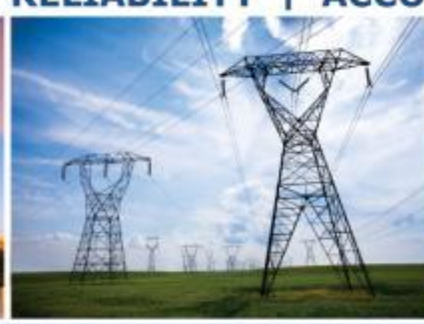
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2014 Summer Reliability Assessment

May 2014

RELIABILITY | ACCOUNTABILITY



Preface

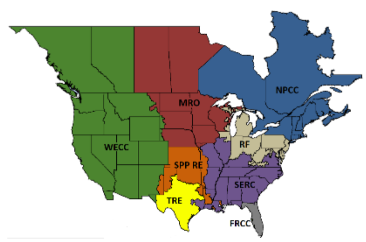
NERC is an international regulatory authority established to evaluate and improve the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; 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.[1] NERC 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 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 available to policy makers and federal, state, and provincial regulators to support decision making within the electricity sector.

NERC prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the U.S. Congress directed NERC to conduct periodic assessments of the reliability and adequacy of North America's BPS.[2,3] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

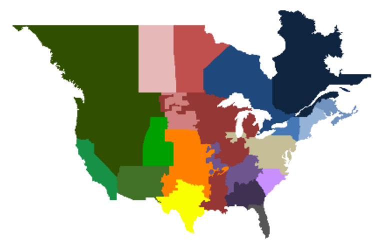
NERC Regional Entities Map

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

NERC Regional Entities Map



NERC Seasonal Assessment Areas



NERC prepares seasonal and long-term assessments of the overall reliability and adequacy of the North American BPS, which is divided into assessment areas for assessments both within and across the eight Regional Entity boundaries (as shown by the corresponding table and maps above).[4] To prepare these assessments, NERC collects and consolidates data, including forecasts for on-peak demand and energy, demand response, resource capacity, and transmission projects, from all areas. This bottom-up approach accounts for virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The information is collected in a consistent manner and analyzed to identify notable trends, emerging issues, and potential concerns regarding future electricity supply, as well as the overall adequacy of the BPS to meet future demand. Reliability assessments are developed to inform industry, policy makers, and regulators and aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] 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. In Canada, NERC has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC Reliability Standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making Reliability Standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in 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 and 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 and enforceable in that jurisdiction.

[2] H.R. 6 as approved by the 109th Congress of the United States, the Energy Policy Act of 2005.

[3] The NERC Rules of Procedure, Section 800, further details the objectives, scope, data, information requirements, and Reliability Assessment Process requiring seasonal and long-term reliability assessments on an annual basis.

[4] These maps were generated using Ventyx-Velocity Suites software, modified by NERC. This content may not be reproduced in whole or any part without the prior express written permission of NERC.

Assessment Development

The *2014 Summer Reliability Assessment* provides an independent assessment of the reliability of the bulk electricity supply and demand in North America between June 2014 and September 2014. The assessment was developed with support from the Reliability Assessment Subcommittee (RAS),[5] at the direction of the NERC Planning Committee (PC).

In March 2014, the eight NERC Regional Entities initially submitted data and information for each of their respective assessment areas to NERC and provided periodic updates throughout the development of the report. External data sources are appropriately cited. For this and other seasonal and long-term assessments, NERC uses an active peer review process to leverage a wide group of industry subject matter expertise to provide essential checks and balances for ensuring the accuracy and completeness of the data and information presented. Inquiries regarding the information, data, and analysis in this assessment may be directed to the NERC Reliability Assessment staff (listed below).

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

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Executive Summary and Key Findings

The *2014 Summer Reliability Assessment* includes a high-level perspective on the adequacy of the generation resources and transmission systems necessary to meet projected summer peak demands. NERC also independently identifies reliability issues of interest and assessment area-specific challenges. The primary objective of the report is to identify areas of concern regarding the reliability of the North American BPS and to make recommendations as needed. The assessment process enables BPS users, owners, and operators to systematically document their operational preparations for the coming season and to exchange vital system reliability information.

As highlighted in numerous recent long-term reliability assessments, the BPS in North America is changing in many ways. Each summer, NERC has observed incremental changes in the resource mix, which has trended toward a generation base that is now predominately (i.e., almost 40 percent) gas-fired generation, an increase of 28 percent five years ago. The continued wide-scale retirement of coal, petroleum, nuclear, and other baseload generation is largely being addressed by the addition of gas-fired and variable (e.g., wind, solar) resources.

From a resource adequacy perspective, all of the assessment areas that NERC evaluates appear to have sufficient resources to meet peak demand. Previous summer assessments highlighted potential resource adequacy concerns in ERCOT. New resources, expected to be in service in early August, will increase ERCOT's planning reserve margin above the NERC Reference Margin Level. However, if extreme system peaks occur before these new resources are available, ERCOT may need to take progressive steps to protect system integrity depending on the severity of the capacity shortage.

The *2014 Summer Reliability Assessment* shows that peak demand forecasts are flat compared to last year, which also results in sufficient reserve margins needed to maintain BPS reliability. However, NERC continues to monitor the overall changes to the BPS's resource mix and the operating characteristics of different types of resources. For example, in New England, a large natural gas-fired generation portfolio has created challenges in ensuring that natural gas can be supplied and transported to all generators that are needed to maintain electric reliability. Much of the focus on electric and gas interdependencies targets conditions during the winter season when the availability of natural gas for electric generators competes with the high demands of residential heating. However, the summer season presents a separate set of concerns regarding gas availability. Specifically, natural gas storage facilities are refilled during the summer season while several pipelines and pipeline compressor stations are also undergoing maintenance.

NERC has identified three key findings for the upcoming summer:

NERC-wide, Assessment Areas Meet Summer Reference Margin Levels

- In ERCOT, adequate planning margins are contingent on pending capacity expected in August. Additionally, the implementation of a new load forecasting methodology has resulted in a lower annual growth rate. ERCOT may face operational challenges due to insufficient reserves if the summer peak occurs prior to the availability of planned capacity, or if actual peak demand is substantially higher than the load forecast.
- In MISO, unit retirements, derates, and mothballs contribute to reduced margins.

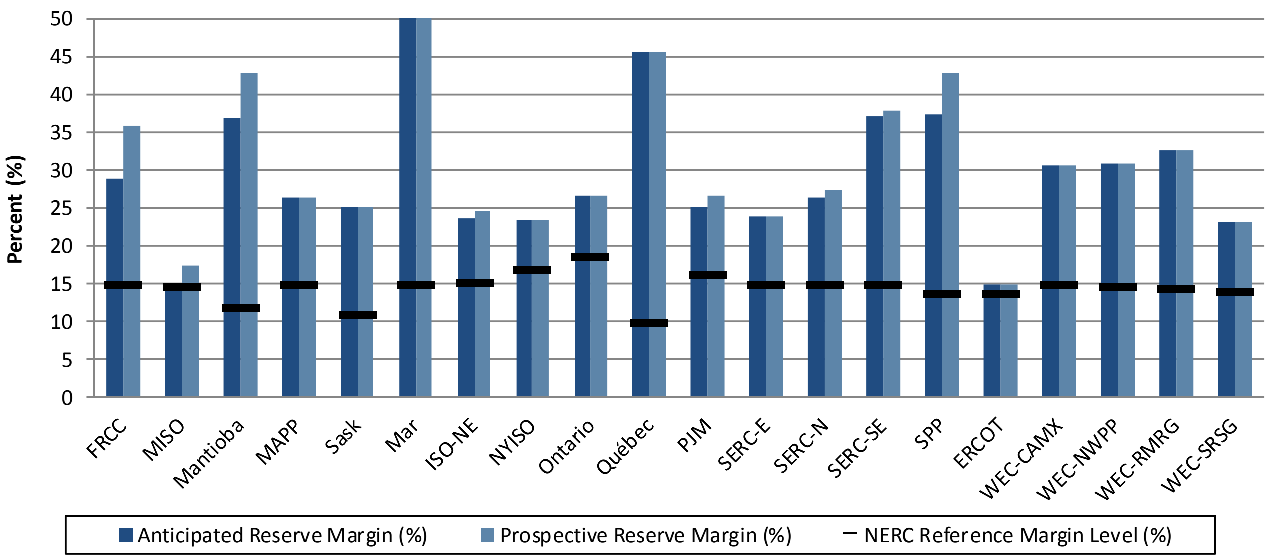
Continued Impacts of Baseload Retirements

- Since 2011, there have been almost 43 GW of baseload (coal, nuclear, petroleum, and natural gas) retirements, contributing to reduced margins in some assessment areas, as well as a reduction in the availability of essential reliability services, such as frequency response and inertia.
- Ontario retired the area's last coal plant (Thunder Bay Generating Station) in April. The Anticipated Margin has fallen by 10 percent since last summer but remains well above the NERC Reference Margin Level.
- Localized reliability issues are not expected to impact this summer, though some Regions have noted the need for transmission upgrades over the next two years.

Summer Gas-Electric Transportation Considerations

- Meeting summer peaks requires increasing dependence on gas-fired capacity.
- Summer pipeline maintenance and increased demand for natural gas storage injections can contribute to constraints for interruptible gas-fired generation.

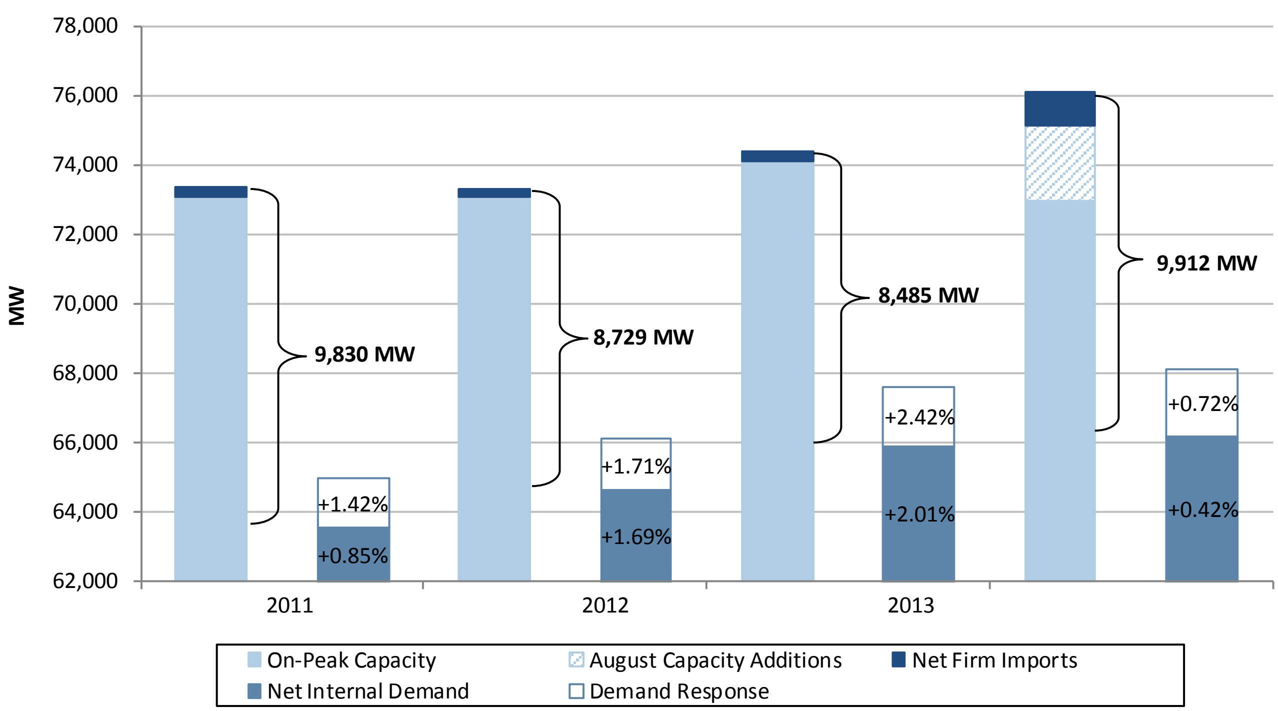
Figure 1: 2014 Summer Peak Planning Reserve Margins by Assessment Area[6]



TRE-ERCOT Summer Planning Reserve Margin Projected to Meet NERC Reference Margin Level by August

ERCOT plans to add four combined-cycle plants (combined 2,112 MW summer rating), which are expected to be in service prior to the summer peak demand in August. However, ERCOT may face challenges in maintaining sufficient reserves if the summer peak occurs before this new capacity is available. This could increase the risk of entering emergency operating conditions or Energy Emergency Alerts (EEAs), including the possibility of curtailment of interruptible load and even rotating outages of firm load. These capacity additions will help ERCOT meet the 13.75 percent Reference Margin Level for the first time since 2011, reversing the trend of diminishing planning reserve margins.

Figure 2: ERCOT Demand and Reserves (2011–2014)[7]



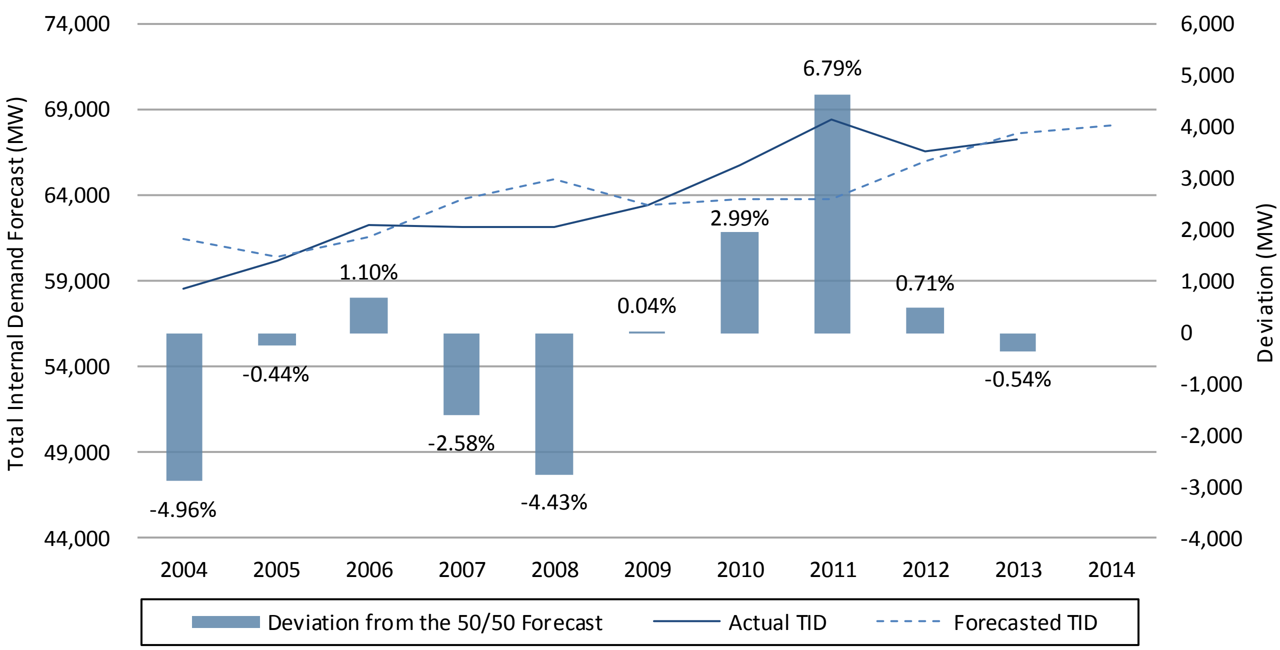
[6] Reserve margins exceeding 50 percent are not shown.

[7] When considering the addition of new wind and solar resources, August capacity additions total 2,155 MW.

In addition to the new capacity, recent modifications to ERCOT's load forecast methodology contribute to the increasing reserve margin. The peak demand forecast dictates the calculated reserve margin; therefore, it is important to understand what contributes to that load forecast. The projected peak demand (Total Internal Demand) for the 2014 summer is 68,096 MW, or 0.72 percent higher than last summer's forecast. This is a substantial deviation from the average annual growth rate between for Total Internal Demand of 1.81 percent that was observed from 2010 to 2013 (Figure 2). ERCOT's new load forecast attempts to capture more accurately the changing relationship between energy and economic growth and, specifically, the impacts of energy efficiency and price-driven demand response. Other changes to the methodology include the adoption of a neural network model to forecast daily energy and the incorporation of regional growth forecasts for each customer class (i.e., residential, commercial, and industrial), as opposed to relying on only non-farm employment as the economic driver.[8]

Using the old forecasting methodology, observations across the 10-year historical period appear to be representative of a healthy 50-50 load forecast[9]—five years below forecast and five years over forecast. However, the ERCOT historical Total Internal Demand is lower than actual from 2009 to 2012, with a maximum forecast deviation (from the mean) of 6.79%, which occurred in 2011 (Figure 3) when ERCOT experienced extraordinarily hot summer weather. ERCOT's new forecasting methodology lowers the peak demand forecast values when compared to the previous forecast, though it still shows some anticipated growth. NERC will continue to monitor ERCOT's demand growth and validate the new forecast methodology in conjunction with ERCOT and TRE.

Figure 3: 2004–2014 Actual vs. Forecast Demand, including Deviation from the 50/50 Forecast



MISO Unit Retirements, Derates, and Mothballs Contribute to Reduced Margins

MISO's Anticipated Reserve Margin is 0.02 above the NERC Reference Margin Level of 14.8 percent for the 2014 summer season, which is lower than the 18.1 percent reported in last year's assessment. The reduction is attributed to approved retirements, suspensions, and capacity transfers due to the integration of MISO South. Regarding transfers, MISO is only relying on 1,000 MW of capacity located in MISO South toward the Anticipated Reserve Margin. The contract path limit is appropriate to reflect ongoing discussions on transfer capability across the integration seams of the new MISO South area.

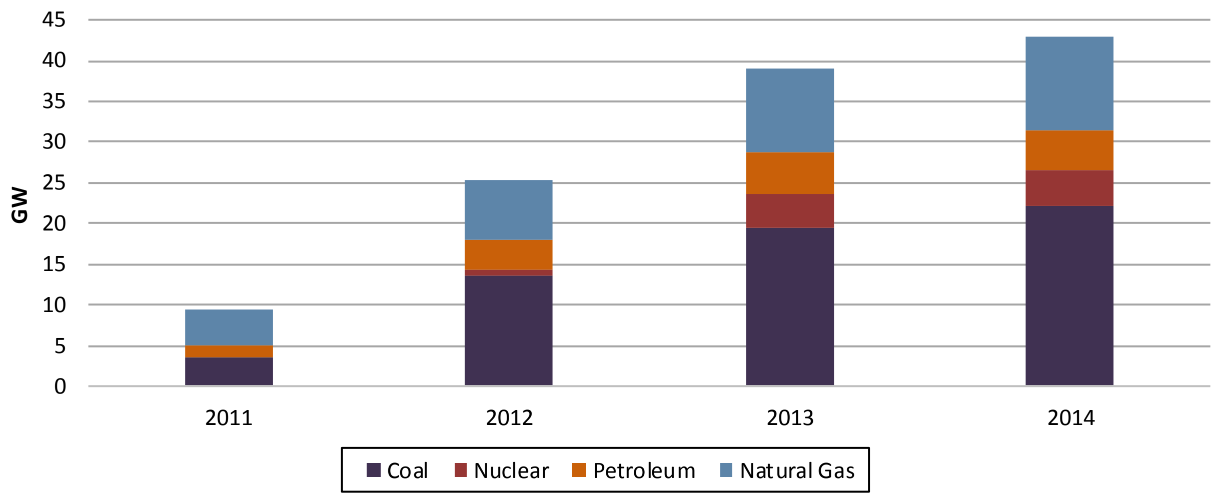
[8] Additional detail on this issue is provided in the ERCOT section and on the ERCOT website.

[9] A 50/50 load forecast is based on probability, specifically a 50 percent probability that actual demand will be higher than the forecast midpoint and a 50 percent probability that it will be lower.

Continued Impacts of Baseload Retirements

Since conducting its initial special assessment on this issue in late 2010,[10] NERC continues to monitor ongoing reliability impacts of NERC-wide unit retirements through its seasonal and long-term assessments. Since January 2011, the introduction and implementation of several environmental regulations combined with increased natural gas availability has contributed to the closure of nearly 43 GW of baseload capacity.[11, 12] Plant closures include 22 GW of coal-fired capacity, 4 GW of nuclear, 5 GW of petroleum, and 11 GW of mostly older gas-fired capacity.

Figure 4: Tracking Retirements (January 2011–April 2014)



In the United States, impending compliance requirements for the Environmental Protection Agency (EPA) Mercury and Air Toxics Standards (MATS) regulations have especially contributed to the accelerated retirements of coal-fired units—particularly for older plants for which retrofits are not economically viable. Several Canadian provinces, particularly in NPCC-Ontario, where the last coal-fired plant (Thunder Bay Generating Station) was closed in April, have implemented similar environmental regulations, concluding a 10-year policy implementation. In NPCC-New England, Salem Harbor Units 1 and 2 recently retired. Additionally, six coal units (L.V. Sutton Steam Electric Plant Units 1–3, Canadys Units 2 and 3, and Branch Unit 2) were closed in the SERC-SE and SERC-E Assessment Areas. In the WECC Region, approximately 900 MW of additional coal was retired during 2013.

Since 2012, four nuclear plants have been decommissioned,[13] with a fifth closure (Vermont Yankee Nuclear Power) expected in late 2014. The contributing factors that led to these plant closures vary but often include economic considerations for affordable replacement capacity—particularly gas-fired. Current and anticipated maintenance costs are also considered, as well as additional costs for compliance with potential regulations, specifically Section 316(b) of the Clean Water Act. With the assumption that nuclear plants would not be exempt from Section 316(b), all five nuclear plants would eventually require the installation of closed-loop cooling systems to comply with the rule. These costs, along with existing and future maintenance and permitting expenses, impact decisions to close nuclear power plants.

In response to these recent plant closures, system planners and operators NERC-wide are addressing potential reliability impacts at a localized level, primarily by adding transmission enhancements or replacement capacity. While no assessment areas are expecting any reliability impacts during this summer, recent retirements have contributed to lower reserve margins in Ontario and MISO. NERC will continue to track long-term impacts in the *2014 Long-Term Reliability Assessment*.

[10] NERC: 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.
[11] Source: Ventyx Velocity Suite; EIA Electric Power Monthly – February 2014.
[12] Capacity is based on net summer capacity.
[13] Includes: (1.) San Onofre Nuclear Generating Station in southern California – 2013; (2.) Kewaunee Nuclear Power Plant in Wisconsin – 2013; (3.)Crystal River-3 Nuclear Power Plant in Florida – 2013; (4.) Gentilly Nuclear Generating Station in Québec – 2012.

Summer Gas-Electric Transportation Issues

The development of unconventional shale sources of natural gas—particularly during the past five years—has resulted in a substantial shift in the North American resource mix. As noted in NERC's *2013 Long-Term Reliability Assessment*, natural gas is the fastest growing source of new capacity—chiefly in PJM, MISO, New York, New England, and IESO. Table 1 presents the amount of gas-fired capacity in each assessment area:

Table 1: Assessment Areas Heavily Dependent on Gas-Fired Capacity[14]

Assessment Area	Total Capacity (GW)	Gas-Capable Capacity (GW)	Percent of Total (%)
PJM	185	80	43.2
MISO	177	69	39.0
New York (NYISO)	38	21	55.3
New England (ISO-NE)	35	19	53.1
IESO	33	10	30.0

Growing reliance on gas-fired resources has led NERC, FERC, and other industry stakeholders to highlight the need for increased coordination between the gas and electricity industries. This coordination is especially important during the winter months to address potential supply restrictions created by extreme weather events (e.g., freezing wellheads, competing transportation capacity for residential heating and electric generators, etc.). However, the summer season presents a separate set of potential reliability impacts that require ongoing coordination. Specifically, the electricity industry must be aware of pipeline maintenance schedules and promote ongoing coordination to ensure individual generators do not face supply shortages—principally those that can be resolved through coordination—during peak conditions.

The New England ISO (ISO-NE) has been very proactive in promoting new communication and preparatory actions to reduce fuel supply risks during system operating peak conditions during the summer and winter seasons. Recent guidance regarding gas-electric dependencies include FERC Order 787[15] and subsequent ISO-NE tariff revisions. These revisions explicitly authorize ISO-NE to share confidential information about natural gas-fired generation located in New England, with the operating personnel of interstate natural gas pipeline companies (provided that the information is operationally necessary and will be shared only with the pipeline company directly serving that generator). This information exchange includes maintenance schedules to promote outage coordination between the industries, output schedules for individual generators, and discussion of any real-time information concerning specific resources for maintaining reliability.

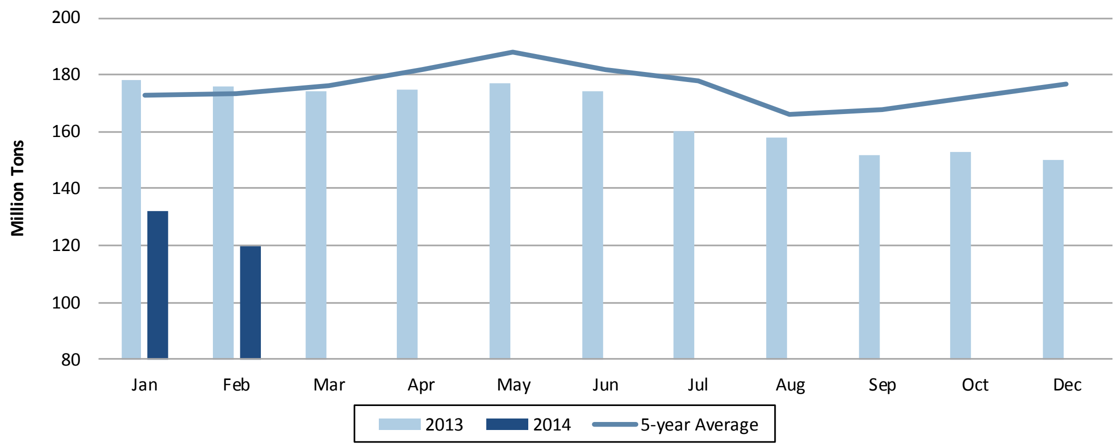
Other Summer Reliability Issues

Coal Supply Impacts Caused by Constrained Rail Service Could Create Reliability Impacts

Despite the ongoing retirements, NERC-wide, coal-fired generation is projected to account for approximately one-third of the total on-peak resource mix during the 2014 summer. A majority of coal-fired power plants depends on coal delivery by railroad from distant mines. During the 2013–2014 winter, periods of extreme cold temperatures limited rail transport, driving down coal inventories at several plants. Concurrently, colder temperatures increased electricity usage, which in turn led to higher net electricity generation, particularly from coal plants, which further drove down inventories.

[14] EIPC Study: Gas-Electric System Interface Study.
[15] FERC Order 787.

Figure 5: Electricity Sector Coal Stocks[16]



Coal inventories were further reduced by delivery impacts caused by the growing use of railroads to transport oil, especially in the upper Midwest. According to the Energy Information Administration (EIA), power plant coal inventories have reached their lowest level since March 2006. While these conditions did not directly affect BPS reliability during the winter season, some utilities in ERCOT, SPP, and MISO that are heavily dependent on coal have expressed concerns in meeting summer peak demand. The EIA projects improvements prior to the summer peak, as demand during the shoulder months is typically much lower, allowing power plants to replenish inventories.

Summer Demand Outlook Impacted by New Forecasting Methods and Slower Economic Growth

NERC-wide, the projected peak Total Internal Demand for the 2014 summer is 853,005 MW, a reduction from the 2013 summer forecast of 854,119 MW.[17] This decline is partially due to continued penetration of energy efficiency programs and distributed generation, as well as reduced electricity demand, which is partially caused by current economic conditions. Other impacts result from updates or modifications to the load forecast assumptions in several assessment areas, including New England,[18] PJM, ERCOT, and Manitoba Hydro.

Revisions to the historical economic data and the addition of another year of actual data in PJM's forecasting model contributed to lower demand projection forecast in that area compared to the prior summer forecast. Similarly, Manitoba Hydro also enhanced its demand-forecasting methods, basing projections on different historic load factors. As discussed earlier, ERCOT's load forecast resulted in a demand increase of only 490 MW since last summer, compared to the 1,112 MW increase between 2011 and 2012 and the 1,530 MW increase between 2012 and 2013. Entity movements and footprint changes since the 2013 summer also impacted footprints and corresponding demand projections in MRO-MAPP, MISO, SERC-N, SERC-SE, SPP, WECC-SRSG, and WECC-NWPP. Additional details on these changes are provided in the respective sections throughout this report.

[16] Source: EIA Today in Energy – April 24, 2014.

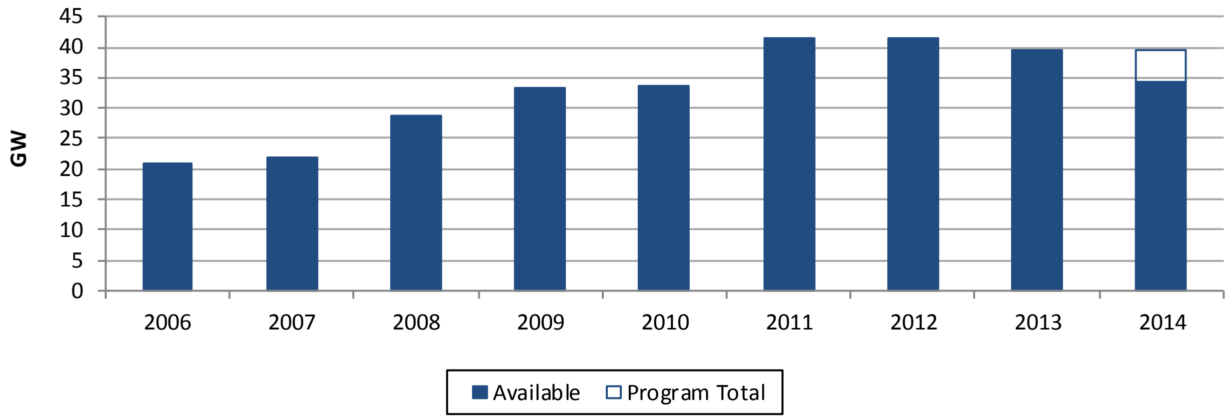
[17] NERC-wide Total Internal Demand forecast is based on a non-coincident basis, meaning the forecasted peak demand for each assessment area occurs during different hours throughout the four-month summer season.

[18] In previous NERC seasonal assessments and due to the structure of New England's capacity market, Total Internal Demand was not reduced by Energy Efficiency resources. New England is now embedding this reduction of approximately 1,507 MW into the load forecast. Therefore, the reduction of 1,182 MW since last summer is primarily attributed to the treatment of Energy Efficiency.

Demand Response Programs Improve Planning

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

Figure 6: Summer Demand Response Growth (2006–2014)



Beginning in 2014, the program total for four different Demand Response programs will be provided for each area, in addition to the portion expected to be available during the peak. NERC-wide, Demand Response participation is growing, while the industry continues to gain better understanding of these programs and the ability to incorporate program availability into system planning. For the 2014 summer, NERC-wide Demand Response programs total approximately 39,400 MW, with 34,800 expected to be available during the peak.

MISO South Integration

Entergy and its six utility operating companies, previously reported as part of the SERC Assessment Areas, integrated into the Midcontinent Independent System Operator, Inc. (MISO) in December 2013. This addition added approximately 15,500 miles of transmission, 30,000 MW of generation capacity, and 35,000 MW of peak load into the MISO footprint. MISO now coordinates all RTO activities in the newly combined footprint, consisting of all or parts of 15 states with the integration of Entergy and other MISO South entities. This transition has led to substantial changes to MISO's market dispatch, creating the potential for unanticipated flows across the following systems: Tennessee Valley Authority (TVA), Associated Electric Cooperative Inc. (AECI), and Southern Balancing Authority.

In conjunction with the integration, the Operations Reliability Coordination Agreement (ORCA) was introduced to mitigate any potential reliability impacts associated with changing market dispatch patterns and potential unanticipated flows across neighboring systems. The upcoming summer is the first peaking season since the integration of the Entergy area into MISO. For seasonal planning purposes, MISO is addressing transfer limitations by derating 8,299 MW of capacity in the MISO South and only counting for a 1,000 MW contract path to the MISO North/Central regions—which is less than the flow limit identified in the ORCA. Therefore, only the 1,000 MW transfer is assumed in the reserve margin calculation. Additionally, 2,990 MW of Energy-Only resources in MISO that do not have firm point-to-point transmission rights will be categorized as Existing-Other capacity.

Neighboring Balancing Authorities (BAs) have highlighted concern in not having sufficient information on the effect that the new boundaries of the MISO system will have on their systems. However, the aforementioned flow limitations in place for this summer should minimize any potential reliability concerns. In addition to limiting the flows, other reliability processes, such as Congestion Management Process and Transmission Loading Relief, may also be used to mitigate potential adverse impacts on system reliability. The new topography of the MISO system necessitates an ongoing coordination effort to ensure that interconnection issues across operational seams are identified and mitigated.

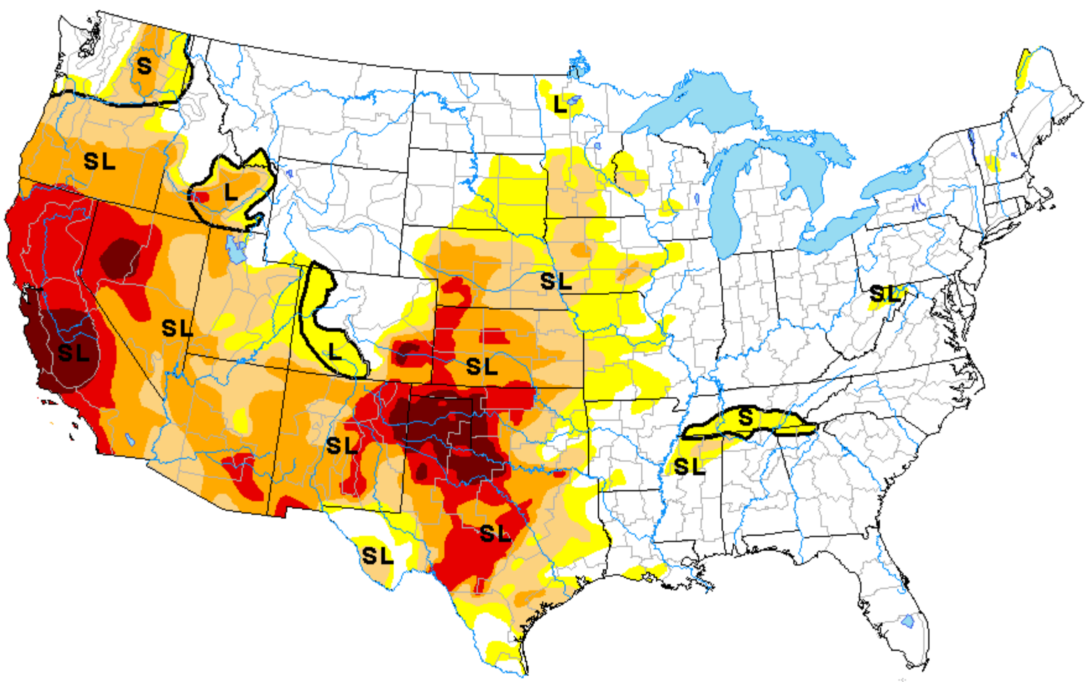
Drought, Extreme Weather, and Other Potential Reliability Impacts

The National Oceanic and Atmospheric Administration (NOAA) indicates drought persistence or intensification will continue in the central and southwestern parts of the United States—particularly SPP, TRE-ERCOT, and most of WECC (Figure 6). NOAA's Climate Prediction Center (CPC) also forecasts above-normal temperatures in these regions.

In southern California, the closure of the San Onofre Nuclear Generating Station (2,250 MW) last year is not expected to have reliability impacts this summer due to the recent addition of 1,840 MW of gas-fired generation and 1,770 MW of nameplate solar generation installed during 2013. Although the California Independent System Operator (CAISO) reported reduced hydro generation in southern California, reservoir conditions have improved with spring precipitation. Load-Serving Entities (LSEs) and BAs within WECC regularly perform individual studies related to extreme weather and drought conditions for the seasonal assessments; none reported any issues.

Although NOAA is highlighting severe and exceptional drought conditions in central and northern Texas, ERCOT does not anticipate reservoir levels to impact power plant operations during the 2014 summer season.

Figure 7: U.S. Drought Monitor (Updated April 22, 2014)[19]



Drought Intensity		Drought Impact Types	
	D0-Abnormally Dry		Dominant Impacts
	D1-Moderate Drought	S	S = Short-Term (<6 months)
	D2-Severe Drought	L	L = Long-Term (>6 months)
	D3-Extreme Drought		
	D4-Exceptional Drought		

The Predictive Services National Interagency Fire Center released the latest Wildland Fire Potential Outlook on April 1, 2014, with projections through July. Projections indicate southern California wildfires will worsen during this time, which could potentially impact BPS operations if high-voltage transmission lines are in the path of these fires. These natural disasters are somewhat seasonal phenomena in southern California, and CAISO continues work closely with state and federal agencies to monitor fires that could impact BPS reliability. In prior seasons, individual lines have often been temporarily taken out of service; widespread reliability impacts have been rare. However, if lines are taken out of service—or forced out of service—

[19] NOAA National Drought Monitor.

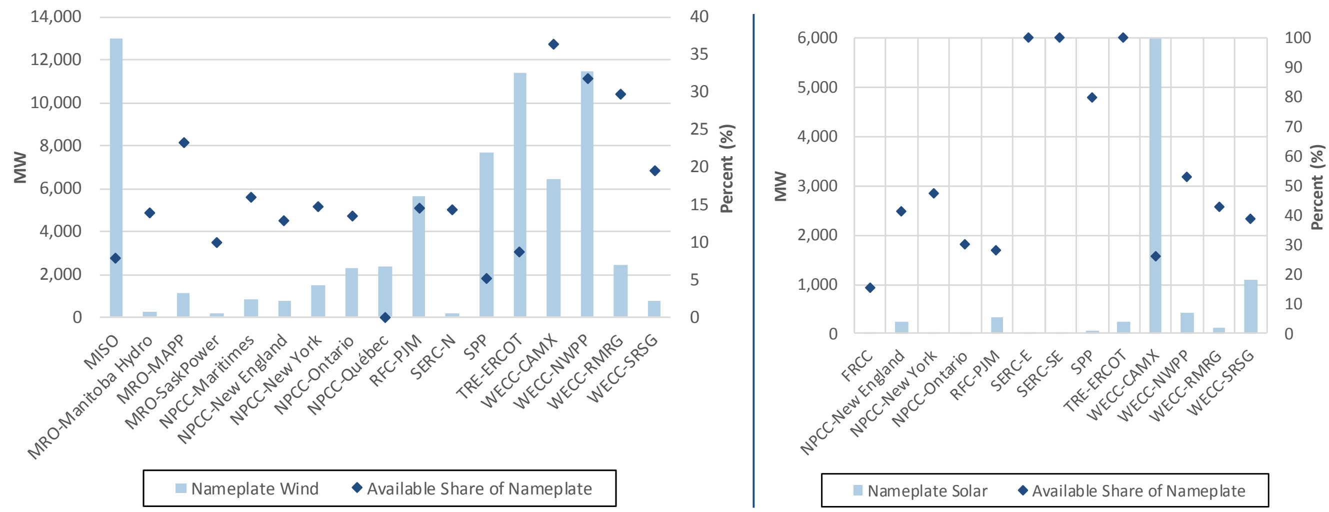
during a period of system stress, the reliability of the system can be compromised. System operators in CAISO use situational awareness tools to monitor the proximity of wildfires to transmission lines.[20]

NERC-wide Variable Generation

Approximately 5.2 GW of projected nameplate wind capacity has been added since last summer. The most notable additions were in SPP (1,509 MW), MISO (1,435 MW), WECC (763 MW), NPCC-Québec (529 MW), NPCC-Ontario (347 MW), and TRE-ERCOT (282 MW).

Solar resources also increased by 5.4 GW (nameplate) since the 2013 summer. Most of these additions were in southern California, with 4,318 MW of nameplate solar added to the WECC-CAMX Assessment Area. The PJM and NPCC-New England Assessment Areas also added 198 MW and 114 MW, respectively. Figure 7 presents nameplate solar and wind capacity for the 2014 summer, along with the percentages projected to be available during peak demand.

Figure 8: 2014 Summer Nameplate Wind (Left) and Solar (Right) with Projected Available Share during Peak Demand



Operationally, the increase in wind and solar resources continues to challenge operators with the inherent swings, or ramps, in power output. In certain areas where large concentrations of wind resources have been added, system planners accommodate added variability by increasing the amount of available regulating reserves and potentially carrying additional operating reserves. Because weather plays a key factor in determining wind and solar output, enhancing regional wind and solar forecasting systems can provide more accurate generation projections. Other methods include curtailment and limitation procedures used when generation exceeds the available regulating resources. In this respect, operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools must be enhanced to assist operators in maintaining BPS reliability.

[20] CAISO Report.

Projected Demand, Resources, and Reserve Margins[21]

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	45,759	42,663	55,035	57,969	29.00	35.88	15.00
MISO*	127,247	122,504	140,892	143,882	15.01	17.45	14.80
MRO-Manitoba	3,408	3,196	4,380	4,569	37.05	42.97	12.00
MRO-MAPP*	5,056	4,958	6,265	6,268	26.35	26.41	15.00
MRO-SaskPower	3,232	3,147	3,941	3,941	25.23	25.23	11.00
NPCC-Maritimes	3,738	3,417	6,231	6,231	82.35	82.35	15.00
NPCC-New England	26,658	25,958	32,120	32,342	23.74	24.59	15.20
NPCC-New York	33,666	32,477	40,112	40,112	23.51	23.51	17.00
NPCC-Ontario	23,025	23,025	28,536	28,536	23.93	23.93	18.60
NPCC-Québec	21,100	21,100	30,759	30,759	45.78	45.78	10.00
PJM*	157,141	145,981	182,866	185,077	25.27	26.78	16.20
SERC-E	43,547	41,890	51,904	51,904	23.90	23.90	15.00
SERC-N*	41,804	39,777	50,258	50,698	26.35	27.45	15.00
SERC-SE*	46,488	44,377	60,836	61,164	37.09	37.83	15.00
SPP*	49,614	48,575	66,796	69,478	37.51	43.03	13.60
TRE-ERCOT	68,096	66,179	76,091	76,091	14.98	14.98	13.75
WECC-CAMX	52,353	50,398	65,916	65,916	30.79	30.79	15.00
WECC-NWPP*	66,424	65,351	85,597	85,597	30.98	30.98	14.79
WECC-RMRG	11,943	11,408	15,136	15,136	32.68	32.68	14.45
WECC-SRSG*	22,706	22,318	27,507	27,507	23.25	23.25	13.90
EASTERN INTERCONNECTION	610,383	581,442	730,169	742,168	25.58	27.64	-
QUÉBEC INTERCONNECTION	21,100	21,100	30,759	30,759	45.78	45.78	10.00
TEXAS INTERCONNECTION	68,096	66,179	76,091	76,091	14.98	14.98	13.75
WECC INTERCONNECTION	153,426	149,475	194,156	194,156	29.89	29.89	15.00
TOTAL-NERC	**853,005**	**818,196**	**1,031,175**	**1,043,174**	**26.03**	**27.50**	**-**

*Footprint changes since the *2013 Summer Reliability Assessment*.

2014 NERC Assessment Areas[22]

[21] See Appendix II for additional information on resource category and planning reserve margin criteria.
[22] This map was created by NERC staff using Ventyx Velocity Suite.

FRCC

Demand	Megawatts (MW)
Total Internal Demand	**45,759**
Total Demand Response – Available	3,096
Net Internal Demand	**42,663**
Demand Response	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	2,585
Direct Control Load Management (DCLM) - Available	2,585
Interruptible Load (IL) - Program Total	511
Interruptible Load (IL) - Available	511
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	53,001
Net Firm Transfers	2,034
Anticipated Resources	**55,035**
Existing-Other Capacity	2,935
Prospective Resources	**57,969**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**29.00**
Prospective Reserve Margin	**36.00**
NERC Reference Margin Level	**15.00**

The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity Division members and 24 Member Services Division members, composed of investor-owned utilities (IOU), electric cooperatives, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities, with 68 registered entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. FRCC contains a population of more than 16 million people and has a geographic coverage of about 50,000 square miles over peninsular Florida.

FRCC applies a NERC Reference Margin Level of 15 percent. The FRCC criteria as approved by the Florida Public Service Commission is set at 15 percent for non-investor-owned utilities and recognized as 20 percent reserve margin criteria for investor-owned utilities (IOU). Based on the expected load and generation capacity, the reserve margin is projected to be 29 percent for the upcoming summer season. FRCC is forecast to reach its 2014 summer non-coincident Net Internal Demand of 42,663 MW in August. This projection for the 2014 summer is consistent with historical weather-normalized FRCC demand growth. The projected 2014 summer peak is slightly lower compared to the 2013 summer forecast.

Demand response (DR) is projected to decrease by 1.3 percent since last summer's projection and is approximately 6.8 percent of the total summer peak demand. FRCC treats Demand-Side Management (DSM) programs as demand reducing or load-modifying. Based on past experience, these programs are used on a limited basis, but expected to be fully available when called upon. FRCC does not anticipate any issues with the availability of DSM programs during the 2014 summer.

FRCC energized a 102.5 MW biomass unit early in 2014. Additionally, a 1,212 MW natural gas combined-cycle unit is scheduled to be in service prior to the summer peak. There are 1,340 MW of generation under firm contract, available to be imported into FRCC from the SERC-SE Assessment Area throughout the summer season, and an additional 837 MW of member-owned generation that is dynamically dispatched out of SERC-SE. All firm on-peak capacity imports into FRCC have firm transmission service agreements in place to ensure deliverability, with such capacity resources included in the FRCC reserve margin. The Operations Planning Working Group hold weekly conference calls to coordinate outages and discuss potential operational issues. FRCC Transmission Operators (TO) and adjacent SERC TOs coordinate through weekly calls.

Currently, about 1,020 MW of undervoltage load shedding (UVLS) is armed within FRCC. The majority of the UVLS relays are designed to respond to local low-voltage conditions that could be caused by multiple contingency events. FRCC will have one new Special Protection System (SPS) placed in service prior to the 2014 summer peak. The new SPS is designed to preserve dynamic voltage stability in an area serviced by a long radial line. FRCC has retired five SPSs since the last summer assessment as a result of a periodic review showing that these SPSs were no longer needed.

FRCC performed a Summer Transmission Assessment and Operational Seasonal Study to assess the adequacy and robustness of the Bulk Electric System (BES) within FRCC under expected 2014 summer peak load and under anticipated system conditions (taking into account generation and transmission maintenance activities). This 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 to ensure the BES performs adequately throughout the summer time frame. The study results demonstrated that potential thermal and voltage conditions exceeding the applicable screening criteria will be successfully mitigated under normal conditions, single-contingency events, and selected multiple-contingency events. The FRCC BES is expected to perform reliably for the anticipated 2014 summer peak season system operating conditions.

MISO

Demand	Megawatts (MW)
Total Internal Demand	**127,247**
Total Demand Response - Available	4,743
Net Internal Demand	**122,504**
Demand Response	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	944
Direct Control Load Management (DCLM) - Available	832
Interruptible Load (IL) - Program Total	4,045
Interruptible Load (IL) - Available	3,911
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	138,605
Net Firm Transfers	2,287
Anticipated Resources	**140,892**
Existing-Other	2,990
Prospective Resources	**143,882**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**15.01**
Prospective Reserve Margin	**17.45**
NERC Reference Margin Level	**14.80**

The Midcontinent Independent System Operator, Inc. (MISO) currently manages energy and operating reserves markets that consist of 36 Local Balancing Authorities and 391 Market Participants, who serve approximately 42 million people. On Dec. 19, 2013, MISO began coordinating all Regional Transmission Organization (RTO) activities in the newly combined footprint consisting of all or parts of 15 states with the integration of the MISO South entities.

***Footprint Change**: On January 1, 2012, Duke Energy Ohio/Kentucky (DEOK) was consolidated into the PJM RTO, removing approximately 5,700 MW of load and generation from MISO's footprint. Entergy and its six utility operating companies will be integrated into MISO in December 2014. This addition will bring 15,500 miles of transmission, 30,000 MW of generation capacity, and 35,000 MW of load into the MISO footprint.*

The NERC Reference Margin Level for MISO (referred to as the MISO Planning Reserve Margin requirement) is 14.8 percent for the 2014–2015 planning year, which runs from June 1, 2014, through May 31, 2015. The Anticipated Reserve Margin of 15.0 percent is slightly above the NERC Reference Margin Level. This number dropped from 28.1 percent in 2013 mainly due to approved retirements, suspensions, and removal of non-firm imports. Only 1,000 MW of MISO South resources are counted toward aggregate margins at coincident peak demand to align with expected dispatch within the RTO footprint. It is always possible for a combination of higher loads, higher forced outage rates, fuel limitations, and other factors to lead to an amount of reserves below the MISO Planning Reserve Margin. However, the curtailment of firm load is a low-probability event for the 2014 summer season based on a probabilistic analysis performed by MISO in which a Planning Reserve Margin model is run at varying resource levels above and below the base resource level.

MISO forecasts the coincident Total Internal Demand to peak at 127,247 MW during the 2014 summer season, which is an increase of 32.3 percent from summer 2013. The major driver for the increase in demand is the integration of the MISO Southern entities. The 2014 forecast includes transmission losses that align with NERC reliability assessment guidelines. Including transmission losses provides a more accurate representation of peak system demand relative to generation requirements. MISO allows DSM programs to be included in the Planning Resource Auction.[23] The amount of DSM programs that are expected to be available on peak this summer is 4,743 MW, consisting of 832 MW of Direct Control Load Management (DCLM) and 3,911 MW of Interruptible Load (IL). These DSM programs result in MISO's coincident Net Internal Demand to be projected at 122,504 MW.

MISO projects 138,605 MW of Existing-Certain capacity to be available during summer 2014. Included in this capacity is 3,953 MW of behind-the-meter generation. 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 are 1,027 MW of wind (approximately 8 percent of wind-registered capacity) that MISO expects to be available to serve load this summer. The main reason for the drop of 6 percentage points (from 14.1 to 8) is the fact that MISO did not count on the Transmission-Limited and Energy-Only (Existing-Other) resources toward the Existing-Certain capacity.

All other intermittent resources receive their unforced capacity rating based on historical summer performance up to the amount that they have Network Resource Interconnection Service (NRIS) or firm point-to-point Interconnection Service Right.[24]

[23] MISO Planning Resource Auction (PRA).
[24] MISO Generator Interconnection.

Due to transmission limitations, 8,299 MW of capacity is derated; the majority of this limit is due to the MISO South surplus above demand being excluded, in accordance with the 1,000 MW contract path between MISO South and MISO North/Central. Also, 2,990 MW of Energy-Only resources that don't have firm point-to-point transmission right were categorized as Existing-Other capacity. MISO's capacity transactions amount to a net firm import of 2,287 MW.

To support reliable and efficient transmission service, MISO develops its MISO Transmission Expansion Plan (MTEP) annually to identify, assess, and address reliability issues within its BES footprint. The last MTEP study, MTEP13, was approved by the MISO Board of Directors in December 2013. The study tested the existing transmission plan using NERC Reliability Standards and developed additional mitigation as required to address any identified issues. Eleven transmission projects that have been evaluated as part of the MTEP13 plan are proposed to be in service by or before September 2014. These projects are mainly transmission line and substation equipment upgrades.

Similar to previous years, MISO is conducting a Summer Readiness workshop in which it collaborates with stakeholders to maximize preparedness for the summer period. This workshop includes an assessment of MISO's resources and the projected reserve margin given the forecasted 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.

During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local Balancing Authorities (BAs) to obtain the amount of DR resources that would be available under a given notification time (e.g., two hours). If MISO reaches the point of needing to call on these resources, then MISO will deploy only the amount needed with the expectation that all will perform. 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 summer 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 expected beyond the 2014 summer 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.

Low water levels and high water temperatures can always result from unusually hot and dry weather, and these situations are resolved through existing procedures, depending on the circumstances.

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 the need arises in real-time operations.

MRO-Manitoba Hydro

Demand	Megawatts (MW)
Total Internal Demand	**3,408**
Total Demand Response - Available	212
Net Internal Demand	**3,196**
Demand Response	Megawatts (MW)
Load as a Capacity Resource (LCR) - Program Total	223
Load as a Capacity Resource (LCR) - Available	212
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	5,440
Net Firm Transfers	-1,060
Anticipated Resources	**4,380**
Existing-Other	189
Prospective Resources	**4,569**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**37.05**
Prospective Reserve Margin	**42.97**
NERC Reference Margin Level	**12.00**

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. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Authority (PA) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of the Midcontinent Independent System Operator (MISO). MISO is the Reliability Coordinator (RC) for Manitoba Hydro.

Manitoba Hydro is projecting reserve margins above the NERC Reference Margin Level of 12 percent for the 2014 summer assessment period.

There are no significant changes to the load forecast. However, Manitoba Hydro has changed the demand forecasting method since the last summer assessment period. Manitoba Hydro now calculates the summer peaks based on the historical monthly load factors (ratio of the average hourly energy over a month divided by the energy used during the peak hour) applied to the monthly system energy. Manitoba Hydro's system energy is primarily based on three segments of the market: Residential, General Service Mass Market, and Top Consumers (Manitoba Hydro's largest industrial customers) with a small amount remaining for miscellaneous groups such as street lighting and seasonal customers.

No generation resources have been added or retired since summer 2013; however, there have been slight increases in DSM. No issues have been identified that would significantly impact generator availability, and no significant generator uprates or derates are planned for the assessment period.

Manitoba Hydro has 1,060 MW of Firm exports and no imports during the summer. There is no anticipated need for emergency imports for the 2014 summer.

Manitoba Hydro will be completing the Riel Reliability Improvement[25] Initiative this summer. This project will improve reliability of the transmission system serving Winnipeg and southern Manitoba. There are no known project delays or transfer constraints projected to impact reliability during the 2014 summer.

On at least an annual basis, Manitoba Hydro performs an operational study to determine storage reserve requirements necessary to meet demand based on both high and low load growth, according to historic information. No unique operational problems have been observed. There are no expected seasonal operations concerns for the assessment period. Manitoba Hydro does not foresee any concern with the DR resources to meet the peak demand. When the total load of the Interruptible Load (IL) or curtailable load customer is below the minimum protected load of the customer, that particular customer will not be able to contribute to DR—particularly during planned or unplanned maintenance. Curtailable load contract describes any restriction on deploying DR resources.

[25] Riel Reliability Improvement Initiative.

MRO-MAPP

Demand	Megawatts (MW)
Total Internal Demand	**5,056**
Total Demand Response - Available	98
Net Internal Demand	**4,958**
Demand Response	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	106
Direct Control Load Management (DCLM) - Available	92
Interruptible Load (IL) - Program Total	14
Interruptible Load (IL) - Available	6
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	7,334
Net Firm Transfers	-1,069
Anticipated Resources	**6,265**
Existing-Other	3
Prospective Resources	**6,268**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**26.00**
Prospective Reserve Margin	**26.00**
NERC Reference Margin Level	**15.00**

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 Balancing Authority areas (WAUE and MISO) and 13 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.

***Footprint Changes**: There has been one change to the MAPP PA footprint since the previous summer assessment, Minnesota Municipal Utilities Association (MMUA) has withdrawn from the MAPP Assessment Area.*

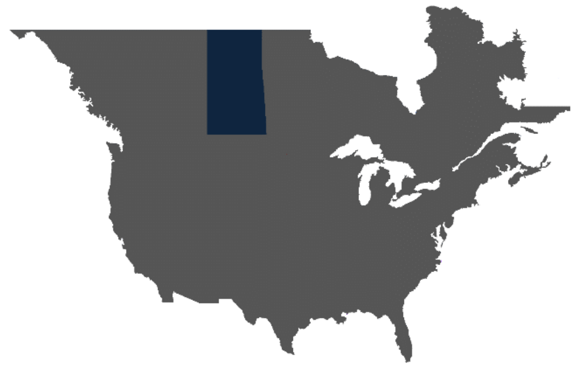
Anticipated and Prospective Reserve Margins for MAPP exceed the NERC Reference Margin Level of 15 percent due to the assessment area's strong generation portfolio and DSM programs for the 2014 summer. With the withdrawal of MMUA (256 MW demand), the demand expected in the MAPP Assessment Area is expected to be lower than what had been forecasted last summer. Demand in Basin Electric Power Cooperative (BEPC) continues to grow as a result of the oil activity in Northwestern North Dakota. The 2014 summer assessment forecast includes 147 MW of projected year-over-year demand growth compared to the 2013 actual summer peak.

Since the previous summer seasonal assessment, there have been 226 MW of capacity additions. Due to needed repairs, Ames Municipal Electric Systems will have 18 MW of capacity unavailable for the 2014 summer season. There are no additional generation resource additions for summer 2014. Missouri River main stem water levels may affect hydro generation. The U.S. Army Corps of Engineers' current forecast indicates that the expected runoff for the year will result in generation being reduced to 84 percent of normal unless a significant unexpected increase in runoff occurs.

MAPP is projecting 390 MW of imports and 1,458 MW of exports, with a net export of 1,068 MW. Several transmission projects will have been completed or will continue through the 2014 summer season, all of which are intended to increase the reliability of the MAPP transmission system. Despite the unexpected load growth in the northwestern North Dakota area, and some minor instability that is currently being studied, the MAPP Assessment Area does not foresee any reliability or capacity issues becoming problematic during the upcoming summer.

MRO-SaskPower

Demand	Megawatts (MW)
Total Internal Demand	**3,232**
Total Demand Response - Available	85
Net Internal Demand	**3,147**
Demand Response	Megawatts (MW)
Interruptible Load (IL) - Program Total	85
Interruptible Load (IL) - Available	85
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	3,941
Net Firm Transfers	0
Anticipated Resources	**3,941**
Existing-Other	0
Prospective Resources	**3,941**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**25.00**
Prospective Reserve Margin	**25.00**
NERC Reference Margin Level	**11.00**



Saskatchewan is a province of Canada that comprises a geographic area of 651,900 square km and approximately 1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Authority/Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. It is a Provincial Crown Corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections. Significant footprint changes have not occurred during the past two years and are not expected in future years.

SaskPower seasonal operations are expected to be adequate for the summer, and no significant seasonal constraints have been identified. Peak demand for the SaskPower system is experienced in the winter.

SaskPower projects adequate reserve margins during the 2014 summer assessment period. SaskPower's criteria 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 NERC Reference Margin Level, which has not changed since the prior summer assessment.

There is little change in the economic outlook from last summer's forecast, and there are no changes in area footprint or seasonal weather outlook. Total internal hourly interval demand is forecast to be 3,232 MW for the 2014 summer assessment period. Increase in demand is approximately 3.5 percent from last year.

No significant generator uprates, derates, or additions are planned for the upcoming summer. No units have retired since the prior summer assessment, but a 66 MW (gross) unit will be retired during the upcoming 2014 summer season. There are no Firm transfers for the 2014 summer. SaskPower is not planning to rely on emergency imports for the current assessment period.

SaskPower has one transmission project planned for 2014 summer to improve local transmission reliability. A second 230-138 kV auto-transformer will be installed in an existing transmission station during the 2014 summer, which will improve the reliability of power supply in the Estevan area.

The 2014 summer season joint study with Manitoba Hydro, with input from Basin Electric (North Dakota), determines the import/export capabilities with neighboring BAs for the 2014 summer assessment period. As part of the study, applicable guidelines are issued to respective control rooms before the summer season begins. No significant seasonal constraints have been identified.

NPCC-Maritimes

Demand	Megawatts (MW)
Total Internal Demand	**3,738**
Total Demand Response - Available	321
Net Internal Demand	**3,417**
Demand Response	Megawatts (MW)
Interruptible Load (IL) - Program Total	338
Interruptible Load (IL) - Available	321
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	6,231
Net Firm Transfers	0
Anticipated Resources	**6,231**
Existing-Other	0
Prospective Resources	**6,231**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**82.35**
Prospective Reserve Margin	**82.35**
NERC Reference Margin Level	**15.00**

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

The Maritimes Area is a winter-peaking system and is projecting adequate reserve margins above the NERC Reference Margin Level (or operating reserve requirements) for the 2014 summer. The summer 2014 forecast peak of 3,738 MW represents a 6.3 percent increase over the 2013 summer forecast of 3,515 MW. This increase can be attributed to a combination of both weather and economic influences. All NPCC Reliability Coordinator Areas, including the Maritimes, follow a one-day-in-ten-years load loss criterion. For planning purposes, a 20 percent NERC Reference Margin Level is adopted for Maritimes, based on the following equation: 20% x (Forecast Peak Load MW – Interruptible Load (IL) MW).

The only DR considered in resource adequacy assessments for the Maritimes Assessment Area is Interruptible Load (IL), which comes from industrial customers under contract. Because of the variability of industrial load at any one time and the small amount of megawatts, these values do not have significant impact for seasonal planning purposes.

The fuel mix is very diverse within the Maritimes Area, and it is not dependent on a single fuel source, thus allowing greater system reliability.[26]

The Maine Power Reliability Program (MPRP) in New England and the refurbishment of the Eel River HVdc interconnection between Québec and New Brunswick both have the ability to impact the amount of energy transfers between New Brunswick/New England and New Brunswick/Hydro Québec. The respective operations study 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 derate on the interface during its outage. Neither of these outages should cause any reliability issues, because the Maritimes Assessment Area is not reliant on energy transfers to meet its requirements.

As a winter-peaking system, the operating challenge during the summer is the possibility of light system loads occurring together with high wind generator outputs. If this scenario were to happen, procedures are in place to mitigate the event. Monitoring of thermal unit dispatch under periods of high wind and low load (e.g., shoulder season overnight hours) is an area of focus, and work to better assess steam unit minimum loads and minimum steam system configurations is ongoing.

[26] The percentage by rated capacity of generation by fuel type includes: Nuclear (8.76 %), Natural Gas (7.10 %), HFO/Natural Gas (4.26%), Coal/Petroleum Coke (35.58%), Light Oil (2.94%), Diesel (8.76%), Bunker (0.82 %), Hydro/Tidal: (17.96%), Biomass (2.36%), Biogas (0.026%), and Wind (11.40%).

NPCC-New England

Demand	Megawatts (MW)
Total Internal Demand	**26,658**
Total Demand Response - Available	700
Net Internal Demand	**25,958**
Demand Response	Megawatts (MW)
Load as a Capacity Resource (LCR) - Program Total	700
Load as a Capacity Resource (LCR) - Available	700
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	30,837
Net Firm Transfers	1,283
Anticipated Resources	**32,120**
Existing-Other	221
Prospective Resources	**32,342**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**23.74**
Prospective Reserve Margin	**24.59**
NERC Reference Margin Level	**15.20**

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

During the peak demand week of July 13, 2014, ISO-NE forecasts Existing-Certain Generation of 30,769 MW to meet the Net Internal Demand of 25,958 MW for the 2014 summer and exceed the NERC Reference Margin Level of 15.2 percent.

The Existing-Certain Generation value originates with Seasonal Claimed Capabilities (SCC) of 30,829 MW. A planned outage value of 60 MW was subtracted from the total SCC, resulting in the Existing-Certain capacity of 30,769 MW. New England is accounting for 1,383 MW in imports and 100 MW exports for a net import of 1,283 MW. This equates to the Existing-Certain and Net Firm Transfers total of 32,052 MW (a 23.5 percent margin). With 68 MW of new generation added to Existing-Certain, this gives New England 32,120 MW of Anticipated internal capacity. The Prospective Resources account for an additional 221 MW of Settlement Only Generation.[27] The resulting Anticipated Reserve Margin is 23.7 percent with a Prospective Reserve Margin of 24.6 percent.

The forecast margins do not include the short-term capacity and energy purchases from neighboring systems that are anticipated to help serve the electrical demands on the system. Net Imports of 1,283 MW are only a portion of the import Total Transfer Capability (TTC) for New England. The TTC for New England imports is 4,814 MW.

For the 2014 summer, ISO-NE has 700 MW of active DR that are expected to be available on-peak.[28] There are 1,507 MW of passive DR (i.e., Energy Efficiency and Conservation), which are treated as demand reducers in this report. Passive DR are accounted for in the Total Internal Demand forecast of 26,658 MW.

Since the 2013 summer, 53 MW of new generation (38 MW of wood/refuse and 15 MW of natural gas) has become commercial, and ISO-NE anticipates that an additional 68 MW of wood/refuse fueled generation will be available for the 2014 summer. Also of note is the retirement of two Salem Harbor units, which accounts for a 585 MW reduction of capacity. Overall, New England will experience a net reduction of 464 MW of generation for the 2014 summer period.

New England has deployed the Metrix Zonal load forecast, which produces a zonal load forecast for the eight regional load zones for up to six days in advance through the current operating day. This forecast enhances reliability on a zonal level by taking into account conflicting weather patterns. An example would be when the Boston zone is forecast to be 65 degrees while the Hartford area is forecasting 90 degrees. This zonal forecast ensures an accurate reliability commitment on a regional level. The eight zones are then summed for a total New England load. This additional year of data in New England's Advanced Neural Network (ANN) models and Similar Day Analysis (SimDays) improves the zonal forecast compared to last summer.

New bulk power transmission facilities are planned to be placed in service in New England for the 2014 summer. Some of the more significant improvements include equipment as part of the Maine Power Reliability Project (MPRP). The transmission improvements are located in an area known as the Southern Connector Region of the MPRP project and will provide

[27] "Settlement Only" refers to generating units that produces less than 5 MW and are entitled to receive capacity credit but are not centrally dispatched by the ISO control room and not monitored in real time.

[28] This consists of 489 MW of Real-Time Demand Response (RTDR) Program and 211 MW of Real-Time Emergency Generation (RTEG) Program, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP 4).

additional support to local load to the Portland, Maine Seacoast area and reinforce power transfers into and out of the area. This project will also increase overall transfer capabilities from Maine to the rest of the New England system.

During the spring of 2014, the Type III Rumford Special Protection System will be removed. This SPS was needed as support for long-duration transmission outages associated with the MPRP project. This portion of the project is expected to be complete in the spring of 2014. Also, since last summer, the Type I 386 SPS has been retired. This was accomplished when the newly constructed transmission facilities (MPRP Surowiec, Ravens Farm, and Yarmouth 345 kV lines) were placed into service.

The New England generation fleet continues to be reliant on natural gas as a primary fuel source. Approximately 45 percent of the area's generation is gas-fired, and 22 percent of this claims dual-fuel capability. This generation can provide up to 54 percent of New England's electric energy on any given operating day. Generators in New England are heavily dependent on pipeline capacity released by the firm capacity rights holders, with only a few holding mainline firm transportation contracts. Though fuel supply concerns for natural gas-fired generation are more significant during the winter season, difficulties can arise during the summer season.

In past years, ISO-NE has taken a number of steps to communicate and prepare for fuel supply risks during system operating peak conditions.[29] Most recent improvements have come as a result of FERC Order 787 and subsequent ISO-NE tariff revisions that explicitly authorize ISO-NE to share confidential information concerning natural gas-fueled generation located in New England with the operating personnel of interstate natural gas pipeline companies, provided that the information is operationally necessary and that it will be shared only with the pipeline company directly serving that generator. This information exchange includes maintenance schedules to promote outage coordination between the industries, output schedules for individual generators, and discussion of any real-time information concerning specific resources for the purpose of maintaining reliability.

With these enhanced communicating methods, ISO-NE and the interstate natural gas pipeline operators will be able to improve the forecast of their combined systems and discuss specific system conditions, and they may be able to take actions under their existing authorities to avoid reliability problems. When sharing this information with the interstate natural gas pipeline operators, the pipeline operators may be able to provide information on gas availability that will allow ISO-NE to better anticipate and address potential reliability problems in the event that there is insufficient fuel for all gas-fired generators to meet their schedules. Along with near-term weather data, load forecasts, and planned outage conditions, this information is also used to develop short-term and long-term operating plans.

[29] These efforts and improvements are listed in the ISO New England Strategic Planning Initiative.

NPCC-New York

Demand	Megawatts (MW)
Total Internal Demand	**33,666**
Total Demand Response - Available	1,189
Net Internal Demand	**32,477**
Demand Response	Megawatts (MW)
Load as a Capacity Resource (LCR) - Program Total	1,189
Load as a Capacity Resource (LCR) - Available	1,189
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	37,983
Net Firm Transfers	2,129
Anticipated Resources	**40,112**
Existing-Other	0
Prospective Resources	**40,112**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**24.00**
Prospective Reserve Margin	**24.00**
NERC Reference Margin Level	**17.00**

The New York Independent System Operator (NYISO) is the only Balancing Authority in the New York Control Area (NYCA). The NYCA is over 48,000 square miles, serving a total population of about 19.4 million people, and it peaks annually in the summer. This report addresses the reliability assessment for the NYCA for May 2014 through October 2014. The NYISO is registered as the sole Balancing Authority and Reliability Coordinator for the NYCA, which encompasses the state of New York.

The weather-normalized 2013 peak was 33,497 MW, 218 MW (0.66 percent) higher than the 2013 summer forecast of 33,279. The current 2014 peak forecast is 33,666 MW and exceeds the 2013 summer peak forecast by 387 MW (1.16 percent). This projected increase is attributed primarily to higher growth in New York City. The impacts of energy efficiency and conservation have been accounted for in the growth rates of the 2014 summer peak demand forecast. It is estimated that the 2013 summer peak demand was reduced by about 300 MW through such programs. New behind-the-meter solar-photovoltaic generation reduced the peak load by an estimated 10 MW to 15 MW.

The New York State Reliability Council (NYSRC) has established an Installed Reserve Margin (IRM)[30] of 17 percent for the 2014 summer season, and the NYISO anticipates adequate capacity to meet the IRM. Since the 2013 summer period there have been generator nameplate additions of 218 MW and retirements or mothballing of 164 MW. Significant additions include the Orangeville Wind Farm (93.9 MW), the return to service of the Astoria turbines GT10 and GT11 (63.6 MW), and the return to service of the Niagara Biogen (56 MW), along with various small generator additions (4.6 MW). Significant reductions include the retirements of Syracuse Energy (101.6 MW), Station 9 (19 MW), and Freeport 9 (2.1 MW), and the mothballing of Châteaugay Power (19.7 MW) and Ravenswood GT7 (22 MW).

No unique operational problems are expected for the summer of 2014. The NYISO maintains Joint Operating Agreements with each of its adjacent Reliability Coordinators that include provisions for the procurement, or supply, of emergency energy, and provisions for wheeling emergency energy from remote areas if required. Prior to the operating month, the NYISO identifies to neighboring control areas both the capacity-backed transactions that are expected to be imported into and exported from NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2014 summer season the New York Balancing Authority expects to have 2,129 MW of net import capacity available.

The NYISO anticipates sufficient resources to meet peak demand without the need to resort to emergency operations. The Emergency Demand Response Program (EDRP) and ICAP/Special Case Resource program (ICAP/SCR) are designed to promote participation, and the expectation is for full participation of these programs in the summer of 2014. There is no limitation as to the number of times a resource can be called upon to provide a response. The Special Case Resources are required to respond when notice has been provided in accordance with the NYISO procedures; response from the EDRP is voluntary for all events. Further control actions are outlined in the policies and procedures of the NYISO.

[30] The term "Installed Reserve Margin" is unique to the NYSRC and applied as the NERC Reference Margin Level for this assessment.

NPCC-Ontario

Demand	Megawatts (MW)
Total Internal Demand	**23,025**
Total Demand Response - Available[31]	0
Net Internal Demand	**23,025**
Demand Response	Megawatts (MW)
Interruptible Load (IL) - Program Total	1,353
Interruptible Load (IL) - Available	503
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	28,536
Net Firm Transfers	0
Anticipated Resources	**28,536**
Existing-Other	0
Prospective Resources	**28,536**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**23.93**
Prospective Reserve Margin	**23.93**
NERC Reference Margin Level	**18.60**

Ontario 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 IESO serves the power needs of more than 13 million people.

For 2014, the NERC Reference Margin Level is 18.6 percent.[32] Both the Anticipated and Prospective Reserve Margins are both adequate for the 2014 summer season.

The forecasted peak demand, under normal weather for the summer of 2014, is 23,025 MW. This forecast is fairly similar to the 23,275 MW forecast for the previous summer. Peak demand continues to be shaped by four main factors: the economy, the growth in embedded generation, the impacts of conservation, and the influence of prices. The forecast for this summer's peak is lower than the forecast for last summer's. This is due to the fact that the combined impacts of increased embedded generation capacity, prices, and conservation savings far outweigh the growth in consumption arising from population growth and economic expansion, thus leading to lower peak summer demand.

For the 2013 summer period, the Ontario Power Authority's (OPA) DR programs were activated five times, and dispatched loads accounted for just over 665 MWh during the summer daily peaks. At the time of the 2013 summer peak, the activated demand measures amounted to 94 MW. All these programs act to temporarily reduce load and are triggered according to market prices, the supply cushion, or by contract.

DR (demand measures) is not decremented from demand, but are instead treated as a resource to be dispatched as necessary. To determine the amount of effective capacity, the IESO uses historical data to project the amount of DR that will be available during periods of peak demand. While DR programs have not changed, the IESO continually updates the calculation for effective capacity to reflect the most recent participant behavior.

Time-of-use rates and the Global Adjustment Allocation are pricing programs that act to reduce demand during the summer peaks. Both of these are incorporated in the demand forecast.

Since the previous assessment, there has not been a significant change to the conservation programs, demand measures, or pricing impacts. There is a program total of 1,353 MW of IL for this upcoming summer. Of that total, just over 503 MW are deemed reliably available at the time of the system peak.

At the end of 2013, 3,000 MW of coal-fired generation was retired in Southern Ontario. In April 2014, Thunder Bay Generating Station burned its last supply of coal. As a result, Ontario is now the first jurisdiction in North America to fully eliminate coal as a source of electricity generation.

The Lower Mattagami project expansion saw the addition of a third unit at Little Long Generating Station (67 MW capacity) in January 2014. The addition of a third unit at Harmon Generating Station with a 78 MW capacity is expected in June 2014.

By summer 2014, 601 MW of wind generation is expected to come into service, bringing the total grid-connected wind generation to 2,326 MW. The Thunder Bay Condensing Turbine Project began commercial operations in mid-2013, adding 40 MW of capacity since the prior summer assessment. Additionally, 10 MW of grid-connected solar capacity is expected to be in service by July 2014. This addition will be the first grid-connected solar project in Ontario.

[31] For this assessment, IESO is counting DR as part of the On-Peak Capacity category.

[32] Calculated annually for the next five years in accordance with the NPCC resource adequacy design criterion and is published on the IESO website: IESO Forecasts & 18-Month Outlooks.

In its determination of resource adequacy, the IESO plans for Ontario to meet NPCC regional criteria without reliance on external resources. For use during daily operation, operating agreements between the IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by the IESO. No reliance on emergency energy is assumed to meet the NERC Reference Margin Level for Ontario this summer. IESO also participates in a simultaneous activation of a reserve group that includes IESO, ISO-New England, New Brunswick Power, NYISO, and PJM. This participation enhances recovery from generation losses when they occur.

One autotransformer will be taken out of service at Bruce A Generating Station during the summer season, causing a minor reduction for Flow Away From Bruce Complex and Wind (FABCW) interface.

Early in the summer, one 500 kV circuit from Lennox Generating Station to Hawthorn Transformer Station will be taken out of service, causing a significant reduction for the Flow Into Ottawa interface during the outage. Depending on the primary demand in the Ottawa area, a local load rejection SPS may be armed during the planned outage.

The completion date for transmission reinforcements from the Niagara region into the Hamilton-Burlington area continues to be delayed. Completion of this project will increase the transfer capability from the Niagara region to the rest of the Ontario system. Until the project is in service, the supply needs in southern Ontario will continue to be met through the existing system.

Overvoltage control reactive enhancements in northwestern Ontario will be complete by the end of 2014. Some enhancements related to this project are already in service, and as a result, there are no dynamic or static reactive power-limited areas in the Ontario BPS.

Ontario will continue to experience Surplus Baseload Generation (SBG)[33] conditions over the next summer. While Ontario has observed SBG conditions over several summer seasons, in the fall of 2013 IESO implemented variable generation dispatch tools and the setting of floor prices for flexible nuclear generation. These new tools are expected to assist with the management of SBG over the summer period.

IESO concluded its Renewable Integration Initiative in fall 2013. The Renewable Integration Initiative delivered a number of enhancements, including the setting of floor prices for wind and solar generation, integration of the hourly centralized forecast into the IESO scheduling tools, and enhanced visibility of renewable output for the IESO. This project provided the IESO with the ability to dispatch wind and solar generation.

[33] Surplus Baseload Generation (SBG).

NPCC-Québec

Demand	Megawatts (MW)
Total Internal Demand	**21,100**
Total Demand Response - Available	0
Net Internal Demand	**21,100**
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	32,237
Net Firm Transfers	-1,478
Anticipated Resources	**30,759**
Existing-Other	0
Prospective Resources	**30,759**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**45.78**
Prospective Reserve Margin	**45.78**
NERC Reference Margin Level	**10.00**

The Québec system is winter peaking because a large amount of space-heating load is present during winter operating periods. The all-time internal peak hourly demand is 39,031 MW, which occurred on January 22, 2014. Summer peak demands are typically about 56 percent of peak winter demand. Another important characteristic is that generation on the system is almost 92 percent hydro, with a total installed capacity for the 2014 summer operating period of 43,523 MW. Transmission voltages are 735, 315, 230, 161, 120, and 69 kV with a ±450 kV HVdc multi-terminal line. Transmission line length totals 33,613 km (20,886 miles). Population served is about 8 million, and the Province of Québec has an area of approximately 1,667,000 km^2 (643,600 sq. mi.).

Given the amount of available capacity and the load forecast level in the summer, there are no significant impacts associated with exports capacity. The Québec Assessment Area does not rely on imports during the summer period.

No particular transmission project is required for the upcoming summer period. A second -300/+300-Mvar static var compensator (SVC) will be installed at Bout-de-l'Île substation in June 2014 in preparation for the upcoming winter. Most transmission line, transformer, and generating unit maintenance is done during the summer. Resource availability is not a problem at all during summer operating periods even though exports to summer peaking subregions[34] of NPCC are sustained during peak hours. Internal generating unit and transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales, and margins.

During summer periods, reactive capability of generators is not a problem. Hydro-Québec TransÉnergie (HQT) does not expect to encounter any kind of low-voltage problem during the summer. On the contrary, controlling overvoltages on the 735 kV network during off-peak hours is the concern. This is accomplished mainly with the use of shunt reactors. Typically, about 15,000 Mvar of 735 kV shunt reactors may be connected at any given time during the summer, with seven to ten 735 kV lines out of service for maintenance. Most shunt capacitors, at all voltage levels, are disconnected during the summer.

On a few occasions during the last summers, several 735 kV lines in the southern part of the system became heavily loaded, due to the hot temperatures in southern Québec. Although this is a new issue at Hydro-Québec, the situation is expected to happen again because summers are getting warmer, the air-conditioning load is increasing year after year, and transfers to summer peaking systems are increasing. Studies have been performed, thermal limits have been optimized, and mitigating measures have been implemented to ensure that no line becomes overloaded following a contingency in hot temperature periods.

Following the disturbance event that occurred on July 3, 2013, on the HQT transmission system, information related to this event was provided to NPCC. In December 2013, NPCC created a working group to further analyze the operations and design of the transmission system. NPCC and HQT agreed that the event analysis would be presented for discussion to various NPCC technical and operational task forces. Moreover, lessons learned will be issued following the review of the findings and recommendations by NPCC's working groups and task forces.

[34] The terms "subregion" and "assessment area" are used interchangeably in this report.

PJM

Demand	Megawatts (MW)
Total Internal Demand	**157,141**
Total Demand Response - Available	11,160
Net Internal Demand	**145,981**
Demand Response	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	852
Direct Control Load Management (DCLM) - Available	852
Interruptible Load (IL) - Program Total	13,590
Interruptible Load (IL) - Available	10,308
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	180,921
Net Firm Transfers	1,945
Anticipated Resources	**182,866**
Existing-Other	2,211
Prospective Resources	**185,077**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**25.27**
Prospective Reserve Margin	**26.78**
NERC Reference Margin Level	**16.20**

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

***Footprint Change**: This assessment includes East Kentucky Power Cooperative (EKPC) load and generation, which joined the PJM RTO on June 1, 2013.*

The PJM RTO Reserve Requirement, calculated by PJM, is 16.2 percent for the 2014–2015 planning period, which runs from June 1, 2014, through May 31, 2015. The PJM RTO Reserve Requirement (applied in this assessment as the NERC Reference Margin Level) is slightly higher (0.3 percentage points) this year. At 25 percent, all expected margins remain above the PJM Reserve Requirement during the 2014 summer peak season.

Revisions to historical economic data and the addition of another year of load experience to the load forecasting model resulted in generally lower peak and energy forecasts for this year compared to the forecast for this year done last year. All load models were estimated with historical data from January 1998 through August 2013. The models were simulated with weather data from 1974 through 2012. The economic forecast used was Moody's Analytics' November 2013 release. Available DR decreased slightly from 10,742 MW in 2013 to 10,308 MW 2014, partially due to higher prices for this resource in the PJM forward capacity market. PJM now has added three Demand Response products: Limited DR (10 days during the summer peak season for a maximum of six hours per day), Extended Summer DR (unlimited days during summer for 10 hours per day) and Annual DR (unlimited days throughout the year for a maximum of 10 hours per day).

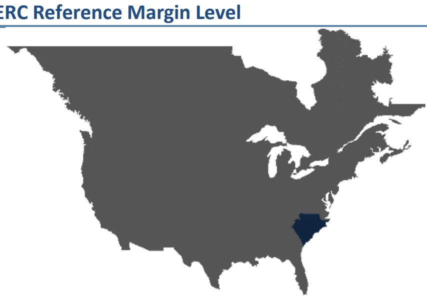
PJM had a net decrease of 2,620 MW of generation resources since last summer. PJM does not allow summer peak season scheduled maintenance; consequently, there are no significant generator uprates or derates planned for the upcoming summer.

Various transmission enhancements were added to the PJM bulk system since last summer, including eight BES transformers and approximately 500 Mvar of shunt capacitors. Four variable shunt reactors were also added in the Dominion Virginia Power area of PJM for light-load voltage control. The Eastlake 5 unit in Ohio was converted into a 485 Mvar synchronous condenser. Two SPSs have been added to the PJM system for N-1-1 contingency mitigation. They will be retired once transmission enhancements are completed.

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

SERC

	SERC-E	SERC-N	SERC-SE
Demand	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand	**43,547**	**41,804**	**46,488**
Total Demand Response - Available	1,657	2,027	2,111
Net Internal Demand	**41,890**	**39,777**	**44,377**
Demand Response	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	614	165	777
Direct Control Load Management (DCLM) - Available	614	165	777
Interruptible Load (IL) - Program Total	1,020	1,231	1,260
Interruptible Load (IL) - Available	1,020	1,231	1,260
Critical Peak-Pricing (CPP) with Load Control - Program Total	23	0	0
Critical Peak-Pricing (CPP) with Load Control - Available	23	0	0
Load as a Capacity Resource (LCR) - Program Total	0	631	74
Load as a Capacity Resource (LCR) - Available	0	631	74
Projected Resource Categories (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
On-Peak Capacity	50,757	51,416	63,001
Net Firm Transfers	1,147	-1,159	-2,165
Anticipated Resources	**51,904**	**50,258**	**60,836**
Existing-Other	0	440	328
Prospective Resources	**51,904**	**50,698**	**61,164**
Planning Reserve Margins	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**21.00**	**30.00**	**42.00**
Prospective Reserve Margin	**21.00**	**31.00**	**43.00**
NERC Reference Margin Level	**15.00**	**15.00**	**15.00**



SERC-E

SERC-N

SERC-SE

SERC is a summer-peaking area that covers all or portions of Alabama, Florida, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, South Carolina, Tennessee, and Virginia. The SERC Assessment Area excludes SERC members that are also members of PJM or MISO. The SERC Assessment Area covers approximately 308,900 square miles and serves a population estimated at 39.4 million. There are 12 Balancing Authorities in the SERC Assessment Area: Alcoa Power Generating, Inc. – Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Constellation Energy Control and Dispatch, LLC (CECD), Duke Energy Carolinas and Duke Energy Progress (Duke), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (Santee Cooper, SCPSA), Southern Company Services, Inc. (Southern), and Tennessee Valley Authority (TVA).

Footprint Changes*: The entities within the SERC-W Assessment Area (BAs: Louisiana Generating, LLC and Entergy) joined MISO on December 19, 2013, and are no longer reported in SERC's Assessment Area. Additionally, East Kentucky Power Cooperative (EKPC) joined PJM on June 1, 2013, and is no longer reported in SERC's Assessment Areas.*

Anticipated and Prospective Reserve Margins remain above NERC's Reference Margin Level of 15 percent for all three SERC Assessment Areas, despite recent changes the subregional[35] footprints.

SERC utilities have incorporated expected future energy efficiency standards into their sales models per data from the Department of Energy's Energy Information Administration and have developed a Statistically Adjusted End-use (SAE) model incorporating the end-use details into econometric methodologies.

The entities within the SERC Assessment Area take into account generation outages, load forecasts, and high loads in various long-term and operations planning activities. Considered factors include improved economy, changes to electricity and natural gas prices, extreme summer heat conditions, and the potential addition of any new customers.

With projected levels of DR and Energy Efficiency/Conservation programs utilized during the summer season, the impact to the assessment areas will be minimal. These programs are counted as a resource or as a load modifier depending on the type of the program offered, as well as different methodologies among SERC utilities.

[35] The terms "subregion" and "assessment area" are used interchangeably in this report.

All SERC utilities continue to offer DR and EE programs, but the changes from the prior summer season are not significant. Some members have expanded their DSM programs to include lighting and appliance programs.

SERC utilities have not identified any issues that could impact generator availability for the upcoming summer. Sutton Units 1–3 and Canadys Units 2 and 3, as well as Branch Unit 2 have recently been retired. Additionally, utilities within SERC have added the Sutton combined-cycle unit and corresponding power purchase plans. Transmission projects such as the upgrade of the Aiken Hampton 115 kV line, construction of a 230 kV line between Winyah and Bucksville, construction of a 230 kV line between Pisgah and Shiloh, and the addition of the Union 500 kV Sub Install #2 500/161 kV Bank have been added to the SERC Assessment Area since the prior summer assessment.

There are few distributed and variable resources in the SERC Assessment Area, and there have been no changes to how expected on-peak capacity values are calculated. Wind and solar resources are analyzed based on historical patterns and are included for on-peak capacity and reserve margins, but at some level of reduced capacity equivalent. For hydro resources, capacity and energy production are based on comprehensive modeling of the competing water management requirements. Considering the relative capacity and operational nature of these resources, expected on-peak capacity values are predictable and consistent.

Past experiences and studies have indicated reactive power limits for certain situations between Philadelphia, Mississippi, and Northeast Tennessee. Operating guides (providing mitigation options) have been put into place to provide voltage support in these areas.

The SERC Near-Term Study Group (SERC-NTSG)[36] coordinates the development of quarterly planning cases for the purposes of near-term reliability assessments. The transactions mentioned previously are built into these planning studies developed for the respective time periods. The coordinated development of these cases ensures consistent treatment among assessment areas. SERC utilities coordinate available transmission interface capability and any planned work with potential capacity transfer impacts with their first-tier neighbors on a regular basis. In addition, SERC entities through SERC-NTSG participate in a summer peak season evaluation. Through this they work closely with the operations area of the respective systems to identify peak season activities that could impact the performance of the bulk power supply facilities, including generation and transmission outages, unavailable capacity, and known or expected power transfers under both normal and contingency conditions. SERC utilities routinely test DR resources to validate their capabilities to identify and address any availability or performance concerns and expect these resources to perform as specified in their contracts. Thus, there are no concerns with the use of DR resources to meet peak demand.

An Operations Reliability Coordination Agreement (ORCA)[37] has been put into place between MISO and other impacted entities[38] in order to mitigate any potential reliability impacts associated with flows in excess of the existing contract limits between the MISO North/Central and MISO South, as well as additional flows modeled by the neighboring entities. As this is the first summer since integration of the Entergy area into MISO, the neighboring BAs do not have operating experience on the effect that the geography of the MISO system will have on the neighboring systems. In addition to limiting the flows, other reliability processes, such as Congestion Management Process (CMP) and TLR, will also be used to mitigate any adverse impacts on system reliability.

[36] SERC Near-Term Study Group (NTSG) Documents.

[37] Operations Reliability Coordination Agreement (ORCA).

[38] Midcontinent Independent System Operator, Inc. ("MISO") and Associated Electric Cooperative Inc. ("AECI"), Louisville Gas and Electric Company ("LG&E"), Kentucky Utilities Company ("KU"), PowerSouth Energy Cooperative ("PowerSouth"), Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company by and through their agent Southern Company Services, Inc. (collectively, "Southern Companies"), the Southwest Power Pool ("SPP") and the Tennessee Valley Authority ("TVA").

SPP

Demand	Megawatts (MW)
Total Internal Demand	**49,614**
Total Demand Response - Available	1,039
Net Internal Demand	**48,575**
Demand Response	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	49
Direct Control Load Management (DCLM) - Available	49
Interruptible Load (IL) - Program Total	942
Interruptible Load (IL) - Available	942
Load as a Capacity Resource (LCR) - Program Total	48
Load as a Capacity Resource (LCR) - Available	48
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	65,863
Net Firm Transfers	933
Anticipated Resources	**66,796**
Existing-Other	2,682
Prospective Resources	**69,478**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**38.00**
Prospective Reserve Margin	**43.00**
NERC Reference Margin Level	**13.60**

Southwest Power Pool (SPP) is a NERC Regional Entity (RE) that encompasses all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas and covers 370,000 square miles. For this NERC report, the SPP Assessment Area also includes the entire state of Nebraska. The SPP Assessment Area reporting footprint includes the Nebraska entities, which are registered with the Midwest Reliability Organization Regional Entity and are also part of the SPP Planning Coordinator. SPP's footprint consists of 17 Balancing Authority Areas, including 48,368 miles of transmission line, 915 generating plants, and 2,378 substations.

***Footprint Changes**: The SPP Assessment Area had three members (CLECO, Lafayette Utilities System, and Louisiana Energy and Power Authority) that joined MISO on December 19, 2013. The SPP RC is coordinating with Entergy, CLECO, Lafayette Utilities System, Louisiana Energy and Power Authority, and MISO for the transition of those entities to the MISO Reliability Coordinator footprint and eventually into the MISO BA Area and the MISO Market. The transition to the MISO RC footprint is scheduled to take place June 1, 2014, and is not expected to impact the 2014 SPP RE summer assessment. The transition of these entities to the MISO BA and Market is expected to occur in December 2014. This transition into the MISO Market and BA is expected to result in significant changes in flows as compared to what has historically been observed and managed using existing congestion management processes. SPP and MISO are evaluating ways to mitigate reliability concerns from these operational changes by improving how flows are accounted for and reviewing congestion management techniques for potential enhancements. These additional coordination activities are expected to continue beyond the summer season to ensure the continued reliable operation of the interconnected transmission system. The map above represents the current SPP footprint for this assessment.*

The transition of CLECO, Lafayette Utilities System, and Louisiana Energy and Power Authority to the MISO footprint resulted in a decreased SPP demand forecast compared to the 2013 summer assessment. The coincident Total Internal Demand forecast for the 2013 summer was 53,853 MW, and the 2014 coincident Total Internal Demand forecast is 49,614 MW. The Anticipated Reserve Margin remains well above the 13.6 percent NERC Reference Margin Level for SPP. While some SPP Assessment Area members are currently looking into enhancing their load forecasting methods, no new enhancements have been added since last year's summer assessment.

SPP Assessment Area planning staff conducts long-term load pocket studies that take into account higher loads than the 50/50 forecast. Considered factors are the loss of the largest generator in the study area with the loss of a transmission tie to the study area.

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. The utilization of DR resources is not vital for meeting the energy and capacity obligations of the SPP Region. SPP Assessment Area members are continuing to expand DR and energy efficiency programs.

SPP does not expect any issues that will impact generator availability but has noted that coal supplies could potentially be reduced/delayed due to railroad congestion. The SPP Assessment Area is continuing to monitor this situation. SPP did not have any new generation come online, and no units were retired since the 2013 summer assessment. No significant generator uprates or derates have been reported for the upcoming summer season.

The SPP Generation Working Group (GWG) has been reviewing section SPP Criteria 12.1.5.3.g, the Accreditation for Renewable Resource (Wind and Solar). The GWG's intention is to ensure the accreditation process meets the Assessment Area needs while not being overly cumbersome to the Resource Owners. The SPP GWG recently approved a change in the accreditation process, which is pending approval. The SPP GWG performed an analysis using operations data from the SPP footprint and sample data from 17 wind resources (varying wind turbine type, geographical location, and age of the facility).

The GWG then applied this data to the existing SPP Criteria 12.1.5.3.g, proposed Criteria language, and compared the results to a more rigorous ELCC (Effective Load Carrying Capability) study. The proposed Criteria language will now include the 3 percent top load hours and will occur 60 percent of the time. The GWG made these proposed changes after extensive discussions and researching the operations data. The new proposed SPP Criteria Section 12.1.5.3.g now covers accreditation for both wind and solar renewable resources, has a less stringent confidence interval, and has been benchmarked against solar operational data for the resources and detailed ELCC Studies.

The SPP Assessment Area has identified several flowgates as being constraints on the transmission system. These constraints can be mitigated by redispatching generation, and no reliability issues are expected. The SPP Assessment Area has identified load pockets that require must-run generation for voltage support. Operating guides have been put into place to provide mitigation.

SPP, along with other Joint Parties in the region and MISO, are currently managing reliability concerns from MISO's recent operational changes under the provisions of the Operations Reliability Coordination Agreement (ORCA). 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 to try to develop, test, and implement 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 their 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 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

Demand	Megawatts (MW)
Total Internal Demand	**68,096**
Total Demand Response - Available	1,917
Net Internal Demand	**66,179**
Demand Response	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	255
Direct Control Load Management (DCLM) - Available	255
Interruptible Load (IL) - Program Total	432
Interruptible Load (IL) - Available	432
Load as a Capacity Resource (LCR) - Program Total	1,231
Load as a Capacity Resource (LCR) - Available	1,231
Projected Resource Categories	Megawatts (MW)
On-Peak Capacity	75,131
Net Firm Transfers	960
Anticipated Resources	**76,091**
Existing-Other	0
Prospective Resources	**76,091**
Planning Reserve Margins	Percent (%)
Anticipated Reserve Margin	**14.98**
Prospective Reserve Margin	**14.98**
NERC Reference Margin Level	**13.75**

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator (ISO) for the ERCOT Interconnection, scheduling power on an electric grid that covers approximately 200,000 square miles. It connects 40,530 miles of transmission lines and 566 generation units and serves about 23 million electricity consumers. The ERCOT Region is an electric interconnection that is located entirely in the state of 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 the Anticipated and Prospective Reserve Margins for TRE-ERCOT are 14.89 percent, above the NERC Reference Margin Level of 13.75 percent, based on the projected time of system peak.[39]

Planned resources include four new power plants (combined 2,112 MW summer rating), which are expected to be in service prior to the forecast summer peak demand, as well as a 30 MW solar plant, Barilla Solar 1, and a 149 nameplate MW (13 MW peak capacity) wind plant, Goldthwaite Wind 1. An extreme system peak that occurs prior to completion of the four new gas units could result in Energy Emergency Alerts (EEAs). In response to EEAs, ERCOT would perform the following actions depending on the severity of the EEA situation: 1) dispatch uncommitted generators, 2) deploy loads serving as reserves (Load Resources), 3) utilize emergency capacity available through its DC ties, 4) arrange for block transfers of load to neighboring grids, and 5) deploy Interruptible Load (IL) (Emergency Response Service). As a last resort, ERCOT would instruct its grid operators to shed load on a rotating basis. At this time there are no impending environmental or drought restrictions for the upcoming summer that would reduce ERCOT generating capability.

The ERCOT peak demand forecast (Total Internal Demand) for summer 2014 is 68,096 MW and is expected to occur in early August. The forecast is 1.3 percent higher than last summer's actual peak demand of 67,245 MW but is 1.8 percent lower than the 2014 forecast used for the *2013 Long-Term Reliability Assessment*.[40] This decrease is due to changes to ERCOT's load forecast methodology that better capture the changing relationship between energy and economic growth and, specifically, the impacts of energy efficiency and price-driven DR.[41] 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 (residential, commercial, and industrial) by using historical premise, population, and nonfarm employment data, as opposed to relying on just nonfarm employment as the economic driver.

For summer 2014 ERCOT estimates that it will have 1,231 MW of Load Resources (LRs) providing ancillary services that are contractually committed to ERCOT during summer peak hours and are categorized as a load-modifying capacity resource. ERCOT also has Emergency Resource Service (ERS), a 10- and 30-minute DR and distributed generation service designed to be deployed in the late stages of a grid emergency, prior to shedding involuntary firm load. The 30-minute product and distributed generation participation are new program enhancements approved last year. ERS is forecast to provide 432 MW

[39] The Anticipated Reserve Margin of 14.89 percent is based on the time of the forecasted system peak.
[40] NERC: 2013 Long-Term Reliability Assessment.
[41] ERCOT uses a cost allocation method called 4CP to recover transmission costs for the ERCOT grid from large customers (i.e., loads greater than 700 kW of peak demand in retail choice areas, municipal utilities, and electric cooperatives). The method allocates transmission costs based on averaging the measured demand during the ERCOT coincident peak hours for June, July, August, and September. ERCOT market protocols require projects to be in service by June 1 to be included as available capacity in its summer resource adequacy assessments.

for the 2014 summer season. Of note is that ERCOT has opened its real-time energy market to loads that can respond to real-time base point instructions. Finally, ERCOT reports the DR peak load impacts of programs managed by several Transmission Service Providers (TSPs). These TSPs have individual contractual programs with loads that can respond to instructions to reduce total energy usage. These programs are expected to attract approximately 255 MW of additional DR capacity this summer. ERCOT's load forecasting methodology does not allow for separate energy efficiency impact estimation.

With respect to transmission planning, all the Competitive Renewable Energy Zone (CREZ) projects were placed into service by January 2014. The latest Regional Transmission Plan[42] for ERCOT identified a list of projected 2014 reliability constraints. The associated transmission projects to address these constraints will not be completed before this summer. Most of these constraints are located in the Permian Basin and Eagle Ford Shale oil and natural gas exploration and production areas, where demand has increased faster than previously anticipated. Multiple transmission upgrades scheduled to be completed in the West Texas area prior to this summer are expected to reduce the congestion and improve the reliability in the Permian Basin area.

Some of the projected 2014 reliability constraints are planned to be addressed with operational solutions that may include temporarily reconfiguring the system, running less-efficient generation, or in some cases establishing a procedure to shed load in the event that a contingency occurs.

A stability assessment indicated that an N-1-1 contingency (loss of two 345 kV circuits) in southern Texas can potentially depress the voltage below 0.8 per unit if it occurred during peak load conditions. An existing UVLS scheme with less than 300 MW of load in the area can improve the voltage recovery to prevent a cascading event.

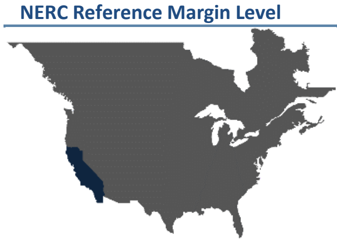
No significant transmission equipment (i.e., SVC, FACTS controllers, HVdc) or UVLS schemes are expected to be in place before the upcoming summer. ERCOT has implemented two new SPSs in the West Texas area. ERCOT performs annual reviews of SPSs to determine if any can be retired and has identified and retired four such SPSs during its latest review. Additionally, two SPSs were modified due to new stations being built in the ERCOT system: Stanton SPS and Barney Davis SPS.

With respect to operational procedures for integrating variable renewable generation, no new procedures have been developed in time for the summer season. However, ERCOT is working with its wind forecaster to improve how the existing ERCOT Large Ramp Alert System (ELRAS) notifies operations staff of any predicted large ramps and is implementing a solar forecasting procedure.

[42] ERCOT Regional Transmission Plan, released in October 2013.

WECC

	CAMX	NWPP	RMRG	SRSG
Demand	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand	**52,353**	**66,424**	**11,943**	**22,706**
Total Demand Response - Available	1,955	1,073	535	388
Net Internal Demand	**50,398**	**65,351**	**11,408**	**22,318**
Demand Response	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Direct Control Load Management (DCLM) - Program Total	463	803	0	60
Direct Control Load Management (DCLM) - Available	437	657	0	60
Interruptible Load (IL) - Program Total	987	416	535	328
Interruptible Load (IL) - Available	984	416	535	328
Load as a Capacity Resource (LCR) - Program Total	534	0	0	0
Load as a Capacity Resource (LCR) - Available	534	0	0	0
Projected Resource Categories	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
On-Peak Capacity	63,554	81,870	15,412	33,320
Net Firm Transfers	2,362	3,727	-276	-5,813
Anticipated Resources	**65,916**	**85,597**	**15,136**	**27,507**
Existing-Other	0	0	0	0
Prospective Resources	**65,916**	**85,597**	**15,136**	**27,507**
Planning Reserve Margins	Percent (%)	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**31.00**	**31.00**	**32.68**	**23.00**
Prospective Reserve Margin	**31.00**	**31.00**	**32.68**	**23.00**
NERC Reference Margin Level	**15.00**	**14.80**	**14.45**	**13.90**



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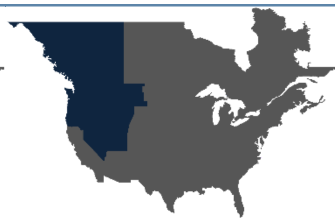

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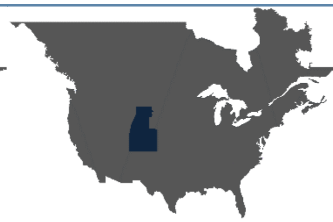
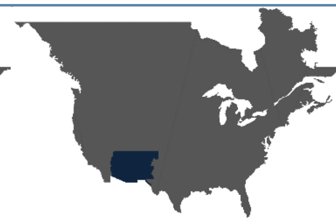


RMRG



SRSG

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 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 81 million people, it is the largest and most diverse of the Regional Entities. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 Western states in between.

***Footprint Changes**: 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 (Nevada Power), within the NWPP subregion. The Nevada Power and Sierra Pacific Power were removed from the SRSG and NWPP, respectively.*

For the summer assessment, the WECC Assessment Area is divided into four subregions:[43] Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CA/MX).[44] 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 Anticipated and Prospective Reserve Margins for the four WECC subregions, and all zones within the subregions, are expected to exceed the NERC Reference Margin Level[45] for the upcoming summer season. The NERC Reference Margin Level is calculated using a building block methodology[46] created by WECC's 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, due largely to the construction of power plants in anticipation of a load growth that was interrupted by the economic recession. It should be noted that abnormal weather conditions, either warmer or colder than average, would result in reserve margins different from those reported in this

[43] The terms "subregion" and "assessment area" are used interchangeably in this report.
[44] Northwest Power Pool, Rocky Mountain Reserve Group, Southwest Reserve Sharing Group.
[45] The NERC Reference Margin Level and all reserve margins are for planning purposes. Firm load would not be disrupted to maintain these margins. Rather, the margins are reference points that indicate areas that have lower reserves and tighter margins. The tighter margins are not forecasts of resource shortages. However, areas with tighter margins have a higher possibility, although not likelihood, of resource shortages associated with extreme events such as record-setting temperature deviations.
[46] Elements of the Building Block Target are detailed in the NERC: Seasonal Assessment – Methods and Assumptions report.

assessment. In addition, severe adverse weather conditions or unexpected equipment failure may result in localized power supply or delivery limitations.

The aggregate WECC 2014 summer total coincident peak demand is forecast to be 153,426 MW and is projected to occur in July. The forecast is 0.8 percent above last summer's actual peak demand of 152,259 MW, which occurred with above-normal temperatures and improving economic conditions in portions of the region. The 2014 summer coincident peak demand forecast is 0.1 percent above last summer's forecast coincident peak demand of 153,248 MW, reflecting increases in energy efficiency as well as continued slow demand growth associated with the economic downturn. All margin results assume demands associated with normal weather conditions.

In 2013, more than 4,700 MW of thermal generation was retired, including 2,250 MW of nuclear generation, 909 MW of coal-fired generation, and 1,588 MW of natural gas-fired generation. However, those retirements were replaced by more than 9,500 MW of generation additions, including 1,206 MW of wind generation, 3,162 MW of natural gas-fired generation, and 3,990 MW of solar generation. 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. Southern California, in CA/MX, is expected to have adequate reserves for the upcoming summer season, but this area could experience supply issues due to the retirement of the 2,250 MW San Onofre Nuclear Generating Station and the expected reduced hydro generation associated with the drought conditions in California. However, CAISO reports that the retired capacity and the expected reduced hydro generation in Southern California, which has been lessened with improved precipitation, has been offset by 1,840 MW of natural gas-fired generation and 1,770 MW of solar generation installed during 2013.

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 LSEs and BAs within WECC, and none of these entities have reported any extreme weather or drought-related issues. 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.

In addition to the Nevada ON Line project referenced above, the Montana Alberta Tie Line (MATL), a 300 MW, 230 kV transmission line between northern Montana and southern Alberta, entered service in June 2013. Although this line does not increase import capability into Alberta, due to internal constraints that limit imports to 800 MW, it does give Alberta increased operational flexibility for energy imports.

On September 8, 2011, customers in Baja California, Mexico; southern California's Imperial, Orange and San Diego counties; and a small portion of southwestern Arizona experienced a major power outage. Several entities within WECC have taken, or are in the process of taking, actions to prevent similar disturbances in the future. These actions include the implementation of additional real-time data exchange and coordination with additional entities in the Southwest. These processes will help facilitate a more detailed monitoring capability of neighboring systems in their energy management systems and real-time contingency analysis applications. In addition, the WECC Reliability Coordinator[47] has coordinated the development of an interim monitoring procedure of the San Diego and Imperial Valley areas with specific actions that will be taken for overload conditions. In response to the June 5, 2012, letter sent by NERC to Regional Entity executives,[48] WECC has established an update page on the WECC website that reports on the status of "Key Categories of Findings and Recommendations" highlighted in the NERC letter. This page is updated monthly with the latest information concerning activities related to these recommendations. These updates are found on the September 8, 2011, Outage Event Response page on the WECC website.[49]

[47] As of February 12, 2014, the WECC Reliability Coordinator—as part of the WECC bifurcation effort—became Peak Reliability, a wholly independent company.

[48] NERC: Follow-Up Actions for September 8, 2011 Southwestern Blackout.

[49] http://www.wecc.biz/About/sept8/Pages/default.aspx

Appendix I: Reliability Assessment Subcommittee Roster

Reliability Assessment Subcommittee Roster

Name	Position	Represents	Organization
Layne Brown	Chair	WECC*	WECC
Amir Najafzadeh	Vice Chair	SERC*	SERC
Richard Becker	Member	FRCC*	FRCC
Philip A. Fedora	Member	NPCC*	NPCC
Paul D. Kure	Member	RFC*	RFC
Paul Walter	Member	MRO*	ATC System Planning LLC
Lewis De La Rosa	Member	TRE*	TRE
Alan C. Wahlstrom	Member	SPP RE*	SPP RE
Brad Woods	Member	TRE	TRE
Vince Ordax	Member	FRCC	FRCC
John G Mosier Jr.	Member	NPCC	NPCC
John Lawhorn	Member	MRO	MISO
Salva R. Andiappan	Member	MRO	MRO
Digaunto Chatterjee	Member	MRO	MISO
Peter Wong	Member	NPCC	ISO-NE
William B. Kunkel	Member	MRO	MRO
Mark J. Kuras	Member	RFC	PJM
Esam A.F. Khadr	Member	RFC	PSE&G
Mohammed Ahmed	Member	RFC	AEP
Barbara A. Doland	Member	SERC	SERC
Hubert C. Young	Member	SERC	SCE&G
K. R. (Chuck) Chakravarthi	Member	SERC	Southern Company Services, Inc.
Ben Crisp	Member	SERC	SERC
Gary S. Brinkworth	Member	SERC	TVA
Chris Haley	Member	SPP RE	SPP Inc.
Pete Warnken	Member	TRE	ERCOT
James Leigh-Kendall	Member	WECC	SMUD
Maria Haney	Observer	SERC	SERC
Tina G. Ko	Observer	WECC	BPA
David Burnham	Observer	FERC	FERC
Alan Phung	Observer	FERC	FERC

*Regional Entity Representative

Appendix II: Seasonal Reliability Concepts

Seasonal Reliability Concepts

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

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