Capacity Market (FCM).

The 1,489 MW of energy efficiency/conservation includes installed measures (e.g., products, equipment, systems, services, practices, or strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. The 656 MW of active demand resources consist of real-time demand response (RTDR) and real-time emergency generation (RTEG), which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP-4). These active demand resources can be used to help mitigate an actual or anticipated capacity deficiency. OP-4 Action 2 is implemented to dispatch RTDR and manage operating reserve requirements. Action 6, which is the dispatch of RTEG, may be implemented to maintain 10-minute reserve.

Unannounced audits for active demand resources are conducted twice per year during the summer and winter periods. The results for the audit of 2013–2014 winter demand resources showed an average performance of 100.3 percent of capacity supply obligations (CSO) for RTDR and RTEG. The ISO expects demand resources to perform as needed to meet the demand on the basis of these audit results, as well as the historical response of RTDR when activated.

Demand resources submit an hourly status of their capability to ISO-NE. System operators can view the status in real time. System operators also can monitor the real-time performance of the resources relative to their capacity supply obligations using telemetry from each resource.

Eight generators will have retired by the end of 2014, which accounts for a loss of 1,827 MW since the 2013–2014 winter assessment. Seven of these are fossil-fired generators, and one is a nuclear power plant. ISO-NE anticipates that the retirement of these non-gas-fired generators will further aggravate the existing natural gas pipeline constraints. New generation, totaling 10 MW (40.2 MW nameplate) of renewable energy is forecast to be available during the 2014–2015 winter assessment.

ISO-NE anticipates the potential for various amounts of single-fuel, gas-only power plants to be temporarily unavailable during cold or extreme winter weather conditions or during force majeure conditions on the regional gas grid. New England projects that up to 4,254 MW of natural-gas-fired capacity will most likely be at risk for this winter period. It is accounted for within the Existing-Other category. New England could experience higher rates of gas-fired generator outages if large gas infrastructure contingencies or non-gas-fired electrical contingencies occur. The ISO-NE long- and short-term outage coordination efforts evaluate and account for gas-fired generation at risk, and ISO-NE would balance the mitigation of these scenarios with real-time supplemental commitment and use of emergency procedures, as needed.

The forecast for the 2014–2015 winter period includes on-peak firm capacity imports of 912 MW. These firm capacity imports, which include transfers from Québec, New York, and New Brunswick, have been contracted for delivery within the 2014–2015 FCM capacity commitment period. Additionally, 100 MW of firm exports to New York are projected for the 2014–2015 winter. ISO-NE does not reply on emergency imports for meeting the Reserve Margin Level.

During the 2014–2015 winter, ISO-NE will conduct fuel audits as part of the FERC-approved Winter Reliability Program for dual-fuel generators, a process that proved a success during the 2013/2014 winter.[17]

ISO-NE has several procedures for dealing with loss of system capacity, including the following:

- Operating Procedure #4 – *Action during a Capacity Deficiency* (details use of DR, emergency energy purchases, voltage reductions, reduction of system reserve requirements, requests for non-obligated capacity, and public appeals)
- Operating Procedure #7 – *Action in an Emergency* (covers shedding of firm system load)
- Operating Procedure #21 – *Energy Inventory Accounting and Action during an Energy Emergency* (details actions to be taken for forecast energy and fuel shortages)

The 2014–2015 Winter Reliability Program will also address several challenges ISO-NE has identified that could have an impact on generation during the 2014–2015 winter period. Similar to last year's program, the 2014–2015 Winter Reliability Program provides incentives to maintain a fuel inventory, fuel availability, or both for the coming winter and includes the following components:

- A winter DR program that may be called upon 30 times during the winter of 2014–2015.
- A dual-fuel commissioning program that will incent the creation of more dual-fuel facilities in New England by aiding with the commissioning costs of dual fuel.
- A dual-fuel testing program that will aid in the costs associated with the fuel swap testing that will ensure a smooth fuel swap during the winter period.
- An incentive program to store fuel oil onsite before the start of winter.
- An incentive program to contract for LNG for New England resources before the winter.

In addition, ISO-NE expects significant market improvements for the 2014–2015 winter with the implementation of the Energy Market Offer Flexibility project. This market change will improve pricing incentives by allowing participants to update their offers in real time to reflect changing fuel costs, such as supply offer parameters, with hourly granularity that reflect operational limits and varying intra-day costs. ISO-NE has also modified its Information Policy, which allows for improved coordination between gas and electric power sectors per FERC Order 787.[18]

[17] FERC, Order Accepting Tariff Revisions, (September 9, 2014).
[18] ISO New England Information Policy (ISO tariff, Attachment D) (2014). FERC, Communication of Operational Information between Natural Gas Pipelines and Electric Transmission Operators, Order No. 787, final rule (November 15, 2013)

NPCC-New York

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**24,737**
Load as a Capacity Resource	843
Net Internal Demand	**23,894**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transfers	1,078
Existing-Certain & Future-Planned Capacity	40,963
Anticipated Resources	**42,041**
Prospective Resources	**42,041**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**75.95**
Prospective Reserve Margin	**75.95**
NERC Reference Margin Level	**17.00**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level
The New York State Reliability Council (NYSRC) Installed Reserve Margin (IRM) of 17 percent extends through April 2015. Because this margin will be reassigned in 2015, NYISO will use the default Reference Margin Level of 15 percent.
Load Forecast Method
Coincident; normal weather (50/50)
Peak Season
Summer
Planning Considerations for Wind Resources
Modeled with a 31 percent capacity factor
Planning Considerations for Solar Resources
Modeled with a 1 percent capacity factor
Footprint Changes
n/a

Assessment Area Overview

NYISO is the only BA in the New York Control Area (NYCA). The NYCA is over 48,000 square miles. It serves a total population of about 19.7 million people and peaks annually in the summer. This report addresses the reliability assessment for the NYCA for December 2014 through February 2015.

The New York State Reliability Council (NYSRC) has determined that an Installed Reserve Margin (IRM) of 17 percent in excess of the NYCA coincident peak demand forecast is required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion for the capability year running from May 1, 2014, through April 30, 2015. The 2014–2015 capability year IRM is unchanged from the IRM set for 2013–2014. The NYCA is a summer-peaking region and, as such, NYISO anticipates that adequate resources will be available for the upcoming winter season. Reserve margins of approximately 76 percent are expected for the winter season before accounting for maintenance, derates and unplanned outages.

The 2014–2015 winter season peak load forecast is 24,737 MW, which is 0.1 percent more than the forecast peak of 24,709 MW for the 2013–2014 winter and 1,001 MW (3.89 percent) less than the actual winter peak in 2013–2014 of 25,738 MW, which was a new all-time winter peak load for New York, set on January 7, 2014. By contrast, the 2014 summer peak load forecast was 33,666 MW.

In preparing for the 2013–2014 winter, the NYISO implemented new cold weather procedures to monitor gas nominations, oil inventories, and expected oil replenishment schedules for all dual-fuel, gas-fired, and oil-fired generators prior to each cold day. This process will be in place for the 2014–2015 winter.

Last winter, all reserve requirements were met throughout the winter operating period despite significant generator capacity derates on some of the coldest days. DR was activated on January 7. No firm load shedding was required, and no emergency procedures were utilized.

There have been no significant new additions to transmission or generation in the NYCA since the previous winter season. Some generation has returned or will return to service from mothball during the winter season, including the Danskammer plant located in Southeastern New York, close to the load center of the state.

NPCC-Ontario

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**22,149**
Demand Response	555
Net Internal Demand	**21,594**

Resource Projections	Megawatts (MW)
Existing-Certain & Future-Planned Capacity	29,248
Anticipated Resources	**29,248**
Prospective Resources	**29,248**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**35.45**
Prospective Reserve Margin	**35.45**
NERC Reference Margin Level	**19.50**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level

The IESO-established Reserve Margin Requirement is applied as the Reference Margin Level.

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Summer

Planning Considerations for Wind Resources

Modeled, based on historic performance and historic weather data

Planning Considerations for Solar Resources

Modeled, based on historic weather data; 30 percent for summer

Footprint Changes

n/a

Assessment Area Overview

Ontario’s electrical power system covers an area of 415,000 square miles and serves the power needs of more than 13 million people. Ontario is interconnected electrically with Québec, Manitoba, Minnesota, Michigan, and New York.

Ontario’s electrical power system is interconnected electrically with Quebec, Manitoba, Minnesota, Michigan, and New York. Ontario covers an area of 415,000 square miles, and the Independent Electricity System Operator (IESO) serves the power needs of more than 13 million people.

For the calendar year 2015, the reference reserve margin is 19.5 percent. Ontario IESO treats DR as a resource for its own assessments, while in this assessment DR is used as a load modifier, as requested by NERC. As a consequence, the target reserve margin numbers in this assessment are higher than those in IESO reports. Both the Anticipated and the Prospective Planning Reserve Margins (both are 35 percent) are above the target for Ontario area during the upcoming winter season.

The forecast peak demand, under normal weather, for the winter of 2014–2015 is 22,149 MW. Peak demand continues to be shaped by three main factors: the economy, the growth in distribution-connected generation, and the impacts of conservation. The impacts of economic and population growth are expected to remain fairly muted as economic growth comes from the less-energy-intensive service sector. Embedded generation does not have the same impact on winter peaks as it does on summer peak demands because the vast majority of the embedded generation is solar powered and the winter demand peaks after the sun has set. The winter peak is influenced by the impact of lighting efficiency improvements as lighting load is contributing less to the peak.

IESO's demand measures include Demand Response 3 (DR3), Peak Saver, and Dispatchable Loads. Demand measures are not decremented from demand in IESO's assessments, but are instead treated as a resource to be dispatched as necessary. Peak Saver is not available during the winter as it is an air conditioner cycling program that reduces the overall effective capacity of DR to 555 MW in the winter period. Earlier in 2014, the DR3 program was integrated into the IESO market, allowing it to be activated based on scheduling in the constrained sequence (security and economic assessed). The change is anticipated to provide more transparency to the market and result in a more accurate method of DR activation. The IESO expects the performance of the program to be similar to previous years. Past experience indicates resources respond as offered when called upon.

Since the last winter assessment, Ontario has seen 757 MW of new installed wind capacity and 145 MW of new installed hydro capacity. Also since the last winter assessment, Atikokan GS (205 MW) was converted from coal to biomass. Planned resources, which are expected to be in service prior to the forecast winter peak demand, include 620.6 MW of wind, 80 MW of solar, and 265 MW of new hydro capacity. Ontario assumes that wind contributes 33.1 percent of its capacity on peak, and solar does not contribute any capacity at the time of the winter peak. In April 2014, Thunder Bay Generating Station burned its last supply of coal. Construction is underway to convert it to biomass, and it is scheduled to return in late January 2015 (142 MW). Two electricity storage facilities (2 MW and 4 MW) have connected and are available to provide regulation service.

There are no new significant transmission projects planned before or during this winter. Early in December, one of the tie circuits with NY will be taken out of service, causing a significant reduction in import/export capability through the NY interface. Since the IESO conducts its planning assessments without reliance on external resources, this outage will not affect adequacy this coming winter.

NPCC-Québec

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**37,985**
Load-Modifying Contractually Interruptible	1,458
Supply-Side Direct Control Load Management	250
Net Internal Demand	**36,277**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transactions (Transfers)	129
Existing-Certain & Future-Planned Capacity	40,518
Anticipated Resources	**40,647**
Prospective Resources	**40,647**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**12.05**
Prospective Reserve Margin	**12.05**
NERC Reference Margin Level	**10.80**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level
Reference Reserve Margin Levels are drawn from the Québec Area 2013 Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee in December 2013.
Load Forecast Method
Coincident; normal weather (50/50)
Peak Season
Winter
Planning Considerations for Wind Resources
On-peak contribution is approximately 30 percent of the total.
Planning Considerations for Solar Resources
n/a
Footprint Changes
n/a

Assessment Area Overview

The Québec Assessment Area is a NERC subregion 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 20,886 miles (33,613 km) as of December 31, 2013. The area is winter peaking.

The Québec Area demand forecast for the 2014–2015 winter peak (37,985 MW) is 750 MW higher than the demand forecast presented in last year's winter assessment, which is mainly attributed to the residential sector and specifically to higher peak demand for space heating use.

The Reference Margin Level is drawn from the Québec Area 2013 Interim Review of Resource Adequacy,[19] which was approved by NPCC's Reliability Coordinating Committee on December 3, 2013. The Reference Margin Level is 10.8 percent for the 2014–2015 winter period, which is slightly higher than in the 2013–2014 WRA (10.1 percent). The anticipated reserve margin level is not expected to drop below the NERC Reference Margin Level of 10.8 percent for the 2014–2015 winter operating period. For this winter assessment, reserve margin level evaluations were done for peak conditions only.

[19] NPCC 2013 Québec Balancing Authority Area Interim Review of Resource Adequacy

The DR and energy efficiency/conservation programs have an estimated combined impact of 3,800 MW under winter peak conditions (2014–2015). Demand forecasts take into account the load shaving resulting from the residential dual-energy program, a rate option for residential customers equipped with a dual-energy space heating system (electric/fuel oil). When the outside temperature falls below a given level (-12°C for Montréal), the space heating system automatically runs on the fuel oil, and the electricity used during that period is billed at higher rates. The impact of this program on peak load demand is estimated to be around 650 MW during the period assessment.

In the Québec subregion, DR programs are specifically designed for peak-load reduction during winter operating periods. DR consists of interruptible demand programs for large industrial customers, treated as supply-side resources, totaling 1,460 MW for the 2014–2015 winter period. It is 200 MW less than last winter. DR programs are usually used in situations where either the load is expected to reach high levels or when resources are expected to be insufficient to meet peak load demand. Interruptible load program specifications differ among programs and participating customers. They usually allow for one or two calls for reduction per day and between 40 and 100 hours of load interruption per winter period. Interruptible load programs are planned with participating industrial customers with whom contracts are signed.

Before the peak period, generally during the fall season, all customers are regularly contacted in order to reaffirm their commitment to provide capacity when called, during peak periods. The impact of the energy efficiency/conservation programs is evaluated at 1,440 MW for the 2014–2015 winter peak period and is included in the demand forecast (active and to-be-deployed programs). These programs have been in place for several years, and the records show that customer response is very reliable. A voltage reduction program with an estimated impact of 250 MW is also implemented.

A total of 1,190 MW of new installed capacity is planned for the 2014–2015 winter peak: 660 MW from hydro generation, 480 MW from wind resources (with a contribution at peak estimated at 145 MW), and 50 MW from biomass. For wind resources, capacity contribution at peak period is estimated at 30 percent of contractual capacity, thus representing 830 MW for the 2014–2015 winter period. Maximum wind capacity is set to equal contractual capacity, which generally equals nameplate capacity. There are no planned resource retirements that would significantly impact the available on-peak capacity for the next winter. Hydraulic conditions for this upcoming winter peak period are such that reservoir levels are sufficient to meet both peak demand and daily energy demand throughout the winter.

The Québec Area presents a positive net transfer during the 2014–2015 winter peak period, with firm capacity sales totaling 671 MW to New England and Ontario (Cornwall) and capacity purchases totaling 800 MW. Expected capacity purchases are planned by Hydro-Québec Distribution as needed for the Québec internal demand. In this regard, Hydro-Québec Distribution has designated the Massena–Châteauguay (1,000 MW) and Dennison–Langlois (100 MW) interconnections to meet its resource requirements during the winter peak period. However, the Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level.

In 2013, Hydro-Québec TransÉnergie (HQT) added a new 735 kV section at the Bout-de-l'Île substation located in the east end of the Montréal Island. The Boucherville–Duvernay line (Line 7009) has been looped into this substation, and the first of two ±300 Mvar Static Var Compensators (SVCs) has been added to the 735 kV section. The second SVC was installed during fall 2014, as well as one 735/315 kV, 1,650 MVA transformer bank. This new 735 kV station will allow redistribution of the load around the Greater Montréal area and will accommodate load growth in the eastern part of Montréal. A second 735/315 kV, 1,650 MVA transformer bank is planned to be commissioned before summer 2015. This project will allow for future major modifications to the Montréal area regional subsystem. Many of the present 120 kV distribution substations will be rebuilt and upgraded to 315 kV, like most of the Montréal regional network.

Another major transmission project presently underway is the construction of the first phase of the Romaine River Hydro Complex. By the end of 2014, La Romaine-2 (640 MW) generating station will be integrated at the Arnaud 735/315/161-kV substation with a 262 km (162 mile) line initially operated at 315 kV.

The integration of the Romaine River Hydro Complex requires system upgrades that include the construction of a new 735 kV switching substation to be named “Aux Outardes,” located between the existing Micoua and Manicouagan substations. Two 735 kV lines will be redirected into the new substation, and one new 735 kV line (5 km, or 3 miles) will be built between the Aux Outardes and Micoua substations. This project was initially planned to be commissioned at the end of 2014 but has been delayed to September 2015.

During the 2014–2015 winter operating period, no significant issues concerning neighboring areas that could impact operations in the Québec Area have been identified. However, during very cold weather periods, planned interchange schedules are coordinated between NPCC subregions. In this context, NPCC conference calls are held as necessary. There are no known potential issues that could substantially impact the assessment projections.

PJM

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**133,509**
Load-Modifying Contractually Interruptible	43
Net Internal Demand	**133,466**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transactions (Transfers)	4,255
Existing-Certain & Future-Planned Capacity	186,778
Anticipated Resources	**191,033**
Prospective Resources	**191,033**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**43.13**
Prospective Reserve Margin	**43.13**
NERC Reference Margin Level	**15.90**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level

The PJM RTO Reserve Requirement is applied as the Reference Margin Level for this assessment.

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Summer

Planning Considerations for Wind Resources

On-peak contribution of 13 percent of installed capacity

Planning Considerations for Solar Resources

38 percent of nameplate capacity

Footprint Changes

This year's report includes the load and generation of East Kentucky Power Cooperative, which was integrated into PJM on June 1, 2013.

Assessment Area Overview

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of DE, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, Virginia, WV, and DC. PJM companies serve 61 million people and cover 243,417 square miles. PJM is a BA, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and Reliability Coordinator.

The PJM RTO Reserve Requirement as calculated by PJM is 16.2 percent for the 2014–2015 winter. The PJM RTO Reserve Requirement is 0.3 percentage points higher this year compared to what was reported last year, due to forced outage rates on older coal units being higher than normal. These units are nearing the end of their lives and will be retired over the next several years. The Reserve Margin Requirement will drop in the future when these units retire and their forced outage rates no longer are considered in the PJM Reserve Requirement Study. There is no significant difference in the demand forecast for this winter versus last.

For the first time, PJM has DR available in the winter. In the past, the only time PJM counted DR in the reliability calculations was during the summer months of June–September. New products are now available in PJM for DR that can be called all year. The DR available in the winter (43 MW) is significantly smaller (0.33 percent of the summer amount) than the amount available in the summer. Last winter PJM had no DR included in its reliability calculations. This winter, PJM included 43 MW of DR and expects this number to increase in the future.

Extreme weather can affect unit performance during the winter as was experienced last winter. If normal weather is assumed, no significant generator unavailability is expected. No other issues are expected to affect generator unavailability.

Beginning September 2014, the Dooms–Lexington 500 kV line will be out to complete a rebuild project. Existing stability restrictions for this outage would restrict generation or pumping at Bath to two units (removing about 2,000 MW of capacity) for an extended period of time. A new temporary SPS was designed that will allow up to 5 units to operate. The number of units tripped is determined by the operating status of Bath units (i.e., pump, generating, synchronous condensing, Mvar output, etc.). The SPS will be temporary for the duration of the rebuild of the Dooms–Lexington 500 kV line. The expected removal date of the SPS is June 1, 2016.

PJM runs a seasonal operating study for each summer and winter season. It looks at near-term operational issues (if any) and determines if operators are expected to experience out-of-the-ordinary operating scenarios. A case with 2 percent higher than 50/50 load and expected transfers was the basis for the analysis. Higher-than-expected generator forced outages (28,000 MW) were simulated to mimic the situation faced last winter.

No reliability issues were identified. Off-cost generation re-dispatch and switching solutions were required to control local thermal or voltage violations in some areas. Adequate installed capacity was available to fulfill reserve requirements.

PJM requires Generation Owners to place resources into the Maximum Emergency Category if environmental restrictions limit run hours below pre-determined levels. Max Emergency units are the last to be dispatched. Gas supply and transportation risks are captured in PJM resource planning studies to the extent they impact generator forced outage rates. All forced outages, whether outside management control or not, are included in the calculations used in planning studies. PJM currently assumes all forced outage rates are random across all seasons and independent of each other. PJM is investigating gas supply and transportation risk considering the potential correlation with extreme weather (and high winter loads) and the potential for the loss of multiple units due to gas transportation disruptions.

PJM took into account the experiences of last winter and made the following changes for the upcoming winter:

- Use a Cold Weather Resource Capability Testing and Preparation Checklist.
- Make additional operations data (e.g., dual-fuel capability and availability) and any resource limitations, such as environmental restrictions, available.
- Improve tracking of performance of external capacity resources.
- Improve data sharing and coordination with the gas industry.
- Clarify the process to seek environmental waivers and what PJM's role is.
- Improve interregional coordination and situational awareness during emergencies.
- Improve emergency procedures (e.g., voltage reduction and emergency bid procedures).
- Implement a new unit testing procedure for units that have not run in eight weeks.
- Use gas unit dispatch in real-time operations to include clarity in dispatcher communications and sharing of updated unit parameters and time frames for long lead time units.
- Use a Capacity Performance Product to improve unit performance, improve operational flexibility, and incentivize fuel security.

SERC

Demand Projections

	SERC-E Megawatts (MW)	SERC-N Megawatts (MW)	SERC-SE Megawatts (MW)
Total Internal Demand	**41,903**	**40,306**	**44,183**
Load-Modifying DCLM	9	0	10
Load-Modifying Contractually Interruptible	956	1,184	46
Load-Modifying Critical Peak-Pricing	31	0	0
Load-Modifying Load as a Capacity Resource	0	544	0
Net Internal Demand	**40,907**	**38,578**	**44,127**

Resource Projections

	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Net Firm Capacity Transfers	2,240	-209	-3,009
Existing-Certain & Future-Planned Capacity	53,347	53,556	67,638
Anticipated Resources	**55,587**	**53,347**	**64,629**
Existing-Other, Future-Other Capacity	47	959	306
Prospective Resources	**55,634**	**54,306**	**64,935**

Planning Reserve Margins

	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**35.89**	**38.28**	**46.46**
Prospective Reserve Margin	**36.00**	**40.77**	**47.16**
NERC Reference Margin Level	**15.00**	**15.00**	**15.00**

SERC-E

SERC-N

SERC-SE

Summary of Methods and Assumptions

Reference Margin Level

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

Load Forecast Method

Coincident; normal weather (50/50)

Peak Season

Summer

Planning Considerations for Wind Resources

As reported by individual Generator Owners

Planning Considerations for Solar Resources

As reported by individual Generator Owners

Footprint Changes

South Mississippi Electric Power Association (SERC-SE) was reported as part of SERC-SE in the 2013-14 Winter Reliability Assessment, but joined the MISO Assessment Area on December 19, 2013.

Assessment Area Overview

The SERC Assessment Area is a summer-peaking area covering all or portions of Alabama, Florida, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, South Carolina, Tennessee, and Virginia; it excludes entities that are members of PJM or MISO. The SERC Assessment Area covers approximately 308,900 square miles and serves a population estimated at 39.4 million. The SERC Assessment Area includes the following 11 BAs: Alcoa Power Generating, Inc. – Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), 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).

The NERC Reference Margin Level for SERC is 15 percent. This Reference Margin Level has not changed since the release of the *2013–2014 Winter Reliability Assessment*. SERC's Planning Reserve Margins, anticipated and prospective, remain above NERC's Reference Margin Level of 15 percent.

The load forecast for the Assessment Area is expected to be lower than the previous winter's forecast by 1.4 percent. This decrease is due to several factors, including slow expected economic growth and a small effect from appliance efficiency trends.

Since the last winter assessment, SERC entities have made various improvements and changes to load forecasting methods, including improvements in appliance saturation and efficiency modeling, and revisions for changing economic outlooks. PowerSouth has developed a Statistically Adjusted End-Use (SAE) forecasting model that combines end-use and econometric models. PowerSouth used the SAE model to develop new regression equations for deriving average residential power use, thus improving predictive capabilities.

Since winter 2013–2014, the following generation was added or is planned to be added in the SERC Assessment Area:

- Ratcliffe CC (August 2014, 730 MW, gas)
- Cane Run 7 CC (commercial operation May 2015, initial energy production winter 2014–2015, 691 MW, gas)

The following generating units were retired in the SERC Assessment Area since winter 2013–2014:

- Widows Creek 1, 2, 4, and 6 Steam (July 2014, 652 MW, coal)

One SERC entity reports that coal pile inventories are exceptionally low due to insufficient rail deliveries. If gas supplies were to become constrained over the winter, the combined effect could impact generator availability within the entity's area. However, there is no expected impact to generator availability during the winter season. To mitigate risks that could lead to unavailability, SERC entities use inventory management, communications with and monitoring of the coal and gas industries, dual-fuel capabilities, and high reserve margins. Additionally, several gas plants own gas storage facilities or connect to multiple pipelines.

A number of units have Mercury and Air Toxics Standards (MATS) compliance-related outages planned during the fall and spring outage seasons, with spring outages starting as early as January 3, 2015. The outages are carefully planned to minimize system impacts, and with the current high reserves, no significant impacts to resource availability are anticipated.

To improve reliability in the SERC Assessment Area, several transmission system enhancements have recently been completed or are currently in progress. The V.C. Summer #2 Interconnection Project, which includes two new 230 kV transmission circuits, was placed into service last winter. The V.C. Summer–Killian (37 miles) and V.C. Summer–Lake Murray (22 miles) lines both originate at the V.C. Summer Nuclear Generating Station and are intended to interconnect the new V.C. Summer Generator reliably into the BES.

TVA is currently replacing breakers at a 161 kV substation to reduce the risk of high-magnitude faults not being cleared by primary protection. TVA is also reconductoring the Widows Creek–Reese Ferry 161 kV transmission line to enhance the ability to operate the Raccoon Mountain Pumped Storage plant in pumping mode during certain area generation dispatch patterns.

Entergy and its six utility operating companies, and South Mississippi Electric Power Association, previously reported as part of the SERC Assessment Area but integrated into the Midcontinent Independent System Operator, Inc. (MISO) in December 2013. This addition added approximately 15,500 miles of transmission, 50,000 MW of generation capacity, and 35,000 MW of peak load to the MISO footprint. MISO now coordinates all RTO activities in the newly combined area, consisting of all or parts of 15 states.

Within this expanded MISO Balancing Area, the contract path capacity is limited to 1000 MW between the original MISO Midwest system and the new MISO South system. MISO market dispatches that result in power transfers between the Midwest and South portions of its system can result in significant unscheduled power flows through neighboring systems Tennessee Valley Authority (TVA), Associated Electric Cooperative, Inc. (AECI), Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), PowerSouth, Southwest Power Pool, Inc. (SPP), and Southern Company. These neighboring systems have raised concerns regarding the power flows, especially if the market dispatches exceed 2000 MW transferred from MISO South to MISO Midwest. At this time, no long-term joint planning studies have been conducted to determine long-term transmission system impacts. MISO and the neighboring systems have begun to establish long-term arrangements for both reliable operations and coordinated planning. In addition, SERC regional study groups are assessing and refining SERC modeling and reliability assessments to better reflect the expanded MISO BA in regional long-term planning and operational planning assessments.

Prior to MISO starting merged market operations in December 2013, MISO and the neighboring systems developed an Operations Reliability Coordination Agreement (ORCA) to address reliability concerns during an initial operating transition period. The ORCA is set to expire in April 2015. MISO and its neighboring systems continue to explore other reliability processes to mitigate any adverse impacts on system reliability in the operational time frame.

SERC entities are performing or have recently performed special operating studies related to the upcoming winter season. PowerSouth is performing a winter assessment that includes extreme cold weather combined with known line and generator outages. Among other studies, TVA prepares for the winter peak by studying loss of natural gas supply due to freezing. Based on these studies and recent experience, no unique operational problems have been observed.

Within the SERC Assessment Area, most outages related to the January 6–7, 2014 polar vortex occurred as a result of frozen sensors/indicators and equipment. The frozen devices stemmed from malfunctioning or failed heating elements, as well as temperatures falling below the design basis for equipment. These unplanned, weather-related outages, coupled with unexpectedly high loads, resulted in the need to take steps to maintain reliability. SERC entities enacted a variety of steps, such as dispatching reserves, calling for distribution level voltage reductions, utilizing DR, and shedding less than 300 MW of firm load.

Based on experience during the polar vortex, an entity in SERC-N expressed concerns on the various approaches to the usage of transmission loading relief procedures in the region as a way to mitigate the impacts of parallel flows on neighboring systems. Significant loading on higher-voltage facilities during the extreme weather event was caused by high load, unscheduled flows, and large transfers supplying power to other entities that were energy constrained due to the extreme weather. Transmission loading relief procedures were not readily used to reduce loading, due to studies and communications with neighboring RCs indicating that relief would likely curtail transactions that supplied power to those energy-constrained entities and exacerbate power supply constraints.

SERC entities identified a number of lessons learned during the 2014 polar vortex and are reviewing plans and procedures or have already implemented those lessons, which include the following:

- Need for review of assumptions regarding anticipated peak winter loads and analysis of super peak conditions.
- Load-shedding procedures:
  - Determine whether load shedding should be performed on a rotating or non-rotating basis.
  - Remove time targets for rolling blocks of load to avoid sidetracking operators.
- Heating and freeze protection:
  - Identify and implement improvements to existing freeze protection systems.

- Improve staging of auxiliary heat sources.
- Develop a consistent design basis for freeze protection on new generation units.

SPP

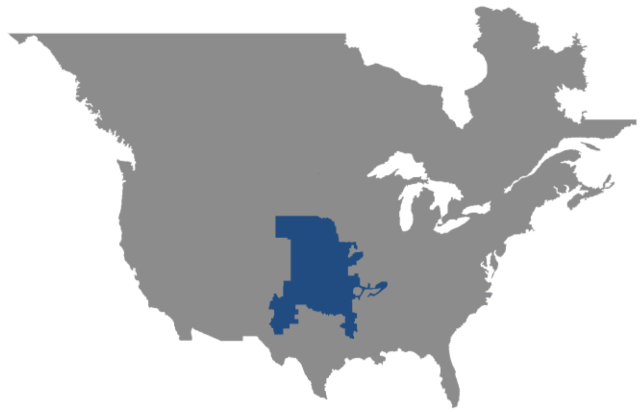
Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**35,265**
Load-Modifying Load as a Capacity Resource	48
Net Internal Demand	**35,217**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transfers	1,146
Existing-Certain & Future-Planned Capacity	64,179
Anticipated Resources	**65,325**
Existing-Other, Future-Other Capacity	0
Prospective Resources	**65,325**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**85.49**
Prospective Reserve Margin	**85.49**
NERC Reference Margin Level	**13.60**

Assessment Area Footprint



Summary of Methods and Assumptions

Reference Margin Level
SPP established target of 13.6 percent.
Load Forecast Method
Coincident; normal weather (50/50)
Peak Season
Summer
Planning Considerations for Wind Resources
n/a
Planning Considerations for Solar Resources
n/a
Footprint Changes
n/a

Assessment Area Overview

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 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 Planning Reserve Margins remain above SPP's target reserve margin of 13.6 percent.

The SPP Assessment Area is showing approximately a 2 percent increase in Total Internal Demand (35,265 MW) for the 2014–2015 winter assessment compared to the 2013–2014 winter forecast (34,415 MW). The SPP Assessment Area hit a new winter peak of 37,106 MW, which occurred on January 6, 2014. DR programs in the SPP Assessment Area are voluntary and are primarily targeted for summer peak load reduction use. 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 expect any issues to impact generator availability but has noted that coal supplies could potentially be reduced or delayed due to railroad congestion. The SPP Assessment Area is continuing to monitor this situation. In January 2013, the SPP Assessment Area created a gas-electric task force to oversee the activities between the gas and electric industries in SPP. This effort has provided a greater operational awareness of the gas fuel supply in the assessment area and led to the creation of the Weather Operational Plan. This is a communication plan between the major gas suppliers in the SPP Assessment Area and SPP Operations. The SPP Assessment Area has a diverse gas pipeline infrastructure and an adequate gas supply. SPP has experienced limited restriction with firm gas supply requirements. SPP has not experienced forced outages or derates due to gas supply in the SPP Assessment Area.

The SPP Assessment Area expects 1,200 MW of nameplate wind to be on-line by the end of the assessment time frame; no units have been retired since the 2013–2014 winter assessment. The SPP Assessment Area expects 7,618 MW of capacity derates to occur during the winter season based on scheduled outage information submitted to SPP's CROW system.

The expected on-peak capacity values for variable generation are determined by historical performance guidelines.[20] The net capability for wind is determined on a monthly basis using an eight-step process for establishing net capability. Wind facilities that have been in commercial operation for three years or less must include the most recently available engineering data. If MW values are not available, estimates may be used based on wind data that is correlated with reference towers outside a 50-mile radius of the facility's location. Such estimates must be approved by the SPP Generation Working Group (GWG).

The net capability for solar resources is determined on a monthly basis via the same eight-step process applicable to wind resources. Solar data that is correlated beyond 200 miles of the reference measuring device must also be approved by the SPP GWG.[21]

Only a small percentage of capacity transactions in the SPP Assessment Area contribute to the reserve margin during the winter peak. Imports that are counted for capacity are backed by firm generation and transmission contracts. Several entities expect capacity transactions for economic purposes only.

The SPP Assessment Area has identified several flowgates as being constraints on the transmission system. These constraints can be mitigated by redispatching generation; no reliability issues are anticipated. The SPP Assessment Area has several local issues that require specific generation commitments in order to provide sufficient reactive reserve for those areas. Operating guides have been put into place to provide mitigation.

SPP, along with other joint parties (Tennessee Valley Authority (TVA), Associated Electric Cooperative, Inc. (AECI), Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), PowerSouth, Southern Company) in the Region and MISO, are currently managing reliability concerns from MISO's recent operational changes under the provisions of the Operations Reliability Coordination Agreement (ORCA). Under Phase 1 of the ORCA, unless otherwise agreed to by the joint parties, MISO transfers between MISO Central/North and MISO South are limited. The Joint Parties and MISO continue to work toward developing, testing, and implementing subsequent phases of the ORCA that would allow this reliability limit to potentially increase under certain conditions.

SPP will not impede reliability by limiting the exchange of energy between MISO Central/North and MISO South except as required for SPP to maintain its own reliable operations, even if it requires MISO to exceed its current 1,000 MW path. While SPP and MISO are currently in litigation over the terms and conditions of the compensation due to SPP when MISO may exceed its 1,000 MW path, the two Assessment Areas continue to work together to ensure around-the-clock reliable operations.

SPP and MISO have also recently agreed to improvements to the methodology for accounting for the flow impacts of import and export transactions used in the congestion management process. Both SPP and MISO are continuing

[20] Section 12

[21] Facilities that have been in commercial operation for four years or more must include a minimum of four years or up to 10 years of the most recent commercial operation data available, whichever is greater. Metered hourly net power output (MWh) data may be used. After three years of commercial operations, if the Load-Serving Member does not perform or provide the net capability calculations to SPP, then the net capability for the resource will be 0 MW. Net capability calculations are to be updated at least once every three years.

to discuss additional improvements to ensure all sources of flows are properly accounted for within the region. SPP is currently working with MISO to implement a market-to-market congestion management process that will serve to enhance reliability by more efficiently responding to congestion that occurs on flowgates impacted by both RTOs. It is expected that the market-to-market process will be in place by March 1, 2015.

TRE-ERCOT

Peak Season Demand, Resources, and Reserve Margins

Demand Projections	Megawatts (MW)
Total Internal Demand	**52,837**
Load-Modifying Contractually Interruptible	844
Load-Modifying Load as a Capacity Resource	1,231
Net Internal Demand	**50,762**

Resource Projections	Megawatts (MW)
Net Firm Capacity Transfers	143
Existing-Certain & Future-Planned Capacity	76,457
Anticipated Resources	**76,600**
Existing-Other	2,707
Prospective Resources	**79,307**

Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**50.90**
Prospective Reserve Margin	**56.23**
NERC Reference Margin Level	**13.75**

Assessment Area Footprint

Summary of Methods and Assumptions

Reference Margin Level
ERCOT-established Reference Margin of 13.75 percent
Load Forecast Method
Coincident; normal weather (50/50)
Peak Season
Summer
Planning Considerations for Wind Resources
Effective Load-Carrying Capability (ELCC) of 8.7 percent
Planning Considerations for Solar Resources
ERCOT incorporates 100 percent capacity contribution.
Footprint Changes
n/a

Assessment Area Overview

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator (ISO) for the ERCOT Interconnection, scheduling power on an electric grid that connects 40,530 miles of transmission lines and 550 generation units and serving about 23 million electricity consumers. The ERCOT Region is an electric interconnection that is located entirely in Texas and operates as a single BA. The Texas Reliability Entity (TRE) is responsible for the RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

Based on ERCOT's load forecast and the resource capacity expected to be available, both Anticipated and Prospective Reserve Margins are calculated to be 50.9 percent and 56.0 percent, respectively, at the time of the forecast system peak. These levels are well above the reference level of 13.75 percent established by ERCOT. The Prospective Planning Reserve Margin assumes that about 2,600 MW of mothballed generation capacity, categorized as Existing-Other, could potentially be made available through Reliability-Must-Run contracts between ERCOT and the resource owners.

According to the ERCOT demand forecast, the 2014–2015 winter peak demand is forecast to be 52,837 MW, which is 11 percent above the 47,632 MW forecast for last year's winter peak, and 8 percent below the actual 2013–2014 winter peak demand of 57,256 MW. This increase in the winter peak demand forecast is due to using a 12-year normal weather forecast instead of using the expected seasonal forecast for the upcoming winter. Last year's winter seasonal forecast indicated a milder-than-normal winter, which resulted in a lower peak demand forecast. Also impacting the forecast are major changes to ERCOT's load forecasting framework that better capture the changing relationship between energy and economic growth and, specifically, the impacts of energy efficiency and price-driven DR, such as efforts by large customers to reduce their peak demand charges. The main changes to the methodology include adoption of a neural network model to forecast daily energy, and incorporation of regional growth forecasts for each customer class by using historical premise, population, and nonfarm employment data, as opposed to relying on just nonfarm employment as the economic driver. These changes partially offset the demand increase resulting from the shift from a seasonal weather forecast to a 12-year normal weather forecast.

Forecast peak demand reduction attributable to demand-side management resources amounts to 2,075 MW for the winter season. Out of this total, 1,231 MW comes from contractually committed load resources that provide operating reserves in the ancillary services market, as well as 844 MW of Emergency Response Service (ERS) designed to be deployed in the late stages of a grid emergency prior to shedding involuntary firm load. Energy efficiency impacts are embedded in ERCOT's load forecast and not separated for reporting purposes.

Since the last winter assessment, seven generation projects, for a total winter capacity rating of 2,334 MW, have entered into commercial operations. Of this total, 2,268 MW, or 97 percent, are from new gas-fired combined-cycle units. The remaining capacity is represented by renewable technologies, including a 39 MW solar photovoltaic plant and two wind plants with a combined peak capacity contribution of 27 MW and nameplate rating of 310 MW. Generating units retired since the last winter assessment total 254 MW.

Although ERCOT does not expect issues with gas or water supply for the winter season based on projected conditions, natural gas curtailments continue to represent the largest source of generation-related availability risk. Extreme cold snaps can result in significant unit outages and deratings, particularly for north Texas. ERCOT estimates that about 4,900 MW of capacity could be unavailable due to gas curtailments under a scenario where extreme low temperatures (at the 10^{th} percentile probability limit) coincided with the forecast system peak load. To help address this risk, ERCOT met with gas supply companies to identify critical loads for gas supply. To address availability problems due to frozen instrumentation and other equipment problems, ERCOT held a number of meetings with GOPs on weatherization and associated lessons learned, and will also visit generators in the fall that had availability issues during last winter's cold weather.

Regarding other availability risks, the summer rainfall, while not enough to eliminate the drought, has been generally helpful in keeping water levels from dropping to critical levels for all but a few units. ERCOT is not projecting capacity restrictions for the winter season due to lake and reservoir levels, assuming that drought mitigation measures are successfully implemented for affected generating units. Some generation owners also have low coal supply inventories due to rail transportation issues associated with Powder River Basin deliveries, and are thus limiting unit availability during off-peak hours. However, ERCOT does not expect coal supply constraints to impact capacity availability during peak load hours. Finally, ERCOT is monitoring the possible impacts of the U.S. Environmental Protection Agency's Transport Rule for NO_X and SO_2 emissions. On October 23, 2014, the U.S. District Court lifted its stay on the rule. Depending on how the EPA implements the rule, there is a risk that coal plant owners may decide to mothball their uncontrolled units during the winter season.

On an operational level, ERCOT continues to focus on improving renewable output forecasting and changing its ancillary service methodology to account for the growing impact of renewable intermittent resources. For forecasting, ERCOT has issued a request for proposals to start a solar forecasting procedure and is testing wind forecasting using additional forecasting services. ERCOT is also working with stakeholders to study low-inertia conditions, where high renewable generation displaces thermal synchronous generation inertia. A process of checking the system inertia and then adjusting reserves to ensure sufficient frequency response to avoid UFLS is being studied. The ERCOT Future Ancillary Services Team (FAST), which was established in 2014 to facilitate stakeholder input and address substantive implementation issues to support development of proposed market protocol revisions, is considering the implementation of new reserve product categories.

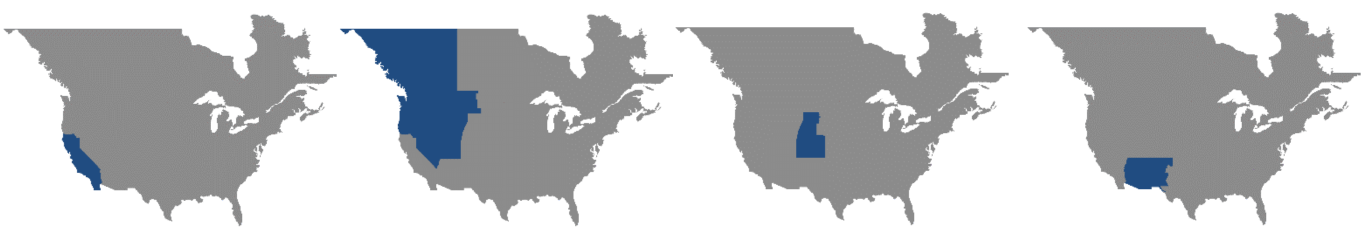
Concerning transmission projects, multiple transmission upgrades are scheduled to be completed in the west Texas area prior to this winter. These upgrades are expected to reduce congestion and improve the reliability in the Permian Basin oil and natural gas exploration and production areas, where demand continues to grow faster than historical load growth for those areas. ERCOT and its transmission service providers (TSPs) will rely on short-term operational plans to address congestion in other areas, such as Houston and the Lower Rio Grande Valley, until transmission projects have been completed. Nevertheless, there are no new or planned SPSs or Remedial Action Schemes (RASs) anticipated for the upcoming winter season.

WECC

Demand Projections	WECC-CAMX Megawatts (MW)	WECC-NWPP Megawatts (MW)	WECC-RMRG Megawatts (MW)	WECC-SRSG Megawatts (MW)
Total Internal Demand	**39,910**	**69,492**	**9,892**	**15,399**
Load-Modifying DCLM	0	60	0	0
Load-Modifying Contractually Interruptible	932	259	333	338
Load-Modifying Load as a Capacity Resource	38	0	0	0
Net Internal Demand	**38,940**	**69,173**	**9,559**	**15,061**

Resource Projections	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Net Firm Capacity Transfers	-319	1,077	446	-1,205
Existing-Certain & Future-Planned Capacity	55,975	81,754	13,865	31,406
Anticipated Resources	**55,656**	**82,831**	**14,311**	**30,202**
Prospective Resources	**55,656**	**82,831**	**14,311**	**30,202**

Planning Reserve Margins	Percent (%)	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**42.93**	**19.75**	**49.71**	**100.53**
Prospective Reserve Margin	**42.93**	**19.75**	**49.71**	**100.53**
NERC Reference Margin Level	**11.00**	**16.75**	**15.00**	**15.00**



Summary of Methods and Assumptions

Reference Margin Level
Determined by WECC's building block method for each subregion.
Load Forecast Method
Coincident (Western Interconnection); normal weather (50/50)
Peak Season
Summer: CA/MX; RMRG; SRSG; Winter: NWPP
Planning Considerations for Wind Resources
Modeling, primarily based on historic data
Planning Considerations for Solar Resources
Modeling, primarily based on historic data
Footprint Changes
In 2014 there were changes in the boundaries of two WECC subregions. In late 2013, Nevada Power and Sierra Pacific Power installed the ON Line transmission project, an 800 MW, 500 kV transmission line that connects the two BAs. With the transmission line addition, these two BAs were consolidated into one BA (Nevada Power) in the NWPP subregion, and the old Nevada Power and Sierra Pacific Power were removed from SRSG and NWPP, respectively.

Assessment Area Overview

The Western Electricity Coordinating Council (WECC) is one of eight Regional Entities 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 the NERC Regions. 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 this assessment, the WECC Assessment Area is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CA/MX). These subregional divisions are used for this study as they are structured around reserve-sharing groups that have similar annual demand patterns as well as similar operating practices.

The Existing, Anticipated, and Prospective Reserve Margins for WECC's four subregions, and all zones within the subregions, are expected to exceed their respective NERC Reference Reserve Margins[22] for the upcoming winter

[22] The NERC Reference Reserve Margins referenced throughout the WECC 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

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 elements of the building block margin calculation are consistent from year to year, but the calculations can, and do, have slight annual variances by region and subregion. 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.

The aggregate WECC 2014–2015 winter total coincident peak demand is forecast to be 134,693 MW and is projected to occur in December. The forecast is 3.1 percent above last winter's actual peak demand of 130,664 MW, which was established under normal to milder-than-normal temperatures and improving economic conditions in portions of the region. The 2014–2015 winter coincident peak demand forecast is 2.1 percent above last winter's forecast coincident peak demand of 131,980 MW, reflecting weather effects, increases in energy efficiency, and continued demand growth associated with slow economic growth. All margin results assume demands associated with normal weather conditions.

WECC entities are anticipating a 14.2 percent increase in their DSM programs compared to last year's winter assessment. The 2014–2015 winter demand forecast includes 1,960 MW of DSM, composed of 60 MW of Direct Control Load Management (DCLM), 1,862 MW of contractually interruptible demand, and 38 MW of load as a capacity resource.

As a percent of Total Internal Demand, total DR could reduce peak demand by 1.46 percent. Interruptible demand programs for the winter period focus primarily on large water-pumping operations and large industrial operations, such as mining. In some situations, these programs may be activated by LSEs during high power-cost periods but, in general, the programs are only activated during periods when local power supply issues arise. Each LSE is responsible for verifying the accuracy of its DSM and energy efficiency programs. Methods for verification of DSM include direct end-use metering, sample end-use metering, and baseline comparisons of metered demand and usage. State and other regulatory drivers have led to nominal increases in DSM program penetration within the WECC subregions. Within some established market structures, DSM has been established as an ancillary service.[24]

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 is working with the natural gas industry to study potential impacts to reliability as the Western Interconnection becomes more reliant on natural-gas-fired generation.

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. WECC is not aware of any expected extreme weather issues. Portions of WECC have been experiencing severe drought conditions, particularly in the summer-peaking Southwest and in California. The reduced hydroelectric generation in those areas has led to increased thermal generation but has not resulted in significant supply issues and is not expected to significantly adversely impact reliability this winter. 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.

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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.

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

[24] AESO_2014_Long-term_Outlook.pdf

Appendix I: 2014–WRA Reference Case Data Summary

The following table contains data collected by NERC to assess the reserve margins for each Assessment Area. The methods and assumptions for the data collection process can be found on the NERC website. More detailed Assessment Area data can be requested from NERC.

Winter 2014-15: Projected Demand, Resources, & Planning Reserve Margins

Assessment Area / Interconnection	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	44,636	41,658	60,043	62,167	44	49	15.0
MISO	103,238	100,692	144,149	146,115	43	45	14.8
MRO-Manitoba	4,591	4,350	5,318	5,474	22	26	12.0
MRO-MAPP†	5,736	5,366	6,815	7,255	27	35	15.0
MRO-SaskPower	3,469	3,383	4,064	4,064	20	20	11.0
NPCC-Maritimes	5,398	5,139	6,750	6,750	31	31	20.0
NPCC-New England	21,086	20,389	25,997	33,051	28	62	13.3
NPCC-New York	24,737	23,894	42,041	42,041	76	76	17.0
NPCC-Ontario	22,149	22,149	29,248	29,248	32	32	19.5
NPCC-Québec	37,985	36,277	40,647	40,647	12	12	10.8
PJM†	133,509	133,466	191,033	191,033	43	43	15.9
SERC-E	41,903	40,907	55,587	55,634	36	36	15.0
SERC-N	40,306	38,578	53,347	54,306	38	41	15.0
SERC-SE†	44,183	44,127	64,629	64,935	46	47	15.0
SPP	35,265	35,217	65,325	65,325	85	85	13.6
TRE-ERCOT	52,837	50,762	76,600	79,307	51	56	13.8
WECC-CAMX	39,910	38,940	55,656	55,656	43	43	11.0
WECC-NWPP†	69,492	69,173	82,831	82,831	20	20	16.8
WECC-RMRG	9,892	9,559	14,311	14,311	50	50	15.0
WECC-SRSG†	15,399	15,061	30,202	30,202	101	101	15.0
EASTERN INTERCONNECTION	530,206	519,315	754,345	767,397	45	48	-
QUÉBEC INTERCONNECTION	37,985	36,277	40,647	40,647	12	12	11
TEXAS INTERCONNECTION	52,837	50,762	76,600	79,307	51	56	14
WECC INTERCONNECTION‡	134,693	132,733	183,000	183,000	38	38	15
TOTAL-NERC	**755,721**	**739,086**	**1,054,592**	**1,070,351**	**43**	**45**	**-**

†Denotes a boundary change

‡WECC coincident peak

Appendix II: Reliability Assessment Glossary

Term	Definition
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice (Source: NERC Glossary of Terms)
Anticipated Resources	Includes Existing-Certain Capacity, Net Firm Transfers (Imports – Exports), and Tier 1 Capacity Additions.
Anticipated Reserve Margin	Anticipated Resources minus Net Internal Demand, divided by Net Internal Demand, shown as a percentile.
Assessment Area	Based on existing ISO/RTO footprints; otherwise, based on individual Planning Coordinator or group of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated.
Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. (Source: NERC Glossary of Terms)
Bulk Electric System	See NERC Glossary of Terms
Bulk-Power System	A) Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
Capacity Transfers (Transactions)	There are three types of capacity transfers (transactions): Firm: “Firm” transfers that require the execution of a contract that is in effect during the projected peak. The net of all Firm transfers (imports minus exports) are applied towards Anticipated Resources. Modeled: transfers that are applicable for Assessment Areas that model potential feasible transfers (imports/exports). While these transfers do not have Firm contracts, modeling of the existing transmission, including transfer capability, has been executed to verify these transfers can occur during the peak season. The net of all Modeled transfers (imports minus exports) are applied towards Anticipated Resources. Expected: transfers without the execution of a Firm contract, but with a high expectation that a Firm contract will be executed in the future and will be in effect during the projected peak. The net of all Modeled transfers (imports minus exports) are applied towards Prospective Resources.
Conservation (Energy Conservation)	A reduction in energy consumption that corresponds with a reduction in service demand. Service demand can include buildings-sector end uses such as lighting, refrigeration, and heating; industrial processes; or vehicle transportation. Unlike energy efficiency, which is typically a technological measure, conservation is better associated with behavior. Examples of conservation include adjusting the thermostat to reduce the output of a heating unit, using occupancy sensors that turn off lights or appliances, and car-pooling. (Source: DOE-EIA)
Critical Peak-Pricing (CPP) with Load Control	Price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours. Critical Peak Pricing (CPP) with Direct Load Control combines Direct Load Control with a pre-specified high price for use during designated critical peak periods triggered by system contingencies or high wholesale market prices. Subset of Controllable and Dispatchable Demand Response.
	Dispatchable and Controllable Demand-Side Management that combines direct remote control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.
Curtailment	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction. (Source: NERC Glossary of Terms)
Demand	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand Response	Changes in electric use by Demand-Side resources from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when required to maintain system reliability. Demand Response can be counted in resource adequacy studies either as a load-modifier, or as a resource.

	Controllable and Dispatchable Demand Response requires the System Operator to have physical command of the resources (Controllable) or be able to activate it based on instruction from a control center. Controllable and Dispatchable Demand Response includes four categories: Critical Peak Pricing (CPP) with Load Control; Direct Control Load Management (DCLM); Load as a Capacity Resource (LCR); and Interruptible Load (IL).
Demand-Side Management	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand. (Source: NERC Glossary of Terms)
Derate	The amount of capacity that is expected to be unavailable during the seasonal peak.
Designated Network Resource	Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a Commission-approved reserve sharing program.
Distributed Energy Resources (DERs)	Distributed energy resources (DERs) are smaller power sources that can be aggregated to provide power necessary to meet regular demand. As the electricity grid continues to modernize, DERs such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid. (Source: EPRI)
Distributed Generation	See *Distributed Energy Resources*
Equivalent Forced Outage Rate demand (EFORd)	EFORd measures the probability that a unit will not meet its demand periods for generating requirements because of forced outages or deratings.
Energy Efficiency	Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems. Results in permanent changes to electricity use by replacement of end-use devices with more efficient end-use devices or more effective operation of existing devices. Generally, it results in reduced consumption across all hours rather than event-driven targeted load reductions. (Source: DOE-EIA)
Estimated Diversity	The electric utility system's load is made up of many individual loads that make demands on the system, with peaks occurring at different times throughout the day. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid.
Existing-Certain Capacity	Included in this category are existing generator units (expressed in MW), or portions of existing generator units, that are physically located within the assessment area that meet at least one of the following requirements when examining the projected peak for the summer and winter of each year: (1) unit must have a Firm capability (defined as the commitment of generation service to a customer under a contractual agreement to which the parties to the service anticipate no planned interruption (applies to generation and transmission), a Power Purchase Agreement (PPA), and Firm transmission; (2) unit must be classified as a Designated Network Resource; (3) where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
Disturbance	An unplanned event that produces an abnormal system condition; any perturbation to the electric system, or the unexpected change in ACE that is caused by the sudden failure of generation or interruption of load. (Source: NERC Glossary of Terms)
Existing-Other Capacity	Included in this category are existing generator units, or portions of existing generator units, that are physically located within the assessment area that do not qualify as Existing-Certain when examining the projected peak for the summer and winter of each year. Accordingly, these are the units, or portions of units, may not be available to serve peak demand for each season/year.
Energy-Only	Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area. Designated energy –only resources do not have capacity rights.
Firm (Transmission Service)	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. (Source: NERC Glossary of Terms)

Forced Outage	The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. Also, the condition in which the equipment is unavailable due to unanticipated failure. (Source: NERC Glossary of Terms)
Frequency Regulation	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control. (NERC Glossary of Terms)
Frequency Response	Equipment: The ability of a system or elements of the system to react or respond to a change in system frequency. System: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz). (Source: NERC Glossary of Terms)
Expected (Provisional) Capacity Transfers	Future transfers that do not currently have a Firm contract, but there is a reasonable expectation that a Firm contract will be signed. These transfers are included in the Prospective Resources.
Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services. (NERC Glossary of Terms)
Generator Owner	Entity that owns and maintains generating units. (NERC Glossary of Terms)
Independent Power Producer	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity. (NERC Glossary of Terms)
Interconnection	When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Québec. (NERC Glossary of Terms)
Interruptible Load or Interruptible Demand	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (NERC Glossary of Terms)
Load	An end-use device or customer that receives power from the electric system. (NERC Glossary of Terms)
Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers. (NERC Glossary of Terms)
Net Energy for Load (NEL)	The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amount of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred in the transmission and distribution. (Source: FERC-714)
	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities. (NERC Glossary of Terms)
Net Internal Demand	Total Internal Demand reduced by dispatchable and controllable Demand Response. (NERC Glossary of Terms)
Non-Firm Transmission Service	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption. (NERC Glossary of Terms)
Non-spinning Reserves	The portion of Operating Reserve consisting of (1) generating reserve not connected to the system but capable of serving demand within a specified time; or (2) interruptible load that can be removed from the system in a specified time.(NERC Glossary of Terms)
Off-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (NERC Glossary of Terms)
On-Peak	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand. (NERC Glossary of Terms)
Open Access Same Time Information Service	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously. (NERC Glossary of Terms)
Open Access Transmission Tariff	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves. (NERC Glossary of Terms)
Operating Reserves	The capability above Firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Planning Coordinator (Planning Authority)	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. (NERC Glossary of Terms)

Planning Reserve Margins	Anticipated Reserve Margin: Anticipated Resources, less Net Internal Demand, divided by Net Internal Demand. Prospective Reserve Margin: Prospective Resources, less Net Internal Demand, divided by Net Internal Demand. Adjusted-Potential Reserve Margin: Adjusted-Potential Resources, less Net Internal Demand, divided by Net Internal Demand.
Peak Demand	The highest hourly integrated Net Energy For Load (or highest instantaneous demand) within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). (NERC Glossary of Terms)
Power Purchase Agreement	Guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner.
Prospective Capacity Resources	Anticipated Resources plus Existing-Other capacity, plus 50 percent of Tier 2 Capacity, plus net Expected transfers.
Prospective Capacity Reserve Margin	Prospective Capacity Resources minus Net Internal Demand shown divided by Net Internal Demand, shown as a percentile.
Ramp Rate (Ramp)	Schedule: the rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. Generator: the rate, expressed in megawatts per minute, that a generator changes its output. (NERC Glossary of Terms)
Rating	The operational limits of a transmission system element under a set of specified conditions. (NERC Glossary of Terms)
Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (MVar). (NERC Glossary of Terms)
Real Power	The portion of electricity that supplies energy to the load. (NERC Glossary of Terms)
Reference Margin Level	This metric is typically based on the load, generation, and transmission characteristics for each Assessment Area. In some cases, it is a requirement implemented by the respective state(s), provincial authority, ISO/RTO, or other regulatory body. If such a requirement exists, the respective Assessment Area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level may fluctuate for each season of the assessment period. If a Reference Margin Level is not provided by an Assessment Area, NERC applies a 15 percent Reference Margin Level for predominately thermal systems and 10 percent for predominately hydro systems.
Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. (NERC Glossary of Terms)
Renewable Energy (Renewables	Energy derived from resources that are regenerative or for all practical purposes cannot be depleted. Types of renewable energy resources include moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy. Municipal solid waste (MSW) is also considered to be a renewable energy resource. (Source: DOE-EIA)
Reserve Sharing Group	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group. (Source: NERC Glossary of Terms)
Stand-by Load under Contract	Demand which is normally served by behind-the-meter generation, which has a contract to provide power if the generator becomes unavailable.
Spinning Reserves	Unloaded generation that is synchronized and ready to serve additional demand.(NERC Glossary of Terms)
Time-of-Use (TOU)	Rate and/or price structures with different unit prices for use during different blocks of time.

	Time-Sensitive Pricing (Non-dispatchable Demand Response) — Retail rates and/or price structures designed to reflect time-varying differences in wholesale electricity costs, and thus provide consumers with an incentive to modify consumption behavior during high-cost or peak periods.
Total Internal Demand	Projected sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Total Internal Demand should be reduced by indirect Demand-Side Management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all non-dispatchable Demand Response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs). Adjustments for controllable Demand Response should not be included in this value.
	The demand of a metered system, which includes the Firm demand, plus any Controllable and Dispatchable DSM load and the load due to the energy losses incurred within the boundary of the metered system. (Source: NERC Glossary of Terms)
Transmission-Limited Resources	The amount of transmission-limited generation resources that have deliverability limitations to serve load within the Region. If capacity is limited by both studied transmission limitations and generator derates, the generator derates takes precedence.
Uncertainty	The magnitude and timing of variable generation output is less predictable than for conventional generation.
Variable Energy Resources	Resources with output that are highly variable subject to weather fluctuations such as wind speed and cloud cover.
Variability	The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.

Appendix III: 2014 Polar Vortex Scenario Analysis

Overview

The January 6–8, 2014, polar vortex subjected much of North America to extreme cold weather, presenting particular challenges for system operators in both the Eastern and Texas Interconnections. During the event, portions of the BPS were stressed with high periods of demand, establishing new winter peak demand for several areas. Concurrently, an increased number of units experienced forced outages amounting to over 10,000 MW, resulting in the use of emergency operating procedures and calling DR programs in several areas. Despite these extreme conditions, the BPS remained stable and generally performed reliably throughout the event, primarily because of preparation efforts prior to the cold snap. Specifically, Generator Owners took preemptive steps to prepare equipment for the freezing temperatures. These steps included cancelling scheduled generator outages, installing additional insulation, and testing dual-fuel capabilities. Similarly, system operators coordinated with neighboring areas to ensure resource availability and share other pertinent information.

Subsequent to a thorough review of the event, NERC released the *Polar Vortex Review* in September 2014, based on data and information provided from the NERC Generator Availability Data System (GADS), as well as supplemental support from the impacted Assessment Areas. According to these data, it was concluded that forced outages during the event were primarily caused by the following:

1. inoperable equipment in extreme low temperatures,
2. unavailability of fuel at generating units (due to supply or transportation or a combination), and
3. challenges for some dual-fuel capable units in switching from a primary to a secondary fuel.

Colder temperatures contributed to higher electricity demand while also increasing the demand for natural gas used for residential heating in some parts of North America. These conditions stressed the ability of pipeline operators and suppliers to deliver natural gas to the power sector, which resulted in a significant amount of gas-fired generation being unavailable due to gas curtailments. This was particularly relevant considering that gas-fired units accounted for approximately 40 percent of the generation mix during the 2014 polar vortex. Accordingly, natural-gas-fired units were also the most impacted compared to other generators, representing over 55 percent of all forced outages during the event.

Scenario Assumptions

In addition to the *Polar Vortex Review*, NERC staff conducted scenarios for MISO, PJM, SERC-E, and TRE-ERCOT for the 2014–2015 and 2015–2016 winters. Each of these Assessment Areas experienced higher-than-normal forced outage rates during the event. NERC's scenario assumptions involved applying these actual forced outage rates as derates to existing and projected (Tier 1) capacity data from the *2014LTRA* reference case and the *2014–2015 WRA* reference case.[25] The projected loads were assumed to be consistent with the extreme loads during the extreme event. **Note: The scenario reserve should not be compared to the NERC Reference Margin Level, as this target is assumed under normal 50/50 conditions.**

Fuel Derates and Net Internal Demand Assumptions (Based on Actual Forced Outages and Demand)

	Applied Derate (%)							
Assessment Area	Coal	Petroleum	Natural Gas	Nuclear	Wind	Solar	Other Generation	Assumed Net Internal Demand
MISO	15	10	30	0	100	100	0	107
PJM	21	0	34	4	0	100	6,100 MW	107
SERC-E	0	0	0	0	100	100	0	118
TRE-ERCOT	15	0	25	0	100	100	0	110

[25] The *2014LTRA* reference case can be found in Appendix I of the *2014LTRA* and the *2014–2015 WRA* reference case can be found in Appendix I of the *2014–2015 WRA*.

The tables below are the assumptions used to derive the reserve margins for the individual Assessment Areas. The amount of capacity derated from the Existing-Certain capacity by fuel type is listed under “Capacity Derates by Fuel Type”. For example, the scenario for MISO, the total amount of capacity derated is 22949 MW: 9344 MW of coal, 335 MW of petroleum, and 13267 MW of natural gas.

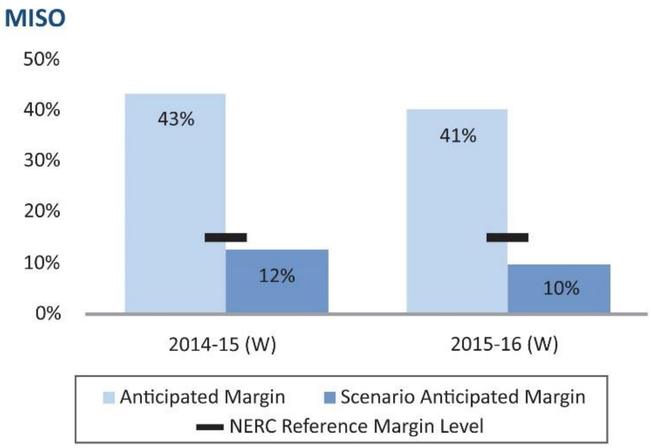
MISO's Polar Vortex Scenario		
DEMAND / DEMAND-SIDE MANAGEMENT	2014-15 (W)	2015-16 (W)
Total Internal Demand	110,549	111,808
Total Projected Demand Response - Available	2,546	4,743
Net Internal Demand	108,003	106,729
CAPACITY		
Capacity Adjustments	-	6,876
Existing-Certain	119,177	114,794
Existing-Other	1,966	4,849
Planned - Tier 1	-	1,116
NET CAPACITY TRANSFERS		
Net Firm Transfers	2,023	1,113
Net Expected Transfers	-	-
RESOURCE CATEGORIES		
Existing-Certain & Net Firm Transfers	121,200	115,907
Anticipated	121,200	117,023
Prospective	123,166	121,872
PLANNING RESERVE MARGINS		
Existing-Certain & Net Firm Transfers Margin	12%	9%
Scenario Anticipated Margin	12%	10%
Prospective Margin	14%	14%
CAPACITY DERATES BY FUEL TYPE		
Coal	9,344	9,344
Petroleum	335	335
Natural Gas	13,270	13,270
Nuclear	-	-
Biomass	-	-
Solar	-	-
Wind	-	-
Geothermal	-	-
Water	-	-
Pumped Storage	-	-
Other	-	-

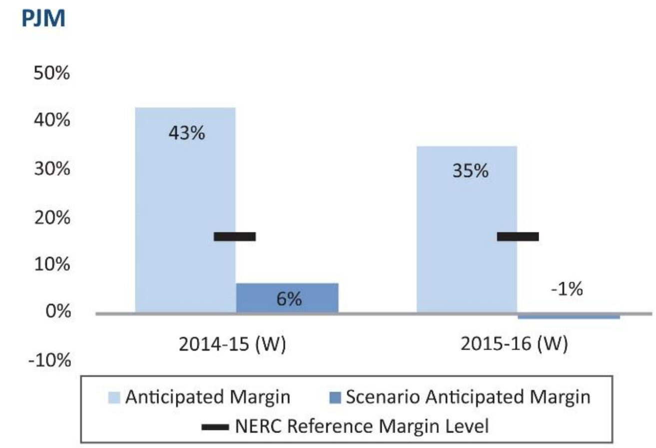
PJM's Polar Vortex Scenario		
DEMAND / DEMAND-SIDE MANAGEMENT	2014-15 (W)	2015-16 (W)
Total Internal Demand	142,549	144,702
Total Projected Demand Response - Available	43	-
Net Internal Demand	142,506	144,702
CAPACITY		
Capacity Adjustments	-	-
Existing-Certain	146,514	137,497
Existing-Other	-	380
Planned - Tier 1	-	1,483
NET CAPACITY TRANSFERS		
Net Firm Transfers	4,255	3,919
Net Expected Transfers	-	-
RESOURCE CATEGORIES		
Existing-Certain & Net Firm Transfers	150,769	141,416
Anticipated	150,769	142,899
Prospective	150,769	143,279
PLANNING RESERVE MARGINS		
Existing-Certain & Net Firm Transfers Margin	6%	-2%
Scenario Anticipated Margin	6%	-1%
Prospective Margin	6%	-1%
CAPACITY DERATES BY FUEL TYPE		
Coal	13,729	13,729
Petroleum	-	-
Natural Gas	18,988	18,988
Nuclear	1,356	1,356
Biomass	-	-
Solar	92	92
Wind	-	-
Geothermal	-	-
Water	-	-
Pumped Storage	-	-
Other	6,100	6,100

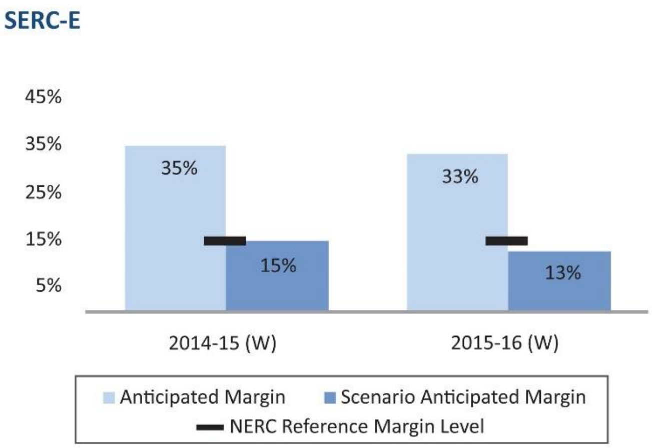
SERC-E's Polar Vortex Scenario		
DEMAND / DEMAND-SIDE MANAGEMENT	2014-15 (W)	2015-16 (W)
Total Internal Demand	49,446	50,110
Total Projected Demand Response - Available	996	1,017
Net Internal Demand	48,450	48,910
CAPACITY		
Capacity Adjustments	-	328
Existing-Certain	53,316	52,899
Existing-Other	47	1,565
Planned - Tier 1	-	-
NET CAPACITY TRANSFERS		
Net Firm Transfers	2,240	2,184
Net Expected Transfers	-	-
RESOURCE CATEGORIES		
Existing-Certain & Net Firm Transfers	55,556	55,083
Anticipated	55,556	55,083
Prospective	55,604	56,648
PLANNING RESERVE MARGINS		
Existing-Certain & Net Firm Transfers Margin	15%	13%
Scenario Anticipated Margin	15%	13%
Prospective Margin	15%	16%
CAPACITY DERATES BY FUEL TYPE		
Coal	-	-
Petroleum	-	-
Natural Gas	-	-
Nuclear	-	-
Biomass	-	-
Solar	30	28
Wind	-	-
Geothermal	-	-
Water	-	-
Pumped Storage	-	-
Other	-	-

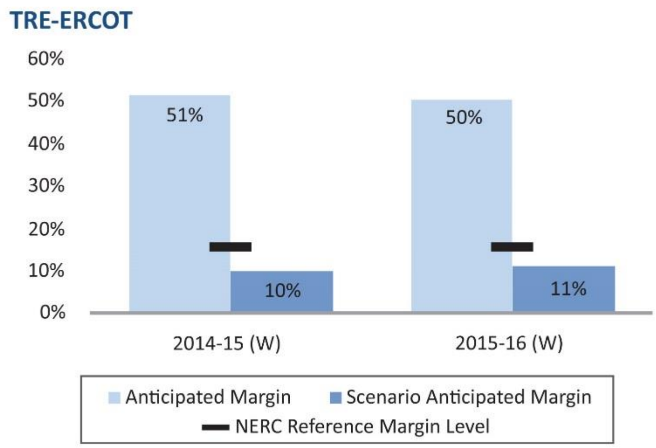
TRE-ERCOT's Polar Vortex Scenario		
DEMAND / DEMAND-SIDE MANAGEMENT	2014-15 (W)	2015-16 (W)
Total Internal Demand	58,121	59,091
Total Projected Demand Response - Available	2,075	1,662
Net Internal Demand	56,046	57,263
CAPACITY		
Capacity Adjustments	-	-
Existing-Certain	61,197	59,069
Existing-Other	2,707	2,326
Planned - Tier 1	149	3,874
NET CAPACITY TRANSFERS		
Net Firm Transfers	143	343
Net Expected Transfers	-	-
RESOURCE CATEGORIES		
Existing-Certain & Net Firm Transfers	61,340	59,412
Anticipated	61,489	63,286
Prospective	64,196	65,612
PLANNING RESERVE MARGINS		
Existing-Certain & Net Firm Transfers Margin	9%	4%
Scenario Anticipated Margin	10%	11%
Prospective Margin	15%	15%
CAPACITY DERATES BY FUEL TYPE		
Coal	2,605	2,605
Petroleum	-	-
Natural Gas	11,267	11,267
Nuclear	-	-
Biomass	-	-
Solar	179	123
Wind	1,060	996
Geothermal	-	-
Water	-	-
Pumped Storage	-	-
Other	-	-

Results









Polar Vortex Scenario Conclusion

This analysis demonstrates that a repeated extreme weather event with conditions similar to those observed during the 2014 polar vortex would result in adequate Anticipated Resources for the 2014–2015 winter, based on the *2014–2015WRA* and the *2014LTRA* reference cases. The resulting scenario reserve margins are significantly lower than the NERC Reference Margin Level, as expected; however, the scenario reserve margin cannot be compared to the NERC Reference Margin level as this target is based on a 50/50 normal load. Instead, NERC compares the resulting Scenario Anticipated Margin to zero percent in order to determine if the Assessment Area has more resources than demand in this extreme scenario. This highlights the need for system planners to consider generator performance and potential fuel limitations during extreme weather events, particularly for natural-gas-fired units in the resource adequacy assessment. The conclusion is in conjunction with the recommendation for Key Finding #3: NERC, Regional Entities, and the industry should assess scenarios that reflect severe winter conditions.